BEFORE THE

LOUISIANA PUBLIC SERVICE COMMISSION

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| APPLICATION OF ENTERGY<br>LOUISIANA, LLC FOR APPROVAL OF<br>REGULATORY BLUEPRINT<br>NECESSARY FOR COMPANY TO<br>STRENGTHEN THE ELECTRIC GRID<br>FOR STATE OF LOUISIANA | )<br>)<br>)<br>)<br>)<br>) | DOCKET NO. U-_____ |

# DIRECT TESTIMONY

OF

KENNETH F. GALLAGHER

ON BEHALF OF

ENTERGY LOUISIANA, LLC

AUGUST 2023

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# I. INTRODUCTION

Q1. PLEASE STATE YOUR NAME, BUSINESS ADDRESS, AND OCCUPATION.

A. My name is Kenneth F. Gallagher. My business address is 1452 Hampton Hill Circle, McLean, Virginia 22101. I am president of KFG, Inc., a consulting firm specializing in public utility economics.

Q2. ON WHOSE BEHALF ARE YOU SUBMITTING THIS DIRECT TESTIMONY?

A. I am testifying before the Louisiana Public Service Commission ("LPSC" or the "Commission") on behalf of Entergy Louisiana, LLC ("ELL" or the "Company").[1]

Q3. PLEASE DESCRIBE YOUR EDUCATIONAL AND PROFESSIONAL BACKGROUND.

A. In 1971, I received a Bachelor of Science degree in Economics from the University of Maryland. I have also received a Master of Business Administration degree in Finance from American University and a Master of Arts degree in Economics from Georgetown University. Throughout my education, I have taken numerous courses in economic theory, statistics, finance, and accounting. Furthermore, I am a member of the American Economic Association and the American Finance Association.

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[1] On September 14, 2015, the LPSC issued Order No. U-33244-A formally approving the business combination of Legacy EGSL and Legacy ELL, through which those companies' combined substantially all of their respective assets and liabilities into a single operating company, Entergy Louisiana Power, LLC, which subsequently changed its name to Entergy Louisiana, LLC ("ELL"). Upon consummation of the business combination, ELL became the public utility that is subject to LPSC regulation and its successor of Legacy EGSL and Legacy ELL.

Prior to beginning my current work as a consultant specializing in public utility economics in 1974, I was employed by the Montgomery County Department of Finance, performing studies relevant to valuation of land and buildings for the Maryland Department of Assessments and Taxation. In 1973, I was promoted to an administrative position with the Montgomery County Office of Facilities and Management, specializing in problems related to the allocation of budgeted funds for leased office space and properties acquired for public use.

During my work as a utility rate consultant, I have been responsible for the preparation of financial and economic studies concerning various aspects of utility rate regulation. These studies have dealt primarily with the determination of the fair rate of return, cost of service, rate base, and revenue requirements. I have also performed detailed studies of the cost of fuel for fuel rate proceedings on behalf of the State of Maryland Office of People's Counsel.

Q4. HAVE YOU PREVIOUSLY TESTIFIED BEFORE ANY REGULATORY BODY?

A. Yes. I have testified previously before the Council of the City of New Orleans, the LPSC, the Maine Public Service Commission, the Maryland Public Service Commission, the Minnesota Public Service Commission, the Washington Utilities and Transportation Commission, the Public Utility Commission of Texas, and the Federal Energy Regulatory Commission ("FERC"). See Exhibit KFG-1 for a list of previous proceedings in which I provided testimony.

## II. PURPOSE OF TESTIMONY

Q5. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. My testimony supports the cost of service or "Rate Case" aspect of the Company's Application, a distinction which Company witness Phillip May's Direct Testimony describes in greater detail. In that regard, the purpose of my testimony is two-fold. First, I provide the updated funding requirements for the decommissioning trusts maintained for the LPSC-retail jurisdictional portions of the Waterford 3 Steam Electric Station ("Waterford 3")[2] and the River Bend Station ("River Bend")[3] generating facilities owned by ELL.[4] These funding requirements support Adjustment AJ30 – Decommissioning Expense Adjustment discussed by Company witness Chris E. Barrilleaux. I also present the Lead-Lag analysis, which supports Adjustment AJ19 – Cash Working Capital. Companies witness Chris Barrilleaux discusses this adjustment as well.

Q6. PLEASE SUMMARIZE YOUR ANALYSIS OF DECOMMISSIONING FUNDING.

A. Based upon my analysis of the existing Decommissioning Trust Fund balances, as well as the most recent site-specific decommissioning cost studies and other relevant

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[2] Waterford 3 is a single-unit 1193 MW nuclear steam-electric generating station located near Killona, Louisiana, which was constructed by ELL's predecessor, Louisiana Power & Light Company, and began commercial operation in September 1985. Waterford 3 employs the pressurized-water-reactor design. *See* 2022 FERC Form 1.

[3] River Bend is a single-unit 988 MW nuclear steam-electric generating station located near St. Francisville, Louisiana, which was constructed by ELL's predecessor, Gulf States Utilities Company, and began commercial operation in June 1986. River Bend employs the boiling-water-reactor design. *See* 2022 FERC Form 1.

[4] Both facilities are operated by Entergy Operations, Inc. for ELL.

decommissioning related cost factors, the annual decommissioning revenue requirement is $33.662 million for Waterford 3 and $10.967 million for the 70% share of River Bend, beginning in calendar year 2025. Such proposed amounts are based upon the decommissioning costs identified in the most recent site-specific studies commissioned for each plant and reasonable projections in both cost growth and trust earnings.[5]

It should be noted that my updated decommissioning revenue requirement analysis includes, among other things, a reevaluation of ELL's annual funding requirement for both plants, which incorporates the Nuclear Regulatory Commission's ("NRC") recent approvals of ELL's license extension applications. I present the results of my updated decommissioning revenue requirement analysis based on the currently available site-specific studies for Waterford 3 and River Bend. As discussed in the Direct Testimony of Company witness Ryan O'Malley, I prepared an alternative calculation of the decommissioning revenue requirement that differs from the current updated analysis that does not change the combined decommissioning revenue requirement but partially addresses the estimated shortfall in the Waterford 3 decommissioning funds.

[5] The most recent site-specific studies are attached as Exhibits KFG-3 and KFG-4, and the results of each study are further described in Section IV of my testimony.

Q7. CAN YOU PLEASE SUMMARIZE YOUR LEAD-LAG STUDY?

A. The Company proposes that a cash working capital adjustment be made to the rate base in this proceeding to reflect its working capital needs for operating cash using the Lead-Lag approach. A necessary input to the determination of cash working capital is the Lead-Lag analysis, which measures the timing associated with the receipt of revenues from the provision of service relative to the timing associated with payment of cash expenses such as payroll, vendor payment obligations, and payments to taxing authorities. The Lead-Lag analysis combined with the Test Year amounts of the various categories of revenue and expense, as adjusted, when necessary, determines whether a rate base addition of cash working capital is needed to pay expenses prior to receipt of related revenue or, conversely, whether a rate base deduction is necessary due to the fact that expenses were paid after receipt of related revenue. The results of the Lead-Lag analysis are summarized in Exhibit KFG-2 along with a more detailed discussion of the analysis of the various categories of revenue and expense lags.[6]

## III. LPSC GUIDANCE FOR CALCULATING DECOMMISSIONING EXPENSE

Q8. HAS THE LPSC PROVIDED ANY GUIDANCE FOR CALCULATING THE APPROPRIATE AMOUNT OF DECOMMISSIONING EXPENSE FOR RATEMAKING PURPOSES?

A. Yes. In Order No. U-31237, dated August 27, 2010, the Commission approved ELL's application to increase decommissioning funding in rates for both of its nuclear

[6] Exhibit KFG-2 and the supporting workpapers are being provided on CD.

facilities. The increases in funding provided by Order No. U-31237 were intended to meet the NRC "Minimum" level of trust funding for Waterford 3 and River Bend, which at that time was based on a forty-year license life for each facility.

Q9. DID ORDER NO. U-31237 REQUIRE THAT THE LEVEL OF DECOMMISSIONING FUNDING BE REASSESSED?

A. Yes. In Order No. U-31237, the Commission recognized that the approved increase in funding was "intended to serve only to meet the decommissioning funding requirements on an interim basis, and the Staff and the Companies agree that both the Waterford 3 and River Bend funding requirements will be reevaluated based on site-specific cost studies after [Legacy] ELL and [Legacy] EGSL, respectively, have filed for and received the NRC's responses to requests for license extensions for the two nuclear facilities."[7] In December 2018, the NRC approved ELL's twenty-year license extension requests to operate Waterford 3[8] through October 2044 and River Bend through August 2045.[9] These approvals triggered the provision of Order No. U-31237 requiring that the funding requirement be reevaluated based on site-specific

[7] *See* Order No. U-31237 (August 27, 2010), *In re: Joint Application of Entergy Gulf States Louisiana, L.L.C. and Entergy Louisiana, LLC for Approval of an Increase in Funding for Decommissioning for River Bend and Waterford 3 Nuclear Facilities/LPSC Docket No. U-31237, Order, Id.* at p. 5.

[8] *See* United States Nuclear Regulatory Commission, *Entergy Louisiana, LLC and Entergy Operations, Inc. Docket No. 50-458 River Bend Station, Unit 1 Renewed Facility Operating License* (December 20, 2018), *available at* https://www.nrc.gov/docs/ML1828/ML18284A369.pdf.

[9] The River Bend renewed license was issued on December 20, 2018, and the Waterford 3 renewed license was issued on December 27, 2018. The renewed River Bend and Waterford 3 licenses are available on the NRC's ADAMS database using Accession Numbers ML18284A369 and ML18275A133, respectively. *See* United States Nuclear Regulatory Commission, *Entergy Louisiana, LLC and Entergy Operations, Inc. Docket No. 50-382 Waterford Steam Electric Station, Unit 3 Renewed Facility Operating License* (December 27, 2018), *available at* https://www.nrc.gov/docs/ML1827/ML18275A133.pdf.

decommissioning costs studies. Accordingly, ELL obtained updated site-specific studies for River Bend and Waterford 3, which were completed in March 2018[10] and May 2019, respectively. Testimony and analysis of decommissioning revenue requirements in response to that order was filed in Docket U-36103. That site-specific analysis was updated for purposes of this case.

## IV. DECOMMISSIONING REVENUE REQUIREMENT METHODOLOGY AND ASSUMPTIONS

Q10. HOW SHOULD THE REVENUE REQUIREMENT ASSOCIATED WITH DECOMMISSIONING COSTS BE DETERMINED FOR RATEMAKING PURPOSES IN THIS PROCEEDING?

A. In general, the revenue requirement associated with decommissioning expense for ratemaking is determined by estimating the necessary annual trust contributions needed to accumulate the funds needed to decommission the nuclear units when the license life of each unit is concluded, and decommissioning must begin. There are several key data inputs necessary for this analysis. To start, a current dollar estimate of decommissioning cost is determined. That cost is then escalated to determine the amount of decommissioning costs expected to be incurred in the time period of anticipated decommissioning. After taking into account trust fund balances escalated

[10] The 2018 Decommissioning Cost Analysis for River Bend Station, attached as Exhibit KFG-4, was commissioned by Entergy Texas, Inc. for its base rate case before the Public Utility Commission of Texas. ELL did not procure an updated report for use in this Application. The Waterford 3 Report was completed in 2019. The cost estimates utilized in both analyses were updated to reflect 2022 dollars.

for earnings and future contributions (at the current rate), the amount of revenue requirement to be reflected in customer rates can be determined. This methodological approach has been approved by the LPSC in all cases involving the determination of the decommissioning revenue requirement with which I am familiar.

Q11. DID YOU FOLLOW THIS APPROACH TO QUANTIFY THE REVISED DECOMMISSIONING REVENUE REQUIREMENT FOR ELL'S NUCLEAR UNITS IN THIS CASE?

A. Yes, I did. I used the same revenue requirement modeling approach that resulted in the Commission-approved decommissioning revenue requirements for the Waterford 3 and River Bend units in Docket No. U-31237. Consistent with that approach, the annual revenue requirement based on the site-specific decommissioning estimate was determined by taking into consideration expected future funds accumulation, including expected earnings on fund accumulations in the trust. Again, consistent with the prior methodology used for ELL, the revenue requirement was quantified on a five-year levelized step increase approach. Under this approach, decommissioning revenue requirements are fixed for five-year intervals increasing by the rate of inflation after each fifth-year interval. In sum, the key inputs into the revenue requirement model are as follows:

- The current dollar decommissioning cost (site-specific) estimate;[11]

[11] The ELL decommissioning funding proposal reflects the most recent site-specific decommissioning cost estimates using NRC extended license lives, sixty years. The existing approved decommissioning funding level is premised upon NRC minimum calculations and utilizes non-extended license lives, forty years.

- The projected decommissioning cost escalation rate;
- The available current decommissioning trust fund balances;
- The projected trust funds earnings rate; and
- The projected decommissioning funding period (60-year license life).

### A. Nuclear Decommissioning Cost Estimate

Q12. HAS THE COMPANY CONSIDERED THE ENTIRE COST TO DECOMMISSION WATERFORD AND RIVER BEND IN DETERMINING THE AMOUNT THAT SHOULD BE INCLUDED IN ELL'S RETAIL RATES?

A. Yes, it has. As noted earlier, as a starting point for Waterford, the Company has considered 100% of the cost to decommission the facility in its analysis. For LPSC retail ratemaking purposes, however, a revenue requirement offset is reflected in the adjustment in order to recognize the portion of decommissioning cost that is allocable to Entergy New Orleans, LLC ("ENO") pursuant to the existing ELL-ENO purchased power agreement ("PPA") for Waterford 3. For LPSC retail ratemaking recovery purposes associated with River Bend in this proceeding, the Company is only considering the LPSC-retail jurisdictional, 57.5% portion of the regulated 70% of River Bend because 42.5% of the output from the regulated 70% of River Bend is subject to a PPA with Entergy Texas, Inc. ("ETI"), which is not considered in the Louisiana retail rate analysis. The remaining 30% of River Bend was initially owned by the former Cajun Electric Cooperative ("Cajun") before ELL's predecessor acquired it as part of Cajun's bankruptcy proceedings in 1997. This 30% share of River Bend is currently treated as unregulated plant for purposes of ELL retail rates.[12] Therefore, the analysis presented here only considers the LPSC-retail jurisdictional portion of the 70% share of River Bend.

Q13. IN PRESENTING THE NEEDED DECOMMISSIONING FUNDING, HAS THE PROPOSED FUNDING LEVEL BEEN REDUCED ON ACCOUNT OF THE DEREGULATED ASSET PLAN ("DAP")?

A. No. In Order U-31237, the LPSC affirmed that the decommissioning costs for the DAP portion of the LPSC-jurisdictional share of River Bend should be included in ELL's rates "separately, and in addition to, the 4.6 cents per kWh."[13] As such, the Company has included the full regulated 70% share of River Bend decommissioning costs in its analysis here.

Q14. WHAT DECOMMISSIONING COST ESTIMATES DID THE COMPANY USE IN ITS ANALYSIS?

A. As noted previously, for both River Bend and Waterford 3, the Company analyzed the required decommissioning funding based on site-specific analyses performed by TLG Services, which analyses, as updated, using 2022 dollars. I have attached these site-

[12] Decommissioning costs of the 30% share of River Bend are separately covered by a decommissioning fund that was transferred from Cajun to Legacy EGSL in the Cajun bankruptcy proceedings.

[13] "The nuclear decommissioning costs of the DAP portion of River Bend should be returned to EGSL's revenue requirement consistent with the original DAP order and collected separately, and in addition to, the 4.6 cents per kWh." *See* Order No. U-31237 (August 27, 2010), *In re: Joint Application of Entergy Gulf States Louisiana, L.L.C. and Entergy Louisiana, LLC for Approval of an Increase in Funding for Decommissioning for River Bend and Waterford 3 Nuclear Facilities/LPSC Docket No. U-31237, Order, Id.* at Ordering Paragraph 9.

specific studies to my testimony as KFG-3 and KFG-4. The site-specific study using the DECON[14] method for Waterford 3 estimates the cost to decommission and dismantle Waterford 3 to be $1.277 billion (in 2019 dollars); similarly, the site-specific study using the DECON method for River Bend estimates indicates the regulated 70% share of cost to decommission and dismantle River Bend to be $855 million (in 2018 dollars).

These studies utilized site-specific, technical information unique to both Waterford 3 and River Bend and are relied on by ELL in the normal course of business to account for the asset retirement obligations associated with each of these facilities. TLG Services has performed decommissioning cost analyses for numerous utilities and retail regulators across the country.

### B. Nuclear Decommissioning Escalation Rate

Q15. HOW DID YOU DETERMINE THE DECOMMISSIONING COST ESCALATION RATE THAT YOU USED IN YOUR ANALYSIS?

A. As noted earlier, a cost escalation rate is necessary to determine an appropriate amount of decommissioning cost that must be paid in the future via trust fund contributions and accumulations. To determine the cost escalation rate that should be used to calculate the future value of the decommissioning costs, I used an approach to decommissioning cost escalation that the LPSC has previously approved for ratemaking purposes. The

[14] DECON is defined as "the alternative in which the equipment, structures, and portions of a facility and site containing radioactive contaminants are removed or decontaminated to a level that permits the property to be released for unrestricted use shortly after cessation of operations." *See* KFG-Ex. 4, p. ix, 8-9.

approach tracks that employed by the NRC and used in its financial assurance formula to quantify minimum requirements. In this context, whereas the NRC, for Minimum Financial Assurance purposes, relies upon the values in historical indices set out for that purpose, my recommendation for future cost escalation is to use the same formula but use forecasts of those values to determine the future cost escalation. Thus, to be consistent with the NRC's financial assurance formula, ELL obtained forecasts of indices relevant to the cost categories used in the NRC weighted average escalation formula for its "minimum value" determination to establish reasonable escalation rates for those cost categories.

The specifically defined cost category weights and their related escalation rates are set out or referenced within the NRC's NUREG-1307, Revision 19 publication, with labor and energy rates published by the U.S. Bureau of Labor Statistics. To be consistent with the NRC financial assurance formula, I quantified the proposed Waterford 3 and River Bend decommissioning cost escalation rates using the NRC's specific cost categories but, in this case, using forecasts for the Labor, Energy-Electric Power, Energy-Fuel Oil, and Waste Burial factors.

Q16. PLEASE EXPLAIN HOW THE NRC COST CATEGORIES AND THEIR RESPECTIVE WEIGHTINGS WERE UTILIZED.

A. Chapter 3, Development of Cost Adjustment Formula ("Chapter 3"), of NRC's NUREG-1307, Revision 19, Report on Waste Burial Charges (February 2023) provides the basis for identifying the four cost categories mentioned above. For purposes of developing the escalation formula, the NRC explains in NUREG-1307, Revision 19 that decommissioning costs can be divided into three general areas within which costs tend to escalate similarly. Those general areas are as follows:

- Labor, materials, and services;
- Energy and transportation; and
- Radioactive waste disposal (Burial cost).

For purposes of the NRC formula, each category grouping above is assigned a percentage of the generic total costs in 1986 dollars identified in 10 C.F.R. § 50.75. Given the fact that site-specific analyses are being utilized in this analysis, the generic weightings are no longer appropriate. In their stead, the site-specific estimates of the above cost categories are, in my opinion, more relevant. Those relevant cost percentages are:

- Labor (i.e., labor, materials, and services): 68% (River Bend) 72% (Waterford 3);
- Energy (i.e., energy and waste transportation): 18% (River Bend) 20% (Waterford 3); and
- Burial (i.e., radioactive waste disposal): 14% (River Bend) 9% Waterford 3).

For my analysis, I used these percentages to calculate the weighted escalation rate applied to the TLG determined site-specific estimates.

Q17. WHAT COST ESCALATION RATES ARE APPROPRIATE FOR EACH OF THE COST CATEGORIES IDENTIFIED ABOVE?

A. To obtain the most relevant basis for forecasting the overall escalation rate, forecast data for indices that align with those employed in the NRC formula were obtained from the Economics and Country Risk from IHS Markit (formerly known as Global Insight) ("Global Insight") forecasting organization.[15] The cost escalation rates for the labor and energy factors were derived from forecasts developed by the Global Insight forecasting organization, which align with the U.S. Department of Labor and Bureau of Labor Statistics ("BLS") indices for labor and energy data covering the period from 2023-2032. Highly Sensitive Protected Material ("HSPM") Exhibits KFG-5 and KFG-6 identify the specific forecast data used for each of the relevant categories and the calculation of the escalation rates.

To obtain the basis for the escalation of the Labor component of decommissioning costs, Chapter 3.1 of NUREG-1307, Revision 19 relating to Labor Escalation Factors indicates that the labor category should be escalated at a rate tied to the BLS Employment Cost Index. I used Global Insights' forecast of the Employment Cost Index of 3.70% for the relevant period.

Chapter 3.2 of NUREG-1307 Revision 19 relating to Energy Escalation Factors indicates that the appropriate basis for calculating the weighted average projected energy escalation rate is a weighted average Produce Price Index ("PPI") forecast rate

[15] Global Insight founded the modern economic forecasting industry. It originated through the merger of Wharton Econometric Forecasting Associates ("WEFA") and Data Resources Inc. ("DRI"), together with Primark Decision Economics (later called Decision Economics, Inc.).

for Industrial Electric Power and Light Fuel Oil. For this purpose, I used Global Insight forecasts of the PPI for Electric Power and Fuel Oil. Consistent with the NUREG-1307 formula, I determined a weighted average or composite of the electricity and light fuel oil rates. Using the approach employed in the NRC formula, a composite energy escalation rate of 2.03% is calculated using weightings of 58% electricity and 42% fuel oil for a pressurized water reactor ("PWR") (Waterford 3) and a composite energy escalation rate of 1.92% is calculated using weightings of 54% electricity and 46% fuel oil for a boiling water reactor ("BWR") (River Bend).

Finally, the waste burial component of the composite escalation factor must be estimated. Due to the unavailability of any published forecast projecting future escalation for this component, historical data must be used and extrapolated. As will be discussed below, a 7.22% escalation rate for BWR waste burial and a 7.54% escalation rate for PWR waste burial is proposed based on historic NRC published data.

Q18. WHY IS THE HISTORIC BURIAL ESCALATION RATE SELECTED AS AN APPROPRIATE ESCALATION RATE FOR THE WASTE BURIAL COMPONENT?

A. Unlike the forecasts of Labor and Energy costs used in the NRC formula, there are no published forecasts of expected future waste burial costs for nuclear generating facilities. Given the unavailability of published forecasts, the historical trends of burial cost escalation are the only data available for analysis. The NRC has established a generic disposal site index "For Generators Located in the Unaffiliated States and those

Located in Compact-Affiliated States having a Disposal Facility" and notes that licensees meeting that criterion should use this value for their cost estimates.[16] Because Louisiana is an unaffiliated state, it is reasonable to rely on changes in this index to develop an historical cost trend relevant for Waterford 3 and River Bend burial costs. Given the lack of any additional, alternative data it is my judgment that the use of this index is a reasonable basis for projecting burial cost for purposes of the projected overall cost escalation rate. In addition, as concerns the use of this data for forecasting purposes, it appears based on the observations of the NRC in describing the construction of this index that the NRC has indicated that in certain circumstances this index may understate the estimated future cost of decommissioning.[17] In this regard, the NRC has indicated that the burial indices assume LLW processing was accomplished before decommissioning has commenced. However, for plants that have significant LLW remaining at the time of decommissioning, the burial cost indices do not reflect such LLW decommissioning cost. In this context NUREG -1307 Revision 19 states as follows:

> Some of this (LLW) waste may ultimately need to be disposed of during decommissioning. This LLW could be significant for plants with extended operating periods (*e.g.,* beyond 40 years), and the disposal costs of this additional volume may not be accounted for in a decommissioning trust fund based upon the formula calculation.[18]

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[16] Short, S. and Toyooka, M., *Report on Waste Burial Charges,* United States Nuclear Regulatory Commission at pp. 2-3 (February 2023) [hereinafter "NUREG-1307, Rev.19"], *available at* https://www.nrc.gov/docs/ML2304/ML23044A207.pdf.

[17] NUREG-1307, Rev. 19 at p. 3 (discussing Low Level Waste ("LLW") burial costs in its indices).

[18] *Id.*

This suggests that whatever information can be inferred from historical burial cost data for licensees such as Waterford 3 and River Bend, the escalation rate of future decommissioning burial costs may be expected to be higher in the future than the historic trends reflected in the NRC's index.

Q19. GIVEN THIS, WHAT IS YOUR RECOMMENDATION FOR THE ESCALATION RATES FOR BURIAL COSTS?

A. I recommend the use of the long-term trend in NRC burial cost data for BWR and PWR burial costs for "Generators Located in Compact-Affiliated States having no Disposal Facility," although it may understate the escalation rate. HSPM Exhibits KFG-5 and KFG-6 reflect the historical rate of escalation beginning in 1986 and ending in 2022 for the NRC published burial data presented in NUREG 1307, Revision 19. In order to make a calculation of the average annual growth rate, I took the index values presented in 2022, and used an index value of 1.00 to represent costs in 1986 dollars – the prescribed NRC index starting date. I then created a table showing the years of costs that these indexes covered and solved for the average annual growth rate that would be needed to move from an index value of 1.00 in 1986 to the 12.296 value for a BWR and 13.712 value for a PWR from the NRC Table for 2022 costs. This calculation resulted in a growth rate of approximately 7.22% for a BWR and 7.54% for a PWR.

Q20. WHAT ARE THE OVERALL DECOMMISSIONING COST ESCALATION RATES THAT YOU HAVE DETERMINED?

A. As can be seen from HSPM Exhibits KFG-5 and KFG-6, the overall decommissioning cost escalation rates calculated for Waterford 3 is 3.70% and for River Bend is 3.87%. While these updated escalation rates are lower than the most recent decommissioning cost analysis, it should be noted that the labor escalator has increased significantly due to recent inflation and projected effects on labor markets.

Q21. WHAT IS THE CURRENT LPSC-APPROVED DECOMMISSIONING COST ESCALATION RATE FOR WATERFORD 3 AND THE REGULATED 70% SHARE OF RIVER BEND?

A. The overall decommissioning cost escalation rate approved by the LPSC and currently in place for Waterford 3 and the regulated 70% share of River Bend decommissioning funding purposes is 4.25%.[19] The 4.25% rate was approved by the LPSC in 2010 and based on data available only up through the 2008 time period. The proposed overall decommissioning cost escalation rates of 3.70% and 3.87%, while albeit lower, reflect an explainable computational difference from the existing rate of 4.25%. The proposed escalation rates are premised upon the weightings of cost categories (Labor, Energy, Burial) consistent with the site-specific analyses rather than the NRC generic formula

[19] *See,* Order No. U-31237 (August 27, 2010), *In re: Joint Application of Entergy Gulf States Louisiana, L.L.C. and Entergy Louisiana, LLC for Approval of an Increase in Funding for Decommissioning for River Bend and Waterford 3 Nuclear Facilities/LPSC Docket No. U-31237, Order, Id.* at Exhibits A and B.

weightings, and the weightings consistent with the site-specific analyses reduce the effect of the burial cost escalation rate on the overall weighted escalation rate.

### C. Nuclear Decommissioning Trusts

Q22. HAVING DETERMINED THE CURRENT DOLLAR DECOMMISSIONING COST ESTIMATES AND THE COST ESCALATION RATES, WHAT WAS THE NEXT STEP?

A. The next step in quantifying the decommissioning cost revenue requirement is the quantification of the market or liquidation values for the decommissioning trust funds that currently exist from prior contributions and cumulative trust earnings. The liquidation value of the trust is calculated as amounts in the trust net of unrealized taxes and fees and represents the net cash available to actually fund decommissioning. For purposes of determining ELL's decommissioning funding plan and retail revenue requirements for Waterford 3 and River Bend, the actual December 31, 2022, liquidation values were used as the starting point. As can be seen in the beginning balance in HSPM Exhibits KFG-5 and KFG-6, the trust fund liquidation values are $618.3 million for Waterford 3 and $263.6 million for the LPSC-jurisdictional portion of the 70% portion share of River Bend.[20] In the revenue requirement modeling, these amounts are estimated to grow into the future based upon projected contributions from rates and projected after tax earnings. Having determined the beginning trust balances,

[20] The use of liquidation values net of taxes and fees was approved in the prior approach to funding valuation used in prior cases. These amounts were supplied by ESL.

the next step is to determine a projection of after-tax earnings rates. It should be noted that recent stock market turmoil has caused these values to drop 12-18% respectively during the period of analysis last year.

Q23. PLEASE EXPLAIN THE METHODOLOGY USED TO ESTIMATE THE TRUST FUNDS' ANNUALIZED AFTER-TAX EARNING RATES.

A. A weighted average after-tax return for the funds for each of the years 2023 through 2044-2045 was estimated. Although contributions to the funds are expected to end in 2044 for Waterford 3 and 2045 for the regulated 70% share of River Bend, the funds will continue to earn a rate of return on decreasing balances, as funds are utilized for decommissioning expenditures through the decommissioning periods. The calculations of the weighted average after-tax earnings estimates were based on the forecasts provided by Entergy Services, LLC's ("ESL") Treasury Department and are reflected in HSPM Exhibits KFG-5 and KFG-6.

Q24. CAN YOU DESCRIBE HOW THE AFTER-TAX EARNINGS RATES WERE DETERMINED?

A. The analysis of forecasted after-tax earnings was performed by ESL's Treasury Department. The starting point for the after-tax earnings rates projected for the decommissioning trusts was the year-end 2022 actual parameters for capital structure, actual cost rates and currently applicable tax rates for decommissioning trust investments. Going forward, the actual 2022 capital structure of the trusts (60%

equity/40% debt) was assumed, along with the forecasted earnings and cost rates from the IHS Markit forecasts. The projected equity return averages approximately 9.50%.

## V. PROPOSED NUCLEAR DECOMMISSIONING REVENUE REQUIREMENTS

Q25. PLEASE SUMMARIZE THE RESULTS OF ELL'S UPDATED REVENUE REQUIREMENT ANALYSIS RELATING TO THE DECOMMISSIONING OF WATERFORD 3 AND RIVER BEND NUCLEAR GENERATING UNITS.

A. The updated decommissioning revenue requirement analysis described above indicates that increasing ELL's annual decommissioning funding to $33.662 million for Waterford 3 and $10.967 million for the 70% share of River Bend, based on the 2018-2019 site-specific studies attached to my testimony.

Q26. DID THE COMPANY REQUEST THAT YOU PERFORM AN ALTERNATIVE REVENUE REQUIREMENT ANALYSIS?

A. Yes. As discussed by Mr. O'Malley, the Company requested that I perform an alternative analysis that maintains the current combined decommissioning revenue requirement for two years but reallocates where the funds are deposited between Waterford 3 and River Bend.

Q27. PLEASE EXPLAIN THE REVENUE NEUTRAL ANALYSIS.

A. Under the revenue requirement analysis, the current overall decommissioning revenue requirement remains in place for 2024 and 2025 but with a shift in funding as between the two units on an overall revenue neutral basis. The revenue neutral shift in funding is intended to reduce the extent to which Waterford 3 is underfunded relative to River Bend based on the analysis as follows:

| **2024 Revenue Requirement ($ millions)** | | |
|---|---|---|
| | **Current** | **Proposed** |
| Waterford 3 | 7.731 | 13.521 |
| River Bend | 10.195 | 4.405 |
| TOTAL | 17.926 | 17.926 |

## VI. CASH WORKING CAPITAL PRINCIPLES

Q28. CAN YOU DESCRIBE THE ROLE OF CASH WORKING CAPITAL IN THE DETERMINATION OF RATE BASE?

A. In the determination of utility rate base, cash working capital represents the amount of capital that must be provided by investors over and above the investment in plant and other rate base items necessary to bridge the gap in time between cash payments for expenses required to provide utility service and revenue collections received for such service.

There are two approaches to the quantification of cash working capital, which are in general use in utility ratemaking, the balance sheet approach, and the lead-lag approach. The approach that is the preferred method of the LPSC and that is most often used across the country for ratemaking purposes is the lead-lag analysis. This analysis relies, fundamentally, upon the measurement of the difference in the timing of revenue receipts and cash payments for expenses including taxes. In this context, noncash items such as depreciation and deferred tax expenses are not reflected in the analysis. The analysis outlined below relies upon the lead-lag analysis.

The difference in timing subject to analysis in this case is referred to as a "lead" or a "lag" depending upon the relative timing of cash inflows and cash outflows. Some analysts use the term "lead" with regard to expenses and "lag" with regard to revenues, but this report generally refers to all the timing differences as "lags," positive or negative regardless of whether revenue or expense is at issue. There is no difference in the application of this analysis.

The other measure of cash working capital not used in this study, the balance sheet method, relies upon the amount of measured differences in the amounts of categories of short-term payables and receivables derived from monthly balance sheets as the basis for cash flow and cash working capital. This balance sheet approach is somewhat less reliable because it does not focus on the specific timing of cash inflows and cash outflows, but this approach may be useful as a supplement if the detailed revenue and expense data related to timing are not readily available. In my experience, there are occasions where analysts will supplement the lead-lag analysis with a form of the balance sheet approach, however, I do not generally agree with that approach. In the analysis that I propose, there are revenue and expense lag data available without balance sheet items.

As noted above, the primary purpose of the lead-lag study is to establish accurately the amount of cash needed to support utility operations from the time payments are made to employees, vendors, taxing authorities, and other parties to provide electric service before the time that revenues are received for such services from customers. Under such circumstances a rate base addition is necessary. It should also be noted that it may be the case, conversely, if cash is available to fund operations from receipt of revenue before the payment of expense, then cash is supplied from such revenue. This circumstance would result in a deduction from rate base.

## A. ELL Lead-Lag Analyses Overview

Q29. CAN YOU DESCRIBE THE METHODOLOGICAL APPROACH TO YOUR ANALYSIS?

A. The lead-lag analysis undertaken for this case studied the specific timing associated with the various components of revenue receipts and expense payments that ELL incurred during the twelve months ended December 31, 2022, the Test Year in this proceeding. Net lags (i.e., revenue lag net of expense lag) for each category of cash operating expense were developed. In connection with developing revenue and expense lag data, it should be noted that, due to the volume of billing and payment transactions for several categories of revenues and expenses, randomly selected samples of revenue and expense billing and payment data were utilized.

Specifically, the following billing and payment items were analyzed: (1) the lag in the eight principal aspects of revenue receipt from ELL's customers; and (2) the lag in the aspects of each category of cash payroll, fuel and purchased power, operations and maintenance ("O&M") expense, tax expense, and interest expense items. The issue of funds availability, or float, was also analyzed. This item, which will be discussed in more detail below, involves measuring the amount of time necessary for funds to be available due to bank account clearing for checks, cash and the various forms of electronic receipt and payment. Funds availability is applicable to both revenues and expenses where payments and receipts are transacted by means other than wire transfer, also known as electronic funds transfer ("EFT"), or automated clearinghouse ("ACH"). As noted previously, noncash expenses such as depreciation and deferred tax expense were not analyzed because, as noncash expenses, these items do not represent a source or use of cash working capital. The summary of the lags for all of the revenue and expense categories is presented on Exhibit KFG-2.

As concerning the issue of random sampling referred to above, professional judgment as well as certain aspects of statistical sampling principles were utilized to determine sample size for those areas of the lead-lag analysis where sampling was necessary. The specific sample sizes used in the analysis are identified in the discussion of the various revenues and expenses lags below. Regarding the invoice data utilized, the transaction data were extracted (i.e., "queried") from ELL's accounts receivable and payable databases for invoice dates that occurred during 2022.

## B. ELL Lead-Lag Analysis Revenues

Q30. CAN YOU DESCRIBE HOW YOU ANALYZED THE LAG IN REVENUES?

A. For purposes of analyzing revenue lag, a separate lag was calculated for each of the most significant categories of ELL 2022 revenues. Each of these categories included separate lags for separate components of the overall revenue receipt lag. The categories were defined as follows:

- Revenues from four retail customer classes: Residential, Commercial, Industrial, and Public Authority and Street Lighting;
- Revenue from non-associated company Purchase Power Agreement ("PPA") Transactions;
- Revenues from Midcontinent Independent System Operators, Inc. ("MISO") Transmission Settlement transactions on both a weekly and monthly basis; and
- Revenues from Entergy System associated company Purchase Power Agreement, which are labeled as MSS-4-like Purchased Power Agreement transactions.

ELL's revenues were broken down into these groups because analysis revealed that the patterns of revenue receipt and payment amounts showed variation in the length of the cash conversion cycles such that revenue lags differed materially from each other during the Test Year. The analysis that underlies this lead-lag study evaluates four separate revenue receipt lag components for each of the categories of test year revenue:

- Service period to meter read (Service Period);
- Meter read and billing lag (Metering to Billing where applicable);
- Collection lag (Billing to Payment); and
- Funds availability lag (where applicable).

The revenue lag for a given revenue category is the total of the component lags associated with each of the separate revenue receipt lag components. The overall ELL revenue lag is the weighted average of the eight revenue category lags. This process resulted in a weighted average revenue lag of 39.5 days for ELL in 2022.

### C. <u>Retail Rate Class Revenue Lag</u>

Q31. CAN YOU DESCRIBE IN MORE DETAIL THE APPROACH USED TO QUANTIFY THE REVENUE LAG?

A. The revenue receipt lag measurements are based on randomly selected samples of customer bills from each of four retail revenue classes: Residential (sample of 180), Commercial (sample of 173), Public Authority and Street Lighting (sample of 176), and Industrial (sample of 122 bills). For each of these bill samples, data were obtained from the Company's customer database for the key dates that highlight the cash collection cycle.

The starting point of the revenue lag analysis is defined as the Service Period. The Service Period Lag represents the period of time during which electric service was provided to customers and for which those customers were billed. ELL's retail customers receive monthly bills for electric service; each bill is from 1 of 21 billing cycles for monthly service days. The monthly Service Period Lag is 30.4 days (365/12) with a service period midpoint of 15.2 (30.4 days/2) days for each of the four retail revenue classes, or the midpoint of a typical month in a typical year.

The second step in the billing process for retail customers is Meter Read and Billing Lag. This lag represents the time it takes to create and render a bill based on the usage for a given billing month. For each of the four retail customer groups quantified, the Meter Read and Billing Lag Days were quantified as the time between the day on which the customer's meter was read and the day on which the bill for that usage was mailed to the customer. This lag differs slightly for each retail class and ranges from 3.0 to 4.2 days.

The Collection Lag refers to the time it takes a customer to remit payment for service once it has been mailed. Collection Lag was quantified as the difference in days between the pay date of the bill and the mail date of the bill. This lag also differs for each retail class and varies from 16.2 to 23.3 days.

Regarding the computation of the final component of the revenue lag, the funds availability lag (or "float") represents the time period necessary for funds from payments by customers to be available to the Company. Checks, ACH transactions, and EFTs each require a certain period of time to clear from a customer's account and to be available for use in the Company's account. The lag time for this lack of funds availability must be calculated separately and added to the revenue lag. ELL customers have a variety of options available to make payments, including mail payments, service center, automatic draft, and wire transfers. Data available from ELL's remittance processing operations were analyzed and factored in the immediacy of cash availability from all reported forms of payment. Based on this analysis, a lag of 1.1 days for each of the related classes of customers is appropriate.

### D. Non-Retail Revenue Lag

Q32. CAN YOU DESCRIBE THE LAG ANALYSIS ASSOCIATED WITH NON-RETAIL REVENUE, THAT IS PPA, MSS-4-LIKE, AND MISO REVENUE?

A. There are four (4) categories of non-retail revenue. Those categories include PPA revenue, MSS-4-Like revenue, and two types of MISO transactions.

In regard to PPA revenues, such revenues are received by ELL pursuant to standard PPA contract payment terms between ELL and its counterparties. Those terms generally reflect payment requirements of under a standardized contract calling for payment approximately 20 days after the monthly service period. Because the payment requirements are similar for all of these transactions, the expense lag and receipt lag will be the same. To determine this lag, a random sample of 36 invoices was selected. That analysis resulted in a lag collection lag of 18.0 days. Since there is no metering or billing lag in these contracts, only the service period and collection lags are considered. In addition, since there is no funds availability lag, due to the use of wire transfers for the receipt of PPA revenue, the PPA revenue lag is 33.2 days.

### E. MISO Revenue Lag

MISO revenues are received on a weekly and monthly basis, pursuant to the terms set out in the MISO Business Practices Manual. Under this approved MISO process, weekly transaction receipts by ELL are received 16.5 days after the weekly settlement. Monthly transaction receipts are received 27.2 days after the monthly settlement.

### F. MSS-4-like Revenue Lag

MSS-4-like revenues reflect ELL's receipts from certain purchased power transactions among Entergy Operating Companies that are FERC-approved tariffs that are virtually identical in payment terms to those which existed under the former Entergy System Agreement. Because the payment requirements are similar for all of these transactions, the expense lag and receipt lag will be the same. To determine this revenue lag, a sample of the 22 monthly invoices for MSS-4-like transactions was examined. Since the lag for MSS-4 like revenues is identical to the lag in MSS-4-like expense, the transactions analysis focused on MSS-4 like samples of expenses. Since MSS-4-like transactions have no metering lag or a billing lag, the relevant lag components are service period and collection. Revenues are received (and expenses are paid) electronically, so there is no funds availability lag. Therefore, based upon the analysis, the overall lag for MSS-4-like revenue is 59.2 days.

## G. ELL Lead-Lag Analysis – Expenses

Q33. HOW WERE CASH EXPENSES ANALYZED IN YOUR LEAD-LAG STUDY?

A. As will be discussed in more detail below, the lag in overall expense was analyzed in several categories of cash O&M expense, tax expense, and other items. Below is a list summarizing these categories:

- O&M – Payroll
- O&M – Fuel (Coal, Oil, Gas, Nuclear)
- O&M – Purchased Power (*e.g.*, Cogeneration, PPAs, MSS-4-Like, MISO, etc.)
- O&M – Entergy Services, LLC
- O&M – Big Cajun
- O&M – Other O&M Expense
- Taxes Other Than Income – Payroll, Property, Other – State, Local, etc.
- Income Taxes – Federal ("FIT") and State ("SIT")
- Interest Expense

Just as ELL's revenue lag needs to be adjusted for funds availability, ELL's expense lag needs to be adjusted for the effect of funds availability. This determination is discussed in those categories of expenses where appropriate.

## H. O&M Payroll Expense Lag

Q34. DESCRIBE HOW THE PAYROLL LAG IS DETERMINED.

A. The overall payroll lag is determined to be 23.7 days and has four separate components. The components are:

- The lag in regular payroll payments,
- The lag in remitting payroll withholding items,
- The lag in annual incentive payments, and
- The lag in funds availability, or float.

### 1. Regular Payroll Lag and Float

ELL employees are paid every other week with a one-week payment delay. The regular payroll lag measures the time from the midpoint of the payroll period – the period during which work was performed and during which expense accrued – to the date of payment for that work. This lag is calculated at 13.0 days. As further detailed below, after taking into account funds availability for regular payroll due to payment by check (as opposed to direct deposit), the regular payroll lag is 13.0 days even after giving effect to a float lag for those employees paid by check.

### 2. Payroll Withholdings Remittance Lag

Separately analyzed were the lag days to remit to the appropriate entity the payroll withholding items such as payroll taxes and employee deductions. Payroll deductions for employee-paid taxes, benefits, and other withholdings are calculated separately using the Company's payment practices for each item. The lag for these payments is 16.6 days or approximately 3.6 days longer than regular payroll.

**3. O&M Payroll Funds Availability**

As noted above, funds availability reflects cash in a payer's bank account dedicated to a specific payment that has not yet cleared from its originating account. On the expense side of the lag computation, funds availability, or check float, represents the period of time that funds remain available to the Company in its accounts after payments have been made by check – either to employees or to third-party vendors – and recorded on the books. This delay results from the fact that checks do not clear the Company's accounts on the day that the checks are distributed. Checks clear when the employee or vendor deposits the check, whereas ACH, EFT, and direct deposit payment methods generally settle after one day. This availability of cash to the Company must be separately accounted for as an addition to the expense lag in the lead-lag analysis. A significant amount of payroll is direct deposit, 99%, but the funds availability must be measured both to reflect the time to settle the direct deposit transactions and to reflect the float associated with the 1% of payroll still paid by check. Even though the funds availability lag is 4.7 days for those paid by check there is no additional lag for total regular payroll and annual incentive pay on a weighted-average basis. Withholdings amounts are remitted electronically, and thus there is no associated funds availability lag.

## I. Lag in O&M Fuel, Purchased Power Expense

Q35. HOW WAS THE LAG IN THE VARIOUS CATEGORIES OF FUEL AND PURCHASED POWER EXPENSES MEASURED?

A. To compute the payment lags for fuel and purchased power expenses, the data were segmented into the separate components of fuel expense and of purchased power expense. Those components are:

- Fuel: Coal, Oil, Gas, Nuclear; and
- Purchased Power: Cogeneration, MSS-4-Like, System Energy Resources, Inc. ("SERI"), Hydro, and Other PPAs

For each of the categories of fuel and purchased power, a separate lag was calculated for (1) the service period and (2) the payment date to determine the overall payment lag. A separate component for funds availability was not needed since virtually all payments for fuel and purchased power are made electronically. The payment lag days for the components of fuel and purchased power expense are as follows:

| **Description – Fuel** | **Lag (Days)** |
|---|---|
| Coal | 17.1 |
| Oil | 10.6 |
| Gas | 36.0 |
| Nuclear | 74.7 |
| **Description – Purchased Power** | |
| Cogeneration | 42.4 |
| Hydro | 32.7 |
| MSS-4-like | 59.2 |
| PPAs | 33.2 |
| SERI | 28.7 |
| MISO Weekly | 14.5 |
| MISO Monthly | 27.2 |

The expense lags for each of the Fuel and Purchased Power categories were calculated either from the entire population of associated invoices, or if the number of invoices was very large, from a randomly selected sample from that population. In connection with the fuel lag for coal, this lag was calculated using a sample of 49 invoices. The fuel lag for oil expenses was calculated using the Test Year population of all 27 invoices. The fuel lag for gas expenses was calculated using a randomly selected sample of 75 invoices. Based upon the analysis of invoices, the fuel lag calculation for oil is 9.6 days, the fuel lag calculation for coal is 17.1 days and the fuel lag calculated for gas is 36.0 days. The lag for each category of expenses was calculated based upon the weighted dollar value of the individual invoices.

ELL acquires nuclear fuel for both Waterford 3 and River Bend nuclear facilities through a lease agreement and makes quarterly payments per the terms of this lease approximately 28 days after the end of each quarterly service period for both units. To determine the nuclear fuel lag, eight (8) quarterly lease invoices were examined. Using the methodology of a weighted-average lag – as described previously for the oil, and gas fuel expenses – the average lag for nuclear fuel expenses is 74.7 days.

Regarding Purchased Power, this category was separated into several subcategories: Cogeneration, PPA, MISO, and MSS-4-like. Below is a summary of the sample sizes used to calculate the weighted-average lag for each expense category:

| **Category** | **Sample Size** |
|---|---|
| MISO Weekly | N/A |
| MISO Monthly | N/A |
| Cogeneration | 48 |
| MSS-4-like | 20 |
| Hydro | 32 |
| PPA – Other | 36 |
| SERI | 12 |

A random sample of invoice entries was queried from the population of Cogeneration and PPA – Other invoices. The entire population of test year invoices was used for MSS-4-like, Hydro, and SERI expenses. The same weighted-average methodology was applied to each data set to determine the lag days associated with each category of purchased power expense. The Hydro refers to power and energy purchased from hydro-power stations, including from the Catalyst Old River (also known as Murray Hydro) generating facility. SERI purchased power refers to payments made to System Energy Resources, Inc. for ELL's share of the output of the Grand Gulf generating facility.[21] The payments to MISO result from the variety of transactions that occur due to integration with MISO.

Two separate lags for two anticipated groups of MISO invoices were developed using the MISO Business Practices Manual. As for MISO weekly payments, Entergy Operating Companies – including ELL – will have weekly settlements of MISO invoices which each operating company will be either a net payer or a net receiver of revenues. When ELL is a net payer, the lag is expected to be 14.5 days; when ELL is a net receiver, the lag is expected to be 16.5 days. This difference is due to collection time at MISO.

MISO monthly payments, Entergy Operating Companies – including ELL – will have monthly settlements with MISO for transmission expenses. The total payment lag for the associated invoices will be 27.2 days for both revenue and expenses.

[21] SERI has a 90% ownership interest in the Grand Gulf Steam Electric Generating Station, a single unit nuclear plant located in Mississippi. SERI sells the output from the plant to several of the Entergy Operating Companies, including ELL, under a Unit Power Sales Agreement.

### J. Lag in Entergy Services, LLC ("ESL") Expenses

Q36. HOW WAS THE LAG FOR AFFILIATE EXPENSE DERIVED?

A. ESL is a subsidiary of Entergy Corporation that provides technical and administrative services to all of the Entergy Operating Companies, including ELL. A weighted-average approach consistent with that applied for other expense categories was applied to determine the lag in payments for ESL services. ELL paid twelve monthly invoices related to affiliate transactions with an average lag of 34.1 days. This lag is consistent with the terms of the ESL-ELL Service Agreement.

### K. Lag in Big Cajun Expenses

Q37. WHAT IS BIG CAJUN EXPENSE AND HOW IS THE PAYMENT LAG FOR THESE EXPENSES DETERMINED?

A. ELL has a 42% interest in Big Cajun 2 Unit 3. Louisiana Generating Company, L.L.C. ("NRG") is the majority owner and operates the facility. The invoice totals include costs for coal and oil in addition to O&M, capital insurance, and stores expenses. ELL paid 12 invoices from NRG during the Test Year. The same weighted-average lag calculation was applied to the NRG invoices as well as to invoices in other segments of this study. The weighted-average lag for Big Cajun expenses is 43.9 days. Since Big Cajun payments are made by wire, no funds lag availability is needed.

### L. Lag in Other O&M Expenses

Q38. HOW WAS THE LAG IN OTHER O&M EXPENSES QUANTIFIED?

A. Due to the large volume of Other O&M Expense invoices, the lag in Other O&M expenses was quantified using a two-step sampling process. First, the population of invoices which represents those invoices not included in those categories identified elsewhere in this study were identified. That process resulted in 60,659 entries in the Company's accounts payable system. These data were sorted into six strata based on the dollar amount of the invoice lines that appear on the entries in the accounting system. Below is a list of the six groups and the grouping of invoices referenced in this group:

| **Invoice Group** |
|---|
| Over $100,000 |
| $50,001 - $100,000 |
| $25,001 - $50,000 |
| $10,001 - $25,000 |
| $2,500 - $10,000 |
| Less than $2,500 |

A sample of approximately 50 invoice entries was then taken from each of these stratified invoice populations. This sampling process resulted in 300 usable invoices across the six groups.

A dollar-weighted average lag was calculated for each stratum, as is illustrated in the workpapers. These lags were then weighted according to the distribution of invoice lines for that stratum in the entire population across the six strata. The weighted-average Other O&M expense lag was 46.6 days for all the six strata.

A similar approach was taken to calculate the float or funds availability lag for Other O&M. The funds availability lag, calculated as the difference between reconciliation, or settlement date, and payment date, was determined for the same sample of invoices in each stratum and weighted according to that stratum's relative presence in the population. The weighted-average float calculation was 2.2 days, for a total Other O&M Expense lag of 49.1 days.

### M. Lag in Taxes Other than Income Taxes

Q39. THERE ARE A NUMBER OF TAX ITEMS THAT ARE TAXES OTHER THAN INCOME TAXES. HOW DID YOU DERIVE THE LAG IN THESE TAX ITEMS?

A. Taxes Other than Income Taxes encompass several categories of payments:

- Payroll-Related Taxes (Payroll Lag);
- FICA (Payroll Lag);
- Federal Unemployment ("FUTA") – employer's share (Payroll Lag);
- State Unemployment ("SUTA") – employer's share (Payroll Lag);
- Inspection and Supervision Fees;
- Property Taxes;
- City Occupation Tax;

- Occupational License Fees;
- Federal and State Excise Taxes;
- Local Franchise Requirements;
- State Franchise Taxes; and
- Federal Highway Use Taxes.

Each of these categories has a particular payment structure determined by the appropriate taxing authority except when taxes are assigned from payments made to ESL and thus the ESL expense lag is used for those amounts. The lags for the taxes not related to ESL payment obligations were calculated by the statute definitions and supplemented with payroll tax data for the Test Year ended December 31, 2022. For lead-lag purposes in this case, I utilize the statutory requirements set out for the payment of these categories of taxes.

### N. <u>Lag in Current Income Taxes</u>

Q40. HOW DID YOU DERIVE THE LAG IN STATE AND FEDERAL INCOME TAXES?

A. The Federal tax code provides for four (4) installment payments of the annual income tax liability. This process is also followed by the state of Louisiana. For lead-lag study purposes I propose the use of the statutory requirements for these expenses. A lag of 38.5 days in current federal and state income taxes was quantified by using the statutory payment dates of April 15, June 15, September 15, and December 15 for taxes.

## O. Lag in Interest Expense

Q41. HOW HAVE YOU TREATED INTEREST EXPENSE FOR LEAD-LAG STUDY PURPOSES?

A. The traditional treatment afforded by the LPSC (as well as other Commissions) for this item has been to include the lag in interest payments in the lead-lag study. Given LPSC precedent, I have typically followed this practice. Even though interest for ratemaking purposes is a part of the cost of capital included in the determination of the fair rate of return, interest, unlike return on equity, interest is an item reflected on the income statement for accounting purposes.

Q42. WHY DOES THE CONSIDERATION OF INTEREST EXPENSE AS A COST OF CAPITAL ITEM AFFECT THE TREATMENT OF THIS ITEM FOR LEAD-LAG PURPOSES?

A. The typical argument in this regard is that investor behavior reflects the risks associated with the payment of interest and dividends, and such risks are reflected in the cost of capital. Despite this argument, I propose continued adherence to the LPSC traditional treatment for purposes of this case.

Interest expense lag was calculated on the assumption of semiannual bond payments. The lag for interest expense is 91.3 days.

## VII. LEAD-LAG ANALYSIS SUMMARY

Q43. DO YOU HAVE ANY OTHER OBSERVATIONS REGARDING THE LEAD-LAG ANALYSIS PRESENTED IN THIS TESTIMONY?

A. The Company's lead-lag analysis was properly developed consistent with LPSC practice and with sound ratemaking principles. The lags developed in this analysis reflect reasonable business practices and should be appropriately applied to Test Year adjusted cash expenses to determine the appropriate amount of the cash working capital component of rate base. As noted earlier, these lead-lag data shall be applied to the relevant cost of service cash expenses to determine the effect of cash working capital in the rate base.

Q44. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes, at this time.

# AFFIDAVIT

**STATE OF LOUISIANA**

**PARISH OF ORLEANS**

**NOW BEFORE ME,** the undersigned authority, personally came and appeared, **KENNETH F. GALLAGHER**, 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.

K. F. Gallagher

Kenneth F. Gallagher

**SWORN TO AND SUBSCRIBED BEFORE ME**
**THIS 17th DAY OF AUGUST 2023**

Sean D. Moore

**NOTARY PUBLIC**

**My commission expires:** upon death

**Sean D. Moore-La. Bar No. 20303**
**Notary Public for the State of Louisiana**
**My commission expires upon death**

Prior List of Testimony for Kenneth F. Gallagher

| DATE | CODE | COMPANY | JURISDICTION | CLIENT | DOCKET NO. |
|---|---|---|---|---|---|
| 5/79 | 4 | Columbia Gas of Maryland | Maryland | People's Counsel | 7316 |
| 12/79 | 4 | Washington Gas Light | Maryland | People's Counsel | 7394 |
| 1/80 | 9 | South Central Bell | Louisiana | Public Service Comm. | U-14133 |
| 6/80 | 8 | Delmarva Power & Light | Maryland | People's Counsel | 7239 |
| 8/80 | 8 | Baltimore Gas & Electric | Maryland | People's Counsel | 7238-L |
| 9/80 | 9 | Gulf States Utilities | Louisiana | Public Service Comm. | U-14444/14495 |
| 10/80 | 4 | Washington Gas Light | Maryland | People's Counsel | 7466 |
| 11/80 | 8 | Potomac Edison | Maryland | People's Counsel | 7241-C |
| 12/80 | 9 | South Central Bell | Louisiana | People's Counsel | U-14673 |
| 1/81 | 4 | Central Louisiana Electric | Louisiana | Public Service Comm. | U-14648 |
| 3/81 | 8 | Potomac Electric Power Co. | Maryland | People's Counsel | 7240-F |
| 4/81 | 8 | Baltimore Gas & Electric | Maryland | People's Counsel | 7288-O |
| 5/81 | 8 | Delmarva Power & Light | Maryland | People's Counsel | 7289-L |
| 6/81 | 14 | Northwestern Bell Telephone | Minnesota | Public Service Comm. | 421/GR-80-911 |
| 6/81 | 4 | Cambridge Gas Company | Maryland | People's Counsel | 7518 |
| 7/81 | 4 | Frederick Gas Company | Maryland | People's Counsel | 7534 |
| 9/81 | 1 | Washington Water Power | Washington | Utilities & Trans. Comm. | U-81-15/1673 |
| 9/81 | 8 | Potomac Edison | Maryland | People's Counsel | 7241-D/E |
| 11/81 | 4 | Washington Gas Light | Maryland | People's Counsel | 7585 |
| 2/82 | 7 | Potomac Electric Power Co. | Maryland | People's Counsel | 7587 |
| 3/82 | 7 | Potomac Edison | Maryland | People's Counsel | 7604 |
| 3/82 | 9-7 | Southwestern Elec. Power Co. | Louisiana | Public Service Comm. | U-15180 |
| 4/82 | 8 | Baltimore Gas & Electric | Maryland | People's Counsel | 7238-TU |
| 4/82 | 8 | Potomac Edison | Maryland | People's Counsel | 7241-F |
| 5/82 | 4 | Columbia Gas of Maryland | Maryland | People's Counsel | 7637 |
| 6/82 | 8 | Delmarva Power & Light | Maryland | People's Counsel | 7238-O |
| 6/82 | 4 | Central Louisiana Elec. Co. | Louisiana | Public Service Comm. | U-15297 |
| 7/82 | 7 | Gulf States Utilities | Louisiana | Public Service Comm. | U-15271 |
| 8/82 | 7 | Washington Gas Light | Maryland | People's Counsel | 7639 |
| 9/82 | 7 | Delmarva Power & Light | Maryland | People's Counsel | 7643 |
| 11/82 | 9 | C&P Telephone of Maryland | Maryland | People's Counsel | 7661 |

| DATE | CODE | COMPANY | JURISDICTION | CLIENT | DOCKET NO. |
|---|---|---|---|---|---|
| 11/82 | 7 | Potomac Electric Power Co. | Maryland | People's Counsel | 7662 |
| 5/83 | 4 | Columbia Gas of Maryland | Maryland | People's Counsel | 7727 |
| 6/83 | 4 | Washington Gas Light | Maryland | People's Counsel | 7725 |
| 8/83 | 4-7 | Central Louisiana Elec. Co. | Louisiana | Public Service Comm. | U-15622 |
| 9/83 | 4 | Delmarva Power & Light Co. | Maryland | People's Counsel | 7734 |
| 9/83 | 7 | Gulf States Utilities Co. | Louisiana | Public Service Comm. | U-15640/15641 |
| 11/83 | 7 | New Orleans Public Service | Louisiana | Public Service Comm. | U-15685 |
| 2/84 | 7 | New England Telephone | Maryland | Public Utilities Comm. | 83-213 |
| 5/84 | 4 | South Central Bell Telephone | Louisiana | Public Service Comm. | U-15955 |
| 9/84 | 8 | Baltimore Power & Light Co. | Maryland | People's Counsel | 7238-F |
| 9/84 | 4 | Delmarva Power & Light | Maryland | People's Counsel | 7829 |
| 12/84 | 4 | Central Maine Power Co. | Maine | Public Utilities Comm. | 84-120 |
| 1/85 | 4-7 | Louisiana Power & Light | Louisiana | Public Service Comm. | U-15991 |
| 1/85 | 4-7 | New Orleans Public Service | Louisiana | Public Service Comm. | U-16092 |
| 3/85 | 9 | C&P Telephone of Maryland | Maryland | People's Counsel | 7651 |
| 6/85 | 4 | Potomac Edison | Maryland | People's Counsel | 7678 |
| 1/86 | 4 | Central Louisiana Elec. Co. | Louisiana | Public Service Comm. | U-16510 |
| 1/86 | 8 | Potomac Edison | Maryland | People's Counsel | 8523 |
| 4/86 | 4 | Central Maine Power Co. | Maine | Public Utilities Comm. | 85-212 |
| 4/86 | 8 | Baltimore Gas & Electric Co. | Maryland | People's Counsel | 8520/8520-A |
| 5/86 | 8 | Delmarva Power & Light | Maryland | People's Counsel | 8521 |
| 5/86 | 20 | ATICOM of Maryland | Maryland | People's Counsel | 7941 |
| 6/86 | 13 | C&P of Maryland | Maryland | People's Counsel | 7901 |
| 11/86 | 4 | Conowingo Power Co. | Maryland | People's Counsel | 7962 |
| 12/86 | 4 | Baltimore Gas & Electric | Maryland | People's Counsel | 7973 |
| 1/87 | 4 | Potomac Electric Power Co. | Maryland | People's Counsel | 7972 |
| 4/87 | 8 | Baltimore Gas & Electric Co. | Maryland | People's Counsel | 8520-D |
| 5/87 | 8 | BG&E Delmarva, PEPCO | Maryland | People's Counsel | 8520/21/22 |
| 5/87 | 8 | Potomac Electric Power Co. | Maryland | People's Counsel | 8522B |
| 7/87 | 20 | Baltimore Gas & Electric | Maryland | People's Counsel | 8053 |
| 10/87 | 20 | Washington Refuse Industry | Washington | Util. & Trans. Comm. | TG-2016 |

| DATE | CODE | COMPANY | JURISDICTION | CLIENT | DOCKET NO. |
|---|---|---|---|---|---|
| 10/87 | 8 | Baltimore Gas & Electric | Maryland | People's Counsel | 8520-C |
| 11/87 | 20 | C&F Telephone of Maryland | Maryland | People's Counsel | 7903-Phase 1 |
| 11/87 | 8 | Potomac Electric Power Co. | Maryland | People's Counsel | 8522-C |
| 4/88 | 8 | Potomac Electric Power Co. | Maryland | People's Counsel | 8522-D |
| 4/88 | 8 | Potomac Edison | Maryland | People's Counsel | 8523-E |
| 7/88 | 8 | Potomac Edison | Maryland | People's Counsel | 8523-F |
| 10/88 | 4 | Louisiana Power and Light Co. | Louisiana | LP&L | U-17906 |
| 12/88 | 4 | Columbia Gas of Maryland | Maryland | People's Counsel | 6149 |
| 3/89 | 4 | Baltimore Gas & Electric | Maryland | People's Counsel | 8190 |
| 7/89 | 4 | Baltimore Gas & Electric | Maryland | People's Counsel | 8208 |
| 7/89 | 4-25 | Maryland Natural Gas | Maryland | People's Counsel | 8191 |
| 9/89 | 7-24 | Pacific Northwest Bell | Washington | Util.& Trans. Comm. | U-89-2398-F |
| 10/89 | 4 | Baltimore Gas & Electric | Maryland | People's Counsel | 8208 |
| 12/89 | 8 | Baltimore Gas & Electric | Maryland | People's Counsel | 8520-G/H |
| 2/90 | 8 | Baltimore Gas & Electric | Maryland | People's Counsel | 8520-G/H |
| 3/90 | 8 | Baltimore Gas & Electric | Maryland | People's Counsel | 8520-I |
| 3/90 | 8 | Baltimore Gas & Electric | Maryland | People's Counsel | 8520-J |
| 5/90 | 7 | Columbia Gas of Maryland | Maryland | People's Counsel | 8258 |
| 8/90 | 7 | Bangor Hydro Electric Co. | Maine | Public Utilities Comm. | 90-001 |
| 8/90 | 18 | Louisiana Power and Light Co. | Louisiana | LP&L | U-17906 |
| 10/90 | 4 | Baltimore Gas & Electric | Maryland | People's Counsel | 8278 |
| 10/90 | 4-7 | Central Maine Power Co. | Maine | Public Utilities Comm. | 90-076 |
| 1/91 | 1 | Sno-King & Northwest Garbage | Washington | Util. &B Trans. Comm. | TG-900067/8 |
| 6/91 | 4-7 | Bangor Hydro Electric Co. | Maine | Public Utilities Comm. | 91-310 |
| 6/91 | 4-7 | New Orleans Public Service | Louisiana | NOPSI | UD-91-1 |
| 4/92 | 24 | US West Communications | Washington | Util. & Trans. Comm. | U-89-3245-P |
| 5/92 | 4 | Edison Gas | Maryland | People's Counsel | 8449 |
| 8/92 | 4-24 | C&P Telephone of Maryland | Maryland | People's Counsel | 8462 |
| 10/92 | 8 | Delmarva Power & Light | Maryland | People's Counsel | 8521-C |
| 1/93 | 4 | Baltimore Gas & Electric | Maryland | People's Counsel | 8487 |
| 2/93 | 20 | Louisiana Power and Light Co. | Louisiana | LP&L | U-20181 |

| DATE | CODE | COMPANY | JURISDICTION | CLIENT | DOCKET NO. |
|---|---|---|---|---|---|
| 9/93 | 7 | Bangor Hydro Electric Co. | Maine | Public Utilities Comm. | 93-062 |
| 2/94 | 20 | Conowingo Power Company | Maryland | Cecil County Gov't | 8583 |
| 4/94 | 8 | Potomac Edison Company | Maryland | People's Counsel | 8523-J |
| 10/94 | 4 | Entergy Gulf States | Louisiana | Entergy Gulf States | U-19904 |
| 2/95 | 4 | Entergy Louisiana | Louisiana | Entergy Louisiana | U-20925 |
| 10/95 | 4 | Chesapeake Utilities Corp. | Maryland | People's Counsel | 8707 |
| 11/95 | 4 | Entergy Gulf States, Inc. | Louisiana | Gulf States Utilities | U-21485 |
| 2/96 | 4-24 | Bell Atlantic of Maryland | Maryland | People's Counsel | 8715 |
| 7/96 | 4 | BG&E/PEPCO | Maryland | People's Counsel | 8725 |
| 10/96 | 4 | Entergy Gulf States | Louisiana | Entergy Gulf States | U-22092 |
| 8/97 | 7 | Bangor Hydro Electric Co. | Maine | Public Utilities Comm. | 97-116 |
| 12/97 | 4 | Entergy Gulf States | Louisiana | Entergy Gulf States | U-22491 |
| 9/99 | 4 | Entergy Gulf States | Louisiana | Entergy Gulf States | U-23358 |
| 12/99 | 4 | Entergy Gulf States | Louisiana | Entergy Gulf States | U-24182 |
| 3/00 | 4 | Entergy Louisiana | Louisiana | Entergy Louisiana | U-23356 |
| 1/01 | 4 | Entergy Gulf States | Louisiana | Entergy Gulf States | U-24993 |
| 1/02 | 4 | Entergy Gulf States | Louisiana | Entergy Gulf States | U-25687 |
| 8/04 | 4-18 | Entergy Gulf States | Texas | Entergy Gulf States | U-30123 |
| 8/04 | 4-8 | Entergy Gulf States | Louisiana | Entergy Gulf States | U-19904 |
| 9/04 | 4 | Entergy Louisiana | Louisiana | Entergy Gulf States | U-20925 |
| 10/04 | 4-8 | Entergy Gulf States | Louisiana | Entergy Gulf States | U-28349 |
| 5/05 | 4 | Entergy Gulf States | Louisiana | Entergy Gulf States | U-28035 |
| 9/07 | 4-18 | Entergy Gulf States | Texas | Entergy Gulf States | U-34800 |
| 12/09 | 4-18 | Entergy Texas Inc. | Texas | Entergy Texas, Inc. | U-37744 |
| 12/09 | 18 | Entergy Louisiana/Entergy Gulf States | Louisiana | Entergy Louisiana | U-31237 |
| 11/10 | 25 | Entergy New Orleans | New Orleans | Entergy New Orleans | UD-07-03 |
| 1/11 | 25 | Entergy New Orleans | New Orleans | Entergy New Orleans | UD-11-01 |
| 5/11 | 25 | Entergy New Orleans | New Orleans | Entergy New Orleans | UD-07-03 |
| 7/11 | 25 | Entergy New Orleans | New Orleans | Entergy New Orleans | UD-11-03 |
| 9/11 | 8 | Entergy Gulf States Louisiana | Louisiana | Entergy Gulf States La. | U-27103 |
| 2/13 | 21 | Entergy Gulf States Louisiana | Louisiana | Entergy Gulf States La. | U-32707 |
| 2/13 | 21 | Entergy Louisiana, LLC | Louisiana | Entergy Louisiana, LLC | U-32708 |

| DATE | CODE | COMPANY | JURISDICTION | CLIENT | DOCKET NO. |
|---|---|---|---|---|---|
| 3/13 | 21, 4 | Entergy Louisiana, LLC | New Orleans | Entergy Louisiana, LLC | UD-13-01 |
| 9/13 | 18 | Entergy Texas Inc. | Texas | Entergy Texas, Inc. | 41791 |
| 10/14 | 25, | Entergy New Orleans/Entergy Louisiana, LLC | New Orleans | Entergy New Orleans/ Entergy Louisiana, LLC | UD-14-02 |
| 7/16 | 25 | Entergy New Orleans, Inc. | New Orleans | Entergy New Orleans | UD-16-03 |
| 09/18 | 21 | Entergy New Orleans, LLC | New Orleans | Entergy New Orleans | UD-18-07 |
| 03/19 | 21 | Entergy New Orleans, LLC | New Orleans | Entergy New Orleans | UD-18-07 |
| 7/22 | 18 | Entergy Louisiana, LLC | Louisiana | Entergy Louisiana | U-36103 |

CASE LIST SUBJECT CODES FOR
KENNETH F. GALLAGHER

1. Fair Rate of Return
2. Relationship Between Future Construction Expenditures, AFUDC, CWIP and Future Financial Indicators.
3. Rate Design
4. Revenue Requirement
5. Pricing Proposal
6. Presorting Discount
7. Attrition
8. Fuel Costs and Fuel Adjustment Rates
9. Repression
10. Price Squeeze
11. Revenue Requirement – Rate Base (only)
12. Fair Rate of Return – Cost of Equity Capital (only)
13. Price Elasticity of Demand and its Revenue Requirement Implications
14. Statistical Properties of Time Series Regression Technique
15. Cogeneration
16. Fair Rate of Return – Capital Structure (only)
17. Energy Cost Adjustment Rate Procedures
18. Nuclear Decommissioning
19. Prudence
20. Cost of Service Issues
21. Revenue Requirement – Cash Working Capital (only)

22. Access Charges
23. Financial Integrity
24. Telephone Incentive Rate Plan/Affiliate Transactions
25. Miscellaneous Policy Issues

**BEFORE THE**

**LOUISIANA PUBLIC SERVICE COMMISSION**

| | | |
|---|---|---|
| **APPLICATION OF ENTERGY LOUISIANA, LLC FOR APPROVAL OF REGULATORY BLUEPRINT NECESSARY FOR COMPANY TO STRENGTHEN THE ELECTRIC GRID FOR STATE OF LOUISIANA** | ) ) ) ) ) ) | **DOCKET NO. U-_____** |

**EXHIBIT KFG-2**

**EXHIBIT IS PROVIDED ON CD ONLY**

**AUGUST 2023**

BEFORE THE

LOUISIANA PUBLIC SERVICE COMMISSION

| | | |
|---|---|---|
| APPLICATION OF ENTERGY LOUISIANA, LLC FOR APPROVAL OF REGULATORY BLUEPRINT NECESSARY FOR COMPANY TO STRENGTHEN THE ELECTRIC GRID FOR STATE OF LOUISIANA | ) ) ) ) ) ) | DOCKET NO. U-_____ |

EXHIBIT KFG-3

EXHIBIT IS PROVIDED
ON CD ONLY

AUGUST 2023

BEFORE THE

LOUISIANA PUBLIC SERVICE COMMISSION

| | | |
|---|---|---|
| APPLICATION OF ENTERGY LOUISIANA, LLC FOR APPROVAL OF REGULATORY BLUEPRINT NECESSARY FOR COMPANY TO STRENGTHEN THE ELECTRIC GRID FOR STATE OF LOUISIANA | ) ) ) ) ) ) | DOCKET NO. U-_____ |

**EXHIBIT KFG-4**

**EXHIBIT IS PROVIDED ON CD ONLY**

**AUGUST 2023**

**BEFORE THE**

**LOUISIANA PUBLIC SERVICE COMMISSION**

| | | |
|---|---|---|
| **APPLICATION OF ENTERGY** | ) | |
| **LOUISIANA, LLC FOR APPROVAL OF** | ) | |
| **REGULATORY BLUEPRINT** | ) | **DOCKET NO. U-_____** |
| **NECESSARY FOR COMPANY TO** | ) | |
| **STRENGTHEN THE ELECTRIC GRID** | ) | |
| **FOR STATE OF LOUISIANA** | ) | |

**EXHIBIT KFG-5**

**HIGHLY SENSITIVE**
**PROTECTED MATERIAL**

**INTENTIONALLY OMITTED**

**AUGUST 2023**

**BEFORE THE**

**LOUISIANA PUBLIC SERVICE COMMISSION**

| | | |
|---|---|---|
| **APPLICATION OF ENTERGY** | ) | |
| **LOUISIANA, LLC FOR APPROVAL OF** | ) | |
| **REGULATORY BLUEPRINT** | ) | |
| **NECESSARY FOR COMPANY TO** | ) | **DOCKET NO. U-_____** |
| **STRENGTHEN THE ELECTRIC GRID** | ) | |
| **FOR STATE OF LOUISIANA** | ) | |

**EXHIBIT KFG-6**

## HIGHLY SENSITIVE
## PROTECTED MATERIAL

**INTENTIONALLY OMITTED**

**AUGUST 2023**