EXHIBIT ____ (LK-1)

EXHIBIT ____ (LK-1)

RESUME OF LANE KOLLEN, VICE PRESIDENT

EDUCATION

University of Toledo, BBA
Accounting

University of Toledo, MBA

PROFESSIONAL CERTIFICATIONS

Certified Public Accountant (CPA)

Certified Management Accountant (CMA)

PROFESSIONAL AFFILIATIONS

American Institute of Certified Public Accountants

Georgia Society of Certified Public Accountants

Institute of Management Accountants

More than twenty-five years of utility industry experience in the financial, rate, tax, and planning areas. Specialization in revenue requirements analyses, taxes, evaluation of rate and financial impacts of traditional and nontraditional ratemaking, utility mergers/acquisition diversification. Expertise in proprietary and nonproprietary software systems used by utilities for budgeting, rate case support and strategic and financial planning.

RESUME OF LANE KOLLEN, VICE PRESIDENT

EXPERIENCE

1986 to Present:

J. Kennedy and Associates, Inc.: Vice President and Principal. Responsible for utility stranded cost analysis, revenue requirements analysis, cash flow projections and solvency, financial and cash effects of traditional and nontraditional ratemaking, and research, speaking and writing on the effects of tax law changes. Testimony before Connecticut, Florida, Georgia, Indiana, Louisiana, Kentucky, Maine, Minnesota, North Carolina, Ohio, Pennsylvania, Tennessee, Texas, and West Virginia state regulatory commissions and the Federal Energy Regulatory Commission.

1983 to 1986:

Energy Management Associates: Lead Consultant.
Consulting in the areas of strategic and financial planning, traditional and nontraditional ratemaking, rate case support and testimony, diversification and generation expansion planning. Directed consulting and software development projects utilizing PROSCREEN II and ACUMEN proprietary software products. Utilized ACUMEN detailed corporate simulation system, PROSCREEN II strategic planning system and other custom developed software to support utility rate case filings including test year revenue requirements, rate base, operating income and pro-forma adjustments. Also utilized these software products for revenue simulation, budget preparation and cost-of-service analyses.

1976 to 1983:

The Toledo Edison Company: Planning Supervisor.
Responsible for financial planning activities including generation expansion planning, capital and expense budgeting, evaluation of tax law changes, rate case strategy and support and computerized financial modeling using proprietary and nonproprietary software products. Directed the modeling and evaluation of planning alternatives including:

Rate phase-ins.
Construction project cancellations and write-offs.
Construction project delays.
Capacity swaps.
Financing alternatives.
Competitive pricing for off-system sales.
Sale/leasebacks.

RESUME OF LANE KOLLEN, VICE PRESIDENT

CLIENTS SERVED

Industrial Companies and Groups

Air Products and Chemicals, Inc.
Airco Industrial Gases
Alcan Aluminum
Armco Advanced Materials Co.
Armco Steel
Bethlehem Steel
Connecticut Industrial Energy Consumers
ELCON
Enron Gas Pipeline Company
Florida Industrial Power Users Group
General Electric Company
GPU Industrial Intervenors
Indiana Industrial Group
Industrial Consumers for
  Fair Utility Rates - Indiana
Industrial Energy Consumers - Ohio
Kentucky Industrial Utility Customers, Inc.
Kimberly-Clark Company
Lehigh Valley Power Committee
Maryland Industrial Group
Multiple Intervenors (New York)
National Southwire
North Carolina Industrial
  Energy Consumers
Occidental Chemical Corporation
Ohio Energy Group
Ohio Industrial Energy Consumers
Ohio Manufacturers Association
Philadelphia Area Industrial Energy
  Users Group
PSI Industrial Group
Smith Cogeneration
Taconite Intervenors (Minnesota)
West Penn Power Industrial Intervenors
West Virginia Energy Users Group
Westvaco Corporation

Regulatory Commissions and Government Agencies

Georgia Public Service Commission Staff
Kentucky Attorney General's Office, Division of Consumer Protection
Louisiana Public Service Commission Staff
Maine Office of Public Advocate
New York State Energy Office
Office of Public Utility Counsel (Texas)

RESUME OF LANE KOLLEN, VICE PRESIDENT

Utilities

Allegheny Power System
Atlantic City Electric Company
Carolina Power & Light Company
Cleveland Electric Illuminating Company
Delmarva Power & Light Company
Duquesne Light Company
General Public Utilities
Georgia Power Company
Middle South Services
Nevada Power Company
Niagara Mohawk Power Corporation
Otter Tail Power Company
Pacific Gas & Electric Company
Public Service Electric & Gas
Public Service of Oklahoma
Rochester Gas and Electric
Savannah Electric & Power Company
Seminole Electric Cooperative
Southern California Edison
Talquin Electric Cooperative
Tampa Electric
Texas Utilities
Toledo Edison Company

Expert Testimony Appearances
of
Lane Kollen
As of January 2006

Date	Case	Jurisdict.	Party	Utility	Subject
10/86	U-17282 Interim	LA	Louisiana Public Service Commission Staff	Gulf States Utilities	Cash revenue requirements financial solvency.
11/86	U-17282 Interim Rebuttal	LA	Louisiana Public Service Commission Staff	Gulf States Utilities	Cash revenue requirements financial solvency.
12/86	9613	KY	Attorney General Div. of Consumer Protection	Big Rivers Electric Corp.	Revenue requirements accounting adjustments financial workout plan.
1/87	U-17282 Interim	LA 19th Judicial District Ct.	Louisiana Public Service Commission Staff	Gulf States Utilities	Cash revenue requirements, financial solvency.
3/87	General Order 236	WV	West Virginia Energy Users' Group	Monongahela Power Co.	Tax Reform Act of 1986.
4/87	U-17282 Prudence	LA	Louisiana Public Service Commission Staff	Gulf States Utilities	Prudence of River Bend 1, economic analyses, cancellation studies.
4/87	M-100 Sub 113	NC	North Carolina Industrial Energy Consumers	Duke Power Co.	Tax Reform Act of 1986.
5/87	86-524-E-	WV	West Virginia Energy Users' Group	Monongahela Power Co.	Revenue requirements. Tax Reform Act of 1986.
5/87	U-17282 Case In Chief	LA	Louisiana Public Service Commission Staff	Gulf States Utilities	Revenue requirements, River Bend 1 phase-in plan, financial solvency.
7/87	U-17282 Case In Chief Surrebuttal	LA	Louisiana Public Service Commission Staff	Gulf States Utilities	Revenue requirements River Bend 1 phase-in plan, financial solvency.
7/87	U-17282 Prudence Surrebuttal	LA	Louisiana Public Service Commission Staff	Gulf States Utilities	Prudence of River Bend 1, economic analyses, cancellation studies.

Expert Testimony Appearances
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Lane Kollen
As of January 2006

Date	Case	Jurisdict.	Party	Utility	Subject
7/87	86-524 E-SC Rebuttal	WV	West Virginia Energy Users' Group	Monongahela Power Co.	Revenue requirements, Tax Reform Act of 1986.
8/87	9885	KY	Attorney General Div. of Consumer Protection	Big Rivers Electric Corp.	Financial workout plan.
8/87	E-015/GR-87-223	MN	Taconite Intervenors	Minnesota Power & Light Co.	Revenue requirements, O&M expense, Tax Reform Act of 1986.
10/87	870220-EI	FL	Occidental Chemical Corp.	Florida Power Corp.	Revenue requirements, O&M expense, Tax Reform Act of 1986.
11/87	87-07-01	CT	Connecticut Industrial Energy Consumers	Connecticut Light & Power Co.	Tax Reform Act of 1986.
1/88	U-17282	LA 19th Judicial District Ct.	Louisiana Public Service Commission Staff	Gulf States Utilities	Revenue requirements, River Bend 1 phase-in plan, rate of return.
2/88	9934	KY	Kentucky Industrial Utility Customers	Louisville Gas & Electric Co.	Economics of Trimble County completion.
2/88	10064	KY	Kentucky Industrial Utility Customers	Louisville Gas & Electric Co.	Revenue requirements, O&M expense, capital structure, excess deferred income taxes.
5/88	10217	KY	Alcan Aluminum National Southwire	Big Rivers Electric	Financial workout plan. Corp.
5/88	M-87017 -1C001	PA	GPU Industrial Intervenors	Metropolitan Edison Co.	Nonutility generator deferred cost recovery.
5/88	M-87017 -2C005	PA	GPU Industrial Intervenors	Pennsylvania Electric Co.	Nonutility generator deferred cost recovery.
6/88	U-17282	LA 19th Judicial District Ct.	Louisiana Public Service Commission Staff	Gulf States Utilities	Prudence of River Bend 1 economic analyses, cancellation studies, financial modeling.

Expert Testimony Appearances
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As of January 2006

Date	Case	Jurisdict.	Party	Utility	Subject
7/88	M-87017- -1C001 Rebuttal	PA	GPU Industrial Intervenors	Metropolitan Edison Co.	Nonutility generator deferred cost recovery, SFAS No. 92
7/88	M-87017- -2C005 Rebuttal	PA	GPU Industrial Intervenors	Pennsylvania Electric Co.	Nonutility generator deferred cost recovery, SFAS No. 92
9/88	88-05-25	CT	Connecticut Industrial Energy Consumers	Connecticut Light & Power Co.	Excess deferred taxes, O&M expenses.
9/88	10064 Rehearing	KY	Kentucky Industrial Utility Customers	Louisville Gas & Electric Co.	Premature retirements, interest expense.
10/88	88-170- EL-AIR	OH	Ohio Industrial Energy Consumers	Cleveland Electric Illuminating Co.	Revenue requirements, phase-in, excess deferred taxes, O&M expenses, financial considerations, working capital.
10/88	88-171- EL-AIR	OH	Ohio Industrial Energy Consumers	Toledo Edison Co.	Revenue requirements, phase-in, excess deferred taxes, O&M expenses, financial considerations, working capital.
10/88	8800 355-EI	FL	Florida Industrial Power Users' Group	Florida Power & Light Co.	Tax Reform Act of 1986, tax expenses, O&M expenses, pension expense (SFAS No. 87).
10/88	3780-U	GA	Georgia Public Service Commission Staff	Atlanta Gas Light Co.	Pension expense (SFAS No. 87).
11/88	U-17282 Remand	LA	Louisiana Public Service Commission Staff	Gulf States Utilities	Rate base exclusion plan (SFAS No. 71)
12/88	U-17970	LA	Louisiana Public Service Commission Staff	AT&T Communications of South Central States	Pension expense (SFAS No. 87).
12/88	U-17949 Rebuttal	LA	Louisiana Public Service Commission Staff	South Central Bell	Compensated absences (SFAS No. 43), pension expense (SFAS No. 87), Part 32, income tax normalization.

Expert Testimony Appearances
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As of January 2006

Date	Case	Jurisdict.	Party	Utility	Subject
2/89	U-17282 Phase II	LA	Louisiana Public Service Commission Staff	Gulf States Utilities	Revenue requirements, phase-in of River Bend 1, recovery of canceled plant.
6/89	881602-EU 890326-EU	FL	Talquin Electric Cooperative	Talquin/City of Tallahassee	Economic analyses, incremental cost-of-service, average customer rates.
7/89	U-17970	LA	Louisiana Public Service Commission Staff	AT&T Communications of South Central States	Pension expense (SFAS No. 87), compensated absences (SFAS No. 43), Part 32.
8/89	8555	TX	Occidental Chemical Corp.	Houston Lighting & Power Co.	Cancellation cost recovery, tax expense, revenue requirements.
8/89	3840-U	GA	Georgia Public Service Commission Staff	Georgia Power Co.	Promotional practices, advertising, economic development.
9/89	U-17282 Phase II Detailed	LA	Louisiana Public Service Commission Staff	Gulf States Utilities	Revenue requirements, detailed investigation.
10/89	8880	TX	Enron Gas Pipeline	Texas-New Mexico Power Co.	Deferred accounting treatment, sale/leaseback.
10/89	8928	TX	Enron Gas Pipeline	Texas-New Mexico Power Co.	Revenue requirements, imputed capital structure, cash working capital.
10/89	R-891364	PA	Philadelphia Area Industrial Energy Users Group	Philadelphia Electric Co.	Revenue requirements.
11/89 12/89	R-891364 Surrebuttal (2 Filings)	PA	Philadelphia Area Industrial Energy Users Group	Philadelphia Electric Co.	Revenue requirements, sale/leaseback.
1/90	U-17282 Phase II Detailed Rebuttal	LA	Louisiana Public Service Commission Staff	Gulf States Utilities	Revenue requirements , detailed investigation.

Expert Testimony Appearances
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Date	Case	Jurisdict.	Party	Utility	Subject
1/90	U-17282 Phase III	LA	Louisiana Public Service Commission Staff	Gulf States Utilities	Phase-in of River Bend 1, deregulated asset plan.
3/90	890319-EI	FL	Florida Industrial Power Users Group	Florida Power & Light Co.	O&M expenses, Tax Reform Act of 1986.
4/90	890319-EI Rebuttal	FL	Florida Industrial Power Users Group	Florida Power & Light Co.	O&M expenses, Tax Reform Act of 1986.
4/90	U-17282	LA 19th Judicial District Ct.	Louisiana Public Service Commission Staff	Gulf States Utilities	Fuel clause, gain on sale of utility assets.
9/90	90-158	KY	Kentucky Industrial Utility Customers	Louisville Gas & Electric Co.	Revenue requirements, post-test year additions, forecasted test year.
12/90	U-17282 Phase IV	LA	Louisiana Public Service Commission Staff	Gulf States Utilities	Revenue requirements.
3/91	29327, et. al.	NY	Multiple Intervenors	Niagara Mohawk Power Corp.	Incentive regulation.
5/91	9945	TX	Office of Public Utility Counsel of Texas	El Paso Electric Co.	Financial modeling, economic analyses, prudence of Palo Verde 3.
9/91	P-910511 P-910512	PA	Allegheny Ludlum Corp., Armco Advanced Materials Co., The West Penn Power Industrial Users' Group	West Penn Power Co.	Recovery of CAAA costs, least cost financing.
9/91	91-231 -E-NC	WV	West Virginia Energy Users Group	Monongahela Power Co.	Recovery of CAAA costs, least cost financing.
11/91	U-17282	LA	Louisiana Public Service Commission Staff	Gulf States Utilities	Asset impairment, deregulated asset plan, revenue requirements.

Expert Testimony Appearances
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Date	Case	Jurisdict.	Party	Utility	Subject
12/91	91-410-EL-AIR	OH	Air Products and Chemicals, Inc., Armco Steel Co., General Electric Co., Industrial Energy Consumers	Cincinnati Gas & Electric Co.	Revenue requirements, phase-in plan.
12/91	10200	TX	Office of Public Utility Counsel of Texas	Texas-New Mexico Power Co.	Financial integrity, strategic planning, declined business affiliations.
5/92	910890-EI	FL	Occidental Chemical Corp.	Florida Power Corp.	Revenue requirements, O&M expense, pension expense, OPEB expense, fossil dismantling, nuclear decommissioning.
8/92	R-00922314	PA	GPU Industrial Intervenors	Metropolitan Edison Co.	Incentive regulation, performance rewards, purchased power risk, OPEB expense.
9/92	92-043	KY	Kentucky Industrial Utility Consumers	Generic Proceeding	OPEB expense.
9/92	920324-EI	FL	Florida Industrial Power Users' Group	Tampa Electric Co.	OPEB expense.
9/92	39348	IN	Indiana Industrial Group	Generic Proceeding	OPEB expense.
9/92	910840-PU	FL	Florida Industrial Power Users' Group	Generic Proceeding	OPEB expense.
9/92	39314	IN	Industrial Consumers for Fair Utility Rates	Indiana Michigan Power Co.	OPEB expense.
11/92	U-19904	LA	Louisiana Public Service Commission Staff	Gulf States Utilities/Entergy Corp.	Merger.
11/92	8649	MD	Westvaco Corp., Eastalco Aluminum Co.	Potomac Edison Co.	OPEB expense.
11/92	92-1715-AU-COI	OH	Ohio Manufacturers Association	Generic Proceeding	OPEB expense.

Expert Testimony Appearances
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As of January 2006

Date	Case	Jurisdict.	Party	Utility	Subject
12/92	R-00922378	PA	Armco Advanced Materials Co., The WPP Industrial Intervenors	West Penn Power Co.	Incentive regulation, performance rewards, purchased power risk, OPEB expense.
12/92	U-19949	LA	Louisiana Public Service Commission Staff	South Central Bell	Affiliate transactions, cost allocations, merger.
12/92	R-00922479	PA	Philadelphia Area Industrial Energy Users' Group	Philadelphia Electric Co.	OPEB expense.
1/93	8487	MD	Maryland Industrial Group	Baltimore Gas & Electric Co., Bethlehem Steel Corp.	OPEB expense, deferred fuel, CWIP in rate base
1/93	39498	IN	PSI Industrial Group	PSI Energy, Inc.	Refunds due to over-collection of taxes on Marble Hill cancellation.
3/93	92-11-11	CT	Connecticut Industrial Energy Consumers	Connecticut Light & Power Co.	OPEB expense.
3/93	U-19904 (Surrebuttal)	LA	Louisiana Public Service Commission Staff	Gulf States Utilities/Entergy	Merger. Corp.
3/93	93-01 EL-EFC	OH	Ohio Industrial Energy Consumers	Ohio Power Co.	Affiliate transactions, fuel.
3/93	EC92-21000 ER92-806-000	FERC	Louisiana Public Service Commission Staff	Gulf States Utilities/Entergy Corp.	Merger.
4/93	92-1464-EL-AIR	OH	Air Products Armco Steel Industrial Energy Consumers	Cincinnati Gas & Electric Co.	Revenue requirements, phase-in plan.
4/93	EC92-21000 ER92-806-000 (Rebuttal)	FERC	Louisiana Public Service Commission Staff	Gulf States Utilities/Entergy Corp.	Merger.

**Expert Testimony Appearances
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As of January 2006**

Date	Case	Jurisdict.	Party	Utility	Subject
9/93	93-113	KY	Kentucky Industrial Utility Customers	Kentucky Utilities	Fuel clause and coal contract refund.
9/93	92-490, 92-490A, 90-360-C	KY	Kentucky Industrial Utility Customers and Kentucky Attorney General	Big Rivers Electric Corp.	Disallowances and restitution for excessive fuel costs, illegal and improper payments, recovery of mine closure costs.
10/93	U-17735	LA	Louisiana Public Service Commission Staff	Cajun Electric Power Cooperative	Revenue requirements, debt restructuring agreement, River Bend cost recovery.
1/94	U-20647	LA	Louisiana Public Service Commission Staff	Gulf States Utilities Co.	Audit and investigation into fuel clause costs.
4/94	U-20647 (Surrebuttal)	LA	Louisiana Public Service Commission Staff	Gulf States Utilities	Nuclear and fossil unit performance, fuel costs, fuel clause principles and guidelines.
5/94	U-20178	LA	Louisiana Public Service Commission Staff	Louisiana Power & Light Co.	Planning and quantification issues of least cost integrated resource plan.
9/94	U-19904 Initial Post-Merger Earnings Review	LA	Louisiana Public Service Commission Staff	Gulf States Utilities Co.	River Bend phase-in plan, deregulated asset plan, capital structure, other revenue requirement issues.
9/94	U-17735	LA	Louisiana Public Service Commission Staff	Cajun Electric Power Cooperative	G&T cooperative ratemaking policies, exclusion of River Bend, other revenue requirement issues.
10/94	3905-U	GA	Georgia Public Service Commission Staff	Southern Bell Telephone Co.	Incentive rate plan, earnings review.
10/94	5258-U	GA	Georgia Public Service Commission Staff	Southern Bell Telephone Co.	Alternative regulation, cost allocation.

**Expert Testimony Appearances
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Lane Kollen
As of January 2006**

Date	Case	Jurisdict.	Party	Utility	Subject
11/94	U-19904 Initial Post-Merger Earnings Review (Rebuttal)	LA	Louisiana Public Service Commission Staff	Gulf States Utilities Co.	River Bend phase-in plan, deregulated asset plan, capital structure, other revenue requirement issues.
11/94	U-17735 (Rebuttal)	LA	Louisiana Public Service Commission Staff	Cajun Electric Power Cooperative	G&T cooperative ratemaking policy, exclusion of River Bend, other revenue requirement issues.
4/95	R-00943271	PA	PP&L Industrial Customer Alliance	Pennsylvania Power & Light Co.	Revenue requirements. Fossil dismantling, nuclear decommissioning.
6/95	3905-U	GA	Georgia Public Service Commission	Southern Bell Telephone Co.	Incentive regulation, affiliate transactions, revenue requirements, rate refund.
6/95	U-19904 (Direct)	LA	Louisiana Public Service Commission	Gulf States Utilities Co.	Gas, coal, nuclear fuel costs, contract prudence, base/fuel realignment.
10/95	95-02614	TN	Tennessee Office of the Attorney General Consumer Advocate	BellSouth Telecommunications, Inc.	Affiliate transactions.
10/95	U-21485 (Direct)	LA	Louisiana Public Service Commission	Gulf States Utilities Co.	Nuclear O&M, River Bend phase-in plan, base/fuel realignment, NOL and AltMin asset deferred taxes, other revenue requirement issues.
11/95	U-19904 (Surrebuttal)	LA	Louisiana Public Service Commission	Gulf States Utilities Co. Division	Gas, coal, nuclear fuel costs, contract prudence, base/fuel realignment.
11/95 12/95	U-21485 (Supplemental Direct) U-21485 (Surrebuttal)	LA	Louisiana Public Service Commission	Gulf States Utilities Co.	Nuclear O&M, River Bend phase-in plan, base/fuel realignment, NOL and AltMin asset deferred taxes, other revenue requirement issues.

Expert Testimony Appearances
of
Lane Kollen
As of January 2006

Date	Case	Jurisdict.	Party	Utility	Subject
1/96	95-299-EL-AIR 95-300-EL-AIR	OH	Industrial Energy Consumers	The Toledo Edison Co. The Cleveland Electric Illuminating Co.	Competition, asset writeoffs and revaluation, O&M expense, other revenue requirement issues.
2/96	PUC No. 14967	TX	Office of Public Utility Counsel	Central Power & Light	Nuclear decommissioning.
5/96	95-485-LCS	NM	City of Las Cruces	El Paso Electric Co.	Stranded cost recovery, municipalization.
7/96	8725	MD	The Maryland Industrial Group and Redland Genstar, Inc.	Baltimore Gas & Electric Co., Potomac Electric Power Co. and Constellation Energy Corp.	Merger savings, tracking mechanism, earnings sharing plan, revenue requirement issues.
9/96 11/96	U-22092 U-22092 (Surrebuttal)	LA	Louisiana Public Service Commission Staff	Entergy Gulf States, Inc.	River Bend phase-in plan, base/fuel realignment, NOL and AltMin asset deferred taxes, other revenue requirement issues, allocation of regulated/nonregulated costs.
10/96	96-327	KY	Kentucky Industrial Utility Customers, Inc.	Big Rivers Electric Corp.	Environmental surcharge recoverable costs.
2/97	R-00973877	PA	Philadelphia Area Industrial Energy Users Group	PECO Energy Co.	Stranded cost recovery, regulatory assets and liabilities, intangible transition charge, revenue requirements.
3/97	96-489	KY	Kentucky Industrial Utility Customers, Inc.	Kentucky Power Co.	Environmental surcharge recoverable costs, system agreements, allowance inventory, jurisdictional allocation.
6/97	TO-97-397	MO	MCI Telecommunications Corp., Inc., MCImetro Access Transmission Services, Inc.	Southwestern Bell Telephone Co.	Price cap regulation, revenue requirements, rate of return.

Expert Testimony Appearances
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As of January 2006

Date	Case	Jurisdict.	Party	Utility	Subject
6/97	R-00973953	PA	Philadelphia Area Industrial Energy Users Group	PECO Energy Co.	Restructuring, deregulation, stranded costs, regulatory assets, liabilities, nuclear and fossil decommissioning.
7/97	R-00973954	PA	PP&L Industrial Customer Alliance	Pennsylvania Power & Light Co.	Restructuring, deregulation, stranded costs, regulatory assets, liabilities, nuclear and fossil decommissioning.
7/97	U-22092	LA	Louisiana Public Service Commission Staff	Entergy Gulf States, Inc.	Depreciation rates and methodologies, River Bend phase-in plan.
8/97	97-300	KY	Kentucky Industrial Utility Customers, Inc.	Louisville Gas & Electric Co. and Kentucky Utilities Co.	Merger policy, cost savings, surcredit sharing mechanism, revenue requirements, rate of return.
8/97	R-00973954 (Surrebuttal)	PA	PP&L Industrial Customer Alliance	Pennsylvania Power & Light Co.	Restructuring, deregulation, stranded costs, regulatory assets, liabilities, nuclear and fossil decommissioning.
10/97	97-204	KY	Alcan Aluminum Corp. Southwire Co.	Big Rivers Electric Corp.	Restructuring, revenue requirements, reasonableness
10/97	R-974008	PA	Metropolitan Edison Industrial Users Group	Metropolitan Edison Co.	Restructuring, deregulation, stranded costs, regulatory assets, liabilities, nuclear and fossil decommissioning, revenue requirements.
10/97	R-974009	PA	Penelec Industrial Customer Alliance	Pennsylvania Electric Co.	Restructuring, deregulation, stranded costs, regulatory assets, liabilities, nuclear and fossil decommissioning, revenue requirements.
11/97	97-204 (Rebuttal)	KY	Alcan Aluminum Corp. Southwire Co.	Big Rivers Electric Corp.	Restructuring, revenue requirements, reasonableness of rates, cost allocation.

Expert Testimony Appearances
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Date	Case	Jurisdict.	Party	Utility	Subject
11/97	U-22491	LA	Louisiana Public Service Commission	Entergy Gulf States, Inc.	Allocation of regulated and nonregulated costs, other revenue requirement issues.
11/97	R-00973953 (Surrebuttal)	PA	Philadelphia Area Industrial Energy Users Group	PECO Energy Co.	Restructuring, deregulation, stranded costs, regulatory assets, liabilities, nuclear and fossil decommissioning.
11/97	R-973981	PA	West Penn Power Industrial Intervenors	West Penn Power Co.	Restructuring, deregulation, stranded costs, regulatory assets, liabilities, fossil decommissioning, revenue requirements, securitization.
11/97	R-974104	PA	Duquesne Industrial Intervenors	Duquesne Light Co.	Restructuring, deregulation, stranded costs, regulatory assets, liabilities, nuclear and fossil decommissioning, revenue requirements, securitization.
12/97	R-973981 (Surrebuttal)	PA	West Penn Power Industrial Intervenors	West Penn Power Co.	Restructuring, deregulation, stranded costs, regulatory assets, liabilities, fossil decommissioning, revenue requirements.
12/97	R-974104 (Surrebuttal)	PA	Duquesne Industrial Intervenors	Duquesne Light Co.	Restructuring, deregulation, stranded costs, regulatory assets, liabilities, nuclear and fossil decommissioning, revenue requirements, securitization.
1/98	U-22491 (Surrebuttal)	LA	Louisiana Public Service Commission Staff	Entergy Gulf States, Inc.	Allocation of regulated and nonregulated costs, other revenue requirement issues.
2/98	8774	MD	Westvaco	Potomac Edison Co.	Merger of Duquesne, AE, customer safeguards, savings sharing.

Expert Testimony Appearances
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Date	Case	Jurisdict.	Party	Utility	Subject
3/98	U-22092 (Allocated Stranded Cost Issues)	LA	Louisiana Public Service Commission Staff	Entergy Gulf States, Inc.	Restructuring, stranded costs, regulatory assets, securitization, regulatory mitigation.
3/98	8390-U	GA	Georgia Natural Gas Group, Georgia Textile Manufacturers Assoc.	Atlanta Gas Light Co.	Restructuring, unbundling, stranded costs, incentive regulation, revenue requirements.
3/98	U-22092 (Allocated Stranded Cost Issues) (Surrebuttal)	LA	Louisiana Public Service Commission Staff	Entergy Gulf States, Inc.	Restructuring, stranded costs, regulatory assets, securitization, regulatory mitigation.
10/98	97-596	ME	Maine Office of the Public Advocate	Bangor Hydro-Electric Co.	Restructuring, unbundling, stranded costs, T&D revenue requirements.
10/98	9355-U	GA	Georgia Public Service Commission Adversary Staff	Georgia Power Co.	Affiliate transactions.
10/98	U-17735	LA	Louisiana Public Service Commission Staff	Cajun Electric Power Cooperative	G&T cooperative ratemaking policy, other revenue requirement issues.
11/98	U-23327	LA	Louisiana Public Service Commission Staff	SWEPCO, CSW and AEP	Merger policy, savings sharing mechanism, affiliate transaction conditions.
12/98	U-23358 (Direct)	LA	Louisiana Public Service Commission Staff	Entergy Gulf States, Inc.	Allocation of regulated and nonregulated costs, tax issues, and other revenue requirement issues.
12/98	98-577	ME	Maine Office of Public Advocate	Maine Public Service Co.	Restructuring, unbundling, stranded cost, T&D revenue requirements.
1/99	98-10-07	CT	Connecticut Industrial Energy Consumers	United Illuminating Co.	Stranded costs, investment tax credits, accumulated deferred income taxes, excess deferred income taxes.

Expert Testimony Appearances
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Date	Case	Jurisdict.	Party	Utility	Subject
3/99	U-23358 (Surrebuttal)	LA	Louisiana Public Service Commission Staff	Entergy Gulf States, Inc.	Allocation of regulated and nonregulated costs, tax issues, and other revenue requirement issues.
3/99	98-474	KY	Kentucky Industrial Utility Customers	Louisville Gas and Electric Co.	Revenue requirements, alternative forms of regulation.
3/99	98-426	KY	Kentucky Industrial Utility Customers	Kentucky Utilities Co.	Revenue requirements, alternative forms of regulation.
3/99	99-082	KY	Kentucky Industrial Utility Customers	Louisville Gas and Electric Co.	Revenue requirements.
3/99	99-083	KY	Kentucky Industrial Utility Customers	Kentucky Utilities Co.	Revenue requirements.
4/99	U-23358 (Supplemental Surrebuttal)	LA	Louisiana Public Service Commission Staff	Entergy Gulf States, Inc.	Allocation of regulated and nonregulated costs, tax issues, and other revenue requirement issues.
4/99	99-03-04	CT	Connecticut Industrial Energy Consumers mechanisms.	United Illuminating Co.	Regulatory assets and liabilities, stranded costs, recovery
4/99	99-02-05	CT	Connecticut Industrial Utility Customers mechanisms.	Connecticut Light and Power Co.	Regulatory assets and liabilities stranded costs, recovery
5/99	98-426 99-082 (Additional Direct)	KY	Kentucky Industrial Utility Customers	Louisville Gas and Electric Co.	Revenue requirements.
5/99	98-474 99-083 (Additional Direct)	KY	Kentucky Industrial Utility Customers	Kentucky Utilities Co.	Revenue requirements.
5/99	98-426 98-474 (Response to Amended Applications)	KY	Kentucky Industrial Utility Customers Kentucky Utilities Co.	Louisville Gas and Electric Co. and	Alternative regulation.

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Date	Case	Jurisdict.	Party	Utility	Subject
6/99	97-596	ME	Maine Office of Public Advocate	Bangor Hydro-Electric Co.	Request for accounting order regarding electric industry restructuring costs.
6/99	U-23358	LA	Louisiana Public Public Service Comm. Staff	Entergy Gulf States, Inc.	Affiliate transactions, cost allocations.
7/99	99-03-35	CT	Connecticut Industrial Energy Consumers	United Illuminating Co.	Stranded costs, regulatory assets, tax effects of asset divestiture.
7/99	U-23327	LA	Louisiana Public Service Commission Staff	Southwestern Electric Power Co., Central and South West Corp, and American Electric Power Co.	Merger Settlement Stipulation.
7/99	97-596 (Surrebuttal)	ME	Maine Office of Public Advocate	Bangor Hydro-Electric Co.	Restructuring, unbundling, stranded cost, T&D revenue requirements.
7/99	98-0452-E-GI	WVa	West Virginia Energy Users Group	Monongahela Power, Potomac Edison, Appalachian Power, Wheeling Power	Regulatory assets and liabilities.
8/99	98-577 (Surrebuttal)	ME	Maine Office of Public Advocate	Maine Public Service Co.	Restructuring, unbundling, stranded costs, T&D revenue requirements.
8/99	98-426 99-082 (Rebuttal)	KY	Kentucky Industrial Utility Customers	Kentucky Utilities Co.	Revenue requirements.
8/99	98-474 98-083 (Rebuttal)	KY	Kentucky Industrial Utility Customers	Louisville Gas and Electric Co. and Kentucky Utilities Co.	Alternative forms of regulation.
8/99	98-0452-E-GI (Rebuttal)	WVa	West Virginia Energy Users Group	Monongahela Power, Potomac Edison, Appalachian Power, Wheeling Power	Regulatory assets and liabilities.

**Expert Testimony Appearances
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As of January 2006**

Date	Case	Jurisdict.	Party	Utility	Subject
10/99	U-24182 (Direct)	LA	Louisiana Public Service Commission Staff	Entergy Gulf States, Inc.	Allocation of regulated and nonregulated costs, affiliate transactions, tax issues, and other revenue requirement issues.
11/99	21527	TX	Dallas-Ft.Worth Hospital Council and Coalition of Independent Colleges and Universities	TXU Electric	Restructuring, stranded costs, taxes, securitization.
11/99	U-23358 Surrebuttal Affiliate Transactions Review	LA	Louisiana Public Service Commission Staff	Entergy Gulf States, Inc.	Service company affiliate transaction costs.
04/00	99-1212-EL-ETPOH 99-1213-EL-ATA 99-1214-EL-AAM		Greater Cleveland Growth Association	First Energy (Cleveland Electric Illuminating, Toledo Edison)	Historical review, stranded costs, regulatory assets, liabilities.
01/00	U-24182 (Surrebuttal)	LA	Louisiana Public Service Commission Staff	Entergy Gulf States, Inc.	Allocation of regulated and nonregulated costs, affiliate transactions, tax issues, and other revenue requirement issues.
05/00	2000-107	KY	Kentucky Industrial Utility Customers	Kentucky Power Co.	ECR surcharge roll-in to base rates.
05/00	U-24182 (Supplemental Direct)	LA	Louisiana Public Service Commission Staff	Entergy Gulf States, Inc.	Affiliate expense proforma adjustments.
05/00	A-110550F0147	PA	Philadelphia Area Industrial Energy Users Group	PECO Energy	Merger between PECO and Unicom.
07/00	22344	TX	The Dallas-Fort Worth Hospital Council and The Coalition of Independent Colleges and Universities	Statewide Generic Proceeding	Escalation of O&M expenses for unbundled T&D revenue requirements in projected test year.
05/00	99-1658-EL-ETP	OH	AK Steel Corp.	Cincinnati Gas & Electric Co.	Regulatory transition costs, including regulatory assets and liabilities, SFAS 109, ADIT, EDIT, ITC.

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Date	Case	Jurisdict.	Party	Utility	Subject
07/00	U-21453	LA	Louisiana Public Service Commission	SWEPCO	Stranded costs, regulatory assets and liabilities.
08/00	U-24064	LA	Louisiana Public Service Commission Staff	CLECO	Affiliate transaction pricing ratemaking principles, subsidization of nonregulated affiliates, ratemaking adjustments.
10/00	PUC 22350 SOAH 473-00-1015	TX	The Dallas-Ft. Worth Hospital Council and The Coalition of Independent Colleges And Universities	TXU Electric Co.	Restructuring, T&D revenue requirements, mitigation, regulatory assets and liabilities.
10/00	R-00974104 (Affidavit)	PA	Duquesne Industrial Intervenors	Duquesne Light Co.	Final accounting for stranded costs, including treatment of auction proceeds, taxes, capital costs, switchback costs, and excess pension funding.
11/00	P-00001837 R-00974008 P-00001838 R-00974009		Metropolitan Edison Industrial Users Group Penelec Industrial Customer Alliance	Metropolitan Edison Co. Pennsylvania Electric Co.	Final accounting for stranded costs, including treatment of auction proceeds, taxes, regulatory assets and liabilities, transaction costs.
12/00	U-21453, U-20925, U-22092 (Subdocket C) (Surrebuttal)	LA	Louisiana Public Service Commission Staff f	SWEPCO	Stranded costs, regulatory assets.
01/01	U-24993 (Direct)		Louisiana Public Service Commission Staff	Entergy Gulf States, Inc.	Allocation of regulated and nonregulated costs, tax issues, and other revenue requirement issues.
01/01	U-21453, U-20925 and U-22092 (Subdocket B) (Surrebuttal)		Louisiana Public Service Commission Staff	Entergy Gulf States, Inc,.	Industry restructuring, business separation plan, organization structure, hold harmless conditions, financing.
01/01	Case No. 2000-386	KY	Kentucky Industrial Utility Customers, Inc.	Louisville Gas & Electric Co.	Recovery of environmental costs, surcharge mechanism.
01/01	Case No. 2000-439	KY	Kentucky Industrial Utility Customers, Inc.	Kentucky Utilities Co.	Recovery of environmental costs, surcharge mechanism.

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Date	Case	Jurisdict.	Party	Utility	Subject
02/01	A-110300F0095 A-110400F0040	PA	Met-Ed Industrial Users Group Penelec Industrial Customer Alliance	PU, Inc. FirstEnergy	Merger, savings, reliability.
03/01	P-00001860 P-00001861	PA	Met-Ed Industrial Users Group Penelec Industrial Customer Alliance	Metropolitan Edison Co. and Pennsylvania Electric Co.	Recovery of costs due to provider of last resort obligation.
04 /01	U-21453, U-20925, U-22092 (Subdocket B) Settlement Term Sheet	LA	Louisiana Public Public Service Comm. Staff	Entergy Gulf States, Inc.	Business separation plan: settlement agreement on overall plan structure.
04 /01	U-21453, U-20925, U-22092 (Subdocket B) Contested Issues	LA	Louisiana Public Public Service Comm. Staff	Entergy Gulf States, Inc.	Business separation plan: agreements, hold harmless conditions, separations methodology.
05 /01	U-21453, U-20925, U-22092 (Subdocket B) Contested Issues Transmission and Distribution (Rebuttal)	LA	Louisiana Public Public Service Comm. Staff	Entergy Gulf States, Inc.	Business separation plan: agreements, hold harmless conditions, Separations methodology.
07/01	U-21453, U-20925, U-22092 (Subdocket B) Transmission and Distribution Term Sheet	LA	Louisiana Public Public Service Comm. Staff	Entergy Gulf States, Inc.	Business separation plan: settlement agreement on T&D issues, agreements necessary to implement T&D separations, hold harmless conditions, separations methodology.
10/01	14000-U	GA	Georgia Public Service Commission Adversary Staff	Georgia Power Co.	Review requirements, Rate Plan, fuel clause recovery.
11/01 (Direct)	14311-U	GA	Georgia Public Service Commission Adversary Staff	Atlanta Gas Light Co.	Revenue requirements, revenue forecast, O&M expense, depreciation, plant additions, cash working capital.

**Expert Testimony Appearances
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Date	Case	Jurisdict.	Party	Utility	Subject
11/01 (Direct)	U-25687	LA	Louisiana Public Service Commission	Entergy Gulf States, Inc.	Revenue requirements, capital structure, allocation of regulated and nonregulated costs, River Bend uprate.
02/02	25230	TX	Dallas Ft.-Worth Hospital Council & the Coalition of Independent Colleges & Universities	TXU Electric	Stipulation. Regulatory assets, securitization financing.
02/02 (Surrebuttal)	U-25687	LA	Louisiana Public Service Commission	Entergy Gulf States, Inc.	Revenue requirements, corporate franchise tax, conversion to LLC, River Bend uprate.
03/02 (Rebuttal)	14311-U	GA	Georgia Public Service Commission Adversary Staff	Atlanta Gas Light Co.	Revenue requirements, earnings sharing plan, service quality standards.
03/02	001148-EI	FL	South Florida Hospital and Healthcare Assoc.	Florida Power & Light Co.	Revenue requirements. Nuclear life extension, storm damage accruals and reserve, capital structure, O&M expense.
04/02 (Supplemental Surrebuttal)	U-25687	LA	Louisiana Public Service Commission	Entergy Gulf States, Inc.	Revenue requirements, corporate franchise tax, conversion to LLC, River Bend uprate.
04/02	U-21453, U-20925 and U-22092 (Subdocket C)		Louisiana Public Service Commission Staff	SWEPCO	Business separation plan, T&D Term Sheet, separations methodologies, hold harmless conditions.
08/02	EL01-88-000	FERC	Louisiana Public Service Commission Staff	Entergy Services, Inc. and The Entergy Operating Companies	System Agreement, production cost equalization, tariffs.
08/02	U-25888	LA	Louisiana Public Service Commission	Entergy Gulf States, Inc. and Entergy Louisiana, Inc.	System Agreement, production cost disparities, prudence.
09/02	2002-00224 2002-00225	KY	Kentucky Industrial Utilities Customers, Inc.	Kentucky Utilities Co. Louisville Gas & Electric Co.	Line losses and fuel clause recovery associated with off-system sales.
11/02	2002-00146 2002-00147	KY	Kentucky Industrial Utilities Customers, Inc.	Kentucky Utilities Co. Louisville Gas & Electric Co.	Environmental compliance costs and surcharge recovery.
01/03	2002-00169	KY	Kentucky Industrial Utilities Customers, Inc.	Kentucky Power Co.	Environmental compliance costs and surcharge recovery.

Expert Testimony Appearances
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Date	Case	Jurisdict.	Party	Utility	Subject
04/03	2002-00429 2002-00430	KY	Kentucky Industrial Utility Customers, Inc.	Kentucky Utilities Co. Louisville Gas & Electric Co.	Extension of merger surcredit, flaws in Companies' studies.
04/03	U-26527	LA	Louisiana Public Service Commission	Entergy Gulf States, Inc.	Revenue requirements, corporate franchise tax, conversion to LLC, Capital structure, post test year Adjustments.
06/03	EL01-88-000 Rebuttal	FERC	Louisiana Public Service Commission Staff	Entergy Services, Inc. and the Entergy Operating Companies	System Agreement, production cost equalization, tariffs.
06/03	2003-00068	KU	Kentucky Industrial Utility Customers	Kentucky Utilities Co.	Environmental cost recovery, correction of base rate error.
11/03	ER03-753-000	FERC	Louisiana Public Service Commission Staff	Entergy Services, Inc. and the Entergy Operating Companies	Unit power purchases and sale cost-based tariff pursuant to System Agreement.
11/03	ER03-583-000, ER03-583-001, and ER03-583-002 ER03-681-000, ER03-681-001 ER03-682-000, ER03-682-001, and ER03-682-002 ER03-744-000, ER03-744-001 (Consolidated	FERC	Louisiana Public Service Commission	Entergy Services, Inc., the Entergy Operating Companies, EWO Marketing, L.P, and Entergy Power, Inc.	Unit power purchase and sale agreements, contractual provisions, projected costs, levelized rates, and formula rates.
12/03	U-26527 Surrebuttal	LA	Louisiana Public Service Commission	Entergy Gulf States, Inc.	Revenue requirements, corporate franchise tax, conversion to LLC, Capital structure, post test year adjustments.
12/03	2003-0334 2003-0335	KY	Kentucky Industrial Utility Customers, Inc.	Kentucky Utilities Co. Louisville Gas & Electric Co.	Earnings Sharing Mechanism.
12/03	U-27136	LA	Louisiana Public Service Commission	Entergy Louisiana, Inc.	Purchased power contracts between affiliates, terms and conditions.

Expert Testimony Appearances
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As of January 2006

Date	Case	Jurisdict.	Party	Utility	Subject
03/04	U-26527 Supplemental Surrebuttal	LA	Louisiana Public Service Commission	Entergy Gulf States, Inc.	Revenue requirements, corporate franchise tax, conversion to LLC, capital structure, post test year adjustments.
03/04	2003-00433	KY	Kentucky Industrial Utility Customers, Inc.	Louisville Gas & Electric Co.	Revenue requirements, depreciation rates, O&M expense, deferrals and amortization, earnings sharing mechanism, merger surcredit, VDT surcredit.
03/04	2003-00434	KY	Kentucky Industrial Utility Customers, Inc.	Kentucky Utilities Co.	Revenue requirements, depreciation rates, O&M expense, deferrals and amortization, earnings sharing mechanism, merger surcredit, VDT surcredit.
03/04	SOAH Docket 473-04-2459, PUC Docket 29206	TX	Cities Served by Texas-New Mexico Power Co.	Texas-New Mexico Power Co.	Stranded costs true-up, including including valuation issues, ITC, ADIT, excess earnings.
05/04	04-169-EL-	OH	Ohio Energy Group, Inc.	Columbus Southern Power Co. & Ohio Power Co.	Rate stabilization plan, deferrals, T&D rate increases, earnings.
06/04	SOAH Docket 473-04-4555 PUC Docket 29526	TX	Houston Council for Health and Education	CenterPoint Energy Houston Electric	Stranded costs true-up, including valuation issues, ITC, EDIT, excess mitigation credits, capacity auction true-up revenues, interest.
08/04	SOAH Docket 473-04-4556 PUC Docket 29526 (Suppl Direct)	TX	Houston Council for Health and Education	CenterPoint Energy Houston Electric	Interest on stranded cost pursuant to Texas Supreme Court remand.
09/04	Docket No. U-23327 Subdocket B	LA	Louisiana Public Service Commission	SWEPCO	Fuel and purchased power expenses recoverable through fuel adjustment clause, trading activities, compliance with terms of various LPSC Orders.
10/04	Docket No. U-23327 Subdocket A	LA	Louisiana Public Service Commission	SWEPCO	Revenue requirements.

Expert Testimony Appearances
of
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As of January 2006

Date	Case	Jurisdict.	Party	Utility	Subject
12/04	Case No. 2004-00321 Case No. 2004-00372	KY	Gallatin Steel Co.	East Kentucky Power Cooperative, Inc., Big Sandy RECC, etal.	Environmental cost recovery, qualified costs, TIER requirements, cost allocation.
02/05	18638-U	GA	Georgia Public Service Commission	Atlanta Gas Light Co.	Revenue requirements.
02/05	18638-U Panel with Tony Wackerly	GA	Georgia Public Service Commission	Atlanta Gas Light Co.	Comprehensive rate plan, pipeline replacement program surcharge, performance based rate plan.
02/05	18638-U Panel with Michelle Thebert	GA	Georgia Public Service Commission	Atlanta Gas Light Co.	Energy conservation, economic development, and tariff issues.
03/05	Case No. 2004-00426 Case No. 2004-00421	KY	Kentucky Industrial Utility Customers, Inc.	Kentucky Utilities Co. Louisville Gas & Electric	Environmental cost recovery, Jobs Creation Act of 2004 and § 199 deduction, excess common equity ratio, deferral and amortization of nonrecurring O&M expense.
06/05	2005-00068	KY	Kentucky Industrial Utility Customers, Inc.	Kentucky Power Co.	Environmental cost recovery, Jobs Creation Act of 2004 and §199 deduction, margins on allowances used for AEP System sales.
06/05	050045-EI	FL	South Florida Hospital and Healthcare Assoc.	Florida Power & Light Co.	Storm damage expense and reserve, RTO costs, O&M expense projections, return on equity performance incentive, capital structure, selective second phase post-test year rate increase.
09/05	20298-U	GA	Georgia Public Service Commission	Atmos Energy Corp.	Revenue requirements, roll-in of surcharges, cost recovery through surcharge, reporting requirements.
09/05	20298-U Panel with Victoria Taylor	GA	Georgia Public. Service Commission	Atmos Energy Corp.	Affiliate transactions, cost allocations, capitalization, cost of debt.
11/05	2005-00351 2005-00352	KY	Kentucky Industrial Utility Customers, Inc.	Kentucky Utilities Co. Louisville Gas and Electric Co.	Workforce Separation Program cost recovery and shared savings through VDT surcredit.

EXHIBIT ____ (LK-2)

OJS Exhibit No. 1

DIRECT TESTIMONY OF
OLIVER J SEVER
ON BEHALF OF APPALACHIAN POWER COMPANY AND
WHEELING POWER COMPANY
BEFORE THE PUBLIC SERVICE COMMISSION
OF WEST VIRGINIA IN CASE NO. 05-1278-E-PC-PW-42T

Q. PLEASE STATE YOUR NAME, BUSINESS ADDRESS AND POSITION.

A. My name is Oliver J. Sever. My business address is 1 Riverside Plaza, Columbus, Ohio 43215. I am employed by American Electric Power Service Corporation (AEPSC), as Managing Director of Financial Forecasting. AEPSC supplies engineering, financing, accounting and similar planning and advisory services to the subsidiaries of American Electric Power Company, Inc. (AEP), of which Appalachian Power Company (APCo) and Wheeling Power Company (WPCo) are operating subsidiaries. Hereinafter I will refer to these companies either individually as APCo or WPCo or jointly as "the Companies".

Q. PLEASE BRIEFLY DESCRIBE YOUR EDUCATIONAL BACKGROUND AND BUSINESS EXPERIENCE.

A. I received a Bachelor of Science Degree in Business Administration from The Ohio State University in 1979, and a Master of Business Administration from the University of Dayton in 1983. In addition, I completed the Darden Partnership Program at the Darden Graduate School of Business Administration, University of Virginia, in February 1997.

After working in the Controller's Division of a non-affiliated utility for the period 1979 to 1983, I joined AEPSC in 1983 as an Assistant Financial Analyst in the Controller's Department (now Corporate Planning and Budgeting Division). I was promoted to Financial Analyst in June 1984, Senior Financial Analyst in January 1987, Senior Administrative Assistant II in January 1990, Senior Administrative Assistant I in January 1992, Manager of Financial Planning and Forecasting in April 1992 and Director of Financial Planning and Forecasting in January 1998. I was elected Vice President of Financial Planning in June 2000 and assumed my current position in July 2005.

Q. WHAT ARE YOUR DUTIES AND RESPONSIBILITIES AS MANAGING DIRECTOR OF FINANCIAL FORECASTING?

A. I am responsible for the administration and supervision of the financial forecasting processes for the AEP System. In this capacity, I coordinate utilization of short-term and long-term financial planning models used in the development of operating and capital expenditure forecasts for the AEP System, provide management with the projected operational data underlying the financial forecast, monitor actual performance and review the preparation of forecasted information for use in regulatory proceedings.

Q. HAVE YOU EVER APPEARED AS A WITNESS BEFORE A REGULATORY COMMISSION?

A. Yes, in addition to previous testimony filed before this Commission, I have testified on behalf of APCo before the Virginia State Corporation Commission and the Federal Energy Regulatory Commission (FERC). I have also testified on behalf of Indiana Michigan Power Company before the Michigan Public Service Commission and the

Indiana Utility Regulatory Commission and have testified on behalf of Ohio Power Company (OPCo) before the Public Utilities Commission of Ohio.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY IN THIS PROCEEDING?

A. The purpose of my testimony can be divided into three parts, which I have organized in sections. In Section 1, I will present the forecast of the Companies' Expanded Net Energy Cost (ENEC) and Requirement for the periods ending December 31, 2006, 2007 and 2008. In Section 2, I support certain total going-level adjustments to the test-year level of revenue and expense. These adjustments recognize the planned shift of Century Aluminum and Pechiney from OPCo to APCo and modify the test-year level of steam plant maintenance to recognize the post test-year in-service date of the Amos Selective Catalytic Reduction (SCR) facilities. In Section 3, I provide the actual capital structure and associated cost of debt and preferred stock as of December 2004 for the Companies, as well as projections of the same information for the years ended December 2005, 2006, 2007 and 2008. I also support the Companies' projected level of construction expenditures for 2005, 2006 and 2007 and the related use and sources of funds statement shown in Statement C, pages 34 and 35 of 38. Finally, I support the forecasted dollars of investment used by Company witness Eads to calculate the individual revenue requirements associated with the proposed incremental surcharges.

Q. WERE THE DATA YOU ARE RELYING ON PREPARED BY YOU OR UNDER YOUR SUPERVISION?

A. Yes. They represent the combined efforts of numerous AEP personnel. I have reviewed the data and believe they are based on valid assumptions and are representative of revenues and costs expected in the future.

Section 1 – Expanded Net Energy Cost (ENEC) and Requirement

Q. **HAVE YOU FILED EXHIBITS TO SUPPORT YOUR TESTIMONY REGARDING ENEC?**

A. Yes, I am sponsoring the following exhibits:

- OJS Exhibit No. 2 summarizes the Companies' forecasted ENEC and Requirement for the years 2006 – 2008;
- OJS Exhibit No. 3 is a sources and uses of energy statement for the years 2006 – 2008; and
- OJS Exhibit No. 4 details the projected West Virginia jurisdictional sales for the years 2006 – 2008.

Q. **WOULD YOU PLEASE DEFINE ENEC?**

A. As shown on OJS Exhibit No. 2, ENEC is defined as the net cost of all sources of energy incurred in supplying the Companies' internal load plus certain other costs and credits. OJS Exhibit No. 2, page 1 of 2, provides the ENEC and OJS Exhibit No. 2, page 2 of 2 provides the corresponding energy requirement. The costs include fossil fuel consumed, purchased power from external sources, and System Pool transactions, which are offset by revenues from off-system sales. In addition, ENEC includes certain other revenues associated with transmission service and emission allowance gains, as well as certain other production costs. These costs are primarily for fuel handling and environmental costs such as chemicals and the cost of emission allowances.

Q. WAS THE PROJECTED ENEC DEVELOPED USING THE SAME BASIC METHODOLOGY USED FOR FORECASTING ENEC IN THE MOST RECENT RATE PROCEEDING BEFORE THIS COMMISSION?

A. Generally, the process and intent of the ENEC schedules has not changed from the last filing. However, since that time, the items included in the ENEC have been expanded to include additional variable costs. Most notable is the cost of "consumables" related to environmental facilities. In addition to the cost of the fuel, incremental consumable expenses associated with operating SCR and Flue Gas Desulfurization environmental facilities are now included in the derivation of ENEC. In addition to the total APCo ENEC for APCo West Virginia, OJS Exhibit No. 2 includes footnotes relating to the cost to serve WPCo's retail customers.

Fuel Expense and Fuel Handling (OJS Exhibit No. 2, Page 1, lines 3, 4)

Q. PLEASE DESCRIBE HOW APCO'S PROJECTED COSTS OF FUEL CONSUMED AND FUEL HANDLING WERE CALCULATED?

A. The cost of fossil fuel consumed was based on the generation forecast for each of APCo's fossil generating units as projected for the years 2006 through 2008 by AEPSC's Resource Planning Section utilizing the simulation model PROMOD. PROMOD utilizes the cost of fuel delivered, as supplied by Company witness Baker, scheduled maintenance outages and forced outage factors to determine the level of generation required to meet load.

APPALACHIAN POWER COMPANY
AND WHEELING POWER COMPANY
Expanded Net Energy Cost and Requirement
For the Years 2006 - 2008
($000)

OJS Exhibit No. 2
Page 1 of 2

Line No.		Year 2006	Year 2007	Year 2008
1	Expanded Net Energy Cost and Requirement ($000)			
2	Fossil Generation (Energy)			
3	Fuel Expense	531,855	547,303	523,091
4	Fuel Handling	11,495	13,654	13,797
5	Plus:			
6	Purchased Power (Demand)	32,626	31,074	37,704
7	Purchased Power (Energy)	52,238	59,596	41,364
8	Capacity Settlement (Demand)	172,041	181,995	196,017
9	Off-System Sales Received from Pool (Demand)	-	-	-
10	Off-System Sales Received from Pool (Energy)	116,829	117,986	129,302
11	Primary Energy Received (Energy)	186,588	157,068	205,471
12	PJM Costs - Excluding Admin (Demand)	9,177	10,242	10,133
13	SO2 and NOx Expenses (Energy)	14,113	22,901	28,445
14	Less:			
15	Energy Delivered to Pool for Off-System Sales (Demand)	-	-	-
16	Energy Delivered to Pool for Off-System Sales (Energy)	116,822	119,002	122,619
17	Primary Energy Delivered (Energy)	-	34	-
18	CSW Tie Revenue (Energy)	27,272	29,553	28,162
19	Transmission Settlement (Demand)	11,680	32,074	35,771
20	3rd Party Transmission Revenue (Demand)	42,129	27,108	26,820
21	Off-System Sales Revenue (Demand)	-	-	-
22	Off-System Sales Revenue (Energy)	294,150	275,711	290,260
23	FTR Revenue Net of Congestion Costs (Demand)	4,086	-	-
24	Gain/(Loss) on Sale of Allowances (Energy)	9,135	9,728	1,124
25	Sub-Total Expanded Net Energy Cost ($000)	621,687	648,608	680,568
26	Wyoming-Jacksons Ferry Loss Factor Adjustment (Demand)	-	(5,737)	(6,893)
27	Wyoming-Jacksons Ferry Loss Factor Adjustment (Energy)	-	293	339
28	Total Adjusted Expanded Net Energy Cost ($000)	621,687	643,164	674,014
29	Expanded Net Energy Cost and Requirement (Demand & Energy)			
30	Total Demand	155,949	158,392	174,370
31	Total Energy	465,738	484,772	499,644
32	Total Expanded Net Energy Cost ($000)	621,687	643,164	674,014
33	*Memo Items:*			
34	Wheeling Purchases (Demand)	24,199	24,595	24,809
35	Wheeling Purchases (Energy)	41,315	46,527	48,513

APPALACHIAN POWER COMPANY
AND WHEELING POWER COMPANY
Expanded Net Energy Cost and Requirement
For the Years 2006 - 2008
(GWh)

Line No.		Year 2006	Year 2007	Year 2008
1	Expanded Net Energy Cost and Requirement (GWh)			
2	Fossil Generation	28,676	31,363	30,239
3	Hydro Generation	605	620	626
4	Total Generation	29,281	31,983	30,865
5	Plus:			
6	Purchased Power	3,454	3,679	3,410
7	Off-System Sales Received from Pool	6,133	5,915	6,200
8	Primary Energy Received	13,361	10,841	12,373
9	Other	-	-	-
10	Less:			
11	Energy Delivered to Pool for Off-System Sales	5,332	5,347	5,121
12	Primary Energy Delivered	-	2	-
13	Off-System Sales	8,592	8,341	8,527
14	Expanded Net Energy Cost and Requirement (GWh)	38,305	38,728	39,199
15	Memo Item:			
16	Wheeling Purchases	2,190	2,228	2,255

Agreement, which is subject to the jurisdiction of the FERC, regulates the inter-company charges and credits for capacity and energy among the AEP Operating companies with generating facilities (Pool members). The Pool members are APCo, Columbus Southern Power Company, OPCo, Kentucky Power Company and Indiana Michigan Power Company.

In accordance with the Pool Agreement, APCo's capacity settlement charges were calculated by multiplying its projected capacity deficit by the equalization rate. APCo is a deficit member of the Pool and its deficit position was determined by multiplying its Member Load Ratio (MLR) by the total system capacity, and comparing that result to its own capacity. The equalization rate is composed of a fixed investment rate and a fixed operating rate based on the cost of the surplus companies. To the extent there is more than one surplus company then the deficit companies' equalization rate will be based on the weighted rates of the surplus companies.

<u>Off-System Sales Received from Pool (OJS Exhibit No. 2, page 1, lines 9, 10)</u>

Q. DEFINE THE COSTS INCLUDED IN OFF-SYSTEM SALES RECEIVED FROM THE AEP POOL.

A. In accordance with the Pool Agreement, the cost of off-system sales received from the Pool is APCo's MLR share of the total costs incurred by the AEP System, less its MLR share of the APCo-owned generation for off-system sales. This item is APCo's allocated share of the total system cost incurred to make these sales to third parties.

<u>Primary Energy Received (OJS Exhibit No. 2, page 1, line 11)</u>

Q. HOW WAS PRIMARY ENERGY RECEIVED CALCULATED?

A. In accordance with the Pool Agreement, the charges for primary energy received were priced at the average variable cost (fuel + ½ maintenance expense) of the company delivering energy to APCo.

PJM Costs – Excluding Admin (OJS Exhibit No. 2, page 1, line 12)

Q. DESCRIBE THE COSTS INCLUDED IN "PJM COSTS – EXCLUDING ADMIN".

A. This value is the forecasted cost of operating within the PJM environment (the benefits of PJM membership are embedded in other components of ENEC). Included are estimated exit and SECA (Seams Elimination Cost Assignment) costs. Exit costs are for firm and non-firm, point-to-point transmission costs to transfer power within PJM. SECA costs are transitional costs/revenues approved by FERC for the recovery of lost revenues associated with the elimination of rate pancaking between PJM and the Midwest ISO.

SO_2 and NO_x Expenses (OJS Exhibit No. 2, page 1, line 13)

Q. DESCRIBE THE COSTS INCLUDED IN "SO_2 AND NO_X EXPENSES".

A. "SO_2 and NO_X Expenses" include the costs of consumed emission allowances and chemical consumables used to minimize emissions. The expenses associated with SO_2 have been estimated pursuant to the methodology established in the FERC-approved AEP Interim Allowance Agreement (IAA). NO_X expenses are projected to be zero during the forecast period ending December 31, 2006. Other expenses for consumables include, but may not be limited to lime, limestone, urea and trona.

Energy Delivered to Pool for Off-System Sales (OJS Exhibit No. 2, page 1, lines 15, 16)

Q. PLEASE EXPLAIN ENERGY DELIVERED TO POOL FOR OFF-SYSTEM SALES.

A. The credits associated with the energy delivered to the Pool for off-system sales are the cost of APCo's generation or purchases assigned to those sales. Those credits were reduced by APCo's MLR share of its own generation used for off-system sales in order to prevent recording a sale of energy to itself. This component of the Pool reduces the ENEC for costs incurred by APCo, but assigned off-system.

Primary Energy Delivered (OJS Exhibit No. 2, page 1, line 17)

Q. DESCRIBE HOW PRIMARY ENERGY DELIVERED IS CALCULATED.

A. To the extent APCo has energy available for other member companies during an hour, PROMOD would sell that energy to the Pool. APCo would be reimbursed based on its average variable cost of production (fuel + ½ maintenance expense). No such sales are projected for 2006; however, a minor level of energy is projected to be sold to the Pool in 2007.

CSW Tie Revenue (OJS Exhibit No. 2, page 1, line 18)

Q. PLEASE EXPLAIN CSW TIE REVENUE.

A. To the extent that AEP's east zone has available power to sell to AEP's west zone, the power is sold between zones at market prices. The FERC-approved AEP System

Integration Agreement governs these inter-zone transactions. When such transactions occur, the east companies generating for the sale are reimbursed for their costs and receive their MLR share of the margin generated by the sale. The value on line 18 is the projected amount for sales to the west zone of AEP.

Transmission Settlement (OJS Exhibit No.2, page 1, line 19)

Q. **EXPLAIN HOW THE TRANSMISSION SETTLEMENT IS CALCULATED.**

A. APCo's transmission settlement revenue is calculated in accordance with the FERC-approved AEP Transmission Equalization Agreement (TEA). The TEA regulates the inter-company charges and credits for high-voltage transmission investment among the same AEP Operating companies which are parties to the Pool Agreement. In accordance with the TEA, APCo's transmission revenue is calculated by multiplying its projected transmission investment surplus by its carrying charge rate. With the completion of the Wyoming-Jacksons Ferry line in mid 2006, APCo is projected to be a surplus member of the transmission pool and its surplus position is determined by multiplying the MLR by the total system investment, and comparing that result to its own investment.

Third Party Transmission Revenue (OJS Exhibit No. 2, page 1, line 20)

Q. **EXPLAIN HOW THIRD PARTY TRANSMISSION REVENUE IS PROJECTED.**

A. Third party transmission revenue consists of fees paid to the AEP east companies for use of their transmission lines. The AEP east companies are reimbursed in accordance with the FERC-approved OATT (Open Access Transmission Tariff) and APCo shares in these reimbursements based on its MLR.

Off-System Sales Revenue (OJS Exhibit No. 2, page 1, lines 21, 22)

Q. DESCRIBE HOW REVENUES FROM OFF-SYSTEM SALES WERE DETERMINED.

A. Revenues from the various components of off-system sales were developed on a System basis with APCo receiving credit for its MLR share of such revenue. Specifically, the revenues were based on the kWh sales levels included in the AEPSC Load Forecast. Revenues related to known off-system sales were developed in accordance with the terms of the specific existing agreements governing those known off-system sales. The remaining sales are assumed sales with unknown parties. The revenues for such sales assume the recovery of costs incurred to make the sale along with a forecast of net realization or margin.

FTR Revenue Net of Congestion Costs (OJS Exhibit No 2, page 1, line 23)

Q. PLEASE EXPLAIN FTR REVENUE NET OF CONGESTION COSTS?

A. Within the PJM RTO, members receive FTR revenues and incur congestion costs, which may or may not offset each other. FTRs are financial instruments, which entitle the holder to receive compensation for certain congestion-related transmission charges that arise when the grid is congested. APCo's share of FTR revenues is forecasted to exceed its congestion costs in 2006 by approximately $4 million.

Gain/(Loss) on Sale of Allowances (OJS Exhibit No. 2, page 1, line 24)

Q. EXPLAIN WHAT IS INCLUDED IN GAIN/(LOSS) ON SALE OF ALLOWANCES.

A. Gain/(Loss) on Sale of Allowances includes the proceeds from the sale of withheld allowances in the annual EPA auction, gains associated with the reallocation of allowances related to the Gavin Scrubber and gains associated with market sales of allowances. The provisions of the previously mentioned IAA also govern these allowance transactions.

Wyoming-Jacksons Ferry Loss Factor Adjustment (OJS Exhibit No. 2, page 1, lines 26, 27)

Q. DESCRIBE THE WYOMING-JACKSONS FERRY ADJUSTMENT.

A. When the demand forecast was developed, the level of line losses was based on historical relationships prior to the completion of the Wyoming-Jacksons Ferry line. The benefits of the line will begin immediately when the line goes into service; however, the 58MW reduction in APCo's peak demand will not be realized until the expected winter peak in January 2007. The amounts on lines 26 and 27 are a quantification of APCo's reduced MLR.

Q. WHAT ARE THE PROJECTED ENEC AMOUNTS FOR THE PERIODS ENDING 2006, 2007 AND 2008?

A. As shown on OJS Exhibit No. 2, APCo's projected ENEC for 2006 is $621.7 million and 38,305 GWh; for 2007, $643.2 million and 38,728 GWh; and for 2008, $674.0 million and 39,199 GWh. I have provided this information to Company witnesses Eads and Ferguson for their use.

EXHIBIT ____ (LK-3)

LG&E ENERGY

LG&E Energy LLC
220 West Main Street (40202)
P.O. Box 32030
Louisville, Kentucky 40232

November 19, 2004

Elizabeth O'Donnell, Executive Director
Public Service Commission of Kentucky
211 Sower Boulevard
P. O. Box 615
Frankfort, Kentucky 40602

RECEIVED
NOV 1 9 2004
PUBLIC SERVICE COMMISSION

Attention: Mr. Isaac S. Scott

Subject: Monthly Environmental Surcharge Report

Dear Ms. O'Donnell:

Pursuant to KRS 278.183(3), Kentucky Utilities Company (KU) files herewith the original and 5 copies of its Environmental Surcharge Report for the month of October 2004. In accordance with the Commission's Order in Case No. 2000-439, KU has included the calculation and supporting documentation of the Environmental Surcharge Factor effective during the December 2004 billing month.

Respectfully,

Robert M. Conroy
Manager, Rates

Enclosures

KU

KENTUCKY UTILITIES COMPANY
ENVIRONMENTAL SURCHARGE REPORT

Calculation of Monthly Billed Environmental Surcharge Factor - MESF
For the Expense Month of October 2004

MESF = CESF - BESF

Where:

CESF	=	Current Period Jurisdictional Environmental Surcharge Factor
BESF	=	Base Period Jurisdictional Environmental Surcharge Factor

Calculation of MESF:

CESF, from ES Form 1.1	=	3.15%
BESF, from Case No. 2003-00434	=	0.30%
MESF	=	2.85%

Effective Date for Billing: December billing cycle beginning December 1, 2004

Submitted by: ______________________

Title: Manager, Rates

Date Submitted: November 19, 2004

ES Form 1.00

KENTUCKY UTILITIES COMPANY
ENVIRONMENTAL SURCHARGE REPORT
Calculation of Total E(m) and Jurisdictional Surcharge Billing Factor For the Expense Month of October 2004

Calculation of Total E(m)

Total E(m) = 1994E(m) + 2001E(m)

1994E(m) = [(RB / 12) (ROR)] + OE - BAS, where

RB	=	Environmental Compliance Rate Base for the 1994 Plan
ROR	=	Rate of Return on the 1994 Plan Rate Base
OE	=	Pollution Control Operating Expenses for the 1994 Plan
BAS	=	Gross Proceeds from By-Product and Allowance Sales

Post-1994E(m) = [(RB / 12) (ROR+(ROR -DR)(TR/(1-TR)))] + OE, where

RB	=	Environmental Compliance Rate Base for the 2001 Plan
ROR	=	Rate of Return on the 2001 Plan Rate Base
DR	=	Debt Rate (both short-term and long-term debt)
TR	=	Composite Federal & State Income Tax Rate
OE	=	Pollution Control Operating Expenses for the 2001 Plan

		1994 Plan	Post-1994 Plan
RB	=	$ -	$ 229,080,361
RB / 12	=	-	19,090,030
ROR [1994 Plan]	=	0.00%	
(ROR + (ROR - DR) (TR / (1 - TR))) [2001 Plan]	=		11.48%
OE	=	-	412,893
BAS	=	-	
1994E(m)	=	-	
Post-1994E(m)	=		2,604,428
Total E(m) = 1994E(m) + Post-1994E(m)	=		$ 2,604,428

Calculation of Jurisdictional Environmental Surcharge Billing Factor

Jurisdictional Allocation Ratio for Expense Month	=	72.44%
Jurisdictional E(m) = Total E(m) x Jurisdictional Allocation Ratio	=	$ 1,886,648
Adjustment for Monthly True-up (from Form 2.0)	=	(5,205)
Prior Month Adjustment (if necessary)	=	-
Final Adjustment and True-up for Over Recovery per Commission Order 2003-00068	=	-
Net Jurisdictional E(m) = Jurisdictional E(m) minus Adjustment for Over/(Under) Recovery	=	$ 1,881,443
Jurisdictional R(m) = Average Monthly Jurisdictional Revenue for the 12 Months Ending with the Current Expense Month	=	$ 59,769,681
Jurisdictional Environmental Surcharge Billing Factor: Net Jurisdictional E(m) / Jurisdictional R(m) ; as a % of Revenue	=	3.15%

EXHIBIT ____ (LK-4)

KPCO CAPITALIZATION AND COST OF CAPITAL
TEST YEAR ENDING 6/30/2005

. **KPCO Capitalization, Cost of Capital, and Gross Revenue Conversion Factor Per Filing**

	Per Book Balance	KPCO Proforma Adjustments	KPCO Adjusted Capitalization	KPCO Reapportioned Adjusted Capitalization	Capital Ratio	Component Costs	Weighted Avg Cost	Grossed Up Cost	Kentucky Jurisdictional Factor	Revenue Requirement
Short Term Debt	-	3,350,473	3,350,473	3,374,508	0.39%	3.34%	0.0131%	0.0131%	99.00%	112,111
Long Term Debt	487,716,122	(3,921,902)	483,794,220	487,264,770	56.55%	5.70%	3.2232%	3.2385%	99.00%	27,626,957
Accts Receivable Financing	30,139,598	-	30,139,598	30,355,808	3.52%	2.99%	0.1053%	0.1058%	99.00%	902,830
Common Equity	331,354,481	6,923,708	338,278,189	340,704,864	39.54%	11.50%	4.5469%	7.5736%	99.00%	64,609,239
Sub Total	849,210,201	6,352,279	855,562,480	861,699,950	100.00%			10.93%		93,251,138
Job Development Tax Credit	6,137,470		6,137,470							
Total Capital	855,347,671	6,352,279	861,699,950	861,699,950	100.00%			10.93%		93,251,138

. ***KPCO Capitalization, Cost of Capital, and Gross Revenue Conversion Factor Adjusting Capitalization for:***
Capitalization Adjustment 1 - Reduction to Reflect 13 Month Average M&S Inventory

	KPCO Reapportioned Adjusted Capitalization	KIUC Proforma Adjustment 1	KIUC Adjusted Reapportioned Capitalization After Adjustment 1	KIUC Adjusted Capital Ratio	Component Cost	Weighted Avg Cost	Grossed Up Cost	Kentucky Jurisdictional Factor	Revenue Requirement	Incremental Revenue Requirement
Short Term Debt	3,374,508	(2,210,060)	1,164,448	0.14%	3.34%	0.0045%	0.0045%	99.00%	38,687	(73,425)
Long Term Debt	487,264,770	-	487,264,770	56.69%	5.70%	3.2315%	3.2468%	99.00%	27,626,957	-
Accts Receivable Financing	30,355,808	-	30,355,808	3.53%	2.99%	0.1056%	0.1061%	99.00%	902,830	-
Common Equity	340,704,864	-	340,704,864	39.64%	11.50%	4.5586%	7.5931%	99.00%	64,609,239	-
Total Capital	861,699,950	(2,210,060)	859,489,890	100.00%		7.90%	10.95%		93,177,713	(73,425)

KPCO CAPITALIZATION AND COST OF CAPITAL
TEST YEAR ENDING 6/30/2005

II. KPCO Capitalization, Cost of Capital, and Gross Revenue Conversion Factor Adjusting Capitalization for:
Capitalization Adjustments 1 & 2 - Removal of KPCO's Reliability Capital Adjustments

	KIUC Adjusted Reapportioned Capitalization After Adjustment 1	KIUC Proforma Adjustment 1	KIUC Adjusted Reapportioned Capitalization After Adjustment 2	KIUC Adjusted Capital Ratio	Component Cost	Weighted Avg Cost	Grossed Up Cost	Kentucky Jurisdictional Factor	Revenue Requirement	Incremental Revenue Requirement
Short Term Debt	1,164,448	(196,622)	967,826	0.11%	3.34%	0.0038%	0.0038%	99.00%	32,154	(6,532)
Long Term Debt	487,264,770	(3,181,718)	484,083,052	56.69%	5.70%	3.2312%	3.2465%	99.00%	27,446,560	(180,397)
Accts Receivable Financing	30,355,808	-	30,355,808	3.55%	2.99%	0.1063%	0.1068%	99.00%	902,830	-
Common Equity	340,704,864	(2,161,660)	338,543,204	39.64%	11.50%	4.5591%	7.5939%	99.00%	64,199,315	(409,924)
Total Capital	859,489,890	(5,540,000)	853,949,890	100.00%		7.90%	10.95%		92,580,859	(596,854)

V. KPCO Capitalization, Cost of Capital, and Gross Revenue Conversion Factor Adjusting Capitalization for:
Capitalization Adjustments 1,2 & 3 - Recognize Additional Pension Funding in 2005

	KIUC Adjusted Reapportioned Capitalization After Adjustment 2	KIUC Proforma Adjustment 3	KIUC Adjusted Reapportioned Capitalization After Adjustment 3	KIUC Adjusted Capital Ratio	Component Cost	Weighted Avg Cost	Grossed Up Cost	Kentucky Jurisdictional Factor	Revenue Requirement	Incremental Revenue Requirement
Short Term Debt	967,826	(6,904)	960,922	0.11%	3.34%	0.0038%	0.0038%	99.00%	31,925	(229)
Long Term Debt	484,083,052	(3,453,136)	480,629,916	56.69%	5.70%	3.2312%	3.2465%	99.00%	27,250,774	(195,786)
Accts Receivable Financing	30,355,808	(216,539)	30,139,269	3.55%	2.99%	0.1063%	0.1068%	99.00%	896,390	(6,440)
Common Equity	338,543,204	(2,414,949)	336,128,255	39.64%	11.50%	4.5591%	7.5939%	99.00%	63,741,358	(457,957)
Total Capital	853,949,890	(6,091,528)	847,858,362	100.00%		7.90%	10.95%		91,920,447	(660,412)

KPCO CAPITALIZATION AND COST OF CAPITAL
TEST YEAR ENDING 6/30/2005

I. KPCO Capitalization, Cost of Capital, and Gross Revenue Conversion Factor Adjusting Capitalization for:
Capitalization Adjustments 1,2,3 & 4 - *Remove Prior Deferral* of RTO Formation Costs

	KIUC Adjusted Reapportioned Capitalization After Adjustment 3	KIUC Proforma Adjustment 4	KIUC Adjusted Reapportioned Capitalization After Adjustment 4	KIUC Adjusted Capital Ratio	Component Cost	Weighted Avg Cost	Grossed Up Cost	Kentucky Jurisdictional Factor	Revenue Requirement	Incremental Revenue Requirement
Short Term Debt	960,922	-	960,922	0.11%	3.34%	0.0038%	0.0038%	99.00%	31,925	-
Long Term Debt	480,629,916	-	480,629,916	56.73%	5.70%	3.2338%	3.2491%	99.00%	27,250,774	-
Accts Receivable Financing	30,139,269	-	30,139,269	3.56%	2.99%	0.1064%	0.1069%	99.00%	896,390	-
Common Equity	336,128,255	(677,767)	335,450,488	39.60%	11.50%	4.5536%	7.5846%	99.00%	63,612,831	(128,528)
Total Capital	847,858,362	(677,767)	847,180,595	100.00%		7.90%	10.94%		91,791,920	(128,528)

II. KPCO Capitalization and Cost of Capital; Gross Revenue *Conversion Factor* Adjusted to Reduce Capitalization and to Remove OH and WV Taxes

	KIUC Adjusted Reapportioned Capitalization	KIUC Adjusted Capital Ratio	Component Cost	Weighted Avg Cost	Grossed Up Cost	Kentucky Jurisdictional Factor	Revenue Requirement	Incremental Revenue Requirement
Short Term Debt	960,922	0.11%	3.34%	0.0038%	0.0038%	99.00%	31,925	-
Long Term Debt	480,629,916	56.73%	5.70%	3.2338%	3.2491%	99.00%	27,250,774	-
Accts Receivable Financing	30,139,269	3.56%	2.99%	0.1064%	0.1069%	99.00%	896,390	-
Common Equity	335,450,488	39.60%	11.50%	4.5536%	7.5685%	99.00%	63,477,988	(134,843)
Total Capital	847,180,595	100.00%		7.90%	10.93%		91,657,077	(134,843)

KPCO CAPITALIZATION AND COST OF CAPITAL
TEST YEAR ENDING 6/30/2005

VII. KPCO Capitalization and Cost of Capital; Gross Revenue Conversion Factor Adjusted to Reduce Capitalization, Remove OH and WV Taxes and Reflect Kentucky Tax Rate Reduction

	KIUC Adjusted Reapportioned Capitalization	KIUC Adjusted Capital Ratio	Component Cost	Weighted Avg Cost	Grossed Up Cost	Kentucky Jurisdictional Factor	Revenue Requirement	Incremental Revenue Requirement
Short Term Debt	960,922	0.11%	3.34%	0.0038%	0.0038%	99.00%	31,925	-
Long Term Debt	480,629,916	56.73%	5.70%	3.2338%	3.2491%	99.00%	27,250,774	-
Accts Receivable Financing	30,139,269	3.56%	2.99%	0.1064%	0.1069%	99.00%	896,390	-
Common Equity	335,450,488	39.60%	11.50%	4.5536%	7.4880%	99.00%	62,802,690	(675,298)
Total Capital	847,180,595	100.00%		7.90%	10.85%		90,981,779	(675,298)

VIII. KPCO Capitalization and Cost of Capital; Gross Revenue Conversion Factor Adjusted to Reduce Capitalization, Remove OH & WV Taxes, Reflect Kentucky Tax Rate Reduction, and Include §199 Deductions

	KIUC Adjusted Reapportioned Capitalization	KIUC Adjusted Capital Ratio	Component Cost	Weighted Avg Cost	Grossed Up Cost	Kentucky Jurisdictional Factor	Revenue Requirement	Incremental Revenue Requirement
Short Term Debt	960,922	0.11%	3.34%	0.0038%	0.0038%	99.00%	31,925	-
Long Term Debt	480,629,916	56.73%	5.70%	3.2338%	3.2491%	99.00%	27,250,774	-
Accts Receivable Financing	30,139,269	3.56%	2.99%	0.1064%	0.1069%	99.00%	896,390	-
Common Equity-Production	116,621,910	13.77%	11.50%	1.5831%	2.5379%	99.00%	21,285,512	(548,320)
Common Equity-Non Production	218,828,578	25.83%	11.50%	2.9705%	4.8848%	99.00%	40,968,858	-
Total Capital	847,180,595	100.00%		7.90%	10.78%		90,433,459	(548,320)

IX. KPCO Capitalization and Cost of Capital; Gross Revenue Conversion Factor Adjusted to Reduce Capitalization, Remove OH & WV Taxes, Reflect Kentucky Tax Rate Reduction, Include §199 Deductions, and Adjust ROE

	KIUC Adjusted Reapportioned Capitalization	KIUC Adjusted Capital Ratio	Component Cost	Weighted Avg Cost	Grossed Up Cost	Kentucky Jurisdictional Factor	Revenue Requirement	Incremental Revenue Requirement
Short Term Debt	960,922	0.11%	3.34%	0.0038%	0.0038%	99.00%	31,925	-
Long Term Debt	480,629,916	56.73%	5.70%	3.2338%	3.2491%	99.00%	27,250,774	-
Accts Receivable Financing	30,139,269	3.56%	2.99%	0.1064%	0.1069%	99.00%	896,390	-
Common Equity-Production	116,621,910	13.77%	9.35%	1.2871%	2.0634%	99.00%	17,306,047	(3,979,465)
Common Equity-Non Production	218,828,578	25.83%	9.35%	2.4151%	3.9715%	99.00%	33,309,463	(7,659,395)
Total Capital	847,180,595	100.00%		7.05%	9.39%		78,794,598	(11,638,860)

EXHIBIT ____ (LK-5)

FEDERAL ENERGY REGULATORY COMMISSION
WASHINGTON, D.C. 20426

In Reply Refer To:
OMTR-CA
Docket No. AC04-101-000
4/4/05

American Electric Power Service Corporation
Attention: Leonard V. Assante
Vice President Regulatory Accounting Services
1 Riverside Plaza
Columbus, Ohio 43215-2373

Thank you for your August 27, 2004 letter, on behalf of certain of American Electric Power Company, Inc.'s public utility electric operating companies (AEP), asking us to approve your request to transfer regional transmission organization (RTO) start-up and integration costs, inclusive of related carrying charges, from Account 186, Miscellaneous Deferred Debits, to Account 182.3, Other Regulatory Assets.[1] You also request authorization to amortize a portion of the regulatory assets on a straight-line basis over a period of 15 years beginning January 1, 2005, and to defer a carrying charge in Account 182.3 on the unamortized balance of the regulatory assets until the deferred costs are fully amortized.

Your proposed accounting is approved. This approval is for accounting purposes only and is not determinative for ratemaking purposes.[2]

---

[1] AEP's operating companies subject to this request include 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] If rate recovery of all or part of the deferred costs is later disallowed, the disallowed costs should be charged to Account 426.5, Other Deductions, at the time of the disallowance.

This letter order constitutes final agency action. To request that the Commission rehear your case, you must file a request within 30 days of the date of this letter order (see 18 C.F.R. § 385.713).

Sincerely,

James K. Guest
Chief Accountant

EXHIBIT ____ (LK-5)

FEDERAL ENERGY REGULATORY COMMISSION
WASHINGTON, D.C. 20426

In Reply Refer To:
OMTR-CA
Docket No. AC04-101-000
4/4/05

American Electric Power Service Corporation
Attention: Leonard V. Assante
Vice President Regulatory Accounting Services
1 Riverside Plaza
Columbus, Ohio 43215-2373

Thank you for your August 27, 2004 letter, on behalf of certain of American Electric Power Company, Inc.'s public utility electric operating companies (AEP), asking us to approve your request to transfer regional transmission organization (RTO) start-up and integration costs, inclusive of related carrying charges, from Account 186, Miscellaneous Deferred Debits, to Account 182.3, Other Regulatory Assets.[1] You also request authorization to amortize a portion of the regulatory assets on a straight-line basis over a period of 15 years beginning January 1, 2005, and to defer a carrying charge in Account 182.3 on the unamortized balance of the regulatory assets until the deferred costs are fully amortized.

Your proposed accounting is approved. This approval is for accounting purposes only and is not determinative for ratemaking purposes.[2]

[1] AEP's operating companies subject to this request include Appalachian Power Company, Columbus Southern Power Company, Indiana Michigan Power Company, Kentucky Power Company, Kingsport Power Company, Ohio Power Company, and Wheeling Power Company.

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This letter order constitutes final agency action. To request that the Commission rehear your case, you must file a request within 30 days of the date of this letter order (see 18 C.F.R. § 385.713).

Sincerely,

James K. Guest
Chief Accountant

EXHIBIT ____ (LK-6)

Kentucky Power Company

REQUEST

Please provide the Company's budgeted/projected off-system sales revenues, off-system sales expenses, and off-system sales margins for November 2005 through December 2006, including the most recent revisions or expectations. Provide all assumptions underlying the budgeted amounts and/or most recent revisions or expectations, data, computations, and work papers, including electronic spreadsheets with formulas intact. in sufficient detail to understand the basis for and to replicate the Company's qualifications. separately identify sales to other AEP utilities and to unaffiliated third parties and detail all allocations pursuant to the AEP Interconnection Agreement.

RESPONSE

CONFIDENTIAL

The requested information is confidential and the Company has requested confidential protection in the form of a Motion for Confidential Treatment.

Below are the Company's projected off-system sales revenues, expenses and margins for November 2005 through December 2006.

CONFIDENTIAL

Kentucky Power Company Off-System Sales

		$millions		
		Revenue	Expense	Margin
Nov	2005			
Dec	2005			
Jan	2006			
Feb	2006			
Mar	2006			
Apr	2006			
May	2006			
Jun	2006			
Jul	2006			
Aug	2006			
Sep	2006			
Oct	2006			
Nov	2006			
Dec	2006			
				$ 30

Please see the attached pages for assumptions. The model that produces these estimates is not a spreadsheet and any calculations are internal to the model. Input data is voluminous and contain confidential information and will be made available for inspection at the Company's offices.

CONFIDENTIAL

WITNESS: Errol K Wagner

EXHIBIT ____ (LK-7)

STEPTOE & JOHNSON LLP

ATTORNEYS AT LAW

David B. Raskin
202.429.6254
draskin@steptoe.com

ORIGINAL

1330 Connecticut Avenue, NW
Washington, DC 20036-1795
Tel 202.429.3000
Fax 202.429.3902
steptoe.com

November 1, 2005

Honorable Magalie Roman Salas, Secretary
Federal Energy regulatory Commission
888 First Street, N.E.
Washington, D.C. 20426

Re: American Electric Power Service Corporation
Docket No. ER06-141-000

I. INTRODUCTION

American Electric Power Service Corporation, on behalf of certain operating companies of the American Electric Power system[1] (collectively "AEP") submits for filing an original and five copies of a proposed amendment to the System Integration Agreement ("SIA") among the indicated operating companies. The SIA was accepted for filing by the Commission in 2000 in Docket No. ER98-2770. The proposed amendment is being made in accordance with the terms of the SIA.

II. BACKGROUND

AEP is a multi-state electric utility holding company system, providing service at retail and wholesale to customers in parts of eleven states. Prior to 2000, the AEP system consisted of seven operating companies providing service in parts of seven states – APCO in Virginia and West Virginia, I&M in Indiana and Michigan, KPCO in Kentucky, OPCO and CSP in Ohio, Wheeling Power Company in West Virginia and Kingsport Power Company in Tennessee. As a public utility holding company system registered under the Public Utility Holding Company Act of 1935 ("PUHCA") the AEP system was planned and operated on an integrated basis, pursuant

[1] The Companies are AEP Texas Central Company ("TCC"), AEP Texas North Company ("TNC"), Appalachian Power Company ("APCO"), Columbus Southern Power Company ("CSP"), Indiana Michigan Power Company ("I&M"), Kentucky Power Company ("KPCO"), Ohio Power Company ("OPCO"), Public Service Company of Oklahoma ("PSO") and Southwestern Electric Power Company ("SWEPCO"). Wheeling Power Company and Kingsport Power Company own no power supply facilities and are not parties to the SIA.

to an Interconnection Agreement dated as of July 6, 1951, as amended ("East Pool Agreement"). In 2000, AEP merged with the former Central and South West ("CSW") System, a registered electric utility holding company system consisting of four operating companies providing service in parts of four states – SWEPCO in Arkansas, Louisiana and Texas, PSO in Oklahoma and TCC and TNC in Texas. The CSW system was planned and operated on an integrated basis pursuant to the CSW Operating Agreement, dated as of January 1, 1997, as amended ("West Pool Agreement").

In March 2000, the Commission approved the AEP/CSW merger, subject to certain conditions not here pertinent. As part of its approval of the merger, the Commission found the SIA, with certain modifications ordered by the Commission, to be just and reasonable.[2] The SIA provides for the coordination of power supply resources of the pre-merger AEP operating companies ("East Zone Companies") with those of the former CSW Companies ("West Zone Companies") to the extent achievable given available transmission capability between the two zones. The SIA is a supplement, not a substitute for, the East Pool Agreement and the West Pool Agreement. In other words, it is a "bridge agreement" between the East and West pool agreements. The two pool agreements were preserved intact to avoid cost shifts among the operating companies and zones and to reflect the existing ownership of generating units.

The SIA provides for the distribution of certain costs and benefits between the East and West Zones, while the existing pool agreements continue to control the distribution of costs and benefits within each zone. Under this structure, the costs of generating capacity in the East Zone are shared among the operating companies in that zone, and the costs of generating capacity in the West Zone are shared among the operating companies in that zone. The SIA provides for the transfer of capacity and energy between the two zones when such transfers are economical after loads are served in each zone, limited by transmission availability between the zones. As specifically relevant here, it also provides for the sharing of the profits associated with off-system trading and marketing activities.

The SIA contains four service schedules: Schedule A which governs the allocation of capacity and purchased power costs; Schedule B which governs pricing of system capacity exchanges; Schedule C which governs pricing for system energy exchanges; and Schedule D which governs the allocation of "Trading and Marketing Realizations", *i.e.*, net revenues or margins from off-system sales.

III. SCHEDULE D – ALLOCATION OF TRADING AND MARKETING REALIZATIONS

AEP proposes to amend only Service Schedule D. Under the currently effective Service Schedule D, margins from long-term off system sales (sale of one year or more entered into prior to the merger) are directly assigned to the Zone in which such sales originated. Margins from all other transactions are allocated according to a two-tier system. The first tier uses relative

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[2] *American Electric Power Company and Central and South West Corporation*, Opinion No. 242, 90 FERC ¶ 61,242 at 61,799 (2000).

historical levels of margins in a Base Year, defined as the twelve calendar months before the consummation of the merger. Based on such historical experience, approximately 91% of the first-tier margins are allocated to the East Zone and 9% to the West. The second tier consists of margins above Base Year levels, which are allocated based on generating capacity owned by the companies in each zone - resulting in a current allocation of approximately 71% to the East Zone and 29% to the West.

Service Schedule D, unlike the other Service Schedules, contains a "sunset" provision, calling for a re-evaluation of the allocation of Trading and Marketing Realizations after five years' experience. The Schedule provides:

> This allocation of trading market realization shall be in effect until the last day of the fifth full calendar year following the consummation of the merger. At least sixty days prior to the day specified in the preceding sentence, Agent shall file with the FERC under Section 205 of the Federal Power Act the methodology to allocate trading market realizations thereafter, supported by evidence demonstrating the justness and reasonableness of the filed methodology, (SIA, Schedule D-3, Original Sheet No. 36).

Since the merger was consummated in June, 2000, the filing required by section D-3 must be made by November 1, 2005.

The sunset provision was added as a result of a stipulation between the merger applicants (AEP and CSW) and the Commission Trial Staff, based on a concern of the Staff, that, *inter alia*, the base period allocation "could become stale or inappropriate."[3] This provision therefore reflects an agreement that, after the initial five-year period, the allocation of trading and marketing revenues would be modified, if and as necessary, to reflect updated actual experience.

IV. AEP'S PROPOSED AMENDMENT

As contemplated by the sunset provision discussed above, AEP has evaluated actual experience during the first five years of the merger. Based on that evaluation, AEP proposes to revise the method of allocating Trading and Marketing Realizations. The proposed method would retain the existing arrangement until the end of the month in which the Commission issues an order accepting or approving a revised method for allocating these Realizations that is no longer subject to suspension or potential refund. Thereafter, it would allocate margins based on a direct assignment method in lieu of using historical experience from a test period and owned generation as a proxy for actual sales. Under this direct assignment methodology, Trading and Marketing Realizations will be allocated to the zone in which the underlying transactions occurred or originated. Descriptions of the realizations that will be allocated to each zone are described below:

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[3] *American Electric Power Company and Central and South west Corporation*, Initial Decision, 89 FERC ¶ 63,007 (2000) at 65,038.

(a) AEP East Zone – Trading and Marketing Realizations allocated to the AEP East Zone include the following: (1) Trading and Marketing Realizations resulting from Trading and Marketing Activities at locations served by either the regional transmission organization PJM Interconnection, L.L.C. ("PJM") or the Midwest Independent Transmission System Operator, Inc. ("MISO");[4] (2) Trading and Marketing Realizations resulting from Trading and Marketing Activities at other locations that are initially assigned to originate or terminate within PJM/MISO and are ultimately settled financially without physical delivery or are settled with power from a location different than PJM/MISO.

(b) AEP West Zone – Trading and Marketing Realizations allocated to the AEP West Zone include the following: (1) Trading and Marketing Realizations resulting from Trading and Marketing Activities at locations served by either the Electric Reliability Council of Texas ("ERCOT") or the Southwest Power Pool ("SPP"); (2) Trading and Marketing Realizations resulting from Trading and Marketing Activities at other locations that are initially assigned to originate or terminate within either ERCOT or SPP and are ultimately settled financially without physical delivery or are settled with power from an area different than ERCOT or SPP.

(c) Any Trading and Marketing activities that originate in either the AEP East or West Zone and terminate in the other zone shall be assigned to the origination zone.

(d) AEP East Zone and AEP West Zone – Any Trading and Marketing Realizations that cannot be directly assigned to either the AEP East Zone or AEP West Zone based on the above criteria, will be allocated between the two zones. Such allocation will be based on the ratio of each zone's Trading and Marketing Realizations for the current month under (a), (b) and (c) above plus each zone's total Trading and Marketing Realizations for the previous eleven (11) months, excluding any months that occurred prior to the effective date of this Revised Schedule D.

V. EVIDENCE THAT THE PROPOSED ALLOCATION IS JUST AND REASONABLE

Schedule D-3 provides that the required Section 205 filing must include "evidence demonstrating the justness and reasonableness of the proposed methodology." AEP submits herewith the affidavit of J Craig Baker, Senior Vice President – Regulatory Services for American Electric Power Service Corporation. Mr. Baker discusses how the proposed direct assignment method is just and reasonable because it reflects, more accurately than the two-tiered method currently in effect, the relative contribution to system sales revenues of the two zones. The present method was correctly found just and reasonable by the Commission based on a proxy that was reasonable based on the facts available at the time of the merger. However, the proposed method does not rely on proxies and has the added advantage of reflecting actual experience

[4] The East Zone Companies are members of PJM. PJM and MISO are in the process of developing a joint and common market, and, pursuant to Commission directives, have taken several steps toward that goal, including the elimination of through and out rates in the combined PJM/MISO region and development of a Joint Operating Agreement between MISO and PJM.

during the time period in which realizations are being allocated. Mr. Baker explains how changed circumstances since the time of the merger make the use of a static allocation methodology, as used in the first tier, and an allocation based on generation capacity as in the second tier, less reflective of actual contributions of the zones to Trading and Marketing Realizations than the proposed method. In addition, since the East and West Pool Agreements, which remain intact, allocate the costs of generating capacity directly to each zone (except as involved in surplus capacity exchanges between the two zones) a direct assignment of the margins made possible by the existence of such generation is highly appropriate. Finally, Mr. Baker explains that the proposed methodology automatically addresses inherent differences between the system agreements and current settlements that are unique within the East and West Zones that result in inconsistent treatment of allocations under the current formula. In sum, Mr. Baker explains that the proposed methodology is consistent with the purpose of the SIA to provide, *inter alia* "an equitable sharing of the benefits and costs of such coordinated arrangements."

Mr. Baker also directed the preparation of Exhibit I to this filing, comparing allocations that occurred in the 12 months ended June 30, 2005 under the current methodology with those that would occur under the proposed direct assignment method.

VI. STATUS OF ERCOT OPERATING COMPANIES

The data submitted with this filing showing the effect of the proposed changes to the SIA includes a demonstration of the effects without TCC and TNC (Exhibit I, p. 2 of 2). The reason is that TCC and TNC will no longer have any retail or wholesale loads to which such realizations could be allocated and have almost completed the divestiture of their generating resources. For these reasons, AEP plans, in the near future, to make a filing with the Commission removing TCC and TNC from the West Pool Agreement along with certain dedicated contracts listed, for informational purposes, on Attachment A to this filing. Under the Texas Restructuring Act,[5] the two companies are completing the final stage of exiting the generation business and have already exited the business of serving retail load. The two companies will thus no longer be involved in the coordinated planning and operation of power supply facilities as contemplated by both the West Pool Agreement and the SIA. A conforming amendment removing the names of the two companies from the SIA will be made when the filing formally removing the two companies from the West Pool Agreement is made.

VII. EFFECTIVE DATE

AEP requests an effective date of January 1, 2006. Proposed Service Schedule D, as filed, provides that the existing allocation method remain in place during an Initial Period ending the last day of the month after the date of a Commission order in this docket that accepts or approves a changed allocation methodology without suspension or potential refund. Accordingly, if the Commission issues an order accepting this filing without suspension and not subject to refund, there may be no Initial Period, and the change to the allocation methodology can go into effect

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[5] Tex. Util. Code Ann. Chapter 39 (Vernon 1998 & Supp 2005).

on January 1, 2006. If the Commission finds that the filing could be unjust and unreasonable, and issues an order suspending the filing and setting it for hearing, the change in allocation methods would not take effect until the month following the date of the Commission's order after the hearing is concluded.

This proposed treatment produces a result that is consistent with the Commission's typical treatment of allocation filings like this one. Even if the Commission were to suspend AEP's filing, [6] it would be inconsistent with Commission precedent for the Commission to order refunds in these circumstances. The granting of refunds under the FPA is discretionary, not mandatory.[7] Refunds are certainly appropriate where a utility has been determined to have been charging a rate higher than that ultimately found just and reasonable; but in cases where the issue is the apportionment of costs among operating companies in a holding company system, the Commission typically has exercised its discretion and not granted refunds. It stated its rationale for doing so in *Southern Company Services, Inc.* [8]

> The ordering of refunds [under Section 205(e)] is discretionary. In a case involving cost-of-service issues and rate levels, the Commission typically orders refunds of amounts collected in excess of the amount ultimately found just and reasonable. In other instances, such as cases involving rate design, however, the Commission often has exercised its discretion and not ordered refunds. The present circumstances involve the Southern pooling agreement where the amounts involved do not, overall, represent excess revenues to the Southern System. There is no issue in this case as to the legitimacy of these production O&M expenses or as to the appropriate total level of production O&M expenses; the sole issue is their classification, and thus their apportionment among the operating companies. Additionally, operational decisions made while the operating companies' proposed costs classification was in effect, and thus made in reliance on that classification, cannot be undone.

Likewise, in a case involving another AEP pool agreement, the Commission, declined to issue retroactive refunds despite its finding that the agreement should have been implemented immediately rather than being phased in over a period of years as originally proposed by AEP. The Commission said:

> Retroactive elimination of the phase-in provision as well as retroactive implementation of some of the other changes ordered in the Agreement would result in a significant likelihood of undercollection of costs. The AEP operating companies that paid "too little" in light of retroactive application would be required to make additional payments to the surplus companies but might well

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[6] *See, e.g., American Electric Power Service Corporation*, 28 FERC ¶ 61,228 (1984).
[7] *Towns of Concord, Norwood & Wellesley v. FERC*, 995 F 2d 67-73 (D.C. Cir. 1991).
[8] 64 FERC ¶ 61,033 (1993).

> be unable to recover these amounts from their own customers. The result would be to leave the AEP System as a whole uncompensated for some of its costs. We shall therefore direct AEP Service to eliminate the phase-in provision prospectively from the date of this Opinion, while allowing the phase-in provision to retain its effectiveness retroactively.[9]

In fact, AEP submits that the Commission lacks statutory authority to order refunds of amounts collected under the rate changes filed in this proceeding. Section 205 of the FPA, under which this filing is being made, provides for rates to be made subject to refund only in the case of *increased* rates or charges. The amendment filed herein does not seek to increase any rate or charge. It merely seeks to change the allocation among operating companies of off-system sales margins that serve to *decrease* the costs of the affected operating companies. The AEP system, as a whole, will receive no increase in revenues as a result of the proposed amendment. It merely seeks a change in the way that benefits are allocated among the operating companies.

Accordingly, AEP proposes, and has reflected in the amendment as filed, that the current allocation method employed under Service Schedule D will remain in effect until the Commission issues an order accepting or approving this filing without suspension or potential refund. Such treatment would be consistent with the Commission's discretionary refund policy, discussed above, because it would avoid the necessity of AEP putting one set of proposed rates into effect subject to refund, to be replaced by later rates that are approved by the Commission. Moreover, the current method, which AEP proposes to leave in place until the Commission has issued an order approving the rate change, has been found by the Commission to be just and reasonable based on information available at the time of the merger.[10]

XIII. REQUESTED RELIEF- SETTLEMENT PROCEDURES

AEP respectfully requests the Commission to accept the proposed amendment for filing without suspension, investigation or hearing. However, if the Commission issues an order suspending and investigating this matter, AEP requests that settlement judge procedures be invoked to allow AEP to pursue resolution among AEP and affected stakeholders without litigation.

XI. COMPLIANCE WITH THE REQUIREMENTS OF 18 C.F.R. § 35.13

A. List of Documents Enclosed - § 35.13 (b) (1).

Submitted with this filing are the filing documents, in hard copy and electronic format:

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[9] *American Electric Power Service Corp.*, 44 FERC & 61,206, reh'g denied, 45 FERC & 61,408 (1988), reh'g denied, 46 FERC & 61,382 (1989), Order Requiring Rebilling, 52 FERC & 61,151 (1990) (rejecting requests to order retroactive refunds of charges collected subject to a subsequently eliminated transmission agreement applicable to the AEP System operating companies).

[10] Regardless of whether the Commission accepts AEP's proposal to maintain the current allocation method for an Initial Period, AEP requests that any changes to the filed method resulting from the Commission's review or investigation of the proposal be applied prospectively.

1. This Letter of Transmittal.

2. Proposed amendment to Schedule D of the SIA, submitted in red-line and clean versions, with appropriate tariff designations.

3. Affidavit of J. Craig Baker.

4. Exhibit I, showing the allocation of Trading and Marketing Realizations for the 12 month period ended June 30, 2005, compared with the allocation that would have resulted if the proposed direct assignment allocation method had been in effect.

5. Attachment A – a list of TCC and TNC dedicated contracts submitted for informational purposes.

6. Attachment B – a list of persons upon whom this filing has been served.

B. Proposed Effective Date -- § 35.13 (b) (2).

AEP seeks an effective date for the proposed amendment of January 1, 2006.

C. Names and Addresses of Persons Served – Section 35.13 (B) (3).

Copies of this filing have been served upon the state public service commissions of Arkansas, Indiana, Kentucky, Louisiana, Michigan, Ohio, Oklahoma, Tennessee, Texas, Virginia, West Virginia and each of AEP's power sales customers whose rates could be affected by the filing.

D. Brief Description of the Rate Schedule Change -- § 35.13 (b) (4).

The rate schedule change is described above.

E. Statement of Reasons for the Rate Schedule Change -- § 35.13 (b) (5).

The reasons for the rate schedule change are discussed above and in the attached affidavit of J. Craig Baker.

F. Statement Regarding Requisite Agreement to the Rate Schedule Change -- § 35.13 (b) (6).

AEP hereby represents that each of its affiliated AEP Operating Companies have agreed to the filing of this amendment.

G. Statement Regarding Expenses or Costs -- § 35.13 (g) (7).

None of the costs or expenses underlying the rates contained in the agreement have been alleged or adjudicated to be illegal, duplicative, or unnecessary costs demonstrably due to discriminatory employment practices.

H. Cost of Service and Revenue Information – §§ 35.13 (c) and (d).

There is no cost of service underlying the proposed amendment. The amendment merely changes a component of a formula rate that allocates off-system sales margins among the parties to the agreement. To allow analysis of the effect of the proposed amendment, AEP has provided, as Exhibit I, a table comparing the allocation of margins under the present and proposed methods for the 12 month period ended June 30, 2005.

AEP cannot accurately forecast the effect of this change in allocation methodology in future years because such effect will depend upon conditions in the marketplace that are currently unknown. AEP therefore requests a waiver of the requirement to provide a revenue comparison of existing and proposed rates for a future year. The Commission has granted such a waiver in the past where utilities are filing changes that affect opportunity transactions, the prices and amounts of which cannot be predicted in advance.[11]

AEP believes it has presented information sufficient for the Commission to determine the justness and reasonableness of the proposed amendment. To the extent that this filing fails to contain any information otherwise required for technical compliance with the Commission's regulations, AEP requests that compliance with such regulations be waived.

I. Issues Presented.

To the extent Order No. 663 applies, the issue presented herein is the justness and reasonableness of the proposed amendment.

[11] *See, e.g. Northeast Utilities Service Co.*, 62 FERC ¶ 61,294 (1993).

XI. CORRESPONDENCE AND COMMUNICATIONS

Correspondence or communications regarding this matter should be sent to the following:

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Respectfully submitted,

David Raskin
Attorney for American Electric Power Service Corporation

EXHIBIT ____ (LK-8)

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

American Electric Power Service Corporation	Docket No. ER06-____ -000

AFFIDAVIT OF J. CRAIG BAKER

I. INTRODUCTION

J. Craig Baker, being first duly sworn, states as follows:

1. I am Senior-Vice President-Regulatory Services, for American Electric Power Service Corporation. My business address is 1 Riverside Plaza, Columbus, Ohio 43215. My educational background and business experience are set forth in an Attachment to this Affidavit.

2. American Electric Power Service Corporation ("AEPSC") provides professional services to the companies of the American Electric Power System (collectively "AEP"). AEP is an electric utility holding company system providing service to customers at retail and wholesale in parts of eleven states.

3. The purpose of this Affidavit is to provide evidence demonstrating the justness and reasonableness of a proposed amendment to the System Integration Agreement ("SIA" or "Agreement") among certain AEP operating companies.

II. BACKGROUND

4. On May 19, 2000, AEPSC, on behalf of certain operating companies of the American Electric Power System, ("AEP" or "Company") filed the SIA in

compliance with the Federal Energy Regulatory Commission's May 15, 2000 Order in Docket No. ER98-2770.

5. The Agreement was filed in connection with the merger of AEP and the former Central and South West system ("CSW"). The Agreement provides for the coordination of the generation resources of Appalachian Power Company ("APCO"), Columbus Southern Power Company ("CSP"), Indian Michigan Power Company ("I&M"), Kentucky Power Company ("KPCO") and Ohio Power Company ("OPCO"), collectively referred to in the Agreement as the "AEP Operating Companies" and referred to herein as the "East Zone Companies", with those of Public Service Company of Oklahoma ("PSO"), Southwestern Electric Power Company ("SWEPCO"), Texas Central Company ("TCC") (formerly Central Power and Light Company), and Texas North Company ("TNC") (formerly West Texas Utilities Company), collectively referred to in the Agreement as the "CSW Operating Companies" and referred to herein as the "West Zone Companies". AEP and CSW were each electric utility holding company systems. Each had a system pool agreement providing for the integration of resources and loads on each system, which remained intact after the merger. The System Integration Agreement (SIA) is a bridge agreement that provides for coordination of the combined system.

6. The SIA became effective on the date of consummation of the merger between American Electric Power Company, Inc. and Central and South West Corporation, which occurred on June 15, 2000. Following consummation of the

merger, AEPSC ("Agent") became the agent on behalf of all of the East Zone and West Zone Companies identified above.

7. The Agreement includes Service Schedule D, which describes the allocation methodology of Trading and Marketing Realizations between the East Zone and West Zone Companies. Service Schedule D requires the Agent to make a filing to specify the future allocation methodology of these realizations.

As stated in Schedule D:

> "This allocation of trading market realization shall be in effect until the last day of the fifth full calendar year following the consummation of the merger. At least sixty days prior to the day specified in the preceding sentence, Agent shall file with the FERC under Section 205 of the Federal Power Act the methodology to allocate trading market realizations thereafter, supported by evidence demonstrating the justness and reasonableness of the filed methodology."
> (Section D3, Original Sheet No. 36)

8. The above-quoted language was added to the Agreement as a result of a stipulation between the applicants in the merger case before FERC and the Commission Trial Staff, based on a concern of the Trial Staff that the Base Year allocation, as currently provided in the Agreement "could become stale or inappropriate." The quoted provision therefore reflects an agreement that, after the initial five-year period, the allocation of Trading and Marketing realizations would be modified, if necessary, to reflect actual experience.

9. This affidavit has been prepared in support of the above filing requirement. The changes to Schedule D made in this filing are described more fully below. AEP is not proposing to modify any other portions of the Agreement.

III. PROPOSED ALLOCATION OF TRADING AND MARKETING REALIZATIONS

10. After an Initial Period described in the filing, AEP proposes to allocate Trading and Marketing Realizations between the East Zone and West Zone using a direct assignment allocation methodology. Trading and Marketing Realizations will generally be allocated to the zone in which the underlying transactions occurred or originated. As AEP enters into trading and marketing transactions, individual transactions are assigned to the AEP East or West Zones based primarily on the geographical location of the Trading and Marketing Activity, which considers transmission paths, and available economic generation. Terms of each transaction are recorded in an appropriate risk book, which is also segregated under the proposed method based upon the AEP zone that will support each book. Once recorded in the appropriate risk book, each transaction is assigned a specific deal identification number. The deal identification number along with delivery point and/or risk book remains associated with the transaction as it flows into the settlement systems where margins are assigned to the appropriate zone. Descriptions of the realizations that will be allocated to each zone are described below:

(a) AEP East Zone – Trading and Marketing Realizations allocated to the AEP East Zone include the following: (1) Trading and Marketing Realizations resulting from Trading and Marketing Activities at locations served by either the regional transmission organization PJM Interconnection, L.L.C. ("PJM") or the Midwest Independent Transmission System Operator, Inc. ("MISO"); (2)

Trading and Marketing Realizations resulting from Trading and Marketing Activities at other locations that are initially assigned to originate or terminate within PJM/MISO and are ultimately settled financially without physical delivery or are settled with power from a location different than PJM/MISO.

(b) AEP West Zone – Trading and Marketing Realizations allocated to the AEP West Zone include the following: (1) Trading and Marketing Realizations resulting from Trading and Marketing Activities at locations served by either the Electric Reliability Council of Texas ("ERCOT") or the Southwest Power Pool ("SPP"); (2) Trading and Marketing Realizations resulting from Trading and Marketing Activities at other locations that are initially assigned to originate or terminate within either ERCOT or SPP and are ultimately settled financially without physical delivery or are settled with power from an area different than ERCOT or SPP.

(c) Any Trading and Marketing Activities that originate in either the AEP East or West Zone and terminate in the other zone shall be assigned to the origination zone.

(d) AEP East Zone and AEP West Zone – Any Trading and Marketing Realizations that cannot be directly assigned to either the AEP East Zone or AEP West Zone based on the above criteria, will be allocated between the two zones. Such allocation will be based on the ratio of each zone's Trading and Marketing Realizations for the current month under (a), (b) and (c) above plus each zone's total Trading and Marketing Realizations for the previous eleven (11) months, excluding any months that occurred prior to the effective date of this Revised Schedule D.

IV. JUSTNESS AND REASONABLENESS OF THE PROPOSED METHOD

10. The proposed allocation method is consistent with the purpose and intent of the Agreement. As stated in Article III – Objectives of the Agreement:

> "3.1 Purpose
> The purpose of this Agreement is to provide the contractual basis for coordinated planning, operation and maintenance of the power supply resources of the Combined System to achieve economies consistent with the provision of reliable electric service and *an equitable sharing of the benefits and costs of such coordinated arrangements*." (Original Sheet No. 11, *emphasis added*).

11. As indicated above, Schedule D provides for a re-evaluation of the allocation methodology after five years to determine an equitable allocation method between the East and West Zones on a going-forward basis, based on actual experience. The proposed method provides an equitable allocation between the AEP East and AEP West Zones based on the actual contributions of the respective zones during the past five years. During the Company's review of the existing allocation methodology several facts became apparent, leading to the proposed change to the allocation method.

13. First, the AEP East and AEP West Zones' contributions to these realizations have changed over time, resulting in a higher percentage of Trading and

Marketing Realizations being contributed by the AEP East Zone than their current allocation.

14. The first tier of the current allocation method utilizes historical levels of Trading and Marketing Realizations prior to the AEP-CSW merger and the second tier is based upon the generation capacity of each zone. The first tier is based upon a static allocation and, as a constant, does not account for any circumstances that may change over time. The second tier allocation, based upon generation capacity, has not provided a strong correlation with Trading and Marketing Realizations because it does not consider native load requirements nor the ability of generation in each zone to make off-system sales economically, given its variable cost relative to market prices.[1]

15. AEP anticipates the addition of significant generation resources in both zones over the next decade. The proposed direct assignment allocation methodology will better correlate to the addition and cost of such generation. To the extent that new generation resources result in additional Trading and Marketing Realizations, these realizations will be received in greater proportion by the Operating Companies that acquire or build such resources under the proposed method.

16. A direct assignment allocation method is particularly just and reasonable given that the cost of the generating resources in each zone is primarily borne by the operating companies in each zone. The only exception relates to

[1] These findings are within the limited scope and context of revising and updating the allocation methodology at this time. The Company maintains that the current allocation methodology was reasonable and suitable given the circumstances and information known at the time of the AEP-CSW merger.

surplus capacity and energy exchanges made pursuant to the other service schedules of the SIA, which allocate the costs and benefits of such exchanges. The direct assignment allocation method correctly provides that customers who bear the cost of the generating resources should be assigned the benefits made possible by those resources.

17. The development of centralized markets in PJM and MISO, pursuant to Commission policy and the expected development of such a market in SPP facilitates direct assignment of realizations by making it easier to identify the locus of transactions.

18. Finally, the proposed methodology automatically addresses inherent differences between the system agreements and current settlements that are unique within the AEP East Zone and the AEP West Zone. An example is the treatment and settlement of emission allowances, as described below.

19. Currently, the margin on Trading and Marketing Realizations associated with physical off-system sales is computed for the East Zone Companies using the average inventory cost of emission allowances consumed to make these sales. However, the average inventory cost of allowances for a given operating company is typically much less than the current market price of such allowances. As a result, operating companies contributing to Trading and Marketing Realizations are receiving average inventory cost reimbursement, but may be required to replace these allowances in their inventory at a much higher market price. Such treatment is consistent among the East Zone Companies since these companies are controlled by the AEP Interconnection

Agreement, whereby monthly capacity payments are exchanged, and the Interim Allowance Agreement that addresses SO_2 allowance settlement[2]. However, these agreements do not apply to the West Zone Companies, which use replacement cost of emission allowances to compute physical off-systems sales margins. As a result of this difference, reported margins on sales from generators in the East Zone are larger than for comparable sales in the West Zone, which distorts the allocation of realizations from off-system sales transactions under the current methodology. The proposed direct assignment allocation methodology eliminates this distortion. It accommodates the differences in each zone's emission allowance settlements by allowing each zone to separately compute the level of Trading and Marketing Realizations based upon each zone's applicable Operating Agreement(s).

20. Based on the first five years' experience under the merger, and the other considerations discussed above, direct assignment is the most equitable allocation methodology, consistent with the objective and purpose specified in the Agreement. In any allocation exercise, it is preferable to make direct assignments where possible rather than reflect an approximate equitable sharing of the Trading and Marketing Realizations using a proxy that necessarily lacks precision and involves some measure of judgment. The proposed method relies on the actual contributions from each zone. As such,

[2] The Interim Allowance Agreement is by and among the Appalachian Power Company, Columbus Southern Power Company, Indiana Michigan Power Company, Kentucky Power Company, Ohio Power Company, and American Electric Power Service Corporation as Agent.

as the volume and level of Trading and Marketing Realizations increases or decreases from time-to-time in each zone, any concern of retaining an equitable correlation between the contribution and allocation of Trading and Marketing Realizations between the zones based on proxies will be eliminated.

V. EFFECTS OF THE PROPOSED METHOD

21. Exhibit I (which was prepared under my direction and supervision) shows the actual Trading and Marketing Realizations subject to allocation under the Agreement for the 12-month period ended June 30, 2005. Also included in this Exhibit is an estimate of the allocation of the Trading and Marketing Realizations that would have occurred during the same time period under the proposed direct assignment allocation methodology. The allocation of Trading and Marketing Realizations under the proposed method reflects the actual contributions to realizations made in the areas associated with each zone (as described in Section III above) during the period.

22. AEP also anticipates that it will be making a filing with the Commission revising the Operating Agreement among the CSW Operating Companies and the SIA to reflect the removal of TCC and TNC from the agreements. The subsequent filing is made necessary by Texas electric restructuring law that requires both TCC and TNC to exit the generation and power sales business, since they will remain in the wires business. Pertinent details and timeframe will be provided in the anticipated filing.

23. In terms of effects on this filing, the removal of TCC and TNC from the Agreement will have implications on the allocation of Trading and Marketing Realizations. Since TCC and TNC will no longer be in the generation and power sales business, they will no

longer receive any allocation of Trading and Marketing Realizations under Schedule D[3]. In order to illustrate the long-term effects of this known and measurable event, the allocation of the margins under the proposed direct assignment allocation methodology are presented with both TCC and TNC removed from the SIA, with the margin allocation results provided in Exhibit I, p. 2 of 2.

24. For the historic 12-month period analyzed, the change from the current allocation methodology to the proposed direct assignment allocation methodology results in an increased allocation of Trading and Marketing Realizations to the East Zone Companies. This increase relative to the current allocation methodology is to be expected since the East Zone Companies, at present, provide a greater portion of the total AEP Trading and Marketing Realizations than their current allocation. Consequently, the effect of moving to the proposed methodology for this 12-month period would have been positive for the East Zone Companies had it been in effect for the 12-month period shown on the Exhibit.

25. While the proposed allocation methodology is expected to result in a reduction in the allocation of Trading and Marketing Realizations to the West Zone Companies, the results are equitable considering the level of realizations contributed by these companies during the period. This reduction in the allocation of Trading and Marketing Realizations to the West Zone Companies, while significant, is similar to the potential effects from normal variations in sales margins in the off-system wholesale market, and, I believe, does not represent an undue burden on these companies' retail customers.

26. PSO and SWEPCO are the only two West Zone Companies serving retail customers. Both PSO and SWEPCO have provisions for passing through a portion of their respective

[3] TCC and TNC removal from SIA sharing of Trading and Marketing Realizations will be based upon the removal date of these companies from the SIA.

allocation of Trading and Marketing Realizations through their fuel clauses as a credit against the cost of fuel. For the 12-month period of July 2004 to June 2005, the difference between the actual allocation and the proposed allocation of Trading and Marketing Realizations, in terms of the approximate impact on retail fuel rates, is provided below:

Table I – Trading and Marketing Realization Impacts on Retail Fuel Rates

CSW Operating Company-Jurisdiction	Approximate Retail Fuel Rate Increase
PSO-Oklahoma	\$0.00048/kWh
SWEPCO-Arkansas	\$0.00030/kWh
SWEPCO-Louisiana	\$0.00030/kWh
SWEPCO-Texas	\$0.00029/kWh

27. As seen in the table, the fuel factor bill impact on a typical residential customer with an average monthly usage of 1,000 kWh would have been only approximately 29 to 48 cents per month during the period.

28. I further note that no particular level of Trading and Marketing Realizations is guaranteed within these jurisdictions. Off-system sales, for example, are affected by market forces and the ability of AEP generation resources to take advantage of sales opportunities created by these market forces, if and when these opportunities occur. Fuel rate increases of the magnitude shown in Table I are possible based on normally occurring fluctuations to the volume and level of Trading and Marketing Realizations over a given period. Such increases are also small compared to fluctuations that can occur in the underlying fuel prices. As such, AEP submits that the impacts presented in Table I are not unduly

burdensome on retail customers and impacts at this level can occur even under the existing allocation methodology.

29. In addition, relative to historic levels, the level of Trading and Marketing Realizations allocated to the CSW Operating Companies under the direct assignment allocation methodology in Attachments III and IV is 43.5% higher than margins realized by those companies during the 12-month period prior to the AEP/CSW merger.

30. Finally, as stated in Section I of this report, this modification to the Schedule D allocation methodology will not affect other portions of the Agreement. As such, System Capacity Exchange and System Energy Exchange Schedules are not impacted by this proposal, and any such change will require regulatory approval by this Commission.

VI. SUMMARY

31. AEP's proposed methodology for future allocation of Trading and Marketing Realizations as described in the Revised Schedule D is consistent with the current Schedule D filing requirement. I believe that the justness and reasonableness of the proposed allocation methodology is self-evident because it reflects actual contributions to Trading and Marketing Realizations.

32. For the historic period analyzed, the change in methodology would have resulted in a greater allocation to the East Zone Companies and a reduction in the allocation to the West Zone Operating Companies. The change in the allocation to the West Zone Companies' retail customers over the period would result in fuel rate and bill impacts that would not be unduly burdensome, given the magnitude of the changes relative to total retail rates, and is further supported by the fact that no particular level of Trading and Marketing Realizations is guaranteed.

33. The proposed methodology provides a potential offset to the cost of any new generation resources in the two zones, in that any additional Trading and Marketing Realizations resulting from the addition of these resources will be retained by the respective zone. Finally, the proposed allocation methodology has no impact on the other portions of the Agreement, including System Capacity and Energy Exchange Schedules that provide a mutual benefit to all AEP and CSW Operating Companies.

J. Craig Baker

Subscribed and sworn to before me this
28th day of October, 2005.

My Commission expires: 05-18-08

Notary Public

NOTARIAL SEAL STATE OF OHIO

MANMOHAN K. SACHDEVA
Notary Public, State of Ohio
My Commission Expires 05-18-08

J. CRAIG BAKER

ATTACHMENT TO AFFIDAVIT

EDUCATION AND PROFESSIONAL BACKGROUND:

I received a Bachelor's Degree in Business Administration from Walsh College in 1970 and a Masters Degree in Business Administration in Finance from Akron University in 1980. I joined the American Electric Power (AEP) System in 1968 and through 1979 held various positions in the Computer Applications Division. I transferred to the System Operation Division in 1979 and held positions of Administrative Assistant and Assistant Manager. In 1985, I took the position of Staff Analyst in the Controllers Department and, in 1987, I became Manager-Power Marketing in the System Power Markets Department. In 1991, I became Director, Interconnection Agreements and Marketing. I became Vice President-Power Marketing for AEPSC and Senior Vice President of Energy Marketing for AEP Energy Services, Inc. in November 1996 and August 1997, respectively. On July 1, 1998 I became Vice President of Transmission Policy for AEPSC. In June 2000, I became Senior Vice President of Public Policy for AEPSC. In 2001, I assumed my current position.

RESPONSIBILITIES IN CURRENT POSITION:

I am responsible for AEP's activities before eleven state regulatory commissions and the Federal Energy Regulatory Commission ("Commission" or "FERC"). A major focus of my activities since 1998 has been AEP's participation in regional transmission organizations ("RTOs") including AEP's participation in PJM and the Southwest Power Pool RTO. I have submitted testimony to the Commission on transmission pricing policy issues, including the importance of a regional rate design.

Exhibit I

Exhibit I
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Allocation of Trading and Marketing Realizations
System Integration Agreement – Schedule D
Twelve Months Ending June 30, 2005

AEP and CSW Operating Companies	Allocation of Trading and Marketing Realizations Under Current Schedule D		Allocation of Trading and Marketing Realizations Under Direct Assignment	
	($000)	(Percent)	($000)	(Percent)
AEP East Zone				
APCo	$126,139	31.9%	$141,382	31.7%
CSP	68,803	17.4%	77,401	17.4%
I&M	76,497	19.3%	86,225	19.4%
KPCo	29,699	7.5%	33,302	7.5%
OPCo	94,667	23.9%	107,069	24.0%
Subtotal - AEP East Zone	**$395,805**	**100.0%**	**$445,379**	**100.0%**
AEP West Zone				
PSO	$26,229	30.6%	$10,669	29.5%
SWEPCO	32,393	37.8%	14,056	38.9%
TCC & TNC	27,115	31.6%	11,437	31.6%
Subtotal - AEP West Zone	**$85,736**	**100.0%**	**$36,162**	**100.0%**
TOTAL AEP	**$481,541**		**$481,541**	

Exhibit I
Page 2 of 2

Allocation of Trading and Marketing Realizations
System Integration Agreement – Schedule D
Twelve Months Ending June 30, 2005

AEP and CSW Operating Companies	Allocation of Trading and Marketing Realizations Under Current Schedule D ($000)	(Percent)	Allocation of Trading and Marketing Realizations Under Direct Assignment Excluding TCC & TNC ($000)	(Percent)
AEP East Zone				
APCo	$126,139	31.9%	$141,382	31.7%
CSP	68,803	17.4%	77,401	17.4%
I&M	76,497	19.3%	86,225	19.4%
KPCo	29,699	7.5%	33,302	7.5%
OPCo	94,667	23.9%	107,069	24.0%
Subtotal - AEP East Zone	**$395,805**	**100.0%**	**$445,379**	**100.0%**
AEP West Zone				
PSO	$26,229	30.6%	$15,603	43.1%
SWEPCO	32,393	37.8%	20,559	56.9%
TCC & TNC	27,115	31.6%	0	0.0%
Subtotal - AEP West Zone	**$85,736**	**100.0%**	**$36,162**	**100.0%**
TOTAL AEP	$481,541		$481,541	