costs. AEP requests that those rates also be permitted to become effective as of November 1, 2005.

4. Due to the work involved in finalizing the Settlement Agreement, as well as work involved in finalizing the tariff sheets for filing, the Settlement Agreement was not filed prior to the November 1, 2005 effective date for AEP's new rates. The Settlement Agreement, as well as the relevant tariff sheets reflecting the terms of that agreement, has been filed this day with the Commission.

5. AEP requests that the rates contained in the Settlement Agreement - rather than the rates contained in the March 31, 2005 filing - be permitted to go into effect while the Commission is reviewing the Settlement Agreement and that those rates be given an effective date of November 1, 2005.

6. Good cause exists to permit AEP to implement the rates contained in the Settlement Agreement pending the Commission's review of the settlement documents. The changes to the rate schedules resulting from the settlement are lower than the rates the Commission has previously determined would go into effect on November 1, 2005. Consequently, substituting the settlement rates for previously filed rates will harm no party to this matter. Further, the requested relief will also simplify PJM's billing processes since allowing the settlement rates to go into effect now would permit PJM to bill its customers correctly rather than knowingly bill them an incorrect amount and then later pay refunds for the difference. The Commission can grant the relief requested in this Motion without limiting interested parties' opportunity to comment on the settlement documents contemporaneously filed with this Motion.

7. AEP requests that the Commission shorten the time allowed for parties to respond to this motion to 7 days from the date of filing. Because the requested relief would allow AEP to implement a rate change that decreases rates that the Commission has already permitted to go into effect, AEP does not expect objections to this Motion. AEP desires expedited consideration of this Motion so that PJM billing personnel will know as soon a possible how to bill transmission customers in the AEP East Zone.

WHEREFORE, for the foregoing reasons, AEP requests leave to implement rates contained in the Settlement Agreement filed with the Commission on the date hereof, pending the Commission's review of that filing. AEP also requests that the Commission consider this Motion on an expedited basis.

Respectfully submitted,

Kevin F. Duffy
Sandra K. Williams
American Electric Power
Service Corporation
1 Riverside Plaza
Columbus, Ohio 43215
Telephone: (614) 716-1617
FAX: (614) 716-2950

Dated November 7, 2005

CERTIFICATE OF SERVICE

I certify that a copy of the foregoing Motion to Put Tariff Changes into Effect on an Expedited Basis filed by American Electric Power Service Corporation was served upon the parties to this proceeding this 7th day of November 2005.

____
Sandra K. Williams

November 7, 2005

The Honorable Magalie R. Salas
Secretary
Federal Energy Regulatory Commission
888 First Street, N.E.
Washington, D.C. 20426

VIA OVERNIGHT MAIL

Re: Offer of Settlement -- American Electric Power Service Corporation,

Docket No. ER05-751-000

Dear Ms. Salas:

American Electric Power Service Corporation ("AEP"), on behalf of certain operating companies of the American Electric Power System[1] submits for filing with the Commission an original and fourteen copies of a Settlement Agreement with attachments and an Explanatory Statement, pursuant to Rule 602 of the Commission's Rules of Practice and Procedure.

The Settlement Agreement is among AEP and certain Parties in this proceeding listed in Attachment A to the Settlement Agreement. The Settlement Agreement, resolves all issues in dispute in Docket No. ER05-751.

By order issued on June 22, 2005, as revised by Order issued September 2, 2005, this matter was scheduled for hearing to begin January 31, 2006. This case is pending before Judge Harfeld. AEP requests that this filing be forwarded to Judge Harfeld for certification to the Commission. AEP further requests that, upon certification, the Commission act on this filing promptly. Prompt acceptance of the Settlement Agreement will allow the rates, as provided for in the Settlement Agreement, to go into effect as scheduled on November 1, 2005.

AEP submits the following documents as part of this settlement filing:

1. the Explanatory Statement;
2. the Settlement Agreement;
3. Attachment A to the Settlement Agreement listing the Parties to the Settlement;

[1] Appalachian Power Company, Columbus Southern Power Company, Indiana Michigan Power Company, Kentucky Power Company, Kingsport Power Company, Ohio Power Company, and Wheeling Power Company.

4. Attachment B to the Settlement Agreement, revised tariff pages (clean version);
5. Attachment C to the Settlement Agreement, revised tariff pages (redline version);
6. A draft Commission letter order accepting the Settlement in paper and electronic form (diskette, Microsoft Word format);
7. A Motion to Put the Tariff Changes into Effect on an Expedited Basis; and
8. Certificate of Service.

AEP has served copies of this filing on all Parties and advises parties that, pursuant to Rule 602(d)(2), comments on the Settlement Agreement will be due on or before November 28, 2005, and reply comments will be due on or before December 8, 2005.

Respectfully submitted,

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Attorneys for
American Electric Power Service Corporation

Enclosures

cc: The Honorable David I. Harfeld
Parties

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

American Electric Power Service Corporation) Docket No. ER05-751-000

EXPLANATORY STATEMENT
IN SUPPORT OF SETTLEMENT AGREEMENT

Pursuant to Rule 602 of the Commission's Rules of Practice and Procedure, 18 CFR § 385.602, American Electric Power Service Corporation ("AEP"), on behalf of certain operating companies of the American Electric Power System[2] and certain Parties in these proceedings (together, "Parties to the Settlement"), hereby submits this Explanatory Statement in support of the concurrently filed Settlement Agreement which is intended to resolve all issues in this proceeding.[3]

I. INTRODUCTION

The Settlement arises from settlement discussions held over a matter of months in the above-referenced docket relating to AEP's March 31, 2005 filing to increase its transmission rates. In that filing, AEP explained that, with the Commission's determination in Docket No. EL02-111-000, *et. al.*, to eliminate out and through rates for transactions that sink in the combined PJM Interconnection, L.L.C. ("PJM")/ Midwest Independent Transmission System Operator, Inc. footprint, AEP would, correspondingly lose revenues.

[1]Appalachian Power Company, Columbus Southern Power Company, Indiana Michigan Power Company, Kentucky Power Company, Kingsport Power Company, Ohio Power Company, and Wheeling Power Company.
[2] The Parties to the Settlement include AEP, Blue Ridge Power Association, Old Dominion Electric Cooperative, AEP Intervenor Group, Buckeye Power, Inc., Ormet Primary Aluminum Corporation, American Municipal Power-Ohio, Inc., Wabash Valley Power Association, Inc., Indiana Municipal Power Agency, City of Dowagiac, Michigan, and City of Sturgis, Michigan.

Although the Commission has adopted, subject to hearing, a transitional mechanism termed a Seams Elimination Cost Assignment ("SECA") charge that is intended to replace out and through revenues while it applies, that charge will be collected only through April 1, 2006. Due to the temporary nature of the SECA, as well as other matters pending before the Commission, AEP elected to propose adjustments to its rates and zonal rate design prior to the elimination of the SECA, so that its overall revenue requirement is current. Consequently, AEP filed a transmission cost-of-service analysis in support of its East Zone revenue requirement based on both a historic and projected test year. AEP requested an effective date of June 1, 2005 for its new rate structure.

On May 31, 2005, the Commission accepted the proposed tariff revisions, suspended their effectiveness until November 1, 2005, when they would be allowed into effect subject to refund, and set the proposed revisions for hearing. *American Electric Power Service Corp.*, 111 FERC ¶ 61,305 (2005). On June 9, 2005, the Chief Judge appointed the Honorable David I. Harfeld as presiding Administrative Law Judge in this case. After a June 21, 2005, pre-hearing conference, Judge Harfeld issued a procedural schedule that set this matter for hearing to begin January 24, 2006. By agreement of the Parties, settlement conferences were held on July 26, 2005, and August 23, 2005, and continued through several conference calls held during August, September and October. By order issued September 13, 2005, the Chief Judge suspended the procedural schedule pending finalization of settlement documents to be filed with the Commission.

II. SUMMARY OF SETTLEMENT

The Settlement provides a phased approach to increasing AEP's East Zone transmission rates. The rate increases reflect the impact on AEP's rates as a result of the elimination of the SECA on AEP's rates, among other things. In addition to defining the rates applicable to each phase of the increase, the Settlement resolves all issues associated with the new rates and the manner in which they will be applied.

Article I sets out the procedural history of the proceedings and the efforts of the Parties and FERC Trial Staff to reach a settlement.

Articles II and III set out the scope of the Settlement and the rate-related terms of the Settlement. The Settlement provides a three-phase approach to increasing AEP's East Zone transmission rates. The Phase 1 rate treatment provided for in the Settlement Agreement reflects rates that would be effective beginning November 1, 2005 through March 31, 2006, corresponding to the duration of the SECA charges and revenues. The Settlement Agreement provides for a stated unit rate of $1,081.06/MW-month for the rates for Firm Network and Point-to-Point Transmission Service in Phase 1. The on-peak and off-peak rates for hourly non-firm point-to-point service will be up to the rate for firm daily on-peak/16 and firm daily off-peak/24, respectively.

Phase 2 rates go into effect April 1, 2006. The Settlement Agreement provides for a stated unit rate of $1,621.40/MW-month for the rates for Firm Network and Point-to-Point Transmission Service on Phase 2. The on-peak and off-peak rates for hourly Non-Firm Point-to-Point Service will be calculated on the same basis as for the Phase 1 rates.

The Phase 3 rates reflect the addition of AEP's Wyoming-Jackson's Ferry line that is expected to go in service in mid-2006. The Settlement Agreement provides for a stated unit rate of $1,757.40/MW-month for the rates for Firm Network and Point-to-Point Transmission Service under Phase 3. The on-peak and off-peak rates for hourly Non-Firm Point-to-Point Service will also be calculated on the same basis as the Phase 1 rates.

The billings for the Phase 1, Phase 2 and Phase 3 rates are subject to adjustments to reduce costs. Bills will be adjusted to reflect any credits and/or charges allocated to the AEP Zone through post-SECA and intra-PJM rate design proceedings, including the proceedings currently underway in Docket No. EL05-121. The bills will also be adjusted to reflect revenue credits allocated by PJM to the AEP Zone for revenues from Point-to-Point Transmission Service with a point of delivery in the AEP Zone or at the PJM border, consistent with the pro forma PJM tariff sheets contained in AEP's application in this matter. Finally, the bills will be adjusted to reflect any credits and/or charges allocated to the AEP Zone by PJM or others through the implementation of PJM's Schedule 12, including application of Schedule 12 to the Wyoming-Jackson's Ferry facilities.

The Settlement Agreement provides that AEP will not make a rate filing for a new East Zone transmission service rate that will go into effect before one-year from the start of the Phase 3 rates or January 1, 2008, whichever is earlier. This moratorium will not preclude the collection of the costs of new transmission facilities developed as part of PJM's Regional Transmission Expansion Planning Protocol that are located outside the AEP zone and assigned to the AEP zone by the PJM Schedule 12 process, or the crediting elements listed above.

Under the terms of the Settlement Agreement, there will be an increase in the annual and monthly revenue requirement for AEP's generators contained in PJM's Ancillary Service Schedule 2 (Reactive Supply and Voltage Control from Generation Sources Service) reflecting a revenue requirement of $24,633,299. The Settlement Agreement also provides that, at the appropriate time, the Schedule 2 revenue requirement may be increased by $1,457,831.81 to reflect AEP's acquisition of the Twelvepole Creek facility.[4] Other than that increase, the Schedule 2 revenue requirement is subject to the same moratorium condition as the East Zone transmission rate. In addition, the rate for Ancillary Service Schedule 1 (Scheduling, System Control and Dispatch) will be $0.0686/MWh, reflecting a decrease in that rate. Finally, the recovery of regional transmission organization start-up costs will be separately billed to recover from ratepayers $2,362,185 per year through approximately May 2015.

In addition to defining the rates applicable to each phase of the increase, Article III provides for the net revenue requirement (after deducting for RTO start-up costs) for the Phase 1 and Phase 3 rates; provides for AEP to make the necessary tariff changes to effectuate the Settlement Agreement and otherwise resolves all issues associated with the new rates and the manner in which they will be applied.

The remaining articles (Articles IV, V, and VI) address procedural aspects of the Settlement including implementation, non-severability, rights reserved, waiver and amendment, and the scope of review. Specifically, the standard of review for modifications to the Settlement Agreement proposed by any Party to the Settlement after it is approved by the Commission will be the *Mobile-Sierra* public interest standard. The standard of review for modifications to the Settlement Agreement proposed by any non-Party to the Settlement and the Commission, after it is approved by the Commission, will be the most stringent standard permitted by law. Depending upon the outcome of appeals now pending before the United States Courts of Appeals for the District of Columbia Circuit and Ninth Circuit, that standard may be the *Mobile-Sierra* standard or the just and reasonable

[4] The tariff sheets included as part of the settlement documents reflect changes to Schedule 2 that are not directly related to the instant settlement but which are instead reflective of changes PJM made recently in an unrelated docket. The tariff sheets relevant to this docket have been superimposed on top of those sheets.

standard.

III. RESPONSE TO REQUIRED QUESTIONS

By order dated October 23, 2003, the Chief Administrative Law Judge requires that five questions be answered as part of every Explanatory Statement submitted in support of a proposed settlement. The questions, and specific responses applicable to this Settlement Agreement are as follows:

1. What are the issues underlying the settlement and what are the major implications?

The issue raised in this proceeding that underlies the Settlement Agreement is: What should be the appropriate rates and revenue requirement for transmission billings on AEP's transmission system commencing November 1, 2005, under the provisions of the PJM Open Access Transmission Tariff. There are no major implications arising from this underlying issue.

2. Whether any of the issues raise policy implications?

The resolution of the underlying issue does not raise any policy implications.

3. Whether other pending cases may be affected?

The Settlement Agreement addresses the specific transmission service rates at issue in this proceeding. Therefore, no other pending cases are affected by the Settlement Agreement.

4. Whether the settlement involves issues of first impression, or if there are any previous reversals on the issues involved?

There are no issues of first impression presented in this proceeding or resolved by the Settlement Agreement. There are no previous reversals with respect to the transmission rates at issue in this proceeding.

5. **Whether the proceeding is subject to the just and reasonable standard or whether there is Mobile-Sierra language making it the standard, i.e., the applicable standards of review?**

This proceeding on AEP's rate filing is subject to the just and reasonable standard. Section 6.7 of the Settlement Agreement contains language that applies the *Mobile-Sierra* public interest standard of review to the Parties to the Settlement as to any modifications they may propose to the Settlement Agreement after it is approved by the Commission.

IV. CONCLUSION

As discussed above, the attached Settlement Agreement resolves all issues in the captioned proceeding and the Parties to the Settlement urge the Commission to accept the Settlement Agreement without condition or modification. The Parties to the Settlement in this proceeding have authorized counsel for AEP to make this filing on their behalf.

Respectfully submitted,

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Sandra K. Williams
American Electric Power
Service Corporation
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Telephone: (614) 716-1617
FAX: (614) 716-2950
Attorneys for
American Electric Power Service Corporation

Dated November 7, 2005

CERTIFICATE OF SERVICE

I certify that a copy of the foregoing Settlement Filing filed by American Electric Power Service Corporation was served upon the parties to this proceeding this 7th day of November 2005.

Sandra K. Williams

In Reply Refer To:
American Electric Power Service Corporation
Docket No. ER05-751-000

Attn: Kevin F. Duffy
Sandra K. Williams
Counsel for American Electric Power Service Corporation
1 Riverside Plaza
Columbus, Ohio 43205

Dear Counsel:

On November 8, 2005, a Stipulation and Agreement in Docket No ER05-571-000 ("Settlement Agreement") was filed on behalf of American Electric Power Service Corporation ("AEP"), Ormet Primary Aluminum Corporation, American Municipal Power-Ohio, Inc., Wabash Valley Power Association, Inc., AEP Intervenor Group, Buckeye Power, Inc, The Blue Ridge Power Agency, Old Dominion Electric Cooperative, Indiana Municipal Power Agency and the Cities of Dowagiac and Sturgis, Michigan. The Settlement Agreement would resolve all of the issues between the AEP and the intervening parties in that proceeding.

Comments on the Settlement were filed by ____________. The Settlement Agreement is in the public interest and is hereby approved.

The Commission's approval of the Settlement Agreement does not constitute approval of, or precedent regarding, any principle or issue in this proceeding.

Magalie R. Salas
Secretary

cc: Public File
All Parties

Kentucky Power Company

REQUEST

Refer to the Bethel Testimony, pages 8 and 9 and the Application, Section V, Workpaper S-4, page 33 of 41.

a. Lines 17 through 23 on page 8 of the testimony describe the calculation of the estimated Network Integrated Transmission Service ("NTS") revenues shown in the workpaper. Is it correct that the NTS revenues are based on estimates of both the NTS rate that Mr. Bethel expects will be effective April 1, 2006, and the Network Service Peak Load ("NSPL") that will be used in 2006?

b. At what point in time will either the actual NTS rate or actual NSPL that will be in effect after the end of the suspension period in this case be known?

RESPONSE

a. It is correct, as stated in the referenced testimony, that the NTS revenues are based on an estimate of the NTS rate that Mr. Bethel expects will be effective April 1, 2006. That rate is now embodied in the Settlement Agreement provided in Response to Staff Request 22. The NSPL used in the revenue calculation is also estimated, as the testimony states, using the NSPL applicable to AEP Zone NTS load of load serving entities other than the AEP Companies during 2005.

b. The actual NSPLs that will be billed during 2006 were not then and are not yet known, but should be determined prior to PJM issuing NTS bills for service January 2006.

WITNESS: Dennis Bethel

Kentucky Power Company

REQUEST

Refer to the Bethel Testimony, pages 9 and 10. AEP has filed an appeal of the FERC decision to eliminate Through and Out ("T&O") transmission charges. FERC has also opened Docket No. EL05-121-000, in which AEP has filed a proposal to change the PJM transmission rate design. If AEP is successful in these matters, its incremental revenues would reduce its costs in the future. Given the uncertainty regarding both the outcome of these matters and the timing of that outcome, explain how Kentucky Power intends to protect its ratepayers from paying for costs that may be reduced if AEP succeeds.

RESPONSE

The uncertainty in these matters and the likely timing of such outcomes means that any adjustment in this case to offset the reduction in Kentucky Power revenues caused by the elimination of transmission charges for Through and Out transactions within the PJM/MISO region cannot now be known and measurable. Thus there is no basis for an adjustment in this case to assume that KPCo will receive revenues from a PJM regional rate design in reversal of the FERC's decision to eliminate T&O charges. However, if and when AEP is successful in these matters, any additional revenue that KPCO would receive would be reflected in future base rate case cost of service studies as a revenue credit to test year cost of service, thereby reducing retail rates. This would provide ratepayers with adequate future protection.

WITNESS: Dennis Bethel

Kentucky Power Company

REQUEST

Refer to the Bethel Testimony, page 10. Concerning the amortization of the PJM expansion expense, provide the monthly amortization expense for calendar year 2005 for Kentucky Power.

RESPONSE

The 2005 monthly amortization expense related to the PJM expansion expense is approximately $14,000 for Kentucky Power.

WITNESS: Dennis W Bethel

Kentucky Power Company

REQUEST

Refer to the Bethel Testimony, Exhibits DWB-1, DWB-2, and DWB-3.

a. Concerning Exhibit DWB-1, page 1 of 2, lines 1 through 10, provide the actual PTP revenue credits to AEP Zone for all months available after July 2005. In addition, provide a supplemental response to this request as soon as the actual PTP revenue credits to AEP Zone are available for the remainder of calendar year 2005.

b. Concerning Exhibit DWB-2, pages 1 and 2 of 2, provide the same information shown on this exhibit for the months of 2005 currently available. In addition, provide a supplemental response to this request as soon as the information is available for the remainder of calendar year 2005.

c. Concerning Exhibit DWB-3, pages 1 and 2 of 2, provide the same information shown on this exhibit for the months of 2005 currently available. In addition, provide a supplemental response to this request as soon as the information is available for the remainder of calendar year 2005.

RESPONSE

a. The estimated PTP revenue credits received by AEP from PJM are as follows:

August 2005	$695,660.45
September 2005	$540,385.94
October 2005	$578,426.44

b. The net ECRC revenue that has been booked for KPCo so far in 2005 is as follows:

July 2005	$3,033.88
August 2005	$1,489.66
September 2005	$ 644.12
October 2005	$ 933.88

c. The RTO Formation Charges and Revenues under the PJM Open Access Transmission Tariff for KPCo's portion of the RTO Start-up Cost Amortization booked to date in 2005 are as follows:

July 2005	$10,690
August 2005	$10,667
September 2005	$10,992
October 2005	$10,983

WITNESS: Dennis Bethel

Kentucky Power Company

REQUEST

Refer to the Direct Testimony of Robert W. Bradish ("Bradish Testimony") and RWB Exhibits 1 and 2. Kentucky Power's expense for "implicit" congestion costs for the 9 months ended June 30, 2005, was $4,597,608. The testimony states that the forecasted "implicit" congestion costs of $4,958,940 for 2006 are based on "an annualization of nine months of actual history ending June 30, 2005." The 2 exhibits do not reflect how this annualization was performed. Provide the supporting workpapers, including all assumptions and calculations, and a narrative explanation, which demonstrate how annualizing a 9-month expense of $4.6 million produces a 12-month amount of $4.96 million.

RESPONSE

Please see response to AG 1st Set, Item 64.

WITNESS: Robert Bradish

Kentucky Power Company

REQUEST

Refer to the Bradish Testimony, pages 7 through 9, and RWB Exhibits 1 and 2. Provide the supporting workpapers, including all assumptions and calculations, along with a narrative explanation, which show the derivation of the forecasted Financial Transmission Rights ("FTR") revenues of $7,961,292 for 2006.

RESPONSE

Please see response to AG 1st Set, Item 64.

WITNESS: Robert W Bradish

Kentucky Power Company

REQUEST

Refer to the Bradish Testimony, pages 10 and 11, and RWB Exhibit 3. Provide the supporting workpapers, including all assumptions and calculations, along with a narrative explanation, showing the derivation of the forecasted net congestion costs of ($3,002,352) for Kentucky Power for 2006.

RESPONSE

Please see response to AG 1st Set, Item 64. Net Congestion is calculated by subtracting the projected congestion costs from the projected FTR revenues.

WITNESS: Robert W Bradish

Kentucky Power Company

REQUEST

Refer to the Bradish Testimony, pages 10 through 12 and the Direct Testimony of David M. Roush ("Roush Testimony"), page 11, concerning the proposed cost recovery tracking mechanism for FTR revenues and "implicit" congestion costs.

a. Both witnesses refer to the tremendous volatility of these items and, based on that volatility, state that these items should not be included in base rates. Provide a thorough description of this volatility and a detailed explanation for why this degree of volatility occurs.

b. Page 12, lines 2 through 4, of the Bradish Testimony includes the proposal that, beginning in June 2007, the proposed tracking mechanism also include Auction Revenue Rights ("ARR"). Page 10 of the Bradish Testimony states that ARRs will take the place of FTRs beginning in June 2007. Based on this understanding, clarify whether the statement on lines 2 through 4 at page 12 of the testimony should state that "in June 2007, . . . ARR revenues be included in the mechanism in place of FTR revenues." Explain the response.

RESPONSE

a. Please refer to RWB Exhibit 1 for actual congestion costs and FTR revenues by month beginning in October 2004 through June 2005. As seen in this exhibit, monthly congestion costs range from $145,739 in March 2005 to $986,232 in January 2005 with an average value of $510,845. The wide swing in congestion costs can be attributed to a number of factors including fuel costs, load changes, transmission outages, and generation outages. Each of these factors can affect LMP values at the various nodal points.

b. In the first two full years after joining PJM, AEP is allocated FTRs directly based on peak load. Beginning in June 2007, this will change to a two-step process. Instead of being allocated FTRs directly, AEP will be allocated Auction Revenue Rights (ARRs) based on the company's peak load. AEP then may choose to either convert those ARRs into FTRs directly, or sell the ARRs to another party in an auction and collect the revenue from the sale. Since AEP can choose to do either, it could actually have revenue from both FTRs and ARRs. Therefore, the sentence is appropriate as it was written.

WITNESS: Robert W Bradish

Kentucky Power Company

REQUEST

Refer to the Bradish Testimony, pages 12 through 20 and RWB Exhibits 1, 3, and 4. The testimony indicates that the 2006 forecast amounts for operating reserves expenses, synchronous condensing service charges, reactive supply service charges, and blackstart service charges were all based on an annualization of 9 months of actual history for the period ending June 30, 2005. The exhibits do not reflect how this annualization was performed. Provide the supporting workpapers, including all assumptions and calculations, and narrative explanations, which demonstrate how annualizing the 9-month expenses for each of these items produces the 12-month amounts identified in the testimony.

RESPONSE

Please see response to AG 1st Set, Item 65.

WITNESS: Robert W Bradish

Kentucky Power Company

REQUEST

Refer to the Bradish Testimony, pages 20 through 25, and RWB Exhibit 5. Provide the supporting workpapers, including all assumptions and calculations, along with a narrative explanation, showing the derivation of the forecasted PJM administrative fees of $3,529,848 for Kentucky Power for 2006.

RESPONSE

Please see response to AG 1st Set, Item 71.

WITNESS: Robert W Bradish

Kentucky Power Company

REQUEST

Refer to the Bradish Testimony, RWB Exhibits 1 through 5. Provide versions of each exhibit showing the actual information for the months of 2005 currently available. Include all calculations, workpapers, and assumptions used to determine the 2005 actual amounts. In addition, provide a supplemental response to this request as soon as the information is available for the remainder of calendar year 2005.

RESPONSE

Please see pages 2 through 7 of this item. Please note on page 3 of this item, the calculated values for FTR revenues and congestion costs differ slightly from the actual amounts reported on page 2 of this item. This is due to the fact that the PJM bill is received after the accounting books have been closed for the month. Therefore, an estimate is provided each month for the PJM-related items. In the subsequent month, an adjustment is made to reconcile the difference between the estimated amount and the actual amount from the PJM bill.

WITNESS: Robert W Bradish

KPCo 2005 PJM Monthly (Revenues) / Expenses

2005 (Revenue) / Expense	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	2005 Total
PJM Implicit Congestion	$ 986,232	$ 474,176	$ 145,739	$ 299,854	$ 659,383	$ 714,526	$ 2,380,276	$ 1,643,685	$ 658,971	$ 2,036,827			$ 9,999,668
PJM FTR Revenue	$ (573,604)	$ (732,773)	$ 83,344	$ (347,233)	$ (501,351)	$ (1,496,781)	$ (3,608,806)	$ (2,985,666)	$ (2,945,415)	$ (2,444,200)			$(15,552,485)
PJM Operating Reserve	$ 134,619	$ 124,741	$ 130,580	$ 136,100	$ (11,875)	$ 376,082	$ 364,835	$ 338,041	$ 315,258	$ 387,155			$ 2,295,535
PJM Net Synchronous Condensing	$ 72,459	$ 21,475	$ 33,640	$ 10,266	$ 14,236	$ (11,160)	$ 55,746	$ 33,646	$ 51,706	$ 20,272			$ 302,286
PJM Net Reactive Supply	$ (5,263)	$ 38,197	$ 56,107	$ 18,193	$ 44,858	$ 41,239	$ 41,702	$ 41,200	$ 34,269	$ 50,268			$ 360,771
PJM Net Blackstart	$ 2	$ 2,881	$ 1,978	$ 1,249	$ (154)	$ 163	$ 458	$ 318	$ 210	$ 537			$ 7,643
PJM Administrative Fees	$ 260,773	$ 252,236	$ 311,050	$ 234,611	$ 228,439	$ 227,763	$ 242,235	$ 226,215	$ 199,205	$ 189,092			$ 2,371,618
Total KPCo PJM Test Year (Revenues) / Expenses	$ 875,219	$ 180,932	$ 762,437	$ 353,039	$ 433,537	$ (148,167)	$ (523,555)	$ (702,561)	$ (1,685,796)	$ 239,951			$ (214,964)

RWB Exhibit 1

KPCo Actual Monthly 2005 Net Congestion Costs

2005 (Revenue) / Expense	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	2005 Total
FTR Revenue for 2005													
AEP FTR Revenues	$ (7,641,784)	$ (9,400,804)	$ 1,063,328	$ (4,430,120)	$ (6,396,412)	$ (19,096,468)	$ (47,209,701)	$ (39,766,389)	$ (39,681,154)	$ (32,927,386)			$ (205,486,891)
KPCo MLR	0.07537	0.07838	0.07838	0.07838	0.07838	0.07838	0.07647	0.07508	0.07423	0.07423			
KPCo FTR Revenues	$ (575,961)	$ (736,835)	$ 83,344	$ (347,233)	$ (501,351)	$ (1,496,781)	$ (3,610,126)	$ (2,985,660)	$ (2,945,532)	$ (2;444,200)	$ -	$ -	$ (15,560,335)
Implicit Congestion Costs for 2005													
AEP Implicit Congestion Costs	$ 13,112,246	$ 6,058,134	$ 1,859,422	$ 3,825,686	$ 8,412,602	$ 9,116,194	$ 31,166,973	$ 21,897,308	$ 8,986,262	$ 27,338,366			$ 131,773,194
KPCo MLR	0.07537	0.07838	0.07838	0.07838	0.07838	0.07838	0.07647	0.07508	0.07423	0.07423	-	-	
KPCo Implicit Congestion	$ 988,270	$ 474,837	$ 145,741	$ 299,857	$ 659,380	$ 714,527	$ 2,383,338	$ 1,644,050	$ 667,050	$ 2,029,327	$ -	$ -	$ 10,006,377
Net Congestion Costs													
AEP System	$ 5,470,462	$ (3,342,670)	$ 2,922,750	$ (604,434)	$ 2,016,190	$ (9,980,274)	$ (16,042,728)	$ (17,869,081)	$ (30,694,893)	$ (5,589,020)	$ -	$ -	$ (73,713,697)
KPCo Operating Company	$ 412,309	$ (261,998)	$ 229,085	$ (47,376)	$ 158,029	$ (782,254)	$ (1,226,788)	$ (1,341,610)	$ (2,278,482)	$ (414,873)	$ -	$ -	$ (5,553,958)

(1) AEP will be allocated Auction Revenue Rights beginning in June 2007.

KPCo Actual Monthly 2005 Net Other Costs or Revenues

2005 (Revenue) / Expense	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	2005 Total
PJM Operating Reserve	$ 134,619	$ 124,741	$ 130,580	$ 136,100	$ (11,875)	$ 376,082	$ 364,835	$ 338,041	$ 315,258	$ 387,155			$ 2,295,535
Total KPCo Net Other New Costs or Revenues	$ 134,619	$ 124,741	$ 130,580	$ 136,100	$ (11,875)	$ 376,082	$ 364,835	$ 338,041	$ 315,258	$ 387,155	$ -	$ -	$ 2,295,535

RWB Exhibit 3

KPCo Actual Monthly 2005 Net Ancillary Services

2005 (Revenue) / Expense	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	2005 Total
PJM Net Synchronous Condensing	$ 72,459	$ 21,475	$ 33,640	$ 10,266	$ 14,236	$ (11,160)	$ 55,746	$ 33,646	$ 51,706	$ 20,272			$ 302,286
PJM Net Reactive Supply	$ (5,263)	$ 38,197	$ 56,107	$ 18,193	$ 44,858	$ 41,239	$ 41,702	$ 41,200	$ 34,269	$ 50,268			$ 360,771
PJM Net Blackstart	$ 2	$ 2,881	$ 1,978	$ 1,249	$ (154)	$ 163	$ 458	$ 318	$ 210	$ 537			$ 7,643
Total KPCo Net Ancillary Services	$ 67,198	$ 62,552	$ 91,725	$ 29,708	$ 58,941	$ 30,243	$ 97,907	$ 75,165	$ 86,184	$ 71,077	$ -	$ -	$ 670,699

RWB Exhibit 4

KPCo Actual Monthly 2005 PJM Administrative Fees

2005 (Revenue) / Expense	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	2005 Total
PJM Administrative Fees	$ 260,773	$ 252,236	$ 311,050	$ 234,611	$ 228,439	$ 227,763	$ 242,235	$ 226,215	$ 199,205	$ 189,092			$ 2,371,617
Total KPCo PJM Administrative Fees	$ 260,773	$ 252,236	$ 311,050	$ 234,611	$ 228,439	$ 227,763	$ 242,235	$ 226,215	$ 199,205	$ 189,092	$ -	$ -	$ 2,371,617

RWB Exhibit 5

Kentucky Power Company
October 2004 - October 2005
(Revenue) / Expense

		2004			2005										
	Acct	10	11	12	1	2	3	4	5	6	7	8	9	10	Grand Total
PJM Implicit Congestion-LSE	4470093	$ 260,683	$ 167,192	$ 889,823	$ 986,232	$ 474,176	$ 145,739	$ 299,854	$ 659,383	$ 714,526	$ 2,380,276	$ 1,643,685	$ 658,971	$ 2,036,827	$ 11,317,367
PJM FTR Revenue-LSE	4470101	$ (59,238)	$(177,232)	$(483,005)	$(573,604)	$(732,773)	$ 83,344	$ (347,233)	$ (501,351)	$(1,496,781)	$(3,608,806)	$ (2,985,666)	$(2,945,415)	$(2,444,200)	$(16,271,961)
PJM Oper.Reserve Rev-LSE	4470108		$(123,076)	$ 229,951	$ 134,619	$ 124,741	$ 130,580	$ 136,100	$ (11,875)	$ 376,082	$ 364,835	$ 338,041	$ 315,258	$ 387,155	$ 2,402,411
PJM Ancillary Serv.-Sync	5550041			$ 118,434	$ 72,459	$ 21,475	$ 33,640	$ 10,266	$ 14,236	$ (11,160)	$ 55,746	$ 33,646	$ 51,706	$ 20,272	$ 420,720
PJM OATT Ancill.-Reactive	5550042			$ 36,929	$ (5,263)	$ 38,197	$ 56,107	$ 18,193	$ 44,858	$ 41,239	$ 41,702	$ 41,200	$ 34,269	$ 50,268	$ 397,699
PJM OATT Ancill. - Black	5550043			$ 1,308	$ 2	$ 2,881	$ 1,978	$ 1,249	$ (154)	$ 163	$ 458	$ 318	$ 210	$ 537	$ 8,950
PJM Admin.Services-LSE	5560003	$ 225,924	$ 230,904	$ 243,851	$ 260,773	$ 252,236	$ 311,050	$ 234,611	$ 228,439	$ 227,763	$ 242,235	$ 226,215	$ 199,205	$ 189,092	$ 3,072,296

		2005										
	Acct	1	2	3	4	5	6	7	8	9	10	Grand Total
PJM Implicit Congestion-LSE	4470093	$ 986,232	$ 474,176	$ 145,739	$ 299,854	$ 659,383	$ 714,526	$ 2,380,276	$ 1,643,685	$ 658,971	$ 2,036,827	$ 9,999,668
PJM FTR Revenue-LSE	4470101	$(573,604)	$(732,773)	$ 83,344	$(347,233)	$(501,351)	$(1,496,781)	$(3,608,806)	$(2,985,666)	$(2,945,415)	$(2,444,200)	$(15,552,485)
PJM Oper.Reserve Rev-LSE	4470108	$ 134,619	$ 124,741	$ 130,580	$ 136,100	$ (11,875)	$ 376,082	$ 364,835	$ 338,041	$ 315,258	$ 387,155	$ 2,295,535
PJM Ancillary Serv.-Sync	5550041	$ 72,459	$ 21,475	$ 33,640	$ 10,266	$ 14,236	$ (11,160)	$ 55,746	$ 33,646	$ 51,706	$ 20,272	$ 302,286
PJM OATT Ancill.-Reactive	5550042	$ (5,263)	$ 38,197	$ 56,107	$ 18,193	$ 44,858	$ 41,239	$ 41,702	$ 41,200	$ 34,269	$ 50,268	$ 360,771
PJM OATT Ancill. - Black	5550043	$ 2	$ 2,881	$ 1,978	$ 1,249	$ (154)	$ 163	$ 458	$ 318	$ 210	$ 537	$ 7,643
PJM Admin.Services-LSE	5560003	$ 260,773	$ 252,236	$ 311,050	$ 234,611	$ 228,439	$ 227,763	$ 242,235	$ 226,215	$ 199,205	$ 189,092	$ 2,371,617

Kentucky Power Company

REQUEST

Refer to the Direct Testimony of James E. Henderson ("Henderson Testimony"), pages 6 and 7.

a. The determination of the average service lives for the Production Plant did not use the same approach as was used for the Transmission, Distribution, and General Plant. Explain in detail why the same approach was not used for all types of utility plant.

b. Explain in detail why the probable demolition cost for the Big Sandy Plant was included in the depreciation rates proposed for the Production Plant.

c. Is the inclusion of probable demolition cost for a utility plant normally included in depreciation rates? Explain the response in detail.

RESPONSE

a. The life span forecast was used for Production Plant because this plant is located at a specific location and the surviving balance will be retired, in total, at a future date. This compares to Transmssion, Distribution and General Plant that will experience continuous retirements but it is envisioned that those systems will continue to operate. Please refer to Exhibit JEH-1, pages 2 and 3 for a discussion of the life span forecast method.

b. The probable demolition cost for the Big Sandy Plant was included in the depreciation rates because it ensures that the generation of customers using the Plant will also pay for the costs of its future demolition.

c. Expected demolition of facilities such as Steam Production Plants are usually included in depreciation rates in order to provide for recovery of the future demolition costs from the generation of customers using the Plant. These costs were included in the Company's current depreciation rates approved by the Kentucky Commission in Case No. 91-066.

WITNESS: James E Henderson

Kentucky Power Company

REQUEST

Refer to the Henderson Testimony, Exhibit JEH-1, page iii. Mr. Henderson is recommending that Kentucky Power adopt and apply the depreciation accrual rates at the primary plant account level and the accumulated depreciation be established by the primary plant account as of a specific date. Kentucky Power currently applies depreciation rates and maintains the accumulated depreciation by functional plant classification.

a. Explain why Kentucky Power has not used the primary plant account level prior to the filing of this case.

b. Provide the name of each operating company within the total AEP system, and indicate whether it follows the primary plant account level or functional plant classification. To the extent Mr. Henderson knows, which approach is more commonly followed in the investor-owned electric industry today: primary plant account level or functional plant classification?

RESPONSE

a. Kentucky Power has not used depreciation rates at the primary account level because the rates approved in KP's last Case No. 91-066 were approved at the functional plant level.

b. Appalachian Power Co. Applies rates by account. Maintains reserve at functional level.
Columbus Southern Power Applies rates and maintains reserve by account.
Indiana Michigan Power Applies rates by account. Maintains reserve at functional level.
Kingsport Power Applies rates and maintains reserve at functional level
Ohio Power - Applies rates by account. Maintains reserve at functional level.
Wheeling Power - Applies rates and maintains reserve at functional level.
AEP Texas Central - Applies rates and maintains reserve by account.
AEP Texas North - Applies rates by account. Maintains reserve at functional level.
Public Service Company of Oklahoma - Applies rates by account. Maintains reserve at functional plant level.
SWEPCO - Applies rates by account. Maintains reserve at functional level.

Based on Mr. Henderson's conversations with Depreciation Consultants and other investor utilities, the mix is similar to the AEP System Companies, but the trend is to apply depreciation rates and maintain reserves at the plant account level.

WITNESS: James E Henderson

KENTUCKY POWER COMPANY
American Electric Power
SECOND DATA REQUESTS OF COMMISSION STAFF
Case No. 2005-00341

Item No. 36

Refer to the Direct Testimony of Paul R. Moul ("Moul Testimony"), page 3, and Exhibit No. PRM-1, Schedule 3, page 2.

a. Provide the *Value Line Investment Survey* ("*Value Line*") pages for each of the companies in the electric proxy group ("Electric Group").

b. Several companies in the Electric Group - Ameren Corp., DTE Energy Co., Exelon Corp., MGE Energy Inc., Vectren Corp., WPS Resources, and Wisconsin Energy - have both gas and electric operations. Kentucky Power has no gas operations. Explain why it is appropriate to compare Kentucky Power to the Electric Group that contains combination companies.

c. WPS Resources' 2004 revenues, as reported in *Value Line*, show that only 17 percent were generated from electric operations. Provide the threshold that Kentucky Power used to determine which companies would be included in the Electric Group.

d. Exelon Corp., one of the companies in the Electric Group, is in the process of obtaining regulatory approval for and completing a merger with Public Service Enterprises. Explain why Exelon Corp. should be included in the Electric Group.

Response

a. The Value Line reports dated April 1 and June 3, 2005 for Electric Group are attached.

b. Each of the companies that are included in the Electric Group are classified as electric companies according to Value Line. Further, with the convergence of energy utilities in recent years, both electric companies and gas distribution companies have displayed similar risk characteristics. As such, there is presently no basis to distinguish the rate of return for a combination electric and gas utility from an electric utility alone.

c. No threshold was employed. All candidates characterized as electric companies by Value Line were included.

Witness: Paul R. Moul

KENTUCKY POWER COMPANY
American Electric Power
SECOND DATA REQUESTS OF COMMISSION STAFF
Case No. 2005-00341

d. Exelon is the acquiring company in the proposed acquisition of Public Service Enterprise Group. In a business combination, there is usually an acquiring company involved. In the selection process, it is the target company of an acquisition or merger, which would be eliminated from consideration. Exelon would be the acquiring company as it will issue 1.225 common shares of its stock for each common share of PSEG. Hence, PSEG would be eliminated from consideration, while Exelon would be considered. The reason for this treatment rests with the fact that once an offer has been made and accepted by the target company, its stock begins to trade on the basis of the transaction price being offered by the acquiring company. That price usually involves a premium that is offered in order to obtain control of the target company and to induce existing stockholders to participate in the sale of their shares. At that point, the stock price disconnects from the earnings forecasts made by securities' analysts when the target company operated independently. When a company is the target of an acquisition, a more defined number of cash flows are reflected in the stock price with particular emphasis being placed on the acquisition price (i.e., the liquidating dividend) of the stock. That is to say, the target company's stock price is the product primarily of the buy-out price of the stock. As such, the long-term horizon of future dividend payments ceases to be the focus of investors. Rather, the acquisition price becomes the paramount consideration in the current stock price along with dividend payments that will occur up to the time the company is acquired and its stock no longer trades.