STATE OF INDIANA

INDIANA UTILITY REGULATORY COMMISSION

VERIFIED PETITION OF SOUTHERN INDIANA GAS AND ELECTRIC COMPANY D/B/A CENTERPOINT ENERGY INDIANA SOUTH ("CEI SOUTH") FOR (1) AUTHORITY TO MODIFY ITS RATES AND CHARGES FOR ELECTRIC UTILITY SERVICE THROUGH A PHASE-IN OF RATES, (2) APPROVAL OF NEW SCHEDULES OF RATES AND CHARGES, AND NEW AND REVISED RIDERS, INCLUDING BUT NOT LIMITED TO A NEW TAX ADJUSTMENT RIDER AND A NEW GREEN POWER RIDER (3) APPROVAL OF A CRITICAL PEAK PRICING ("CPP") PILOT PROGRAM, (4) APPROVAL OF REVISED DEPRECIATION RATES APPLICABLE TO ELECTRIC AND COMMON PLANT IN SERVICE, (5) APPROVAL OF NECESSARY AND APPROPRIATE ACCOUNTING RELIEF, INCLUDING AUTHORITY TO CAPITALIZE AS RATE BASE ALL CLOUD COMPUTING COSTS AND DEFER TO A REGULATORY ASSET AMOUNTS NOT ALREADY INCLUDED IN BASE RATES THAT ARE INCURRED FOR THIRD-PARTY CLOUD COMPUTING ARRANGEMENTS, AND (6) APPROVAL OF AN ALTERNATIVE REGULATORY PLAN GRANTING CEI SOUTH A WAIVER FROM 170 IAC 4-1-16(f) TO ALLOW FOR REMOTE DISCONNECTION FOR NON-PAYMENT	)	**CAUSE NO. 45990**

INDIANA OFFICE OF UTILITY CONSUMER COUNSELOR

REDACTED PUBLIC'S EXHIBIT NO. 12

PUBLIC TESTIMONY OF OUCC WITNESS DR. DAVID E. DISMUKES

MARCH 12, 2024

Respectfully submitted,

T. Jason Haas
Deputy Consumer Counselor
Attorney No. 34983-29

STATE OF INDIANA

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EXHIBIT LIST

I. <u>INTRODUCTION</u>

Q. 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. PLEASE STATE YOUR OCCUPATION AND CURRENT PLACE OF EMPLOYMENT.

A. I am a consulting economist with the Acadian Consulting Group ("ACG").

Q. PLEASE DESCRIBE ACG AND ITS AREAS OF EXPERTISE.

A. ACG is 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 located in Baton Rouge, Louisiana.

Q. DO YOU HOLD ANY ACADEMIC POSITIONS?

A. Yes. I am a professor emeritus at Louisiana State University ("LSU"). Prior to my retirement in January 2023, I served as a full professor, executive director, and director of policy analysis at the LSU Center for Energy Studies and as a full tenured professor in the Department of Environmental Sciences and the director of the Coastal Marine Institute in the LSU College of the Coast and Environment. I also serve as a senior fellow at the Institute of Public Utilities at Michigan State University, where I have taught energy regulatory staff and other utility stakeholders about principles, trends, and issues in the electric and natural gas industries. I also currently serve as a Distinguished Fellow and Senior Economist with the Institute for Energy Research in Washington, D.C.

Q. HAVE YOU PREVIOUSLY TESTIFIED BEFORE THE INDIANA UTILITY REGULATORY COMMISSION?

A. Yes. My academic vitae is attached as Appendix A. It includes a list of the Indiana Utility Regulatory Commission ("Commission" or "IURC") proceedings in which I have testified, a list of all my publications, presentations, pre-filed expert witness testimony in other jurisdictions, expert reports, expert legislative testimony, and affidavits.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. I have been retained by the Indiana Office of Utility Consumer Counselor ("OUCC") to address certain regulatory and policy issues related to the general rate case filed by Southern Indiana Gas and Electric Company D/B/A CenterPoint Energy Indiana South ("CEI South" or "the Company"). I specifically have been asked to address the Company's proposed allocated cost of service study ("ACOSS"), revenue distribution, and rate design.

Q. HOW IS THE REMAINDER OF YOUR TESTIMONY ORGANIZED?

A. The balance of my testimony is organized into the following sections:

- Section II: Summary of Recommendations
- Section III: Proposed Rate Increase
- Section IV: Allocated Cost of Service Study
- Section V: Revenue Distribution
- Section VI: Rate Design
- Section VII: Proposed TOU-CPP Pilot
- Section VII: Conclusion and Recommendations

II. SUMMARY OF RECOMMENDATIONS

Q. PLEASE SUMMARIZE YOUR FINDINGS REGARDING ENERGY AFFORDABILITY IN THE COMPANY'S SERVICE TERRITORY.

A. The Company's utility rates continue to place significant burdens on low- and moderate-income customers. I recommend the Commission consider energy affordability in evaluating how revenue responsibilities are determined across customer classes as well as establishing customer service charges that can be regressive in nature and harm lower/middle income and lower usage customers.

Q. PLEASE SUMMARIZE YOUR ACOSS RECOMMENDATIONS.

A. I recommend the Commission not accept the Company's ACOSS for ratemaking purposes. The Company's ACOSS incorrectly classifies fixed costs associated with production plant assets as exclusively demand-related. The Company's methods are inconsistent with how these production/generation assets are used in serving the Company's system needs with the capacity accreditation of the Company's renewable generation facilities, and deviates from commonly accepted cost allocation practices that recognize the dual role production facilities serve. The Company's ACOSS results are also flawed because they rely on the results of a minimum system study ("MSS") to classify part of CEI South's distribution investments as being customer related. The effect of these two errors in the Company's ACOSS is that it favors large customers with relatively higher load factors over residential and small commercial customers with relatively lower load factors.

Q. WHAT IS YOUR RECOMMENDATION REGARDING THE COMPANY'S PROPOSED REVENUE DISTRIBUTION?

A. I recommend the Commission adopt a revenue distribution allocation method based on my alternative ACOSS results. I also recommend, consistent with the policy goals of rate gradualism, the Commission limit rate increases to any single rate class to no more than 1.15 times the overall system average increase. My proposed revenue distribution methodology reduces the maximum total base revenue increase of any single rate class to 18.42 percent, compared to the Company's proposed maximum rate increase of 24.03 percent.

Q. WHAT ARE YOUR CUSTOMER CHARGE RECOMMENDATIONS?

A. I recommend the Commission reject the Company's proposed customer charge increases. The proposed increases are not needed and will detrimentally impact the public policy goals of promoting energy efficiency. Likewise, such proposals will burden low-use and low-income customers with a greater portion of the rate increase than the system average percent rate increase.

Q. WHAT IS YOUR RECOMMENDATION REGARDING THE COMPANY'S PROPOSED TIME-OF-USE CRITICAL PEAK PRICING PILOT?

A. I recommend the Commission not approve the proposed time-of-use ("TOU") critical peak pricing ("CPP" collectively, "TOU-CPP") Pilot. The proposal is incomplete and lacks clearly defined goals, objectives, and how the proposal's performance will be evaluated. More importantly, the TOU-CPP proposal lacks critical consumer protection provisions including limitations on the Company's ability to call future CPP events and adequate assurance that residential service

Rate RS-CPP as proposed will be revenue neutral. Finally, the proposed Rate RS-CPP includes significantly high on-peak and CPP rates for relatively long, extended time durations that could potentially lead to rate shock and other financial burdens for participating ratepayers.

III. PROPOSED RATE INCREASE

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

A. The Company is requesting an increase in its retail electric rates by approximately $118.8 million over a three-phase rate implementation.[1] If approved, the Company's proposal will result in a total system average increase in rates of 16.02 percent.[2] This includes a $65.5 million, or 20.17 percent, increase in residential service customers' ("Rate RS") rates and increases to general service classes ranging from 9.04 percent for high load factor service ("Rate HLF") customers to 16.49 percent for large power service ("Rate LP") customers.[3]

Q. WHAT IS THE BASIS FOR THE COMPANY'S REQUESTED RATE INCREASE?

A. The Company stated it was required under Indiana law to file a general rate case before the end of its current electric transmission, distribution, and storage system improvement charge ("TDSIC") plan approved by the Commission in Cause No. 44910.[4] This TDSIC plan expired December 31, 2023, shortly after the Company's filing in the current proceeding.[5] However, even absent its statutory obligation, the Company implies it would likely have filed the current rate increase request given

[1] Petition at ¶18.
[2] *Id.*
[3] Direct Testimony of John D. Taylor at 22, Table JDT-4.
[4] Direct Testimony of Richard C. Leger at 9:13-15.
[5] *Id.*

recent investment (rate base) increases. The Company states its rate base has grown from $1.296 million to $1.733 million since its last rate case 14 years ago and is projected to grow an additional $1.087 million through the end of the test year.[6] CEI South claims these increases are necessary and consistent with the same industry transformation impacting its peers, transitioning its generation fleet from aging coal-fired generation units through early retirement to new natural gas and renewable powered generation units.[7]

Q. HAVE COMPANY CUSTOMERS SEEN INCREASES IN RATES SINCE THE COMPANY'S LAST RATE CASE FILING 14 YEARS AGO?

A. Yes. Even though the Company has not filed a rate case since 2009, CEI South's customers have experienced annual rate increases through tracker mechanisms. Most notable among these is the Company's TDSIC mechanism.

Q. HAVE YOU CONDUCTED AN ANALYSIS OF THE COMPANY'S RETAIL RATES RELATIVE TO PEER ELECTRIC UTILITIES?

A. Yes. Exhibit DED-1 examines the Company's historic retail rates relative to other regional public electric utilities. My analysis shows CEI South has some of the highest rates in the region, especially for residential ratepayers, and that the affordability of the Company's rates relative to other regional peer utilities has not been improving over time.

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 FERC. I examined specific

[6] *Id.,* at 9:15-25.
[7] *Id.,* at 9:27 to 10:3.

investment and expense trends by major account as defined by the FERC Uniform System of Accounts ("USOA"). Average revenues (retail revenues divided by sales in megawatt-hour or "MWh" 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 11 vertically integrated investor-owned utilities operating within Indiana, Michigan, or Kentucky.

Q. WHAT DOES YOUR RESIDENTIAL RATE COMPARISON SHOW?

A. Exhibit DED-1 shows that the Company's residential rates (average non-fuel revenues) have consistently been above the reported averages for the regional peer utilities. CEI South's ten-year average residential rate of $0.116/kWh is higher than the peer group's average residential rate of $0.086/kWh and among the highest in the region, exceeded in 2022 by only DTE Electric Company ("DTE") and Northern Indiana Public Service Company ("NIPSCO").

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

A. Yes. Exhibit DED-1 also compares the Company's estimated commercial base rates (average non-fuel revenues) to the regional peer utilities. This analysis shows the Company's commercial rates are also higher than those of regional peers. The Company's estimated commercial rates have averaged $0.057/kWh over the past decade, compared to a peer average of $0.050/kWh over the same comparable period.

Q. ARE YOUR RESULTS CONSISTENT WITH OTHER PUBLISHED FINDINGS REGARDING THE COMPANY'S RATES RELATIVE TO OTHER REGIONAL UTILITIES?

A. Yes. The Commission recently released a July 1, 2023, survey of residential customer rates for regulated Indiana electric utilities. This analysis reflects that, regardless of usage amount, the Company's residential rates were higher than all other Indiana regulated utilities.[8] This includes both investor-owned and municipal utilities. The Commission should recognize the potential impact on energy affordability caused by CEI South's consistently high rates.

Q. HOW DO YOU DEFINE ENERGY AFFORDABILITY?

A. Energy affordability defines how expensive energy is relative to household income. Affordability, more generally, can be utilized as an index number to measure, among other things, the ability of a specific type of household to pay for essential utility services such as water, electric, and/or natural gas.

Q. ARE THERE ANY THRESHOLDS AT WHICH ENERGY SIMPLY BECOMES "UNAFFORDABLE" OR "BURDENSOME?"

A. Yes. The most accepted and utilized threshold at which utilities, and thus energy, becomes unaffordable or burdensome is when the percentage of income spent on energy exceeds six percent.[9] This threshold comes from the Fisher, Sheehan, and Colton's Home Energy Affordability Gap Study from 2011. The threshold is based on the premise that total shelter costs (including rent/mortgage and all utilities) should not exceed 30 percent of income and that 20 percent of shelter

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[8] 2023 Residential Bill Survey, Indiana Utility Regulatory Commission.
[9] *See,* "Understanding Energy Affordability" ACEEE, 2015, page 2.

costs should be allocated to energy bills. Thus, 20 percent of 30 percent yields a six percent affordable utility burden.[10] Utility burdens below six percent are classified as "affordable," and energy burdens above six percent are classified as "unaffordable."

Q. HOW DOES ACADEMIC LITERATURE EXAMINE UTILITY AFFORDABILITY?

A. The academic literature examines energy affordability through various metrics but predominantly through utility and energy burden rates. Utility burden rates measure the impact of a utility bill on household income. The American Council for an Energy Efficient Economy (ACEEE)'s *Understanding Energy Affordability* Report best encapsulates what academicians have studied. ACEEE's report determines four drivers of high energy burdens: (1) physical (i.e. housing age and type, poor insulation, weather extremes); (2) economic (i.e. chronic or sudden economic hardship); (3) behavioral (lack of access to information for bill payment assistance); and (4) policy (insufficient programs for bill assistance, high fixed customer charges).[11] It also examines utility burden rates throughout the United States, classifying any total utility burden above six percent as a household that experiences a high energy burden.[12]

Q HOW IS THE CONCEPT OF ENERGY AFFORDABILITY RECOGNIZED IN REGULATION AND PUBLIC POLICY?

A. Energy affordability is increasingly becoming an important regulatory policy consideration with various states and local governments now setting energy

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[10] Fisher, Sheehan, and Colton. "Home Energy Affordability in New York: The Affordability Gap 2008-2010", June 2011, page 2.
[11] "Understanding Energy Affordability" ACEEE, 2015, page 2.
[12] *Id.*, at page 3.

affordability targets. Recently, New York set a state-wide goal of achieving a six percent energy burden.[13] The City of Portland, Oregon, released a Ten-Year Plan to Reduce Energy Burden in Oregon Affordable Housing.[14] The California Public Utilities Commission ("CPUC") developed the state's first energy affordability metric that tracks affordability for essential services (electric, gas, water, and communications).[15] The Pennsylvania Public Utility Commission ("PPUC") examined home energy burdens for low-income Pennsylvanians in its Home Energy Affordability 2019 report[16] and subsequently issued a policy statement on March 21, 2020, establishing maximum energy burdens for customers.[17] These examples demonstrate that examining energy affordability has become paramount in utility regulation across the country.

Q. HAVE YOU ESTIMATED ENERGY AFFORDABILITY USING CEI SOUTH'S RESIDENTIAL RATES?

A. Yes. Exhibit DED-2 presents residential Energy Affordability Index estimates at both the 15th and 20th income percentiles. This analysis finds that both indexes have increased since 2021 to greater than six percent, indicating a significant level of energy burden for both income brackets. The analysis furthermore finds that customers in the bottom 15 percentile of regional incomes have seen energy burdens in excess of six percent of non-housing income since at least 2015.

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[13] "Understanding and Alleviating Energy Cost Burden in New York City," (August 2019) NYC Mayor's Office of Sustainability and the Mayor's Office for Economic Opportunity, at p. 2.
[14] "Reducing the Energy Burden in Oregon Affordable Housing – Ten-year Plan," (2018), Built Environment Energy Working Group.
[15] California Public Utilities Commission Order 18-07-006, 2018.
[16] Exhibit OPC (A)-24, Home Energy Affordability for Low-Income Customers in Pennsylvania, (January 2019) Pennsylvania Public Utility Commission.
[17] 52 PA. Code Ch. 69.

Q. WHAT DO THESE FINDINGS MEAN FOR CEI SOUTH'S RATE DESIGN PROPOSALS?

A I recommend the Commission consider these energy affordability findings in evaluating how revenue responsibilities are determined across customer classes as well as in establishing customer service charges that can be regressive in nature and harm lower income/lower usage customers. These energy affordability findings support my recommendations, which I will discuss in greater detail later in my testimony.

IV. <u>ALLOCATED COST OF SERVICE STUDY</u>

A. Introduction

Q. WHAT IS THE PURPOSE OF AN ALLOCATED COST OF SERVICE STUDY?

A. A class cost of service study or allocated cost of service study ("ACOSS") reconciles utility costs and revenues across different customer classes. The goal of an ACOSS is to evaluate the cost of providing service and the revenue responsibility for each individual customer class. ACOSS results are used to estimate class specific rates of return and can serve as a guidepost for class revenue responsibilities and ultimately rates.

Q. HOW IS AN ACOSS PREPARED?

A. An ACOSS 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. PLEASE EXPLAIN DEMAND-RELATED COSTS.

A. Demand-related costs are associated with meeting maximum electricity demands. At the distribution level, electric substations and line transformers are designed, in part, to meet the maximum customer demand requirements. The most common demand allocation factors used in an ACOSS are those related to system coincident peaks ("CP") or non-coincident peaks ("NCP"). At the production level, most power plants, also referred to as production plants, or electric generation units ("EGU"), are typically viewed as being designed to serve both the utility's energy and demand/capacity needs. The exact degree of this split between energy and demand depends on the individual EGU in question and how that unit is dispatched with baseload units serving more of the utility's energy needs and peaking units serving more of the utility's capacity or demand needs. Therefore, it is not uncommon to develop composite energy and demand allocators to allocate plant-in-service costs associated with a utility's generation fleet.

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., kilowatt-hour ("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 an ACOSS 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 AN ACOSS RELATE TO COMMONLY QUOTED ECONOMIC PRINCIPLES?

A. An ACOSS is 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 ACOSS is to develop cost responsibility estimates for each customer class, which in turn, can be used to develop rates. An ACOSS is based upon a set of historic utility book costs that have accumulated over decades. Rates are, therefore, based upon historic average costs, while economic theory suggests 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 the presence of joint and common costs, difficult.

Q. ARE THERE ANY OTHER CONFOUNDING PROBLEMS THAT CAN ARISE WITH AN ACOSS?

A. Yes. The problems listed above are confounded by the fact that the cost information utilized in an ACOSS is 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 an ACOSS. It is often up to regulators to exercise an appropriate level of judgment regarding the nature of these costs, the results of the ACOSS, and the implications both have in setting fair, just, and reasonable rates. This is one of the reasons why many regulators use ACOSS results as a "guide" in setting rates and are not unnecessarily bound by their results.

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

A. The ACOSS process is significantly different than the revenue requirement or cost of capital phase of a typical rate case. While the latter two processes focus on determining how much revenue will be recovered through rates, the ACOSS process determines how those costs (revenue requirements) will be recovered through customer rates. The primary controversy with the evaluation of various ACOSS 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, and less costs to larger high load factor customer classes and off-peak 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.

Q. PLEASE EXPLAIN THE BIASES IN METHODOLOGIES THAT ARE SKEWED TOWARD PEAK CONSIDERATIONS.

A. Residential and small commercial customer electricity loads are typically weather sensitive. Larger industrial customers, on the other hand, use electricity in processes that are generally not weather sensitive and tend not to cycle up and down, but rather run on a more continuous basis. Because of this, daily and annual usage patterns for these two customer classes are significantly different. The peak loads for residential and small commercial customers tend to be more "peaked" than those for industrial customers, which are steadier and more evenly distributed across peak and non-peak hours. For example, an average residential customer may have relatively little electricity use during overnight hours and during weekday day-time working hours. Residential customers do exhibit relatively significant use during early summer evening hours corresponding to returning home from work, and potentially during chilly early winter morning hours if the customer uses electric resistance heating. Similarly, small commercial customers see limited electricity use outside of workday hours. Thus, residential and small commercial customers tend to have relatively lower load factors than large industrial customers.

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

A. A load factor is defined as the ratio of the average load in kilowatt hours 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 taking the energy used during a period and dividing it by the product of the maximum demand 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. DOES A HIGH LOAD FACTOR INDICATE GREATER SYSTEM EFFICIENCY?

A. Yes, since a higher system load factor can be indicative of, or lead to better system resource utilization, other things being equal. However, it should be recognized that all utilities inherently have customers with different load profiles due to differences in how customers use electricity. Furthermore, the development of integrated wholesale bulk electricity transmission systems has allowed utilities to collectively diversify generation resources and individual system demands, which has reduced the impact of individual system load characteristics on generation needs in recent years. While rates should recognize and promote the efficient utilization of utility system resources, one should use caution in placing too much emphasis on this principle of rewarding high load factor industrial customers to the detriment of low load factor residential and small commercial customers.

Q. WHAT IMPACT DOES COST ALLOCATION HAVE ON REVENUE RECOVERY?

A. Higher use customers, such as industrial customers, are inherently more price sensitive than lower use customers due to the relative impact increases in rates can have on these customers' total utility bills and the margins of produced goods. These higher use industrial customers tend to have more energy supply alternatives that can include fuel switching and self-generation, which is part of the reason why they are more price sensitive. These considerations can result in differences in revenue generation given the differences in the price elasticities of demand (i.e., price sensitivities) for the two sets of customers (residential, industrial).

Q. EXPLAIN HOW SOME ACOSS METHODS CAN BE BIASED AGAINST LOWER LOAD-FACTOR CUSTOMERS.

A. Utilities by their nature are capital intensive industries with high levels of capital expenditures required to develop systems to generate and transmit power to customers. Therefore, deciding the appropriate allocation of costs associated with utility capital investments (e.g., utility "plant in service") largely affects the cost of providing service. Utilities can often over-emphasize peak demand factors in allocating these large plant costs in order to assign more costs away from their price sensitive customers. Likewise, utilities can emphasize non-diversified single CP demands, NCP demands, and individual customer demands in allocating costs associated with transmission and distribution plant facilities to favor high-load factor customers relative to low-load factor customers. Finally, utilities can over-emphasize customer connection aspects of lower voltage distribution facilities to favor high-use customers relative to low-use customers.

B. Overview of Company's ACOSS

Q. PLEASE DESCRIBE CEI SOUTH'S ACOSS APPROACH.

A. The Company utilizes the traditional three-step ACOSS approach. First, the Company functionalizes its costs into ten separate functions: production; transmission; substation; primary distribution; secondary distribution; transformation; onsite and metering; lighting; customer service; and fuel expenses.[18] Second, the Company classifies these functionalized costs as customer costs, demand costs, or energy costs.[19] Finally, the Company defines a series of individual allocators to allocate these functionalized and classified costs to individual rate classes.[20]

Q. PLEASE DESCRIBE HOW THE COMPANY CLASSIFIES ITS PRODUCTION PLANT COSTS.

A. The Company classifies all fixed costs associated with production plant assets as 100 percent demand related. The Company then utilizes the average class contribution to coincident system peak during four summer months, June through

[18] Direct Testimony of John D. Taylor at 5:18-8-11.
[19] *Id.* at 5:18-20.
[20] *Id.* at 7:4-5.

September ("4CP"), of the historic base period to allocate these costs to various rate classes.[21] The Company notes it examined system monthly peak load data for the years 2010-2022 and found that its system peak loads failed all three tests used by the Federal Energy Regulatory Commission ("FERC") in five of the last six years (i.e. 2017-2022).[22] The Company concluded from this finding that a 4CP peak demand measure was thus more appropriate than examining average contributions to each monthly coincident peak (i.e., "12CP").[23]

Q. PLEASE DESCRIBE THE COMPANY'S COST ALLOCATION METHODOLOGY FOR TRANSMISSION DEMAND-RELATED COSTS.

A. The Company classifies all fixed costs associated with transmission plant assets as 100 percent demand-related. However, the Company allocates these costs based on 12CP.[24] The Company explains that its 12CP demand allocation method for demand-related transmission costs is based on the principle that the utility installs facilities to maintain a reasonably constant level of reliability throughout the year.[25] The Company specifically notes that it designs its transmission system to be operated under contingencies without significant disruption and that greater renewable generation integrated onto the grid has begun to increase challenges associated with transmission system operations during periods of high renewable production and lower load requirements occurring in spring and fall periods.[26]

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[21] *Id.* at 11:15-17.
[22] *Id.* at 12:7-8.
[23] *Id.* at 12:8-10.
[24] *Id.* at 11:17-19.
[25] *Id.* at 12.
[26] *Id.* at 13.

Q. PLEASE EXPLAIN HOW THE COMPANY CLASSIFIES ITS DISTRIBUTION PLANT INVESTMENTS.

A. The Company argues that all distribution costs should be classified as either customer- or demand-related, or a combination of these two factors.[27] The Company initially stated that it utilized a Minimum System Study ("MSS") to define a portion of its transformers (FERC Account 368) as partially customer-related, while classifying all other non-customer-related distribution as fully demand-related.[28] However, in response to discovery the Company corrected its CCOSS, noting that its initial filing was in error and failed to correctly utilize the results of its MSS.[29]

Q. HAVE YOU EXAMINED THE COMPANY'S ACOSS RESULTS?

A. Yes. Exhibit DED-3 presents the results of the Company's ACOSS, which estimates an overall test year rate of return ("ROR") at current rates of 3.56 percent. Estimated individual class returns range from negative 3.72 percent for the residential water heating service ("Rate B") class to 14.92 percent for the outdoor lighting ("Rate OL") class. The residential service ("Rate RS") rate class is estimated by the Company to have achieved an ROR of 2.99 percent during the test year under current rates, which is 0.84 of the system average on a relative rate of return ("RORR") basis.

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

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[27] *Id.* at 6:18-20.
[28] *Id.* at 6:28 to 7:2.
[29] Company's Response to Data Request OUCC 4.26.

A. Yes. I disagree with the Company's classification of fixed production costs as exclusively demand-related. I also disagree with the Company's reliance on the results of its MSS to classify line transformer distribution plant assets as being partially customer-related. I will discuss each of these disagreements in greater detail in the following sections of my testimony.

C. Classification of Production Plant

Q. PLEASE DESCRIBE HOW THE COMPANY CLASSIFIES AND ALLOCATES PRODUCTION PLANT COSTS.

A. The Company classifies all of its fixed production plant costs as being entirely demand-related, and allocates such costs to classes based on each classes' contribution to test year 4CP demand.[30]

Q. PLEASE EXPLAIN THE CONCERNS YOU HAVE WITH THE COMPANY'S PRODUCTION PLANT CLASSIFICATION.

A. I disagree with the Company's classification of production plant assets since it assumes that the only purpose of these assets is to support maximum system demands. Such an assumption is inconsistent with the dual role these production/generation assets play in serving both peak demand and low cost energy requirements for off-peak periods on the Company's system. Equally important is the fact that the Company's proposed classification ignores the significant portion of its current production plant in service that is associated with renewable generation assets, which provide very limited capacity benefits and should not be exclusively classified as demand related.

[30] *Id.* at 11:15-17.

Q. HOW DOES THE COMPANY'S PROPOSED PRODUCTION PLANT CLASSIFICATION DIFFER FROM HOW THESE ASSETS ARE USED IN PRACTICE?

A. Electric generation units ("EGUs") are typically viewed as serving both energy and demand/capacity needs of a utility. The exact degree of this demand/energy split, however, varies by individual utility depending on its composition of generation plants and the role each generating plant plays in system dispatch. Historically, "baseload" generation units were used to serve steady, consistent, multi-hour energy loads, whereas natural gas turbines and other "peakers" were used as demand changed in any given day. It is not uncommon, therefore, to develop composite energy and demand allocators that represent this mixed use and classification.

Q. HAVE OTHER REGULATORY AGENCIES RECOGNIZED THIS JOINT ENERGY AND DEMAND ROLE FOR PRODUCTION PLANT ASSETS?

A. Yes. The Michigan Public Service Commission ("MPSC") has recognized that energy loads are an important contributing factor of production plant costs and has classified a portion of these production costs as energy-related.[31] In a 2015 review of cost of service allocations for DTE Electric Company ("DTE Electric"), the MPSC explained that a utility does not design generation to meet the needs of its various customer types for only a few hours of the year, but rather utilizes a variety of

[31] *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. 17689, Opinion and Order, dated June 15. 2015.

generators to both provide sufficient capacity and provide low-cost energy to customers.

> The Commission agrees with the Staff, the Attorney General, Energy Michigan, and [Environmental and Consumer Advocates] that DTE Electric's production system was not designed and built solely for the purpose of providing capacity for four hours a year. Indeed, if that were the case, DTE Electric's generation asset portfolio would be very different and would certainly include far fewer of the large base load units that comprise much of the company's current fleet. Instead of building a system to simply meet demand, the company developed its production plant to both deliver energy and provide capacity at the lowest <u>overall</u> cost to <u>all</u> customers who use the system. Thus, DTE Electric's generating system includes a mix of base load plants that were significant investments, but that provide abundant, reliable, and low-cost energy to all customers, and peaking plants, with low fixed production costs and typically higher fuel costs than the base load units. These peaking plants are the units that are used to meet peak demand in the summer months.[32]

Q. CAN YOU PROVIDE SOME EXAMPLES OF COMMONLY-USED CLASSIFICATION METHODS THAT REFLECT THE DIVERSITY OF PRODUCTION PLANT USE?

A. Yes. Examples of these composite energy and demand allocators include the Average and Peak ("A&P") cost allocation methodology, also called the Peak and Average cost allocation methodology, and the Average and Excess ("A&E") cost allocation methodology.

Q. EXPLAIN HOW THE A&P METHOD CLASSIFIES PRODUCTION PLANT COSTS.

[32] *Id.*

A. The A&P method is a subset of the larger category of production plant cost allocation methods categorized by the NARUC Electric Utility Cost Allocation Manual as "Judgmental Energy Weightings."[33] The A&P method has two components. The first component, referred to as the "average" component, represents each customer class's average hourly energy consumption throughout the test year, and is calculated by simply dividing annual energy consumption for each customer class by 8,760, the number of hours in a year. The second component, referred to as the "peak" component, represents each class's contribution to system peak demand. Judgment is used to determine the appropriate weighting of each of these two components,[34] though one empirical way in which these weightings can be derived is based on a utility's system load factor. In this way 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., one minus the system load factor).

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

A. Yes. Exhibit DED-4 shows the Company's system load factor for 2022 using the 4 CP measure of peak demand. My analysis shows that the Company's system load factor is 47.2 percent when using a 4 CP measure of peak demand.

Q. ARE THE RESULTS OF YOUR ANALYSIS TIME SPECIFIC?

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[33] Electric Utility Cost Allocation Manual (January 1992), National Association of Regulatory Utility Commissioners ("NARUC"), pp. 57-59.

[34] *Id.* at p. 57.

A. No. Exhibit DED-4 shows the historic trends in the Company's system load factors for a five-year period 2018 through 2022, which tend to be relatively stable, between 47.2 and 50.1 percent.

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

A. The results of the analysis presented in Exhibit DED-4 suggest the current 4 CP classification of demand-related production costs is too heavily weighted towards demand considerations relative to energy when compared to the Company's actual reported data.

Q. ARE THERE WAYS TO EMPIRICALLY ASSESS THE FUNCTION INDIVIDUAL GENERATION UNITS PROVIDE TO A UTILITY'S ELECTRICAL SYSTEM?

A. Yes. The most basic method is an examination of individual units' "capacity factor." The capacity factor is a measure of a generation plant's utilization. Units with a high capacity factor are said to be operating at high utilization (like a baseload generation plant), whereas a low capacity factor unit is typically one held in reserve to meet peak loads that are typically stimulated by weather.

Q. HAVE YOU ANALYZED THE COMPANY'S GENERATOR-SPECIFIC CAPACITY FACTORS?

A. Yes. Exhibit DED-5 presents the result of an analysis associated with each of the Company's non-renewable EGUs, and each unit's capacity factor during the test year to characterize the role the unit serves in the Company's dispatch of electricity. All facilities with annual capacity factors less than 15 percent were assumed to be fully classified as serving the utility's demand requirements, while most other facilities were divided between energy and demand classifications. This means that the Company's A.B. Brown Station, which had a 63.62 percent capacity factor during 2022, was classified as 63.12 percent energy-related and 36.88 percent demand-related.

Q. WHAT ARE THE RESULTS OF YOUR ANALYSIS OF THE RELATIVE CLASSIFICATION OF INDIVIDUAL COMPANY GENERATION UNITS?

A. Exhibit DED-5 finds that a substantial portion of the Company's 2022 non-renewable gross plant in service was devoted to the provision of energy and not directly associated with meeting the Company's demand-needs. Specifically, I find that 47.32 percent of the Company's 2022 non-renewable gross plant in service is appropriately classified as being energy-related, and 52.68 percent appropriately classified as being demand-related. The Company's methodology, however, would classify 100 percent of this gross generation plant in service as necessary to meet its peak demand requirements, regardless of how those units are typically utilized.

Q. ARE THERE OTHER WAYS TO ANALYZE GENERATION FUNCTIONS?

A. Yes. Besides examination of individual capacity factors, one can also examine the levelized cost of each generation unit relative to established market analyses. For instance, Exhibit DED-6 presents the results of an analysis that examines the levelized annual cost for each of the Company's non-renewable EGUs compared with the "Cost of New Entry" (or "CONE") prices estimated by MISO in its most recent analysis of the 2023/2024 Planning Resource Auction ("PRA") results.[35] All

[35] 2023/2024 Planning Resource Auction (PRA) Results; (May 19, 2023); MISO.

costs less than the MISO CONE price can be classified as demand-related, whereas prices above the MISO CONE can be classified as energy-related.

Q. WHAT ARE THE RESULTS OF YOUR CONE ANALYSIS?

A. Exhibit DED-6 finds that, at most, 45.31 percent of the Company's non-renewable production plant in service could be classified as being associated with the provision of demand functions. This again is significantly different than the Company's proposed methods, which classifies 100 percent of its production plant as demand-related.

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

A. Conceptually, A&E classification methods involve developing two components that are combined by the use of a weighted average.[36] The first component, referred to as the "average" component, represents each rate class's 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 rate class's contribution to the sum of each customer class's maximum annual peak demand, or NCP. These components are combined through the use of a weighted average. 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. WHAT IS THE BASIS FOR THE EXCESS DEMAND MEASURE VERSUS FULL PEAK DEMAND?

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

A. Superficially, the A&E method appears to develop a hybrid weighted energy and demand allocation factor, recognizing the joint energy and demand functions of production plant. However, it should not be confused with a simple weighting of class demand and energy requirements, similar to the previously referenced A&P methodology.[37] Proponents of the A&E cost allocation approach, typically large/industrial customer groups, argue that using full class peak demand "double counts" class energy use during periods. These stakeholders often argue that the use of "excess demand" rather than total demand solves this purported "double counting problem." However, in using the excess component only, the A&E methodology directly places a higher emphasis on each class's demand contribution relative to energy. Thus, the A&E method, itself, suffers from a bias that favors relatively higher load factor classes like industrial customers, and at lower load factor classes' expense (such as residential and small commercial customers).

Q. DO YOU AGREE WITH "DOUBLE COUNTING" CLAIMS MADE ABOUT THE A&P METHODOLOGY?

A. No, such arguments incorrectly conflate the concepts of energy and demand and the roles each of these play in utility system planning. These arguments are also faulty since they effectively presume that utilities design systems to first meet the needs of baseload customers and only later develop resources dedicated to customers that have peaking requirements. In other words, it assumes utilities plan one set of generation plants for one group of customers (i.e., industrial), and an

[37] *Id.* at 57-58.

entirely different set of plants to serve another (i.e., residential and small commercial). All of these arguments are incorrect since, in reality, demand and energy reflect separate and differing utility planning parameters and system planners develop resources to meet all of their load requirements, not separately to meet individual, or class-specific requirements.

Q. PLEASE EXPLAIN WHAT YOU MEAN BY CONFLATING THE CONCEPTS OF ENERGY AND DEMAND AS IT RELATES TO UTILITY SYSTEM PLANNING.

A. This conflation presumes that energy and peak energy use are virtually consubstantial, with energy being part of peak energy use, and presumably peak being a part of energy. Peak energy usage, for instance, can be divided into a portion representing its average annual system requirement, and a second portion representing its load requirement in excess of this requirement. However, this conflation does not reflect the reality of utility system planning wherein a utility is required to plan for energy and capacity system requirements as independent, not a single consubstantial system parameter. A utility must ensure that it has enough generating capacity to meet its peak system requirements (i.e., its coincident peak), as well as assure that the plant it develops to meet its load requirements is least cost in nature.

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 will assign the “excess demand” component of the calculation a zero value, since peak demand requirements equal average demand requirements, effectively considering the class as having no peak demand requirements.

However, customer classes with a 100 percent load factor utilize system resources during all hours, both peak and off-peak. Thus, 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 peaker generation units. The utility considers its needs 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.

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

A. Yes. There is a mathematical error that arises in the use of the A&E method underscoring its weakness. In order to "make the math work," the A&E method cannot use a traditional CP measure of demand (like the Company, and most utilities use), but instead must use an NCP measure.

Q. PLEASE EXPLAIN THIS MATHEMATICAL ISSUE.

A. The NARUC Manual notes that use of a 1 CP demand measure within an A&E calculation will result in estimates that are identical to a general 1 CP demand-only measure, which effectively undermines the entire purpose of developing a hybrid demand-energy classification.[38] In order to prevent this outcome from occurring, the NARUC Manual suggests using an NCP demand measure:

> If your objective is – as it should be using [an A&E] method – to reflect the impact of average

[38] Electric Utility Cost Allocation Manual (January 1992), National Association of Regulatory Utility Commissioners, at 50.

> 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.[39]

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. First, utilities typically do not use NCP measures in planning, developing, or operating generation units since an NCP assumes a low level of load diversity, thus amplifying customer peak demand requirements on the utility's system. In other words, if a utility did use an NCP measure for planning purposes, it would have to develop a unique set of generation plants for each of its major customer classes – something that clearly does not happen. While the use of an NCP may be appropriate for distribution facilities which serve isolated segments of a utility's system, it is not appropriate for generation assets that serve regional system demands with high levels of load diversity.[40] 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 classification method that avoids this computation error.

Q. ARE THERE OTHER CONCERNS WITH THE COMPANY'S CLASSIFICATION OF ALL FIXED COSTS ASSOCIATED WITH ITS PRODUCTION PLANT ASSETS AS 100 PERCENT DEMAND-RELATED?

[39] *Id.*
[40] *See*, *Id.*, at 97.

A. Yes. The Company's classification of all fixed costs associated with its production plant assets as 100 percent demand-related ignores the significant portion of the Company's production plant in service that is related to renewable EGUs. As stated previously, the composition of generation plants and the role each generating plant plays in system dispatch contributes to the classification of the asset for CCOSS purposes. Renewable generation facilities provide limited capacity service for a utility, mainly providing energy service for a utility.

Q. HAVE YOU EXAMINED THE COMPOSITION OF THE COMPANY'S TEST YEAR PRODUCTION PLANT ASSETS?

A. Yes. Exhibit DED-7 examines the individual units comprising the Company's test year production plant in service, including the unit, primary fuel, gross and net plant in service. This analysis shows that nearly 52.5 percent of the Company's test year net plant in service is associated with non-dispatchable solar renewable generation resources.

Q. HAS THE UNIQUE ROLE OF RENEWABLE GENERATION ASSETS BEEN RECOGNIZED BY OTHER REGULATORY COMMISSIONS?

A. Yes. The Iowa Utilities Board ("IUB") in a March 2014 Order involving the MidAmerican Energy Company found that demand-based allocations assume, as a basic premise, that all generation is built to meet peak demand, but that this is not the case when examining renewable generation such as wind generators.[41] The IUB noted that at the time the average capacity accreditation for wind generation by Mid-Continent Independent System Operations ("MISO") was 14

[41] *In Re: MidAmerican Energy Company,* Iowa Utilities Board Docket No. RPU-2013-0004, Order Approving Settlement, With Modifications, and Requiring Additional Information dated March 17,2014.

percent, meaning that 86 percent of nameplate capacity associated with these generators cannot be used to fulfill resource adequacy requirements in MISO.[42] The IUB thus found that allocating renewable generation using demand-based allocations produced unreasonable results, compared to approaches that considered use during non-peak periods such as hourly cost modeling.[43]

Q. ARE YOU AWARE OF RECENT COST OF SERVICE STUDIES SUPPORTED BY ELECTRIC DISTRIBUTION COMPANIES THAT HAVE RECOGNIZED THE NEED TO DISTINGUISH BETWEEN RENEWABLE AND NON-RENEWABLE GENERATION ASSETS?

A. Yes. In a November 4, 2022, rate case filing with the Montana Public Service Commission ("MPSC"), Montana-Dakota Utilities Company ("MDU") included an allocated cost of service study that recognized the need to distinguish between renewable and non-renewable generation assets.[44] Specifically, MDU estimated the demand-related portion of its renewable production plant assets separately from its fossil fuel production plant assets by examining the ratio of accredited Zonal Resource Credits ("ZRC") from MISO compared to the asset's nameplate capacity.[45] A similar process has been used in a recent rate case filing by Interstate Power and Light ("IPL") before the Iowa Utilities Board.[46]

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[42] *Id.*
[43] *Id.*
[44] *In the Matter of the Application of Montana-Dakota Utilities Co. for Authority to Establish Increased Rates for Electrical Service;* MPSC Docket No. 2022.11.099; Application at Schedule L-2 and Direct Testimony of David E. Dismukes at 17:16 to 18:5.
[45] *Id.,* Direct Testimony of David E. Dismukes at 18:9-17.
[46] *In Re: Interstate Power and Light Company,* Iowa Utilities Board Docket No. RPU-2023-0002, Direct Testimony of Lucas Bressan at 11:9-19.

Q. WHAT IS MISO'S CURRENT CAPACITY ACCREDITATION METHODOLOGY FOR SOLAR RENEWABLE GENERATION UNITS?

A. MISO's current process for accrediting solar photovoltaic resources is based on three years of historical average output for hours ending 15, 16, and 17 eastern standard time ("EST") for the most recent spring, summer and fall months and hours ending 8, 9, 19, and 20 EST for the most recent winter months.[47] New solar resources are accredited at 50 percent of nameplate capacity for spring, summer and fall months, and at 5 percent of nameplate capacity for winter months.[48]

Q. HAVE YOU ANALYZED THE PORTION OF TEST YEAR PRODUCTION PLANT WHICH SHOULD BE CLASSIFIED AS 100 PERCENT ENERGY-RELATED?

A. Yes. Exhibit DED-8 analyzes the portion of Company test year production plant in service that should be classified as serving 100 percent energy-related functions. This analysis values 50 percent of net production plant in service associated with Company rate based solar facilities as being strictly energy-related based on MISO's accreditation for such resources. This analysis finds that 26.2 percent of the Company's test year net plant in service should be classified as 100 percent energy-related, with the remainder classified as serving joint demand and energy functions.

Q. WHAT IS YOUR RECOMMENDATION REGARDING THE APPROPRIATE CLASSIFICATION OF COSTS RELATED TO PRODUCTION PLANT?

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[47] Resource Accreditation White Paper (November 2023), Mid-Continent Independent Systems Operator, version 1.1 at 12.
[48] *Id.*

A. I recommend that the Commission reject the Company's proposal to classify all production plant assets as being 100 percent demand-related. The Company's proposal is inconsistent with customer demands placed on the Company's system, inconsistent with the function generation serves as recognized by the Commission and other regulatory commissions in the past, and inconsistent with the capacity accreditation of the Company's renewable generation facilities. Instead, I recommend the Commission rely on the results of my alternative ACOSS, which (1) classifies 50 percent of costs associated with the Company's renewable generation assets as fully energy-related, and (2) uses an A&P method to classify the remaining production plant costs based on Company observed test year system load factors. My proposed classification method classifies 61.49 percent of the Company's production plant costs as being energy-related, with the inverse (38.51 percent) being classified as demand related for the test year.

D. Use of a Minimum System Study to Classify Distribution Plant Costs

Q. PLEASE DESCRIBE HOW THE COMPANY CLASSIFIES THE CUSTOMER AND DEMAND COMPONENTS OF ITS DISTRIBUTION PLANT COSTS.

A. The Company states that it relied on the results of an MSS to classify 56 percent of costs associated with FERC Account 368 – Line Transformers as customer-related.[49] However, in response to discovery the Company clarified that the results of its MSS were not correctly reflected in its ACOSS, and that it would update the results of its ACOSS during the course of this proceeding.[50]

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[49] Direct Testimony of John D. Taylor, Attachment JDT-2.
[50] Company's Response to Data Request OUCC 4.26.

Q. PLEASE EXPLAIN THE THEORETIC BASIS FOR A "MINIMUM SYSTEM" STUDY OR ANALYSIS.

A. Such studies are often advocated by those holding the view that higher level distribution plant investments are made to serve a dual-nature: one consisting of meeting system load requirements, the other being focused on customer interconnection or access that requires a customer-based allocation component. This minimum system component is determined through a MSS, or a related Zero-Intercept Study.

Q. WHAT ARE MSS AND ZERO-INTERCEPT STUDIES?

A. MSS and zero-intercept studies are cost allocation methodologies that attempt to estimate separate customer-related versus load-related costs. An MSS does this by estimating the hypothetical costs of developing a "minimum" system that only provides customers with connection to a utility's electric distribution system, but not a system sufficient to actually serve the customer's electrical requirements. Likewise, a zero-intercept study utilizes regression analysis techniques to estimate the relationship between the electric demand requirements on a system and costs associated with installation of new distribution plant assets. Using these regression analyses, a zero-intercept study then calculates a hypothetical minimum cost by calculating the costs of the distribution plant assets given zero demand requirements.

Q. PLEASE DESCRIBE THE MECHANICS OF AN MSS.

A. Many distribution system assets can be classified as having both a customer and an energy component. For instance, distribution substations are built to serve customers, but are often expanded to meet increases in customer loads. An MSS study attempts to separate the customer-related portion of total system costs from those associated with serving loads (or service volumes). An MSS study estimates the hypothetical costs of developing a minimum system to serve customers with no load. These calculations involve subjectivity, since they use accounting and engineering analyses to develop assumptions about the minimum sizes and costs associated with various distribution system components, while still satisfying system requirements such as pole height and efficient conductor and transformer sizes. The costs associated with these "minimum" components are then added together to derive the total minimum costs associated with the hypothetical system with no energy usage. This estimate is then divided by total actual system costs to approximate the customer-related share of overall distribution system costs.

Q. ARE THERE ANY THEORETICAL SHORTCOMINGS TO USING MSS AND ZERO-INTERCEPT STUDIES BASED STUDIES FOR CLASSIFICATION OF DISTRIBUTION PLANT ASSETS?

A. Yes. Both MSS and zero-intercept studies depend on deeply flawed counterfactual theoretical premises. MSS-based analyses deal in hypotheticals that do not exist in the real world, including the assumption that somehow there is an electric distribution system out there in the world that could or would be plausibly built to serve customers but not load. No such system exists, making the underlying assumptions and modeling of a "minimum system" difficult, if not impossible, to verify. Even if a minimum electric distribution system could be constructed in real life, it would still have the ability to service at least a portion of customers' loads, undermining this modeling approach's fundamental premise.

Q. DOES THE NARUC COST ALLOCATION MANUAL RECOGNIZE THESE CHALLENGES?

A. Yes. The NARUC Electric Cost Allocation Manual ("NARUC Manual") recognized this fundamental failing of MSS approaches in its discussion of the approach.

> Cost analysts disagree on how much of the demand costs should be allocated to customers when the minimum-size distribution method is used to classify distribution plant. When using this distribution method, the analyst must be aware that the minimum-size distribution equipment has a certain load-carrying capability, which can be viewed as a demand-related cost.[51]

Q. WHAT ARE THE THEORETICAL FAILINGS OF ZERO-INTERCEPT BASED STUDIES?

A. A zero-intercept-based approach is simply a statistically-based MSS approach and suffers, conceptually, from the same shortcomings. A zero-intercept analysis attempts to model an empirical relationship that does not exist. One should recognize that the argument that electric distribution costs are related to the number of customers on a utility's system is not a new argument, and the academic literature in utility regulation has questioned for quite some time the use of both MSS and zero-intercept studies.

Q. HOW HAS THE ACADEMIC LITERATURE IN UTILITY REGULATION QUESTIONED THE USE OF MSS AND ZERO-INTERCEPT STUDIES?

[51] Electric Utility Cost Allocation Manual (January 1992), NARUC, p. 95.

A. Dr. James Bonbright, in his seminal work on public utility regulation, published originally in the 1970s, raises a number of questions about the use of MSS and zero-intercept methodologies in classifying costs. Dr. Bonbright's primary concern was the lack of empirical support in the academic literature for a causal relationship between distribution system costs and the number of customers. The true driving factors of utility distribution system costs are much more complicated and depend on a host of other factors, such as the size of a service territory and the population density within. The incremental costs of constructing an appropriate distribution system to serve an additional customer within an urban area with existing nearby infrastructure is substantially less than the costs to extend an existing utility system by potentially miles to serve an additional customer located in a rural area, a fact inherently ignored by MSS and Zero-Intercept methodologies.

> …the annual costs of this phantom, minimum-sized distribution system are treated as customer costs and are deducted from the annual costs of the existing system, only the balance being included among those demand-related costs to be mentioned in the following section. Their [minimum distribution costs] inclusion among the customer costs is defended on the ground that, since they vary directly with the area of the distribution system (or else with the lengths of the distribution lines, depending on the type of distribution system), they therefore vary directly with the number of customers. Alternatively, they are calculated by the "zero-intercept" method whereby regression equations are run relating cost to various sizes of equipment and eventually solving for the cost of a zero-sized system (Sterzinger, 1981).
>
> What this last-named cost imputation overlooks, of course, is the very weak correlation between the area (or the mileage) of a distribution system and the number of customers served by this system. For it makes no allowance for the density factor (customers per linear mile or per square mile). Our casual

> empiricism is supported by a more systematic regression analysis in (Lessels, 1980) where no statistical association was found between distribution costs and number of customers. Thus, if the company's entire service area stays fixed, an increase in number of customers does not necessarily betoken any increase whatever in the costs of a minimum-sized distribution system.[52]

Q. WHAT WAS DR. BONBRIGHT'S CONCLUSION REGARDING THE USE OF MSS AND ZERO-INTERCEPT STUDIES?

A. Dr. Bonbright found attempts to classify costs associated with a minimum-sized distribution system, whether determined through the use of a MSS or a Zero-Intercept Study, as something other than demand-related as potentially of merit. However, he ultimately concluded that classifying these costs as customer-related as CEI South has done in the current proceeding is "clearly indefensible,"[53] due to the lack of a relationship between changes in number of customers on a utility system and its distribution costs.

Q. HAVE OTHER JURISDICTIONS REJECTED THE USE OF AN MSS?

A. Yes. In 2021, the Michigan Public Service Commission rejected a proposal that Consumers Energy be required to submit an MSS in its next rate case.[54] Likewise, in 2010, the Rhode Island Public Utilities Commission rejected a request that it require the use of a minimum system study for Narragansett Electric Company D/B/A National Grid.[55]

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[52] James C. Bonbright, et al. Principles of Public Utility Rates. 1988 Edition. Arlington, VA: Public Utilities Reports, Inc., p. 491.
[53] *Id.*, p. 492.
[54] *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-20963, Order, dated December 22, 2021.
[55] *In re: the Application of The Narragansett Electric Company D/B/A National Grid For Approval of A Change in Electric Base Distribution Rates*. Docket No. 4065, Decision and Order, dated April 29, 2010.

Q. WHAT IS YOUR RECOMMENDATION REGARDING THE RELIANCE ON AN MSS TO ALLOCATE COSTS ASSOCIATED WITH DISTRIBUTION PLANT ASSETS?

A. I recommend that the Commission reject the Company's proposed MSS approaches in the classification of line transformers. MSS and related zero-intercept approaches are fundamentally flawed and provide little to no value as to the just and reasonable setting of rates. Research has shown that these methods are flawed, and some state regulatory commissions have gone so far as to reject their use. Further, while MSS is used by some utilities, it is not commonly used by all utilities. Thus, I recommend the Commission appropriately classify assets included in distribution plant accounts 367 as 100 percent demand-related, consistent with the Company's initial filing in this proceeding.

E. Summary of ACOSS Findings

Q. PLEASE SUMMARIZE YOUR ACOSS FINDINGS.

A. Exhibit DED-9 presents the results of my alternative ACOSS which (1) classifies 50 percent of costs associated with production plant assets as 100 percent energy related; (2) utilizes an A&P cost allocation approach to allocate remaining costs associated with production plant assets; and (3) appropriately classifies costs associated with distribution plant line transformers as 100 percent demand-related, consistent with the Company's initial CCOSS filing in the current proceeding. My alternative CCOSS analyses show that the Company's incorrect classification of production plant assets skews the allocation of costs and revenue responsibilities away from larger customers and onto residential and small commercial customers. I recommend that the Commission rely on the results of my alternative ACOSS as a fair and reasonable estimation of relative costs of service between Company customer classes.

V. REVENUE DISTRIBUTION

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. The revenue distribution process often uses the results from the ACOSS 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 final class revenue responsibilities 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 can result in a very significant and adverse rate impact 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 set of broad ratemaking policy goals.

Q. WHAT ARE THOSE BROADER RATEMAKING POLICY GOALS?

A. Generally accepted utility ratemaking principles include:

1) Rates should be fair, just, and reasonable, and not unduly discriminatory.

2) To the extent possible, gradualism should be used to protect customers from rate shock.

3) Rate continuity should be maintained.

4) Rates should be informed by costs, but class cost of service results need not be the only factor used in rate development.

5) Rates should be understandable to customers.

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

A. It is important to consider all 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 resulting rates that are fair, just, and reasonable. There is no pre-set or universally accepted formula for developing rates and, as a result, sound judgment is necessary to formulate a rate design that meets these objectives.

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

A. The Company states cost of service was just one of several considerations or criteria the Company reviewed in establishing class revenue requirements.[56] Specifically, the Company considered three criteria related to the design of utility rates: (1) cost of service results; (2) class contributions to present revenue levels and the resulting inter-class subsidies; and (3) customer impact considerations

[56] Direct Testimony of John D. Taylor at 18:26 to 19:4.

including the Company's belief that moderation should be employed in accomplishing movement towards system-wide rate of return parities.[57] The Company, observing these criteria, allocated full revenue increases to street lighting service ("Rate SL") schedule revenues required to equal cost of service, offsetting this revenue increase with a corresponding revenue decrease to outdoor lighting service ("Rate OL").[58] Finally, water heating service revenues were increased by a capped 1.5 times the system average increase of 16.02 percent, with remaining rate classes receiving proportionate rate increases above their cost to serve to account for the deficiency created.[59] Exhibit DED-10 presents the Company's estimated current class relative rates of return ("RROR") and its proposed revenue distribution.

Q. WHAT DO YOU MEAN BY RROR?

A. The RROR effectively standardizes the class-specific rate of return estimated by an ACOSS 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 percent ROR, and further assume that the system-wide average ROR estimated by the same ACOSS 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

[57] *Id.* at 20:8-13.
[58] *Id.* at 21:7-9.
[59] *Id.* at 21:9-17.

(*i.e.*, there is no cross-subsidy). A RROR that is greater than 1.0 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 but greater than zero can be said to be making a less-than-average contribution to the overall system.

Q. DO YOU AGREE THAT A CLASS RROR LESS THAN 1.0 IS PROBLEMATIC OR INEQUITABLE?

A. Not necessarily. Consistent with the principles identified above, there may be policy reasons to support a result that reflects an inequitable cross-subsidization. For example, the presence and/or continuation of a RROR below 1.0 could be the result of a prior agreed-upon rate freeze that prevents class rates from increasing to correct the revenue deficiency (relative to cost of service). In this example, the presence of a RROR below 1.0 is simply a function of a prior policy decision, not necessarily the result of some arbitrary or intentionally designed inequity.

Q. WHAT ARE THE CLASS RATE INCREASES UNDER THE COMPANY'S PROPOSED REVENUE DISTRIBUTION?

A. The Company proposes to increase base rates by 16.02 percent on a system-wide average basis. However, under the Company's proposed revenue distribution, residential customers would receive a 20.17 percent increase in total rates, with water heating service customers receiving a 24.03 percent increase in total rates. This is equal to 1.26 and 1.50, respectively, times the proposed system average increase of 16.02 percent.[60]

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[60] *Id.* at 22, Table JDT-4.

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

A. No. The Company's proposed revenue distributions suffer from two major deficiencies. First, the Company's proposal is based on the results of a faulty ACOSS that overstates the extent of any current subsidy from high-load factor industrial customers to low-load factor residential customers. Second, the Company's proposed cap on proposed rate increases of 1.5 times the proposed system average rate increase is inconsistent with rate gradualism and could also negatively impact energy affordability, particularly for the Company's low and middle income customers as I discussed earlier in my testimony.

Q. WHAT IS YOUR RECOMMENDATION REGARDING THE COMPANY'S PROPOSED REVENUE DISTRIBUTION?

A. I recommend that the Commission adopt a more reasonable revenue distribution allocation method based on my alternative ACOSS results, that also limits the rate increase to any single customer class to 1.15 times the overall system average increase. This reduces the maximum total revenue increase under the Company's proposed revenue distribution of any single rate class to 18.42 percent, compared to the Company's proposed maximum rate increase of 24.03 percent.

Q. HAVE YOU PREPARED A SUMMARY OF THE EFFECTS OF YOUR PROPOSED REVENUE DISTRIBUTION?

A. Yes. Exhibit DED-11 presents an illustrative summary of the effects of my proposed revenue distribution under the Company's proposed system average rate increase of 16.02 percent. My proposed revenue distribution would increase base rates for the residential class by 17.51 percent, compared to the Company's proposal which would increase such rates by 20.17 percent.

VI. RATE DESIGN

Q. HOW SHOULD POLICY BALANCE COST ASSIGNMENTS BETWEEN 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 FOR 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.

Q. PLEASE DISCUSS THE COMPANY'S CUSTOMER CHARGE PROPOSALS.

A. Exhibit DED-12 presents a summary of the Company's proposed increases in monthly customer charges for residential and small general service ("Rate SGS") rate classes. The Company currently assesses fixed monthly charges to these two rate classes through two elements: a fixed monthly customer charge, and a fixed monthly component to the Transmission, Distribution, and Storage System Improvement Charge ("TDSIC").[61] For Rate RS, the Company proposes to raise the current fixed monthly customer charge of $10.84 to $23.20. For Rate SGS, CEI South proposes to raise the monthly customer charge from $10.84 to $22.50. The Company claims that customers will see no incremental impact since total monthly customer charges for the test year, including the fixed portion of TDSIC, is the same as the proposed customer charge amounts.[62]

Q. HAVE YOU PREPARED AN ANALYSIS OF COMMON CUSTOMER-RELATED COSTS TO CURRENT CUSTOMER CHARGES?

A. Yes, and this analysis is provided in Exhibit DED-13. Customer-related costs included in this analysis include: a return of and on electric meters and service drops; meter operating expenses (i.e. removing and setting meters); meter maintenance expenses; and customer account expenses such as meter reading expenses, customer records expenses and customer billing and accounting expenses. The analysis shows that the Rate RS recovers more than 57.7 percent of customer-related expenses through the current customer charge without accounting for the fixed component of the TDSIC. Likewise, Rate SGS customers

[61] Direct Testimony of John D. Taylor at 23:14-17.
[62] *Id.* at 23:14-24.

recover 49.4 percent of current customer-related expenses through the current customer charge without taking into account the fixed component of the TDSIC. When the current fixed component of the TDSIC is included in this analysis, these percentages increase to 92.3 and 79.0 percent, respectively. These results do not demonstrate a need to increase residential and small commercial customer charges on a cost-causation basis, or even to retain the existing fixed component of the TDSIC since a majority of customer-related costs are recovered through the base monthly customer charge.

Q. HAVE YOU COMPARED THE COMPANY'S PROPOSED RESIDENTIAL CUSTOMER CHARGES TO OTHER REGIONAL ELECTRIC UTILITIES?

A. Yes, and this analysis is presented in Exhibit DED-14, which surveys current residential and small commercial customer charges for major electric utility companies operating in Indiana and surrounding states. The Company's current residential customer charge of $10.84 per month is above the average residential customer charge of $10.72 for other regional utilities. When the current residential fixed component of the TDSIC tracker ($6.50) is added, the combined effective monthly customer charge of $17.34 is very close to the highest residential customer charge in region, with only Kentucky Power Company having a higher customer charge of $17.50. CEI South's pending proposal in this case would require its customers to pay the highest residential customer charge in the region.

Q. IS THE COMPANY'S PROPOSAL TO INCREASE ITS RESIDENTIAL AND COMMERCIAL CUSTOMER CHARGES CONSISTENT WITH THE PROMOTION OF ENERGY EFFICIENCY AND CONSERVATION?

A. No. 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.

Q. HAVE OTHER REGULATORS RECOGNIZED THE NEGATIVE IMPACTS THAT CUSTOMER CHARGE INCREASES CAN HAVE FOR ENERGY EFFICIENCY?

A. Yes. In rejecting a request by Baltimore Gas and Electric ("BGE") to increase customer charges as part of a larger rate design proposal, the Maryland Public Service Commission ("MD PSC") 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.[63]

Q. CAN YOU POINT TO ANY OTHER REGULATORY EXAMPLES?

A. Yes. The Montana Public Service Commission ("MT PSC") previously rejected a proposed straight fixed variable rate design for Energy West Montana citing several reasons, including the impact of the proposal on energy conservation efforts. MT PSC stated in its decision that:

[63] 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 (*"Case No. 9299")*. Order No. 85374 at p. 99, rel. February 22, 2013.

> The Commission agrees that most distribution costs are not avoidable, and that volumetric distribution charges may encourage conservation actions that, all other things being equal, reduce the utility's embedded cost recovery between rate cases and contribute to future rate increases.
>
> …
>
> The Commission agrees that an SFV rate design is a clean and administratively inexpensive way to decouple revenue from volume. An often-cited public policy justification for revenue decoupling is to remove the volume disincentive for cost-effective conservation investment by a gas distribution company, which through SFV and other decoupling methods is rendered indifferent to the volume of gas consumed. Yet, SFV rates decouple revenue at the cost of decreasing returns to conservation investment by customers. For this reason the net conservation benefit of revenue decoupling via SFV rates is not clear, and may be negative.[64]

Q. ARE THERE OTHER REGULATORY EXAMPLES IN WHICH A COMMISSION REJECTED A PROPOSED INCREASE IN FIXED CUSTOMER CHARGES DUE TO THE DETRIMENTAL EFFECT ON EFFORTS TO CONSERVE ELECTRICITY?

A. Yes. In 2012, the Missouri Public Service Commission ("MO PSC") rejected Ameren Missouri's proposed increase in customer charge for residential and small service classes. The Commission expressed opposition to shifting costs from volumetric rates to fixed customer charges because it would send the erroneous message to customers that the Commission is discouraging efforts to conserve electricity:

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[64] *In The Matter Of Energy West Montana, Application To Establish Increased Service Rates In Its Great Falls, Cascade, And West Yellowstone Service Areas*, Montana Public Service Commission, Docket No. D2010.9.90, Order No, 7132c, at 29–30.

> Shifting customer costs from variable volumetric rates, which a customer can reduce through energy efficiency efforts, to fixed customer charges, that cannot be reduced through energy efficiency efforts, will tend to reduce a customer's incentive to save electricity. Admittedly, the effect on payback periods associated with energy efficiency efforts would be small, but increasing customer charges at this time would send exactly [the] wrong message...[65]

Q. IS THERE A RECENT EXAMPLE OF A REGULATORY COMMISSION REJECTING A PROPOSED INCREASE IN RESIDENTIAL AND SMALL COMMERCIAL CUSTOMER CHARGES?

A. Yes. In rejecting a request by Northern States Power Company to increase customer charges[66] as part of a larger rate design proposal, the Minnesota Public Utilities Commission ("MPUC") recognized the need to allow customers the opportunity to control their monthly bills by reducing energy usage.

> Monthly customer charges are an important component of the Company's Residential and Small General Service rates by facilitating recovery of the costs caused by each customer that do not vary with the amount of energy used. However, higher fixed customer charges discourage customers from conserving energy and investing in renewable energy by reducing the impact of these efforts on the customers' bills. Customer charges also tend to confuse and alienate customers by impairing customer understanding of their energy bills. The Commission notes that Minn. Stat. §216B.03 requires the Commission to design rates to encourage energy conservation and renewable-energy use to "the maximum reasonable extent." Considering this statutory mandate and the evidence submitted by the parties, the Commission agrees with the ALJ that it is

[65] Missouri Public Service Commission, Report and Order, In the Matter of Union Electric Company Tariff to Increase Its Annual Revenues for Electric Service, File No. ER-2012-0166, December 12, 2012, pages 110-111.

[66] I*n re the Appl. of Northern States Power Co., for Authority to Increase Rates for Elec. Serv. in the State of Minn*., Docket E-002/GR-21-630, Findings of Fact, Conclusions, and Order, at 114 (MPUC July 17, 2023).

> reasonable and appropriate to lower the monthly customer charge for the Residential and Small General Service classes to $ 6.00.[67]

Q. ARE THESE COMMISSIONS ALONE IN THEIR 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 a straight-fixed variable ("SFV") rate design as an alternative to decouple utility revenue from sales. An SFV places all fixed costs into fixed charges while relegating only variable costs to volumetric rates. The Company's current customer charge proposal, which attempts to recover an additional level of class revenue responsibilities through the customer charge, regardless of costs, could be thought of as a pricing proposal consistent with these SFV principles. However, 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 billing a fixed monthly rate, regardless of how much customers consume</u>.[68]

[67] *Id*. at 116-117.

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

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. <u>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</u>. Such customer disincentives persist even when SFV rates are applied to individual components of the bill, such as charges for distribution service.[69]

Q. CAN HIGH CUSTOMER CHARGES LEAD TO OTHER PROBLEMS?

A. Yes. In addition to disincentivizing energy efficiency, increased customer charges also shift the rate burden within a customer class to lower-use customers. This

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

results in equity concerns, as lower-use customers have been shown in empirical research to be associated with lower-income households.[70]

Q. ARE ALL RATE CLASSES ASSESSED MONTHLY TDISC CHARGES PARTIALLY ON A FIXED CHARGE BASIS?

A. No. All medium and large commercial rate classes are assessed monthly TDISC charges based on monthly demand charges. Only Rates RS, SGS, and water heating service customers are assessed a fixed monthly and volumetric TDISC charge.[71]

Q. ARE YOU AWARE OF ANY OTHER INDIANA UTILITIES THAT RECOVER TDISC-ELIGIBLE CAPITAL INVESTMENTS PARTIALLY THROUGH FIXED CHARGES?

A. No. When asked in discovery, the Company also did not provide examples of other jurisdictional Indiana utilities it was aware of that recovered monthly TDSIC charges based partially on a fixed charge basis.[72]

Q. WHAT ARE YOUR CUSTOMER CHARGE RECOMMENDATIONS AND CONCLUSIONS?

A. I recommend the Commission reject the Company's proposal to increase customer charges. I also recommend the Commission direct the Company to eliminate its

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[70] *See,* 2020 Residential Energy Consumption Survey ("RECS"), U.S. Energy Information Administration; *See also,* Kontokosta, Constantine, *et. al.* (2020), "Energy Cost Burdens for Low-Income and Minority Households," *Journal of the American Planning Association*, Vol. 86 no. 1; and Brown, Marilyn A, *et. al.* (March 2020), "Low-Income Energy Affordability: Conclusions from a Literature Review," Oak Ridge National Laboratory.

[71] Appendix K – Transmission, Distribution and Storage System Improvement Charge, Southern Indiana Gas and Electric Company D/B/A CenterPoint Energy Indiana South Tariff for Electric Service at Sheet No. 75. Note that street and outdoor lighting customers are assessed TDISC charges as a fixed monthly charge due to how electric service for these customers is billed.

[72] Company's Response to OUCC 18.1.

current fixed component for monthly TDSIC charges for Rates RS, SGS, and water heating service customers, instead assessing monthly TDSIC charges fully as volumetric energy charges. The Company's current base customer charges for Rates RS and SGS are in-line with regional customer charges and would recover more than fifty percent of monthly customer-related costs for these customer classes. The Company's proposed increase to its base customer charges and its current practice of inflating its monthly customer charge through fixed TDSIC charges detrimentally impacts the public policy goals of promoting energy efficiency and burdens low-use customers.

VII. PROPOSED TOU-CPP PILOT

A. Overview

Q. PLEASE DESCRIBE THE COMPANY'S PROPOSED TIME-OF-USE WITH CRITICAL PEAK PRICING PILOT.

A. The Company proposes a new time-of-use ("TOU") with critical peak pricing ("CPP," collectively "TOU-CPP Pilot") to allow for more efficient utilization of the Company's system and provide a tool to help manage peak loads during hours of highest usage and provide customers with an opportunity to lower their bills.[73] The proposed program will be implemented as a pilot program so that the Company can better understand potential benefits of a full program and build effective communication tools to help ensure future success of the program.[74]

[73] Direct Testimony of Matthew A. Rice at 12:9-11.
[74] *Id.,* at 13:8-10.

Q. WHAT IS THE TIMELINE ASSOCIATED WITH THE PROPOSED TOU-CPP PILOT PROGRAM?

A. The proposed TOU-CPP Pilot is projected to be a pilot program estimated to cost approximately $1.75 million.[75] The proposed pilot rate will be active for two years, after which the Company proposes to evaluate impacts and processes associated with the TOU-CPP Pilot and lead a rate development study in year three of the TOU-CPP Pilot.[76] Of the $1.75 million in total costs associated with the proposed TOU-CPP Pilot, the Company estimates that approximately $0.92 million in expenses will be capitalized, with the remaining $0.84 million directly expensed.[77]

Q. WHAT ARE THE CUSTOMER REQUIREMENTS ASSOCIATED WITH THE PROPOSED TOU-CPP PILOT PROGRAM?

A. The Company proposes to cap enrollment in the proposed TOU-CPP Pilot program to 500 residential customers to, "provide evaluators with a sufficient sample size for assessing the electricity demand impacts, participant experience, and pilot cost-effectiveness and to obtain useful insights for CEI South program administrators."[78] To be eligible to participate in the TOU-CPP Pilot program, residential customers must have at least one year of automated meter data at the time of registration.[79] Similarly, the residential customer must not be enrolled in an existing demand response program such as the Company's Summer Cycler or Thermostat Load Control programs.[80]

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[75] *Id.,* at 15:23-24; and 15-16, Table MAR-4.
[76] *Id.* at 15-16, Table MAR-4.
[77] *Id.*
[78] *Id.*, at 13:16-19.
[79] *Id.,* at 13:22-23.
[80] *Id.,* at 13:24-26.

Q. WHAT ARE THE RATES ASSOCIATED WITH THE PROPOSED TOU-CPP PILOT?

A. The Company proposes a Rate RS-CPP that include separate winter (defined as December through February) and summer (defined as March through November) rates. Proposed volumetric rates during the winter period would consist of a uniform volumetric energy charge of $0.16270 per kWh. Proposed volumetric rates during the summer period would consist of on-peak service during weekdays, 1:00 p.m. to 7:00 p.m. of $0.28214 per kWh, and $0.07054 all other hours. Service during both winter and summer periods would also include a monthly service charge of $23.20 per customer and a volumetric charge during called CPP events of $0.56429 per kWh.[81]

Q. HOW WILL THE COMPANY INCENT CUSTOMERS TO PARTICIPATE IN THE PROPOSED TOU-CPP PILOT?

A. The Company proposes to provide a one-time incentive of $75 for customers who enroll in the proposed program.[82]

Q. DO YOU HAVE ANY CONCERNS ASSOCIATED WITH THE PROPOSED TOU-CPP PILOT?

A. Yes. The proposed TOU-CPP Pilot is not well designed. It lacks clearly established goals and objectives for the proposed pilot, such that it will be difficult to measure future success or usefulness of the program. Likewise, the proposed TOU-CPP Pilot lacks many consumer protection provisions that should be included in such a program. I will discuss each of these concerns in greater detail below.

[81] *Id.,* Attachment MAR-3.
[82] *Id.,* at 14:2-3.

B. The Proposed TOU-CPP Pilot Lacks Clearly Established Goals and Objectives to Measure Future Success or Usefulness of Program

Q. HAS THE COMPANY OUTLINED GOALS IT HAS FOR THE PROPOSED TOU-CPP PILOT?

A. Yes. The Company has identified four separate "goals" associated with the proposed TOU-CPP Pilot program:

1) Gauge residential customer interest in time-varying pricing, determine expected participation rates, and gain an understanding of CEI South's likely marketing costs to enroll customers;

2) Learn the electricity demand and energy impacts of the TOU rates and CPP events, including:

   a. Average reduction in electricity demand per participant during the TOU rate on-peak period and the average increase in electricity demand per participant during the TOU rate off-peak period;

   b. Average impact of CPP events on electricity demand per participant before, during, and after CPP events;

   c. The impact of the CPP events on the participant's energy consumption;

   d. The impact of the TOU rate on participants' energy consumption; and

   e. Whether the demand or energy impacts vary significantly by customer demographics, home type, or availability of different enabling technologies such as smart thermostats.

3) Learn the impacts of the TOU rates and CPP events on participant customer bills and whether the bill savings are commensurate with or exceed the cost to participants of attempting to shift their loads to lower priced periods; and

4) Learn the avoided demand and energy costs and other non-energy benefits from the pilot as well as the likely cost-effectiveness of TOU rates with CPP.[83]

Q. ARE THESE GOALS WELL CONSTRUCTED?

A. No. The Company's proposed TOU-CPP goals are not well constructed to elicit meaningful insights to help the Company or other stakeholders in designing effective time-variant rates. The Company's proposal (1) co-mingles two separate

[83] *Id.,* at 15:1-21.

rate structures into a single pilot program, (2) fails to outline expected peak reduction or other benefits associated with the program, and (3) fails to outline in sufficient detail how the cost-effectiveness of the TOU-CPP pilot program will be evaluated in the future.

Q. PLEASE EXPLAIN HOW THE PROPOSED TOU-CPP PILOT CO-MINGLES TWO SEPARATE RATE STRUCTURES INTO A SINGLE PILOT PROGRAM.

A. The proposed TOU-CPP pilot combines both a proposed TOU rate structure for residential customers and a proposed CPP program into a single proposed pilot rate. Importantly, neither residential TOU rates nor a residential CPP program have previously been implemented in the Company's service territory. This means that the proposed TOU-CPP pilot will be evaluating, for the first time, the potential merits and demerits associated with each element simultaneously, not each in isolation. This combination of two different types of rates makes it difficult, if not impossible, to completely understand and assess what is actually motivating changes in ratepayer usage under the proposed pilot.

Q. DOES THE IMPLEMENTATION OF THE PROPOSED TOU-CPP PILOT LIMIT INSIGHT INTO THE POTENTIAL MERITS OF A RESIDENTIAL TOU RATE OR RESIDENTIAL CPP PROGRAM?

A. Yes. Consider the potential that the proposed TOU-CPP Pilot is negatively viewed by participating residential customers at the end of the program who find that the pilot difficult to understand. Convoluting both TOU rate structures and a CPP program would mean that the Commission would have limited insight into if customer confusion is being driven by the TOU rate structure, which includes seasonal winter and summer rates and two rate periods during summer periods, or the CPP program, which requires customers to actively conserve electricity after receiving a utility text message. Likewise, if the proposed TOU-CPP Pilot is found to result in customers reducing usage during peak demand periods, the Commission would have limited insight into what portion of these benefits were attributable individually to either the TOU rate structure or the CPP program.

Q. HAVE OTHER JURISDICTIONS INVESTIGATED THE POTENTIAL BENEFITS OF TIME-VARIANT RATES?

A. Yes. Many other jurisdictions have adopted time-varying rates including TOU, CPP, peak time rebate, and variable peak pricing rates. A 2017 meta-analysis of 60 pilot programs found that all types of time-varying rates produced beneficial peak reductions.[84] However, this analysis also found that actual peak reduction benefits across different types of time-varying rates were similar.[85]

Q. HAS THE COMPANY ESTIMATED THE EXPECTED BENEFITS ASSOCIATED WITH AND COST-EFFECTIVENESS OF THE PROPOSED TOU-CPP PILOT?

A. No. The Company states that it is seeking recovery in the current case to develop the proposed TOU-CPP Pilot to analyze potential benefits, including demand savings, of a TOU-CPP rate structure,[86] and thus has not estimated expected demand savings or cost-effectiveness of the proposed TOU-CPP Pilot.[87]

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[84] Ahmad Faruqui, *et. al.* (December 2017), "Arcturus 2.0: A meta-analysis of time-varying rates for electricity," The Electricity Journal, Vol. 30 Issue 10 at 64-72.
[85] *Id.*
[86] Company's Response to Data Request OUCC 18.3.
[87] Company's Response to Data Request OUCC 37.11.

Q. IS THE COMPANY'S LACK OF EXPECTED BENEFITS ASSOCIATED WITH OR COST-EFFECTIVENESS OF THE PROPOSED TOU-CPP PILOT CONCERNING?

A. Yes. The lack of any *ex-ante* analysis of expected benefits or cost-effectiveness associated with the proposed TOU-CPP Pilot significantly limits the ability to judge any future successes or failures of the proposed pilot. If the proposed pilot results in less benefits than would be expected of such a program, this should be grounds to examine any impediment for such a failing. Without sufficiently laying out such expectations prior to implementation, negative results such as these may be inaccurately interpreted as successes.

Q. HAS THE COMPANY OUTLINED HOW IT WILL EVALUATE FUTURE COST-EFFECTIVENESS OF THE TOU-CPP PILOT PROGRAM?

A. No. The Company states that evaluation criteria will be assessed in the future like all other resources within the Company's Integrated Resource Plan ("IRP").[88] The Company also states that, generally, this will involve examination of metering data from an appropriate base period to determine load shifting during CPP events, but, importantly, the Company has not developed evaluation criteria that will be used to evaluate benefits associated with the proposed TOU-CPP Pilot.[89]

Q. HOW IS THE COMPANY'S FAILURE TO OUTLINE EVALUATION CRITERIA ASSOCIATED WITH THE PROPOSED TOU-CPP PILOT PROBLEMATIC?

A. The Company's proposal puts the proverbial "cart-before-the-horse," asking for approval of the proposed TOU-CPP Pilot with the expectation that future

[88] *Id*.
[89] *Id.*

evaluation criteria will be developed after approval. This leads to a variety of potential problems, highlighted by the Company's general response concerning the use of historic metering data. Specifically, the Company has not clarified if the referenced base period is intended to be prior to implementation of the TOU-CPP Pilot or non-CPP periods after implementation of the TOU-CPP Pilot. Second, it is not clear that, if the referenced base period is prior to the implementation of the TOU-CPP Pilot, how the Company will ensure that sufficiently detailed metering information has been retained to analyze hourly customer usage. Third, it is not clear that, if the referenced base period is non-CPP periods after implementation of the TOU-CPP Pilot, how the Company will assess load reduction associated with implementation of a TOU rate structure independent of the proposed CPP program. This highlights the need to establish a general outline for future evaluation criteria to ensure that the proposed pilot elicits results consistent with the goals of the pilot.

Q. HAS THE COMPANY ESTABLISHED CLEAR GOALS ASSOCIATED WITH THE PROPOSED TOU-CPP PILOT?

A. No. The Company's proposed TOU-CPP Pilot does not include clear goals for policy makers to judge future successes or failures of the proposed pilot. Specifically, the Company's proposal (1) co-mingles two separate rate structures into a single pilot program, (2) fails to outline expected peak reduction or other benefits associated with the program, and (3) fails to outline in sufficient detail how the cost-effectiveness of the TOU-CPP pilot program will be evaluated in the future.

C. Failure to Establish Clear Consumer Protection Provisions

Q. HOW WILL FUTURE CPP EVENTS BE DETERMINED?

A. The Company's proposed Rate RS-CPP tariff provides limited terms associated with future potential CPP events. CPP events will be called at the sole discretion of the Company up to four consecutive hours per day and 16 events per calendar year, including five times during each Summer and Winter periods and three times during Spring and Fall periods.[90] Indeed, while the Company states that it will attempt to notify customers by 7:00 p.m. the evening prior to a called CPP event, it retains the ability to call an emergency CPP event with as little as two hour notice for customers and that furthermore, these emergency events will not count towards the defined limits on the number of possible events during a season or year.[91]

Q. ARE THESE GUIDELINES SUFFICIENT?

A. No. The Company's CPP guidelines are insufficient, failing to address a multitude of aspects to the calling of CPP events which may lead to future customer confusion. For example, the Company proposal would allow it to call future CPP events during both on-peak and off-peak periods, potentially leading to customer confusion for customers who attribute off-peak periods to lower electricity rates yet are charged rates significantly greater than even proposed on-peak rates during CPP events.[92] Similarly, the Company proposal reserves the right to call CPP events during both summer and winter pricing periods, which again may lead to

[90] *Id.,* Attachment MAR-3 at 2.
[91] *Id.*
[92] Company's Response to Data Request OUCC 37.11.

customer confusion since the Company's proposed winter pricing regime is limited to a single volumetric rate without on-peak and off-peak distinctions.[93]

Q. DOES THE COMPANY'S PROPOSED TOU-CPP PILOT PROPOSE LIMITS ON THE POTENTIAL FREQUENCY OF FUTURE CALLED CPP EVENTS?

A. No. Beyond limiting the future CPP events to 16 per year, the proposed TOU-CPP Pilot provides few restrictions on the frequency of potential called CPP events, such as the number of events during a given month or week, or even the potential for multiple consecutive days of called events.[94] Customers who enroll in the proposed pilot program under the expectation that called CPP events would be infrequent could potentially be in for a rude awakening if exposed to five consecutive days of called CPP events during a winter ice storm or summer heat wave.

Q. DOES THE COMPANY'S PROPOSED TOU-CPP PILOT PROPOSE LIMITS ON THE POTENTIAL TO CALL CPP EVENTS DURING ADVERSE WEATHER CONDITIONS?

A. No. The Company explicitly leaves open the potential to call CPP events under the proposed TOU-CPP Pilot during adverse weather events.[95] This creates the potential for participating customers to receive significant electric charges for space heating and cooling requirements during oppressive weather situations.

Q. IS THE PROPOSED TOU-CPP PILOT INTENDED TO BE REVENUE NEUTRAL?

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[93] *Id.*
[94] *Id.*
[95] *Id.*

A. Yes. The Company states that it intends the proposed TOU-CPP Pilot to be revenue neutral.[96] However, as noted previously, the Company's proposed CPP framework allows for the ability to call CPP events during both winter and summer pricing periods and during on-peak and off-peak hours. Indeed, the Company's workpapers assume that only 69 percent of CPP usage would occur during summer on-peak periods, with 25 percent occurring during summer off-peak periods and 6 percent occurring during winter pricing periods.[97] Therefore it is possible that the final TOU-CPP Pilot could result in increased Company revenues over standard residential service rates.

Q. ARE THERE OTHER SEASONAL CONCERNS ASSOCIATED WITH THE COMPANY'S PROPOSED TOU-CPP PILOT?

A. Yes. The Commission should recognize that the Company does not propose an on-peak pricing period for winter use. Beyond the very problematic potential of leading to increased Company revenues over standard residential service rates, this design would also send mixed messages to customers regarding when system peaks are expected to occur and how to change behavior to lessen electricity rate requirements.

Q. HAS THE COMPANY DEVELOPED DETAILED TERMS OF SERVICE AND OTHER ITEMS PROSCRIBING OPERATIONS OF THE PROPOSED TOU-CPP PILOT FOR CUSTOMERS?

A. No. The Company has not yet developed an application or other educational materials that will be provided to interested customers prior to enrolling in the

[96] Company's Response to Data Request OUCC 18.4.
[97] Company's Response to Data Request OUCC 18.4a, Attachment.

proposed TOU-CPP Pilot, beyond the proposed Rate RS-CPP tariff.[98] Therefore, it is unclear if interested customers will have a clear understanding of the potential for increased charges through the proposed TOU-CPP Pilot.

Q. HAS THE COMPANY DEVELOPED CONFLICT RESOLUTION PLANS FOR PARTICIPATING CUSTOMERS NEGATIVELY IMPACTED BY THE PROPOSED TOU-CPP PILOT?

A. No. The Company states that the proposed TOU-CPP Pilot will be voluntary and that any potential future billing disputes will be handled in a manner comparable to the manner the Company resolves current billing disputes.[99]

Q. ARE THERE OTHER CONCERNS ASSOCIATED WITH THE PROPOSED TOU-CPP PILOT?

A. Yes. CEI South proposes to use the same consultant (Cadmus) that assisted the Company in the design of the TOU-CPP Pilot in the eventual evaluation of the proposed pilot.[100] This presents a potential conflict of interest as the Company's evaluator of the TOU-CPP Pilot will have a vested interest in overstating benefits of a pilot they were intimately involved in designing.

Q. HOW HAS THE COMPANY DEVELOPED ITS PROPOSED RATE RS-CPP?

A. The Company states that in designing its proposed Summer TOU rates it, "[used] an **industry ratio** of approximately four to one for the peak period to off-peak period price."[101] The Company states that this on-peak price differential should elicit an approximate 10 percent reduction in peak period electricity demand

[98] Company's Response to Data Request OUCC 37.10.
[99] *Id*.
[100] Direct Testimony of Matthew A. Rice at 16:2-3.
[101] *Id.,* at 17:5-7, *emphasis added.*

without enabling technologies and 25 percent with enabling technologies.[102] Likewise, the Company proposes to establish a CPP rate that is twice the summer on-peak rate or four times the summer off-peak rates.[103]

Q. ARE YOU FAMILIAR WITH ANY INDUSTRY RATIO ASSOCIATED WITH ON-PEAK AND OFF-PEAK TOU RATES?

A. No, I am not aware of any standard industry ratio defining that on-peak TOU rates should be four times that of off-peak TOU rates. Indeed, in response to discovery, the Company provided a more nuanced discussion regarding the trade-off between large and small peak to off-peak ratios, with larger ratios providing greater price incentives while potentially causing rate shock to households unfamiliar with TOU rates.[104] The Company states that its consultant recommended a "relatively modest" four to one on-peak to off-peak ratio as a good starting point for transitioning to TOU pricing.[105]

Q. DO YOU AGREE THAT APPROPRIATE TOU RATES INVOLVE TRADE-OFFS BETWEEN PROVIDING PRICE INCENTIVES TO ENCOURAGE LOAD SHIFTING AND AVOIDING POTENTIAL RATE SHOCK?

A. Yes. However, it is also important to consider the duration or window associated with such time periods when designing TOU rates, as this heavily impacts the ability of customers to shift electrical usage from on-peak to off-peak periods. Shorter on-peak windows can be coupled with higher on-peak to off-peak pricing ratios to discourage usage during a narrow period of time, while longer on-peak

[102] *Id.,* at 17:8-12.
[103] Direct Testimony of John D. Taylor at 28:15-17.
[104] Company's Response to Data Request OUCC 37.4.
[105] *Id.*

windows can be coupled with more modest on-peak to off-peak pricing ratios that provide more limited price incentives to decrease usage during these long periods. The Company proposes a relatively long six-hour on-peak window, 1:00 p.m. to 7:00 p.m., with a rather substantial $0.28214 base kWh charge.[106] This is even more significant when one considers that the Company proposes a volumetric charge during called CPP events that is double this already high on-peak charge, of $0.56429 per kWh.[107]

D. Conclusion and Recommendation

Q. WHAT IS YOUR RECOMMENDATION REGARDING THE COMPANY'S PROPOSED TOU-CPP PILOT?

A. I recommend the Commission not approve the proposed TOU-CPP Pilot. The program as proposed by the Company lacks clearly defined goals and objectives and information on how progress or achievement of these goals will be measured in the future. Likewise, the program as proposed by the Company lacks critical consumer protection provisions including limitations on the Company's ability to call future CPP events, and adequate assurance that Rate RS-CPP as proposed will be revenue neutral. Finally, the proposed Rate RS-CPP includes significantly high on-peak and CPP rates for extended durations that could potentially lead to rate shock in the future.

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[106] Direct Testimony of Matthew A. Rice at 17, Table MAR-5.
[107] *Id.*

VIII. CONCLUSION AND RECOMMENDATIONS

Q. PLEASE SUMMARIZE YOUR FINDINGS REGARDING ENERGY AFFORDABILITY IN THE COMPANY'S SERVICE TERRITORY.

A. CEI South's rates continue to place significant burdens on low- and moderate-income customers. I recommend the Commission consider energy affordability in evaluating how revenue responsibilities are determined across customer classes as well as establishing customer service charges that can be regressive in nature, and harm lower usage and lower/middle-income customers.

Q. PLEASE SUMMARIZE YOUR ACOSS RECOMMENDATIONS.

A. I recommend the Commission not accept the Company's ACOSS for ratemaking purposes. The Company's ACOSS incorrectly classifies fixed costs associated with production plant assets as exclusively demand-related. The Company's methods are inconsistent with how these production/generation assets are used in serving the Company's system needs. The Company's ACOSS is inconsistent with the capacity accreditation of the Company's renewable generation facilities, and deviates from commonly accepted cost allocation practices that recognize the dual role that production facilities serve. The Company's ACOSS results are also flawed since they rely on the results of an MSS to classify part of its distribution investments as being customer related. The effect of these two errors in the Company's ACOSS is that it favors large customers with relatively higher load factors over residential and small commercial customers with relatively lower load factors.

Q. WHAT IS YOUR RECOMMENDATION REGARDING THE COMPANY'S PROPOSED REVENUE DISTRIBUTION?

A. I recommend the Commission adopt a revenue distribution allocation method based on my alternative ACOSS results. I furthermore recommend, consistent with the policy goals of rate gradualism, the Commission limit rate increases to any single rate class to no more than 1.15 times the overall system average increase. My proposed revenue distribution methodology reduces the maximum total base revenue increase of any single rate class to 18.42 percent, compared to the Company's proposed maximum rate increase of 24.03 percent.

Q. WHAT ARE YOUR CUSTOMER CHARGE RECOMMENDATIONS?

A. I recommend the Commission reject the Company's proposed customer charge increases for residential and commercial customers. The proposed increases are not needed and will detrimentally impact the public policy goals of promoting energy efficiency. Likewise, such proposals will burden low-use and low-income customers with a greater than system average percent rate increase.

Q. WHAT IS YOUR RECOMMENDATION REGARDING THE COMPANY'S PROPOSED TIME-OF-USE CRITICAL PEAK PRICING PILOT?

A. I recommend that the Commission not approve the proposed TOU-CPP Pilot. The proposal is incomplete and lacks clearly defined goals, objectives, and how the proposal's performance will be evaluated. More importantly, the TOU-CPP proposal lacks critical consumer protection provisions including limitations on the Company's ability to call future CPP events, and adequate assurance that residential service Rate RS-CPP as proposed will be revenue neutral. Finally, the proposed Rate RS-CPP includes significantly high on-peak and CPP rates for relatively long, extended time durations that could potentially lead to rate shock and other financial burdens for participating ratepayers.

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

2023-Current	Professor Emeritus
2014-2023	Executive Director (Retired in 2023)
2007-2023	Director, Division of Policy Analysis
2006-2023	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)

2014-2023	Professor (Joint Appointment with CES)
2010-2023	Director, Coastal Marine Institute
2010-2014	Adjunct Professor

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

2006-2023	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 & ADVISORY APPOINTMENTS

2023 – Current	Distinguished Fellow & Senior Economist Institute For Energy Research Washington, D.C.
2017 -- Current	Member, National Petroleum Council. U.S. Department of Energy.
2020-2023	Co-Chairperson, Energy Advisory Committee, World Trade Center New Orleans, Louisiana.
2007-2023	Louisiana Representative, Interstate Oil and Gas Compact Commission; Energy Resources, Research & Technology

	Committee.
2007-2023	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.

PUBLICATIONS: BOOKS AND MONOGRAPHS

1. *Energy and Environment: The Grand Challenges of 21st Century.* (2022). With Chris F. D'Elia and Bryan F. Snyder. New York: Kendell Hunt Publishers. Pp. 153.
2. *Power System Operations and Planning in a Competitive Market*. (2002). With Fred I. Denny. New York: CRC Press. Pp. 133.
3. *Distributed Energy Resources: A Practical Guide for Service.* (2000). With Ritchie Priddy. London: Financial Times Energy. Pp. 60.

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3. "Current Trends and Issues in Reforming State-level Solar Net Energy Metering Policies." (2020). *Journal of Energy Law and Resources*. Vol. VIII: 419-451.
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5. "Understanding the challenges of industrial carbon capture and storage: An example in a U.S. petrochemical corridor." (2019). With Michael Layne and Brian Snyder. *International Journal of Sustainable Energy* 38(1):13-23.
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2. "Trends and Issues in the Natural Gas Industry and the Development of LNG: Implications for Louisiana. (2004) *Proceedings of the 51st Mineral Law Institute*, Louisiana State University, Baton Rouge, LA. April 2, 2004.

3. "Competitive Bidding in the Electric Power Industry." (2003). *Proceedings of the Association of Energy Engineers*. December 2003.

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5. "A New Consistent Approach to Modeling Regional Economic Impacts of Offshore Oil and Gas Activities." (2002). With Vicki Zatarain. *Proceedings of the 2002 National IMPLAN Users Conference*: 241-258.

6. "Analysis of the Economic Impact Associated with Oil and Gas Activities on State Leases." (2002). With Dmitry Mesyanzhinov, Robert H. Baumann, and Allan G. Pulsipher. *Proceedings of the 2002 National IMPLAN Users Conference*: 149-155.

7. "Do Deepwater Activities Create Different Impacts to Communities Surrounding the Gulf OCS?" (2001). *Proceedings of the International Association for Energy Economics: 2001: An Energy Odyssey?* April.

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10. “Asymmetric Choice and Customer Benefits: Lessons from the Natural Gas Industry.” (1999). With Rachelle F. Cope and Dmitry Mesyanzhinov. *Proceedings of the International Association for Energy Economics: The Only Constant is Change* August: 444-452.

11. “Modeling Electric Power Markets in a Restructured Environment” (1998). With Robert F. Cope and Dan Rinks. *Proceedings of the International Association for Energy Economics: Technology’s Critical Role in Energy and Environmental Markets*. October: 48-56.

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2. “The Road Ahead: The Outlook for Louisiana Energy.” (2006). In *Commemorating Louisiana Energy: 100 Years of Louisiana Natural Gas Development*. Houston, TX: Harts Energy Publications, 68-72.

3. “Competitive Power Procurement An Appropriate Strategy in a Quasi-Regulated World.” (2004). In *Electric and Natural Gas Business: Using New Strategies, Understanding the Issues.* With Elizabeth A. Downer. Edited by Robert Willett. Houston, TX: Financial Communications Company, 91-104.

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5. “Challenges and Opportunities for Distributed Energy Resources in the Natural Gas Industry.” (2002). In *Natural Gas and Electric Industries Analysis 2001-2002*. Edited by Robert Willett. With Martin J. Collette, Ritchie D. Priddy, and Jeffrey M. Burke. Houston, TX: Financial Communications Company, 114-131.

6. “The Hydropower Industry of the United States.” (2000). With Dmitry Mesyanzhinov. In *Renewable Energy: Trends and Prospects*. Edited by E.W. Miller and A.I. Panah. Lafayette, PN: The Pennsylvania Academy of Science, 133-146.

7. “Electric Power Generation.” (2000). In the *Macmillan Encyclopedia of Energy*. Edited by John Zumerchik. New York: Macmillan Reference.

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1. Review of ***Renewable Resources for Electric Power: Prospects and Challenges***. Raphael Edinger and Sanjay Kaul. (Westport, Connecticut: Quorum Books, 2000), pp 154. ISBN 1-56720-233-0. *Natural Resources Forum*. (*2000*).

2. Review of ***Electricity Transmission Pricing and Technology***, edited by Michael Einhorn and Riaz Siddiqi. (Boston: Kluwer Academic Publishers, 1996) pp. 282. ISBN 0-7923-9643-X. *Energy Journal* 18 (1997): 146-148.

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.

PUBLICATIONS: TRADE AND PROFESSIONAL JOURNALS

1. “The Impact of Globalization, Decarbonization, and Politicization: Forecasting the outlook for the energy and energy transition along the Gulf Coast. *Landman* (2023, Forthcoming, Fall Edition).

2. “Opportunities for Carbon Capture, Utilization and Storage in Louisiana.” (2020). *LOGA Industry Report*. Summer: 18-21.

3. “The Challenges of the Regulatory Review of Diversification Mergers.” (2016). With Michael W. Deupree. *Electricity Journal*. 29 (2016): 9-14.

4. “Unconventional Natural Gas and the U.S. Manufacturing Renaissance” (2013). *BIC Magazine*. Vol. 30: No. 2, p. 76 (March).

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30. *Principal Investigator.* "Energy Policy Development in Louisiana." Louisiana Department of Natural Resources. Total Project: $150,000. Status: Completed.

31. *Principal Investigator.* "Preparing Louisiana for the Possible Federal Regulation of

Greenhouse Gas Regulation." With Michael D. McDaniel. Louisiana Department of Economic Development. Total Project: $98,543. Status: Completed.

32. *Principal Investigator*. "OCS Studies Review: Louisiana and Texas Oil and Gas Activity and Production Forecast; Pipeline Position Paper; and Geographical Units for Observing and Modeling Socioeconomic Impact of Offshore Activity." (2008). With Mark J. Kaiser and Allan G. Pulsipher. U.S. Department of the Interior, Minerals Management Service. Total Project: $377,917 (3 years). Status: Completed.

33. *Principal Investigator*. "State and Local Level Fiscal Effects of the Offshore Petroleum Industry." (2007). With Loren C. Scott. U.S. Department of the Interior, Minerals Management Service. Total Project: $241,216 (2.5 years). Status: Completed.

34. *Principal Investigator*. "Understanding Current and Projected Gulf OCS Labor and Ports Needs." (2007). With Allan. G. Pulsipher, Kristi A. R. Darby. U.S. Department of the Interior, Minerals Management Service. Total Project: $169,906. (one year). Status: Completed.

35. *Principal Investigator*. "Structural Shifts and Concentration of Regional Economic Activity Supporting GOM Offshore Oil and Gas Activities." (2007). With Allan. G. Pulsipher, Michelle Barnett. U.S. Department of the Interior, Minerals Management Service. Total Project: $78,374 (one year). Status: Awarded, Completed.

36. *Principal Investigator*. "Plaquemine Parish's Role in Supporting Critical Energy Infrastructure and Production." (2006). With Seth Cureington. Plaquemines Parish Government, Office of the Parish President and Plaquemines Association of Business and Industry. Total Project: $18,267. Status: Completed.

37. *Principal Investigator*. "Diversifying Energy Industry Risk in the Gulf of Mexico." (2006). With Kristi A. R. Darby. U.S. Department of the Interior, Minerals Management Service. Total Project: $65,302 (two years). Status: Awarded, Completed.

38. *Principal Investigator*. "Post-Hurricane Assessment of OCS-Related Infrastructure and Communities in the Gulf of Mexico Region." (2006). U.S. Department of the Interior, Minerals Management Service. Total Project Funding: $244,837. Status: Completed.

39. *Principal Investigator*. "Ultra-Deepwater Road Mapping Process." (2005). With Kristi A. R. Darby, Subcontract with the Texas A&M University, Department of Petroleum Engineering. Funded by the Gas Technology Institute. Total Project Funding: $15,000. Status: Completed.

40. *Principal Investigator*. "An Examination of the Opportunities for Drilling Incentives on State Leases." (2004). With Robert H. Baumann and Kristi A. R. Darby. Louisiana Office of Mineral Resources. Total Project Funding: $75,000. Status: Completed.

41. *Principal Investigator*. " An Examination on the Development of Liquefied Natural Gas Facilities on the Gulf of Mexico." (2004). With Dmitry V. Mesyanzhinov and Mark J. Kaiser. U.S. Department of the Interior, Minerals Management Service. Total Project Funding $101,054. Status: Completed.

42. *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.

43. *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.

44. *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.

45. *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.

46. *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.

47. *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.

48. *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.

49. *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.

50. *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.

51. *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. "The role and outlook for CCS in Louisiana energy manufacturing development." (2024). GINP-CCS International Network. February 20, 2024.

2. "Louisiana energy manufacturing development outlook and the energy transition." (2024). Greater Baton Rouge Industry Alliance. February 1, 2024.

3. "Gulf Coast Energy Outlook 2024." (2023). LSU Center for Energy Studies, Baton Rouge, LA, Fall 2023.

4. "Louisiana clean, green industry: reconciling industrial decarbonization, capital formation, and growth." (2023). Louisiana State Bar Association, Public Utility Section. December 1, 2023.

5. "Expert witness training: considerations for preparation and effective execution during public utility regulatory hearings and proceedings." (2023). On the Behalf of the National Association of State Utility Consumer Advocates, Accounting and Finance Subcommittee. September 21, 2023.

6. “Gulf cost energy outlook: traditional resources and the energy transition.” (2023). AAPL/Gulf Coast Land Institute Meetings. April 26, 2023.

7. “Ratepayer considerations in the promotion of clean energy.” (2023). Public Utility Law Section Roundtable Discussion. April 21, 2023.

8. “Gulf coast energy outlook: traditional resources and the energy transition.” (2023). Louisiana Engineering Society. April 19, 2023.

9. “Carbon capture & storage: three thoughts and considerations.” (2023). Gulf Coast Power Association. 9th Annual MISO/SPP Conference. March 9, 2023.

10. “Natural gas markets: prices; trends; and ratepayer impacts.” (2023). Maryland Energy Advocates Virtual Monthly Meeting. February 17, 2023.

11. “Hydrogen overview and its role in Louisiana decarbonization.” (2022). Louisiana Public Service Commission Monthly Business & Executive Meeting. November 17, 2022.

12. “High winter natural gas prices and ratepayer impacts.” (2022). National Association of State Utility Consumer Advocates (“NASUCA”) Annual Conference. November 14, 2022.

13. “Facing the future together: the Louisiana energy transition, industrial decarbonization, and capital formation trends.” (2022). Louisiana Chemical Association: Annual Meeting 2022. October 27, 2022.

14. “Louisiana and the energy transition: reconciling industrial decarbonization, capital formation, and growth.” (2022). Louisiana Air and Waste Management 2022 Annual Meeting. October 26, 2022.

15. “The Louisiana energy transition, industrial decarbonization, and industrial capital formation trends.” (2022). Postlethwaite & Netterville: 2022 Governmental Update. August 4, 2022.

16. “Identifying and mapping regulatory requirements for CCUS projects.” (2022). SECARB Offshore GOM Gulf Regulator Workshop. New Orleans LA. May 16, 2022.

17. “Louisiana industrial decarbonization opportunities.” (2022). Louisiana Chemical Association/Louisiana Chemical Industry Alliance Legislative Meeting. May 11, 2022. Baton Rouge, LA.

18. “Natural Gas outlook, 2022: supply, demand, and geopolitical considerations.” (2022). National Association of State Utility Consumer Advocates (“NASUCA”) Monthly Natural Gas Committee Webinar. March 30, 2022.

19. “Louisiana industrial decarbonization opportunities.” (2022). LSU Law School, Journal of Energy Law and Resources Symposium on Energy Transitions. February 4, 2022. Baton Rouge, LA.

20. Panelist. Grid Resiliency in the Era of Extreme Weather. Gulf Coast Power Association 8th Annual MISO/SPP Regional Meeting. February 9, 2022. New Orleans, LA.

21. Panelist. Natural Gas Industry Update. (2022). National Association of State Utility Consumer Advocates Annual Meeting. (virtual). November 8, 2021.

22. “Overview of Louisiana’s greenhouse gas emissions and trends.” (2021). Louisiana Energy Users Group (“LEUG”) Meeting. November 11, 2021.

23. “State of energy in Louisiana: a preview of the 2021 Gulf Coast Energy Outlook.” (2021). Financial Planning Association of Baton Rouge. November 10, 2021.

24. “Replacing natural gas and industrial decarbonization: utility and ratemaking issues.” (2021). Virtual Joint Annual Meeting: Virginia Committee for Fair Utility Rates, Old Dominion Committee for Fair Utility Rates, and Virginia Industrial Gas Users Group Workshop. September 8, 2021.

25. “Louisiana 2021 GHG Inventory: Update and summary of preliminary findings.” (2021). Presentation before the Climate Initiative Task Force. July 29, 2021.

26. “Opportunities for the development of a hydrogen economy in Louisiana.” (2021). Louisiana Energy Climate Solutions Workshop. June 15, 2021.

27. “Natural gas: Building gas system resilience. Overview of the 2021 polar vortex and its implications for gas resiliency.” (2021). National Association of State Utility Consumer Advocates (“NASUCA”). Virtual mid-year meeting. June 14, 2021.

28. “Status and briefing on the Louisiana greenhouse gas inventory and emissions analysis.” (2021). Scientific Advisory Group (“SAG”) Meeting, Governor’s Climate Initiative Task Force. March 29, 2021.

29. “Louisiana carbon capture: sinks; sources; and the role of transportation in industrial applications.” (2021). LSU Journal of Energy Law & Resources Symposium on Carbon Capture and Solutions. February 5, 2021.

30. “Natural gas outlook, 2021: production, demand, pandemic and policy.” (2021). National Association of State Utility Consumer Advocates (“NASUCA”) Monthly Natural Gas Committee Webinar. January 20, 2021.

31. “Consumer Perspectives on the Rate Design of the Future.” (2020). National Association of State Utility Consumer Advocates (“NASUCA”). Annual Conference, November 10.

32. “Evaluation of Louisiana’s Depleted Gas Reservoirs for Geological Carbon Sequestration.” (2020). Louisiana Mid-Continent Oil and Gas Association (“LMOGA”) Carbon Capture and Underground Storage (“CCUS”) Committee Meeting. August 25.

33. “The 2020 Gulf Coast Energy Outlook: COVID-19 update.” (2020). Baton Rouge Area Chamber of Commerce Business Webinar. COVID-19 and Global Supply Impacts on the Capital Region and Louisiana Economies. Baton Rouge, LA. June 3.

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

35. “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.

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

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

38. "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.

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

40. "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

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

42. "Louisiana's coast and the energy industry." (2019). 2019 API Delta Chapter Joint Society Luncheon Meeting. November 12, 2019, New Orleans, LA.

43. "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.

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

45. "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)

46. "Natural gas outlook: supply, demand, and prices." (2019). NASUCA Mid-Year Meeting. Portland, OR, June 20.

47. "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.

48. "Overview of Louisiana energy issues and outlook." (2019). Australian Media Visit, Greater New Orleans, Inc./Baton Rouge Area Foundation. Baton Rouge, LA, April 29.

49. "Gulf Coast Energy Outlook 2019: Regional trends and outlook." (2019). Women's Energy Network. Baton Rouge, LA, April 23.

50. "MISO Grid Vision 2033." (2019). 2019 Spring Regulator and Policymaker Forum. New Orleans, LA, April 15-16.

51. "Ratepayer benefits of reforming PURPA." (2019). LSU Center for Energy Studies Industry Advisory Council Meeting. March 27.

52. "Incentives, risk, and the changing nature of regulation." (2019). NASUCA Water Committee monthly meeting/webinar. March 13.

53. "Gulf Coast Energy Outlook 2019: Production, trade and infrastructure trends." (2019). 66th Annual Mineral Board Institute Meetings. Baton Rouge, LA, March 14.

54. "A golden age: energy outlook 2019." (2019). Engineering News Record Webinar. February 13.

55. Panelist. (2019). Baton Route Advocate, 2019 Economic Outlook Summit. Baton Rouge Advocate. January 8.

56. “MISO Grid Vision 2033.” (2018). 2018 Winter Regulatory and Policymaker Forum. New Orleans, LA, December 11.

57. “Gulf Coast Energy Outlook 2019.” (2018). LSU Center for Energy Studies, Baton Rouge, LA, Fall 2018.

58. “How LNG is transforming Louisiana’s energy economy.” (2018). Louisiana State Bar Association, Public Utility Section. Baton Rouge, LA, November 30.

59. “Overview of Louisiana LNG issues and trends.” (2018). Kean Miller Law Firm: Energy and Environmental Practice Group. Baton Rouge, LA, November 28.

60. “Infrastructure and capacity: challenges for development.” (2018). Society of Utility and Regulatory Financial Analysts (SURFA) Annual Meeting, New Orleans, LA, April 20.

61. “Louisiana industrial cogeneration trends.” (2018). Annual Louisiana Solid Waste Association Conference, Lafayette, LA, March 16.

62. “Gulf Coast industrial development: overview of trends and issues.” (2018). Gulf Coast Power Association Meetings, New Orleans, LA, February 8.

63. “Energy outlook – reflection on market trends and Louisiana implications.” (2017). IberiaBank Corporation Bank Board of Directors Meeting, New Orleans, LA. November 15.

64. “Integrated carbon capture and storage in the Louisiana chemical corridor.” (2017). Industry Associates Advisory Council Meeting, Baton Rouge, LA. November 7.

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

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

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

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

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

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

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

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

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

74. “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.

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

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

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

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

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

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

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

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

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

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

85. “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.

86. “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.

87. “Trends and Issues in Net Metering and Solar Generation.” (2015). Louisiana Rural Electric Cooperative Meeting. November 5.

88. “Electric Power: Industry Overview, Organization, and Federal/State Distinctions.” (2015). EUCI. October 16.

89. “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.

90. “Update and General Business Matters.” (2015). CES Industry Associates Meeting. Baton Rouge, Louisiana. Fall 2015.

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

92. “Industry on the Move – What’s Next?” (2015). Event Sponsored by Regional Bank and 1012 Industry Report. May 5.

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

94. “Energy, Louisiana, and LSU.” (2015). LSU Science Café. Baton Rouge, Louisiana. April 28.

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

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

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

98. “Louisiana’s Changing Energy Environment.” (2015). John P. Laborde Energy Law Center Advisory Board Spring Meeting, Baton Rouge, Louisiana. March 27.

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

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

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

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

103. “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.

104. “Overview EPA’s Proposed Clean Power Plan and Impacts for Louisiana.” (2014). Clean Cities Coalition Meeting, Baton Rouge, Louisiana. November 5.

105. “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.

106. “A Look at America’s Growing Demand for Natural Gas.” (2014). Louisiana Chemical Association Annual Meeting, New Orleans, Louisiana. October 23.

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

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

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

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

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

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

113. "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.

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

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

116. "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.

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

118. "Leveraging Energy for Industrial Development." (2013). 2013 Governor's Energy Summit, Jackson, Mississippi. December 5.

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

136. "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.

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

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

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

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

141. "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.

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

143. "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.

144. "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.

145. "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.

146. "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.

147. "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.

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

149. "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.

150. "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.

151. "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.

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

153. "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.

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

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

156. "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.

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

158. "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.

159. "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.

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

161. "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.

162. "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.

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

164. "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.

165. "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.

166. "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.

167. "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.

168. "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.

169. "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.

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

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

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

173. 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.

174. "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.

175. "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.

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

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

178. “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.

179. “Gulf Coast Energy Outlook: Issues and Trends.” Women’s Energy Network, Louisiana Chapter. September 17, 2009. Baton Rouge, LA.

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

181. “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.

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

183. “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

184. “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.

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

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

187. “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.

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

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

190. “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.

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

192. "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.

193. "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.

194. "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.

195. "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.

196. "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.

197. "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.

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

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

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

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

202. "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.

203. "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.

204. "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.

205. "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.

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

207. "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.

208. "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.

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

210. "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.

211. "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.

212. "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.

213. "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.

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

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

216. 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.

217. 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

218. 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.

219. "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

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

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

222. “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.

223. “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.

224. “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.

225. “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.

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

227. “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.

228. “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.

229. “The Outlook for Energy.” Lagniappe Studies Continuing Education Course. Baton Rouge, LA. July 11, 2005.

230. “The Outlook for Energy.” Sunshine Rotary Club. Baton Rouge, LA. April 27, 2005.

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

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

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

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

235. “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.

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

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

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

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

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

241. "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.

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

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

244. 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.

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

246. "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.

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

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

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

250. "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.

251. "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.

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

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

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

255. "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.

256. "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.

257. "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.

258. "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.

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

260. "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.

261. "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.

262. "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.

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

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

265. "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.

266. "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.

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

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

269. "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.

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

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

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

273. "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.

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

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

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

277. 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.

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

279. "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.

280. "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.

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

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

283. "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.

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

285. "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.

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

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

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

289. "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.

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

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

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

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

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

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

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

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

298. 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.

299. 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. Cause No. 45967. (2024). Before the Indiana Utility Regulatory Commission. *Petition of Northern Indiana Public Service Company LLC Pursuant to Ind. Code §§ 8-1-2-42, 8-1-2-42.7 and 8-1-2-61 for (1) authority to modify its retail rates and charges for gas utility service through a phase in of rates; (2) approval of new schedules of rates and charges, general rule sand regulations, and riders (both existing and new): (3) approval of a new sales reconciliation adjustment mechanism; (4) approval of revised gas deprecation rates applicable to its gas plant in service; (5) approval of necessary and appropriate accounting relief, including but not limited to approval of certain deferral mechanisms for pensions, other post-retirement benefits and line locate expenses; and (6) to the extent necessary, approval of any of the relief requested herein pursuant to Ind. Code Ch. 8-1-2-5.* On Behalf of Indiana Office of Utility Consumer Counselor. Issues: sales reconciliation adjustment.

2. Expert Testimony. F.C. No. 1176. (2024). Before the Public Service Commission of the District of Columbia. *In the Matter of the Application of Potomac Electric Power Company for Authority to Implement a Multiyear Rate Plan for Electric Distribution Service in the District of Columbia.* On Behalf of the Office of the People's Counsel for the District of Columbia. Issues: affordability, revenue distribution, rate design, multi-year rate planning, bill stabilization adjustment.

3. Expert Testimony. Case No. 23-0460-E-42T (2023). Before the Public Service Commission of West Virginia Charleston. *In the Matter of Monongahela Power Company and the Potomac Edison Company rule 42T tariff filing to increase rates and charges.* On Behalf of the Consumer Advocate Division of the Public Service Commission of West Virginia. Issues: cost of service, zero intercept study, revenue allocation, rate design, net energy metering rider.

4. Expert Testimony. Docket No. DPU 23-81. (2023). Before the Commonwealth of Massachusetts Department of Public Utilities. *Petition of Fitchburg Gas and Electric Light Company d/b/a Unitil (Gas Division), pursuant to G.L. c. 164, § 94 and 220 CMR 5.00, for Approval of a General Increase in Base Distribution Rates for Gas Service and a Performance-Based Ratemaking Plan.* On Behalf of the Massachusetts Office of the Attorney General, Office of Ratepayer Advocacy. Direct and Surrebuttal. Issues: alternative regulation performance-based ratemaking, cost of service, revenue distribution, rate design.

5. Expert Testimony. Docket No. DPU 23-80. (2023). Before the Commonwealth of Massachusetts Department of Public Utilities. *Petition of Fitchburg Gas and Electric Light Company d/b/a Unitil (Electric Division), pursuant to G.L. c. 164, § 94 and 220 CMR 5.00, for Approval of a General Increase in Base Distribution Rates for Electric Service and a Performance-Based Ratemaking Plan.* On Behalf of the Massachusetts Office of the Attorney General, Office of Ratepayer Advocacy. Direct and Surrebuttal. Issues: alternative regulation performance-based ratemaking, cost of service, revenue distribution, rate design.

6. Expert Testimony. Case No. 23-03803-W-42T and 23-0384-S-42T (2023). Before the Public Service Commission of West Virginia Charleston. In the Matter of West Virginia-America Water Company rule 42T application to increase rates and charges. On Behalf of the Consumer Advocate Division of the Public Service Commission of West Virginia. Issues: revenue distribution, rate design, affordability, service quality.

7. Expert Testimony. Cause No. 45933 (2023). Before the Indiana Utility Regulatory Commission. *Petition of Indiana Michigan Power Company an Indiana Corporation, for authority to increase rates and charges for electric utility service through a phase in rate adjustment; and for approval of related relief including: (1) revised depreciation rates, including cost of removal less salvage, and updated depreciation expense; (2) accounting relief, including deferrals and amortization; (3) inclusion of capital investment; (4) rate adjustment mechanism proposals, including new grant projects rider and modified tax rider; (5) a voluntary residential customer powerpay program; (6) waiver or declination of jurisdiction with respect to certain rules to facilitate implementation of the powerpay program; (7) cost recovery for cook plant subsequent license renewal evaluation project; and (8) new schedules of rates, rules and regulations.* On Behalf of Indiana Office of Utility Consumer Counselor. Issues: cost of service, rate design, revenue distribution, service fees.

8. Expert Report. (2023). *Alternative regulation deficiencies and potential ratepayer harms*. On Behalf of the Office of the Consumer Advocate of Iowa. October 3, 2023.

9. Expert Testimony. Docket No. 2023.06.057. (2023). Before the Public Service Commission of the State of Montana. *In the Matter of Energy West Montana's Application for Approval of Gas Cost Hedging Plan for West Yellowstone.* On Behalf of the Montana Consumer Counsel. Issues: gas hedging program.

10. Legislative Testimony. (2023). Ratepayer harms from alternative regulation in Oklahoma. Appearing on the Behalf of the Petroleum Alliance of Oklahoma. October 23, 2023.

11. Expert Testimony. Cause No. 45911. (2023). Before the State of Indiana Utility Regulatory Commission. *Petition of Indianapolis Power & Light Company D/B/A AES Indiana ("AES Indiana") for authority to increase rates and charges for electric utility service, and for approval of related relief, including (1) revised depreciation rates, (2) accounting relief, including deferrals and amortizations, (3) inclusion of capital investments, (4) rate adjustment mechanism proposals, including new economic development rider, (5) remote disconnect/reconnect process and (6) new schedules of rates, rules and regulations for service*. On Behalf of Indiana Office of Utility Consumer Counselor. Direct and Cross-Answering. Issues: allocated cost of service, revenue distribution, rate design, trackers.

12. Expert Testimony. Docket No. 23-06007. (2023). Before the Public Utilities Commission of Nevada. *In the Matter of the Application by Nevada Power Company D/B/A NV Energy, filed pursuant to NRS 704.110(3) and NRS 704.110(4), addressing its annual revenue requirement for general rates charged to all classes of electric customers.* On Behalf of the Nevada Bureau of Consumer Protection. Issues: marginal cost of service study, embedded cost of service study, revenue distribution, rate design.

13. Expert Testimony. Docket No. UE-230172. (2023). Before the Washington Utilities and Transportation Commission. *Washington Utilities and Transportation Commission, Complainant v. Pacificorp dba Pacific Power & Light Company, Respondent.* On Behalf of the Washington State Office of the Attorney General Public Counsel Unit. Issues: rate

design, revenue distribution, cost of service.

14. Expert Testimony. Case No. U-21389. (2023). Before the Michigan Public Service Commission. *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*. On Behalf of the Michigan Department of the Attorney General. Issues: capital expenditure adjustments, overview of proposal.

15. Expert Report. Case No. 22-1094-WW-AIR. (2023). *Audit of the Application to Increase Rates of Aqua Ohio, Inc. For the Period July 1, 2022 through June 30, 2023.* Prepared for the Public Utilities Commission of Ohio. Issues: cost of service, billing determinants, revenue distribution, rate design.

16. Expert Report. Case No. 22-1096-ST-AIR. (2023). *Audit of the Application to Increase Rates of Aqua Ohio Wastewater, Inc*. *For the period July 1, 2022 through June 30, 2023*. Prepared for the Public Utilities Commission of Ohio. Issues: cost of service, billing determinants, revenue distribution, rate design.

17. Expert Report. *Analysis of the effectiveness and ratepayer impacts regarding the Natural Gas Rate Stabilization Act of 2005. (S.C. Code Ann. Section 58-5-410).* On Behalf of the South Carolina Department of Consumer Affairs. July 27, 2023.

18. Expert Testimony. Docket No. 2023-70-G. (2023). Before the Public Service Commission of South Carolina. *In the Matter of: Dominion Energy South Carolina, Inc's application for adjustments in its natural gas rate schedules and tariffs.* On Behalf of the South Carolina Department of Consumer Affairs. Issues: revenue credit, revenue distribution, rate design. Direct and Surrebuttal.

19. Expert Testimony. Docket No. E-01345A-22-0144. (2023). Before the Arizona Corporation Commission. *In the Matter of the Application of Arizona Public Service Company for a hearing to determine the fair value of the utility property of the company for ratemaking purposes, to fix a just and reasonable rate of return thereon, and to approve rate schedules designed to develop such return. On Behalf of the Utilities Division Arizona Corporation Commission.* Issues: cost of service, revenue distribution, rate design. Direct and Surrebuttal.

20. Expert Testimony. Docket No. 23-0068 (consol.) 23-0069. (2023). Before the Illinois Commerce Commission. *North Shore Gas Company, The Peoples Gas Light and Coke Company Proposed general increase in rates and revisions to service classifications, riders and terms and conditions of service.* On Behalf of the People of the State of Illinois. Issues: integrity management, infrastructure metrics, natural gas policy, state gas policy.

21. Expert Testimony. Docket No. 23-067. (2023). Before the Illinois Commerce Commission. *Ameren Illinois Company Proposed general increase in gas delivery service rates.* On Behalf of the Illinois Attorney General. Issues: integrity management, infrastructure metrics, natural gas policy, state gas policy.

22. Expert Testimony. Docket No. 23-066. (2023). Before the Illinois Commerce Commission. *Northern Illinois Gas Company d/b/a Nicor Gas Company Proposed general increase in gas rates.* On Behalf of the People of the State of Illinois. Issues: integrity management, infrastructure metrics, natural gas policy, state gas policy.

23. Expert Testimony. Docket No. U-22-081. (2023). Before the Regulatory Commission of

Alaska. *In the Matter of the Revenue Requirement Study Designated as TA334-4 Filed by Enstar Natural Gas Company, A Division of SEMCO Energy, Inc.* On Behalf of the Attorney General, Regulatory Affairs & Public Advocacy Section. Issues: cost of service, rate design, revenue distribution.

24. Expert Testimony. Docket No. U-22-078. (2023). Before the Regulatory Commission of Alaska. *In the Matter of the Revenue Requirement Study and Tariff Filing Designated as TA510-1 Filed by Alaska Electric Light & Power Company.* On Behalf of the Office of the Attorney General, Regulatory Affairs & Public Advocacy Section. Issues: cost of service, rate design, seasonal rates, revenue allocation, customer charge.

25. Expert Testimony. Docket No. 2022.11.099. (2023). Before the Department of Public Service Regulation. *In the Matter of Montana-Dakota Utilities Co. for Authority to Establish Increased Rates for Electric Service.* On Behalf of the Montana Consumer Counsel. Direct and Cross-Answering. Issues: rate increase, cost of service study, marginal cost of service, revenue allocation, rate design.

26. Expert Testimony. Docket No. U-22-078. (2023). Before the Regulatory Commission of Alaska. *In the Matter of the Revenue Requirement Study and Tariff Filing Designated as TA510-1 Filed by Alaska Electric Light & Power Company.* On Behalf of the Office of the Attorney General, Regulatory Affairs & Public Advocacy Section. Issues: rate design, cost of service, revenue allocation, seasonal rates.

27. Expert Testimony. Docket No. U-21193. (2023). 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.* On Behalf of the Michigan Department of the Attorney General. Issues: Resource planning, coal retirements, asset amortization, financial compensation mechanism.

28. Expert Testimony. Docket No. RP22-1033. (2023). Before the Federal Energy Regulatory Commission. *Northern Natural Gas Company.* On Behalf of the Northern Municipal Distributors Group and the Midwest Region Gas Task Force Association. Issues: tariff provisions, rate analysis, discount adjustment.

29. Expert Testimony. Docket No. 22-061-U. (2023). Before the Arkansas Public Service Commission. *In the Matter of an Investigation into Potential Cost Shifting Associated with Net Metering.* On Behalf of the Office of Tim Griffin, Attorney General of Arkansas. Issues: policy, net metering background.

30. Expert Testimony. Docket No. 22F-0263EG. (2023). Before the Public Utility Commission of the State of Colorado. *Olson's Greenhouses of Colorado, LLC. Complainant, v. Public Service Company of Colorado Respondent*. On Behalf of Olson's Greenhouses of Colorado, LLC. Issues: reliability, system upgrades, weather normalization.

31. Expert Testimony. Docket No. 2022.07.078. (2022). Before the Public Service Commission of the State of Montana. *In the Matter of NorthWestern Energy's Application for Authority to Increase Retail Electric and Natural Gas Utility Rates and for Approval of Electric and Natural Gas Service Schedules and Rules and Allocated Cost of Service and Rate Design.* On Behalf of the Montana Consumer Counsel. Direct and Cross-Intervenor. Issues: riders, fixed cost recovery mechanism, power cost adjustment, cost of service, revenue distribution.

32. Expert Testimony. Docket No 2022-254-E. (2022). Before the Public Service Commission

of South Carolina. *In the Matter of: Application of Duke Energy Progress, LLC for Authority to Adjust and Increase its Electric Rates and Charges.* On Behalf of South Carolina Department of Consumer Affairs. Direct and Surrebuttal. Issues: Cost of service, revenue allocation, rate design.

33. Expert Testimony Docket No. 22-06014. (2022). *Before the Public Utilities Commission of Nevada. In the Matter of the Application by Sierra Pacific Power Company D/B/A NV Energy, filed pursuant to NRS 704.110(3) and NRS 704.110(4), addressing its annual revenue requirement for general rates charged to all classes of electric customers*. On Behalf of the Nevada Bureau of Consumer Protection. Issues: rate design, cost of services, marginal cost of service, revenue distribution.

34. Expert Testimony Docket No. 2022.06.067. (2022). *Before the Public Service Commission of the State of Montana. In RE NorthWestern Energy's Application for an Advanced Metering Opt-Out Tariff.* On Behalf of the Montana Consumer Counsel. Direct and Rebuttal. Issues: meter issues, opt-out fees, tariffs options.

35. Expert Testimony Docket No. 16-036-FR. (2022). *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 Arkansas Attorney General Leslie Rutledge.* Issues: Rate design, netting adjustment, performance standards, projected year adjustments.

36. Expert Testimony Formal Case No. 1169. (2022). *Before the Public Service Commission of the District of Columbia. In the Matter of the application of Washington Gas Light Company for authority to increase existing rates and charges for gas service.* On Behalf of the People's Counsel for the District of Columbia. Direct and Rebuttal. Issues: Revenue allocation, weather normalization, rate design.

37. Expert Testimony Case No. U-21224. (2022). *Before the Michigan Public Service Commission. 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*. On Behalf of the Michigan Department of the Attorney General. Issues: cost of service, revenue distribution, policy overview.

38. Expert Report. Case No. 695287. (2022). Before the Nineteenth Judicial District Court, The Parish of East Baton Rouge, State of Louisiana. *Washington-St. Tammany Electric Cooperative, Inc. and Claiborne Electric Cooperative, Inc., Plaintiff v. Louisiana Generating, L.L.C., Defendant.* On Behalf of Louisiana Generating, L.L.C. Issues: environmental regulations, re-fueling, regulatory rules, collateral benefits.

39. Expert Report. Case No. 0:20-cv-60981-AMC. (2022). *Café, Gelato & Panini LLC, d/b/a Café Gelato Panini, on behalf of itself and all others similarly situated, Plaintiff v. Simon Property Group, Inc., Simon Property Group, L.P., M. S. Management Associates, Inc. And The Town Center at Boca Raton Trust, Defendant.* On Behalf of Simon Property Group, Inc.

40. Expert Testimony Case No. U-20836. (2022). *Before the 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.* On Behalf of the Michigan Department of the Attorney General. Issues: cost of service, revenue

distribution, peer comparison.

41. Expert Testimony. D.P.U. 22-22. (2022*). Before the Department of Public Utilities of the Commonwealth of Massachusetts. Petition of NSTAR Electric Company d/b/a Eversource Energy for Approval of a Performance-Based Ratemaking Plan and 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 Massachusetts Office of the Attorney General Office of Ratepayer Advocacy. Issues: rate design, TFP analysis, rate increases, benchmark analysis, revenue distribution. Direct and Surrebuttal.

42. Expert Testimony. Docket No. 21-097-U. (2022). In the Matter of the Application of Black Hills Energy Arkansas, Inc. for Approval of a General Change in Rates and Tariffs. On Behalf of the Office of Arkansas Attorney General. Issues: cost of service, rate design, reliability, billing determinant adjustment.

43. Expert Testimony. Docket No. 2021-361-G. (2022). Before the Public Service Commission of South Carolina. *In the Matter of: Dominion Energy South Carolina, Inc.'s Request for Approval of New Natural Gas Energy Efficiency Programs*. On Behalf of South Carolina Department of Consumer Affairs. Issues: DSM Rider, energy efficiency, shared savings. Direct and Surrebuttal.

44. Expert Report. Case No. 21-596-ST-AIR. (2022). *Audit of the Application to Increase Rates of Aqua Ohio Wastewater, Inc. For the Period January 1, 2021 through December 31, 2021*. Prepared for Public Utilities Commission of Ohio. Issues: rate design, cost of service, revenue distribution.

45. Expert Report. Case No. 21-595-WW-AIR. (2022). *Audit of the Application to Increase Rates of Aqua Ohio, Inc*. *For the Period January 1, 2021 through December 31, 2021.* Prepared for Public Utilities Commission of Ohio. Issues: rate design, cost of service, revenue distribution.

46. Expert Testimony. Docket No. 2021.09.112. (2022). *Before the Public Service Commission of the State of Montana. In the Matter of NorthWestern Energy's Annual PCCAM Filing and Application for Approval of Tariff Changes.* On Behalf of the Montana Consumer Counsel. Issues: wholesale energy hedging, market exposure, overview of PCCAM filing, demand side management costs.

47. Expert Affidavit. Docket No. 2:21-cv-1074. (2021). In the United States District Court for the Western District of Louisiana. *The State of Louisiana by and through its Attorney General, Jeff Landry et al. Plantiffs, v. Joseph R. Biden, Jr., in his official capacity as President of the United States; et al., Defendants.* On Behalf of the Attorney General of Louisiana. Issues: social cost of carbon, carbon tax, environmental policy.

48. Expert Testimony. Case No. U21090. (2021). *Before the Michigan Public Service Commission. In the matter of the application of Consumers Energy Company for approval of its Integrated Resource Plan pursuant to MCL 460.6t, certain accounting approvals, and for other relief*. On Behalf of the Michigan Department of the Attorney General. Issues: IRP, coal plant retirements, acquisition premiums, financial compensation mechanism.

49. Expert Testimony. Docket No 16-036-FR. (2021). 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 Arkansas Attorney General Leslie Rutledge. Issues: netting adjustments, rate increases, projected year

adjustments, reliability.

50. Expert Report. Docket JCCP No. 4861. (2021). Before the Superior Court of the State of California County of Los Angeles, Central Civil West. *Coordination Proceeding Special Title [Rule 3.550] Southern California Gas Leak Cases.* On Behalf of Toll Brothers. Issues: gas leak, public service obligation, integrity management.

51. Expert Testimony. Docket No. U-35927. (2021). Before the Louisiana Public Service Commission. *In Re: Application of 1803 Electric Cooperative, Inc. for Approval of Power Purchase Agreements and for Cost Recovery.* Direct and Cross-Answering. On Behalf of Cleco Cajun LLC. Issues: tolling agreements, generation acquisition, risk factors.

52. Expert Testimony. Docket No. 21-060-U. (2021). Before the Arkansas Public Service Commission. *In the Matter of Joint Application of Centerpoint Energy Resources Corp. and Summit Utilities Arkansas, Inc. For all Necessary Authorizations and Approvals for Summit Utilities Arkansas, Inc. To Acquire the Arkansas Assets of Centerpoint Energy Resources Corp. and for Approval of a Certificate of Public Convenience and necessity for Summit Utilities Arkansas, Inc.* Direct and Surrebuttal. On Behalf of the Office of Arkansas Attorney General Leslie Rutledge. Issues: asset acquisition, ratepayer benefits, acquisition synergies, Rider FRP.

53. Expert Affidavit. Civil Action No. 2:21-cv-00778 (2021). Before the United States District Court for the Western District of Louisiana. *The State of Louisiana v. Joseph R. Biden, Jr.* Issues: leasing and drilling moratorium, state revenue, coastal restoration, economic activity.

54. Expert Testimony. Docket No. 21-044-U (2021). Before the Arkansas Public Service Commission. *In the Matter of Centerpoint Energy Resources Corp. D/B/A Centerpoint Energy Arkansas Gas' Request to Extend Rider FRP.* On Behalf of the Office of Arkansas Attorney General Leslie Rutledge. Issues: ratepayer benefits, service quality, cost of service, FRP extension.

55. Expert Testimony. Docket No. 17-010-FR (2021). 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.* On Behalf of the Office of Arkansas Attorney General Leslie Rutledge. Issues: rate increase, investment and expense trends, revenue deficiency, leak performance.

56. Expert Testimony. Case No. U-20963 (2021). Before the Michigan Public Service Commission. *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.* On Behalf of the Michigan Department of the Attorney General. Issues: cost of service, peak allocation, revenue distribution.

57. Expert Testimony. U-20-072, U-20-073, U-20-074. (2021). Before the Regulatory Commission of Alaska. *In the Matter of the Revenue Requirement study and Tariff Filing designated as TA886-2 filed by Alaska Power Company, In the Matter of the Revenue Requirement study and Tariff filing designated as TA6-521 filed by Goat Lake Hydro, Inc., In the Matter of the Revenue Requirement study and Tariff filing designated as TA4-573 filed by BBL Hydro, Inc.* On Behalf of the Alaska Office of Attorney General. Issues: rate groups, cost of service.

58. Expert Testimony. Docket No. P20-001. (2021). Before the Louisiana Pilotage Fee

Commission. *In Re: Request for Increase in Approved Pilot Complement; Increased Funding for necessary Additional Manpower; Upward Adjustment of Estimated Average Annual Pilot Compensation; and Related Relief Pursuant to LA R.S. 34:112.* On Behalf of the Louisiana Chemical Association (LCA) and Louisiana Mid-Continent Oil & Gas Association (LMOGA). Issues: unreasonable requests, fee structure, economic impact, over earnings.

59. Expert Testimony. D.P.U. 20-120. (2021). Before the Commonwealth of Massachusetts Before the Department of Public Utilities. *Petition of Boston Gas Company d/b/a National Grid Pursuant to G.L. c. 164, 94 and 220 C.M.R. 5.00 for Approval of an Increase in Base Distribution Rates and Approval of a Performance-Based Ratemaking Plan.* On Behalf of the Massachusetts Office of the Attorney General Office of Ratepayer Advocacy. Issues: rate increase, accelerated depreciation, benchmarking analysis, performance incentive mechanism.

60. Expert Testimony. RPU-2020-0001. (2020). Before the Iowa Utilities Board. *In Re: Iowa-American Water Company.* On Behalf of the Office of Consumer Advocate. Issues: rate increase, test trackers, RSM accounting ratemaking construct.

61. Expert Testimony. BPU Docket Nos. QO19010040 and GO20090622. (2020). Before the New Jersey Board of Public Utilities. *In the Matter of the Petition of New Jersey Natural Gas Company for Approval of Energy Efficiency Programs and the Associated Cost Recovery Mechanisms Pursuant to the Clean Energy Act, N.J.S.A. 48:3-87.8 et seq. and 48:3-98.1 et seq.* On behalf of the Division of Rate Counsel. Issues: CBA requirements, capacity benefits, volatility benefits.

62. Expert Testimony. Docket No. 2020-125-E. (2020). Before the Public Service Commission of South Carolina. *In the Matter of: Application of Dominion Energy South Carolina, Incorporated for Adjustments of Rates and Charges (See Commission Order No. 2020-313).* On Behalf of the South Carolina department of Consumer Affairs. Issues: cost of service, revenue allocation, rate design.

63. Answering Testimony. Before the United States of America Federal Energy Regulatory Commission. Docket No. RP20-614-000 and RP20-618-000. (2020). *Transcontinental Gas Pile Line Company, LLC.* On Behalf of the North Carolina Utilities Commission. Issues: Tariff revisions, assessment of Transco claims.

64. Expert Testimony. Docket No. 16-036-FR. (2020). *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. Direct and Surrebuttal*. On Behalf of the Arkansas Attorney General Leslie Rutledge. Issues: rate increases, investment and expenses trends, load forecast, historic year netting adjustment, reliability issues.

65. Expert Testimony. Docket No. 2019.12.101. (2020). Before the Public Service Commission of the State of Montana. *In the Matter of NorthWestern Energy's Application for Approval of Capacity Resource Acquisition.* On the Behalf of the Montana Consumer Counsel. Issues: sale of capital asset, evaluation benefits, ratepayer cost exposure, reserve fund.

66. Expert Testimony. Formal Case No. 1162. (2020). Before the Public Service Commission of the District of Columbia. *In the Matter of the Application of Washington Gas Light Company for Authority to Increase Existing Rates and Charges for Gas Service*. On Behalf

of the Office of the People's Counsel. Issues: rate increase, revenue adjustment, weather normalization, rate design, revenue distribution.

67. Expert Testimony. Docket No. E-01345A-19-0236. (2020). Before the Arizona Corporation Commission. *In the Matter of the Application of Arizona Public Service Company for Ratemaking Purposes to Fix a Just and Reasonable Rate of Return Thereon, to Approve Rate Schedules Designed to Develop such Return*. Direct and Surrebuttal. On Behalf of the Utilities Division of the Arizona Corporation Commission. Issues: Cost of Service, Revenue Distribution, Rate Design.

68. Expert Testimony. Docket No. 17-010-FR. (2020). 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.* On Behalf of the Arkansas Attorney General Leslie Rutledge. Issues: rate increase, leak replacement and reduction, netting adjustment, revenue deficiency, accounting policy changes.

69. Expert Testimony. Case No. U-20697. (2020). Before the Michigan Public Service Commission. *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*. On Behalf of the Michigan Department of Attorney General. Issues: cost of service, revenue distribution, rate design.

70. Expert Testimony. Docket No. 2019.09.058. (2020). Before the Public Service Commission of the State of Montana. *In the Matter of NorthWestern Energy's Annual PCCAM Filing and Application for Approval of Tariff Changes*. On the Behalf of the Montana Consumer Counsel. Issues: purchase power expenses, cost sharing, PCAAM power cost.

71. Expert Testimony. Formal Case No. 1156. (2020). Before the 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.* Direct, Rebuttal, Surrebuttal, Supplemental, and Second Supplemental. On Behalf of the Office of the People's Counsel. Issues: revenue distribution, rate design, customer charge, performance metric policies, performance metric incentives.

72. Expert Testimony. Case No. U-20561. (2019). Before the 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*. On Behalf of the Michigan Department of Attorney General. Issues: Cost of service, allocation of production plant, allocation of sub-transmission plant, revenue distribution.

73. Expert Testimony. Cause No. 45253. (2019). Before the 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*. On Behalf of the Indiana Office of

Utility Consumer Counsel. Issues: Decoupling, revenue decoupling mechanism and design, commission policy, benchmarking analysis.

74. 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.* On Behalf of the Arkansas Attorney General Leslie Rutledge. Issues*:* Solar investment, risk assessment, proposed rider.

75. 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.* On Behalf of the Arkansas Attorney General Leslie Rutledge. Issues: rate design, reliability, and formula rate plan.

76. 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*. On Behalf of the Arkansas Attorney General Leslie Rutledge. Issues: Solar project approval, ratepayer risk, cost allocation.

77. 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.* On Behalf of the Arkansas Attorney General Leslie Rutledge. Issues: retail rates, leak analysis, revenue deficiency, investments.

78. 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.* On Behalf of the Michigan Department of Attorney General. Issues: load forecasting, least-cost system planning.

79. 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.* On Behalf of the City of Leesburg. Issues: retail rates, customer growth, sales trends and forecasts, policy, cost of service, socio-economic trends and forecasts.

80. 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.* On behalf of the Division of Rate Counsel. Issues: economic impact, cost benefit analysis, decoupling mechanisms.

81. 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)*. On behalf of the Division of Rate Counsel. Issues: economic impact, cost benefit analysis, infrastructure replacement, cost recovery tracker mechanisms.

82. 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.* On Behalf of the Mississippi

Public Utilities Staff. Issues: Net-metering, distributed generation.

83. 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.* On Behalf of the Montana Consumer Counsel. Issues: Net-metering, cost of service, revenue distribution, rate design.

84. 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*. On the Behalf of the Kansas Electric Power Cooperative, Inc. Issues: merger impacts, rates, tariffs.

85. 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.* On Behalf of the Arkansas Attorney General Leslie Rutledge. Issues: formula rate plan, plant investment and expenses benchmarking analysis, reliability.

86. 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.* On Behalf of the Arkansas Attorney General Leslie Rutledge. Issues: rate design, reliability, and formula rate plan.

87. 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.* On Behalf of the Mississippi Public Utilities Staff. Issues: cost of service and rate design.

88. 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.

89. 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.* On behalf of the Division of Rate Counsel. Issues: regulatory policy and cost-benefit analyses.

90. 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.* On behalf of the Division of Rate Counsel. Issues: rate proposal, revenue decoupling, regulatory policy, cost benchmarking.

91. 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. On Behalf of Energy XXI GOM, LLC. Issues: cost of service, rate design, and alternative regulation.

92. 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*. On Behalf of the Arkansas Attorney General Leslie Rutledge. Issues: cost of service, rate design, billing determinates.

93. 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.* On Behalf of the Arkansas Attorney General Leslie Rutledge. Issues: cost of service, rate design, alternative regulation, formula rate plan.

94. 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*. On Behalf of the North Dakota Service Commission Advocacy Staff. Issues: cost of service, marginal cost of service, and rate design.

95. 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.

96. 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.

97. 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”). On behalf of the Division of Rate Counsel. Issues: economic impact, infrastructure replacement program rider, pipeline replacement, leak rate comparisons and cost benefit analysis.

98. 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.

99. 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.

100. 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.

101. 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.* On Behalf of the Office of the Kentucky Attorney General. Issues: rate design, revenue allocation, economic development.

102. 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.* On Behalf of the Arkansas Attorney General Leslie Rutledge. Issues: cost of service, rate design, alternative regulation, formula rate plan.

103. 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.

104. 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.

105. 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.

106. 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.

107. 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.

108. 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.

109. 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.

110. 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 Office of Consumer Advocate. Issue: revenue stabilization mechanism, revenue decoupling.

111. 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.

112. 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.

113. 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.

114. 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.

115. 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.

116. 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.

117. 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.

118. 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.

119. 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.

120. 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.

121. 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.

122. 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.

123. 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.

124. 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.

125. 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.

126. 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.

127. 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.

128. 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.

129. 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.

130. 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.

131. 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.

132. 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.

133. 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.

134. 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.

135. 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.

136. 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.

137. 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.

138. 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.

139. 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.

140. 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.

141. 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

142. 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.

143. 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.

144. 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.

145. 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.

146. 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.

147. 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.

148. 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.

149. 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.

150. 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.

151. 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.

152. 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.

153. 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.

154. 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.

155. 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.

156. 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.

157. 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.

158. 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.

159. 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.

160. 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.

161. 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.

162. 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)

163. 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.

164. 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.

165. 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.

166. 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.

167. 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.

168. 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.

169. 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.

170. 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.

171. 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.

172. 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.

173. 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.

174. 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.

175. 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.

176. 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.

177. 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.

178. Expert Report, Recommendation, and Proposed Rule: Docket Number R-29380-A, ex parte, (2009). Before the Louisiana Public Service Commission. In re: Environmental Adjustment Clause and Environmental Certification for Electric Power Generation Resources. 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 cost recovery treatment; other generation planning issues.

179. 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.

180. 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.

181. 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.

182. 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.

183. 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.

184. 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.

185. 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.

186. 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.

187. 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)

188. 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)

189. 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.

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

191. 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.

192. 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).

193. 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.

194. 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.

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

196. 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.

197. 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.

198. 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.

199. 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)

200. 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.

201. 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.

202. 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.

203. 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).

204. 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.

205. 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.

206. 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.

207. 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)

208. 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.

209. 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.

210. 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).

211. 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.

212. 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.

213. 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

214. 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.

215. 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.

216. 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.

217. 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.

218. 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.

219. 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.

220. 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)

221. 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.

222. 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.

223. 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.

224. 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.

225. 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.

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

227. 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.

228. 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).

229. 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.

230. 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.

231. 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.

232. 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.

233. 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.

234. 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.

235. 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.

236. 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.

237. 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.

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

239. 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.

240. 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.

241. 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

Baton Rouge Business Report, Selected as one of the "Capital Region 500" (2023).

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.

Program Committee Member (2016). Gulf Coast Power Association Conference. New Orleans.

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. 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 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).

Witness: Dismukes
Cause No. 45990

Table of Exhibits

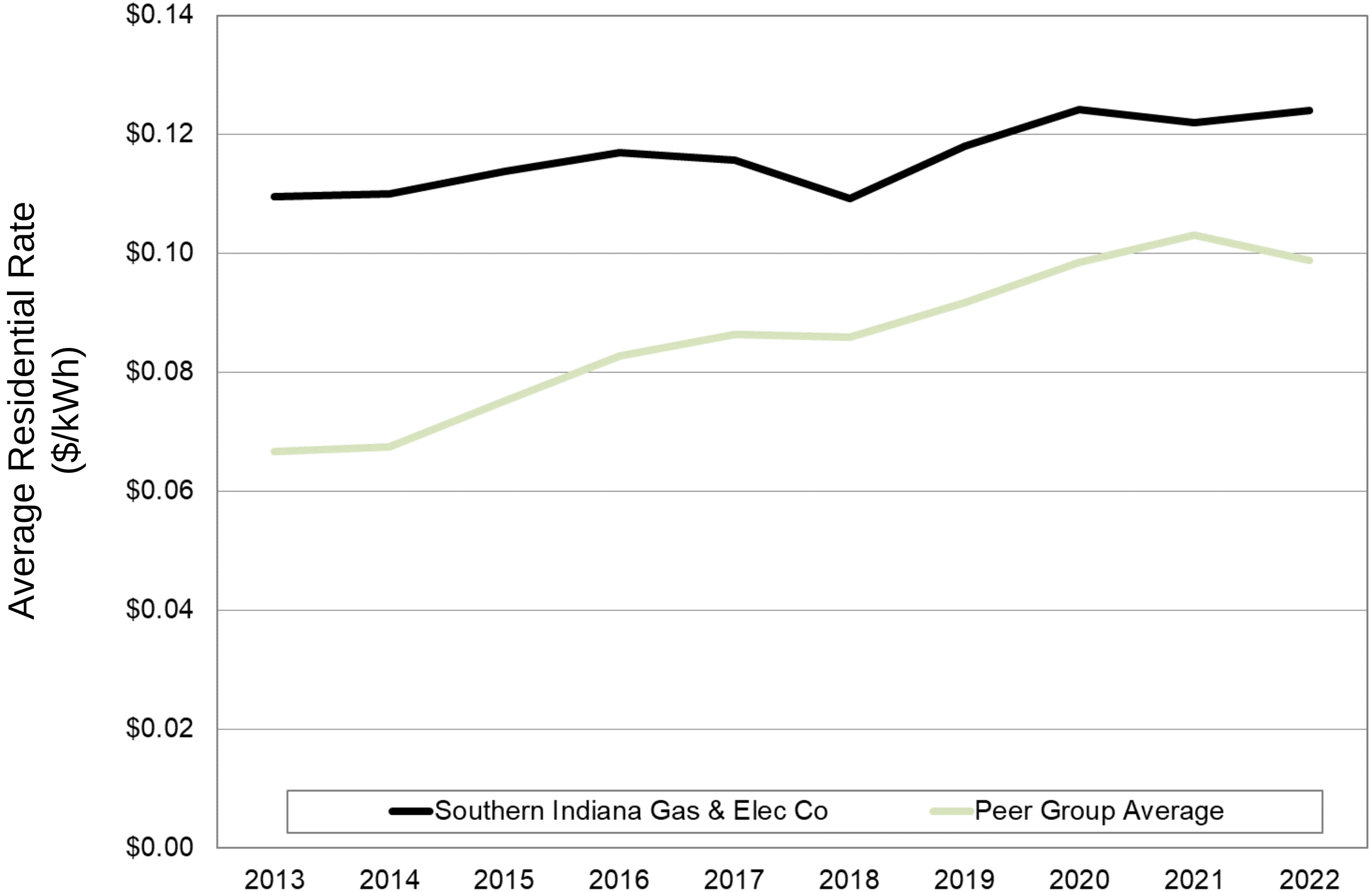
Comparison of CEI South's Rates to Regional Peers
Residential Rates

Company	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
	($/kWh)									
Southern Indiana Gas & Elec Co	**$0.110**	**$0.110**	**$0.114**	**$0.117**	**$0.116**	**$0.109**	**$0.118**	**$0.124**	**$0.122**	**$0.124**
Consumers Energy Co	0.091	0.091	0.097	0.106	0.109	0.108	0.111	0.109	0.127	0.116
DTE Electric Company	0.117	0.108	0.117	0.129	0.129	0.129	0.136	0.147	0.151	0.143
Indianapolis Power & Light Co	0.057	0.054	0.061	0.071	0.075	0.075	0.080	0.083	0.085	0.074
Indiana Michigan Power Co	0.041	0.054	0.064	0.072	0.078	0.085	0.099	0.115	0.115	0.108
Kentucky Utilities Co	0.058	0.059	0.065	0.070	0.075	0.069	0.077	0.082	0.085	0.087
Louisville Gas & Electric Co	0.061	0.061	0.070	0.073	0.078	0.073	0.080	0.086	0.085	0.087
Northern Indiana Pub Serv Co	0.091	0.094	0.099	0.100	0.113	0.109	0.113	0.129	0.132	0.130
Duke Energy Indiana, LLC	0.068	0.072	0.076	0.078	0.080	0.079	0.083	0.087	0.092	0.084
Duke Energy Kentucky	0.050	0.046	0.048	0.053	0.053	0.057	0.061	0.064	0.070	0.071
Kentucky Power Co	0.034	0.035	0.053	0.074	0.074	0.076	0.079	0.082	0.089	0.087
Peer Group Average	**$0.067**	**$0.068**	**$0.075**	**$0.083**	**$0.086**	**$0.086**	**$0.092**	**$0.098**	**$0.103**	**$0.099**

Company	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
	(Ranking)									
Southern Indiana Gas & Elec Co	**10**	**11**	**10**	**10**	**10**	**10**	**10**	**9**	**8**	**9**
Consumers Energy Co	8	8	8	9	8	8	8	7	9	8
DTE Electric Company	11	10	11	11	11	11	11	11	11	11
Indianapolis Power & Light Co	4	4	3	3	4	4	5	4	3	2
Indiana Michigan Power Co	2	3	4	4	6	7	7	8	7	7
Kentucky Utilities Co	5	5	5	2	3	2	2	3	2	6
Louisville Gas & Electric Co	6	6	6	5	5	3	4	5	4	4
Northern Indiana Pub Serv Co	9	9	9	8	9	9	9	10	10	10
Duke Energy Indiana, LLC	7	7	7	7	7	6	6	6	6	3
Duke Energy Kentucky	3	2	1	1	1	1	1	1	1	1
Kentucky Power Co	1	1	2	6	2	5	3	2	5	5

Source: FERC Form 1

Comparison of CEI South's Rates to Regional Peers
Residential Rates



Source: FERC Form 1

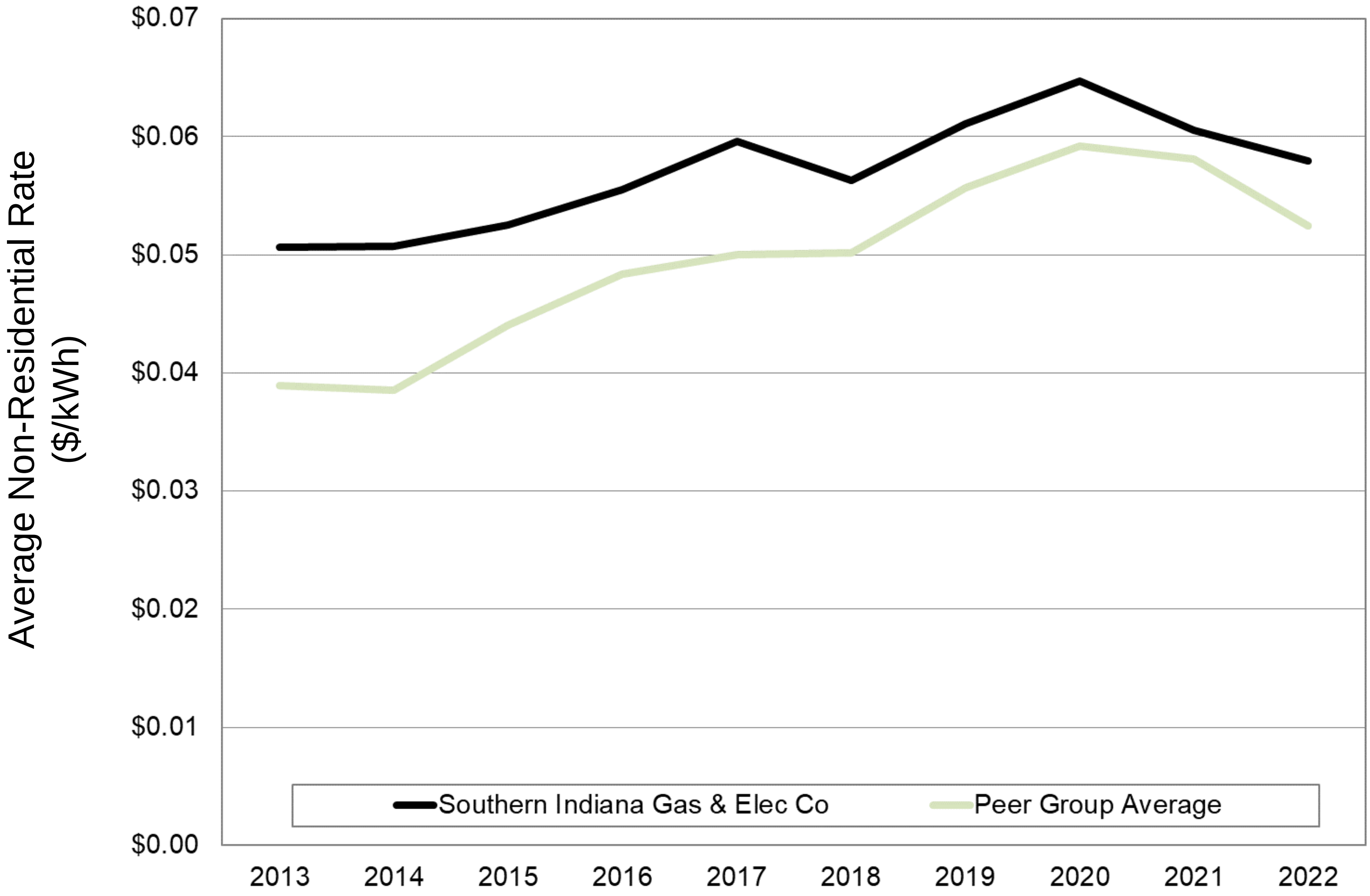
Comparison of CEI South's Rates to Regional Peers
Non-Residential Rates

Company	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
	($/kWh)									
Southern Indiana Gas & Elec Co	**$0.051**	**$0.051**	**$0.053**	**$0.055**	**$0.060**	**$0.056**	**$0.061**	**$0.065**	**$0.061**	**$0.058**
Consumers Energy Co	0.054	0.050	0.055	0.055	0.057	0.057	0.062	0.065	0.063	0.050
DTE Electric Company	0.062	0.057	0.058	0.061	0.063	0.062	0.067	0.071	0.075	0.066
Indianapolis Power & Light Co	0.045	0.045	0.050	0.058	0.058	0.058	0.061	0.062	0.064	0.055
Indiana Michigan Power Co	0.012	0.020	0.028	0.035	0.039	0.041	0.049	0.059	0.056	0.048
Kentucky Utilities Co	0.037	0.038	0.042	0.047	0.049	0.046	0.054	0.058	0.058	0.060
Louisville Gas & Electric Co	0.042	0.042	0.050	0.053	0.055	0.051	0.059	0.063	0.062	0.062
Northern Indiana Pub Serv Co	0.048	0.049	0.054	0.053	0.059	0.056	0.060	0.059	0.058	0.057
Duke Energy Indiana, LLC	0.039	0.041	0.043	0.045	0.045	0.046	0.050	0.052	0.050	0.044
Duke Energy Kentucky	0.039	0.034	0.034	0.038	0.036	0.044	0.053	0.055	0.051	0.044
Kentucky Power Co	0.010	0.010	0.026	0.040	0.038	0.042	0.043	0.047	0.044	0.038
Peer Group Average	**$0.039**	**$0.039**	**$0.044**	**$0.048**	**$0.050**	**$0.050**	**$0.056**	**$0.059**	**$0.058**	**$0.052**

Company	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
	(Ranking)									
Southern Indiana Gas & Elec Co	**9**	**10**	**8**	**9**	**10**	**7**	**9**	**9**	**7**	**8**
Consumers Energy Co	10	9	10	8	7	9	10	10	9	5
DTE Electric Company	11	11	11	11	11	11	11	11	11	11
Indianapolis Power & Light Co	7	7	6	10	8	10	8	7	10	6
Indiana Michigan Power Co	2	2	2	1	3	1	2	5	4	4
Kentucky Utilities Co	3	4	4	5	5	5	5	4	6	9
Louisville Gas & Electric Co	6	6	7	6	6	6	6	8	8	10
Northern Indiana Pub Serv Co	8	8	9	7	9	8	7	6	5	7
Duke Energy Indiana, LLC	5	5	5	4	4	4	3	2	2	3
Duke Energy Kentucky	4	3	3	2	1	3	4	3	3	2
Kentucky Power Co	1	1	1	3	2	2	1	1	1	1

Source: FERC Form 1

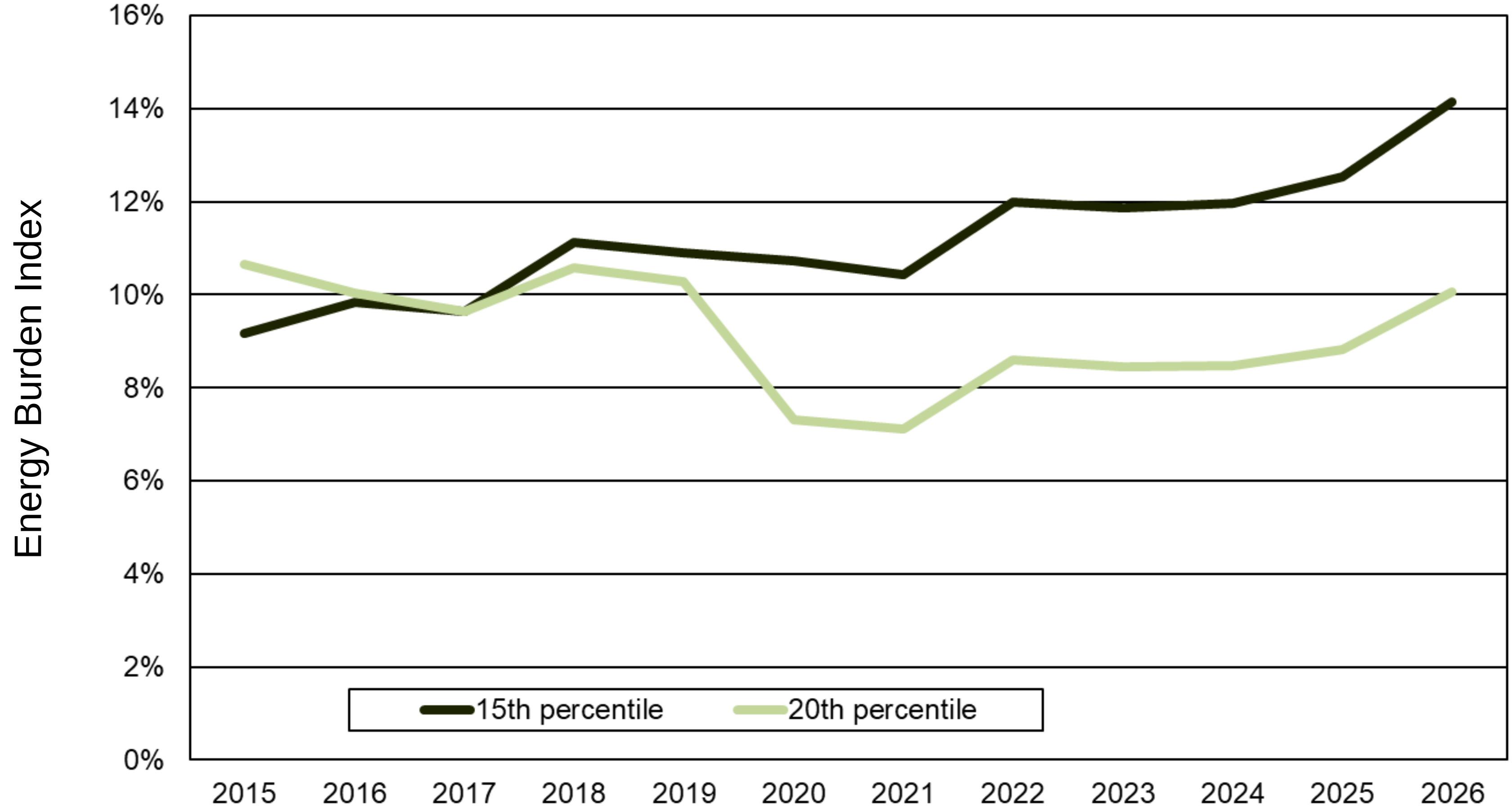
Comparison of CEI South's Rates to Regional Peers Residential Rates



Source: FERC Form 1

Energy Burden in CEI South's Service Territory

Witness: Dismukes
Cause No. 45990
Exhibit DED-2



Source: Census Bureau and CEI South Tariffs.

Results of CEI South's Allocated Cost of Service Study: Relative Rate of Return at Current Rates

Line No.	Account Description	Total CEI South	Residential: Residential Service (RS)	Residential: Water Heating (B)	Small General Service (SGS)	Demand General Service (DGS)	Large Power Service (LP)	High Load Factor Service (HLF)	Lighting: Outdoor Lighting (OL)	Lighting: Street Lighting (SL)
1	**Rate Base**									
2	Electric Plant in Service	$3,903,417,227	$1,890,792,021	$ 10,604,590	$ 80,518,536	$1,099,761,750	$ 758,812,968	$ 27,387,476	$ 8,946,173	$ 26,593,713
3	Accumulated Depreciation and Amortization	(1,227,300,954)	(605,930,521)	(4,175,694)	(28,979,564)	(333,956,266)	(227,404,616)	(8,311,811)	(3,861,732)	(14,680,750)
4	Net Electric Plant in Service	$2,676,116,273	$1,284,861,500	$ 6,428,895	$ 51,538,972	$ 765,805,484	$ 531,408,352	$ 19,075,665	$ 5,084,441	$ 11,912,964
5	Total Other Rate Base Items	144,352,487	$ 69,468,970	$ 483,738	$ 3,075,424	$ 39,221,516	$ 30,129,059	$ 1,429,035	$ 154,613	$ 390,131
6	**Total Electric Rate Base**	**$2,820,468,760**	**$1,354,330,471**	**$ 6,912,634**	**$ 54,614,396**	**$ 805,027,000**	**$ 561,537,411**	**$ 20,504,700**	**$ 5,239,054**	**$ 12,303,095**
7	**Operating Income**									
8	**Operating Revenues**									
9	Base Rate Revenues	$ 267,328,655	$ 132,139,578	$ 530,561	$ 5,953,227	$ 75,824,903	$ 48,031,238	$ 1,868,205	$ 1,152,148	$ 1,828,794
10	Rider Revenues	118,109,906	59,668,199	479,352	3,587,192	38,038,775	15,410,774	750,947	29,159	145,507
11	Variable Production Revenue	18,054,808	6,551,059	34,459	291,427	5,155,612	5,597,499	331,601	36,004	57,149
12	Special Contract Revenue	46,020,892	20,418,261	134,463	903,619	12,615,290	11,135,081	562,703	79,779	171,695
13	Other Revenues	8,866,673	4,165,919	26,571	182,035	2,376,320	1,966,416	98,149	17,147	34,116
14	Sale for Resale and Transmission Revenue	22,823,902	10,344,727	69,424	457,585	6,225,625	5,338,514	262,486	38,862	86,679
15	Fuel Cost Revenues	202,463,492	70,924,387	386,972	3,167,056	56,507,591	66,334,390	4,045,017	424,413	673,667
16	Fuel Cost Revenue_Special Contract	57,729,010	20,222,879	110,338	903,032	16,112,175	18,914,119	1,153,368	121,014	192,085
17	**Total Operating Revenues**	**$ 741,397,336**	**$ 324,435,009**	**$ 1,772,139**	**$ 15,445,172**	**$ 212,856,292**	**$ 172,728,031**	**$ 9,072,475**	**$ 1,898,526**	**$ 3,189,691**
18	**Operating Expenses**									
19	Fuel Cost	$ 260,192,501	$ 91,147,266	$ 497,310	$ 4,070,088	$ 72,619,766	$ 85,248,509	$ 5,198,384	$ 545,427	$ 865,751
20	Variable Production Cost	8,275,422	2,992,105	15,739	133,105	2,358,817	2,579,330	153,779	16,444	26,102
21	O&M and A&G Expenses	158,064,440	85,580,244	929,097	4,292,765	37,150,721	28,201,151	1,370,815	94,562	445,085
22	Depreciation and Amortization Expense	179,942,886	88,152,522	540,335	3,800,903	50,253,646	34,743,144	1,321,704	335,709	794,922
23	Taxes other than Income	12,339,079	6,088,836	41,745	271,814	3,363,913	2,379,679	93,563	23,136	76,392
24	Deferred Taxes	12,280,774	5,906,698	30,712	240,717	3,496,726	2,434,187	88,695	23,814	59,225
25	Current Income Tax	9,973,261	4,029,671	(25,570)	238,321	3,943,355	1,549,941	76,451	77,708	83,384
26	**Total Operation and Maintenance Expenses**	**$ 641,068,364**	**$ 283,897,343**	**$ 2,029,368**	**$ 13,047,713**	**$ 173,186,943**	**$ 157,135,941**	**$ 8,303,393**	**$ 1,116,801**	**$ 2,350,862**
27	**Net Operating Income**	**$ 100,328,972**	**$ 40,537,666**	**$ (257,229)**	**$ 2,397,460**	**$ 39,669,348**	**$ 15,592,090**	**$ 769,082**	**$ 781,725**	**$ 838,829**
28	**Rate of Return on Rate Base ("ROR")**	**3.56%**	**2.99%**	**-3.72%**	**4.39%**	**4.93%**	**2.78%**	**3.75%**	**14.92%**	**6.82%**
29	**Relative Rate of Return ("RROR")**	**1.00**	**0.84**	**-1.05**	**1.23**	**1.39**	**0.78**	**1.05**	**4.19**	**1.92**

Source: Direct Testimony of John D. Taylor, Exhibit JDT-1.

Results of CEI South's Allocated Cost of Service Study: Required Income at Equalized Rates

Line No.	Account Description	Total CEI South	Residential: Residential Service (RS)	Residential: Water Heating (B)	Small General Service (SGS)	Demand General Service (DGS)	Large Power Service (LP)	High Load Factor Service (HLF)	Lighting: Outdoor Lighting (OL)	Lighting: Street Lighting (SL)
1	<u>Revenue Requirement</u>									
2	**Required Income Under Company's Proposed ROR**									
2	Total Electric Rate Base	$2,820,468,760	$1,354,330,471	$ 6,912,634	$ 54,614,396	$ 805,027,000	$ 561,537,411	$ 20,504,700	$ 5,239,054	$ 12,303,095
3	Proposed Rate of Return	7.06%	7.06%	7.06%	7.06%	7.06%	7.06%	7.06%	7.06%	7.06%
4	**Required Operating Income @ 7.06% ROR**	$ 199,125,094	$ 95,615,731	$ 488,032	$ 3,855,776	$ 56,834,906	$ 39,644,541	$ 1,447,632	$ 369,877	$ 868,599
5	**Operating Expenses**									
6	Fuel Cost	$ 260,192,501	$ 91,147,266	$ 497,310	$ 4,070,088	$ 72,619,766	$ 85,248,509	$ 5,198,384	$ 545,427	$ 865,751
7	Variable Production Cost	8,275,422	2,992,105	15,739	133,105	2,358,817	2,579,330	153,779	16,444	26,102
8	O&M and A&G Expenses	158,064,440	85,580,244	929,097	4,292,765	37,150,721	28,201,151	1,370,815	94,562	445,085
9	Depreciation and Amortization Expense	179,942,886	88,152,522	540,335	3,800,903	50,253,646	34,743,144	1,321,704	335,709	794,922
10	Taxes other than Income	12,339,079	6,088,836	41,745	271,814	3,363,913	2,379,679	93,563	23,136	76,392
11	Deferred Taxes	2,307,513	1,117,745	6,269	47,599	650,126	448,574	16,190	5,289	15,721
12	Current Income Tax	9,973,261	4,788,953	24,443	193,118	2,846,599	1,985,613	72,505	18,525	43,504
13	Gross-up Income Tax	29,404,270	14,119,319	72,066	569,372	8,392,658	5,854,203	213,768	54,619	128,264
14	Gross-up Other Expenses	530,562	254,765	1,300	10,274	151,435	105,632	3,857	986	2,314
15	**Total Operating Expenses**	**$ 661,029,935**	**$ 294,241,757**	**$ 2,128,305**	**$ 13,389,038**	**$ 177,787,682**	**$ 161,545,834**	**$ 8,444,567**	**$ 1,094,697**	**$ 2,398,055**
16	**Total Revenue Requirement**	**$ 860,155,029**	**$ 389,857,488**	**$ 2,616,337**	**$ 17,244,814**	**$ 234,622,588**	**$ 201,190,376**	**$ 9,892,199**	**$ 1,464,574**	**$ 3,266,654**
17	<u>**Revenue Deficiency**</u>									
18	**Operating Revenues**									
19	Base Rate Revenues	$ 267,328,655	$ 132,139,578	$ 530,561	$ 5,953,227	$ 75,824,903	$ 48,031,238	$ 1,868,205	$ 1,152,148	$ 1,828,794
20	Rider Revenues	118,109,906	59,668,199	479,352	3,587,192	38,038,775	15,410,774	750,947	29,159	145,507
21	Variable Production Revenues	18,054,808	6,551,059	34,459	291,427	5,155,612	5,597,499	331,601	36,004	57,149
22	Special Contract Revenue	46,020,892	20,418,261	134,463	903,619	12,615,290	11,135,081	562,703	79,779	171,695
23	Other Revenues	8,866,673	4,165,919	26,571	182,035	2,376,320	1,966,416	98,149	17,147	34,116
24	Sale for Resale and Transmission Revenue	22,823,902	10,344,727	69,424	457,585	6,225,625	5,338,514	262,486	38,862	86,679
25	Fuel Cost Revenue	202,463,492	70,924,387	386,972	3,167,056	56,507,591	66,334,390	4,045,017	424,413	673,667
26	Fuel Cost Revenue_Special Contract	57,729,010	20,222,879	110,338	903,032	16,112,175	18,914,119	1,153,368	121,014	192,085
27	**Total Operating Revenues**	**$ 741,397,336**	**$ 324,435,009**	**$ 1,772,139**	**$ 15,445,172**	**$ 212,856,292**	**$ 172,728,031**	**$ 9,072,475**	**$ 1,898,526**	**$ 3,189,691**
28	**Revenue Deficiency (Surplus)**	**$ 118,757,693**	**$ 65,422,479**	**$ 844,197**	**$ 1,799,642**	**$ 21,766,296**	**$ 28,462,345**	**$ 819,723**	**$ (433,951)**	**$ 76,963**
29	**Required Rate Increase (Decrease)**	**16.02%**	**20.17%**	**47.64%**	**11.65%**	**10.23%**	**16.48%**	**9.04%**	**-22.86%**	**2.41%**
30	**Relative Rate Increase**	**1.00**	**1.26**	**2.97**	**0.73**	**0.64**	**1.03**	**0.56**	**-1.43**	**0.15**

Source: Direct Testimony of John D. Taylor, Exhibit JDT-1.

CEI South's Estimated System Load Factors, 2018-2022

	2018	2019	2020	2021	2022
Total MWh Sold	4,958,022	4,703,924	4,495,185	4,644,664	4,591,751
Total Hours in Year	8,760	8,760	8,784	8,760	8,760
Avg. Demand Factor	**566**	**537**	**512**	**530**	**524**
4 CP Peak Demand	1,132	1,109	1,052	1,059	1,110
System Load Factor	**50.0%**	**48.4%**	**48.7%**	**50.1%**	**47.2%**

Source: FERC Form 1.

Analysis of CEI South's Electric Generation Unit Capacity Factors, 2022

Witness: Dismukes
Cause No. 45990
Exhibit DED-5

Station Name	Plant Type	Nameplate Capacity (MW)	2022 Net Generation (MWh)	Capacity Factor	Allocation Energy	Allocation Demand	Plant in Service Energy	Plant in Service Demand	Plant in Service Total
A.B. Brown Station	Steam	530.46	2,933,222	63.12%	63.12%	36.88%	$585,766,007	$342,208,357	$ 927,974,364
A.B. Brown Turbine 3	Com Turbine Peaking	88	38,443	4.99%	0.00%	100.00%	-	30,190,735	30,190,735
A.B. Brown Turbine 4	Com Turbine Peaking	88	41,352	5.36%	0.00%	100.00%	-	31,408,673	31,408,673
F.B. Culley Station	Steam	414.93	854,332	23.50%	23.50%	76.50%	143,721,774	467,747,779	611,469,553
Warrick Unit #4	Steam	161.5	871,777	61.62%	61.62%	38.38%	121,322,779	75,562,650	196,885,429
Subtotals:							**$850,810,560**	**$947,118,194**	**$1,797,928,754**
					Production Plant Classification:		**47.32%**	**52.68%**	**100.00%**

Source: FERC Form 1.

Analysis of CEI South's Electric Generation Unit Costs to MISO Estimated CONE Price

Witness: Dismukes
Cause No. 45990
Exhibit DED-6

Station Name	Plant Type	Estimated Service Life	Nameplate Capacity (MW)	Total Plant In Service	Fixed Costs ($/year)	Variable Costs ($)	Levelized Cost ($/kW-year)	MISO CONE Zone 6 ($/MW-day)	MISO CONE Zone 6 ($/kW-year)	Allocation Energy	Allocation Demand	Plant in Service Energy	Plant in Service Demand	Plant in Service Total
A.B. Brown Station	Steam	33.94	530.5	$ 927,974,364	$ 27,339,802	$ 120,725,682	$ 279.13	$ 270.11	$ 98.59	64.68%	35.32%	$600,205,033	$327,769,331	$ 927,974,364
A.B. Brown Turbine 3	Com Turbine Peaking	33.94	88.0	30,190,735	889,474	4,921,783	66.04	270.11	$ 98.59	0.00%	100.00%	-	30,190,735	30,190,735
A.B. Brown Turbine 4	Com Turbine Peaking	33.94	88.0	31,408,673	925,356	5,782,340	76.22	270.11	$ 98.59	0.00%	100.00%	-	31,408,673	31,408,673
F.B. Culley Station	Steam	27.36	414.9	611,469,553	22,350,510	45,728,674	164.07	270.11	$ 98.59	39.91%	60.09%	244,044,421	367,425,132	611,469,553
Warrick Unit #4	Steam	42.42	161.5	196,885,429	4,640,819	49,553,760	335.57	270.11	$ 98.59	70.62%	29.38%	139,040,701	57,844,728	196,885,429
Subtotals:												**$983,290,155**	**$814,638,599**	**$1,797,928,754**
										Production Plant Classification:		**54.69%**	**45.31%**	**100.00%**

Source: FERC Form 1, and MISO Planning Resource Auction, 2023-2024.

Summary of Test Year Electric Generation Units

Unit Name	Primary Fuel	Renewable (Y/N)	Gross Plant ($000)	Accumulated Reserve ($000)	Net Plant ($000)	Percent of Total (%)
F.B. Culley Unit 3	Coal	N	$ 468,178	$ 351,836	$116,342	12.0%
A.B. Brown 3	Gas	N	32,929	29,546	3,384	0.3%
A.B. Brown 4	Gas	N	31,409	28,513	2,896	0.3%
Blackfoot	Landfill Gas	Y	11,703	6,842	4,862	0.5%
Oak Hill Solar	Solar	Y	5,372	1,557	3,814	0.4%
Volkman Solar	Solar	Y	7,259	2,951	4,307	0.4%
Troy Solar	Solar	Y	97,673	14,191	83,482	8.6%
A.B. Brown 5 &6	Gas	N	339,618	4,865	334,754	34.4%
Posey County Solar Project	Solar	Y	426,973	8,302	418,671	43.1%
Total Generation Plant			**$1,421,114**	**$ 448,602**	**$972,512**	**100.0%**
Total Renewable Generation Plant			**$ 548,979**	**$ 33,844**	**$515,136**	**53.0%**

Source: Company's Response to Data Request OUCC 18.2.

Summary of Test Year Net Production Plant in Service

Witness: Dismukes
Cause No. 45990
Exhibit DED-8

Unit Name	Primary Fuel	Renewable (Y/N)	Gross Plant ($000)	Accumulated Reserve ($000)	Net Plant ($000)	Percent of Total (%)	Classification: Energy-Only	Classification: Joint Energy/Demand
F.B. Culley Unit 3	Coal	N	$ 468,178	$ 351,836	$116,342	12.0%	0.0%	12.0%
A.B. Brown 3	Gas	N	32,929	29,546	3,384	0.3%	0.0%	0.3%
A.B. Brown 4	Gas	N	31,409	28,513	2,896	0.3%	0.0%	0.3%
Blackfoot	Landfill Gas	Y	11,703	6,842	4,862	0.5%	0.0%	0.5%
Oak Hill Solar	Solar	Y	5,372	1,557	3,814	0.4%	0.2%	0.2%
Volkman Solar	Solar	Y	7,259	2,951	4,307	0.4%	0.2%	0.2%
Troy Solar	Solar	Y	97,673	14,191	83,482	8.6%	4.3%	4.3%
A.B. Brown 5 &6	Gas	N	339,618	4,865	334,754	34.4%	0.0%	34.4%
Posey County Solar Project	Solar	Y	426,973	8,302	418,671	43.1%	21.5%	21.5%
Total Generation Plant			**$1,421,114**	**$ 448,602**	**$972,512**	**100.0%**	**26.2%**	**73.8%**

Source: Company’s Response to Data Request OUCC 18.2.

Results of Alternative Cost of Service Study
Relative Rate of Return at Current Rates

Witness: Dismukes
Cause No. 45990
Exhibit DED-9

Line No.	Account Description	Total CEI South	Residential: Residential Service (RS)	Residential: Water Heating (B)	Small General Service (SGS)	Demand General Service (DGS)	Large Power Service (LP)	High Load Factor Service (HLF)	Lighting: Outdoor Lighting (OL)	Lighting: Street Lighting (SL)
1	<u>Rate Base</u>									
2	Electric Plant in Service	$3,903,417,227	$1,785,151,067	$ 10,923,669	$ 79,421,327	$1,084,013,822	$ 865,758,574	$ 37,147,240	$11,057,123	$ 29,944,405
3	Accumulated Depreciation and Amortization	(1,227,300,954)	(574,969,154)	(4,254,451)	(28,639,573)	(329,958,396)	(258,265,531)	(11,097,563)	(4,470,015)	(15,646,271)
4	Net Electric Plant in Service	$2,676,116,273	$1,210,181,913	$ 6,669,218	$ 50,781,754	$ 754,055,426	$ 607,493,043	$ 26,049,677	$ 6,587,108	$ 14,298,133
5	Total Other Rate Base Items	144,352,487	$ 69,460,545	$ 483,764	$ 3,075,336	$ 39,220,260	$ 30,137,588	$ 1,429,814	$ 154,781	$ 390,399
6	**Total Electric Rate Base**	**$2,820,468,760**	**$1,279,642,458**	**$ 7,152,982**	**$ 53,857,090**	**$ 793,275,686**	**$ 637,630,632**	**$ 27,479,491**	**$ 6,741,890**	**$ 14,688,532**
7	**<u>Operating Income</u>**									
8	**Operating Revenues**									
9	Base Rate Revenues	$ 267,328,655	$ 132,139,578	$ 530,561	$ 5,953,227	$ 75,824,903	$ 48,031,238	$ 1,868,205	$ 1,152,148	$ 1,828,794
10	Rider Revenues	118,109,906	59,668,199	479,352	3,587,192	38,038,775	15,410,774	750,947	29,159	145,507
11	Variable Production Revenue	18,054,808	6,551,059	34,459	291,427	5,155,612	5,597,499	331,601	36,004	57,149
12	Special Contract Revenue	46,020,892	19,741,047	135,530	895,364	12,555,275	11,788,653	620,320	92,622	192,081
13	Other Revenues	8,866,673	4,068,687	26,724	180,850	2,367,703	2,060,253	106,421	18,991	37,043
14	Sale for Resale and Transmission Revenue	22,823,902	9,969,112	70,015	453,006	6,192,338	5,701,015	294,443	45,985	97,986
15	Fuel Cost Revenues	202,463,492	70,924,387	386,972	3,167,056	56,507,591	66,334,390	4,045,017	424,413	673,667
16	Fuel Cost Revenue_Special Contract	57,729,010	20,222,879	110,338	903,032	16,112,175	18,914,119	1,153,368	121,014	192,085
17	**Total Operating Revenues**	**$ 741,397,336**	**$ 323,284,948**	**$ 1,773,952**	**$ 15,431,154**	**$ 212,754,373**	**$ 173,837,941**	**$ 9,170,321**	**$ 1,920,336**	**$ 3,224,311**
18	**Operating Expenses**									
19	Fuel Cost	$ 260,192,501	$ 91,147,266	$ 497,310	$ 4,070,088	$ 72,619,766	$ 85,248,509	$ 5,198,384	$ 545,427	$ 865,751
20	Variable Production Cost	8,275,422	2,992,105	15,739	133,105	2,358,817	2,579,330	153,779	16,444	26,102
21	O&M and A&G Expenses	158,064,440	82,294,120	919,764	4,234,600	37,466,645	30,897,868	1,577,003	146,661	527,781
22	Depreciation and Amortization Expense	179,942,886	84,003,773	550,874	3,755,326	49,718,569	38,877,942	1,694,912	417,207	924,283
23	Taxes other than Income	12,339,079	5,760,280	42,287	267,838	3,333,807	2,697,538	121,636	29,384	86,309
24	Deferred Taxes	12,280,774	5,580,149	31,751	237,390	3,445,863	2,766,476	119,128	30,376	69,641
25	Current Income Tax	9,973,261	4,657,161	(25,658)	247,094	3,961,276	973,823	27,621	66,442	65,502
26	**Total Operation and Maintenance Expenses**	**$ 641,068,364**	**$ 276,434,855**	**$ 2,032,065**	**$ 12,945,442**	**$ 172,904,743**	**$ 164,041,485**	**$ 8,892,463**	**$ 1,251,941**	**$ 2,565,369**
27	**Net Operating Income**	**$ 100,328,972**	**$ 46,850,094**	**$ (258,114)**	**$ 2,485,712**	**$ 39,849,629**	**$ 9,796,456**	**$ 277,858**	**$ 668,395**	**$ 658,942**
28	**Rate of Return on Rate Base ("ROR")**	**3.56%**	**3.66%**	**-3.61%**	**4.62%**	**5.02%**	**1.54%**	**1.01%**	**9.91%**	**4.49%**
29	**Relative Rate of Return ("RROR")**	**1.00**	**1.03**	**-1.01**	**1.30**	**1.41**	**0.43**	**0.28**	**2.79**	**1.26**

Source: Direct Testimony of John D. Taylor, Exhibit JDT-1.

Results of Alternative Cost of Service Study
Required Increase at Equalized Rates

Witness: Dismukes
Cause No. 45990
Exhibit DED-9

Line No.	Account Description	Total CEI South	Residential: Residential Service (RS)	Residential: Water Heating (B)	Small General Service (SGS)	Demand General Service (DGS)	Large Power Service (LP)	High Load Factor Service (HLF)	Lighting: Outdoor Lighting (OL)	Lighting: Street Lighting (SL)
1	**Revenue Requirement**									
2	**Required Income Under Company's Proposed ROR**									
2	Total Electric Rate Base	$2,820,468,760	$1,279,642,458	$ 7,152,982	$ 53,857,090	$ 793,275,686	$ 637,630,632	$ 27,479,491	$ 6,741,890	$ 14,688,532
3	Proposed Rate of Return	7.06%	7.06%	7.06%	7.06%	7.06%	7.06%	7.06%	7.06%	7.06%
4	**Required Operating Income @ 7.06% ROR**	$ 199,125,094	$ 90,342,758	$ 505,001	$ 3,802,311	$ 56,005,263	$ 45,016,723	$ 1,940,052	$ 475,977	$ 1,037,010
5	**Operating Expenses**									
6	Fuel Cost	$ 260,192,501	$ 91,147,266	$ 497,310	$ 4,070,088	$ 72,619,766	$ 85,248,509	$ 5,198,384	$ 545,427	$ 865,751
7	Variable Production Cost	8,275,422	2,992,105	15,739	133,105	2,358,817	2,579,330	153,779	16,444	26,102
8	O&M and A&G Expenses	158,064,440	82,294,120	919,764	4,234,600	37,466,645	30,897,868	1,577,003	146,661	527,781
9	Depreciation and Amortization Expense	179,942,886	84,003,773	550,874	3,755,326	49,718,569	38,877,942	1,694,912	417,207	924,283
10	Taxes other than Income	12,339,079	5,760,280	42,287	267,838	3,333,807	2,697,538	121,636	29,384	86,309
11	Deferred Taxes	2,307,513	1,055,296	6,458	46,950	640,817	511,795	21,960	6,536	17,702
12	Current Income Tax	9,973,261	4,524,854	25,293	190,440	2,805,046	2,254,681	97,168	23,840	51,939
13	Gross-up Income Tax	29,404,270	13,340,673	74,572	561,477	8,270,147	6,647,499	286,482	70,286	153,133
14	Gross-up Other Expenses	530,562	240,715	1,346	10,131	149,224	119,946	5,169	1,268	2,763
15	**Total Operating Expenses**	**$ 661,029,935**	**$ 285,359,082**	**$ 2,133,641**	**$ 13,269,956**	**$ 177,362,839**	**$ 169,835,107**	**$ 9,156,494**	**$ 1,257,054**	**$ 2,655,762**
16	**Total Revenue Requirement**	**$ 860,155,029**	**$ 375,701,839**	**$ 2,638,641**	**$ 17,072,267**	**$ 233,368,102**	**$ 214,851,830**	**$ 11,096,546**	**$ 1,733,031**	**$ 3,692,773**
17	**Revenue Deficiency**									
18	**Operating Revenues**									
19	Base Rate Revenues	$ 267,328,655	$ 132,139,578	$ 530,561	$ 5,953,227	$ 75,824,903	$ 48,031,238	$ 1,868,205	$ 1,152,148	$ 1,828,794
20	Rider Revenues	118,109,906	59,668,199	479,352	3,587,192	38,038,775	15,410,774	750,947	29,159	145,507
21	Variable Production Revenues	18,054,808	6,551,059	34,459	291,427	5,155,612	5,597,499	331,601	36,004	57,149
22	Special Contract Revenue	46,020,892	19,741,047	135,530	895,364	12,555,275	11,788,653	620,320	92,622	192,081
23	Other Revenues	8,866,673	4,068,687	26,724	180,850	2,367,703	2,060,253	106,421	18,991	37,043
24	Sale for Resale and Transmission Revenue	22,823,902	9,969,112	70,015	453,006	6,192,338	5,701,015	294,443	45,985	97,986
25	Fuel Cost Revenue	202,463,492	70,924,387	386,972	3,167,056	56,507,591	66,334,390	4,045,017	424,413	673,667
26	Fuel Cost Revenue_Special Contract	57,729,010	20,222,879	110,338	903,032	16,112,175	18,914,119	1,153,368	121,014	192,085
27	**Total Operating Revenues**	**$ 741,397,336**	**$ 323,284,948**	**$ 1,773,952**	**$ 15,431,154**	**$ 212,754,373**	**$ 173,837,941**	**$ 9,170,321**	**$ 1,920,336**	**$ 3,224,311**
28	**Revenue Deficiency (Surplus)**	**$ 118,757,693**	**$ 52,416,891**	**$ 864,690**	**$ 1,641,113**	**$ 20,613,730**	**$ 41,013,888**	**$ 1,926,225**	**$ (187,305)**	**$ 468,462**
29	**Required Rate Increase (Decrease)**	**16.02%**	**16.21%**	**48.74%**	**10.64%**	**9.69%**	**23.59%**	**21.00%**	**-9.75%**	**14.53%**
30	**Relative Rate Increase**	**1.00**	**1.01**	**3.04**	**0.66**	**0.60**	**1.47**	**1.31**	**-0.61**	**0.91**

Source: Direct Testimony of John D. Taylor, Exhibit JDT-1.

CEI South's Proposed Revenue Distribution

Witness: Dismukes
Cause No. 45990
Exhibit DED-10

Line No.	Account Description	Total CEI South	Residential: Residential Service (RS)	Residential: Water Heating (B)	Small General Service (SGS)	Demand General Service (DGS)	Large Power Service (LP)	High Load Factor Service (HLF)	Lighting: Outdoor Lighting (OL)	Lighting: Street Lighting (SL)
1	<u>Allocated Cost of Service Study Results</u>									
2	Current Operating Revenues	$ 741,397,336	$ 324,435,009	$ 1,772,139	$ 15,445,172	$ 212,856,292	$ 172,728,031	$ 9,072,475	$ 1,898,526	$ 3,189,691
3	Operating Income	$ 100,328,972	$ 40,537,666	$ (257,229)	$ 2,397,460	$ 39,669,348	$ 15,592,090	$ 769,082	$ 781,725	$ 838,829
4	Rate Base	$ 2,820,468,760	$ 1,354,330,471	$ 6,912,634	$ 54,614,396	$ 805,027,000	$ 561,537,411	$ 20,504,700	$ 5,239,054	$ 12,303,095
5	**Rate of Return**	**3.56%**	**2.99%**	**-3.72%**	**4.39%**	**4.93%**	**2.78%**	**3.75%**	**14.92%**	**6.82%**
6	**Relative Rate of Return**	**1.00**	**0.84**	**(1.05)**	**1.23**	**1.39**	**0.78**	**1.05**	**4.19**	**1.92**
7	<u>Proposed Revenue Increase</u>									
8	Proposed Rate of Return	7.06%								
9	Current Operating Revenues	$ 741,397,336								
10	Proposed Operating Revenue Increase	118,757,693								
11	**Proposed Revenue Requirement**	**$ 860,155,029**								
12	**<u>Proposed Revenue Allocation at Full Cost of Service</u>**									
13	Current Operating Revenues	$ 741,397,336	$ 324,435,009	$ 1,772,139	$ 15,445,172	$ 212,856,292	$ 172,728,031	$ 9,072,475	$ 1,898,526	$ 3,189,691
14	Total Revenue Requirement at Equal Rates of Return	860,155,029	389,857,488	2,616,337	17,244,814	234,622,588	201,190,376	9,892,199	1,464,574	3,266,654
15	Incremental Revenue Increase at Equal Rates of Return	$ 118,757,693	$ 65,422,479	$ 844,197	$ 1,799,642	$ 21,766,296	$ 28,462,345	$ 819,723	$ (433,951)	$ 76,963
16	**Percent Increase at Proposed Rate of Return**	**16.02%**	**20.17%**	**47.64%**	**11.65%**	**10.23%**	**16.48%**	**9.04%**	**-22.86%**	**2.41%**
17	**Relative Increase**	**1.00**	**1.26**	**2.97**	**0.73**	**0.64**	**1.03**	**0.56**	**(1.43)**	**0.15**
18	**<u>Step One Adjustments</u>**									
19	Maximum Rate Increase at 1.50 times System Average	24.03%	-	24.03%	-	-	-	-	-	-
20	Step One Revenue Adjustments	$ (418,403)	$ -	$ (418,403)	$ -	$ -	$ -	$ -	$ -	$ -
21	Revenue Allocation after Step One Adjustments	$ 118,339,290	$ 65,422,479	$ 425,794	$ 1,799,642	$ 21,766,296	$ 28,462,345	$ 819,723	$ (433,951)	$ 76,963
22	Revenue Deficiency after Step One Adjustments	418,403								
23	**<u>Step Two Adjustments</u>**									
24	Minimum Rate Increase at 0.00 times System Average	0.00%	-	-	-	-	-	-	0.00%	-
25	Step Two Revenue Adjustments	433,951	$ -	$ -	$ -	$ -	$ -	$ -	$ 433,951	$ -
26	Revenue Allocation after Step Two Adjustments	$ 118,773,241	$ 65,422,479	$ 425,794	$ 1,799,642	$ 21,766,296	$ 28,462,345	$ 819,723	$ -	$ 76,963
27	Revenue Deficiency after Step Two Adjustments	$ (15,548)								
28	**<u>Step Three Adjustments</u>**									
29	Basis for Step Three Adjustment (non-Lighting and Water Heating)	$ 734,536,980	$ 324,435,009	$ -	$ 15,445,172	$ 212,856,292	$ 172,728,031	$ 9,072,475	$ -	$ -
30	Allocation of Remaining Revenue Deficiency	$ (15,548)	$ (6,867)	$ -	$ (327)	$ (4,506)	$ (3,656)	$ (192)	$ -	$ -
31	**Total Proposed Revenue Increase**	**$ 118,757,693**	**$ 65,415,611**	**$ 425,794**	**$ 1,799,315**	**$ 21,761,790**	**$ 28,458,688**	**$ 819,531**	**$ -**	**$ 76,963**
32	**<u>Summary</u>**									
33	Current Operating Revenues	$ 741,397,336	$ 324,435,009	$ 1,772,139	$ 15,445,172	$ 212,856,292	$ 172,728,031	$ 9,072,475	$ 1,898,526	$ 3,189,691
34	Revenue Increase	118,757,693	65,415,611	425,794	1,799,315	21,761,790	28,458,688	819,531	-	76,963
35	**Proposed Revenue**	**$ 860,155,029**	**$ 389,850,620**	**$ 2,197,934**	**$ 17,244,487**	**$ 234,618,082**	**$ 201,186,719**	**$ 9,892,007**	**$ 1,898,526**	**$ 3,266,654**
36	**Proposed Revenue Change (%)**	**16.02%**	**20.16%**	**24.03%**	**11.65%**	**10.22%**	**16.48%**	**9.03%**	**0.00%**	**2.41%**
37	**Relative Proposed Revenue Increase**	**1.00**	**1.26**	**1.50**	**0.73**	**0.64**	**1.03**	**0.56**	**0.00**	**0.15**

Source: Direct Testimony of John D. Taylor, Exhibit JDT-1.

Alternative Proposed Revenue Distribution

Witness: Dismukes
Cause No. 45990
Exhibit DED-11

Line No.	Account Description	Total CEI South	Residential: Residential Service (RS)	Residential: Water Heating (B)	Small General Service (SGS)	Demand General Service (DGS)	Large Power Service (LP)	High Load Factor Service (HLF)	Lighting: Outdoor Lighting (OL)	Lighting: Street Lighting (SL)
1	<u>Allocated Cost of Service Study Results</u>									
2	Current Operating Revenues	$ 741,397,336	$ 323,284,948	$ 1,773,952	$ 15,431,154	$ 212,754,373	$ 173,837,941	$ 9,170,321	$ 1,920,336	$ 3,224,311
3	Operating Income	$ 100,328,972	$ 46,850,094	$ (258,114)	$ 2,485,712	$ 39,849,629	$ 9,796,456	$ 277,858	$ 668,395	$ 658,942
4	Rate Base	$ 2,820,468,760	$ 1,279,642,458	$ 7,152,982	$ 53,857,090	$ 793,275,686	$ 637,630,632	$ 27,479,491	$ 6,741,890	$ 14,688,532
5	**Rate of Return**	**3.56%**	**3.66%**	**-3.61%**	**4.62%**	**5.02%**	**1.54%**	**1.01%**	**9.91%**	**4.49%**
6	**Relative Rate of Return**	**1.00**	**1.03**	**(1.01)**	**1.30**	**1.41**	**0.43**	**0.28**	**2.79**	**1.26**
7	<u>Proposed Revenue Increase</u>									
8	Proposed Rate of Return	7.06%								
9	Current Operating Revenues	$ 741,397,336								
10	Proposed Operating Revenue Increase	118,757,693								
11	**Proposed Revenue Requirement**	**$ 860,155,029**								
12	**<u>Proposed Revenue Allocation at Full Cost of Service</u>**									
13	Current Operating Revenues	$ 741,397,336	$ 323,284,948	$ 1,773,952	$ 15,431,154	$ 212,754,373	$ 173,837,941	$ 9,170,321	$ 1,920,336	$ 3,224,311
14	Total Revenue Requirement at Equal Rates of Return	860,155,029	375,701,839	2,638,641	17,072,267	233,368,102	214,851,830	11,096,546	1,733,031	3,692,773
15	Incremental Revenue Increase at Equal Rates of Return	$ 118,757,693	$ 52,416,891	$ 864,690	$ 1,641,113	$ 20,613,730	$ 41,013,888	$ 1,926,225	$ (187,305)	$ 468,462
16	**Percent Increase at Proposed Rate of Return**	**16.02%**	**16.21%**	**48.74%**	**10.64%**	**9.69%**	**23.59%**	**21.00%**	**-9.75%**	**14.53%**
17	**Relative Increase**	**1.00**	**1.01**	**3.04**	**0.66**	**0.60**	**1.47**	**1.31**	**(0.61)**	**0.91**
18	**<u>Step One Adjustments</u>**									
19	Maximum Rate Increase at 1.15 times System Average	18.42%	-	18.42%	-	-	18.42%	18.42%	-	-
20	Step One Revenue Adjustments	$ (9,766,434)	$ -	$ (537,914)	$ -	$ -	$ (8,991,542)	$ (236,978)	$ -	$ -
21	Revenue Allocation after Step One Adjustments	$ 108,991,259	$ 52,416,891	$ 326,776	$ 1,641,113	$ 20,613,730	$ 32,022,346	$ 1,689,247	$ (187,305)	$ 468,462
22	Revenue Deficiency after Step One Adjustments	9,766,434								
23	**<u>Step Two Adjustments</u>**									
24	Minimum Rate Increase at 0.00 times System Average	0.00%	-	-	-	-	-	-	0.00%	-
25	Step Two Revenue Adjustments	187,305	$ -	$ -	$ -	$ -	$ -	$ -	$ 187,305	$ -
26	Revenue Allocation after Step Two Adjustments	$ 109,178,564	$ 52,416,891	$ 326,776	$ 1,641,113	$ 20,613,730	$ 32,022,346	$ 1,689,247	$ -	$ 468,462
27	Revenue Deficiency after Step Two Adjustments	$ 9,579,129								
28	<u>Step Three Adjustments</u>									
29	Basis for Step Three Adjustment	$ 737,703,048	$ 323,284,948	$ -	$ 15,431,154	$ 212,754,373	$ 173,837,941	$ 9,170,321	$ -	$ 3,224,311
30	Allocation of Remaining Revenue Deficiency	$ 9,579,129	$ 4,197,879	$ -	$ 200,375	$ 2,762,631	$ 2,257,299	$ 119,077	$ -	$ 41,868
31	**Total Proposed Revenue Increase**	**$ 118,757,693**	**$ 56,614,770**	**$ 326,776**	**$ 1,841,488**	**$ 23,376,361**	**$ 34,279,644**	**$ 1,808,324**	**$ -**	**$ 510,330**
32	**<u>Summary</u>**									
33	Current Operating Revenues	$ 741,397,336	$ 323,284,948	$ 1,773,952	$ 15,431,154	$ 212,754,373	$ 173,837,941	$ 9,170,321	$ 1,920,336	$ 3,224,311
34	Revenue Increase	118,757,693	56,614,770	326,776	1,841,488	23,376,361	34,279,644	1,808,324	-	510,330
35	**Proposed Revenue**	**$ 860,155,029**	**$ 379,899,718**	**$ 2,100,728**	**$ 17,272,642**	**$ 236,130,734**	**$ 208,117,586**	**$ 10,978,645**	**$ 1,920,336**	**$ 3,734,640**
36	**Proposed Revenue Change (%)**	**16.02%**	**17.51%**	**18.42%**	**11.93%**	**10.99%**	**19.72%**	**19.72%**	**0.00%**	**15.83%**
37	**Relative Proposed Revenue Increase**	**1.00**	**1.09**	**1.15**	**0.75**	**0.69**	**1.23**	**1.23**	**0.00**	**0.99**

Source: Direct Testimony of John D. Taylor, Exhibit JDT-1.

Comparison of Current and Proposed Customer Charges

Description	Residential: Residential Service (RS)	Residential: Water Heating (B)	Small General Service (SGS)	Demand Generation Service: Group 1 (DGS)	Demand Generation Service: Group 2 (DGS)	Demand Generation Service: Group 3 (DGS)	Off Season Service (OSS)	Large Power Service (LP)
Current Customer Charge ($/month)	$ 10.84	$ 4.93	$ 10.84	$ 14.78	$ 34.49	$ 73.90	$ 14.78	$ 147.80
Proposed Customer Charge ($/month)	$ 23.20	$ 14.76	$ 22.50	$ 17.15	$ 34.49	$ 73.90	$ 17.15	$ 171.47
Percent Increase	**114.03%**	**199.36%**	**107.59%**	**16.02%**	**0.00%**	**0.00%**	**16.02%**	**16.02%**

Source: Direct Testimony of John D. Taylor, Exhibit JDT-3.

Current Customer Charge Revenues to Costs

Witness: Dismukes
Cause No. 45990
Exhibit DED-13

	Residential				
Description	**Residential Service (RS)**	**Water Heating (B)**	**Small General Service (SGS)**	**Demand General Service (DGS)**	**Large Power Service (LP)**
Current Monthly Customer Charge	**$ 10.84**	**$ 4.93**	**$ 10.84**	**$ 14.78**	**$ 147.80**
Current Fixed TDISC Charge	**$ 6.50**	**$ 5.56**	**$ 6.50**	**$ -**	**$ -**
Total Customer-related Revenue Requirement	$ 30,105,013	$ 725,592	$ 2,615,005	$ 3,401,506	$ 31,383
Total Customer Bills	1,602,925	38,634	119,184	111,793	1,272
Total Customer-related Costs per Customer	**$ 18.78**	**$ 18.78**	**$ 21.94**	**$ 30.43**	**$ 24.67**
Percent of Customer-related Costs recovered in current Customer Charge					
Without TDISC	**57.72%**	**26.25%**	**49.41%**	**48.58%**	**599.05%**
With current TDISC	**92.33%**	**55.85%**	**79.03%**	**48.58%**	**599.05%**

Source: Direct Testimony of John D. Taylor, Exhibit JDT-1.

Survey of Regional Customer Charges

Company	State	Residential Customer Charge ($/month)	Small Commercial Customer Charge ($/month)
CenterPoint Energy (Current)	**IN**	**$ 10.84**	**$ 10.84**
CenterPoint Energy (Proposed)	**IN**	**$ 23.20**	**$ 22.50**
Ameren Illinois Company	IL	$ 6.33	$ 40.00
Cleveland Electric Illum Co	OH	$ 4.00	$ 7.00
Consumers Energy Co	MI	$ 8.00	$ 20.00
AES Ohio (Dayton Power & Light Co)	OH	$ 9.75	$ 16.68
DTE Electric Company	MI	$ 8.50	$ 11.25
Duke Energy Indiana, LLC	IN	$ 10.54	$ 10.70
Duke Energy Kentucky	KY	$ 13.00	$ 15.00
Duke Energy Ohio Inc	OH	$ 8.00	$ 12.00
Indianapolis Power & Light Co	IN	$ 16.75	$ 39.40
Indiana Michigan Power Co	IN	$ 14.79	$ 24.65
Indiana Michigan Power Co	MI	$ 7.25	$ 17.45
Kentucky Power Co	KY	$ 17.50	$ 25.00
Kentucky Utilities Co	KY	$ 16.12	$ 41.06
Louisville Gas & Electric Co	KY	$ 13.69	$ 35.28
Northern Indiana Pub Serv Co	IN	$ 14.00	$ 32.50
Ohio Edison Co	OH	$ 4.00	$ 7.00
Ohio Power Co	OH	$ 10.00	$ 9.40
Peer Group Average		**$ 10.72**	**$ 21.43**

Source: Utility Tariffs.

AFFIRMATION

I affirm, under the penalties for perjury, that the foregoing representations are true.

David E. Dismukes
Acadian Consulting Group ("ACG") for
Indiana Office of Utility Consumer Counselor

Cause No. 45990
CenterPoint Energy Indiana S

March 12, 2024_
Date

CERTIFICATE OF SERVICE

The undersigned counsel for the OUCC certifies that on March 12, 2024 a copy of this ***Redacted Testimony of Public Exhibit No. 12 , Witness Dr. David E. Dismukes*** was electronically served, via e-mail, upon all parties of record in this proceeding.

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