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February 1, 2019

<u>Via Hand-Delivery</u>

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

     Re: **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 and
for Related Relief**
           City Council of New Orleans Docket No. UD-18-07

Dear Ms. Johnson:

Please find enclosed one original and three (3) copies of the public, redacted version of
the **Direct Testimony of Justin R. Barnes on Behalf of the Alliance for Affordable Energy** in
the above-captioned docket. Please file the attached documents and this letter in the record of the
proceeding and return one time stamped copy to our courier, in accordance with normal
procedures. The HSPM version of the Direct Testimony will be served in hard copy only to the
appropriate parties who have executed Non-Disclosure Certificates pursuant to Council
Resolution R-07-432.

Thank you for your attention to this matter. Please contact me if you have any questions
with regards to this filing.

Sincerely,

Logan A. Burke

Logan Atkinson Burke
Executive Director
Alliance for Affordable Energy
4505 S. Claiborne Avenue
New Orleans, LA 70125
(504) 208-9761
logan@all4energy.org

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cc: Official Service List

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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

OF

JUSTIN R. BARNES

ON BEHALF OF THE

ALLIANCE FOR AFFORDABLE ENERGY

PUBLIC VERSION

FEBRUARY 1, 2019

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AAE Exhibit JRB-1: Curriculum Vitae of Justin R. Barnes

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1   **I.   INTRODUCTION**

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

3   POSITION.

4   A.   My name is Justin R. Barnes, and my business address is 401 Harrison Oaks Blvd.,

5   Suite 100, Cary, North Carolina, 27513. My current position is Director of Research

6   with EQ Research LLC.

7   Q2.   PLEASE DESCRIBE YOUR EDUCATIONAL AND OCCUPATIONAL

8   BACKGROUND.

9   A.   I obtained a Bachelor of Science in Geography from the University of Oklahoma

10   in Norman in 2003 and a Master of Science in Environmental Policy from Michigan

11   Technological University in 2006. I was employed at the North Carolina Solar

12   Center at N.C. State University for more than five years as a Policy Analyst and

13   Senior Policy Analyst, where I worked on the *Database of State Incentives for*

14   *Renewables and Efficiency ("DSIRE")* project, and several other projects related to

15   state renewable energy and energy efficiency policy. I joined EQ Research in 2013

16   as a Senior Analyst and become the Director of Research in 2015.

17   In my current position, I coordinate EQ Research's various research

18   projects for clients, assist in the oversight of EQ Research's electric industry

19   regulatory and general rate case tracking services, and perform customized research

20   and analysis to fulfill client requests. I have testified before utility regulatory

21   commissions in the states of Colorado, New Hampshire, North Carolina,

1   Oklahoma, South Carolina, Texas, and Utah as an expert in clean energy policy,

2   rate design, and cost of service. My *curriculum vitae* is attached as AAE Exhibit

3   JRB-1.

4   Q3.   HAVE YOU PREVIOUSLY SUBMITTED TESTIMONY BEFORE THE

5   COUNCIL OF THE CITY OF NEW ORLEANS ("COUNCIL")?

6   A.   No.

7   Q4.   ON WHOSE BEHALF ARE YOU SUBMITTING TESTIMONY?

8   A.   I am submitting testimony on behalf of the Alliance for Affordable Energy

9   ("AAE").

10   Q5.   WHAT IS THE PURPOSE OF YOUR TESTIMONY?

11   A.   My testimony addresses the reasonableness of Entergy New Orleans' ("ENO,"

12   "Entergy," or "Company") proposals for an increase to the residential customer

13   charge, a revised framework for demand-side management ("DSM") programs, and

14   the rate design associated with the proposed Electric Advanced Metering

15   Infrastructure ("AMI") Rider, the Demand-Side Management Cost Recovery rider

16   ("DSMCR" or "Rider DSMCR") (for DSM programs), and the Distribution Grid

17   Modernization rider ("DGM" or "Rider DGM") (for grid modernization

18   investments). I have developed a series of recommendations for modifying these

19   proposals to better align them with the goals of supporting energy efficiency on the

20   part of customers, avoiding undue adverse impacts on residential customers and

21   low-income customers in particular, and with the sound principles of cost causation.

1   My testimony discusses the shortcomings of each of these individual proposals as

2   well as how they would operate together in a cyclical or reinforcing fashion that is

3   contrary to these goals.

4   Q6.   PLEASE DESCRIBE HOW YOUR TESTIMONY IS ORGANIZED.

5   A.   My testimony is organized into the following sections.

6   • Section II describes my objections to ENO's proposed increase in the residential

7   fixed charge, provides a more generalized discussion of the negative impacts

8   that fixed charges would have on ENO's customers and recommends an

9   appropriate residential customer charge.

10   • Section III describes the reasons why the proposed Electric AMI Charge should

11   use a volumetric rather than fixed monthly rate design.

12   • Section IV describes why proposed Rider DGM, if approved by the Council,

13   should use a volumetric rather than a percentage of bill-based design.

14   • Section V discusses the Company's proposed DSM framework and

15   recommends modifications that include the elimination of the Lost Contribution

16   to Fixed Costs ("LCFC") component in favor of full decoupling, modifications

17   to the proposed performance incentive structure, and the reasons why rider

18   DSMCR should use a volumetric rather than a percentage of bill-based design.

19   • Section VI summarizes the cross-cutting nature of these collective proposals

20   and explains how they fit together in a manner that would be highly damaging

21   to the encouragement of energy efficiency and to the majority of Entergy's

1   residential customers. I conclude this section with a summary of my

2   recommendations to the Council.

3   II.   RESIDENTIAL FIXED CHARGES

4   A.   Summary of Proposed Residential Fixed Charges and Justification

5   Q7.   PLEASE DESCRIBE ENTERGY'S PROPOSAL FOR SETTING THE

6   RESIDENTIAL FIXED CHARGE.

7   A.   The Company proposes to set the residential customer charge at $15.53/month. This

8   value is arrived at by starting with the customer unit cost value of $21.07/month

9   from the Company's Period II cost of service study. Entergy reduces this amount

10   by 14.6% to reflect its proposed rate class cost allocation, arriving at a value of

11        $18.01/month, which is $9.94/month higher than the current nominal customer

12   charge of $8.07/month. The Company then reduced the amount of the theoretical

13   increase by 25% in the interest of "gradualism," arriving at a proposed increase of

14        $7.46/month. When added to the current charge, this results in a proposed

15   residential customer charge of $15.53/month.[1] The true effective increase after

16   incorporating the effects of current percentage-based rider rates and proposed

17   percentage-based rider rates would be $7.94/month. This reflects a rider-adjusted

18   current rate of $8.20/month, and a rider-adjusted proposed rate of $16.14/month.[2]

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[1] Revised Direct Testimony of Joshua B. Thomas at 63:14-64:2 (Sept. 2018) ("Thomas Direct").
[2] These values exclude the franchise tax but include all other rate riders.

1   Q8.   DO THE AMOUNTS YOU DESCRIBE ABOVE INCLUDE THE COMPANY'S

2   PROPOSED ELECTRIC AMI CHARGE?

3   A.   No. The proposed 2019 Electric AMI Charge adds an additional $2.95/month in the

4   form of a fixed charge. That brings the total of all fixed charges to $19.09/month

5   and the increase to $10.89/month in 2019 when adjusted for all riders, or

6         $18.48/month and $10.41/month if only the 2019 Electric AMI Charge is included.

7   These amounts would change over time according to rate rider adjustments. For the

8   sake of simplicity, I have used only the $18.48/month and $10.41/month figures as

9   the proposed customer charge and proposed increase in the customer charge

10   throughout the remainder of my testimony. From this basis of comparison, ENO's

11   proposal represents an increase of 129% relative to current fixed charges for both

12   New Orleans and Algiers customers.

13 Q9.   WHY DOES ENO WANT TO INCREASE THE RESIDENTIAL CUSTOMER

14   CHARGE TO BE CLOSER TO ITS CALCULATED EMBEDDED CUSTOMER-

15   RELATED COSTS?

16 A.   Company witness Thomas states several objectives for its proposal, which can be

17   paraphrased as: (1) preserving ENO's revenues; (2) reducing cross-subsidies

18   related to energy efficiency and solar photovoltaic ("PV") adoption; (3) stabilizing

19   residential bills; and (4) stabilizing ENO's cash flow metrics.[3] Company witness

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[3] Thomas Direct at 62:16-23.

1   Talkington also offers the justification that the increase is necessary to align rates

2   with the costs indicated by the Company's embedded cost of service study.[4]

3   Q10. DO YOU AGREE THAT ENO'S PROPOSED RESIDENTIAL CUSTOMER

4   CHARGE IS REASONABLE?

5   A.   No. I object to the Company's proposal for several reasons, as follows:

6   1. The proposed charge and the amount of the proposed increase is extreme and

7   fails to reflect the true nature of gradualism in utility ratemaking, as evidenced

8   by national trends in residential fixed charges.

9   2. The proposal would result in a considerable dilution of customer incentives to

10   use less energy, in conflict with the Council's policy of supporting energy

11   efficiency, including but not limited to recognizing energy efficiency as a

12   "high-priority energy resource" and resolving to "align customer pricing and

13   incentives to encourage investment in energy efficiency."[5]

14   3. The Company's calculated customer unit cost, which forms the starting point

15   for its derivation of the proposed charge, is inflated by the inclusion of

16   numerous costs that bear little or no relationship with the costs associated with

17   connecting a customer to the grid, or which vary directly with the number of

18   customers being served. Utilizing this inflated customer unit cost for rate design

19   would cause relatively lower usage customers to subsidize relatively higher

20   usage customers.

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[4] Revised Direct Testimony of Myra L. Talkington at 26:10-17 (Sept. 2018) ("Talkington Direct").
[5] Council Resolution No. R-07-600.

1   4.   The negative impacts of increases to fixed charges would fall disproportionately

2   on low-income customers while generally benefitting higher-income

3   customers.

4   Furthermore, the Company's proposed Electric AMI Charge would

5   effectively charge customers multiple fixed charges for metering and metering-

6   related costs, once for the cost of existing metering and again for the costs of AMI.

7   I generally address the proposed Electric AMI Charge in a separate section of my

8   testimony, but I mention it immediately below in the context of customer impacts

9   because it constitutes an additional monthly fixed charge. To be clear, I am not

10   objecting to the recovery of the un-depreciated costs of legacy meters, as the

11   Council has already ruled on this issue. I only address the mechanism for that cost

12   recovery from the perspective of rate design.

13   Q11.   ARE THE OBJECTIVES VOICED BY COMPANY WITNESSES THOMAS

14   AND   TALKINGTON   REASONABLE,   AND   WOULD   ENTERGY'S

15   PROPOSALS ACHIEVE THOSE OBJECTIVES?

16   A.   The Company's proposals would contribute to achieving the revenue stability

17   objectives noted by Company witness Thomas. The more pertinent questions are

18   whether using fixed charges to achieve them is necessary given the Company's

19   other revenue fixing proposals, which include a renewed Formula Rate Plan with a

20   revenue decoupling mechanism, and how to weigh any remaining perceived need

21   against the negative impacts on customer energy efficiency incentives and low-

1   income customers. AAE witness Pamela Morgan discusses how decoupling would

2   support ENO's financial stability in greater detail.

3   Similarly, relatively higher fixed charges can contribute to customer bill

4   stability, but the Company has presented no evidence that customers would support

5   a large increase in fixed charges as a mechanism for achieving more stable bills. In

6   fact, survey research that the Company conducted in connection with its fixed bill

7   option proposal indicates that only 30% of customers were likely or very likely to

8   participate in the program, which provides bill stability in exchange for a premium.[6]

9   Another way to view this is that 70% of customers are not interested in paying a

10   premium in order to achieve more stable bills.

11   Finally, the references to rate design replicating cost structure made by ENO

12   witness Talkington, and cross-subsidization created by energy efficiency and PV

13   adoption made by ENO witness Thomas, stem from the false premise that the

14   results of the Company's embedded cost of service study is determinative for the

15   purpose of setting rates that provide economically efficient price signals. There are

16   two prominent inaccuracies with this premise. First, marginal rather than embedded

17   costs are the proper basis for developing economically efficient price signals.

18   Second, an embedded cost of service study does not account for the negative public

19   policy impacts of the result, most notably the departure from economic efficiency

20   in rates and the dilution of customer incentives to use less energy and thereby

21   contribute to producing long-term system cost savings. Embedded cost of service

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[6] Revised Direct Testimony of Raiford L. Smith at 26:8-11 (Sept. 2018) ("Smith Direct").

1   studies are useful for determining the amount of revenue to collect, not how to

2   collect that revenue. As I discuss further in my testimony, contrary to ENO witness

3   Thomas' assertion, the Company's proposed fixed charges would cause low usage

4   customers such as those that invest in energy efficiency and PV, to subsidize high

5   usage customers.

6   Q12.   PLEASE DESCRIBE THE DIFFERENCE BETWEEN EMBEDDED COSTS

7   AND MARGINAL COSTS AND WHY THIS DIFFERENCE IS IMPORTANT

8   FOR RATE DESIGN.

9   A.   Embedded costs are costs that have already been incurred (*i.e.*, on a utility's books)

10   while marginal costs are forward-looking, evaluating the incremental costs

11   associated with adding one more customer, one more unit of demand, or one more

12   unit of energy. The rationale for using marginal costs as the basis for rate design is

13   that marginal cost pricing supports the economically efficient use of a good or

14   service. In other words, when looking to achieve outcomes based on pricing

15   incentives in rates, it makes more sense to look to future costs rather than costs that

16   can no longer be avoided. Embedded cost studies still serve a purpose in that they

17   aid in determining how responsibility for embedded costs and the associated

18   revenue requirement should be divided between different customers or groups of

19   customers.

20   As Company Witness Gillam observes, "[t]he objective of preparing a cost

21   of service study for either electric or gas operations is to determine the portion of a

22   utility's costs, as measured by its revenue requirement, for which each of the

1   various rate classes is responsible. This then becomes one of the factors in

2   determining the revenue level appropriately allocated to each rate class, *though the*

3   *Council has wide discretion in the area of rate design.*"[7]

4   **B.   ENO's Proposed Fixed Charge Increases Are Extreme**

5   Q13.   IN WHAT WAYS ARE THE COMPANY'S PROPOSED RESIDENTIAL FIXED

6   CHARGES EXTREME?

7   A.   The proposed customer charges for the residential class are extreme insofar as they

8   would result in:

9   1. Fixed monthly charges far in excess of the national average, other Entergy

10   affiliates, and those of corporations deemed comparable to Entergy

11   mentioned in the Direct Testimony of Robert Hevert.[8]

12   2. An increase far in excess, both in monetary and percentage terms, of

13   increases approved by regulators in other states during rate cases filed

14   during roughly the last four years, including those approved for comparable

15   companies.

16   Q14.   HOW DID YOU ARRIVE AT THE CONCLUSIONS ABOVE AND WHAT

17   EVIDENCE DO YOU PRESENT TO SUPPORT THESE CLAIMS?

18   A.   I conducted a review of current residential customer charges for 168 investor-

19   owned utilities ("IOUs") in 49 states and the District of Columbia.[9] The utilities in

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[7] Revised Direct Testimony of Phillip B. Gillam at 13:4-14:2 (Sept. 2018) (emphasis added).
[8] Revised Direct Testimony of Robert B. Hevert at 14, Table 2 (Sept. 2018) ("Hevert Direct").
[9] Nebraska is the only state not represented in this survey. Nebraska is unique in that it is the only state served entirely by consumer-owned utilities not subject to external rate regulation.

1   this survey encompass all major IOUs and nearly all smaller IOUs in each state,

2   thus it presents a comprehensive national picture of residential fixed charges. I also

3   conducted a review of adopted increases in residential customer charges for IOU

4   general rate case applications filed since July 2014. A total of 165 general rate cases

5   are represented in this sample, though the total number of utilities is lower because

6   several utilities had multiple rate cases during this time frame. Consequently, the

7   sample of adopted increases reflects these utilities more than once. Both datasets

8   are generally current as of November 16, 2018, but I have also added the results of

9   a recently completed rate case for Entergy Texas, which concluded in December

10   2018.[10]

11   As I noted above, the "comparable" utilities are based on the proxy

12   companies that ENO witness Hevert selected for his return on equity analysis. To

13   generate these averages, I selected all of the local distribution utilities affiliated

14   with these companies from my larger dataset of fixed charges and approved

15   increases.

16   Q15.   PLEASE SUMMARIZE THE RESULTS OF THE RESEARCH YOU DESCRIBE

17   ABOVE.

18   A.   Table 1 below presents comparisons between current fixed monthly charge

19   averages and ENO's current ($8.07/month) and proposed nominal rates inclusive

20   of the proposed Electric AMI Charge ($18.48/month). Table 2 presents averages of

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[10] Public Utilities Commission of Texas, Docket No. 48371, Order (Dec. 20, 2018).

1   *increases* approved in rate cases filed during the last four years relative to the

2   Company's proposed increase of $10.41/month, or 129%.

3   **Table 1: Fixed Charge Comparisons**

Basis of Comparison	Fixed Charge ($)	ENO Current Difference ($)	ENO Current Difference %	ENO Proposed Difference ($)	ENO Proposed Difference %
National Average	$10.40	-$2.33	-22.40%	$8.08	77.70%
ENO Affiliate Average	$7.33	$0.74	10.10%	$11.15	152.11%
ENO Comparables	$10.73	-$2.66	-24.79%	$7.75	72.23%
ENO Current	$8.07				
ENO Proposed	$18.48				

4   **Table 2: Fixed Charge Increase Comparisons**

Basis of Comparison	Increase ($)	Increase (%)	ENO Above ($)	ENO Above (%)
National Average	$0.96	13.80%	$9.45	115.20%
ENO Affiliate Average	$2.22	31.77%	$8.19	97.23%
ENO Comparables	$1.08	15.74%	$9.33	113.26%
ENO Proposed	$10.41	129.00%		

5   Tables 1 and 2 clearly show that ENO's current residential customer charge

6   is moderately below the national average, but already slightly above the average

7   for Entergy affiliates. The increase ENO proposes would place the residential

8   customer charge well in excess of the national average and dramatically exceed

9   recent national averages for fixed charge increases and those awarded to Entergy

10   affiliates. The two increases for Entergy affiliates represented in Table 2 refer to a

11    $1.44/month (20.7%) increase granted in 2016 to Entergy Arkansas resulting in a

12   current rate of $8.40/month and a $3.00/month increase granted to Entergy Texas

13   in 2018 that results in a current rate of $10.00/month (a 42.9% increase). Combined,

14   these translate to the $2.22/month and 31.77% averages reflected in Table 2.

1   Q16.   PLEASE   EXPLAIN   WHY   YOU   INCLUDED   A   COMPARISON   TO

2   COMPANIES "COMPARABLE" TO ENO IN YOUR ANALYSIS.

3   A.   ENO witness Hevert describes his selection of proxy companies as intended to

4   consist of those with "comparable companies in terms of financial, business, and

5   regulatory risks."[11] To be clear, none of his selection criteria involve an assessment

6   of a company's risk profile based on revenue generated via fixed charges. However,

7   it is inescapable that fixed charges do have the effect of providing a high degree of

8   certainty for a portion of a utility's revenue during a given month or year (*i.e.*, little

9   or no risk of under-recovery), making it less vulnerable to sales fluctuations. In fact,

10   ENO witness Thomas cites revenue preservation and stabilizing cash flow metrics

11   to support finance operations in support of the Company's customer charge

12   proposal.[12]

13   I make no claims as to how fixed charge revenue may specifically affect a

14   utility's risk profile. Nevertheless, I do believe that Hevert's list of proxy

15   companies is illustrative insofar as it represents an additional basis for comparing

16   different utilities, and shows results similar to the national and ENO affiliate

17   comparisons I have done. Certainly, the comparisons do not suggest that the

18   Company's financial position presents a driving need for such a large increase in

19   order to reduce its risk profile, in particular in light of the other measures the

20   Company proposes with similar objectives, and the detrimental impact that such an

21   increase would have on many of the Company's customers.

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[11] Hevert Direct at 80:11-12.
[12] Thomas Direct at 62:16, 20-23.

1 Q17. ARE THE COMPANY'S PROPOSED INCREASES TO RESIDENTIAL FIXED

2   CHARGES CONSISTENT WITH THE PRINCIPLE OF GRADUALISM?

3 A.   Absolutely not. Company witness Talkington states that ENO's proposals

4   "balances rate design considerations of setting rates at cost and employing

5   gradualism to avoid undue customer impacts."[13] However, as evidenced by both

6   the amount and percentage of the proposed increase embodied within the residential

7   customer charge and the accompanying Electric AMI Charge, the Company's

8   proposal clearly does not represent "gradualism" as practiced by regulators in other

9   states. It is only "gradual" with respect to the Company's calculated customer-

10   related unit costs, which I disagree with and discuss in the next sub-section of my

11   testimony.

12 Q18. IN REFERENCE TO YOUR OBJECTIONS TO THE COMPANY'S PROPOSED

13   RESIDENTIAL CUSTOMER CHARGE AND CUSTOMER IMPACTS, ARE

14   YOU ALSO OBJECTING TO THE COST ALLOCATION THE COMPANY

15   PROPOSES FOR THE RESIDENTIAL CLASS?

16 A.   No. I am not taking a position on the overall cost allocation methodology or the

17   overall revenue requirement. In other words, I am contesting rate design rather than

18   the revenue requirement for the residential customer class. While I refer to the

19   Company's cost of service study and use some of the associated outputs in my own

20   calculations, I do so only because it is necessary to define a starting point for this

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[13] Talkington Direct at 26:14-15.

14

1   purpose. This should not be seen as an endorsement of the cost allocation

2   methodology Entergy employs or its overall revenue request.

3   **C.   Impacts on Customer Energy Efficiency Incentives**

4   Q19.   PLEASE SUMMARIZE HOW FIXED CHARGES AFFECT CONSUMER

5   INCENTIVES TO CONSERVE ELECTRICITY.

6   A.   Fixed charges cannot be avoided by reducing energy consumption or demand for

7   electricity. If one assumes the same total revenue requirement for a class of

8   customers, a rate design weighted towards fixed charges produces less of a

9   customer incentive to pursue energy efficiency because collecting a larger amount

10   of revenue via fixed charges lowers the amount to be collected from other charges.

11   That produces lower rates for those other charges, reducing the amount of cost

12   savings that a customer can achieve by modifying their energy usage patterns or

13   making investments in more efficient equipment.

14   Q20.   PLEASE EXPLAIN THE CONCEPT OF PRICE ELASTICITY OF DEMAND

15   AND HOW IT RELATES TO ENERGY EFFICIENCY.

16   A.   Price elasticity, for electricity or any other product or service, measures how

17   changes in price influence the purchasing behavior of consumers. The Council's

18   energy savings potential study refers to the definition used by the Electric Power

19   Research Institute ("EPRI"), stating, "price elasticity of demand is a measure of

1   how price changes influence electricity use."[14] I believe that this is a reasonable

2   definition for the term.

3   Price elasticity is typically reflected as a fraction or ratio, most often a

4   negative number (*e.g.*, -0.5). A negative elasticity number indicates that increases

5   in price are associated with declining consumption or use. Conversely, it indicates

6   that decreases in price produce greater consumption or use. Not surprisingly, most

7   products or services, including electricity, exhibit negative price elasticity. A

8   hypothetical elasticity of -0.5 indicates that a 10% increase in price produces a 5%

9   decrease in consumption. Conversely, it indicates that a 10% reduction in electricity

10   prices would produce a 5% increase in consumption.

11   Price elasticity can also be differentiated by the time horizon being

12   considered. Short-run price elasticity tends to be lower than long-run price elasticity

13   because over longer time horizons, consumers become aware of more alternatives

14   and those alternatives become more attractive. For example, replacing an aging

15   appliance is more attractive than replacing a new one with a more efficient model.

16   Therefore, when fixed charges cause a reduction in the volumetric rates that

17   a customer would otherwise pay, they cause an increase in electricity consumption

18   relative to what it would be with a lower fixed charge and higher volumetric rate.

19   This effect increases over time because electricity demand is more elastic in the

20   long run than the short run.

---

[14] Optimal Energy, Inc., *Study of Potential for Energy Savings in New Orleans*, at 59 (Aug. 31, 2018) ("New Orleans Energy Savings Study").

1   Q21.   HOW WOULD ENTERGY'S RATE PROPOSALS SPECIFICALLY AFFECT

2   RESIDENTIAL ELECTRICITY CONSUMPTION?

3   A.   I have calculated that based on short-run (1-5 years) price elasticity the combined

4   fixed charge increases, would undo the equivalent of roughly 2.48 to 3.65 times the

5   Program Year ("PY") 6 efficiency target (*i.e.*, years of efficiency savings),

6   depending on the value used for price elasticity. Using a long-run price elasticity

7   assumption would triple my higher estimate to roughly 11 times the PY 6 target,

8   essentially undoing all of the savings produced by Energy Smart and more. In other

9   words, the proposed customer charge and AMI charge fixed would cause increases

10   in consumption equivalent to years of Energy Smart efficiency savings relative to

11   a scenario where the same amount of total revenue is collected using a volumetric

12   energy charge. From the perspective of supporting customer investments in energy

13   efficiency and achieving greater savings, fixed charge increases are akin to driving

14   with one foot on the gas and one foot on the brake.

15   Q22.   PLEASE EXPLAIN HOW YOU MADE THIS CALCULATION.

16   A.   The Council's New Orleans Energy Savings Study utilized a short-run (1-5 years)

17   price elasticity of -0.13 for the first tier of a hypothetical inclining block rate and a

18   price elasticity of -0.26 for the second tier. EPRI reports a mean short-run value of

19   -0.3 from a survey of relevant literature, with a range of -0.2 to -0.6. Based on the

20   Company's test year billings, translating the proposed nominal fixed charge

21   increase ($7.46/month) to a volumetric rate would increase the energy rate by 0.73

22   cents/kWh and translating the proposed first year AMI charge ($2.95/month) to a

1   volumetric rate produces a further energy rate increase of 0.29 cents/kWh. Thus the

2   total increase in the energy rate to raise the same amount of revenue as the

3   combined fixed charge increase and AMI charge ($10.41/month) is 1.02

4   cents/kWh. This equates to an energy rate increase of 10.85% relative to what the

5   energy rate would be if both portions remain fixed.

6   Applying the elasticity assumptions used in the New Orleans Energy

7   Savings Study, the combined fixed charge increase and AMI charge would result

8   in electricity use 2.21% higher than if both charges were volumetric. Using the

9   EPRI mean value for price elasticity, the increase in use is 3.26%. These increases

10   equate to 49.2 million kWh using the lower price elasticity number and 72.4 million

11   kWh using the higher EPRI figure. The savings target for PY 6 of the Energy Smart

12   program was roughly 19.9 million kWh.[15]

13   For my long-run estimate, as the New Orleans Energy Savings Study notes,

14   EPRI's literature survey showed that long-run demand elasticity values may range

15   from -0.7 to -1.4, with a mean value of -0.9.[16] I used this mean value in my long-

16   run impact estimate.

17   Q23. IS THIS CONSISTENT WITH THE COUNCIL'S GOALS FOR ENERGY

18   EFFICIENCY?

19   A.   No. As I previously observed, the Council has expressly stated that it wishes to

20   "align customer pricing and incentives to encourage investment in energy

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[15] Revised Direct Testimony of D. Andrew Owens at 10, Table 1 (Sept. 2018) ("Owens Direct"). The savings target amounts were summed to combine the New Orleans and Algiers divisions.
[16] New Orleans Energy Savings Study at 59.

1   efficiency."[17] The Company's emphasis on fixed charges in rate design has the

2   opposite effect.

3   Q24.   ARE THE NEGATIVE IMPACTS OF FIXED CHARGES ON ENERGY

4   EFFICIENCY RECOGNIZED ELSEWHERE?

5   A.   Yes. The effect is recognized in the Council's own New Orleans Energy Savings

6   Study under hypothetical fixed charge scenarios. It is also recognized by states that

7   have prioritized energy efficiency. The American Council for an Energy-Efficiency

8   Economy ("ACEEE") 2018 Energy Efficiency Scorecard lists the top five states in

9   energy efficiency policy as: Massachusetts, Rhode Island, California, Vermont, and

10   Connecticut.[18] Among IOUs, the average residential fixed charge in these five

11   states is $6.05/month. Furthermore, of the 14 IOUs operating in these states, only

12   two, Green Mountain Power in Vermont and United Illuminating in Connecticut,

13   have residential customer charges higher than $10/month, with United Illuminating

14   only marginally higher at $10.04/month.

15   These rankings do not consider rate design, so the rankings themselves are

16   not biased towards states with lower residential fixed charges. Rather, the

17   collectively low residential fixed charges are indicative of a desire to avoid diluting

18   the effectiveness of state efficiency goals with counterproductive residential rate

19   design.

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[17] Council Resolution No. R-07-600.
[18] ACEEE, *The 2018 State Efficiency Scorecard* (last accessed January 25, 2019), https://aceee.org/state-policy/scorecard.

1   **D.   The Proper Basis for Setting a Reasonable Residential Customer Charge**

2   Q25.   WHAT COSTS DOES ENO CLASSIFY AS CUSTOMER-RELATED FOR THE

3   PURPOSE OF DETERMINING ITS CALCULATED CUSTOMER UNIT COST?

4   A.   ENO's derivation of customer-related costs includes the embedded costs of meters,

5   service drops, meter reading, billing, customer service, and customer records and

6   collection, as well as allocations of certain distribution expenses and a variety of

7   general and administrative overhead costs. The Company characterizes the costs

8   embodied within its proposed residential customer charge as "costs that are incurred

9   by a utility even if a customer does not impose a demand on the Company's

10   capacity or consume energy. These costs vary with [sic] number of customers

11   served."[19] At a different point, ENO also describes these costs as those that are "not

12   correlated to the number of kilowatt hours of electricity used by the customer."[20]

13   Q26.   DO YOU AGREE WITH THIS DELINEATION OF CUSTOMER-RELATED

14   COSTS AND THE APPROPRIATE BASIS FOR ESTABLISHING CUSTOMER

15   CHARGES?

16   A.   I agree that the customer charge should reflect the cost of a customer that does not

17   impose a demand or consume energy. This cost is represented by the incremental

18   cost of connecting a customer (*i.e.*, the marginal cost), which is generally limited

19   to the costs for a meter and service drop along with expenses for meter reading,

20   billing, and customer service.[21] Another way to view the appropriate role of the

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[19] Thomas Direct at 61:20-22.
[20] Thomas Direct at 62:10-11.
[21] Jim Lazar & Wilson Gonzalez, *Smart Rate Design for a Smart Future*, at 36, REGULATORY ASSISTANCE
PROJECT (July 2015), http://www.raponline.org/document/download/id/7680.

1   customer charge that produces a similar result is to define customer-related costs as

2   those that vary directly with the number of customers.[22] However, it is a mistake to

3   conflate the costs associated with such a zero-load customer with costs that are not

4   directly correlated with customer demand or energy consumption. Many joint

5   system costs vary more indirectly with one or more cost categories and

6   consequently do not fall neatly within the customer, demand, or energy

7   classification.

8   Q27.   HAVE YOU DEVELOPED AN ESTIMATE FOR ESTABLISHING A

9   REASONABLE RESIDENTIAL CUSTOMER CHARGE?

10 A.   I developed two estimates to provide a reasonable range. My calculations show that

11   a reasonable customer charge would fall within a range from $8.13-$9.53/month.

12   This would correspond to an increase in the current residential customer charge of

13         $0.06-$1.46/month (0.7-18.1%).

14 Q28.   PLEASE DESCRIBE HOW YOU DEVELOPED THE VALUES YOU LIST

15   ABOVE FOR AN APPROPRIATE RESIDENTIAL CUSTOMER CHARGE.

16 A.   I used an excerpt from the Company's cost of service study prepared in response to

17   AAE 2-4 depicting the costs associated with Entergy's calculated residential

18   customer-related unit cost as the starting point. For both estimates, I excluded all

19   costs that are not allocated based on the number of customers in the Company's

20   embedded cost of service study, applied to the items that determine the rate base

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[22] *Id.* at 83.

1   and operating expenses. Thus for my high-end estimate, I excluded a variety of

2   general, administrative, and miscellaneous rate base and expense items. Those

3   remaining rate base and operating expense items include FERC accounts associated

4   with meters, service drops, customer service, and the customer information and

5   billing system.

6   I applied multipliers to the revised net plant in service amounts derived from

7   the exclusion process above to reflect the Company's return and the incremental

8   taxes and expenses on that return. I then reduced the sum of expenses, return, and

9   incremental taxes by 14.6% so as to be consistent with the Company's proposed

10   residential class cost allocation, as described by Company witness Thomas.[23] I

11   divided the resultant reduced sum by total annual residential bills to derive the

12   customer charge.

13   For the low-end estimate, I performed the same general set of calculations.

14   However, I also excluded rate base and expenses associated with installations on

15   customer premises in FERC Accounts 371 and 587, operating expenses associated

16   with overhead and underground lines in FERC Accounts 583, 583, 593, and 594,

17   and advertising expenses in FERC Account 909.[24]

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[23] Thomas Direct at 63:18-21.

[24] Customer service drops are traditionally considered an exclusively customer-related cost because, apart from customers in multi-family buildings, each customer requires a service drop. However, a portion of the costs of the service drop could also be considered demand-related because customers with larger loads may require a larger service drop. My estimates retain all costs of service drops as customer-related and includable within the customer charge.

1   Q29.   PLEASE EXPLAIN WHY YOU EXCLUDED GENERAL, ADMINISTRATIVE,

2   AND MISCELLANEOUS COST COMPONENTS IN YOUR DERIVATION OF

3   AN APPROPRIATE CUSTOMER CHARGE.

4   A.   The cost components I retained are those directly associated with customer

5   metering, connection, billing, and customer service. By contrast, the costs I

6   excluded can be described as general overhead costs that cannot be assigned to a

7   specific function. It is reasonable to exclude them from the customer charge

8   because they do not vary directly with the number of customers.

9   Q30.   PLEASE EXPLAIN WHY YOU EXCLUDED FERC ACCOUNTS 371 AND 587

10   FROM YOUR LOW-END CUSTOMER CHARGE ESTIMATE.

11   A.   FERC Account 371 relates to utility-owned plants on customer premises located on

12   the customer's side of the meter. Entergy has indicated that the equipment in this

13   account is composed of lighting fixtures on the premises of residential customers.[25]

14   FERC Account 587 relates to expenses associated with customer installations,

15   including property leased to customers and contained in FERC Account 372.

16   Neither relates to costs that are directly associated with connecting a customer to

17   the grid, thus even if they are allocated to the residential class as a whole, it is

18   improper to include them as a component of the residential customer charge.

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[25] ENO response to AAE 3-1(b).

1   Q31.   PLEASE EXPLAIN WHY YOU EXCLUDED FERC ACCOUNTS 583, 584, 593,

2   AND 594 FROM YOUR LOW-END CUSTOMER CHARGE ESTIMATE.

3   A.   These accounts collectively relate to operation and maintenance costs for overhead

4   and underground distribution lines. Both elements are part of the shared distribution

5   system that serves all customers. Since these costs are not attributable to the

6   incremental cost of connecting an additional customer to the grid, they should not

7   be reflected in the customer charge.

8   Q32.   PLEASE EXPLAIN WHY YOU EXCLUDED FERC ACCOUNT 909 FROM

9   YOUR LOW-END CUSTOMER CHARGE ESTIMATE.

10   A.   Advertising and the provision of information to customers may fall generally within

11   the customer service function. However, such information is not, strictly speaking,

12   related to connecting a customer to the grid, and FERC Account 908 includes

13   expenses directly associated with customer assistance (*e.g.*, processing customer

14   inquiries). Furthermore, advertising costs do not necessarily bear any direct

15   relationship to the number of customers that a utility serves.

16   Q33.   YOU PREVIOUSLY STATED THAT MARGINAL COSTS ARE THE PROPER

17   BASIS FOR DESIGNING ECONOMICALLY EFFICIENT RATES. ARE YOUR

18   ESTIMATES OF THE APPROPRIATE CUSTOMER CHARGE BASED ON

19   MARGINAL COSTS?

20   A.   Strictly speaking, they are not based on marginal costs because the Company did

21   not perform a study of marginal customer costs. However, by confining the

22   boundaries of costs included in the charge to those that vary directly with the

1   number of customers, they do represent a reasonable estimate of the incremental

2   costs to connect a customer to the grid. Therefore, they provide a better estimate

3   than the values indicated by the Company's embedded cost of service study.

4   **E.   Disproportionate Impacts of Fixed Charges on Low-Income Customers**

5   Q34.   PLEASE EXPLAIN HOW THE COMPANY'S PROPOSED FIXED CHARGES

6   WOULD HAVE A DISPROPORTIONATE IMPACT ON LOW-INCOME

7   CUSTOMERS?

8   A.   ENO calculated a customer "indifference" threshold of roughly 1,000 kWh of

9   electric usage per month. [26] The indifference threshold defines the amount of

10   monthly electricity consumption at which a customer experiences the same total

11   annual bill increase under the Company's proposed fixed charge as they would if

12   the amount of the proposed increase in the fixed charge was translated to a

13   volumetric rate that raises an equivalent amount of revenue. A customer with

14   average monthly usage below the indifference threshold prefers a volumetric rate

15   to a fixed rate while customers with average usage above the indifference threshold

16   is made better off by higher fixed charges and lower variable charges.

17   ENO has provided data showing that, on average, lower income customers

18   tend to have average monthly usage below the indifference threshold, thus, in

19   general, they would experience larger adverse impacts in terms of increases to their

20   annual electricity costs as a result of the proposed fixed charge. Conversely, higher

21   income customers tend to be better off. Table 3 below shows a breakdown of

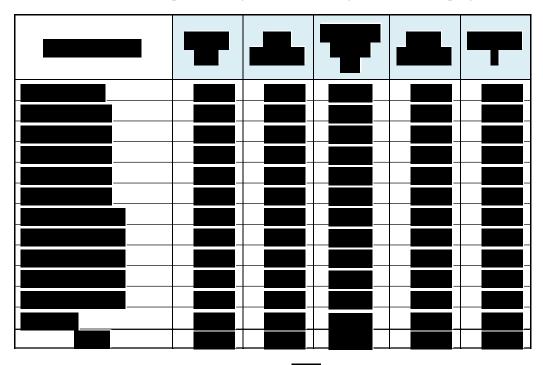[26] Thomas Direct at 64:9-10.

1   customer usage for twelve income categories broken down into four average

2   monthly usage tranches.[27]

3   **Table 3: Average Monthly Electric Use by Income Category**

████████████	██	██	███	██	██
██████████	███	██	███	██	███
██████████	███	██	███	███	███
██████████	███	███	███	███	███
██████████	███	███	███	███	███
██████████	███	███	███	███	███
██████████	███	███	███	███	███
███████████	███	███	███	███	███
███████████	███	███	███	███	███
███████████	███	███	███	███	███
███████████	███	███	███	███	███
███████	███	███	████	███	███
██████	███	███	████	███	███

4   Table 3 shows that roughly [[   ]] of residential customers in total

5   experience [[   ]] when revenue is collected via a fixed charge.

6   Furthermore, [[   ]] of customers with incomes [[   ]] are

7   made worse off, and [[   ]] of customers in the [[

8   ]] are worse off. Thus the burdens of relatively higher

9   fixed charges fall disproportionately on those with lower incomes, while higher

10   income customers generally benefit. Furthermore, customers with the lowest

11   incomes are the most likely to experience negative impacts from fixed charge rate

12   designs. These customers would also experience the largest negative impacts

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[27] Table 3 is derived from ENO response to AAE 2-5, HPSM Attachment C.

1   because larger percentages of the lower income customers fall within the lowest

2   average usage category (less than 500 kWh/month).

3   Q35.   CAN YOU PROVIDE ANY OTHER EVIDENCE THAT LOW-INCOME

4   CUSTOMERS WOULD BE PARTICULARLY HARMED BY FIXED CHARGE

5   INCREASES?

6   A.   Yes. Entergy provided energy use statistics for customers that experienced

7   disconnection of service for non-payment during the 2017 calendar year, and it

8   stands to reason that those customers experiencing most difficulty paying their bills

9   are those with lower incomes. Roughly 47% of customers that were disconnected

10   had average usage of less than 1,000 kWh/month during the 12 months prior to

11   disconnection.[28] In other words, 47% of residential customers that had difficulty

12   paying their electric bill in 2017 would have been even worse off by higher fixed

13   charges. Furthermore, this data shows that disconnection risk is not correlated with

14   above average or irresponsible electric usage resulting in a high bill. Customers

15   with lower than average monthly usage are nearly equally likely to experience

16   difficulty paying their bills as higher usage customers.

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[28] Derived from ENO response to AAE 2-6, Attachment.

1   Q36.   IF 47% OF DISCONNECTED CUSTOMERS WOULD HAVE BEEN EVEN

2   WORSE OFF AT HIGHER FIXED CHARGE RATES, DOES THAT NOT ALSO

3   MEAN THAT 53% WOULD HAVE BEEN BETTER OFF?

4   A.   It is true that a greater percentage of 2017 disconnected customers would have in

5   theory been better off with a higher fixed charge and lower volumetric charges.

6   However, high fixed charges coupled with lower usage charges are a poor solution

7   for addressing the needs of those high usage customers. For one, higher fixed

8   charges would be punitive on a group of customers that is nearly as large as the

9   group they help. Second, inordinately high usage can be addressed through targeted

10   energy efficiency, or potentially other measures such as enforcement of building

11   codes. Those strategies can produce outcomes that leave all customers better off,

12   rather than just helping some at the expense of nearly as many others.

13 Q37.   YOU PREVIOUSLY MENTIONED THE SURVEY ENO CONDUCTED ON

14   CUSTOMER INTEREST IN PAYING A PRICE PREMIUM IN EXCHANGE

15   FOR BILL STABILITY. DID THIS SURVEY SHOW ANY DIFFERENCES IN

16   INTEREST BETWEEN RELATIVELY LOWER AND HIGHER INCOME

17   CUSTOMERS?

18 A.   As noted by Company witness Raiford, overall 30% of customers stated that they

19   were likely or very likely to be interested in such an arrangement. [29] The

20   percentages for lower-income customers are similar, at 32% for customers with

21   incomes of $50,000 or less, and 30% for customers with incomes of $35,000 or

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[29] Smith Direct at 26:8-11.

1   less. Thus if one looks at a higher fixed charge as a "premium" for low usage

2   customers (since it causes higher bills), the survey does not suggest that a majority

3   of customers, low-income or otherwise, are interested in paying such a premium in

4   exchange for greater bill stability. To the contrary, a large majority representing

5   70% of customers, including lower-income customers, are not interested.

6   **III.   AMI COST RECOVERY MECHANISM**

7   Q38.   PLEASE SUMMARIZE THE COMPANY'S PROPOSED COST RECOVERY

8   MECHANISM FOR AMI DEPLOYMENT.

9   A.   The Company proposes to establish a new Electric AMI Charge under which AMI

10   costs would be recovered under an annually adjusted fixed monthly charge. The

11   same design is proposed for the Gas AMI Charge, but I only address the Electric

12   AMI Charge. The proposed annual charges are depicted in Table 4 below:[30]

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[30] Thomas Direct, ENO Exhibit JBT-9.

1   **Table 4: Proposed AMI Charges**

	Electric	Gas
2019	2.95	0.60
2020	3.67	0.96
2021	3.28	0.87
2022	3.01	0.77
2023	2.79	0.65
2024	2.57	0.53
2025	2.35	0.41
2026	2.13	0.29
2027	1.91	0.17
2028	1.69	0.05
2029	1.47	0
2030	1.25	0
2031	1.03	0
2032	0.81	0
2033	0.60	0
2034	0.40	0
2035	0	0

2

3   Q39.   IS THE PROPOSED ELECTRIC AMI CHARGE ADDITIVE TO THE

4   COMPANY'S PROPOSED RESIDENTIAL FIXED CHARGE?

5   A.   Yes. For instance, the proposed 2019 Electric AMI Charge of $2.95/month would

6   apply on top of the Company's proposed customer charge of $15.53/month,

7   bringing the total nominal fixed charge for these components to $18.48/month.

8   Q40.   WHAT JUSTIFICATION DOES THE COMPANY PROVIDE FOR THE

9   PROPOSED FIXED CHARGE DESIGN OF THE AMI CHARGE?

10   A.   Company witness Thomas states, "The number of customers ENO serves, in large

11   part, drives the level of costs associated with AMI. Therefore . . . these costs should

12   be recovered through a customer charge so that a customer bears only the cost that

13   customer causes."[31]

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[31] Thomas Direct at 66:6-8.

1   Q41.   DO YOU AGREE THAT THIS IS A REASONABLE BASIS FOR USING A

2   FIXED MONTHLY CHARGE FOR AMI COST RECOVERY? PLEASE

3   EXPLAIN WHY OR WHY NOT.

4   A.   I do not agree. While it is true that metering and associated metering costs are

5   typically recovered through fixed monthly charges, AMI is not "typical" metering.

6   As I previously stated, fixed customer charges should recover the cost of connecting

7   a customer to the grid. Advanced metering and the associated incremental costs

8   above traditional meters are not strictly necessary for the customer to be connected

9   to the grid. A non-advanced meter and associated infrastructure can do so at lower

10   costs. AMI is used for much more than measurement of a customer's consumption

11   for billing purposes. Furthermore, since customers do not have a meaningful choice

12   of whether to take service through an advanced meter from a cost perspective, those

13   customers are not truly "causing" the incremental advanced metering costs.

14   Treating AMI costs exclusively as customer-related just because they relate to

15   "metering," and consequently recovering them through a customer charge is an

16   oversimplification of the cost causation factors at play.

17   The incremental costs of AMI above traditional metering are more

18   accurately viewed as primarily energy and/or demand related because AMI

19   deployment is generally undertaken with a goal of producing system cost savings

20   associated at least in part with energy or demand related functions, or system

21   operation and reliability. While it is true that some cost savings categories, such as

22   meter reading expenses, fall within the customer domain, meters capable of

23   automated reading (*e.g.*, "drive-by" reading) can provide this type of cost savings

1   at a lower incremental cost to customers. Other quasi-customer related operational

2   savings, such as service connections and reconnections entail specific fees charged

3   to the customer responsible for the service, meaning that they are directly

4   assignable costs to an individual customer rather than customer costs assignable to

5   a customer class as a whole.

6   Q42. PLEASE EXPLAIN YOUR CONTENTION THAT CUSTOMERS "DO NOT

7   HAVE A MEANINGFUL CHOICE OF WHETHER TO TAKE SERVICE

8   THROUGH AN ADVANCED METER."

9   A.   While Entergy's Proposed Rider Schedule AMO provides a mechanism for

10   customers to opt-out of taking service through an AMI meter, opt-out customers

11   must pay a one-time fee of either $131.94 (pre-AMI install) or $146.96 (post-AMI

12   install), plus a monthly fee of $12.42/month.[32] For a customer seeking to opt-out in

13   order to avoid AMI charges for AMI capabilities that they do not intend to take

14   advantage of, Rider AMO is not a meaningful alternative since such a customer

15   would incur higher charges by virtue of opting out.[33]

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[32] Entergy New Orleans, Rider AMO (Advanced Metering Opt-Out), http://www.entergy-neworleans.com/content/price/tariffs/eno/enol_amo.pdf.
[33] Rider AMO is reflected as effective October 30, 2018 on the Company's website, but it is my understanding that the Council has not yet issued its final approval.

1   Q43.   IS THE COMPANY'S EVALUATION OF AMI COSTS AND BENEFITS IN

2   ALIGNMENT WITH THE SUPPOSITION THAT THE INCREMENTAL

3   COSTS OF AMI ARE PRIMARILY RELATED TO PRODUCING ENERGY

4   AND DEMAND COST SAVINGS?

5   A.   Yes. The cost-benefit analysis that ENO used to support its rate application to invest

6   in AMI shows consumption reduction as the largest benefit of AMI, without which

7   AMI deployment would not produce a net customer benefit on either a nominal or

8   a net present value ("NPV") basis. Added to this are peak capacity reduction

9   benefits and reductions in unaccounted for energy. In total, these three categories

10   produce 63.4% of the NPV benefit and 64.8% of the nominal benefit in the

11   Company's analysis.[34] It is therefore reasonable to consider the incremental cost of

12   AMI deployment as primarily energy and demand related.

13   Q44.   ARE THERE OTHER POLICY GOALS THAT ARGUE AGAINST USING A

14   FIXED CHARGE STRUCTURE SFOR RECOVERY OF AMI COSTS?

15   A.   Yes. A fixed monthly charge works at cross-purposes with the single largest source

16   of purported customer benefits: savings due to reduced energy consumption. It

17   takes what would otherwise be a variable cost of consumption that contains a

18   conservation incentive and translates it to a fixed cost that cannot be avoided,

19   thereby diluting customer incentives to conserve energy from what would

20   otherwise be the case.

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[34] CNO Docket No. UD-16-04, Application of Entergy New Orleans Inc. for Approval to Deploy Advanced
Metering Infrastructure, Request for Cost Recovery and Related Relief at 10, Table 1 (Oct. 2016).

1   Furthermore, it is fundamentally unfair to customers to have to effectively

2   pay two fixed metering charges, one for the un-depreciated cost of legacy meters

3   and one for AMI infrastructure at the same time. Relative to another AMI charge

4   design (*e.g.*, volumetric or percentage-based), this causes lower usage customers,

5   including a larger percentage of lower income customers, to shoulder the greater

6   share of the cost burden while passing the larger share of major benefit streams

7   (*i.e.*, energy and capacity cost savings) to higher usage customers.

8   Q45.   WHAT ARE YOUR RECOMMENDATIONS TO THE COUNCIL ON THE

9   DESIGN OF THE AMI CHARGE?

10 A.   I recommend that the Council adopt a volumetric rate design in order to support

11   energy efficiency, protect the greater portion of lower income customers from

12   disproportionate impacts, and distribute the costs and benefits of AMI more

13   equitably. This is also the simplest way to align fixed monthly charges with the

14   costs necessary to connect a zero-load customer to the system, since customers

15   would continue to pay for the cost of the minimum meter necessary to do so through

16   their payment for the un-depreciated costs of legacy meters.

17   With respect to cost and benefit sharing, the Council should be cognizant

18   that while a volumetric AMI charge would cause lower usage customers to pay less

19   towards AMI deployment, when those same customers act to reduce their energy

20   consumption or peak period demands, higher usage customers still receive a greater

21   portion of the benefits of the associated cost savings. Therefore, while higher usage

22   customers pay more under a volumetric design, they also receive more in return.

1   **IV.   RIDER DGM RATE DESIGN**

2   Q46.   PLEASE DESCRIBE THE PURPOSE OF PROPOSED RIDER DGM.

3   A.   Rider DGM is proposed by the Company as a new rate rider for the recovery of

4   capital investments for grid modernization projects. Entergy proposes that the rates

5   reflected in Rider DGM be updated on a quarterly basis as new costs are incurred.

6   The Company has initially proposed five such grid modernization projects in its

7   rate application for inclusion in Rider DGM. The costs for these projects are

8   estimated at $59.3 million. [35] The five projects are composed of three main

9   equipment investments: self-healing network areas, smart devices, and new

10   conductors.[36] Entergy is also requesting the establishment of a streamlined process

11   for Council review and approval of additional future grid modernization projects

12   that would be incorporated into the charges under Rider DGM.[37]

13   Q47.   WHAT RATE STRUCTURE DOES THE COMPANY PROPOSE TO USE FOR

14   RIDER DGM?

15   A.   Rider DGM would operate under a percentage of bill-based structure, like the

16   Company's current formula rate adjustment, increasing the charge for every

17   individual base rate component (*i.e.*, the fixed customer charge, demand charge,

18   and base energy charges) by an incremental amount.

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[35] Revised Direct Testimony of Erica H. Zimmerer at 29, Figure 4 (Sept. 21, 2018).
[36] *Id.* at 25-29.
[37] *Id.* at 34-36.

1   Q48.   DOES ENTERGY PROVIDE ANY JUSTIFICATION FOR THIS CHOICE OF

2   RATE STRUCTURE?

3   A.   No.

4   Q49.   DO YOU AGREE THAT THE PERCENTAGE OF BILL-BASED DESIGN IS

5   AN APPROPRIATE RATE STRUCTURE FOR RIDER DGM?

6   A.   No, for two reasons. First, it effectively increases the fixed customer charge, and

7   therefore reduces consumer incentives for energy conservation. Second, the

8   Company's grid modernization investments are investments in the shared

9   distribution system. They do not encompass any customer-related functions or

10   involve costs that otherwise vary directly with the number of customers on the

11   system or connecting a customer to the system. Thus the charge is unreasonable

12   both from a perspective of public policy in support of energy efficiency, and from

13   the perspective of cost causation.

14   Q50.   IF THE COUNCIL WERE TO APPROVE PROPOSED RIDER DGM, HOW

15   SHOULD THE STRUCTURE BE REVISED?

16   A.   The charge in Rider DGM should be aligned with how the Company charges for

17   distribution service more generally in its base rates. For residential customers, this

18   would result in an exclusively volumetric charge. For non-residential customers it

19   may be appropriate for the charge to have a demand component, but only to the

20   extent that an individual investment is caused by additional demand on the system.

21   The current set of five projects target reliability improvements rather than demand

1   growth, thus the charge associated with these investments should also be volumetric

2   for non-residential customers.

3   Q51.   IS SUCH A VOLUMETRIC DESIGN TYPICAL FOR SIMILAR GRID

4   MODERNIZATION RIDERS IN OTHER JURISDICTIONS?

5   A.   Yes. As Company witness Faruqui notes, most grid modernization or distribution

6   infrastructure improvement riders take the form of a volumetric charge.[38]

7   **V.   DSM PROGRAM STRUCTURE AND RIDER**

8   **A.   Summary of ENO's DSM Proposal**

9   Q52.   PLEASE BRIEFLY SUMMARIZE ENTERGY'S DSM PROPOSAL.

10 A.   Entergy's proposal has several elements, as follows:

11   • A mechanism that allows Entergy to earn a return on energy efficiency program

12   expenses at its pre-tax weighted average cost of capital ("WACC").

13   • A lost fixed cost recovery mechanism that compensates Entergy for foregone

14   sales as a result of energy efficiency program investments, referred to as the

15   Lost Contribution to Fixed Costs ("LCFC") component.

16   • A performance incentive that provides for increases or decreases to the

17   Company's return on program expenditures depending on the amount of energy

18   savings achieved relative to annual targets.

19   The Company proposes that the collective costs associated with all of these

20   elements be recovered via a new rate rider, Rider DSMCR. Rider DSMCR rates

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[38] Revised Direct Testimony of Dr. Ahmad Faruqui at 55:4-7 (Sept. 21, 2018) ("Faruqui Direct").

1   would be set on a percentage of bill basis, such that all base charges are effectively

2   increased by a defined percentage.

3   Q53.   WHAT   JUSTIFICATION   DOES   ENTERGY   PROVIDE   FOR   THE

4   COLLECTIVE COMPONENTS OF ITS DSM PROPOSAL?

5   A.   The rationale behind the Company's proposals is discussed in the most detail by

6   Company witness Faruqui. To paraphrase, Dr. Faruqui states that allowing DSM

7   expenses to be effectively rate-based will place energy efficiency at a level

8   equivalent to generation investments from the utility's perspective; a lost revenue

9   adjustment mechanism ("LRAM") is necessary to render the Company indifferent

10   to revenue losses caused by energy efficiency investments; and a performance

11   incentive is an appropriate mechanism for elevating energy efficiency to something

12   of a "preferred resource" status. In other words, the Company proposes removing

13   disincentives to support greater energy efficiency that are ingrained within the

14   utility business model to make the utility indifferent, supplemented with additional

15   revenue opportunities that transform indifference into active support. The Company

16   does not provide any justification for the use of a percentage of bill-based structure

17   in Rider DSMCR, though I understand that this structure is used in the Company's

18   approved energy efficiency charge and other riders.

19   Q54.   WHAT ARE YOUR OBSERVATIONS ABOUT THE OVERALL DESIGN AND

20   POLICY RATIONALE FOR ENTERGY'S DSM PROPOSAL?

21   A.   I agree that creating utility revenue indifference and incentives for good

22   performance are sound policy principles on which to base a DSM program

1   structure. However, I disagree with Dr. Faruqui's assertion that allowing energy

2   efficiency program expenses to be rate-based is necessary to place energy

3   efficiency on par with other resources. The Company already has both an obligation

4   to pursue least cost resources and an obligation to abide by the requirements placed

5   on it by the Council, including but not limited to goals that the Council sets for

6   energy efficiency.

7   I also disagree that the proposals made by the Company and how they fit

8   together are the best way to implement the principles I do agree with. Specifically,

9   full decoupling is a superior mechanism to a lost revenue adjustment for rendering

10   a utility indifferent to declines in sales caused by energy efficiency, and the

11   performance incentive mechanism combined with a rate of return reward on all

12   program costs fails to create an environment where only good performance is

13   rewarded with additional earnings opportunities.

14 Q55. IS ALLOWING A UTILITY TO EARN A RATE OF RETURN ON DSM

15   EXPENSES A COMMON FEATURE OF ENERGY EFFICIENCY SUPPORT

16   POLICIES IN OTHER JURISDICTIONS?

17 A.   It is relatively uncommon. Dr. Faruqui describes a small number of examples in the

18   states of Illinois, Maryland, New York, and Utah as indicative of "the beginning of

19   a new trend" towards this type of mechanism. [39] At best I think this type of

20   conclusion is preliminary and quite a stretch. Three examples in the last two years

21   do not make a trend. Furthermore, the Utah bill was essentially written by Rocky

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[39] Faruqui Direct at 29:17-19.

1   Mountain Power for its own benefit and received significant criticism from many

2   parties, including consumer advocates, as an "end run" around the regulatory

3   process.[40] Likewise, the Illinois was often referred to as "the ComEd bill", which

4   among other things provided a bailout for ComEd's nuclear power plants, and as

5   initially written, would have effectively eliminated net metering.[41] It is more

6   accurate I think to consider it a trend in something that utilities want, but that has

7   yet to reach a strong position as a best practice.

8   What should not be lost in this discussion is that a utility's rate of return is

9   simply a number. When applied to program expenditures, it produces an incentive

10   amount, but nothing dictates that such a percentage-based multiplier be tied to the

11   allowable return on capital investments. In fact, using the rate of return in this

12   fashion distorts the playing field in the utility's favor rather than leveling it because

13   energy efficiency expenditures produce both foregone energy expenses in addition

14   to foregone capital investments. When a return is earned on all program

15   expenditures, the foregone energy costs that would not have otherwise earned a

16   return because they are pass-through costs are capitalized and produce a profit for

17   the utility. AAE witness Pamela Morgan describes further differences in the cost

18   structure and risk profile of DSM investments relative to supply-side resources that

19   should be considered in efforts to "level the playing field."

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[40] Brian Maffly, *Critics say Rocky Mountain Power Plan would stick it to Utah ratepayers in the name of clean air*, Salt Lake Tribune (Feb. 9, 2016), http://archive.sltrib.com/article.php?id=3495566&itype=CMSID.
[41] Julie Vahling. *Why the new Exelon/ComEd bill is bad for Illinois consumers*, Illinois Times (May 26, 2016), https://illinoistimes.com/article-17265-why-the-new-exelon_comed-bill-is-bad-for-illinois-consumers html.

1   Q56.   PLEASE   PROVIDE   AN   EXAMPLE   THAT   ILLUSTRATES   THE

2   "DISTORTION" YOU REFER TO ABOVE.

3   A.   Consider a hypothetical example where an energy efficiency measure has a cost-

4   effectiveness ratio of 1.0, meaning that it is cost effective but only just so. The

5   benefits side of this equation is composed of cost savings of 75% avoided energy

6   costs and 25% avoided capacity costs over the measure lifetime. Based on this

7   breakdown one could say that 75% of the cost is energy related and 25% is capacity

8   related, or a ratio of $0.75 and $0.25 for every $1.00. Thus the foregone investment

9   on which the utility would otherwise earn a return is $0.25. At a hypothetical 10%

10   rate of return, the utility lost earnings of $0.025. However, if all expenditures are

11   capitalized at the 10% rate of return, the utility earns $0.10. Thus the utility is being

12   overcompensated for its foregone investment and the playing field is tilted.

13   Ratepayers become responsible for an incremental cost on program expenses that

14   they would not have otherwise paid without the energy efficiency investment.

15   **B.   LCFC Component of Rider DSMCR**

16 Q57.   PLEASE DESCRIBE THE COMPANY'S LCFC ADJUSTMENT MECHANISM.

17 A.   Under this mechanism, Entergy would project energy efficiency savings on an

18   annual basis and calculate how that savings translates to a reduction in cost recovery

19   for fixed components of its infrastructure, excluding fuel and other riders. The

20   result is the LCFC component of the DSM charge. The LCFC is to be trued-up with

21   actual savings each year. The LCFC is also excluded from the Company's separate

22   decoupling proposal contained within the proposed Formula Rate Plan.

1 Q58. WHAT ARE THE DISADVANTAGES TO LRAMS SUCH AS THE LCFC

2   PROPOSED BY ENTERGY?

3 A.   To be clear, a LRAM, sometimes referred to as a lost margin recovery mechanism,

4   can be thought of as a limited form of decoupling since the scope of sales variation

5   is *limited* to a specific cause. While such a mechanism does render a utility

6   indifferent to forgone sales due to energy efficiency, it can also create a perverse

7   incentive for a utility to discourage customer efficiency outside of a program since

8   sales attrition outside of the program receives no compensation. In other words, it

9   does not entirely eliminate the throughput incentive. In addition, the mechanism

10   must by necessity rely on estimates of savings, requiring that considerable attention

11   be devoted to methodology and data to ensure accurate counting.

12   Finally, there an implicit assumption in the mechanism that all projected

13   savings actually translate to an equivalent under-recovery of fixed costs for the

14   utility, which is never actually true at a precise level, and not necessarily true even

15   on a higher, more generalized level. That is, lost revenues are not themselves

16   equivalent to under-recovery of fixed costs because other factors, such as weather,

17   customer growth, economic growth, or off-system sales may provide a balancing

18   effect. For example, if one assumed that energy efficiency resulted in a 0.5%

19   reduction in sales during a given year, but hot weather contributed to a 0.5%

20   increase in sales relative to expectations, there is not an actual under-recovery of

21   fixed costs. In this scenario, LCFC would therefore charge customers twice for the

22   same fixed costs.

1   Q59. PLEASE PROVIDE AN EXAMPLE OF THE "PERVERSE INCENTIVE" YOU

2   REFER TO WITH RESPECT TO DISCOURAGING INCREASED ENERGY

3   EFFICIENCY OUTSIDE OF AN INCENTIVE PROGRAM.

4   A.   Entergy's proposal to dramatically increase the residential fixed charge is a perfect

5   example of this type of behavior. This dampens rates-related incentives for

6   customers to be more efficient in their energy use generally, but such savings have

7   a value equivalent to those achieved within an energy efficiency program.

8   Consequently, a utility like Entergy is not supportive of rate designs that produce

9   those savings because they are not counted as lost fixed costs that it is entitled to

10   recover.

11 Q60. YOU PREVIOUSLY STATED THAT A FULL DECOUPLING MECHANISM

12   WOULD BE SUPERIOR TO THE COMPANY'S LCFC. PLEASE ELABORATE

13   ON WHY THIS IS TRUE.

14 A.   Full decoupling completely removes the throughput incentive. In doing so, it avoids

15   creating an incentive to discourage non-programmatic energy savings. It also ties

16   cost recovery directly to the actual under-recovery of fixed costs, avoiding the

17   inherent danger that a mechanism such as the LCFC will go beyond making a utility

18   "whole" and instead become a profit center.

19 Q61. DOES ENTERGY'S SEPARATE DECOUPLING PROPOSAL WITHIN THE

20   PROPOSED FORMULA RATE PLAN ACCOMPLISH THESE SAME GOALS?

21 A.   No. By creating a separation and exclusion between two limited forms of

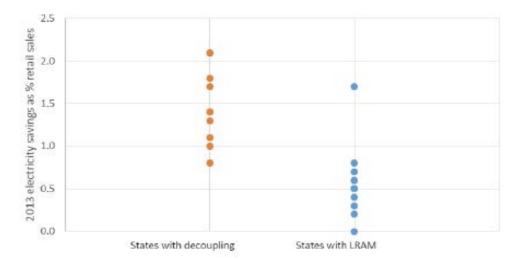22   decoupling, it not only makes the ratemaking system more complicated than it

1   needs to be, it also retains all of the disadvantages of the LCFC that I have

2   described. AAE witness Pamela Morgan elaborates on the national prevalence of

3   LRAMs such as the proposed LCFC, shortcomings in the LCFC model, and how a

4   revised decoupling mechanism would remove the need for the proposed LCFC.

5   Q62.   WOULD FULL DECOUPLING PROVIDE A BETTER FOUNDATION FOR

6   ACHIEVING THE CITY'S ENERGY EFFICIENCY GOALS THAN THE

7   COMPANY'S PROPOSED LCFC?

8   A.   Yes. There is strong evidence that decoupling is generally associated with better

9   energy efficiency outcomes than LRAMs like the LCFC. Figures 1 and 2,

10   developed by ACEEE, illustrate this general theme, first by comparing 2013 energy

11   savings data in states with decoupling to those with a LRAM (Figure 1) and then

12   separately depicting the same comparison except for limiting the scope to include

13   only states with an energy efficiency resource standard ("EERS") (Figure 2).[42]

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[42] Annie Gilleo *et al.*, *Valuing Efficiency: A Review of Lost Revenue Adjustment Mechanisms*, ACEEE, at
16, Figure 12 & 17, Figure 14 (June 2015),
https://aceee.org/sites/default/files/publications/researchreports/u1503.pdf.

1   **Figure 1: Comparison of Energy Savings With Decoupling vs. LRAM**
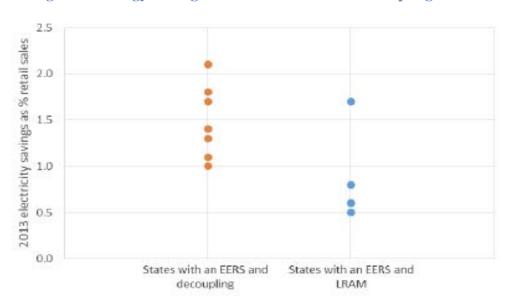

2

3   **Figure 2: Energy Savings in EERS States With Decoupling vs. LRAM**

4

5   It is clear in both of these figures that decoupling is associated with better

6   energy efficiency outcomes than LRAMs. For the reasons I have described, ACEEE

7   only considers LRAMs appropriate as a temporary solution for addressing concerns

8   about revenue losses due to efficiency gains. Consequently, ACEEE has observed:

9   LRAM as a permanent policy fix is fraught with flaws. The regulatory
10   burden is great, and the potential to shortchange customers and

1   overcompensate utilities is ever present. As states gain more experience
2   with LRAMs, problems continue to arise. Several states are striving for a
3   simpler and fairer way to implement an LRAM that all parties will sign on
4   to. In practice, an ideal LRAM possessing all of those qualities has yet to
5   present itself. Finally, as noted above, having an LRAM policy in place
6   does not currently appear to be associated with states' achieving higher
7   levels of energy efficiency program spending or energy savings.[43]

8 Q63. ARE YOU PROVIDING ANY RECOMMENDATIONS TO THE COUNCIL

9   REGARDING THE DETAILS OF DECOUPLING DESIGN ITSELF?

10 A.   No. Decoupling design details are discussed in the Direct Testimony of AAE

11   witness Pamela Morgan.

12   **C.   Performance Incentive Structure**

13 Q64. PLEASE DESCRIBE ENTERGY'S PROPOSED ENERGY EFFICIENCY

14   PERFORMANCE INCENTIVE FRAMEWORK.

15 A.   Entergy proposes a performance structure whereby the rate of return it would earn

16   on rate-based efficiency program expenditures is tied to achieving specified

17   percentages of annual energy savings targets, as follows:

18   •   Savings less than 60% of target: 100 basis point reduction

19   •   Savings from 60 – 95% of target: no change in return

20   •   Savings from 95 – 120% of target: 100 basis point increase

21   •   Savings in excess of 120% of target: 200 basis point increase[44]

22   This type of structure is sometimes referred to as "step-based" because

23   when placed in graphic form it resembles a series of steps.

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[43] *Id.* at 21.
[44] Owens Direct at 26, Figure 3.

1   Q65.   DO YOU AGREE THAT THE PERFORMANCE INCENTIVE MECHANISMS

2   CAN BE A REASONABLE WAY OF ALIGNING UTILITY INCENTIVES TO

3   PURSUE ENERGY EFFICIENCY?

4   A.   Yes, generally speaking. Some research on the cause and effect relationship

5   between the provision of performance incentives and achieved energy savings has

6   been inconclusive due to the fact that multiple policy factors can be associated with

7   producing lower or higher levels of savings. For instance, in a 2015 report, ACEEE

8   found that states with performance incentive policies spent significantly more on

9   energy efficiency as percentage of utility revenue than states without performance

10   incentives (2.0% vs. 1.4%) and produced higher savings as a percentage of retail

11   sales (0.9% vs. 0.5%).[45] However, the same report also found that if states were

12   grouped by whether they had an EERS or not, little difference could be seen within

13   the EERS and no EERS subgroups between states with and without performance

14   incentives. That said, the report concludes that in aggregate some correlation exists

15   between spending and results as well as the existence of performance incentives,

16   speculating that performance incentives may be important for securing support

17   from utility management even though the absolute effect is difficult to quantify.[46]

18   Therefore, I agree that performance incentives should be considered as a

19   method for encouraging support for energy efficiency, but I think the Council

20   should be cautious in how it approaches the matter. The point is to reward truly

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[45] Seth Nowak *et al.*, *Beyond Carrots for Utilities: A National Review of Performance Incentives for Energy Efficiency*, ACEEE, at 24 (May 2015), https://aceee.org/sites/default/files/publications/researchreports/u1504.pdf.
[46] *Id.* at 25.

1   good performance with an incentive, such that the incremental cost is a reasonable

2   tradeoff for the contribution it makes to the success of the program. It should not

3   be a mechanism that provides rewards for all potential program outcomes because

4   at that point the incentive is simply a cost that serves no beneficial purpose. As

5   shown by the statistics I have presented above on the relative effectiveness of an

6   EERS compared to performance incentives, the stick is sometimes more effective

7   than the carrot.

8   Q66. WHAT WEAKNESSES DO YOU SEE IN ENTERGY'S PROPOSED

9   PERFORMANCE INCENTIVE DESIGN?

10 A.   First, Entergy's proposal to earn a return on all program expenditures provides

11   incentives that are too rich, effectively providing a shareholder return regardless of

12   the amount of savings achieved relative to the target. Second, the step-based design

13   creates only a loose tie between performance and incentive rewards.

14 Q67. PLEASE ELABORATE ON HOW THE PERFORMANCE INCENTIVE

15   STRUCTURE IS "TOO RICH."

16 A.   If a performance incentive is to truly reward good performance, there should be a

17   reasonable minimum threshold at which no incentive is allowed. Entergy's

18   proposed design does not allow for that since it permits a return for shareholders

19   even if expenditures produce little savings. While the allowed return on

20   expenditures is reduced for missing a 60% target threshold, the reduction is modest

21   and retains most of the benefit that would otherwise accrue to shareholders.

1   Q68.   PLEASE DESCRIBE THE SHORTCOMINGS OF THE COMPANY'S

2   PROPOSED STEP-BASED PERFORMANCE INCENTIVE DESIGN.

3   A.   The chief problem with this type of design is that it can create large differences in

4   incentive amounts that are tied to small differences in performance, particularly

5   when the granularity of the individual steps is low. This can contribute to goal-

6   seeking behavior based on relatively arbitrary step divisions, and can lead to

7   contentious disagreements when achieved results approach the step divisions. For

8   instance, under Entergy's proposal, achieving 94.9% of the savings target produces

9   no incremental performance incentive, while reaching 95% would result in an

10   increased return of 100 basis points. Entergy would also have no incentive to target

11   additional savings within the 95% to 119.9% range because the incentive reward

12   remains the same apart from the ingrained spending incentive created by the rate of

13   return structure. However, that spending is to a large degree disconnected from an

14   equivalent incentive to produce results.

15 Q69.   WHAT ALTERNATIVE STRUCTURE DO YOU RECOMMEND FOR AN

16   ENERGY EFFICIENCY PERFORMANCE INCENTIVE?

17 A.   The incentive should contain several elements, as follows:

18   •   A meaningful minimum savings threshold below which no additional earnings

19   are received, such as meeting 80% of an annual target, supplemented with the

20   potential for penalties for unreasonably poor performance (*i.e.*, a symmetrical

21   incentive system).

1   • A more graduated incentive, with more granular steps (*e.g.*, 5% increments) or

2   a formula where each incremental kWh of energy savings produces an

3   incremental incentive.

4   • A cap on total incentive awards, which could be set as a percentage of total

5   program costs, a fixed dollar amount, net ratepayer benefits, or another metric.

6   These characteristics could be established under a rate of return model or a

7   different design where incentive awards do not bear any relationship to the

8   Company's allowed rate of return. In other words, nothing necessitates using the

9   Company's rate of return as a benchmark. For instance, the structure could allow

10   an incentive of 1% of program expenditures at 80% of the target, 2% at 85%, and

11   so forth. That represents a more granular step-wise approach similar to that

12   currently reflected in the Company's Formula Rate Plan Rider, which utilizes 5%

13   increments for determining return on equity reward percentages.

14   A formulaic model without steps would utilize an equation to draw a curve

15   or a line where the percentage of the savings goal sits on one axis and the incentive

16   award percentage sits on the other axis. For example, if the line is linear with no

17   incentive at a minimum savings threshold of 80% and an 8% return on expenses at

18   savings of 120% of the target as a maximum, the incentive at 100% of the target is

19   4% of expenses. In the form of a linear equation with the incentive on the Y-axis

20   and performance on the X-axis, this would be reflected as follows:

21   Formula: $Y = (X/5) - 16$

22   Example (92% of target): $Y = (92/5) - 16 = 18.4 - 16 = 2.4\%$

1   Such a formula can be easily applied at whatever degree of precision the

2   Council wishes.

3   Q70.   ARE YOU MAKING ANY RECOMMENDATIONS FOR SPECIFIC ENERGY

4   EFFICIENCY TARGETS THAT WOULD UNDERPIN THIS PERFORMANCE

5   INCENTIVE DESIGN?

6   A.   No. However, I will observe that incremental performance incentives represent a

7   cost that serves little useful purpose if the targets themselves are unambitious.

8   Company witness Owens presented the Company's historic performance at

9   meeting annual energy efficiency targets in his testimony, showing that over the

10   last seven program years, the Company has achieved 113% of the aggregate targets

11   for the ENO Legacy division and 94% for the Algiers division.[47] The establishment

12   of more ambitious targets that are difficult to consistently achieve would provide a

13   justification for the associated incremental costs.

14   For that reason, while I have provided numeric examples to illustrate how

15   the model would function, in practice the scale (*e.g.*, minimum and maximum

16   incentives) should be responsive to the level of ambition embodied in the targets.

17   Past program results, as well as the issue I have raised with respect to the

18   Company's proposal overshooting true financial indifference, suggest that an

19   incentive equivalent to the Company's weighted cost of capital should only be

20   awarded for target achievement well in excess of 100%.

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[47] Owens Direct at 10, Table 1.

1 Q71. PLEASE ELABORATE ON YOUR SUGGESTION THAT A PERFORMANCE

2   INCENTIVE INCLUDE PENALTIES FOR POOR PERFORMANCE.

3 A.   As I previously observed, sometimes sticks are more effective than carrots. A

4   symmetrical incentive combines both of these aspects, as the Company has

5   proposed. An incentive design that includes adverse consequences for unreasonably

6   poor performance sets a floor of minimum expectations without compromising

7   reward upside for good performance. Such a floor is not dissimilar to how many

8   state renewable energy targets are structured, where a failure to achieve goals is

9   met with compliance payments or civil penalties that cannot be recovered from

10   ratepayers. The Council would of course retain discretion to waive or mitigate

11   penalties for extraordinary circumstances or otherwise reasonable justification.

12   With respect to a penalty model, I suggest that the Council consider a

13   variable penalty based on foregone cost savings for each kWh between the amount

14   of savings achieved and the minimum threshold. A variable penalty set at average

15   marginal energy and capacity costs would align with the goal of using energy

16   efficiency to produce system cost savings. The Council would also retain the

17   discretion to impose additional fines as it sees fit for instances where compliance

18   shortfalls can be attributed to specific acts of negligence, such as willful failure to

19   abide by Council directives.

1   Q72. COULD SUCH A DESIGN BE EXTENDED TO PROGRAMS TARGETING

2   REDUCTIONS IN PEAK DEMAND RATHER THAN JUST ENERGY

3   SAVINGS?

4   A.   Yes. Based on my understanding, the Council has not historically established peak

5   demand reduction goals. Many other jurisdictions have found value in establishing

6   peak demand reduction targets in addition to energy savings targets, and it would

7   be reasonable for the Council to consider doing so. The performance incentive

8   model I have described could be adapted to supporting peak reduction targets as

9   well. Care would have to be taken to ensure that demand savings are not double-

10   counted, and it may be reasonable to use a different performance incentive scale for

11   demand reduction measures because the cost savings benefits peak demand

12   reduction are likely to be weighted towards avoided capital costs. This influences

13   the amount of performance incentive that would make the utility financially

14   indifferent.

15   **D.   Rider DSMCR Rate Design**

16   Q73. IS THE PERCENTAGE OF BILL RATE STRUCTURE CONTAINED IN RIDER

17   DSMCR AN APPROPRIATE WAY TO RECOVER ENERGY EFFICIENCY

18   PROGRAM COSTS?

19   A.   No. The percentage of bill-based design effectively increases the fixed charge that

20   a customer pays each month. This is not appropriate for two reasons. First, it

21   dampens the energy conservation price signal that a customer sees relative to a fully

22   volumetric charge, operating at cross-purposes to the goals of the program and

1   penalizing the precise type of customer behavior the program targets. Second,

2   energy efficiency investments avoid future energy supply costs, and potentially

3   distribution infrastructure costs, on the shared system. This objective does not have

4   a customer-specific component or any other relationship to costs associated with

5   connecting a customer to the electric grid.

6   Q74. YOU PREVIOUSLY STATED THAT CUSTOMER SERVICE EXPENSES ARE

7   GENERALLY CONSIDERED CUSTOMER-RELATED. WOULD THE SAME

8   NOT BE TRUE FOR CUSTOMER SERVICE EXPENSES RELATED TO

9   EFFICIENCY PROGRAMS?

10   A.   No. For normal utility operations, customer service is an integral part of making

11   the ability to purchase energy available to a customer. By contrast, customer service

12   aspects associated with energy efficiency programs are effectively energy or

13   demand related because their function is to enable investments that avoid the need

14   for additional energy or capacity resources. As such they are akin to the costs that

15   would be associated with energy or fuel purchases, or the conduct of a solicitation

16   for capacity resources.

17   Q75. WHAT ARE YOUR RECOMMENDATIONS FOR THE RATE DESIGN TO BE

18   USED FOR RIDER DSMCR?

19   A.   The conservation signal and cost causation would be more accurately reflected in a

20   volumetric charge. This is how energy efficiency program costs are commonly

21   recovered, with the occasional variation that uses a demand-based charge for

22   program elements targeting demand reductions. As in utility rates more generally,

1   demand-based energy efficiency program charges are limited to larger non-

2   residential customer classes.

3   **VI.   DISCUSSION OF CROSS-CUTTING ISSUES & CONCLUSION**

4   Q76. PLEASE SUMMARIZE YOUR GENERAL ASSESSMENT OF ENTERGY'S

5   RATE APPLICATION.

6   A.   The Company's collective requests are one of the most aggressive attempts to fix

7   utility revenues that I have ever seen in a single rate application, if not the most

8   aggressive. As I have discussed throughout my testimony, many of the individual

9   elements would do so in a manner that conflicts with supporting customer

10   investments in energy efficiency and increasing customers' ability to control their

11   energy bills. What is even more concerning is that the individual proposals would

12   operate in concert with one another to exacerbate these issues while at the same

13   time enhancing Entergy's earnings. The individual proposals I have critiqued are

14   each problematic in their own right, but the total effect is even greater than the sum

15   of the parts. The total effect is a reinforcing cycle of fixed charge escalation,

16   dilution of customer efficiency incentives, and higher costs to achieve the same

17   energy efficiency goals.

18   Q77. PLEASE ELABORATE ON HOW ENTERGY'S PROPOSALS WOULD

19   CREATE THE "REINFORCING CYCLE" YOU REFER TO ABOVE.

20   A.   This cycle starts with the direct increases in fixed charges that Entergy has

21   proposed, specifically the increase in the residential customer charge and the fully

1   fixed AMI charge. In the first year, that produces a total nominal fixed charge

2   increase of $10.41/month. As I have already described, that would alone sacrifice

3   years worth of energy savings achieved through the Energy Smart program.

4   Layered on top of this are further indirect increases in fixed charges via the use of

5   percentage of bill-based riders, including those proposed under Rider DGM and

6   Rider DSMCR. With a higher residential customer charge, these riders produce a

7   higher indirect increase in the residential customer charge than would be the case

8   if the customer charge was lower. For instance, if the total combined percentage

9   increase for both riders was 10%, the incremental indirect increase in the residential

10   customer charge is $0.807/month at the current customer charge of $8.07/month,

11   but would be $1.553/month at the proposed customer charge.

12   When rate design related incentives for customer energy efficiency are

13   diluted, achieving the same energy efficiency results will require greater DSM

14   spending. This effect is unavoidable, as lower customer cost savings through rates

15   will have to be supported by greater incentives in order to overcome cost barriers.

16   At the same time, Entergy has proposed revising the manner in which it earns

17   performance incentives to be based on DSM spending. This translates to

18   incrementally higher program costs that would be further increased by the LCFC

19   component of Rider DSMCR and further still by the Company's proposal to

20   amortize the balance over three years. As I have described above, those higher costs

21   are then passed to customers through a percentage of bill-based charge that

22   effectively increases the residential customer charge by an amount that varies

1   directly in relation to the amount of the customer charge, which the Company

2   proposes to roughly double.

3   Thus, the cycle is one where an increase on one fixed charge component

4   produces increases in others, the combination of which dilute rate-related customer

5   incentives for energy efficiency—producing higher DSM program costs which in

6   turn result in further effective increases in fixed charges. Entergy benefits

7   financially from this cycle through a proposed DSM performance incentive that

8   rewards greater spending in a manner that is connected only very loosely to results.

9   Q78.   IS SUCH A RESULT IN THE INTEREST OF NEW ORLEANS RATEPAYERS?

10   A.   No. The Company's proposals would encourage higher electricity consumption and

11   reduce residential customers' ability to control their electric costs, with the greatest

12   negative impacts falling on customers with lower incomes. In doing so, it would

13   directly increase the costs of meeting energy efficiency targets and indirectly

14   contribute to higher system costs by increasing load growth and the potential need

15   for future capital investments. Entergy would benefit financially from such an

16   outcome but its ratepayers would not.

17   Q79.   PLEASE SUMMARIZE YOUR RECOMMENDATIONS TO THE COUNCIL.

18   A.   I recommend that the Council:

19   • Adopt a residential customer charge consistent with the costs of connecting a

20   customer to the electric grid and my low-end customer charge calculation of

21          $8.13/month, in order to properly reflect cost causation, avoid significant

1   adverse impacts on customers with lower incomes, and support the Council's

2   policies on energy efficiency.

3   •   Adopt a volumetric rate design for the recovery of AMI costs on the basis that

4   the incremental costs of AMI above traditional meters are associated primarily

5   with producing energy and demand-related cost savings.

6   •   Adopt a rate design consistent with how customers are charged for the use of

7   the shared distribution system for the recovery of costs associated with the

8   Company's proposed grid modernization investments, should the Council

9   approve any such investments.

10   •   Reject the Company's proposal to re-establish the LCFC within Rider DSMCR

11   and instead adopt a full decoupling mechanism consistent with the

12   recommendations of AAE witness Pamela Morgan.

13   •   Adopt a volumetric rate design for recovery of the costs of any approved DSM

14   program.

15   •   Reject the Company's proposed DSM performance incentive structure and

16   instead adopt a structure that contains symmetrical incentives and penalties and

17   a more granular performance reward calculation, as discussed in more detail in

18   the body of my testimony. This design could include a variation to incentivize

19   peak demand reduction if the Council were to adopt peak demand reduction

20   targets, which should be considered for future programs.

21   Q80.   DOES THIS CONCLUDE YOUR TESTIMONY?

22   A.   Yes.

AFFIDAVIT

STATE OF NORTH CAROLINA   )

)

COUNTY OF WAKE   )

       I, Justin Barnes, 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.

Justin Barnes

SWORN TO AND SUBSCRIBED BEFORE ME THIS 28th **DAY OF** January

Blake W. Elder

NOTARY PUBLIC

My commission expires: May 16, 2021

Exhibit JRB-1

Curriculum Vitae of Justin R. Barnes

JUSTIN R. BARNES

(919) 825-3342, jbarnes@eq-research.com

EDUCATION

Michigan Technological University   Houghton, Michigan
Master of Science, Environmental Policy, August 2006
Graduate-level work in Energy Policy.

University of Oklahoma   Norman, Oklahoma
Bachelor of Science, Geography, December 2003
Area of concentration in Physical Geography.

RELEVANT EXPERIENCE

Director of Research, July 2015 – present
Senior Analyst & Research Manager, March 2013 – July 2015
EQ Research, LLC and Keyes, Fox & Wiedman, LLP   Cary, North Carolina

- Oversee state legislative, regulatory policy, and general rate case tracking service that covers policies such as net metering, interconnection standards, rate design, renewables portfolio standards, state energy planning, state and utility incentives, tax incentives, and permitting. Responsible for service design, formulating improvements based on client needs, and ultimate delivery of reports to clients. Expanded service to cover energy storage.
- Oversee and perform policy research and analysis to fulfill client requests, and for internal and published reports, focused primarily on drivers of distributed energy resource (DER) markets and policies.
- Provide expert witness testimony on topics including cost of service, rate design, distributed energy resource DER value, and DER policy including incentive program design, rate design issues, and competitive impacts of utility ownership of DERs.
- Managed the development of a solar power purchase agreement (PPA) toolkit for local governments, a comprehensive legal and policy resource for local governments interested in purchasing solar energy, and the planning and delivery of associated outreach efforts.

Senior Policy Analyst, January 2012 – May 2013;
Policy Analyst*, September 2007 – December 2011
North Carolina Solar Center, N.C. State University   Raleigh, North Carolina

- Responsible for researching and maintaining information for the Database of State Incentives for Renewables and Efficiency (DSIRE), the most comprehensive public source of renewables and energy efficiency incentives and policy data in the United States.
- Managed state-level regulatory tracking for private wind and solar companies.
- Coordinated the organization's participation in the SunShot Solar Outreach Partnership, a U.S. Department of Energy project to provide outreach and technical assistance for local governments to develop and transform local solar markets.
- Developed and presented educational workshops, reports, administered grant contracts and associated deliverables, provided support for the SunShot Initiative, and worked with diverse group of project partners on this effort.
- Responsible for maintaining the renewable portfolio standard dataset for the National Renewable Energy Laboratory for use in its electricity modeling and forecasting analysis.
- Authored the *DSIRE RPS Data Updates*, a monthly newsletter providing up-to-date data and historic compliance information on state RPS policies.

- Responded to information requests and provided technical assistance to the general public, government officials, media, and the energy industry on a wide range of subjects, including federal tax incentives, state property taxes, net metering, state renewable portfolios standard policies, and renewable energy credits.
- Extensive experience researching, understanding, and disseminating information on complex issues associated with utility regulation, policy best practices, and emerging issues.

SELECTED ARTICLES and PUBLICATIONS

- EQ Research and Synapse Energy Economics for Delaware Riverkeeper Network. *Envisioning Pennsylvania's Energy Future.* 2016.
- Barnes, J., R. Haynes. *The Great Guessing Game: How Much Net Metering Capacity is Left?.* September 2015. Published by EQ Research, LLC.
- Barnes, J., Kapla, K. *Solar Power Purchase Agreements (PPAs): A Toolkit for Local Governments.* July 2015. For the Interstate Renewable Energy Council, Inc. under the U.S. DOE SunShot Solar Outreach Partnership.
- Barnes, J., C. Barnes. *2013 RPS Legislation: Gauging the Impacts.* December 2013. Article in Solar Today.
- Barnes, J., C. Laurent, J. Uppal, C. Barnes, A. Heinemann. *Property Taxes and Solar PV: Policy, Practices, and Issues.* July 2013. For the U.S. DOE SunShot Solar Outreach Partnership.
- Kooles, K, J. Barnes. *Austin, Texas: What is the Value of Solar; Solar in Small Communities: Gaston County, North Carolina*; and *Solar in Small Communities: Columbia, Missouri.* 2013. Case Studies for the U.S. DOE SunShot Solar Outreach Partnership.
- Barnes, J., C. Barnes. *The Report of My Death Was An Exaggeration: Renewables Portfolio Standards Live On.* 2013. For Keyes, Fox & Wiedman.
- Barnes, J. *Why Tradable SRECs are Ruining Distributed Solar.* 2012. Guest Post in Greentech Media Solar.
- Barnes, J., multiple co-authors. *State Solar Incentives and Policy Trends.* Annually for five years, 2008-2012. For the Interstate Renewable Energy Council, Inc.
- Barnes, J. *Solar for Everyone?* 2012. Article in Solar Power World On-line.
- Barnes, J., L. Varnado. *Why Bother? Capturing the Value of Net Metering in Competitive Choice Markets.* 2011. American Solar Energy Society Conference Proceedings.
- Barnes, J. *SREC Markets: The Murky Side of Solar.* 2011. Article in State and Local Energy Report.
- Barnes, J., L. Varnado. *The Intersection of Net Metering and Retail Choice: an overview of policy, practice, and issues.* 2010. For the Interstate Renewable Energy Council, Inc.

TESTIMONY

New Hampshire Public Utilities Commission. Docket No. DE 17-189. May 2018. On behalf of Sunrun Inc. Review of Liberty Utilities application for approval of customer-sited battery storage program, analysis of time-of-use rate design, program cost-benefit analysis, cost-effectiveness of utility-owned vs. non-utility owned storage assets. Developed a proposal for an alternative program utilizing non-utility owned assets under an aggregator model with elements for benefits sharing and ratepayer risk reduction.

North Carolina Utilities Commission. Docket No. E-7 Sub 1146. January 2018. On behalf of the North Carolina Sustainable Energy Association. Duke Energy Carolinas general rate case application. Analysis of the cost basis for the residential customer charge and validity of the utility's minimum system study, allocation of coal ash remediation costs, and grid modernization rider proposal, including the reasonableness of the program, class distribution of costs and benefits, and cost allocation.

Ohio Public Utilities Commission. Docket No. 17-1263-EL-SSO. November 2017*. On behalf of the Ohio Environmental Council. ***Testimony prepared but not filed due to settlement in related case.** Duke Energy Ohio proposal to reduce compensation to net metering customers. Provided analysis of

capacity value of solar net metering resources in the PJM market and distribution of that value to customers. Also analyzed the cost basis of the utility proposal for recovery of net metering credit costs, focused on PJM settlement protocols and how the value of DG customer exports is distributed among ratepayers, load-serving entities, and distribution utilities based on load settlement practices.

North Carolina Utilities Commission, Docket No. E-2 Sub 1142. October 2017. On behalf of the North Carolina Sustainable Energy Association. Duke Energy Progress general rate case application. Analysis of the cost basis for the residential customer charge and validity of the utility's minimum system study, allocation of coal ash remediation costs, and advanced metering infrastructure deployment plans and cost-benefit analysis.

Public Utility Commission of Texas, Control No. 46831. June 2017. On behalf of the Energy Freedom Coalition of America. El Paso Electric general rate case application, including separate DG customer class. Analysis of separate DG rate class and rate design proposal, cost basis, DG load research study, and analysis of DG costs and benefits, and alignment of demand ratchets with cost causation principles and state policy goals, focused on impacts on customer-sited storage.

Utah Public Service Commission, Docket No. 14-035-114. June 2017. On behalf of Utah Clean Energy. Rocky Mountain Power application for separate distributed generation (DG) rate class. Provided analysis of grandfathering of existing DG customers and best practices for review of DG customer rates and DG value. Developed proposal for addressing revisions to DG customer rates in the future.

Colorado Public Utilities Commission, Proceeding No. 16A-0055E. May 2016. On behalf of the Energy Freedom Coalition of America. Public Service Company of Colorado application for solar energy purchase program. Analysis of program design from the perspective of customer demand and needs, and potential competitive impacts. Proposed alternative program design.

Public Utility Commission of Texas, Control No. 44941. December 2015. On behalf of Sunrun, Inc. El Paso Electric general rate case application, including separate DG customer class. Analysis of separate rate class and rate design proposal, cost basis, DG load research study, and analysis of DG costs and benefits.

Oklahoma Corporation Commission, Cause No. PUD 201500271. November 2015. On behalf of the Alliance for Solar Choice. Analysis of Oklahoma Gas & Electric proposal to place distributed generation customers on separate rates, rate impacts, cost basis of proposal, and alignment with rate design principles.

South Carolina Public Service Commission, Docket No. 2015-54-E. May 2015. On behalf of The Alliance for Solar Choice. South Carolina Electric & Gas application for distributed energy programs. Alignment of proposed programs with distributed energy best practices throughout the U.S., including incentive rate design and community solar program design.

South Carolina Public Service Commission, Docket No. 2015-53-E. April 2015. On behalf of The Alliance for Solar Choice. Duke Energy Carolinas application for distributed energy programs. Alignment of proposed programs with distributed energy best practices throughout the U.S., including incentive rate design and community solar program design.

South Carolina Public Service Commission, Docket No. 2015-55-E. April 2015. On behalf of The Alliance for Solar Choice. Duke Energy Progress application for distributed energy programs. Alignment of proposed programs with distributed energy best practices throughout the U.S., including incentive rate design and community solar program design.

South Carolina Public Service Commission, Docket No. 2014-246-E. December 2014. On behalf of The Alliance for Solar Choice. Generic investigation of distributed energy policy. Distributed energy best practices, including net metering and rate design for distributed energy customers.

AWARDS, HONORS & AFFILIATIONS

- Solar Power World Magazine, Editorial Advisory Board Member (October 2011 – March 2013)
- Michigan Tech Finalist for the Midwest Association of Graduate Schools Distinguished Master's Thesis Awards (2007)
- Sustainable Futures Institute Graduate Scholar Michigan Tech University (2005-2006)

<center>**CERTIFICATE OF SERVICE**</center>

I hereby certify that a copy of the foregoing **Direct Testimony of Justin R. Barnes 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

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

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

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

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

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

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

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

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

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

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

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