

February 10, 2016

BY HAND DELIVERY

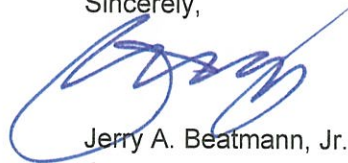
Ms. Lora W. Johnson
Clerk of Council
Council of the City of New Orleans
City Hall, Room IE09
1300 Perdido Street
New Orleans, LA 70112

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

Dear Ms. Johnson:

Enclosed please find an original and four (4) copies of the Report of the Advisors Regarding Issues Related to Decoupling. Please file the attached Report and this letter in the record of this proceeding in accordance with your normal procedure.

Sincerely,



Jerry A. Beatmann, Jr.
Counsel

JAB/dpm
Enclosures

cc: Official Service List

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

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

REPORT OF THE ADVISORS REGARDING ISSUES RELATED TO DECOUPLING

Pursuant to Resolution No. R-14-511, the Council’s Utility Advisors (“Advisors”) present this Report on Issues Related to Decoupling to the Council for its consideration. The Advisors have worked through an extensive stakeholder process with Entergy New Orleans, Inc. (“ENO”)¹ and the Intervenors in this proceeding, and after carefully considering the comments of the parties, now recommend to the Council that it direct ENO to include in its next base rate case a decoupling mechanism as described in detail herein. The Advisors deeply appreciate the good faith participation in this docket by all parties and believe that the recommended mechanism strikes the right balance between assuring the utility a reasonable return, removing any incentive ENO might have to oppose programs, such as Energy Smart, that may reduce sales, and protecting the ratepayers from rate volatility.

BACKGROUND

Under the traditional “cost-of-service” ratemaking methodology that is used to set rates for ENO, rates are typically set at a level sufficient to allow the utility to recover costs incurred in providing service to its customers based on the operating experience of a typical 12-month

¹ On September 1, 2015, the service territory of ELL-Algiers was transferred to ENO. Prior to that date, ENO and ELL both participated in this proceeding. Throughout this document “Companies” refers to ENO and ELL-Algiers, acting jointly prior to September 1, 2015, and “Company” refers to ENO representing the entire service territory within Orleans Parish after September 1, 2015.

period (“Test Year”).² The utility’s total revenue requirement is determined by adding the total of the Test Year fixed and variable expenses, including taxes, and the Council-allowed return on investment.³ It reflects all the operating and other costs incurred to provide service to the public, including operating expenses like fuel, labor, and maintenance as well as the cost of capital invested to provide service (which includes interest on debt, a “fair” return on equity to investors and a depreciation allowance).⁴ The fixed cost portion of the revenue requirement is then allocated to customer rate classes and divided by the amount of sales in the Test Year to develop kWh and kW rates to be charged to customers.⁵ The rates are set to offer the utility a “reasonable opportunity” to recover its revenue requirement, but a utility may ultimately recover more or less than its revenue requirement when its sales or costs are more or less than those included in the development of the Test Year revenue requirement upon which the rates were based. In past Formula Rate Plans (“FRP”), the Council specified that if ENO earns a certain percentage more or less than the approved return on equity, the difference in revenue will be trued-up through the annual FRP process.⁶

Energy efficiency programs, and other programs and events that cause utility sales to decrease, therefore negatively impact the utility’s ability to recover its authorized revenue

² Test Year sales and operating costs are typically adjusted to reflect “normal” weather. The costs are also typically examined by regulators to make sure they are reasonable costs and may be adjusted for any differences from the Test Year expected in the future that are known and measurable at the time rates are set.

³ The return on investment should be set at a level that allows the utility to continue to attract investment by shareholders into the company and to procure financing for capital investments at reasonable terms. Criteria for setting the return on investment include considerations such as the risk of non-recovery faced by the utility, what level of return similarly-situated utilities earn, etc.

⁴ See e.g., Regulatory Assistance Project, Jim Lazar, Frederick Weston, and Wayne Shirley, “Revenue Regulation and Decoupling: A Guide to Theory and Application, at 4, June 2011, <http://www.raonline.org/document/download/id/902>.

⁵ Because different customer classes (residential, commercial, industrial) have different characteristics that result in different impacts on the system, different kWh and kW rates are often set for different customer classes.

⁶ Certain costs and revenue reimbursement to the utility are “trued up” exclusive of a return on equity evaluation, such as actual fuel costs and costs of energy efficiency programs. For example, in the case of ELL-Algiers Energy Smart programs, this process occurs in the ELL-Algiers fuel adjustment clause.

requirement when customers pay a per kWh rate. This effect may lead utilities to resist energy efficiency, distributed generation programs, and other initiatives that reduce utility sales.

Making utilities whole for these lost revenues so that the utility is returned to the position of having a reasonable opportunity to recover its authorized revenue requirement removes the disincentive for utilities to participate in and promote energy efficiency programs and other customer initiatives such as net energy metering (“NEM”) that reduce sales.

Utilities have both fixed and variable costs associated with serving their customers. Variable costs, such as fuel, increase or decrease in the short term based on how much energy is consumed while fixed costs, such as the costs of poles, wires, transformers, etc., do not increase or decrease in the short term based on how much energy is consumed. If the utility’s demand is reduced over the long term, it should be able to reduce its fixed costs over time, but it cannot do so on a monthly billing cycle basis. Under cost-of-service regulation, utilities tend to have a large component of fixed costs associated with investments like power plants and transmission and distribution lines. Because it is difficult for utilities to reduce this large component of their costs, they have a naturally-occurring incentive to increase profits by increasing sales of electricity rather than by cutting costs. In some cases for some utilities, a 1% increase in sales could lead to as much as a 5% increase in profits, with corresponding decreases in profits when sales decrease.

It is important to understand that as customers implement energy efficiency measures and other customer initiatives, which result in purchasing less power, under ENO’s current volumetric-based rates, those customers begin to pay less for both ENO’s fixed costs and its variable costs. Entergy’s variable costs will decrease as consumption decreases, however, the fixed costs of the ENO system do not decrease in the near term as electric consumption is

reduced. The problem with allowing energy efficiency customers to pay a decreasing share of the present fixed costs of the system *even though those costs do not decrease with reduced usage* is that it creates a significant risk that the utility will not have a reasonable opportunity to meet the fixed cost portion of its revenue requirement. The United States Supreme Court has held that regulators must allow a utility the opportunity to earn a reasonable rate of return on its investment,⁷ so this is a situation that should be addressed by the Council.

A secondary problem occurs in that a utility faced with declining sales, in an effort to continue to earn its revenue requirement, may request regulatory action to readjust revenues. That revenue readjustment action may shift the fixed costs no longer being paid by energy efficiency or NEM customers onto its other customers. A fairness issue develops when total utility fixed cost related revenue is adjusted for customer rate classes without a fully allocated cost of service analysis to reassess the impacts of energy efficiency and NEM on fixed cost responsibility and rate design. The adjustment of customer revenues should adhere to the regulatory principle of linking cost causation to fairness in the rates designed to recover such costs, in other words, “that all approved rates reflect to some degree the costs actually caused by the customer who must pay them.”⁸

The Council currently addresses some of these concerns with respect to the Energy Smart program through a lost contribution to fixed costs (“LCFC”) mechanism, where the Company gets compensated for lost revenues specifically attributable to the Energy Smart program. This methodology has addressed Energy Smart lost revenues in the context of an FRP thus far; however, concerns have been raised regarding the fact that it does not completely remove the

⁷ See *Bluefield Water Works & Improvement Co. v. W. Va. Pub. Serv. Comm’n*, 262 U.S. 679 (1923); see also *Federal Power Comm’n v. Hope Natural Gas Co.*, 320 U.S. 591 (1944).

⁸ See *KN Energy, Inc. v. FERC*, 968 F.2d 1295, 1300 (D.C. Cir. 1992); *Transmission Access Policy Study Group v. FERC*, 225 F.3d 667, 708 (D.C. Cir. 2000); *Pac. Gas & Elec. v. FERC*, 373 F.3d 1315 (D.C. Cir. 2004).

utility's incentive to increase kWh sales, and that it may result in an over-recovery of fixed costs. Due to these concerns, the Council in Resolution No. R-13-363, opened this inquiry into decoupling as a possible alternative to the LCFC method of addressing the lost revenues problem. While the LCFC method has been limited to revenue impacts from energy efficiency programs, decoupling addresses a much broader approach to evaluating ongoing fixed-cost revenue requirements.

Decoupling methods address the issues of maintaining the approved level of revenue to cover the utility's fixed costs. In its simplest form, decoupling adds a "true-up" mechanism that adjusts rates periodically between rate cases based upon the over- or under-recovery of the fixed cost-related revenue requirement. Decoupling creates a situation where the utility has no natural incentive to either discourage or promote energy efficiency and other customer incentives related to usage because ENO receives the same revenue to cover fixed costs whether sales increase or decrease.

In Resolution No. R-13-363, the Council initially directed the Companies to file a decoupling cost recovery proposal for consideration by the Council, specifically responding to several issues raised in a memorandum by the Regulatory Assistance Project ("RAP"). However, neither the Companies, nor any Intervenor filed a decoupling proposal that met the Council's criteria. Therefore, the Council issued Resolution No. R-14-511 on November 20, 2014, establishing a procedural schedule by which the Companies, Intervenors and Advisors could gather enough data to create and propose a decoupling mechanism suitable for New Orleans.

Pursuant to the procedural schedule set forth in Resolution No. R-14-511, the Company, Intervenors, and Advisors held three technical meetings in early 2015, the last of which was on April 14, 2015. The Company submitted a draft proposal on July 13, 2015, and the Intervenors

and Advisors provided feedback on the draft proposal on August 12, 2015. The Company submitted its final comments on October 12, 2015. The Alliance for Affordable Energy (“Alliance”) filed comments on November 13, 2015 and the Company replied on December 23, 2015. Finally, pursuant to Resolution No. R-14-511, the Advisors now submit this Report to the Council.

The stakeholder technical meetings were open to all Intervenors in the docket and were generally well attended. The Companies, the Advisors, the Alliance, Green Coast Enterprises (“GCE”), and the Gulf States Renewable Energy Industries Association (“GSREIA”) were all active participants in the stakeholder process and attended one or more of the technical meetings. Subsequent to the stakeholder meetings, the Companies filed their Joint Comments Regarding the Consideration of Issues Related to Decoupling on July 13, 2015 (“Companies’ Joint Comments”). Joint Comments responding to Entergy’s proposal were filed by the Alliance, GCE and the Greater New Orleans Housing Alliance (“GNOHA”) on August 12, 2015 (“Intervenor Joint Comments”), and GSREIA filed comments concurring in the Intervenor Joint Comments (the Alliance, GCE, GNOHA, and GSREIA referred to collectively as the “Intervenors”). On August 12, 2015, the Advisors submitted feedback to the Companies (“Advisor Comments”). On October 12, 2015, ENO filed its Final Comments with the Council (“ENO Final Comments”), on November 13, 2015 the Alliance filed responsive comments (“Alliance Comments”), and on December 23, 2015, ENO filed responsive comments (“ENO Responsive Comments”).

THE DECOUPLING MECHANISM

Over the course of the stakeholder process, several issues related to decoupling were discussed, with the parties reaching consensus on several issues and continuing debate on others. Having reviewed the proposals put forth by Entergy and the comments made on those proposals

by the Intervenor, the Advisors recommend the following approach with respect to addressing (i) the continued fair recovery of total utility fixed costs between rate cases, (ii) the continued fair recovery of fixed costs among customer rate classes, and (iii) the specific issue of lost revenues associated with energy efficiency and demand side management (“DSM”) programs.

A. Timing

1. *Comments of the Parties*

The Companies proposed that the decoupling mechanism be implemented in conjunction with a new, electric FRP to be developed as part of the next base rate case (currently anticipated to be filed in 2018).⁹ The Intervenor stated their support for decoupling and indicated in their comments that they did not object to implementation of a decoupling mechanism at the time of the next base rate case, but also would not object to an earlier implementation.¹⁰ In the Advisor Comments, the Advisors agreed that coordinating the timing of the implementation of decoupling with the next ENO base rate case is sensible since it would provide a good opportunity to set the authorized revenue requirement by customer rate class and would allow the Council to assess the impact of all rate changes at once.¹¹

2. *Advisor Recommendation*

The Advisors recommend first that a full decoupling mechanism should be developed by the Companies and considered by the Council in conjunction with ENO’s next base rate case, currently anticipated to be filed in 2018. The Advisors believe that such an approach would be the most reasonable approach in light of the need to establish an up-to-date authorized revenue by rate class baseline for the decoupling mechanism. This approach would also allow the

⁹ Companies’ Joint Comments at 3 and 7.

¹⁰ Intervenor Joint Comments at 2.

¹¹ Advisor Comments at 1-2.

Council to review the decoupling impact upon ratepayers when combined with several other changes to rates that are also anticipated to be incorporated into that base rate case, including, but not limited to combining the ENO and ELL-Algiers rates into a single city-wide rate, potential changes to the net energy metering rate, and the potential establishment of a new FRP. It is important for the Council to be able to review the total impact of all changes together, so that any unanticipated negative effects can be avoided.

B. Duration

1. Comments of the Parties

The Companies proposed that if a full decoupling mechanism is adopted, it should be a three-year pilot program to be implemented in conjunction with a new, electric FRP to be developed as part of the next base rate case (currently anticipated to be filed in 2018).¹² The Intervenors, however, argued that having a decoupling mechanism that is separate from the FRP mechanism is confusing and possibly duplicative, and that it would be more helpful to discuss either decoupling or an FRP.¹³ The Advisors also supported the proposal to implement decoupling through a three-year pilot program running either concurrently with an FRP,¹⁴ or as a stand-alone decoupling revenue adjustment mechanism if no FRP is approved by the Council.

2. Advisor Recommendation

The Advisors recommend that decoupling initially be implemented for a specific three-year period, to begin with the implementation of rate changes arising from the next ENO base rate case.

¹² Companies' Joint Comments at 3 and 7.

¹³ Intervenor Joint Comments at 2.

¹⁴ Advisor Comments at 2.

C. Basic Structure

1. *Comments of the Parties*

In their filing, the Companies presented a full decoupling mechanism, as they had been instructed to do by the Council, but recommended that a full revenue decoupling mechanism not be adopted, stating that instead the Council should consider adopting a revenue adjustment mechanism similar to the ENO FRP that was in place from test years 2009 through 2011.¹⁵ They noted that the FRP included recovery of the lost revenues specifically from utility-sponsored energy efficiency programs, LCFC, directly linking the estimated sales volume impacts of the utility's energy efficiency programs to the revenue collections of the utility, which the Companies found preferable to a full revenue decoupling mechanism.¹⁶

The Companies proposed in their Joint Comments that the decoupling mechanism be developed as a stand-alone rider, which could then either be shown as a separate line item on a customer's bill, incorporated into the FRP rider amount on the customer's bill, or included within the Energy Charge line item on the customer's bill.¹⁷ The Intervenors oppose having the decoupling adjustment shown as a separate line item on customer bills, they would prefer to have decoupling treated in the same manner as any adjustment to rates made under an FRP.¹⁸ The Advisor Comments support the inclusion of the decoupling adjustment in the aggregate FRP Rider amount on the customer's bill, or, if implemented without an approved FRP, its incorporation into the revised tariffs.¹⁹

In its Final Comments ENO reiterated that its strongly preferred approach, upon review of all proposed mechanisms, is still an Energy Efficiency/Demand Side Management Rider

¹⁵ Companies' Joint Comments at 2.

¹⁶ *Id.*

¹⁷ *Id.* at 8.

¹⁸ Intervenor Joint Comments at 3.

¹⁹ Advisor Comments at 2.

(“EE/DSM Rider”) to recover lost revenues specifically related to the energy efficiency and DSM programs.²⁰ As ENO notes, this mechanism would most closely replicate the current LCFC model being used to recover lost revenues due to the Energy Smart program.²¹ In the event that an EE/DSM Rider is not adopted, then ENO reiterated its support for the alternative approach set forth in the Companies’ Joint Comments of a decoupling mechanism implemented in conjunction with a new FRP.²² ENO also stated, however, that the decoupling approach set forth by the Advisor Comments, which would assume an approved FRP, would also be an acceptable approach.²³ In ENO’s Responsive Comments, it reiterated its strong preference to address lost revenues through a new EE/DSM Rider, which, ENO argues, is cost-effective to administer, provides transparency, and is ultimately the least risky to ENO’s customers relative to adopting some variation of revenue decoupling.²⁴

With respect to its preferred approach of an EE/DSM Rider, ENO argued in its Final Comments that it would address two key issues (1) providing a stable source of funding for EE/DSM programs that could be implemented upon the expiration of those programs in March 2017; and (2) addressing the issue of lost revenues associated with utility-sponsored energy efficiency and demand side management programs.²⁵ ENO would base the lost revenue component of the EE/DSM rider on the use of “deemed savings” values.²⁶ In the Alliance Comments, the Alliance argues that the purpose of revenue decoupling is broader and more important than just addressing the Energy Smart lost revenue problem.²⁷ The Alliance states that

²⁰ ENO Final Comments at 1-2 and 3.

²¹ *Id.* at 2.

²² *Id.*

²³ *Id.*

²⁴ ENO Responsive Comments at 2.

²⁵ ENO Final Comments at 3.

²⁶ *Id.* at 4.

²⁷ Alliance Comments at 1.

the objective of decoupling should be to assure the utility receives its authorized revenue as contemplated by the Council in the next rate case, no more, no less, whether or not outside events or efficiency programs lead to customer usage increasing or decreasing.²⁸

With respect to the second alternative discussed in ENO's Final Comments, the ENO-designed decoupling/FRP Pilot Alternative, ENO suggests a tailored decoupling mechanism within a broader, to-be-developed FRP.²⁹ ENO notes that while this decoupling proceeding was not designed to necessarily determine whether an FRP would ultimately be approved in conjunction with the Company's next base rate case, the FRP does have significant advantages as the new rate-setting mechanism to be used for decoupling because it is based on actual data.³⁰

With respect to the Advisors' proposal of first performing revenue requirement calculations per an approved FRP Tariff to determine the appropriate total utility revenue adjustment to be implemented, then determining the allocated revenue adjustment by using the allocation methodology approved in the recent rate case and employing billing determinants related to the current decoupling test year, ENO notes that this does appear to align with decoupling principles.³¹ ENO also noted that it has investigated the feasibility of such an allocation approach and believes that such an approach could be implemented.³² In its Comments, the Alliance also stated that the method set forth in the Advisor Comments appears reasonable, but also suggested that it is not necessary to determine exactly how full decoupling

²⁸ *Id.*

²⁹ ENO Final Comments at 5.

³⁰ *Id.* The Advisors add that the previous FRP revenue adjustments were also substantially influenced by pro-forma adjustments to the actual or per books data of the evaluation test year.

³¹ *Id.* at 9.

³² *Id.*

will be implemented, since doing so may depend on the rate design the Council determines to use.³³

2. *Advisor Recommendation*

The Advisors recommend the implementation of a full decoupling mechanism. To the extent that an FRP is adopted by the Council in the next base rate case, the Advisors recommend that the decoupling mechanism be implemented in conjunction with the annual FRP revenue adjustment. Applying a consistent allocation methodology to the FRP adjustment would allow an annual determination of the allocated fixed cost revenue requirements, and a recovery of such from each customer rate class consistent with the methodology used in the baseline rate case. Thus, ENO's annual authorized fixed cost revenue requirement would be recovered in aggregate through adjustments based on the actual revenue and allocated fixed-cost revenue requirement for each customer rate class. The decoupling rate adjustment (cents/kWh) would be applied to each rate class by dividing the allocated rate class revenue requirement by the then current test year billing determinates. This revenue adjustment approach should help reduce the volatility of the decoupling adjustment. If an FRP is approved, the Advisors also recommend that the revenue adjustment due to decoupling be included in the aggregate FRP Rider amount on the customer's bill. Implementing decoupling through the FRP evaluation and revenue adjustment would allow for transparency and Council oversight and review of the decoupling mechanism. Since customers are already familiar with FRP adjustments on their bills, customer confusion regarding decoupling should be minimized.

In the event that an FRP is not adopted in the next rate case, the Advisors recommend an alternative approach to full decoupling. The principal differences between implementing

³³ Alliance Comments at 2.

decoupling with an FRP and this alternative approach would be the determination of annual total utility fixed cost revenue requirement and the presentation of the adjustment on the customer's bill. Without an FRP mechanism, the Advisors recommend that the total utility fixed cost revenue requirement approved in the most recent rate case be maintained, with limited exceptions, as the target revenue requirement for annual decoupling adjustments for a period of three years. The limited exceptions could include (i) a reset of the target revenue requirement by another rate action related to significant changes to fixed costs, or (ii) if a substantial event or change to the fixed cost of service, such as the addition of new generating capacity, occurs between rate cases and the Council determines such change requires an adjustment to the fixed cost revenue requirement and interim recovery of the new costs. If such a re-determination of the fixed-cost revenue requirement is necessary, such change could be evaluated as an interim adjustment to the decoupling target annual revenue requirement. Recovery of such costs, if approved through an interim rider, would be recognized in the calculation of the annual decoupling adjustment. If such an event occurs, the Company should be required to file a rate case within a nine-month period from the effective date of such interim recovery to update the fixed-cost revenue requirement baseline used in decoupling.

For this non-FRP approach, the Advisors recommend a stand-alone decoupling rider to facilitate the following: (i) greater transparency for review, (ii) customer rate class calculations of allocated revenue requirement and recovery of such amounts, and (iii) any necessary true-ups. Notwithstanding the determination of the annual decoupling revenue adjustment by customer rate class, the recovery of the decoupling adjustment could be incorporated into the revised tariffs ensuing from the rate case to eliminate the confusion and concern resulting from introducing the decoupling concept as a new line item on customer bills.

With respect to ENO's preferred approach of a stand-alone EE/DSM rider, the Advisors note that ENO's proposal would base the lost revenue component of such a rider on the use of "deemed savings" values.³⁴ The Advisors do not recommend this approach for several reasons: (i) the adjustment limited to Energy Smart programs is not as comprehensive as full decoupling; (ii) the adjustment represents a separate increment to the Council's approved revenue requirement, whereas the Advisors' recommended alternatives with and without an FRP update both cost responsibility and billing determinates in maintaining the Council-approved revenue requirement; and (iii) the Council has been moving away from the estimates of the "deemed savings" approach in favor of actual, evaluated savings through evaluation, measurement and verification (EM&V").

The Advisors note that a full decoupling mechanism would avoid the issue of potential overearnings by the utility in situations where reduced sales due to EE/DSM are offset by increased sales through load growth or due to weather conditions, etc. It would also allow lost sales from other sources and customer incentives, such as customer-owned solar and distributed generation, to be accounted for in assuring that the Company has the ability to earn its authorized revenue requirement.

D. Test Year

1. Comments of the Parties

The Companies proposed using a calendar year as the test year.³⁵ The Advisor Comments also supported the use of a calendar year test year.³⁶

³⁴ ENO Final Comments at 4.

³⁵ Companies' Joint Comments at 8.

³⁶ Advisor Comments at 2-3.

2. *Advisor Recommendation*

The Advisors recommend that a calendar year test year with twelve months of actual/historical data be utilized for the decoupling mechanism. With the approved fixed cost revenue requirements by customer rate class from the Combined Rate Case providing the baseline for decoupling, the test year for the first decoupling revenue adjustment should be the most recent full calendar year of historical data subsequent to the Combined Rate Case, which should be the 12 months ending December 31, 2018.

E. Application to ENO Electric and Gas Service

1. *Comments of the Parties*

The Companies proposed limiting the application of decoupling to electric customers only.³⁷

2. *Advisor Recommendation*

The Advisors recommend that the implementation of decoupling be limited to electric customers at this time, and that the Council defer any consideration of including natural gas customers until such time as information becomes available regarding the results of implementing electric utility decoupling for at least three years, and such results are evaluated by the Council.

F. Costs to be Included in the Decoupling Mechanism

1. *Comments of the Parties*

The Companies also proposed that any full decoupling mechanism include the allocated portion of total fixed and non-fuel variable costs required to serve affected residential and small commercial customers, excluding any costs included in riders or other recovery mechanisms.³⁸

³⁷ Companies' Joint Comments at 8.

³⁸ *Id.* at 10.

The Intervenors argued that the authorized revenue requirement should include recovery of all fixed costs plus a rate of return, but that variable costs could be recovered either through the revenue requirement or riders.³⁹ The Intervenors question which expenses would be included in non-fuel variable costs.⁴⁰ The Advisor Comments opposed the Companies' proposal, arguing that all utility fixed costs, regardless of the recovery mechanism, should be included in the decoupling mechanism.⁴¹ In ENO's Final Comments, the Company stated that it understands the Advisors' position and does not object to certain fixed costs currently recovered through riders being recovered in revised base rates once such base rates are determined in conjunction with the next base rate case.⁴²

2. *Advisor Recommendation*

The Advisors recommend that all utility fixed costs be included in the decoupling revenue adjustment, regardless of the revenue recovery mechanism used to recover any specific fixed (non-fuel) costs. Revenue recovery mechanisms should not dictate the allocation of fixed cost responsibility and the corresponding decoupling revenue adjustment. The Combined Rate Case determining the authorized fixed cost revenue requirement reference or baseline for an annual decoupling revenue adjustment should include all utility fixed costs, regardless of whether such costs are recovered in base rates or through a rider.

³⁹ Intervenor Joint Comments at 2.

⁴⁰ *Id.* at 4.

⁴¹ Advisor Comments at 4.

⁴² ENO Final Comments at 9.

G. Adjustments to the Revenue Requirement

1. *Comments of the Parties*

In some decoupling mechanisms, a weather normalization adjustment is made. The parties reached consensus through the stakeholder process that such an adjustment mechanism would not be desirable for New Orleans.

The Companies proposed using targeted revenue-per-customer amounts and recommended not including a weather normalization adjustment.⁴³ They did propose in their Joint Comments to implement an annual “K-Factor” adjustment (a 2.25% value was used) to the revenue-per-customer amount to reflect the fact that the utility’s cost of service is generally increasing between rate proceedings.⁴⁴ The Intervenors opposed the proposal to include a K-Factor adjustment.⁴⁵ The Advisor Comments opposed the Companies’ proposed use of a K-factor adjustment⁴⁶ to estimate an annual cost of service adjustment. Rather, the Advisors asserted that the authorized fixed cost revenue requirement reference or baseline should be determined on an allocated basis for each customer class, and that the allocation methodology should be applied consistently on an annual basis (starting with the baseline rate case) for the decoupling revenue adjustments by customer rate class.⁴⁷

In ENO’s Reply Comments, the Company noted that while the use of an annual cost of service adjustment is an essential component of a decoupling mechanism, the proposal to implement decoupling with an FRP (or similar to-be-determined annual rate-setting mechanism) reduces the necessity of implementing a K-Factor adjustment since changes to the cost of service would be contemplated within the annual rate-setting process and any changes in rates resulting

⁴³ Companies’ Joint Comments at 10-11.

⁴⁴ *Id.* at 11.

⁴⁵ Intervenor Joint Comments at 4.

⁴⁶ Advisor Comments at 5.

⁴⁷ *Id.*

from that process.⁴⁸ In ENO's Final Comments, the Company argues that a true-up mechanism that ensures that it collects exactly the same revenue requirement every year with no adjustment is inappropriate where, as in New Orleans, the load is still rebounding and continuing to grow.⁴⁹ ENO argues that increases in the revenue requirement over time are necessary for ENO to provide safe, reliable, and affordable electric service to New Orleans, and if decoupling were to be a stand-alone rate-setting mechanism, fairness would require a method of recognizing changes to the cost of service, such as a K-Factor mechanism.⁵⁰ The Alliance clarified in their Comments that they do not object to a decoupling mechanism (so long as it meets other stated requirements) that allows for adjustments of authorized revenue based on changes in the number of customers in a class.⁵¹ In its Responsive Comments, however, ENO emphasized that any fair decoupling mechanism must include a provision for changes in cost of service that occur between rate cases, whether due to increases in the number of customers, inflationary pressures, or the need for capital investments to serve customers reliably and safely.⁵²

2. *Advisor Recommendation*

The Advisors recommend that, with limited exceptions, no further adjustments be made to the revenue requirement to be recovered through the decoupling mechanism. If the decoupling adjustment were implemented in conjunction with an approved annual FRP evaluation, the FRP adjustment would address annual changes to the recovery of fixed costs. If no annual FRP evaluation was approved for a period of years following the rate case, the Company should be allowed to recover certain significant increases in the fixed cost of service, if

⁴⁸ ENO Final Comments at 6.

⁴⁹ *Id.* at 7.

⁵⁰ *Id.*

⁵¹ Alliance Comments at 2.

⁵² ENO Responsive Comments at 2.

approved by the Council, on an interim basis. As discussed above, the limited exceptions could include (i) reset of the revenue requirement by another rate action related to fixed costs, or (ii) a substantial event or change to the fixed cost of service requiring an adjustment to the fixed cost revenue requirement and interim recovery of such, as determined by the Council. If such a re-determination of the fixed-cost revenue requirement is necessary, such change could be evaluated as an interim adjustment to the decoupling target annual revenue requirement. Interim recovery of such costs, such as through a Council-approved interim rider, would be recognized in the calculation of the annual decoupling adjustment. If such an event occurs, the Company should be required to file a rate case within a nine-month period from the effective date of such interim recovery to update the fixed-cost revenue requirement baseline used in decoupling.

A weather normalization adjustment to the annual decoupling adjustment is not necessary because the baseline established in the next base rate case should include a weather normalization adjustment.

The Advisors oppose ENO's proposal to include an estimated percent increase in total utility fixed costs each year (a "K-Factor" adjustment) to a cumulative authorized revenue per customer in each customer class, because this effectively changes the Council approved total utility revenue requirement without any annual review, and also because it results in a different authorized revenue by customer rate class than that resulting from the allocation methodology used in a rate case. The proposed K-Factor simply estimates a prospective annual growth rate for cost of service based on recent historic data. ENO's Comments acknowledge that the application of the K-Factor resulted in a steady increase in year-to-year allowed revenues for each period between rate cases. Such an approach runs the risk of being disassociated from, and therefore out of sync with, measurable drivers of the utility's cost of service. All of the cost data

used in a rate case change overtime, and the elements making up the K-Factor are no different. The K-Factor therefore may essentially become inappropriate or lead to erroneous results due to changes in costs, providing another reason why periodic general rate cases or a comprehensive evaluation of all the costs of service should be required to determine if there should be any change in the revenue requirement target for the decoupling adjustment. The allocation methodology in a decoupling mechanism should be consistent with the allocation methodology used in a rate case. The use of the K-Factor adjustment as proposed by the Company would also arbitrarily induce significant decoupling adjustment amounts for Large Electric High Load Factor and High Voltage customers. An annual cost-of-service allocation (as described below) would not create such large variations in fixed cost revenue requirement by customer rate class.

H. Allocation of Costs

1. Comments of the Parties

The Companies also proposed that any full decoupling mechanism include only residential and small commercial customers.⁵³ In ENO's Final Comments, ENO noted that it had proposed only including Residential and Small Commercial rate classes in its initial proposal because of the significant volatility that would occur in the other rate classes, however implementing a decoupling mechanism along with an annual rate setting mechanism that includes rate categories similar to an integrated resource plan ensures that all customers share in the changes to the cost of service without unduly burdening only a few rate categories.⁵⁴

The Intervenors argued in their comments that the Companies should not exclude municipal customers, large electric, or large electric high load factor customers, and

⁵³ Companies' Joint Comments at 10.

⁵⁴ ENO Final Comments at 6.

recommended that the Council reject any proposal to exclude customer classes except for those with fewer than 20 customers.⁵⁵

In response to the Intervenor's argument that only rate classes with fewer than 20 customers should be excluded from the decoupling program, ENO noted in its Final Comments, that upon review, collapsing the Large Electric and Large Electric High Load Factor categories into one class for the purpose of decoupling may be a reasonable compromise and could be explored further along with the inclusion of the Municipal Buildings rate category if the Council requires implementation of a decoupling mechanism subsequent to the next base rate case.⁵⁶ ENO stated that it agreed with the Advisor recommendation to include all rate classes, if the Advisor design of first performing calculations per the annual rate setting mechanism to determine the appropriate rate change to be implemented, then using an allocation method based on the last rate case and on billing determinants tied to the decoupling test year is adopted.⁵⁷

2. *Advisor Recommendation*

The Advisors recommend that all electric customer classes be included in the decoupling mechanism. The Advisors oppose ENO's proposal to include only the residential and small commercial customer classes in the decoupling mechanism because it would overburden residential and small commercial customers with cost of service/revenue adjustments that would otherwise be allocated to all rate classes consistent with the cost responsibility by customer class determined in a base rate case.

The authorized fixed cost revenue requirement reference or baseline will be determined on an allocated basis for each customer class in the Combined Rate Case. The allocation

⁵⁵ Intervenor Joint Comments at 3.

⁵⁶ ENO Final Comments at 7-8.

⁵⁷ *Id.* at 9.

methodology should be applied consistently on an annual basis to determine the decoupling revenue adjustments by customer class. The fixed-cost customer rate class allocation factor could be updated annually, based on average demands in each class, current monthly demands available from large customers (actual data from recording meters and coincidence factor used with maximum demand meters), and any recent load research data or significant changes to recorded large customer demands as applicable. Entergy uses Oracle software to estimate hourly customer rate class demands on an ongoing monthly basis, so updating the annual allocation factor should not be burdensome.

I. True-Up Frequency

1. *Comments of the Parties*

The Companies proposed an annual true-up to review and adjust the allowed revenues, similar to what has occurred historically with the FRP.⁵⁸

2. *Advisor Recommendation*

The Advisors recommend that the decoupling mechanism, whether implemented in conjunction with an FRP or as a stand-alone mechanism, incorporate an annual review of and adjustment to allowed revenues similar to what has occurred historically with the FRP.

J. Symmetry in the Application of the Decoupling Revenue Adjustment

1. *Comments of the Parties*

The Companies proposed in their Joint Comments that it would be appropriate to provide symmetrical treatment of any over or under-collection of allowed revenues.⁵⁹ The Intervenors support a formula adjustment with no bandwidth beyond a *de minimus* amount.⁶⁰ The Advisor Comments supported the symmetrical treatment of any over or under-collection of authorized

⁵⁸ Companies' Joint Comments at 8.

⁵⁹ *Id.*

⁶⁰ Intervenor Joint Comments at 2-3.

revenues, and the annual review and adjustment to allowed revenues,⁶¹ regardless of whether the decoupling adjustment is applied as a standalone adjustment or in conjunction with an FRP.

2. Advisor Recommendation

The Advisors recommend that treatment of any over-collection of the revenue requirement be treated symmetrically with any under-collection of the revenue requirement by customer rate class under the decoupling mechanism.

K. Rate Caps and Carrying Charges

1. Comments of the Parties

The Companies proposed that the Council avoid implementing a rate cap on the decoupling adjustment, arguing that rate caps can have the negative, unintended consequence of creating large deferred balances that could take several years to flow through to customers.⁶² The Companies noted that if unforeseen circumstances result in a rate adjustment related to decoupling that the Council deems too large, the Council can at that time adopt a rate cap and deferral.⁶³ If a rate cap is imposed by the Council, the Companies recommended that any unrecovered balances (positive or negative) be carried forward to the next year and incorporate carrying charges at the current pre-tax weighted average cost of capital based on the then-allowed return on equity.⁶⁴ The Intervenors supported the proposal not to implement a rate cap, noting that the Council has the authority to make adjustments as needed, should unforeseen circumstances arise.⁶⁵ The Advisor Comments also supported a decoupling mechanism that does not include a rate cap, and the Advisors similarly note that the Council has the ability to make

⁶¹ Advisor Comments at 3.

⁶² Companies' Joint Comments at 9.

⁶³ *Id.*

⁶⁴ *Id.*

⁶⁵ Intervenor Joint Comments at 3-4.

adjustments as needed should unforeseen circumstances arise.⁶⁶ If a rate cap is approved, the Advisor Comments agreed that carrying charges should apply to both positive and negative deferred balances, but stated that a just and reasonable carrying charge should be determined by the Council.⁶⁷

2. *Advisor Recommendation*

The Advisors oppose including a rate cap in a full decoupling mechanism due to the potential for large deferred balances to accrue and incur carrying charges, all of which must then ultimately be recovered from customers. In the unusual event that a rate impact due to the decoupling mechanism were to be of significant size to cause concern, the Council would be able to make an adjustment to the decoupling implementation at that time.

In the event that the Council determines that a rate cap is desirable, the Advisors recommend that ENO be permitted to carry any unrecovered balance (positive or negative) above or below the cap over until the next annual rate implementation, and to amortize any such balance over the following rate implementation year. The Advisors agree that such deferred balances would incorporate carrying charges as determined by the Council in the rate case, and that such carrying charges should be applied symmetrically to both positive and negative deferred balances.

L. Procedural Schedules for Decoupling Reports

1. *Comments of the Parties*

The Companies proposed to file the annual decoupling report contemporaneously with any FRP annual report filing for the same time period, and to provide the Advisors and other Parties sixty (60) days to comment on the annual report, such that the new rate reflecting any

⁶⁶ Advisor Comments at 4.

⁶⁷ *Id.*

adjustments could be implemented effective the first billing cycle of September in the filing year, concurrent with any FRP rate implementation.⁶⁸

The Advisor Comments also supported an annual decoupling report filing date contemporaneous with the FRP. However, if the filing is made contemporaneously with the FRP Evaluation Report, the Advisor Comments argued that a 75-day comment period would be more reasonable.⁶⁹ The Advisor Comments also supported an effective date of the first billing cycle of September if filed with an FRP or if filed on a stand-alone basis.⁷⁰

2. *Advisor Recommendation*

If the decoupling revenue adjustment is applied in conjunction with an FRP, the Advisors recommend that a decoupling mechanism be subject to the same annual filing deadline and procedural schedule as the FRP. Historically, this has meant an annual FRP Evaluation Report filing date of May 31, with 75 days for comments/responses by interested parties, and an ultimate rate change implementation date of the first billing cycle in September. If an FRP is approved, the Council will determine the implementation date of the rate adjustment.

To the extent that a decoupling mechanism is implemented as a stand-alone mechanism and not in conjunction with an FRP, the Advisors believe an annual decoupling report filing date of May 31, with 60 days for comments/responses by interested parties and an ultimate rate change implementation date of the first billing cycle of the month following Council approval, would be reasonable.

⁶⁸ Companies' Joint Comments at 9.

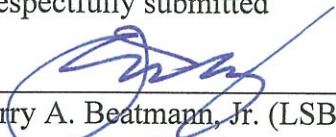
⁶⁹ Advisor Comments at 3.

⁷⁰ *Id.* at 3-4.

CONCLUSION

For the reasons set forth above, the Advisors recommend that the Council issue a Resolution directing ENO to incorporate a decoupling mechanism consistent with the mechanism recommended herein into its next base rate case filing.

Respectfully submitted



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Docket No. UD-08-02

I hereby certify that I have this 10th day of February, 2016, served the required number of copies of the foregoing report upon all other known parties of this proceeding, as listed below, by electronic mail.

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