STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

In the matter of the Application of	)	
CONSUMERS ENERGY COMPANY	)	
for authority to increase its rates for	)	Case No. U-20697
the generation and distribution of	)	
electricity and for other relief.	)	
	)	

QUALIFICATIONS
AND
DIRECT TESTIMONY
OF
DAVID E. DISMUKES, Ph.D.

June 24, 2020

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MICHIGAN DEPARTMENT OF THE ATTORNEY GENERAL

QUALIFICATIONS OF DAVID E. DISMUKES, Ph.D.

Line No.

I. INTRODUCTION

Q. WOULD YOU PLEASE STATE YOUR NAME AND BUSINESS ADDRESS?

A. My name is David E. Dismukes. My business address is 5800 One Perkins Place Drive, Suite 5-F, Baton Rouge, Louisiana, 70808.

Q. ON WHOSE BEHALF DO YOU TESTIFY IN THIS PROCEEDING?

A. I am testifying on behalf of the Michigan Department of the Attorney General ("AG").

Q. WOULD YOU PLEASE STATE YOUR OCCUPATION AND CURRENT PLACE OF EMPLOYMENT?

A. I am a Consulting Economist with the Acadian Consulting Group ("ACG"), a research and consulting firm that specializes in the analysis of regulatory, economic, financial, accounting, statistical, and public policy issues associated with regulated and energy industries. ACG is a Louisiana-registered partnership, formed in 1995, and is located in Baton Rouge, Louisiana.

Q. DO YOU HOLD ANY ACADEMIC POSITIONS?

A. Yes. I am a full Professor, Executive Director, and Director of Policy Analysis at the Center for Energy Studies, Louisiana State University ("LSU"). I am also a full Professor in the Department of Environmental Sciences and the Director of the Coastal Marine Institute in the School of the Coast and Environment at LSU. I also serve as an Adjunct Professor in the E. J. Ourso College of Business Administration (Department of

Economics), and I am a member of the graduate research faculty at LSU. Lastly, I also serve as a Senior Research Fellow at the Institute of Public Utilities ("IPU") at the Michigan State University ("MSU") where I regularly teach courses on utility regulation and other energy topics. Appendix A provides my academic curriculum vitae, which includes a full listing of my publications, presentations, pre-filed expert witness testimony, expert reports, expert legislative testimony, and affidavits.

Q. HAVE YOU PREVIOUSLY TESTIFIED BEFORE THIS COMMISSION?

A. Yes. I provided expert testified before the Commission in Case No. U-14893, a general rate case filing for SEMCO Energy Gas Company, Case No. U-20471, DTE Electric Company's ("DTE") recent Integrated Resource Plan filing, and Case No. U-20561, DTE's general rate case filing.

<u>MICHIGAN DEPARTMENT OF THE ATTORNEY GENERAL</u>

<u>DIRECT TESTIMONY OF DAVID E. DISMUKES, Ph.D.</u>

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. I have been retained by the AG to provide an expert opinion to the Michigan Public Service Commission ("Commission") on issues related to Consumers Energy Company ("Consumers" or "Company") proposed class cost of service study ("CCOSS") and its proposed revenue distribution.

Q. HAS YOUR TESTIMONY BEEN PREPARED BY YOU OR UNDER YOUR DIRECTION AND CONTROL?

A. Yes.

Q. HAVE YOU PREPARED ANY SCHEDULES IN SUPPORT OF YOUR RECOMMENDATIONS?

A. Yes. I have prepared 17 schedules in support of my direct testimony that were prepared by me or under my direct supervision.

Q. HOW IS THE REMAINDER OF YOUR TESTIMONY ORGANIZED?

A. My testimony is organized into the following sections:

- Section II: Summary of Recommendations
- Section III: Proposed Rate Increase
- Section IV: Class Cost of Service Study
- Section V: Revenue Distribution
- Section VI: Rate Design
- Section VII: Conclusions and Recommendations

II. <u>SUMMARY OF RECOMMENDATIONS</u>

Q. PLEASE SUMMARIZE YOUR CONCLUSIONS AND RECOMMENDATIONS REGARDING THE COMPANY'S CLASS COST OF SERVICE STUDY?

A. I recommend the Commission utilize an alternative CCOSS methodology that utilizes a 4CP 50-0-50 cost allocation method for classifying and allocating costs associated with production plant facilities.

Q. WHAT IS YOUR RECOMMENDED REVENUE DISTRIBUTION?

A. I recommend that the Commission adopt a revenue distribution that reflects the alternative CCOSS recommendations discussed earlier. Ultimate revenue distribution effects of these changes will depend on the Commission's adopted revenue requirement for the Company. However, based on the Company's proposed revenue requirement, the changes discussed earlier would result in the residential customer class receiving only a 10.9 percent increase in rates. Additionally, secondary customers would receive a 3.7

percent increase in rates, while primary customers would receive a 1.3 percent decrease in rates.

Q. WHAT ARE YOUR CUSTOMER CHARGE RECOMMENDATIONS AND CONCLUSIONS?

A. I recommend that the Commission direct the Company to maintain customer charges at their current levels. The Company's proposal would detrimentally impact the public policy goals of promoting energy efficiency.

Q. HAVE YOU PREPARED ANY EXHIBITS DETAILING YOUR PROPOSED RATES?

A. Yes. Exhibit AG-2.16 presents an explanatory comparison of the results of my proposed alternative CCOSS recommendations at the Company's proposed revenue requirement to both current and Company proposed rates.

III. PROPOSED RATE INCREASE

Q. PLEASE SUMMARIZE THE COMPANY'S PROPOSED RATE INCREASE.

A. The Company is requesting to increase its rates by $244 million for the 12-month period ending December 31, 2021.[1] If awarded, rates will increase by 5.9 percent on a system-wide basis and by 14.0 percent for the residential class alone.[2] Further, this proceeding represents the fifth time the Company has increased rates since 2015, four of which have arisen over just as many years.

Q. HAVE YOU EXAMINED THE HISTORICAL TREND IN THE COMPANY'S RATES?

[1] Application of Consumers Energy Company at ¶ 5.
[2] Direct Testimony of Hubert W. Miller III, 8:3-4.

A. Yes. Exhibit AG-2.1 shows the Company's rate increase trends since Case No. 15645 in 2009. The Company has seen its annual revenues increase by $849.7 million, or by nearly three percent per year over an 11-year period.

Q. WHAT HAVE THESE INCREASES MEANT FOR RESIDENTIAL RATEPAYERS?

A. These historic rate increases have disproportionately impacted residential and other smaller usage customer classes relative to primary-voltage and other high load factor customer classes. The revenues collected from residential customers have increased by 45.6 percent since Case No. 15645. Revenues from primary-voltage customers, on the other hand, have decreased by 0.5 percent over the same period. These trends will only continue if the Company's proposals are accepted in full by the Commission in this proceeding. The Company's proposed 14.0 percent increase to residential rates is larger than any other increase being proposed for any other customer class including primary-voltage customers.

Q. DOES THE COMPANY ROUTINELY PREPARE ANALYSES OF THE COMPETITIVENESS OF ITS RATES RELATIVE TO COMPETING UTILITIES?

A. Yes. The Company prepares an analysis of the competitiveness of its rates relative to the U.S., Midwestern and Michigan based rates published by the U.S. Department of Energy, Energy Information Administration ("EIA").[3] The Company's 2019 competitiveness analysis shows that its rates compare poorly to competing Midwestern

[3] Company's Response to Data Request AG-CE-289.

utilities.[4] The analysis also shows that the Company's residential and commercial retail rates are particularly uncompetitive relative to regional peers.

Q. PLEASE DISCUSS THE RESULTS FROM THE 2019 RATE ANALYSIS IN MORE DETAIL.

A. The Company's residential rates are higher than the Midwestern or U.S. averages, and are also higher than most all other Michigan utilities. The Company has some of the highest residential rates in the country, exceeding the state-wide average of all states in the continental U.S. outside of New England and California.[5] In its regional peer analysis, the Company found that its residential rates were higher than all Midwestern competitors with the exception of Interstate Power and Light and DTE Electric Company.[6]

Q. WHAT DOES THE COMPANY'S 2019 ANALYSIS SHOW REGARDING COMPETITIVENESS OF ITS COMMERCIAL RATES?

A. The Company's rate competitiveness analysis shows that its commercial rates are higher than all Midwestern peers, U.S., and Michigan utility averages. The Company's commercial retail rates are also some of the highest in the country, exceeding the state-wide average of all states in the continental U.S. outside of New England and California.[7] Similarly, in its regional peer analysis, the Company found that its commercial rates were higher than all other competing Midwestern electric utilities.[8]

Q. WHAT DOES THE COMPANY'S ANALYSIS SHOW REGARDING COMPETITIVENESS OF ITS INDUSTRIAL RATES IN 2019?

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[4] Company's Response to Data Request AG-CE-289, Attachment U20697-AG-CE-289-Miller_ATT_1 "2019 12_Month End_Electric.pptx," at 1.
[5] *Id.,* at 2.
[6] *Id.*, at 9.
[7] *Id.*, at 3.
[8] *Id.*, at 11.

A. The Company's analysis shows that its industrial rates are higher than the average of all Midwestern, U.S., and Michigan utility averages. However, the Company's industrial rates are competitive with some regional peers operating in Ohio, Indiana, and Wisconsin.[9]

Q. HAVE YOU CONDUCTED YOUR OWN RETAIL RATE BENCHMARKING ANALYSIS?

A. Yes. I have examined the Company's historic retail rates relative to other midwestern public electric utilities. My analysis shows that the Company's residential and commercial rates are noticeably higher relative to other regional peer utilities, while its industrial rates are relatively more competitive to the same group of regional peer utilities.

Q. PLEASE DISCUSS THE DATA YOU UTILIZED IN YOUR PEER ANALYSIS.

A. My analysis started with the collection of a full decade's worth of Form 1, Annual Report data filed by regulated utilities with the Federal Energy Regulatory Commission ("FERC"). Average revenues (retail revenues divided by sales in kilowatt-hour or "kWh" terms) were developed by backing out fuel-related costs from overall sales revenues included in the Form 1.

Q. HOW WERE THE REGIONAL PEER UTILITIES DETERMINED?

A. Peer utilities include investor-owned utilities operating within the midwestern region of the U.S. and members of the Midcontinent Independent System Operators ("MISO") regional transmission organization. There are 14 utilities in this regional electric utility peer group, including the Company, used in my statistical benchmarking analysis.

[9] *Id.*, at 12.

Utilities were selected by their geographic location (proximity to Michigan) and size (i.e. sales and number of customers) in relation to Consumers Energy.

Q. HAVE YOU PREPARED AN EXHIBIT SUMMARIZING YOUR FINDINGS?

A. Yes. Exhibit AG-2.2 summarizes and compares the historic trends in regional utility residential average base revenues (revenue per kWh) or prices over the past decade. Exhibits AG-2.3 and AG-2.4 provide similar comparisons for commercial and industrial customer classes, respectively.

Q. WHAT DOES YOUR RESIDENTIAL RATE COMPARISON SHOW?

A. Exhibit AG-2.2 shows that Consumers' residential rates (average base revenues) have been above the average reported for other regional peer utilities every year over the past decade. The Company's ten-year average residential rate of $0.100/kWh is noticeably higher than the peer group's average residential rate of $0.089/kWh. With 1 representing the utility with the lowest rates, the Company's residential rates have fallen from a rank of 9th lowest in 2010 to 11th (out of 14) in 2019. In 2019, the Company's residential rates were higher than all other peer utilities with the exception of the two Alliant Energy affiliates (Wisconsin Power and Light Company and Interstate Power and Light Company) and DTE Electric Company.

Q. DO YOU SEE THE SAME KINDS OF RELATIONSHIPS IN THE COMPANY'S COMMERCIAL RETAIL RATES?

A. Yes. Exhibit AG-2.3 compares the Company's estimated commercial base rates (average revenues) to regional peer utilities. This analysis shows that the Company's commercial rates are also higher than those regional peers on an absolute basis, as well as a percentage change basis. The Company's estimated commercial base rates have averaged \$0.074/kWh over the past decade, and \$0.081/kWh over the past five years compared to a peer average of \$0.067/kWh and \$0.073/kWh over the comparable two periods, respectively. In the 14-member regional peer group, the Company's commercial rates have fallen from a rank of 9th lowest in 2010 to 11th in 2019. In 2019, the Company's commercial rates were higher than all other peer utilities except for Indianapolis Power and Light Company, Northern Indiana Public Service Company, and Interstate Power and Light Company.

Q. HAVE YOU PREPARED A COMPARISON OF THE COMPANY'S INDUSTRIAL RATES RELATIVE TO OTHER REGIONAL PEER UTILITIES?

A Yes. A comparison of the Company's industrial retail rates is provided in Exhibit AG-2.4. In contrast with the Company's high residential and commercial rates, the Company's industrial rates have recently been competitive to regional peers. The Company's estimated industrial base rates average \$0.036/kWh over the past decade, only slightly higher than the regional average of \$0.035/kWh. Over the past five years, the Company's estimated industrial base rates have averaged lower than the regional average, \$0.035/kWh compared to \$0.039/kWh for the region. This is due to a markedly improved relative position of the Company's industrial rates relative to regional peers. In the 14-member region peer group, the Company's industrial rates have improved from a rank of 11th lowest in 2010 to 4th lowest in 2019. In 2019, the Company's industrial rates were lower than all regional peers with the exception of Wisconsin Public Service Corporation, Kentucky Power Company, and Ameren Illinois Company.

Q. WHAT HAS ACCOUNTED FOR THE DISPROPORTIONATE NATURE OF THE COMPANY'S PAST RATE INCREASES AND THE WORSENING COMPETITIVENESS OF THE COMPANY'S RESIDENTIAL AND COMMERCIAL RATES?

A. The large rate increases for residential customers relative to larger usage/higher load factor customers is mainly a function of the Company's proposed CCOSS methods. As will be discussed in greater detail later, Section 11 of Act 286 took effect after January 1, 2009,[10] and proposed a cost allocation method for production plant facilities beginning with Case No. 15645 in November 2009.[11] Section 11 of Act 286 also required the Commission adopt cost-of-service based rates. These new cost allocation methods resulted in more costs being allocated to residential customers relative to higher load factor customers. The methodology adopted as a result of Act 286 was subsequently changed by the Commission in Case No. U-17688 in 2015 in order to "better recognize the value of capacity in Consumers' system."[12] This new cost allocation method was adopted beginning with Case No. 17735 in that same year,[13] an action later given some legislative support through Act 341 of 2016.[14]

Q. IS THE COMPANY PROPOSING ANY UNIQUE COST ALLOCATION METHODS IN THIS PROCEEDING THAT WILL SHIFT COST RECOVERY MORE TOWARDS RESIDENTIAL AND SMALLER COMMERCIAL CUSTOMERS?

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[10] 2008 PA 286 § 11(1).
[11] In the matter of the application of Consumers Energy Company for authority to increase its rates for the generation and distribution of electricity and for other relief; Case No. U-15645 *et al.*; Order at 69-72.
[12] In the Matter, on the Commission's Own Motion to Commence a Proceeding to Implement the Provision of Public Act 169 of 2014; MCL 460.11(3) *et seq.*, with Regards to Consumers Energy Company; Case No. U-17688; Opinion and Order at 17.
[13] In the matter of the application of Consumers Energy Company for authority to increase its rates for the generation and distribution of electricity and for other relief; Case No. U-17735; Order at 96-98.
[14] 2016 PA 341 § 11(1).

A Yes. The Company's proposed production plant cost allocation method, referred to as the 4 CP 89-0-11 method, disproportionately allocates a large share of its overall costs on a method that will favor higher load-factor customer classes at the expense of low load-factor classes. I will discuss this methodology and its shortcomings, in a later section of my testimony.

IV. CLASS COST OF SERVICE STUDY

A. Introduction

Q. WHAT IS THE PURPOSE OF A CLASS COST OF SERVICE STUDY OR CCOSS?

A. A "CCOSS" is a modeling approach that reconciles utility costs and revenues across different customer classes. The goal of a CCOSS is to determine the cost of providing service to an individual customer class and the revenue contribution each class makes to cover those costs. The results of these studies produce class specific rates of return and revenue requirements which, in turn, can be used as an input in developing class specific revenue responsibilities and rates.

Q. HOW IS A CCOSS PREPARED?

A. Typically, a CCOSS utilizes a set of historic or project cost information which is (1) "functionalized," (2) "classified," and (3) "allocated." The functionalization process simply categorizes costs based upon the functions they serve within a utility's overall operations (i.e. production, transmission, and distribution). The classification process characterizes costs by "type" including those that are (1) demand-related, (2) commodity-related, or (3) customer-related. The last step of the process "allocates" each of these costs to a respective jurisdiction or customer class as appropriate.

Q. CAN YOU EXPLAIN WHAT YOU MEAN BY DEMAND-RELATED COSTS?

A. Yes. Demand-related costs are associated with meeting maximum energy demands. Electric substations and line transformers at the distribution level are designed, in part, to meet the maximum customer demand requirements. The most common demand allocation factors used in a CCOSS are those related to system coincident peaks ("CP") or non-coincident peaks ("NCP").

Q. HOW ARE ENERGY-RELATED COSTS DEFINED?

A. Energy-related costs are defined as those that tend to change with the amount or volume of electricity (i.e., kWh) sold. Electric generation costs and high-voltage transmission lines, for instance, can be allocated, in part, based on some measure of electricity sales.

Q. WHAT ABOUT CUSTOMER-RELATED COSTS?

A. Customer-related costs are those associated with connecting customers to the distribution system, metering household or business usage, and performing a variety of other customer support functions.

Q. IS THIS A RELATIVELY SIMPLE PROCESS?

A. No. Some costs can be clearly identified and directly assigned to a function or category, while other costs are more ambiguous and difficult to assign. The primary challenge in conducting a CCOSS is the treatment of what are known as "joint and common" costs. Given their shared or integrated nature, these joint and common costs can often be difficult to compartmentalize. Therefore, unique allocation factors are utilized in a CCOSS to classify joint and common costs. The process of developing these cost allocation factors can become subjective and is often imbued with policy considerations.

Q. HOW DOES A CCOSS RELATE TO ECONOMIC PRINCIPLES?

A. A CCOSS is also referred to as a "fully allocated cost study" since it allocates test year revenues, rate base, expenses, and depreciation to various jurisdictions and customer classes based upon a series of different allocation factors. The purpose of the CCOSS is to estimate the cost responsibility for various customer classes, which in turn are used to develop rates. At the core of a CCOSS is a set of historic book costs for a utility that have accumulated over decades. Rates are, therefore, based upon historic average costs; whereas, economic theory suggests that the most efficient form of pricing in perfectly competitive markets should be based upon marginal costs. However, regulated utilities do not operate in perfectly competitive markets and, by their very nature, are natural monopolies. Thus, reaching the ideal pricing formula outlined in economic theory is impossible since the nature of natural monopolies makes pricing in the presence of declining average costs, coupled with a number of joint and common costs, difficult. This problem is exacerbated by the fact that the cost information utilized in a CCOSS are usually historic and static, not dynamic and forward-looking. These analytic deficiencies undermine many experts' cost causation/pricing claims. As a result, in regular practice there is no single correct answer that is revealed in a CCOSS. It is often up to regulators to exercise an appropriate level of judgment regarding the nature of these costs, the results of the CCOSS, and the implications both have in setting fair, just, and reasonable rates. This is one of the reasons why many regulators use CCOSS results as a "guide" in setting rates and are not bound by their results.

Q. WHAT CONTROVERSIES ARISE IN THE ANALYSIS AND COMPARISON OF VARIOUS COSS METHODOLOGIES?

A. The CCOSS process is significantly different than the revenue requirement or cost of capital phase of a typical rate case. While the latter two activities are dedicated to determining how much revenue will be recovered through rates, the CCOSS process determines how those costs (revenue requirements) will be recovered through customer rates. The primary controversy with the evaluation of various CCOSS results often rests with determining whether costs (revenue requirements) will be recovered by the relative customer share of each class, the peak load contributions of each customer class, or whether and how the approach will be tempered through the use of customer, peak, and off-peak usage considerations. Methodologies that are heavily skewed toward customer and peak considerations, for instance, can tend to shift costs more than proportionally to relatively lower load-factor customers, such as residential and small commercial customers. These approaches can also fail to capture the service being provided by the utility (*i.e.*, electric service in this case), and how the value of that service varies by the amount purchased by different customer classes.

B. Overview of Company's CCOSS

Q. PLEASE DESCRIBE THE COMPANY'S PROPOSED COST ALLOCATION METHODOLOGIES.

A. The Company provided two versions of its CCOSS model. The first version is based upon the Commission's decision in Case U-18322, the Company's last general rate case approved via final order. A second version builds off the first, expanding it to incorporate additional proposals.[15]

[15] Direct Testimony of Josnelly C. Aponte at 7:3-9.

Q. PLEASE DESCRIBE THE DEMAND ALLOCATORS USED WITHIN THE COMPANY'S CCOSS MODELS.

A. The Company uses a variety of demand allocators within its CCOSS. The Company uses what it refers to as a "4CP 89-0-11" cost allocation method to allocate production plant costs that are classified as "demand-related."[16] This is a hybrid allocation factor based on a weighted average that has two separate components. The first component is based on each rate class' contribution to the Company's average four monthly CPs ("4CP") and receives an 89 percent weight. The second component is comprised of each rate classes' contribution to the Company's annual energy requirement and has an 11 percent weight.[17] The Company's demand-related classification of transmission plant is based upon what it refers to as a "12CP 100" cost allocation method, which measures the Company's average twelve monthly CP ("12CP").[18] For lower-voltage distribution facilities classified as demand-related, the Company uses each rate class' relative NCP demand.[19]

Q. DO YOU DISAGREE WITH ANY OF THE ASSUMPTIONS OR ALLOCATION FACTORS INCORPORATED IN THE COMPANY'S PROPOSED CCOSS?

A. Yes. I disagree with the Company's CCOSS cost allocation method related to the classification of production plant and will discuss this in more detail below in the next section of my testimony.

[16] Direct Testimony of Josnelly C. Aponte at 15:22-25.
[17] Direct Testimony of Josnelly C. Aponte at 11:4-5; and 16:12-20.
[18] Direct Testimony of Josnelly C. Aponte at 11:7-8.
[19] See, Workpaper file "ex0220-Aponte-1 – 3 and WP-1-81.xlsx."

C. Classification of Production Plant

Q. PLEASE DESCRIBE THE COMPANY'S 4CP 89-0-11 PRODUCTION PLANT COST ALLOCATOR?

A. As noted earlier, the Company's production plant cost allocation method is a hybrid approach that uses a 4CP 89-0-11 demand classification. This 4CP 89-0-11 approach is a proposed modification by the Company to the Commission's existing 4CP 75-0-25 cost allocation approach that dates back to June 2015 and the Commission's Order in Case No. U-17688.[20] Prior to this Order, the Company had utilized a 12CP 50-25-25 cost allocation methodology as outlined by the Legislature in Public Act 286 of 2008 (hereafter, "Act 286").

Q. PLEASE DESCRIBE ACT 286.

A. Act 286 was part of a package of bills that passed the Michigan Legislature in late 2008[21] and has been described as a "smorgasbord" of changes to then-existing utility laws.[22] Included in these changes was Section 11, often referred to as the "de-skewing" provision,[23] which required the Commission to phase in electric rates set equal to cost of service over a five-year period.[24]

Q. WHAT CCOSS CHANGES AROSE FROM SECTION 11 OF ACT 286?

A. Section 11 of Act 286 required the Commission to move rates towards actual cost of providing service and utilize a 50-25-25 cost allocation methodology. However, Act

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[20] In the matter, on the Commission's own motion to commence a proceeding to implement the provisions of Public Act 169 of 2014; MCL 460.11(3) *et seq.*, with regards to Consumers Energy Company; Case No. U-17688; Opinion and Order (June 30, 2015).
[21] 2008 PA 286.
[22] Babcock, Lisa and Rodger Kershner (January 2011), Changes in the Law Governing Public Utilities, Michigan Bar Journal, January 2011:37.
[23] *Id.*, at 2011:40.
[24] 2008 PA 286 § 11.

286 does allow the Commission to modify this prescribed cost allocation methodology, provided a greater amount of costs would not be allocated to primary service customers.[25] Act 286, section 11(1) notes:

> This subsection applies beginning January 1, 2009. Except as otherwise provided in this subsection, the commission shall phase in electric rates equal to the cost of providing service to each customer class over a period of 5 years from the effective date of the amendatory act that added this section. If the commission determines that the rate impact on industrial metal melting customers will exceed the 2.5% limit in subsection (2), the commission may phase in cost-based rates for that class over a longer period. The cost of providing service to each customer class shall be based on the allocation of production-related and transmission costs based on using the 50-25-25 method of cost allocation. <u>The commission may modify this method to better ensure rates are equal to the cost of service if this method does not result in a greater amount of production-related and transmission costs allocated to primary customers</u>.[26]

Q. HOW IS THE 50-25-25 METHOD DEFINED?

A. Act 286 did not define the 50-25-25 method, but the Commission later accepted a Staff interpretation based on: (1) 12 CP demand weighted 50 percent; (2) energy use coincident to MISO on-peak periods weighted 25 percent; and (3) annual total energy use weighted 25 percent.[27] The Commission modified the 50-25-25 cost allocation method in Case No. 16794 to utilize a 4CP measure of demand rather than 12CP after finding that the proposed change produced meaningful reductions in primary and secondary customers' monthly bills.[28] The Commission used this methodology to allocate production plant facilities until June 2015, when it approved the current 4CP 75-0-25 allocation

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[25] 2008 PA 286 § 11(1).
[26] 2008 PA 286 § 11(1), *emphasis added*.
[27] In the Matter of the Application of The Detroit Edison Company for Authority to Increase its Rates, Amend its Rate Schedules and Rules Governing the Distribution and Supply of Electric Energy, and for Miscellaneous Accounting Authority; Case No. U-15244; Opinion and Order at 77; and In the Matter of the Application of Consumers Energy Company for Authority to Increase its Rates for the Generation and Distribution of Electricity and for Other Relief; Case No. U-15645 *et al,*; Order at 69-72.
[28] In the Matter of the Application of Consumers Energy Company for Authority to Increase its Rates for the Generation and Distribution of Electricity and for Other Relief; Case No. U-16794; Order at 107.

method in Case No. U-17688, a limited proceeding to examine cost allocation and rate design methods for the Company.

Q. WHY DID THE COMMISSION INITIATE A PROCEEDING IN 2015 TO EXAMINE COST ALLOCATION AND RATE DESIGN METHODS FOR THE COMPANY?

A. In June 2014, Public Act 169 of 2014 (hereafter, "Act 169") was signed into law.[29] Act 169 continued to hold that cost-based rates should be based on the allocation of production-related and transmission costs using the 50-25-25 cost allocation method. However, it provided that the Commission could modify the method to "better ensure rates are equal to the cost of service."[30] Act 169 also required the Commission to commence a proceeding to examine cost allocation methods and rate design methods for each utility to set rates.[31]

Q. WHY DID THE COMMISSION MODIFY THE PRODUCTION PLANT COST ALLOCATION METHOD IN CASE NO. U-17688?

A. In Case No. U-17688, the Company's initial CCOSS proposal utilized a 100 percent 4CP cost allocation methodology for classifying and allocating costs associated with production plant facilities,[32] thereby entirely removing any energy considerations or measurements to the allocation factor. The Company made this recommendation based on its own exploration of various cost allocation methods and the recommendations of an industrial rate working group.[33]

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[29] 2014 PA 169 § 11.
[30] 2014 PA 169 § 11(1).
[31] 2014 PA 169 § 11(3).
[32] In the matter, on the Commission's own motion to commence a proceeding to implement the provisions of Public Act 169 of 2014; MCL 460.11(3) *et seq.*, with regards to Consumers Energy Company; Case No. U-17688; Opinion and Order (June 30, 2015) at 3.
[33] *Id.*

Q. DID STAFF AGREE WITH THE COMPANY'S COST CLASSIFICATION ASSERTIONS?

A. No. Staff disagreed with the Company's proposal and instead argued that production systems are built and operated to meet both capacity and energy requirements.[34] The Commission ultimately agreed with Staff's proposal (a 4CP 75-0-25 cost allocation method) since it was based upon a sound empirical examination of (1) annual energy and peak demand use and (2) relative base-load to non-base-load plant in service statistics.[35]

Q. HAS THE LEGISLATURE REVISITED SECTION 11 OF ACT 286?

A. Yes. As mentioned above, Act 286 was revised by Act 169,[36] which was itself changed again in Public Act 341 of 2016 ("Act 341").[37] The latter notably modified Section 11 to remove the prior-preferred production cost 50-25-25 cost allocation method and instead include a reference to a "75-0-25" cost allocation method. Importantly, Act 341 also permits the Commission to modify this cost allocation approach if it determined these approaches did not ensure appropriate cost of service-driven rates.[38] Likewise, the Legislature granted increased flexibility to the Commission in setting cost of service-based rates, allowing for the Commission to implement rate changes over time if it determines that there is a material impact on customer rates.[39]

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[34] In the matter, on the Commission's own motion to commence a proceeding to implement the provisions of Public Act 169 of 2014; MCL 460.11(3) *et seq.*, with regards to Consumers Energy Company; Case No. U-17688; Opinion and Order (June 30, 2015) at 5.
[35] In the matter, on the Commission's own motion to commence a proceeding to implement the provisions of Public Act 169 of 2014; MCL 460.11(3) *et seq.*, with regards to Consumers Energy Company; Case No. U-17688; Opinion and Order (June 30, 2015) at 16-17.
[36] 2014 PA 169 § 11.
[37] 2016 PA 341 § 11.
[38] 2016 PA 341 § 11(1); note Act 341 does not define the referenced 75-0-25 cost allocation methodology.
[39] *Id.*

> Except as otherwise provided in this subsection, the commission shall ensure the establishment of electric rates equal to the cost of providing service to each customer class. In establishing cost of service rates, the commission shall ensure that each class, or sub-class, is assessed for its fair and equitable use of the electric grid. If the commission determines that the impact of imposing cost of service rates on customers of an electric utility would have a material impact on customer rates, the commission may approve an order that implements those rates over a suitable number of years. The commission shall ensure that the cost of providing service to each customer class is based on the allocation of production-related costs based on using the 75-0-25 method of cost allocation and transmission costs based on using the 100% demand method of cost allocation. The commission may modify this method if it determines that this method of cost allocation does not ensure that rates are equal to the cost of service.[40]

Q. HAVE YOU EXAMINED THE COMPANY'S MONTHLY SYSTEM PEAKS?

A. Yes. Exhibit AG-2.5 presents the Company's monthly system peaks over the past five years (2015-2019) using: a one (1) Coincident Peak ("1 CP") method; a 4 CP method; and a 12 CP method. These measurements show that the Company's system is summer peaking with average summer peak demands (i.e. 4 CP) that are 20 to 27 percent greater than its annual average monthly peak (i.e. 12 CP). This reinforces the earlier Staff finding that measurements of demand impacting production plant should be based on 4 CP rather than 12 CP demand measures.

Q. WHAT FUNCTIONS DO PRODUCTION FACILITIES SERVE?

A. The Commission notes in Case No. U-17689 (involving DTE Electric) that electric generating units ("EGUs") are designed to serve both energy and demand/capacity needs of a utility.[41] The exact degree of this split between energy and demand functionality depends on the individual EGU in question and its place in the utility's dispatch curve.[42]

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[40] *Id.*

[41] In the Matter, on the Commission's own motion to commence a proceeding to implement the provisions of Public Act 169 of 2014; MCL 460.11(3) *et seq.*, with regard to DTE Electric Company; Case No. U-17689, Opinion and Order at 21 and 22.

[42] Today in Energy (August 17, 2012), "Electric generator dispatch depends on system demand and the relative cost of operation," Energy Information Administration.

EGUs defined as baseload units serve more of the utility's energy needs, while EGUs defined as peaking units serve more of the utility's demand or capacity needs. It is therefore not uncommon to develop composite energy and demand allocators that represent this mixed use and classification.

Q. DOES THE COMMISSION'S CURRENT 4CP 75-0-25 COST ALLOCATION METHOD RESEMBLE COST ALLOCATION METHODS USED IN OTHER REGULATORY JURISDICTIONS?

A. Yes. The Commission's 4CP 75-0-25 cost allocation method from Case No. U-17688, and the proposed 4CP 89-0-11 cost allocation method, closely resembles the Average and Peak ("A&P") cost allocation methodology,[43] or peak and average demand cost allocation methodology,[44] used in some other regulatory jurisdictions.

Q. PLEASE DESCRIBE AN A&P COST ALLOCATION METHODOLOGY.

A. An A&P cost allocation methodology is based upon a two-component weighted average. The first component represents each rate class' share of a utility's total annual energy sales, and the second component represents each rate class' share of a utility's annual system peak demand. These components are combined through a weighted average: in the case of the 4CP 75-0-25 allocation, 75 percent demand and 25 percent energy.

Q. DOES THE 4CP 75-0-25 ALLOCATION METHOD DEVIATE FROM COMMONLY ACCEPTED COST ALLOCATION PRACTICES?

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[43] See, for example, In the Matter of the Application of Entergy Arkansas, Inc. for Approval of Changes in Rates for Retail Electric Service, Arkansas Public Service Commission Docket No. 13-028-U, Direct Testimony of Corey A. Pettett, 8:11-20.

[44] Electric Utility Cost Allocation Manual (January 1992), National Association of Regulatory Utility Commissioners at 57-59.

A. Yes. While the framework of the 4CP 75-0-25 allocation adheres to commonly accepted cost allocation practices, the 75 percent demand and 25 percent energy weighting for classifications does not. It is typically accepted that the weighting between demand and energy components should be equal (i.e. 50-50) or based on the utility's system load factor.[45] This latter method weights the energy component by the utility's overall system load factor while the peak demand component is weighted by the inverse of the system load factor (*i.e.*, 1 minus the system load factor).

Q. PLEASE DEFINE WHAT IS MEANT BY A "LOAD FACTOR."

A. A load factor is defined as the ratio of the average load in kilowatts supplied during a designated period to the peak or maximum load in kilowatts occurring in that period. The load factor is expressed as a percentage and may be derived by multiplying the megawatt hours in the period by 100 and dividing by the product of the maximum demand in megawatts and the number of hours in the period. A system that is estimated to have a high load factor is often thought to be utilizing electricity more efficiently since usage is consistent and does not swing largely between average and peak periods. Conversely, systems with low load factors must maintain idle capacity in order to meet the relatively large swings in load between average and peak periods.

Q. HAVE YOU CALCULATED THE SYSTEM LOAD FACTOR FOR THE COMPANY?

A. Yes. Exhibit AG-2.6 shows the Company's system load factor for 2019 using different measures of peak demand, specifically 1 CP, 4 CP, and 12 CP. This analysis shows that the Company's system load factor ranges from 49.9 to 67.9 percent based on

[45] *See*, Electric Utility Cost Allocation Manual (January 1992), National Association of Regulatory Utility Commissioners at 57-59.

the measure of peak demand. However, under 4 CP, the measure of peak demand used in the current production plant allocator, results in a system load factor for the test year that is 56.5 percent.

Q. DO THE RESULTS OF YOUR ANALYSIS FOR THE TEST YEAR DIFFER FROM PRIOR YEARS OF COMPANY OPERATIONS?

A. No. Exhibit AG-2.7 shows the Company's system load factors using 4 CP for the five-year period 2015 through 2019. As can be seen from this exhibit, the Company's system load factors have been stable throughout the five-year period. Specifically, the Company's system load factors have consistently been in a narrow range of between 52.8 and 56.5 percent.

Q. WHAT DO THE COMPANY'S SYSTEM LOAD FACTORS FOR THE TEST YEAR IMPLY?

A. The results of the analyses presented in Exhibits AG-2.5 through AG-2.7 imply that 4CP is an appropriate measure of demand for the utility; however, the current 4CP 75-0-25 cost allocation methodology is too heavily weighted towards demand considerations relative to energy when compared to the Company's actual reported data. The Commission noted in Case No. U-17689 that electric utilities develop and operate production plant facilities around both capacity and energy requirements. The analysis of the Company's system load factors shows that the split between these two functional requirements is essentially equal, a finding that should be reflected in the allocation for cost of service purposes in the Company's CCOSS.

Q. WHY DOES THE COMPANY PROPOSE TO MODIFY THE EXISTING 4CP 75-0-25 COST ALLOCATION METHOD TO A 4CP 89-0-11 ALLOCATION?

A. The Company's primary position continues to be that 100 percent of its production plant should be allocated to demand, consistent with its position in past cases. The Company backs off this somewhat extreme position, however, by proposing in this proceeding to use a mixed or hybrid approach consistent with the Commission's past practices, yet one that is based on a 89-0-11 weighting.[46] The Company's proposed weighting (89-0-11) is based on an updated analysis of generating plant statistics prepared by Staff in 2013 in Case No. U-17688,[47] which the Commission used in its justification of the current 4CP 75-0-25 cost allocation regime. The Company states that updating this analysis, and modifying assumptions on how plants serve base load, results in an 11 percent energy weighting.[48]

Q. HAVE YOU REVIEWED THE COMPANY'S UPDATED ANALYSIS OF THE COMPANY'S GENERATING PLANT STATISTICS?

A. Yes. The Company's analysis examines the total plant in service, or plant costs, of each of the Company's generation units for the years 2016 through 2018.[49] The Company then examined the cost associated with its coal generation facilities multiplied by the minimum operating capacity associated with the facility. The ratio of this result to the Company's total plant in service was then multiplied by the ratio of minimum system to maximum system demand.

Q. DO YOU AGREE WITH THE COMPANY'S ANALYSIS?

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[46] Direct Testimony of Josnelly C. Aponte at 15:22-25.
[47] In the matter, on the Commission's own motion to commence a proceeding to implement the provisions of Public Act 169 of 2014; MCL 460.11(3) *et seq.,* with regard to Consumers Energy Company; Case No. U-17688; Direct Testimony of Charles E. Putnam; Exhibits S-3 and S-4.
[48] Direct Testimony of Josnelly C. Aponte at 16:3-20.
[49] See, Workpaper file "ex0220-Aponte-4.xlsx."

A. No. The Company's analysis contains inappropriate assumptions that lead to an incorrect set of production plant allocation factor weights. These incorrect assumptions include: (1) inconsistencies with the Staff's 2013 analysis; and (2) the use of assumptions that are either not relevant to the Company's current operations or are otherwise unfounded.

Q. HOW IS THE COMPANY'S ANALYSIS OF ITS GENERATING PLANT STATISTICS INCONSISTENT WITH STAFF'S 2013 APPROACH?

A. Staff's 2013 analysis first examined the ratio of (a) total plant in service associated with Company baseload coal generation units to (b) the Company's total plant in service. This ratio was calculated for a single year (2013) which, in turn, was combined with an analysis of minimum hourly system load to maximum hourly system load over a five-year period (2009 to 2013). The Company's analysis differs from the 2013 Staff analysis in an important way: the Company's analysis weighs costs associated with its baseload coal facilities by minimum operating capacity at each facility, an approach that is wholly inconsistent with 2013 Staff analysis.

Q. WHY IS IT INAPPROPRIATE TO WEIGH BASELOAD PLANT IN SERVICE BY MINIMUM OPERATING LOADS?

A. Primarily because Staff's 2013 analysis was based on a combination of separate analyses of relative baseload generating plant in service and system load profiles, specifically the relative system loads occurring at both minimum demand levels and at annual system peaks. The Company's approach, which weights baseload plant in service by minimum operating loads, double counts the effect of system load profiles. This double counting arises because the 2013 Staff methodology (and analysis) already includes a consideration of baseload generation needed at minimum system load periods.

Q. HAVE YOU EXAMINED THE EFFECT OF REMOVING THIS INAPPROPRIATE ASSUMPTION FROM THE COMPANY'S CALCULATIONS?

A. Yes. Exhibit AG-2.8 shows the effect of removing the Company's weightings of base load generation facilities which increases the energy part of the allocator to a percentage that could be as high as 24.8 percent. These corrected results are more consistent with the Commission's current allocation approach of 75-0-25, and the 2013 Staff findings that utilize a 25 percent energy weight.

Q. DO YOU SUPPORT THIS MODIFIED RESULT?

A. No. The 2013 Staff analysis is a combination of two separate analyses: (a) relative plant in service and (b) system load profiles. Each of these analyses are potentially relevant in determining an appropriate weighting of energy and demand requirements on a system. Specifically, the use of a plant in service measure provides information on the costs of expensive baseload generation units on a system, while the use of system load profile measures provide information on system demands. The multiplicative combination of these two measures, however, is questionable since it can undervalue the energy requirements on a system.

Q. IS THERE AN ALTERNATIVE APPROACH THAT WOULD PROVIDE MORE APPROPRIATE RESULTS

A. Yes, and I have provided the results of this alternative analysis as Exhibit AG-2.9. Rather than using multiplication, this alternative analysis uses simple averages. This analysis also removes the Company's inappropriate weighting of base load generation facilities discussed earlier. The results of this analysis show that the energy weighting based on the consideration of simple averages ranges from 49.9 to 51.6 percent; a range consistent with my recommended 50-0-50 weighting.

D. Alternative Classification of Production Plant

Q. ARE THERE ALTERNATIVE COST ALLOCATION METHODS TO CLASSIFYING COSTS ASSOCIATED WITH PRODUCTION PLANT ASSETS?

A. Yes. In addition to the Commission's existing 4CP 75-0-25 and my proposed A&P cost allocation methodology – i.e. 4CP 50-0-50 – there are a multitude of potential alternative cost allocation methods for assigning costs associated with production plant assets. The Company's filing, for instance, discusses three alternative cost allocation methodologies: (1) Judgmental or Discretionary Energy Weightings ("DEW"); (2) Average and Excess ("A&E"); and (3) Equivalent Peaker ("EP").[50]

Q. WHAT DOES THE COMPANY MEAN BY "DISCRETIONARY ENERGY WEIGHTINGS"?

A. The term DEW appears to represent a broad category of cost allocation methods that utilize weightings of a customer classes contribution to peak demand and annual energy requirements.[51] These methods are based on the understanding that EGUs are designed to serve both energy and demand/capacity needs of a utility, and thus a customer class's contribution to each of these system planning requirements should be recognized in a cost of service study. The Commission's current 4CP 75-0-25 is an example of a DEW, using the Company's nomenclature. The earlier discussed A&P cost

[50] Direct Testimony of Josnelly C. Aponte at 14:16 to 15:18.
[51] Electric Utility Cost Allocation Manual (January 1992); National Association of Regulatory Utility Commissioners at 57.

allocation methodology is also discussed within the Electric Utility Cost Allocation Manual ("NARUC Manual") as a DEW.[52]

Q. PLEASE DESCRIBE THE ALTERNATIVE A&E COST ALLOCATION METHODOLOGY.

A. Conceptually, A&E cost allocation methods involve developing two components that are also combined by the use of a weighted average.[53] The first component, referred to as the "average" component, represents each rate class' average hourly energy consumption throughout the test year, and is calculated by simply dividing annual energy consumption for each rate class by 8,760, the number of hours in a year. The second component, referred to as the "excess" component, represents each class' contribution to system peak demand. As mentioned earlier, these components are combined through the use of a weighted average; specifically the average component is weighted by the utility's overall system load factor while the excess component is weighted by the inverse of the system load factor (*i.e.*, 1 minus the system load factor).

Q. PLEASE EXPLAIN THE DIFFERENCE BETWEEN AN A&P METHODOLOGY AND AN A&E METHODOLOGY.

A. The A&P methodology that I propose is similar to the A&E methodology that can also be utilized for classifying production plant. Conceptually both methods involve developing an energy and demand component that are then combined by use of a weighted average based on the utility's system load factor. In other words, both methodologies are intended to be a hybrid energy and demand allocator reflecting the

[52] Electric Utility Cost Allocation Manual (January 1992); National Association of Regulatory Utility Commissioners at 57.

[53] *See*, Electric Utility Cost Allocation Manual (January 1992), National Association of Regulatory Utility Commissioners, pp. 49-51.

joint energy and demand functions of production plant. In practice, however, an A&E methodology places more sensitivity on a rate class' demand contribution and reduces the sensitivity of a rate class' annual energy usage in comparison to an A&P methodology. This is due to an A&E valuing a class' peak demand, the "excess" component, relative to the class' average demand exaggerating the effect of a class' load factor on the relative classification of energy and peak demand elements. An A&E can tend to be more favorable to relatively higher load factor classes, like industrial customers.

Q. HAS AN A&E ALLOCATION BEEN ARGUED TO BE SUPERIOR TO A&P METHODOLOGIES?

A. Yes. It is argued by some that an A&P allocation method double-weights the energy component of a customer's usage patterns by utilizing average demand in both the average and peak components of the calculation.[54] It is argued that A&E corrects for this double-weighting by utilizing only excess demand during peak periods. Such arguments are incorrect in that they conflate the concepts of energy and demand and their roles in utility system planning, essentially viewing the utility's role in system planning as serving the needs of baseload customers before customers with peaker load profiles. In reality the demand and energy needs of a utility's customers are distinct parameters that utilities independently have to plan for.

Q. CAN YOU PROVIDE AN EXAMPLE OF THIS LOGICAL ERROR?

A. Yes. Consider a customer class with a 100 percent load factor. The A&E methodology would assign an excess demand component of zero, as peak demand

[54] *See*, In the Matter of the Application of DTE Electric Company for Authority to Increase its Rates, Amend its Rate Schedules and Rules Governing the Distribution and Supply of Electric Energy, and for Miscellaneous Accounting Authority; Case No. U-20561; Rebuttal Testimony of Justin Bieber at 8:14-17.

requirements equal average demand requirements, effectively considering the class as having no peak demand requirements. This while a customer class with a 100 percent load factor utilizes system resources during all hours, including peak system demand periods. In other words, the A&E methodology effectively views the utility role in system planning as first serving the needs of its high load factor customers through baseload generation units, and then serving the needs of lower load factor customers through more expensive generation units. In reality the utility considers the needs of its system on a total system basis, ensuring that it has sufficient resources to supply its customers during peak demand periods and sufficient baseload generation resources to supply its customers with relatively inexpensive energy during base demand periods. In the earlier example, the A&P methodology would still assign a customer class with a 100 percent load factor some peak demand requirement, as customers in the class consume electricity during system peak load periods. In other words, the A&P methodology correctly views all customers as having both energy and demand requirements.

Q. ARE THERE OTHER CONCERNS ASSOCIATED WITH AN A&E COST ALLOCATION METHODOLOGY?

A. Yes. Mathematically, any measure of peak demand, for example the Commission's current practice of measuring peak demand via 4CP, can be utilized in the calculation of A&E cost allocators. However, it is often argued that the only appropriate measurement of peak demand in an A&E cost allocation is a NCP measure to avoid certain mathematical issues that can arise in the A&E cost allocation methodology.[55]

[55] *See*, In the Matter of the Application of DTE Electric Company for Authority to Increase its Rates, Amend its Rate Schedules and Rules Governing the Distribution and Supply of Electric Energy, and for Miscellaneous Accounting Authority; Case No. U-20561; Direct Testimony of Steve W. Chriss at 21:12-13.

Q. PLEASE EXPLAIN THIS MATHEMATICAL ISSUE.

A. The use of a CP measure can lead to a computational issue that can arise when calculating A&E-based allocators. The NARUC Manual, for instance, notes that use of a 1 CP allocation factor within A&E calculations will result in results that are identical to a general 1 CP allocation factor (i.e. negating the hybrid demand-energy nature of the A&E cost allocation methodology).[56] The NARUC Manual suggests using NCP measure of demand to avoid this problem.

> If your objective is – as it should be using [an A&E] method – to reflect the impact of average demand on production plant costs, then it is a mistake to allocate the excess demand with a coincident peak allocation factor because it produces allocation factors that are identical to those derived using a CP method. Rather, use the NCP to allocate the excess demands.[57]

Q. DO YOU BELIEVE THAT THE USE OF NCP IS AN APPROPRIATE MEASURE OF PEAK DEMAND FOR ALLOCATING COSTS RELATED TO PRODUCTION PLANT ASSETS?

A. No. NCP assumes a low level of load diversity thus amplifying customer peak demand requirements on the utility's system. This is appropriate for distribution facilities which serve isolated segments of a utility's system, but not EGUs which serve regional system demands with high levels of load diversity.[58] The observed computational problem inherent in the A&E method does not support its use and, if anything, suggests the need to use an alternative cost allocation method that avoids the issue such as the A&P cost allocation method. The use of a NCP demand measure in the A&E allocator

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[56] Electric Utility Cost Allocation Manual (January 1992), National Association of Regulatory Utility Commissioners ("NARUC") at 50.
[57] Electric Utility Cost Allocation Manual (January 1992), National Association of Regulatory Utility Commissioners ("NARUC") at 50.
[58] *See*, Electric Utility Cost Allocation Manual (January 1992), National Association of Regulatory Utility Commissioners ("NARUC") at 97.

calculation simply represents an attempt to work around a known computational problem by using an inappropriate measure of demand that is inconsistent with the capacity concerns EGUs are designed and operated to address.

Q. WHAT IS THE EQUIVALENT PEAKER COST ALLOCATION METHOD?

A. The equivalent peaker and related base-intermediate-peak cost allocation methods are cost allocation methods that seek to determine production capacity costs based on the composition of generation facilities being allocated. In these allocation methods, rate base for each operating generation facility is calculated and then classified between demand and energy classifications based on the characteristics of the generation facility. Rate base associated with peaking plants are classified as 100 percent demand-related, while rate base of other generating units are carefully proportioned between demand and energy classifications.[59]

Q. HAS THE COMMISSION PREVIOUSLY EXPRESSED A PREFERENCE TO EXAMINE THE RESULTS OF AN EQUIVALENT PEAKER COST ALLOCATION METHOD FOR COMPARISON PURPOSES?

A. Yes. In a prior DTE Electric rate case, parties recommended that the Commission review DTE's production cost allocation method in the Company's next rate case.[60] The Administrative Law Judge ("ALJ") agreed with this recommendation, noting that the Company had failed to rebut evidence that energy costs allocated through the Company's CCOSS are less than MISO Locational Marginal Prices ("LMP"), while allocated capacity

[59] Electric Utility Cost Allocation Manual (January 1992), National Association of Regulatory Utility Commissioners at 52-53.

[60] These parties included Michigan Environmental Council ("MEC"), Natural Resources Defense Council ("NRDC"), and the Sierra Club. See: In the Matter of the Application of DTE Electric Company for Authority to Increase its Rates, Amend its Rate Schedules and Rules Governing the Distribution and Supply of Electric Energy, and for Miscellaneous Accounting Authority; Case No. U-20162; Order at 125.

costs are higher than estimated Cost of New Entry ("CONE").[61] The Commission also agreed with this assessment and reminded parties of its previously expressed preference for the equivalent peaker cost allocation method or something similar:[62]

> That any party proposing to revise the production cost allocation method in a future case include in its evidentiary presentation an analysis using the equivalent peaker method or an approximation for comparison purposes. On pages 52-53 of the NARUC Manual, it states that "[e]quivalent peaker methods are based on generation expansion planning practices, which consider peak demand loads and energy loads separately in determining the need for additional generation capacity and the most cost-effective type of capacity to be added.[63]

Q. WHAT WAS THE ORIGIN OF THE COMMISSION'S EXPRESSED PREFERENCE TO EXAMINE THE RESULTS OF AN EQUIVALENT PEAKER OR SIMILAR COST ALLOCATION METHOD?

A. The Commission's preference can be discerned from discussion in Case No. U-18014, where the Commission was asked to accept a proposal to use a 100 percent demand classification for all costs associated with its production plant facilities.[64] This was the second time the Commission was asked to consider such a proposal, and in the U-18014 proposal for decision, which the Commission ultimately accepted, the ALJ rejected the 100 percent classification as being unsupported when compared against the evidence presented regarding the "longstanding recognition of the importance of considering energy consumption as well as peak demand in allocating production

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[61] In the Matter of the Application of DTE Electric Company for Authority to Increase its Rates, Amend its Rate Schedules and Rules Governing the Distribution and Supply of Electric Energy, and for Miscellaneous Accounting Authority; Case No. U-20162; Notice of Proposal for Decision at 228.
[62] *Id.*; Order at 129.
[63] *Id.*
[64] In the matter of the application of DTE Electric Company for authority to increase its rates, amend its rate schedules and rules governing the distribution and supply of electric energy, and for miscellaneous accounting authority; Case No. U-18014; Order at 100.

costs."[65] The ALJ noted that the defense of the 100 percent demand classification was based on repetitive arguments, and asked parties to provide a more analytical examination of the subject, particularly one examining the characteristics of the utility's generation resources, to better match costs with cost-causation.[66] It was in this context the ALJ laid out the standard the Commission later accepted.[67]

Q. DO YOU FEEL YOUR SYSTEM LOAD FACTOR ANALYSIS ADDRESSES THE COMMISSION'S CONCERNS?

A. Yes. In past cases, the Commission has brought up the equivalent peaker cost allocation method in the context of seeking quantifiable information to address the appropriate division between demand and energy components in the allocation of production costs. An analysis of the Company's system load factor addresses this concern. In fact, my finding of a system load factor of approximately 50 percent implies that the Company's system, during its all-in system peak demand events, is serving a demand wherein half of which is equivalent to the annual average load requirements placed on the system and the other half is 'peak' demand that only occurs during these peak events. In other words, during these system peak demand events, half of the load present are baseloads, while the other half can be considered peak loads.

Q. HAVE YOU CONDUCTED ANY ANALYSIS OF THE RELATIVE CLASSIFICATION OF INDIVIDUAL COMPANY GENERATION UNITS?

A. Yes. Exhibits AG-2.10 and AG-2.11 present the results of two separate analyses of the Company's EGU operations during the test year. The first analysis, presented as

[65] *Id.* at 98.
[66] *Id.*
[67] *Id.* at 98-101.

Exhibit AG-2.10, examines the gross plant in service of each unit, and the unit's capacity factor during the test year to characterize the role the unit serves in the Company's dispatch of electricity. The second analysis, presented as Exhibit AG-2.11, also examines the gross plant in service of each unit but relies on an examination of the levelized cost of each unit relative to established market analyses to classify the function the unit serves. This second analysis can be appropriately viewed as a close facsimile to the equivalent peaker method the Commission has noted in the past.

Q. WHAT IS THE RESULT OF YOUR FIRST ANALYSIS OF COMPANY EGU OPERATIONS?

A. My first analysis of Company EGU operations results in a 48.6-51.4 split between energy and capacity functions within the Company's rate base. For this analysis, I assumed that all generation units with capacity factors below 15 percent served only demand functions on the Company's system, while units with larger capacity factors serve both energy and demand functions based on the unit's capacity factor. Therefore, units such as those included in the J.H. Campbell complex are dispatched during more hours of the year, and thus have higher capacity factors, are classified as serving a larger degree of energy functions relative to demand functions. Specifically, 65.3 percent of plant in service associated with Campbell Unit 3 is classified as energy-related, while 55.4 percent of plant in service associated with Campbell Units 1 and 2 are classified as energy-related, based on observed 2019 capacity factors for these facilities.

Q. WHAT IS THE RESULT OF YOUR SECOND ANALYSIS OF COMPANY EGU OPERATIONS?

A. My second analysis of Company EGU operations finds that, at most, only 56.5 percent of the Company's production plant in service could be classified as being associated with provision of demand-functions. In this second analysis, I examined the levelized annual cost for each of the Company's EGUs compared with CONE prices found by MISO in its most recent analysis of the 2019/2020 Planning Resource Auction ("PRA") results.[68] All costs less than the MISO CONE price were classified as being associated with provision of demand functions, while prices above the MISO CONE price were classified as being associated with the provision of energy functions. All of the Company's non-hydro facilities, with the exception of Karn 3 and 4, were classified as serving at least some energy functions.

E. CCOSS Recommendations

Q. WHAT IS YOUR RECOMMENDATION REGARDING THE APPROPRIATE ALLOCATION OF COSTS ASSOCIATED WITH PRODUCTION PLANT FACILITIES?

A. I recommend that the Commission modify the weighting of the existing 4CP 75-0-25 cost allocation method to one that equally weights demand and energy concerns, or a 4 CP 50-0-50 cost allocation methodology. My proposed 4CP 50-0-50 cost allocation method is based on my analysis of what would constitute a fair and reasonable approximation of the relative cost of service. Specifically, my proposed 4CP 50-0-50 would make the cost allocation of the Company's production plant consistent with recent system load factors for the Company over the last five years (2015 through 2019), which have consistently ranged between 52.8 and 56.5 percent. Furthermore, my

[68] 2019/2020 Planning Resource Auction (PRA) Results; (April 12, 2019); MISO.

recommendation would make the cost allocation consistent with examinations of the relative classification of individual Company generation units.

Q. HAVE YOU CALCULATED THE CLASS REVENUE RESPONSIBILITIES UTILIZING A 4CP 50-0-50 ALLOCATOR?

A. Yes. Exhibit AG-2.12 compares class revenue (cost) responsibilities utilizing a variety of methods including the Company's proposed 4CP 89-0-11 method and my 4CP 50-0-50 proposal. Exhibit AG-2.12 shows that the Company's proposed cost allocation would increase rates for residential customers by $293.1 million, compared to the current 4CP 75-0-25 cost allocation method, which would increase rates for residential customers by $270.6 million. In other words, the Company's proposal would result in an additional $22.4 million allocated to residential customers. The proposed 4CP 50-0-50 cost allocation method would result in $230.6 million allocated to residential customers, $62.5 million less than that proposed by the Company under its cost allocation approach.

Q. WOULD YOUR CCOSS RECOMMENDATIONS CHANGE THE CLASS RATES OF RETURN?

A. Yes. Using my recommended allocation factors, I have also prepared an explanatory alternative CCOSS, which is attached to this testimony as Exhibit AG-2.13. It should be noted, however, that the alternative CCOSS presented in Exhibit AG-2.13 is independent of revenue requirement adjustments supported by other witnesses for the AG and is thus presented for explanatory purposes only. In addition, I have prepared Exhibit AG-2.14, which shows the results of the Company's CCOSS in this same format.

V. <u>REVENUE DISTRIBUTION</u>

A. Revenue Distribution Policy Objectives

Q. PLEASE EXPLAIN THE PURPOSE OF THE REVENUE DISTRIBUTION PROCESS IN SETTING RATES.

A. The revenue distribution process allocates a utility's overall revenue deficiency across customer classes, which in turn is used to establish a new set of retail rates to be applied prospectively. The revenue distribution process often uses the results from the CCOSS as its starting point, but not necessarily as its ending point. Class-specific revenue responsibilities are established by allocating the system-wide revenue deficiency to classes that are under-earning, relative to their estimated ROR, and assigning, at least in theory, revenue decreases to those classes that are over-earning relative to their CCOSS-estimated class returns. The class revenue responsibilities that are finally established are then used, in conjunction with each class's billing determinants, to determine rates. In summary, the revenue distribution process can be thought of as the initial step taken to establish rates.

Q. DOES THE REVENUE DISTRIBUTION PROCESS INCLUDE ANY POLICY CONSIDERATIONS?

A. Yes. Allocating the overall system-wide revenue deficiency entirely on a full cost of service basis could result in outcomes inconsistent with Commission policies, including situations leading to adverse rate impacts for certain under-earning classes. To avoid such a result, regulators often temper the revenue responsibilities assigned to various customer classes in order to meet a broad set of ratemaking policy goals.

Q. WHAT ARE THOSE BROADER RATEMAKING POLICY GOALS?

A. There are several generally accepted rate-making principles used in utility regulation that include:

- Rates should be fair, just, and reasonable, and not unduly discriminatory.
- To the extent possible, gradualism should be used to protect customers from rate shock.
- Rate continuity should be maintained.
- Rates should be informed by costs, but class cost of service results need not be the only factor used in rate development.
- Rates should be understandable to customers.

Q. HOW ARE THE ABOVE PRINCIPLES APPLIED IN DEVELOPING RATES FOR A REGULATED UTILITY?

A. Regulators often consider all, or many of the principles I mentioned above. However, any principle's relative weight can change depending upon the importance of certain policy goals. Rate design should strike a balance between policy goals and result in rates that are fair, just, and reasonable. There is no pre-set or universally accepted formula for developing rates and, as a result, judgment is necessary to formulate a rate design that meets these objectives.

Q. ARE THESE PRINCIPLES APPLIED DIFFERENTLY IN MICHIGAN?

A. To an extent. Act 341 requires that the Commission approve rates equal to the cost of providing service to each customer class.[69] This requirement is universal across all customer classes, with small exceptions for the establishment of low-income and senior citizen rates for eligible customers.[70] However, Act 341 also provides for the

[69] 2016 PA 341 § 11(1).
[70] 2016 PA 341 § 11(2).

potential for the Commission to implement customer rate changes over a period of time if the Commission determines that the impact of imposing cost of service rates would have a material impact on customer rates.[71] In all, the generally accepted rate-making principles are applied in Michigan the same as in other jurisdictions, though Michigan ratemaking potentially places a greater emphasis on informing rates by costs than some other jurisdictions.

B. Company's Proposed Revenue Distribution

Q. PLEASE EXPLAIN HOW THE COMPANY PROPOSES TO DISTRIBUTE ITS CLASS REVENUE REQUIREMENTS.

A. The Company's proposed revenue allocations are based on its CCOSS results and would move each class' rates to levels that equalize its individual class rate of return ("ROR") (or 100 percent relative rate of return ("RROR")). The Company's revenue allocations are split between those associated with the provision of production and delivery services. Exhibit AG-2.15 presents the Company's revenue distribution under its proposed rates. The proposed revenue increase across all customer classes is 5.9 percent. On an individual customer class basis, the Company proposed increase ranges from a 6.1 percent decrease to primary-voltage customers to a 14.0 percent increase to residential customers.

Q. WHAT DO YOU MEAN BY A RROR?

A. A RROR effectively standardizes class-specific rates of return to the overall system average. In other words, it divides the estimated class ROR by the estimated system ROR. For instance, assume that the residential class is earning a class-specific eight

[71] 2016 PA 341 § 11(1).

percent ROR and further assume that the system-wide average ROR estimated by the same CCOSS is also eight percent. The residential class, in this example, can be said to be earning a 1.0 RROR if the estimated ROR is the same as the overall system (*i.e.*, eight percent divided by eight percent equals 1.0). Put another way, any class earning a 1.0 RROR can be said to be making its full contribution to the system's overall ROR (*i.e.*, there is no cross-subsidy). A RROR that is greater than one indicates that a particular class is contributing more than the system average contribution to the Company's overall return. Likewise, a class that earns a RROR less than 1.0 can be said to be making a less-than-average contribution to the overall system and is effectively being partially subsidized by other classes.

C. Revenue Distribution Recommendations

Q. DO YOU AGREE WITH THE COMPANY'S PROPOSED REVENUE DISTRIBUTION?

A. No. The Company's proposed revenue distribution places too great a burden on many customer classes. For example, the Company is requesting a 5.9 percent overall increase in this proceeding, while also proposing that residential customers receive a 14.0 percent increase in total revenues, an increase that is over 2.36 times the system average increase. Perhaps more striking, the Company proposes to <u>decrease</u> rates for lighting and primary voltage customers to the tune of 5.2 and 6.1 percent, respectively. Indeed, the Company proposes to increase rates for residential customers by more than $280 million, more than the system-wide requested increase of $244 million, meaning that the Company's assigns nearly 115 percent of its requested rate increase to residential customers while providing decreases to lighting and primary voltage customers.

Q. WHAT IS YOUR RECOMMENDED REVENUE DISTRIBUTION?

A. I recommend that the Commission adopt a revenue distribution that reflects the alternative CCOSS recommendations discussed earlier. Ultimate revenue distribution effects of these changes will depend on the Commission's adopted revenue requirement for the Company. However, based on the Company's proposed revenue requirement, the changes discussed earlier would result in the residential customer class receiving only a 10.9 percent increase in rates. Additionally, secondary customers would receive a 3.7 percent increase in rates, while primary customers would receive a 1.3 percent decrease in rates.

Q. HAVE YOU PREPARED AN EXAMPLE OF YOUR PROPOSED REVENUE DISTRIBUTION?

A. Yes. Using the Company's proposed revenue requirement, and my proposed alternative CCOSS recommendations discussed earlier, I have prepared Exhibit AG-2.15, which presents an explanatory revenue distribution along with the Company's recommended revenue distribution.

Q. HAVE YOU PREPARED ANY EXHIBITS THAT PROVIDE EXPLANATORY RATES USING YOUR PROPOSED ALTERNATIVE CCOSS RECOMMENDATIONS AND REVENUE DISTRIBUTION?

A. Yes. Exhibit AG-2.16 presents an explanatory comparison of the results of my proposed alternative CCOSS recommendations at the Company's proposed revenue requirement to both current and Company proposed rates.

VI. <u>RATE DESIGN</u>

A. Rate Design Objectives

Q. HOW SHOULD POLICY BALANCE RATE DESIGN GOALS BETWEEN SETTING APPROPRIATE CUSTOMER CHARGES AND VOLUMETRIC RATES?

A. Modern utility pricing theory is primarily concerned with the development of optimal tariff design, which over the years has become dominated by a form of pricing referred to as a "two-part tariff," sometimes referred to more technically as a non-linear (or non-uniform) pricing approach. Once a class revenue requirement is established, the goal for regulators should be one that sets the most appropriate rates based upon various efficiency and equity considerations. Balancing the weight of how costs are recovered between fixed rates, variable rates, block rates, and seasonal rates are all integrated parts of that process.

Q. WHAT IS THE APPROPRIATE ROLE OF COSTS IN SETTING RATES BASED UPON A TWO-PART TARIFF?

A. Costs can be instructive in establishing a baseline upon which prices may be set, but costs do not need to serve as the sole or exclusive basis for rates in order for them to be set optimally (i.e., fixed charges do not need to strictly equal fixed costs, variable rates need not strictly equal variable costs). Unfortunately, the "fixed charge-equals-fixed cost" philosophy gets repeated so often that it can often drown out meaningful discussions about other equally important considerations in setting rates in imperfect markets. In fact, appropriate rate setting in the context of a two-part tariff typically has more to do with consumer demand than it does with cost.

B. Customer Charge Proposals

Q. IS THE COMPANY PROPOSING TO INCREASE ANY CUSTOMER CHARGES?

A. Yes. The Company proposes increases to customer charges associated with residential and Secondary Time-of-Use ("GSTU") customers. In summary, the Company is proposing the following customer charge increases:[72]

- An increase in the customer charge for its residential classes of approximately 13.3 percent.
- An increase in the customer charge for its GSTU class of 50.0 percent.

Q. DID YOU PREPARE AN ANALYSIS OF COSTS COMMONLY ASSOCIATED WITH CUSTOMER CHARGES?

A. Yes. That analysis is provided in Exhibit AG-2.17. "Customer-related" expense accounts are those typically allocated on the basis of customers and can include: removing and setting meters; maintenance of meters; services expense; maintenance of service drops; meter reading expense; dispatch applications and orders; customer records and collections; customer billing and accounting; customer service and information; and sales expense. These costs can also include the depreciation expense associated with the service drop and meter plant accounts and property taxes, as well as the carrying charges (at the Company's requested rate of return) for the customer portion of services investment and 100 percent of the meters investment.

Q. HOW DO THE COMPANY'S RESIDENTIAL CUSTOMER CHARGE REVENUES COMPARE WITH THE RESULTS OF ITS CCOSS?

A. As shown in Exhibit AG-2.17, the customer charge revenue associated with the residential classes is approximately 76 percent of their class cost responsibility.

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[72] Direct Testimony of Hubert W. Miller III, Schedule F-3.0.

Q. DO THESE RESULTS INDICATE ANY PRESSING NEED TO MAKE ANY INCREASES IN RESIDENTIAL CUSTOMER CHARGES?

A. No. The residential class reports customer charge revenues that are estimated to cover more than 76 percent of their customer-related costs. Also, as mentioned earlier, this "fixed charge-equals-fixed cost" philosophy is often repeated but bears little impact on the development of efficient price signals. In fact, appropriate rate setting in the context of a two-part tariff typically has more to do with consumer demand than it does with cost.

Q. ARE THERE OTHER CONCERNS REGARDING THE PROPOSED INCREASES IN RESIDENTIAL CUSTOMER CHARGE?

A. Yes. The Company's rate design proposal is inconsistent with energy efficiency since it reduces economic incentives for ratepayers to control monthly utility bills through energy efficiency and conservation efforts, because only the variable component of bills is avoidable. As an extreme example, under a Straight Fixed Variable ("SFV") rate design, consumers would pay the same charge for non-energy related activities regardless of their usage level. As a result, inefficient customers would pay the same monthly utility bill as relatively more efficient customers, negating all incentive to seek greater efficiency.

Q. HAVE OTHER COMMISSIONS RECOGNIZED THE DETRIMENTAL EFFECT INCREASED FIXED CHARGES HAVE ON ENERGY EFFICIENCY?

A. Yes. In rejecting a request by Baltimore Gas and Electric to increase customer charges as part of a larger rate design proposal, the Maryland Public Service Commission

("MPSC") recognized the need to allow customers the opportunity to control their monthly bills by reducing energy usage.

> Even though this issue was virtually uncontested by the parties, we find we must reject Staff's proposal to increase the fixed customer charge from $7.50 to $8.36. Based on the reasoning that ratepayers should be offered the opportunity to control their monthly bills to some degree by controlling their energy usage, we instead adopt the Company's proposal to achieve the entire revenue requirement increase through volumetric and demand charges. This approach also is consistent with and supports our EmPOWER Maryland goals.[73]

Q. IS THE MARYLAND COMMISSION ALONE IN ITS BELIEF THAT HIGH FIXED CHARGES DISCOURAGE EFFICIENT USE OF ENERGY?

A. No. A research document presented for consideration by the membership of the National Association of Regulatory Utility Commissioners ("NARUC") lists SFV rate design as an alternative to delink utility revenue from sales. An SFV places all fixed-related costs to fixed charges while relegating only variable charges to volumetric rates. The NARUC research noted this type of rate design was problematic because of its effects on customer incentives to conserve energy:

> **Straight-Fixed Variable Rate Design.** This mechanism eliminates all variable distribution charges and costs are recovered through a fixed delivery services charge or an increase in the fixed customer charge alone. With this approach, it is assumed that a utility's revenues would be unaffected by changes in sales levels if all its overhead or fixed costs are recovered in the fixed portion of customers' bills. <u>This approach has been criticized for having the unintended effect of reducing customers' incentive to use less electricity or gas by eliminating their volumetric charges and</u>

[73] Maryland Public Service Commission Case No. 9299*, In the Matter of the Application of Baltimore Gas and Electric Company for Adjustment in its Electric and Gas Base Rates.* Maryland Public Service Commission, Order No. 85374 at p. 99, rel. February 22, 2013.

> billing a fixed monthly rate, regardless of how much customers consume.[74]

Q. HAS ANY NATIONAL PUBLIC POLICY ANALYSIS NOTED THE EFFICIENCY DISINCENTIVES ASSOCIATED WITH SFV-TYPE RATE DESIGNS?

A. Yes. The National Action Plan for Energy Efficiency ("NAPEE"), a joint venture of the U.S. Department of Energy and U.S. Environmental Protection Agency, published a whitepaper on various rate design effects on encouraging energy efficient behaviors. The NAPEE postulated that SFV had a detrimental effect on economic signals to encourage customers to change energy usage behavior and investments in energy efficiency devices, and specifically noted that such disincentives persist even when applied to individual components of a customer's utility bill, such as SFV for strictly distribution services:

> Because [SFV] tends to shift costs out of volumetric charges, it tends to reduce customers' efficiency incentive, because the marginal price of additional consumption is reduced. While SFV rates are being considered to better reflect the utility's costs behind the rate, these rates do not encourage customers to change energy usage behavior or invest in efficiency technologies. Such customer disincentives persist even when SFV rates are applied to individual components of the bill, such as charges for distribution service.[75]

Q. WHAT ARE YOUR CUSTOMER CHARGE RECOMMENDATIONS AND CONCLUSIONS?

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[74] "Decoupling for Electric & Gas Utilities: Frequently Asked Questions (FAQ)" (September 2007), Grants & Research Department, National Association of Regulatory Utility Commissioners, p. 5. (Emphasis added), available at https://www.maine.gov/mpuc/legislative/archive/2006legislation/DecouplingRpt-AttachC.pdf.

[75] National Action Plan for Energy Efficiency, "Customer Incentives for Energy Efficiency Through Electric and Natural Gas Rate Design" at 13-14, prepared by William Prindle, ICF International, Inc. (September 2009) (emphasis added), available at https://www.epa.gov/sites/production/files/2015-08/documents/rate_design.pdf.

A. My specific customer charge recommendations and conclusions are provided in Exhibit AG-2.16. I recommend that the Commission direct the Company to maintain customer charges at their current levels. The Company's proposal would detrimentally impact the public policy goals of promoting energy efficiency.

VII. CONCLUSIONS AND RECOMMENDATIONS

Q. PLEASE SUMMARIZE YOUR CONCLUSIONS AND RECOMMENDATIONS REGARDING THE COMPANY'S CLASS COST OF SERVICE STUDY?

A. I recommend the Commission utilize an alternative CCOSS methodology that utilizes a 4CP 50-0-50 cost allocation method for classifying and allocating costs associated with production plant facilities.

Q. WHAT IS YOUR RECOMMENDED REVENUE DISTRIBUTION?

A. I recommend that the Commission adopt a revenue distribution that reflects the alternative CCOSS recommendations discussed earlier. Ultimate revenue distribution effects of these changes will depend on the Commission's adopted revenue requirement for the Company. However, based on the Company's proposed revenue requirement, the changes discussed earlier would result in the residential customer class receiving only a 10.9 percent increase in rates. Additionally, secondary customers would receive a 3.7 percent increase in rates, while primary customers would receive a 1.3 percent decrease in rates.

Q. WHAT ARE YOUR CUSTOMER CHARGE RECOMMENDATIONS AND CONCLUSIONS?

A. I recommend that the Commission direct the Company to maintain customer charges at their current levels. The Company's proposal would detrimentally impact the public policy goals of promoting energy efficiency.

Q. HAVE YOU PREPARED ANY EXHIBITS DETAILING YOUR PROPOSED RATES?

A. Yes. Exhibit AG-2.16 presents an explanatory comparison of the results of my proposed alternative CCOSS recommendations at the Company's proposed revenue requirement to both current and Company proposed rates.

Q. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A. Yes.

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EDUCATION

Ph.D., Economics, Florida State University, 1995.
M.S., Economics, Florida State University, 1992.
M.S., International Affairs, Florida State University, 1988.
B.A., History, University of West Florida, 1987.
A.A., Liberal Arts, Pensacola State College, 1985.

Master's Thesis: *Nuclear Power Project Disallowances: A Discrete Choice Model of Regulatory Decisions*

Ph.D. Dissertation: *An Empirical Examination of Environmental Externalities and the Least-Cost Selection of Electric Generation Facilities*

ACADEMIC APPOINTMENTS

Louisiana State University, Baton Rouge, Louisiana

Center for Energy Studies

2014-Current	Executive Director
2007-Current	Director, Division of Policy Analysis
2006-Current	Professor
2003-2014	Associate Executive Director
2001-2006	Associate Professor
1999-2001	Research Fellow and Adjunct Assistant Professor
1995-2000	Assistant Professor

College of the Coast and the Environment (Department of Environmental Studies)

2014-Current	Professor (Joint Appointment with CES)
2010-Current	Director, Coastal Marine Institute
2010-2014	Adjunct Professor

E.J. Ourso College of Business Administration (Department of Economics)

2006-Current	Adjunct Professor
2001-2006	Adjunct Associate Professor
1999-2000	Adjunct Assistant Professor

Michigan State University, East Lansing, Michigan

Institute of Public Utilities

2018-current Senior Fellow

Florida State University, Tallahassee, Florida

College of Social Sciences, Department of Economics

1995 Instructor

PROFESSIONAL EXPERIENCE

Acadian Consulting Group, Baton Rouge, Louisiana

2001-Current	Consulting Economist/Principal
1995-1999	Consulting Economist/Principal

Econ One Research, Inc., Houston, Texas

1999-2001 Senior Economist

Florida Public Service Commission, Tallahassee, Florida

Division of Communications, Policy Analysis Section

1995 Planning & Research Economist

Division of Auditing & Financial Analysis, Forecasting Section

1993	Planning & Research Economist
1992-1993	Economist

Project for an Energy Efficient Florida/FlaSEIA, Tallahassee, Florida

1994 Energy Economist

Ben Johnson Associates, Inc., Tallahassee, Florida

1991-1992	Research Associate
1989-1991	Senior Research Analyst
1988-1989	Research Analyst

GOVERNMENT APPOINTMENTS

2017-Current	Member, National Petroleum Council. U.S. Department of Energy.
2007-Current	Louisiana Representative, Interstate Oil and Gas Compact Commission; Energy Resources, Research & Technology Committee.
2007-Current	Louisiana Representative, University Advisory Board Representative; Energy Council (Center for Energy, Environmental and Legislative Research).
2005	Member, Task Force on Energy Sector Workforce and Economic Development (HCR 322).

2003-2005	Member, Energy and Basic Industries Task Force, Louisiana Economic Development Council
2001-2003	Member, Louisiana Comprehensive Energy Policy Commission.

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3. Review of ***Electric Cooperatives on the Threshold of a New Era*** by Public Utilities Reports. (Vienna, Virginia: Public Utilities Reports, 1996) pp. 232. ISBN 0-910325-63-4. *Energy Journal* 17 (1996): 161-62.

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2. “The Challenges of the Regulatory Review of Diversification Mergers.” (2016). With Michael W. Deupree. *Electricity Journal*. 29 (2016): 9-14.
3. “Unconventional Natural Gas and the U.S. Manufacturing Renaissance” (2013). *BIC Magazine*. Vol. 30: No. 2, p. 76 (March).
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35. *Principal Investigator*. "Examination of the Economic Impacts Associated with Large Customer, Industrial Retail Choice." (2004). With Dmitry V. Mesyanzhinov. Louisiana Mid-Continent Oil and Gas Association. Total Project Funding: $37,000. Status: Completed.

36. *Principal Investigator*. "Economic Opportunities from LNG Development in Louisiana." (2003). With Dmitry V. Mesyanzhinov. Metrovision/New Orleans Chamber of Commerce and the Louisiana Department of Economic Development. Total Project Funding: $25,000. Status: Completed.

37. *Principal Investigator*. "Marginal Oil and Gas Properties on State Leases in Louisiana: An Empirical Examination and Policy Mechanisms for Stimulating Additional Production." (2002). With Robert H. Baumann and Dmitry V. Mesyanzhinov. Louisiana Office of Mineral Resources. Total Project Funding: $72,000. Status: Completed.

38. *Principal Investigator*. "A Collaborative Investigation of Baseline and Scenario Information for Environmental Impact Statements." (2002). With Dmitry V. Mesyanzhinov and Williams O. Olatubi. U.S. Department of Interior, Minerals Management Service. Total Project Funding: $557,744. Status: Awarded, In Progress.

39. *Co-Principal Investigator*. "An Analysis of the Economic Impacts of Drilling and Production Activities on State Leases." (2002). With Robert H. Baumann, Allan G. Pulsipher, and Dmitry V. Mesyanzhinov. Louisiana Office of Mineral Resources. Total Project Funding: $8,000. Status: Completed.

40. *Principal Investigator*. "Cost Profiles and Cost Functions for Gulf of Mexico Oil and Gas Development Phases for Input Output Modeling." (1998). With Dmitry Mesyanzhinov and

Allan G. Pulsipher. U.S. Department of Interior, Minerals Management Service. Total Project Funding: $244,956. Status: Completed.

41. *Principal Investigator*. "An Economic Impact Analysis of OCS Activities on Coastal Louisiana." (1998). With Dmitry Mesyanzhinov and David Hughes. U.S. Department of Interior, Minerals Management Service. Total Project Funding: $190,166. Status: Completed.

42. *Principal Investigator*. "Energy Conservation and Electric Restructuring in Louisiana." (1997). Louisiana Department of Natural Resources." Petroleum Violation Escrow Program Funds. Total Project Funding: $43,169. Status: Completed.

43. *Principal Investigator*. "The Industrial Supply of Electricity: Commercial Generation, Self-Generation, and Industry Restructuring." (1996). With Andrew Kleit. Louisiana Energy Enhancement Program, LSU Office of Research and Development. Total Project Funding: $19,948. Status: Completed.

44. *Co-Principal Investigator*. "Assessing the Environmental and Safety Risks of the Expanded Role of Independents in Oil and Gas E&P Operations on the U.S. Gulf of Mexico OCS." (1996). With Allan Pulsipher, Omowumi Iledare, Dmitry Mesyanzhinov, William Daniel, and Bob Baumann. U.S. Department of Interior, Minerals Management Service, Grant Number 95-0056. Total Project Funding: $109,361. Status: Completed.

ACADEMIC CONFERENCE PAPERS/PRESENTATIONS

1. "The changing nature of Gulf of Mexico energy infrastructure." (2017). Session 3B: New Directions in Social Science Research. 27th Gulf of Mexico Region Information Technology Meetings. U.S. Department of the Interior, Bureau of Ocean Energy Management, Environmental Studies Program. New Orleans, LA. August 24.

2. "Capacity utilization, efficiency trends, and economic risks for modern CHP installations." (2017). U.S. Department of Energy, 2017 Industrial Energy Technology Conference, New Orleans, LA June 21.

3. "Vulnerability assessment of the central Gulf of Mexico coast using a multi-dimensional approach." (2016). With Siddhartha Narra. Eighth International Conference on Environmental Science and Technology. June 6-10, Houston, TX.

4. "The Impact of Infrastructure Cost Recovery Mechanisms on Pipeline Replacements and Leaks." (2015). With Gregory Upton. Southern Economic Association Meeting 2015. New Orleans, Louisiana. November 23.

5. "The Impact of Infrastructure Cost Recovery Mechanisms on Pipeline Replacements and Leaks" (2015). With Gregory Upton. 38th IAEE International Conference, Antalya, Turkey. May 26.

6. "Modifying Renewables Policies to Sustain Positive Economic and Environmental Change" (2015). IEEE Annual Green Technologies ("Greentech") Conference. April 17.

7. "The Gulf Coast Industrial Investment Renaissance and New CHP Development Opportunities." (2014). Industrial Energy and Technology Conference, New Orleans, Louisiana. May 20.

8. “Estimating Critical Energy Infrastructure Value at Risk from Coastal Erosion” (2014). With Siddhartha Narra. American’s Estuaries: 7th Annual Summit on Coastal and Estuarine Habitat Restoration. Washington, D.C., November 3-6.

9. “Economies of Scale, Learning Curves, and Offshore Wind Development Costs” (2012). With Gregory Upton. Southern Economic Association Annual Conference, New Orleans, LA November 17.

10. “Analysis of Risk and Post-Hurricane Reaction.” (2009). 25th Annual Information Transfer Meeting. U.S. Department of the Interior, Minerals Management Service. January 7.

11. “Legacy Litigation, Regulation, and Other Determinants of Interstate Drilling Activity Differentials.” (2008). With Christopher Peters and Mark Kaiser. 28th Annual USAEE/IAEE North American Conference: Unveiling the Future of Future of Energy Frontiers. New Orleans, LA, December 3.

12. “Gulf Coast Energy Infrastructure Renaissance: Overview.” (2008). 28th Annual USAEE/IAEE North American Conference: Unveiling the Future of Future of Energy Frontiers. New Orleans, LA, December 3.

13. “Understanding the Impacts of Katrina and Rita on Energy Industry Infrastructure.” (2008). American Chemical Society National Meetings, New Orleans, Louisiana. April 7.

14. "Determining the Economic Value of Coastal Preservation and Restoration on Critical Energy Infrastructure." (2007). With Kristi A. R. Darby and Michelle Barnett. International Association for Energy Economics, Wellington, New Zealand, February 19.

15. “Regulatory Issues in Rate Design, Incentives, and Energy Efficiency.” (2007). 34th Annual Public Utilities Research Center Conference, University of Florida. Gainesville, FL. February 16.

16. “An Examination of LNG Development on the Gulf of Mexico.” (2007). With Kristi A.R. Darby. US Department of the Interior, Minerals Management Service. 24th Annual Information Technology Meeting. New Orleans, LA. January 9.

17. “OCS-Related Infrastructure on the GOM: Update and Summary of Impacts.” (2007). U.S. Department of the Interior, Minerals Management Service. 24th Annual Information Technology Meeting. New Orleans, LA. January 10.

18. “The Economic Value of Coastal Preservation and Restoration on Critical Energy Infrastructure.” (2006). With Michelle Barnett. Third National Conference on Coastal and Estuarine Habitat Restoration. Restore America’s Estuaries. New Orleans, Louisiana, December 11.

19. “The Impact of Implementing a 20 Percent Renewable Portfolio Standard in New Jersey.” (2006). With Seth E. Cureington. Mid-Continent Regional Science Association 37th Annual Conference, Purdue University, Lafayette, Indiana, June 9.

20. “The Impacts of Hurricane Katrina and Rita on Energy infrastructure Along the Gulf Coast.” (2006). Environment Canada: 2006 Artic and Marine Oilspill Program. Vancouver, British Columbia, Canada.

21. "Hurricanes, Energy Markets, and Energy Infrastructure in the Gulf of Mexico: Experiences and Lessons Learned." (2006). With Kristi A.R. Darby and Seth E. Cureington. 29th Annual IAEE International Conference, Potsdam, Germany, June 9.

22. "An Examination of the Opportunities for Drilling Incentives on State Leases in Louisiana." (2005). With Kristi A.R. Darby. 28th Annual IAEE International Conference, Taipei, Taiwan (June).

23. "Fiscal Mechanisms for Stimulating Oil and Gas Production on Marginal Leases." (2004). With Jeffrey M. Burke. International Association of Energy Economics Annual Conference, Washington, D.C. (July).

24. "GIS and Applied Economic Analysis: The Case of Alaska Residential Natural Gas Demand." (2003). With Dmitry V. Mesyanzhinov. Presented at the Joint Meeting of the East Lakes and West Lakes Divisions of the Association of American Geographers in Kalamazoo, MI, October 16-18.

25. "Are There Any In-State Uses for Alaska Natural Gas?" (2002). With Dmitry V. Mesyanzhinov and William E. Nebesky. IAEE/USAEE 22nd Annual North American Conference: "Energy Markets in Turmoil: Making Sense of It All." Vancouver, British Columbia, Canada. October 7.

26. "The Economic Impact of State Oil and Gas Leases on Louisiana." (2002). With Dmitry V. Mesyanzhinov. 2002 National IMPLAN Users' Conference. New Orleans, Louisiana, September 4-6.

27. "Moving to the Front of the Lines: The Economic Impact of Independent Power Plant Development in Louisiana." (2002). With Dmitry V. Mesyanzhinov and Williams O. Olatubi. 2002 National IMPLAN Users' Conference. New Orleans, Louisiana, September 4-6.

28. "New Consistent Approach to Modeling Regional Economic Impacts of Offshore Oil and Gas Activities in the Gulf of Mexico." (2002). With Vicki Zatarain. 2002 National IMPLAN Users' Conference. New Orleans, Louisiana, September 4-6.

29. "Distributed Energy Resources, Energy Efficiency, and Electric Power Industry Restructuring." (1999). American Society of Environmental Science Fourth Annual Conference. Baton Rouge, Louisiana. December.

30. "Estimating Efficiency Opportunities for Coal Fired Electric Power Generation: A DEA Approach." (1999). With Williams O. Olatubi. Southern Economic Association Sixty-ninth Annual Conference. New Orleans, November.

31. "Applied Approaches to Modeling Regional Power Markets." (1999.) With Robert F. Cope. Southern Economic Association Sixty-ninth Annual Conference. New Orleans, November 1999.

32. "Parametric and Non-Parametric Approaches to Measuring Efficiency Potentials in Electric Power Generation." (1999). With Williams O. Olatubi. International Atlantic Economic Society Annual Conference, Montreal, October.

33. "Asymmetric Choice and Customer Benefits: Lessons from the Natural Gas Industry." (1999). With Rachelle F. Cope and Dmitry Mesyanzhinov. International Association of Energy Economics Annual Conference. Orlando, Florida. August.

34. "Modeling Regional Power Markets and Market Power." (1999). With Robert F. Cope. Western Economic Association Annual Conference. San Diego, California. July.

35. "Economic Impact of Offshore Oil and Gas Activities on Coastal Louisiana" (1999). With Dmitry Mesyanzhinov. Annual Meeting of the Association of American Geographers. Honolulu, Hawaii. March.

36. "Empirical Issues in Electric Power Transmission and Distribution Cost Modeling." (1998). With Robert F. Cope and Dmitry Mesyanzhinov. Southern Economic Association. Sixty-Eighth Annual Conference. Baltimore, Maryland. November.

37. "Modeling Electric Power Markets in a Restructured Environment." (1998). With Robert F. Cope and Dan Rinks. International Association for Energy Economics Annual Conference. Albuquerque, New Mexico. October.

38. "Benchmarking Electric Utility Distribution Performance." (1998) With Robert F. Cope and Dmitry Mesyanzhinov. Western Economic Association, Seventy-sixth Annual Conference. Lake Tahoe, Nevada. June.

39. "Power System Operations, Control, and Environmental Protection in a Restructured Electric Power Industry." (1998). With Fred I. Denny. IEEE Large Engineering Systems Conference on Power Engineering. Nova Scotia, Canada. June.

40. "Benchmarking Electric Utility Transmission Performance." (1997). With Robert F. Cope and Dmitry Mesyanzhinov. Southern Economic Association, Sixty-seventh Annual Conference. Atlanta, Georgia. November 21-24.

41. "A Non-Linear Programming Model to Estimate Stranded Generation Investments in a Deregulated Electric Utility Industry." (1997). With Robert F. Cope and Dan Rinks. Institute for Operations Research and Management Science Annual Conference. Dallas Texas. October 26-29.

42. "New Paradigms for Power Engineering Education." (1997). With Fred I. Denny. International Association of Science and Technology for Development, High Technology in the Power Industry Conference. Orlando, Florida. October 27-30

43. "Cogeneration and Electric Power Industry Restructuring." (1997). With Andrew N. Kleit. Western Economic Association, Seventy-fifth Annual Conference. Seattle, Washington. July 9-13.

44. "The Unintended Consequences of the Public Utilities Regulatory Policies Act of 1978." (1997). National Policy History Conference on the Unintended Consequences of Policy Decisions. Bowling Green State University. Bowling Green, Ohio. June 5-7.

45. "Assessing Environmental and Safety Risks of the Expanding Role of Independents in E&P Operations on the Gulf of Mexico OCS." (1996). With Allan Pulsipher, Omowumi Iledare, Dmitry Mesyanzhinov, and Bob Baumann. U.S. Department of Interior, Minerals Management Service, 16th Annual Information Transfer Meeting. New Orleans, Louisiana.

46. "Empirical Modeling of the Risk of a Petroleum Spill During E&P Operations: A Case Study of the Gulf of Mexico OCS." (1996). With Omowumi Iledare, Allan Pulsipher, and Dmitry Mesyanzhinov. Southern Economic Association, Sixty-Sixth Annual Conference. Washington, D.C.

47. "Input Price Fluctuations, Total Factor Productivity, and Price Cap Regulation in the Telecommunications Industry" (1996). With Farhad Niami. Southern Economic Association, Sixty-Sixth Annual Conference. Washington, D.C.
48. "Recovery of Stranded Investments: Comparing the Electric Utility Industry to Other Recently Deregulated Industries" (1996). With Farhad Niami and Dmitry Mesyanzhinov. Southern Economic Association, Sixty-Sixth Annual Conference. Washington, D.C.
49. "Spatial Perspectives on the Forthcoming Deregulation of the U.S. Electric Utility Industry." (1996) With Dmitry Mesyanzhinov. Southwest Association of American Geographers Annual Meeting. Norman, Oklahoma.
50. "Comparing the Safety and Environmental Performance of Offshore Oil and Gas Operators." (1995). With Allan Pulsipher, Omowumi Iledare, Dmitry Mesyanzhinov, William Daniel, and Bob Baumann. U.S. Department of Interior, Minerals Management Service, 15th Annual Information Transfer Meeting. New Orleans, Louisiana.
51. "Empirical Determinants of Nuclear Power Plant Disallowances." (1995). Southern Economic Association, Sixty-Fifth Annual Conference. New Orleans, Louisiana.
52. "A Cross-Sectional Model of IntraLATA MTS Demand." (1995). Southern Economic Association, Sixty-Fifth Annual Conference. New Orleans, Louisiana.

ACADEMIC SEMINARS AND PRESENTATIONS

1. Panelist. "Fuel Security, Resource Adequacy & Value of Transmission." (2019). 6th Annual Electricity Dialogue at Northwestern University: Energy and Capacity: Transitions? Northwestern University Center of Law, Regulation, and Economic Growth.
2. "Air Emissions Regulation and Policy: The Recently Proposed Cross State Air Pollution Rule and the Implications for Louisiana Power Generation." Lecture before School of the Coast & Environment. November 5, 2011.
3. "Energy Regulation: Overview of Power and Gas Regulation." Lecture before School of the Coast & Environment, Course in Energy Policy and Law. October 5, 2009.
4. "Trends and Issues in Renewable Energy." Presentation before the School of the Coast & Environment, Louisiana State University. Spring Guest Lecture Series. May 4, 2007.
5. "CES Research Projects and Status." Presentation before the U.S. Department of the Interior, Minerals Management Service, Outer Continental Shelf Scientific Committee Meeting, New Orleans, LA May 22, 2007.
6. "Hurricane Impacts on Energy Production and Infrastructure." Presentation Before the 53rd Mineral Law Institute, Louisiana State University. April 7, 2006.
7. "Trends and Issues in the Natural Gas Industry and the Development of LNG: Implications for Louisiana. (2004) 51st Mineral Law Institute, Louisiana State University, Baton Rouge, LA. April 2, 2004.
8. "Electric Restructuring and Conservation." (2001). Presentation before the Department of Electrical Engineering, McNesse State University. Lake Charles, Louisiana. May 2, 2001.

9. “Electric Restructuring and the Environment.” (1998). Environment 98: Science, Law, and Public Policy. Tulane University. Tulane Environmental Law Clinic. March 7, New Orleans, Louisiana.

10. “Electric Restructuring and Nuclear Power.” (1997). Louisiana State University. Department of Nuclear Science. November 7, Baton Rouge, Louisiana.

11. “The Empirical Determinants of Co-generated Electricity: Implications for Electric Power Industry Restructuring.” (1997). With Andrew N. Kleit. Florida State University. Department of Economics: Applied Microeconomics Workshop Series. October 17, Tallahassee, Florida.

PROFESSIONAL AND CIVIC PRESENTATIONS

1. “Ratepayer benefits of reforming PURPA”. (2020). Harvard Electricity Policy Group Webinar. PURPA: A time to reform or reduce its role? March 26.

2. “Pipeline industry: economic trends and outlook”. (2020). Joint Industry Association Annual Meeting. Louisiana Mid-Continent Oil and Gas Association (“LMOGA”) and the Louisiana Oil and Gas Association (“LOGA”). Lake Charles, LA March 5.

3. “The outlook for natural gas: storm clouds ahead?” (2020). National Association of State Utility Consumer Advocates (“NASUCA”). Natural Gas Committee Webinar, February 26.

4. “The 2020 Gulf Coast Energy Outlook”. (2020). University of Louisiana Lafayette, Southern Unconventional Resources Center for Excellence. Lafayette, LA February 16.

5. “Opportunities for carbon capture, utilization, and storage in the Louisiana chemical corridor”. (2020). Air and Waste Management Association, Louisiana Section Luncheon. Gonzales, LA January 16.

6. Panelist. (2020). Baton Route Advocate, 2020 Economic Outlook Summit. Baton Rouge Advocate. January 8.

7. “2020 Louisiana business climate outlook: the view from the energy sector.” (2019). American Council of Engineering Companies Fall Conference. November 21, 2019. Baton Rouge, LA

8. “The urgency of PURPA reform in protecting ratepayers.” (2019). Americans for Tax Reform, Fall 2019 Coalition Leaders Summit, November 14, 2019. New Orleans, LA.

9. “Louisiana’s coast and the energy industry.” (2019). 2019 API Delta Chapter Joint Society Luncheon Meeting. November 12, 2019, New Orleans, LA.

10. “Reforming PURPA: implications for ratepayers.” (2019). Thomas Jefferson Institute for Public Policy, Annual Energy Summit, State Policy Network Annual Meeting. Colorado Springs, CO, October 28.

11. “Natural gas outlook: supply, demand and prices.” (2019). National Association of State Utility Consumer Advocates, Natural Gas Committee Monthly Meeting. July 30, 2019.

12. “The economic impacts and outlook for LNG development on the Gulf Coast.” (2019). 73rd Annual Meeting of the Southern Legislative Conference of the Council of State Governments. New Orleans, LA, July 14. (prepared presentation, hurricane cancellation)

13. “Natural gas outlook: supply, demand, and prices.” (2019). NASUCA Mid-Year Meeting. Portland, OR, June 20.
14. “Overview of Louisiana LNG issues and trends.” (2019). Berlin: LNG, Energy Security, and Diversity Reporting Tour, LSU Center for Energy Studies. Baton Rouge, LA, May 9.
15. “Overview of Louisiana energy issues and outlook.” (2019). Australian Media Visit, Greater New Orleans, Inc./Baton Rouge Area Foundation. Baton Rouge, LA, April 29.
16. “Gulf Coast Energy Outlook 2019: Regional trends and outlook.” (2019). Women’s Energy Network. Baton Rouge, LA, April 23.
17. “MISO Grid Vision 2033.” (2019). 2019 Spring Regulator and Policymaker Forum. New Orleans, LA, April 15-16.
18. “Ratepayer benefits of reforming PURPA.” (2019). LSU Center for Energy Studies Industry Advisory Council Meeting. March 27.
19. “Incentives, risk, and the changing nature of regulation.” (2019). NASUCA Water Committee monthly meeting/webinar. March 13.
20. “Gulf Coast Energy Outlook 2019: Production, trade and infrastructure trends.” (2019). 66th Annual Mineral Board Institute Meetings. Baton Rouge, LA, March 14.
21. “A golden age: energy outlook 2019.” (2019). Engineering News Record Webinar. February 13.
22. Panelist. (2019). Baton Route Advocate, 2019 Economic Outlook Summit. Baton Rouge Advocate. January 8.
23. “MISO Grid Vision 2033.” (2018). 2018 Winter Regulatory and Policymaker Forum. New Orleans, LA, December 11.
24. “Gulf Coast Energy Outlook 2019.” (2018). LSU Center for Energy Studies, Baton Rouge, LA, Fall 2018.
25. “How LNG is transforming Louisiana’s energy economy.” (2018). Louisiana State Bar Association, Public Utility Section. Baton Rouge, LA, November 30.
26. “Overview of Louisiana LNG issues and trends.” (2018). Kean Miller Law Firm: Energy and Environmental Practice Group. Baton Rouge, LA, November 28.
27. “Infrastructure and capacity: challenges for development.” (2018). Society of Utility and Regulatory Financial Analysts (SURFA) Annual Meeting, New Orleans, LA, April 20.
28. “Louisiana industrial cogeneration trends.” (2018). Annual Louisiana Solid Waste Association Conference, Lafayette, LA, March 16.
29. “Gulf Coast industrial development: overview of trends and issues.” (2018). Gulf Coast Power Association Meetings, New Orleans, LA, February 8.
30. “Energy outlook – reflection on market trends and Louisiana implications.” (2017). IberiaBank Corporation Bank Board of Directors Meeting, New Orleans, LA. November 15.
31. “Integrated carbon capture and storage in the Louisiana chemical corridor.” (2017). Industry Associates Advisory Council Meeting, Baton Rouge, LA. November 7.

32. “The outlook for natural gas and energy development on the Gulf Coast.” (2017). Louisiana Chemical Association, Annual Meeting, New Orleans, LA. October 26.

33. “Critical energy infrastructure: the big picture on resiliency research.” (2017). National Academies of Science, Engineering, and Medicine. New Orleans, LA. September 18.

34. “The changing nature of Gulf of Mexico energy infrastructure.” (2017). 27th Gulf of Mexico Region Information Technology Meetings, New Orleans, LA, August 24.

35. “Capacity utilization, efficiency trends, and economic risks for modern CHP installations.” (2017). Industrial Energy Technology Conference, New Orleans, LA. June 21.

36. “Crude oil and natural gas outlook: Where are we and where are we going?” (2017). CCREDC Economic Trends Panel. Corpus Christi, TX, June 15.

37. “Navigating through the energy landscape.” (2017). Baton Rouge Rotary Luncheon. Baton Rouge, LA, May 24.

38. “The 2017-2018 Louisiana energy outlook.” (2017). Junior Achievement of Greater New Orleans, JA BizTown Speaker Series. New Orleans, LA, May 12.

39. “The Gulf Coast energy economy: trends and outlook.” (2017). Society for Municipal Analysts. New Orleans, LA, April 21.

40. “Gulf coast energy outlook.” (2017). E.J. Ourso College of Business, Dean’s Advisory Council, Energy Committee Meeting. Baton Rouge, LA, March 31.

41. “Recent trends in energy: overview and impact for the banking community.” (2017). Oil and Gas Industry Update, Louisiana Bankers Association. Baton Rouge, LA, March 24.

42. “How supply, demand and prices have influenced unconventional development.” (2016). Energy Annual Meeting, CLEER-University Advisory Board Lecture. New Orleans, LA, September 17.

43. “The Basics of Natural Gas Production, Transportation, and Markets.” (2016). Center for Energy Studies. Baton Rouge, LA, August 1.

44. “Gulf Coast industrial development: trends and outlook.” (2016). Investor Relations Group Meeting, Edison Electric Institute. New Orleans, LA, June 23.

45. “The future of policy and regulation: Unlocking the Treasures of Utility Regulation.” (2016). Annual Meeting, National Conference of Regulatory Attorneys. Tampa, FL, June 20.

46. “Utility mergers: where’s the beef?”. (2016). National Association of State Utility Consumer Advocates Mid-Year Meetings. New Orleans, LA, June 6.

47. “Overview of the Clean Power Plan and its application to Louisiana.” (2016). Shell Oil Company Internal Meeting. April 12.

48. “Energy and economic development on the Gulf Coast: trends and emerging challenges.” (2016). Gas Processors Association Meeting. New Orleans, LA, April 11.

49. “Unconventional Oil and Gas Drilling Trends and Issues.” (2016). French Delegation Visit, LSU Center for Energy Studies. March 16.

50. “Gulf Coast Industrial Growth: Passing clouds or storms on the horizon?” (2016). Gulf Coast Power Association Meetings. New Orleans, LA, February 18.

51. "The Transition to Crisis: What do the recent changes in energy markets mean for Louisiana?" (2016). Louisiana Independent Study Group. February 2.

52. "Regulatory and Ratepayer Issues in the Analysis of Utility Natural Gas Reserves Purchases" (2016). National Association of State Utility Consumer Advocates Gas Consumer Monthly Meeting. January 25.

53. "Emerging Issues in Fuel Procurement: Opportunities & Challenges in Natural Gas Reserves Investment." (2015). National Association of State Utility Consumer Advocates Annual Meeting. Austin, Texas. November 9.

54. "Trends and Issues in Net Metering and Solar Generation." (2015). Louisiana Rural Electric Cooperative Meeting. November 5.

55. "Electric Power: Industry Overview, Organization, and Federal/State Distinctions." (2015). EUCI. October 16.

56. "Natural Gas 101: The Basics of Natural Gas Production, Transportation, and Markets." (2015). Council of State Governments Special Meeting on Gas Markets. New Orleans, LA. October 14.

57. "Update and General Business Matters." (2015). CES Industry Associates Meeting. Baton Rouge, Louisiana. Fall 2015.

58. "The Impact of Infrastructure Cost Recovery Mechanisms on Pipeline Replacements and Leaks." (2015). 38th IAEE 2015 International Conference. Antalya, Turkey. May 26.

59. "Industry on the Move – What's Next?" (2015). Event Sponsored by Regional Bank and 1012 Industry Report. May 5.

60. "The State of the Energy Industry and Other Emerging Issues." (2015). Lex Mundi Energy & Natural Resources Practice Group Global Meeting. May 5.

61. "Energy, Louisiana, and LSU." (2015). LSU Science Café. Baton Rouge, Louisiana. April 28.

62. "Energy Market Changes and Impacts for Louisiana." (2015). Kinetica Partners Shippers Meeting, New Orleans, Louisiana. April 22.

63. "Incentives, Risk and the Changing Nature of Utility Regulation." (2015). NARUC Staff Subcommittee on Accounting and Finance Meetings, New Orleans, Louisiana. April 22.

64. "Modifying Renewables Policies to Sustain Positive and Economic Change." (2015). IEEE Annual Green Technologies ("Greentech Conference"). April 17.

65. "Louisiana's Changing Energy Environment." (2015). John P. Laborde Energy Law Center Advisory Board Spring Meeting, Baton Rouge, Louisiana. March 27.

66. "The Latest and the Long on Energy: Outlooks and Implications for Louisiana." (2015). Iberia Bank Advisory Board Meeting, Baton Rouge, Louisiana. February 23.

67. "A Survey of Recent Energy Market Changes and their Potential Implications for Louisiana." (2015). Vistage Group, New Orleans, Louisiana. February 4.

68. "Energy Prices and the Outlook for the Tuscaloosa Marine Shale." (2015). Baton Rouge Rotary Club, Baton Rouge, Louisiana. January 28.

69. "Trends in Energy & Energy-Related Economic Development." (2014). Miller and Thompson Presentation, Baton Rouge, Louisiana. December 30.

70. "Overview EPA's Proposed Rule Under Section 111(d) of the Clean Air Act: Impacts for Louisiana." (2014). Louisiana State Bar: Utility Section CLE Annual Meeting, Baton Rouge, Louisiana. November 7.

71. "Overview EPA's Proposed Clean Power Plan and Impacts for Louisiana." (2014). Clean Cities Coalition Meeting, Baton Rouge, Louisiana. November 5.

72. "Impacts on Louisiana from EPA's Proposed Clean Power Plan." (2014). Air & Waste Management Annual Environmental Conference (Louisiana Chapter), Baton Rouge, Louisiana. October 29, 2014.

73. "A Look at America's Growing Demand for Natural Gas." (2014). Louisiana Chemical Association Annual Meeting, New Orleans, Louisiana. October 23.

74. "Trends in Energy & Energy-Related Economic Development." (2014). 2014 Government Finance Officer Association Meetings, Baton Rouge, Louisiana. October 9.

75. "The Conventional Wisdom Associated with Unconventional Resource Development." (2014). National Association for Business Economics Annual Conference, Chicago, Illinois. September 28.

76. Unconventional Oil & Natural Gas: Overview of Resources, Economics & Policy Issues. (2014). Society of Environmental Journalists Annual Meeting. New Orleans, Louisiana. September 4.

77. "Natural Gas Leveraged Economic Development in the South." (2014). Southern Governors Association Meeting, Little Rock, Arkansas. August 16.

78. "The Past, Present and Future of CHP Development in Louisiana." (2014). Louisiana Public Service Commission CHP Workshop, Baton Rouge, Louisiana. June 25.

79. "Regional Natural Gas Demand Growth: Industrial and Power Generation Trends." (2014). Kinetica Partners Shippers Meeting, New Orleans, Louisiana. April 30.

80. "The Technical and Economic Potential for CHP in Louisiana and the Impact of the Industrial Investment Renaissance on New CHP Capacity Development." (2014). Electric Power 2014, New Orleans, Louisiana. April 1.

81. "Industry Investments and the Economic Development of Unconventional Development." (2014). Tuscaloosa Marine Shale Conference & Expo, Natchez, Mississippi. March 31.

82. Discussion Panelist. Energy Outlook 2035: The Global Energy Industry and Its Impact on Louisiana, (2014). Grow Louisiana Coalition, Baton Rouge, Louisiana. March 18.

83. "Natural Gas and the Polar Vortex: Has Recent Weather Led to a Structural Change in Natural Gas Markets?" (2014). National Association of State Utility Consumer Advocates Monthly Gas Committee Meeting. February 19.

84. "Some Unconventional Thoughts on Regional Unconventional Gas and Power Generation Requirements." (2014). Gulf Coast Power Association Special Briefing, New Orleans, Louisiana. February 6.

85. "Leveraging Energy for Industrial Development." (2013). 2013 Governor's Energy Summit,

Jackson, Mississippi. December 5.

86. "Natural Gas Line Extension Policies: Ratepayer Issues and Considerations." (2013). National Association of State Utility Consumer Advocates Annual Meeting, Orlando, Florida. November 19.

87. "Replacement, Reliability & Resiliency: Infrastructure & Ratemaking Issues in the Power & Natural Gas Distribution Industries." (2013). Louisiana State Bar, Public Utility Section Meetings. November 15.

88. "Natural Gas Markets: Leveraging the Production Revolution into an Industrial Renaissance." (2013). International Technical Conference, Houston, TX. October 11.

89. "Natural Gas, Coal & Power Generation Issues and Trends." (2013). Southeast Labor and Management Public Affairs Committee Conference, Chattanooga, Tennessee. September 27.

90. "Recent Trends in Pipeline Replacement Trackers." (2013). National Association of State Utility Consumer Advocates Monthly Gas Committee Meeting. September 19.

91. Discussion Panelist (2013). Think About Energy Summit, America's Natural Gas Alliance, Columbus Ohio. September 16-17.

92. "Future Test Years: Issues to Consider." (2013). National Regulatory Research Institute, Teleseminar on Future Test Years. August 28.

93. "Industrial Development Outlook for Louisiana." (2013). Louisiana Water Synergy Project Meetings, Jones Walker Law Firm, Baton Rouge, Louisiana. July 30.

94. "Natural Gas & Electric Power Coordination Issues and Challenges." (2013). Utilities State Government Organization Conference, Pointe Clear, Alabama. July 9.

95. "Natural Gas Market Issues & Trends." (2013). Western Conference of Public Service Commissioners, Santa Fe, New Mexico. June 3.

96. "Louisiana Unconventional Natural Gas and Industrial Redevelopment." (2013). Louisiana Chemical Association/Louisiana Chemical Industry Alliance Annual Legislative Conference, Baton Rouge, Louisiana. May 8.

97. "Infrastructure Cost Recovery Mechanism: Overview of Issues." (2013). Energy Bar Association Annual Meeting, Washington, D.C. May 1.

98. "GOM Offshore Oil and Gas." (2013). Energy Executive Roundtable, New Orleans, Louisiana. March 27.

99. "Louisiana Unconventional Natural Gas and Industrial Redevelopment." (2013). Risk Management Association Luncheon, March 21.

100. "Natural Gas Market Update and Emerging Issues." (2013). NASUCA Gas Committee Conference Call/Webinar, March 12.

101. "Unconventional Resources and Louisiana's Manufacturing Development Renaissance." (2013). Baton Rouge Press Club, De La Ronde Hall, Baton Rouge, LA, January 28.

102. "New Industrial Operations Leveraged by Unconventional Natural Gas." (2013) American Petroleum Institute-Louisiana Chapter. Lafayette, LA, Petroleum Club, January 14.

103. "What's Going on with Energy? How Unconventional Oil and Gas Development is Impacting Renewables, Efficiency, Power Markets, and All that Other Stuff." (2012). Atlanta Economics Club Monthly Meeting. Atlanta, GA. December 11.

104. "Trends, Issues, and Market Changes for Crude Oil and Natural Gas." (2012). East Iberville Community Advisory Panel Meeting. St. Gabriel, LA. September 26.

105. "Game Changers in Crude and Natural Gas Markets." (2012). Chevron Community Advisory Panel Meeting. Belle Chase, LA, September 17.

106. "The Outlook for Renewables in a Changing Power and Natural Gas Market." (2012). Louisiana Biofuels and Bioprocessing Summit. Baton Rouge, LA. September 11.

107. "The Changing Dynamics of Crude and Natural Gas Markets." (2012). Chalmette Refining Community Advisory Panel Meeting. Chalmette, LA, September 11.

108. "The Really Big Game Changer: Crude Oil Production from Shale Resources and the Tuscaloosa Marine Shale." (2012). Baton Rouge Chamber of Commerce Board Meeting. Baton Rouge, LA, June 27.

109. "The Impact of Changing Natural Gas Prices on Renewables and Energy Efficiency." (2012). NASUCA Gas Committee Conference Call/Webinar. 12 June 2012.

110. "Issues in Gas-Renewables Coordination: How Changes in Natural Gas Markets Potentially Impact Renewable Development" (2012). Energy Bar Association, Louisiana Chapter, Annual Meeting, New Orleans, LA. April 12, 2012.

111. "Issues in Natural Gas End-Uses: Are We Really Focusing on the Real Opportunities?" (2012). Energy Bar Association, Louisiana Chapter, Annual Meeting, New Orleans, LA. April 12, 2012.

112. "The Impact of Legacy Lawsuits on Conventional Oil and Gas Drilling in Louisiana." (2012). Louisiana Oil and Gas Association Annual Meeting, Lake Charles, LA. February 27, 2012.

113. "The Impact of Legacy Lawsuits on Conventional Oil and Gas Drilling in Louisiana." (2012) Louisiana Oil and Gas Association Annual Meeting. Lake Charles, Louisiana. February 27, 2012.

114. "Louisiana's Unconventional Plays: Economic Opportunities, Policy Challenges. Louisiana Mid-Continent Oil and Gas Association 2012 Annual Meeting. (2012) New Orleans, Louisiana. January 26, 2012.

115. "EPA's Recently Proposed Cross State Air Pollution Rule ("CSAPR") and Its Impacts on Louisiana." (2011). Bossier Chamber of Commerce. November 18, 2011.

116. "Facilitating the Growth of America's Natural Gas Advantage." (2011). BASF U.S. Shale Gas Workshop Management Meeting. Florham Park, New Jersey. November 1, 2011.

117. "CSAPR and EPA Regulations Impacting Louisiana Power Generation." (2011). Air and Waste Management Association (Louisiana Section) Fall Conference. Environmental Focus 2011: a Multi-Media Forum. Baton Rouge, LA. October 25, 2011.

118. "Natural Gas Trends and Impact on Industrial Development." (2011). Central Gulf Coast Industrial Alliance Conference. Arthur R. Outlaw Convention Center. Mobile, AL.

September 22, 2011.

119. "Energy Market Changes and Policy Challenges." (2011). Southeast Manpower Tripartite Alliance ("SEMTA") Summer Conference. Nashville, TN September 2, 2011.

120. "EPA Regulations, Rates & Costs: Implications for U.S. Ratepayers." (2011). Workshop: "A Smarter Approach to Improving Our Environment." 38th Annual American Legislative Exchange Council ("ALEC") Meetings. New Orleans, LA. August 5, 2011.

121. Panelist/Moderator. Workshop: "Why Wait? Start Energy Independence Today." 38th Annual American Legislative Exchange Council ("ALEC") Meetings. New Orleans, LA. August 4, 2011.

122. "Facilitating the Growth of America's Natural Gas Advantage." Texas Chemical Council, Board of Directors Summer Meeting. San Antonio, TX. July 28, 2011.

123. "Creating Ratepayer Benefits by Reconciling Recent Gas Supply Opportunities with Past Policy Initiatives." National Association of State Utility Consumer Advocates ("NASUCA"), Monthly Gas Committee Meeting. July 12, 2011.

124. "Energy Market Trends and Policies: Implications for Louisiana." (2011). Lakeshore Lion's Club Monthly Meeting. Baton Rouge, Louisiana. June 20, 2011.

125. "America's Natural Gas Advantage: Securing Benefits for Ratepayers Through Paradigm Shifts in Policy." Southeastern Association of Regulatory Commissioners ("SEARUC") Annual Meeting. Nashville, Tennessee. June 14, 2011.

126. "Learning Together: Building Utility and Clean Energy Industry Partnerships in the Southeast." (2011). American Solar Energy Society National Solar Conference. Raleigh Convention Center, Raleigh, North Carolina. May 20, 2011.

127. "Louisiana Energy Outlook and Trends." (2011). Executive Briefing. Counsul General of Canada. LSU Center for Energy Studies, Baton Rouge, Louisiana. May 24, 2011.

128. "Louisiana's Natural Gas Advantage: Can We Hold It? Grow It? Or Do We Need to be Worrying About Other Problems?" (2011). Louisiana Chemical Association Annual Legislative Conference, Baton Rouge, Louisiana, May 5, 2011.

129. "Energy Outlook and Trends: Implications for Louisiana. (2011). Executive Briefing, Legislative Staff, Congressman William Cassidy. LSU Center for Energy Studies, Baton Rouge, Louisiana. March 25, 2011.

130. "Regulatory Issues in Inflation Adjustment Mechanisms and Allowances." (2011). Gas Committee, National Association of State Utility Consumer Advocates ("NASUCA"). February 15, 2011.

131. "Regulatory Issues in Inflation Adjustment Mechanisms and Allowances." (2010). 2010 Annual Meeting, National Association of State Utility Consumer Advocates ("NASUCA"), Omni at CNN Center, Atlanta, Georgia, November 16, 2010.

132. "How Current and Proposed Energy Policy Impacts Consumers and Ratepayers." (2010). 122nd Annual Meeting, National Association of Regulatory Utility Commissioners ("NARUC"), Omni at CNN Center, Atlanta, Georgia, November 15, 2010.

133. "Energy Outlook: Trends and Policies." (2010). 2010 Tri-State Member Service

Conference; Arkansas, Louisiana, and Mississippi Electric Cooperatives. L'Auberge du Lac Casino Resort, Lake Charles, Louisiana, October 14, 2010.

134. "Deepwater Moratorium and Louisiana Impacts." (2010). The Energy Council Annual Meeting. Gulf of Mexico Deepwater Horizon Accident, Response, and Policy. Beau Rivage Conference Center. Biloxi, Mississippi. September 25, 2010.

135. "Overview on Offshore Drilling and Production Activities in the Aftermath of Deepwater Horizon." (2010) Jones Walker Banking Symposium. The Oil Spill: What Will it Mean for Banks in the Region? New Orleans, Louisiana. August 31, 2010.

136. "Long-Term Energy Sector Impacts from the Oil Spill." (2010). Second Annual Louisiana Oil & Gas Symposium. The BP Gulf Oil Spill: Long-Term Impacts and Strategies. Baton Rouge Geological Society. August 16, 2010.

137. "Overview and Issues Associated with the Deepwater Horizon Accident." (2010). Global Interdependence Meeting on Energy Issues. Baton Rouge, LA. August 12, 2010.

138. "Overview and Issues Associated with the Deepwater Horizon Accident." (2010). Regional Roundtable Webinar. National Association for Business Economics. August 10, 2010.

139. "Deepwater Moratorium: Overview of Impacts for Louisiana." Louisiana Association of Business and Industry Meeting. Baton Rouge, LA. June 25, 2010.

140. Moderator. Senior Executive Roundtable on Industrial Energy Efficiency. U.S. Department of Energy Conference on Industrial Efficiency. Office of Renewable Energy and Energy Efficiency. Royal Sonesta Hotel, New Orleans, LA. May 21, 2010.

141. "The Energy Outlook: Trends and Policies Impacting Southeastern Natural Gas Supply and Demand Growth." Second Annual Local Economic Analysis and Research Network ("LEARN") Conference. Federal Reserve Bank of Atlanta. March 29, 2010.

142. "Natural Gas Supply Issues: Gulf Coast Supply Trends and Implications for Louisiana." Energy Bar Association, New Orleans Chapter Meeting. Jones Walker Law Firm. January 28, 2010, New Orleans, LA.

143. "Potential Impacts of Federal Greenhouse Gas Legislation on Louisiana Industry." LCA Government Affairs Committee Meeting. November 10, 2009. Baton Rouge, LA

144. "Regulatory and Ratemaking Issues Associated with Cost and Revenue Tracker Mechanisms." National Association of State Utility Consumer Advocates ("NASUCA") Annual Meeting. November 10, 2009.

145. "Louisiana's Stakes in the Greenhouse Gas Debate." Louisiana Chemical Association and Louisiana Chemical Industry Alliance Annual Meeting: The Billing Dollar Budget Crisis: Catastrophe or Change? New Orleans, LA.

146. "Gulf Coast Energy Outlook: Issues and Trends." Women's Energy Network, Louisiana Chapter. September 17, 2009. Baton Rouge, LA.

147. "Gulf Coast Energy Outlook: Issues and Trends." Natchez Area Association of Energy Service Companies. September 15, 2009, Natchez, MS.

148. "The Small Picture: The Cost of Climate Change to Louisiana." Louisiana Association of Business and Industry, U.S. Chamber of Commerce, Louisiana Oil and Gas Association,

and LSU Center for Energy Studies Conference: Can Louisiana Make a Buck After Climate Change Legislation? August 21, 2009. Baton Rouge, LA.

149. “Carbon Legislation and Clean Energy Markets: Policy and Impacts.” National Association of Conservation Districts, South Central Region Meeting. August 14, 2009. Baton Rouge, LA.

150. “Evolving Carbon and Clean Energy Markets.” The Carbon Emissions Continuum: From Production to Consumption.” Jones Walker Law Firm and LSU Center for Energy Studies Workshop. June 23, 2009. Baton Rouge, LA

151. “Potential Impacts of Cap and Trade on Louisiana Ratepayers: Preliminary Results.” (2009). Briefing before the Louisiana Public Service Commission. Business and Executive Meeting, May 12, 2009. Baton Rouge, LA.

152. “Natural Gas Outlook.” (2009). Briefing before the Louisiana Public Service Commission. Business and Executive Meeting, May 12, 2009. Baton Rouge, LA.

153. “Gulf Coast Energy Outlook: Issues and Trends.” (2009). ISA-Lafayette Technical Conference & Expo. Cajundome Conference Center. Lafayette, Louisiana. March 12, 2009.

154. “The Cost of Energy Independence, Climate Change, and Clean Energy Initiatives on Utility Ratepayers.” (2009). National Association of Business Economics (NABE). 25th Annual Washington Economic Policy Conference: Restoring Financial and Economic Stability. Arlington, VA March 2, 2009.

155. Panelist, “Expanding Exploration of the U.S. OCS” (2009). Deep Offshore Technology International Conference and Exhibition. PennWell. New Orleans, Louisiana. February 4, 2009.

156. “Gulf Coast Energy Outlook.” (2008.) Atmos Energy Regional Management Meeting. Louisiana and Mississippi Division. New Orleans, Louisiana. October 8, 2008.

157. “Background, Issues, and Trends in Underground Hydrocarbon Storage.” (2008). Presentation before the LSU Center for Energy Studies Industry Advisory Board Meeting. Baton Rouge, Louisiana. August 27, 2008.

158. “Greenhouse Gas Regulations and Policy: Implications for Louisiana.” (2008). Presentation before the Praxair Customer Seminar. Houston, Texas, August 14, 2008.

159. “Market and Regulatory Issues in Alternative Energy and Louisiana Initiatives.” (2008). Presentation before the 2008 Statewide Clean Cities Coalition Conference: Making Sense of Alternative Fuels and Advanced Technologies. New Orleans, Louisiana, March 27, 2008.

160. “Regulatory Issues in Rate Design, Incentives, and Energy Efficiency.” (2007) Presentation before the New Hampshire Public Utilities Commission. Workshop on Energy Efficiency and Revenue Decoupling. November 7, 2007.

161. “Regulatory Issues for Consumer Advocates in Rate Design, Incentives, and Energy Efficiency.” (2007). National Association of State Utility Consumer Advocates, Mid-Year Meeting. June 12, 2007.

162. “Regulatory and Policy Issues in Nuclear Power Plant Development.” (2007). LSU Center

for Energy Studies Industry Advisory Council Meeting. Baton Rouge, LA. March 23, 2007.

163. "Oil and Gas in the Gulf of Mexico: A North American Perspective." (2007). Canadian Consulate, Heads of Mission EnerNet Workshop, Houston, Texas. March 20, 2007.

164. "Regulatory Issues for Consumer Advocates in Rate Design, Incentives & Energy Efficiency. (2007). National Association of State Utility Consumer Advocates ("NASUCA") Gas Committee Monthly Meeting. February 13, 2006.

165. "Recent Trends in Natural Gas Markets." (2006). National Association of Regulatory Utility Commissioners, 118th Annual Convention. Miami, FL November 14, 2006.

166. "Energy Markets: Recent Trends, Issues & Outlook." (2006). Association of Energy Service Companies (AESC) Meeting. Petroleum Club, Lafayette, LA, November 8, 2006.

167. "Energy Outlook" (2006). National Business Economics Issues Council. Quarterly Meeting, Nashville, TN, November 1-2, 2006.

168. "Global and U.S. Energy Outlook." (2006). Energy Virginia Conference. Virginia Military Institute, Lexington, VA October 17, 2006.

169. "Interdependence of Critical Energy Infrastructure Systems." (2006). Cross Border Forum on Energy Issues: Security and Assurance of North American Energy Systems. Woodrow Wilson Center for International Scholars. Washington, DC, October 13, 2006.

170. "Determining the Economic Value of Coastal Preservation and Restoration on Critical Energy Infrastructure." (2006) The Economic and Market Impacts of Coastal Restoration: America's Wetland Economic Forum II. Washington, DC September 28, 2006.

171. "Relationships between Power and Other Critical Energy Infrastructure." (2006). Rebuilding the New Orleans Region: Infrastructure Systems and Technology Innovation Forum. United Engineering Foundation. New Orleans, LA, September 24-25, 2006.

172. "Outlook, Issues, and Trends in Energy Supplies and Prices." (2006.) Presentation to the Southern States Energy Board, Associate Members Meeting. New Orleans, Louisiana. July 14, 2006.

173. "Energy Sector Outlook." (2006). Baton Rouge Country Club Meeting. Baton Rouge, Louisiana. July 11, 2006.

174. "Oil and Gas Industry Post 2005 Storm Events." (2006). American Petroleum Institute, Teche Chapter. Production, Operations, and Regulations Annual Meeting. Lafayette, Louisiana. June 29, 2006.

175. "Concentration of Energy Infrastructure in Hurricane Regions." (2006). Presentation before the National Commission on Energy Policy Forum: Ending the Stalemate on LNG Facility Siting. Washington, DC. June 21, 2006.

176. "LNG—A Premier." (2006). Presentation Given to the U.S. Department of Energy's "LNG Forums." Los Angeles, California. June 1, 2006.

177. "Regional Energy Infrastructure, Production and Outlook." (2006). Executive Briefing for Board of Directors, Louisiana Oil and Gas Plc., Enhanced Exploration, Inc. and Energy Self-Service, Inc. Covington, Louisiana, May 12, 2006.

178. "The Impacts of the Recent Hurricane Season on Energy Production and Infrastructure

and Future Outlook." Presentation before the Industrial Energy Technology Conference 2006. New Orleans, Louisiana, May 9, 2006.

179. "Update on Regional Energy Infrastructure and Production." (2006). Executive Briefing for Delegation Participating in U.S. Department of Commerce Gulf Coast Business Investment Mission. Baton Rouge, Louisiana May 5, 2006.

180. "Hurricane Impacts on Energy Production and Infrastructure." (2006). Presentation before the Interstate Natural Gas Association of America Mid-Year Meeting. Hyatt Regency Hill Country. April 21, 2006.

181. "LNG—A Premier." Presentation Given to the U.S. Department of Energy's "LNG Forums." Astoria, Washington. April 28, 2006.

182. Natural Gas Market Outlook. Invited Presentation Given to the Georgia Public Service Commission and Staff. Georgia Institute of Technology, Atlanta, Georgia. March 10, 2006.

183. The Impacts of Hurricanes Katrina and Rita on Louisiana's Energy Industry. Presentation to the Louisiana Economic Development Council. Baton Rouge, Louisiana. March 8, 2006.

184. Energy Markets: Hurricane Impacts and Outlook. Presentation to the 2006 Louisiana Independent Oil and Gas Association Annual Conference. L'Auberge du Lac Resort and Casino. Lake Charles, Louisiana. March 6, 2006

185. Energy Market Outlook and Update on Hurricane Damage to Energy Infrastructure. Presentation to the Energy Council 2005 Global Energy and Environmental Issues Conference. Santa Fe, New Mexico, December 10, 2005.

186. "Putting Our Energy Infrastructure Back Together Again." Presentation Before the 117th Annual Convention of the National Association of Regulatory Utility Commissioners (NARUC). November 15, 2005. Palm Springs, CA

187. "Hurricanes and the Outlook for Energy Markets." Presentation before the Baton Rouge Rotary Club. November 9, 2005, Baton Rouge, LA.

188. "Hurricanes, Energy Supplies and Prices." Presentation before the Louisiana Department of Natural Resources and Atchafalaya Basin Committee Meeting. November 8, 2005. Baton Rouge, LA.

189. "The Impact of the Recent Hurricane's on Louisiana's Energy Industry." Presentation before the Louisiana Independent Oil and Gas Association Board of Directors Meeting. November 8, 2005. Baton Rouge, LA.

190. "The Impact of the Recent Hurricanes on Louisiana's Infrastructure and National Energy Markets." Presentation before the Baton Rouge City Club Distinguished Speaker Series. October 13, 2005. Baton Rouge, LA.

191. "The Impact of the Recent Hurricanes on Louisiana's Infrastructure and National Energy Markets." Presentation before Powering Up: A Discussion About the Future of Louisiana's Energy Industry. Special Lecture Series Sponsored by the Kean Miller Law Firm. October 13, 2005. Baton Rouge, LA.

192. "The Impact of Hurricane Katrina on Louisiana's Energy Infrastructure and National Energy Markets." Special Lecture on Hurricane Impacts, LSU Center for Energy Studies, September 29, 2005.

193. "Louisiana Power Industry Overview." Presentation before the Clean Air Interstate Rule Implementation Stakeholders Meeting. August 11, 2005. Louisiana Department of Environmental Quality.

194. "CES 2005 Legislative Support and Outlook for Energy Markets and Policy." Presentation before the LMOGA/LCA Annual Post-Session Legislative Committee Meeting. August 10-13, 2005. Perdido Key, Florida.

195. "Electric Restructuring: Past, Present, and Future." Presentation to the Southeastern Association of Tax Administrators Annual Conference. Sheraton Hotel and Conference Facility. New Orleans, LA July 12, 2005.

196. "The Outlook for Energy." Lagniappe Studies Continuing Education Course. Baton Rouge, LA. July 11, 2005.

197. "The Outlook for Energy." Sunshine Rotary Club. Baton Rouge, LA. April 27, 2005.

198. "Background and Overview of LNG Development." Energy Council Workshop on LNG/CNG. Biloxi, Ms: Beau Rivage Resort and Hotel, April 9, 2005.

199. "Natural Gas Supply, Prices, and LNG: Implications for Louisiana Industry." Cytec Corporation Community Advisory Panel. Fortier, LA January 14, 2005.

200. "The Economic Opportunities for a Limited Industrial Retail Choice Plan." Louisiana Department of Economic Development. Baton Rouge, Louisiana. November 19, 2004.

201. "Energy Issues for Industrial Customers of Gas and Power." Louisiana Association of Business and Industry, Energy Council Meeting. Baton Rouge, Louisiana. October 11, 2004.

202. "Energy Issues for Industrial Customers of Gas and Power." Annual Meeting of the Louisiana Chemical Association and the Louisiana Chemical Industry Alliance. Point Clear, Alabama. October 8, 2004.

203. "Energy Issues for Industrial Customers of Gas and Power." American Institute of Chemical Engineers – New Orleans Section. New Orleans, LA. September 22, 2004.

204. "Natural Gas Supply, Prices and LNG: Implications for Louisiana Industry." Dow Chemical Company Community Advisory Panel Meeting. Plaquemine, LA. August 9, 2004.

205. "Energy Issues for Industrial Customers of Gas and Power." Louisiana Chemical Association Post-Legislative Meeting. Springfield, LA. August 9, 2004.

206. "LNG In Louisiana." Joint Meeting of the Louisiana Economic Development Council and the Governors Cabinet Advisory Council. Baton Rouge, LA. August 5, 2004.

207. "Louisiana Energy Issues." Louisiana Mid-Continent Oil and Gas Association Post Legislative Meetings. Sandestin, Florida. July 28, 2004.

208. "The Gulf South: Economic Opportunities Related to LNG." Presentation before the Energy Council's 2004 State and Provincial Energy and Environmental Trends Conference. Point Clear, AL, June 26, 2004.

209. "Natural Gas and LNG Issues for Louisiana." Presentation before the Rhodia Community Advisory Panel. May 20, 2004, Baton Rouge, LA.

210. "The Economic Opportunities for LNG Development in Louisiana." Presentation before the Louisiana Chemical Association Plant Managers Meeting. May 27, 2004. Baton Rouge, LA.

211. The Economic Opportunities for LNG Development in Louisiana." Presentation before the Louisiana Chemical Association/Louisiana Chemical Industry Alliance Legislative Conference. May 26, 2004. Baton Rouge, LA.

212. "The Economic Opportunities for LNG Development in Louisiana." Presentation before the Petrochemical Industry Cluster, Greater New Orleans, Inc. May 19, 2004, Destrehan, LA.

213. "Industry Development Issues for Louisiana: LNG, Retail Choice, and Energy." Presentation before the LSU Center for Energy Studies Industry Associates. May 14, 2004, Baton Rouge, LA.

214. "The Economic Opportunities for LNG Development in Louisiana." Presentation before the Board of Directors, Greater New Orleans, Inc. May 13, 2004, New Orleans, LA.

215. "Natural Gas Outlook: Trends and Issues for Louisiana." Presentation before the Louisiana Joint Agricultural Association Meetings. January 14, 2004, Hotel Acadiana, Lafayette, Louisiana.

216. "Natural Gas Outlook" Presentation before the St. James Parish Community Advisory Panel Meeting. January 7, 2004, IMC Production Facility, Convent, Louisiana.

217. "Competitive Bidding in the Electric Power Industry." Presentation before the Association of Energy Engineers. Business Energy Solutions Expo. December 11-12, 2003, New Orleans, Louisiana.

218. "Regional Transmission Organization in the South: The Demise of SeTrans" Presentation before the LSU Center for Energy Studies Industry Associates Advisory Council Meeting. December 9, 2003. Baton Rouge, Louisiana.

219. "Affordable Energy: The Key Component to a Strong Economy." Presentation before the National Association of Regulatory Utility Commissioners ("NARUC"), November 18, 2003, Atlanta, Georgia.

220. "Natural Gas Outlook." Presentation before the Louisiana Chemical Association, October 17, 2003, Pointe Clear, Alabama.

221. "Issues and Opportunities with Distributed Energy Resources." Presentation before the Louisiana Biomass Council. April 17, 2003, Baton Rouge, Louisiana.

222. "What's Happened to the Merchant Energy Industry? Issues, Challenges, and Outlook" Presentation before the LSU Center for Energy Studies Industry Associates Advisory Council Meeting. November 12, 2002. Baton Rouge, Louisiana.

223. "An Introduction to Distributed Energy Resources." Presentation before the U.S. Department of Energy, Office of Renewable Energy and Energy Efficiency, State Energy Program/Rebuild America Conference, August 1, 2002, New Orleans, Louisiana.

224. "Merchant Energy Development Issues in Louisiana." Presentation before the Program Committee of the Center for Legislative, Energy, and Environmental Research (CLEER), Energy Council. April 19, 2002.

225. "Merchant Power Plants and Deregulation: Issues and Impacts." Presentation before 24th Annual Conference on Waste and the Environment. Sponsored by the Louisiana Department of Environmental Quality. Lafayette, Louisiana, Cajundome. March 18, 2002.

226. "Merchant Power and Deregulation: Issues and Impacts." Presentation before the Air and Waste Management Association Annual Meeting. Baton Rouge, LA, November 15, 2001.

227. "Moving to the Front of the Lines: The Economic Impact of Independent Power Production in Louisiana." Presentation before the LSU Center for Energy Studies Merchant Power Generation and Transmission Conference, Baton Rouge, LA. October 11, 2001.

228. "Economic Impacts of Merchant Power Plant Development in Mississippi." Presentation before the U.S. Oil and Gas Association Annual Oil and Gas Forum. Jackson, Mississippi. October 10, 2001.

229. "Economic Opportunities for Merchant Power Development in the South." Presentation before the Southern Governor's Association/Southern State Energy Board Meetings. Lexington, KY. September 9, 2001.

230. "The Changing Nature of the Electric Power Business in Louisiana." Presentation before the Louisiana Department of Environmental Quality. Baton Rouge, LA, August 27, 2001.

231. "Power Business in Louisiana: Background and Issues." Presentation before the Louisiana Interagency Group on Merchant Power Development . Baton Rouge, LA, July 16, 2001.

232. "The Changing Nature of the Electric Power Business in Louisiana: Background and Issues." Presentation before the Louisiana Office of the Governor. Baton Rouge, LA, July 16, 2001.

233. "The Changing Nature of the Electric Power Business in Louisiana: Background and Issues." Presentation before the Louisiana Department of Economic Development. Baton Rouge, LA, July 3, 2001.

234. "The Economic Impacts of Merchant Power Plant Development In Mississippi." Presentation before the Mississippi Public Service Commission. Jackson, Mississippi, March 20, 2001.

235. "Energy Conservation and Electric Restructuring." With Ritchie D. Priddy. Presentation before the Louisiana Department of Natural Resources. Baton Rouge, Louisiana, October 23, 2000.

236. "Pricing and Regulatory Issues Associated with Distributed Energy." Joint Conference by Econ One Research, Inc., the Louisiana State University Distributed Energy Resources Initiative, and the University of Houston Energy Institute: "Is the Window Closing for Distributed Energy?" Houston, Texas, October 13, 2000.

237. "Electric Reliability and Merchant Power Development Issues." Technical Meetings of the Louisiana Public Service Commission. Baton Rouge, LA. August 29, 2000.

238. "A Introduction to Distributed Energy Resources." Summer Meetings, Southeastern Association of Regulatory Utility Commissioners (SEARUC). New Orleans, LA. June 27, 2000.

239. Roundtable Moderator/Discussant. Mid-South Electric Reliability Summit. U.S. Department of Energy. New Orleans, Louisiana. April 24, 2000.

240. "Electricity 101: Definitions, Precedents, and Issues." Energy Council's 2000 Federal Energy and Environmental Matters Conference. Loews L'Enfant Plaza Hotel, Washington, D.C. March 11-13, 2000.

241. "LSU/CES Distributed Energy Resources Initiatives." Los Alamos National Laboratories. Office of Energy and Sustainable Systems. Los Alamos, New Mexico. February 16, 2000.

242. "Distributed Energy Resources Initiatives." Louisiana State University, Center for Energy Studies Industry Associates Meeting. Baton Rouge, Louisiana. December 15, 1999.

243. "Merchant Power Opportunities in Louisiana." Louisiana Mid-Continent Oil and Gas Association (LMOGA) Power Generation Committee Meetings. Baton Rouge, Louisiana. November 10, 1999.

244. Roundtable Discussant. "Environmental Regulation in a Restructured Market" The Big E: How to Successfully Manage the Environment in the Era of Competitive Energy. PUR Conference. New Orleans, Louisiana. May 24, 1999.

245. "The Political Economy of Electric Restructuring In the South" Southeastern Electric Exchange, Rate Section Annual Conference. New Orleans, Louisiana. May 7, 1999.

246. "The Dynamics of Electric Restructuring in Louisiana." Joint Meeting of the American Association of Energy Engineers and the International Association of Facilities Managers. Metairie, Louisiana. April 29, 1999.

247. "The Implications of Electric Restructuring on Independent Oil and Gas Operations." Petroleum Technology Transfer Council Workshop: Electrical Power Cost Reduction Methods in Oil and Gas Field Operations. Lafayette, Louisiana, March 24, 1999.

248. "What's Happened to Electricity Restructuring in Louisiana?" Louisiana State University, Center for Energy Studies Industry Associates Meeting. March 22, 1999.

249. "A Short Course on Electric Restructuring." Central Louisiana Electric Company. Sales and Marketing Division. Mandeville, Louisiana, October 22, 1998.

250. "The Implications of Electric Restructuring on Independent Oil and Gas Operations." Petroleum Technology Transfer Council Workshop: Electrical Power Cost Reduction Methods in Oil and Gas Field Operations. Shreveport, Louisiana, October 13, 1998.

251. "How Will Utility Deregulation Affect Tourism." Louisiana Travel Promotion Association Annual Meeting, Alexandria, Louisiana. January 15, 1998.

252. "Reflections and Predictions on Electric Utility Restructuring in Louisiana." With Fred I. Denny. Louisiana State University, Center for Energy Studies Industry Associates Meeting. November 20, 1997.

253. "Electric Utility Restructuring in Louisiana." Hammond Chamber of Commerce, Hammond, Louisiana. October 30, 1997.

254. "Electric Utility Restructuring." Louisiana Association of Energy Engineers. Baton Rouge, Louisiana. September 11, 1997.

255. "Electric Utility Restructuring: Issues and Trends for Louisiana." Opelousas Chamber of Commerce, Opelousas, Louisiana. June 24, 1997.

256. "The Electric Utility Restructuring Debate In Louisiana: An Overview of the Issues." Annual Conference of the Public Affairs Research Council of Louisiana. Baton Rouge, Louisiana. March 25, 1997.

257. "Electric Restructuring: Louisiana Issues and Outlook for 1997." Louisiana State University, Center for Energy Studies Industry Associates Meeting, Baton Rouge, Louisiana, January 15, 1997.

258. "Restructuring the Electric Utility Industry." Louisiana Propane Gas Association Annual Meeting, Alexandria, Louisiana, December 12, 1996.

259. "Deregulating the Electric Utility Industry." Eighth Annual Economic Development Summit, Baton Rouge, Louisiana, November 21, 1996.

260. "Electric Utility Restructuring in Louisiana." Jennings Rotary Club, Jennings, Louisiana, November 19, 1996.

261. "Electric Utility Restructuring in Louisiana." Entergy Services, Transmission and Distribution Division, Energy Centre, New Orleans, Louisiana, September 12, 1996

262. "Electric Utility Restructuring" Louisiana Electric Cooperative Association, Baton Rouge, Louisiana, August 27, 1996.

263. "Electric Utility Restructuring -- Background and Overview." Louisiana Public Service Commission, Baton Rouge, Louisiana, August 14, 1996.

264. "Electric Utility Restructuring." Sunshine Rotary Club Meetings, Baton Rouge, Louisiana, August 8, 1996.

265. Roundtable Moderator, "Stakeholder Perspectives on Electric Utility Stranded Costs." Louisiana State University, Center for Energy Studies Seminar on Electric Utility Restructuring in Louisiana, Baton Rouge, May 29, 1996.

266. Panelist, "Deregulation and Competition." American Nuclear Society: Second Annual Joint Louisiana and Mississippi Section Meetings, Baton Rouge, Louisiana, April 20, 1996.

EXPERT WITNESS, LEGISLATIVE, AND PUBLIC TESTIMONY; EXPERT REPORTS, RECOMMENDATIONS, AND AFFIDAVITS

1. Expert Testimony. Docket No. 2019.09.058. (2020). *In the Matter of NorthWestern Energy's Annual PCCAM Filing and Application for Approval of Tariff Changes*. Issues: purchase power expenses, cost sharing, PCAAM power cost.

2. Expert Testimony. Formal Case No. 1156. (2020). Public Service Commission of the District of Columbia. *In the matter of Potomac Electric Power Company for authority to implement a multiyear rate plan for electric distribution service in the district of Columbia.* Issues: revenue distribution, rate design, customer charge, performance metric policies, performance metric incentives.

3. Expert Testimony. Case No. U-20561. (2019). Michigan Public Service Commission. *In the matter of the Application of DTE Electric Company for authority to increase its rates, amend its rate schedules and rules governing the distribution and supply of electric energy, and for miscellaneous accounting authority*. Issues: Cost of service, allocation of production plant, allocation of sub-transmission plant, revenue distribution.

4. Expert Testimony. Cause No. 45253. (2019). Indiana Utility Regulatory Commission. *Petition of Duke Energy Indiana, LLC Pursuant to Ind. Code 8-1-2-42.7 and 8-1-2-61, for (1) Authority to Modify its Rates and Charges for Electric Utility Service through a Step-In of New Rates and Charges using a Forecasted Test Period; (2) Approval of New Schedules of Rates and Charges, General Rules and Regulations, and Riders; (3) Approval of a Federal Mandate Certificate Under Ind. Code 8-1-8.4-1; (4) Approval of Revised Electric Depreciation Rates Applicable to its Electric Plant in Service; (5) Approval of Necessary and Appropriate Accounting Deferral Relief; and (6) Approval of a Revenue Decoupling Mechanism for Certain Customers Classes*. Issues: Decoupling, revenue decoupling mechanism and design, commission policy, benchmarking analysis.

5. Expert Testimony. Docket 19-019-U. (2019). Before the Arkansas Public Service Commission. *In the Matter of the Petition of Entergy Arkansas, LLC for Approval of a Build-Own-Transfer Arrangement for a Renewable Resource and for all other Related Approvals.* Issues*:* Solar investment, risk assessment, proposed rider.

6. Expert Testimony. Docket No. 16-036-FR. (2019). Before the Arkansas Public Service Commission. *In the Matter of the Formula Rate Plan Filings of Entergy Arkansas, Inc., Pursuant to APSC Docket No. 15-015-U.* Issues: rate design, reliability, and formula rate plan.

7. Expert Testimony. Docket No. 19-019-U. (2019). Before the Arkansas Public Service Commission. *In the Matter of the Petition of Entergy Arkansas, LLC for Approval of a Build-Own-Transfer Arrangement for a Renewable Resource and for all other Related Approvals*. Issues: Solar project approval, ratepayer risk, cost allocation.

8. Expert Testimony. Docket No. 17-010-FR. (2019). Before the Arkansas Public Service Commission. *In the Matter of the Formula Rate Plan Filings of Centerpoint Energy Resources Corp. D/B/A Centerpoint Energy Arkansas Gas Pursuant to APSC Docket No. 15-098-U.* Issues: retail rates, leak analysis, revenue deficiency, investments.

9. Expert Testimony. Case No. U-20471. (2019). Before the Michigan Public Service Commission. *In the matter of the Application of DTE Electric Company for approval of its Integrated Resource Plan pursuant to MCL 460.6t, and for other relief.* Issues: load forecasting, least-cost system planning.

10. Expert Report. Docket No. 18-004422. (2019). Before the State of Florida Division of Administrative Hearings. *Peoples Gas System vs. South Sumter Gas Company, LLC and the City of Leesburg.* Issues: retail rates, customer growth, sales trends and forecasts, policy, cost of service, socio-economic trends and forecasts.

11. Expert Testimony. Docket Nos. GO18101112 and EO18101113. (2019). Before the New Jersey Board of Public Utilities. *In the Matter of the Public Service Electric and Gas Company for Approval of its Clean Energy Future-Energy Efficiency ("CEF-EE") Program on a Regulated Basis.* Issues: economic impact, cost benefit analysis, decoupling

mechanisms.

12. Expert Testimony. Docket Nos. EO18060629 and GO18060630. (2019). Before the New Jersey Board of Public Utilities. *In the Matter of the Public Service Electric and Gas Company for Approval of the Second Energy Strong Program (Energy Strong II)*. Issues: economic impact, cost benefit analysis, infrastructure replacement, cost recovery tracker mechanisms.

13. Expert Report. Docket No. 2011-AD-2. (2019). On Behalf of the Mississippi Public Service Commission. *Order Establishing Docket to Investigate the Development and Implementation of Net Metering Programs and Standards.* Issues: Net-metering, distributed generation.

14. Expert Testimony. Docket No. D2018.2.12. (2018). Before the Public Service Commission of the State of Montana. *In the Matter of NorthWestern Energy's Application for Authority to Increase Retail Electric Utility Service Rates and for Approval of Electric Service Schedules and Rules and Allocated Cost of Service and Rate Design.* Issues: Net-metering, cost of service, revenue distribution, rate design.

15. Expert Testimony. Docket No. 19-SEPE-054-MER. (2018). Before the Kansas Corporation Commission. *In the Matter of the Joint Application of Sunflower Electric Power Corporation and Mid-Kansas Electric Company, Inc. for an Order Approving the Merger of Mid-Kansas Electric Company, Inc. into Sunflower Electric Power Corporation*. Issues: merger impacts, rates, tariffs.

16. Expert Testimony. Docket No. 18-046-FR. (2018). Before the Arkansas Public Service Commission. *In the Matter of the Formula Rate Plan Filings of Oklahoma Gas and Electric Company Pursuant to APSC Docket No. 16-052-U.* Issues: formula rate plan, plant investment and expenses benchmarking analysis, reliability.

17. Expert Testimony. Docket No. 16-036-FR. (2018). Before the Arkansas Public Service Commission. *In the Matter of the Formula Rate Plan Filings of Entergy Arkansas, Inc., Pursuant to APSC Docket No. 15-015-U.* Issues: rate design, reliability, and formula rate plan.

18. Expert Testimony. Docket No. 2017-AD-0112. (2018). Before the Mississippi Public Service Commission. *In Re: Encouraging Stipulation of Matters in Connection with the Kemper County IGCC Project.* Issues: cost of service and rate design.

19. Expert Affidavit. Docket No. 87011-E. (2018). Before the 16th Judicial District Court Parish of St. Martin State of Louisiana. *Bayou Bridge Pipeline, LLC versus 38.00 Acres, More or Less, Located in St. Martin Parish; Barry Scott Carline, et al.* Issues: economic impacts.

20. Expert Testimony. Docket No. QO18080843. (2018). Before the New Jersey Board of Public Utilities. *In the Matter of the Petition of Nautilus Offshore Wind, LLC for the Approval of the State Waters Wind Project and Authorizing Offshore Wind Renewable Energy Certificates.* Issues: regulatory policy and cost-benefit analyses.

21. Expert Testimony. Docket No. ER18010029 and GR18010030. (2018). Before the New Jersey Board of Public Utilities. *In the Matter of the Petition of Public Service Electric and Gas Company for Approval of an Increase in Electric and Gas Rates and for Changes in the Tariffs for Electric and Gas Service, B.P.U.N.J. No. 16 Electric and B.P.U.N.J No. 16*

Gas, and for Changes in Depreciation Rates, Pursuant to N.J.S.A. 48:2-18, N.J.S.A. 48:2-21 and N.J.S.A. 48:2-21.1, and for Other Appropriate Relief. Issues: rate proposal, revenue decoupling, regulatory policy, cost benchmarking.

22. Expert Testimony. Docket No. T-34695. (2018). Before the Louisiana Public Service Commission. *In re: Application for a rate increase on service originating at Grand isle and termination at St. James for Crude Petroleum as currently outlined in LPSC Tariff No. 75.2*. Issues: cost of service, rate design, and alternative regulation.

23. Expert Testimony. Docket No. 17-071-U. (2018). Before the Arkansas Public Service Commission*. In the Matter of the Application of Black Hills Energy Arkansas, Inc. for Approval of a General Change in Rates and Tariffs*. Issues: cost of service, rate design, billing determinates.

24. Expert Testimony. Docket No. 17-010-FR. (2018). Before the Arkansas Public Service Commission. *In the Matter of the Formula Rate Plan Filing of CenterPoint Energy Resources Corp. D/B/A CenterPoint Energy Arkansas Gas Pursuant to APSC Docket No. 15-098-U.* Issues: cost of service, rate design, alternative regulation, formula rate plan.

25. Expert Testimony. Case No. PU-17-398. (2018). Before the North Dakota Public Service Commission. *In the Matter of the Application of Otter Tail Power Company for Authority to Increase Rates for Electric Utility Service in North Dakota*. Issues: cost of service, marginal cost of service, and rate design.

26. Expert Testimony. Docket No. 20170179-GU. (2018). Before the Florida Public Service Commission. *In re: Petition for rate increase and approval of depreciation study by Florida City Gas.* On Behalf of the Citizens of the State of Florida. Issues: policy issues concerning long-term gas capacity procurement.

27. Expert Testimony. Docket No. 18-KCPE-095-MER. (2018). Before the Kansas Corporation Commission. *In the Matter of the Joint Application of Great Plains Energy Incorporated, Kansas City Power & Light Company, and Westar Energy, Inc. for Approval of the Merger of Westar, Inc. and Great Plains Energy Incorporated.* On the Behalf of the Kansas Electric Power Cooperative, Inc. Issues: merger/acquisition policy, financial risk, and ring-fencing.

28. Expert Testimony. Docket No. GR17070776. (2018). Before the New Jersey Board of Public Utilities. In the Matter of the Petition of Public Service Electric and Gas Company for Approval of the Next Phase of the Gas System Modernization Program and Associated Cost Recovery Mechanism ("GSMP II"). Issues: economic impact, infrastructure replacement program rider, pipeline replacement, leak rate comparisons and cost benefit analysis.

29. Expert Affidavit. Case No. 18-489. (2018). Before the Civil District Court for the Parish of Orleans, State of Louisiana. *Bayou Bridge Pipeline, LLC versus The White Castle Lumber and Shingle Company Limited and Jeanerette Lumber & Shingle CO. L.L.C.* Issues: economic impact of crude oil pipeline development.

30. Expert Testimony. Docket No. 16-036-FR. (2017). Before the Arkansas Public Service Commission. *In the Matter of the Formula Rate Plan Filings of Entergy Arkansas, Inc., Pursuant to APSC Docket No. 15-015-U*. On behalf of the Office of the Arkansas Attorney

General Leslie Rutledge. Issue: cost of service, rate design, alternative regulation, formula rate plan.

31. Expert Testimony. Docket No. 2017-AD-0112. (2017). Before the Mississippi Public Service Commission. *In re: Encouraging Stipulation of Matters in Connection with the Kemper County IGCC Project*. On Behalf of the Mississippi Public Utilities Staff. Issues: financial analysis, rates and cost trends, economic impacts of proposal.

32. Expert Testimony. Case No. 2017-00179. (2017). Before the Public Service Commission, Commonwealth of Kentucky. *Electronic Application of Kentucky power Company For (1) A General Adjustment of Its Rates for Electric Service; (2) An Order Approving Its 2017 Environmental Compliance Plan; (3) An Order Approving Its Tariffs and Riders; (4) An Order Approving Accounting Practices to Establish a Regulatory Asset or Liability Related to the Big Sandy 1 Operation Rider; and (5) An Order Granting All Other Required Approvals and Relief.* Issues: rate design, revenue allocation, economic development.

33. Expert Testimony. Docket No. 17-010-FR. (2017). Before the Arkansas Public Service Commission. *In the Matter of the Formula Rate Plan Filing of CenterPoint Energy Resources Corp. D/B/A CenterPoint Energy Arkansas Gas Pursuant to APSC Docket No. 15-098-U.* Issues: cost of service, rate design, alternative regulation, formula rate plan.

34. Expert Testimony. Formal Case No. 1142. (2017). Before the Public Service Commission of the District of Columbia. *In the Matter of the Merger of AltaGas Ltd. and WGL Holdings, Inc.* On Behalf of the Office of the People's Counsel. Issues: merger/acquisition policy, financial risk, ring-fencing, and reliability.

35. Expert Testimony. D.P.U. 17-05. (2017). Before the Massachusetts Department of Public Utilities. *Petition of NSTAR Electric Company and Western Massachusetts Electric Company each d/b/a Eversource Energy for Approval of an Increase in Base Distribution Rates for Electric Service Pursuant to G.L. c. 164, § 94 and 220 C.M.R. § 5.00*. On Behalf of the Massachusetts Office of the Attorney General Office of Ratepayer Advocacy. Issues: performance-based ratemaking, multi-factor productivity estimation.

36. Deposition and Testimony. (2017) Before the Nebraska Section 70, Article 13 Arbitration Panel. *Northeast Nebraska Public Power District, City of South Sioux City Nebraska; City of Wayne, Nebraska; City of Valentine, Nebraska; City of Beatrice, Nebraska; City of Scribner, Nebraska; Village of Walthill, Nebraska, vs. Nebraska Public Power District.* On the Behalf of Baird Holm LLP for the Plaintiffs. Issues: rate discounts; cost of service; utility regulation, economic harm.

37. Expert Testimony. Docket No. 16-052-U. (2017). Before the Arkansas Public Service Commission. *In the Matter of the Application of the Oklahoma Gas and Electric Company for Approval of a General Change in Rates, Charges and Tariffs.* On the Behalf of the Office of Arkansas Attorney General Leslie Rutledge. Issues: cost of service, rate design, alternative regulation, formula rate plan.

38. Expert Testimony. Docket No. 16-KCPE-593-ACQ. (2016). Before the Kansas Corporation Commission. *In the Matter of the Joint Application of Great Plains Energy Incorporated, Kansas City Power & Light Company, and Westar Energy, Inc. for Approval of the Acquisition of Westar, Inc. by Great Plains Energy Incorporated.* On the Behalf of the Kansas Electric Power Cooperative, Inc. Issues: merger/acquisition policy, financial

risk, and ring-fencing.

39. Expert Testimony. Formal Case No. 1139. (2016). Before the Public Service Commission of the District of Columbia. *In the Matter of the Application of Potomac Electric Power Company for Authority to Increase Existing Retail Rates and Charges for Electric Distribution Service.* On the Behalf of the Office of the People's Counsel for the District of Columbia. Issues: cost of service, rate design, alternative regulation.

40. Expert Affidavit. Docket No. CP15-558-000 (2016). Before the United States of America Federal Energy Regulatory Commission. *PennEast Pipeline Company, LLC*. Affidavit and Reply Affidavit. On the Behalf of the New Jersey Division of Rate Counsel. Issues: pipeline capacity, peak day requirements.

41. Expert Testimony. Docket No. RPU-2016-0002. (2016). Before the Iowa Utilities Board. *In re: Iowa American Water Company application for revision of rates.* On behalf of the Citizens of the State of Florida. Issue: revenue stabilization mechanism, revenue decoupling.

42. Expert Testimony. Docket No. 15-015-U. (2016). Before the Arkansas Public Service Commission. *In the Matter of the Formula Rate Plan Filings of Entergy Arkansas, Inc., Pursuant to APSC Docket No. 15-015-U*. On behalf of the Office of the Arkansas Attorney General Leslie Rutledge. Issue: formula rate plan evaluation.

43. Expert Testimony. Docket Nos. 160021-EI, 160061-EI, 160062-EI, and 160088-EI. (2016). Before the Florida Public Service Commission. *In re: Petition for rate increase by Florida Power & Light Company (consolidated).* On behalf of the Citizens of the State of Florida. Issue: load forecasting.

44. Expert Testimony. Docket Nos. 160021-EI, 160061-EI, 160062-EI, and 160088-EI. (2016). Before the Florida Public Service Commission. *In re: Petition for rate increase by Florida Power & Light Company (consolidated).* On behalf of the Citizens of the State of Florida. Issue: off-system sales incentives.

45. Expert Testimony. Project No. 5-103. (2016). United States of America Federal Energy Regulatory Commission. *Confederated Salish and Kootenai Tribes Energy Keepers, Incorporated*. On behalf of the Flathead, Mission, and Jocko Valley Irrigation Districts and the Flathead Joint Board of Control of the Flathead, Mission, and Jocko Valley Irrigation Districts.

46. Expert Testimony. Docket No. 15-098-U. (2016). Before the Arkansas Public Service Commission. *In the Matter of the Application of CenterPoint Energy Resources Corp. d/b/a CenterPoint Energy Arkansas Gas for a General Change or Modification in its Rates, Charges and Tariffs.* On behalf of the Office of the Arkansas Attorney General. Issues: formula rate plan, cost of service and rate design.

47. Expert Testimony. BPU Docket No. GM15101196. (2016). *In the Matter of the Merger of Southern Company and AGL Resources, Inc*. On behalf of the New Jersey Division of Rate Counsel. Issues: merger standards of review, customer dividend contributions, synergy savings and costs to achieve, ratemaking treatment of merger-related costs.

48. Expert Testimony. Docket No. 15-078-U. (2015). Before the Arkansas Public Service Commission. *In the Matter of the Joint Application of SourceGas Inc., SourceGas LLC,*

SourceGas Holdings LLC and Black Hills Utility Holdings, Inc. for all Necessary Authorizations and Approvals for Black Hills Utility Holdings, Inc. to Acquire SourceGas Holdings LLC. On behalf of the Office of the Arkansas Attorney General. Issues: public policy and regulatory policy associated with the acquisition.

49. Expert Testimony. Docket No. 15-031-U. (2015). Before the Arkansas Public Service Commission. *In the Matter of the Application of SourceGas Arkansas Inc. for an Order Approving the Acquisition of Certain Storage Facilities and the Recovery of Investments and Expenses Associated Therewith.* On behalf of the Office of the Arkansas Attorney General. Issues: cost-benefit analysis, transmission cost analysis, and a due diligence analysis.

50. Expert Testimony. Docket No. 15-015-U. (2015). Before the Arkansas Public Service Commission. *In the Matter of the Application of Entergy Arkansas, Inc. for Approval of Changes in Rates for Retail Electric Service.* On behalf of the Office of the Arkansas Attorney General. Issues: economic development riders and production plant cost allocation.

51. Expert Testimony. Docket No. 7970. (2015). Before the Vermont Public Service Board. *Petition of Vermont Gas Systems, Inc., for a certificate of public good pursuant to 30 V.S.A.§ 248, authorizing the construction of the "Addison Natural Gas Project" consisting of approximately 43 miles of new natural gas transmission pipeline in Chittenden and Addison Counties, approximately 5 miles of new distribution mainlines in Addison County, together with three new gate stations in Williston, New Haven, and Middlebury, Vermont*. On behalf of AARP-Vermont. Issues: net economic benefits of proposed natural gas transmission project.

52. Expert Testimony. File No. ER-2014-0370 (2015). Before the Public Service Commission of the State of Missouri. *In the Matter of Kansas City Power & Light Company for Authority Implement A General Rate Increase for Electric Service*. On behalf of the Missouri Office of the People's Counsel. Issues: customer charges, rate design, revenue distribution, class cost of service, and policy and ratemaking considerations in connection with electric vehicle charging stations.

53. Expert Testimony. File No. ER-2014-0351 (2015). Before the Public Service Commission of the State of Missouri. *In the Matter of The Empire District Electric Company for Authority To File Tariffs Increasing Rates for Electric Service Provided to Customers In the Company's Missouri Service Area*. On behalf of the Missouri Office of the People's Counsel. Issues: customer charges, rate design, revenue distribution, and class cost of service.

54. Expert Testimony. D.P.U. 14-130 (2015). Before the Massachusetts Department of Public Utilities. *Petition of Fitchburg Gas and Electric Light Company d/b/a Unitil for approval by the Department of Public Utilities of the Company's 2015 Gas System Enhancement Program Plan, pursuant to G.L. c. 164, § 145, and for rates effective May 1, 2015.* On behalf of the Attorney General's Office. Issues: ratepayer protections, cost allocations, rate design, performance metrics.

55. Expert Testimony. D.P.U. 14-131 (2015). Before the Massachusetts Department of Public Utilities. *Petition of The Berkshire Gas Company for approval by the Department of Public Utilities of the Company's Gas System Enhancement Program Plan for 2015, pursuant to*

G.L. c. 164, § 145, and for rates effective May 1, 2015. On behalf of the Attorney General's Office. Issues: ratepayer protections, cost allocations, rate design, performance metrics.

56. Expert Testimony. D.P.U. 14-132 (2015). Before the Massachusetts Department of Public Utilities. *Petition of Boston Gas Company and Colonial Gas Company d/b/a National Grid for approval by the Department of Public Utilities of the Companies' Gas System Enhancement Program for 2015, pursuant to G.L. c. 164, § 145, and for rates effective May 1, 2015*. On behalf of the Attorney General's Office. Issues: ratepayer protections, cost allocations, rate design, performance metrics.

57. Expert Testimony. D.P.U. 14-133 (2015). Before the Massachusetts Department of Public Utilities. *Petition of Liberty Utilities for approval by the Department of Public Utilities of the Company's Gas System Enhancement Program Plan for 2015, pursuant to G.L. c. 164, § 145, and for rates effective May 1, 2015*. On behalf of the Attorney General's Office. Issues: ratepayer protections, cost allocations, rate design, performance metrics.

58. Expert Testimony. D.P.U. 14-134 (2015). Before the Massachusetts Department of Public Utilities. *Petition of Bay State Gas Company d/b/a Columbia Gas of Massachusetts for approval by the Department of Public Utilities of the Company's Gas System Enhancement Program Plan for 2015, pursuant to G.L. c. 164, § 145, and for rates to be effective May 1, 2015*. On behalf of the Attorney General's Office. Issues: ratepayer protections, cost allocations, rate design, performance metrics.

59. Expert Testimony. D.P.U. 14-135 (2015). Before the Massachusetts Department of Public Utilities. *Petition of NSTAR Gas Company for approval by the Department of Public Utilities of the Company's Gas System Enhancement Program Plan for 2015, pursuant to G.L. c. 164, § 145, and for rates to be effective May 1, 2015*. On behalf of the Attorney General's Office. Issues: ratepayer protections, cost allocations, rate design, performance metrics.

60. Expert Report. Docket No. X-33192 (2015). Before the Louisiana Public Service Commission. *Examination of the Comprehensive Costs and Benefits of Net Metering in Louisiana.* On behalf of the Louisiana Public Service Commission. Issues: cost-benefit, cost of service, rate impact.

61. Expert Testimony. F.C. 1119 (2014). Before the District of Columbia Public Service Commission. *In the Matter of the Merger of Exelon Corporation, Pepco Holdings, Inc., Potomac Electric Power Company, Exelon Energy Delivery Company, LLC, and new Special Purpose Entity, LLC*. On behalf of the Office of the People's Counsel. Issues: economic impact analysis, reliability, consumer investment fund, regulatory oversight, impacts to competitive electricity markets.

62. Expert Report. Civil Action 1:08-cv-0046 (2014). Before the U.S. District Court for the Southern District of Ohio. *Anthony Williams, et al., v. Duke Energy International, Inc., et al.* On behalf of Markovits, Stock & DeMarco, Attorneys & Counselors at Law. Issues: public utility regulation, electric power markets, economic harm.

63. Expert Testimony. D.P.U. 14-64 (2014). Before the Massachusetts Department of Public Utilities. *NSTAR Gas Company/HOPCO Gas Services Agreement. On behalf of the Office of the Public Advocate*. Issues: certain ratemaking features associated with the proposed Gas Service Agreement.

64. Expert Testimony. Docket Nos. 14-0224 and 14-0225 (2014). Before the Illinois Commerce Commission. *In the Matter of the Peoples Gas Light and Coke Company and North Shore Gas Company Proposed General Increase in Rates for Gas Service (consolidated)*. On behalf of the People of the State of Illinois. Issues: test year expenses, cost benchmarking analysis, pipeline replacement, and leak rate comparisons.

65. Expert Testimony. Docket 8191 (2014). Before the Vermont Public Service Board. *In Re: Petition of Green Mountain Power Corporation for Approval of a Successor Alternative Regulation Plan.* On the behalf of AARP-Vermont. Issues: Alternative Regulation.

66. Expert Testimony. Docket No. 2013-00168 (2014). Before the Maine Public Utilities Commission. *In the Matter of the Request for Approval of an Alternative Rate Plan (ARP 2014) Pertaining to Central Maine Power Company*. On behalf of the Office of the Public Advocate. Issues: class cost of service study, marginal cost of service study, revenue distribution and rate design.

67. Expert Testimony. D.P.U. 13-90 (2013). Before the Massachusetts Department of Public Utilities. *Petition of Fitchburg Gas and Electric Light Company (Electric Division) d/b/a Unitil to the Department of Public Utilities for approval of the rates and charges and increase in base distribution rates for electric service.* On behalf of the Office of the Ratepayer Advocate. Issues: capital cost adjustment mechanism and performance-based regulation.

68. Expert Testimony. BPU Docket Nos. EO13020155 and GO13020156. (2013). Before the State of New Jersey Board of Public Utilities. *I/M/O The Petition of Public Service Electric & Gas Company for the Approval of the Energy Strong Program.* On behalf of the Division of Rate Counsel. Issues: economic impact, infrastructure replacement program rider, pipeline replacement, leak rate comparisons and cost benefit analysis.

69. Expert Testimony. D.P.U. 13-75 (2013). Before the Massachusetts Department of Public Utilities. *Investigation by the Department of Public Utilities on its Own Motion as to the Propriety of the Rates and Charges by Bay State Gas Company d/b/a Columbia Gas of Massachusetts set forth in Tariffs M.D.P.U. Nos. 140 through 173, and Approval of an Increase in Base Distribution Rates for Gas Service Pursuant to G.L. c. 164, § 94 and 220 C.M.R. § 5.00 et seq., filed with the Department on April 16, 2013, to be effective May 1, 2013*. On the Behalf of the Office of the Attorney General, Office of Ratepayer Advocacy. Issues: Target infrastructure replacement program rider, pipeline replacement, and leak rate comparisons; environmental benefits analysis; O&M offset; and cost benchmarking analysis.

70. Expert Testimony. Docket No. 13-115 (2013). Before the Delaware Public Service Commission. *In the Matter of the Application of Delmarva Power & Light Company FOR an Increase in Electric Base Rates and Miscellaneous Tariff Changes* (Filed March 22, 2013). On the Behalf of Division of the Public Advocate. Issues: pro forma infrastructure proposal, class cost of service study, revenue distribution, and rate design.

71. Expert Testimony. Formal Case No. 1103 (2013). Before the Public Service Commission of the District of Columbia. *In the Matter of the Application of the Potomac Electric Power Company for Authority to Increase Existing Retail Rates and Charges for Electric Distribution Service*. On the Behalf of the Office of the People's Counsel of the District of Columbia. Issues: Pro forma adjustment for reliability investments.

72. Expert Testimony. Case No. 9326 (2013). Before the Public Service Commission of Maryland. *In the Matter of the Application of Baltimore Gas and Electric Company for Adjustments to its Electric and Gas Base Rates*. On the Behalf of the Maryland Office of the People's Counsel. Issues: Electric Reliability Investment ("ERI") initiatives, pro forma gas infrastructure proposal, tracker mechanisms, class cost of service study, revenue distribution, and rate design

73. Rulemaking Testimony. (2013). Before the Louisiana Tax Commission. Examination of Louisiana Assessors' Association Well Diameter Analysis, economic development policies regarding midstream assets and industrial development.

74. Expert Testimony. Case No. 9317 (2013). Before the Public Service Commission of Maryland. *In the Matter of the Application of Delmarva Power & Light Company for Adjustments to its Retail Rates for the Distribution of Electric Energy*. Direct, and Surrebuttal. On the Behalf of the Maryland Office of the People's Counsel. Issues: Grid Resiliency Charge, tracker mechanisms, pipeline replacement, class cost of service study, revenue distribution, and rate design.

75. Expert Testimony. Case No. 9311 (2013). Before the Public Service Commission of Maryland. *In the Matter of the Application of Potomac Electric Power Company for an Increase in its Retail Rates for the Distribution of Electric Energy*. Direct, and Surrebuttal. On the Behalf of the Maryland Office of the People's Counsel. Issues: Grid Resiliency Charge, tracker mechanisms, pipeline replacement, class cost of service study, revenue distribution, and rate design.

76. Expert Testimony. Docket No. 12AL-1268G (2013). Before the Public Utilities Commission of the State of Colorado. *In the Matter of the Tariff Sheets Filed by Public Service Company of Colorado with Advice No. 830 – Gas. Answer*. On the Behalf of the Colorado Office of Consumer Counsel. Issues: Pipeline System Integrity Adjustment, tracker mechanisms, pipeline replacement and leak rate comparisons.

77. Expert Testimony. BPU Docket No. EO12080721 (2013). Before the New Jersey Board of Public Utilities. *In the Matter of the Public Service Electric & Gas Company for Approval of an Extension of Solar Generation Program*. On the Behalf of the New Jersey Division of Rate Counsel. Direct, Rebuttal, Surrebuttal. Issues: solar energy market design, solar energy market conditions, solar energy program design and net economic benefits.

78. Expert Testimony. BPU Docket No. EO12080726 (2013). Before the New Jersey Board of Public Utilities. *In the Matter of the Petition of Public Service Electric & Gas Company for Approval of a Solar Loan III Program.* On the Behalf of the New Jersey Division of Rate Counsel. Direct, Rebuttal and Surrebuttal. Issues: solar energy market design, solar energy market conditions, solar energy program design.

79. Expert Testimony. BPU Docket No. EO11050314V. (2012). Before the New Jersey Board of Public Utilities. *In the Matter of the Petition of Fishermen's Atlantic City Windfarm, LLC for the Approval of the State Waters Project and Authorizing Offshore Wind Renewable Energy Certificates*. On the Behalf of the New Jersey Division of Rate Counsel. December 17, 2012. Issues: approval of offshore wind project and ratepayer financial support for the proposed project.

80. Expert Testimony. D.P.U. 12-25. (2012). Before the Massachusetts Department of Public

Utilities. *In the Matter of Bay State Gas Company d/b/a/ Columbia Gas Company of Massachusetts Request for Increase in Rates*. On the Behalf of the Office of the Attorney General, Office of Ratepayer Advocacy. Issues: Target infrastructure replacement program rider, pipeline replacement and leak rate comparisons.

81. Expert Testimony. Docket Nos. UE-120436, et.al. (consolidated). (2012). Before the Washington Utilities and Transportation Commission. *Washington Utilities and Transportation Commission v. Avista Corporation D/B/A Avista Utilities*. On the Behalf of the Washington Attorney General, Office of the Public Counsel. Issues: Revenue Decoupling, lost revenues, tracker mechanisms, attrition adjustments.

82. Expert Testimony. Case No. 9286. (2012) Before the Public Service Commission of Maryland. *In Re: Potomac Electric Power Company ("Pepco") General Rate Case*. On the Behalf of the Maryland Office of the People's Counsel. Issues: Capital tracker mechanisms/reliability investment mechanisms, reliability issues, regulatory lag, class cost of service, revenue distribution, rate design.

83. Expert Testimony. Case No 9285. (2012) Before the Public Service Commission of Maryland. *In Re: the Delmarva Power and Light Company General Rate Case*. On the Behalf of the Maryland Office of the People's Counsel. Issues: Capital tracker mechanisms/reliability investment mechanisms, reliability issues, regulatory lag, class cost of service, revenue distribution, rate design.

84. Expert Testimony. Docket Nos. UE-110876 and UG-110877 (consolidated). (2012). Before the Washington Utilities and Transportation Commission. *Washington Utilities and Transportation Commission v. Avista Corporation D/B/A Avista Utilities*. On the Behalf of the Washington Attorney General, Office of the Public Counsel. Issues: Revenue Decoupling, lost revenues, tracker mechanisms.

85. Expert Testimony. BPU Docket No. EO11050314V. (2012). Before the New Jersey Board of Public Utilities. *In the Matter of the Petition of Fishermen's Atlantic City Windfarm, LLC for the Approval of the State Waters Project and Authorizing Offshore Wind Renewable Energy Certificates*. On the Behalf of the New Jersey Division of Rate Counsel. February 3, 2012. Issues: approval of offshore wind project and ratepayer financial support for the proposed project.

86. Expert Testimony. Docket No. NG 0067. (2012). Before the Public Service Commission of Nebraska. *In the Matter of the Application of SourceGas Distribution, LLC Approval of a General Rate Increase*. On the Behalf of the Public Advocate. January 31, 2012. Issues: Revenue Decoupling, Customer Adjustments, Weather Normalization Adjustments, Class Cost of Service Study, Rate Design.

87. Expert Testimony. Docket No. G-04204A-11-0158. (2011). Before the Arizona Corporation Commission. On the Behalf of the Arizona Corporation Commission Staff. *In the Matter of the Application of UNS Gas, Inc. for the Establishment of Just and Reasonable Rates and Charges Designed to Realize a Reasonable Rate of Return on the Fair Value of Its Arizona Properties*. Issues: Revenue Decoupling; Class Cost of Service Modeling; Revenue Distribution; Rate Design.

88. Expert Testimony. Formal Case Number 1087. (2011). Before the Public Service Commission of the District of Columbia. On the Behalf of the Office of the People's

Counsel of the District of Columbia. *In the Matter of the Application of Potomac Electric Power Company for Authority to Increase Existing Retail Rates and Charges for Electric Distribution Service*. Issues: Regulatory lag, ratemaking principles, reliability-related capital expenditure tracker proposals.

89. Expert Affidavit. Case No. 11-1364. (2011). *The State of Louisiana, the Louisiana Department of Environmental Quality, and the Louisiana Public Service Commission v. United States Environmental Protection Agency and Lisa P. Jackson.* Before the United States Court of Appeals for the District of Columbia Circuit. On the behalf of the State of Louisiana, the Louisiana Department of Environmental Quality, and the Louisiana Public Service Commission. Issues: Impacts of environmental costs on electric utilities, compliance requirements, investment cost of mitigation equipment, multi-area dispatch modeling and plant retirements.

90. Expert Affidavit. Docket No. EPA-HQ-OAR-2009-0491. (2011). Before the U.S. Environmental Protection Agency. *Federal Implementation Plans: Interstate Transport of Fine Particulate Matter and Ozone and Correction of SIP Approvals*. On the Behalf of the Louisiana Public Service Commission. Issues: Impacts of environmental costs on electric utilities, compliance requirements, investment cost of mitigation equipment, multi-area dispatch modeling and plant retirements.

91. Expert Testimony. Case No. 9296. (2011). Before the Maryland Public Service Commission. *On the Behalf of the Maryland Office of People's Counsel. In the Matter of the Application of Washington Gas Light Company for Authority to Increase Existing Rates and Charges and Revise its Terms and Conditions for Gas Service*. Issues: Infrastructure Cost Recovery Rider; Class Cost of Service Modeling; Revenue Distribution; Rate Design.

92. Expert Testimony. Docket No. G-01551A-10-0458. (2011). Before the Arizona Corporation Commission. On the Behalf of the Arizona Corporation Commission Staff. *In the Matter of the Application of Southwest Gas Corporation for the Establishment of Just and Reasonable Rates and Charges Designed to Realize A Reasonable Rate of Return on the Fair Value of its Properties throughout Arizona*. Issues: Revenue Decoupling; Class Cost of Service Modeling; Revenue Distribution; Rate Design.

93. Expert Testimony. Docket No. 11-0280 and 11-0281. (2011). Before the Illinois Commerce Commission. On the Behalf of the Illinois Attorney General, the Citizens Utility Board, and the City of Chicago, Illinois. *In re: Peoples Gas Light and Coke Company and North Shore Natural Gas Company*. Issues: Revenue Decoupling and Rate Design. (Direct and Rebuttal)

94. Expert Testimony. D.P.U. 11-01. (2011). Before the Massachusetts Department of Public Utilities. On the Behalf of the Office of the Attorney General, Office of Ratepayer Advocacy. *Petition of the Fitchburg Electric and Gas Company (Electric Division) for Approval of A General Increase in Electric Distribution Rates and Approval of a Revenue Decoupling Mechanism*. Issues: Capital Cost Rider, Revenue Decoupling.

95. Expert Testimony. D.P.U. 11-02. (2011). Before the Massachusetts Department of Public Utilities. On the Behalf of the Office of the Attorney General, Office of Ratepayer Advocacy. *Petition of the Fitchburg Electric and Gas Company (Gas Division) for Approval of A General Increase in Electric Distribution Rates and Approval of a Revenue Decoupling Mechanism*. Issues: Pipeline Replacement Rider, Revenue Decoupling.

96. Expert Affidavit. Docket No. EL-11-13 (2011). Before the Federal Energy Regulatory Commission. Petition for Preliminary Ruling, Atlantic Grid Operations. On the Behalf of the New Jersey Division of Rate Counsel. Issues: Offshore wind generation development, offshore wind transmission development, ratemaking treatment of development costs, transmission development incentives.

97. Expert Opinion. Case No. CI06-195. (2011). Before the District Court of Jefferson County, Nebraska. On the Behalf of the City of Fairbury, Nebraska and Michael Beachler. In re: Endicott Clay Products Co. vs. City of Fairbury, Nebraska and Michael Beachler. Issues: rate design and ratemaking, time of use and time differentiated rate structures, empirical analysis of demand and usage trends for tariff eligibility requirements.

98. Expert Testimony. D.P.U. 10-114. (2010). Before the Massachusetts Department of Public Utilities. On the Behalf of the Office of the Attorney General, Office of Ratepayer Advocacy. Petition of the New England Gas Company for Approval of A General Increase in Electric Distribution Rates and Approval of a Revenue Decoupling Mechanism. Issues: infrastructure replacement rider.

99. Expert Testimony. D.P.U. 10-70. (2010). Before the Massachusetts Department of Public Utilities. Petition of the Western Massachusetts Electric Company for Approval of A General Increase in Electric Distribution Rates and Approval of a Revenue Decoupling Mechanism. On the Behalf of the Office of the Attorney General, Office of Ratepayer Advocacy. Issues: Revenue decoupling; infrastructure replacement rider; performance-based regulation; inflation adjustment mechanisms; and rate design.

100. Expert Testimony. G.U.D. Nos. 998 & 9992. (2010). Before the Texas Railroad Commission. In the Matter of the Rate Case Petition of Texas Gas Services, Inc. On the Behalf of the City of El Paso, Texas. Issues: Cost of service, revenue distribution, rate design, and weather normalization.

101. Expert Testimony. B.P.U Docket No. GR10030225. (2010). Before the New Jersey Board of Public Utilities. In the Matter of the Petition of New Jersey Natural Gas Company for Approval of Regional Greenhouse Gas Initiative Programs and Associated Cost Recovery Mechanisms Pursuant to N.J.S.A. 48:3-98.1. On the Behalf of the Department of the Public Advocate, Division of Rate Counsel. Issues: solar energy proposals, solar securitization issues, solar energy policy issues.

102. Expert Testimony. D.P.U. 10-55. (2010). Before the Massachusetts Department of Public Utilities. Investigation Into the Propriety of Proposed Tariff Changes for Boston Gas Company, Essex Gas Company, and Colonial Gas Company. (d./b./a. National Grid). On the Behalf of the Office of the Attorney General, Office of Ratepayer Advocacy. Issues: Revenue decoupling; pipeline-replacement rider; performance-based regulation; partial productivity factor estimates, inflation adjustment mechanisms; and rate design.

103. Expert Testimony. Cause No.43839. (2010). Before the Indiana Utility Regulatory Commission. In the Matter of Southern Indiana Gas and Electric Company d/b/a/ Vectren Energy Delivery of Indiana, Inc. (Vectren South-Electric). On the behalf of the Indiana Office of Utility Consumer Counselor (OUCC). Issues: revenue decoupling, variable production cost riders, gains on off-system sales, transmission cost riders.

104. Congressional Testimony. Before the United States Congress. (2010). U.S. House of

Representatives, Committee on Natural Resources. Hearing on the Consolidated Land, Energy, and Aquatic Resources Act. June 30, 2010.

105. Expert Testimony. Before the City Counsel of El Paso, Texas; Public Utility Regulatory Board. (2010). On the Behalf of the City of El Paso. In Re: Rate Application of Texas Gas Services, Inc. Issues: class cost of service study (minimum system and zero intercept analysis), rate design proposals, weather normalization adjustment, and its cost of service adjustment clause, conservation adjustment clause proposals, and other cost tracker policy issues.

106. Expert Testimony. Docket 09-00183. (2010). Before the Tennessee Regulatory Authority. In the Matter of the Petition of Chattanooga Gas Company for a General Rate Increase, Implementation of the EnergySMART Conservation Programs, and Implementation of a Revenue Decoupling Mechanism. On the Behalf of Tennessee Attorney General, Consumer Advocate & Protection Division. Issues: revenue decoupling and energy efficiency program review and cost effectiveness analysis.

107. Expert Testimony and Exhibits. Docket No. 10-240. (2010). Before the Louisiana Office of Conservation. In Re: Cadeville Gas Storage, LLC. On the Behalf of Cardinal Gas Storage, LLC. Issues: alternative uses and relative economic benefits of conversion of depleted hydrocarbon reservoir for natural gas storage purposes.

108. Expert Testimony. Docket No. 09505-EI. (2010). Before the Florida Public Service Commission. In Re: Review of Replacement Fuel Costs Associated with the February 26, 2008 outage on Florida Power & Light's Electrical System. On the Behalf of the Florida Office of Public Counsel for the Citizens of the State of Florida. Issues: Replacement costs for power outage, regulatory policy/generation development incentives, renewable and energy efficiency incentives.

109. Expert Testimony. Docket 09-00104. (2009). Before the Tennessee Regulatory Authority. In the Matter of the Petition of Piedmont Natural Gas Company, Inc. to Implement a Margin Decoupling Tracker Rider and Related Energy Efficiency and Conservation Programs. On the Behalf of the Tennessee Attorney General, Consumer Advocate & Protection Division. Issues: revenue decoupling, energy efficiency program review, weather normalization.

110. Expert Testimony. Docket Number NG-0060. (2009). Before the Nebraska Public Service Commission. In the Matter of SourceGas Distribution, LLC Approval for a General Rate Increase. On the Behalf of the Nebraska Public Advocate. October 29, 2009. Issues: revenue decoupling, inflation trackers, infrastructure replacement riders, customer adjustment rider, weather normalization rider, weather normalization adjustments, estimation of normal weather for ratemaking purposes.

111. Expert Report and Deposition. Before the 23rd Judicial District Court, Parish of Assumption, State of Louisiana. On the Behalf of Dow Hydrocarbons and Resources, Inc. September 1, 2009. (Deposition, November 23-24, 2009). Issues: replacement and repair costs for underground salt cavern hydrocarbon storage.

112. Expert Testimony. D.P.U. 09-39. Before the Massachusetts Department of Public Utilities. (2009). Investigation Into the Propriety of Proposed Tariff Changes for Massachusetts Electric Company and Nantucket Electric Company (d./b./a. National Grid). On the Behalf of the Office of the Attorney General, Office of Ratepayer Advocacy.

Issues: Revenue decoupling; infrastructure rider; performance-based regulation; inflation adjustment mechanisms; revenue distribution; and rate design.

113. Expert Testimony. D.P.U. 09-30. Before the Massachusetts Department of Public Utilities. (2009). In the Matter of Bay State Gas Company Request for Increase in Rates. On the Behalf of the Office of the Attorney General, Office of Ratepayer Advocacy. Issues: Revenue decoupling; target infrastructure replacement program rider; revenue distribution; and rate design.

114. Expert Testimony. Docket EO09030249. (2009). Before the New Jersey Board of Public Utilities. In the Matter of the Petition of Public Service Electric and Gas Company for Approval of a Solar Loan II Program and An Associated Cost Recovery Mechanism. On the Behalf of the Department of the Public Advocate, Division of Rate Counsel. Issues: solar energy market design, renewable portfolio standards, solar energy, and renewable financing/loan program design.

115. Expert Testimony. Docket EO0920097. (2009). Before the New Jersey Board of Public Utilities. In the Matter of the Verified Petition of Rockland Electric Company for Approval of an SREC-Based Financing Program and An Associated Cost Recovery Mechanism. On the Behalf of the Department of the Public Advocate, Division of Rate Counsel. Issues: solar energy market design; renewable energy portfolio standards; solar energy.

116. Expert Rebuttal Report. Civil Action No.: 2:07-CV-2165. (2009). Before the U.S. District Court, Western Division of Louisiana, Lake Charles Division. Prepared on the Behalf of the Transcontinental Pipeline Corporation. Issues: expropriation and industrial use of property.

117. Expert Testimony. Docket EO06100744. (2008). Before the New Jersey Board of Public Utilities. In the Matter of the Renewable Portfolio Standard – Amendments to the Minimum filing Requirements for Energy Efficiency, Renewable Energy, and Conservation Programs and For Electric Distribution Company Submittals of Filings in connection with Solar Financing (Atlantic City Electric Company). On the Behalf of the Department of the Public Advocate, Division of Rate Counsel. Issues: Solar energy market design; renewable energy portfolio standards; solar energy. (Rebuttal and Surrebuttal)

118. Expert Testimony. Docket EO08090840. (2008). Before the New Jersey Board of Public Utilities. In the Matter of the Renewable Portfolio Standard – Amendments to the Minimum filing Requirements for Energy Efficiency, Renewable Energy, and Conservation Programs and For Electric Distribution Company Submittals of Filings in connection with Solar Financing (Jersey Central Power & Light Company). On the Behalf of the Department of the Public Advocate, Division of Rate Counsel. Issues: Solar energy market design; renewable energy portfolio standards; solar energy. (Rebuttal and Surrebuttal)

119. Expert Testimony. Docket UG-080546. (2008). Before the Washington Utilities and Transportation Commission. On the Behalf of the Washington Attorney General (Public Counsel Section). Issues: Rate Design, Cost of Service, Revenue Decoupling, Weather Normalization.

120. Congressional Testimony. (2008). Senate Republican Conference: Panel on Offshore Drilling in the Restricted Areas of the Outer Continental Shelf. September 18, 2008.

121. Expert Testimony. Appeal Number 2007-125 and 2007-299. (2008). Before the Louisiana Tax Commission. On the Behalf of Jefferson Island Storage and Hub, LLC (AGL Resources). Issues: Valuation Methodologies, Underground Storage Valuation, LTC Guidelines and Policies, Public Purpose of Natural Gas Storage. July 15, 2008 and August 20, 2008.

122. Expert Testimony. Docket Number 07-057-13. (2008). Before the Utah Public Service Commission. In the Matter of the Application of Questar Gas Company to File a General Rate Case. On the Behalf of the Utah Committee of Consumer Services. Issues: Cost of Service, Rate Design. August 18, 2008 (Direct, Rebuttal, Surrebuttal).

123. Rulemaking Testimony. (2008). Before the Louisiana Tax Commission. Examination of Replacement Cost Tables, Depreciation and Useful Lives for Oil and Gas Properties. Chapter 9 (Oil and Gas Properties) Section. August 5, 2008.

124. Legislative Testimony. (2008). Examination of Proposal to Change Offshore Natural Gas Severance Taxes (HB 326 and Amendments). Joint Finance and Appropriations Committee of the Alabama Legislature. March 13, 2008.

125. Public Testimony. (2007). Issues in Environmental Regulation. Testimony before Gubernatorial Transition Committee on Environmental Regulation (Governor-Elect Bobby Jindal). December 17, 2007.

126. Public Testimony. (2007). Trends and Issues in Alternative Energy: Opportunities for Louisiana. Testimony before Gubernatorial Transition Committee on Natural Resources (Governor-Elect Bobby Jindal). December 13, 2007.

127. Expert Report and Recommendation: Docket Number S-30336 (2007). Before the Louisiana Public Service Commission. In re: Entergy Gulf States, Inc. Application for Approval of Advanced Metering Pilot Program. Issues: pilot program for demand response programs and advanced metering systems.

128. Expert Testimony. Docket EO07040278 (2007). Before the New Jersey Board of Public Utilities. In the Matter of the Petition of Public Service Electric & Gas Company for Approval of a Solar Energy Program and An Associated Cost Recovery Mechanism. On the Behalf of the Department of the Public Advocate, Division of Rate Counsel. Issues: renewable energy market development, solar energy development, SREC markets, rate impact analysis, cost recovery issues.

129. Expert Testimony: Docket Number 05-057-T01 (2007). Before the Utah Public Service Commission. In the Matter of: Joint Application of Questar Gas Company, the Division of Public Utilities, and Utah Clean Energy for Approval of the Conservation Enabling Tariff Adjustment Options and Accounting Orders. On the behalf of the Utah Committee of Consumer Services. Issues: Revenue Decoupling, Demand-side Management; Energy Efficiency policies. (Direct, Rebuttal, and Surrebuttal Testimony)

130. Expert Testimony (Non-sworn rulemaking testimony) Docket Number RR-2008, (2007). Before the Louisiana Tax Commission. In re: Commission Consideration of Amendment and/or Adoption of Tax Commission Real/Personal Property Rules and Regulations. Issues: Louisiana oil and natural gas production trends, appropriate cost measures for wells and subsurface property, economic lives and production decline curve trends.

131. Expert Report, Recommendation, and Proposed Rule: Docket Number R-29213 & 29213-A, ex parte, (2007). Before the Louisiana Public Service Commission. In re: In re: Investigation to determine if it is appropriate for LPSC jurisdictional electric utilities to provide and install time-based meters and communication devices for each of their customers which enable such customers to participate in time-based pricing rate schedules and other demand response programs. On the behalf of the Louisiana Public Service Commission Staff. Report and Recommendation. Issues: demand response programs, advanced meter systems, cost recovery issues, energy efficiency issues, regulatory issues.

132. Expert Report, Recommendation, and Proposed Rule: Docket Number R-29712, ex parte, (2007) Before the Louisiana Public Service Commission. In re: Investigation into the ratemaking and generation planning implications of nuclear construction in Louisiana. On the behalf of the Louisiana Public Service Commission Staff. Report and Recommendation. Issues: nuclear cost power plant development, generation planning issues, and cost recovery issues.

133. Expert Testimony, Case Number U-14893, (2006). Before the Michigan Public Service Commission. In the Matter of SEMCO Energy Gas Company for Authority to Redesign and Increase Its Rates for the Sale and Transportation of Natural Gas In its MPSC Division and for Other Relief. On the behalf of the Michigan Attorney General. Issues: Rate Design, revenue decoupling, financial analysis, demand-side management program and energy efficiency policy. (Direct and Rebuttal Testimony).

134. Expert Report, Recommendation, and Proposed Rule: Docket Number R-29380, ex parte, (2006). Before the Louisiana Public Service Commission. In re: An Investigation Into the Ratemaking and Generation Planning Implications of the U.S. EPA Clean Air Interstate Rule. On the behalf of the Louisiana Public Service Commission Staff. Report and Recommendation. Issues: environmental regulation and cost recovery; allowance allocations and air credit markets; ratepayer impacts of new environmental regulations.

135. Expert Affidavit Before the Louisiana Tax Commission (2006). On behalf of ANR Pipeline, Tennessee Gas Transmission and Southern Natural Gas Company. Issues: Competitive nature of interstate and intrastate transportation services.

136. Expert Affidavit Before the 19th Judicial District Court (2006). Suit Number 491, 453 Section 26. On behalf of Transcontinental Pipeline Corporation, et.al. Issues: Competitive nature of interstate and intrastate transportation services.

137. Expert Testimony: Docket Number 05-057-T01 (2006). Before the Utah Public Service Commission. In the Matter of: Joint Application of Questar Gas Company, the Division of Public Utilities, and Utah Clean Energy for Approval of the Conservation Enabling Tariff Adjustment Options and Accounting Orders. On the behalf of the Utah Committee of Consumer Services. Issues: Revenue Decoupling, Demand-side Management; Energy Efficiency policies. (Rebuttal and Supplemental Rebuttal Testimony)

138. Legislative Testimony (2006). Senate Committee on Natural Resources. Senate Bill 655 Regarding Remediation of Oil and Gas Sites, Legacy Lawsuits, and the Deterioration of State Drilling.

139. Expert Report: Rulemaking Docket (2005). Before the New Jersey Bureau of Public

Utilities. In re: Proposed Rulemaking Changes Associated with New Jersey's Renewable Portfolio Standard. Expert Report. The Economic Impacts of New Jersey's Proposed Renewable Portfolio Standard. On behalf of the New Jersey Office of Ratepayer Advocate. Issues: Renewable Portfolio Standards, rate impacts, economic impacts, technology cost forecasts.

140. Expert Testimony: Docket Number 2005-191-E. (2005). Before the South Carolina Public Service Commission. On behalf of NewSouth Energy LLC. In re: General Investigation Examining the Development of RFP Rules for Electric Utilities. Issues: Competitive bidding; merchant development. (Direct and Rebuttal Testimony).

141. Expert Testimony: Docket No. 05-UA-323. (2005). Before the Mississippi Public Service Commission. On the behalf of Calpine Corporation. In re: Entergy Mississippi's Proposed Acquisition of the Attala Generation Facility. Issues: Asset acquisition; merchant power development; competitive bidding.

142. Expert Testimony: Docket Number 050045-EI and 050188-EI. (2005). Before the Florida Public Service Commission. On the behalf of the Citizens of the State of Florida. In re: Petition for Rate Increase by Florida Power & Light Company. Issues: Load forecasting; O&M forecasting and benchmarking; incentive returns/regulation.

143. Expert Testimony (non-sworn, rulemaking): Comments on Decreased Drilling Activities in Louisiana and the Role of Incentives. (2005). Louisiana Mineral Board Monthly Docket and Lease Sale. July 13, 2005

144. Legislative Testimony (2005). Background and Impact of LNG Facilities on Louisiana. Joint Meeting of Senate and House Natural Resources Committee. Louisiana Legislature. May 19, 2005.

145. Public Testimony. Docket No. U-21453. (2005). Technical Conference before the Louisiana Public Service Commission on an Investigation for a Limited Industrial Retail Choice Plan.

146. Expert Testimony: Docket No. 2003-K-1876. (2005). On Behalf of Columbia Gas Transmission. Expert Testimony on the Competitive Market Structure for Gas Transportation Service in Ohio. Before the Ohio Board of Tax Appeals.

147. Expert Report and Testimony: Docket No. 99-4490-J, *Lafayette City-Parish Consolidated Government, et. al. v. Entergy Gulf States Utilities, Inc. et. al*. (2005, 2006). On behalf of the City of Lafayette, Louisiana and the Lafayette Utilities Services. Expert Rebuttal Report of the Harborfront Consulting Group Valuation Analysis of the LUS Expropriation. Filed before 15th Judicial District Court, Lafayette, Louisiana.

148. Expert Testimony: ANR Pipeline Company v. Louisiana Tax Commission (2005), Number 468,417 Section 22, 19th Judicial District Court, Parish of East Baton Rouge, State of Louisiana Consolidated with Docket Numbers: 480,159; 489,776;480,160; 480,161; 480,162; 480,163; 480,373; 489,776; 489,777; 489,778;489,779; 489,780; 489,803; 491,530; 491,744; 491,745; 491,746; 491,912;503,466; 503,468; 503,469; 503,470; 515,414; 515,415; and 515,416. In re: Market structure issues and competitive implications of tax differentials and valuation methods in natural gas transportation markets for interstate and intrastate pipelines.

149. Expert Report and Recommendation: Docket No. U-27159. (2004). On Behalf of the Louisiana Public Service Commission Staff. Expert Report on Overcharges Assessed by Network Operator Services, Inc. Before the Louisiana Public Service Commission.

150. Expert Testimony: Docket Number 2004-178-E. (2004). Before the South Carolina Public Service Commission. On behalf of Columbia Energy LLC. In re: Rate Increase Request of South Carolina Electric and Gas. (Direct and Surrebuttal Testimony)

151. Expert Testimony: Docket Number 040001-EI. (2004). Before the Florida Public Service Commission. On behalf of Power Manufacturing Systems LLC, Thomas K. Churbuck, and the Florida Industrial Power Users Group. In re: Fuel Adjustment Proceedings; Request for Approval of New Purchase Power Agreements. Company examined: Florida Power & Light Company.

152. Expert Affidavit: Docket Number 27363. (2004). Before the Public Utilities Commission of Texas. Joint Affidavit on Behalf of the Cities of Texas and the Staff of the Public Utilities Commission of Texas Regarding Certified Issues. In Re: Application of Valor Telecommunications, L.P. For Authority to Establish Extended Local Calling Service (ELCS) Surcharges For Recovery of ELCS Surcharge.

153. Expert Report and Testimony. Docket 1997-4665-PV, 1998-4206-PV, 1999-7380-PV, 2000-5958-PV, 2001-6039-PV, 2002-64680-PV, 2003-6231-PV. (2003) Before the Kansas Board of Tax Appeals. (2003). In the Matter of the Appeals of CIG Field Services Company from orders of the Division of Property Valuation. On the Behalf of CIG Field Services. Issues: the competitive nature of natural gas gathering in Kansas.

154. Expert Report and Testimony: Docket Number U-22407. Before the Louisiana Public Service Commission (2002). On the Behalf of the Louisiana Public Service Commission Staff. Company examined: Louisiana Gas Services, Inc. Issues: Purchased Gas Acquisition audit, fuel procurement and planning practices.

155. Expert Testimony: Docket Number 000824-EI. Before the Florida Public Service Commission. (2002). On the Behalf of the Citizens of the State of Florida. Company examined: Florida Power Corporation. Issues: Load Forecasts and Billing Determinants for the Projected Test Year.

156. Public Testimony: Louisiana Board of Commerce and Industry (2001). Testimony on the Economic Impacts of Merchant Power Generation.

157. Expert Testimony: Docket Number 24468. (2001). On the Behalf of the Texas Office of Public Utility Counsel. Public Utility Commission of Texas Staff's Petition to Determine Readiness for Retail Competition in the Portion of Texas Within the Southwest Power Pool. Company examined: AEP-SWEPCO.

158. Expert Report. (2001) On Behalf of David Liou and Pacific Richland Products, Inc. to Review Cogeneration Issues Associated with Dupont Dow Elastomers, L.L.C. (DDE) and the Dow Chemical Company (Dow).

159. Expert Testimony: Docket Number 01-1049, Docket Number 01-3001. (2001) On behalf the Nevada Office of Attorney General, Bureau of Consumer Protection. Petition of Central Telephone Company-Nevada D/b/a Sprint of Nevada and Sprint Communications L.P. for Review and Approval of Proposed Revised Performance Measures and Review and

Approval of Performance Measurement Incentive Plans. Before the Public Utilities Commission of Nevada.

160. Expert Affidavit: Multiple Dockets (2001). Before the Louisiana Tax Commission. On the Behalf of Louisiana Interstate Pipeline Companies. Testimony on the Competitive Nature of Natural Gas Transportation Services in Louisiana.

161. Expert Affidavit before the Federal District Court, Middle District of Louisiana (2001). Issues: Competitive Nature of the Natural Gas Transportation Market in Louisiana. On behalf of a Consortium of Interstate Natural Gas Transportation Companies.

162. Public Testimony: Louisiana Board of Commerce and Industry (2001). Testimony on the Economic and Ratepayer Benefits of Merchant Power Generation and Issues Associated with Tax Incentives on Merchant Power Generation and Transmission.

163. Expert Testimony: Docket Number 01-1048 (2001). Before the Public Utilities Commission of Nevada. On the Behalf of the Nevada Office of the Attorney General, Bureau of Consumer Protection. Company analyzed: Nevada Bell Telephone Company. Issues: Statistical Issues Associated with Performance Incentive Plans.

164. Expert Testimony: Docket 22351 (2001). Before the Public Utility Commission of Texas. On the Behalf of the City of Amarillo. Company analyzed: Southwestern Public Service Company. Issues: Unbundled cost of service, affiliate transactions, load forecasting.

165. Expert Testimony: Docket 991779-EI (2000). Before the Florida Public Service Commission. On the Behalf of the Citizens of the State of Florida. Companies analyzed: Florida Power & Light Company; Florida Power Corporation; Tampa Electric Company; and Gulf Power Company. Issues: Competitive Nature of Wholesale Markets, Regional Power Markets, and Regulatory Treatment of Incentive Returns on Gains from Economic Energy Sales.

166. Expert Testimony: Docket 990001-EI (1999). Before the Florida Public Service Commission. On the Behalf of the Citizens of the State of Florida. Companies analyzed: Florida Power & Light Company; Florida Power Corporation; Tampa Electric Company; and Gulf Power Company. Issues: Regulatory Treatment of Incentive Returns on Gains from Economic Energy Sales.

167. Expert Testimony: Docket 950495-WS (1996). Before the Florida Public Service Commission. On the Behalf of the Citizens of the State of Florida. Company analyzed: Southern States Utilities, Inc. Issues: Revenue Repression Adjustment, Residential and Commercial Demand for Water Service.

168. Legislative Testimony. Louisiana House of Representatives, Special Subcommittee on Utility Deregulation. (1997). On Behalf of the Louisiana Public Service Commission Staff. Issue: Electric Restructuring.

169. Expert Testimony: Docket 940448-EG -- 940551-EG (1994). Before the Florida Public Service Commission. On the Behalf of the Legal Environmental Assistance Foundation. Companies analyzed: Florida Power & Light Company; Florida Power Corporation; Tampa Electric Company; and Gulf Power Company. Issues: Comparison of Forecasted Cost-Effective Conservation Potentials for Florida.

170. Expert Testimony: Docket 920260-TL, (1993). Before the Florida Public Service

Commission. On the Behalf of the Florida Public Service Commission Staff. Company analyzed: BellSouth Communications, Inc. Issues: Telephone Demand Forecasts and Empirical Estimates of the Price Elasticity of Demand for Telecommunication Services.

171. Expert Testimony: Docket 920188-TL, (1992). Before the Florida Public Service Commission. On the Behalf of the Florida Public Service Commission Staff. Company analyzed: GTE-Florida. Issues: Telephone Demand Forecasts and Empirical Estimates of the Price Elasticity of Demand for Telecommunication Services.

REFEREE AND EDITORIAL APPOINTMENTS

Contributor, 2014-2018, *Wall Street Journal*, *Journal Reports*, Energy

Editorial Board Member, 2015-2017, *Utilities Policy*

Referee, 2014-Current, *Utilities Policy*

Referee, 2010-Current, *Economics of Energy & Environmental Policy*

Referee, 1995-Current*, Energy Journal*

Contributing Editor, 2000-2005, *Oil, Gas and Energy Quarterly*

Referee, 2005, *Energy Policy*

Referee, 2004, *Southern Economic Journal*

Referee, 2002, *Resource & Energy Economics*

Committee Member, IAEE/USAEE Student Paper Scholarship Award Committee, 2003

PROPOSAL TECHNICAL REVIEWER

California Energy Commission, Public Interest Energy Research (PIER) Program (1999).

PROFESSIONAL ASSOCIATIONS

American Economic Association, American Statistical Association, Southern Economic Association, Western Economic Association, International Association of Energy Economists ("IAEE"), United States Association of Energy Economics ("USAEE"), the National Association for Business Economics ("NABE"), and the Energy Bar Association (National and Louisiana Chapter; current Board member of LA chapter).

HONORS AND AWARDS

National Association of Regulatory Utility Commissioners (NARUC). Best Paper Award for papers published in the *Journal of Applied Regulation* (2004).

Baton Rouge Business Report, Selected as "Top 40 Under 40" (2003).

Omicron Delta Epsilon (1992-Current).

Interstate Oil and Gas Compact Commission (IOGCC) "Best Practice" Award for Research on the Economic Impact of Oil and Gas Activities on State Leases for the Louisiana Department of Natural Resources (2003).

Distinguished Research Award, Academy of Legal, Ethical and Regulatory Issues, Allied Academics (2002).

Florida Public Service Commission, Staff Excellence Award for Assistance in the Analysis of Local Exchange Competition Legislation (1995).

TEACHING EXPERIENCE

Energy and the Environment (Survey Course)

Principles of Microeconomic Theory

Principles of Macroeconomic Theory

Lecturer, Environmental Management and Permitting. Lecture in Natural Gas Industry, LNG and Markets.

Lecturer, Electric Power Industry Environmental Issues, Field Course on Energy and the Environment. (Dept. of Environmental Studies).

Lecturer, Electric Power Industry Trends, Principles Course in Power Engineering (Dept. of Electric Engineering).

Lecturer, LSU Honors College, Senior Course on "Society and the Coast."

Continuing Education. Electric Power Industry Restructuring for Energy Professionals.

"The Gulf Coast Energy Situation: Outlook for Production and Consumption." Educational Course and Lecture Prepared for the Foundation for American Communications and the Society for Professional Journalists, New Orleans, LA, December 2, 2004

"The Impact of Hurricane Katrina on Louisiana's Energy Infrastructure and National Energy Markets." Educational Course and Lecture Prepared for the Foundation for American Communications and the Society for Professional Journalists, Houston, TX, September 13, 2005.

"Forecasting for Regulators: Current Issues and Trends in the Use of Forecasts, Statistical, and Empirical Analyses in Energy Regulation." Instructional Course for State Regulatory Commission Staff. Institute of Public Utilities, Kellogg Center, Michigan State University. July 8-9, 2010.

"Regulatory and Ratemaking Issues with Cost and Revenue Trackers." Michigan State University, Institute of Public Utilities. Advanced Regulatory Studies Program. September 29, 2010.

"Demand Modeling and Forecasting for Regulators." Michigan State University, Institute of Public Utilities. Advanced Regulatory Studies Program. September 30, 2010.

"Demand Modeling and Forecasting for Regulators." Michigan State University, Institute of Public Utilities, Forecasting Workshop, Charleston, SC. March 7-9, 2011.

"Regulatory and Cost Recovery Approaches for Smart Grid Applications." Michigan State University, Institute of Public Utilities, Smart Grid Workshop for Regulators. Charleston, SC. March 7-11, 2011.

"Regulatory and Ratemaking Issues Associated with Cost and Expense Adjustment Mechanisms." Michigan State University, Institute of Public Utilities, Advanced Regulatory Studies Program. Lansing, Michigan. September 28, 2011.

"Utility Incentives, Decoupling, and Renewable Energy Programs." Michigan State University, Institute of Public Utilities, Advanced Regulatory Studies Program. Lansing, Michigan. September 29, 2011.

"Regulatory and Cost Recovery Approaches for Smart Grid Applications." Michigan State University, Institute of Public Utilities, Smart Grid Workshop for Regulators. Charleston, SC. March 6-8, 2012.

"Traditional and Incentive Ratemaking Workshop." New Mexico Public Utilities Commission Staff. Santa Fe, NM October 18, 2012.

"Traditional and Incentive Ratemaking Workshop." New Jersey Board of Public Utilities Staff. Newark, NJ. March 1, 2013.

"Natural Gas Issues and Recent Market Trends." Michigan State University Institute of Public Utilities, GridSchool Regulatory Studies Program, East Lansing, Mich., March 29, 2017.

"Gas Supply Planning and Procurement: Regulatory Overview and issues." Michigan State University Institute of Public Utilities, Basic Regulatory Studies Program, East Lansing, Mich., Aug 17, 2017.

"Natural Gas Supply Issues and Challenges." Michigan State University Institute of Public Utilities, Basic Regulatory Studies Program, East Lansing, Mich., Aug 17, 2017.

"Incentives, Risk and Changes in the Nature of Regulation." Michigan State University Institute of Public Utilities, Basic Regulatory Studies Program, East Lansing, Mich., Aug 18, 2017.

"Traditional and Alternative Forms of Regulation: Background and Overview." Michigan State University Institute of Public Utilities, Advanced Regulatory Studies Program, East Lansing, Mich., October 2, 2017.

"Traditional and Alternative Forms of Regulation: Utility and policy motivations for risk and change." Michigan State University Institute of Public Utilities, Advanced Regulatory Studies Program, East Lansing, Mich., October 2, 2017.

"Traditional and Alternative Forms of Regulation: Incentives and Formula Based Methods." Michigan State University Institute of Public Utilities, Advanced Regulatory Studies Program, East Lansing, Mich., October 2, 2017.

THESIS/DISSERTATIONS COMMITTEES

Active:
1 Thesis Committee Memberships (Environmental Studies)
2 Ph.D. Dissertation Committee (Economics)
Completed:

8 Thesis Committee Memberships (Environmental Studies, Geography)
4 Doctoral Committee Memberships (Information Systems & Decision Sciences, Agricultural and Resource Economics, Economics, Education and Workforce Development).
2 Doctoral Examination Committee Membership (Information Systems & Decision Sciences, Education and Workforce Development)
1 Senior Honors Thesis (Journalism, Loyola University)

LSU SERVICE AND COMMITTEE MEMBERSHIPS

Committee Member, Energy Education Curriculum Committee. E.J. Ourso College of Business. LSU (2016-Current).

Chairman, LSU Energy Initiative/LSU Energy Council (2014-Current).

Co-Director & Steering Committee Member, LSU Coastal Marine Institute (2009-2014).

CES Promotion Committee, Division of Radiation Safety (2006).

Search Committee Chair (2006), Research Associate 4 Position.

Search Committee Member (2005), Research Associate 4 Position.

Search Committee Member (2005), CES Communications Manager.

LSU Graduate Research Faculty, Associate Member (1997-2004); Full Member (2004-2010); Affiliate Member with Full Directional Rights (2011-2014); Full Member (2014-current).

LSU Faculty Senate (2003-2006).

Conference Coordinator. (2005-Current) Center for Energy Studies Conference on Alternative Energy.

LSU CES/SCE Public Art Selection Committee (2003-2005).

Conference Coordinator. Center for Energy Studies Annual Energy Conference/Summit. (2003-Current).

Conference Coordinator. Center for Energy Studies Seminar Series on Electric Utility Restructuring and Wholesale Competition. (1996-2003).

Co-Chairman, Review Committee, Louisiana Port Construction and Development Priority Program Rules and Regulations, On Behalf of the LSU Ports and Waterways Institute. (1997).

LSU Main Campus Cogeneration/Turbine Project, (1999-2000).

LSU InterCollege Environmental Cooperative. (1999-2001).

LSU Faculty Senate Committee on Public Relations (1997-1999).

LSU Faculty Senate Committee on Student Retention and Recruitment (1999-2003).

PROFESSIONAL SERVICE

Board Member (2018). Energy Bar Association, Louisiana Chapter.

Program Committee Member (2017). Gulf Coast Power Association Conference. New Orleans, LA.

Program Committee Member (2016). Gulf Coast Power Association Conference. New Orleans, LA.

Program Committee Member (2015). Gulf Coast Power Association Workshop/Special Briefing. "Gulf Coast Disaster Readiness: A Past, Present and Future Look at Power and Industry Readiness in MISO South."

Advisor (2008). National Association of Regulatory Utility Commissioners ("NARUC"). Study Committee on the Impact of Executive Drilling Moratoria on Federal Lands.

Steering Committee Member, Louisiana Representative (2008-Current). Southeast Agriculture & Forestry Energy Resources Alliance. Southern Policies Growth Board.

Advisor (2007-Current). National Association of State Utility Consumer Advocates ("NASUCA"), Natural Gas Committee.

Program Committee Chairman (2007-2008). U.S. Association of Energy Economics ("USAEE") Annual Conference, New Orleans, LA

Finance Committee Chairman (2007-2008). USAEE Annual Conference, New Orleans, LA

Committee Member (2006), International Association for Energy Economics ("IAEE") Nominating Committee.

Founding President (2005-2007) Louisiana Chapter, USAEE.

Secretary (2001) Houston Chapter, USAEE.

Advisor, Louisiana LNG Buyers/Developers Summit, Office of the Governor/Louisiana Department of Economic Development/Louisiana Department of Natural Resources, and Greater New Orleans, Inc. (2004).

Table of Schedules

Title	Schedule
Analysis of Historic Company Rates	Exhibit AG-2.1
Residential Non-Fuel Revenues per kWh, 2010-2019	Exhibit AG-2.2
Commercial Non-Fuel Revenues per kWh, 2010-2019	Exhibit AG-2.3
Industrial Non-Fuel Revenues per kWh, 2010-2019	Exhibit AG-2.4
Consumers' Monthly System Peak Loads, 2015-2019	Exhibit AG-2.5
Monthly Load Factor Under Alternative Peak Demands, 2019	Exhibit AG-2.6
Consumers' Monthly System Load Factor, 2015-2019	Exhibit AG-2.7
Modified Analysis of Company Production Allocation -- No Baseload Weightings	Exhibit AG-2.8
Modified Analysis of Company Production Allocation -- No Baseload Weightings and Averaged Results	Exhibit AG-2.9
Alternative Analysis of Consumers' Electric Generation Units -- 2019 Capacity Factors	Exhibit AG-2.10
Alternative Analysis of Consumers' Electric Generation Units -- Levelized Costs	Exhibit AG-2.11
Comparison of CCOSS Results, Under Alternative Production Demand Allocation Factors	Exhibit AG-2.12
Results of Alternative Class Cost of Service Study	Exhibit AG-2.13
Results of Company Class Cost of Service Study	Exhibit AG-2.14
Comparison of Company and Alternative Revenue Allocation	Exhibit AG-2.15
Comparison of Company and Alternative Proposed Rates	Exhibit AG-2.16
Analysis of Current Customer Charge to Customer-related Costs	Exhibit AG-2.17

Analysis of Historic Company Rates

Witness Dismukes
Case No. 20697
Exhibit AG-2.1

		Residential			Secondary			Primary			Lighting and Unmetered			Self Generation		
Case Number	Year	Total Present Revenues ($000)	Total Proposed Revenues ($000)	Change (%)	Total Present Revenues ($000)	Total Proposed Revenues ($000)	Change (%)	Total Present Revenues ($000)	Total Proposed Revenues ($000)	Change (%)	Total Present Revenues ($000)	Total Proposed Revenues ($000)	Change (%)	Total Present Revenues ($000)	Total Proposed Revenues ($000)	Change (%)
U-15645	2009	$ 1,376,261	$ 1,446,204	5.1%	$ 814,699	$ 845,111	3.7%	$ 1,050,979	$ 1,087,031	3.4%	$ 37,274	$ 42,239	13.3%	$ 4,730	$ 2,802	-40.8%
U-16191	2010	1,431,905	1,564,205	9.2%	836,774	859,672	2.7%	1,149,306	1,147,417	-0.2%	41,939	43,936	4.8%	10,893	1,306	-88.0%
U-16794	2012	1,576,637	1,637,609	3.9%	909,661	945,401	3.9%	1,097,763	1,125,371	2.5%	45,000	41,411	-8.0%	2,773	438	-84.2%
U-17087	2013	1,687,443	1,753,453	3.9%	922,748	982,558	6.5%	1,172,897	1,140,020	-2.8%	41,016	42,002	2.4%	5,604	649	-88.4%
U-17735	2015	1,763,387	1,887,521	7.0%	1,010,037	1,045,919	3.6%	1,142,732	1,126,413	-1.4%	38,954	36,897	-5.3%	3,207	1,527	-52.4%
U-17990	2017	1,860,819	1,910,420	2.7%	1,033,873	1,032,619	-0.1%	1,122,193	1,186,816	5.8%	37,282	39,844	6.9%	4,768	2,534	-46.9%
U-18322	2018	1,894,646	1,939,279	2.4%	1,009,189	1,046,552	3.7%	1,197,143	1,179,130	-1.5%	39,504	43,084	9.1%	5,047	1,917	-62.0%
U-20134	2019	1,941,413	1,920,548	-1.1%	1,064,095	1,048,154	-1.5%	1,142,799	1,155,173	1.1%	42,152	43,739	3.8%	3,429	1,535	-55.2%
U-20697		**$ 2,004,276**	**$ 2,284,513**	**14.0%**	**$ 1,034,909**	**$ 1,065,094**	**2.9%**	**$ 1,046,175**	**$ 982,450**	**-6.1%**	**$ 42,673**	**$ 40,470**	**-5.2%**	**$ 5,609**	**$ 5,648**	**0.7%**

Source: Company Compliance Filings; Company Petition, Attachment A.

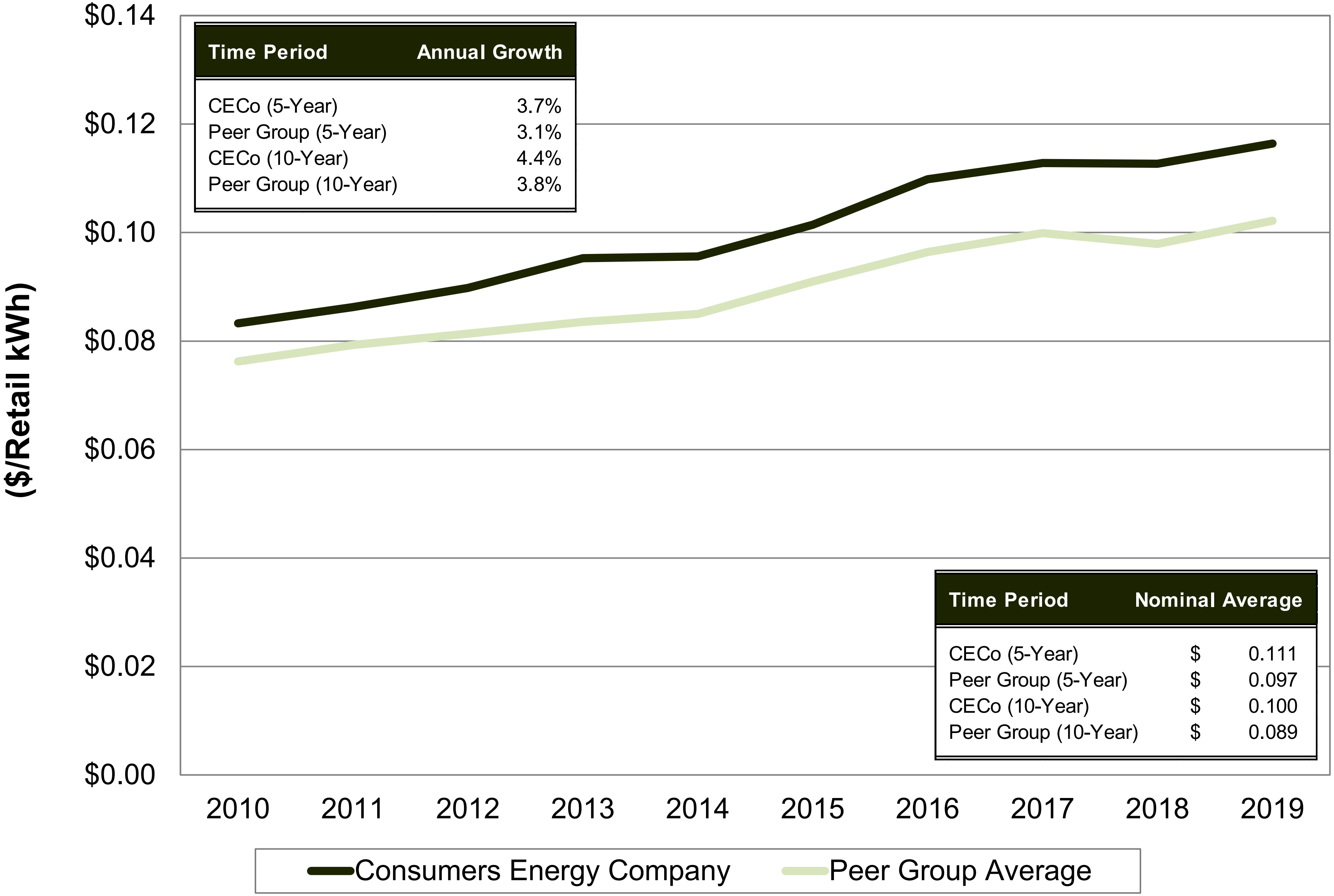
Residential Non-Fuel Revenues per kWh, 2010-2019

Company	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
	($/kWh)									
Consumers Energy Company	**$ 0.083**	**$ 0.086**	**$ 0.090**	**$ 0.095**	**$ 0.096**	**$ 0.101**	**$ 0.110**	**$ 0.113**	**$ 0.113**	**$ 0.116**
Ameren Illinois Company	0.078	0.079	0.072	0.056	0.056	0.063	0.067	0.068	0.059	0.063
DTE Electric Company	0.101	0.104	0.114	0.120	0.111	0.119	0.130	0.131	0.130	0.138
Duke Energy Indiana, LLC	0.065	0.069	0.070	0.075	0.079	0.082	0.084	0.086	0.085	0.087
Indianapolis Power & Light Company	0.055	0.056	0.061	0.061	0.060	0.063	0.072	0.076	0.078	0.086
Interstate Power and Light Company	0.097	0.097	0.097	0.101	0.102	0.114	0.121	0.126	0.132	0.144
Kentucky Power Company	0.048	0.057	0.056	0.054	0.065	0.068	0.083	0.084	0.083	0.085
Louisville Gas and Electric Company	0.056	0.060	0.062	0.068	0.071	0.075	0.076	0.082	0.077	0.083
MidAmerican Energy Company	0.069	0.070	0.075	0.074	0.076	0.086	0.091	0.094	0.091	0.092
Northern Indiana Public Service Company	0.079	0.080	0.087	0.093	0.096	0.100	0.100	0.113	0.109	0.113
Northern States Power Company (Minnesota)	0.068	0.074	0.074	0.082	0.085	0.087	0.099	0.100	0.103	0.101
Wisconsin Electric Power Company	0.096	0.103	0.104	0.113	0.113	0.123	0.122	0.123	0.120	0.123
Wisconsin Power and Light Company	0.086	0.092	0.092	0.094	0.097	0.101	0.102	0.112	0.104	0.111
Wisconsin Public Service Corporation	0.096	0.090	0.093	0.096	0.094	0.103	0.105	0.105	0.102	0.103
Peer Group Average	**$ 0.076**	**$ 0.079**	**$ 0.081**	**$ 0.084**	**$ 0.085**	**$ 0.091**	**$ 0.096**	**$ 0.100**	**$ 0.098**	**$ 0.102**

Company	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
	($/kWh)									
Consumers Energy Company	**9**	**9**	**9**	**10**	**10**	**10**	**11**	**10**	**11**	**11**
Ameren Illinois Company	7	7	5	2	1	1	1	1	1	1
DTE Electric Company	14	14	14	14	13	13	14	14	13	13
Duke Energy Indiana, LLC	4	4	4	6	6	5	5	5	5	5
Indianapolis Power & Light Company	2	1	2	3	2	2	2	2	3	4
Interstate Power and Light Company	13	12	12	12	12	12	12	13	14	14
Kentucky Power Company	1	2	1	1	3	3	4	4	4	3
Louisville Gas and Electric Company	3	3	3	4	4	4	3	3	2	2
MidAmerican Energy Company	6	5	7	5	5	6	6	6	6	6
Northern Indiana Public Service Company	8	8	8	8	9	8	8	11	10	10
Northern States Power Company (Minnesota)	5	6	6	7	7	7	7	7	8	7
Wisconsin Electric Power Company	12	13	13	13	14	14	13	12	12	12
Wisconsin Power and Light Company	10	11	10	9	11	9	9	9	9	9
Wisconsin Public Service Corporation	11	10	11	11	8	11	10	8	7	8

Source: FERC Form 1.

Residential Non-Fuel Revenues per kWh, 2010-2019



Time Period	Annual Growth
CECo (5-Year)	3.7%
Peer Group (5-Year)	3.1%
CECo (10-Year)	4.4%
Peer Group (10-Year)	3.8%

Time Period	Nominal Average	
CECo (5-Year)	$	0.111
Peer Group (5-Year)	$	0.097
CECo (10-Year)	$	0.100
Peer Group (10-Year)	$	0.089

Source: FERC Form 1.

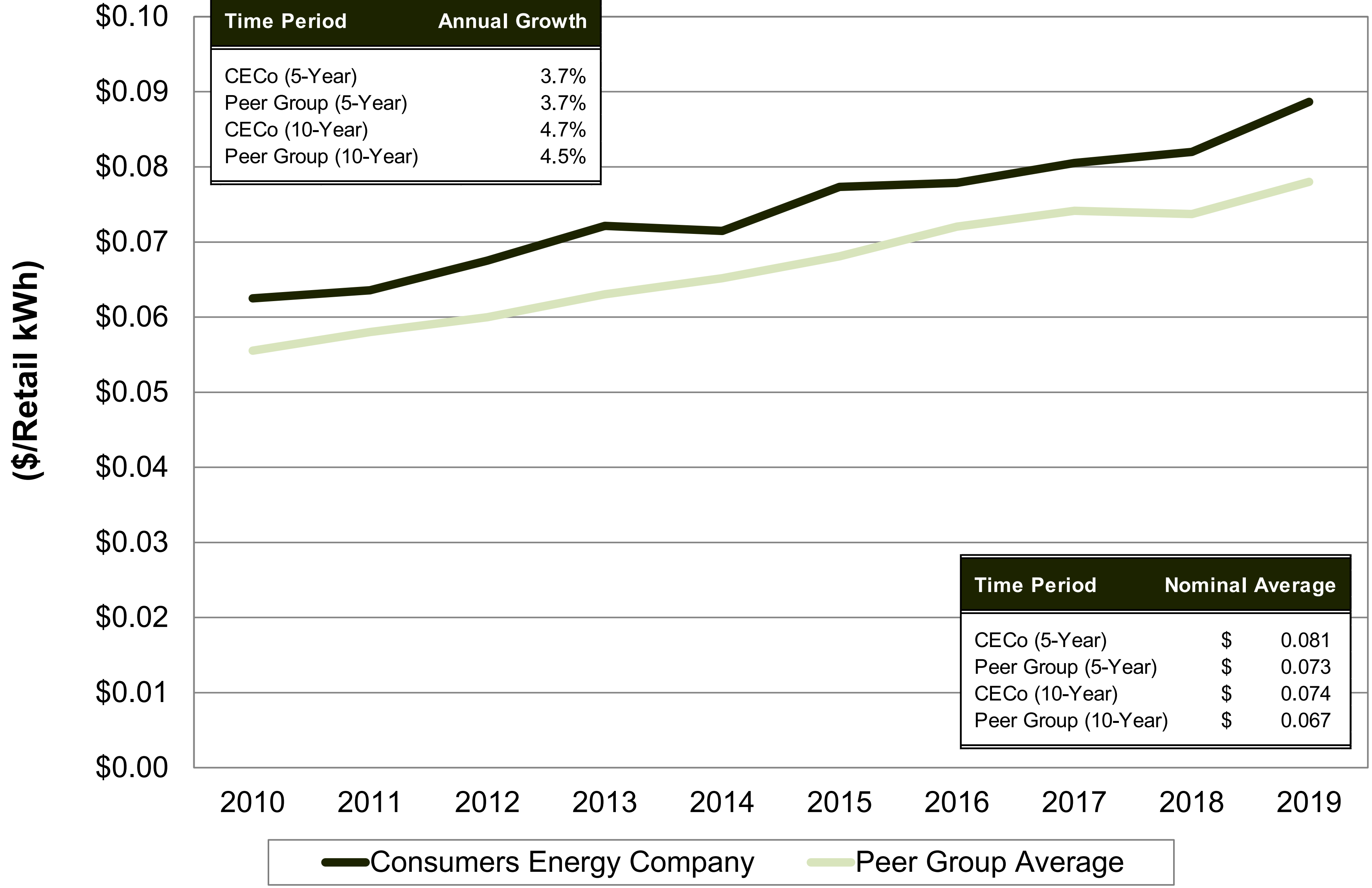
Commercial Non-Fuel Revenues per kWh, 2010-2019

Company	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
	($/kWh)									
Consumers Energy Company	**$ 0.063**	**$ 0.064**	**$ 0.068**	**$ 0.072**	**$ 0.071**	**$ 0.077**	**$ 0.078**	**$ 0.081**	**$ 0.082**	**$ 0.089**
Ameren Illinois Company	0.020	0.019	0.017	0.022	0.025	0.027	0.031	0.031	0.028	0.031
DTE Electric Company	0.068	0.068	0.076	0.079	0.070	0.072	0.075	0.077	0.078	0.083
Duke Energy Indiana, LLC	0.052	0.054	0.053	0.059	0.062	0.062	0.065	0.066	0.067	0.071
Indianapolis Power & Light Company	0.064	0.066	0.068	0.069	0.070	0.073	0.082	0.080	0.083	0.096
Interstate Power and Light Company	0.062	0.061	0.060	0.066	0.069	0.076	0.080	0.083	0.091	0.101
Kentucky Power Company	0.050	0.058	0.058	0.056	0.073	0.071	0.082	0.085	0.085	0.085
Louisville Gas and Electric Company	0.050	0.055	0.056	0.060	0.062	0.066	0.067	0.071	0.067	0.074
MidAmerican Energy Company	0.051	0.052	0.056	0.057	0.059	0.065	0.067	0.069	0.068	0.071
Northern Indiana Public Service Company	0.065	0.067	0.078	0.080	0.082	0.086	0.088	0.101	0.097	0.099
Northern States Power Company (Minnesota)	0.043	0.047	0.048	0.054	0.055	0.056	0.068	0.068	0.069	0.070
Wisconsin Electric Power Company	0.069	0.077	0.078	0.082	0.082	0.085	0.085	0.085	0.083	0.085
Wisconsin Power and Light Company	0.067	0.074	0.073	0.076	0.078	0.081	0.082	0.085	0.081	0.085
Wisconsin Public Service Corporation	0.060	0.057	0.058	0.059	0.059	0.065	0.065	0.064	0.063	0.064
Peer Group Average	**$ 0.056**	**$ 0.058**	**$ 0.060**	**$ 0.063**	**$ 0.065**	**$ 0.068**	**$ 0.072**	**$ 0.074**	**$ 0.074**	**$ 0.078**

Company	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
	($/kWh)									
Consumers Energy Company	**9**	**9**	**9**	**10**	**10**	**11**	**8**	**9**	**9**	**11**
Ameren Illinois Company	1	1	1	1	1	1	1	1	1	1
DTE Electric Company	13	12	12	12	9	8	7	7	7	7
Duke Energy Indiana, LLC	6	4	3	5	5	3	2	3	3	4
Indianapolis Power & Light Company	10	10	10	9	8	9	10	8	10	12
Interstate Power and Light Company	8	8	8	8	7	10	9	10	13	14
Kentucky Power Company	3	7	6	3	11	7	12	12	12	10
Louisville Gas and Electric Company	4	5	5	7	6	6	4	6	4	6
MidAmerican Energy Company	5	3	4	4	3	4	5	5	5	5
Northern Indiana Public Service Company	11	11	13	13	14	14	14	14	14	13
Northern States Power Company (Minnesota)	2	2	2	2	2	2	6	4	6	3
Wisconsin Electric Power Company	14	14	14	14	13	13	13	13	11	8
Wisconsin Power and Light Company	12	13	11	11	12	12	11	11	8	9
Wisconsin Public Service Corporation	7	6	7	6	4	5	3	2	2	2

Source: FERC Form 1.

Commercial Non-Fuel Revenues per kWh, 2010-2019



Time Period	Annual Growth
CECo (5-Year)	3.7%
Peer Group (5-Year)	3.7%
CECo (10-Year)	4.7%
Peer Group (10-Year)	4.5%

Time Period	Nominal Average	
CECo (5-Year)	$	0.081
Peer Group (5-Year)	$	0.073
CECo (10-Year)	$	0.074
Peer Group (10-Year)	$	0.067

Source: FERC Form 1.

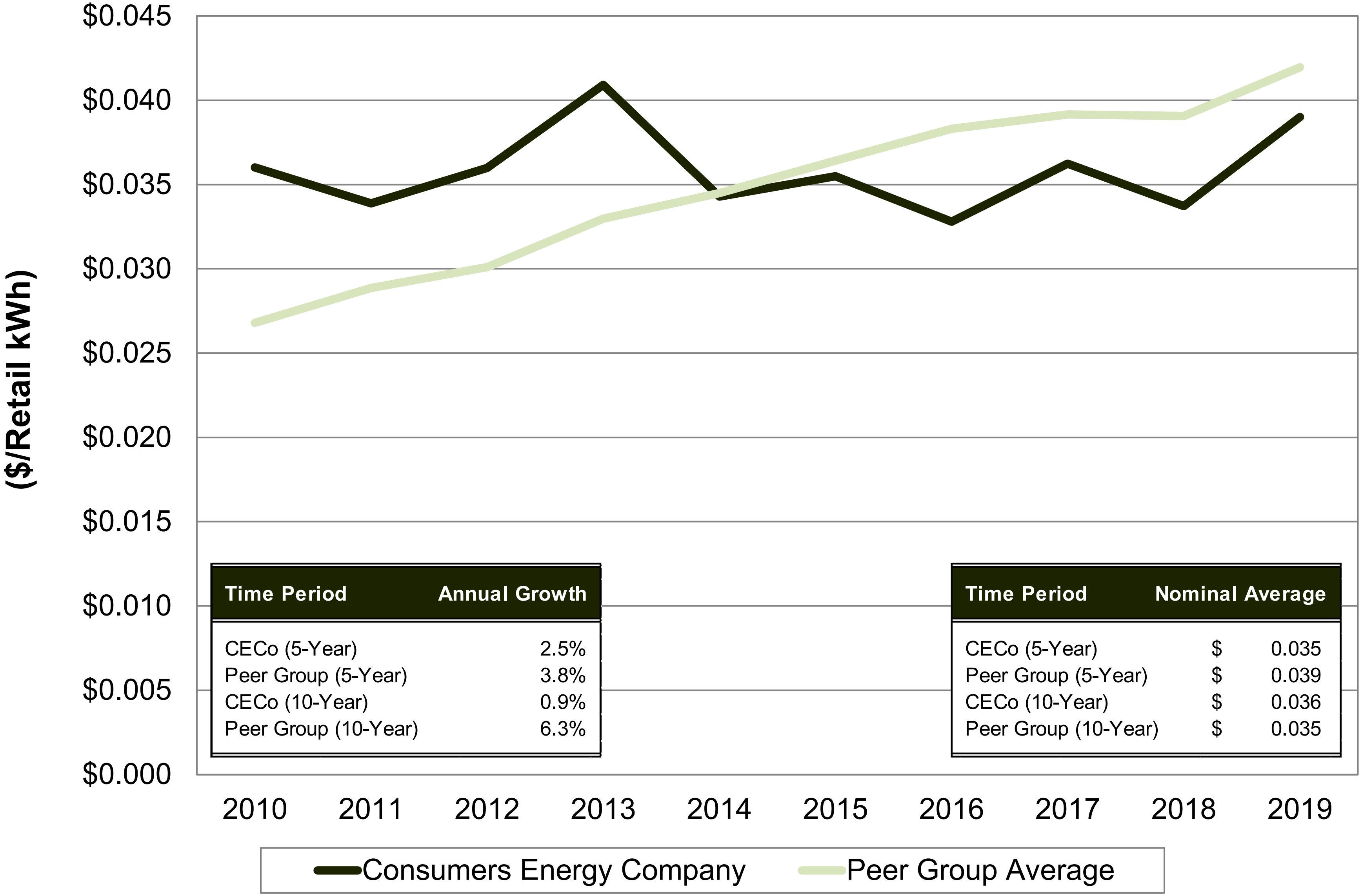
Industrial Non-Fuel Revenues per kWh, 2010-2019

Company	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
	($/kWh)									
Consumers Energy Company	**$ 0.036**	**$ 0.034**	**$ 0.036**	**$ 0.041**	**$ 0.034**	**$ 0.035**	**$ 0.033**	**$ 0.036**	**$ 0.034**	**$ 0.039**
Ameren Illinois Company	(0.017)	(0.014)	(0.011)	(0.001)	0.001	(0.001)	(0.002)	(0.001)	(0.001)	0.001
DTE Electric Company	0.039	0.039	0.043	0.044	0.042	0.040	0.040	0.043	0.041	0.044
Duke Energy Indiana, LLC	0.033	0.034	0.033	0.039	0.040	0.041	0.043	0.042	0.042	0.045
Indianapolis Power & Light Company	0.041	0.042	0.043	0.044	0.046	0.046	0.053	0.052	0.054	0.058
Interstate Power and Light Company	0.029	0.027	0.027	0.030	0.033	0.039	0.041	0.041	0.049	0.056
Kentucky Power Company	0.018	0.020	0.019	0.019	0.024	0.025	0.030	0.029	0.028	0.030
Louisville Gas and Electric Company	0.030	0.034	0.033	0.035	0.035	0.039	0.039	0.041	0.038	0.043
MidAmerican Energy Company	0.026	0.027	0.030	0.030	0.032	0.038	0.040	0.042	0.044	0.046
Northern Indiana Public Service Company	0.030	0.032	0.034	0.036	0.038	0.040	0.038	0.043	0.039	0.042
Northern States Power Company (Minnesota)	0.027	0.030	0.030	0.035	0.036	0.038	0.046	0.045	0.047	0.048
Wisconsin Electric Power Company	0.032	0.039	0.040	0.046	0.049	0.048	0.047	0.048	0.046	0.049
Wisconsin Power and Light Company	0.037	0.042	0.042	0.044	0.046	0.049	0.050	0.051	0.050	0.051
Wisconsin Public Service Corporation	0.023	0.025	0.027	0.028	0.027	0.032	0.033	0.031	0.031	0.032
Peer Group Average	**$ 0.027**	**$ 0.029**	**$ 0.030**	**$ 0.033**	**$ 0.034**	**$ 0.036**	**$ 0.038**	**$ 0.039**	**$ 0.039**	**$ 0.042**

Company	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
	($/kWh)									
Consumers Energy Company	**11**	**10**	**10**	**10**	**6**	**4**	**3**	**4**	**4**	**4**
Ameren Illinois Company	1	1	1	1	1	1	1	1	1	1
DTE Electric Company	13	11	13	13	11	9	8	10	7	7
Duke Energy Indiana, LLC	10	8	8	9	10	11	10	7	8	8
Indianapolis Power & Light Company	14	13	14	12	13	12	14	14	14	14
Interstate Power and Light Company	6	5	4	4	5	8	9	5	12	13
Kentucky Power Company	2	2	2	2	2	2	2	2	2	2
Louisville Gas and Electric Company	7	9	7	6	7	7	6	6	5	6
MidAmerican Energy Company	4	4	6	5	4	5	7	8	9	9
Northern Indiana Public Service Company	8	7	9	8	9	10	5	9	6	5
Northern States Power Company (Minnesota)	5	6	5	7	8	6	11	11	11	10
Wisconsin Electric Power Company	9	12	11	14	14	13	12	12	10	11
Wisconsin Power and Light Company	12	14	12	11	12	14	13	13	13	12
Wisconsin Public Service Corporation	3	3	3	3	3	3	4	3	3	3

Source: FERC Form 1.

Industrial Non-Fuel Revenues per kWh, 2010-2019



Time Period	Annual Growth
CECo (5-Year)	2.5%
Peer Group (5-Year)	3.8%
CECo (10-Year)	0.9%
Peer Group (10-Year)	6.3%

Time Period	Nominal Average	
CECo (5-Year)	$	0.035
Peer Group (5-Year)	$	0.039
CECo (10-Year)	$	0.036
Peer Group (10-Year)	$	0.035

Source: FERC Form 1.

Consumers' Monthly System Peak Loads, 2015-2019

	Monthly Peak Loads				
	2015	2016	2017	2018	2019
January	4,391	5,271	5,339	5,403	5,306
February	3,510	5,085	5,065	5,090	5,065
March	4,209	4,976	4,845	4,686	5,058
April	4,572	4,670	4,593	4,609	4,535
May	5,556	5,755	5,349	7,071	4,402
June	6,940	6,811	6,929	7,202	6,274
July	6,414	7,347	7,057	7,568	7,476
August	7,320	7,635	6,566	7,021	6,664
September	6,136	7,254	6,989	7,288	6,041
October	5,726	4,914	4,948	5,540	5,053
November	3,965	4,874	4,850	4,930	4,973
December	4,516	5,458	5,400	5,015	5,138
1 CP	**7,320**	**7,635**	**7,057**	**7,568**	**7,476**
4 CP	**6,703**	**7,262**	**6,885**	**7,270**	**6,614**
12 CP	**5,271**	**5,838**	**5,661**	**5,952**	**5,499**

Source: FERC Form 1.

Monthly Load Factor Under Alternative Peak Demands, 2019

Witness Dismukes
Case No. 20697
Exhibit AG-2.6

	Peak Demand Measure		
	1 CP	4 CP	12 CP
Total MWh Sold	32,707,948	32,707,948	32,707,948
Total Hours in Year	8,760	8,760	8,760
Avg. Demand Factor	**3,734**	**3,734**	**3,734**
Peak Demand	7,476	6,614	5,499
System Load Factor	**49.9%**	**56.5%**	**67.9%**

Source: FERC Form 1.

Consumers' Monthly System Load Factor, 2015-2019

Witness Dismukes
Case No. 20697
Exhibit AG-2.7

	2015	2016	2017	2018	2019
Total MWh Sold	32,992,002	33,659,725	33,248,491	34,088,752	32,707,948
Total Hours in Year	8,760	8,784	8,760	8,760	8,760
Avg. Demand Factor	**3,766**	**3,832**	**3,795**	**3,891**	**3,734**
4 CP Peak Demand	6,703	7,262	6,885	7,270	6,614
System Load Factor	**56.2%**	**52.8%**	**55.1%**	**53.5%**	**56.5%**

Source: FERC Form 1.

Modified Analysis of Company Production Allocation – No Baseload Weightings

Witness Dismukes
Case No. 20697
Exhibit AG-2.8

Line No.	Generating Plant	2019 Status	Plant Type	Gross Plant in Service 2016	2017	2018
				---------------------- ($000)	----------------------	
	Baseload Coal Generating Plants					
1	BC Cobb 4&5	RETIRED	Coal	$ 821	$ -	$ -
2	Whiting	RETIRED	Coal	508	-	-
3	Weadock 7&8	RETIRED	Coal	3,956	-	-
4	Campbell 1&2	OPERATING	Coal	1,004,790	1,018,672	1,052,381
5	Karn 1&2	OPERATING	Coal	1,176,869	1,170,630	1,183,311
6	Campbell 3	OPERATING	Coal	1,647,655	1,654,427	1,687,701
7	**Total Baseload Coal**			**$ 3,834,600**	**$ 3,843,729**	**$ 3,923,392**
	All Generating Plants					
8	Campbell 1&2	OPERATING	Coal	$ 1,004,790	$ 1,018,672	$ 1,052,381
9	BC Cobb 4&5	RETIRED	Coal	821	-	-
10	Whiting	RETIRED	Coal	508	-	-
11	Karn 1&2	OPERATING	Coal	1,176,869	1,170,630	1,183,311
12	Karn 3&4	OPERATING	Gas	323,197	341,733	348,060
13	Weadock 7&8	RETIRED	Coal	3,956	-	-
14	Campbell 3	OPERATING	Coal	1,647,655	1,654,427	1,687,701
15	Zeeland	OPERATING	Gas	338,463	339,551	378,577
16	Weadock	RETIRED	Gas	1,622	-	-
17	Thetford	OPERATING	Gas	20,795	20,698	20,743
18	Whiting	RETIRED	Gas	1,738	-	-
19	Morrow	RETIRED	Gas	233	224	-
20	Gaylord	OPERATING	Gas	5,077	5,195	318
21	Straits	OPERATING	Gas	2,199	2,199	52
22	Campbell	RETIRED	Gas	1,788	1,782	-
23	Jackson	OPERATING	Gas	364,000	374,120	384,907
24	Hardy	OPERATING	Storage	14,913	17,574	20,353
25	Hodenpyl	OPERATING	Run-of-River Hydro	9,725	10,228	10,852
26	Tippy	OPERATING	Run-of-River Hydro	9,651	9,746	10,989
27	Ludington-51%	OPERATING	Pumped Storage	290,224	353,898	411,124
28	Foote - FPC #2436	OPERATING	Hydro	7,254	7,730	8,579
29	Cooke - FPC #2450	OPERATING	Hydro	3,873	3,929	6,152
30	Five Channels - FPC #2453	OPERATING	Hydro	5,483	5,918	6,686
31	Loud - FPC #2449	OPERATING	Hydro	3,929	3,979	4,589
32	Alcona - FPC #2447	OPERATING	Hydro	5,502	5,583	6,560
33	Mio - FPC #2448	OPERATING	Hydro	6,081	6,204	8,794
34	Croton - FPC #2468	OPERATING	Hydro	12,089	16,989	17,623
35	Rogers - FPC #2451	OPERATING	Hydro	8,617	11,679	13,259
36	Webber - FPC #2566	OPERATING	Hydro	11,084	12,887	13,139
37	Calkins Bridge (Allegan) - FPC #785	OPERATING	Hydro	5,563	7,026	7,902
38	Lake Winds Energy Park	OPERATING	Wind	225,512	226,953	227,158
39	Cross Winds Energy Park	OPERATING	Wind	241,624	240,767	326,035
40	GVSU Solar Garden	OPERATING	Solar	7,605	7,960	7,960
41	WMU Solar Garden	OPERATING	Solar	4,125	3,817	3,824
42	Circuit West Solar	OPERATING	Solar	-	-	2,885
43	**Total Generating Plants**			**$ 5,766,567**	**$ 5,882,096**	**$ 6,170,512**
44	**Baseload Coal as Percentage of Total Generating Plant**		**(line 7 / line 43)**	**66.5%**	**65.3%**	**63.6%**

Line No.	Hourly System Load (kW)	2016	2017	2018
45	Minimum Hourly Load	2,656,380	2,674,215	2,748,047
46	Maximum Hourly Load	7,635,347	7,057,054	7,567,978
47	**Minimum to Maximum Hourly Load**	**34.8%**	**37.9%**	**36.3%**
48	**Production Plant Costs Related to Energy (line 44 x line 47)**	**23.1%**	**24.8%**	**23.1%**
49	**Three-Year Average**	**23.7%**		

Source: Exhibit JCA-4.

Modified Analysis of Company Production Allocation – No Baseload Weightings and Averaged Results

Witness Dismukes
Case No. 20697
Exhibit AG-2.9

line no.	Generating Plant	2019 Status	Plant Type	Gross Plant in Service 2016	2017	2018
				----------- ($000) ----------		
	Baseload Coal Generating Plants					
1	BC Cobb 4&5	RETIRED	Coal	$ 821	$ -	$ -
2	Whiting	RETIRED	Coal	508	-	-
3	Weadock 7&8	RETIRED	Coal	3,956	-	-
4	Campbell 1&2	OPERATING	Coal	1,004,790	1,018,672	1,052,381
5	Karn 1&2	OPERATING	Coal	1,176,869	1,170,630	1,183,311
6	Campbell 3	OPERATING	Coal	1,647,655	1,654,427	1,687,701
7	**Total Baseload Coal**			**$ 3,834,600**	**$ 3,843,729**	**$ 3,923,392**
	All Generating Plants					
8	Campbell 1&2	OPERATING	Coal	$ 1,004,790	$ 1,018,672	$ 1,052,381
9	BC Cobb 4&5	RETIRED	Coal	821	-	-
10	Whiting	RETIRED	Coal	508	-	-
11	Karn 1&2	OPERATING	Coal	1,176,869	1,170,630	1,183,311
12	Karn 3&4	OPERATING	Gas	323,197	341,733	348,060
13	Weadock 7&8	RETIRED	Coal	3,956	-	-
14	Campbell 3	OPERATING	Coal	1,647,655	1,654,427	1,687,701
15	Zeeland	OPERATING	Gas	338,463	339,551	378,577
16	Weadock	RETIRED	Gas	1,622	-	-
17	Thetford	OPERATING	Gas	20,795	20,698	20,743
18	Whiting	RETIRED	Gas	1,738	-	-
19	Morrow	RETIRED	Gas	233	224	-
20	Gaylord	OPERATING	Gas	5,077	5,195	318
21	Straits	OPERATING	Gas	2,199	2,199	52
22	Campbell	RETIRED	Gas	1,788	1,782	-
23	Jackson	OPERATING	Gas	364,000	374,120	384,907
24	Hardy	OPERATING	Storage	14,913	17,574	20,353
25	Hodenpyl	OPERATING	Run-of-River Hydro	9,725	10,228	10,852
26	Tippy	OPERATING	Run-of-River Hydro	9,651	9,746	10,989
27	Ludington-51%	OPERATING	Pumped Storage	290,224	353,898	411,124
28	Foote - FPC #2436	OPERATING	Hydro	7,254	7,730	8,579
29	Cooke - FPC #2450	OPERATING	Hydro	3,873	3,929	6,152
30	Five Channels - FPC #2453	OPERATING	Hydro	5,483	5,918	6,686
31	Loud - FPC #2449	OPERATING	Hydro	3,929	3,979	4,589
32	Alcona - FPC #2447	OPERATING	Hydro	5,502	5,583	6,560
33	Mio - FPC #2448	OPERATING	Hydro	6,081	6,204	8,794
34	Croton - FPC #2468	OPERATING	Hydro	12,089	16,989	17,623
35	Rogers - FPC #2451	OPERATING	Hydro	8,617	11,679	13,259
36	Webber - FPC #2566	OPERATING	Hydro	11,084	12,887	13,139
37	Calkins Bridge (Allegan) - FPC #785	OPERATING	Hydro	5,563	7,026	7,902
38	Lake Winds Energy Park	OPERATING	Wind	225,512	226,953	227,158
39	Cross Winds Energy Park	OPERATING	Wind	241,624	240,767	326,035
40	GVSU Solar Garden	OPERATING	Solar	7,605	7,960	7,960
41	WMU Solar Garden	OPERATING	Solar	4,125	3,817	3,824
42	Circuit West Solar	OPERATING	Solar	-	-	2,885
43	**Total Generating Plants**			**$ 5,766,567**	**$ 5,882,096**	**$ 6,170,512**
44	**Baseload Coal as Percentage of Total Generating Plant**		**(line 7 / line 43)**	**66.5%**	**65.3%**	**63.6%**

line no.	Hourly System Load (kW)		2016	2017	2018
45	Minimum Hourly Load		2,656,380	2,674,215	2,748,047
46	Maximum Hourly Load		7,635,347	7,057,054	7,567,978
47	**Minimum to Maximum Hourly Load**		**34.8%**	**37.9%**	**36.3%**
48	**Production Plant Costs Related to Energy**	**Average (lines 44, 47)**	**50.6%**	**51.6%**	**49.9%**
49	**Three-Year Average**		**50.7%**		

Source: Exhibit JCA-4.

Alternative Analysis of Consumers' Electric Generation Units – 2019 Capacity Factors

Station Name	Plant Type	Nameplate Capacity (MW)	2019 Net Generation (MWh)	Capacity Factor	Allocation Energy	Allocation Demand	Plant in Service Energy	Plant in Service Demand	Plant in Service Total
Campbell 3 (CECo)	Steam	855	4,890,416	65.26%	65.26%	34.74%	$ 1,129,413,579	$ 601,182,704	$ 1,730,596,283
Karn 1 & 2	Steam	544	1,761,860	36.97%	36.97%	63.03%	440,478,427	750,917,889	1,191,396,316
Campbell 1 & 2	Steam	644	3,123,408	55.36%	55.36%	44.64%	583,781,344	470,699,054	1,054,480,398
Jackson Gas Plant	Gas Turbine	653	2,176,641	38.04%	38.04%	61.96%	149,676,526	243,786,379	393,462,905
Zeeland	Gas Turbine / Steam	968	4,075,671	48.06%	48.06%	51.94%	185,412,916	200,409,666	385,822,582
Karn 3 &4	Steam	1,402	41,863	0.34%	0.00%	100.00%	-	364,007,181	364,007,181
Subtotals:							**$ 2,488,762,792**	**$ 2,631,002,873**	**$ 5,119,765,665**
					Production Plant Classification:		**48.6%**	**51.4%**	**100.0%**

Source: FERC Form 1.

Alternative Analysis of Consumers' Electric Generation Units – Levelized Cost

Witness Dismukes
Case No. 20697
Exhibit AG-2.11

Station Name	Plant Type	Estimated Service Life	Nameplate Capacity (MW)	Total Plant in Service	Fixed Cost ($/year)	Variable Costs ($)	Levelized Cost ($/kW-year)	MISO CONE Zone 7 ($/MW-day)	MISO CONE Zone 7 ($/kW-year)	Allocation Energy	Allocation Demand	Plant in Service Energy	Plant in Service Demand	Plant in Service Total
Campbell 3 (CECo)	Steam	62.7	855	$ 1,730,596,283	$ 27,602,693	$ 140,360,908	$ 196	$ 243.37	$ 88.83	54.76%	45.24%	$ 947,662,608	$ 782,933,675	$ 1,730,596,283
Karn 1 & 2	Steam	62.7	544	1,191,396,316	19,002,553	84,000,729	189	243.37	88.83	53.09%	46.91%	632,457,851	558,938,465	1,191,396,316
Campbell 1 & 2	Steam	62.7	644	1,054,480,398	16,818,769	106,947,830	192	243.37	88.83	53.78%	46.22%	567,055,395	487,425,003	1,054,480,398
Jackson Gas Plant	Gas Turbine	50.7	653	393,462,905	7,767,215	58,496,253	101	243.37	88.83	12.44%	87.56%	48,936,574	344,526,331	393,462,905
Zeeland	Gas Turbine / Steam	59.5	968	385,822,582	6,485,116	86,796,066	96	243.37	88.83	7.80%	92.20%	30,112,513	355,710,069	385,822,582
Karn 3 &4	Steam	62.7	1,402	364,007,181	5,805,848	20,226,927	19	243.37	88.83	0.00%	100.00%	-	364,007,181	364,007,181
Subtotals:												**$ 2,226,224,941**	**$ 2,893,540,724**	**$ 5,119,765,665**
										Production Plant Classification:		**43.5%**	**56.5%**	**100.0%**

Source: FERC Form 1 and MISO 2019 PRA Results.

Comparison of CCOSS Results, Under Alternative Production Demand Allocation Factors

Witness Dismukes
Case No. 20697
Exhibit AG-2.12

	Total Electric	Total Jurisdiction	Total Residential Service	Total Commercial Secondary	Total Primary	Total Lighting & Unmetered	Rate GSG	Total Non-Jurisdictional
		($000)						
Company Proposed 89-0-11 4CP Method								
Revenue Deficiency	$ 254,475	$ 244,233	$ 293,075	$ 23,999	$ (73,242)	$ (2,458)	$ 2,859	$ 10,242
Proposed Rate Increase	6.33%	6.12%	15.04%	2.39%	-7.35%	-5.89%	165.98%	41.62%
Relative Proposed Rate Increase	1.00	0.97	2.37	0.38	-1.16	-0.93	26.21	6.57
Alternative 50-0-50 4CP Method								
Revenue Deficiency	$ 254,475	$ 244,256	$ 230,556	$ 32,314	$ (22,978)	$ 1,085	$ 3,279	$ 10,220
Change from Company's Proposed Allocation	$ (0)	$ 23	$ (62,519)	$ 8,315	$ 50,264	$ 3,543	$ 420	$ (23)
Proposed Rate Increase	6.33%	6.12%	11.83%	3.22%	-2.30%	2.60%	190.35%	41.53%
Relative Proposed Rate Increase	1.00	0.97	1.87	0.51	-0.36	0.41	30.05	6.56
Current 75-0-25 4CP Method								
Revenue Deficiency	$ 254,475	$ 244,241	$ 270,644	$ 26,982	$ (55,208)	$ (1,187)	$ 3,010	$ 10,234
Change from Company's Proposed Allocation	$ (0)	$ 8	$ (22,430)	$ 2,983	$ 18,034	$ 1,271	$ 151	$ (8)
Proposed Rate Increase	6.33%	6.12%	13.89%	2.69%	-5.54%	-2.84%	174.72%	41.59%
Relative Proposed Rate Increase	1.00	0.97	2.19	0.42	-0.87	-0.45	27.59	6.57
Alternative Average and Excess 4CP Method								
Revenue Deficiency	$ 254,475	$ 245,639	$ 308,250	$ 16,270	$ (81,940)	$ 395	$ 2,664	$ 8,836
Change from Company's Proposed Allocation	$ -	$ 1,407	$ 15,175	$ (7,729)	$ (8,698)	$ 2,854	$ (195)	$ (1,407)
Proposed Rate Increase	6.33%	6.15%	15.81%	1.62%	-8.22%	0.95%	154.65%	35.90%
Relative Proposed Rate Increase	1.00	0.97	2.50	0.26	-1.30	0.15	24.42	5.67
Alternative Equivalent Peaker 4CP Method								
Revenue Deficiency	$ 254,475	$ 244,252	$ 241,011	$ 30,923	$ (31,383)	$ 492	$ 3,208	$ 10,223
Change from Company's Proposed Allocation	$ 0	$ 19	$ (52,064)	$ 6,925	$ 41,859	$ 2,950	$ 349	$ (19)
Proposed Rate Increase	6.33%	6.12%	12.36%	3.08%	-3.15%	1.18%	186.27%	41.54%
Relative Proposed Rate Increase	1.00	0.97	1.95	0.49	-0.50	0.19	29.41	6.56

Source: Exhibits of Josnelly C. Aponte, Schedule F-1.1.

Results of Alternative Class Cost of Service Study - Production and Distribution at Current Rates

Account Description	Total Electric	Total Jurisdictional Electric	Total Residential Service	Total Commercial Secondary	Total Primary	Total Lighting & Unmetered	Rate GSG	Total Non Jurisdictional
Rate Base								
Total Electric Plant in Service	$ 17,064,931	$ 16,992,862	$ 9,299,709	$ 4,439,168	$ 2,912,661	$ 301,166	$ 40,159	$ 72,069
Less: Depreciation Reserve	(6,698,735)	(6,667,694)	(3,602,546)	(1,765,647)	(1,113,153)	(170,917)	(15,430)	(31,041)
Plus: Construction Work In Progress (CWIP)	357,439	355,665	188,590	90,009	71,213	4,805	1,049	1,773
Plus: Future Use	2,545	2,523	1,128	563	788	13	31	22
Total Net Electric Plant in Service	$ 10,726,180	$ 10,683,357	$ 5,886,882	$ 2,764,093	$ 1,871,508	$ 135,067	$ 25,808	$ 42,823
Plus: Working Capital	$ 1,227,083	$ 1,221,209	$ 679,989	$ 298,660	$ 229,894	$ 10,964	$ 1,702	$ 5,873
Plus: Rate Base Additions	0	0	0	0	0	0	0	0
Less: Rate Base Deductions	(59,839)	(59,809)	(35,454)	(16,763)	(5,776)	(1,644)	(172)	(30)
Total Rate Base	**$ 11,893,424**	**$ 11,844,757**	**$ 6,531,417**	**$ 3,045,990**	**$ 2,095,626**	**$ 144,386**	**$ 27,338**	**$ 48,667**
Operating Income								
Electric Operating Revenues								
Total Rate Revenue	$ 4,017,792	$ 3,993,182	$ 1,949,148	$ 1,003,525	$ 997,036	$ 41,750	$ 1,722	$ 24,610
Total Revenue Credits	379,354	378,374	169,951	88,509	113,356	2,261	4,298	980
Total Electric Operating Revenues	$ 4,397,146	$ 4,371,556	$ 2,119,099	$ 1,092,034	$ 1,110,391	$ 44,011	$ 6,020	$ 25,590
Electric Operating Expenses								
Fuel and P&I Expense	$ 1,683,201	$ 1,664,639	$ 733,907	$ 394,401	$ 523,610	$ 9,633	$ 3,087	$ 18,563
Transmission Expense	477,556	472,640	222,685	105,296	141,584	2,334	741	4,916
Other O&M Expense	684,695	681,800	393,661	167,621	111,729	7,599	1,189	2,895
Depreciation & Amortization Expense	705,582	701,945	385,502	179,541	124,016	11,511	1,374	3,637
Other Taxes	263,853	263,096	138,177	68,982	51,202	4,225	511	757
Federal Income Taxes	53,928	54,407	22,707	16,319	14,657	807	(82)	(480)
Total Electric Operating Expenses	$ 3,868,814	$ 3,838,526	$ 1,896,639	$ 932,159	$ 966,798	$ 36,108	$ 6,821	$ 30,288
Other Income Adjustments	$ 6,234	$ 6,203	$ 3,289	$ 1,570	$ 1,242	$ 84	$ 18	$ 31
Total Operating Income	**$ 534,565**	**$ 539,232**	**$ 225,749**	**$ 161,445**	**$ 144,835**	**$ 7,987**	**$ (783)**	**$ (4,667)**
Rate of Return on Rate Base ("ROR")	**4.49%**	**4.55%**	**3.46%**	**5.30%**	**6.91%**	**5.53%**	**-2.86%**	**-9.59%**
Relative Rate of Return ("RROR")		**1.00**	**0.76**	**1.16**	**1.52**	**1.22**	**-0.63**	

Source: Exhibits of Josnelly C. Aponte, Schedule F-1.1.

Results of Alternative Class Cost of Service Study - Production and Distribution at Current Rates

Account Description	Total Electric	Total Jurisdiction	Total Residential Service	Total Commercial Secondary	Total Primary	Total Lighting & Unmetered	Rate GSG	Total Non Jurisdictional
Required Income Under Company's Proposed ROR								
Total Rate Base	$ 11,893,424	$ 11,844,757	$ 6,531,417	$ 3,045,990	$ 2,095,626	$ 144,386	$ 27,338	$ 48,667
Proposed Rate of Return	6.09%	6.09%	6.09%	6.09%	6.09%	6.09%	6.09%	6.09%
Required Operating Income @ 6.09 ROR	**$ 724,604**	**$ 721,639**	**$ 397,925**	**$ 185,576**	**$ 127,676**	**$ 8,797**	**$ 1,666**	**$ 2,965**
Electric Operating Expenses								
Current Total Electric Operating Expenses	$ 3,868,814	$ 3,838,526	$ 1,896,639	$ 932,159	$ 966,798	$ 36,108	$ 6,821	$ 30,288
Total Electric Operating Expenses	**$ 3,868,814**	**$ 3,838,526**	**$ 1,896,639**	**$ 932,159**	**$ 966,798**	**$ 36,108**	**$ 6,821**	**$ 30,288**
Total Cost of Service	**$ 4,593,418**	**$ 4,560,165**	**$ 2,294,564**	**$ 1,117,735**	**$ 1,094,474**	**$ 44,905**	**$ 8,487**	**$ 33,253**
Net Operating Income (Present Rates)								
Total Rate Revenue	$ 4,017,792	$ 3,993,182	$ 1,949,148	$ 1,003,525	$ 997,036	$ 41,750	$ 1,722	$ 24,610
Plus: Total Revenue Credits	379,354	378,374	169,951	88,509	113,356	2,261	4,298	980
Plus: Other Income Adjustments	6,234	6,203	3,289	1,570	1,242	84	18	31
Total Electric Operating Revenues	**$ 4,403,380**	**$ 4,377,758**	**$ 2,122,388**	**$ 1,093,604**	**$ 1,111,633**	**$ 44,095**	**$ 6,039**	**$ 25,621**
Income Deficiency	**$ 190,039**	**$ 182,407**	**$ 172,176**	**$ 24,132**	**$ (17,160)**	**$ 810**	**$ 2,448**	**$ 7,632**
Revenue Deficiency	**$ 254,475**	**$ 244,256**	**$ 230,556**	**$ 32,314**	**$ (22,978)**	**$ 1,085**	**$ 3,279**	**$ 10,220**
Proposed Rate Increase (Decrease)	**6.33%**	**6.12%**	**11.83%**	**3.22%**	**-2.30%**	**2.60%**	**190.35%**	**41.53%**
Relative Proposed Rate Increase		**1.00**	**1.93**	**0.53**	**-0.38**	**0.42**	**31.12**	

Source: Exhibits of Josnelly C. Aponte, Schedule F-1.1.

Results of Company Class Cost of Service Study - Production and Distribution at Current Rates

Account Description	Total Electric	Total Jurisdictional Electric	Total Residential Service	Total Commercial Secondary	Total Primary	Total Lighting & Unmetered	Rate GSG	Total Non Jurisdictional
Rate Base								
Total Electric Plant in Service	$ 17,064,931	$ 16,992,862	$ 9,535,629	$ 4,407,816	$ 2,723,043	$ 287,799	$ 38,575	$ 72,069
Less: Depreciation Reserve	(6,698,735)	(6,667,694)	(3,706,632)	(1,751,815)	(1,029,495)	(165,020)	(14,732)	(31,041)
Plus: Construction Work In Progress (CWIP)	357,439	355,665	194,663	89,202	66,332	4,461	1,008	1,773
Plus: Future Use	2,545	2,523	1,128	563	788	13	31	22
Total Net Electric Plant in Service	$ 10,726,180	$ 10,683,357	$ 6,024,789	$ 2,745,766	$ 1,760,666	$ 127,253	$ 24,883	$ 42,823
Plus: Working Capital	$ 1,227,083	$ 1,221,209	$ 691,732	$ 297,099	$ 220,457	$ 10,299	$ 1,623	$ 5,873
Plus: Rate Base Additions	0	0	0	0	0	0	0	0
Less: Rate Base Deductions	(59,839)	(59,809)	(35,454)	(16,763)	(5,776)	(1,644)	(172)	(30)
Total Rate Base	**$ 11,893,424**	**$ 11,844,757**	**$ 6,681,066**	**$ 3,026,102**	**$ 1,975,347**	**$ 135,908**	**$ 26,334**	**$ 48,667**
Operating Income								
Electric Operating Revenues								
Total Rate Revenue	$ 4,017,792	$ 3,993,182	$ 1,949,148	$ 1,003,525	$ 997,036	$ 41,750	$ 1,722	$ 24,610
Total Revenue Credits	379,354	378,394	174,158	87,956	109,987	2,023	4,270	961
Total Electric Operating Revenues	$ 4,397,146	$ 4,371,576	$ 2,123,306	$ 1,091,481	$ 1,107,023	$ 43,773	$ 5,992	$ 25,571
Electric Operating Expenses								
Fuel and P&I Expense	$ 1,683,201	$ 1,664,639	$ 759,860	$ 390,952	$ 502,750	$ 8,163	$ 2,913	$ 18,563
Transmission Expense	477,556	472,640	222,685	105,296	141,584	2,334	741	4,916
Other O&M Expense	684,695	681,800	400,294	166,739	106,398	7,223	1,145	2,895
Depreciation & Amortization Expense	705,582	701,945	397,787	177,909	114,142	10,815	1,292	3,637
Other Taxes	263,853	263,097	139,036	68,868	50,512	4,176	505	756
Federal Income Taxes	53,928	54,409	18,861	16,830	17,749	1,025	(56)	(481)
Total Electric Operating Expenses	$ 3,868,814	$ 3,838,529	$ 1,938,523	$ 926,594	$ 933,136	$ 33,735	$ 6,540	$ 30,285
Other Income Adjustments	$ 6,234	$ 6,203	$ 3,395	$ 1,556	$ 1,157	$ 78	$ 18	$ 31
Total Operating Income	**$ 534,565**	**$ 539,249**	**$ 188,178**	**$ 166,442**	**$ 175,044**	**$ 10,116**	**$ (531)**	**$ (4,684)**
Rate of Return on Rate Base ("ROR")	**4.49%**	**4.55%**	**2.82%**	**5.50%**	**8.86%**	**7.44%**	**-2.02%**	**-9.62%**
Relative Rate of Return ("RROR")		**1.00**	**0.62**	**1.21**	**1.95**	**1.63**	**-0.44**	

Source: Exhibits of Josnelly C. Aponte, Schedule F-1.1.

Results of Company Class Cost of Service Study - Production and Distribution at Current Rates

Account Description	Total Electric	Total Jurisdiction	Total Residential Service	Total Commercial Secondary	Total Primary	Total Lighting & Unmetered	Rate GSG	Total Non Jurisdictional
Required Income Under Company's Proposed ROR								
Total Rate Base	$ 11,893,424	$ 11,844,757	$ 6,681,066	$ 3,026,102	$ 1,975,347	$ 135,908	$ 26,334	$ 48,667
Proposed Rate of Return	6.09%	6.09%	6.09%	6.09%	6.09%	6.09%	6.09%	6.09%
Required Operating Income @ 6.09 ROR	**$ 724,604**	**$ 721,639**	**$ 407,042**	**$ 184,365**	**$ 120,348**	**$ 8,280**	**$ 1,604**	**$ 2,965**
Electric Operating Expenses								
Current Total Electric Operating Expenses	$ 3,868,814	$ 3,838,529	$ 1,938,523	$ 926,594	$ 933,136	$ 33,735	$ 6,540	$ 30,285
Total Electric Operating Expenses	**$ 3,868,814**	**$ 3,838,529**	**$ 1,938,523**	**$ 926,594**	**$ 933,136**	**$ 33,735**	**$ 6,540**	**$ 30,285**
Total Cost of Service	**$ 4,593,418**	**$ 4,560,168**	**$ 2,345,566**	**$ 1,110,958**	**$ 1,053,484**	**$ 42,015**	**$ 8,145**	**$ 33,250**
Net Operating Income (Present Rates)								
Total Rate Revenue	$ 4,017,792	$ 3,993,182	$ 1,949,148	$ 1,003,525	$ 997,036	$ 41,750	$ 1,722	$ 24,610
Plus: Total Revenue Credits	379,354	378,394	174,158	87,956	109,987	2,023	4,270	961
Plus: Other Income Adjustments	6,234	6,203	3,395	1,556	1,157	78	18	31
Total Electric Operating Revenues	**$ 4,403,380**	**$ 4,377,778**	**$ 2,126,701**	**$ 1,093,036**	**$ 1,108,180**	**$ 43,851**	**$ 6,010**	**$ 25,602**
Income Deficiency	**$ 190,039**	**$ 182,390**	**$ 218,864**	**$ 17,922**	**$ (54,696)**	**$ (1,836)**	**$ 2,135**	**$ 7,649**
Revenue Deficiency	**$ 254,475**	**$ 244,233**	**$ 293,075**	**$ 23,999**	**$ (73,242)**	**$ (2,458)**	**$ 2,859**	**$ 10,242**
Proposed Rate Increase (Decrease)	**6.33%**	**6.12%**	**15.04%**	**2.39%**	**-7.35%**	**-5.89%**	**165.98%**	**41.62%**
Relative Proposed Rate Increase		**1.00**	**2.46**	**0.39**	**-1.20**	**-0.96**	**27.14**	**6.80**

Source: Exhibits of Josnelly C. Aponte, Schedule F-1.1.

Comparison of Company and Alternative Revenue Allocation - Production and Transmission Revenues

Class	Consumers Energy Proposed Current Revenues ($000)	Consumers Energy Proposed Proposed Increase ($000)	Consumers Energy Proposed Proposed Revenues ($000)	Consumers Energy Proposed Percent Increase	AG Proposed Current Revenues ($000)	AG Proposed Proposed Increase ($000)	AG Proposed Proposed Revenues ($000)	AG Proposed Percent Increase
Residential Service								
Summer On-peak RSP	$ 1,270,724	$ 98,710	$ 1,369,434	7.8%	$ 1,270,724	$ 37,456	$ 1,308,180	2.9%
Smart Hours RSH	6,241	575	6,816	9.2%	6,241	270	6,511	4.3%
Night Time Savers RPM	793	39	833	4.9%	793	(1)	792	-0.1%
Non-Transmitting Meters RNT	13,473	1,315	14,788	9.8%	13,473	629	14,102	4.7%
Total Residential	$ 1,291,232	$ 100,639	$ 1,391,871	7.8%	$ 1,291,232	$ 38,354	$ 1,329,586	3.0%
Secondary Service								
Energy-only GS	$ 383,868	$ (10,443)	$ 373,425	-2.7%	$ 383,868	$ (8,757)	$ 375,111	-2.3%
Time-of-Use GSTU	328	(9)	319	-2.8%	328	(8)	320	-2.4%
Demand GSD	319,627	(15,728)	303,899	-4.9%	319,627	(9,011)	310,616	-2.8%
Total Secondary Service	$ 703,823	$ (26,180)	$ 677,643	-3.7%	$ 703,823	$ (17,775)	$ 686,047	-2.5%
Primary Service								
Energy-only GP	$ 105,669	$ (19,764)	$ 85,905	-18.7%	$ 105,669	$ (19,004)	$ 86,665	-18.0%
Demand GPD	430,127	(57,990)	372,137	-13.5%	430,127	(34,862)	395,265	-8.1%
Time-of-Use GPTU	378,499	(10,456)	368,044	-2.8%	378,499	8,167	386,666	2.2%
Energy Intensive EIP	22,488	(3,107)	19,381	-13.8%	22,488	4,742	27,230	21.1%
Total Primary Service	$ 936,783	$ (91,317)	$ 845,467	-9.7%	$ 936,783	$ (40,957)	$ 895,826	-4.4%
Lighting & Unmetered Class								
Metered Lighting GML	$ 740	$ (125)	$ 614	-17.0%	$ 740	$ 192	$ 932	26.0%
Unmetered Lighting GUL	4,381	(821)	3,559	-18.8%	4,381	1,039	5,419	23.7%
Unmetered GU-XL / LED	1,088	(171)	917	-15.7%	1,088	313	1,401	28.8%
Unmetered GU	7,646	(362)	7,284	-4.7%	7,646	514	8,159	6.7%
Total Lighting & Unmetered Service	$ 13,854	$ (1,479)	$ 12,375	-10.7%	$ 13,854	$ 2,058	$ 15,912	14.9%
Self-generation Class								
Small Self-generation GSG-1	$ -	$ -	$ -	0.0%	$ -	$ -	$ -	0.0%
Large Self-generation GSG-2	4,015	-	4,015	0.0%	4,015	-	4,015	0.0%
Total Self-Generation	$ 4,015	$ -	$ 4,015	0.0%	$ 4,015	$ -	$ 4,015	0.0%
Production and Transmission - Bundled	**$ 2,949,707**	**$ (18,336)**	**$ 2,931,370**	**-0.6%**	**$ 2,949,707**	**$ (18,320)**	**$ 2,931,387**	**-0.6%**
Secondary Service								
Energy-only GS	$ -	$ -	$ -	0.0%	$ -	$ -	$ -	0.0%
Demand GSD	-	-	-	0.0%	-	-	-	0.0%
Total Secondary Service	$ -	$ -	$ -	0.0%	$ -	$ -	$ -	0.0%
Primary Service								
Energy-only GP	$ -	$ -	$ -	0.0%	$ -	$ -	$ -	0.0%
Demand GPD	-	-	-	0.0%	-	-	-	0.0%
Total Primary Service	$ -	$ -	$ -	0.0%	$ -	$ -	$ -	0.0%
Production and Transmission - ROA Service	**$ -**	**$ -**	**$ -**	**0.0%**	**$ -**	**$ -**	**$ -**	**0.0%**
Total Jurisdictional Service - Production and Transmission	**$ 2,949,707**	**$ (18,336)**	**$ 2,931,370**	**-0.6%**	**$ 2,949,707**	**$ (18,320)**	**$ 2,931,387**	**-0.6%**
Less: PSCR Factor Revenues	$ 134,502	$ -	$ 134,502		$ 134,502	$ -	$ 134,502	
Less: GSG-2 and GI-2 PSCR Revenues	5,960	136	6,096		5,960	136	6,096	
Rounding	-	(50)	(50)		-	(44)	(44)	
Total Jurisdictional Base Revenues - Production and Transmission	**$ 2,809,244**	**$ (18,522)**	**$ 2,790,722**	**-0.7%**	**$ 2,809,244**	**$ (18,499)**	**$ 2,790,745**	**-0.7%**

Source: Direct Testimony of Hubert W. Miller III, Workpaper "ex0220-Miller-1-3 and WP-1-25.xlsx."

Comparison of Company and Alternative Revenue Allocation - Distribution Revenues

Class	Consumers Energy Proposed: Current Revenues	Proposed Increase	Proposed Revenues	Percent Increase	AG Proposed: Current Revenues	Proposed Increase	Proposed Revenues	Percent Increase
		---------- ($000) ----------				---------- ($000) ----------		
Residential Service								
Summer On-peak RSP	$ 701,562	$ 176,736	$ 878,298	25.2%	$ 701,562	$ 177,549	$ 879,110	25.3%
Smart Hours RSH	3,079	830	3,909	27.0%	3,079	890	3,968	28.9%
Night Time Savers RPM	439	114	553	25.9%	439	117	557	26.7%
Non-Transmitting Meters RNT	7,965	1,916	9,882	24.1%	7,965	1,910	9,875	24.0%
Total Residential	$ 713,045	$ 179,597	$ 892,642	25.2%	$ 713,045	$ 180,465	$ 893,510	25.3%
Secondary Service								
Energy-only GS	$ 209,431	$ 37,419	$ 246,850	17.9%	$ 209,431	$ 37,091	$ 246,521	17.7%
Time-of-Use GSTU	156	5	161	3.0%	156	(4)	152	-2.8%
Demand GSD	114,329	17,707	132,036	15.5%	114,329	17,538	131,866	15.3%
Total Secondary Service	$ 323,915	$ 55,131	$ 379,047	17.0%	$ 323,915	$ 54,624	$ 378,539	16.9%
Primary Service								
Energy-only GP	$ 14,409	$ 3,112	$ 17,521	21.6%	$ 14,409	$ 3,059	$ 17,468	21.2%
Demand GPD	33,069	7,895	40,963	23.9%	33,069	7,775	40,844	23.5%
Time-of-Use GPTU	41,177	11,299	52,476	27.4%	41,177	11,174	52,352	27.1%
Energy Intensive EIP	1,712	311	2,023	18.2%	1,712	299	2,011	17.4%
Total Primary Service	$ 90,367	$ 22,616	$ 112,983	25.0%	$ 90,367	$ 22,307	$ 112,674	24.7%
Lighting & Unmetered Class								
Metered Lighting GML	$ 871	$ (54)	$ 817	-6.2%	$ 871	$ (53)	$ 818	-6.1%
Unmetered Lighting GUL	19,368	(1,171)	18,197	-6.0%	19,368	(1,173)	18,195	-6.1%
Unmetered GU-XL / LED	6,931	(3)	6,928	0.0%	6,931	(11)	6,920	-0.2%
Unmetered GU	1,649	504	2,153	30.6%	1,649	503	2,152	30.5%
Total Lighting & Unmetered Service	$ 28,819	$ (724)	$ 28,096	-2.5%	$ 28,819	$ (734)	$ 28,086	-2.5%
Self-generation Class								
Small Self-generation GSG-1	$ -	$ -	$ -	0.0%	$ -	$ -	$ -	0.0%
Large Self-generation GSG-2	1,594	39	1,633	2.4%	1,594	23	1,617	1.4%
Total Self-Generation	$ 1,594	$ 39	$ 1,633	2.4%	$ 1,594	$ 23	$ 1,617	1.4%
Delivery - Bundled	**$ 1,157,741**	**$ 256,659**	**$ 1,414,400**	**22.2%**	**$ 1,157,741**	**$ 256,685**	**$ 1,414,426**	**22.2%**
Secondary Service								
Energy-only GS	$ 1,055	$ 238	$ 1,293	22.6%	$ 1,055	$ 237	$ 1,293	22.5%
Demand GSD	6,116	994	7,111	16.3%	6,116	988	7,104	16.2%
Total Secondary Service	$ 7,171	$ 1,233	$ 8,404	17.2%	$ 7,171	$ 1,225	$ 8,397	17.1%
Primary Service								
Energy-only GP	$ 1,028	$ 244	$ 1,272	23.7%	$ 1,028	$ 241	$ 1,269	23.4%
Demand GPD	17,997	4,731	22,729	26.3%	17,997	4,655	22,653	25.9%
Total Primary Service	$ 19,025	$ 4,975	$ 24,000	26.2%	$ 19,025	$ 4,896	$ 23,921	25.7%
Delivery - ROA Service	**$ 26,196**	**$ 6,208**	**$ 32,404**	**23.7%**	**$ 26,196**	**$ 6,121**	**$ 32,318**	**23.4%**
Total Jurisdictional Service - Delivery	**$ 1,183,937**	**$ 262,867**	**$ 1,446,804**	**22.2%**	**$ 1,183,937**	**$ 262,807**	**$ 1,446,744**	**22.2%**
Rounding	-	(112)	(112)		-	(51)	(51)	
Total Jurisdictional Base Revenues - Delivery	**$ 1,183,937**	**$ 262,755**	**$ 1,446,693**	**22.2%**	**$ 1,183,937**	**$ 262,755**	**$ 1,446,693**	**22.2%**

Source: Direct Testimony of Hubert W. Miller III, Workpaper "ex0220-Miller-1-3 and WP-1-25.xlsx."

Comparison of Company and Alternative Revenue Allocation - Total Revenues

Class	Consumers Energy Proposed Current Revenues	Consumers Energy Proposed Proposed Increase	Consumers Energy Proposed Proposed Revenues	Consumers Energy Proposed Percent Increase	AG Proposed Current Revenues	AG Proposed Proposed Increase	AG Proposed Proposed Revenues	AG Proposed Percent Increase
	---------- ($000) ----------				---------- ($000) ----------			
Residential Service								
Summer On-peak RSP	$ 1,972,286	$ 275,446	$ 2,247,732	14.0%	$ 1,972,286	$ 215,005	$ 2,187,291	10.9%
Smart Hours RSH	9,320	1,405	10,725	15.1%	9,320	1,160	10,479	12.4%
Night Time Savers RPM	1,233	153	1,386	12.4%	1,233	116	1,349	9.4%
Non-Transmitting Meters RNT	21,438	3,231	24,670	15.1%	21,438	2,538	23,977	11.8%
Total Residential	$ 2,004,276	$ 280,236	$ 2,284,513	14.0%	$ 2,004,276	$ 218,819	$ 2,223,096	10.9%
Secondary Service								
Energy-only GS	$ 593,299	$ 26,977	$ 620,276	4.5%	$ 593,299	$ 28,334	$ 621,633	4.8%
Time-of-Use GSTU	484	(5)	479	-1.0%	484	(12)	472	-2.5%
Demand GSD	433,955	1,980	435,935	0.5%	433,955	8,527	442,482	2.0%
Total Secondary Service	$ 1,027,738	$ 28,952	$ 1,056,690	2.8%	$ 1,027,738	$ 36,848	$ 1,064,586	3.6%
Primary Service								
Energy-only GP	$ 120,078	$ (16,652)	$ 103,425	-13.9%	$ 120,078	$ (15,945)	$ 104,133	-13.3%
Demand GPD	463,196	(50,096)	413,101	-10.8%	463,196	(27,087)	436,109	-5.8%
Time-of-Use GPTU	419,677	843	420,519	0.2%	419,677	19,341	439,018	4.6%
Energy Intensive EIP	24,200	(2,796)	21,404	-11.6%	24,200	5,041	29,241	20.8%
Total Primary Service	$ 1,027,150	$ (68,701)	$ 958,450	-6.7%	$ 1,027,150	$ (18,650)	$ 1,008,501	-1.8%
Lighting & Unmetered Class								
Metered Lighting GML	$ 1,610	$ (179)	$ 1,431	-11.1%	$ 1,610	$ 139	$ 1,750	8.7%
Unmetered Lighting GUL	23,749	(1,993)	21,756	-8.4%	23,749	(134)	23,615	-0.6%
Unmetered GU-XL / LED	8,019	(174)	7,845	-2.2%	8,019	303	8,321	3.8%
Unmetered GU	9,295	143	9,437	1.5%	9,295	1,017	10,312	10.9%
Total Lighting & Unmetered Service	$ 42,673	$ (2,203)	$ 40,470	-5.2%	$ 42,673	$ 1,324	$ 43,998	3.1%
Self-generation Class								
Small Self-generation GSG-1	$ -	$ -	$ -	0.0%	$ -	$ -	$ -	0.0%
Large Self-generation GSG-2	5,609	39	5,648	0.7%	5,609	23	5,632	0.4%
Total Self-Generation	$ 5,609	$ 39	$ 5,648	0.7%	$ 5,609	$ 23	$ 5,632	0.4%
Total - Bundled	**$ 4,107,448**	**$ 238,323**	**$ 4,345,770**	**5.8%**	**$ 4,107,448**	**$ 238,365**	**$ 4,345,813**	**5.8%**
Secondary Service								
Energy-only GS	$ 1,055	$ 238	$ 1,293	22.6%	$ 1,055	$ 237	$ 1,293	22.5%
Demand GSD	6,116	994	7,111	16.3%	6,116	988	7,104	16.2%
Total Secondary Service	$ 7,171	$ 1,233	$ 8,404	17.2%	$ 7,171	$ 1,225	$ 8,397	17.1%
Primary Service								
Energy-only GP	$ 1,028	$ 244	$ 1,272	23.7%	$ 1,028	$ 241	$ 1,269	23.4%
Demand GPD	17,997	4,731	22,729	26.3%	17,997	4,655	22,653	25.9%
Total Primary Service	$ 19,025	$ 4,975	$ 24,000	26.2%	$ 19,025	$ 4,896	$ 23,921	25.7%
Total - ROA Service	**$ 26,196**	**$ 6,208**	**$ 32,404**	**23.7%**	**$ 26,196**	**$ 6,121**	**$ 32,318**	**23.4%**
Total Jurisdictional Service - Residential	$ 2,004,276	$ 280,236	$ 2,284,513	14.0%	$ 2,004,276	$ 218,819	$ 2,223,096	10.9%
Total Jurisdictional Service - Secondary	1,034,909	30,185	1,065,094	2.9%	1,034,909	38,074	1,072,983	3.7%
Total Jurisdictional Service - Primary	1,046,176	(63,725)	982,450	-6.1%	1,046,176	(13,753)	1,032,422	-1.3%
Total Jurisdictional Service - Lighting	42,673	(2,203)	40,470	-5.2%	42,673	1,324	43,998	3.1%
Total Jurisdictional Service - Self-Generation	5,609	39	5,648	0.7%	5,609	23	5,632	0.4%
Total Jurisdictional Service - Totals	**$ 4,133,644**	**$ 244,531**	**$ 4,378,175**	**5.9%**	**$ 4,133,644**	**$ 244,487**	**$ 4,378,131**	**5.9%**
Less: PSCR Factor Revenues	$ 134,502	$ -	$ 134,502		$ 134,502	$ -	$ 134,502	
Less: GSG-2 and GI-2 PSCR Revenues	5,960	136	6,096		5,960	136	6,096	
Rounding	-	(162)	(162)		-	(95)	(95)	
Total Jurisdictional Base Revenues - Total Revenues	**$ 3,993,181**	**$ 244,233**	**$ 4,237,415**	**6.1%**	**$ 3,993,181**	**$ 244,256**	**$ 4,237,437**	**6.1%**

Source: Direct Testimony of Hubert W. Miller III, Workpaper "ex0220-Miller-1-3 and WP-1-25.xlsx."

Comparison of Company and Alternative Proposed Rates

Description	Company's Present Rate	Company's Proposed Rate	Increase from Present Rate	Alternative Rate	Increase from Present Rate
Residential Summer On-peak (RSP)					
Production:					
Production - Summer - Non-Capacity - On-peak kWh	$ 0.090785	$ 0.054372	-40.1%	$ 0.047773	-47.4%
Production - Summer - Non-Capacity - Off-peak kWh	$ 0.061121	$ 0.036609	-40.1%	$ 0.032165	-47.4%
Production - Summer - Capacity - On-peak kWh	$ 0.052967	$ 0.070983	34.0%	$ 0.070983	34.0%
Production - Summer - Capacity Charges - Off-peak kWh	$ 0.035660	$ 0.047710	33.8%	$ 0.047710	33.8%
Production - Winter - Non-Capacity - All kWh	$ 0.061121	$ 0.042029	-31.2%	$ 0.036928	-39.6%
Production - Winter - Capacity - All kWh	$ 0.035660	$ 0.046840	31.4%	$ 0.046840	31.4%
Production - Provisions - Peak Savers (ACPC)	$ (8.00)	$ (8.00)	0.0%	$ (8.00)	0.0%
Production - Provisions - Peak Time Rewards	$ (0.95)	$ (1.00)	5.3%	$ (1.00)	5.3%
Production - Provisions - Critical Peak Pricing - Critical-peak Charge	$ 0.95	$ 1.00	5.3%	$ 1.00	5.3%
Production - Provisions - Critical Peak Pricing - Non-critical Credits	$ (0.032260)	$ (0.015122)	-53.1%	$ (0.015122)	-53.1%
Production - Annual PSCR Factor	$ 0.004440	$ 0.004440	0.0%	$ 0.004440	0.0%
Transmission:					
Transmission - Summer - On-peak kWh	$ -	$ 0.029989		$ 0.029989	
Transmission - Summer - Off-peak kWh	$ -	$ 0.020157		$ 0.020157	
Transmission - Winter - All kWh	$ -	$ 0.015705		$ 0.015705	
Distribution:					
Distribution - System Access	$ 7.50	$ 8.50	13.3%	$ 7.50	0.0%
Distribution - Rate	$ 0.047054	$ 0.060209	28.0%	$ 0.061596	30.9%
Distribution - Provisions - Senior Citizen (RSC)	$ (3.75)	$ (4.25)	13.3%	$ (3.75)	0.0%
Distribution - Provisions - Low Income Credit (LIAC)	$ (7.50)	$ (30.00)	300.0%	$ (7.50)	0.0%
Distribution - Provisions - Income Assistance (RIA)	$ (7.50)	$ (8.50)	13.3%	$ (7.50)	0.0%
ROA Service - Distribution:					
ROA Service - Distribution - System Access	$ 7.50	$ 8.50	13.3%	$ 7.50	0.0%
ROA Service - Distribution - Rate	$ 0.047054	$ 0.060209	28.0%	$ 0.061596	30.9%
ROA Service - Distribution - Provisions - Senior Citizen (RSC)	$ (3.75)	$ (4.25)	13.3%	$ (3.75)	0.0%
ROA Service - Distribution - Provisions - Low Income Credit (LIAC)	$ (7.50)	$ (30.00)	300.0%	$ (7.50)	0.0%
ROA Service - Distribution - Provisions - Income Assistance (RIA)	$ (7.50)	$ (8.50)	13.3%	$ (7.50)	0.0%

Source: Direct Testimony of Hubert W. Miller III, Workpaper "ex0220-Miller-1-3 and WP-1-25.xlsx."

Comparison of Company and Alternative Proposed Rates

Description	Company's Present Rate	Company's Proposed Rate	Increase from Present Rate	Alternative Rate	Increase from Present Rate
Residential Smart Hours (RSH)					
Production:					
Production - Summer - Non-Capacity - On-peak kWh	$ 0.088051	$ 0.054372	-38.2%	$ 0.047773	-45.7%
Production - Summer - Non-Capacity - Off-peak kWh	$ 0.059280	$ 0.036609	-38.2%	$ 0.032165	-45.7%
Production - Summer - Capacity - On-peak kWh	$ 0.051101	$ 0.070983	38.9%	$ 0.070983	38.9%
Production - Summer - Capacity - Off-peak kWh	$ 0.034404	$ 0.047710	38.7%	$ 0.047710	38.7%
Production - Winter - Non-Capacity - On-peak kWh	$ 0.066561	$ 0.043691	-34.4%	$ 0.038389	-42.3%
Production - Winter - Non-Capacity - Off-peak kWh	$ 0.059280	$ 0.041306	-30.3%	$ 0.036293	-38.8%
Production - Winter - Capacity - On-peak kWh	$ 0.038629	$ 0.051437	33.2%	$ 0.051437	33.2%
Production - Winter - Capacity - Off-peak kWh	$ 0.034404	$ 0.045217	31.4%	$ 0.045217	31.4%
Production - Provisions - Peak Savers (ACPC)	$ (8.00)	$ (8.00)	0.0%	$ (8.00)	0.0%
Production - Provisions - Peak Time Rewards	$ (0.95)	$ (1.00)	5.3%	$ (1.00)	5.3%
Production - Provisions - Critical Peak Pricing - Critical-peak Charge	$ 0.95	$ 1.00	5.3%	$ 1.00	5.3%
Production - Provisions - Critical Peak Pricing - Non-critical Credits	$ (0.032260)	$ (0.015122)	-53.1%	$ (0.015122)	-53.1%
Production - Annual PSCR Factor	$ 0.004440	$ 0.004440	0.0%	$ 0.004440	0.0%
Transmission:					
Transmission - Summer - On-peak kWh	$ -	$ 0.029989		$ 0.029989	
Transmission - Summer - Off-peak kWh	$ -	$ 0.020157		$ 0.020157	
Transmission - Winter - On-peak kWh	$ -	$ 0.017714		$ 0.017714	
Transmission - Winter - Off-peak kWh	$ -	$ 0.015572		$ 0.015572	
Distribution:					
Distribution - System Access	$ 7.50	$ 8.50	13.3%	$ 7.50	0.0%
Distribution - Rate	$ 0.047054	$ 0.060209	28.0%	$ 0.061596	30.9%
Distribution - Provisions - Senior Citizen (RSC)	$ (3.75)	$ (4.25)	13.3%	$ (3.75)	0.0%
Distribution - Provisions - Low Income Credit (LIAC)	$ (7.50)	$ (30.00)	300.0%	$ (7.50)	0.0%
Distribution - Provisions - Income Assistance (RIA)	$ (7.50)	$ (8.50)	13.3%	$ (7.50)	0.0%
ROA Service - Distribution:					
ROA Service - Distribution - System Access	$ 7.50	$ 8.50	13.3%	$ 7.50	0.0%
ROA Service - Distribution - Rate	$ 0.047054	$ 0.060209	28.0%	$ 0.061596	30.9%
ROA Service - Distribution - Provisions - Senior Citizen (RSC)	$ (3.75)	$ (4.25)	13.3%	$ (3.75)	0.0%
ROA Service - Distribution - Provisions - Low Income Credit (LIAC)	$ (7.50)	$ (30.00)	300.0%	$ (7.50)	0.0%
ROA Service - Distribution - Provisions - Income Assistance (RIA)	$ (7.50)	$ (8.50)	13.3%	$ (7.50)	0.0%

Source: Direct Testimony of Hubert W. Miller III, Workpaper "ex0220-Miller-1-3 and WP-1-25.xlsx."

Comparison of Company and Alternative Proposed Rates

Description	Company's Present Rate	Company's Proposed Rate	Increase from Present Rate	Alternative Rate	Increase from Present Rate
Residential Nighttime Savers (RPM)					
Production:					
Production - Summer - Non-Capacity - On-peak kWh	$ 0.095146	$ 0.054372	-42.9%	$ 0.047773	-49.8%
Production - Summer - Non-Capacity - Off-peak kWh	$ 0.080874	$ 0.045082	-44.3%	$ 0.039609	-51.0%
Production - Summer - Non-Capacity - Super Off-peak kWh	$ 0.047573	$ 0.030610	-35.7%	$ 0.026894	-43.5%
Production - Summer - Capacity - On-peak kWh	$ 0.055219	$ 0.070983	28.5%	$ 0.070983	28.5%
Production - Summer - Capacity - Off-peak kWh	$ 0.046936	$ 0.052252	11.3%	$ 0.052252	11.3%
Production - Summer - Capacity - Super Off-peak kWh	$ 0.027609	$ 0.031810	15.2%	$ 0.031810	15.2%
Production - Winter - Non-Capacity - On-peak kWh	$ 0.066602	$ 0.043691	-34.4%	$ 0.038389	-42.4%
Production - Winter - Non-Capacity - Off-peak kWh	$ 0.061845	$ 0.048455	-21.7%	$ 0.042573	-31.2%
Production - Winter - Non-Capacity - Super Off-peak kWh	$ 0.047573	$ 0.037342	-21.5%	$ 0.032809	-31.0%
Production - Winter - Capacity - On-peak kWh	$ 0.038653	$ 0.051437	33.1%	$ 0.051437	33.1%
Production - Winter - Capacity - Off-peak kWh	$ 0.035892	$ 0.045985	28.1%	$ 0.045985	28.1%
Production - Winter - Capacity - Super Off-peak kWh	$ 0.027609	$ 0.032981	19.5%	$ 0.032981	19.5%
Production - Provisions - Peak Savers (ACPC)	$ (8.00)	$ (8.00)	0.0%	$ (8.00)	0.0%
Production - Provisions - Peak Time Rewards	$ (0.95)	$ (1.00)	5.3%	$ (1.00)	5.3%
Production - Provisions - Critical Peak Pricing - Critical-peak Charge	$ 0.95	$ 1.00	5.3%	$ 1.00	5.3%
Production - Provisions - Critical Peak Pricing - Non-critical Credits	$ (0.032260)	$ (0.015122)	-53.1%	$ (0.015122)	-53.1%
Production - Annual PSCR Factor	$ 0.004440	$ 0.004440	0.0%	$ 0.004440	0.0%
Transmission:					
Transmission - Summer - On-peak kWh	$ -	$ 0.029989		$ 0.029989	
Transmission - Summer - Off-peak kWh	$ -	$ 0.021582		$ 0.021582	
Transmission - Summer - Super Off-peak kWh	$ -	$ 0.013138		$ 0.013138	
Transmission - Winter - On-peak kWh	$ -	$ 0.017714		$ 0.017714	
Transmission - Winter - Off-peak kWh	$ -	$ 0.015870		$ 0.015870	
Transmission - Winter - Super Off-peak kWh	$ -	$ 0.011382		$ 0.011382	
Distribution:					
Distribution - System Access	$ 7.50	$ 8.50	13.3%	$ 7.50	0.0%
Distribution - Rate	$ 0.04705	$ 0.06021	28.0%	$ 0.06160	30.9%
Distribution - Provisions - Senior Citizen (RSC)	$ (3.75)	$ (4.25)	13.3%	$ (3.75)	0.0%
Distribution - Provisions - Low Income Credit (LIAC)	$ (7.50)	$ (30.00)	300.0%	$ (7.50)	0.0%
Distribution - Provisions - Income Assistance (RIA)	$ (7.50)	$ (8.50)	13.3%	$ (7.50)	0.0%
ROA Service - Distribution:					
ROA Service - Distribution - System Access	$ 7.50	$ 8.50	13.3%	$ 7.50	0.0%
ROA Service - Distribution - Rate	$ 0.047054	$ 0.060209	28.0%	$ 0.061596	30.9%
ROA Service - Distribution - Provisions - Senior Citizen (RSC)	$ (3.75)	$ (4.25)	13.3%	$ (3.75)	0.0%
ROA Service - Distribution - Provisions - Low Income Credit (LIAC)	$ (7.50)	$ (30.00)	300.0%	$ (7.50)	0.0%
ROA Service - Distribution - Provisions - Income Assistance (RIA)	$ (7.50)	$ (8.50)	13.3%	$ (7.50)	0.0%

Source: Direct Testimony of Hubert W. Miller III, Workpaper "ex0220-Miller-1-3 and WP-1-25.xlsx."

Comparison of Company and Alternative Proposed Rates

Description	Company's Present Rate	Company's Proposed Rate	Increase from Present Rate	Alternative Rate	Increase from Present Rate
Residential Non-Transmitting Meters (RSM)					
Production:					
Production - Summer - Non-Capacity - First 600 kWh	$ 0.060529	$ 0.042029	-30.6%	$ 0.036928	-39.0%
Production - Summer - Non-Capacity - Excess kWh	$ 0.080047	$ 0.054372	-32.1%	$ 0.047773	-40.3%
Production - Summer - Capacity - First 600 kWh	$ 0.035129	$ 0.046840	33.3%	$ 0.046840	33.3%
Production - Summer - Capacity - Excess kWh	$ 0.046457	$ 0.055837	20.2%	$ 0.055837	20.2%
Production - Winter - Non-Capacity - All kWh	$ 0.060529	$ 0.042029	-30.6%	$ 0.036928	-39.0%
Production - Winter - Capacity - All kWh	$ 0.035129	$ 0.046840	33.3%	$ 0.046840	33.3%
Production - Annual PSCR Factor	$ 0.004440	$ 0.004440	0.0%	$ 0.004440	0.0%
Transmission:					
Transmission - Summer - First 600 kWh	$ -	$ 0.020385		$ 0.020385	
Transmission - Summer - Excess kWh	$ -	$ 0.024301		$ 0.024301	
Transmission - Winter - All kWh	$ -	$ 0.015705		$ 0.015705	
Distribution:					
Distribution - System Access	$ 7.50	$ 8.50	13.3%	$ 7.50	0.0%
Distribution - Opt-out Fee	$ 3.00	$ 3.00	0.0%	$ 3.00	0.0%
Distribution - Rate	$ 0.047054	$ 0.060209	28.0%	$ 0.061596	30.9%
Distribution - Provisions - Senior Citizen (RSC)	$ (3.75)	$ (4.25)	13.3%	$ (3.75)	0.0%
Distribution - Provisions - Low Income Credit (LIAC)	$ (7.50)	$ (30.00)	300.0%	$ (7.50)	0.0%
Distribution - Provisions - Income Assistance (RIA)	$ (7.50)	$ (8.50)	13.3%	$ (7.50)	0.0%
ROA Service - Distribution:					
ROA Service - Distribution - System Access	$ 7.50	$ 8.50	13.3%	$ 7.50	0.0%
ROA Service - Distribution - Opt-out Fee	$ 3.00	$ 3.00	0.0%	$ 3.00	0.0%
ROA Service - Distribution - Rate	$ 0.047054	$ 0.060209	28.0%	$ 0.061596	30.9%
ROA Service - Distribution - Provisions - Senior Citizen (RSC)	$ (3.75)	$ (4.25)	13.3%	$ (3.75)	0.0%
ROA Service - Distribution - Provisions - Low Income Credit (LIAC)	$ (7.50)	$ (30.00)	300.0%	$ (7.50)	0.0%
ROA Service - Distribution - Provisions - Income Assistance (RIA)	$ (7.50)	$ (8.50)	13.3%	$ (7.50)	0.0%

Source: Direct Testimony of Hubert W. Miller III, Workpaper "ex0220-Miller-1-3 and WP-1-25.xlsx."

Comparison of Company and Alternative Proposed Rates

Description	Company's Present Rate	Company's Proposed Rate	Increase from Present Rate	Alternative Rate	Increase from Present Rate
Secondary Energy-only (GS)					
Production:					
Production - Summer - Non-Capacity - All kWh	$ 0.062210	$ 0.040543	-34.8%	$ 0.041006	-34.1%
Production - Summer - Capacity - All kWh	$ 0.034294	$ 0.038384	11.9%	$ 0.038384	11.9%
Production - Winter - Non-Capacity - All kWh	$ 0.061580	$ 0.037458	-39.2%	$ 0.037886	-38.5%
Production - Winter - Capacity - All kWh	$ 0.033947	$ 0.039925	17.6%	$ 0.039925	17.6%
Production - Annual PSCR Factor	$ 0.004440	$ 0.004440	0.0%	$ 0.004440	0.0%
Transmission:					
Transmission - Summer - All kWh	$ -	$ 0.014830		$ 0.014830	
Transmission - Winter - All kWh	$ -	$ 0.015425		$ 0.015425	
Distribution:					
Distribution - System Access	$ 20.00	$ 20.00	0.0%	$ 20.00	0.0%
Distribution - Rate	$ 0.042472	$ 0.052253	23.0%	$ 0.052122	22.7%
Distribution - Provisions - Education GEI	$ (0.000748)	$ (0.000829)	10.8%	$ (0.000698)	-6.7%
ROA Service - Distribution:					
ROA Service - Distribution - System Access	$ 20.00	$ 20.00	0.0%	$ 20.00	0.0%
ROA Service - Distribution - Rate	$ 0.042472	$ 0.052253	23.0%	$ 0.052122	22.7%
ROA Service - Distribution - Provisions - Education GEI	$ (0.000748)	$ (0.000829)	10.8%	$ (0.000698)	-6.7%

Source: Direct Testimony of Hubert W. Miller III, Workpaper "ex0220-Miller-1-3 and WP-1-25.xlsx."

Comparison of Company and Alternative Proposed Rates

Description	Company's Present Rate	Company's Proposed Rate	Increase from Present Rate	Alternative Rate	Increase from Present Rate
Secondary Time-of-Use (GSTU)					
Production:					
Production - Summer - Non-Capacity - On-peak kWh	$ 0.109946	$ 0.055239	-49.8%	$ 0.055871	-49.2%
Production - Summer - Non-Capacity - Mid-peak kWh	$ 0.086391	$ 0.042076	-51.3%	$ 0.042557	-50.7%
Production - Summer - Non-Capacity - Off-peak kWh	$ 0.055495	$ 0.028761	-48.2%	$ 0.029090	-47.6%
Production - Summer - Capacity - On-peak kWh	$ 0.060609	$ 0.054260	-10.5%	$ 0.054260	-10.5%
Production - Summer - Capacity - Mid-peak kWh	$ 0.047624	$ 0.045082	-5.3%	$ 0.045082	-5.3%
Production - Summer - Capacity - Off-peak kWh	$ 0.030592	$ 0.029094	-4.9%	$ 0.029094	-4.9%
Production - Winter - Non-Capacity - On-peak kWh	$ 0.057913	$ 0.043572	-24.8%	$ 0.044071	-23.9%
Production - Winter - Non-Capacity - Off-peak kWh	$ 0.050720	$ 0.035152	-30.7%	$ 0.035554	-29.9%
Production - Winter - Capacity - On-peak kWh	$ 0.031925	$ 0.045497	42.5%	$ 0.045497	42.5%
Production - Winter - Capacity - Off-peak kWh	$ 0.027960	$ 0.033991	21.6%	$ 0.033991	21.6%
Production - Provisions - Interruptible (GSI)	$ -	$ (0.017518)		$ (0.017518)	
Production - Annual PSCR Factor	$ 0.004440	$ 0.004440	0.0%	$ 0.004440	0.0%
Transmission:					
Transmission - Summer - On-Peak kWh	$ -	$ 0.020964		$ 0.020964	
Transmission - Summer - Mid-Peak kWh	$ -	$ 0.017418		$ 0.017418	
Transmission - Summer - Off-Peak kWh	$ -	$ 0.011241		$ 0.011241	
Transmission - Winter - On-Peak kWh	$ -	$ 0.017577		$ 0.017577	
Transmission - Winter - Off-Peak kWh	$ -	$ 0.013132		$ 0.013132	
Distribution:					
Distribution - System Access	$ 20.00	$ 30.00	50.0%	$ 20.00	0.0%
Distribution - Peak kW	$ -	$ 1.34		$ 1.30	
Distribution - Rate	$ 0.042472	$ 0.034680	-18.3%	$ 0.034680	-18.3%
Distribution - Provisions - Education GEI	$ (0.000748)	$ (0.000829)	10.8%	$ (0.000698)	-6.7%

Source: Direct Testimony of Hubert W. Miller III, Workpaper "ex0220-Miller-1-3 and WP-1-25.xlsx."

Comparison of Company and Alternative Proposed Rates

Description	Company's Present Rate	Company's Proposed Rate	Increase from Present Rate	Alternative Rate	Increase from Present Rate
Secondary Demand (GSD)					
Production:					
Production - Summer - Non-Capacity - Peak kW	$ 8.10	$ 3.19	-60.6%	$ 3.19	-60.6%
Production - Summer - Non-Capacity - All kWh	$ 0.043298	$ 0.033511	-22.6%	$ 0.035680	-17.6%
Production - Summer - Capacity - Peak kW	$ 13.04	$ 14.23	9.1%	$ 14.23	9.1%
Production - Summer - Capacity - All kWh	$ -	$ -		$ -	
Production - Winter - Non-Capacity - Peak kW	$ 6.10	$ 1.65	-73.0%	$ 1.65	-73.0%
Production - Winter - Non-Capacity - All kWh	$ 0.040994	$ 0.030961	-24.5%	$ 0.032965	-19.6%
Production - Winter - Capacity - Peak kW	$ 11.04	$ 12.69	14.9%	$ 12.69	14.9%
Production - Winter - Capacity - All kWh	$ -	$ -		$ -	
Production - Provisions - Interruptible (GSI)	$ -	$ (0.017518)		$ (0.017518)	
Production - Annual PSCR Factor	$ 0.004440	$ 0.004440	0.0%	$ 0.004440	0.0%
Transmission:					
Transmission- Summer - Peak kW	$ -	$ 5.64		$ 5.64	
Transmission - Winter - Peak kW	$ -	$ 5.02		$ 5.02	
Distribution:					
Distribution - System Access	$ 30.00	$ 30.00	0.0%	$ 30.00	0.0%
Distribution - Peak kW	$ 1.15	$ 1.34	16.5%	$ 1.32	14.8%
Distribution - Rate	$ 0.029722	$ 0.034680	16.7%	$ 0.034680	16.7%
Distribution - Provisions - Education GEI					
ROA Service - Distribution:					
ROA Service - Distribution - System Access	$ 30.00	$ 30.00	0.0%	$ 30.00	0.0%
ROA Service - Distribution - Peak kW	$ 1.15	$ 1.34	16.5%	$ 1.32	14.8%
ROA Service - Distribution - Rate	$ 0.029722	$ 0.034680	16.7%	$ 0.034680	16.7%
ROA Service - Distribution - Provisions - Education GEI	$ (0.000616)	$ (0.000659)	7.0%	$ (0.000596)	-3.2%

Source: Direct Testimony of Hubert W. Miller III, Workpaper "ex0220-Miller-1-3 and WP-1-25.xlsx."

Comparison of Company and Alternative Proposed Rates

Description		Company's Present Rate		Company's Proposed Rate	Increase from Present Rate		Alternative Rate	Increase from Present Rate
Primary Energy-only Voltage Level 1 (GP VL 1)								
Production:								
Production - Summer - Non-Capacity - All kWh	$	0.048787	$	0.034485	-29.3%	$	0.035288	-27.7%
Production - Summer - Capacity - All kWh	$	0.037321	$	0.034070	-8.7%	$	0.034070	-8.7%
Production - Winter - Non-Capacity - All kWh	$	0.048293	$	0.031861	-34.0%	$	0.032603	-32.5%
Production - Winter - Capacity - All kWh	$	0.036943	$	0.035420	-4.1%	$	0.035420	-4.1%
Production - Annual PSCR Factor	$	0.004440	$	0.004440	0.0%	$	0.004440	0.0%
Transmission:								
Transmission- Summer - All kWh	$	-	$	0.013809		$	0.013809	
Transmission - Winter - All kWh	$	-	$	0.014357		$	0.014357	
Distribution:								
Distribution - System Access	$	100.00	$	100.00	0.0%	$	100.00	0.0%
Distribution - Rate	$	0.005733	$	0.006407	11.8%	$	0.006331	10.4%
Distribution - Substation Ownership Credit	$	(0.000287)	$	(0.000767)	167.2%	$	(0.000767)	167.2%
Distribution - Provisions - Education GEI	$	(0.000571)	$	(0.000516)	-9.6%	$	(0.000437)	-23.5%
ROA Service - Distribution:								
ROA Service - Distribution - System Access	$	100.00	$	100.00	0.0%	$	100.00	0.0%
ROA Service - Distribution - Rate	$	0.005733	$	0.006407	11.8%	$	0.006331	10.4%
ROA Service - Distribution - Substation Ownership Credit	$	(0.000287)	$	(0.000767)	167.2%	$	(0.000767)	167.2%
ROA Service - Distribution - Provisions - Education GEI	$	(0.000571)	$	(0.000516)	-9.6%	$	(0.000437)	-23.5%

Source: Direct Testimony of Hubert W. Miller III, Workpaper "ex0220-Miller-1-3 and WP-1-25.xlsx."

Comparison of Company and Alternative Proposed Rates

Description	Company's Present Rate	Company's Proposed Rate	Increase from Present Rate	Alternative Rate	Increase from Present Rate
Primary Energy-only Voltage Level 2 (GP VL 2)					
Production:					
Production - Summer - Non-Capacity - All kWh	$ 0.053957	$ 0.034909	-35.3%	$ 0.035722	-33.8%
Production - Summer - Capacity - All kWh	$ 0.042491	$ 0.034615	-18.5%	$ 0.034615	-18.5%
Production - Winter - Non-Capacity - All kWh	$ 0.053463	$ 0.032253	-39.7%	$ 0.033004	-38.3%
Production - Winter - Capacity - All kWh	$ 0.042113	$ 0.035987	-14.5%	$ 0.035987	-14.5%
Production - Annual PSCR Factor	$ 0.004440	$ 0.004440	0.0%	$ 0.004440	0.0%
Transmission:					
Transmission - Summer - All kWh	$ -	$ 0.014030		$ 0.014030	
Transmission - Winter - All kWh	$ -	$ 0.014587		$ 0.014587	
Distribution:					
Distribution - System Access	$ 100.00	$ 100.00	0.0%	$ 100.00	0.0%
Distribution - Rate	$ 0.007723	$ 0.010920	41.4%	$ 0.010844	40.4%
Distribution - Substation Ownership Credit	$ (0.000287)	$ (0.002180)	659.6%	$ (0.002180)	659.6%
Distribution - Provisions - Education GEI	$ (0.000571)	$ (0.000516)	-9.6%	$ (0.000437)	-23.5%
ROA Service - Distribution:					
ROA Service - Distribution - System Access	$ 100.00	$ 100.00	0.0%	$ 100.00	0.0%
ROA Service - Distribution - Rate	$ 0.007723	$ 0.010920	41.4%	$ 0.010844	40.4%
ROA Service - Distribution - Substation Ownership Credit	$ (0.000287)	$ (0.000287)	0.0%	$ (0.000287)	0.0%
ROA Service - Distribution - Provisions - Education GEI	$ (0.000571)	$ (0.000516)	-9.6%	$ (0.000437)	-23.5%

Source: Direct Testimony of Hubert W. Miller III, Workpaper "ex0220-Miller-1-3 and WP-1-25.xlsx."

Comparison of Company and Alternative Proposed Rates

Description	Company's Present Rate	Company's Proposed Rate	Increase from Present Rate	Alternative Rate	Increase from Present Rate
Primary Energy-only Voltage Level 3 (GP VL 3)					
Production:					
Production - Summer - Non-Capacity - All kWh	$ 0.058898	$ 0.035595	-39.6%	$ 0.036424	-38.2%
Production - Summer - Capacity - All kWh	$ 0.047432	$ 0.035443	-25.3%	$ 0.035443	-25.3%
Production - Winter- Non-Capacity - All kWh	$ 0.058404	$ 0.032887	-43.7%	$ 0.033653	-42.4%
Production - Winter - Capacity - All kWh	$ 0.047054	$ 0.036847	-21.7%	$ 0.036847	-21.7%
Production - Annual PSCR Factor	$ 0.004440	$ 0.004440	0.0%	$ 0.004440	0.0%
Transmission:					
Transmission - Summer - All kWh	$ -	$ 0.014366		$ 0.014366	
Transmission - Winter - All kWh	$ -	$ 0.014936		$ 0.014936	
Distribution:					
Distribution - System Access	$ 100.00	$ 100.00	0.0%	$ 100.00	0.0%
Distribution - Rate	$ 0.013386	$ 0.016629	24.2%	$ 0.016553	23.7%
Distribution - Provisions - Education GEI	$ (0.000571)	$ (0.000516)	-9.6%	$ (0.000437)	-23.5%
ROA Service - Distribution:					
ROA Service - Distribution - System Access	$ 100.00	$ 100.00	0.0%	$ 100.00	0.0%
ROA Service - Distribution - Rate	$ 0.013386	$ 0.016629	24.2%	$ 0.016553	23.7%
ROA Service - Distribution - Provisions - Education GEI	$ (0.000571)	$ (0.000516)	-9.6%	$ (0.000437)	-23.5%

Source: Direct Testimony of Hubert W. Miller III, Workpaper "ex0220-Miller-1-3 and WP-1-25.xlsx."

Comparison of Company and Alternative Proposed Rates

Description	Company's Present Rate	Company's Proposed Rate	Increase from Present Rate	Alternative Rate	Increase from Present Rate
Primary Demand Voltage Level 1 (GPD VL 1)					
Production:					
Production - Summer - Non-Capacity - On-Peak kW	$ 9.34	$ 6.33	-32.2%	$ 6.33	-32.2%
Production - Summer - Non-Capacity - On-Peak kWh	$ 0.026510	$ 0.027643	4.3%	$ 0.033760	27.3%
Production - Summer - Non-Capacity - Off-Peak kWh	$ 0.017182	$ 0.017803	3.6%	$ 0.021743	26.5%
Production - Summer - Capacity - On-Peak kW	$ 13.82	$ 14.27	3.3%	$ 14.27	3.3%
Production - Winter - Non-Capacity - On-Peak kW	$ 8.34	$ 5.33	-36.1%	$ 5.33	-36.1%
Production - Winter - Non-Capacity - On-Peak kWh	$ 0.021641	$ 0.022639	4.6%	$ 0.027649	27.8%
Production - Winter - Non-Capacity - Off-Peak kWh	$ 0.018953	$ 0.021052	11.1%	$ 0.025710	35.7%
Production - Winter - Capacity - On-Peak kW	$ 12.82	$ 13.27	3.5%	$ 13.27	3.5%
Production - Provisions - Interruptible GI - Summer On-Peak kW	$ (7.00)	$ (7.00)	0.0%	$ (7.00)	0.0%
Production - Provisions - Interruptible GI - Winter On-Peak kW	$ (6.00)	$ (6.00)	0.0%	$ (6.00)	0.0%
Production - Provisions - Interruptible GI-2 - Summer Capacity & Transmission	$ 0.028890	$ 0.024857	-14.0%	$ 0.024857	-14.0%
Production - Provisions - Interruptible GI-2 - Winter Capacity & Transmission	$ 0.025559	$ 0.023762	-7.0%	$ 0.023762	-7.0%
Production - Provisions - Interruptible GI-2 - LMP	$ 0.029146	$ 0.029146	0.0%	$ 0.029146	0.0%
Production - Annual PSCR Factor	$ 0.004440	$ 0.004440	0.0%	$ 0.004440	0.0%
Transmission:					
Transmission- Summer - On-Peak kW	$ 6.58	$ 7.03	6.8%	$ 7.03	6.8%
Transmission - Winter - On-Peak kW	$ 6.58	$ 6.55	-0.5%	$ 6.55	-0.5%
Distribution:					
Distribution - System Access	$ 200.00	$ 200.00	0.0%	$ 200.00	0.0%
Distribution - Maximum kW	$ 0.91	$ 0.70	-23.1%	$ 0.69	-24.2%
Distribution - Substation Ownership	$ (0.45)	$ (0.34)	-24.4%	$ (0.34)	-24.4%
Distribution - Joint Substation Ownership	$ (0.31)	$ (0.23)	-25.8%	$ (0.23)	-25.8%
Distribution - Rate	$ -	$ -		$ -	
Distribution - Provisions - Education GEI	$ (0.000314)	$ (0.000259)	-17.5%	$ (0.000230)	-26.8%
ROA Service - Distribution:					
ROA Service - Distribution - System Access	$ 200.00	$ 200.00	0.0%	$ 200.00	0.0%
ROA Service - Distribution - Maximum kW	$ 0.91	$ 0.70	-23.1%	$ 0.69	-24.2%
ROA Service - Distribution - Substation Ownership	$ (0.45)	$ (0.34)	-24.4%	$ (0.34)	-24.4%
ROA Service - Distribution - Rate	$ -	$ -		$ -	
ROA Service - Distribution - Provisions - Education GEI	$ (0.000314)	$ (0.000259)	-17.5%	$ (0.000230)	-26.8%

Source: Direct Testimony of Hubert W. Miller III, Workpaper "ex0220-Miller-1-3 and WP-1-25.xlsx."

Comparison of Company and Alternative Proposed Rates

Description	Company's Present Rate	Company's Proposed Rate	Increase from Present Rate	Alternative Rate	Increase from Present Rate
Primary Demand Voltage Level 2 (GPD VL 2)					
Production:					
Production - Summer - Non-Capacity - On-Peak kW	$ 9.84	$ 6.41	-34.9%	$ 6.41	-34.9%
Production - Summer - Non-Capacity - On-Peak kWh	$ 0.034239	$ 0.027983	-18.3%	$ 0.034175	-0.2%
Production - Summer - Non-Capacity - Off-Peak kWh	$ 0.022191	$ 0.018022	-18.8%	$ 0.022010	-0.8%
Production - Summer - Capacity - On-Peak kW	$ 14.32	$ 14.50	1.3%	$ 14.50	1.3%
Production - Winter - Non-Capacity - On-Peak kW	$ 8.84	$ 5.40	-39.0%	$ 5.40	-39.0%
Production - Winter - Non-Capacity - On-Peak kWh	$ 0.027950	$ 0.022917	-18.0%	$ 0.027989	0.1%
Production - Winter - Non-Capacity - Off-Peak kWh	$ 0.024479	$ 0.021311	-12.9%	$ 0.026026	6.3%
Production - Winter - Capacity - On-Peak kW	$ 13.32	$ 13.48	1.2%	$ 13.48	1.2%
Production - Provisions - Interruptible GI - Summer On-Peak kW	$ (7.00)	$ (7.00)	0.0%	$ (7.00)	0.0%
Production - Provisions - Interruptible GI - Winter On-Peak kW	$ (6.00)	$ (6.00)	0.0%	$ (6.00)	0.0%
Production - Provisions - Interruptible GI-2 - Summer Capacity & Transmission	$ 0.039453	$ 0.026704	-32.3%	$ 0.026704	-32.3%
Production - Provisions - Interruptible GI-2 - Winter Capacity & Transmission	$ 0.036122	$ 0.025668	-28.9%	$ 0.025668	-28.9%
Production - Provisions - Interruptible GI-2 - LMP	$ -	$ -		$ -	
Production - Annual PSCR Factor	$ 0.004440	$ 0.004440	0.0%	$ 0.004440	0.0%
Transmission:					
Transmission - Summer - On-Peak kW	$ 6.71	$ 7.14	6.4%	$ 7.14	6.4%
Transmission - Winter - On-Peak kW	$ 6.71	$ 6.65	-0.9%	$ 6.65	-0.9%
Distribution:					
Distribution - System Access	$ 200.00	$ 200.00	0.0%	$ 200.00	0.0%
Distribution - Maximum kW	$ 1.86	$ 2.69	44.6%	$ 2.68	44.1%
Distribution - Substation Ownership	$ (0.97)	$ (0.96)	-1.0%	$ (0.96)	-1.0%
Distribution - Rate	$ -	$ -		$ -	
Distribution - Provisions - Education GEI	$ (0.000314)	$ (0.000259)	-17.5%	$ (0.000230)	-26.8%
ROA Service - Distribution:					
ROA Service - Distribution - System Access	$ 200.00	$ 200.00	0.0%	$ 200.00	0.0%
ROA Service - Distribution - Maximum kW	$ 1.86	$ 2.69	44.6%	$ 2.68	44.1%
ROA Service - Distribution - Substation Ownership	$ (0.97)	$ (0.96)	-1.0%	$ (0.96)	-1.0%
ROA Service - Distribution - Rate	$ -	$ -		$ -	
ROA Service - Distribution - Provisions - Education GEI	$ (0.000314)	$ (0.000259)	-17.5%	$ (0.000230)	-26.8%

Source: Direct Testimony of Hubert W. Miller III, Workpaper "ex0220-Miller-1-3 and WP-1-25.xlsx."

Comparison of Company and Alternative Proposed Rates

Description	Company's Present Rate	Company's Proposed Rate	Increase from Present Rate	Alternative Rate	Increase from Present Rate
Primary Demand Voltage Level 3 (GPD VL 3)					
Production:					
Production - Summer - Non-Capacity - On-Peak kW	$ 10.34	$ 6.53	-36.8%	$ 6.53	-36.8%
Production - Summer - Non-Capacity - On-Peak kWh	$ 0.042156	$ 0.028533	-32.3%	$ 0.034847	-17.3%
Production - Summer - Non-Capacity - Off-Peak kWh	$ 0.027322	$ 0.018376	-32.7%	$ 0.022443	-17.9%
Production - Summer - Capacity - On-Peak kW	$ 14.82	$ 14.85	0.2%	$ 14.85	0.2%
Production - Winter - Non-Capacity - On-Peak kW	$ 9.34	$ 5.50	-41.1%	$ 5.50	-41.1%
Production - Winter - Non-Capacity - On-Peak kWh	$ 0.034413	$ 0.023368	-32.1%	$ 0.028539	-17.1%
Production - Winter - Non-Capacity - Off-Peak kWh	$ 0.030139	$ 0.021730	-27.9%	$ 0.026538	-11.9%
Production - Winter - Capacity - On-Peak kW	$ 13.82	$ 13.80	-0.1%	$ 13.80	-0.1%
Production - Provisions - Interruptible GI - Summer On-Peak kW	$ (7.00)	$ (7.00)	0.0%	$ (7.00)	0.0%
Production - Provisions - Interruptible GI - Winter On-Peak kW	$ (6.00)	$ (6.00)	0.0%	$ (6.00)	0.0%
Production - Provisions - Interruptible GI-2 - Summer Capacity & Transmission	$ 0.049807	$ 0.030487	-38.8%	$ 0.030487	-38.8%
Production - Provisions - Interruptible GI-2 - Winter Capacity & Transmission	$ 0.046476	$ 0.030403	-34.6%	$ 0.030403	-34.6%
Production - Provisions - Interruptible GI-2 - LMP	$ -	$ -		$ -	
Production - Annual PSCR Factor	$ 0.004440	$ 0.004440	0.0%	$ 0.004440	0.0%
Transmission:					
Transmission - Summer - On-Peak kW	$ 6.98	$ 7.31	4.7%	$ 7.31	4.7%
Transmission - Winter - On-Peak kW	$ 6.98	$ 6.81	-2.4%	$ 6.81	-2.4%
Distribution:					
Distribution - System Access	$ 200.00	$ 200.00	0.0%	$ 200.00	0.0%
Distribution - Maximum kW	$ 3.60	$ 4.58	27.2%	$ 4.57	26.9%
Distribution - Rate	$ -	$ -		$ -	
Distribution - Provisions - Education GEI	$ (0.000314)	$ (0.000259)	-17.5%	$ (0.000230)	-26.8%
ROA Service - Distribution:					
ROA Service - Distribution - System Access	$ 200.00	$ 200.00	0.0%	$ 200.00	0.0%
ROA Service - Distribution - Maximum kW	$ 3.60	$ 4.58	27.2%	$ 4.57	26.9%
ROA Service - Distribution - Rate	$ -	$ -		$ -	
ROA Service - Distribution - Provisions - Education GEI	$ (0.000314)	$ (0.000259)	-17.5%	$ (0.000230)	-26.8%

Source: Direct Testimony of Hubert W. Miller III, Workpaper "ex0220-Miller-1-3 and WP-1-25.xlsx."

Comparison of Company and Alternative Proposed Rates

Description	Company's Present Rate	Company's Proposed Rate	Increase from Present Rate	Alternative Rate	Increase from Present Rate
Primary Time-of-Use Voltage Level 1 (GPTU VL 1)					
Production:					
Production - Summer - Non-Capacity - High-peak kWh	$ 0.093060	$ 0.050387	-45.9%	$ 0.056445	-39.3%
Production - Summer - Non-Capacity - Mid-peak kWh	$ 0.081694	$ 0.043807	-46.4%	$ 0.049074	-39.9%
Production - Summer - Non-Capacity - Low-peak kWh	$ 0.065924	$ 0.034060	-48.3%	$ 0.038155	-42.1%
Production - Summer - Non-Capacity - Off-peak kWh	$ 0.049286	$ 0.024837	-49.6%	$ 0.027823	-43.5%
Production - Summer - Capacity - High-peak kWh	$ 0.025831	$ 0.053210	106.0%	$ 0.053210	106.0%
Production - Summer - Capacity - Mid-peak kWh	$ 0.022676	$ 0.050795	124.0%	$ 0.050795	124.0%
Production - Summer - Capacity - Low-peak kWh	$ 0.018299	$ 0.040795	122.9%	$ 0.040795	122.9%
Production - Summer - Capacity - Off-peak kWh	$ 0.013681	$ 0.027556	101.4%	$ 0.027556	101.4%
Production - Winter - Non-Capacity - High-peak kWh	$ 0.058501	$ 0.039569	-32.4%	$ 0.044327	-24.2%
Production - Winter - Non-Capacity - Mid-peak kWh	$ 0.056823	$ 0.037405	-34.2%	$ 0.041903	-26.3%
Production - Winter - Non-Capacity - Off-peak kWh	$ 0.049918	$ 0.034740	-30.4%	$ 0.038917	-22.0%
Production - Winter - Capacity - Mid-peak kWh	$ 0.016239	$ 0.028765	77.1%	$ 0.028765	77.1%
Production - Winter - Capacity - Low-peak kWh	$ 0.015773	$ 0.028752	82.3%	$ 0.028752	82.3%
Production - Winter - Capacity - Off-peak kWh	$ 0.013856	$ 0.024746	78.6%	$ 0.024746	78.6%
Production - Annual PSCR Factor	$ 0.004440	$ 0.004440	0.0%	$ 0.004440	0.0%
Transmission:					
Transmission - Summer - High-peak kWh	$ -	$ 0.023683		$ 0.023683	
Transmission - Summer - Mid-peak kWh	$ -	$ 0.022609		$ 0.022609	
Transmission - Summer - Low-peak kWh	$ -	$ 0.018158		$ 0.018158	
Transmission - Summer - Off-peak kWh	$ -	$ 0.012265		$ 0.012265	
Transmission - Winter - High-peak kWh	$ -	$ 0.012803		$ 0.012803	
Transmission - Winter - Mid-peak kWh	$ -	$ 0.012797		$ 0.012797	
Transmission - Winter - Off-peak kWh	$ -	$ 0.011014		$ 0.011014	
Distribution:					
Distribution - System Access	$ 200.00	$ 200.00	0.0%	$ 200.00	0.0%
Distribution - Maximum kW	$ 0.91	$ 0.70	-23.1%	$ 0.69	-24.2%
Distribution - Substation Ownership	$ (0.45)	$ (0.34)	-24.4%	$ (0.34)	-24.4%
Distribution - Rate	$ -	$ -		$ -	
Distribution - Provisions - Education GEI	$ (0.000314)	$ (0.000259)	-17.5%	$ (0.000230)	-26.8%

Source: Direct Testimony of Hubert W. Miller III, Workpaper "ex0220-Miller-1-3 and WP-1-25.xlsx."

Comparison of Company and Alternative Proposed Rates

Description	Company's Present Rate	Company's Proposed Rate	Increase from Present Rate	Alternative Rate	Increase from Present Rate
Primary Time-of-Use Voltage Level 2 (GPTU VL 2)					
Production:					
Production - Summer - Non-Capacity - High-peak kWh	$ 0.095060	$ 0.051007	-46.3%	$ 0.057139	-39.9%
Production - Summer - Non-Capacity - Mid-peak kWh	$ 0.083694	$ 0.044346	-47.0%	$ 0.049678	-40.6%
Production - Summer - Non-Capacity - Low-peak kWh	$ 0.067924	$ 0.034479	-49.2%	$ 0.038624	-43.1%
Production - Summer - Non-Capacity - Off-peak kWh	$ 0.051286	$ 0.025142	-51.0%	$ 0.028165	-45.1%
Production - Summer - Capacity - High-peak kWh	$ 0.027831	$ 0.054061	94.2%	$ 0.054061	94.2%
Production - Summer - Capacity - Mid-peak kWh	$ 0.024676	$ 0.051608	109.1%	$ 0.051608	109.1%
Production - Summer - Capacity - Low-peak kWh	$ 0.020299	$ 0.041448	104.2%	$ 0.041448	104.2%
Production - Summer - Capacity - Off-peak kWh	$ 0.015681	$ 0.027997	78.5%	$ 0.027997	78.5%
Production - Winter - Non-Capacity - High-peak kWh	$ 0.060501	$ 0.040056	-33.8%	$ 0.044872	-25.8%
Production - Winter - Non-Capacity - Mid-peak kWh	$ 0.058823	$ 0.037865	-35.6%	$ 0.042418	-27.9%
Production - Winter - Non-Capacity - Off-peak kWh	$ 0.051918	$ 0.035167	-32.3%	$ 0.039396	-24.1%
Production - Winter - Capacity - High-peak kWh	$ 0.018239	$ 0.029225	60.2%	$ 0.029225	60.2%
Production - Winter - Capacity - Mid-peak kWh	$ 0.017773	$ 0.029212	64.4%	$ 0.029212	64.4%
Production - Winter - Capacity - Off-peak kWh	$ 0.015856	$ 0.025142	58.6%	$ 0.025142	58.6%
Production - Annual PSCR Factor	$ 0.004440	$ 0.004440	0.0%	$ 0.004440	0.0%
Transmission:					
Transmission - Summer - High-peak kWh	$ -	$ 0.024062		$ 0.024062	
Transmission - Summer - Mid-peak kWh	$ -	$ 0.022971		$ 0.022971	
Transmission - Summer - Low-peak kWh	$ -	$ 0.018449		$ 0.018449	
Transmission - Summer - Off-peak kWh	$ -	$ 0.012461		$ 0.012461	
Transmission - Winter - High-peak kWh	$ -	$ 0.013008		$ 0.013008	
Transmission - Winter - Mid-peak kWh	$ -	$ 0.013002		$ 0.013002	
Transmission - Winter - Off-peak kWh	$ -	$ 0.011190		$ 0.011190	
Distribution:					
Distribution - System Access	$ 200.00	$ 200.00	0.0%	$ 200.00	0.0%
Distribution - Maximum kW	$ 1.86	$ 2.69	44.6%	$ 2.68	44.1%
Distribution - Substation Ownership	$ (0.97)	$ (0.96)	-1.0%	$ (0.96)	-1.0%
Distribution - Rate	$ -	$ -		$ -	
Distribution - Provisions - Education GEI	$ (0.000314)	$ (0.000259)	-17.5%	$ (0.000230)	-26.8%

Source: Direct Testimony of Hubert W. Miller III, Workpaper "ex0220-Miller-1-3 and WP-1-25.xlsx."

Comparison of Company and Alternative Proposed Rates

Description	Company's Present Rate	Company's Proposed Rate	Increase from Present Rate	Alternative Rate	Increase from Present Rate
Primary Time-of-Use Voltage Level 3 (GPTU VL 3)					
Production - Summer - Non-Capacity - High-peak kWh	$ 0.100060	$ 0.052009	-48.0%	$ 0.058263	-41.8%
Production - Summer - Non-Capacity - Mid-peak kWh	$ 0.088694	$ 0.045218	-49.0%	$ 0.050654	-42.9%
Production - Summer - Non-Capacity - Low-peak kWh	$ 0.072924	$ 0.035157	-51.8%	$ 0.039384	-46.0%
Production - Summer - Non-Capacity - Off-peak kWh	$ 0.056286	$ 0.025637	-54.5%	$ 0.028719	-49.0%
Production - Summer - Capacity - High-peak kWh	$ 0.032831	$ 0.055354	68.6%	$ 0.055354	68.6%
Production - Summer - Capacity - Mid-peak kWh	$ 0.029676	$ 0.052842	78.1%	$ 0.052842	78.1%
Production - Summer - Capacity - Low-peak kWh	$ 0.025299	$ 0.042439	67.7%	$ 0.042439	67.7%
Production - Summer - Capacity - Off-peak kWh	$ 0.020681	$ 0.028667	38.6%	$ 0.028667	38.6%
Production - Winter - Non-Capacity - High-peak kWh	$ 0.065501	$ 0.040843	-37.6%	$ 0.045754	-30.1%
Production - Winter - Non-Capacity - Mid-peak kWh	$ 0.063823	$ 0.038609	-39.5%	$ 0.043252	-32.2%
Production - Winter - Non-Capacity - Off-peak kWh	$ 0.056918	$ 0.035859	-37.0%	$ 0.040170	-29.4%
Production - Winter - Capacity - High-peak kWh	$ 0.023239	$ 0.029924	28.8%	$ 0.029924	28.8%
Production - Winter - Capacity - Mid-peak kWh	$ 0.022773	$ 0.029911	31.3%	$ 0.029911	31.3%
Production - Winter - Capacity - Off-peak kWh	$ 0.020856	$ 0.025743	23.4%	$ 0.025743	23.4%
Production - Annual PSCR Factor	$ 0.004440	$ 0.004440	0.0%	$ 0.004440	0.0%
Transmission:					
Transmission - Summer - High-peak kWh	$ -	$ 0.024637		$ 0.024637	
Transmission - Summer - Mid-peak kWh	$ -	$ 0.023520		$ 0.023520	
Transmission - Summer - Low-peak kWh	$ -	$ 0.018890		$ 0.018890	
Transmission - Summer - Off-peak kWh	$ -	$ 0.012759		$ 0.012759	
Transmission - Winter - High-peak kWh	$ -	$ 0.013319		$ 0.013319	
Transmission - Winter - Mid-peak kWh	$ -	$ 0.013313		$ 0.013313	
Transmission - Winter - Off-peak kWh	$ -	$ 0.011458		$ 0.011458	
Distribution:					
Distribution - System Access	$ 200.00	$ 200.00	0.0%	$ 200.00	0.0%
Distribution - Maximum kW	$ 3.60	$ 4.58	27.2%	$ 4.57	26.9%
Distribution - Rate	$ -	$ -		$ -	
Distribution - Provisions - Education GEI	$ (0.000314)	$ (0.000259)	-17.5%	$ (0.000230)	-26.8%

Source: Direct Testimony of Hubert W. Miller III, Workpaper "ex0220-Miller-1-3 and WP-1-25.xlsx."

Comparison of Company and Alternative Proposed Rates

Description	Company's Present Rate	Company's Proposed Rate	Increase from Present Rate	Alternative Rate	Increase from Present Rate
Primary Energy Intensive Level 1 (EIP VL 1)					
Production:					
Production - Summer - Non-Capacity - Critical-peak kWh	$ 0.094746	$ 0.063300	-33.2%	$ 0.112100	18.3%
Production - Summer - Non-Capacity - High-peak kWh	$ 0.063164	$ 0.042200	-33.2%	$ 0.074733	18.3%
Production - Summer - Non-Capacity - Mid-peak kWh	$ 0.058664	$ 0.037326	-36.4%	$ 0.066100	12.7%
Production - Summer - Non-Capacity - Low-peak kWh	$ 0.047172	$ 0.029767	-36.9%	$ 0.052715	11.8%
Production - Summer - Non-Capacity - Off-peak kWh	$ 0.033312	$ 0.020329	-39.0%	$ 0.036000	8.1%
Production - Summer - Capacity - Critical-peak kWh	$ 0.042915	$ 0.024182	-43.7%	$ 0.024182	-43.7%
Production - Summer - Capacity - High-peak kWh	$ 0.028610	$ 0.016121	-43.7%	$ 0.016121	-43.7%
Production - Summer - Capacity - Mid-peak kWh	$ 0.026572	$ 0.015758	-40.7%	$ 0.015758	-40.7%
Production - Summer - Capacity - Low-peak kWh	$ 0.021367	$ 0.012961	-39.3%	$ 0.012961	-39.3%
Production - Summer - Capacity - Off-peak kWh	$ 0.015089	$ 0.008294	-45.0%	$ 0.008294	-45.0%
Production - Winter - Non-Capacity - Critical-peak kWh	$ 0.090809	$ 0.050786	-44.1%	$ 0.089936	-1.0%
Production - Winter - Non-Capacity - High-peak kWh	$ 0.060539	$ 0.033857	-44.1%	$ 0.059957	-1.0%
Production - Winter - Non-Capacity - Mid-peak kWh	$ 0.047652	$ 0.032241	-32.3%	$ 0.057096	19.8%
Production - Winter - Non-Capacity - Off-peak kWh	$ 0.033492	$ 0.028535	-14.8%	$ 0.050533	50.9%
Production - Winter - Capacity - Critical-peak kWh	$ 0.041132	$ 0.012126	-70.5%	$ 0.012126	-70.5%
Production - Winter - Capacity - High-peak kWh	$ 0.027421	$ 0.008084	-70.5%	$ 0.008084	-70.5%
Production - Winter - Capacity - Mid-peak kWh	$ 0.021584	$ 0.007975	-63.1%	$ 0.007975	-63.1%
Production - Winter - Capacity - Off-peak kWh	$ 0.015170	$ 0.006989	-53.9%	$ 0.006989	-53.9%
Production - Annual PSCR Factor	$ 0.004440	$ 0.004440	0.0%	$ 0.004440	0.0%
Transmission:					
Transmission - Summer - Critical-peak kWh	$ -	$ 0.035057		$ 0.035057	
Transmission - Summer - High-peak kWh	$ -	$ 0.023371		$ 0.023371	
Transmission - Summer - Mid-peak kWh	$ -	$ 0.022845		$ 0.022845	
Transmission - Summer - Low-peak kWh	$ -	$ 0.018789		$ 0.018789	
Transmission - Summer - Off-peak kWh	$ -	$ 0.012024		$ 0.012024	
Transmission - Winter - Critical-peak kWh	$ -	$ 0.017580		$ 0.017580	
Transmission - Winter - High-peak kWh	$ -	$ 0.011720		$ 0.011720	
Transmission - Winter - Mid-peak kWh	$ -	$ 0.011562		$ 0.011562	
Transmission - Winter - Off-peak kWh	$ -	$ 0.010132		$ 0.010132	
Distribution:					
Distribution - System Access	$ 200.00	$ 200.00	0.0%	$ 200.00	0.0%
Distribution - Maximum kW	$ 0.91	$ 0.70	-23.1%	$ 0.69	-24.2%
Distribution - Substation Ownership	$ (0.45)	$ (0.34)	-24.4%	$ (0.34)	-24.4%
Distribution - Rate	$ -	$ -		$ -	

Source: Direct Testimony of Hubert W. Miller III, Workpaper "ex0220-Miller-1-3 and WP-1-25.xlsx."

Comparison of Company and Alternative Proposed Rates

Description	Company's Present Rate	Company's Proposed Rate	Increase from Present Rate	Alternative Rate	Increase from Present Rate
Primary Energy Intensive Level 2 (EIP VL 2)					
Production:					
Production - Summer - Non-Capacity - Critical-peak kWh	$ 0.099746	$ 0.064079	-35.8%	$ 0.113479	13.8%
Production - Summer - Non-Capacity - High-peak kWh	$ 0.068164	$ 0.042719	-37.3%	$ 0.075652	11.0%
Production - Summer - Non-Capacity - Mid-peak kWh	$ 0.063664	$ 0.037785	-40.6%	$ 0.066913	5.1%
Production - Summer - Non-Capacity - Low-peak kWh	$ 0.052172	$ 0.030133	-42.2%	$ 0.053363	2.3%
Production - Summer - Non-Capacity - Off-peak kWh	$ 0.038312	$ 0.020579	-46.3%	$ 0.036443	-4.9%
Production - Summer - Capacity - Critical-peak kWh	$ 0.047915	$ 0.024569	-48.7%	$ 0.024569	-48.7%
Production - Summer - Capacity - High-peak kWh	$ 0.033610	$ 0.016379	-51.3%	$ 0.016379	-51.3%
Production - Summer - Capacity - Mid-peak kWh	$ 0.031572	$ 0.016010	-49.3%	$ 0.016010	-49.3%
Production - Summer - Capacity - Low-peak kWh	$ 0.026367	$ 0.013168	-50.1%	$ 0.013168	-50.1%
Production - Summer - Capacity - Off-peak kWh	$ 0.020089	$ 0.008427	-58.1%	$ 0.008427	-58.1%
Production - Winter - Non-Capacity - Critical-peak kWh	$ 0.095809	$ 0.051411	-46.3%	$ 0.091042	-5.0%
Production - Winter - Non-Capacity - High-peak kWh	$ 0.065539	$ 0.034273	-47.7%	$ 0.060694	-7.4%
Production - Winter - Non-Capacity - Mid-peak kWh	$ 0.052652	$ 0.032638	-38.0%	$ 0.057798	9.8%
Production - Winter - Non-Capacity - Off-peak kWh	$ 0.038492	$ 0.028886	-25.0%	$ 0.051155	32.9%
Production - Winter - Capacity - Critical-peak kWh	$ 0.046132	$ 0.012320	-73.3%	$ 0.012320	-73.3%
Production - Winter - Capacity - High-peak kWh	$ 0.032421	$ 0.008213	-74.7%	$ 0.008213	-74.7%
Production - Winter - Capacity - Mid-peak kWh	$ 0.026584	$ 0.008103	-69.5%	$ 0.008103	-69.5%
Production - Winter - Capacity - Off-peak kWh	$ 0.020170	$ 0.007101	-64.8%	$ 0.007101	-64.8%
Production - Annual PSCR Factor	$ 0.004440	$ 0.004440	0.0%	$ 0.004440	0.0%
Transmission:					
Transmission - Summer - Critical-peak kWh	$ -	$ 0.035618		$ 0.035618	
Transmission - Summer - High-peak kWh	$ -	$ 0.023745		$ 0.023745	
Transmission - Summer - Mid-peak kWh	$ -	$ 0.023211		$ 0.023211	
Transmission - Summer - Low-peak kWh	$ -	$ 0.019090		$ 0.019090	
Transmission - Summer - Off-peak kWh	$ -	$ 0.012216		$ 0.012216	
Transmission - Winter - Critical-peak kWh	$ -	$ 0.017861		$ 0.017861	
Transmission - Winter - High-peak kWh	$ -	$ 0.011908		$ 0.011908	
Transmission - Winter - Mid-peak kWh	$ -	$ 0.011747		$ 0.011747	
Transmission - Winter - Off-peak kWh	$ -	$ 0.010294		$ 0.010294	
Distribution:					
Distribution - System Access	$ 200.00	$ 200.00	0.0%	$ 200.00	0.0%
Distribution - Maximum kW	$ 1.86	$ 2.69	44.6%	$ 2.68	44.1%
Distribution - Substation Ownership	$ (0.97)	$ (0.96)	-1.0%	$ (0.96)	-1.0%
Distribution - Rate	$ -	$ -		$ -	

Source: Direct Testimony of Hubert W. Miller III, Workpaper "ex0220-Miller-1-3 and WP-1-25.xlsx."

Comparison of Company and Alternative Proposed Rates

Description	Company's Present Rate	Company's Proposed Rate	Increase from Present Rate	Alternative Rate	Increase from Present Rate
Primary Energy Intensive Level 3 (EIP VL 3)					
Production:					
Production - Summer - Non-Capacity - Critical-peak kWh	$ 0.096746	$ 0.065338	-32.5%	$ 0.115710	19.6%
Production - Summer - Non-Capacity - High-peak kWh	$ 0.065164	$ 0.043559	-33.2%	$ 0.077139	18.4%
Production - Summer - Non-Capacity - Mid-peak kWh	$ 0.060664	$ 0.038528	-36.5%	$ 0.068228	12.5%
Production - Summer - Non-Capacity - Low-peak kWh	$ 0.049172	$ 0.030725	-37.5%	$ 0.054412	10.7%
Production - Summer - Non-Capacity - Off-peak kWh	$ 0.035312	$ 0.020984	-40.6%	$ 0.037159	5.2%
Production - Summer - Capacity - Critical-peak kWh	$ 0.044915	$ 0.025157	-44.0%	$ 0.025157	-44.0%
Production - Summer - Capacity - High-peak kWh	$ 0.030610	$ 0.016771	-45.2%	$ 0.016771	-45.2%
Production - Summer - Capacity - Mid-peak kWh	$ 0.028572	$ 0.016393	-42.6%	$ 0.016393	-42.6%
Production - Summer - Capacity - Low-peak kWh	$ 0.023367	$ 0.013483	-42.3%	$ 0.013483	-42.3%
Production - Summer - Capacity - Off-peak kWh	$ 0.017089	$ 0.008628	-49.5%	$ 0.008628	-49.5%
Production - Winter - Non-Capacity - Critical-peak kWh	$ 0.092809	$ 0.052421	-43.5%	$ 0.092832	0.0%
Production - Winter - Non-Capacity - High-peak kWh	$ 0.062539	$ 0.034947	-44.1%	$ 0.061888	-1.0%
Production - Winter - Non-Capacity - Mid-peak kWh	$ 0.049652	$ 0.033279	-33.0%	$ 0.058934	18.7%
Production - Winter - Non-Capacity - Off-peak kWh	$ 0.035492	$ 0.029454	-17.0%	$ 0.052160	47.0%
Production - Winter - Capacity - Critical-peak kWh	$ 0.043132	$ 0.012615	-70.8%	$ 0.012615	-70.8%
Production - Winter - Capacity - High-peak kWh	$ 0.029421	$ 0.008410	-71.4%	$ 0.008410	-71.4%
Production - Winter - Capacity - Mid-peak kWh	$ 0.023584	$ 0.008296	-64.8%	$ 0.008296	-64.8%
Production - Winter - Capacity - Off-peak kWh	$ 0.017170	$ 0.007271	-57.7%	$ 0.007271	-57.7%
Production - Annual PSCR Factor	$ 0.004440	$ 0.004440	0.0%	$ 0.004440	0.0%
Transmission:					
Transmission - Summer - Critical-peak kWh	$ -	$ 0.036470		$ 0.036470	
Transmission - Summer - High-peak kWh	$ -	$ 0.024313		$ 0.024313	
Transmission - Summer - Mid-peak kWh	$ -	$ 0.023766		$ 0.023766	
Transmission - Summer - Low-peak kWh	$ -	$ 0.019546		$ 0.019546	
Transmission - Summer - Off-peak kWh	$ -	$ 0.012509		$ 0.012509	
Transmission - Winter - Critical-peak kWh	$ -	$ 0.018288		$ 0.018288	
Transmission - Winter - High-peak kWh	$ -	$ 0.012192		$ 0.012192	
Transmission - Winter - Mid-peak kWh	$ -	$ 0.012028		$ 0.012028	
Transmission - Winter - Off-peak kWh	$ -	$ 0.010540		$ 0.010540	
Distribution:					
Distribution - System Access	$ 200.00	$ 200.00	0.0%	$ 200.00	0.0%
Distribution - Maximum kW	$ 3.60	$ 4.58	27.2%	$ 4.57	26.9%
Distribution - Rate	$ -	$ -		$ -	

Source: Direct Testimony of Hubert W. Miller III, Workpaper "ex0220-Miller-1-3 and WP-1-25.xlsx."

Analysis of Current Customer Charge to Customer-related Costs

	Total Residential Service	Secondary: Energy-only ("GS")	Secondary: Demand ("GSD")	Primary: Energy-only Voltage Levels 1-3 ("GP VL 1"; "GP VL 2"; "GP VL 3")	Primary: Demand Voltage Levels 1-3 ("GPD VL 1"; "GPD VL 2"; "GPD VL 3")	Primary: Primary Time-of-Use Voltage Levels 1-3 ("GPTU VL 1"; "GPTU VL 2"; "GPTU VL 3")	Primary: Energy Intensive Levels 1-3 ("EIP VL 1"; "EIP VL 2"; "EIP VL 3")
Customer Related Costs per Company's CCOSS:							
Total Customer-Related Costs	$ 191,729,402	$ 40,712,726	$ 6,318,537	$ 2,666,615	$ 5,083,168	$ 3,392,031	$ 227,625
Average Number of Customers	1,620,698	195,747	19,907	1,598	1,059	1,032	19
Monthly Customer-Related Costs/Customer	$ 9.86	$ 17.33	$ 26.45	$ 139.06	$ 400.00	$ 273.90	$ 998.36
Customer Charge Revenue at Current Rates	$ 145,862,820	$ 46,979,280	$ 7,166,520	$ 1,917,600	$ 2,541,600	$ 2,476,800	$ 45,600
Monthly Customer Charge Revenue/Customer	$ 7.50	$ 20.00	$ 30.00	$ 100.00	$ 200.00	$ 200.00	$ 200.00
Relationship of Customer Charge Revenues to Customer-Related Costs	**76.1%**	**115.4%**	**113.4%**	**71.9%**	**50.0%**	**73.0%**	**20.0%**

Source: Direct Testimony of Josnelly C. Aponte, Schedule F-1.1; and Direct Testimony of Hubert W. Miller III, Schedule F-3.0.

PROOF OF SERVICE - U-20697

The undersigned certifies that a copy of the ***Qualifications and Direct Testimony of David E. Dismukes, Ph.D.*** that was filed on behalf of the Attorney General was served upon the parties listed below by emailing the same to them at their respective e-mail addresses on the 24th day of June 2020.

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Digitally signed by Celeste R. Gill
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