



Entergy Arkansas, Inc.
Regulatory Affairs
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VIA OVERNIGHT MAIL

March 20, 2014

Chairman James M. Allison
Tennessee Regulatory Authority
Attn. Sharla Dillon, Docket Manager
Tennessee Regulatory Authority
502 Deaderick Street, 4th Fl
Nashville, TN 37243

Re: In the Matter of the Application of Entergy Arkansas, Inc. for
Approval of Changes in Rates for Retail Electric Service TRA
Docket No. 13-00114

Dear Mr. Allison:

On March 1, 2013, Entergy Arkansas, Inc. (EAI), filed with the Arkansas Public Service Commission (APSC), an Application for Approval of Changes in Rates for Retail Electric Service in APSC Docket No. 13-028-U. On August 21, 2013, EAI filed the same Application and supporting documents with the Tennessee Regulatory Authority (TRA) to initiate a docket for a general change in rates for EAI's Tennessee customers. In its August 21, 2013 transmittal letter, EAI indicated that it would supplement its TRA filing with the APSC order reflecting its final decision when issued. The purpose of this letter is to file one original and four hard copies as well as an enclosed CD with an electronic copy of each of the following items that have occurred in APSC Docket No. 13-028-U, each of which is attached hereto:

1. Erratas filed on March 11, 2013; March 25, 2013; April 10, 2013; May 13, 2013; August 28, 2013; August 30, 2013; September 12, 2013;
2. EAI's Rebuttal Testimony filed on August 26, 2013;
3. EAI's Sur-Surrebuttal Testimony filed on September 23, 2013;
4. Order 21, issued on December 30, 2013;
5. APSC General Staff's Compliance Filing, filed on January 9, 2014;
6. Order 22, issued on January 16, 2014;
7. EAI's Compliance Filing filed on January 29, 2014;
8. EAI's Supplemental Compliance Filing filed on February 14, 2014;
9. Order 24, issued on February 20, 2014.

March 20, 2014

In addition, EAI's compliance tariffs for filing with TRA with requested effective date of April 30, 2014 (first billing cycle of May 2014) are attached to this transmittal letter. The base rate increase approved by the Commission results in the following increases:

Class	\$ Increase	% Increase
Residential	28,995,695	6.12
Small General Service	19,782,751	8.17
Large General Service	31,941,173	12.77
Lighting	0	0
Total	80,719,619	8.17

Even with the base rate increase, a residential customer using 1,000 kWh per month will experience only a negligible increase on the customer's bill as a result of the net impact of the base rate increase and changes to EAI's existing riders and new riders. The APSC approved a new Capacity Cost Recovery Rider (Rider CCR) to recover costs associated with short term and pre-approved purchase power contracts. The amount recovered by Rider CCR, however, will be offset by a credit customers will receive from the newly approved Mid-Continent Independent System Operator, Inc. (MISO) Rider, which will flow through to customers revenues and credits received from MISO. In addition, the Capacity Acquisition Rider is moving from rider recovery to base rates. A typical residential customer using 1000 kWh is paying \$90.33 in April 2014. As a result of the change in rates, the May 2014 bill will be \$90.56, an increase of \$0.23.

EAI is requesting that the TRA place its pending retail rate case application in TRA Docket No. 13-00114 on its next Conference Agenda scheduled April 14, 2014 to render a decision on EAI's application and its requested effective date of April 30, 2014 for its proposed revised tariffs.

EAI is requesting the 30 day notice required in TRA Rule 1220-4-1-.04 be waived to allow EAI to place its compliance tariffs in effect with the first billing cycle of May 2014 (which begins April 30, 2014) for its retail customers residing in Tennessee.

If you have any questions, please do not hesitate to call me at 501-377-5876.

Sincerely,



Laura R. Landreaux
Manager, Regulatory Affairs

Attachments

BEFORE THE
ARKANSAS PUBLIC SERVICE COMMISSION

IN THE MATTER OF THE APPLICATION	)	
OF ENTERGY ARKANSAS, INC. FOR	)	DOCKET NO. 13-028-U
APPROVAL OF CHANGES IN RATES FOR	)	
RETAIL ELECTRIC SERVICE	)	

REBUTTAL TESTIMONY

OF

DAVID E. HUNT

DIRECTOR, REGULATORY ACCOUNTING
ENTERGY SERVICES, INC.

ON BEHALF OF

ENTERGY ARKANSAS, INC.

AUGUST 26, 2013

1 **I. INTRODUCTION AND BACKGROUND**

2 Q. PLEASE STATE YOUR NAME, TITLE, AND BUSINESS ADDRESS.

3 A. My name is David E. Hunt. I am employed by Entergy Services, Inc.
4 ("ESI") as Director, Regulatory Accounting. My business address is 425
5 West Capitol Avenue, Little Rock, Arkansas 72207.

6

7 Q. ON WHOSE BEHALF ARE YOU TESTIFYING?

8 A. I am submitting this rebuttal testimony to the Arkansas Public Service
9 Commission ("APSC" or the "Commission") on behalf of Entergy
10 Arkansas, Inc. ("EAI" or the "Company").

11

12 Q. HAVE YOU ADOPTED THE TESTIMONY PREVIOUSLY FILED BY
13 PHILLIP B. GILLAM ON BEHALF OF EAI IN THIS DOCKET?

14 A. Yes, I have adopted the testimony previously filed by Phillip B. Gillam on
15 behalf of EAI in this docket.

16

17 Q. PLEASE DESCRIBE YOUR EDUCATIONAL BACKGROUND AND
18 PROFESSIONAL EXPERIENCE.

19 A. A summary of my educational and professional background is contained in
20 EAI Exhibit DEH-1.

21

22 Q. WHAT ARE THE DUTIES AND RESPONSIBILITIES OF YOUR
23 CURRENT POSITION?

1 A. As Director, Regulatory Accounting, I am responsible for supervising the
2 Regulatory Accounting Department, which prepares accounting and
3 financial data along with preparation of supporting testimony for rate filings
4 by the Entergy Operating Companies.¹

5
6 Q. HAVE YOU PREVIOUSLY FILED TESTIMONY IN A REGULATORY
7 PROCEEDING?

8 A. Yes. A list of the proceedings is included in EAI Exhibit DEH-1.

9

10 Q. WHAT IS THE PURPOSE OF YOUR REBUTTAL TESTIMONY?

11 A. My testimony will address several issues raised by parties in this case
12 related to the cost-of-service study and the various riders or rider changes
13 proposed by the Company. More specifically, my rebuttal testimony will:

14 1. address the cost-of-service study methodology proposed by the
15 ASPC General Staff ("Staff");

16 2. address the proposed disallowance of costs related to the
17 development of the Company's revenue requirement model as
18 proposed by the Hospitals and Higher Education Group
19 ("HHEG");

20 3. address the treatment of the Wholesale Base Load ("WBL")
21 Capacity sales under the System Agreement Service Schedule

¹ The Entergy Operating Companies include EAI; Entergy Gulf States Louisiana, L.L.C.; Entergy Louisiana, LLC; Entergy Mississippi, Inc.; Entergy New Orleans, Inc.; and Entergy Texas, Inc.

1 MSS-4 – Unit Power Purchase (“MSS-4”)² in Staff’s proposed
2 cost-of-service study;
3 4. update EAI’s proposed revenue requirement; and
4 5. address issues raised by Staff and Intervenor’s related to the
5 Midcontinent Independent System Operator, Inc. (“MISO”) Rider
6 (“MISO Rider”), the Capacity Cost Recovery Rider (“Rider
7 CCR”), and the Energy Cost Recovery Rider (“Rider ECR”).
8

9 **II. RESPONSE TO COST-OF-SERVICE STUDY ISSUES**

10 **A. Cost-of-Service Study Methodology**

11 Q. DID STAFF USE THE SAME COST-OF-SERVICE STUDY MODEL TO
12 DEVELOP ITS COST-OF-SERVICE STUDY RESULTS AS EAI?

13 A. No. EAI’s cost-of-service study was prepared using the Company’s TM1
14 model, while the Staff used an Excel-based model.
15

16 Q. HOW DO THE RESULTS OF THE TWO DIFFERENT MODELS
17 COMPARE?

18 A. Both models functionalize, classify, and allocate costs to customer
19 classes, but with slightly different revenue requirement and class
20 allocation results. Some of these differences are expected given the fluid

² MSS-4 provides the basis for making a unit power purchase between Companies. Currently EAI has specific wholesale baseload capacity under purchased power agreements with other Operating Companies governed by MSS-4. EAI will replace MSS-4 with a new wholesale tariff with similar provisions as MSS-4 so that these sales can continue after EAI terminates its participation in the System Agreement December 18, 2013.

1 nature of positions during the exchange of testimony. There are a few
2 specific allocation issues I will address below.

3

4 Q. ARE THERE ANY ALLOCATION FACTOR CHANGES THAT SHOULD
5 BE MADE TO THE COMPANY'S COST-OF-SERVICE MODEL?

6 A. Yes. Based on a review of EAI's cost-of-service allocation method in
7 Docket No. 09-084-U, the rate base and expenses associated with the
8 Regional Transmission and Market Operations ("RTMO") should be
9 allocated based on transmission plant rather than production plant as
10 originally filed to maintain consistency between rate cases. This
11 difference is quantified later in my testimony. The Company recommends
12 that Staff adopt this allocation factor as well.

13

14 Q. WHAT SPECIFIC DIFFERENCES IN ALLOCATION METHODOLOGY
15 ARE THERE BETWEEN THE COMPANY AND STAFF?

16 A. In addition to the RTMO-related recommendation I just described, the
17 Company recommends that Additional Facilities Charges revenue
18 associated with the Lighting rate class should be directly assigned to the
19 Lighting rate class rather than allocated using a gross plant allocator as in
20 Staff's cost-of-service model. The direct assignment of those revenues
21 based on available information provides a more accurate result. Company
22 witness Corey A. Pettett addresses the Company's position on the

1 reasonableness of certain other allocation factors used in Staff's allocation
2 methodology and their impact to retail customer classes.

3

4 Q. ARE THERE ANY OTHER DIFFERENCES THAT NEED TO BE
5 ADDRESSED?

6 A. Yes. There are differences in the labor allocation factor, LOMTOA, but
7 these amounts will be in flux until a final payroll level is established in this
8 proceeding. This type of difference is expected to be ultimately resolved
9 through a compliance cost-of-service study. There is also a small
10 calculation error in the RBXNISC (rate base excluding non-investor
11 supplied capital) allocation factor that EAI and Staff representatives have
12 discussed, and Staff is expected to address it in its surrebuttal testimony.

13

14 **B. Revenue Requirement Model Disallowance**

15 Q. DO YOU AGREE WITH HHEG WITNESS LARRY BLANK'S
16 RECOMMENDATION TO DISALLOW COSTS ASSOCIATED WITH THE
17 DEVELOPMENT OF TM1?³

18 A. No. The Company's TM1 cost-of-service model meets the requirements
19 for use in an Arkansas rate proceeding. The current requirements are set
20 by APSC Rules of Practice and Procedure Section 9, Appendix I, General
21 Requirements, 4. Cost of Service, A:
22

³ Blank Direct Testimony at 49-51.

1 A utility which produces its cost of service study by computer
2 shall ensure, either before or at the time of filing a rate
3 application, that Staff has been provided all of the computer
4 software necessary for Staff to independently run the utility's
5 cost of service. When such software is confidential,
6 proprietary, or covered by a license agreement, it shall be
7 provided under the terms of a protective order or agreement.

8 EAI has complied with this requirement by obtaining sufficient
9 license agreements for any party (not just Staff) to Docket No. 13-028-U,
10 providing on-site training for Staff, and granting access to the TM1 model
11 to all parties that made such a request. Those parties were also provided
12 basic written documentation to run the model, and Company personnel
13 were made available for assistance. The Commission's rules recognize
14 the diversity of cost-of-service modeling options that are available to
15 utilities including EAI. Mr. Blank has provided no evidence that EAI is out
16 of compliance with APSC rules and, as such, his recommendation to
17 disallow TM1 development costs is not reasonable.

18
19 **C. Response To Treatment Of WBL Capacity Sales**

20 Q. WHAT IS THE ISSUE RELATED TO THE WBL CAPACITY SALES?

21 A. EAI sells a portion of capacity from Arkansas Nuclear One Units 1 and 2,
22 White Bluff Steam Electric Station Units 1 and 2, and Independence
23 Steam Electric Station Unit 1, called the "WBL Capacity," to other
24 Operating Companies⁴. The WBL Capacity is not allocated to serve EAI's
25 retail customer load, and retail customers should not pay for the costs of

⁴ EAI also sells a portion of its non-retained share of Grand Gulf to those companies, but those costs are handled through the Grand Gulf Rider.

1 that capacity nor benefit from the energy produced. The issue revolves
2 around the appropriate methodology to insulate retail customers from the
3 costs and revenues related to the WBL Capacity sales. There are two
4 methodologies to accomplish that goal which have been proposed in this
5 case. The Company's approach uses the revenue received from the WBL
6 Capacity sales as an offset to any WBL Capacity-related costs included in
7 the cost-of-service study ("revenue credit method"). The second method
8 eliminates the costs and the revenues associated with the WBL Capacity
9 sales from the cost-of-service study ("elimination method"). EAI used the
10 revenue credit method in its filed cost-of-service study. Staff used the
11 elimination method in its cost-of-service study.⁵

12
13 Q. IS THE ELIMINATION METHOD FOR ADDRESSING WBL CAPACITY
14 SALES IN STAFF'S COST-OF-SERVICE STUDY A REASONABLE
15 ALTERNATIVE?

16 A. Yes. The elimination method taken by Staff should not produce
17 significantly different results than the revenue credit method used in the
18 Company's cost-of-service study. The primary difference is the higher
19 common equity return included in the WBL Capacity wholesale tariffs.
20 This difference is quantified later in my testimony.

21
22 Q. WHY DID THE COMPANY USE THE REVENUE CREDIT METHOD?

⁵ Butler Direct Testimony at 5-7.

1 A. The Company used the revenue credit method because it is the most
2 administratively simple and direct approach to insulate retail customers
3 from WBL Capacity costs.

4

5 Q. WHY DID THE STAFF CHOOSE THE ELIMINATION METHOD?

6 A. The Staff chose the elimination method based on its review of the
7 Commission's findings in Order No. 9 in Docket No. 03-028-U and Order
8 No. 7 in Docket No. 12-038-U ("WBL Orders") related to the WBL Capacity
9 and concluded that EAI's method was inconsistent with those findings.⁶

10

11 Q. WHAT REQUIREMENTS FOR RETAIL BASE RATEMAKING
12 TREATMENT OF WBL CAPACITY SALES ARE CONTAINED IN THE
13 WBL ORDERS?

14 A. The WBL Orders do not contain specific directives on how WBL Capacity
15 sales should be addressed in a base rate case.⁷ It is reasonable that the
16 APSC expects this issue to be resolved in this proceeding based on its
17 directives to address the base rate cost recovery of Arkansas Nuclear One
18 Units 1 and 2 Available WBL Capacity in this case.⁸

19

⁶ Butler Direct Testimony at 7.

⁷ In Order No. 9 of Docket No. 03-028-U, the APSC directed the Company to address ratepayer protections for certain riders.

⁸ Docket No. 12-038-U, Order No. 7 at 19.

1 Q. DO YOU AGREE WITH STAFF THAT THE REVENUE CREDIT METHOD
2 IS INCONSISTENT WITH THE COMMISSION'S DIRECTIVES IN THE
3 WBL ORDERS?

4 A. No. The Commission has demonstrated an interest in seeking a variety of
5 solutions to regulatory cost recovery issues.⁹ The Company's revenue
6 credit method presents a direct approach to resolve the issue of how to
7 address the WBL Capacity costs in the retail base ratemaking.
8 Nevertheless, the Company does not object to the elimination method
9 used in Staff's cost-of-service study to address the WBL Capacity sales.

10

11 Q. WHAT IS THE WBL CAPACITY REVENUE REQUIREMENT FOR THE
12 RESPECTIVE METHODOLOGIES?

13 A. Staff's methodology produced a WBL Capacity revenue requirement of
14 \$34,319,948 that was shown in Staff's cost-of-service study as a reduction
15 in costs to the overall requested revenue requirement. The Company's
16 methodology produced an offset to the revenue requirement, a revenue
17 credit, of \$35,831,703.¹⁰

18

19 **D. Revenue Requirement Update**

20 Q. PLEASE DISCUSS THE COMPANY'S UPDATE TO THE REVENUE
21 REQUIREMENT IN ITS COST-OF-SERVICE STUDY.

⁹ See Docket No. 08-137-U, Order No. 1.

¹⁰ Includes a minor adjustment discussed in Mr. Zakrzewski's rebuttal testimony.

1 A. The Company has identified changes to its requested revenue
2 requirement to reflect updated inputs to the WACC calculation, MISO
3 letter of credit fees, WBL Capacity revenue credit¹¹ and RTMO allocation
4 change. Application of these changes to the EAI's cost-of-service study
5 provided in Staff 1-18 results in a revenue requirement reduction of
6 \$11,565,255 with a revised revenue deficiency of \$161,426,141, and a
7 revised EAI retail revenue requirement of \$1,149,927,789.

8 If Staff's elimination method for WBL Capacity sales as proposed
9 by Ms. Butler were incorporated in the Company's cost-of-service study,
10 the retail revenue requirement would increase by \$1,511,782 with a
11 revised revenue deficiency of \$162,937,923, and a revised EAI retail
12 revenue requirement of \$1,151,439,571.

13

14 **III. RESPONSE TO ISSUES RELATED TO RIDERS**

15 **A. MISO Rider**

16 Q. PLEASE DESCRIBE THE ISSUE RELATED TO CARRYING COSTS ON
17 EAI'S MISO IMPLEMENTATION COSTS.

18 A. Staff witness Jeff Hilton recommended that carrying costs be eliminated
19 from the unamortized balance of MISO implementation costs that would
20 be recovered through the MISO Rider, consistent with the Commission's
21 direction in Order No. 76 in Docket No. 10-011-U.¹²

¹¹ The WACC, MISO letter of credit fee, and WBL Capacity revenue credit are discussed in Mr. Zakrzewski's rebuttal testimony.

¹² Hilton Direct Testimony at 13.

1

2 Q. DO YOU AGREE WITH STAFF'S RECOMMENDATION?

3 A. Yes. The adjustment would be consistent with the Commission's order,
4 which was issued after the Company filed this case. Elimination of the
5 carrying costs results in a \$2.65 million reduction in the MISO Rider
6 revenue requirement.

7

8 Q. STAFF MADE OTHER RECOMMENDATIONS ASSOCIATED WITH THE
9 MISO RIDER. PLEASE DESCRIBE THEM.

10 A. Staff witness Elana Davis recommended certain annual reporting
11 requirements for the MISO Rider and recommended that carrying costs
12 not be applied to the over- or under-recovered balance on the MISO Rider
13 in the annual true-up calculation.¹³

14

15 Q. ARE THESE RECOMMENDATIONS REASONABLE?

16 A. The Company agrees to provide a report, as outlined in Ms. Davis'
17 testimony, to accompany the annual MISO Rider filing. However, the
18 Company believes that it is reasonable to apply carrying charges in the
19 true-up calculation for the MISO Rider.

20

21 Q. WHY IS IT REASONABLE TO INCLUDE CARRYING CHARGES IN THE
22 MISO RIDER CALCULATION?

¹³ Davis Direct Testimony at 8-9.

1 A. The Commission has allowed carrying costs on over- or under-recovery
2 balances in other approved riders such as the Rider ECR and the
3 Production Cost Allocation Rider ("Rider PCA"), which are similar in
4 operation to the Company's recommendation for the proposed MISO
5 Rider. Carrying costs are appropriate for both the Company and its
6 customers to compensate either party for the time value of money (i.e.,
7 similar to a temporary loan). Moreover, Staff bases its recommendation
8 not to apply carrying charges for the over-and under-recovered balance, in
9 part, on Order No. 76 in Docket No. 10-011-U.¹⁴ The carrying costs at
10 issue in Docket No. 10-011-U were associated with the original deferral of
11 costs as a regulatory asset. The order did not address any subsequent
12 carrying charges for the MISO Rider true-up because EAI did not propose
13 the rider until this proceeding.

14 To clarify the Company's position, the over- or under-recovery
15 measurement for MISO Rider carrying costs would not include the
16 deferred MISO costs balance. The only carrying costs that would be
17 applied to deferred MISO costs would be associated with any variances
18 between the estimated annual amortization amount and actual annual
19 amortization incurred under the rider.

20
21 **B. Rider CCR**

22 **Q. DID STAFF RECOMMEND CHANGES TO RIDER CCR?**

¹⁴ Davis Direct Testimony at 8.

1 A. Yes. Staff witness Davis recommended several reporting requirements for
2 inclusion in Rider CCR that are being addressed by Company witness
3 Kurtis W. Castleberry.¹⁵ Staff also recommends a change to the threshold
4 for triggering an interim adjustment from \$10 million, as proposed by the
5 Company, to 10 percent, and the elimination of carrying charges on any
6 true-up balances.¹⁶

7
8 Q. IS STAFF'S INTERIM ADJUSTMENT PROPOSAL REASONABLE?

9 A. No. A dollar threshold is appropriate, as explained in the direct testimony
10 of Company witness Phillip B. Gillam:

11 As explained in paragraph 55.5 of Rider CCR, if short-term
12 and limited-term capacity purchases with capacity costs
13 exceeding \$10 million for the life of the contract are entered
14 into, the Company may request an interim rate adjustment.
15 Similarly, if a purchase with significant capacity costs were to
16 expire and be replaced with a much lower cost purchase
17 (e.g., \$10 million less than the original contract value), the
18 Company would propose an interim rate adjustment to
19 reflect this change.¹⁷

20 It is more appropriate to focus on significant cost changes as a
21 result of an additional capacity contract or the expiration of an existing
22 capacity contract as the driver for an interim adjustment rather than
23 focusing on variations because the capacity costs may go up or down due
24 to capacity transactions in the annual MISO auctions that have no

¹⁵ *Id.* at 17.

¹⁶ *Id.* at 18.

¹⁷ Gillam Direct Testimony at 39.

1 relationship to the percentage of the contract costs in Rider CCR at the
2 time of these transactions.

3 Staff also references the 10 percent trigger in Rider ECR as
4 support for its Rider CCR recommendation.¹⁸ The 10 percent trigger
5 mechanism is appropriate for Rider ECR but not Rider CCR because of
6 the much larger balances recovered by Rider ECR than is anticipated for
7 Rider CCR. The 10 percent trigger for Rider ECR allows for variances in
8 the tens of millions of dollars due to the large base to which the trigger is
9 applied. As an example, the trigger for an interim adjustment would be
10 \$32.6 million based on the 2013 Rider ECR filing on March 15, 2013 in
11 Docket No. 09-084-U.¹⁹ Until the Company and Staff gain greater
12 experience with the cost activity in Rider CCR, the more reasonable option
13 is to rely upon the \$10 million trigger as opposed to the 10 percent trigger
14 for an interim adjustment.

15

16 Q. IS STAFF'S RECOMMENDATION THAT CARRYING COSTS SHOULD
17 NOT BE APPLIED IN THE ANNUAL TRUE-UP OF RIDER CCR RATES
18 REASONABLE?

19 A. No, for the same reasons I explained for the MISO Rider. The
20 Commission has recognized carrying costs in the annual true-up
21 calculations of Rider ECR and Rider PCA. The same recognition for

¹⁸ Davis Direct Testimony at 18.

¹⁹ $\$326,356,829 \times 10\% = \$32,635,683$

1 customers' or the Company's time value of money should be made in the
2 annual true-up of Rider CCR rates.
3

4 **C. Rider ECR**

5 Q. WHAT REVISION TO RIDER ECR HAS STAFF RECOMMENDED?

6 A. Staff witness Regina Butler recommended that the Energy Allocation
7 Factor be added to the true-up calculation formula in Rider ECR. In
8 addition, she recommended that the Rider ECR cost rate continue to be
9 filed as an informational filing and certain additional reporting
10 requirements.²⁰
11

12 Q. ARE HER RECOMMENDATIONS REASONABLE?

13 A. Yes. The addition of the Energy Allocation Factor to the formula is
14 appropriate in light of the Company's proposal to return to an average fuel
15 cost calculation that incorporates an Energy Allocation Factor as part of
16 the energy cost determination. The filing of the Rider ECR cost rate as an
17 informational filing only is reasonable. The reporting requirements
18 recommended by Ms. Butler to provide additional accounting information
19 in Reporting Requirement No. 3 and update the language in Reporting
20 Requirement No. 7 to include the MISO Tariff instead of the Energy
21 System Agreement are reasonable.
22

²⁰ Butler Direct Testimony at 11, 13-15.

1 **IV. CONCLUSION**

2 Q. COULD YOU BRIEFLY SUMMARIZE YOUR TESTIMONY?

3 A. The Company's cost-of-service model produced results generally
4 consistent with the cost-of-service study methodology employed by Staff
5 witness Klucher with a few noted exceptions. The recommendation by
6 HHEG witness Blank to disallow costs associated with the development of
7 the Company's cost-of-service model is not reasonable and is without
8 justification. The Company identified the impact on its revenue
9 requirement that would result from updating inputs to the WACC
10 calculation and the use of the Staff's methodology to address how WBL
11 Capacity sales are treated in the cost-of-service study.

12 In addition, the Company agrees with Staff that not applying
13 carrying costs on the unamortized deferred MISO Implementation cost
14 balance is consistent with a prior Commission decision on that issue, but
15 believes that carrying costs should be applied on the true-up of the MISO
16 Rider Revenue Requirement on the MISO Rider and Rider CCR for the
17 same reason that they are now applied on balances in Riders ECR and
18 PCA. Finally, the Company agrees to certain reporting requirement
19 recommendations for the MISO Rider and Rider ECR.

20
21 Q. DOES THIS CONCLUDE YOUR REBUTTAL TESTIMONY?

22 A. Yes.

CERTIFICATE OF SERVICE

I, Steven K. Strickland, do hereby certify that a copy of the foregoing has been served upon all parties of record by forwarding the same by electronic mail and/or first class mail, postage prepaid, this 26th day of August, 2013.

/s/ Steven K. Strickland
Steven K. Strickland

BEFORE THE
ARKANSAS PUBLIC SERVICE COMMISSION

IN THE MATTER OF THE APPLICATION	)	
OF ENTERGY ARKANSAS, INC. FOR	)	DOCKET NO. 13-028 -U
APPROVAL OF CHANGES IN RATES FOR	)	
RETAIL ELECTRIC SERVICE	)	

EAI EXHIBIT DEH-1

EDUCATIONAL, PROFESSIONAL, AND
WORK EXPERIENCE OF
DAVID E. HUNT

EDUCATIONAL, PROFESSIONAL, AND WORK EXPERIENCE OF DAVID E. HUNT

Education

I graduated in May 1992 from the University of Central Arkansas at Conway, Arkansas, with a Bachelor of Business Administration degree in accounting with a minor in mathematics. I also earned a Master of Business Administration degree from the University of Arkansas at Little Rock in May 2007. I have completed several professional development courses in the areas of public utility accounting, utility finance, and ratemaking. My certifications described below also require thirty to forty hours of continuing professional education on accounting or accounting-related topics each year.

Work and Professional Experience

I joined Arkansas Power & Light Company, predecessor to Entergy Arkansas, Inc. ("EAI"), in May 1992 as an Accountant I in the Regulatory Accounting & Tax department. Since that time I have worked in a variety of areas for Entergy Services, Inc. ("ESI") including Regulatory Accounting, Budgeting, Marketing, Call Center Operations, Revenue Requirements and Analyses, and Regulatory Strategy, and for EAI in Meter Reading and Regulatory Affairs. In February 2012, I accepted my current position as Director, Regulatory Accounting for ESI.

I hold several professional certifications. I am a Certified Public Accountant ("CPA"), Certified Management Accountant, Certified Internal Auditor, Certified Financial Manager, and Chartered Global Management Accountant. I am licensed to practice as a CPA in Arkansas.

I am a member of the American Institute of Certified Public Accountants, Arkansas Society of Certified Public Accountants ("ASCPA"), Institute of Management Accountants

("IMA"), Institute of Internal Auditors, Society of Utility Regulatory and Financial Analysts ("SURFA"), and the Society of Depreciation Professionals. I served in several leadership positions with these organizations including Chairman of the ASCPA Industry & Commerce Committee, President of the Arkansas Central Chapter of the IMA, and SURFA board member.

Testimony

I have provided testimony in the following proceedings:

Arkansas Public Service Commission

Docket No. 08-091-U

Docket No. 12-038-U

Council of the City of New Orleans

Docket No. UD-13-01

Louisiana Public Service Commission

Docket No. 32707

Docket No. 32708

Mississippi Public Service Commission

Docket No. 2009-UN-388

BEFORE THE
ARKANSAS PUBLIC SERVICE COMMISSION

IN THE MATTER OF THE APPLICATION	)	
OF ENTERGY ARKANSAS, INC. FOR	)	
APPROVAL OF CHANGES IN RATES FOR	)	DOCKET NO. 13-028-U
RETAIL ELECTRIC SERVICE	)	

REBUTTAL TESTIMONY

OF

ERIC FOX

DIRECTOR

FORECAST SOLUTIONS

ITRON, INC.

ON BEHALF OF

ENTERGY ARKANSAS, INC.

AUGUST 26, 2013

1 **I. INTRODUCTION**

2 Q. PLEASE STATE YOUR NAME.

3 A. My name is Eric Fox.

4

5 Q. ARE YOU THE SAME ERIC FOX WHO FILED DIRECT TESTIMONY IN
6 THIS DOCKET ON MARCH 1, 2013?

7 A. Yes, I am.

8

9 Q. ON WHOSE BEHALF ARE YOU TESTIFYING?

10 A. I am submitting this Rebuttal Testimony to the Arkansas Public Service
11 Commission (“APSC” or the “Commission”) on behalf of Entergy
12 Arkansas, Inc. (“EAI” or the “Company”).

13

14 Q. WHAT IS THE PURPOSE OF YOUR REBUTTAL TESTIMONY?

15 A. The purpose of my rebuttal testimony is to address Randall J.
16 Falkenberg’s testimony representing the Arkansas Electric Energy
17 Consumers (“AEEC”) in regards to weather-sensitivity in the industrial
18 sector and Robert H. Swaim’s testimony representing the General Staff of
19 the Arkansas Public Service Commission (“Staff”) in regards to his use of
20 30-year normal vs. 20-year normal weather for normalizing electric sales.

21

22

II. REBUTTAL OF MR. FALKENBERG'S TESTIMONY

Q. ON PAGE 27 OF MR. FALKENBERG'S TESTIMONY MR. FALKENBERG INFERS THAT THE INDUSTRIAL TEST-YEAR SALES SHOULD BE WEATHER NORMALIZED. IS HE CORRECT?

A. No. There is no evidence that the industrial sales classification in the EAI service area is weather-sensitive. The scatter plots below in Figure 1 show monthly average industrial use (per billing day) against average monthly temperature for the small industrial revenue class, and for the large industrial revenue class in Figure 2.

**Figure 1
Small Industrial Average Use vs. Average Temperature**

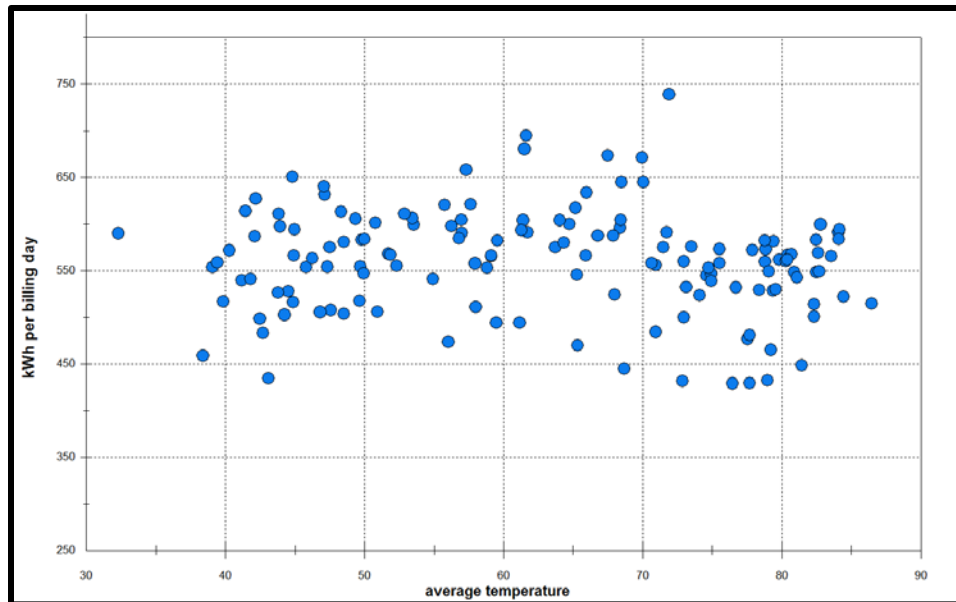
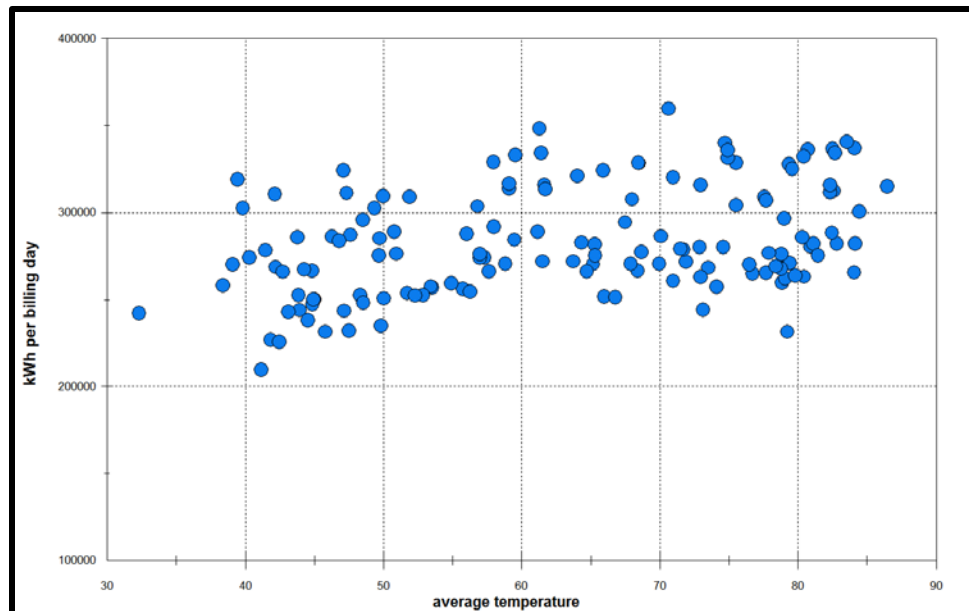


Figure 2
Large Industrial Sales vs Temperature



Sales per day are on the Y axis, average daily temperature (for the billing month period) is on the X axis. For the “small” class of industrial customers in Figure 1, the scatter plots show average customer use per billing day against average monthly temperature over the billing period. For the “large” industrial customer class in Figure 2, the scatter shows total industrial sales on a per billing day against average monthly temperature over the billing period. There is no observable relationship between industrial use and average monthly temperature in either scatter plot. Neither the Staff nor EAI has found this class of customers to be weather sensitive.

Q. WHAT IS MR. FALKENBERG’S EVIDENCE THAT THE INDUSTRIAL SECTOR IS WEATHER-SENSITIVE?

1 A. On page 27 of Mr. Falkenberg's testimony he cites the use of an industrial
2 monthly econometric sales model in Georgia Power's 2013 IRP filing as
3 proof that the industrial customer class is weather-sensitive. The model
4 used by Georgia Power includes an economic driver, price, and cooling
5 degree-days ("CDD"). Because the model included a CDD variable,
6 Mr. Falkenberg concludes that industrial sales are in fact
7 weather-sensitive. There is no information as to whether the CDD
8 variable was statistically significant or had any meaningful contribution to
9 the variation in monthly industrial sales.

10 While I agree with Mr. Falkenberg that factories can have large
11 cooling loads, this load is still small relative to factory process loads, and
12 as a result, total energy use is not likely to show any significant change
13 with change in temperature. Industrial cooling load requirements are more
14 likely correlated with internal production activity than external
15 temperatures.

16

III. REBUTTAL OF MR. SWAIM'S TESTIMONY

Q. MR. SWAIM ARGUES THAT SALES SHOULD BE WEATHER
NORMALIZED USING A 30-YEAR AVERAGE OF HISTORICAL
TEMPERATURE DATA. DO YOU AGREE?

A. No. Temperatures have generally been increasing over the last 20 years
– there have been more CDDs and fewer Heating Degree-Days (“HDDs”).
The 20-year normal used in EAI’s filing is more representative of what’s
likely to occur in the near-term than an average based on thirty-years of
data. Figures 3 and 4 show the CDD and HDD trends for Little Rock over
the last 20 years.

**Figure 3
Cooling Degree-Day Trend**

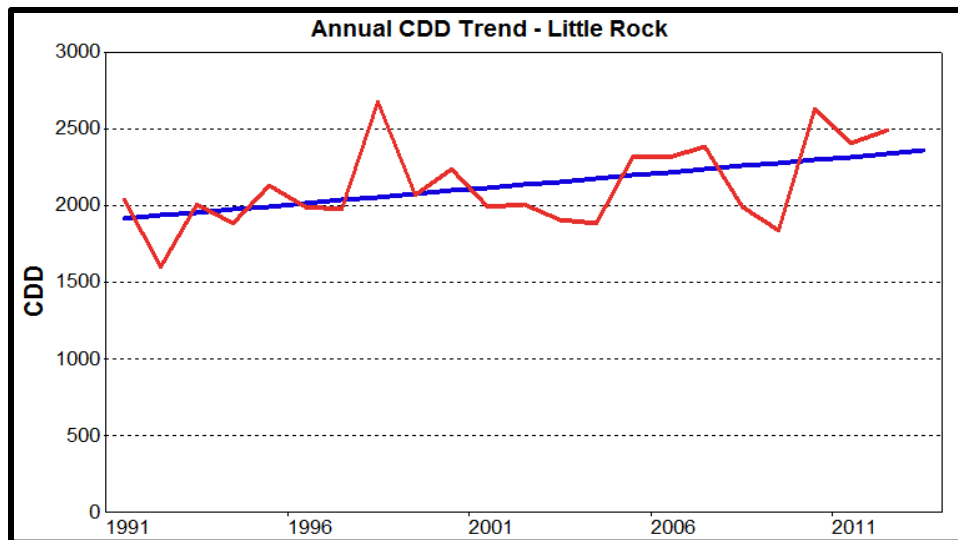
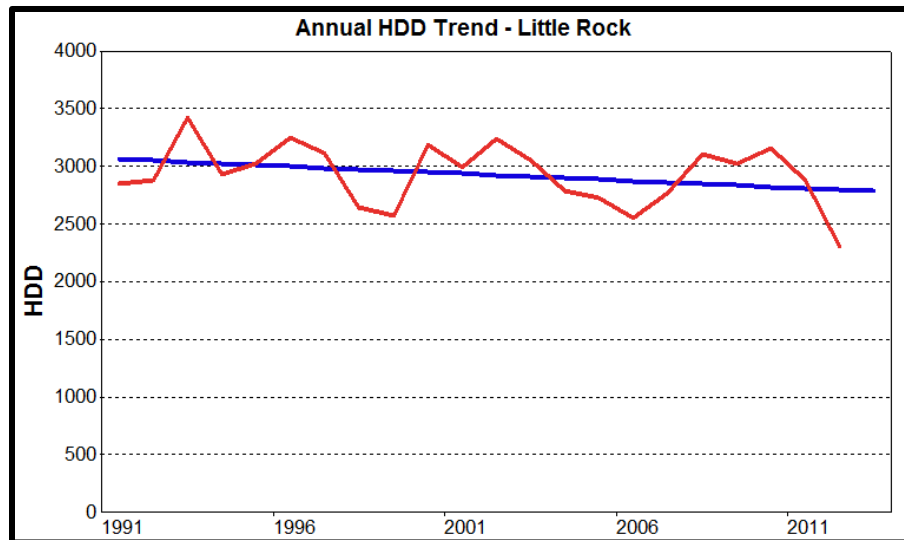


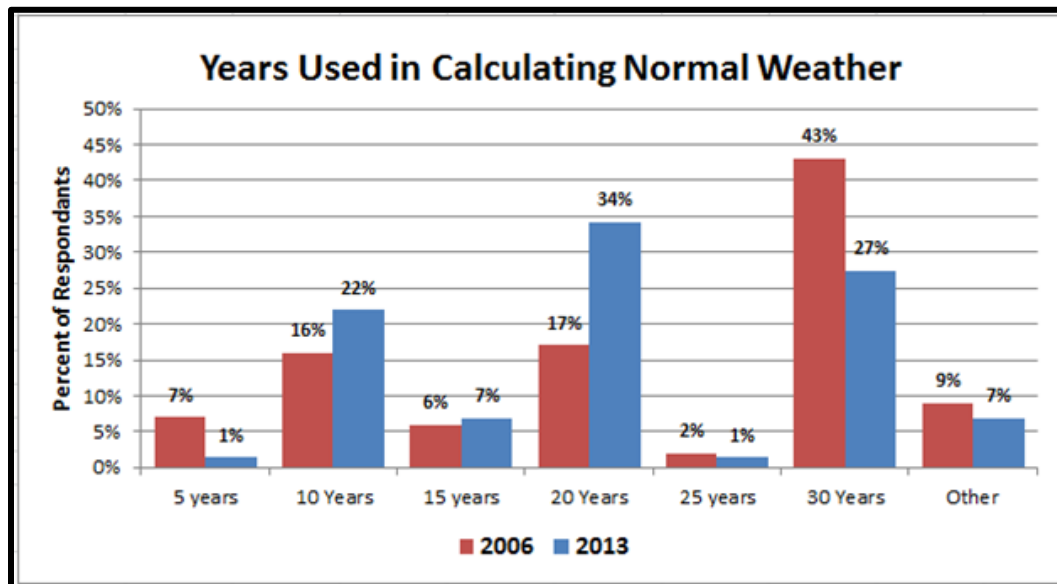
Figure 4
Heating Degree-Day Trend



It is fairly clear that CDDs have been trending up and HDDs have been trending down.

The Little Rock temperature trend is happening across the country. Within the electric industry there has been significant discussion as to how best to capture the changing temperature trends in sales and energy forecasts and normalizing sales. While 30 years has been the industry standard in the past, given the temperature trends more utilities are shifting to a shorter historical timeframe in defining normal weather. Figure 5 compares the 2006 and 2013 Itron Utility Forecaster's Benchmark Surveys.

Figure 5
Number of Years Used in Defining Normal Weather
(Itron Utility Survey)



In 2006, 43 percent of the respondents used a 30-year normal weather. In the latest survey the percentage using a 30-year normal weather dropped to 27 percent. The percentage using 20 years or less for calculating normal temperatures increased from 46 percent in 2006 to 64 percent in 2013. The largest increase was in the number of respondents using 20 years to define normal weather; the number respondents increased from 17 percent to 34 percent. The U.S. Energy Information Agency ("EIA") is also moving towards a shorter-historical time period. The 2013 U.S. Annual Energy Outlook is based on a 10-year CDD and HDD trend forecast.

1 **IV. CONCLUSION**

2 Q. COULD YOU BRIEFLY SUMMARIZE YOUR TESTIMONY?

3 A. Mr. Falkenberg believes that the industrial sales classes should be
4 weather normalized based on an industrial sales forecast model estimated
5 and used in the Georgia Power 2013 IRP filing. The evidence EAI has
6 and has provided to Mr. Falkenberg does not indicate that the industrial
7 customer base in the EAI service area is weather-sensitive. The Staff has
8 also found the industrial customer classes to not be weather-sensitive.
9 The industrial rate classes should not be adjusted for weather for the
10 purpose of developing the test-year sales.

11 Mr. Swaim believes it is more appropriate to use a 30-year
12 normal for weather for normalizing sales. The evidence supports that
13 20-year normal weather is more representative of what is likely to occur.
14 The majority of electric utilities and the EIA are moving towards a shorter
15 historical timeframe (less than 30 years) for calculating normal weather
16 conditions. HDD and CDD based on 20 years of historical data should be
17 used for determining test-year sales.

18

19 Q. DOES THIS CONCLUDE YOUR REBUTTAL TESTIMONY?

20 A. Yes.

CERTIFICATE OF SERVICE

I, Steven K. Strickland, do hereby certify that a copy of the foregoing has been served upon all parties of record by forwarding the same by electronic mail and/or first class mail, postage prepaid, this 26th day of August, 2013.

/s/ Steven K. Strickland
Steven K. Strickland

BEFORE THE
ARKANSAS PUBLIC SERVICE COMMISSION

IN THE MATTER OF THE APPLICATION)
OF ENTERGY ARKANSAS, INC. FOR) DOCKET NO. 13-028-U
APPROVAL OF CHANGES IN RATES FOR)
RETAIL ELECTRIC SERVICE)

DIRECT TESTIMONY

OF

GREGORY R. ZAKRZEWSKI

REGULATORY PROJECT COORDINATOR, REGULATORY ACCOUNTING

ENTERGY SERVICES, INC.

ON BEHALF OF

ENTERGY ARKANSAS, INC.

AUGUST 26, 2013

1 **I. INTRODUCTION**

2 Q. PLEASE STATE YOUR NAME.

3 A. My name is Gregory R. Zakrzewski.

4

5 Q. ARE YOU THE SAME GREGORY R. ZAKRZEWSKI WHO FILED
6 DIRECT TESTIMONY IN THIS DOCKET ON MARCH 1, 2013?

7 A. Yes, I am.

8

9 Q. ON WHOSE BEHALF ARE YOU TESTIFYING?

10 A. I am submitting this rebuttal testimony to the Arkansas Public Service
11 Commission ("APSC" or the "Commission") on behalf of Entergy
12 Arkansas, Inc. ("EAI" or the "Company").

13

14 Q. WHAT IS THE PURPOSE OF YOUR REBUTTAL TESTIMONY?

15 A. The purpose of my rebuttal testimony is to respond to certain accounting
16 and tax-related issues and recommendations raised in the direct testimony
17 of the APSC General Staff ("Staff") witnesses Jeff Hilton, Robert Daniel,
18 Ron Garner, Rick Dunn, LaToya Johnson, Judy Lindholm, William
19 Matthews, Claude Robertson and Bill Taylor, as well as Arkansas Attorney
20 General ("AG") witness William Marcus and other parties that filed
21 testimony in this docket. Because I am responding to a number of
22 recommendations made by several witnesses, some of whom raised
23 issues related to similar topics, my rebuttal testimony is organized by

1 issue. As such, I respond to various Staff and intervenor testimony as
2 appropriate within each topic section presented. Some of my
3 recommendations are supported by other Company witnesses. I also
4 propose an additional Pro Forma Adjustment to the Company's filed case
5 to reflect the net savings expected from Entergy Corporation's Human
6 Capital Management ("HCM") initiative.

7

8 Q. PLEASE PROVIDE AN OVERVIEW OF THE ISSUES ADDRESSED IN
9 THIS REBUTTAL TESTIMONY.

10 A. In the sections that follow, I address issues related to the following topics:

- 11 • the pro forma adjustment to reflect net savings from the HCM
12 initiative.
- 13 • working capital adjustments raised by Staff.
- 14 • expense adjustments raised by various Staff and intervenors.
- 15 • Current, Accrued and Other Liabilities raised by Staff.
- 16 • dismantlement of production assets raised by Mr. Garner and
17 Mr. Selecky.
- 18 • the Company's Entergy Technology Company adjustment
19 raised by Staff.
- 20 • the use of forecasted Data used by Staff.
- 21 • the Company's capital structure raised by Staff and intervenors.
- 22 • Accumulated Deferred Income Tax ("ADIT") raised by Staff.

- 1 • the calculation of income tax expense raised by Staff witness
- 2 Hilton.
- 3

1 **II. PRO FORMA ADJUSTMENT FOR HCM INITIATIVE**

2 Q. PLEASE DISCUSS THE ADDITIONAL PRO FORMA ADJUSTMENT
3 THAT THE COMPANY IS PROPOSING RELATED TO THE HCM
4 INITIATIVE.

5 A. As discussed by Company witness Hugh McDonald, after EAI filed this
6 case, Entergy Corporation announced its HCM initiative, an effort to
7 redesign the entire organization to better align its resources to meet future
8 challenges. This effort is expected to produce net savings starting in 2013
9 that will continue into the future. The actual savings and costs associated
10 with this initiative will not be known until the organization design is
11 finalized and employees are designated to fill the available positions.
12 However, the Company has estimated the net annual operations and
13 maintenance ("O&M") savings it expects to achieve over the next three
14 years. This net annual O&M savings is based on the difference between
15 the gross annual O&M savings associated with the initiative less the costs
16 to achieve these savings. The Company is requesting Regulatory Asset
17 treatment of the costs associated with achieving these savings and
18 requests that it be allowed to amortize these costs over a three year
19 period. EAI Exhibit GRZ-2 shows the derivation of the HCM pro forma
20 adjustment.

21
22 Q. WHAT WAS THE STARTING POINT FOR DETERMINING THE GROSS
23 ANNUAL O&M SAVINGS?

1 A. Employee head count as of December 31, 2012 was the starting point for
2 determining the gross annual O&M savings. This is important because
3 various adjustments proposed by Staff and intervenors in this case are
4 affected and should take into consideration the impact of the HCM
5 adjustment to avoid double-counting. This includes the Staff's
6 adjustments, associated with payroll (adjustment IS-16), plant retirements
7 (adjustment IS-33), and the removal of costs associated with the White
8 Bluff Steam Electric Station ("White Bluff"), the Independence Steam
9 Electric Station ("ISES"), and Arkansas Nuclear One ("ANO") (adjustment
10 IS-34). The impact on these adjustments is discussed later in my
11 testimony.

12
13 Q. PLEASE DISCUSS THE ESTIMATED EXPENSES ASSOCIATED WITH
14 ACHIEVING THE HCM SAVINGS.

15 A. The estimated expenses associated with achieving these savings include
16 costs related to executing this initiative including separation, relocation,
17 and benefits cost. The Company requests authorization to record these
18 expenses as a Regulatory Asset, including a return on the unamortized
19 balance, and to amortize these costs over a three-year period beginning in
20 2014. The Company believes that a three year amortization period is
21 appropriate because this is approximately the same time period (2013 –
22 2015) over which the Company will expend the dollars associated with this
23 initiative.

1

2 **III. WORKING CAPITAL ASSET ADJUSTMENTS**

3 **A. Adjustments EAI Considers Appropriate**

4 Q. STAFF WITNESS DUNN RECOMMENDS ADJUSTMENTS TO VARIOUS
5 WORKING CAPITAL ASSETS WHICH WERE NOT MADE BY THE
6 COMPANY. PLEASE ADDRESS HIS RECOMMENDATIONS.

7 A. I agree that some of Mr. Dunn's proposed adjustments are appropriate to
8 make. I agree that the elimination of the storm cost recovery account
9 (\$1,145,924) is appropriate because it is related to securitization.¹ I also
10 agree with the adjustment of \$98,640 to the prepayment accounts for
11 Edison Electric Institute ("EEI") and Nuclear Energy Institute ("NEI") dues.
12 Below, I address Mr. Dunn's proposed adjustments with which I disagree.

13

14 **B. Accounts Receivable Affiliate (Account 146)**

15 Q. WHAT ADJUSTMENTS DID MR. DUNN RECOMMEND RELATED TO
16 ACCOUNTS RECEIVABLE AFFILIATE?

17 A. Mr. Dunn recommends eliminating \$5,323,940 in Accounts Receivable
18 Affiliate because these accounts are nonretail.²

19

20 Q. IS THIS ADJUSTMENT APPROPRIATE TO MAKE?

¹ Dunn Direct Testimony at 7.

² *Id.*

1 A. No. The balances in these two Accounts are related to revenues that the
2 Company receives from wholesale customers that take transmission
3 service under the Entergy Open Access Transmission Tariff. Retail
4 customers always have received credit for these revenues as an offset to
5 its revenue requirement in prior base rate proceedings, and would receive
6 such credit through the Midcontinent Independent System Operator, Inc.
7 (“MISO”) Rider. Accordingly, the accounts receivable balance associated
8 with these revenues should remain in the cost-of-service study.

9

10 **C. Clearing Accounts (Account 184)**

11 Q. WHAT ADJUSTMENTS DID MR. DUNN RECOMMEND RELATED TO
12 CLEARING ACCOUNTS?

13 A. Mr. Dunn recommends elimination of all the balances in Account 184 from
14 his Working Capital Assets.³

15

16 Q. IS THAT ADJUSTMENT APPROPRIATE?

17 A. No. Costs in Account 184 represent amounts expended by the Company
18 that are not currently charged to O&M expense or plant accounts. The
19 costs in these accounts, which include Vehicle/Transportation Clearing,
20 Non-Productive Time Clearing, and Safety Training Loader, reflect costs
21 incurred to provide utility service to customers, and Mr. Dunn cannot and
22 does not assert otherwise. The Company has expended funds to benefit

³ *Id.*

1 customers, and these amounts should not be excluded from rate base
2 simply because of a timing issue. These costs meet the working capital
3 asset requirements in that they are not interest bearing, they are
4 necessary in providing utility service, and they are not included elsewhere
5 in rate base. The clearing account balances of \$3,231,112 for these
6 accounts should be included in working capital assets.

7

8 **D. Prepaid Taxes Franchise - LA (Account 165403)**

9 Q. WHAT ADJUSTMENT DID MR. DUNN RECOMMEND RELATED TO
10 PREPAID TAXES FRANCHISE – LA?

11 A. Mr. Dunn recommends elimination of the balance in Account 165403 from
12 his working capital assets because he says that it is a non-jurisdictional
13 account.⁴

14

15 Q. IS THIS ADJUSTMENT APPROPRIATE?

16 A. No. The prepayment included in this account is for franchise taxes paid in
17 Louisiana associated with the Company's two-thirds ownership interest in
18 the Ouachita Plant, which is located near Sterlington, Louisiana. These
19 costs should be included in working capital assets because the franchise
20 tax is an expense associated with operation of the Ouachita Plant, which
21 is used to serve EAI's retail customers.

22

⁴ *Id* at 7.

1 **E. Regulatory Asset for Rate Case Expenses**

2 Q. IS MR. DUNN'S RECOMMENDATION TO EXCLUDE THE COMPANY'S
3 REQUESTED REGULATORY ASSET FOR RATE CASE EXPENSES
4 FROM RATE BASE REASONABLE?

5 A. No. The Company is undergoing significant structural changes, as
6 discussed by Mr. McDonald, which benefit customers and which drove the
7 need for this case. The Company expects to incur approximately \$3.5
8 million in costs associated with this case which incorporates the costs and
9 savings associated with these changes into rates. Accordingly, it is
10 reasonable to allow the Company to establish a regulatory asset for the
11 rate case expenses and to recover the amortization of those costs over
12 three years as explained later in this testimony.

13
14 **IV. EXPENSE ADJUSTMENTS**

15 **A. Industry Dues Expenses**

16 Q. PLEASE DESCRIBE MR. MARCUS PROPOSED ADJUSTMENT TO
17 INDUSTRY DUES EXPENSE.

18 A. Mr. Marcus proposed an increase in the amount of EEI and NEI dues that
19 are not allowable over and above what the Company removed in
20 Adjustment AJ 20.⁵ Company witness Brady Aldy addresses Mr. Marcus'
21 recommendation regarding EEI dues, and Company witness Jay Thayer

⁵ Marcus Direct Testimony at 68-73.

1 addresses Mr. Marcus' recommendation regarding NEI dues. Each EAI
2 witness explains why Mr. Marcus' recommendation is not appropriate.

3

4 Q. IS MR. MARCUS RECOMMENDATION FOR AN AMOUNT RELATED TO
5 EEI AND NEI DUES ASSOCIATED WITH LOBBYING REASONABLE?

6 A. As I indicated previously in discussing Staff witness Dunn's adjustment to
7 prepaids for these items, I believe it is reasonable that prepaids should be
8 based on the percentage used for the expense adjustment included in the
9 filing and not the inflated percentage used by Mr. Marcus.⁶

10

11 **B. Directors and Officers ("D&O") Insurance**

12 Q. MR. MARCUS RECOMMENDS THAT \$71,737 OF THE D&O
13 INSURANCE PREMIUM SHOULD BE REMOVED FROM THE
14 COMPANY'S COSTS BASED UPON HIS VIEW THAT SHAREHOLDERS
15 SHOULD PAY HALF OF THIS EXPENSE.⁷ IS HIS ADJUSTMENT
16 REASONABLE?

17 A. No. The adjustment is not appropriate because EAI's expense for this
18 item already reflects an allocation of half of the D&O insurance expense.
19 In the Company's initial filing, Adjustment AJ06K removed one-half of the
20 Company's total test year D&O insurance expense consistent with a
21 similar adjustment in Docket No. 06-101-U. In response to a data request

⁶ *Id.*

⁷ *Id. at 73.*

1 from Staff, EAI updated its filing to reflect 12 months actual costs. At that
2 time, it was determined that Entergy Corporation, EAI's parent company,
3 had been directly billed and paid for one half of EAI's D&O insurance
4 premium cost. Because the Company's updated 2012 actual costs only
5 included one-half of the D&O insurance premiums, Adjustment AJ06K was
6 not required. The Company provided additional documentation for the
7 D&O insurance premiums in its responses to Staff Data Requests 3-8, 49-
8 1, 49-2, 107-1, 169-1 and 180-3.

9 Staff witness Judy Lindholm addressed this issue on pages 7-8 of
10 her direct testimony and in her Staff Adjustment IS-6K. She agrees that
11 the Company should be allowed to recover its cost associated with D&O
12 insurance.⁸ Her testimony notes that this expense was ordinary and
13 necessary as well as reasonable and that isolating one insurance
14 component, such as this, and applying a special adjustment against it is
15 not warranted. Ms. Lindholm also notes that providing D&O liability
16 insurance is an accepted industry practice without which it would be
17 unlikely that the Company could attract qualified and competent officers
18 and directors, and that this coverage is a typical component of any utility
19 industry or any other industry insurance portfolio.

20

⁸ Lindholm Direct Testimony at 7-8.

1 **C. Rate Case Expense**

2 Q. DO YOU AGREE WITH STAFF WITNESS LATOYA JOHNSON'S
3 ASSERTION THAT THE COMPANY'S TEST YEAR O&M EXPENSE
4 INCLUDES INTERNAL PAYROLL COSTS FOR RATE CASE
5 EXPENSES?⁹

6 A. No. Ms. Johnson's recommendation assumes that the Company's test
7 year O&M expense includes some level of internal payroll costs
8 associated with Entergy Services, Inc. ("ESI")¹⁰ rate case support
9 services. This is an improper assumption. The Company deferred all
10 costs (both internal¹¹ and external¹²) associated with this case in 2012
11 consistent with its request seeking regulatory asset treatment and
12 amortization of these costs. The amount deferred in 2012 for these costs
13 was \$748,511. Because of this deferral, the Company's test year O&M
14 expense does not include any level of expense associated with these ESI
15 rate case support services.

16

17 Q. WHAT IS YOUR RECOMMENDATION REGARDING RATE CASE
18 EXPENSES?

⁹ Johnson Direct Testimony at 8-9.

^{10 10} ESI is a subsidiary of Entergy Corporation that provides technical and administrative services to the Entergy Operating Companies. The Entergy Operating Companies include EAI; Entergy Gulf States Louisiana, L.L.C.; Entergy Louisiana, LLC ("ELL"); Entergy Mississippi, Inc.; Entergy New Orleans, Inc.; and Entergy Texas, Inc.

¹¹ Internal costs include EAI - direct costs excluding payroll and benefits; ESI support services costs including payroll and payroll related costs.

¹² External costs include consultants and legal support expenses at both EAI and ESI.

1 A. My recommendation is to continue to allow the Company to defer the rate
2 case costs as a Regulatory asset and amortize them over a three year
3 period. In the alternative if the Commission accepts Ms. Johnson's
4 recommendation, then \$748,511 must be added to expense to account for
5 internal ESI support servicers, along with Ms. Johnson's \$386,286
6 amortization of expenses associated with external consultants and legal
7 support services. This would be a total increase of \$1,134,797 to the cost
8 of service for rate case expenses.

9

10 **V. UNDISTRIBUTED STORES EXPENSE AND FUEL STOCK EXPENSES**

11 **UNDISTRIBUTED**

12 Q. PLEASE DESCRIBE THE ADJUSTMENTS MR. DUNN PROPOSES TO
13 MAKE TO WORKING CAPITAL ASSETS FOR FEDERAL ENERGY
14 REGULATORY COMMISSION ("FERC") ACCOUNT 163 - STORES
15 EXPENSE UNDISTRIBUTED ("UNDISTRIBUTED STORES") AND FERC
16 ACCOUNT 152 - FUEL STOCK EXPENSES UNDISTRIBUTED
17 ("UNDISTRIBUTED FUEL STOCK").

18 A. Mr. Dunn recommends reducing the Company's Materials and Supplies
19 ("M&S") Inventory balance included in working capital assets by the
20 amount included in FERC Account 163, and he recommends reducing the
21 Fuel Inventory balance included in working capital assets by the balance
22 included in FERC Account 152.¹³

¹³ Dunn Direct Testimony at 7-9.

1

2 Q. WHAT IS THE BASIS FOR MR. DUNN'S RECOMMENDED EXCLUSION
3 OF FERC ACCOUNTS 163 AND 152 FROM WORKING CAPITAL
4 ASSETS?

5 A. Mr. Dunn states his reason for excluding Account 163 is that “[s]tores is a
6 clearing account that temporarily accumulates costs to be distributed to
7 maintenance or construction projects in progress.”¹⁴ He further states that
8 “[t]hey should be excluded because the most currently known and
9 measurable pro forma level of expense is included in the Company’s cost-
10 of-service and because allowing a return on stores is additive and would
11 allow for over-recovery.”¹⁵ He states that his reason for excluding FERC
12 Account 152 is because undistributed fuel stock “operates similar to a
13 clearing account, temporarily accumulating costs which are then cleared
14 to fuel expense subject to exact recovery riders with associated carrying
15 charges.”¹⁶

16

17 Q. FOR WHAT PURPOSE ARE THESE ACCOUNTS USED?

18 A. Account 163 accumulates costs incurred in the operation of general
19 storerooms so that these costs can be distributed equitably to either
20 construction projects (where they would be capitalized) or O&M expense.
21 These costs are distributed between these two categories through the

¹⁴ *Id.* at 7.

¹⁵ *Id.* at 8.

¹⁶ *Id.* at 9.

1 development of a rate that is then applied to issues from Account 154 -
2 plant materials and operating supplies. Account 163 is necessary
3 because it allows for the equitable distribution of undistributed stores costs
4 to either construction projects or O&M expense. The costs existing in this
5 balance sheet account have not yet been charged to either O&M or capital
6 and are therefore a proper component of rate base.

7 Account 152 accumulates costs incurred in the unloading and
8 handling of fuel before it is consumed at the generating plant. These
9 costs are charged to expense through the development of a rate that is
10 then applied to the fuel (Account 151) as it is consumed at the coal plants.
11 Account 152 is necessary because it allows for an equitable distribution of
12 these costs to fuel expense based on fuel consumed at the coal plants
13 rather than charging these costs direct to expense as they are incurred.
14 The costs existing in this balance sheet account have not yet been
15 charged to fuel expense and are therefore a proper component of rate
16 base.

17

18 Q. WHAT GUIDANCE DOES THE FERC UNIFORM SYSTEM OF
19 ACCOUNTS ("USOA") PROVIDE REGARDING THESE ACCOUNTS?

20 A. The general instructions in the FERC USOA and/or the specific
21 instructions for Accounts 151, 152, 154, and 163¹⁷ generally describe the

¹⁷ Account 151 – Fuel Stock; Account 152 – Fuel Stock Expenses Undistributed; Account 154 – Plant Materials and Operating Supplies; Account 163 – Stores Expense Undistributed.

1 costs to be included in the account and prescribe that these costs **will** be
2 charged/cleared from these accounts to either construction work-in-
3 progress ("CWIP") or O&M as the inventory is used. For example, when
4 material is issued out of Account 154 and charged to O&M expense, a
5 charge out of Account 163 occurs at the current loading rate, which
6 distributes the costs of storing that material to O&M expense.

7 These instructions also dictate that the balances in the
8 undistributed stores and undistributed fuel stock accounts shall be
9 attributable to the balances in the M&S and fuel stock inventory accounts
10 respectively, (*i.e.* there is a proportional relationship between the balances
11 in the undistributed stores and the undistributed fuel stock accounts and
12 the balances in the M&S and fuel stock inventory accounts). This
13 inventory accounting, as prescribed by the USOA, also conforms to
14 generally accepted accounting standards. Therefore, the Company's
15 accounting practice for these accounts is consistent with the FERC USOA
16 and generally accepted accounting standards.

17
18 Q. IS MR. DUNN'S CHARACTERIZATION OF ACCOUNTS 152 AND 163
19 AS "TEMPORARILY ACCUMULATING COSTS"¹⁸ ACCURATE?

20 A. No. As I explained above these accounts continuously accumulate costs
21 which are to be charged or cleared to CWIP or O&M. The Company
22 always maintains an investment in these accounts as long as it maintains

¹⁸ Dunn Direct Testimony at 7-9

1 an investment in the corresponding inventory accounts. However, Mr.
 2 Dunn's exclusion of these accounts assumes that there typically is not an
 3 investment in these accounts, even though Mr. Dunn does not and cannot
 4 support such as assumption. The assets included in these working capital
 5 asset accounts are necessary in providing utility service.

6 Table1 illustrates the accounting process for these accounts:

7

Table 1						
Accounting Process for M&S, Fuel and Undistributed expenses						
Account	Beginning Balance	Purchases During Year	Charges to O&M Expense	Charges to CWIP / Plant		Ending Balance
AC 154 -M&S	123,000	350,000	69,200	276,800		127,000
AC 163-UDS	20,000	56,000	11,000	44,000		21,000
AC 151-Fuel	38,800	177,800	174,600			42,000
AC 152-UDS	1,164	5,496	5,400			1,260

8
9

10 Q. PLEASE PROVIDE AN ILLUSTRATION OF HOW THE AMOUNTS
 11 SHOWN IN TABLE 1 ABOVE WOULD BE REFLECTED IN THE
 12 COMPANY'S COST-OF-SERVICE CALCULATION.

13 A. Table 2 shows how these amounts would be reflected in the Company's
 14 cost-of-service study:

15

Table 2				
Cost-of-Service Treatment for M&S, Fuel and Undistributed expenses				
Cost Category	Rate Base		O&M	
	Plant	WCA	Expenses	
M&S	276,800	127,000	69,200	
Undistributed Stores expenses	44,000	21,000	11,000	
Fuel		42,000	174,600	
Undistributed Fuel expenses		1,260	5,400	

1

2

3 Q. PLEASE PROVIDE AN ILLUSTRATION OF HOW THE AMOUNTS
4 SHOWN IN TABLE 1 ABOVE WOULD BE REFLECTED IN THE COST-
5 OF-SERVICE CALCULATION IF MR. DUNN'S RECOMMENDATION IS
6 ACCEPTED.

7 A. Table 3 shows how these amounts would be reflected in the cost-of-
8 service calculation based on Mr. Dunn's recommendation:

Table 3				
Cost-of-Service Treatment for M&S, Fuel and Undistributed expenses				
Cost Category	Rate Base		O&M	
	Plant	WCA	Expenses	
M&S	276,800	127,000	69,200	
Undistributed Stores expenses	44,000	-	11,000	
Fuel		42,000	174,600	
Undistributed Fuel expenses		-	5,400	

9

10

11 Q. WHAT DO TABLES 1, 2, AND 3 ABOVE ILLUSTRATE?

1 A. Table 1 shows the accounting process through which purchases of
2 inventory and associated undistributed charges go into the inventory
3 accounts. This inventory and the undistributed charges are then charged
4 out to O&M or capital as the inventory is used. Again, contrary to Mr.
5 Dunn's implicit assumption, there is always a balance in these inventory
6 and undistributed charges accounts because these assets are necessary
7 to provide utility service.

8 Table 2 shows where each category of cost is appropriately
9 reflected as plant, working capital assets, or O&M expense in the
10 Company's cost-of-service study.

11 Table 3 shows the inequity that would result from adopting Mr.
12 Dunn's recommendation. As that table reflects, each category of cost is
13 appropriately reflected in the cost-of-service study except for the balances
14 in the undistributed stores and undistributed fuel stock categories.
15

16 Q. PLEASE ADDRESS MR. DUNN'S STATEMENT THAT UNDISTRIBUTED
17 STORES "...SHOULD BE EXCLUDED BECAUSE THE MOST
18 CURRENTLY KNOWN AND MEASURABLE PRO FORMA LEVEL OF
19 EXPENSE IS INCLUDED IN THE COMPANY'S COST-OF-SERVICE
20 STUDY AND BECAUSE ALLOWING A RETURN ON STORES IS
21 ADDITIVE AND WOULD ALLOW FOR OVER-RECOVERY."¹⁹

¹⁹ Dunn Direct Testimony at 8.

1 A. Mr. Dunn is mistaken in his conclusion that allowing a return on stores is
2 additive and would allow for over-recovery. These costs are not in two
3 places at once. As illustrated above in Table 1, following the normal
4 accounting process, the ending balance of undistributed stores expense is
5 not included in plant, and it is not included in O&M expense. He does not
6 and cannot point to any adjustments in this case to support his statement
7 that "stores should be removed from WCA [working capital assets] in
8 recognition of its appropriate treatment as part of rate base assigned to
9 pro forma plant or part of pro forma expenses."²⁰ The Company did not
10 make a pro forma adjustment in this case to assign the undistributed
11 stores expense balance to pro forma plant or pro forma O&M expense as
12 alleged by Mr. Dunn. Therefore, for purposes of EAI's cost-of-service
13 study, these balances should remain as part of working capital.

14
15 Q. CAN YOU ADDRESS MR. DUNN'S COMMENT ABOUT
16 UNDISTRIBUTED STORES THAT "WHILE IN CWIP, THEY
17 ACCUMULATE ALLOWANCE FOR FUNDS USED DURING
18 CONSTRUCTION AND WHEN THE PROJECTS ARE COMPLETED
19 THESE COSTS ARE THEN TRANSFERRED TO PLANT AND
20 INCLUDED IN RATE BASE"²¹?

²⁰ *Id.*

²¹ *Id.*

1 A. This statement does not support Mr. Dunn's adjustment. Both M&S and
2 undistributed costs are issued out of inventory and charged to CWIP.
3 CWIP balances accrue allowance for funds used during construction
4 ("AFUDC"), and then the CWIP balances are transferred to plant when the
5 projects are completed. CWIP and AFUDC are part of the normal
6 ratemaking process. The Company does not accrue AFUDC on
7 undistributed stores costs while these costs remain in the inventory
8 account.

9

10 Q. DID MR. DUNN EXPRESS ANY OTHER CONCERNS REGARDING
11 UNDISTRIBUTED FUEL STOCK OTHER THAN HIS STATEMENT THAT
12 THE ACCOUNT OPERATES SIMILAR TO A CLEARING ACCOUNT?

13 A. Yes. Although his main concern and basis for recommending a
14 disallowance is because the undistributed fuel stock account functions
15 similar to a clearing account, he also points out that the undistributed fuel
16 stock costs are cleared to fuel expense that is subject to exact recovery
17 riders with associated carrying charges.²² However, here again, this is not
18 an appropriate basis to exclude these costs. To understand why this is
19 the case, an explanation as to how fuel inventory costs are addressed
20 may be helpful.

21 Fuel inventory costs (including undistributed fuel stock) are cleared
22 out of the fuel inventory account and charged to expense as the fuel is

²² *Id.* at 8-9.

1 consumed at the coal plants. This fuel expense is collected from
2 customers through an exact recovery rider, the Energy Cost Recovery
3 Rider ("Rider ECR"), which also provides for carrying charges on any
4 over- or under-recovery balance. As a result, the Company either pays a
5 carrying charge on an over-recovery balance or collects a carrying charge
6 on an under-recovery balance. This is part of the ratemaking process.
7 This exact recovery rider process does not include any type of return on
8 the costs included in fuel inventory.

9

10 Q. ARE THE INCLUSION OF UNDISTRIBUTED STORES AND
11 UNDISTRIBUTED FUEL STOCK IN WORKING CAPITAL ASSETS
12 CONSISTENT WITH THE MODIFIED BALANCE SHEET APPROACH
13 DESCRIBED BY MR. DUNN IN HIS DIRECT TESTIMONY?

14 A. Yes. As described by Mr. Dunn in his direct testimony, the Modified
15 Balance Sheet Approach, prescribed by this Commission, requires "that
16 jurisdictional assets, other than plant, that are not interest bearing, that are
17 necessary in providing utility service, and that are not considered
18 elsewhere in the cost-of-service be included in a utility's rate base as
19 WCA [working capital assets]."²³ There is no dispute that the undistributed
20 stores and undistributed fuel stock are jurisdictional assets, that they are
21 not interest bearing, and that they are necessary in providing utility
22 service. I also have demonstrated above that these assets are not

²³ *Id.* at 4.

1 included elsewhere in the cost-of-service study and therefore they should
2 be included in the Company's rate base as working capital assets.

3

4 Q. DOES MR. DUNN PROVIDE ANY FACTUAL SUPPORT OR
5 DOCUMENTATION TO SUPPORT HIS RECOMMENDED REMOVAL OF
6 UNDISTRIBUTED STORES AND UNDISTRIBUTED FUEL STOCK
7 FROM WORKING CAPITAL ASSETS?

8 A. No. Mr. Dunn provides no factual support, reference to accounting
9 standards, or any other authority to support his adjustments. He does
10 provide a theoretical basis for removing both undistributed stores and
11 undistributed fuel stock from working capital assets. He alleges that these
12 two accounts function as clearing accounts which are temporarily used to
13 accumulate costs and distribute the costs to the appropriate O&M or
14 CWIP accounts. I have demonstrated above that these accounts are not
15 temporary in nature and that the balances in these accounts are directly
16 related to the inventory accounts which are also included in working
17 capital assets and which he does not recommend be removed.

18 Mr. Dunn also claims that the undistributed stores expense is
19 included as part of rate base assigned to pro forma plant or part of pro
20 forma expenses. However, he provides no support or documentation for
21 this claim other than the conclusory statement in his testimony. I have
22 demonstrated above (see Tables 1, 2, and 3) that these amounts are not
23 included elsewhere in the cost-of-service study. I also have explained

1 above that the Company has not made any pro forma adjustments to
2 include these amounts elsewhere in the cost-of-service study.

3

4 Q. MR. DUNN ASSERTS THAT HIS TREATMENT OF UNDISTRIBUTED
5 STORES EXPENSE IS CONSISTENT WITH THE COMMISSION'S
6 ORDER NO. 10 IN DOCKET NO. 06-101-U?²⁴ WHAT IS YOUR
7 RESPONSE?

8 A. While it is true that Mr. Dunn's treatment of undistributed stores expense
9 is consistent with the Commission's Order No. 10, the Commission's
10 exclusion of undistributed stores expense from M&S inventory in Docket
11 No. 06-101-U is contrary to the treatment of these costs in prior EAI base
12 rate proceedings, including Docket Nos. 81-144-U, 82-314-U, 84-199-U,
13 84-249-U and 96-360-U. The exclusion of these costs from M&S
14 inventory also is inconsistent with the accounting treatment prescribed by
15 the FERC USOA and generally accepted accounting standards. Rather
16 than expand upon the exceptional treatment of undistributed stores
17 ordered in Docket No. 06-101-U, the Commission should revisit the prior,
18 unique treatment of these costs in this case.²⁵

19

²⁴ Dunn Direct Testimony at 8.

²⁵ Although EAI appealed Order No. 10 to the Court of Appeals, the Commission's decision on this issue was upheld. The Court's decision was based on an arbitrary and capricious standard and ultimately, the Court found that there was sufficient evidence in the record to support the Commission's decision. Here, my testimony presents substantial evidence that the treatment EAI proposes is consistent with ratemaking principles and generally accepted accounting standards, and therefore, the treatment in Docket No. 06-101-U should be reversed.

1 Q. ARE YOU AWARE OF ANY PROCEEDINGS IN WHICH THE STAFF
2 HAS MADE A RECOMMENDATION TO EXCLUDE UNDISTRIBUTED
3 FUEL STOCK FROM WORKING CAPITAL ASSETS?

4 A. Yes. The Staff has made this recommendation to exclude undistributed
5 fuel stock from working capital assets in the Company's last base rate
6 case Docket No. 09-084-U. However, this case was settled and the
7 Commission did not issue an order explicitly excluding undistributed fuel
8 stock from working capital assets. The Staff did not make this
9 recommendation in Docket No. 06-101-U, nor has it made this
10 recommendation in any of the Company's prior base rate proceedings
11 referenced above.

12

13 Q. PLEASE SUMMARIZE YOUR RECOMMENDATION REGARDING
14 MR. DUNN'S EXCLUSION OF UNDISTRIBUTED STORES EXPENSE
15 FROM M&S INVENTORY INCLUDED IN WORKING CAPITAL ASSETS
16 AND HIS EXCLUSION OF UNDISTRIBUTED FUEL STOCK FROM FUEL
17 INVENTORY INCLUDED IN WORKING CAPITAL ASSETS.

18 A. The Commission should reject Mr. Dunn's recommendation to exclude
19 undistributed stores expense from M&S inventory and his
20 recommendation to exclude undistributed fuel stock from fuel inventory.
21 The Company has an investment in the undistributed stores and
22 undistributed fuel stock just like it has an investment in the M&S inventory
23 and fuel inventory. These investments are not temporary in nature.

1 Rather, these accounts are constantly cleared and restocked. The
2 balances in these accounts meet all the requirements of the Modified
3 Balance Sheet Approach to setting working capital as described by Mr.
4 Dunn, *i.e.* the accounts are not interest bearing, are necessary in
5 providing utility service, and are not considered elsewhere in the cost-of-
6 service study.

7
8 **VI. CURRENT, ACCRUED AND OTHER LIABILITIES**

9 **A. Adjustments EAI Considers Appropriate**

10 Q. HAVE YOU REVIEWED MR. DUNN'S PROPOSED ADJUSTMENTS TO
11 VARIOUS CURRENT, ACCRUED AND OTHER LIABILITIES ("CAOL")?

12 A. Yes. I agree that his proposed adjustments to include accounts 232FUA,
13 232072 and 234711 in CAOL are reasonable. I also agree that his
14 adjustment to income taxes payable of \$457,543 is reasonable. However,
15 I would note that all adjustments made to CAOL will depend on the time
16 period used in determining the Company's final capital structure. Below, I
17 address Mr. Dunn's proposed adjustments which I do not consider
18 appropriate.

19
20 **B. Interest on Accumulated Provision for Property Insurance (Account**
21 **228101)**

22 Q. WHAT ADJUSTMENT DID MR. DUNN RECOMMEND FOR INTEREST
23 ON ACCUMULATED PROVISION FOR PROPERTY INSURANCE?

1 A. Mr. Dunn recommends the inclusion of the (\$244,331) balance in CAOL.²⁶

2

3 Q. IS THIS ADJUSTMENT APPROPRIATE?

4 A. No. The interest in this account is associated with the balance in the
5 Accumulated Provision for Property Insurance account. This account is
6 not included in CAOL, and, therefore, the associated interest associated
7 with this reserve should not be included in CAOL.

8

9 C. **Accounts Payable Bulk Power/System Agreement (Account 234711)**

10 Q. WHAT ADJUSTMENT DID MR. DUNN RECOMMEND FOR ACCOUNT
11 234711 - POWER/SYSTEM AGREEMENT?

12 A. Mr. Dunn recommends the inclusion of the net balance of Accounts
13 234711 and 182391 in CAOL. I agree with his recommendation to include
14 these accounts but the balance in Account 146711 should also be
15 included in the net balance calculated to include in CAOL. All three of
16 these accounts are interrelated and reflect transactions associated with
17 bulk power transactions.

18

19 D. **Contingent Liability Accounts**

20 Q. WHAT ADJUSTMENT DID MR. DUNN RECOMMEND RELATED TO
21 CONTINGENT LIABILITY ACCOUNTS?

²⁶ Dunn Direct Testimony at 10.

1 A. Mr. Dunn recommends inclusion of the balances in Non-Income Tax
2 Contingency (Account 236105), Critical Infrastructure Protection ("CIP")
3 Reserve (Account 253CIP), and FERC Reserves accounts (Account
4 253RES).²⁷

5
6 Q. ARE THESE ADJUSTMENTS APPROPRIATE?

7 A. No. First, the Non Income Tax Contingency account should not be
8 included in CAOL because it is related to the Company's FAS 5
9 contingency that is adjusted quarterly based on a review of the Company's
10 exposure associated with various non-income tax related liabilities. The
11 expense associated with this liability is not included in the cost-of-service
12 study, and, therefore, the related contingency account should not be
13 included in CAOL.

14 The liabilities recorded in the CIP Reserve and FERC Reserve
15 accounts are for contingent liabilities related to proposed penalties for
16 FERC, North American Electric Reliability Corporation ("NERC"), and
17 Southeast Electric Reliability Corporation ("SERC") regulation violations.
18 The expense associated with these liabilities is recorded in below-the-line
19 accounts which are not included in the cost-of-service study. The
20 expense is not included in the cost-of-service study and, accordingly, the
21 liability should not be included in calculating CAOL either.

22

²⁷ *Id.*

1 **E. Prepaid Contributions In Aid Of Construction (“CIAC”) And**
2 **Associated Income Tax Gross-Ups (Accounts 253F and 253G)**

3 Q. WHAT ADJUSTMENT DID MR DUNN RECOMMEND RELATED TO
4 PREPAID CIAC AND ASSOCIATED INCOME TAX GROSS UPS?

5 A. Mr. Dunn recommends inclusion of the balances in Prepaid CIAC and
6 associated income tax gross-up accounts in CAOL.²⁸

7
8 Q. IS THIS ADJUSTMENT APPROPRIATE?

9 A. No. On a monthly basis, as the funds are expended and recorded in
10 CWIP, the associated amounts from these Prepaid CIAC accounts are
11 credited against the CWIP balance. The Company receives no benefit
12 from these funds as they are specifically used to pay for the construction
13 of specific facilities.

14
15 **F. Dividends Payable On Common Stock (Account 238001)**

16 Q. WHAT ADJUSTMENT DID MR. DUNN RECOMMEND RELATED TO
17 DIVIDENDS PAYABLE ON COMMON STOCK?

18 A. Mr. Dunn recommends inclusion of \$1,179,187 related to dividends
19 payable on common stock using EAI's actual lag days based on a four
20 year average of dividends paid in 2008 through 2011.²⁹

21

²⁸ *Id.*

²⁹ *Id.* at 11.

1 Q. IS THIS ADJUSTMENT APPROPRIATE?

2 A. No. Dividends payable on common stock using EAI's actual lag days
3 should be included in CAOL based on actual dividends paid during the
4 test year instead of a four-year average. Therefore, I recommend
5 including dividends payable on common stock of \$273,973 in CAOL. This
6 methodology is consistent with the calculation in EAI Exhibit JDW-3 to the
7 Rebuttal Testimony of J. David Wright in Docket No. 06-101-U, which the
8 APSC adopted by its Order No. 22.³⁰

9

10 **G. Interest Payable**

11 Q. IS MR. DUNN'S ADJUSTMENT TO INTEREST PAYABLE
12 REASONABLE?

13 A. No. The balances associated with accrued interest payable should be
14 adjusted, however they should be adjusted based on the debt and cost
15 rates ultimately approved in this case.

16

17 **H. Additional Lag Day Calculation**

18 Q. DO YOU AGREE WITH MR. DUNN'S RECOMMENDATION TO ADJUST
19 THE LAG DAYS ASSOCIATED WITH VARIOUS ACCOUNTS WHICH
20 WOULD INCREASE THE COMPANY'S CAOL BY \$14,677,548?

21 A. No. Mr. Dunn proposed adjusting the lag days for these accounts to what
22 he deems to be a more representative level. However, he provides no

³⁰ Docket No. 06-101-U, Order No. 22 at 6-7.

1 support or justification for making this adjustment. The Company has
2 calculated lag days associated with these accounts based on a 13-month
3 average consistent with the calculation of lag days in the Company's last
4 two rate cases: Docket Nos. 06-101-U and 09-084-U. It is inappropriate
5 to adjust the 13-month average balance in these CAOL accounts without
6 support or justification.

7
8 Q. WHAT IS MR. DUNN'S RATIONALE FOR MAKING THIS
9 ADJUSTMENT?

10 A. Mr. Dunn states that he is adjusting the balances to more representative
11 levels, and he uses lag days associated with some other CAOL accounts
12 that have been accepted by Staff and the Company as representative for
13 those specific accounts. The Company does not agree that these same
14 lag days should be applied to these additional accounts without a detailed
15 analysis on these accounts. Mr. Dunn's recommendation to increase the
16 CAOL balances associated with these accounts should be rejected
17 because he provides no support or justification to show that his
18 adjustment is reasonable.

19

20 **VII. DISMANTLEMENT OF PRODUCTION ASSETS**

21 Q. HAVE YOU REVIEWED MR. GARNER'S RECOMMENDED
22 PROCEDURE REGARDING THE DISMANTLEMENT OF PRODUCTION
23 ASSETS ON PAGES 26 THROUGH 28 OF HIS DIRECT TESTIMONY?

1 A. Yes.

2

3 Q. WILL YOU ADDRESS ANY PORTION OF THAT PROCEDURE?

4 A. Yes. Mr. Garner's procedure regarding the dismantlement of production
5 assets includes several recommendations, but I only address his final
6 recommendation regarding gains from the future sale or disposition of land
7 at the site of these production assets.

8

9 Q. WHAT IS MR. GARNER PROPOSING IN THAT SECTION OF HIS
10 TESTIMONY?

11 A. Mr. Garner proposes that, in the event that EAI was to sell land after
12 dismantlement of power plants that are now on that land, then customers
13 would receive the benefit of that sale, to the extent it does not exceed the
14 cost of dismantling the generating assets on the site, as a reduction in the
15 dismantlement costs.

16

17 Q. IS THIS AN APPROPRIATE RECOMMENDATION?

18 A. No. There are a variety of reasons why this is not appropriate, particularly
19 at this time. To begin with, the Company does not have any specific plans
20 to dismantle the power plants on the land in question, nor does it have any
21 plans for the sale of that land. It would be premature to determine the
22 regulatory treatment of such a transaction at this time. Furthermore, there
23 is no certainty that a gain would occur from the sale of land. If such a sale

1 was to result in a loss, Mr. Garner does not address whether he supports
2 the inverse result of his recommendation, i.e., that the resulting loss would
3 be recoverable as a component of EAI's cost-of-service study.
4

5 Q. DOES THE USOA ADDRESS THE FOR SALES OF LAND?

6 A. Yes. Electric Plant Instruction 7(e) specifically states that unless land has
7 been included in Plant Held for Future Use, any gain from the disposition
8 of the land is to be accounted for in FERC Account 421.1, an account not
9 considered in the cost-of-service study. I believe this is an appropriate
10 accounting treatment and that gains (or losses) on the disposition of land
11 should not be included in the cost of service absent some unique or
12 special circumstances. Mr. Garner has provided no explanation why it
13 would be reasonable to make this adjustment prior to a sale of the land or
14 why, even if the land were sold at a gain above the dismantling cost, the
15 accounting should be contrary to the USOA, which has been adopted by
16 the APSC.
17

18 Q. WHY DO YOU BELIEVE GAINS AND/OR LOSSES ON THE
19 DISPOSITION OF LAND SHOULD BE EXCLUDED FROM THE COST-
20 OF-SERVICE STUDY?

21 A. The amount included in rate base, and for which customers are paying as
22 part of the cost of EAI's providing them service, is the original cost of the
23 land. A market value that would reflect an unrecognized gain on the land

1 would not be included in rate base. What that means is that the customer
2 is only providing a return on the original cost of the land. All of the risk of
3 the potential future value of the land is borne by the Company's
4 shareholders. If it is appropriate to include the gain in the cost-of-service
5 study if or when it occurs, it would be appropriate to include the unrealized
6 gain in rate base.

7

8 Q. IS THERE VALIDITY TO THE ARGUMENT THAT THE CUSTOMER
9 SHOULD BENEFIT FROM THE GAIN BECAUSE THE GAIN COULD
10 ONLY BE REALIZED IF THE FACILITIES ARE REMOVED FROM THE
11 SITE AND THE COST OF REMOVING THE FACILITIES WAS
12 INCLUDED IN RATES?

13 A. No. It is true that the land is encumbered by the asset on the site. The
14 total cost of the asset (encumbrance) is a component of EAI's cost-of-
15 service over its life span as it is used and useful in providing service to the
16 customer. Because the asset is a depreciable asset, the Company is able
17 to recover the service value³¹ of the asset over its service life. Removal of
18 the asset merely restores the land to its pre- purchased state. If the asset
19 was not on the site, the value of the site would increase or decrease in
20 value due to demand for the site. The removal of the asset restores the

³¹ Per definition 37 of USOA, service value means the difference between original cost and net salvage value of electric plant.

1 status quo and enables the site to achieve the value it would have
2 achieved without the facility ever having been there.

3

4 Q. ARE THERE ANY OTHER MATTERS RELATED TO DISMANTLEMENT
5 THAT YOU WISH TO ADDRESS?

6 A. Yes. Mr. Selecky makes a proposal that is similar, but more egregious, to
7 that of Mr. Garner.

8

9 Q. WHAT IS MR. SELECKY'S PROPOSAL?

10 A. Mr. Selecky proposes that the Company should not be allowed to recover
11 the cost to dismantle its generating assets regardless of whether the land
12 is ever sold. In fact, Mr. Selecky proposes that the Company's
13 dismantlement cost should be reduced by 30 percent to recognize the
14 potential future gain on the disposition of the land at the production sites.
15 Below, I address the regulatory reasons why it is inappropriate to reduce
16 the dismantlement costs. Company witness Patricia Cartwright addresses
17 the value of the land at the sites in her rebuttal testimony.

18

19 Q. IS IT APPROPRIATE TO REDUCE THE DISMANTLEMENT FOR
20 INCREASES IN THE VALUE OF THE LAND IN ADVANCE OF AN
21 ACTUAL SALE OF THE LAND?

22 A. No. In my opinion, it is never appropriate to include the market value of
23 land, whether greater than or less than the original cost, in the

1 determination of recoverable cost. The Company is entitled to a return on
2 the original cost of land dedicated to providing service to its customers as
3 a component of rates. No more, no less. The Company is also entitled to
4 recover the service value of depreciable assets dedicated to providing
5 service to its customers as a component of rates. If the unrecognized
6 potential gain or loss in the value of the land is included in the calculation
7 of service value, which it is not under the USOA, then the Company
8 should be entitled to include that potential gain in rate base. Furthermore,
9 if the value of the land has declined below original cost, the Company
10 should be entitled to add that loss to the cost of dismantlement and to
11 recover that cost from customers. Recognition of future gains or losses on
12 real property is not appropriate for ratemaking purposes.

13
14 **VIII. ENTERGY TECHNOLOGY COMPANY**

15 Q. PLEASE COMMENT ON STAFF WITNESS LATOYA JOHNSON'S
16 ADJUSTMENT IS-9, IMPUTED REVENUE FROM ENTERGY
17 TECHNOLOGY COMPANY ("ETC").³²

18 A. EAI has complied with the Commission's Order No. 7 in Docket
19 No. 96-198-U to impute revenues in ratemaking proceedings based on the
20 stipulated investment in fiber optics network equipment, the accumulation
21 of depreciation expense, and the use of the most recent, allowed before-
22 tax-rate of return. This approach was used in EAI's base rate proceedings

³² Johnson Direct Testimony at 7.

1 in Docket Nos. 96-360-U and 06-101-U without objection from any party.
2 Staff now recommends updating the depreciation rate and the before-tax-
3 rate of return to the rates recommended by Staff in the instant proceeding
4 before these rates have been approved by the Commission. The Staff's
5 proposed adjustment reflects a new interpretation of Order No. 7 in Docket
6 No. 96-198-U.

7
8 Q. WHAT WOULD BE THE IMPACT OF THE CALCULATION OF THE
9 REVENUE IF STAFF'S REVISED METHOD IS ADOPTED?

10 A. Staff's proposed method for calculating the ETC adjustment would
11 increase depreciation expense, which would accelerate the decline in net
12 plant investment of the fiber optics equipment. When the net plant amount
13 reaches \$0, EAI would stop imputing revenue from the stipulated
14 investment amount.

15
16 Q. DOES EAI FAVOR ONE APPROACH OR THE OTHER?

17 A. No. EAI's approach is consistent with past regulatory decisions and
18 produces an imputed revenue amount of \$226,677. The amount of the
19 adjustment under Staff's interpretation cannot be quantified until a
20 depreciation rate and a before-tax rate of return on rate base are ordered
21 in this proceeding.

22

1 **IX. PAYROLL ADJUSTMENTS**

2 Q. HAVE YOU REVIEWED STAFF WITNESS BILL TAYLOR'S PAYROLL
3 ADJUSTMENT?

4 A. Yes. I have reviewed Mr. Taylor's payroll adjustment and note that he
5 makes the following adjustments to the Company's payroll adjustment with
6 which I disagree:

- 7 • Adjustment of employee headcount through May 2013,
- 8 • Adjustment of test year O&M payroll to remove actual test year
9 wages for employees at the Hot Spring Plant,
- 10 • Addition of a separate adjustment to the payroll adjustment to
11 remove actual test year wages for employees at the Hot Spring
12 Plant,
- 13 • Adjustment of the Company's O&M expense ratio associated
14 with payroll, and
- 15 • Use of a five-year average for test year O&M payroll expense.

16
17 Q. CAN YOU PROVIDE A BRIEF DESCRIPTION OF THE MECHANICS OF
18 THE PAYROLL ADJUSTMENT?

19 A. Yes. The O&M payroll adjustment annualizes wage and benefit expenses
20 for known and measurable changes due to wage increases and changes
21 in employee levels. The calculation associated with the change in
22 employee levels is based on the monthly increase or decrease in
23 headcount that occurs during the test year. Staff typically updates this

1 calculation using headcount data through the latest month available before
2 it files testimony.

3

4 Q. PLEASE ADDRESS MR. TAYLOR'S ADJUSTMENT TO EMPLOYEE
5 HEADCOUNT THROUGH MAY 2013.

6 A. As indicated above, Staff typically updates the Company's payroll
7 adjustment to reflect headcount using the most up to date data available,
8 which in this case was through May 2013. However, because of the
9 Company's HCM initiative and the additional pro forma adjustment which
10 the Company is proposing related to this initiative, an update to reflect
11 employee headcount changes which have occurred in 2013 is not
12 appropriate. This proposed HCM adjustment is based on headcounts as
13 of December 31, 2012. The impacts of any headcount changes which
14 occur after December 31, 2012 are reflected in this additional adjustment
15 for the HCM initiative, so it would be inappropriate to update the
16 Company's payroll adjustment to reflect headcount changes which
17 occurred in 2013 because that impact is being captured in the HCM
18 adjustment.

19

20 Q. PLEASE ADDRESS MR. TAYLOR'S ADJUSTMENT TO REMOVE
21 EMPLOYEES AT THE HOT SPRING PLANT.

22 A. The payroll costs associated with the employees at the Hot Spring Plant
23 are included in Staff adjustment IS-18, which recognizes the estimated

1 annual costs associated with the operation of the Hot Spring Plant. The
2 increase in headcount associated with these employees was also included
3 in the payroll adjustment. Mr. Taylor appropriately removes the
4 associated headcount from the payroll adjustment. However, he
5 inadvertently removes this same payroll expense a second time by
6 calculating a separate adjustment associated with these employees and
7 subtracting it from his calculated payroll adjustment that has already been
8 reduced based on headcount.

9

10 Q. IS MR. TAYLOR'S CALCULATION OF THE COMPANY'S O&M
11 EXPENSE RATIO USED IN THE PAYROLL ADJUSTMENT
12 REASONABLE?

13 A. No. The O&M allocation percentages used by Mr. Taylor to allocate
14 payroll costs between O&M and Capital are inappropriate. Mr. Taylor
15 used EAI's response to Staff data request 2-6 to calculate his five-year
16 average percentages and EAI's response to Staff data request 35-1 for his
17 test year O&M percentages. However, it is more appropriate for Mr.
18 Taylor to update his calculation of test year O&M percentages using the
19 payroll amount that was supplied to him in the updated response to Staff
20 data request 35-1. Mr. Taylor has also adjusted the O&M allocation
21 percentages in the headcount change section of the payroll adjustment to
22 reflect the use of a five-year average. The payroll adjustment is designed
23 to begin with test year O&M payroll and adjust for monthly headcount

1 changes and wage increases so that O&M expense appropriately reflects
2 payroll expense based on these known and measurable changes. An
3 additional adjustment to these percentages based on a five-year average
4 is inconsistent with the calculations that were used in rates set in Docket
5 Nos. 09-084-U and 06-101-U.

6

7 Q. PLEASE ADDRESS MR. TAYLOR'S USE OF A FIVE-YEAR AVERAGE
8 TO CALCULATE O&M PAYROLL EXPENSE.

9 A. Mr. Taylor calculates a five-year average O&M payroll expense that is
10 used in the wage increase section of his proposed payroll adjustment. His
11 starting point for the EAI direct calculation is the test year O&M expense.
12 He then removes wages of the Hot Spring Plant employees from his test
13 year O&M expense. The test year O&M expense number he starts with
14 does not include the Hot Spring Plant employee costs, so it is incorrect to
15 remove them again as he does in this calculation. The payroll adjustment
16 is designed to annualize test year O&M payroll expenses based on known
17 and measurable changes. An additional adjustment to normalize the
18 Company's O&M payroll and allocation percentage based on a five-year
19 average is inconsistent with the calculations that were used in Docket
20 Nos. 09-084-U and 06-101-U and with the use of actual headcounts
21 instead of five-year averages. Mr. Taylor's additional adjustments to
22 normalize the payroll based on five-year averages is unsupported and
23 inappropriate because, as with the headcount, the starting point for all

1 calculations should be the latest available information adjusted for known
2 and measurable changes.

3

4 Q. IS HHEG WITNESS GARRETT'S RECOMMENDATION TO REVERSE
5 THE COMPANY'S PRO FORMA PAYROLL ADJUSTMENT
6 REASONABLE?

7 A. No. Mr. Garrett's recommendation to make no adjustment is
8 unreasonable because it does not factor in any changes which occur
9 during the test year or pro forma period. As I explained above, the
10 Company's payroll adjustment is designed to annualize wage and benefit
11 expenses for known and measurable changes due to wage increases and
12 changes in employee levels as of the end of the test year. The Company
13 is also making an HCM adjustment to encompass reductions in the
14 workforce level that will occur during the pro forma period. Mr. Garrett's
15 proposed payroll adjustment does not consider the adjustments already
16 made by EAI and is therefore not reasonable.

17

18 X. **MUTUAL ASSISTANCE AND LOANED LABOR**

19 Q. CAN YOU BRIEFLY DESCRIBE THE COMPANY'S MUTUAL
20 ASSISTANCE AND LOANED LABOR PROCESSES?

21 A. Mutual assistance networks are voluntary partnerships of electric utilities
22 that are committed to helping restore power whenever and wherever
23 assistance is needed. Electric utilities impacted by a major outage event

1 are able to increase the size of their workforce by borrowing crews from
2 other utilities. When called upon, a utility will send skilled line workers to
3 help with the restoration efforts of a fellow utility. EAI is a member of three
4 Regional Mutual Assistance Organizations and accordingly, the Company
5 is called on to provide restoration support to other member utilities. When
6 EAI is called on to provide restoration support, the costs (including payroll)
7 associated with providing this restoration support is billed to the utility
8 requesting support and the costs and reimbursements are recorded in
9 account 174 and are not included in the Company's O&M expense.

10 The loaned labor process functions in a manner that is somewhat
11 similar to a mutual assistance network. Under the loaned labor process
12 the Entergy Operating Companies are able to "loan" resources between
13 Operating Companies. When a loaning of resources occurs, an employee
14 charges his time such that it is billed to the appropriate Operating
15 Company that is using the loaned resource. For example, when an EAI
16 lineman is called on to provide restoration support to Entergy Mississippi,
17 Inc. ("EMI") during a hurricane, the lineman charges his time to an
18 appropriate code so that his expenses (including payroll) are appropriately
19 billed to EMI and the costs and reimbursements are recorded in account
20 174 and are not included in EAI's O&M expense.

21

22 Q. DOES EAI PARTICIPATE IN THE MUTUAL ASSISTANCE AND
23 LOANED LABOR PROCESS?

1 A. Yes. EAI participates in both the mutual assistance program and the
2 loaned labor program on a regular basis. The number of individuals and
3 amount of time involved in providing this support are typically limited and
4 short in duration. The costs associated with providing this type of
5 assistance occurs annually, and because these costs and reimbursements
6 are recorded in account 174, they are not included in EAI's O&M expense.

7 Occasionally catastrophic events take place, which require the
8 Company to send numerous crews for extended periods of time to support
9 the restoration efforts. Unfortunately, during the last six months of 2012,
10 there were three catastrophic events (Hurricanes Isaac and Sandy and
11 wind storms in Kentucky and West Virginia) where EAI was called on to
12 provide numerous crews for extended periods of time in support of the
13 restoration efforts for these events. These catastrophic type events are
14 unusual and non-recurring in nature. EAI is not typically called on to
15 provide this type of restoration support. The loaded straight time payroll
16 cost associated with supporting these efforts was approximately \$1.9
17 million and would normally have been included in EAI's O&M expense.

18

19 Q. ARE THE PAYROLL COSTS ASSOCIATED WITH EAI'S
20 PARTICIPATION IN THE MUTUAL ASSISTANCE AND LOANED
21 LABOR PROCESS INCLUDED IN EAI'S TEST YEAR O&M EXPENSES?

1 A. No. As stated above these costs are charged to account 174 and billed to
2 the utility requesting assistance and are not included in EAI's O&M
3 expense.

4

5 Q. DID EAI MAKE A PROFORMA ADJUSTMENT TO PUT BACK INTO O&M
6 EXPENSE THE COSTS ASSOCIATED WITH PROVIDING MUTUAL
7 ASSISTANCE AND LOANED LABOR?

8 A. The Company did not make an adjustment to include labor costs billed to
9 other utilities under these processes which are associated with non-
10 catastrophic type events which occurred in 2012. These type of billings
11 associated with non-catastrophic events are normal and recurring and the
12 associated payroll expense should not be included in O&M expense.

13 The Company did include an adjustment to its O&M expense to add
14 back the \$1.9 million of loaded payroll costs associated with the
15 catastrophic storms discussed above. These types of storms are atypical.
16 Mr. Taylor agrees that this adjustment is appropriate and added back
17 these same costs in his payroll adjustment.

18

19 Q. HAVE YOU REVIEWED MR. TAYLORS ADJUSTMENT IS-34 TO
20 REMOVE MUTUAL ASSISTANCE AND LOANED LABOR?

21 A. Yes. Mr. Taylor is proposing to make an additional adjustment to remove
22 mutual assistance and loaned labor costs from O&M expense that are not
23 included in O&M expense. As I discussed above, the Company's O&M

expense does not include the costs associated with providing mutual assistance and loaned labor. The Company has added back to O&M expense only the costs associated with catastrophic events (\$1.9 million) which Mr. Taylor agrees is appropriate. The Company's O&M cost does not include approximately \$3 million in costs associated with non-catastrophic events. However, Mr. Taylor is now proposing to remove what he deems to be a normalized level of loaned labor and mutual assistance costs despite the fact that the Company's O&M costs are already reduced by \$3 million because the Company's O&M expense does not include these costs billed to other utilities for non-catastrophic events. If Mr. Taylor wants to normalize all mutual assistance and loaned labor costs using a five-year average then he must add back all of the mutual assistance and loaned labor costs that were not included in test year O&M expense. The net impact of adding back total test year mutual assistance and loaned labor costs reduced by the five-year normalized amount is a reduction of \$561,892 to the Company's original proposed adjustment as shown in Table 4 below.

Table 4
EAI Mutual Assistance/Loaned Labor Adjustment IS-16

Total Mutual Assistance and Loaned Labor costs during 2012	4,909,171
Less 5 year average Mutual Assistance and Loaned Labor costs	(3,563,633)
Net increase to test year O&M costs	1,345,537
Mutual Assistance and Loaned Labor added in adjustment IS-16	1,907,429
Net decrease	(561,892)

1

2 Q. WHAT IS YOUR RECOMMENDATION REGARDING MR. TAYLOR'S
3 PROPOSED ADJUSTMENT?

4 A. If Mr. Taylor's adjustment to normalize mutual assistance and loaned labor
5 costs is accepted, then his original adjustment to increase O&M costs by
6 \$1,907,429 should be reduced by \$561,892. This results in a net increase
7 to the Company O&M payroll expense of \$1,345,537 for mutual
8 assistance and loaned labor costs.

9

10 Q. MR. MARCUS RECOMMENDS TO EITHER REVERSE THE
11 COMPANY'S MUTUAL ASSISTANCE AND LOANED LABOR
12 ADJUSTMENT OR TO ANNUALIZE IT. PLEASE RESPOND.

13 A. I have addressed Mr. Marcus's concerns about the Company's mutual
14 assistance and loaned labor adjustment above. I have demonstrated that
15 the Company did not add back all of its loaned labor and mutual
16 assistance costs to test year O&M expense. If mutual assistance costs
17 are normalized, I have calculated the appropriate amount associated with
18 this alternative based on a historical five-year time period as described
19 above.

20

1 **XI. REVENUES FROM WHOLESALE BASE LOAD UNITS**

2 Q. PLEASE COMMENT ON STAFF WITNESS BUTLER'S
3 RECOMMENDATION REGARDING THE TREATMENT OF COSTS
4 ASSOCIATED WITH THE WBL GENERATING UNITS?

5 A. Company witness David Hunt addresses Ms. Butler's recommendation
6 and states the Company's position regarding this treatment. I note that
7 should the Commission accept the Company's original "revenue credit
8 method" (as described by Mr. Hunt), then this revenue credit amount
9 should be reduced by \$25,773 as indicated in the response to Staff 83-3.
10 The original total Company revenue credit was \$35,858,005 that amount
11 should have been \$35,832,232.

12
13 **XII. RETIRED PLANTS O&M**

14 Q. IS MS. LINDHOLM'S ADJUSTMENT IS-33 TO REMOVE \$4,326,518 OF
15 O&M EXPENSE ASSOCIATED WITH PLANT UNITS THAT THE
16 COMPANY IS RETIRING REASONABLE?

17 A. I agree it is reasonable to make an adjustment needs to be made to
18 remove costs that will no longer exist once these plants are retired.
19 However, there are several issues that have to be considered in making
20 this adjustment. First, until these plants are dismantled, the Company will
21 continue to incur some level of O&M costs in maintaining the plant sites.
22 Company witness Kurtis Castleberry describes in his rebuttal testimony
23 that the appropriate level of ongoing O&M costs is \$607,596. Second, as I

noted in earlier discussions regarding payroll and HCM, the Company is making an adjustment which contemplates the ongoing payroll levels including the payroll charged to these plants during the test year. Third, as Ms. Lindholm has done, the analysis to calculate this adjustment must start with the direct O&M costs associated with the plants being retired. Therefore, the adjustment to eliminate O&M costs associated with retired plants should be \$2,287,550 as shown in Table 5.

Table 5
Retired Plants O&M Adjustment

Staff IS-33 Adjustment Reduction to Expense	\$ 4,326,518
Less Labor Costs Included in IS-33*	1,431,372
Less Retired Plant Units On-Going Expenses**	607,596
Net IS-33 Adjustment to Expense	\$ 2,287,550
* Labor adjustments encompassed in Company's proposed HCM adjustment.	
** Addressed in Mr. Kurtis Castleberry's rebuttal testimony.	

Q. DO YOU AGREE WITH MR. MARCUS' ADJUSTMENT RELATED TO RETIRED PLANTS?

A. No. As explained above, I agree that an adjustment needs to be made, but disagree with the costs Mr. Marcus utilized to make his adjustments. Mr. Marcus makes his recommendation based on 2012 FERC Form 1 data for each plant.

Q. WHY IS IT NOT APPROPRIATE TO START WITH FORM 1 COST DATA?

1 A. Form 1 data is total plant data which includes payroll costs. As discussed
2 above and in other sections of my testimony the Company's HCM
3 adjustment is already adjusting all test year payroll costs to the
4 appropriate level. The Form 1 plant costs data also includes an allocation
5 of Fossil Operations support costs (which also includes payroll). Fossil
6 Operations support costs will not be going away because a plant is being
7 retired. And again, as I have previously indicated the HCM adjustment is
8 encompassing all payroll related adjustments. The reduction associated
9 with retired plants should be determined by analyzing direct O&M costs
10 related to the plants being retired as was done by Ms. Lindholm.

11
12 **A. Lake Catherine 4**

13 Q. IS MR. HILTON'S RECOMMENDATION RELATED TO THE RELIABILITY
14 SUSTAINABILITY PROJECT AT LAKE CATHERINE UNIT 4
15 REASONABLE?³³

16 A. Yes. I agree that Mr. Hilton's recommendation to approve a regulatory
17 asset associated with the Lake Catherine Unit 4 reliability sustainability
18 project is reasonable.

19
20 Q. DO YOU AGREE WITH MR. MARCUS RECOMMENDATION RELATED
21 TO THE RELIABILITY SUSTAINABILITY PROJECT AT LAKE
22 CATHERINE UNIT 4?

³³ Hilton Direct Testimony at 11-12.

1 A. No. Mr. Marcus recommends against approval of a regulatory asset
2 associated with the Lake Catherine Unit 4 reliability sustainability project.³⁴
3 Mr. Castleberry explains in his rebuttal testimony that Mr. Marcus makes
4 unsupported statements about the future level of spending at Lake
5 Catherine 4. Mr. Marcus also make erroneous conclusions about the level
6 of costs associated with retired or retiring plants because he utilizes FERC
7 Form 1 data for O&M expenses which is inappropriate to determine the
8 direct costs associated with each power plant as I explained above. Thus
9 the premise for Mr. Marcus' recommendation is incorrect and should be
10 rejected.

11

12 **B. Ouachita Plant Transmission**

13 Q. DO YOU AGREE WITH MS. LINDHOLM'S RECOMMENDATION
14 RELATED TO THE OUACHITA TRANSMISSION UPGRADE COST?

15 A. Yes. Ms. Lindholm's adjustment correctly updates this cost to reflect the
16 amount of expected expense based on latest available data.³⁵

17

18 **XIII. CAPITAL ADDITIONS**

19 Q. PLEASE DESCRIBE STAFF WITNESS WILLIAM MATTHEWS'
20 METHODOLOGY FOR DETERMINING PROJECTED PLANT
21 ADDITIONS.

³⁴ Marcus Direct Testimony at 66.

³⁵ Linholm Direct Testimony at 5-6.

1 A. Mr. Matthews identifies a number of projects that could be traced to the
2 Company's original Application amount and the Company's original
3 estimate. He then reviews each of these 96 projects to determine the
4 level of completion and recent construction activity as of April 30, 2013
5 and allowed projected additions of \$120,819,618 related to such projects.
6 For blanket projects, Mr. Matthews includes a projected amount of
7 \$50,548,912 based on the average of 2012 blanket closings for the
8 number of months remaining in the test year. He also includes
9 \$29,400,000 related to software and additional hardware related to the
10 transition to MISO. The final component of Mr. Matthews estimate is
11 actual gross additions for January through April 2013 of \$101,264,801,
12 resulting in a total plant addition of \$302,033,331.³⁶

13
14 Q. DOES MR. MATTHEW'S METHODOLOGY PROUDCE A REASONABLE
15 RESULT?

16 A. No. Mr. Matthews' methodology excludes from consideration a large
17 number of projects for which project level detail is not included in the
18 Company's original \$408 million plant additions estimate. The Company
19 budgets expenditures at a higher level than detailed projects, and
20 therefore a lower level of detail is not available to provide. Except for
21 blanket closing, Mr. Matthews has essentially allowed zero dollars in
22 additions for these types of projects.

³⁶ Matthews Direct Testimony at 5-7.

1 For example, Mr. Matthews only reviewed 96 specific projects while
2 EAI has over 600 projects with open CWIP balances as of the end of July
3 2013. EAI projected \$408 million of capital additions and Mr. Matthews'
4 methodology does not pick up a large number of the projects with open
5 CWIP balances. This problem with Mr. Matthews' methodology gets
6 smaller as more actual additions are included for 2013 in subsequent
7 updates, but even then the problem of not picking up all open CWIP
8 balances that will close by the end of 2013 is not completely resolved.
9 This is because for those projects where the lower level of detail was not
10 available and not specifically identified in EAI's Application, only actual
11 dollars closed through the current period are picked up and allowed as a
12 component of rate base.

13
14 Q. WHAT DO YOU PROPOSE IN ORDER TO IMPROVE ON MR.
15 MATTHEWS' METHODOLOGY?

16 A. Mr. Matthew's methodology should be updated through the latest available
17 additions (currently July 2013) and be expanded to include analysis of
18 current open projects. I have calculated that additions would be
19 \$384,238,164 utilizing Mr. Matthew's methodology updated through July
20 2013 actual plant closings and including current open projects expected to
21 be in service by the end of 2013 (inclusion of projects not specifically
22 identified in the Application). Even with the inclusion of the current open
23 projects expected to close by the end of 2013, the \$384 million estimate is

1 a conservative estimate. This estimate excludes those projects started
2 after July 2013 but expected to be completed by the end of 2013. EAI
3 Exhibit GRZ-3 provides details of the Company's updated capital
4 additions.

5

6 Q. IS HHEG WITNESS LARRY BLANK'S RECOMMENDATION TO
7 DISALLOW COSTS ASSOCIATED WITH THE DEVELOPMENT OF THE
8 COMPANY'S REVENUE REQUIREMENT MODEL REASONABLE?

9 A. No, Mr. Blank's recommendation is unfounded. Company witness David
10 Hunt addresses Mr. Blank's concerns in his rebuttal testimony.

11

12 **XIV. FORECASTED DATA**

13 Q. STAFF WITNESS ROBERT SWAIM'S METHODOLOGY FOR
14 CALCULATING PRESENT RATE REVENUES INCLUDES USING A
15 FORECAST TO PROJECT THESE REVENUES FOR 2013 BASED
16 UPON DATA FROM 2012. DID THE COMPANY USE A 2013
17 FORECASTED TEST YEAR TO DEVELOP ITS REVENUE
18 REQUIREMENT?

19 A. No, the Company utilized a forward-looking test period that ended
20 December 31, 2012. This period consisted of six months actual historical
21 data ended June 30, 2012 and six months projected data for the six
22 months ended December 31, 2012. The test period information was
23 updated to reflect 12 months actual historical data. The test year data

1 was adjusted only for changes that were reasonably known and
2 measurable at the time it filed its case.

3
4 Q. CAN THE COMPANY UPDATE ITS CASE TO REFLECT THE USE OF
5 FORECASTED 2013 DATA?

6 A. No. The Company would need to start over entirely and use a test year
7 based on 2013 forecasted data to fully recognize the implications
8 associated with using a forecasted test year. Based on the current APSC
9 Rules of Practice and Procedure, as described in my direct testimony, this
10 is not allowable.

11

12 **XV. SHORT-TERM DEBT**

13 **A. Staff's Recommendation**

14 Q. WHAT LEVEL OF SHORT-TERM DEBT HAS STAFF WITNESS ROBERT
15 DANIEL RECOMMENDED IN HIS DIRECT TESTIMONY?

16 A. Mr. Daniel recommends including \$70,562,407 of short-term debt in EAI's
17 weighted cost of capital calculation at a cost rate of 1.68 percent. The
18 recommended balance is comprised of and \$55,250,000 of short-term
19 loans from EAI's credit facilities at a 2.10 percent cost rate and an
20 additional \$15,312,407 reflecting a daily average balance for 2012 of EAI's
21 borrowing from the Money Pool at a 0.16 percent cost rate.³⁷

22

³⁷ Daniel Direct Testimony, Exhibit RD-7.

1 Q. MR. DANIEL CITED A NEED FOR ADDITIONAL INFORMATION ON
2 THE COMPANIES' POSITION NOT TO REFLECT SHORT-TERM DEBT
3 IN THE COST OF CAPITAL CALCULATION.³⁸ CAN YOU ELABORATE
4 ON THE COMPANY'S POSITION?

5 A. Yes. The following sections explain why it is appropriate to exclude short-
6 term debt from the cost of capital calculation. I describe the purpose for
7 which the Company obtained those financial tools, demonstrate why the
8 Company's usage has not been indicative of permanent financing, and
9 quantify how inclusion of short-term debt in the capital structure penalizes
10 the Company.

11

12 **B. Credit Facilities**

13 Q. WHAT CREDIT FACILITIES DOES EAI HAVE AVAILABLE?

14 A. EAI has two credit facilities available currently: a \$20 million credit facility
15 with a current cost rate of 1.78 percent that expires in April 2014 and a
16 \$150 million credit facility with a current cost rate of 1.70 percent that
17 expires in March 2018.³⁹ The \$20 million credit facility is provided by a
18 local bank and is typically renegotiated each year. The \$150 million credit
19 facility is provided by a group of national and international banks and has
20 a five-year term expiring in March 2018. Because the \$150 million credit

³⁸ *Id.* at 15.

³⁹ Entergy Corporation 10-Q for the Quarterly Period Ended June 30, 2013 at 45 (August 7, 2013).

1 facility has a term longer than one year, authorization to enter into this
2 agreement was last obtained in Order No. 2 of Docket No. 12-059-U.⁴⁰
3

4 Q. WHY DID EAI ARRANGE THESE CREDIT FACILITIES?

5 A. EAI arranges bank credit facilities to meet unique liquidity, working capital,
6 and short-term financing situations.⁴¹ The credit facilities provide the
7 Company with the financial flexibility⁴² to meet short-term needs at known
8 and reasonable terms rather than having to secure short-term financing on
9 an ad hoc basis. The Company's experience with the costs of major
10 storm restoration, plant acquisitions, and similar events merits the need for
11 having a readily available source of short-term financing. The Company
12 also has a need for such credit facilities as it becomes a member of MISO.
13 I discuss this new need later in my testimony.
14

15 Q. DOES EAI USE THESE CREDIT FACILITIES AS AN ONGOING PART
16 OF ITS PERMANENT FINANCING?

17 A. No. The Company's goal is to maintain access to the credit facilities for
18 those events where the funds may be needed for a relatively short period
19 of time.
20

⁴⁰ A description of the credit facility was provided on pages 10-11 in the Direct Testimony of Steven C. McNeal in Docket No. 11-090-U.

⁴¹ *Id.* at 10.

⁴² Company witness Jay A. Lewis provides an overview of overall financial flexibility in his Direct Testimony at 8-10.

1 Q. HOW HAS EAI USED THESE CREDIT FACILITIES RECENTLY?

2 A. EAI has used the credit facilities recently to meet credit facility
3 requirements and bridge the financing of major corporate events until
4 long-term financing was obtained. Between January 1, 2012 and July 31,
5 2013, EAI accessed its credit facilities four times for very short periods as
6 shown in Table 6 below.

7 **Table 6**
8 **EAI Credit Facility Utilization⁴³**
9

Credit Facility	Loan Amount (Millions of \$)	Loan Date	Loan Payment Date	Number of Days Outstanding
Local ⁴⁴	50	1/31/12	2/8/12	8
National	1	3/12/12	3/13/12	1
National	150	11/29/12	12/18/12	19
Local	20	11/29/12	12/14/12	15

10 The total interest expense paid for all four uses of the credit facilities was
11 \$187,334.
12

13 Q. WHAT WAS THE PURPOSE FOR THE EACH LOAN PRESENTED
14 ABOVE?

15 A. The \$50 million loan was in support of a payment that was made in early
16 2012 where EAI was required to pay \$156 million in a lump sum to other
17 Entergy Operating Companies as a result of a FERC decision in Docket

⁴³ From EAI's response to Staff 70-1, Addendum 1.

⁴⁴ EAI's previous one year local credit facility that expired in April 2012 had a maximum borrowing capacity of \$78 million compared to \$20 million on the current local credit facility.

1 No. EL-01-88.⁴⁵ The \$1 million 1 day loan was made to satisfy the
2 representations in the loan agreement that only needed to be satisfied for
3 the initial draw under the credit facility (the national credit facility was put
4 in place on March 9, 2012). The full amount of both credit facilities was
5 drawn for several days in late November and early December 2012 to
6 facilitate the acquisition of the Hot Spring Plant until the Company could
7 issue long-term debt. The Company subsequently issued \$200 million of
8 first mortgage bonds in December 2012 and the credit facilities were
9 repaid.

10

11 Q. DOES EAI ANTICIPATE A NEW USE OF THE \$150 MILLION CREDIT
12 FACILITY AS PART OF JOINING MISO?

13 A. Yes. MISO requires market participants to provide collateral to ensure
14 creditworthiness in satisfying market settlements. The current estimate for
15 EAI's collateral is \$23 million. This requirement may be satisfied by
16 making a cash deposit or providing a letter of credit in the required
17 amount. In lieu of making a cash deposit, EAI will provide a letter of credit
18 under its \$150 million credit facility and has included the letter of credit fee
19 as part of the MISO pro forma adjustment (AJ24).⁴⁶ The Company

⁴⁵ See the February 15, 2012 direct testimonies of Steven K. Strickland and Phillip B. Gillam in Docket No. 09-084-U regarding this additional payment and its subsequent inclusion in Rider PCA.

⁴⁶ The letter of credit fee based on the current estimate is \$339,250 (\$23,000,000 x 1.475 percent). The new estimate is a slight reduction from the \$480,000 fee included in the Company's original filing.

1 expects to provide \$12 million of the letter of credit in September 2013
2 with the remaining \$11 million provided in December 2013.
3

4 Q. HOW LONG WILL THE COMPANY BE REQUIRED TO MAINTAIN THE
5 \$23 MILLION LETTER OF CREDIT RELATED TO MISO OPERATIONS?

6 A. The Company expects to be required to maintain the \$23 million letter of
7 credit for the foreseeable future and, based on its interpretation of MISO
8 requirements, will always need to provide collateral to operate in MISO.
9 The amount of collateral will be evaluated after EAI gains experience in
10 the MISO markets and then be adjusted accordingly.
11

12 Q. WHAT CONSEQUENCES DOES ISSUING THE LETTER OF CREDIT
13 HAVE UPON THE \$150 MILLION CREDIT FACILITY?

14 A. By providing the \$23 million letter of credit, EAI will be limited to accessing
15 the remaining \$127 million of the credit facility for other corporate
16 purposes.
17

18 Q. IS MR. DANIEL'S RECOMMENDATION TO INCLUDE \$55.25 MILLION
19 OF THE \$170 MILLION AVAILABLE TO EAI FROM ITS CURRENT
20 CREDIT FACILITIES APPROPRIATE?

21 A. No. Mr. Daniel's recommendation to include \$55.25 million of EAI's credit
22 facilities as a short-term debt component of the capital structure is not
23 appropriate because:

- 1 • it is not reflective of EAI's purpose for obtaining the credit
- 2 facilities;
- 3 • it is not indicative of EAI's actual use of its credit facilities; and
- 4 • it is not supportive of EAI's need to issue a letter of credit to
- 5 participate in MISO.

6

7 Q. IF THE COMMISSION ACCEPTS MR. DANIEL'S RECOMMENDATION

8 TO INCLUDE A PORTION OF THE CREDIT FACILITIES AS SHORT-

9 TERM DEBT, DO YOU HAVE ANY RECOMMENDATIONS ON HOW

10 THAT AMOUNT SHOULD BE CALCULATED?

11 A. Yes. If a portion of the credit facilities is required to be included as short-

12 term debt in the cost of capital, that portion should be based on EAI's

13 actual use of its credit facilities. Staff Direct Exhibit RD-7 reflects a test

14 year average of \$55,250,000 calculated by taking the loan amounts from

15 the test year, totaling them, and dividing by four. This method does not

16 take into account the limited time periods the loans were utilized. By

17 taking into account the number of days the loans were outstanding during

18 the test year, the updated cost rates, and the limitation that the MISO

19 letter of credit places on the national credit facility, the amount of short-

20 term debt associated with credit facilities to include in the cost of capital

21 would be \$8.5 million with a weighted average cost rate of 1.72 percent.

22 The calculation is provided in EAI Exhibit GRZ-4.

23

1 **C. Money Pool**

2 Q. WHAT IS THE MONEY POOL?

3 A. The Money Pool is a FERC-approved inter-company borrowing
4 arrangement designed to reduce Entergy Corporation's utility subsidiaries'
5 dependence on external short-term borrowings subject to a cap on overall
6 short-term borrowings.⁴⁷ Any funds lent to or borrowed from the Money
7 Pool had a daily interest rate that ranged from 0.02 percent to 0.20
8 percent between January 1, 2012 and July 31, 2013.

9 In many ways, the Money Pool is like a money market account
10 where cash may be held and earn interest until it is needed. The
11 additional flexibility of the Money Pool is that the participant may also
12 borrow funds from this same account.

13

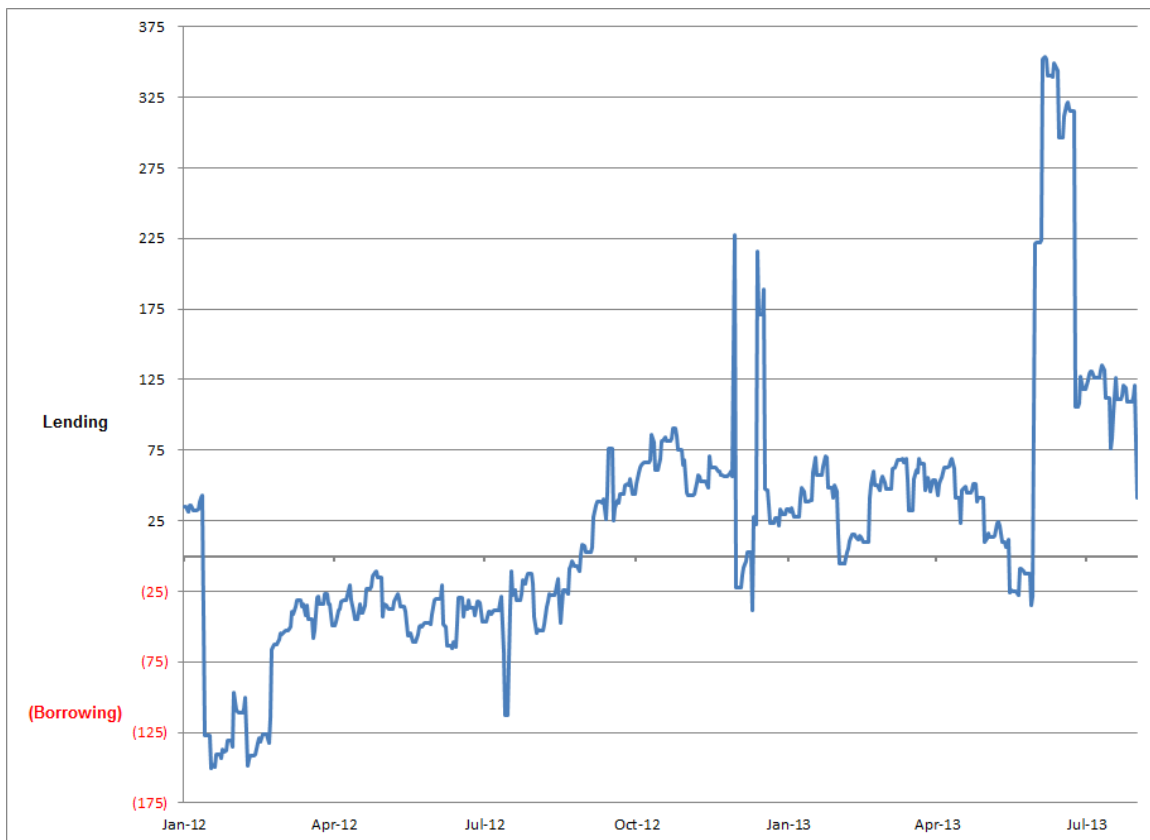
14 Q. DOES EAI ACTIVELY PARTICIPATE IN THE MONEY POOL?

15 A. Yes. EAI changes its position in the Money Pool almost every business
16 day due to its cash needs. Figure 1 below reflects the range of EAI's
17 position in the Money Pool from January 1, 2012 through July 31, 2013.

18

⁴⁷ Entergy Arkansas, Inc. 2012 FERC Form 1, Page 123.25.

Figure 1
Entergy Arkansas, Inc.
Money Pool Balance
Millions of \$
January 2012 – July 2013



Q. PLEASE EXPLAIN SOME OF THE PEAKS AND VALLEYS REFLECTED
 IN FIGURE 1 ABOVE.

A. As I described earlier, EAI was required to pay \$156 million in a lump sum
 to other Entergy Operating Companies in January 2012 as a result of a
 FERC decision in Docket No. EL-01-88.⁴⁸ As this payment occurred in a

⁴⁸ See Docket No. 09-084-U, Order No. 24 (March 28, 2012), authorizing this additional payment to be included in Rider PCA.

1 low revenue period, a short-term borrowing was necessary. Because EAI
2 is leaving the System Agreement in December 2013, this type of payment
3 is not expected in the future.

4 The Company gradually reversed this borrowing position to a
5 moderate lending position by the third quarter of 2012. The Money Pool
6 activity in late 2012 reflected the financing activities necessary to complete
7 the Hot Spring Plant acquisition and subsequent first mortgage bond debt
8 financing. The extended period of lending to the Money Pool reflected the
9 uncertainty of when the final approval for the Hot Spring Plant acquisition
10 would be received.⁴⁹ As discussed in the credit facilities section above,
11 the credit facilities were fully drawn down the day before the acquisition
12 with the proceeds placed in the Money Pool awaiting a transfer of cash on
13 November 30, 2012, for ultimate payment to the seller. Approximately
14 \$200 million in proceeds from the sale of first mortgage bonds in
15 December 2012 were briefly deposited in the Money Pool with \$170
16 million of the proceeds used to fully repay the credit facilities shortly after
17 the placement of the bonds.

18 EAI's last peak in Money Pool activity occurred in May through July
19 2013. The significant increase in lending to the Money Pool reflected
20 EAI's financing and tax payment activity including the issuance of first

⁴⁹ The APSC approved the Hot Spring Plant acquisition on July 11, 2012, in Order No. 8 of Docket No. 11-069-U. The final non-APSC approval to purchase the facility was not received until November 13, 2012, as described in the November 21, 2012 Compliance Testimony of Kurtis W. Castleberry in Docket 11-069-U.

1 mortgage bonds in May and June 2013 (combined proceeds of
2 approximately \$369 million), a \$207 million income tax payment to the
3 Internal Revenue Service in June 2013, and transfer of funds out of the
4 Money Pool into cash holdings in preparation to satisfy the \$300 million
5 first mortgage bond debt maturing on August 1, 2013.

6

7 Q. MR. DANIEL STATES THAT CUSTOMERS DO NOT BENEFIT FROM
8 THE INTEREST INCOME EAI RECEIVES ON LOANS MADE TO THE
9 MONEY POOL.⁵⁰ IS HIS OBSERVATION CORRECT?

10 A. Mr. Daniel is correct that the interest income from EAI's Money Pool
11 lending is not reflected in the Company's cost-of-service study. The
12 interest expense incurred from EAI's Money Pool borrowing is also not
13 included in the Company's cost-of-service study.

14

15 Q. HOW MUCH INTEREST INCOME AND INTEREST EXPENSE IS AT
16 ISSUE?

17 A. The amounts at issue are very small. Table 7 below summarizes the
18 interest income, interest expense, and net of the two for various periods
19 between January 2012 and July 2013.

20

⁵⁰ Daniel Direct Testimony at 17.

Table 7
Entergy Arkansas, Inc.
Money Pool Interest Income and Expense
January 2012 – July 2013

Time Period	Income	Expense	Net Income / (Expense)
2012 Test Year	\$28,851	\$59,506	(\$30,655)
12 Months Ended July 2013	\$63,726	\$4,670	\$59,056
Jan 2012 – July 2013	\$65,575	\$60,224	\$5,351

Q. IS MR. DANIEL'S \$15.3 MILLION MONEY POOL BORROWING RECOMMENDATION REPRESENTATIVE OF EAI'S ANTICIPATED ONGOING MONEY POOL PARTICIPATION?

A. No. As described earlier, the Company's Money Pool usage is very event-driven. Whether the Company will be a net lender to or a net borrower from the Money Pool cannot be predicted with any reasonable accuracy. Even within a short timeframe, EAI's net lending or borrowing position can change. Table 8 below provides cumulative daily Money Pool balances for several 12-month periods.

Table 8
Entergy Arkansas, Inc.
Net Lending / (Borrowing) From the Money Pool
\$ Millions

12 Months Ending	Amount
March 2012	(13.4)
June 2012	(27.8)
September 2012	(25.4)
December 2012	(15.3)
March 2013	13.0
June 2013	49.5

Q. ARE THERE OTHER CONSIDERATIONS FOR EVALUATING WHETHER AN AMOUNT FOR MONEY POOL BORROWING SHOULD BE INCLUDED IN EAI'S COST OF CAPITAL CALCULATION?

A. Yes, the Money Pool Agreement⁵¹ has no requirement that the other counterparties to the agreement must make funds available for EAI to borrow. Mr. Daniel's recommendation incorrectly assumes that \$15.3 million will always be available for EAI to borrow from the Money Pool.

Q. IS MR. DANIEL'S RECOMMENDATION TO INCLUDE \$15.3 MILLION OF BORROWING FROM THE MONEY POOL IN EAI'S COST OF CAPITAL APPROPRIATE?

⁵¹ Included as Attachment 1 to EAI's Response to Staff 72-1.

1 A. No. In conclusion, Mr. Daniel's recommendation to include \$15.3 million
2 of Money Pool borrowing as part of the short-term debt component of the
3 capital structure is not appropriate because:

- 4 • there is no evidence that EAI will remain a net borrower from the
5 Money Pool because EAI's use of the Money Pool is so event
6 driven;
- 7 • the net interest earned or paid for using the Money Pool is
8 immaterial to the Company's cost-of-service; and
- 9 • there is no guarantee EAI will have \$15.3 million available to
10 borrow on an ongoing basis.

11

12 **D. Reasonableness of Short-Term Debt Recommendation**

13 Q. WHAT IS THE REVENUE REQUIREMENT IMPACT OF MR. DANIEL'S
14 SHORT-TERM DEBT RECOMMENDATION?

15 A. Adoption of Mr. Daniel's recommendation would lower EAI's retail revenue
16 requirement by approximately \$3.3 million based on Staff's retail rate base
17 and recommended cost of capital.

18

19 Q. IS THIS REDUCTION REASONABLE IN LIGHT OF EAI'S PURPOSE
20 FOR AND ACTUAL USE OF ITS CREDIT FACILITIES AND THE MONEY
21 POOL DISCUSSED ABOVE?

22 A. No, it is not reasonable. Adopting the recommendation would penalize the
23 Company for prudent cash management practices and financial

1 arrangements that the Company has determined best meets the needs of
2 serving its customers by assuring the Company access to cash at
3 reasonable terms when the need may arise.
4

5 **XVI. ACCUMULATED DEFERRED INCOME TAXES (“ADIT”)**

6 Q. WHAT ARE THE RECOMMENDATIONS OF STAFF AND OTHER
7 INTERVENORS REGARDING ADIT?

8 A. Staff witness Dunn is the only witness to perform a full review of ADIT and
9 he recommends inclusion of \$1,844,949,418 of ADIT in the cost of capital
10 calculation.⁵² HHEG witness Garrett does not present an overall ADIT
11 review but he recommends inclusion of FIN 48⁵³ ADIT in the capital
12 structure.⁵⁴ Mr. Dunn also includes FIN 48 ADIT in his recommendation. I
13 will address FIN 48 issues initially, followed by the remaining ADIT issues.
14

15 **A. Financial Accounting Standards Board Interpretation No. 48 (“FIN**
16 **48”)**

17 Q. WHAT IS FIN 48?

18 A. The full title of FIN 48 is *Accounting for Uncertainty in Income Taxes: An*
19 *Interpretation of FASB Statement No. 109*. Mr. Dunn and Mr. Garrett have
20 captured the basic purpose of FIN 48. The interpretation cited above

⁵² Dunn Direct Testimony at 12-14.

⁵³ The FIN 48 requirements are now subsumed within Accounting Standards Codification (“ASC”) 740 – Income Taxes. In 2010, the Financial Accounting Standards Board implemented a new structure of accounting and reporting standards that also modified how the standards were referenced. This change in nomenclature did not modify the FIN 48 requirements.

⁵⁴ Garrett Direct Testimony at 5-8.

1 provides guidance on the financial statement presentation of the impacts
2 of tax positions that, in the judgment of a company and its auditor, may not
3 be upheld by the income tax authorities. The FERC also provided
4 guidance on FIN 48 presentation for utilities in Docket No. AI07-2-000 as
5 noted by Mr. Dunn.⁵⁵ Though Mr. Dunn interprets this guidance as
6 “effectively treating the FIN 48 as cost free capital,”⁵⁶ the letter does not
7 support that interpretation. It states, “This guidance is for Commission
8 financial accounting and reporting purposes only and is without prejudice
9 to the ratemaking practice or treatment that should be afforded the items
10 addressed herein.”

11

12 Q. BOTH MR. DUNN AND MR. GARRETT CITE A FIN 48 ADIT AMOUNT
13 OF \$256,654,557 THAT IS AT ISSUE. IS THEIR QUANTIFICATION
14 CORRECT?

15 A. Not exactly. Both witnesses are correct that EAI did exclude FIN 48 from
16 ADIT balances included in the cost of capital calculation, but they
17 misunderstand the full adjustment made by the Company. The majority of
18 FIN 48 ADIT excluded by the Company was related to a FIN 48 tax
19 position taken in December 2012 that generated a significant net
20 operating loss (“NOL”) for EAI. The NOL ADIT is included in debit balance
21 ADIT accounts. When EAI excluded the large FIN 48 ADIT credit

⁵⁵ Dunn Direct Testimony at 14.

⁵⁶ *Id.*

1 balances, it also removed the NOL ADIT debit balances generating a net
2 zero change for much of the total ADIT balance. The \$76 million in IRS
3 cash deposits referenced by Mr. Dunn and Mr. Garrett⁵⁷ and included as a
4 component of CAOL is no longer an issue as those deposits were used to
5 satisfy a large tax obligation in June 2013.⁵⁸

6

7 Q. BECAUSE EAI IS IN AN NOL POSITION, IS THE COMPANY ABLE TO
8 UTILIZE ANY TAX SAVINGS GENERATED BY THE FIN 48 POSITIONS
9 AS COST FREE CAPITAL?

10 A. No, quite the opposite. Being in an NOL position means the Company did
11 not have enough taxable income in its current and prior two tax returns to
12 be able to seek a refund of prior tax payments to obtain a cash tax benefit.
13 Those NOLs are being carried forward to future tax years and utilized as
14 EAI incurs taxable income. Mr. Dunn's and Mr. Garrett's argument that
15 EAI has the cash now to use as cost-free capital is not correct.⁵⁹

16

17 Q. HOW LONG DOES EAI EXPECT TO BE IN AN NOL POSITION?

18 A. Many factors will influence EAI's future taxable income (including the
19 result of this proceeding), which is one of the main factors in determining
20 how long EAI will be in an NOL position. EAI has included forecasted

⁵⁷ Dunn Direct Testimony at 13; Garrett Direct Testimony at 5.

⁵⁸ The total tax owed was \$283.2 million. \$76 million was satisfied by the IRS cash deposits plus the \$207.2 million in additional cash paid by the Company mentioned in the Money Pool section of my testimony.

⁵⁹ Dunn Direct Testimony at 14; Garrett Direct Testimony at 7.

1 ADIT through December 31, 2013, including an estimated utilization of
2 \$73.69 million⁶⁰ of the NOL in 2013. As of the end of the pro forma year,
3 the NOL balances exceed the FIN 48 position balances.
4

5 Q. ARE THERE OTHER FACTORS FOR THE COMMISSION TO
6 CONSIDER WHEN EVALUATING HOW TO TREAT THE FIN 48 ISSUES
7 NOT ASSOCIATED WITH THE NOL?

8 A. Yes. The Commission should examine the results of FIN 48 ADIT issues
9 that were addressed in Docket No. 09-084-U.⁶¹ EAI and other parties
10 arrived at a unique treatment via settlement for FIN 48 issues where FIN
11 48 ADIT balances were excluded from the cost of capital but a procedure
12 was established that recognized the rate impact of FIN 48 issues
13 successfully resolved with the IRS. Mr. Dunn describes the \$343,564
14 credit that will flow back to customers as a result of this procedure.⁶²

⁶⁰ \$73.6 million of NOL utilization translates into approximately \$210 million of taxable income.

⁶¹ Docket No. 09-084-U, Section 5.A. of the Settlement Agreement Joint Exhibit at 7 (May 10, 2010).

⁶² Dunn Direct Testimony at 15.

1

2 Q. DID THIS PROCEDURE REFLECT A REASONABLE RESULT THAT
3 BALANCED THE INTERESTS OF CUSTOMERS AND THE COMPANY?

4 A. Yes. The Company was not penalized with lowered rates for FIN 48 ADIT
5 reflecting positions that were not upheld with the IRS, while customers will
6 receive the benefit of successful FIN 48 ADIT positions.

7

8 Q. WOULD SIMILAR TREATMENT BE APPROPRIATE IN THIS
9 PROCEEDING?

10 A. No. Given the Company's current NOL status, application of that
11 ratemaking approach could prove problematic. That approach relied on a
12 "with and without" calculation of the impact on the retail revenue
13 requirement of the FIN 48 ADIT. If only FIN 48 ADIT credit balances were
14 excluded from ratemaking without recognition of associated NOL ADIT
15 debt balances, the remaining ADIT used for base ratemaking purposes
16 would be understated.

17

18 Q. ARE YOU FAMILIAR WITH MR. GARRETT'S REFERENCE TO THE
19 TREATMENT OF FIN 48 ISSUES BEFORE THE PUBLIC UTILITY
20 COMMISSION OF TEXAS ("PUCT")?⁶³

21 A. Yes. Mr. Garrett refers to a PUCT decision in Docket No. 35717 involving
22 Oncor Electric Delivery Company LLC ("Oncor"). This same Oncor

⁶³ Garrett Direct Testimony at 5-6.

1 decision was previously noted by EAI in Docket No. 09-084-U.⁶⁴ Mr.
2 Garrett also refers to a recent Entergy Texas, Inc. (“ETI”) rate case
3 decision in PUCT Docket No. 39896 where the order allowed ETI to track
4 tax positions ultimately lost before the IRS.

5

6 Q. IS MR. GARRETT’S REVIEW OF PUCT TREATMENT OF FIN 48
7 ISSUES COMPLETE?

8 A. No. Mr. Garrett omitted several material facts surrounding FIN 48 issues
9 before the PUCT. Subsequent to the Oncor decision, the PUCT ordered
10 utilities with FIN 48 issues included in rates to not just “track” the tax
11 positions, but authorized prospective recovery of the revenue requirement
12 related to FIN 48 issues lost before the IRS. In Docket No. 38339,
13 CenterPoint Electric Delivery Company, LLC (“CenterPoint”) was
14 authorized to establish a deferred tax account tracker.⁶⁵ ETI was allowed
15 similar regulatory treatment.

16 Mr. Garrett also fails to acknowledge the magnitude and status of
17 the ETI FIN 48 issues in PUCT Docket No. 39896. The amount at issue
18 for ETI was fairly limited, amounting to only a \$4.6 million rate base
19 reduction. The Order on Rehearing referenced by Mr. Garrett including
20 the FIN 48 issue is currently under appeal by ETI.

21

⁶⁴ Docket No. 09-084-U, Warren Rebuttal Testimony at 38.

⁶⁵ PUCT Docket No. 39896, Order on Rehearing at 4.

1 Q. PLEASE DESCRIBE THE COMPANY'S RECOMMENDED TREATMENT
2 OF FIN 48 ISSUES IN THIS CASE?

3 A. The Company recommends the exclusion of FIN 48 ADIT and the related
4 NOL, which effectively has little to no impact on the ADIT balances in the
5 cost of capital and of which EAI has recognized no cash benefit..
6

7 **B. Other ADIT Issues**

8 Q. IF FIN 48 ADIT DOES NOT MATERALLY AFFECT THE ADIT BALANCE
9 IN THE COST OF CAPITAL, WHAT ISSUES COMPRISE THE
10 DIFFERENCE BETWEEN THE APSC STAFF AND EAI POSITIONS ON
11 ADIT?

12 A. The major differences are the inclusion of ADIT related to FAS 158,
13 unrecovered System Agreement payments, under-recovered Grand Gulf
14 Rider ("Rider GGR") costs, and depreciation ADIT associated with Staff's
15 plant additions adjustment. I will address each major ADIT issue below. I
16 will also discuss some minor issues with Deferred MISO Cost ADIT and
17 pre-July 2007 normalization amounts. EAI Exhibit GRZ-5 quantifies my
18 recommended adjustments to Staff's ratemaking ADIT balances.
19
20

1 Q. MR. DUNN RECOMMENDS EXCLUDING THE IMPACTS OF SFAS 109
2 AND 158 FROM ADIT IN HIS DIRECT TESTIMONY.⁶⁶ IS HIS
3 PROPOSED ADJUSTMENT REASONABLE?

4 A. Yes, I agree that SFAS 109 and 158 ADIT should be eliminated for
5 ratemaking purposes.

6

7 Q. ARE ADDITIONAL ADJUSTMENTS NEEDED TO FULLY ELIMINATE
8 SFAS 158 FOR RATEMAKING PURPOSES?

9 A. Yes. There is an additional \$28,731,000 of SFAS 158 ADIT included as a
10 credit balance in ADIT accounts 190221 and 190222.⁶⁷ These amounts
11 also should be excluded for ratemaking purposes.

12

13 Q. WHY SHOULD ADIT RELATED TO UNRECOVERED SYSTEM
14 AGREEMENT PAYMENTS BE EXCLUDED?

15 A. System Agreement payments including the unrecovered costs generating
16 the ADIT item are currently being recovered through Rider PCA. Based
17 on Order No. 24 in Docket No. 09-084-U, the Rider PCA rate is designed
18 to recover all System Agreement payments by the last billing cycle of
19 December 2013.⁶⁸ At that time the unrecovered balance and associated
20 ADIT is designed to be zero. Continuing to reflect an ADIT balance for

⁶⁶ Dunn Direct Testimony at 12.

⁶⁷ See EAI's response to Staff 113-1 for a listing of all FAS 158-related balances.

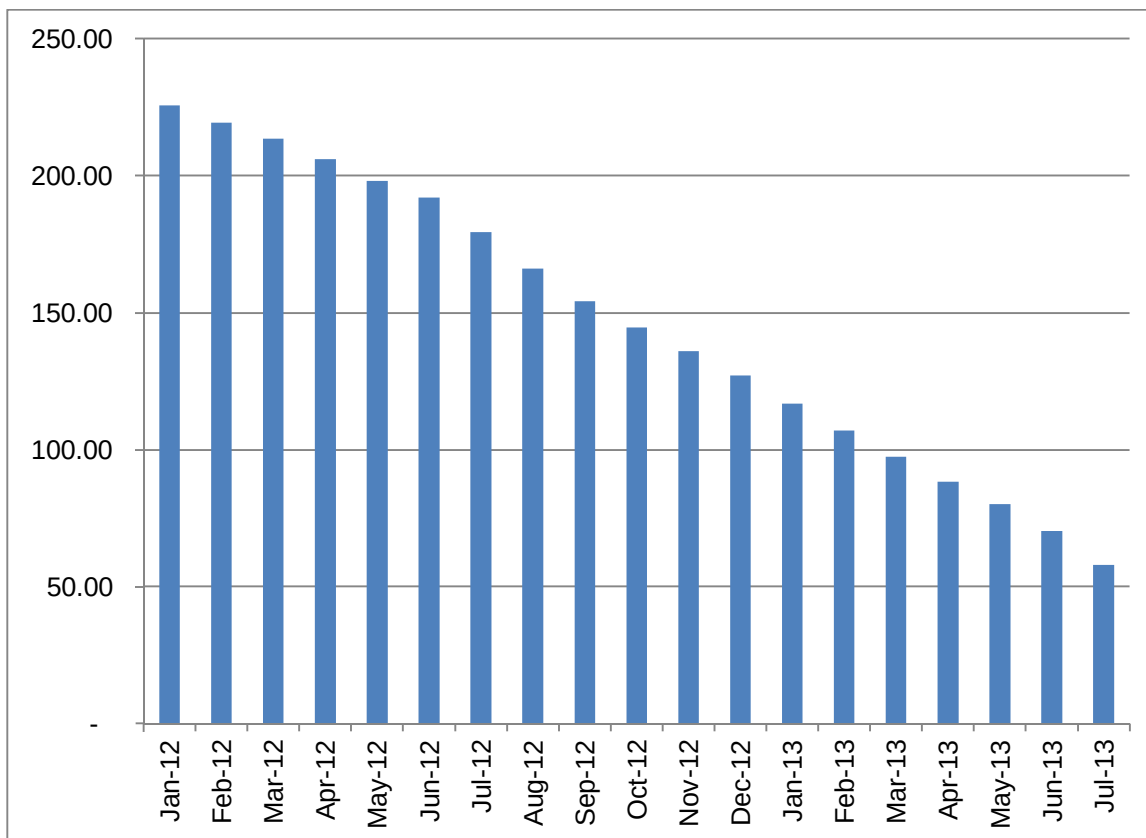
⁶⁸ See June 1, 2013 direct testimony of Company witness Phillip B. Gillam in Docket No. 09-084-U for the latest Rider PCA rate determination designed to end Rider PCA in December 2013.

1 this item would not reflect the objective of the APSC in structuring the
2 current Rider PCA rate to complete collection of the PCA balance by the
3 end of 2013.

4 Figure 2 below presents the unrecovered balances from the
5 January 31, 2012 through July 31, 2013. The trajectory of the balances is
6 supportive of the Company's position that there will be no material
7 unrecovered balance as of December 31, 2013, consistent with the intent
8 of Order No. 24 in Docket No. 09-084-U.

9

Figure 2
 Entergy Arkansas, Inc.
 Unrecovered System Agreement Balances
 January 2012 – July 2013
 \$ Millions

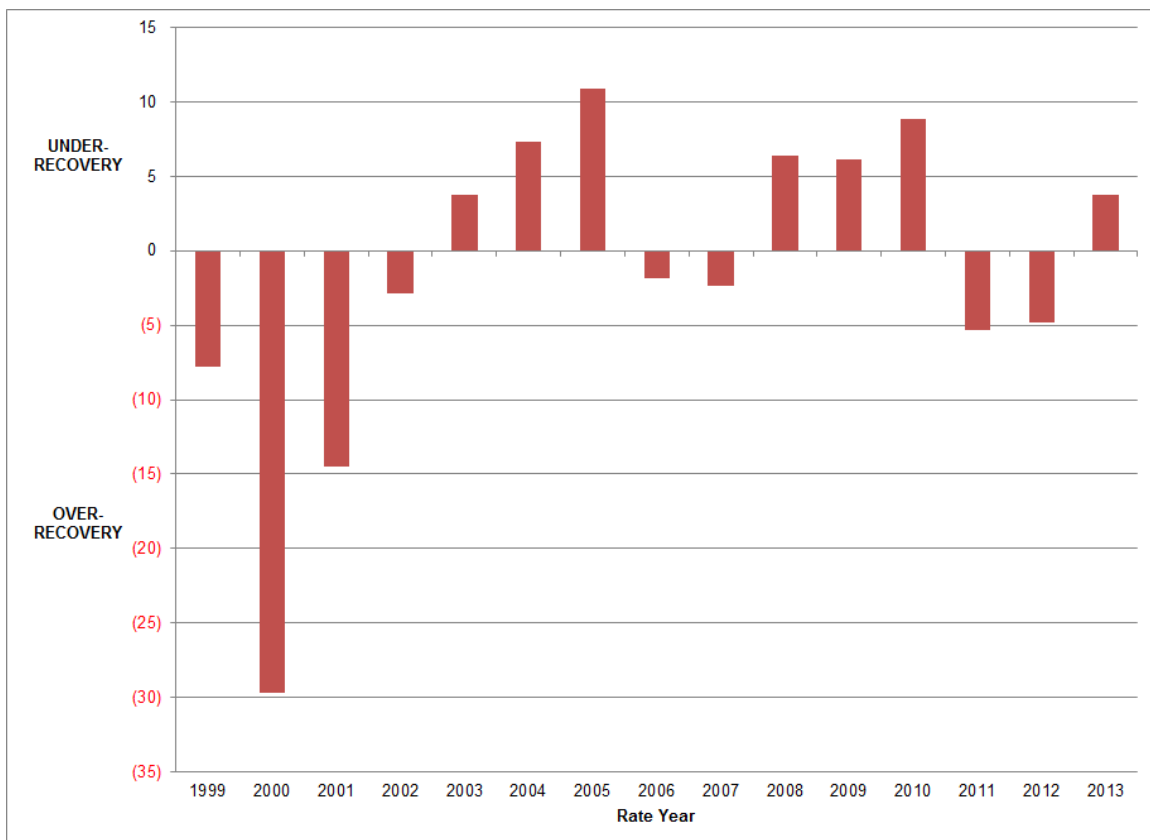


Q. WHY SHOULD RIDER GGR ADIT BE EXCLUDED?

A. The Rider GGR ADIT at issue is generated whenever the Rider GGR revenues are above (creates debt balance ADIT) or below (creates credit balance) Grand Gulf costs. As currently designed, Rider GGR is not biased toward under- or over-collecting revenues. Ideally, each month's collections would exactly equal costs. Selecting the December 31, 2012, credit balance ADIT for Rider GGR for inclusion in base rates presumes

1 that Rider GGR will always be under-recovering Grand Gulf costs. Rider
 2 GGR over-/under-recovery balances included in prior Rider GGR rate
 3 updates are presented in Figure 3 below.

4 Figure 3
 5 Entergy Arkansas, Inc.
 6 Rider GGR
 7 Under-/ (Over-) Recovery Balances
 8 Reflected in Rates
 9 1999 – 2013 Rate Years



10
 11
 12 Figure 3 indicates no bias towards an ongoing under-recovery. It is
 13 appropriate to assume a Rider GGR over-/under-recovery balance of zero
 14 will occur because that best reflects the design of Rider GGR's recovery

1 mechanism thus any associated ADIT will be zero. It should also be noted
2 that Rider GGR does not provide for interest associated with under/over
3 collecting revenues.

4

5 Q. IS DEPRECIATION-RELATED ADIT IN MR. DUNN'S ADIT
6 RECOMMENDATION SYNCHRONIZED WITH MR. MATTHEW'S
7 RECOMMENDED PLANT ADDITIONS?

8 A. No. EAI's depreciation-related ADIT balances are forecasted through
9 December 31, 2013, and synchronized with the plant additions included in
10 AJ14 (Plant Transfers). AJ14 includes \$408.2 million of plant additions
11 during 2013 where as Mr. Matthew's proposed adjustment improperly
12 includes only \$302 million of plant additions.⁶⁹ Mr. Dunn's testimony did
13 not describe an adjustment to ADIT to reflect the lower level of plant
14 additions.

15

16 Q. HAVE YOU QUANTIFIED THE NECESSARY ADJUSTMENT TO
17 REFLECT DEPRECIATION-RELATED ADIT BASED ON STAFF'S
18 PLANT ADDITIONS RECOMMENDATION?

19 A. Yes. As an initial estimate, Staff's ADIT would need to be reduced by
20 \$23.8 million to reflect differences between Staff's plant additions and the
21 ADIT reflected in the cost of capital. This estimate is a calculation based

⁶⁹ Matthews' Direct Testimony at 6-7.

1 on the ratio of Staff plant additions (\$302 million) to the Company's plant
2 additions (\$408.2 million).

3 The Company's plant transfers included in AJ14 are the appropriate
4 level of capital additions which are synchronized with the Company's
5 proposed depreciation-related ADIT. If Mr. Matthews' proposed plant
6 transfer adjustment, as revised, is adopted, then an assessment of the
7 depreciation-related ADIT should be conducted to ensure accurate
8 matching of those items.

9

10 Q. IS AN ADIT VALUE RELATED TO DEFERRED MISO TRANSITION
11 COSTS INCLUDED IN STAFF'S ADIT BALANCES?

12 A. Yes. Accounts 190241 and 190242 include small ADIT balances related
13 to deferred MISO Transition Costs approved in Orders No. 6 and 15 of
14 Docket No. 10-011-U. An ADIT balance of \$167,435 is included in those
15 accounts.

16

17 Q. SHOULD THIS ADIT BALANCE BE REMOVED FROM STAFF'S ADIT
18 RATEMAKING BALANCE?

19 A. Yes. Based on Order No. 76 in Docket No. 10-011-U where carrying
20 costs for deferred MISO Transition costs were not approved, it is
21 appropriate to exclude the associated ADIT balances from the cost of
22 capital. If the ADIT remains as part of the cost of capital, the Company
23 effectively experiences a negative carrying cost on the deferred MISO

1 Transition costs though a lower cost of capital applied to its remaining rate
2 base.

3
4 Q. DO YOU AGREE WITH MR. DUNN'S CALCULATED AMOUNT FOR THE
5 PRE-JULY 1, 2007 FLOW THROUGH AMOUNT?

6 A. No. Mr. Dunn included the incorrect amount for ADIT Accounts 190609
7 and 190610 – Sale of EPA Allowances – Federal & State. The correct
8 amount to eliminate for the pre-July 1, 2007 balances is \$240,853.
9 However, this \$240,853 was the amount he included in his totals rather
10 than eliminating it. The correct amount to include in ADIT for these two
11 accounts for post-June 30, 2007 ADIT is \$498,091⁷⁰ for a net change in
12 ADIT of \$257,238.

13

14 **XVII. OTHER COST OF CAPITAL ISSUES**

15 Q. CAN YOU COMMENT ON MR. MARCUS' CONCERN⁷¹ REGARDING
16 THE COMPANY'S COST OF LONG TERM DEBT?

17 A. Yes. Mr. Marcus expresses concern that the Company's cost of debt may
18 be too high based on the latest data he had available to him at the time he
19 filed his testimony. I have addressed his concerns by updating the
20 Company's Cost of Capital to include the long term debt issuances he
21 discusses in his testimony as well as other expected changes to the

⁷⁰ Total balance in accounts of \$738,944 less pre July 1, 2007 balance of \$240,853.

⁷¹ Marcus Direct at 12.

1 Company's cost of capital. Those updates are included in my rebuttal
2 Cost of Capital calculation.
3

4 Q. IS THERE A DIFFERENCE BETWEEN THE COMMON EQUITY
5 BALANCE USED BY STAFF AND THE COMPANY IN THEIR
6 RESPECTIVE COST OF CAPITAL CALCULATION?

7 A. Yes, there is a difference in point in time used for the common equity
8 balance. Staff uses the December 31, 2012 per book common equity
9 balance of \$1,581.2 million⁷² and the Company uses a balance with
10 known and measurable adjustments through December 31, 2013 balance
11 of \$1,693.3 million⁷³ for a difference of \$112.0 million. This difference has
12 a significant impact on the revenue requirement because the cost of
13 capital will be understated. Based on Staff's retail rate base and weighted
14 cost of capital using EAI's common equity balance, the revenue
15 requirement increase would be approximately \$9 million.
16

17 Q. WHY IS IT APPROPRIATE TO USE A COMMON EQUITY BALANCE
18 WITH KNOWN AND MEASURABLE ADJUSTMENTS THROUGH THE
19 END OF THE PRO FORMA YEAR?

20 A. It is appropriate to use a common equity balance with known and
21 measurable adjustments through December 31, 2013 so that as many

⁷² Staff Direct Exhibit RD-19.

⁷³ Included in EAI Exhibit GRZ-6.

1 elements of the cost of capital are synchronized with the rate base to
2 which the cost of capital will be applied. To the extent possible, plant in
3 service and accumulated depreciation include known and measurable
4 changes through December 31, 2013. EAI's cost of capital provided in
5 EAI Exhibit GRZ-6 reflects known and measurable adjustments to most
6 elements of the capital structure through the end of the pro forma year
7 (December 31, 2013). Staff's current cost of capital recommendation
8 reflects a mix of dates including long-term debt, preferred stock, and
9 common equity balances as of December 31, 2012, while other items
10 such as the ADIT balances are reflected as of December 31, 2013.

11
12 Q. WHAT EVIDENCE SUPPORTS A COMMON EQUITY BALANCE OF
13 \$1,693.3 MILLION AS OF DECEMBER 31, 2013?

14 A. As a starting point, EAI had a common equity balance of \$1,618 million as
15 of June 30, 2013⁷⁴ which closes the \$112 million gap between Staff and
16 EAI by \$12.2 million. To begin addressing the remaining \$99.8 million
17 difference, an evaluation of EAI's recent third and fourth quarter net
18 income results is necessary. EAI's current base rates generate the
19 majority of EAI's net income and have been in effect since July 2010.
20 Table 9 below lists EAI's third and fourth quarter net income results from
21 2010 through 2012.

⁷⁴ See EAI's response to Staff data request 192-1.

Table 9
Entergy Arkansas, Inc.
Third and Fourth Quarter Net Income
2010 through 2012
Millions of \$

Year	3Q Net Income	4Q Net Income
2010	93.3	8.7
2011	80.9	8.0
2012	82.6	10.2
Best Results	93.3	10.2
Worst Results	80.9	8.0

Based on recent net income experience, the worst to best net income experience would range from \$88.9 to 103.5 million as an increase the common equity balance. The primary events that decrease the common equity balance are the payment of preferred stock and common stock dividends. For the last half of 2013, EAI will pay \$3.4 million in preferred stock dividends and does not expect to pay any common stock dividends.⁷⁵

Q. DOES THIS ANALYSIS OF NET INCOME AND DIVIDENDS SUPPORT THE REASONABLENESS OF THE \$99.8 MILLION INCREASE TO THE COMMON EQUITY BALANCE EAI EXPECTS TO OCCUR IN THE LAST HALF OF 2013?

A. Yes. Although the \$99.8 million value is at the higher end of the best outcome of \$101.1 million,⁷⁶ it is still within the range of reasonableness for this type of adjustment.

⁷⁵ See EAI's response to Staff 134-1.

⁷⁶ \$103.5 million net income less \$3.4 million in dividends = \$101.1 million.

1

2 Q. WHAT OTHER FACTOR SHOULD BE CONSIDERED IN EVALUATING
3 THE REASONABLENESS OF THE \$99.8 MILLION VALUE?

4 A. Another factor to review is how the \$99.8 million value affects the debt-to-
5 equity ratio in EAI's capital structure. Mr. Daniel has recommended a debt
6 to equity ratio of 53 percent to 47 percent for EAI.⁷⁷ Using the external
7 financing elements as described in Mr. Daniel's testimony and exhibits,⁷⁸
8 EAI's capital structure presented in EAI Exhibit GRZ-6 matches his
9 recommended ratio.

10

11 **XVIII. AGREED UPON ADJUSTMENTS**

12 Q. CAN YOU PLEASE ADDRESS THE REMAINING ACCOUNTING
13 ADJUSTMENTS THAT THE COMPANY HAS EITHER AGREED TO OR
14 IS NOT SPECIFICALLY DISPUTING IN ITS REBUTTAL TESTIMONY?

15 A. Yes. Listed below are the accounting adjustments that the Company is in
16 agreement with or is not specifically addressing in rebuttal testimony:

- 17 1. Update Cost-of-Service to December 31, 2012 actuals;
18 2. Update Working Capital Assets and Liabilities through June
19 30, 2013 actuals;

⁷⁷ Daniel Direct Testimony at 14.

⁷⁸ Daniel Direct Testimony at 12–14 and Direct Exhibit RD-6.

- 1 3. Agree to deferral of Lake Catherine 4 Sustainability Reliability
- 2 Project as a regulatory asset for recovery in next rate case
- 3 consistent with Mr. Hilton's recommendation;
- 4 4. Staff adjustment IS-6 a \$180 reduction to postal rate increase;
- 5 5. Staff adjustment IS-20 a \$70,162 additional reduction to O&M
- 6 expense;
- 7 6. Marcus adjustment of \$65,780 reduction of various
- 8 advertising related costs.
- 9 7. Update customer deposit interest rate to .50 percent.
- 10 8. Agree with Ms. Lindholm's adjustment related to the Ouachita
- 11 transmission upgrades.

12

13 Q. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

14 A. Yes.

CERTIFICATE OF SERVICE

I, Steven K. Strickland, do hereby certify that a copy of the foregoing has been served upon all parties of record by forwarding the same by electronic mail and/or first class mail, postage prepaid, this 26th day of August, 2013.

/s/ Steven K. Strickland
Steven K. Strickland

BEFORE THE
ARKANSAS PUBLIC SERVICE COMMISSION

IN THE MATTER OF THE APPLICATION	)	
OF ENTERGY ARKANSAS, INC. FOR	)	DOCKET NO. 13-028 -U
APPROVAL OF CHANGES IN RATES FOR	)	
RETAIL ELECTRIC SERVICE	)	

EAI EXHIBIT GRZ-2

EAI HCM PRO FORMA ADJUSTMENT

EAI Exhibit GRZ-2
Docket No. 13-028-U
Page 1 of 1

ENTERGY ARKANSAS, INC.
HUMAN CAPITAL MANAGEMENT INITIATIVE
ESTIMATED SAVINGS AND ESTIMATED COSTS TO ACHIEVE SAVINGS

Estimated Savings		<u>16,600,000</u>
Total estimated costs to achieve savings:	<u>27,300,000</u>	<u>9,100,000</u>
The Company is proposing to amortize costs to achieve savings over 3 years.		

BEFORE THE
ARKANSAS PUBLIC SERVICE COMMISSION

IN THE MATTER OF THE APPLICATION	)	
OF ENTERGY ARKANSAS, INC. FOR	)	DOCKET NO. 13-028-U
APPROVAL OF CHANGES IN RATES FOR	)	
RETAIL ELECTRIC SERVICE	)	

EAI EXHIBIT GRZ-3

EAI CAPITAL ADDITIONS

**ENTERGY ARKANSAS, INC.
CAPITAL ADDITIONS FOR REBUTTAL COST OF SERVICE
PROJECTED AS OF DECEMBER 31, 2013**

<u>Matthews Methodology Updated thru July 2013</u>	<u>Amount</u>	
Actual Closings Jan 13 Thru July 13	\$ 168,175,188	(same methodology as Matthews - updated through July)
Blankets Estimate Aug 13 thru Dec 13	31,593,070	5 months times 2012 average monthly Distribution Blankets Closings (same methodology as Matthews)
MISO - December 2013	29,400,000	(same methodology as Matthews)
Matthews allowed 2013 closing \$ estimate	120,819,618	(Matthews value based on identified projects in estimate -- adjusted for Retail Adj amounts)
Remove 2013 \$s closed related to projects allowed by Matthews	(5,399,795)	
Sub-Total	<u>\$ 344,588,081</u>	
<u>Additional Expected Closings by December 2013 (Based on Additions Estimate)</u>		
July 2013 CWIP Projects - Confirmed with Functional personnel -- high level of confidence projects will be "in-service" by Dec 2013.*		
Nuclear	\$ 12,828,028	
Transmission Line & Sub	14,063,228	
Transmission Grid	4,141,030	
Distribution - Storm	4,647,458	Additions estimate same as CWIP - not specifically estimated
Remove 2013 \$s closed related to projects allowed by Matthews	(273,009)	
Distribution - Non-storm	4,060,339	
Sub-Total	<u>\$ 39,467,074</u>	
Total	<u>\$ 384,055,155</u>	

Final adjustment above will be refined where appropriate to include the ratemaking adjustments (253107 Retail Adj amounts).

*Projects with CWIP balance over \$50,000

BEFORE THE
ARKANSAS PUBLIC SERVICE COMMISSION

IN THE MATTER OF THE APPLICATION	)	
OF ENTERGY ARKANSAS, INC. FOR	)	DOCKET NO. 13-028-U
APPROVAL OF CHANGES IN RATES FOR	)	
RETAIL ELECTRIC SERVICE	)	

EAI EXHIBIT GRZ-4

CREDIT FACILITIES ANALYSIS

**Entegy Arkansas, Inc.
Credit Facility Analysis**

Credit Facility	Loan Amount	Adjustments	Adjusted Loan Amount	Loan Date	Loan Payment Date	Days Outstanding	Day Weighted Balance	Interest Rate	Day Weighted Interest
Local	50,000,000		50,000,000	1/31/2012	2/8/2012	8	1,095,890	1.78%	19,507
National	1,000,000		1,000,000	3/12/2012	3/13/2012	1	2,740	1.70%	47
National	150,000,000	(23,000,000)	127,000,000	11/29/2012	12/18/2012	19	6,610,959	1.70%	112,386
Local	20,000,000		20,000,000	11/29/2012	12/14/2012	15	<u>821,918</u>	1.78%	<u>14,630</u>
Total							<u><u>8,531,507</u></u>		<u><u>146,570</u></u>
Weighted Rate									<u><u>1.72%</u></u>

BEFORE THE
ARKANSAS PUBLIC SERVICE COMMISSION

IN THE MATTER OF THE APPLICATION	)	
OF ENTERGY ARKANSAS, INC. FOR	)	DOCKET NO. 13-028-U
APPROVAL OF CHANGES IN RATES FOR	)	
RETAIL ELECTRIC SERVICE	)	

EAI EXHIBIT GRZ-5

ADIT

Entergy Arkansas, Inc.
Analysis of Staff ADIT
Pro Forma Year Ended December 31, 2013

Line	Description	Accounts	Amount
1	Total ADIT at 12/31/2013		1,907,448,791
	<u>Staff Adjustments</u>		
2	FAS 109		(82,036,096)
3	FAS 158		32,700,034
4	Pre-2007		<u>(13,163,310)</u>
5	Total Staff Adjustments		<u>(62,499,373)</u>
6	Staff's Recommended ADIT		1,844,949,418
	<u>EAI Proposed Adjustments to Staff ADIT</u>		
7	Remove FAS 158 Completely	190221 / 190222	(28,731,000)
8	Remove Unrecovered Rider PCA ADIT	190241 / 190242	(49,901,035)
9	Remove Unrecovered Rider GGR ADIT	190131 / 190132	(6,782,823)
10	Deferred MISO Transition Costs ADIT	190241 / 190242	(167,435)
11	Correct Pre-2007 Sale of EPA Allowances	190609 / 190610	(257,238)
12	Synchronize Staff ADIT and Staff Plant	Various	<u>(23,793,160)</u>
13	Total EAI Proposed Adjustments		<u>(109,632,691)</u>
14	Adjusted Staff ADIT		<u><u>1,735,316,727</u></u>

BEFORE THE
ARKANSAS PUBLIC SERVICE COMMISSION

IN THE MATTER OF THE APPLICATION	)	
OF ENTERGY ARKANSAS, INC. FOR	)	DOCKET NO. 13-028-U
APPROVAL OF CHANGES IN RATES FOR	)	
RETAIL ELECTRIC SERVICE	)	

EAI EXHIBIT GRZ-6

REBUTTAL COST OF CAPITAL

ENTERGY ARKANSAS, INC.
COST OF CAPITAL FOR REBUTTAL COST OF SERVICE
PROJECTED AS OF DECEMBER 31, 2013

	(1)	(2)	(3)	(4)	(5)
Line	Description	Amount	Proportion	Rate	Weighted Average Rate of Return on Rate Base
		\$	%	%	%
1	Long-Term Debt	1,892,222,811	32.11%	4.82%	1.55%
2	Preferred Stock	114,733,615	1.95%	5.99%	0.12%
3	Common Equity	1,693,265,932	28.73%	10.40%	2.99%
4	Accumulted Deferred				
5	Income Taxes	1,711,841,567	29.04%	0.00%	0.00%
6	Pre-1971 Accumulated Deferred				
7	Investment Tax Credits	0	0.00%	0.00%	0.00%
8	Post-1970 Accumulated Deferred				
9	Investment Tax Credits	38,955,640	0.66%	7.41%	0.05%
10	Customer Deposits	88,559,392	1.50%	0.50%	0.01%
11	Short-Term/Interim Debt	0	0.00%	0.00%	0.00%
12	Current, Accrued, and Other				
13	Liabilities				
14	Working Capital Liabilities	172,939,964	2.93%	0.00%	0.00%
15	DOE Obligation	181,271,902	3.08%	0.06%	0.00%
16	Totals	<u>5,893,790,823</u>	<u>100.00%</u>		<u>4.71%</u>

BEFORE THE
ARKANSAS PUBLIC SERVICE COMMISSION

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OF ENTERGY ARKANSAS, INC. FOR	)	DOCKET NO. 13-028-U
APPROVAL OF CHANGES IN RATES FOR	)	
RETAIL ELECTRIC SERVICE	)	

DIRECT TESTIMONY

OF

HUGH T. MCDONALD

PRESIDENT AND CHIEF EXECUTIVE OFFICER

ENTERGY ARKANSAS, INC.

ON BEHALF OF

ENTERGY ARKANSAS, INC.

AUGUST 26, 2013

1 **I. INTRODUCTION**

2 Q. PLEASE STATE YOUR NAME.

3 A. My name is Hugh T. McDonald.

4

5 Q. ARE YOU THE SAME HUGH T. MCDONALD WHO FILED DIRECT
6 TESTIMONY IN THIS DOCKET ON MARCH 1, 2013?

7 A. Yes, I am.

8

9 Q. ON WHOSE BEHALF ARE YOU TESTIFYING?

10 A. I am submitting this rebuttal testimony to the Arkansas Public Service
11 Commission ("APSC" or the "Commission") on behalf of Entergy
12 Arkansas, Inc. ("EAI" or the "Company").

13

14 Q. WHAT IS THE PURPOSE OF YOUR REBUTTAL TESTIMONY?

15 A. The purpose of my rebuttal testimony is to identify the significant issues
16 raised by parties in their initial testimonies and identify the EAI witness
17 who will respond to those issues. In addition, I will explain the Human
18 Capital Management initiative that was announced recently to provide the
19 basis for an adjustment to the Company's payroll expense resulting from
20 this initiative.

21

22

1 **II. ISSUES RAISED IN THE CASE AND RESPONSIVE WITNESSES**

2 Q. PLEASE GIVE AN OVERVIEW OF THE STATUS OF THE CASE.

3 A. At its most basic level, a general rate proceeding involves resetting a
4 utility's rates to allow it to recover its cost of providing service to its
5 customers. This process involves determining the current cost of
6 providing service, the revenue requirement, based upon a recent cost
7 year. That updated revenue requirement is compared to the revenues
8 that are generated by existing rates applied to an updated level of
9 customer usage. The difference is the amount of additional revenue, the
10 revenue deficiency, that the utility needs to collect from customers. In
11 addition, the case involves a determination of how costs should be
12 allocated among the various customer classes, and the design of rates to
13 collect these costs from customers.

14 EAI in its direct case presented costs recorded during the 2012 test
15 year based on six months historical data through June 30, 2012 and six
16 months projected data through December 31, 2012.¹ The Company then
17 made adjustments for changes that were known to occur in 2013 and
18 whose cost impact could be measured. The Company also presented
19 recommendations for how to allocate these costs among the various
20 categories of customers and proposed specific rates to collect these costs
21 from these customer classes.

¹ In response to Staff 1-18, EAI updated its test year to reflect 12 months of actual data through December 31, 2013.

1 The APSC General Staff (“Staff”) was the only party that presented
2 a complete cost of service study as an alternative to the one presented by
3 EAI. Staff’s case was based upon EAI’s actual test year amounts² The
4 difference in the revenue deficiency between the Company’s
5 recommendation and the Staff’s recommendation is \$81 million.³ In their
6 responsive testimonies, other parties commented on specific cost items,
7 as well as cost allocation and rate design. The Company’s witnesses
8 address all these issues in their rebuttal testimonies, identifying areas of
9 agreement or disagreement and explaining where a misunderstanding or
10 error may account for the differences.

11

12 Q. WHAT ARE THE MOST SIGNIFICANT ISSUES IN THE CASE?

13 A. As is typical in many rate proceedings, on the cost, or revenue
14 requirement, side of the equation, the return that EAI would be allowed to
15 earn on its investments to provide service is a highly contested issue. EAI
16 has proposed a 10.4 percent return on equity (“ROE”) based upon various
17 methods of analyses intended to determine a reasonable return compared
18 to a peer group of utilities, while recognizing the effects of federal
19 monetary policy on these traditional cost of equity analyses. EAI’s
20 recommended ROE also is based upon judgment that includes various
21 factors such as investor expectations, the large, pending investment in

² Hilton Direct Testimony at 8-9.

³ *Id.* at 6.

1 facilities EAI must make to provide service to its customers and lower
2 growth trends seen in the industry due to penetration of energy efficiency
3 measures and slower overall economic growth.

4 While the Staff cost of capital witness recognized that current
5 economic and market conditions have an impact on its analysis, it relied
6 only on a discounted cash flow methodology and recommended an ROE
7 of 9.6 percent, the top of its range, in an attempt to address the current
8 market abnormalities.⁴ Other witnesses addressing EAI's return discount
9 the impact of the conditions EAI cites and recommend far lower returns of
10 9.25 to 9.4 percent.⁵

11 EAI witness Sam Hadaway presents an update of his analysis
12 based on more current economic data and explains that the Company's
13 request for a 10.4 percent Return on Equity remains reasonable in current
14 market conditions, while EAI witness Julie Cannell reaffirms her view that
15 this level of ROE is consistent with investors' current expectations.

16

17 Q. YOU EXPLAINED IN YOUR DIRECT TESTIMONY THAT ONE
18 PURPOSE FOR THIS CASE WAS TO REVISE EAI'S COST
19 STRUCTURE TO ALIGN WITH ITS OPERATIONS IN MISO BECAUSE
20 THE COMPANY IS TERMINATING ITS PARTICIPATION IN THE

⁴ Daniel Direct Testimony at 35-38.

⁵ Marcus Direct Testimony at 43-45; Parcell Direct Testimony at 34-35; Gorman Direct Testimony at 38-39.

1 SYSTEM AGREEMENT. WERE THERE ANY ISSUES RAISED
2 RELATED TO THIS STRUCTURAL CHANGE?

3 A. Yes. As a result of joining the Mid-Continent Independent System
4 Operator, Inc. ("MISO") in December, EAI proposed several tariff changes,
5 including closing EAI's Optional Interruptible Service Rider ("Rider OIS") to
6 *new* customers and introduce two new tariffs that would allow customers
7 to participate in MISO markets through EAI. These two revisions drew
8 considerable comment from Arkansas Electric Energy Consumers
9 ("AEEC") and the Hospital and Higher Education Group ("HHEG").

10 AEEC and HHEG opposed closing Rider OIS to new customers
11 and expressed concern about any phase-out or termination of the rider.
12 EAI did not propose in this case to close Rider OIS to customers currently
13 utilizing the OIS Rider nor did it recommend when the OIS Rider would be
14 phased out. These parties also questioned the benefit of the new tariffs
15 because they would rely on a MISO market price of capacity as the value
16 provided to a customer willing to interrupt its load as a resource available
17 to EAI to meet its customers' load. EAI witness Kurtis Castleberry
18 explains in his rebuttal testimony why the terms of Rider OIS are generally
19 inconsistent with EAI's operation in MISO and, as a result, the Company
20 has proposed to close Rider OIS to *new* customers, but allow existing
21 customers to continue to take service under this tariff. In response to
22 opportunities provided by the MISO markets, EAI has proposed new tariffs

1 to provide the value of the MISO markets to customers that have flexibility
2 in their operations.
3

4 Q. WHAT OTHER WITNESSES AND ISSUES IS EAI ADDRESSING IN ITS
5 REBUTTAL TESTIMONY?

6 A. Other EAI rebuttal witnesses and their topics include:

- 7 1. S. Brady Aldy, Director, Transmission and Distribution
8 Operations for EAI, who addresses issues related to a
9 proposed cost adjustment to account for a change in EAI's
10 vegetation management cycles, proposed adjustment to EAI's
11 requested changes to miscellaneous service fees, issues
12 concerning EAI's recommendations for changes to provisions
13 within the Extension of Facilities Policy, and recommendations
14 for change in the Company's non-residential deposit policy.
- 15 2. Kurtis W. Castleberry, Director, Resource Planning for EAI,
16 who addresses issues raised by the parties associated with
17 EAI's transition to post-System Agreement operations later
18 this year;
- 19 3. Patrick J. Cicio. Director, Mid-Office and Energy Settlements
20 for the System Planning and Operations ("SPO") Department
21 of, Entergy Services, Inc. ("ESI") who explains the Company's
22 proposed methodology to determine avoided energy cost and
23 avoided capacity cost for cogenerators;

- 1 4. Donald J. Clayton, Vice President, Tangibl LLC, who responds
- 2 to issues related to the derivation of depreciation rates;
- 3 5. William R. Crean, Principle Estimator, Black & Veatch, who
- 4 addresses issues related to dismantling costs for generating
- 5 plants that are being retired as they affect the proposed
- 6 depreciation rates;
- 7 6. Eric Fox, Director, Forecast Solutions, Itron, Inc., who
- 8 addresses issues related to weather normalization of sales;
- 9 7. Kevin G. Gardner, Vice President, Human Resources
- 10 Programs, ESI, who addresses issues related to employee
- 11 and executive compensation programs;
- 12 8. David E. Hunt, Director of Regulatory Accounting for ESI, who
- 13 adopts Mr. Phillip B. Gillam's direct testimony and addresses
- 14 issues related to the Staff's cost-of-service study methodology
- 15 in his rebuttal testimony, including the treatment of the
- 16 Wholesale Baseload Capacity sales; the Energy Cost
- 17 Recovery Rider, the Capacity Cost Recovery Rider , and the
- 18 MISO Rider; and provides an update of EAI's proposed
- revenue requirement based on updated calculations of EAI's
- Weighted-Average Cost of Capital and the WBL Capacity
- sales;
9. Jay C. Hartzell, Professor of Finance, and the Allied
- Bancshares Centennial Fellow at the McCombs School of

1 Business at the University of Texas at Austin, who addresses
2 issues related to the inclusion in rates of financially related
3 incentive compensation;

4 10. Jay A. Lewis, Vice President, Regulatory Strategy, ESI, who
5 addresses issues related to EAI's calculation of Allowance for
6 Funds Used During Construction;

7 11. Corey A. Pettett, Director of Rate Design and Administration
8 for ESI, who addresses issues related to the derivation of
9 billing determinants and resulting base rate sales revenue,
10 allocation factors, rate design, and Rider OIS;

11 12. David Pickles, Senior Vice President of ICF International, who
12 addresses issues related to the base load calculation and
13 escalation factor used by Staff in developing billing
14 determinants;

15 13. Jay K. Thayer, Vice President, Engineering for ESI, who
16 addresses issues related to Nuclear Energy Institute dues;
17 and

18 14. Gregory R. Zakrzewski, who addresses certain accounting
19 and tax-related issues and recommendations raised by other
20 parties in the case, and provides a pro forma adjustment to
21 reflect the net savings expected from the Human Capital
22 Management initiative, which I explain in the next section of
23 my testimony.

1 15. Patricia Cartwright, Senior Vice President – Valuation Services
2 for Arthur Financial Services, LLC, who addresses the land
3 values of the EAI generating facilities.
4

5 **III. HUMAN CAPITAL MANAGEMENT**

6 Q. DESCRIBE THE HUMAN CAPITAL MANAGEMENT INITIATIVE AND
7 THE GOALS OF THE PROGRAM.

8 A. Human Capital Management (“HCM”) is a companywide strategic
9 imperative chartered by Entergy’s executive leadership team. A principal
10 goal of HCM is to reduce the Entergy companies’ costs in a way that
11 makes the company more efficient and effective in the future. To that end,
12 HCM seeks to take steps to optimize the Entergy Corporation companies’
13 organizational structure, processes, and work practices. All employees
14 will go through a selection process which will help Entergy Corporation
15 match employee knowledge, skills and abilities with the future jobs in the
16 organization. Since some positions may change and new positions may
17 be created, it's necessary to undergo this selection process to determine
18 the best employee for each position. The selection process for Officers
19 occurred in July and all employee selection rounds will be complete by
20 November 2013. Since HCM is a three year initiative, certain redesigns
21 will not be completed by the end of 2013 but should be completed by the
22 end of 2015. Although the HCM process is not complete at this stage, Mr.
23 Zakrzewski provides an estimate of known 2013 planned savings offset by

1 a three year amortization of the costs required to implement these
2 savings.

3

4 Q. DOES THIS CONCLUDE YOUR REBUTTAL TESTIMONY?

5 A. Yes.

CERTIFICATE OF SERVICE

I, Steven K. Strickland, do hereby certify that a copy of the foregoing has been served upon all parties of record by forwarding the same by electronic mail and/or first class mail, postage prepaid, this 26th day of August, 2013.

/s/ Steven K. Strickland
Steven K. Strickland

BEFORE THE
ARKANSAS PUBLIC SERVICE COMMISSION

IN THE MATTER OF THE APPLICATION	)	
OF ENTERGY ARKANSAS, INC. FOR	)	DOCKET NO. 13-028-U
APPROVAL OF CHANGES IN RATES FOR	)	
RETAIL ELECTRIC SERVICE	)	

DIRECT TESTIMONY

OF

JAY C. HARTZELL, PH., D.

ON BEHALF OF

ENTERGY ARKANSAS, INC.

AUGUST 26, 2013

1 **I. INTRODUCTION**

2 Q. PLEASE STATE YOUR NAME.

3 A. My name is Jay C. Hartzell.

4

5 Q. ARE YOU THE SAME JAY C. HARTZELL WHO FILED DIRECT
6 TESTIMONY IN THIS DOCKET ON MARCH 1, 2013?

7 A. Yes, I am.

8

9 Q. ON WHOSE BEHALF ARE YOU TESTIFYING?

10 A. I am submitting this rebuttal testimony to the Arkansas Public Service
11 Commission (“APSC” or the “Commission”) on behalf of Entergy
12 Arkansas, Inc. (“EAI” or the “Company”).

13

14 Q. WHAT IS THE PURPOSE OF YOUR REBUTTAL TESTIMONY?

15 A. The purpose of my rebuttal testimony is to addresses certain arguments
16 raised by the Hospital and Higher Education (“HHEG”) witnesses Mark E.
17 Garrett and Larry Blank, and Attorney General (“AG”) witness William B.
18 Marcus in opposition to inclusion in rates of what has been termed
19 “financially” related incentive compensation.

20

21 Q. HAVE YOU REVIEWED THE TESTIMONY OF HHEG WITNESSES
22 GARRETT AND BLANK?

23 A. Yes, I have.

1 Q. CAN YOU PLEASE SUMMARIZE THE PORTIONS OF THEIR
2 TESTIMONY TO WHICH YOU WILL RESPOND?

3 A. I will respond to Mr. Garrett's list of six reasons why incentive
4 compensation can be excluded from rates.¹ Both Mr. Garrett and Dr.
5 Blank claim that earnings and equity-based incentives do not align the
6 interests of shareholders and ratepayers in a regulated setting.² I reply to
7 these arguments, as well.

8

9 Q. HAVE YOU REVIEWED THE TESTIMONY OF AG WITNESS MR.
10 MARCUS?

11 A. Yes.

12

13 Q. CAN YOU PLEASE SUMMARIZE THE PORTIONS OF THE TESTIMONY
14 OF MR. MARCUS TO WHICH YOU WILL RESPOND?

15 A. Mr. Marcus makes many of the same arguments as Mr. Garrett. Both
16 focus on the fact that the ultimate value of incentive-based compensation
17 is uncertain (although the expected value can be calculated at the time it
18 is issued), and both point out that managers could stand to benefit from
19 rate increases through stock-based compensation. Therefore, my
20 responses to Mr. Garrett's testimony also apply to the related portions of
21 Mr. Marcus's testimony.

¹ Garrett Direct Testimony at 12-14.

² *Id.* at 30; Blank Direct Testimony at 6-9.

1 **II. RESPONSE TO MR. GARRETT’S POLICY ARGUMENTS OPPOSING**
2 **INCLUSION OF “FINANCIALLY” BASED INCENTIVE IN RATES**

3 Q. WHAT LIST OF REASONS DOES MR. GARRETT GIVE AS TO WHY
4 FINANCIALLY BASED INCENTIVES MAY BE EXCLUDED FROM
5 RATES?

6 A. Mr. Garrett makes several arguments as to why “financially” based
7 incentive compensation should be excluded from rates. Specifically, he
8 argues that:

- 9 1) Payment is uncertain.
- 10 2) Incentive plans tied to company earnings performance are
11 held in general disfavor because many factors that
12 significantly impact earnings are outside the control of most
13 company employees and have limited value to customers.
- 14 3) Earnings-based incentive plans can discourage
15 conservation.
- 16 4) The utility and its stockholders assume none of the financial
17 risks associated with financially based incentive payments.
- 18 5) Incentive payments based on financial performance
19 measures should be made out of increased earnings.
- 20 6) Financially based incentive payments embedded in rates
21 shelter the utility against the risk of earnings erosion through
22 attrition.

1 Mr. Garrett goes on to argue that financial incentives differ from
2 operational incentives because ratepayers have no stake in an incentive
3 plan design based on financial performance measures, while they do have
4 a stake in such a plan to the extent it is based on operational performance
5 measures.³ There are logical and theoretical problems with these
6 arguments, as I discuss below. Company witness Kevin G. Gardner also
7 addresses the flaws in Mr. Garrett's analysis.

8

9 Q. PLEASE ADDRESS MR. GARRETT'S ARGUMENT THAT FUTURE
10 PAYMENT OF FINANCIALLY BASED INCENTIVE COMPENSATION IS
11 UNCERTAIN.

12 A. It is true that payment of incentive compensation in the future is designed
13 to be uncertain. Indeed, this is a key aspect of the effectiveness of
14 incentive compensation, because the risk associated with the level of
15 future compensation provides incentives for positive employee
16 performance. However, this uncertainty does not imply that such incentive
17 compensation is an unreasonable, unnecessary, or non-recurring
18 business expense. If Mr. Garrett's argument were valid, no incentive
19 compensation, whether it is financially or operationally based, would be a
20 candidate for inclusion in rates, which is a position already considered and

³ In a stipulation filed by HHEG and EAI in this docket on August 19, 2013, HHEG conceded that some of HHEG's members utilize employee incentive compensation plans where several factors, including financial performance, influence the amount of employee incentive compensation, which includes employee bonuses.

1 rejected by the Commission.⁴ At some level, many future costs of doing
2 business are uncertain at the time rates are set. I understand that by
3 using a test year, the Commission has a sample data point that, despite
4 this inherent level of uncertainty, becomes the starting point for setting
5 rates. EAI's incentive compensation plan design provides the potential for
6 payment of incentive compensation at varying levels dependent on the
7 degree of financial success. This potential variation is consistent with the
8 use of the test-year level of incentive compensation payments as the basis
9 for setting rates.

10

11 Q. WHAT IS YOUR RESPONSE TO MR. GARRETT'S POSITION THAT
12 INCENTIVE PLANS BASED ON COMPANY EARNINGS ARE HELD IN
13 GENERAL DISFAVOR BECAUSE MANY FACTORS THAT
14 SIGNIFICANTLY IMPACT EARNINGS ARE OUTSIDE THE CONTROL
15 OF MOST COMPANY EMPLOYEES AND HAVE LIMITED VALUE TO
16 CUSTOMERS?

17 A. Here, Mr. Garrett uses examples of "good luck" to argue that because
18 random chance can influence whether employees make targets or not,
19 this possibility somehow leads to the conclusion that such compensation
20 plans are held in disfavor. Mr. Garrett, however, conveniently ignores the
21 fact that the luck might be bad – e.g., an unseasonably mild summer might
22 weaken the firm's financial performance and make it less likely that the

⁴See Docket No. 06-101-U, Order No. 10 at 62-69.

1 firm hits some financial targets. Moreover, the impact of such events can
2 also affect the level of performance on operational measures such as
3 reliability, such that Mr. Garrett's argument raises no meaningful
4 distinction from the types of incentive payments that the Commission
5 currently allows in rates.

6 The effect of random chance – both positive and negative
7 surprises – is why nearly every overall compensation package provides
8 some component of safe pay, such as salary, instead of consisting of only
9 incentive-based pay. An incentive-only pay package would be too risky
10 from the employee's perspective and too expensive from the firm's
11 perspective due to this greater risk. A balanced approach, however, that
12 includes some incentive compensation, adds the possibility of a reward to
13 the negative of risk. Moreover, that possibility of reward motivates
14 employees to take actions that are in the shareholders' and ratepayers'
15 best interests.

16 The uncertainty of payment of a portion of their compensation
17 provides incentives for employees to take actions that are in the best
18 interest of shareholders and ratepayers alike. The nature of the workplace
19 is such that it is impossible to perfectly observe and verify the employees'
20 actions. Instead, one must rely on signals or indications. These signals or
21 indications will include some element of luck or chance. Ultimately, by
22 properly balancing such incentive compensation with fixed salaries, all
23 parties can be better off – employees, shareholders, and customers.

1 Q. IS THIS VIEW, THAT A BALANCED APPROACH IN SETTING A
2 REASONABLE OVERALL COMPENSATION LEVEL IS BENEFICIAL TO
3 RATEPAYERS, CONSISTENT WITH OTHER TESTIMONY IN THIS
4 CASE?

5 A. Yes. EAI witness Mr. Gardner's testimony discusses EAI's overall
6 compensation, the ways in which it is designed to attract and retain
7 qualified and competent employees, and the ways in which it is
8 reasonable. APSC General Staff ("Staff") witness Bill Taylor concurs with
9 Mr. Gardner. As Mr. Taylor notes in his testimony, "Attracting and
10 retaining qualified and competent employees is beneficial to
11 ratepayers...."⁵ Mr. Taylor goes on to conclude that EAI's total
12 compensation expense, including stock-based incentive compensation, is
13 reasonable, and thus should be allowed in rates. Thus, Mr. Gardner and
14 Mr. Taylor focus on the details of EAI's overall compensation design in a
15 way that is consistent with my testimony r-stock-based incentives can
16 provide benefits to the Company's customers as part of a well-balanced
17 and reasonable overall compensation program.

18 Q. WHAT IS YOUR RESPONSE TO MR. GARRETT'S CONTENTION THAT
19 EARNINGS-BASED INCENTIVE PLANS CAN DISCOURAGE
20 CONSERVATION?

⁵ Taylor Direct Testimony at 6.

1 A. Mr. Garrett hypothesizes that an earnings-based performance target will
2 improperly motivate employees to disregard beneficial programs, such as
3 demand side management, if they perceive that such programs may
4 depress earnings. Mr. Garrett offers no evidence that any such incentive
5 is created by EAI's incentive plan. In fact, his footnote 12 on page 46
6 argues that this rationale is especially relevant in Texas, rather than
7 Arkansas. Moreover, to the extent that an incentive plan encourages the
8 attraction of incremental customers – such as in connection with an
9 economic development program – it may have the positive result of
10 spreading the Company's fixed costs among a larger customer base, to
11 the benefit of all customers. More fundamentally, an appropriate balance
12 of performance incentives in the incentive plan design will avoid the result
13 he hypothesized. For example, when an incentive plan design balances
14 both earnings targets and cost control performance through budget and
15 process efficiency targets, the design should lead managers to reduce
16 costs, which in the long run will directly benefit customers. At the same
17 time, including performance targets related to reliable service and
18 customer satisfaction helps ensure that cost-cutting does not erode
19 customer service.

20 Q. IS MR. GARRETT CORRECT THAT THE UTILITY AND ITS
21 STOCKHOLDERS ASSUME NONE OF THE FINANCIAL RISKS
22 ASSOCIATED WITH INCENTIVE PAYMENTS?

1 A. Based on my understanding of the ratemaking process, this statement is
2 false. If the exact level of incentive compensation for every year was
3 included in rates in that year, then it might be true. However, by using a
4 test year and setting the appropriate incentive compensation level based
5 on that year's data, an expected level of incentive compensation is
6 included in future rates. The utility and shareholders still face financial risk
7 or variation due to fluctuations around that expected level. If incentive
8 compensation is above the amount put in rates, shareholders of the firm
9 will pay that extra amount.

10 In addition, Mr. Garrett's claim here misses the whole point of
11 incentive compensation. The reason incentive compensation is effective
12 is that it puts a portion of the employees' pay at risk. The goal is not to put
13 more risk on the shareholders – they are already bearing the risk of the
14 employees' actions that affect the firms' profitability. By exposing
15 employees' pay to risk or variation, employees have an increased
16 incentive to take actions that are in both shareholders' and ratepayers'
17 best interests.

1 Q. IS THERE ANY MERIT TO MR. GARRETT'S CLAIM THAT INCENTIVE
2 PAYMENTS BASED ON FINANCIAL PERFORMANCE MEASURES
3 SHOULD BE MADE OUT OF INCREASED EARNINGS?

4 A. I do not understand Mr. Garrett's claim or objection here. The test year
5 provides a measure of "expected" or "normal" compensation, including
6 both salaries and reasonable or customary incentive compensation. It is
7 this expected level that is recovered through rates, and thus, shareholders
8 do indeed bear the cost of any additional – or, better than expected –
9 compensation. Thus, what Mr. Garrett claims should happen is exactly
10 what does happen; shareholders pay for compensation that is greater than
11 expectations out of increased earnings.

12

13 Q. IS MR. GARRETT'S VIEW CORRECT THAT INCENTIVE PAYMENTS
14 EMBEDDED IN RATES SHELTER THE UTILITY AGAINST THE RISK OF
15 EARNINGS EROSION THROUGH ATTRITION?

16 A. No. Including a representative level of incentive compensation in rates
17 does not act as a typical financial hedge, unlike the characterization put
18 forth by Mr. Garrett. Hedges act as insurance and pay off more if the
19 firm's performance weakens. Recovering incentive compensation through
20 rates would provide a level cash flow to the utility, holding revenues
21 constant. If the firm's performance weakens due to shocks to its cost
22 structure, then this level cash flow would indeed improve its financial
23 stability, but no more so than other cost components of the rates in place.

1 However, if the performance weakens due to a drop in revenues (for
2 example, due to a drop in electricity consumption), then the cash flow
3 traced to the inclusion of incentive compensation in rates would drop as
4 well (because it is part of the costs that go into establishing the per-unit
5 price). Even if the additional cash flow improves the financial health of the
6 utility, however, a financially healthy utility is in the customers' best
7 interest. As I pointed out in my direct testimony, a utility that is financially
8 unhealthy would likely incur greater costs in the future that would be borne
9 by customers.

10 This last point brings up another problem with Mr. Garrett's
11 testimony. He states:

12 When incentive compensation payments are based on
13 financial performance measures, one could loosely state the
14 compensation agreement between shareholders and
15 employees in this manner: "if you increase shareholder
16 earnings, we will pay you a bonus." The intended
17 beneficiaries to this agreement are the shareholders and the
18 employees. Ratepayers have no stake in this agreement;
19 therefore, they should bear none of the costs that result from
20 such an agreement. If, instead, one could state the
21 agreement in this manner: "if you will help increase reliability
22 and quality of service to the customers, we will pay you a
23 bonus," then, ratepayers would have a stake in the
24 agreement, and could share in a portion of the costs.⁶

25 Mr. Garrett's statement that ratepayers have no stake in the first
26 agreement he references is incorrect in my opinion. Ratepayers are likely
27 to benefit from a financially healthy utility for the many reasons discussed
28 in my direct testimony. In addition, a well-balanced incentive plan that

⁶ Garrett Direct Testimony at 21-22.

1 provides reasonable compensation and rewards employees based on
2 operational measures in addition to financial measures will help ensure
3 that improvements in shareholders' welfare do not come at the expense of
4 customer welfare.

5

6 Q. IS MR. GARRETT'S STATEMENT THAT RATEPAYERS HAVE NO
7 STAKE IN INCENTIVE COMPENSATION AGREEMENTS BASED ON
8 FINANCIAL PERFORMANCE MEASURES LOGICAL AND CONSISTENT
9 WITH HIS OTHER STATEMENTS?

10 A. No. In addition to the benefits that ratepayers experience from a
11 financially healthy utility (as discussed in my direct testimony), perhaps the
12 easiest way to see the error in Mr. Garrett's argument that ratepayers
13 have no stake in such incentive compensation plans is to consider an
14 incentive plan that motivates employees to achieve increased efficiencies
15 or control costs, such as budgetary targets. Because of the regulatory
16 process, the benefits of any cost controls would be passed along to
17 ratepayers through lower rates in the future. Thus, it seems obvious that it
18 is in the ratepayers' interests that the utility implements a fair and
19 reasonable incentive compensation plan that motivates employees to
20 control costs.

21 Mr. Garrett admits this point, as on page 25 where, following his
22 argument that the short-term incentive costs should be shared by
23 ratepayers and shareholders, he states: "This equal sharing between

1 ratepayers and shareholders recognizes that both benefit from the
2 structure of the Company's plans. Ratepayers benefit through increased
3 operational efficiencies and shareholders benefit through managements'
4 ability to redirect incentive costs included in rates to the shareholders if
5 excess profits are not sufficiently available to make the payments." Based
6 on this discussion, it is clear that Mr. Garrett understands that ratepayers
7 ultimately benefit from incentive compensation plans that lead to greater
8 cost control, via the regulatory process. Thus, Mr. Garrett contradicts his
9 earlier statement on pages 21 and 22 that ratepayers have no stake in
10 these types of agreements.

11
12 **III. RESPONSE TO MR. GARRETT AND DR. BLANK'S CLAIMS THAT**
13 **RATEPAYERS DO NOT BENEFIT FROM STOCK-BASED INCENTIVES**
14 **IN A REGULATED ENVIRONMENT**

15 Q. DO YOU AGREE WITH MR. GARRETT'S AND DR. BLANK'S
16 CHARACTERIZATION THAT YOUR CONCLUSIONS DO NOT HOLD IN
17 A REGULATED ENVIRONMENT?

18 A. No, I do not.

19
20 Q. WHY DO YOUR CONCLUSIONS STILL APPLY IN A REGULATED
21 ENVIRONMENT?

22 A. Mr. Garrett argues that my conclusions are not valid from a ratemaking
23 perspective because in the presence of stock-based compensation,

1 executives can have the incentive to seek regulated rate increases. While
2 this incentive may be present, Mr. Garrett is ignoring the role of the
3 ratemaking process itself, which is designed to allow only reasonable rate
4 increases. This process offers a check and balance on stock-based
5 incentive compensation, much the way that boards of directors,
6 shareholders, and other stakeholders help monitor executive
7 compensation more broadly, ensuring that it is reasonable.

8 This point is related to Dr. Blank's testimony in which he argues
9 that in a regulated environment, shareholders only benefit from excessive
10 capital investment and not cost cutting. He also claims that it is well-
11 known that managers in a regulated firm will tend to over-invest in capital,
12 leading to higher total costs.

13

14 Q. WHAT KEY ASSUMPTIONS ARE MISSING FROM DR. BLANK'S
15 TESTIMONY?

16 A. First, Dr. Blank seems to argue that regulated firms have no incentive to
17 cut costs to improve shareholder value, even while he admits that
18 shareholders stand to benefit from such cuts between rate cases. He also
19 says that these cuts do not benefit customers, thereby ignoring the fact
20 that these cost-saving measures will tend to be reflected in rates after the
21 next rate case. Thus, in a similar vein to the discussion above, the rate-
22 making process itself is crucial – it partitions gains from cost-cutting

1 measures between shareholders and ratepayers, implying that stock-
2 based incentives will also tend to benefit ratepayers.

3 Secondly, Dr. Blank's claim that excessive capital investment will
4 occur in a regulated environment appears to rely on an assumption that he
5 does not make clear – that the rate of return on capital that a regulated
6 company is allowed to earn is *greater* than its cost of capital. While not
7 spelled out in his testimony, this assumption is behind the results in the
8 two classic articles he cites (see his footnotes 2 and 3).⁷ As stated in
9 Averch and Johnson , “The essential characteristic to be demonstrated is:
10 if the rate of return allowed by the regulatory agency is greater than the
11 cost of capital...then the firm will substitute capital for the other factor of
12 production and operate at an output where cost is not minimized”⁸ Wellis
13 states, “The ‘fair return’ that a regulated company is permitted to earn
14 must be greater than the company’s cost of capital...Equality of ‘fair
15 return’ with the cost of capital yields an indeterminate solution.”⁹

16 My conclusions do not rely on such a flaw in the regulatory process.
17 This appears to be why Dr. Blank believes that my testimony is
18 contradictory.¹⁰ But, if the regulatory process ensures that companies are
19 allowed to earn their cost of capital (and not more), then it is true that

⁷ See H. Averch & L. Johnson (1962), “Behavior of the Firm under Regulatory Constraint,” *American Economic Review*, Vol. 52, at 1052-1069 and S. Wellisz (1963), “Regulation of Natural Gas Pipeline Companies: An Economic Analysis,” *Journal of Political Economy*, Vol. 71, at 30-43.

⁸ Averch & L. Johnson at 1053.

⁹ Wellisz at 35.

¹⁰ Blank Direct Testimony at 8.

1 stock-based compensation can provide an incentive to managers to curtail
2 excessive investment.

3

4 Q. WHAT ELSE DO MR. GARRETT AND DR. BLANK IGNORE ABOUT
5 YOUR TESTIMONY'S APPLICABILITY IN A REGULATED
6 ENVIRONMENT?

7 A. While Mr. Garrett and Dr. Blank claim that my conclusions do not hold in a
8 regulated environment, they ignore the fact that empirical evidence from
9 the regulated utility industry supports my conclusions. Perhaps the most
10 direct of these is a study that examined the differences in performance of
11 two divisions within a regulated utility company – one that added an
12 incentive compensation plan with payouts based on financial measures
13 such as sales, costs, and investments, plus employee absenteeism, and a
14 second division that served as a control group because it did not take part
15 in the incentive plan. The authors of this study found that, for the division
16 that added the incentive plan, performance was significantly better along
17 several dimensions, including operational measures (e.g., reliability) and
18 employee health and safety.¹¹ In addition, I discussed in my testimony the
19 empirical evidence in the literature that firms – both broadly and utilities in
20 particular – with higher market values tend to also have higher customer

¹¹ M.M. Petty, Bart Singleton, and David W. Connell, "An Experimental Evaluation of an Organizational Incentive Plan in the Electric Utility Industry," 77 *Journal of Applied Psychology*, 4 at 427-436 (1992).

1 satisfaction, supporting the conclusion that the goals of financial success
2 and customer satisfaction are interrelated.¹²
3

4 **IV. CONCLUSION**

5 Q. COULD YOU BRIEFLY SUMMARIZE YOUR TESTIMONY?

6 A. Mr. Garrett and Mr. Marcus, who makes similar points, gives a list of
7 reasons why stock-based incentive compensation should be excluded
8 from rates. However, these reasons reflect an incomplete understanding
9 of the role of variability in incentive-based compensation (whether it is
10 linked to stock prices or what have been typically referred to as
11 “operational measures”). Moreover, these reasons also tend to ignore the
12 role of stock-based incentive compensation as part of an overall, balanced
13 and reasonable set of compensation tools that can be used to attract,
14 motivate and retain talented executives, thereby benefitting both
15 shareholders and ratepayers.

16 Furthermore, Mr. Garrett and Dr. Blank attempt to argue that my
17 conclusions are not valid in a regulated setting. However, these
18 arguments appear to either ignore the regulatory process or to require that
19 it is substantially flawed, leading to perverse incentives for managers of
20 regulated companies. In contrast, existing empirical evidence (discussed
21 in my direct testimony but apparently ignored by both Mr. Garrett and Dr.

¹² Christopher D. Ittner and David F. Larcker, “Are Nonfinancial Measures Leading Indicators of Financial Performance? An Analysis of Customer Satisfaction,” 36 *Journal of Accounting Research*, Supplement 1998 at 1 - 35.

1 Blank) suggests that financial incentives can tend to benefit other
2 stakeholders, even in a regulated utility.

3

4 Q. DOES THIS CONCLUDE YOUR REBUTTAL TESTIMONY?

5 A. Yes.

CERTIFICATE OF SERVICE

I, Steven K. Strickland, do hereby certify that a copy of the foregoing has been served upon all parties of record by forwarding the same by electronic mail and/or first class mail, postage prepaid, this 26th day of August, 2013.

/s/ Steven K. Strickland
Steven K. Strickland

BEFORE THE
ARKANSAS PUBLIC SERVICE COMMISSION

IN THE MATTER OF THE APPLICATION	)	
OF ENTERGY ARKANSAS, INC. FOR	)	DOCKET NO. 13-028-U
APPROVAL OF CHANGES IN RATES FOR	)	
RETAIL ELECTRIC SERVICE	)	

REBUTTAL TESTIMONY

OF

JAY K. THAYER

VICE PRESIDENT, ENGINEERING

ENTERGY SERVICES, INC.

ON BEHALF OF

ENTERGY ARKANSAS, INC.

AUGUST 26, 2013

1 **I. INTRODUCTION**

2 Q. PLEASE STATE YOUR NAME.

3 A. My name is Jay K. Thayer.

4

5 Q. ARE YOU THE SAME JAY K. THAYER WHO FILED DIRECT
6 TESTIMONY IN THIS DOCKET ON MARCH 1, 2013?

7 A. Yes, I am.

8

9 Q. ON WHOSE BEHALF ARE YOU TESTIFYING?

10 A. I am submitting this rebuttal testimony to the Arkansas Public Service
11 Commission ("APSC" or the "Commission") on behalf of Entergy
12 Arkansas, Inc. ("EAI" or the "Company").

13

14 Q. WHAT IS THE PURPOSE OF YOUR REBUTTAL TESTIMONY?

15 A. The purpose of my rebuttal testimony is to respond to Section III.I.2 of the
16 Direct Testimony of William B. Marcus on behalf of the Arkansas Attorney
17 General ("AG"), regarding Nuclear Energy Institute ("NEI") dues.¹

18

¹ At pages 70-73 of his direct testimony concerning NEI dues, Mr. Marcus refers to me as "Mr. Fox." In fact, I was the one who provided direct testimony on this subject.

1 **II. NUCLEAR ENERGY INSTITUTE DUES**

2 Q. WOULD YOU BRIEFLY SUMMARIZE YOUR UNDERSTANDING OF
3 MR. MARCUS' TESTIMONY CONCERNING NEI DUES INCLUDED IN
4 THE COMPANY'S FILING?

5 A. Yes. Beginning at page 70 of his direct testimony, Mr. Marcus has
6 proposed to disallow an additional \$172,584 in NEI dues on the basis that
7 he believes that NEI's "public relations activities" should not be paid for by
8 EAI's customers. Mr. Marcus proposes to cut in half the NEI dues
9 included in rates.

10
11 Q. PLEASE DESCRIBE THE PUBLIC RELATIONS ACTIVITIES
12 MR. MARCUS IDENTIFIED AS BEING OBJECTIONABLE.

13 A. Mr. Marcus cites to a dozen or so NEI publications designed to provide
14 public education about nuclear energy. Without explaining why, he also
15 cites a Union of Concerned Scientists article critical of NEI. He contends
16 the NEI publications are "image advertising supporting nuclear power."²
17 He concludes that "[m]any Arkansas ratepayers disagree with this
18 perspective," and the costs should not be funded through rates.³ He also
19 objects to NEI's polling and opinion research activities.

20

² Marcus Direct Testimony at 72.

³ *Id.*

1 Q. DO YOU AGREE WITH MR. MARCUS' CONCLUSIONS REGARDING
2 THESE MATERIALS?

3 A. No, I do not. I believe the conclusions he draws from these materials are
4 short-sighted and not in the best interests of the Company's customers.
5

6 Q. WHAT IS THE BASIS FOR YOUR POSITION?

7 A. First, I observe that Mr. Marcus has had to reach well outside the 2012
8 test year in this case, back as far as 2007, to find publications he regards
9 as objectionable. For example, he cites an NEI "*Insights*" article from
10 August/September 2007, which he characterizes as a "public relations
11 campaign to teach Belarusian children (who live near the real nuclear
12 disaster of Chernobyl) not to fear nuclear power."⁴ In fact, this is a nine
13 paragraph article concerning a group of Belarusian children who were
14 brought to South Carolina for, among other things, "medical, dental and
15 vision care." While in South Carolina, the children visited Duke Energy
16 Corporation's Oconee Nuclear Station's visitor center. The article hardly
17 supports the characterization given to it by Mr. Marcus.

18 Putting aside this mischaracterization, NEI does indeed do some
19 work to educate the public about nuclear power and its benefits. This is
20 not the primary thrust of NEI's body of work (much of which I described in
21 my direct testimony), but this kind of work is important in minimizing the
22 cost to EAI caused by sometimes-misguided attacks on nuclear

⁴ *Id.*

1 operations in the nuclear regulatory arena. The small amount we pay for
2 this sort of public outreach might be exceeded by costs associated with
3 addressing a single public opposition to a Nuclear Regulatory Commission
4 (“NRC”) licensing action for Arkansas Nuclear One (“ANO”).
5

6 Q. MR. MARCUS SUGGESTS MANY ARKANSAS RATEPAYERS
7 DISAGREE WITH NEI’S PERSPECTIVE. HOW DO YOU RESPOND TO
8 MR. MARCUS’ COMPLAINT THAT PAYING FOR THESE
9 EDUCATIONAL MATERIALS “FORCE[S] BOTH OF THESE DISPARATE
10 SETS OF RATEPAYERS ON THE LEFT AND THE RIGHT TO FUND
11 THROUGH ELECTRICAL RATES POLITICAL VIEWS THAT THEY
12 OPPOSE”?⁵

13 A. These materials are designed to inform the public about the benefits of
14 nuclear generation sources. As I mentioned previously, such information
15 may lead the public to forego opposition to the current generation mix in
16 Arkansas in ways that would have imposed costs on the ratepayers.
17

18 Q. YOU PREVIOUSLY MENTIONED MR. MARCUS’ CITATION OF A
19 UNION OF CONCERNED SCIENTISTS ARTICLE. WHAT
20 SIGNIFICANCE DO YOU FIND IN THIS?

21 A. The Union of Concerned Scientists is not an advocate of nuclear power.
22 As it states on its website, from which Mr. Marcus pulled an article critical

⁵ *Id.*

1 of the NEI: "Prudence dictates that we develop as many options to reduce
2 global warming emissions as possible, and begin by deploying those that
3 achieve the largest reductions most quickly and with the lowest costs and
4 risk. Nuclear power today does not meet these criteria."⁶

5 These kinds of statements can encourage opposition to nuclear
6 power generators such as ANO. The NEI's publications seek to provide
7 information about the benefits of nuclear power.

8

9 Q. ARE THERE ANY LICENSING ACTIONS ON THE HORIZON THAT
10 COULD BE AFFECTED BY WIDESPREAD PUBLIC OPPOSITION TO
11 NUCLEAR POWER?

12 A. Yes. The NRC has recently issued several orders requiring nuclear plants
13 to implement compensatory measures to address issues identified as a
14 result of analysis of the earthquake and tsunami, and ensuing nuclear
15 plant damage that occurred at the Japanese Fukushima-Dai'ichi nuclear
16 station on March 11, 2011. Those NRC orders are not highly prescriptive.
17 By that, I mean that the orders imposed certain standards on the
18 licensees, but they do not dictate exactly what changes the licensees must
19 implement to comply. The public is given many opportunities to be
20 involved in these kinds of proceedings, and with non-prescriptive orders,
21 there may be room for disagreement about what changes are enough to

⁶ http://www.ucsusa.org/nuclear_power/nuclear_power_and_global_warming/ucs-position-on-nuclear-power.html.

1 fulfill the intent of the orders. The Company welcomes public participation
2 in such proceedings, but participation by informed members of the public
3 is more productive. NEI's publications facilitate informed participation
4 such that needless costs are not incurred in the process.

5

6 Q. YOU MENTIONED MR. MARCUS OBJECTED TO NEI POLLING AND
7 OPINION RESEARCH. WHY IS THAT WORK OF VALUE?

8 A. The polling that Mr. Marcus reports as being done every 6 months to a
9 year is used to gauge the effectiveness of NEI's educational efforts.
10 Without that work, it would be difficult to adjust NEI's educational outreach
11 for effectiveness.

12

13 Q. DO YOU HAVE ANY OTHER CONCERNS REGARDING MR. MARCUS'
14 RECOMMENDATION FOR NEI DUES?

15 A. Yes. Mr. Marcus presents no basis for his proposed disallowance of one-
16 half of NEI dues. Instead, as noted above, he identified a few publications
17 and activities he believes the Company's customers should not pay for,
18 and without any explanation of his calculus, proposed that only half the
19 Company's actual share of NEI dues should be included in rates. This is
20 arbitrary, and should not be permitted.

21

1 **III. CONCLUSION**

2 Q. COULD YOU BRIEFLY SUMMARIZE YOUR TESTIMONY?

3 A. Yes. Mr. Marcus' proposed disallowance of one-half of NEI dues fails to
4 take into account the valid need for educational materials concerning
5 nuclear power, and the tangible benefit (and reduced regulatory cost) to
6 the ratepayers of a public educated about generation choices. Moreover,
7 Mr. Marcus' proposal to include only half the NEI dues in rates is arbitrary
8 and unsupported by any analysis. For these reasons, I continue to
9 support a recovery of 75.4 percent of NEI dues, with 24.6 percent
10 associated with costs that are not appropriate for recovery in rates.
11 Attached to my testimony as EAI Exhibit JKT-3 is a copy of the 2012
12 lobbying expenditure percentages as calculated by NEI. This information
13 was provided as part of EAI's response to AG data request AG 3-29.

14

15 Q. DOES THIS CONCLUDE YOUR REBUTTAL TESTIMONY?

16 A. Yes.

CERTIFICATE OF SERVICE

I, Steven K. Strickland, do hereby certify that a copy of the foregoing has been served upon all parties of record by forwarding the same by electronic mail and/or first class mail, postage prepaid, this 26th day of August, 2013.

/s/ Steven K. Strickland
Steven K. Strickland

BEFORE THE
ARKANSAS PUBLIC SERVICE COMMISSION

IN THE MATTER OF THE APPLICATION	)	
OF ENTERGY ARKANSAS, INC. FOR	)	DOCKET NO. 13-028-U
APPROVAL OF CHANGES IN RATES FOR	)	
RETAIL ELECTRIC SERVICE	)	

EAI EXHIBIT JKT-3

2012 NEI LOBBYING EXPENDITURES

NEI Expenditures By Category						
Category	2007	2008	2009	2010	2011	2012
1) Business Gifts	0.10%	0.10%	0.10%	0.10%	0.10%	0.10%
2) Institutional, consumption-inducing, and other advertising expenses	9.90%	12.80%	9.80%	9.83%	11.70%	8.40%
3) Public relations expenses	1.10%	1.10%	2.70%	1.79%	1.90%	3.20%
4) Legislative Matters including advocacy before any legislative body	13.30%	12.40%	11.40%	12.92%	11.20%	12.00%
5) Representation before governmental bodies including municipalities	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
6) Legal expenses not included in other categories	2.50%	3.70%	6.10%	2.41%	5.00%	4.70%
7) Contributions and donations	1.50%	1.30%	1.10%	1.25%	1.25%	1.00%
8) Total for Categories	28.40%	31.40%	31.20%	28.30%	31.15%	29.40%
				For AJ20.3	* =	24.60%
Source:						
Rob Dubrow, CPA						
Sr. Director-Finance and Controller						
Nuclear Energy Institute						
9/6/2012						

BEFORE THE
ARKANSAS PUBLIC SERVICE COMMISSION

IN THE MATTER OF THE APPLICATION)
OF ENTERGY ARKANSAS, INC. FOR)
APPROVAL OF CHANGES IN RATES FOR)
RETAIL ELECTRIC SERVICE)

DOCKET NO. 13-028-U

REBUTTAL TESTIMONY

OF

JULIE M. CANNELL

ON BEHALF OF

ENTERGY ARKANSAS, INC.

AUGUST 26, 2013

1 **I. INTRODUCTION**

2 Q. PLEASE STATE YOUR NAME.

3 A. My name is Julie M. Cannell.

4

5 Q. ARE YOU THE SAME JULIE M. CANNELL WHO FILED DIRECT
6 TESTIMONY IN THIS DOCKET ON MARCH 1, 2013?

7 A. Yes, I am.

8

9 Q. ON WHOSE BEHALF ARE YOU TESTIFYING?

10 A. I am submitting this rebuttal testimony to the Arkansas Public Service
11 Commission (“APSC” or the “Commission”) on behalf of Entergy
12 Arkansas, Inc. (“EAI” or the “Company”).

13

14 Q. WHAT IS THE PURPOSE OF YOUR REBUTTAL TESTIMONY?

15 A. The purpose of my rebuttal testimony is to comment on the respective
16 return on equity (“ROE”) recommendations set forth in the direct
17 testimonies of Mr. Robert Daniel on behalf of the APSC General Staff
18 (“Staff”); Mr. William Marcus for the Arkansas Attorney General (“AG”); Mr.
19 David Parcell representing the Arkansas Electric Energy Consumers, Inc.
20 (“AEEC”); and Mr. Michael Gorman on behalf of the Federal Executive
21 Agencies (“FEA”). Additionally, I address specific comments of Messrs.
22 Parcell and Daniel in regard to my direct testimony, as well an aspect of
23 Mr. Marcus’ testimony.

1 I have extensive experience over the past three-plus decades in the
2 market for utility securities. The overarching purpose of my testimony is to
3 bring this experience to the Commission and provide input as to investor
4 expectations regarding the cost of capital in the marketplace.

5

6 **II. REBUTTAL SUMMARY**

7 Q. PLEASE SUMMARIZE THE KEY POINTS OF YOUR REBUTTAL
8 TESTIMONY.

9 A. The respective ROE recommendations of the AG (9.25 percent), AEEC
10 (9.25 percent), FEA (9.4 percent), and Staff (9.6 percent) do not meet the
11 expectations of investors. None adequately compensates investors for
12 the risk they are assuming with an investment in EAI. Additionally, the AG
13 and AEEC respective proposals are lower than only one of the 155 ROE
14 amounts allowed for integrated electric utilities nationwide since the
15 beginning of 2009.¹ FEA's is less than only two, and Staff's is less than
16 only three over that same period of time.

17 Both Mr. Parcell and Mr. Daniel challenge the 10.4 percent ROE
18 within the 10.2 percent to 10.4 percent range that I support. Mr. Parcell

¹ EAI Exhibit JMC-2 accompanying this testimony presents authorized ROEs for integrated electric utilities from 2009-2Q13. It should be noted that there were no ROEs granted to integrated electric utilities prior to 2009 that were lower than the levels reflected in this exhibit. Only one company—Connecticut-based wires-only utility United Illuminating Co. ("UIL")—received a lower ROE of 8.75%. As Regulatory Research Associates ("RRA") stated in its evaluation of the UIL order, "The DPUC authorized an 8.75% return on equity (ROE) which is almost 200 basis points below the average of state commission ROE authorizations in 2008, and the *lowest non-penalty ROE determination for energy utilities nationwide in at least the last 30 years.*" (emphasis added) It can therefore be inferred that no integrated electric company received an ROE allowance less than those displayed in the exhibit.

1 claims there is no basis for that number because he believes recent strong
2 price performance means that investment risk has not risen in the electric
3 utility industry. I disagree with his assessment. Electric utilities'
4 investment performance has been driven by factors originating from
5 outside the industry. Mr. Daniel states that EAI's 10.4 percent ROE
6 proposal that I endorse is different from the range derived from Dr.
7 Hadaway's recommendation and that I performed no quantitative analysis
8 to reach my conclusion. My role in this case is to convey the viewpoint of
9 investors, not to construct the econometric models and provide
10 quantitative analyses as supplied by Dr. Hadaway and others, including
11 Messrs. Parcell, Gorman, Marcus, and Daniel. Ultimately, the cost of
12 capital is determined by the market, not by the application of econometric
13 models. While some investors may consider the results of these models
14 when making decisions to buy and sell certain stocks, investors ultimately
15 apply judgment in making the final determination in the price they are
16 willing to purchase or sell the stock.

17 As illustrated in my direct testimony and reiterated herein, the
18 change in stock price can be dramatic when investors are disappointed.
19 Should investors' expectations fail to be met for EAI's potential for growth
20 in earnings and dividends, it is probable that investors would both adjust
21 the price they are willing to pay for the stock of the Company's parent and
22 reevaluate their opinion of Arkansas regulation. This would increase the
23 cost of capital to the Company and ultimately the cost of service to

1 ratepayers and potentially affect the cost of capital for other Arkansas
2 utilities.

3 Additionally, my rebuttal testimony comments on Mr. Marcus'
4 position that the allowed ROE should reflect the returns integrated into
5 corporate pension plans.

6

7 **III. RETURN ON EQUITY**

8 Q. IN YOUR OPINION, ARE THE ROE RECOMMENDATIONS OF THE
9 INTERVENING PARTIES AND STAFF CONSISTENT WITH INVESTOR
10 EXPECTATIONS?

11 A. No. The ROE proposals set forth by AG (9.25 percent), AEEC (9.25
12 percent), and FEA (9.4 percent) are well below the return level expected
13 by investors. Staff's recommendation of 9.6 percent is also insufficient
14 compensation for the risk investors would be assuming in an investment in
15 EAI. While interest rates have been near historically low levels, the
16 monetary policy of the Federal Reserve System ("Fed") created that
17 circumstance, as stated in my direct testimony. Additionally, as Dr.
18 Hadaway's rebuttal testimony discusses in depth, the Federal Open
19 Market Committee at its June 19, 2013 meeting signaled that a change
20 toward more restrictive monetary policy could be forthcoming in the near
21 future. Interest rates have risen in response to that indication, and with
22 them, risk to investors.

1 Should the APSC adopt any of the intervening parties' or Staff's
2 proposals, which reflect an overreaction to artificially low interest rates, I
3 believe it would have a potentially detrimental impact on investor
4 perceptions regarding the Company's earnings and dividend prospects as
5 well as investors' view of the quality and consistency of Arkansas
6 regulation. An ROE outcome in the current proceeding deemed as being
7 inadequate in meeting investors' requirements for risk compensation most
8 likely would result in a deterioration of investors' perceptions of the quality
9 of the Arkansas regulatory environment. Because regulatory consistency
10 is important to investors, a reduction of the currently allowed 10.2 percent
11 return to anywhere within a range of 9.25 percent to 9.6 percent,
12 particularly since industry and market risk are still considerable and
13 interest rates are rising, is likely to be disappointing to investors. In a
14 jurisdiction marked by negative regulatory perception, investors would
15 likely require higher compensation for risk associated with utilities
16 governed by that regulatory jurisdiction.

17
18 Q. ARE THE INTERVENING PARTIES' RECOMMENDATIONS
19 CONSISTENT WITH RECENT NATIONWIDE TRENDS FOR ALLOWED
20 RETURNS?

1 A. No, they are not. As EAI Exhibit JMC-2 illustrates, in the 155 rate case
2 decisions rendered since the beginning of 2009² for integrated electric
3 utilities in which an ROE was established, there has been only one
4 allowed ROE lower than the 9.25 percent recommended by the AG and
5 AEEC, only two ROEs below the 9.4 percent proposed by FEA, and only
6 three below Staff's recommendation.

7 Such results suggest that none of the foregoing ROE
8 recommendations would meet investor expectations for the Company.
9 Moreover, an authorized return at or near the levels proposed by the
10 intervening parties would put the Company at a distinct disadvantage in
11 the competition for capital going forward. Adopting the AG, AEEC, FEA,
12 or Staff proposal also would represent a step backward by the
13 Commission in establishing a constructive, consistent regulatory
14 framework for Arkansas. It bears mention that Regulatory Research
15 Associates ("RRA") continues to maintain the "Average/3" ranking of
16 Arkansas regulation it has had in place since early 2011. Prior to that,
17 RRA had assessed Arkansas as "Below Average/1" since April 2006. The
18 undue reliance on low interest rates by these witnesses produces
19 unrealistic equity return rates that do not reflect the requirement that
20 utilities must raise capital in all markets. Significant changes in allowed
21 ROEs like those proposed in this case particularly by the AG and AEEC,

² 2009 was chosen to reflect roughly the onset of the Great Recession and attendant credit crisis, uncertainty surrounding which still exists.

1 but also the FEA and Staff, ignore the fact that investment in utility assets
2 is a long-term proposition and also that interest rates are beginning to rise.
3

4 **IV. RESPONSE TO WITNESS PARCELL**

5 Q. PLEASE TURN NOW TO MR. PARCELL'S COMMENTARY ON YOUR
6 TESTIMONY. WHAT IS HIS GENERAL POSITION?

7 A. Mr. Parcell posits that my "comments are not supportive of the specific
8 10.40 percent return on equity requested by EAI."³ The first of his
9 comments involves increasing risk in the utility industry, which he claims
10 does not exist. Mr. Parcell opines that "the relevant demonstration of risks
11 is how EAI and other utilities have fared on a relative basis in comparison
12 to other types of investments.... This indicates no increase in the relative
13 risks for the electric utilities over the past several years."⁴
14

15 Q. DO YOU AGREE WITH HIS POSITION?

16 A. No. It is a well-known fact—and my direct testimony and that of other
17 witnesses note this—that electric utilities' defensive characteristics are
18 particularly prominent at certain times, including the beginning of
19 recessions. In such periods, it is not unusual for most utility stocks to
20 outperform other types of investments, as investors seek relative safety
21 and income during periods of uncertainty. But it should be noted that

³ Parcell Direct Testimony at 46.

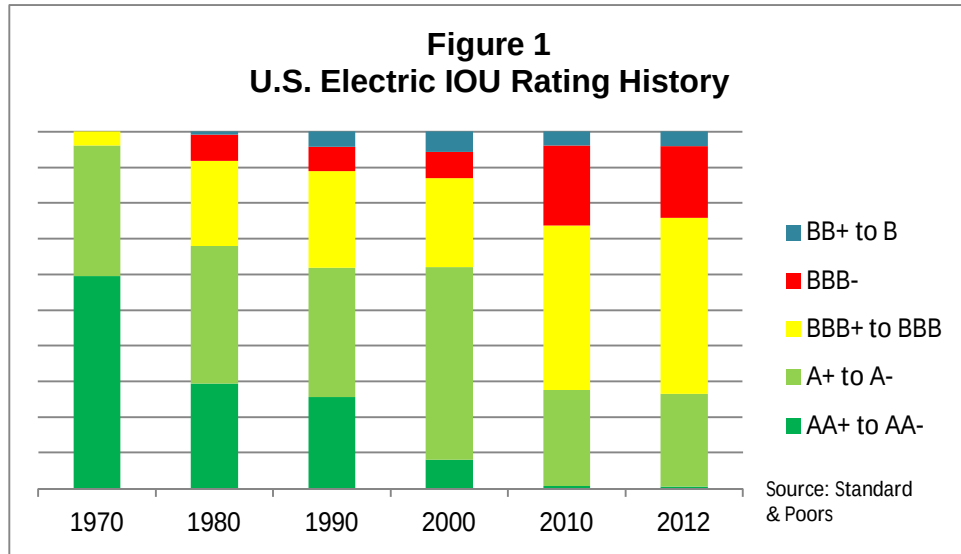
⁴ *Id.*

1 “relative” is the operative word in the preceding sentence. Such investor
2 behavior does not signify that the utility industry is without risk. Further, as
3 soon as the economy displays any hint of resurgence and/or interest rates
4 show signs of rising (even where recessionary conditions are still present),
5 electric utility stocks can quickly move to an under-performance mode as
6 investors shift to placing more emphasis on economically-sensitive stocks
7 and related price appreciation.

8 Thus, since the onset of the recession in late 2008/early 2009 and
9 attendant credit crisis, the relative outperformance of electric utility stocks
10 can logically be explained by the attractive dividend yield most utility
11 companies offer. As the Fed pursued an accommodative monetary policy
12 over this period, interest rates have dropped steeply, resulting in most
13 money market funds and other so-called safe interest-bearing investments
14 not providing competitive returns. Conversely, electric utilities have
15 afforded investors largely consistent income opportunities coupled with
16 price appreciation for an attractive total return on investment.

17 But the fact that investors have flocked to the group in recent times
18 to obtain needed income and relative perceived safety in their investments
19 does not mean that the industry’s risk has not risen. As graphically
20 displayed in Figure 1, credit quality in the electric utility industry has
21 weakened significantly since the last major utility construction cycle.
22 While some credit rating criteria may have been changed in general, there
23 is no mistaking the fact that the electric utility industry’s moving from a

1 single “A” industry at the start of the 1980s to a “BBB” industry currently
 2 reflects heightened risk.



3
 4 Mr. Parcell also states that I performed no quantitative analysis in
 5 supporting EAI’s request for a 10.4 percent ROE within a 10.2 percent to
 6 10.4 percent range. It is not my responsibility in this proceeding to
 7 construct the econometric models utilized by several witnesses, including
 8 Mr. Parcell and others, to calculate the equity rate of return. Rather, my
 9 role in this case is to present the expectations of investors—investors who
 10 may or may not utilize the results produced by those types of models in
 11 their decision-making, but who do not necessarily build the models
 12 themselves. So, while econometric models and quantitative analyses may
 13 be one consideration in reaching an investment decision, ultimately
 14 judgment must be applied to determine the investment attractiveness of
 15 an individual company. My judgment, which is based on over three

1 decades of experience with the electric utility industry, two decades of
2 which were spent as a securities analyst and portfolio manager for a major
3 investment organization, qualifies me to comment on investors'
4 expectations for the allowed ROE in this case.

5

6 **V. RESPONSE TO WITNESS DANIEL**

7 Q. WHAT DISAGREEMENT DID MR. DANIEL EXPRESS IN REGARD TO
8 YOUR DIRECT TESTIMONY?

9 A. Similar to Mr. Parcell, Mr. Daniel comments that I performed no
10 quantitative analysis to support EAI's requested ROE of 10.4 percent
11 within a 10.2 percent to 10.4 percent range. Additionally, he points out
12 that the Company's request, which I endorsed, is beyond the proposed 9.6
13 percent to 10.0 percent ROE range contained in Dr. Hadaway's direct
14 testimony.

15

16 Q. PLEASE COMMENT ON MR. DANIEL'S CONCERNS.

17 A. As noted in my foregoing comments regarding Mr. Parcell's views on my
18 direct testimony, conducting a quantitative analysis was beyond the scope
19 of my responsibilities in this proceeding. Mr. Daniel correctly states that
20 the 10.2 percent to 10.4 percent ROE range I support on behalf of EAI is
21 above the ROE range set forth by Dr. Hadaway in his direct testimony.
22 However, as both Mr. Daniel and Dr. Hadaway observe in their respective
23 direct testimonies, the current low level of interest rates has impacted the

1 results in certain econometric models—the DCF, in particular.⁵ But
2 interest rates have begun to rise, and Dr. Hadaway’s rebuttal testimony
3 states that increase serves as further validation of the Company’s ROE
4 request and highlights the unrealistic character of the other parties’ ROE
5 recommendations. Mr. Daniel’s testimony also notes that the existing
6 macroeconomic circumstances have had a dampening impact on electric
7 utility growth patterns. In short, it is necessary to look beyond quantitative
8 models with their temporal influences to fully encompass the risks
9 investors are undertaking to invest in the electric utility industry at the
10 current time. Investors may incorporate such models in their investment
11 analysis, but they understand the shortcomings inherent in modeling,
12 particularly when external circumstances are as skewed from historic
13 norms as they are at the present time. Accordingly, investors must then
14 apply judgment to reflect the multiple risks—large capital programs and
15 attendant funding requirements, environmental mandates, regulatory
16 challenges, to name several—to arrive at a decision that fully reflects the
17 investment paradigm for a given company.

18
19 Q. DID MR. DANIEL EXPRESS FURTHER CONCERNS REGARDING
20 YOUR DIRECT TESTIMONY?

21 A. Yes. He takes exception to my discussion regarding allowed ROE levels
22 for other utilities whose service territories are located in the Southeast.

⁵ Daniel Direct Testimony at 35-36; Hadaway Direct Testimony at 19-20, 33.

1 Mr. Daniel states that the APSC “has previously rejected the notion of
2 relying on such an approach to establishing the cost of equity for
3 ratemaking purposes. Further, the returns on equity allowed by other
4 commissions for different companies under varying circumstances in
5 conjunction with the employment of varying ratemaking approaches simply
6 cannot provide reasonable foundation for a conclusive determination of
7 the required return on equity for EAI.”

8

9 Q. PLEASE RESPOND.

10 A. My direct testimony includes a discussion of allowed ROEs in the
11 Southeast not in an effort to persuade the Commission to place undue
12 emphasis on this factor, but rather to present a full picture of investor
13 expectations. Investors make decisions on a comparative basis, with
14 geography (*i.e.*, service territory) being one criterion they consider.
15 Additionally, when a utility is part of a multi-state holding company, equity
16 investors evaluate the returns of the holding company permitted in all
17 jurisdictions—the only vehicle in which they can invest—as part of their
18 analysis.

19

1 **VI. RESPONSE TO WITNESS MARCUS**

2 Q. PLEASE ADDRESS MR. MARCUS' COMMENTARY ON UTILITIZING
3 PENSION RETURNS AS AN ADDITIONAL MEANS FOR REACHING AN
4 APPROPRIATE LEVEL OF ROE IN THIS PROCEEDING. DO YOU
5 AGREE WITH HIS REASONING?

6 A. No. The derivation of pension returns incorporates a different process
7 than does that of establishing an ROE for a regulated electric utility in a
8 rate proceeding. These two processes are used for different purposes.
9 The former involves making actuarial as well as overall stock market
10 performance assumptions for the purpose of determining the expected
11 returns involved in meeting a corporation's pension obligations over a
12 lengthy period of time. The latter process incorporates consideration of an
13 appropriate equity return level required by investors for a specific
14 company, a utility that investors examine relative to other investment
15 prospects, for presumably a finite time frame. In short, the two processes
16 are different. Mr. Marcus is mixing apples with oranges.

17
18 Q. HAS THE APSC ADDRESSED THE ISSUE OF COMPARING PENSION
19 FUND EXPECTED RETURNS TO THAT OF ESTABLISHING ROES?

20 A. Yes. In Docket No. 04-121-U, a case involving CenterPoint Arkla, the
21 Commission stated:

22
23 AG witness Marcus considered expected returns on equity
24 investments in pension plans by utilities as determined from
25 utility annual reports. (T. 1366, 1456-1458) There are two

1 major problems with this sort of analysis: (1) It is unclear
2 how long the time horizon is; and (2) these returns are
3 expected, not required. It is well-established that expected
4 returns may be less than, equal to, or greater than required
5 returns. For that reason, expected returns cannot be used
6 directly as a proxy for required returns, which is the
7 information sought in a general rate case.⁶

8
9 **VII. CONCLUSION**

10 Q. DO YOU HAVE ANY FINAL COMMENT TO MAKE ON THE ROE
11 RECOMMENDATIONS OF THE INTERVENING PARTIES AND STAFF?

12 Yes. My experience leads me to conclude that the ROEs proposed by the
13 AG, AEEC, FEA, and Staff would disappoint investors. It further leads me
14 to conclude that the ROE requested by the Company would be viewed as
15 constructive and consistent with the Commission's prior authorizations
16 and the rising risk of utilities as well as the general market for equities.

17
18 Q. DOES THIS COMPLETE YOUR REBUTTAL TESTIMONY?

19 A. Yes, it does.

⁶ Docket No. 04-121-U, Order No. 16 at 46 (September 19, 2005).

CERTIFICATE OF SERVICE

I, Steven K. Strickland, do hereby certify that a copy of the foregoing has been served upon all parties of record by forwarding the same by electronic mail and/or first class mail, postage prepaid, this 26th day of August, 2013.

/s/ Steven K. Strickland
Steven K. Strickland

BEFORE THE
ARKANSAS PUBLIC SERVICE COMMISSION

IN THE MATTER OF THE APPLICATION	)	
OF ENTERGY ARKANSAS, INC. FOR	)	DOCKET NO. 13-028 -U
APPROVAL OF CHANGES IN RATES FOR	)	
RETAIL ELECTRIC SERVICE	)	

EAI EXHIBIT JMC-2

AUTHORIZED ROEs 2009 – 2Q13

[illegible]

BEFORE THE
ARKANSAS PUBLIC SERVICE COMMISSION

IN THE MATTER OF THE APPLICATION)
OF ENTERGY ARKANSAS, INC. FOR)
APPROVAL OF CHANGES IN RATES FOR)
RETAIL ELECTRIC SERVICE)

DOCKET NO. 13-028-U

DIRECT TESTIMONY

OF

KEVIN G. GARDNER

VICE PRESIDENT, HUMAN RESOURCES PROGRAMS
ENTERGY SERVICES, INC.

ON BEHALF OF

ENTERGY ARKANSAS, INC.

AUGUST 26, 2013

1 **I. INTRODUCTION**

2 Q. PLEASE STATE YOUR NAME.

3 A. My name is Kevin G. Gardner

4

5 Q. ARE YOU THE SAME KEVIN G. GARDNER WHO FILED DIRECT
6 TESTIMONY IN THIS DOCKET ON MARCH 1, 2013?

7 A. Yes, I am.

8

9 Q. ON WHOSE BEHALF ARE YOU TESTIFYING?

10 A. I am submitting this Rebuttal Testimony to the Arkansas Public Service
11 Commission (“APSC” or the “Commission”) on behalf of Entergy
12 Arkansas, Inc. (“EAI” or the “Company”).

13

14 Q. WHAT IS THE PURPOSE OF YOUR REBUTTAL TESTIMONY?

15 A. The purpose of my rebuttal testimony is to respond to the findings and
16 recommendations of APSC General Staff (“Staff”) witness Bill Taylor on
17 employee and executive compensation programs and to certain issues
18 raised by other parties on that subject, including Attorney General (“AG”)
19 witness William B. Marcus and the Hospital and Higher Education Group
20 (“HHEG”) witness Mark Garrett. EAI witness Jay A. Hartzell will address
21 some issues raised by HHEG witness Larry Blank’s direct testimony and
22 Mr. Garrett’s testimony.

23

1 Q. HAVE YOU REVIEWED THE TESTIMONY FILED BY STAFF AND
2 INTERVENORS IN THIS PROCEEDING?

3 A. Yes, I have.
4

5 Q. CAN YOU BRIEFLY DESCRIBE STAFF'S TESTIMONY?

6 A. Mr. Taylor provides an overview of the evidence I presented to support
7 EAI's compensation programs, including their design and components. In
8 particular, Mr. Taylor cites the third-party compensation surveys used to
9 substantiate that EAI's compensation structure and levels are reasonable.
10 Mr. Taylor concludes that these survey results demonstrate that EAI's
11 compensation structure is consistent with industry practice and that its
12 compensation levels, which are benchmarked against other companies
13 with which EAI must compete for qualified and competent employees, are
14 also consistent with industry practice and reasonable.¹

15 Mr. Taylor also recognized that attracting and retaining qualified
16 and competent employees is beneficial to ratepayers, because it improves
17 the quality of service and reduces the cost of electric utility service by
18 avoiding the added cost associated with hiring and training employees.
19 Mr. Taylor points out that failure to retain qualified and competent
20 employees elevates the cost of service due to the cost of hiring and

¹ Taylor Direct Testimony at 6.

1 training; therefore, better employee retention results in lower costs to
2 ratepayers.²

3

4 Q. WHAT WAS STAFF'S CONCLUSION?

5 A. Mr. Taylor acknowledged that reasonable and necessary expenses of the
6 Company which are necessary for the provision of utility service should be
7 allowed in rates. Mr. Taylor stated that, as Staff does with all other
8 reasonable and necessary expenses, he looked at the overall
9 compensation levels and compensation structure and determined that
10 EAI's overall compensation levels are reasonable, including incentive and
11 stock-based compensation. Thus, Mr. Taylor did not recommend an
12 adjustment to the overall level of employee compensation included in
13 EAI's cost of service other than specific payroll adjustments described in
14 his testimony.

15

16 Q. DID THE OTHER PARTIES DRAW THE SAME CONCLUSION?

17 A. No. Neither Mr. Marcus nor Mr. Garrett opined on the reasonableness of
18 EAI's total compensation levels or their compensation structure.

19

20 Q PLEASE SUMMARIZE AND RESPOND TO AG WITNESS MARCUS'
21 RECOMMENDATION.

² *Id.*

1 Mr. Marcus contended that the Commission should disallow all long-term
2 incentives and stock-based compensation³ and require a sharing of the
3 compensation based on financial metrics 50-50 between ratepayers and
4 shareholders for short-term incentive programs.⁴ It is important to note
5 that Mr. Marcus provides no analytical basis for sharing of the financial
6 metrics 50-50.

7 Below and in the rebuttal testimony of Jay Hartzell, EAI rebuts Mr.
8 Marcus' argument that long term incentive and stock-based compensation
9 should be disallowed.

10

11 Q. PLEASE SUMMARIZE MR. GARRETT'S RECOMMENDATION.

12 A. Mr. Garrett presented testimony that focused on what other states in his
13 review have allowed to be recovered in rates in the form of incentive
14 payments for financial performance.⁵ While Mr. Garrett evaluated EAI's
15 short-term and long-term incentive compensation structures separately,
16 his conclusions are the same with respect to both that the Commission
17 should disallow all incentive compensation that is based entirely on the
18 financial performance of the Company.⁶

19

³ Marcus Direct Testimony at 55.

⁴ *Id.* at 57.

⁵ Garrett Direct Testimony at 12.

⁶ In a stipulation filed by HHEG and EAI in this docket on August 19, 2013, HHEG conceded that some of HHEG's members utilize employee incentive compensation plans where several factors, including financial performance, influence the amount of employee incentive compensation, which includes employee bonuses.

1 Q. IS MR. GARRETT'S STATE COMPARISON APPROACH
2 APPROPRIATE?

3 A. No. Mr. Garrett's survey of other jurisdictions does not consider whether
4 the utilities in the states he reviewed provide a reasonable and necessary
5 level of total compensation for its employees. Mr. Garrett's one size fits all
6 approach ignores evidence presented in this case on the total level of
7 compensation provided to EAI employees and the reasonableness of the
8 compensation structure. Moreover, comparing the ratemaking practices of
9 other states with respect to this issue is unpersuasive. States approach
10 ratemaking differently on a variety of issues and recommending this
11 Commission follow other states on these compensation decisions deprives
12 the Commission of its independent evaluation of the reasonableness of
13 EAI's compensation expense presented in this case.

14

15 Q. DO EITHER THE AG OR HHEG PROVIDE ANY TESTIMONY THAT EAI'S
16 TOTAL LEVEL OF COMPENSATION IS UNREASONABLE, EXCESSIVE,
17 OR ABNORMAL?

18 A. No.⁷

19

⁷ In a stipulation filed by HHEG and EAI in this docket on August 19, 2013, HHEG conceded that some of HHEG's members considered several factors, including information obtained from market surveys, when establishing their employee incentive compensation plans.

1 **III. SUPPLEMENTAL RETIREMENT PLANS**

2 Q. PLEASE DESCRIBE THE ISSUE RAISED BY MR GARRETT
3 REGARDING SUPPLEMENTAL RETIREMENT PLANS.

4 A. Mr. Garrett recommended that shareholders pay for the costs of the
5 supplemental executive retirement plans. Specifically, he noted that
6 ratepayers should pay for all the executive benefits included in the
7 Company's regular pension plans (i.e., on salary levels up to \$255,000),
8 and shareholders should pay for the additional executive benefits included
9 in the supplemental plans (i.e., on salary levels above \$255,000).

10
11 Q. IS MR GARRETT'S APPROACH APPROPRIATE?

12 A. No. As with the issue of compensation, Mr. Garrett's attempt to justify
13 non-recovery of nonqualified pension plans costs is not consistent with
14 accepted market practice in the area of benefits design. The \$255,000
15 salary threshold referenced in his testimony is simply the Internal Revenue
16 Code limit on the level of retirement benefits that qualify for tax treatment
17 favorable to EAI. This IRS limit is not intended to convey a threshold for
18 reasonable plan design.

19
20 **IV. CONCLUSION**

21 Q. COULD YOU BRIEFLY SUMMARIZE EAI'S POSITION ON THESE
22 ISSUES IN THIS DOCKET?

1 A. EAI must have the necessary compensation programs, including incentive
2 and equity based programs, to attract and retain the talent to meet the
3 needs of our customers in a safe, reliable, and cost-effective manner. The
4 EAI compensation programs meet this objective with a structure that is
5 reasonably designed, and consistent with similarly situated companies,
6 including utilities. The performance metrics found in these programs are
7 consistent with market practice, as evidenced by survey data contained in
8 my direct testimony. These metrics contain a balance of operational,
9 customer service, safety, financial and individual performance factors to
10 ensure alignment between the employee, our customers and our
11 company's sustainability. Thus, it is appropriate to include recovery of
12 these reasonable and necessary compensation costs. Removing
13 incentive-based and/or equity-based compensation elements would be
14 contrary to the prevalent market practice which incorporates a portion of
15 compensation at risk based on the ability to meet our customer needs
16 while maintaining a financially strong company.

17 While witnesses for the AG and HHEG offer philosophical
18 observations on the potential for misalignment with the customer through
19 the use of incentive and equity compensation programs, there is no
20 evidence of this misalignment at EAI. EAI's compensation programs are
21 reasonably designed and necessary to attract and retain talent, as noted
22 in my direct testimony.⁸ A well-balanced total compensation program is a

⁸ Gardner Direct Testimony at 4-5.

1 key element in this successful relationship between our customers, our
2 workforce, and the company.

3

4 Q. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

5 A. Yes.

CERTIFICATE OF SERVICE

I, Steven K. Strickland, do hereby certify that a copy of the foregoing has been served upon all parties of record by forwarding the same by electronic mail and/or first class mail, postage prepaid, this 26th day of August, 2013.

/s/ Steven K. Strickland
Steven K. Strickland

BEFORE THE
ARKANSAS PUBLIC SERVICE COMMISSION

IN THE MATTER OF THE APPLICATION	)	
OF ENTERGY ARKANSAS, INC. FOR	)	DOCKET NO. 13-028-U
APPROVAL OF CHANGES IN RATES FOR	)	
RETAIL ELECTRIC SERVICE	)	

DIRECT TESTIMONY

OF

KURTIS W. CASTLEBERRY

DIRECTOR, RESOURCE PLANNING

ENTERGY ARKANSAS, INC.

ON BEHALF OF

ENTERGY ARKANSAS, INC.

AUGUST 26, 2013

1 **I. INTRODUCTION**

2 Q. PLEASE STATE YOUR NAME.

3 A. My name is Kurtis W. Castleberry.

4

5 Q. ARE YOU THE SAME KURTIS W. CASTLEBERRY WHO FILED DIRECT
6 TESTIMONY IN THIS DOCKET ON MARCH 1, 2013?

7 A. Yes, I am.

8

9 Q. ON WHOSE BEHALF ARE YOU TESTIFYING?

10 A. I am submitting this rebuttal testimony to the Arkansas Public Service
11 Commission (“APSC” or the “Commission”) on behalf of Entergy
12 Arkansas, Inc. (“EAI” or the “Company”).

13

14 Q. WHAT IS THE PURPOSE OF YOUR REBUTTAL TESTIMONY?

15 A. The purpose of my rebuttal testimony is to address a number of issues
16 raised by the parties associated with proposals that are the direct result of
17 EAI’s exit from the Entergy System Agreement¹ on December 18, 2013.

¹ The Entergy System Agreement (“System Agreement”) is a rate schedule approved by the Federal Energy Regulatory Commission (“FERC”) and contract entered into among Entergy Services, Inc. (“ESI”) and the Operating Companies, which requires the Operating Companies to plan, construct and operate their generation and bulk transmission facilities as a single, integrated electric system. On December 19, 2005, EAI gave notice that it will terminate its participation in the System Agreement effective December 18, 2013. ESI is a subsidiary of Entergy Corporation that provides technical and administrative services to all the Operating Companies. The Entergy Operating Companies include EAI; Entergy Gulf States Louisiana, L.L.C.; Entergy Louisiana, LLC; Entergy Mississippi, Inc.; Entergy New Orleans, Inc.; and Entergy Texas, Inc.

1 The transition to post-System Agreement operations will affect the way
2 that EAI conducts its operations, as I explained in my direct testimony in
3 this proceeding. That transition is fundamental to the positions that I, as
4 well as a number of other EAI witnesses, are taking in this case. My
5 testimony explains why the positions taken by several intervenors do not
6 reflect the realities of EAI's transition to post-System Agreement
7 operations.

8

9 Q. WHY IS THAT TRANSITION SO SIGNIFICANT TO THIS PROCEEDING?

10 A. EAI will terminate its participation in the System Agreement on
11 December 18, 2013 and operate as a member of the Midcontinent
12 Independent System Operator, Inc.'s ("MISO") Regional Transmission
13 Organization ("RTO") and participate in the various markets offered by the
14 MISO RTO beginning December 19, 2013. With this significant change in
15 EAI's operations, numerous revisions to EAI's costs and tariffs need to be
16 implemented to reflect this new operating arrangement. Notably, the
17 APSC General Staff ("Staff") recognizes the influence of these changes on
18 EAI's operations, as reflected by the general agreement among the
19 Company and Staff on many of the major issues I discuss.

20 On the other hand, several witnesses for intervenors in this
21 proceeding fail to recognize the necessary changes to EAI's tariffs and
22 cost structures that must take place in order to reflect EAI's operations in
23 MISO. In particular, those witnesses oppose EAI's proposed revisions to

1 the Optional Interruptible Service Rider ("Rider OIS"), as well as the two
2 experimental tariffs that EAI has proposed for operations in MISO (i.e., the
3 Market Valued Load Modifying Resource Rider ("MVLMR") and the Market
4 Valued Demand Response Rider ("MVDRR"). Their bases for opposition
5 are inconsistent with and ignore the reality of EAI's membership in MISO
6 and the opportunities provided by the MISO markets.

7
8 Q. HOW IS THE REMAINDER OF YOUR TESTIMONY ORGANIZED?

9 A. First, I respond to the intervenors' positions on tariff changes EAI has
10 proposed to reflect EAI's operations in the MISO RTO. These tariffs
11 include Rider OIS, the proposed MVLMR and MVDRR, the proposed
12 Capacity Cost Recovery Rider ("Rider CCR"), the Energy Cost Recovery
13 Rider ("Rider ECR"), the Large Cogeneration Rider ("Rider LCR") and
14 Small Cogeneration Rider ("Rider SCR"), and the Standby Service Rider
15 ("Rider SSR"). Then, I address issues related to certain resource planning
16 and operations matters overseen by my Resource Planning and
17 Operations organization. Specifically, I respond to issues related to plant
18 retirements, the Lake Catherine Unit 4 Reliability/Sustainability project, the
19 Hot Spring Plant acquisition, the assignment of costs of 4 MW of
20 additional capacity from Mabelvale Units 1 and 3 to retail, affiliate charges
21 for generation and resource planning services, and plant dismantlement
22 costs.

23

1 **II. TARIFF CHANGES RESULTING FROM EAI'S JOINING MISO**

2 **A. Rider OIS**

3 Q. YOU INDICATED THAT SEVERAL INTERVENORS CRITICIZED EAI'S
4 PROPOSED CHANGES TO RIDER OIS. WHAT MODIFICATIONS HAS
5 EAI PROPOSED FOR THAT TARIFF?

6 A. As I explained in my direct testimony,² the design of Rider OIS becomes
7 obsolete when EAI becomes a member of MISO. Unlike historical
8 operation within the System Agreement, the MISO markets provide the
9 mechanisms for, and set the compensation value and terms of interruption
10 for participation by an interruptible customer. However, I also explained
11 that EAI recognizes that many existing customers taking service under
12 Rider OIS may have made investments and designed their operations
13 based upon an assumption that Rider OIS would continue:

14
15 EAI recognizes that many existing customers taking service
16 under Rider OIS may have made investments and designed
17 their operations based upon an assumption that Rider OIS
18 would continue. As a result, the Company proposes to close
19 the rider to new customers but will continue to offer the rider
20 to customers currently taking service under the rider. The
21 Company will evaluate this situation and propose an
22 approach to phase out the existing tariff at a later time.
23 However, there are changes that are needed to the existing
24 OIS tariff to make Rider OIS consistent with MISO's LMR –
25 Demand Response Product.³

26 Taking these factors into consideration, the Company proposed in this
27 proceeding to close Rider OIS to new customers, but continue to offer the

² Castleberry Direct Testimony at 44 - 45.

³ *Id* at 45.

1 rider to existing customers currently taking service under this rider and
2 revise the terms of Rider OIS to the extent necessary to conform to EAI's
3 operation within MISO. Additionally, EAI is proposing the experimental
4 riders MVLMR and MVDRR to be available to customers that seek to take
5 advantage of interruptible products within MISO.

6

7 Q. WHAT POSITION DID STAFF TAKE ON THE COMPANY'S PROPOSAL?

8 A. Staff witness Regina Butler supported EAI's proposed changes to Rider
9 OIS. Specifically, Ms. Butler recommended EAI's proposed changes be
10 approved, including closing Rider OIS to new customers and re-evaluating
11 the long-term disposition of the rider at a later time.⁴

12

13 Q. WHAT WERE THE CONCERNS RAISED BY INTERVENORS WITH
14 RESPECT TO THE COMPANY'S PROPOSED REVISIONS TO RIDER
15 OIS?

16 A. There were numerous concerns raised by various parties. Arkansas
17 Electric Energy Consumers ("AEEC") witness Randall Falkenberg
18 asserted that EAI's proposal to close Rider OIS is harmful to existing
19 businesses in Arkansas, as well as potential new economic development.
20 He recommends that the Commission reject what he asserts to be EAI's
21 proposal to close and phase out Rider OIS, concluding that EAI is

⁴ Butler Direct Testimony at 16.

1 undervaluing the capacity that Rider OIS provides to the Company. He
2 recommends that Rider OIS remain open so that it can continue to provide
3 the value that the Commission recognized in Docket No. 96-360-U.⁵

4 The Hospitals and Higher Education Group (“HHEG”) filed the
5 testimony of numerous witnesses related to Rider OIS, each of which take
6 the position that Rider OIS should remain open and that existing
7 customers could have stranded investment if Rider OIS is phased out.
8 Like AEEC, HHEG asserts that the Company’s proposal is a “step-back”
9 from the APSC’s objectives in Docket No. 96-360-U and that EAI is
10 undervaluing Rider OIS capacity.⁶

11 Wal-Mart witness Kenneth Baker focuses only on what he calls the
12 “grandfathered” customers, recommending that the Commission ensure
13 that Rider OIS continues to be effective, and at the same compensation
14 level, until those grandfathered customers have recouped their
15 investments.⁷

16

17 Q. MR. FALKENBERG AND MULTIPLE HHEG WITNESSES OPPOSE
18 CLOSURE OF RIDER OIS TO NEW BUSINESS. PLEASE DESCRIBE
19 WHY CLOSURE TO NEW BUSINESS IS APPROPRIATE.

⁵ Falkenberg Direct Testimony at 45 - 55.

⁶ See e.g., Blank Direct Testimony at 9-10, 13-14; Ward Direct Testimony at 13-15; Mathis Direct Testimony at 3-6.

⁷ Baker Direct Testimony at 6 - 7.

1 A. As I explained above, Rider OIS does not reflect EAI's operation as a
2 member of MISO and outside of the System Agreement because the tariff,
3 approved in 1996, does not contemplate EAI's access to the MISO market
4 for capacity, nor does it reflect the procedures by which MISO will utilize
5 interruptible demand as MISO performs its duties in coordination with
6 EAI's Local Balancing Authority. Consequently, EAI has determined that
7 the benefit customers receive from Rider OIS is not representative of the
8 benefit the Company will receive for the interruptible load in the MISO
9 market. However, as I have explained, rather than withdraw the Rider OIS
10 schedule, EAI has proposed to close Rider OIS to new customers but
11 allow existing customers that currently take service under the tariff to
12 continue to do so.

13

14 Q. IS THE CONCERN EXPRESSED REGARDING INVESTMENTS MADE
15 BY CURRENT RIDER OIS CUSTOMERS WITHIN THE SCOPE OF THIS
16 PROCEEDING?

17 A. No, it is not. As I explained in my direct testimony, EAI has not proposed
18 to terminate or phase out Rider OIS for existing customers at this time.
19 Rather, as Ms. Butler noted, the potential to eliminate Rider OIS for
20 existing customers is an issue that should be addressed in the future as
21 EAI gains more experience operating in MISO and its markets.⁸ EAI

⁸ Butler Direct Testimony at 16.

1 needs experience operating in MISO and to obtain additional information
2 about existing Rider OIS customers' investments in facilities in order to
3 develop a future phase-out plan for existing customers taking service
4 under Rider OIS that takes both of those factors into consideration.

5

6 Q. EVERGREEN PACKAGING, INC. ("EVERGREEN") WITNESS MIKE
7 ELMORE STATES THAT MISO DOES NOT REQUIRE EAI'S RIDER OIS
8 CUSTOMERS TO REGISTER AS A LOAD MODIFYING RESOURCE
9 ("LMR"). DO YOU AGREE WITH THIS STATEMENT?

10 A. Yes. MISO does not have a requirement that EAI's Rider OIS customers
11 register as an LMR. Neither does MISO have the authority to dictate any
12 of the provisions of Rider OIS, nor any of EAI's other retail rate schedules.
13 However, if EAI is to utilize Rider OIS interruptible load in MISO's resource
14 adequacy construct to secure value for that resource, EAI must register
15 the Rider OIS customers as LMRs. The value of Rider OIS interruptible
16 load to EAI and its customers is dependent upon that load being qualified
17 as a MISO planning resource.

18

19 Q. WOULD YOU PLEASE COMMENT ON MR. FALKENBERG'S
20 OBJECTIONS TO THE RIDER OIS REQUIREMENT THAT CUSTOMERS
21 BE REGISTERED AS LMRS?

22 A. Mr. Falkenberg states that requiring Rider OIS customers to register is
23 discriminatory to other customers because EAI does not require

1 customers participating in Demand Side Management (“DSM”) or Energy
2 Efficiency programs to register as a LMR.⁹ The requirement that Rider
3 OIS customers be registered as LMRs is not discriminatory. The
4 programs to which Mr. Falkenberg refers do not require the individual
5 customer to actively participate in the same manner required for
6 interruptible service under Rider OIS. In that respect, Rider OIS is not
7 comparable to the energy efficiency programs to which Mr. Falkenberg
8 refers.

9

10 Q. MR. FALKENBERG TAKES ISSUE WITH EAI’S PROPOSED HOURS OF
11 INTERRUPTION. PLEASE DESCRIBE DIFFERENCES IN THE HOURS
12 OF INTERRUPTION FOR EAI’S PROPOSED RIDER OIS RATE
13 SCHEDULE AS COMPARED TO THE CURRENTLY EFFECTIVE RIDER
14 OIS RATE SCHEDULE.

15 A. The proposed changes to the hours of Rider OIS interruption are minimal,
16 but they are required to qualify the interruptible load under Rider OIS as
17 an LMR in MISO. To be eligible for registration as an LMR, customers
18 must be able to maintain the target demand reduction for at least four
19 hours. In keeping with that minimum requirement, EAI added one hour to
20 the allowed Hours per Interruption during the non-summer months in Rider
21 OIS. The existing Rider OIS rate schedule defines the maximum

⁹ Falkenberg Direct Testimony at 56.

allowable Hours per Interruption during a non-summer month to be 3 hours per interruption. EAI changed that to 4 hours per interruption to insure the requirements on the customer reflected the requirements for LMRs. The maximum allowable Days per Month, the maximum allowable Interruptions per Day and the maximum allowable Hours per Month under Rider OIS did not change.

For comparison, the maximum hours of interruption allowed under the currently effective Rider OIS schedule are shown in Table 1 and the maximum hours of interruption allowed under the proposed Rider OIS schedule are shown in Table 2.

Table 1
Current Rider OIS Maximum Hours of Interruption

<u>Season</u>	<u>Days Per Month</u>	<u>Interruptions Per Day</u>	<u>Hours Per Interruption</u>	<u>Hours Per Month</u>
Summer Months	10	1	4	35
Other Months	10	2	3	55

Table 2
Proposed Rider OIS Maximum Hours of Interruption

<u>Season</u>	<u>Days Per Month</u>	<u>Interruptions Per Day</u>	<u>Hours Per Interruption</u>	<u>Hours Per Month</u>
Summer Months	10	1	4	35
Other Months	10	2	4	55

Q. MR. FALKENBERG STATES THAT THE COMPANY'S TERMS OF SERVICE FOR RIDER OIS EXCEED THOSE REQUIRED TO MEET THE

1 MISO LMR PROGRAM, CITING NON-SUMMER INTERRUPTIONS. IS
2 THIS A VALID CRITICISM?¹⁰

3 A. No. The minimum MISO requirement for LMR registration is that the
4 customer must be capable of being interrupted by MISO at least the first
5 five times during the Summer Season of any planning year. The
6 Availability paragraph of Rider OIS requires this same provision as a
7 requirement for service under Rider OIS. MISO does not state that LMRs
8 will not be deployed during non-summer months. Hence, the provisions
9 authorizing interruption during non-summer months in Rider OIS are
10 appropriate and further support the maintenance of the current level of
11 payments to Rider OIS customers, which EAI has sought to preserve in
12 this case.

13

14 Q. IF MISO CALLS EAI FOR INTERRUPTION DURING THE NON-
15 SUMMER MONTHS, WHAT IS THE OBLIGATION OF RIDER OIS
16 CUSTOMER TO INTERRUPT?

17 A. Customers are obligated to interrupt pursuant to direction from MISO or
18 will be subject to the penalty provisions in Paragraph 41.5.5 of the tariff,
19 which are the same for both summer and non-summer months.

20

¹⁰ *Id.*

1 Q. MR. BLANK ASSERTS THAT INTERRUPTIBLE TARIFFS FOR OTHER
2 LOAD SERVING ENTITY ("LSE") COMPANIES ARE STRUCTURED
3 DIFFERENTLY FROM EAI'S PROPOSED RIDER OIS; THEREFORE,
4 THERE IS NO NEED TO MODIFY THE CURRENTLY EFFECTIVE
5 RIDER OIS RATE SCHEDULE. WHAT FLAWS DO YOU SEE WITH
6 THIS ARGUMENT?

7 A. First, changes to Rider OIS were required to obtain the value in MISO
8 from the Rider OIS load, as I explained earlier, and EAI's proposed
9 changes to the tariff were necessary to comply with MISO's LMR
10 requirements. Second, to be able to agree with Mr. Blank's argument, one
11 would have to believe that the best rate structure for EAI is the rate
12 structure that the majority of utilities use. Although there is merit in
13 reviewing rate structures used by other utilities, it would be absurd to
14 assume that one method is better than another based on a tally of how
15 many utilities use a certain method. Third, Mr. Blank did not reveal in his
16 testimony that some of the interruptible rate schedules his associate would
17 have reviewed have been closed to new business or closed to all
18 customers. Finally, Mr. Blank states that "[n]one of the investor-owned
19 MISO LSEs we reviewed link their retail tariff interruptible service to MISO
20 demand response programs in a fashion similar to that which EAI
21 proposed in this case."¹¹ However, in the same paragraph, he offers

¹¹ Blank Direct Testimony at 11.

1 examples of provisions from these other LSEs that, in fact, are similar to
2 the EAI provisions.¹²

3

4 Q. MR. BLANK TAKES ISSUE WITH THE COMPANY'S NOTIFICATION
5 PROVISION IN RIDER OIS, STATING THAT THE LANGUAGE WAS
6 LIFTED FROM THE MISO ELIGIBILITY REQUIREMENT AND THAT THE
7 NOTIFICATION PROVISION MAKES NO SENSE.¹³ PLEASE DESCRIBE
8 THE COMPANY'S INTENT FOR THE PROPOSED RIDER OIS
9 NOTIFICATION PROVISION.

10 A. MISO's Demand Response Business Practices Manual states that one of
11 the requirements to qualify an LMR as a planning resource is, "The LMR
12 must be available for reducing Demand by its maximum reduction level (or
13 to its firm service level) with no more than 12 hours notification."¹⁴ Rider
14 OIS merely repeats that MISO provision. The Company's intent is that
15 Rider OIS customer's LMR registration will be based on that 12-hour
16 notice. When the Company is notified by MISO of an event warranting
17 interruption under the provisions of Rider OIS, the Company would in turn
18 notify the customer using the mutually agreed upon communication

¹² Those being: 1) MidAmerican Energy Company tariff sheet B.3-30 curtailment condition where if the utility incurs MISO charges or penalties due to failure of a customer to interrupt, then those MISO charges and penalties are passed on to the customer; and 2) Northern Indiana Public Service Company's ("NIPSCO") Rider 675 "Interruptible Industrial Service Rider provisions where customers must meet the eligibility requirements of MISO and assume liability for penalties imposed by MISO. At least two utilities have some provisions similar to those that EAI is proposing for Rider OIS. The proposed Rider OIS is a suitable union of the existing Rider OIS schedule and new provisions reflecting EAI's participation in the MISO market.

1 method established when the customer contracted for service under Rider
2 OIS. Therefore, customers will have 12 hours notice less the time it takes
3 the Company to notify the customer to interrupt. The time it takes to notify
4 customers will be dependent upon the notification method agreed to by
5 the customer and the Company.

6

7 Q. DO YOU AGREE WITH MR. FALKENBERG'S AND MR. BLANK'S
8 ASSERTIONS THAT THE VALUE OF CAPACITY PROVIDED UNDER
9 RIDER OIS SHOULD CONTINUE BECAUSE THE COMMISSION
10 APPROVED IT IN A RATE CASE EAI FILED IN 1996?

11 A. No. These assertions are not valid for two reasons. First, as I explained
12 previously, EAI is not proposing to change the value of interruption to
13 customers currently taking service under Rider OIS. Second, these
14 parties argue that EAI should permanently maintain a tariff that was
15 approved more than 15 years ago and designed to reflect the value and
16 operation of EAI in the System Agreement. This argument ignores
17 completely the significant change in EAI's operations and cost structure
18 that will result from EAI's operation in MISO and participation in the MISO
19 markets.¹⁵

20

¹³ *Id* at 15 -16.

¹⁴ See MISO Business Practices Manual BPM-026 at 64.

¹⁵ In this respect, I would note that the Commission recognized the opportunities that this market provides EAI in Order No. 12 in Docket No. 12-038-U, directing EAI to include the evaluation of MISO's capacity market in its resource planning process.

1 Q. ADDITIONALLY, MR. FALKENBERG POINTS TO SEVERAL
2 DIFFERENT CAPACITY VALUES AND/OR SPECIFIC PURCHASES
3 MADE BY EAI, TO SUPPORT HIS ASSERTION THAT EAI NEEDS
4 RIDER OIS CAPACITY, PRESUMABLY TO CONCLUDE THAT RIDER
5 OIS SHOULD REMAIN OPEN. HOW DO YOU RESPOND?

6 A. Mr. Falkenberg does not provide a reasonable basis for retaining the
7 current Rider OIS tariff. First, he mischaracterizes my direct testimony by
8 stating that I do not believe EAI needs interruptible capacity.¹⁶ Apparently
9 trying to assert some inconsistency, he references recent EAI capacity
10 transactions approved in Docket No. 12-038-U and the proposed Lake
11 Catherine Unit 4 Reliability/Sustainability project. In fact, in my direct
12 testimony I did state, "EAI no longer needs its Rider OIS."¹⁷ As I explained
13 in my direct testimony, and here, the current Rider OIS does not reflect the
14 value of that resource where EAI is operating within MISO. In MISO, the
15 value of the Rider OIS resource is more akin to the opportunities in the
16 MISO capacity auction I discuss in the next section of my testimony rather
17 than the capacity additions referenced by Mr. Falkenberg. Nevertheless,
18 the proposed changes to this rider are designed to protect current
19 customers' investments in reliance upon the rider's availability, while at the
20 same time providing value to other customers by making the rider
21 consistent with the Company's operations in the MISO markets.

¹⁶ Falkenberg Direct Testimony at 48.

¹⁷ Castleberry Direct Testimony at 45.

1 Furthermore, Mr. Falkenberg's argument to keep Rider OIS open
2 based on an assumed need for capacity and values associated with life-
3 of-unit and multi-year transactions is surprising, given that Mr. Falkenberg
4 was testifying just a year ago in Docket No. 12-038-U that "excess
5 capacity exists in the Entergy area which will depress prices for years to
6 come."¹⁸ The MISO market provides EAI with the opportunity to utilize the
7 excess capacity that Mr. Falkenberg referred to in Docket No. 12-038-U,
8 and as I explain later, EAI's new interruptible tariffs will more accurately
9 reflect the value of this resource going forward.

10

11 Q. HOW DO YOU RESPOND TO MR. BLANK'S CONCLUSION THAT EAI'S
12 PROPOSAL UNDERVALUED RIDER OIS CAPACITY?¹⁹

13 A. EAI has not proposed to change the value of interruptible capacity in Rider
14 OIS, so his conclusion is misplaced for that reason alone.

15

16 Q. DOES EAI HAVE AN OBLIGATION TO PROVIDE INTERRUPTIBLE
17 SERVICE, AS MR. FALKENBERG IMPLIES?²⁰

18 A. I am not aware of any obligation, nor did Mr. Falkenberg cite any authority
19 for his assertion. While EAI may be under no obligation, the Company
20 views a customer's capability to change its load as a potential resource to

¹⁸ Docket No. 12-038-U, Falkenberg Direct Testimony at 13.

¹⁹ Blank Direct Testimony at 13.

²⁰ Falkenberg Direct Testimony at 51 - 52.

1 serve all customers' load requirements. That is why EAI has proposed
2 two new tariffs, which I address below, that would provide customers the
3 opportunity to gain value through the MISO markets from flexibility in how
4 they operate.

5

6 **B. MVLMR and MVDRR**

7 Q. PLEASE DESCRIBE THESE TARIFFS THAT ARE INTENDED TO
8 ALLOW CUSTOMERS PARTICIPATION THROUGH EAI IN THE MISO
9 MARKETS.

10 A. EAI has developed two experimental tariffs, MVLMR and MVDRR, that
11 would allow its retail customers access to MISO's capacity and demand
12 response products. Participation is similar to the way that EAI's
13 interruptible loads are used today; participating customers curtail usage
14 when notified. Similar to Rider OIS, customers must make a one year
15 commitment to participate for MISO's upcoming planning year. The value
16 that a MVLMR customer would receive for participation would be based
17 upon the value of capacity in MISO's Planning Resource Auction. The
18 value that a MVDRR customer would receive would be based on the value
19 of energy in the MISO energy market.

20

21 Q. PLEASE EXPLAIN HOW THE PLANNING RESOURCE AUCTION SETS
22 THE VALUE OF CAPACITY?

1 A. Within MISO, LSEs, including EAI, must demonstrate that they have an
2 adequate level of capacity to meet their forecasted coincident peak load
3 for the planning year plus a reserve margin. Essentially, LSEs take steps
4 to convert owned and/or contracted capacity into Zonal Resource Credits
5 ("Resource Credits") that count toward this requirement. LSEs have the
6 option to submit a fixed plan using these Resource Credits or can elect to
7 purchase or sell Resource Credits in the Planning Resource Auction.
8 Purchases in the auction are made at the clearing price, which is set at the
9 cost of the last Resource Credit to clear the auction. Therefore, the
10 Planning Resource Auction clearing price represents the most accurate
11 value for capacity with a one-year term.

12
13 Q. WHAT WAS THE RESPONSE OF PARTIES TO THE PROPOSED
14 TARIFFS?

15 A. Staff witness Regina Butler recommended that Riders MVLMR and
16 MVDRR be approved. Given their experimental nature, Ms. Butler also
17 recommended that EAI be required to maintain cost data to more fully
18 justify the charges and penalties proposed in the riders.²¹ HHEG and
19 AEEC asserted that customers do not have adequate information under
20 those tariffs to determine whether participation is in their interest.
21 Evergreen's Mr. Elmore questioned why EAI proposed to have customers

²¹ Butler Direct Testimony at 17.

1 participate through the Company rather than directly and why certain
2 MISO options for demand response resources are not available under the
3 tariff.²² Wal-Mart's Mr. Baker raised a similar issue regarding participation,
4 adding that any decision to participate in MISO's Demand Response
5 markets should not affect a customer's ability to self-direct under the
6 Commission's Rules for Conservation and Energy Efficiency ("C&EE")
7 Rules.²³ Mr. Falkenberg raises concern regarding the 10 percent
8 administration charge.²⁴ I will address the issues regarding the pricing
9 and categories offered to customers under these tariffs, as well as the
10 influence of Demand Response participation in MISO on a customer's
11 self-direct option. EAI witness Corey Pettett will address the
12 administrative fee.

13
14 Q. HOW DO YOU RESPOND TO THE RECOMMENDATION FOR
15 MAINTAINING DETAILED COST DATA?

16 A. I agree with Ms. Butler that, because of the experimental nature of the
17 tariffs, it would be appropriate for EAI to maintain cost data to more fully
18 document the charges and penalties proposed in the riders for future
19 revision.

20

²² Elmore Direct Testimony at 3 – 5.

²³ Baker Direct Testimony at 9.

²⁴ Falkenberg Direct Testimony at 57.

1 Q. DO YOU AGREE THAT UNCERTAINTY EXISTS REGARDING
2 CAPACITY AND ENERGY VALUES IN THE MARKET?

3 A. Yes. That uncertainty is a reality of the current utility business. The fact is
4 that, within MISO, capacity and energy pricing is driven by market results
5 and will change from year to year for capacity and every hour for energy.
6 Nevertheless, as I explained in my direct testimony, the market is the best
7 indicator of the value that an interruptible resource provides to the
8 Company and all of its customers.

9

10 Q. WOULD PARTICIPATION IN THESE TARIFFS AFFECT A
11 CUSTOMER'S SELF-DIRECT DECISION?

12 A. EAI does not believe that participation in these tariffs would alter a
13 customer's right to self-direct under the C&EE Rules.

14

15 Q. MR. ELMORE INDICATES THAT HIS UNDERSTANDING IS THAT AN
16 EAI RETAIL CUSTOMER CAN REGISTER WITH MISO AS A MARKET
17 PARTICIPANT INDEPENDENT OF ANY CONTRACTUAL
18 ARRANGEMENT WITH EAI. IS THIS THE CASE?

19 A. Retail customers are prohibited from acting as Market Participants by
20 Arkansas law unless the Commission determines that it is in the public
21 interest.²⁵

²⁵ Ark. Code Ann. 23-18-1004.

1 **C. Capacity Cost Recover Rider**

2 Q. HOW IS THE PROPOSED RIDER CCR RELATED TO EAI'S
3 TRANSITION TO OPERATION IN MISO?

4 A. As I explained in my direct testimony, as a member of MISO and a
5 network customer under the MISO Open Access Transmission, Energy
6 and Operating Reserve Markets Tariff ("MISO Tariff"), EAI will have
7 access to a potentially broader bilateral capacity market and an organized
8 capacity market that it has not had access to previously. This is very
9 different from current operations under the System Agreement in which
10 Service Schedule MSS-1 equalizes the costs of each Operating
11 Company's generation capability pursuant to a formula and ESI's System
12 Planning and Operations group makes short- and limited-term capacity
13 purchases on behalf of all the Operating Companies and allocates the
14 capacity to each Operating Company. Joint purchases and cost
15 equalization through System Agreement Service Schedule MSS-1 will
16 terminate on December 18, 2013 coincident with EAI's exit from the
17 System Agreement. When EAI begins operating independently within
18 MISO, Rider CCR will provide a mechanism through which EAI is best
19 positioned to take advantage of economic opportunities to purchase or sell
20 capacity and provide the benefits and costs to its customers at the same
21 time.

1 Q. HOW DID PARTIES REACT TO THE PROPOSED TARIFF?

2 A. Staff witness Elena Davis opposed the tariff because EAI does not
3 currently have approval from the Commission to participate in the MISO
4 Planning Resource Auction and because the Company plans to file for
5 approval of a formula rate plan in the near future.²⁶ Further, because the
6 costs of EAI's recently approved²⁷ Power Purchase Agreement ("PPA")
7 with Entegra Power Group, LLC. began during 2013, she recommended
8 that those costs be recovered in base rates.²⁸ She also listed a number of
9 concerns about the Staff's ability to review the Company's purchases
10 retroactively. AG witness William Marcus shared Ms. Davis' concerns
11 regarding what he sees as a lack of prior approvals for capacity
12 purchases, although he recommended allowing the recently approved
13 PPA to be recovered in base rates.²⁹ Mr. Falkenberg objected to the rider,
14 arguing that EAI has "too many riders."³⁰ He also stated that allowing
15 recovery of capacity costs in a rider would promote "gaming" by the
16 utility.³¹

17

²⁶ Davis Direct Testimony at 12.

²⁷ Docket No. 12-038-U, Order No. 12 at 5.

²⁸ Davis Direct Testimony at 12.

²⁹ Marcus Direct Testimony at 78 – 79.

³⁰ Given Mr. Falkenberg's proposal to have Rider OIS continued, his objection to riders appears limited to them being used to allow the Company, rather than customers, to recover dollars.

³¹ Falkenberg Direct Testimony at 43.

1 Q. HOW DO YOU RESPOND?

2 A. As I explained above, Rider CCR would allow EAI the ability to optimize
3 the benefits of its participation in MISO by replacing the historical billings
4 through MSS-1 that currently take place under the System Agreement with
5 a mechanism that aligns the costs EAI will incur as it operates on behalf of
6 its customers in MISO with the benefits its customers receive. Also, since
7 Staff has filed its direct testimony in this case, EAI has requested approval
8 from the Commission to participate in the MISO Planning Resource
9 Auction³² and Staff and the AG have recommended Commission approval,
10 subject to certain reporting requirements.³³ In that filing, EAI describes
11 how the Planning Resource Auction provides the opportunity for EAI to
12 realize benefits that could be passed to its customers through Rider CCR
13 commensurate with the costs. Additionally, the filing explains
14 uncertainties associated with the resource requirements in MISO, and how
15 EAI, depending upon certain MISO proposals, could be short or long
16 capacity for the partial planning period of 2014. If EAI has more capacity
17 than load, it will have the opportunity to sell that capacity in the Planning
18 Resource Auction and flow the revenue from those sales to customers
19 through Rider CCR. The Commission authorized EAI to join MISO based
20 upon the potential production cost savings that the Company could realize

³² Docket No. 10-011-U, EAI's Motion for Authorization to Participate in the MISO Planning Resource Auction (August 12, 2013).

³³ Docket No. 10-011-U, Staff's Response to EAI's Motion for Authorization to Participate in the MISO Planning Resource Auction (August 21, 2013); AG's Response to EAI's Motion for Authorization to Participate in the MISO Planning Resource Auction (August 22, 2013).

1 through the MISO energy and ancillary service markets, and the
2 Commission further recognized the potential benefit of the Planning
3 Resource Auction in Docket No. 12-038-U when it directed EAI to
4 incorporate participation in that market into EAI's resource planning
5 process.³⁴ Rider CCR would allow the costs of participation in this market,
6 as well as other opportunities that may become available to EAI to be
7 recovered commensurate with their benefits. In addition, I believe that
8 Ms. Davis' and Mr. Marcus' concerns regarding review can be addressed
9 through the reporting requirements I address below.

10

11 Q. WHAT IS YOUR RESPONSE TO MS. DAVIS' RECOMMENDATIONS
12 FOR REPORTING REQUIREMENTS FOR RIDER CCR?

13 A. I think it is important to conduct additional discussions with the Staff to
14 determine the most appropriate information for such a report. Some of
15 Ms. Davis' recommendations appear tailored to opportunities that EAI may
16 have in the MISO Planning Resource Auction,³⁵ while others (e.g.
17 discussion of EAI's Integrated Resource Plan) address long-term planning
18 issues that are different from those MISO Planning Resource Auction
19 opportunities. As I explained above, EAI has requested approval to
20 participate in the Planning Resource Auction and Staff has recommended
21 Commission approval, subject to certain reporting requirements. I

³⁴ Docket No. 12-038-U, Order No. 12 at 5.

1 recommend that the Commission direct EAI and Staff to work towards
2 jointly developing the scope of such a report.

3
4 Q. ARE MR. FALKENBERG'S CONCERNS ABOUT GAMING VALID?

5 A. No. EAI has proposed an annual review of costs included in Rider CCR in
6 order to provide the Commission the ability to ensure that costs were
7 prudently incurred. This review should address any concerns over
8 whether EAI acquired capacity in a reasonable manner and not based
9 upon what Mr. Falkenberg calls "gaming." The Commission has a number
10 of tools to review the prudence of the Company's decisions, including
11 those related to costs and revenues that would flow through Rider CCR.

12

13 **D. Rider ECR**

14 Q. WITH EAI'S TRANSITION TO MISO, YOU PROPOSED TO INCLUDE A
15 NUMBER OF MISO SCHEDULES AND OTHER COSTS FOR
16 RECOVERY WITHIN RIDER ECR. WHAT WERE THE OTHER
17 PARTIES' REACTIONS TO YOUR PROPOSAL?

18 A. No party opposed recovery of those MISO schedules through Rider ECR.

19

³⁵ Davis Direct Testimony at 17.

1 Q. EAI ALSO REQUESTED THAT RIDER ECR BE MODIFIED TO
2 RECOVER CERTAIN ENVIRONMENTAL COMPLIANCE COSTS. HOW
3 DID OTHER PARTIES RESPOND TO THIS REQUEST?

4 A. Staff and AEEC opposed the recovery through Rider ECR of the on-going
5 costs associated with activated carbon and calcium bromide capture
6 required for EAI to comply with the U.S. Environmental Protection
7 Agency's regulations governing Mercury and Air Toxic Standards
8 ("MATS") at the White Bluff Steam Electric Station ("White Bluff") and
9 Independence Steam Electric Station ("ISES"). Specifically, Staff's
10 Ms. Butler testified that it is premature to recommend approval of EAI's
11 proposal before those costs are incurred and that EAI should put forth a
12 more definitive plan for how it will comply with MATS.³⁶ Mr. Falkenberg
13 asserted that inclusion of these costs would complicate the annual Rider
14 ECR review process and recommended including these costs in base
15 rates.³⁷

16

17 Q. PLEASE DESCRIBE EAI'S COMPLIANCE PLANS.

18 A. Currently, White Bluff Units 1 and 2 and ISES Units 1 and 2³⁸ are not
19 equipped with the necessary controls to achieve MATS compliance. The
20 original deadline for MATS compliance at White Bluff and ISES was

³⁶ Butler Direct Testimony at 13.

³⁷ Falkenberg Direct Testimony at 58 – 59.

³⁸ EAI does not have an ownership interest in ISES Unit 2 but is the operator for both units.

1 April 16, 2015. However, EAI has secured a one-year extension until
2 April 16, 2016 from the Arkansas Department of Environmental Quality
3 (“ADEQ”) for these plants. A copy of EAI’s request for that extension and
4 ADEQ’s approval is attached to my testimony as EAI Exhibit KWC-1.

5 As reflected in the extension correspondence in
6 EAI Exhibit KWC-1, EAI has committed to ADEQ to install activated
7 carbon injection and calcium bromide injection systems at each of the
8 units at White Bluff and ISES. The time line attached to the extension
9 estimates that these controls will be operational during 2015. At that
10 point, as I described previously,³⁹ EAI would incur the costs of activated
11 carbon and calcium bromide consumed at those units based upon the
12 energy generated at those units.

13

14 Q. ARE THESE COSTS APPROPRIATE FOR RECOVERY THROUGH
15 RIDER ECR?

16 A. Yes. As I explained in my direct testimony,⁴⁰ the amount of these
17 commodities needed for MATS compliance is a function of how much
18 electricity is generated at White Bluff and ISES in the future. The energy
19 to be generated at these plants is determined based on a number of
20 factors, including the availability of those units and the costs of alternative
21 sources. Consequently, neither the amount nor the price of the

³⁹ Castleberry Direct Testimony at 50-51.

⁴⁰ *Id.*

1 commodities that will be needed in the future can be known with sufficient
2 accuracy now to include an adjustment in base rates.

3 Additionally, these costs are similar to emission allowance
4 costs/revenues currently recovered in or passed through Rider ECR. In
5 Docket No. 06-101-U, the Commission approved the use of Rider ECR to
6 refund any revenues it receives from the sale of sulfur dioxide
7 allowances⁴¹ issued by ADEQ in excess of the Company's needs.
8 Likewise, in APSC Docket No. 09-093-TF, the Commission approved the
9 recovery of nitrogen oxide allowances imposed on EAI's coal and gas-
10 fired units.⁴² EAI has finalized its plans for compliance with MATS and
11 has begun the process of installing the required equipment. The
12 Company expects to begin incurring the costs of compliance in late 2015.

13

14 Q. WHAT IS YOUR RESPONSE TO MS. BUTLER'S ASSERTION THAT IT
15 IS PREMATURE TO RECOMMEND APPROVAL OF THESE COSTS AT
16 THIS TIME?

17 A. Ms. Butler appears to make her recommendation based on the two
18 concerns I mention above (i.e., EAI is not currently incurring these costs,
19 and EAI has not finalized its plans for MATS compliance). As I explained,
20 EAI has committed to making the necessary investments to achieve
21 MATS compliance through the installation of the injectable systems for

⁴¹ Docket No. 06-101-U, Order No. 10 at 105.

⁴² Docket No. 09-093-TF, Order No. 2 at 8.

1 activated carbon and calcium bromide. Accordingly, I fail to see why a
2 decision cannot be reached until these commodity costs are being
3 incurred, as Ms. Butler appears to advocate. Additionally, because the
4 costs of these commodities are dependent upon unit output, they are
5 appropriate for recovery through Rider ECR. EAI would not begin to
6 recover these costs until they are incurred, and all EAI seeks here is
7 confirmation that the costs for these commodities are recoverable through
8 Rider ECR, just as the other similar environmental costs associated with
9 unit output I described above.

10

11 Q. HOW DO YOU RESPOND TO MR. FALKENBERG'S ASSERTION THAT
12 THE INCLUSION OF THESE COSTS WOULD COMPLICATE THE
13 REVIEW PROCESS FOR RIDER ECR COSTS?

14 A. As I explained above, these costs are similar in nature to other emission
15 allowance costs/revenues currently included in Rider ECR. There is no
16 reason to believe that the inclusion of these costs would present any
17 additional complication to reviewing the costs in Rider ECR than the costs
18 of environmental compliance already recovered in Rider ECR.

19

1 **E. Large Cogeneration Rider, Small Cogeneration Rider, and Standby**
2 **Service Rider**

3 Q. WHAT CHANGES HAS EAI PROPOSED TO RIDER LCR AND SCR?

4 A. These tariffs currently contain several references to the System
5 Agreement and/or Service Schedules within that agreement.⁴³ Because
6 EAI is terminating its participation in the System Agreement, those
7 references will no longer be appropriate in this tariff. Second, as a result
8 of joining MISO, EAI will be participating in a Day 2 Market,⁴⁴ which
9 includes day-ahead and real-time settlements and locational marginal
10 pricing. Tariff revisions are needed to reflect properly the circumstances
11 of Qualifying Facilities' ("QF") operations within the MISO Day 2 Market.
12

13 Q. WHAT WAS STAFF'S CONCERNS WITH THOSE ADJUSTMENTS?

14 A. Staff witness Clark Cotten requested that the Company explain how QF
15 payments will be determined for EAI's operations in MISO. EAI witness
16 Patrick Cicio provides additional details regarding EAI's proposed
17 methodologies for calculating avoided costs for these tariffs.
18

⁴³ See e.g., Section 34.4 of Rider SCR; Sections 35.3, 35.5 of Rider LCR.

⁴⁴ Day 2 Markets are centralized region-wide markets operated by RTOs that include day ahead unit commitments, a real time balancing market, and an integrated ancillary services markets. In a Day 2 Market, generators are required to schedule or bid into the market, locational marginal prices are used to price the use of the transmission grid, congestion charges replace "first come, first served" transmission service, and financial transmission rights ("FTRs") are used to hedge congestion. The "Day 2" label arose because these are things that RTOs began to implement after they initially began to operate, or in the "Day 2" of their creation.

1 Q. DID EAI PROPOSE ANY OTHER CHANGES TO THESE RIDERS?

2 A. Yes. In my direct testimony I explained how EAI was proposing to add
3 clarifying language to Riders LCR and SCR, as well as Rider SSR, to
4 ensure that the appropriate additional facilities charges are recovered from
5 customers that are governmental agencies, based on the Commission's
6 approval of the Company's Additional Facilities Charge Rider –
7 Governmental ("Rider AFCRG") in Docket No. 12-096-TF.⁴⁵

8

9 Q. DID OTHER PARTIES SUPPORT THIS CHANGE?

10 A. No. Staff witness Robert Swaim recommended that the Commission
11 reject the proposed changes because EAI has not demonstrated that the
12 insurance provisions approved in Rider AFCRG or the customer's
13 purchase of insurance coverage EAI proposed for governmental entities
14 taking service under Riders SSR, SCR, or LCR is appropriate.⁴⁶

15

16 Q. HOW DO YOU RESPOND?

17 A. Because the Company currently has no customers that are governmental
18 agencies taking service under Rider LCR, Rider SCR, or Rider SSR, EAI
19 is agreeable to addressing this provision of these tariffs at a later time.

20

⁴⁵ Castleberry Direct Testimony at 48 – 49.

⁴⁶ Swaim Direct Testimony at 6 - 7.

1 **III. RESOURCE PLANNING IMPACTS ON BASE RATES**

2 Q. ARE THERE ANY COST ADJUSTMENTS PARTIES PROPOSED THAT
3 YOU ARE ADDRESSING?

4 A. Yes. Given my team's responsibility for the planning and operation of
5 EAI's generating assets, I address in this section several adjustments
6 proposed by the Staff to the cost of EAI's generating assets included in
7 the Company's cost-of-service study.

8
9 **A. Units Being Retired**

10 Q. WHAT ADJUSTMENTS DID THE STAFF PROPOSE REGARDING THE
11 UNITS THAT EAI PLANS TO RETIRE?

12 A. Staff witness Judy Kay Lindholm proposed several adjustments to the
13 costs associated with EAI's generating units based upon EAI's plan to
14 retire those units. Earlier this year, EAI's Resource Planning and
15 Operations Committee recommended, and President and Chief Executive
16 Officer Hugh T. McDonald approved, the retirement of Lake Catherine
17 Units 1, 2, and 3, Lynch Unit 3, Mabelvale Units 2 and 4, and Couch Unit 2
18 upon EAI's transition into the MISO RTO. Ms. Lindholm's recommended
19 adjustments would remove the operating and maintenance ("O&M") costs
20 associated with these generating units based upon her assumption that,
21 because they are no longer operating, EAI would incur no O&M expense.
22 Ms. Lindholm has utilized the direct O&M costs related to these plants in
23 making her recommendation. In addition, she proposed to modify payroll

1 costs at Lake Catherine Unit 4 through her adjustments related to the
2 retirements of Lake Catherine Units 1, 2, and 3. The payroll aspects of
3 Ms. Lindholm's adjustment are addressed by Mr. Zakrzewski.

4

5 Q. DID OTHER PARTIES RECOMMEND ANY ADJUSTMENTS FOR THESE
6 RETIRED PLANTS?

7 A. Yes. Mr. Marcus recommends that \$6.4 million be removed from base
8 rates due to these plant retirements. Similar to Ms. Lindholm, Mr. Marcus
9 incorrectly assumes that EAI would not continue to incur non-fuel O&M
10 costs for these plants once they are retired. However, Mr. Marcus makes
11 his recommendation based on 2012 FERC Form 1 data provided for each
12 unit. As Mr. Zakrzewski discusses in his testimony, use of FERC Form 1
13 data is not appropriate for this purpose because Form 1 data includes an
14 allocation of indirect production expenses. Any analysis should be based
15 on direct O&M costs related to these plants.

16

17 Q. ARE THE ADJUSTMENTS RECOMMENDED BY MS. LINDHOLM AND
18 MR. MARCUS APPROPRIATE?

19 A. Generally, no. I recognize that Ms. Lindholm and Mr. Marcus are
20 attempting to reflect the changes to EAI's costs associated with those
21 units' retirements. However, the proposed adjustments would not reflect
22 the on-going costs associated with these retired units.

23

1 Q. WHY WOULD EAI CONTINUE TO INCUR COSTS AT A RETIRED
2 GENERATING UNIT?

3 A. Until these sites are decommissioned and demolished, EAI will continue to
4 incur expenses for activities such as periodic security rounds, periodic
5 Spill Prevention, Control and Countermeasures rounds as required by the
6 ADEQ, periodic Storm Water Pollution Prevention Plan ADEQ inspections,
7 routine National Pollutant Discharge Elimination System water discharge
8 sampling as required by ADEQ, contract oversight for when contractors
9 are on site, and various other activities. EAI's projection for the O&M and
10 payroll expense at these units to be retired is shown in
11 EAI Exhibit KWC-2.

12

13 Q. WHAT AMOUNT DO YOU RECOMMEND FOR THE ON-GOING O&M
14 EXPENSES RELATED TO THESE PLANTS?

15 A. I recommend an inclusion of \$607,596 for on-going O&M expense related
16 to these plants, as shown in EAI Exhibit KWC-2. Mr. Zakrzewski
17 incorporates this figure into the appropriate adjustment to O&M expense
18 for these units being retired.

19

20 **B. Lake Catherine Unit 4**

21 Q. DID OTHER PARTIES RAISE ANY CONCERNS OVER COSTS FOR
22 LAKE CATHERINE UNIT 4?

1 A. Yes. Mr. Marcus recommends that regulatory asset treatment for the
2 Lake Catherine Unit 4 Reliability/Sustainability project not be allowed, and
3 additionally recommends a downward adjustment to the on-going O&M
4 costs associated with that unit.

5

6 Q. HOW DO YOU RESPOND TO MR. MARCUS' RECOMMENDATIONS?

7 A. Mr. Zakrzewski addresses the proposed regulatory asset treatment of the
8 Lake Catherine Unit 4 Reliability/Sustainability project costs and on-going
9 non-fuel O&M costs in his rebuttal testimony. However, I disagree with
10 Mr. Marcus' assumption that a downward adjustment in O&M is
11 appropriate. Mr. Marcus cites to EAI's response to data request Staff
12 1088 as the basis for his assumption. The information provided in that
13 response included only incremental O&M costs for the years 2014 through
14 2017 and would thus not be representative of total O&M cost projections.

15

16 C. **Mabelvale Units 1 and 3 Allocation**

17 Q. STAFF'S MS. BUTLER REQUESTED THAT EAI PROVIDE AN
18 ANALYSIS SHOWING THE ECONOMIC BENEFIT FOR ALLOCATING
19 ADDITIONAL CAPACITY FROM MABELVALE UNITS 1 AND 3 TO
20 RETAIL. PLEASE PROVIDE THIS ANALYSIS.

21 A. Mabelvale Units 1 and 3 have a total generation capability of
22 approximately 26 MW. EAI has estimated that the marginal cost to
23 continue to operate these units for 2014 and 2015 will be approximately

1 \$70,000 per year. So, the marginal cost of keeping this capacity available
2 for the next two years is approximately \$.22/kW-month. However, the
3 total revenue requirement for the total Mabelvale capacity, 26 MW, is
4 estimated to be approximately \$920,000 per year, which results in an
5 average capacity cost of about \$2.95/kW-month. Therefore, the
6 \$2.95/kW-month value represents the marginal cost to EAI's retail
7 customers for this approximately 4 MW of capacity. At this level of cost,
8 the 4 MW of capacity provided by these two units compares well to the
9 recent Purchase Power Agreement ("PPA") that the Commission found
10 prudent in Docket No. 12-038-U. The price of the capacity also compares
11 well to the contracted price for interruptible demand agreed to by BRS in
12 Docket No. 13-032-P, which was \$3.17/kw-month for the first 5 years of
13 service.

14
15 Q. CAN YOU ESTIMATE THE ECONOMIC BENEFIT TO RETAIL
16 CUSTOMERS OF THIS 4 MW OF CAPACITY?

17 A. It is not practical to quantify the economic benefits of this capacity given
18 the small quantity and cost involved. The additional Mabelvale capacity
19 will provide some level of Resource Credits in MISO and a hedge against
20 high energy costs, should a price spike in energy prices occur. Given the
21 marginal cost of the capacity as compared to a comparable market
22 transaction, the capacity from Mabelvale Units 1 and 3 is a reasonable
23 addition to EAI's generation portfolio.

1 **D. Hot Spring Plant Costs**

2 Q. WHAT ADJUSTMENTS WERE PROPOSED FOR THE COSTS OF THE
3 HOT SPRING PLANT?

4 A. AG's Mr. Marcus recommends an adjustment to the Long Term Service
5 Agreement ("LTSA") costs that would reduce EAI's O&M expense for the
6 plant by \$1,484,036. As Mr. Marcus correctly notes, the LTSA costs
7 incurred for the Hot Spring Plant depend upon the number of starts for the
8 unit and the number of hours it runs. Mr. Marcus' recommended
9 adjustment is based on the average expected run cases for the unit,
10 whereas EAI used an average derived from the high and average run
11 cases. Additionally, Mr. Marcus proposes to reduce the amount of non-
12 LTSA O&M expenses for the Hot Spring Plant by \$368,023.

13
14 Q. WHAT IS YOUR RESPONSE TO THESE ADJUSTMENTS?

15 A. Mr. Marcus' proposed adjustment to LTSA costs demonstrates why EAI
16 originally proposed to recover LTSA costs through Rider ECR⁴⁷ because
17 those costs would be dependent upon the actual operation of the unit
18 rather than projections. Both Mr. Marcus and I are proposing costs based
19 upon the expected operation of the unit, with the outcome being that

⁴⁷ EAI original proposed Rider ECR recovery for LTSA costs in Docket No. 06-152-U, the docket where EAI's purchase of the Ouachita Plant was approved. EAI's proposal for LTSA cost treatment was opposed by Staff and AG and rejected by the Commission.

1 neither of us can provide as accurate an assessment and recovery of
2 those costs as would occur with recovery under Rider ECR.

3 Mr. Marcus' proposal to reduce the amount of non-LTSA O&M is
4 based upon what he describes as a three-year average of forecasted
5 O&M for the plant, and contrary to Staff's proposed adjustment,
6 Mr. Marcus normalizes the costs associated with the future hydrogen seal
7 replacement anticipated for the plant. His adjustment would result in a
8 reduction of \$286,494 from EAI's filing. EAI based its estimate for non-
9 LTSA O&M costs for the Hot Spring Plant on the methodology utilized by
10 Mr. Marcus in Docket No. 09-084-U to estimate the O&M expenses for the
11 Ouachita Plant. In this case, however, he has expanded the types of
12 projects to be considered and normalized to derive his proposed
13 adjustment. I do not believe Mr. Marcus has provided an adequate basis
14 to depart from the method he utilized previously, and so I would
15 recommend that this adjustment be rejected.

16

17 **D. Affiliate Charges for Resource Planning**

18 Q. DID ANY PARTY COMMENT ON EAI'S INCLUDING IN ITS COST-OF-
19 SERVICE STUDY THE COSTS ASSOCIATED WITH THE USE OF THE
20 SYSTEM PLANNING ORGANIZATION ("SPO") WITHIN ESI TO ASSIST
21 EAI WITH RESOURCE PLANNING?

1 A. Yes. Staff witness Claude Robertson reviewed the contracts for the
2 services to be provided and recommended inclusion of these costs.⁴⁸
3 AEEC's Mr. Falkenberg asserted that the use of ESI may not be the least
4 cost option for these services and recommended that the Commission
5 reduce EAI's request by 20 percent, or \$2 million, as a way to incent EAI
6 to seek out other bids or to develop this capability internally.⁴⁹

7
8 Q. HOW DO YOU RESPOND TO MR. FALKENBERG'S
9 RECOMMENDATION?

10 A. EAI explained in Docket No. 10-011-U why it decided to utilize SPO to
11 support the Company's generation resource planning because the
12 organization already has extensive knowledge of EAI's generating units,
13 transmission facilities, and load serving requirements. This expertise is
14 invaluable at a time in which EAI is transitioning from operations within the
15 System Agreement to operations as a member of MISO, separate and
16 apart from the other Operating Companies. Mr. Falkenberg provides no
17 basis for his recommendation to reduce EAI's request by 20 percent as a
18 means to incent the Company to pursue other options. The costs that EAI
19 has included for generation planning in its cost-of-service study should be
20 considered reasonable at the level recommended by Staff's Mr. Robertson
21 in his adjustment IS-25.

⁴⁸ Robertson Direct Testimony at 7-8.

⁴⁹ Falkenberg Direct Testimony at 60 – 61.

1 **E. Dismantlement Costs**

2 Q. PLEASE DESCRIBE THE REPORTING REQUIREMENTS PROPOSED
3 BY STAFF WITNESS RONALD GARNER IN CONNECTION WITH THE
4 DISMANTLEMENT OF EAI GENERATING FACILITIES.

5 A. Mr. Garner recommends that:

6
7 ..by the effective date of the depreciation rates approved in
8 this docket, for each of the units that the Company plans to
9 retire by the end of 2013, EAI provide a report showing the
10 anticipated start date for dismantlement and within six
11 months of the start date for each unit, EAI provide a
12 complete dismantlement plan. I also recommend that, at
13 least 90 days prior to beginning the dismantlement, EAI
14 provide a copy of the selected winning bid from the Request
15 For Proposal process along with the key factors used to
16 select the winning bid. Upon completion of each plant's
17 dismantlement, I recommend that EAI provide a report that
18 compares the actual costs to the costs estimated in the
19 dismantlement study by major cost category along with an
20 explanation of variances greater than five percent of the total
21 category cost.⁵⁰

22
23 Q. DOES EAI CURRENTLY HAVE PLANS TO DISMANTLE ANY OF ITS
24 GENERATING FACILITIES?

25 A. At the present time, EAI has not targeted any specific EAI generating unit
26 for dismantlement or issued any bids for dismantlement work. However,
27 EAI continues to evaluate the long-term plans for its generation sites,
28 including the option for dismantlement.

29

⁵⁰ Garner Direct Testimony at 22.

1 Q. IS THE COMPANY AGREEABLE TO THE DISMANTLEMENT
2 REPORTING REQUIREMENTS PROPOSED BY MR. GARNER?

3 A. Yes, but with some modifications that EAI believes are reasonable. For
4 instance, the Company proposes to adjust the timing of Mr. Garner's
5 requirements to better approximate actual bidding experiences.

6

7 Q. WHAT SPECIFIC TIMING MODIFICATIONS DOES EAI PROPOSE?

8 A. First, EAI proposes to provide a complete dismantlement report within
9 three months of the start date for each unit instead of Staff's proposed six
10 months. Second, EAI proposes to provide a copy of the selected winning
11 bid from a Request for Proposal process to the Commission within 30
12 days of the start date of the dismantlement project instead of Staff's
13 proposed 90 days. This recommended change is intended to reflect
14 actual bidding experience where contractors typically condition their bid
15 responses on a shorter period of time. Additionally, to help preserve the
16 integrity of the bidding process, EAI proposes that the submission of any
17 such winning bid selection would be made under the appropriate
18 confidential protection. EAI understands that Staff is amenable to EAI's
19 proposed changes on these items.

20

21 Q. DOES MR. GARNER PROPOSE ANY ADDITIONAL REPORTING
22 REQUIREMENTS?

1 A. Yes. Mr. Garner proposes that EAI provide an updated dismantlement
2 costs study in support of each depreciation study submitted by the
3 Company and explain variances greater than five percent of the total
4 category cost from the previous dismantlement cost study.⁵¹

5
6 Q. DOES THE COMPANY CONSIDER THESE PROPOSED REPORTING
7 REQUIREMENTS REASONABLE?

8 A. Generally, yes, with some modifications. EAI believes it is reasonable to
9 provide a dismantlement cost study at the time it proposes new
10 depreciation rates if the previous dismantlement cost study is greater than
11 10 years old. This time frame recognizes the longer shelf life appropriate
12 for a dismantlement study and the fact that such studies can be expensive
13 to undertake. Further, the Company also agrees it is reasonable to
14 respond to specific questions from Staff relating to any variances by total
15 category cost from the prior dismantlement cost study the Company
16 provided.

17
18 Q. CAN YOU ELABORATE ON THE RATIONALE FOR THE
19 MODIFICATION TO ADJUST TO A 10-YEAR DISMANTLEMENT
20 STUDY?

⁵¹ Garner Direct Testimony at 22.

1 A. EAI believes that a reasonable shelf life for a dismantlement cost study is
2 10 years. A component of the dismantlement cost estimate that can
3 fluctuate is the value of scrap metal, but these prices can fluctuate
4 between the time a bid is accepted and the dismantlement project is
5 completed. Additionally, the cost to perform a dismantlement cost study
6 on too frequent of a basis would cause unnecessary costs for customers
7 and should not be incurred simply at the time new depreciation rates are
8 proposed. Rather, the trigger for performing a new dismantlement study
9 should be the fact that any prior, existing one has surpassed its life and is
10 no longer reasonably deemed valid. Thus, to avoid unnecessary
11 expenses associated with performing new studies too frequently, it is more
12 appropriate to use an existing, valid study and periodically adjust the scrap
13 values to reflect fluctuations in scrap prices.

14

15 Q. DOES THIS CONCLUDE YOUR TESTIMONY?

16 A. Yes.

CERTIFICATE OF SERVICE

I, Steven K. Strickland, do hereby certify that a copy of the foregoing has been served upon all parties of record by forwarding the same by electronic mail and/or first class mail, postage prepaid, this 26th day of August, 2013.

/s/ Steven K. Strickland
Steven K. Strickland

BEFORE THE
ARKANSAS PUBLIC SERVICE COMMISSION

IN THE MATTER OF THE APPLICATION	)	
OF ENTERGY ARKANSAS, INC. FOR	)	DOCKET NO. 13-028 -U
APPROVAL OF CHANGES IN RATES FOR	)	
RETAIL ELECTRIC SERVICE	)	

EAI EXHIBIT KWC-1

ADEQ CORRESPONDENCE



Arkansas Environmental Support
425 West Capitol Avenue
A-TCBY-22D
Little Rock, AR 72203
Tel 501-377-4033
Fax 281-297-6128
G. Tracy Johnson, Manager
Arkansas Environmental Support

AR-13-030

March 28, 2013

Hand Delivered

Mr. Mike Bates
Chief, Air Division
Arkansas Department of Environmental Quality
5301 Northshore Drive
North Little Rock, AR 72118

RECEIVED
MAR 28 2013
mpc 2:45pm

Subject: Request for Mercury and Air Toxics Standards Compliance Deadline Extension

Reference: Entergy Arkansas, Inc. – White Bluff Plant
AFIN: 35-00110 Permit No.: 0263-AOP-R7

Entergy Arkansas, Inc. – Independence Plant
AFIN: 32-00042 Permit No.: 0449-AOP-R7

Dear Mr. Bates:

The purpose of this letter is to request a one (1) year extension of the compliance deadlines set forth in the U.S. Environmental Protection Agency's (EPA's) Mercury and Air Toxics Standards ("MATS"), 77 Fed. Reg. 9304 (Feb. 16, 2012), for Units 1 and 2 located at the Entergy Arkansas, Inc. (EAI) – White Bluff Plant and Units 1 and 2 located at the EAI – Independence Plant. The MATS rule, promulgated pursuant to the Clean Air Act § 112(d), which became effective on April 16, 2012, sets forth stringent limits for mercury, particulate matter, and acid gases on a 30-day rolling average basis for each unit. Currently, Units 1 and 2 at White Bluff and Units 1 and 2 at Independence are not equipped with the necessary controls to achieve compliance with MATS. Based upon the anticipated control equipment installation schedule for each unit, which is timed to the necessary outage for construction, and the time required for commissioning equipment and certifying controls, EAI requires additional time to comply with MATS.

According to the federal Clean Air Act, the compliance deadline for regulations promulgated pursuant to § 112(d) is no later than three (3) years after the effective date of the standards. See 42 U.S.C. § 7412(i)(3)(A). Therefore, the compliance deadline for MATS is April 16, 2015. The Act and EPA's implementing regulations allow the Arkansas Department of Environmental Quality (ADEQ), as the state agency with an approved permitting program, to "issue a permit that grants an extension permitting an existing source up to 1 additional year to comply with standards . . . if such additional period is necessary for the installation of controls." 42 U.S.C. § 7412(i)(3)(B); see also 40 CFR § 63.6(i)(4)(i)(A). Moreover, in the final MATS rule, EPA recognized several situations in which control installation schedules may take more than three

(3) years and would be appropriate for a compliance deadline extension, including when staggering control installations are necessary for reliability purposes, when there are other site-specific challenges related to the construction, or permitting, or when there may be labor, procurement or resources challenges which constrain the installation schedule. See 77 Fed. Reg. 9304, at 9310-12.

Pursuant to EPA's implementing regulations, 40 CFR § 63.6(i)(6)(i), extension requests per § 63.6(i)(4)(i) must include: (1) a description of the controls to be installed to comply with the standard; and (2) a compliance schedule which outlines the date by which the installation of emission controls equipment will commence, the date in which the installation will be complete, and the date by which final compliance will be achieved.

For Units 1 and 2 at White Bluff and Units 1 and 2 at Independence, the emission controls to be installed for mercury control are an activated carbon injection and a calcium halide injection system.

Included in the compliance schedule for White Bluff Units 1 and 2 and Independence Units 1 and 2 is the anticipated schedule for Entergy Gulf State Louisiana's Unit 6 located at the Nelson Plant, see Attachment A. It reflects the anticipated schedule for executing the design, permitting, and equipment procurement of the controls for each of the Units in parallel. Unit outages must be staggered due to system reliability constraints. The earliest available Unit outages were selected based upon emission controls equipment delivered to site and sufficient time for pre-outage construction work. Final compliance is expected by April 16, 2016.

The requested extensions - and the installation schedules and constraints on which they are based - are consistent with EPA's discussion in the MATS rule of the range of circumstances which may trigger the need for additional time to comply and which justify an extension for compliance.

Please note that Attachment A provides our current estimated schedule for installation and commissioning of the necessary controls, but unanticipated delays may occur due to such things as permitting delays, work stoppages, lack of materials, equipment or skilled labor, and adjustments due to reliability concerns. Thus, an additional request for extension may be warranted; and EAI reserves the right to request an additional extension for any of the units consistent with applicable law.

We appreciate your prompt response to this request. Should you wish to discuss the requests or the enclosed supporting information, we are available at your convenience and ask that you contact me at 501-377-4033, or Kelly McQueen, 501-377-5760.

Sincerely,

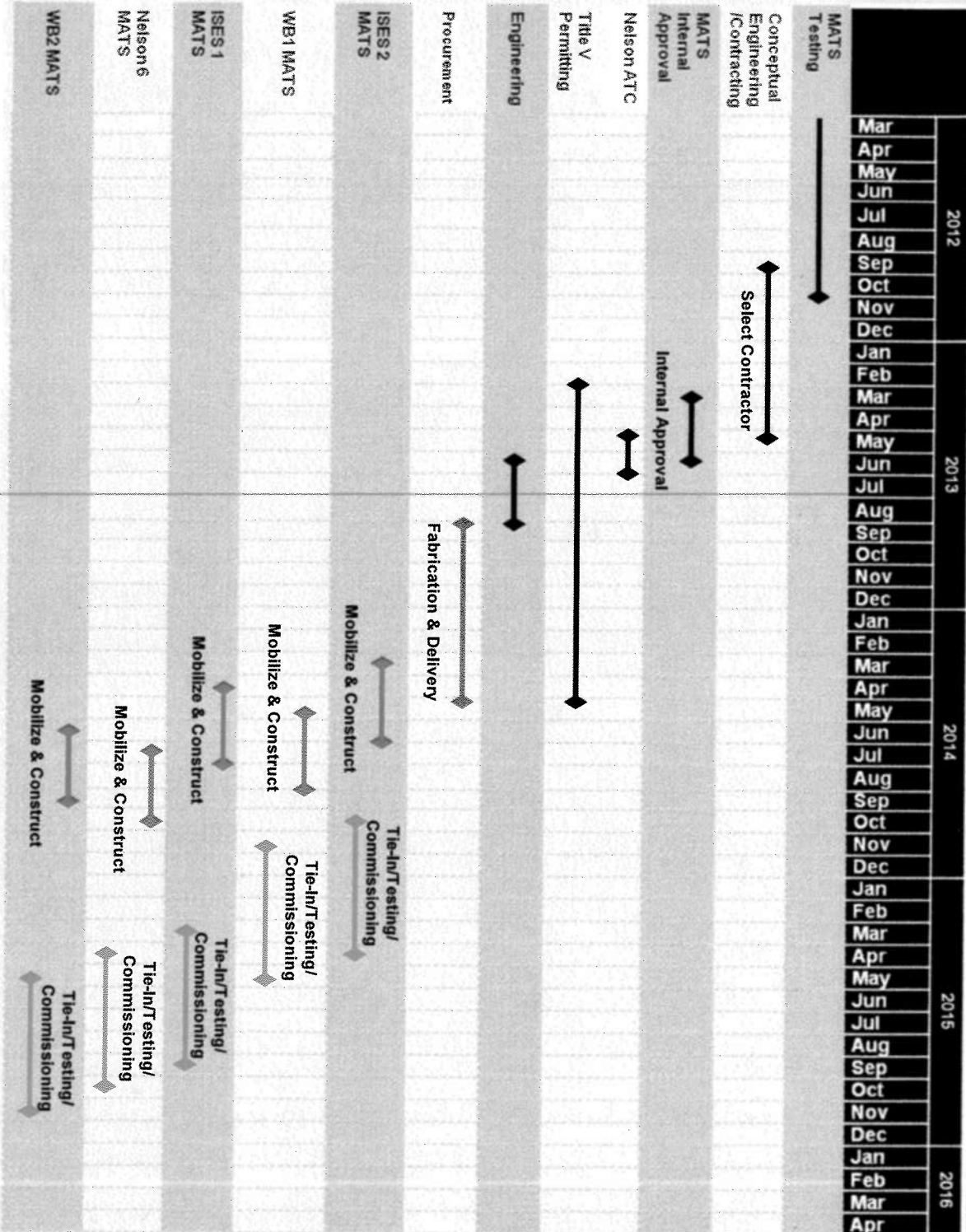


G. Tracy Johnson, Manager
Arkansas Environmental Support

Enclosure (Attachment A)

cc: Thomas Rheaume, P.E. – ADEQ Air Permits Branch Manager

MATS Project Timeline





ARKANSAS
Department of Environmental Quality

April 2, 2013

G. Tracy Johnson, Manager
Entergy
Arkansas Environmental Support
425 West Capitol Avenue
Little Rock, AR 72203

Re: Request for One-Year Extension of MACT Compliance Date
Entergy Arkansas, Inc. – White Bluff Plant
AFIN 35-00110, Permit 0263-AOP-R7
Entergy Arkansas, Inc. – Independence Plant
AFIN 32-00042, Permit 0449-AOP-R7

Dear Mr. Johnson:

We are in receipt of your March 28, 2013, letter regarding the Entergy Arkansas, Inc. – White Bluff and Independence Plants (Entergy Arkansas) requesting that the Arkansas Department of Environmental Quality (“ADEQ”) grant a one-year extension of the compliance date for the Mercury and Air Toxics Standards (“MATS”) promulgated at 40 C.F.R. Part 63 Subpart UUUUU. The MATS contain a requirement of compliance no later than three (3) years from the April 16, 2012, effective date of the standard. Therefore, the compliance date for MATS is established as April 16, 2015.

The federal Clean Air Act and federal regulations provide that ADEQ, as a state agency with an approved Part 70 (Title V) permit program, may grant an existing source an extension of up to one (1) year to comply with the standard. *See* 42 U.S.C. § 7412(i)(3)(B); *see also* 40 C.F.R. 63.6(i)(4)(i)(A).

Entergy Arkansas has indicated that the requested extension is necessary in order to install additional pollution control equipment at the White Bluff and Independence Plants in order to facilitate compliance with the standard. The request identifies the applicable control equipment to include an activated carbon injection and calcium halide injection system. Entergy Arkansas has indicated that construction/installation of the control equipment will begin at the White Bluff Plant on or about May 2014 and at the Independence Plant on or about March 2014. Final compliance with the MATS will be achieved by April 16, 2016.

ADEQ agrees that the information contained in the March 28, 2013, letter is consistent with the criteria justifying a one (1) year extension of the MATS compliance date. Therefore, the compliance date for MATS for both facilities shall be April 16, 2016.

Additionally, as part of the extension process as indicated at 40 C.F.R. 63.6(i)(4)(i)(A), the conditions of the extension must be incorporated into the Title V permits for each facility. Within ninety (90) days of the date of this letter, submit air permit applications to incorporate the extension and all relevant MATS requirements into the Title V permits of the White Bluff and Independence plants.

If you should have any questions about this matter, please feel free to contact me.

Sincerely,

A handwritten signature in black ink, appearing to read "Mike Bates", written in a cursive style.

Mike Bates
Air Division Chief

cc: Thomas Rheaume, Air Permits Branch Manager
Stuart Spencer, Attorney Specialist

BEFORE THE
ARKANSAS PUBLIC SERVICE COMMISSION

IN THE MATTER OF THE APPLICATION	)	
OF ENTERGY ARKANSAS, INC. FOR	)	DOCKET NO. 13-028 -U
APPROVAL OF CHANGES IN RATES FOR	)	
RETAIL ELECTRIC SERVICE	)	

EAI EXHIBIT KWC-2

NON-PAYROLL O&M REQUIREMENTS FOR RETIRED UNITS

WORKING AS OF 8-20-13

Lvl 2 Phy Loc	Source Summ Resource	2014 \$ TO REMAIN AFTER PLANT/UNIT RETIRED	REVISED EXPLANATIONS
CHP_COUCH_PLANT	CTC_SUMMARY	67,000	Perform all Fossil required NERC testing, equipment maintenance on sump pumps, water pumps, transformers, ponds at Couch, fire extinguishers, potential security service for unstaffed sites, HVAC, maintain buildings and equipment: lead paint and asbestos abatement as required, yard/grounds maintenance, perform environmental testing, sampling, and reporting to support NPDES permits and Stormwater permits
CHP_COUCH_PLANT	DPR_SUMMARY	-	
CHP_COUCH_PLANT	EEX_SUMMARY	4,205	Expenses for site visits for testing and monitoring.
CHP_COUCH_PLANT	MTL_SUMMARY	203	Loader
CHP_COUCH_PLANT	MTS_SUMMARY	14,000	Misc. boiler, other electric plant, nitrogen, minor upkeeps, oil leaks, misc. consumables/PPE needed for employees onsite for rounds & maintenance
CHP_COUCH_PLANT	OGL_SUMMARY	2,000	Water bills, telecom expense (no cell tower signal near this plant), waste disposal
CHP_COUCH_PLANT	OTD_SUMMARY	67,000	Monthly and quarterly ADEQ sampling requirements, annual NPDES permits, Stormwater permits, Air permits depending on timing of unit retirements, hazardous material disposal, universal waste disposal
CHP_COUCH_PLANT	OUT_SUMMARY	-	
CHP_COUCH_PLANT	RNT_SUMMARY	7,260	Equipment rentals - forklifts, boom, back-up diesel generator, dehumidifiers etc. - examples for the removal of asbestos, lead paint - oil leaks etc.
CHP_COUCH_PLANT	SCR_SUMMARY	-	
CHP_COUCH_PLANT	TCM_SUMMARY	11,940	This is the T1 network connection - long distance support that must be retained due to the ongoing compliance testing and maintenance at this remote site
CHP_COUCH_PLANT	TPC_SUMMARY	1,491	Transportation lease vehicle costs associated with 1 pool vehicles located at Lake Catherine for the purpose of travel to couch for inspection, environmental maintenance etc.
CHP_COUCH_PLANT Total		175,099	

Lvl 2 Phy Loc	Source Summ Resource	2014 \$ TO REMAIN AFTER PLANT/UNIT RETIRED	REVISED EXPLANATIONS
CLS_CECIL_LYNCH_SUM	CTC_SUMMARY	67,000	Perform all Fossil required NERC testing, equipment maintenance on sump pumps, water pumps, transformers, fire extinguishers, potential security service for unstaffed sites, HVAC, maintain buildings and equipment: lead paint and asbestos abatement as required, yard/grounds maintenance, perform environmental testing, sampling, and reporting to support NPDES permits and Stormwater permits
CLS_CECIL_LYNCH_SUM	DPR_SUMMARY	-	
CLS_CECIL_LYNCH_SUM	EEX_SUMMARY	-	
CLS_CECIL_LYNCH_SUM	MTL_SUMMARY	1,014	Loader
CLS_CECIL_LYNCH_SUM	MTS_SUMMARY	20,000	Misc. boiler, other electric plant, nitrogen, minor upkeeps, oil leaks, misc. consumables/PPE needed for employees onsite for rounds & maintenance
CLS_CECIL_LYNCH_SUM	OGL_SUMMARY	25,000	Water bills and North Little Rock Electric, Waste disposal
CLS_CECIL_LYNCH_SUM	OTD_SUMMARY	40,000	Monthly and quarterly ADEQ sampling requirements, annual NPDES permits, Stormwater permits, Air permits depending on timing of unit retirements, hazardous material disposal, universal waste disposal
CLS_CECIL_LYNCH_SUM	OUT_SUMMARY	14,645	
CLS_CECIL_LYNCH_SUM	RNT_SUMMARY	4,411	Equipment rentals - forklifts, boom, dehumidifiers etc. - examples for the removal of asbestos, lead paint - oil leaks etc.
CLS_CECIL_LYNCH_SUM	SCR_SUMMARY	1,028	Loader
CLS_CECIL_LYNCH_SUM	TCM_SUMMARY	17,000	This is the T1 network connection - long distance support that must be retained due to the ongoing compliance testing and maintenance at this remote site
CLS_CECIL_LYNCH_SUM	TPC_SUMMARY	766	
CLS_CECIL_LYNCH_SUM	CLT_Total	190,864	
MSS_MOSES	CTC_SUMMARY	63,000	HVAC/grass cutting/Waste Removal/Fire Ext Inspect/NERC Testing/VRC Operator 1 day per week.
MSS_MOSES	DPR_SUMMARY	0	
MSS_MOSES	INS_SUMMARY	0	Loader
MSS_MOSES	MTL_SUMMARY	125	Loader
MSS_MOSES	MTS_SUMMARY	500	Cylinder gas/xformer nitrogen
MSS_MOSES	OGL_SUMMARY	1,200	Utilities
MSS_MOSES	OTD_SUMMARY	1,500	Environmental permits, licenses, fees
MSS_MOSES	OUT_SUMMARY	14,645	
MSS_MOSES	SCR_SUMMARY	1,028	Loader

Lvl 2 Phy Loc	Source Summ Resource	2014 \$ TO REMAIN AFTER PLANT/UNIT RETIRED	REVISED EXPLANATIONS
MSS MOSES	TCM SUMMARY	12,000	Telecom line required for security system
MSS MOSES	TPC SUMMARY	0	
MSS MOSES Total		93,998	
RTP RITCHIE PLANT	CTC SUMMARY	72,000	HVAC/grass cutting/Waste Removal/Fire Ext Inspect/NERC Testing
RTP RITCHIE PLANT	DPR SUMMARY	0	
RTP RITCHIE PLANT	EEX SUMMARY	13,000	VRC 1 operator/1 day per week
RTP RITCHIE PLANT	MTL SUMMARY	2,750	Loader
RTP RITCHIE PLANT	MTS SUMMARY	11,000	Cylinder gas/xformer nitrogen
RTP RITCHIE PLANT	OGL SUMMARY	500	Telecom Service
RTP RITCHIE PLANT	OTD SUMMARY	30,000	Environmental permits, licenses, fees
RTP RITCHIE PLANT	OUT SUMMARY	5,966	
RTP RITCHIE PLANT	SCR SUMMARY	419	Loader
RTP RITCHIE PLANT	TCM SUMMARY	12,000	Telecom line required for security system
RTP RITCHIE PLANT	TPC SUMMARY	0	
RTP RITCHIE PLANT Total		147,635	
	All Total	607,596	

BEFORE THE
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IN THE MATTER OF THE APPLICATION	)	
OF ENTERGY ARKANSAS, INC. FOR	)	DOCKET NO. 13-028-U
APPROVAL OF CHANGES IN RATES FOR	)	
RETAIL ELECTRIC SERVICE	)	

REBUTTAL TESTIMONY

OF

JAY A. LEWIS

VICE PRESIDENT, REGULATORY STRATEGY

UTILITY OPERATIONS GROUP

ENTERGY SERVICES, INC.

ON BEHALF OF

ENTERGY ARKANSAS, INC.

AUGUST 26, 2013

1 **I. INTRODUCTION**

2 Q. PLEASE STATE YOUR NAME.

3 A. My name is Jay A. Lewis.

4

5 Q. ARE YOU THE SAME JAY A. LEWIS WHO FILED DIRECT TESTIMONY
6 IN THIS DOCKET ON MARCH 1, 2013?

7 A. Yes, I am.

8

9 Q. ON WHOSE BEHALF ARE YOU TESTIFYING?

10 A. I am submitting this rebuttal testimony to the Arkansas Public Service
11 Commission (“APSC” or the “Commission”) on behalf of Entergy
12 Arkansas, Inc. (“EAI” or the “Company”).

13

14 Q. WHAT IS THE PURPOSE OF YOUR REBUTTAL TESTIMONY?

15 A. The purpose of my rebuttal testimony is to address comments made by
16 witnesses for the APSC General Staff (“Staff”), the Hospital and Higher
17 Education Group (“HHEG”), and Kroger Company (“Kroger”) related to the
18 Company’s proposals associated with the allowance for funds used during
19 construction (“AFUDC”).

20

1 **II. RESPONSE TO AFUDC COMMENTS**

2 **A. Calculation Of AFUDC Rate**

3 Q. SEVERAL PARTIES HAVE COMMENTED ON THE COMPANY'S
4 PROPOSALS RELATED TO ACCRUING AFUDC. WOULD YOU
5 PLEASE SUMMARIZE THESE COMMENTS?

6 A. Staff witness Robert Daniel and Kroger witness Neal Townsend take the
7 position that all sources of capital are fungible, and thereby ADIT can be
8 used as a source of funding AFUDC.¹ Staff witness William L. Matthews,
9 and HHEG witness Mark E. Garrett state that AFUDC should not accrue
10 on projects that are delayed more than four months, although HHEG
11 states that the continued accrual of AFUDC should require APSC
12 approval. In contrast, the Staff's Mr. Daniel proposes that the Company
13 simply continue to suspend accrual of AFUDC for any interruption that
14 exceeds four months.² Lastly, Mr. Daniel claims that compounding
15 AFUDC no more frequently than annually is more closely aligned with the
16 frequency of general rate cases allowed under Arkansas law.³

17
18 Q. WHAT IS YOUR RESPONSE TO THE ARGUMENT OF MESSRS.
19 DANIEL AND TOWNSEND THAT FUNDS ARE FUNGIBLE AND THAT
20 THERE ARE OTHER SOURCES OF CAPITAL TO FUND
21 CONSTRUCTION, SUCH AS ADIT?

¹ Daniel Direct Testimony at 46; Townsend Direct Testimony at 5.

² Matthews Direct Testimony at 11; Garrett Direct Testimony at 10.

³ Daniel Direct Testimony at 47.

1 A. Mr. Daniel recognizes that Construction Work in Progress (“CWIP”), the
2 term that refers to the cost of assets under construction, does not produce
3 ADIT because he acknowledges that “ADIT related to depreciation
4 expense is generated when plant is in service and not during the
5 construction phase....”⁴ This statement is significant because it
6 acknowledges that all ADIT is being used to determine the return on rate
7 base that is being used to determine the revenue requirements on assets
8 in service in this rate case. If all ADIT is used to support rate base, and if
9 CWIP does not produce ADIT, then it follows that ADIT should have
10 nothing to do with determining the AFUDC rate.

11
12 Q. MR. DANIEL, HOWEVER, ARGUES THAT BECAUSE MONEY IS
13 FUNGIBLE, ALL LIABILITIES ON THE BALANCE SHEET ARE
14 SOURCES TO FUND ALL ASSETS.⁵ HOW DO YOU RESPOND?

15 A. Fungibility does not make money grow. As I said above, there is only so
16 much ADIT, and it is being used to support rate base. To the extent ADIT
17 is attributed to CWIP, the ADIT supporting rate base should be reduced.
18 Moreover, AFUDC and rate of return on rate base (“RORB”) are separate
19 and distinct both conceptually and practically. It is improper to conflate the
20 two. In determining RORB, the Commission is seeking to answer the
21 question, “What return do rates paid by customers need to provide to the

⁴ Daniel Direct Testimony at 46.

⁵ *Id.*

1 Company in order to adequately compensate the Company for the cost of
2 funds that it uses in financing its overall operations and investments?”
3 Conversely, the determination of the AFUDC rate seeks to answer the
4 question, “What return should the Company be allowed to accrue on
5 assets that are under construction in order to properly capture the cost of
6 funds used in financing that construction?” The questions are
7 substantially different, and the methodologies used in determining the
8 applicable returns should be different as well.

9

10 Q. HOW ARE THE CONCEPTS OF RORB AND AFUDC DIFFERENT AND
11 WHY DO THESE DIFFERENCES JUSTIFY A DIFFERENT RATE FOR
12 EACH?

13 A. RORB and AFUDC are based on different concepts and are used for
14 entirely different purposes. RORB directly relates to rates currently being
15 paid by customers for the electric service they receive from the Company
16 related to assets in use to provide that service. Conversely, AFUDC has
17 nothing to do with current rates because CWIP, on which AFUDC is
18 accrued, is excluded from rate base on which current rates are set.
19 Accordingly, current rates are unaffected by CWIP and AFUDC. In
20 addition, the determination of the RORB looks to the overall financing of
21 the Company’s operations, and therefore takes into account factors such
22 as ADIT, customer deposits, working capital, and other sources of funds
23 that relate to the Company’s ongoing operations as a whole. Conversely,

1 AFUDC relates solely to the relatively small portion of the Company's
2 assets that are under construction at any given point in time. The
3 calculation of AFUDC necessarily and properly focuses on the funding
4 sources that are actually available to and used by the Company to finance
5 the construction of those assets because those assets are under
6 construction and not eligible to be included in rates and are otherwise
7 producing no cash flows during their construction.

8 These differences demonstrate the fatal flaw in the position taken
9 by Mr. Daniel and Mr. Townsend that seeks to equate RORB with AFUDC.
10 It is simply a fact that the entire balance of ADIT, as well as customer
11 deposits, working capital, and the other "zero cost" items included in the
12 determination of RORB, are fully utilized in determining the RORB.
13 Including these sources again in the determination of AFUDC is "double
14 dipping". These sources are already fully utilized in determining RORB
15 and are irrelevant to the financing of CWIP.

16 This is why the calculation of AFUDC approved by FERC does not
17 follow the approach recommended by Staff and Kroger, and why the
18 APSC utilized the FERC approach in setting EAI's rates until the Company
19 agreed in a settlement to use a different approach only in exchange for
20 other elements in the settlement and under the agreement that such an
21 action served as no precedent for future APSC decision making.⁶

⁶ Docket No 09-084-U, Joint Motion to Approve Settlement filed May 10, 2010, Joint Exhibit at 7-8.

1

2 Q. WHAT IS THE HARM IN USING THE APPROACH RECOMMENDED BY
3 MESSRS. DANIEL AND TOWNSEND TO CALCULATE AFUDC?

4 A. The approach results in a lower AFUDC rate by improperly including
5 sources of funds that have nothing to do with CWIP and that are already
6 fully utilized in determining RORB. Setting AFUDC lower than the actual
7 cost of financing assets under construction discourages a utility from
8 making investment. In addition, adopting a proposal to set an artificially
9 low AFUDC rate is particularly counterproductive at this time given the
10 large investment required in the near future by EAI, which I explained in
11 my direct testimony.⁷

12

13 B. **Timing Of AFUDC Accrual on Projects Subject to APSC Approval**

14 Q. WHAT IS YOUR RESPONSE TO STAFF WITNESS MATTHEWS'
15 RECOMMENDATION THAT AFUDC ACCRUAL SHOULD NOT BEGIN
16 UNTIL THE PROJECT HAS BEEN APPROVED BY THE APSC?⁸

17 A. Staff witness Matthews states that this recommendation only applies to
18 projects requiring APSC approval and is only to avoid having ratepayers
19 pay AFUDC cost above a reasonable level. However, EAI already
20 provides that customer protection in its policy to reverse AFUDC accrual if
21 a construction project is either canceled or not approved by the

⁷ Lewis Direct Testimony at 4-8.

⁸ Matthews Direct Testimony at 9-10.

1 Commission. As a result, there is no situation in which customers
2 ultimately would pay for AFUDC on this type of canceled project or project
3 not approved by the APSC. Rather, accruing AFUDC as construction cost
4 is incurred properly reflects the financing cost incurred by the Company.
5

6 **C. Treatment of Interrupted Projects**

7 Q. WHAT IS YOUR RESPONSE TO STAFF WITNESS MATTHEWS' AND
8 HHEG WITNESS GARRETT'S POSITION THAT PROJECTS
9 INTERRUPTED MORE THAN FOUR MONTHS SHOULD NOT ACCRUE
10 AFUDC?

11 A. Mr. Matthews' and Mr. Garrett's recommendations do not take into
12 account the realities of scheduling and performing utility construction work.
13 Mr. Matthews statement that "four months is a sufficient time in which to
14 resolve many of these issues"⁹ associated with an interruption in
15 construction is not based in the reality of utility operations in which
16 construction delays are often beyond the control of the Company. For
17 example, EAI is often prevented from completing a construction project
18 because of a customer's delay in completion of its portion of the work. In
19 other cases, construction delays are due to securing permits or other
20 regulatory approvals. One example is a current project at Carpenter Dam
21 wherein EAI was required to design a project, submit it to the FERC for
22 approval, and then schedule the work at some point in the future. This

⁹ Matthews Direct Testimony at 11.

1 process took significantly longer than four months. Additionally, it is not
2 uncommon for projects at Arkansas Nuclear One to be designed and
3 submitted to the Nuclear Regulatory Commission for approval, but when
4 approval is received, the construction can only be performed during a
5 scheduled refueling outage, which occurs every 18 months. Each of
6 these examples demonstrates why an interruption of more than four
7 months in a construction project is often beyond the ability of EAI to
8 control.

9 My direct testimony listed reasons such as these, as well as others,
10 wherein projects were delayed for reasons beyond the control of EAI.
11 Even in those situations where delay is within EAI's control, it is often in
12 the customer's best interest to maintain flexibility in construction
13 scheduling such that highest priority work can be performed, even if this
14 results in a delay in completing other work.

15
16 **D. Frequency of AFUDC Compounding**

17 Q. WHAT IS YOUR RESPONSE TO STAFF WITNESS DANIEL'S POSITION
18 THAT AFUDC SHOULD BE COMPOUNDED NO MORE FREQUENTLY
19 THAN ON AN ANNUAL BASIS?

20 A. Mr. Daniel justifies this position by stating that this time period better
21 aligns the Company's accrual with the determination of an annual revenue
22 requirement and with the frequency of general rate cases allowed under

1 Arkansas law.¹⁰ However the timing of rate cases has little, if anything, to
2 do with the financing of construction costs. As stated in my direct
3 testimony, the determining factor for the FERC's decision in setting
4 compounding frequency was the frequency of cash outlays for interest and
5 dividend payments. The Company typically makes interest payments on
6 long-term debt quarterly or semi-annually, and common dividend
7 payments as frequently as monthly. Based on this timing, semi-annual
8 compounding is a reasonable approach. Few utilities file rate cases as
9 frequently as each year, but each utility incurs financing cost on
10 construction projects on a continuous basis.¹¹

11

12 Q. STAFF WITNESS DANIEL REFERENCES SEVERAL DOCKETS¹² AND
13 IMPLIES SOME PRECEDENTIAL NATURE TO THEM. HAVE YOU
14 REVIEWED THESE REFERENCES?

15 A. Yes. Every one of the dockets referenced by Mr. Daniel was resolved via
16 a settlement among the parties where presumably some give and take or
17 compromise resulted in these settlements. Each of these settlements
18 included a "Rights of the Parties" clause which specifically stated that the
19 settlement agreement was not to be used or argued as establishing
20 precedent for any methodology or rate treatment in any future proceeding.

¹⁰ Daniel Direct Testimony at 47.

¹¹ EAI has waited as long as a decade, or longer, between filing rate cases; See APSC Docket Nos. 84-249-U, 96-360-U, 06-101-U, and 13-028-U.

1 A copy of these settlements is included in my EAI Exhibit JAL-5 attached
2 to this rebuttal testimony. Mr. Daniel's reference to these dockets as any
3 indication of Commission precedent is inappropriate.

4

5 Q. HHEG WITNESS GARRETT MAKES A SIMILAR IMPLICATION WHEN
6 HE SAYS "THE COMPANY HAS NOT ARTICULATED ANY GOOD
7 REASON WHY THE APSC SHOULD TREAT IT DIFFERENTLY THAN
8 THE OTHER REGULATED UTILITIES IN THE STATE."¹³ PLEASE
9 COMMENT.

10 A. As stated in my direct testimony, the Company's use of the overall cost of
11 capital for AFUDC purposes was the result of a settled case which
12 specifically stated that the settlement was not precedential. As stated
13 above, treatment of other utilities was also subject to settlements which
14 included similar provisions stating that the settlements were not
15 precedential. As far as I am aware, the APSC has neither specifically
16 studied the issue of AFUDC in a rule-making proceeding nor stated a
17 policy regarding AFUDC.

18

¹³ Garrett Direct Testimony at 10.

1 **III. CONCLUSION**

2 Q. COULD YOU BRIEFLY SUMMARIZE YOUR TESTIMONY?

3 A. The FERC formula EAI recommends for determining the AFUDC rate is
4 appropriate because it reflects the actual cost of financing construction
5 projects and is consistent with the Commission-approved Company
6 practice for the Company for over 30 years. The only deviation from this
7 historical practice came as a result of a settlement which is not precedent
8 for any future APSC decision.

9 The Company recommends that construction projects requiring
10 APSC approval, or for which approval has been sought, should accrue
11 AFUDC from the time the project begins because such timing properly
12 reflects the cost of financing construction costs incurred by the Company.
13 Any concern regarding customers being charged AFUDC for projects not
14 approved by the APSC is addressed by the Company's policy to reverse
15 AFUDC on any canceled projects or projects not approved by the
16 Commission.

17 The Company recommends that AFUDC be compounded semi-
18 annually because this is consistent with the frequency of interest and
19 dividend payments for financings used to fund construction projects.

20 Finally, the Company recommends that it be allowed to accrue
21 AFUDC during periods of interrupted construction greater than four
22 consecutive months because such interruptions are often beyond the
23 control of the Company.

1

2 Q. DOES THIS CONCLUDE YOUR REBUTTAL TESTIMONY?

3 A. Yes.

CERTIFICATE OF SERVICE

I, Steven K. Strickland, do hereby certify that a copy of the foregoing has been served upon all parties of record by forwarding the same by electronic mail and/or first class mail, postage prepaid, this 26th day of August, 2013.

/s/ Steven K. Strickland
Steven K. Strickland

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OF ENTERGY ARKANSAS, INC. FOR	)	DOCKET NO. 13-028-U
APPROVAL OF CHANGES IN RATES FOR	)	
RETAIL ELECTRIC SERVICE	)	

EAI EXHIBIT JAL-5

SETTLEMENT DOCKETS REFERENCED BY STAFF

Referenced Stipulation/Docket	Applicable "Rights of the Parties" Provision(s)
Stipulation and Settlement Agreement in Docket No. 06-124-U among General Staff, Arkansas Western Gas Company, and the Arkansas Attorney General as approved in Order No. 6, noting at page 8, "The record has been fully developed and a complete discussion of the issues has been undertaken with each Settling Party being a strong advocate for their respective testimony positions."	<u>Section 4.A. RIGHTS OF THE PARTIES</u> This Agreement is made upon the explicit understanding that it constitutes a negotiated settlement which is in the public interest. Nothing herein shall constitute an admission of any claim, defense, rule, or interpretation of law, allegation of fact, principle or method of ratemaking, or cost-of-service determination or rate design, or terms or conditions of service, or the application of any rule, or interpretation of law, that may underlie, or be perceived to underlie, this Agreement. <u>4.C. RIGHTS OF THE PARTIES</u> Except as to matters specifically agreed to be done or to occur in the future, no party shall be precluded from taking any position on the merits of any issue in any subsequent proceeding in any forum. This Agreement shall not be used or argued as establishing precedent for any methodology or rate treatment in any future proceeding.
Stipulation and Settlement Agreement in Docket No. 06-160-U between General Staff and United Water Arkansas as approved in Order No. 6	<u>1.B. GENERAL</u> ...A complete discussion of the issues has been undertaken by the Settling Parties, with each being a strong advocate of their respective positions as reflected in their pre-filed testimony. <u>4.A. RIGHTS OF THE PARTIES</u> This Agreement is made upon the explicit understanding that it constitutes a negotiated settlement which is in the public interest. Nothing herein shall constitute an admission of any claim, defense, rule, or interpretation of law, allegation of fact, principle or method of ratemaking, or cost-of-service determination or rate design, or terms or conditions of service, or the application of any rule, or interpretation of law, that may underlie, or be perceived to underlie, this Agreement. <u>4.C. RIGHTS OF THE PARTIES</u> Except as to matters specifically agreed to be done or to occur in the future, no party shall be precluded from taking any position on the merits of any issue in any subsequent proceeding in any forum. This Agreement shall not be used or argued as establishing precedent for any methodology or rate treatment in any future proceeding...
Stipulation and Settlement Agreement in Docket No. 06-161-U between General Staff and CenterPoint Energy Resources Corp. as approved in Order No. 6, noting at page 8, "The record has been fully developed and a complete discussion of the issues has been undertaken by the Settling Parties with each being a strong advocate for their respective testimony positions."	<u>5.A. RIGHTS OF THE PARTIES</u> This Agreement is made upon the explicit understanding that it constitutes a negotiated settlement which is in the public interest. Nothing herein shall constitute an admission of any claim, defense, rule, or interpretation of law, allegation of fact, principle or method of ratemaking, or cost-of-service determination or rate design, or terms or conditions of service, or the application of any rule, or interpretation of law, that may underlie, or be perceived to underlie, this Agreement. <u>5.C. RIGHTS OF THE PARTIES</u> Except as to matters specifically agreed to be done or to occur in the future, no party shall be precluded from taking any position on the merits of any issue in any subsequent proceeding in any forum. This Agreement shall not be used or argued as establishing precedent for any methodology or rate treatment in any future proceeding.
Agreement in Docket No.	<u>5.A. RIGHTS OF THE PARTIES</u>

07-026-U among General Staff, Arkansas Oklahoma Gas Corporation, the Arkansas Attorney General, and West Central Arkansas Gas Consumers, Inc. as approved in Order No. 7, noting at page 7, "The record is fully developed and a complete discussion of the issues has occurred, with each party strongly advocating their respective positions as reflected in their filed testimony."	This Agreement is made upon the explicit understanding that it constitutes a negotiated settlement which is in the public interest. Nothing herein shall constitute an admission of any claim, defense, rule, or interpretation of law, allegation of fact, principle or method of ratemaking, or cost-of-service determination or rate design, or terms or conditions of service, or the application of any rule, or interpretation of law, that may underlie, or be perceived to underlie, this Agreement. <u>5.C. RIGHTS OF THE PARTIES</u> Except as to matters specifically agreed to be done or to occur in the future, no party shall be precluded from taking any position on the merits of any issue in any subsequent proceeding in any forum. This Agreement shall not be used or argued as establishing precedent for any methodology or rate treatment in any future proceeding.
Stipulation and Settlement Agreement in Docket No. 09-130-U between General Staff and United Water Arkansas as approved in Order No. 7	<u>1.B. GENERAL</u> ...A complete discussion of the issues has been undertaken by the Settling Parties, with each being a strong advocate for their respective positions as reflected in their pre-filed testimony... <u>5.A. RIGHTS OF THE PARTIES</u> This Agreement is made upon the explicit understanding that it constitutes a negotiated settlement which is in the public interest. Nothing herein shall constitute an admission of any claim, defense, rule, or interpretation of law, allegation of fact, principle or method of ratemaking, or cost-of-service determination or rate design, or terms or conditions of service, or the application of any rule, or interpretation of law, that may underlie, or be perceived to underlie, this Agreement. <u>5.C. RIGHTS OF THE PARTIES</u> Except as to matters specifically agreed to be done or to occur in the future, no party shall be precluded from taking any position on the merits of any issue in any subsequent proceeding in any forum. This Agreement shall not be used or argued as establishing precedent for any methodology or rate treatment in any future proceeding...
Settlement Agreement in Docket No. 10-052-U among General Staff, the Arkansas Attorney General, and The Empire District Electric Company as approved in Order No. 7	<u>1. PROCEDURAL SCHEDULE & RECORD DEVELOPMENT</u> ...In pursuit of settlement, a complete discussion of the issues outstanding was undertaken among the Settling Parties with each being a strong advocate for its respective position... <u>6.A. RIGHTS OF THE PARTIES</u> This Agreement is made upon the explicit understanding that it constitutes a negotiated settlement which is in the public interest. Nothing herein shall constitute an admission of any claim, defense, rule, or interpretation of law, allegation of fact, principle or method of ratemaking, or cost-of-service determination or rate design, or terms or conditions of service, or the application of any rule, or interpretation of law, that may underlie, or be perceived to underlie, this Agreement. <u>6.C. RIGHTS OF THE PARTIES</u> Except as to matters specifically agreed to be done or to occur in the future, no party shall be precluded from taking any position on the merits of any issue in any subsequent proceeding in any forum. This Agreement shall not be used or argued as establishing precedent for any methodology or rate

Settlement Agreement in Docket No. 10-067-U among General Staff, the Arkansas Attorney General, Oklahoma Gas and Electric Company, and Northwest Arkansas Industrial Energy Consumers as approved in Order No. 6	treatment in any future proceeding... <u>1. PROCEDURAL SCHEDULE & RECORD DEVELOPMENT</u> ...In pursuit of settlement, a complete discussion of the issues outstanding was undertaken among the Settling Parties, each being a strong advocate for its respective position... <u>5.A. RIGHTS OF THE PARTIES</u> This Agreement is made upon the explicit understanding that it constitutes a negotiated settlement which is in the public interest. Nothing herein shall constitute an admission of any claim, defense, rule, or interpretation of law, allegation of fact, principle or method of ratemaking, or cost-of-service determination or rate design, or terms or conditions of service, or the application of any rule, or interpretation of law, that may underlie, or be perceived to underlie, this Agreement. <u>5.C. RIGHTS OF THE PARTIES</u> Except as to matters specifically agreed to be done or to occur in the future, no party shall be precluded from taking any position on the merits of any issue in any subsequent proceeding in any forum. This Agreement shall not be used or argued as establishing precedent for any methodology or rate treatment in any future proceeding.

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APPROVAL OF CHANGES IN RATES FOR	)	DOCKET NO. 13-028-U
RETAIL ELECTRIC SERVICE	)	

REBUTTAL TESTIMONY

OF

PATRICIA A. CARTWRIGHT

SR. VICE PRESIDENT, ARTHUR FINANCIAL SERVICES LLC

ON BEHALF OF

ENTERGY ARKANSAS, INC.

AUGUST 26, 2013

1 **I. BACKGROUND AND INTRODUCTION**

2 Q. PLEASE STATE YOUR NAME, TITLE, AND BUSINESS ADDRESS.

3 A. My name is Patricia R. Cartwright. I am Sr. Vice President of Arthur
4 Financial Services, LLC. My business address is 1205 Sam Bass Road,
5 Ste. 200, Round Rock, Texas 78681.

6

7 Q. ON WHOSE BEHALF ARE YOU TESTIFYING?

8 A. I am testifying on behalf of Entergy Arkansas, Inc. ("EAI or the
9 "Company").

10

11 Q. BY WHOM ARE YOU EMPLOYED AND IN WHAT CAPACITY?

12 A. I am employed by Arthur Financial Services, LLC, in Austin, Texas as
13 Senior Vice President—Valuation Services.

14

15 Q. PLEASE STATE YOUR EDUCATION, PROFESSIONAL AND WORK
16 EXPERIENCE.

17 A. I received a Bachelor of Science degree, Magna Cum Laude, in Finance
18 from California State University. I am an Accredited Senior Appraiser in
19 the American Society of Appraisers ("ASA"). I have been an active
20 member of the ASA, serving for ten years on the governing board of the
21 Los Angeles Chapter in a variety of capacities including Programs Chair,
22 Business Valuation Chair and finally Senior Vice President from 2001 to
23 2002. I have over 26 years of experience providing valuation and value-

1 related consulting services with both regional and nationwide consulting
2 firms. I have performed valuations for such purposes as purchase price
3 allocation, corporate reorganization, transfer pricing studies, insolvency,
4 fairness opinions, gift and estate tax, employee stock ownership plans,
5 and bankruptcy for Fortune 1000 companies throughout the energy
6 industry.

7

8 Q. HAVE YOU PREVIOUSLY TESTIFIED BEFORE A REGULATORY
9 COMMISSION?

10 A. No.

11

12 Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

13 A. The purpose of my testimony is to rebut Federal Executive Agencies
14 ("FEA") witness James T. Selecky's testimony regarding the land values of
15 the EAI generating facilities by offering my professional opinion of the
16 market value in fee simple of the land as if vacant and clear on October
17 10, 2012 at five generation facilities in Arkansas. I was engaged by the
18 Company to perform the land appraisals at these five EAI power plant
19 sites in 2012. The report documenting my findings is attached to this
20 testimony as EAI Exhibit PAC-1.

1 **II. LAND APPRAISAL STUDY**

2 Q. PLEASE DESCRIBE THE APPRAISAL STUDY'S SCOPE.

3 A. The scope of the assignment was to determine the current market value in
4 fee simple of the land as if clear and vacant at five power plant sites in
5 Arkansas currently held by Entergy Arkansas, Inc. The first was a 495.98
6 acre site located at 598 Phillips Road, Helena, Phillips County, Arkansas
7 72342. The second was a 120.64 acre site located at 5800 Lynch Drive,
8 North Little Rock, Arkansas 72117. The third was a 208.13 acre site
9 located at 141 West County Line Road, Malvern, Arkansas 72104. The
10 fourth was a 105.71 acre site located at 547 Highway 82 East, Stamps,
11 Arkansas 71860. The fifth was a 260.13 acre site located at 5624
12 Highway 70 W., Forrest City, Arkansas 72335. My appraisal was
13 conducted in compliance with the requirements of the Uniform Standards
14 of Professional Appraisal Practice.

15
16 Q. WHAT IS THE DEFINITION OF MARKET VALUE?

17 Market value is differentiated from other types of value in that it is created
18 by the collective patterns of the market. Market value means the most
19 probable price which a property should bring in a competitive and open
20 market under all conditions requisite to a fair sale, the buyer and seller
21 each acting prudently and knowledgeably, and assuming the price is not
22 affected by undue stimulus. Implicit in this definition is the consummation
23 of a sale as of a specified date and the passing of title from seller to buyer

1 under conditions whereby: 1) a reasonable time is allowed for exposure in
2 the open market; 2) both parties are well informed or well advised, and
3 acting in what they consider their own best interests; 3) buyer and seller
4 are typically motivated; 4) payment is made in terms of cash in U.S.
5 dollars or in terms of financial arrangements comparable thereto; and 5)
6 the price represents the normal consideration for the property sold
7 unaffected by special or creative financing or sales concessions granted
8 by anyone associated with the sale.

9

10 Q. DID YOU MAKE SITE VISITS TO ANY OF THE PLANTS IN THE
11 STUDY?

12 A. I personally inspected each site, as well as its surrounding environs. As
13 set forth in my report, I considered information including the micro and/or
14 macro market environments with respect to physical and economic factors
15 as well as research with respect to tax data, zoning requirements, flood
16 zone status, demographics, and comparable sales data. My report also
17 explains that I relied on the sales comparison method.

18

19 Q. WHAT HIGHEST AND BEST USE DID YOU DETERMINE FOR EACH
20 PROPERTY?

21 A. The concept of highest and best use represents the premise upon which
22 value is based. The four criteria that highest and best use must meet are:
23 legally permissible, physically possible, financially feasible, and maximally

1 productive. These concepts are explained more fully in my report with
2 respect to the individual site locations.
3

4 **III. LAND APPRAISAL RESULTS**

5 Q. BRIEFLY SUMMARIZE THE RESULTS OF YOUR LAND APPRAISAL
6 STUDY?

7 A. It is my professional opinion that the current market value in fee simple of
8 the 495.98 acre site located at 598 Phillips Rd. Helena, Phillips County,
9 Arkansas is \$1,100,000 USD if clear and vacant.

10 It is my professional opinion that the current market value in fee
11 simple of the 120.64 acre site located at 5800 Lynch Drive, North Little
12 Rock, Arkansas is \$1,950,000 USD if clear and vacant.

13 It is my professional opinion that the current market value in fee
14 simple of the 208.13 acre site located at 141 West County Line Road,
15 Malvern, Arkansas is \$2,350,000 USD if clear and vacant.

16 It is my professional opinion that the current market value in fee
17 simple of the 105.71 acre site located at 547 Highway 82 East Stamps,
18 Arkansas is \$300,000 USD if clear and vacant.

19 It is my professional opinion that the current market value in fee
20 simple of the 260.13 acre site located at 5624 Highway 70 W. Forrest City,
21 Arkansas is \$750,000 USD if clear and vacant.

1 **IV. REBUTTAL OF MR. SELECKY**

2 Q. WHAT ISSUES DOES MR. SELECKY RAISE REGARDING THE
3 VALUATION OF THE LAND FOR EACH OF THE EAI PLANTS?

4 A. On page 27 of Mr. Selecky's direct testimony, he argues that dismantling
5 the EAI generating units will make the land a valuable asset for the
6 potential sale or reuse of the land in the future. He then proposes a 30
7 percent offset to the dismantlement cost estimates.

8
9 Q. HOW DID MR. SELECKY ARRIVE AT HIS USE OF 30 PERCENT AS
10 THE APPROPRIATE VALUE OF THE LAND SITES IN ARKANSAS?

11 A. Mr. Selecky used results of the Entergy Louisiana, LLC¹ ("ELL") land
12 appraisal analysis as a proxy for the EAI land values, although he does
13 not offer any reason as to why those values serve as an appropriate
14 proxy. Regardless, as I explain further below, his general methodology is
15 flawed and should be disregarded.

16
17 Q. WHY ARE THE ELL LAND VALUES NOT AN APPROPRIATE PROXY
18 TO VALUE THE EAI LAND VALUES?

19 A. The ELL land values are significantly higher than those of the EAI
20 properties. Each ELL property has an industrial highest and best use, with

¹ Entergy Louisiana, LLC is one of the six Entergy Operating Company. The Entergy Operating Companies include Entergy Arkansas, Inc.; Entergy Gulf States Louisiana, L.L.C.; Entergy Louisiana, LLC; Entergy Mississippi, Inc.; Entergy New Orleans, Inc.; and Entergy Texas, Inc.

1 good river access. The properties are located near large population
2 centers. The ELL land values represent an average of 31.9 percent of the
3 cost of dismantlement. By way of further example, two of the EAI parcels
4 have an agricultural highest and best use—which tends to result in lower
5 values than those with the industrial use like with the ELL property. The
6 EAI properties are largely remote from large population centers. The EAI
7 land values average 8.5 percent of the cost of dismantlement.

8

9 Q. DO YOU AGREE WITH MR. SELECKY'S PROPOSED METHODOLOGY
10 THAT DISMANTLING THE FACILITIES ON THE EAI GENERATING
11 SITES WILL ADD VALUE TO THE LAND?

12 A. No. For each property, the land was appraised as if clear and vacant and
13 available to its highest and best use. In other words, it was appraised as if
14 the dismantlement had already taken place. Thus, the dismantlement of
15 the generating assets would not increase the appraised value of the land.
16 Additionally, in each case the cost of dismantlement greatly exceeds the
17 land value. Consequently, dismantlement would remove an impediment
18 to the sale of the property and thus allow the owner to realize the land
19 value. Therefore, there is no support for Mr. Selecky's proposed
20 methodology that dismantling the facilities adds value to the land, and it is
21 more accurate that dismantling the facilities merely provides for the
22 appraised value of the land to be realized.

23

1 Q. DOES THIS CONCLUDE YOUR REBUTTAL TESTIMONY?

2 A. Yes.

CERTIFICATE OF SERVICE

I, Steven K. Strickland, do hereby certify that a copy of the foregoing has been served upon all parties of record by forwarding the same by electronic mail and/or first class mail, postage prepaid, this 26th day of August, 2013.

/s/ Steven K. Strickland
Steven K. Strickland

BEFORE THE
ARKANSAS PUBLIC SERVICE COMMISSION

IN THE MATTER OF THE APPLICATION	)	
OF ENTERGY ARKANSAS, INC. FOR	)	DOCKET NO. 13-028-U
APPROVAL OF CHANGES IN RATES FOR	)	
RETAIL ELECTRIC SERVICE	)	

EAI EXHIBIT PAC-1
LAND APPRAISAL REPORT



Market Value Study of the Land at Five Sites held by Entergy Arkansas, Inc. as of October 10, 2012 and Comparison to Dismantlement Costs at each site



December 27, 2012

Mr. Brian Caldwell
Manager of Regulatory Accounting
Entergy Services, Inc.
425 West Capitol Avenue
Little Rock, Arkansas 72203

Re: Market Value in Fee Simple of the Land as if Clear and Vacant of Five Power Plant Sites held by Entergy Arkansas, Inc. as of October 10, 2012 and Comparison to Current Estimated Dismantlement Costs at each site

Dear Mr. Caldwell:

As you requested, we have conducted an investigation and analysis of the market value in fee simple of the land as if vacant and clear at each of the five power plant sites identified by Entergy Arkansas, Inc. (Entergy Arkansas). Our date of value is October 10, 2012. Our appraisal has been conducted consistent with the requirements of Uniform Standards of Professional Appraisal Practice (USPAP).

The purpose of our investigation and analysis is to establish the market value of the land at each site in fee simple as if vacant and clear and contrast that market value with current estimated dismantlement costs Value Indications at each site. We were provided estimated dismantlement costs for each site in a study prepared by Black & Veatch and dated December 4, 2012.

Market value is defined as:

...the most probable price which a property should bring in a competitive and open market under all conditions requisite of a fair sale, the buyer and seller each acting prudently and knowledgeably, and assuming the price is not affected by undue stimulus.

Implicit in this definition is the consummation of a sale as of a specified date and the passing of title from seller to buyer under conditions whereby:

- 1) A reasonable time is allowed for exposure in the open market;
- 2) Both parties are well informed or well advised, and acting in what they consider their own best interests;
- 3) Buyer and seller are typically motivated;
- 4) Payment is made in terms of cash in US dollars or in terms of financial arrangements comparable thereto; and
- 5) The price represents the normal consideration for the property sold unaffected by special or creative financing or sales concessions granted by anyone associated with the sale.¹

A Fee Simple Interest is defined as:

Absolute ownership unencumbered by any other interest or estate, subject only to the limitations imposed by the governmental powers of taxation, eminent domain, police power, and escheat.²

Based on the analysis described in the accompanying report and subject to Enclosure A, Assumptions and Limiting Conditions, it is our opinion that on October 10, 2012 the market value of land as if vacant and clear for each of the five sites below can be reasonably stated as presented in Table A below.

Table A Entergy Arkansas Power Plant Sites' Land – October 10, 2012 Summary of Concluded Market Values - USD		
Power Plant Location	Acres	Market Value
Couch – 547 Highway 82 East Stamps, AR	105.71	\$300,000.00
Lake Catherine – 141 West Country Line Road Malvern, AR	208.13	2,350,000.00
Lynch – 5800 Lynch Drive North Little Rock, AR	120.64	1,950,000.00
Moses – 5624 Highway 70 W. Forest City AR	260.13	750,000.00
Ritchie – 598 Phillips Rd. Helena, AR	495.98	\$1,100,000.00

¹ As defined by the Office of the Comptroller of Currency (OCC) under 12 CFR, Part 34, Subpart C-Appraisals, 34.42 Definitions, the Board of Governors of the Federal Reserve System (FRS) and the Federal Deposit Insurance Corporation in compliance with Title XI of FIRREA, consistent with as well as the guidelines of the USPAP as promulgated by the Appraisal Foundation and the American Society of Appraisers.

² The Dictionary of Real Estate Appraisal, Fifth Edition, Appraisal Institute, 2010.

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Next, we were provided a current dismantlement cost study for each site which had been completed by Black & Veatch as of December 4, 2012. The results are presented in Table B below.

Table B Entergy Arkansas Power Plants Black & Veatch Dismantlement Costs – USD December 4, 2012					
Plant	No. of Units	Max nameplate (MW)	Utility	Fuel Type	Dismantlement Costs
Couch	2	190		Gas/Oil	\$11,278,923.00
Lake Catherine	4	746	ELL	Gas/Oil	26,829,220.00
Lynch	4	265	ELL	Gas/Oil	14,128,564.00
Moses	2	138	ELL	Gas/Oil	9,070,270.00
Ritchie	2	380	EGSI	Gas/Oil	\$12,465,507.00

In each case, the current estimated dismantlement cost for the site exceeds the market value of the land as if vacant and clear on October 10, 2012 as Table C below illustrates.

Table C Entergy Arkansas Power Plants Dismantlement Cost vs. Market Value of Land – USD			
Plant	Dismantlement Cost	Market Value of Land	Dismantlement Cost in Excess of Market Value of Land
Couch	\$11,278,923.00	\$300,000.00	\$10,978,923.00
Lake Catherine	26,829,220.00	2,350,000.00	24,479,220.00
Lynch	14,128,564.00	1,950,000.00	12,178,564.00
Moses	9,070,270.00	750,000.00	8,320,270.00
Ritchie	\$12,465,507.00	\$1,100,000.00	\$11,365,507.00

The accompanying report provides an explanation of the methodology used and outlines the basis upon which our opinion of value has been developed. Accordingly, the attached Report is intended to comply with the reporting requirements set forth under Standard Rule 2-2c of USPAP.

Mr. Brian Caldwell

December 27, 2012

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Patricia Cartwright, ASA is certified as required by the mandatory Recertification Program as set forth in the Constitution, By Laws and Administrative Rules of the American Society of Appraisers and is in compliance with the Recertification Program. Arthur Financial Services, LLC appreciates the opportunity to provide this analysis.

Respectfully submitted,

Arthur Financial Services, LLC

A handwritten signature in black ink that reads "Patricia Cartwright". The script is cursive and fluid, with the first letter of each word being capitalized and prominent.

Patricia Cartwright, ASA/Business Valuations
Sr. Vice President—Financial & Economic Analysis

ENCLOSURE A

ASSUMPTIONS AND LIMITING CONDITIONS

- Unless otherwise specifically noted in the body of the report, it is assumed that title to the properties appraised is clear and marketable and that there are no recorded or unrecorded matters or exceptions to title that would adversely affect marketability or value. Arthur Financial Services, LLC is not aware of any title defects nor has it been advised of any unless such is specifically noted in the report. Arthur Financial Services, LLC, however, has not examined title and makes no representations relative to the condition thereof. Documents dealing with liens, encumbrances, easements, deed restrictions, clouds and other conditions that may affect the quality of title have not been reviewed.
- Unless otherwise stated in this report, the existence of hazardous material, which may or may not be present on the property, was not observed by the appraisers. Arthur Financial Services, LLC has no knowledge of the existence of such materials on or in the property. Arthur Financial Services, LLC, however, is not qualified to detect such substances. The presence of substances such as asbestos, urea formaldehyde foam insulation, contaminated groundwater or other potentially hazardous materials may affect the value of the property. The value estimate is predicated on the assumption that there is no such material on or in the property that would cause a loss in value. No responsibility is assumed for any such conditions, or for any expertise or engineering knowledge required to discover them.

We have inspected, as thoroughly as possible by observation, the land; however, it was impossible to personally inspect conditions beneath the soil. Therefore, no representation is made as to these matters unless specifically considered in the appraisal.

- All furnishings, equipment and business operations, except as specifically stated and typically considered as part of real property, have been disregarded with only real property being considered in the report unless otherwise stated.
- It is assumed that all factual data furnished by the client, property owner, owner's representative, or persons designated by the client or owner to supply said data are accurate and correct unless otherwise specifically noted in the appraisal report. Unless otherwise specifically noted in the appraisal report, Arthur Financial Services, LLC has no reason to believe that any of the data furnished contain any material error. Information and data referred to in this paragraph include, without being limited to, numerical street addresses, lot and block numbers, assessor's parcel numbers, land dimensions, square footage area of the land, and related data. Any material error in any of the above data could have a substantial impact on the conclusions reported. Thus, Arthur Financial Services, LLC reserves the right to amend conclusions reported if made aware of any such error.
- The date of value to which any of the conclusions and opinions expressed in this report apply, is set forth in the Letter of Transmittal. Further, the dollar amount of any value opinion herein rendered is based upon the purchasing power of the American Dollar on that date. This appraisal is based on market conditions existing as of the date of this

appraisal. The appraiser(s) assumes no responsibility for economic or market factors occurring at some later date that may affect the opinions herein stated.

- Arthur Financial Services, LLC assumes no private deed restrictions, limiting the use of the subject in any way.
- Unless otherwise noted in the body of the report, it is assumed that there are no mineral deposits or subsurface rights of value involved in this appraisal, whether they are gas, liquid, or solid. Nor are the rights associated with extraction or exploration of such elements considered unless otherwise stated in this appraisal report. Unless otherwise stated it is also assumed that there are no air or development rights of value that may be transferred.
- Arthur Financial Services, LLC is not aware of any contemplated public initiatives, governmental development controls, or rent controls that would significantly affect the value of the subject.
- The estimate of market value, which may be defined within the body of this report, is subject to change with market fluctuations over time. Market value is highly related to exposure, time promotion effort, terms, motivation, and conclusions surrounding the offering. The value estimate(s) consider the productivity and relative attractiveness of the property, both physically and economically, on the open market.
- Unless specifically set forth in the body of the report, nothing contained herein shall be construed to represent any direct or indirect recommendation of Arthur Financial Services, LLC to buy, sell, or hold the properties at the value stated.
- Also, unless otherwise noted in the body of this report, it is assumed that no changes in the present zoning ordinances or regulations governing use, density, or shape are being considered. The property is appraised assuming that all required licenses, certificates of occupancy, consents, or other legislative or administrative authority from any local, state, or national government or private entity or organization have been or can be obtained or renewed for any use on which the value estimates contained in this report is based, unless otherwise stated.
- This report shall not be advertised to the public or otherwise used to induce a third party to purchase the property or to make a "sale" or "offer for sale" of any "security", as such terms are defined and used in the Securities Act of 1933, as amended. Any third party, not covered by the exemptions herein, who may possess this report, is advised that he or she should rely on his or her independently secured advice for any decision in connection with this property. Arthur Financial Services, LLC shall have no accountability or responsibility to any such third party.
- Any value estimate provided in the report applies to the entire property, and any pro ration or division of the title into fractional interests will invalidate the value estimate, unless such pro ration or division of interests has been set forth in the report.
- The maps, plats, sketches, graphs, photographs and exhibits included in this report are for illustration purposes only and are to be utilized only to assist in visualizing matters

discussed within this report. Except as specifically stated, data relative to size or area of the subject and comparable properties have been obtained from sources deemed accurate and reliable.

- No opinion is intended to be expressed on matters which may require legal expertise or specialized investigation or knowledge beyond that customarily employed by real estate appraisers. Values and opinions expressed presume that environmental and other governmental restrictions/conditions by applicable agencies have been met, including but not limited to seismic hazards, flight patterns, decibel levels/noise envelopes, fire hazards, hillside ordinances, density, allowable uses, building codes, permits, licenses, etc. No survey, engineering study or architectural analysis has been made known to Arthur Financial Services, LLC unless otherwise stated within the body of this report. If the Consultant has not been supplied with a termite inspection, survey or occupancy permit, no responsibility or representation is assumed or made for any costs associated with obtaining same or for any deficiencies discovered before or after it is obtained. No representation or warranty is made concerning obtaining these items. Arthur Financial Services, LLC assumes no responsibility for any costs or consequences arising due to the need, or the lack of need, for flood hazard insurance.
- Acceptance or use of this report constitutes full acceptance of the Contingent and Limiting Conditions and special assumptions set forth in this report. It is the responsibility of the client, or client's designees, to read in full, comprehend and thus become aware of the aforementioned contingencies and limiting conditions. Neither the Appraiser nor Arthur Financial Services, LLC assumes responsibility for any situation arising out of the client's failure to become familiar with and understand the same. The client is advised to retain experts in areas that fall outside the scope of the real estate appraisal/consulting profession if so desired.
- Arthur Financial Services, LLC assumes that the subject analyzed herein will be under prudent and competent management and ownership; neither inefficient nor super-efficient.
- It is assumed that there is full compliance with all applicable federal, state, and local environmental regulations and laws unless noncompliance is stated, defined and considered in the appraisal report.
- No survey of the boundaries of the property was undertaken. All areas and dimensions furnished are presumed to be correct. It is further assumed that no encroachments to the realty exist.
- As part of the client's requested scope of work, an estimate of insurable value is provided herein. Arthur Financial Services, LLC has followed traditional appraisal standards to develop a reasonable calculation based upon industry practices and industry accepted publications such as the Marshall Valuation Service handbook. The methodology employed is a derivation of the cost approach which is primarily used as an academic exercise to help support the market value estimate and therefore is not reliable for Insurable Value estimates. Actual construction costs and related estimates can vary greatly from this estimate.

This analysis should not be relied upon to determine proper insurance coverage, which can only be properly estimated by consultants considered experts in cost estimation and insurance underwriting. It is provided to aid the client/reader/user as part of their overall decision making process.

- Information furnished by others, upon which all or portions of the accompanying appraisal is founded, is believed to be reliable, but has not been verified or audited except where expressly stated. No warranty is given as to the accuracy of such information.
- In accordance with the USPAP, Statement of Appraisal Standards No.3 (SMT-3), this appraisal is considered a "retrospective" appraisal. It is considered retrospective in that the date of the report is subsequent to the effective date of our appraisal.
- Responsible ownership and competent management are assumed.
- Neither all nor any part of the contents of this report (especially any conclusions as to value), the identity of the appraiser(s), or the firm with which the appraiser(s) is connected shall be disseminated to the public through advertising, public relations, news, sales, or other media without the prior written consent and approval of the appraiser(s).
- Neither, Arthur Financial Services, LLC nor its principals have any current or contemplate any future interest in the business or asset(s) appraised.
- This analysis is founded on information available at the writing of this report. Should additional information become available, we reserve the right to reassess our opinion.

ENCLOSURE B

CERTIFICATE OF APPRAISERS

I certify that, to the best of my knowledge and belief:

- The statements of fact contained in this report are true and correct.
- The reported analyses, opinions and conclusions are limited only by the reported assumptions and limiting conditions and they are my personal, impartial and unbiased professional analyses, opinions and conclusions.
- I have no present or prospective interest in the property that is the subject of this report, and I have no personal interest with respect to the parties involved.
- I have no bias with respect to the property that is the subject of this report or to the parties involved with this assignment.
- My engagement in this assignment was not contingent upon developing or reporting predetermined results.
- Compensation for completing this assignment is not contingent upon the development or reporting of a predetermined value or direction in value that favors the cause of the client, the amount of the value opinion, the attainment of a stipulated result, or the occurrence of a subsequent event directly related to the intended use of this appraisal.
- This appraisal assignment was not based upon a requested minimum valuation, a specific valuation, or the approval of a loan.
- My analyses, opinions and conclusions were developed and this report has been prepared, in conformity with the USPAP.
- The reported analyses, opinions, and conclusions were developed, and this report has been prepared, in conformity with the requirements of the Code of Professional Ethics and Standards of Professional Appraisal Practice of the Appraisal Institute.
- The use of this report is subject to the requirements of the Appraisal Institute relating to review by its duly authorized representatives.
- As of the date of this report, Stephen Cosby, MAI, MRICS has completed the continuing education program of the Appraisal Institute.
- Both, Patricia Cartwright, ASA and Stephen Cosby, MAI, MRICS made a personal inspection of the property that is the subject of this report.
- Stephen Cosby, MAI, MRICS, provided significant professional assistance to the person signing this report.

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EXECUTIVE SUMMARY

Arthur Financial Services, LLC has conducted an investigation, analysis and valuation of the market value in fee simple of the land as if vacant and clear at each of the five identified Entergy Arkansas power plant sites, as of October 10, 2012.

The purpose of our investigation and analysis is to establish the market value of the land at each site in fee simple as if vacant and clear and contrast that market value with current estimated dismantlement costs at each site. We were provided estimated dismantlement costs for each site in a study prepared by Black & Veatch and dated December 4, 2012.

Work Performed

For this investigation, we performed the following steps:

- We inspected each site and its surrounding environs.
- We compiled economic research pertaining to the current state of the Arkansas economy, which included state characteristics, business environment, real gross domestic product, and unemployment rate. We reviewed and considered current economic circumstances as well as leading economic indicators to assess the condition of the Arkansas economy.
- We compiled research regarding Arkansas' Electricity Industry, including net electricity generation by source, market participants, and distribution. This information allowed us to review and consider current industry conditions and their potential impact on land values within its geographic market.
- We reviewed the micro and macro market environments with respect to physical and economic factors relevant to the valuation process. This process included interviews with regional/local market participants, available published data, and other various resources including applicable tax data, zoning requirements, flood zone status, demographics, construction expense data and comparable sales and listings data.
- Once all necessary information was obtained we evaluated the information's depth and completeness and considered the facts and circumstances involved. In the process, we were able to determine the most appropriate valuation methodology. We chose the sales comparison approach.
- In conducting the sales comparison approach, we contrasted the subject property's characteristics with those of comparable properties which had recently sold in similar transactions or were currently listed. We then adjusted the prices of the comparable transactions or listings according to the presence, absence or degree of characteristics which influence value. In the process we developed a sales adjustment grid for each subject property. We then correlated and reconciled the results into a reasonable and defensible conclusion of market value for the land at each subject site in fee simple as if clear and vacant on the October 10, 2012.



Market Value of Land

Relying on the foregoing analysis as more fully described in the accompanying report and subject to Enclosure A, Assumptions and Limiting Conditions, it is our opinion that on October 10, 2012 the market value of the land in fee simple as if clear and vacant for each of the five sites may be reasonably stated as indicated on Table A below.

Executive Summary Table A Entergy Arkansas Power Plant Sites' Land – October 10, 2012 Summary of Concluded Market Values - USD		
Power Plant Location	Acres	Market Value
Couch – 547 Highway 82 East Stamps, AR	105.71	\$300,000
Lake Catherine – 141 West Country Line Road Malvern, AR	208.13	2,350,000
Lynch – 5800 Lynch Drive North Little Rock, AR	120.64	1,950,000
Moses – 5624 Highway 70 W. Forest City AR	260.13	750,000
Ritchie – 598 Phillips Rd. Helena, AR	495.98	\$1,100,000

Dismantlement Costs

We were provided a current estimated dismantlement cost study for each site by Entergy Arkansas which had been completed by Black & Veatch as of December 4, 2012. The results are presented in Table B below.

Executive Summary Table B Entergy Arkansas Power Plants Black & Veatch Dismantlement Study – USD December 4, 2012				
Plant	No. of Units	Max nameplate (MW)	Fuel Type	Costs
Couch	2	190	Gas/Oil	\$11,278,923
Lake Catherine	4	746	Gas/Oil	26,829,220
Lynch	4	265	Gas/Oil	14,128,564
Moses	2	138	Gas/Oil	9,070,270
Ritchie	2	380	Gas/Oil	\$12,465,507



Comparison between Market Value of Land and Dismantlement Costs

Once we had determined the market value of the land in fee simple as if clear and vacant for each subject site on October 10, 2012, we contrasted those values with the estimated cost of dismantlement for each site per the Black & Veatch Dismantlement Study of December 4, 2012. Table C below presents the comparison. In each case the estimated cost of dismantlement exceeds the market value of the land in fee simple as if clear and vacant.

Executive Summary Table C			
Entergy Arkansas' Power Plants			
Dismantlement Cost vs. Market Value of Land - USD			
Plant	Dismantlement Cost	Market Value of Land	Dismantlement Cost in Excess of Market Value of Land
Couch	\$11,278,923.00	\$300,000.00	\$10,978,923.00
Lake Catherine	26,829,220.00	2,350,000.00	24,479,220.00
Lynch	14,128,564.00	1,950,000.00	12,178,564.00
Moses	9,070,270.00	750,000.00	8,320,270.00
Ritchie	\$12,465,507.00	\$1,100,000.00	\$11,365,507.00



INTRODUCTION

Arthur Financial Services, LLC has conducted an investigation, analysis and valuation of the land in fee simple as if vacant and clear at each of the five identified Entergy Arkansas power plant sites, as of October 10, 2012. In addition, we were provided current estimated dismantlement costs for each site in a study prepared by Black & Veatch and dated December 4, 2012.

Our valuation is a limited scope appraisal to be used for the purpose of providing Entergy Arkansas information regarding the comparison between the market value for land assets and the estimated cost of dismantlement. Our appraisal has been conducted consistent with the requirements of USPAP.

Definition of Value

Market value is defined as:

...the most probable price which a property should bring in a competitive and open market under all conditions requisite of a fair sale, the buyer and seller each acting prudently and knowledgeably, and assuming the price is not affected by undue stimulus.

Implicit in this definition is the consummation of a sale as of a specified date and the passing of title from seller to buyer under conditions whereby:

- 1) A reasonable time is allowed for exposure in the open market;
- 2) Both parties are well informed or well advised, and acting in what they consider their own best interests;
- 3) Buyer and seller are typically motivated;
- 4) Payment is made in terms of cash in US dollars or in terms of financial arrangements comparable thereto; and
- 5) The price represents the normal consideration for the property sold unaffected by special or creative financing or sales concessions granted by anyone associated with the sale.³

A Fee Simple Interest is defined as:

Absolute ownership unencumbered by any other interest or estate, subject only to the limitations imposed by the governmental powers of taxation, eminent domain, police power, and escheat.⁴

³ As defined by the Office of the Comptroller of Currency (OCC) under 12 CFR, Part 34, Subpart C-Appraisals, 34.42 Definitions, the Board of Governors of the Federal Reserve System (FRS) and the Federal Deposit Insurance Corporation in compliance with Title XI of FIRREA, consistent with as well as the guidelines of the USPAP as promulgated by the Appraisal Foundation and the American Society of Appraisers.

⁴ The Dictionary of Real Estate Appraisal, Fifth Edition, Appraisal Institute, 2010.



Scope of Work

The scope of the assignment relates to the extent and manner in which research is conducted, data are gathered and analysis is applied, all based upon the following problem-identifying factors stated elsewhere in this report:

- ✓ Client,
- ✓ Intended use,
- ✓ Intended user,
- ✓ Type of opinion,
- ✓ Effective Date of opinion,
- ✓ Relevant characteristics about the subject, and
- ✓ Assignment conditions.

Intended Use of Report

This appraisal is to be used to establish the market value in fee simple of the land as if clear and vacant at each of five identified power plant sites held by Entergy Arkansas for the purpose of contrasting that market value with the current estimated dismantlement costs at each site, and for use in a utility rate case.

Intended User of Report

This appraisal is to be used by Entergy Arkansas in a utility rate case, and no other user may rely on our report unless specifically indicated. The intended user is the person (or entity) who the appraiser intends will use the results of the appraisal. The client may provide the appraiser with information about other potential users of the appraisal, but the appraiser ultimately determines who the appropriate users are given the appraisal problem to be solved. Identifying the intended users is necessary so that the appraiser can report the opinions and conclusions developed in the appraisal in a manner that is clear and understandable to the intended users. Parties who receive or might receive a copy of the appraisal are not necessarily intended users. The appraiser's responsibility is to the intended users identified in the report, not to all readers of the appraisal report.

Extent to Which the Properties were Identified

The property was legally identified through the following sources:

- postal address
- legal description
- survey

Extent to Which the Properties were Inspected

Both, Patricia Cartwright, ASA and Stephen Cosby, MAI, MIRCS inspected the subject, as well as its surrounding environs on October 10 -October 11, 2012l.



Market Type and Extent of the Data Researched

We reviewed the micro and macro market environments with respect to physical and economic factors relevant to the valuation process. This process included interviews with regional/local market participants, available published data, and other various resources including:

- applicable tax data,
- zoning requirements,
- flood zone status,
- demographics,
- construction expense data and
- comparable data

Reporting and Records Keeping

The accompanying report is a Summary Appraisal Report, which provides an explanation of the methodology used and outlines the basis upon which our opinion of value has been developed. Accordingly, this summary report is intended to comply with the reporting requirements set forth under Standards Rule 2-2c of USPAP. As such, it presents limited discussions of the data, reasoning, and analyses that were used in the appraisal process to develop the appraiser's opinion of value. The depth of discussion contained in this report is specific to the needs of the client and for the intended use stated herein.

Hypothetical Conditions

A hypothetical condition is defined as "that which is contrary to what exists but is supposed for the purpose of analysis. Hypothetical conditions assume conditions contrary to known facts about physical, legal, or economic characteristics of the subject property; or about conditions external to the property, such as market conditions or trends; or about the integrity of data used in the analysis."⁵

The subject sites are currently improved with power plants. We have been tasked with valuation of the property assuming the power plant is not present – the land is clear and vacant. That assumption is hypothetical. We have also assumed there are no lingering environmental concerns at any of the subject sites.

⁵ Ibid.



ARKANSAS

Arkansas is located in the south central United States (US). The state is bordered by Tennessee to the east and across the Mississippi River, Louisiana to the south, Texas and Oklahoma to the west, and Missouri to the north.

Demographics

The state has a total geographical area of 43,179.00 square miles, with 18.80 million forested acres. The total population of the state in July 2004 was 2,752,629.00. Population growth is not robust but stable. In 2003, the per capital personal income was \$24,289.00 annually.



Recent Economic Performance

Arkansas' economy has been founded on its farms, forests, and mines, with a growing agricultural manufacturing sector. According to a report issued by the University of Arkansas, the state's economy was less affected by the recent national recession than most other states because of its concentration on agricultural industries:

Those industries are much more stable than financial and real estate services, which were impacted by the recession. Arkansas' economy is not as vulnerable because these are basic commodities that people continue to use even as the overall economy may decline.⁶

In 2009, the agricultural sector generated \$1.10 billion in state tax revenue, which represented 14.20 percent of all state taxes collected. From 2008 through 2009, the US economy contracted 1.70 percent, while Arkansas' GDP grew by 0.50 percent. From 2008 through 2009, the national decrease in state tax collections averaged 8.50 percent. Arkansas' state tax collections decreased 0.80 percent during that same time.

In January of 2011 the unemployment rate for Arkansas was 8.1 percent, by June of that same year it remained at 8.1 percent. In January of 2012 the unemployment rate for Arkansas was 7.6 percent. It gradually declined to 7.2 percent by June 2012. The unemployment rate for Arkansas was 7.2 percent in October 2012.

⁶ Archie Flanders, assistance professor of agricultural economics for the University of Arkansas, March 18, 2012.



According to Kathy Deck, director of the Center for Business and Economic Research:

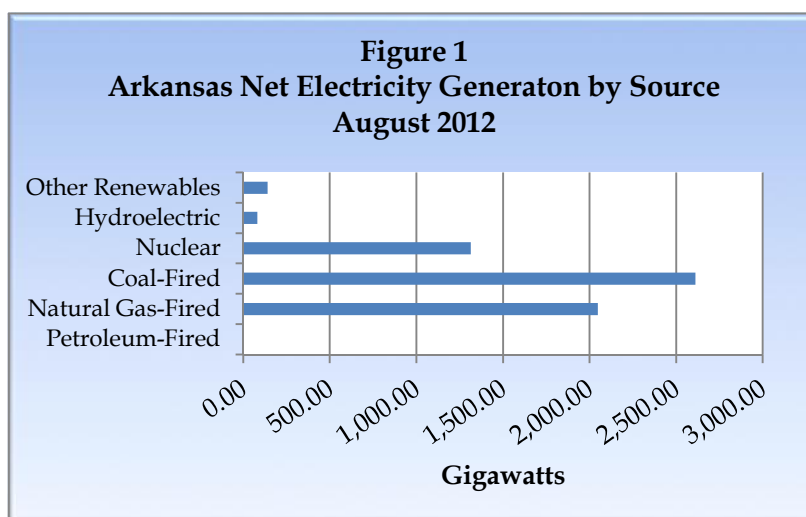
Arkansas' business cycles have historically been more muted. Our lows have not been as low, but our highs haven't been as high. The challenge is to keep downside managed while also getting an economy that is positioned to take advantage of really good times as well.

ARKANSAS ELECTRICITY INDUSTRY

Arkansas is located within the SERC/SPP region. According to the state profile provided by the US Energy Information Administration's 2012 report, in 2010 Arkansas' net summer generation capacity was 15,981.00 megawatts. As a result, Arkansas ranked as the twenty-fifth largest electricity generator in the US.

In 2010, Arkansas generated 61,000,105.00 megawatt hours. Electrical utilities accounted just more than 77.00 percent of total hours generated. The total retail sales in 2010 were 48,194,285.00 megawatt hours. As Figure 1 illustrates, coal and natural gas contributed the largest portion of electricity generated in August 2012. This represented a shift in generations source. In 2007, coal remained the largest source of fuel representing just over 50.00 percent of the total source used to generate electricity.

However, at that time nuclear technology generated 30.80 percent of the states electricity compared to only 12.40 percent coming from natural gas. This shift away from nuclear technology towards natural gas can be attributed to the lower natural gas prices today.



Market Participants

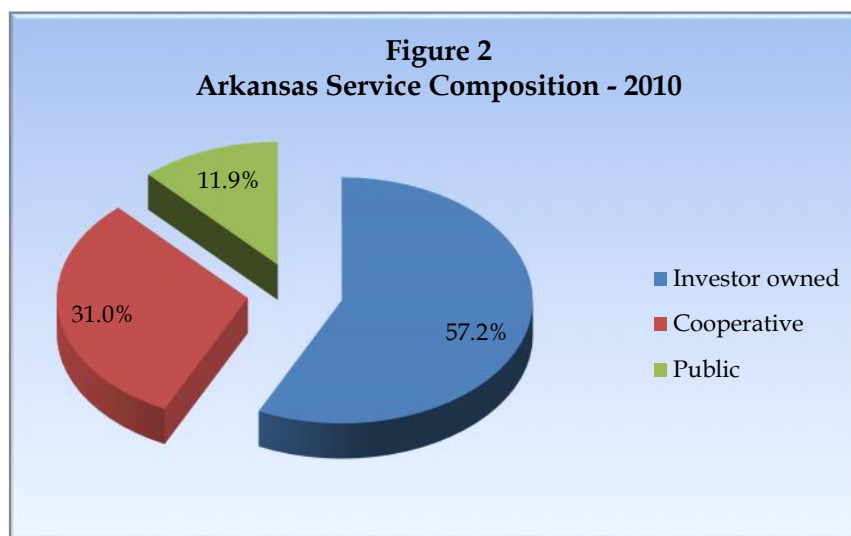
In 2010, the ten largest plants represented a combined 71.20 percent of the net summer generating capacity. The largest plant had a summer generating capacity of 2,020.00 megawatts, primarily used gas as its source of energy and was operated by Union Power Partners LP.

In 2010, the state's largest electricity generators, by net summer capacity, were Entergy Arkansas, Inc., Union Power Partners LP, Associated Electric Coop, Inc., Dynegy Services Plum Point LLC, Hot Spring Power Co. LLC, and DEGS of O&M, LLC.



Distribution

In 2010, there were 37 retail electricity sales entities that distributed electricity to roughly 1.50 million customers within Arkansas. Just over 57.00 percent of the customers were served by investor owned entities. The remaining customers were either served by public or cooperative service providers. About one-third of Arkansas' households use electricity as their primary energy source for home heating.



DETERMINATION OF LAND VALUES

Arthur Financial Services, LLC has conducted an appraisal of the market value of land assets for the following five Entergy Arkansas power plant locations.

- Couch - 547 Highway 82 East Stamps, Arkansas 71860,
- Lake Catherine - 141 West County Line Road Malvern, Arkansas 72104,
- Lynch - 5800 Lynch Drive North Little Rock, Arkansas 72117,
- Moses - 5624 Highway 70 W Forest City, Arkansas 72335, and
- Ritchie - 598 Phillips Rd. Helena, Phillips County, Arkansas.



Couch

Entergy Arkansas' Couch power plant is located at 547 Highway 82 East Stamps, Arkansas 71860. The power plant sits on 105.71 acre site or 4,604,728.00 square feet. The subject property has been owned for the past three years by Entergy Arkansas and is not being marketed for sale.







Land Valuation

We have employed the sales comparison method to value the subject land in fee simple as if clear and vacant, utilizing the comparable data summarized in the map and table presented below. In addition, we have provided a synopsis of our analysis on the following pages.



Table 1
Entergy Arkansas' Couch Plant
Comparable Land Market Transactions Summary - USD

No.	Property Location	Transaction		Proposed Use	Actual Sale Price	Size (Acres)	Price Per Acre
		Type	Date				
1	County Road 5, Lewisville, AR	Sale	Dec 11	\$0.00	\$660,000.00	280.00	\$2,357.00
2	Lafayette 4, Bradley, AR	Sale	Feb 11	0.00	241,000.00	160.26	1,504.00
3	Lafayette 55, Lewisville, AR	Sale	Mar 10	0.00	141,000.00	160.00	881.00
4	CR 5, Lewisville, AR	Listing	Oct 12	0.00	1,050,000.00	500.00	2,100.00
5	Hwy 82, Stamps, AR	Listing	Oct 12	0.00	308,000.00	234.37	1,314.00
6	Hwy 82, Stamps, AR	Listing	Oct 12	\$0.00	\$250,000.00	15.13	\$16,523.00
Subject	547 Highway 82 East, Stamps, AR			Agricultural		105.71	

Transaction amounts adjusted for cash equivalency and/or development costs (where applicable) as compiled by CBRE.



Exposure/Marketing Time Information

Exposure or marketing time for comparable sales ranged between 6 and 24 or more months, with an average exposure or marketing time of 12 months. Local market professionals' opinion of typical exposure or marketing time was 6 to 12 months. Estimated exposure or marketing time for the subject property was 12 months.

Data Sources Utilized

- Size - Statements by Entergy Arkansas,
- Flood Hazard - FEMA, and
- Zoning - City of Stamps.

Highest and Best Use

In appraisal practice, the concept of highest and best use represents the premise upon which value is based. The four criteria the highest and best use must meet are:

- Legally permissible,
- Physically possible,
- Financially feasible, and
- Maximally productive.

The highest and best use analysis of the subject land as if clear and vacant is agricultural.

Discussion/Analysis of Land Sales

The sales utilized represent the best data available for comparison with the subject and were selected from the greater Stamps area with a widening search within Lafayette County for sufficient data. These comparables were chosen because they were available larger land sales and listings.

Land Listing One. This comparable represents 280.00 acres on County Road 5 outside Lewisville (the larger city in the county). The site has an irregular shape with generally level topography. The property sold in December 2011 for \$660,000.00, or \$2,357.00 per acre.

The 20.00 percent upward adjustment for size reflects this comparable's inferior feature with respect to economies of scale regarding parcel size. Typically, as size increases, unit prices decline and vice versa. The typical relationship is for a 10.00-20.00 percent differential in price per unit prices for every doubling or halving of size - unless the size differential is overly significant. This is also reflected by this sale and listing four which differ primarily as a result of size. Overall, this comparable was deemed inferior in comparison to the subject and an upward net adjustment was warranted to the sales price indicator.

Land Sale Two. This comparable represents 160.26 acres on Lafayette County Road 4 outside Bradley, Arkansas. The site has a rectangular shape with generally level topography. The property sold in February 2011 for \$241,000.00, or \$1,504.00 per acre.



The 10.00 percent upward adjustment for size reflects this comparable's inferior feature with respect to economies of scale regarding parcel size as with sale one. The adjustment for location was warranted due to its distance from the larger communities. The adjustment is indicated by sales two and three and listing five compared against sales one and four. Therefore, an upward adjustment of 100.00 percent was judged proper for this comparable. Overall, this comparable was deemed inferior in comparison to the subject and an upward net adjustment was warranted to the sales price indicator.

Land Sale Three. This comparable represents 160.00 acres on Lafayette County Road 55 near Lewisville. The site has a rectangular shape with generally level topography. The property sold in March 2010 for \$141,000.00, or \$881.00 per acre. The property is located directly south of the city of Lewisville.

In terms of conditions of sale, this comparable was considered inferior and received an upward adjustment of 30.00 percent for this characteristic due to this being a sale from the foreclosing bank after a foreclosure had occurred. Typically, the differential between bank-owned property sale prices and market value ranges from 10.00-40.00 percent as banks tend to divest such properties quickly. The 10.00 percent upward adjustment for size reflects this comparable's inferior feature with respect to economies of scale regarding parcel size as with sale one. The adjustment for location was warranted due to its location on a dirt road versus paved road access like the other properties. Therefore, an upward adjustment of 100.00 percent was judged proper for this comparable. Overall, this comparable was deemed inferior in comparison to the subject and an upward net adjustment was warranted to the sales price indicator.

Land Sale Four. This comparable represents 500.00 acres on County Road 5 outside Lewisville. The site has an irregular shape with generally level topography. The property was listed as of October 2012 for \$1,050,000.00, or \$2,100.00 per acre. Seller does not own any minerals.

In terms of conditions of sale, this comparable was considered superior and received a downward adjustment of negative 20.00 percent for this characteristic due to this being a listing versus a closed sale. The adjustment is the typical differential between listing and selling prices as indicated by review of land sales data over the past few years as well as expectations of brokers in the market. The 30.00 percent upward adjustment for size reflects this comparable's inferior feature with respect to economies of scale regarding parcel size as with sale one. This listing, along with sale one, provides an additional basis for this adjustment. Overall, this comparable was deemed inferior in comparison to the subject and an upward net adjustment was warranted to the sales price indicator.

Land Sale Five. This comparable represents 234.37 acres on Highway 82 outside Stamps. The site has an irregular shape with generally level topography. The property was listed as of October 2012 for \$308,000.00, or \$1,314.00 per acre. The Dorcheat Bayou Tract (#03019-03111) is located about 12 miles northwest of the city of Magnolia and about five miles southeast of the town of Stamps, Arkansas.



In terms of conditions of sale, this comparable was considered superior and received a downward adjustment of negative 20.00 percent for this characteristic due to this being a listing versus a closed sale as with listing four. The 20.00 percent upward adjustment for size reflects this comparable's inferior feature with respect to economies of scale regarding parcel size as with sale one. The adjustment for location was warranted due to its access from a dirt road although it is listed as being in the Highway 82 corridor. Therefore, an upward adjustment of 100.00 percent was judged proper for this comparable. Overall, this comparable was deemed inferior in comparison to the subject and an upward net adjustment was warranted to the sales price indicator.

Land Sale Six. This comparable represents 15.13 acres on Highway 82 within the downtown area. The site has a rectangular shape with generally level topography. The property was listed October 2012 for \$250,000.00, or \$16,523.00 per acre. Property is located in downtown Stamps. The property has frontage on Highway 82 and is described as "ripe for development" by the broker.

In terms of conditions of sale, this comparable was considered superior and received a downward adjustment of negative 20.00 percent for this characteristic due to this being a listing versus a closed sale as with listing four. The negative 60.00 percent downward adjustment for size reflects this comparable's superior feature with respect to economies of scale regarding parcel size as with sale one. The adjustment for location was warranted due to location within downtown Stamps although the subject is located adjacent the city park. Therefore, a downward adjustment of negative 20.00 percent was judged proper for this comparable. Overall, this comparable was deemed superior in comparison to the subject and a downward net adjustment was warranted to the sales price indicator.



Summary of Adjustments

As presented on Table 2, based on our comparative analysis, the following adjustments were made to each comparable:

Table 2							
Entergy Arkansas' Couch Plant							
Comparable Land Market Transactions Analysis - USD							
	1	2	3	4	5	6	Subject
Transaction Type	Sale	Sale	Sale	Listing	Listing	Listing	---
Transaction Date	Dec 11	Feb 11	Mar 10	Oct 12	Oct 12	Oct 12	---
Sales Price	\$660,000.00	\$241,000.00	\$141,000.00	\$1,050,000.00	\$308,000.00	\$250,000.00	---
Size (Acres)	280.00	160.26	160.00	500.00	234.37	15.13	105.71
Price (\$ Per AC)	\$2,357.00	\$1,504.00	\$881.00	\$2,100.00	\$1,314.00	\$16,523.00	
Property Rights Conveyed							
Financing Terms 1							
Conditions of Sale			30.00 %	-20.00 %	-20.00 %	-20.00 %	
Market Conditions (Time)							
Subtotal	\$2,357.00	\$1,504.00	\$1,146.00	\$1,680.00	\$1,051.00	\$13,219.00	
Size	20.00 %	10.00 %	10.00 %	40.00 %	20.00 %	-60.00 %	
Shape							
Corner							
Frontage							
Topography							
Location		100.00 %	100.00 %		100.00 %	-20.00 %	
Zoning/Density							
Utilities							
Highest & Best Use							
Total Other Adjustments	20.00 %	110.00 %	110.00 %	40.00 %	120.00 %	-80.00 %	
Value Indications for Subject	\$2,829.00	\$3,158.00	\$2,406.00	\$2,352.00	\$2,313.00	\$2,644.00	
Transaction amounts adjusted for cash equivalency and/or development costs (where applicable) as compiled by CBRE.							

Discussion with Market Participants

Discussions with brokers indicated that the land market in Lafayette County is very "thin". Most transactions have been leases for hunting or timber purposes. The presence of mineral rights, however, could have a dramatic effect on the land value. We have specifically not addressed the potential for the contributory value of mineral rights as we have assumed such mineral rights are not present for the subject site.



Value Indications and Reconciliation

Based on the preceding analysis, the following table presents the value indications:

Table 3				
Entergy Arkansas' Couch Plant				
Land Market Value Analysis - USD				
\$ Per AC		Subject Acres		Value Indications
\$2,313.00	x	105.71	=	\$244,507.00
\$3,158.00	x	105.71	=	\$333,832.00
Indicated Market Value:				\$300,000.00
(Rounded \$ Per AC)				\$2,838.00

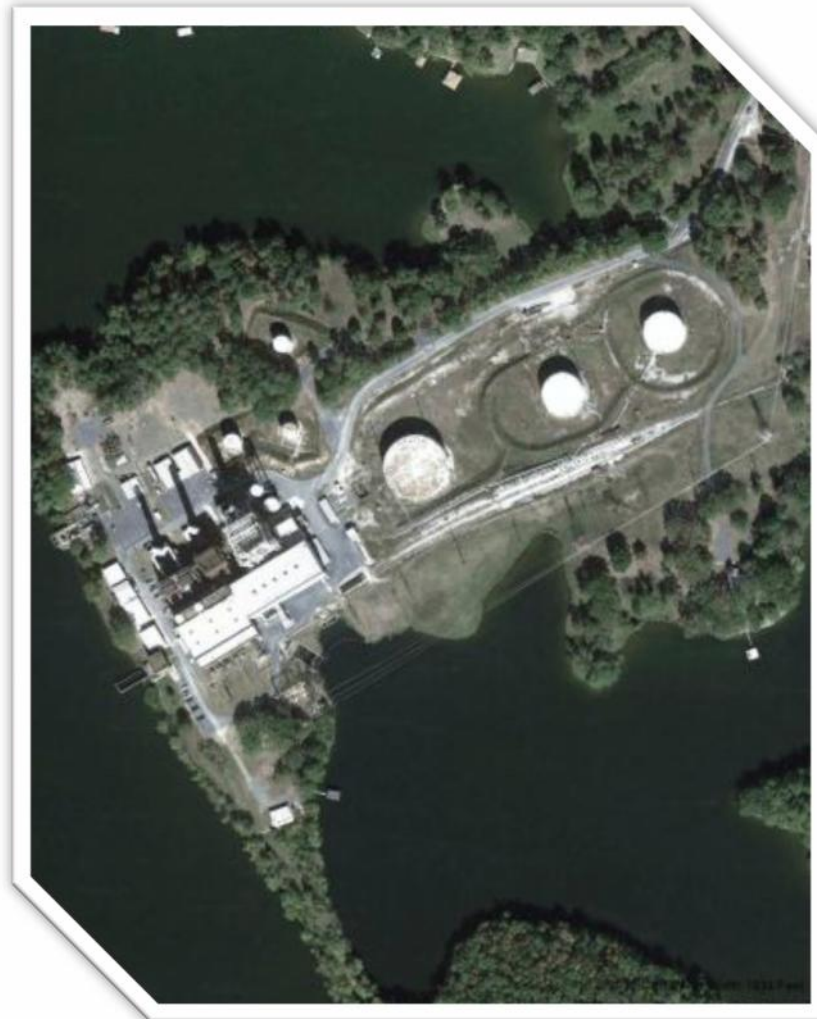
Concluded Value

Based on the foregoing, it is our opinion that the market value of the subject land in fee simple as if clear may be reasonably stated as \$300,000 US dollars on October 10, 2012.



Lake Catherine

Entergy Arkansas' Lake Catherine power plant is located at 141 West Country Line Road Malvern, Arkansas. The power plant sits on a 208.13 acre site. The site is along the banks of Lake Catherine and has significant lake frontage. The subject property has been owned for the past three years by Entergy Arkansas and is not being marketed for sale.









Land Valuation

We have employed the sales comparison method to value the subject land in fee simple as if clear and vacant, utilizing the comparable data summarized in the map and table presented below. In addition, we have provided a synopsis of our analysis on the following pages.





Table 4							
Entergy Arkansas' Lake Catherine Plant							
Comparable Land Market Transactions Summary - USD							
No.	Property Location	Transaction		Proposed Use	Actual Sale Price	Size (Acres)	Price Per Acre
		Type	Date				
1	6400 Central Ave, Hot Springs, AR	Sale	Jul- 09	Residential	\$1,000,000.00	22.86	\$43,745.00
2	Hwy 7 North and Goat Hill Road, Hot Springs, AR	Sale	Jun- 07	Subdivision	1,200,000.00	230.00	5,217.00
3	810 Marian Anderson Rd. Hot Springs, AR	Sale	Oct- 06	Residential	1,025,000.00	52.37	19,572.00
4	6400 Central Ave Hot Springs, AR	Sale	May-06	Residential	1,616,000.00	36.70	44,033.00
5	Hwy 290 and Carpenter Dam Rd, Hot Springs, AR	Listing	Oct-12	Subdivision	1,042,917.00	75.03	13,900.00
6	Carpenter Dame Rd @ Grand Pr. Drive, Hot Springs, AR	Listing	12-Oct	Not Stated	\$1,576,050.00	35.00	\$45,030.00
Subject	141 West Country Line Road, Malvern, Arkansas			Not Stated		208.13	
Transaction amounts adjusted for cash equivalency and/or development costs (where applicable) as compiled by CBRE.							

Exposure/Marketing Time Information

Exposure or marketing time for comparable sales ranged between 6 and 24 or more months, with an average exposure or marketing time of 12 months. Local market professionals' opinions regarding typical exposure or marketing times ranged from 6 to 12 months. Estimated exposure or marketing time for the subject property was 12 months.

Data Sources Utilized

- Size – Statements by Entergy Arkansas,
- Flood Hazard – FEMA, and
- Zoning – No zoning.

Highest and Best Use

The same previously identified criteria listed on page 10 apply.

The highest and best use analysis of the subject land as if clear and vacant is residential



Analysis of Land Sales

The sales utilized represent the best data available for comparison with the subject and were selected from the Hot Springs lake area first but with a widening search for sufficient data. The lake frontage areas are fully developed, and there have been no recent and relevant large tract sales along the lake frontages. At the same time, Lake Catherine is not viewed as favorably as Lake Hamilton. This can be seen through comparison of residential lot prices. Review of those data against off-lake lot prices also indicates that properties within the lake influence area of Lake Hamilton are good proxies from a location standpoint to properties which are near or fronting Lake Catherine. The issue with Lake Catherine is that it is not as large as Lake Hamilton and thus has fewer recreational possibilities. This was considered within the location adjustments applied below.

Land Listing One. This comparable represents 22.86 acres at 6400 Central Ave. The site has an irregular shape with gently rolling topography and exhibits frontage on Highway 7. At the time of the sale, the property was vacant. The site is not subject to zoning, and the proposed use is for a residential subdivision. All utilities were available to the site. The property sold in July 2009 for \$1,000,000.00, or \$43,745.00 per acre. This site is located on the north side of Massey Road between Central Avenue and Highway 290. It is the excess land portion of the Legends at Hot Springs subdivision. This sale is not considered completely arm's-length but the price was agreed to through an appraisal, and the purchaser is controlled by a different developer.

The negative 75.00 percent downward adjustment for size reflects this comparable's superior feature with respect to economies of scale regarding parcel size. Typically, as size increases, unit prices decline and vice versa. The typical relationship is for a 10.00-20.00 percent differential in price per unit prices for every doubling or halving of size - unless the size differential is overly significant. This is also reflected by sales two and three which are both located away from the lakes and were both intended for residential development. Overall, this comparable was deemed superior in comparison to the subject and a downward net adjustment was warranted to the sales price indicator.

Land Sale Two. This comparable represents 230.00 acres at Hwy 7 North and Goat Hill Road. The site has an irregular shape with level, at street grade topography and exhibits the following frontage: Hwy 7 North and Goat Hill Road. At the time of the sale, the property was vacant. The site is zoned partly Commercial but mostly residential while the proposed use is for a residential development. All utilities were available to the site. The property sold in June 2007 for \$1,200,000.00, or \$5,217.00 per acre. This comparable represents the sale of a 230.00 acre tract located in north Hot Springs. The property is zoned for commercial and residential use. The property was purchased for the development of a platted subdivision with a private lake. The development did not move forward, however.

The downward market conditions (time) adjustment of negative 10.00 percent reflects the changing market conditions since the date of sale. This sale predates the recession at which point at least some degree of decline in property values has occurred. However, as indicated by sales one and four as well, the Hot Springs area did not experience the kind of rampant acceleration in residential land prices prior to the recession that were seen in other areas. Based on the pricing differential of sales one and four in addition to other available data, a small



downward adjustment for market conditions is applied. The adjustment for location was warranted due to its location on the north side of Hot Springs away from the lake influenced area. The adjustments for location are developed by ranking the sales after other adjustments are applied. Therefore, an upward adjustment of 150.00 percent was judged proper for this comparable. Overall, this comparable was deemed inferior in comparison to the subject and an upward net adjustment was warranted to the sales price indicator.

Land Sale Three. This comparable represents 52.37 acres at 810 Marion Anderson Road in the southwestern part of the Hot Springs area. The site has an irregular shape with moderately sloped topography. At the time of the sale, the property was vacant. The site is not subject to zoning, and the proposed use is for a residential subdivision. No sewer utilities were available to the site. The property sold in October 2006 for \$1,025,000.00, or \$19,572.00 per acre. This property is located near Lake Hamilton, but does not contain frontage. The lake is visible from some portions of the site. The property has since had water/sewer extended to it.

The downward market conditions (time) adjustment of negative 10.00 percent reflects the declining market conditions since the date of sale as explained with sale two. The negative 70.00 percent downward adjustment for size reflects this comparable's superior feature with respect to economies of scale regarding parcel size as explained with sale one. The adjustment for location was warranted due to its location to the southwest in a more rural area away from the lake influence area. Therefore, an upward adjustment of 30.00 percent was judged proper for this comparable. Overall, this comparable was deemed superior in comparison to the subject and a downward net adjustment was warranted to the sales price indicator.

Land Sale Four. This comparable represents 36.70 acres at 6400 Central Ave. The site has an irregular shape with gently rolling topography and exhibits the following frontage: Highway 7. At the time of the sale, the property was agricultural. The site is not subject to zoning, and the proposed use is for a residential subdivision. No sewer utilities were available to the site. The property sold in May 2006 for \$1,616,000.00, or \$44,033.00 per acre. This site is located on the north side of Massey Road between Central Avenue and Highway 290. This is the parent tract to Sale One.

The downward market conditions (time) adjustment of negative 10.00 percent reflects the declining market conditions since the date of sale as explained with sale two. The negative 70.00 percent downward adjustment for size reflects this comparable's superior feature with respect to economies of scale regarding parcel size as explained with sale one. Overall, this comparable was deemed superior in comparison to the subject and a downward net adjustment was warranted to the sales price indicator.

Land Sale Five. This comparable represents 75.03 acres at Hwy 290 and Carpenter Dam Rd. The site has an irregular shape with level to rolling topography and exhibits the following frontage: Highway 290 and Redoak Drive. At the time of the sale, the property was vacant. The site is not subject to zoning, and the proposed use is not specified. No sewer utilities were available to the site. The property was listed as of October 2012 for \$1,042,917.00, or \$13,900.00 per acre.



In terms of conditions of sale, this comparable was considered superior and received a downward adjustment of negative 20.00 percent for this characteristic due to this being a listing versus a closed sale. The adjustment is the typical differential between listing and selling prices as indicated by review of land sales data over the past few years as well as expectations of brokers in the market. The negative 50.00 percent downward adjustment for size reflects this comparable's superior feature with respect to economies of scale regarding parcel size as explained with sale one. The adjustment for location was warranted due to its location further south of the lake influence area. Therefore, an upward adjustment of 50.00 percent was judged proper for this comparable. Overall, this comparable was deemed superior in comparison to the subject and a downward net adjustment was warranted to the sales price indicator.

Land Sale Six. This comparable represents 35.00 acres at Carpenter Dam Rd at Grand Pt Drive. The site has an irregular shape with rolling topography and exhibits the following frontage: Carpenter Dam Rd and Grand Point Drive. At the time of the sale, the property was vacant. The site is zoned R-1, and the proposed use is not specified. No sewer utilities were available to the site. The property sold in October 2012 for \$1,576,050.00, or \$45,030.00 per acre.

In terms of conditions of sale, this comparable was considered superior and received a downward adjustment of negative 20.00 percent for this characteristic due to this being a listing versus a closed sale as with listing five. The negative 70.00 percent downward adjustment for size reflects this comparable's superior feature with respect to economies of scale regarding parcel size as explained with sale one. Overall, this comparable was deemed superior in comparison to the subject and a downward net adjustment was warranted to the sales price indicator.



Summary of Adjustments

As presented on Table 5, based on our comparative analysis, the following adjustments were made to each comparable:

Table 5							
Entergy Arkansas' Lake Catherine Plant							
Comparable Land Market Transactions Analysis - USD							
	1	2	3	4	5	6	Subject
Transaction Type	Sale	Sale	Sale	Sale	Listing	Listing	
Transaction Date	Jul 2009	Jun 2007	Oct 2006	May 2006	Oct 2012	Oct 2012	
Proposed Use	Residential Subdivision	Residential	Residential Subdivision	Residential Subdivision	Not Stated	Not Stated	Residential
Sale Price	\$1,000,000.00	\$1,200,000.00	\$1,025,000.00	\$1,616,000.00	\$1,042,917.00	\$1,576,050.00	---
Size (Acres)	22.86	230.00	52.37	36.70	75.03	35.00	208.13
Price Per Acre	\$43,745.00	\$5,217.00	\$19,572.00	\$44,033.00	\$13,900.00	\$45,030.00	---
Price (\$ Per AC)	\$43,745.00	\$5,217.00	\$19,572.00	\$44,033.00	\$13,900.00	\$45,030.00	
Property Rights Conveyed							
Financing Terms							
1							
Conditions of Sale					-20.00%	-20.00%	
Market Conditions (Time)		-10.00%	-10.00%	-10.00%			
Subtotal	\$43,745.00	\$4,696.00	\$17,615.00	\$39,629.00	\$11,120.00	\$36,024.00	
Size	-75.00%		-70.00%	-70.00%	-50.00%	-70.00%	
Shape							
Corner							
Frontage							
Topography							
Location		150.00%	30.00%		50.00%		
Zoning/Density							
Utilities							
Highest & Best Use							
Total Other Adjustments	-75.00%	150.00%	-40.00%	-70.00%	0.00%	-70.00%	
Value Indications for Subject	\$10,936.00	\$11,739.00	\$10,569.00	\$11,889.00	\$11,120.00	\$10,807.00	
Transaction amounts adjusted for cash equivalency and/or development costs (where applicable) as compiled by CBRE.							

Discussions with Market Participants

Discussions with brokers yielded no specific lake frontage sales. Upon describing the property as being on Lake Catherine, brokers indicated that this was not as desirable as Lake Hamilton properties. Sales activity is very light for residentially oriented properties and generally consists



of small (5 acre +/- tracts) versus larger tracts -nothing in the size range of the subject. The brokers indicated that they would expect the value of the subject to lie between \$10,000.00 to \$20,000.00 per acre depending on how healthy the Hot Springs residential market may become in the foreseeable future

Value Indications and Reconciliation

Based on the preceding analysis, the following table presents the value indications:

Table 6				
Entergy Arkansas' Lake Catherine Plant				
Land Market Value Analysis - USD				
\$ Per AC		Subject Acres		Value Indications
\$10,569.00	x	208.13	=	\$2,199,726.00
\$11,889.00	x	208.13	=	\$2,474,458.00
Indicated Market Value:				\$2,350,000.00
		(Rounded \$ Per AC)		\$11,291.02

Concluded Value

Based on the foregoing, it is our opinion that the market value of the subject land in fee simple as if clear may be reasonably stated as \$2.35 million US dollars on October 10, 2012.



Lynch

Entergy Arkansas' Lynch power plant is located at 5800 Lynch Drive North Little Rock, Pulaski County, Arkansas 72117. The power plant sits on a 120.64 acre site or 5,255,078.00 square feet. Lynch has been owned by Entergy Arkansas over the past three years and has not been marketed during that time.









Land Valuation

We have employed the sales comparison method to value the subject land in fee simple as if clear and vacant, utilizing the comparable data summarized in the map and table presented below. In addition, we have provided a synopsis of our analysis on the following pages.

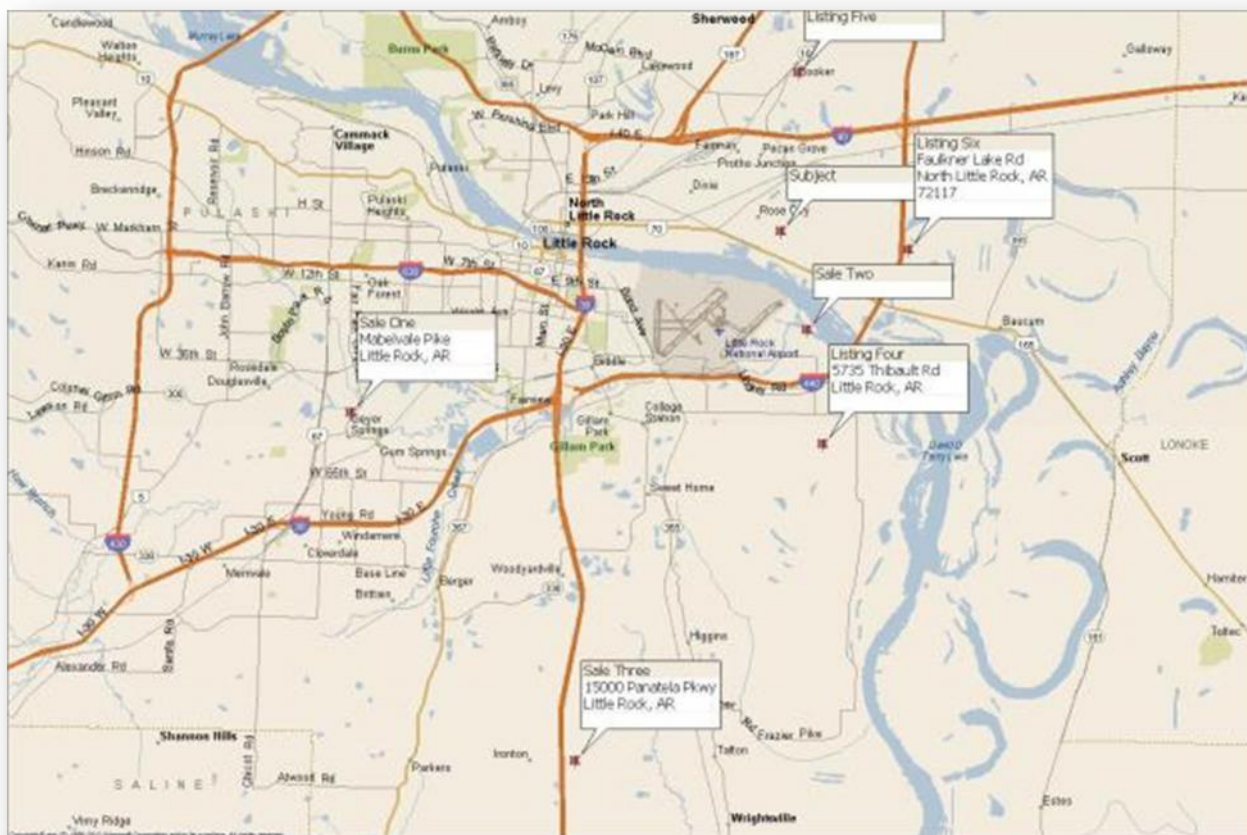


Table 7							
Entergy Arkansas' Lynch Plant							
Comparable Land Market Transactions Summary - USD							
No.	Property Location	Transaction		Proposed Use	Actual Sale Price	Size (Acres)	Price Per Acre
		Type	Date				
1	Mabelvale Pike, Little Rock, AR	Sale	May 10	PDR	\$600,000.00	20.00	\$30,000.00
2	County Farm Rd, Little Rock, AR	Sale	Sept 08	Agricultural	546,000.00	21.00	26,000.00
3	15000 Panatella, Little Rock (Rural), AR	Sale	Oct 08	None	255,000.00	58.00	4,397.00
4	5735 Thibault Road Little Rock (Rural), AR	Listing	Jun 12	None	1,570,000.00	78.50	20,000.00
5	3300 Highway 161, North Little Rock, AR	Listing	Jun 12	C-3 & I-2	3,800,000.00	48.00	79,167.00
6	Faulkner Lake, Road, North Little Rock, AR	Listing	Feb 11	I-2	\$1,345,250.00	54.00	\$24,912.00
Subject	5800 Lynch Drive North Little Rock, AR			I-3, Industrial Park District		120.64	
Transaction amounts adjusted for cash equivalency and/or development costs (where applicable) as compiled by CBRE.							



Exposure/Marketing Time Information

Exposure or marketing time for comparable sales ranged between 6 and 24 or more months, with an average exposure or marketing time of 12 months. Local market professionals' opinions of typical exposure or marketing times ranged from 6 to 12 months. Estimated exposure or marketing time for the subject property was 12 months.

Data Sources Utilized

- Size - Statement by Entergy Arkansas, Inc.,
- Flood Hazard - FEMA, and
- Zoning - City of North Little Rock.

Highest and Best Use

The same previously identified criteria listed on page 10 apply.

The highest and best use analysis of the subject land as if clear and vacant is industrial

Analysis of Land Sales

The sales utilized represent the best data available for comparison with the subject and were selected from the greater North Little Rock area. These sales were chosen based upon being larger tracts of land with similar potential uses.

Land Listing One. This comparable represents 20.00 acres on Mabelvale Pike. The site has an irregular shape with generally level topography and exhibits the following frontage: Mabelvale Pike. At the time of the sale, the property was vacant. The site is zoned PDR, and the proposed use is for multi-family residential. All utilities were available to the site. The property sold in May 2010 for \$600,000.00, or \$30,000.00 per acre. This property was purchased for the development of a multi-family project known as The Orchards at Mabelvale (low income senior housing). The site is located at the southeast quadrant of Mabelvale Pike and Davmar Drive.

The negative 40.00 percent downward adjustment for size reflects this comparable's superior feature with respect to economies of scale regarding parcel size. Typically, as size increases, unit prices decline and vice versa. The typical relationship is for a 10.00-20.00 percent differential in price per unit prices for every doubling or halving of size - unless the size differential is overly significant. This adjustment was marginally visible from the other sales. Overall, this comparable was deemed superior in comparison to the subject and a downward net adjustment was warranted to the sales price indicator.

Land Sale Two. This comparable represents 21.00 acres on County Farm Road on the south side of the Arkansas River in Little Rock. The site has a rectangular shape with generally level topography. At the time of the sale, the property was vacant. No sewer utilities were available to the site. The property sold in September 2008 for \$546,000.00, or \$26,000.00 per acre. Due to location, this is a particularly relevant sale to the subject.



The negative 40.00 percent downward adjustment for size reflects this comparable's superior feature with respect to economies of scale regarding parcel size as with sale one. Overall, this comparable was deemed superior in comparison to the subject and a downward net adjustment was warranted to the sales price indicator.

Land Sale Three. This comparable represents 58.00 acres at 15000 Panatella east of Little Rock. The site has an irregular shape with generally level topography and exhibits the following frontage: I-530 and 145th Street. At the time of the sale, the property was vacant. The site is not subject to zoning and the proposed use is for agricultural use. All utilities were available to the site. The property sold in October 2008 for \$255,000.00, or \$4,397.00 per acre.

The negative 15.00 percent downward adjustment for size reflects this comparable's superior feature with respect to economies of scale regarding parcel size as with sale one. The adjustment for location was warranted due to its location farther outside the city limits with the adjustment reflected by comparison against the other comparables once other adjustments are applied.

Therefore, an upward adjustment of 300.00 percent was judged proper for this comparable. Overall, this comparable was deemed inferior in comparison to the subject and an upward net adjustment was warranted to the sales price indicator.

Land Sale Four. This comparable represents 78.50 acres at 5735 Thibault Road. The site has a rectangular shape with generally level topography and exhibits the following frontage: Thibault Road. At the time of the sale the property was vacant. The site is not subject to zoning. No sewer utilities were available to the site. The property sold in June 2012 for \$1,570,000.00, or \$20,000.00 per acre. Property is located in the flood zone.

In terms of conditions of sale, this comparable was considered superior and received a downward adjustment of negative 25.00 percent for this characteristic due to this being a listing versus a closed sale. The adjustment is the typical differential between listing and selling prices as indicated by review of land sales data over the past few years as well as expectations of brokers in the market. The negative 10.00 percent downward adjustment for size reflects this comparable's superior feature with respect to economies of scale regarding parcel size as with sale one. Overall, this comparable was deemed superior in comparison to the subject and a downward net adjustment was warranted to the sales price indicator.

Land Sale Five. This comparable represents 48.00 acres at 3300 Highway 161. The site has a rectangular shape with generally level topography and exhibits the following frontage: Highway 161. At the time of the sale the property was vacant. The site is zoned C-3 & I-2. All utilities were available to the site. The property sold in June 2012 for \$3,800,000.00, or \$79,167.00 per acre. This represents a listing of a 48- acre tract of land situated along the east side of Highway 161, about 1,000.00 feet north of Interstate 40, in North Little Rock. The property is zoned C-3, for commercial use, along the Highway 161 frontage with the remaining rear site area being zoned I-2, for industrial use. The property is being marketed for potential commercial use, however.

In terms of conditions of sale, this comparable was considered superior and received a downward adjustment of negative 25.00 percent for this characteristic due to this being a listing versus a closed sale as with listing four. The negative 20.00 percent downward adjustment for



size reflects this comparable's superior feature with respect to economies of scale regarding parcel size as with sale one. With respect to zoning/density, this comparable was considered superior in this aspect and received a downward adjustment of negative 50.00 percent because of the commercial zoning designation of this property which implies a greater utility of use with the adjustment indicated against the other comparables once all other necessary adjustments are applied. Overall, this comparable was deemed superior in comparison to the subject and a downward net adjustment was warranted to the sales price indicator.

Land Sale Six. This comparable represents 54.00 acres at Faulkner Lake Road. The site has an irregular shape with generally level topography and exhibits the following frontage: Faulkner Lake Road. At the time of the sale the property was vacant. The site is zoned I-2. All utilities were available to the site. The property sold in February 2011 for \$1,345,250.00, or \$24,912.00 per acre. This comparable is located along the south side of Faulkner Lake Road, a short distance westerly from Interstate Highway 440. The site has visibility from Interstate Highway 440. The Caterpillar plant is located in close proximity to the east of the property. The property has areas that are located within the 100-year floodplain.

In terms of conditions of sale, this comparable was considered superior and received a downward adjustment of negative 25.00 percent for this characteristic due to this being a listing versus a closed sale as with listing four. The negative 15.00 percent downward adjustment for size reflects this comparable's superior feature with respect to economies of scale regarding parcel size as with sale one. Overall, this comparable was deemed superior in comparison to the subject and a downward net adjustment was warranted to the sales price indicator.



Summary of Adjustments

As presented on Table 8, based on our comparative analysis, the following adjustments were made to each comparable:

Table 8							
Entergy Arkansas' Lynch Plant							
Comparable Land Market Transactions Analysis - USD							
	1	2	3	4	5	6	Subject
Transaction Type	Sale	Sale	Sale	Listing	Listing	Listing	---
Transaction Date	May 10	Sep 08	Oct 08	Jun 12	Jun 12	Feb 11	---
Proposed Use	PDR	Agricultural	None	None	C-3 & I-2	I-2	I-3, Industrial
Sale Price	\$600,000.00	\$546,000.00	\$255,000.00	\$1,570,000.00	\$3,800,000.00	\$1,345,250.00	---
Size (Acres)	20.00	21.00	58.00	78.50	48.00	54.00	120.64
Price Per Acre	\$30,000.00	\$26,000.00	\$4,397.00	\$20,000.00	\$79,167.00	\$24,912.00	---
Property Rights Conveyed							
Financing Terms 1							
Conditions of Sale				-25.00%	-25.00%	-25.00%	
Market Conditions (Time)							
Subtotal	\$30,000.00	\$26,000.00	\$4,397.00	\$15,000.00	\$59,375.00	\$18,684.00	
Size	-40.00%	-40.00%	-15.00%	-10.00%	-20.00%	-15.00%	
Shape							
Corner							
Frontage							
Topography							
Location			300.00%				
Zoning/Density					-50.00%		
Utilities							
Highest & Best Use							
Total Other Adjustments	-40.00%	-40.00%	285.00%	-10.00%	-70.00%	-15.00%	
Value Indications for Subject	\$18,000.00	\$15,600.00	\$16,927.00	\$13,500.00	\$17,813.00	\$15,881.00	
Transaction amounts adjusted for cash equivalency and/or development costs (where applicable) as compiled by CBRE.							

Discussion with Market Participants

Brokers indicated that the subject site would have a good degree of demand due to its location within an industrial area but industrial demand has waned over the past several years. Residential demand is limited in this segment of Little Rock but it is located close to employment centers and some degree of multifamily use is possible. Because of the size, brokers suggested a price range for the subject of \$10,000.00 to \$30,000.00 per acre – a wide range, but there is not a lot of direction in that specific location from which to draw.



Value Indications and Reconciliation

Based on the preceding analysis, the following table presents the value indications:

Table 9 Entergy Arkansas' Lynch Plant Land Market Value Analysis - USD				
\$ Per AC		Subject Acres		Indicated Values
\$13,500.00	x	120.64	=	\$1,628,640.00
\$18,000.00	x	120.64	=	\$2,171,520.00
Indicated Market Value:				\$1,950,000.00
		(Rounded \$ Per AC)		\$16,164.00

Concluded Value

Based on the foregoing, it is our opinion that the market value of the subject land in fee simple as if clear may be reasonably stated as \$1.95 million US dollars on October 10, 2012.



Moses

Entergy Arkansas' Moses power plant is located at 5624 Highway 70 W Forest City, St. Francis County, Arkansas 72335. The plant sits on a 120.64 acre site or 5,255,078.00 square feet. Moses has been owned by Entergy Arkansas over the past three years and has not been marketed during that time.









Land Valuation

We have employed the sales comparison method to value the subject land in fee simple as if clear and vacant, utilizing the comparable data summarized in the map and table presented below. In addition, we have provided a synopsis of our analysis on the following pages.

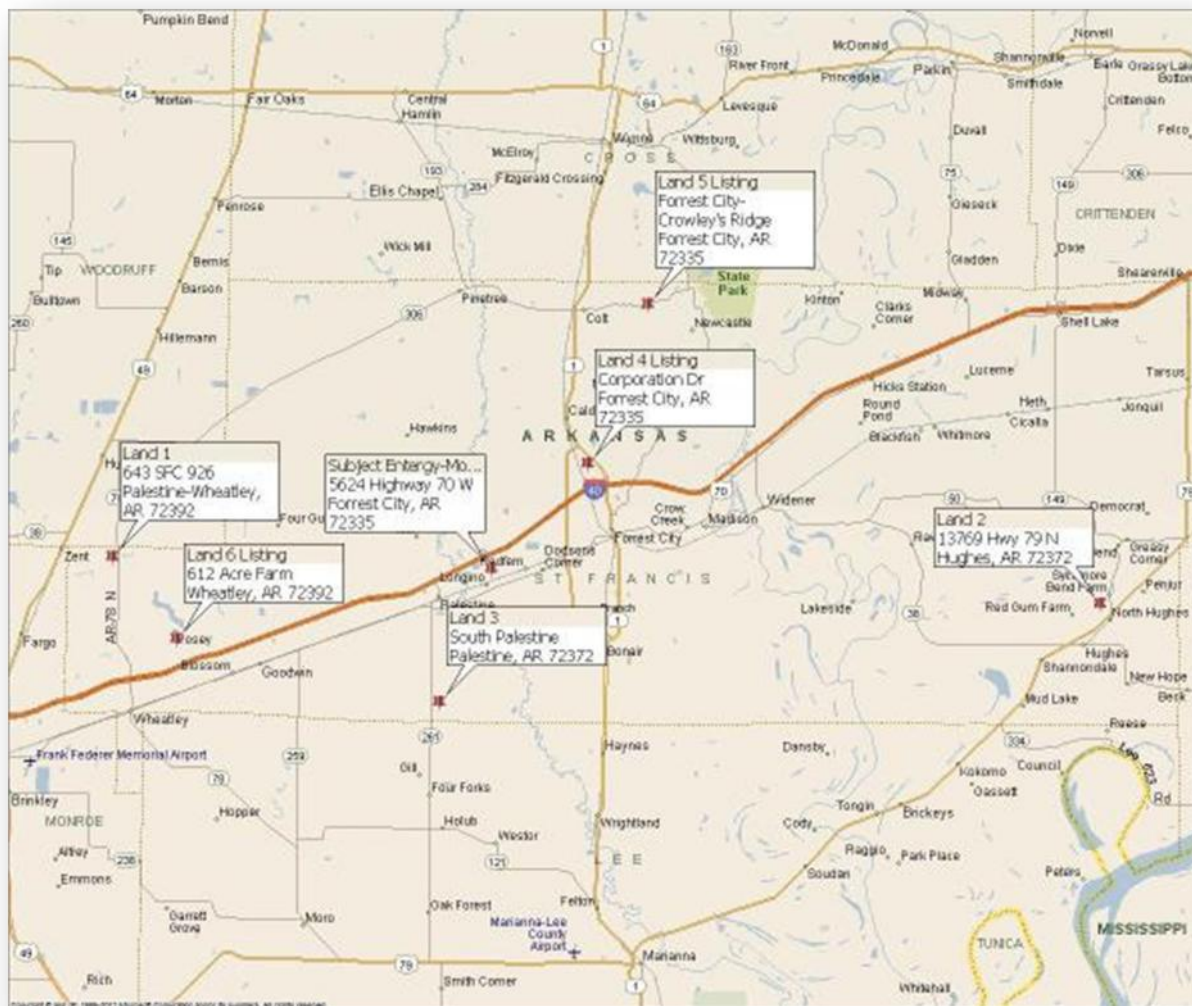


Table 10
Entergy Arkansas' Moses Plant
Comparable Land Market Transactions Summary - USD

No.	Property Location	Transaction		Proposed Use	Actual Sale Price	Size (Acres)	Price Per Acre
		Type	Date				
1	643 SFC 926 Palestine- Wheatley, AR	Sale	Mar 12	\$0.00	\$1,114,000.00	480.00	\$2,321.00
2	13769 Hwy 79 N, Hughes, AR	Sale	Sept 10	0.00	\$1,704,000.00	693.36	2,458.00
3	South of Palestine, Palestine, AR	Sale	Apr 10	0.00	\$600,000.00	148.28	4,046.00
4	Corporation Dr., Forrest City, AR	Listing	Sept 11	0.00	\$1,560,000.00	120.00	13,000.00
5	Forrest City, Forrest City, AR	Listing	Oct 12	0.00	\$489,000.00	201.00	2,433.00
6	St. Francis, Wheatley, AR	Listing	Oct 12	\$0.00	\$2,144,380.00	612.68	\$3,500.00
Subject	5624 Hwy 70 W, Forrest City, Arkansas			Agricultural		260.13	

Transaction amounts adjusted for cash equivalency and/or development costs (where applicable) as compiled by CBRE.



Exposure/Marketing Time Information

Exposure or marketing time for comparable sales ranged between 6 and 24 or more months, with an average exposure or marketing time of 12 months. Local market professionals' opinions of typical exposure or marketing times ranged from 6 to 12 months. Estimated exposure or marketing time for the subject property was 12 months.

Data Sources Utilized

- Size - Statement by Entergy Arkansas, Inc.,
- Flood Hazard - FEMA, and
- Zoning - City of Lake Forest.

Highest and Best Use

The previously identified criteria listed on page 10 apply.

The highest and best use analysis of the subject land as if clear and vacant is agricultural.

Analysis of Land Sales

The sales utilized represent the best data available for comparison with the subject and were selected from the greater Forrest City area. These sales were chosen based upon being larger tracts of land with similar potential uses.

Land Listing One. This comparable represents 480.00 acres at 643 SFC 926. The site has an irregular shape with generally level topography. The property sold in March 2012 for \$1,114,000.00, or \$2,321.00 per acre.

The 20.00 percent upward adjustment for size reflects this comparable's inferior feature with respect to economies of scale regarding parcel size. Typically, as size increases, unit prices decline and vice versa. The typical relationship is for a 10.00-20.00 percent differential in price per unit prices for every doubling or halving of size - unless the size differential is overly significant. This adjustment was marginally visible from the other sales. Overall, this comparable was deemed inferior in comparison to the subject and an upward net adjustment was warranted to the sales price indicator.

Land Sale Two. This comparable represents 693.36 acres at 13769 Hwy 79 N. The site has an irregular shape with generally level topography. The property sold in September 2010 for \$1,704,000.00, or \$2,458.00 per acre.

The 30.00 percent upward adjustment for size reflects this comparable's inferior feature with respect to economies of scale regarding parcel as with sale one. Overall, this comparable was deemed inferior in comparison to the subject and an upward net adjustment was warranted to the sales price indicator.



Land Sale Three. This comparable represents 148.28 acres South of Palestine. The site has an irregular shape with generally level topography. The property sold in April 2010 for \$600,000.00, or \$4,046.00 per acre.

The negative 20.00 percent downward adjustment for size reflects this comparable's superior feature with respect to economies of scale regarding parcel as with sale one. Overall, this comparable was deemed superior in comparison to the subject and a downward net adjustment was warranted to the sales price indicator.

Land Sale Four. This comparable represents 120.00 acres within the Forrest City Industrial Park along Corporation Drive. The site has an irregular shape with generally level topography and exhibits the following frontage: Corporation Drive and Eldridge Road. At the time of our research, the property was vacant. The site is zoned Industrial, and the proposed use is for industrial development. All utilities were available to the site. The property was listed as of September 2011 (which remains current) for \$1,560,000.00, or \$13,000.00 per acre. This comparable represents the remaining land in the Forrest City Industrial Park. The property contains several sites with some having rail access.

In terms of conditions of sale, this comparable was considered superior and received a downward adjustment of negative 25.00 percent for this characteristic due to this being a listing versus a closed sale. The adjustment is the typical differential between listing and selling prices as indicated by review of land sales data over the past few years as well as expectations of brokers in the market. The negative 25.00 percent downward adjustment for size reflects this comparable's superior feature with respect to economies of scale regarding parcel as with sale one. The adjustment for location was warranted due to this listing being of prepared industrial sites in the city's industrial park with all utility services (which is buried within this adjustment). Therefore, a downward adjustment of negative 40.00 percent was judged proper for this comparable. Overall, this comparable was deemed superior in comparison to the subject and a downward net adjustment was warranted to the sales price indicator.

Land Sale Five. This comparable is of a 201.00 acre tract located to the north of Forrest City in the Crowley's Ridge area. The site has an irregular shape with a generally level topography. The site is currently vacant. The property was listed as of October, 2012 for \$489,000.00 or \$2,433.00 per acre.

In terms of conditions of sale, this comparable was considered superior and received a downward adjustment of negative 25.00 percent for this characteristic due to this being a listing versus a closed sale as with listing four. Overall, this comparable was deemed superior in comparison to the subject and a downward net adjustment was warranted to the sales price indicator.



Land Sale Six. This comparable represents 612.68 acres on St. Francis Road near Wheatley. The site has an irregular shape with generally level topography. The property was listed as of October 2012 for \$2,144,380.00, or \$3,500.00 per acre. One-half mineral rights convey at list price but this is not a natural gas or energy area.

In terms of conditions of sale, this comparable was considered superior and received a downward adjustment of negative 25.00 percent for this characteristic due to this being a listing versus a closed sale as with listing four. The 30.00 percent upward adjustment for size reflects this comparable's inferior feature with respect to economies of scale regarding parcel as with sale one. Overall, this comparable was deemed superior in comparison to the subject and a downward net adjustment was warranted to the sales price indicator.

Summary of Adjustments

As presented on Table 11, based on our comparative analysis, the following adjustments were made to each comparable:

Table 11							
Entergy Arkansas' Moses Plant							
Comparable Land Market Transactions Analysis - USD							
	1	2	3	4	5	6	Subject
Transaction Type	Sale	Sale	Sale	Listing	Listing	Listing	---
Transaction Date	Mar 12	Sept 10	Apr 10	Sept 11	Oct 12	Oct 12	---
Proposed Use	\$1,114,000.00	\$1,704,000.00	\$600,000.00	\$1,560,000.00	\$489,000.00	\$2,144,380.00	---
Adjusted Sale Price 1	\$1,114,000.00	\$1,704,000.00	\$600,000.00	\$1,560,000.00	\$489,000.00	\$2,144,380.00	---
Size (Acres)	480.00	693.36	148.28	120.00	201.00	612.68.00	260.13
Price (\$ Per AC)	\$2,321.00	\$2,458.00	\$4,046.00	\$13,000.00	\$2,433.00	\$3,500.00	
Property Rights Conveyed							
Financing Terms 1							
Conditions of Sale				-25.00%	-25.00%	-25.00%	
Market Conditions (Time)							
Subtotal	\$2,321.00	\$2,458.00	\$4,046.00	\$9,750.00	\$1,825.00	\$2,625.00	
Size	20.00%	30.00%	-20.00%	-25.00%		30.00%	
Shape							
Corner							
Frontage							
Topography							
Location				-40.00%			
Zoning/Density							
Utilities							
Highest & Best Use							
Total Other Adjustments	20.00%	30.00%	-20.00%	-65.00%	0.00%	30.00%	
Value Indication for Subject	\$2,785.00	\$3,195	\$3,237	\$3,413	\$1,825	\$3,413	
Transaction amounts adjusted for cash equivalency and/or development costs (where applicable) as compiled by CBRE.							



Discussion with Market Participants

The broker for Listing 6 suggested that the typical price for land in the area of the subject is \$3,200 to \$3,300 per acre.

Value Indications and Reconciliation

Based on the preceding analysis, the following table presents the value indications:

Table 12				
Entergy Arkansas's Moses Plant				
Land Market Value Analysis - USD				
\$ Per AC		Subject Acres		Value Indications
\$1,825.00	x	260.13	=	\$474,737.00
\$3,413.00	x	260.13	=	\$887,824.00
Indicated Market Value:				\$750,000.00
		(Rounded \$ Per AC)		\$2,883.17

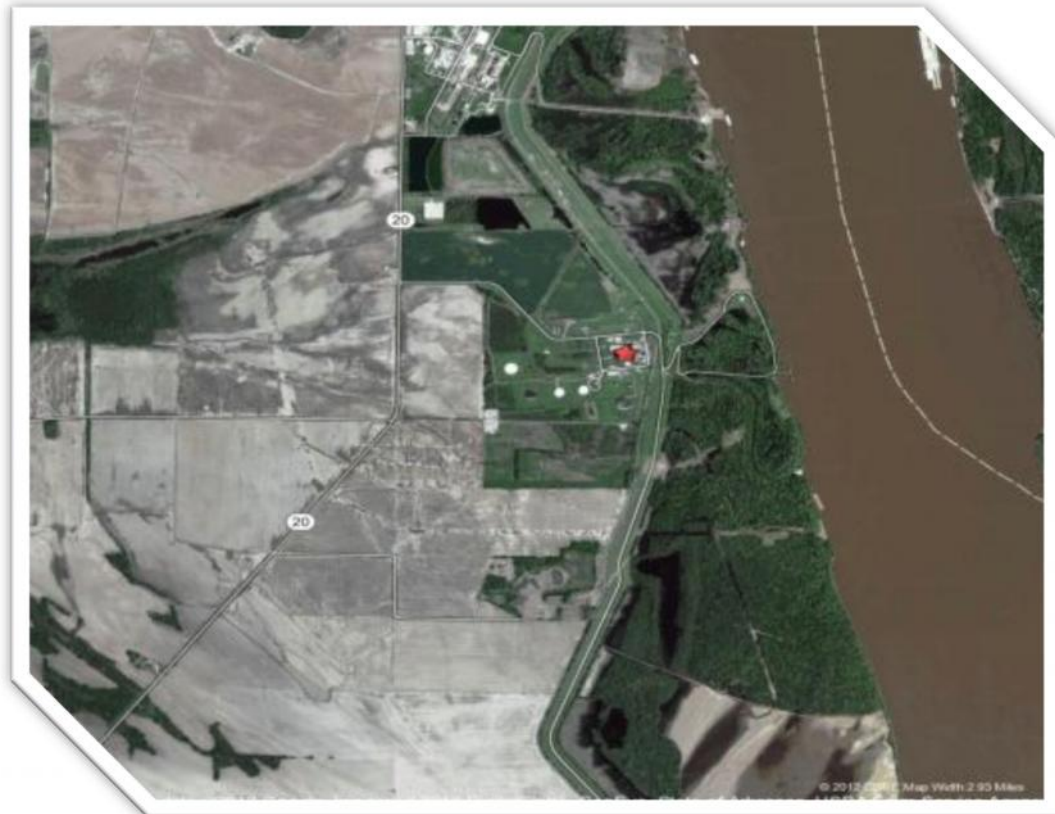
Concluded Value

Based on the foregoing, it is our opinion that the market value of the subject land in fee simple as if clear may be reasonably stated as \$750,000 US dollars on October 10, 2012.



Ritchie

Entergy Arkansas' Ritchie power plant is located at 598 Phillips Rd Helena, Phillips County, Arkansas 72342. The power plant sits on a 495.98 acre site or 21,604,889.00 square feet. Ritchie has been owned by Entergy Arkansas over the past three years and has not been marketed during that time.









Land Valuation

We have employed the sales comparison method to value the subject land in fee simple as if clear and vacant, utilizing the comparable data summarized in the map and table presented below. In addition, we have provided a synopsis of our analysis on the following pages.



Table 13
Entergy Arkansas' Ritchie Plant
Comparable Land Market Transactions Summary - USD

No.	Property Location	Transaction		Proposed Use	Actual Sale Price	Size (Acres)	Price Per Acre
		Type	Date				
1	21930 Hwy 20, Elaine, AR	Sale	Feb 10	\$0.00	\$1,560,012.00	676.01	\$2,308.00
2	Hwy 242, West Helena, AR	Listing	Oct 12	0.00	1,020,000.00	340.00	3,000.00
3	Big Creek, Marvell, AR	Listing	Oct 12	0.00	496,000.00	320.00	1,550.00
4	Hwy 20 and Hwy 462, Elaine, AR	Listing	Oct 12	0.00	\$1,530,750.00	785.00	\$1,950.00
Subject	598 Phillips Rd, Helena, AR					495.98	

Transaction amounts adjusted for cash equivalency and/or development costs (where applicable) as compiled by CBRE.



Exposure/Marketing Time Information

Exposure or marketing time for comparable sales ranged between 6 and 24 or more months, with an average exposure or marketing time of 12 months. Local market professionals' opinions of typical exposure or marketing times ranged from 6 to 12 months. Estimated exposure or marketing time for the subject property was 12 months.

Data Sources Utilized

- Size - Statement by Entergy Arkansas, Inc.,
- Flood Hazard - FEMA, and
- Zoning - City of Helena.

Highest and Best Use

The previously identified criteria listed on page 10 apply.

The highest and best use analysis of the subject land as if clear and vacant is speculative holding likely for and industrial-related use.

Analysis of Land Sales

The sales utilized represent the best data available for comparison with the subject and were selected from the greater Helena area. These sales were chosen based upon being larger tracts of land with similar potential uses.

Land Listing One. This comparable represents 676.01 acres at 21930 Hwy 20. The site has an irregular shape with generally level topography. The property sold in February 2010 for \$1,560,012.00, or \$2,308.00 per acre.

There is no perception of different characteristics for this property so no adjustments were applied. The site is large like the subject and has a generally similar location. There is no apparent benefit for a property in the location of the subject to have Mississippi River access - it would simply be viewed as agricultural property.

Land Sale Two. This comparable represents 340.00 acres at Hwy 242. The site has an irregular shape with generally level topography. The property was listed as of October 2012 for \$1,020,000.00, or \$3,000.00 per acre. It is bordered on the north by the Saint Francis National Forest and is located off of AR HWY 242 near West Helena. The Mississippi River and Storm reek Lake are also located within 5 miles of the property.

In terms of conditions of sale, this comparable was considered superior and received a downward adjustment of negative 25.00 percent for this characteristic due to this being a listing versus a closed sale. The adjustment is the typical differential between listing and selling prices as indicated by review of land sales data over the past few years as well as expectations of brokers in the market. No physical or locational adjustments were considered to be warranted. Overall, this comparable was deemed superior in comparison to the subject and a downward net adjustment was warranted to the sales price indicator.



Land Sale Three. This comparable represents 320.00 acres at Big Creek. The site has an irregular shape with generally level topography. The property was listed as of October 2012 for \$496,000.00, or \$1,550.00 per acre. This property is located just northeast of Marvell in Phillips County, Arkansas.

In terms of conditions of sale, this comparable was considered superior and received a downward adjustment of negative 25.00 percent for this characteristic due to this being a listing versus a closed sale as with listing two. No physical or locational adjustments were considered to be warranted. Overall, this comparable was deemed superior in comparison to the subject and a downward net adjustment was warranted to the sales price indicator.

Land Sale Four. This comparable represents 785.00 acres at Hwy 20 and Hwy 462. The site has an irregular shape with generally level topography. The property was listed as of October 2012 for \$1,530,750.00, or \$1,950.00 per acre.

In terms of conditions of sale, this comparable was considered superior and received a downward adjustment of negative 25.00 percent for this characteristic due to this being a listing versus a closed sale as with listing two. No physical or locational adjustments were considered to be warranted. Overall, this comparable was deemed superior in comparison to the subject and a downward net adjustment was warranted to the sales price indicator.



Summary of Adjustments

As presented in Table 14, based on our comparative analysis, the following adjustments were made to each comparable:

Table 14 Entergy Arkansas' Ritchie Plant Comparable Land Market Transactions Analysis - USD					
	1	2	3	4	Subject
Transaction Type	Sale	Listing	Listing	Listing	---
Transaction Date	Feb 10	Oct 12	Oct 12	Oct 12	---
Adjusted Sale Price 1	\$1,560,012.00	\$1,020,000.00	\$496,000.00	\$1,530,750.00	---
Size (Acres)	676.01.00	340.00	320.00	785.00	495.98
Price (\$ Per AC)	\$2,308.00	\$3,000.00	\$1,550.00	\$1,950.00	
Property Rights Conveyed					
Financing Terms 1					
Conditions of Sale		-25.00%	-25.00%	-25.00%	
Market Conditions (Time)					
Subtotal	\$2,308.00	\$2,250.00	\$1,163.00	\$1,463.00	
Size					
Shape					
Corner					
Frontage					
Topography					
Location					
Zoning/Density					
Utilities					
Highest & Best Use					
Total Other Adjustments	0.00%	0.00%	0.00%	0.00%	
Value Indications for Subject	\$2,308.00	\$2,250.00	\$1,163.00	\$1,463.00	
Transaction amounts adjusted for cash equivalency and/or development costs (where applicable) as compiled by CBRE.					

Discussion with Market Participants

We conducted numerous discussions with brokers regarding potential value for the subject. Many would not guess as they did not know if there would be any contributory value to the direct Mississippi River access. One broker suggested that the subject property value should lie in the range from \$3,000 to \$4,000 per acre, but this is not supported by the available sale or listing data – including one of his own listings.



Value Indications and Reconciliation

Based on the preceding analysis, the following table presents the value indications:

Table 15 Entergy Arkansas' Ritchie Plant Land Market Value Analysis - USD				
\$ Per AC		Subject Acres.		Value Indications
\$1,163.00	x	495.98	=	\$576,825.00
\$2,308.00	x	495.98	=	\$1,144,722.00
Indicated Market Value:				\$1,100,000.00
(Rounded \$ Per AC)				\$2,218.00

Concluded Value

Based on the foregoing, it is our opinion that the market value of the subject land in fee simple as if clear and vacant may be reasonably stated as \$1.10 million US dollars on September 30, 2012.

SUMMARY

Based on the foregoing analyses for the subject Entergy Arkansas sites it is our opinion that the market value in fee simple of the land as if clear and vacant may be reasonably stated as presented on Table 16 on October 10, 2012

Table 16 Entergy Arkansas Power Plant Sites' Land – October 10, 2012 Summary of Concluded Market Values - USD		
Power Plant Location	Acres	Market Values
Couch – 547 Highway 82 East Stamps, AR	105.71	\$300,000.00
Lake Catherine – 141 West Country Line Road Malvern, AR	208.13	2,350,000.00
Lynch – 5800 Lynch Drive North Little Rock, AR	120.64	1,950,000.00
Moses – 5624 Highway 70 W. Forest City AR	260.13	750,000.00
Ritchie – 598 Phillips Rd. Helena, AR	495.98	\$1,100,000.00



DISMANTLEMENT COSTS

Referring to Table 17 below, we were provided a dismantlement study by Entergy Arkansas for each of the subject power plant locations which was conducted by Black & Veatch and dated December 4, 2012.⁷

Table 17 Entergy Arkansas Power Plants Black & Veatch Dismantlement Study--USD December 4, 2012					
Plant	No. of Units	Max nameplate (MW)	Utility	Fuel Type	Costs
Couch	2	190		Gas/Oil	\$11,278,923.00
Lake Catherine	4	746	ELL	Gas/Oil	26,829,220.00
Lynch	4	265	ELL	Gas/Oil	14,128,564.00
Moses	2	138	ELL	Gas/Oil	9,070,270.00
Ritchie	2	380	EGSI	Gas/Oil	\$12,465,507.00

DISMANTLEMENT COSTS COMPARED TO MARKET VALUE OF LAND

As Tables 18 below presents, the estimated dismantlement costs for Entergy Arkansas' Couch, Lake Catherine, Lynch, Moses, and Ritchie power plants exceed market value in fee simple of the land as if clear and vacant for each location.

Table 18 Entergy Arkansas Power Sites Dismantlement Cost vs. Market Value of Land - USD			
Plant	Dismantlement Cost	Market Value of Land	Dismantlement Cost in Excess of Market Value of Land
Couch	\$11,278,923.00	\$300,000.00	\$10,978,923.00
Lake Catherine	26,829,220.00	2,350,000.00	24,479,220.00
Lynch	14,128,564.00	1,950,000.00	12,178,564.00
Moses	9,070,270.00	750,000.00	8,320,270.00
Ritchie	\$12,465,507.00	\$1,100,000.00	\$11,365,507.00

⁷ Black & Veatch's Dismantlement Study dated December 4, 2012 has been retained in our working files.

EXHIBIT I: FOUNDATION

FOUNDATION

1. Interviews and discussions with Brian Caldwell of Entergy Asset Management, Inc. and real estate market participants.
2. www.electricity.doe.gov, "The Electric Delivery System", February 2006.
3. www.eia.doe.gov, Annual Energy Outlook 2012.
4. US Energy Information Administration, Electric Power Annual 2011.
5. www.entergy.com, Generation Portfolio 2012.
6. <http://www.bea.gov/newsreleases/national/gdp/gdphighlights.pdf>.
7. www.cogeneration.net.
8. www.nma.org.
9. www.ifp.com.
10. www.wikipedia.com.
11. www.econlib.org.
12. Ibbotson Associates' Stocks, Bonds, Bills and Inflation, 2012 Valuation Yearbook.
13. With regard to the Arkansas Economic Outlook on October 10, 2012:
 1. US Bureau of Labor Statistics,
 2. Archie Flanders, assistance professor of agricultural economics for the University of Arkansas, March 18, 2012, and
 3. Quarterly Business Analysis, Center of Business and Economic Research, Sam M. Walton College of Business.
14. Office of Comptroller of the Currency (OCC), 12 CFR Part 34, Subpart C - Appraisals, 34.42 (g); Office of Thrift Supervision (OTS), 12 CFR 564.2 (g); Appraisal Institute, The dictionary of Real Estate Appraisal, 5th ed. (Chicago: Appraisal Institute, 2010), 122-123. This is also compatible with the RTC, FDIC, FRS and NCUA definitions of market value as well as the example referenced in the Uniform Standards of Professional Appraisal Practice (USPAP).
15. The Dictionary of Real Estate Appraisal, Fifth Edition, Appraisal Institute, 2010.

EXHIBIT II: APPRAISERS' CREDENTIALS

PATRICIA R. CARTWRIGHT, ASA

PROFESSIONAL QUALIFICATIONS

PRESENT POSITION: Ms. Cartwright is a Senior Vice President- Valuation Services with Arthur Financial Services, LLC, in the Austin, Texas office. Ms. Cartwright has over 26 years experience providing valuation and value-related consulting services with both regional and nationwide consulting firms.

EXPERIENCE: Ms. Cartwright specializes in the valuation of businesses, business interests, securities and intellectual property. She has performed valuations for such purposes as purchase price allocation, corporate reorganization, transfer pricing studies, insolvency, fairness opinions, gift and estate tax, employee stock ownership plans and bankruptcy. She has provided valuation services for Fortune 1000 companies throughout the energy industry as well as other industries.

A frequent public speaker, Ms. Cartwright has addressed a variety of professional, educational and governmental organizations on diverse topics including:

- Institute for Professionals in Taxation – “Accounting for Business Combinations – Fair Value Accounting Moving Toward International Convergence”
- The Tax Executives Institute in The Woodlands, TX – “Defining and Scoping An Appraisal Assignment”
- The Tax Executives Institute in Atlanta, GA – “Asset Impairment Analysis (SFAS 142 and 144)”
- The Tax Executives Institute in Houston, TX – “The Income Approach to the Valuation of a Refinery”
- The Association for Corporate Growth in Austin, TX – “SFAS 141(R)”
- The University of Texas at Austin Institute for Innovation, Creativity and Capital (IC2) – “Business Valuation Theory & Methodology”
- The Real Estate Center of Texas A&M – “Purchase Price Allocation for Financial Accounting Purposes”
- The Internal Revenue Service – “Financial Analysis & The Development of a Discounted Cash Flow Model” and The California State Department of Transportation – “Developing the Appropriate Equity Discount Rate”

EXPERT TESTIMONY: Ms. Cartwright has testified repeatedly regarding business enterprise values, securities values, rates of return, intellectual property and intangible assets in the following courts:

Mono County, California Superior Court
San Diego County, California Superior Court
Los Angeles County, California Superior Court
District Court of San Patricio County, Texas, 156th Judicial District
Town of Wallingford, Connecticut

EDUCATION: Ms. Cartwright received a Bachelor of Science degree, Magna Cum Laude, in Finance from California State University.

PROFESSIONAL: Ms. Cartwright is an Accredited Senior Appraiser in the American Society of Appraisers, in the discipline of Business Valuations. She has been an active member of the ASA, serving for ten years on the governing board of the Los Angeles Chapter in a variety of capacities including Programs Chair, Business Valuation Chair and finally Senior Vice President from 2001 to 2002.

STEPHEN COSBY, MAI, MRICS

PROFESSIONAL QUALIFICATIONS

- PRESENT POSITION:** Mr. Cosby is a Managing Director - Valuation & Advisory Services with CBRE, Inc. in the Fayetteville, Arkansas office. Mr. Cosby has over 27 years experience providing real estate valuation and value-related consulting services with both regional and nationwide consulting firms.
- EXPERIENCE:** Mr. Cosby is a senior real estate professional in real property valuation and consulting with a thorough knowledge of complex real property valuations and regulatory guidelines. Mr. Cosby also has extensive litigation experience.
- Mr. Cosby was President of Cosby & Associates, Inc. Before that, he was a Division Manager at Pyron, Cosby & Associates. Before joining Pyron, he was a staff appraiser at Associated Appraisers, Inc.
- EDUCATION:** Mr. Cosby received a Bachelor of Science in Business Administration, Finance from the University of Arkansas.
- PROFESSIONAL:** Mr. Cosby is a Designated Member of the Appraisal Institute (MAI). He is also a Designated Member (MRICS) of the Royal Institute of Chartered Surveyors. He is a State Certified Appraiser in Arkansas, Oklahoma, Missouri, Kansas, Louisiana, and Texas.
- CONTINUING EDUCATION:** All current requirements have been completed for each of the state's certifications as well as the Appraisal Institute for the MAI designation.

BEFORE THE
ARKANSAS PUBLIC SERVICE COMMISSION

IN THE MATTER OF THE APPLICATION)
OF ENTERGY ARKANSAS, INC. FOR)
APPROVAL OF CHANGES IN RATES FOR)
RETAIL ELECTRIC SERVICE)

DOCKET NO. 13-028-U

REBUTTAL TESTIMONY

OF

COREY A. PETTETT

DIRECTOR OF RATE DESIGN AND ADMINISTRATION

ENTERGY SERVICES, INC.

ON BEHALF OF

ENTERGY ARKANSAS, INC.

AUGUST 26, 2013

1 **I. INTRODUCTION**

2 Q. PLEASE STATE YOUR NAME.

3 A. My name is Corey A. Pettett.

4

5 Q. ARE YOU THE COREY A. PETTETT WHO FILED DIRECT TESTIMONY
6 IN THIS DOCKET ON MARCH 1, 2013?

7 A. Yes, I am.

8

9 Q. ON WHOSE BEHALF ARE YOU TESTIFYING?

10 A. I am submitting this rebuttal testimony to the Arkansas Public Service
11 Commission (“APSC” or the “Commission”) on behalf of Entergy
12 Arkansas, Inc. (“EAI” or the “Company”).

13

14 Q. WHAT IS THE PURPOSE OF YOUR REBUTTAL TESTIMONY?

15 A. The purpose of my rebuttal testimony is to respond to several issues
16 raised by witnesses for the APSC General Staff (“Staff”), the Attorney
17 General (“AG”) and intervenors in their testimonies filed in this proceeding
18 on August 2, 2013. Those issues and witnesses are listed below:

- 19 • Billing determinants and resulting base rate sales revenue and
20 allocation issues raised by Staff witness Robert H. Swaim,
21 Arkansas Electric Energy Consumers, Inc. (“AEEC”) witness
22 Randall J. Falkenberg, and Hospitals and Higher Education
23 Group (“HHEG”) witness Steven A. Ward;

- 1 • Allocation factor issues raised by Staff witness Matthew S.
- 2 Klutchner, AEEC's Mr. Falkenberg, AG witness William B.
- 3 Marcus, HHEG witness Larry Blank, and Wal-Mart witness
- 4 Steve W. Chriss;
- 5 • Rate design issues raised by AG's Mr. Marcus, Wal-Mart's Mr.
- 6 Chriss, HHEG witnesses William E. Tinsley, Blank, and Ward;
- 7 Staff's Mr. Swaim, and AEEC's Mr. Falkenberg; and
- 8 • Interruptible rate issues raised by AEEC's Mr. Falkenberg and
- 9 by HHEG witnesses Ward, Blank and Charles Mathis.

1 **II. DEVELOPMENT OF BILLING DETERMINANTS**

2 **A. Comments Regarding Pro forma to Billing Determinants**

3 Q. AEEC CLAIMS THE COMPANY PROVIDED NO DOCUMENTATION
4 SUPPORTING ADJUSTMENTS TO LARGE USAGE ACCOUNTS.¹
5 PLEASE COMMENT.

6 A. EAI documented the information it used to adjust billing determinants for
7 known changes in operations for its large customers. That documentation
8 was provided to AEEC and all other parties in response to AEEC 5-17 and
9 AEEC 7-4. These responses are included as highly sensitive EAI Exhibit
10 CAP-2 to my testimony.

11
12 Q. PLEASE ADDRESS HHEG'S RECOMMENDATION THAT THE
13 COMMISSION REQUIRE EAI TO MODIFY BILLING DETERMINANTS
14 TO REFLECT ADDITIONAL CONSUMPTION RESULTING FROM THE
15 EXPANSION OF THE COMPANY'S VEGETATION MANAGEMENT
16 PROGRAM.

17 A. Mr. Ward provided no explanation of how such an adjustment could even
18 be calculated or any support for the reasonableness of his
19 recommendation. For example, it is unclear what factors could be
20 assumed as relevant to make any projections about how an expanded
21 vegetation program would result in additional energy consumption. The

¹ Falkenberg Direct Testimony at 26.

1 Commission should reject this recommendation because it is speculative
2 and would not be a known and measurable adjustment.
3

4 **B. General Response to Staff Billing Determinant Methodology**

5 Q. WHAT IS THE SIGNIFICANCE OF SETTING BILLING DETERMINANTS
6 AS PART OF THE PROCESS OF DETERMINING A UTILITY'S
7 REVENUE REQUIREMENT IN A BASE RATE CASE?

8 A. Billing determinants are the foundation of the revenue calculations. They
9 are the quantities used to calculate rate schedule base rate revenue and
10 are also used to develop the energy and demand portion of the allocation
11 factors.

12 To the extent billing determinants are not properly determined then
13 the resulting present base rate revenue that is an input to a rate class
14 deficiency or sufficiency, along with allocation factors that are used to
15 allocate costs to rate classes, will also not be properly determined. In
16 short, inaccurate billing determinants can cause the Company's revenues
17 to be over- or understated.

18

19 Q. HOW DID EAI DETERMINE THE BILLING DETERMINANTS IT USED IN
20 PREPARING THIS CASE?

21 A. The billing determinants in the test year include the historical period of
22 January through June 2012 and the projected period of July through
23 December 2012. A test year mix of six months historical billing

1 determinants followed by six months of projected billing determinants is
2 consistent with Arkansas law.²

3 The development of billing determinants for the projected period is
4 based upon information from the corresponding months of 2011. This was
5 necessary because the only data available for the projected period were at
6 the revenue class level (residential, commercial, industrial etc.). Detailed
7 rate schedule information was not available, so I used the revenue class
8 to rate schedule relationships from 2011 to develop rate schedule billing
9 determinants for the projected period of 2012.

10 For July through September 2012, actual revenue class kWh were
11 weather adjusted because these data were available. Actual data were
12 not available for October through December 2012 so the Company's kWh
13 forecast, by revenue class, was used. The July through December 2012
14 kWh usage by revenue class were proportioned to the various Company
15 rate schedules based upon historical relationships from the corresponding
16 months of July through December 2011 to create billing determinants.

17 The test year billing determinants are based on six months of
18 historical information, three months of historical kWh usage at the revenue
19 class level and three months of forecasted kWh usage at the revenue
20 class level. The development of the billing determinants included pro
21 forma adjustments to annualize the number of customers, to adjust to

² Ark. Code Ann. § 23-4-406.

1 normal weather for January through September and to adjust for
2 reasonably known and measurable changes for certain individual large
3 usage customers as described in my direct testimony.

4

5 Q. YOU STATED THAT JULY THROUGH DECEMBER 2011 DATA WAS
6 USED TO CREATE THE PROJECTED PERIOD OF THE TEST YEAR
7 AND JANUARY THROUGH JUNE 2012 DATA WAS USED TO
8 DEVELOP THE HISTORIC PORTION OF THE TEST YEAR. WHAT
9 WAS THE SOURCE OF DATA USED TO DEVELOP THE BILLING
10 DETERMINANTS FOR JULY 2011 THROUGH JUNE 2012?

11 A. The Company analyzed over 120,000,000 individual customer billing
12 records. These records were then summarized to obtain billing
13 determinants for each billing component of each rate schedule, including
14 the effects of various minimum usage requirements in those rate
15 schedules.

16

17 Q. HAS THE COMPANY UPDATED ITS BILLING DETERMINANTS
18 DURING THE COURSE OF THIS CASE?

19 A. Yes. In May 2013, EAI updated the billing determinants and rate class
20 revenue requirements and revenues based on more current data. The
21 revenues were based on actual data through December 31, 2012. The
22 updated filing was provided to parties in an updated data request

1 response.³ This update, which I will refer to as the “Updated Test Year”, is
2 based on actual data through the end of December 2012 and which
3 replaced the projections that were used in the Company’s original filing. I
4 adjusted the actual sales for 2012, as I did previously for the first six
5 months of the initial filing, to annualize the number of customers, to adjust
6 to normal weather, and to adjust for reasonably known and measurable
7 changes for certain individual large usage customers.

8

9 Q. WAS THERE A SIGNIFICANT DIFFERENCE IN THE UPDATED TEST
10 YEAR COMPARED TO THE ORIGINAL?

11 A. Yes. Actual sales were significantly less than those EAI forecasted for the
12 last three months of 2012.

13

14 Q. PLEASE DESCRIBE STAFF’S METHODOLOGY TO DEVELOP THE
15 BILLING DETERMINANTS IT USED AS PART OF STAFF’S COST-OF-
16 SERVICE STUDY.

17 A. At a high level, Staff’s methodology estimates billing determinants and
18 resulting revenues for the calendar year 2013 using historical
19 compounded annual growth rates applied to usage per customer and
20 number of customers in 2012.

21 At a more detailed level, consider the method for the Residential
22 rate class. The Residential rate class billing determinants are sensitive to
23 weather as are the resulting revenues and allocation factors used in a

³ Addendum 5 to APSC 1-18.

1 cost-of-service study. The test year billing determinants must reflect
2 normal weather conditions. In an attempt to accomplish this, Staff's
3 method took the average usage from the months of May and November in
4 2012 and defined that average usage as the 2012 base usage where base
5 usage in theory has no weather related usage. Staff then increased the
6 2012 based usage by the historical five-year compounded growth rate to
7 set the 2013 base usage. Staff then identified two factors using actual
8 2012 monthly data: 1) energy usage (kWh) per cooling degree day; and
9 2) energy usage (kWh) per heating degree day.⁴ I will refer to these
10 factors as usage per degree day. Then for each month of 2013, Staff took
11 base usage, added the number of cooling degree days times the usage
12 per cooling degree day, added the number of heating degree days times
13 the usage per heating degree day and then multiplied that result times an
14 estimated number of customers in each month. Or as shown in a formula:

$$\begin{aligned} \text{Monthly kWh} = & \text{number of customers} \times (\text{base usage} + \\ & (\text{heating degree days} \times \text{usage per heating degree day}) + \\ & (\text{cooling degree days} \times \text{usage per cooling degree day})) \end{aligned}$$

⁴ Cooling degree days are the number of degrees that a day's average temperature is above 65 degrees Fahrenheit. Heating degree days are the number of degrees that a day's average temperature is below 65 degrees Fahrenheit.

1 Q. HOW DO THE RESULTING BASE RATE REVENUES OF THE STAFF
2 FORECASTING METHODOLOGY COMPARE TO THE BASE RATE
3 REVENUES PRODUCED BY EAI?

4 A. A comparison of the results is shown in Table 1. The Company's Updated
5 Test Year produced base rate revenues of \$988,501,648 compared to
6 \$1,003,322,628 produced by Staff's methodology. While Staff's
7 methodology produced similar results to the base rate revenues in the
8 Company's original filing, the Updated Test Year values are the
9 appropriate ones for comparison because they represent the most recent
10 values based on actual billing data.

11
12 **Table 1**
13 **Base Rate Revenues Comparison**
14

	Initial Filing	Updated Filing	Staff
Revenues	\$1,003,387,493	\$988,501,648	\$1,003,222,628

15
16 Q. DOES STAFF'S APPROACH RELY ON INFORMATION THAT IS
17 REASONABLY KNOWN AND MEASURABLE?

18 A. No. The Staff's methodology forecasts customer growth and growth in the
19 average base usage per customer past the end of the 2012 test year to
20 December 31, 2013. Both of these adjustments are based upon
21 forecasts, and forecasts do not meet the known and measurable test.

1 Q. WHAT IS THE KNOWN AND MEASURABLE TEST?

2 A. Arkansas law sets this standard for any adjustments to test year data:

3

4 However, the commission shall also permit adjustments to
5 any test year so utilized to reflect the effects on an
6 annualized basis of any and all changes in circumstances
7 which may occur within twelve (12) months after the end of
8 the test year where such changes are both reasonably
9 known and measurable.⁵

10

11 Q. WHY DO YOU SAY THAT THE STAFF ADJUSTMENTS TO THE
12 COMPANY'S DATA DO NOT MEET THIS REASONABLY KNOWN AND
13 MEASURABLE TEST?

14 A. The Staff's billing determinants and resulting base rate revenues should
15 not be used because they are based upon a forecast that utilizes
16 assumptions that are not reasonably known and measurable. This
17 forecast utilizes historical data and applies a growth rate. The growth
18 rates are not reasonably known and measurable. Staff's adjustment is not
19 based on anything that could reasonably be expected, much less known,
20 to occur in the 2013 pro forma year and is likewise not based on expected
21 consequences that are reasonably measurable.

22

23 Q. WHAT DO YOU CONCLUDE ABOUT THE APPROPRIATE BILLING
24 DETERMINANTS AND DERIVATION OF BASE RATE REVENUES FOR
25 USE IN SETTING THE COMPANY'S RATES IN THIS CASE?

⁵ Ark. Code Ann. § 23-4-406.

1 A. The Company's Updated Test Year billing determinants and base rate
2 sales revenue are based on actual data through December 31, 2012 and
3 adjusted to normal weather, annualized number of customers and usage
4 to end of test year and pro formed certain individual large usage
5 customers. All these adjustments to the test year represent reasonably
6 known and measurable information suitable for use in a base rate
7 proceeding. The Company's billing determinants are therefore a
8 reasonable basis upon which to develop the Company's base rate
9 revenues in this case. In contrast, the Staff's methodology is based upon
10 forecasts that utilize data that do not meet the reasonably known and
11 measureable test and are therefore not appropriate for ratemaking.

12 If the Commission were to determine that using forecasts, based on
13 2012 calendar year data, through the end of the 2013 is a reasonable
14 methodology, two adjustments to Staff's methodology would be
15 imperative. First, Staff's forecasting methodology should be modified to
16 reflect updated and more accurate data and to correct certain flaws in the
17 methodology that I will describe later in this section of my testimony.

18 Second, allocation factors always should be developed based on
19 the same set of billing determinants used to develop revenues. Therefore,
20 if the amount of energy (kWh) and demand (kW) used to calculate
21 revenues increases, then so should the energy and demands used to
22 allocate costs, and vice versa.

1 Q. ARE THERE OTHER IMPLICATIONS FROM ADOPTING A METHOD TO
2 IDENTIFY BILLING DETERMINANTS THAT USES A FORECAST TO
3 DERIVE VALUES THROUGH THE END OF THE 2013 PRO FORMA
4 PERIOD?

5 A. Yes. If the Commission were to accept a methodology that projects
6 revenues for 2013 based upon data from 2012, then all other inputs to the
7 Company's cost-of-service study also should be projected through the end
8 of 2013. This latter adjustment would align the period of time for both
9 revenues and revenue requirement under the regulatory matching
10 principle. EAI's revenue requirement in its cost-of-service study is based
11 on actual rate base and expenses adjusted only for reasonably known and
12 measurable events in 2013. EAI witness Gregory R. Zakrzewski
13 describes in his rebuttal testimony the complimentary changes to revenue
14 requirement if revenues are projected through the end of 2013 so that the
15 matching principle is met.

16

17 C. **Modifications to Staff Methodology Required to Make Results**
18 **Reasonable**

19 Q. ARE THERE ADJUSTMENTS THAT WOULD MAKE THE RESULTS
20 USING STAFF'S METHODOLOGY REASONABLE?

21 A. While I believe that using projections of 2012 data is not appropriate and
22 renders the result questionable under the reasonably known and
23 measurable test, there are five adjustments to Staff's methodology that

1 otherwise may correct certain flaws in the data used in the methodology in
2 order to produce results closer to what should be considered reasonable:

- 3 1. Modify residential base usage and weather effects assumptions;
- 4 2. Remove residential Time-Of-Use ("TOU") double counting of
5 energy;
- 6 3. Update the pro forma adjustment to the Large General Service
7 ("LGS") rate class;
- 8 4. Update agricultural pumping number of customers; and
- 9 5. Remove standby service double counting of kWh and revenues.

10 I explain each of these in the remainder of my testimony in this section.
11

12 **1. Modify residential base usage and weather effects assumptions**

13 Q. WHY DOES STAFF'S METHOD FOR DETERMINING BASE USAGE
14 FOR RATE CLASSES THAT ARE WEATHER SENSITIVE NEED
15 MODIFICATION?

16 A. The Staff methodology depends upon a forecast of base usage per
17 customer for the Residential rate class and the commercial portion of the
18 Small General Service ("SGS") rate class. Staff defines base usage as
19 the average per customer usage in what Staff assumes are the months
20 with the least weather influence or the lowest usage months of each year
21 for these rate classes -- May and November for the Residential and SGS --
22 commercial rate classes and April for General Farm Service.
23

1 Q. DOES STAFF'S USE OF THESE LOW USAGE MONTHS REASONABLY
2 ADDRESS THE IMPACT OF WEATHER ON CUSTOMER USAGE IN
3 THESE RATE CLASSES?

4 A. No. The months used by Staff with the lowest use per customer in the
5 year nevertheless still include air conditioning and / or heating usage
6 based on the fact they have cooling and / or heating degree days as
7 reported by the weather service, as demonstrated in Figure 1 below.
8 Base usage that was truly stripped of weather impact would not include
9 cooling and / or heating degree days. Yet, Staff's methodology fails to
10 account for this remaining weather impact.

11

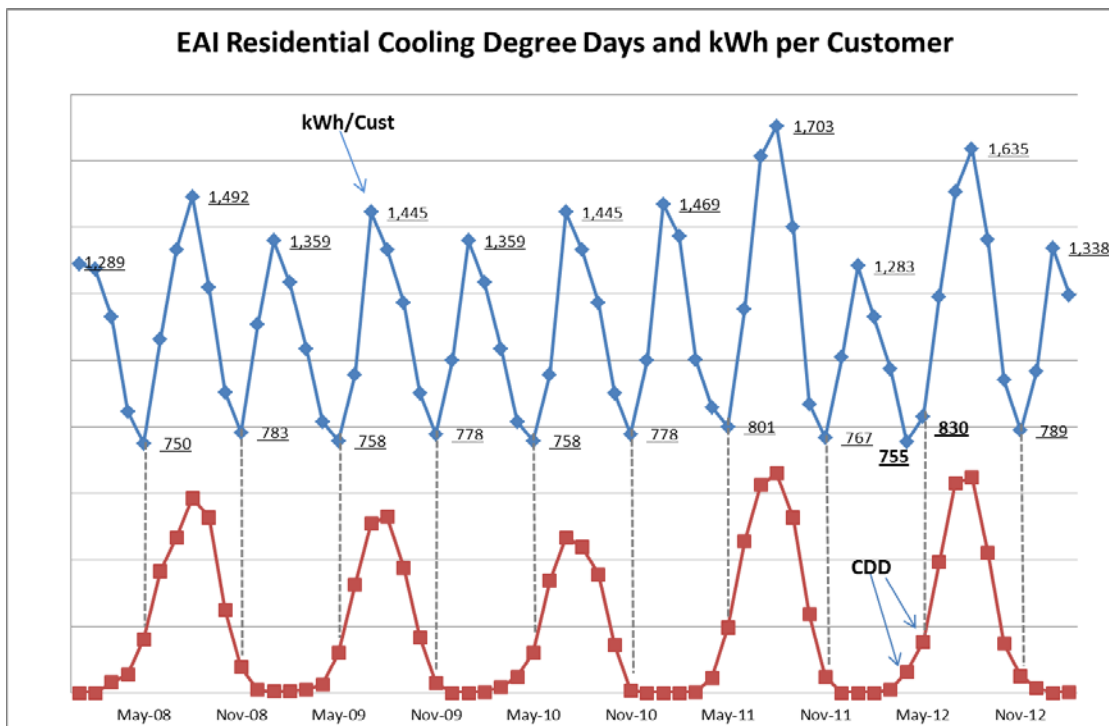
12 Q. HOW DO THE COOLING AND HEATING DEGREE DAY DATA
13 INDICATE THAT STAFF'S BASE USAGE ASSUMPTIONS HAVE NOT
14 PROPERLY ADJUSTED FOR THE WEATHER IMPACT ON USAGE?

15 A. Base usage should be usage that is not sensitive to weather. Thus, a
16 month of base usage should not include any degree days. However, in
17 most years used in Staff's methodology, there are cooling degree days in
18 the months used to determine base usage. For example, Staff's analysis
19 of residential usage shows year-to-year variation in base usage because
20 there are cooling degree days present in those months. In particular, the
21 base usage for 2012 for residential customers in Staff's analysis is 810
22 kWh (average of 830 for May 2012 and 789 for November 2012). This is
23 higher than the average base usage in the prior four years. Staff selected

1 830 kWh base usage per customer from the month of May 2012. May
2 contained more cooling degree days than is ideal, and certainly more than
3 other years, to determine base usage. Staff made this selection even
4 though April 2012 base usage was 755 kWh per customer and contained
5 fewer cooling degree days. The presence of these cooling degree days in
6 Staff's assumption demonstrates that 830 cannot reasonably be
7 considered to be base usage. Had Staff's methodology used the more
8 appropriate 755 kWh from the month of April instead of the 830 kWh from
9 the month of May, then the average base usage for 2012 would have
10 been 772 kWh instead of 810 kWh per customer.

11 Figure 1 shows how high the residential usage per customer is for
12 May 2012 relative to the month of May for the prior years. This figure also
13 shows there are, in fact, cooling degree days ("CDD") in the months of
14 May and November, Staff's base usage months. Specifically in May of
15 2012 look at the base usage of 830 and follow the dotted line down to the
16 next line, which represents the number of cooling degree days in May.
17 The level of cooling degree days in May 2012 corresponding to the 830 is
18 higher than the number of cooling degree days in most other months that
19 determine base usage (follow the dotted lines straight down from May or
20 November of other years). The number of cooling degree days in April
21 2012 that correspond to base usage of 755 is also lower than the cooling
22 degree days for May and would be a more suitable base usage level for
23 spring 2012.

Figure 1
EAI Residential Cooling Degree Days and kWh per Customer



Q. WHAT IS THE SIGNIFICANCE OF A BASE USAGE ASSUMPTION THAT IS TOO HIGH?

A. The selection of an appropriate base usage is critical because base usage has a significant impact on the calculation of billing determinants and base rate revenue. The 2012 base usage forecast used in Staff's methodology significantly impacts Staff's calculation of billing determinants and base rate revenue because it is used to compute the compound annual growth rate used to calculate the 2013 base usage. In short, Staff's high base usage forecast overstates residential base rate revenue in the 2012 test year. For example, Staff's residential compound annual growth rate for

1 residential base usage is 1.39 percent. By substituting the usage per
2 customer for the month of April 2012 (a more fair assumption with fewer
3 cooling degree days) instead of May 2012 (Staff's assumption), the
4 compound annual growth rate changes to 0.18 percent.

5

6 Q. IS THERE ANOTHER WAY TO TEST THE REASONABLENESS OF
7 STAFF'S BASE USAGE AND THE COMPOUNDED ANNUAL GROWTH
8 RATE APPLIED TO 2012 BASE REVENUE?

9 A. Yes. A comparison of the actual historical compound growth rate to the
10 rate used in Staff's methodology to determine that rate is a good check on
11 its reasonableness. The Staff methodology used five years of base usage
12 to calculate a compounded growth rate of 1.39 percent. In reality,
13 however, the usage per customer for the residential revenue class has
14 been relatively flat for 2008 to 2012 as shown in Table 2, with an actual
15 annual compounded growth rate from 2008 to 2012 of only 0.27 percent.⁶
16 Put another way, Table 2 demonstrates that residential customers on
17 average have consumed far less energy than predicted using Staff's
18 methodology.

⁶ Source: Company records as reported for residential revenue class

Table 2
EAI Residential Annual Usage Per Customer 2008-2012

	MWh Usage Per
Year	Residential Customer
2008	12.35
2009	12.34
2010	12.44
2011	12.53
2012	12.48
Compounded	0.27%
Growth Rate	

Q. WHAT DOES THIS COMPARISON OF THE STAFF'S COMPOUNDED ANNUAL GROWTH RATE OF RESIDENTIAL USAGE TO THE ACTUAL GROWTH RATE INDICATE?

A. The Staff's compounded annual growth rate is overstated, assumes customers are using more energy than is reasonable compared to reality, and thus, overstates the Company's revenue. Company witness David Pickles has independently reviewed Staff's base usage calculation and compound growth rate. Mr. Pickles concludes in his rebuttal testimony that Staff's base usage estimates are unreasonably high and the compounded growth rate is inconsistent with the results of the Company's energy efficiency efforts to date and expected results going forward that are directed at meeting utility energy efficiency targets set by the APSC. Additionally, Mr. Pickles explains that Staff's forecasted results are inconsistent with federal standards that require customers use increasingly efficient equipment and appliances and recent regional and

1 national projections that indicate declining per capita electricity
2 consumption across all sectors.

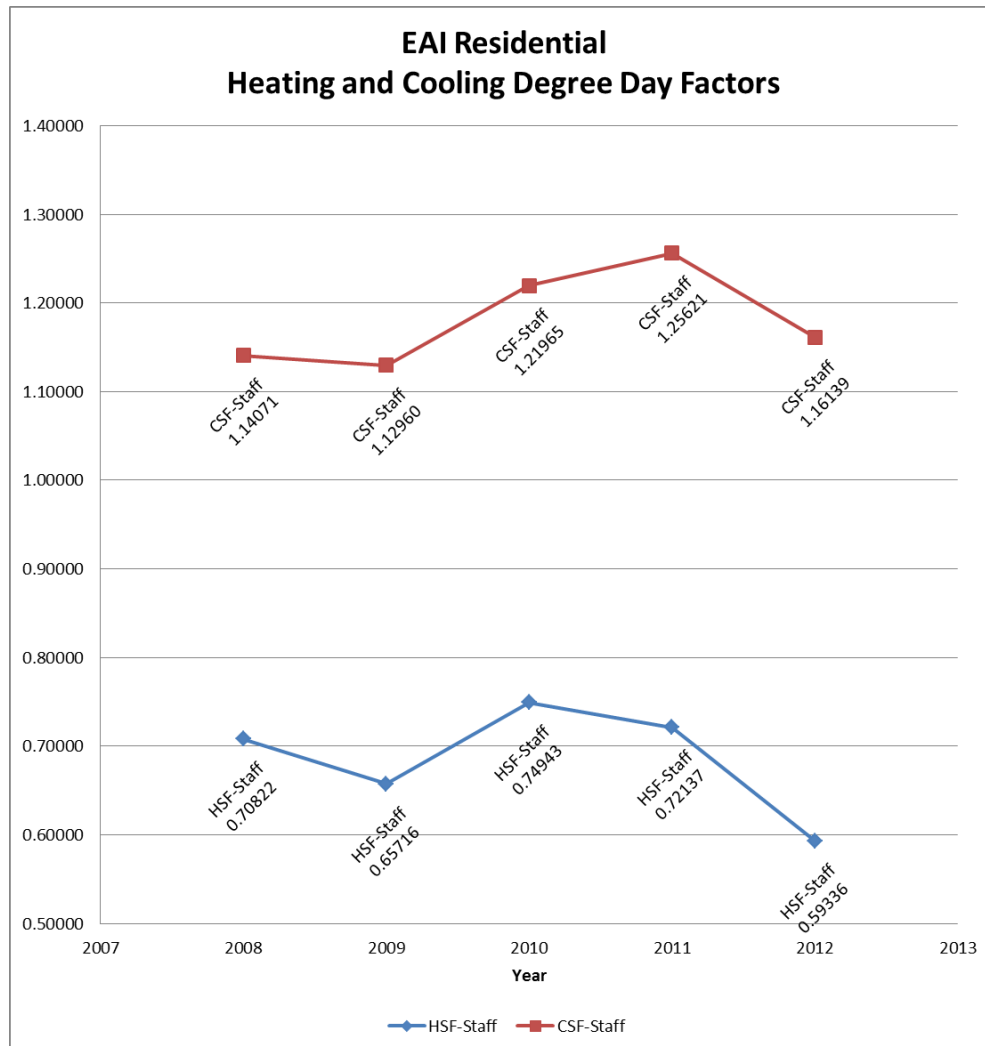
3
4 Q. WHAT OTHER REVISION TO STAFF'S RESIDENTIAL METHODOLOGY
5 SHOULD BE MADE?

6 A. After identifying the base usage for a rate class, Staff determines the
7 usage per degree day, which consists of two factors that use actual 2012
8 monthly data: 1) energy (kWh) usage per cooling degree day; and 2)
9 energy (kWh) usage per heating degree day. Staff's usage per degree
10 day factors are questionable.

11
12 Q. DOES THE QUESTIONABLE RESULT FOR BASE USAGE AFFECT
13 STAFF'S DETERMINATION OF KWH USAGE PER HEATING AND
14 COOLING DEGREE DAY?

15 A. Yes. Staff's questionable base usage assumption affects the usage per
16 heating and cooling degree day because the usage per degree day is the
17 total kWh per customer, less base usage, divided by degree days.
18 Therefore, if the base usage assumption is unreasonable and in need of
19 modification, then the resulting usage per degree days would also need to
20 be adjusted. Figure 2 below shows how the 2012 residential usage per
21 degree day used in Staff's methodology compares to previous years.

Figure 2
EAI Residential Heating and Cooling Degree Day Factors



Q. WHAT DO YOU CONCLUDE FROM THIS?

A. The 2012 kWh usage per heating and cooling degree day factors used in Staff's analysis are unreasonably low. For example, in 2012 the Staff's residential base usage was 810 kWh (which is the average of 830 kWh in May 2012 and 789 kWh in November 2012, as shown in Figure 1) and the

1 resulting usage per degree day of 1.16139 for cooling and 0.59336 for
2 heating are low. The Staff methodology uses only the one year point
3 estimate for determining kWh usage per degree day. Again, just as Staff's
4 selection of 830 kWh per customer from the month of May 2012 resulted
5 in overstating base usage, that selection of May 2012 base usage results
6 in a kWh per degree day factor that is too low.

7

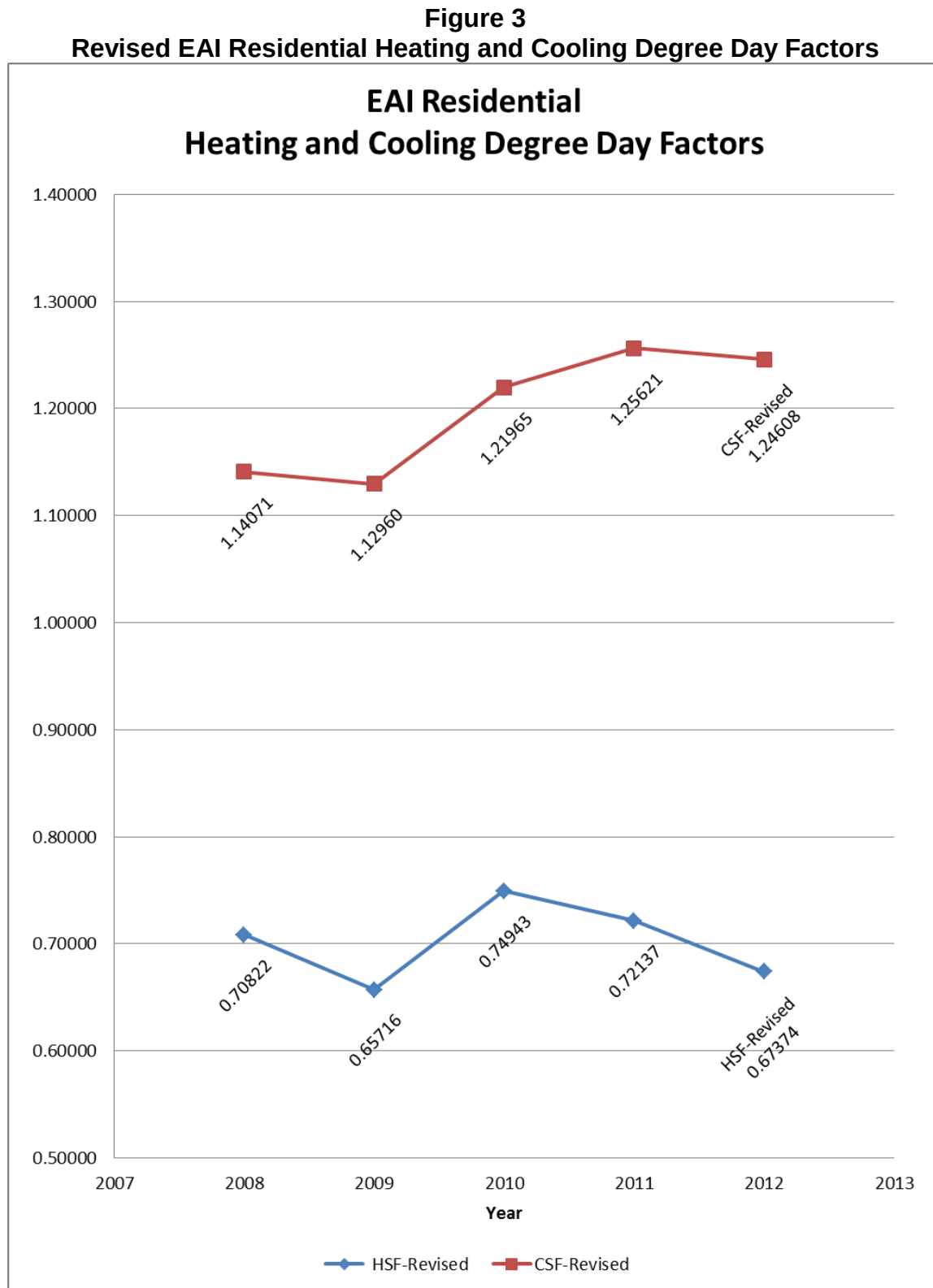
8 Q. IF YOU WERE TO USE A REASONABLE FIGURE FOR BASE USAGE,
9 WHAT WOULD BE THE USAGE PER DEGREE DAY?

10 A. If residential base usage was adjusted to 772 kWh (755 kWh from April
11 2012 plus 789 kWh from November 2012 divided by 2 to get an average,
12 as shown in Figure 1 above), then Figure 3 shows revised usage per
13 degree estimates to be used in 2012. The 2012 results in Figure 3 are
14 more reasonable because once the base usage estimate is modified to be
15 more accurate then so too are the kWh per cooling and degree day factors
16 in the chart below.

17

1

2



3

4

1 Q. HAVE YOU REVISED STAFF'S RESIDENTIAL INPUT ASSUMPTIONS
2 USING STAFF'S METHODOLOGY?

3 A. Yes. I have revised the Staff residential assumptions for 1) Base usage;
4 2) Base usage compound growth and resulting 2013 base usage; and 3)
5 Usage per degree day. The original and revised input assumptions are
6 shown for the Residential rate class in Table 3.
7

8 **Table 3**
9 **Residential Input Assumptions**
10

	Staff Assumption	Revised Assumption
Base Usage 2012 (kWh)	810	772
Base Usage 2013 (kWh)	821	773
kWh / CDD	1.16139	1.24608
kWh / HDD	0.59336	0.67374

11

12 **2. Remove residential TOU double counting of energy**

13 Q. HOW DID STAFF'S METHODOLOGY TREAT THE DEVELOPMENT OF
14 BILLING DETERMINANTS FOR RESIDENTIAL TOU ("RT") AND
15 RESIDENTIAL ENERGY MANAGEMENT TOU ("RMT")?

16 A. The RT and RMT rate schedules are included in the Staff's projection of
17 total Residential customers and the projection of total Residential use per
18 kWh for each month. To make these projections, the product of
19 customers and use per kWh is calculated each month and then summed
20 to produce the annual energy (kWh) for the Residential rate class.

1

2 Q. WAS THE ENERGY CONSUMPTION FOR THE RT AND RMT RATE
3 SCHEDULES REMOVED FROM THE TOTAL RESIDENTIAL ENERGY
4 FORECAST TO CALCULATE RT AND RMT BASE REVENUE?

5 A. No, but it should have been. The RT and RMT energy consumption was
6 not removed from the total Residential energy forecast that was then used
7 by Staff to determine the General Purpose Residential or Non-TOU base
8 revenue. However, the RT and RMT base revenues were also then
9 calculated separately by Staff using historical billing determinants. Thus
10 the RT and RMT energy was improperly used to calculated base revenue
11 in two places in Staff's base revenue calculation spreadsheet.

12

13 Q. WERE THE RT AND RMT REVENUES THEN DOUBLE COUNTED?

14 A. Yes, but Staff has subsequently relieved this concern.

15

16 **3. Update the pro forma adjustment to the LGS rate class**

17 Q. WHAT RECOMMENDATION DO YOU HAVE REGARDING THE LGS
18 RATE CLASS BILLING DETERMINANTS?

19 A. The information used in Staff's forecast should be updated to reflect the
20 most current data available, which represent the most reasonably known
21 and measurable data. The Updated Test Year was pro formed by the
22 Company for reasonably known and measurable changes. One of the
23 reasonably known and measurable changes was the individual large

1 usage customer pro forma to account for known plant expansions and
2 closures. In the Updated Test Year, the Company pro formed a 1.88
3 percent increase to the General Service TOU ("GST") and Large Power
4 Service TOU ("PST") rate schedule energy (kWh) and pro formed a -0.4
5 percent decrease to the LGS and Large Power Service ("LPS") rate
6 schedule energy (kWh). In contrast, Staff's methodology pro formed a
7 4.18 percent increase to energy (kWh) for GST and PST rate schedules
8 rate and pro formed a -0.8 percent decrease for LGS and LPS rate
9 schedule energy (kWh). This results, again, in overstated revenues for
10 EAI.

11 The reason for the difference between the Company pro forma for
12 LGS, LPS, GST and PST rate schedule customers and the Staff's pro
13 forma is because the Staff methodology used the pro forma adjustment
14 from the Company's initial rate filing based on six months actual and six
15 months projected data in the test year. It would have been more
16 appropriate for the Staff methodology to incorporate the pro forma
17 adjustments from the Updated Test Year of 1.88 percent increase to GST
18 and PST energy (kWh) and -0.4 percent decrease to the LGS and LPS
19 energy (kWh) into Staff's methodology to ensure that methodology
20 reflected the most recent and accurate data.

1

2 **4. Update agricultural pumping number of customers**

3 Q. DO YOU HAVE COMMENTS ABOUT THE AGRICULTURAL PUMPING
4 DATA THE STAFF METHODOLOGY USED TO DEVELOP BILLING
5 DETERMINANTS?

6 A. Yes. It appears that the number of 2013 agricultural pumping customers
7 the Staff assumed in its methodology was based on the number of
8 customers taking service under this tariff in 2012 and in January and
9 February of 2013. Staff's assumptions overstate the number of customers
10 because the actual number of both seasonal and monthly agricultural
11 pumping customers as of June 2013 is much less than that assumed in
12 Staff's methodology. Staff's methodology should be modified to reflect the
13 actual number of customers through June 2013 because the higher than
14 reasonable number of customers assumed in Staff's methodology
15 significantly impacts the resulting energy usage. In short, by assuming a
16 higher number of customers, Staff's methodology in turn overstates the
17 expected energy usage; and as discussed previously, an overstated
18 usage assumption in turn causes EAI's revenues to be overstated. Figure
19 4 and Figure 5 show the number of agricultural pumping customers used
20 in Staff's methodology compared to the actual number.
21

Figure 4
 Number of Agricultural Pumping Customers – Seasonal

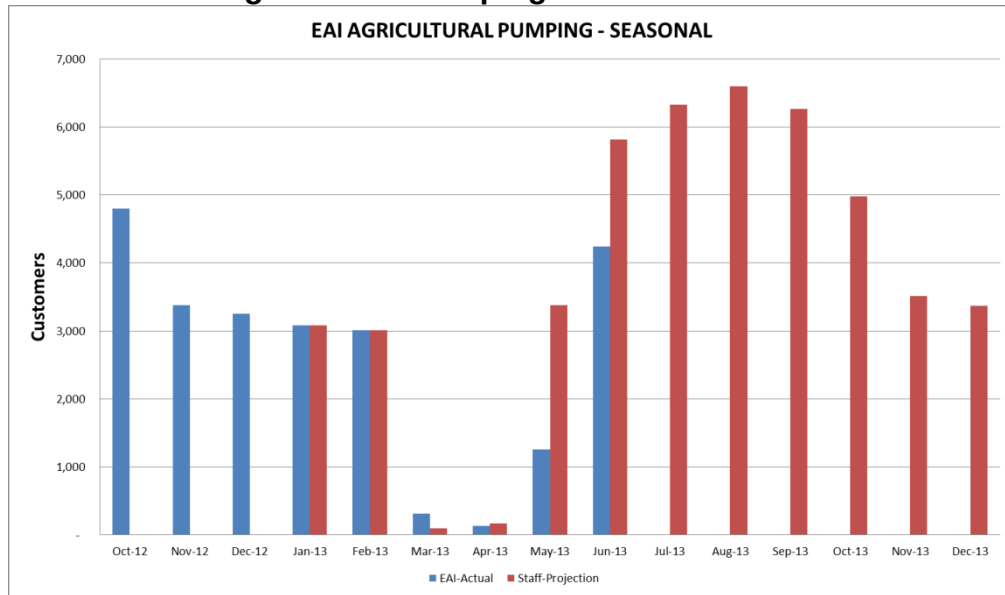
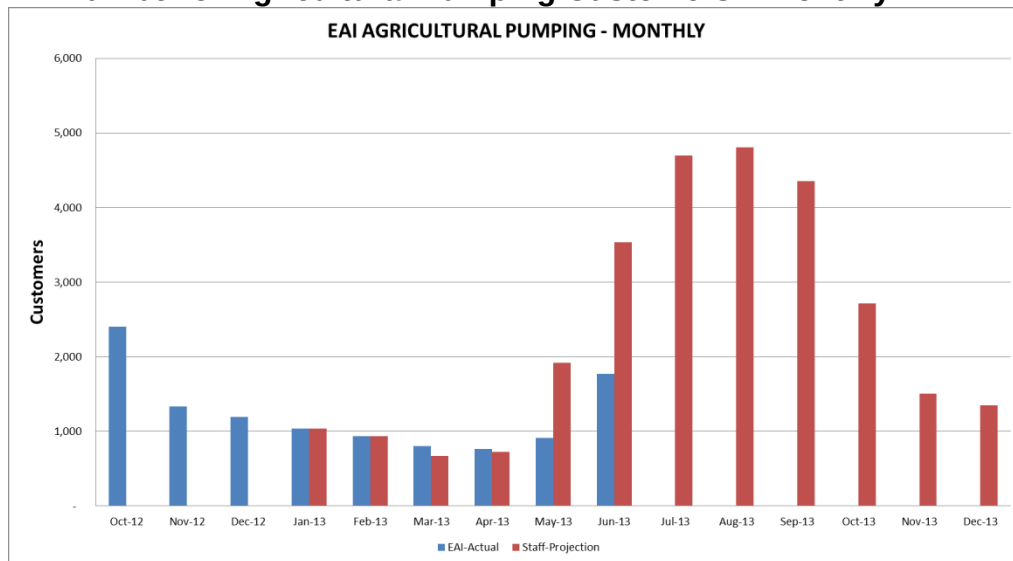


Figure 5
 Number of Agricultural Pumping Customers – Monthly



1

2 **5. Remove standby service double counting of kwh and revenues**

3 Q. HOW DID STAFF'S METHODOLOGY TREAT STANDBY SERVICE IN
4 THE DEVELOPMENT OF BILLING DETERMINANTS?

5 A. Staff's methodology included standby service energy in the SGS and the
6 LGS rate classes. Then, the methodology applied the SGS or LGS rate
7 schedule charges to that usage.

8

9 Q. WHAT IS THE EFFECT OF THIS APPROACH?

10 A. Applying the rate schedule charges distorts the revenues for each rate
11 class because the billing determinants and resulting revenues for standby
12 service are not part of either the SGS or the LGS rate class. However, in
13 Staff's cost-of-service study, standby service revenue is used to offset the
14 revenue requirement, and the billing determinants are not included in the
15 development of the allocation factors for either rate class. The end result
16 is a double counting of the standby service revenues -- once in the SGS
17 and LGS rate classes and then again as an offset to the revenue
18 requirement in the Staff cost-of-service study. In other words, including
19 the revenues cancels the offset. The double counting of the standby
20 service revenues causes the Company's overall revenues to be
21 overstated.

22

1 **6. Other Comments Regarding Staff's Calculation**

2 Q. DO YOU HAVE OTHER COMMENTS ABOUT THE DATA THE STAFF
3 USED IN DEVELOPMENT OF BILLING DETERMINANTS?

4 A. Yes. The data Staff relied upon as the basis for its adjustments are
5 multiple years of the Company's per book customer counts and customer
6 energy (kWh) usage. Per book information includes billing determinants
7 that are recorded on the Company's books. However, out of period
8 adjustments recorded in a particular month reflect adjustments not to that
9 month, but to prior month(s). For example, adjustments to energy usage
10 in March and April may be made in July and would be reflected in July per
11 book data. These energy adjustments should be reflected in March and
12 April when the usage actually occurred, which is what the Company has
13 done.

14 Therefore, while per book information is appropriate for reporting
15 purposes, it should not be used for revenue calculations in the context of a
16 rate case, as Staff has done, because the information may skew the
17 results for a particular month. Out-of-period adjustments can cause
18 significant month-to-month variations in billing determinants and can be
19 particularly detrimental to forecasting techniques. Additionally, per book
20 information does not take into account reasonably known and measurable
21 future changes for individual customers, such as industrial plant
22 expansions or closures, that are developed for a fully pro formed rate case
23 test year.

D. Comparison of Results

Q. HAVE YOU CALCULATED REVISED REVENUES FOR EACH RATE CLASS WITH THE CHANGES DISCUSSED IN YOUR TESTIMONY

A. Yes. Table 4 summarizes the level of base rate revenues that would result using the updated assumptions I have explained but still putting them through Staff's methodology. These changes include:

- Residential assumptions as shown in Table 3;
- Residential TOU double counting of kWh;
- Pro forma adjustment to LGS rate class;
- Update Agricultural pumping number of customers; and
- Standby service double counting of kWh and revenues.

**Table 4
 Revised Base Rate Revenues**

	Revenues		
Rate Class	Staff	Revised	Difference
Residential	\$474,235,018	\$467,346,301	\$6,888,717
Small General Service	\$249,078,548	\$245,425,449	\$3,653,099
Large General Service	\$258,058,268	\$253,708,139	\$4,350,129
Lighting	\$21,850,794	\$21,850,794	\$0
Total	\$1,003,222,628	\$988,330,683	\$14,891,945

1 Q. WHAT DO YOU RECOMMEND TO THE COMMISSION REGARDING
2 BILLING DETERMINANTS?

3 A. The Commission should adopt the billing determinants presented by the
4 Company in the Updated Test Year. The source of the billing
5 determinants is the Company's billing system that have been pro formed
6 for reasonably known and measurable changes which conforms to the
7 standard required for information used in a rate case.

8 If the Commission were to determine that Staff's method, which
9 again does not include reasonably known and measurable data, should be
10 used, then the adjustments to the input assumptions described above
11 should be adopted with the resulting revenues as shown in Table 4.

12 If the Commission were to determine that Staff's method should be
13 used, then the Company should also be allowed to adjust its cost-of-
14 service study with projections through the end of 2013 so that the
15 revenues and revenue requirement used to set the Company's rates will
16 be on a consistent basis.

17 Finally, allocation factors should be developed consistent with the
18 billing determinants used to develop revenues.

19

1 **III. ALLOCATION METHODOLOGIES**

2 **A. Production Demand Allocation**

3 Q. WHAT COMMENTS WERE MADE REGARDING THE COMPANY'S
4 PROPOSED USE OF AVERAGE (OR ENERGY) AND PEAK
5 PRODUCTION DEMAND ALLOCATION?

6 A. Staff witness Klutcher supported the use of the Energy and Peak in his
7 direct testimony, and AG witness Marcus concluded the Average and
8 Peak method is generally reasonable.⁷ AEEC witness Falkenberg and
9 HHEG witness Blank recommend the 12 coincident peak methodology in
10 their direct testimony.⁸ Wal-Mart witness Chriss recommended the
11 Commission consider whether the proposed production demand allocator
12 is appropriate without recommending a specific method.⁹

13
14 Q. HOW DO YOU RESPOND TO THESE COMMENTS REGARDING THE
15 ENERGY AND PEAK METHOD FOR ALLOCATION OF PRODUCTION
16 COSTS?

17 A. The issue of production demand allocation has been thoroughly debated
18 in past rate cases. Each party generally can be expected to advocate an
19 interest in the allocation of costs that aligns with its client's direct interests.
20 For example, the AEEC and HEEG witnesses both express a preference

⁷ Klutcher Direct Testimony at 6; Marcus Direct Testimony at 81.

⁸ Falkenberg Direct Testimony at 11; Blank Direct Testimony at 25.

⁹ Chriss Direct Testimony at 12.

1 for methods that rely more on the four summer months, such as the
2 Average and Excess 4 Coincident Peak ("A&E4CP"), because those
3 methods would most likely shift costs away from higher load factor
4 customers, such as industrial customers, and onto the residential rate
5 class as compared to the Energy and Peak. The AG witness Marcus
6 states, "If any change were to be made for EAI, I believe that a greater
7 energy-related allocation of fixed production plant than 'average and peak'
8 could also be found reasonable."¹⁰

9 In contested cases, the Commission has consistently approved the
10 Energy and Peak method to allocate production demand costs.¹¹
11 However, the Commission also has approved rate case settlements where
12 all or some parties have reached agreement on a methodology that
13 departed from Energy and Peak, such as the resolution of the Company's
14 last general rate proceeding in Docket No. 09-084-U.¹² If there is a
15 change made based upon public policy or other appropriate
16 considerations, then, as many of the other parties opined, there should be
17 a gradual and thoughtful process to minimize abrupt customer impacts.
18 Even using a consistent production allocation method, as a rate class'
19 load and energy change over time, there are changes in the allocation of
20 costs to rate classes.

¹⁰ Marcus Direct Testimony at 84.

¹¹ Docket No. 06-101-U, Order No. 10 (June 15, 2007) at 93.

¹² Docket No. 09-084-U, Order No. 18 (May 28, 2010).

1

2 **B. Distribution Cost Allocation**

3 Q. WHAT COMMENTS WERE MADE REGARDING THE COMPANY'S
4 PROPOSED DISTRIBUTION ALLOCATION METHODS USING THE
5 MAXIMUM DIVERSIFIED DEMAND AND THE NON-COINCIDENT
6 PEAK?

7 A. AG witness Marcus accepted the Company's distribution allocation
8 methods.¹³ AEEC witness Falkenberg recommended the Company
9 perform a minimum distribution system study for future use.¹⁴ HHEG
10 witness Blank agreed with distribution allocation methods except for line
11 transformers and secondary lines, where in both cases he recommended
12 the Commission adopt an allocator based on weighted combination of
13 non-coincident peak and number of customers.¹⁵

14

15 Q. HOW DO YOU RESPOND TO THESE COMMENTS REGARDING THE
16 METHODS FOR ALLOCATING DISTRIBUTION COSTS?

17 A. I previously noted, the Company's allocation is consistent with past rate
18 cases. More importantly the Company's allocation represents a
19 reasonable method for allocating distribution costs and other parties'

¹³ Marcus Direct Testimony at 85.

¹⁴ Falkenberg Direct Testimony at 20.

¹⁵ Blank Direct Testimony at 31-35.

1 comments in their testimony do not undermine the reasonableness of
2 EAI's approach.

3

4 **C. Allocation of Revenue Requirement**

5 Q. PLEASE DESCRIBE YOUR UNDERSTANDING OF THE STAFF'S
6 RECOMMENDATION FOR ALLOCATING THE REVENUE
7 REQUIREMENT TO THE RATE CLASSES.

8 A. My understanding is that Mr. Klutcher recommended taking the decrease
9 in revenue requirement for the Lighting rate class that resulted from the
10 cost-of-service study so that there would be no change in the Lighting rate
11 class rates. He then recommended that this decrease be used to reduce
12 the increase in revenue requirement for the LGS rate class indicated by
13 the cost-of-service study.

14 While Staff's recommendation does not follow the cost causation
15 principle, it may have merit from a public policy perspective of gradually
16 moving the LGS rate class to its full cost-of-service.

17

1 **IV. RATE DESIGN**

2 **A. Residential**

3 Q. AG WITNESS MARCUS RECOMMENDED CHANGES TO THE
4 RESIDENTIAL RATE DESIGN.¹⁶ PLEASE BRIEFLY DESCRIBE HIS
5 RECOMMENDATION.

6 A. In general, Mr. Marcus recommended no change in the customer charge
7 and to apply all base rate decrease to the first block while considering an
8 increase to the second block. Mr. Marcus did not provide support based
9 in cost causation for his recommendation to change the residential rate
10 design. Instead, he proposed changes to the residential rate design
11 based on public policy considerations of increasing the cost effectiveness
12 of energy efficiency, encouraging conservation, reducing electrical
13 consumption, and increasing the use of natural gas for certain purposes.¹⁷

14
15 Q. DO YOU HAVE COMMENTS REGARDING HIS RECOMMENDED
16 RESIDENTIAL RATE DESIGN?

17 A. Yes. First, Mr. Marcus recognized the need for gradualism in rate design
18 and does not propose a drastic change. However, the increase in the
19 customer charge the Company recommends is based on cost causation.

20 The Company proposed to increase the customer charge to move toward

¹⁶ Marcus Direct Testimony at 85-91.

¹⁷ *Id.* at 85-92.

1 the appropriate cost level, as I explained in my direct testimony.¹⁸ Staff
2 noted the Company's recommended increase, and did not oppose it.¹⁹ No
3 other party addressed the issue.

4 Inverted rates are not cost-based because residential customers
5 have an increasing load factor with increased energy usage. Declining
6 block rates are cost based because the design recognizes an increasing
7 load factor with increase energy usage. EAI Exhibit CAP-3 contains
8 analysis demonstrating that load factor increases with increased use.²⁰

9 Using cost causation and gradualism as guiding rate design
10 principles allows consumers to make economic choices while managing
11 rate changes. This approach can be tempered with public policy to a
12 slight or to a great degree where the economic choice becomes skewed
13 toward prescribed outcomes. It is within the Commission's informed
14 discretion how little or how much public policy should affect residential rate
15 design, so long as the result is just and reasonable.

16 The Company recommends the Commission approve its proposed
17 residential rate design that is based on cost causation while recognizing
18 the concern of customer impacts through gradual rate changes.
19

¹⁸ Pettett Direct Testimony at 27.

¹⁹ Swaim Direct Testimony at 6.

²⁰ Docket No. 09-084-U, Meyer Rebuttal Testimony, EAI Exhibit GDM-4.

1 **B. Large General Service**

2 Q. WAL-MART WITNESS CHRISS RECOMMENDS THAT THE DEMAND
3 RELATED REVENUES COLLECTED THROUGH DEMAND CHARGES
4 FOR THE LGS RATE BE SET TO 65.66 PERCENT OF THE TOTAL LGS
5 REVENUES, WHICH IS EQUAL TO THE AMOUNT OF DEMAND
6 REVENUES RECOVERED THROUGH DEMAND CHARGES FOR
7 GST.²¹ DO YOU AGREE WITH THIS RECOMMENDATION?

8 A. No. The LGS rate and the GST rates serve two different purposes. The
9 LGS rate serves customers that have a slightly lower load factor than the
10 GST rate. Customers with a load factor of less than 60 percent will find
11 the LGS rate more attractive. Customers with load factors greater than 60
12 percent will find the GST rate more attractive. The LGS rate reflects the
13 pricing for lower load factor type load with more reliance on the energy
14 charge and less reliance on the demand charge compared to the GST
15 rate.

16
17 Q. MR. CHRISS RELIES IN PART ON THE UNIT COST OF SERVICE TO
18 MAKE HIS RECOMMENDATION²². IS THE UNIT COST OF SERVICE
19 THE ONLY DRIVER IN DESIGNING RATES?

20 A. No. The unit cost of service study is a guide, not the absolute answer in
21 rate design. The relationship of the different rate offerings should provide

²¹ Chriss Direct Testimony at 9-10.

²² *Id* at 6.

1 a progression from lower load factor type load with rates that have a
2 greater reliance on the energy pricing component, such as SGS, to very
3 high load factor type load with rates that have less reliance on energy
4 pricing but a higher reliance on the demand charge, such as PST. The
5 Company's proposed rates accomplish this progression in pricing different
6 loads' characteristics.

7
8 Q. IF MR. CHRISS' RECOMMENDATION WAS FOLLOWED, WHAT
9 WOULD HAPPEN TO THE RELATIONSHIP OF THE PRICING
10 BETWEEN LGS AND GST?

11 A. The pricing between LGS and GST would overlap. This would eliminate
12 the current progression between rates that recognizes the reward of
13 increased utilization, load factor, and the resulting reward of lower unit
14 costs.

15
16 Q. IF A CUSTOMER IS ON THE LGS RATE BUT FINDS WAYS TO
17 INCREASE LOAD FACTOR ABOVE 60 PERCENT, WHAT OPTIONS
18 DOES THE CUSTOMER HAVE?

19 A. The customer should move to the GST rate because that rate would be
20 more cost effective.

21

1 Q. MR. BLANK DESCRIBES THE MINIMUM DEMAND PROVISIONS OF
2 THE LGS, GST, LPS AND PST TARIFFS AS DISCRIMINATORY.²³ DO
3 YOU AGREE?

4 A. No. The application of a rate schedule demand minimum is a common
5 rate design methodology that recognizes there are differences in the cost
6 of facilities and electric services for customers with different load
7 requirements. The LGS and GST tariffs generally apply to customers with
8 less than 1,000 kW of average monthly demand. The LPS and PST tariffs
9 generally apply to customers with more than 1,000 kW of average monthly
10 demand. The Company's investment in lines, transformers and facilities
11 to serve customers that have demand usage in the "hundreds" is less than
12 the investment required to serve a customer with demands in the
13 "thousands." The minimum demand provisions for the LGS and GST
14 tariffs require a billing of no less than 100 kW while the minimum demand
15 provision for the LPS and PST tariffs requires a billing of no less than
16 1,000 kW. These minimum demand provisions recognize cost
17 responsibility for the required facilities to serve the two rate groups.

18

19 Q. PLEASE ADDRESS MR. BLANK'S RECOMMENDATION THAT THE
20 COMMISSION ORDER EAI TO ELIMINATE THE MINIMUM BILLING
21 DEMAND PROVISIONS OF THE LGS, GST, LPS AND PST TARIFFS.

²³ Blank Direct Testimony at 45-48.

1 A. For the reasons set out above, the Commission should reject the
2 recommendation to eliminate the minimum billing demands for LGS, GST,
3 LPS and PST tariffs.

4

5 Q. MR. BLANK IN HIS DIRECT TESTIMONY POINTS OUT THAT THE GST
6 RATE HAS A LOWER DEMAND CHARGE THAN THE PST RATE
7 DESIGN.²⁴ MR. BLANK CONTINUES TO RECOMMEND CHANGES TO
8 THE GST AND PST RATES. DO YOU HAVE COMMENTS REGARDING
9 HIS COMMENTS?

10 A. Yes. Mr. Blank is correct that there is an anomaly between the GST and
11 PST rate designs where the demand charge for PST is higher than GST
12 even though the energy charges are the same. In APSC Docket No. 06-
13 101-U, the Company proposed to combine the GST and PST rates into
14 one new rate as a solution to the inverted rate that Mr. Blank describes.²⁵
15 Ultimately, the new rate design that combined GST and PST was not
16 adopted at that time. The Company is willing to propose a new rate
17 design that combines the GST and PST rate schedules.

18

19 Q. MR. BLANK'S TESTIMONY SUGGESTS THAT LGS, LPS, GST AND
20 PST SHOULD ALL BE TREATED AS SEPARATE RATE CLASSES FOR

²⁴ *Id* at 43-45.

²⁵ Docket No. 06-101-U, Meyer Direct Testimony at 19-20.

1 ALLOCATION OF COSTS AND THE RESULTING RATE DESIGN.²⁶ HE
2 ALSO SUGGESTS THAT THE COMPANY'S FILING IS LACKING IN
3 DATA BECAUSE THE LGS RATE CLASS HAS NOT BEEN
4 DISAGGREGATED INTO THE SEPARATE RATE CLASSES FOR LGS,
5 LPS, GST AND PST. DO YOU HAVE COMMENTS REGARDING THIS
6 TESTIMONY?

7 A. Yes. Historically, the Company has treated the LGS, LPS, GST and PST
8 rates as one rate class that it has referred to as LGS. To my knowledge,
9 other than the rate design issue regarding GST and PST described above,
10 no other party in past rate proceedings has suggested separating the four
11 rate schedules within the LGS rate class into separate rate classes (LGS,
12 LPS, GST and PST). No other party in this docket or in past rate cases
13 has suggested that the Company's filing has been incomplete because it
14 did not file separate minimum filing requirement schedules for each rate
15 schedule within the LGS rate class as proposed by Mr. Blank. Thus, Mr.
16 Blank's suggestion that the Company's filing is lacking is misguided.

17 In addition, I disagree with Mr. Blank that customers on these four
18 individual rate schedules within the LGS rate class are so different in load
19 characteristics to warrant the creation of four separate rate classes, one
20 each for LGS, LPS, GST and PST, instead of one LGS rate class
21 containing all four rate schedules.

²⁶ Blank Direct Testimony at 36-41.

1 If that were the case then other rate classes should also be
2 disaggregated down to the rate schedule level. For example, the SGS
3 rate class contains the following rate schedules: Small General Service,
4 General Farm Service, Community Antenna TV Amplifier Service,
5 Municipal Pumping Service, Agricultural Water Pumping Service, Cotton
6 Ginning Service and Traffic Signal Service. At some point there are
7 diminishing returns on the level of detail at which costs are allocated. The
8 treatment of aggregating the four rate schedules, LGS, LPS, GST and
9 PST into one LGS rate class is consistent with the creation of other rate
10 classes that have multiple rate schedules within a rate class.

11

12 **C. Riders**

13 Q. AEEC WITNESS FALKENBERG AND AG WITNESS MARCUS
14 RECOMMENDED CHANGING THE APPLICATION OF THE CAPACITY
15 COST RECOVERY RIDER ("RIDER CCR"), AND THE MIDCONTINENT
16 INDEPENDENT SYSTEM OPERATOR, INC. ("MISO") RIDER FROM A
17 PERCENT OF REVENUE TO KWH.²⁷ DO YOU HAVE COMMENTS
18 REGARDING THEIR RECOMMENDATION?

19 A. Yes. To begin, Mr. Falkenberg states that Rider CCR costs are
20 production demand related costs and MISO Rider costs are transmission
21 related costs. I agree. Both riders were allocated to the rate classes

²⁷ Falkenberg Direct Testimony at 44; Marcus Direct Testimony at 93.

1 based on allocation factors related to their respective cost causation. This
2 allocation of costs was addressed in the direct testimony of EAI witness
3 Phillip Gillam, which has since been adopted by David Hunt.²⁸

4 Once the costs are allocated to the rate classes, then the issue
5 becomes how to recover the costs within a rate class. Mr. Falkenberg
6 argues that capacity costs should not be recovered based on the percent
7 of revenue rider because the rider would apply to all base rate revenue
8 including the customer charge. He further argued that capacity costs
9 should not be recovered through a customer charge.

10 Mr. Marcus made similar arguments as Mr. Falkenberg, but for the
11 residential rate, and Mr. Marcus recommended a kWh charge for both the
12 MISO Rider and Rider CCR for the residential rate class.

13

14 Q. WHY DID THE COMPANY PROPOSE A PERCENT OF RIDER
15 APPLICATION FOR RIDERS CCR AND MISO?

16 A. Applying Rider CCR and the MISO Rider on a percent of revenue basis
17 keeps the relationship of the various components of the rate design
18 constant. For example, if the rate in question has a customer charge, an
19 energy charge and a demand charge, then applying a rate on a percent of
20 revenue basis would keep all proportions of a rate design constant. If a
21 rider is applied as a kWh charge, however, then that would skew the

²⁸ Gillam Direct Testimony at 30, 37.

1 relationship of the energy and demand charge and result in an overall
2 higher energy charge. Generally, a higher energy charge would be to the
3 detriment of higher load factor customers and to the favor of lower load
4 factor customers, everything else being equal.

5 Another option would be to collect the costs through these riders
6 from some rate classes on a kWh basis while charging other rate classes
7 on a \$ per kW basis. In this alternative, the change in demand versus
8 energy related rate components could cause customers to migrate from
9 one rate schedule to another in order to save money. For the Residential
10 rate class this is not an option because the meters do not register demand
11 and the rate therefore includes only customer and kWh charges.

12 Whether Rider CCR and the MISO Rider are applied on a kWh
13 basis or percent of revenue for residential customer is not the significant
14 issue. The Company recommends the same rate design approach for
15 each rate class in both Rider CCR and the MISO Rider for administrative
16 efficiency and to avoid customer confusion.

17
18 **D. Commercial Space and Water Heat**

19 Q. HHEG WITNESS WARD OBJECTS TO THE CLOSING OF THE
20 COMMERCIAL SPACE HEATING RIDER ("CSHR").²⁹ PLEASE
21 COMMENT.

²⁹ Ward Direct Testimony at 17-18.

1 A. EAI has proposed to close the CSHR tariff consistent with the practice of
2 eliminating special treatment for electric heating and water heating load
3 that was the basis for closing the Separately Metered Commercial Space
4 and Water Heating Rider ("SMWHR") in the Company's general rate
5 proceeding in Docket No. 06-101-U. The concept for the CSHR and the
6 SMWHR is the same. SMWHR prices heating energy at a different rate
7 during the heating season, while CSHR effectively forgives heating
8 demand by pricing a base load that represents load exclusive of heating
9 load during the heating season. It is inequitable and inconsistent to have
10 one special heating rate closed to new customers while permitting the
11 other to remain available when the purpose of both riders is to provide a
12 reduced billing for heating load.

13
14 **E. Additional Facilities Charge Rider Governmental**

15 Q STAFF WITNESS SWAIM RECOMMENDED THAT EAI BE DIRECTED
16 TO FILE THE ADDITIONAL FACILITIES CHARGE RIDER
17 GOVERNMENTAL ("AFCRG") APPROVED IN DOCKET 12-096-TF IN
18 THIS DOCKET. WHAT IS YOUR RESPONSE?

19 A. The Company will file a new AFCRG in the compliance filing consistent
20 with the AFCRG approved in Docket No. 12-096-TF.

1 **F. Standby Service, Small and Large Cogeneration**

2 Q. PLEASE EXPLAIN THE COMPANY'S PROPOSED CHANGES TO
3 STANDBY SERVICE RIDER, SMALL COGENERATION RIDER, LARGE
4 COGENERATION RIDER CONCERNING GOVERNMENTAL ENTITIES.

5 A. Each of these proposed rate schedules contains a section entitled
6 "INSURANCE AND/OR INDEMNIFICATION", which in simple terms
7 requires governmental entities to provide insurance in lieu of indemnifying
8 the Company against loss, damage, etc. resulting from the customer's
9 equipment that is interconnected with the Company.

10
11 Q. WHAT IS STAFF'S RECOMMENDATION REGARDING THESE
12 CHANGES TO STANDBY SERVICE RIDER ("SSR"), LARGE
13 COGENERATION RIDER ("LCR"), AND SMALL COGENERATION
14 RIDER ("SCR")?

15 A. Mr. Swaim recommended the Commission reject the alternative insurance
16 provision.

17
18 Q. HOW DO YOU RESPOND TO MR. STAFF'S RECOMMENDATION?

19 A. It is more equitable and efficient for each governmental customer that
20 cannot sign a contract containing an indemnification provision but wishing
21 to take service on Riders SSR SCR and LCR to assume the cost of its
22 own insurance. Otherwise, that cost will effectively be subsidized by other

1 customers or Riders SSR, SCR and LCR will be effectively unavailable for
2 governmental entities.

3

4 Q. MR. TINSLEY RECOMMENDED THAT THE COMMISSION REJECT
5 THE PROPOSED RATE MODIFICATIONS IN SSR, LCR AND SCR
6 ARGUING THAT THOSE MODIFICATIONS WOULD DISCOURAGE THE
7 USE OF COMBINED HEAT AND POWER ("CHP").³⁰ PLEASE
8 RESPOND.

9 A. Riders LCR and SCR provide a means by which CHP, or cogenerating,
10 customers of EAI may be compensated for any excess generation above
11 their own site requirements that are put to the Company. The prices paid
12 for such energy are determined by a methodology approved by the
13 Commission. The only rate modification proposed for Riders LCR and
14 SCR in this case is a change in the monthly charge from \$16.77 to \$21.73,
15 an increase of \$4.86 that is based on the cost-of-service study. Mr.
16 Tinsley's concerns that a \$4.86 monthly charge increase for Riders LCR
17 and SCR would negatively affect the economics of CHP projects that
18 would be expected to cost millions of dollars are unfounded.

19

20 Q. PLEASE ADDRESS EAI'S PROPOSED CHANGES TO RIDER SSR.

³⁰ Tinsley Direct Testimony at 7.

1 A. Rider SSR provides for various power and energy supply products for
2 cogenerating customers' use during planned maintenance periods or
3 unplanned outages of on-site generating equipment. The prices for these
4 energy products are taken from the LPS tariff, which ensures that energy
5 consumption for cogenerating customers is priced equivalent to similar
6 service to firm power customers. There is no preferential treatment, nor is
7 there any punitive pricing for SSR service.

8 The Reservation Charge included in Rider SSR recognizes that the
9 Company must have available generation, transmission, and distribution
10 facilities that can satisfy the full site energy requirements for CHP, or
11 cogenerating, customers, regardless of whether any energy is supplied by
12 the Company. This Reservation Charge is an appropriate pricing
13 mechanism that charges a CHP customer for the costs incurred by the
14 Company to provide the required facilities and services for the service
15 requested by that customer. Absent the Reservation Charge, non-CHP
16 customers would pay higher rates for the facilities needed to serve CHP
17 customers. The pricing of services under proposed Rider SSR reflects the
18 costs incurred by the Company to provide service to CHP customers. To
19 price such services at any other level would lead to distorted economics
20 for CHP projects and uneconomic decision-making, as well as
21 subsidization by all other customers.

22

1 **V. INTERRUPTIBLE SERVICE**

2 **A. Optional Interruptible Service Rider**

3 Q. WHAT REVISIONS HAS EAI PROPOSED FOR THE OPTIONAL
4 INTERRUPTIBLE SERVICE RIDER ("RIDER OIS")?

5 A. The Company has proposed to close the tariff to new customers and to
6 revise the terms of the tariff so that the interruptible load can be classified
7 as a Load Modifying Resource ("LMR") within the MISO market. In short,
8 current customers would be grandfathered with service continuing under
9 the revised terms.

10
11 Q. WHAT WAS THE RESPONSE OF PARTIES IN THE CASE?

12 A. Staff witness Regina Butler agreed with the Company's proposed
13 revisions to Rider OIS, including closing Rider OIS to new customers.³¹
14 Wal-Mart witness Kenneth E. Baker agreed with the Company's proposal
15 to continue to provide service to current customers on Rider OIS but
16 expressed concerns about how long current customers would be able to
17 continue service on Rider OIS.³² AEEC witness Falkenberg and HHEG
18 witnesses Blank and Ward opposed closing the tariff to new customers.³³

19
20 Q. WHAT IS YOUR RESPONSE?

³¹ Butler Direct Testimony at 21.

³² Baker Direct Testimony at 3.

³³ Falkenberg Direct Testimony at 6, Ward Direct Testimony at 16-17 and Blank Direct Testimony at 10.

1 A. First, there hardly can be said to be any harm in closing the tariff to
2 prospective customers who today do not take this service; simply put there
3 can be no harm to customers associated with not providing them a service
4 that they currently do not have today. Additionally, the Company has not
5 proposed any provision to phase out or terminate Rider OIS to existing
6 customers in this case. Any such concerns are premature and not
7 relevant to this docket. These concerns should be expressed at such time
8 and in such forum as the Company proposes such a phase-out. Further,
9 as to the revised terms for the grandfathered OIS customers, EAI witness
10 Kurtis Castleberry explains the basis for the proposed revisions to Rider
11 OIS to conform with EAI's participation in the MISO market in his direct
12 and rebuttal testimonies.

13
14 Q. PLEASE ADDRESS MR. FALKENBERG'S RECOMMENDATION TO
15 ELIMINATE THE "EXCESS" DEMAND CHARGE APPLIED TO RIDER
16 OIS NON-FIRM DEMAND.³⁴

17 A. Mr. Falkenberg's recommendation is not appropriate because it would
18 unreasonably value interruptible load for customers on TOU rates at a
19 much greater value than interruptible load for non-TOU customers. The
20 Company's proposed LGS, GST, LPS and PST tariffs yield effective
21 average monthly values for interruptible load under Rider OIS ranging

³⁴ Falkenberg Direct Testimony at 6.

1 from \$10.89 per kW to \$10.41 per kW. Yet, Mr. Falkenberg's proposal
2 would increase, without reason, those monthly values for interruption to
3 roughly \$15 per kW for TOU customers taking service under Rider OIS.
4 Mr. Castleberry explains in his rebuttal testimony why the existing value
5 inherent in Rider OIS for interruptible is too high given the market value of
6 capacity in the MISO markets. Adopting Mr. Falkenberg's
7 recommendation would only exacerbate that situation.

8

9 Q. CAN YOU ADDRESS CONCERNS ASSOCIATED WITH THE
10 PROPOSED REVISION IN RIDER OIS TO ALLOW EAI TO TERMINATE
11 SERVICE TO EXISTING CUSTOMERS TAKING SERVICE UNDER THE
12 TARIFF³⁵?

13 A. Yes. The Company has no intention of arbitrarily terminating an
14 Agreement for Interruptible Service. The proposed termination language
15 was intended to allow EAI to terminate Rider OIS service only if the
16 customer could not meet the terms of the tariff. To clarify this intent, EAI
17 proposes to modify section 41.7 of the proposed Rider OIS to read:

18

19 Unless modified by the provisions in sections 41.5.5, the
20 Agreement for Interruptible Service shall be for a minimum
21 period of one year and a maximum of five years at the
22 customer's option, and shall be automatically renewed for
23 successive terms equal in length to the initial term until
24 terminated by advance written notice from customer no less
25 than three months prior to any anniversary date. The
26 Agreement for Interruptible Service may be cancelled by

³⁵ Ward Direct Testimony at 17 and Mathis Direct Testimony at 8.

1 Company in the event that the Customer cannot meet the
2 requirements for service under this rate schedule or the
3 contractual provisions of his Agreement for Interruptible
4 Service.

5
6 **B. MVLMR and MVDRR**

7 Q. MR. WARD TESTIFIED THAT INTERRUPTIBLE DEMAND WAS NOT
8 DEFINED IN THE MARKET VALUED LMR ("MVLMR") RATE SCHEDULE
9 AND THAT IT IS NOT CLEAR WHETHER THE INTERRUPTIBLE
10 DEMAND VALUE IS FIXED OR SUBJECT TO MONTHLY
11 VARIATIONS³⁶. CAN YOU EXPLAIN HOW INTERRUPTIBLE DEMAND
12 IS DEFINED IN THE MVLMR RATE SCHEDULE?

13 A. Yes. Interruptible Demand is defined in section 56.2 of the MVLMR rate
14 schedule as "The difference between the customer's monthly billed
15 demand for firm service and the Firm Contract Demand, but not less than
16 zero (0)." Firm Contract Demand is defined in section 56.2 as "The
17 amount of load the customer agrees not to exceed during a demand
18 response event." Therefore, Interruptible Demand can vary by month.

19 As an example: assume a customer contracted for 700 kW of firm
20 demand. If his firm service billing demand for a month was 800 kW, then
21 the Interruptible Demand for that month would be 100 kW. The credit in
22 section 56.4.1 of MVLMR would apply to 100 kW. If in the next month, the
23 customer's firm service billing demand for the month was 850 kW, then

³⁶ Ward Direct Testimony at 9, 22.

1 the Interruptible Demand for that month would be 150 kW. The
2 Interruptible Demand will vary because it is dependent on the monthly
3 billed firm demand, which in turn is dependent on the customer's
4 registered load each month.

5

6 Q. PLEASE COMMENT ON MR. WARD'S ISSUE WITH THE 10 PERCENT
7 ADMINISTRATIVE CHARGE ASSOCIATED WITH PROPOSED RATE
8 SCHEDULE MVDRR.³⁷

9 A. EAI does not have estimates for the level of costs that will be incurred to
10 administer the MVDRR, nor is it practical at this point to develop an
11 estimate. The tariff is being offered on an experimental basis, and the
12 Company believes, based on its experience, that a simple and definitive
13 administrative cost recovery approach that varies with the level of the
14 settlements is practical and appropriate for an experimental rider. EAI
15 agrees with Ms. Butler's recommendation that the Company maintain cost
16 data associated with activities required to perform the administrative tasks
17 associated with the MVDRR once the rider is implemented and such data
18 become available. Staff's recommendation reflects a reasonable
19 approach to the implementation of a new tariff process.

20

21 Q. DOES THIS CONCLUDE YOUR REBUTTAL TESTIMONY?

³⁷ *Id.* at 12.

1 A. Yes at this time.

CERTIFICATE OF SERVICE

I, Steven K. Strickland, do hereby certify that a copy of the foregoing has been served upon all parties of record by forwarding the same by electronic mail and/or first class mail, postage prepaid, this 26th day of August, 2013.

/s/ Steven K. Strickland
Steven K. Strickland

BEFORE THE
ARKANSAS PUBLIC SERVICE COMMISSION

IN THE MATTER OF THE APPLICATION	)	
OF ENTERGY ARKANSAS, INC. FOR	)	DOCKET NO. 13-028 -U
APPROVAL OF CHANGES IN RATES FOR	)	
RETAIL ELECTRIC SERVICE	)	

EAI EXHIBIT CAP-2

AEEC 5-17 AND AEEC 7-4

THIS EXHIBIT CONTAINS HIGHLY SENSITIVE PROTECTED INFORMATION
PROVIDED PURSUANT TO THE COMMISSION'S INTERIM PROTECTIVE
ORDER NO. 2 ISSUED ON FEBRUARY 21, 2013 IN THIS DOCKET.

BEFORE THE
ARKANSAS PUBLIC SERVICE COMMISSION

IN THE MATTER OF THE APPLICATION	)	
OF ENTERGY ARKANSAS, INC. FOR	)	DOCKET NO. 13-028-U
APPROVAL OF CHANGES IN RATES FOR	)	
RETAIL ELECTRIC SERVICE	)	

EAI EXHIBIT CAP-3
RESIDENTIAL LOAD ANALYSIS

ENTERGY ARKANSAS, INC.
ARKANSAS PUBLIC SERVICE COMMISSION
Docket No. 09-084-U - 2009 RATECASE

Response of: Entergy Arkansas, Inc.
to the One Hundred Forty-Second Set of Data
Requests
of Requesting Party: Arkansas Public Service Commission Filed: 12/15/09

Question No. APSC 142-1

Part No.:

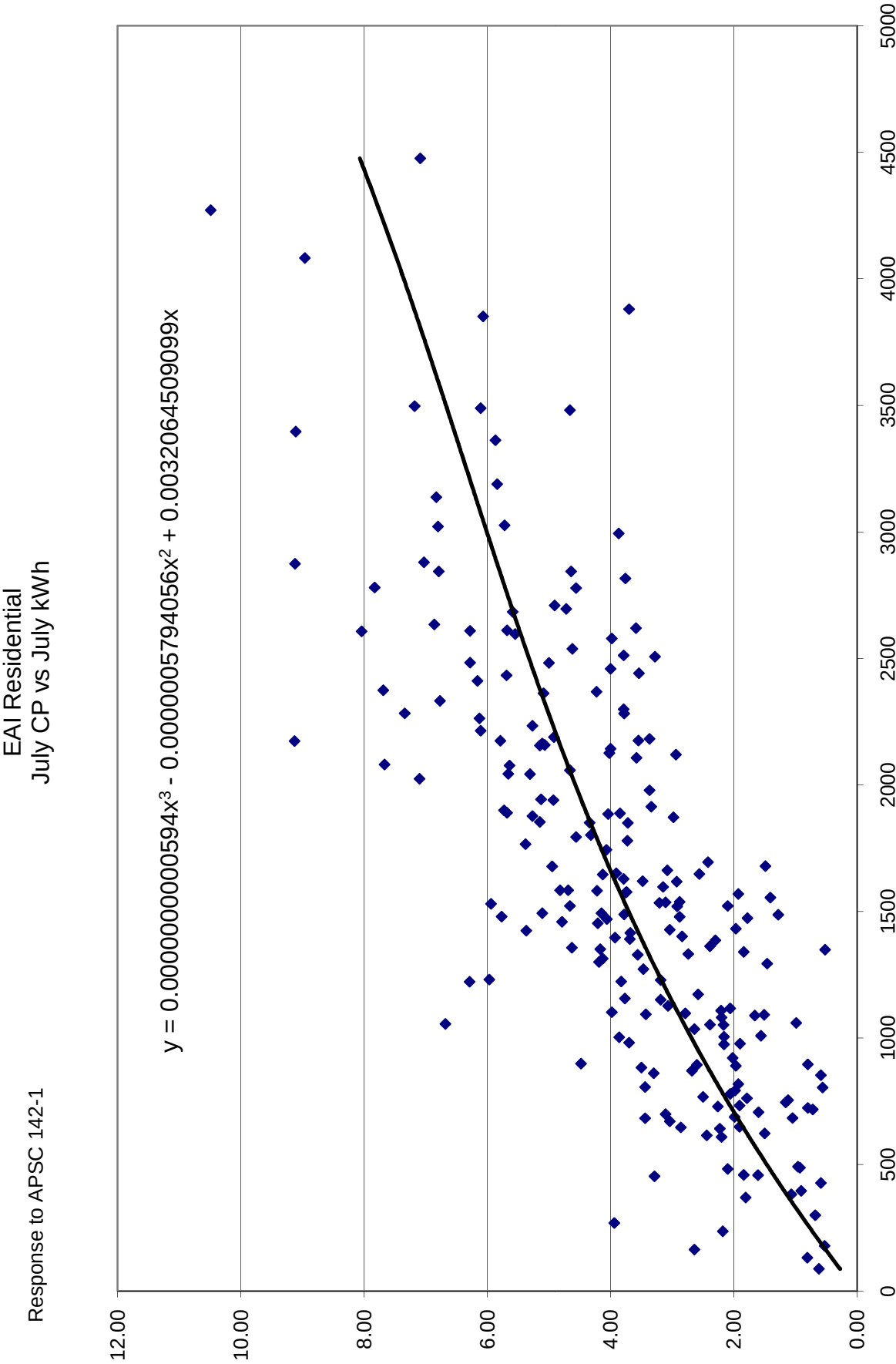
Addendum:

Question:

In his Direct Testimony on pages 32 and 33, Company witness Gordon D. Meyer states that “residential customers have an increasing load factor with increased energy usage” and that “this increasing load factor indicates that as energy usage increases, the unit cost (\$/kWh) for fixed cost declines.” Please provide the analysis Mr. Meyer relied upon to support those two statements.

Response:

As indicated in Mr. Meyer’s testimony on page 33, the two statements are based on his sur-surrebuttal testimony in Docket No. 06-101-U. Attached is the analysis developed for that Docket.



EAI Residential
Response to APSC 142-1

Jul kwh	july cp
779	2.06
1459	4.79
978	1.90
1340	1.84
382	1.07
1428	3.04
871	2.68
179	0.53
1574	3.76
1363	2.39
2156	5.15
1092	1.51
1522	4.66
688	1.99
2120	2.94
132	0.81
458	1.61
164	2.64
269	3.94
609	2.20
707	1.60
861	3.30
729	2.26
1648	2.56
724	0.80
2512	3.79
1620	3.48
459	1.84
396	0.91
975	2.16
488	0.93
804	0.56
1231	5.97
1117	2.06
88	0.62
2174	5.79
671	3.04
894	2.60
642	2.23
1480	5.77
853	0.59
767	2.50
1272	3.47
1005	2.16
1679	1.49
921	2.02
762	1.79
1300	4.19
1940	4.93
615	2.44
1850	3.72

300	0.68
454	3.29
1646	4.13
1357	4.63
733	1.91
1888	3.85
1223	3.83
370	1.81
1470	4.06
818	1.93
718	0.72
1802	4.32
647	2.86
699	3.11
982	3.70
1584	4.82
492	0.96
1156	3.77
2634	6.86
1098	2.79
1744	4.07
684	1.05
1488	3.78
2263	6.13
755	1.12
1386	2.30
3489	6.11
883	3.50
1222	6.29
2507	3.28
1402	2.84
2058	4.66
1173	2.58
1538	2.88
236	2.18
1487	1.28
1794	4.56
2024	7.10
2332	6.77
1536	3.11
2282	3.78
1534	3.21
2778	4.56
1877	5.27
1577	3.74
2182	3.37
2077	5.64
2844	6.79
2173	9.13
1584	4.69
2299	3.79
1229	3.19
2081	7.67
1979	3.37
1009	1.56
683	3.44

1555	1.41
746	1.16
649	1.91
1629	3.79
1851	4.34
2214	6.11
1520	2.92
1052	2.17
1329	3.56
1854	5.15
1678	4.95
1943	5.13
1003	3.86
1102	3.98
1127	3.07
1314	4.13
2538	4.62
4476	7.09
1432	1.97
1094	3.43
806	3.44
1780	3.73
1663	3.08
1053	2.39
483	2.10
3189	5.84
2844	4.64
2459	4.00
1415	3.68
890	1.97
2044	5.66
1453	4.21
2482	5.00
1493	5.11
2483	6.28
2283	7.34
896	0.80
1089	1.66
1056	6.68
2411	6.16
1349	0.52
3481	4.66
1872	2.98
1294	1.46
623	1.50
1060	0.99
2780	7.83
3880	3.70
1035	2.64
899	4.48
1151	3.19
2994	3.87
3021	6.80
1108	2.21
1081	2.20
2164	5.11

2175	3.55
1397	3.93
3362	5.87
1618	2.93
2880	7.03
2189	4.92
793	1.98
1522	2.10
1582	4.22
2126	4.02
1479	2.88
4271	10.49
2607	8.04
2874	9.12
3137	6.83
2620	3.59
2362	5.09
3396	9.11
2107	3.58
1391	3.69
2158	5.07
3497	7.18
1597	3.15
3026	5.72
2441	3.54
2611	5.68
1885	4.04
2596	5.55
1351	4.17
2043	5.31
427	0.59
2433	5.69
1530	5.94
2609	6.28
1914	3.34
1766	5.38
2374	7.69
2709	4.91
1493	4.15
1569	1.93
2684	5.59
3851	6.07
4082	8.96
1474	1.78
1651	3.91
2143	4.00
2368	4.23
1900	5.73
2696	4.72
1890	5.68
2579	3.98
1424	5.37
1695	2.42
2816	3.76
1332	2.74
2234	5.27

EAI Residential July CP vs July kWh
Response to APSC 142-1

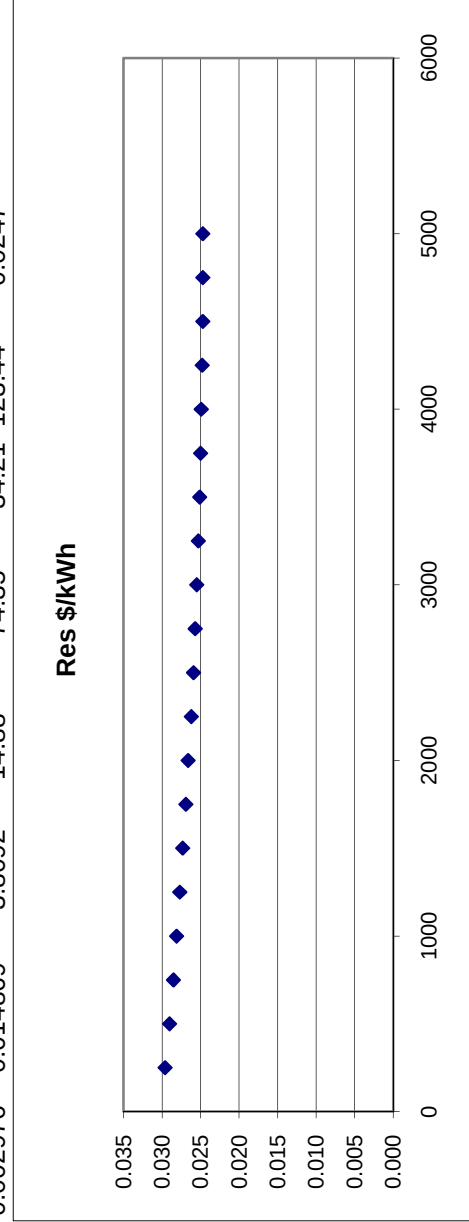
kWh	Pred kW	Load Factor	Energy \$/kWh	Demand \$/kWh	Demand \$/CP	Energy\$	Dem\$ Eng	Dem\$ Pk	Total \$	Tot \$/kWh
250	0.77	0.445	0.002976	0.014869	3.8092	0.74	3.72	2.93	7.39	0.0296
500	1.47	0.466	0.002976	0.014869	3.8092	1.49	7.43	5.60	14.52	0.0290
750	2.10	0.489	0.002976	0.014869	3.8092	2.23	11.15	8.00	21.38	0.0285
1000	2.69	0.509	0.002976	0.014869	3.8092	2.98	14.87	10.25	28.10	0.0281
1250	3.22	0.532	0.002976	0.014869	3.8092	3.72	18.59	12.27	34.58	0.0277
1500	3.71	0.554	0.002976	0.014869	3.8092	4.46	22.30	14.13	40.89	0.0273
1750	4.16	0.576	0.002976	0.014869	3.8092	5.21	26.02	15.85	47.08	0.0269
2000	4.57	0.600	0.002976	0.014869	3.8092	5.95	29.74	17.41	53.10	0.0266
2250	4.96	0.621	0.002976	0.014869	3.8092	6.70	33.46	18.89	59.05	0.0262
2500	5.32	0.644	0.002976	0.014869	3.8092	7.44	37.17	20.26	64.87	0.0259
2750	5.67	0.664	0.002976	0.014869	3.8092	8.18	40.89	21.60	70.67	0.0257
3000	6.01	0.684	0.002976	0.014869	3.8092	8.93	44.61	22.89	76.43	0.0255
3250	6.34	0.702	0.002976	0.014869	3.8092	9.67	48.32	24.15	82.14	0.0253
3500	6.68	0.718	0.002976	0.014869	3.8092	10.42	52.04	25.45	87.91	0.0251
3750	7.01	0.733	0.002976	0.014869	3.8092	11.16	55.76	26.70	93.62	0.0250
4000	7.36	0.744	0.002976	0.014869	3.8092	11.90	59.48	28.04	99.42	0.0249
4250	7.73	0.753	0.002976	0.014869	3.8092	12.65	63.19	29.45	105.29	0.0248
4500	8.12	0.759	0.002976	0.014869	3.8092	13.39	66.91	30.93	111.23	0.0247
4750	8.53	0.763	0.002976	0.014869	3.8092	14.14	70.63	32.49	117.26	0.0247
5000	8.98	0.763	0.002976	0.014869	3.8092	14.88	74.35	34.21	123.44	0.0247

199,325,080 Prod Dem
111,622,045 Prod Dem*.56 (kWh)
87,703,035 Prod Dem*.44 (CP)

111,622,045 Prod Dmd Rev Req kWh
7,506,798,448 kWh
0.014869 per kWh

87,703,035 Prod Dmd Rev Req CP
1,918,675 CP
23,024,100 CP*12
3.8092 per kW

22,341,813 Energy Rev Req
7,506,798,448 kWh
0.002976 per kWh



July CP kW vs kWh Reg Equation

$$0 \text{ int} \\ 0.003206 \text{ x} \\ -0.000000579 \text{ x}^2 \\ 0.000000000594 \text{ x}^3$$

BEFORE THE
ARKANSAS PUBLIC SERVICE COMMISSION

IN THE MATTER OF THE APPLICATION	)	
OF ENTERGY ARKANSAS, INC. FOR	)	DOCKET NO. 13-028-U
APPROVAL OF CHANGES IN RATES FOR	)	
RETAIL ELECTRIC SERVICE	)	

REBUTTAL TESTIMONY

OF

DAVID K. PICKLES

SENIOR VICE PRESIDENT

ICF INTERNATIONAL

ON BEHALF OF

ENTERGY ARKANSAS, INC.

AUGUST 26, 2013

1 **I. INTRODUCTION**

2 Q. PLEASE STATE YOUR NAME.

3 A. My name is David K. Pickles. My business address is 7160 North Dallas
4 Parkway, Suite 340, Plano, Texas 75024. I am employed by ICF
5 International ("ICF"), as Senior Vice President.

6
7 Q. ON WHOSE BEHALF ARE YOU SUBMITTING THIS TESTIMONY?

8 A. I am submitting this rebuttal testimony to the Arkansas Public Service
9 Commission ("APSC" or the "Commission") on behalf of Entergy
10 Arkansas, Inc. ("EAI" or the "Company").

11

12 Q. PLEASE STATE YOUR EDUCATION, PROFESSIONAL AND WORK
13 EXPERIENCE.

14 A. I am a 1986 graduate of the University of Wyoming with a Bachelor of
15 Science Degree in Economics and a 1988 graduate of the University of
16 Wyoming with a Master of Science Degree in Regulatory Economics. I
17 have 25 years of experience in the planning, implementation, and
18 evaluation of Demand Side Management ("DSM") programs. I have been
19 employed by ICF for approximately nine years, and currently serve as
20 Senior Vice President in the Energy Efficiency Practice. Prior to joining
21 ICF, I was employed by: Navigant Consulting as Director in the energy
22 efficiency practice; PHI Consulting, where I served as interim Chief
23 Technology Officer for Honeywell's Energy Information Services business

1 unit; Central and Southwest Utilities (now AEP) as Vice President of
2 Marketing, Development, and Operations for the unregulated energy
3 services group; and Synergic Resources Corporation as a Director in the
4 energy efficiency practice. I previously held positions as Utility Specialist
5 and Senior Utility Analyst with the Iowa Consumer Advocates Office, and
6 Utility Analyst II with the Iowa Utilities Board, where I was responsible for
7 helping develop positions and testimony regarding energy efficiency and
8 integrated resource planning. I have led the development of over 100
9 individual energy efficiency programs, including: program design,
10 establishment of incentives, forecasting of participation, creation of
11 marketing strategies, and estimation of implementation costs. I have also
12 led the development of energy efficiency potential studies for utility clients
13 in Arizona, Arkansas, Delaware, Florida, Hawaii, Illinois, Louisiana,
14 Maryland, Michigan, Mississippi, North Carolina, South Carolina, Texas,
15 Virginia, Washington, D.C., and Wisconsin. A statement of my
16 background and experience is attached as EAI Exhibit DKP-1.

17
18 Q. PLEASE DESCRIBE ICF INTERNATIONAL.

19 A. Founded in 1969, ICF is a consulting and professional services firm
20 supporting the energy, environmental, health, technology, and aviation
21 sectors. Publicly traded (NASDAQ: ICFI) with over 4,500 staff and \$937
22 million in annual revenue in 2012, ICF currently implements more than
23 130 energy efficiency programs for 42 utilities in 28 states. ICF has been

1 the lead contractor for the Environmental Protection Agency's ("EPA")
2 ENERGY STAR® program since its inception and also supports the U.S.
3 Department of Energy's Better Buildings and Commercial Building Alliance
4 programs

5

6 Q. WHAT ARE YOUR RESPONSIBILITIES AS SENIOR VICE PRESIDENT
7 FOR ICF?

8 A. I manage ICF's implementation of energy efficiency programs in the
9 southwest United States, as well as our energy efficiency policy and
10 business development activities nationwide. I am responsible for the
11 conduct and supervision of all regional energy efficiency related work,
12 including the assessment of energy efficiency potential and the design and
13 implementation of energy efficiency programs for utilities and the federal
14 government. I currently supervise the implementation of approximately 30
15 individual energy efficiency programs.

16

17 Q. HAVE YOU PREVIOUSLY TESTIFIED BEFORE A REGULATORY
18 COMMISSION?

19 A. Yes. I filed reply testimony before the APSC in Docket No. 07-085-TF on
20 September 29, 2009 regarding EAI's Energy Efficiency Programs. In
21 addition, I have testified before regulatory commissions in Iowa, Illinois,
22 South Carolina, Virginia, Arizona, and Louisiana on issues related to

1 energy efficiency program planning, design, and policy, and other
2 ratemaking topics.

3
4 Q. WHAT IS THE PURPOSE OF YOUR REBUTTAL TESTIMONY?

5 A. The purpose of my rebuttal testimony is to address aspects of the base
6 load calculation and escalation factor used by APSC General Staff
7 ("Staff") witness Robert H. Swaim in his inclusion of forecasting of
8 customer usage in developing his billing determinants for EAI. I identify
9 several significant concerns associated with Staff's approach and
10 demonstrate that its methodology results in estimates of electricity usage
11 per customer that are unreasonably high considering EAI's
12 implementation of comprehensive energy efficiency programs and their
13 growth over the past few program years. I also demonstrate that Staff's
14 methodology is inconsistent with national experience.

15

16 **II. ELECTRICITY USAGE PER CUSTOMER**

17 Q. DESCRIBE STAFF'S METHODOLOGY TO ESTIMATE THE PRO
18 FORMA YEAR BILLING DETERMINANTS INCLUDING THE
19 DETERMINATION OF USAGE PER CUSTOMER.

20 A. The billing determinant model in Staff's methodology first estimates per-
21 customer base usage (i.e., the customer's non-weather sensitive usage)
22 as the average per customer usage during the months of May and
23 November, 2012. It then estimates the pro forma year base usage by

1 escalating the 2012 May/November average by the five year compound
2 average growth rate in base usage (as calculated) or 1.39 percent (in the
3 case of residential customers.)
4

5 Q. DO YOU FIND STAFF'S METHODOLOGY TO BE APPROPRIATE?

6 A. No. Company witness Corey A. Pettett addresses several shortcomings
7 inherent in the application of Staff's methodology in this case, including
8 (but not limited to): a) it does not utilize known and measurable data, b) it
9 overestimates base usage by using as its foundation two months (May
10 and November) that include weather sensitive usage, c) it underestimates
11 weather sensitive usage; and d) it escalates the estimate of base usage at
12 a compound growth rate that is highly influenced by the start and end
13 years chosen and by the months selected during those years. In addition
14 to Mr. Pettett's concerns, Staff's methodology, as applied in this case,
15 produces critical errors in billing determinants in that (1) it does not
16 address the Commission's recent rulemakings requiring EAI to make large
17 incremental investments in energy efficiency programs and EAI's
18 achievements in promoting energy efficiency in response to those APSC
19 directives, and (2) the five-year period chosen by Staff as being
20 representative does not reflect important, known, and significant recent
21 developments such as changes in building codes and appliance efficiency
22 standards. In short, the estimates produced by Staff's methodology in this
23 case do not reflect the most accurate or reasonable data of EAI.

1 As a result of these shortcomings in the choice of data incorporated
2 into Staff's methodology, its methodology erroneously suggests that usage
3 per customer will increase over time. Put another way, Staff's
4 methodology incorrectly forecasts that customers will use more energy in
5 the future. As described more fully below, this conclusion is unrealistic
6 and inconsistent not only with the actual data that Mr. Pettett presents, but
7 also with the findings of other experts who have studied this issue and is
8 intuitively at odds with known drivers of electricity usage.

9

10 Q. WHY IS IT INAPPROPRIATE TO ESCALATE BASE USAGE USING THE
11 FIVE YEAR COMPOUND GROWTH RATE AS USED IN STAFF'S
12 METHODOLOGY?

13 A. It is inappropriate because the five-year compound growth rate cannot
14 reasonably be expected to equal the growth rate between 2012 and 2013,
15 as assumed in Staff's methodology. In addition to the problems
16 associated with the selection of start year, end year, and months as
17 described by Mr. Pettett, the fundamental drivers of growth in the previous
18 five years have changed for the 2012-2013 period.

19 For example, in Docket No. 08-144-U, the Commission adopted an
20 energy efficiency resource standard establishing electric utility reduction
21 goals as a percentage of each investor-owned utility's 2010 retail sales of
22 0.25 percent in 2011, 0.50 percent in 2012, and 0.75 percent in 2013.¹

¹ Docket No. 08-144-U, Order No. 17 at 34.

1 The five year growth rates as used by Staff clearly do not fully reflect EAI's
2 introduction of large scale energy efficiency programs equal to at least
3 0.75 percent of EAI's 2010 sales in 2013 consistent with the Commission's
4 directive.

5 Further, the five year growth rate used by Staff's methodology does
6 not fully reflect federal standards that require customers use increasingly
7 efficient equipment. Because the standards in effect for 2012-2013 are
8 significantly more efficient than those in effect over the previous five years,
9 Staff's growth rate is necessarily overstated.

10

11 Q. HOW HAS EAI RESPONDED TO THE COMMISSION'S ENERGY
12 EFFICIENCY RESOURCE STANDARD?

13 A. According to EAI's 2011-2013 Program Plan, Annual Reports, and Energy
14 Efficiency Cost Rate Rider updates provided as part of Docket No. 07-
15 085-TF, EAI has introduced 16 new energy efficiency and demand
16 response programs that span the residential and commercial sectors.² In
17 2011, EAI spent approximately \$13.4 million on energy efficiency
18 programs with evaluated electricity savings of approximately 41,958 MWh.
19 In 2012, both the dollars that EAI spent and its evaluated electricity
20 savings increased substantially to approximately \$28.5 million spent and

² Docket No. 07-085-TF, EAI's Application seeking approval of its Energy Efficiency Programs for the 2011-2013 Program Years at 3 (March 2, 2011).

1 107,627 MWh in evaluated savings.³ EAI's current approved budget for
2 2013 is \$53 million,⁴ with an expected reduction in sales of 165,469
3 MWh.⁵

4 These trends in budget and evaluated savings indicate a robust
5 and increasing commitment by EAI to energy efficiency programs that is
6 not reflected in the five year compound growth rate used by Staff and that
7 will contribute to a decline in average usage per customer.

8

9 Q. DOES THE FIVE YEAR GROWTH RATE ESTIMATED IN STAFF'S
10 METHODOLOGY PROPERLY ACCOUNT FOR THE NEW FEDERAL
11 EFFICIENCY STANDARDS?

12 A. No. The federal Energy Independence and Security Act of 2007 (EISA)⁶
13 implemented new efficiency standards for light bulbs that take effect over
14 the 2012 to 2014 time period, as illustrated in Figure 1 below.

15

³ Docket No. 07-085-TF, EAI Arkansas Energy Efficiency Program Portfolio 2012 Annual Report Workbook at Tab A2 (April 8, 2013).

⁴ In Docket No. 07-085-TF, EAI filed its Application to request approval of an increase in funding of \$8.3 million in 2013 for several programs that are experiencing unanticipated growth with an expected incremental net energy savings of 41,229 MWh (August 7, 2013).

⁵ Docket No. 07-085-TF, EAI's Application seeking approval of its Energy Efficiency Programs for the 2011-2013 Program Years at 6 (March 2, 2011).

⁶ Energy Independence and Security Act of 2007 <http://www.gpo.gov/fdsys/pkg/BILLS-110hr6enr/pdf/BILLS-110hr6enr.pdf>.

Figure 1
Phase In of EISA Light Bulb Efficiency Standards



According to the Energy Information Administration, most light bulbs generally used in residential applications will be required to be at least 30 percent more efficient than traditional incandescent bulbs by 2014⁷ with wattage reductions of up to 67 percent by 2020. As lighting represents approximately 13 percent of residential electricity use, the increasing efficiency standards will substantially impact per capita electricity consumption as existing lamps burn out and are replaced.⁸

In addition, other residential and commercial appliance and equipment efficiency standards and building codes continue to be updated, most recently through the American Energy Manufacturing

⁷ Energy Information Administration "Light bulb standards begin taking effect in 2012" <http://www.eia.gov/todayinenergy/detail.cfm?id=4150>.

⁸ Energy Information Administration "How much lighting is used for electricity in the United States?" <http://www.eia.gov/tools/faqs/faq.cfm?id=99&t=3>.

1 Technical Corrections Act⁹ with further updates under consideration as
2 part of The Energy Savings and Industrial Competitiveness Act of 2011.¹⁰

3 The net effect of all these codes and standards is to depress the
4 growth rate relative to that experienced in the previous five years. In other
5 words, the net effect of recognizing these changes is that one would
6 expect to see lower customer usage rates, not higher as Staff's
7 methodology predicts.

8

9 Q. IS INCREASING ENERGY USE PER CUSTOMER AS SUGGESTED BY
10 STAFF'S METHODOLOGY CONSISTENT WITH ESTIMATES
11 GENERATED BY OTHER EXPERTS?

12 A. No. In its 2013 Annual Energy Outlook,¹¹ the Energy Information
13 Administration ("EIA") projects that electricity consumption per household
14 will decrease by 6 percent between 2011 and 2040. Significant efficiency
15 gains in lighting, appliances, and computers are expected to more than
16 offset additional electricity demands from increased space cooling and
17 increasing use of personal electronics and other new loads as illustrated
18 below in Figure 56 from the EIA Annual Energy Outlook. These
19 expectations are directly at odds with Staff's usage forecasts.

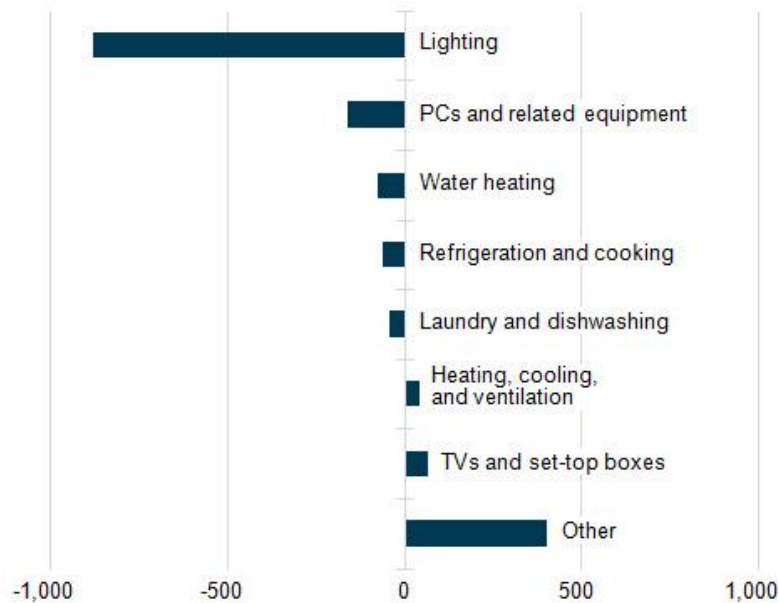
20

⁹ American Energy Manufacturing Technical Corrections Act
<http://www.gpo.gov/fdsys/pkg/PLAW-112publ210/pdf/PLAW-112publ210.pdf>.

¹⁰ The Energy Savings and Industrial Competitiveness Act of 2011
<http://www.gpo.gov/fdsys/pkg/BILLS-112s1000is/pdf/BILLS-112s1000is.pdf>.

¹¹ Energy Information Administration *Annual Energy Outlook 2013 with Projections to 2040*
<http://www.eia.gov/forecasts/aeo/>.

Figure 56. Change in residential electricity consumption
 for selected end uses in the Reference case, 2011-2040
 (kilowatthours per household)



Q. DOES THE TREND OF DECLINING SALES PER CUSTOMER HOLD
 FOR OTHER CUSTOMER CLASSES?

A. Yes. EIA's Annual Energy Outlook provides detailed projections at a national and regional level for electricity use across all major sectors. Arkansas is in EIA's West South Central Region along with Texas, Louisiana, and Oklahoma for the purposes of regional projections. Reference case Table 2 and Table 2.7¹² can be used to calculate projected per capita electricity use across multiple sectors over the period from 2011 to 2040. Between 2011 and 2040 at a national level, per capita electricity use is expected to decline by approximately 4 percent in the

¹² Energy Information Administration *Annual Energy Outlook 2013 with Projections to 2040* Table 2 and Table 2.7 http://www.eia.gov/forecasts/aeo/sector_electric_power_all.cfm#elecdecline.

1 residential sector, 2 percent in the commercial sector, and 4 percent
2 across all sectors. The projected declining per capita consumption trends
3 are stronger in the West South Central region with expected declines in
4 per capita electricity consumption of approximately 8 percent in the
5 residential sector, 12 percent in the commercial sector, and 12 percent
6 across all sectors between 2011 and 2040.

7

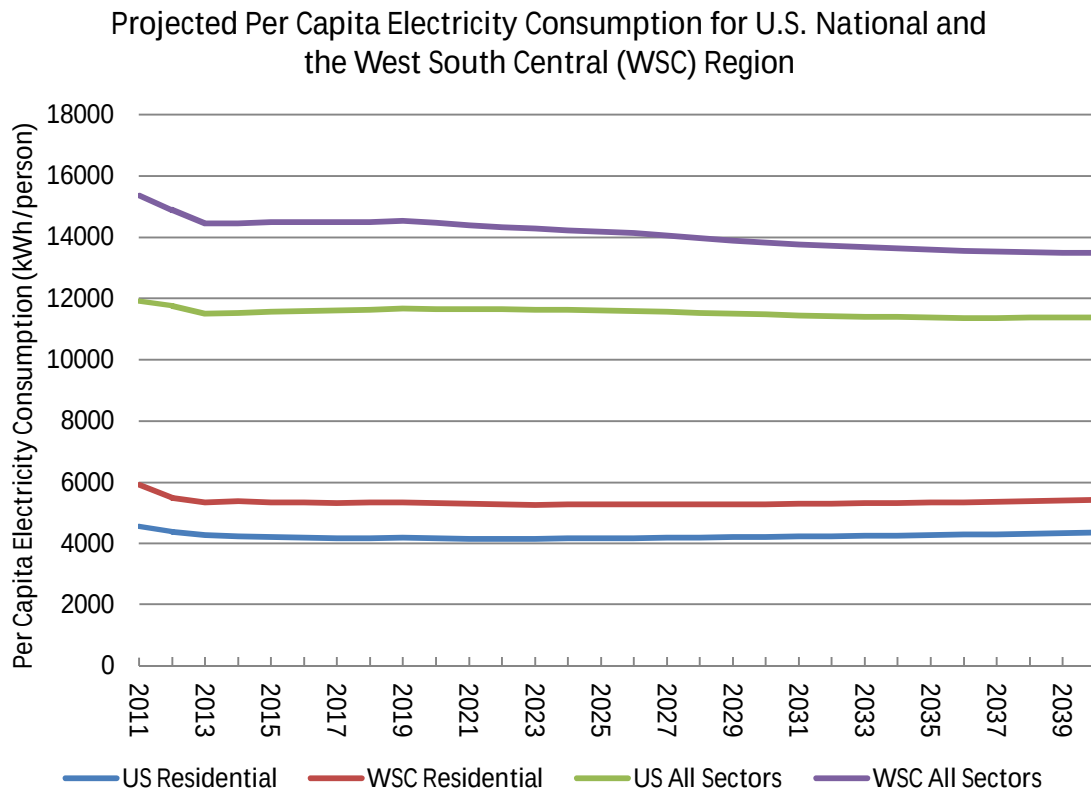
8 Q. DO THE DECLINING TRENDS HOLD FOR THE NEAR TERM (2011-
9 2015)?

10 A. Yes. At the national level, per capita electricity consumption is projected
11 to decrease by approximately 3 percent between 2011 and 2015 across
12 all sectors and by 7.6 percent in the residential sector. For the West
13 South Central region, the decline is expected to be approximately 6
14 percent for the same period across all sectors and 9.7 percent in the
15 residential sector, as illustrated below in Figure 2.

16

1

Figure 2



2

3

4

5

Source: Data calculated from Energy Information Administration Annual Energy Outlook 2013 with Projections to 2040 Table 2 and Table 2.7
http://www.eia.gov/forecasts/aeo/sector_electric_power_all.cfm#elecdecline

6

7

III. CONCLUSION

8

Q. COULD YOU BRIEFLY SUMMARIZE YOUR TESTIMONY?

9

A. Yes. The use of a five-year compound annual growth rate in Staff's methodology for projecting increases in electricity usage per customer is inappropriate given the facts and circumstances in this case, including the energy efficiency program targets enacted by the APSC in late 2010. In addition, recent EAI trends along with regional and national projections all indicate declining per capita electricity consumption across all sectors.

10

11

12

13

14

1 Thus, Staff's methodology, which in this case forecasts increasing usage,
2 is unrealistic and does not adequately account for the new efficiency
3 regulatory environment or national trends.

4

5 Q. DOES THIS CONCLUDE YOUR REBUTTAL TESTIMONY?

6 A. Yes.

CERTIFICATE OF SERVICE

I, Steven K. Strickland, do hereby certify that a copy of the foregoing has been served upon all parties of record by forwarding the same by electronic mail and/or first class mail, postage prepaid, this 26th day of August, 2013.

/s/ Steven K. Strickland
Steven K. Strickland

BEFORE THE
ARKANSAS PUBLIC SERVICE COMMISSION

IN THE MATTER OF THE APPLICATION	)	
OF ENTERGY ARKANSAS, INC. FOR	)	DOCKET NO. 13-028-U
APPROVAL OF CHANGES IN RATES FOR	)	
RETAIL ELECTRIC SERVICE	)	

EAI EXHIBIT DKP-1

EDUCATIONAL, PROFESSIONAL AND
WORK EXPERIENCE OF DAVID K. PICKLES

David Pickles

ICF International

SENIOR VICE PRESIDENT

EDUCATION

Master of Science Degree in Regulatory Economics, University of Wyoming, Laramie, Wyoming, 1988
Bachelor of Science Degree in Economics, University of Wyoming, Laramie, Wyoming, 1986

EXPERIENCE OVERVIEW

Mr. Pickles serves as a Senior Vice President for the Energy Efficiency Practice, where he is responsible for project execution, business development, and management. Mr. Pickles has over twenty five years experience as a regulator, utility senior executive, and industry consultant focused on energy efficiency. Experienced with energy efficiency program design and management, product assessment and business planning, marketing, operations, rate making, and regulatory policy he has helped numerous public and private sector clients evaluate and implement over 100 individual energy efficiency programs and testified as an expert witness on over 20 occasions.

PROJECT EXPERIENCE

ENERGY EFFICIENCY PROGRAMS, POLICY, AND IMPLEMENTATION

For the Maryland Energy Administration, provided an analysis of DSM program cost recovery and rate making practices, including assessment of potential models and utility oversight practices.

For SCANA, provided DSM potential analysis and testimony regarding the ability of DSM to defer the need for a nuclear power plant.

For Arizona Public Service, provided testimony regarding the appropriate recovery of DSM program cost, lost margins, and shareholder incentives.

Developed DSM program filings (including DSM potential, detailed program designs, regulatory filing and benchmarking documents) for the Southern Maryland Electric Cooperative.

Currently supervising the implementation of over 37 individual energy efficiency programs for numerous utility clients, including Oncor, CenterPoint, Entergy, AEP, PNM, New Mexico Gas, PacifiCorp, We Energies, DTE, and Consumers Energy.

Developed DSM program filings (including DSM potential, detailed program designs, regulatory filing and benchmarking documents) for the electric and gas service territories of We Energies (Wisconsin).

For Progress Energy Carolinas, developed a DSM market potential study in North and South Carolina.

Supported Oncor and CenterPoint in the analysis of DSM cost recovery and shareholder incentives through the Public Utility Commission of Texas.

Drafted the energy efficiency chapters of Texas state energy plan on behalf of the Texas Governor's Office.

Developed DSM program filings (including DSM potential, detailed program designs, regulatory filing and benchmarking documents, and full implementation services) for Baltimore Gas and Electric.

Facilitated the efforts of the North American Energy Standards Board to develop ANSI certified standards for DSM planning and evaluation.

Supported the State of Delaware in the analysis and introduction of a Sustainable Energy Utility.

For a confidential Southwestern electric utility, provided a detailed assessment of DSM cost recovery mechanisms including financial modeling of alternative DSM cost recovery, lost margin, and shareholder incentive mechanisms.

For Delmarva Power and Light, estimated achievable DSM savings potential over a 25 year planning horizon and prepared the IRP filing, answered data requests, and participated in regulatory proceedings.

For Potomac Energy Power Company, developed three-year DSM implementation plans for service territories in Maryland and the District of Columbia. Assistance included evaluating programs for cost effectiveness by accounting for customer counts, demographics, and avoided costs unique to each territory and assisting in the preparation of budget estimates and forecasting of participation and load impacts. Prepared regulatory filing documents and participated in hearings before the Maryland Public Service Commission.

For, Hawaii Electric Light Company, provided screening of potential DSM programs and rate designs, detailed cost-effectiveness analysis, program design and implementation guidelines, review of cost recovery and incentive mechanisms, and preparation of regulatory filing documents.

For, Nova Scotia Power, provided DSM regulatory filing assistance. Mr. Pickles' responsibilities included a detailed assessment of DSM cost recovery and shareholder incentive mechanisms, energy efficiency legislation, minimum appliance standards, energy efficient mortgages, and home energy rating systems.

For Exelon, Mr. Pickles provided detailed energy efficiency program design guidelines and implementation plans for a commercial lighting rebate program and a residential air conditioning tune-up program.

For Maui Electric, Mr. Pickles provided DSM program screening, cost effectiveness evaluation, and program design and implementation guidelines.

For Centerior DSM Collaborative Mr. Pickles provided a review and analysis of the structure and procedures of a diverse collaborative, developing recommendations for process improvements.

For Iowa-Illinois Gas & Electric, reviewed all DSM implementation activities. Mr. Pickles analyzed Iowa-Illinois' implementation activities for consistency with administrative rules and regulatory expectations.

For Peoples Natural Gas, developed an energy efficient customer financing program. Provided program design and analysis for a customer financing program in multiple states, including program design, solicitation of banks and other financial institutions, contract negotiation, and implementation procedures.

For a consortium of utilities, including: Consolidated Edison, Southern Indiana Gas and Electric, Tucson Electric, and Hawaiian Electric, reviewed energy efficiency financing programs. Included an analysis of the structure and risk profiles of potential financing techniques, a best practices review of the financing programs of other utilities and other industries, market research including conjoint analysis, and development of program design recommendations.

Assessed energy efficiency new business opportunities, including financing and leasing. Assisted in the market research (focus groups, conjoint survey) and managed a project to determine competitive activities in financing, new business planning methodologies, and forecasted profitability for new business ventures.

For Florida Power Corp, developed a DSM financing program including financial structure and process flows.

For Carolina Power and Light, surveyed energy efficiency financing programs. Provided a survey and best practices review of utility financing programs.

For a confidential Midwestern utility, assessed the potential for customer financing programs to provide customer acceptance consistent with that of simple subsidies and rebates. This project included an analysis of the DSM and marketing goals of the utility, an analysis of the change in economic benefit under financing, a review of acceptance experienced by other utilities, and recommendations for program design.

For multiple clients, prepared an analysis of innovative DSM in a competitive environment. Mr. Pickles provided a summary and analysis of innovative approaches to allocating and collecting the economic costs of DSM programs from program participants and non-participants. This project includes a survey of all state regulatory commissions and selected utilities, and a comparative analysis of rate impacts, effectiveness and equity.

For Wisconsin Public Service, Mr. Pickles provided a comparative analysis of DSM rebate and DSM loan programs to assess the ability of each to address regulatory goals and to identify the optimal design elements of DSM financing programs.

For Indiana Municipal Power Agency, assessed the rate and revenue impacts of DSM programs. Mr. Pickles provided revisions to IMPA's DSM programs, and provided detailed analysis of the timing and level of rate impacts and revenue fluctuations.

For Hawaii Electric Company, provided a screening of various potential energy efficiency rate designs (including time-of-use rates, interruptible rates, and stand-by generation rates.) Based on the results, Mr. Pickles developed detailed rate designs and implementation plans for the selected rates, and prepared regulatory filings.

FOR GUAM POWER AUTHORITY, PROVIDED AN ANALYSIS AND DESIGN OF AVOIDED COST BASED TIME-OF-USE AND INTERRUPTIBLE RATES. MR. PICKLES DESIGNED AND EVALUATED TOU RATES FOR ALL CUSTOMER CLASSES AND LARGE CUSTOMER INTERRUPTIBLE RATES BASED ON APPLICATION OF AVOIDED COSTS.

NEW BUSINESS AND PRODUCT PLANNING

In more than 10 assignments for energy and utility companies, Mr. Pickles performed new product ideation, characterization, screening, business model creation, market assessment, business plan creation, and provided varying levels of support in obtaining funding, negotiating joint ventures, creating operating plans, identifying acquisition targets, and related start-up activities.

For, Electric Power Research Institute (EPRI) provided an analysis of potential new revenue opportunities for electric utilities. Principal author of the EPRI report *New Service Opportunities for Electric Utilities*.

For a large utility holding company, helped redefine the product development and funding process, developing new standards and procedures for business model assessment and new enterprise management.

For Commonwealth Edison, Mr. Pickles provided an analysis and market potential screening for a wide range revenue and load growth technologies and programs.

For a confidential client, Mr. Pickles developed an assessment of new business opportunities. Performed market research (focus groups, conjoint survey) and managed a project to determine competitive activities in non-traditional service, to assess new business planning methodologies, and forecast profitability for new business ventures.

For a large municipal energy organization, provided an overview of the market potential and business requirements for a wide range of new products and services. Created an operating framework for the selected new venture and helped identify and negotiate with a joint venture partner.

For Ameren, Mr. Pickles provided a redesign of their new business development process and investment decision making process. He established decision criteria, stage gates, hurdle rates and standards for investment. He also institutionalized this process by assessing two potential new products, performed due diligence and participated in senior management evaluation process of acquisitions.

For a private equity fund, provided an assessment of their investment in an energy management outsourcing company and recommended a revised business model and infrastructure.

For a large real estate investment trust, Mr. Pickles represented senior management in negotiations with a utility to form a joint venture to provide facilities management outsourcing. He assessed core capabilities, contract structure, allocations of risk, control, dissolution, and related issues.

For a confidential utility, conceived and introduced a new product offering involving energy equipment ownership, maintenance, and energy supply. Developed an innovative program wherein price is indexed to measures of customer profitability. Established procedures for managing risk and for sharing benefits of retail access with customers while retaining rights to commodity supply.

For a utility affiliate, developed and introduced end-use pricing (chauffage) program. Obtained \$50 million equity commitment from holding company for customer premise equipment and negotiated two such contracts. Integrated energy rights marketing into such contracts providing for agency rights over energy supply.

For a confidential real-estate holding company, established strategy for entering energy services business and performed target identification and acquisition analysis of energy service and energy information companies. Also determined bid price(s) and negotiation strategy.

For a consortium of utilities, managed a multiclient study of customer financing programs, including an analysis of the structure and risk profiles of potential financing techniques, a best practices review of the financing programs of other utilities and other industries, market research including conjoint analysis, and development of program design recommendations.

For a confidential utility Client, developed a business plan for two-way customer communications, CATV, telephony, and other information services in conjunction with utility service. This project included an analysis of the costs and operational savings of potential system configurations, customer acceptance, and related items.

For a confidential client, participated in the valuation and development of a revised business model and growth plan for an energy service subsidiary. Assessed strategic issues (such as product line, sectors, etc.) and tactical issues (e.g., cash management, pricing, etc.) Provided assessment of energy information and automation markets, distributed generation, and related products. Developed new management and staffing structure.

For a water heater manufacturer, developed a business plan for a turn-key financing program. Developed a water heater financing/leasing program to be offered nationally in conjunction with participating utilities. This project included program design, role of financial institutions, marketing approach, and related tasks.

For a utility affiliate, developed integration and bidding strategy for combining commodity supply (in deregulated markets), performance contracting, financing, consolidated billing, and energy information services. Managed the development of joint bids with power marketing subsidiary and secured contracts.

DEAL FLOW & DUE DILIGENCE

For a private equity fund, provided an investigation of potential investments in energy sector technology and outsourcing ventures. Provided business assessment and development, market research, deal structuring, and start-up services.

For a large holding company, prepared for entry into the electrical contracting business. Developed business model, identified acquisition targets, performed valuation and due diligence, participated in negotiations, and developed integration and operations procedures.

For a \$600 million venture capital investment fund, provided energy sector investment advice and deal-flow. Provided analyses of energy markets and business plans. Developed investment processes, provided analysis of management teams, and supported due-diligence and deal structuring. Assisting portfolio companies with start-up issues and keiretsu relationships.

For an investment bank, obtained additional investors for spin-out of an energy and home automation subsidiary. Reviewed Offering Memorandum, solicited investors in the U.S. and Europe, and helped structure the deal.

For a confidential client, provided identification of potential acquisition targets, profiling, analysis of potential synergies, assessment of integration issues, recommended deal terms.

For a utility, defined the approach and led a client team in an assessment of a potential acquisition. Activities included analysis of management team, process mapping, competitive analysis, development of comparables and deal structure, strategic review, due diligence (legal, HR, IT), customer interviews, and related activities.

For a large energy sector investment advisor, assisted in the establishment of a new fund to acquire distressed energy sector assets. Assessed potential strategic partners, market potential, fund structures, and acquisition targets.

BUSINESS UNIT EXECUTIVE MANAGEMENT

Led turn around team for a \$100M/year struggling energy services business. Performed valuation, management assessment, developed new strategic plan, assessed business processes and funds management. Developed new processes for guarantee management and bonding and assessed growth path and ability to make and integrate acquisitions.

Led turn around team for a \$30M/year energy services businesses. Developed new value propositions, marketing plan, sales processes, and contracting procedures. Prepared business plan and developed partners and equity sources for an MBO.

For a confidential utility client, conceived and led a 16-member team in the development of a business plan, securing of funding, development, and introduction of an advanced energy information system. Negotiated profit sharing venture with leading information technology provider and brought product from concept to commercial availability in 11 months.

For a private Internet company, determined all aspects of an aggregation and building portal designed to create purchasing communities for the occupants of large office and multi-family buildings. Raised funding, negotiated venture capital agreements, set requirements, oversaw development, and supervised sales.

OPERATIONS

For a confidential energy client, determined market channel strategy and negotiated sales alliances and distributorships with several companies, including power marketers, one of the nation's largest property management companies, a telecommunications company specializing in the office building market, and an electrical contractor. Established wholesale and shared margin relationships.

For a confidential energy client, developed all aspects of corporate marketing strategy including print, television and radio. Introduced disciplined market research into business planning and operations process. Pioneered use of conjoint studies and competitive intelligence in establishing pricing. Introduced observational market research for purposes of identifying new product opportunities.

Determined wholesale marketing strategy and identified competitive targets for the economic development and wholesale marketing rates of a confidential client. This project included a high level analysis of approximately 400 potential targets based upon prices currently paid, the cost structure of their current supplier, potential receptiveness to energy services, and other criteria.

For a utility affiliate, established channel strategy and led negotiations with the world's largest manufacturer of HVAC equipment to co-market energy information systems both domestically and abroad. Relationship includes integration of complementary information systems and co-branding.

For a confidential client, established branding strategy and led negotiations with the world's largest manufacturer of building controls to private label energy systems in certain market segments. Relationship provides for extensive support services (implementation, training, and operations), profit sharing, market exclusivity, and product co-development.

For a utility affiliate, oversaw transition of previously regulated National Account Managers to unregulated business. Developed training program and established code of conduct. Developed market based compensation structures.

For a utility affiliate, developed, in conjunction with an investment bank, bidding strategy and acquisition analysis of large independent energy service company. Extended framework to perform ongoing shareholder value analysis of the acquirer and used this model to establish business planning guidelines.

For a utility affiliate, recruited and trained sales staff from outside the utility industry, set and administered sales goals and methods. Oversaw the development of a lead identification, sales tracking, and contact management system.

For a utility affiliate, led team of business analysts and attorneys in development of contracts for performance contracting, energy information services, chauffage, distributorships, joint ventures, and other business structures.

EMPLOYMENT HISTORY

ICF International	Senior Vice President	2010-date
ICF Consulting	Vice President	2004-2010
Navigant Consulting	Director, Market Strategy	2000-2003
PHI Management Consultants/Honeywell	Principal, Chief Technology Officer	1999-2000
EnerShop, Subsidiary of Central & South West Services	Vice President Marketing, Development, and Operations (Officer)	1996-1999
Synergic Resources Corporation	Director, Pricing & Product Development	1992 - 1995
Iowa Office of Consumer Advocate/Iowa Utilities Board	Utility Specialist/Senior Analyst	1988-1992

BEFORE THE
ARKANSAS PUBLIC SERVICE COMMISSION

IN THE MATTER OF THE APPLICATION	)	
OF ENTERGY ARKANSAS, INC. FOR	)	DOCKET NO. 13-028-U
APPROVAL OF CHANGES IN RATES FOR	)	
RETAIL ELECTRIC SERVICE	)	

DIRECT TESTIMONY

OF

PATRICK J. CICIO

DIRECTOR, MID-OFFICE AND ENERGY SETTLEMENT
ENERGY SERVICES, INC.

ON BEHALF OF

ENTERGY ARKANSAS, INC.

AUGUST 26, 2013

1 **I. BACKGROUND**

2 Q. PLEASE STATE YOUR NAME, TITLE, AND BUSINESS ADDRESS.

3 A. My name is Patrick J. Cicio. My business address is Entergy Services,
4 Inc. ("ESI"),¹ Parkwood II Building, Suite 300, 10055 Grogan's Mill Road,
5 The Woodlands, Texas 77380. I am the Director, Mid-Office and Energy
6 Settlements for the System Planning and Operations ("SPO") department,
7 a department of ESI.

8

9 Q. ON WHOSE BEHALF ARE YOU TESTIFYING?

10 A. I am testifying on behalf of Entergy Arkansas, Inc. ("EAI" or the
11 "Company").

12

13 Q. PLEASE DESCRIBE YOUR DUTIES.

14 A. I am responsible for administering the Intra-System Billing associated with
15 the Entergy System Agreement, overseeing fuel and power settlements
16 and reporting, as well as compliance with the electric reliability standards,
17 directing the department budgets, and establishing and implementing the
18 overall risk management policy for transactions in the power and fuel
19 markets.

20

¹ ESI is a service company subsidiary of Entergy Corporation that provides technical and administrative services to all the Operating Companies.

1 Q. PLEASE STATE YOUR EDUCATION, PROFESSIONAL AND WORK
2 EXPERIENCE.

3 A. My education, professional and work experience is contained in EAI
4 Exhibit PJC-1.

5

6 Q. HAVE YOU PREVIOUSLY TESTIFIED BEFORE A REGULATORY
7 COMMISSION?

8 A. Yes. A listing of my prior testimony is included in EAI Exhibit PJC-1.

9

10 Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

11 A. My testimony responds to APSC General Staff ("Staff") witness Clark
12 Cotten's request that the Company provide an explanation of EAI's
13 proposed methodology to determine avoided energy cost and avoided
14 capacity cost in the Small Cogeneration Rider ("Rider SCR") and Larger
15 Cogeneration Rider (Rider LCR") tariffs. In response to that request, I
16 address certain matters related to EAI's proposed revisions to its current
17 methodology used to calculate the avoided costs that are used to pay
18 Qualifying Facilities ("QFs") for non-firm, as-available energy put to the
19 Company pursuant to the Public Utility Regulatory Policy Act ("PURPA").²
20 My testimony will:

² QFs consist of electric generating facilities that are "qualifying cogeneration facilities" or qualifying small power production facilities" as defined under Federal Energy Regulatory Commission ("FERC") regulations. *E.g.*, 18 C.F.R. Section 292.101 (2012).

- 1 • provide a brief history of EAI's current methodology used to
2 calculate avoided costs to be paid to QFs that was determined
3 to be consistent with PURPA and related federal and state
4 regulations and state law by the Commission in Docket No. 04-
5 113-U;³
- 6 • describe the options that will be available to QFs following the
7 integration of EAI into the Midcontinent Independent System
8 Operator, Inc. ("MISO")⁴ Regional Transmission Organization
9 ("RTO");
- 10 • explain the Company's avoided cost proposal, including the
11 formula to be used to calculate avoided cost for purposes of
12 EAI's Rider LCR, and how the proposal will be implemented,
13 including how the proposal differs with respect to QFs registered
14 as separate Load Zones in MISO, which will include all QFs
15 larger than 20 MW⁵ and QFs embedded within the EAI Load
16 Zone, which will include all QFs smaller than or equal to 20 MW;
17 and

³ Docket No. 04-113-U, Order No. 18 at 11, 20-21; Order No. 21 at 13.

⁴ MISO is an independent, non-profit regional transmission operator responsible for maintaining reliable transmission of power in 12 U.S. states and the Canadian province of Manitoba. See <https://www.midwestiso.org/AboutUs/Pages/MISOFAQ.aspx>

⁵ If a BTM QF larger than 20 MW has host load greater than generation, such that the BTM QF never puts to EAI, and they do not have a contract to be paid for their put, EAI did not register these QFs in a customer specific load zone.

- 1 • explain the effect of EAI's transition into the MISO RTO on the
2 calculation of avoided cost under Rider SCR.

3
4 **II. CURRENT APPROACH TO CALCULATING AVOIDED COSTS**

5 Q. HOW IS AVOIDED COST DEFINED IN ARKANSAS?

6 A. The Commission's Cogeneration Rule 1.1(b)(6) defines "Avoided Energy
7 Cost" as "the incremental costs to an electric utility of electric energy or
8 capacity or both that, but for the purchase from the qualifying facility or
9 qualifying facilities, such utility would generate itself or purchase from
10 another source."⁶ The definition of avoided cost in EAI's Rider LCR is
11 consistent with this definition. In its current version, it provides that the
12 energy payment will be based upon "the highest avoided energy cost on
13 the Entergy Electric System at the time energy is purchased from the
14 customer."⁷

15
16 Q. PLEASE DESCRIBE EAI's CURRENT APPROACH TO CALCULATING
17 AVOIDED COST.

18 A. As the language I just mentioned indicates, EAI's avoided cost currently is
19 calculated for purposes of Rider LCR based upon the cost to the Entergy

⁶ Arkansas Cogeneration Rules 1.1(b)(6)

⁷ Rider LCR, Section 35.3. Note that this language applies to "Option 2." "Option 1" contemplates a situation where the avoided cost is calculated at the time the contract is negotiated, but there currently are no Rider LCR customers who have such a contract.

1 Electric System⁸ as calculated pursuant to the Entergy System
2 Agreement. As the Commission's Administrative Law Judge noted in
3 Docket No. 04-113-U,
4

5 [T]he Entergy [Electric] System is dispatched on a
6 system wide basis. Because the Entergy [Electric]
7 System responds to changes in load on a system wide
8 basis, and not on a jurisdiction specific basis, hourly
9 avoided costs cannot be calculated for EAI on a stand
10 alone basis.⁹

11 That docket was implemented in response to a Petition for Declaratory
12 Order filed by EAI with the Commission seeking to resolve a number of
13 issues and sub-issues related to certain refinements implemented by EAI
14 and the other Entergy Operating Companies¹⁰ to the calculation of the
15 avoided cost rate for the Entergy Electric System paid to QFs. One of
16 these refinements became appropriate because of the profound changes
17 that the market for wholesale electricity had undergone. Ultimately, the
18 APSC concluded that EAI's refinements to its avoided cost calculation
19 were consistent with PURPA and related federal and state regulations and
20 state law.¹¹

⁸ The Entergy Electric System is comprised of the generation and bulk transmission facilities of the Operating Companies, which facilities are operated as a single, integrated electric system.

⁹ Docket No. 04-113-U, Order No. 18 at 5.

¹⁰ The other Entergy Operating Companies are Entergy Gulf States, Inc.; Entergy Louisiana, LLC; Entergy Mississippi, Inc.; and Entergy New Orleans, Inc. The Entergy System refers collectively to all five Operating Companies and Entergy Services, Inc., which frequently acts as agent on behalf of all the Operating Companies.

¹¹ Docket No. 04-113-U, Order No. 18 at 11, 20-21; Order No. 21 at 13.

1 Q. COULD EAI CONTINUE TO USE THE CURRENT METHODOLOGY TO
2 CALCULATE AVOIDED COSTS PURSUANT TO RIDER LCR?

3 A. No. As EAI witness Kurtis W. Castleberry explained in his direct
4 testimony in this proceeding, when EAI terminates its participation in the
5 Entergy System Agreement in December 2013, the “avoided energy cost
6 on the Entergy System” referenced in Rider LCR will no longer be
7 applicable to EAI, and neither would it reflect the cost avoided by the
8 Company as a result of a QF put.¹² In addition, once EAI’s participation in
9 the System Agreement ends and EAI is operating in MISO, one of the key
10 elements of EAI’s current avoided cost methodology (i.e., “avoided cost
11 rejected purchases,” or wholesale power purchases that would have been
12 made but for the objective to be able to accommodate puts of energy from
13 QFs), will no longer be available. Accordingly, a change in the calculation
14 methodology must be implemented. Further, as discussed below, once
15 EAI integrates into the MISO Day 2 Market¹³ construct, the avoided cost
16 can be actually observed via MISO settlements data, obviating the need
17 for an after-the fact determination of avoided costs based on modeling by

¹² Castleberry Direct Testimony at 46.

¹³ Day 2 Markets are centralized region-wide markets operated by RTOs that include day ahead unit commitments, a real time balancing market, and an integrated ancillary services markets. In a Day 2 Market, generators are required to schedule or bid into the market, locational marginal prices are used to price the use of the transmission grid, congestion charges replace “first come, first served” transmission service, and financial transmission rights (“FTRs”) are used to hedge congestion. The “Day 2” label arose because these are things that RTOs began to implement after they initially began to operate, or in the “Day 2” of their creation.

1 EAI. In the next section, I provide additional details regarding the options
2 Mr. Castleberry discussed generally in his direct testimony.¹⁴
3

4 **III. OPTIONS FOR QFS IN THE MISO DAY 2 MARKET**

5 Q. WHAT OPTIONS WILL BE AVAILABLE TO QFs FOLLOWING THE
6 COMPANY'S INTEGRATION INTO THE MISO DAY 2 MARKET?

7 A. Essentially, there are two options, the Hybrid Option and the Behind-the-
8 Meter ("BTM") Option. A QF must elect either one or the other. MISO
9 describes these options in a document entitled "Qualifying Facilities
10 Generator Readiness for MISO Reliability Coordination and Market
11 Integration," which is available on the MISO website.¹⁵ My understanding
12 is that the only QF in EAI's territory that could qualify for the Hybrid Option
13 in MISO already has registered as a Market Participant in MISO and thus
14 will use the Hybrid Option. However, because customers may switch
15 between options, as I discuss later, I will explain both options here.
16

17 Q. WHAT IS THE HYBRID OPTION?

18 A. The Hybrid Option allows QFs to receive the benefits of being a
19 participating generator in the MISO Day 2 Market. QFs that register their
20 generator(s) in the MISO commercial model and become MISO Market

¹⁴ Castleberry Direct Testimony at 47.

¹⁵ <https://www.misoenergy.org/Library/Repository/Communication%20Material/Strategic%20Initiatives/Qualifying%20Facility%20Generator%20Readiness.pdf>.

1 Participants are eligible to participate (*i.e.*, submit offers or self-schedule)
2 in both the day-ahead and real-time MISO markets up to the generator's
3 maximum capacity minus the host load. Under this hybrid approach, a QF
4 effectively separates its generation into a portion that serves its host load
5 and a portion that the QF will be able to use to participate directly in the
6 MISO market. The portion of the QF generation participating in the market
7 would be registered as a generator in the MISO commercial model by
8 either the QF or an agent of the QF. However, even the portion that is
9 dedicated to serving host load can be sold into the MISO energy markets
10 under conditions where host load is less than expected. This can be done
11 on a day-ahead basis or on an unscheduled basis in the real-time market.

12 Q. WHAT OPTIONS ARE AVAILABLE TO QFs THAT ELECT THE HYBRID
13 OPTION AND THUS BECOME MISO MARKET PARTICIPANTS?

14 A. QFs that register in the commercial model and participate as MISO Market
15 Participants:

- 16 • may register net excess generation in the market and offer it to
17 the energy, capacity, and ancillary services markets;
- 18 • may offer generation above their registered level to the energy
19 markets subject to market business practices and tariff
20 requirements;

- 1 • may participate in asset-sourced bilateral transactions from their
- 2 generating unit, both with buyers in the MISO markets and
- 3 buyers outside of the MISO region;
- 4 • may put energy to the EAI through the use of an asset-sourced
- 5 financial schedule and receive an avoided cost payment; and
- 6 • may withdraw supplemental, backup or maintenance energy for
- 7 host load pursuant to the applicable retail rate.

8

9 Q. ARE THERE REQUIREMENTS OF QFs THAT ELECT TO BECOME
10 MARKET PARTICIPANTS?

11 A. Yes. These requirements are defined in the MISO Tariff and Business
12 Practice Manuals. Without attempting to modify the requirements
13 established by MISO, QFs that register in the MISO commercial model
14 and participate as MISO Market Participants:

- 15 • must provide revenue-quality metering data for each of their
- 16 Commercial Pricing Nodes (“CPNodes”) in the market;
- 17 • must provide MISO adequate metering and data to determine
- 18 whether flexible economic resources offered and accepted in the
- 19 real-time market are dispatched by their owners in a manner
- 20 consistent with set points issued by MISO; this verification is
- 21 needed so that MISO can assure reliable operation within its
- 22 Balancing Authority in real time; and

- must have Automatic Generation Control (“AGC”) for resources offering regulation service into the market. (Note: The energy market has a 5-minute periodicity, so AGC is encouraged for that market as well, but is not required.)¹⁶

Q. IF QFs ELECT TO PARTICIPATE USING THE HYBRID MODEL, ARE THERE OPTIONS THAT NO LONGER WILL BE AVAILABLE TO THEM IN THE MISO MARKET?

A. No. QF resources participating in the market via the Hybrid Option would still be able to put energy to EAI through the use of an asset-sourced financial schedule and receive an avoided cost payment. It should be noted that Hybrid QFs also have the option to sell unscheduled energy to the MISO real-time market subject to the rules that apply within that market.

Q. HOW WILL QFs THAT ELECT THE HYBRID OPTION FOR POWER THAT THEY GENERATE AND DELIVER TO THE TRANSMISSION GRID BE COMPENSATED?

A. Hybrid QFs will be paid either directly by MISO, for the power they deliver to the MISO market; or they have the option of scheduling the output of their generator bilaterally to another buyer in MISO with whom they have a

¹⁶ The MISO Tariffs and Business Practice Manuals can be located at <https://www.misoenergy.org/Library/Pages/Library.aspx>

1 private commercial arrangement. When output is scheduled to a buyer,
2 through a process I describe below, the buyer pays the QF directly for the
3 energy in accordance with the parties' commercial arrangements. The
4 transaction is also allocated the marginal losses to the transaction and, if
5 applicable, congestion charges, which are assigned to the buyer, seller, or
6 a proportion to both via the financial bilateral schedule market instrument.

7
8 Q. HOW ARE BILATERAL SCHEDULES IMPLEMENTED IN MISO?

9 A. Bilateral schedules within MISO are implemented via the MISO settlement
10 process, through a transaction called a financial schedule ("FinSched").
11 FinScheds are bilateral transactions with a seller, buyer, source, delivery
12 point, sink, quantity, and term. Either party can schedule the FinSched
13 with MISO. The FinSched transaction may be allocated marginal losses
14 and, if applicable, congestion charges, which may be assigned to the
15 buyer, the seller, or a proportion to both depending on the particular
16 FinSched agreement. A FinSched with a MISO generator as its source is
17 called an asset-sourced FinSched; it is the MISO equivalent of a physical
18 bilateral sale in a non-Day 2 Market. An asset-sourced FinSched requires
19 a MISO generator that is registered in the MISO commercial model and
20 that delivers energy to the MISO grid, whether scheduled or unscheduled
21 by MISO.

22
23 Q. WILL HYBRID QFs BE PAID BY EAI?

1 A. As explained above, Hybrid QFs will be paid either by MISO or by a
2 purchaser under a private bilateral arrangement. If EAI is the purchaser
3 under a bilateral arrangement, the sale will involve a FinSched and the
4 Hybrid QF will be paid by EAI. This would be the case if EAI and the QF
5 have entered into a private bilateral agreement, or if the QF is putting to
6 EAI and being paid through an applicable avoided cost rate on file with the
7 APSC. In addition, hybrid QFs will pay EAI under the applicable state
8 tariff for any standby, supplemental, or maintenance energy that they
9 purchase from EAI to serve their host load.

10

11 Q. PLEASE DESCRIBE THE BEHIND-THE-METER OPTION.

12 A. QFs that elect the BTM Option will keep all of their facilities behind the
13 meter and will not be able to participate directly in the MISO markets.
14 Under this option, a QF will put all energy in excess of its host load to its
15 host utility pursuant to the host utility's avoided cost tariff. For each QF
16 customer that does not become a Market Participant, EAI will include the
17 behind-the-meter QF generation and its host load in a separate Load Zone
18 CPNode. This QF-specific Load Zone will be registered in the MISO
19 commercial model, and like all Load Zones in MISO will constitute a
20 CPNode. The QF and its host load will be modeled as a single net
21 injection point at the load CPNode. The establishment of a separate Load
22 Zone requires certain metering and telemetry requirements; therefore, EAI
23 has not created separate Load Zones for QFs smaller than or equal to

1 20 MW.¹⁷

2

3 Q. WILL QFs THAT CHOOSE THE BTM OPTION BE ABLE TO SELL
4 CAPACITY, ENERGY, OR ANCILLARY SERVICES INTO THE MISO
5 DAY 2 MARKET?

6 A. No. The BTM QF will not be registered as a generator in MISO's
7 commercial model, and therefore the BTM QF will not be eligible to
8 participate in any of the MISO markets or the MISO settlement process.
9 Further, a BTM QF is not registered as a generator in the MISO
10 commercial model, so it cannot be paid by MISO nor can it be the source
11 for an asset-based FinSched or transmission schedule.

12

13 Q. WHO WILL PAY BTM QFs FOR ENERGY THAT THEY PUT TO EAI?

14 A. BTM QFs will be paid by EAI. MISO will credit EAI for the net injection
15 (negative load) at the QF-specific Load Zone CPNode according to the
16 terms of the MISO Tariff, and the Company will, in turn, rely upon MISO's
17 market settlement data to determine the payment to the QF pursuant to
18 the terms of Rider LCR.

19

¹⁷ It should be noted that the MISO Tariff provides for a demand response program known as Behind-the-Meter Generation; although they have similar names, the BTM Option for QFs has no relation to the Behind-the-Meter Generation demand response program in MISO, and it is important for purposes of my testimony and this proceeding not to confuse the two.

1 Q. WILL A QF HAVE THE ABILITY TO SWITCH BACK AND FORTH
2 BETWEEN THE HYBRID AND THE BTM APPROACH?

3 A. Unless the Company is relieved by FERC of its obligation to purchase QF
4 puts, a QF would have the ability to switch between the Hybrid Option and
5 BTM Option each quarter. As explained by Mr. Castleberry in his direct
6 testimony, the Company plans to file a request with FERC to be relieved
7 of its obligation to enter into new QF purchase arrangements once it is in
8 MISO.¹⁸ If the FERC terminates the Company's obligation to accept QF
9 put energy (from QFs greater than 20 MW in size), all such QFs that wish
10 to sell energy would be required to register as Market Participants and to
11 deliver their energy to load other than the host; effectively, all QFs would
12 operate under the Hybrid Option, but the Hybrid Option would no longer
13 include the right of the QF to put excess energy to EAI through a
14 FinSched.

¹⁸ Castleberry Direct Testimony at 47.

1 **IV. IMPLEMENTATION**

2 Q. WILL A BTM QF BE REQUIRED TO REGISTER ITSELF AS A
3 SEPARATE LOAD ZONE IN MISO?

4 A. No. The Company will be responsible for the registration of QFs that do
5 not register themselves.

6

7 Q. DOES THAT MEAN THAT A BTM QF WILL NOT HAVE ANY
8 INTERACTION WITH MISO?

9 A. No, it does not. As the regional Reliability Coordinator, MISO has
10 established certain registration and reliability data communication
11 requirements for generators, which are spelled out in more detail in the
12 “Qualifying Facilities Generator Readiness for MISO Reliability
13 Coordination and Market Integration” document I referenced earlier in this
14 testimony.

1 **V. AVOIDED COST FORMULA**

2 Q. HOW WILL THE COMPANY CALCULATE AVOIDED COST UNDER THE
3 PROPOSED METHODOLOGY?

4 A. As a preliminary matter, it should be noted that the avoided cost pricing
5 methodology proposed by the Company would use calculations that are
6 made by MISO for the credits and charges associated with QF energy.
7 Separately, any costs incurred directly by the Company to manage QF
8 puts in the MISO Day 2 Market, such as the costs that may be incurred to
9 administer the real-time scheduling option would be assessed to QFs.
10 The Company simply would sum these MISO-determined credits and
11 charges in each hour during which energy is delivered and then add any
12 approved administrative costs incurred by the Company.

13
14 Q. WHAT WILL THE MISO-DETERMINED CREDITS AND CHARGES YOU
15 MENTIONED INCLUDE?

16 A. The MISO settlement data will include hourly values for the amount of
17 energy injected by the QF (shown as a negative load), the relevant
18 Locational Marginal Price ("LMP"), and other market charges (including,
19 but not necessarily limited to, Revenue Sufficiency Guarantee ("RSG"),
20 Schedule 17, and Schedule 24 charges) assessed by MISO to EAI and
21 identified by MISO as being associated with the QF energy. For each
22 hour, the avoided cost payment will be the product of the relevant LMP
23 times the quantity of energy injected, less the other market charges

1 associated with the QF. The monthly payment will be the sum of the
2 results of each of these hourly amounts, which will be calculated by MISO
3 and identified on the settlement statement. The charge to account for any
4 applicable administrative charges incurred by EAI will be deducted from
5 the avoided cost energy payment.

6

7 Q. WHAT IS THE SPECIFIC FORMULA THAT THE COMPANY WOULD
8 USE TO CALCULATE AVOIDED COST UNDER ITS PROPOSED
9 METHODOLOGY?

10 A. The formula is set forth below.

11 Monthly Payment (MP) for a Qualifying Facility (QF) putting power to the
12 Company shall be:¹⁹

13

$$MP_{QF} = \left(\sum_{i=1}^n [LMP_{QF,i} \times MWh_{QF,i}] - OMC_{QF,i} \right) - MCC$$

14

¹⁹ This formula describes the components of the avoided cost rate and is presented for clarity. The actual calculation of these amounts will be made by MISO and set forth on daily settlement statements provided by MISO along with the underlying price, quantity, and charge type information.

1 Where.²⁰

2 $LMP_{QF,i}$ The Real Time Locational Marginal Price for hour “i”
3 at the Applicable Load Zone for BTM QFs and generator bus for Hybrid
4 QFs as expressed in dollars per megawatt-hour;

5 $MWh_{QF,i}$ Megawatt-hours either (1) injected by the BTM QF for
6 hour “i” of the month or (2) excess energy scheduled by an accepted
7 asset-sourced FinSched from the Hybrid QF to the Company, consistent
8 with the terms and conditions of the avoided cost tariff; and

9 $OMC_{QF,i}$ Other Market Charges associated with a QF non-firm
10 energy sale that are assessed by MISO to the Company as they appear
11 on the MISO settlement statements, if the QF is either a BTM QF
12 registered as a separate Load Zone or a Hybrid QF.

13 MCC Monthly customer service charge for administrative costs
14 incurred directly by the Company to manage QF put.

15

16 Q. WILL PUTS FROM HYBRID QFs BE PRICED IN THE SAME WAY?

17 A. Yes. Hybrid QFs electing to put excess energy to EAI will enter
18 FinScheds. The source and sink of the FinSched will be the generator
19 CPNode. EAI will be credited by MISO for the energy (MWh) delivered
20 through the FinSched at the generator CPNode, based on the applicable

²⁰ The terms used in the definitions in this formula are as defined in the MISO Tariff.

1 real-time LMP at that CPNode. EAI will pay the Hybrid QF under the
2 formula outlined above.

3 It is important to note that while the avoided cost paid to both BTM
4 QFs and Hybrid QFs will include an adjustment for Other Market Charges,
5 those charges may be different. For example, while a Hybrid QF putting
6 to the Company through a FinSched will contribute to EAI's Schedule 17
7 and Schedule 24 charges, it will not contribute to the Company's RSG
8 charges, unless MISO changes its tariff.

9

10 Q. WILL AVOIDED COST TO ALL QFs BE PRICED UNDER THIS SAME
11 FORMULA?

12 A. No. First, QFs that are 100 kW or below in size, and thus subject to EAI's
13 proposed Rider SCR, will continue to be paid based upon a projected
14 avoided cost rate,²¹ albeit with the projections being for avoided cost in the
15 MISO market. Currently, with EAI as participant in the Entergy System
16 Agreement, those projections are developed using the PROMOD
17 production cost simulation model. In order to project avoided costs in the
18 MISO Day 2 Market, EAI will use the AURORA model to produce these
19 projections. Second, the Company has not registered QFs equal to or
20 less than 20 MW to the Company as separate Load Zones in the MISO

²¹ See Schedule SQF.

1 commercial model because of the metering and telemetry requirements
2 necessary to do so.
3

4 Q. HOW DOES THE COMPANY PROPOSE TO PRICE AVOIDED COST
5 FOR QFs THAT DO NOT MEET THIS THRESHOLD?

6 A. The Company proposes to calculate avoided cost for the smaller QFs at
7 the applicable real-time LMP for Load Zone imbalances. EAI does not
8 anticipate MISO market charges associated with these QFs will be
9 material given the very small levels of put, and, therefore, does not believe
10 that a deduction of such charges would be included as part of the avoided
11 cost calculation.
12

13 Q. WHEN DOES THE COMPANY PROPOSE TO ISSUE PAYMENTS TO
14 QFs?

15 A. EAI proposes to issue avoided cost payments to QFs for energy delivered
16 during a month after the Company has been paid by MISO for that energy.
17 The Company anticipates receiving true-up charges or credits from MISO
18 and proposes to account for those true-ups in subsequent billing periods.
19 An initial payment followed by true-ups will more accurately reflect its
20 avoided cost by aligning the schedule of receipts received by the
21 Company from MISO with the schedule for issuing avoided cost payments
22 by the Company to QFs.
23

- 1 Q. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?
- 2 A. Yes.

CERTIFICATE OF SERVICE

I, Steven K. Strickland, do hereby certify that a copy of the foregoing has been served upon all parties of record by forwarding the same by electronic mail and/or first class mail, postage prepaid, this 26th day of August, 2013.

/s/ Steven K. Strickland
Steven K. Strickland

BEFORE THE
ARKANSAS PUBLIC SERVICE COMMISSION

IN THE MATTER OF THE APPLICATION	)	
OF ENTERGY ARKANSAS, INC. FOR	)	DOCKET NO. 13-028-U
APPROVAL OF CHANGES IN RATES FOR	)	
RETAIL ELECTRIC SERVICE	)	

EAI EXHIBIT PJC-1

EDUCATION, PROFESSIONAL AND WORK EXPERIENCE

BEFORE THE
ARKANSAS PUBLIC SERVICE COMMISSION

IN THE MATTER OF THE APPLICATION	)	
OF ENTERGY ARKANSAS, INC. FOR	)	DOCKET NO. 13-028-U
APPROVAL OF CHANGES IN RATES FOR	)	
RETAIL ELECTRIC SERVICE	)	

DIRECT TESTIMONY

OF

S. BRADY ALDY

DIRECTOR, TRANSMISSION AND DISTRIBUTION OPERATIONS

ENTERGY ARKANSAS, INC.

ON BEHALF OF

ENTERGY ARKANSAS, INC.

AUGUST 26, 2013

1 **I. INTRODUCTION**

2 Q. PLEASE STATE YOUR NAME.

3 A. My name is S. Brady Aldy.

4

5 Q. ARE YOU THE SAME S. BRADY ALDY WHO FILED DIRECT
6 TESTIMONY IN THIS DOCKET ON MARCH 1, 2013?

7 A. Yes, I am.

8

9 Q. ON WHOSE BEHALF ARE YOU TESTIFYING?

10 A. I am submitting this rebuttal testimony to the Arkansas Public Service
11 Commission (“APSC” or the “Commission”) on behalf of Entergy
12 Arkansas, Inc. (“EAI” or the “Company”).

13

14 Q. WHAT IS THE PURPOSE OF YOUR REBUTTAL TESTIMONY?

15 A. My rebuttal testimony will address certain reductions of proposed
16 vegetation management costs recommended in the direct testimonies of
17 APSC General Staff (“Staff”) witness Claude Robertson, Arkansas
18 Attorney General (“AG”) witness William B. Marcus, and Hospitals and
19 Higher Education Group (“HHEG”) witness Steven Ward. I also will
20 discuss the disallowance of test year expenses associated with industry
21 dues recommended by Mr. Marcus.

22 In addition, I will address the direct testimonies filed by Staff
23 witnesses Katrina Owoh and HHEG witness William E. Tinsley pertaining

1 to Rate Schedule No. 29, Charges Related To Customer Activity and the
2 direct testimony of Staff witness Clark D. Cotten and Arkansas Electric
3 Energy Consumers, Inc. ("AEEC") witness Randall J. Falkenberg in regard
4 to Rate Schedule No. 60, Extension of Facilities Policy ("Line Extension
5 Policy") and customer deposit issues.

6

7 **II. VEGETATION MANAGEMENT**

8 Q. PLEASE EXPLAIN THE CHANGE TO EAI'S VEGETATION
9 MANAGEMENT PROGRAM.

10 A. In my direct testimony I explained the need for EAI to move away from the
11 current practice of cycle tree trimming that uses an overall 5.5 year
12 average cycle time and begin using a stepped approach that considers the
13 population density of each circuit. Our experience shows that circuits in
14 more densely populated areas typically have less right-of-way and faster
15 growing tree species than do circuits in less populated areas. EAI
16 categorizes circuits as low, medium, and high population density. The
17 vast majority of EAI's circuits are low density, 724 out of 1140 total
18 circuits, while 196 circuits are considered medium density, and the
19 remaining 220 circuits are classified as high density.

20 The stepped approach I propose would allow for an average trim
21 cycle of 3.5 years for high density circuits, 4.5 years for medium density,
22 and 5.5 years for low density. This plan brings the overall average cycle
23 time to just over 5 years.

1 Q. DID STAFF AGREE WITH THIS PROPOSAL?

2 A. Yes. Staff witness Claude Robertson concluded that the proposed
3 expense adjustment to implement the plan is reasonable.¹ However,
4 Mr. Robertson recommended that, because the changes to the cycle trim
5 plan would not occur until the 2014 trim cycle, the Commission not
6 approve the increase in expense due to this change because the costs are
7 not known and measurable at this time.²

8

9 Q. DO YOU KNOW HOW MUCH THIS CHANGE IN THE COMPANY'S
10 TREE TRIMMING POLICY WILL COST?

11 A. Yes. Although the 2014 trim plan will not be in effect until January 1,
12 2014, the contracts that govern this work were signed in 2012, and the
13 actual circuits to be trimmed have already begun to be identified in 2013.
14 Therefore, the costs of this change are known and measurable and are
15 proper for inclusion in EAI's rates beginning January 1, 2014. As
16 explained in my direct testimony, that amount is on average \$17.8 million
17 per year.³

18

19 Q. HOW DID THE OTHER PARTIES RESPOND TO THIS PROPOSAL?

20 A. Arkansas Attorney General ("AG") witness Bill Marcus also agrees with
21 the Company's proposal; however, he recommends that the increase in

¹ Robertson Direct Testimony at 7.

² *Id.*

³ Aldy Direct Testimony at 37.

1 costs be made using the Company's 2012 vegetation cost level as the
2 baseline. Mr. Marcus also recommends that reactive trimming be set at 5
3 percent for medium and high density circuits only.⁴ Hospitals and Higher
4 Education Group ("HHEG") witness Steven Ward said that the
5 Commission should not approve increases associated with changes to the
6 cycle trim plan until the impact to revenue from fewer outages and the
7 impact to storm restoration are considered.⁵

8

9 Q. DO YOU AGREE WITH MR. MARCUS RECOMMENDATIONS?

10 A. Not entirely. Because the line miles trimmed in 2012 are not significantly
11 different from those proposed based on the new plan, the increase in
12 costs associated with my proposal and that of Mr. Marcus are not
13 significantly different. However, I do not agree with Mr. Marcus that the
14 2012 costs should be used as the baseline for making this adjustment
15 because the costs for vegetation management varies from year to year
16 based on the specific circuits selected for the trim plan and their
17 associated per line mile price. Therefore, the appropriate baseline cost
18 level is the 3-year average vegetation management cost of \$16.4 million
19 because it captures the effect of these variations over time.

20

21 Q. HOW DO YOU RESPOND TO MR. WARD'S RECOMMENDATION?

⁴ Marcus Direct Testimony at 61.

⁵ Ward Direct Testimony at 8.

1 A. Mr. Ward offers no opinion as to whether he agrees or disagrees that the
2 proposed adjustment to implement the revised maintenance plan is
3 reasonable. However, he contends that the adjustment must consider any
4 increased revenues available to EAI from improved reliability, but he offers
5 no basis upon which to calculate that revenue. I do not know how to
6 calculate this impact either, given the uncertainties associated with the
7 numerous causes of vegetation related outages, which are most often
8 associated with extreme weather.

9

10 **III. INDUSTRY DUES**

11 Q. PLEASE SUMMARIZE THE RECOMMENATION IN YOUR DIRECT
12 TESTIMONY WITH RESPECT TO INDUSTRY DUES.

13 A. In my direct testimony, I provide support for the Company's request to
14 include in base rates its membership dues to the Southeastern Electric
15 Exchange ("SEE") and the Edison Electric Institute ("EEI"). In the
16 Company's cost-of-service study it included 100 percent of SEE dues, but
17 reduced the amount paid to EEI by 28.06 percent to reflect removal of an
18 amount EEI attributed to lobbying activities.

19

20 Q. DID OTHER PARTIES AGREE WITH YOUR RECOMMENDATION?

21 A. Generally, yes. Staff witness Latoya Johnson agreed with the inclusion of
22 SEE and EEI dues amounts as filed. Mr. Marcus for the AG agreed with

1 including 100 percent of SEE dues, but recommends 47.2 percent of EEI
2 dues be disallowed.

3

4 Q. PLEASE SUMMARIZE MR. MARCUS'S RECOMMENDATIONS.

5 A. Mr. Marcus begins his analysis with EAI's proposed 26 percent reduction
6 to the Regulatory Activities portion of these dues. From there, Mr. Marcus
7 includes further reductions of 2.3 percent for advertising and 2.4 percent
8 for public relations based on 2009 EEI budget data provided by Oklahoma
9 Gas and Electric in Docket No. 10-067-U, and 16.5 percent for Regulatory
10 Advocacy based on EEI's 2005 budget report by the National Association
11 of Regulatory Utility Commissioners ("NARUC"). Additionally, Mr. Marcus
12 recommends 75 percent of the Industry Issues portion of these dues be
13 disallowed.

14

15 Q. ARE MR. MARCUS' RECOMMENDATIONS APPROPRIATE?

16 A. No. Before the year begins, EEI provides an initial estimate of the
17 percentage of dues used for lobbying when it provides the dues invoice to
18 EAI. This estimate is revised in March of that same year, followed by a
19 final calculation in March of the following year. Attached to my testimony
20 as EAI Exhibit SBA-2 is the final calculation of these amounts for 2012
21 that was provided by EEI on March 27, 2013. This information was
22 provided as part of EAI's response to Staff data request 122-1. Based on
23 his recommendation, I assume that Mr. Marcus refers to this data

1 response as the basis for his increase in the reduction of the Industry
2 Issues portion from 36 percent to 75 percent. However, Mr. Marcus fails
3 to recognize that the updated Regular Activities portion decreased from 26
4 percent to 17.9 percent.

5

6 Q. HOW DO YOU RESPOND TO MR. MARCUS' RECOMMENDATION FOR
7 AN ADDITIONAL REDUCTION FOR PUBLIC RELATIONS,
8 ADVERTISING, AND REGULATORY ADVOCACY?

9 A. I do not see a reasonable basis to support his recommendation. As I
10 explained above, EEI calculates the percentages of dues amounts
11 attributed to lobbying activities and provides those amounts annually. The
12 reductions I support are based on the actual figures for 2012 provided by
13 EEI. Mr. Marcus provides only his opinion that public relations,
14 advertising, and regulatory advocacy amounts should be disallowed,
15 based on past information that is eight years old, and offers no evidence
16 that the amounts proposed are inappropriate for 2012 expenses. As a
17 result, I have no basis to assume that Mr. Marcus' assertion that figures
18 from 2009 and 2005 would be applicable today.

19

20 Q. PLEASE PROVIDE YOUR RECOMMENDATION.

21 A. For the reasons stated above, I continue to support the amount of dues for
22 EEI and SEE proposed in my direct testimony, adjusted to reflect the most
23 recent figures provided by EEI. As shown in EAI Exhibit SBA-2, the actual

portion of EEI dues for 2012 attributed to lobbying decreased from 26 percent to 17.9 percent for the Regular Activities portion of dues and increased from 36 percent to 75.4 percent for the Industry Issues portion. This results in an overall adjustment of 24.4 percent of EEI dues. Table 1 below summarizes these changes.

Table 1
Original Estimated Dues Allowance Versus EEI Final Calculations

	Test Year Dues	Not Recoverable in Rates			
		Direct (Estimated) %	Direct (Estimated) \$	EEI update %	EEI update \$
Regular Activities Membership Dues	\$289,308	26.0%	\$ 75,220	17.9%	\$ 51,786
Industry Dues	28,931	36.0%	10,415	75.4%	\$ 21,814
Restore Power	907	0.0%	-	0.0%	\$ -
Contribution to Edison Foundation & Institute for Electric Efficiency	5,444	100.0%	5,444	100.0%	\$ 5,444
	324,590		91,079		79,044

IV. POLICY AND TARIFF CHANGES

A. Proposed Modifications to Miscellaneous Services Fees

Q. WHAT ARE MS. OWOH'S RECOMMENDATIONS FOR EAI'S PROPOSED CHANGES TO RATE SCHEDULE NO. 29, CHARGES RELATED TO CUSTOMER ACTIVITY ("CAC TARIFF")?

A. Ms. Owoh supported EAI's recommended changes to miscellaneous service fees included in the CAC Tariff with the exception of EAI's proposed addition of the new § 29.20, Charge for Study Costs to Accommodate Customer Service Requests. This new section provides that customers reimburse the Company for the costs of studies required

1 for interconnection to the Company's facilities or to support a customer's
2 new demand and energy requirements. Ms. Owah requested that the
3 Company provide additional information in its rebuttal testimony to
4 substantiate the proposed change and why the current practice is no
5 longer reasonable.⁶

6

7 Q. PLEASE EXPLAIN WHY EAI PROPOSES TO CHANGE THE CURRENT
8 PROCESS.

9 A. EAI proposed to add \$29.20 to the CAC Tariff to address customer
10 reimbursement to the Company for the costs of studies required for
11 interconnection to the Company's facilities or to support a customer's new
12 demand and energy requirements. As I explained in my direct testimony,
13 these requests for service from and/or interconnection with the Company's
14 facilities may require analyses of the impacts on the Company's system
15 and/ or on other customers. The current practice has been for EAI to
16 notify the customer if a study is required and provide the customer
17 information on an engineering firm that the customer should contact to
18 procure the study. EAI must approve the engineering firm that conducts
19 the study because of the Company's technical standards required to
20 perform the study to ensure the engineering firm has the required utility
21 technical expertise. The preference is to work with firms that are already
22 familiar with EAI's infrastructure as well as EAI's technical requirements

⁶ Owah Direct Testimony at 7.

1 for interconnection. The customer then enters into a contract for the
2 performance of the study and pays the engineering firm for the cost of the
3 study.

4 The new § 29.20 would simplify the process for procuring these
5 studies by allowing the Company to directly contract with the engineering
6 firm and bill the customer for the cost of the study. EAI's knowledge of its
7 facilities involved in the interconnection requires that it be actively involved
8 in working with the engineering firm and customer to establish the
9 appropriate scope and details of the study. EAI's proposal allows an
10 efficient determination of the appropriate scope and resource, thereby
11 simplifying the process for procuring the studies.

12

13 Q. DID THE OTHER PARTIES PROVIDE ANY RESPONSE TO EAI'S
14 PROPOSAL TO ADD § 29.20?

15 A. Yes. HHEG's Mr. Tinsley recommended that the Commission reject the
16 proposed change to require customers to allow EAI to procure the studies.
17 Mr. Tinsley indicates that allowing the Company to produce the studies
18 does not provide an incentive for the Company to control the costs related
19 to the performance of these studies. Mr. Tinsley recommends EAI allow
20 customers to continue to procure interconnection studies when required
21 from a pool of at least three contractors approved by EAI.

22

23 Q. WHAT IS YOUR RESPONSE TO MR. TINSLEY?

1 A. While I disagree with Mr. Tinsley's inference that allowing the Company to
2 procure the studies on behalf of the customer does not provide an
3 incentive for the Company to control the costs to perform these studies, I
4 believe it would be reasonable to provide customers the alternative for EAI
5 or the customer to procure the interconnection study.

6

7 Q. HOW WOULD EAI IMPLEMENT THE OPTION TO ALLOW CUSTOMERS
8 TO DIRECTLY PROCURE REQUIRED INTERCONNECTION STUDIES?

9 A. EAI would identify at least three engineering firms that would be qualified
10 to provide the studies and maintain a list to be made available to
11 customers who request to procure their own interconnection studies.

12

13 Q. DESCRIBE MR. MARCUS' OBJECTION TO EAI'S PROPOSAL TO
14 INCREASE THE METER TEST FEE, THE TRIP FEE, AND
15 RECONNECTION FEE NORMAL WORKING HOURS.

16 A. Mr. Marcus notes that EAI has not changed the level of the Meter Test,
17 Trip, and Reconnection fees since 2005.⁷ Mr. Marcus recommends, to the
18 extent such fees are based on the costs of the activities caused the cost,
19 the fees should be increased by no more than the increase Consumer
20 Price Index ("CPI") rate since the last time the fees were changes to
21 protect cost sensitive customers. Mr. Marcus explains that these fees are
22 applied to customers who cannot pay their bills, who, in his opinion, are

⁷ Marcus Direct Testimony at 76.

1 most likely lower income customers. Table 2 shows the fees
2 recommended by Mr. Marcus compared to the amount recommended by
3 EAI.

4 **Table 2**
5 **Marcus' Recommended Fee Compared to EAI's Proposal**
6

<u>Fee Description</u>	<u>Marcus</u>	<u>EAI</u>
Meter Test Fee	\$62.40	\$79.00
Trip Fee	\$16.80	\$20.00
Reconnect Fee Normal Working Hours	\$42.00	\$49.00

7
8 Mr. Marcus does not recommend a change to the Reconnection Fee After
9 Normal Working hours.

10
11 Q. WHAT IS YOUR RESPONSE TO MR. MARCUS' RECOMMENDATION?

12 A. I do not concur with Mr. Marcus' recommendation to calculate the change
13 in the Meter Test Fee, Trip Fee, and Reconnection Fee Normal Working
14 Hours based on the increase in the CPI. EAI's fees were calculated
15 based on the Company's cost of providing these activities, the
16 methodology historically accepted by the Commission for determining the
17 level of these type fees. Staff witness Ms. Owoh reviewed EAI's
18 miscellaneous fees and indicated that "[t]he charges requested by EAI are
19 reasonable and are comparable to those of the other electric IOUs,"⁸

⁸ Owoh Direct Testimony at 4.

1 which are shown on her Direct Exhibit KO-2. I continue to support the
2 Company's proposed fee changes.
3

4 **B. Proposed Modifications to Rate Schedule No. 60, Extension of**
5 **Facilities Policy ("EOFP")**

6 Q. WHAT ISSUES DID STAFF WITNESS CLARK COTTEN RAISE IN
7 REGARD TO EAI'S EOFP?

8 A. Mr. Cotten recommends the Company modify the definition and
9 application of its Residential Allowance to exclude the cost of the
10 transformer from the calculation of costs for extensions greater than 800
11 feet. Currently, if the extension is 800 feet or less the customer receives
12 credit for the cost of the transformer as part of the job cost ("Residential
13 Allowance"). If the extension is greater than 800 feet EAI prorates the
14 cost of the extension based on the length of the extension that is greater
15 than the 800 foot Residential Allowance as compared to the total length of
16 the extension to determine the amount of cost that the customer for which
17 the customer is responsible. Mr. Cotten recommends that the cost of the
18 transformer be excluded from the amount to be prorated and charged for
19 the portion of the extension that exceed the Residential Allowance.

20 Additionally, Mr. Cotten recommends that the Company file a
21 standard form agreement to include in Policy Schedule No. 13 that
22 describes facilities it will supply and the revenue guarantee required from

1 a developer in accordance with Section 60.3.4, Planned Land Use
2 Developments.

3
4 Q. WHAT IS YOUR RESPONSE TO MR. COTTEN'S PROPOSED
5 CHANGES TO EOFP?

6 A. EAI agrees that it would be appropriate to adjust the calculation of the
7 costs for extensions greater than the Residential Allowance of 800 feet to
8 exclude the cost of the transformer. Because the entire cost of the
9 transformer is credited for extensions less than 800 feet, it is logical to
10 credit customers whose extensions exceed the 800 feet for the same cost
11 of the transformer. The customer would still be responsible for the costs
12 for any line extension (poles, wire, and framing) exceeding the Residential
13 Allowance.

14 EAI also agrees it would be appropriate to provide a standard form
15 agreement in Policy Schedule No. 13 that describes facilities it will supply
16 and the revenue guarantee required from a developer in accordance with
17 Section 60.3.4, Planned Land Use Developments. Attached as
18 EAI Exhibit SBA-3 is an agreement that the Company believes fairly
19 effectuates the applicable tariff provisions.

20

21 Q. WHAT IS MR. FALKENBERG'S CONCERN WITH THE CHANGES
22 PROPOSED TO THE EOFP?

1 A. Mr. Falkenberg raises a concern with EAI's proposed change to Section
2 60.2.8.A. in which EAI proposed to clarify that easements are to
3 accommodate year-round truck / equipment accessibility to the
4 Company's facilities. Mr. Falkenberg identifies the change as an
5 expansion of the Company's policy regarding easements and access to
6 provide and maintain electric facilities. Mr. Falkenberg recommends that
7 EAI be required to pay a fair market value for easements that are intended
8 to provide electric service for any customer in addition to the customer
9 requesting construction services. Mr. Falkenberg further recommends
10 that the Company work with the customer requesting construction services
11 to clearly establish an easement route that will avoid Additional or Unusual
12 Costs unless incurred at the customer's request. Finally, Mr. Falkenberg
13 recommends that the Company should be required to pay a fair market
14 value for easements that benefit the public and should be required to
15 construct at the Company's sole expense any roads or access for the
16 Company's facilities and year-round truck/equipment accessibility to those
17 facilities.

18
19 Q. WHAT IS YOUR RESPONSE TO MR. FALKENBERG'S CONCERN AND
20 RECOMMENDATIONS?

21 A. They are not warranted. If a customer requests an extension of service, it
22 is reasonable to expect that the customer should be responsible to provide
23 suitable easements to EAI over, across and under property necessary for

1 the location of the line to that customer at no cost to EAI. It is equally
2 reasonable and necessary that these easements provide EAI the
3 incidental or secondary right to free ingress and egress over adjacent
4 lands of the customer to and from the right of way for the purpose of
5 building, maintaining, repairing, and operating the electrical facilities within
6 the right of way as part of EAI's duty to provide safe and reliable electric
7 service. In fact, EAI's right of way instruments specifically provide for the
8 right of ingress and egress across adjacent lands of the property owner to
9 and from the right of way for these specific purposes. The proposed
10 clarifying language of Section 60.2.8.A. simply reflects these necessary
11 secondary easement rights. These secondary easements should only be
12 exercised when necessary and in a reasonable manner so as not to cause
13 unnecessary burden or damage to the property of the customer.

14 EAI works with the customer as much as possible to determine the
15 optimal route for the facilities, keeping in mind the costs of the alternate
16 routes. The Company is guided by EOFP Section 60.2.11 which provides
17 the following in regard to the Company's optimal service route:

18
19 The Company will build facilities to an optimal delivery point
20 and along an optimal route with regard to Company's costs.
21 If a non-optimal delivery point or route is requested and
22 provided, any cost in excess of the cost for the optimal
23 delivery points and route shall be paid by the customer
24 through a Mandatory Contribution in Aid of Construction.

25 Additionally, the power of eminent domain granted to public utilities
26 by Arkansas statutes and the Constitution generally is exercised when the

1 utility is unable to negotiate suitable right of way for an agreed
2 compensation with a landowner who does not want electrical lines or
3 facilities extended onto the landowner's property. This may be the case
4 when lines need to be relocated due to highway projects or in connection
5 with transmission line projects. Under eminent domain law, EAI is
6 required to pay just compensation for the taking of property.

7

8 **C. Proposed Modifications to Non-Residential Deposit Policy**

9 Q. WHAT WAS MR. FALKENBERG'S RECOMMENDATION REGARDING
10 EAI'S CUSTOMER DEPOSIT POLICIES?

11 A. Mr. Falkenberg states that EAI's customer deposit policies are unfair to
12 non-residential customers because EAI refunds deposits to residential
13 customers in 12 months while the Company only provides refunds to non-
14 residential customers when their accounts are closed. Mr. Falkenberg
15 recommends that the Commission waive General Service Rule ("GSR")
16 4.06 which requires deposit refunds for residential customers with good
17 pay habits and apply the rule to non-residential customers as well.
18 Mr. Falkenberg also expressed concern with EAI's exemption to GSR
19 4.02.A that allows EAI to impose a new or increased deposit for non-
20 residential customers who do not maintain specified credit metrics, in
21 addition to the other reasons provided under GSR 4.02.A such as late

1 payments, returned checks, and bankruptcy. Mr. Falkenberg
2 recommends the Commission eliminate this provision from EAI's tariff.⁹
3

4 Q. WHAT IS YOUR RESPONSE?

5 A. The Company administers its customer deposit policies in accordance
6 with the Commission's GSRs, as amended by certain exemptions
7 approved by the Commission based upon evidence presented by EAI.
8 EAI's policies for non-residential customer and residential customers merit
9 different treatment. While the number of non-residential uncollectible
10 accounts may be fewer than residential accounts, when a non-residential
11 account becomes delinquent or files for bankruptcy, the exposure to the
12 Company and ultimately the other ratepayers is much greater than with a
13 residential customer. The Company must maintain adequate security
14 from its non-residential customers in order to protect other customers'
15 from large losses following bankruptcies or non-payment upon closure
16 from its non-residential customers, many of whom have never paid a late
17 bill prior to the decision to file bankruptcy.¹⁰
18

19 Q. DOES THIS CONCLUDE YOUR TESTIMONY?

20 A. Yes, it does.

⁹ Falkenberg Direct Testimony at 34-35.

¹⁰ Docket No. 09-084-U, Majewski Direct Testimony at 4.

CERTIFICATE OF SERVICE

I, Steven K. Strickland, do hereby certify that a copy of the foregoing has been served upon all parties of record by forwarding the same by electronic mail and/or first class mail, postage prepaid, this 26th day of August, 2013.

/s/ Steven K. Strickland
Steven K. Strickland

BEFORE THE
ARKANSAS PUBLIC SERVICE COMMISSION

IN THE MATTER OF THE APPLICATION	)	
OF ENTERGY ARKANSAS, INC. FOR	)	DOCKET NO. 13-028-U
APPROVAL OF CHANGES IN RATES FOR	)	
RETAIL ELECTRIC SERVICE	)	

EAI EXHIBIT SBA-2

2012 EEI LOBBYING EXPENDITURES



March 27, 2013

Dear Committee Members:

We have completed the calculation of EEI's expenditures relating to influencing legislation for calendar year 2012. A total of 17.9% of our regular dues was devoted to non-deductible activities in 2012. In addition, 75.4% of the assessment for the SFA for Industry Issues, 19.9% of the assessment for the SFA for Environment, 9.6% of the assessment for the Utility Solid Waste Activities Group ("USWAG"), and 95.6% of the assessment for the Water Advocacy Coalition (WAC) were devoted to non-deductible activities in 2012. These percentages may affect the extent to which your 2012 EEI dues and SFA payments qualify as a deductible business expense.

These actual figures differ from the earlier estimates contained in your 2012 dues invoice and our letter dated March 29, 2012. For your convenience, a chart with original and revised estimates for 2012 and 2013, as well as actual results for 2012, is provided below. The actual percentages for calendar year 2013 will be provided to you by mid-2014.

Summary of 2012 and 2013 Estimated, Revised and Actual Percentages

	Regular Activities	Separately Funded Activities (SFA)			
	Core Dues	Industry Issues	Environment	USWAG	WAC
2012					
Original Estimate on dues invoice	26.0%	36.0%	2.0%	-	-
Revised Estimate – March 2012	22.0%	34.0%	6.0%	9.0%	75.0%
Actual/Final	17.9%	75.4%	19.9%	9.6%	95.6%
2013					
Original Estimate on dues invoice	22.0%	34.0%	10.0%	-	-
Revised Estimate – March 2013	18.0%	40.0%	10.0%	10.0%	95.0%

Please do not hesitate to contact me at (202) 508-5540 or jschlenker@eei.org if you have any questions.

Sincerely,

John Schlenker
CFO & Treasurer

BEFORE THE
ARKANSAS PUBLIC SERVICE COMMISSION

IN THE MATTER OF THE APPLICATION	)	
OF ENTERGY ARKANSAS, INC. FOR	)	DOCKET NO. 13-028-U
APPROVAL OF CHANGES IN RATES FOR	)	
RETAIL ELECTRIC SERVICE	)	

EAI EXHIBIT SBA-3

POLICY SCHEDULE NO. 13 - DRAFT AGREEMENT

EXTENSION OF SERVICE AGREEMENT PLANNED LAND USE DEVELOPMENTS

This Agreement was made and entered into on _____, by and between _____ ("Developer" or "Applicant") and Entergy Arkansas, Inc. ("EAI" or the "Company"), a corporation.

1. GENERAL

When a planned land use development is defined by the Company to be an area of at least 100 contiguous acres in size for purposes of the Company's facilities installation and is being developed over a period of several years for residential, commercial, or industrial use and in which it will be necessary for the Company to construct three-phase feeder circuits to provide adequate service for the anticipated electric loads of the completed planned development, the Company and the Developer will sign this Extension of Service Agreement Planned Land Use Developments ("Agreement") in order for the Company to extend its facilities to provide electric service when needed, including as set forth in Rate Schedule No. 60. This Agreement will describe the facilities to be provided by the Company and the Revenue Guarantee required by the Developer.

The terms used in this Agreement will have the same meaning as set forth in the Company's Rate Schedule No. 60, and in the event of any conflict between this Agreement and Rate Schedule No. 60, Rate Schedule No. 60 will control.

The Company will provide the necessary facilities as reasonably requested by the Developer if the Developer agrees to make an Annual Revenue Guarantee and an Annual Payment to the Company as set forth herein. With respect to the facilities provided by EAI, the Company's Estimated Net Investment in the facilities will be determined by the Company by estimating the cost of the facilities, including overhead and underground facilities, and subtracting contributions for underground facilities and/or other contributions made by the Developer and/or allowances granted in accordance with the Company's Rate Schedule §60.3.4. For residential subdivisions the Residential Allowance will be multiplied by the number of platted lots to determine the total allowance. However, no credit for unused allowances will be applied against the Additional or Unusual Costs as set forth in the Company's Rate Schedule No. §60.2.7.

Developer will not voluntarily assign in whole or in part its rights or delegate its duties under this Agreement without the prior written consent of the Company, which consent will not be unreasonably conditioned, delayed, or withheld.

2. APPLICANT DATA

Address of Applicant:

Initial application date:

Service point location and description:

Description of work:

3. SKETCH OF DEVELOPER'S CONSTRUCTION PLAN

A sketch of the Developer's construction plan is provided as Attachment A.

4. EXPLANATION OF COSTS

An explanation of all Company costs in reasonable detail is provided as Attachment B. Attachment B may be amended by the Company from time to time to reflect additional costs that may be incurred by the Company. The Company will provide reasonable notice to the Developer of any such amendments to Attachment B.

5. PRE-CONSTRUCTION APPLICANT OBLIGATIONS

The Applicant shall obtain all necessary rights-of-way from all property owners over whose property the facilities shall be located, and complete the applicable form(s) supplied by the Company, that grants to the Company (or its successors and assigns) the rights and privileges to construct, maintain and operate said facilities. Such completed forms shall be appropriately signed and delivered by Developer to the Company prior to construction.

It is expressly understood that said rights-of-way and all electrical facilities erected for serving the applicable planned land use development under this Agreement shall always be and remain the property of the Company. The Company has the right, at its discretion, to serve any other customers or land use developments from said facilities or any extension thereof at any time.

Developer will complete the additional items listed below before the Company begins construction. These items may include but are not limited to the acquisition of permits and right-of-way clearing. If Developer has no such obligations the space below shall show "None".

6. ESTIMATED CONSTRUCTION START AND COMPLETION DATES

Construction will start when this Agreement is executed and approved and when any required pre-construction payment is returned to the Company and the items in § 5 above, if any, have been completed

7. TERMS OF PAYMENT (Pursuant to Rate Schedule No. 60, including Section 60.3.4)

With respect to the Annual Revenue Guarantee to be paid by the Developer to the Company for single-phase facilities that have been in place for the entire contract year, the Company's Estimated Net Investment will be multiplied by 1.25% times 12 months. The Company's Estimated Net Investment in single-phase facilities that have not been in place for the entire contract year will be multiplied by 1.25% times the number of months in the contract year in which said facilities were in place.

With respect to the Annual Revenue Guarantee to be paid by the Developer to the Company for three-phase facilities that have been in place for the entire contract year, the Company's Estimated Net Investment will be multiplied by 2.5% times 12 months. The Company's Estimated Net Investment in three-phase facilities that have not been in place for the entire

contract year will be multiplied by 2.5% times the number of months in the contract year in which said facilities were in place.

With respect to the Annual Payment to be made on an annual basis at the end of each contract year by the Developer to the Company, the Developer will pay the positive difference, if any, between the sum of the amounts determined for the applicable Annual Revenue Guarantee and the annual total accumulated electric revenue excluding Riders ECR, NDCR, GGR and all other Rate Riders that may become effective by Commission order, franchise adjustment, and sales tax from all customers within the planned development. In the event that such Revenue exceeds the Annual Revenue Guarantee, then no payment will be made by either Developer or the Company.

Failure by the Developer to make any of the required payments or guarantees shall constitute a material breach of this Agreement and a violation of the Company's Rate Schedule No. 60. In such case, the Company, without further notice to the Developer, may pursue all legal and equitable rights the Company has including seeking a lien with respect to the Developer's property.

The Company may require developer to pay a Contribution of \$_____ prior to the beginning of construction.

Any "amount" or "timing" blanks herein will be completed by the Company.

8. REIMBURSEMENT BY THE COMPANY

There will be no reimbursement by the Company to Developer.

9. ENGINEERING STUDY SUMMARY

The engineering study if necessary to design this extension is attached as Attachment C.

10. APPROVALS

ENTERGY ARKANSAS, INC.

By:

By:

Date:

Approved:

Title:

Date:

DIS WR#		Project #:		Business Unit:	A0000
Department:		Resource:		Activity:	
Physical Location:	<u>DAR</u>	Location:		Account Number:	
Residential		Commercial		Industrial	

BEFORE THE
ARKANSAS PUBLIC SERVICE COMMISSION

IN THE MATTER OF THE APPLICATION	)	
OF ENTERGY ARKANSAS, INC. FOR	)	DOCKET NO. 13-028-U
APPROVAL OF CHANGES IN RATES FOR	)	
RETAIL ELECTRIC SERVICE	)	

REBUTTAL TESTIMONY

OF

WILLIAM R. CREAN

PRINCIPAL ESTIMATOR, BLACK & VEATCH

ON BEHALF OF

ENTERGY ARKANSAS, INC.

AUGUST 26, 2013

1 **I. INTRODUCTION**

2 Q. PLEASE STATE YOUR NAME.

3 A. My name is William R. Crean.

4

5 Q. ARE YOU THE SAME WILLIAM R. CREAN WHO FILED DIRECT
6 TESTIMONY IN THIS DOCKET ON MARCH 1, 2013?

7 A. Yes, I am.

8

9 Q. ON WHOSE BEHALF ARE YOU TESTIFYING?

10 A. I am submitting this rebuttal testimony to the Arkansas Public Service
11 Commission (“APSC” or the “Commission”) on behalf of Entergy
12 Arkansas, Inc. (“EAI” or the “Company”).

13

14 Q. WHAT IS THE PURPOSE OF YOUR REBUTTAL TESTIMONY?

15 A. The purpose of my rebuttal testimony is to rebut and address the following
16 issues raised by the Federal Executive Agencies’ (“FEA”) witness James
17 Selecky:

- 18 • Mr. Selecky’s proposal to remove the contingency factor from EAI’s
19 dismantling study,
- 20 • Mr. Selecky’s attributing value to the sites of the dismantled plant
21 sites, and
- 22 • Mr. Selecky’s claim that removal of concrete and utilities three feet
23 below grade is an improvement to the land.

1 **II. RESPONSE TO FEA**

2 Q. WHAT IS FEA'S POSITION REGARDING THE APPLICATION OF
3 CONTINGENCY TO EAI'S DISMANTLING ESTIMATES?

4 A. Mr. Selecky testifies that "the contingency factor unnecessarily increases
5 the estimated cost to decommission the production plants. The
6 contingency factor does not reflect a real cost but provides a safeguard at
7 the expense of current ratepayers in the event that the cost estimate is
8 low."¹

9
10 Q. DO YOU AGREE WITH FEA'S POSITION?

11 A. No. Contingencies are a necessary and accepted part of any projected
12 estimates. Cost estimates are developed based on the known scope of
13 the project at the time the estimate is conducted. For every estimate,
14 there is always some degree of scope which is unknown at the time of the
15 estimate. Contingency is merely the recognition that this unknown scope
16 will result in cost for the project. For example, anyone who has taken bids
17 for a home improvement project can likely agree that bid estimates often
18 vary both from each other and from the final costs of the actual work
19 performed. Large remodeling project bids often include a contingency
20 factor. Including contingency dollars in an estimate is a universally
21 accepted practice and the contingency in the Company's dismantlement
22 cost estimate are a reasonable element of the cost.

23

¹ Selecky Direct Testimony at 20.

1 Q. MR. SELECKY IMPLIES THAT THE USE OF A CONTINGENCY IS A
2 SORT OF INSURANCE TO PROTECT THE COMPANY, IS THAT A
3 CORRECT PRESUMPTION?

4 A. No. The purpose of a contingency is not to provide insurance but to
5 provide assurance that the estimator has provided a valid and reasonable
6 estimate of a probable outcome.

7
8 Q. WHAT DOES THE USE OF A CONTINGENCY IN THE ESTIMATE
9 PURPORT TO REPRESENT?

10 A. A number of events could and probably will occur that cannot be
11 estimated with precision. Examples would be weather changes, labor
12 availability, equipment shortages, fluctuations in cost of consumables, and
13 unforeseen obstacles. Although all of these types of influences are not
14 likely to occur, some will and if the estimator does not provide a
15 reasonable approximation of what the likely cost will be (a contingency) he
16 or she will have failed to provide a valid and reasoned estimate of the like
17 cost of the project.

18
19 Q. WHAT IS YOUR BASIS FOR CLAIMING THAT THE INCLUSION OF
20 CONTINGENCIES IN COST ESTIMATES IS A UNIVERSALLY
21 ACCEPTED PRACTICE?

22 A. The following are references to just a few of the articles and standard
23 practices that support my position.²

² Copies of the articles and standard practices are being provided to the other parties as workpapers.

- 1 • “Contingency in Capital Cost Estimation,”
- 2 • “Risk Assessment and Contingency Estimating,”
- 3 • “Contingency Estimating – General Principles,”
- 4 • “A Prototype Risk Analysis for Determining Contingency Using
- 5 Approximate Reasoning Method,” and
- 6 • “Risk Analysis and Contingency Determination Using Parametric
- 7 Estimating.”
- 8

9 Q. WHAT IS FEA’S POSITION REGARDING THE POTENTIAL VALUE OF
10 EXISTING PRODUCTION SITES?

11 A. On page 19 of Mr. Selecky’s direct testimony, he stated, “Any existing
12 production site is valuable because it has access to electric transmission
13 lines, water supplies, and transportation network and may already have
14 environmental permits.” Mr. Selecky proposes that the value of the land
15 should be included as an off-setting cost to the cost to dismantle the
16 facilities.

17
18 Q. DO YOU AGREE WITH FEA’S POSITION?

19 A. No. Future generation planning will consider where load growth is
20 expected to occur, how best to meet these requirements, environmental
21 regulations at the time of planning for this next generation facility, and the
22 choice of technology to satisfy this load requirement. Mr. Selecky
23 references a Consumers Energy decision to site a proposed new
24 generation coal plant at an existing facility site. However, Mr. Selecky fails

1 to recognize that when Consumers abandoned its new generation coal
2 plant for a combined cycle plant, the new plant was proposed for a
3 different location. This example demonstrates that there are a multitude of
4 issues that must be considered when siting a new facility and that the
5 future generation requirements may rule out existing sites that would not
6 be of any value because of these requirements. Thus, one cannot and
7 should not conclude, as Mr. Selecky has, that any existing production site
8 is necessarily valuable because of its access to existing facilities.

9

10 Q. WOULD YOU ADDRESS THE ISSUE RAISED BY MR. SELECKY
11 REGARDING THE POTENTIAL INCREASED VALUE OF EXISTING
12 PRODUCTION SITES?

13 A. Yes. In regard to the removal of foundation and utilities down to the depth
14 of three feet below grade, Mr. Selecky proposes that this practice is an
15 improvement to land and makes the land more valuable.

16

17 Q. DO YOU AGREE WITH THIS ASSESSMENT?

18 A. No. Removal of foundations and utilities below grade simply restores the
19 land to its original unencumbered state. The removal of foundations and
20 utilities down to a depth of three feet below grade only partially restores
21 the land to its original unencumbered state. Future use of the site
22 requiring excavations below three feet would likely encounter deep
23 foundations and utilities which would result in increased costs and make
24 the site less valuable than it was in its original unencumbered state.
25 Further, the dismantlement estimate includes the removal of the existing

1 plant fence. Not removing foundation and utilities below grade will require
2 this fence to remain and may require additional actions and costs on the
3 part of EAI to safeguard the property to protect against potential hazards
4 and liability concerns. The probability that any future use of this land
5 could employ the present foundations or utilities is highly unlikely. Mr.
6 Selecky seems to acknowledge on page 23 of his direct testimony that it is
7 difficult to assign a value to any potential future use of the existing
8 structures. EAI witness Patricia Cartright also addresses Mr. Selecky's
9 position on future land values in her rebuttal testimony.

10

11 **III. CONCLUSION**

12 Q. COULD YOU BRIEFLY SUMMARIZE YOUR TESTIMONY?

13 A. Contingency, a common and reasonable practice, should remain in the
14 dismantlement estimate. Further, there should be no off-setting cost to
15 potential land value of the existing production site, and preparing the land
16 to three feet below grade should be viewed as a removal of a liability
17 rather than as an improvement to the land and only partially restores the
18 land to its original condition.

19

20 Q. DOES THIS CONCLUDE YOUR REBUTTAL TESTIMONY?

21 A. Yes.

CERTIFICATE OF SERVICE

I, Steven K. Strickland, do hereby certify that a copy of the foregoing has been served upon all parties of record by forwarding the same by electronic mail and/or first class mail, postage prepaid, this 26th day of August, 2013.

/s/ Steven K. Strickland
Steven K. Strickland

BEFORE THE
ARKANSAS PUBLIC SERVICE COMMISSION

IN THE MATTER OF THE APPLICATION	)	
OF ENTERGY ARKANSAS, INC. FOR	)	DOCKET NO. 13-028-U
APPROVAL OF CHANGES IN RATES FOR	)	
RETAIL ELECTRIC SERVICE	)	

REBUTTAL TESTIMONY

OF

SAMUEL C. HADAWAY

PRINCIPAL, FINANCO, INC.

ON BEHALF OF

ENTERGY ARKANSAS, INC.

AUGUST 26, 2013

1 **I. INTRODUCTION**

2 Q. PLEASE STATE YOUR NAME.

3 A. My name is Samuel C. Hadaway.

4

5 Q. ARE YOU THE SAME SAMUEL C. HADAWAY WHO FILED DIRECT
6 TESTIMONY IN THIS DOCKET ON MARCH 1, 2013?

7 A. Yes, I am.

8

9 Q. ON WHOSE BEHALF ARE YOU TESTIFYING?

10 A. I am submitting this rebuttal testimony to the Arkansas Public Service
11 Commission ("APSC" or the "Commission") on behalf of Entergy
12 Arkansas, Inc. ("EAI" or the "Company").

13

14 Q. WHAT IS THE PURPOSE OF YOUR REBUTTAL TESTIMONY?

15 A. The purpose of my rebuttal testimony is to respond to the rate of return on
16 equity ("ROE") recommendations offered by APSC General Staff ("Staff")
17 witness Robert Daniel, Arkansas Attorney General ("AG") witness William
18 B. Marcus, Arkansas Electric Energy Consumers ("AEEC") witness David
19 C. Parcell, and Federal Executive Agencies ("FEA") witness Michael P.
20 Gorman.

21 In my analysis, I will respond to the other parties' ROE
22 recommendations and demonstrate that their recommendations are not

1 consistent with the current increasing interest rate environment or the
2 recent capital market turmoil that has occurred. I will also respond to the
3 other witnesses' comments on the methodology I used to estimate EAI's
4 cost of equity, and I will update my ROE analysis for current capital market
5 costs and conditions.

6

7 **II. ROE RECOMMENDATIONS OF STAFF AND INTERVENORS**

8 Q. WHAT ARE THE OTHER PARTIES' ROE RECOMMENDATIONS?

9 A. The parties' ROE recommendations are summarized in Table 1 below:

10

11 **Table 1**

12 **ROE Recommendations**

13 <u>Party/Witness</u>	14 <u>ROE</u> <u>Recommendation</u>
15 Staff	9.60%
16 AG*	9.25%
17 AEEC	9.25%
FEA	9.40%

18

19 Q. WHAT IS YOUR ASSESSMENT OF THE OTHER PARTIES' ROE
20 RECOMMENDATIONS?

21 A. The other parties' recommendations are not consistent with the increasing
22 interest rate environment that has resulted from the Federal Reserve
23 System's ("FED") tapering down of its stimulative monetary policies. The
24 other witnesses' ROE estimates continue to be based on mechanical
25 applications of traditional cost of equity estimation models. In the present
26 transition to higher interest rates, these approaches cannot accurately

1 assess the market cost of equity. Some of the other witnesses (Mr.
2 Marcus and Mr. Parcell) appear to believe interest rates will remain low
3 into the indefinite future, and their ROE recommendations are far below
4 ROEs granted for other integrated electric utilities like EAI.

5

6 **III. UPDATED ROE ANALYSIS**

7 Q. HAVE YOU UPDATED THE DISCOUNTED CASH FLOW ("DCF") AND
8 RISK PREMIUM ANALYSES THAT YOU INITIALLY PRESENTED IN
9 YOUR DIRECT TESTIMONY?

10 A. Yes. As I customarily do, I have updated my DCF and risk premium
11 models to account for current market conditions.

12

13 Q. DOES YOUR UPDATED DCF ANALYSIS DEMONSTRATE THE
14 TECHNICAL DIFFICULTIES THAT CURRENTLY EXIST FOR
15 TRADITIONAL ROE ESTIMATION MODELS?

16 A. Yes. The updated DCF model results do not pass basic tests of
17 reasonableness. A comparison of ROE estimates from the DCF model to
18 contemporaneous estimates from the equity risk premium model
19 demonstrates significant difficulty in deriving reliable results from the DCF
20 model.

21 As I will show later, utility interest rates over the past three months
22 have increased by over 70 basis points (see Table 2 below). During this

1 time, estimates of ROE from the DCF model have dropped by 30 to 70
2 basis points.¹ These results are not consistent with basic economic theory
3 or simple common sense. While ROE does not necessarily move in
4 lockstep with interest rates, the two do move in the same direction. When
5 an ROE estimation model produces an entirely contrary result, as the DCF
6 model currently does, that model should be reconsidered and other
7 approaches should be given more weight. My updated risk premium
8 model shows more reasonable outcomes. That model currently indicates
9 that ROE has increased by 30 to 40 basis points, with a current ROE
10 range of 10.0 percent to 10.4 percent.²

11 As I will explain in more detail later, all quantitative models for
12 estimating ROE, over the past several years, have been significantly
13 impacted by artificially low interest rates, which resulted from the
14 government's expansionary monetary policy. Additionally, the Federal
15 Open Market Committee ("FOMC"), in its June 19, 2013 policy
16 announcement, has signaled a shift toward less accommodative monetary
17 policy, and the capital markets have now responded with an increasing
18 interest rate trend. Given the structure of and required inputs for the
19 quantitative models used to estimate ROE, it is virtually impossible, with
20 the data so far available, to capture these trends. Therefore, based on

¹ In my direct testimony filed on March 1, 2013, my DCF range was 9.6 percent to 10.0 percent (EAI Exhibit SCH-6). The updated DCF range, based on exactly the same methodology and exactly the same comparable company group, is currently 8.9 percent to 9.7 percent.

² In my direct testimony, the indicated risk premium range was 9.7 percent to 10.0 percent (EAI Exhibit SCH-7).

1 portions of my quantitative results and my further review of other
2 economic data and current market conditions, I continue to support an
3 allowed ROE of 10.4 percent for EAI. Under current market conditions
4 and economic circumstances, I believe that an ROE at this level is
5 reasonable for establishing the Company's rates.

6

7 **IV. ECONOMIC CONDITIONS AND UPWARD INTEREST TRENDS**

8 Q. WHAT IS THE CURRENT OUTLOOK FOR THE U.S. ECONOMY?

9 A. The U.S. economy is finally on what appears to be a sustainably
10 improving track. The housing markets in many parts of the country have
11 firmed up, and prices are increasing. The stock market has largely
12 recovered from its losses during the financial crisis and consumer
13 confidence is improving. Although unemployment remains a concern,
14 most economists now expect the government's monetary policy to
15 become less stimulative over the coming year.

16 In this regard, on June 19, the FOMC issued the following policy
17 statement indicating somewhat improved economic conditions:

18 Information received since the Federal Open Market
19 Committee met in May suggests that economic activity has
20 been expanding at a moderate pace. *Labor market*
21 *conditions have shown further improvement in recent*
22 *months, on balance, but the unemployment rate remains*
23 *elevated. Household spending and business fixed*
24 *investment advanced, and the housing sector has*
25 *strengthened further, but fiscal policy is restraining economic*
26 *growth. Partly reflecting transitory influences, inflation has*

1 been running below the Committee's longer-run objective,
2 but longer-term inflation expectations have remained stable.

3 Consistent with its statutory mandate, the Committee seeks
4 to foster maximum employment and price stability. The
5 Committee expects that, with appropriate policy
6 accommodation, economic growth will proceed at a
7 moderate pace and the unemployment rate will gradually
8 decline toward levels the Committee judges consistent with
9 its dual mandate. *The Committee sees the downside risks to*
10 *the outlook for the economy and the labor market as having*
11 *diminished since the fall.* The Committee also anticipates
12 that inflation over the medium term likely will run at or below
13 its 2 percent objective.

14 The Committee will closely monitor incoming information on
15 economic and financial developments in coming months.
16 The Committee will continue its purchases of Treasury and
17 agency mortgage-backed securities, and employ its other
18 policy tools as appropriate, until the outlook for the labor
19 market has improved substantially in a context of price
20 stability. The Committee is prepared to increase or reduce
21 the pace of its purchases to maintain appropriate policy
22 accommodation as the outlook for the labor market or
23 inflation changes. In determining the size, pace, and
24 composition of its asset purchases, the Committee will
25 continue to take appropriate account of the likely efficacy
26 and costs of such purchases as well as the extent of
27 progress toward its economic objectives.³

28 As noted in the highlighted portions of the announcement, in its June 19
29 comments, the FOMC recognized the economy's improving conditions.
30 This slightly changed stance from the FOMC has led to investors'
31 expectations for less accommodative monetary policy, which, in turn, have
32 led to significant increases in long-term interest rates.

33

³ FOMC Press Release, www.federalreserve.gov (June 19, 2013) (emphasis added).

1 Q. WHAT IS THE CONNECTION BETWEEN FOMC MONETARY POLICY
2 AND THE CHANGES IN INTEREST RATES?

3 A. Over the past several years, the FOMC has attempted to stimulate the
4 economy by various monetary policy methods. Recently, the most widely
5 discussed of those methods have been programs called "Quantitative
6 Easing 3" ("QE3" and "Operation Twist"). Under the QE3 program, the
7 FOMC has directed the purchase of \$85 billion per month of long-term
8 mortgage back securities and other long-term U.S. Government
9 instruments, thus pushing down the yields on those securities. Through
10 Operation Twist, the Fed has issued short-term U.S. Treasury bills to
11 repurchase longer-term U.S. Treasury bonds, thus again holding down
12 yields in the longer-term markets. As noted above, in its June 19, 2013
13 press release, the FOMC indicated that improving economic conditions
14 might lead to tapering off of its stimulus programs. Since that
15 announcement, long-term interest rates have increased significantly.

16

17 Q. IN YOUR DIRECT TESTIMONY, YOU PROVIDED DATA THAT
18 ILLUSTRATED INTEREST RATE TRENDS AND THE SPREADS
19 BETWEEN U.S. TREASURY BOND YIELDS AND YIELDS ON BAA
20 UTILITY BONDS. HAVE YOU UPDATED THAT INFORMATION?

21 A. Yes. In EAI Exhibit SCH-8, page 1, I have updated the government and
22 utility interest rates and the associated spread data. These data are

1 summarized in Table 2 below.

Table 2
Long-Term Interest Rate Trends

Month	Triple-B Utility Rate	30-Year Treasury Rate	Triple-B Utility Spread
Aug-11	5.22	3.65	1.57
Sep-11	5.11	3.18	1.93
Oct-11	5.24	3.13	2.11
Nov-11	4.93	3.02	1.91
Dec-11	5.07	2.98	2.09
Jan-12	5.06	3.03	2.03
Feb-12	5.02	3.11	1.91
Mar-12	5.13	3.28	1.85
Apr-12	5.11	3.18	1.93
May-12	4.97	2.93	2.04
Jun-12	4.91	2.70	2.21
Jul-12	4.85	2.59	2.26
Aug-12	4.88	2.77	2.11
Sep-12	4.81	2.88	1.93
Oct-12	4.54	2.90	1.64
Nov-12	4.42	2.80	1.62
Dec-12	4.56	2.88	1.68
Jan-13	4.66	3.08	1.58
Feb-13	4.74	3.17	1.57
Mar-13	4.72	3.16	1.56
Apr-13	4.49	2.93	1.56
May-13	4.65	3.11	1.54
Jun-13	5.08	3.40	1.68
Jul-13	5.21	3.61	1.60
3-Mo Avg	4.98	3.37	1.61
12-Mo Avg	4.73	3.06	1.67

Sources: Mergent Bond Record; www.federalreserve.gov.

Three month average is for May-July 2013.

Twelve month average is for August 2012-July 2013.

2
 3 The data in Table 2 partially reflect the increase in interest rates that has
 4 occurred since the June 19 FOMC announcement, with the July 2013
 5 average rates being near the highest levels during the past two years.

1 The Baa Average Utility rate for July 2013 (5.21%) was 72 basis points
2 higher than the Average Utility rate for April 2013 (4.49%).

3
4 Q. HAVE LONG-TERM INTEREST RATES MOVED UP FURTHER
5 RELATIVE TO THE JULY 2013 AVERAGES?

6 A. Yes. The June and July average rates contain about three weeks of data
7 in June from before the FOMC announcement. Although a changed Fed
8 posture had been partially anticipated, with interest rates firming up
9 slightly in May, the June 19 announcement caused a sharper jump. I
10 normally rely on the monthly averages and generally base my analysis on
11 three-month averages to smooth out random fluctuations. However, when
12 a significant policy shift occurs, I believe near-term rates should be
13 considered as well. Therefore, in Table 3, I provide the daily yields for the
14 30-year and 10-year Treasury bonds and long-term Baa corporate and
15 Baa utility bonds from August 1 forward. In my risk premium analysis,
16 presented later, I also use the more recent data to illustrate the effect of
17 higher interest rates on current ROE estimates.

18

Table 3
August 2013 Interest Rates

	30- Year Treasury	10- Year Treasury	Baa Corporate	Baa Utility
8/1/2013	3.77	2.74	5.40	5.27
8/2/2013	3.69	2.63	5.31	5.18
8/5/2013	3.73	2.67	5.31	5.18
8/6/2013	3.73	2.67	5.37	5.24
8/7/2013	3.68	2.61	5.36	5.23
8/8/2013	3.65	2.58	5.33	5.19
8/9/2013	3.63	2.57	5.31	5.17
8/12/2013	3.67	2.61	5.33	5.20
8/13/2013	3.75	2.71	5.43	5.30
8/14/2013	3.75	2.71	5.43	5.30
8/15/2013	3.81	2.77	5.47	5.33
8/16/2013	3.86	2.84	5.54	5.39
8/19/2013	3.89	2.88	5.58	5.43

Sources: www.federalreserve.gov, H-15 Series.
 Moody's (Mergent) Bond Record.

1

2

3 Q. WHAT DO INTEREST RATE FORECASTS SHOW FOR THE COMING
 4 YEAR?

5 A. Interest rates are expected to rise further. In EAI Exhibit SCH-8, page 2, I
 6 provide the forward Bloomberg curve for Treasury yields through
 7 December 31, 2014. These forecasts reflect the significant expected
 8 increase in interest rates. These data are summarized in Table 4 below.

Table 4
Interest Rate Forecast

	July 2013	Dec 2014E
1-Yr. Treasuries	0.1%	0.9%
10-Yr. Treasuries	2.6%	3.4%
30-Yr. Treasuries	3.6%	4.2%

Source: www.federalreserve.gov (June rates).
Projected rates are from the Bloomberg Active Treasuries
curve, August 19, 2013, shown in EAI Exhibit SCH-8 at 2.

Q. HOW DO THESE TRENDS AFFECT THE COST OF EQUITY FOR
UTILITIES SUCH AS EAI?

A. There are at least two effects. First, with the tapering off of the Fed's
stimulative monetary policy, which has artificially depressed market
interest rates over the past two years, more normal market supply and
demand conditions should begin to prevail. Second, as this happens, the
costs of both debt and equity should move more in parallel relative to
disequilibrium conditions between debt and equity costs that have existed
while the government's debt market intervention has occurred. As
economic conditions improve and as market-driven, higher interest prevail,
the reliability of cost of equity estimates from the traditional cost of equity
models should improve.

Q. HOW DO THE OTHER PARTIES' ROE RECOMMENDATIONS
COMPARE TO THE RATES OF RETURN AUTHORIZED BY OTHER
STATE UTILITY COMMISSIONS AROUND THE COUNTRY?

1 A. They are substantially lower. Over the past five years, average allowed
 2 ROEs have ranged between 10.6 percent to 9.8 percent. Table 5 below
 3 summarizes the ROE data for integrated electric utilities like EAI.

Table 5
Authorized Equity Returns for Vertically-Integrated Electric Utilities

	2009	2010	2011	2012	2013*
Average ROE	10.63%	10.38%	10.24%	10.10%	9.84%

Source: Regulatory Focus, SNL Regulatory Research Associates, Major Rate Case Decisions, July 9, 2013; January 17, 2013; January 10, 2012; January 7, 2011; and January 8, 2010.

*2013 average is for first two quarters only.

4
 5 Q. IN THEIR ANALYSES, SOME OF THE OTHER WITNESSES USE THE
 6 CAPITAL ASSET PRICING MODEL ("CAPM"). CAN YOU EXPLAIN
 7 WHY THE CAPM CURRENTLY UNDERSTATES ROE AND WHY CAPM
 8 ESTIMATES SHOULD NOT BE INCLUDED TO ESTIMATE EAI'S COST
 9 OF CAPITAL?

10 A. Yes. The CAPM requires three inputs to estimate ROE:

- 11 1) the risk-free interest rate (R_f);
- 12 2) the market risk premium for stocks relative to the risk-free rate
- 13 ($R_m - R_f$); and
- 14 3) a measure of market-related, or nondiversifiable, risk (β or beta).

15 The CAPM estimate of ROE is calculated from the following equation:

16
$$ROE = R_f + \beta(R_m - R_f).$$

1 Under present market conditions, and as applied by the other parties in
2 their CAPM analyses, two of the three CAPM inputs tend to understate
3 ROE. The risk-free rate, R_f , is understated because, due to the
4 government's easy money policy and investors' flight to safety, the U.S.
5 Treasury rates used for R_f are artificially low. The second input, the
6 market risk premium ($R_m - R_f$) is also understated. This is the case
7 because the other parties base their market risk premium estimates on
8 historical data or prior academic studies that do not reflect the recent
9 market turmoil. While there is no objective source for measuring the
10 widening equity risk premium phenomenon, the wide risk spreads that
11 occurred in late 2008 and early 2009 are indicative of that effect. For the
12 other parties to ignore ongoing market volatility and to routinely apply the
13 CAPM without adjustment produces unreasonably low estimates of ROE.
14 In this environment, CAPM estimates of ROE provide no valuable insight
15 into setting a reasonable ROE level for EAI.

1 **V. REBUTTAL OF STAFF WITNESS DANIEL**

2 Q. WHAT IS THE BASIS FOR MR. DANIEL'S 9.6 PERCENT ROE
3 RECOMMENDATION?

4 A. Mr. Daniel uses the constant growth DCF model as his primary
5 methodology. He applies that model to a selected 19-company, "risk-
6 comparable" group as well as to a larger "industry" sample. In his DCF
7 model, Mr. Daniel uses current dividends plus one-quarter of a year's
8 dividend growth to determine the expected yield. In the yield calculation,
9 stock prices are from the 13 weeks following the Value Line editions used
10 to obtain his underlying data (Central Edition, December 2012-March
11 2013; West Edition, February-April 2013; and East Edition, February-May
12 2013). For the expected DCF growth rate, Mr. Daniel reviews four growth
13 rate alternatives: g1 is the average of Value Line, Zacks, and Yahoo 5-
14 year earnings growth rate projections; g2 is the average of Value Line's
15 projected 3-5 year growth rates in earnings, dividends, and book value;
16 and g3 is Value Line's average 5-year historical growth rate in earnings.
17 His g4 growth rate is the Congressional Budget Office's ("CBO") average
18 projected GDP growth rate for 2013-2017. Adding these growth rate
19 averages to the expected dividend yields, Mr. Daniel finds a DCF range of
20 9.0 percent to 9.6 percent for his risk comparable group and 8.8 percent to
21 9.8 percent for his larger industry group.

1 Q. WHAT IS YOUR GENERAL ASSESSMENT OF MR. DANIEL'S
2 ANALYSIS AND FINAL RECOMMENDATION?

3 A. Mr. Daniel's ROE recommendation is below EAI's cost of equity. Even at
4 the top of his DCF range, Mr. Daniel's 9.6 percent recommendation is too
5 low because his analysis is based entirely on data that existed prior to the
6 recent change in the Fed's monetary policy, and some of the technical
7 aspects of his analysis lead to lower ROE estimates. In the transition
8 period to higher interest rates that is now underway, Mr. Daniel's routine
9 DCF model application cannot reflect the higher cost of capital that has
10 resulted. Mr. Daniel's analytical model results, especially his update of my
11 analysis, suggest that the cost of equity is declining. Such results are not
12 consistent with the 70 basis point increase in utility interest rates that has
13 occurred during the past three months. Under these conditions, the DCF
14 model results, including Mr. Daniel's current analysis, should be
15 reconsidered, and more weight should be given to other approaches.

16

17 Q. AT PAGE 28, LINES 1-5, MR. DANIEL SAYS THAT HE HAS
18 "CONCERNS" WITH YOUR COMPARABLE COMPANY SAMPLE. HE
19 SAYS THAT YOUR INCLUSION OF NATURAL GAS REVENUES IN
20 YOUR MINIMUM REGULATED REVENUES SELECTION CRITERION
21 CAUSES YOUR GROUP TO CONTAIN "COMPANIES WITH RISK

1 PROFILES THAT COULD BE MATERIALLY DIFFERENT THAN EAI.”

2 HOW DO YOU RESPOND TO THIS CRITICISM?

3 A. Mr. Daniel’s comments appear to be more a justification for his own “risk-
4 comparable” group selections than any real criticism of my selection
5 criteria. If anything, the regulated natural gas revenues, which I include in
6 my regulated percentage of revenues criterion, are generally viewed as
7 *less risky* relative to EAI’s integrated electric utility operations. If there
8 were any difference in the risk profiles of our groups, my group, therefore,
9 would be viewed as less risky than Mr. Daniel’s. I include companies in
10 my group with both electric and gas regulated revenues because Value
11 Line includes those companies in its “Electric Utility” editions, even though
12 such companies are sometimes referred to as “combination” electric and
13 gas utilities. Finally, Mr. Daniel’s own data show that, on average, there is
14 no meaningful difference between the market data for our respective
15 groups. The average dividend yield for his “risk comparable” companies,
16 shown in his Exhibit RD-12, is 3.86 percent. In his update of my group
17 analysis, as shown in his Exhibit RD-18, the average dividend yield is 3.91
18 percent. Furthermore, the estimated constant growth DCF ROE from his
19 update of my group analysis is 9.3 percent, which is exactly the middle of
20 the calculated DCF range for his “risk comparable” group. All these
21 factors show that Mr. Daniel’s comments about my regulated revenues

1 selection criterion are misplaced and should be disregarded by the
2 Commission.

3

4 Q. ON PAGES 30 AND 32, MR. DANIEL DISCUSSES YOUR GDP
5 GROWTH ESTIMATE AND SAYS THAT YOUR "OLDER GDP DATA
6 CONTINUE TO *PROP UP* [YOUR] FINAL RESULT." WHAT IS YOUR
7 RESPONSE TO THIS COMMENT?

8 A. Mr. Daniel's comment is not consistent with his own discussion of the
9 required DCF model growth rate. In that discussion he states:
10 "Theoretically, the growth rate in the DCF methodology is one that is
11 expected to persist to infinity. Practically, the appropriate DCF growth rate
12 is inherently long-term."⁴ I base my GDP growth forecast on 60 years of
13 data because investors are clearly aware of economic relationships that
14 have existed during that time period. To use only the most recent,
15 recession dominated data, as Mr. Daniel appears to support, would mean
16 that investors ignore the possibility that inflation may return to higher
17 levels and that real economic growth may return to prerecession levels.
18 While U.S. demographics and questions about future productivity gains
19 have dampened some forecasts for future economic growth, those factors
20 are taken into account in my forecast. As I explained in my direct
21 testimony: "The long-run historical [60-year] average GDP growth rate is

⁴ Daniel Direct Testimony at 29.

1 6.5 percent, but my estimate of long-term expected growth is 5.6 percent.
2 My forecast is lower because my forecasting method gives much more
3 weight to the more recent 10- and 20-year periods.”⁵ While Mr. Daniel and
4 others may wish to select lower GDP growth rates to use in their DCF
5 analyses, their exclusion of periods of higher inflation and more robust
6 growth is not consistent with investors’ longer-term experience, as is
7 required in the DCF model. I offer more data for the Commission’s
8 consideration to provide a more balanced view of longer-term
9 expectations, not to “prop up” the expected long-term DCF growth rate.

10

11 Q. ON PAGES 33-34, MR. DANIEL DISCUSSES HIS UPDATE OF YOUR
12 DCF ANALYSIS AND CONCLUDES THAT WITH MORE RECENT DATA,
13 YOUR ANALYSIS SUPPORTS AN ROE RANGE OF 9.3 PERCENT TO
14 9.6 PERCENT. SHOULD THIS UPDATE OF YOUR ANALYSIS BE
15 GIVEN SIGNIFICANT WEIGHT IN THE COMMISSION’S
16 DELIBERATION?

17 A. No. Mr. Daniel’s update of my analysis has exactly the same technical
18 problems that I discussed previously. The lower results that he obtains
19 are not consistent with the rising interest rate environment that now exists.
20 As such, the updated DCF results do not meet the basic test of

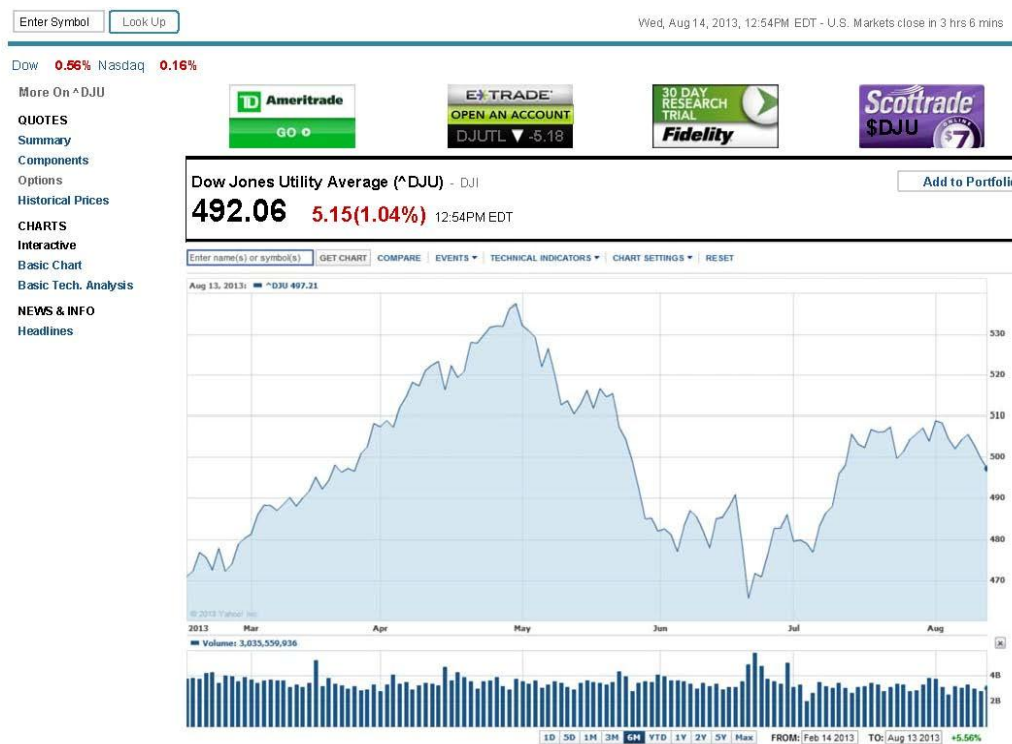
⁵ Hadaway Direct Testimony at 44-45.

1 reasonably relative to rising ROE estimates that come from the basic
 2 bond yield plus equity risk premium model.

3
 4 Q. CAN YOU DEMONSTRATE THE EFFECT THAT MORE RECENT
 5 STOCK PRICES HAVE IN MR. DANIEL'S UPDATED ANALYSIS?

6 A. Yes. The time period selected by Mr. Daniel (March-May 2013) happens
 7 to correspond to the peak in utility prices. More important, that peak
 8 occurred prior to the FOMC announcement of its revised monetary policy
 9 and the increasing interest rates that have since occurred. Graph 1 below
 10 vividly illustrates the timing issue associated with Mr. Daniel's update.

11 **Graph 1**
 12 **Dow Jones Utility Average**
 13



14

1 The peak in utility prices occurred on April 30, 2013, at the middle of
2 Mr. Daniel's update re-pricing period. In his analysis, the effect of this
3 timing issue was to create the lowest possible dividend yields that have
4 occurred in recent years. In the DCF model, along with less optimistic
5 analysts' growth forecasts that also occurred as utility shares appeared to
6 be overpriced,⁶ the results were the lowest possible estimates of ROE.
7 This type of update, although possibly unintentional on Mr. Daniel's part, is
8 not representative of the cost of equity for EAI. As shown in my updated
9 risk premium analysis, the indicated ROE estimate, based on projected
10 interest rates for the coming year, is 100 basis points higher than Mr.
11 Daniel reports for his update of my DCF analysis. As explained
12 previously, under these circumstances, the DCF results do not meet tests
13 of reasonableness and should not be the basis for setting EAI's allowed
14 ROE.

15
16 Q. PLEASE SUMMARIZE YOUR REBUTTAL OF STAFF WITNESS DANIEL.

17 A. Mr. Daniel's ROE recommendation is below EAI's cost of equity because
18 his analysis is based entirely on the traditional constant growth DCF
19 model applied to data that existed before the Fed's shift to less
20 accommodative monetary policy. In effect, his analysis ignores the 70
21 basis point increase in utility borrowing costs that has occurred during the

⁶ *Id.* at 19.

1 past three months and the even higher rates that are projected for the
2 coming year. While the Commission may have given preference to the
3 traditional DCF model in past cases, under present market conditions, a
4 broader, more-timely approach is required to set a reasonable ROE for
5 EAI. Although Mr. Daniel may have attempted to mitigate the effects of
6 recent market conditions by going to the top of his range, his analysis was
7 performed before the full effect of changed Fed policy could be
8 considered, and therefore, his recommendation remains below EAI's
9 market cost of equity

10

11 **VI. REBUTTAL OF AG WITNESS MARCUS**

12 Q. WHAT IS THE BASIS FOR MR. MARCUS' ROE RECOMMENDATION?

13 A. Mr. Marcus discusses ROE on pages 12-45 of his testimony. In that
14 discussion, he provides five sections that range from economic conditions
15 to returns from pension and nuclear decommissioning funds, to risk
16 premium and CAPM theory, to returns allowed by other regulatory
17 commissions. Nowhere in that discussion does he provide a direct
18 estimate of the cost of equity. As noted previously, however, he ultimately
19 recommends an ROE of 9.25 percent, and would reduce that ROE by a
20 further 10 basis points if the ITC transaction is approved.⁷ While there is
21 no specific quantitative basis for Mr. Marcus' 9.25 percent ROE, he states

⁷ Marcus Direct Testimony at 44.

1 that he would expect his recommendation to be near the bottom of a
2 Commission DCF range.⁸

3

4 Q. ON PAGES 19-20, MR. MARCUS PROVIDES A PORTION OF THE
5 FOMC JUNE 19, 2013 ANNOUNCEMENT THAT YOU DISCUSSED
6 PREVIOUSLY. FROM HIS READING OF THAT PORTION OF THE
7 ANNOUNCEMENT, MR. MARCUS (AT 20, LINE 18) CONCLUDES:
8 “THEREFORE, LARGE INCREASES IN INTEREST RATES ARE NOT
9 LIKELY IN THE NEAR TERM.” IS MR. MARCUS’ CONCLUSION
10 CONSISTENT WITH THE CAPITAL MARKET’S REACTION TO THE
11 FOMC ANNOUNCEMENT?

12 A. No. As shown previously, interest rates have increased by over 70 basis
13 points during the past three months (EAI Exhibit SCH-8, page 1), and they
14 are expected to increase further during the coming year (EAI Exhibit SCH-
15 8, page 2). The entire thesis of Mr. Marcus’ ROE discussion appears to
16 be based on his mistaken assumption that interest rates will not rise in the
17 near term. While he provides only limited quantitative analysis (no
18 traditional DCF or risk premium analysis), he repeats the low interest rate
19 theme throughout his discussion.

20

⁸ *Id.*

1 Q. ON PAGES 22-23, MR. MARCUS CRITICIZES YOUR TRADITIONAL
2 BOND YIELD PLUS EQUITY RISK PREMIUM ANALYSIS, SAYING THAT
3 YOUR ANALYSIS “LACKS MERIT” BECAUSE IT USES ALLOWED
4 RATES OF RETURN AS A PROXY FOR WHAT THE MARKET MIGHT
5 EXPECT. HOW DO YOU RESPOND TO THIS CRITICISM?

6 A. Mr. Marcus' criticisms are misplaced. Allowed rates of return from all the
7 regulatory commissions around the country are the best reflection possible
8 of the returns that investors expect utilities to receive. For Mr. Marcus to
9 say that such information is “circular” or that use of such data “requires the
10 Commission to abdicate its responsibility” is at best hyperbole. While it
11 might be circular for a utility commission to base its return decisions on the
12 national average, that is not what I recommended in my risk premium
13 analysis. The historical relationship between allowed returns and the cost
14 of debt is what investors have actually seen for utilities and what they may
15 reasonably expect for the future. By adding the consensus risk premium
16 to current and projected utility interest rates, my analysis tracks what
17 investors should reasonably expect, and it is, therefore, an appropriate
18 method for estimating investors' return requirements. It is not an
19 abdication of responsibility, and it is entirely consistent with the *Bluefield*
20 and *Hope* decisions, for regulators to evaluate their rate of return
21 allowances by reviewing current and projected utility interest rates and by
22 considering rates of return allowed for other similarly situated utilities.

1

2 Q. ON PAGES 23-35, MR. MARCUS DISCUSSES ACTUARIAL RATE OF
3 RETURN ASSUMPTIONS FOR PENSION AND NUCLEAR
4 DECOMMISSIONING TRUST FUNDS AS WELL RATE OF RETURN
5 PROJECTIONS FROM ANALYSTS' AND ACADEMIC STUDIES. IS THIS
6 DISCUSSION PERTINENT TO SETTING EAI'S COST OF EQUITY?

7 A. No. This discussion appears to be a further effort to misdirect attention
8 away from Mr. Marcus's lack of basic analysis. While Mr. Marcus tells the
9 Commission not to consider other regulatory commissions' allowed
10 ROEs,⁹ he nevertheless offers 13 pages discussing actuarial and
11 academic assumptions that have little direct connection with the cost of
12 equity for utilities. Ms. Cannell discusses these issues further in her
13 rebuttal testimony.

14

15 Q. ON PAGES 42-43, MR. MARCUS PROVIDES A CAPM ANALYSIS,
16 WHICH, "BASED ON REALISTIC MARKET ASSUMPTIONS,"
17 INDICATES AN ROE RANGE OF 6.46 PERCENT TO 7.61 PERCENT.
18 WHAT IS YOUR RESPONSE TO THIS ANALYSIS?

19 A. Mr. Marcus' CAPM analysis is negatively affected by all the current market
20 factors that I have described previously. With his June 20-July 22, 2013
21 Treasury bond risk-free rate at 3.58 percent, the results from that model,

⁹*Id.* at 23.

1 even with the most generous assumptions about the market risk premium,
2 are less than 8.5 percent. Under such circumstances, the CAPM results
3 provide little guidance on a reasonable ROE for EAI. Mr. Marcus' further
4 discussion of additions to his CAPM calculations to obtain an ROE
5 estimate above 9 percent does not provide any analytical basis for setting
6 EAI's allowed rate of return.

7
8 Q. PLEASE SUMMARIZE YOUR REBUTTAL OF AG WITNESS MARCUS.

9 A. Mr. Marcus' testimony is confusing and potentially misleading. He
10 provides no analysis that can be examined to assist in setting EAI's cost of
11 capital. Rather, he offers extreme and generally irrelevant anecdotes. His
12 testimony should be evaluated accordingly.

13

14 **VII. REBUTTAL OF AECC WITNESS PARCELL**

15 Q. WHAT IS THE BASIS FOR MR. PARCELL'S 9.25 PERCENT ROE
16 RECOMMENDATION?

17 A. Mr. Parcell summarizes the results of his analysis on page 2. Based on
18 DCF, CAPM, and Comparable Earnings ("CE") analyses, he concludes
19 that the reasonable ROE range is 9.0 percent to 9.5 percent, with a
20 midpoint recommendation of 9.25 percent. He reports a DCF range of
21 8.4 percent to 9.1 percent, a CAPM range of 6.3 percent to 6.7 percent,
22 and a CE range of 9.0 percent to 10.0 percent.

1

2 Q. DOES MR. PARCELL REASONABLY CONSIDER THE CHANGE IN FED
3 POLICY OR THE EFFECT OF THAT CHANGE ON CAPITAL COSTS?

4 A. No. Although, at pages 7-13, Mr. Parcell provides a lengthy discussion of
5 economic cycles and conditions dating back to the mid-1970s, at page 13,
6 the conclusion he reaches is entirely incorrect. There he states: "Utility
7 interest rates are currently at levels below those prevailing prior to the
8 financial crisis of late 2008 to early 2009 and are near the lowest levels in
9 the past 35 years." While it is certainly true that interest rates are lower
10 than they were during most of Mr. Parcell's discussion period, that fact is
11 largely irrelevant, and it is simply not true that rates are continuing down or
12 that they are near the lowest levels in 35 years. As shown previously in
13 Table 2, utility interest rates have increased by over 70 basis points since
14 April 2013, and projections are for further increases. Mr. Parcell's
15 misinterpretation of the current interest rate environment appears to be a
16 major deficiency in his analysis, and it is indicative of the unreasonably
17 low level of his ROE recommendation.

18

19 Q. HOW IS MR. PARCELL'S DCF ANALYSIS STRUCTURED?

20 A. He applies a constant growth DCF analysis to an 11-company reference
21 group and to the 21-company comparable group that I used in my direct
22 testimony. His estimated DCF range of 8.4 percent to 9.1 percent is well

1 above most of the DCF results shown in his Exhibit DCP-6, page 4 of 4,
2 and many of the mean and median values shown in the table on page 25
3 of his testimony. From his analysis in Exhibit DCP-6, the median and
4 mean results for his group are 8.0 percent and 8.2 percent, respectively,
5 and for my group they are 7.9 percent to 8.3 percent. Additionally, the
6 wider analytical range from all the means and medians in his exhibit
7 appears to be based on Mr. Parcell's selections from DCF calculations
8 that could easily have supported almost any ROE estimate he chose.
9 Such a subjective approach is generally not acceptable. Mr. Parcell's
10 mechanical DCF analysis based on his subjective growth rate selections
11 does not provide a meaningful estimate of EAI's cost of equity and should
12 be dismissed by the Commission.

13

14 Q. HOW IS MR. PARCELL'S CAPM ANALYSIS STRUCTURED?

15 A. Mr. Parcell applies a standard CAPM analysis to his 11-company
16 comparable group and to my 21-company group. In that analysis, he uses
17 the average April-June 2013 yield on 20-year Treasury bonds (2.78%) as
18 the risk-free rate; Value Line's adjusted beta coefficients; and a
19 combination of his own calculations of the market risk premium (6.6%)
20 along with the long-term geometric and arithmetic market premiums from
21 Morningstar/Ibbotson Associates (4.1%-5.7%). From this analysis, he

1 concludes that the CAPM cost of equity for EAI is 6.3 percent to 6.7
2 percent.¹⁰

3

4 Q. WHAT IS THE BASIS FOR MR. PARCELL'S CE ESTIMATE?

5 A. He reviews earned rates of return on book value for his and my proxy
6 groups for historical periods between 1992 and 2012 as well as
7 prospective earned rates of return projected by Value Line for 2012 and
8 for the 2016-2018 period. He also reviews historical earned rates of return
9 for the S&P 500 Composite. He compares the earned rates of return to
10 the average market-to-book ratios for the groups and concludes that an
11 earned ROE of 9.0 percent to 10.0 percent should result in market-to-book
12 ratios that substantially exceed 100 percent.¹¹

13

14 Q. WHAT IS YOUR ASSESSMENT OF MR. PARCELL'S ANALYSIS AND
15 RECOMMENDATION?

16 A. Mr. Parcell's DCF recommendation does not follow from his analysis. His
17 subjective conclusion, that the reasonable DCF range is 9.0 percent to
18 9.5 percent, is not supported by the much lower results from his DCF and
19 CAPM analyses. While his upward adjustment from the analytical results
20 might appear generous toward the Company, his analytical result starting
21 point is so low that he still recommends an unreasonably low ROE. His

¹⁰ Parcell Direct Testimony at 29.

¹¹ *Id.* at 34.

1 comparable earnings ROE estimates are also extremely questionable
2 because he relies on rates of return on book value and his interpretation of
3 the results is entirely subjective. Although his comparable group analyses
4 indicate an ROE range of 9.0 percent to 12.1 percent¹² and his S&P 500
5 group produces a range of 12.4 percent to 14.7 percent,¹³ he concludes
6 that a range of 9.0 percent to 10.0 percent is appropriate. His CE
7 approach is unreliable, and the result that he picks has little to do with the
8 analysis he presents. Such an approach adds nothing to the task of
9 estimating a reasonable ROE and should be rejected.

10

11 Q. ON PAGES 35-39, MR. PARCELL CRITICIZES VARIOUS ASPECTS OF
12 YOUR DCF ANALYSIS. WHAT IS YOUR GENERAL RESPONSE TO
13 HIS CRITICISMS?

14 A. His criticisms are not accurate. His first criticism of my first DCF
15 approach, which is based on analysts' earnings growth rate projections, is
16 that I "...assume that investors rely exclusively on EPS projections in
17 making investment decisions."¹⁴ This statement is inaccurate with respect
18 to the DCF model because that model does not require an estimate of all
19 the things investors consider. It requires an estimate of investors'
20 expected growth rates. Many regulatory economists use analysts' growth

¹² *Id.* at 32-33.

¹³ *Id.* at 33.

¹⁴ *Id.* at 38.

1 rate projections in the DCF model, because it is well known that analysts
2 consider all the information about which Mr. Parcell is concerned.
3 Professional analysts then boil all that information down to a widely
4 followed earnings per share ("EPS") growth rate. I use that growth rate for
5 one of the three DCF model estimates that I provide because professional
6 analysts' estimates are closely followed by investors and, therefore, it is
7 reasonable to believe that investors' expectations for future growth is
8 affected by those projections.

9

10 Q. ON PAGES 39-40, MR. PARCELL CRITICIZES YOUR GDP FORECAST
11 BECAUSE IT IS BASED ON HISTORICAL DATA, AND HE OFFERS A
12 TABLE OF OTHER GDP FORECASTS THAT ARE LOWER THAN
13 YOURS. WHAT IS YOUR RESPONSE TO HIS CRITICISMS AND
14 COMPARISON DATA?

15 A. Mr. Parcell's comments about my estimate of expected long-term GDP
16 growth are misplaced. His contention that there is an inconsistency in my
17 approach between using analysts' earnings growth rate projections in one
18 model and historical data to forecast expected GDP growth in another is a
19 mischaracterization and is potentially misleading. Analysts incorporate all
20 the available data, both historical data and prospective data, in their
21 earnings growth forecasts. Investors use these professional forecasts in
22 forming their own overall growth rate expectations and making their final

1 investment decisions. Investors also know that macroeconomic factors,
2 such as overall GDP growth, will affect their investment results. Investors
3 certainly know that recent GDP growth has been dampened by the
4 financial crisis and resulting economic recession that has occurred. If that
5 recent *historical* experience were the only basis for investors' longer-term
6 growth rate expectations, it is highly unlikely that current stock market
7 prices would be supported. Investors use a combination of all sources of
8 data available to them, and that is the approach I have attempted to
9 provide by presenting both analysts' earnings forecasts and estimates of
10 future GDP growth based on the historical relationships that investors
11 have experienced.

12 While most econometric forecasts, including mine, rely on trending
13 and averaging of historical data, my forecast uses a weighting process
14 that gives more weight to more recent years when GDP growth has been
15 lower. GDP forecasts and economic forecasts in general are difficult and
16 are often unduly influenced by current data and very recent experience. I
17 used the very long-term St. Louis Federal Reserve Bank data to mitigate
18 this well-known forecasting deficiency.

19 Mr. Parcell's GDP forecasts from the Social Security Administration
20 ("SSA") and the Energy Information Agency ("EIA") of the U.S.
21 Department of Energy do indicate that nominal GDP is expected to grow
22 at rates of 4.6 percent and 4.5 percent, respectively. The reason that

1 these forecasts are much lower than mine is because both SSA and EIA
2 project lower real growth and much lower inflation than has occurred
3 heretofore in the U.S. economy. The SSA forecast indicates that the real
4 growth rate in the U.S. economy will permanently decline from a
5 historically low 3.0 percent to an even lower level of 2.1 percent. EIA
6 projects that real growth will be somewhat higher at 2.7 percent, but
7 forecasts that inflation will fall to below 2 percent and remain at that low
8 level throughout the forecast period to 2035.

9 These forecasts are in stark contrast to historical experience. The
10 actual St. Louis Federal Reserve GDP data are presented in my GDP
11 forecast in EAI Exhibit SCH-5. While Government forecasters may hope,
12 for reasons of policy, deficit reduction, and the survival of Social Security,
13 to see permanently low growth and inflation, their recent forecasts are not
14 at all consistent with longer-term historical results.

15

16 Q. ON PAGE 44, MR. PARCELL CRITICIZES YOUR TRADITIONAL RISK
17 PREMIUM ANALYSIS, SAYING THAT ALLOWED RATES OF RETURN
18 ARE NOT NECESSARILY RELIABLE INDICATORS OF INVESTOR-
19 REQUIRED RISK PREMIUMS AND THAT YOUR ANALYSIS DOES NOT
20 CONSIDER THE RELATIVE RISK OF THE SUBJECT COMPANY
21 RELATIVE TO ALL THE COMPANIES INCLUDED IN YOUR RISK
22 PREMIUM ANALYSIS. ARE THESE VALID CRITICISMS?

1 A. No, they are not. The data in my risk premium study, covering essentially
2 all major electric utility rate cases before state commissions since 1980,
3 represent the best efforts of rate of return witnesses and decision makers
4 in literally hundreds of cases to estimate investors' return requirements.
5 While it is true that there will always be timing differences and other case
6 specific issues that may affect ROE, over a 30-year period the average
7 annual results represent as nearly as possible an unbiased estimate of
8 what investors expected utilities to receive. Second, Mr. Parcell's
9 statement about relative risk not being considered in my analysis is simply
10 mistaken. My analysis, in fact, uses the subject company's bond rating to
11 determine the base interest rate to be used in the analysis. For this
12 reason, the estimated ROE from my analysis is lower for an "Aa" company
13 than for a company rated "A," etc. Mr. Parcell's criticisms of my basic risk
14 premium methodology are entirely misplaced.

15

16 Q. ON PAGE 45, MR. PARCELL CONCLUDES HIS CRITICISMS OF YOUR
17 RECOMMENDATIONS, SAYING THAT COST OF EQUITY MODELS
18 SUCH AS DCF AND CAPM ARE BASED ON A PRESUMPTION OF AN
19 "EFFICIENT" MARKET IN WHICH ALL RELEVANT INFORMATION IS
20 REFLECTED IN STOCK PRICES. HOW DO YOU RESPOND TO
21 MR. PARCELL'S CONCLUDING REMARKS?

1 A. While I agree that capital market are highly competitive and are presumed
2 by many to be "efficient," Mr. Parcell's use of the term is out of context.
3 He would apparently have the Commission ignore the artificially low level
4 of current interest rates that have been caused by the government's credit
5 market intervention and assume that current DCF and CAPM estimates of
6 ROE are accurate. His own subjective adjustments to arrive at
7 recommendations not currently supported by these models show that his
8 concluding remarks are not accurate.

9

10 **VIII. REBUTTAL OF FEA WITNESS GORMAN**

11 Q. WHAT IS THE BASIS FOR MR. GORMAN'S 9.40 PERCENT ROE
12 RECOMMENDATION?

13 A. Mr. Gorman bases his recommendation on three versions of the DCF
14 model (two constant growth models and one multi-stage growth model), a
15 risk premium analysis, and the CAPM. Mr. Gorman concludes that the
16 reasonable ROE range is 9.15 percent to 9.60 percent. His recommended
17 ROE of 9.4 percent is the approximate midpoint of this range.

18

19 Q. WHAT IS YOUR TECHNICAL ASSESSMENT OF MR. GORMAN'S ROE
20 TESTIMONY AND RECOMMENDATION?

21 A. Mr. Gorman's recommendation is understated because, in his analysis, he
22 applies inconsistent and incorrect approaches to reach his final ROE

1 recommendation. Several specific factors detract from Mr. Gorman's
2 analysis. In his multi-stage DCF analysis, Mr. Gorman's result is low
3 because his long-term GDP growth rate in that model is significantly
4 understated. Mr. Gorman's risk premium analysis is also flawed because
5 he rejects the well-documented, inverse relationship between equity risk
6 premiums and interest rates levels. Equity risk premiums increase when
7 interest rates are low and decrease when interest rates are higher. When
8 adjustments are made to correct these areas of Mr. Gorman's analysis,
9 his results support an ROE over 10 percent.

10

11 Q. WHAT ARE YOUR PRINCIPAL AREAS OF DISAGREEMENT WITH
12 MR. GORMAN?

13 A. Mr. Gorman's analysis is negatively skewed by his assumptions and his
14 application of the models. While Mr. Gorman applies a non-constant
15 growth DCF model similar to mine and agrees that GDP growth is an
16 appropriate input for that model, for his long-term growth rate, he relies on
17 relatively short-term GDP growth rate forecasts that are dominated by
18 recent historically low inflation. Mr. Gorman's GDP growth forecast
19 contains inflation estimates that are almost a full percentage point below
20 longer-term historical averages. This approach is inconsistent with the
21 long-term growth rate assumption required in the DCF model.

1 In his risk premium analysis, Mr. Gorman selects risk premiums
2 that are not consistent with recent risk premium data because he fails to
3 include the well-documented inverse relationship between risk premiums
4 and interest rates, *i.e.*, the tendency for risk premiums to widen when
5 interest rates are low and narrow when interest rates are high. This
6 omission causes Mr. Gorman's risk premium estimates to be significantly
7 understated.

8

9 Q. PLEASE ELABORATE ON YOUR SPECIFIC DISAGREEMENTS WITH
10 MR. GORMAN'S MULTI-STAGE DCF ANALYSES.

11 A. Mr. Gorman uses analysts' growth forecasts in the first five years of his
12 multi-stage analysis and then a GDP growth forecast for years 11 and
13 later. In the intermediate years, six through 10, he interpolates between
14 the first and third stages. Mr. Gorman's estimate of future GDP growth is
15 far too low. His forecasts for five- and 10-year periods are from the Blue
16 Chip Financial Forecasts. The current Blue Chip consensus is low
17 because it is dominated by recent, virtually zero growth in the economy,
18 and it is based on assumed long-term inflation rates of only about 2.0
19 percent.

20 As shown in my GDP forecast (EAI Exhibit SCH-5), these inflation
21 rates are lower than four out of six 10-year periods in the last 60 years.
22 The nominal 4.9 percent growth rate that Mr. Gorman uses is itself lower

1 than nominal GDP growth in most of the 10-year periods (other than the
2 most recent periods, which include GDP growth rates of -1.2 percent and
3 0.4 percent for 2008 and 2009, respectively). Mr. Gorman's use of
4 recently depressed, short-term data for his long-term DCF growth rate
5 creates an unrealistically low estimate of ROE.

6

7 Q. IN HIS DCF ANALYSIS, MR. GORMAN USES YOUR COMPARABLE
8 GROUP, EXCEPT HE REMOVES TECO ENERGY BECAUSE IT IS
9 INVOLVED IN AN ACQUISITION OF NEW MEXICO GAS COMPANY,
10 WHICH TECO ANNOUNCED ON MAY 28, 2013. DO YOU AGREE
11 THAT TECO ENERGY SHOULD BE REMOVED FROM YOUR
12 COMPARABLE GROUP?

13 A. No. This acquisition does not have a material effect on the suitability of
14 TECO Energy for inclusion in my comparable group. In the acquisition
15 announcement, TECO stated that New Mexico Gas would be acquired for
16 an aggregate value of \$950 million, including the assumption of \$200
17 million of debt. For the year ended January 31, 2013, New Mexico Gas
18 had net income of \$23.2 million. By comparison, TECO Energy had total
19 assets of \$7.4 billion and total long-term debt of \$3.0 billion at year-end
20 2012. For 2012, TECO Energy reported net income from continuing
21 operations of \$246 million. In this context, TECO Energy's financial
22 situation is not materially affected by this acquisition.

1

2 Q. WHY DO YOU DISAGREE WITH MR. GORMAN'S RISK PREMIUM
3 ANALYSIS?

4 A. Mr. Gorman's risk premium analysis fails to include the well-documented
5 tendency for risk premiums to expand when interest rates are low. When
6 his analysis is modified to properly reflect wider risk premiums when
7 interest rates are lower, Mr. Gorman's risk premium analysis indicates a
8 much higher ROE.

9

10 Q. WHY ARE MR. GORMAN'S ROE RESULTS SO LOW IN HIS RISK
11 PREMIUM ANALYSIS?

12 A. Mr. Gorman's risk premium data are presented in FEA Exhibit MPG-12
13 and FEA Exhibit MPG-13. He discusses the analysis on pages 28-33 of
14 his testimony. The analysis consists of two parts. In one approach,
15 Mr. Gorman adds government bond equity risk premiums of 4.41 percent
16 to 6.31 percent to a projected Treasury bond yield of 4.0 percent. This
17 produces an ROE result of 9.84 percent using a 25 percent weight for the
18 lower end of the range and a 75 percent weight for the upper end. In
19 Mr. Gorman's second approach, he adds a utility bond risk premium of
20 3.03 percent to 4.87 percent to the recent "Baa" utility bond yield of 4.87
21 percent. This produces an ROE result of 9.30 percent using the same 25
22 percent/75 percent weighting scheme as discussed above. From these

1 two results, Mr. Gorman concludes that an ROE of 9.60 percent is
2 appropriate (approximate midpoint of 9.30 percent and 9.84 percent).

3

4 Q. IN THE RISK PREMIUM ANALYSIS DESCRIBED IN YOUR DIRECT
5 TESTIMONY, YOU USED A STANDARD REGRESSION ANALYSIS TO
6 ACCOUNT FOR THE INVERSE RELATIONSHIP BETWEEN RISK
7 PREMIUMS AND INTEREST RATES. WHAT DO MR. GORMAN'S RISK
8 PREMIUM DATA INDICATE WHEN THIS APPROACH IS USED?

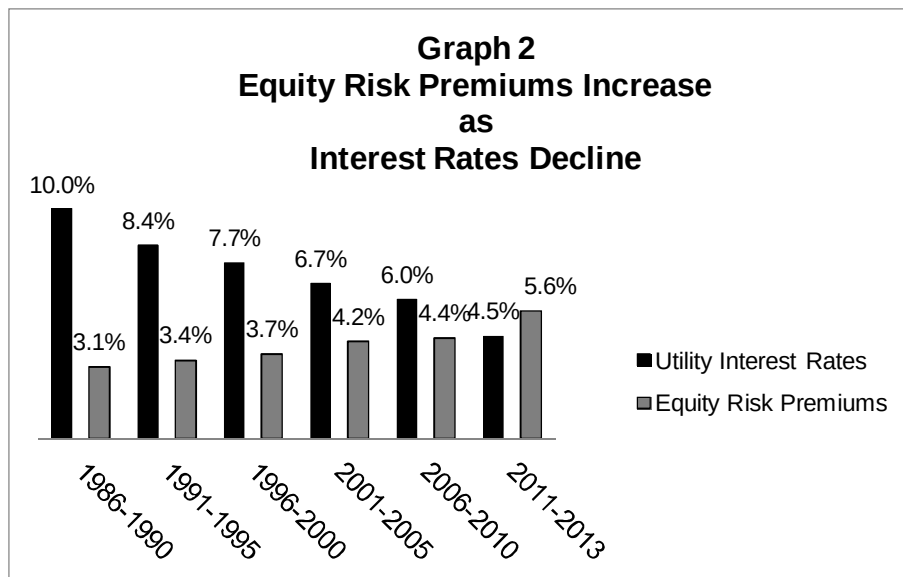
9 A. In EAI Exhibit SCH-9, pages 2 and 4, I have applied the standard
10 regression analysis to calculate "interest rate adjustment" factors for Mr.
11 Gorman's two risk premium studies. This approach properly takes into
12 account the inverse relationship between equity risk premiums and
13 interest rates. With this adjustment, Mr. Gorman's Treasury bond risk
14 premium analysis indicates an ROE of 10.24 percent, as shown in pages
15 1 to 2 of EAI Exhibit SCH-9. For his utility bond risk premium analysis, the
16 indicated ROE is 9.94 percent as shown on pages 3-4 of EAI Exhibit
17 SCH-9. These results confirm that Mr. Gorman's risk premium data
18 support an ROE over 10.0 percent.

19

20 Q. IN YOUR DIRECT TESTIMONY, YOU SHOWED THAT THE INVERSE
21 RELATIONSHIP BETWEEN EQUITY RISK PREMIUMS AND INTEREST
22 RATES CAN BE SEEN WITHOUT USING A REGRESSION ANALYSIS

1 APPROACH. DOES THAT ANALYSIS APPLY TO YOUR REBUTTAL OF
2 MR. GORMAN'S RISK PREMIUM ANALYSIS AS WELL?

3 A. Yes. While statistical analysis is often used to substantiate certain
4 economic and financial relationships, for the equity risk premium issue the
5 relationship is so basic that simple observation of the data for various time
6 periods makes the inverse relationship clear. In Graph 2 below, average
7 utility bond yields and average equity risk premiums are presented for
8 each non-overlapping five-year period between 1986 and 2010 and for
9 2011 through the second quarter of 2013 from the portion of my equity risk
10 premium data that Mr. Gorman used.



11
12 These data show that equity risk premiums have consistently increased as
13 interest rates have declined. This result is a simple reflection of the fact
14 that required rates of return in the stock market are not entirely dependent

1 on changes in interest rates. Because utilities must compete with other
2 types of equity investments for capital, the ROE for utilities does not
3 change by as much as the observed changes in interest rates. For
4 Mr. Gorman to use the unadjusted simple average of long-term equity risk
5 premiums with current interest rates is simply wrong. Such an approach
6 will consistently understate the required ROE.

7

8 Q. MR. GORMAN CRITICIZES YOUR GDP GROWTH FORECAST
9 BECAUSE IT IS HIGHER THAN HIS BLUE CHIP FORECAST, WHICH
10 CONTAINS MUCH LOWER PROJECTED INFLATION RATES. HOW DO
11 YOU RESPOND TO MR. GORMAN'S CRITICISMS?

12 A. As acknowledged by Mr. Gorman, his Blue Chip forecasts are for only the
13 next five- and 10-year periods, and those forecasts indicate inflation rates
14 of only 2.1 percent and 2.2 percent, respectively. My GDP growth rate
15 estimate is based on a much longer time period, which is consistent with
16 the DCF model's requirements and with what investors can reasonably
17 expect once economic conditions become more stable. While my forecast
18 includes the near-term, low inflation rates that dominate Mr. Gorman's
19 five- and 10-year periods, I also include longer-term data that cover other
20 economic conditions, which can reasonably be expected to occur over the
21 very long-run DCF model horizon. Although I use data dating back to
22 1952 from the St. Louis Federal Reserve Bank database, my forecast is

1 not a simple average or extrapolation of the historical data. Like most
2 econometric forecasts, my approach uses the long-run historical
3 relationships to project what investors may reasonably expect for the long-
4 run future.

5 However, to account for recent data having a greater influence on
6 current expectations, I applied a weighted averaging process that gives
7 about five times as much weight to the most recent 10 years as compared
8 to the earliest 10 years. Giving more weight to the more recent, low
9 inflation years also lowers the overall forecast. For example, my updated
10 forecast is for a future growth rate of 5.6 percent, while the overall long-
11 run average of the data is a growth rate of 6.5 percent. In this context, Mr.
12 Gorman's criticism of my longer-term GDP growth forecast is
13 unwarranted.

14

15 Q. MR. GORMAN CRITICIZES YOUR RISK PREMIUM ANALYSIS
16 BECAUSE YOU USED PROJECTED RATES IN PART OF THAT
17 ANALYSIS. HOW DO YOU RESPOND?

18 A. Mr. Gorman's criticisms are misplaced. His risk premium analysis is very
19 similar to mine in the sense that we both rely on current and projected
20 interest rates. We both recognize that interest rates are forecast to
21 increase in the coming years and that this near unanimous viewpoint
22 should be reflected in the ROE analysis in this case.

1 **IX. UPDATED ROE ANALYSIS**

2 Q. HAVE YOU UPDATED YOUR ROE ANALYSIS TO TAKE INTO
3 ACCOUNT RECENT DATA AND THE CURRENT CONDITIONS IN THE
4 CAPITAL MARKETS?

5 A. Yes. As discussed previously, I have updated my ROE analysis for
6 current market conditions using the same methodologies that I employed
7 in my previous analysis.

8

9 Q. WHAT ARE THE RESULTS OF YOUR UPDATED DCF ANALYSES?

10 A. My updated DCF results are shown in EAI Exhibit SCH-10. As I
11 discussed previously, the results for this updated analysis are somewhat
12 lower than the DCF estimates I provided in my direct testimony (EAI
13 Exhibit SCH-6). Given the 70 basis point increase in interest rates that
14 has occurred since April, such lower DCF results do not meet the basic
15 test of reasonableness. For this reason, I recommend that more weight
16 should be given to my updated risk premium analysis, which provides,
17 although still low, ROE estimates that are at least in part consistent with
18 the increasing interest rate trend that is now occurring.

19

20 Q. WHAT ARE THE RESULTS OF YOUR UPDATED BOND YIELD PLUS
21 RISK PREMIUM ANALYSIS?

1 A. My updated risk premium analysis is presented in EAI Exhibit SCH-11.
2 My updated risk premium models indicate an ROE range of 10.0 percent
3 to 10.4 percent. The low end of the range is based on the average Baa
4 Utility interest rate for the three months ended July 2013. The upper end
5 of the range is based on the Bloomberg Forward Curve projected rate for
6 December 31, 2014. The intermediate result based on recent Baa spot
7 rates, is 10.2 percent. The projected and spot rates reflect the Fed's more
8 recent policy position and, therefore, are more reasonable estimates of the
9 cost of equity.

10

11 Q. WHAT DO YOU CONCLUDE FROM YOUR UPDATED ROE
12 ANALYSES?

13 A. Given the increasing interest rate environment that now exists, the
14 Company's requested 10.4 percent ROE is reasonable. The lower
15 updated DCF results, based on data from Value Line and average stock
16 prices for May-July 2013, cannot accurately reflect the FOMC policy shift
17 or the rising interest rates that have resulted. For this reason, I believe
18 more emphasis should be placed on the current risk premium results,
19 based on more recent interest rate data that do reflect the policy shift. As
20 noted above, factoring in interest rate projections for 2014, the updated
21 risk premium analysis indicates an ROE of 10.4 percent. My updated

1 analysis confirms that the recommendations of the other parties, as
2 discussed herein, are unreasonably low.

3

4 Q. DOES THIS CONCLUDE YOUR REBUTTAL TESTIMONY?

5 A. Yes.

CERTIFICATE OF SERVICE

I, Steven K. Strickland, do hereby certify that a copy of the foregoing has been served upon all parties of record by forwarding the same by electronic mail and/or first class mail, postage prepaid, this 26th day of August, 2013.

/s/ Steven K. Strickland
Steven K. Strickland

BEFORE THE
ARKANSAS PUBLIC SERVICE COMMISSION

IN THE MATTER OF THE APPLICATION	)	
OF ENTERGY ARKANSAS, INC. FOR	)	
APPROVAL OF CHANGES IN RATES FOR	)	DOCKET NO. 13-028-U
RETAIL ELECTRIC SERVICE	)	

EAI EXHIBIT SCH-8

ECONOMIC DATA

Entergy Arkansas

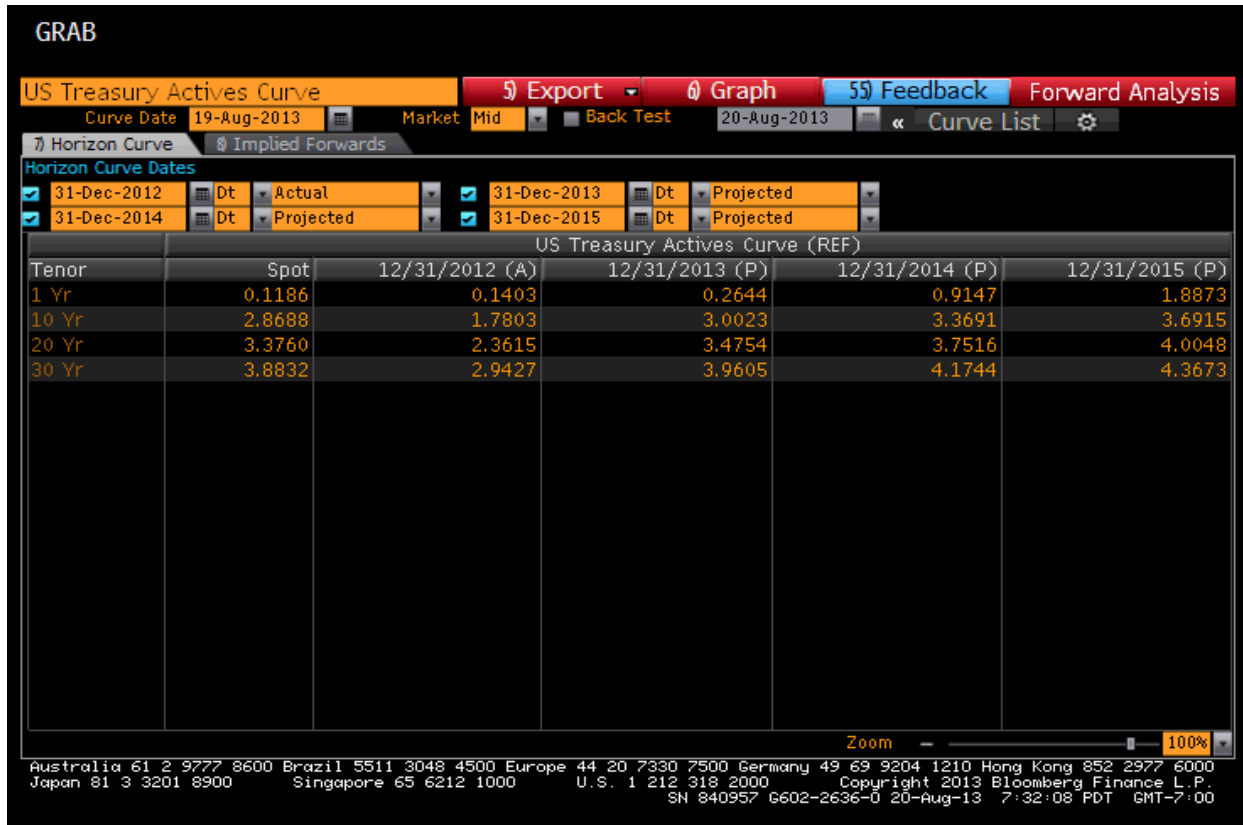
Long-Term Interest Rate Trends

Month	Triple-B Utility Rate	30-Year Treasury Rate	Triple-B Utility Spread
Aug-10	5.55	3.80	1.75
Sep-10	5.53	3.77	1.76
Oct-10	5.62	3.87	1.75
Nov-10	5.85	4.19	1.66
Dec-10	6.04	4.42	1.62
Jan-11	6.06	4.52	1.54
Feb-11	6.10	4.65	1.45
Mar-11	5.97	4.51	1.46
Apr-11	5.98	4.50	1.48
May-11	5.74	4.29	1.45
Jun-11	5.67	4.23	1.44
Jul-11	5.70	4.27	1.43
Aug-11	5.22	3.65	1.57
Sep-11	5.11	3.18	1.93
Oct-11	5.24	3.13	2.11
Nov-11	4.93	3.02	1.91
Dec-11	5.07	2.98	2.09
Jan-12	5.06	3.03	2.03
Feb-12	5.02	3.11	1.91
Mar-12	5.13	3.28	1.85
Apr-12	5.11	3.18	1.93
May-12	4.97	2.93	2.04
Jun-12	4.91	2.70	2.21
Jul-12	4.85	2.59	2.26
Aug-12	4.88	2.77	2.11
Sep-12	4.81	2.88	1.93
Oct-12	4.54	2.90	1.64
Nov-12	4.42	2.80	1.62
Dec-12	4.56	2.88	1.68
Jan-13	4.66	3.08	1.58
Feb-13	4.74	3.17	1.57
Mar-13	4.72	3.16	1.56
Apr-13	4.49	2.93	1.56
May-13	4.65	3.11	1.54
Jun-13	5.08	3.40	1.68
Jul-13	5.21	3.61	1.60
3-Mo Avg	4.98	3.37	1.61
12-Mo Avg	4.73	3.06	1.67

Sources: Mergent Bond Record (Utility Rates); www.federalreserve.gov (Treasury Rates).

Monthly averages are for the respective periods ending July 2013.

Entergy Arkansas Interest Rate Forecast from Forward Price Curves



Entergy Arkansas

Moody's Daily Long-Term Corporate Bond Yields

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Credit Trends Home > Bond Yields

Daily Bond Yields and Key Indicators

Updated by 11 am ET with data from the previous business day.

Data as of 19-AUG-13

[Contact Us](#)

Moody's Daily Long-term Corporate Bond Yield Averages

	Utilities	Industrial	Corporate
Aaa	NA	4.71	4.71
Aa	4.69	4.92	4.81
A	4.87	5.00	4.94
Baa	5.43	5.73	5.58
Avg	5.00	5.09	5.05

Moody's Daily Treasury Yield Averages

Short-Term (3-5 yrs)	1.11
Medium-Term (5-10 yrs)	2.21
Long-Term (10+ yrs)	3.57

Moody's Daily Public Utility Common Stock Yield Averages

Price	298.75
Yield	4.44
New Dividend	13.27

Moody's Commodity and Scrap Price Indexes

Spot Commodity Index	6166.04
Industrial Metals Index	1877.25

* Moody's "Aaa" Utilities Index was suspended on 12/10/01. Since 2000, TVA was the only issuer left in the index as a decade of deregulation, debt growth, competition, and consolidation eliminated the rest of the Aaa universe.

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BEFORE THE
ARKANSAS PUBLIC SERVICE COMMISSION

IN THE MATTER OF THE APPLICATION	)	
OF ENTERGY ARKANSAS, INC. FOR	)	DOCKET NO. 13-028-U
APPROVAL OF CHANGES IN RATES FOR	)	
RETAIL ELECTRIC SERVICE	)	

EAI EXHIBIT SCH-9

UPDATE OF GORMAN RISK PREMIUM ANALYSIS

Entergy Arkansas**Update of Gorman Risk Premium Analysis - Treasury Bond (Projected)**

	(1)	(2)	(3)
	TREASURY BOND YIELD	AUTHORIZED ELECTRIC RETURNS	INDICATED RISK PREMIUM
1986	7.80%	13.93%	6.13%
1987	8.58%	12.99%	4.41%
1988	8.96%	12.79%	3.83%
1989	8.45%	12.97%	4.52%
1990	8.61%	12.70%	4.09%
1991	8.14%	12.55%	4.41%
1992	7.67%	12.09%	4.42%
1993	6.60%	11.41%	4.81%
1994	7.37%	11.34%	3.97%
1995	6.88%	11.55%	4.67%
1996	6.70%	11.39%	4.69%
1997	6.61%	11.40%	4.79%
1998	5.58%	11.66%	6.08%
1999	5.87%	10.77%	4.90%
2000	5.94%	11.43%	5.49%
2001	5.49%	11.09%	5.60%
2002	5.43%	11.16%	5.73%
2003	4.96%	10.97%	6.01%
2004	5.05%	10.75%	5.70%
2005	4.65%	10.54%	5.89%
2006	4.99%	10.36%	5.37%
2007	4.83%	10.36%	5.53%
2008	4.28%	10.46%	6.18%
2009	4.07%	10.48%	6.41%
2010	4.25%	10.34%	6.09%
2011	3.91%	10.22%	6.31%
2012	2.92%	10.01%	7.09%
2013	3.14%	9.80%	6.66%
AVERAGE	5.99%	11.34%	5.35%

INDICATED COST OF EQUITY

PROJECTED TREASURY BOND YIELD*	4.00%
TREASURY BOND AVG ANNUAL YIELD DURING STUDY	5.99%
INTEREST RATE DIFFERENCE	-1.99%

INTEREST RATE CHANGE COEFFICIENT	-44.77%
ADJUSTMENT TO BASIC RISK PREMIUM	0.89%

BASIC RISK PREMIUM	5.35%
INTEREST RATE ADJUSTMENT	0.89%
EQUITY RISK PREMIUM	6.24%

PROJECTED TREASURY BOND YIELD*	4.00%
INDICATED EQUITY RETURN	10.24%

Notes:

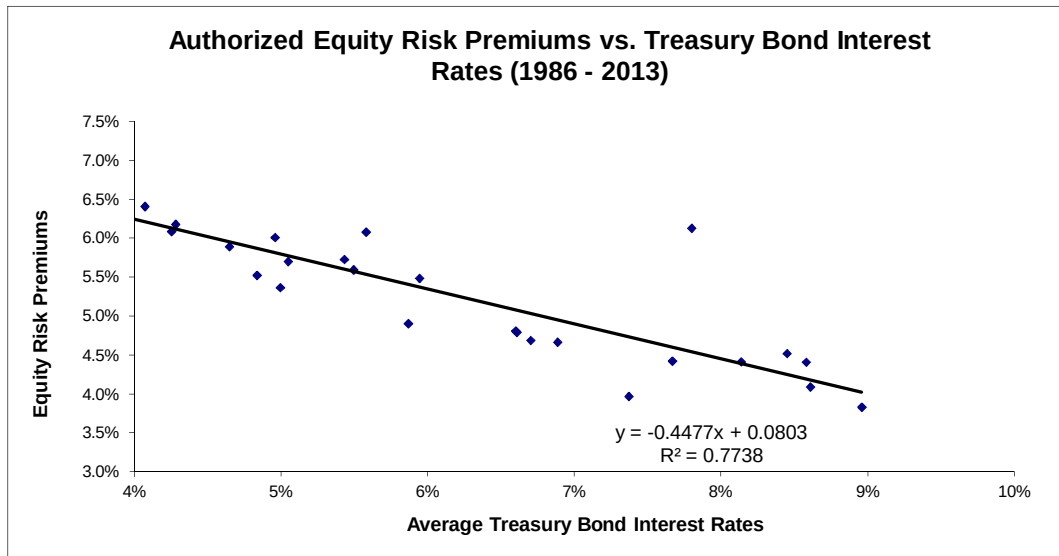
Columns 1-3: FEA Exhibit MPG-12 (2013 data through June)

*See Gorman Direct, page 32, lines 16-19 for Projected Treasury Bond Yield .

See regression data on page 2 of this Exhibit for derivation of "Interest Rate Change Coefficient."

Entergy Arkansas

Update of Gorman Risk Premium Analysis - Treasury Bond



SUMMARY OUTPUT

Regression Statistics	
Multiple R	0.879649299
R Square	0.773782889
Adjusted R Square	0.765082231
Standard Error	0.004283006
Observations	28

ANOVA					
	df	SS	MS	F	Significance F
Regression	1	0.001631415	0.001631415	88.93383472	7.08549E-10
Residual	26	0.000476948	1.83441E-05		
Total	27	0.002108362			

	Coefficients	Standard Error	t Stat	P-value	Lower 95%	Upper 95%	Lower 95.0%	Upper 95.0%
Intercept	0.080311826	0.00295629	27.16642527	1.29296E-20	0.074235085	0.0863886	0.074235085	0.08638857
X Variable 1	-0.447655678	0.047469055	-9.43047373	7.08549E-10	-0.545229718	-0.350082	-0.54522972	-0.3500816

Entergy Arkansas

	(1)	(2)	(3)
	AVERAGE "A" RATED PUBLIC UTILITY BOND YIELD	AUTHORIZED ELECTRIC RETURNS	INDICATED RISK PREMIUM
1986	9.58%	13.93%	4.35%
1987	10.10%	12.99%	2.89%
1988	10.49%	12.79%	2.30%
1989	9.77%	12.97%	3.20%
1990	9.86%	12.70%	2.84%
1991	9.36%	12.55%	3.19%
1992	8.69%	12.09%	3.40%
1993	7.59%	11.41%	3.82%
1994	8.31%	11.34%	3.03%
1995	7.89%	11.55%	3.66%
1996	7.75%	11.39%	3.64%
1997	7.60%	11.40%	3.80%
1998	7.04%	11.66%	4.62%
1999	7.62%	10.77%	3.15%
2000	8.24%	11.43%	3.19%
2001	7.76%	11.09%	3.33%
2002	7.37%	11.16%	3.79%
2003	6.58%	10.97%	4.39%
2004	6.16%	10.75%	4.59%
2005	5.65%	10.54%	4.89%
2006	6.07%	10.36%	4.29%
2007	6.07%	10.36%	4.29%
2008	6.53%	10.46%	3.93%
2009	6.04%	10.48%	4.44%
2010	5.46%	10.34%	4.88%
2011	5.04%	10.22%	5.18%
2012	4.13%	10.01%	5.88%
2013	4.20%	9.80%	5.60%
AVERAGE	7.39%	11.34%	3.95%

INDICATED COST OF EQUITY

CURRENT "Baa" UTILITY BOND YIELD*	4.87%
MOODY'S AVG ANNUAL YIELD DURING STUDY	7.39%
INTEREST RATE DIFFERENCE	-2.52%
INTEREST RATE CHANGE COEFFICIENT	-44.56%
ADJUSTMENT TO BASIC RISK PREMIUM	1.12%
BASIC RISK PREMIUM	3.95%
INTEREST RATE ADJUSTMENT	1.12%
EQUITY RISK PREMIUM	5.07%
CURRENT "Baa" UTILITY BOND YIELD*	4.87%
INDICATED EQUITY RETURN	9.94%

Notes:

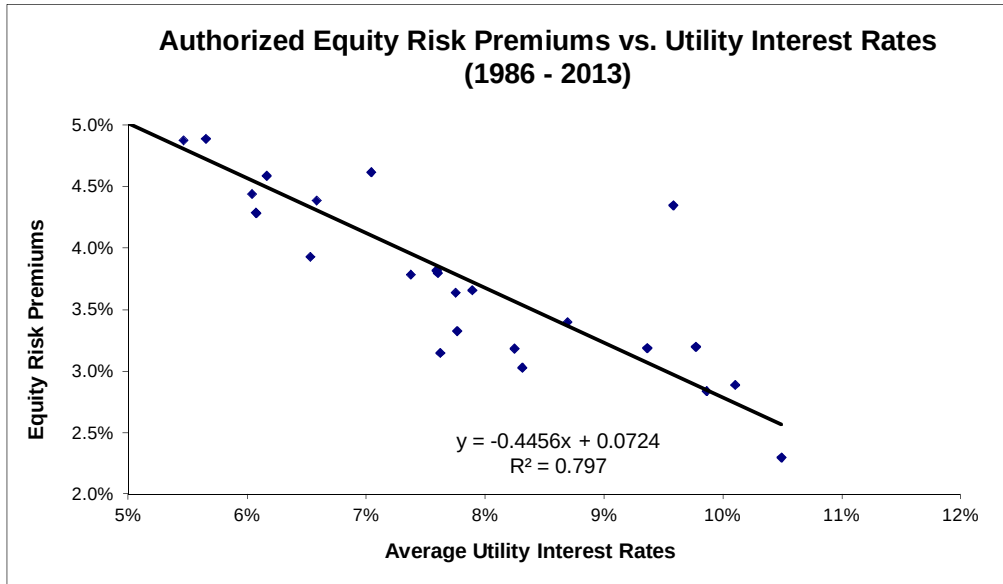
Columns 1-3: FEA Exhibit MPG-13 (2013 data through June).

*See Gorman Direct, page 33, lines 1-3 for Current "Baa" Utility Bond Yield.

See regression data on page 4 of this Exhibit for derivation of "Interest Rate Change Coefficient."

Entergy Arkansas

Update of Gorman Risk Premium Analysis - Utility Bond



SUMMARY OUTPUT

Regression Statistics	
Multiple R	0.892770638
R Square	0.797039412
Adjusted R Square	0.789233236
Standard Error	0.004010501
Observations	28

ANOVA

	df	SS	MS	F	Significance F
Regression	1	0.0016422	0.0016422	102.10369	1.70616E-10
Residual	26	0.0004182	1.608E-05		
Total	27	0.0020604			

	Coefficients	tandard Errc	t Stat	P-value	Lower 95%	Upper 95%	Lower 95.0%	Upper 95.0%
Intercept	0.072416882	0.0033464	21.64038	3.749E-18	0.065538305	0.079295459	0.065538305	0.079295459
X Variable 1	-0.445583931	0.044097	-10.10464	1.706E-10	-0.536226562	-0.3549413	-0.53622656	-0.354941301

BEFORE THE
ARKANSAS PUBLIC SERVICE COMMISSION

IN THE MATTER OF THE APPLICATION	)	
OF ENTERGY ARKANSAS, INC. FOR	)	
APPROVAL OF CHANGES IN RATES FOR	)	DOCKET NO. 13-028-U
RETAIL ELECTRIC SERVICE	)	

EAI EXHIBIT SCH-10
DISCOUNTED CASH FLOW ANALYSIS

Entergy Arkansas
Discounted Cash Flow Analysis
Summary Of DCF Model Results

Company	Constant Growth DCF Model Analysts' Growth Rates	Constant Growth DCF Model Long-Term GDP Growth	Low Near-Term Growth Two-Stage Growth DCF Model
1 ALLETE	10.4%	9.6%	9.4%
2 Alliant Energy Co.	9.4%	9.5%	9.3%
3 American Elec. Pwr.	8.6%	10.0%	9.8%
4 Avista Corp.	8.9%	10.3%	10.0%
5 Black Hills Corp	10.4%	8.8%	8.5%
6 CMS Energy Corp.	9.6%	9.5%	9.6%
7 DTE Energy Co.	8.5%	9.7%	9.6%
8 Great Plains Energy	10.3%	9.8%	10.0%
9 Hawaiian Electric	8.0%	10.4%	9.9%
10 IDACORP	6.8%	9.1%	8.9%
11 Integrys Energy	9.1%	10.2%	9.7%
12 Pinnacle West	8.8%	9.6%	9.5%
13 Portland General	9.0%	9.2%	9.0%
14 SCANA Corp.	8.7%	9.7%	9.4%
15 Sempra Energy	7.4%	8.9%	8.7%
16 Southern Co.	9.0%	10.3%	10.0%
17 Teco Energy, Inc.	8.8%	10.7%	10.3%
18 UNS Energy Corp.	10.9%	9.3%	9.7%
19 Westar Energy	9.3%	10.0%	9.6%
20 Wisconsin Energy	8.8%	9.3%	9.7%
21 Xcel Energy Inc.	8.6%	9.6%	9.5%
GROUP AVERAGE	9.0%	9.7%	9.5%
GROUP MEDIAN	8.9%	9.6%	9.6%

Sources: Value Line Investment Survey, Electric Utility (East), May 24, 2013; (Central), Jun 21, 2013; (West), Aug 2, 2013.

NOTE: SEE PAGE 5 OF THIS EXHIBIT FOR FURTHER EXPLANATION OF EACH COLUMN.

**Entergy Arkansas
Constant Growth DCF Model
Analysts' Growth Rates**

	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
Company	Recent Price(P0)	Next Year's Div(D1)	Dividend Yield	Analysts' Estimated Growth			Average Growth (Cols 4-6)	ROE K=Div Yld+G (Cols 3+7)
				Value Line	Zacks	Thomson		
1 ALLETE	49.92	1.96	3.93%	7.00%	6.50%	6.00%	6.50%	10.4%
2 Alliant Energy Co.	50.52	1.96	3.88%	5.00%	5.70%	5.93%	5.54%	9.4%
3 American Elec. Pwr.	46.31	2.04	4.41%	4.50%	3.90%	4.06%	4.15%	8.6%
4 Avista Corp.	27.36	1.28	4.68%	4.00%	4.30%	4.50%	4.27%	8.9%
5 Black Hills Corp	48.85	1.56	3.19%	11.50%	5.00%	5.00%	7.17%	10.4%
6 CMS Energy Corp.	27.56	1.08	3.92%	5.50%	5.80%	5.87%	5.72%	9.6%
7 DTE Energy Co.	67.68	2.73	4.03%	4.00%	4.60%	4.67%	4.42%	8.5%
8 Great Plains Energy	23.06	0.96	4.16%	6.50%	6.20%	5.58%	6.09%	10.3%
9 Hawaiian Electric	26.07	1.24	4.76%	3.50%	3.70%	2.40%	3.20%	8.0%
10 IDACORP	48.72	1.68	3.45%	2.00%	4.00%	4.00%	3.33%	6.8%
11 Integrys Energy	59.08	2.72	4.60%	3.50%	5.00%	5.00%	4.50%	9.1%
12 Pinnacle West	56.92	2.28	4.01%	5.00%	4.60%	4.73%	4.78%	8.8%
13 Portland General	31.00	1.12	3.61%	3.50%	6.30%	6.45%	5.42%	9.0%
14 SCANA Corp.	50.56	2.08	4.11%	4.50%	4.60%	4.75%	4.62%	8.7%
15 Sempra Energy	81.78	2.64	3.23%	4.50%	5.00%	2.90%	4.13%	7.4%
16 Southern Co.	44.68	2.08	4.66%	4.50%	4.40%	4.28%	4.39%	9.0%
17 Teco Energy, Inc.	17.48	0.88	5.04%	3.50%	5.00%	2.83%	3.78%	8.8%
18 UNS Energy Corp.	47.45	1.76	3.71%	6.50%	7.00%	8.00%	7.17%	10.9%
19 Westar Energy	32.22	1.40	4.35%	6.00%	5.10%	3.90%	5.00%	9.3%
20 Wisconsin Energy	41.61	1.52	3.65%	5.50%	5.20%	4.89%	5.20%	8.8%
21 Xcel Energy Inc.	29.22	1.15	3.94%	4.50%	4.50%	4.96%	4.65%	8.6%
GROUP AVERAGE	43.24	1.72	4.06%	5.00%	5.07%	4.80%	4.95%	9.0%
GROUP MEDIAN			4.01%					8.9%

Sources: Value Line Investment Survey, Electric Utility (East), May 24, 2013; (Central), Jun 21, 2013; (West), Aug 2, 2013.

NOTE: SEE PAGE 5 OF THIS EXHIBIT FOR FURTHER EXPLANATION OF EACH COLUMN.

Entergy Arkansas
Constant Growth DCF Model
Long-Term GDP Growth

	(9)	(10)	(11)	(12)	(13)
	Next				ROE
Company	Recent Price(P0)	Year's Div(D1)	Dividend Yield	GDP Growth	K=Div Yld+G (Cols 11+12)
1 ALLETE	49.92	1.96	3.93%	5.63%	9.6%
2 Alliant Energy Co.	50.52	1.96	3.88%	5.63%	9.5%
3 American Elec. Pwr.	46.31	2.04	4.41%	5.63%	10.0%
4 Avista Corp.	27.36	1.28	4.68%	5.63%	10.3%
5 Black Hills Corp	48.85	1.56	3.19%	5.63%	8.8%
6 CMS Energy Corp.	27.56	1.08	3.92%	5.63%	9.5%
7 DTE Energy Co.	67.68	2.73	4.03%	5.63%	9.7%
8 Great Plains Energy	23.06	0.96	4.16%	5.63%	9.8%
9 Hawaiian Electric	26.07	1.24	4.76%	5.63%	10.4%
10 IDACORP	48.72	1.68	3.45%	5.63%	9.1%
11 Integrys Energy	59.08	2.72	4.60%	5.63%	10.2%
12 Pinnacle West	56.92	2.28	4.01%	5.63%	9.6%
13 Portland General	31.00	1.12	3.61%	5.63%	9.2%
14 SCANA Corp.	50.56	2.08	4.11%	5.63%	9.7%
15 Semptra Energy	81.78	2.64	3.23%	5.63%	8.9%
16 Southern Co.	44.68	2.08	4.66%	5.63%	10.3%
17 Teco Energy, Inc.	17.48	0.88	5.04%	5.63%	10.7%
18 UNS Energy Corp.	47.45	1.76	3.71%	5.63%	9.3%
19 Westar Energy	32.22	1.40	4.35%	5.63%	10.0%
20 Wisconsin Energy	41.61	1.52	3.65%	5.63%	9.3%
21 Xcel Energy Inc.	29.22	1.15	3.94%	5.63%	9.6%
GROUP AVERAGE	43.24	1.72	4.06%	5.63%	9.7%
GROUP MEDIAN			4.01%		9.6%

Sources: Value Line Investment Survey, Electric Utility (East), May 24, 2013; (Central), Jun 21, 2013; (West), Aug 2, 2013.

NOTE: SEE PAGE 5 OF THIS EXHIBIT FOR FURTHER EXPLANATION OF EACH COLUMN.

Entergy Arkansas
Low Near-Term Growth
Two-Stage Growth DCF Model

	(14)	(15)	(16)	(17)	(18)	(19)	(20)	(21)	(22)	(23)	(24)
Company	2014 Div	2017 Div	Annual Change to 2017	CASH FLOWS							ROE=Internal Rate of Return (Yrs 0-150)
				Recent Price	Year 1 Div	Year 2 Div	Year 3 Div	Year 4 Div	Year 5 Div	Year 5-150 Div Growth	
1 ALLETE	1.96	2.20	0.08	-49.92	1.96	2.04	2.12	2.20	2.32	5.63%	9.4%
2 Alliant Energy Co.	1.96	2.20	0.08	-50.52	1.96	2.04	2.12	2.20	2.32	5.63%	9.3%
3 American Elec. Pwr.	2.04	2.30	0.09	-46.31	2.04	2.13	2.21	2.30	2.43	5.63%	9.8%
4 Avista Corp.	1.28	1.40	0.04	-27.36	1.28	1.32	1.36	1.40	1.48	5.63%	10.0%
5 Black Hills Corp	1.56	1.70	0.05	-48.85	1.56	1.61	1.65	1.70	1.80	5.63%	8.5%
6 CMS Energy Corp.	1.08	1.30	0.07	-27.56	1.08	1.15	1.23	1.30	1.37	5.63%	9.6%
7 DTE Energy Co.	2.73	3.15	0.14	-67.68	2.73	2.87	3.01	3.15	3.33	5.63%	9.6%
8 Great Plains Energy	0.96	1.20	0.08	-23.06	0.96	1.04	1.12	1.20	1.27	5.63%	10.0%
9 Hawaiian Electric	1.24	1.30	0.02	-26.07	1.24	1.26	1.28	1.30	1.37	5.63%	9.9%
10 IDACORP	1.68	1.90	0.07	-48.72	1.68	1.75	1.83	1.90	2.01	5.63%	8.9%
11 Integrys Energy	2.72	2.80	0.03	-59.08	2.72	2.75	2.77	2.80	2.96	5.63%	9.7%
12 Pinnacle West	2.28	2.60	0.11	-56.92	2.28	2.39	2.49	2.60	2.75	5.63%	9.5%
13 Portland General	1.12	1.25	0.04	-31.00	1.12	1.16	1.21	1.25	1.32	5.63%	9.0%
14 SCANA Corp.	2.08	2.25	0.06	-50.56	2.08	2.14	2.19	2.25	2.38	5.63%	9.4%
15 Sempra Energy	2.64	3.00	0.12	-81.78	2.64	2.76	2.88	3.00	3.17	5.63%	8.7%
16 Southern Co.	2.08	2.30	0.07	-44.68	2.08	2.15	2.23	2.30	2.43	5.63%	10.0%
17 Teco Energy, Inc.	0.88	0.95	0.02	-17.48	0.88	0.90	0.93	0.95	1.00	5.63%	10.3%
18 UNS Energy Corp.	1.76	2.28	0.17	-47.45	1.76	1.93	2.11	2.28	2.41	5.63%	9.7%
19 Westar Energy	1.40	1.52	0.04	-32.22	1.40	1.44	1.48	1.52	1.61	5.63%	9.6%
20 Wisconsin Energy	1.52	2.00	0.16	-41.61	1.52	1.68	1.84	2.00	2.11	5.63%	9.7%
21 Xcel Energy Inc.	1.15	1.35	0.07	-29.22	1.15	1.22	1.28	1.35	1.43	5.63%	9.5%
GROUP AVERAGE											9.5%
GROUP MEDIAN											9.6%

Sources: Value Line Investment Survey, Electric Utility (East), May 24, 2013; (Central), Jun 21, 2013; (West), Aug 2, 2013.

NOTE: SEE PAGE 5 OF THIS EXHIBIT FOR FURTHER EXPLANATION OF EACH COLUMN.

Entergy Arkansas
Discounted Cash Flow Analysis
Column Descriptions

Column 1: Three-month Average Price per Share (May 2013-Jul 2013)	Column 13: Column 11 Plus Column 12
Column 2: Estimated 2014 Div per Share from Value Line	Column 14: Estimated 2014 Div per Share from Value Line
Column 3: Column 2 Divided by Column 1	Column 15: Estimated 2017 Div per Share from Value Line
Column 4: "Est'd '10-'12 to '16-'18" Earnings Growth Reported by Value Line	Column 16: (Column 15 Minus Column 14) Divided by Three
Column 5: "Next 5 Years" Company Growth Estimate as Reported by Zacks.com	Column 17: See Column 1
Column 6: "Next 5 Years (per annum) Growth Estimate Reported by Thomson Financial Network (at Yahoo Finance)	Column 18: See Column 14
Column 7: Average of Columns 4-6	Column 19: Column 18 Plus Column 16
Column 8: Column 3 Plus Column 7	Column 20: Column 19 Plus Column 16
Column 9: See Column 1	Column 21: Column 20 Plus Column 16
Column 10: See Column 2	Column 22: Column 21 Increased by the Growth Rate Shown in Column 23
Column 11: Column 10 Divided by Column 9	Column 23: See Column 12
Column 12: Average of GDP Growth During the Last 10 year, 20 year, 30 year, 40 year, 50 year, and 60 year growth periods. See EAI Exhibit SCH-5	Column 24: The Internal Rate of Return of the Cash Flows in Columns 17-22 along with the Dividends for the Years 6-150 Implied by the Growth Rates shown in Column 23

BEFORE THE
ARKANSAS PUBLIC SERVICE COMMISSION

IN THE MATTER OF THE APPLICATION	)	
OF ENTERGY ARKANSAS, INC. FOR	)	
APPROVAL OF CHANGES IN RATES FOR	)	DOCKET NO. 13-028-U
RETAIL ELECTRIC SERVICE	)	

EAI EXHIBIT SCH-11

RISK PREMIUM ANALYSIS

Entergy Arkansas

Risk Premium Analysis-Electric

(Based on Projected Interest Rates)

	MOODY'S AVERAGE PUBLIC UTILITY BOND YIELD (1)	AUTHORIZED ELECTRIC RETURNS (2)	INDICATED RISK PREMIUM
1980	13.15%	14.23%	1.08%
1981	15.62%	15.22%	-0.40%
1982	15.33%	15.78%	0.45%
1983	13.31%	15.36%	2.05%
1984	14.03%	15.32%	1.29%
1985	12.29%	15.20%	2.91%
1986	9.46%	13.93%	4.47%
1987	9.98%	12.99%	3.01%
1988	10.45%	12.79%	2.34%
1989	9.66%	12.97%	3.31%
1990	9.76%	12.70%	2.94%
1991	9.21%	12.55%	3.34%
1992	8.57%	12.09%	3.52%
1993	7.56%	11.41%	3.85%
1994	8.30%	11.34%	3.04%
1995	7.91%	11.55%	3.64%
1996	7.74%	11.39%	3.65%
1997	7.63%	11.40%	3.77%
1998	7.00%	11.66%	4.66%
1999	7.55%	10.77%	3.22%
2000	8.14%	11.43%	3.29%
2001	7.72%	11.09%	3.37%
2002	7.53%	11.16%	3.63%
2003	6.61%	10.97%	4.36%
2004	6.20%	10.75%	4.55%
2005	5.67%	10.54%	4.87%
2006	6.08%	10.36%	4.28%
2007	6.11%	10.36%	4.25%
2008	6.65%	10.46%	3.81%
2009	6.28%	10.48%	4.20%
2010	5.55%	10.34%	4.79%
2011	5.13%	10.29%	5.16%
2012	4.27%	10.17%	5.90%
AVERAGE	8.68%	12.09%	3.41%

INDICATED COST OF EQUITY

PROJECTED TRIPLE-B UTILITY BOND YIELD*	5.78%
MOODY'S AVG ANNUAL YIELD DURING STUDY	8.68%
INTEREST RATE DIFFERENCE	-2.90%

INTEREST RATE CHANGE COEFFICIENT	-42.81%
ADJUSTMENT TO AVG RISK PREMIUM	1.24%

BASIC RISK PREMIUM	3.41%
INTEREST RATE ADJUSTMENT	1.24%
EQUITY RISK PREMIUM	4.65%

PROJECTED TRIPLE-B UTILITY BOND YIELD*	5.78%
INDICATED EQUITY RETURN	10.43%

(1) Moody's Investors Service

(2) Regulatory Focus, Regulatory Research Associates, Inc.

*Projected triple-B bond yield is 161 basis points over projected long-term Treasury bond rate of 4.17%.

The triple-B spread is for 3 months ended July 2013 from EAI Exhibit SCH-8, p. 1.

The projected Treasury bond rate is the 30 year rate at 12/31/2014 from EAI Exhibit SCH-8, p. 2.

Entergy Arkansas

Risk Premium Analysis-Electric

(Based on Current 3-Month Average Interest Rates)

	MOODY'S AVERAGE PUBLIC UTILITY BOND YIELD (1)	AUTHORIZED ELECTRIC RETURNS (2)	INDICATED RISK PREMIUM
1980	13.15%	14.23%	1.08%
1981	15.62%	15.22%	-0.40%
1982	15.33%	15.78%	0.45%
1983	13.31%	15.36%	2.05%
1984	14.03%	15.32%	1.29%
1985	12.29%	15.20%	2.91%
1986	9.46%	13.93%	4.47%
1987	9.98%	12.99%	3.01%
1988	10.45%	12.79%	2.34%
1989	9.66%	12.97%	3.31%
1990	9.76%	12.70%	2.94%
1991	9.21%	12.55%	3.34%
1992	8.57%	12.09%	3.52%
1993	7.56%	11.41%	3.85%
1994	8.30%	11.34%	3.04%
1995	7.91%	11.55%	3.64%
1996	7.74%	11.39%	3.65%
1997	7.63%	11.40%	3.77%
1998	7.00%	11.66%	4.66%
1999	7.55%	10.77%	3.22%
2000	8.14%	11.43%	3.29%
2001	7.72%	11.09%	3.37%
2002	7.53%	11.16%	3.63%
2003	6.61%	10.97%	4.36%
2004	6.20%	10.75%	4.55%
2005	5.67%	10.54%	4.87%
2006	6.08%	10.36%	4.28%
2007	6.11%	10.36%	4.25%
2008	6.65%	10.46%	3.81%
2009	6.28%	10.48%	4.20%
2010	5.55%	10.34%	4.79%
2011	5.13%	10.29%	5.16%
2012	4.27%	10.17%	5.90%
AVERAGE	8.68%	12.09%	3.41%

INDICATED COST OF EQUITY

CURRENT TRIPLE-B UTILITY BOND YIELD*	4.98%
MOODY'S AVG ANNUAL YIELD DURING STUDY	8.68%
INTEREST RATE DIFFERENCE	-3.70%

INTEREST RATE CHANGE COEFFICIENT	-42.81%
ADJUSTMENT TO AVG RISK PREMIUM	1.58%

BASIC RISK PREMIUM	3.41%
INTEREST RATE ADJUSTMENT	1.58%
EQUITY RISK PREMIUM	5.00%

CURRENT TRIPLE-B UTILITY BOND YIELD*	4.98%
INDICATED EQUITY RETURN	9.98%

(1) Moody's Investors Service

(2) Regulatory Focus, Regulatory Research Associates, Inc.

*Current triple-B utility bond yield is three month average of Moody's Triple-B Public Utility Bond Yield Average through July 2013 from EAL Exhibit SCH-8, p. 1.

Entergy Arkansas

Risk Premium Analysis-Electric

(Based on Current Spot Interest Rates)

	MOODY'S AVERAGE PUBLIC UTILITY BOND YIELD (1)	AUTHORIZED ELECTRIC RETURNS (2)	INDICATED RISK PREMIUM
1980	13.15%	14.23%	1.08%
1981	15.62%	15.22%	-0.40%
1982	15.33%	15.78%	0.45%
1983	13.31%	15.36%	2.05%
1984	14.03%	15.32%	1.29%
1985	12.29%	15.20%	2.91%
1986	9.46%	13.93%	4.47%
1987	9.98%	12.99%	3.01%
1988	10.45%	12.79%	2.34%
1989	9.66%	12.97%	3.31%
1990	9.76%	12.70%	2.94%
1991	9.21%	12.55%	3.34%
1992	8.57%	12.09%	3.52%
1993	7.56%	11.41%	3.85%
1994	8.30%	11.34%	3.04%
1995	7.91%	11.55%	3.64%
1996	7.74%	11.39%	3.65%
1997	7.63%	11.40%	3.77%
1998	7.00%	11.66%	4.66%
1999	7.55%	10.77%	3.22%
2000	8.14%	11.43%	3.29%
2001	7.72%	11.09%	3.37%
2002	7.53%	11.16%	3.63%
2003	6.61%	10.97%	4.36%
2004	6.20%	10.75%	4.55%
2005	5.67%	10.54%	4.87%
2006	6.08%	10.36%	4.28%
2007	6.11%	10.36%	4.25%
2008	6.65%	10.46%	3.81%
2009	6.28%	10.48%	4.20%
2010	5.55%	10.34%	4.79%
2011	5.13%	10.29%	5.16%
2012	4.27%	10.17%	5.90%
AVERAGE	8.68%	12.09%	3.41%

INDICATED COST OF EQUITY

CURRENT TRIPLE-B UTILITY BOND YIELD*	5.43%
MOODY'S AVG ANNUAL YIELD DURING STUDY	8.68%
INTEREST RATE DIFFERENCE	-3.25%

INTEREST RATE CHANGE COEFFICIENT	-42.81%
ADJUSTMENT TO AVG RISK PREMIUM	1.39%

BASIC RISK PREMIUM	3.41%
INTEREST RATE ADJUSTMENT	1.39%
EQUITY RISK PREMIUM	4.80%

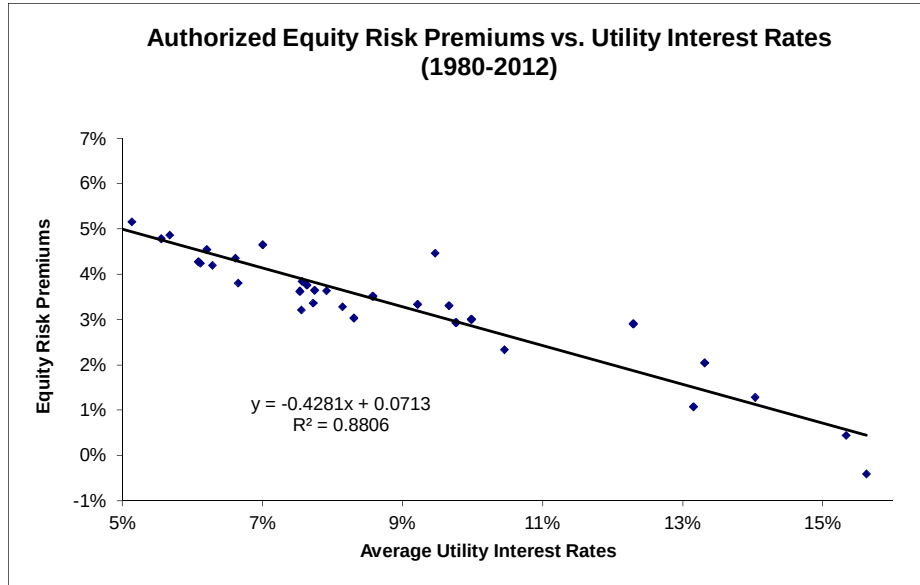
CURRENT TRIPLE-B UTILITY BOND YIELD*	5.43%
INDICATED EQUITY RETURN	10.23%

(1) Moody's Investors Service

(2) Regulatory Focus, Regulatory Research Associates, Inc.

*Current triple-B utility bond yield is Moody's Triple-B Public Utility Bond Yield at Aug 19, 2013 from EAI Exhibit SCH-8, p. 3.

Entergy Arkansas
 Risk Premium Analysis-Electric
 Regression Analysis & Interest Rate Change Coefficient



SUMMARY OUTPUT

Regression Statistics	
Multiple R	0.938398087
R Square	0.88059097
Adjusted R Square	0.876739066
Standard Error	0.00472491
Observations	33

ANOVA					
	df	SS	MS	F	Significance F
Regression	1	0.005103707	0.005103707	228.6118562	7.45897E-16
Residual	31	0.000692068	2.23248E-05		
Total	32	0.005795775			

	Coefficients	Standard Error	t Stat	P-value	Lower 95%	Upper 95%	Lower 95.0%	Upper 95.0%
Intercept	0.07127957	0.002591562	27.50448302	2.42768E-23	0.065994045	0.076565095	0.065994045	0.076565095
X Variable 1	-0.428076736	0.028312111	-15.11991588	7.45897E-16	-0.485819666	-0.370333805	-0.485819666	-0.370333805