BEFORE THE

COUNCIL OF THE CITY OF NEW ORLEANS

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

DIRECT TESTIMONY AND EXHIBITS

OF

PAMELA G. MORGAN

ON BEHALF OF THE

ALLIANCE FOR AFFORDABLE ENERGY

FEBRUARY 1, 2019

TABLE OF CONTENTS

LIST OF EXHIBITS

I. INTRODUCTION

Q1. PLEASE STATE YOUR NAME, BUSINESS ADDRESS, AND CURRENT POSITION.

A. My name is Pamela G. Morgan, and my business address is PO Box 1263, Tubac, Arizona, 85646. My current position is President of Graceful Systems LLC.

Q2. PLEASE DESCRIBE YOUR EDUCATIONAL AND OCCUPATIONAL BACKGROUND.

A. I have been involved with energy utility issues since 1984, when I started as an associate at a law firm representing industrial customers of natural gas distribution companies and industrial customers of publicly-owned utilities that took service from the Bonneville Power Administration. Over the course of my career, summarized in my curriculum vitae, AAE Exhibit PGM-1, I was employed for over 20 years by Portland General Electric ("PGE"), a mid-sized investor-owned utility in Oregon. With the exception of a brief period I spent in distribution operations, most of my work at PGE involved regulatory affairs, including almost eight years in which I served as PGE's Vice President of Regulatory Affairs. I am very familiar with rate cases, riders and adjustment clauses, and the regulatory policies relating to demand-side resources.

After leaving PGE in 2009, I was engaged for numerous consulting projects by clients ranging from the Natural Resources Defense Council ("NRDC") to the National Association of Regulatory Utility Commissioners. Pertinent to this case, I have considerable experience with energy utility decoupling. In 2009 and 2012, I did extensive research for a report on the rate effects of electric and natural gas utility decoupling mechanisms. For the original 2009 report, performed for NRDC, I studied and summarized the decoupling mechanisms and calculated their rate effects for 12 electric utilities and 28 natural gas utilities. I updated the study in 2012-13 for NRDC, American Council for an Energy-Efficient Economy ("ACEEE"), and the Regulatory Assistance Project, this time for 27 electric utilities and 50 natural gas utilities. Around those years, I also provided expert testimony on decoupling issues for NRDC in several cases and spoke at a number of conferences and workshops on the topic, most notably at the 2014 U.S. Energy Information Administration Annual Energy Conference.

More recently, I have served as an expert witness for NRDC and The Alliance for Solar Choice regarding rate design matters. I co-authored a paper on the uses and abuses of class cost of service studies in current utility rate cases. I have also consulted on strategy using the tools of system dynamics.

Q3. HAVE YOU PREVIOUSLY SUBMITTED TESTIMONY BEFORE THE COUNCIL OF THE CITY OF NEW ORLEANS ("COUNCIL")?

A. No.

Q4. ON WHOSE BEHALF ARE YOU SUBMITTING TESTIMONY?

A. I am submitting testimony on behalf of the Alliance for Affordable Energy ("AAE").

Q5. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. My testimony describes for the Council a decoupling mechanism for Entergy New Orleans ("ENO" or "Company") that conforms to the parameters the Council adopted in Council Resolution No. R-16-103. ENO's proposed Formula Rate Plan ("FRP"), that it asserts includes a decoupling mechanism, does not appear to provide a decoupling mechanism either as the Council ordered or as decoupling is commonly understood. A standard decoupling mechanism makes the utility financially indifferent to a difference between the test year assumption of its revenue from energy- and demand-driven billing determinants and its actual revenue from those billing determinants. ENO's FRP, as proposed, does not do this. I recommend three changes to conform ENO's proposal to a standard decoupling mechanism:

- Remove it from the effects of the FRP dead-band;
- Clarify that it will operate only on revenues ENO receives from energy- and demand-driven billing determinants. The decoupling mechanism will not operate on either (1) revenues from customer charge billing determinants or minimum bill requirements in tariffs; or (2) revenues collected under tariff riders that are subject to full reconciliation (*i.e.*, ENO receives only the costs within the rider, not more or less depending on its sales); and
- Clarify that the comparison is between the most recent approved revenues and the actual revenues, allocated to rate classes/schedules per approved allocation factors, and not to a calculation of required allocated revenues that includes changes in costs during the decoupling period.

With these changes, the ENO's decoupling mechanism will be simple, transparent, and operable regardless of whether the Council approves ENO's proposed FRP or, if an FRP is approved, whether the FRP triggers a rate increase or decrease in a given year.

My testimony also recommends that the Council reject the Lost Contribution to Fixed Costs ("LCFC") mechanism ENO proposes as part of its Demand-Side Management Cost Recovery ("DSMCR") Rider. The LCFC is unnecessary if the Council adopts a standard decoupling proposal for ENO, and no other state or regulator that I am aware of has approved both a LCFC *and* a decoupling mechanism for a utility. The effects of an LCFC mechanism and decoupling overlap but the LCFC is a far inferior method of achieving the objective of holding the utility neutral to any negative revenue effects of offering energy efficiency and demand reduction programs. Moreover, the interaction of ENO's proposed LCFC with its FRP is confusing at best.

Q6. PLEASE DESCRIBE HOW YOUR TESTIMONY IS ORGANIZED.

A. My testimony is organized into the following sections.

- Section II defines decoupling, relying on my own work as well as the Council's conclusions in Council Resolution No. R-16-103. Based on my current understanding of ENO's testimony and proposed tariffs, it has not proposed a standard decoupling mechanism and the mechanism it includes in its proposed FRP will not accomplish decoupling. I describe three changes to ENO's proposal that result in a standard decoupling mechanism that efficiently removes ENO's throughput incentive and works well either independently of or with the FRP, should the Council adopt ENO's proposal.

- Section III describes the LCFC mechanism included in ENO's proposed DSMCR Rider and attempts to describe how this mechanism will interact with the FRP. I identify the questions about the LCFC and its interaction with the FRP left unanswered by both the Company's testimony and proposed tariffs. This section concludes with the reasons the Council should reject the LCFC regardless of the decision it reaches on the DSMCR Rider as well as my recommendation that it do so.
- Section IV concludes my testimony with a summary of my recommendations to the Council.

II. DECOUPLING

A. Decoupling, defined

Q7. HOW DO YOU DEFINE DECOUPLING?

A. Decoupling, as used in my 2009 and 2012-13 studies, is a regulatory mechanism that adjusts rates periodically to ensure that the amount a utility books as revenue for fixed cost recovery is no more and no less than the amount of revenue authorized by the regulator for that cost coverage. Some mechanisms use the revenue authorized in the utility's last general rate case; others adjust the revenue for specific cost changes or according to a formula, and still others convert the revenue into a per-customer account number, usually by rate schedule, rather than as a single dollar amount. The means of accomplishing decoupling do not affect how customers pay for energy utility services, enabling utilities to maintain volumetric rates without experiencing any negative revenue effects from its programs or conservation efforts that result independently from the utility's efforts. On some regular basis, the decoupling mechanism provides a rate adjustment to ensure that customers, in effect, receive refunds or pay surcharges based on whether the revenues the utility actually received from customers were greater or less than the revenues the regulator authorized. This difference can occur for many reasons, primary among which are weather, economic conditions, energy efficiency programs and incentives, and customer behavior that cause the use of electricity or natural gas to differ from amounts assumed in the ratemaking process.

Q8. DO YOU STILL AGREE WITH THAT DEFINITION?

A. Yes. Decoupling is, first and foremost, a true-up or reconciliation of rate case assumptions for fixed cost revenues to actual fixed cost revenues. Fixed cost in this sense does not mean the cost does not vary; it simply means that the cost does not vary with how much energy a given customer uses from the utility at a single moment (demand) or over some period of time (energy), typically a month or billing period.

Q9. IS THERE JUST ONE WAY TO ACCOMPLISH DECOUPLING?

A. No. As my 2012-13 report detailed, there is considerable variation in the decoupling mechanisms regulators have approved for energy utilities. These variations generally have to do with differences in how regulators, with input from utilities and their stakeholders, answered these questions:

- When we compare actual fixed cost revenue to authorized fixed cost revenue to remove the throughput incentive, should authorized revenue change from year to year by any means other than a general rate case?
- How often should we make a decoupling adjustment?
- Should the actual revenues used in the mechanism be adjusted to remove the effects of weather differently than the approach used in setting authorized revenues (sometimes called weather normalization)?
- When we compare actual revenues to authorized revenues, should we do that on an overall utility basis or by customer class or rate schedule?
- Should there be any limits on the size of decoupling adjustments that occur and, if there are limits, what should happen to refund or surcharge amounts in excess of the limits? Should the decoupling apply to the full difference between actual and authorized revenues or only some part of it?

All decoupling mechanism reconcile – true-up – actual revenue to the rate case revenue assumption. This characteristic is what breaks the through-put incentive.

Q10. WHAT WERE THE ELEMENTS OF A DECOUPLING MECHANISM THAT THE COUNCIL ORDERED ENO TO FILE IN COUNCIL RESOLUTION NO. R-16-103?

A. Council Resolution No. R-16-103 ordered ENO to file a decoupling mechanism with these elements:

- Applicable only to electric customers but all of such customers, regardless of rate class or schedule.

- An authorized fixed cost revenue requirement set either through the next rate case (this case) or, if the Council also approved an FRP in the next rate case, the authorized fixed cost revenue requirement emerging from that annual process, allocated to each customer rate class consistent with the allocation methodology used in the rate case.
- Inclusive of all fixed costs, regardless of the revenue recovery mechanism used for them.
- With no adjustment of the actual revenues for weather and no adjustment of the authorized revenue requirement other than the FRP, if approved.
- An annual true-up to adjust actual revenues to authorized revenues, with under- and over-collections treated symmetrically and no cap on the amounts surcharged or refunded.
- Using the same filing deadlines as an FRP if an FRP is approved.

Q11. BASED ON YOUR EXPERIENCE, DO YOU AGREE THAT ALL OF THESE PARAMETERS ARE APPROPRIATE?

A. Based on my experience, I would modify two of these parameters.

Q12. WHAT IS THE FIRST PARAMETER THAT YOU WOULD RECOMMEND MODIFYING?

A. The first parameter I would modify has to do with the fixed cost revenues included in the decoupling mechanism. I agree with ENO's proposal to exclude the rate base, revenue, and expense effects of any costs the Council has authorized ENO to recover pursuant to a tariff that requires reconciliation of the revenues recovered for that cost to the cost itself, such as the Fuel Adjustment Clause. Regardless of how ENO's tariffs recover these charges, the reconciliation means that selling more or less pursuant to energy- and demand-driven billing determinants provides ENO no financial benefit. Accordingly, the rate design for such riders can work to reinforce policy goals other than the utility's financial stability. For example, sections IV and V of the direct testimony of AAE witness Justin R. Barnes describes the negative effects of ENO's proposed rate design for the Distribution Grid Modernization Rider and Rider DSMCR. This rate design, which affects all billing determinants on a schedule, emphasizes ENO's financial stability over other policy objectives.

I do recommend that the decoupling tariff include a list, that ENO maintains through tariff changes as necessary, of the riders or other tariffs that meet the reconciliation criteria. From my review, it appears that the following[1] would qualify for exclusion from the decoupling mechanism:

- Fuel Adjustment Clause
- Environmental Adjustment Clause Rider
- Rough Production Cost Equalization Adjustment Rider
- Purchased Power and Capacity Acquisition Cost Recovery Rider
- Midcontinent Independent System Operator ("MISO") Cost Recovery Rider
- Demand-Side Management Cost Recovery Rider

[1] *See* Revised Application of Entergy New Orleans, LLC for a Change in Electric and Gas Rates Pursuant to Council Resolutions R-15-194 and R-17-504 for Related Relief, Statement A-3 – Electric (Proposed Electric Rate Tariffs) (Sept. 21, 2018) ("Application"); *see also* Revised Direct Testimony of Phillip B. Gillam at 53:10-20 (Sept. 21, 2018) ("Gillam Direct").

- Securitized Storm Cost Recovery Rider
- Securitized Storm Cost Offset Rider
- Distribution Grid Modernization Rider

Q13. WHAT IS THE SECOND PARAMETER YOU WOULD RECOMMEND MODIFYING?

A. The second parameter Council Resolution No. R-16-103 states that I would modify relates to the first one I just discussed. After participating in numerous decoupling cases, I have come to believe that a utility can, and usually should, maintain some degree of financial risk with respect to revenues associated with billing determinants or tariff charges that are not energy- or demand-driven. The most prominent examples of these for ENO are the customer charge billing determinant on the Residential Electric Service rate schedule and the minimum bill associated with the lowest demand tier billing determinant on most of its other electric service rate schedules. Revenues under these billing determinants will vary primarily with customer counts for each rate schedule. In other words, if ENO adds or loses customer accounts under its electricity service tariffs, it will increase or decrease its revenue without that difference being returned to or recovered from all other customers.

Maintaining this financial connection to the number of customer accounts is a good step toward helping the utility stay customer centric and in tune with the big picture of the financial and community health of its service territory.

Q14. DOES YOUR RECOMMENDATION SUPPORT THE LEVELS ENO PROPOSES IN THIS CASE FOR THE RESIDENTIAL CUSTOMER CHARGE AND ITS VARIOUS MINIMUM BILL AMOUNTS?

A. No. Although I have conducted no comprehensive study, the amount of revenue ENO proposes to collect through its proposed customer and Advanced Metering Infrastructure ("AMI") charges and various minimum bills appears high. As one can see from my AAE Exhibit PGM-2,[2] the amount ENO proposes to recover from customer charges, including the AMI charge, and minimum bills, is over $52 million per year. This amount exceeds ENO's required operating income (without gross-up for taxes and bad debt) at an Earned Return on Common Equity ("EROE") of 10.5%, and also exceeds 12% of ENO's total proposed base revenue requirement. In total, ENO is recovering over one-third of its total revenue/revenue requirement through either rates that do not vary with usage or on a dollar-for-dollar reconciliation basis.

One of the benefits of decoupling is that the mechanism itself supports the utility's financial stability. Declines in energy and/or demand will not harm it financially. Utilities commonly support requests to increase customer charges or minimum bill amount with the argument that doing so will increase their financial stability. Decoupling accomplishes this goal, but without the negative effects on customers' financial incentives to increase energy efficiency or reduce their

[2] AAE Exhibit PGM-2 includes calculations of customer charges and minimum bill amounts in ENO's tariffs multiplied by customer accounts under each schedule, which is then compared to a calculation of required operating income.

demand that customer charges and minimum bills have. With decoupling, utilities, and their ratings agencies and financial analysts, have assurance that changes in energy use or levels of demand will not harm the utility's finances. The utility can maintain good financial standing without raising customer charges or minimum bills. This means that rate design can focus on supporting policy objectives other than financial stability, such as encouraging conservation, demand management, and investments in energy efficient and demand-reducing equipment. Similarly, a standard decoupling mechanism reduces the need to enhance a utility's financial standing through a high authorized return on common equity.

Any dollars collected through billing determinants that do not vary with energy or demand lower the benefit that individual households or businesses can achieve by pursuing conservation, energy efficiency, and/or demand reduction and management. Reductions in these benefits makes it less likely that all customers will benefit from avoided utility investments in yet more baseload and peaking generation and sizing decisions throughout the distribution system. Conversely, the more revenue collected through energy- and demand-driven billing determinants, the more incentive customers have to participate in a utility energy efficiency and demand reduction/management program or even simply invest on their own or with a third-party service provider. Section II.C of the direct testimony of AAE witness Justin R. Barnes discusses at length, with references and examples, the effect rate design choices can have on ratepayer incentive to invest in energy efficiency and the energy efficiency that does or does not result.

B. Three changes to ENO's proposed decoupling will provide it and the Council with an effective, beneficial mechanism.

Q15. WHAT IS THE FIRST CHANGE YOU RECOMMEND TO ENO'S DECOUPLING PROPOSAL?

A. To ensure that ENO is operating under an effective, simple, and transparent decoupling mechanism, it cannot be subject to the dead-band that ENO proposes for its FRP.

ENO states that it will not follow its four-step decoupling process if the FRP results in a finding that the EROE is within the dead-band.[3] In other words, it will not decouple if either:

- The difference in assumed fixed cost revenues and actual fixed cost revenues is less than the dead-band amount, or
- The difference in assumed fixed costs and actual fixed costs is less than the dead-band amount, or
- Some combination of these two (such that they offset each other) that causes the FRP to result in a finding of no adjustment.

In any of these cases, ENO will simply not decouple its revenues from the throughput incentive. ENO explains that it increased the dead-band for its proposed FRP "because it incentivizes the Company to manage its resources efficiently."[4] Apparently, it considers energy- and demand-driven revenues to be resources it can

[3] *See* Gillam Direct at 32:6-9 ("The Company proposes to implement the Decoupling Pilot Program within the Electric FRP through a four-step process to be applied if and only if a Rate Adjustment is necessary under the terms of the rider. In other words, if the EROE is within the dead band, then the process will not be applied.").
[4] *Id.* at 29:19-20.

manage. To the extent the decoupling mechanism remains subject to a dead-band, ENO remains financially interested in encouraging energy use and demands to exceed assumptions, working against its own Energy Smart programs.

Based on my 2009 and 2012-13 work calculating the sizes of decoupling rate changes, both refunds and surcharges, I know that decoupling adjustments are generally small. If wide dead-bands were a common practice, utilities with decoupling would have rarely made decoupling adjustments. In other words, these decoupled utilities would also have retained their full throughput incentive, working against their programs to help customers increase energy efficiency and lower energy use and demand. Of course, I am not aware of any decoupling mechanism that is subject to a dead-band as ENO proposes.

Q16. DO YOU HAVE ANY OTHER COMMENTS ON THE PROPOSED FRP'S DEAD-BAND?

A. Yes, although my comment does not relate specifically to decoupling. In my experience with dead-bands on recovery mechanisms, whether limited riders such as fuel and purchased power adjustment clauses or ENO's comprehensive FRP, I have never seen an all-or-nothing dead-band such as ENO currently uses and proposes to continue using. By "all-or-nothing," I mean that if the result is just one dollar within the dead-band, nothing happens and if it is one dollar outside the dead-band, an adjustment equal to the full difference between the actual and the mechanisms "normal" occurs. This is in contrast to a dead-band that functions such that only amounts outside the dead-band, lower or higher, are subject to the rider's function. For example, PGE has had, for some time, a power cost adjustment clause with a dead-band of 250 basis points. Only if actual power costs exceeded or were less than the assumed power costs by more than this dead-band would the difference that was outside the dead-band be refunded or surcharged, respectively. The utility absorbed or benefited from the difference between actual and assumed that fell within the dead-band.

Q17. DOES THE PROPOSED FRP RIDER MAKE CLEAR HOW IT ACCOMPLISHES DECOUPLING?

A. No. ENO's proposed FRP tariff does not make clear how it accomplishes decoupling. I carefully compared ENO's proposed FRP to the current FRP tariff located in Volume 3, Statement A-4 – Electric of the rate case application, page 32.1 of the current tariff, found at pdf page 1500 of the Application. Although the proposed tariff has sections marked as changes, none of them mention decoupling other than the assertion, on page 30.1: "Additionally, this Rider EFRP seeks to comply with Resolution R-16-103 ('Decoupling Pilot Resolution'), which established a three-year pilot program to begin with implementation of new base rates from the Combined Rate Case, Council Docket No. UD-18-XX__."[5]

All that has changed in pertinent part is the that the proposed FRP will allocate all fixed *and variable* costs and revenues pursuant to allocation factors that will result from the Council's action in this rate case. If the FRP triggers by producing an EROE that is outside of the dead-band, ENO will allocate both the

[5] Gilliam Direct, ENO Exhibit PBG-7 at 1 of 22.

fixed and variable cost/revenue differences according to the allocation method[6] and design a going-forward rate that recovers the new levels of the Evaluation Period ("EP") revenue requirements. This allocation is also illustrated by ENO witness Gillam in ENO Exhibit PBG-8.

Q18. WHAT DOES IT MEAN FOR DECOUPLING IF THE PROPOSED FRP OPERATES IN THE SAME MANNER AS THE PRIOR FRP?

A. Allocating FRP adjustments according to a class cost of service study does not fundamentally change the nature of the FRP. Thus, if the proposed tariff accomplishes decoupling, then the prior one did as well. And, in that case, why did the Council find it necessary to investigate the matter over many years and order ENO to file a decoupling mechanism with this case?

Q19. DOES THE EXAMPLE IN ENO EXHIBIT PBG-8 HELP YOU CONCLUDE WHETHER THE PROPOSED FRP ACCOMPLISHES DECOUPLING OR NOT?

A. Yes, the illustration in ENO Exhibit PBG-8 actually highlights the differences in the hypothetical result of the proposed FRP with decoupling and the expected result of a standard decoupling mechanism, being performed on a rate class/schedule basis similar to what the proposed FRP does.

Page 1 of ENO Exhibit PBG-8 shows a baseline (rate case test year) fixed cost revenue requirement of $190,794,569 for the residential class. Presumably, the rate case Residential Electric Service tariff was designed to recover that amount

[6] *Id.*

through its customer charge and energy-based billing determinants such that the test year fixed revenue assumed for the residential class was also $190,794,569.

Page 3 of ENO Exhibit PBG-8 shows EP (listed as current year) actual fixed cost revenue from the residential class as $189,090,136.

A standard decoupling mechanism would subtract the actual EP fixed cost revenue from the rate case test year fixed cost revenue, producing the need to collect a surcharge of $1,704,433 from the residential class. Most often, this would be done through a charge designed to run until the next decoupling adjustment, usually a year later. The utility would track the amounts actually recovered under the decoupling mechanism so that it recovered the deficiency, no more and no less.

Rather than recovering the difference between the rate case revenue assumption and the actual revenues, however, the calculations on ENO Exhibit PBG-8 show a surcharge to the residential class of $3,055,611,[7] and the example provides no time frame over which the designed surcharge would persist. Presumably, it would persist until the next EP that resulted in a triggering of the FRP.

Q20. DOES THE EXAMPLE IN ENO EXHIBIT PBG-8 CLARIFY FOR YOU THE REGULATORY NATURE OF THE CURRENT OR PROPOSED FRP?

A. No, the example does not clarify for me the regulatory nature of either the current or proposed FRP. I am left with these three related concerns with regard to the efficacy of the FRP in accomplishing decoupling:

[7] Gillam Direct, ENO Exhibit PBG-8 at 5 of 8.

- Does the FRP reconcile or true-up the rate case test year cost and revenue assumptions to the actual ones – the EP – of a given year? Is it backward-looking such that any surcharge or refund is collecting those past differences? In which case, does ENO track what it recovers so that it does not recover more than the past differences?
- Or does the FRP effectively establish a new test year of costs and revenues – the EP test year – and set going-forward rates based on that test year? In which case, do the new test year/EP rates simply stay in effect until changed again by another triggering of the FRP? And does the next EP use the updated costs and revenues for the FRP calculations?
- If the FRP does reset the test year costs and revenues, does that happen ONLY if the FRP results in some adjustment, positive or negative, to rates?

Q21. GIVEN THE ABOVE, WHAT IS YOUR SECOND RECOMMENDED CHANGE TO THE DECOUPLING MECHANISM ENO HAS INCLUDED IN ITS PROPOSED FRP?

A. Whether the decoupling mechanism remains embedded in the FRP or not,[8] the tariff must make clear that the decoupling will operate only on revenues ENO receives from energy- and demand-driven billing determinants, and not on either:

(1) Revenues from customer charge billing determinants or minimum bill requirements in tariffs; or

[8] It may be easiest and most transparent to extract the decoupling mechanism from the FRP and have a stand-alone tariff. This is not necessary, however, so long as the changes I recommend occur.

(2) Revenues collected under tariff riders that are subject to full reconciliation (*i.e.*, ENO receives only the costs within the rider, not more or less depending on its sales).

This clarification could appear in Attachment C, page 30.14, of the proposed FRP tariff.[9] To support this change, I recommend that the proposed FRP tariff also contain forms as described below:

- A report of the actual revenues ENO received from energy- and demand-driven billing determinants, not adjusted for normal weather, by rate class/rate schedule if the Council prefers, and allocated between fixed and variable costs.[10] The report should exclude revenues collected under either:
    - Billing Determinants that do not vary according to billing period energy use or demand (*e.g.*, customer charges, minimum bill amounts, other fixed fees).
    - Riders that provide for matching of amounts recovered with the approved recoverable costs. The decoupling tariff should list these riders and update the list as it changes from time to time.
- A calculation subtracting the portion of actual revenues allocated to fixed costs from the more recent of the portion of authorized revenues allocated to fixed costs:
    - In a rate case test year; or

[9] Gilliam Direct, ENO Exhibit PBG-7 at 14 of 22.
[10] ENO Exhibit PBG-8, page 2, has an example of how it could do this.

  - Pursuant to an FRP Evaluation Period that results in a rate adjustment, whether that is an increase or a decrease (in other words, the EP supporting that rate change becomes the most recent test year).
- A report of the revenues actually collected from customers or returned to customers in the prior EP and the difference, if any and whether positive or negative, necessary to fully reconcile the prior year's decoupling adjustment.

Q22. WHAT IS THE THIRD CHANGE TO ENO'S PROPOSED FRP WITH DECOUPLING?

A. The FRP tariff must make clear that the decoupling comparison being made is between the most recent approved revenues and the actual revenues, allocated to rate classes/schedules per approved allocation factors, and not to a calculation of required allocated revenues that includes changes in costs during the decoupling period. Again, it is likely that changes to the definitions of ENO's proposed FRP and/or Attachment C of ENO Exhibit PBG-7 could accomplish this clarification.

Q23. HOW WILL THESE PROPOSED CHANGES WORK WITHIN THE OTHER PORTIONS OF THE FRP?

A. For the proposed FRP's purposes of updating ENO's costs and calculating a new revenue requirement, all of its calculations involving revenue could use the following:

- The booked EP revenues for those revenue categories that are outside the decoupling mechanism;

- The post-decoupling calculations for those EP revenue categories that are subject to the decoupling mechanism.

Q24. SHOULD ENO SHOW THE DECOUPLING ADJUSTMENT AS A LINE ITEM ON ITS UTILITY BILLS?

A. Showing the decoupling adjustment as a line item on ENO's utility bills would be more confusing than helpful to customers. In my experience, very few utility customers ever study the line items on their utility bills or even know what they stand for. What is important about decoupling is that the decoupled utility has reduced the near-term financial conflict it otherwise would experience by encouraging energy efficiency and demand-side management. Many people intuitively understand and believe that all companies, including utilities, do better financially the more they sell. Without decoupling, this is generally true for electric utilities under traditional rate plans, and customers may be suspicious of utilities' energy efficiency efforts that they perceive as contrary to the utility's interests. Decoupling changes this, and that is what should be communicated, not the particular amounts of any one year's decoupling results.

Q25. WHAT ARE THE STRENGTHS OF YOUR DECOUPLING PROPOSAL?

A. This proposal is simple, and the calculations are transparent. Assuming the Council finds it appropriate to approve ENO's proposed FRP, the decoupling mechanism can work in concert with that rider without being swallowed by it. Indeed, by operating only on revenues resulting from billing determinants that vary with energy or demand, it makes the minimum possible alteration to the FRP to actually accomplish decoupling.

Moreover, if the Council adopts this recommendation, ENO should also eliminate the Lost Contributions to Fixed Costs ("LCFC") mechanism from its Demand-Side Management Cost Recovery ("DSMCR") Rider. As I explain below in section III, how the LCFC interacts with the proposed FRP is confusing and the LCFC is far from best practice in regulatory policies surrounding energy efficiency. It is likely to lead to over-recovery of the allegedly lost contributions to fixed costs in the program year ENO proposes to recover LCFC. The recommended changes to ENO's proposed decoupling mechanism I describe above remove any need for LCFC recovery. The reconciliation of actual fixed cost revenues resulting from billing determinants that are affected by energy and demand savings to the levels assumed for these revenues in a test year holds the utility neutral to the achieved savings of energy efficiency programs and actions affecting customer electricity use and demand that are outside the utility's programs as well, which LCFC cannot do. Decoupling keeps the utility whole no matter what the cause of unanticipated usage patterns – it captures far more than LCFC, including the energy effects of codes and standards and of customer decisions to acquire more energy efficient equipment outside of programs, economic trends, or simple conservation. These actions, of course, are even more beneficial to customers than utility programs because they do not come at a cost to the utility that it must recover from the customers.

Q26. DO YOU HAVE ANY OTHER RECOMMENDATIONS REGARDING DECOUPLING?

A. Yes. As many industry participants and observers have noted, the societal, cultural and economic environment within which utilities operate is changing. Different technologies that allow households and businesses to do their jobs without using electricity delivered by a utility are increasing and becoming more attractive every year. It behooves the utility, its regulator, and all of its interested stakeholders to regularly look at what is happening with respect to the use of energy and demand placed on the utility. This sometimes happens in an Integrated Resource Planning process, but the filing of an annual decoupling adjustment calculation is a prime time to step back and ask:

- Why did things change from the energy we expected customers would use and the demand they would make to the energy they actually used and the demand they actually made?
- Which changes were surprising, whether surprisingly good or surprisingly bad?
- Does what we are seeing have any implications for what we are doing?

III. LOST CONTRIBUTION TO FIXED COSTS

A. A revised Decoupling Mechanism will remove the need for the proposed LCFC, the interaction of which with the proposed FRP are confusing.

Q27. WHAT IS ENO'S PROPOSED LCFC?

A. The LCFC is the weighted average of the most recently approved base rates in effect on the filing date (July 31, 2019, for the Interim Energy Efficiency Rider, October 2019 and subsequent years for the DSMCR) multiplied by the deemed, projected lost sales (kWh and/or kW) attributable to the Energy Smart Programs for the applicable program year.[11] In other words, the LCFC purports to return to ENO revenues that it would have received *but for* its energy efficiency programs. "But for" worlds, however, never actually occur; there is always much more that has happened than the sum of the elements being extracted to create this imaginary world. Decoupling does not rely on creating an imaginary world; the LCFC does.

Q28. DOES ENO DEFINE THE TERM 'WEIGHTED AVERAGE OF THE MOST RECENTLY APPROVED BASE RATES" OR PROVIDE AN EXAMPLE OF THE CALCULATION?

A. No. The only statement regarding this is from Company witness Faruqui, who says: "I understand that AGM is a term ENO uses to describe the volumetric (cents per kWh) portion of ENO's base rates excluding fuel and other riders."[12] Worksheet F from the ENO June 28, 2018 compliance filing re: LCFC for Program Year ("PY") 7 implies that the calculation is total revenue for a given period divided by the energy sales for that same period. It is possible that the weighting referenced will be by rate schedule/class energy usage, energy savings, or per the allocations in the Class Cost of Service Study. It appears that the AGM includes all billing determinants in calculating LCFC, regardless of whether energy efficiency programs can actually affect those billing determinants. In other words, even

[11] *See* Application, Statement A-3 – Electric (Proposed Electric Rate Tariffs), Rider Schedule EECR-1 (Interim Energy Efficiency Cost Recovery Rider) at 37.1 (pdf page 1377 of the Application); Owens Direct, ENO Exhibit DAO-3 at DSMCR Rider Attachment B, page 2 of 4.
[12] Revised Direct Testimony of Dr. Ahmad Faruqui at 25 n.22 (Sept. 2018) ("Faruqui Direct").

though the ratepayers must pay the customer charge regardless of how much they reduce their electricity use through Energy Smart programs, the LCFC calculations assume that a portion of the customer charge is 'lost."

While I recommend that the Council eliminate the LCFC, it should certainly require that ENO define the term in the tariff if it continues it in any form.

Q29. IS ENO PRESENTLY RECOVERING LCFC FROM ITS CUSTOMERS?

A. No. Council Resolution No. R-17-176 disallowed the collection of LCFC for program years 7, 8, and 9, but did require ENO to continue to track and file an annual calculation of LCFC.[13] Notwithstanding this, ENO's currently effective tariff EFRP-4[14] continues to include LCFC as a ratemaking adjustment to Evaluation Periods under the FRP and the Interim Energy Efficiency Cost Recovery Rider, filed May 31, 2018, and effective June 29, 2018, also states that its charges include LCFC.[15] I suspect this is an oversight on ENO's part, but good regulatory practice would be to ensure current tariffs conform to current practices. Simply tracking the LCFC for accounting purposes does not require tariff language.

Q30. HOW DOES ENO PROPOSE THAT LCFC WORK PURSUANT TO TARIFF CHANGES IN THIS CASE?

---

[13] Council Resolution No. R-17-176 at 35, LCFC Recovery Mechanism ¶ 10.
[14] Application, Statement A-4 – Electric (Present Electric Rate Tariffs), Rider Schedule EFRP-4 at 32.1-32.20 (pdf pages 1500-1519 of the Application).
[15] Application, Statement A-4 – Electric (Present Electric Rate Tariffs), Rider Schedule EECR at 40.1-40.3 (pdf pages 1548-1550 of the Application).

A. I made a timeline for myself to ensure I could understand the operation of the LCFC recovery and its interrelationship with the proposed FRP. This is the timeline I deduced from the ENO filing:

- August 2019. ENO begins to recover LCFC for savings from Energy Smart programs in the remainder of PY 2019, if the Council approves the Interim EECR.
- October 2019. DSMCR filing with projected LCFC (deemed savings from estimated participants/measures * Weighted Average Approved Base Rates ("WAABR")) for PY 2020.
- January 2020. DSMCR rider with projected 2020 LCFC included in bill calculations.
- October 2020. DSMCR filing.
    - Projected LCFC for PY 2021 – deemed savings from estimated participants/measures * WAABR.
    - Reconciliation of projected LCFC for PY 2019. Proposed reconciliation covers the difference between estimated numbers of participants/measures and actual numbers of participants/measures.[16] Dr. Faruqui suggests that it will also cover the difference between the WAABR that may occur if the FRP during any given program year results in a rate adjustment and, thus,

[16] *See* Revised Direct Testimony of D. Andrew Owens, ENO Exhibit DAO-3 at DSMCR Rider Attachment B, page 4 of 4; Application, Statement A-4 – Electric (Present Electric Rate Tariffs), Rider Schedule EFRP-4, Attachment G (pdf page 1518 of the Application) (Sept. 2018) ("Owens Direct").

changes the base rates.[17] He does not describe how this reconciliation would happen nor does the proposed DSMCR tariff provide the calculation. It is unclear if ENO would adjust the WABBR for the results of the FRP as of the beginning of the program year or only for the months of the program year that the change is in effect.

Q31. WHAT ADDITIONAL RECONCILIATION OF THE DEEMED LCFC SHOULD OCCUR?

A. Reconciliation *should* cover the difference ENO provides for the following:

- Projected LCFC *revenues* and LCFC *revenues* actually received.
- Deemed savings and savings resulting after Evaluation, Measurement and Verification ("EM&V"). It may take considerable time to obtain the EM&V results; program year LCFC recoveries would need to stay open until all EM&V relating to that program year has been completed.
- The timing of savings, *i.e.*, the billing periods when the projected LCFC assumed the savings would occur and reduce kWh or kW and the billing periods such savings actually occurred. In my experience, energy efficiency program savings do not all occur on the first day of a given program year or even smoothly across that year – often they are back-end loaded. Again, ENO does not state what assumption about timing it will use in calculating the LCFC it proposes to collect up-front during the year it is working to obtain the savings

[17] Faruqui Direct at 25:8-18.

through its programs. In any event, whatever the assumed timing, the actual timing is likely to differ and reconciliation should take this into account.

Q32. PLEASE RESUME WITH THE TIMELINE.

A. The process continues repeating until both the LCFC ends and all reconciliation occurs. Basic reconciliation lags for one year; reconciliation based on EM&V could lag by many years. Moreover, integrating EM&V is necessary but can dramatically increase the level of contention in the process.

Q33. HOW DOES ENO'S LCFC PROPOSAL INTERACT WITH THE PROPOSED FRP?

A. I cannot say for sure, either for PY 2019 or PY 2020 and beyond. I will describe the reasons my confusion for 2020 and beyond first.

For program years 2020 and beyond, I found three conflicting statements in ENO's testimony, none of which clarify the matter:

- The proposed tariff says "C) Present base rate revenue shall not be adjusted for the Lost Contribution to Fixed Costs resulting from any energy efficiency programs in the calendar year subsequent to the Evaluation Period."[18] In other words, the 2020 Evaluation Period ("EP") would NOT include PY 2021 LFCF. This language possibly exists because the prior FRP included an estimate of LCFC for the PY that was the same as the EP; *e.g.*, PY 2020 LCFC in EP 2020. However, the tariff language does not say whether the ENO will adjust the EP

[18] Gillam Direct, ENO Exhibit PBG-7 at 14 of 22 (Attachment C, 1. C)).

revenue to exclude LCFC recovered in the program year that is the same as the EP; *e.g.*, would the 2020 EP include LCFC ENO recovered during PY 2020?

- Witness Owens' testimony includes the following explanation:

> In other words, the amount of LCFC recovered each year on a contemporaneous basis would be based only on that PY's DSM investments. In theory, when overall base rates are set through the FRP each year, assuming the Council and ENO agree to implement an FRP as the successor ratemaking mechanism to this rate case, ENO would be 'made whole.' If the Council and ENO opt against implementing an FRP, then Rider DSMCR would be adjusted each year to reflect updated, incremental (or decremental) LCFC amounts until such time as base rates are next reset, at which point the total amount included as LCFC in Rider DSMCR would be removed assuming the issue has been satisfactorily addressed in the base rate reset.[19]

- ENO response to APC 3-4 says:

> For example, assume that the Energy Smart programs occurring in the calendar year 2020 are recovered through the DSMCR, as proposed by the Company, beginning January 1, 2020 through December 31, 2020 and, that the FRP is approved with the calendar year 2020 as one of the applicable Evaluation Period Test Years. Further, assume that Rider DSMCR for calendar year 2020 recovers contemporaneously the components described by Mr. Owens on pages 16-35, including the anticipated LCFC costs incurred and experienced by ENO in 2020. Beginning January 1, 2021, the LCFC associated with the 2020 Energy Smart programs will not be included in the DSMCR for cost recovery any longer because the reduced usage (kwh sales) generated by the 2020 Energy Smart programs, as well as all prior programs, will be reflected in the 2020 Test Year Evaluation Period Report's EROE filed in 2021 for rates effective beginning later in 2021. Therefore, there is no double counting of the reduced sales resulting from Energy Smart or other DSM initiatives.

[19] Owens Direct at 20:6-15. The LCFC adjustment could be decremental if the projected savings in the forward year were less than the current year.

Q34. HOW ARE THESE THREE STATEMENTS AMBIGUOUS ABOUT THE INTERACTION OF THE LCFC WITH THE FRP?

A. These three separate explanations leave me with at least three CONCERNS:

- Are revenues paid as LCFC (*e.g.*, 2020) in the EP (*e.g.*, also 2020) included in ENO Exhibit PBG-7, Attachment B, page 30.12, line 1 of the proposed FRP?
- Is witness Owens suggesting that an FRP in 2021 based on a 2020 EP will make ENO whole for the 2020 PY sales that would have occurred but for the energy efficiency programs (a) during the period from 1/1/21 to 8/31/21? and/or (b) beyond 8/31/21? How will the FRP accomplish this given that no adjustment occurs until September? What about the first 8 months of the year after the PY?
- Does it matter whether the FRP results in a rate adjustment or not? If it does not, does that mean that ENO believes other events/changes during the prior program year mean that it did not actually 'lose' that contribution to fixed costs?

Q35. IF THE COUNCIL APPROVES THE INTERIM ENERGY EFFICIENCY RIDER FOR THE LAST FIVE MONTHS OF 2019 AND THE FRP, HOW WILL THOSE TWO MECHANISMS INTERACT IN THE FIRST FRP FILING APRIL 2020?

A. Neither the tariffs nor testimony in the filing contains any information about how this interaction will work when ENO files the 2019 EP under the proposed FRP. All of the concerns I listed above remain, plus the uncertainty of whether ENO will annualize the 2019 LCFC if it includes it in the FRP.

Q36. IF THE COUNCIL APPROVES A STANDARD DECOUPLING MECHANISM FOR ENO, AS YOU RECOMMEND, DOES ENO NEED THE LCFC?

A. No. A utility that has a decoupling mechanism will automatically recover the net effect of any energy or demand reduction resulting from its programs, along with changes in energy and demand resulting from matters outside of its influence or control.

B. ENO Support for the LCFC is Lacking.

Q37. HOW DOES ENO SUPPORT ITS PROPOSED LCFC?

A. ENO witness Owens primarily supports the entire DSMCR, including the LCFC but also its other components. For example, Owens states:

> For these and other reasons that I describe below, the Council has indicated that demand-side resources should be on an equal financial footing with traditional supply-side resources. ENO's proposed model fulfills this directive.[20]
>
> As such, under a customer-centric view of the regulatory model, DSM offerings can be a viable resource for meeting customers' energy needs and should be treated in a more similar fashion to traditional supply-side resources in terms of financial recovery. ENO's proposed model would accomplish this goal.[21]
>
> To address the inherent challenges of offering DSM in the traditional utility business model, which Dr. Faruqui discusses at length, and to provide a more level playing field between DSM investments and more traditional, supply-side investments, ENO has consistently advocated that cost recovery for DSM offerings must fairly address three distinct elements. These include (1) direct and indirect costs of DSM offerings, (2) lost contributions to fixed costs ("LCFC" or "lost revenues"), and (3) some form of incentive. As Dr. Faruqui discusses in greater detail, numerous DSM advocates like ACEEE, for example, have argued in recent years that appropriately addressing these three elements will create the right ingredients to "level the playing field" between DSM and supply-side alternatives and will, in fact, increase the likelihood that a utility will maximize the utilization of cost-effective DSM to meet customer needs. Through the course of Energy Smart beginning

[20] Owens Direct at 5:8-11 (referencing Council Resolution No. R-07-600).
[21] Owens Direct at 6:6-10.

> with PY1, the Council has thoughtfully addressed these three elements.[22]

ENO witness Dr. Faruqui echoes the argument that the LCFC (and rest of the DSMCR) is necessary to put demand-side investments on the same footing as supply-side investments, and adds another argument: that the proposed DSMCR is "well-aligned with current industry practices."[23] In response to Question 20, he states:

> Q20. DO NATIONAL DSM AND ENVIRONMENTAL POLICY GROUPS SUPPORT LCFC RECOVERY AND PERFORMANCE INCENTIVES AS IMPORTANT ASPECTS OF A ROBUST DSM INITIATIVE?
>
> A. Yes. For instance, the ACEEE maintains that the traditional utility COS model discourages investment in energy efficiency, recognizes the need to incorporate an appropriate mechanism for recovery of lost revenues, and recognizes the need for creating meaningful performance incentives. The NRDC, a national environmental group, likewise asserts that current policies can position energy efficiency investments against utilities' financial obligations, and that "regulator and governing boards should update these policies to ensure utilities' incentives are fully aligned with those of their customers in receiving reliable and affordable energy services." To do so, the NRDC recommends allowing utilities to recover revenues that were reduced as a result of efficiency efforts.[24]

Q38. DOES ENO EXPLAIN WHY IT IS PROPOSING THE LCFC GIVEN THAT IT IS PROPOSING A DECOUPLING MECHANISM PURSUANT TO THE COUNCIL'S DIRECTION?

A. No. ENO does not directly explain why decoupling within the FRP is inadequate to provide it financial stability with respect to fixed costs that it recovers under a

[22] Owens Direct at 18:7-19.
[23] Faruqui Direct at 6:1-2.
[24] Faruqui Direct at 19:4-16; *see also id.* at 12-14.

rate design that includes billing determinants based on energy and demand, although I suspect the absence of this explanation may relate to the concerns and questions I raised in section IIB regarding the interaction of the two mechanisms.

1. An LCFC is Not Necessary to Level the Playing Field Between Demand-Side and Supply-Side Resources.

Q39. DO YOU AGREE THAT THE LCFC COMPONENT OF ENO'S PROPOSED DSMCR IS NECESSARY TO LEVEL THE PLAYING FIELD BETWEEN DEMAND-SIDE MANAGEMENT ("DSM") INVESTMENTS AND MORE TRADITIONAL SUPPLY-SIDE INVESTMENTS?

A. No, I do not agree with either witness Owens or Dr. Faruqui that LCFC is necessary to "level the playing field" between DSM and supply-side investments. The similarities between DSM and generating resources – primarily that they both help meet the electricity needs of a utility's customers – have long blinded utilities and others to the very significant ways in which the two are different and in which DSM resources are far more appealing to utilities than supply-side resources. Foremost in my mind is that utilities have no responsibility for the operation of the DSM assets:

- It does not matter if they remain in service, how available they are or how much of the time that they are available they are actually providing service;
- The utility has no responsibility for operation and maintenance costs associated with them or any capital additions that may be necessary;
- Only rarely does a utility receive a guaranteed margin, such as the LCFC provides, for a generating resource.

Once the program has paid a customer the incentive or otherwise sold the customer on making a DSM investment, how the resource operates and whether it produces the result for which the customer hoped is solely the customer's responsibility. This is vastly different than a supply-side resource, where the utility remains responsible for the entire operating life of the resource, including premature obsolescence. During my years with PGE, for example, PGE closed its only nuclear plant well before its depreciation life because the plant had become economically obsolete. While PGE ultimately recovered most of its remaining investment in the plant, the litigation took years and PGE lost much of the carrying cost associated with recovering that remaining investment over time. DSM investments do not take years to plan and construct, as many supply-side resources do, raising the possibility for conditions demonstrating the need for the resource to change. The confluence of rapid change and many large generating plants in the 1980's resulted in more than one utility facing extreme financial distress from regulatory disallowances of costs sunk into no longer necessary generating plants. As utilities enter the turbulent times of today's cultural, societal, economic, demographic, and technological change, it is possible that utilities could find themselves in similar circumstances in which large generating resources, planned and built over years, no longer fit the need when they finally come on-line. DSM, for which costs are spent in one year, and the prudence determined in advance or close to the time of expenditure, face none of these issues.

2. National DSM and Environmental Groups Do Not Support Mechanisms Such as the LCFC.

Q40. DO YOU AGREE WITH WITNESS FARUQUI THAT NATIONAL DSM AND ENVIRONMENTAL POLICY GROUPS SUPPORT LCFC?

A. I do not agree with Dr. Faruqui that national DSM and environmental groups – he names specifically the ACEEE and NRDC – support a lost revenue adjustment mechanism, which is what the LCFC is.

First, Dr. Faruqui is conflating lost revenue recovery through a mechanism with decoupling and incentives for fulfilling energy efficiency goals. For example, the map he presents on page 14 of his testimony is titled "States with Lost Revenue Recovery Provision." Both NRDC and ACEEE carefully and consistently distinguish between the two. This is from an August 2018 white paper found on NRDC's website:[25]

> Fortunately, there is a simple, effective, and proven way to eliminate this conflict: break the link between the utility's revenue and the amount of energy it sells by adjusting rates to ensure that the utility collects its authorized fixed costs, no less and no more. Combined with other key policies to encourage energy efficiency, such *decoupling mechanisms* can free utilities to help customers save energy whenever it is cheaper than producing and delivering it.

The same whitepaper, however, has this to say about lost revenue mechanisms such as "LRAM," of which the LCFC is an example:

> **Lost revenue adjustment mechanisms (LRAM)**: Giving a utility *lost revenues* from its energy-efficiency programs removes the utility's disincentive to support those programs, but still allows the

[25] NRDC, *Removing Disincentives to Utility Energy Efficiency Efforts*, at 2 (May 2012), https://www.nrdc.org/sites/default/files/decoupling-utility-energy.pdf (attached as AAE Exhibit PGM-3); NRDC, *Electric and Gas Decoupling in the U.S.* (Aug. 2018), https://www.nrdc.org/sites/default/files/decoupling-maps-package-01.18.17.pdf.

> utility to benefit from increased sales. Because a utility does not have to give up *found revenues*—when sales are higher than assumed in the rate-setting process—lost revenues are asymmetric and cause customers to pay a windfall to the utility when sales are above the volume used to set rates. An LRAM makes it unlikely that a utility will implement valuable market transformation programs, because savings from these programs are difficult to evaluate. LRAMs add controversy to the process of measuring energy savings from efficiency programs because significant dollars are now attached to savings. Finally, an LRAM presents an opportunity for gaming: if a utility runs an energy-efficiency program that looks good on paper but saves little or nothing in practice, the utility keeps the revenue associated with the unsaved energy while also collecting lost revenues.

It is difficult to construe these excerpts, or the remainder of the whitepaper, as support for the LCFC or for Dr. Faruqui's view that the two mechanisms are interchangeable and equally desirable.

ACEEE aligns well with the NRDC views. On its website under the heading "Aligning Utility Business Models with Energy Efficiency,"[26] ACEEE identifies the following comprehensive strategy to achieve high utility sector energy efficiency savings:

1. Establish specific energy efficiency savings targets
2. Align utility ratemaking with energy efficiency by incorporating:
    1. Program cost recovery
    2. Full revenue decoupling
    3. Earnings opportunities tied to performance toward savings targets

In addressing types of regulatory tools for the comprehensive strategy, ACEEE mentions only symmetrical revenue decoupling as the tool to remove a utility's

[26] ACEEE, *Aligning Utility Business Models with Energy Efficiency*, https://aceee.org/sector/state-policy/toolkit/aligning-utility.

throughput incentive. It does not mention an LRAM or LCFC mechanism. In a later section of the toolkit, ACEEE addresses LRAMs specifically and concludes that it: "strongly recommends full revenue decoupling as the preferable approach to address *both* lost margin recovery and the throughput incentive."[27] ACEEE's most recent 2017 State Scorecard reinforces its preference for decoupling over an LRAM: states having only one or more utilities with an LRAM receive 0 points; states having at least one gas or electric utility with decoupling receive 0.5 points; only states having both an electric and gas utility with a decoupling mechanism receive the full 1 point.[28] The Scorecard also counters Dr. Faruqui's claim[29] that an LRAM such as the LCFC is the most common approach to addressing sales lost to utility DSM efforts. The 2017 Scorecard states that, for electric utilities, 16 states had adopted decoupling and 15 an LRAM. For natural gas utilities, only seven had chosen an LRAM and 22 had adopted a decoupling mechanism.[30] Even more recently than the 2017 Scorecard, NRDC's decoupling map as of August 2018, identifies 17 states, covering 41 electric utilities, that had adopted decoupling as of that date. NRDC does not indicate states or count utilities with an LRAM, likely for the reasons discussed in its White Paper.

[27] *Id.*
[28] ACEEE, *2017 State Energy Efficiency Scorecard*, at 18, https://aceee.org/state-policy/scorecard ("2017 Scorecard").
[29] Faruqui Direct at 12:19-20. Dr. Faruqui does not provide a reference for his conclusion. For his map found on page 14, he cites a Brattle Group study as of December 2017.
[30] 2017 Scorecard at 47.

Q41. IF THE COUNCIL ADOPTS THE CHANGES TO ENO'S PROPOSED DECOUPLING MECHANISM THAT YOU RECOMMEND, WILL DEMAND-SIDE AND SUPPLY-SIDE RESOURCES BE TREATED THE SAME WITH RESPECT TO UTILITY REVENUES?

A. Yes. To the extent that ENO's tariffs enable the recovery of the costs of demand-side and supply-side resources through billing determinants that vary according to energy or demand, the recommended decoupling mechanism will reconcile the actual amount of revenues under those tariffs to the amount expected in ENO's most recent test year. There will be no color-coding of revenues for supply-side fixed costs versus revenues for demand-side fixed costs, other than through the operation of the DSMCR as a true-up of demand-side program costs.

C. Recommendations for ENO's Proposed LCFC.

Q42. WHAT DO YOU RECOMMEND THE COUNCIL DO WITH RESPECT TO THE LCFC THAT ENO PROPOSES BE PART OF THE INTERIM ENERGY EFFICIENCY RIDER AND THE DSMCR?

A. I recommend that the Council reject the LCFC and instead adopt the changes to produce a simple decoupling mechanism that I describe in section IIC.

IV. CONCLUSION AND SUMMARY OF RECOMMENDATIONS

Q43. WHAT ARE YOUR CONCLUSIONS REGARDING ENO'S APPLICATION IN THIS RATE CASE?

A. Based on the components of the filing that I reviewed in the course of understanding the LCFC and proposed decoupling mechanism, and given the numerous questions and concerns I have raised in the prior pages of this testimony, I suggest that it is time for all concerned to step back and look at the totality of (1) what ENO has in place before anything from this filing takes effect and (2) what ENO seeks to change or supplement about its current regulatory posture. What is the big picture here? Is it "customer-centric," as ENO claims to want?[31] Do all of ENO's Riders and policy proposals cumulate to a framework that non-experts, or even experts, can understand? Do the interactions amongst all of the pieces make sense?

Q44. PLEASE SUMMARIZE YOUR RECOMMENDATIONS.

A. In brief, I recommend that:

- The Council approves the changes I recommend to the decoupling mechanism ENO has embedded within its proposed FRP.
- The Council rejects the LCFC ENO proposes as part of its DSMCR rider.

Q45. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes, it does.

---

[31] *See, e.g.,* Owens Direct at 6:7.

AFFIDAVIT

STATE OF ARIZONA)
)
COUNTY OF PIMA)

I, Pamela Morgan, do hereby swear under the penalty of perjury the following:

That I am the person identified in the attached prepared testimony and that such testimony was prepared by me under my direct supervision; that the answers and information set forth therein are true and accurate to the best of my personal knowledge and belief; and that if asked the questions set forth herein, my answers thereto would, under oath, remain the same.

Pamela G. Morgan

Pamela Morgan

SWORN TO AND SUBSCRIBED BEFORE ME THIS 28 DAY OF Jan, 2019

LENORE CASILLAS
Notary Public - State of Arizona
PIMA COUNTY
My Commission Expires
April 30, 2021

Lenore Casillas

NOTARY PUBLIC

My commission expires: 04/30/2021

Exhibit PGM-1

Curriculum Vitae of Pamela G. Morgan

Pamela Grace Morgan
PO Box 1263 Tubac AZ
(503) 701 2875 (cell); pamela@gracefulsystems.com (email)

Pamela Morgan is Principal Consultant at Graceful Systems LLC, the company she formed in May 2009. Graceful Systems helps stakeholders in the energy utility industry and other industries and systems engage in a collaborative process to explore, understand, and develop generative strategies in response to complex challenges that are dynamic, inter-relate with many other challenges and have no answer. The process empowers the stakeholders to turn disorganization and divisiveness into order and collective performance, through which they can embrace innovation and continuous learning. Graceful Systems builds on this work with mapping tools that help groups collectively visualize how they think things are happening and use that collective representation as a basis for dynamic strategy.

CAPABILITIES OVERVEW

- Strong strategic and integrative thinker and leader of group strategic work
- Excellent written and oral communication skills, including large group/conference presentations
- Thorough understanding of all aspects of the electric utility industry and economic regulation
- Solid experience with developing, delivering and evaluating training and performance development and evaluation programs
- High personal initiative and motivation
- Deep commitment to learning

PROFESSIONAL EXPERIENCE

GRACEFUL SYSTEMS, President, 2009 to current
Consulting, training, and process facilitation in purpose, vision and strategy, with a focus on the energy business sector and applications of leadership of adaptive change, collaborative process and systems thinking

Current and recent clients and projects

National Association of Regulatory Commissioners

Designed and delivered systems thinking training to utility regulatory commissions; Researched cutting edge practices in utility resource planning and procurement and designed and delivered stakeholder processes to develop new rules for resource planning and procurement

Natural Resources Defense Council

Comprehensive study of decoupling mechanisms in the United States, including their designs and rate impacts

Expert witness in a number of regulatory proceedings: rate cases, resource and energy efficiency plans, and rulemakings

Development of policies for long-term sustained growth of energy efficiency in Chile

Portland Energy Conservation Inc.

Served as Interim Executive Director and lead on strategy development as this non-profit organization transitioned from its prior work in designing and implementing energy efficiency programs for utilities (now being operated from the for-profit organization CLEAResult) to a mission centered in the intersections of energy efficiency, community, and environment.

Portland State University

Served as faculty for the graduate-level and professional development course "Designing the Smart Grid for Sustainable Communities."

Speaking and Training in Systems Thinking

American Leadership Forum of Oregon, Portland General Electric, IBM Global Intelligent Utility Network Coalition, University of Idaho Utility Executive Course, Willamette University Utility Management Certificate course

The Alliance for Solar Choice

Expert witness in regulatory proceedings

United States Energy Association

Assessment of and recommendations for improving the regulatory relationship of TANESCO, Tanzania's electric utility, and EWURA, the independent regulator in Tanzania

EQ RESEARCH, Energy Policy Expert, 2015 to 2018

Consulting and expert witness services to businesses active in renewables, energy efficiency, energy storage and electric vehicles; policy papers

PORTLAND GENERAL ELECTRIC COMPANY, 121 SW Salmon, Portland OR 97204, 1999 to 2009

A vertically-integrated electric utility company serving over 800,000 customers in the most populous areas of Oregon

<u>Executive Loan, Natural Resources Defense Council, May 2008 to May 2009</u>

Development and support of NRDC policy positions and representation of NRDC in specific forums, including state public utility commissions.

<u>Executive cross-training, Distribution, April 2007 to May 2008</u>

Management of teams and departments responsible for fleet, major system maintenance, contract management, pole attachments, customer-owned equipment services, field support services, energy efficiency delivery and education services. Position included continued leadership of PGE's strategic planning and executive guidance of PGE's Advisory

Committee on Diversity.

Vice President, Regulatory Affairs and Strategic Planning, January 2003 to April 2007
Management of regulatory affairs as below, planning and delivery of strategic discussions for PGE's leadership team, and guidance of the process for creating and improving its Statement of Direction.

Vice President, Public Policy and Regulatory Affairs, May 2001 to January 2003
Responsibilities as below plus management of federal, regional, state and local government affairs and policy and corporate communications.

Vice President, Rates and Regulatory Affairs, January 1999 to May 2001
Development of regulatory policy and strategy; management of Oregon Public Utility Commission (OPUC) and Federal Energy Regulatory Commission (FERC) filings and dockets, PGE rate requests, pricing and tariff development, and Bonneville Power Administration (BPA) matters; expert witness on retail regulatory matters.

CONNEXT, INC., 1301 Fifth Avenue, Suite 1900, Seattle, WA 98101, 1997 to 1999
A software solutions company providing distribution and customer management, billing, and energy analysis products and services to utilities and energy service providers

Vice President, Strategy and Product Management, March 1998 to December 1998
Vice President, Strategic Relationships, June 1997 to March 1998
Management of product management functions; initiation, closure, and management of strategic alliances, which included Siebel Systems Software, ESRI, Oracle and others; negotiation, and administration of client contracts; and strategic planning.

PORTLAND GENERAL ELECTRIC, 1986 to 1997

Vice President, Rates and Regulatory Affairs, October 1996 to June 1997
Director, Regulatory Policy, August 1989 to October 1996
Assistant General Counsel, August 1986 to August 1989

GARVEY, SCHUBERT, ADAMS & BARER, Suite 2650, 1211 SW Fifth Avenue, Portland, Oregon 97204, 1984 to 1986
A general commercial practice law firm with offices in Seattle, Portland, and Washington D.C.

Associate, January 1984 to July 1986

EDUCATION

UNIVERSITY OF WASHINGTON SCHOOL OF LAW, J.D. 1981 with Honors, Order of the Coif, Washington Law Review, 1979-1981, LSAT 784

WASHINGTON STATE UNIVERSITY, B.A. 1978 Summa Cum Laude, Phi Beta Kappa, Pi Sigma Alpha (Political Science Honorary)

OTHER EXPERIENCE

Oregon Humanities, Board of Directors, 2013 to present
Volunteers of America Oregon, Board of Directors, 2001 to 2011
Institute for Metropolitan Studies, Board of Directors, 2006 to present
Oregon Public Employees Retirement System, Board of Governors, 1993 to May 1997
American Leadership Forum, Class X, 1995-present
City Club of Portland, 1984 to present
    1989 to 1991 - Vice-President, Board of Governors
Oregon Humane Society, Board of Governors, 1991 to 1993
White House Fellow Program, semi-finalist, 1989
Law Clerk, Judge Eugene A. Wright, U.S. Court of Appeals for the Ninth Circuit
Exchange Student, July 1972 to June 1973
    Rotary Club International Youth Exchange Program; Zaandam, The Netherlands

ARTICLES

<ins>Planning for the Future</ins>: Four changes to integrated resource planning could significantly improve alignment between future utility spending and the forces and changes that are Up-ending past preconceptions of how to predict future load. The Electricity Journal, Volume 22, Issue 5, June 2009

<ins>Rate Impacts and Key Design Elements of Gas and Electric Utility Decoupling</ins>: A Comprehensive Review. The Electricity Journal, Volume 22, Issue 8, October 2009

<ins>Evolving Regulation for the Utility of the Future</ins>: Economic regulation began when much about retail electricity service was unknown. It supported a rapid evolution of technology, business models, and customers. Now, when much is unknown about the technology, business models, and customers of the future, economic regulation can serve this role again. Doing so requires only that we decide what to keep. The Electricity Journal, Volume 23, Issue 2, March 2010

<ins>From VHS to DVD: Need for a New Business Model for the Electricity Industry in the 21st Century</ins>. Sales and financial performance for most utilities could definitely use a shot in the arm. Fortunately, opportunity awaits in the form of valuable services that could offer companies whole new areas of endeavor. ElectricityPolicy.com, Fall 2010

<ins>Underachieving in Energy Efficiency and the Continuing Search for a New Business Model</ins>.

We are asking utilities to do things that cut against the grain of their business model. At the same time, and despite all our efforts, the planning, acquisition, and operation of resources still favors things we can touch –generation – over energy efficiency. No one is winning under the rules of this game. ElectricityPolicy.com, Spring 2011
Toward New Business Models: Outcome-Based Energy Services for People. Utilities have traditionally provided customers a commodity – electricity – to meet demand. But as the industry evolves, pushed by disruptive technologies, we may see demand for new services and applications, much like those that have reshaped other industries. ElectricityPolicy.com, Summer 2011

Submission for SEPA's 51st State: A Blueprint for Energy/Electricity Services in Fertile Ground. This thought paper identifies five key areas in which changes to electric utility law and practices could unleash innovation and move the system toward decentralized and, where possible, distributed authority and responsibility, empowering end users and the communities to which they belong. http://sepa51.org/submissions.php Spring 2015

New Uses for an Old Tool: Using Cost of Service Studies to Design Rates in Today's Electric Utility Service World. This paper, co-authored with Kelly Crandall, explores the history and processes of class cost of service studies (CCOSS), describes their limitations, some of which date back to their origins and some of which are new in light of current circumstances, and suggests steps electric utility regulators and stakeholders can take to use CCOSS productively in making rate design recommendations and decisions. https://eq-research.com/eq-publications/new-uses-old-tool/ Spring 2017

Additional publications can be found at http://www.gracefulsystems.com/publications-and-papers.htm

REFERENCES

Stephen Hawke, former Executive Vice-President, Portland General Electric
stephenroberthawke@gmail.com

Behzad Hosseini, Director – Office of the Chief Information Officer
behzadhosseini@msn.com
503-807-5231

Maura O'Neill, http://www.mauraoneill.com/bio/
maura@mauraoneill.com
206-605-0790

Exhibit PGM-2

Calculation of the Amount of ENO Fixed Revenues

Calculation of the amount of ENO "fixed" revenues; *i.e.*, revenues not subject to variation in energy use or demand

Rate Class/ Schedule	Customer Charge or Minimum Bill	Period II # of Accounts	"Fixed" Amounts, Annualized
RES	15.53	181,500	$ 33,824,340.00
SES	16.39	19131	$ 3,762,685.08
LES	681.45	333	$ 2,723,074.20
LEHLFS	706.89	606	$ 5,140,504.08
	Per proposed tariff rate schedules	Above counts per ENO Exhibit MLT-3, page 2	$ 45,450,603.36
AMI revenue	Gillam, page 7		$ 7,100,000.00
		Total	$ 52,550,603.36

Calculation of ENO Capital Structure for 2018 test period – see page 3142 of filing

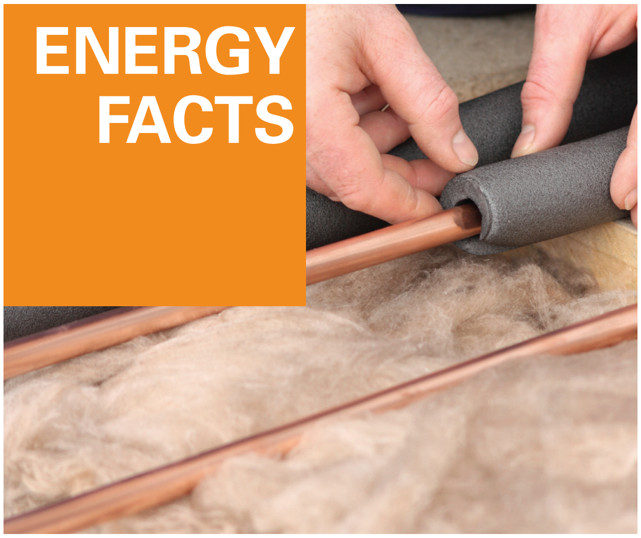
	Capital Amount	Cap Structure	Cost	WA Cost		WA COC
Debt	$ 400,973,227	47.80%	4.82%	2.30%	$ 19,326,910	2.30%
Equity	$ 437,936,000	52.20%	10.50%	5.61%	$ 45,983,280	5.48%
	$ 838,909,227			7.79%	$ 65,310,190	7.79%

Calculation of ENO required Operating Income for 2018 test period – see page 2792 of filing

Year end 2018	
Rate Base	$ 670,578,815
	* (7.79%)
Required Operating income	$ 52,205,445.00

Exhibit PGM-3

Natural Resources Defense Council Decoupling Article



Removing Disincentives to Utility Energy Efficiency Efforts

Using energy more efficiently is the cheapest and cleanest way to serve America's energy needs, with enormous potential to save money (nearly $700 billion by 2020), create jobs, and reduce pollution (1.1 gigatons of carbon dioxide by 2020), through improvements in buildings, processes, and devices served by America's electric and natural gas utilities.[1] Energy-efficiency programs that provide customers with information, assistance, and incentives for energy-efficiency improvements are needed to overcome the persistent market barriers that prevent households, businesses, and industry from taking advantage of this opportunity.[2] Despite the benefits efficiency provides to customers, under traditional regulation, a utility that successfully helps its customers become more efficient risks not being able to cover its costs of serving customers and providing a return to investors. This creates a powerful disincentive to utility engagement in energy efficiency. Regulators can solve this problem by implementing decoupling mechanisms that adjust rates to ensure a utility collects the costs its regulator or governing board authorizes, no less and no more. More than half the states have adopted decoupling for either electric or natural gas utilities, and it is a necessary (but not sufficient) part of the package of policies that allow a utility to invest in the cheapest and cleanest energy resource: energy efficiency.

Utilities, together with their regulators and governing boards, are responsible for providing customers with reasonably priced, reliable energy services. Whether utilities only distribute energy, have competitively provided generation service but are responsible for resource acquisition, or provide fully integrated distribution, transmission, and generation service, they have a critical role in increasing energy efficiency. Utilities have existing relationships with customers as "energy authorities," and will collectively invest more than $2 trillion in infrastructure between 2010 and 2030.[3] They also have the ability to reduce transaction costs for third-party providers of efficiency services. But under traditional regulation, utilities are discouraged from investing in the best performing and cheapest resource—energy efficiency—because it hurts them financially.

Traditionally, utilities recover fixed costs from consumption (volumetric) charges. When sales fall, utilities may not recover all their fixed costs, and when sales increase, utilities may collect more than their authorized fixed costs and reasonable return. Motivated by this *throughput incentive*, utilities may work against energy efficiency despite policies promoting it.

NRDC
The Earth's Best Defense

For more information, please contact:

Dylan Sullivan
dsullivan@nrdc.org
(312) 663-9900
switchboard.nrdc.org/blogs/dsullivan/

Devra Wang
dwang@nrdc.org
(415) 875-6100
switchboard.nrdc.org/blogs/dwang/

Donna De Costanzo
ddecostanzo@nrdc.org
(212) 727-2700
switchboard.nrdc.org/blogs/ddecostanzo/

Mona Yew
myew@nrdc.org
011+86-136-1108-6118

www.nrdc.org/policy
www.facebook.com/nrdc.org
www.twitter.com/nrdc

The throughput incentive most often contributes to utility *inaction* on energy efficiency, even though it is the cheapest way to meet energy needs. In addition, various utilities have actively countered efficiency, for example by opposing—or not supporting—highly cost-effective efficiency codes for new buildings and standards for new appliances and equipment at the local, state, and national level.

Fortunately, there is a simple, effective, and proven way to eliminate this conflict: break the link between the utility's revenue and the amount of energy it sells by adjusting rates to ensure that the utility collects its authorized fixed costs, no less and no more. Combined with other key policies to encourage energy efficiency, such *decoupling mechanisms* can free utilities to help customers save energy whenever it is cheaper than producing and delivering it.

THE CONFLICTED UTILITY

Despite the important role utilities can play to help customers be more energy efficient, most utilities' cost recovery is tied to meeting or beating the sales level assumed when rates are established, despite the environmental and economic risks associated with rising sales.

With traditional regulation, a regulator (for investor-owned utilities) or governing board (for publicly-owned utilities) determines the amount of revenue the utility needs to collect from customers to recover its prudently-incurred costs of maintaining and investing in the system's wires, pipes, and generators—including, for investor-owned utilities, providing the utility's investors with reasonable returns on investments. Then, the regulator or governing board divides this authorized revenue by the amount of energy it expects customers to consume, and establishes a rate—a charge per *kilowatt hour* (kWh) or *therm*.

Once rates are set, usually every few years, the utility's *actual* revenue is based on how much energy customers use, and any increases or decreases in consumption affect a utility's ability to recover its authorized fixed costs, even though the short-term costs themselves do not change. Much of a typical utility's cost of serving customers—for example, servicing debt, and paying for generation, transmission, and distribution equipment already installed—is independent of energy use in the near term. Typically, more than three-fifths of the retail value of kilowatt hours and one-fourth of the retail value of therms represent fixed costs. With this framework, any increase in sales above forecasted levels means the utility will collect more revenue than the regulator or governing board intended, creating windfall profits at customer expense. Conversely, any decrease in sales means the utility collects less than its approved fixed costs of service, including its return on rate base for investor-owned utilities, incurring financial harm.

The utility thus faces a strong disincentive to invest or engage in anything that decreases sales, including energy-efficiency, distributed renewable energy generation, or combined heat and power generation, even if they are the most cost-effective way to meet customer needs. This also has the perverse effect of focusing regulator and utility attention on throughput and the commodity cost of energy instead of on performance, energy services (like light or heat) and total energy bills. Customers lose in every scenario: if sales are higher than projected, they pay for windfall profits; if sales are lower, the utility can still recover its approved costs but has to go through a costly litigated regulatory proceeding to do so, which customers pay for. And regardless of whether sales go up or down, customers lose the economic benefits they would have enjoyed if their utility invested in cost-effective energy efficiency.

DECOUPLING: BREAKING THE LINK BETWEEN UTILITY COST RECOVERY AND ENERGY SALES

A decoupling mechanism is simply a system to regularly adjust rates to ensure a utility's *actual* revenues match its *authorized* revenues to recover its fixed costs. Regulators of investor-owned utilities and governing boards of publicly owned utilities can use regular, small adjustments in rates (typically less than ±3 percent[4]) to ensure that utilities recover their authorized fixed costs—no more and no less. The small rate adjustments break the link between—or decouple—a utility's revenues and sales by either restoring to the utility or giving back to customers the money that was under- or over-collected as a result of fluctuations in retail sales. This ensures that utilities:

- Recover only the prudently incurred fixed costs that were approved by their regulator or governing board
- Cannot make a windfall by encouraging higher sales
- Are not penalized when energy-efficiency programs, clean distributed generation, and other demand-side efforts reduce sales

To implement a decoupling mechanism, regulators or governing boards set up a periodic automatic process to compare actual and authorized revenues and adjust rates accordingly. These rate reconciliations can take place as frequently as every month or as seldom as every year; most mechanisms use annual adjustments.[5]

Decoupling adjusts rates between *rate cases* (the formal process that utilities are mandated to go through to set the rate at which they are allowed to charge consumers for their service). Decoupling ensures a utility collects no more and no less than its authorized revenue—the amount of revenue the regulator or governing board determined is necessary for the utility to maintain reliability and provide reasonable returns to its investors. Decoupling removes the throughput incentive and is suitable for any utility network system (electricity or natural gas, investor-owned or publicly owned). A utility that implements decoupling is free to invest in energy efficiency without endangering recovery of its fixed costs. Decoupling also enables regulators and governing boards to maintain volumetric rates that give customers an incentive to conserve or use energy efficiently.

Eliminating Utility Disincentives for Energy Efficiency: Illustrating the Problem and the Solution

THE PROBLEM

Regulators of investor-owned utilities or governing boards of publicly-owned utilities set rates by determining required revenue—which includes both fixed and variable costs of service—assuming a level of sales for the year(s) ahead, and dividing the revenue requirement by the assumed sales.

Example of Setting Initial Rates:

Assumed annual sales = 100 kWh
Variable cost = $.04 per kWh (mostly operating costs of power plants)
Fixed cost = $6 (the costs of investments in and operation of the system, of which $.60 is intended to provide a return to investors)
Revenue requirement = $4 variable cost + $6 fixed cost = $10
Rate per kWh = $.10 per kWh ($10/100kWh)

When annual sales diverge from the sales assumption, the utility will either under- or over-recover the fixed-cost element of its revenue requirement, which has a large impact on profits.

Example: Sales *Below* Assumption

Actual annual sales = 95 kWh
Variable costs total $.04 per kWh x 95 kWh = $3.80
Fixed costs = $6, including $.60 of investor return
Actual revenue requirement = $9.80 ($3.80 + $6)
Actual revenues = $9.50 (95 kWh x $.10 per kWh)
Loss = $.30 ($9.80-$9.50)
Utility has under-collected its fixed costs and foregone its opportunity to profit.

Example: Sales *Above* Assumption

Actual annual sales = 105 kWh
Variable costs total $.04 per kWh x 105 kWh = $4.20
Fixed costs = $6, including $.60 of investor return
Actual revenue requirement = $10.20 ($4.20 + $6)
Actual revenues = $10.50 (105 kWh x $.10 per kWh)
Windfall profit = $.30 ($10.50-$10.20)
Utility has over-collected its fixed costs, and it has received a 50 percent profit windfall.

The bottom line:

Every kWh of reduced sales loses the company $.06 in fixed cost recovery; every kWh of increased sales yields an equal windfall. If higher levels of consumption incur higher rates—to promote efficient use—the problem worsens.

THE SOLUTION

Decoupling mechanisms use modest, regular rate reconciliations every year to compensate for under- or over-collection of fixed costs during the previous year.

Example: Reconciliation for Utility *Over-collection* of $.30:

Sales assumption for the following year = 100 kWh
Variable cost = $.04 per kWh (no change from prior year)
Fixed cost = $6.00 (no change from prior year)
Revenue requirement = $4.00 variable cost + $6.00 fixed cost – $0.30 over-collection = $9.70
Rate per kWh = $.097 per kWh ($9.70 / 100 kWh)
The utility's rate is adjusted to return the $.30 to customers that were over-collected the previous year.

Proven Effective

Years of experience in numerous states shows that decoupling eliminates the disincentive for utilities to help their customers become more energy efficient. For example, an independent review of Northwest Natural's decoupling mechanism commissioned by Oregon regulators found that the utility, in response to decoupling, shifted marketing resources from image-building advertising to energy-efficiency, took a strong public stance in favor of energy-efficiency, and changed compensation policies.[6] The report concluded:

> Based on the information and input that we have received and reviewed, we recommend that some form of revenue decoupling be retained. It has been effective in reducing the variability of distribution revenues and in altering NW Natural's incentives to promote energy-efficiency. While [the decoupling mechanism] does not provide an *incentive* for NW Natural to promote energy-efficiency, it does remove most of the *disincentive* that exists with the standard rates.[7]

The experience of California's investor-owned electric utilities also shows the impact of decoupling: as part of a package of policies that includes aggressive energy-saving targets and incentives for good performance in delivering energy efficiency, utilities more than doubled their energy savings in 2008 compared to a decade earlier when regulators had eliminated decoupling for several years.[8]

Nationally, decoupling clearly supports investment in energ-efficiency. In 2010, seven of the 10 states with the highest per-capita investment in electric energy-efficiency programs, and eight of the 10 states with the highest per-capita investment in natural gas energy-efficiency programs had decoupling in place or had adopted decoupling as state policy.[9] Over the last few years regulators around the country have increasingly adopted decoupling policies; half the states in the nation now have policies to break the link between recovery of fixed costs and sales for natural gas and/or electric utilities. (Please see http://www.nrdc.org/energy/decoupling/).

Real Results from Small Adjustments

Decoupling has a powerful impact on a utility's incentives, but requires only a small change in the ratemaking process. The regulator or governing board still determines the utility's authorized amount of revenue to recover its fixed costs (and a reasonable return for investor-owned utilities) and divides the authorized revenue by sales to determine the rate. The primary difference is that the regulator or governing board then sets up an automatic process to regularly compare the amount of revenue the utility *actually* collected from its customers to the *authorized* revenue, and periodically adjusts rates up or down to ensure that they match. This process does *not* ensure that the utility attains a certain level of profit: profit will continue to be determined by the difference between a utility's authorized revenues and actual costs.

A study of the rate impacts of decoupling found that they "tend to be small, even miniscule," and that they "go both ways, providing both refunds and surcharges to customers."[10] The study also found:

> "Compared to total residential retail rates, including gas commodity and variable electricity costs, decoupling adjustments have been most often under 2%, positive or negative, with the majority under 1%. Using Energy Information Administration (EIA) data for 2007 on gas and electric consumption per customer and average rates, this amounts to less than $1.50 per month in higher or lower charges for residential gas customers and less than $2.00 per month in higher or lower charges for residential electric customers."[11]

Alternatives to Decoupling Have Significant Drawbacks

Regulators have implemented other policies to attempt to remove the throughput incentive and manage utilities' energy efficiency related revenue erosion. However, these policies have significant drawbacks.

- **High fixed charges:** Raising fixed (customer) charges to collect what regulators determined are fixed costs removes *utilities'* disincentive to invest in efficiency as effectively as decoupling, but harms *customers* because it reduces their rewards for saving energy since less of the customer bill varies with energy usage. It also shifts costs to customers who use less energy—because of choice, necessity, or investment in energy efficiency—and sends the wrong long-term price signals to customers, since costs that are fixed in the short-term are often variable in the long-term.
- **Lost revenue adjustment mechanisms (LRAM):** Giving a utility *lost revenues* from its energy-efficiency programs removes the utility's disincentive to support those programs, but still allows the utility to benefit from increased sales. Because a utility does not have to give up *found revenues*—when sales are higher than assumed in the rate-setting process—lost revenues are asymmetric and cause customers to pay a windfall to the utility when sales are above the volume used to set rates. An LRAM makes it unlikely that a utility will implement valuable market transformation programs, because savings from these programs are difficult to evaluate. LRAMs add controversy to the process of measuring energy savings from efficiency programs because significant dollars are now attached to savings. Finally, an LRAM presents an opportunity for gaming: if a utility runs an energy-efficiency program that looks good on paper but saves little or nothing in practice, the utility keeps the revenue associated with the unsaved energy while also collecting lost revenues.
- **Forecasting:** Using a sales forecast that assumes a certain amount of energy-efficiency savings when setting rates still allows the utility to benefit from increased usage, requires consumers to pay for windfalls whenever sales are higher than projected, and encourages the utility to seek no more efficiency than that assumed in the rate-setting process.

- **Frequent rate cases:** A utility that engages in annual rate cases would still benefit from increased sales *between* these rate cases, and all parties would endure the time and expense of a rate case with limited benefit because costs may not materially change over a year.

DECOUPLING IS NECESSARY BUT NOT SUFFICIENT

Decoupling removes a utility's disincentive to improve the efficiency of customer energy use and makes it indifferent to pursuing energy efficiency. However, decoupling alone will not necessarily turn a conflicted utility into one committed to capturing all cost-effective energy efficiency. Decoupling is part of a package of policies that lead to maximum energy-efficiency success. Other critical policies include:[12]

- Making cost-effective energy efficiency the highest priority energy resource and setting aggressive energy- and demand-saving targets to capture the full potential
- Allowing utilities timely recovery of prudently incurred costs of delivering energy-efficiency programs
- Providing performance-based shareholder incentives for investor-owned utilities to reward energy efficiency and ensure that investments in cost-effective energy-efficiency opportunities are at least as attractive over time as alternative investments in generation and infrastructure
- Conducting independent evaluation, measurement, and verification of energy-efficiency program impacts
- Ensuring that energy-efficiency program portfolios comprehensively address all major energy uses by residential, business, and industrial customers, and include programs targeted to assist lower-income households

Efficiency efforts will be significantly compromised if they have to compete against utilities with powerful financial incentives to encourage customers to increase energy consumption. Moreover, utility engagement and support is important to the success of energy-efficiency programs, regardless of the entity administering programs.[13] Regulators recognize this; electric and/or natural gas utilities in states that have used third party administrators, including Wisconsin, New York, Vermont, and Oregon, are decoupled. As more states implement aggressive energy-efficiency targets, regulators, governing boards and stakeholders should consider decoupling a necessary component of a policy package that will maximize energy and cost-savings for customers.

Exploring Further Resources on Decoupling

For more detailed information on policies to break the link between recovery of authorized fixed costs and sales, see:

U.S. Environmental Protection Agency, National Action Plan for Energy Efficiency. "Aligning Utility Incentives with Investments in Energy Efficiency," November 2007, http://www.epa.gov/cleanenergy/documents/suca/incentives.pdf.

Sheryl Carter, "Breaking the Consumption Habit: Ratemaking for Efficient Resource Decisions," *Electricity Journal* 2001;14(10):66-74. http://www.sciencedirect.com/science/article/pii/S104061900100255X.

Wayne Shirley, Jim Lazar, Frederick Weston, "Revenue Decoupling: Standards and Criteria," Report to the Minnesota Public Utilities Commission, Regulatory Assistance Project, http://www.raponline.org/document/download/id/850. June 2008.

Dylan Sullivan, Devra Wang, Drew Bennett, "Essential to Energy Efficiency, but Easy to Explain: Frequently Asked Questions about Decoupling," *Electricity Journal* 2011; 24(8):56-70.

Regulatory Assistance Project, "Revenue Regulation and Decoupling: A Guide to Theory and Application," June 2011, http://www.raponline.org/document/download/id/902.

References

1. Hannah Choi Granade et al., "Electric Power and Natural Gas, Unlocking Energy Efficiency in the U.S. Economy," 6 and 118, McKinsey Global Energy and Materials, July 2009, http://www.mckinsey.com/Client_Service/Electric_Power_and_Natural_Gas/Latest_thinking/Unlocking_energy_efficiency_in_the_US_economy.aspx (accessed October 27, 2011).

2. Devra Wang, Rebecca Stanfield, Donna DeCostanzo, Mona Yew, "Doing More and Using Less: Regulatory Reforms for Electricity and Natural Gas Utilities Can Spur Energy Efficiency," http://www.nrdc.org/energy/doingmoreusingless.asp (accessed October 27, 2011).

3. Marc W. Chupka et al., "Transforming America's Power Industry," The Brattle Group, Prepared for The Edison Foundation, www.eei.org, November 2008, http://www.eei.org/ourissues/finance/Documents/Transforming_Americas_Power_Industry.pdf (accessed October 27, 2011).

4. Pamela G. Lesh, "Rate Impacts and Key Design Elements of Gas and Electric Utility Decoupling: A Comprehensive Review," June 30, 2009, 3, http://raponline.org/document/download/id/509 (accessed October 27, 2011).

5. *Ibid*, 6.

6. Daniel G. Hansen, Steven D. Braithwait, "A Review of Distribution Margin Normalization as Approved by the Oregon Public Utility Commission for Northwest Natural," Christensen Associates, March 31, 2005, http://www.cee1.org/eval/db_pdf/472.pdf (accessed October 27, 2011).

7. *Ibid*, 75.

8. Sierra Martinez, Devra Wang, James Chou, "California Restores its Energy Efficiency Leadership," Natural Resources Defense Council, March 9, 2010, http://docs.nrdc.org/energy/files/ene_10030901a.pdf. (accessed October 27, 2011); Devra Wang, "Energy efficiency continues to save money and cut pollution in California," Natural Resources Defense Council Switchboard, May 26, 2010, http://switchboard.nrdc.org/blogs/dwang/energy_efficiency_continues_to.html (accessed October 27, 2011).

9. California, Connecticut, Idaho, Massachusetts, New York, Oregon, and Vermont. Consortium for Energy Efficiency, "State of Efficiency Program Industry Report," Table 6, January 12, 2011, http://www.cee1.org/ee-pe/docs/Table%206.pdf (accessed October 27, 2011); California, Massachusetts, Minnesota, New Jersey, New York, Oregon, Utah, and Wisconsin, Consortium for Energy Efficiency, "State of Efficiency Program Industry Report," Table 9, January 12, 2011, http://www.cee1.org/ee-pe/docs/Table%209.pdf (accessed October 27, 2011).

10. *Supra* at 4.

11. *Ibid*, 4.

12 Devra Wang, Rebecca Stanfield, Donna DeCostanzo, Mona Yew, "Doing More and Using Less: Regulatory Reforms for Electricity and Natural Gas Utilities Can Spur Energy Efficiency," Natural Resources Defense Council, January 2011, http://www.nrdc.org/energy/files/doingmoreusingless.pdf (accessed October 27, 2011).

13 Lisa Schwartz, "The Role of Decoupling Where Energy Efficiency is Required by Law," Regulatory Assistance Project, September 2009. http://www.raponline.org/docs/RAP_Schwartz_IssuesletterSept09_2009_08_25.pdf, (accessed March 1, 2012).

 © Natural Resources Defense Council May 2012

CERTIFICATE OF SERVICE

I hereby certify that a copy of the foregoing **Direct Testimony and Exhibits of Pamela G. Morgan on Behalf of the Alliance for Affordable Energy** has been served on the persons listed below by electronic mail and/or U.S. First-Class mail, postage prepaid:

Lora W. Johnson, lwjohnson@nola.gov Clerk of Council City Hall - Room 1E09 1300 Perdido Street New Orleans, LA 70112 (504) 658-1085 - office (504) 658-1140 - fax *Service of Discovery not require* **Erin Spears,** espears@nola.gov **Bobbie Mason,** bfmason1@nola.gov **Connolly Reed,** careed@nola.gov City Hall - Room 6E07 1300 Perdido Street New Orleans, LA 70112 (504) 658-1110 - office (504) 658-1117 – fax **Andrew Tuozzolo,** CM Moreno Chief of Staff, avtuozzolo@nola.gov 1300 Perdido St. Rm. 2W40 New Orleans, LA. 70112 **CITY OF NEW ORLEANS** **Sunni LeBeouf**, sunni.lebeouf@nola.gov **Michael J. Laughlin**, mjlaughlin@nola.gov **Mary Katherine Kaufman**, mkkaugman@nola.gov Law Department 1300 Perdido Street City Hall – Suite 5E03 New Orleans, LA 70112 **David Gavlinski**, dsgavlinski@nola.gov Council Chief of Staff City Hall – Room 1E06 1300 Perdido Street New Orleans, LA 70112	**NEW ORLEANS CITY COUNCIL CONSULTANTS** **Clinton A. Vince,** clinton.vince@dentons.com **Presley Reed,** presley.reedjr@dentons.com **Emma F. Hand,** emma.hand@dentons.com 1900 K Street NW Washington, DC 20006 (202) 408-6400 - office (202) 408-6399 - fax **Basile J. Uddo (**504) 583-8604 cell, buddo@earthlink.net **J. A. "Jay" Beatmann, Jr.** (504) 256-6142 cell, (504) 524-5446 office direct, jay.beatmann@dentons.com c/o DENTONS US LLP 650 Poydras Street Suite 2850 New Orleans, LA 70130 **Walter J. Wilkerson,** wwilkerson@wilkersonplc.com **Kelley Bazile**, kbazile@wilkersonplc.com **Yves Gelin,** ygelin@wilkersonplc.com Wilkerson and Associates, PLC 650 Poydras Street - Suite 1913 New Orleans, LA 70130 (504) 522-4572 - office (504) 522-0728 - fax **Philip Movish,** pmovish@ergconsulting.com **Victor M. Prep,** vprep@ergconsulting.com **Joseph W. Rogers,** jrogers@ergconsulting.com **Byron S. Watson**, bwatson@ergconsulting.com **Cortney Crouch,** ccrouch@ergconsulting.com

Norman White, norman.white@nola.gov
Chief Financial Officer
Department of Finance
City Hall – Room 3E06
1300 Perdido Street
New Orleans, LA 70112

ADMINISTRATIVE HEARING OFFICER

Hon. Jeffrey S. Gulin,
judgegulin@gmail.com
3203 Bridle Ridge Lane
Lutherville, MD 21093
(410) 627-5357

ENTERGY NEW ORLEANS, INC.

Gary E. Huntley, 504-670-3680,
ghuntle@entergy.com
Entergy New Orleans, Inc.
Vice-President, Regulatory Affairs
1600 Perdido Street, L-MAG 505B
New Orleans, LA 70112
504-670-3615 fax

Polly S. Rosemond, 504-670-3567,
prosemo@entergy.com
Entergy New Orleans, Inc.
Manager, Regulatory Affairs
1600 Perdido Street, L-MAG 505B
New Orleans, LA 70112

Derek Mills, dmills3@entergy.com
Project Manager
1600 Perdido Street, Bldg. #505
New Orleans, LA 70112
504-670-3527

Seth Cureington, 504-670-3602,
scurein@entergy.com
Entergy New Orleans, Inc.
Manager, Resource Planning
1600 Perdido Street, L-MAG 505B
New Orleans, LA 70112

Legend Consulting Group
8055 East Tufts Ave., Suite 1250
Denver, CO 80237-2835
(303) 843-0351 - office
(303) 843-0529 – fax

Errol Smith, (504) 284-8733,
ersmith@btcpas.com
Bruno and Tervalon
4298 Elysian Fields Avenue
New Orleans, LA 70122
(504) 284-8296 – fax

ALLIANCE FOR AFFORDABLE ENERGY

Logan Atkinson Burke,
logan@all4energy.org
Sophie Zaken, regulatory@all4energy.org
Alliance for Affordable Energy
4505 S. Claiborne Avenue
New Orleans, LA 70125

350 LOUISIANA

Renate Heurich, 504-473-2740,
350louisiana@gmail.com
1407 Napoleon Ave, #C
New Orleans, LA, 70115

Andy Kowalczyk,
a.kowalczyk350no@gmail.com
1115 Congress St.
New Orleans, LA 70117

BUILDING SCIENCE INNOVATORS

Myron Katz, PhD
302 Walnut Street
New Orleans, LA 70118
504-343-1243
Myron.bernard.katz@gmail.com
Myron.katz@energyrater.com

Keith Woods, kwood@entergy.com

Timothy Cragin (504) 576-6523 office, tcragin@entergy.com
Brian L. Guillot (504) 576-2603 office, bguill1@entergy.com
Alyssa Maurice-Anderson (504) 576-6523 office, amauric@entergy.com
Harry Barton (504) 576-2984 office, hbarton@entergy.com
Karen Freese (504) 576-4170 office, kfreese@entergy.com
Entergy Services, Inc.
Mail Unit L-ENT-26E
639 Loyola Avenue
New Orleans, LA 70113
(504) 576-5579 – fax

Joe Romano, III (504) 576-4764, jroman1@entergy.com
Suzanne Fontan (504) 576-7497, sfontan@entergy.com
Danielle Burleigh (504) 576-6185, dburlei@entergy.com
Therese Perrault (504-576-6950), tperrau@entergy.com
Entergy Services, Inc.
Mail Unit L-ENT-4C
639 Loyola Avenue
New Orleans, LA 70113
(504)576-6029 – fax

SEWERAGE AND WATER BOARD OF NEW ORLEANS

John H. Chavanne, 225-638-8922, jchav@bellsouth.net
111 West Main St., Suite 2B
PO Box 807
New Roads, LA 70760-8922
Fax 225-638-8933

Brian A. Ferrara, bferrara@swbno.org

AIR PRODUCTS AND CHEMICALS, INC.

Katherine W. King, katherine.king@keanmiller.com
Randy Young, randy.young@keanmiller.com
400 Convention St., Suite 700
Baton Rouge, LA 70802
Or
P.O. Box 3513 70821-3513

Carrie R. Tournillon, carrie.tournillon@keanmiller.com
900 Poydras St., Suite 3600
New Orleans, LA 70112

Mark Zimmerman, zimmerman@airproducts.com
720 I Hamilton Blvd.
Allentown, PA 18195-1501
610-481-1288

Maurice Brubaker, mbrubaker@consultbai.com
16690 Swigly Ridge Rd., Suite 140
Chesterfield, MO 63017
Or
P.O. Box 412000
Chesterfield, MO 63141-2000

CRESCENT CITY POWER USERS' GROUP

Luke F. Piontek, Lpiontek@roedelparsons.com, Jsulzer@roedelparsons.com

Christian J. Rhodes
Shelley Ann McGlathery
Roedel, Parsons, Koch, Blache, Balhoff & McCollister
1515 Poydras Street, Suite 2330
New Orleans, LA 70112

Yolanda Y. Grinstead, ygrinstead@swbno.org Legal Department 625 St. Joseph St., Rm 201 New Orleans, LA 70165 504-585-2154 **SIERRA CLUB** **Grace Morris**, 973-997-7121 Grace.Morris@sierraclub.org 4422 Bienville Ave New Orleans, LA 70119 **Dave Stets,** 804-222-4420, Dave.Stets@BySolar.net 2101 Selma St. New Orleans, LA 70122 **Julie DesOrmeaux Rosenzweig, 337-577-8494,** Julie.Rosenzweig@sierraclub.org PO Box 8619 New Orleans, LA 70182	**Lane Kollen (**lkollen@jkenn.com) **Stephen Baron (**sbaron@jkenn.com) **Randy Futral (**rfutral@jkenn.com) **Richard Baudino (**rbaudino@jkenn.com) **Brian Barber (**brbarber@jkenn.com) J. Kennedy & Associates 570 Colonial Park Dr., Suite 305 Rosewell, Ga. 30075 **JUSTICE AND BEYOND** **Rev. Gregory Manning**, 913-940-5713, gmanning1973@yahoo.com **Pat Bryant,** 504-905-4137, pat46bryant@yahoo.com **Happy Johnson**, 504-315-5083, hjohnson1081@gmail.com **Sylvia McKenzie,** sylkysmooth.sm@cox.net c/o A Community Voice 2221 St. Claude Ave. New Orleans, LA 7011

Additionally, pursuant to the New Orleans, Louisiana Code of Ordinances, Ch. 158, Art. III, Div. 1, § 158-236, the following persons have been served with copies of the aforementioned document, in triplicate, via U.S. first-class mail, postage prepaid:

Councilwoman Helena Moreno
City Hall, Room 2W40
1300 Perdido Street
New Orleans, LA 70112
morenocouncil@nola.gov

Councilwoman Joseph I. Giarrusso
City Hall, Room 2W80
1300 Perdido Street
New Orleans, LA 70112
Joseph.Giarrusso@nola.gov

Councilwoman Kristin Gisleson Palmer
City Hall, Room 2W70
1300 Perdido Street
New Orleans, LA 70112
Kristin.Palmer@nola.gov

Councilman Cyndi Nguyen
City Hall, Room 2W60
1300 Perdido Street
New Orleans, LA 70112
Cyndi.Nguyen@nola.gov

Mayor Latoya Cantrell
The Mayor's Office
City Hall, 2nd Floor
1300 Perdido Street
New Orleans, LA 70112

Lora W. Johnson, lwjohnson@nola.gov
Clerk of Council
City Hall - Room 1E09
1300 Perdido Street
New Orleans, LA 70112
(504) 658-1085 - office
(504) 658-1140 - fax

Councilman Jason Rogers Williams
City Hall, Room 2W50
1300 Perdido Street
New Orleans, LA 70112
jasonwilliams@nola.gov

Councilwoman Jay H. Banks
City Hall, Room 2W10
1300 Perdido Street
New Orleans, LA 70112
Jay.banks@nola.gov

Councilman Jared C. Brossett
City Hall, Room 2W20
1300 Perdido Street
New Orleans, LA 70112
councildistrictd@nola.gov

Reketti Peters
City Hall, Council Research Division
1300 Perdido Street
New Orleans, LA 70112
rapeters@nola.gov

Sunni LeBeouf, sunni.lebeouf@nola.gov
City Attorney
Michael J. Laughlin, mjlaughlin@nola.gov
Mary Katherine Kaufman,
mkkaugman@nola.gov
Law Department
1300 Perdido Street
City Hall – Suite 5E03
New Orleans, LA 70112

Norman White, norman.white@nola.gov
Chief Financial Officer
Department of Finance
City Hall – Room 3E06
1300 Perdido Street
New Orleans, LA 70112

David Gavlinski, dsgavlinski@nola.gov
Council Chief of Staff, Council Utilities
Regulatory Office
City Hall – Room 1E06
1300 Perdido Street
New Orleans, LA 70112

Washington, D.C., this 1st day of February, 2019.

Al Luna
Litigation Assistant
Earthjustice