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July 26, 2019

Lora W. Johnson, CMC, LMMC
Clerk of Council
Room 1E09, City Hall
1300 Perdido Street
New Orleans, LA 70112

Re: *Revised 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*
Council Docket No. UD-18-07

Dear Ms. Johnson:

On behalf of Entergy New Orleans, LLC ("ENO" or the Company), please find enclosed for your further handling an original and three copies of the Public Version of the Post-Hearing Brief of Entergy New Orleans, LLC, which I would appreciate your filing into the record of this proceeding. Please file an original and two copies into the record in the above referenced matter, and return a date-stamped copy to our courier.

Please note that certain portions of the Post-Hearing Brief of Entergy New Orleans, LLC contain Highly Sensitive Protected Materials and are being provided this date as a Confidential Version to appropriate reviewing representatives generally in accordance with the terms of the Council's Official Protective Order set forth in Resolution R-07-432.

All service copies are being provided by electronic means. No hard copies will be sent. Should you have difficulty accessing the electronic files, please contact the undersigned. Should you otherwise have any questions regarding the above/attached, please do not hesitate to contact me.

With kindest regards, I am

Sincerely,

Alyssa Maurice-Anderson

Alyssa Maurice-Anderson

AMA/amb
Enclosures
cc: Official Service List via email

RECEIVED
JUL 26 2019
BY: AMB

BEFORE THE

COUNCIL OF THE CITY OF NEW ORLEANS

APPLICATION OF	)	
ENTERGY NEW ORLEANS, LLC,	)	
FOR A CHANGE IN ELECTRIC AND	)	Docket No. UD-18-07
GAS RATES PURSUANT TO COUNCIL	)	
RESOLUTIONS R-15-194 AND R-17-504	)	
AND FOR RELATED RELIEF	)	

POST-HEARING BRIEF OF ENTERGY NEW ORLEANS, LLC

PUBLIC VERSION

July 26, 2019

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POST-HEARING BRIEF OF ENTERGY NEW ORLEANS, LLC

Entergy New Orleans, LLC ("ENO" or the "Company"), through its undersigned counsel, respectfully submits this Post-Hearing Brief in support of its request that the Council of the City of New Orleans ("Council") grant the relief sought in its Revised 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 and supporting testimony and work papers ("Rate Case Filing") submitted to the Council on September 21, 2018, finding, among other things, ENO's proposed electric and gas rates to be just and reasonable.

I. INTRODUCTION

In this proceeding, for the first time, the Council will establish a combined electric rate structure for all residents of the City of New Orleans, both those residing on the east bank of the Mississippi River, (sometimes referred to as "Legacy ENO Customers") and those residing on the west bank of the river in Algiers (sometimes referred to as "Algiers Customers"). This new combined rate structure will enable the Company to provide its customers throughout the City reliable, twenty-first century service that incorporates the industry's technological advances and that will continue to meet customers' evolving expectations and the Council's policy objectives. ENO seeks the Council's regulatory support and oversight for ENO's ongoing and future efforts that are designed to complete ENO's transition into a true twenty-first century utility.

Technology is driving rapid and transformational changes in how everyone lives and works; it affects virtually every aspect of our culture, society, and everyday lives. Technological advancements also are continuing to change how power is generated, delivered and consumed. Distributed energy resources ("DERs"), including those sourced from renewables, are continuing to become more economic, and demand-side management ("DSM") activities, when properly administered, can be a valuable resource in managing the portfolio of resources that meets customers' energy needs and the utility's goals for an environmentally sustainable fleet for the communities it serves. Similarly, as DERs become more economic, these advancements are changing customers' expectations about the kinds and quality of services they expect from their utility. Utilities are observing increased customer adoption of DERs like rooftop solar photovoltaics ("PV"), smart thermostats, battery energy storage, and electric vehicles ("EVs"), with the expectation that the grid will accommodate these choices. Additionally, utilities are observing increased customer expectations regarding access to real-time information requiring enhanced reliability for uninterrupted connectivity, for convenience and flexibility.

ENO recognizes the effects these changes are having on its business and the opportunities and challenges that are present and are driving the need to transform ENO's operational capabilities to meet and exceed its customers' evolving expectations. As such, ENO is:

- Planning for and beginning to execute a comprehensive grid modernization strategy that will create a grid capable of meeting customers' changing needs and expectations, while delivering enhanced reliability and functional capabilities (*e.g.*, better integration of DERs and EVs) to all customers;
- Seeking to integrate DSM into its core business so that DSM can be a viable and sustainable resource for meeting customers' energy needs;
- Seeking to expand the amount of renewable resources in its supply portfolio through a commitment to add up to 100 MW of such resources; and
- Engaging customers to a greater extent in order to learn more about what they want from an array of options in terms of advanced functionality, greater convenience, stability, and control over managing their utility service and over the environmental impact of their energy usage.

As of the filing of this case, ENO expects to invest approximately [redacted] in its infrastructure during the period 2018-2022. Such investments include the New Orleans Power Station ("NOPS") and Advanced Metering Infrastructure ("AMI"), which the Council has concluded are in the public interest.

[redacted] ENO invested over the previous five years, and ENO's credit ratings are not strong and reflect its considerable risk. The Company's issuer rating from Moody's Investors Service ("Moody's") is one notch below investment grade.[1] The Company's issuer rating from Standard & Poor's Financial Services LLC ("S&P") is two notches above investment grade. S&P, however, expressly states that the rating is due to ENO's being part of the Entergy Corporation group and that its stand-alone issuer rating would be the lowest investment grade rating. Only two other U.S. investor-owned electric utilities recently have been rated below investment grade – one in bankruptcy and the other abandoned construction of a nuclear plant. The latter utility, SCANA Corporation ("SCANA"), has the same split credit rating ENO has, with a below investment grade rating from Moody's and an above investment grade rating from S&P.

Nevertheless, the Company has a plan that allows it to make substantial investments to modernize ENO's service to customers, while maintaining the Company's financial condition and affordable rates. Successfully executing that plan depends on the Council's taking constructive steps to maintain ENO's cash flow, its financial condition and the constructive regulatory environment in which ENO has operated since its emergence from bankruptcy in 2007 following Hurricane Katrina.

The determination of the authorized Return on Equity ("ROE") in this proceeding and rates set at a level reasonably designed to achieve it will be the cornerstone for ENO's financial stability and flexibility as the Company undertakes a large, aggressive capital program to

1 Major utility investors such as insurance companies and pension funds operate under legal restrictions that severely limit their ability to invest in below investment-grade debt instruments.

transform the delivery of electric service with new technology consistent with the expectations and policies established by this Council. If the cornerstone is strong, and there is adequate foundation, such as mechanisms to provide timely cost recovery of prudently incurred costs, then that transformation is likely to meet stakeholders' expectations. If that cornerstone is weak, then that transformation will be hindered and may not meet cost and pace expectations.

Neither a formula rate plan with forward-looking adjustments (as proposed by the Advisors), nor riders (such as those proposed by the Company) will remedy the authorization of an unreasonably low ROE because they are mechanisms designed to reduce regulatory lag. Reducing regulatory lag is necessary to provide ENO with a reasonable opportunity to earn a reasonable return, as required by *Bluefield*[2] and *Hope*.[3] If the allowed ROE is set unreasonably low at the onset, reducing regulatory lag alone will be insufficient to maintain ENO's financial condition. Thus, the Council should approach this issue with an eye to the future of the City of New Orleans and its residents and ensure a healthy utility by setting just and reasonable rates that include an appropriate ROE, while also mitigating regulatory lag to allow ENO a reasonable opportunity to earn that allowed return.

The ROE decision is not solely a decision about financial concepts and comparisons, although they are important. The decision on setting a ROE is about the level of financial resources that the Council is providing ENO to meet the Council's objectives to transform ENO's operations to deliver new and better service to customers. Those resources are

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2 Bluefield Waterworks & Improvement Co. v. Public Service Commission of West Virginia, 262 U. S. 679 (1923) ("Bluefield").

3 Federal Power Commission v. Hope Natural Gas Co., 320 U.S. 591 (1944) ("Hope").

fundamental to the financial health of ENO and the Company's ability to execute on the plan that it has developed to meet the Council's objectives. That is why the ROE decision is the financial cornerstone. The ROE determines the equity available for ENO to reinvest in new infrastructure to improve and maintain the quality of service provided to customers. A utility must invest equity into improvements needed to serve customers in order to prevent the utility's financial condition from deteriorating and becoming riskier (*e.g.*, if a utility were to fund new investments with debt only, it could become overly debt-laden). As a result, the ROE decision can also affect debt costs. Thus, an unreasonably low ROE would constrain ENO's ability to invest in its facilities in a timely manner consistent with the Council's and customers' expectations while maintaining ENO's financial condition over the long-term.

Moreover, credit rating agencies consider the regulatory environment in which each company operates as a significant factor in setting credit ratings, and those credit ratings directly affect the cost of capital needed for investments that benefit customers and drive overall customer rates.[4] The Council's allowed ROE can be a bellwether of the state of the regulatory environment, and the setting of a low ROE can be a factor in adverse credit ratings actions. Thus, a constructive ROE determination will help ENO meet the Council's objectives to deliver timely to customers the benefits of the AMI, Grid Modernization, and Smart Cities investments, as well as other benefits, at the lowest reasonable cost.

In this proceeding, ENO has recommended an ROE of 10.75%, which would be reduced to 10.50% for electric operations through an incentive mechanism intended to encourage

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[4] Phillips, Charles F., Jr., *The Regulation of Public Utilities*, at 250 (Public Utilities Reports, Inc. 3rd ed. 1993).

improvement in reliability performance. This recommendation is based on multiple analyses consistent with the important developments regarding the determination of ROE and is consistent with a constructive regulatory environment. In contrast, the other parties' ROE recommendations and the proper consideration of qualitative factors, especially the Advisors' recommendation of 8.93%, are unreasonably low and are not consistent with a constructive regulatory environment of a financially sound utility. The other parties' recommendations are either heavily or solely dependent on a single analysis that produces ROE estimates that are unreliably low. In fact, the Advisors' recommendation of 8.93% is below virtually every other ROE authorized for a vertically integrated utility since at least 1980. As Company witness Mr. Joshua Thomas observed, it is irreconcilable for ENO to be one of a few utilities with a non-investment grade credit rating but have the lowest ROE in the country.[5] SCANA, which has similar credit ratings as ENO, has an authorized ROE of 10.75%.

Furthermore, the Council should consider all proposed mechanisms to address regulatory lag. Without the certainty of mechanism(s) that provide a reasonable opportunity for timely recovery of Council-approved, prudently-incurred costs, all stakeholders could be harmed. As explained more fully below, if the Council were not to approve ratemaking mechanisms that address regulatory lag, ENO would likely have to file "pancaked" rate cases to maintain reasonable cash flows, which would significantly increase regulatory costs and ultimately would frustrate the Company's and the Council's goals and drive up regulatory costs.

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5 Tr. (Thomas) 06/20/19 at 156 ("The Advisors' recommendation would recommend the lowest ROE in the country. Mr. Hevert noted that ENO has one of the few non-investment grade credit ratings in the entire industry. I don't know how one could reconcile those two things.").

II. THE RATES RESULTING FROM THIS PROCEEDING MUST BE JUST AND REASONABLE

It is a bedrock ratemaking principle in Louisiana that a utility is entitled to have its rates set at a level designed to give the utility a reasonable opportunity to recover all of its prudently incurred costs.[6] An electric utility recovers its prudently incurred costs through a rate structure that typically has at least two major components: (1) the utility's base rates, and (2) a fuel adjustment charge ("FAC").[7] The utility's regulator determines which types of costs will be recovered through each component of the utility's rate structure, but, typically, a utility recovers fuel, purchased power, and other variable costs of operation through its fuel adjustment clause, while other costs are recovered through base rates.[8] Generally, a regulator sets a utility's base rates in a proceeding known as a base rate case.[9]

The regulator's process for determining whether a utility's existing base rates are producing sufficient revenues is well-established.[10] First, financial data from a twelve month

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[6] *South Cent. Bell Tel. Co. v. Louisiana Pub. Serv. Comm'n*, 594 So. 2d 357, 366 (La. 1992) ("Under that principle, South Central Bell is entitled to be compensated for all prudent investments at their actual cost when made (their 'historical' cost) irrespective of whether individual investments are deemed necessary or beneficial in hindsight; and the utility is entitled to the presumption that the investments were prudent, unless the contrary is shown. . . . Because, as Justice Brandeis observed, there is no essential difference between a capital charge and an operating expense, as a cost of supplying the service that must be met from the revenue requirement, the Commission's failure to apply the rule equally to both types of costs or investments was arbitrary and unjustified.") (citations omitted).

[7] *Daily Advertiser v. Trans-La*, 612 So. 2d 7, 23 (La. 1993) ("Such [automatic adjustment] clauses are generally adopted in a rate proceeding as an integral part of a utility's overall rate structure."). A gas utility typically recovers its prudently incurred costs through similar components, *i.e.*, base rates and a purchased gas adjustment ("PGA") clause.

[8] *Gulf States Utils. Co. v. Louisiana Pub. Serv. Comm'n*, No. 92-1185 (La. 3/17/94); 633 So. 2d 1258, 1262 n.12.

[9] As ratemaking has evolved, regulators have used additional ratemaking tools to adjust rates and a utility's rate structure to provide sufficient revenue.

[10] South Cent. Bell Tel. Co. v. Louisiana Pub. Serv. Comm'n, 352 So. 2d 964, 967 (La. 1977).

period referred to as the "test year," typically the most recent annual period from which actual operating data are available,[11] is gathered and used to calculate four variables: (1) revenues, (2) operating expenses, (3) rate base, and (4) fair rate of return.[12] The first three variables may be adjusted for known and measurable changes that will occur within a reasonable time after the end of the test year.[13] The utility's operating expenses and its investment in rate base are scrutinized to ascertain whether costs were prudently incurred. The fair rate of return is calculated by determining the cost of each of the several classes of capital used by the utility (debt, preferred stock, and common equity) and by determining the weighted average cost of capital ("WACC"), calculated on the basis of the relative proportions of the several classes of capital in the utility's total capitalization.[14] The figures computed for test year operating expenses, test year rate base, and the fair rate of return are then plugged into the ratemaking formula to determine the utility's revenue requirement, which is the sum of the utility's operating expenses and the fair return on its investment.[15] If the test year revenues exceed the utility's

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11 The standard filing requirements set forth in the Code of the City of New Orleans, Louisiana, (1995), ("City Code") Division 3, Section 158-131, et seq., direct the submission of revenue requirements and other relevant data for the twelve months immediately following the historical test year, Period II, or forecasted test year. Either the historical or forecasted test year may serve as the basis for setting ENO's rates.

12 *Central Louisiana Elec. Co. v. Louisiana Pub. Serv. Comm'n*, 508 So.2d 1361, 1367 (La. 1987); see South Cent. Bell Tel. Co., 352 So. 2d at 967.

13 *Central Louisiana Elec. Co.*, 508 So. 2d at 1369. See also §154-41. (*Proforma adjustments* means adjustments made to Period I and Period II actual figures for known and measurable changes.)

14 South Cent. Bell Tel. Co. v. Louisiana Pub. Serv. Comm'n, 594 So. 2d 357, 362 (La. 1992).

15 The ratemaking formula is as follows:

$$R = E + r(RB)$$

Where,

R = Revenue Requirement;

E = Operating Expenses;

revenue requirement, then a rate reduction is appropriate; if, however, the utility's revenue requirement exceeds test year revenues, a rate increase is justified.[16]

The cost of common equity, that is, the required ROE, is not subject to empirical verification, like the cost of debt, because it reflects what the equity investor perceives as the risk of the investment. Accordingly, parties to a rate case retain experts to estimate the level of risk accompanying an equity investment in the utility and the corresponding ROE; generally, the riskier the investment, the higher the ROE should be.[17] The legal standards guiding these experts are well-settled and described in two commonly cited U.S. Supreme Court decisions, which the Council has also recognized. In *Bluefield*, the Court wrote:

> A public utility is entitled to such rates as will permit it to earn a return on the value of the property which it employs for the convenience of the public equal to that generally being made at the same time and in the same general part of the country on investments in other business undertakings which are attended by corresponding risks and uncertainties. . . . [18]

Subsequently, in *Hope*, the Court wrote:

> The rate-making process under the [Natural Gas] Act, i.e., the fixing of "just and reasonable" rates, involves a balancing of the investor and the consumer interests. . . . By that standard the return to the equity owner should be commensurate with returns on investments in other enterprises having corresponding risks. That return, moreover, should be sufficient to assure confidence in the financial integrity of the enterprise, so as to maintain its credit and to attract capital.[19]

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r = Fair Rate of Return; and

RB = Rate Base.

See, *e.g.*, Charles F. Phillips, *The Regulation of Public Utilities*, *at* 176-80 (1993).

[16] See generally *South Cent. Bell Tel. Co.*, 352 So. 2d at 968.

[17] Louisiana Power & Light Co. v. Louisiana Pub. Serv. Comm'n, 523 So. 2d 850, 858 (La. 1988).

[18] *Bluefield*, 262 U.S. 679, 692-693 (1923).

[19] *Hope*, 320 U.S. 591, 603 (1944)(citations omitted).

The Council has acknowledged these decisions and its duty to set an ROE that comports with standards set forth therein, when setting just and reasonable rates for ENO:

> [It is] the Council's obligation to authorize rates for ENO that are just and reasonable and to maintain ENO's financial health so that it can attract necessary capital to do business. The US. Supreme Court cases [*Bluefield*] and [*Hope*] require utility regulators to authorize a rate of return on common equity that will (1) fairly compensate capital invested in the utility; (2) enable the utility to offer a return adequate to attract new capital on reasonable terms; and (3) maintain the utility's financial health.[20]

Consistent with this process, a base rate case in Louisiana typically commences with the utility's filing of test year financial data, which may be very detailed and voluminous and may be accompanied by written testimony, and the utility's proposed base rates. After the filing, a period of discovery commences in which the Staff/Advisors and other parties that may have intervened in the rate case can examine the utility's financial data in more detail, question utility representatives about the financial data, and determine the accuracy of the financial data and whether any of the financial data includes costs that may have resulted from the utility's imprudence. Upon the conclusion of this initial discovery period, the Staff (including its consultants) and other parties typically file written testimony raising their objections to the utility's filing. This objecting testimony and subsequent rounds of objecting testimony, if permitted, establish the universe of issues that the utility and the other parties will litigate before the regulator during the course of the base rate case. If a cost is not challenged by any other party in its testimony, then that cost will be included in the ratemaking formula discussed above

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20 Resolution R-09-136, Council Docket No. UD-08-03 (April 10, 2009) at 10.

because a utility's costs are presumed to be prudent and recoverable.[21]

III. RELEVANT BACKGROUND

ENO's base rates for its Legacy ENO customers were last established by the Council in Docket No. UD-08-03. At that time, the Council also approved a Formula Rate Plan ("FRP") for a three-year period, the last Test Year for which was 2011. ENO's current base rates were established as a result of that 2011 Test Year proceeding in Resolution R-13-270 approved by the Council on August 8, 2013. Subsequently, the Council authorized several adjustments to ENO's rates to recognize several transactions through riders, including 1) ENO's participation in a Power Purchase Agreement with Entergy Louisiana, LLC ("ELL") to receive output from the Ninemile 6 Combined Cycle Gas Turbine facility;[22] 2) ENO's acquisition of ELL's electric operations and related assets and liabilities in the Fifteenth Ward of the City of New Orleans (Algiers), located on the west bank of the Mississippi River (the "Algiers Transaction")[23] and 3) ENO's purchase of Union Power Block 1.[24]

In connection with the approval of the Algiers Transaction, Resolution R-15-194 maintained a four-step change in base rates for Algiers Customers[25] designed to bring customer rates more in line with the 2012 test year cost of service on which rates were based. The last of

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21 South Cent. Bell Tel. Co. v. Louisiana Pub. Serv. Comm'n, 594 So. 2d 357, 366 (La. 1992); Gulf States Utils. Co. v. Louisiana Pub. Serv. Comm'n, 578 So. 2d 71 (La. 1991).

22 Council Resolution R-12-29 (Feb 2, 2012) Agreement in Principle, p. 3. See also, Council Resolution R-14-281 (Jul 10, 2014).

23 Resolution R-15-194 (May 14, 2015).

24 Resolution R-15-542 (Nov. 19, 2015).

25 The four-step change in rates was authorized by Council Resolution R-14-278 dated July 10, 2014, which approved an Agreement in Principle ("2014 Algiers AIP") that established a rate path for Algiers Customers. That rate path included successive annual base rate increases followed by implementation of an annual formula rate plan FRP.

the four-step changes was implemented in July 2017. Resolution R-15-194 also authorized several geographically-specific riders, *i.e.*, the Fuel Adjustment Clause, the Midcontinent Independent System Operator, Inc. ("MISO") Cost Recovery Rider, the Ninemile 6 Non-fuel Cost Recovery Rider and the city franchise fee, to be maintained on a geographic-specific basis, such that these mechanisms preserved the ELL rate structure on which Algiers Customers' rates were based until rates could be combined in the next base rate case. That same resolution, Resolution R-15-194, also required that ENO file its next base rate proceeding ("the Combined Rate Case") no sooner than the first quarter 2018, based on a 12-month historical test year (Period I) ending December 31, 2017.[26]

In addition, Council Resolution R-15-542, approved an agreement in principle providing, among other things, that: 1) ENO's acquisition of Union Power Block 1 was in the public interest; and 2) that the unit's non-fuel revenue requirement would be recovered through the Purchased Power and Capacity Acquisition Cost Recovery Rider until the implementation of new rates from the Combined Rate Case. Also, in advance of the filing of the Combined Rate Case, without any proceedings beforehand, the Council issued Resolution R-17-504, dated September 28, 2017, which further directed ENO's filing for the proceeding, including, among others, the following:

- That ENO should make the filing no later than July 31, 2018;
- That the Company should have as its objective the presentation of a single set of rates and tariffs for all customers in New Orleans, including a single MISO rider, unless significant rate shock could occur to single or multiple classes of customers;

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[26] Resolution R-15-194 (May 14, 2015), Agreement in Principle, p. 7.

- That the Company should make a Period II filing reflecting the 12-months ending December 31, 2018;

- That the Company include all of ENO's revenues and costs subject to ratemaking treatment, including an allocation of total costs among the rate classes (*i.e.*, matching the allocation of total costs to the total revenues of each ratepayer class) as part of each fully allocated electric and gas cost of service study (i.e., Period I, Period II, and any out of period adjustments);

- That ENO should provide a complete set of FRP implementation documents, to the extent ENO seeks implementation of an FRP;

- That the Company should provide ratepayer funding requirements and a funding mechanism for Council Energy Smart initiatives; and

- That the Company should provide other information listed in the resolution and appropriate to comprise a filing sufficient to comply with all Council requirements, fully apprise the Council of the nature of ENO's request, and allow the Council to thoroughly and efficiently review the filing.

Also in anticipation of the Combined Rate Case, the Council approved three additional resolutions with implications for the Combined Rate Case. The first resolution, Resolution R-16-103, was the culmination of a multi-year effort by many stakeholders in Docket UD-08-02 to reach agreement upon a decoupling mechanism to be applied to ENO's rates. Resolution R-16-103 required ENO to include in its next base rate case filing a proposal for a full decoupling mechanism meeting certain criteria, including, but not limited to a three-year pilot program to begin with rate changes arising from the Combined Rate Case.[27]

The second resolution directed ENO to develop a voluntary green pricing option to support the development of renewable resources. Specifically, in Resolution R-18-97 dated April 5, 2018, the Council ordered that:

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27 Resolution R-16-103 (Apr. 7, 2016), p. 21.

> In the Combined Rate Case to be filed this year, ENO shall propose for the Council's consideration a green pricing proposal under which customers may voluntarily choose to have some or all of the electricity supplied by renewable resources. The rider proposed by ENO should contain multiple options for customers, at least one of which should allow customers to choose to supply 100% of their electricity needs through renewable resources. The green pricing proposal should reflect to a reasonable extent ENO's incremental net cost to provide this option to customers. [28]

The third resolution issued by the Council that had direct bearing on the filing of the Combined Rate Case was Resolution R-18-227. In connection with an inquiry initiated by the Council in order to preserve benefits related to the Tax Cuts and Jobs Act of 2017 ("Tax Cut Act"), which became effective as of January 1, 2018, the Company and the Advisors entered into an Agreement in Principle ("Tax Cut Act AIP") that was approved by the Council via Resolution R-18-227. The Tax Cuts Act AIP provided for, among other things, treatment of the benefits of the Tax Cuts Act (*i.e.*, adjustments to current tax expense reflected in rates, Protected excess accumulated deferred income tax ("ADIT") and Unprotected ADIT), with the final ratemaking treatment of the amortization of the Protected ADIT balance to be determined as a result of the instant proceeding.

As explained in detail below, ENO has submitted filings in the instant docket in accordance with the Council's directives and requesting rates and a new rate structure that will result in just and reasonable.

IV. <u>ENO'S COMBINED RATE CASE APPLICATION</u>

On July 31, 2018, the Company submitted its Rate Case Filing. Shortly after submitting its Combined Rate Case filing, ENO received feedback from various members of the Council

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28 Resolution R-18-97 (Apr. 15, 2018), p. 9.

expressing serious concern about the potential effects on certain ENO customers resulting from ENO's proposed combined rate structure.

In response to that thoughtful feedback, ENO withdrew its July 31, 2018 filing and submitted a revised application on September 21, 2018. ENO's Revised Application, like its previous application, does not seek to receive more revenue from customers overall; in fact, ENO proposes to reduce electric and gas revenues received from customers overall by over $20 million. As part of that overall revenue reduction, ENO requests that the Council approve, based on its Period II Electric and Gas Cost of Service Studies for the projected test year ending December 31, 2018 with pro forma adjustments reflecting conditions through December 31, 2019, an electric base rate revenue level of $428.4 million and a gas base rate revenue level of $41.4 million, which recently has been updated (and lowered) to $40.1 million.

These base rate revenue levels are predicated on a 10.75% requested ROE (supported by the Revised Direct Testimony of Company witness Robert M. Hevert) and the Company's projected December 31, 2018 capital structure, which includes a 52.2% equity ratio. As stated previously, a constructive ROE determination in this proceeding is an important step in continuing a constructive regulatory environment.[29] With respect to electric base rates only, the Company proposes that electric base rates be calculated using a 10.50% ROE, 25 basis points less than Mr. Hevert's recommendation, in accordance with the Company's proposed Reliability Incentive Mechanism ("RIM") Plan. The RIM Plan is a transparent, straightforward approach to addressing the Company's electric reliability performance by aligning the earnings component of

[29] Exhibit ENO-1 (Thomas Revised Direct) at 49.

ENO's electric base rates to its reliability performance.[30]

ENO further requests that the Council adopt new FRPs for electric and gas operations, with ENO's Electric FRP including provisions to implement the Decoupling Pilot Program outlined in Council Resolution R-16-103. The FRPs, which the Council has approved previously, are a cost-effective and efficient way of effecting timely adjustment of rate levels, as necessary, thereby reducing regulatory lag and better matching rate changes to the trends and events that are driving changes in costs.[31] Should the Company improve its reliability performance, the RIM Plan would increase the earnings component of ENO's future FRPs. The Electric and Gas FRPs are described below.

In conjunction with the FRPs, ENO further proposes new contemporaneous cost recovery riders for large investments, such as the AMI Project, the Grid Modernization Project, and the Gas Infrastructure Replacement Program Project to address regulatory lag. The AMI Project, the Grid Modernization Project, and the Gas Infrastructure Replacement Program are large capital projects and, absent contemporaneous cost recovery, ENO's cash flow will deteriorate and capital will be lost and will not be available for reinvestment and investment in improvements in the Company's infrastructure at a time when cash flow and capital are critical to the Company.[32] Similarly, the Company proposes that the Purchased Power and Capacity Acquisition Cost Recovery ("PPCACR") Rider be revised and continue to be used to address regulatory lag

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30 *Id*. at 23.

31 *Id*. at 52.

32 *Id*. at 53.

associated with the non-fuel revenue requirement of new resource acquisitions.[33]

As part of its new electric rate structure, ENO proposes the Council approve the Demand-Side Management Cost Recovery ("DSMCR") Rider, which would implement a new model for DSM cost recovery. Rider DSMCR attempts to fulfill the Council's earliest stated objectives for Energy Smart, namely to "provide sufficient, timely, and stable program funding" to deliver DSM offerings to customers and to place DSM investment on equal footing with more traditional supply-side resources and other investments in capital assets used to serve ENO's customers.[34] These riders are discussed in more detail *infra*.

In implementing its combined electric base rates, ENO requests approval of the Algiers Residential Rate Transition ("ARRT") Plan. The ARRT Plan calls for the commencement of a gradual path to a single, combined rate structure for both Legacy ENO and Algiers residential customers through a three-year phase-in that mitigates rate shock to Algiers residential customers, which currently have lower electric base rates than Legacy ENO residential customers.[35] The ARRT Plan accomplishes the mitigation by reallocating a portion of the base rate reduction allocated to certain rate classes to the Algiers residential customers through a rider.[36] Additionally, to the extent that a long-term approach to a combined residential rate structure is not developed in this case, in the third year, ENO proposes that the Council revisit ENO's rate structure or consider additional rate changes to complete the transition to a combined

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33 Exhibit ENO-41 (Gillam Revised Direct) at 44-45.

34 Exhibit ENO-10 (Owens Revised Direct) at 15.

35 Exhibit ENO-1 (Thomas Revised Direct) at 3-4.

36 *Id*. at 16.

residential rate structure.[37] Additionally, ENO requests that the current residential customer charge of $8.07 be increased to $15.53,[38] as compared to the fully cost-based residential customer charge of $21.07.[39] ENO's proposed customer charge balances the rate design considerations of setting rates at cost and employing gradualism to avoid undue customer impacts.

ENO's proposed electric rate structure would result in a typical Legacy ENO residential customer using 1,000 kilowatt-hours per month having a bill of $124.13, an increase of $2.02 per month, and a typical Legacy Algiers residential customer with the same usage per month having a bill of $107.93, an increase of $3.65.[40] ENO's proposed gas rate structure would result in a typical ENO residential customer using one hundred cubic feet of gas per month having a bill of $79.02, a decrease of $3.09 per month.

ENO also proposes new solutions that give customers more control over their utility service and allow them to use it in new ways with the following new service offerings: Green Power, Community Solar, and options to add EV charging infrastructure.[41]

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37 *Id*. at 3-4.

38 *Id*. at 61.

39 *Id*. at 63.

40 As explained later and in the Revised Direct Testimony of Company witness, Myra L. Talkington, the second step of the phase-in would increase a typical residential Algiers customers' monthly bill by roughly the same amount.

41 Exhibit ENO-19 (Smith Revised Direct) at 40-49; Exhibit ENO-10 (Owens Revised Direct) at 35-71.

A. The proposed Electric and Gas FRPs are very similar to the previous FRPs approved by the Council.

The starting point for the proposed Electric FRP Rider was ENO's previous Electric FRP Rider, which was approved by the Council in Resolution R-09-136, dated April 12, 2009. The proposed Electric FRP Rider continues many features of its predecessor, such as the use of the previous calendar year as the Evaluation Period, the authorized return on equity set in this proceeding as the target Evaluation Period Cost of Equity ("EPCOE") with a dead band centered on the EPCOE, and a formula that adjusts the FRP revenue level for the Evaluation Period to prospectively earn the EPCOE, commonly referred to as "resetting to the midpoint."[42] The new features proposed in this proceeding include: (1) potential adjustments to the EPCOE pursuant to the proposed RIM Plan's formula; (2) provisions to implement the Decoupling Pilot Program, which Council Resolution R-16-103 requires; and (3) a provision for an interim Rate Adjustment for the timely recovery of the NOPS non-fuel revenue requirement.[43]

Similarly, the starting point for the proposed Gas FRP Rider was the previous ENO Gas FRP Rider. The proposed Gas FRP Rider continues many features of its predecessor, which are the same as the rate adjustment features as outlined above for the Electric FRP Rider.[44] The new features for the Gas FRP Rider are minor.

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42 Exhibit ENO-41 (Gillam Revised Direct) at 27-28.

43 *Id*. at 28-29.

44 *Id*. at 46-47.

B. The Company and the Council have certain shared objectives that will result in increased investment for which timely recovery through riders (or alternative mechanism(s)) is necessary.

Utilities are currently undergoing a paradigm shift caused by the need for large new investments in infrastructure and technology at a time of increasing costs and decreasing average usage per residential customer.[45] A regulatory environment that provides for contemporaneous cost recovery of large investments outside of the traditional rate case provides the utility the necessary opportunity to earn its allowed return while continuing to invest in the system and mitigate operational risks.[46] Such contemporaneous recovery also better matches the investment with those customers receiving the benefits. The Council has recognized this in the past, as demonstrated through the authorization of contemporaneous cost recovery for investments in Ninemile 6 and Union Power Block through the PPCACR Rider, which ENO proposes be modified in this proceeding as discussed below. The Council in various rulings has identified areas of investment that are important to achieving benefits for customers, and, in this proceeding, ENO proposes rate mechanisms for timely recovery of such costs.

1. Advanced Metering Infrastructure Charge

On October 18, 2016, in Council Docket UD-16-04, ENO filed its Application seeking authorization from the Council for the Company to acquire, construct, deploy, own, operate and maintain AMI, which includes advanced meters that enable two-way data communication, a secure and reliable communications network that supports two-way data communication, related and supporting systems ("AMI Implementation"), along with related accounting treatment for

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45 Exhibit ENO-1(Thomas Revised Direct) at 53.

46 *Id*.

existing and future assets and costs. ENO estimated the total capital investment in AMI to be approximately $75 million. ENO further explained that the AMI Implementation would produce a collective net benefit to ENO's electric and gas customers of $27 million on a present value basis.

Because of the significant overall investment required to deploy AMI – and the resulting benefit to customers as the deployment occurs – the Company requested implementation of a customer charge calculated on a per-customer basis that would recover the costs of AMI, net of certain benefits, phased in over the period 2019 through 2022 (*i.e.*, the "AMI Charge"), and the charge would be assessed to all metered electric and gas ENO customers. On February 8, 2018, in Resolution R-18-37, the Council approved a Stipulated Settlement and Term Sheet regarding the AMI Implementation. The Term Sheet provided that the prudently incurred costs associated with AMI were eligible for recovery from ENO's customers through electric and gas rates resulting from a final order of the Council in this rate case. The Term Sheet recognized that ENO and the Advisors were unable to reach agreement on the specific method for cost recovery at that time and reserved the parties' rights to argue their cost recovery positions in future proceedings.

ENO proposes that the Council authorize ENO to include in electric and gas bills beginning in the first billing cycle of August 2019, the effective date of base rates from this case, an Electric AMI Charge and a Gas AMI Charge. Both would change annually, beginning on January 1, 2020. After 2022, the Electric AMI Charge and Gas AMI Charge would decline over time based on the pre-determined changes as reflected in the rate schedule included in the Company's filing. The proposed schedules for the Electric and Gas AMI Charges are attached to Exhibit ENO-1 as Exhibit JBT-9. Absent contemporaneous cost recovery, the AMI Project and other major capital projects would cause ENO's cash flow to deteriorate, and capital will be lost and will not be available for reinvestment and investment in improvements in the Company's infrastructure at a time when cash flow and capital is critical to the Company.[47]

ENO proposes a customer charge for recovery of AMI costs because the number of customers ENO serves, in large part, drives the level of the costs associated with AMI. Therefore, as discussed above, these costs should be recovered through a customer charge so that a customer bears only the cost that customer causes.[48] The proposed customer charges in Exhibit JBT-9 were calculated using the same cost and benefit estimates presented by ENO in Docket UD-16-04 but updated to reflect the acceleration of the project, the new federal corporate income tax rate, an update to projected customer counts, and the proposed weighted average cost of capital in this case, which is based on an adjusted ROE of 10.50%. The charges are intended to recover the net present value of the Electric and Gas AMI revenue requirements.[49] Any differences in the revenue resulting from the customer charges and the actual costs of AMI would be reconciled through the proposed Electric and Gas FRPs.

2. Energy Smart – Demand-Side Management Cost Recovery Rider

To address the inherent challenges of offering DSM in the traditional utility business model, which ENO witness Dr. Faruqui, who is a principal with the Brattle Group and has over 40 years of academic, consulting and research experience as an energy economist,[50] discusses at

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47 Exhibit ENO-1 (Thomas Revised Direct) at 53.

48 *Id*. at 66.

49 *Id*.

50 Exhibit ENO-14 (Faruqui Revised Direct) at 1.

length,[51] and to provide a more level playing field between DSM investments and more traditional, supply-side investments, ENO has proposed the DSMCR rider for recovery of ENO's investments in implementing the Council's Energy Smart program. The new model will utilize regulatory asset-based cost recovery.

As Company witness Andrew Owens explains, moving to a regulatory asset-based cost recovery model has several benefits, including: (1) it will allow DSM investment to be treated similar to traditional supply-side and other investments in capital assets; [52] (2) it has a lesser rate impact than traditional DSM cost recovery;[53] and (3) it will enable ENO to continue to provide its customers with a variety of cost-effective DSM offerings through Energy Smart, as occurs today, while offering flexibility to potentially expand offerings.[54] This structure aligns with the Council's Energy Smart goals first defined in its Resolution R-07-600: to "provide sufficient, timely, and stable program funding to deliver energy efficiency,"[55] to develop a process to "align incentives equally for [energy] efficiency and supply side resources,"[56] and "to provide an opportunity to earn a comparable profit for saving energy as is generally available for generating or delivering energy."[57]

The structure of the DSMCR rider includes four elements, discussed by Mr. Owens:

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51 *See* Exhibit ENO-14 (Faruqui Revised Direct) at 9-12.

52 Exhibit ENO-10 (Owens Revised Direct) at 19.

53 Exhibit ENO-12 (Owens Rebuttal) at 17-22.

54 Exhibit ENO-10 (Owens Revised Direct) at 19.

55 Resolution R-07-600 at 4. *See* also Council Resolution R-14-122 ("[T]he Council finds it in the public interest to provide the necessary funding to continue the existing Energy Smart Programs to assure continuity of energy efficiency programs in New Orleans…").

56 Resolution R-07-600 at 3.

57 Resolution R-07-600 at 3.

1. Under the proposed DSMCR rider, ENO will estimate the total investment required to provide the Council's Energy Smart offerings for the next calendar year (or "PY"). These estimates would be based on the savings goals and associated budgets approved by the Council as part of the IRP process and evaluation of the DSM Potential Study. The total balance associated with DSM investment for a given PY will be amortized over three years.[58]
2. The second component involves taking the resulting balance corresponding to the total amount of the investment in DSM offerings for a given PY and the Company being allowed to earn a return at ENO's pre-tax WACC based on its allowed electric ROE, subject to a performance adjustment.[59] The performance adjustment is a proposed incentive mechanism involving ENO's allowed ROE that ties cost recovery to ENO's overall performance relative to annual savings goals and/or other Council-approved DSM metrics. The performance adjustment involving ENO's allowed ROE is not included in Rider DSMCR during the first year of recovery, but instead would be incorporated into the mechanism through the first true-up cycle and actual results would be reflected in the final year (or third year) of recovery.[60]
3. The third component would recover lost contributions to fixed costs ("LCFC") on a contemporaneous basis each year, although not as part of the DSM investment balance that is being amortized. The amount of LCFC included in Rider DSMCR

[58] Exhibit ENO-10 (Owens Revised Direct) at 19, 22.

[59] Exhibit ENO-10 (Owens Revised Direct) at 19.

[60] Exhibit ENO-10 (Owens Revised Direct) at 20-21.

would be adjusted each year based on the incremental (or decremental) change to ENO's DSM investment and resulting projected energy savings. In other words, the amount of LCFC recovered each year on a contemporaneous basis would be based only on that Program Year's DSM investment savings.[61]

4. The fourth component included in DSMCR Rider will be an adjustment resulting from a true-up that will occur once a year based on prior year actual results. The Company proposes that the DSMCR Rider rates be set only once a year and take effect at the beginning of each PY with the first billing cycle.[62]

Adoption of the Company's proposed DSMCR Rider would best support ENO's goal of increasing DSM offerings and would facilitate the Council's goal of increasing DSM. This supportive ratemaking structure has a proven track record of success in other jurisdictions.[63] Moreover, as acknowledged by Advisors witness Prep, "increases in Energy Smart funding are expected to be ***substantial*** as the program kWh annual savings are increased to meet the goal of 2% of annual kWh sales."[64] As summed up by Dr. Faruqui, "[g]iven the increase in investment needed to keep up with the escalating goals for Energy Smart, it is important that the Council provide the necessary support by approving ENO's fair and appropriate ratemaking proposal."[65]

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61 Exhibit ENO-10 (Owens Revised Direct) at 20.

62 Exhibit ENO-10 (Owens Revised Direct) at 20.

63 Exhibit ENO-14 (Faruqui Revised Direct) at 23-24.

64 Exhibit ADV-3 (Prep Direct) at 68 (emphasis added).

65 Exhibit ENO-14 (Faruqui Revised Direct) at 35.

3. Renewables – Purchased Power and Cost Acquisition Recovery Rider

The Council has established a policy objective of having ENO obtain a wider range of renewable options for customers and, in furtherance of that policy, ordered ENO to file an application requesting approval of renewable resources.[66] In July 2018, the Company filed the required application, and, in July 2019, the Council approved the Stipulated Settlement Term Sheet entered by the parties.

ENO proposes that the existing PPCACR Rider be modified so that it can serve as a recovery mechanism applicable to all customers for the non-fuel revenue requirement of Company investments in solar PV resources and power purchase agreements ("PPAs") or other emerging technology, including battery storage projects.[67] Absent contemporaneous cost recovery, investment in renewable resources and other major capital projects would cause ENO's cash flow to deteriorate, and capital will be lost and will not be available for reinvestment and investment in improvements in the Company's infrastructure at a time when cash flow and capital is critical to the Company.[68] The Company proposes to allocate the PPCACR Rider revenue requirement to the rate classes using the base rate revenue requirement allocation methodology approved by the Council in this proceeding.[69] Similar to the current PPCACR Rider, there will be a cumulative over/under calculation that compares the cumulative over/under balance and the applicable monthly costs to the PPCACR Rider Revenue for that operations

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66 Resolution R-18-97, dated April 5, 2018.

67 Exhibit ENO-3 (Thomas Rebuttal Testimony) 10; Exhibit ENO-41 (Gillam Revised Direct) at 44-45.

68 Exhibit ENO-1 (Thomas Revised Direct) at 53.

69 Exhibit ENO-41(Gillam Revised Direct) at 45.

month.[70] Any prior period adjustments will be added or subtracted and an interest component will be applied based on the average of the beginning of the month and end of the month cumulative over/under balance for the operations month using that month's prime interest rate.[71]

4. Grid Modernization and Smart Cities – Distribution Grid Modernization Rider

Company witness Erica Zimmerer's Revised Direct Testimony describes the numerous ways in which a modernized electric grid can benefit ENO's customers. These benefits include (i) improvements in reliability, both in the long-term and immediately upon deployment of grid modernization technologies, (ii) increasing the grid's ability to accommodate DERs like behind-the-meter solar generation and battery storage systems, (iii) increasing interoperability and potentially facilitating optimization, of DERs, (iv) increasing capacity for adoption of EVs, (v) facilitating increased functionality of smart-home appliances and devices, and (vi) providing the foundation for future adoption of Smart Cities applications and technologies.[72] No party to this proceeding has questioned the fact that a modernized electric grid can facilitate these and many more benefits for customers.

Furthermore, the Council has repeatedly expressed support for ENO's efforts to modernize the grid in New Orleans and even expressed a sense of urgency for the Company's pursuit of this initiative. In Resolution No. R-18-36 and Resolution No. R-18-536, which concern the Council's Smart Cities initiative, the Council stated that "the cornerstone of a Smart

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70 *Id*.

71 *Id*.

72 Exhibit ENO-8 (Zimmerer Revised Direct) 17-19.

Cities initiative is the modernization of the electric grid."[73] The Council also noted the importance of adopting Smart Cities technologies in the near term, stating that "New Orleans stands at the edge of this technological frontier and how we respond will either make us a true twenty-first century city or consign us to being a technological backwater laggard."[74] The Council has also stated that "deploying sustainable strategies and becoming technologically smarter is necessary to improve quality of life and to gain a competitive advantage in attracting investment and positive growth."[75] These Resolutions, together with the undisputed evidence of the benefits of grid modernization that ENO has submitted in this proceeding, demonstrate alignment between the Council and the Company on the importance of modernizing the electric grid in New Orleans.

Absent contemporaneous cost recovery, Grid Modernization and other major capital projects would cause ENO's cash flow to deteriorate, and capital will be lost and will not be available for reinvestment and investment in improvements in the Company's infrastructure at a time when cash flow and capital are critical to the Company.[76] Accordingly, the Company proposes a Distribution Grid Modernization ("Rider DGM") in order to recover on a timely basis the prudently incurred capital investment associated with Council-approved grid modernization projects not recovered in base rates from this proceeding.

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73 Resolution R-18-536 at 2; Resolution R-18-36 at 2.

74 Resolution R-18-36 at 2.

75 *Id*.

76 Exhibit ENO-1 (Thomas Revised Direct) at 53.

Under the Rider DGM, the rider rate would be redetermined four times each year to recover the costs associated with grid modernization plant closings during each calendar year quarter. The rider rate would recover: (1) the pre-tax return on the cumulative grid modernization plant closings, net of the associated provision for depreciation and the associated accumulated deferred income taxes, (2) depreciation expense associated with the same, and (3) an annual reconciliation of the difference between the revenue requirement and actual revenue collected for the reconciliation period. The reconciliation period would be the twelve-month period ending December 31 of each year after the initial filing year, and the reconciliation difference would be included in the April 30 filing each year starting in 2021 and applied to bills commencing on the first billing cycle of June of each year. In addition to allowing for the rate redetermination, the annual reconciliation filing would provide the Council, its Advisors and stakeholders with a transparent way to track ENO's spending on grid modernization projects, monitor ENO's adherence to the project budgets, and consider the prudence of its project execution and the costs ENO incurs in constructing and designing the projects following their completion.

The pre-tax return would be calculated using the statutory state and federal income tax rates, along with the Company's actual capital structure and actual cost rates for long-term debt based on the Company's pre-tax WACC for the twelve-month period ending December 31 immediately preceding the filing date. The cost of equity initially will be the adjusted equity return approved by the Council in this rate case. In the future, the cost of equity would be the adjusted EPCOE calculated in the most recent Electric FRP taking into account the RIM Plan, regardless of whether the Electric FRP results in a Rate Adjustment.

5. Gas Infrastructure Replacement Program Rider

The Company proposes a Gas Infrastructure Replacement Program ("GIRP") Rider ("GIRP Rider") in order to provide ENO with timely cost recovery and certainty as to the recovery of the long-term capital investments urgently needed to replace aging gas distribution pipelines and thereby assure the safety and reliability of the gas distribution system. As explained by Company witness Michelle P. Bourg, in past years, the replacement of gas pipe resulting from the damage caused by Hurricanes Katrina and Rita was financed primarily with insurance funds. As a result, the rebuild program replaced much of ENO's aging infrastructure that sustained flood damage. However, there is still more work to do to mitigate the risk associated with the operation of a vintage gas system.[77] Vintage low-pressure facilities now in use, for example, leak at a rate 250 times greater than existing polyethylene facilities. As explained in detail by Ms. Bourg, "while the ENO system is safe and continues to operate safely, the remaining vintage gas facilities in operation today do not perform well and threaten the continued safe operation of the system."[78]

The federally-mandated gas distribution Integrity Management ("IM") program has identified and prioritized the risk in the operation of vintage facilities as the most significant threat to gas distribution system safety.[79] The risks associated with operating a vintage low-

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77 Exhibit ENO-24 (Bourg Rebuttal) at 3-5.

78 *Id.* See also *id*. at 15 ("The system continues to operate and be maintained in a safe and prudent manner by ENO today, as evidenced by ENO's ability to address leaks appropriately and timely. ENO places a strong focus on meeting federal and state pipeline safety regulations that govern the design, operation and maintenance of the City's gas distribution system. In the critical area of leak survey and leak repair, ENO's practices of performing more frequent leakage surveys and its focus on minimizing the duration and backlog of leaks requiring permanent repair exceed the required regulation.")

79 *Id.* at 3-4.

pressure gas distribution system are currently being managed in a manner that both preserves the safety of the system and steadily replaces vintage pipe. Pursuant to Council authorization in Docket No. UD-07-02, Resolution No. 13 R-17-38, during 2017 and through January 2018, ENO made GIRP investment of approximately $12 million to replace or abandon 51 miles of pipe. As of January 2018, 186 miles of low-pressure piping remain in service in the City, with an additional 7 miles of vintage plastic piping remaining.[80]

ENO can best accomplish the improvement in the safety and reliability of its gas distribution system by implementing the GIRP. The GIRP would employ a condition-based approach similar to that outlined in ENO's IM program and previously employed in the rebuild program, with the scope expanded beyond flooded areas of the City. The GIRP will also enable ENO to address historical underground utility conflicts between gas pipe and other utilities (*e.g.*, water, sewer) arising in connection with prior gas infrastructure replacement.[81] These unknown conflicts were introduced during the installation of new gas main and service piping, using trenchless installation technologies in areas with existing underground utilities, due to challenges with positively identifying adjacent underground utility facilities that may not be marked. Underground utility conflicts are an issue of increasing concern for gas utility operators nation-wide and an issue that the natural gas utility industry recognizes needs attention. Guided by the condition-based approach in its IM Plan, ENO proposes to address historical underground utility

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80 Exhibit ENO-22 (Bourg Revised Direct) at 16-17.

81 *Id*. at 11.

conflicts through the following processes: engineering review, sewer inspections, conflict repair, documentation, and customer education/public outreach.[82]

The GIRP Rider as proposed by ENO would allow the Company to implement the GIRP over a ten-year period (2017-2027), with contemporaneous cost recovery of the associated plant investment. ENO will support program implementation with annual reporting, consistent with the recommendation of Advisors' witness Mr. Joseph W. Rogers in Council Docket No. UD-07-02, as well as annual updates regarding ENO's progress in addressing historical underground utility conflicts.[83] Absent contemporaneous cost recovery, ENO's cash flow will deteriorate and capital will be lost and will not be available for reinvestment and investment in improvements in the Company's infrastructure at a time when cash flow and capital are critical to the Company.[84]

At hearing, Company witness Ms. Michelle Bourg explained why, from an operational and practical standpoint, the Company's proposed GIRP rider is the best way to accomplish the pipe replacement. The extent and scope of the project is large enough that the revenue certainty associated with a rider offering timely cost recovery will allow the Company to compete with other utilities across the country to attract the needed contractors and other resources necessary over the next decade to complete the project. As Ms. Bourg testified:

> [T]he rider provides for us the certainty and the clarity as to the Council's intent and the predictable cash flow, right, to execute this project. … [I]t benefits us greatly to have this mechanism in place so that we can attract and retain the most qualified resources to come to the city because we've got competition with every

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82 *Id*. at 21-24.

83 *Id.* at 27-28.

84 Exhibit ENO-1 (Thomas Revised Direct) at 52-53.

> other gas utility that's seeking to undertake large scale infrastructure placement programs.
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> So knowing that we've got a guarantee of sorts to do this work out through the 2027 time frame attracts these folks to come to the city. They've got to buy material. They've got to house resources. They've got warehouses they have to stand up. So they're investing capital plant in the city to do this work and it helps us to attract those folks by having the mechanisms secured in place.[85]

Moreover, "[b]y providing contractors with a steady, predictable pace of work, they are more able to preserve economics of scale, which in turn means lower contractor costs to the Company."[86] Further, through ENO's practice of issuing requests for proposals every three years for contractor services, ENO is able to keep contractor pricing competitive and provide contractors with an incentive to remain operational in the New Orleans area.[87]

Like the Rider DGM, the Company proposes a GIRP Rider in order to recover on a timely basis the capital investment costs associated with the GIRP project, including utility conflicts expense. Under the GIRP Rider, the rider rate would be redetermined four times each year to recover the costs associated with GIRP Project closings during each calendar year quarter.[88] The rider rate would recover: (1) the pre-tax return on the cumulative grid modernization plant closings, net of the associated provision for depreciation and the associated accumulated deferred income taxes, (2) depreciation expense associated with the same, (3) the expenses associated with the identification and resolution of underground utility conflicts, (4) and an annual reconciliation of the difference between the revenue requirement and actual

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85 Tr. (Bourg) 6/17/19 at 117; 147, and 148.

86 Exhibit ENO-24 (Bourg Rebuttal) at 25.

87 *Id.*

88 Exhibit ENO-41 (Gillam Revised Direct) at 49.

revenue collected for the reconciliation period.[89] The reconciliation period would be the twelve-month period ending December 31 of each year after the initial filing year, and the reconciliation difference would be included in the May 31 filing each year starting in 2021 and applied to bills commencing on the first billing cycle of July of each year.[90]

The pre-tax return would be calculated using the statutory state and federal income tax rates, along with the Company's actual capital structure and actual cost rates for long-term debt based on the Company's pre-tax weighted-average cost of capital for the twelve-month period ending December 31 immediately preceding the filing date. The cost of equity initially will be the equity return approved by the Council in this rate case as adjusted by the RIM Plan.[91]

6. Gas Research and Development (R&D) Charge

ENO seeks authorization for an initial three-year period of a modest once-a-year $1 per-meter charge that would enable ENO to leverage and benefit from the much larger collective R&D investment made by local gas distribution companies serving roughly two-thirds of all gas meters across the United States.[92] As explained by Ms. Bourg, through the funding provided by the R&D charge, ENO will be able to take advantage of nationwide research and development investments into expanding the supply of clean, abundant, and affordable natural gas, ensuring a safe and reliable delivery infrastructure, and promoting the clean and efficient use of natural gas. The investment in this groundbreaking research is administered by the non-profit Gas

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89 *Id*.

90 *Id*.

91 *Id*. at 50.

92 Exhibit ENO-22 (Bourg Revised Direct) pp. 33-39.

Technology Institute and these R&D programs have produced tangible benefits for participating utilities, including dozens of commercial technologies and analytical tools.[93] This cost of participation in these programs is driven by the number of the Company's gas customers. Accordingly, ENO has proposed collection on a per-meter basis.

V. CONTESTED ISSUES

A. ENO requests an ROE of 10.75% based on multiple models consistent with recent regulatory developments and qualitative data, which ROE would be reduced to 10.50% for electric operations through the RIM Plan; the other parties' ROE recommendations are unreasonably low and are heavily or entirely based on a single model that produces unrealistic ROE estimates for ENO's level of risk.

ENO is requesting a 10.75% ROE estimated by Mr. Robert Hevert. This ROE would then be reduced to 10.50% for the purposes of the base rates for electric service set by the Council in this proceeding based on the application of the RIM Plan sponsored by ENO witnesses Joshua Thomas and Melonie Stewart. ENO also seeks the opportunity to earn the 10.75% ROE recommended by Mr. Hevert for the term of its proposed Electric and Gas FRPs by using 10.75% as EPCOE, which would be adjusted in the Electric FRP by the RIM Plan so that the initial Adjusted EPCOE would be 10.50%.[94]

1. The standards for determining a utility's ROE are well-settled, but recent developments indicate that multiple methodologies should be employed to estimate ROE to reflect investors' expectations.

In general terms, the cost of equity, or ROE, is the return that investors require to make

93 *Id.*

94 *Id*. at 49-50.

an equity investment in the Company.[95] The ROE is based on the principle of opportunity costs. Any equity investment results in a forgone opportunity to invest in alternative assets, so for an equity investment to make sense, the expected return must be at least equal to the expected returns from alternative and comparable investment opportunities.[96] Investments with comparable risks are expected to offer similar returns, so the opportunity cost of an investment should equal the return available on an investment with similar risk.[97]

Because the cost of equity in a particular entity cannot be directly observed, it must be estimated based on market data and using various financial models.[98] These models require certain assumptions that vary in importance and applicability depending on market conditions. Because ROEs are based on opportunity costs, the models are applied to a group of comparable "proxy" companies. The models produce a range of results from which the ROE is estimated.[99] Informed and reasoned judgment is involved in the decision of which models to use, the inputs into those models, the choice of proxy companies, the interpretation of the model results, and the consideration of data outside the models that can affect the cost of equity.[100] The key consideration is ensuring the overall analysis reasonably reflects investors' views of the financial markets in general and of the utility in particular, as compared to the proxy companies.[101]

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[95] Exhibit ENO-26 (Hevert Revised Direct) at 6.

[96] *Id*.

[97] *Id*. at 6-7.

[98] *Id*.

[99] *Id*. at 10.

[100] *Id*. at 7.

[101] *Id*. at 10.

Besides relevant economic and financial risk and the results of quantitative analyses, authorized returns for similarly-situated utilities in other jurisdictions are important and relevant points of reference for the Council in determining the appropriate ROE in this case.[102] Setting a ROE for ENO that is measurably lower than those available to other regulated utilities can have adverse practical effects on ENO's ability to provide quality service at reasonable cost to its customers. ENO competes with other regulated utilities for the long-term capital necessary to maintain and update its infrastructure and continually improve its service.[103] Authorized ROEs for regulated utilities are publicly available information and thus likely reflected in the expectations of investors. If investors can potentially earn a return from a utility with an authorized ROE similar to those of other similarly-situation utilities, they will likely choose to invest in that utility over one with an authorized ROE below industry-level.[104]

The United States Supreme Court in its *Hope* and *Bluefield* decisions, which are discussed earlier in this Brief, established the general parameters for determining a fair and reasonable ROE for investors in regulated utilities. In those cases, the Court found that the ROE should be comparable to returns expected on other investments with comparable risks, sufficient to assure confidence in the utility's financial integrity, and adequate to maintain and support its credit and attract capital.[105] The Council adheres to this precedent, previously determining that

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102 *Id*. at 8.

103 Exhibit ENO-29 (Hevert Revised Rebuttal) at 16.

104 *Id*.

105 *Bluefield Water Works & Improvement Co. v. Pub. Serv. Comm'n* of W. Va., 262 U.S. 679, 67 L.Ed. 1176, 43 S.Ct. 675 (1923); *Power Comm'n v. Hope Natural Gas Co*., 320 U.S. 591, 88 L.Ed. 333, 64 S.Ct. 281 (1944).

an ROE must fairly compensate utility-invested capital, allow utilities to offer returns adequate to attract new capital on reasonable terms, and maintain the financial health of the utility.[106] All parties agree that these are the standards by which the Council should determine the ROE for the rates set in this proceeding. The Federal Energy Regulation Commission ("FERC"), however determined late last year that four models, which are discussed *infra*, should be used in setting an ROE that results in just and reasonable rates as opposed to a single model used in isolation.[107] FERC's approach provides well-reasoned, persuasive guidance. In fact, *Hope*, which the Council has recognized as setting forth the standard for determining a utility's ROE, is a decision from FERC's predecessor, the Federal Power Commission, applying the Natural Gas Act. The recent FERC order regarding ROE is a decision applying the very similar Federal Power Act. Therefore, it would be arbitrary for the Council to ignore the developments from the FERC regarding ROE.

2. The simple fact that ENO is among the few below investment grade ratings sets it apart from all others. So, to suggest that the Company should have an authorized return equal to the return available to investment grade utilities is incorrect. [108]

The Council should give careful consideration to ENO's credit ratings when determining ENO's ROE, despite what the other parties contend. All of the parties to this case generally agree that ENO's credit ratings merit serious consideration in determining a just and reasonable

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106 Resolution R-09-136, *In the Matter of Entergy New Orleans, Inc.'s Application for a Change in Electric and Gas Rates Pursuant to Council Resolution* R-06-459, Docket No. UD-08-03, Resolution and Order Approving Agreement in Principle, April 2, 2009, at 10.

107 Docket Nos. EL14-12-003 and EL15-45-000, *Order Directing Briefs*, 165 FERC ¶ 61,118 (November 15, 2018) at P. 34-40.

108 Tr. (Hevert) 06/19/19 at 62-63.

ROE in conformance with the *Hope* and *Bluefield* standards. A critical issue for most utility equity investors with respect to a company's credit rating is whether the company is above or below investment grade.[109] Investors in utility stock tend to be institutional, and their guidelines focus on investment grade entities. Although S&P rates ENO as an investment grade company with an issuer credit rating of BBB+, Moody's rates ENO below investment-grade at Ba1, or three "notches" below the S&P rating.[110] Moody's has rated only two other investor-owned electric utilities as below investment grade: PG&E Corp., which recently filed for bankruptcy,[111] and SCANA Corporation (SCANA), which has a split credit rating just as ENO does and whose subsidiary South Carolina Electric and Gas was authorized a 10.75% ROE by the South Carolina Public Service Commission.[112] Moody's below investment grade rating for ENO makes it far riskier than any proxy company used by either Mr. Hevert or the Advisors and Intervenors in their ROE analyses, and calls for a ROE at the upper end of the range of results from Mr. Hevert's analyses.[113] For the same reason, this means that even the upper end of the highest range proposed by the Intervenors is inadequate for a utility with ENO's risk profile.

Moody's concern regarding ENO's geography is borne out by recent hurricanes in the area, especially Hurricane Katrina and its massive damage, lengthy evacuations and outages, and

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109 *Id.* at 23.

110 Exhibit ENO-26 (Hevert Revised Direct) at 12; Exhibit ADV-8 (Watson Surrebuttal and Cross-Answering) at 21.

111 PG&E Corp.'s subsidiary Pacific Gas and Electric Company is also rated below investment grade. Exhibit ENO-31 (Hevert Rejoinder) at 2.

112 Exhibit ENO-31 (Hevert Rejoinder) at 3.

113 *Id*.

resulting bankruptcy filing for ENO. Moody's concern is also shared by S&P.[114] Significantly, the S&P rating for ENO reflects its affiliation with Entergy Corporation, its parent company, and does not reflect ENO's stand-alone risk profile, which S&P rates at the lowest investment-grade tier of BBB- and which is two notches below the average credit rating (BBB+) of the Advisors' proxy group.[115] S&P cites ENO's small size and geographical locations as drivers for this stand-alone rating, which are the same bases for Moody's rating for ENO.[116] Even though its credit rating for ENO is higher than that of Moody's, S&P considers ENO to have "significant financial risk."[117] This is how Mr. Hevert characterized it at hearing:

> The Standard & Poor's rating for the Company is Triple B plus, similar to the others, but Standard & Poor's also notes what it refers to as a standalone credit profile. The standalone credit profile is the S&P's view of the Company's risk assuming no extraordinary support from the parent company. So it is effectively the subject Company's, in this case, Entergy New Orleans, credit profile assuming no assistance from the parent. There Standard & Poor's assigned the rating of Triple B minus, which is the lowest investment grade credit rating. So any deterioration in its credit quality on a standalone basis would put the Company below investment grade.[118]

The undisputed evidence shows that capital markets will look to Moody's opinion of ENO's credit risk in making investment decisions. Therefore, that rating must be considered in determining ENO's reasonable ROE.[119] Discontinuing use of Moody's for ratings related to

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114 Exhibit ENO-4 (Thomas Rejoinder) at 7-8; Exhibit ENO-1 (Thomas Revised Direct), Exhibit JBT-3.

115 Exhibit ENO-31 (Hevert Rejoinder) at 4, 35; Exhibit ENO-1 (Thomas Revised Direct), Ex. JBT-3 at 6.

116 Exhibit ENO-31 (Hevert Rejoinder) at 4; Exhibit ENO-1 (Thomas Revised Direct), Ex. JBT-3 at 5.

117 Tr. (Watson) 06/21/19 at 58.

118 Tr. (Hevert) 06/19/19 at 64, l. 3 – 17

119 Exhibit ENO-4 (Thomas Rejoinder) at 79.

issuance of public debt (as has been suggested by Advisors witness Watson)[120] could result in negative reactions from investors, as use of Moody's is standard practice for the industry, especially for bond issuances.[121] In addition, the absence of a Moody's rating for such an issuance could raise questions among investors and increase the effect of any potential change in S&P's ratings, causing investors to demand a higher return on those bonds, which will translate to higher costs for ENO's customers.[122]

There can be no dispute that Moody's is a sophisticated ratings agency with a long history of rating the credit of vertically integrated electric utilities such as ENO, and that it has rated ENO below investment grade. This credit rating will influence investors' decisions as to the return they will require on capital they invest in ENO, and therefore it must inform the Council's decision on the appropriate ROE to set in this case.

3. ENO's proposed ROE is based on a proper analysis considering multiple financial models and appropriate qualitative data.

Mr. Hevert was the only witness offering an opinion on ENO's estimated ROE that performed a comprehensive analysis that fairly measured ENO's risk. His recommendation results from a balanced approach considering the relative strengths and weaknesses of multiple analytical methodologies as well as considerable empirical and qualitative information in analyzing and giving appropriate weight to their results.[123] Mr. Hevert, a financial analyst and consultant with 30 years of experience working in regulated utility industries, performed an in-

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120 Exhibit ADV-8 (Watson Surrebuttal and Cross-Answering) at 21–22.

121 Exhibit ENO-4 (Thomas Rejoinder) at 9-10.

122 *Id*. at 10.

123 Exhibit ENO-26 (Hevert Revised Direct) at 82.

depth analysis applying four widely-accepted empirical financial models to develop his ROE recommendation of 10.75%.[124] Specifically, Mr. Hevert relied upon the Discounted Cash Flow ("DCF") model, including the Constant Growth and Multi-Stage forms; the Capital Asset Pricing Model ("CAPM"); the Bond Yield Plus Risk Premium approach; and the Expected Earnings model.[125]

In contrast, the opposing witnesses give considerable weight to the DCF method, even though it produces ROE estimates in some cases more than 150 basis points below the returns authorized for other electric utilities.[126] For example, the Advisors' ROE witnesses' recommendation of 8.93% is based primarily on Mr. Watson's DCF analysis. Mr. Walters set the low end of his recommended range (*i.e.*, 9.00%) by reference to his DCF model results, and Mr. Baudino relies principally on his DCF results in arriving at his ROE recommendation.[127]

The FERC, however, determined late last year that the DCF model in isolation did not satisfy the standards set forth in *Hope* and *Bluefield*. In a November 15, 2018 *Order Directing Briefs*, the FERC found that "in light of current investor behavior and capital market conditions, relying on the DCF methodology alone will not produce a just and reasonable ROE."[128] Further, in an October 16, 2018 *Order Directing Briefs*, FERC found that although it "previously relied solely on the DCF model to produce the evidentiary zone of reasonableness...," it is "...concerned

124 Exhibit ENO-26 (Hevert Revised Direct) at 3-5; Exhibit ENO-31 (Hevert Rejoinder) at 6.

125 Exhibit ENO-26 (Hevert Revised Direct) at 3; Tr. (Hevert) 06/19/19 at 16.

126 Exhibit ENO-29 (Hevert Revised Rebuttal) at 5 (Chart 1).

127 *Id*. at 3-4.

128 Docket Nos. EL14-12-003 and EL15-45-000, *Order Directing Briefs*, 165 FERC ¶ 61,118 (November 15, 2018) at para. 34.

that relying on that methodology alone will not produce just and reasonable results."[129] As FERC explained, it is important to understand "how investors analyze and compare their investment opportunities."[130] FERC also explained that, although certain investors may give some weight to the DCF approach, other investors "place greater weight on one or more of the other methods. . . ."[131] As a result of this analysis, the FERC determined that the four models that Mr. Hevert used to determine his recommended ROE – the DCF, the CAPM, the Bond Yield plus Risk Premium approach, and the Expected Earnings model - should all be used in setting just and reasonable ROEs.[132]

Mr. Hevert was the only ROE witness to follow the FERC's guidance and use all four models. Given the fallacy in several of the Constant Growth DCF model's underlying assumptions under current market conditions as recognized by FERC, and comparing his Constant Growth DCF results with 1,556 electric utility rate cases since 1980 (none of which resulted in an authorized ROE below 9% for a vertically-integrated utility), Mr. Hevert determined that his DCF mean low results are highly improbable.[133] Although he does not contend that a DCF analysis should not be afforded any weight in estimating ENO's cost of equity, Mr. Hevert explains that the range of results produced by the DCF model should be

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[129] Docket No. EL11-66-001, *et al.*, *Order Directing Briefs* 165 FERC ¶ 61,030 (October 16, 2018) at para. 30.

[130] *Id*. at para. 33.

[131] *Id*. at para. 35

[132] Docket Nos. EL14-12-003 and EL15-45-000, *Order Directing Briefs*, 165 FERC ¶ 61,118 (November 15, 2018) at P. 34-40.

[133] Exhibit ENO-26 (Hevert Revised Direct) at 23-24.

carefully considered.[134] Mr. Hevert considered the results of his DCF model in developing his ROE recommendation, but, given ENO's risk profile and that it is one of only three vertically integrated utilities with a below investment grade rating, he opined that ENO's ROE is toward the upper end of the range of ROEs developed by all the models he employed, including the DCF.[135]

ENO's significant capital investment program and its effect on cash flows; ENO's credit profile and the effect on that profile from the Tax Cut Act and current capital market conditions; the geographic risk involved in ENO's operations; and ENO's relatively small size and non-diverse customer base all played prominent roles in Mr. Hevert's determination of a reasonable ROE, as did flotation costs as a permanent reduction to necessary capital.[136] Mr. Hevert also analyzed ENO's business risks as compared to a proxy group of comparable companies and the implications of those risks in arriving at the appropriate ROE.[137]

Mr. Hevert's analysis indicated a range of 10.25% to 11.25% for equity investors' required ROE for investment in integrated electric utilities. Considering current capital market conditions and ENO's higher risk profile relative to comparable companies, including ENO's below investment grade credit rating from Moody's, Mr. Hevert established that ENO's request for an ROE of 10.75% is reasonable.[138]

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134 Exhibit ENO-29 (Hevert Revised Rebuttal) at 13.

135 Tr. (Hevert) 06/19/19 at 19-20.

136 Exhibit ENO-26 (Hevert Revised Direct) at 3-4.

137 *Id*. at 5.

138 *Id*.

4. Other parties' ROE recommendations are unreasonably low and based on faulty and incomplete analyses.

The Advisors, Air Products and Chemicals, Inc. ("APC"), and Crescent City Power Users' Group ("CCPUG") oppose ENO's requested ROE and offer testimony recommending much lower alternatives ROEs. Their recommended ROEs are unreasonably low and would deprive ENO of the opportunity to earn a return comparable to other companies of similar risk, thereby violating the standards set forth by the United States Supreme Court for determining a utility's cost of equity.

None of the recommendations made by these parties give proper and required consideration to ENO's below investment grade credit rating from Moody's, and they are all well below the average authorized ROEs for vertically integrated electric utilities with higher credit ratings. Thus, adopting these recommendations would require equity investors to commit capital to a much riskier utility than average for a lower return than average – a trade most investors would be unlikely to make. Advisors' recommended ROE of 8.93% would be among the lowest authorized ROEs of any regulated utility in the United States, even though ENO is one of only a handful of those companies with a below investment grade ratings. Company witness Mr. Thomas described that as an irreconcilable outcome at hearing:

> The Advisors' recommendation would recommend the lowest ROE in the country. Mr. Hevert noted that ENO has one of the few non-investment grade credit ratings in the entire industry. I don't know how one could reconcile those two things.[139]

[139] Tr. (Thomas) 6/20/19 at 156.

The evidence clearly shows that ENO is one of the riskiest utilities in the United States, based on its below investment grade credit rating, the likelihood of severe weather events associated with its geography, the lack of diversity in its customer base, and its smaller size based on total customers and revenues. Because the Company is a riskier investment than other vertically integrated utilities, investors require a return on their capital that is higher than that of other utilities. Yet, the average authorized ROE for vertically integrated utilities over the last five years is more than 86 basis points higher than the Advisors' recommendation, which is also lower than all such authorized ROEs since 1980.[140] The ROE of 9.35% proposed by both CCPUG witness Richard Baudino and APC witness Christopher Walters is also not supported by ROEs authorized for other vertically-integrated utilities.[141] It is 44 basis points below the average authorized ROE for vertically integrated electric utilities and below all but eight ROEs authorized for vertically-integrated electric utilities since 2014.[142]

The common thread between the unreasonably low ROE recommendations of the Advisors, Air Products, and CCPUG is their witnesses' inappropriate dependence on the results of the DCF method, which in some cases, produces ROE estimates more than 150 basis points below average returns authorized for other electric utilities.[143] Since 2014, the Constant Growth DCF model has produced ROE estimates notably below returns ultimately authorized by

140 Exhibit ENO-29 (Hevert Revised Rebuttal) at 5-6, Chart 2; Exhibit ENO-3 (Thomas Rebuttal) at 11.

141 Exhibit ENO-29 (Hevert Revised Rebuttal) at 3.

142 *Id*. at 5.

143 *Id*. at 3-4.

regulatory commissions for those utilities.[144] Given current market conditions, DCF analyses can produce unrealistically low results in the range recommended by Advisors, because many of its underlying assumptions do not currently hold.[145] Therefore, it should be given less weight than the other models, and certainly not used as a primary basis for an ROE recommendation.[146] However, both Advisors and CCPUG rely primarily or exclusively on the Constant Growth DCF model results in making their recommendations.

Moreover, as discussed above, the FERC recently determined that reliance upon the DCF model to the exclusion of all others will not produce a just and reasonable ROE considering current investor behavior and capital market conditions.[147] Mr. Watson admitted that the FERC has realized that it is not sufficient to rely solely upon the Two-Step DCF model in setting just and reasonable ROEs.[148] The FERC recognized that the cost of equity to a regulated utility depends on what the market expects, not precisely what will happen, and that in determining a utility's ROE, it must look at how investors analyze and compare investment opportunities.[149] The FERC concluded, and Mr. Watson conceded, that the DCF methodology cannot, standing

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144 *Id.* at 4-5, Chart 1.

145 *Id*. at 10, citing State of North Carolina Utilities Commission, Docket No. E-7, Sub 1146, In the Matter of Application of Duke Energy Carolinas, LLC, for Adjustment of Rates and Charges Applicable to Electric Utility Service in North Carolina, Order Accepting Stipulation, Deciding Contested Issues, and Requiring Revenue Reduction (July 25, 2017).

146 *Id.* at 120-121.

147 Docket Nos. EL14-12-003 and EL15-45-000, *Order Directing Briefs*, 165 FERC ¶ 61,118 (November 15, 2018) at P. 34.

148 Tr. (Watson) 06/21/19 at 23.

149 Docket Nos. EL14-12-003 and EL15-45-000, *Order Directing Briefs*, 165 FERC ¶ 61,118 (November 15, 2018) at P. 35.

alone, reflect how investors make investment decisions.[150] As observed above, the FERC now proposes to rely not only upon the results of the DCF, but also those of the CAPM, Expected Earnings, and Risk Premium models, as the traditional methods investors use to estimate expected returns, and to give each of those four models equal weight in developing just and reasonable ROEs allowed for transmission owners.[151]

Mr. Hevert's application of the CAPM, the Bond Yield Plus Risk Premium, and Expected Earnings models, to supplement his DCF approach, reveals that the ROE recommendations made by the Advisors and Intervenors are unduly low.[152] If the Council adopted those recommendations, they would increase ENO's regulatory and economic risk and hinder its ability to compete for reasonably-priced capital, thereby increasing its cost of capital to the detriment of its customers.[153]

In summary, Mr. Hevert conducted a series of analyses using well known and commonly used methods and made appropriate adjustments based on qualitative data accounting for ENO's unique risk profile to determine the Company's ROE. Although he included the DCF model in his analysis, Mr. Hevert explained that DCF model results should be viewed with caution in the current market environment, which is consistent with developments from the FERC. Consequently, the other methodologies he employed, including the two, risk premium-based

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150 *Id*. at P. 37, 42; Tr. (Watson) 06/21/19 at 23.

151 Docket Nos. EL14-12-003 and EL15-45-000, *Order Directing Briefs*, 165 FERC ¶ 61,118 (November 15, 2018) at P. 36.

152 Exhibit ENO-29 (Hevert Revised Rebuttal) at 15.

153 *Id*. at 6.

approaches and the expected earnings analysis, should be given more weight. Based on this analysis, he recommended an ROE range of 10.25% to 11.25%.

The Advisors and Intervenors' ROE recommendations rely too heavily on the DCF models despite their unreasonable results and the FERC guidance requiring use of the four models employed by Mr. Hevert. Further, their recommendations fail to appropriately account for ENO's below investment grade credit rating and other factors that make ENO a riskier investment than its peers. In doing so, they ask the Council to set one of the lowest ROEs in almost 40 years for an investment in one of the riskiest utilities in the United States. In contrast, the Company's requested 10.75% percent ROE is a reasonable estimate of its required return, consistent with recently authorized ROEs for vertically integrated utilities and should be approved by the Council.

5. A supportive ROE determination is necessary to maintain a constructive regulatory environment and ENO's financial condition so as to help ENO timely meet the Council's objectives for the benefits of customers.

The Council's allowed ROE can be a bellwether of the state of the regulatory environment, and the setting of a substantially lower than requested ROE can be a factor in adverse credit ratings actions. For example, in 2014, Moody's passed over Entergy Arkansas, Inc. ("EAI") for a credit ratings upgrade after a rate case order from the Arkansas Public Service Commission setting an unexpectedly low ROE, thus, effectively downgrading EAI relative to its peers in the industry.[154] Mr. Thomas expressed this same concern at hearing:

> The ROE decision is one of the most visible and most important portions of determining how conducive that regulatory environment is. And an ROE

[154] Exhibit ENO-1 (Thomas Revised Direct) at 50-51 and Exhibit JBT-7.

> recommendation of the lowest ROE in the United States would certainly signal to the credit rating agencies that there could be some concern about the regulatory environment in which ENO is operating.[155]

Providing temporary benefits to customers through an unreasonable ROE determination likely would harm customers in the long-run through higher future capital costs given ENO's weak credit ratings relative to the industry and the importance of this case to ENO's creditworthiness.[156]

Furthermore, now is not the time to jeopardize the constructive regulatory environment and ENO's financial condition. Given the expected level of investment during the period 2018-22, which investments include NOPS, the AMI Project, renewable resources, and grid modernization – all investments that the Council has found to be in the public interest, it is important that the Council take constructive steps to maintain ENO's cash flow and financial condition and the constructive regulatory environment in which ENO has operated since its emergence from bankruptcy in 2007 following Hurricane Katrina.[157]

Contrary to the Advisors' argument, the Council's determination of an appropriate ROE is not simply a choice of and comparisons between financial concepts and models; ROE determines the cash flow and equity capital ENO will have to invest in its infrastructure to meet the Council objectives of transforming ENO's operations to provide new and improved service to its customers.[158] A utility must invest equity into improvements needed to serve customers in

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155 Tr. (Thomas) 6/20/17 at 145.

156 Exhibit ENO-1 (Thomas Revised Direct) at 42-43.

157 *Id.*

158 Exhibit ENO-4 (Thomas Rejoinder) at 5; Exhibit ENO-1 (Thomas Revised Direct) at 51.

order to prevent the utility's financial condition from deteriorating and becoming more risky (e.g., if a utility were to fund new investments with debt only, it could become overly debt-laden), which could lead to higher capital costs for customers.[159] It is neither possible nor practical to force a utility to fund investment with the expectation of earning an unreasonably low return, nor is it reasonable or prudent to fund that investment using a disproportionate level of debt due to underfunded equity capital.[160] Thus, an unreasonably low ROE would limit ENO's ability to timely invest in projects like AMI, Grid Modernization, Smart Cities in a manner consistent with Council's and customers' expectations, while maintaining its financial condition over the long-term.[161] Additionally, the Tax Cut Act has created uncertainty for regulated utilities by reducing utilities access to cost-free capital to fund investments needed to serve customers.[162] This has caused both Moody's and S&P to express concern regarding the financial health of utilities.[163]

Nevertheless, the Company has a plan that allows it to pass on to customers the benefits of the Tax Cut and Jobs Act, make substantial investments to modernize ENO's service to customers, and maintain the Company's financial condition. But, successfully executing that plan depends on the Council's continuation of a constructive regulatory environment now and in the future.[164] Accordingly, a constructive ROE decision in this case is necessary to position

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159 Exhibit ENO-1 (Thomas Revised Direct) at 51.

160 Exhibit ENO-3 (Thomas Rebuttal) at 11.

161 Exhibit ENO-4 (Thomas Rejoinder) at 5.

162 Exhibit ENO-1 (Thomas Revised Direct) at 45-46.

163 *Id*. at 43-45.

164 *Id*. at 49.

ENO so that it can undertake the transformational change that the Council, the Company, and the customers envision for utility service in the future at the lowest reasonable cost.

6. The Reliability Incentive Mechanism is a reasonable way to address reliability.

ENO has over the last two to three years embarked on focused, long-term efforts to improve the reliability of its electric distribution service, including increasing its maintenance and reliability spending in the near-term and making significant investments in critical infrastructure using innovative technologies to modernize its distribution system performance.[165] The Company went from spending approximately $7 million on baseline reliability initiatives to just over $14 million in 2018, and the Company has begun to see improvements in its reliability performance.[166] Beyond its increased focus and spending on reliability initiatives, ENO proposes the RIM Plan as a transparent and straightforward approach towards achievement of certain reliability performance goals, making the earnings component of its rates contingent upon reliability performance. The plan balances the interests of ENO, its customers, and the Council; correlates ENO's ROE with its reliability performance; and is administratively straightforward to implement.[167] Similar plans have been implemented by regulators in other jurisdictions.[168]

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165 Exhibit ENO-6 (Stewart Revised Direct) at 10.

166 Tr. (Stewart) 06/18/19 at 119-120.

167 *Id.* at 26.

168 *See, e.g.*, Mississippi Public Service Commission Docket No. 2014-UN-132, Direct Testimony of Dr. Julius A. Wright (June 2014) explaining mechanism, available at https://www.psc.state.ms.us/InSiteConnect/InSiteView.aspx?model=INSITE_CONNECT&queue=CTS_ARCHIVEQ&docid=330349, and Order approving FRP (December 11, 2014), available at https://www.psc.state.ms.us/InSiteConnect/InSiteView.aspx?model=INSITE_CONNECT&queue=CTS_ARCHIVEQ&docid=344797; Pennsylvania Public Utilities Commission Docket No. R-2017-2640058, Order (10/25/2018), available at http://www.puc.state.pa.us/about_puc/consolidated_case_view.aspx?Docket=R-2017-2640058; and Rhode

Under the RIM Plan, the electric base rate revenue requirement in this case should be determined with the baseline ROE set at 10.75% as recommended by Mr. Hevert, with a Reliability Adjustment of negative 25 basis points down to 10.50% for purposes of the electric cost of service study.[169] ENO also proposes that future rate adjustments in the Electric FRP be determined by the RIM Plan's adjusted ROE/EPCOE formula, in which the adjusted ROE is the sum of the baseline ROE approved in this case and the Reliability Adjustment, up to either +/-25 basis points.[170] Contrary to the argument made by the Advisors, CCPUG and Air Products in opposing ENO's proposed RIM Plan, a mechanism tying reliability performance to any financial outcome should be symmetrical.[171] Symmetry in incentives is a logical way to heighten focus on attainment of the underlying goal of the RIM Plan. Although there should be a reasonable range representing the expected level of reliability performance where no ROE adjustment occurs, if a financial value (*i.e.*, penalty) can be ascribed to performance below the range, then a value exists for performance above the range.[172]

For purposes of the RIM Plan and application of the EPCOE formula to calculate the adjusted ROE, reliability performance would be based on ENO's System Average Interruption Frequency ("SAIFI").[173] SAIFI measures the average number of outages or interruptions per customer per year; most electric utilities use SAIFI to review the reliability of their systems,

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Island Public Utilities Commission Order No. 15382 (May 20, 1997), available at http://www.ripuc.org/eventsactions/docket/2515-Narragansett-Ord15382_Ord15399_9-97.pdf.

169 *Id*. at 24.

170 *Id*. at 23.

171 Exhibit ENO-3 (Thomas Rebuttal) at 20.

172 *Id*.

173 *Id*. at 25.

excluding major outage events.[174] SAIFI is calculated for a particular time period by adding the number of customers experiencing a sustained outage of greater than five minutes during the period and dividing that number by the average annual number of customers.[175] Over the long-term, ENO seeks to perform in the top quartile of electric utilities in the United States in terms of SAIFI benchmarking.[176] Given that SAIFI is an industry-standard method for measuring reliability performance and because it specifically measures the number of outages, it is an appropriate metric to gauge reliability improvements for purposes of the RIM Plan.[177]

The purpose behind and goal of the RIM Plan is to address an issue that is important to the Council, ENO, and its customers – reliability performance – and provide an incentive to the Company such that the earnings component of its rates could be affected – positively or negatively – depending on ENO's success in improving its reliability.[178] The concept is based on reliability mechanisms that have previously been approved by other state regulatory agencies.[179] Such a result has potential benefits for all parties involved. The plan is also designed such that if ENO offers reliability in line with the average SAIFI scores of similarly sized and situated utilities, it will earn its authorized ROE, which comports with the regulatory compact.[180] Reliable service is ENO's goal, but providing reliable service comes at a cost; the question

[174] Exhibit ENO-6 (Stewart Revised Direct) at 25.

[175] *Id*. at 25-26.

[176] *Id*. at 40.

[177] Id. at 41-42.

[178] Tr. (Thomas) 06/20/19 at 67, 69.

[179] Tr. (Thomas) 06/20/19 at 69-70.

[180] Tr. (Thomas) 06/20/19 at 72.

becomes what is the appropriate balance between the two.[181] This is a tradeoff that regulators must factor into their decision-making on just and reasonable rates. Having reliability performance goals set by the Council through the RIM Plan helps answer that question and provides ENO with concrete goals it will strive to meet its future because results will have measurable consequences.

B. The Company's equity ratio should be based on the filed equity ratio, and use of a hypothetical equity ratio or an equity ratio cap is unlawful and arbitrary.

In its Revised Application, the Company proposes that its weighted average cost of capital reflect an equity ratio of 52.2%, which is the projected December 31, 2018 Period II test year equity ratio.[182] The Period II equity ratio is lower than the actual December 31, 2018 Period I test year equity ratio of 54.93%.[183] Additionally, the Company's proposed equity ratio falls within the equity ratio range of the proxy companies used by Company witness Mr. Hevert to estimate ENO's ROE, which range was 46.26% to 61.82%.[184]

The Advisors, however, propose that ENO's equity ratio be capped at 50% for purposes of setting rates in this proceeding and rate adjustments during the term of the Formula Rate Plans. CCPUG proposes that the Company's capital structure should reflect a hypothetical amount of short-term debt. The equity ratio used for setting base rates in this proceeding should be the Company's filed equity ratio and use of a hypothetical equity ratio or an equity ratio cap is unlawful and arbitrary.

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181 Tr. (Thomas) 06/20/19 at 74-76, 177.

182 Exhibit ENO-33 (Todd Revised Direct) at 14.

183 *Id*. at 15.

184 Exhibit ENO-26 (Hevert Revised Direct) at 81.

1. **Louisiana law does not permit a regulator to ignore the utility's actual equity ratio unless there is imprudence, and no party has raised a credible issue of prudence.**

Prior to 1992, the Louisiana Supreme Court had concluded that a regulator could substitute a hypothetical capital structure for a utility's actual capital structure without finding a utility's capital structure to be imprudent or unreasonable.[185] For example, in 1979, the court upheld a regulator's decision to use a hypothetical 45% equity ratio for fixing base rates, as opposed to the regulator's previously chosen hypothetical 55% equity ratio or the utility's projected equity ratio of 50%, which was expected to increase to 55%.[186]

In 1992, the Louisiana Supreme Court rejected its previous decisions and held that a utility is entitled to have its base rates fixed using its actual capital structure absent a finding that the capital structure resulted from imprudence.[187] The supreme court based its conclusion on the inconsistency of applying the prudent investment rule to value rate base at cost but ignoring a prudent capital structure in favor of using a "theoretically optimal" capital structure for ratemaking purposes and the "injustice and arbitrariness" of such a ratemaking practice.[188] The supreme court went on to explain that, prior to 1992, it was not aware of the inconsistent application of the prudent investment rule and failed to take into account "better reasoned decisions" prohibiting the disregard of actual capital structures without a finding of imprudence

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185 South Cent. Bell Tel. Co. v Louisiana Pub. Serv. Comm'n, 373 So. 2d 478, 480-485 (La. 1979); South Cent. Bell Tel. Co. v Louisiana Pub. Serv. Comm'n, 352 So. 2d 964, 971-972 (La. 1977).

186 *South Cent. Bell Tel. Co.*, 373 So. 2d at 482.

187 South Cent. Bell Tel. Co. v Louisiana Pub. Serv. Comm'n, 594 So. 2d 357, 363-368 (La. 1979).

188 *Id*. at 366.

or unreasonableness.[189]

Neither the Advisors nor CCPUG have claimed that ENO's Period II projected equity ratio or the higher, actual Period I actual equity ratio resulted from imprudence. Although Advisors' witness Mr. Watson argued incorrectly that the Council could employ an "appropriate equity ratio" instead of the actual equity ratio,[190] he confirmed at hearing that he was not claiming that ENO's proposed capital structure or any investment decision was imprudent.[191] Although CCPUG witness Mr. Kollen proposes that the Company's proposed equity ratio be reduced as a result of his proposed short-term debt presumption, Mr. Kollen acknowledged that he was not claiming that the Company had been imprudent with respect to its use of short-term debt.[192] Accordingly, no basis exists for disregarding ENO's projected Period II equity ratio, and based on the evidence and controlling law, ENO is entitled to have its base rates fixed on its projected Period II equity ratio, or the higher actual Period I equity ratio.

2. The Advisors' proposed equity ratio is arbitrary and should be rejected as it could harm customers.

Mr. Watson's reasoning supporting his proposed equity ratio cap is flawed and as a consequence, his proposal is arbitrary and capricious. First, Mr. Watson argues that his 50% equity ratio cap is supported by "past rate actions and investment proposals, [in which] a 50% equity ratio was accepted as reasonable and employed by ENO for cost forecasting purposes."[193]

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189 *Id*. at 367-368.

190 Exhibit ADV-6, (Watson Direct) at 54.

191 Tr. (Watson) 06/21/19 at 56-57; Exhibit ENO-4 (Thomas Rejoinder), Exhibit JBT-15.

192 Tr. (Kollen) 06/20/19 at 14-16.

193 Exhibit ADV-6 (Watson Direct) at 54-55.

Mr. Watson's arguments are without merit. The past rate action to which he refers is the recovery of the non-fuel revenue requirement associated with Union Power Block 1, but the 50% limitation of the equity ratio for calculating that revenue requirement occurred pursuant to a non-precedential agreement in principle.[194] In fact, ENO expressly stated in Council Docket No. UD-15-01 that the 50% equity ratio limitation would be temporary until the Council set base rates in this proceeding.[195] Mr. Watson, however, ignores this statement in his testimonies. The Council would be arbitrary and capricious if it were to rely on a non-precedential agreement in principle to cap ENO's equity ratio at 50%.

The investment proposal to which Mr. Watson refers is a data request response in Council Docket No. UD-07-02 related to ENO's Gas Infrastructure Rebuild and, more recently, the Gas Infrastructure Replacement Program, which is a ten-year long capital project aimed at improving the reliability and safety of ENO's gas distribution system.[196] Company witness Mr. Thomas explained that, in context, the 50% equity ratio typically is used as a financial planning assumption because the equity ratio is expected to be a percentage near 50% in the future.[197] Mr. Watson does not provide any explanation as to why the Council should transform a planning assumption reflected in a discovery response to an equity ratio cap to be used for ratemaking purposes. Indeed, the Council would be taking an arbitrary and capricious leap to make a

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[194] Resolution R-15-542 at Ordering Paragraph 3 ("The ratemaking provisions related to the recovery of costs associated with the Power Block 1 Purchase that are set forth in the Union Power Purchase AIP are just and reasonable.") *See also* Union Power Station Power Block 1 Purchase Agreement in Principle, Paragraph 12, Council Docket No. UD-15-01.

[195] Tr. (Thomas) 06/20/19 at 169-170.

[196] Exhibit ENO-22 (Bourg Revised Direct) at 11-20.

[197] Tr. (Thomas) 06/20/19 at 136-138; Exhibit ENO-3 (Thomas Rebuttal) at 23.

financial planning assumption into an equity ratio cap without any valid reason to support such a leap.

Next, Mr. Watson argues that ENO's proposed equity ratio is the result of "double leverage," which he defines as ENO having a higher equity ratio than its parent, Entergy Corporation, which was expected to have a December 31, 2018 equity ratio of 34.1%. He further observes that, with double leverage, Entergy Corporation is effectively borrowing money and investing that money in ENO as equity in order to increase ENO's revenue requirement.[198] Mr. Watson's argument is nonsensical. First, customers are benefitting from ENO's relationship with Entergy Corporation because Standard & Poor's has assigned ENO a BBB+ credit rating as a direct result of ENO being a part of the Entergy Corporation group.[199] This higher rating tends to lower debt costs borne by customers. Second, Mr. Watson rejected his own double-leverage rationale by concluding that a 34.1% equity ratio "might not be considered prudent"[200] and arbitrarily selected 50% for his equity ratio cap to eliminate the effect of the alleged double leverage. When determining a ROE for a regulated utility, the source of funds of the investor is irrelevant. Moreover, at hearing, Mr. Watson admitted that he employed no standard to determine how much ENO's equity ratio should be reduced to eliminate the effect of the alleged double leverage.[201]

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198 Exhibit ADV-6 (Watson Direct) at 50-51.

199 Exhibit ENO-1 (Thomas Revised Direct), Exhibit JBT-3.

200 Exhibit ADV-6 (Watson Direct) at 54.

201 Tr. (Watson) 06/21/19 at 63-67 ("What I meant and what I mean here is I do not have an explicit quantitative standard for what is reasonable.").

Finally, Mr. Watson argues that ENO's proposed equity ratio is unreasonable based on his comparison of ENO's proposed equity ratio to the other Entergy Operating Companies' equity ratios.[202] Mr. Watson is misinterpreting the other Entergy Operating Companies' equity ratios and his comparison sheds no light on the issue. ENO's proposed equity ratio falls within the range of the other Entergy Operating Companies' equity ratios, 47.1% to 53.7%. Additionally, Mr. Watson fails to consider critical business factors that indicate ENO's proposed equity ratio should be higher than ELL's equity ratio. For example, on a relative basis, ENO is smaller than the other Entergy Operating Companies and must plan for larger debt issuances on a relative basis to have access to debt rates that are attractive; thus, a higher equity ratio is necessary to maintain ENO's equity ratio in a reasonable range while engaging in debt financing.[203] Thus, Mr. Watson's proposed 50% equity ratio cap is arbitrary and capricious.

In addition to his arguments in favor of a proposed 50% equity ratio cap being meritless, Mr. Watson does not address the harmful incentives an equity ratio cap may set into motion. In order to prevent its equity from being taken without just compensation while undertaking significant capital investment, an equity ratio cap would drive a utility to manage its equity ratio through relatively costly small debt issuances.[204] Thus, although the utility's weighted equity return may be reduced to meet some short-term objective, its weighted debt cost could increase.

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202 Exhibit ADV-6 (Watson Direct) at 52. The other Entergy Operating Companies are Entergy Arkansas, LLC; ELL; Entergy Mississippi, LLC; and Entergy Texas, Inc.

203 Exhibit ENO-3 (Thomas Rebuttal) at 26; Tr. (Thomas) 06/20/19 at 124-125.

204 Tr. (Thomas) 06/20/19 at 127-128.

3. CCPUG's proposal to include short-term debt in ENO's cost of capital also is arbitrary and would understate ENO's cost of capital.

CCPUG witness Mr. Kollen proposes that the Council "presume" that ENO's capital structure for setting base rates should include 2% short-term debt with a cost rate approximating the Money Pool borrowing rate because it is the lowest cost of financing[205] and thereby lower ENO's proposed equity ratio to 51.16%.[206] Mr. Kollen's proposal is arbitrary and capricious in all respects. First, Mr. Kollen incorrectly claims that ENO has been a borrower from the Money Pool "on balance over the last three years."[207] In fact, ENO was a borrower from the Money Pool for nineteen days in 2016 and zero days in 2017; in 2018, ENO was a borrower for 155 days but on average had a balance of over $6.6 million in lendings into the Money Pool.[208] Furthermore, ENO does not intend to use short-term debt to finance its rate base.[209] Accordingly, there is no factual basis to support Mr. Kollen's proposal.

Second, Mr. Kollen has not articulated any basis for his presumed 2% short-term debt weighting. It is an amount Mr. Kollen selected without any analysis or standard. Indeed, Mr. Kollen could have selected a 5%, 10%, or higher weighting using his lowest-cost rationale. This unprincipled approach to capital structure is the precise "injustice and arbitrariness" that the Louisiana Supreme Court observed with the use of a hypothetical capital structures, as discussed above.

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205 Exhibit CCPUG-1 (Kollen Direct) at 39-40.

206 Exhibit CCPUG-1 (Kollen Direct) at 42.

207 *Id*. at 38.

208 Exhibit ENO-3 (Thomas Rebuttal) at 28.

209 *Id*. at 29.

Third, Mr. Kollen's use of the Money Pool borrowing rate as the cost of short-term debt without a reasoned or factual basis is also specious. The Money Pool is not a standalone financing tool as its participants have no obligation to lend to the Money Pool, and, accordingly the borrowing rate is not intended to compensate other participants for committing funds for others' use.[210] If other participants were required to maintain a lending balance at all times to make funds available as Mr. Kollen's proposal would require, then there would be a more significant cost to the lending participants, which would in turn be charged to ENO[211] thus making his assumed cost of this short-term financing erroneous.

C. The Company and the Advisors agree that the Council should take new measures to address regulatory lag so that the Company can make substantial investment to meet the Council's policy objectives and customers' evolving expectations, and the Council should approve a set of ratemaking mechanisms, including Formula Rate Plans, to address regulatory lag.

The Company and the Advisors agree that regulatory lag is a concern for ENO given its planned capital program and that the Council should approve new ratemaking measures to address regulatory lag. Mr. Thomas presented evidence showing that its capital investment in infrastructure to bring benefits to customers will be substantial in the coming years and explained that the Company has a plan that allows it to pass on to customers the benefits of the Tax Cut Act, make substantial investments to modernize ENO's service to customers, and maintain the Company's financial condition, all the while maintaining reasonable rates. But, successfully executing that plan depends on the Council's continuation of a constructive regulatory

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210 *Id*. at 28-29.

211 *Id*.

environment now and in the future.[212]

Mr. Thomas listed five steps that ENO recommends the Council take to maintain ENO's financial condition and a constructive regulatory environment that ensures that ENO can meet the Council's policy objectives and customers' evolving expectations. These first three recommended steps involve the Company's concerns regarding regulatory lag: (1) a constructive ROE determination;[213] (2) adoption of new Formula Rate Plans like the ones in place in 2009 through 2012; and (3) authorization of contemporaneous cost recovery riders for large investments, such as the AMI Project, the Grid Modernization Project, and the GIRP.[214] Mr. Thomas then explained that ENO's undertaking of these large investments absent contemporaneous cost recovery would cause ENO's cash flow to deteriorate and capital to be lost and not be available for reinvestment and investment in improvements in the Company's infrastructure at a time when cash flow and capital is critical to the Company.[215] To illustrate his point, he presented an illustration of the effects regulatory lag on cash flow under two cost recovery scenarios in Exhibit JBT-8: (1) a contemporaneous cost recovery rider, which is redetermined every quarter and (2) a traditional FRP with an annual rate adjustment. This analysis showed that a contemporaneous cost recovery rider would be the superior choice for maintaining ENO's financial condition. Accordingly, ENO proposed that the Council approve the Electric and Gas AMI Charge; the GIRP Rider; and the Rider DGM with a streamlined

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212 Exhibit ENO-1 (Thomas Revised Direct) at 48-49.

213 Although mechanisms to address regulatory lag cannot cure an unreasonable low authorized ROE, if an ROE is high enough it can provide the equivalent of regulatory lag mitigation.

214 *Id*. at 49-50.

215 *Id*. at 53.

regulatory process for review and approval of grid modernization projects and continue the PPCACR. These ratemaking mechanisms are referred to as the "Specific Project Riders."

No parties objected to the establishment of Electric and Gas FRPs. The Advisors recognized the Company's concerns regarding regulatory lag but rejected the proposed Specific Project Riders (except a modified version of the PPCACR Rider) and proposed instead that the FRPs include forward-looking pro forma adjustments to account for known and measurable costs (and attendant revenue changes) in the calendar year following the historic FRP evaluation period so as to address the Company's regulatory lag concerns.[216] Advisors witness Mr. Rogers testified as follows:

> To mitigate concerns related to regulatory lag, witness Prep recommends that the Council approve an annual Electric utility FRP and annual Gas utility FRP for a period of three years. As proposed, the FRP would provide for an annual adjustment to ENO electric and Gas Rates to reduce the time between regulatory base rate actions and mitigate regulatory lag. Additionally, and to further mitigate regulatory lag, Witness Prep recommends that ENO be allowed to include prospective proforma adjustments for known and measurable capital additions budgeted for the 12-month period immediately following the FRP test year.[217]

In the Advisors' opinions, the prospective pro forma adjustments for known and measurable capital additions made all of the Specific Project Riders unnecessary.[218]

At hearing, Advisors witness Mr. Prep confirmed that the Advisors continued to recommend prospective pro forma adjustments for known and measurable cost changes in the

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216 Exhibit ENO-3 (Thomas Rebuttal) at 8.

217 Exhibit ADV-1, (Rogers Direct) at 21-22; Exhibit ADV-3 (Prep Direct) at 78 ("The additional provision for FRP adjustments would state: 'ENO may propose other known and measurable costs that are supportable and expected to be incurred in the prospective 12 months following the FRP Evaluation Period.'"); Deposition of Victor M. Prep on March 14, 2019 at 54. The portions of the deposition cited herein are included in Exhibit ENO-3 (Thomas Rebuttal), Exhibit JBT-11 *in globo.*

218 *E.g.,* Exhibit ADV-6 (Watson Direct) at 81.

FRPs to address the Company's concerns regarding regulatory lag.[219] Such known and measurable cost changes include plant additions and related changes to depreciation expense, accumulated depreciation, property tax expense, and ADIT and operating expense changes.[220] Also, the pro forma adjustments could address known and measurable revenue changes, such as a large gas customer reconfiguring its operations so that its gas demand decreased materially and its electric demand increased substantially.[221]

The Company agrees that some riders would be unnecessary during the term of the FRPs with forward-looking adjustments, assuming that ENO could implement those riders should the FRPs terminate.[222] Other Specific Project Riders would remain necessary to provide contemporary cost recovery because they addressed investment beyond the proposed term of the FRPs.[223] Additionally, the Company noted that ENO would not agree to an FRP that includes an ROE at the unreasonably low level that the Advisors and other parties proposed.[224]

The only party that objected to addressing the Company's regulatory lag concerns by including prospective proforma adjustments in the FRPs was CCPUG because it claims such treatment would give ENO the incentive to increase costs.[225] CCPUG also objected to the DGM and GIRP Riders purportedly because a traditional FRP would mitigate regulatory lag

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219 Tr. (Prep) 06/20/19 at 179-180.

220 *Id*. at 180-181.

221 *Id*. at 182-183.

222 Exhibit ENO-3 (Thomas Rebuttal) at 9.

223 *Id*. at 9-10.

224 *Id*. at 10-11.

225 Exhibit CCPUG-2 (Kollen Surrebuttal and Cross-Answering) at 25-27.

sufficiently and the riders would eliminate any review of these costs.[226] CCPUG's objections are speculative and not supported by the evidence.

Accordingly, ENO requests that the Council approve an ROE for the Formula Rate Plans that facilitates ENO's expected substantial investment and prospective proforma adjustments in the FRPs, as recommended by the Advisors, to reduce regulatory lag. CCPUG's objection to such adjustments is contrary to the Council's objectives. Alternatively, the Company recommends that the Council approve traditional FRPs and the proposed Specific Project Riders, as CCPUG's objections to the Specific Project Riders are without merit.

1. The Council should both address regulatory lag and approve a reasonable ROE for the Formula Rate Plans that facilitates ENO's expected substantial investment to benefit customers.

ENO cannot agree to an FRP[227] that includes an ROE at the level that the Advisors and other parties proposed, as these recommendations are unreasonably low and would result in one of the lowest ROEs implemented for any vertically-integrated utility. For parties to support (or not oppose) ratemaking mechanisms to address regulatory lag but eliminate the benefits of such mechanisms by recommending an unreasonably low ROE is gamesmanship. Such recommendations are not a path to constructive regulation or to meeting customers' expectations at the lowest reasonable cost.

As explained above, in this proceeding, the ROE determination is especially important because of ENO's substantial capital investment requirements in the near term. ROE determines

[226] Exhibit CCPUG-3 (Baudino Direct) at 57-58.

[227] As a mechanism that supplants a utility's right to file a base rate case, the unilateral imposition of a FRP by a regulator would be an unconstitutional taking of property. The Company must agree to forego the exercise of its right to file a base rate case for such a mechanism to be implemented.

the equity available for capital reinvestment in the utility to provide benefits to customers.[228] In short, it is not in the public interest to adopt a regulatory paradigm that assumes that the utility will fund substantial investment with the expectation of earning an unreasonably low return; neither is it in the public interest to fund substantial investment using a disproportionate level of debt due to underfunded equity capital.

2. The Company supports an FRP with forward-looking adjustments as a way of addressing regulatory lag while minimizing the need for additional riders, but some riders and a streamlined process for reviewing and approving grid modernization projects would still be needed.

Incorporating forward-looking pro forma adjustments to account for known and measurable costs (and attendant revenue changes) in the calendar year following the FRP evaluation period in a properly structured FRP would address the Company's concerns regarding regulatory lag to a great degree. Such treatment of known and measurable costs and attendant revenue changes would mitigate the need for the Electric and Gas AMI Charge Rider, the Gas R&D Charge and the DGM Rider, during the term of the FRPs and assuming the riders would be implemented after the FRPs terminate.[229]

CCPUG argues that the Council should not permit such forward-looking pro forma adjustments because they would provide ENO "a behavioral incentive to increase its costs."[230] CCPUG's argument is misguided because the Council actually is directing ENO to increase certain costs recovered in base rates for the benefit of customers, including long-term cost

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228 Exhibit ENO-1 (Thomas Revised Direct) at 51-52.

229 *Id.* at 8-9.

230 Exhibit CCPUG-2 (Kollen Surrebuttal) at 26.

savings and other benefits. The Council approved the AMI Project, which will increase ENO's rate base in the near-term while bringing long-term cost savings.[231] The Council approved construction of the NOPS to meet capacity and reliability needs.[232] The Council has been critical of ENO's electric distribution reliability,[233] and, accordingly, it is necessary to increase Distribution Reliability and Vegetation Management Spending to improve ENO's reliability performance.[234] Also, the Council has directed ENO to prioritize a comprehensive grid modernization initiative.[235] Very simply, the Council has declared these and various other policy objectives serve the public interest and ENO must increase its costs to satisfy those. CCPUG's view is contrary to the Council's directives.

Despite the constructive modifications to the Formula Rate Plans proposed by the Advisors, the proposed GIRP Rider and PPCACR rider, however, would remain necessary, and the Council should establish a streamlined process for reviewing and approving grid modernization projects. The GIRP Rider would remain necessary due to the nature and timing of the GIRP, which is expected to take place over ten years – a period significantly longer than the proposed term of the Gas FRP. The GIRP Rider would provide the regulatory certainty that 1) is needed to assure investors that ENO will have a mechanism in place to provide ENO an opportunity to recover its significant, prudently incurred investment in this project and 2)

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231 Resolution R-18-37, dated February 4, 2018.

232 Resolution R-18-65 (Mar 8, 2018) and Resolution R-19-78 (Feb. 21, 2019).

233 Exhibit ENO-1 (Thomas Revised Direct) at 4, 23.

234 Exhibit ENO-6 (Stewart Revised Direct) at 30-36.

235 Resolution R-18-36; Exhibit ENO-8 (Zimmerer Revised Direct) at 7-9.

facilitates the Company's ability to maintain qualified contractors throughout the duration of the project at a time when there is robust demand and competition for these resources.[236]

Additionally, the PPCACR Rider would remain necessary due to similar timing considerations. The proposed PPCACR Rider provides for recovery of non-fuel costs of new, Council-approved resources when there is no Electric FRP in effect. Currently, there is no ongoing project that ENO would seek to recover through the PPCACR Rider, given no opposition to the recovery of the non-fuel costs associated with NOPS through the proposed Electric FRP. However, the Company believes that this rider should continue with its proposed scope because it could serve as a recovery mechanism for Company investments in solar PV resources, other capacity additions or other emerging technology to meet renewable resource needs the Council has and will continue to identify in the coming years.[237] Although the Advisors and CCPUG have argued that the PPCACR Rider operates automatically, Paragraph I of the proposed PPCACR Rider states that the only non-fuel costs that may be recovered through the rider are those associated with a new resource authorized by the Council.[238] Therefore, there is no harm to customers from the Council adopting the proposed scope of the PPCACR Rider.

Company witness Ms. Zimmerer describes the streamlined process for the Council's review and approval grid modernization projects in her Revised Direct Testimony.[239] The process ENO proposes is similar to the process previously employed by the Council, as well as

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236 Exhibit ENO-3 (Thomas Rebuttal) at 9.

237 *Id*. at 10.

238 *Id*.; Exhibit ENO-41 (Gillam Revised Direct), Exhibit PBG-11.

239 Exhibit ENO-8 (Zimmerer Revised Direct) at 34-36.

the Louisiana Public Service Commission ("LPSC"), for the gas infrastructure rebuild and replacement programs and involves the submission of details on project design, engineering, expected benefits, estimated budgets, anticipated timelines, and other aspects of grid modernization projects and technical conferences to address issues regarding the projects.[240]

3. Alternatively, the Company's proposed FRP and all of the Specific Project Riders should be approved.

Should the Council not approve the Advisors' recommendation to include forward-looking adjustments in the FRPs, then the Council should approve the Company's proposed FRPs and all the Specific Project Riders. Although the Advisors principally object to these riders claiming they result in inappropriate single-issue ratemaking, this objection is not well-founded. ENO is proposing these riders in the context of Electric and Gas FRPs being in place and effective during the first three years of the riders' terms. In that way, the Council can consider all of the Company's costs on at least an annual basis, and inappropriate single-issue ratemaking will not occur during that period.[241]

Additionally, despite concerns regarding single-issue ratemaking, the Advisors admit that riders may be used to provide for the recovery of significant costs incurred between base rate changes in order to reduce regulatory lag.[242] Indeed, when the Tax Cut Act's reduction to the federal corporate income tax rate became effective January 1, 2018, the Council embraced single-issue ratemaking. The Council directed ENO to immediately recognize regulatory

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240 *Id*.

241 Exhibit ENO-3 (Thomas Rebuttal) at 30.

242 Exhibit ADV-1 (Rogers Direct) at 17-18 ("[R]iders may be used to provide for the recovery of significant costs incurred between full rate case proceedings that were not otherwise accounted for in base rates.").

liabilities to preserve the benefits of the income tax expense reduction for customers and avoid regulatory lag that would have benefitted ENO.[243] The Council wrote that "the reduction in ENO's electric and gas revenue requirements based upon the Tax Law should be immediately captured for the benefits of ENO's ratepayers thereby enabling the benefit to result in savings to customers."[244] The Council expressed no interest in determining whether other cost elements of ENO's electric and gas revenue requirements had increased to offset income tax expense reduction.

Here, ENO is proposing the Specific Project Riders to reduce regulatory lag between FRP rate adjustments so that ENO has a reasonable opportunity to earn its authorized return.[245] ENO expects capital additions to occur every month associated with the GIRP, Grid Modernization, and the AMI Project over a multi-year period. Rate cases cannot be conducted nearly frequently enough to keep pace with this lag. [246] The planned annual investment outpaces the recovery of that investment through depreciation several times over, and the inability of depreciation expense or sales growth to cover the planned investment supports the recovery of these costs through the riders proposed by ENO.[247] Otherwise, the Company will not be permitted a reasonable opportunity to earn its authorized return. Moreover, the receipt of benefits by customers from the capital projects associated with the Specific Project Riders and the need for and fairness of

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243 Resolution R-18-38, dated February 8, 2018, Ordering Paragraph 1.

244 *Id*. at 4.

245 Exhibit ENO-3 (Thomas Rebuttal) at 32.

246 *Id*.

247 *Id*.

timely cost recovery justify the Specific Project Riders and outweigh concerns about single-issue ratemaking.[248]

Furthermore, CCPUG's argument that the DGM and GIRP Riders do not contain procedures to protect customers like the FRPs is without merit.[249] CCPUG witness Mr. Baudino is ignoring important testimony regarding customer protections associated with the DGM and GIRP Riders. Company witness Ms. Bourg explained that the GIRP Rider would operate in conjunction with the annual Council reviews of GIRP, as recommended by the Advisors witness Mr. Rogers in Council Docket No. UD-07-02.[250] Similarly, as mentioned above, the Company proposes that the DGM Rider operate in a regulatory framework in which the Council would approve the grid modernization projects to be recovered through the DGM Rider. These regulatory proceedings augment the Council's/Advisors' quarterly review of the DGM and GIRP Riders. In these proceedings, the Company would be presenting its plans and expects to have constructive discussions about how these plans are designed to meet customers' needs. As a result, implementation of these riders and the associated regulatory processes would increase transparency for the Council and Intervenors, in addition to providing prospective information in these projects rather than relying on an after-the-fact review, which would be the result of CCPUG's recommended approach. Only after receiving approval from the Council would the Company seek to recover these costs through the proposed riders, which will then be subject to Council review. Thus, these two investment programs would receive significant focused

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248 *Id*. at 31.

249 Exhibit CCPUG-3 (Baudino Direct) at 57-58.

250 Exhibit ENO-22 (Bourg Revised Direct) at 28.

attention and would permit the Electric and Gas FRPs to focus on other aspects of ENO's operations. Moreover, these Specific Project Riders include true-up mechanisms that ensure customers pay only the prudently incurred costs of the project, including a reasonable return.

The Company believes specific factors favor the Council authorizing the Specific Project Riders. Advisors' witness Mr. Watson's view on the circumstances under which the use of a rider for cost recovery is appropriate is unduly limited and fails to recognize the financial ramifications of the transformational change that the Council, the Company and the Community envision for ENO. Mr. Watson claims that single-issue ratemaking through a rider would be appropriate only if a prudently incurred cost exhibited significantly variability and could not be controlled by the utility.[251] Such factors are applied to expenses to justify rider recovery, such as ENO's FAC and Combined MISO Rider,[252] and should not be applied to capital investment, as is the case with the Specific Project Riders.[253] As discussed previously, Advisors witness Mr. Rogers expressly recognizes a situation exists in which rider recovery is appropriate in the absence of Mr. Watson's identified factors.[254] The Company believes that Mr. Watson's factors are unreasonably narrow and should be rejected in this context.

ENO submits that a different framework for analysis is called for — one that meaningfully takes into account the financial ramifications of achieving significant regulatory

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251 Exhibit ADV-6 (Watson Direct) at 76.

252 Exhibit ADV-1 (Rogers Direct) at 30 ("As the costs that I recommend be allowed recovery through this rider can be significantly variable in nature and are outside of ENO's control, I recommend that the Council implement the combined MISO Rider as proposed in ENO's Exhibit PBG-10.").

253 Exhibit ENO-3 (Thomas Rebuttal) at 34.

254 Exhibit ADV-1 (Rogers Direct) at 17-18.

goals and directives through capital investment or a long-term expense obligation, in lieu of such investment, and that balances the interests of customers and the utility. Specifically, the Council should consider these factors when determining whether a rider, such as the Specific Project Riders, is an appropriate cost recovery mechanism. First, the Council must find undertaking the capital project or entering into the long-term expense obligation to be in the public interest; in other words, the Council effectively has directed ENO undertake the investment or the obligation.[255] Second, the Council must find that subjecting ENO to regulatory lag with respect to the recovery of the cost associated with the project or obligation presents significant cash flow and/or earnings concerns.[256] These concerns generally would arise from a large investment closing to plant in service at a single point in time or requiring multiple periodic closings each year over the long-term or the recognition of a large recurring long-term expense. Third, the rider must include an exact cost recovery mechanism so that customers bear only the revenue requirement associated with the investment or long-term expense and the utility cannot retain any over-earnings or suffer any under-earnings with respect to the investment or long-term expense.[257] The three factors described above are present with respect to the Specific Project Riders proposed by ENO, and the Company respectfully requests that the Council determine

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[255] *See id.* at 34 ("Furthermore, the Council has directed ENO to incur certain costs (*e.g.*, adding renewable resources to ENO's supply portfolio, DSM activities, reliability and grid modernization enhancements, AMI, etc.) to obtain benefits for customers.").

[256] *See id.* at 31 ("[T]he Advisors recognize that regulatory lag in the context of ENO's planned investment is a legitimate concern.").

[257] *Id*. at 36 ("Further, the riders generally ensure that the utility does not recover more than its authorized ROE with respect to such capital costs. Again, this is a benefit to customers.").

such factors are present and authorize the Specific Project Riders. It is imperative that regulatory goals and the means to achieve them are properly aligned in this proceeding.

a. AMI Charge

On February 8, 2018, in Resolution R-18-37, the Council approved a Stipulated Settlement and Term Sheet regarding the AMI Implementation. The Term Sheet provided that the prudently incurred costs associated with AMI were eligible for recovery from ENO's customers through electric and gas rates resulting from a final order of the Council in this rate case. The Term Sheet recognized that ENO and the Advisors were unable to reach agreement on the specific method for cost recovery at that time and reserved the parties' rights to argue their cost recovery positions in future proceedings.[258]

ENO proposes that AMI costs be recovered through an AMI Charge applied to electric and gas rates. The charge would commence on January 1, 2020, and ENO would file annual revisions thereafter during the term of the charge necessary to support full AMI cost recovery. After 2020 (for gas service) or 2022 (for electric service), the AMI charge would decline based on the schedule shown in Exhibit JBT-9 to the direct testimony of ENO witness Joshua B. Thomas.[259]

Advisors, in contrast, recommend that ENO recover AMI-related costs through base rates, and that ENO account for changes in the level of costs occurring over time through the Advisors' recommended Formula Rate Plan.[260] In this respect, Advisors' recommendation

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[258] Exhibit ENO-1 (Thomas Revised Direct) at 65.

[259] *Id.* at 65-55, Exhibit JBT-9.

[260] Exhibit ADV-3 (Prep Direct) at 9, 25, 34, 36-37.

acknowledges ENO's concerns regarding regulatory lag with respect to the recovery of AMI-related costs net of savings. The Alliance for Affordable Energy ("AAE") objects to recovery of AMI-related costs through a fixed charge and argues instead for their recovery through a "volumetric" rate design, though AAE witness Barnes provides no specifics regarding the mechanics or implementation of this rate design.[261]

ENO agrees that Electric and Gas FRPs that permit forward-looking adjustments, as suggested by the Advisors, could serve as a substitute for the AMI Charges, *for the duration of the FRPs*, assuming ENO's other concerns regarding the Advisors' FRP proposal can be resolved.[262] However, absent adoption of a mutually agreeable FRP, and for any future period following the termination of such FRP, ENO continues to support use of a fixed monthly charge, with annual revisions, for recovery of AMI costs. A customer charge is appropriate for recovery because the number of customers ENO serves, in large part, drives the level of the costs associated with AMI. ENO calculated the proposed customer charges in Exhibit JBT-9 using the same cost and benefit estimates presented by ENO in Docket UD-16-04 but updated to reflect the acceleration of the project, the new federal corporate income tax rate, an update to projected customer counts, and the proposed weighted average cost of capital in this case.[263]

ENO disagrees with AAE's and Advisors' objections to recovery of AMI Charges through a fixed customer charge. A fixed customer charge ties clearly and directly to cost causation principles that are fundamental to rate design. Each customer requires an advanced

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261 Exhibit ENO-3 (Thomas Rebuttal) at 43; Exhibit AAE-3 (Barnes Direct) at 34.

262 Exhibit ENO-3 (Thomas Rebuttal) at 44.

263 Exhibit ENO-1 (Thomas Revised Direct) at 66.

meter to receive the service and benefits provided through advanced metering. The number of meters is closely tied to the number of customers taking service. The usage level of individual customers does not affect the cost of the meter or the associated AMI communication systems, so an energy-based charge is not consistent with cost causation. The vast preponderance of the AMI costs is fixed. All of these facts plainly support recovery of AMI costs through a fixed charge. Furthermore, ENO's proposal to adjust the AMI charge annually greatly reduces regulatory lag, to the benefit of customers, as the AMI costs and the AMI charge steadily decline.[264] For these reasons, the Council should approve ENO's proposed electric and AMI Charges.

b. Distribution Grid Modernization Rider

As noted above, the Council's and ENO's priorities are aligned with regard to the importance of modernizing the electric grid in New Orleans. The best way to bring the Council and ENO's shared vision for a modernized grid in New Orleans to fruition in the most timely and cost-effective manner possible is through approval and utilization of the DGM Rider. Company witness Erica Zimmerer explains the process efficiency benefits of facilitating uninterrupted, continuous work on grid modernization projects and the reasons this kind of work flow can enable cost reductions for customers. Mr. Thomas explains that the DGM Rider would provide timely cost recovery, and therefore, the cash flow that is necessary to facilitate this kind of uninterrupted work.[265] Due to these dynamics, it is common for regulators who want to prioritize grid modernization work to approve riders dedicated to grid modernization cost

[264] Exhibit ENO-3 (Thomas Rebuttal) at 45-46.

[265] Exhibit ENO-1 (Thomas Revised Direct) at 52-58.

recovery, as Dr. Faruqui explains.[266] Thus, if the Council wishes to facilitate timely and cost-efficient deployment of grid modernization to support its Smart Cities initiative (which Council Resolutions have indicated is an important, and time-sensitive priority) it should approve the DGM Rider as proposed by the Company.

D. The Council should approve the Company's proposed rates and rate design, including the Algiers Residential Rate Transition Plan.

1. 1. The Company's proposed revenue allocation reasonably balances cost of service principles, Council policy, and customer rate impacts.

Once the appropriate overall revenue requirement is established, the revenue requirement must be allocated among ENO's nine electric and five gas rate classes, so that rates can be designed to collect each class' assigned revenues. A number of objectives are important to consider in the rate design process. First, to the extent possible, rates should take into consideration cost causation.[267] Second, when making changes in rate design, the Company recognizes that rate stability and rate impacts are important to customers as well.[268] These objectives can be conflicting, but when customer effects are considered, the Company's proposed rate design is a reasonable balance of these objectives.[269]

Company witness Philip B. Gillam established the initial revenue requirement for each rate class, for both the projected and historic test year, based on the cost of service study. He provided this information to Company witness Myra L. Talkington. For the reasons explained in

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266 Exhibit ENO-14 (Faruqui Revised Direct) at 42-43.

267 Exhibit ENO-16 (Faruqui Rebuttal) at 19-20.

268 Exhibit ENO-16 (Faruqui Rebuttal) at 18-19.

269 Exhibit ENO-45 (Talkington Revised Direct) at 22; Exhibit ENO-16 (Faruqui Rebuttal) at 17-20.

the testimony of ENO witness Orlando Todd,[270] the Company believes that Period II rates are more representative of going forward costs and is requesting that the Council adopt its proposed Period II rates.[271]

The Company believes that rate levels should take into consideration the cost to serve each rate class, and, accordingly, it considered the class cost data resulting from the cost of service study, summarized in Statement FF of the filing. However, for several reasons, ENO management has directed an approach to cost allocation and rate design that does not strictly follow the cost of service. The Company was concerned that strict adherence to this concept, in the circumstances of this case, would result in significant customer impacts, particularly to the residential class of customers. Therefore, the Company chose to look at rate design from a more comprehensive standpoint, considering not only the rate change effects on base rates, but also the overall customer bill impacts, including changes to applicable riders. A final important factor considered by ENO was the Council's historical practice regarding the class allocation of rate changes.

Taking into account these various rate design considerations, the Company proposes to base ENO's electric rates on the historic class allocation method utilized by the Council, rather than on the results of the cost of service studies sponsored by Mr. Gillam. As a result, each rate class initially received the ENO system average base rate increase of 46.1 percent. It is critical to understand that a substantial portion of this increase in base rate revenues is due to the fact that costs already recovered in riders were simply moved to base rates. Therefore, while base

[270] Exhibit ENO-33 (Todd Revised Direct) at 4.

[271] Exhibit ENO-45 (Talkington Revised Direct) at 23.

revenues increase, the overall impact of ENO's rate request (inclusive of revenues from the new AMI Charge for Electric Service ("AMICE") and Interim Energy Efficiency Cost Recovery ("EECR") Rider, is a decrease of $20.3 million.[272]

Finally, the Company further considered the disparate impact of the rate changes among customer classes, and the potential for rate shock for Algiers residential customers. To account for these matters, the Company re-allocated certain capacity costs among the classes on an energy basis rather than demand basis (discussed immediately below), and applied the ARRT Plan (discussed below in section D.2), to adjust the amount of revenue requirement allocated to the various customer classes.[273] ENO's proposed allocation results in a revenue decrease for every customer class save for lighting, as shown in Exhibit MLT-3 to Ms. Talkington's Revised Direct Testimony.[274]

For the gas business, the Company's Period II corrected gas cost of service study indicates that the current annual rate schedule revenue requirement for the Gas jurisdiction is approximately $40.1 million in base rate revenue.[275] This represents an approximate $2.2 million base rate revenue sufficiency (exclusive of AMI charge), compared to the Company's currently effective gas base rates.[276] ENO proposes to design base rates to meet the Company's total corrected gas sales revenue requirement.[277] As with the electric revenue requirement, the

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272 *Id.* at 27.

273 *Id.* at 24-25.

274 Exhibit ENO-45 (Talkington Revised Direct) at Exhibit MLT-3.

275 The corrected amount is shown in Table 3 to Mr. Gillam's Revised Direct Testimony, Exhibit ENO-41.

276 Exhibit ENO-41 (Gillam Revised Direct) at 11.

277 The small correction to the overall gas revenue requirement should be reflected in the final compliance

Company chose not to base proposed rates strictly on the cost-of-service studies and, instead, to maintain the currently effective base rate revenue allocations. Statement AA-2 to the filing shows the allocation of the filed base revenue requirement among customer classes.[278]

All of the parties' recommended revenue allocations in this case depart from the cost of service study in order to address customer rate impacts. However, other parties object to certain aspects of the overall process by which ENO arrived at its class revenue allocation, despite the fact that the overall results do not differ materially from that of ENO's. ENO next discusses these objections and explains the Company's well-reasoned position, while recognizing that class revenue allocation is an area where the Council exercises significant discretion.

a. Energy-based Allocation of Capacity Costs

As mentioned earlier, to address disparate customer class rate impacts and maintain the Council-approved methodology (in place since their inception in 2003), ENO allocated capacity costs associated with the Resource Plan PPAs using the relative percentage of energy sales (kWh) attributable to each class. This allocation method decreases the capacity expenses allocated to the residential rate class by $4.9 million and re-allocates that amount among the remaining customer classes. The reallocation occurs as a matter of rate design and is not reflected in the electric cost of service study.[279]

Advisor witness Prep and CCPUG witness Baron object to the energy-based allocation of the Resource Plan PPAs capacity expenses. They argue that it is contrary to the demand-based

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rates established in this case.

278 Exhibit ENO-45 (Talkington Revised Direct) at 47; Exhibit ENO-55 (Rate Case Filing).

279 *Id.* at 28-29.

allocation used in the cost of service study, at odds with cost causation principles, and creates improper subsidies among customer classes. To the contrary, as shown by ENO witness Thomas, the energy allocation not only is effective to address residential customer rate impacts, it is also founded on sound policy and cost causation principles.

Mr. Thomas explains that the amount of energy sales is an appropriate allocator for these two resources because of the low-cost energy they provide, which particularly benefits large energy users. Energy sales, in fact, is the basis for the current allocation of these capacity expenses, by virtue of being recovered through the Fuel Adjustment Clause pursuant to the agreement in principle approved by the Council in Resolution R-03-272 (May 15, 2003).[280] From 2003 until the end of 2008, large energy users captured a large portion of the energy savings resulting from these PPAs relative to then-current natural gas prices.[281] For these reasons, the energy-based allocation of the purchased power capacity costs is reasonable and the Council should maintain that allocation.

b. Advisors' Proposed Electric and Gas Revenue Allocation

Mr. Prep proposes a method for allocating the gas and electric revenue requirement among customer classes that differs in certain respects from ENO's approach. Though he claims that the allocations follow his class cost of service study, Mr. Prep, like the other cost allocation witnesses, departs from the cost of service in order to arrive at what he believes to be reasonable class revenue allocations. He accomplishes this departure by his adjustment to the *return component* of the revenue requirement, where he applies *varying* class before-tax rates of return

280 Exhibit ENO-1 (Thomas Revised Direct) at 22.

281 Exhibit ENO-3 (Thomas Rebuttal) at 17.

on allocated rate base to determine the corresponding total revenue change for each class.[282] ENO cannot support Advisors' methodology, for several reasons.

Mr. Prep did not apply any discernible standard to determine appropriate class before-tax rates of return or use any methodology such that his approach may reasonably be reviewed or accurately duplicated.[283] His allocation method is wholly subjective. Consistent, objectively identifiable and replicable allocation factors, however, are critical to the production of a meaningful cost of service study. By way of comparison, ENO bases every external allocation factor in its cost of service study on an objectively identifiable and reproducible statistic, consistently applied from case to case.[284]

Mr. Prep's approach does moderate adverse rate impacts to classes but applying wildly variable class returns does not remotely capture ENO's capital cost of serving those classes. In fact, Mr. Prep's approach has confused cost allocation and rate moderation principles.[285] ENO's overall WACC in making investments is its capital cost of serving all customers. To illustrate this point, without in any way agreeing with Advisors' cost of capital proposals, note that Advisors recommend ENO earn a return of 8.93% to recover the cost of compensating investors for capital provided so ENO can serve and build infrastructure. However, Mr. Prep proposes electric class returns ranging from 1.60% (residential) to 21.31% (municipal building).[286] These differences from overall cost of capital are arbitrary and unexplained as to how they represent the

[282] Exhibit ADV-3 (Prep Direct) at 30.

[283] Exhibit ENO-46 (Talkington Rebuttal) at 4-5.

[284] Exhibit ENO-47 (Talkington Rejoinder) at 6-7.

[285] Exhibit ENO-46 (Talkington Rebuttal) at 5.

[286] Exhibit ENO-47 (Talkington Rejoinder) at 6.

cost of serving a particular class. Instead, they represent an unduly subjective effort to arrive at revenue assignments for each class in order to avoid adverse rate impacts.[287]

c. CCPUG Proposed Electric and Gas Revenue Allocation

CCPUG accepts ENO's cost of service study, but recommends that the base rate electric revenue requirement be allocated to classes based on a 46.1% equal percentage increase, without further adjustment to the allocation of purchased power capacity costs, and further subject to a "mitigation adjustment" so that no class receives an overall increase greater than 2%.[288] As explained above, the Company's energy-based allocation of capacity costs is consistent with the energy benefits provided by the purchased power contracts and preserves the status quo allocation.

Mr. Baron's allocation departs from the cost of service study, as does that of ENO and the Advisors. However, Mr. Baron's methodology results in a rate increase for the residential, small electric, municipal, and lighting classes.[289] ENO's revenue allocation results in a revenue increase only for the lighting class.[290] Mr. Prep's electric class revenue allocations reduce current revenues for all classes.[291] ENO continues to urge, as it has throughout this case, that its class revenue allocation results in just and reasonable rates, but that ultimately the Council should weigh all the allocation proposals in the exercise of its sound discretion.

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287 *Id.* at 6.

288 Exhibit CCPUG-5 (Baron Direct) at 25-26.

289 *Id.* at 26, Table 6.

290 Exhibit ENO-45 (Talkington Revised Direct) at Exhibit MLT-3.

291 Exhibit ADV-3 (Prep Direct) at 31, Table 5.

With regard to the gas revenue requirement, Mr. Baron proposes to adjust ENO's revenue allocation to reduce by 25% what he describes as subsidies paid by gas rate classes whose revenues are above the costs assigned by the cost of service study. Mr. Baron, however, makes a further adjustment such that no class receives a revenue increase as a result of this case. As with electric rates, ENO continues to support its allocation methodology for gas customers, which maintains the existing allocation relationships among the customer classes.[292] ENO further believes, as with electric rates, the Council has discretion to arrive at a just and reasonable revenue allocation for gas customers.

d. APC Re-Allocation of Adjustments to ENO Revenue Requirement

For the most part, APC witness Mr. Brubaker does not take issue with ENO's cost of service study and cost allocation proposals. However, he recommends, to the extent the Council adopts any reductions to the electric revenue requirement proposed by ENO, that the Council spread those reduced amounts only among "those customer classes whose revenues would be above cost of service under ENO's rate proposal."[293]

ENO does not agree that adjustments to its electric revenue requirement (other than the corrections already identified by the Company) are appropriate, as explained by other ENO rebuttal witnesses. Beyond that, Mr. Brubaker's recommendation is very similar in concept to Mr. Baron's proposal to use disallowances to reverse the re-allocations of the ARRT Plan, discussed in section D.2 of this brief. For the same reasons explained therein, Mr. Brubaker's

292 Exhibit ENO-45 (Talkington Revised Direct) at 47.

293 Exhibit APC-3 (Brubaker Direct) at 15.

proposal inappropriately mixes matters regarding the determination of the revenue requirement with cost allocation, and the Council should reject his proposal.[294]

e. ***Allocation of demand costs to interruptible customers***

ENO's cost of service study excludes 85% of the interruptible load from the demands used to calculate the average 12 CP allocation factor. The remaining 15% of interruptible demand remains in the calculation to recognize the requirement to maintain generation reserves on behalf of all customers.[295] Basic cost causation principles dictate that as ENO does not need to acquire capacity to serve interruptible customers at peak demand, interruptible customers should be excluded from allocations calculated based on contribution to peak demand.[296]

Advisor witness Prep contends that ENO has given too large a demand credit to interruptible demand in the cost of service analysis. He considers frequency of actual interruption of these customers in assigning cost responsibility to interruptible customers, and in addition conducted a study to calculate the value of interruptible load. As a result, Mr. Prep recommends allocation of a larger amount of demand-related costs to these customers in the cost of service study.[297]

ENO notes that no party recommends strictly following the cost of service study in order to allocate the revenue requirements. Accordingly, this and certain other recommended adjustments to ENO's cost of service study are of limited practical importance in setting rates.

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294 *See* Exhibit ENO-46 (Talkington Rebuttal) at 6.

295 *Id.* at 10-11; Tr. (Talkington) 06/18/19 at 70; Exhibit ENO-46 (Talkington Rebuttal) at 9.

296 Exhibit ENO-47 (Talkington Rejoinder) at 9-10.

297 Exhibit ADV-3 (Prep Direct) at 47-48; Exhibit ADV-5 (Prep Surrebuttal and Cross-Answering) at 13-14.

Nonetheless, ENO disagrees with Mr. Prep's adjustment to the calculation of interruptible demand.

First, the number of actual interruptions imposed on the customer is not relevant to the allocation of costs to interruptible customers, since ENO can plan its acquisition of generation resources to avoid the cost of serving the customer at the peak regardless of the actual interruption of the customer.[298] Moreover, Mr. Prep's focus on attempting to determine the market value of interruptible service is off the mark in this context. ENO is not trying to acquire interruptible capacity or determine a fair market price for such an acquisition. ENO's objective is instead to determine what portion of its embedded production investment and fixed production costs should fairly and reasonably be allocated to an interruptible customer. Basic principles of cost causation support excluding interruptible customers from cost allocations based on contribution to peak demand, when these customers do not contribute to that demand.[299]

2. ENO's proposed Algiers Residential Rate Transition Plan is reasonable and should be adopted.

As explained by ENO rate design witness Myra L. Talkington, the combination of Legacy New Orleans and Algiers customers' rates leads to significant bill effects for Algiers residential customers, either under the Cost of Service Study or the Council's historical allocation methodology. Moreover, the bill increases to lower usage residential customers in general resulting from this case stand in contrast to the fact that the overall result of this case

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298 Exhibit ENO-46 (Talkington Rebuttal) at 9-10.

299 *Id.* at 10.

produces a revenue decrease to ENO, and significant revenue decreases for certain other classes.[300]

In light of these circumstances, ENO proposes to moderate the impact of the overall rate increase for Algiers residential customers through implementation of what it has been referred to as the ARRT Plan. ENO has developed the ARRT Plan in response to feedback received from members of the Council and its Advisors as to the need to develop a reasonable path toward a single, combined rate structure for all customers. The ARRT Plan will moderate the bill impact of the rate change for Algiers residential customers by temporarily re-allocating a portion of the Algiers residential customer base revenue requirement to other customer classes. Despite this re-allocation, a typical Algiers residential customer would receive an initial 3.5% overall rate increase under ENO's proposal.[301]

Over the course of a three-year period following the establishment of rates in this case, however, ENO will initiate a second step, 3.5% increase for Algiers residential customers, and a corresponding decrease in the revenue requirement re-allocated to other affected customer classes, to move Algiers residential customers toward parity with Legacy ENO residential customers. At the end of this three-year period (2021), if the Council has not already determined a final cost allocation and rate design methodology, ENO proposes that the Council revisit the phase-in and Algiers residential customer rate design, in order to re-evaluate the appropriateness of the cost allocation and rate design.[302] The other rate classes participating in the ARRT plan

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300 Exhibit ENO-45 (Talkington Revised Direct) at 2, 29, Exhibit MLT-3.

301 *Id.* at 30.

302 *Id.* at 2-3, 29-30.

are those who would receive an overall bill reduction of 10% or more as a result of ENO's proposed rate change (exclusive of the ARRT Plan). These classes are: Large Electric, Large Electric High Load Factor, High Voltage, and Large Interruptible. However, even after the re-allocation under the ARRT Plan, these customer classes continue to receive a significant overall rate decrease.[303]

There is substantial agreement among the parties that rate impacts for Algiers residential customers should be mitigated, but some disagreement over the details of how best to implement the ARRT. CCPUG does not oppose the ARRT, though Mr. Baron proposes a re-allocation of revenue requirement reductions in connection with the ARRT, to which ENO responds below.[304] Though APC does not address the ARRT, it raised no issue as to ENO's proposal to reallocate revenues between its rate class and Algiers customers. Advisors similarly agree that rate mitigation is necessary for Algiers customers, but make several changes to the ARRT as designed by ENO.

First, Advisors would confine the reallocation of revenues to customers within the ENO residential class; in other words, under Advisors' approach, revenues would be re-allocated to Legacy ENO residential customers, rather than other customer classes, in order to mitigate Algiers residential rate impacts.[305] This is an area of ratemaking where the Council exercises substantial discretion, and both ENO's and Advisors' approach provide rate mitigation to Algiers residential customers. The difference is that ENO's approach re-allocates revenues to classes

303 *Id.* at 30.

304 Exhibit ENO-46 (Talkington Rebuttal) at 24.

305 Exhibit ADV-3 (Prep Direct) at 80-82.

who are already receiving the largest rate decreases of any of the customer classes, while the Advisors' approach re-allocates revenues solely to Legacy ENO residential customers, who do not otherwise receive a rate decrease.[306]

The second important difference between ENO's and the Advisors' approaches is that ENO would implement the ARRT through a separate rider calculation utilizing a percent of revenue application. Accordingly, the phase-in does not affect the design or level of any of ENO's other proposed riders, nor its proposed base rates. ENO has attached its proposed Base Rate Adjustment Rider as Exhibit MLT-4 to Ms. Talkington's Direct Testimony.[307] This rider would set forth two rate adjustments applicable to Algiers residential customers and to the Large Electric, Large Electric High Load Factor, High Voltage, and Large Interruptible rate classes. The rate adjustments applicable to the Algiers residential customers, which would be expressed as a percentage, would initially be negative and decrease at the second step of the plan. The rate adjustments applicable to the Large Electric, Large Electric High Load Factor, High Voltage, and Large Interruptible rate classes, which also would be expressed as percentage, would initially be positive and decrease at the second step.

Advisor witness Prep agreed that ENO could make the ARRT future adjustments in the context of a rider, as ENO proposes. However, he also opined, in the alternative, that ENO could accomplish the future adjustments through a modification of the existing residential base rate tariff, in the course of the three-year FRP, or in future rate actions if necessary.[308] To the extent

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[306] Tr. (Thomas) 06/20/19 at 63.

[307] Exhibit ENO-45 (Talkington Revised Direct) at 31.

[308] *Id.* at 22.

the Council approves an adjustment through a standalone rider, the Advisors' concept of the ARRT appears to be similar to ENO's approach, although the Advisors would limit participation in Algiers mitigation to the residential class of customers. However, Mr. Prep did not provide specifics in his testimony or deposition of the specific design of either a rider or a modified base rate residential tariff. Thus, it is unclear from the Advisors' proposal under what terms and conditions a residential rate structure might be designed and implemented under either a rider or a base rate tariff alternative.

ENO, however, does not support implementation of Algiers residential customer mitigation through changes to the existing residential base rate tariff. This approach would add significant unnecessary complexity to the tariff design and billing of residential customers, with the potential for unnecessary customer confusion.[309] Moreover, ENO's rider approach would be applied to a single set of rates, consistent with the objective of Resolution R-17-504.

Additionally, ENO cannot support the alternative of making future ARRT rate changes in the context of the FRP. Based on Mr. Prep's surrebuttal testimony, the Company understands the Advisors' intent to be that during the course of the FRP, Algiers residential customers would receive no less than a 4% overall increase with each annual adjustment until the disparity in base rates is eliminated, regardless of whether the independent FRP adjustment were smaller, or even otherwise a decrease. However, under the Advisors' approach, the ARRT-related adjustments would still be subsumed within the adjustments required by the FRP. The Advisors' proposal

[309] *Id.* at 22-23.

raises concerns for ENO, in terms of its ability to eliminate the rate disparity in a reasonably predictable fashion.

ENO's mitigation proposal focuses solely on addressing the current disparity in the impact of the proposed base rate change on residential customers and uses the subsequent increase for Algiers customers solely to reduce the current disparity. ENO's approach would be implemented through a rate rider independent of changes that occur as a result of FRP reviews. As a result, the existing base rate disparity would be directly addressed by ENO's proposal, although not completely remedied unless the Council directs ENO to do so. The Advisors' proposal, however, would be implemented in the larger context of annual changes as part of the overall FRP rate adjustments. As a result, the degree to which the annual adjustments would eliminate the base rate disparity would be diluted, and the ability of the Advisors' proposal to eliminate the disparity in a reasonable time is subject to question.[310]

One final aspect of the ARRT plan concerns a proposal from CCPUG. Mr. Baron proposes that the first $3.325 million of any Council approved revenue adjustment to ENO's requested revenue requirements be used to eliminate ENO's proposed Base Rate Adjustment Rider changes to large customers. In other words, Mr. Baron would dedicate revenue requirement disallowances to eliminating the increased allocations to certain customer classes that are necessary to mitigate Algiers residential rate impacts under ENO's ARRT Plan.[311]

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310 Exhibit ENO-47 (Talkington Rejoinder) at 16.

311 Exhibit ENO-46 (Talkington Rebuttal) at 24; Exhibit CCPUG-5 (Baron Direct) at 27-28.

ENO disagrees with Mr. Baron's recommendation, because it improperly intermingles the establishment of the overall revenue requirement with the class allocation of that revenue requirement. Instead of first determining the overall base rate revenue requirement, then applying rate moderation methodologies with an understanding of the overall impact on the revenue requirement in mind, the effect of Mr. Baron's approach is to "cherry pick" the allocation of certain adjustments to the revenue requirement in order to advantage certain customer classes. Contrary to Mr. Baron's methodology, it is important to understand the impact of the overall change in the base rate revenue requirement—whether it be a large increase, a large decrease, little change, etc.—in order to have a firm starting point in mind for determining whether rate moderation is in order.

For all these reasons, the Council should adopt the ARRT plan as proposed by ENO.

3. The Company's proposed customer charge reduces subsidies among high and low usage residential customers, and reasonably balances consideration of cost of service principles and customer rate impacts.

In order to move its electrical residential customer charge closer to the actual cost of service, and to lessen the subsidies paid by higher usage residential customers to lower usage customers, ENO proposes to increase the charge from current $8.07 per month to $15.53 per month. The current charge is less than half of the fully cost-based customer charge of $21.07.[312] ENO is proposing to move partially, but not totally, to cost-of-service to balance cost-based rates with consideration of customer impacts.[313]

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312 Exhibit ENO-45 (Talkington Revised Direct) at 26.

313 Exhibit ENO-46 (Talkington Rebuttal) at 11; Exhibit ENO-1 (Thomas Revised Direct) at 62.

The purpose of this charge is to recover customer-related costs, which ENO defines as the minimum cost to be able to serve the customer, even if the customer does not impose a demand on the system or consume energy. The customer charge captures items such as the cost of meters, meter reading, and bill preparation.[314] By moving the residential customer charge toward the actual cost of serving the customers, ENO seeks to provide an equitable allocation among residential customers of the costs they impose on the system which are unaffected by the amount of energy they use.

Taking this approach to establishment of the customer charge is sound public policy. It reduces subsidies among members of the residential class that may arise, in particular, due to the consumption-reducing effects of energy efficiency and solar PV adoption. ENO's proposed customer charge stabilizes residential bills, as a smaller share of costs varies due to weather and other uncontrollable factors. A residential customer charge set nearer to cost also stabilizes ENO cash flow metrics, benefitting customers by contributing to stronger credit metrics that can support a lower cost of capital.[315] On balance, ENO's proposal appropriately weighs the competing rate design considerations and is reasonable.[316]

Advisors witness Victor Prep agrees that a higher customer charge is appropriate. Advisors also recognize that ENO's full cost-based customer charge calculation accurately reflects the unit cost of service for residential customers.[317] Nevertheless, Mr. Prep concludes, in

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314 *Id*. at 61.

315 *Id.* at 61-63.

316 Exhibit ENO-47 (Talkington Rejoinder) at 15.

317 *Id.* at 12, Exhibit MLT-6.

the face of ENO's thorough explanations, and with no supporting explanation of his own, that ENO's proposed customer charge calculation has no "sound basis." Ultimately, he recommends only a token increase in the charge, to $10, "to moderate the bill impact on customers with lower or minimal usage."[318]

It is evident that Advisors are concerned with the rate impact of the change in the customer charge.[319] However, they have provided no evaluation whatsoever to demonstrate the validity of that concern. Moreover, the facts speak otherwise. For Legacy ENO residential customers on average, the overall rate change is a modest 1.29%, including the effect of the higher customer charge. While it is true that lower usage level residential customers experience higher overall relative percentage increases, it is also true that they have the lowest overall bills and currently receive the largest subsidies from higher usage residential customers. Quite simply, under the current customer charge, higher use residential customers are paying the cost of ENO's ability to provide service to their lower usage neighbors.[320]

AAE also opposes ENO's proposed customer charge, and recommends a charge of just $8.13 per month, virtually no change from the current customer charge.[321] AAE witness Barnes claims that the ENO proposal is relatively high compared to an average customer charge derived from his survey of other utility companies around the country.[322] He agreed with Company

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318 Exhibit ADV-3 (Prep Direct) at 60; Exhibit ENO-46 (Talkington Rebuttal) at Exhibit MLT-7.

319 Exhibit ADV-4 (Prep Surrebuttal) at 30 (expressing concern that ENO proposal is significantly more than a gradual rate increase).

320 Exhibit ENO-47 (Talkington Rejoinder) at 14-15.

321 Exhibit AAE-3 (Barnes Direct) at 21.

322 *Id.* at 11-13.

witness Talkington, however, that ENO should base the customer charge on Company-specific information, not on benchmarks.[323] This is particularly the case when, as Mr. Barnes further agreed, numerous benchmark companies have customer charges at or above the $15.53 level proposed by ENO, and Mr. Barnes made no effort to research or understand the degree of comparability, if any, between ENO and the other companies.[324]

Similar to Mr. Prep, Mr. Barnes contends that ENO's proposal is not consistent with principles of gradualism.[325] Again, the data does not support this claim, as Mr. Barnes does not show any material difference in the total bill to residential customers between his proposal and that of ENO.[326] While Mr. Barnes pointed to the fact that ENO affiliates Entergy Arkansas and Entergy Texas had lower customer charges than ENO, he ignored the fact that the level of customer charge currently approved for Entergy Arkansas and Entergy Texas represent 74% and 73%, respectively, of their customer-related costs derived from their respective unit cost studies. For ENO, on the other hand, its current customer charge only represents 38% of its customer costs. The Advisors' proposal of $10.00 would only represent 48% of those costs while the lower AAE proposed customer charge would represent and even smaller share of those costs than the Advisors' proposal.[327] In contrast, if the Council adopts ENO's proposed customer charge, it will recover 74-75% of ENO's customer-related costs.[328]

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323 Tr. (Barnes) 06/21/19, at 13; ENO Exhibit -47 (Talkington Rejoinder) at 11.

324 Tr. (Barnes) 06/21/19, at 9-13.

325 Exhibit AAE-3 (Barnes Direct) at 14.

326 Exhibit ENO-46 (Talkington Rebuttal) at 15.

327 *Id.* at 16.

328 Tr. (Talkington) 06/18/19 at 99-100.

Mr. Barnes further contends that increasing fixed charge recovery through the customer charge will discourage energy efficiency.[329] Mr. Barnes agrees with Company witness Dr. Faruqui, however, that customers consider total bill, rather than specific portions such as the fixed charge, when considering investments in energy efficiency.[330] Dr. Faruqui further explained, and Mr. Barnes confirmed, that ENO's proposed $7.46 increase in its fixed charge represents approximately 6% of an average residential total bill of $120. Assuming revenue neutrality and constant usage, such a fixed charge increase would result in a 6% decrease in volumetric share of total bill. Such a small change, explained Dr. Faruqui, is unlikely to undermine a customer's incentive to conserve electricity.[331]

Next, Mr. Barnes argues that ENO's proposed fixed charge increase will have a disproportionate impact on low-income customers. He finds this to be concerning based on the premise that low usage customers fall at the lower end of the income spectrum as compared to high usage customers.[332] But 40% of ENO's low-income customers are high usage customers.[333] These low-income customers' bills will *decrease* due to the lower volumetric charge resulting from the increase in the customer charge. Moreover, for those low-income customers whose bills increase, there are several programs and bill options available to protect them from financial

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329 Exhibit AAE-3 (Barnes Direct) at 17-19; Exhibit AAE-5 (Barnes Surrebuttal) at 2.

330 *Id.* at 6-7.

331 Tr. (Barnes) 6/21/19, at 13-14; Exhibit ENO-18 (Faruqui Rejoinder) at 2.

332 Exhibit AAE-3 (Barnes Direct) at 25; Exhibit AAE-5 (Barnes Surrebuttal) at 8-9.

333 Exhibit ENO-16 (Faruqui Rebuttal) at 23.

hardship.[334] These are better alternatives than continuing the unnecessary subsidization of some residential customers by others.[335] As Company witness Thomas explained during the hearing:

> But I guess that my point is if I am worried about what customer needs the most help, I'm thinking about that low-income customer who has high usage, the one that parties in their opening statements referred to as having, you know, a high degree of their -- a higher percentage of their disposal income that goes to their electric bill. If anybody needs help, it is that customer. And I think the Company's proposal best helps that customer. And I think additional proposals that are made by the Company with respect to energy efficiency and other programs could further help to alleviate the burden on low-income customers.[336]

Finally, Mr. Barnes urges that ENO's cost of service study includes costs that should not be recovered through the customer charge.[337] To the contrary, it is Mr. Barnes' approach that is too restrictive. ENO limits the costs recovered through the customer charge to those that it must expend to be prepared to serve a customer, regardless of the level, if any, of the customer's consumption. These types of costs are properly considered to be fixed, and properly allocated based on the number of customers, since they do not vary with usage. Mr. Barnes' approach, on the other hand, unreasonably assumes, for example, that ENO expends $0 in general administrative costs to support its basic customer service functions, and $0 for customer premises utility installation activities that relate to the fixed cost of service.[338] ENO's proposed residential electric customer charge is supported by the preponderance of the evidence, is reasonable, and should be adopted.

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334 Exhibit ENO-16 (Faruqui Rebuttal) at 23-24.

335 *See* Exhibit ENO-16, (Faruqui Rebuttal) at 23-24.

336 Tr. (Thomas) 6/20/19 at 95.

337 Exhibit AAE-3 (Barnes Direct) at 22-24.

338 Exhibit ENO-46 (Talkington Rebuttal) at 17; Exhibit ENO-47 (Talkington Rejoinder) at 13.

4. The CLEP is indistinguishable from past proposals previously rejected by the Council.

Building Science Innovators, LLC ("BSI") has, as part of this proceeding, once again sought to have the Council approve and the Company implement a concept known as Consumer Lowered Electricity Pricing or "CLEP." As Mr. Owens' Rebuttal Testimony notes, the Council has previously rejected BSI's CLEP proposals due to numerous flaws and erroneous assumptions underlying the proposal.[339] When confronted with this reality, BSI did not attempt to modify CLEP or otherwise address the flaws previously identified by the Council. Instead, BSI's witness responded with incomprehensible procedural arguments (in testimony) and pointed to portions of its witness' Direct Testimony. These efforts do not result in any evidence that demonstrates why the Council should revisit and reverse its previous determinations regarding the merits, or lack thereof, of the CLEP concept. The Council should stand by its previous determinations and continue to decline the invitation to force the Company to incur unnecessary costs and to inflict the costs of the CLEP proposal on New Orleanians.

E. The Council should approve the Company's proposed decoupling approach because it is consistent with Resolution R-16-103 and eliminates the possibility of double recovery.

The Company submitted its proposal to comply with Resolution R-16-103, which requires ENO to file a three-year decoupling pilot program for the Council's consideration in this proceeding, through its proposed Electric FRP. The proposed Electric FRP takes the same approach to calculating the Company's earned ROE as the previous Electric FRP and excludes

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339 Exhibit ENO-12 (Owens Rebuttal) at 50, citing Council Resolutions Nos. R-16-106 and R-17-100.

all rider revenues and costs to be recovered through riders so as to prevent any chance of double-recovery of costs recovered through riders.[340]

Also, although Resolution R-16-103 directed that ENO recalculate a fixed-cost customer rate class allocation factor or factors each year consistent with the cost allocation methodology used in this proceeding and use those factors to allocate the FRP evaluation period electric revenue requirement to each rate class,[341] the Company recommends that it not be required to recalculate allocation factors each year unless the Council designed rates based strictly on rate class cost allocation resulting from the allocation factors contained in ENO's Period II Electric Cost of Service Study because it would be a waste of resources.[342] The Company makes this recommendation because (1) strictly following the rate class cost allocation from the cost of service study allocation factors would cause a disruptive increase in cost responsibility for the Residential Rate Class[343] and (2) the Council had not adopted such a rate class cost allocation in its last two rate cases.[344] Thus, the Company proposed that the FRP Evaluation Period electric revenue requirement be allocated consistent with the relative allocation of the base electric revenue among the rate classes approved by the Council,[345] absent some material change that

340 Exhibit ENO-41 (Gillam Revised Direct), Exhibit PBG-7, page 14 of 22.

341 Resolution R-16-103, Ordering Paragraph 5.

342 Exhibit ENO-41 (Gillam Revised Direct) at 34-35.

343 The Period II Electric Cost of Service Study allocated the Residential Rate Class approximately $224 million in costs; however, the Company proposed that the Residential Rate Class approximately $191 million in costs.

344 Exhibit ENO-41 (Gillam Revised Direct) at 34-35.

345 *Id*.

indicated that relative allocation should be modified.[346] For example, if the Council determined in this proceeding that the Residential Rate Class should provide 45% of the Company's revenue, despite the fact that the allocation factors indicate that the Residential Rate Class should bear more than 45% of the Company's revenue, then, the Company would allocate 45% of the FRP evaluation period electric revenue requirement to the Residential Rate Class so as to maintain the relative cost responsibility amongst ENO's rate classes set by the Council in this proceeding.[347] Such an approach is consistent with the spirit of Resolution R-16-103.[348]

The Advisors took issue with these aspects of the Company's proposed Electric FRP. First, the Advisors' witness Mr. Prep proposes that the all rider revenues and costs that are to be recovered through riders be included in the calculation of the Company's earned ROE for the Electric FRP using what Mr. Prep called his "Total Cost of Service Approach." Second, the Advisors argue that the Company should be required to recalculate allocation factors, although they proposed a cost allocation method that does not follow their own proposed allocation factors. Additionally, AAE witness Ms. Morgan argues that the decoupling portion of ENO's proposed FRP be revamped entirely and replaced with something fundamentally different, disregarding what the Council instructed in Resolution R-16-103. As explained more fully below, the Council should reject the Advisors' and AAE's positions and approve the decoupling-related provisions of ENO's proposed Electric FRP.

346 *Id*. at 37. For example, if ENO gained or lost one electric customer or group of electric customers with a significant demand, then the Company would modify the previously approved relative cost allocation subject to the Council approval.

347 *Id.*, Exhibit PBG-7, page 1 of 8 (Residential Rate Class).

348 Exhibit ENO-42 (Klucher Adopting Direct and Rebuttal) at 22.

1. The Advisors' Total Cost of Service Approach is an untested and an unnecessary departure from the typical ratemaking approach used before the Council, which would harm customers in certain instances.

The Council should reject the Advisors' proposal that the Total Cost of Service Approach be required in the Electric FRP. No evidence has been offered to show that any other retail regulator in the country requires the utilities that it regulates to include rider revenues and costs recovered through those riders when setting base rates.[349] Such approach would include revenues and costs, such as Fuel Adjustment Clause revenues and FAC-recoverable expenses, that are irrelevant to the base rate adjustment that the Electric FRP determines.[350] ENO demonstrated that the Total Cost of Service Approach does not change the level of ENO's base revenue requirement to be recovered in base rates,[351] and at hearing, ENO witness Mr. Klucher explained that the Total Cost of Service Approach would not give the Council a better understanding of ENO's financial performance because the approach would not have any effect on the calculation of ENO earnings, if done correctly.[352] Furthermore, he explained that the Total Cost of Service Approach could have the effect of shifting cost responsibility among the rate classes, although ENO's base revenue requirement from a Total Company perspective would be unaffected.[353] In summary, the Total Cost of Service Approach adds no value to the Electric FRP and the Council's regulation of ENO, and the Council should reject it in favor of

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349 Tr. (Prep) 06/20/19 at 186.

350 *Id*. at 184-185. ("Q. And it is not -- is it your intent for the Company to recover fuel expenses through the formula rate plan? A. Fuel expenses are recovered -- designed to be recovered in the fuel adjustment clause rider, if I understand your question.").

351 Exhibit ENO-43 (Klucher Rejoinder) at 4-5.

352 Tr. (Klucher) 06/18/19 at 19-21.

353 Tr. (Klucher) 06/17/19 at 204-205.

the approach (*i.e.*, exclusion of rider revenues and costs recoverable through them) previously used by the Council for many, many years.

2. The Advisors have not provided a credible reason why updated external allocation factors are needed for each FRP cycle, and, at hearing, Mr. Prep indicated the relative cost responsibility established in the rate case should be maintained.

The Advisors' insistence that the Company update external allocation factors for each FRP Evaluation Period is unreasonable because the Advisors disregarded their external allocation factors when proposing rates in this proceeding. When the Advisors calculated each rate class's revenue requirement, they varied the required rates of return for each rate class, as opposed to applying the Total Company required rate of return to each rate class.[354] Exhibit VP-20, which is included in Exhibit ADV-5, presents the Advisors' proposed total electric revenue requirement and shows the varying required rates of return for each rate class on Line 3. For example, the required rate of return for the Residential Rate Class is 1.60%, but the required rate of return for the Small Electric Rate Class is 18.32%. When asked how the varying required rates of return for each rate class were developed, Mr. Prep responded that there was no algorithm[355] or standard used, and that the only constraint was that the rate classes' revenue requirements added together equal the Total Company Revenue Requirement.[356]

The varied required rates of return for each rate class override the Advisors' external allocation factors.[357] At hearing, the Company questioned Mr. Prep regarding Exhibit VP-20.[358]

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354 Exhibit ADV-3 (Prep Direct) at 30.

355 Exhibit ENO-42 (Klucher Rebuttal) at 20 (referring to Exhibits MSK-7 and MSK-5).

356 Exhibit ADV-3 (Prep Direct) at 30.

357 Exhibit ENO-42 (Klucher Rebuttal) at 19-20.

Mr. Prep confirmed that his external allocation factors allocated 55% of ENO's electric rate base to the Residential Rate Class. But, he then confirmed that the Residential Rate Class's 1.60% required rate of return resulted in the Residential Rate Class being allocated only 10% of the Total Company required rate of return of rate base.[359] When the Company examined the effects of the varied required rates of return for each rate class versus the external allocation factors in the context of Exhibit VP-9, which was the initial version of Exhibit VP-20, the Company found that, although the external allocation factors allocated 55% of ENO's electric rate base and 48% of ENO's Operating Expenses to the Residential Rate Class, the Advisors' Residential Rate Class revenue requirement was only 44% of ENO's total revenue requirement.[360] This demonstrates that the external allocation factors are not driving the Advisors' cost allocation process.

No reason exists for the Company to be required to recalculate external allocation factors but then disregard those factors by applying varying required rates of return by rate class that overrides the external allocation factors in each FRP filing. The more straightforward course of action is to simply allocate 44% of the FRP evaluation period electric revenue requirement to the Residential Rate Class, if that is what the Council decides in this proceeding.

Moreover, the Advisors' cost allocation process is not consistent with Resolution R-16-103. Ordering Paragraph 5 directs that "the allocation methodology should be applied consistently on an annual basis" and that "the fixed-cost customer rate class allocation factor

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358 Tr. (Prep) 06/20/19 at 190-192.

359 Tr. (Prep) 06/20/19 at 193.

360 Exhibit ENO-42 (Klucher Rebuttal) at 19-20.

should be updated annually, based on average demands in each class." This paragraph requires a consistent application of external allocation factors, *i.e.* average demands, from this proceeding through the decoupling pilot program, and Mr. Prep's approach does not do that because (1) the varying before-tax rates of return for each rate class override the allocation from the external allocation factors and (2) the redetermination of those varying before-tax rates of return is not based on a replicable methodology.[361] In other words, Mr. Prep's approach involves application of subjective judgment and, thus, does not promote consistency (*i.e.*, *rate* stability) from one year to the next.

Furthermore, the Advisors have not been able to describe consistently how the Company should allocate the FRP Evaluation Period electric revenue requirement and, at hearing, indicated that relative cost responsibility amongst ENO's rate classes set by the Council in this proceeding should be maintained, which is the Company's position. At first, Mr. Prep took the position that ENO should approach the allocation of the FRP evaluation period electric revenue requirement as he did when developing Exhibit VP-20 (and its predecessor Exhibit VP-9) and should use its judgment to develop the rate class required rates of return to determine the required return on rate base for each rate class:

> Q. So what relative rates of return should ENO start with when it makes its FRP filing?
>
> A. Should ENO start with?
>
> Q. Yes, sir.

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[361] Exhibit ENO-43 (Klucher Rejoinder) at 7-8.

> A. Well, they should use their judgment same as I had in basing my recommendation. I would make an application if I were in that side or in that party looking at the present cost of service, which is there, the present revenue, seeing what return component I have and how much I would change that class by class, and I would build my recommendation for application in the same way.[362]

At hearing, Mr. Prep changed his position to one similar to the Company's. When confronted with a situation involving the required rate of return for the FRP Evaluation Period decreasing, which could occur if ENO's cost of debt decreased or its debt ratio increased, Mr. Prep testified that the relative cost responsibility amongst the rate classes established by the Council be maintained:

> Q. Assume in the FRP filing ENO's cost of capital decreased. Would ENO have to develop new customer class rates of returns in order to file its FRP?
>
> A. It's -- What decreased? Would you repeat, please?
>
> Q. Cost of capital.
>
> A. Okay.
>
> Q. Would ENO have to change the customer class rates of return from this rate case?
>
> A. If there would be a change, it would be consistent -- If there would have to be a change because of the cost of -- total cost for ENO, the WACC or the rate of return, ***I would recommend that the relatives that existed at the end of this docket be maintained*** such that the rate base by rate class, the relatives in rates of return and corresponding returns in composite added to the total company return on rate base based on the ROE or on -- I'm sorry -- the cost of capital at that time.[363]

ENO's proposed Electric FRP maintains the relative cost responsibility amongst the rate classes established by the Council for all costs.

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362 Exhibit ENO-42 (Klucher Rebuttal), Exhibit MSK-5 at 39.

363 Tr. (Prep) 06/20/19 at 202-203 (emphasis supplied).

The only reason that the Advisors have provided for why the Company should update the external allocation factors is contradicted by Mr. Prep's hearing testimony. In his filed testimony, Mr. Prep testified that the updating of external allocation factors was "necessary to reflect the change in usage patterns related to increased energy efficiency, distributed energy resources, renewables including solar, new products and equipment, and other current impacts affecting usage that were not as much of a concern in years previous" and criticized ENO's decoupling proposal because "it would maintain the relative basis of customer class revenue requirements static for the next three years of FRPs."[364] As one can see from the preceding paragraph, Mr. Prep now is in favor maintaining the relative cost responsibility amongst the rate classes.

In reality, maintaining the relative cost responsibility amongst the rate classes established by the Council in this proceeding and disregarding the external allocation factors is the only way to prevent a disruptive shift in cost responsibility to the Residential Rate Class from that approved by the Council in this proceeding. For external allocation factors to cause a cost of service study to mirror the revenue allocation being proposed by the Advisors and/or other parties in this case, a substantial change in the Residential Rate Class's 12-Coincident Peak ("12-CP") demand would be required, all else being equal.[365] Even a decrease in the Residential Rate Class's demand of 20% would not move the Residential Rate Class's cost responsibility to the level being proposed in this proceeding, and that is not likely to occur organically in the three-

[364] Exhibit ADV-5 (Prep Surrebuttal) at 27.

[365] Exhibit ENO-43 (Klucher Rejoinder) at 10.

year term of the decoupling pilot program.[366] Accordingly, the Council should reject the Advisors' recommendation requiring the Company to annually update external allocation factors.

3. AAE's new decoupling concerns are untimely and disregard the results of the deliberate stakeholder process.

In conjunction with ENO's 2012 Integrated Resource Plan ("IRP") proceeding (Docket No. UD-08-02), the Council issued Resolution R-13-363 dated October 10, 2013, which directed ENO to file a decoupling proposal for consideration by the Council. Resolution R-13-363 did not prescribe the parameters and/or features of decoupling; rather, Resolution R-13-363 served to initiate a more than two-year collaborative process that involved stakeholder engagement, several full-day technical meetings, and multiple rounds of written comments before the Advisors issued their final Report and Recommendations to the Council on February 10, 2016 ("Advisor Report").[367] After further opportunity for public comment, the Council adopted the Advisor Report and issued Resolution R-16-103 on April 7, 2016. Resolution R-16-103 set forth a number of specific requirements to incorporate a decoupling proposal into ENO's next base rate case.[368]

As described above, ENO complied with R-16-103, including filing on September 6, 2016 illustrative examples of how decoupling would work in a pilot program in compliance with Paragraph 13 of R-16-103.[369] In contrast, the AAE is recommending fundamental changes to the decoupling methodology prescribed in R-16-103, long past the time that a decoupling

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366 *Id*. at 11.

367 Exhibit ENO-12 (Owens Rebuttal) at 3.

368 *Id*.

369 *Id*.

mechanism was collaboratively developed and ultimately implemented by the Council. AAE's recommendations should be rejected as untimely and are an inappropriate end run around the Council's established process.

Moreover, AAE witness Morgan admits that she "did not participate in any of the proceedings or workshops that led to the Council's Resolution No. R-16-103."[370] At hearing she also admitted that at the time she prepared her direct testimony she had not reviewed any of the numerous reports, comments, and other resolutions that were filed over the lengthy course of the Council's decoupling proceeding.[371] Ms. Morgan further admitted that she did not review the illustrative examples submitted by ENO on September 6, 2016.[372] Rather, instead of offering an opinion on whether ENO's proposed FRP with decoupling complies with the Council's directives for a pilot decoupling mechanism, Ms. Morgan focused on suggesting untimely, substantive changes to the Council's Resolution R-16-103 in order to conform it to what she considers "standard decoupling."[373]

For example, Ms. Morgan recommends excluding customer charge and minimum bill revenues from the decoupling calculations, which she admits is inconsistent with Paragraph 6 of Resolution R-16-103.[374] Ms. Morgan also admitted that her "standard decoupling" proposal is inconsistent with Paragraphs 2, 5, and 9 (assuming Paragraph 9 is consistent with the operations

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370 Exhibit AAE-2 (Morgan Surrebuttal) at 3.

371 Tr. (Morgan) 06/18/19 at 161-163.

372 Tr. (Morgan) 06/18/19 at 163-164.

373 Exhibit AAE-1 (Morgan Direct) at 1.

374 Tr. (Morgan) 06/18/19 at 169-170.

described in the Advisor Report at page 22) of Resolution R-16-103.[375] Finally, Ms. Morgan recommended that any decoupling mechanism should not be subject to a dead band,[376] which is contrary to the Advisors' interpretation of Resolution R-16-103 as well as the Company's position.[377]

Given that the collaborative process to develop a pilot decoupling mechanism for New Orleans began nearly seven years ago and Resolution R-16-103 was issued over three years ago, it is simply too late in the process for entertaining the AAE's recommendations to fundamentally change how a pilot decoupling adjustment should operate in New Orleans. The time to challenge the pilot decoupling mechanism that was embodied in Resolution R-16-103 is long past, and the Council should reject the AAE's alternative decoupling mechanism. The consensus reached after many years of hard work and arduous debate among the stakeholders to produce Resolution R-16-103 should not be upended in this proceeding because one party has a different viewpoint that fails to consider the resolution defining the contours of the decoupling pilot in New Orleans.

F. The Company's proposed Rider DMSCR should be approved because it is the best way to attain the Council's policy objective of achieving indifference between supply-side and demand-side resources.

At the outset of the Council's Energy Smart initiative, the Council resolved, through Resolution R-07-600, to "provide sufficient, timely, and stable program funding to deliver energy efficiency,"[378] to develop a process to "align incentives equally for [energy] efficiency

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375 *Id*. at 172-174, 176.

376 *Id*. at 166.

377 Exhibit ADV-4 (Prep Direct) at 79.

378 Resolution R-07-600 at 4. *See* also Council Resolution R-14-122 ("[T]he Council finds it in the public interest to provide the necessary funding to continue the existing Energy Smart Programs to assure

and supply side resources,"[379] and "to provide an opportunity to earn a comparable profit for saving energy as is generally available for generating or delivering energy."[380] To achieve those objectives, the Company proposed a progressive new model for cost recovery related to DSM initiatives offered through Energy Smart, called the Demand-Side Management Cost Recovery Rider (DSMCR),[381] which would continue the Council-approved practice of using a rider as the mechanism for providing consistent and stable funding for DSM initiatives.

As summarized by Mr. Owens, the model ENO proposes to employ would use a regulatory asset tied to each year's DSM investments, which would earn a return and be amortized over three years, to recover the costs of each Program Year ("PY") of Energy Smart.[382] The return and the determination of the rate of return that ENO would earn on the regulatory asset would function as an incentive mechanism for achieving the savings goals established during the IRP process.[383] The rider would also recover LCFC contemporaneously as DSM investments are being made, which is consistent with the Council's historic practices, but would not include those dollars as part of the regulatory asset.[384]

This improved, progressive DSM cost recovery model will allow the Company to expand and enhance Energy Smart and potentially implement other DSM offerings, facilitate recovering

continuity of energy efficiency programs in New Orleans…").

379 Resolution R-07-600 at 3.

380 Resolution R-07-600 at 3.

381 Rider DSMCR is attached to Mr. Owens's Revised Direct Testimony (Exhibit ENO-10) as Exhibit DAO-3.

382 Exhibit ENO-10 (Owens Revised Direct) at 3. As Mr. Owens also notes, the Council's practice has been to approve new budgets for Energy Smart in three-year cycles, typically coinciding with the filing of a new triennial Integrated Resource Plan.

383 Exhibit ENO-10 (Owens Revised Direct) at 3.

384 Exhibit ENO-10 (Owens Revised Direct) at 3.

associated costs, and position DSM as an ongoing core component of ENO's business capable of delivering customer-centric solutions in a timely, cost-effective, and responsive manner. Moreover, as explained by ENO witness Dr. Faruqui, who is a principal with the Brattle Group and has over 40 years of academic, consulting and research experience as an energy economist,[385] the Rider DSMCR "fully aligns the interests of ENO and its customers in order to maximize the savings produced from" the Council's Energy Smart program.[386] Dr. Faruqui also explained that the regulatory asset model for recovery of DSM investment has recently been embraced by several other progressive regulators seeking to maximize DSM benefits for customers.[387]

In crafting an effective DSM cost recovery model, it is undisputed that the mechanism must address three elements: (1) direct and indirect costs of DSM measures; (2) recovery of fixed costs related to lost kWh sales from DSM products and services; and (3) a performance incentive tied to savings achieved. For example, Dr. Faruqui discusses how numerous DSM advocates like the American Council for an Energy-Efficient Economy ("ACEEE") have argued in recent years that appropriately addressing these three elements will create the right ingredients to "level the playing field" between DSM and supply-side alternatives and will, in fact, increase the likelihood that a utility will maximize the utilization of cost-effective DSM to meet customer needs.[388] AAE witness Barnes also agreed that "creating utility revenue indifference and

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385 Exhibit ENO-14 (Faruqui Revised Direct) at 1.

386 Exhibit ENO-16 (Faruqui Rebuttal) at 2.

387 Exhibit ENO-14 (Faruqui Revised Direct) at 29-31; Exhibit ENO-16 (Faruqui Rebuttal) at 7-9.

388 Exhibit ENO-14 (Faruqui Revised Direct) at 19.

incentives for good performance are sound public policy principles."[389] Similarly, Advisors witness Prep agreed that aligning utilities' incentives in such a way that the utility is indifferent as to investing in demand-side resources as compared to investing in supply-side resources is an important policy goal,[390] and that "the revenue impacts of increasing energy efficiency should be addressed in a timely manner."[391] The Council has recognized those three elements as necessary for effective DSM as well.[392]

ENO's proposed Rider DSMCR , as supported by Dr. Faruqui, fully addresses all three elements in a way that is designed to maximize the potential for achieving the Council's aggressive Energy Smart savings goals and implementing the Council's policy objective of creating economic indifference between supply-side and demand-side resources. As explained by Mr. Owens, the regulatory asset-based cost recovery model, with the associated performance adjustments, will help put DSM investment on equal investment footing with other types of traditional utility assets.[393] In other words, if supply-side resources and DSM are to be treated equally, the utility's investments in each should be afforded similar treatment. Further, earning a return on DSM investments is more consistent with the general view of ENO's owners that investments (whether in traditional assets or in DSM) should present an opportunity to earn a fair

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389 Exhibit AAE-3 (Barnes Direct) at 38.

390 Tr. (Prep) 06/20/19 at 203.

391 Exhibit ADV-5 (Prep Surrebuttal and Cross-Answering) at 29.

392 *See*, *e.g.*, Council Resolution No. R-15-140 (… "DSM industry best practices support the recovery of fixed costs from kWh sales reductions due to DSM programs…") and Resolution No. R-07-600 supporting recovery of program costs and incentives.

393 Exhibit ENO-10 (Owens Revised Direct) at 23.

return.[394] Given that cost-effective DSM investments are desired by customers and can help lower costs over the long-term, they should be afforded an opportunity to earn a return.

Implementing a new regulatory asset-based cost recovery model is the best mechanism to help put the Council's policy goals into practice. In contrast, the Advisors and AAE positions with respect to recovery of lost fixed costs revenues and performance incentives fall well short of accomplishing the Council's goals.

2. The Advisors' proposed EECR cost recovery mechanism should be rejected because it falls short of accomplishing the Council's DSM goals and it is incomplete.

Advisors witness Prep recommends using the "proposed EECR Rider as the cost recovery mechanism" for Energy Smart.[395] Presumably this means the Interim Energy Efficiency Cost Recovery Rider included as Exhibit DAO-2 to Mr. Owens's Revised Direct Testimony. As explained by Mr. Owens, the interim Rider EECR is a modified version of the previously-approved EECR rider that the Council directed ENO to implement[396] for use to fund Energy Smart from the time that new base rates are adopted as a result of this proceeding until the end of PY 9, which is currently set to end on December 31, 2019.[397]

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394 Exhibit ENO-10 (Owens Revised Direct) at 23.

395 Exhibit ADV-4 (Prep Direct) at 68.

396 R-17-623 provided that, "in the absence of any additional supplemental [Energy Smart Legacy] funding ordered by the Council prior to June 2018," ENO should implement an EECR rider "on ENO Legacy customer bills commencing with the first billing cycle in July 2018." Although ENO anticipated that the Council would approve the May 22, 2018 AIP, including the funding allocation for Energy Smart, ENO filed the EECR out of the abundance of caution and in order to ensure compliance with Resolution R-17-623, as well as continuous funding for Energy Smart. Ultimately that EECR rider was never needed or implemented.

397 Exhibit ENO-10 (Owens Revised Direct) at 14.

The "Interim EECR" is intended serve as a temporary funding mechanism for <u>both</u> the Legacy and Algiers Energy Smart offerings approved in Resolution R-17-623.[398] It was merely intended to support the status quo until Rider DSMCR could be implemented starting in 2020 with Energy Smart PY 10.[399] Importantly, it does not include a mechanism for recovery of LCFC or a reasonable performance incentive commensurate with the expected future investments in Energy Smart. In other words, the Interim EECR is fundamentally flawed as an ongoing funding mechanism for DSM for ENO because it will not place DSM investment on equal footing with more traditional supply-side resources and other investments in capital assets used to serve ENO's customers and therefore is inconsistent with the Council's stated policy objectives regarding energy efficiency funding.

In his Surrebuttal and Cross-Answering testimony, Mr. Prep acknowledged the defect in his proposal with respect to LCFC, explaining that while the Advisors still do not support Rider DMSCR, "the revenue impacts of increasing energy efficiency should be addressed in a timely manner."[400] Mr. Prep's proposal to address LCFC is to make adjustments to ENO's proposed FRP to allow for pro forma adjustments to evaluation period billing determinants for the twelve months subsequent to the FRP evaluation period.[401] While Mr. Owens explained that Mr. Prep's proposal "would seem to present a workable" solution,[402] it is of course first contingent on an acceptable FRP being adopted. If there is no FRP implemented, or upon the expiration of any

398 Exhibit ENO-10 (Owens Revised Direct) at 14.

399 Exhibit ENO-10 (Owens Revised Direct) at 14-15.

400 Exhibit ADV-5 (Prep Surrebuttal and Cross-Answering) at 29.

401 Exhibit ADV-5 (Prep Surrebuttal and Cross-Answering) at 29.

402 Exhibit ENO-13 (Owens Adopting and Rejoinder) at 7.

FPR that is adopted, Mr. Prep's Rider EECR does not include a mechanism to address the revenue impacts of increasing energy efficiency that he agrees should be addressed in a timely manner.[403] Second, it is unclear from Mr. Prep's proposal what type of documentation or other evidence would be required to support a pro forma adjustment to billing determinants.[404] Without knowing if that is a bar that can be met, ENO cannot support Mr. Prep's proposal.

Third, even if the first two issues are resolved in an acceptable FRP, Rider DSMCR remains the best mechanism for addressing LCFC because it provides contemporaneous recovery of LCFC whereas Mr. Prep's FRP approach would not make a rate adjustment for LCFC until eight months into the year in which the DSM programs causing the reduced sales are implemented. In other words, FRP rate adjustments are not made until September each year, meaning that the lost fixed cost revenues attributable to DSM programs starting in January would not be reflected in rates until September – a lag of eight months. Rider DSMCR, on the other hand, includes contemporaneous recovery of LCFC beginning in January of each year.[405] Thus, to accomplish the Council's goal of putting supply-side and demand-side resources on a level playing field, the DSMCR rider is the better approach.

With respect to a performance incentive mechanism, the Advisors' EECR proposal is also inadequate and incomplete. Mr. Prep recommends that the incentive mechanism and associated amounts be deferred until after this proceeding when the Council considers costs and

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403 Exhibit ADV-5 (Prep Surrebuttal and Cross-Answering) at 29.

404 Exhibit ENO-13 (Owens Rejoinder) at 7.

405 Exhibit ENO-12 (Owens Rebuttal) at 12.

budgets for Energy Smart PY 10-12.[406] Given the Council's objectives of developing and implementing a DSM cost recovery framework that provides sufficient, timely, and stable program funding to deliver energy efficiency as well as aligning incentives equally for [energy] efficiency and supply side resources (a principle with which Mr. Prep agrees[407]), it makes no sense to defer the incentive mechanism structure, particularly with no guidelines at all around its potential future form. That does not provide the Company the certainty necessary to make DSM a core part of its business or put DSM on a level playing field with supply-side resources. This piecemeal approach instead of putting in place a comprehensive DSM investment program serves no legitimate interest.

The Advisors' proposal is analogous to a Company being told it can recover the costs of a new supply-side resource but that the allowed return, if any, would be determined in the future on a year-by-year basis. Moreover, in this proceeding the Council is undertaking a comprehensive examination of all factors affecting electric and gas rates for ENO's customers. The recommendation to leave an issue as important as DSM recovery unresolved in this proceeding is contrary to the purpose of a comprehensive rate case and seems to advocate for "single-issue ratemaking," which the Advisors have historically claimed to oppose. The Council should decline to follow Mr. Prep's recommendation to partially resolve the issue of DSM funding in this proceeding.

Finally, the only specific criticism of Rider DSMCR by Mr. Prep seems to be at page 69 of his Direct Testimony where he states that: "Energy Smart funding requirements will likely

406 Tr. (Prep) 6/20/19 at 203-204.

407 Tr. (Prep) 6/20/19 at 203.

keep increasing substantially each year, and the combined customer obligations prospectively will be less with the contemporaneous Energy Smart recovery being treated as expenses, rather than as a regulatory asset."[408] Mr. Prep provided no analysis to support his conclusion that his proposed Rider EECR has a lesser rate impact than Rider DSMCR. Mr. Owens, on the other hand, tested Mr. Prep's conclusion and found that, due to spreading out cost recovery over several years instead of just one, plus certain ADIT treatment associated with the regulatory asset approach of Rider DSMCR, Rider DSMCR has a lower rate impact on customers than Rider EECR.[409]

In particular, assuming that 95% of savings targets are achieved and, accordingly, no additional ROE incentives are in effect for Rider DSMCR, Rider DSMCR has a lower rate impact, on a net present value basis ("NPV"), of approximately $3 million for assumed Energy Smart programs implemented during 2020 through 2025.[410] Further, assuming the highest scenario where ENO achieves 120% of savings targets and includes a 200 basis points ROE adder per ENO's proposed incentive framework, Rider DSMCR has a lower rate impact of nearly $4 million (NPV) compared to EECR for the same time period.[411] Mr. Owens's analyses were not contested by any party. It remains unclear why the Advisors are opposed to a framework that has a lower rate impact on customers using the same inputs and methodology that are consistently used to compare alternative options to serve customers' energy needs.

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408 Exhibit ADV-4 (Prep Direct) at 69.

409 Exhibit ENO-12 (Owens Rebuttal) at 17-22.

410 Exhibit ENO-12 (Owens Rebuttal) at 22.

411 Exhibit ENO-12 (Owens Rebuttal) at 22.

In summary, in response to the Council's ambitious DSM goals, the Company's desire to incorporate DSM as a core part of its business, and the Council's and the Company's shared objective of creating indifference between investing in supply-side versus demand-side resources, the Company has proposed a modern, progressive DSM cost recovery mechanism designed as a win-win for all stakeholders. The Advisors, in contrast, simply propose to maintain the status quo, which will not likely advance the Council's Energy Smart vision.

3. The AAE's proposed changes to Rider DSMCR are unnecessary and reflect a lack of understanding of the Council's Energy Smart framework and policies.

The AAE appears generally supportive of the Company's approach, as AAE witness Barnes explains in his Surrebuttal that:

> my recommended DSM program design is quite similar to what ENO originally proposed. I agree with ENO that an indifference mechanism to address potential revenue attrition from energy efficiency should be adopted, and that the DSM program design should allow the Company to receive a performance incentive for successfully supporting increased customer energy efficiency. Where we appear to differ is on the amount of that incentive and how closely it ties to achieving energy efficiency savings goals.[412]

Mr. Barnes also said he agreed with the principle first articulated by AAE witness Morgan some years ago that, "[i]deally, the utility's efforts on energy efficiency should include a performance based earnings opportunity that is as good ***or better*** than it has for new generation to recognize the qualitative benefits of energy efficiency to both customers and the community in general."[413]

412 Exhibit AAE-5 (Barnes Surrebuttal) at 14.

413 Tr. (Barnes) 6/21/19 at 17-18; Tr. (Morgan) 6/18/19, at 186.

While the AAE disagreed with including an LCFC recovery mechanism in rider DSMCR, its witnesses were both in agreement that LCFC needed to be addressed,[414] and Ms. Morgan explained her position that LCFC would be addressed through her proposed decoupling mechanism and therefore not needed in Rider DSMCR.[415] As explained earlier, however, Ms. Morgan's proposed decoupling mechanism is inconsistent with Resolution R-16-103, and Mr. Owens explained that the decoupling mechanism embodied within Resolution R-16-103 does not address LCFC.[416] In fact, Advisors witness Prep recognized that flaw, which, as discussed earlier, he attempts to resolve through proposed revisions to the FRP to allow pro forma adjustments to test year billing determinants.

Accordingly, absent an agreeable FRP solution, and assuming the Council does not change the decoupling mechanism embodied in R-16-103 in favor of Ms. Morgan's proposed decoupling,[417] maintaining the Company's proposed LCFC adjustment in Rider DSMCR is necessary. In fact, Ms. Morgan agreed at hearing that, if a decoupling mechanism that compensates for lost kW sales caused by DSM is not adopted, something else needs to be in place to address the issue, particularly "[i]f regulators and the service territories' goals are to

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414 Exhibit AAE-5 (Barnes Surrebuttal) at 14; Tr. (Morgan) 6/18/19 at 182.

415 Exhibit AAE-5 (Barnes Surrebuttal) at 14-15; Exhibit AAE-1 (Morgan Direct) at 30-31.

416 Exhibit ENO-12 (Owens Rebuttal) at 10-11.

417 Even should the Council adopt Ms. Morgan's decoupling proposal, Mr. Owens explained that LCFC recovery would remain a troublesome issue because, under Ms. Morgan's decoupling proposal, rate changes that would address lost revenues would not occur until over a year after the revenues were lost, which creates significant and perpetual lag. (Exhibit ENO-13 (Owens Rejoinder) at 7-8). That type of lag is inconsistent with the policy goal of creating indifference between supply-side and demand-side resources.

have the utility pursue energy efficiency with all due attention."[418] Something else is necessary here because R-16-103 decoupling does not compensate for lost energy sales caused by cost-effective DSM investments. Thus, the LCFC component of Rider DSMCR is necessary.

With respect to the performance incentive, AAE witness Barnes recommends an unnecessarily punitive mechanism that does not recognize the Council's Energy Smart framework already in place in New Orleans. Indeed, Mr. Barnes admitted at hearing that he has never testified before the Council or anywhere else in Louisiana.[419] More importantly, Mr. Barnes has not participated in any way in ENO's IRP or Energy Smart proceedings,[420] and while he recalled reviewing "a couple New Orleans" resolutions in preparation for his testimony, he could not recall if he reviewed any of the specific resolutions addressing Energy Smart or the Company's IRP proceedings.[421] Thus, Mr. Barrnes's unfamiliarity with the Council's Energy Smart program is not surprising.

Despite having no background in the Council's Energy Smart program, Mr. Barnes recommended a performance incentive framework in which the Company would earn no return on its investment if it failed to achieve a minimum savings target threshold plus additional penalties on top of the elimination of the earnings opportunity.[422] In addition, Mr. Barnes recommended a more granular framework with more "steps" than the Company proposed, as

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418 Tr. (Morgan) 6/18/19 at 182.

419 Tr. (Barnes) 6/21/19 at 4-5.

420 Tr. (Barnes) 6/21/19 at 5-6.

421 Tr. (Barnes) 6/21/19 at 5-8.

422 Exhibit AAE-5 (Barnes Surrebuttal) at 14-15.

well as a cap on total incentives.[423] As Mr. Owens explained, the Company is agreeable to a more granular framework with more steps,[424] but Mr. Barnes's other recommendations are unnecessary under the Council's Energy Smart framework already in place.

Under the Company's proposed Rider DSMCR, the Company would reduce the earnings on its DSM investments by 100 basis points for failing to meet at least 60% of the PY's targets.[425] As the Council is aware, but Mr. Barnes presumably is not, the Council exercises considerable control over Energy Smart, including approving the individual measures implemented each year that make up the Energy Smart portfolio, establishing the overall portfolio budget for the year, and establishing the savings target.[426] While the Company participates extensively in developing those criteria, ultimately it is the Council's decision as to what ENO implements.[427] After the portfolio, budgets, and savings target are established by the Council for a year, the Company uses its capital to implement the various customer offerings that comprise the Energy Smart portfolio.[428]

Under that framework, it is not reasonable, absent a finding of imprudence on the Company's part, to penalize the Company by limiting recovery solely to Energy Smart investments below a predetermined savings threshold, and, additionally, to impose a second-step penalty equivalent to the value of foregone cost savings for failing to achieve the minimum

423 Exhibit AAE-5 (Barnes Surrebuttal) at 14-15.

424 Exhibit ENO-13 (Owens Rejoinder) at 10-11.

425 *Id.*

426 *Id.*

427 *Id.*

428 *Id.*

threshold. If the Council found that the Company was imprudent in how it implemented any of its efforts, it could disallow up to 100% of the investments for those measures, which would also mean that the Company earns no incentive on those disallowed amounts.[429] Accordingly, given that the Company is implementing the Council's directives with the Company's capital, no more onerous "penalty" mechanism is needed.

The same holds true with respect to Mr. Barnes's proposed incentive cap. Because the Council establishes the budget for each Energy Smart program year, there already is an effective cap in that the Company is not authorized to spend more than the budget. An additional cap is unnecessary.

G. The Company's proposed depreciation rates should be adopted.

4. The Company's proposed depreciation rates are based on sound analysis conducted by a depreciation expert.

Depreciation rates are intended to provide recovery of invested capital, cost of removal, and credit for salvage over the expected life of the applicable property.[430] As part of its initial and revised case in this proceeding, ENO witness Mr. Donald J. Clayton, a Certified Depreciation Professional who has performed numerous depreciation studies over the years, submitted a depreciation study that he conducted based on electric and gas utility plant in service at December 31, 2016. Schedules I and II in the Depreciation Study Reports attached as Exhibit DJC-3 and DJC-4 to his Revised Direct Testimony detail the results of the study.[431] Mr. Clayton determined service life and net salvage estimates and developed depreciation rates for all of the

429 *Id.*

430 Exhibit ENO-35 (Clayton Revised Direct), at 5-6.

431 *Id*. at Exh. DJC-4 and Exhibit ENO-35A.

Company's gas and electric plant except for intangible plant, asset retirement obligations, and acquisition premiums. As a result of that study, Mr. Clayton recommended revised depreciation accrual rates for ENO's electric and gas utility property in his Direct Testimony. Company witness Lisa Walther used the depreciation rates from that study to develop test year adjusted depreciation expense for both electric and gas cost of service.[432]

The revised depreciation rates recommended by Mr. Clayton resulted in a $2.5 million increase to ENO's annualized electric depreciation expense/accrual amounts and a $137,000 increase to ENO's annualized gas depreciation expense/accrual amounts based on the study's 2016 plant balances.[433] The increases are primarily required as a result of increases in investment levels since the Company's last depreciation studies.[434]

CCPUG is the only party to the proceeding that challenged any aspect of Mr. Clayton's depreciation study. The Advisors and all other parties but CCPUG have accepted all of Mr. Clayton's updated depreciation rates for all of the various categories of gas and electric property. Even CCPUG has accepted the bulk of Mr. Clayton's depreciation and amortization recommendations. There are only three discrete issues CCPUG has raised with respect to Mr. Clayton's recommended depreciation rates.

First, in his Direct Testimony, CCPUG witness Mr. Lane Kollen has recommended the Council adopt a 40-year depreciable life for Union Power Block 1 ("Union PB1") instead of the

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432 Exhibit ENO-40, (Walther Revised Direct) at 12-13.

433 Exhibit ENO-35 (Clayton Revised Direct) at Exh. DJC-4 and Exhibit ENO-35A.

434 Gas depreciation rates were last updated in 2009. Electric property depreciation rates were last updated in 1980. Exhibit ENO-35 (Clayton Revised Direct) at 4.

more appropriate 30-year depreciable life proposed by the Company. Second, Mr. Kollen has also made the reckless recommendation that the Council forego inclusion of a reasonable demolition cost, or net negative salvage value, for Union PB1 in the Company's depreciation rates. Instead, Mr. Kollen makes the unreasonable recommendation that no demolition cost at all be included in the plant's depreciation rate. Finally, Mr. Kollen recommends that the Council adopt a 20-year amortization period for the general plant accumulated depreciation reserve deficiency instead of the more reasonable 10-year amortization period proposed by the Company.

Each of these issues will be discussed in detail below. However, all three of Mr. Kollen's depreciation recommendations are patently unreasonable and should be rejected by the Council. A 40-year depreciable life for the Union PB1 does not match the depreciable lives of similar plants and is unreasonable. Failure to include a reasonable demolition cost estimate in the plant's depreciable cost is inequitable and will penalize future customers who will not receive service from the plant. And a 20-year amortization period for the general plant accumulated depreciation reserve deficiency is significantly longer than the underlying lives of the assets themselves and is unreasonable.

5. CCPUG's recommendations regarding Union PB1 have no merit and are based on a results-oriented approach that does not balance the interests of stakeholders.

a. Service Life

The General Instructions to the FERC Uniform System of Accounts ("USOA") requires that utilities use a method of depreciation that allocates the service value of depreciable property in a systematic and rational manner over the *service life* of the property.[435] The instructions also indicate that estimated service lives of depreciable property must be supported by engineering, economic, or other depreciation studies.[436] In this case, ENO is the only party that complied with these USOA requirements and supported its proposed useful life of Union PB1 with a comprehensive depreciation study and sound professional engineering testimony.

The Company has proposed a reasonable 30-year depreciable life for the Union PB1 based on the useful life determinations design-life specifications of similar plants. However, CCPUG witness Mr. Kollen claims that the Company's recommended 30-year service life is "excessively short" and that a 40-year service life should be used for Union PB1. Mr. Kollen points to certain data reported by the Energy Information Administration ("EIA"), *i.e.*, Energy Information Administration November 2018 Form EIA-860M ("Form EIA-860M").[437] In particular, Mr. Kollen indicates that the data reported by EIA shows "there are combined cycle units that were in service for 40 to 50 years before their retirements," ... "and combined cycle units that have been in operation for 40 to 50 years and still remain in operation."[438] Mr. Kollen argues that this data indicates that plants similar to Union PB1 have a 40-year life. However, as both Mr. Clayton and Mr. Robert Breedlove, ESL's Director of Fleet Maintenance in Power Generation, point out, Mr. Kollen's argument is fatally flawed.

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435 *See* 18 C.F.R. Pt. 101, General Instructions, No. 22(A) (Depreciation Accounting).

436 *See* 18 C.F.R. Pt. 101, General Instructions, No. 22(B) (Depreciation Accounting).

437 Exhibit CCPUG-1 (Kollen Direct) at 29.

438 Exhibit CCPUG-1 (Kollen Direct) at 29.

In the first instance, while criticizing ENO witness Robert Breedlove's testimony as speculative,[439] Mr. Kollen has also characterized his assertion of a 40-year service life as "entirely possible," which, on its face, is sheer speculation. He has included the further conditional assertion that it "may be economic to operate Union PB1 for more than 40 years," which underscores the guesswork underlying his position. In fact, only a small population of the November 2018 Form EIA-860M data set referenced by Mr. Kollen in his Direct Testimony is offered to support this claim.[440]

As Mr. Clayton points out, the data that Mr. Kollen relies on to support his recommendation of a 40-year service life reflects the life span of the referenced power stations but does not reflect the average age of the dollars that have been spent at each station. In other words, Mr. Kollen identifies the length of time that the oldest individual items of plant have been in service but does not reflect the life of any of the investments related to plant items that have been made subsequent to the initial in-service date. Since depreciation reflects the capital recovery of the investment in *all* of the plant items, the ages of all of the plant items to be recovered through depreciation must be used in developing appropriate depreciation rates.[441]

Additionally, using the EIA data as the basis for depreciation rates (*i.e.*, using the overall life span as the average service life) produces a bias toward lives that are too long for depreciation purposes. Even though a generating station may be in service beyond 30 years, it is often the case that the average age of the investment in the station will be below 30 years. In his

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439 Exhibit CCPUG-2 (Kollen Surrebuttal and Cross-Answering) at 17-18.

440 Exhibit ENO-49 (Breedlove Rejoinder) at 4.

441 Exhibit ENO-36 (Clayton Rebuttal) at 1-2.

Rebuttal Testimony, Mr. Clayton provided a simple example that illustrates this point. If we assume a 40-year life span for Union PB1 and annual additions subsequent to the initial in-service date totaling a very conservative 2.5% of the initial investment, the average life of the overall investment would be 30 years and not 40 years as proposed by Mr. Kollen.[442]

Furthermore, as Mr. Breedlove testified, the comparison Mr. Kollen relies upon for his recommendation of a 40-year service life for Union PB1 was not based on a broad population of units representative of the entire industry of combined-cycle gas turbine ("CCGT") plants. Instead, Mr. Kollen chose a small, results-oriented sampling of units for comparison and uses it to try to support an unjustified position regarding Union PB1. Mr. Kollen never stated in his testimony why these units were chosen for comparison to Union PB1 other than the fact that these units had significantly longer-than-average service lives among the data population taken from the EIA Form 860M database.[443]

There is also insufficient operational data for CCGTs of the vintage of Union PB1 to conclude that these units can operate beyond 30 years without extending the initial service life by introduction of substantial capital investment.[444] According to the Electric Power Research Institute, "[t]ypical design lives of fossil- fuel plants are in the range of 25 years or 200,000 operating hours, but many **can be extended** to more than 40 years **with increased investment**. Many individual component parts have significantly shorter design lives." (emphasis added).[445]

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442 Exhibit ENO-36 (Clayton Rebuttal) at 2.

443 Exhibit ENO-49 (Breedlove Rejoinder) at 3-4.

444 Exhibit ENO-48 (Breedlove Rebuttal) at 6-7.

445 Exhibit ENO-48 (Breedlove Rebuttal) at Exh. RAB-2.

In fact, ENO witness Mr. Breedlove cautions against strict reliance on statistical information reported by EIA because of, among other things, differences in CCGT technology. Mr. Kollen points out in his testimony that the service lives for combined-cycle units "may be 40 years or more" when reviewing actual service lives reported by the EIA.[446] However, a closer review of the EIA data relied upon by Mr. Kollen reveals that the average useful life of all currently-retired combined-cycle units listed in the EIA database is 26.8 years – significantly less than the 40 years suggested by Mr. Kollen. Analysis of the combined-cycle units that have been retired with a useful life at or longer than the 40 years suggested by Mr. Kollen indicates that such units are significantly different in technology than the Union PB1 plant as judged by the size of the plant, which has significantly increased as newer technologies have been introduced into the industry. For example, the average size of the retired combined-cycle plant population is less than 50 MW, whereas the Union PB1 plant has a nominal rating of 538 MW.[447]

Mr. Breedlove also pointed out that, when analyzing the operating CCGT units that are older than 30 years as set forth on Form EIA-860M (Exhibit RAB-1, p. 2), there is a pattern in the types of CCGTs that are still in operation at that age. That pattern generally reflects (i) significantly smaller plants (*e.g.*, ELL's Sterlington Unit 7) with older technology, and (ii) older legacy steam turbines that were repowered. Mr. Kollen does not state in his testimony whether these repowered units were included in his analysis of the age of existing CCGT units, but the

446 Exhibit CCPUG-1 (Kollen Direct) at 29.

447 Exhibit ENO-48 (Breedlove Rebuttal) at 7-8.

inclusion of such units in the data set provided by Mr. Kollen would not be comparable to Union PB1.[448]

Mr. Breedlove also testified that the EIA data cited by Mr. Kollen, when viewed in proper context, supports a 30-year useful life more than it does Mr. Kollen's position. In reaching his conclusion, he relied on his 20 years of responsibility for maintaining CCGTs and discussions with Original Equipment Manufacturers and long-term service providers. The prevailing industry literature and statistical data, combined with Mr. Breedlove's years of experience in managing CCGTs, led him to the conclusion that the size, vintage, and operating profile of Union PB1 support Mr. Clayton's recommended 30-year useful life for establishing depreciation rates for this plant.[449] Mr. Kollen's experience in this field is certainly not superior to that of a certification depreciation expert and an engineer with more than 20 years of managing fossil generating units. Accordingly, Mr. Kollen's recommendation is less reliable than that of the Company witnesses and should be given no weight.

In fact, the full set of Form EIA-860M data from which Mr. Kollen sourced his limited sample of generating units supports the Company's position. The average age of retired CCGT units in that full data set is approximately 27 years, versus an average retirement age of 52 years for the combined Natural Gas Steam Turbine and Conventional Steam Coal plants listed in the Form EIA-60M.[450] This data from the entire population of power plants shows that the fleet of newer CCGT plants has experienced significantly shorter service lives than the older fired-boiler

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448 Exhibit ENO-48 (Breedlove Rebuttal) at 9-10.

449 Exhibit ENO-48 (Breedlove Rebuttal) at 10.

450 Exhibit ENO-49 (Breedlove Rejoinder) at Exh. RAB-3.

and steam turbine power plants. In sum, more complete sampling of the EIA data referenced by Mr. Kollen clearly demonstrates a significant difference in CCGT actual service life compared to older technology plants (with an in-service date prior to 2000).[451] Mr. Clayton also observes that Union PB1 was not originally constructed or operated by ENO or another utility. As a more modern, large frame machine, Union PB1 was constructed to achieve greater thermal efficiencies and output as compared to older combustion turbine and combine-cycle plants. These design features have required trade-offs in design margin, which impact the plant's useful/service life. As such, the life of the plant is expected to be somewhat less than plants constructed by Entergy or other investor-owned electric utilities.[452]

A 30-year average service life is also within the range of lives used by other generators for facilities similar to Union PB1. Entergy Mississippi, LLC ("EML") has used a 30-year life for its Hinds and Atalla power plants, which are very similar to the Union Power Block. In addition, a compilation of deprecation statistics based on information reported in FERC Form 1 shows that other companies use 30-year lives for similar plants.[453] For example, Ameren has service lives of 30 years for its Joppa and Grand Tower Stations. Indianapolis Power and Light actually uses a 25-year life for its Eagle Valley Station, which is a large combined cycle facility built in 2002 and is similar to Union PB1.[454]

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[451] Exhibit ENO-49 (Breedlove Rejoinder) at 3-4.

[452] Exhibit ENO-36 (Clayton Rebuttal) at 3; Tr. (Clayton) 6/18/19 at 148-149.

[453] Exhibit ENO-36 (Clayton Rebuttal) at Exh. DJC-5.

[454] Exhibit ENO-36 (Clayton Rebuttal) at 3, Exh. DJC-5.

As explained by Mr. Breedlove, within the first 30 years of operation, several major and costly refurbishments are required to keep such a station in service and these investments will have lives far shorter than 30 years.[455]

Finally, Mr. Clayton also outlined in his Rebuttal Testimony the harm that would result from establishing a useful life for Union PB1 that was too long. If the initial service life is set too long, future customers will have to make up capital recovery shortfalls over shorter and shorter timeframes. In extreme cases, customers who never benefited from the output of the plant will have to pay for a portion of the plant's cost. Also, if the life is set too long, the total revenue requirement over the life of the asset will be higher than it should be because the average rate base over the life of the asset will be higher than it would be if the proper life is used.[456]

b. Salvage Value

As Mr. Clayton explained, it is unreasonable to assume that there will be no cost of removal associated with Union PB1 when it is ultimately taken out of service. Based on his analysis of historical retirements for other similar Entergy CCGT stations, it is clear that the cost of removal will exceed the gross salvage value of the retired equipment, and negative 8% is well within the range used by other electric companies.[457]

For its CCGTs, Entergy Arkansas, LLC and EML are currently using negative 10%. In Entergy Louisiana, LLC's most recent depreciation study, negative 8% net salvage for other

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455 Exhibit ENO-36 (Clayton Rebuttal) at 4.

456 Exhibit ENO-36 (Clayton Rebuttal) at 4.

457 Exhibit ENO-36 (Clayton Rebuttal) at 4-5.

production was estimated. Importantly, this estimate includes the Union Power Blocks 3 and 4, which are identical to Union PB1. In the most recent study for EML, which has not yet been approved by the Mississippi Public Service Commission, negative 7% was estimated for the Attala station and negative 10% was estimated for the Hinds station.[458]

Mr. Kollen is also wrong to argue that it is inappropriate to use gross salvage and cost of removal data related to interim retirements as a guide for net salvage amounts. As Mr. Clayton explains, when studies of final dismantlement costs are not available, it is very appropriate to use gross salvage and cost of removal related to interim retirements as an input to the net salvage estimate, and this is routinely done by depreciation professionals.[459]

Mr. Clayton also explained that his net salvage estimate was based on detailed dismantlement studies done for similar plants. EML has recently commissioned dismantlement studies by Sargent and Lundy for its Attala and Hinds stations, which are similar to Union PB1. The estimates for the Attala and Hinds stations include analysis of both interim retirements and the final dismantlement cost estimated by Sargent and Lundy.[460]

Mr. Clayton also explained that it is appropriate to include net negative salvage (or net cost of removal) in the deprecation rate so that customers who benefit from the use of the asset during its service life pay the total cost of the asset, including its ultimate disposition cost. If net cost of removal is not included in the deprecation rate, customers who have never benefited from

458 Exhibit ENO-36 (Clayton Rebuttal) at 5.

459 Exhibit ENO-36 (Clayton Rebuttal) at 5, 7.

460 Exhibit ENO-36 (Clayton Rebuttal) at 6.

the use of the asset will end up paying for the ultimate disposal of the asset.[461]

Finally, Mr. Clayton observed that Mr. Kollen's position with respect to net salvage directly contradicts his position with respect to Union PB1's service life. For service life, Mr. Kollen wants ENO to rely on data for stations other than Union PB1. But for net salvage, he insists that ENO rely on specific experience for Union PB1. This is inconsistent. To estimate 0% net salvage due to a lack of specific plant data shows just how little experience Mr. Kollen has with respect to standard utility plant depreciation practices. The Company has detailed studies of future removal costs for stations similar to Union PB1 that are a far better basis for establishing the net salvage rate than simply using 0% as recommended by Mr. Kollen.[462]

6. The Company's proposed recovery period for the electric general plant deficiency is reasonable, and CCPUG's is arbitrary.

ENO has been using a scheduled retirements approach for its general plant other than structures and improvements for many years. However, the existing rates for electric general plant have been too low, and the book reserve as of the study date was approximately $10.2 million lower than it should have been. ENO depreciation witness Mr. Clayton accordingly separated this portion of the book reserve so that the shortfall in recovery can be trued-up and recovered over a 10-year period.[463] The 10-year period is a reasonable period to balance the interests of the Company and its customers, given that reserves are typically resolved over the remaining life of the assets, which is shorter than 10 years. The proposed 10-year

461 Exhibit ENO-36 (Clayton Rebuttal) at 6.

462 Exhibit ENO-37, Rejoinder Testimony of Donald J. Clayton, at. 8.

463 Exhibit ENO-35 (Clayton Direct) at 14.

amortization period will not overburden ENO's customers but still allow recovery of the reserve by the Company in a reasonable amount of time.[464]

CCPUG witness Kollen does not dispute adjustment of the plant reserve deficiency. He claims, however, that ENO's proposed 10-year amortization of its general plant reserve deficiency is unreasonably short, given the magnitude of the deficiency, and recommends increasing the amortization period to 20 years.[465] Mr. Kollen's recommendation strays far from the treatment of the plant reserve deficiency that is consistent with the "remaining life" depreciation methodology that all parties recognize is appropriate for establishing depreciation rates, and unreasonably extends the recovery of the deficiency. Therefore, the Council should reject Mr. Kollen's result-oriented attempt to reduce ENO's depreciation expense and revenue requirement.

Mr. Clayton explains that the remaining life methodology calls for reserve deficiencies to be trued-up over a time equal to the average remaining life of the underlying depreciable group. In the case of general plant, that average remaining life is 5.9 years. ENO has already mitigated the impact of that amortization on its revenue requirement by proposing to extend the amortization period from 5.9 to 10 years.[466] As Mr. Clayton noted during the hearing, Mr. Kollen's recommended 20-year amortization period, however, "would be longer than the [depreciable] life of any of the underlying general plant asset categories."[467]

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464 Tr. (Clayton) 6/18/19, at 146.

465 Exhibit CCPUG-1 (Kollen Direct) at 36-37.

466 Exhibit ENO-36 (Clayton Rebuttal) at 8.

467 Tr. (Clayton) 6/18/19 at 147, 159-160.

As Mr. Clayton summarized the harm to the Company and customers that would occur if the amortization period extended to 20 years:

> To go to a 20-year amortization is simply not justified. Delaying capital recovery beyond a reasonable period such as 10 years fosters generational inequity, raises the overall cost to customers, and contributes to a higher risk profile for the Company. The use of capital recovery periods that are set arbitrarily too long will depress the amount of internally generated funds available for asset replacement and put the Company in a position where alternative and more costly sources of capital must be found.[468]

H. The various revenue requirement adjustments recommended by the Advisors and the Intervenors should be rejected.

1. The Council should approve ENO's inclusion in rate base of the portion of net operating loss accumulated deferred income taxes ("NOL ADIT") attributable to accelerated tax depreciation consistent with Internal Revenues Service normalization rulings reviewing regulated ratemaking treatment of NOL ADIT in other jurisdictions.

Accelerated tax depreciation yields tax deductions that result in credit ADIT in Account 282; this ADIT is included in rate base and reduces rate base.[469] The ADIT is included as a reduction in rate base because the deductions create cost-free capital by delaying tax payments to the government.[470] When any business has more income tax deductions, which come from various sources including accelerated tax depreciation, than taxable income, the excess of the income tax deductions over taxable income is called a net operating loss or "NOL." Because the business does not defer tax payments for the deductions giving rise to the NOL, the business is allowed to deduct the NOL on future income tax returns. On the business's accounting books,

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468 Exhibit ENO-37 (Clayton Rejoinder) at 9.

469 Exhibit ENO-50 (Roberts Rebuttal) at 10.

470 *Id*. at 10-11.

the NOL is recorded as an asset in the ADIT accounts.[471] In the case of a utility, that NOL ADIT quantifies the amount of income taxes that was unable to be deferred from accelerated tax depreciation deductions.[472]

In this proceeding, ENO seeks to include only the NOL ADIT associated with accelerated tax depreciation deductions consistent with Internal Revenue Service ("IRS") normalization rulings reviewing regulated ratemaking treatment of NOL ADIT in other jurisdictions, which have been issued in the last five years.[473] If the Council rejects ENO's proposed treatment of NOL ADIT in this proceeding, the IRS could find that the normalization rules, Internal Revenue Code §168(i)(9) and Treasury Regulation §1.167(l)-1, have been violated and require ENO to discontinue its use of accelerated tax depreciation on its income tax return; this would result in significantly lower ADIT balances at ENO and a substantial increase in costs to customers because of the resulting increase in rate base.[474]

Accordingly, the Council should approve ENO's inclusion of the portion of NOL ADIT attributable to accelerated tax depreciation in rate base consistent with IRS normalization rulings regarding other regulators' ratemaking decisions. ENO is only requesting that the NOL ADIT be included in rate base consistent with IRS normalization rulings. The Advisors' objection to ENO's proposed treatment of NOL ADIT is based on their incorrect belief that deferred income

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[471] *Id*. at 9.

[472] *Id*. at 10-11.

[473] *See Id.*, Exhibit RLR-2.

[474] *Id*. at 12.

tax expense from accelerated tax depreciation increases ENO's revenue requirement and revenues.

a. ENO is only requesting that the NOL ADIT attributable to accelerated tax depreciation be included in rate base consistent with IRS normalization rulings in order to prevent the loss of accelerated tax depreciation.

The IRS normalization rulings issued in 2014 and 2015 included as Exhibit RLR-2 to Exhibit ENO-50 are what requires the Council to approve ENO's inclusion of the portion of NOL ADIT attributable to accelerated tax depreciation in rate base. In 1999, the Louisiana Supreme Court affirmed an LPSC decision excluding the utility's NOL ADIT from rate base on the grounds that the NOL ADIT was attributable to the deregulated portion of the utility's operations and not regulated accelerated tax depreciation[475] and observed that "no Internal Revenue Service rules or regulations" precluded the NOL ADIT analysis presented by the LPSC Staff's consultant.[476] Since then, however, the IRS has issued rulings that prescribe how a utility is to determine what portion of NOL ADIT is attributable to accelerated tax depreciation.

As explained by Company witness Mr. Roberts, Treasury Regulation §1.167(l)-1(h)(1)(iii) provides if the accelerated tax depreciation claimed by a utility causes a NOL or increases a NOL, then the amount of ADIT included in rate base shall be determined in a manner "satisfactory to the district director."[477] The IRS has issued private letter rulings explaining what

475 *Entergy Gulf States, Inc. v. Louisiana Pub. Serv. Comm'n*, 730 So.2d 890, 911 (La. 1999) ("[W]e find that the Commission did not act arbitrarily or capriciously by not reconsidering its previous ruling to exclude from rate base the NOL and AMT carryforwards discussed hereinabove based upon its determination that the carryforwards were caused by the deregulated portion of River Bend.").

476 *Id*.

477 Exhibit ENO-50 (Roberts Rebuttal) at 11-12; Exhibit ENO-52, (Roberts Rejoinder) at 5-6.

method is satisfactory for determining the portion of NOL ADIT attributable to accelerated tax depreciation; Exhibit RLR-2 to Exhibit ENO-50 contains two IRS private letter rulings ("PLRs"): one dated September 2014 and the other dated November 2015. The only method that the IRS has found acceptable is the "with and without method."[478] The method of determining the NOL ADIT attributable to accelerated tax depreciation used by the Company in this proceeding is the "last dollars deducted" method, which produces the same result as a "with and without" method.[479]

In the September 2014 PLR, the IRS concluded that the reduction of rate base by the full amount of the utility's ADIT balance unreduced by the NOL ADIT attributable to accelerated tax depreciation would be inconsistent with Internal Revenue Code §168(i)(9) and Treasury Regulation §1.167(l)-1 and that the use of a NOL ADIT balance for rate base purposes less than the amount attributable to accelerated depreciation computed on a "with and without" basis would be inconsistent with Internal Revenue Code §168(i)(9) and Treasury Regulation §1.167(l)-1.[480] In the November 2015 PLR, the IRS concluded that the reduction of rate base by the full amount of the utility's ADIT balance unreduced by the NOL ADIT attributable to accelerated tax depreciation would be inconsistent with Internal Revenue Code §168(i)(9) and Treasury Regulation §1.167(l)-1 and that the use of a NOL ADIT balance offset less than the amount

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478 Exhibit ENO-52 (Roberts Rejoinder) at 6.

479 *Id*.

480 Exhibit ENO-50 (Roberts Rebuttal), Exhibit RLR-2, pages 10-11 of 19.

attributable to accelerated tax depreciation computed on a "last dollars deducted" basis would be inconsistent with Internal Revenue Code §168(i)(9) and Treasury Regulation §1.167(l)-1.[481]

ENO is not requesting a ratemaking treatment more favorable than the ratemaking treatment that the IRS required in the September 2014 PLR and the November 2015 PLR. Advisors witness Mr. Proctor agrees that ENO requested ratemaking treatment for NOL ADIT attributable to accelerated tax depreciation is "very similar" to the ratemaking treatment that the IRS required in those PLRs.[482] Accordingly, the Council should approve ENO's inclusion in rate base of the portion of NOL ADIT attributable to accelerated tax depreciation so as to avoid a normalization violation.

Moreover, these IRS normalization rulings are consistent with proper ratemaking. As mentioned above, accelerated tax depreciation yields tax deductions that result in credit ADIT in Account 282; ENO has included this ADIT in rate base to reduce rate base because it measures the potential cost-free capital available to the Company from the delay of tax payments. But, because ENO has is in a NOL position, some of the accelerated tax depreciation has not delayed tax payments. Thus, both the credit ADIT and the NOL ADIT asset must be netted together to measure the amount of cost-free capital available to ENO.[483]

Additionally, Mr. Proctor has offered an alternative recommendation if the Council concludes that the NOL ADIT is included in rate base. He recommends that an amount equal to

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481 *Id.*, Page 18 of 19.

482 Tr. (Proctor) 6/21/19 at 84.

483 Exhibit ENO-50 (Roberts Rebuttal) at 10-11.

the NOL ADIT be included as reduction to deferred income tax expense.[484] Mr. Proctor agrees that his alternative recommendation is similar to the ratemaking proposal discussed in the November 2015 PLR.[485] The IRS concluded that including an amount equal to the NOL ADIT as reduction to deferred income tax expense would be inconsistent with Internal Revenue Code §168(i)(9) and Treasury Regulation §1.167(l)-1[486] As Mr. Roberts described it in his testimony, this alternative recommendation is merely flow-through accounting, which violates the normalization rules, in particular Internal Revenue Code §168(i)(9)(B).[487]

b. The Advisors' objection to ENO's proposed treatment of NOL ADIT is based on their incorrect belief that deferred income tax expense from accelerated tax depreciation increases ENO's revenue requirement and revenues.

The Advisors witness Mr. Proctor's objection to ENO's proposed treatment of NOL ADIT is that, during the period ENO generated an NOL "ENO's recovery of the depreciation related deferred income taxes increased ENO's cash revenues by an amount equal to the deferred taxes" and "provided cost-free capital from the customers."[488] That is, when a utility uses accelerated tax depreciation on its tax return, a utility includes in its rates the resulting deferred income tax expense and gets "through the rates it is permitted to charge its customers – a direct

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484 Exhibit ADV-10, Direct Testimony of James M. Proctor, at 81.

485 Tr. (Proctor) 6/21/19 at 88-89.

486 Exhibit ENO-50 (Roberts Rebuttal), Exhibit RLR-2, Pages 18 of 19.

487 Exhibit ENO-50 (Roberts Rebuttal) at 14.

488 Exhibit ADV-13 (Proctor Surrebuttal and Cross-Answering) at 50.

cash flow benefit from those customers for the deferred income tax expense on its books."[489] According to Mr. Proctor, this is "the most fundamental flaw" in ENO's position.[490]

Mr. Proctor is incorrect; deferred income tax expense resulting from accelerated tax depreciation does not increase ENO's revenue requirement or rates and does not increase revenues received from customers. At hearing, ENO questioned Mr. Proctor concerning Exhibit RLR-6, which presents four examples related to the determination of income tax expense to be included in a utility's revenue requirement.[491] In each example, the utility had the same Regulatory Pre-Tax Income; however, in each example, the utility had a different Tax Return Taxable Income due to various timing differences. The exhibit showed for each example the calculation of Total Current Income Tax Expense (Line 6c), Deferred Income Tax Expense (Line 7), and the Income Tax Expense to be included in a utility's cost of service (Line 8), which was the sum of Total Current Income Tax Expense and Deferred Income Tax Expense. Mr. Proctor agreed that the calculations for these three items were all correct for the four examples.[492]

The focus of the questions turned to two examples on Exhibit RLR-6: Example One, in which there was no timing difference as Regulatory Pre-Tax Income was the same as Tax Return Taxable Income,[493] and Example 3, in which there was a timing difference similar to that which

489 Exhibit ADV-10 (Proctor Direct) at 74-75.

490 Exhibit ADV-13 (Proctor Surrebuttal and Cross-Answering) at 50.

491 Exhibit ENO-52 (Roberts Rejoinder), Exhibit RLR-6.

492 Tr. (Proctor) 06/21/19 at 103-107.

493 *Id*. at 103.

occurs when a utility uses accelerated tax depreciation on its income tax return.[494] The pertinent portions of Exhibit RLR-6 are shown below.

Line		Example One	Example Three
1	Regulatory/Tax Revenue	$ 1,000	$ 1,000
2	Regulatory Expense	$ 700	$ 700
3	Regulatory Pre-Tax Income (Line 1 - Line 2)	$ 300	$ 300
4	Tax Deduction Less/(More) Than Regulatory Expense (Timing Difference)	$ -	$ (100)
5	Tax Return Taxable Income (Line 3 plus Line 4)	$ 300	$ 200
6c	Total Current Income tax expense (Amount Payable to IRS on current tax return) (Line 5 times 21%) (Also equal to Line 6a plus Line 6b)	$ 63	$ 42
7	Deferred Income Tax Expense (credit) (-Line 4 times 21%)	$ -	$ 21
8	Income tax expense included in cost of service (Line 6c + Line 7)	$ 63	$ 63

When confronted with this exhibit, Mr. Proctor admitted that whether or not ENO uses accelerated tax depreciation on its tax return does not affect the level of income tax expense included in ENO's revenue requirement and customers' rates,[495] that is, the amounts on line 8 are the same, thus contradicting what he stated in his filed testimony. When pressed on whether he stated in his deposition that deferred income tax expense from accelerated tax depreciation increased ENO's revenue requirement, he responded that he "may have misspoke."[496] Indeed, Mr. Proctor misspoke not only in his deposition but also in his filed testimonies.

494 *Id*. at 104.

495 *Id*. at 114-115.

496 *Id*. at 112-113. The colloquy is as follows:

As one can see from the excerpt from Exhibit RLR-6, if a utility uses accelerated tax depreciation on its tax return, the utility's deferred income tax expense does increase, as Mr. Proctor points out in his filed testimonies, but, at the same time, the utility's current income tax expense decreases, which Mr. Proctor ignores. Mr. Roberts explained this in his Rebuttal Testimony.[497] Exhibit RLR-3 attached to Exhibit ENO-52 demonstrate that ENO's use of accelerated tax depreciation has no effect on the level income tax expense included in ENO's revenue requirement in its Period II Electric and Gas Cost of Service Studies. As a result, when considering income tax expense, a utility's customers are indifferent as to whether a utility uses accelerated tax depreciation on its tax return (i.e., Example Three) to defer tax payments or not (i.e., Example One). Thus, Mr. Proctor's argument that "a utility receives – through the rates it is permitted to charge its customers – a direct cash flow benefit from those customers for the deferred income tax expense on its books" is incorrect, and his analogy of this alleged cash benefit being a loan from the customer is misleading.

Mr. Proctor's misunderstanding about the effect of deferred income tax expense on a utility's revenue requirement is the reason that he complains the IRS normalization rulings

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Q. It has the effect of increasing the revenue requirement in your opinion; right?

A. Oh. Wait a minute. Okay. The amount of income tax expense that's recovered in rates is $63. Okay?

Q. Uh-huh (indicating affirmatively).

A. By including the deferred income tax in rates, they're paying an amount of tax that is greater than the amount -- It should be they're paying an amount of tax that is less than the amount that is collected in rates. Okay? So I may have misspoke with respect to the answer in the deposition. . . .

497 Exhibit ENO-50 (Roberts Rebuttal) at 3 ("Customers' rates reflect the same amount of income tax expense because the deferred income tax expense for normalized items is offset dollar for dollar by an increase or reduction in the current income tax expense.").

included as Exhibit RLR-2 to Exhibit ENO-50 contain "misinformation."[498] At hearing, Mr. Proctor testified that his misinformation issue concerned the fact that the taxpayers in those rulings did not state that deferred income tax expense was reflected in their rates in prior periods and the IRS did not discuss deferred income tax expense.[499] As shown by Exhibit RLR-6, the use of accelerated tax depreciation, although it increases deferred income tax expense, does change the level of income tax expense reflected in a utility's revenue requirement. Thus, Mr. Proctor's claim of misinformation is a misunderstanding on his part, not an infirmity in the PLR.

Mr. Proctor's other reason why he says that the Council should give no weight to the IRS normalization rulings in Exhibit RLR-2 is that they are not precedential with respect to ENO and/or the Council.[500] ENO has not argued that they are precedential. Rather, ENO has stated that Internal Revenue Code §168(i)(9) and Treasury Regulation §1.167(l)-1 are the IRS normalization rules applicable to all utilities regarding the ratemaking treatment for NOL ADIT; that the rules make clear that the amount of a utility's NOL ADIT asset that is attributable to accelerated tax depreciation must be included in rate base; and that the IRS normalization rulings in Exhibit RLR-2 interpret and apply the normalization rules. Ultimately, Mr. Proctor conceded that the Council should give the IRS normalization rulings some weight after assessing the facts in those rulings and comparing those facts to the facts presented in this proceeding.[501]

[498] Exhibit ADV-13 (Proctor Surrebuttal and Cross-Answering) at 49-50.

[499] Tr. (Proctor) 06/21/19 at 91-92.

[500] Exhibit ADV-13 (Proctor Surrebuttal) at 49-50.

[501] Tr. (Proctor) 06/21/19 at 90.

2. The Council should approve ENO's exclusion of ADIT subject to FASB Interpretation No. 48 ("FIN 48") from rate base.

FIN 48 is a financial accounting pronouncement that establishes rules for identifying uncertain tax positions taken by taxpayers, measuring the portion of tax deduction benefits that are likely to be forfeited, and reflecting that fact on their financial statements. An uncertain tax position occurs when a taxpayer takes an aggressive tax deduction on its tax return to lower its tax liability.[502] If the uncertain position is ultimately sustained in the future, the effect will be to lower rate base and potentially rates to customers. ENO has excluded from its rate base the portion of various ADIT liabilities that is unlikely to produce cost-free capital due to the aggressive tax position taken by ENO in its filings with the tax authorities. The Advisors and CCPUG take issue with the exclusion of the FIN 48 ADIT.

The Advisors propose that the FIN 48 ADIT be included in rate base because, similar to the NOL ADIT issue, they argue that DIT expense related to the FIN 48 ADIT included in ENO's revenue requirement produced a cost-free loan from customers.[503] Similar to the NOL ADIT issue, the Advisors are incorrect. At hearing, Mr. Proctor agreed that Example Three in Exhibit RLR-6 also occurred when a utility took an aggressive tax position like those underlying the FIN 48 ADIT at issue.[504] Thus, Exhibit RLR-6 shows that if a utility takes an aggressive tax position on its tax return, the utility's ***deferred income tax expense does increase***, as Mr. Proctor points out in his filed testimonies, but, at the same time, the utility's current income tax expense

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502 Exhibit ENO-50 (Roberts Rebuttal) at 16.

503 Exhibit ADV-10 (Proctor Direct) at 83.

504 Tr. (Proctor) 06/21/19 at 105.

decreases, which Mr. Proctor ignores. Again, Mr. Roberts explained this in his Rebuttal Testimony.[505] Exhibit RLR-7 (HSPM) attached to Exhibit ENO-52 demonstrates that ENO's aggressive tax positions underlying the FIN 48 ADIT essentially have no effect on the level income tax expense included in ENO's revenue requirement in its Period II Electric and Gas Cost of Service Studies. As a result, when considering income tax expense, a utility's customers are indifferent as to whether a utility uses aggressive tax positions on its tax return (i.e., Example Three) to defer tax payments or not (i.e., Example One). Thus, once again, Mr. Proctor's argument that "a utility receives – through the rates it is permitted to charge its customers – a direct cash flow benefit from those customers for the deferred income tax expense on its books" is incorrect, and his analogy of this alleged cash benefit being a loan from the customer is misleading.

Furthermore, FIN 48 ADIT is not cost free capital because it has a cost to ENO. ENO accrues interest expense on its aggressive tax positions, and that interest expense is borne by ENO and not recovered by ENO from customers in rates.[506]

The Advisors and CCPUG respond that the interest expense of prudent or successful FIN 48 positions should be borne by customers and the FIN 48 ADIT should be included in rate base.[507] Such treatment is unfair. No one expects the FIN 48 ADIT to produce cost-free

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505 Exhibit ENO-50 (Roberts Rebuttal) at 3 ("Customers' rates reflect the same amount of income tax expense because the deferred income tax expense for normalized items is offset dollar for dollar by an increase or reduction in the current income tax expense.").

506 *Id*. at 19.

507 Exhibit ADV-13 (Proctor Surrebuttal and Cross-Answering) at 63; Exhibit CCPUG-1 (Kollen Direct) at 26.

capital,[508] but, under that proposal, customers are guaranteed that the FIN 48 ADIT reduces rate base, and ENO is not guaranteed recovery of its interest expense.[509] The only way it would be fair to include the FIN 48 ADIT in rate base in this proceeding is if ENO would be allowed to recoup the lost revenues from including the FIN 48 ADIT in rate base in the event that the underlying aggressive tax positions were rejected.[510]

As an alternative, the Advisors recommend that, if the Council permits ENO to exclude the FIN 48 ADIT from rate base, then ENO should also exclude the associated deferred income tax expense from its revenue requirement.[511] Such alternative should be rejected. Again, Mr. Proctor is ignoring the associated effect on current income tax expense. If the deferred income tax expense is excluded, then the associated effect on current income tax expense should be excluded as well, resulting in no change to ENO's revenue requirement. As stated above, when ENO defers tax payments because of aggressive tax positions, current income tax expense decreases by the amount that deferred income tax expense increases so that the level of income tax expense included in rates is unaffected.[512] That is income tax normalization.

3. The Advisors conceded at hearing that including the ADIT related to stranded meters in rate base is a normalization violation; therefore, the Council should reject the Advisors' recommendation to include such ADIT in rate base.

The Agreement in Principle approved in Council Docket No. UD-16-04 ("AMI AIP")

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508 Exhibit ENO-50 (Roberts Rebuttal) at 20.

509 Exhibit ENO-52 (Roberts Rejoinder) at 14.

510 *Id*. at 14.

511 Exhibit ADV-10 (Proctor Direct) at 85.

512 Exhibit ENO-50 (Roberts Rebuttal) at 3 and 8.

established an amortization to permit ENO to recover its investment in the meters to be retired as a result of the AMI project, which amortization ENO is seeking to recover in rates in this proceeding. The amortization set in the AMI AIP does not allow ENO to earn its full WACC return on the unamortized net book value of the stranded meters over the course of the amortization. The Advisors propose that the ADIT associated with the stranded meters be included in rate base as a reduction to rate base so that the ADIT results in a revenue requirement calculated at ENO's full WACC, while the assets whose depreciation generated that credit are being afforded a return at a lower rate of return.[513]

The Advisors' proposed ratemaking treatment is a violation of the IRS normalization rules discussed above. Internal Revenue Code Section 168(i)(9) requires consistency between the inclusion of these assets or the corresponding regulatory asset in rate base and the inclusion of the related ADIT liability in rate base.[514] The Advisors' proposal is being inconsistent by proposing the full WACC be applied to the ADIT related to the stranded meters but that the full WACC not be applied to the stranded meters.[515] At hearing, Advisors witness Mr. Watson agreed that the Advisors' proposed treatment violated the IRS normalization rules.[516]

Mr. Watson then further explained that he recommended that ENO reclassify the ADIT as a regulatory liability to avoid the violation of the IRS normalization rules.[517] The IRS normalization rules cannot be circumvented by the accounting subterfuge suggested by Mr.

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513 Exhibit ENO-3 (Thomas Rebuttal) at 59.

514 Exhibit ENO-50 (Roberts Rebuttal) at 15.

515 *Id*.

516 Tr. (Watson) 06/21/19 at 72.

517 *Id*.

Watson, who is neither a certified public accountant nor an income tax expert. Internal Revenue Code Section 168(i)(9) requires ENO to establish a reserve for the deferral of taxes for the difference between book and tax depreciation and that reserve has to be treated consistently with respect to rate base. The code section does not reference a particular account. Changing the name of the reserve or the book account of the reserve does not negate the requirement for the reserve (i.e., the accelerated tax depreciation ADIT) to be treated consistent with the related assets for rate base purposes.[518] Accordingly, the Council should reject the Advisors' proposal regarding ADIT related to the stranded meters.

4. The Prepaid Pension Asset is driven by cash contributions by ENO to the pension trust fund only, which are not excessive, to the extent they exceed pension expense and not the market value of the pension trust fund assets as contended by the Advisors; therefore, the Advisors' recommendation should be rejected.

There is no dispute that the Prepaid Pension Asset should be part of ENO's rate base. The only issue is the valuation of the Prepaid Pension Asset. For valuation purposes, the Company proposes to use the Period II year-end balance, which then is allocated between ENO's electric and gas operations. The Advisors witness Mr. Proctor proposes that another value be used, which is lower and is closer to the historical five-year average year-end value of the Prepaid Pension Asset due to the growth of the Prepaid Pension Asset from recent financial market conditions and the amount of ENO's contributions.[519] The Advisors' reasoning is incorrect because the Prepaid Pension Asset's growth is not driven by the market value of the pension trust fund assets but by ENO's contributions to the pension trust fund. Furthermore,

518 Exhibit ENO-52 (Roberts Rebuttal) at 13.

519 Exhibit ADV-13 (Proctor Surrebuttal and Cross-Answering) at 69.

ENO's contributions to the pension trust fund are not excessive. Thus, the Advisors' proposed valuation is arbitrary in all respects.

The Prepaid Pension Asset's growth is not driven by the market value of the pension trust fund assets but by ENO's contributions to the pension trust fund in excess of pension expense. The change in the amount of the prepaid pension assets between January 1 of any year and December 31 of the same year is a function of ENO's pension expense and contributions. Contributions are tendered according to a plan provided by ENO's actuary setting forth the expected amount of the contributions and their timing. Pension expense is generally determined at the beginning of the year by ENO's actuary. The Company's response to Data Request Advisors 3-35, Exhibit JBT-16 to Exhibit ENO-4, shows that the year-to-year change in the balance of the Prepaid Pension Asset is the difference between the Company's cash pension contributions and its pension expense.[520] The market value of the pension trust fund assets has no effect on the quantification of the Prepaid Pension Asset.

At hearing, ENO demonstrated that Mr. Proctor did not understand what costs ENO was seeking to recover through the Prepaid Pension Asset, when he wrote his filed testimony. At the beginning of cross-examination, Mr. Proctor asserted that the fair or market value of the pension trust fund assets affected the calculation of the Prepaid Pension Asset.[521] He also reiterated his filed-testimony view that the financial market conditions in the latter part of 2018 could have a

520 Exhibit ENO-4 (Thomas Rejoinder) at 20.

521 Tr. (Proctor) 06/21/19 at 117-118; Exhibit ADV-13 (Proctor Surrebuttal and Cross-Answering) at 68 ("abnormally impressive performance of asset markets").

substantial impact on the Prepaid Pension Asset that ENO sought to include in rate base.[522] As cross-examination progressed, Mr. Proctor admitted that the market value of the pension trust fund assets did not affect the Prepaid Pension Asset. He admitted that the financial market conditions in the latter part of 2018 did not affect the Prepaid Pension Asset.[523] When asked whether, before he filed his Direct Testimony, the Company advised him in its response to Advisors 3-37, which was marked as Exhibit ENO-66, that financial market conditions did not affect the Prepaid Pension Asset, he contended that market conditions did have an effect.[524] But when confronted with his previous deposition testimony, he agreed that the Company had informed him that financial market conditions did not affect the Prepaid Pension Asset and that he agreed with the Company's statement:

> . . . And then I asked you the next question, In those two paragraphs, doesn't the Company write that the actual net gains and losses that are experienced during the year have no effect on the prepaid pension asset? (As read.)
>
> Did I read that piece correctly?
>
> A. Yes.
>
> Q. Okay. And you answered, That's what this says, but, I mean, I agreed with that. My testimony said that also. (As read.) Did I read that correctly?
>
> A. Yes. My answer today is not inconsistent with that. . . .[525]

At the end of cross-examination, Mr. Proctor agreed that the change in the Prepaid Pension Asset between December 31, 2017 and December 31, 2018 was the difference between ENO's

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[522] *Id*. at 119; Exhibit ADV-9 (Proctor Direct) at 68.

[523] Tr. (Proctor) 06/21/19 at 122.

[524] *Id*. at 121-122.

[525] Tr. (Proctor) 06/21/19 at 125.

contributions to the pension trust fund and pension expense; he further agreed that the fair market value of the pension trust fund assets as of December 31, 2018 did not affect the Prepaid Pension Asset.[526]

Mr. Proctor's conclusion that ENO made unnecessary contributions to the pension trust fund is arbitrary as well. Mr. Proctor's conclusion appears to be based on the fact that ENO contributed more to the pension trust fund than required by the Employee Retirement Income Security Act of 1974 ("ERISA"). ERISA is one minimum funding requirement, but there are others applicable to ENO.[527] ENO's pension trust fund is underfunded by $45 million.[528] ENO must have an Adjusted Funding Target Attainment Percentage ("AFTAP") greater than 80% to be able to provide its retirees with the benefit options that ENO has committed to make available to them.[529] Also, ENO's contributions lower pension expense. Earnings on those contributions to the trust provide a credit to pension expense, and the contributions mitigate Pension Benefit Guarantee Corporation premiums, which would otherwise be included in pension expense.[530] Thus, ENO's level of contributions is the result of many factors, and Mr. Proctor has not endeavored to assess all those factors.

Moreover, Mr. Proctor's five-year average valuation is arbitrary. First, all elements of ENO's Period II rate base is valued based on projected year-end balances and projected thirteen-month average balances. None of them go as far back in time as Mr. Proctor's five-year average

526 *Id*. at 136.

527 Exhibit ENO-4 (Thomas Rejoinder) at 22.

528 *Id*. at 23.

529 *Id*.

530 *Id*.

valuation. Second, use of an averaging convention is an approach that could reasonably be applied when costs have shown a history of volatility in both increases and decreases, and the goal would be to smooth out the effect in rates. Applying a five-year average to a cost that has increased during the five-year period simply subjects the Company's recovery of that cost to undue regulatory lag, and the Advisors have supported the concept that undue regulatory lag would not provide ENO with an opportunity to earn a reasonable return on its prudent investment.[531]

5. CCPUG's recommendation to eliminate the Company's pro forma adjustments associated with the 2019 capital additions ignores the Council's rules and sound ratemaking principles.

Through Pro Forma Adjustment AJ14, the Company proposes that its rate base incorporate plant additions through December 31, 2019, which is the calendar year in which new rates will be effective. Reflecting plant additions through December 31, 2019 better aligns base rates with the cost of providing electric and gas service during the first twelve months that base rates from this proceeding are in effect. Additionally, reflecting plant additions through December 31, 2019 better aligns with the first evaluation period under the proposed Gas and Electric Formula Rate Plans. The pro forma electric rate base additions total $64.4 million, and the additions for the gas rate base total $25.7 million.[532] Advisors agree with this pro forma adjustment to the Period II revenue requirement.[533]

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531 *Id*. at 24.

532 Exhibit ENO-33 (Todd Revised Direct) at 15-17. Company witness Laura Beauchamp adopted Mr. Todd's Revised Direct Testimony.

533 *See* Exhibit ENO-3 (Thomas Rebuttal) at 53.

CCPUG witness Kollen alone opposes inclusion of the 2019 capital additions in ENO's rate base. Mr. Kollen incorrectly claims that City Council resolutions do not permit this pro forma adjustment to the calendar 2018 Period II results, and that ENO's proposal goes beyond what he claims are allowable known and measurable changes to test year information.[534] Mr. Kollen's claims are without merit.

As explained in the Rebuttal Testimony of Company witness Thomas, Council ratemaking requirements specifically contemplate the pro forma proposed by ENO. Resolution R-17-504, highlighted by Mr. Kollen, contains no language prohibiting ENO from proposing adjustments to reflect cost levels expected in 2019. More to the point, the Code of the City of New Orleans authorizes a utility to make pro forma adjustments to reflect known and measurable changes. Specifically, the Code defines pro forma adjustments as "adjustments to Period I and Period II actual figures for known and measurable changes." This language plainly supports the Company's inclusion of pro forma adjustments to reflect cost levels in the year when the base rates from this proceeding will go into effect.[535] Additionally, Louisiana state law is clear that known and measurable changes occurring within a reasonable period after the test period may be included in rates.[536] Mr. Kollen's allegation that known and measurable adjustments may not be made unless and until the revenues or costs are actually incurred[537] is completely unreasonable.

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534 *E.g.*, Exhibit CCPUG-2 (Kollen Surrebuttal and Cross-Answering) at 8-10; Exhibit CCPUG-1 (Kollen Direct) at 9-12.

535 Exhibit ENO-3 (Thomas Rebuttal) at 52.

536 *Central Louisiana Elec. Co. v. Lousiana Pub. Serv. Comm'n*, 508 So. 2d 1361, 1369-1370 (La. 1987) (affirming the reversal of an LPSC order denying rate relief associated with a generation unit placed into service after the test year).

537 *E.g.*, Exhibit CCPUG-2 (Kollen Surrebuttal and Cross-Answering) at 9-10.

His position would prohibit known and measurable adjustments to Period II altogether, despite the City Code's and Louisiana law's authorization for such adjustments.[538]

Mr. Kollen is also off base in contending that the pro forma adjustment creates a mismatch between revenues and costs. In particular, Mr. Kollen complains about the rates from this proceeding being effective August 1, 2019, when the pro forma adjustments consider cost levels as of December 31, 2019. Mr. Kollen, however, ignores that under the Company's proposal, the rates from this proceeding will be in effect until September 2020. Thus, considering cost levels through December 31, 2019 is reasonable and, indeed, provides a better matching of revenues and costs. Pro forma adjustment AJ14 is consistent with Council ratemaking policies, better matches cost recovery to the period during the rates will be in effect and aligns the recovery of the investments with the period in which customers are receiving the benefits of the investment.[539] The Council should approve ENO's inclusion of these capital additions in rates.

7. ENO proposes that the Council set an amortization period of three years for the Algiers Transaction Expense Regulatory Asset and establish a new regulatory asset for the Algiers Migration Expenses to be recovered over five years; the Council should reject CCPUG's recommendations, which are intended to interfere with the timely recovery of these costs.

On October 30, 2014, ENO and ELL filed a joint application requesting that the Council approve the sale to ENO of ELL's Algiers electric operations and the related assets and liabilities, which sale is referred herein to as the "Algiers Transaction." On May 7, 2015, ENO, ELL, and the Council Advisors entered into an Agreement in Principle ("Algiers Transaction AIP") recommending that the Council approve the Algiers Transaction, and the Council

538 Exhibit ENO-3 (Thomas Rebuttal) at 52.

539 Tr. (Beauchamp) 06/17/19 at 164.

approved the Algiers Transaction AIP in Council Resolution R-15-194. On September 15, 2015, the Algiers Transaction closed, and ENO became the electric utility for both Legacy ENO Customers and Algiers Customers. Paragraph 4.I of the Algiers Transaction AIP authorizes the deferral of external transaction expenses related to the Algiers Transaction and recovery commencing with the instant rate case but does not establish an amortization period.

The Company proposes to recover this transaction expense regulatory asset, which is estimated to have a balance of $1.1 million by the first billing cycle of August 2019, over three years. The Company proposes a three-year amortization period because such period results in an amortization that is consistent with the term of the Electric FRP being proposed in this proceeding.[540] CCPUG complains that the amortization period is "unnecessarily short" and should be ten years to minimize the effect on the base revenue requirement and to minimize the potential of over-recovery if the Electric FRP is not renewed after its initial three-year term.[541] Ten years is an unreasonable amortization period and does not balance annual rate effects against the long-term effect of increasing customer payments on a nominal basis.[542]

The Company proposes that the Algiers Migration Expenses be deferred and be recovered over a multi-year period to better match the recovery of the expenses with the benefits from those expenses. As explained by Ms. Stewart, the Algiers Migration Expenses will be incurred over 2018 and 2019 to facilitate the billing of current and future Algiers Customers as ENO customers and to eliminate the current back-office processes and associated expense

[540] Exhibit ENO-33 (Todd Revised Direct) at 26.

[541] Exhibit CCPUG-1 (Kollen Direct) at 34.

[542] Exhibit ENO-3 (Thomas Rebuttal) at 58.

necessary to account for Algiers Customers' payments. So, rather than treat all or a significant portion of these expenses as non-fuel operations and maintenance expense and recover the same in a single year, ENO proposes that the Algiers Migration Expenses be deferred and recovered over five years with the unamortized balance included in rate base.[543] The CCPUG witness does not oppose the deferral of these expenses; rather, he recommends that the deferral not be recovered in the rates effective August 2019 but at a later time when the savings associated with the expenses are realized.[544] CCPUG is trying to prevent the timely recovery of these expenses, and its recommendation should be rejected.

6. The Council should approve the Company's calculation of the CWC allowance for electric and gas operations and reject CCPUG's recommendation.

The Cash Working Capital ("CWC") allowance is an adjustment to rate base and represents the cash required to be provided by investors over and above the investment in plant and other rate base items that is necessary to bridge the timing gap between cash payments for expenditures required to provide utility service and the revenue collections for such service.[545] Company witness Kenneth F. Gallagher presents, consistent with Section 158-133 B (12) of the Code of the City of New Orleans, the lead-lag analysis that supports the level of CWC allowance in the Company's rate request.[546] His findings are included in Exhibit KFG-2 to Exhibit ENO-38 and support CWC allowances of ($1.481) million in the Period II Electric Rate Base and $0.583

543 Exhibit ENO-33 (Todd Revised Direct) at 26-27.

544 Exhibit CCPUG-1 (Kollen Direct) at 35-36.

545 Exhibit ENO-38 (Gallagher Revised Direct) at 4.

546 *Id*. at 3.

million for Period II Gas Rate Base. CCPUG witness Mr. Kollen argues that the lead-lag analysis incorrectly omits "the dividend component of the return on equity as a cash expense" in the lead-lag analysis causing the CWC rate base amounts to be overstated.[547] Mr. Kollen's argument is without merit. No retail regulator has ever accepted Mr. Kollen's argument, and, including a common dividend component in a lead-lag analysis is conceptually unsound. Also, Mr. Kollen's analysis of the dividend component does not measure common dividend payments by ENO. Accordingly, the Council should approve the Company's calculation of the CWC allowance.

First, at hearing, Mr. Kollen admitted that he was not aware of any retail regulators that have agreed with his opinion that a common dividend component should be included in a cash working capital analysis.[548]

Second, a common dividend component in a lead-lag analysis is conceptually unsound. First of all, common dividends are not expenses, and the lead-lag analysis should only consider revenues and expenses. This is because the objective of a lead-lag analysis is to measure the timing of payment of cash expenses incurred in providing utility service versus the receipt of cash revenues for that service. If revenue receipt from customers occurs after expense payments are made by the Company, investor capital is the source of those expense payments; if revenue receipt from customers occurs before the expense payments are made by the Company, then investor capital is not needed.[549] Additionally, Council practice and rule require that expenses be

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547 Exhibit CCPUG-1 (Kollen Direct) at 26.

548 Tr. (Kollen) 06/20/19 at 27.

549 Exhibit ENO-38 (Gallagher Revised Direct) at 4-5.

the subject of the lead-lag analysis,[550] and common dividends are not an expense.[551] At one point in the hearing, Mr. Kollen even claimed that common dividends were "revenues."[552] If that were so, then including common dividends in Mr. Gallagher's lead-lag analysis would result in an improper double-count of revenues as Mr. Gallagher's lead-lag analysis already includes revenues.[553] Furthermore, the timing of the payment common dividends is implicitly included as a component in the determination of the investors' required ROE; thus, to seek, as Mr. Kollen does in this case, a reduction in rate base for alleged cash flow "benefits" via lowering the rate base is not only improperly reducing the earned ROE (and the ability of the Company to pay common dividends) but is also double-counting the timing of cash flow effects of common dividends already considered in determining the required ROE.[554] Therefore, for these reasons, including a common dividend component in a lead-lag analysis is conceptually unsound.

Third, Mr. Kollen's proposed adjustment to the Company's lead-lag analysis does not measure the cash effects of ENO's common dividends paid but rather is based on Entergy Corporation. Such an approach is inconsistent with measuring ENO's CWC allowance. At hearing, Mr. Kollen testified that dividend payments and the lead-lag days used in his proposed adjustment are associated with Entergy Corporation's common dividend payments to its

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550 Exhibit ENO-39 (Gallagher Rebuttal) at 2.

551 *Id*. at 3; Tr. (Kollen) 06/20/19 at 21.

552 Tr. (Kollen) 06/20/19 at 24 ("A. If you're talking about the delineated operating expenses on the income statement in the Form 1, that's correct, but [the dividend component of the return on equity] is included in the operating income line item, which is revenues, which is included in the cash working capital study. . . .").

553 Exhibit ENO-38 (Gallagher Revised Direct) at 6.

554 Exhibit ENO-39 (Gallagher Rebuttal) at 4-5.

shareholders and not based on ENO's common dividend payments to its shareholder.[555] In contrast, the Company's lead-lag analysis is based solely on data reflecting ENO's expenses payments and revenue receipts.[556] Therefore, Mr. Kollen's proposed adjustment, which essentially includes hypothetical common dividend payments in the Company's lead-lag analysis,[557] is improper and should be rejected.

7. The Council should reject the Advisors' recommendation to exclude expenses related to ENO's Restricted Stock Incentive Plan.

Advisors' witness Mr. Ferris opines that the expenses associated with ENO's Restricted Stock Incentive Plan should not be recovered in rates.[558] In his direct testimony, Mr. Ferris based this opinion on a settlement agreement reached between Advisors and ENO in 2010 to resolve ENO's electric and gas FRP filings.[559] As part of that non-precedential settlement, ENO agreed not to seek recovery of expenses related to its Long-Term Incentive, Equity Awards, Restricted Share Awards, and Stock Option Incentive Compensation plans.[560] However, Mr. Thomas pointed out on rebuttal that this agreement by ENO only applied to the term of the FRP, which has since lapsed, and that it was the result of settlement negotiations.[561] Regardless, ENO has excluded expenses of certain other executive incentive compensation expenses that were

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555 Tr. (Kollen) 06/20/19 at 26-27.

556 Exhibit ENO-38 (Gallagher Revised Direct), Exhibit KFG-2 at 3.

557 Exhibit ENO-39 (Gallagher Rebuttal) at 5-6.

558 Exhibit ADV-17 (Ferris Direct) at 7.

559 Exhibit ENO-3 (Thomas Rebuttal) at 50; Exhibit ADV-17 (Ferris Direct) at 7-10.

560 *Id*.

561 *Id*. at 50-51.

previously identified in the 2010 settlement.[562] Mr. Thomas also noted that the Advisors did not seek to disallow ENO's Restricted Stock Incentive Plan expenses in the 2012 electric and gas FRP filings.[563]

In response, Mr. Ferris pivoted on surrebuttal and now makes unsupported claims that the Restricted Stock Incentive Plan depends on Entergy Corporation's long-term performance and therefore is a significant benefit to its shareholders. He then argues that ENO failed to show that the plan benefits customers or any justification for recovering the costs of the plan in rates. According to Mr. Ferris, whether the plan is reasonable does not matter; instead, the beneficiaries of the plan and who pays for it are determinative. Mr. Ferris makes the baseless assumption that because the shareholders benefit from the plan, customers receive no benefit. He cites to no evidence to support this statement. Mr. Ferris has performed no analysis to show that the costs associated with the Company's restricted stock program are imprudent.[564] Without such a showing, the presumption is that the plan is a legitimate, prudently incurred cost of service that should be recovered through rates in accordance with fundamental legal ratemaking standards.

Utility companies like ENO regularly use incentive compensation related to financial goals to compete for and retain employees.[565] Having such goals as part of incentive compensation plans encourages utility personnel to use financial resources reasonably and

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562 *Id*.

563 *Id*. at 51.

564 Id and South Cent. Bell Tel. Co. v. Louisiana Pub. Serv. Comm'n, 594 So. 2d 357, 366 (La. 1992).

565 Exhibit ENO-4 (Thomas Rejoinder) at 31.

resolve operational challenges using the most cost-effective approach.[566] Therefore, ENO's customers do benefit from its personnel balancing operational and safety goals with financial goals.[567] The costs of ENO's restricted stock program are reasonable and necessary because the plan helps the Company attract and retain qualified personnel essential to providing reliable service at reasonable costs.[568] Mr. Ferris concedes this, testifying that the primary products of the program "are to improve operating efficiency and encourage fiscal responsibility . . ."[569] He offers no evidence that the restricted stock incentive plan does not in fact directly benefit ENO's customers in the manner in which Mr. Thomas explained. Because the expenses related to the restricted stock incentive plan are reasonable and prudent and directly benefit customers by improving service quality and reducing service costs, they should be included in the Company's cost of service and recovered in rates.[570]

I. The Securitized Storm Cost Offset Rider - SSCO Rider ("SSCO Rider") is the result of a complex transaction and settlement providing benefits to both customers and the Company and should not be disturbed.

Advisors witness Mr. Watson proposes that the SSCO Rider be eliminated because of single-issue ratemaking and that the deferred tax benefits included in the rider be incorporated into the Company's electric base rate revenue requirement.[571] The Council should reject this proposal. The SSCO Rider is the product of a complex transaction and settlement regarding the

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566 *Id*.

567 *Id*.

568 *Id*.

569 Exhibit ADV-17 (Ferris Direct) at 7-8.

570 *See,* e.g., Docket No. 13-028-U, In the Matter of the Application of Entergy Arkansas, Inc., for Approval of Changes in Rates for Retail Electric Service, Order (August 15, 2014) at Section IV.

571 Exhibit ADV-6 (Watson Direct) at 77-79.

recovery of ENO's Hurricane Isaac storm costs and funding of the storm reserve through securitization and is intended to work in concert in with the Securitized Storm Cost Recovery Rider SSCR ("SSCR Rider").

The SSCO Rider was established through a settlement agreement in Council Docket No. UD-14-01 between ENO and the Advisors allowing to ENO to execute a securitization in 2015 to finance ENO's Hurricane Isaac storm costs and to fully fund ENO's storm reserve; the Council approved this settlement in Resolution R-15-195, dated May 14, 2015. The SSCO Rider provides certain agreed-upon ADIT benefits to customers and recovers certain agreed-upon ADIT costs from the securitization through a rider mechanism on a dollar-for-dollar basis in the same manner as the SSCR Rider recovers amounts for the payment of the balance of the securitization bonds.[572] The value of ADIT underlying the SSCO Rider was an agreed-upon amount of ADIT including a credit amount for the casualty loss recognized on the storm damage to the existing assets that were replaced as a result of the storm and the ADIT associated with the new assets.[573] This agreed-upon ADIT amount also included a debit ADIT amount resulting from the securitization proceeds being treated as taxable income upon receipt causing ENO to incur income tax expense.[574] Paragraphs 49 through 53 of Resolution R-15-193, which is the securitization financing order, contemplate no alteration of this Resolution as long as the storm recovery bonds are outstanding, and the SSCR Rider and the SSCO Rider were always intended to work in concert to provide a cost effective mechanism to capture the costs and credits of

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572 Exhibit ENO-3 (Thomas Rebuttal) at 40.

573 *Id*. at 41.

574 *Id*.

securitized storm recovery costs. Indeed, in his testimony in Council Docket No. UD-14-01, Mr. Watson referred to the SSCR Rider and the SSCO Rider as a singular ratemaking mechanism and that it was appropriate for the riders to work in concert (as a singular mechanism):

> My review of the Securitization Application and sample rate calculations with regard to the SSCR and the SSCO indicates that their designs and construction, as filed, ***are an appropriate mechanism*** by which ENO may collect the funds required to service the securitization bonds' debt and return tax-related savings resulting from Isaac SRCs and casualty loss deduction to ratepayers. (Emphasis added.)[575]

Also, in that testimony, Mr. Watson acknowledged that the Combined Rate Case would occur in the future and did not recommend at that time that the SSCO Rider terminate as a result of the Combined Rate Case as he now proposes.[576]

Moreover, in this proceeding, Mr. Watson ignores the debit ADIT amount resulting from the securitization proceeds being treated as taxable income, which would increase rate base by $6.1 million and the revenue requirement by $0.7 million.[577] Failure to include these amounts in the Advisors' recommended electric base rate revenue requirement would result in ENO not recovering all of its costs associated with the securitization contrary to the intent of the settlement agreement approved by the Council. Thus, the Council should reject the Advisors' proposal to terminate the SSCO Rider as it would provide no appreciable benefit to customers or the Company and would be inconsistent with the Council-approved settlement in Council Docket No. UD-14-01.

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575 Direct Testimony of Byron S. Watson, Docket No. UD-14-01, at 17 (emphasis added) (footnotes omitted). This quote is included in Exhibit ENO-4 (Thomas Rejoinder) at 27.

576 Exhibit ENO-4 (Thomas Rejoinder) at 27.

577 Exhibit ENO-3 (Thomas Rebuttal) at 41.

J. The Council Should Approve ENO's Proposed Community Solar Offering in this Proceeding.

As Mr. Owens's testimony notes, the Company began developing its proposal for the Community Solar Offering ("CSO") in 2016 and began discussing the concept of its proposal with the Council's Advisors and other Parties to this proceeding in early 2018.[578] ENO's efforts culminated in the creation of Rider CSO and the Company's proposal to approve Rider CSO and the associated customer offering in this proceeding. Rider CSO would utilize existing and Council-approved solar generation assets located within New Orleans to support the offering. CSO would allow customers to "subscribe" to a certain portion of these solar generating assets and receive monthly bill credits for the energy generated by the portion of the assets to which they are subscribed. Mr. Owens's testimonies outline the various benefits that ENO's proposed CSO would provide to participating and non-participating customers, none of which are in dispute.[579]

Despite the undisputed evidence in the record about the potential benefits of ENO's proposed CSO, the Advisors have opposed Council approval of Rider CSO. The Advisors expressed no concerns about the merits of ENO's proposed CSO, but rather expressed concerns about the interplay between Rider CSO and the Council's Community Solar Program, which is still being developed in Council Docket No. UD-18-03.[580] The Advisors' main concern seems to be that ENO's proposed Rider CSO would not comply with the rules being developed in Docket

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578 Exhibit ENO-12 (Owens Rebuttal) at 34-35.

579 Exhibit ENO-10 (Owens Revised Direct) at 35-37; Exhibit ENO-12 (Owens Rebuttal) at 41-42.

580 Exhibit ENO-12 (Owens Rebuttal) at 37.

UD-18-03. The Advisors also express a general concern, which is unsubstantiated by any analyses, that the proposed CSO would somehow hinder participation in the Council Community Solar Program, should that program eventually come to fruition.[581] As a result, the Advisors have made the questionable recommendation that ENO withdraw Rider CSO from consideration in this proceeding and re-submit the proposal in a separate proceeding (presumably in Docket UD-18-03).[582]

The Advisors' criticisms, and their recommendations, lack any foundation in evidence submitted in this proceeding. Mr. Owens' testimony notes that ENO's proposed Rider CSO was not intended to conform to the rules applicable to unregulated developers seeking to participate in the Council's proposed Community Solar Program.[583] Instead, ENO's proposal can be viewed as complementary to, but deliberately designed to be separate from, the Council's program.[584] ENO's proposal would make use of larger generating facilities than would be allowed under the Council's proposed rules, making ENO's proposal in some respects a "utility-scale" community solar offering – one which has the potential to be available much sooner than any offerings eventually developed through the Council's framework. This and other features of ENO's proposed CSO mean that ENO's proposal would provide greater benefits than a proposal

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581 Exhibit ADV-1 (Rogers Direct) at 44.

582 Exhibit ADV-1 (Rogers Direct) at 45-46; Exhibit ADV-5 (Prep Surrebuttal and Cross-Answering) at 37-38.

583 Exhibit ENO-12 (Owens Rebuttal) at 38-39. It should be noted that at the time ENO submitted its Revised Application, the Council's rulemaking to develop the proposed Community Solar Rules was still underway. As of the date of this filing, that proceeding is still underway, with the Advisors, CURO and ENO all due to submit filings during the third quarter of 2019. The Council did adopt the proposed rules, with an effective date of May 1, 2019, but additional procedural steps (and possibly additional funding) are required before the Council's program will be open for enrollment. *See* Council Resolution No. R-19-111.

584 As Mr. Owens noted, the AAE's comments in Docket UD-18-03 expressed support for allowing ENO's proposal to move forward on a separate track. Exhibit ENO-12 (Owens Rebuttal) at 42-43.

conforming to those rules, as Mr. Owens explained.[585] The Advisors did not submit testimony to dispute the benefits identified by Mr. Owens, but rather simply recommended that ENO withdraw its proposal and re-submit the same proposal in Docket UD-18-03.

As Mr. Owens's testimony notes, this recommendation makes no sense and would create administrative waste.[586] The Council's rules plainly state that proposals for community solar offerings that do not comply with the rules must be submitted to the Council for approval.[587] ENO has made such a submittal in this proceeding. The Council rules also note that such an application would need to "demonstrate why the alternative proposal brings greater benefits than a proposal conforming to the Community Solar Rules would bring."[588] Again, ENO has met this burden with the unrefuted testimony and evidence submitted in this proceeding. To require ENO to withdraw a proposal that meets the burdens outlined in the Council's Community Solar Rules, only to resubmit that same proposal and evidence in another proceeding, serves no useful purpose.[589] In this proceeding, ENO has (i) acknowledged the ways in which Rider CSO and the associated offering do not comply with the Council's Community Solar Rules, (ii) sought Council approval for Rider CSO despite these variances, and (iii) demonstrated with undisputed evidence why Rider CSO can bring greater benefits to customers than if it were modified to conform to the Council's Rules. As such, Rider CSO meets the requirements for Council approval and should be approved in this proceeding.

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585 Exhibit ENO-12 (Owens Rebuttal) at 40-42.

586 Exhibit ENO-13 (Owens Adopting and Rejoinder) at 12-13.

587 *See* Council Resolution R-19-111.

588 *Id*.

589 Exhibit ENO-13 (Owens Adopting and Rejoinder) at 13.

VI. REVENUE REQUIREMENT CORRECTIONS

At hearing through the live testimony of Company witness Matthew S. Klucher, the Company presented the revenue requirements effect of corrections to the Company's Period II Electric and Gas Cost of Service Studies provided to the parties either through discovery or filed testimony.[590]

The corrections to the Company's Period II Electric Revenue Requirement do not have a noticeable effect; the total effect is an increase of $0.029 million from three corrections.[591] The first correction pertains to update and corrections to ADIT included in rate base. The Company provided the parties the revenue requirement effect of these corrections in its response ADV 9-2; they reduced the Period II Electric Revenue Requirement by $1.017 million.[592] At hearing, Company witness Mr. Thomas explained that one part of these corrections relates to an update of ADIT subject to FIN 48 excluded from rate base, as shown in HSPM Table 3 in his Revised Direct Testimony; the update was provided to the parties in the Company's response to ADV 1-29(b).[593] The other part relates to a correction to the NOL ADIT included in rate base as shown in Table 4 in his Revised Direct Testimony; that part was provided to the parties in the Company's response to ADV 5-9.[594] The second correction pertains to ADIT included in rate base. Mr. Thomas explained the second correction in his Rebuttal Testimony related to ADIT that is included in the SSCO Rider and, therefore, should not be included in the base rate revenue

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590 Tr. (Klucher) 06/17/19 at 177-179.

591 *Id*. at 179.

592 *Id*. at 178.

593 Tr. (Thomas) 06/20/19 at 35.

594 *Id*.

requirement;[595] it increased the Period II Electric Revenue Requirement by $1.144 million.[596] The third correction relates to depreciation expense related to the Paterson plant, which was provide to the parties in the Company's response to CCPUG 2-18; the third correction decreased the revenue requirement of $97,814.[597] Thus, the Company's corrected Period II Electric Revenue Requirement is $428.285 million.

The correction to the Company's Period II Gas Revenue Requirement reduces the revenue requirement by $1.310 million.[598] The correction concerns the update of ADIT subject to FIN 48 excluded from rate base and the correction to the NOL ADIT included in rate base, as described above. Thus, the Company's corrected Period II Gas Revenue Requirement is $40.060 million.

VII. UNCONTESTED ISSUES

Below is a limited number of issues that have not presented a dispute among the parties and should be adopted in connection with the implementation of rates resulting from the initial setting of rates or subsequent adjustments in accordance with mechanisms established herein.

595 Exhibit ENO-3 (Thomas Rebuttal) at 42-43.

596 Tr. (Klucher) 06/17/19 at 178-179.

597 *Id*.

598 *Id*. at 179.

A. The Council should approve the recovery of the NOPS non-fuel revenue requirement through an in-service rate adjustment in the Electric FRP.

ENO and the Advisors agree that the NOPS non-fuel revenue requirement should be recovered from customers through an in-service rate adjustment in the Electric FRP.[599] The in-service rate adjustment would become effective the first billing cycle of the month after the NOPS enters commercial operation.[600] The amount of the in-service rate adjustment would be based on an updated estimated non-fuel revenue requirement provided at least seventy-five days prior to commercial operation.[601] The in-service rate adjustment would occur outside the bandwidth.[602] The in-service adjustment would cease once the NOPS non-fuel revenue requirement was reflected in a subsequent September FRP Rate Adjustment.[603] In the event that Electric FRP is not established, Council Resolution R-18-65 provides that the NOPS revenue requirement be reflected through an in-service adjustment to the decoupling mechanism ultimately approved by the Council.[604]

Although CCPUG has raised an issue concerning the depreciation rate applied to NOPS, the Company submits that such issue should be resolved in conjunction with the updated estimated non-fuel revenue requirement.

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599 Tr. (Prep) 6/20/19 at 182.

600 Exhibit ENO-1 (Thomas Revised Direct) at 67.

601 *Id*.

602 Exhibit ADV-5 (Prep Surrebuttal) at 24-25.

603 *Id*.

604 *See* Resolution R-18-65 (March 8, 2018).

B. The Council should approve the establishment and recovery of a regulatory asset for the Company's incremental rate case expenses.

ENO proposes to defer the rate case expenses as a regulatory asset and amortize the balance over three years with the unamortized balance included in rate base.[605] The deferred expenses would include only incremental rate case expenses associated with certain ESI personnel, excluding personnel that routinely work on ENO regulatory matters, and the Company's external attorneys and regulatory consultants. The deferred expenses also would include any Council Advisors expenses in excess of the amount included in the Period II per books non-fuel O&M.[606]

ENO preliminarily estimated that its rate case expenses will total approximately $3.7 million on a total Company basis based on actual incremental rate case expenses incurred in the 2008 ENO Rate Case,[607] and proposed that the rate case expense adjustments, Adjustments AJ19, in the Electric and Gas Period II Cost of Service Studies be updated with actual costs and be allocated 81% to electric and 19% to gas operations in the compliance filing resulting from a decision in this proceeding. Based on the record in this proceeding, no party opposes the proposed regulatory asset or its recovery as described above.

C. The Council should approve the Combined MISO Rider.

The Company proposes that the Council approve in this proceeding a single combined Midcontinent Independent System Operator, Inc. Cost Recovery Rider ("Combined MISO Rider"), which is included as Exhibit PBG-10 to Exhibit ENO-41 applicable to both ENO

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605 Exhibit ENO-33 (Todd Revised Direct) at 28.

606 *Id*.

607 *Id*.

Legacy Customers and Algiers Customers, to recover the net expenses billed to ENO by MISO. The Combined MISO Rider proposed in this rate case is substantially similar to the majority of the two current MISO Riders for ENO Legacy Customers and Algiers Customers.[608]

The combined MISO Rider revenue requirement would include expenses, such as MISO administration expenses and line of credit fees, and revenues, such as Long-Term and Short-Term Point-to-Point Transmission Service revenues and Network Integration Transmission Service revenues. The combined MISO Rider revenue requirement would also include planning resource auction revenues and expenses. All of the expenses and revenues identified in the proposed Combined MISO Rider are included in the current MISO Riders' revenue requirements.[609] Also, the combined MISO Rider revenue requirement would be allocated to the rate classes based on the Transmission Demand Allocation Factor ("TDAF") as approved by the Council in this proceeding.[610] For subsequent redeterminations, the TDAF for each rate class would be developed consistent with the methodology approved in this proceeding.

To facilitate transition to the Combined MISO Rider, in May 2019, ENO filed the Combined MISO Rider with its annual redetermination filings for the current MISO Riders. The Company proposes that the current MISO Riders and MISO rider rates remain in effect until the rates from this proceeding become effective as of the first billing cycle of August 2019.[611] This would only be one month later than the redetermined MISO Rider rates usually become

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608 Exhibit ENO-41 (Gillam Revised Direct) at 39.

609 *Id*. at 40.

610 *Id*. at 41.

611 *Id*. at 42-43.

effective; thus, the MISO Rider rates effective July 2018 would then be in effect for thirteen months (July 2018 through July 2019) instead of twelve months.

The Advisors recommend that the Council approve the Combined MISO Rider,[612] and no party opposes the same. Accordingly, the Council should approve the Combined MISO Rider and the proposed transition described above.

D. The Council should approve the recovery of all affiliate PPA capacity expenses and Long-Term Service Agreement ("LTSA") expenses to base rates subject to an exact recovery process presently used for Grand Gulf Unit Power Sales Agreement ("UPSA") capacity expenses, and the Company's proposed Combined FAC Rider.

The current FAC Rider produces two separate FAC rates – one for the Legacy ENO Customers and another for the Algiers Customers. Although fuel and energy expenses are generally pooled and allocated among customers of both groups based on energy usage during the operations month, there are certain expenses that are allocated to Legacy ENO Customers or Algiers Customers but not both.[613] For example, Legacy ENO Customers' FAC rate includes capacity expenses associated with a PPA with ELL sourced from the unregulated 30% portion of River Bend owned by ELL and a PPA with EAI sourced from its wholesale baseload resources, which PPAs are referred to herein as the "Resource Plan PPAs."[614] The Algiers Customers' FAC rate does not reflect these capacity expenses. In contrast, the Algiers Customers' FAC rate includes Algiers Energy Smart expenses and a repricing mechanism for a portion of Grand

612 Exhibit ADV-1 (Rogers Direct) at 29-30.

613 Exhibit ENO-44 (Celino Revised Direct) at 3.

614 *Id*.

Gulf's monthly fuel expense.[615] The Legacy ENO Customers' FAC Rider rate does not reflect these items. These allocations and rate treatments occur in the Geographic-Specific Legacy ENO Adjustment and the Geographic-Specific Algiers Adjustment contained in the current FAC Rider.[616] Additionally, the current FAC Rider has two separate over/under mechanisms tracking two separate over/under balances for each of the two customer groups.[617]

The Company proposes to realign all affiliate PPA capacity expenses and LTSA expenses, including those expenses that are currently recovered in the FAC, to base rates subject to an existing exact recovery process, which is in place today for Grand Gulf UPSA capacity expenses, the "Schedule A" process.[618] The capacity expenses associated with the following PPAs would be recovered through this process: the Resource Plan PPAs; the Ninemile 6 PPA, the capacity expenses of which are recovered solely through the PPCACR Rider; and the Algiers Transaction PPA, which is sourced from a share of the output of ELL's resources, including Ninemile 6, at the time of the Company's purchase of ELL's Algiers electric operations in 2015.[619] The following LTSA expenses associated with following units would be recovered through this process: Union Power Station Power Block 1 and ELL's Ninemile 6, Perryville, and Acadia units.[620]

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615 *Id*. at 4.

616 *Id*.

617 *Id*.

618 Exhibit ENO-33 (Todd Revised Direct) at 17-18.

619 *Id*. at 19.

620 *Id*. at 22.

The Council established the Schedule A process for the Grand Gulf UPSA capacity expenses as part of a settlement in Resolution R-91-157, dated September 5, 1991, which is in effect today. Each month, Grand Gulf's owner, System Energy Resources, Inc., bills ENO for Grand Gulf's actual non-fuel and fuel costs. The Council has set an annual amount of non-fuel costs, which are capacity expenses on ENO's books, to be reflected in ENO's base rates, today, $90.625 million.[621] This amount, which is broken down by month, first was set forth on a schedule attached to Resolution R-91-157 entitled "Schedule A." If the actual amount billed to ENO for the capacity expenses differs from the monthly amount set forth in Schedule A, the difference, over- or under-collection, is reflected in the Legacy ENO Customers' FAC rate.[622]

ENO further proposes that the monthly over- or under-collection associated with the Resource Plan PPAs would be returned or recovered through the FAC.[623] This is consistent with the energy allocation of the capacity expense estimate allocation used in the development of electric base rates, which is discussed by Mr. Thomas. The monthly over- or under-collection associated with the Ninemile 6 PPA and the Algiers Transaction PPA would be returned or recovered through the proposed PPCACR Rider.[624] The monthly over- or under-collection associated with the LTSA expenses would be returned or recovered through the proposed

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621 *Id*. at 18.

622 *Id*.

623 *Id*. at 20.

624 *Id*.

PPCACR Rider.[625] The Schedule A amounts for the proposed combined FAC Rider and the proposed PPCACR Rider are included in Exhibit OT-2 (HSPM).

The proposed Combined FAC Rider, which is included as Exhibit SMC-2 to Exhibit ENO-44, incorporates the addition of the Resource Plan PPA capacity expenses to the Schedule A process. Additionally, Combined FAC Rider:

- the elimination of the Grand Gulf Repricing Mechanism for Algiers Customers, which is discussed by Company witness Joshua B. Thomas[626];
- the elimination of the recovery of Algiers Energy Smart expenses, which ENO proposes to recover through a rider specifically for energy efficiency costs;
- elimination of the allocation to Legacy ENO Customers of Union Power Block 1 fuel expenses and wholesale revenues so that all customers are allocated these expenses and benefit from these revenues; and
- the combination of the two over/under balances into a single over/under balance.[627]

The Company also proposes to make a technical change to the monthly calculation of the

FAC Rider over/under balance so that it uses per book FAC Rider revenue from its accounting records instead of calculated FAC Rider collections.[628] Additionally, in Section I.B, the current FAC Rider requires the Company to provide notice if the current month's FAC Rider rates are 25% higher than the previous month's. With the removal of the capacity expenses associated with the Resource Plan PPAs, the potential exists for the notification frequency to

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625 *Id*. at 23.

626 Exhibit ENO-1 (Thomas Revised Direct) at 60-61.

627 Exhibit ENO-44 (Celino Revised Direct) at 5-6.

628 *Id*. at 10-11.

increase inadvertently because of the reduction in the expenses recovered through the FAC.[629] To prevent this, ENO proposes to change the notification threshold to an increase of 1 cent per kilowatt-hour from the prior month's FAC Rider rate, which roughly equates to what the current 25% threshold represents on average.[630] This would provide the Council with the notice and information the Council expects, thus preserving the intent and fulfilling the purpose of the original notification requirement.

The Advisors witness Mr. Rogers commented that the proposed Combined FAC Rider was a "significant improvement" over the existing FAC Rider[631] and recommended its approval subject to the correction of some formula errors and the inclusion of all of the monthly over- or under-collection in his proposed Purchase Power Cost Recovery Rider ("PPCR") Rider,[632] which would replace the existing PPCACR Rider.[633] As a result, only the PPCR would have a Schedule A.[634] In its Rebuttal Testimony, the Company explained there were no substantive disputes regarding the Combined FAC Rider except for the issue whether any over- and under-collections should be included in the Combined FAC Rider, which ENO believed was dependent on the final resolution of the cost allocation issues associated with the Resource Plan PPA capacity expenses.[635]

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629 *Id*. at 11.

630 *Id*. and Exhibit SMC-5.

631 Exhibit ADV-1 (Rogers Direct) at 23.

632 *Id*. at 23-27.

633 *Id*. at 31-34.

634 *Id*. at 25.

635 Exhibit ENO-3 (Thomas Rebuttal) at 6.

Accordingly, the Council should approve (1) the recovery of all affiliate PPA capacity expenses and LTSA expenses, including those expenses that are currently recovered in the FAC, to base rates subject to an existing exact recovery process in place today for Grand Gulf UPSA capacity expenses and (2) the Combined FAC Rider subject to correction of all formula errors and proper alignment of the monthly over- or under-collections related to the capacity expenses associated with the Grand Gulf UPSA and the Resource Plan PPAs.

E. The Council should approve the proposed Purchased Gas Adjustment ("PGA") Rider.

The proposed PGA Rider is included as Exhibit SMC-7 to Exhibit ENO-44. Currently, like the current FAC Rider, the calculation of the PGA over/under surcharge starts with a calculation of PGA Rider collections using operations month usage data and the PGA Rider rates billed during the operations month. The Company proposes to use per book PGA Rider revenue from its accounting records instead of calculated PGA Rider collections.[636] The Advisors witness Mr. Rogers recommends that the Council approve the proposed PGA Rider subject to the correction of the errors identified in his Exhibit JWR-5.[637] Accordingly, the Council should approve the proposed PGA Rider subject to the correction of the errors identified in Exhibit JWR-5.

F. The Council should approve the unopposed new electric service offerings.

As described in the summary of ENO's Combined Rate Case filing above, ENO has proposed several new voluntary offerings to the meet the expectations of the Council and ENO's customers. Each of those offerings is described below.

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636 Exhibit ENO-44 (Celino Revised Direct) at 13-14.

637 Exhibit ADV-1 (Rogers Direct) at 29.

1. EV Charging

In the Revised Application, ENO proposed two different EV charging concepts, both of which are designed to expand access to EV charging infrastructure in New Orleans. Mr. Owens also described in his Revised Direct Testimony a separate initiative that ENO recently began to expand beneficial electrification efforts in New Orleans via rebates, including rebates for customer-owned EV charging infrastructure.[638]

The first concept proposed by ENO would be available to non-residential customers and involves ENO constructing, owning, and operating EV charging infrastructure on customer-owned property. Cost recovery is designed around the methodology behind ENO's existing Additional Facilities Charge ("AFC") rider, and a draft rate schedule (EV Charging Infrastructure ("EVCI") was included with Mr. Owens's revised Direct Testimony as Exhibit DAO-5.[639] The Advisors supported the EVCI rider,[640] and no other party objected.

The second concept, available to public institutions, involves ENO constructing, owning, and operating EV charging infrastructure solely for public use at a handful of key public locations in New Orleans. ENO intends to collaborate with City officials to determine optimal locations for the EV chargers, which could include downtown City-owned right-of-way (*e.g.*, adjacent to City Hall), public libraries and schools, parks, and other recreational areas.[641] Under this concept, ENO proposes to invest up to $500,000 and would work to maximize the number of

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638 Exhibit ENO-10 (Owens Revised Direct) at 69-71.

639 *Id*. at Exhibit DAO-5.

640 Exhibit ADV-8 (Watson Surrebuttal and Cross-Answering) at 50.

641 Exhibit ENO-10 (Owens Revised Direct) at 58.

EV chargers installed, which depending on installed costs, might be in the range of 30-50 Level 2 chargers.[642]

In Advisors witness Watson's Surrebuttal, he supported the proposal to invest up to $500,000 in public EV chargers as well as Mr. Owens's proposal that the siting of the chargers be developed through a stakeholder process in Council Docket No. UD-18-01.[643] No other party opposed ENO's proposal with respect to public EV chargers.

With respect to the residential EV charger rebate program already being offered to customers, Advisors witness Watson supported the rebate program as "consistent with the Council's policies on energy efficiency and environmental benefits."[644] However, Mr. Watson went on to recommend that the Council allow ENO on an interim basis to continue its $250 per Level 2 charger rebated program … until the commencement of the ES PY 2020."[645] At that time, Mr. Watson recommended that the Council direct ENO to propose any future EV charging rebate … as a ES program in a future ES PY filing."[646]

The Company is opposed to including the EV rebate program as part of Energy Smart. Mr. Owens explained that, as part of a broader beneficial electrification[647] effort, the Company

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642 Exhibit ENO-10 (Owens Revised Direct) at 58.

643 Exhibit ADV-8 (Watson Surrebuttal and Cross-Answering) at 51 (citing to Exhibit ENO-12 (Owens Rebuttal) at 48).

644 Exhibit ADV-6 (Watson Direct) at 97.

645 *Id.* at 97-98.

646 *Id.* at 98.

647 There are various definitions for the term "beneficial electrification;" for example, the Environmental and Energy Study Institute ("EESI") defines it as "a term for replacing direct fossil fuel use (*e.g.*, propane, heating oil, gasoline) with electricity in a way that reduces overall emissions and energy costs." *See* https://www.eesi.org/projects/electrification.

created a website[648] in early 2018 that offers customers a range of incentives ($ rebates) for conversion of equipment that use fossil fuel to electric.[649] For example, the Company offers rebates for conversion of forklifts and other warehouse operations, fleet operations such as trucking and shore power, and of course electric vehicle charging infrastructure.[650] The Company also offers incentives for billboard electrification.[651] These incentives add value for ENO's customers through increased electric sales and many provide environmental and other societal benefits.[652] Given that these efforts are fundamentally designed to encourage conversion to more efficient/less polluting electric alternatives, they will ***increase*** overall electric sales, and contrary to Mr. Watson's suggestion, Energy Smart is not the appropriate forum to evaluate these efforts, the level of spending, or cost recovery. Energy Smart is intended by design to ***reduce*** electric sales. Accordingly, the eTech efforts and associated expenses should be left to operate as-is and in the future recovered via normal ratemaking (*e.g.*, via the Company's proposed FRP if one were to be approved).

2. Fixed Bill

ENO has withdrawn from consideration in this proceeding the proposed Fixed Bill Option, Schedule FBO, originally submitted as Exhibit RLS-4 to the Revised Direct Testimony of Mr. Smith, which was subsequently adopted by Mr. Owens.[653]

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648 *See* http://entergyetech.com/.

649 Exhibit ENO-12 (Owens Rebuttal) at 49.

650 Exhibit ENO-12 (Owens Rebuttal) at 49.

651 Exhibit ENO-12 (Owens Rebuttal) at 49.

652 Exhibit ENO-12 (Owens Rebuttal) at 49.

653 Exhibit ENO-19 (Smith Revised Direct) at Exhibit RLS-4.

3. Pre-pay

In the Revised Direct Testimony of Raiford L. Smith, the Company proposed pre-pay options for both its electric and gas residential customers.[654] Mr. Owens, who adopted Mr. Smith's testimony, explained in his Rejoinder Testimony that pre-pay is contingent on the implementation of the AMI customer web portal, which took longer than expected, and that the additional integration and IT development efforts required to implement pre-pay electric and gas service are more complex than were originally envisioned.[655] Accordingly, the Company is requesting that approval of pre-pay electric and gas service be suspended, and the Company commits to filing a status report addressing a revised timeline and estimated implementation costs by the end of 2019. The Company then anticipates refiling the pre-pay rate schedules for approval at a later date, including potentially in conjunction with the annual FRP filing, if one is approved in this case.

4. Green Pricing Option

ENO complied with Resolution R-18-197 by sponsoring the Green Power Option rate schedule, which is attached as Exhibit RLS-6 to the Revised Direct Testimony of Mr. Smith.[656] No party objected to ENO's proposed Green Power Option rate schedule.

G. The Implementation of Grid Mod Assets depreciation rates should be approved.

Ms. Zimmerer explained that grid modernization involves the installation of additional communications devices (access points and relays) that will in some cases extend and in other

[654] Exhibit ENO-19 (Smith Revised Direct) at Exhibits RLS-1 and RLS-2.

[655] Exhibit ENO-13 (Owens Rejoinder) at 14.

[656] Exhibit ENO-19 (Smith Revised Direct) at Exhibit RLS-6.

cases increase the capacity of the AMI communications network that is currently being deployed. As those additional communications devices are installed, both advanced meters and Smart Grid Devices will all utilize the same communications network. The Company is recommending approval of a 15-year useful life for those assets − access points, relays, and any grid modernization asset with a microprocessor and/or communications component ("Grid Mod Assets") − for ratemaking purposes (equating to a depreciation rate of 6.67%).[657] A 15-year life is appropriate for those assets for several reasons: (1) the Council approved a 15-year life for the exact same Silver Springs Network access points and relays in the Company's AMI docket;[658] (2) The LPSC, the Arkansas Public Service Commission, and the Mississippi Public Service Commission have all approved a15-year useful life for AMI-related assets;[659] and (3) a 15-year useful life is appropriate for those types of assets because of the possibility of technological obsolescence that can affect the usability of those assets over the long-term.[660] No party opposed implementation of the Grid Mod Assets depreciation rates. Accordingly, these depreciation rate should be approved.

VIII. TAX REFORM PLAN UPDATE

Effective January 1, 2018, the Tax Cut Act reduced the federal corporate income tax rate from 35% to 21%. On May 22, 2018, the Council approved an Agreement in Principle, which

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657 Exhibit ENO-8 (Zimmerer Revised Direct) at 36.

658 Resolution R-18-37.

659 Exhibit ENO-8 (Zimmerer Revised Direct) at 36-37, citing LPSC Order No. U-31393 (Mar. 25, 2011) and LPSC Order No. U-34320 (Aug. 25, 2017); APSC Docket No. 10-109-U, Order No. 8 (Aug. 3, 2011) and Docket No. 16-060-U, Order No. 8 (Oct. 30, 2017); and MPSC Docket No. 2016-UA-261, Order Approving Application (May 4, 2017).

660 Exhibit ENO-8 (Zimmerer Revised Direct) at 37.

set forth a plan to pass on income tax rate reduction benefits resulting from the Tax Cut Act to customers, along with excess deferred taxes, ("Tax Reform Plan") during the period January 1, 2018 through July 31, 2019 based on the Company's assumption that base rates would change effective August 1, 2019.[661] Specifically, the Tax Reform Plan quantifies the reduction in income tax expense to be $15.2 million for the period January 1, 2018 through July 31, 2019 and proposes that customers receive bill credits of $6.8 million over the period July 2018 through July 2019 through the PPCACR Rider and the PGA Rider and that the remainder offset expenses associated with the Energy Smart.[662] Also, the change in the federal income tax rate changes the valuation of ADIT on ENO's books and results in excess deferred taxes. The Tax Reform Plan quantifies ENO's unprotected excess deferred taxes to be $35.2 million as of December 31, 2017 and proposes to provide the benefit of Unprotected Excess Deferred Taxes to customers prior to July 31, 2019 through bill credits of $14.1 million over the period July 2018 through July 2019 through the FAC Rider and offsets to Grid Modernization and Smart City investments and Energy Smart expenses.[663]

Accordingly, in both Period II cost of service studies, the Unprotected Excess Deferred Taxes are eliminated from rate base consistent with the ENO's Tax Reform Plan, resulting in an increase to rate base through the reduction of the ADIT balances and the regulatory liability associated with the Unprotected Excess Deferred Taxes.[664] Company witness Mr. Thomas,

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[661] Resolution R-18-227.

[662] Exhibit ENO-1 (Thomas Revised Direct) at 31.

[663] *Id*. at 31-32.

[664] *Id*. at 38.

however, explained that if the timing of the Grid Modernization and Smart City Pilot investments does not occur as planned, the change in rate base from the Tax Reform Plan may have to be updated.[665]

The Company expects nearly all of the income tax expense savings to be provided to customers or utilized to offset expenses by July 31, 2019 consistent with the Tax Reform Plan. The Company does not expect to fully utilize the entirety of the Unprotected Excess Deferred Taxes to offset Energy Smart expenses and Grid Modernization and Smart City Pilot investments by July 31, 2019. As of June 30, 2019, ENO has approximately $17 million of Unprotected Excess Deferred Taxes that have not been utilized. Accordingly, ENO requests that the Council direct ENO to include the actual remaining Unprotected Excess Deferred Taxes balance as of July 31, 2019 in electric base rates in the Company's compliance filing in this proceeding consistent with Mr. Thomas's testimony and direct ENO on how to treat any remaining income tax expense savings as of July 31, 2019.

IX. CONCLUSION

ENO is requesting that the Council put in place a new combined rate structure that will enable the Company to provide its customers throughout the City reliable, twenty-first century service that incorporates the industry's technological advances and that will continue to meet customers' evolving expectations and the Council's policy objectives. The Company has a plan that allows it to undertake a large, aggressive capital program to transform the delivery of electric service to customers and maintain the Company's financial condition. But successfully

665 *Id*. at 39.

executing that plan depends on the continuation of the constructive regulatory environment in which ENO has operated since its emergence from bankruptcy in 2007 following Hurricane Katrina.

ENO's Revised Application contains many important requests that support its plan to transform its operations at the lowest reasonable cost for the benefit of customers. To the extent that these various requests are contested, ENO submits that, as shown in this Brief, ENO's various requests will result in just and reasonable rates for all customers as the transformation commences and a new rate structure that will produce just and reasonable rates in the future. More specifically, as discussed at the beginning of this Brief, the determination of the authorized ROE in this proceeding will be the cornerstone of this transformation. Accordingly, the Company requests an ROE of 10.75%, which ROE would be reduced to 10.50% for electric operations through the RIM Plan. This recommendation is based on multiple analyses consistent with the important developments regarding the determination of ROE and is consistent with a constructive regulatory environment. In contrast, the other parties' ROE recommendations, especially the Advisors', are unreasonably low and are not consistent with a constructive regulatory environment. Next, with that cornerstone, an adequate foundation of ratemaking mechanisms to mitigate regulatory lag is necessary. Both Advisors and the Company agree steps to mitigate regulatory lag are necessary in light of ENO's aggressive capital program. Accordingly, the Company requests that the Council implement new measures to address regulatory lag; these measures should incorporate Electric and Gas FRPs and other riders, discussed herein, so that ENO can make the investments necessary to meet the Council's policy objectives and customers' evolving expectations and at the same time maintain the Company's financial condition. In short, ENO needs the Council's continued regulatory support if ENO is to achieve the transformation into a true twenty-first century utility that the Council, the Company, and customers envision for ENO. For these reasons and the reason set forth throughout this brief, ENO respectfully requests that the Council adopt ENO's proposed electric and gas base rates and all requested elements of its proposed rate structure as set forth in its Revised Application.

Respectfully submitted,

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CERTIFICATE OF SERVICE

I hereby certify that I have this 26th day of July, 2019, served the required number of copies of the foregoing pleading upon all other known parties of this proceeding individually and/or through their attorney of record or other duly designated individual, by: ☒ electronic mail, ☐ facsimile, ☒ hand delivery, and/or by depositing same with ☒ overnight mail carrier, or ☐ the United States Postal Service, postage prepaid.

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