**Entergy Services, Inc.**
639 Loyola Avenue 70113-3125
P.O. Box 61000
New Orleans, LA 70161
Tel 504 576-2603
Fax 504 576-5579

**Brian L. Guillot**
Counsel
Legal Services – Regulatory
bguill1@entergy.com

July 13, 2015

***Via Hand Delivery***
Ms. Lora W. Johnson, CMC
Clerk of Council
Room 1E09, City Hall
1300 Perdido Street
New Orleans, LA 70112

Re: *In Re*: Resolution Regarding Proposed Rulemaking to Establish Integrated Resource Planning Components and Reporting Requirements for Entergy New Orleans, Inc. (Docket No. UD-08-02)

Dear Ms. Johnson:

Pursuant to Council Resolution R-14-511, enclosed please find an original and three copies of Entergy New Orleans, Inc. ("ENO") and Entergy Louisiana, LLC's ("ELL-Algiers") Joint Comments Regarding the Consideration of Issues Related to Decoupling. Please file an original and two copies into the record in the above-referenced matter, and return a date-stamped copy to our courier.

Thank you for your assistance with this matter.

Sincerely,

Brian L. Guillot

BLG/jw
Enclosures
cc: Official Service List UD-08-02 *(via electronic mail)*

**BEFORE THE**
**COUNCIL OF THE CITY OF NEW ORLEANS**

| | | |
|---|---|---|
| **IN RE: RESOLUTION REGARDING PROPOSED RULEMAKING TO ESTABLISH INTEGRATED RESOURCE PLANNING COMPONENTS AND REPORTING REQUIREMENTS FOR ENTERGY NEW ORLEANS, INC.** | ) ) ) ) ) ) | **DOCKET NO. UD-08-02** |

**JOINT COMMENTS OF ENTERGY NEW ORLEANS, INC. AND ENTERGY LOUISIANA, LLC REGARDING THE CONSIDERATION OF ISSUES RELATED TO DECOUPLING**

Entergy New Orleans, Inc. ("ENO") and Entergy Louisiana, LLC ("ELL-Algiers") (collectively the "Companies"),[1] pursuant to Resolution R-14-511, respectfully submit their Joint Comments Regarding the Consideration of Issues Related to Decoupling.

## I. EXECUTIVE SUMMARY

The Council of the City of New Orleans ("CNO" or the "Council"), in Resolution R-14-511, directed the Companies to "submit a draft proposal for a mechanism to address the lost revenue problem to the Advisors and the Intervenors for comment."[2] As discussed more fully below, over the last six months, the Companies, the Council Advisors and Intervenors have engaged in a collaborative process and considered numerous issues related to full revenue decoupling. In conjunction with this collaborative process, the Companies have analyzed and modeled various full revenue decoupling (sometimes referred to herein as "full decoupling")

1 It should be noted that in Resolution R-15-194, the Council approved the transfer of ELL-Algiers assets and service obligations to ENO under Docket No. UD-14-02. Pursuant to Resolution R-15-194, the effectuation of that transaction is anticipated for September 1, 2015. Assuming that the transaction is completed, the provision of electric service in all of Orleans Parish will be the responsibility of ENO and will no longer be served by the Companies, as referenced in Resolution R-14-511. For simplicity, however, the combined companies will still be referenced as the "Companies" herein.

2 CNO Resolution R-14-511, at 11, Ordering ¶ 2.

mechanism designs and parameters and, in compliance with Resolution R-14-511, have developed the full revenue decoupling mechanism discussed and submitted herein.

Although the Companies have developed and submitted this mechanism, the Companies recommend that a full revenue decoupling mechanism not be adopted. Rather than adopting a full decoupling mechanism, the Companies recommend that, in conjunction with the next full base rate case, the Council consider adopting a mechanism similar to the ENO Formula Rate Plan ("FRP") that was in place for test years 2009 through 2011. That FRP included recovery of the lost revenues directly attributable to reduced sales resulting from utility-sponsored energy efficiency programs, also referred to as lost contributions to fixed costs (hereinafter, "LCFC" or "lost revenues"). The LCFC approach directly links the sales volume impacts of the utility's energy efficiency programs to the revenue collections of the utility and, in the Companies' view, is preferable to the implementation of a full revenue decoupling mechanism.

If the Council ultimately requires the Companies to implement a full decoupling mechanism, the Companies recommend that a three-year full decoupling pilot be implemented in conjunction with a new, to-be-developed electric FRP. The Companies' rationale for adopting full decoupling in conjunction with an electric FRP is to ensure that the Companies' earnings are reasonable and reflect changes to cost of service as well as ensure that rate classes not affected by full decoupling would at least be considered in any annual rate changes resulting from those earnings reviews. The Companies also recommend that the various design parameters discussed at length below be incorporated into any subsequent Council Resolution addressing the specifics of a three-year decoupling pilot. Piloting a full decoupling mechanism within a new FRP provides a level of risk mitigation for both the Companies and customers during the evaluation period. The Council can determine after the pilot period has ended if the full decoupling mechanism was successful and achieved the goals of increasing the level of energy efficiency adoption while mitigating utility revenue erosion.

## II. INTRODUCTION

### A. Procedural Background

In CNO Docket No. UD-08-02, which relates to the long-term integrated resource plan ("IRP") for the Companies, the Council issued Resolution R-13-363 on October 10, 2013. In that Resolution, the Council directed the Companies, among other matters, to address the potential for full decoupling as discussed in a memorandum from the Regulatory Assistance Project ("RAP"), which was attached to the Council's Resolution. On February 7, 2014, the Companies filed Joint Comments discussing various means to address LCFC resulting from energy efficiency and related policies, including the current lost revenue mechanism incorporated into the Council-approved EnergySmart program. The use of an LCFC mechanism to address lost revenues from utility-sponsored energy efficiency programs are often referred to as "partial" or "limited" decoupling. The Companies also expressed concerns regarding possible unforeseen and unintended consequences that may result from adopting a full decoupling mechanism.

Given the Companies' stated concerns, as well as the need for further clarity regarding specific elements of a full decoupling mechanism, the Companies requested that the issues described in the RAP memorandum be fully aired, discussed, and vetted through the IRP docket vis-à-vis a new procedural schedule and, further, that any specific design aspects of a full decoupling mechanism be considered only after those issues have been fully explored.

On April 7, 2014, the Alliance for Affordable Energy ("Alliance") filed their comments and agreed with the Companies that stakeholder engagement and public discussion was needed to work through the numerous issues and concerns raised by the potential adoption of full decoupling. On May 13, 2014, the Companies filed Reply Comments to address several points raised by the Alliance. Most importantly, the Companies noted that "RAP and the Alliance [have] provided no evidence that the Council's current approach to addressing lost revenues associated with implementation of EnergySmart has led to, or perpetuated, opposition by the Companies toward advancing energy efficiency in New Orleans, or otherwise implementing the optimal level of supply- and demand-side resources that will ensure the Companies can continue providing safe and reliable service at the lowest reasonable cost."[3]

On July 14, 2014, the Advisors filed their Report regarding the proceeding and recommended the development of a stakeholder process and a procedural schedule to fully vet the numerous issues presented by the potential adoption of full decoupling. In Resolution R-14-511, issued in November 2014, the Council issued the following procedural schedule:

> 1. Within 150 days of the issuance of a resolution by the Council, the Companies shall convene no less than three technical meetings with the Advisors and the Intervenors who choose to participate.
>
> 2. Within 90 days of the last technical conference, the Companies should submit a draft proposal for a mechanism to address the lost revenue problem to the Advisors and the Intervenors for comment.
>
> 3. Within 30 days of the submission of the Companies draft proposed mechanism, the Advisors and Intervenors may provide written feedback to the Companies.
>
> 4. Within 60 days of receipt of such feedback the Companies should submit their final proposal for a mechanism to address the lost revenue problem to the Council.

3 See Reply Comments of ENO and ELL-Algiers to the Alliance's Comments Regarding Revenue Decoupling Pursuant to Council Resolution R-13-363, at 2.

5. Within 30 days of the submission of the Companies' proposal to the Council, Intervenors may file comments with the Council.

6. Within 30 days of the submission of Intervenor comments, the Companies may file responsive comments.

7. Within 60 days of the submission of responsive comments, the Advisors shall submit an Advisors' Report to the Council.

## B. The Collaborative Process

The RAP memorandum attached to Council Resolution R-13-363 identified various issues related to the design of a full decoupling mechanism, the development of true-up mechanisms, and a listing of several items that the Council later ordered the Companies to consider in its decoupling proposal to be filed in conjunction with step 2 of the adopted procedural schedule. More specifically, the relevant issues raised in the RAP memorandum included:

- How frequently should revenues be reviewed and adjusted (for example, monthly, quarterly, semi-annually or annually)?
- Should the rate impact of annual adjustments be capped, and if so what should be the treatment of any unrecovered or undistributed balances?
- Should existing tariff riders be consolidated into a new revenue reconciliation rider under decoupling? If not, should rider costs be coordinated with revenue adjustment?
- Should decoupling apply only to distribution costs or should it also include generation costs?
- Should all elements of power supply, including investment-related costs and variable operating costs be converted into a comprehensive power supply cost recovery mechanism?
- Should revenue-per-customer amounts for each decoupled customer class be adjusted based on historical trends in use, trends in cost of service for the customer class (sometimes called a "k factor), or for other purposes?
- What tariff classes, if any, should be excluded from the mechanism (such as tariff classes with less than ten customers, customers with fixed contract demands and special contracts customers)?

- Should large industrial customers be excluded from the decoupling mechanism?[4]

Beginning in February 2015, the Companies, Advisors, Intervenors and other stakeholders (the "Parties") held a series of three Technical Conferences to explore the various issues raised in the RAP memorandum, other design attributes that needed to be considered, and numerous related matters that would affect the design, timing, and potential implementation of a full revenue decoupling mechanism. The three Technical Conferences were held on February 4, March 26, and April 14, 2015 and resulted in several documents, which are included in Appendices A and B. Appendix A includes a matrix of numbered issues that were thoroughly discussed and debated during the first two Technical Conferences. The final version of the matrix included in Appendix A reflects redline changes, comments, and suggestions from the Council's Advisors and other stakeholders. Appendix B is a 1-page summary of the various design attributes of a full decoupling mechanism. It should be noted that several of the design attributes were not yet specified at the time of the third Technical Conference (April 14, 2015) because the Companies were still conducting various financial modeling analyses. Through this collaborative stakeholder process, the Companies have considered the comments and ideas from the Advisors, the Alliance, Green Coast Enterprises, and other stakeholders when formulating the full decoupling mechanism described below.

[4] See Memorandum on Regulatory Options for Advancing Energy Efficiency, Regulatory Assistance Project, June 2013, at page 6.

## III. FULL DECOUPLING MECHANISM

### A. Key Terms

As noted above, at the last Technical Conference held on April 14, 2015, the Companies proposed a number of specific design attributes in the Preliminary Discussion Document "Potential Key Terms of a Full Revenue Decoupling Mechanism for ENO" (see Appendix B). Following the same outline structure, the Companies have further refined the proposed key terms as discussed below:

Timing: The Parties concurred that any full decoupling mechanism would be developed by the Companies and considered by the Council in conjunction with ENO's next base rate case in 2018.[5] Further, following the resolution of that combined base rate case, any full decoupling mechanism that is approved by the Council would be implemented at the beginning of the next calendar year based on the prior calendar year test year's results. The Companies note that the next base rate case will be filed after the Companies are operating on a combined basis or, in other words, following the transfer of the ELL-Algiers assets and liabilities from ELL to ENO. Finally, the combined Companies operating as a single entity are likely to seek a new FRP in conjunction with the next base rate case filing. The design of any such FRP would reflect any Council directives involving the specific parameters of a full decoupling mechanism.

Duration: All Parties agreed that the initial term of any full decoupling mechanism would be limited to a three-year pilot phase. The Companies propose that the duration of a pilot full decoupling mechanism run concurrently with that of an FRP (should such an FRP be approved) in conjunction with the Companies' next base rate case. For example, if the Companies were to

---

[5] Per Council Resolution R-15-194, in Council Docket UD-14-02, "The Combined Rate Case shall not be submitted to the Council prior to the first quarter of 2018 and shall be based on a 12-month historical test year (Period 1) ended December 31, 2017."

implement a full decoupling mechanism and separate FRP at the conclusion of the next base rate case, both mechanisms would run concurrently for three years beginning with the same calendar test year.

Test Year: The Companies propose using a calendar year as the test year for any full decoupling mechanism and new FRP approved by the Council, which was unopposed.

Type: The full decoupling mechanism would be developed as a stand-alone rider to facilitate greater transparency, customer class-specific calculations and recovery amounts, and any necessary true-ups. The full decoupling mechanism rider could be explicitly shown as a separate line item on the customer's bill, added to (or deducted from) any FRP rider amount on the customer's bill, or even included within the Energy Charge line item should the Companies and Council determine that to be optimal.

Service: As part of the three year pilot phase, the proposed decoupling mechanism would only apply to the Companies' electric service customers. Any consideration of a full revenue decoupling mechanism for ENO's natural gas service would be deferred until such time as more information becomes available regarding outcomes from the pilot.

Affected Customers: The proposed full decoupling mechanism would only involve residential and small commercial customer classes, which predominantly rely upon volumetric (cents/kWh) charges in terms of rate design.

Symmetry: All Parties agreed that it would be appropriate to provide symmetrical treatment of any over or under-collection of allowed revenues relative to actual revenue levels for the historic calendar test year in question.

True-up Frequency: The Companies proposed an annual review of and adjustment to, allowed revenues similar to what has occurred historically with the FRP, which was unopposed.

Filing Date: Using a calendar year test year, the Companies propose to file the annual full revenue decoupling review report(s) contemporaneous with any FRP annual report filing covering the same historic calendar year test year.

Comment Period: The Advisors and other Parties comments would be due sixty (60) days following the submission of the Companies report.

Rate Implementation Date: Any rate change resulting from the annual review filing will be implemented effective with the first billing cycle of September in the filing year and would be in conjunction and concurrent with any FRP rate implementation as discussed above under Timing.

Rate Caps: The purpose of an annual rate impact cap would be to potentially minimize the volatility of rate changes on customers resulting from the annual review filing. Rate caps, however, can have the negative unintended consequence of building large deferred balances (either positive or negative) which could take multiple years to flow through to customers. The Companies historic modeling analysis discussed further below for the years 2009 through 2014 indicates that any rate changes from a full decoupling mechanism would be similar to rate changes that customers experienced during the years 2009 through 2011 through the now-expired FRP. As such, the Companies are not proposing that a full decoupling mechanism include at its onset any rate cap. Should unforeseen circumstances arise after implementation of a full decoupling mechanism, such as an annual adjustment in an amount that is too large for customers to effectively manage, the Companies can request and/or the Council can adopt a rate cap and deferral.

Treatment of Any Over/Under Amount: If the Council does adopt some form of a rate cap in conjunction with approval of a full decoupling mechanism, the Companies would propose to carryover any unrecovered balance (positive or negative) above or below the Annual Rate Impact Cap until the next annual rate implementation (the first billing cycle of the next September). Any such balance would be amortized over the following rate implementation year beginning with the first billing cycle of September. Note that such an approach could present certain challenges if the addition of the amortized balance to the amount resulting from the review of the historic calendar year test year results in an overall amount that is above (or below) any adopted Annual Rate Impact Cap.

Carrying Cost: Subject to the Council approving a full decoupling mechanism that includes an Annual Rate Impact Cap, any amounts that are deferred due to an over or under collection as well as any amounts necessary to true-up the rider would incorporate carrying charges at the current pre-tax weighted average cost of capital based on the then allowed return on equity.

Affected Cost: The Companies are vertically-integrated utilities in which the cost to serve customers includes investments in and expenses related to generation, transmission, distribution, and customer service. The Companies propose that the full decoupling mechanism would include the allocated portion of total fixed and non-fuel variable costs required to serve affected residential and small commercial customers. That said, any costs that are currently included in existing (or future) riders or other recovery mechanisms would be excluded from treatment through the full decoupling mechanism.

Revenue-per-Customer Adjustment: The Companies' proposed full decoupling mechanism would utilize targeted Revenue-per-Customer amounts for each affected customer class based on the Authorized Revenue Requirement resulting from the Companies' next base rate case filing results.

Weather Adjustment: The Companies propose that the full decoupling mechanism not include a weather normalization adjustment.

K-Factor Adjustment: A K-factor adjustment is frequently used in a full decoupling mechanism to reflect the fact that the utility's cost of service is generally increasing between rate proceedings. Changes to a utility's cost of service over time occur due to changes in costs to operate and maintain utility infrastructure (*e.g.*, labor cost increases, general inflation) as well as increased utility capital investments reflected in rate base. Based on modeling of historic data for 2009 - 2014 as discussed further below, the Companies propose to use a K-factor of approximately 2.25% to reset targeted Revenue-per-Customer amounts each year during the period modeled. While the 2.25% value is based on recent historic data, the Companies will reevaluate and propose an updated K-factor in conjunction with the Companies next base rate case proceeding should the Council determine as part of this proceeding that the Companies should implement a 3-year full revenue decoupling pilot.

The Companies proposal to include the pilot of the full decoupling mechanism within the context of an FRP will help to mitigate the need to estimate the "right" K-factor level to use during a three year pilot because the Companies' actual earnings will be evaluated annually as part of the FRP. More specifically and as discussed further below, the decoupling mechanism's Authorized Revenue Requirement will be included in the present rate revenues of the Companies' FRP calculations to determine if the current revenue requirement is adequately recovered. If the annual allowed revenue requirement calculated as part of the FRP is different than the full decoupling mechanism's Authorized Revenue Requirement, any change in the level of revenues resulting from the full decoupling mechanism will be factored into the FRP result. By including the full decoupling mechanism within the context of an FRP, the necessary annual change in the revenue requirement will be reflected in affected customers' bills, reducing the need for an accurate estimation of the K-factor as overall results will be annually determined and reviewed in the FRP.

Other Adjustments: The Companies do not propose any other adjustments to the full decoupling mechanism at this time (e.g., adjustment to reflect changes to economic conditions).

## B. Calculation of the Full Decoupling Mechanism

### 1. Summary of Decoupling Analysis and Modeling

The Companies modeling results for the historic years analyzed (2009 – 2014) are shown in Table 1 below.

**Table 1**

**Entergy New Orleans, Inc.**
**Decoupling Adjustment Calculation**
**Summary of Results**

| ***Residential*** | **2009** | **2010** | **2011** | **2012** | **2013** | **2014** |
|---|---|---|---|---|---|---|
| Average Number of Customers | 130,062 | 136,476 | 141,540 | 145,681 | 148,844 | 151,274 |
| Decoupling Adjustment (Applied in the Next Year) | ($2,397,163) | ($10,427,080) | ($6,660,442) | $5,057,169 | $5,224,971 | $5,347,369 |
| Decoupling Adj as % of Actual Base Revenues | (2.29)% | (8.69)% | (5.42)% | 4.31% | 4.26% | 4.20% |
| ***Master Metered Residential Apartments*** | | | | | | |
| Average Number of Customers | 9 | 2 | 1 | 1 | 1 | - |
| Decoupling Adjustment (Applied in the Next Year) | ($110,975) | ($197,140) | ($158,821) | ($156,921) | ($133,991) | $0 |
| Decoupling Adj as % of Actual Base Revenues | (10.66)% | (48.25)% | (59.50)% | (58.67)% | (54.25)% | #DIV/0! |
| ***Small Electric*** | | | | | | |
| Average Number of Customers | 15,007 | 15,719 | 16,101 | 16,363 | 16,469 | 16,684 |
| Decoupling Adjustment (Applied in the Next Year) | ($466,848) | ($407,007) | $1,307,772 | $2,836,600 | $3,540,408 | $3,848,672 |
| Decoupling Adj as % of Actual Base Revenues | (1.10)% | (0.89)% | 2.85% | 6.13% | 7.54% | 7.94% |
| ***Municipal Buildings*** | | | | | | |
| Average Number of Customers | 286 | 279 | 280 | 284 | 281 | 284 |
| Decoupling Adjustment (Applied in the Next Year) | ($458,496) | ($406,980) | ($18,172) | $35,084 | $90,936 | $175,434 |
| Decoupling Adj as % of Actual Base Revenues | (17.30)% | (15.69)% | (0.80)% | 1.53% | 4.02% | 7.77% |
| ***Large Electric*** | | | | | | |
| Average Number of Customers | 511 | 516 | 488 | 437 | 415 | 399 |
| Decoupling Adjustment (Applied in the Next Year) | ($310,117) | $569,307 | $2,318,749 | $2,737,528 | $2,620,861 | $1,944,973 |
| Decoupling Adj as % of Actual Base Revenues | (0.95)% | 1.73% | 7.72% | 10.19% | 10.03% | 7.39% |
| ***Large Electric High Load Factor*** | | | | | | |
| Average Number of Customers | 286 | 294 | 334 | 391 | 428 | 455 |
| Decoupling Adjustment (Applied in the Next Year) | ($318,980) | ($729,189) | $3,600,572 | $12,577,299 | $19,407,676 | $23,669,406 |
| Decoupling Adj as % of Actual Base Revenues | (0.63)% | (1.36)% | 6.23% | 20.65% | 30.88% | 36.00% |
| ***Master Metered Non-Residential*** | | | | | | |
| Average Number of Customers | 9 | 7 | 5 | 4 | 3 | 2 |
| Decoupling Adjustment (Applied in the Next Year) | $636,438 | $288,250 | ($339,803) | ($598,127) | ($491,326) | ($53,477) |
| Decoupling Adj as % of Actual Base Revenues | 27.50% | 14.00% | (16.54)% | (29.90)% | (31.36)% | (6.80)% |
| ***High Voltage*** | | | | | | |
| Average Number of Customers | 2 | 2 | 2 | 2 | 2 | 2 |
| Decoupling Adjustment (Applied in the Next Year) | ($683,858) | ($10,726) | $299,450 | $918,273 | $1,335,698 | $1,237,657 |
| Decoupling Adj as % of Actual Base Revenues | (10.19)% | (0.17)% | 4.99% | 16.61% | 25.42% | 22.50% |
| ***Experimental Interruptible*** | | | | | | |
| Average Number of Customers | 1 | 1 | 1 | 2 | - | - |
| Decoupling Adjustment (Applied in the Next Year) | $33,672 | $52,870 | $57,337 | $377,080 | ($124,093) | $0 |
| Decoupling Adj as % of Actual Base Revenues | 12.66% | 20.86% | 22.40% | 143.07% | (100.00)% | #DIV/0! |
| ***Large Interruptible*** | | | | | | |
| Average Number of Customers | 1 | 1 | 1 | 1 | 1 | 1 |
| Decoupling Adjustment (Applied in the Next Year) | $32,695 | $663,349 | $775,872 | $836,911 | $1,270,393 | $1,886,859 |
| Decoupling Adj as % of Actual Base Revenues | 0.72% | 16.46% | 19.29% | 20.57% | 33.91% | 58.19% |

Table 1 illustrates the estimated decoupling adjustments by year during the 2009 through 2014 period if ENO[6] had implemented a stand-alone full decoupling mechanism instead of using the Formula Rate Plan that was in effect for the Test Years 2009-2011[7]. The analysis summarized above also assumes that:

- The stand-alone full decoupling mechanism would have continued through 2014;
- A K-Factor of 2.25% was applied to the 2010 through 2014 Test Years to adjust the Allowed Revenue-per-Customer levels;
- All revenue adjustments were flowed back to the customer at the end of the same test year (essentially to simplify the modeling presentation and avoid the complication of addressing true-ups);
- There are no true-up adjustments needed for the difference between the decoupling adjustment calculated and the decoupling adjustment billed to customers in the rate effective period (again to simplify the modeling presentation);
- The stand-alone full decoupling mechanism was applied to all costs, including fixed and non-fuel variable costs, and for all functions including generation, transmission, distribution, and customer service; and
- No rate caps were applied.

Based on the results presented in Table 1, the Companies recommend that any full decoupling mechanism ultimately exclude the rate categories that have very few or no customers by 2014, as well as rate categories that appeared to have significant volatility (those rate categories include Master Metered Residential Apartments, Municipal Buildings, Large Electric, Large Electric High Load Factor, Master Metered Non-Residential, High Voltage, Experimental Interruptible and Large Interruptible). These results also further support the Companies' argument that if the Council should decide to implement a full revenue decoupling mechanism,

[6] ENO's results and analysis do not include ELL-Algiers data to simplify the illustrative analysis.

[7] Beginning with Test Year 2012, ENO's FRP had expired so that no filing data exists for Test Years 2012-2014.

that mechanism should be included within the Companies' next combined base rate filing where an updated Unit Cost Study by rate categories can be developed to reflect the then current level of customers and costs.

In order to develop a full revenue decoupling model using the same essential methodology that would be used in conjunction with the next base rate case proceeding, the Companies used the ENO 2008 Rate Case Compliance Filing results to identify the amount of Authorized Annual Base Revenue (or Revenue Requirement) and the total number of bills to allocate to each of the rate categories (see Appendix C). To develop the Annual Decoupling Adjustment, the Companies started by calculating the Test Year 2008 Authorized Monthly Revenue-per-Customer values. Those values were derived by dividing the Test Year 2008 Authorized Annual Base Revenue by the total number of customer bills by rate class. Under this approach, the Companies allocate all costs, including fixed and non-fuel variable costs, as well as all of the functional cost components (generation, transmission, distribution and customer service). As part of the analysis, the Companies reviewed the differential between the fixed and non-fuel variable costs and determined that almost all of the costs for the residential and small commercial (Small Electric Service) rate categories are fixed costs (see Appendix D).

After the Test Year 2008 Authorized Monthly Revenue-per-Customer values were developed ("Base 2008 Authorized Revenues"), the Base 2008 Authorized Revenues were multiplied by the 2009 average number of customer bills by rate class to determine the amount of 2009 Allowed Revenues by rate class. The Actual Base Revenues of each rate class were compared to the Allowed Revenues to calculate the amount of the Total Decoupling Adjustment by rate class (shown in the Test Year for simplicity, but would actually be applied in the following year, 2010, starting with the rate effective date). Beginning with the 2010 calculation, a K-factor of 2.25% was applied to the Allowed Revenues by rate class in each subsequent year through 2014 to adjust for cost of service changes as discussed above (see Appendix E).

The Companies created two additional models of the Electric FRP as a stand-alone mechanism (see Appendix F) and the Electric FRP including the Decoupling Adjustment within the revenue calculations (see Appendix G). Both models include the actual ENO Electric FRP Compliance Results for the Test Years 2009 through 2011. Beginning in 2012, ENO's Electric FRP had expired so no actual filing data is available for the 2012 through 2014 Test Years.

To model illustrative FRP results for the 2012 through 2014 Test Years, the Companies utilized relevant data from ENO's FERC Form 1 filings with minimal adjustments to approximate the removal of the Gas Product Line from the illustrative FRP results. Both models show that had ENO continued to file the Electric FRP through a 2014 test year, the test years of 2012 and 2013 would have resulted in significant rate increases (see Appendix F and Appendix G page 1). In the example of the Electric FRP with the decoupling adjustments included, the results appear significantly different from the stand-alone Electric FRP examples because the decoupling adjustments are already included in the FRP results. For instance, in the 2012 Test Year, the stand-alone FRP example results in an FRP increase of $17.1M (see Appendix F page 1). For the same 2012 Test Year in the FRP with decoupling included (see Appendix G page 1), however, the FRP still results in an increase of $9.2M, but it is reduced by the $7.9M decoupling adjustments that have already been included for Residential ($5.1M) and Small Electric ($2.8M) rate categories (see Appendix E page 1).

For 2012, the stand-alone decoupling mechanism would not have adequately compensated the Companies for the short-fall in revenue collections because of other changes that were either not addressed by the K-factor level or are due to a short-fall in collections from the other rate classes. Conversely, for 2014, the stand-alone decoupling mechanism resulted in $9.2M in rate increases for the Residential ($5.3M) and Small Electric ($3.8M) rate categories (see Appendix E page 1). ENO's actual earnings level calculated for the 2014 stand-alone FRP (see Appendix F page 1), however, was an overall FRP decrease of $(11.4M). By incorporating the decoupling mechanism within the FRP calculation, the rate increase resulting from the stand-alone decoupling mechanism was "corrected" and the resulting net or total decrease in the 2014 FRP with decoupling calculation is $(20.7M) (see Appendix G page1).

As stated, should the Council ultimately mandate a full decoupling mechanism in the next combined base rate case and implement a three-year pilot, the Companies propose that the decoupling pilot be run in conjunction with a new, to-be-proposed electric FRP. This approach will help ensure that the Companies' annual earnings are reasonable and that the rate classes not included in the pilot will participate in any annual rate changes resulting from cost of service changes. Implementing full decoupling on a stand-alone basis would only address the revenue levels of the rate classes that the Council ultimately determines would be appropriate to include in the mechanism. Based on the modeling analysis presented above, full revenue decoupling, if mandated, would only be appropriate for residential and small commercial rate classes. As summarized above in Table 1, various rate categories have too few customers and/or significant revenue volatility over time where the utilization of full revenue decoupling presents serious challenges and could result in significant harm to affected customers.

## C. Summary

Based on the modeling analyses presented above that use six years of historic data, it is not clear that any benefits would be derived from adoption of a full revenue decoupling mechanism for the residential and small commercial rate classes. Instead, the results clearly show the potential for harm to customer classes with few customers or customer classes that experience revenue volatility from year-to-year due to various factors. Additionally, the analyses do not demonstrate that adoption of a full decoupling mechanism, in and of itself, provides a better approach than current methods of addressing the throughput disincentive inherent in energy efficiency and related efforts.

The Companies continue to believe that the current mechanism of estimating lost revenues directly attributable to utility-sponsored energy efficiency programs is a preferable approach because it directly links the sales volume impacts of the utility's energy efficiency programs to the revenue collections of the utility. The stand-alone decoupling analysis demonstrates the broad impacts and significant volatility that a full decoupling mechanism potentially has on individual customer rate classes. In fact, much of the revenue volatility from year to year appears to be tied to the impacts of weather changes on utility sales as opposed to the impacts of energy efficiency programs such as EnergySmart.

Should the Council ultimately require the Companies to develop and implement a three year full decoupling mechanism pilot, the Companies' recommend that the full decoupling pilot be run in conjunction with a new, to-be-developed electric FRP. The overarching rationale for adopting full decoupling in conjunction with an electric FRP is to ensure: that the Companies' earnings are reasonable; that results reflect changes to cost of service; and that other rate classes participate in any annual rate changes resulting from those earnings reviews. The Companies also recommend that the various design parameters discussed at length above be incorporated into any subsequent Council resolution addressing the specifics of a three year decoupling pilot.

Finally, piloting a full decoupling mechanism within a new FRP provides a level of risk mitigation for both the Companies' customers and the Companies during the evaluation period.

The Council can determine after the pilot period has ended if the full decoupling mechanism was successful and achieved the goals of increasing the level of energy efficiency adoption while removing the utility throughput disincentive related to the promotion of energy efficiency and conservation programs.

RESPECTFULLY SUBMITTED:

Kathryn J. Lichtenberg, La. Bar No.1836
Timothy S. Cragin, La. Bar No. 22313
Brian L. Guillot, Bar No. 31759
639 Loyola Avenue, Mail Unit L-ENT-26E
New Orleans, Louisiana 70113
Telephone: (504) 576-6571
Facsimile: (504) 576-5579

By: ______________________
Brian L. Guillot

ATTORNEYS FOR
ENTERGY NEW ORLEANS, INC. AND
ENTERGY LOUISIANA, LLC

**CERTIFICATE OF SERVICE**
**Docket No. UD-08-02**

I hereby certify that I have this 13th day of July 2015, served the required number of copies of the foregoing report upon all other known parties of this proceeding, by: ☒ electronic mail, ☐ facsimile, ☐ overnight mail, ☐ hand delivery, and/or ☐ United States Postal Service, postage prepaid.

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

W. Thomas Stratton, Jr.
Director, City Council Utilities
Regulatory Office
City of New Orleans
City Hall, Room 6E07
1300 Perdido Street
New Orleans, LA 70112

Evelyn F. Pugh, Esq.
Council Chief of Staff
New Orleans City Council
City Hall, Room 1E06
1300 Perdido Street
New Orleans, LA 70112

Sharonda Williams
City Attorney Office
City Hall, Room 5E03
1300 Perdido Street
New Orleans, LA 70112

Norman S. Foster
Department of Finance
City Hall, Room 3W06
1300 Perdido Street
New Orleans, LA 70112

Hon. Jeffery S. Gulin
3203 Bridle Ridge Lane
Lutherville, GA 21093

Clinton A. Vince, Esq.
Presley R. Reed, Jr., Esq.
Emma F. Hand, Esq.
Dentons US LLP
1301 K Street, NW
Suite 600, East Tower
Washington, DC 20005-3364

Basile J. Uddo, Esq.
J.A. “Jay” Beatmann, Jr.
c/o Dentons US LLP
The Poydras Center, Suite 2850
650 Poydras Street
New Orleans, LA 70130-6132

Walter J. Wilkerson, Esq.
Bobbie Mason, Esq.
Kelley Bazile
Wilkerson and Associates, PLC
The Poydras Center, Suite 1913
650 Poydras Street
New Orleans, LA 70130

Joseph A. Vumbaco, P.E.
Legend Consulting Group Limited
8055 East Tufts Avenue
Suite 1250
Denver, CO 80237-2835

Errol Smith, CPA
Bruno and Tervalon
4298 Elysian Fields Avenue
New Orleans, LA 70122

Charles Rice, Jr.
Entergy New Orleans, Inc.
Mail Unit L-MAG-505A
1600 Perdido Street
New Orleans, LA 70112

Kathryn J. Lichtenberg, Esq.
Timothy S. Cragin, Esq.
Brian L. Guillot, Esq.
Lawrence J. Hand, Jr., Esq.
Edward Wicker, Jr., Esq.
Entergy Services, Inc.
Mail Unit L-ENT-26E
639 Loyola Avenue
New Orleans, LA 70113

Kimberly A. Fontan
Entergy Services, Inc.
4809 Jefferson Highway
Mail Unit L-JEF-357
Jefferson, LA 70121

Randy Day
Director
The Folger Coffee Company
14601 Old Gentilly Road
New Orleans, LA 70129

Fred M. Mazurski, CEM, CDSM
Energy USG Corporation
550 West Adams Street
Chicago, IL 60661-3676

Gary Huntley
Entergy New Orleans, Inc.
Mail Unit L-MAG-505B
1600 Perdido Street
New Orleans, LA 70112

Seth Cureington
Polly S. Rosemond
Al D. Eiffert
Entergy New Orleans, Inc.
Mail Unit L-MAG-505B
1600 Perdido Street
New Orleans, LA 70112

Joseph J. Romano, III
Suzanne Fontan
Entergy Services, Inc.
Mail Unit L-ENT-4C
639 Loyola Avenue
New Orleans, LA 70113

Michael L. Winberry
Jacobs Technology Inc.
13800 Old Gentilly Rd., Bldg. 320
New Orleans, LA 70129

Ernest L. Edwards, Jr.
Beirne, Maynard & Parsons, L.L.P.
601 Poydras Street
Suite 2200
New Orleans, LA 70130-6097

Joshua Smith
Staff Attorney
Sierra Club Environnemental Law
Program
85 Second Street, 2nd Floor
San Francisco, CA 94105

Casey DeMoss
CEO
Alliance for Affordable Energy
2372 St. Claude Avenue, 300A
New Orleans, LA 40117

Thomas W. Milliner
Brian Burke
Anzelmo, Milliner & Burke LLC
3636 S. I-10 Service Road W.
Suite 206
Metairie, LA 70001

Jeff Cantin
C. Tucker Crawford
Heather Pohnan
Gulf States Renewable Energy Industries Association
643 Magazine Street, Suite 102
New Orleans, LA 70130

Jacquelyn Dadakis, Managing Director
Gina LaMacchia, GCE Services
2725 So. Broad Street
New Orleans, LA 70125

Abby Schwimmer
Policy Manager
Southeast Energy Efficiency Alliance
50 Hurt Plaza SE, Suite 1250
Atlanta, GA 30303

Karla Loeb
Margot Want
Posigen Solar Solutions
2424 Edenborn Ave., Suite 550
Metairie, LA 70001

C. Tucker Crawford
Co-Founder/Partner
South Coast Solar, LLC
2605 Ridgelake Drive
Metairie, LA 70002

New Orleans, Louisiana, this 13th day of July, 2015.

Brian L. Guillot