BEFORE THE
ARKANSAS PUBLIC SERVICE COMMISSION

IN THE MATTER OF THE APPLICATION	)	
OF ENTERGY ARKANSAS, INC. FOR	)	DOCKET NO. 06-101-U
APPROVAL OF CHANGES IN RATES FOR	)	
RETAIL ELECTRIC SERVICE	)	

DIRECT TESTIMONY

OF

PHILLIP B. GILLAM

DIRECTOR, REVENUE REQUIREMENTS AND ANALYSES

ENTERGY SERVICES, INC.

ON BEHALF OF

ENTERGY ARKANSAS, INC.

AUGUST 15, 2006

I. INTRODUCTION AND BACKGROUND

Q. PLEASE STATE YOUR NAME, BUSINESS ADDRESS, EMPLOYER AND JOB TITLE.

A. My name is Phillip B. Gillam. My business address is 425 West Capitol, Little Rock, Arkansas 72201. I am employed by Entergy Services, Inc. ("ESI") as Director of Revenue Requirements and Analyses.

Q. PLEASE DESCRIBE YOUR EDUCATIONAL AND PROFESSIONAL BACKGROUND.

A. A summary of my education and work experience is included as EAI Exhibit PBG-1.

Q. ON WHOSE BEHALF ARE YOU SUBMITTING THIS TESTIMONY?

A. I am submitting this Direct Testimony to the Arkansas Public Service Commission ("APSC" or the "Commission") on behalf of Entergy Arkansas, Inc. ("EAI" or the "Company").

Q. HAVE YOU PROVIDED EXPERT TESTIMONY BEFORE THIS COMMISSION PREVIOUSLY?

A. Yes. I provided testimony before the APSC in Docket Nos. 03-191-TF, 05-116-U, and 06-055-U.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. First, I will present the results of the Company's cost-of-service study based upon a test year that is the period of six months historical ending December 31, 2005 and six months projected ending June 30, 2006 ("Test Year").

Second, I will propose a new rider, EAI Rate Schedule No. 48, the Production Cost Allocation Rider ("Rider PCA"), to recover any payments by EAI or credit any receipts to EAI resulting from the Federal Energy Regulatory Commission ("FERC") Opinion No. 480 and Opinion No. 480-A, dated June 1, 2005, and December 19, 2005, respectively, or subsequent orders in Docket No. EL01-88-001 (the "FERC Decision").[1]

Third, I will explain the operation of EAI's proposed Rate Schedule No. 49, Capacity Management Rider ("Rider CM"). EAI witness Robert R. Cooper provides the resource planning background that supports the need for Rider CM. EAI witness Steven M. Fetter supports the reasons a rider is an appropriate mechanism to recover the type of capacity costs associated with Rider CM. EAI witnesses Dr. Roger A. Morin and Mr. Fetter discuss how these transactions impact the required return on common equity.

Fourth, I will present a base rate revenue requirement for fuel and purchased energy should the Commission eliminate the Company's existing Energy Cost Recovery Rider ("Rider ECR") as a result of its

[1] Opinion No. 480, 111 FERC ¶ 61,311, *aff'd* Opinion No. 480-A, 113 FERC ¶ 61,282 (2005).

investigation in Docket No. 06-055-U. I also will present a base rate revenue requirement for costs resulting from the FERC Decision should the Commission eliminate Rider ECR and not approve Rider PCA.

Finally, I will address the assignment of existing EAI capacity as proposed by EAI witness Andrew P. Frits in Docket No. 03-028-U and deferred to a later proceeding as directed by the Commission in Order No. 7 issued on April 30, 2003 in that docket.

The following exhibits are attached in support of my Direct Testimony:

Exhibit No.	**Description**
EAI Exhibit PBG-1	Educational and Professional Background
EAI Exhibit PBG-2	Cost-of-Service Summary for the Test Year ended June 30, 2006
EAI Exhibit PBG-3	Rider PCA
EAI Exhibit PBG-4	Rider CM
EAI Exhibit PBG-5	Rider ECR and Rider PCA proposed adjustments to Base Rates
EAI Exhibit PBG-6	Allocation of Capacity

II. COST-OF-SERVICE STUDY

Q. WHAT IS THE OBJECTIVE OF PREPARING A COST-OF-SERVICE STUDY?

A. The objective of preparing a cost-of-service study is to assign or allocate each relevant component of a utility's costs on an appropriate basis in order to determine the relative cost to serve each of the various customer rate classes. The cost-of-service study relates utility costs to those measurable customer characteristics (capacity demand, energy usage, number of customers, etc.) which require costs to be incurred. In aggregate, the costs are normally expressed in terms of revenue requirement. This then becomes one of the factors to be considered in determining the revenue level appropriate for each customer rate class, *i.e.,* the revenues a customer pays should reflect the costs that the customer imposes on the utility as a result of using the utility's system. In addition, a cost-of-service study provides functional revenue requirement information that is useful in the rate design process.

Q. PLEASE DESCRIBE IN GENERAL TERMS HOW THE COST-OF-SERVICE STUDY IS STRUCTURED.

A. The starting point in the study's preparation was the unadjusted rate base, revenues and operating expenses for the Test Year. The rate base, revenue, and expense components in the cost-of-service study presented in Minimum Filing Requirement ("MFR") Schedules G-1, G-2 and G-3 are shown on a historical period, a projected period and an unadjusted total Test Year basis. Following each such unadjusted total Test Year amount are the adjustments made to that component, if any. Where applicable, the adjusted amount is also shown. Summaries of the adjusted values are presented for the major rate base, revenue and expense categories, *e.g.,* plant-in-service. The adjusted values are also presented in the cost-of-service study summary in EAI Exhibit PBG-2.

Q. WHICH COMPANY WITNESSES SUPPORT THE UNADJUSTED TEST YEAR DATA AND THE ADJUSTMENTS REFLECTED IN THE COST-OF-SERVICE STUDY?

A. Company witness J. David Wright supports the unadjusted Test Year data used in the cost-of-service study. The Test Year adjustments and the Company witness sponsoring each adjustment are listed in Table 1 below:

Table 1

Adjustment	**Description**	**Sponsor**
1.	Fuel Recovery Revenue, Fuel and Purchased Power Expense	Phillip B. Gillam
2.	Reclassification	J. David Wright
3.	Fuel Inventory – 45 day	J. David Wright
4.	Investment in System Fuels Inc. (“SFI”)[2]	J. David Wright

[2] SFI is an affiliate of EAI that procures fuel on EAI’s behalf.

5.	Decommissioning	J. David Wright
6.	Miscellaneous Adjustments	J. David Wright
7.	Income Taxes	J. David Wright
8.	Removal of Grand Gulf Costs	J. David Wright
9.	Entergy Technology Company (“ETC”) Revenues	J. David Wright
10.	Working Capital	J. David Wright
11.	Storm Damage	J. David Wright
12.	Interest Synchronization	J. David Wright
13.	Annualize Depreciation Expense	J. David Wright
14.	Plant Transfers	J. David Wright
15.	Payroll	J. David Wright
16.	ICT Transmission	J. David Wright
17.	MSS-1 Reserve & MSS-2 Transmission Equalization [3]	J. David Wright
18.	Pension/Other Post-Retirement Employee Benefits (“OPEBs”)	J. David Wright
19.	Retail/Wholesale Split – After Adjustments	Phillip B. Gillam
20.	Capacity Acquisition	J. David Wright
21.	Broadband Over Powerlines	J. David Wright

Q. ARE THERE ANY ADJUSTMENTS NOT REFLECTED IN THE COST-OF-SERVICE STUDY?

[3] Service Schedule MSS-1: Reserve Equalization (“MSS-1”) and Service Schedule MSS-2: Transmission Equalization (“MSS-2”) are two service schedules which are part of the System Agreement.

A. Yes. The following base rate adjustments shown in Table 2 will be discussed in Section V of this testimony.

Table 2

Adjustment	Description	Sponsors
22	Projected Fuel and Purchased Energy	Phillip B. Gillam Roger Q Mills
23	EAI Projected FERC Allocation	Phillip B. Gillam Michael J. Goin

Q. PLEASE DISCUSS THE COST-OF-SERVICE ADJUSTMENTS YOU ARE SPONSORING.

A. Adjustment 1 – Fuel Recovery Revenue, Fuel and Purchased Power Expense is an adjustment to revenue and expenses associated with base revenue, and exact recovery fuel and purchased power. This adjustment also reclassifies Resource Plan Capacity Revenue to Rate Schedule Revenue for purposes of determining the Revenue Deficiency. It also removes Unbilled Revenue and Deferred Fuel, reclassifies Miscellaneous Service Revenues from Rate Schedule to Other Electric Revenue, reclassifies the Economic Development Rider Credit to Sales Expense and adjusts Uncollectible Expense. This adjustment removes all Rate Schedule Revenue because the Company is presenting a Functional Cost of Service Study per the requirements of the APSC Rules of Practice and Procedure ("RPP") Section 9 Appendix IA. Because EAI does not bill its customers on an unbundled (functional) basis, Rate Schedule Revenues are not available on a functional basis. Company witness Gordon D. Meyer addresses the determination of Retail Rate Schedule Revenues, for the purpose of determining revenue deficiency, in his testimony.

Adjustment 19 – Retail/Wholesale Split – After Adjustments is an adjustment to revenue and expenses due to the change in wholesale load at EAI and the 200 MW Power Purchase Agreements ("PPAs") (125 MW to Entergy Gulf States, Inc. ("EGSI") and 75 MW to Entergy Mississippi, Inc. ("EMI")). Revenues from Service Schedule MSS-1, Service Schedule MSS-2 and the Open Access Transmission Tariff ("OATT"), which are FERC-approved tariffs, are impacted by the resulting change in responsibility ratio due to the change in wholesale load. Also, OATT revenues are increased as a result of the EAI wholesale customers shifting to the OATT for transmission service.

Q. BRIEFLY OUTLINE THE GENERAL METHODS EMPLOYED IN THIS STUDY TO APPORTION RATE BASE, REVENUE AND OPERATING EXPENSES.

A. I have used the industry-accepted approach that utilizes the successive application of the processes of functionalization, classification and allocation with respect to all components of rate base, revenue and operating expenses.

Q. PLEASE DISCUSS THE FUNCTIONALIZATION PROCESS.

A. Functionalization is the separation of costs by the major functions of generation (or production), transmission, distribution, and customer service in order to facilitate the determination of how to allocate the Company's costs to the various customer rate classes.

Q. ARE ALL COSTS ASSIGNABLE TO ONE OF THESE FOUR FUNCTIONS?

A. No. There are many items that represent an amalgamation of more than one of these functions and must be addressed as an aggregated amount. For example, while certain parts of general plant may be assigned to one or more of these four functions, the majority of general plant supports all four functions and must be addressed on a composite basis.

Q. ARE ANY OF THE COST FUNCTIONALIZATION PROCEDURES YOU USED DIFFERENT FROM THOSE IN THE APSC RPP SECTION 9 APPENDIX IA (“RPP GUIDELINES”)?

A. Yes. I used functionalization procedures that are different from those in the RPP Guidelines for a number of reasons. First, in general, I used the traditional approach of functionalizing costs that the Company utilized in previous initial and compliance filings of cost-of-service studies. This traditional approach relies on the direct assignment of costs to the functions (Generation, Transmission, Distribution, and Customer Service) where the information is available. Only when costs cannot be directly assigned are they then allocated to the appropriate function based on analysis of account detail or past practice. I believe such a traditional approach yields a more just and reasonable allocation of the Company's costs to its customer classes than the default functionalization procedures identified in the RPP Guidelines.

A net plant factor has not been utilized to functionalize costs for any FERC account even though the RPP Guidelines specifies the use of such factors as a default. My decision is supported by the traditional approach of functionalizing costs, as described above, as well as the Electric Utility Cost Allocation Manual published by the National Association of Regulatory Utility Commissioners ("NARUC Handbook"). When the NARUC Handbook recommends the use of a plant factor to functionalize costs, it utilizes total or gross plant rather than net plant. For example, Gross General Plant is identified as an approach to functionalize FERC Account 935 – Maintenance of General Plant. The use of a gross general plant factor is more appropriate to functionalize costs because Operation and Maintenance ("O&M") expense is not positively correlated with net general plant, *i.e.*, O&M expense does not decrease to zero over the depreciable life of general plant.

Therefore, as traditionally reflected in EAI's cost-of-service studies, as recommended by the NARUC Handbook, and in recognition that plant-related revenue requirements are not positively correlated with net plant, *i.e.,* decrease to zero over the depreciable life of general plant, I utilized a gross plant factor to functionalize costs when necessary rather than a net plant factor as identified in the RPP Guidelines for default purposes.

The Company's plant allocators used to functionalize the General Plant Accounts are based on the function(s) that those costs support as described in Table 3 below:

Table 3

Account – Description	**Functional Allocator**
393 - Stores Equipment	Adjusted Distribution Plant ("PLDTOA")
394 - Tools, Shop and Garage Equipment and 395 – Laboratory Equipment	Adjusted Transmission and Distribution Plant ("PLTDTOA")
396 - Power Operated Equipment	Adjusted Production, Transmission and Distribution Plant ("PLPTDTOA")

For FERC Account 399 - Other Tangible Property, EAI used the Production Energy Allocation Factor ("PEAF") because Coal Mining Equipment is recorded in this account for EAI. All other General Plant accounts utilize the allocator prescribed by the RPP Guidelines, *i.e.,* Total Operations and Maintenance Labor Adjusted ("LOMTOA").

For FERC A&G Account 924 - Property Insurance, EAI used an analysis of the sub-accounts within Account 924, and allocated each accordingly – Nuclear Insurance by LPTOA, Environmental Insurance by

Total Production and Distribution Plant Adjusted ("PLPDTOA") and Property Insurance (including Storm Damage) by PLTDTOA. This compares to the default factor in the RPP Guidelines of Total Net Plant Adjusted ("NPLTOA") to functionalize all costs in Account 924.

For FERC A&G Account 928 - Regulatory Commission Expense, EAI used an analysis of the costs by docket number and allocated accordingly. For example, the costs associated with the OATT were allocated by Total Transmission Plant Adjusted ("PLTTOA") instead of Total Revenue Requirements ("TRR") as prescribed by the RPP Guidelines for all costs in Account 928. The use of a detailed analysis to functionalize costs is preferred to utilizing an overall default allocator because the detailed analysis results in a more accurate assignment of costs to the function causing the cost to be incurred.

For FERC A&G Account 930.1 - General Advertising, EAI used Total Customer Services Operation and Maintenance Expense Adjusted ("OMCSTOA") instead of LOMTOA as prescribed by the RPP Guidelines because these costs support the Customer Service function.

For FERC A&G Account 930.2 - Miscellaneous General Expenses, EAI used an analysis of the sub-accounts within 930.2 and allocated each accordingly – Nuclear-related costs by LPTOA, Industry Dues and Corporate memberships by PLTOA and Directors Fees and Other Dues by LOMTOA. The default factor in the RPP Guidelines is LOMTOA to functionalize all costs in account 930.2.

For FERC A&G Account 935 - Maintenance of General Plant, EAI used PDAF for Nuclear-related costs and Gross General Plant Excluding Coal Mining Equipment ("PLGECM") for the remaining costs. For FERC Taxes Other Than Income Account 408 - Ad Valorem Taxes, EAI used PLTOA instead of NPLTOA to functionalize costs. The RPP Guidelines list Net General Plant in Service ("GPIS") and NPLTOA as the default factors for purposes of functionalization. As stated earlier, I believe it is more appropriate to use gross plant and specific account information to functionalize costs as opposed to utilizing a net plant factor.

Q. PLEASE DESCRIBE THE CLASSIFICATION PROCESS.

A. Classification is the separation of functionalized costs into demand-related, energy-related, or customer-related categories. An example of a demand-related cost is the cost associated with distribution substations. Energy-related costs, while not the same as variable costs, are costs considered to be associated with sales (kWh), or generation, rather than demand (kW). The cost of fuel consumed by production facilities is the best example of an energy-related cost, and tends also to be a variable cost because maintenance frequency is related to the operational output of the plant. Certain production maintenance expenses, although not variable in an economic sense, are generally considered as energy-related for cost-of-service purposes. Boiler maintenance expense charged to Account 512 is one example of such a cost. Customer-related costs are costs which are incurred even if a customer does not impose demand on the system or consume energy. The costs of reading meters and preparing bills are examples of customer-related costs. Finally, there are typically a few costs which are revenue-related. Uncollectible accounts expense charged to Account 904 is an example of a revenue-related cost.

Q. PLEASE DESCRIBE THE ALLOCATION PROCESS.

A. The functionalization and classification processes provide understanding of the nature of the costs and, thereby, make it possible to select the most appropriate basis on which to allocate individual costs. The allocation process apportions costs to the various customer rate classes through the use of an “allocation factor.” Generally, costs are allocated on the basis of a demand, energy or customer relationship. In a limited number of instances, a revenue relationship may be used to allocate costs.

Many cost items cannot be functionalized and classified to the point that a specific demand, energy or customer allocation factor can be determined to be the appropriate allocator. In such cases, related cost items, as they have been allocated to the customer rate classes, are commonly used as allocators. For example, synchronized interest expense in the income tax calculation, which is related to the total rate base, is typically allocated using a factor consisting of the rate base allocation to the customer rate classes.

Q. WHAT METHODS WERE UTILIZED TO ALLOCATE THE COMPANY'S TEST YEAR COSTS?

A. Mr. Meyer discusses the methods that were utilized to allocate each of the major function/classification cost categories in his Direct Testimony. He also discusses the development of the corresponding allocation factors, which I utilized in preparing the Company's cost-of-service study. Costs not directly associated with one of the major function/classification cost categories were allocated on factors developed in the cost-of-service study which I judged most appropriate for each such cost.

Q. PLEASE DISCUSS THE RESULTS OF THE COST-OF-SERVICE STUDY SUMMARIZED ON PAGE 1 OF EAI EXHIBIT PBG-2.

A. Based on the required rate of return on rate base of 6.44 percent provided to me by Mr. Wright, the Company's cost-of-service study indicates that the current annual base rate revenue requirement for the Arkansas Retail jurisdiction is $1,053.9 million, as indicated on line 15, page 1 of EAI Exhibit PBG-2. This represents a $150.4 million revenue deficiency under the Company's currently effective base rates, as indicated on line 17, page 1 of EAI Exhibit PBG-2. This revenue deficiency was provided to Mr. Meyer for use in rate design.

III. PRODUCTION COST ALLOCATION RIDER

Q. WHAT IS THE STATUS OF IMPLEMENTING THE FERC DECISION IN FERC DOCKET NO. EL01-88-001?

A. On April 10, 2006, ESI, on behalf of the Entergy Operating Companies,[4] filed with the FERC in Docket No. EL01-88-004, a compliance filing ("Compliance Filing") in response to the FERC Decision. The Compliance Filing, if accepted, would revise Service Schedule MSS-3: Exchange of Electric Energy Among The Companies ("MSS-3") of the System Agreement to implement the allocation of production costs among the Operating Companies required by the FERC Decision.

Q. HOW WOULD THE COMPLIANCE FILING CHANGE MSS-3?

A. The proposed change in MSS-3 adds several new sections: Section 30.11: Rough Production Cost Equalization; Section 30.12: Actual Production Cost; Section 30.13: Average Production Cost; and Section 30.14: Billing Procedure for Section 30.09 (d). With this revision, MSS-3 sets out a procedure to determine the amount of payments or receipts, over a prospective 12 month period, for each Operating Company resulting from the implementation of the FERC Decision.

[4] The Entergy Operating Companies include EAI; EGSI; Entergy Louisiana, LLC ("ELL"), formerly known as Entergy Louisiana, Inc. or ELI; EMI; and Entergy New Orleans, Inc ("ENOI").

Q. HOW DOES EAI PROPOSE TO RECOVER THE REQUIRED FERC PAYMENTS FROM ITS RETAIL CUSTOMERS?

A. As EAI witness Hugh T. McDonald discusses in his Direct Testimony, these costs would be included as purchased energy expenses and recovered in the normal operation of Rider ECR. However, this Commission is considering the prospective elimination of Rider ECR in a separate proceeding. Therefore, EAI proposes alternatively a new rider to recover the payments arising from the FERC Decision from its retail customers in that event. The proposed Rider PCA addresses payments or receipts, but for the purpose of this testimony, payments are assumed. Any receipts arising from this proposed Rider PCA would be addressed in the same manner as payments, as outlined in the explanation of procedures later in this testimony. The proposed Rider PCA is included in <u>EAI Exhibit PBG-3.</u>

Q. PLEASE EXPLAIN THE GENERAL OPERATION OF RIDER PCA.

A. Rider PCA defines a procedure that first allocates the payments that EAI is required to make on a total Company basis between its retail and wholesale jurisdictions. The tariff then allocates the Arkansas retail portion of these payments among EAI's retail rate classes. The procedure defines a method to track any over-recovery or under-recovery from EAI's retail customers and applies that difference to the next rider cycle.

Q. HOW WOULD RIDER PCA ALLOCATE PAYMENTS BETWEEN EAI'S WHOLESALE AND RETAIL JURISDICTIONS?

A. As prescribed in the Production Cost Allocation Rate Formula in Attachment C, page 1 of 2 in EAI Exhibit PBG-3, the rider would use an Energy Allocation Factor ("EAF") to allocate the payments between its retail and wholesale jurisdictions. Based on a June filing, the EAF is calculated based upon the actual customer energy usage for the preceding twelve months ending February of the filing year adjusted for known and material customer changes. The energy usage associated with the current PPAs between EAI and its affiliated Companies will be excluded from the application of this formula. These PPAs are not part of EAI's net area load.

Q. HOW WOULD THE RATES FOR EACH RATE CLASS BE DETERMINED?

A. As prescribed in the Production Cost Allocation Rate Formula in Attachment C, page 1 of 2 in EAI Exhibit PBG-3, the sum of the production cost payment allocated to retail and any True-up Adjustment ("TUA"), would be multiplied by one plus the Retail Bad Debt Rate. Then, as prescribed in Attachment B, using the EAF, the Retail FERC Allocation would be allocated to each rate class by multiplying it by the Retail Class Energy Allocation Factor adjusted for known and material customer changes. The ensuing amounts would be divided by the kWh sales for each rate class to determine the cost per kWh for each class.

Q. WHY IS A TUA NECESSARY?

A. A TUA is needed to calculate, and incorporate in subsequent rates, any over-recovery or under-recovery of payments associated with Rider PCA to ensure customers pay no more or less than required.

Q. HOW WILL THE TUA BE DETERMINED?

A. The calculation is prescribed in the Production Cost Allocation Rate Formula in Attachment C, page 1 of 2 in EAI Exhibit PBG-3. According to the proposed formula, the TUA would be derived by first multiplying the Monthly FERC Allocation of production payments by the actual Retail Energy Allocation Factor for the Production Cost Allocation Period. The Production Cost Allocation Period is the 12-month period ending February of the current year, based on a June filing. These monthly amounts would then be compared to the monthly revenue collected, adjusted for bad debts and the prior period true-up adjustment ("PTU"). In the initial filing, the PTU will be zero. A carrying charge would then be applied to the monthly over-recovered or under-recovered balances, resulting in the total TUA for the month.

Q. PLEASE DESCRIBE HOW THE CARRYING COSTS ARE DETERMINED AND WHY THEY ARE INCLUDED IN THE TRUE-UP ADJUSTMENT.

A. The formula prescribes a monthly Carrying Charge Rate based on the authorized rate of return on rate base most recently approved for EAI by the Commission in a non-appealable final order. The monthly rates would be based on application of the formula, 1 + (CCR x 22-j divided by 12), where CCR is the annual carrying charge rate and j is the number of the calculation month (i.e., March=1, April=2, etc.). The portion of the formula represented by the term "22-j" is the length of time between the month of the over- or under-recovery measurement and the over- or under-recovery collection mid-point.

This monthly rate would then be applied to the over-recovery or under-recovery amount for that particular month. The over-recovery or under-recovery amount for the month is the difference between the retail portion of the Monthly FERC Allocation of production payments and the retail revenue under Rider PCA, adjusted for the Retail Bad Debt Rate and the prior period true-up adjustment (variable PTU). PTU would be calculated by taking the prior period TUA and dividing by 12.

The reason for including carrying costs in the TUA is to compensate either the customer or the Company for the time value of money during the intervening period between collection of the money and the subsequent payback of that money.

Q. HOW OFTEN WOULD RIDER PCA BE UPDATED?

A. The rates for Rider PCA would be updated annually. At least 30 days prior to receipt of the first bill rendered to the Company pursuant to the FERC Decision and thereafter on or about June 1 of each year, EAI would file new rider rates. New rates would be effective for the first billing cycle of the month in which the first bill is issued and thereafter with the first billing cycle for July of the filing year, and would remain in effect until updated.

Q. WHY WOULD RIDER PCA NOT BE UPDATED UNTIL JUNE 1 OF EACH YEAR?

A. Based on the Compliance Filing with the FERC, the Annual FERC Allocation in the revised MSS-3 would be redetermined for billing each June 1 based on the prior year's production costs. The updated Annual FERC Allocation will not be available until June 1 of each year because it is based upon data from the FERC Form 1.

Q. WHAT TYPE OF ANNUAL REVIEW DO YOU ANTICIPATE?

A. Workpapers supporting the annual filing would be provided with the new rate calculation. The APSC General Staff ("Staff") would have approximately 30 days to review the calculation.

Q. DOES RIDER PCA REQUIRE SPECIFIC APSC APPROVAL FOR THE ANNUALLY REDETERMINED RATES?

A. No. The Staff would review the filed calculation, and the Company would make any rate changes to correct errors identified by the Staff in its review before the first billing cycle for July.

Q. DOES RIDER PCA HAVE A PROVISION FOR INTERIM ADJUSTMENTS?

A. Yes. If there is a cumulative over-recovery or under-recovery balance which exceeds 10 percent of the APSC jurisdictional portion of the Annual FERC Allocation included in the most recently filed rate redetermination under Rider PCA, then either the Staff or the Company may propose an interim revision to the then currently effective Production Cost Allocation Rates ("PCA Rates").

Q. WHAT HAPPENS IF RIDER PCA TERMINATES?

A. If Rider PCA is terminated by a future order of the Commission, the PCA Rates would continue in effect until such costs were reflected under another mechanism or until the implementation of new base rates reflecting such costs. If the Company were no longer allocated costs pursuant to the FERC Decision, any under-recovery at the end of the last month would be recovered from current customers over six months, beginning with the first billing cycle in the second month. In the event there is an over-recovery at the end of the last month, the balance would be returned to customers over one month, beginning with the first billing cycle in the second month. Any over- or under-recovery balance would be subject to carrying charges calculated under the method previously described.

IV. CAPACITY MANAGEMENT RIDER

Q. PLEASE PROVIDE A BRIEF OVERVIEW OF THE CAPACITY MANAGEMENT RIDER THAT THE COMPANY IS PROPOSING.

A. As discussed by Mr. Cooper in his Direct Testimony, EAI's load requirements indicate a need to purchase capacity. Commensurate with that need, the Company requires a means to recover reasonable costs associated with those capacity purchases. Due to the variable nature and the level of costs associated with those purchases, as discussed in detail by Company witnesses Mr. Cooper and Mr. Fetter, I propose a separate rider, Rider CM, as the recovery mechanism for such costs until the costs can be reflected in base rates.

A separate rider with an annually redetermined rate to recover the cost of incremental (or decremental) capacity purchases between general rate cases is appropriate because of the variability of amount and contract term for these capacity purchases.

Q. PLEASE PROVIDE AN OVERVIEW OF RIDER CM.

A. Rider CM defines a mechanism that would allow EAI to recover, or credit, the APSC retail jurisdictional share of changes in costs, compared to the level of costs reflected in base rates, associated with the acquisition of EAI capacity, the acquisition or termination of purchased capacity contracts, effects of changes to reserve equalization costs, any amortization of APSC-approved deferred capacity costs, and the imputation of debt associated with PPAs having a duration equal to or greater than three years.

Q. PLEASE EXPLAIN THE GENERAL OPERATION OF RIDER CM.

A. Rider CM provides for the development of Capacity Rates by application of the formula ("Capacity Rate Formula") as set out in Attachment B of EAI Exhibit PBG-4. The redetermined Capacity Rates would be based on the retail Capacity Revenue Requirement associated with the following costs:

(A) Acquired Capacity Costs,

(B) Purchased Capacity Costs,

(C) Reserve Equalization Costs,

(D) Deferred Capacity Costs, and

(E) Imputed Debt Cost.

Q. PLEASE DESCRIBE THESE COSTS IN GREATER DETAIL.

A. The Acquired Capacity Costs are the costs directly related to the operation of any EAI generation unit acquired and such other items identified in the generation unit purchase agreement as approved by the Commission.

The Purchased Capacity Costs include the difference between the EAI's retail portion of Purchased Capacity Costs and the corresponding amount reflected in the then currently approved base rates. EAI has included $5.4 million of total Purchased Capacity costs, or $4.6 million on an Arkansas retail basis, in the cost-of-service study.

Likewise, the Reserve Equalization Costs include the difference between EAI's retail portion of the revenue/expense incurred pursuant to MSS-1 and the corresponding amount reflected in the then currently approved base rates. EAI has included $7.1 million of total Reserve Equalization Costs, or $6.7 million on an EAI retail basis, in the cost-of-service study.

The rate base and expenses would be based on the calendar year immediately preceding the filing, unless otherwise specified, and would be calculated in accordance with the formula set out in Attachment B to Rider CM. The return utilized in determining the Acquired Capacity Costs would be the Before-Tax Rate of Return on Rate Base that was last approved by the Commission in a rate proceeding or that which has been authorized by the Commission.

As further discussed by Company witnesses Mr. Fetter and Dr. Morin, costs recovered would also include the impact of imputed debt due to the increased risk associated with PPAs that are three years or longer in duration.

Q. HOW WOULD RIDER CM ALLOCATE COSTS BETWEEN EAI'S WHOLESALE AND RETAIL JURISDICTIONS?

A. Only those costs that are not directly assigned to a jurisdiction would be allocated between EAI's wholesale and retail jurisdictions. Should an allocation be necessary, the rider would utilize a Production Demand Allocation Factor ("PDAF") to allocate the Capacity Costs between the retail and wholesale jurisdictions. The PDAF would be calculated based upon the actual customer demand and energy usage for the 12 month period ending in February of the filing year, adjusted for known and material customer changes. The data associated with current and projected PPAs between EAI and its affiliated Companies pursuant to System Agreement Service Schedule MSS-4: Unit Power Purchase ("MSS-4")[5] would be excluded from the application of this formula because the capacity associated with these transactions is not considered EAI capacity and the load associated with these PPAs is not part of EAI's net area load.

[5] EAI currently has entered into PPAs with EGSI, ELL, EMI, and ENOI. All PPAs except for the one between EAI and ENOI are billed under Service Schedule MSS-4, which provides the basis for making a unit power purchase between Companies. The PPA with ENOI was approved with a different tariff, subject to refund, to be rebilled under MSS-4 after the FERC decision in FERC Docket No. ER-03-583, with future billings under MSS-4.

Q. HOW WOULD THE RATES FOR EACH RATE CLASS BE DETERMINED?

A. As prescribed in the Capacity Rate Formula in Attachment B, page 1 of 3 in EAI Exhibit PBG-4, EAI's Retail Capacity Revenue Requirement would be allocated to each rate class using the appropriate Rate Class Production Demand Allocation Factor. The Capacity Revenue Requirement calculated for each rate class would then be divided by the Class Base Rate Revenue to determine the rate as a monthly percentage for each rate class.

Q. WOULD THERE BE A TRUE-UP ADJUSTMENT FOR RIDER CM?

A. No. All changes in rates would be prospective and would not include an automatic true-up adjustment.

Q. HOW OFTEN WOULD RIDER CM BE UPDATED?

A. The Capacity Rates for Rider CM would be redetermined annually. EAI would file the redetermined Capacity Rates on or about June 1 of each year beginning in 2007 and would be effective for bills rendered on and after the first billing cycle for July of the filing year.

Q. WHAT TYPE OF ANNUAL REVIEW DO YOU ANTICIPATE?

A. Workpapers supporting the annual filing would be provided with the new rate calculation. The Staff would have approximately three weeks to review the calculation, and verify that the formula was correctly applied.

Q. DOES RIDER CM REQUIRE SPECIFIC APSC APPROVAL FOR THE ANNUALLY REDETERMINED RATES?

A. No. After the Staff completes its review of the rate calculation, the Company would make any changes to correct errors identified by the Staff in its review before the first billing cycle for July of the filing year.[6] However, the costs would be subject to Staff audit through September 1, with any issues arising out of that audit to be resolved by the APSC through a hearing and order prior to the end of the calendar year so that the result could be reflected in the next annual update cycle.

Q. DOES RIDER CM HAVE A PROVISION FOR INTERIM ADJUSTMENTS?

A. Yes. If there is an EAI capacity acquisition or purchased capacity contract that exceeds $10 million in APSC jurisdictional revenue requirement, then either the Staff or the Company may propose an interim revision to the then currently effective Rider CM rates.

[6] Unlike Rider ECR, Rider CM is not an exact recovery rider in that Rider CM does not have an annual true-up provision.

Q. HOW DOES RIDER CM TERMINATE?

A. Rider CM would terminate by a future order of the Commission or through changes in the applicable regulations or laws. If terminated, the approved Capacity Rates would continue to be in effect until such costs are reflected in another mechanism or new base rates reflecting the Capacity Revenue Requirement are approved and implemented.

V. INCLUSION OF RIDER ECR AND RIDER PCA COSTS IN BASE RATES

Q. IN DOCKET NOS. 05-116-U AND 06-055-U, THE APSC IS EVALUATING THE PROSPECTIVE ELIMINATION OF RIDER ECR. HOW WOULD EAI RECOVER ITS FUEL AND PURCHASED ENERGY COSTS IF THE APSC DECIDES TO ELIMINATE RIDER ECR?

A. If, as a result of its investigation in Docket No. 06-055-U, the APSC eliminates Rider ECR, then these costs must be recovered through another rate mechanism. Although base rate recovery for these costs is not EAI's recommended method, it would be necessary to include the level of fuel and purchased energy expense in the pro forma test year ended June 30, 2007 in the Company's base rates, if the APSC does not provide an alternative mechanism for recovery of these costs as outlined in the termination provisions of Rider ECR. This retail revenue requirement is $369.4 million, as shown in EAI Exhibit PBG-5 page 1 of 2 and Adjustment 22. Company witness Roger Q Mills provides the basis for my calculation of this amount. We will compare the data supporting this adjustment to similar contemporaneous information as it becomes available during the pendency of this proceeding, and I will supplement this testimony, if appropriate. Pursuant to Rider ECR termination procedures, the Company would also expect to recover any cumulative under-recovery of fuel and purchased energy costs using the currently approved Energy Cost Rates, if Rider ECR is terminated, and until an alternative mechanism is approved by the Commission.

Q. THE COMPANY HAS PROPOSED RIDER PCA TO RECOVER EAI'S PORTION OF COSTS IT WILL INCUR AS A RESULT OF THE FERC DECISION AS AN ALTERNATIVE TO RECOVERY VIA RIDER ECR. IF THE APSC ELIMINATES RIDER ECR AND DOES NOT APPROVE RIDER PCA, HOW DOES EAI PROPOSE TO RECOVER THE FERC-ALLOCATED COSTS?

A. In that event, it would be necessary to include the associated retail revenue requirement in the Company's base rates. The pro forma adjustment to reflect this known and measurable change occurring within the 12-month period ended June 30, 2007 is $265.2 million, as shown in EAI Exhibit PBG-5 page 2 of 2, and Adjustment 23. Company witness Michael J. Goin provides the derivation of the total Company amount. We will compare the data supporting this adjustment to similar contemporaneous information as it becomes available during the pendency of this proceeding, and I will supplement this testimony, if appropriate.

VI. ALLOCATION OF CAPACITY

Q. WHAT IS THE STATUS OF EAI'S PROPOSAL IN DOCKET NO. 03-028-U CONCERNING THE ALLOCATION OF EXISTING EAI CAPACITY TO THE RETAIL AND WHOLESALE JURISDICTIONS?

A. In Order No. 7 in Docket No. 03-028-U, the Commission ruled:

> The remaining issues in this proceeding including those raised by EAI's proposal to amend the methodologies by which EAI's production costs are allocated between EAI's retail and wholesale jurisdictions associated with existing and incremental additions of capacity should be transferred to a new docket and addressed contemporaneously with EAI's resource planning process, as provided for in § 11 of Act 204 of 2003 (Ark. Code Ann. § 23-1 8-1 06).

Because all the Company's costs and EAI's resource planning process are addressed in this Docket, it is appropriate to also address EAI's proposed method for allocating costs associated with existing and incremental additions of capacity in this proceeding.

Q. HOW DOES EAI PROPOSE TO ALLOCATE COSTS ASSOCIATED WITH EXISTING AND INCREMENTAL CAPACITY ADDITIONS?

A. The Company's position is the same as that proposed by Company witness Andrew P. Frits in Docket No. 03-028-U. Based on the PDAF used in Docket No. 96-360-U, the wholesale jurisdiction is responsible for

13.87 percent of the Company's production demand costs based on the 1995 test year. In that proceeding, the Company proposed a fixed allocation of production demand cost for existing production capacity on an 86.13 percent / 13.87 percent retail/wholesale split, respectively. In this proceeding, the Company proposes to allocate to the retail jurisdiction 86.13 percent of existing production demand costs until the allocation methodology described herein is changed with the approval of the Commission. EAI Exhibit PBG-6 replicates and updates EAI Exhibit APF-2 in Docket No 03-028-U, which depicts the allocation of the existing production capability at the 86.13 percent / 13.87 percent split.

The Production Energy Allocation Factor ("PEAF") allocates production non-fuel energy-related costs, including fuel inventory and certain production operation and maintenance expenses. Production non-fuel energy costs are costs that are functionalized as production-related and then classified as energy-related. In Docket No. 96-360-U, the PEAF allocated 86.23 percent of production non-fuel energy-related costs to retail and 13.77 percent to wholesale. For existing production capability, this allocation should also be fixed. The Company has allocated 86.23 percent of production non-fuel energy-related costs associated with existing production capability to retail and 13.77 percent to wholesale. These would be for the same types of costs previously allocated in Docket No. 96-360-U by the PEAF. For the same reason that it is appropriate to fix the allocation of production demand costs at 86.13 percent to retail for existing production capability, it is appropriate to fix the PEAF allocation of production non-fuel energy costs to retail at 86.23 percent.

The Company proposes to allocate newly acquired capacity between the retail and wholesale jurisdictions by direct assignment. The Company will make capacity decisions in the future based on the individual needs of the retail and wholesale jurisdictions. The cost of the new capacity would then be assigned to each jurisdiction accordingly. For example, the capacity acquisition proposed in this case will serve the needs of EAI's retail customers. If the APSC approves this transaction, the Company would assign that capacity and its related costs solely to the retail jurisdiction. Similarly, if an acquisition was made for the benefit of both the retail and wholesale jurisdictions, say 70 MW, with 60 MW assigned to retail and 10 MW assigned to wholesale based upon their respective needs, the capacity costs would be directly assigned in the same proportion.

Q. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A. Yes, it does.

BEFORE THE
ARKANSAS PUBLIC SERVICE COMMISSION

IN THE MATTER OF THE APPLICATION	)	
OF ENTERGY ARKANSAS, INC. FOR	)	DOCKET NO. 06-101-U
APPROVAL OF CHANGES IN RATES FOR	)	
RETAIL ELECTRIC SERVICE	)	

EAI EXHIBIT PBG-1

EDUCATIONAL, PROFESSIONAL AND
WORK EXPERIENCE OF

PHILLIP B. GILLAM

EDUCATIONAL AND PROFESSIONAL BACKGROUND OF
PHILLIP B. GILLAM

I hold a Bachelor of Science degree in accounting from the University of Arkansas at Little Rock, Little Rock, Arkansas.

I am a Certified Public Accountant in Arkansas and belong to the Arkansas Society of Certified Public Accountants and the American Institute of Certified Public Accountants.

BUSINESS EXPERIENCE

From 1978 through 1980 I worked for the University of Arkansas Industrial Research & Extension Center as an Analyst, Small Business Development Center.

I began working for Entergy Arkansas Inc.'s ("EAI") predecessor Arkansas Power & Light Company ("AP&L") in 1980 as a Staff Accountant in the Property Accounting Section. I was responsible for Property Accounting related special projects and year-end tax information reporting. I was promoted to Accountant in 1982 and transferred to the Taxes & Special Studies Section where I was responsible for preparing accounting data for various rate filings and state and federal income tax reports. In 1983 I accepted the position of Supervisor of Taxes & Special Studies where I was directly responsible for state and local tax filings such as sales tax and ad valorem taxes, as well as preparing and reviewing accounting data, testimony and exhibits for various rate filings.

In 1988, I moved to Property Accounting as Supervisor where I was responsible for the accounting of AP&L's non-nuclear generation and transmission plant assets, which included Construction Work in Progress ("CWIP") accounting, the Continuing Property Record ("CPR"), and year-end and ad hoc projects.

In 1991, I moved to New Orleans, Louisiana, as Manager of Property Accounting for Louisiana Power & Light Company and New Orleans Public Service Inc. where I was responsible for all Property Accounting functions and activities including CWIP, CPR, year-end and ad hoc projects. In 1999 I accepted a position with ESI as Property Accounting Manager for the Entergy System where I was responsible for the accounting of the Operating Companies'[1] generation plant assets.

In 1999, I accepted a position as Manager of Corporate Reporting in charge of Corporate Governance of the Property Accounting function including plant accounting policies, capital accounting process oversight and plant accounting special projects.

In 2002, I moved to Little Rock as Director, Revenue Requirements and Analyses, and am responsible for the development of cost-of-service studies for each jurisdiction. I am also responsible for EAI's periodic filings related to the Grand Gulf Rider M33, the ANO Decommissioning Cost Rider M26, and the Energy Cost Recovery Rider.

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[1] The Entergy Operating Companies include Entergy Arkansas, Inc.; Entergy Gulf States, Inc.; Entergy Louisiana, LLC; Entergy Mississippi, Inc.; and Entergy New Orleans, Inc.

BEFORE THE
ARKANSAS PUBLIC SERVICE COMMISSION

IN THE MATTER OF THE APPLICATION	)	
OF ENTERGY ARKANSAS, INC. FOR	)	DOCKET NO. 06-101-U
APPROVAL OF CHANGES IN RATES FOR	)	
RETAIL ELECTRIC SERVICE	)	

EAI EXHIBIT PBG-2

COST OF SERVICE SUMMARY

Entergy Arkansas, Inc.
Cost of Service
Test Year Ended June 30, 2006
(Thousands of Dollars)

LINE #	DESCRIPTION	TOTAL COMPANY	TOTAL RETAIL	TOTAL OF ALL FUNCTIONS RESID	SGS	TOTAL LGS	TOTAL LIGHTING	TOTAL WHSL
1	TOTAL RATE BASE	4,273,442	3,822,531	1,731,031	927,775	1,089,009	74,716	450,910
	REVENUES							
2	RETAIL RATE SCHEDULE	-	-	-	-	-	-	-
3	WHOLESALE SALES	-	-	-	-	-	-	-
4	TOTAL RATE SCHEDULE REVENUE (L2 + L3)	-	-	-	-	-	-	-
5	TOTAL SYSTEM SALES AND OTHER REVENUE	40,974	35,464	15,152	8,372	11,046	893	5,510
6	TOTAL REVENUE (L4 + L5)	40,974	35,464	15,152	8,372	11,046	893	5,510
7	TOTAL EXPENSES	476,392	427,376	195,131	99,568	120,461	12,216	49,016
8	TOTAL UTILITY INCOME (L6 - L7)	(435,418)	(391,912)	(179,979)	(91,196)	(109,415)	(11,323)	(43,506)
9	EARNED RETURN ON RATE BASE (L8 / L1)	-10.19%	-10.25%	-10.40%	-9.83%	-10.05%	-15.16%	-9.65%
10	REQUIRED RATE OF RETURN ON RATE BASE	6.44%	6.44%	6.44%	6.44%	6.44%	6.44%	6.44%
11	REQUIRED RETURN ON RATE BASE (L1 * L10)	275,210	246,171	111,478	59,749	70,132	4,812	29,039
12	INCOME DEFICIENCY/(SURPLUS) (L11 - L8)	710,628	638,083	291,457	150,944	179,547	16,135	72,544
13	REVENUE CONVERSION FACTOR	N/A	N/A	1.65672	1.64806	1.64571	1.66281	1.64541
14	REVENUE DEFICIENCY/(SURPLUS) (L12 * L13)	1,173,307	1,053,942	482,864	248,766	295,482	26,829	119,366
15	RATE SCHEDULE REVENUE REQUIREMENT (L4 + L14)	1,173,307	1,053,942	482,864	248,766	295,482	26,829	119,366
16	RATE SCHEDULE REVENUE	1,021,510	903,576	432,842	207,903	242,729	20,102	117,934
17	TOT FUNCTIONAL RATE SCH REVENUE DEF (L15 - L16)	151,797	150,366	50,023	40,863	52,753	6,728	1,432

Note: Proposed Revenue Requirement = Required Revenue Requirement

Numbers may not add or tie to other schedules due to rounding.

Entergy Arkansas, Inc.
Cost of Service
Test Year Ended June 30, 2006
(Thousands of Dollars)

LINE #	DESCRIPTION	TOTAL COMPANY	TOTAL RETAIL	TOTAL OF ALL FUNCTIONS RESID	SGS	TOTAL LGS	TOTAL LIGHTING	TOTAL WHSL
	MFR SCHEDULE A-1 CALCULATION WITH RATE SCHEDULE REVENUE							
1	RATE BASE (P1, L1)	4,273,442	3,822,531	1,731,031	927,775	1,089,009	74,716	450,910
2	ADJUSTED OPERATING REVENUE (P1, L6 + L16)	1,062,484	939,040	447,994	216,275	253,776	20,994	123,444
	ADJUSTED OPERATING EXPENSE							
3	OPERATING EXPENSE EX REVENUE RELATED (P1,	476,392	427,376	195,131	99,568	120,461	12,216	49,016
	ADD: REVENUE RELATED EXPENSE							
4	BAD DEBT (P1, L16 * BAD DEBT FACTOR)	3,544	3,544	2,955	334	44	210	(0)
5	NET INCOME TAX (P1, L16 + L4) * INCOME TAX	399,297	353,038	168,623	81,419	95,193	7,802	46,260
6	ADJUSTED EXPENSES (L3 + L4 + L5)	879,233	783,957	366,710	181,321	215,698	20,229	95,275
7	ADJUSTED OPERATING INCOME (L2 - L6)	183,251	155,082	81,285	34,954	38,078	766	28,169
8	CURRENT RATE OF RETURN (L7 / L1)	4.29%	4.06%	4.70%	3.77%	3.50%	1.02%	6.25%
9	REQUIRED RATE OF RETURN	6.44%	6.44%	6.44%	6.44%	6.44%	6.44%	6.44%
10	REQUIRED OPERATING INCOME (L1 * L9)	275,210	246,171	111,478	59,749	70,132	4,812	29,039
11	OPERATING INCOME DEFICIENCY (L10 - L7)	91,959	91,089	30,194	24,794	32,055	4,046	870
12	REVENUE CONVERSION FACTOR	1.65071	1.65076	1.65672	1.64806	1.64571	1.66281	1.64541
13	REVENUE DEFICIENCY (L11 * L12)	151,797	150,366	50,023	40,863	52,753	6,728	1,432
14	TOTAL REVENUE REQUIREMENT (L2 + L13)	1,214,281	1,089,405	498,017	257,138	306,528	27,722	124,876
	ADJUSTED REVENUES OTHER THAN							
15	RATE SCHEDULE REVENUE (P1, L5)	40,974	35,464	15,152	8,372	11,046	893	5,510
16	RATE SCHEDULE REVENUE REQUIREMENT (L14 - L15)	1,173,307	1,053,942	482,864	248,766	295,482	26,829	119,366

Numbers may not add or tie to other schedules due to rounding.

Entergy Arkansas, Inc.
Cost of Service
Test Year Ended June 30, 2006
(Thousands of Dollars)

LINE #	DESCRIPTION	TOTAL OF ALL FUNCTIONS: TOTAL COMPANY	TOTAL RETAIL	RESID	SGS	TOTAL LGS	TOTAL LIGHTING	TOTAL WHSL
	RATE BASE							
1	PLANT IN SERVICE	6,820,555	6,067,604	2,700,502	1,467,717	1,762,625	136,759	752,952
2	ACCUMULATED DEPRECIATION	(3,011,167)	(2,658,582)	(1,151,872)	(639,106)	(797,513)	(70,090)	(352,585)
3	FUEL INVENTORY	32,892	28,362	10,135	5,966	11,928	334	4,529
4	MATERIALS & SUPPLIES	91,112	81,272	35,637	19,772	24,015	1,847	9,840
5	PREPAYMENTS	5,451	4,936	2,160	1,177	1,501	97	515
6	INVESTMENT IN SFI	11,001	9,486	3,390	1,995	3,989	112	1,515
7	WORKING CASH	323,598	289,453	131,079	70,254	82,463	5,658	34,144
8	TOTAL RATE BASE	4,273,442	3,822,531	1,731,031	927,775	1,089,009	74,716	450,910
	REVENUES							
	RATE SCHEDULE REVENUE							
9	RETAIL RATE SCHEDULE	-	-	-	-	-	-	-
10	WHOLESALE SALES	-	-	-	-	-	-	-
11	TOTAL RATE SCHEDULE REVENUE	-	-	-	-	-	-	-
	SYSTEM SALES							
12	ENTERGY POWER POOL	1,162	1,001	391	228	375	8	161
13	SYSTEM SALES TO OTHERS	712	613	245	143	222	4	99
14	IMPUTED TRANSMISSION	134	100	40	24	35	0	35
15	RESOURCE PLAN REVENUE	-	-	-	-	-	-	-
16	TOTAL SYSTEM SALES	2,008	1,714	676	394	632	12	294
17	OTHER OPERATING REVENUES	38,965	33,750	14,477	7,978	10,415	881	5,216
18	TOTAL SYSTEM SALES AND OTHER REVENUE	40,974	35,464	15,152	8,372	11,046	893	5,510
19	TOTAL REVENUE	40,974	35,464	15,152	8,372	11,046	893	5,510
	EXPENSES							
	OPERATING & MAINTENANCE EXPENSE							
20	PRODUCTION	215,901	187,470	73,292	42,787	69,979	1,412	28,431
21	TRANSMISSION	23,473	17,304	7,005	4,147	6,096	56	6,169
22	DISTRIBUTION	49,767	49,524	24,542	13,755	8,923	2,303	243
23	CUSTOMER ACCOUNTING	38,899	38,621	30,947	7,076	295	302	278
24	CUSTOMER SERVICES	8,226	8,226	6,890	1,255	25	56	-
25	SALES	2,092	1,861	818	453	546	43	231
26	ADMINISTRATIVE AND GENERAL	156,581	138,841	62,146	32,884	40,987	2,824	17,740
27	TOTAL OPERATING & MAINTENANCE EXPENSE	494,940	441,846	205,641	102,358	126,851	6,996	53,094
28	GAIN ON DISPOSITION OF ALLOWANCE	-	-	-	-	-	-	-
29	REGULATORY DEBIT/CREDIT	524	524	233	127	152	12	-
30	DEPRECIATION EXPENSE	239,718	216,135	96,231	51,072	59,825	9,007	23,583
31	TAXES OTHER THAN INCOME TAX	41,747	37,645	16,882	8,954	11,073	735	4,102
32	CURRENT STATE INCOME TAX	(48,210)	(43,077)	(19,855)	(10,142)	(12,339)	(741)	(5,133)
33	CURRENT FEDERAL INCOME TAX	(230,901)	(206,364)	(95,284)	(48,517)	(59,070)	(3,493)	(24,537)
34	DEFERRED FEDERAL INCOME TAX	(16,149)	(14,608)	(6,609)	(3,204)	(4,576)	(219)	(1,541)
35	DEFERRED STATE INCOME TAX	(1,111)	(1,019)	(477)	(178)	(368)	3	(91)
36	INVESTMENT INCOME TAX	(4,167)	(3,706)	(1,631)	(902)	(1,088)	(85)	(461)
37	TOTAL EXPENSE	476,392	427,376	195,131	99,568	120,461	12,216	49,016

Numbers may not add or tie to other schedules due to rounding.

BEFORE THE
ARKANSAS PUBLIC SERVICE COMMISSION

IN THE MATTER OF THE APPLICATION	)	
OF ENTERGY ARKANSAS, INC. FOR	)	DOCKET NO. 06-101-U
APPROVAL OF CHANGES IN RATES FOR	)	
RETAIL ELECTRIC SERVICE	)	

EAI EXHIBIT PBG-3

PROPOSED RATE SCHEDULE NO. 48

PRODUCTION COST ALLOCATION RIDER (PCA)

48.0 PRODUCTION COST ALLOCATION RIDER (NR)

48.1 REGULATORY AUTHORITY

The Arkansas Legislature has delegated authority to the Arkansas Public Service Commission ("APSC" or the "Commission") to regulate public utilities in the State of Arkansas, including Entergy Arkansas, Inc. ("EAI" or the "Company"). The APSC's regulatory authority over the provision of electric service applies not only in the Distribution Service area allocated to EAI by the APSC but also extends to service to customers who have been released to EAI by other electric distribution utilities, when such release for service has been approved by the Commission pursuant to Rule 7.04.(b) of the Commission's Rules of Practice and Procedure. Similarly, the Tennessee Regulatory Authority exercises such authority delegated to it by the Tennessee Legislature in areas of the State of Tennessee served by EAI.

48.2 PURPOSE

The purpose of this Production Cost Allocation Rider ("Rider PCA") is to recover, from EAI's retail customers, the retail allocation of the Company's annual payments/receipts ("FERC Allocation") to/from the other Entergy Operating Companies[1] as directed in Docket No. EL01-88-001, Opinion Nos. 480 and 480-A, and any subsequent modification thereof ("FERC Decision"). Rider PCA shall recover from retail customers any payments made or return to retail customers any receipts received pursuant to the FERC Allocation unless and to the extent those payments or receipts are expressly reflected in base rates or another EAI retail rider. Rider PCA shall apply in accordance with the provisions of § 48.3 below to electric service billed under certain rate schedules, whether metered or unmetered.

48.3 PRODUCTION COST ALLOCATION RATES

The Production Cost Allocation rates ("PCA Rates") shall be set forth in Attachment A to this Rider PCA.

48.4 ANNUAL DETERMINATION

At least 30 days prior to receipt of the first bill rendered to the Company pursuant to the FERC Decision and thereafter on or about June 1 each year, beginning in 2007, the Company shall file PCA Rates with the Commission. The PCA Rates, as set out in Attachment A, shall be determined by application of the formula ("PCA Rate Formula") set out in Attachment B and Attachment C to this Rider PCA. The PCA Rates so determined shall be effective for bills rendered on and after the first billing cycle of the month in which the first FERC Allocation bill is issued and thereafter with the first billing cycle for July of the filing year and shall remain in effect until updated. Each such set of PCA Rates shall be filed in Commission Report Docket No. 86-033-A and shall be accompanied by a set of workpapers sufficient to fully document the calculations of the redetermined PCA Rates.

[1] The Entergy Operating Companies are Entergy Arkansas, Inc., Entergy Gulf States, Inc., Entergy Louisiana, LLC (formerly Entergy Louisiana, Inc.), Entergy Mississippi, Inc., and Entergy New Orleans, Inc.

Redetermined PCA rates shall reflect the retail allocation of any payments or receipts relating to the FERC Allocation together with a true-up adjustment reflecting the over- or under-recovery of the twelve month period ending the last day of the preceding February. Any over- or under-recovery balance will be decreased or increased by monthly carrying charges based on the rate of return on rate base last approved for the Company by the Commission in a non-appealable order. The cumulative over- or under-recovery as of the last day of the preceding February shall be subtracted from or added to the rider level in the annual Redetermination. (NR)

48.5 INTERIM ADJUSTMENT

Should a cumulative over-recovery or under-recovery balance arise which exceeds ten (10) percent of the APSC jurisdictional portion of the annual FERC Allocation included in the most recently filed rate redetermination under this Rider PCA, then either the APSC General Staff or the Company may propose an interim revision to the then currently effective PCA Rates.

48.6 TERM

This Rider PCA shall remain in effect until terminated in accordance with applicable regulations or laws.

If this Rider PCA is terminated by a future order of the Commission, the PCA Rates shall continue in effect until such costs are reflected under another mechanism or until the implementation of new base rates reflecting such costs.

If the Company is no longer allocated FERC Allocation payments or receipts, any under-recovery at the end of the last month that FERC Allocation payments or receipts are recorded (“End Month”) will be recovered from current customers over six months beginning with the first billing cycle of the second month following the End Month. In the event of an over-recovery at the End Month, the balance will be returned to customers over one month beginning with the first billing cycle in the second month following the End Month. Any over- or under-recovery balance will be subject to carrying charges calculated under the method described in Attachment C adjusted to reflect the shorter recovery or return period.

(NR)

Rider PCA Rates

The Net Monthly Rates set forth in EAI's schedules identified below will be adjusted by the following Rate Adjustment amounts:

Rate Class	Rate Schedules	Rate Adjustment
Residential	RS, RT	$x.xxxx per kWh
Small General Service	SGS, GFS, L2, MP, AP, CGS, CTV, SMWHR	$x.xxxx per kWh
Large General Service	LGS, LPS, LCTOU, SSR	$x.xxxx per kWh
Lighting	L1, L1SH, L4	$x.xxxx per kWh

Rider PCA Rate Calculation

(NR)

Rate Class	EAF_C[1]	RFAL By Class[2]	Class kWh[3]	Rate Adjustments[4]
Residential	%	$		$x.xxxx per kWh
Small General Service	%	$		$x.xxxx per kWh
Large General Service	%	$		$x.xxxx per kWh
Lighting	%	$		$x.xxxx per kWh
Total	%	$		

Notes:

(1) EAF_C is the Retail Class Energy Allocation Factor for the 12 month period ending 4 months prior to the filing date (a June filing would use 12 months ending February data) calculated using actual retail class energy usage adjusted for known and material customer changes

(2) Retail FERC Allocation Level (RFAL) from Attachment C * EAF_C

(3) Class billed kWh for the 12 month period ending 4 months prior to the filing date adjusted for known and material customer changes

(4) (RFAL By Class) / Class kWh

(NR)

PRODUCTION COST ALLOCATION RATE FORMULA

RFAL = RETAIL FERC ALLOCATION LEVEL

RFAL = $[(AFA * EAF_A) + TUA] * (1 + BDR)$

WHERE,

AFA = ANNUAL FERC ALLOCATION PAYMENT/RECEIPT (1)

EAF_A = RETAIL ENERGY ALLOCATION FACTOR FOR THE PRODUCTION COST ALLOCATION PERIOD ADJUSTED FOR KNOWN AND MATERIAL CUSTOMER CHANGES (2) (3)

BDR = RETAIL BAD DEBT RATE (4)

TUA = TRUE-UP ADJUSTMENT FOR THE PRODUCTION COST ALLOCATION PERIOD INCLUDING CARRYING CHARGES (5)

$$TUA = \sum_{j=1}^{12} [(FA_j * EAF_B) - ((PCAR_j / (1 + BDR)) - PTU_j)] * (1 + CCR * ((22 - j) / 12))$$ (6)

WHERE,

FA_j = FERC ALLOCATION FOR MONTH j OF THE PRODUCTION COST ALLOCATION PERIOD

EAF_B = UNADJUSTED RETAIL ENERGY ALLOCATION FACTOR FOR THE PRODUCTION COST ALLOCATION PERIOD (7)

$PCAR_j$ = REVENUE UNDER RIDER PCA FOR MONTH j OF THE PRODUCTION COST ALLOCATION PERIOD PLUS AN IMPUTED LEVEL OF REVENUES FOR SALES UNDER SPECIAL RATE CONTRACTS WHERE THE PRODUCTION COST ALLOCATION IS NOT SEPARATELY BILLED

BDR = RETAIL BAD DEBT RATE (4)

PTU_j = PRIOR PERIOD TRUE-UP ADJUSTMENT APPLICABLE FOR MONTH j OF THE PRODUCTION COST ALLOCATION PERIOD

CCR = CARRYING CHARGE RATE

(NR)

Notes:

(1) The Annual FERC Allocation Payment/Receipt is EAI's annual payment/receipt to/from the other Entergy Operating Companies pursuant to the FERC Decision.
(2) The Production Cost Allocation Period is the 12 month period ending 4 months prior to the filing date (a June filing would use 12 months ending February data).
(3) EAF_A is calculated using actual energy usage for the Production Cost Allocation Period adjusted for known and material customer changes.
(4) The Retail Bad Debt Rate is calculated by dividing the net retail bad debt expenses by retail revenues for the Production Cost Allocation Period.
(5) The Carrying Charge Rate shall be the authorized rate of return on rate base most recently approved for EAI by the Commission in a non-appealable order.
(6) Month *j* shall be determined by March = 1, April = 2 through February = 12.
(7) EAF_B is calculated using actual energy usage for the Production Cost Allocation Period.

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. 06-101-U

EAI EXHIBIT PBG-4

PROPOSED RATE SCHEDULE NO. 49

CAPACITY MANAGEMENT RIDER (CM)

ARKANSAS PUBLIC SERVICE COMMISSION

Original	Sheet No. 49.1	Schedule Sheet 1 of 6 Including Attachments	
Replacing	Sheet No.		
Entergy Arkansas, Inc. Name of Company			
Kind of Service: Electric	Class of Service: All		Docket No.: Order No.: Effective:
Part III. Rate Schedule No. 49			
Title: Capacity Management Rider (CM)			PSC File Mark Only

(NR)

49.0 CAPACITY MANAGEMENT RIDER

49.1 REGULATORY AUTHORITY

The Arkansas Legislature has delegated authority to the Arkansas Public Service Commission ("APSC" or the "Commission") to regulate public utilities in the State of Arkansas, including Entergy Arkansas, Inc. ("EAI" or the "Company"). The APSC's regulatory authority over the provision of electric service applies not only in the Distribution Service area allocated to EAI by the APSC but also extends to service to customers who have been released to EAI by other electric distribution utilities, when such release for service has been approved by the Commission pursuant to Rule 7.04.(b) of the Commission's Rules of Practice and Procedure. Similarly, the Tennessee Regulatory Authority exercises such authority delegated to it by the Tennessee Legislature in areas of the State of Tennessee served by EAI.

49.2 PURPOSE

The purpose of this Capacity Management Rider ("Rider CM") is to recover, from EAI's retail customers, changes in costs associated with the EAI-acquired capacity, purchased capacity, reserve equalization, any amortization of approved deferred capacity costs as ordered by the APSC, and the imputation of debt due to Power Purchase Agreements ("PPAs") that are 3 years or greater in duration. Rider CM shall apply in accordance with the provisions of § 49.3 below to electric service billed under certain rate schedules, whether metered or unmetered.

49.3 CAPACITY MANAGEMENT RATES

The Capacity Management rates ("Capacity Rates") shall be set forth in Attachment A to this Rider CM.

49.4 ANNUAL DETERMINATION

On or before June 1 of each year, beginning in 2007, the Company shall file Capacity Rates with the Commission. The Capacity Rates, as set out in Attachment A, shall be determined by application of the formula ("Capacity Rate Formula") set out in Attachment B to this Rider CM. The rate base and expenses shall be based on the calendar year immediately preceding the filing ("Test Year"), unless otherwise specified, and shall be calculated in accordance with the formula set out in Attachment B to this Rider CM. The Capacity Rates so determined shall be effective for bills rendered on and after the first billing cycle for July of the filing year and shall remain in effect until updated. Each such set of Capacity Rates shall be filed in Commission Report Docket No. 86-033-A and shall be accompanied by a set of workpapers sufficient to fully document the calculations of the redetermined Capacity Rates.

ARKANSAS PUBLIC SERVICE COMMISSION

Original	Sheet No. 49.2	Schedule Sheet 2 of 6 Including Attachments	
Replacing	Sheet No.		
Entergy Arkansas, Inc. Name of Company			
Kind of Service: Electric	Class of Service: All		Docket No.: Order No.: Effective:
Part III. Rate Schedule No. 49			
Title: Capacity Management Rider (CM)			PSC File Mark Only

(NR)

49.5 STAFF AND COMMISSION REVIEW

Prior to June 21, Staff shall review the filed Capacity Rates to verify that the formula in Attachment B has been correctly applied and shall notify the Company of any necessary corrections. Prior to September 1, Staff shall file with the Commission and provide to the Company the results of any audit it may conduct of the filed Capacity Rates and associated work papers. If no Staff audit is filed by September 1, the Capacity Rates shall become final on that date. If Staff proposes no adjustment to the Capacity Rates as a result of a filed audit, the Capacity Rates shall become final upon the audit's filing. In the event the Company within ten days disputes any Staff-proposed adjustment to the Capacity Rates that arises from the audit, the Commission will establish a procedural schedule providing for a hearing prior to November 15, and shall issue its Order resolving any disputed issues and finalizing the Capacity Rates prior to December 31. The effect of the Commission's Order resolving disputed issues shall be reflected in the next Annual Determination under § 49.4.

49.6 INTERIM ADJUSTMENT

Should the impact of an EAI-acquired capacity or purchased capacity exceed $10 million in APSC jurisdictional annual revenue requirement, then either the APSC General Staff or the Company may propose an interim determination of the then currently effective Capacity Rates.

49.7 TERM

This Rider CM shall remain in effect until terminated in accordance with applicable regulations or laws.

If this Rider CM is terminated by a future order of the Commission, the Capacity Rates shall continue to be in effect until such costs are recovered through another mechanism or until the implementation of new base rates reflecting such costs.

Docket No.:
Order No.:
Effective:

Attachment A to
Rate Schedule No. 49
Attachment Page 1 of 1
Schedule Sheet 3 of 6
Including Attachments

(NR)

Rider CM Rates

All retail rates and applicable riders on file with the APSC will be increased or decreased by the monthly percentage listed below:

Rate Class	Rate Schedules	Applicable Monthly Percentage
Residential	RS, RT	xx.xxxx%
Small General Service	SGS, GFS, L2, MP, AP, CGS, CTV, SMWHR	xx.xxxx%
Large General Service	LGS, LPS, LCTOU, SSR	xx.xxxx%
Lighting	L1, L1SH, L4	xx.xxxx%

(NR)

Entergy Arkansas, Inc.
Capacity Rate Formula
Test Year Ending __________________
($000's omitted)

Class Allocation & Rate Development					
Line No.	Class	Class Allocator (1)	Capacity Revenue Reqmt ($) (2)	Base Rate Revenue ($) (3)	Monthly Percent (4)
	APSC Retail				
1	Residential				xx.xxx%
2	Small General Service				xx.xxx%
3	Large General Service				xx.xxx%
4	Lighting				xx.xxx%
5	**Total APSC Retail**				

Notes:
(1) Most recently approved Rate Class Production Demand Allocation Factor
(2) Attachment B, Page 2, Line 26 * Class Allocator
(3) The Base Rate Revenue for the previous calendar year
(4) Class Capacity Revenue Requirement / Class Base Rate Revenue

(NR)

Entergy Arkansas, Inc.
Capacity Revenue Requirement
Arkansas Retail Jurisdiction
Test Year Ending December 31, ______

Line No.	Description	Amount (000's)
	I. Acquired Capacity Costs (A)	
	Rate Base	
1	Plant in Service	
2	Accumulated Depreciation & Amortization	
3	Total Rate Base (Line 1 – Line 2)	
4	Before-Tax Rate of Return on Rate Base from last approved rate case	xx.xx%
5	Return on Rate Base (Line 3 * Line 4)	
	Expenses/(Revenues)	
6	Operation & Maintenance Expense	
7	Reserve Equalization (Revenue)	
8	Depreciation & Amortization Expense	
9	Total Expenses (Sum of Lines 6 – 8)	
10	**Total Acquired Capacity Costs (Line 5 + Line 9)**	
	II. Purchased Capacity Costs (B)	
11	Purchased Capacity Costs (C)	
12	Purchased Capacity Costs included in Base Rates	
13	**Net Purchased Capacity Costs (Line 11 – Line 12)**	
	III. Reserve Equalization	
14	Reserve Equalization Expense/(Revenue)	
15	Reserve Equalization Expense/(Revenue) included in Base Rates	
16	Reserve Equalization Expense/(Revenue) included in Rider GGR	
17	**Net Reserve Equalization (Line 14 – Sum of Lines 15 - 16)**	
	IV. Deferred Capacity Costs (D)	
18	Amortization of Deferred Capacity	
	V. Imputed Debt Cost	
19	Before-Tax Rate of Return on Rate Base (RORB) (E)	%
20	Before-Tax Rate of RORB from last approved rate case	%
21	Change in Before-Tax RORB (Line 19 – Line 20)	%
22	Rate Base from last approved rate case + Line 3	
23	**Total Imputed Debt Cost (Line 21 * Line 22)**	
24	**Total Capacity Costs (Line 10 + Line 13 + Line 17 + Line 18 + Line 23)**	
25	**Bad Debt Rate (F)**	
26	**Total Capacity Revenue Requirement (Line 24 * (1 + Line 25))**	

(NR)

Notes:

(A) Acquired Capacity Costs as approved by the Commission ("Acquired Capacity Costs") shall be the annual retail cost directly related to the ownership and operation of the EAI generation units acquired after the implementation of the Company's most recently approved base rates. For the year of acquisition, the rate base and expenses shall be based on a proformed (projected) amount. For the year immediately following an acquisition, the rate base shall be based on the actual balances as of December 31 of the Test Year and the expenses shall be based on the actual costs incurred during the Test Year proformed (projected) for twelve months of operations following the acquisition. For subsequent years, the Acquired Capacity Costs shall be the Test Year amounts.

(B) The Retail portion of Purchased Capacity Costs in Account 555.

(C) Capacity not directly assigned to a jurisdiction will be allocated to the Arkansas retail jurisdiction based on the production demand allocation factor ("Energy & Peak"). The production demand allocation factor will be based on the 12 months ending February of the filing year adjusted for known and material customer changes.

(D) Capacity Costs (purchased or acquired) deferred by order of the Commission. The balance of the accounting deferral as of December 31 of the Test Year shall be amortized over twelve months.

(E) The Rate of Return on Rate Base that was last approved by the Commission in a base rate proceeding or that which has been authorized by the Commission adjusted for the impact of imputed debt due to capacity purchases that are 3 years or longer in duration.

(F) The Retail Bad Debt Rate is calculated by dividing the net retail bad debt expenses by total retail revenues for the Test Year.

BEFORE THE
ARKANSAS PUBLIC SERVICE COMMISSION

IN THE MATTER OF THE APPLICATION	)	
OF ENTERGY ARKANSAS, INC. FOR	)	DOCKET NO. 06-101-U
APPROVAL OF CHANGES IN RATES FOR	)	
RETAIL ELECTRIC SERVICE	)	

EAI EXHIBIT PBG-5

Rider ECR and Rider PCA
Proposed Adjustments to Base Rates

ENTERGY ARKANSAS, INC.
PROPOSED ADJUSTMENT TO BASE RATES
FOR FUEL AND PURCHASED ENERGY
TEST YEAR ENDED JUNE 2007
($000)

Ln No	Description	Amount	Reference
1	Fuel and Purchased Energy Cost to be Allocated	356,905	WP AJ 22-2
2	Retail Allocation Factor	0.931778	MFR Schedule G-4a, Page 1
3	Retail Allocated Share	332,556	Line 1 * Line 2
4	Directly Assigned Capacity Acquisition	37,715	WP AJ 22-2
5	Total Retail Fuel and Purchased Energy	370,271	Line 3 + Line 4
	Bad Debt Adjustment		
6	Adjusted ECR Revenue	597,710	WP AJ 1-4
7	Change in Revenue/Expense	(227,439)	Line 5 - Line 6
8	Retail Bad Debt Factor	0.3707%	MFR Schedule C-4
9	Change in Bad Debt Expense (FERC Account 904)	(843)	Line 7 * Line 8
10	Total Retail Revenue Requirement	369,428	Line 5 + Line 9

ENTERGY ARKANSAS, INC.
PROPOSED ADJUSTMENT TO BASE RATES
FOR FERC ALLOCATION
TEST YEAR ENDED JUNE 2007
($000)

Ln No	Description	Amount	Reference
1	Total FERC Allocation Expense	283,569	WP AJ 23-2
2	Retail Allocation Factor	0.931778	MFR Schedule G-4a, Page 1
3	Retail Allocated Share	264,223	Line 1 * Line 2
	Bad Debt Adjustment		
4	Retail Bad Debt Factor	0.3707%	MFR Schedule C-4
5	Change in Bad Debt Expense (FERC Account 904)	979	Line 3 * Line 4
6	Total Retail Revenue Requirement	265,203	Line 3 + Line 5

BEFORE THE
ARKANSAS PUBLIC SERVICE COMMISSION

IN THE MATTER OF THE APPLICATION	)	
OF ENTERGY ARKANSAS, INC. FOR	)	DOCKET NO. 06-101-U
APPROVAL OF CHANGES IN RATES FOR	)	
RETAIL ELECTRIC SERVICE	)	

EAI EXHIBIT PBG-6

ALLOCATION OF CAPACITY

Entergy Arkansas, Inc.
Allocation of Existing Capability

Line	Units	Capacity [1] MW	Retail [2] MW	Wholesale [3] MW
	Owned Capability			
1	ANO Unit 1	841	724	117
2	ANO Unit 2	998	860	138
3	Carpenter Unit 1	29	25	4
4	Carpenter Unit 2	30	26	4
5	Couch Unit 1	23	20	3
6	Couch Unit 2	125	108	17
7	Independence Unit 1	263	227	36
8	Lake Catherine Unit 1	0	0	0
9	Lake Catherine Unit 2	0	0	0
10	Lake Catherine Unit 3	0	0	0
11	Lake Catherine Unit 4	547	471	76
12	Lynch 2	68	59	9
13	Lynch 3	110	95	15
14	Lynch Diesel	5	4	1
15	Mabelvale Unit 1	14	12	2
16	Mabelvale Unit 2	14	12	2
17	Mabelvale Unit 3	14	12	2
18	Mabelvale Unit 4	14	12	2
19	Moses 1	70	60	10
20	Moses 2	70	60	10
21	Remmel Unit 1	4	3	1
22	Remmel Unit 2	3	3	0
23	Remmel Unit 3	4	3	1
24	Ritchie Unit 1	300	258	42
25	Ritchie Unit 3	16	14	2
26	White Bluff Unit 1	465	401	64
27	White Bluff Unit 2	470	405	65
28	Subtotal	4,497	3,873	624
	Capability Purchases[4]			
29	Grand Gulf - Non-Retained Share	320	276	44
30	Grand Gulf - Retained Share	90	78	12
31	Coral-Cottonwood[5]	218	187	30
32	UPP Call Option[5]	200	172	28
33	ConocoPhillips-SRW[5]	25	22	3
34	Exelon-Frontier[5]	38	33	5
35	Subtotal	890	767	124
36	Total	5,387	4,640	747

[1] Capacity level - Summer 2006 for owned capacity and May 2006 Purchase Contracts
[2] Capacity times 1995 Production Demand Allocation Factor (.8613)
[3] Capacity Less Retail
[4] Excludes Co-owners' Capability.
[5] Coral-Cottonwood and Exelon Frontier contracts expire April 2007, ConocoPhillips in June 2007 and UPP Call Option in December 2008.

Note: Numbers may not add or tie to other schedules due to rounding.

CERTIFICATE OF SERVICE

I, Steven K. Strickland, do hereby certify that a copy of the foregoing has been served upon all parties of record this 15th day of August 2006.

__________/ S /___________________

Steven K. Strickland