BEFORE THE

COUNCIL OF THE CITY OF NEW ORLEANS

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

REVISED DIRECT TESTIMONY

OF

PHILLIP B. GILLAM

ON BEHALF OF

ENTERGY NEW ORLEANS, LLC

SEPTEMBER 2018

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I. INTRODUCTION

Q1. PLEASE STATE YOUR NAME AND CURRENT BUSINESS ADDRESS.

A. My name is Phillip B. Gillam. My business address is 425 West Capitol Avenue, Little Rock, Arkansas 72201.

Q2. BY WHOM ARE YOU EMPLOYED AND IN WHAT CAPACITY?

A. I am the Manager of Regulatory Filings for Entergy New Orleans in the Regulatory Services Department of Entergy Services, Inc. ("ESI").[1]

Q3. ON WHOSE BEHALF ARE YOU SUBMITTING THIS REVISED DIRECT TESTIMONY?

A. I am submitting this Revised Direct Testimony to the Council of the City of New Orleans (the "Council") on behalf of Entergy New Orleans, LLC (the "Company" or "ENO").

Q4. PLEASE DESCRIBE YOUR EDUCATIONAL AND PROFESSIONAL BACKGROUND.

A. A summary of my education and work experience is included as Exhibit PBG-1.

[1] ESI is an affiliate of the five Entergy Operating Companies ("EOCs") and provides administrative and support services to the EOCs. The five EOCs are Entergy Arkansas, Inc. ("EAI"), Entergy Louisiana, LLC ("ELL"), Entergy Mississippi, Inc., Entergy Texas, Inc., and ENO.

II. PURPOSE OF TESTIMONY

Q5. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. My Revised Direct Testimony presents the results of both the electric and gas cost of service studies based on data for the test years ending December 31, 2017 ("Period I") and December 31, 2018 ("Period II"), both of which test years have been proformed for known and measurable changes as of December 31, 2019, as well as identification of witnesses who support various components of the cost of service. In support of those cost of service studies, the purpose of my Revised Direct Testimony in this proceeding is to:

- describe the electric cost of service studies for the test years ending December 31, 2017 and December 31, 2018 presented in Statement F (Electric);
- discuss the methodology employed in preparing the Company's cost of service studies presented in the Cost of Service Workpapers provided in support of Statement F;
- sponsor certain pro forma adjustments in the electric and gas cost of service studies (Exhibit PBG-2);
- present the jurisdictional and class results of the Company's cost of service studies presented in Statement F (Exhibits PBG-3 through PBG-6);
- sponsor and discuss the framework and mechanics of ENO's proposed Electric Formula Rate Plan Rider ("Rider EFRP-5") presented in Exhibit

PBG-7 and Exhibit PBG-8, which presents a hypothetical example of the application of the Company's proposed decoupling provisions, which proposal was required by Council Resolution R-16-103, dated April 7, 2016;

- sponsor and discuss the framework and mechanics of the Company's proposed Gas Formula Rate Plan Rider ("Rider GFRP-5") presented in Exhibit PBG-9;
- sponsor and discuss framework and mechanics of the Company's proposed Combined Midcontinent Independent System Operator, Inc. Cost Recovery Rider ("MISO Rider") presented in Exhibit PBG-10;
- sponsor and discuss the framework and mechanics of the Company's proposed revised Rider PPCACR presented in Exhibit PBG-11;
- sponsor and discuss the framework and mechanics of the Company's proposed Gas Infrastructure Rider presented in Exhibit PBG-12; and
- sponsor and discuss the framework of the Company's proposed Distribution Grid Modernization Rider ("Rider DGM") presented in Exhibit PBG-13.

III. ELECTRIC AND GAS COST OF SERVICE STUDIES

A. Overview

Q6. PLEASE DESCRIBE THE TEST YEARS FOR PERIOD I AND PERIOD II.

A. Period I, or the historical test year, is comprised of the twelve months ended December 31, 2017. Period II, or the forecast test year, is comprised of the twelve months ended December 31, 2018.

Q7. HAS THE COMPANY PRESENTED PROFORMED DATA FOR BOTH PERIOD I AND PERIOD II?

A. Yes. Those pro forma adjustments to the cost of service are presented, in large measure, by Company witness Lisa Walther.

Q8. IS THE PERIOD I PROFORMED HISTORICAL TEST YEAR THE BASIS OF THE COMPANY'S REQUESTED CHANGE IN RATES IN THIS FILING?

A. No. The Company's electric and gas rate requests are based upon the Period II proformed test year. As explained in the testimony of Company witness Orlando Todd, proformed Period II, as filed, is more representative of the level of costs the Company expects to incur during the rate effective period and is a reasonable representation of what ENO believes to be normal business operations during that time frame. The Company has also proformed certain costs (*e.g.*, Plant-in-Service and Payroll) through the end of 2019 to better align the recovery of costs with the first rate effective period, which is expected to be August 2019 through August 2020, if the proposed Formula Rate Plan is adopted as presented.

Q9. WHAT EXHIBITS AND OTHER INFORMATION ARE YOU SPONSORING FOR THE ELECTRIC COST OF SERVICE STUDIES?

A. I sponsor the exhibits listed in the Table of Contents. In addition, I sponsor or co-sponsor the following Minimum Filing Requirements ("MFRs") Statements:

- A-1 (Summary of Revenue Requirements – Electric);
- A-1 (Summary of Revenue Requirements – Gas);
- B-1 (Summary of Jurisdictional Rate Base – Electric);
- B-1 (Summary of Jurisdictional Rate Base – Gas);
- B-12 (Calculation of Cash Working Capital – Electric);
- B-12 (Calculation of Cash Working Capital – Gas);
- C-1 (Jurisdictional Income Statement – Electric);
- C-1 (Jurisdictional Income Statement – Gas);
- C-9 (Gross Revenue Conversion Factor);
- C-10 (Tax Expansion Factor);
- F (Cost of Service Study – Electric Period I);
- F (Cost of Service Study – Electric Period II);
- F (Cost of Service Study – Gas Period I); and
- F (Cost of Service Study – Gas Period II).

Q10. WERE THE COMPANY'S COST OF SERVICE STUDIES PREPARED SOLELY FOR THIS COUNCIL RATE PROCEEDING?

A. Yes. The Company prepared the cost of service studies in accordance with Council

Resolution R-15-194, dated May 15, 2015 and Resolution R-17-504, dated September 28, 2017. Resolution R-15-194 approved an Agreement in Principle authorizing the Algiers Transaction. Prior to September 1, 2015, ENO and Entergy Louisiana, LLC both provided retail electric service in the City of New Orleans subject to the regulatory jurisdiction of the Council. Historically, ENO provided electric service to retail customers throughout the portion of the City of New Orleans situated on the east bank of the Mississippi River ("Legacy ENO Customers"). ELL provided Council-regulated electric service to retail customers in the Fifteenth Ward of the City of New Orleans ("Algiers"), which is located on the west bank of the Mississippi River. I refer to these customers as the "Algiers Customers." On September 1 2015, ENO purchased Algiers electric operations and the related assets and liabilities, which sale commonly is referred to as the "Algiers Transaction."

Q11. DO THE PERIOD II ELECTRIC COST OF SERVICE RESULTS SHOWN IN STATEMENT F REPRESENT THE TOTAL CHANGE IN RATES REQUESTED BY THE COMPANY IN THE ELECTRIC CASE?

A. No, the Period II Electric Cost of Service Study does not capture the total change in rates requested because the rate relief requested also addresses costs and savings that have been excluded or not captured in the Period II Electric Cost of Service Study. In conjunction with the Period II Electric Cost of Service Study, the Company requests an overall decrease of approximately $20.3 million to its Total Retail Revenue, as shown in Table 1, Line 11 below. The Period II Electric Cost of Service Study in Statement F supports only the proposed $428.4 million in Base Rate Revenue shown on Line 1 and the resulting Base Rate Revenue Deficiency of $135.2 million shown on Line 14.

Table 1
Summary of Electric Rate Relief Requested
Based on the Period II Electric Cost of Service

	Description	Amount ($ millions)	Witness
1	Base Rate Revenue Based on the Cost of Service Study[2]	428.4	Phillip B. Gillam
2	Fuel and Purchased Energy Revenue After Realignment	117.4	Myra L. Talkington
3	Revenue from Existing Riders After Realignment	17.6	Phillip B. Gillam
4	AMI Charge Electric	7.1	Joshua B. Thomas
5	Interim Energy Efficiency Cost Recovery Rider[3]	6.0	D. Andrew Owens
6	**Proposed Total Revenue** (Sum of L1 through L5)	**576.5**	
7	Present Base Rate Revenues[4]	293.2	Myra L. Talkington
8	Fuel and Purchased Energy	209.8	Myra L. Talkington
9	Revenue from Existing Riders	93.9	Phillip B. Gillam
10	**Present Total Revenues** (Sum of L7 through L9)	**596.9**	
11	**Total Revenue Deficiency/ (Sufficiency)** (L6 – L10)	**($20.3)**	
12	Base Rate Revenue Based on Cost of Service Study (L1)	428.4	Phillip B. Gillam
13	Present Base Rate Revenues (L7)	293.2	Myra L. Talkington
14	**Total Base Revenue Deficiency/(Sufficiency)** (L12 – L13)	**135.2**	

Note: Amounts may not tie due to rounding.

Q12. PLEASE EXPLAIN WHY THERE IS A BASE REVENUE DEFICIENCY BUT A TOTAL REVENUE SUFFICIENCY AT THE SAME TIME.

A. A substantial driver in the proposed change in Base Rate Revenues is the realignment of costs from recovery through various riders to recovery through ENO's base rates. Because the costs were already being recovered from customers outside of base rates, the realignment to ENO's base rates does not cause the overall amount of revenues to

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[2] Statement F, Page RR 1, Line 35, Total Retail Column on the Summary of Model Results. The total in Line 1 of the above table also includes Additional Facilities Charge Revenues of $153,195.

[3] This amount has not been annualized and reflects only a five-month revenue requirement to recover the difference between Energy Smart Program Year 9 originally anticipated funding and costs.

[4] Statement F, Page RR 1, Line 4, Total Retail Column on the Summary of Model Results.

be collected from customers to increase. These realignments involved over $100 million in revenue requirement and are discussed later in my testimony and the Revised Direct Testimonies of Company witnesses Orlando Todd and Scott M. Celino. Company witness Joshua B. Thomas also addresses the Company's request that the Council consider alternative class cost allocation methodologies in determining the appropriate allocation of costs given the changes that ENO has experienced since the Council last considered the design of ENO's rates.

One of the principal objectives of this proceeding is to realign the non-fuel revenue requirement associated with Union Station Power Block 1 ("Union PB1") from the Purchased Power and Capacity Acquisition Cost Recovery Rider ("PPCACR Rider"), which was applicable only to Legacy ENO Customers, to the Company's base rates so that the Union PB1 non-fuel revenue requirement is recovered from both Legacy ENO Customers and Algiers Customers as contemplated by the Agreement in Principle approved in Resolution R-15-542, dated November 19, 2015, and Council Resolution R-17-504, which calls for a single set of base rates for all ENO customers. Because the Company currently is recovering the Union PB1 non-fuel revenue requirement through the PPCACR Rider, the realignment to base rate does not increase the Company's revenue to be collected from customers.

Q13. WHAT IS THE AMI CHARGE ELECTRIC REFERENCED IN TABLE 1?

A. As discussed by Mr. Thomas, ENO is proposing a fixed charge to recover the net costs of the Advanced Metering Infrastructure ("AMI") project. AMI includes advanced meters that enable two-way data communication and a related communications network that supports two-way data communication. In Resolution R-18-37, dated February 8, 2018, the Council approved a Stipulated Settlement and Term Sheet regarding AMI that provided that the prudently incurred costs associated with AMI were eligible for recovery through electric and gas rates resulting from a final order of the Council in this proceeding. The net costs of the AMI project are not included in the Electric and Gas Cost of Service Studies so that ENO does not recover these costs twice.

Q14. WHAT IS THE INTERIM ENERGY EFFICIENCY COST RECOVERY RIDER REFERENCED IN TABLE 1?

A. As discussed by Company witness D. Andrew Owens, the Interim Energy Efficiency Cost Recovery Rider is the recovery mechanism proposed for funding Energy Smart from the time that new base rates are adopted as a result of this proceeding until the end of Program Year 9, which is currently set to end on December 31, 2019. This rider would serve as an interim universal funding mechanism for Energy Smart offerings approved in Council Resolution R-17-623, dated December 14, 2017, for both Legacy ENO Customers and Algiers Customers. Like the net costs of AMI, the costs associated with Energy Smart are not included in the Electric Cost of Service Studies so that ENO does not recover these costs twice.

Q15. HOW ARE THE PERIOD I AND PERIOD II ELECTRIC COST OF SERVICE FILING PACKAGES STRUCTURED?

A. The Electric Cost of Service Filing Packages contain all the workpapers that support the development of the Electric Cost of Service Studies presented in Statement F (Electric) as shown in Table 2 below.

Table 2
Structure of Electric Cost of Service Packages and Sponsoring Witnesses

Volume	Major Section	Description	Witness
I	RR	Cost of Service Study	Phillip B. Gillam
	SUM	Summary by Adjustment	Phillip B. Gillam
	RB	Per Book Data - Rate Base	Lisa Walther
	RV	Per Book Data - Revenues	Lisa Walther
	EX	Per Book Data - Expenses	Lisa Walther
II	AJ	Adjustments - Pro Forma Adjustments	See Exhibit PBG-2; Lisa Walther
	AF	Allocation Factors:	
	AF 1	Demand	Myra L. Talkington
	AF 2	Energy	Myra L. Talkington
	AF 3	Customer	Myra L. Talkington
	AF 4	Revenue	Myra L. Talkington and Phillip B. Gillam
	AF 5	Direct	Phillip B. Gillam
	AF 6	Internal	Phillip B. Gillam
	AF 7	Labor Study	Phillip B. Gillam
	AF 8	Payroll Workpapers	Lisa Walther
	MD	Miscellaneous Data:	
	MD.1	Revenue Conversion Factor	Phillip B. Gillam
	MD.2	Regulatory Commission Factor	Phillip B. Gillam
	MD.3	Uncollectible Factor	Phillip B. Gillam
	MD.4	Required Rate of Return	Phillip B. Gillam

Q16. NOW TURN TO THE COMPANY'S REQUESTED RATE RELIEF REGARDING ITS GAS OPERATIONS. DOES THE PERIOD II COST OF SERVICE RESULTS SHOWN IN STATEMENT F REPRESENT THE TOTAL CHANGE IN GAS BASE RATES REQUESTED BY THE COMPANY?

A. No. Like the Period II Electric Cost of Service Study discussed above, the Period II Gas Cost of Service Study does not capture the total change in rates requested because the rate relief requested also addresses costs and savings that have been excluded or not captured in the Period II Gas Cost of Service Study. In conjunction with the Period II Gas Cost of Service Study, the Company requests an overall decrease of approximately $0.1 million to its Total Gas Revenue as shown in Table 3, Line 8. The Period II Gas Cost of Service Study in Statement F supports the proposed $41.4 million in Base Rate Revenue and the Base Rate Revenue Sufficiency of $0.9 million shown on Line 11 in the last row below.

Table 3
Summary of Gas Rate Relief Requested
Based on the Period II Gas Cost of Service

	Description	Amount ($ millions)	Witness
1	Base Rate Revenue Based on Cost of Service Study[5]	41.4	Phillip B. Gillam
2	Purchased Gas Adjustment	34.9	Myra L. Talkington
3	AMI Charge Gas	0.8	Joshua B. Thomas
4	**Proposed Total Revenue** (L1 + L2 + L3)	**77.1**	
5	Present Base Rate Revenues[6]	42.3	Myra L. Talkington
6	Purchased Gas Adjustment	34.9	Myra L. Talkington
7	**Present Total Revenues** (L5 + L6)	**77.2**	
8	**Total Revenue Deficiency/ (Sufficiency)** (L4 – L7)	**(0.1)**	
9	Base Rate Revenue Based on Cost of Service Study (L1)	41.4	Phillip B. Gillam
10	Present Base Rate Revenues (L5)	42.3	Myra L. Talkington
11	**Total Base Revenue Deficiency/(Sufficiency)** (L9 – L10)	**(0.9)**	

Q17. DOES THE AMI CHARGE GAS RELATE TO THE SAME PROCEEDING THAT THE AMI CHARGE ELECTRIC IS RELATED TO?

A. Yes. Both charges stem from the Stipulated Settlement and Term Sheet that provided that the prudently incurred costs associated with AMI were eligible for recovery through electric and gas rates resulting from a final order of the Council in this proceeding.

Q18. HOW ARE THE PERIOD I AND PERIOD II GAS COST OF SERVICE FILING PACKAGES STRUCTURED?

A. The Gas Cost of Service Filing Packages contain all the workpapers that support the development of the Gas Cost of Service Studies presented in Statement F (Gas) as shown in Table 4 below.

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5 Statement F, Page RR 1, Line 35, Total Retail Column on the Summary of Model Results.
6 Statement F, Page RR 1, Line 4, Total Retail Column on the Summary of Model Results.

Table 4 Structure of Gas Cost Of Service Package and Sponsoring Witnesses			
Volume	**Major Section**	**Description**	**Witness**
I	RR	Cost of Service Study	Phillip B. Gillam
	SUM	Summary by Adjustment	Phillip B. Gillam
	RB	Per Book Data - Rate Base	Lisa Walther
	RV	Per Book Data - Revenues	Lisa Walther
	EX	Per Book Data - Expenses	Lisa Walther
II	AJ	Adjustments - Pro Forma Adjustments	See Exhibit PBG-2; Lisa Walther
	AF	Allocation Factors:	
	AF 1	Demand	Myra L. Talkington
	AF 2	Energy	Myra L. Talkington
	AF 3	Customer	Myra L. Talkington
	AF 4	Revenue	Myra L. Talkington and Phillip B. Gillam
	AF 5	Direct	Phillip B. Gillam
	AF 6	Internal	Phillip B. Gillam
	AF 7	Labor Study	Phillip B. Gillam
	AF 8	Payroll Workpapers	Lisa Walther
	MD	Miscellaneous Data:	
	MD.1	Revenue Conversion Factor	Phillip B. Gillam
	MD.2	Regulatory Commission Factor	Phillip B. Gillam
	MD.3	Uncollectible Factor	Phillip B. Gillam
	MD.4	Required Rate of Return	Phillip B. Gillam

B. Cost of Service Process

Q19. WHAT IS THE OBJECTIVE OF PREPARING A FULLY ALLOCATED CLASS COST OF SERVICE STUDY?

A. The objective of preparing a cost of service study for either electric or gas operations is to determine the portion of a utility's costs, as measured by its revenue requirement, for which each of the various rate classes is responsible. This then becomes one of the factors to be considered in determining the revenue level appropriately allocated to each rate class, though the Council has wide discretion in the area of rate design. A cost of service study also provides revenue requirement information by function that is useful in the rate design process.

Q20. WHAT IS A RATE CLASS?

A. A rate class can be defined as a group of customers that are homogenous in terms of usage characteristics and cost causation. ENO currently has fourteen different retail rate classes for ENO Legacy customers: Residential, Master Metered Residential, Small Electric, Municipal Buildings, Large Electric, Large Electric High Load Factor, Master Metered Non-Residential, High Voltage, Large Interruptible, Outdoor Directional Security, Outdoor Night Watchman, Street Lighting, Traffic Signal, and Experimental Interruptible. For ENO Algiers customers, there are four different retail rate classes: Residential, Small General Service, Large General Service, and Lighting. For ENO Gas customers, there are five different retail rate classes: residential, Small General, Large General, Small Municipal and Large Municipal.

Because of the expected combination of rates for all electric customers, as discussed by Company witness Myra L. Talkington, ENO is proposing to collapse and/or eliminate certain rate classes so that there will only be nine rate classes in this rate case and in subsequent rate proceedings. The proposed post-rate case decision electric rate classes are: Residential, Small Electric, Municipal Buildings, Large Electric, Large Electric High Load Factor, Master Metered Non Residential, High Voltage, Large Interruptible and Lighting. The gas rate classes will remain the same.

Q21. PLEASE BRIEFLY OUTLINE THE GENERAL METHODS EMPLOYED IN THE PREPARATION OF THE COST OF SERVICE STUDIES THAT YOU ARE SPONSORING.

A. I used the industry-accepted approach that utilizes the successive application of the processes of functionalization, classification, and allocation with respect to all components of rate base, revenue, and operating expenses. Immediately below, I address the functionalization and classification process. Because the allocation to rate classes is performed in the cost of service studies on a total company adjusted basis, the allocation process is discussed after the pro forma adjustments to the cost of service studies below.

Q22. PLEASE DISCUSS THE FUNCTIONALIZATION PROCESS.

A. Functionalization is the separation of costs by the major functions of generation (or production), transmission, and distribution/customer service, for the electric cost of service, in order to facilitate the determination of how to allocate the Company's costs to the various rate classes.

Gas service, however, has somewhat different functional characteristics. The most significant difference is that the Company purchases all of its gas and, consequently, has no costs that are equivalent to the investment in generating equipment or production facilities on the electric side. The purchased gas cost parallels the fuel and purchased power costs associated with electric service. In her Revised Direct Testimony, Ms. Talkington discusses the allocation methods used in the gas cost of service studies.

Q23. ARE ALL COSTS DIRECTLY ASSIGNABLE TO ONE OF THESE THREE FUNCTIONS?

A. No. There are many items that represent a combination of more than one of these functions and must be addressed as an aggregated amount. For example, although certain parts of general plant may be assigned to one function (*i.e.*, stores equipment), the majority of general plant (*i.e.*, transportation, laboratory equipment, and communication equipment) supports multiple functions and, thus, must be addressed functionalized to more than one function. Thus, these general plant type costs are functionalized based on various drivers.

Similar to the electric cost of service studies, there are cost items for gas that are not associated directly with one certain function. Therefore, the cost must be allocated based on the sum of its associated function. Again, as discussed earlier in the electric section, a good example is the general plant category. While certain parts of general plant may be assigned to one of the gas functions, the majority of general plant supports all gas functions and must be functionalized to more than one function based on various drivers. Thus, discretion is involved in the appropriate functionalization of costs.

Q24. PLEASE DESCRIBE THE CLASSIFICATION PROCESS.

A. Classification is the separation of functionalized costs into demand-related, energy-related, or customer-related categories. An example of a demand-related cost for electric is the cost associated with distribution substations. An example of a demand-related cost for gas is the cost associated with distribution mains. Energy-related costs are costs considered to be associated with sales rather than demand. The cost of fuel consumed by production facilities is the best example of an energy-related cost. Certain production maintenance expenses are generally treated as energy-related for cost of service purposes. Expense charged to electric Account 512 (Maintenance of boiler plant) is an example of such a cost. Customer-related costs are costs that are incurred even if a customer does not impose demand on the system or consume energy. The costs of reading meters and preparing bills are examples of customer-related costs. Finally, there are typically a few costs that are revenue-related. Expense charged to Account 904 (Uncollectible accounts) is an example of a revenue-related cost. Note that discretion is involved in determining the appropriate classification of costs.

Q25. PLEASE DESCRIBE IN GENERAL TERMS HOW THE COST OF SERVICE STUDIES PRESENTED IN THE COST OF SERVICE WORKPAPERS IN STATEMENTS F (ELECTRIC & GAS) WERE DEVELOPED.

A. The starting point for the preparation of the Electric and Gas cost of service studies was the unadjusted, or "per book," rate base, revenues and operating expenses for the Period I and Period II test years. The unadjusted/per book data was loaded into the Cost of Service Ledger where the data was aggregated at the Federal Energy Regulatory Commission ("FERC") account level to the extent possible to ensure consistency in treatment of similar costs. The Cost of Service Ledger is a Utilities International system that includes data used in regulatory filings (*i.e.*, per book data and pro forma adjustments used in cost of service studies, formula rate plans, etc.).

After all pro forma adjustments were entered in the Cost of Service Ledger, the data was loaded into the cost of service model where it was functionalized, classified, and allocated to the rate classes. The rate base, revenue, and expense components in the cost of service studies in Statements F (Electric and Gas) include per book data, adjustments, and total adjusted results (per book plus or minus adjustments if applicable). Summaries of the adjusted values are also presented for the major rate base, revenue, and expense components in Statements F (Electric and Gas).

The summary pages from the Period I gas cost of service study are included in Exhibit PBG-5. The complete study is included in Schedule F of the gas filing requirement package. The summary pages from the Period II gas cost of service study are included in Exhibit PBG-6. The complete study is included in Schedule FF of the gas filing requirement package.

C. Pro Forma Adjustments

Q26. WHAT ARE THE PRO FORMA ADJUSTMENTS IN THE ELECTRIC COST OF SERVICE STUDY?

A. The pro forma adjustments to the cost of service studies are in sections "SUM" and "AJ" of the Cost of Service workpapers in Statements F (Electric). A complete listing of the adjustments, the witnesses supporting each adjustment, and the location of each adjustment in the Cost of Service workpapers is presented in Exhibit PBG-2 for the Electric Cost of Service Study.

Q27. WHICH PRO FORMA ADJUSTMENTS DO YOU SPONSOR?

A. Table 5 below identifies the adjustments that I sponsor or co-sponsor.

Table 5 Pro Forma Adjustment Sponsored by Phillip B. Gillam			
	ENO Cost of Service Adjustments		**Adjustment Description**
1	AJ01A		Rate Schedule and Other Revenue
2	AJ01B		Fuel, Purchased Power and NO_X Expenses
3	AJ01C		Capacity and LTSA Expenses
4	AJ01D		MISO
5	AJ2		Interest Synchronization
6	AJ22		Cash Working Capital
7	AJ23		Uncollectibles /Revenue-Related Expense

Q28. ARE THE PRO FORMA ADJUSTMENTS THAT YOU SPONSOR THE SAME IN THE PERIOD I AND PERIOD II ELECTRIC COST OF SERVICE STUDIES?

A. For the most part, the nature of the pro forma adjustments I sponsor are the same in both periods. AJ01B – Fuel, Purchased Power and NO_x Expenses adjust the same types of costs in both periods, with only the amounts being different. AJ01C - Capacity and Long-Term Service Agreement ("LTSA") Expenses are identical in both periods. AJ01D - MISO, removes the MISO Rider expenses and revenues in both periods, again with only the amounts being different. Although present in both cost of service studies, Adjustments AJ2 - Interest Synchronization and AJ22 – Cash Working Capital differ between the Period I and Period II cost of service studies due to differences in the adjusted rate base and operation and maintenance expenses. AJ 23 – Uncollectible and Revenue-Related Expense also adjusts the same expenses in both periods with only the amounts being different.

Q29. PLEASE DISCUSS THE PORTION OF ELECTRIC ADJUSTMENT AJ1 (SPECIAL RATES) THAT YOU CO-SPONSOR.

A. Adjustment AJ1 adjusts the rate schedule revenues to an ENO normalized level of rate schedule revenues that would be representative of the revenues for the rate effective period, which would be the period after which new rates would be in effect, currently expected to begin August 2019. Ms. Talkington sponsors the base rate revenues included in Adjustment AJ01A as the adjusted present rate revenues. Base rate revenues do not include fuel or special rider revenues. Ms. Talkington also provided the base revenues for ENO Tampering Fees and Facility Charges to be reclassified from rate schedule revenues to other electric revenue.

Within Adjustment AJ01A, I sponsor the elimination of the unbilled revenues, which are the revenues attributable to electricity used by the customer but not yet billed. These revenues are removed because the present base revenues provided by Ms. Talkington for a rate case are determined by pricing 12 months of sales by the appropriate rate amounts; so, there are effectively no unbilled revenues. This treatment of unbilled revenues is consistent with the previous regulatory treatment of unbilled revenues by Council.

Q30. PLEASE DISCUSS THE PURPOSE OF ADJUSTMENT AJ01B.

A. Adjustment AJ01B synchronizes the Company's recoverable fuel revenues, fuel expense, and purchased energy expenses at a value of zero. This adjustment is appropriate because recoverable fuel revenues and fuel and purchased power expenses are currently recovered through mechanisms outside of base rates (*e.g.*, FAC – Fuel Adjustment Clause, and the EAC – Environmental Adjustment Clause Rider).

In Adjustment AJ01B, per book amounts for the following items were reversed (*i.e.*, set to zero):

- Other sales for resale revenue;
- Recoverable fuel expense;
- Recoverable NOX expense;
- Recoverable purchased power expense; and
- Other power supply expenses (deferred system agreement receipts, NOX deferred expense, deferred fuel).

As stated earlier in the description of Adjustment AJ01A, the adjusted present rate revenues in the cost of service study include base rates, but not fuel revenues. Therefore, as a result of Adjustment AJ01B, the Company's fuel revenues and recoverable fuel and purchased power expenses are synchronized at a value of zero for each of its rate classes such that all recoverable fuel and purchased power is removed from the Company's cost of service. This fuel synchronization approach is the easiest and most straightforward approach for the cost of service study to focus on determining base rate revenue requirements for its various rate classes.

Q31. PLEASE DISCUSS THE PURPOSE OF ADJUSTMENT AJ01C.

A. Adjustment AJ01C implements the exact cost recovery process described by Mr. Todd in his Revised Direct Testimony, which process is similar to the exact recovery process employed today for the exact recovery capacity expenses associated with the Grand Gulf Unit Power Sales Agreement between ENO and System Energy

Resources, Inc. ("Grand Gulf UPSA"). As a part of this exact recovery process, the Company is proposing to realign to base rate recovery certain purchased power agreement ("PPA") capacity expenses and LTSA expenses that today are recovered outside of base rates on an exact recovery basis. This proposed exact recovery process involves recovering an estimate of calendar year capacity expenses and LTSA expenses in base rates and truing-up the estimate to the actual expense level on a monthly basis through the FAC or the PPCACR Rider. Today, the Company includes an estimate of Grand Gulf UPSA capacity expenses in base rates and includes the true-up in the FAC.

To implement the exact recovery process, Adjustment AJ01C adds to the Company's operation and maintenance ("O&M") expenses the 2019 calendar year estimate of PPA capacity expenses and LTSA expenses, which estimate is supported by Mr. Todd and shown in his Exhibit OT-2. A portion of these expenses, $32.4 million, broken down by month is included on Schedule A to the proposed PPCACR Rider. The remainder of these expenses, $153.3 million, broken down by month is included on Schedule A to the proposed FAC. This remainder includes the current Schedule A amount associated with the Grand Gulf UPSA. Adjustment AJ01B eliminates the test year level of these expenses to prevent any double recovery.

Q32. WHICH EXPENSES ARE BEING REALIGNED TO BASE RATE RECOVERY THROUGH ADJUSTMENT AJ01C?

A. The capacity expenses associated with the PPA with EAI for a share of the output of EAI's wholesale baseload resources ("EAI WBL PPA") and the PPA with ELL for a share of the output of the unregulated thirty percent portion of River Bend ("RB30% PPA") are being realigned (though, as Mr. Thomas discusses, the effect of this realignment is modified through ENO's proposed cost allocation methodology). These capacity expenses currently are recovered through the FAC. The capacity expenses associated with two PPAs with ELL for shares of the output of Ninemile 6 are being realigned. These capacity expenses currently are recovered through the PPCACR Rider and the Ninemile 6 Nonfuel Cost Recovery Interim Rider.

The LTSA expenses associated with Union PB 1, Ninemile 6, and two other facilities owned by ELL are being realigned. These LTSA expenses currently are recovered through the FAC.

There are capacity expenses included in Adjustment AJ01C that are not being realigned because they are already being recovered in base rates. These are the capacity expenses associated with the Grand Gulf UPSA, which are only reflected in Legacy ENO Customers' base rates today, and the capacity expenses associated with the Algiers Transaction PPA except those attributable to Ninemile 6, which are only reflected in Algiers Customers' base rates today.

Q33. PLEASE DISCUSS THE PURPOSE OF ADJUSTMENT AJ01D.

A. Adjustment AJ01D removes MISO Rider expenses and revenues from the base rate revenue requirement since these revenues and expenses are currently being recovered in the two MISO Riders (ENO Legacy and Algiers) and will continue to be recovered through the combined MISO Rider discussed later in my testimony.

Q34. PLEASE DISCUSS THE PURPOSE OF ADJUSTMENT AJ23.

A. Adjustment AJ23 adjusts revenue-related and uncollectible expenses to reflect the prospective rate year level of total rate schedule revenue for ENO. It also adds adjustments to uncollectible expense and revenue-related taxes other than income taxes (Local Franchise Taxes, and Regulatory Commission - Local) for an ENO prospective level of total rate schedule revenue. All of the expenses adjusted vary directly with the level of retail rate schedule revenue.[7]

The uncollectible accounts expense was adjusted using a five-year average bad debt rate. The adjustment to revenue-related taxes other than income taxes was determined by utilizing a rate based on the per book amounts of rate schedule revenues and revenue-related taxes other than income taxes.

Q35. WHICH COMPANY WITNESSES SUPPORT THE ADJUSTMENTS TO THE PERIOD I AND PERIOD II GAS COST OF SERVICE STUDIES?

A. The correspondingly numbered adjustments in the Period I and Period II cost of service studies have the same purpose, and the Company witness sponsoring each adjustment is listed on Exhibit PBG-2.

Q36. PLEASE DISCUSS THE PARTS OF GAS ADJUSTMENT AJ01, WHICH EXHIBIT PBG-2 INDICATES YOU ARE SPONSORING.

[7] Retail Rate Schedule Revenue is the total revenue received from all rate schedule sources such as Base Rate Revenues, FAC (Fuel) Revenues, Special Riders (*e.g.*, MISO or PPCACR), and other miscellaneous rate schedules (*e.g.*, Facilities Charges or SMS-Standby and Maintenance Service).

A. I sponsor Adjustment AJ01B, which eliminates the Purchased Gas Adjustment ("PGA") revenue included in the adjusted present rate revenue in the Rate Schedule Revenue provided by Ms. Talkington. The corresponding recoverable purchased gas cost that is includable in the Company's PGA adjustment procedure is also eliminated. This adjustment was made to assure that only the Company's base rate revenue requirement was considered for rate making purposes. This adjustment assures that the cost of service study provides accurate measure of the base rate revenue requirement and that overall change in base rates by ensuring that the adjusted fuel revenue and the adjusted fuel costs are properly synchronized. Synchronizing gas revenue and gas expense in this manner, *i.e.*, setting both to zero, by definition also synchronizes sales and gas purchases for the test year.

I also sponsor part of Adjustment AJ01A related to Other Operating Revenue, which part reclassifies certain rate schedule revenue to other gas revenue.

Q37. WHAT IS THE PURPOSE OF GAS ADJUSTMENT AJ23?

A. Adjustment 23 – Uncollectible and Revenue-Related Tax Expense aligns the uncollectible accounts expense and revenue-related tax expense, which directly varies with the level of rate schedule revenue, with rate schedule revenue as adjusted in Adjustments AJ01A and AJ01B. The uncollectible factor that was used was developed using a five-year average.

D. Allocation Process

Q38. PLEASE DESCRIBE THE ALLOCATION PROCESS USED TO DEVELOP THE PERIOD I AND PERIOD II ELECTRIC AND GAS COST OF SERVICE STUDIES.

A. The functionalization and classification processes that I discussed earlier provide an understanding of the nature of the costs and, thereby, make it possible to select an appropriate basis on which to allocate individual costs. The allocation process for electric and gas apportions or distributes costs to the various customer groups, that is, rate classes, through the use of an “allocation factor.” Generally, costs are allocated on the basis of a demand, energy, or customer relationship. In a limited number of instances, a revenue relationship may be used to allocate costs. Mr. Thomas discusses that there are multiple means to allocate costs among customer classes and proposes that the Council consider alternative allocation methodologies through a collaborative process involving all parties to this proceeding.

Many cost items cannot be functionalized and classified to the point that a specific demand, energy, or customer allocation factor can be determined as being the appropriate allocator. In such cases, related cost items, as they have been allocated to the customer groups, are commonly used as allocators. For example, synchronized interest expense in the income tax calculation, which is related to the total rate base, is typically allocated using a factor consisting of the rate base allocation to the rate classes.

Q39. WHAT METHODS WERE USED TO ALLOCATE THE COMPANY’S ADJUSTED TEST YEAR COSTS?

A. Ms. Talkington discusses the methods that were utilized to allocate each of the major function/classification cost categories. She also discusses the development of the corresponding allocation factors utilized in preparing the Company's cost of service studies. Costs not directly associated with one of the major function/classification cost categories were allocated using factors developed in the cost of service study that are most appropriate for each such cost.

Q40. HOW WERE THE ALLOCATION FACTORS APPLIED IN THE COMPANY'S PERIOD I AND PERIOD II ELECTRIC AND GAS COST OF SERVICE STUDIES?

A. The Company's cost of service studies reflected in the Cost of Service Workpapers in Statements F were prepared through a "bottom-up" approach. Under this approach, cost of service line items were first allocated to the rate class level. The results for ENO's rate classes were then summed to determine the revenue requirement by rate class. This approach recognizes that the overall revenue requirement for each product line (electric or gas) is the aggregation of the various electric and gas rate classes.

IV. ELECTRIC FRP RIDER WITH DECOUPLING

Q41. WHAT WAS THE STARTING POINT FOR THE DEVELOPMENT OF THE COMPANY'S PROPOSED ELECTRIC FRP RIDER?

A. 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, as Exhibit 7 to the 2008 Rate Case Agreement in Principle. The proposed

Electric FRP Rider continues many features of its predecessor:

- use of the previous calendar year as the Evaluation Period;
- use of the authorized return on equity set in this proceeding as the target Evaluation Period Cost of Equity ("EPCOE");
- a dead band centered on the EPCOE, in which there would be no change in rates;
- 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," if the Earned Rate of Return on Equity ("EROE") is above or below the dead band;
- seventy-five day review period;
- a specified dispute resolution procedure; and
- a three-year term.

Q42. HOW DOES THE PROPOSED ELECTRIC FRP RIDER DIFFER FROM PREDECESSOR?

A. The changes fall in seven categories: (1) changes recommended by the Company for specific reasons discussed below and in the Revised Direct Testimony of Mr. Thomas, which include changes to the EPCOE to incorporate the proposed Reliability Incentive Mechanism ("RIM") Plan's adjusted return on equity ("ROE") formula; (2) changes to accommodate the Energy Smart program; (3) changes to implement the Decoupling Pilot Program, which Council Resolution R-16-103 requires ENO to present in this rate case; (4) a new provision for an interim Rate Adjustment for the New Orleans Power Station non-fuel revenue requirement; (5) a new provision for changes in income tax rates; (6) a change to the "Extraordinary Cost Changes" provision related to the revenue requirement trigger; and (7) a new provision for Rider PPCACR Transitional Items.

Q43. WHAT ARE THE SPECIFIC REASONS FOR THE CHANGES TO THE PROVISIONS OF THE PRIOR FRP RECOMMENDED BY THE COMPANY?

A. The Company recommends three changes. First, ENO proposes that the Company file its annual Evaluation Reports by April 30 and that any rate adjustment, if necessary, become effective for the first billing cycle in September of the filing year. ENO proposes this change to reduce regulatory lag so that any rate changes are passed on to customers sooner rather than later and provide a reasonable opportunity for the Company to earn its Council-authorized return. Second, ENO proposes that the dead band be increased symmetrically by twenty basis points so that rate adjustments occur only if the EROE exceeds the EPCOE by more than fifty basis points. Using ENO's proposed adjusted ROE of 10.50%, no rate adjustment would occur unless the EROE was less than 10.00% or greater than 11.00%. ENO is proposing this change because it incentivizes the Company to manage its resources efficiently.

Third, ENO is proposing the RIM Plan's adjusted ROE formula that annually adjusts the baseline ROE authorized by the Council in this proceeding based on the Company's future System Average Interruption Frequency Index or "SAIFI." Mr.

Thomas explains why the RIM Plan is an appropriate regulatory mechanism for the Council to consider, and Company witness Melonie P. Stewart explains how the Company intends to improve its distribution reliability performance and the significance of the benchmarks used in the formula

This adjustment, as set forth in Attachment E to the proposed Electric FRP, would add or subtract from the Council-authorized baseline ROE up to 25 basis points depending on ENO's SAIFI Score for the applicable FRP Evaluation Periods. The RIM Plan formula would establish a Target Improvement Score of 1.24 where there would be no adjustment to the Council-authorized ROE. From there, if the SAIFI Score is worse than the Target Improvement Score, but greater than or equal to the Lower Bound SAIFI Score proposed level of 1.40, then a Performance Adjustment percentage will be calculated based on ENO's performance as compared to the Target Improvement Score. For example, if ENO's SAIFI Score for the test period is 1.32 (which is halfway between the Target Improvement Score and the Lower Bound SAIFI Level), then the Performance Adjustment would be 50 percent of a negative 25 basis points, or a negative 12.5 basis points, which is then subtracted from the Council-authorized baseline ROE resulting in the "Adjusted EPCOE" of 10.63% for that FRP test period. Based on the Adjusted EPCOE (midpoint), the FRP dead band used to establish prospective rates would span from 10.13% to 11.13%.

The process works similarly with the Upper Bound SAIFI Score. If the SAIFI Score is better than the Target Improvement Score, but less than or equal to the Upper Bound SAIFI Score proposed level of 1.05, then a Performance Adjustment would be calculated in a manner similar to the Lower Bound calculation. For example, if

ENO's SAIFI Score for the test period is 1.14 (which is a little more than halfway, 10/19 or 52.6%, between the Target Improvement Score and the Upper Bound SAIFI Level), then the Performance Adjustment would be 52.6% of a positive 25 basis points, or a positive 13 basis points, which is then added to the Council-authorized ROE resulting in the Performance Adjusted EPCOE/midpoint of 10.88%, resulting in a dead band spanning from 10.38 to 11.38% to set prospective rates.

Note that the Upper Bound SAIFI Level is not symmetrical with the Lower Bound SAIFI Level, so that it is more challenging for the Company to achieve and reach the very top of the performance band. Also, Mr. Thomas has included a graph in his testimony that shows how the EPCOE would adjust as ENO's SAIFI Score changes.

Q44. WHAT ARE THE CHANGES TO ACCOMMODATE THE ENERGY SMART NEW ORLEANS PROGRAM ("ENERGY SMART")?

A. As discussed by Company witness D. Andrew Owens, the Company proposes that the costs of Energy Smart, the Lost Contribution to Fixed Costs associated with Energy Smart, and the related incentive mechanism be recovered from customers through the Interim Energy Efficiency Cost Recovery Rider and, later, the Demand-Side Management Cost Recovery Rider. Accordingly, the proposed Electric FRP Rider would no longer include mechanisms to recover the Lost Contribution to Fixed Costs associated with Energy Smart or any energy efficiency incentive penalty or reward. Additionally, ENO has included in Attachment C, Section 1, Paragraph C, a provision expressly stating that no adjustment to Present Base Revenues should be made to reflect the Lost Contribution to Fixed Costs associated with Energy Smart, which is expected to occur in the calendar year after the first Evaluation Period.

Q45. HOW DOES THE COMPANY PROPOSE TO IMPLEMENT THE DECOUPLING PILOT PROGRAM WITHIN THE ELECTRIC FRP?

A. The Company proposes to implement the Decoupling Pilot Program within the Electric FRP through a four-step process to be applied if and only if a Rate Adjustment is necessary under the terms of the rider. In other words, if the EROE is within the dead band, then the process will not be applied.

In a nutshell, the object of the four-step process is to calculate a Fixed and Variable Revenue Deficiency or Excess for each rate class based on the allocation of the Electric Revenue Requirement by rate class and Fixed Cost versus Variable Cost classification determined in this rate case, whatever it may be, and then to calculate a corresponding FRP Rate Adjustment for each rate class. The Electric FRP Rider refers to the Electric Revenue Requirement determined in this rate case as the "Baseline Rate Class Fixed and Variable Revenue Requirement." ENO proposes to include the Baseline Rate Class Fixed and Variable Revenue Requirement as a table in Attachment G to the Electric FRP Rider. Currently, the table is not populated. In the compliance filing to follow the rate case, ENO intends to populate the table based on the Council's decision in this rate case, if the proposed Electric FRP Rider is approved. For the ease of discussion, I refer to the Baseline Rate Class Fixed and Variable Revenue Requirement as the "Baseline Revenue Requirement" in the remainder of my testimony.

Q46. HAS THE COMPANY DESCRIBED THIS PROCESS TO PARTIES PREVIOUSLY?

A. Yes. The Company illustrated this four-step process in its Summary of Illustrative Examples of Decoupling Mechanism Filing dated September 6, 2016 pursuant to Ordering Paragraph 13 of Council Resolution R-16-103.

Q47. PLEASE EXPLAIN WHY THE COMPANY IS FOCUSED ON THE ALLOCATION OF THE ELECTRIC REVENUE REQUIREMENT BY RATE CLASS DETERMINED IN THIS RATE CASE?

A. The Company is focused on that allocation because the Decoupling Pilot Program Resolution, Council Resolution R-16-103, provides that the fixed cost and variable cost revenue requirements be recovered from each rate class consistent with the allocation methodology used in the baseline rate case.

Q48. PLEASE DEFINE FIXED COST AND VARIABLE COST REVENUE REQUIREMENT IN THE CONTEXT OF THE PROPOSED DECOUPLING PILOT.

A. As discussed earlier, in the cost of service process, costs are first functionalized and then classified as Demand, Energy, or Customer. The Fixed Cost Revenue Requirement consists of all Demand and Customer costs; the Variable Cost Revenue Requirement consists of all Energy costs. For the Period II Electric Cost of Service Study, the Fixed Cost Revenues Requirement is $426,205,181 and the Variable Cost Revenue Requirement is $2,050,814 as shown in Exhibit PBG-8, page 1 of 8.

Q49. PLEASE PROVIDE AN EXAMPLE OF HOW THE BASELINE RATE CLASS FIXED AND VARIABLE REVENUE REQUIREMENT WOULD BE USED IN THE ELECTRIC FRP.

A. A comprehensive example is attached as Exhibit PBG-8. It assumes that in this rate case, the Council determines that ENO's Baseline Electric Revenue Requirement is $428.3 million and that, out of that $428.3 million, the Residential Rate Class's Baseline Fixed Revenue Requirement is $190.8 million, which is 44.55% of ENO's Electric Revenue Requirement, and its Baseline Variable Revenue Requirement is $0.9 million, which is 0.21% of ENO's Baseline Electric Revenue Requirement.

Now, assume a Rate Adjustment is necessary in an Evaluation Period and ENO's Electric Revenue Requirement increases by $3 million to $431.3 million. Using the Baseline Rate Class Fixed and Variable Revenue Requirement, in the Electric FRP, the Residential Rate Class's Fixed Revenue Requirement would be approximately $192.1 (*i.e.*, 44.55% times $431.3 million), and its Variable Revenue Requirement would be approximately $0.9 million (*i.e.*, 0.21% times $431.3 million). This is the first step of the four-step process.

Q50. WHY IS THE COMPANY NOT PROPOSING TO ALLOCATE THE EVALUATION PERIOD ELECTRIC REVENUE REQUIREMENT TO EACH RATE CLASS USING RATE CLASS ALLOCATION FACTORS CALCULATED BASED ON EVALUATION PERIOD DATA?

A. If the Council does not follow the allocation factors calculated in the class cost of service study filed in this case, then recalculating those same allocation factors based on Evaluation Period data should not occur and would be a waste of resources. The Company is proposing that the Council not adopt the rate class allocation of the Electric Revenue Requirement from ENO's filed Electric Cost of Studies because it would result in a disruptive shift in cost responsibility to the Residential Rate Class. Furthermore, the Council has not adopted the rate class allocation of the Electric Revenue Requirement from ENO's filed Electric Cost of Studies in its last two rate cases. Thus, the most practical way to implement the Decoupling Pilot Program is to rely on the allocation of the Electric Revenue Requirement by rate class and Fixed Cost versus Variable Cost classification determined in this rate case.

Q51. PLEASE DESCRIBE THE NEXT TWO STEPS IN THE PROCESS.

A. The second step is to allocate each Rate Class's Evaluation Period Base Revenue (and FRP Revenue, if any,) between Fixed Revenue and Variable Revenue using the Baseline Revenue Requirement.

Using the above example, the Baseline Residential Rate Class Fixed Revenue Requirement is 99.52% of the Baseline Residential Rate Class Revenue Requirement (*i.e.*, $190.8 million divided by $191.7 million). Therefore, assuming the Residential Rate Class's Base Revenue totals $190.0 million, then the Residential Rate Class Evaluation Period Fixed Revenue would be $189.1 million (*i.e.*, 99.52% times $190.0 million), and the Residential Rate Class Evaluation Period Variable Revenue would be $0.9 million.

The third step in the process is to compute each rate class's Evaluation Period Fixed and Variable Revenue Deficiency or Excess. An example of the computation is shown in Table 6 below using the example amounts discussed previously.

Table 6
Calculation of Residential Rate Class Revenue Deficiency/(Excess)
($M)

	Residential Rate Class Revenue Requirement	Residential Rate Class Revenue	Residential Rate Class Revenue Deficiency/(Excess)
Fixed	192.1	189.1	3.0
Variable	0.9	0.9	0.0
Rate Class Revenue Deficiency/(Excess)			3.0

Q52. WHAT IS THE FINAL STEP IN THE PROCESS?

A. The final step in the process is to calculate the Rate Adjustment for each rate class, which calculation is shown on Attachment A to the proposed Electric FRP Rider. Continuing the example, the Residential Rate Class Rate Adjustment would be 1.61%. Because the Rate Adjustment is applied to Base Revenue, only Base Revenue is considered in the calculation and not FRP Revenue, if any.

Q53. WITH THE PROPOSED FRP RIDER, SHOULD THE COUNCIL EXPECT ALL RATE CLASSES TO HAVE THE SAME RATE ADJUSTMENT?

A. No, the Council should expect each rate class to have a different rate adjustment. This would be very different from the previous FRP Rider, which guaranteed that each rate class would have the same Rate Adjustment. In fact, the Council should be prepared for the possibility that an Evaluation Report could show positive rate adjustments for some classes, immaterial rate adjustments for some classes, and negative rate adjustments for some classes. For example, assume an extremely mild temperature year results in ENO's EROE falling below the dead band because residential and small commercial customers used less electricity cooling their homes and businesses. Under such a scenario, the Residential and Small Electric Rate Classes could have positive rate adjustments, that is, rate increases, while other rate classes did not.

Q54. WHAT WOULD HAPPEN IF THE BASELINE REVENUE REQUIREMENT CHANGED SIGNIFICANTLY IN ANY RATE CLASS?

A. If something occurs that makes the Baseline Revenue Requirement no longer representative of rate class cost responsibility in the future, then the Company must be permitted to revise the Baseline Revenue Requirement. Such revision would be subject to the Council's approval of the Company's revision or the Council's modification of the Baseline Revenue Requirement so that the Company has an opportunity to recover its revenue requirement. This exception to the four-step process is included in Section II.B.2 of the Electric FRP Rider.

Q55. WHAT IS THE FOURTH RECOMMENDED CHANGE TO ELECTRIC FRP?

A. The New Orleans Power Station ("NOPS") non-fuel revenue requirement is proposed to be a cost item subject to the Provision for Other Rate Changes of this EFRP. Because the NOPS is scheduled to be completed in 2020, the Company proposes to use this provision as a reasonable and effective transition of the incremental non-fuel revenue requirement associated with the NOPS. If the Council approves this new provision, the Company then proposes that the final first-year estimated revenue requirement should be determined in connection with a filing by ENO submitted no later than seventy-five days prior to the expected in-service date of the NOPS, setting forth the then-current estimate of the incremental non-fuel revenue requirement associated with the NOPS. The estimated first-year revenue requirement determined as a result of such filing shall form the basis for an in-service Rate Adjustment outside of the FRP bandwidth mechanism in the Extraordinary Cost Change Revenue Requirement (Line 13 in Attachment F of the proposed EFRP). The NOPS non-fuel revenue requirement will either be allocated to the rate classes in the same proportion as the baseline revenue requirement by rate class determined in the 2018 Rate Case or allocated based on a methodology determined by the Council. The initial FRP rates by rate class will be calculated in accordance with Attachment A of Rider EFRP. Mr. Todd discusses the current estimate of the first-year NOPS non-fuel revenue requirement.

Q56. WHAT IS THE FIFTH RECOMMENDED CHANGE TO ELECTRIC FRP?

A. A proposed provision was added in Section III E. to describe the effect of any tax rate changes to the FRP while the FRP is in progress. The recent Tax Cuts and Jobs Act is a good example of a tax rate change that could occur during the term of the proposed FRP, and this new provision outlines how the FRP would handle such a tax rate change.

Q56. WHAT IS THE SIXTH RECOMMENDED CHANGE TO ELECTRIC FRP?

A. A proposed provision was added to the Extraordinary Cost Changes section (Section III A.) to increase the revenue requirement impact trigger from $2 million in the previous FRP to $6 million. This increase in the trigger is due primarily to the increases in the electric rate base since the last FRP was approved.

Q57. WHAT IS THE SEVENTH RECOMMENDED CHANGE TO ELECTRIC FRP?

A. A proposed provision was added to the Extraordinary Cost Changes section (Section II D.) for Rider PPCACR Transitional Items. If the Company constructs or acquires future capacity and recovers those approved costs through the Rider PPCACR, then those costs could eventually be realigned to the FRP.

V. COMBINED MIDCONTINENT INDEPENDENT SYSTEM OPERATOR, INC. (“MISO”) RIDER

Q58. PLEASE PROVIDE AN OVERVIEW OF THE COMPANY’S PROPOSED COMBINED MISO RIDER.

A. 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 and is designed to recover certain costs billed to ENO by MISO and other costs on a combined basis as further detailed below. The Company is also proposing to use this combined rider in the upcoming 2019 MISO Rider filing in order to facilitate the transition from the two current riders and two rate structures to the combined rate structure expected to become effective in August 2019. This transition is explained in greater detail later in this section.

The proposed MISO Rider, like the current riders, provides the mechanism to develop the rider revenue requirement by application of the formula set out in Attachment B. A copy of the Combined MISO Rider and Attachment B are included in Exhibit PBG-10. The Combined MISO Rider revenue requirement would reflect the following costs and revenues: (1) estimated Net MISO Charges or Credits (*i.e.*, MISO charges and credits for which recovery has not been requested separately through the Fuel Adjustment Clause) and (2) a true-up of actual revenue to actual costs, including carrying charges.

Q59. PLEASE DESCRIBE THE INCLUDED EXPENSES AND REVENUES IN GREATER DETAIL.

A. As listed in Attachment B, the estimated Net MISO Charges or Credits are expenses charged to ENO such as MISO administration expenses and line of credit fees and credits, that is, revenues for Long-Term and Short-Term Point-to-Point Transmission Service, Non-Firm Point-To-Point Transmission Service and Network Integration Transmission Service in the New Orleans Transmission Pricing Zone and revenues from Wholesale Distribution Services. The estimated Net MISO Charges or Credits also include planning resource auction revenues and expenses. All of these expenses and revenues are included in the current MISO Riders.

Q60. ARE THERE ANY COSTS AND REVENUES IN THE CURRENT MISO RIDER REVENUE REQUIREMENT THAT ARE BEING ELIMINATED IN THE COMBINED MISO RIDER?

A. Yes, some items in the current MISO Riders were eliminated from this proposed rider. The eliminated items include but are not limited to the costs associated with the MISO Implementation Deferral and offsets to a transmission revenue credit and Independent Coordinator of Transmission ("ICT") costs included in current base rates, which are no longer necessary due to base rates being reset in this proceeding.

Q61. HOW WOULD THE RATES FOR EACH RATE CLASS BE DETERMINED FOR THE MISO RIDER?

A. The Company is proposing that rates for each rate class be determined as prescribed in the Rate Development Formula in Attachment B (which is included in Exhibit PBG-10). ENO's MISO Rider revenue requirement would be allocated to the retail jurisdiction and each rate class based on the Transmission Demand Allocation Factor ("TDAF") as approved by the Council in this proceeding. For subsequent redeterminations, the retail jurisdiction and rate class allocator factors would be developed consistent with the methodology approved for allocating the MISO Rider in this rate case. The MISO Rider rate class revenue requirement would be divided by the applicable Class Base Rate Revenue to determine the applicable rate as a monthly percentage of base rate revenue.

Q62. DOES THE PROPOSED COMBINED MISO RIDER INCLUDE A TRUE-UP?

A. Yes. Like the current MISO Riders, the Company is proposing that the Combined MISO Rider include an annual true-up mechanism to address any differences between the actual MISO Rider revenue and the actual MISO Rider transmission revenue requirement. The true-up mechanism also will include a carrying cost provision on the over- or under-recovery balance based on the then-current Before-Tax Weighted-Average Cost of Capital.

Q63. HOW WOULD THIS TRUE-UP WORK?

A. The Company is proposing that beginning in 2020, there would be a true-up of the actual MISO Rider revenue to the actual MISO Rider revenue requirement for the twelve (12) months ended March 31 of the filing year as defined on Attachment B, page 4 in Exhibit PBG-10.

Q64. HOW OFTEN WOULD THE COMBINED MISO RIDER BE UPDATED?

A. The Company is proposing that the Combined MISO Rider would be updated annually through a filing on May 31 beginning in 2020 with the new combined rider rate becoming effective the first billing cycle of July.

Q65. PLEASE EXPLAIN THE TRANSITION OF THE MISO RIDER IN GREATER DETAIL.

A. The Company proposes to file three versions of MISO Rider Filings in May 2019: (1) a Combined MISO Rider version, based on the proposed Combined MISO Rider field in this proceeding, an ENO Legacy MISO Rider version, and an Algiers MISO Rider version. In the Combined MISO Rider version, the Company would combine the two true-up balances (ENO Legacy and Algiers) calculated in the 2019 filing.

The Company anticipates that base rates to be implemented from this proceeding would become effective on the first billing cycle of August 2019. Accordingly, the Company proposes that MISO Rider redetermination be delayed until August 2019 and, in August 2019 the Combined MISO Rider rate become effective at the same time as the change in base rates. This would only be one month later than MISO Rider rates would usually become effective and therefore the MISO Rider rates that came out of the 2018 MISO Rider filing would then be effective for thirteen months (July 2018 through July 2019) instead of twelve months. Alternatively, the two current versions could be used for the rate redetermination effective July 2019 and then be subsequently changed the following month in August 2019 or later depending on the outcome of this proceeding.

VI. REVISED RIDER PPCACR

Q66. WHAT WILL HAPPEN TO THE UNION PB1 AND NINEMILE 6 PPA COSTS CURRENTLY RECOVERED THROUGH THE RIDER PPCACR?

A. Effective with new base rates from this proceeding, the Company will no longer recover the Union PB1 and Ninemile 6 PPA costs exclusively through the Rider PPCACR and the initial Purchased Power and Capacity Acquisition Cost Recovery Revenue Requirement will be set to zero because the Union PB1 and Ninemile 6 PPA costs will be recovered through base rates, subject to an exact cost recovery process in the case of the Ninemile 6 PPA expenses. Also, if there is a remaining cumulative over/under collection balance from the current Rider PPCACR, that balance will be included in the revised Rider PPCACR and will be recovered under the provisions of this revised Rider PPCACR.

Q67. WHAT COSTS ARE PROPOSED TO BE RECOVERED THROUGH THIS REVISED RIDER PPCACR?

A. There will be three types of costs that will be recoverable in this Rider PPCACR. The first type of costs will be the difference (positive or negative) between the estimated PPA capacity and Long-Term Service Agreement ("LTSA") expenses in the new base rates from this proceeding and the actual PPA capacity and LTSA expenses incurred by the Company on a monthly basis. Mr. Thomas discusses the rationale for implementing this exact cost recovery process.

The estimated PPA capacity and LTSA expenses are included as a "Schedule A" to this Rider PPCACR similar to the "Schedule A" that is currently part of the Fuel Adjustment Clause ("FAC") and will only include estimated PPA capacity expenses associated with the Ninemile 6 PPA and the Algiers Transaction PPA. As discussed earlier, all other estimated capacity expenses PPAs (Grand Gulf UPSA, EAI WBL PPA, and RB30% PPA) will be included in Schedule A for the FAC. Mr. Todd discusses the new Schedule A's in detail in his testimony and provides the estimated PPA capacity and LTSA expenses amount to be included in base rates and a monthly breakdown to be used in the calculation of the rider's Purchased Power and Capacity Acquisition Cost Recovery Revenue Requirement.

The second type of costs that will be recoverable in this rider is the non-fuel revenue requirement related to constructed and/or acquired capacity (*e.g.*, a power plant similar to the Union Acquisition), which could also include future capacity projects such as battery storage capacity projects.

The final type of cost that will be recovered in this rider is the cost related to new PPAs and new LTSAs the Company may enter into.

Q68. HOW WILL RIDER PPCACR REVENUE REQUIREMENT BE ALLOCATED TO THE RATE CLASSES?

A. The Company proposes to allocate the Rider PPCACR revenue requirement to the rate classes using the base rate revenue requirement allocation methodology approved by the Council in this proceeding. For any subsequent redetermination of the allocation factors, they will be done consistent with the methodology approved in this case unless modified by the Council in a future rate proceeding.

Q69. WILL THERE BE AN OVER/UNDER PROVISION IN THE RIDER PPCACR?

A. Yes. Similar to the current Rider PPCACR, 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 month. 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.

Q70. HOW WILL THE RIDER PPCACR RATES FOR EACH RATE CLASS BE DETERMINED?

A. The Company is proposing that rates for each rate class be determined as prescribed in the Rate Development Formula in Attachment B, which is included in Exhibit PBG-10. ENO's Rider PPCACR revenue requirement, which will include the operating month costs plus the cumulative (over)/under true-up balance, would be allocated to each rate class based on the base revenue requirement allocation methodology approved by the Council in this proceeding. The Rider PPCACR rate class revenue requirement would be divided by the applicable Class Base Rate Revenue to determine the applicable rate as a monthly percentage of base rate revenue.

VII. GAS FRP RIDER

Q71. WHAT WAS THE STARTING POINT FOR THE DEVELOPMENT OF THE PROPOSED GAS FRP RIDER?

A. The starting point for the proposed Gas FRP Rider was the previous ENO Gas FRP Rider, which was approved as Exhibit 7 to the 2008 Rate Case Agreement in Principle. Similar to the proposed Electric FRP, the proposed Gas FRP Rider continues many features of its predecessor:

- use of the previous calendar year as the Evaluation Period;
- using the authorized return on equity set in this proceeding as the EPCOE;
- a dead band centered on the EPCOE, in which there would be no change in rates;

- a formula adjusting the FRP revenue level to earn the EPCOE, commonly referred to as "resetting to the midpoint", if the Earned Return on Equity is above or below the dead band;
- seventy-five day review period;
- a specified dispute resolution procedure; and
- a three-year term.

Q72. HOW DOES THE PROPOSED GAS FRP RIDER DIFFER FROM PREDECESSOR?

A. For the Gas FRP, there are only three changes recommended by the Company for specific reasons discussed below.

Q73. WHAT ARE THE CHANGES RECOMMENDED BY THE COMPANY FOR SPECIFIC REASONS?

A. The Company recommends three changes. First, for the reasons discussed previously, ENO proposes that the Company file its Gas Evaluation Report by April 30, same as the Electric FRP, and that the initial rate adjustment, if necessary, become effective for the first billing cycle in September. Second, ENO proposes a provision similar to the one proposed in the EFRP regarding the treatment of changes in the tax rate. This new provision can be found in Section III D. Finally, ENO proposes to increase the revenue requirement impact trigger to the Extraordinary Cost Changes section (Section III A.) from $750 thousand in the previous FRP to $1 million. This increase in the trigger is due primarily to the increases in the gas rate base since the last FRP was approved.

VIII. GAS INFRASTRUCTURE RIDER

Q74. PLEASE DESCRIBE THE COMPANY'S PROPOSAL FOR THE GAS INFRASTRUCTURE RIDER.

A. The Company proposes a Gas Infrastructure Replacement Program Rider ("GIRP Rider") in order to recover the costs associated with replacing aging infrastructure to improve the safety and reliability of the gas distribution system. Company witness Michelle P. Bourg further describes the need for this recovery mechanism from a historical and operational standpoint, and Mr. Thomas describes the policy reasons supporting the GIRP Rider. I discuss the mechanics of the GIRP Rider.

Q75. PLEASE DESCRIBE THE INITIAL COST RECOVERY (SERVICE) PERIOD AND RATE DETERMINATION PROCESS FOR THE GIRP RIDER.

A. The Company proposes to recover the investment and expenses as defined in Section IV of the GIRP Rider that have not been reflected in the Company's rates and are placed into service and/or expended during the Initial Service Period (*i.e.*, from January 1, 2020 through March 31, 2020). This "Initial Service Period" assumes the rates implemented as a result of this rate case include plant in service through December 31, 2019. Otherwise, the Initial Service Period will be dependent on the plant in service date approved in this rate case. The initial rate determination will apply the formula set forth in Attachments B and C of the GIRP Rider. The rate filing will be made within 60 days of the end of the Initial Service Period, or May 31, 2020 for this example, and after a thirty-day review period, the rate will be effective for bills rendered on and after the first billing cycle of July 2020.

Q76. PLEASE DESCRIBE THE RATE REDETERMINATION PROCESS FOR THE GIRP RIDER.

A. The Company is proposing a quarterly rate redetermination, with each quarterly filing submitted within sixty days after each three month period or "Service Period." Assuming an Initial Service Period ending March 31, 2020, the next Service Period would end June 30, 2020 and the filing would be made by August 31, 2020. The redetermined GIRP Rider rate will reflect: (1) the pre-tax return on the cumulative Eligible Plant, net of the associated provision for depreciation and the associated accumulated deferred income taxes, (2) depreciation expense associated with the Eligible Plant, (3) the expenses associated with the identification and resolution of underground utility conflicts, and (4) an annual reconciliation of the difference between the revenue requirement and actual revenue collected for the reconciliation period. The reconciliation period will be the twelve month period ending December 31 of each year after the initial filing year, and the reconciliation difference will 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.

Q77. WHAT ARE THE ELIGIBLE COSTS THAT WILL BE REFLECTED IN THE GIRP RIDER RATE REDETERMINATION?

A. The Eligible Costs that will be reflected in the GIRP Rider Rate Redetermination include the incremental investment in pipeline safety improvements projects implemented under ENO's Integrity Management plan. Each quarter's incremental plant in service additions will be added to the previous cumulative Eligible Plant total. In addition, the Eligible Costs will include the operation and maintenance expenses associated with the identification and resolution of underground utility conflicts (variable "UCE" in Attachment B of the rider).

Q78. HOW IS THE PRE-TAX RETURN CALCULATED AND APPLIED TO THE ELIGIBLE PLANT IN THE GIRP RIDER?

A. The pre-tax return will 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 and short-term debt and preferred stock 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 will be the equity return approved by the Council in this rate case. The pre-tax return rate will then be applied to the cumulative Eligible Cost amount for that Service Period.

Q79. HOW WILL THE DEPRECIATION EXPENSE BE CALCULATED FOR THE GIRP RIDER?

A. The depreciation expense will be calculated by applying the annual accrual rates for the appropriate plant accounts to the cumulative original cost of the Eligible Plant.

Q80. HOW WILL THE GIRP RIDER RATE BE CALCULATED AND APPLIED TO CUSTOMER BILLS?

A. First, a revenue-related expense factor will be applied to the previously calculated revenue requirement. Once the full GIRP Rider revenue requirement is calculated, the rate for each of the five gas rate classes will be determined by dividing the revenue requirement by four and then dividing that one-fourth revenue requirement by one-fourth of the rate class rate schedule revenue for the twelve month period ending December 31 of the preceding year. The GIRP Rider Rate will be expressed as a percentage carried to four decimal places and will be applied to the net monthly rates, excluding “Adjustments” or “Other Adjustments” as these terms are defined in each Company rate schedule and customer class.

Q81. WHAT IS THE PROPOSED TERM OF THE GIRP RIDER?

A. The Company proposes that the term of the GIRP Rider be through 2027, regardless of whether an FRP remains in place for ENO. This term definition is needed to insure that the all costs associated with the replacement program will be recovered in this recovery mechanism. If this GIRP Rider is terminated before 2027, then the Company proposes that the GIRP Rider Rate then in effect should continue to remain in effect until the Council approves an alternative recovery mechanism. At that time, any cumulative over-recovery or under-recovery resulting from application of the then-current GIRP Rider Rate, inclusive of carrying costs at the pre-tax weighted-average cost of capital, should be applied to customer billings over the twelve month period beginning on the first billing cycle of the second month following the termination of the GIRP Rider in a manner prescribed by the Council.

IX. DISTRIBUTION GRID MODERNIZATION RIDER

Q82. PLEASE DESCRIBE THE COMPANY'S PROPOSAL FOR THE DISTRIBUTION GRID MODERNIZATION RIDER.

A. The Company proposes a Distribution Grid Modernization ("Rider DGM") in order to recover the capital investment costs associated with Council-approved grid modernization projects not recovered in base rates from this proceeding as described in the Revised Direct Testimony of Company witness Erica H. Zimmerer. Company witnesses Mr. Thomas and Dr. Ahmad Faruqui describe the why this recovery mechanism is reasonable and necessary. My testimony focuses on the mechanics of the rider, which are very similar to the GIRP Rider discussed in the previous section.

Q83. PLEASE DESCRIBE THE INITIAL COST RECOVERY PERIOD AND RATE DETERMINATION PROCESS FOR THE RIDER DGM.

A. The Company proposes to recover the costs as defined in Section IV of the Rider DGM that have not been reflected in the Company's rates from the 2018 rate case proceeding and are placed into service from January 1, 2020 through March 31, 2020.

This "Initial Service Period" assumes the rates implemented as a result of this rate case include plant in service through December 31, 2019. Otherwise, the Initial Service Period will be dependent on the plant in service date approved in this rate case. The initial rate determination will apply the formula set forth in Attachments B and C of the Rider DGM. The rate filing will be made within 30 days of the end of the Initial Service Period, or April 30, 2020 for this example, and after a 30-day review period the rate will be effective for bills rendered on and after the first billing cycle of June 2020.

Q84. PLEASE DESCRIBE THE RATE REDETERMINATION PROCESS FOR THE RIDER DGM.

A. The Company is proposing a quarterly rate redetermination, with each quarterly filing submitted within 30 days after each three month period or "Service Period". Assuming an Initial Service Period ending March 31, 2020, the next Service Period would end June 30, 2020 and the filing would be made by July 31, 2020. The redetermined Rider DGM rate will reflect: (1) the pre-tax return on the cumulative Eligible Plant, net of the associated provision for depreciation and the associated accumulated deferred income taxes, (2) depreciation expense associated with the Eligible Plant and (3) an annual reconciliation of the difference between the revenue requirement and actual revenue collected for the reconciliation period. The reconciliation period will be the twelve month period ending December 31 of each year after the initial filing year, and the reconciliation difference will 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 redetermination of the rate Rider DGM will reflect, this annual filing will 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.

Q85. WHAT ARE THE ELIGIBLE COSTS THAT WILL BE REFLECTED IN THE RIDER DGM RATE REDETERMINATION?

A. The eligible costs or Eligible Plant that will be reflected in the Rider DGM Rate Redetermination is the incremental investment in Council-approved grid modernization projects. Each quarter's incremental plant in service additions will be added to the previous cumulative Eligible Plant total.

Q86. HOW IS THE PRE-TAX RETURN CALCULATED AND APPLIED TO THE ELIGIBLE PLANT IN THE RIDER DGM?

A. The pre-tax return will 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 and short-term debt and preferred stock 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 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, regardless of whether the Electric FRP results in a Rate Adjustment. The pre-tax return rate will then be applied to the cumulative Eligible Plant amount for that Service Period.

Q87. HOW WILL THE DEPRECIATION EXPENSE BE CALCULATED FOR THE RIDER DGM?

A. The depreciation expense will be calculated by applying the annual accrual rates for the appropriate plant accounts to the cumulative original cost of the Eligible Plant.

Q88. HOW WILL THE RIDER DGM RATE BE CALCULATED AND APPLIED TO CUSTOMER BILLS?

A. First, a revenue-related expense factor will be applied to the previously calculated revenue requirement. Once the full Rider DGM revenue requirement is calculated, the rate for each of the nine electric rate classes will be determined first by allocating the revenue requirement to each class based on the Distribution Demand Allocation Factor, and then by dividing the rate class revenue requirement by the rate class rate schedule revenue for the twelve-month period ending December 31 of the preceding year. The Rider DGM Rate will be expressed as a percentage carried to four decimal places and will be applied to the net monthly rates, excluding “Adjustments” or “Other Adjustments” as these terms are defined in each Company rate schedule and customer class.

Q89. WHAT IS THE PROPOSED TERM OF THE RIDER DGM?

A. The Company proposes that the Rider DGM be in effect through the date of implementation of the next Base Rate Case filing unless it is terminated by a future order of the Council. If the Rider DGM is terminated, the Rider DGM Rates then in effect will continue to be applied until the Council approves an alternative recovery mechanism.

Q90. DOES THIS CONCLUDE YOUR REVISED DIRECT TESTIMONY?

A. Yes.

AFFIDAVIT

STATE OF ARKANSAS

PULASKI COUNTY

NOW BEFORE ME, the undersigned authority, personally came and appeared, **Phillip B. Gillam**, who after being duly sworn by me, did depose and say:

That the above and foregoing is his sworn testimony in this proceeding and that he knows the contents thereof, that the same are true as stated, except as to matters and things, if any, stated on information and belief, and that as to those matters and things, he verily believes them to be true.

Phillip B. Gillam

Phillip B. Gillam

SWORN TO AND SUBSCRIBED BEFORE ME
THIS 11th DAY OF SEPTEMBER, 2018.

Cindy Pickett

NOTARY PUBLIC

My commission expires: 4-26-25

CINDY PICKETT
PULASKI COUNTY
NOTARY PUBLIC - ARKANSAS
My Commission Expires April 26, 2025
Commission No. 12693695

EDUCATIONAL AND PROFESSIONAL BACKGROUND OF PHILLIP B. GILLAM

Q1. PLEASE DESCRIBE YOUR EDUCATIONAL BACKGROUND AND WORK EXPERIENCE.

A. I hold a Bachelor of Science degree in accounting from the University of Arkansas at Little Rock. I am a Certified Public Accountant in Arkansas and belong to the Arkansas Society of Certified Public Accountants and the American Institute of Certified Public Accountants.

From 1978 through 1980, I worked for the University of Arkansas Industrial Research & Extension Center as an Analyst, Small Business Development Center.

I began working for EAI predecessor Arkansas Power & Light Company ("AP&L") in 1980 as a Staff Accountant in the Property Accounting Section. I was responsible for Property Accounting related special projects and year-end tax information reporting. I was promoted to Accountant in 1982 and transferred to the Taxes & Special Studies Section where I was responsible for preparing accounting data for various rate filings and state and federal income tax reports. In 1983, I accepted the position of Supervisor of Taxes & Special Studies where I was directly responsible for state and local tax filings such as sales tax and ad valorem taxes, as well as preparing and reviewing accounting data, testimony and exhibits for various rate filings.

In 1988, I moved to Property Accounting as Supervisor where I was responsible for the accounting of AP&L's non-nuclear generation and transmission plant assets, which included Construction Work in Progress ("CWIP") accounting, the Continuing Property Record ("CPR"), and year-end and ad hoc projects.

In 1991, I moved to New Orleans, Louisiana, as Manager of Property Accounting for Louisiana Power & Light Company and New Orleans Public Service, Inc. where I was responsible for all Property Accounting functions and activities including CWIP, CPR, year-end and ad hoc projects. In 1996, I accepted a position with ESI as Property Accounting Manager where I was responsible for the accounting of the Operating Companies' generation plant assets.

In 1999, I accepted a position as Manager of Corporate Reporting in charge of Corporate Governance of the Property Accounting function including plant accounting policies, capital accounting process oversight and plant accounting special projects.

In 2002, I moved to Little Rock to assume the role of Director, Revenue Requirements and Analyses. In that role, I was responsible for the development of cost-of-service studies and other revenue requirement analyses for each jurisdiction.

In 2014, I assumed my current role, Manager, Regulatory Filings, Entergy New Orleans, Inc. In this role, I am responsible for regulatory filings at the Council of the City of New Orleans ("Council") relating to various rate proceedings such as rate cases, Formula Rate Plan filings and other special riders.

Q2. HAVE YOU PREVIOUSLY PROVIDED TESTIMONY BEFORE A REGULATORY COMMISSION?

A. Yes. I have provided testimony on cost-of-service and revenue requirement issues in Arkansas Public Service Commission Docket Nos. 03-191-TF, 05-116-U, 06-055-U, 06-101-U, 06-152-U, 07-085-TF, 09-084-U, 11-069-U, 12-038-U, and 13-028-U; in Public Utility Commission of Texas Docket Nos. 37744 and 39366; in Louisiana

Public Service Commission Docket Nos. U-32707 and U-32708; in Council Docket No. UD-11-01 (Phase II), Docket No. UD-13-01, Docket No. UD-14-01, Docket No. UD-14-02, and Docket No. UD-15-01; and in Mississippi Public Service Commission Docket No. 2013-UN-178.

Entergy New Orleans, LLC
Cost of Service
List of Pro Forma Adjustments to Period I and Period II
Electric & Gas

Line No.	Adj. Name	Short Description	Long Description	Witness	Electric	Gas
1	AJ01A	Rate Schedule and Other Revenue	Adjustment to annualize Rate Schedule Revenues; to reclassify certain Rate Schedule Revenues to Other Electric Revenue and remove interdepartmental sales.	Phillip B. Gillam & Myra L. Talkington	X	X
2	AJ01B	Fuel, Purchased Power and NOX Expenses	Adjustment to remove Fuel & Purchased Power costs, Sales for Resale Revenue, NOX Emissions Allowances and deferred fuel & NOX costs.	Phillip B. Gillam	X	
3	AJ01B	Gas Purchases and Deferred Gas Costs	Adjustment to remove Gas Purchases and Deferred Gas Costs.	Phillip B. Gillam		X
4	AJ01C	Capacity & LTSA Expenses	Adjustment to add back capacity and LTSA expenses to be recovered in base rates at the 2019 level.	Phillip B. Gillam	X	
5	AJ01D	MISO	Adjustment to remove the MISO rider expenses and revenues.	Phillip B. Gillam	X	
6	AJ02	Interest Synchronization	This adjustment synchronizes test year interest expense with adjusted rate base and the embedded long term debt rate in the cost of capital.	Phillip B. Gillam	X	X
7	AJ03A	Income Taxes - ADIT	This adjustment is to eliminate items not allowed for rate making purposes, prior year adjustments and to normalize income taxes.	Lisa Walther	X	X
8	AJ03B	Income Taxes - CIT & DIT	This adjustment is to eliminate items not allowed for rate making purposes, prior year adjustments and to normalize income taxes.	Lisa Walther	X	X
9	AJ03C	Income Taxes - NOL CB	Adjustment to remove the NOL Carry Back Refund Liability from Rate Base and the associated amortization expense from Jurisdictional Operating Income since the liability will be fully amortized as of June 2019.	Lisa Walther	X	
10	AJ03D	Income Taxes-CIT - Tax Reform	This adjustment is to adjust current income tax to 2018 effective state tax rate and federal statutory rate as a result of the Tax Cuts and Jobs Act of 2017. (This adjustment is applicable for Period I only.)	Lisa Walther	X	X
11	AJ03D	Income Taxes-DIT Revaluation	This adjustment is to revalue deferred tax expense at the new effective state tax rate in effect for Tax Calendar Year 2018 as a result of the Tax Cuts and Jobs Act of 2017. (This adjustment is applicable for Period I only.)	Lisa Walther	X	X
12	AJ03E	Unprotected Excess ADIT	This adjustment is to remove Unprotected Excess ADIT the benefit of which customers received or realized as per council Resolution R-18-227.	Lisa Walther	X	X
13	AJ03F	Protected Excess ADIT	This adjustment is to reclass from a Regulatory Liability the protected excess ADIT associated with Power Provision accounts to reflect the appropriate return of the protected excess ADIT.	Lisa Walther	X	X
14	AJ03F	Protected Excess ADIT Amortization	This adjustment is to reflect the protected Excess ADIT Amortization.	Lisa Walther	X	X
15	AJ04	External Restructuring Costs	Adjustment to remove external restructuring costs per Docket UD-16-03.	Lisa Walther	X	
16	AJ05	Payroll	Adjustment to reflect the changes in O&M expenses and taxes other than income due to the test year changes related to wage increases and payroll increases/decreases associated with changes in number of employees.	Lisa Walther	X	X
17	AJ06	Reg Debits & Credits	Adjustment to remove regulatory assets including associated amortization a nd to eliminate regulatory debits and credits not recovered in base rates.	Lisa Walther	X	X
18	AJ07	Stock Options & Incentive Compensation	Adjustment to remove the Long Term Incentive Plan, Equity Awards Plan, Stock Options Expense, and Restricted Share Awards Plan from A&G per Docket No. UD-08-03 (TY 2010 AIP).	Lisa Walther	X	X
19	AJ08	ESI, Bank Loans, and Customer Deposits Interest	Adjustment to reclassify interest on electric customer deposits, bank loans interest expense, and ESI interest expense from below-the-line accounts to above-the-line accounts that are includes as part of the cost of service.	Lisa Walther	X	X
20	AJ09	Pension	Adjustment to reflect the prepaid/(accrued) pension balance forecasted through December 31, 2018.	Lisa Walther	X	X
21	AJ10	Product Line Reclass	Adjustment to reclassify product line expenses and rate base items between Gas and Electric.	Lisa Walther	X	X
22	AJ11	Energy Smart	Adjustment to remove Energy Smart customer expenses.	Lisa Walther	X	
23	AJ12	Storm Costs	Adjustment to remove the lock box reserve from rate base and the associated amortization from operating expenses, as well as to remove Accumulated Provision from Property Insurance from account 228100.	Lisa Walther	X	X
24	AJ13	CWIP	Adjustment to record CWIP amount allowed to recover for this filing. This amount is not subject to AFUDC accrual.	Lisa Walther	X	X
25	AJ14	Plant Additions	Adjustment to recognize additions and retirements of Plant-In-Service and related changes to Accumulated Depreciation through December 31, 2019.	Lisa Walther	X	X
26	AJ15	AMI	Adjustment to proform in the Retired Plant Revenue Requirement as agreed in the Council Resolution R-18-37 and to retire the remaining net book value of the existing plant assets and to remove any AMI costs associated with plant, O&M expense, and operational savings.	Lisa Walther	X	X
27	AJ16	Depreciation	Adjustment to annualize depreciation expense based on ENO's proposed depreciation rates, establish a Regulatory Asset for the General Plant Reserve Deficiency, and to record one year's worth of amortization on the General Plant Reserve Deficiency.	Lisa Walther	X	X
28	AJ17	Misc Service Revenues	Adjustment to Miscellaneous Service Revenues to reflect rate year level.	Lisa Walther	X	X
29	AJ18	Miscellaneous Adj	Adjustment to remove ARO costs, certain advertising expenses, and other expenses for which ENO is not seeking recovery. The adjustment also includes additional distribution reliability-related plant additions in rate base and related expense and incremental distribution reliability-related O&M expense and removes forecasted rate base and related expense for plant additions for which ENO is not seeking recovery in the proceeding.	Lisa Walther	X	X

Entergy New Orleans, LLC
Cost of Service
List of Pro Forma Adjustments to Period I and Period II
Electric & Gas

Line No.	Adj. Name	Short Description	Long Description	Witness	Electric	Gas
30	AJ19	Rate Case Expenses	Adjustment to establish a regulatory asset for incremental Rate Case Expenses and to include one year's amortization of a 3-year period of estimated expenses.	Lisa Walther	X	X
31	AJ20	Amortization of Special Rate Making Items	This adjustment adds back the proper level of amortization approved in the Amortization Schedule of Special Ratemaking Items in CNO Docket UD-13-01.	Lisa Walther	X	
32	AJ21	Franchise Tax	Adjustment to remove Local Franchise Tax Expense collected through the Franchise Fee Rider, to adjust Louisiana Corporate Franchise Tax expense to the prospective level (Period I only) and to remove the Louisiana Corporate Franchise Tax Credit per Resolution R-17-228 that was included in the monthly PPCACR bills in January – March 2018 (Period II only).	Lisa Walther	X	X
33	AJ22	Cash Working Capital	Adjustment to calculate the working cash requirement.	Phillip B. Gillam	X	X
34	AJ23	Uncollectible & Revenue Related Expenses	Adjustment to revenue related taxes and uncollectible expenses to reflect rate year level revenue.	Phillip B. Gillam	X	X
35	AJ27	Algiers Transfer Transaction & Consolidation Costs	To establish a regulatory asset for the Algiers Migration Expenses and to record one year of amortization and to record one year of amortization for the Algiers Transaction Costs per CNO Docket No. UD-14-02.	Lisa Walther	X	
36	AJ28	Solar	Adjustment to include first year O&M Expenses and Property Taxes associated with the Distributed Generation Scale Solar Project per CNO Docket No. UD-17-05.	Lisa Walther	X	

Entergy New Orleans, LLC
Cost of Service
Summary Model Results - Revenue Requirement Calculation - Period I
Electric
For the Test Year Ended December 31, 2017

Line No.	Description	Line Item	Per Book	Adjustments	Total Adjusted	RES	SMALL ELECTRIC	LARGE ELECTRIC
1	Rate Base: Rate Base	RBTOA	583,770,915	192,017,312	775,788,227	438,290,335	111,223,210	47,656,020
2								
3	Revenues							
4	Rate Schedule Revenue: Rate Schedule Revenue	RSRTOA	577,580,852	(287,134,163)	290,446,689	138,804,223	49,313,150	19,796,500
5	Other Sales for Resale: Other Sales for Resale	RSORTOA	29,206,790	(29,206,790)	-	-	-	-
6	Other Operating Revenues: Other Operating Revenues	ROTOA	12,227,590	(1,694,123)	10,533,468	5,434,276	1,642,939	699,980
7	Total Revenues (L4 + L5 + L6)	RTOA	619,015,232	(318,035,075)	300,980,156	144,238,499	50,956,089	20,496,480
8								
9	Total Operating Expenses: Total Operating Expenses	OETOA	570,224,941	(233,293,861)	336,931,080	174,872,169	51,143,029	22,412,430
10								
11	Total Operating Income (L7 - L9)	OITOA	48,790,291	(84,741,214)	(35,950,923)	(30,633,670)	(186,940)	(1,915,950)
12								
13	Earned Rate of Return on Rate Base (L11 / L1)	EROR	8.36%	(44.13%)	(4.63%)	(6.99%)	(0.17%)	(4.02%)
14								
15	**REVENUE REQUIREMENT DETERMINATION**							
16	Required Rate of Return	ROR	7.79%	7.79%	7.79%	7.79%	7.79%	7.79%
17	Required Operating Income: Required Operating Income [1]	ROI	45,447,336	14,948,801	60,396,136	34,121,480	8,658,874	3,710,084
18								
19	REVENUE CONVERSION FACTORS							
20	Income Tax Revenue Conversion Factor [2]	REVCOFIT	35.28%	35.28%	35.28%	35.28%	35.28%	35.28%
21	Regulatory Commission Expense Revenue Conversion Factor [2]	REVCOFRC	0.15%	0.15%	0.15%	0.15%	0.15%	0.15%
22	Bad Debt Revenue Conversion Factor [2]	REVCOFBD	(3.61%)	0.40%	0.54%	0.77%	0.14%	0.07%
23								
24	Revenue Conversion Factor [3]	REVCOF	1.3059	1.3603	1.3622	1.3653	1.3568	1.3558
25								
26	REVENUE DEFICIENCY							
27	Operating Income Deficiency/(Excess) [4]	OIDEF	(3,342,956)	99,690,015	96,347,060	64,755,151	8,845,814	5,626,034
28	Incremental Income Tax: Incremental Income Tax [5]	ITDEF	(1,179,423)	35,171,471	33,992,048	22,846,159	3,120,877	1,984,912
29	Incremental Regulatory Commission Expense: Incremental Regulatory Commission Expense [6]	RCDEF	(6,632)	205,999	199,368	134,308	18,233	11,587
30	Incremental Bad Debt Expense: Incremental Bad Debt Expense [7]	BDDEF	163,481	539,420	702,901	677,625	17,336	5,329
31								
32	Total Revenue Deficiency/(Excess) (L27 + L28 + L29 + L30)	REVDEF	(4,365,529)	135,606,906	131,241,377	88,413,243	12,002,260	7,627,862
33	% Increase/(Decrease) (L32 / L4)	REVDEFPCT	(0.76%)	(47.23%)	45.19%	63.70%	24.34%	38.53%
34								
35	Rate Schedule Revenue Requirement (L4 + L32)	REVREQ	573,215,322	(151,527,257)	421,688,066	227,217,466	61,315,410	27,424,362
36	NOL Carryback Revenue Requirement: NOL Carryback Revenue Requirement	REVREQNOLCB	(4,579,492)	4,579,492	-	-	-	-
37	Total Rate Schedule Revenue Requirement (L35 + L36)	REVREQTOT	568,635,830	(146,947,765)	421,688,066	227,217,466	61,315,410	27,424,362
38								
39	Total Revenue Deficiency/(Excess) (L37 - L4)	REVDEFTOT	(8,945,021)	140,186,398	131,241,377	88,413,243	12,002,260	7,627,862
40	Total % Increase/(Decrease) (L39 / L4)	REVDEFTOTPCT	(1.55%)	(48.82%)	45.19%	63.70%	24.34%	38.53%

Notes:
(1) Line 1 * Line 16
(2) Reference MD 1
(3) Reference MD 1 for calculation
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(5) Line 27 * Line 20
(6) (Line 27 + Line 28 + Line 30) * Line 21
(7) (Line 27 + Line 28 + Line 29) * Line 22

Entergy New Orleans, LLC
Cost of Service
Summary Model Results - Revenue Requirement Calculation - Period I
Electric
For the Test Year Ended December 31, 2017

Line No.	Description	Line Item	LARGE INTERRUPTIBLE SERVICE	LARGE ELECTRIC HIGH LOAD FACTOR	HIGH VOLTAGE	MUNICIPAL BUILDING	MASTER METERED NON RES	LIGHTING
1	Rate Base: Rate Base	RBTOA	3,596,478	156,962,051	5,591,005	3,638,710	71,790	8,758,628
2								
3	Revenues							
4	Rate Schedule Revenue: Rate Schedule Revenue	RSRTOA	2,631,582	67,808,174	4,812,091	1,985,924	39,282	5,255,763
5	Other Sales for Resale: Other Sales for Resale	RSORTOA	-	-	-	-	-	-
6	Other Operating Revenues: Other Operating Revenues	ROTOA	63,259	2,364,430	111,832	61,684	1,239	153,829
7	Total Revenues (L4 + L5 + L6)	RTOA	2,694,841	70,172,603	4,923,923	2,047,608	40,521	5,409,592
8								
9	Total Operating Expenses: Total Operating Expenses	OETOA	2,298,880	76,171,846	4,963,947	1,784,250	35,482	3,249,046
10								
11	Total Operating Income (L7 - L9)	OITOA	395,961	(5,999,243)	(40,024)	263,358	5,039	2,160,546
12								
13	Earned Rate of Return on Rate Base (L11 / L1)	EROR	11.01%	(3.82%)	(0.72%)	7.24%	7.02%	24.67%
14								
15	**REVENUE REQUIREMENT DETERMINATION**							
16	Required Rate of Return	ROR	7.79%	7.79%	7.79%	7.79%	7.79%	7.79%
17	Required Operating Income: Required Operating Income (1)	ROI	279,991	12,219,703	435,267	283,278	5,589	681,871
18								
19	REVENUE CONVERSION FACTORS							
20	Income Tax Revenue Conversion Factor (2)	REVCOFIT	35.28%	35.28%	35.28%	35.28%	35.28%	35.28%
21	Regulatory Commission Expense Revenue Conversion Factor (2)	REVCOFRC	0.15%	0.15%	0.15%	0.15%	0.15%	0.15%
22	Bad Debt Revenue Conversion Factor (2)	REVCOFBD		0.02%				0.12%
23								
24	Revenue Conversion Factor (3)	REVCOF	1.3549	1.3551	1.3549	1.3549	1.3549	1.3565
25								
26	REVENUE DEFICIENCY							
27	Operating Income Deficiency/(Excess) (4)	OIDEF	(115,970)	18,218,946	475,291	19,920	550	(1,478,675)
28	Incremental Income Tax: Incremental Income Tax (5)	ITDEF	(40,915)	6,427,796	167,687	7,028	194	(521,689)
29	Incremental Regulatory Commission Expense: Incremental Regulatory Commission Expense (6)	RCDEF	(239)	37,505	978	41	1	(3,047)
30	Incremental Bad Debt Expense: Incremental Bad Debt Expense (7)	BDDEF	-	4,964	-	-	-	(2,353)
31								
32	Total Revenue Deficiency/(Excess) (L27 + L28 + L29 + L30)	REVDEF	(157,124)	24,689,212	643,956	26,989	745	(2,005,765)
33	% Increase/(Decrease) (L32 / L4)	REVDEFPCT	(5.97%)	36.41%	13.38%	1.36%	1.90%	(38.16%)
34								
35	Rate Schedule Revenue Requirement (L4 + L32)	REVREQ	2,474,458	92,497,385	5,456,047	2,012,913	40,027	3,249,998
36	NOL Carryback Revenue Requirement: NOL Carryback Revenue Requirement	REVREQNOLCB	-	-	-	-	-	-
37	Total Rate Schedule Revenue Requirement (L35 + L36)	REVREQTOT	2,474,458	92,497,385	5,456,047	2,012,913	40,027	3,249,998
38								
39	Total Revenue Deficiency/(Excess) (L37 - L4)	REVDEFTOT	(157,124)	24,689,212	643,956	26,989	745	(2,005,765)
40	Total % Increase/(Decrease) (L39 / L4)	REVDEFTOTPCT	(5.97%)	36.41%	13.38%	1.36%	1.90%	(38.16%)

Notes:
(1) Line 1 * Line 16
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Entergy New Orleans, LLC
Cost of Service
Summary Model Results - Revenue Requirement Calculation - Period II
Electric
For the Test Year Ended December 31, 2018

Line No.	Description	Line Item	Per Book	Adjustments	Total Adjusted	RES	SMALL ELECTRIC	LARGE ELECTRIC	LARGE INTERRUPTIBLE SERVICE
1	Rate Base: Rate Base	RBTOA	670,578,815	98,738,904	769,317,718	423,727,861	114,637,344	47,646,427	3,433,183
2									
3	Revenues								
4	Rate Schedule Revenue: Rate Schedule Revenue	RSRTOA	539,573,436	(246,409,783)	293,163,652	134,602,540	51,387,058	20,776,705	2,532,217
5	Other Sales for Resale: Other Sales for Resale	RSORTOA	49,940,571	(49,940,571)	-	-	-	-	-
6	Other Operating Revenues: Other Operating Revenues	ROTOA	(10,997,333)	19,275,432	8,278,099	4,186,511	1,315,726	561,361	41,235
7	Total Revenues (L4 + L5 + L6)	RTOA	578,516,674	(277,074,922)	301,441,752	138,789,051	52,702,784	21,338,066	2,573,452
8									
9	Total Operating Expenses: Total Operating Expenses	OETOA	536,708,903	(196,011,575)	340,697,327	171,580,084	53,873,933	22,973,043	2,267,463
10									
11	Total Operating Income (L7 - L9)	OITOA	41,807,771	(81,063,347)	(39,255,576)	(32,791,033)	(1,171,148)	(1,634,977)	305,989
12									
13	Earned Rate of Return on Rate Base (L11 / L1)	EROR	6.23%	(82.10%)	(5.10%)	(7.74%)	(1.02%)	(3.43%)	8.91%
14									
15	**REVENUE REQUIREMENT DETERMINATION**								
16	Required Rate of Return	ROR	7.79%	7.79%	7.79%	7.79%	7.79%	7.79%	7.79%
17	Required Operating Income: Required Operating Income (1)	ROI	52,205,445	7,686,954	59,892,399	32,987,773	8,924,668	3,709,337	267,278
18									
19	REVENUE CONVERSION FACTORS								
20	Income Tax Revenue Conversion Factor (2)	REVCOFIT	35.28%	35.28%	35.28%	35.28%	35.28%	35.28%	35.28%
21	Regulatory Commission Expense Revenue Conversion Factor (2)	REVCOFRC	0.18%	0.18%	0.18%	0.18%	0.18%	0.18%	0.18%
22	Bad Debt Revenue Conversion Factor (2)	REVCOFBD	0.91%	0.49%	0.53%	0.77%	0.14%	0.07%	
23									
24	Revenue Conversion Factor (3)	REVCOF	1.3676	1.3619	1.3625	1.3658	1.3573	1.3562	1.3553
25									
26	REVENUE DEFICIENCY								
27	Operating Income Deficiency/(Excess) (4)	OIDEF	10,397,674	88,750,301	99,147,974	65,778,805	10,095,817	5,344,314	(38,711)
28	Incremental Income Tax: Incremental Income Tax (5)	ITDEF	3,668,386	31,311,848	34,980,235	23,207,313	3,561,889	1,885,519	(13,658)
29	Incremental Regulatory Commission Expense: Incremental Regulatory Commission Expense (6)	RCDEF	26,071	221,601	247,672	164,707	25,122	13,288	(96)
30	Incremental Bad Debt Expense: Incremental Bad Debt Expense (7)	BDDEF	128,230	588,232	716,462	688,556	19,792	5,064	-
31									
32	Total Revenue Deficiency/(Excess) (L27 + L28 + L29 + L30)	REVDEF	14,220,361	120,871,982	135,092,343	89,839,381	13,702,619	7,248,185	(52,465)
33	% Increase/(Decrease) (L32 / L4)	REVDEFPCT	2.64%	(49.05%)	46.08%	66.74%	26.67%	34.89%	(2.07%)
34									
35	Rate Schedule Revenue Requirement (L4 + L32)	REVREQ	553,793,796	(125,537,801)	428,255,995	224,441,921	65,089,677	28,024,890	2,479,752
36	NOL Carryback Revenue Requirement: NOL Carryback Revenue Requirement	REVREQNOLCB	(4,579,482)	4,579,482	-	-	-	-	-
37	Total Rate Schedule Revenue Requirement (L35 + L36)	REVREQTOT	549,214,314	(120,958,319)	428,255,995	224,441,921	65,089,677	28,024,890	2,479,752
38									
39	Total Revenue Deficiency/(Excess) (L37 - L4)	REVDEFTOT	9,640,879	125,451,464	135,092,343	89,839,381	13,702,619	7,248,185	(52,465)
40	Total % Increase/(Decrease) (L39 / L4)	REVDEFTOTPCT	1.79%	(50.91%)	46.08%	66.74%	26.67%	34.89%	(2.07%)

Notes:
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Entergy New Orleans, LLC
Cost of Service
Summary Model Results - Revenue Requirement Calculation - Period II
Electric
For the Test Year Ended December 31, 2018

Line No.	Description	Line Item	LARGE ELECTRIC HIGH LOAD FACTOR	HIGH VOLTAGE	MUNICIPAL BUILDING	MASTER METERED NON RES	LIGHTING
1	Rate Base: Rate Base	RBTOA	160,618,428	5,839,134	3,855,597	73,829	9,485,915
2							
3	Revenues						
4	Rate Schedule Revenue: Rate Schedule Revenue	RSRTOA	71,072,624	5,071,596	2,101,668	40,401	5,578,843
5	Other Sales for Resale: Other Sales for Resale	RSORTOA	-	-	-	-	-
6	Other Operating Revenues: Other Operating Revenues	ROTOA	1,917,661	80,627	49,769	980	124,230
7	Total Revenues (L4 + L5 + L6)	RTOA	72,990,285	5,152,223	2,151,437	41,381	5,703,073
8							
9	Total Operating Expenses: Total Operating Expenses	OETOA	79,113,790	5,242,747	1,917,785	36,798	3,691,684
10							
11	Total Operating Income (L7 - L9)	OITOA	(6,123,505)	(90,524)	233,652	4,582	2,011,389
12							
13	Earned Rate of Return on Rate Base (L11 / L1)	EROR	(3.81%)	(1.55%)	6.06%	6.21%	21.20%
14							
15	**REVENUE REQUIREMENT DETERMINATION**						
16	Required Rate of Return	ROR	7.79%	7.79%	7.79%	7.79%	7.79%
17	Required Operating Income: Required Operating Income [1]	ROI	12,504,356	454,584	300,163	5,748	738,491
18							
19	REVENUE CONVERSION FACTORS						
20	Income Tax Revenue Conversion Factor [2]	REVCOFIT	35.28%	35.28%	35.28%	35.28%	35.28%
21	Regulatory Commission Expense Revenue Conversion Factor [2]	REVCOFRC	0.18%	0.18%	0.18%	0.18%	0.18%
22	Bad Debt Revenue Conversion Factor [2]	REVCOFBD	0.02%				0.12%
23							
24	Revenue Conversion Factor [3]	REVCOF	1.3556	1.3553	1.3553	1.3553	1.3569
25							
26	REVENUE DEFICIENCY						
27	Operating Income Deficiency/(Excess) [4]	OIDEF	18,627,862	545,109	66,511	1,166	(1,272,898)
28	Incremental Income Tax: Incremental Income Tax [5]	ITDEF	6,572,065	192,319	23,466	411	(449,089)
29	Incremental Regulatory Commission Expense: Incremental Regulatory Commission Expense [6]	RCDEF	46,295	1,354	165	3	(3,167)
30	Incremental Bad Debt Expense: Incremental Bad Debt Expense [7]	BDDEF	5,077	-	-	-	(2,026)
31							
32	Total Revenue Deficiency/(Excess) (L27 + L28 + L29 + L30)	REVDEF	25,251,299	738,782	90,142	1,580	(1,727,179)
33	% Increase/(Decrease) (L32 / L4)	REVDEFPCT	35.53%	14.57%	4.29%	3.91%	(30.96%)
34							
35	Rate Schedule Revenue Requirement (L4 + L32)	REVREQ	96,323,923	5,810,378	2,191,810	41,981	3,851,664
36	NOL Carryback Revenue Requirement: NOL Carryback Revenue Requirement	REVREQNOLCB	-	-	-	-	-
37	Total Rate Schedule Revenue Requirement (L35 + L36)	REVREQTOT	96,323,923	5,810,378	2,191,810	41,981	3,851,664
38							
39	Total Revenue Deficiency/(Excess) (L37 - L4)	REVDEFTOT	25,251,299	738,782	90,142	1,580	(1,727,179)
40	Total % Increase/(Decrease) (L39 / L4)	REVDEFTOTPCT	35.53%	14.57%	4.29%	3.91%	(30.96%)

Notes:
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Entergy New Orleans, LLC
Cost of Service
Summary Model Results - Revenue Requirement Calculation - Period I
Gas
For the Test Year Ended December 31, 2017

Line No.	Description	Line Item	Per Book	Adjustments	Total Adjusted	RES	LARGE GENERAL	LARGE MUNICIPAL	SMALL GENERAL	SMALL MUNICIPAL
1	Rate Base: Rate Base	RBTOA	104,367,041	17,366,815	121,733,856	86,631,165	12,581,895	8,954,303	13,346,155	220,337
2										
3	Revenues									
4	Rate Schedule Revenue: Rate Schedule Revenue	RSRTOA	82,805,492	(40,787,052)	42,018,440	26,149,008	6,741,411	2,780,529	6,286,689	60,803
5	Other Operating Revenues: Other Operating Revenues	ROTOA	1,695,237	584,259	2,279,496	1,418,581	365,721	150,843	341,052	3,299
6	Total Revenues (L4 + L5)	RTOA	84,500,729	(40,202,793)	44,297,936	27,567,589	7,107,132	2,931,372	6,627,741	64,102
7										
8	Total Operating Expenses: Total Operating Expenses	OETOA	75,386,241	(41,194,112)	34,192,130	23,002,809	4,332,289	2,522,317	4,275,906	58,808
9										
10	Total Operating Income (L6 - L8)	OITOA	9,114,487	991,319	10,105,806	4,564,780	2,774,843	409,055	2,351,835	5,294
11										
12	Earned Rate of Return on Rate Base (L10 / L1)	EROR	8.73%	5.71%	8.30%	5.27%	22.05%	4.57%	17.62%	2.40%
13										
14	**REVENUE REQUIREMENT DETERMINATION**									
15	Required Rate of Return	ROR	7.92%	7.92%	7.92%	7.92%	7.92%	7.92%	7.92%	7.92%
16	Required Operating Income: Required Operating Income (1)	ROI	8,261,319	1,374,694	9,636,013	6,857,411	995,937	708,790	1,056,434	17,441
17										
18	REVENUE CONVERSION FACTORS									
19	Income Tax Revenue Conversion Factor (2)	REVCOFIT	35.28%	35.28%	35.28%	35.28%	35.28%	35.28%	35.28%	35.28%
20	Regulatory Commission Expense Revenue Conversion Factor (2)	REVCOFRC	0.16%	0.16%	0.16%	0.16%	0.16%	0.16%	0.16%	0.16%
21	Bad Debt Revenue Conversion Factor (2)	REVCOFBD	1.97%	6.82%	(1.98%)	0.47%	0.00%		0.11%	0.01%
22										
23	Revenue Conversion Factor (3)	REVCOF	1.3817	1.4476	1.3280	1.3613	1.3549	1.3549	1.3564	1.3550
24										
25	REVENUE DEFICIENCY									
26	Operating Income Deficiency/(Excess) (4)	OIDEF	(853,169)	383,376	(469,793)	2,292,631	(1,778,905)	299,735	(1,295,401)	12,147
27	Incremental Income Tax: Incremental Income Tax (5)	ITDEF	(301,005)	135,258	(165,747)	808,859	(627,613)	105,749	(457,028)	4,286
28	Incremental Regulatory Commission Expense: Incremental Regulatory Commission Expense (6)	RCDEF	(1,853)	872	(981)	4,906	(3,789)	638	(2,762)	26
29	Incremental Bad Debt Expense: Incremental Bad Debt Expense (7)	BDDEF	(22,828)	35,455	12,627	14,494	(9)	-	(1,859)	1
30										
31	Total Revenue Deficiency/(Excess) (L26 + L27 + L28 + L29)	REVDEF	(1,178,855)	554,961	(623,894)	3,120,890	(2,410,316)	406,123	(1,757,051)	16,460
32	% Increase/(Decrease) (L31 / L4)	REVDEFPCT	(1.42%)	(1.36%)	(1.48%)	11.94%	(35.75%)	14.61%	(27.95%)	27.07%
33										
34	Rate Schedule Revenue Requirement (L4 + L31)	REVREQ	81,626,637	(40,232,091)	41,394,546	29,269,898	4,331,095	3,186,652	4,529,638	77,263

Notes:
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Entergy New Orleans, LLC
Cost of Service
Summary Model Results - Revenue Requirement Calculation - Period II
Gas
For the Test Year Ended December 31, 2018

Line No.	Description	Line Item	Per Book	Adjustments	Total Adjusted	RES	LARGE GENERAL	LARGE MUNICIPAL	SMALL GENERAL	SMALL MUNICIPAL
1	Rate Base: Rate Base	RBTOA	122,593,236	(2,467,240)	120,125,996	85,588,921	12,533,667	8,721,930	13,028,157	253,320
2										
3	Revenues									
4	Rate Schedule Revenue: Rate Schedule Revenue	RSRTOA	92,271,853	(49,981,092)	42,290,761	26,355,085	6,524,543	3,203,503	6,141,672	65,958
5	Other Operating Revenues: Other Operating Revenues	ROTOA	1,021,591	1,186,388	2,207,980	1,375,986	340,643	167,253	320,654	3,444
6	Total Revenues (L4 + L5)	RTOA	93,293,444	(48,794,703)	44,498,741	27,731,071	6,865,186	3,370,756	6,462,326	69,402
7										
8	Total Operating Expenses: Total Operating Expenses	OETOA	81,932,087	(47,628,790)	34,303,297	22,899,864	4,396,578	2,708,992	4,228,966	68,898
9										
10	Total Operating Income (L6 - L8)	OITOA	11,361,357	(1,165,914)	10,195,443	4,831,207	2,468,609	661,765	2,233,360	504
11										
12	Earned Rate of Return on Rate Base (L10 / L1)	EROR	9.27%	47.26%	8.49%	5.64%	19.70%	7.59%	17.14%	0.20%
13										
14	**REVENUE REQUIREMENT DETERMINATION**									
15	Required Rate of Return	ROR	7.92%	7.92%	7.92%	7.92%	7.92%	7.92%	7.92%	7.92%
16	Required Operating Income: Required Operating Income (1)	ROI	9,704,039	(195,298)	9,508,741	6,774,910	992,120	690,397	1,031,262	20,052
17										
18	REVENUE CONVERSION FACTORS									
19	Income Tax Revenue Conversion Factor (2)	REVCOFIT	35.28%	35.28%	35.28%	35.28%	35.28%	35.28%	35.28%	35.28%
20	Regulatory Commission Expense Revenue Conversion Factor (2)	REVCOFRC	0.16%	0.16%	0.16%	0.16%	0.16%	0.16%	0.16%	0.16%
21	Bad Debt Revenue Conversion Factor (2)	REVCOFBD	1.74%	3.78%	(1.13%)	0.47%	0.00%		0.11%	0.01%
22										
23	Revenue Conversion Factor (3)	REVCOF	1.3786	1.4063	1.3396	1.3613	1.3550	1.3550	1.3564	1.3551
24										
25	REVENUE DEFICIENCY									
26	Operating Income Deficiency/(Excess) (4)	OIDEF	(1,657,319)	970,616	(686,703)	1,943,704	(1,476,489)	28,632	(1,202,098)	19,548
27	Incremental Income Tax: Incremental Income Tax (5)	ITDEF	(584,716)	342,441	(242,274)	685,755	(520,918)	10,102	(424,110)	6,897
28	Incremental Regulatory Commission Expense: Incremental Regulatory Commission Expense (6)	RCDEF	(3,634)	2,171	(1,463)	4,209	(3,182)	62	(2,594)	42
29	Incremental Bad Debt Expense: Incremental Bad Debt Expense (7)	BDDEF	(39,168)	49,725	10,557	12,288	(8)	-	(1,725)	2
30										
31	Total Revenue Deficiency/(Excess) (L26 + L27 + L28 + L29)	REVDEF	(2,284,837)	1,364,953	(919,883)	2,645,956	(2,000,596)	38,795	(1,630,527)	26,489
32	% Increase/(Decrease) (L31 / L4)	REVDEFPCT	(2.48%)	(2.73%)	(2.18%)	10.04%	(30.66%)	1.21%	(26.55%)	40.16%
33										
34	Rate Schedule Revenue Requirement (L4 + L31)	REVREQ	89,987,016	(48,616,138)	41,370,878	29,001,041	4,523,947	3,242,298	4,511,145	92,447

Notes:
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(3) Reference MD 1 for calculation
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ENTERGY NEW ORLEANS, LLC ELECTRIC SERVICE RIDER SCHEDULE EFRP-5	Effective: September 1, 2020 Filed: September 2018 Supersedes: Rider EFRP-4 effective 12/1/17 Schedule Consists of: Six Pages Plus Attachments A - G

ELECTRIC FORMULA RATE PLAN RIDER SCHEDULE

I. GENERAL

This Electric Formula Rate Plan Rider Schedule EFRP-5 ("Rider EFRP") defines the procedure by which the rates contained in the Entergy New Orleans, LLC ("ENOL" or "Company") electric rate schedules designated in Attachment A to this Rider EFRP ("Rate Schedules") may be periodically adjusted. Rider EFRP shall apply in accordance with the provisions of Section II.A below to all electric service billed under the Rate Schedules, whether metered or unmetered, and subject to the jurisdiction of the Council of the City of New Orleans ("CNO" or "Council"). T T

Additionally, this Rider EFRP seeks to comply with Resolution R-16-103 ("Decoupling Pilot Resolution"), which established a three-year pilot program to begin with implementation of new base rates from the Combined Rate Case, Council Docket No. UD-18-XX__. T

II. APPLICATION AND REDETERMINATION PROCEDURE

A. RATE ADJUSTMENT

The adjustments to the Company's rates set forth in Attachment A to this Rider EFRP ("Rate Adjustments") shall be added to the rates set out in the monthly bills in accordance with the Company's Rate Schedules. Such Rate Adjustments are determined by rate class consistent with Resolution R-16-103. The Rate Adjustments shall be determined in accordance with the provisions of Sections II.B and II.C below. T

B. ANNUAL FILING AND REVIEW

1. FILING DATE

On or before April 30 of each year, beginning in 2020, ENOL shall file a report with the Council containing an evaluation of the Company's earnings for the immediately preceding calendar year prepared in accordance with the provisions of Section II.C below ("Evaluation Report"). A revised Attachment A shall be included in each such filing containing the Company's proposed revised Rate Adjustments determined in accordance with the provisions of Section II.C below. T

2. REVENUE REQUIREMENT AND REVENUE ALLOCATION T

In the Combined Rate Case, Baseline Revenue Requirements, fixed and variable, excluding the effects of the Algiers Residential mitigation rider, will be established. These Baseline Revenue Requirements will be determined at the rate class level and be included in Attachment G. T

The Evaluation Report shall use the allocation reflected in the Baseline Fixed and Variable Revenue Requirements to allocate the Evaluation Period revenue requirement to fixed and variable revenue requirements by rate class. The Evaluation Report shall use the ratio of the Baseline Fixed Revenue Requirement to the Baseline Variable Revenue Requirement to allocate Evaluation Period Present Base Rate Revenues, excluding the effects of the Algiers Residential mitigation rider, for each rate class between Fixed Present Base Rate Revenues T and Variable Present Base Rate Revenues.

3. REVIEW PERIOD T

The Council's Advisors ("Advisors") and all intervenors ("Intervenors"), which together with ENOL shall be referred to hereinafter, collectively, as the "Parties," shall receive a copy at the time it is filed with the Council of each Evaluation Report filing together with all subsequent
filings in the related proceeding. All Intervenors in Docket UD-18-XX shall be recipients of T
each such Evaluation Report filing. At the time each such Evaluation Report is filed, ENOL shall provide all Parties with workpapers supporting the data and calculations reflected in the Evaluation Report. The Parties may request such clarification and additional supporting data as each deems necessary and within the scope of normal discovery to adequately review the Evaluation Report and ENOL's proposed revised Rate Adjustments. ENOL shall provide such clarifications and additional supporting data sought by the other Parties within fifteen (15) days for each and every request.

The Parties shall then have until July 15 of the filing year or 75 days after filing, whichever is T
longer, to review the Evaluation Report to ensure that it complies with the requirements of Section II.C below. If any of the Parties should detect an error(s) (as distinguished from a regulatory issue(s)) in the application of the principles and procedures contained in Section II.C below, such error(s) shall be formally communicated in writing to the Company and/or
other Parties by July 15 of the filing year. Each such indicated error shall include T
documentation of the proposed correction. The Company shall then have twenty-five (25) days to review any proposed corrections, to work with the other Parties to resolve any differences and to file a revised Attachment A containing Rate Adjustments reflecting all corrections upon which the Parties agree. The Company shall provide the other Parties with appropriate work papers supporting any revisions made to the Rate Adjustments initially filed.

Except where there is an unresolved dispute, which shall be addressed in accordance with the provisions of Section II.B.3 below, the Rate Adjustments initially filed under the provisions of Section II.B.1 above, or such corrected Rate Adjustments as may be determined pursuant to the terms of this Section II.B.2, shall become effective for bills rendered on and after the
first billing cycle for the following month of September ("September Adjustment"). Those Rate T
Adjustments shall then remain in effect until changed pursuant to the provisions of this Rider EFRP.

4. RESOLUTION OF DISPUTED ISSUES T

In the event there is a dispute regarding any Evaluation Report, the Parties shall work together in good faith to resolve such dispute. If the Parties are unable to resolve the dispute by the end of the twenty-five (25) day period provided for in Section II.B.2 above, revised Rate Adjustments reflecting all revisions to the initially filed Rate Adjustments on which the Parties agree shall become effective as provided for in Section II.B.2 above. Any disputed issues shall be submitted to the Council for the setting of an Administrative Hearing before its designated Hearing Officer and a subsequent Resolution of the Council pursuant to the provisions of the Home Rule Charter.

If the Council's final ruling on any disputed issues requires changes to the September T
Adjustment referenced in Paragraph II.B.2 above, the Company shall file a revised Attachment A ("Final Adjustment") containing such further modified Rate Adjustments within fifteen (15) days after receiving the Council's order resolving the dispute. The Company shall provide a copy of the filing to the Council together with appropriate supporting documentation. Such modified Rate Adjustments shall then be implemented with the first billing cycle of the month after the date of the ruling if the ruling is received by the 5th day of the month, otherwise, the modified Rate Adjustments shall then be implemented with the first billing cycle of the second subsequent month after the date of the ruling and shall remain in effect until superseded by Rate Adjustments established in accordance with the provisions of this

Rider EFRP.

Within 60 days after receipt of the Council's final ruling on disputed issues, the Company shall determine the amount to be refunded or surcharged to customers, if any, together with interest at a Council mandated rate of interest. Such refund/surcharge amount shall be based on customers' revenue from the first billing cycle of September of the filing year through the T last date the interim Rate Adjustments were billed. Such refund/surcharge amount shall be applied to customers' bills in the manner prescribed by the Council.

C. ANNUAL REDETERMINATION OF RATE ADJUSTMENTS

1. DEFINITION OF TERMS

a. EVALUATION PERIOD
The Evaluation Period shall be the twelve month period ended December 31 of the calendar year immediately preceding the filing. All data utilized in each Evaluation Report shall be based on actual results for the Evaluation Period as recorded as electric operations on the Company's books in accordance with the Uniform System of Accounts or such other documentation as may be appropriate.

b. EARNED RATE OF RETURN ON COMMON EQUITY
The Earned Return on Common Equity ("EROE") for any Evaluation Period shall be determined in accordance with the EROE Formula set out in Attachment B. The EROE determination shall reflect the Evaluation Period adjustments set out in Attachment C.

c. BENCHMARK RATE OF RETURN ON RATE BASE
The Benchmark Rate of Return on Rate Base ("BRORB") shall be determined in accordance with the BRORB formula set out in Attachment D. The BRORB is the composite weighted embedded cost of capital reflecting the Company's annualized costs of Long-term Debt, Preferred Stock, and Common Equity as of the end of the Evaluation Period. The Debt, Preferred Stock and Equity capitalization ratios, as set out in Attachment D, shall be the actual equity capitalization ratio as of December 31 of the calendar year immediately preceding the filing adjusted for financing activity. T

d. EVALUATION PERIOD COST RATE FOR COMMON EQUITY
The Evaluation Period Cost Rate for Common Equity ("EPCOE") is the Company's cost rate for common equity applicable to the Evaluation Period. The EPCOE value applicable for each Evaluation Period shall be determined in accordance with Attachment E.

e. BASELINE FIXED AND VARIABLE REVENUE REQUIREMENTS T
The Baseline Revenue Requirements are the Company's fixed cost and variable cost base rate revenue requirements by rate class as determined in the Combined Rate Case.

f. EVALUATION PERIOD FIXED AND VARIABLE REVENUE REQUIREMENTS T
The Evaluation Period Fixed and Variable Revenue Requirement are the Company's redetermined fixed cost and variable cost revenue requirements by rate class for the Evaluation Period as determined in accordance with Section II.B.2.

g. EVALUATION PERIOD FIXED AND VARIABLE REVENUES T
The Evaluation Period Fixed and Variable Revenues are the Company's fixed and variable revenues by rate class for the Evaluation Period as determined in accordance with Section II.B.2.

h. ANNUALIZED EVALUATION PERIOD EFRP REVENUE T
The Annualized Evaluation Period EFRP Revenue is the Rider EFRP Rider Rate Adjustment by rate class (Final Adjustments) in effect at the end of the Evaluation Period T

multiplied times the applicable Evaluation Period Billing Revenues.

i. TOTAL RIDER EFRP REVENUE
The Total Rider EFRP Revenue is the Annualized Evaluation Period EFRP Revenue by rate class plus the reduction/increase in Rider EFRP Revenue by rate class as calculated in Attachment F.

j. RATE OF RETURN ON COMMON EQUITY BANDWIDTH
The Rate of Return on Common Equity Bandwidth (“Bandwidth”) shall be an Upper Band equal to the EPCOE plus 0.50% (50 basis points) and a Lower Band equal to the EPCOE minus 0.50% (50 basis points).

2. TOTAL RIDER EFRP REVENUE

In each Evaluation Period, the Total Rider EFRP Revenue level shall be determined using the Rider EFRP Revenue Redetermination Formula set out in Attachment F, which reflects the following rules:

a. If the EROE is less than the Lower Band, the ROE Adjustment shall be equal to the EPCOE minus the EROE.

b. If the EROE is greater than the Upper Band the ROE Adjustment shall be equal to the EPCOE minus the EROE.

c. There shall be no change in Rider EFRP Revenue level for the Evaluation Period if the EROE is less than or equal to the Upper Band and greater than or equal to the Lower Band.

3. TOTAL RIDER EFRP REVENUE ALLOCATION

The Rider EFRP Revenue, as determined under the provisions of Section II.C.2, will be allocated to each rate class by comparing each rate class’s Evaluation Period Fixed and Variable Revenue Requirements to the Evaluation Period Fixed and Variable Revenues, excluding the effects of the Algiers Residential mitigation rider, respectively, in Attachment F. The percentages will be developed by dividing the rate class Rider EFRP Revenue by the applicable rate class base rate revenue, calculated pursuant to Attachment B.

4. RATE ADJUSTMENT REDETERMINATION

All applicable retail rate and rider schedules on file with the Council will be adjusted through Rider Schedule EFRP by these percentages as determined under Section II.C.3, and will be shown on Attachment A to this Rider Schedule EFRP.

III. PROVISIONS FOR OTHER RATE CHANGES

A. EXTRAORDINARY COST CHANGES

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

B. FORCE MAJEURE T

In addition to the rights of ENOL under this Rider, or as provided by law, to make a filing for the pass-through of costs outside the provisions of the Rider EFRP, if any event or events beyond the reasonable control of ENOL including natural disaster, damage or unforeseeable loss of generating capacity, changes in regulation ordered by a regulatory body or other entity with appropriate jurisdiction, and orders or acts of civil or military authority, cause increased costs to ENOL or result in a deficiency of revenues to ENOL which is not readily capable of being addressed in a timely manner under this Rider EFRP, ENOL may file for rate or other relief outside the provisions of the Rider EFRP. Such request shall be considered by the Council in accordance with applicable law governing such filings.

C. NEW ORLEANS POWER STATION T

ENO shall include through an interim rate adjustment effective as of the first billing cycle of the T month following the Commercial Operation Date ("COD") the final estimated first-year revenue requirement associated with the completion of the construction of the New Orleans Power Station ("NOPS"), the construction of which was approved by the Council of the City of New Orleans in Resolution R-18-65. The final first-year estimated revenue requirement shall be determined in connection with a filing by ENO submitted no later than seventy-five (75) days prior to the expected in-service date/COD of NOPS, setting forth the then-current estimate of the incremental revenue requirement associated with ENO's ownership of NOPS. The final estimated first-year revenue requirement determined as a result of such filing shall form the basis for an in-service rate adjustment to the Company's base rates in accordance with Attachment A of this ENOL Rider Schedule FRP-5.

D. RIDER PPCACR TRANSITIONAL ITEMS

This Rider EFRP shall also include transitional revenue requirements from constructed or acquired capacity as approved by the Council effective with the realignment of those revenue requirements from Rider PPCACR to base revenue.

E. CHANGES IN TAX RATE T

In the event of a change in the state or federal corporate income tax rate(s) applicable to ENOL, T and/or any related changes to tax law, including, but not limited to changes that may affect the effective tax rate(s) and/or changes that may affect the treatment of accumulated deferred income tax, ENOL shall include in the FRP Evaluation Report following the change in law, all relevant information for the Council to determine the effect on the revenue requirement and propose related ratemaking treatment to become effective as of the date of the change in law.

T

F. SPECIAL RATE FILINGS

The Company is experiencing a changing business environment and increasing competition. Experimental, developmental, and alternative rate schedules may be appropriate tools for the Company to use to address these conditions. Therefore, nothing in this Rider shall be interpreted as preventing the Company from proposing, or requiring the Council to approve, any revisions to existing rate schedules or implement new rate schedules as may be appropriate. Any such rate changes shall be filed with the Council and evaluated in accordance with the rules and procedures then in effect.

IV. EFFECTIVE DATE AND TERM

Rider EFRP shall continue in effect for three years with annual Evaluation Report filings to be made on or before April 30 of 2020, 2021 and 2022 for the Evaluation Periods 2019, 2020, and 2021, respectively. The Rate Adjustments, resulting from the April 30, 2022 Filing shall continue in effect until such time as new rates become effective pursuant to a final Council order.

ENTERGY NEW ORLEANS, LLC
ELECTRIC FORMULA RATE PLAN RIDER SCHEDULE EFRP -5
FOR THE PERIOD ENDED DECEMBER 31, 200X

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12 Other Rate Changes

Effective: XX-X-XXXX

ATTACHMENT A

ENTERGY NEW ORLEANS, LLC
ELECTRIC FORMULA RATE PLAN RIDER SCHEDULE EFRP-5
<u>RATE ADJUSTMENTS</u>

The following Rate Adjustments will be applied to the rates set out in the monthly bills of Entergy New Orleans, LLC's ("ENOL") Rate Schedules identified below, or such additional rate schedules of ENOL subject to the Electric Formula Rate Plan Rider Schedule EFRP-5 that may become effective. The Rate Adjustments shall be effective for bills rendered on and after the first billing cycle of September of the filing year or as approved by the City Council of the City of New Orleans.

The Net Monthly Bill calculated pursuant to each applicable retail rate schedule* and rider schedule* on file with the City Council of the City of New Orleans will be adjusted monthly by the class percentages below before application of the monthly fuel adjustment except this Rider will not apply to the following:

*Excluded Schedules: AFC, AMICE, BRAR, Contract Minimums, CSO, DGM, DSMCR, DTK, EAC, EECR, EVCI, FAC, FBO, GPO, MES, MISO, PPCACR, PPS, R-8, R-3, RPCEA, SMS, SSCO and SSCR

Base rates producing EFRP percent increases or decreases will be based on Exhibit XX, Column ? to the Agreement in Principle in Docket UD-XX-XX.

ENTERGY NEW ORLEANS, LLC – ELECTRIC
FORMULA RATE PLAN RATES

Line No.	Rate Class	Base Revenue	Fixed and Variable Revenue Deficiency/(Excess)	Total FRP Rates
1	RESIDENTIAL			
2	SMALL ELECTRIC			
3	MUNICIPAL BUILDINGS			
4	LARGE ELECTRIC			
5	LARGE ELECTRIC HIGH LOAD FACTOR			
6	MASTER METERED NON RESIDENTIAL			
7	HIGH VOLTAGE			
8	LARGE INTERRUPTIBLE			
9	LIGHTING			

Attachment B

Line No.	Description		Adjusted Amount
	ENTERGY NEW ORLEANS, LLC – ELECTRIC **EARNED RATE OF RETURN ON COMMON EQUITY FORMULA**		
	TOTAL COMPANY		
1	RATE BASE	P 2, L23	
2	BENCHMARK RATE OF RETURN ON RATE BASE	Att D, L 4, Col D	
3	REQUIRED OPERATING INCOME	L 1 * L 2	
4	NET UTILITY OPERATING INCOME	P 3, L 25	
5	OPERATING INCOME DEFICIENCY/(EXCESS)	L 3 - L 4	
6	REVENUE CONVERSION FACTOR (1)		
7	REVENUE DEFICIENCY/(EXCESS)	L 5 * L 6	
	PRESENT RATE REVENUES		
8	ULTIMATE CUSTOMERS	P 3, L 1	
9	REVENUE REQUIREMENT	L 7 + L 8	
10	PRESENT BASE RATE REVENUES	P 3, L 1	
11	REVENUE DEFICIENCY/(EXCESS)	L 9 - L 10	
12	REVENUE CONVERSION FACTOR (1)		
13	OPERATING INCOME DEFICIENCY/(EXCESS)	L 11/L 12	
14	NOL CARRYBACK REFUND AMORTIZATION	P 3, L 26	
15	OPERATING INCOME DEFICIENCY/(EXCESS) AFTER NOL CARRYBACK REFUND AMORTIZATION	L 13 - L 14	
16	RATE BASE	P 2, L 23	
17	COMMON EQUITY DEFICIENCY/(EXCESS)	L 15/L 16	
18	WEIGHTED EVALUATION PERIOD COST RATE FOR COMMON EQUITY (%)	Att D, L 3, Col D	
19	WEIGHTED EARNED COMMON EQUITY RATE (%)	L 18 - L 17	
20	COMMON EQUITY RATIO (%)	Att D, L 3, Col B	
21	EARNED RATE OF RETURN ON COMMON EQUITY (%)	L 19 /L 20	

T

Notes:

(1) Revenue Conversion Factor = 1 / [(1 - Composite Tax Rate) * (1 – Bad Debt-Revenue Related Tax Rate)] T

Attachment B

ENTERGY NEW ORLEANS, LLC – ELECTRIC RATE BASE (A)				
Line No.	**Description**	**Per Books**	**Adjustments (B)**	**Adjusted Amount**
1	PLANT IN SERVICE			
2	ACCUMULATED DEPRECIATION			
3	**NET UTILITY PLANT** (L1+ L2)			
4	PLANT HELD FOR FUTURE USE			
5	CONSTRUCTION WORK IN PROGRESS (C)			
6	MATERIALS AND SUPPLIES (D)			
7	PREPAYMENTS (D)			
8	CASH WORKING CAPITAL (E)			
9	PROVISION FOR INJURIES & DAMAGES RESERVE (D)			
10	PROVISION FOR PROPERTY INSURANCE RESERVE (D)			
11	PLANT ACQUISITION ADJUSTMENT			
12	INVESTMENT IN SUB-CAPITAL (D)			
13	CUSTOMER ADVANCES			
14	CUSTOMER DEPOSITS			
15	ACCUMULATED DEFERRED INCOME TAXES			
16	ACCUMULATED DEFERRED ITC - PRE-1971			
17	OTHER (F) (G)			
18	FUEL INVENTORY (D)			
19	NET UNAMORTIZED RATE CASE EXPENSE			
20	NET UNAMORTIZED ALGIERS MIGRATION COSTS			
21	NET UNAMORTIZED UNRECOVERED GENERAL PLANT			
22	PENSION LIABILITY RATE BASE EXCL SFAS 158			
23	**RATE BASE** (L3 + Sum of L4 through L22)			

T

Notes:
(A) Ending balances are to be utilized except where otherwise noted
(B) Adjustments as set out in Attachment C to this rider EFRP
(C) Amount not subject to AFUDC accrual
(D) 13-month average balances
(E) Cash Working Capital is deemed to be zero.
(F) Other items included pursuant to Section 6 of Attachment C
(G) Beginning & Ending or 13-mos average as more appropriate

Attachment B

Line No.	Description	Per Books	Adjustments (A)	Adjusted Amount
	ENTERGY NEW ORLEANS, LLC – ELECTRIC OPERATING INCOME			
	REVENUES			
1	SALES TO ULTIMATE CUSTOMERS			
2	EPP & SYSTEM SALES			
3	OTHER ELECTRIC REVENUE			
4	TOTAL OPERATING REVENUES (Sum of L1 through L3)			
	EXPENSES			
	ELECTRIC O&M			
5	PRODUCTION			
6	TRANSMISSION			
7	DISTRIBUTION			
8	CUSTOMER ACCOUNTING			
9	CUSTOMER SERVICE & INFORMATION			
10	SALES			
11	ADMINISTRATIVE & GENERAL			
12	TOTAL ELECTRIC O&M EXPENSES (Sum of L5 through L11)			
13	GAIN FROM DISPOSITION OF ALLOWANCES			
14	REGULATORY DEBITS & CREDITS (B)			
15	DEPRECIATION & AMORTIZATION EXPENSES			
16	INTEREST ON CUSTOMER DEPOSITS			
17	TAXES OTHER THAN INCOME			
18	STATE INCOME TAX			
19	FEDERAL INCOME TAX			
20	PROV DEF INC TAX - STATE – NET			
21	PROV DEF INC TAX - FED – NET			
22	INVESTMENT TAX CREDIT-NET			
23	OTHER (C)			
24	TOTAL UTILITY OPERATING EXPENSES (L12 + Sum of L13 through L23)			
25	**NET UTILITY OPERATING INCOME** (L4 – L24)			
26				

T

Notes:
(A) Adjustments defined in Attachment C
(B) Including, but not limited to, the amortization of regulatory assets and liabilities established in the Agreement in Principle in UD-08-03.
(C) Other items included pursuant to Section 6 of Attachment C

Attachment B

Line No.	Description	Reference	Per Books	Adjustments (A)	Adjusted Amount
	ENTERGY NEW ORLEANS, LLC – ELECTRIC INCOME TAX				
1	TOTAL OPERATING REVENUES	P 3, L 4			
2	TOTAL O&M EXPENSE	P 3, L 12			
3	GAIN FROM DISPOSITION OF ALLOWANCES	P 3, L 13			
4	REGULATORY DEBITS & CREDITS)	P 3, L 14			
5	DEPRECIATION & AMORTIZATION EXPENSE	P 3, L 15			
6	INTEREST ON CUSTOMER DEPOSITS	P 3, L 16			
7	TAXES OTHER THAN INCOME	P 3, L 17			
8	NET INCOME BEFORE INCOME TAXES	L 1- Sum of L 2 through L 7			
9	ADJUSTMENTS TO NET INCOME BEFORE TAXES				
10	TAXABLE INCOME	L 8 + L 9			
	COMPUTATION OF STATE INCOME TAX				
11	STATE TAXABLE INCOME	L 10			
12	STATE ADJUSTMENTS				
13	TOTAL STATE TAXABLE INCOME	Sum of L 11 through L 12			
14	STATE INCOME TAX BEFORE ADJUSTMENTS (B)	L 13*Eff. Tax Rate			
15	ADJUSTMENTS TO STATE TAX				
16	**STATE INCOME TAX**	L 14 + L 15			
	COMPUTATION OF FEDERAL INCOME TAX				
17	TAXABLE INCOME	L 10			
18	STATE INCOME TAX	L 14 as deduction			
19	FEDERAL ADJUSTMENTS				
20	TOTAL FEDERAL TAXABLE INCOME	Sum of L 17 through L 19			
21	FEDERAL INCOME TAX BEFORE ADJUSTMENTS (B)	L 20* Eff. Tax Rate			
22	ADJUSTMENTS TO FEDERAL TAX				
23	**FEDERAL INCOME TAX**	L 21+L 22			

Notes:
(A) Adjustments as defined in Attachment C
(B) The Tax Rate in effect at the time the Evaluation Report is filed shall be utilized.

Attachment C

ENTERGY NEW ORLEANS, LLC

EVALUATION PERIOD ADJUSTMENTS

The actual (per book) data for each Evaluation Period, as reflected in Attachment B, shall be adjusted to reflect the following:

1 **Rate Annualization Adjustment**

A) Present base rate revenue shall be adjusted to reflect, on an annualized basis by Rate Class, the Rate Adjustments in effect at the end of the Evaluation Period under this Rider EFRP. T

B) The rate base, revenue and expense effects associated with any riders, or other rate mechanisms, that ENOL may have in effect during the Evaluation Period which recover specific costs are to be eliminated. The revenue effects of the Algiers Residential mitigation rider are not to be eliminated. T

C) Present base rate revenue shall not be adjusted for the Lost Contribution to Fixed Costs resulting from energy efficiency programs in the calendar year subsequent to the Evaluation Period. The recovery of the Lost Contribution to Fixed Costs shall occur through the Energy Efficiency Rider or approved in the Combined Rate Case.

2 **Interest Synchronization**

All Evaluation Period Interest expenses are to be eliminated and replaced with an imputed interest expense amount equal to the Evaluation Period rate base multiplied by the weighted embedded cost of debt for the Evaluation Period determined in accordance with Attachment D.

3 **Income Taxes**

All state and federal income tax effects including 1) adjustments to taxable income, 2) adjustments to current taxes, 3) provisions for deferred income tax (debit and credit), and 4) accumulated provision for deferred income tax (debit and credit) shall be adjusted or eliminated, as appropriate, to comport with the following principles:

A) Effects associated with other adjustments set out in this Attachment C shall similarly and consistently be adjusted;

B) All effects associated with the difference in the timing of transactions, where the underlying timing difference is eliminated, shall also be eliminated;

C) The corporate state and federal income tax laws legally in effect on the date an Evaluation Report is filed under this EFRP Rider shall be reflected in the calculation of all income tax amounts; and

D) Tax effects normally excluded for ratemaking purposes shall be eliminated. T

4 **Ratemaking Adjustments for Evaluation Report Based on Test Year 2019** T

T

A) Present base rate revenue shall be adjusted to reflect, on an annualized basis, the rate actions resulting from the Combined Rate Case. T

B) The expense credit associated with amounts expensed prior to 2019 but included in any regulatory assets authorized in the Combined Rate Case shall be eliminated. T

C) The amortization of any regulatory asset authorized in the Combined Rate Case shall be annualized.

D) The amortization of Unrecovered General Plant shall be annualized.

E) The depreciation expense associated with Plant in Service shall be annualized.

F) Extraordinary Cost Changes

5 **Ratemaking Adjustments for Evaluation Reports Based on Test Year 2020 and 2021** T

A) Extraordinary Cost Changes T

6 **Reclassifications**

A) Revenues associated with ENOL's rates in the CNO Retail Jurisdiction, but included in Other Electric Revenue on a per book basis (Attachment B, Page 3, Line 3) shall be reclassified as rate schedule revenue.

B) Costs not allowable for ratemaking purposes shall be removed by adjustment from the Evaluation Period cost data. Likewise, costs that are allowed, but recorded below the utility operating income line, shall be included in the Evaluation Period cost data through appropriate reclassification adjustments. These adjustments shall include, but are not limited to the reclassification of below-the-line interest expense T
associated with customer deposits as interest on customer deposits expense. T

7 **Out-of-Period Items**

Expenses and revenues recorded in any Evaluation Period that are related to transactions occurring prior to the Evaluation Period used in the first Filing shall be eliminated by adjustment from the Evaluation Period cost data. This shall include any associated tax adjustments.

8 **Other**

In addition to Adjustments 1 through 7 above, there may, from time-to-time, be special costs or rate effects that occur during an Evaluation Period that require adjustments of the Evaluation Period cost data. Nothing in this Rider EFRP shall preclude any Party from proposing such adjustments.

Attachment D

ENTERGY NEW ORLEANS, LLC

BENCHMARK RATE OF RETURN ON RATE BASE

	Description	(A) Capital Amount (1) ($)	(B) Capital Ratio (%)	(C) Cost Rate (2) (%)	(D) Benchmark Rate of Return on Rate Base (3)
1	LONG-TERM DEBT				
2	PREFERRED EQUITY				
3	COMMON EQUITY				
4	TOTAL		**100%**		

Notes:

(1) Amounts at the end of the Evaluation Period as adjusted for refinancing activities. All Long-Term Debt issues shall reflect the balance net of a) unamortized debt discount, premium, and expense; b) gain or loss on reacquired debt; and c) any adjustments required per Attachment C. All Preferred Stock issues shall reflect the balance net of discount, premium and capital stock expense. T

(2) Annualized cost of Long-Term Debt and Preferred Equity at the end of the Evaluation Period divided by the corresponding Capital Amount. The Long-Term Debt Cost Rates shall include a) annualized amortization of debt discount, premium, and expense; b) annualized gain or loss on reacquired debt; and c) any adjustments required per Attachment C. The Common Equity Cost Rate shall be the Evaluation Period Cost Rate for Common Equity (EPCOE) determined in accordance with Attachment E.

(3) The components of the BRORB column are the corresponding Cost Rates multiplied by the associated Capital Ratio. The BRORB is the sum of the components so determined and expressed as a % to two decimal places (XX.XX%).

Attachment E

ENTERGY NEW ORLEANS, LLC

EVALUATION PERIOD COST RATE FOR COMMON EQUITY PROCEDURE

EVALUATION PERIOD COST RATE FOR COMMON EQUITY

The EPCOE applicable for any Evaluation Report pursuant to this Rider EFRP shall be 10.75% plus or minus the results of the performance factor calculation shown below. T

	SAIFI Score	ROE Adjustment Based on SAIFI Score
Upper Bound SAIFI	1.05	Performance Adjustment = +25 b.p.
Target Improvement	1.24	At Target = No Adjustment to Authorized ROE (10.75%)
Lower Bound SAIFI Level	1.40	Performance Adjustment = -25 b.p.

If ENO SAIFI Score is greater than target, but less than or equal to the Upper Bound SAIFI score then Performance
Adjustment shall be calculated as follows:
Performance Adjustment % = (ENO-TAR)/(UB-TAR)*0.25

If ENO SAIFI Score is less than target, but greater than or equal to Lower Bound SAIFI score then Performance
Adjustment shall be calculated as follows:
Performance Adjustment % = (ENO-TAR)/(TAR-LB)*0.25

Formula Key

ENO = ENO's SAIFI Score for the Test Period
TAR = Target SAIFI Score
UB = Upper Bound SAIFI Score
LB = Lower Bound SAIFI Level

Attachment F

ENTERGY NEW ORLEANS, LLC – ELECTRIC
RIDER EFRP REVENUE REDETERMINATION FORMULA

SECTION 1

BANDWIDTH CHECK

Line No.	DESCRIPTION	REFERENCE		
1	Earned Rate of Return on Common Equity ("EROE")	Attachment B, P 1, L 21		
2	Evaluation Period Cost Rate for Common Equity ("EPCOE")	Per Attachment E		
3	Upper Band	L 2 + 0.50%		T
4	Lower Band	L 2 - 0.50%		T
5	ROE Adjustment	If L1 < L4, then L2 - L1; If L1 > L3, then L2 - L1		
		but no adjustment if L1 ≥ L 4 and L1 ≤ L3		

SECTION 2

ROE BAND RATE ADJUSTMENT

	DESCRIPTION	REFERENCE		
6	ROE Adjustment	Per L 5		
7	Common Equity Capital Ratio	Attachment D, L 3, Col B		
8	Rate Base	Attachment B, P 1, L 1		
9	Revenue Conversion Factor	Attachment B, P 1, L 6		
10	Total Change in Rider EFRP Revenue	L6 * L7 * L8 * L9		

SECTION 3

TOTAL BAND RATE ADJUSTMENT

	DESCRIPTION	REFERENCE		
11	Annualized Evaluation Period EFRP Revenue (1)	See Note 1		
12	(Reduction)/Increase in Rider EFRP Revenue	L 10		
13	Extraordinary Cost Change Revenue Requirement	Per Sec. III.A of the Tariff		T
				T
14	Total Rider EFRP Revenue (2)	L 11 + L 12 + L 13		

Note: T

(1) Rider EFRP Rate Adjustments in effect at the end of the applicable Evaluation Period multiplied by the applicable Evaluation Period billing revenues plus any other applicable adjustments.

(2) The Total Rider EFRP Revenue reflects the total credit or surcharge to be applied to customer bills based on the results of the Rider EFRP Redetermination Formula.

ATTACHMENT F

T

ENTERGY NEW ORLEANS, LLC – ELECTRIC FIXED REVENUE DEFICIENCY/(EXCESS) ($)				
Line No.	**Rate Class**	**Current Fixed Revenue Requirement**	**Current Fixed Revenue**	**Fixed Revenue Deficiency/(Excess)**
1	RESIDENTIAL			
2	SMALL ELECTRIC			
3	MUNICIPAL BUILDINGS			
4	LARGE ELECTRIC			
5	LARGE ELECTRIC HIGH LOAD FACTOR			
6	MASTER METERED NON RESIDENTIAL			
7	HIGH VOLTAGE			
8	LARGE INTERRUPTIBLE			
9	LIGHTING			
10	**TOTALS** (Sum of L1 through L9)			

ATTACHMENT F

T

ENTERGY NEW ORLEANS, LLC – ELECTRIC VARIABLE REVENUE DEFICIENCY/(EXCESS)				
Line No.	**Rate Class**	**Current Variable Revenue Requirement**	**Current Variable Revenue**	**Variable Revenue Deficiency/(Excess)**
1	RESIDENTIAL			
2	SMALL ELECTRIC			
3	MUNICIPAL BUILDINGS			
4	LARGE ELECTRIC			
5	LARGE ELECTRIC HIGH LOAD FACTOR			
6	MASTER METERED NON RESIDENTIAL			
7	HIGH VOLTAGE			
8	LARGE INTERRUPTIBLE			
9	LIGHTING			
10	**TOTALS** (Sum of L1 through L9)			

ATTACHMENT F

T

ENTERGY NEW ORLEANS, LLC – ELECTRIC FIXED AND VARIABLE REVENUE DEFICIENCY/(EXCESS)				
Line No.	**Rate Class**	**Current Fixed and Variable Revenue Requirement**	**Current Fixed and Variable Revenue**	**Fixed and Variable Revenue Deficiency/(Excess)**
1	RESIDENTIAL			
2	SMALL ELECTRIC			
3	MUNICIPAL BUILDINGS			
4	LARGE ELECTRIC			
5	LARGE ELECTRIC HIGH LOAD FACTOR			
6	MASTER METERED NON RESIDENTIAL			
7	HIGH VOLTAGE			
8	LARGE INTERRUPTIBLE			
9	LIGHTING			
10	**TOTALS** (Sum of L1 through L9)			

ATTACHMENT G

T

ENTERGY NEW ORLEANS, LLC – ELECTRIC BASELINE FIXED AND VARIABLE REVENUE REQUIREMENT				
Line No.	**Rate Class**	**Baseline Fixed Revenue Requirement**	**Baseline Variable Revenue Requirement**	**Baseline Fixed and Variable Revenue Requirement**
1	RESIDENTIAL			
2	SMALL ELECTRIC			
3	MUNICIPAL BUILDINGS			
4	LARGE ELECTRIC			
5	LARGE ELECTRIC HIGH LOAD FACTOR			
6	MASTER METERED NON RESIDENTIAL			
7	HIGH VOLTAGE			
8	LARGE INTERRUPTIBLE			
9	LIGHTING			
10	**TOTALS** (Sum of L1 through L9)			

ATTACHMENT G -EXAMPLE

ENTERGY NEW ORLEANS, LLC - ELECTRIC
BASELINE FIXED AND VARIABLE REVENUE REQUIREMENT
($)

Rate Class	Baseline Fixed Revenue Requirement	Baseline Variable Revenue Requirement	Baseline Fixed and Variable Revenue Requirement
Residential	$ 190,794,569	$ 918,065	$ 191,712,634
Small Electric	$ 72,880,433	$ 350,686	$ 73,231,119
Municipal Buildings	$ 2,934,674	$ 14,121	$ 2,948,795
Large Electric	$ 30,969,815	$ 149,020	$ 31,118,835
Large Electric High Load Factor	$ 108,072,421	$ 520,023	$ 108,592,444
Master Metered Non Residential	$ 57,498	$ 277	$ 57,775
High Voltage	$ 8,015,746	$ 38,570	$ 8,054,316
Large Interruptible	$ 4,936,762	$ 23,755	$ 4,960,517
Lighting	$ 7,543,263	$ 36,297	$ 7,579,560
	$ 426,205,181	$ 2,050,814	$ 428,255,995

FOR ILLUSTRATIVE PURPOSES ONLY

ATTACHMENT G - EXAMPLE (SUPPORT)
Entergy New Orleans, LLC
Unit Cost
Electric - Base Case
For the Test Year Ended December 31, 2018

	UNIT COST	Total Company Adjusted	Residential	Small Electric	Large Electric	Large Interruptible Service	Large Electric High Load Factor	High Voltage	Municipal Building	Master Metered Non Res	Lighting
1	TOTAL DEMAND COSTS	368,731,672	177,758,557	56,262,802	27,436,898	2,340,132	94,894,689	5,737,820	2,018,835	40,678	2,241,261
2	ENERGY COSTS EXCL FUEL & PURCHASED ENERGY	2,050,813	789,494	299,347	170,275	56,252	650,208	54,084	10,684	241	20,229
3	TOTAL CUSTOMER COSTS	57,473,510	45,893,870	8,527,529	417,717	83,367	779,025	18,474	162,291	1,062	1,590,174
4	TOTAL REVENUE REQUIREMENT (DEMAND + ENERGY + CUSTOMER)	428,255,995	224,441,921	65,089,677	28,024,890	2,479,752	96,323,923	5,810,378	2,191,810	41,981	3,851,664
5	TOTAL ADJUSTED REVENUE REQUIREMENT	428,255,995	191,712,634	73,231,119	31,118,835	4,960,517	108,592,444	8,054,316	2,948,795	57,775	7,579,560
6	Fixed Cost Revenue Requirement - Actual	426,205,182	223,652,427	64,790,331	27,854,615	2,423,500	95,673,714	5,756,294	2,181,126	41,740	3,831,435
	Variable Cost Revenue Requirement - Actual	2,050,813	789,494	299,347	170,275	56,252	650,208	54,084	10,684	241	20,229
	Fixed Cost Revenue Requirement % - Actual	99.52%	99.65%	99.54%	99.39%	97.73%	99.32%	99.07%	99.51%	99.43%	99.47%
	Variable Cost Revenue Requirement % - Actual	0.48%	0.35%	0.46%	0.61%	2.27%	0.68%	0.93%	0.49%	0.57%	0.53%
	Fixed Cost Revenue Requirement - Adjusted	426,205,181	190,794,569	72,880,433	30,969,815	4,936,762	108,072,421	8,015,746	2,934,674	57,498	7,543,263
	Variable Cost Revenue Requirement - Adjusted	2,050,814	918,065	350,686	149,020	23,755	520,023	38,570	14,121	277	36,297
	Fixed Cost Revenue Requirement % - Adjusted	99.52%	99.52%	99.52%	99.52%	99.52%	99.52%	99.52%	99.52%	99.52%	99.52%
	Variable Cost Revenue Requirement % - Adjusted	0.48%	0.48%	0.48%	0.48%	0.48%	0.48%	0.48%	0.48%	0.48%	0.48%
	% of Total Revenue Requirement - Fixed	99.52%	44.55%	17.02%	7.23%	1.15%	25.24%	1.87%	0.69%	0.01%	1.76%
	% of Total Revenue Requirement - Variable	0.48%	0.21%	0.08%	0.03%	0.01%	0.12%	0.01%	0.00%	0.00%	0.01%
	Total % of Total Revenue Requirement	100.00%	44.77%	17.10%	7.27%	1.16%	25.36%	1.88%	0.69%	0.01%	1.77%

FOR ILLUSTRATIVE PURPOSES ONLY

ATTACHMENT F - EXAMPLE

ENTERGY NEW ORLEANS, LLC - ELECTRIC
FIXED REVENUE DEFICIENCY/(EXCESS)
($)

Line No.	Rate Class	Current Fixed Revenue Requirement	Current Fixed Revenue	Fixed Revenue Deficiency/ (Excess)
1	Residential	$ 192,131,115	$ 189,090,136	$ 3,040,979
2	Small Electric	$ 73,390,972	$ 72,650,421	$ 740,551
3	Municipal Buildings	$ 2,955,232	$ 2,985,634	$ (30,402)
4	Large Electric	$ 31,186,763	$ 30,851,549	$ 335,215
5	Large Electric High Load Factor	$ 108,829,485	$ 109,672,279	$ (842,794)
6	Master Metered Non Residential	$ 57,901	$ 58,717	$ (817)
7	High Voltage	$ 8,071,898	$ 8,061,211	$ 10,686
8	Large Interruptible	$ 4,971,345	$ 4,976,056	$ (4,711)
9	Lighting	$ 7,596,105	$ 7,762,648	$ (166,543)
10	TOTALS (Sum of L1 through L9)	$ 429,190,815	$ 426,108,650	$ 3,082,164

FOR ILLUSTRATIVE PURPOSES ONLY

ATTACHMENT F - EXAMPLE

ENTERGY NEW ORLEANS, LLC - ELECTRIC
VARIABLE REVENUE DEFICIENCY/(EXCESS)
($)

Line No.	Rate Class	Current Variable Revenue Requirement	Current Variable Revenue	Variable Revenue Deficiency/ (Excess)
1	Residential	$ 924,496	$ 909,864	$ 14,632
2	Small Electric	$ 353,143	$ 349,579	$ 3,563
3	Municipal Buildings	$ 14,220	$ 14,366	$ (146)
4	Large Electric	$ 150,064	$ 148,451	$ 1,612
5	Large Electric High Load Factor	$ 523,666	$ 527,721	$ (4,055)
6	Master Metered Non Residential	$ 279	$ 283	$ (4)
7	High Voltage	$ 38,840	$ 38,789	$ 51
8	Large Interruptible	$ 23,921	$ 23,944	$ (22)
9	Lighting	$ 36,551	$ 37,352	$ (801)
10	TOTALS (Sum of L1 through L9)	$ 2,065,180	$ 2,050,350	$ 14,831

FOR ILLUSTRATIVE PURPOSES ONLY

ATTACHMENT F - EXAMPLE

ENTERGY NEW ORLEANS, LLC - ELECTRIC
FIXED AND VARIABLE REVENUE DEFICIENCY/(EXCESS)
($)

Line No.	Rate Class	Current Fixed and Variable Revenue Requirement	Current Fixed and Variable Revenue	Fixed and Variable Revenue Deficiency/ (Excess)
1	Residential	$ 193,055,611	$ 190,000,000	$ 3,055,611
2	Small Electric	$ 73,744,114	$ 73,000,000	$ 744,114
3	Municipal Buildings	$ 2,969,452	$ 3,000,000	$ (30,548)
4	Large Electric	$ 31,336,827	$ 31,000,000	$ 336,827
5	Large Electric High Load Factor	$ 109,353,151	$ 110,200,000	$ (846,849)
6	Master Metered Non Residential	$ 58,180	$ 59,000	$ (820)
7	High Voltage	$ 8,110,738	$ 8,100,000	$ 10,738
8	Large Interruptible	$ 4,995,266	$ 5,000,000	$ (4,734)
9	Lighting	$ 7,632,656	$ 7,800,000	$ (167,344)
10	TOTALS (Sum of L1 through L9)	$ 431,255,995	$ 428,159,000	$ 3,096,995

FOR ILLUSTRATIVE PURPOSES ONLY

ATTACHMENT F - EXAMPLE (SUPPORT)

Rate Class	Current Fixed and Variable Revenue Requirement	Current Fixed Revenue Requirement	Current Variable Revenue Requirement
Residential	$ 193,055,611	$ 192,131,115	$ 924,496
Small Electric	$ 73,744,114	$ 73,390,972	$ 353,143
Municipal Buildings	$ 2,969,452	$ 2,955,232	$ 14,220
Large Electric	$ 31,336,827	$ 31,186,763	$ 150,064
Large Electric High Load Factor	$ 109,353,151	$ 108,829,485	$ 523,666
Master Metered Non Residential	$ 58,180	$ 57,901	$ 279
High Voltage	$ 8,110,738	$ 8,071,898	$ 38,840
Large Interruptible	$ 4,995,266	$ 4,971,345	$ 23,921
Lighting	$ 7,632,656	$ 7,596,105	$ 36,551
	$ 431,255,995	$ 429,190,815	$ 2,065,180

FRP Revenue Requirement Change	$ 3,000,000
Baseline Revenue Requirement	$ 428,255,995
Current FRP Total Revenue Requirement	$ 431,255,995

FOR ILLUSTRATIVE PURPOSES ONLY

ATTACHMENT F - EXAMPLE (SUPPORT)

	CURRENT FRP TY TOTAL REVENUE	FIXED COST REVENUE REQUIREMENT %	VARIABLE COST REVENUE REQUIREMENT %	CURRENT FRP TY FIXED COST REVENUE (COL B * COL C)	CURRENT FRP TY VARIABLE COST REVENUE (COL B * COL D)
Residential	$ 190,000,000	99.52%	0.48%	$ 189,090,136	$ 909,864
Small Electric	$ 73,000,000	99.52%	0.48%	$ 72,650,421	$ 349,579
Municipal Buildings	$ 3,000,000	99.52%	0.48%	$ 2,985,634	$ 14,366
Large Electric	$ 31,000,000	99.52%	0.48%	$ 30,851,549	$ 148,451
Large Electric High Load Factor	$ 110,200,000	99.52%	0.48%	$ 109,672,279	$ 527,721
Master Metered Non Residential	$ 59,000	99.52%	0.48%	$ 58,717	$ 283
High Voltage	$ 8,100,000	99.52%	0.48%	$ 8,061,211	$ 38,789
Large Interruptible	$ 5,000,000	99.52%	0.48%	$ 4,976,056	$ 23,944
Lighting	$ 7,800,000	99.52%	0.48%	$ 7,762,648	$ 37,352
	$ 428,159,000			$ 426,108,650	$ 2,050,350

FOR ILLUSTRATIVE PURPOSES ONLY

ATTACHMENT A -EXAMPLE

ENTERGY NEW ORLEANS, LLC - ELECTRIC
ELECTRIC FORMULA RATE PLAN RIDER SCHEDULE EFRP-5
RATE ADJUSTMENTS

Line No.		Base Revenue	Fixed and Variable Revenue Deficiency/ (Excess)	Total FRP Rates
1	Residential	$ 190,000,000	$ 3,055,611	1.6082%
2	Small Electric	$ 73,000,000	$ 744,114	1.0193%
3	Municipal Buildings	$ 3,000,000	$ (30,548)	-1.0183%
4	Large Electric	$ 31,000,000	$ 336,827	1.0865%
5	Large Electric High Load Factor	$ 110,200,000	$ (846,849)	-0.7685%
6	Master Metered Non Residential	$ 59,000	$ (820)	-1.3903%
7	High Voltage	$ 8,100,000	$ 10,738	0.1326%
8	Large Interruptible	$ 5,000,000	$ (4,734)	-0.0947%
9	Lighting	$ 7,800,000	$ (167,344)	-2.1454%

FOR ILLUSTRATIVE PURPOSES ONLY

ENTERGY NEW ORLEANS, LLC
GAS SERVICE

RIDER SCHEDULE GFRP-5

Effective: September 2020 Billing
Filed: September 2018
Supersedes: GFRP-4 Effective 12/21/17
Schedule Consist of: Five Pages Plus Attachments A - F

GAS FORMULA RATE PLAN RIDER SCHEDULE

I. GENERAL

This Gas Formula Rate Plan Rider Schedule GFRP-5 ("Rider GFRP") defines the procedure by which the rates contained in the Entergy New Orleans, LLC ("ENOL" or "Company") gas rate schedules designated in Attachment A to this Rider GFRP ("Rate Schedules") may be periodically adjusted. Rider GFRP shall apply in accordance with the provisions of Section II.A below to all gas service billed under the Rate Schedules, whether metered or unmetered, and subject to the jurisdiction of the Council of the City of New Orleans ("CNO" or "Council"). T

II. APPLICATION AND REDETERMINATION PROCEDURE

A. RATE ADJUSTMENT

The adjustments to the Company's rates set forth in Attachment A to this Rider GFRP ("Rate Adjustments") shall be added to the rates set out in the monthly bills in accordance with the Company's Rate Schedules. The Rate Adjustments shall be determined in accordance with the provisions of Sections II.B and II.C below.

B. ANNUAL FILING AND REVIEW

1. FILING DATE

On or before April 30 of each year, beginning in 2020, ENOL shall file a report with the Council containing an evaluation of the Company's earnings for the immediately preceding calendar year prepared in accordance with the provisions of Section II.C below ("Evaluation Report"). A revised Attachment A shall be included in each such Filing containing the Company's proposed revised Rate Adjustments determined in accordance with the provisions of Section II.C below. T

2. REVIEW PERIOD

The Council's Advisors ("Advisors") and all intervenors ("Intervenors"), which together with ENOL shall be referred to hereinafter, collectively, as the "Parties," shall receive a copy at the time it is filed with the Council of each Evaluation Report together with all subsequent filings in the related proceeding. All Intervenors in Docket UD-XX-XX shall be recipients of each such Evaluation Report filing. At the time each such Evaluation Report is filed, ENOL shall provide all Parties with workpapers supporting the data and calculations reflected in the Evaluation Report. The Parties may request such clarification and additional supporting data as each deems necessary and within the scope of normal discovery to adequately review the Evaluation Report and ENOL's proposed revised Rate Adjustments. ENOL shall provide such clarifications and additional supporting data sought by the other Parties within fifteen (15) days for each and every request. T

The Parties shall then have until July 15 of the filing year or 75 days after the filing, T
whichever is longer, to review the Evaluation Report to ensure that it complies with the
requirements of Section II.C below. If any of the Parties should detect an error(s) (as
distinguished from a regulatory issue(s)) in the application of the principles and
procedures contained in Section II.C below, such error(s) shall be formally communicated
in writing to the Company and/or other Parties by July 15 of the filing year. Each such T
indicated error shall include documentation of the proposed correction. The Company
shall then have twenty-five (25) days to review any proposed corrections, to work with the
other Parties to resolve any differences and to file a revised Attachment A containing
Rate Adjustments reflecting all corrections upon which the Parties agree. The Company
shall provide the other Parties with appropriate work papers supporting any revisions
made to the Rate Adjustments initially filed.

Except where there is an unresolved dispute, which shall be addressed in accordance
with the provisions of Section II.B.3 below, the Rate Adjustments initially filed under the
provisions of Section II.B.1 above, or such corrected Rate Adjustments as may be
determined pursuant to the terms of this Section II.B.2, shall become effective for bills
rendered on and after the first billing cycle for the following month of September
("September Adjustment"). Those Rate Adjustments shall then remain in effect until T
changed pursuant to the provisions of this Rider GFRP.

3. RESOLUTION OF DISPUTED ISSUES

In the event there is a dispute regarding any Evaluation Report, the Parties shall work together in good faith to resolve such dispute. If the Parties are unable to resolve the dispute by the end of the twenty-five (25) day period provided for in Section II.B.2 above, revised Rate Adjustments reflecting all revisions to the initially filed Rate Adjustments on which the Parties agree shall become effective as provided for in Section II.B.2 above. Any disputed issues shall be submitted to the Council for the setting of an Administrative Hearing before its designated Hearing Officer and a subsequent Resolution of the Council pursuant to the provisions of the Home Rule Charter.

If the Council's final ruling on any disputed issues requires changes to the September T
Adjustment referenced in Paragraph II.B.2 above, the Company shall file a revised Attachment A ("Final Adjustment") containing such further modified Rate Adjustments within fifteen (15) days after receiving the Council's order resolving the dispute. The Company shall provide a copy of the filing to the Council together with appropriate supporting documentation. Such modified Rate Adjustments shall then be implemented with the first billing cycle of the month after the date of the ruling if the ruling is received by the 5^{th} day of the month, otherwise, the modified Rate Adjustments shall then be implemented with the first billing cycle of the second subsequent month after the date of the ruling and shall remain in effect until superseded by Rate Adjustments established in accordance with the provisions of this Rider GFRP.

Within 60 days after receipt of the Council's final ruling on disputed issues, the Company
shall determine the amount to be refunded or surcharged to customers, if any, together
with interest at a Council mandated rate of interest. Such refund/surcharge amount shall
be based on customers' revenue from the first billing cycle of September of the filing year T
through the last date the interim Rate Adjustments were billed. Such refund/surcharge
amount shall be applied to customers' bills in the manner prescribed by the Council.

C. ANNUAL REDETERMINATION OF RATE ADJUSTMENTS

1. DEFINITION OF TERMS

a. EVALUATION PERIOD
The Evaluation Period shall be the twelve month period ended December 31 of the calendar year immediately preceding the filing. All data utilized in each Evaluation Report shall be based on actual results for the Evaluation Period as recorded as gas operations on the Company's books in accordance with the Uniform System of Accounts or such other documentation as may be appropriate.

b. EARNED RATE OF RETURN ON COMMON EQUITY
The Earned Return on Common Equity ("EROE") for any Evaluation Period shall be determined in accordance with the EROE formula set out in Attachment B. The EROE determination shall reflect the Evaluation Period adjustments set out in Attachment C.

c. BENCHMARK RATE OF RETURN ON RATE BASE
The Benchmark Rate of Return on Rate Base ("BRORB") shall be determined in accordance with the BRORB formula set out in Attachment D. The BRORB is the composite weighted embedded cost of capital reflecting the Company's annualized costs of Long-term Debt, Preferred Stock, and Common Equity as of the end of the Evaluation Period. The Debt ,Preferred Stock and Equity capitalization ratios, as set out in Attachment D, shall be the actual equity capitalization ratio as of December 31 of the calendar year immediately preceding the filing adjusted for financing activity. T

d. EVALUATION PERIOD COST RATE FOR COMMON EQUITY
The Evaluation Period Cost Rate for Common Equity ("EPCOE") is the Company's cost rate for common equity applicable to the Evaluation Period. The EPCOE value applicable for each Evaluation Period shall be determined in accordance with Attachment E.

e. ANNUALIZED EVALUATION PERIOD GFRP REVENUE
The Annualized Evaluation Period GFRP Revenue is the Rider GFRP Rider Rate Adjustment (Final Adjustment) in effect at the end of the Evaluation Period multiplied times the applicable Evaluation Period Billing Revenues.

f. TOTAL RIDER GFRP REVENUE
The Total Rider GFRP Revenue is the Annualized Evaluation Period GFRP Revenue plus the reduction/increase in Rider GFRP Revenue as calculated in Attachment F.

g. RATE OF RETURN ON COMMON EQUITY BANDWIDTH
The Rate of Return on Common Equity Bandwidth ("Bandwidth") shall be an Upper Band equal to the EPCOE plus 0.50% (50 basis points) and a Lower Band equal to the EPCOE minus 0.50% (50 basis points).

2. TOTAL RIDER GFRP REVENUE

In each Evaluation Period, the Total Rider GFRP Revenue level shall be determined using the Rider GFRP Revenue Redetermination Formula set out in Attachment F, which reflects the following rules:

a. If the EROE is less than the Lower Band, the ROE Adjustment shall be equal to the EPCOE minus the EROE.

b. If the EROE is greater than the Upper Band the ROE Adjustment shall be equal to the EPCOE minus the EROE.

c. There shall be no change in Rider GFRP Revenue level for the Evaluation Period if the EROE is less than or equal to the Upper Band and greater than or equal to the Lower Band.

3. RIDER GFRP REVENUE ALLOCATION

The Total Rider GFRP Revenue, as determined under the provisions of Section II.C.2, will be allocated to each applicable rate schedule based on an equal percentage of base rate revenue. This percentage will be developed by dividing the Total Rider GFRP Revenue by the total applicable base rate revenue, calculated pursuant to Attachment B.

4. RATE ADJUSTMENT REDETERMINATION

All applicable retail rate and rider schedules on file with the Council will be adjusted through Rider Schedule GFRP by the percentage as determined under Section II.C.3.

III. PROVISIONS FOR OTHER RATE CHANGES

A. EXTRAORDINARY COST CHANGES

It is recognized that from time to time ENOL may experience extraordinary increases or decreases in costs that occur as a result of actions, events, or circumstances beyond the control of the Company. Such costs may significantly increase or decrease the Company's revenue requirements and, thereby, require rate changes that this Rider GFRP is not designed to address. Should ENOL experience such an extraordinary cost increase or decrease having an annual revenue requirement impact exceeding $1 million on a total gas Company basis, then either the Company or the Council may initiate a proceeding to consider a pass-through of such extraordinary cost increase or decrease. T

B. SPECIAL RATE FILINGS

The Company is experiencing a changing business environment and increasing competition. Experimental, developmental, and alternative rate schedules may be appropriate tools for the Company to use to address these conditions. Therefore, nothing in this Rider shall be interpreted as preventing the Company from proposing, or requiring the Council to approve, any revisions to existing rate schedules or implement new rate schedules as may be appropriate. Any such rate changes shall be filed with the Council and evaluated in accordance with the rules and procedures then in effect.

C. FORCE MAJEURE

In addition to the rights of ENOL under this Rider, or as provided by law, to make a filing for the pass-through of costs outside the provisions of the Rider GFRP, if any event or events beyond the reasonable control of ENOL including natural disaster, damage or unforeseeable loss of generating capacity, changes in regulation ordered by a regulatory body or other entity with appropriate jurisdiction, and orders or acts of civil or military authority, cause increased costs to ENOL or result in a deficiency of revenues to ENOL which is not readily capable of being addressed in a timely manner under this Rider GFRP, ENOL may file for rate or other relief outside the provisions of the Rider GFRP. Such request shall be considered by the Council in accordance with applicable law governing such filings.

D. CHANGES IN TAX RATE T

In the event of a change in the state or federal corporate income tax rate(s) applicable to ENO, and/or any related changes to tax law, including, but not limited to changes that may affect the effective tax rate(s) and/or changes that may affect the treatment of accumulated deferred income tax, ENO shall include in the FRP Evaluation Report following the change in law, all relevant information for the Council to determine the effect on the revenue requirement and propose related ratemaking treatment to become effective as of the date of the change in law. T

IV. EFFECTIVE DATE AND TERM

Rider GFRP shall continue in effect for three years with annual Evaluation Report filings to be made on or before April 30 of 2020, 2021, and 2022 for the test years 2019, 2020, and 2021, respectively. The Rate Adjustments resulting from the April 30, 2022 Filing shall continue in effect until such time as new rates become effective pursuant to a final Council order. T T

ENTERGY NEW ORLEANS, LLC
GAS FORMULA RATE PLAN
FOR THE PERIOD ENDED DECEMBER 31, 20XX

TABLE OF CONTENTS to EVALUATION REPORT & WORKPAPERS

Effective XX-X-XX

ATTACHMENT A

ENTERGY NEW ORLEANS, LLC
GAS FORMULA RATE PLAN RIDER SCHEDULE GFRP-5 T
RATE ADJUSTMENTS
FOR THE TEST YEAR ENDED DECEMBER 31, 20XX T

The following Rate Adjustments will be applied to the rates set out in the monthly bills of Entergy New Orleans, LLC's ("ENOL") Rate Schedules identified below, or such additional rate schedules of ENOL subject to the Gas Formula Rate Plan Rider Schedule GFRP-5 that may become effective, but not including special contracts that do not specifically provide for the application of the Rider GFRP-5. The Rate Adjustments shall be effective for bills rendered on and after the first billing cycle of September of the filing year. T T T

The Net Monthly Bill calculated pursuant to each applicable retail rate schedule* on file with the City Council of the City of New Orleans will be adjusted monthly by a percentage of X.XXXX**%** before application of the monthly purchase gas adjustment except this Rider will not apply to the following: T

*Excluded Schedules: AMICG, Contract Minimums, GAFC, GIRP, GR-1, MGS and PGA. T

Base rates producing GFRP percent increases or decreases will be based upon Exhibit X to the Agreement in Principle in Docket UD-XX-XX. T T

Attachment B

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Entergy New Orleans, LLC
Formula Rate Plan
Earned Rate of Return on Common Equity Formula
Gas
For the Test Year Ended December 31, 20XX

Line No.	Description		Adjusted Amount
	TOTAL COMPANY		
1	RATE BASE	Att B, P 2, L 19	
2	BENCHMARK RATE OF RETURN ON RATE BASE	Att D, L 4, Col D	
3	REQUIRED OPERATING INCOME	L 1 * L 2	
4	NET UTILITY OPERATING INCOME	Att B, P 3, L 24	
5	OPERATING INCOME DEFICIENCY/(EXCESS)	L 3 - L 4	
6	REVENUE CONVERSION FACTOR (1)		
7	REVENUE DEFICIENCY/(EXCESS)	L 5 * L 6	
	PRESENT RATE REVENUES		
8	ULTIMATE CUSTOMERS	Att B, P 3, L 1	
9	REVENUE REQUIREMENT	L 7 + L 8	
10	PRESENT RATE REVENUES	Att B, P 3, L 1	
11	REVENUE DEFICIENCY/(EXCESS)	L 9 - L 10	
12	REVENUE CONVERSION FACTOR (1)	L6	
13	OPERATING INCOME DEFICIENCY/(EXCESS)	L 11/L 12	
14	RATE BASE	Att B, P 2, L 19	
15	COMMON EQUITY DEFICIENCY/(EXCESS)	L 13/L 14	
16	WEIGHTED EVALUATION PERIOD COST RATE FOR COMMON EQUITY (%)	Att D, L 3, Col D	
17	WEIGHTED EARNED COMMON EQUITY RATE (%)	L 16 - L 15	
18	COMMON EQUITY RATIO (%)	Att D, L 3, Col B	
19	EARNED RATE OF RETURN ON COMMON EQUITY (%)	L 17/L 18	

T

Notes:

(1) Revenue Conversion Factor = 1 / [(1 - Composite Tax Rate) * (1 - Bad Debt-Regulatory Commission Tax)]

Attachment B

T

Entergy New Orleans, LLC
Formula Rate Plan
Rate Base (A)
Gas
For the Test Year Ended December 31, 20XX

Line No.	Description	Per Books	Adjustments (B)	Adjusted Amount
1	PLANT IN SERVICE			
2	ACCUMULATED DEPRECIATION			
3	**NET UTILITY PLANT** (L1+ L2)			
4	PLANT HELD FOR FUTURE USE			
5	CONSTRUCTION WORK IN PROGRESS (C)			
6	MATERIALS AND SUPPLIES (D)			
7	PREPAYMENTS (D)			
8	CUSTOMER ADVANCES			
9	CUSTOMER DEPOSITS			
10	PROVISION FOR PROPERTY INSURANCE RESERVE (D)			
11	PROVISION FOR INJURIES & DAMAGES RESERVE (D)			
12	GAS STORED UNDERGROUND (D)			
13	ACCUMULATED DEFERRED INCOME TAXES			
14	ACCUMULATED DEFERRED ITC PRE-1971-NET			
15	CASH WORKING CAPITAL (E)			
16	OTHER (F) (G)			
17	NET UNAMORTIZED UNRECOVERED GENERAL PLANT			
18	PENSION LIABILITY EXCLUDING SFAS 158			
19	**RATE BASE** (L3 + Sum of L4 through L18)			

Notes:
(A) Ending balances are to be utilized except where otherwise noted
(B) Adjustments as set out in Attachment C to this rider GFRP. See Section 6 for the Adjustments Summary. See Section 10 for the Adjustment Workpapers.
(C) Amount not subject to AFUDC accrual
(D) 13-month average balances
(E) Cash Working Capital is deemed to be zero.
(F) Other items included pursuant to Section 6 of Attachment C
(G) Beginning & Ending or 13-mos average as more appropriate.

Attachment B

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Entergy New Orleans, LLC
Formula Rate Plan
Operating Income
Gas
For the Test Year Ended December 31, 20XX

Line No.	Description	Per Books	Adjustments (A)	Adjusted Amount
	REVENUES			
1	SALES TO ULTIMATE CUSTOMERS			
2	OTHER GAS REVENUE			
3	TOTAL OPERATING REVENUES (L1 + L2)			
	EXPENSES			
	GAS OPERATION & MAINTENANCE			
4	PRODUCTION -- GAS PURCHASES			
5	TRANSMISSION			
6	DISTRIBUTION			
7	CUSTOMER ACCOUNTING			
8	CUSTOMER SERVICE & INFORMATION			
9	SALES			
10	ADMINISTRATIVE & GENERAL			
11	TOTAL GAS O&M EXPENSES (Sum of L4 - L10)			
12	GAIN FROM DISPOSITION OF ALLOWANCES			
13	REGULATORY DEBITS & CREDITS (C)			
14	DEPRECIATION & AMORTIZATION EXPENSES			
15	INTEREST ON CUSTOMER DEPOSITS			
16	TAXES OTHER THAN INCOME			
17	STATE INCOME TAX			
18	FEDERAL INCOME TAX			
19	PROV DEF INC TAX - STATE – NET			
20	PROV DEF INC TAX - FED – NET			
21	INVESTMENT TAX CREDIT			
22	OTHER (B)			
23	TOTAL UTILITY OPERATING EXPENSES (Sum of L11 - L22)			
24	**NET UTILITY OPERATING INCOME** (L 3 - L 23)			

Notes:
(A) Adjustments defined in Attachment C
(B) Other items included pursuant to Section 6 of Attachment C
(C) Including, but not limited to, the amortization of regulatory assets and liabilities established in the Agreement in Principle in UD-XX-XX.

Attachment B

T

ENTERGY NEW ORLEANS, LLC
Formula Rate Plan
INCOME TAX
GAS
For the Test Year Ended December 31, 20XX

Line No.	Description	Reference	Per Books	Adjustments (A)	Adjusted Amount
1	TOTAL OPERATING REVENUES	Att B, P 3, L 3			
2	TOTAL O&M EXPENSE	Att B, P 3, L 11			
3	GAIN FROM DISPOSITION OF ALLOWANCES	Att B, P 3, L 12			
4	REGULATORY DEBITS & CREDITS	Att B, P 3, L 13			
5	DEPRECIATION & AMORTIZATION EXPENSE	Att B, P 3, L 14			
6	INTEREST ON CUSTOMER DEPOSITS	Att B, P 3, L 15			
7	TAXES OTHER THAN INCOME	Att B, P 3, L 16			
8	NET INCOME BEFORE INCOME TAXES	L1 - Sum of L2 through L7			
9	ADJUSTMENTS TO NET INCOME BEFORE TAXES				
10	TAXABLE INCOME	L8 + L9			
	COMPUTATION OF STATE INCOME TAX				
11	STATE TAXABLE INCOME	L10			
12	STATE ADJUSTMENTS				
13	TOTAL STATE TAXABLE INCOME	L11 + L12			
14	STATE INCOME TAX BEFORE ADJUSTMENTS (B)	L13 * Eff. Tax Rate			
15	ADJUSTMENTS TO STATE TAX				
16	**STATE INCOME TAX**	L14 + L15			
	COMPUTATION OF FEDERAL INCOME TAX				
17	TAXABLE INCOME	L10			
18	STATE INCOME TAX BEFORE ADJUSTMENTS (B)	L14 as deduction			
19	FEDERAL ADJUSTMENTS				
20	TOTAL FEDERAL TAXABLE INCOME	Sum of L17 through L19			
21	FEDERAL INCOME TAX BEFORE ADJUSTMENTS (B)	L 20 * Eff. Tax Rate			
22	ADJUSTMENTS TO FEDERAL TAX				
23	**FEDERAL INCOME TAX**	L21 + L22			

Notes:
(A) Adjustments as defined in Attachment C.
(B) The Tax Rate in effect at the time the Evaluation Report is filed shall be utilized.

Attachment C

ENTERGY NEW ORLEANS, LLC

EVALUATION PERIOD ADJUSTMENTS

The actual (per book) data for each Evaluation Period, as reflected in Attachment B, shall be adjusted to reflect the following:

1. Rate Annualization Adjustment

A) Present base rate revenue shall be adjusted to reflect, on an annualized basis, the Rate Adjustment in effect at the end of the Evaluation Period under this Rider GFRP.

B) The rate base, revenue and expense effects associated with any riders, or other rate mechanisms, that ENOL may have in effect during the Evaluation Period, which recover specific costs are to be eliminated.

2. Interest Synchronization

All Evaluation Period Interest expenses are to be eliminated and replaced with an imputed interest expense amount equal to the Evaluation Period rate base multiplied by the weighted embedded cost of debt for the Evaluation Period determined in accordance with Attachment D.

3. Income Taxes

All state and federal income tax effects including 1) adjustments to taxable income, 2) adjustments to current taxes, 3) provisions for deferred income tax (debit and credit), and 4) accumulated provision for deferred income tax (debit and credit) shall be adjusted or eliminated, as appropriate, to comport with the following principles:

A) Effects associated with other adjustments set out in this Attachment C shall similarly and consistently be adjusted;

B) All effects associated with the difference in the timing of transactions, where the underlying timing difference is eliminated, shall also be eliminated;

C) The corporate state and federal income tax laws legally in effect on the date an Evaluation Report is filed under this GFRP Rider shall be reflected in the calculation of all income tax amounts; and

D) Tax effects normally excluded for ratemaking purposes shall be eliminated.

4. Ratemaking Adjustments for Evaluation Report Based on Test Year 2019 T

A) Present base rate revenue shall be adjusted to reflect, on an annualized basis, the rate actions resulting from the Combined T
Rate Case, Council Docket No. UD-XX-XX. T

B) The depreciation expense associated with Plant in Service shall be annualized. T

C) The amortization of any regulatory assets authorized in the Combined Rate Case shall be annualized. T

D) The expense credit associated with amounts expensed prior to 2019 but included in any regulatory assets authorized in the Combined Rate Case shall be eliminated. T

E) Extraordinary Cost Change T

5. Ratemaking Adjustments for Evaluation Report Based on Test Years 2020 and 2021

A) Extraordinary Cost Change

6. Reclassifications

Costs not allowable for ratemaking purposes shall be removed by adjustment from the Evaluation Period cost data. Likewise, costs that are allowed, but recorded below the utility operating income line, shall be included in the Evaluation Period cost data through appropriate reclassification adjustments. These adjustments shall include, but are not limited to the reclassification of below-the-line interest expense associated with customer deposits as interest on customer deposits expense.

7. Out-of-Period Items

Expenses and revenues recorded in any Evaluation Period that are related to transactions occurring prior to the Evaluation Period used in the first Evaluation Report shall be eliminated by adjustment from the Evaluation Period cost data. This shall include any associated tax adjustments.

8. Other

In addition to Adjustments 1 through 7 above, there may, from time-to-time, be special costs or rate effects that occur during an Evaluation Period that require adjustments of the Evaluation Period cost data. Nothing in this Rider GFRP shall preclude any Party from proposing such adjustments.

Attachment D

ENTERGY NEW ORLEANS, LLC
Formula Rate Plan
BENCHMARK RATE OF RETURN ON RATE BASE
GAS
For the Test Year Ended December 31, 20XX

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	Description	(A) Capital Amount (1) ($)	(B) Capital Ratio (%)	(C) Cost Rate (2) (%)	(D) Benchmark Rate of Return on Rate Base(3)
1	LONG-TERM DEBT				
2	PREFERRED EQUITY				
3	COMMON EQUITY				
4	TOTAL		100.%		

Notes:

(1) Amounts at the end of the Evaluation Period as adjusted for refinancing activities. All Long-Term Debt issues shall reflect the balance net of a) unamortized debt discount, premium, and expense; b) gain or loss on reacquired debt; and c) any adjustments required per Attachment C. All Preferred Stock issues shall reflect the balance net of discount, premium and capital stock expense. The Affiliate Notes shall be excluded from the calculation of the BRORB.

(2) Annualized cost of Long-Term Debt and Preferred Equity at the end of the Evaluation Period divided by the corresponding Capital Amount. The Long-Term Debt Cost Rates shall include a) annualized amortization of debt discount, premium, and expense; b) annualized gain or loss on reacquired debt; and c) any adjustments required per Attachment C. The Common Equity Cost Rate shall be the Evaluation Period Cost Rate for Common Equity (EPCOE) determined in accordance with Attachment E.

(3) The components of the BRORB column are the corresponding Cost Rates multiplied by the associated Capital Ratio. The BRORB is the sum of the components so determined and expressed as a % to two decimal places (XX.XX%).

Attachment E

ENTERGY NEW ORLEANS, LLC

EVALUATION PERIOD COST RATE FOR COMMON EQUITY PROCEDURE

EVALUATION PERIOD COST RATE FOR COMMON EQUITY

The EPCOE applicable for any Evaluation Report pursuant to this Rider GFRP shall be 10.75%.

Attachment F

ENTERGY NEW ORLEANS, LLC
Formula Rate Plan
RIDER FRP REVENUE REDETERMINATION FORMULA
GAS
For the Test Year Ended December 31, XXXX

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SECTION 1

BANDWIDTH CHECK

Line No.	DESCRIPTION	REFERENCE	
1	Earned Rate of Return on Common Equity ("EROE")	Attachment B, P 1, L 19	
2	Evaluation Period Cost Rate for Common Equity ("EPCOE")	Developed per Attachment E	
3	Upper Band ROE	L2 + 50 basis points	
4	Lower Band ROE	L2 – 50 basis points	

SECTION 2

ROE BAND RATE ADJUSTMENT

Line No.	DESCRIPTION	REFERENCE	
5	Earned Rate of Return on Common Equity	L1	
6	ROE Adjustment if Earnings Above Upper Band ROE	If L1 > L3, then Adjustment = L2 - L1, but no adjustment if L1 ≤ L3.	
7	ROE Adjustment if Earnings Below Lower Band ROE	If L1 < L4, then Adjustment = L2 - L1, but no adjustment if L1 ≥ L 4	
8	Common Equity Capital Ratio	Attachment D, L3, Column B	
9	Rate Base	Attachment B, P1, L1	
10	Revenue Conversion Factor	Attachment B, P1, L 6	
11	Total Change in Rider GFRP Revenue	(L6 or L7) * L8 * L9 * L10	

SECTION 3

TOTAL BAND RATE ADJUSTMENT

Line No.	DESCRIPTION	REFERENCE	
12	Annualized Evaluation Period GFRP Revenue (1)		
13	Change in Rider GFRP Revenue	L11	
14	Extraordinary Cost Change Revenue Requirement	Per Sec. III.A of the Tariff	
15	Total Rider GFRP Revenue (2)	L12 + L13 + L14	

Note:
(1) Rider GFRP Rate Adjustments, excluding outside-the-bandwidth adjustments, in effect at the end of the applicable Evaluation Period multiplied by the applicable Evaluation Period revenues.
(2) The Total Rider GFRP Revenue reflects the total credit or surcharge to be applied to customer bills based on the results of the Rider GFRP Redetermination Formula.

ENTERGY NEW ORLEANS, LLC
ELECTRIC SERVICE

RIDER SCHEDULE MISO-1

Effective Date: July 31, 2019
Filed Date: September 2018
Supersedes: MISO effective 12/1/17
Schedule Consists of: Three Pages plus Attachments A - B

MISO COST RECOVERY RIDER

I. GENERAL

The MISO Cost Recovery Rider ("Rider Schedule MISO") or ("MISO Rider") defines the procedure by which Entergy New Orleans, LLC ("ENOL" or "Company") shall implement and adjust rates contained in the rate classes designated in Attachment A to this MISO Rider for recovery of the costs designated in Sections II.B. and II.C. below, including but not limited to costs charged to ENOL pursuant to the Midcontinent Independent System Operator, Inc. ("MISO") Federal Energy Regulatory Commission ("FERC")-approved Open Access Transmission Energy and Operating Markets Tariffs that are not recovered via the Fuel Adjustment Clause as ordered by the Council of the City of New Orleans ("Council") in Council Resolution R-15-139. The MISO Rider shall apply in accordance with the provisions of Section II.A below to all electric service billed under the rate schedules, whether metered or unmetered, and subject to the jurisdiction of the Council. Nothing in this MISO Rider should be considered precedent for ratemaking, legal or policy purposes.

II. APPLICATION AND REDETERMINATION PROCEDURE

A. MISO RIDER RATES

The rates associated with the MISO Rider ("MISO Rider Rates") as set forth on Attachment A shall be derived by the formula set out in Attachment B to this MISO Rider ("MISO Cost Recovery Rider Rate Formula"). The MISO Rider Rates shall be added to the rates set out in the Net Monthly Bill section in the Company's rate schedules. The MISO Rider Rates shall be determined in accordance with the provisions of this MISO Rider and shall be subject to Annual Updates. T

B. MISO RIDER COSTS

The MISO Rider Rates shall be based on the following. T

B.1 NET MISO CHARGES OR CREDITS

The estimated Net MISO Charges/(Credits) as reflected on Attachment B that the Company expects to incur for the twelve (12) months ended June 30 of the calendar year of the filing and that are not recovered via the Fuel Adjustment Clause as ordered by the Council in Resolution R-15-139, shall be recovered through this MISO Rider.

The estimate used to determine the amount of Net MISO Charges/(Credits) for the 2020 and subsequent Annual Updates will be based on Actual ENOL Accounting Data for the nine months ending March 31 of the filing year plus estimated amounts for ENOL for the months April through June of the filing year. Attachment B, Pages 2 and 3 will apply in determining all such Annual Updates. T T T T

B.2 [RESERVED] T T

B.3 LINE OF CREDIT FEES

The estimated costs associated with line of credit fees used in the initial MISO Rider and Annual Updates shall be the amount the Company expects to incur for the twelve (12) months ended May 31 for the subsequent MISO Planning Year.

B.4 PLANNING RESOURCE AUCTION ("PRA")

The estimated net PRA revenues/expenses used in the initial MISO Rider and Annual Updates shall be the amount that the Company expects for the twelve (12) months ended May 31 for the subsequent MISO Planning Year.

B.5 TRUE-UP ADJUSTMENT

In the 2021 and all subsequent filings, a True-up Adjustment shall be made for the difference between the actual MISO Cost Recovery Revenue Requirement for the twelve (12) months ending on March 31 of the filing year and the actual MISO Rider Revenues collected during the twelve (12) months ending on March 31 of the filing year as defined on Attachment B, Page 4. The True-up Adjustment shall include carrying charges based on the then current Louisiana Judicial Rate of Interest applied to the average balance of the Total True-Up Adjustment Before Interest as shown on Attachment B, Page 4.

C. ANNUAL UPDATE

C.1 FILING DATE

On or about May 31, beginning in 2020, the Company shall file a redetermination of the MISO Rider Rates by filing updated versions of Attachments A and B with supporting workpapers and documentation. The Annual Update filing will include a True-up Adjustment as calculated on Attachment B, Page 4.

C.2 MISO RIDER EFFECTIVE DATE

The MISO Rider Rates so determined shall be effective for bills rendered on and after the first (1st) billing cycle of July of the filing year and shall remain in effect until superseded.

D. REVIEW PERIOD & EFFECTIVE DATE

The Council Advisors ("Advisors"), intervenors, and the Company (collectively, the "Parties") shall have fifteen (15) days to ensure that the Annual Update filing complies with the requirements of Sections II.B and II.C above. If any of the Parties should detect any error(s) in the application of the principles and procedures contained in Sections II.B or II.C, such error(s) shall be formally communicated in writing to the other Parties within the same 15 days. Each such indicated dispute shall include, if available, documentation of the proposed correction. The Company shall then have fifteen (15) days to review any proposed corrections, to work with the other Parties to resolve any disputes, and to file a revised Attachment A reflecting all corrections upon which the Parties agree. The Company shall provide the other Parties with appropriate workpapers supporting any revisions made to the MISO Rider Rates initially filed.

Except where there are unresolved disputes, which shall be addressed in accordance with the provisions of Section II.E below, the MISO Rider Rates initially filed under the provisions of Sections II.B or II.C above shall become effective for bills rendered on and after the first billing cycle for the month of July of the filing year. Those MISO Rider Rates shall then remain in effect until changed pursuant to the provisions of this MISO Rider.

E. RESOLUTION OF DISPUTES

In the event there are disputes regarding the annual filing, the Parties shall work together in good faith to resolve such disputes. If the Parties are unable to resolve the disputes or reasonably believe they will be unable to resolve the disputes by the end of the 30 day period provided for in Section II.D above, revised MISO Rider Rates reflecting all revisions to the initially filed MISO Rider Rates on which the Parties agree shall become effective as provided for in Section II.D above. Any remaining disputes shall be submitted to the Council for resolution.

If the Council's final ruling on any disputes requires changes to the MISO Rider Rates initially implemented pursuant to the above provisions, the Company shall file a revised Attachment A containing such further modified MISO Rider Rates within fifteen (15) days after receiving the Council's resolution resolving the disputes. The Company shall provide a copy of the filing to the other Parties together with appropriate supporting documentation. Such modified MISO Rider Rates shall then be implemented with the next applicable monthly billing cycle after said filing and shall remain in effect until superseded by MISO Rider Rates established in accordance with the provisions of this MISO Rider.

Within sixty (60) days after receipt of the Council's final ruling on any disputes, the Company shall determine the amount to be refunded or surcharged to customers, if any, together with interest at the Louisiana Judicial rate as of the date of the annual filing. Such refund/surcharge amount shall be included in the MISO Rider True-up and contained in the next annual redetermination.

F. MISO RIDER REVENUE REQUIREMENT ALLOCATION

The MISO Cost Recovery Revenue Requirement, as stated on Attachment B, Page 2, Line T
13, as determined under the provisions of Sections II.B and II.C above, shall be allocated to T
each of the applicable ENOL rate classes based on the applicable class Transmission
Demand Allocation Factor as a percentage of total Transmission Demand for all rate T
schedules pursuant to Attachment A.

G. MISO RIDER ANNUAL RATE REDETERMINATION

The applicable class retail rates and riders as noted on Attachment A on file with the City of New Orleans shall be adjusted by the applicable class percentage of applicable base rate revenue.

III. INTERIM ADJUSTMENT

If the cumulative MISO Rider True-up Balance exceeds 10% of the annual Net MISO Rider Revenue Requirement included in the most recently filed MISO Rider, then the Advisors or the Company may propose an interim adjustment of the MISO Rider Rates.

IV. TERM

The MISO Rider shall remain in effect until otherwise terminated by a Council resolution, subject to three (3) months advance notice of termination by the Council following reasonable notice and opportunity for hearing. If the MISO Rider is terminated by mutual agreement of the Council and the Company, or if this MISO Rider is terminated by a future Council resolution, the then-existing MISO Rider Rates shall continue to be in effect until new rates reflecting the then-existing MISO Rider Rates are duly approved and implemented. The recovery of any increases or decreases in MISO T
Rider costs subsequent to the last approved filing will also be realigned to base rates or an applicable rider as appropriate. Nothing contained in this MISO Rider shall limit the right of any party to file an appeal as provided by law.

Effective:

ENTERGY NEW ORLEANS, LLC
MISO RIDER RATE FORMULA
MISO RIDER RATE ADJUSTMENTS
JULY 20XX T

I. APPLICABILITY

This rider is applicable under the regular terms and conditions of the Company to all Customers served under any retail electric rate schedule * and/or rider schedule.*

II. NET MONTHLY RATE

The Net Monthly Bill or Monthly Bill calculated pursuant to each applicable retail rate schedule* and/or rider schedule* on file with the City of New Orleans will be adjusted monthly by the appropriate percentage of applicable class base rate revenue, before application of the monthly fuel adjustment.

* Excluded Schedules: AFC, AMICE, BRAR, CSO, DGM, DSMCR, DTK, EAC, EECR, EFRP, EVCI, FAC, FBO, GPO, MES, PPCACR, PPS, R-3, R-8, RPCEA, SMS, SSCO and SSCR T

Ln No.	Rate Class (1)	**MISO Rider Rates (2)**
1	Residential	
2	Small Electric	
3	Municipal Buildings	
4	Large Electric	
5	Large Electric High Load Factor	
6	Master Metered Non Residential	
7	High Voltage	
8	Large Interruptible	
9	Lighting	

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Notes:
(1) Excludes schedules specifically identified on Attachment A above of this MISO Rider.
(2) See Attachment B, Page 1, Col E

Entergy New Orleans, LLC
MISO Rider
MISO Cost Recovery Revenue Requirement Formula
Rate Adjustments - 2020

T

Ln No.	Col A Rate Class (1)	Col B MISO Cost Recovery Revenue Requirement (MCRRR) Class Allocation (%) (2)	Col C MCRRR ($) (3)	Col D Applicable Base Rate Revenue ($) (4)	Col E MISO Rider Rates (5)
1	Residential				
2	Small Electric				
3	Municipal Buildings				
4	Large Electric				
5	Large Electric High Load Factor				
6	Master Metered Non Residential				
7	High Voltage				
8	Large Interruptible				
9	Lighting				
10	Total ENO				

Notes:

(1) Excludes schedules specifically identified on Attachment A, Page 1 of this MISO Rider.

(2) The MISO Cost Recovery Revenue Requirement (MCRRR) shall be allocated to the retail rate classes based on the Transmission Demand Allocation Factor, i.e., the 12 CP allocation factors from the 2018 Rate Case Proceeding. For subsequent redeterminations, the Class Allocation shall be made consistent with the methodology approved in the 2018 Rate Case Proceeding pursuant to Section II.F of this MISO Rider.

(3) See Attachment B, Page 2, Line 13 for the MCRRR. The class amount is the Class Allocation % in Col B times the MCRRR.

(4) The billing determinants (Col D) shall be the ENO Base Rate Revenue applicable to this MISO Rider as approved by the Council in the 2018 Rate Case Proceeding. For subsequent redeterminations the applicable base rate revenue/billing determinates (Col D) shall be the base rate revenue for the Annual true-up period per Section II.B.5 of this MISO Rider.

(5) Class Total MISO Cost Recovery Revenue Requirement (Col C) divided by Class Billing Determinants (Col D).

Entergy New Orleans, LLC
MISO Rider
MISO Cost Recovery Revenue Requirement Formula (1)
For the Twelve Months ended June 30, 20xx (2)
($000'S Omitted)

T

Ln No.	Description	ENO Combined Amount	Reference
	Net MISO Charges/(Credits)		
1	Schedule 10 Invoice	-	Att B Page 3, L6
2	Non-TO Trust Invoice	-	Att B Page 3, L12
3	TO-Trust Invoice	-	Att B Page 3, L19
4	Sch. 31 - Reliability Coordination Service Cost Recovery Adder	-	Att B Page 3, L20
5	Administrative Costs related to Market Settlements	-	Att B Page 3, L21
6	Other MISO Settlements	-	Att B Page 3, L22
7	MISO-related Line of Credit Fee	-	Att B Page 3, L23
8	Planning Resource Auction Costs	-	Att B Page 3, L24
9	**Total ENO Net MISO Charges/(Credits)**	**-**	Sum of Lines 1 - 8
10	Revenue Related Expense Factor (3)		
11	**ENO Net MISO Costs to be Recovered**	**-**	L9 * L10
12	True-up of MISO Cost Recovery Revenue Requirement (MCRRR)	-	Att B Pg 4, L16
13	**MISO Cost Recovery Revenue Requirement (MCRRR)**	**-**	L11 + L12

Notes:
(1) Pursuant to Section II.B of this MISO Rider
(2) Amounts consist of 9 months of actual data and 3 months of forecasted data.
(3) Revenue Related Expense Factor = 1 / (1-ENO Retail Bad Debt Rate). The ENO Bad Debt Rate shall be developed consistent with the methodology used for calculating it in the most recent ENO general rate case and shall use the most recently available calendar year data at the time of filing.

Entergy New Orleans, LLC
MISO Rider
MISO Cost Recovery Revenue Requirement Formula (1)
For the Twelve Months ended June 30, 20xx (2)
($000'S Omitted)

T

Ln No.	Description		ENO Combined Amount	Reference
	Schedule 10 Invoice			
1	Schedule 10	ISO Cost Recovery Adder		
2	Sch. 10 - FERC	FERC Annual Charges Recovery		
3	Schedule 23	Recovery of Sch. 10 & Sch. 17 Costs from Certain GFAS		
4	Schedule 34	Allocation of Costs Associated With Penalty Assessments (3)		
5	Schedule 35	HVDC Agreement Cost Recovery Fee		
6	**Total Schedule 10 Invoice**		**0**	Sum of Lines 1 - 5
	Non-TO Trust Invoice			
7	Schedule 1	Scheduling, System Control, and Dispatch Service		
8	Schedule 2	Reactive Power		
9	Schedule 11	Wholesale Distribution Services (4)		
10	Schedule 15	Power Factor Correction Service		
11	Schedule 20	Treatment of Station Power		
12	**Total Non-TO Trust Invoice**		**0**	Sum of Lines 7-11
	TO-Trust Invoice			
13	Schedule 7	Long & Short-Term Firm Point-To-Point Trans. Service		
14	Schedule 8	Non-Firm Point-To-Point Transmission Service		
15	Schedule 9	Network Integration Transmission Service		
16	Schedule 26	Network Upgrade Charge From Trans. Expansion Plan		
17	Schedule 26-A	Multi-Value Project Usage Rate		
18	Schedule 33	Blackstart Service		
19	**Total TO-Trust Invoice**		**0**	Sum of Lines 13-18
20	**Schedule 31 - Reliability Coordination Service Cost Recovery Adder**			
21	**Administrative Costs related to Market Settlements**			
22	**Other MISO Settlements (5)**			
23	**MISO-related Line of Credit Fees**			
24	**Planning Resource Auction Costs**			

T

Notes:
(1) Pursuant to Section II.B of this MISO Rider
(2) Amounts consist of 9 months of actual data and 3 months of forecasted data.
(3) Cost associated with potential future NERC penalties could show up under Schedule 10 Invoice or Market Settlements.
(4) Includes Wholesale Distribution Services, Prior Period Adjustments and Other.
(5) Other MISO Settlements are defined as MISO Schedules 41 - Storm Securitization, 42a - Accrued Interest Recovery, and 42b - AFUDC Amortization.

Entergy New Orleans, LLC
MISO Rider
MISO Cost Recovery Revenue Requirement Formula (1)
True-up of MISO Cost Recovery Revenue Requirement
For the Period ended March 31, 20xx
($000'S Omitted)

Ln No.	Description	ENO Combined Amount	Reference
	Actual Net MISO Charges/(Credits)		
1	Schedule 10 Invoice		
2	Non-TO Trust Invoice		
3	TO-Trust Invoice		
4	Sch. 31 - Reliability Coordination Service Cost Recovery Adder		
5	Administrative Costs related to Market Settlements		
6	Other MISO Settlements		
7	MISO-related Line of Credit Fee		
8	Planning Resource Auction Costs		
9	**Total ENO Combined Net MISO Charges/(Credits)**	**-**	Sum of Lines 1 - 8
10	Revenue Related Expense Factor (2)		
11	**Actual MISO Cost Recovery Revenue Requirement**	**-**	L9 * L10
12	**Actual MISO Rider Revenue**		
13	**Difference in Actual MISO Cost Recovery Revenue Requirement and Actual MISO Rider Revenue**	**0**	L11 - L12
14	**Louisiana Judicial Rate of Interest**	X%	Section II.B.5 of this MISO Rider
15	**Carrying Cost**		(L13/2) * L14
16	**True-up of MISO Cost Recovery Revenue Requirement**	**0**	L13 + L15

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Notes:
(1) Pursuant to Section II.B of this MISO Rider
(2) See Attachment B, Page 2 Note (3)

ENTERGY NEW ORLEANS, LLC
ELECTRIC SERVICE

RIDER SCHEDULE PPCACR

Effective: July 31, 2019
Filed: September 2018
Supersedes: PPACCR Effective 12/1/17
Schedule Consists of: Three Pages plus Attachment A and B

PURCHASED POWER AND CAPACITY ACQUISITION COST RECOVERY RIDER

I. GENERAL

The purpose of the Purchased Power and Capacity Acquisition Cost Recovery Rider ("Rider Schedule PPCACR") or ("PPCACR Rider") is to provide contemporaneous cost recovery by Entergy New Orleans, LLC ("ENO" or "Company") of the capacity costs associated with any new Purchased Power Agreement ("PPA") or Long-Term Service Agreement ("LTSA") authorized by the Council of the City of New Orleans ("CNO") other than the PPA's listed in Paragraph 4 below, and any new capacity addition, including non-generating storage capacity, owned by ENO either through purchase or construction. The fuel and variable costs associated with the PPA and/or the acquired or constructed capacity addition shall be recovered through Rider Schedule FAC. T T T T T

II. AVAILABILITY

At all points throughout the territory served by the Company where facilities of adequate capacity and suitable phase and voltage are adjacent to the premises to be served, and service is taken according to the Service Standards and Service Regulations of the Company. T

III. APPLICABILITY

This Rider is applicable under the regular terms and conditions of the Company to all Customers that are served under applicable retail electric rate schedules, whether metered or unmetered, and/or rider schedules subject to the jurisdiction of the CNO. T

IV. NEW PPAs AND LTSAs AND CAPACITY ACQUISTIONS AND SCHEDULE A T

The PPCACR Rider is intended to recover the entirety of (1) the capacity expenses associated with new PPAs entered into by ENO and expenses associated with new LTSAs after the effective date of this version of the rider and (2) the non-fuel revenue requirement associated with capacity acquisitions acquired or constructed by ENO after the effective date of this version of the rider. T

For the existing PPAs and LTSAs listed in this paragraph below, only the difference between the actual associated expenses and the estimated associated expenses included in Schedule A to this rider shall be recovered through the PPCACR Rider as authorized by the CNO in Docket No. UD-XX-XX. The PPAs are as follows: the Ninemile 6 PPA approved in CNO Resolution R-12-29, dated February 2, 2012, and the Algiers PPA approved by the CNO in Resolution R-15-194, dated May 14, 2015. The LTSAs are associated with the following units: Union Station Power Block 1, Ninemile 6, Perryville Station, and Acadia Station. T T T T T T T

V. RIDER RATE

A. The Rider PPCACR Rate shall be determined as set forth in Attachment A and Attachment B to this Rider PPCACR. T

The Rider PPCACR Rate will include an over / under recovery computation. This computation will be made in accordance with Attachment B. The over / under recovery computations will include interest on the average of the balances existing at the beginning and end of the current operating month. The interest rate to be utilized is the prime bank lending rate as published in the Wall Street Journal on the last business day of each month. T

B. (1) The Rider PPCACR Rate shall include the estimated monthly non-fuel revenue requirement associated with acquired or constructed capacity addition, including non-generating storage capacity. For the initial estimated monthly revenue requirement shall be the amount determined by the Council. T T

For each calendar year subsequent to the calendar year of the addition, the Company shall update the estimated monthly revenue requirement associated with the addition. Contemporaneously with the October Billing Month Rider PPCACR Filing of each year, the Company shall file a new estimated monthly revenue requirement, which will be based on forecasted information for the following calendar year and which will be used beginning in the first billing cycle of the following January. T

Beginning in calendar year subsequent to any addition, the Company contemporaneously shall file with the May Billing Month Rider PPCACR Filing a computation to true-up the estimated monthly revenue requirement for the previous calendar year to the actual revenue requirement for that calendar year. The difference plus interest calculated using the rate set forth in Paragraph A above shall be included as a Prior Period Adjustment in the over / under recovery computation in the June Billing Month Rider PPCACR Filing. T

(2) The Rider PPCACR Rate shall include the actual monthly revenue requirement calculated as the difference between the approved monthly Schedule A PPA and LTSA amount and the actual amount for the operations month. T

(3) The Rider PPCACR Rate shall include the actual monthly revenue requirement for any approved new PPA or LTSA for the operations month. T

C. The Rider PPCACR Revenue Requirement will be allocated to the Rate Classes based on the allocation of the Base Rate Revenue Requirement approved by the Council in Docket No. UD-18-XX. The Rider PPCACR Rates will be calculated for each Rate Class by dividing the Rate Class Rider PPCACR Revenue Requirement by the estimated Rate Class Base Rate Revenue for the applicable billing month. T

VI. CORRECTION OF ERRORS IN PRIOR PERIODS

The Company is obligated to correct filing errors in prior period Rider PPCACR Filings. Filing errors are differentiated from vendor invoice errors or changes that occur on a continuing basis that are simply corrected in the then-current operating month’s fuel costs. Filing errors in prior period filings shall be described and quantified in a supplemental report in the current operating month filing. Correction of the errors will be through an addition or subtraction to the cumulative over / under recovery balance absent other direction from the CNO. The correction of the error should include interest from the effective date of the error through the effective date of the correction pursuant to Section V above.

VII. TERM

The Rider PPCACR rates associated with acquired or constructed capacity and new PPA's shall T
terminate the last day of the month prior to the implementation of base or Formula Rate Plan T
rates recovering the capacity costs previously recovered through the rider. T

Upon termination of the entire Rider PPCACR, the Rider PPCACR true-up balance at the date of T
termination will be included in Attachment A, Page X, Line XX of the then-effective Rider T
Schedule FAC as a Prior Period Adjustment to the Cumulative (Over)/Under Collection Account.

ENTERGY NEW ORLEANS LLC
PPCACR RIDER RATE FORMULA
PPCACR RIDER RATE ADJUSTMENTS
MONTH XXX 20XX T

I. APPLICABILITY

This rider is applicable under the regular terms and conditions of the Company to all Customers served under any retail electric rate schedule * and/or rider schedule.*

II. NET MONTHLY RATE

The Net Monthly Bill or Monthly Bill calculated pursuant to each applicable retail rate schedule* and/or rider schedule* on file with the City of New Orleans will be adjusted monthly by the appropriate percentage of applicable class base rate revenue, before application of the monthly fuel adjustment.

* Excluded Schedules: AFC, AMICE, BRAR, CSO, DGM, DSMCR, DTK, EAC, EECR, EFRP, EVCI, FAC, FBO, GPO, MES, MISO, PPS, R-3, R-8, RPCEA, SMS, SSCO and SSCR

Entergy New Orleans LLC
Rider PPCACR
PPCACR Rider Rate Formula
Rate Adjustments - MONTH XXX 20XX

Ln No.	Rate Class (1)	**Rider PPCACR Rates (2)**
1	Residential	
2	Small Electric	
3	Municipal Buildings	
4	Large Electric	
5	Large Electric High Load Factor	
6	Master Metered Non Residential	
7	High Voltage	
8	Large Interruptible	
9	Lighting	

Notes:
(1) Excludes schedules specifically identified on Attachment A above of this Rider PPCACR.
(2) See Attachment B, Page 1, Col E

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Entergy New Orleans LLC
Rider PPCACR
Rider PPCACR Revenue Requirement Formula
Rate Adjustments - MONTH XXX 20XX

Ln No.	Col A Rate Class (1)	Col B Rider PPCACR Revenue Requirement (PPCACRRR) Class Allocation (%) (2)	Col C PPCACRRR ($) (3)	Col D Applicable Base Rate Revenue ($) (4)	Col E Rider PPCACR Rates (5)
1	Residential				
2	Small Electric				
3	Municipal Buildings				
4	Large Electric				
5	Large Electric High Load Factor				
6	Master Metered Non Residential				
7	High Voltage				
8	Large Interruptible				
9	Lighting				
10	Total ENO				

Notes:
(1) Excludes schedules specifically identified on Attachment A, Page 1 of this Rider PPCACR.
(2) The PPCACR Revenue Requirement (PPCACRRR) shall be allocated to the retail rate classes based on the allocation of the Base Rate Revenue Requirement determined in the 2018 Combined Rate Case, Council Docket No. UD-18-XX.
(3) Attachment B, Page 2, Line 5. The class amount is the Class Allocation % in Col B times the PPCACRRR.
(4) The billing determinants shall be the estimated monthly ENO Base Rate Revenue for the applicable billing month.
(5) Class Total Rider PPCACR Revenue Requirement (Col C) divided by Class Billing Determinants (Col D).

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ENTERGY NEW ORLEANS, LLC.
PURCHASED POWER AND CAPACITY ACQUISITION COST RECOVERY RIDER

Data Based on Operations Month of XXX 2019

Applied to Bill in the Month of XXX 2019

LINE NO	DESCRIPTION	REFERENCE		
SECTION 1				
	PURCHASED POWER AND CAPACITY ACQUISITION COST RECOVERY REVENUE REQUIREMENT			
1	Constructed or Acquired Capacity Estimated Monthly Revenue Requirement	Attachment B: P3	$0.00	
2	Difference between Actual PPA and LTSA Costs for Operations Month and Schedule A Estimated PPA and LTSA Costs for Corresponding Month Recoverable in Rider Schedule PPCACR	WP1	$0.00	
3	New PPA Costs and LTSA Costs for Operations Month Recoverable in Rider Schedule PPCACR	WP2	$0.00	
4	Recoverable Cumulative (Over) / Under for Operations Month	Attachment B: P2 L15	$0.00	
5	Total Operations Month Rider Schedule PPCACR Revenue Requirement	L1 + L2 + L3 + L4	$0.00	
SECTION 2				
	CUMULATIVE (OVER) / UNDER COLLECTION			
6	Cumulative (Over) / Under Collection from Previous Month	Attachment B: P3 L14 of Previous Month Filing	$0.00	
7	Constructed or Acquired Capacity Estimated Monthly Revenue Requirement	Attachment B: P3	$0.00	
8	Difference between Actual PPA and LTSA Costs for Operations Month and Schedule A Estimated PPA and LTSA Costs for Corresponding Month Recoverable in Rider Schedule PPCACR	Attachment B: P2, L2 of the Month Filing before the Previous Month	$0.00	
9	New PPA Costs and LTSA Costs for Operations Month Recoverable in Rider Schedule PPCACR	WP2		
10	PPCACR Rider Revenue for Operations Month	WP3	$0.00	
11	Prior Period Adjustment		$0.00	
12	Other Council-approved Adjustments		$0.00	
13	Interest on Average of Beginning-of-Month and End-of-Month Cumulative (Over) / Under Balances for Operations Month	((L6 + (L6 + L7 +L8 + L9 - L10 + L11 + L12)) / 2) * ((Prime Rate) / 12) (See Note)	$0.00	
14	Cumulative (Over) / Under for Operations Month	L6 + L7 + L8 + L9 - L10 + L11 + L12 + L13		$0.00
15	Recoverable Cumulative (Over) / Under for Operations Month	L14/12		$0.00

Note: Prime Rate on the last business day of the operations month as stated in the Wall Street Journal was x.x%

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ENTERGY NEW ORLEANS, LLC.

PURCHASED POWER AND CAPACITY ACQUISITION COST RECOVERY RIDER

Data Based on Operations Month of XXX 2019

Applied to Bill in the Month of XXX 2019

LINE NO	DESCRIPTION	ANNUAL AMOUNT	MONTHLY AMOUNT
1	[Year, Facility Name]		

ENTERGY NEW ORLEANS, LLC
GAS SERVICE

RIDER SCHEDULE GIRP

Effective: January 2, 2020
Filed: September 2018
Supersedes: New Schedule
Schedule Consist of: Three Pages and Attachments A, B and C

GAS INFRASTRUCTURE REPLACEMENT PROGRAM RIDER SCHEDULE

I. GENERAL

The purpose of the Gas Infrastructure Replacement Program Rider ("GIRP Rider") is to provide for the recovery by Entergy New Orleans, LLC ("ENOL" or the "Company") of the costs associated with replacing aging infrastructure and improving the safety and reliability of the gas distribution system. The GIRP would employ the same condition-based approach as ENOL's Integrity Management ("IM") plan in accordance with the Federal Pipeline Safety Regulations amended by the U.S. Department of Transportation Pipeline and Hazardous Materials Safety Administration on December 4, 2009.

II. INITIAL RATE DETERMINATION

On or before May 31, 2020, the initial GIRP Rider shall be filed with the Council of the City of New Orleans ("Council") and shall be calculated to recover the costs as defined in Section IV of this Rider that have not been reflected in the Company's base rates per Council Resolution R-XX-XXX and shall be effective for bills rendered on and after the first billing cycle of July 2020. The initial and subsequent redetermined GIRP Rider Rate shall be confirmed by application of the formula set forth in Attachments B and C of this GIRP Rider. Such rate shall be filed with the Council and shall be accompanied by a set of work papers sufficient to document fully the calculations of the GIRP Rider Rate.

III. QUARTERLY RATE REDETERMINATION

After the initial rate determination, the Company shall file a redetermined GIRP Rider Rate with the Council within 60 days after each three month period ("Service Period") as illustrated in Table 1 below:

Table 1:

Line #	Service Period-Date to Which Eligible GIRP Costs Reflected	GIRP Filing Date (On or before)	Effective Date of Rate Change (On and after first billing cycle of)
1	March 31	May 31	July
2	June 30	August 31	October
3	September 30	November 30	January
4	December 31	February 28	April

The redetermined GIRP Rider Rate shall be effective with the first billing cycle following a 30 day review period of the redetermined rate filing. The redetermined rate shall reflect: (1) the pre-tax return, based on the Company's before-tax weighted average cost of capital as of the twelve month period ending December 31 of the preceding calendar year on the cumulative Eligible Plant ("EP"), net of associated accumulated provision for depreciation and associated accumulated deferred income taxes, (2) depreciation expense associated with the EP, and (3) operation and maintenance ("O&M") expenses associated with the identification and resolution of underground utility conflicts .

The GIRP is subject to an annual reconciliation based on a reconciliation period consisting of the twelve month period ending December 31 of each year after the initial filing year. The reconciliation is the difference between the revenue requirement and actual GIRP revenue for the reconciliation period. Beginning in 2021, the difference will be recovered or refunded, as appropriate, over a one-year period commencing on the first billing cycle of July of each year as shown on Attachment C page 4 of 4.

IV. ELIGIBLE COSTS: The Eligible Costs to be reflected in the GIRP Rider Rate Redetermination is defined as the incremental return on and of investments in pipeline safety improvement projects implemented under the IM plan and the O&M expenses associated with the identification and resolution of underground utility conflicts ("Utility Conflicts Expense").

V. COMPUTATION OF THE GIRP RIDER RATE

Determination of Eligible Costs: The Eligible Costs shall be calculated as follows:

A. **Pre-tax return**: The pre-tax return shall be calculated using the statutory state and federal income tax rates, the Company's actual capital structure and actual cost rates for long-term and short-term debt and preferred stock based on the Company's pre-tax weighted average cost of capital as of the twelve month period ending December 31 immediately preceding the filing date. The cost of equity will be the equity return rate approved by the Council as of the last base rate case.

B. Depreciation: The depreciation expense shall be calculated by applying the annual accrual rates, employed in the Company's most recent base rate case for the plant accounts in which each retirement unit of the EP is recorded, applied to the original cost of the EP.

C. Utility Conflicts Expense: The Utility Conflicts Expense shall be determined based on the projected annual O&M expenses associated with the identification and resolution of underground utility conflicts.

D. Application of GIRP Rider Rate: The GIRP Rider Rate will be expressed as a percentage carried to four decimal places and will be applied to the net monthly rates, excluding "Adjustments" or "Other Adjustments" as these terms are defined in each Company rate schedule and customer class including:

Tariff	
RGS	Residential Gas Service
SG	Small General Gas Service
LG	Large General Gas Service
SM	Small Municipal Gas Service
LM	Large Municipal Gas Service

VI. CUSTOMER SAFEGUARD

The Company shall secure and retain all documents necessary to verify the validity of the costs for which it is seeking recovery of the associated fixed costs under GIRP Rider. Such documents shall include, but shall not be limited to, work orders, journal entries, and the assets' in-service dates.

VII. TERM

A. The term of GIRP Rider shall be through 2028, regardless of whether an FRP remains in place for ENOL, unless otherwise modified or terminated in accordance with the provisions of the GIRP Rider or applicable regulations or law.

B. If this GIRP Rider is terminated by a future order of the Council, the GIRP Rider Rate then in effect shall continue to be applied until the Council approves an alternative mechanism by which the Company can recover the costs reflected in the then-current GIRP Rider Rate. At that time, any cumulative over-recovery or under-recovery resulting from application of the then-current GIRP Rider Rate, inclusive of carrying costs at the pre-tax weighted average cost of capital, shall be applied to customer billings over the twelve month billing period beginning on the first billing cycle of the second month following the termination of GIRP Rider in a manner prescribed by the Council.

VIII. APPLICABLE CUSTOMER CLASSES AND SCHEDULES

GIRP Rider shall be applied equally to rate schedules (RGS)-Residential Gas Service, (SG)-Small General Gas Service, (LG)-Large General Gas Service, (SM)-Small Municipal Gas Service, and (LM)-Large Municipal Gas Service and as required under Section V (C) above.

ATTACHMENT A

GAS INFRASTRUCTURE REPLACEMENT PROGRAM RIDER RATE

For billing purposes, an amount equal to (1) the sum of the Net Monthly Rate, excluding “Adjustments” or “Other Adjustments” as these terms are defined in the Company’s rate schedules, RGS, SG, LG, SM and LM, multiplied by (2) the following percentage (“GIRP Rider Rate Percentage”), shall be added to or subtracted from the Net Monthly Rate for all customer bills rendered under ENOL rate schedules RGS, SG, LG, SM and LM. The GIRP Rider Rate is effective for bills rendered on and after the first billing cycle of [July 2020]:

GIRP Rider Rate Percentage (%): X.XXXX%

ATTACHMENT B

GAS INFRASTRUCTURE REPLACEMENT PROGRAM RIDER FORMULA

Formula: The formula for calculation of the GIRP Rider Rate is as follows:

$$\text{GIRP Rider Rate} = \frac{[(EP * PTRR) + DEP + RR] * REF]/4}{PQRR} + [UCE * REF]$$

Where:

EP = Eligible Plant Additions, as defined in Section IV. of GIRP Rider, net of associated accumulated provision for depreciation and associated accumulated deferred income taxes.

PTRR = Pre-tax weighted average cost of capital, as defined in Section V.A. of GIRP Rider. In accordance with Section II of the Gas Infrastructure Replacement Program Rider Formula, for the initial determination of GIRP Rider Rate, the pre-tax return shall be based on ENOL's before-tax weighted average cost of capital (WACC) as of December 31 of the year immediately preceding the filing date.

DEP = Depreciation Expense related to GIRP Rider Eligible Plant Additions.

RR = The amount calculated under the GIRP Rider Reconciliation, as calculated in Attachment C page 4 of 4.

REF = *Revenue Related Expense Factor = 1 / [(1 – Bad Debt Rate – Revenue-related Tax Rate)]

UCE = Operation & maintenance expense incurred during the service period associated with the identification and resolution of underground utility conflicts.

PQRR = One-fourth of the projected annual RGS-, SG, LG, SM and LM rate schedule revenues, excluding purchased gas adjustment revenues for the twelve month period ended December 31.

*Revenue Related Expense Factor shall be calculated as of the twelve month period ended December 31 immediately preceding the filing date.

Entergy New Orleans, LLC
Gas Infrastructure Replacement Program Rider Formula (1)
As of March 31, 2020 (2)
($000'S Omitted)

Ln No.	Description	Amount	Reference
	EP - Eligible Plant Additions		
1	IM Plan Investments		Att C Page 2, L1
2	Accumulated Depreciation		Att C Page 2, L2
3	**Total EP - Eligible Plant Additions**		L1 + L2
4	**Accumulated Deferred Income Tax**		Att C Page 2, L4
	PTRR - Pre-Tax Return		
5	Pre-Tax Weighted Average Cost of Capital (3)		WP X
6	**Return on Net Eligible Plant**		(L3 + L4) * L5
	DEP - Depreciation Expense		
7	Depreciation Expense of IM Plan Investments		Att C Page 2, L5
8	**Total DEP - Depreciation Expense**		L7
9	**UCE - Underground Conflicts Expense**		
10	Underground Conflicts Expense		Att C Page 2, L8
11	RR - Rate Rider Reconciliation		Zero for Initial. Att C Page 4, L3
12	**Return of and on GIRP EP (Excl. UCE)**		L6 + L8 + L11
13	REF - Revenue-related Expense Factor (4)		WP X
14	**Total Quarterly GIRP Revenue Requirement**		(L12 * L13) / 4 + (L10 * L13)
15	PQRR - Projected Quarterly Rate Schedule Revenues		Att C Page 3, L2
16	**GIRP Rider Rate Percentage**		L 14 / L 15

Notes:

(1) Pursuant to Attachment B of this Gas Infrastructure Replacement Program Rider (GIRP).

(2) The Company's initial GIRP rate determination shall contain the Initial Service Period costs associated with GIRP eligible plant. For subsequent redeterminations, the Service Period shall be as of March 31, June 30, September 30, and December 31, respectively, and shall contain the costs associated with GIRP eligible plant and balances as of each Service Period end date, cumulatively, until such time the GIRP rate is reset to zero.

(3) The initial and redetermined PTRR shall be based on the Company's pre-tax weighted average cost of capital as of the twelve month period ending December 31 immediately preceding the filing date.

(4) Revenue-related Expense Factor = 1 / (1-Bad Debt Rate - Revenue-related Tax Rate). Initial and redetermined Revenue-related Expense Factor shall be calculated as of the twelve month period ending December 31 immediately preceding the filing date.

Schedule GIRP
Attachment C
Page 2 of 4

Entergy New Orleans, LLC
Gas Infrastructure Replacement Program Rider Formula
As of March 31, 2020 (1)
($000'S Omitted)

Ln No.	Description	Amount	Reference
	EP - Eligible Plant Additions		
1	Total IM Plan Investments (2)		WP X, L1, Column C
2	Accumulated Depreciation on IM Plan Investments		WP X, L1, Column E
3	**Total EP - Eligible Plant Additions**		L1 + L2
	Accumulated Deferred Income Taxes		
4	Accumulated Deferred Income Tax		WP X
	DEP - Depreciation Expense (3)		
5	Depreciation Expense of IM Plan Investments		WP X, L1, Column G
6	**Total DEP - Depreciation Expense**		L5
7	**UCE - Underground Conflicts Expense**		
8	Underground Conflicts Expense		WP X, L1, Column D

Notes:

(1) The Company's initial GIRP rate determination shall contain the Initial Service Period fixed costs associated with GIRP eligible plant. For subsequent redeterminations, the Service Period shall be as of March 31, June 30, September 30, and December 31, respectively, and shall contain the fixed costs associated with GIRP eligible plant and balances as of each Service Period ended date, cumulatively, until such time the GIRP rate is reset to zero.

(2) Capitalized costs associated with Integrity Management (IM) plan projects.

(3) Annual accrual rates approved in the Utility's most recent base rate case, for the plant accounts in which each retirement unit of GIRP EP is recorded, applied to the original cost of GIRP EP.

Entergy New Orleans, LLC
Gas Infrastructure Replacement Program Rider Formula
As of March 31, 2020
($000'S Omitted)

Ln No.	Description	Amount	Reference
	Projected Rate Schedule Revenues (1)		
1	**Total Projected Rate Schedule Revenues**		WP X, L6
2	**Total Quarterly Projected Rate Schedule Revenues**		L14 / 4

Notes:
(1) The GIRP will contain one-fourth of the projected annual RGS, SG, LG, SM and LM rate schedule revenues, excluding PGA, MGS, GAFC, GR, and GFRP, for the twelve-month period ended December 31.

Schedule GIRP
Attachment C
Page 4 of 4

Entergy New Orleans, LLC
Gas Infrastructure Replacement Program Rider Formula
Rate Rider Reconciliation of GIRP (1)
As of March 31, 2020 (2)
($000'S Omitted)

Ln No.	Description	Amount	Reference
1	GIRP Revenue Collections During Reconciliation Period (3)		WP X, L4
2	GIRP Revenue Requirement During Reconciliation Period (4)		WP X, L5
3	**Total Revenue Requirement (Over)/Under**		L2 - L1
4	Annual Prior Period Rate Rider Reconciliation Adjustment (5)		
5	**RR- Rate Rider Reconciliation GIRP**		L3 + L4

Notes:

(1) This schedule is not applicable for the Initial Filing.

(2) Rider GIRP annual reconciliation based on a reconciliation period consisting of the twelve months ending December 31 of each year. The initial Rider GIRP reconciliation will consist of a reconciliation period from the initial effective date of the GIRP in rates through December 31, 2020 to be filed on or before May 31, 2021.

(3) GIRP revenues collected during the reconciliation period, as outlined in Note 2.

(4) GIRP revenue requirement during the reconciliation period, as outlined in Note 2.

(5) The Prior Period Rate Rider Reconciliation Adjustment is based on the annual reconciliation period consisting of the twelve months endeding December 31 from the preceding year on line 5 of Attachment C, page 4.

ENTERGY NEW ORLEANS, LLC ELECTRIC SERVICE RIDER DGM	Effective: January 2, 2020 Filed: September 2018 Supersedes: New Schedule Schedule Consists of: Three Pages Plus Attachments A, B and C

DISTRIBUTION GRID MODERNIZATION RIDER

I. PURPOSE AND APPLICABILITY

The purpose of the Distribution Grid Modernization Schedule ("Rider DGM") is to establish the Rider DGM Rate by which Entergy New Orleans, LLC ("ENOL" or the "Company") will recover the revenue requirement of the capital investment associated with Council-approved grid modernization projects not recovered in base rates as of the implemenation of Council Resolution R-19-XX [resolution authorizing implementation of rates from 2018 base rate proceeding]. The capital investment associated with routine distribution work and storm hardening shall not be eligible for recovery through this Rider DGM. The Rider DGM Rate is applied in conjunction with the currently applicable rates on file with the Council.

II. APPLICATION AND REDETERMINATION PROCEDURES

A. RATE ADJUSTMENT

The adjustment to the Company's rates set forth in Attachment A to this Rider DGM ("Rate Adjustment") shall be added to the rates set out in the monthly bills in accordance with the Company's Rate Schedules. The Rate Adjustment shall be determined in accordance with the provisions of Sections B and C below.

B INITIAL RATE DETERMINATION

On or before April 30, 2020, the initial Rider DGM Rate shall be filed with the Council by ENOL. The initial Rider DGM Rate shall be calculated to recover the revenue requirement of the costs associated with eligible Grid Modernization Projects ("GMP"), as defined in Section IV of this Rider, which 1) have not been reflected in the Company's rates as of the implementation of Council Resolution R-19-XX and 2) have been placed into service prior to March 31, 2020 ("Initial Service Period"). The initial Rider DGM shall be effective for bills rendered on and after the first billing cycle of June 2020. The initial and subsequent re-determined Schedule DGM Rate shall be determined by application of the formula set forth in Attachment B of Rider DGM ("Rider DGM Rate Formula"). Such rate shall be filed with the Council and shall be accompanied by a set of work papers sufficient to document fully the calculations of the Rider DGM Rate. Subsequent to determination of the initial rate, redetermination of the Rider DGM shall be in accordance with Section III below.

C. QUARTERLY RATE REDETERMINATION

After the initial rate determination, the Company shall file a redetermined Rider DGM Rate with the Council within 30 days after each three month period ("Service Period") ending, March 31, June 30, September 30, and December 31. As illustrated in the table below, the Schedule DGM Rate so redetermined shall be effective with the first billing cycle of the following month. Redetermined Rider DGM rate effective dates shall be on and after the first billing cycle of June, September, December, and March respectively, and shall then remain in effect for three (3) months ("Effective Rate Period") until the next redetermined Rider DGM Rate filing. The redetermined Rider DGM Rate shall be determined by application of the Rider DGM Rate Formula. Each such revised rate shall be filed with the Council and shall be accompanied by a set of workpapers sufficient to document fully the calculations of the redetermined Rider DGM Rate. The redetermined rate shall reflect: (1) the completed grid modernization projects since the previous Schedule DGM Rate filing and (2) the Rider DGM is subject to annual reconciliation based on a reconciliation period consisting of the twelve months ending December 31st of each year after the initial filing year.

Line #	Date to Which Eligible DGM Costs Reflected	DGM Filing Date (On or before)	Effective Date of Rate Change (On and after first billing cycle of)
1	March 31	April 30	June
2	June 30	July 30	September
3	September 30	October 30	December
4	December 31	January 31	March

The redetermined DGM Rider Rate shall be effective with the first billing cycle following a 20-day review period of the redetermined rate filing.

D. REVIEW PERIOD

The Council's Advisors ("Advisors"), intervenors ("Intervenors") and the Company (collectively the "Parties") shall have 20 days after the redetermination filing to ensure that it complies with the requirements of Section IV below. If any of the Parties should detect an error(s) in the application of the principles and procedures contained in Section II.E below, such error(s) shall be formally communicated in writing to the Company and/or other Parties within the same 20 days. Each such indicated dispute shall include, if available, documentation of the proposed correction. The Company shall then have ten (10) days to review any proposed corrections, to work with the other Parties to resolve any differences and to file a revised Attachment A reflecting all corrections upon which the Parties agree. The Company shall provide the other Parties with appropriate work papers supporting any revisions made to the Rate Adjustment initially filed.

Except where there are unresolved disputes with respect to the calculation, which shall be addressed in accordance with the provisions of Section II.E.3 below, the Rate Adjustment initially filed under the provisions of Section II.B or C above, or such corrected Rate Adjustment as may be determined pursuant to the terms of this Section II.D, shall become effective for bills rendered on and after the first billing cycle following the 20 day review period. The Rate Adjustment shall then remain in effect until changed pursuant to the provisions of this Rider DGM.

E. RESOLUTION OF DISPUTED ISSUES

In the event there is a dispute regarding the calculation of a redetermination filing, the Parties shall work together in good faith to resolve such dispute. If the Parties are unable to resolve the dispute by the end of the twenty-fifth day (25th) day described in the thirty day period provided for in Section II.D above, a revised Rate Adjustment reflecting all revisions to the initially filed Rate Adjustment on which the Parties agree shall become effective as provided for in Section II.D above. Any disputed issues shall be submitted to the Council for resolution.

If the Council's final ruling on any disputed issues requires changes to the DGM Rate Adjustment referenced in Paragraph II.B or C above, the Company shall file a revised Attachment A containing such further modified Rate Adjustment within fifteen (15) days after receiving the Council's resolution resolving the dispute. The Company shall provide a copy of the filing to the Council together with appropriate supporting documentation. Such modified Rate Adjustment shall then be implemented with the next applicable monthly billing cycle after said filing and shall remain in effect until superseded by the Rate Adjustment established in accordance with the provisions of this Rider DGM.

Within 60 days after receipt of the Council's final ruling on disputed issues, the Company shall determine the amount to be refunded or surcharged to customers, if any, together with interest at the Louisiana Judicial rate as of the date of the redetermination filing. Such refund/surcharge amount shall be included for recovery in the following redetermination filing.

IV. GRID MODERNIZATION PROJECTS

The amounts eligible to be reflected for recovery in the Rider DGM Rate filings is defined as the return on and of capital investments in Grid Modernization Projects as initially approved by the Council in Resolution R-19-XX and as subsequently approved through the process set forth in the same resolution.

V. CUSTOMER SAFEGUARD

A. **Record Keeping:** The Company shall secure and retain all documents necessary to verify the validity of the costs for which it is seeking recovery of the associated capital expenditures and fixed costs under Rider DGM. Such documents shall include, but shall not be limited to, work orders, journal entries, and the assets' in-service dates.

B. The revenue received under the DGM for the reconciliation period will be compared to the Company's eligible costs for that period. The difference between revenue and costs billed versus the costs incurred will be recovered or refunded, as appropriate, over a one-year period commencing on the first billing cycle of March of each year.

VI. APPLICABLE CUSTOMER CLASSES AND SCHEDULES

Rider DGM shall be applied to applicable rate schedules as set forth in Attachment A.

VII. TERM

A. This Rider DGM shall remain in effect from the date of implementation until the next Base Rate case filing, unless otherwise modified on terms mutually agreeable to the parties or terminated in accordance with the provisions of this Rider DGM (VII.B below) or applicable regulations or laws.

B. If this Rider DGM is terminated by a future order of the Council, the Rider DGM Rates then in effect shall continue to be applied until the Council approves an alternative mechanism by which the Company can recover the costs reflected in the then-current Rider DGM Rates.

ATTACHMENT A

DISTRIBUTION GRID MODERNIZATION RATES

For billing purposes, an amount equal to (1) the sum of the Net Monthly Bill, excluding "Adjustments" or "Other Adjustments" as these terms are defined in the Company's rate schedules, multiplied by (2) the following percentages, which is named the Rider DGM Rate Percentage, shall be added to or subtracted from the Net Monthly Bill for all customer bills rendered under ENOL rate schedules. This Rider DGM Rate, which is effective for bills rendered on and after the first billing cycle of June 2020:

Rider DGM Rate Percentage

*Excluding Schedules AFC, AMICE, BRAR, CSO, DSMCR, DTK, EAC, EECR, EFRP, EVCI, FAC, FBO, GPO, MES, MISO, PPCACR, PPS, R-3, R-8, RPCEA, SMS, SSCO and SSCR

ENTERGY NEW ORLEANS, LLC
Distribution Grid Modernization Rider (Rider DGM)
Distribution Grid Modernization Rates
For the Quarter Ended March 31, 2020
($000's Omitted)

	Col A	**Col B**	**Col C**
Ln No.	**Rate Class (1)**	**Rate Schedule**	**Rider DGM Rate Percentages (2)**
1	Residential	RES	**0.0000%**
2	Small Electric	SE, TS	**0.0000%**
3	Municipal Building	MB	**0.0000%**
4	Large Electric	LE	**0.0000%**
5	Large Electric-High Load Factor	LE-HLF	**0.0000%**
6	Master Metered Non-Residential	MMNR	**0.0000%**
7	High Voltage	HV	**0.0000%**
8	Large Interruptible Service	LIS	**0.0000%**
9	Lighting	ODSL, ONW, HPSV NW, PLS, SL	**0.0000%**

Notes:
(1) Excludes schedules specifically identified on Attachment A.
(2) See Attachment A, Page 2, Col E.

ATTACHMENT A (Cont'd)

ENTERGY NEW ORLEANS, LLC
Distribution Grid Modernization Rider (Rider DGM)
Distribution Grid Modernization Rate Percentages
For the Quarter Ended March 31, 2020
($000's Omitted)

	Col A	Col B	Col C	Col D	Col E
Ln No.	Rate Class	Distribution Demand Allocation Factor (1)	Rider DGM Revenue Requirement (2)	PARSR (3)	Rider DGM Rate Percentage (4)
1	Residential	51.7910%	0	0	**0.0000%**
2	Small Electric	14.3599%	0	0	**0.0000%**
3	Municipal Building	0.5140%	0	0	**0.0000%**
4	Large Electric	7.0517%	0	0	**0.0000%**
5	Large Electric-High Load Factor	24.9719%	0	0	**0.0000%**
6	Master Metered Non-Residential	0.0111%	0	0	**0.0000%**
7	High Voltage	0.0000%	0	0	**0.0000%**
8	Large Interruptible Service	0.0000%	0	0	**0.0000%**
9	Lighting	1.3004%	0	0	**0.0000%**
10	**Total**	**100.0000%**	**0**	**0**	**0.0000%**

Notes:

(1) The Rider DGM Revenue Requirement shall be allocated to the retail rate classes based on the Distribution Demand Allocation Factor, Substation & Primary Lines Allocation Factor (MDD), as approved in Docket XX.

(2) The Rider DGM Revenue Requirement calculated on Attachment C, Page 1 Line 12. The amount allocated to each class is determined by multiplying the Rider DGM Revenue Requirement times the Distribution Demand Allocation Factor in Col B.

(3) The billing determinants are based on the Projected Annual Rate Schedule Revenues for the filing year on Att C, Page 3.

(4) The Rider DGM Rates by Rate Class are determined by dividing the Rate Class Revenue Requirement by the Projected Annual Base Rate Schedule Revenue.

ATTACHMENT B

RIDER DISTRIBUTION GRID MODERNIZATION RATE FORMULA

Formula: The formula for the calculation of the Rider DGM Rate is as follows:

$$\text{Rider DGM Rate} = \frac{[(EP * PTRR) + DEP + RR] * REF}{PARSR}$$

Where:

EP	=	Eligible Plant Additions, as defined in Section IV. of Rider DGM, net of associated accumulated provision for depreciation and associated accumulated deferred income taxes.
PTRR	=	The most recently approved pre-tax weighted average cost of capital.
DEP	=	Depreciation Expense related to Rider DGM Eligible Plant Additions.
RR	=	The amount calculated in the annual DGM Rate Reconciliation process, as calculated in Attachment C.
REF	=	Revenue Related Expense Factor = 1 / [(1 – Bad Debt Rate–Revenue Related Tax Rate)] from the last approved EFRP Evaluation Report.
PARSR	=	The Projected Annual Rate Schedule base rate revenues, excluding fuel adjustment revenues, for the filing year.

ATTACHMENT C

ENTERGY NEW ORLEANS, LLC
Distribution Grid Modernization Rider (Rider DGM)
Cost Recovery Revenue Requirement Formula
For the Quarter Ended March 31, 2020
($000's Omitted)

Ln No.	Description	Amount	Reference
	EP - Eligible Plant Additions		
1	Rider DGM Plant Additions		Att C Page 2, L1
2	Accumulated Depreciation		Att C Page 2, L2
3	**Net Eligible Plant Additions**	**0**	L1 + L2
4	**Accumulated Deferred Income Taxes**	**0**	Att C Page 2, L4
	PTRR - Pre-Tax Return		
5	Pre-Tax Weighted Average Cost of Capital (1)		
6	**Return on Net Eligible Plant**	**0**	(L3 + L4) * L5
	DEP - Depreciation Expense		
7	Depreciation Expense of Eligible Rider DGM Plant Additions	0	Att C Page 2, L6
8	**Total DEP - Depreciation Expense**	**0**	Ln 7
9	**Return of and on** Rider DGM **EP**	**0**	L6 + L8
10	RR - Rate Rider Reconciliation (2)	0	Att C Page 4, L3
11	REF - Revenue Related Expense Factor (3)		
12	**Total Rider DGM Revenue Requirement**	**0**	**(L9 + L10) / L11**

Notes:

(1) The Pre-Tax Weighted Average Cost of Capital, as approved in Docket XX from the 2018 Rate Case Proceeding. For subsequent redeterminations, the Pre-Tax Weighted Average Cost of Capital shall be made consistent with the amounts approved in the annual Formula Rate Plans.

(2) The Rate Rider Reconciliation amount is set at zero for the initial filing and then shall be developed consistent with the methodology in the approved Attachment C, Page 4.

(3) Revenue Related Expense Factor = 1 / (1-ENO Retail Bad Debt Rate). The ENO Bad Debt Rate shall be developed consistent with the methodology used for calculating it in the most recent ENO general rate case and shall use the most recently available calendar year data at the time of filing.

ATTACHMENT C (Cont'd)

ENTERGY NEW ORLEANS, LLC
Distribution Grid Modernization Rider (Rider DGM)
Cost Recovery Revenue Requirement Formula
For the Quarter Ended March 31, 2020 (1)
($000's Omitted)

Ln No.	Description	Amount	Reference
	EP - Eligible Plant Additions		
1	Rider DGM Plant Additions (2)		
2	Accumulated Depreciation		
3	**Net Eligible Plant Additions**	**0**	L1 + L2
	Accumulated Deferred Income Taxes		
4	**Accumulated Deferred Income Tax**	**0**	
	DEP - Depreciation Expense (3)		
5	Depreciation Expense of Eligible Rider DGM Plant Additions	**0**	
6	**Total DEP - Depreciation Expense**	**0**	

Notes:

(1) The Company's initial Rider DGM rate determination shall contain the Initial Service Period fixed costs associated with Rider DGM eligible property. For subsequent redeterminations, the Service Period shall be as of March 31, June 30, September 30, and December 31, respectively, and shall contain the fixed costs associated with Rider DGM eligible property and balances as of each Service Period ended date, cumulatively, until such time the Rider DGM rate is reset to zero

(2) Capitalized investments associated with the approved Rider DGM projects.

(3) Annual depreciation rates as approved in Docket XX from the 2018 Rate Case, for the plant accounts in which each retirement unit of DGMR EP is recorded, applied to the original cost of Rider DGM EP.

ATTACHMENT C (Cont'd)

ENTERGY NEW ORLEANS, LLC
Distribution Grid Modernization Rider (Rider DGM)
Cost Recovery Revenue Requirement Formula
For the Quarter Ended March 31, 2020 (1)
($000's Omitted)

Ln No.	Rate Class	Rate Schedule	Amount
	Projected Rate Schedule Revenues (2)		
1	Residential	RES	0
2	Small Electric	SE, TS	0
3	Municipal Building	MB	0
4	Large Electric	LE	0
5	Large Electric-High Load Factor	LE-HLF	0
6	Master Metered Non-Residential	MMNR	0
7	High Voltage	HV	0
8	Large Interruptible Service	LIS	0
9	Lighting	ODSL, ONW, HPSV	
		NW, PLS, SL	0
6	**Total Projected Rate Schedule Revenues**		**0**

Notes:
(1) The Rider DGM billing determinants will include the Projected Annual Base Rate Schedule Revenues for the filing year.
(2) Projected Annual Base Rate Schedule Revenues

ATTACHMENT C (Cont'd)

ENTERGY NEW ORLEANS, LLC
Distribution Grid Modernization Rider (Rider DGM)
Rate Rider Reconciliation of Rider DGM (1)
For the Twelve Months Ended December 31, 2020 (2)
($000's Omitted)

Ln No.	Description	Amount	Reference
	Reconciliation Period Revenue		
1	Rider DGM Revenue Collections During Reconciliation Period (3)		
	Reconciliation Period Revenue Requirement		
2	Rider DGM Revenue Requirement During Reconciliation Period (4)		
3	**RR- Rate Rider Reconciliation DGM**	**0**	L2 - L1

Notes:
(1) This schedule is not applicable for the initial filings to be made on or before December 31, 2020.
(2) The Rider DGM annual reconciliation based on a reconciliation period consisting of the twelve months ending December 31 of each year. The initial Rider DGM reconciliation will consist of a reconciliation period from the initial effective date of the Rider DGM in rates through December 31, 2020.
(3) The Rider DGM revenues collected during the reconciliation period, as outlined in Note 2.
(4) The Rider DGM eligible costs during the reconciliation period, as outlined in Note 2.