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	))))	DOCKET NO. 16-052-U

DIRECT TESTIMONY OF DAVID E. DISMUKES, PH.D.

ON BEHALF OF

THE OFFICE OF ARKANSAS ATTORNEY GENERAL LESLIE RUTLEDGE

JANUARY 31, 2017

TABLE OF CONTENTS

TABLE OF EXHIBITS

I. <u>INTRODUCTION AND QUALIFICATIONS</u>

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

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

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

A. I am a Consulting Economist with the Acadian Consulting Group, LLC ("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 is located in Baton Rouge, Louisiana.

Q. DO YOU HOLD ANY ACADEMIC POSITIONS?

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

Q. HAVE YOU PREVIOUSLY TESTIFIED BEFORE THE ARKANSAS PUBLIC SERVICE COMMISSION?

A. Yes, I have. Attachment A is my academic vitae, which includes a list of the Arkansas Public Service Commission ("APSC" or "Commission") 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 Consumer Utility Rate Advocacy Division ("CURAD") of the Office of Arkansas Attorney General Leslie Rutledge ("the AG") to provide an expert opinion to the Commission on a variety of economic, regulatory policy, and ratemaking issues that are raised in this proceeding. I will offer an opinion on the appropriateness and reasonableness of the Company's following proposals: Formula Rate Plan (or "FRP"); other riders and rider modifications including the Large Cost Adjustment Rider (Rider "LCA"); jurisdictional cost of service allocations and its class cost of service study ("CCOSS"); revenue distribution; and rate design. My FRP review and analysis will be limited to the Company's specific proposal and how that proposal relates, from a policy perspective, to Arkansas statutes, the Commission's prior decisions on this subject, and the relationship of the Company's FRP proposal to other issues arising in this base rate case.

Q. HOW IS THE REMAINDER OF YOUR TESTIMONY ORGANIZED?

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

- Section II: Summary of Recommendations
- Section III: Formula Rate Plan Proposal
- Section IV: Other Proposed Riders
- Section V: Cost-of-Service Studies
- Section VI: Revenue Distribution and Rate Design
- Section VII: Conclusions and Recommendations

Q. HAVE YOU PREPARED ANY EXHIBITS SUPPORTING YOUR DIRECT TESTIMONY?

A. Yes. The following Direct Exhibits were prepared under my direction and control:

- Direct Exhibit DED-1: Survey of States using Historic and Forecasted Test Years
- Direct Exhibit DED-2: Comparison of Oklahoma Gas and Electric Jurisdictional Allocation Factors
- Direct Exhibit DED-3: Comparison of Company Cost of Service Results and Proposed Revenue Allocations
- Direct Exhibit DED-4: Alternative Revenue Allocation
- Direct Exhibit DED-5: Comparison of Current and Proposed Fixed Charge Recovery
- Direct Exhibit DED-6: Comparison of Current and Proposed Customer Charges
- Direct Exhibit DED-7: Comparison of Customer-related Costs to Customer Charge Revenues

- Direct Exhibit DED-8: Survey of South-Central Regional Electric Utility Customer Charges

- Direct Exhibit DED-9: Comparison of Alternative Rates to Current and Company Proposed Rates

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

Q. WHAT ARE YOUR RECOMMENDATIONS REGARDING THE COMPANY'S PROPOSED FRP?

A. I recommend the Commission approve the Company's FRP subject to the following modifications:

- The Commission should direct the Company to clearly indicate which type of test year it is using, and the definition of this test year needs to be directly tied to the statutory language.

- The capital structure associated with OGE's FRP annual review should be fixed to the same one resulting from the Commission's decision in this proceeding. Such an outcome is consistent with alternative regulation design and consistent with the Commission's decision in the CenterPoint Energy Arkansas ("CEA") FRP approval.

- The Company should be required to provide comparative information that examines the major costs and drivers between its projected and current rate case test year. This comparison would not be used for any reconciliation. Further, this requirement should only be in place for the first two years of the annual FRP process. Thus, the Commission could simply address this transitional issue in the Order arising from this rate case without any need to change any of the descriptions included in the Company's proposed FRP tariff.

Q. PLEASE SUMMARIZE YOUR RECOMMENDATIONS REGARDING THE ADDITIONAL RIDERS BEING PROPOSED BY THE COMPANY.

A. I recommend the Commission:

- Reject the Company's Storm Damage Recover ("SDR") proposals and utilize the projected test year approach, afforded under the Company's proposed FRP, to recover storm-related costs. The Company's argument that storm-related costs could increase its annual FRP revenue increase above the four percent statutory cap is speculative and unsupported. If a unique storm event arises, and imposes costs that cannot be recovered in one year, or accommodated within the FRP, then the Commission can address any special ratemaking mechanisms needed to meet these unique challenges at the time they arise, when the costs and impacts can be determined in a reliably known and measurable fashion.

- Reject the Company's Large Capital Asset ("LCA") Rider recommendations since the proposal is (1) inconsistent with ratepayer protection provisions of Act 725, (2) is not well-defined and based upon a tariff that is general in nature and inconsistent with the Company's proposed FRP, (3) is not supported with any record evidence indicating any need, (4) is based upon a set of cost recovery methods that are inconsistent with Act 725 and the Company's own cost-causation principles articulated elsewhere in its testimony, (5) would likely set a bad precedent for other Arkansas utilities, (6) would likely result in a prudence pre-approval, and (7) has been proposed for a term that is too long and far surpasses the five-year term included in Act 725.

Q. WHAT ARE YOUR JURISDICTIONAL COST ALLOCATION RECOMMENDATIONS?

A. I also recommend the Commission accept the Company's proposed jurisdictional allocations. The methodology is consistent with what was done recently in Oklahoma and is internally consistent with the demand allocators being used in the retail Class Cost of Service Study ("CCOSS") as well.

Q. WHAT ARE YOUR CCOSS RECOMMENDATIONS?

A. I recommend that the Commission adopt the same approach that it utilized in the most recent Entergy Arkansas, Inc. ("EAI") and CEA rate cases. Namely, that the Commission aver on making any decision regarding the relationship between the Company's proposed demand allocators and economic development. Instead, the Commission should only use the

Company's proposed CCOSS results as a starting point in setting the overall revenue distribution in this case, provided this revenue distribution is tempered with many of the same policy considerations the Commission utilized in the EAI and CEA decisions. I will discuss these policy considerations in the subsequent section of my testimony addressing revenue distribution and rate design issues.

Q. HOW SHOULD THE COMMISSION ALLOCATE THE COMPANY'S REVENUE DEFICIENCY IN THIS PROCEEDING?

A. I recommend that the Commission utilize a three-step process to allocate the Company's revenue requirement in this proceeding. In the first step, I recommend the Commission allocate 1.25 times the system average increase to all classes earning less than the overall system rate of return. Second, I recommend that the Commission allocate a moderate increase of 0.50 times the system average increase to all classes estimated as over-earning based upon the Company's CCOSS results. Lastly, I recommend that any remaining revenue requirement left after the first two steps are completed be allocated to the remaining customer class that has not reached its 1.25 times cap – the Standard Power and Light ("PL") customer class.

Q WHAT ARE YOUR RATE DESIGN RECOMMENDATIONS?

A. My revenue distribution and rate design recommendations can be summarized as follows:

- Revenue responsibilities for developing rates should be allocated on a methodology that constrains any one class from receiving a rate increase greater than 1.25 times the system average.
- Revenue responsibilities for developing rates should assign a minimum rate increase to currently over-earning customer classes to 0.5 times the system average increase.
- Existing customer charges should be maintained at current levels.
- The Commission should reject the Company's proposal to establish demand rates for its standard Residential and General Service tariffs.
- The Commission should reject the Company's proposal to eliminate its current volumetric block structure.
- Volumetric rates should be increased according to the results of the Company's cost of service study, modified as follows: all classes are moved toward their cost of service, constrained such that (a) no class should receive an increase of less than 0.5 times the system average; and (b) rates for any one class cannot increase by more than 1.25 times the system average.

III. <u>FORMULA RATE PLAN PROPOSAL</u>

A. Introduction

Q. PLEASE DISCUSS THE COMPANY'S PROPOSED FRP.

A. Act 725 of 2015 ("Act 725")[1] includes provisions that allow utilities to elect to be regulated under a new form of regulation[2] which is referred to as a Formula Rate Plan (or "FRP"). The Company's FRP proposal in this rate case is motivated by the Act 725 provisions.[3] The Company believes that being regulated under an FRP will be more effective and efficient than

[1] Arkansas Act 725 of 2015, "An Act to Reform Rate Making of Public Utilities; To Declare an Emergency; and for Other Purposes."
[2] *Id.*, Section 3.
[3] Direct Testimony of Donald R. Rowlett, p. 6:15-17.

traditional regulation.[4] The Company requests that the Commission approve its proposed FRP, and its corresponding terms and conditions, as being consistent with the Act 725 requirements.

Q. DOES ACT 725 INCLUDE ANY REQUIREMENTS FOR PUBLIC UTILITIES REQUESTING AN FRP?

A. Yes. Any public utility receiving approval for an FRP is prohibited from initiating its first FRP annual review process until at least 180 days after rates have become effective pursuant to a Commission Order in a rate case.[5] Act 725 also restricts the earnings sharing mechanism ("ESM") that is part of the FRP to 50 basis points above or below the "target return rate" or the allowed return on equity ("ROE") set by the Commission.[6] Further, the Act restricts any revenue increase or decrease arising from the FRP to a level below four percent of any rate class's revenue, when compared to the 12-month period preceding the formula rate review test period.[7] Finally, Act 725 restricts any proposed FRP term to no more than five years in length from the date of Commission approval.[8] The Commission may extend an FRP for an additional five years if it finds such an extension to be in the public interest.[9]

[4] *Id.*, p. 6:22 to 7:3.
[5] Ark. Code Ann. § 23-4-1205(c)(2).
[6] Ark. Code Ann. § 23-4-1207.
[6] Ark. Code Ann. § 23-4-1207(d)(2).
[8] Ark. Code Ann. § 23-4-1208(a)(1).
[9] Ark. Code Ann. § 23-4-1208(a)(2).

Q HAS THE COMMISSION REVIEWED ANY OTHER UTILITY FRP REQUESTS SINCE THE PASSAGE OF ACT 725?

A. Yes. The Commission has reviewed and approved FRP proposals made by one jurisdictional electric utility, EAI,[10] and one jurisdictional natural gas utility, CEA.[11] The Commission's EAI FRP approval in Docket No. 15-015-U resulted from a unanimous settlement between the parties in that proceeding whereas the CEA approval in Docket No. 15-098-U was based upon a contested settlement among the parties. Both of these prior FRP decisions are important in formulating the Commission's policies on how FRP proposals will be evaluated and how the specific terms, annual FRP review filing requirements, and other components of an FRP will be handled. Additionally, the Commission has also had the opportunity to review its first annual FRP review for EAI (Docket No. 16-036-FR)[12] over the course of this past year which also sheds some light into how proposed FRPs compare to the actual mechanics of conducting an FRP annual review. I will discuss many of the precedents set in these prior FRP decisions, and how they relate to the Company's FRP proposal throughout this section of my testimony.

Q. PLEASE EXPLAIN THE COMPANY'S FRP PROPOSAL.

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[10] See, In the Matter of the Application of Entergy Arkansas, Inc. for Approval of Changes in Rates for Retail Electric Service, APSC Docket No. 15-015-U.

[11] See, 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, APSC Docket No. 15-098-U.

[12] See, In the Matter of Formula Rate Plan Filings of Entergy Arkansas, Inc., Pursuant to APSC Docket No. 15-015-U, APSC Docket No. 16-036-FR.

A. Act 725 requires utilities to make a declaration to the Commission if they wish to be regulated under an FRP. The Company is making this declaration in the current rate case and is proposing to file its first FRP on or around July 1 of each year, over the next five years. The Company anticipates its first FRP filing on July 1, 2018,[13] a date that should occur after the statutorily-required 180-day waiting period after rates from the instant proceeding go into effect.[14] The parameters of the Company's FRP proposal are generally consistent with the Act 725 requirements. For instance, the Company's FRP application will be based upon a "fully projected test year"[15] that is anticipated to end sometime in 2019. The proposed FRP also includes an ESM that is restricted to 50 basis points above and below the Commission's authorized ROE.[16] The Company's proposed FRP is also based upon a five-year term, consistent with the Act 725 requirements.[17] The proposed FRP also includes a four percent rate cap.[18]

Q. DO YOU HAVE ANY CONCERNS ABOUT THE COMPANY'S FRP PROPOSAL?

A. Yes. I have three concerns about the Company's FRP proposal that include:

- Ambiguity in the Company's proposed FRP test year.

[13] Direct Testimony of Gwin Cash, p. 26: 2.
[14] Ark. Code Ann. § 23-4-1205(c)(2).
[15] Direct Testimony of Gwin Cash, 24:30.
[16] *Id.*, 24:31.
[17] *Id.*, 25:23-26.
[18] *Id.*, 25: 4-6.

- The flexibility being proposed for the capital structure used in the FRP annual review.
- Difficulties that could arise in comparing the first year FRP annual review information with historic trends, particularly in the area of the Company's jurisdictional allocations and its proposed SDR rider.

B. Test Year FRP Ambiguity

Q. BRIEFLY EXPLAIN THE CONCEPT OF A TEST YEAR AND HOW THOSE TEST YEARS ARE USED IN UTILITY REGULATION.

A. The ratemaking process relies on an extensive amount of data and information upon which to set rates. The ratemaking process tries to set rates based upon information that gives a utility a reasonable opportunity to earn a return on and of its prudently-incurred investments as well as a return of its prudently-incurred expenses. Regulators have tried to use information that is reflective of "typical" operating conditions since rates are often set into place for an extended period of time. Information (or data) reflecting typical operating conditions can be based upon historical information, projected information, or a combination of both. Most states, including those using alternative ratemaking mechanisms like an FRP, use historic test years, although there are a number of state regulators that do utilize projected information in the ratemaking process.

Q. HAVE YOU PREPARED AN ANALYSIS OF STATE REGULATORY TEST YEAR POLICIES?

A. Yes. Exhibit DED-1 provides a map that identifies states based upon whether they use historic test years, forecasted test years, or allow utilities to choose between the two types of test years. Currently, there are 31 states that use historic test years, four states that allow the use of forecasted test years, and 15 states that allow utilities to choose between forecasted and historic test years.

Q. DOES ACT 725 AFFORD UTILITIES ANY FLEXIBILITY IN THE TEST YEARS THEY CHOOSE FOR THEIR ANNUAL FRP REVIEW PROCESS?

A. Yes. Ark. Code Ann. § 23-4-1205(a)(2) allows utilities to elect the use of either a fully projected test year or a hybrid test year comprised of up to six months historical and six months projected information, as defined by Ark. Code Ann. § 23-4-406. Ark. Code Ann. § 23-3-1203(4) defines a "projected test year" as being comprised of data projected for the 12 months following the proposed effective date for the first annual FRP review filing. A utility can also elect to use any type of test year consistent with traditional (or non-FRP) regulation as practiced in Arkansas which is limited to a historic test year or what can be thought of as a "hybrid" test year, defined under Ark. Code Ann. § 23-4-406.

Q. EXPLAIN THE STATUTORY DEFINITIONS FOR HISTORIC AND "HYBRID" TEST YEARS UNDER ARK. CODE ANN. § 23-4-406.

A. Ark. Code Ann. § 23-4-406 defines the types of test years the Commission can use to set reasonable rates under traditional regulation. A "historic" test year is defined as one based upon twelve consecutive calendar months of data. The "hybrid," or "partially-projected," test year definition is not so straightforward since, under the traditional regulation test year statute (Ark. Code Ann. § 23-4-406), what can be thought of as a "hybrid" test year is called a "forward-looking" test year and is based upon six months of actual historic information and six months of projected data.

Q. DOES THE TRADITIONAL TEST YEAR STATUTE ALLOW FOR ANY TEST YEAR ADJUSTMENTS?

A. Yes. Ark. Code Ann. § 23-4-406 allows the Commission to utilize any adjustments to either types of test year provided that those adjustments are (a) expected to occur within 12 months of the end of the defined test year and (b) reflect "reasonably known and measurable" changes.

Q. EXPLAIN THE AMBIGUITY IN THE COMPANY'S TEST YEAR DECLARATION.

A. The Company generally appears to be electing to be FRP-regulated by using a "fully projected" test year. This is explicitly stated in the Company's testimony[19] and several of the attachments (particularly Attachment B) that are part of the Company's FRP tariff (Sheet 80) that clearly seems to be based upon the use of a "fully projected test year." However, there is one important place, in Attachment C, which defines all the adjustments that will be made to the FRP historic and test year filing requirements (Attachments B and D), where the Company defines its FRP projected test year as one

[19] Direct Testimony of Gwin Cash, p. 24: 29.

based upon "historic test year with pro forma adjustments." So, on the one hand, most of the Company's filing appears to reference the use of a "fully projected test year," yet in one important other location, this test year appears to be restricted to a "historical test year with [known and measurable] pro forma adjustments."

Q. ISN'T THIS A DIFFERENCE IN SEMANTICS?

A. No. In my experience, a "fully projected test year," in utility regulation tends to reflect something entirely different than just a historical test year with "known and measurable adjustments." A forecast, because it is comprised of some degree of uncertainty, cannot be "known and measurable." Consider, as an example, EAI's recent annual FRP filing, where the test year it utilized in its filing, which was based upon a fully projected test year, was developed from updates to the Company's official forecast, including material that Entergy provided to financial analysts, credit rating agencies and investors, where it cautioned, "[f]orward-looking statements are subject to a number of risks, uncertainties and other factors that could cause actual results to differ materially from those expressed or implied in such forward-looking statements."[20] Thus, one can have a forecast, but a forecast is not "known and measurable."

[20] See, *e.g.*, Entergy – 2016 Analyst Day – June 9, 2016 at page 2.

Q. IS A FULLY PROJECTED TEST YEAR DEVELOPED IN A MANNER DIFFERENT THAN A HISTORIC TEST YEAR WITH KNOWN AND MEASURABLE ADJUSTMENTS?

A. Yes. It is typically the case that a "fully" projected test year is developed from a series of corporate outlooks that take into account such factors that can include, but are not limited to: (1) underlying operational trends, as well as changes in those trends from currently-known information, (2) additionally-known changes that can include discrete or one-time "shocks," (3) corporate goals and outlooks, and (4) professional judgment and guidance. Load forecasts, operation and maintenance expense forecasts, capital budgets, regulatory and policy projections, and a variety of other forecast information are typically used in determining a fully projected test year. In effect, a "fully projected test year" is essentially a "forecasted" test year. While forecasts or projections are often conditioned by historic information, they are also based upon anticipated outcomes, and even goals, that carry with them a certain degree of uncertainty. A historic test year with "reasonably known and measurable" changes is a much more limited and restricted outlook that is fundamentally based on historic information and only includes changes that are expected to occur with a high degree of certainty within a limited period of time. Furthermore, and more importantly, the statutorily-defined time periods under the FRP Act differ depending upon which test year a utility decides to elect.

Q. EXPLAIN WHAT YOU MEAN BY DIFFERING STATUTORILY-DEFINED TIME PERIODS.

A. Under Act 725, a projected test year must occur 12 months after the FRP annual filing date, which OGE currently anticipates being around July 1, 2018. This means that if the Company wanted to utilize a "projected test year," as defined by Act 725, that test year would be based upon data dating from roughly August 2018 to July 2019. If the Company wishes to utilize a "historic test year," with "reasonably known and measurable adjustments," as defined by Ark. Code Ann. § 23-4-406, then it will be restricted to using a time period that is 12 months prior to its FRP annual filing date, which giving reporting lags, could include a time period spanning from June 2017 to May 2018. Any "reasonably known and measurable" adjustments would only be allowed to run to April 2019 which is several months shorter than the allowed "projected test year" end date of July 2019. Thus, statutorily, the Company cannot equate a "projected test year" with a "historic test year" with "reasonably known and measureable" adjustment since the allowed time periods for the differing test year periods are not allowed to be the same.

Q. HAVE YOU ATTEMPTED TO CLARIFY THIS AMBIGUITY?

A. Yes. The Company has explained in discovery that what it has referred to as a "fully forecasted test year" will actually be a historic test year with pro-forma adjustments that include "isolated items where known future charges are expected to occur."[21] Additionally, the Company has provided that this projected test year will not be based on any official Company projected budget or forecast used for corporate management or investor relations purposes.[22]

Q. DO YOU HAVE ANY RECOMMENDATIONS ON HOW TO REMEDY THIS AMBIGUITY?

A. Yes. I recommend that the Commission direct the Company to make two specific clarifications in the definition of its projected test year in Attachment C to Sheet 80. The Company should additionally be required to clearly indicate which type of test year it is using and the definition of this test year needs to be directly tied to the statutory language.

C. Annual FRP Review of Capital Structure

Q. PLEASE EXPLAIN THE CAPITAL STRUCTURE VARIABILITY THAT THE COMPANY PROPOSES TO INCLUDE AS PART OF ITS FRP ANNUAL REVIEW.

A. The Company proposes that it be allowed to project and true-up its capital structure in its annual FRP review within a specific debt-to-equity ("DTE") range. The Company proposes that its reconciliation, which compares its actual (achieved) rate of return to its benchmark rate of return on rate base ("BRORB") be allowed to vary in a range that goes as low as 44 percent debt

[21] Company's response to AG 13-1.
[22] *Id.*

to as high as 50 percent debt for reconciliation purposes.[23] The Company recommends that if its debt falls above of this range, the external capital structure shall be imputed using a 50-50 DTE and if its debt falls below this range, the external capital structure be imputed to 44 percent debt.[24]

Q. WILL ANY OTHER ASPECTS OF THE COMPANY'S RATE OF RETURN BE ALLOWED TO CHANGE IN THE REVIEW AND RECONCILIATION PROCESS?

A. Yes. The cost rate on debt will be allowed to change, but the return on equity ("ROE") will be fixed to the one allowed by the Commission at the conclusion of this proceeding and will remained fixed for the five-year FRP period.[25]

Q. HOW DOES THE COMPANY'S PROPOSAL REGARDING THE CAPITAL STRUCTURE USED IN ITS ANNUAL FRP REVIEW COMPARE TO THE ONES APPROVED FOR EAI AND CEA?

A. The EAI FRP notes that the equity portion of the capital structure it uses for annual FRP review purposes can vary from between 44 to 50 percent.[26] This is the inverse of OGE's current proposal that allows for the equity portion of the Company's capital structure for FRP review purposes to vary from between 50 to 56 percent.[27] OGE's proposal additionally differs from the FRP

[23] Rate Schedule FRP, Sheet 80, Attachment C, Adjustment IIE(4).
[24] *Id.*
[25] *Id.*, Adjustment IIE(5).
[26] Entergy Arkansas, Inc. Electric Service Tariffs. Formula Rate Plan Rider, Rate Schedule 44, Attachment B.5, Arkansas Public Service Commission, filed March 9, 2016
[27] Rate Schedule FRP, Sheet 80, Adjustment IIE(4).

approved by CEA which fixes the capital structure to the one approved by the Commission in its last base rate case (Docket No. 15-098-U).[28]

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

A. No. From a program design perspective, FRP-based rates should be based upon a fixed capital structure as defined by the test year of a utility's most recent (or "cast-off") rate case. Alternative rate plans, like the proposed FRP, are designed to provide incentives for utilities to increase their cost efficiencies by restricting their ability to file for future rate cases. The Company's proposal to allow for a range of possible debt and equity positions would allow the Company to potentially earn incentive returns by simply changing its capital structure, not through efficiencies. This is particularly important relative to the ESM associated with the Company's FRP which allows the Company to retain all earnings up to 50 basis points in excess of the Commission's approved target rate of return.

Q. WHAT ARE YOUR RECOMMENDATIONS REGARDING THE COMPANY'S PROPOSED FRP CAPITAL STRUCTURE FLEXIBILITY?

A. I recommend that the capital structure associated with OGE's FRP annual review be fixed to the one resulting from the Commission's decision in this proceeding. Such an outcome is consistent with alternative regulation design and consistent with the Commission's decision in the CEA FRP approval.

[28] CenterPoint Energy Arkansas Gas, Gas Service Tariffs, Formula Rate Plan Rider, Rider Schedule No. 9, Attachment B.5, Arkansas Public Service Commission, filed September 7, 2016.

D. Annual FRP Review Filing Requirements

Q. DO YOU HAVE ANY CONCERNS ABOUT THE FIRST YEAR ANNUAL FRP FILING REQUIREMENTS?

A. Yes. Act 725 provides for a comparison between comparable projected and historic test years for reconciliation purposes. As noted earlier, the Company appears to be utilizing a projected test year which is corroborated by its observation that "[p]lease note that the Company's first two FRP reviews will not include an historic year review because there will not be a comparative Projected Year revenues associated with the Historic Year."[29] While I understand that Act 725 precludes any financial or cost reconciliation between projected and historic years (until a full 12 months of comparable data is available), I am concerned that waiting two years to begin the process of evaluating the accuracy of the Company's projections may be too long. This could be important in evaluating the Company's annual FRP review jurisdictional allocations as well as in evaluating the reasonableness of certain costs that are included in base rates, and therefore part of the FRP, but are also being recovered through a rider, like the Company's SDR proposal, which I will discuss in further detail in the subsequent section of my testimony.

[29] Direct Testimony of Gwin Cash, p. 26:5-7.

Q. HAVE OTHER ARKANSAS UTILITIES WITH FRPS INCLUDED FINANCIAL COMPARISONS WITH HISTORIC YEARS IN FRP COMPLIANCE FILINGS BEFORE THE COMMISSION?

A. Yes. In its FRP filing in Docket No. 16-036-FR, EAI included financial and cost information for both a projected year encompassing the 2017 calendar year, and a historic year encompassing the 2015 calendar year.[30] Furthermore, EAI computed annual average growth rates by plant and expense account over the five-year period 2011 through 2015.[31] This information was used for validation purposes in examining its projected year balances. EAI additionally presented 2015 actual sales by rate class compared to projected 2017 sales by rate class for the purposes of showing percentage growth in sales the Company was projecting.[32]

Q. EXPLAIN THE COMPANY'S PROPOSAL FOR DETERMINING ITS JURISDICTIONAL ALLOCATIONS FOR FRP REVIEW PURPOSES.

A. The Company correctly notes that jurisdictional revenues and rate base can vary from year to year. Under traditional regulation, the Company uses a jurisdictional COS to allocate rate base and certain revenues to its Arkansas and Oklahoma service territories. The Company notes that the annual filing requirements of the FRP will require it to make similar estimates and the

[30] In the Matter of the Formal Rate Plan Filings of Entergy Arkansas, Inc. Pursuant to APSC Docket No. 15-015-U, APSC Docket No. 16-036-FR, Petition, Attachments B and D.
[31] *Id.*, Attachment E, Item 24.
[32] *Id.*, Item 20.

only tool for doing so is the COS approved in this proceeding. While the Company's proposal is reasonable, it does raise comparability questions since, as I have noted elsewhere in my testimony, the jurisdictional allocations between the current and prior rate cases do differ in non-trivial ways.

Q. DO YOU HAVE ANY RECOMMENDATIONS REGARDING THE COMPANY'S INITIAL FRP ANNUAL REVIEWS?

A. Yes. I recommend that the Company be required to provide comparative information that examines the major costs and drivers between its projected and current rate case test year. This comparison would not be used for any reconciliation. Further, this requirement should only be in place for the first two years of the annual FRP process. Thus, the Commission could simply address this transitional issue in the Order arising from this rate case without any need to change any of the descriptions included in the Company's proposed FRP tariff. As I noted earlier, I also have some issues regarding the reconciliation of storm costs included in base rates and those associated with the Company's proposed SDR which I will address separately in the following section of my testimony.

E. FRP Recommendations

Q. CAN YOU PLEASE SUMMARIZE YOUR FRP RECOMMENDATIONS?

A. I recommend the Commission approve the Company's FRP subject to the following modifications:

- The Commission should direct the Company to clearly indicate which type of test year it is using and the definition of this test year needs to be directly tied to the statutory language.
- The capital structure associated with OGE's FRP annual review should be fixed to the same one resulting from the Commission's decision in this proceeding. Such an outcome is consistent with alternative regulation design and consistent with the Commission's decision in the CEA FRP approval.
- The Company should be required to provide comparative information that examines the major costs and drivers between its projected and current rate case test year. This comparison would not be used for any reconciliation. Further, this requirement should only be in place for the first two years of the annual FRP process. Thus, the Commission could simply address this transitional issue in the Order arising from this rate case without any need to change any of the descriptions included in the Company's proposed FRP tariff.

IV. OTHER PROPOSED RIDERS

A. Introduction

Q. PLEASE DISCUSS THE COMPANY'S RIDER PROPOSALS.

A. The Company is proposing to modify a number of its existing proposals as well as utilizing a new rider that would operate in conjunction with the FRP Rider. These rider proposals include:

- Eliminating the Lost Contribution to Fixed Cost ("LCFC") component of its Energy Efficiency Cost Recovery Rider ("EECR") since these revenues will now be recoverable through the annual FRP process.
- Eliminating the SmartGrid Rider ("SGR") since the Company is proposing to "fold" all of these costs into rates in the instant proceeding.

- Modifying its Energy Cost Rider ("ECR") in order to eliminate the minimum off-system sales credit that has been a component of this rider since its last base rate case.
- Altering its existing Storm Damage Recover ("SDR") rider to recover incremental storm costs not recoverable in base rates.
- Implementing a new Large Capital Asset ("LCA") Rider to recover the costs of major capital projects.

Q. DO YOU HAVE ANY CONCERNS ABOUT THESE RIDER PROPOSALS?

A. Yes. I have concerns with the Company's SDR and LCA proposals which I will discuss, individually, in this section of my testimony. I do not have any issues with the Company's LCFC nor SGR proposals although Mr. William Marcus, another expert appearing on the AG's behalf does address some revenue requirement issues related to these SGR costs.

B. SDR Proposals

Q PLEASE DISCUSS THE COMPANY'S SDR PROPOSAL.

A. The Company is proposing to activate and modify its existing SDR Rider to collect any incremental storm cost that are outside of the amounts included in base rates that will be maintained, presumable at levels approved in this proceeding, in future annual FRP reviews. The costs would still be collected over a period of two years, and would be allocated using the final CCOSS allocation factors resulting from the current rate case.[33]

Q. WHAT DO YOU MEAN BY "RE-ACTIVATING" THIS PARTICULAR RIDER?

A. This SDR Rider was originally approved in Docket No. 08-103-U as a means of recovering a specific set of 2008 storm-related costs rather than including those storm costs into base rates at the time of the Company's last rate case. The Commission, at the time, recognized that if it included these 2008 storm costs, amortized over a two-year period, into rates, the Company would begin to receive a windfall between the expiration of the amortization period and the time of its next base rate case.[34] The Commission opted to use the SDR Rider to recover specific storm costs, truing those up on an annual basis, until such time that the balance fell to zero. Thus, the SDR Rider has been dormant since the 2008 storm costs were completely paid off, an event that occurred presumably in or near the year 2010 assuming the initially requested two-year amortization period.

Q. WHAT IS THE COMPANY'S REASONING FOR PROPOSING TO USE THE SDR RIDER AS A PERMANENT COST RECOVERY MECHANISM ALONGSIDE ITS PROPOSED FRP?

[33] Direct Testimony of Gwin Cash, p. 23:24-28.
[34] In the Matter of the Application of Oklahoma Gas and Electric Company for Approval of a General Change in Rates and Tariffs, APSC Docket No. 08-103-U, Order No. 6, May 20, 2009, p. 16.

A. The Company claims that the rider is necessary because immediate action taken to restore service after a storm may cause the company to risk exceeding the four percent revenue change cap specified by FRP.[35] The Company is suggesting a 24-month recovery period on the grounds that doing so will reduce the impact of storms on customers' bills, and because 24 months is the recovery period originally used to recover costs resulting from the 2008 storm.[36]

Q. DO YOU AGREE WITH THE COMPANY'S ARGUMENTS FOR RE-ACTIVATING AND ALTERING ITS SDR?

A. No. The Company has provided no record evidence that its SDR proposal is needed. Such a proposal is not only premature, but seeks to have a no-cost hedge on future storm costs that would allow it to increase rates beyond the four percent cap allowed under Act 725. Such an approach is inconsistent with the provisions of the FRP Act and should be rejected.

Q. WHAT ARE YOUR SDR RECOMMENDATIONS?

A. I recommend that the Commission reject the Company's SDR proposals and utilize the projected test year approach, afforded under the Company's proposed FRP, to recover storm-related costs. The Company's argument that storm-related costs could increase its annual FRP revenue increase above the

[35] Company's Response to Data Request APSC 72-1.
[36] Company's Response to Data Request APSC 72-3.

four percent statutory cap is speculative and unsupported.[37] If a unique storm event arises, and imposes costs that cannot be recovered in one year, or accommodated within the FRP, then the Commission can address any special ratemaking mechanisms needed to meet these unique challenges at the time they arise, when the costs and impacts can be determined in a reliably known and measurable fashion.

C. LCA Rider Proposal

Q. PLEASE EXPLAIN THE COMPANY'S LCA RIDER PROPOSAL.

A. The Company notes that the purpose of its LCA Rider is to recover the costs associated with very large capital additions.[38] In particular, the types of capital additions that would be of a size and cost that would threaten the Act 725 four percent rate cap.[39] The Company notes that it is simply requesting the creation of the LCA Rider at the current time. No current or anticipated capital projects are earmarked for recovery in this rider and the Company explains that no capital investment would be included in this rider without prior Commission approval.[40] However, once projects are approved for inclusion in this rider, they will remain in the rider until the Company's next

[37] Company's Response to AG 13-2 (d).
[38] Direct Testimony of Donald R. Rowlett, p. 8:15-16.
[39] *Id.*, p. 8:17-18.
[40] *Id.*, p. 9:10-13; 17-18.

base rate case.[41] The Company is requesting that this rider be put into place for an initial term of a decade.[42]

Q. DO YOU HAVE ANY CONCERNS ABOUT THE COMPANY'S LCA RIDER PROPOSAL?

A. Yes. I have a number of concerns about the Company's LCA Rider proposal that includes:

- From a policy perspective, the LCA Rider is entirely inconsistent with the spirit and plain intent of Act 725 and, if approved, would eliminate the one ratepayer protection included in Act 725.
- Approval of the LCA Rider would set a bad policy precedent.
- The LCA Rider is based entirely on speculation: the Company has provided no evidence of the need for the LCA Rider.
- The LCA Rider also suffers from a number of mechanical shortcomings that include:
    - The tariff is incomplete and not well-defined.
    - Cost recovery is not based upon COS principles.
    - Projects would be granted a prudence "pre-approval."
    - The proposed ten-year term for the LCA Rider is too long.

Q. PLEASE EXPLAIN HOW THE LCA RIDER IS INCONSISTENT WITH THE POLICY INTENT OF ACT 725.

[41] *Id.*, p. 9:2-3.
[42] *Id.*, p. 9:4.

A. From a policy perspective, Act 725 is clear when it comes to the terms and conditions under which rates will be allowed to change, both upwards and downwards. Ark. Code Ann. § 23-4-1207(d)(2) states that "the total amount of a revenue increase or decrease for each class shall not exceed four percent of each rate class's revenue for the twelve calendar months preceding the formula rate review test period." There are simply no exceptions, limitations or conditions to this maximum (and minimum) rate change within the four corners of the FRP statute. The plain intent is to maintain rates at reasonable and stable levels. The Company's proposed LCA is an undisguised attempt to block off a certain type of costs from this statutory limitation. If the legislature had any concerns about capital cost recovery, and the ability of that capital cost recovery jeopardizing the four percent cap, it could have included that in the language of Act 725. However, this limitation is not part of the statute.

Q. IS THE COMPANY'S PROPOSED LCA CONSISTENT WITH THE INTENT OF ACT 725?

A. No. The preamble of Act 725 is clear that its <u>intent</u> is to develop a process by which rate reforms can be established that allow utilities to provide reliable service while maintaining <u>stable rates</u>.[43] One of the ways Act 725 facilitates this rate stability is by limiting the rate increases that FRP-regulated

[43] Ark. Code Ann. § 23-4-1202(b).

utilities will pass along to their ratepayers: there are no exceptions to this limitation. Further, the Legislature seems to have been very cognizant that the provision of reliable service will require utilities to incur costs and that the FRP has been designed in a way that balances this requirement against the rate stability goal of the Act. The Legislature did not condition this rate stability for just one set of utility costs while leaving another, potentially larger set of costs, wide open to change.

Q. ARE UTILITIES REQUIRED TO BE REGULATED UNDER ACT 725?

A. No. Act 725 allows utility to "elect" to be regulated under traditional regulation or a form of alternative regulation that has been specifically defined in the statute. There are no conditions on this election. The choice of being regulated under an FRP and the type of test year being utilized by the FRP are both at the discretion of the utility; they are not mandates. The only requirement is that the utility's proposed FRP receives approval by the Commission as being consistent with the Act 725 requirements and in the public interest. The Act, therefore, lets utilities decide whether (a) they want to continue to use traditional incentives and traditional regulation to provide reliable and stable rates to customers or (b) they want to utilize a more expedited approach that can be facilitated under a very strict set of terms and conditions. The Act does not allow utilities to pick and choose across both.

Q. DOES THE COMPANY'S PROPOSED LCA REMOVE AN IMPORTANT ACT 725 RATEPAYER PROTECTION?

A. Yes. The four percent rate cap is a very important ratepayer protection that has been included in Act 725 to ensure the statute's intent is met, which is to ensure rate stability. This would appear to be a small price to pay for utilities electing to be regulated by this statute since, in return for this small concession, FRP-regulated utilities will be allowed to:

- Update their rates on an annual basis in what is a relatively expedited process (relative to a traditional rate case).
- Utilize a projected test year for establishing rates.
- A guaranteed claim to any excess earnings up to 50 basis points of a utility's authorized rate of return.
- An ability to update certain cost rates associated with its overall cost of capital in the annual FRP true-up process.

Q. IS THE COMPANY'S PROPOSED LCA SYMMETRIC?

A. No. Approval of the LCA Rider would give the Company an "out" to raise rates above four percent but does not create a symmetrical opportunity to lower rates below four percent should appropriate circumstances arise in the future. Thus, the LCA will allow the Company to have its proverbial cake and eat it too since it creates an exception on rate increases without any corresponding exception on rate decreases below the four percent level. This exemption cannot be consistent with the intent of Act 725 because, if the

Legislature had wanted to create an asymmetrical relationship between rate increases and rate decreases, it could have easily done so, or defined the terms and conditions in which such asymmetries would be allowed.

Q. EXPLAIN YOUR CONCERNS ABOUT THE POLICY PRECEDENTS THAT COULD ARISE IF THE LCA RIDER IS APPROVED.

A. OGE has not provided any record evidence that shows or even suggests that the Company is in a unique position such that LCA Rider approval could not apply to other utilities. Thus, if the Commission approves the Company's proposed LCA Rider, it holds open the door for other utilities to request similar types of Riders in their future FRP annual reviews or applications. If all FRP utilities receive an LCA or LCA-type Rider, it will fundamentally change the intent of the Act 725 regulatory requirements as I noted in detail above.

Q. HAS THE COMPANY SHOWN THE NEED FOR THE LCA RIDER?

A. No. The Company has not provided any record evidence proving that it will need the LCA Rider or that any kind of financial harm will arise if the LCA Rider is not approved.[44] In short, the proposed LCA Rider is a solution in search of problem.

Q. DOES THE COMPANY'S TESTIMONY CONTRADICT ANY POTENTIAL NEED FOR THE LCA RIDER?

[44] Company's Response to Data Request AG 13-3.

A. Yes. The Company's own testimony contradicts the need for any LCA Rider or any rate increase that may be above the Act 725 four percent requirement. The Company goes to great lengths to stress that it (a) has some of the lowest rates in the region and (b) has not been before the Commission for a rate increase since 2011 when it received a $8.8 million increase (out of a requested $17.7 million). Thus, OGE has seen an annual average increase in rates, since 2011, of about 2.0 percent – far below the 4.0 percent Act 725 cap despite the fact that the Company boasts that all the while it has been able to:

- Accommodate customer growth and service requirements
- Invest over $229.5 million in utility infrastructure, $65.3 million of which is purported not being recovered through current rates.
- Add 700 miles of transmission lines.
- Increase overhead distribution circuit miles by 24 percent.
- Increase underground distribution circuit miles by 174 miles (or 23 percent).
- Add 500 transformers.

The Company has been able to do all this, without the aid of any FRP Rider much less any LCA Rider suggesting that the need for any special ratemaking mechanisms is likely not that significant.

Q. PLEASE EXPLAIN THE MECHANICAL ISSUES ASSOCIATED WITH THE COMPANY'S LCA RIDER PROPOSAL.

A. The Company's LCA Rider proposal suffers from a number of mechanical and tariff design short-comings that include (1) an undefined tariff, (2) a proposed method of establishing rates that is not consistent with Act 725, (3) the establishment of a "pre-prudency" determination on any asset that is included in the Rider for cost recovery purposes, and (4) an exceptionally long term that is unnecessary.

Q. CAN YOU EXPLAIN WHY THE TARIFF IS NOT VERY WELL-DEFINED?

A. The Company explicitly notes that the purpose of the LCA Rider is to recover capital asset costs that would, in effect, force rates above the four percent rate cap included in Act 725.[45] The Company clearly notes, that if the LCA is not approved, it will have to recover those costs through the FRP; or, put another way, the LCA is designed to recover FRP-related costs that are above the four percent Act 725 cap. Thus, it stands to reason that if the LCA is designed to cover another "class" or "category" of FRP costs, the tariff associated with these costs should look very similar, have as much detail, and be conceptually consistent with the FRP in all ways. A simple review and reading of the LCA Rider, however, reveals a document that appears to be nothing more than a loosely-defined placeholder.

Q. EXPLAIN HOW THE PROPOSED LCA AND FRP RIDERS DIFFER.

[45] See, Company Response to Data Request AG 4-18, Company Response to Data Request APSC 45-1, and Direct Testimony of Donald R. Rowlett p. 8:16-19.

A. There are no details on the specifics of how the revenue requirement for the LCA Rider will be determined. For example, it does not indicate whether the LCA Rider will be limited to just the capital costs or if it will include any types of expense items that are tied to those capital costs/assets. The LCA Rider also does not specify whether the revenue requirement will be done on a historic or projected basis; the LCA Rider has no specifics on how it will be annually reconciled, if at all. The cost of capital that will be utilized in the LCA Rider is ambiguous and not consistent with the FRP Rider both in this respect, and as to whether debt cost rates will be allowed to vary during any annual reviews. Lastly, the 30-day review period is too short, and entirely inconsistent with the review period allotted to the same type of (embedded) capital costs that will be recovered in the FRP.

Q. ARE THE RATE DEFINITIONS INCLUDED IN THE LCA RIDER CONSISTENT WITH THOSE REQUIRED UNDER ACT 725?

A. No. Act 725 requires any annual rate changes to be allocated to customer classes in proportion to their base revenue responsibility on their last rate case. The Company's LCA Rider, however, utilizes a class allocation factor that is ambiguous and does not appear to be directly comparable to the Act 725 requirements. Furthermore, the allocation of the annual FRP revenue requirement to each class also implies that each class's FRP revenue responsibility will be proportionally allocated to that class's individual rate components (*i.e.*, allocated proportionally to the customer charge, energy charge, demand rates). The LCA Rider, however, will allocate 100 percent of its revenue requirement to an energy-based (volumetric) charge despite the fact that (a) these are costs that, but for the LCA, would be recovered differently in the FRP, (b) represent costs that are likely plant-related, potentially dominated by production plant, which are usually recovered through a combination of energy and demand charges depending upon the class in question, and (c) are assessed in a volumetric fashion that is entirely inconsistent with the numerous pages of Company expert opinion dismissing the principle of allocating capital costs in such a fashion.

Q. EXPLAIN YOUR CONCERNS ABOUT THE PRE-PRUDENCY ASPECTS OF THE LCA RIDER.

A. The Company has not satisfactorily explained how the prudence of any LCA asset's cost will be evaluated, simply noting that the Company "believes that any project deemed by the Commission, as used and useful, under the LCA is a prudent investment."[46] A plain reading of the proposal and the tariff suggests that the Company's proposed LCA Rider will put the Commission in the position of pre-approving the prudence of the capital costs associated with any asset subject to this rider. More importantly, the Company expects the Commission and other stakeholders to conduct any prudence analysis that

[46] Company's Response to Data Request AG 12-04.

may be allowable under this tariff in a 30-day period. The Commission should reject such a suggestion out of hand.

Q. IS THE PROPOSED LCA RIDER TERM TOO LONG?

A. Yes. The Company is proposing the LCA Rider as a type of supplement to its FRP. Yet, inconsistently, the Company is proposing a term for the LCA Rider that runs for an entire decade – a term far longer and inconsistent with Act 725 that only allows an FRP Rider to last five years. To the extent the Commission allows any LCA Rider to be approved, it needs to be limited to run as long as the FRP, and a utility should be required, as part of approving the LCA Rider, to come in for a full base rate case in five years in order to move the LCA Rider costs into base rates.

Q. WHAT ARE YOUR LCA RIDER RECOMMENDATIONS?

A. I recommend the Commission reject the Company's LCA Rider recommendations since the proposal is (1) inconsistent with ratepayer protection provisions of Act 725, (2) is not well-defined and based upon a tariff that is general in nature and inconsistent with the Company's proposed FRP, (3) is not supported with any record evidence indicating any need, (4) is based upon a set of cost recovery methods that are inconsistent with Act 725 and the Company's own cost-causation principles articulated elsewhere in its testimony, (5) would likely set a bad precedent for other Arkansas utilities, (6) would likely result in a prudence pre-approval, and (7) has been proposed for a term that is too long and far surpasses the five-year term included in Act 725.

D. Summary of Other Rider Recommendations

Q. PLEASE SUMMARIZE YOUR RECOMMENDATIONS REGARDING THE ADDITIONAL RIDERS BEING PROPOSED BY THE COMPANY.

A. I recommend the Commission:

- Reject the Company's SDR proposals and utilize the projected test year approach, afforded under the Company's proposed FRP, to recover storm-related costs. The Company's argument that storm-related costs could increase its annual FRP revenue increase above the four percent statutory cap is speculative and unsupported. If a unique storm event arises, and imposes costs that cannot be recovered in one year, or accommodated within the FRP, then the Commission can address any special ratemaking mechanisms needed to meet these unique challenges at the time they arise, when the costs and impacts can be determined in a reliably known and measurable fashion.
- Reject the Company's LCA Rider recommendations since the proposal is (1) inconsistent with ratepayer protection provisions of Act 725, (2) is not well-defined and based upon a tariff that is general in nature and inconsistent with the Company's proposed FRP, (3) is not supported with any record evidence indicating any need, (4) is based upon a set of cost recovery methods that are inconsistent with Act 725 and the Company's own cost-causation principles articulated elsewhere in its testimony, (5) would likely set a bad precedent for other Arkansas utilities, (6) would likely result in a prudence pre-approval, and (7) has been proposed for a term that is too long and far surpasses the five-year term included in Act 725.

V. <u>COST-OF-SERVICE STUDIES</u>

A. Introduction

Q. WHAT IS THE PURPOSE OF A CCOSS?

A. A CCOSS is a method by which utility costs and revenues are reconciled across different customer classes. The goal of the study is to determine the cost of providing service to either a particular jurisdiction or a particular customer class, and the revenue contribution each makes to cover those costs. The results of a CCOSS produce a rate of return and revenue requirement that can be used as a tool in developing the revenue responsibility and rates for each rate class.

Q. HOW IS A CCOSS PERFORMED?

A. Typically, a CCOSS is performed in three distinct steps: functionalization; categorization; and allocation. The first step in this process, functionalization, simply defines costs based upon their nature, for example, those costs that are production, transmission, distribution, or customer related. The next step of the process "categorizes" each of these respective costs into a particular type of cost, including those that are demand-related, energy-related, or customer-related. The last step of the process "allocates" each of these costs to a respective customer class.

Q. IS THIS A RELATIVELY SIMPLE PROCESS?

A. No. Some costs can be clearly identified and directly assigned to a function or category while several others are more ambiguous and difficult to assign. The primary challenge in conducting a CCOSS is the treatment of what are known as "joint and common" costs. Given their shared or integrated nature, these joint and common costs can often be difficult to compartmentalize into any particular function or category. 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. CAN YOU EXPLAIN WHAT YOU MEAN BY DEMAND-RELATED COSTS?

A. Yes. 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. At the production level, most power plants or electric generation units ("EGU") are typically viewed as being designed to serve both energy and demand/capacity needs of the utility. The exact degree of this split between energy and demand functionality depends on the individual EGU in question and its place in a utility's dispatch curve, with more baseload units serving more of the utility's energy needs and more peak 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. The most common demand allocation factors used in a CCOSS are those related to system coincident peaks ("CP") or non-coincident customer class peaks ("NCP").

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

A. Yes. Energy-related costs are defined as those that tend to change with the amount of electric (*i.e.*, kWh) sold. Electric generation costs and high-voltage transmission lines, for instance, can be allocated, in part, based on some measure of electric 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. HOW DOES A CCOSS RELATE TO COMMONLY-QUOTED ECONOMIC PRINCIPLES?

A. CCOSSs are also referred to as "fully allocated cost studies" since they allocate test year revenues, rate base, expenses, and depreciation to various jurisdictions and customer classes based upon a series of different allocation factors. The purpose of the CCOSS is to estimate the cost responsibility for various jurisdictions and customer classes, which in turn are used to develop rates. At the core of a CCOSS is a set of historic book costs for the Company that has accumulated over decades. Rates are, therefore, based upon historic average costs; whereas, economic theory suggests that the most efficient form of pricing in perfectly competitive markets should be based upon marginal costs. However, distribution utilities do not operate in perfectly competitive markets and, by their very nature, are natural monopolies. Thus, reaching the ideal pricing formula outlined in economic theory is impossible since the nature of natural monopolies makes pricing in the presence of declining average costs, coupled with a number of joint and common costs, difficult. Added to this problem is the additional fact that the costs utilized by a CCOSS are historic and static, not dynamic and forward-looking, undermining many experts' cost causation/pricing claims. There is no single correct answer that is revealed in a CCOSS, and it is often up to regulators to exercise their appropriate judgment regarding the nature of these costs and the implications they have in setting fair, just, and reasonable rates. This is one of the reasons why many regulators use the results of a CCOSS as a "guide" in setting rates, but are not bounded by the results that are generated from these studies.[47]

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

A. The CCOSS process is significantly different than the revenue requirement or cost of capital phase of a typical rate case. While the latter two activities are dedicated to determining how much revenue will be recovered through rates, the CCOSS process determines how those revenues will be recovered, and through which customer rates. The primary controversy with the evaluation of various CCOSS results often rests with determining whether revenues (costs) will be recovered strictly by the peak load contributions of each customer class, or whether the approach will be tempered through the use of peak and off-peak usage considerations. Methodologies that are heavily-biased toward peak considerations (over non-peak or energy), for

[47] See, for example, In the Matter of the Application of Entergy Arkansas, Inc. for Approval of Changes in Rates for Retail Electric Service, APSC Docket No. 06-101-U, Order No. 10, June 15, 2007, p. 102, fn. 51: "The Commission may find that results of an appropriately allocated cost of service do not reflect reasonable increases or decreases among the classes."

instance, can tend to prejudice relatively lower load-factor customers, such as residential and small commercial customers, and prefer larger customer classes and off-peak customers. These approaches also fail to capture the basic commodity being sold by the utility, which is electricity, and how the value of that commodity varies by the amount purchased by different customer classes.

B. Jurisdictional Cost of Service

Q. WHAT IS THE GENERAL PURPOSE OF A JURISDICTIONAL COSS?

A. A jurisdictional cost allocation study attempts to determine the appropriate revenue requirement associated with a utility's costs to serve each of its jurisdictions. Among other items, uniformity can be an important part of this jurisdictional cost estimation process. It is important to use uniform (or consistent) data and to use uniform allocation methodologies. If a utility does not adopt uniform data or methodologies across its jurisdictions, it could easily over- or under-recover its cost of service on a system-wide basis.

Q. HAS THE COMPANY RECENTLY FILED A FULL RATE CASE IN OKLAHOMA?

A. Yes. On December 18, 2015, the Company filed a general rate proceeding (Cause No. PUD 201500273) before the Oklahoma Corporation Commission ("OCC"). This filing included, among other items, a jurisdictional cost allocation study and a CCOSS.[48] In its OCC filing, the Company proposed a number of changes to its prior jurisdictional allocation methodology. For example, the Company proposed to re-functionalize Generation Step-Up ("GSU") transformers and generation radial ties as generation-related as oppose to transmission-related.[49] Both GSUs and generation radial ties are facilities involved with the transfer of electrical power from generation units to nearby transmission systems. The Company had previously functionalized these facilities as transmission facilities based on accounting guidelines; however, the Company proposed to re-functionalize these facilities as generation related based on the fact that the Federal Energy Regulatory Commission's ("FERC") does not consider either GSUs or generation radial ties as transmission assets for purposes of recovery through transmission formula rates.[50]

Q. DID THE COMPANY MAKE ANY OTHER CHANGES TO ITS JURISDICTIONAL ALLOCATION METHODOLOGY IN OKLAHOMA?

A. Yes. The Company proposed to allocate environmental costs based on the Company's production demand allocator, and additional allocate all community solar projects to the Company's Oklahoma jurisdiction based on

[48] In the Matter of the Application of Oklahoma Gas and Electric Company for an Order of the Commission Authorizing Applicant to Modify its Rates, Changes, and Tariffs for Retail Electric Service in Oklahoma, Corporation Commission of Oklahoma Cause No. PUD 201500273, Direct Testimony of David Smith, p. 2:19-22.
[49] *Id.*, p. 11:5-6.
[50] *Id.*, pp. 11:20 to 12:5.

the localized nature of such systems.[51] Perhaps most importantly, the Company proposed to change the Company's prior production demand allocator with a new allocator that made use of an Average and Excess ("A&E") methodology using an average of the Company's four summer coincident peaks ("4CP").[52]

Q. DID THE OCC APPROVE THE COMPANY'S JURISDICTIONAL ALLOCATIONS?

A. The full OCC has yet to approve or reject the Company's proposed jurisdictional allocation, but on December 8, 2016, the assigned Administrative Law Judge ("ALJ") issued a report supporting a proposed settlement agreement between parties to the proceeding.[53] This proposed settlement agreement contained no objections to the Company's proposed allocation of costs between jurisdictions.

Q. HOW DOES THE COMPANY'S OKLAHOMA FILING COMPARE TO THE CURRENT FILING IN ARKANSAS?

A. Exhibit DED-2 presents a comparison of the results from the two sets of jurisdictional allocations. This comparison shows that the Company proposes to allocate only 8.0 percent of total net plant and 8.3 percent of total

[51] *Id.*, p. 12:13-18.
[52] *Id.*, p. 13:7-10.
[53] In the Matter of the Application of Oklahoma Gas and Electric Company for an Order of the Commission Authorizing Applicant to Modify its Rates, Changes, and Tariffs for Retail Electric Service in Oklahoma, Corporation Commission of Oklahoma Cause No. PUD 201500273, Report of the Administrative Law Judge on the Full Evidentiary Hearing.

operating expenses to Arkansas in the current proceeding. This compared to its jurisdictional allocations in its Oklahoma filing that allocated 10.3 percent of total net plant and 7.7 percent of total operating expenses to Arkansas. Notably, the Company's Oklahoma cost allocation is based on a 12-month historic test year ending June 30, 3015, compared with the current application that uses a 12-month historic test year (for initial ratemaking purposes) ending June 30, 2016. The year difference in test years may explain some of the differences in jurisdictional allocations.

Q. WHAT ARE YOUR JURISDICTIONAL COST ALLOCATION RECOMMENDATIONS?

A. I recommend the Commission accept the Company's proposed jurisdictional allocations, as consistent with what was done recently in Oklahoma and avoids over-recovery of its cost of service on a system-wide basis.

C. Class Cost of Service Study

Q. COULD YOU PLEASE DESCRIBE THE COMPANY'S PROPOSED CCOSS DEMAND ALLOCATORS?

A. The Company uses three primary demand allocators in its CCOSS. These include a Production Demand Allocator based on an A&E-4CP allocation methodology, a Transmission Demand Allocator based on an average of 12 Coincident Peaks, and a Distribution Demand Allocator based on a calculation of rate classes' relative non-coincident peaks ("NCP").

Q. IS THE COMPANY USING A DIFFERENT PRODUCTION DEMAND ALLOCATOR IN THIS PROCEEDING?

A. Yes. In each of the Company's last five rate cases, the Company has utilized an Average and Peak ("A&P") or one-coincident peak and average methodology to allocate production-related demand costs.[54] The Company states that its change in its COS methodology provides a reasonable balance between contributions to peak system and energy requirements.[55] Presumably, however, the proposed change is at least partially motivated by State legislation that has been approved since the Company's last rate case and noted by the Company in its filing, though the Company also states that the legislation is not the primary motivation behind its proposal.[56]

Q. PLEASE DISCUSS THE RECENT LEGISLATIVE CHANGES IMPACTING JURISDICTIONAL UTILITIES' COST ALLOCATION METHODOLOGIES.

A. Act 725, discussed earlier in the FRP section of my testimony, also includes language that allows the Commission to approve rates calculated under an A&E 4CP methodology if the Commission finds such rates to be beneficial to economic development:[57]

> Notwithstanding the commission's authority to otherwise determine and fix rates for all classes of customers, including allocating or assigning costs and designing rates, if the commission finds that it will be beneficial to

[54] Company's Response to Data Request AG 12-11.
[55] Direct Testimony of David Smith, 10:21-23.
[56] Direct Testimony of Donald Rowlett, 8:5-12.
[57] Ark. Code Ann. Code § 23-4-422(b) and Ark. Code Ann. § 23-4-422(b)(2)(B).

> economic development or the promotion of employment opportunities, and that will result in just and reasonable rates for all classes of customers, the commission shall determine rates and charges for utility services that:
>
> (…)
>
> Ensure that production demand costs are allocated to each customer class pursuant to the average and excess method shown in Table 4-10B on page 51 of the 1992 National Association of Regulatory Utility Commissioners Manual, as it existed on January 1, 2015, using the average of the four (4) monthly coincident peaks for the months of June, July, August, and September for each class for the coincident peak referenced in Table 4-32 10B of the manual, as it existed on January 1, 2015, or any subsequent version of the manual to the extent it produces an equivalent result.[58]

Q. DOES THE COMPANY SUGGEST THAT THE PROPOSED CHANGE IN PRODUCTION DEMAND COST ALLOCATION WILL PROVIDE BENEFITS TO THE COMPANY AND THE ARKANSAS ECONOMY?

A. Yes. The Company states that it "believes that the 4CP A&E cost allocation methodology will be beneficial to economic development and promote job creation for both existing and new businesses."[59] This statement is provided without any support, and the Company further notes that its decision to change its previous cost allocation methodology is "primarily based upon [the Company's] belief that such methodology most correctly assigns costs among customers…"[60]

[58] Ark. Code Ann. Code § 23-4-422(b) and Ark. Code Ann. § 23-4-422(b)(2)(B).
[59] Direct Testimony of Donald Rowlett, 8:7-9.
[60] *Id.*, 8:10-12.

Q. PLEASE DESCRIBE AN AVERAGE AND PEAK COST ALLOCATION METHODOLOGY.

A. An A&P cost allocation methodology is based upon a two-component weighted average. The first component represents each rate class's share of the utility's total annual energy sales, and the second component represents each rate class's share of the utility's annual system peak demand. These components are combined through the use of a weighted average, specifically the energy component is weighted by the utility's overall system load factor while the peak demand component is weighted by the inverse of the system load factor (*i.e.*, 1 minus the system load factor).

Q. PLEASE DESCRIBE THE COMPANY'S PROPOSED AVERAGE AND EXCESS – 4 COINCIDENT PEAK COST ALLOCATION METHODOLOGY.

A. Conceptually, A&E 4CP cost allocation methods involve developing two components that are also combined by the use of a weighted average.[61] 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 average contribution to the utility's overall system peak demand during the designated four peak

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

months – in the case of the Company the months June through September. As mentioned earlier, these components are combined through the use of a weighted average, specifically the average component is weighted by the utility's overall system load factor while the excess component is weighted by the inverse of the system load factor (*i.e.*, 1 minus the system load factor).

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

A. A load factor is defined as the ratio of the average load in kilowatts supplied during the designated period to the peak or maximum load in kilowatts occurring in that period. The load factor is expressed as a percentage and may be derived by multiplying the kilowatt hours in the period by 100 and dividing by the product of the maximum demand in kilowatts 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. PLEASE EXPLAIN THE DIFFERENCE BETWEEN AN AVERAGE AND PEAK METHODOLOGY AND AN AVERAGE AND EXCESS – 4 COINCIDENT PEAK METHODOLOGY.

A. On the surface, the A&P and A&E-4CP allocation methods appear very similar, and conceptually, both allocation methods involve developing an energy and demand component that are then combined by use of a weighted average based on the utility's system load factor. In other words, both allocators are intended to be a hybrid energy and demand allocator reflecting the joint energy and demand functions of production plant. In practice, however, an A&E-4CP allocation places more sensitivity on a rate class's demand contribution and reduces the sensitivity of a rate class's annual energy usage in comparison to an A&P allocation methodology. An A&E-4CP in general is therefore viewed by industrial and large commercial customers as a more favorable allocator since they tend to have relatively higher load factors.

Q. DOES THE COMPANY PROVIDE ANY EVIDENTIARY SUPPORT FOR DEVIATING FROM ITS PRIOR COST ALLOCATION METHODS?

A. No. As mentioned previously, the only support the Company provides is a blanket statement that it "believes that the 4CP A&E cost allocation methodology will be beneficial to economic development and promote job creation for both existing and new businesses."[62] The Company further notes that its decision to change its previous cost allocation methodology is "primarily based upon [the Company's] belief that such methodology most correctly assigns costs among customers…"[63]

[62] Direct Testimony of Donald Rowlett, 8:7-9.
[63] *Id.*, 8:10-12.

Q. DOES ACT 725 MANDATE THE COMMISSION TO ADOPT A COST ALLOCATION METHOD THAT IS NOT IN THE PUBLIC INTEREST?

A. No. First, from a policy (and not legal) perspective, Act 725 does not appear to supersede the Commission's general authority to determine just and reasonable rates. In fact, the Act explicitly notes that its intent is to NOT supersede the Commission's general ratemaking authority.[64] Second, Act 725 only instructs the Commission to adopt an A&E-4CP methodology if the Commission "finds that it will be beneficial to economic development or the promotion of employment opportunities."[65]

Q. WHAT ARE YOUR CCOSS RECOMMENDATIONS?

A. As laid out above, I generally do not support the Company's use of an A&E-4CP methodology to allocate demand-related production costs. To this end, I recommend that the Commission adopt the same approach that it utilized in the EAI and CEA rate cases. Namely, that the Commission aver on making any decision regarding the relationship between the Company's proposed demand allocators and economic development. Instead, the Commission should only use the Company's proposed CCOSS results as a starting point in setting the overall revenue distribution in this case, provided this revenue distribution is tempered with many of the same policy considerations the Commission utilized in the EAI and CEA decisions. I will discuss these

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[64] Ark. Code Ann. Code § 23-4-422(b).
[65] Ark. Code Ann. Code § 23-4-422(b)(2)(B).

policy considerations in the subsequent section of my testimony addressing revenue distribution and rate design issues.

VI. REVENUE DISTRIBUTION AND RATE DESIGN

A. Revenue Distribution and Rate Design Policy Objectives

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

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

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

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

Q. WHAT ARE THOSE BROADER RATEMAKING POLICY GOALS?

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

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

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

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

Q. HAS THE COMMISSION ACCEPTED RATES WITH SIMILAR RATE DESIGN OBJECTIONS IN THE PAST?

A. Yes. For example, in a past rate case involving CEA, the Commission approved a non-unanimous settlement in part that limited, or "mitigated," rate increases to classes from the results of full cost of service.[66] Thus, the Commission has accepted rates in the past that attempted to balance revenue stability and rate stability considerations in setting customer charges.

B. Company's Proposed Revenue Distribution

Q. WHAT IS THE COMMISSION'S GENERAL POLICY ON REVENUE DISTRIBUTION?

A. The Commission has a long-standing goal that each rate class pay its cost of service.[67] It is also the policy of the Commission that inter-rate class subsidies should be eliminated.[68] At the same time, the Commission has also recognized and accepted rate mitigation strategies that ensure no class receives a rate decrease when other classes are receiving rate increases.[69]

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[66] See, 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, Changes and Tariffs, Docket No. 15-098-U, Order No. 8, September 2, 2016, p. 45.
[67] See, In the Matter of the Application of the Arkansas Oklahoma Gas Corporation for Approval of a General Change in Rates and Tariffs, Docket No. 05-006-U, Order No. 7, December 1, 2005, p. 42.
[68] *Id.*
[69] See, In the Matter of the Application of Entergy Arkansas, Inc., for Approval of Changes in Rates for Retail Electric Service, Docket No. 13-028-U, Order 21, December 30, 2013, p. 133; see also, 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, Changes and Tariffs, Docket No. 15-098-U, Order No. 8, September 2, 2016, p. 45.

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

A. The Company's proposed revenue allocations are based on its CCOSS results, and would move each class's rates to levels that equalize its individual class rate of return ("ROR") (or 100 percent relative rate of return ("RROR")). The Company, however, does adjust this revenue allocation proposal to ensure that no class receives a rate decrease (*i.e.*, those classes that are currently over-earning relative to the proposed system average increase). The Company proposes to use these revenue credits to offset rate increases being proposed for other customer classes. Exhibit DED-3 presents the Company's estimated class rates of return, and its proposed revenue distribution, under its current and proposed rates.

Q. WHAT DO YOU MEAN BY A RROR?

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

Q. IS A CLASS RROR LESS THAN 1.0 PROBLEMATIC OR INEQUITABLE?

A. Not necessarily since, as I noted earlier, there may be public policy reasons to support such results. For example, the presence and/or continuation of a RROR below one 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 below one RROR is simply a function of a prior policy decision, not necessarily the result of some arbitrary or intentionally-designed inequity.

Q. PLEASE EXPLAIN HOW REVENUES WERE ALLOCATED IN THE COMPANY'S LAST RATE CASE.

A. The Company's current rates are the byproduct of a settlement agreement that was part of Docket No. 10-67-U (September 2010). This agreement included a mitigation adjustment distributing surplus revenue resulting from the Lighting class among other customer classes requiring a larger-than-system-average increase.

C. Revenue Distribution Recommendations

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

A. No. The Company's proposed revenue distribution places too great a burden on many customer classes. For example, the Company is requesting a 9.8 percent overall increase in this proceeding, while also proposing that residential customers receive an 18.6 percent increase in total revenues, an increase that is nearly 1.90 times the system average increase. Likewise, the Company proposes to increase rates for the Athletic Field Lighting and Municipal Water Pumping classes by over 20 percent (for both classes): increases that are over two times the requested system average increase.

Q. WHAT ARE YOUR REVENUE DISTRIBUTION RECOMMENDATIONS?

A. I recommend that the Commission utilize a three-step process to allocate the Company's revenue requirement in this proceeding. In the first step, I recommend the Commission allocate 1.25 times the system average increase to all classes earning less than the overall system rate of return according to the Company's CCOSS. Second, I recommend that the Commission allocate a moderate increase of 0.50 times the system average increase to all classes estimated as over-earning based upon the Company's CCOSS results. Lastly, I recommend that any remaining revenue requirement left after the first two steps are completed be allocated equally to the only remaining class customer class that has not reached its 1.25 times cap, the Standard Power and Light ("PL") customer class.

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

A. Yes. My recommended revenue distribution is provided in Exhibit DED-4. Under my alternative revenue distribution proposal, Residential, General Service, MP, and AFL customers receive a 5.16 percent increase in total rates. PL customers receive a 4.51 percent increase in total rates. Finally, Time-of-Use Power and Light ("PL TOU") and Lighting customers receive a 2.06 percent increase in rates. This recommended revenue distribution includes the adjustment to the Company's requested revenue requirement increase supported by the Mr. Marcus.

D. Proposed Rate Design

Q. WHAT ARE THE COMPANY'S RATE DESIGN GOALS?

A. The Company states that its proposed rate design is driven by three objectives: (1) promotion of efficient consumption of energy; (2) provision of pricing product choices that meet customers' pricing preferences; and (3) recovery of the Company's authorized revenue requirements.[70]

Q. IS THE COMPANY PROPOSING ANY SIGNIFICANT RATE DESIGN CHANGES IN THIS PROCEEDING?

A. Yes. The Company is proposing some rather significant and dramatic structural changes to its existing Residential ("R-1") and General Service

[70] Direct Testimony of William Wai, 4:23-26.

("GS-1") rate design. First, the Company proposes to incorporate a demand charge for the R-1 and GS-1 classes. Second, the Company proposes to substantially increase the customer charges for both the R-1 and GS-1 customer classes. Third, the Company proposes to eliminate block energy pricing for the R-1 and GS-1 tariffs.

Q. IS THE COMPANY MAKING ANY PROPOSED CHANGES TO THE LARGER CUSTOMER CLASS RATE DESIGNS?

A. Yes. The Company is also proposing to integrate the Power and Light Time of Use Demand ("PL-TOU-D") and Power and Light Time of Use Energy ("PL-TOU-E") rates.[71]

Q. WHY IS THE COMPANY PROPOSING TO INCORPORATE A DEMAND CHARGE INTO THE R-1 AND GS-1 TARIFFS?

A. The Company states that its research in customer preferences has found that most customers surveyed prefer an alternative to the standard pricing plan currently offered by the Company, and that customers in general desire choice in rates.[72] Specifically, the Company argues that it finds that customer preferences lead some customers to prefer lower prices while others are more interested in convenience or certainty.[73] The Company discusses three different types of rate designs (or rate plans) that would meet these purported customer preferences, including: (1) a standard or default price

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[71] *Id.*, 6:19-20.
[72] Direct Testimony of Bryan Scott, 3:26 to 4:2.
[73] *Id.*, 4:2-4.

plan, (2) a price response plan, and (3) a price security plan.[74] The Company also states that the inclusion of demand charges in the standard price plan will "accurately recover() the utility's costs to provide electric service."[75]

Q. WHY IS THE COMPANY PROPOSING TO INCREASE THE R-1 AND G-1 CUSTOMER CHARGES BY SUCH LARGE AMOUNTS?

A. The Company claims that this proposal is based upon its goal of moving these charges closer to costs.[76] I will discuss the merits of this proposal, and why such proposals are unneeded and undesirable, in more detail later in this section of my testimony.

Q. WHY IS THE COMPANY PROPOSING TO ELIMINATE BLOCK ENERGY PRICING FOR THE R-1 AND GS-1 TARIFFS?

A. The Company appears to be proposing to eliminate block energy pricing for the R-1 and GS-1 tariffs in order to replace them with their newly-proposed demand charges. In order to make this "swap," the Company notes that it will need to eliminate the blocks and raise customer charges in order to lower the overall volumetric energy prices paid by residential customers.[77] The Company also notes its belief that the changes will "more accurately reflect the fixed cost of providing electric service to a customer."[78]

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[74] *Id.*, 4:8-12.
[75] *Id.*, 4:24-25.
[76] Direct Testimony of William Wai, 8:8-10 and 11:2-7.
[77] *Id.*, 7:31.
[78] *Id.*, 7:29 to 8:2.

Q. HAS THE COMPANY PROVIDED ANY TYPICAL BILL ESTIMATES THAT MAY ARISE FROM ITS PROPOSED RESIDENTIAL RATE DESIGN?

A. Yes. The Company states that its R-1 residential class customers will see an average monthly bill increase of 18 percent, or $15.28 per month.[79] This increase will consist of increases to fix charges from a $3.86 increase in the monthly customer charge, and the introduction of an average monthly demand charge of $3.74 per month.[80] The remaining $7.68, or 50.26 percent, will consist of increases to variable energy rates.

E. Demand Charges

Q. WHAT ROLE DO DEMAND CHARGES PLAY IN THE PRICING OF ELECTRIC SERVICE?

A. Generally, demand charges are viewed as another form of fixed charge similar to a customer charge in a two-part tariff. These demand charges are typically set at a rate, measured in dollars per kW demand, where the total demand in any given month is based upon some measure of the customers' actual maximum usage. Historically, larger customer classes, who have more sophisticated on-site metering equipment, have been assessed demand charges in addition to energy and other customer and facilities charges. The advent of digital smart meters, and their proliferation to smaller customer

[79] *Id.*, 7:25-26.
[80] *Id.*, 8:4-17.

classes, has recently stimulated interest in having residential rate designs mirror those currently in place for larger-use customers.

Q. HOW HAVE DEMAND-RELATED COSTS BEEN RECOVERED FROM NON-DEMAND METERED CUSTOMERS?

A Historically, residential and other smaller use customers have only been assessed two charges: a volumetric energy charge and a customer charge. While demand costs are more fixed in nature than energy-related costs, demand-related costs are typically recovered through volumetric rates for most customer classes. These demand-related costs are included in volumetric charges since there is no way to meter and bill such costs. As I mentioned earlier, the introduction of smart meters changes a utility's ability to assess demand-related charges (if approved by their regulators).

Q. DO YOU AGREE WITH THE COMPANY'S PROPOSED CREATION OF DEMAND CHARGES FOR STANDARD RESIDENTIAL AND GENERAL SERVICE TARIFFS?

A. No. There are a number of mechanical issues associated with the Company's proposal, the primary of which is related to the inconsistency in which "costs" are applied to the Company's various rate design components (*i.e.*, customer, energy and demand-related costs). However, there are also a number of important public policy issues associated with a move to demand charges for residential and smaller commercial customers that will be discussed in more detail in the Direct Testimony of Mr. William Marcus, another expert providing testimony in this proceeding for the AG.

Q. PLEASE EXPLAIN YOUR CONCERNS ABOUT THE COMPANY'S DEMAND CHARGE PROPOSALS.

A. My primary concern is that the charges are established in a relatively arbitrary and selective fashion that is in direct contradiction to the Company's rate design goals. For instance, the Company is proposing an R-1 and GS-2 demand charge of $1/kW. These demand charges, however, are well below their corresponding demand-related costs. For instance, the Company's CCOSS estimates per unit R-1 demand costs of $3.74/kW,[81] some 374 percent above the proposed R-1 tariff rate. Likewise, the Company's CCOSS estimates per unit GS-1 demand costs of $5.52/kW,[82] some 552 percent above the proposed GS-1 tariff rate. Thus, the Company's rate design proposals are inconsistent with its own rate design motivations.

Q. DID THE COMPANY EXPLAIN WHY IT WAS SETTING ITS PROPOSED R-1 AND GS-1 DEMAND CHARGES SO FAR BELOW COSTS?

A. Yes. The Company explained that the proposed demand charge has been set at a level below costs for introductory purposes. Demand charges are entirely new for the Company's R-1 and GS-1 customers, so the Company felt it was appropriate and consistent with a rate design principle of gradualism to

[81] *Id.*, 8:16-17.
[82] *Id.*, 11:2-5.

introduce the $1/kW charge as a less dramatic approach rather than setting the rate at a full cost of service level.[83]

Q. ARE THERE ANY OTHER INCONSISTENCIES IN THE COMPANY'S RATE DESIGN PROPOSALS?

A. Yes. The Company has proposed to include demand charges in its base residential tariff but omitted these same charges for its residential and general service time-of-use ("TOU") tariffs despite the fact that customers taking service under theses tariffs also incur demand-related costs. For instance, the Company's own CCOSS notes that the residential and GS TOU classes incur demand-related unit costs of $6.22/kW and $7.92/kW, respectively. The demand-related costs for these TOU tariffs have been shifted entirely to the Company's energy charges. So, while the Company claims that its rate design proposals are motivated by cost causation, its TOU proposals show that costs are being allocated to rates in an arbitrary fashion entirely inconsistent with this purported motivation.

Q. SO, ARE YOU RECOMMENDING AN INCREASE IN THE COMPANY'S R-1 AND GS-1 DEMAND CHARGES?

A. No, and the Company's proposal to reduce the initial impact of the new demand charge is not entirely without merit (assuming the Commission is interested in entertaining the adoption of demand-related charges). The

[83] Company's Response to Data Request APSC 14-02.

ratemaking problem with the Company's proposal, however, is that it allocates those demand-related costs not recovered in its newly proposed rates in a fashion that differs from how those costs have been recovered for decades. Under the Company's proposal, unrecovered demand costs are allocated to fixed customer charges, not to energy-related charges which has been the norm in the past. This is true for both the Company's base R-1 and GS-1 tariff offerings as well as those priced on a TOU basis. The Company has provided no compelling evidence that supports this proposed rate design, nor the fact that it has arbitrarily allocated demand costs to customer-related charges.

Q. HAS THE COMPANY DEFINED THE WAY IN WHICH IT INTENDS TO EDUCATE RATEPAYERS ABOUT THESE NEW RATE DESIGNS?

A. Yes. The Company notes that it currently offers customers access to their usage data through its website. In this information, customers can "visibly understand how their electric consumption behavior affects their demand levels."[84] Additionally, the Company plans to provide education materials to customers on its website that explain demand charges to customers. Importantly, these materials have not yet been finalized, though the Company appears to using materials utilized by an Arizona utility as the basis for the development of its own materials.[85]

[84] Company's Response to Data Request AG 12-14.
[85] *Id.*

Q. WILL THE COMPANY'S PROPOSED DEMAND CHARGES CHANGE THE RELATIVE SHARE OF REVENUES GENERATED FROM FIXED AND VARIABLE CHARGES?

A. Yes. Exhibit DED-5 shows the relative shares between fixed and variable charges for a typical residential customer under the Company's current rates, and its basic residential service proposals in this proceeding. Currently, some 16.9 percent of a standard residential customer's bill is associated with a fixed charge, which is comprised of a customer charge alone. Under the Company's proposal, 30.6 percent of a typical residential customer's bill will be tied to some form of fixed charge that includes an increased customer charge (increased to include 100 percent of the Company's customer-related costs) and the newly proposed demand charge.

Q. WHAT ARE YOUR RECOMMENDATIONS RELATED TO THE COMPANY'S PROPOSED DEMAND CHARGES?

A. I recommend that the Commission reject the Company's proposed demand charges. The movement to these types of rates is premature, not well supported, and is not based upon costs, contrary to the Company's assertions. Further, the Company has not adequately addressed how this type of rate design will impact energy efficiency and behind-the-meter generation like solar. However, to the extent that the Commission does want to adopt a demand-related tariff, I recommend that any costs not recovered in the demand charge be recovered in the volumetric energy charge, not the customer charge as included in the Company's current proposals.

F. Customer Charges

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

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

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

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

Q. WOULD YOU PLEASE DISCUSS THE COMPANY'S CUSTOMER CHARGE PROPOSALS?

A. Yes. A summary of the Company's current and proposed customer charges has been provided in Exhibit DED-6. The Company proposes to increase the customer charge for the R-1 class by $3.86 from $7.94 to $11.80, or by over 48.6 percent.[86] The Company proposes to increase GS-1 and GS-TOU customer charges by $6.25 from $21.75 to $28.00, or by over 28.7 percent.[87] R-TOU customers will likewise see an increase in customer charges of $3.86 from $7.94 to $11.80, or over 48.6 percent. Other customer and rate classes are proposed to see similar large increases in fixed customer charges.

Q. PLEASE EXPLAIN HOW THE COMPANY DEVELOPED ITS PROPOSED RESIDENTIAL CUSTOMER CHARGE.

A. The Company's proposed increase is purportedly designed to "more accurately reflect the fixed cost of providing electric service to a customer."[88]

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[86] Direct Testimony of William Wai, 7:29-31.
[87] *Id.*, p. 10, Table 4.
[88] *Id.*, 8:1-2.

However, the Company provides no explanation regarding how it arrived at its specific customer charge proposals.

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

A. Yes, and that has been provided on Exhibit DED-7. "Customer-related" expense accounts are those typically allocated on the basis of customers and can include: removing and setting meters and house regulators; maintenance of meters and house regulators; services expense; maintenance of services; meter reading expense; dispatch applications and orders; customer records and collections; customer billing and accounting; customer service and information; and sales expense. These costs can also include the depreciation expense associated with the services and meter plant accounts and property taxes as well as the carrying charges (at the Company's requested rate of return) for the customer portion of services investment and 100 percent of the meters' investment.

Q. WHAT DO THE RESULTS OF YOUR ANALYSIS SHOW?

A. In most cases, the Company's current customer charges already recover the vast majority of commonly-recognized customer costs. For instance, the residential customer-related costs are $9.74 compared to the current customer charge revenue of $8.09—recovering over 83 percent of customer-related costs. The General Service customer class has customer-related costs of $12.29, compared to the class's current customer charge of $21.85. Finally, the PL and PL TOU customer classes have customer-related costs of $11.83 and $464.09, compared to current customer charges of $90.62 and $137.65.

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

A. Yes, and this analysis is presented in Exhibit DED-8. This analysis shows that the Company's current residential customer charge of $7.94 is less than the regional average of $10.23, with the proposed new customer charge of $11.80 being greater than the regional average. The Company's General Service current customer charge of $21.75 is currently greater than the regional average of $17.86. Indeed, only five other utilities in the region have higher customer charges for small commercial customers. The Company's proposed $28.00 customer charge for General Service customers will make the Company the second highest utility in the region. For comparison purposes, the Company's Oklahoma jurisdiction has a customer charge for small commercial customers of $24.70.

Q. ARE THERE ANY COMPELLING COST OR POLICY REASONS FOR ADOPTING THE COMPANY'S CUSTOMER CHARGE PROPOSALS?

A. No. The Company's current customer charges already recover a significant portion of commonly-recognized customer costs – over 75 percent for just about every customer class with the exception of the Time-of-Use Power and Light ("PL TOU") class. This is a relatively high revenue recovery share that does not justify any dramatic change in rate design policy by the Commission in this case. Indeed, the Company's proposal to increase the Residential customer charge to $11.80 would increase the Company's recovery to over 121 percent of actual of customer-related costs in direct contradiction with the Company's purported rate design goal of setting rates at costs (not above costs). The primary reason for this "over-recovery" is that the Company is allocating all of the demand-related costs not recoverable under its newly-proposed demand charge in the fixed customer charge, not the volumetric energy charge as has been commonly the case in Arkansas as well as most other states.

Q. WHAT ARE THE COMMONLY-CITED RATIONALES FOR INCREASING CUSTOMER CHARGES?

A. There are two commonly-cited rationales for increasing customer charges. The first is an argument based upon a perceived cost-causation, and as I noted earlier, this does not appear to be a wide-spread problem since most of the Company's customer charges cover a very large share of their customer-related costs. Further, the Company's proposal to set customer charges at levels that are substantially greater than 100 percent of these customer costs flies in the face of its insistence that rates be set at costs. The second rationale often invoked for increasing customer charges is revenue stability. Recovering more revenues through customer charges, as opposed to through volumetric charges, can lead to greater revenue stability because changes in the number of customers can often be more stable than changes in volumetric use.

Q. WOULD THE COMPANY'S FRP DAMPEN ANY REVENUE STABILITY CONCERNS IF ADOPTED BY THE COMMISSION?

A. Yes. Utilities often request large increases in customer charges, relative to requested volumetric charges, in order to reduce revenue collection risks. Utilities do this since customer counts (and revenues) tend to change less frequently, and are less sensitive, to other exogenous factors (weather, income, prices) than sales. The Company's proposed FRP, which will allow it to increase rates if earnings drop below 50 basis points of its allowed ROE, will help dampen the pressures on revenue stability since there is a built-in mechanism to adjust rates should such a contingency arise. Thus, there is no rationale for increasing customer charges in the presence of an FRP which has an inherent "revenue decoupling" component built into the mechanism: any revenue shortfalls impacting earnings beyond the 50 basis point dead-band will be automatically recoverable under an FRP.

Q. WHAT ARE YOUR CUSTOMER CHARGE RECOMMENDATIONS?

A. I recommend that customer charges be maintained at their current levels for all classes with the exception of the PL TOU class and these are summarized on Exhibit DED-9. The requested increases to customer charges are not supported by the Company's own CCOSS. Furthermore, the need for a large increase in customer charges is not needed if the Commission accepts the

Company's proposed FRP. Lastly, increasing customer charges will likely reduce customers' incentive to engage in energy efficiency and conservation measures, an outcome inconsistent with the Commission's energy efficiency and conservation goals. Lastly, it could negatively impact the adoption of new behind-the-meter generation technologies such as distributed solar energy.

G. Volumetric Charges

Q. HOW ARE THE COMPANY'S VOLUMETRIC RATES STRUCTURED?

A. Currently, the Company's volumetric block rates are inclining in the summer and declining in the winter for both the R-1 and GS-1 classes. TOU customers have declining block rates for summer usage summer while winter service rates are charged at a constant rate regardless of usage levels.

Q. PLEASE EXPLAIN THE COMPANY'S RESIDENTIAL VOLUMETRIC RATE DESIGN PROPOSALS.

A. The Company proposes to eliminate block rates given its new rate design proposals that dramatically increase customer charges and assess a new demand rate for the R-1 class. Specifically, the Company proposes to charge all summer usage at a rate of $0.0628 per kWh regardless of the usage amount, and charge all winter usage at a rate of $0.026 per kWh regardless of usage amount. This proposal increases electric charges for the first 1,400 kWh of summer usage by $0.0163 per kWh, while reducing the electric charges for usage greater than 1,400 kWh of summer usage by $0.0049 per kWh. In the alternative, the Company's proposal decreases electric charges for the first 600 kWh of winter usage by $0.003 per kWh, while increasing usage greater than 600 kWh by $0.005 per kWh.

Q. PLEASE EXPLAIN THE COMPANY'S GS-1 VOLUMETRIC RATE DESIGN PROPOSALS.

A. The Company is also proposing to eliminate the block rates for the GS-1 tariff. The Company proposes a uniform rate of $0.0595 per kWh for summer usage, and a uniform rate of $0.02 per kWh for winter usage. This proposal increases electric usage for the first 5,000 kWh by $0.0165, while reducing the electric charges for usage greater than 5,000 kWh by $0.0042 per kWh. In the alternative, the Company's proposal decreases electric charges for the first 1,000 kWh of winter usage by $0.003 per kWh, while increasing electric charges for all winter usage greater than 1,000 kWh by $0.005 per kWh.

Q. WHY IS THE COMPANY PROPOSING TO ELIMINATE VOLUMETRIC BLOCK RATES?

A. The Company has stated that "with the introduction of a demand charge into the pricing structure for R-1 and GS-1 rate classes, the block energy pricing for these classes is not appropriate anymore because demand charge will serve the purpose of recovering transmission and distribution costs that were previously recovered thru the initial block energy price."[89]

[89] Company Response to Data Request AG 3-63.

Q. DO YOU HAVE ANY PROBLEMS WITH THE COMPANY'S VOLUMETRIC RATE DESIGN PROPOSALS?

A. Yes. The Company's proposed revisions significantly increase volumetric rates for lower-use customers during summer months. Specifically, R-1 customers that use less than 1,400 kWh during summer months will see increases to volumetric rates of more than 35 percent. Likewise, GS-1 customers that use less than 5,000 kWh during the summer months will see increases to volumetric rates of more than 38 percent. This outcome arises from the fact that approximately 81.5 percent of residential summer usage is restricted to tier one usage.[90] This significant increase to initial volumetric rates has the effect of increasing the burden on low usage customers even while the Company is increasing fixed charges through significant increases to customer charges and the introduction of demand charges.

Q. WHAT CHANGES DOES THE COMPANY PROPOSE FOR ITS R-1 AND GS-1 TOU AND VARIABLE PEAK PRICING ("VPP") PLANS?

A. As noted earlier, the Company is not proposing to introduce demand rates for the R-1 and GS-1 TOU and VPP customers. Likewise, the Company's proposed changes to variable charges for these customers are not as significant as to those under standard rates. Generally, the Company

[90] Petition, Schedule H-5.

proposes to increase off-peak and base usage rates, thus decreasing the differential between different pricing blocks.

Q. DOES THE COMPANY PROPOSE TO CHANGE ITS VPP BANDS?

A. Yes, and rather significantly. The Company proposes to reduce its threshold for "low" prices to be below \$0.01 from the current \$0.07, "standard" prices to \$0.01 to \$0.023 from the current \$0.07 to \$0.11, "high" prices to \$0.023 to \$0.078 from the current \$0.11 to \$0.20, and the threshold for "critical" prices to greater than \$0.078 from the current \$0.20. Indeed, all currently "standard" prices would be at least now priced as "high," with most considered "critical."

Q. ARE THERE ANY PROBLEMS WITH THE COMPANY'S VPP THRESHOLD PROPOSALS?

A. Potentially. While it is understandable that the Company desires to reduce its thresholds to create greater price variability, the Company's proposed changes are so drastic as to potentially cause confusion among ratepayers. "High" prices are proposed to be at levels that are nearly 265 percent of "standard prices, while "critical" are prices at a rate that is more five times that of "standard" prices. So, the effects of the Company's proposal to change the designation of previously standard prices to either high or critical prices should not be understated.

Q. DO YOU HAVE ANY RECOMMENDATION REGARDING THE COMPANY'S PROPOSED CHANGES TO ITS VPP THRESHOLDS?

A. Yes. I recommend the Commission not adopt the Company's proposed changes to its VPP pricing thresholds. The Company provides no support for its proposed changes, which are significant. In fact, when asked to explain why the Company is proposes to update the criteria used to determine the daily on-peak price level for the VPP programs, it provided no response besides referencing a workpaper file called "VPP Rebanding."[91] The file appears to be nothing more than an examination of the Company's summer 2015 daily average peak prices, grouped in stratifications of 10, 30, 36, and 10 days corresponding to the Company's low, standard, high, and critical thresholds. I would not recommend the Commission base its VPP rate design off the results of a single year of study due to the very real possibility that 2015 may not reflect normal usage patterns for the Company's service territory.

H. Rate Design Recommendation Summary

Q. PLEASE SUMMARIZE YOUR REVENUE DISTRIBUTION AND RATE DESIGN RECOMMENDATIONS.

A. My revenue distribution and rate design recommendations can be summarized as follows:

- Revenue responsibilities for developing rates should be allocated on a methodology that constrains any one class from receiving a rate increase greater than 1.25 times the system average.

[91] Company's Response to Data Request AG 3-65.

- Revenue responsibilities for developing rates should assign a minimum rate increase to currently over-earning customer classes to 0.5 times the system average increase.
- Existing customer charges should be maintained at current levels.
- The Commission should reject the Company's proposal to establish demand rates for its standard Residential and General Service tariffs.
- The Commission should reject the Company's proposal to eliminate its current volumetric block structure.
- Volumetric rates should be increased according to the results of the Company's cost of service study. All classes are moved toward their cost of service, constrained such that (a) no class should receive an increase of less than 0.5 times the system average; and (b) rates for any one class cannot increase by more than 1.25 times the system average.

Q. HAVE YOU PREPARED ANY EXHIBITS DETAILING YOUR PROPOSED RATE DESIGN?

A. Yes. Exhibit DED-9 presents a comparison of my proposed alternative rates to both current and Company proposed rates. Proposed alternative rates in this exhibit include consideration of the adjustment to the Company's proposed revenue requirement increase supported by Mr. Marcus.

VII. <u>CONCLUSIONS AND RECOMMENDATIONS</u>

Q. WHAT ARE YOUR RECOMMENDATIONS REGARDING THE COMPANY'S PROPOSED FRP?

A. I recommend the Commission approve the Company's FRP subject to the following modifications:

- The Commission should direct the Company to clearly indicate which type of test year it is using and the definition of this test year needs to be directly tied to the statutory language.

- The capital structure associated with OGE's FRP annual review should be fixed to the same one resulting from the Commission's decision in this proceeding. Such an outcome is consistent with alternative regulation design and consistent with the Commission's decision in the CEA FRP approval.
- The Company should be required to provide comparative information that examines the major costs and drivers between its projected and current rate case test year. This comparison would not be used for any reconciliation. Further, there is a requirement that should only be in place for the first two years of the annual FRP process. Thus, the Commission could simply address this transitional issue in the Order arising from this rate case without any need to change any of the descriptions included in the Company's proposed FRP tariff.

Q. PLEASE SUMMARIZE YOUR RECOMMENDATIONS REGARDING THE ADDITIONAL RIDERS BEING PROPOSED BY THE COMPANY.

A. I recommend the Commission:

- Reject the Company's SDR proposals and utilize the projected test year approach, afforded under the Company's proposed FRP, to recover storm-related costs. The Company's argument that storm-related costs could increase its annual FRP revenue increase above the four percent statutory cap is speculative and unsupported. If a unique storm event arises, and imposes costs that cannot be recovered in one year, or accommodated within the FRP, then the Commission can address any special ratemaking mechanisms needed to meet these unique challenges at the time they arise, when the costs and impacts can be determined in a reliably known and measurable fashion.
- Reject the Company's LCA Rider recommendations since the proposal is (1) inconsistent with ratepayer protection provisions of Act 725, (2) is not well-defined and based upon a tariff that is general in nature and inconsistent with the Company's proposed FRP, (3) is not supported with any record evidence indicating any need, (4) is based upon a set of cost recovery methods that are inconsistent with Act 725 and the Company's own cost-causation principles articulated elsewhere in its testimony, (5) would likely set a bad precedent for other Arkansas utilities, (6) would likely result in a prudence pre-approval, and (7) has been proposed for a term that is too long and far surpasses the five-year term included in Act 725.

Q. WHAT ARE YOUR JURISDICTIONAL COST ALLOCATION RECOMMENDATIONS?

A. I also recommend the Commission accept the Company's proposed jurisdictional allocations. The methodology is consistent with what was done recently in Oklahoma and is internally consistent with the demand allocators being used in the retail Class Cost of Service Study ("CCOSS") as well.

Q. WHAT ARE YOUR CCOSS RECOMMENDATIONS?

A. I recommend that the Commission adopt the same approach that it utilized in the most recent EAI and CEA rate cases. Namely, that the Commission aver on making any decision regarding the relationship between the Company's proposed demand allocators and economic development. Instead, the Commission should use the Company's proposed CCOSS results as a starting point in setting the overall revenue distribution in this case, provided this revenue distribution is tempered with many of the same policy considerations the Commission utilized in the EAI and CEA decisions.

Q. HOW SHOULD THE COMMISSION ALLOCATE THE COMPANY'S REVENUE DEFICIENCY IN THIS PROCEEDING?

A. I recommend that the Commission utilize a three-step process to allocate the Company's revenue requirement in this proceeding. In the first step, I recommend the Commission allocate 1.25 times the system average increase to all classes earning less than the overall system rate of return. Second, I recommend that the Commission allocate a moderate increase of 0.50 times the system average increase to all classes estimated as over-earning based upon the Company's CCOSS results. Lastly, I recommend that any remaining revenue requirement left after the first two steps are completed be allocated equally to the only remaining class customer classes that has not reached its 1.25 times cap, the Standard Power and Light ("PL") customer class.

Q WHAT ARE YOUR RATE DESIGN RECOMMENDATIONS?

A. My revenue distribution and rate design recommendations can be summarized as follows:

- Revenue responsibilities for developing rates should be allocated on a methodology that constrains any one class from receiving a rate increase greater than 1.25 times the system average.
- Revenue responsibilities for developing rates should assign a minimum rate increase to currently over-earning customer classes to 0.5 times the system average increase.
- Existing customer charges should be maintained at current levels.
- The Commission should reject the Company's proposal to establish demand rates for its standard Residential and General Service tariffs.
- The Commission should reject the Company's proposal to eliminate its current volumetric block structure.
- Volumetric rates should be increased according to the results of the Company's cost of service study. All classes are moved toward their cost of service, constrained such that (a) no class should receive an increase of less than 0.5 times the system average; and (b) rates for any one class cannot increase by more than 1.25 times the system average.

Q. DOES THIS CONCLUDE YOUR PREFILED DIRECT TESTIMONY FILED ON JANUARY 31, 2017?

A. Yes.

CERTIFICATE OF SERVICE

I, Shawn McMurray, hereby certify that on January 31, 2017, I filed a copy of the foregoing utilizing the Commission's Electronic Filing System, which caused a copy to be served upon all parties of record via electronic mail.

/s/ Shawn McMurray
Shawn McMurray