APPENDIX

TABLE I

Line Clearance Guidelines

These growth rates and clearance distances are guidelines for the minimum clearances required. These distances are not static and should serve as ***minimum clearance*** requirements. The total clearance requirements on the transmission system are these distances *plus* the OSHA minimum approach distance from energized conductors as required by voltage for qualified line clearance tree arborists. Good soils and high moisture may cause many species to grow faster. These clearance guidelines are not meant as a requirement for all trees on AEP's rights-of-way. It is understood that during maintenance intervals, trees may encroach into these minimum clearance zones. The guidelines are meant to be used a guide for trimming those trees currently being maintained.

MINIMUM CLEARANCE FROM CONDUCTORS

– ***Species with Fast Regrowth Rates: Prune*** for a *minimum* clearance of 20 feet from conductors

Cottonwood	Willow
Poplar species	Ailanthus
Silver maple	Box Elder

– ***Species with Medium Regrowth Rates:*** Prune for a *minimum* clearance of 15 feet from conductors

Locust	Hackberry
Red maple species	Hickory
Ornamental pear species	Crabapple
Fruit trees (apple, pear, etc.)	Red oak
Elm species	Ash species
Pine, Spruce & Hemlock species	Mulberry
Sweet gum	Sycamore
Bois d'arc (Osage orange, hedge tree)	

– ***Species with Slow Regrowth Rates:*** Prune for a *minimum* clearance of 10 feet from conductors

Catalpa	Cedar
Chinaberry	Persimmon
Magnolia	White oak (round lobes)
Any small variety species (Redbud, dogwood, etc.)	

– ***Possible Exceptions:***
- When the entire trunk of a tree falls within the minimum clearance specifications.
- When due to the branching structure of the tree less trimming would lend itself to an overall healthier tree, yet with acceptable clearance.
- Isolated instances approved by AEP System Forestry representative.

Kentucky Power Company

REQUEST

Refer to page 4 lines 1-6 of Mr. Phillips' Testimony. Please provide a redlined copy of the Company's T&D Vegetation Management Program incorporating the changes to the program proposed by the Company.

RESPONSE

The proposed program changes the timing by which maintenance is performed, not the methods used to perform the maintenance, which are delineated in the guidelines provided in response to question #53. As described in Phillips Testimony page 4 the Company currently uses a Performance Based approach to planning vegetation maintenance and proposes migration to a cyclic approach (Phillips Testimony page 9, lines 1-7).

Performance Based Management is driven by service reliability and differs from a formal cyclic approach through its reliance on reliability data, line inspections and customer complaints as primary inputs into the work plan. A cyclic approach relies primarily on time elapsed since previously maintained, with lesser regard for reliability trends and the other primary inputs of a performance based program.

Given the necessary funding requested in this application, a cyclic approach will be implemented over a four-year period. During this period end-to-end tree trimming, tree removals and widening of ROW where possible for all of KPCo's T&D circuits will take place.

WITNESS: Everett G Phillips

Kentucky Power Company

REQUEST

Refer to page 9 line 14 through page 10 line 2 of Mr. Phillips' Testimony. Please provide studies and related cost estimates for the three year cycle proposed by the Company and for any shorter or longer cycles considered by the Company.

RESPONSE

KPCo plans to migrate to a cycle based vegetation management program over a 4 year period. Phillips Testimony Tables 2 (Total Vegetation Management O&M and Capital Summary) and 5 (Vegetation Management Incremental O&M and Capital Summary) summarize the first 3 years of funding. "A three-year period was used to coincide with KPCo's rate case cycle expectation." (Phillips Testimony page 10 lines 7-8).

Per Phillips Testimony page 10 lines 2-5
"The estimates (of both O&M and Capital) were based on actual line mile tree-trimming clearing expenses, which include base tree trimming work, herbicide application, and incremental tree trimming crews to perform end-to-end clearance, administrative oversight, and follow-up trimming for fast growing vegetation between cycles"

Specific calculations may be found in the attached pages.

WITNESS: Everett G Phillips

Total Cost to Achieve a T & D Cycle Approach				
Total Program Cost	Year	($Million)		
		O&M	Capital	Total
$74,050,988	First	$12.30	$5.40	$17.70
	Second	$12.67	$5.56	$18.23
	Third	$13.05	$5.72	$18.78
	Fourth	$13.45	$5.90	$19.34
	Fifth	$0.00	$0.00	$0.00

Estimated Annual Average Cost to Achieve a T & D Cycle Approach ($ Millions)						
	Distribution		Transmission		Total	
	O&M	Capital	O&M	Capital	O&M	Capital
Average	$11.56	$5.20	$1.31	$0.44	$12.87	$5.64

Estimated Incremental O&M and Capital Cost Summary ($ Millions)						
Year	**Distribution**		**Transmission**		**Total**	
	O&M	Capital	O&M	Capital	O&M	Capital
First	$5.33	$3.18	$0.42	$0.42	$5.75	$3.60
Second	$5.66	$3.33	$0.46	$0.44	$6.12	$3.76
Third	$6.00	$3.48	$0.50	$0.45	$6.50	$3.93
Fourth	$6.36	$3.64	$0.54	$0.46	$6.89	$4.10
Fifth	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00

Kentucky Test Year O&M and Capital Cost Summary ($ Millions) ($ Millions)						
Year	**Distribution**		**Transmission**		**Total**	
	O&M	Capital	O&M	Capital	O&M	Capital
First	$5.72	$1.33	$0.83	$0.00	$6.55	$1.33
Second	$5.72	$1.33	$0.83	$0.00	$6.55	$1.33
Third	$5.72	$1.33	$0.83	$0.00	$6.55	$1.33
Fourth	$5.72	$1.33	$0.83	$0.00	$6.55	$1.33
Fifth	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00

Estimated Annual Cost to Achieve a Five Year Distribution Cycle Approach				
		($Million)		
Total Program Cost	Year	O&M	Capital	Total
67,035,765	First	$11.05	$4.97	$16.02
	Second	$11.38	$5.12	$16.50
	Third	$11.72	$5.28	$17.00
	Fourth	$12.08	$5.43	$17.51
	Fifth	$0.00	$0.00	$0.00

Direct $'s

Test Year	Capital	O&M
2004 - Q3	$275,851	$1,230,537
2004 - Q4	$454,976	$1,819,244
2005 - Q1	$305,063	$1,129,045
2005 - Q2	$292,694	$1,541,366
Test Year Total	$1,328,584	$5,720,192

Step 1 - Unloaded Cost to Achieve

Category	Line Miles	Cost Per Line Mile or Per Year	Cost
4kV to 34.5 kV Trimming & Reclearing	9,546	$5,200	$49,639,200
Herbicide for newly cut r/w (avg 20% of total miles)	1,909	$250	$477,300
Inspections	N/A	$205,000	$820,000
Repetitive Trimming & Herbicide	N/A	$2,000,000	$8,000,000
		Unloaded Total Cost	**$58,936,500**
Years to Implement	**4**		

Step 2 -Adding Inflation Factor

		Inflation Cost	Total Cost Per Year
Plan's Per Year Total Cost	$14,734,125		
Inflation Factor	0.03		
	First Year	N/A	$14,734,125
	Second Year	$442,024	$15,176,149
	Third Year	$455,284	$15,631,433
	Fourth Year	$468,943	$16,100,376
	Fifth Year	$0	$0

Step 3-Determine Loaded Cost To Achieve: O&M and Capital Split (w/35% loadings)

Total Cost Per Year	O&M	Capital Split	Load Capital	Adjusted Total Cost Per Year
	0.75	0.25	0.35	
$14,734,125	$11,050,594	$3,683,531	$4,972,767	$16,023,361
$15,176,149	$11,382,112	$3,794,037	$5,121,950	$16,504,062
$15,631,433	$11,723,575	$3,907,858	$5,275,609	$16,999,184
$16,100,376	$12,075,282	$4,025,094	$5,433,877	$17,509,159
$0	$0	$0	$0	$0
Loaded Cost To Achieve	**$46,231,562**	**$15,410,521**	**$20,804,203**	**$67,035,765**

Step 4 - Determine Base Year

Category	O&M	Capital	Load Capital	Total Test Year
Test Year - (7/1/04-6/30/05)	$5,720,192	$1,328,584	$1,793,588	$7,513,780

Step 5-Determining O&M and Capital Split of Incremental Portion

Year	O&M	Capital	Load Capital	Total Incremental
First	$5,330,402	$2,354,947	$3,179,179	$10,864,528
Second	$5,661,920	$2,465,453	$3,328,362	$11,455,735
Third	$6,003,383	$2,579,274	$3,482,020	$12,064,678
Fourth	$6,355,090	$2,696,510	$3,640,289	$12,691,889
Fifth	$0	$0	$0	$0
Loaded Incremental Cost To Achieve	**$23,350,794**	**$10,096,185**	**$13,629,849**	**$47,076,829**

Step 6 - Total Cost to Maintain

	Line Miles	Cost Per Line Mile	Total Cost
4kV to 34.5 kV	9,546	$3,200	$30,547,200
		Total Cost	$30,547,200

Based on a 4 year approach

Average Line Miles Per Year	Line Mile Per Year	Total Cost
2386.5	$3,200	$7,636,800

Estimated Annual Cost to Achieve a Five Year Transmission Cycle Approach				
		($Million)		
Total Program Cost	Year	O&M	Capital	Total
7,015,223	First	$1.25	$0.42	$1.68
	Second	$1.29	$0.44	$1.73
	Third	$1.33	$0.45	$1.78
	Fourth	$1.37	$0.46	$1.83
	Fifth	$0.00	$0.00	$0.00

	Direct $'s	
Test Year	Capital	O&M
2004 - Q3		$375,628
2004 - Q4		$44,409
2005 - Q1		$96,771
2005 - Q2		$313,417
Test Year Total	$0	$830,225

2.440503	
2.513718	
2.58913	
2.666804	
10.21016	
0.82367	3.264173
0.84838	3.362098
0.873831	3.462961
0.900046	3.56685
3.445927	13.65608

Step 1 - Unloaded Cost to Achieve

Category	Line Miles	Cost Per Line Mile or Per Year	Cost
46kV and above	1,183	$5,000	$5,915,000
46 kV and below	3	$4,500	$13,500
Inspections	N/A	$85,004	$340,016
		Unloaded Total Cost	$6,268,516
Years to Implement	4		

Step 2 -Adding Inflation Factor

		Inflation Cost	Total Cost Per Year
Plan's Per Year Total Cost	$1,567,129		
Inflation Factor	0.03		
	First Year	N/A	$1,567,129
	Second Year	$47,013.87	$1,614,142.87
	Third Year	$48,424.29	$1,662,567.16
	Fourth Year	$49,877.01	$1,712,444.17
	Fifth Year	$0.00	$0.00

Step 3-Determine Loaded Cost To Achieve: O&M and Capital Split (w/35% loadings)

Total Cost Per Year	O&M	Capital Split	Load Capital	Adjusted Total Cost Per Year
	0.80	0.20	0.35	
$1,567,129	$1,253,703	$313,426	$423,124.83	$1,676,828
$1,614,143	$1,291,314	$322,829	$435,818.57	$1,727,133
$1,662,567	$1,330,054	$332,513	$448,893.13	$1,778,947
$1,712,444	$1,369,955	$342,489	$462,359.93	$1,832,315
$0	$0.00	$0.00	$0.00	$0.00
Loaded Cost To Achieve	$5,245,026.56	$1,311,256.64	$1,770,196.46	$7,015,223.02

Step 4 - Determine Base Year

Category	O&M	Capital
Test Year - (7/1/04-6/30/05)	$830,225	$0

Step 5-Determining O&M and Capital Split of Incremental Portion

Year	O&M	Capital	Load Capital (35%)	Total Incremental
First	$423,478	$313,426	$423,125	$846,603
Second	$461,089	$322,829	$435,819	$896,908
Third	$499,829	$332,513	$448,893	$948,722
Fourth	$539,730	$342,489	$462,360	$1,002,090
Fifth	$0	$0	$0	$0
Loaded Incremental Cost To Achieve	$1,924,127	$1,311,257	$1,770,196	$3,694,323

Step 6 - Total Cost to Maintain

	Line Miles	Cost Per Line Mile	Total Cost
46kV and above	1,183	$3,500	$4,140,500
46 kV and below	3	$3,200	$9,600
		Total Cost	$4,150,100

Based on a 4 year approach

Average Line Miles Per Year	Cost per Line Mile Per Year	Total Cost
295.75	$3,500	$1,035,125
0.75	$3,200	$2,400
		$1,037,525

Kentucky Power Company

REQUEST

Please provide a copy of all work papers in hard copy and in electronic spreadsheet format (with formulas intact) supporting the Company's net salvage percentages and ratios used to develop the proposed depreciation rates for each plant account.

RESPONSE

Please see response to Attorney General Question No. 105.

WITNESS: James E Henderson

Kentucky Power Company

REQUEST

Refer to page 8 of the depreciation study included as Exhibit JEH-1 to Mr. Henderson's Testimony. Please explain why the Company chose the 15-year period 1990-2004 to determine the net salvage percentages.

RESPONSE

In Mr. Henderson's judgment, the 15-year period is representative of the net salvage expected to be experienced by the Company over the next several years

WITNESS: James E Henderson

Kentucky Power Company

REQUEST

Refer to page 8 of the depreciation study included as Exhibit JEH-1 to Mr. Henderson's Testimony. Please describe the process and application of the decision criteria employed by the Company in using "judgment" to determine the gross salvage and cost of removal percentages for each account.

RESPONSE

Please refer to the response to Staff Question No. 83.

WITNESS: James E Henderson

Kentucky Power Company

REQUEST

Refer to page 9 of the depreciation study included as Exhibit JEH-1 to Mr. Henderson's Testimony. Please provide a copy of the conceptual demolition cost estimate prepared by the Brandenburg Industrial Service Company.

RESPONSE

Please refer to pages 21 through 53 of 443 in the Depreciation Study Workpapers.

WITNESS: James E Henderson

Kentucky Power Company

REQUEST

Refer to page 9 of the depreciation study included as Exhibit JEH-1 to Mr. Henderson's Testimony. Please provide all work papers, including electronic spreadsheets with formulas intact, that were used to convert the conceptual demolition cost estimate into the net salvage percentages and ratios used to develop the proposed Big Sandy production depreciation rates.

RESPONSE

Please refer to page 3 of 443 of the depreciation study workpapers and to the data provided in response to Attorney General Question No. 105.

WITNESS: James E Henderson

Kentucky Power Company

REQUEST

Refer to Schedule III of the depreciation study included as Exhibit JEH-1 to Mr. Henderson's Testimony. Please provide the same type of information in the same format for the Company's production plant.

RESPONSE

The data shown on Schedule III is not applicable to the Life Span Analysis. Iowa Curves were not used for Production Plant.

WITNESS: James E Henderson

Kentucky Power Company

REQUEST

Refer to Schedule l of the depreciation study included as Exhibit JEH-1 to Mr. Henderson's Testimony. Please confirm that the Company actually plans to retire Big Sandy l in 2015. Provide all support relied on for this assumption. If the Company does not actually plan to retire Big Sandy l in 2015, then please provide the Company's present projection of the retirement year and provide all support relied on for that assumption.

RESPONSE

2015 is the planed retirement date for Big Sandy Unit 1. Please refer to Page 2 of 443 of the depreciation study workpapers.

WITNESS: James E Henderson

Kentucky Power Company

REQUEST

Please identify all federal and/or state requirements that will require the Company to retire Big Sandy l in 2015, if any. If there are no legal mandates to retire Big Sandy l in 2015, then please so state.

RESPONSE

The Company is not aware of any current legal mandates to retire Big Sandy 1 in 2015.

WITNESS: James E Henderson

Kentucky Power Company

REQUEST

Refer to Schedule 1 of the depreciation study included as Exhibit JEH-1 to Mr. Henderson's Testimony. Please provide the computations in electronic format (with formulas intact) underlying the average remaining life by plant account for steam production plant.

RESPONSE

Please refer to the data provided in response to Attorney General Request No. 105.

WITNESS: James E Henderson

Kentucky Power Company

REQUEST

Refer to Schedule 1 of the depreciation study included as Exhibit JEH-1 to Mr. Henderson's Testimony. Please explain the basis for depreciating land rights, including, but not limited to, the basis for the determination of the average remaining life for these assets. If these land rights consist of easements, please confirm that they are perpetual and do not expire.

RESPONSE

The reason to depreciate land rights is that it provides a method to enable the Company to recover the investment in rights-of-way. The average remaining life is based on the age of the investment and the curve selected. Some of the rights-of-way do consist of perpetual easements. The Company's right to use the easements ceases when the property or equipment that occupies the easement is removed or abandoned.

WITNESS: James E Henderson

Kentucky Power Company

REQUEST

Refer to Schedule 1 of the depreciation study included as Exhibit JEH-1 to Mr. Henderson's Testimony. Please provide a list of each asset with an original costs at 12/31/04 of $100,000 or greater. For each of these assets, provide a description of the asset, provide a description of the purpose for which it is used, and identify its physical location.

RESPONSE

Kentucky Power does not maintain an itemized list of assets.

WITNESS: James E Henderson

Kentucky Power Company

REQUEST

For each asset on the list provided in response to the preceding question, provide the Company's work papers, including, but not limited to, electronic spreadsheets with formulas intact, for gross salvage percentages, gross cost of removal percentages, and net salvage percentages.

RESPONSE

The Company did not develop component depreciation rates.

WITNESS: James E Henderson

Kentucky Power Company

REQUEST

With regard to Mr. Bethel's testimony on page 5 at lines 1 through 15, please provide a copy of the FERC Opinion in Docket No. EL04-135-000 reference in the testimony

RESPONSE

The requested FERC Opinion in Docket No. EL04-135-000 is attached.

WITNESS: Dennis W Bethel

109 FERC ¶ 61,168
UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

Before Commissioners: Pat Wood, III, Chairman;
Nora Mead Brownell, Joseph T. Kelliher,
and Suedeen G. Kelly.

Midwest Independent Transmission System Operator, Inc.	Docket No. ER05-6-000
Midwest Independent Transmission System Operator, Inc. PJM Interconnection, LLC., *et al.*	Docket No. EL04-135-000
Midwest Independent Transmission System Operator, Inc. PJM Interconnection, LLC., *et al.*	Docket Nos. EL02-111-010 EL02-111-011 EL02-111-014 EL02-111-015 EL02-111-016 EL02-111-019
Ameren Services Company, *et al.*	Docket Nos. EL03-212-005 EL03-212-006 EL03-212-007 EL03-212-009 EL03-212-011 EL03-212-013 EL03-212-014 EL03-212-016

ORDER ON TRANSMISSION RATE PROPOSALS

(Issued November 18, 2004)

1. In this order we institute a previously-announced new long-term transmission pricing structure, effective December 1, 2004, across the Midwest Independent Transmission System Operator, Inc., (Midwest ISO), and PJM Interconnection, L.L.C. (PJM) regions that eliminates rate pancaking for transmission service under the tariffs of

the two regional transmission organizations (RTOs) to serve load in their combined regions. This order benefits customers by eliminating seams that impede efficient transmission system usage across two highly interconnected regional grids.

I. Background

2. In earlier orders in this proceeding, the Commission ordered the elimination of regional through and out rates between the PJM and Midwest ISO regions effective April 1, 2004,[1] and also found unjust and unreasonable the through and out rates of individual public utilities that had not yet become members of PJM or the Midwest ISO effective April 1, 2004.[2] The Commission directed compliance filings to eliminate the through and out rates for new transactions, but allowed two-year transitional lost revenue recovery mechanisms, so-called Seams Elimination Charge/Cost Adjustments/Assignments (SECAs), to be put in place effective April 1, 2004.[3] On December 17, 2003, the Commission clarified that the through and out rates were eliminated for reservation requests made on or after November 17, 2003, for service commencing on or after April 1, 2004.[4]

3. Subsequently, the Commission provided time for the parties to participate in a stakeholder process to develop these transitional lost revenue recovery mechanisms. On February 6, 2004, noting that it had already allowed the parties additional time for a stakeholder process, the Commission established settlement judge procedures to further aid the parties in developing these transitional lost revenue recovery mechanisms.[5]

4. On February 4, 2004, the Chief Judge filed a report with the Commission on the parties' progress in the ongoing discussions, along with their agreement that the date for elimination of the through and out rates should be extended from April 1, 2004 to May 1,

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[1] Midwest Independent Transmission System Operator, Inc., *et al.*, 104 FERC ¶ 61,105, order on reh'g, 105 FERC ¶ 61,212 (2003), reh'g pending.

[2] *Ameren Services Company, et al.*, 105 FERC ¶ 61,216 (2003).

[3] *See supra* notes 1-2.

[4] *Midwest Independent Transmission System Operator, Inc., et al.*, 105 FERC ¶ 61,288 (2003).

[5] *Midwest Independent Transmission System Operator, Inc., et al.*, 106 FERC ¶ 61,105 (2004).

2004, (but with the two-year transition period continuing to run from April 1, 2004, *i.e.*, effectively shortening the transition period).[6] On February 6, 2004, the Commission accepted this agreement to extend the date for elimination of through and out rates to May 1, 2004, allowing the parties additional time to resolve matters consensually.[7]

5. On March 5, 2004, the Chief Judge filed a report and an agreement among the parties, noting that the parties had participated in fourteen full days of formal settlement negotiations (often involving over 100 participants), and that there had been numerous meetings involving individual participants or groups of participants. This resulted in an agreement, the "Going Forward Principles and Procedures" (Going Forward Principles), that was supported or joined in by 84 parties (some representing more than one utility) that was accepted by the Commission.[8]

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[6] *Midwest Independent Transmission System Operator, Inc., et al.*, 106 FERC ¶ 63,010 (2004).

[7] *Midwest Independent Transmission System Operator, Inc., et al.*, 106 FERC ¶ 61,106 (2004), *reh'g pending.*

[8] *Midwest Independent Transmission System Operator, Inc., et al.*, 106 FERC ¶ 61,262 (2004), *reh'g pending*, (March 19 Order). In accordance with the March 19 Order and earlier orders in these proceedings, multiple compliance filings have been submitted in Docket Nos. EL02-111 and EL03-212 implementing the elimination of through and out rates. On January 2, 2004, the following entities submitted revisions to their respective tariffs to eliminate through and out rates effective April 1, 2004, in accordance with the November 17, 2003 Orders in these proceedings: Midwest ISO, PJM, Ameren Services Company, on behalf of Central Illinois Light Co., Central Illinois Public Service and Union Electric Co. (collectively Ameren); Illinois Power Company (Illinois Power); American Electric Power Service Corporation on behalf of Appalachian Power Service Co., Columbus Southern Power Co., Indiana Michigan Power Co., Kentucky Power Co., Kingsport Power Co., Ohio Power Co., and Wheeling Power Co. (collectively AEP); Commonwealth Edison Company and Commonwealth Edison Company of Indiana (ComEd) and Dayton Power and Light (Dayton). On February 25, 2004, AEP, ComEd and Dayton filed amendments to their January 2, 2004 compliance filings to reflect the extension of the date for elimination of the through and out rates from April 1, 2004 to May 1, 2004 granted on February 6, 2004. On April 5, 2004, Midwest ISO, PJM, Illinois Power and Ameren submitted compliance filings as directed by the March 19 Order.

(continued)

6. This agreement established principles and procedures to guide the parties in the development of a long-term transmission pricing structure that could take effect December 1, 2004, subject to refund and further procedures if appropriate, without the need for a transitional lost revenue recovery mechanism. The agreement retained the through and out rates until December 1, 2004, at which time they would be eliminated entirely. The agreement also provided for continued negotiations to develop a long-term transmission pricing structure that eliminates seams in the PJM and Midwest ISO regions and required the PJM and Midwest ISO transmission owners to file a long-term transmission pricing proposal pursuant to section 205 of the Federal Power Act (FPA).[9] The agreement provided for the filing of one proposal or, if the parties were unable to agree to a single proposal, multiple proposals on October 1, 2004, with a proposed December 1, 2004 effective date. The agreement provided for "backstop" SECA compliance filings to be made on or before November 24, 2004, to take effect December 1, 2004, subject to nominal suspension and refund, in the event that the Commission was unable to implement a replacement pricing structure that eliminates seams as of December 1, 2004.

7. On September 3, 2004, the Chief Judge issued a report indicating that after further settlement and stakeholder conferences two major groups of parties had reached an impasse. The Chief Judge stated that it appeared there would be two competing proposals filed with the Commission on October 1, 2004. The Chief Judge added that additional meetings and conferences were planned in an attempt to come to further agreement.[10]

In this order, as we discuss below, we direct Midwest ISO and PJM and their transmission owners to submit new compliance filings to implement the elimination of through and out rates effective December 1, 2004, which will supercede these prior compliance filings, with the exception of portions of PJM's April 5, 2004 compliance filing addressing rates for the period prior to December 1, 2004, as discussed below. Accordingly, we dismiss as moot Midwest ISO and PJM's January 2, 2004 compliance filings and Midwest ISO's April 5, 2004 compliance filing. In addition, the compliance filings submitted by Ameren, Illinois Power, AEP, ComEd and Dayton are also dismissed as moot, because each of these companies has been integrated into either Midwest ISO or PJM and will not be providing transmission service under its individual tariff on December 1, 2004.

[9] 16 U.S.C. § 824d (2000).

[10] *Midwest Independent Transmission System Operator, Inc., et al.*, 108 FERC ¶ 63,034 (2004).

8. In light of the potential for two alternative proposals, and the need to adopt a single long-term transmission pricing structure, the Commission initiated a FPA section 206[11] proceeding in Docket No. EL04-135-000 and established a refund effective date of December 1, 2004. This proceeding was implemented to ensure that the Commission had adequate authority to implement a new long-term transmission pricing structure for all parties across the PJM and Midwest ISO regions.[12]

9. On October 1, 2004, two competing proposals were submitted. The Unified Plan Proponents[13] filed their proposed Unified Plan pursuant to section 205 of the FPA. The

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[11] 16 U.S.C. § 824e (2000).

[12] *Midwest Independent Transmission System Operator, Inc., et al.*, 108 FERC 61,313 (2004).

[13] The Unified Plan Proponents include: (1) certain Midwest ISO transmission owners: Alliant Energy Corporate Services, Inc., on behalf of its operating company affiliate Interstate Power and Light Co.; American Transmission Co., LLC; Cinergy Services, Inc., on behalf of Cincinnati Gas & Electric Co., PSI Energy, Inc., and Union Light Heat & Power Co. (collectively Cinergy); City of Columbia Water and Light Dept. (Columbia, MO); City Water Light & Power, Springfield, IL; FirstEnergy Service Co., on behalf of American Transmission Systems, Inc. (First Energy); Hoosier Energy Rural Electric Coop., Inc.; Indianapolis Power & Light Co.; International Transmission Co.; Michigan Electric Transmission Co., L.L.C. (Michigan Electric); Minnesota Power, and its subsidiary Superior Water, L&P; Michigan Public Power Agency; Montana–Dakota Utilities Co.; Northern Indiana Public Service Co.; Northern States Power Co., and Northern States Power Co. Wisconsin, subsidiaries of Xcel Energy Inc.; Northwestern Wisconsin Electric Co.; Otter Tail Corp.; Southern Illinois Power Cooperative; and Southern Indiana Gas & Electric Co.; (2) certain PJM transmission owners: Allegheny Electric Coop., Inc. (Allegheny); Jersey Central Power and Light Co.; Metropolitan Edison Co.; Pennsylvania Electric Co.; Old Dominion Electric Coop.; PPL Electric Utilities Coop.; Peco Holdings, Inc., on behalf of Potomac Electric Power Co., Delmarva Power & Light Co., and Atlantic City Electric Co.; Public Service Electric and Gas Co.; Rockland Electric Co.; and UGI Utilities, Inc.; and (3) additional stakeholders: Blue Ridge Power Agency; Borough of Chambersburg, Pennsylvania; Central Virginia Electric Coop. (VEPCO); the Michigan cities of Bay City, Croswell, Dowagiac, Eaton Rapids, Hart, Portland, Sebewaing, St. Louis, and Sturgis; Coalition of Midwest Transmission Customers; Consumers Energy Co. (Consumers Energy); Craig-Botetourt Electric Coop.; Dayton Power and Light Co.; Detroit Edison Co. (Detroit Edison); Edison Mission Energy, Edison Mission Marketing & Trading, Inc., and Midwest Generation

(continued)

Unified Plan Proponents include the majority of Midwest ISO and PJM transmission owners, including several independent transmission companies, and a cross section of other stakeholders, including several large transmission-dependent utilities, municipals and cooperatives, independent generators, power marketers, large retail customers, consumer advocates and state commissions. These entities represent 77 percent of the transmission owners, 59 percent of the net plant investment in transmission infrastructure, and 63 percent of the miles of transmission line in the combined Midwest ISO/PJM region, and they received 33 percent of the revenues for through and out service in the regions in 2002.

10. The Unified Plan is comprised of two parts: (1) the Regional Zonal Rate Design, which consists of the license plate rate structure currently in place in PJM and Midwest ISO,[14] and adjustments to the license plate zonal rates of certain Midwest ISO transmission owners to account for the reduction in revenues for through and out transmission service reflected in those rates; and (2) an Offer of Settlement, on behalf of all of the Unified Plan Proponents, that includes a moratorium on rate design changes through May 31, 2008, a requirement that protocols for allocating responsibility for certain new transmission facilities, i.e., those that benefit customers in both RTOs, be

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EME, LLC (collectively EME Companies); Electri-Cities of North Carolina, Eastern Agency; Great River Energy; Madison Gas and Electric Co.; Michigan Public Service Commission; Michigan South Central Power Agency; MidAmerican Energy Co.; Missouri Joint Municipal Electric Utility Commission; Nordic Marketing LLC.; Pennsylvania Office of Consumer Advocate' Pennsylvania Public Utility Commission; PJM Industrial Customer Coalition; PSEG Energy Resources & Trade, LLC; Southern Maryland Electric Cooperative (SMECO); Soyland Power Coop. Inc. (Soyland); Thumb Electric Coop.; Village of Chelsea; Virginia Municipal Electric Association No. 1; Wisconsin Electric Power (Wisconsin Electric) and Edison Sault Electric Co. (Edison Sault); Wisconsin Public Power Inc.; Wisconsin Public Service Corp. and Upper Peninsula Power Co. (WPSC/UPPCo); and Wolverine Power Supply Coop., Inc. (Wolverine); (collectively, Unified Plan Proponents).

[14] Under a license plate rate design, the RTO's footprint is segregated into a number of transmission pricing zones, typically based on the boundaries of individual transmission owners or groups of transmission owners, and customers taking transmission service for delivery to load within the RTO pay a rate based on the embedded cost of the transmission facilities in the transmission pricing zone where the load is located. Thus, under license plate rates, customers serving load within the RTO pay for the embedded cost of the transmission facilities in the local transmission pricing zone and receive reciprocal access to the entire regional grid.

developed and filed by April 1, 2005, to take effect June 1, 2005, and an offer of transitional payments to certain entities.

11. The Regional Pricing Plan Sponsors[15] filed a competing long-term regional transmission pricing proposal (Regional Pricing Plan) pursuant to section 206 of the FPA. The Regional Pricing Plan Sponsors represent 23 percent of the transmission owners in the Midwest ISO and PJM regions. These entities represent 41 percent of the net plant investment in transmission infrastructure, and 37 percent of the miles of transmission line, in the combined region, and they received 67 percent of the revenues for through and out service in the regions in 2002. Their proposal recovers two-thirds of each transmission owner's revenue requirement through license plate rates, but restructures inter-RTO and intra-RTO rates in the regions so that the remaining third is recovered through a regional pricing mechanism. This regional pricing mechanism reflects an allocation of a portion of the costs of certain high voltage facilities through a regional average "postage stamp" rate (the voltage-based element),[16] and a portion of the costs of transmission facilities to net importing zones based on a system flow analysis (the usage-based element).

II. Notice and Filings

12. Notice of both filings was published in the *Federal Register*, 69 Fed. Reg. 60,8563 (2004), with protests or interventions due on or before October 13, 2004. The entities that filed notices of intervention and timely or late motions to intervene are listed in Appendix A of this order. Several parties filed comments in support of the Unified Plan and in protest of the Regional Pricing Plan and others filed comments in support of the Regional Pricing Plan and in protest of the Unified Plan.

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[15] The Regional Pricing Plan Sponsors include: Allegheny Power, on behalf of Monongahela Power Co., Potomac Edison Co., and West Penn Power Co. ; Ameren AEP; Exelon Corp. on behalf of ComEd and PECO Energy Co. (collectively Exelon); Illinois Power Company; and LG&E Energy, LLC, on behalf of Louisville Gas & Electric Co. and Kentucky Utilities Co. (collectively, LG&E); (collectively, Regional Pricing Plan Sponsors).

[16] In contrast to license plate rates, under which customers serving load within the RTO pay rates based on the embedded cost of the transmission facilities in the local transmission pricing zone where the load is located, under a postage stamp rate design, all customers taking transmission service for delivery to load within the RTO pay the same rate, reflecting the average embedded costs of the transmission facilities throughout the RTO.

13. The order initiating the proceeding in Docket No. EL04-135-000 was published in the *Federal Register*, 69 Fed. Reg. 58,421 (2004). This order directed that notices of intervention and motions to intervene be filed with the Commission on or by October 15, 2004. The entities that filed notices of intervention and timely or late motions to intervene are noted in Appendix A of this order.

III. Discussion

A. Procedural Matters

14. Pursuant to Rule 214 of the Commission's Rules of Practice and Procedure, 18 C.F.R. § 385.214(c) (2004), the notices of intervention and timely, unopposed motions to intervene serve to make the entities that filed them parties to their respective proceedings (*i.e.* the proceeding in which they seek to intervene). Pursuant to Rule 214 of the Commission's Rules of Practice and Procedure 18 C.F.R. § 385.214(d) (2004), we will grant the untimely motions to intervene, in light of the parties' interest in their respective proceedings, the early stage of the respective proceedings, and the absence of any undue prejudice or delay.

B. Rate Design

1. Unified Plan Proposal

15. The Unified Plan, through the proposed Regional Zonal Rate Design and Offer of Settlement: (1) would continue the current license plate rate structure through May 31, 2008; (2) institute transitional surcharges to fund settlement payments to AEP, ComEd, and Dayton through a transition period ending May 31, 2008; (3) require a future filing to address pricing of new cross border transmission facilities; and (4) preserve certain allocations of financial transmission rights (FTRs).

16. Under the Regional Zonal Rate Design, the costs of existing transmission facilities would continue to be recovered through the zonal license plate rate structure currently in effect in each RTO upon the elimination of through and out rates on December 1, 2004. The Regional Zonal Rate Design proposal also would revise the transmission rate formula in Attachment O of the Midwest ISO tariff, and the license plate zonal rates under the Midwest ISO tariff, to adjust revenue credits to reflect the reduction in through and out transmission service revenues due to elimination of rate pancaking between the two RTOs. This adjustment would increase the license plate zonal rates to recover the amount of revenues lost from the elimination of the through and out rate under the Midwest ISO tariff for transactions sinking in PJM.

17. The Offer of Settlement would establish a moratorium through May 31, 2008, on the license plate rate design for existing transmission facilities. Regarding new facilities, the Offer of Settlement would price new transmission facilities in accordance with the regional expansion protocols being developed by each of the RTOs. These pricing protocols generally seek to assign costs of new facilities to the beneficiaries of those facilities. PJM has already developed, and the Commission has conditionally accepted, tariff provisions to implement such a pricing mechanism for regional transmission expansion, and the Midwest ISO is in the process of developing a similar mechanism for allocation of the cost of new facilities. In addition to these provisions for planning within each RTO, the Offer of Settlement would also require the RTOs to file, by April 1, 2005, protocols for the allocation of the cost of new transmission facilities that are built in one RTO but benefit customers in the other RTO, so-called "Cross Border Facilities."

18. The Unified Plan Proponents' Offer of Settlement also provides transitional payments to AEP, ComEd, and Dayton during the rate moratorium period.[17] The Unified Plan Proponents state that these payments are not meant to be compensation for lost through and out revenues. They state that the payments are meant to serve as a mitigation measure to ease the transition from the status quo, with through and out rates in place, to the Regional Zonal Rate Design, which relies entirely on license plate rates with no revenues for through and out service for transactions sinking in the combined region. The companies receiving payments under the Offer of Settlement, AEP, ComEd and Dayton, are distinguished by the Unified Plan Proponents as the only transmission owners that have, or will have, joined an RTO without having been subject to a transition mechanism through intra-RTO rate proceedings. In crafting their proposed transition payments, the Unified Plan Proponents have taken into consideration the transition mechanisms originally proposed by these companies in their December 11, 2002, PJM integration filing in Docket No. ER03-262, *et al.*, which is currently pending before the

[17] The transitional payments will equal: (1) $28 million for AEP, $12 million for ComEd, and $1.1 million for Dayton during each of the first two years of the transition period; (2) $14 million for AEP, $6 million for ComEd, and $0.6 million for Dayton during the third year of the transition period; and (3) $3.5 million for AEP, $1.5 million for ComEd, and $0.143 million for Dayton during the period from December 1, 2007 through May 31, 2008.

Commission.[18] In contrast, the Unified Plan Proponents do not provide payments for Ameren because Ameren has already received compensation for joining Midwest ISO.[19]

2. Details of the Regional Pricing Plan

19. The Regional Pricing Plan maintains the license plate zonal rate design currently in place in the two RTOs for two-thirds of each transmission owner's revenue requirement, but allocates the remaining one-third on a regional basis. The proposal applies a usage-based and a voltage-based method to identify the portion of each transmission owner's transmission revenue requirement that should be allocated on a regional basis and the portion that should be allocated on a local basis. Fifty percent of each transmission owner's transmission revenue requirement is allocated between regional and local rates under the usage-based approach and fifty percent of each transmission owner's revenue requirement is allocated between regional and local rates under the voltage-based approach. The portion of each transmission owner's revenue requirement not allocated to the regional rate under each method is collected through license plate zonal rates. Under the proposal, about 67 percent of the regional transmission costs would be recovered on a license plate approach, 13 percent would be recovered on a usage-based approach (based on net zonal imports) and 21 percent would be recovered on a postage stamp basis.

20. The usage-based element uses a proprietary market and transmission flow simulator, the GE MAPS model, to determine the amount of each transmission owner's cost of service that is allocated regionally. This method relies on modeling power flows across the combined PJM-Midwest ISO region for all hours of the year under two different scenarios, a base case and a change case. The base case represents a self-sufficiency state where each zone (based primarily on control area boundaries) satisfies its power needs internally with no need for imported power. The change case reflects efficient regional dispatch of the system based on generation prices, allowing for imports and exports between zones. A MW-mile analysis is performed for each case by calculating the length of each transmission line in miles multiplied by the power flow in MWs. The change in flow on each transmission line is compared between the base and

[18] *See American Electric Power Service Corporation*, *et al.*, 103 FERC ¶ 61,008 (2003) (order accepting filings, suspending rates, and establishing hearing procedures), *order on reh'g*, 108 FERC ¶ 61,140 (2004).

[19] *See* Unified Plan Proponents' October 1, 2004 Transmittal Letter at 99, *citing*, *Midwest Independent Transmission System Operator, Inc.*, 106 FERC ¶ 61,200 (2004) (order approving uncontested settlement regarding rate adjustments for Ameren's membership in Midwest ISO (GridAmerica Settlement)).

change case to yield a differential in MW-miles for a particular pricing zone. The aggregate of the absolute values of the change in MW-miles for all lines in a pricing zone indicates each zone's contribution to the regional value of the system and is used to determine the portion of a transmission owner's revenue requirement that goes into the regional revenue requirement for a given hour. This amount is determined based on a ratio with the aggregate absolute values of the change in MW-miles for each line in the pricing zone as the numerator and the MW-miles from the base case plus the value in the numerator as the denominator. Once the regional allocation is determined, that amount is then collected from each zone in proportion to its relative net power imports during a given hour in the change case.

21. The voltage-based element divides transmission costs based on voltage levels, with the costs of high-voltage facilities allocated regionally and the costs of lower-voltage facilities allocated locally. For the voltage-based method of allocation, the Regional Pricing Plan Sponsors propose the following: (1) for a transmission owner with facilities operating at voltages of 200 kV or greater, it will allocate 100 percent of facilities operated at voltages above 700 kV, 100 percent of the largest investment class between 200 kV and 700 kV and 50 percent of its second largest investment class between 200 kV and 700 kV; and (2) for a transmission owner with no facilities operated at 200 kV or greater, but with facilities operated at voltages greater than 100 kV, it will allocate 50 percent of its largest investment class. For example, under this proposal, AEP will allocate 100 percent of its 765 kV facilities, 100 percent of its 345 kV facilities, and 50 percent of its 500 kV facilities. Regional Pricing Plan Sponsors' engineering witness testifies that 765 kV, 500 kV and 345 kV facilities provide reliability benefits over a broader region and are therefore appropriately classified as regional, whereas 230 kV and lower kV facilities are a closer call, as they perform both a regional and local function, but that not all systems are similarly designed and lower voltage facilities on some systems may contribute to regional reliability. The portion of each transmission owner's revenue requirement that is identified as providing benefits to the region under the voltage-based method is aggregated across the combined Midwest ISO-PJM region and charged to all load in the combined Midwest ISO-PJM region through a single average "postage stamp" rate – based on the theory that the reliability benefits of backbone transmission facilities benefit all load, not just load served by imported energy.

22. The Regional Pricing Plan Sponsors propose certain transition mechanisms that are intended to moderate the impacts of their proposal. First, a preliminary study of the impacts of the proposal indicates that four pricing zones will experience more than a 50 percent increase in transmission costs as a result of their proposal. The Sponsors propose to limit the increase to 52 percent, and make up the difference from zones that are shown will experience a decrease in transmission costs. The Regional Pricing Plan Sponsors also indicate that they believe that it might be appropriate to use the revenues for service through and out of the Midwest ISO/PJM region to provide additional moderation. They state that it is uncertain what the exact revenues for such service will be, but that it is

expected to be in excess of $100 million. They indicate that if $120 million of through and out service revenues were available for additional moderation, the zonal obligations could be capped at 129 percent of current rates.

23. The Regional Pricing Plan Sponsors also recognize that the usage-based element, which is allocated on the basis of net imports, results in an allocation of $9.05/MWH of net imports. First, Regional Pricing Plan Sponsors submit that this figure is misleading because it measures per-unit costs on net imports, while gross imports are expected to be significantly larger due to simultaneous imports and exports by a zone. They submit that this figure will not affect actual dispatch activity because the allocation of costs is based on modeled imports, not actual imports. However, they recognize that future decisions about construction of generation or transmission plant might be influenced if market participants knew that the same net import-based allocation of costs will be implemented in the future. However, they argue that it is unclear whether such decisions would actually be biased because the impacts of an individual resource decision would be diffused among many zones rather than being captured by one zone. The Regional Pricing Plan Sponsors have tried to address this issue by incorporating a limit on the allocation of each zone's transmission cost of service to regional use – if a zone is a net importer of power during any hour, the amount of its allocation to regional use is limited to zero for that hour. Without this limit, the per-MWH of net import figure would be $13.29 rather than $9.05/MWH.

24. The Regional Pricing Plan Sponsors propose that the Regional Pricing Plan be used to establish rates that will remain in effect until June 1, 2008, in the absence of Commission action under section 205 or 206, and only be adjusted during that time period: (1) on June 1, 2005, to reflect expansion of either RTO to incorporate new transmission owners prior to that time and to improve the modeling based on new data made available in the course of this proceeding; and (2) between June 1, 2005 and June 1, 2008 to reflect only the addition or withdrawal of RTO members. In the absence of Commission action under section 205 or 206, the rate design will continue in effect beyond June 1, 2008, without the moderation mechanisms.

3. Comments in Support of the Unified Plan

25. In addition to the comments filed by the Unified Plan Proponents, several other entities filed individually in support, either in part or in full, for the Unified Plan.[20] Generally, supporters of the Unified Plan believe that license plate rates are a more appropriate rate design for pricing of existing facilities because license plate rates provide stable predictable rates which do not interfere with current market structures, and can be easily implemented to meet the December 1 effective date. Additionally, many supporters note that the Unified Plan is supported by a diverse group of stakeholders and represents considerable compromise towards an acceptable and implementable solution to the elimination of through and out rates.

26. Several Unified Plan supporters claim that throughout the combined Midwest ISO/PJM region, the existing transmission systems were built for service to native load customers and, before open access transmission was mandated in 1996 by Order No. 888,[21] these facilities were primarily used for that purpose. For example, the Indiana Commission states that at the time most existing facilities were constructed it was not anticipated that they would be heavily used for bulk power transfer to serve load outside of the immediate service area. Therefore, the Indiana Commission agrees with the Unified Plan Proponents' assertion that it is reasonable and appropriate for the costs of existing infrastructure to be born by the native load for which it was built.

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[20] *See* comments filed by Cinergy; Great Lakes Utilities; Southwestern Electric Cooperative, Inc.; Wolverine; Joint Comment of the Coalition of Midwest Transmission Customers and the PJM Industrial Customer Coalition; Joint Comments of Allegheny Electric and Soyland; SMECO, Consumers Energy, Wisconsin Electric, Michigan Electric, Indiana Utility Regulatory Commission (Indiana Commission), WPSC/UPPCo., Multiple TDUs, VEPCO, and Delaware Public Service Commission.

[21] *Promoting Wholesale Competition Through Open Access Non-Discriminatory Transmission Services by Public Utilities; Recovery of Stranded Costs by Public Utilities and Transmitting Utilities*, Order No. 888, 61 Fed. Reg. 21,540 (1996), FERC Stats. & Regs. ¶ 31,036 at 31,760-61, *order on reh'g*, Order No. 888-A, 62 Fed. Reg. 12,274 (Mar. 14, 1997), FERC Stats. & Regs. ¶ 31,048 (1997), *order on reh'g*, Order No. 888-B, 81 FERC ¶ 61,248 (1997), *order on reh'g*, Order No. 888-C, 82 FERC ¶ 61,046 (1997), *aff'd in relevant part sub nom.* Transmission Access Policy Study Group v. FERC, 225 F.3d 667 (D.C. Cir. 2000), *aff'd sub nom.* New York v. FERC, 535 U.S. 1 (2002).

27. The Unified Plan Proponents also argue that the rate design embodied in the Unified Plan properly recognizes regional use of the transmission grid. The Unified Plan Proponents argue that all transmission facilities in the combined Midwest ISO/PJM region are equally important and necessary for a functioning, integrated, and reliable regional transmission system and argue that zonal license plate pricing is most appropriate because it assigns equal value to each transmission owner's facilities by providing reciprocal open access throughout the combined Midwest ISO/PJM region. The Unified Plan Proponents also point out that Order No. 2000[22] supports the use of license plate rates during the initial stages of RTO formation, and that, in approving Midwest ISO as an RTO, the Commission authorized the use of license plate rates through January 2008.

28. In addition, the Unified Plan Proponents assert that license plate rates are most compatible with the current developing energy market in Midwest ISO and the overall combined market being developed for the Midwest ISO/PJM region, pointing out that license plate rates have been used for years in the PJM markets. Unified Plan supporters also note that a license plate rate design can be implemented based on existing, Commission-approved revenue requirements and neither requires nor precludes updated cost of service justification. Accordingly, they state that their license plate rate proposal is the only option that can be immediately implemented on December 1, 2004.

29. The Unified Plan Proponents argue that the Unified Plan is the most efficient approach for pricing new transmission because it only assigns cost responsibility of new facilities to those who benefit from the upgrade. They assert that this principle has been approved by the Commission with its approval of PJM's process for allocating the cost of new facilities. The Unified Plan Proponents claim that the Regional Pricing Plan would undermine the new transmission pricing initiatives in place in PJM and being developed in Midwest ISO, because the costs of new facilities will be rolled into the regional pricing component proposed in the Regional Pricing Plan and not priced according to the participant funding initiatives developed or being developed by the RTOs.

30. The Indiana Commission comments on the need to appropriately encourage new transmission investment. Although the Indiana Commission expresses concern over the unproven effectiveness of PJM's process for allocating the cost of new facilities and Midwest ISO's yet to be filed process, it remains supportive of the Unified Plan because

[22] *Regional Transmission Organizations*, Order No. 2000, 65 Fed. Reg. 809 (January 6, 2000), FERC Stats. & Regs. ¶ 31,089 (1999), *order on reh'g*, Order No 2000-A, 65 Fed. Reg. 12,088 (March 8, 2000), FERC Stats. & Regs. ¶ 31,092 (2000), *aff'd sub nom.* Public Utility District No. 1 of Snohomish County, Washington v. FERC, 272 F.3d 607 (D.C. Cir. 2001).

it at least contains a clear procedure for pricing of new investment. In contrast, the Indiana Commission notes, it is unclear how the Regional Pricing Proposal seeks to price new facilities.

31. Unified Plan Proponents argue that the amounts of the proposed settlement payments to AEP, ComEd and Dayton are justified because they take into consideration revenues for through and out service that these companies have continued to receive long past the time that they were originally supposed to join an RTO. Unified Plan Proponents note that in its PJM integration filing in Docket No. ER03-262-000, AEP proposed total revenue neutrality compensation of approximately $366 million, based on the assumption that AEP was to enter PJM in February 2003. Unified Proponents point out that since that time AEP has collected approximately $317 million in continued through and out revenues, and that AEP is entitled to another $5 million from an interim transition rate mechanism agreed to as part of the Going Forward Principles, once it joins PJM. Considering these amounts and the $73 million settlement payment proposed by the Unified Plan, Unified Plan Proponents purport that AEP would receive $30 million more than the transitional arrangement it originally proposed in 2002. Additionally, the Unified Plan Proponents note that these considerations do not take into account the estimated $333 million in increased profits that the Commission has found that AEP will experience over the next five years due to additional off-system sale opportunities from integrating into PJM.[23] Although VEPCO favors retention of license plate rates, and the Unified Plan in general, it contests the need for transition settlement payments or any other lost revenue recovery mechanism.

4. <u>Comments in Support of the Regional Pricing Plan</u>

32. In addition to the Regional Pricing Plan Sponsors, other entities filed individual comments in support of the Regional Pricing Plan.[24] Generally, supporters of the Regional Pricing Plan rate design favor it because it assigns a portion of the cost of existing transmission facilities regionally to account for the fact that, due to regional open access, some transmission facilities are used by customers outside of the immediate pricing zone. For example, the Regional Pricing Plan Sponsors state that the costs and benefits of the expansion of regional energy markets are not evenly distributed today and

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[23] *See* Unified Plan Proponents' October 1, 2004 Transmittal Letter at 97-98, *citing*, *New PJM Companies*, *et al.*, Opinion No. 472, 107 FERC ¶ 61,271 (2004).

[24] *See* comments filed by: Illinois Municipal Electric Agency, Public Utilities Commission of Ohio (Ohio Commission), Northern Illinois Municipal Power Agency, Illinois Commerce Commission (Illinois Commission), Ameren and LG&E, and the Town of Front Royal, Virginia (Front Royal).

that the Regional Pricing Plan better aligns the costs and benefits of today's transmission network. They assert that the usage-based element of the Regional Pricing Plan best satisfies the traditional ratemaking principle that costs should be allocated on the basis of cost causation because, by assigning some costs directly to net importers, it accurately allocates costs to those who benefit from regional access. The Regional Pricing Plan Sponsors claim that the voltage-based pricing element recognizes the ratemaking concept that those who benefit from transmission facilities should pay an appropriate share of the associated costs. They assert that high-voltage facilities provide integral system reliability, a benefit to all system users, and the voltage-based pricing properly captures this by assigning a portion of costs to everyone via a regional postage stamp rate.

33. Supporters of the Regional Pricing Plan claim that the proposal properly recognizes regional use of existing transmission infrastructure. The Illinois Commission states that it supports a transmission pricing mechanism that identifies transmission costs that provide regional benefits and allocates such costs in an appropriate regional manner. The Illinois Commission also points out that the Regional Pricing Plan uses license plate rates as its foundation, but properly modifies them to include a regional pricing component. The Ohio Commission notes that it is in a unique position to offer what it claims to be an objective view of these pricing proposals. It indicates that no single proposal will result in a consistent economic impact on Ohio customers. The Ohio Commission urges the Commission to review these proposals based on basic rate design principles and the Commission's transmission pricing policies. The Ohio Commission states that the Regional Pricing Plan fully adheres to these initiatives because the usage-based pricing element allocates costs to users while the voltage-based pricing element recognizes reliability contributions. The Ohio Commission further notes that the Commission encouraged development of innovative rate designs, including flow-based pricing, later in the same policy statement.

34. The Regional Pricing Plan Sponsors respond to the anticipated criticism that the usage-based pricing element could interfere with efficient decision making by market participants. The Regional Pricing Plan Sponsors argue that it would be improbable if not impossible, for an entity to capture the benefits of a lower future usage-based cost allocation by making investment decisions that reduce zonal net imports because any benefits would be significantly diffused across multiple entities.

35. The Regional Pricing Plan Sponsors clarify that their proposal does not seek to replace transmission expansion protocols already in place or being developed. To the contrary, they submit that their proposal can easily complement such mechanisms by providing a cost recovery vehicle for necessary transmission expansion where a determination as to who benefits from, and should bear cost responsibility for, particular expansions cannot be made.