CASE NUMBER:

99-149

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Schedule 27

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APR 1 5 1999
PUBLIC SERVICE
COMMISSION

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APR 1 5 1999

PUBLIC SERVICE COMMISSION

AMERICAN ELECTRIC POWER SERVICE CORPORATION
BILLINGS UNDER $100K BY WORK ORDER
FOR THE YEAR ENDED 12/31/97

WO	CO	TITLE/DESCRIPTION		AMOUNT	FORM
0837	01	AEPSC (EMF) TASK FORCE - OPER & AEG ADVISE AEP MANAGEMENT REGARDING ELECTRIC& MA	$	124.13	01
0999	01	R&D TASK FORCE - OPER & AEG REVIEW NEW R&D PROJECTS & COORDINATION OF R&D ACT	$	602.22	01
1391	01	ECONOMIC ANLS SYS PLANNING -OPER & AEG ECON ANLS ACTIVITY NOT DIRECTLY RELATED TO LO	$	26.59	01
1436	01	EPRI RESEARCH - OPER & AEG EXPENSES ASSOC W/ PARTICIPATION IN EPRI'TECHNICAL RE	$	413.11	01
1459	01	SYS ACCTG APPL/PLANT ACCOUNTING-OPER&AEGRE-ENG PLANT ACCOUNTING PROCESS & ACTIV-I	$	732.79	01
1470	01	ENGINEERING EDUCATION PROGRAM-OPER & AEG	$	963.13	01
1803	01	OPERATING FORECAST - OPER & AEG	$	397.63	01
1950	01	COMPUTER APPL GEN ADM - OPER & AEG	$	518.18	01
0837	02	AEPSC (EMF) TASK FORCE - OPER & AEG ADVISE AEP MANAGEMENT REGARDING ELECTRIC& MA	$	2,383.46	01
0999	02	R&D TASK FORCE - OPER & AEG REVIEW NEW R&D PROJECTS & COORDINATION OF R&D ACT	$	11,507.06	01
1391	02	ECONOMIC ANLS SYS PLANNING -OPER & AEG ECON ANLS ACTIVITY NOT DIRECTLY RELATED TO LO	$	510.84	01
1436	02	EPRI RESEARCH - OPER & AEG EXPENSES ASSOC W/ PARTICIPATION IN EPRI'TECHNICAL RE	$	7,937.41	01
1459	02	SYS ACCTG APPL/PLANT ACCOUNTING-OPER&AEGRE-ENG PLANT ACCOUNTING PROCESS & ACTIV-I	$	14,077.98	01
1470	02	ENGINEERING EDUCATION PROGRAM-OPER & AEG	$	18,460.76	01
1803	02	OPERATING FORECAST - OPER & AEG	$	7,562.02	01
1950	02	COMPUTER APPL GEN ADM - OPER & AEG	$	10,276.37	01
0837	03	AEPSC (EMF) TASK FORCE - OPER & AEG ADVISE AEP MANAGEMENT REGARDING ELECTRIC& MA	$	357.72	01
0999	03	R&D TASK FORCE - OPER & AEG REVIEW NEW R&D PROJECTS & COORDINATION OF R&D ACT	$	1,718.69	01
1391	03	ECONOMIC ANLS SYS PLANNING -OPER & AEG ECON ANLS ACTIVITY NOT DIRECTLY RELATED TO LO	$	77.85	01
1436	03	EPRI RESEARCH - OPER & AEG EXPENSES ASSOC W/ PARTICIPATION IN EPRI'TECHNICAL RE	$	1,195.24	01
1459	03	SYS ACCTG APPL/PLANT ACCOUNTING-OPER&AEGRE-ENG PLANT ACCOUNTING PROCESS & ACTIV-I	$	2,144.92	01
1470	03	ENGINEERING EDUCATION PROGRAM-OPER & AEG	$	2,779.48	01
1803	03	OPERATING FORECAST - OPER & AEG	$	1,125.37	01
1950	03	COMPUTER APPL GEN ADM - OPER & AEG	$	1,568.60	01
0837	04	AEPSC (EMF) TASK FORCE - OPER & AEG ADVISE AEP MANAGEMENT REGARDING ELECTRIC& MA	$	1,489.47	01
0999	04	R&D TASK FORCE - OPER & AEG REVIEW NEW R&D PROJECTS & COORDINATION OF R&D ACT	$	7,163.19	01
1391	04	ECONOMIC ANLS SYS PLANNING -OPER & AEG ECON ANLS ACTIVITY NOT DIRECTLY RELATED TO LO	$	322.84	01
1436	04	EPRI RESEARCH - OPER & AEG EXPENSES ASSOC W/ PARTICIPATION IN EPRI'TECHNICAL RE	$	4,972.52	01
1459	04	SYS ACCTG APPL/PLANT ACCOUNTING-OPER&AEGRE-ENG PLANT ACCOUNTING PROCESS & ACTIV-I	$	8,894.57	01
1470	04	ENGINEERING EDUCATION PROGRAM-OPER & AEG	$	11,561.57	01
1803	04	OPERATING FORECAST - OPER & AEG	$	4,693.42	01
1950	04	COMPUTER APPL GEN ADM - OPER & AEG	$	6,517.99	01
0837	06	AEPSC (EMF) TASK FORCE - OPER & AEG ADVISE AEP MANAGEMENT REGARDING ELECTRIC& MA	$	124.04	01
0999	06	R&D TASK FORCE - OPER & AEG REVIEW NEW R&D PROJECTS & COORDINATION OF R&D ACT	$	598.88	01
1391	06	ECONOMIC ANLS SYS PLANNING -OPER & AEG ECON ANLS ACTIVITY NOT DIRECTLY RELATED TO LO	$	26.59	01
1436	06	EPRI RESEARCH - OPER & AEG EXPENSES ASSOC W/ PARTICIPATION IN EPRI'TECHNICAL RE	$	413.11	01
1459	06	SYS ACCTG APPL/PLANT ACCOUNTING-OPER&AEGRE-ENG PLANT ACCOUNTING PROCESS & ACTIV-I	$	732.75	01
1470	06	ENGINEERING EDUCATION PROGRAM-OPER & AEG	$	960.80	01
1803	06	OPERATING FORECAST - OPER & AEG	$	393.57	01
1950	06	COMPUTER APPL GEN ADM - OPER & AEG	$	534.82	01
0837	07	AEPSC (EMF) TASK FORCE - OPER & AEG ADVISE AEP MANAGEMENT REGARDING ELECTRIC& MA	$	2,577.08	01
0999	07	R&D TASK FORCE - OPER & AEG REVIEW NEW R&D PROJECTS & COORDINATION OF R&D ACT	$	12,458.21	01
1391	07	ECONOMIC ANLS SYS PLANNING -OPER & AEG ECON ANLS ACTIVITY NOT DIRECTLY RELATED TO LO	$	548.84	01
1436	07	EPRI RESEARCH - OPER & AEG EXPENSES ASSOC W/ PARTICIPATION IN EPRI'TECHNICAL RE	$	8,571.26	01
1459	07	SYS ACCTG APPL/PLANT ACCOUNTING-OPER&AEGRE-ENG PLANT ACCOUNTING PROCESS & ACTIV-I	$	15,126.70	01
1470	07	ENGINEERING EDUCATION PROGRAM-OPER & AEG	$	19,929.10	01
1803	07	OPERATING FORECAST - OPER & AEG	$	8,193.71	01
1950	07	COMPUTER APPL GEN ADM - OPER & AEG	$	11,083.35	01
0837	10	AEPSC (EMF) TASK FORCE - OPER & AEG ADVISE AEP MANAGEMENT REGARDING ELECTRIC& MA	$	1,243.86	01
0999	10	R&D TASK FORCE - OPER & AEG REVIEW NEW R&D PROJECTS & COORDINATION OF R&D ACT	$	5,999.68	01
1391	10	ECONOMIC ANLS SYS PLANNING -OPER & AEG ECON ANLS ACTIVITY NOT DIRECTLY RELATED TO LO	$	267.76	01
1436	10	EPRI RESEARCH - OPER & AEG EXPENSES ASSOC W/ PARTICIPATION IN EPRI'TECHNICAL RE	$	4,145.92	01
1459	10	SYS ACCTG APPL/PLANT ACCOUNTING-OPER&AEGRE-ENG PLANT ACCOUNTING PROCESS & ACTIV-I	$	7,378.45	01
1470	10	ENGINEERING EDUCATION PROGRAM-OPER & AEG	$	9,644.62	01
1803	10	OPERATING FORECAST - OPER & AEG	$	3,940.58	01
1950	10	COMPUTER APPL GEN ADM - OPER & AEG	$	5,372.16	01
0837	21	AEPSC (EMF) TASK FORCE - OPER & AEG ADVISE AEP MANAGEMENT REGARDING ELECTRIC& MA	$	560.65	01
0999	21	R&D TASK FORCE - OPER & AEG REVIEW NEW R&D PROJECTS & COORDINATION OF R&D ACT	$	2,729.19	01
1391	21	ECONOMIC ANLS SYS PLANNING -OPER & AEG ECON ANLS ACTIVITY NOT DIRECTLY RELATED TO LO	$	117.74	01
1436	21	EPRI RESEARCH - OPER & AEG EXPENSES ASSOC W/ PARTICIPATION IN EPRI'TECHNICAL RE	$	1,858.65	01

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WO	CO	TITLE/DESCRIPTION	AMOUNT	FORM
1459	21	SYS ACCTG APPL/PLANT ACCOUNTING-OPER&AEGRE-ENG PLANT ACCOUNTING PROCESS & ACTIV-I	$ 3,246.34	01
1470	21	ENGINEERING EDUCATION PROGRAM-OPER & AEG	$ 4,328.02	01
1803	21	OPERATING FORECAST - OPER & AEG	$ 1,805.37	01
1950	21	COMPUTER APPL GEN ADM - OPER & AEG	$ 2,330.45	01
0848	02	ELECMAG TRANSIENTS PROGRAM - GEN & ROCK ENHANCE EFFORT IN CONJUNCTION WITH (EPRI	$ 14,556.53	02
1499	02	PWR PLT SWITCHGEAR EQ MAINT STY TEAM-GENDEVLP SWITCHGEAR DIAGNOSTIC TEST REPAIR PR	$ 3,923.59	02
1741	02	INTERCONNECTION/COORDINATION OPER - GEN	$ 1,024.86	02
2428	02	SYS HUM RESOURCES IND HYGIENE AUDIT-GEN SERV OF GEN NATURE REL TO IND HYGIENE AUDIT	$ 2,734.55	02
4381	02	EMI MONITOR DEVELOPMENT - GEN DEV 2000 SERIES ELECMAG MNTR,CONST/INSTL15 UNITS;	$ 470.64	02
4414	02	EPRI RESOURCE ALLOCATION FRAMEWORK - GENDEVELOP A RESOURCE ALLOCATION FRAMEWOR	$ 10,979.33	02
4415	02	KAPTON CR EVALUATION - GEN EVAL DUPONT INSUL "KAPTON CR" REBUILD HIGH VOLT MA	$ 666.39	02
4431	02	AGING RATE MICA INSULATION - OPER TEST STATOR COILS FR SMITH MTN #2 &#4 ONSITE & DOL	$ 1,446.69	02
4440	02	ZEBRA MUSSEL CONTROL - GEN GEN ELEC FIELD TO PREVENT SETTLEMENT OF MUSSELS; R	$ 949.91	02
4457	02	EPRI YR 2000 EMBEDDED SYS PROJECT - GEN WORK W/EPRI ON Y2K ISSUES WITH EMBEDDED SYST	$ 12,187.50	02
0848	03	ELECMAG TRANSIENTS PROGRAM - GEN & ROCK ENHANCE EFFORT IN CONJUNCTION WITH (EPRI	$ 2,998.57	02
1499	03	PWR PLT SWITCHGEAR EQ MAINT STY TEAM-GENDEVLP SWITCHGEAR DIAGNOSTIC TEST REPAIR PR	$ 808.62	02
1741	03	INTERCONNECTION/COORDINATION OPER - GEN	$ 209.33	02
2428	03	SYS HUM RESOURCES IND HYGIENE AUDIT-GEN SERV OF GEN NATURE REL TO IND HYGIENE AUDIT	$ 562.20	02
4381	03	EMI MONITOR DEVELOPMENT - GEN DEV 2000 SERIES ELECMAG MNTR,CONST/INSTL15 UNITS;	$ 97.02	02
4414	03	EPRI RESOURCE ALLOCATION FRAMEWORK - GENDEVELOP A RESOURCE ALLOCATION FRAMEWOR	$ 2,251.49	02
4415	03	KAPTON CR EVALUATION - GEN EVAL DUPONT INSUL "KAPTON CR" REBUILD HIGH VOLT MA	$ 137.02	02
4431	03	AGING RATE MICA INSULATION - OPER TEST STATOR COILS FR SMITH MTN #2 &#4 ONSITE & DOL	$ 298.25	02
4440	03	ZEBRA MUSSEL CONTROL - GEN GEN ELEC FIELD TO PREVENT SETTLEMENT OF MUSSELS; R	$ 195.84	02
4457	03	EPRI YR 2000 EMBEDDED SYS PROJECT - GEN WORK W/EPRI ON Y2K ISSUES WITH EMBEDDED SYST	$ 2,512.50	02
0848	04	ELECMAG TRANSIENTS PROGRAM - GEN & ROCK ENHANCE EFFORT IN CONJUNCTION WITH (EPRI	$ 8,353.40	02
1499	04	PWR PLT SWITCHGEAR EQ MAINT STY TEAM-GENDEVLP SWITCHGEAR DIAGNOSTIC TEST REPAIR PR	$ 2,253.22	02
1741	04	INTERCONNECTION/COORDINATION OPER - GEN	$ 574.93	02
2428	04	SYS HUM RESOURCES IND HYGIENE AUDIT-GEN SERV OF GEN NATURE REL TO IND HYGIENE AUDIT	$ 1,557.37	02
4381	04	EMI MONITOR DEVELOPMENT - GEN DEV 2000 SERIES ELECMAG MNTR,CONST/INSTL15 UNITS;	$ 270.80	02
4414	04	EPRI RESOURCE ALLOCATION FRAMEWORK - GENDEVELOP A RESOURCE ALLOCATION FRAMEWOR	$ 6,212.59	02
4415	04	KAPTON CR EVALUATION - GEN EVAL DUPONT INSUL "KAPTON CR" REBUILD HIGH VOLT MA	$ 379.68	02
4431	04	AGING RATE MICA INSULATION - OPER TEST STATOR COILS FR SMITH MTN #2 &#4 ONSITE & DOL	$ 832.30	02
4440	04	ZEBRA MUSSEL CONTROL - GEN GEN ELEC FIELD TO PREVENT SETTLEMENT OF MUSSELS; R	$ 546.54	02
4457	04	EPRI YR 2000 EMBEDDED SYS PROJECT - GEN WORK W/EPRI ON Y2K ISSUES WITH EMBEDDED SYST	$ 7,012.50	02
0848	07	ELECMAG TRANSIENTS PROGRAM - GEN & ROCK ENHANCE EFFORT IN CONJUNCTION WITH (EPRI	$ 11,734.52	02
1499	07	PWR PLT SWITCHGEAR EQ MAINT STY TEAM-GENDEVLP SWITCHGEAR DIAGNOSTIC TEST REPAIR PR	$ 3,164.75	02
1741	07	INTERCONNECTION/COORDINATION OPER - GEN	$ 821.77	02
2428	07	SYS HUM RESOURCES IND HYGIENE AUDIT-GEN SERV OF GEN NATURE REL TO IND HYGIENE AUDIT	$ 2,206.59	02
4381	07	EMI MONITOR DEVELOPMENT - GEN DEV 2000 SERIES ELECMAG MNTR,CONST/INSTL15 UNITS;	$ 379.41	02
4414	07	EPRI RESOURCE ALLOCATION FRAMEWORK - GENDEVELOP A RESOURCE ALLOCATION FRAMEWOR	$ 8,845.06	02
4415	07	KAPTON CR EVALUATION - GEN EVAL DUPONT INSUL "KAPTON CR" REBUILD HIGH VOLT MA	$ 538.03	02
4431	07	AGING RATE MICA INSULATION - OPER TEST STATOR COILS FR SMITH MTN #2 &#4 ONSITE & DOL	$ 1,166.36	02
4440	07	ZEBRA MUSSEL CONTROL - GEN GEN ELEC FIELD TO PREVENT SETTLEMENT OF MUSSELS; R	$ 765.76	02
4457	07	EPRI YR 2000 EMBEDDED SYS PROJECT - GEN WORK W/EPRI ON Y2K ISSUES WITH EMBEDDED SYST	$ 9,825.00	02
0848	10	ELECMAG TRANSIENTS PROGRAM - GEN & ROCK ENHANCE EFFORT IN CONJUNCTION WITH (EPRI	$ 7,111.83	02
1499	10	PWR PLT SWITCHGEAR EQ MAINT STY TEAM-GENDEVLP SWITCHGEAR DIAGNOSTIC TEST REPAIR PR	$ 1,919.01	02
1741	10	INTERCONNECTION/COORDINATION OPER - GEN	$ 493.70	02
2428	10	SYS HUM RESOURCES IND HYGIENE AUDIT-GEN SERV OF GEN NATURE REL TO IND HYGIENE AUDIT	$ 1,330.17	02
4381	10	EMI MONITOR DEVELOPMENT - GEN DEV 2000 SERIES ELECMAG MNTR,CONST/INSTL15 UNITS;	$ 230.25	02
4414	10	EPRI RESOURCE ALLOCATION FRAMEWORK - GENDEVELOP A RESOURCE ALLOCATION FRAMEWOR	$ 5,315.89	02
4415	10	KAPTON CR EVALUATION - GEN EVAL DUPONT INSUL "KAPTON CR" REBUILD HIGH VOLT MA	$ 324.02	02
4431	10	AGING RATE MICA INSULATION - OPER TEST STATOR COILS FR SMITH MTN #2 &#4 ONSITE & DOL	$ 707.79	02
4440	10	ZEBRA MUSSEL CONTROL - GEN GEN ELEC FIELD TO PREVENT SETTLEMENT OF MUSSELS; R	$ 464.70	02
4457	10	EPRI YR 2000 EMBEDDED SYS PROJECT - GEN WORK W/EPRI ON Y2K ISSUES WITH EMBEDDED SYST	$ 5,962.50	02
1110	01	GEN DSM ACTIVITY - OPER GEN DSM ACT TO ENCOURAGE SAFE, EFFICIENTAND ECONOMI	$ 709.82	03
1276	01	APPLIANCE SURVEY - OPER MONITOR APPLIANCE SATURATION TRENDS,CON-SERVATION	$ 1,243.45	03
1369	01	JAPANESE DEVELOPMENT PROGRAM - OPER SECURE JAPANESE MANUFACTURING PLANTS AS O	$ 454.01	03
1452	01	INTELLECTUAL PROPERTY COMMITTEE - OPER IDENTIFYING & MANAGING THE COMPANY'S INTELL	$ 12.24	03
1462	01	CUSTOMER SATISF & LOYALTY MEASURE - OPERDEVELOP & IMPLEMENT THE CUSTOMER SATIS- FA	$ 20.29	03
4436	01	DSTATCOM DEMONSTRATION - OPER DEMONSTRATE VOLTAGE SOURCE INVERTER BASEDSTA	$ 76.51	03

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WO	CO	TITLE/DESCRIPTION		AMOUNT	FORM
4441	01	LOAD PROFILING FOR RETAIL MKTG - OPER STY W/EPRI ON LOAD PROFILING FOR RETAIL MARKET	$	1,396.66	03
8666	01	ABD CONTRACT ADMIN & SOLICITATION - OPERSUPPORT SERVICES RELATED	$	1,406.22	03
1110	02	GEN DSM ACTIVITY - OPER GEN DSM ACT TO ENCOURAGE SAFE, EFFICIENTAND ECONOMI	$	13,985.70	03
1276	02	APPLIANCE SURVEY - OPER MONITOR APPLIANCE SATURATION TRENDS,CON-SERVATION	$	24,709.96	03
1369	02	JAPANESE DEVELOPMENT PROGRAM - OPER SECURE JAPANESE MANUFACTURING PLANTS AS O	$	8,897.86	03
1452	02	INTELLECTUAL PROPERTY COMMITTEE - OPER IDENTIFYING & MANAGING THE COMPANY'S INTELL	$	239.75	03
1462	02	CUSTOMER SATISF & LOYALTY MEASURE - OPERDEVELOP & IMPLEMENT THE CUSTOMER SATIS- FA	$	397.50	03
4436	02	DSTATCOM DEMONSTRATION - OPER DEMONSTRATE VOLTAGE SOURCE INVERTER BASEDSTA	$	1,499.52	03
4441	02	LOAD PROFILING FOR RETAIL MKTG - OPER STY W/EPRI ON LOAD PROFILING FOR RETAIL MARKET	$	27,374.12	03
8666	02	ABD CONTRACT ADMIN & SOLICITATION - OPERSUPPORT SERVICES RELATED	$	27,561.02	03
1110	03	GEN DSM ACTIVITY - OPER GEN DSM ACT TO ENCOURAGE SAFE, EFFICIENTAND ECONOMI	$	2,710.83	03
1276	03	APPLIANCE SURVEY - OPER MONITOR APPLIANCE SATURATION TRENDS,CON-SERVATION	$	4,787.51	03
1369	03	JAPANESE DEVELOPMENT PROGRAM - OPER SECURE JAPANESE MANUFACTURING PLANTS AS O	$	1,725.13	03
1452	03	INTELLECTUAL PROPERTY COMMITTEE - OPER IDENTIFYING & MANAGING THE COMPANY'S INTELL	$	46.47	03
1462	03	CUSTOMER SATISF & LOYALTY MEASURE - OPERDEVELOP & IMPLEMENT THE CUSTOMER SATIS- FA	$	77.09	03
4436	03	DSTATCOM DEMONSTRATION - OPER DEMONSTRATE VOLTAGE SOURCE INVERTER BASEDSTA	$	290.76	03
4441	03	LOAD PROFILING FOR RETAIL MKTG - OPER STY W/EPRI ON LOAD PROFILING FOR RETAIL MARKET	$	5,307.25	03
8666	03	ABD CONTRACT ADMIN & SOLICITATION - OPERSUPPORT SERVICES RELATED	$	5,343.49	03
1110	04	GEN DSM ACTIVITY - OPER GEN DSM ACT TO ENCOURAGE SAFE, EFFICIENTAND ECONOMI	$	8,750.68	03
1276	04	APPLIANCE SURVEY - OPER MONITOR APPLIANCE SATURATION TRENDS,CON-SERVATION	$	15,454.41	03
1369	04	JAPANESE DEVELOPMENT PROGRAM - OPER SECURE JAPANESE MANUFACTURING PLANTS AS O	$	5,568.77	03
1452	04	INTELLECTUAL PROPERTY COMMITTEE - OPER IDENTIFYING & MANAGING THE COMPANY'S INTELL	$	150.05	03
1462	04	CUSTOMER SATISF & LOYALTY MEASURE - OPERDEVELOP & IMPLEMENT THE CUSTOMER SATIS- FA	$	248.78	03
4436	04	DSTATCOM DEMONSTRATION - OPER DEMONSTRATE VOLTAGE SOURCE INVERTER BASEDSTA	$	938.50	03
4441	04	LOAD PROFILING FOR RETAIL MKTG - OPER STY W/EPRI ON LOAD PROFILING FOR RETAIL MARKET	$	17,132.15	03
8666	04	ABD CONTRACT ADMIN & SOLICITATION - OPERSUPPORT SERVICES RELATED	$	17,249.21	03
1110	06	GEN DSM ACTIVITY - OPER GEN DSM ACT TO ENCOURAGE SAFE, EFFICIENTAND ECONOMI	$	665.80	03
1276	06	APPLIANCE SURVEY - OPER MONITOR APPLIANCE SATURATION TRENDS,CON-SERVATION	$	1,175.92	03
1369	06	JAPANESE DEVELOPMENT PROGRAM - OPER SECURE JAPANESE MANUFACTURING PLANTS AS O	$	423.70	03
1452	06	INTELLECTUAL PROPERTY COMMITTEE - OPER IDENTIFYING & MANAGING THE COMPANY'S INTELL	$	11.42	03
1462	06	CUSTOMER SATISF & LOYALTY MEASURE - OPERDEVELOP & IMPLEMENT THE CUSTOMER SATIS- FA	$	18.94	03
4436	06	DSTATCOM DEMONSTRATION - OPER DEMONSTRATE VOLTAGE SOURCE INVERTER BASEDSTA	$	71.41	03
4441	06	LOAD PROFILING FOR RETAIL MKTG - OPER STY W/EPRI ON LOAD PROFILING FOR RETAIL MARKET	$	1,303.51	03
8666	06	ABD CONTRACT ADMIN & SOLICITATION - OPERSUPPORT SERVICES RELATED	$	1,312.39	03
1110	07	GEN DSM ACTIVITY - OPER GEN DSM ACT TO ENCOURAGE SAFE, EFFICIENTAND ECONOMI	$	10,878.87	03
1276	07	APPLIANCE SURVEY - OPER MONITOR APPLIANCE SATURATION TRENDS,CON-SERVATION	$	19,241.42	03
1369	07	JAPANESE DEVELOPMENT PROGRAM - OPER SECURE JAPANESE MANUFACTURING PLANTS AS O	$	6,909.62	03
1452	07	INTELLECTUAL PROPERTY COMMITTEE - OPER IDENTIFYING & MANAGING THE COMPANY'S INTELL	$	186.75	03
1462	07	CUSTOMER SATISF & LOYALTY MEASURE - OPERDEVELOP & IMPLEMENT THE CUSTOMER SATIS- FA	$	309.08	03
4436	07	DSTATCOM DEMONSTRATION - OPER DEMONSTRATE VOLTAGE SOURCE INVERTER BASEDSTA	$	1,163.40	03
4441	07	LOAD PROFILING FOR RETAIL MKTG - OPER STY W/EPRI ON LOAD PROFILING FOR RETAIL MARKET	$	21,232.42	03
8666	07	ABD CONTRACT ADMIN & SOLICITATION - OPERSUPPORT SERVICES RELATED	$	21,420.06	03
1110	10	GEN DSM ACTIVITY - OPER GEN DSM ACT TO ENCOURAGE SAFE, EFFICIENTAND ECONOMI	$	9,856.49	03
1276	10	APPLIANCE SURVEY - OPER MONITOR APPLIANCE SATURATION TRENDS,CON-SERVATION	$	17,378.78	03
1369	10	JAPANESE DEVELOPMENT PROGRAM - OPER SECURE JAPANESE MANUFACTURING PLANTS AS O	$	6,285.98	03
1452	10	INTELLECTUAL PROPERTY COMMITTEE - OPER IDENTIFYING & MANAGING THE COMPANY'S INTELL	$	168.79	03
1462	10	CUSTOMER SATISF & LOYALTY MEASURE - OPERDEVELOP & IMPLEMENT THE CUSTOMER SATIS- FA	$	280.45	03
4436	10	DSTATCOM DEMONSTRATION - OPER DEMONSTRATE VOLTAGE SOURCE INVERTER BASEDSTA	$	1,060.44	03
4441	10	LOAD PROFILING FOR RETAIL MKTG - OPER STY W/EPRI ON LOAD PROFILING FOR RETAIL MARKET	$	19,363.24	03
8666	10	ABD CONTRACT ADMIN & SOLICITATION - OPERSUPPORT SERVICES RELATED	$	19,452.97	03
1144	07	DSM SMART FINANCING PROGRAM - CSP, OP SUPPORT FOR PROG TO PROVIDE FINANCING FOR I	$	5,700.21	04
1144	10	DSM SMART FINANCING PROGRAM - CSP, OP SUPPORT FOR PROG TO PROVIDE FINANCING FOR I	$	5,139.34	04
1492	01	LEASING CO ASSETS TELECOMM - ALL COS USE OF OPER COS TELECOMM TOWERS BY OUT- SIDE	$	1.72	05
8774	01	PAYROLL PROCESSING - ALL DATA PROCESSING SERVICES FOR THE CENTRALIZED PA	$	194.73	05
1492	02	LEASING CO ASSETS TELECOMM - ALL COS USE OF OPER COS TELECOMM TOWERS BY OUT- SIDE	$	66.02	05
8774	02	PAYROLL PROCESSING - ALL DATA PROCESSING SERVICES FOR THE CENTRALIZED PA	$	8,125.38	05
1492	03	LEASING CO ASSETS TELECOMM - ALL COS USE OF OPER COS TELECOMM TOWERS BY OUT- SIDE	$	15.22	05
8774	03	PAYROLL PROCESSING - ALL DATA PROCESSING SERVICES FOR THE CENTRALIZED PA	$	1,654.76	05
1492	04	LEASING CO ASSETS TELECOMM - ALL COS USE OF OPER COS TELECOMM TOWERS BY OUT- SIDE	$	53.69	05
8774	04	PAYROLL PROCESSING - ALL DATA PROCESSING SERVICES FOR THE CENTRALIZED PA	$	6,215.36	05

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WO	CO	TITLE/DESCRIPTION	AMOUNT	FORM
1492	06	LEASING CO ASSETS TELECOMM - ALL COS USE OF OPER COS TELECOMM TOWERS BY OUT- SIDE	$ 1.72	05
8774	06	PAYROLL PROCESSING - ALL DATA PROCESSING SERVICES FOR THE CENTRALIZED PA	$ 216.95	05
1492	07	LEASING CO ASSETS TELECOMM - ALL COS USE OF OPER COS TELECOMM TOWERS BY OUT- SIDE	$ 53.12	05
8774	07	PAYROLL PROCESSING - ALL DATA PROCESSING SERVICES FOR THE CENTRALIZED PA	$ 6,129.08	05
1492	10	LEASING CO ASSETS TELECOMM - ALL COS USE OF OPER COS TELECOMM TOWERS BY OUT- SIDE	$ 34.17	05
8774	10	PAYROLL PROCESSING - ALL DATA PROCESSING SERVICES FOR THE CENTRALIZED PA	$ 3,927.13	05
1492	22	LEASING CO ASSETS TELECOMM - ALL COS USE OF OPER COS TELECOMM TOWERS BY OUT- SIDE	$ 6.32	05
8774	22	PAYROLL PROCESSING - ALL DATA PROCESSING SERVICES FOR THE CENTRALIZED PA	$ 688.00	05
1492	23	LEASING CO ASSETS TELECOMM - ALL COS USE OF OPER COS TELECOMM TOWERS BY OUT- SIDE	$ 5.17	05
8774	23	PAYROLL PROCESSING - ALL DATA PROCESSING SERVICES FOR THE CENTRALIZED PA	$ 584.15	05
1492	42	LEASING CO ASSETS TELECOMM - ALL COS USE OF OPER COS TELECOMM TOWERS BY OUT- SIDE	$ 4.31	05
8774	42	PAYROLL PROCESSING - ALL DATA PROCESSING SERVICES FOR THE CENTRALIZED PA	$ 485.30	05
1492	43	LEASING CO ASSETS TELECOMM - ALL COS USE OF OPER COS TELECOMM TOWERS BY OUT- SIDE	$ 4.88	05
8774	43	PAYROLL PROCESSING - ALL DATA PROCESSING SERVICES FOR THE CENTRALIZED PA	$ 505.71	05
1492	44	LEASING CO ASSETS TELECOMM - ALL COS USE OF OPER COS TELECOMM TOWERS BY OUT- SIDE	$ 17.23	05
8774	44	PAYROLL PROCESSING - ALL DATA PROCESSING SERVICES FOR THE CENTRALIZED PA	$ 1,923.43	05
1492	46	LEASING CO ASSETS TELECOMM - ALL COS USE OF OPER COS TELECOMM TOWERS BY OUT- SIDE	$ 0.29	05
8774	46	PAYROLL PROCESSING - ALL DATA PROCESSING SERVICES FOR THE CENTRALIZED PA	$ 32.43	05
1492	48	LEASING CO ASSETS TELECOMM - ALL COS USE OF OPER COS TELECOMM TOWERS BY OUT- SIDE	$ 6.89	05
8774	48	PAYROLL PROCESSING - ALL DATA PROCESSING SERVICES FOR THE CENTRALIZED PA	$ 734.37	05
1492	49	LEASING CO ASSETS TELECOMM - ALL COS USE OF OPER COS TELECOMM TOWERS BY OUT- SIDE	$ 1.44	05
8774	49	PAYROLL PROCESSING - ALL DATA PROCESSING SERVICES FOR THE CENTRALIZED PA	$ 162.27	05
1492	54	LEASING CO ASSETS TELECOMM - ALL COS USE OF OPER COS TELECOMM TOWERS BY OUT- SIDE	$ 0.86	05
8774	54	PAYROLL PROCESSING - ALL DATA PROCESSING SERVICES FOR THE CENTRALIZED PA	$ 75.13	05
1492	69	LEASING CO ASSETS TELECOMM - ALL COS USE OF OPER COS TELECOMM TOWERS BY OUT- SIDE	$ 0.29	05
8774	69	PAYROLL PROCESSING - ALL DATA PROCESSING SERVICES FOR THE CENTRALIZED PA	$ 10.20	05
1492	71	LEASING CO ASSETS TELECOMM - ALL COS USE OF OPER COS TELECOMM TOWERS BY OUT- SIDE	$ 7.75	05
8774	71	PAYROLL PROCESSING - ALL DATA PROCESSING SERVICES FOR THE CENTRALIZED PA	$ 438.91	05
1492	73	LEASING CO ASSETS TELECOMM - ALL COS USE OF OPER COS TELECOMM TOWERS BY OUT- SIDE	$ 6.03	05
8774	73	PAYROLL PROCESSING - ALL DATA PROCESSING SERVICES FOR THE CENTRALIZED PA	$ 349.42	05
1726	02	INTERCONNECTION/COORDINATION OPER-AP,KP	$ 13,546.79	06
1726	03	INTERCONNECTION/COORDINATION OPER-AP,KP	$ 2,774.64	06
1724	02	TRANSMISSN PLAN OPER - AP, CSP,I&M,OP	$ 3,756.90	07
1724	04	TRANSMISSN PLAN OPER - AP, CSP,I&M,OP	$ 2,143.95	07
1724	07	TRANSMISSN PLAN OPER - AP, CSP,I&M,OP	$ 3,039.47	07
1724	10	TRANSMISSN PLAN OPER - AP, CSP,I&M,OP	$ 1,834.73	07
1824	01	CONSTRUCTION BUDGET - OPER & ROCK	$ 643.68	10
1824	02	CONSTRUCTION BUDGET - OPER & ROCK	$ 27,376.38	10
1824	03	CONSTRUCTION BUDGET - OPER & ROCK	$ 22,120.01	10
1824	04	CONSTRUCTION BUDGET - OPER & ROCK	$ 9,885.31	10
1824	06	CONSTRUCTION BUDGET - OPER & ROCK	$ 522.01	10
1824	07	CONSTRUCTION BUDGET - OPER & ROCK	$ 13,590.37	10
1824	10	CONSTRUCTION BUDGET - OPER & ROCK	$ 12,138.05	10
1824	73	CONSTRUCTION BUDGET - OPER & ROCK	$ 741.80	10
0817	01	MARKET RESEARCH - OPER ANALYZE CUSTOMER CHARACTERISTICS FOR ELECTRICAL U	$ 277.60	12
0987	01	PHASE ANGLE & FREQ MEASUREMENTS - OPER INVESTIGATE PHASE ANGLE METHODS BETWEEN S	$ 4.37	12
1083	01	POLYCHLORINATED BIPHENYLS - OPER INSPECT, TEST, & EVALUATE DISPOSAL OPTIONS & C	$ 266.63	12
1246	01	EAST CENTRAL AREA RELIABILITY ACTV - OPEINVOLVEMENT WITH ECAR GEN/TRANSM STUDIESEXC	$ 549.21	12
1247	01	NORTH AMER ELEC RELIABILITY ACTV - OPER INVOLVEMENT WITH NERC GEN/TRANSM ASSESS-MEN	$ 412.21	12
1398	01	CADPAD/FEEDER DESIGN IMPLEMENTATION-OPERIMPLEMENT A DISTRIBUTION APPLICATION & DES	$ 1,262.08	12
1446	01	WORK MANAGEMENT SYSTEM DEVELOPMENT-OPER REPLATFORM PTS TO CLIENT PLATFORM & IN-	$ 126.18	12
1695	01	LOAAD ANALYSIS STUDIES - OPER DETERMINE LOAD CHARACTER OF END USERS, INDIVIDUAL	$ 229.99	12
1701	01	SYSTEM PLANNING ENERGY RESOURCE - OPER	$ 36.60	12
4375	01	SOLAR MAGNETIC DISTURBANCE SYSTEM - OPERMONITOR (GICS) IN TRANSFORMER & SHUNT REA	$ 79.13	12
4401	01	EPIC IND MKT ASSESS&STRATEGIC ANLS-OPER DEV ELECTECHNLG MKT PLNS FOR IND & COMM SE	$ 1.70	12
4406	01	EPRI VOLTAGE FLICKER PROJECT - OPER PARTICIPATION IN EPRI SPONSORED PROJ ON VOLTAG	$ 0.57	12
4408	01	NATIONAL EARTH COMFORT PROGRAM - OPER PARTICIPATION IN GEOTHERMAL HEAT PUMP CON	$ 553.55	12
4411	01	MAGNETIC FIELD SHIELDING CASE STUDY-OPERMEASUREMENTS IN UNDERGROUND VAULTS & MAN	$ 122.46	12
4412	01	ELEC VEHICLE BATERY CHARGER PROJECT-OPERTESTING ELEC VEHICLE CHARGING SYSTEM R &	$ 50.35	12
4419	01	FAULT ANALY&LIGHTNING LOCATION SYS-OPER VERIFY USAGE & IDENTIFY SPECIFIC BENE TOAEP;	$ 924.58	12

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WO	CO	TITLE/DESCRIPTION		AMOUNT	FORM
4420	01	EASTON DEVLP DSTRBN TSF SWITCH DEMO-OPERMERITS OF SOLID STATE DISTRIBUTION TSF SWIT	$	618.09	12
4421	01	PWR FREQ AC SPARKOVER VOLT MEASURE-OPER EXPER @ OSU TO DETER AIR GAP SPARK OVER V	$	12.33	12
4427	01	ALTERNTV DISTRIBUTION STRUCTURE - OPER EVAL TUBULAR STEEL POLE STRUCTURES FOR SYS	$	358.04	12
4428	01	PWR QAUAL INSTRUMENT LAB DEVELOP - OPER DEVEL DATA ON PROCESS EQUIP & PROVIDE CALI	$	1,032.15	12
4446	01	DISTRBN INFRASTRUCTER PLANNING DEMO-OPERDISTRIBUTION ASSET MGMT PLAN CAPABILITY R&	$	38.19	12
0817	02	MARKET RESEARCH - OPER ANALYZE CUSTOMER CHARACTERISTICS FOR ELECTRICAL U	$	5,396.13	12
0987	02	PHASE ANGLE & FREQ MEASUREMENTS - OPER INVESTIGATE PHASE ANGLE METHODS BETWEEN S	$	83.52	12
1083	02	POLYCHLORINATED BIPHENYLS - OPER INSPECT, TEST, & EVALUATE DISPOSAL OPTIONS & C	$	5,162.66	12
1246	02	EAST CENTRAL AREA RELIABILITY ACTV - OPEINVOLVEMENT WITH ECAR GEN/TRANSM STUDIESEXC	$	11,258.61	12
1247	02	NORTH AMER ELEC RELIABILITY ACTV - OPER INVOLVEMENT WITH NERC GEN/TRANSM ASSESS-MEN	$	8,450.19	12
1398	02	CADPAD/FEEDER DESIGN IMPLEMENTATION-OPERIMPLEMENT A DISTRIBUTION APPLICATION & DES	$	24,333.58	12
1446	02	WORK MANAGEMENT SYSTEM DEVELOPMENT-OPER REPLATFORM PTS TO CLIENT PLATFORM & IN-	$	2,414.13	12
1695	02	LOAAD ANALYSIS STUDIES - OPER DETERMINE LOAD CHARACTER OF END USERS, INDIVIDUAL	$	4,409.23	12
1701	02	SYSTEM PLANNING ENERGY RESOURCE - OPER	$	700.06	12
4375	02	SOLAR MAGNETIC DISTURBANCE SYSTEM - OPERMONITOR (GICS) IN TRANSFORMER & SHUNT REA	$	1,516.22	12
4401	02	EPIC IND MKT ASSESS&STRATEGIC ANLS-OPER DEV ELECTECHNLG MKT PLNS FOR IND & COMM SE	$	34.73	12
4406	02	EPRI VOLTAGE FLICKER PROJECT - OPER PARTICIPATION IN EPRI SPONSORED PROJ ON VOLTAG	$	10.84	12
4408	02	NATIONAL EARTH COMFORT PROGRAM - OPER PARTICIPATION IN GEOTHERMAL HEAT PUMP CON	$	10,717.71	12
4411	02	MAGNETIC FIELD SHIELDING CASE STUDY-OPERMEASUREMENTS IN UNDERGROUND VAULTS & MAN	$	2,362.02	12
4412	02	ELEC VEHICLE BATERY CHARGER PROJECT-OPERTESTING ELEC VEHICLE CHARGING SYSTEM R &	$	949.23	12
4419	02	FAULT ANALY&LIGHTNING LOCATION SYS-OPER VERIFY USAGE & IDENTIFY SPECIFIC BENE TOAEP;	$	17,738.54	12
4420	02	EASTON DEVLP DSTRBN TSF SWITCH DEMO-OPERMERITS OF SOLID STATE DISTRIBUTION TSF SWIT	$	12,003.18	12
4421	02	PWR FREQ AC SPARKOVER VOLT MEASURE-OPER EXPER @ OSU TO DETER AIR GAP SPARK OVER V	$	231.87	12
4427	02	ALTERNTV DISTRIBUTION STRUCTURE - OPER EVAL TUBULAR STEEL POLE STRUCTURES FOR SYS	$	6,868.28	12
4428	02	PWR QAUAL INSTRUMENT LAB DEVELOP - OPER DEVEL DATA ON PROCESS EQUIP & PROVIDE CALI	$	20,501.42	12
4446	02	DISTRBN INFRASTRUCTER PLANNING DEMO-OPERDISTRIBUTION ASSET MGMT PLAN CAPABILITY R&	$	782.04	12
0817	03	MARKET RESEARCH - OPER ANALYZE CUSTOMER CHARACTERISTICS FOR ELECTRICAL U	$	808.48	12
0987	03	PHASE ANGLE & FREQ MEASUREMENTS - OPER INVESTIGATE PHASE ANGLE METHODS BETWEEN S	$	12.51	12
1083	03	POLYCHLORINATED BIPHENYLS - OPER INSPECT, TEST, & EVALUATE DISPOSAL OPTIONS & C	$	772.20	12
1246	03	EAST CENTRAL AREA RELIABILITY ACTV - OPEINVOLVEMENT WITH ECAR GEN/TRANSM STUDIESEXC	$	1,686.85	12
1247	03	NORTH AMER ELEC RELIABILITY ACTV - OPER INVOLVEMENT WITH NERC GEN/TRANSM ASSESS-MEN	$	1,266.03	12
1398	03	CADPAD/FEEDER DESIGN IMPLEMENTATION-OPERIMPLEMENT A DISTRIBUTION APPLICATION & DES	$	3,633.10	12
1446	03	WORK MANAGEMENT SYSTEM DEVELOPMENT-OPER REPLATFORM PTS TO CLIENT PLATFORM & IN-	$	361.69	12
1695	03	LOAAD ANALYSIS STUDIES - OPER DETERMINE LOAD CHARACTER OF END USERS, INDIVIDUAL	$	660.47	12
1701	03	SYSTEM PLANNING ENERGY RESOURCE - OPER	$	104.89	12
4375	03	SOLAR MAGNETIC DISTURBANCE SYSTEM - OPERMONITOR (GICS) IN TRANSFORMER & SHUNT REA	$	226.96	12
4401	03	EPIC IND MKT ASSESS&STRATEGIC ANLS-OPER DEV ELECTECHNLG MKT PLNS FOR IND & COMM SE	$	5.20	12
4406	03	EPRI VOLTAGE FLICKER PROJECT - OPER PARTICIPATION IN EPRI SPONSORED PROJ ON VOLTAG	$	1.63	12
4408	03	NATIONAL EARTH COMFORT PROGRAM - OPER PARTICIPATION IN GEOTHERMAL HEAT PUMP CON	$	1,605.79	12
4411	03	MAGNETIC FIELD SHIELDING CASE STUDY-OPERMEASUREMENTS IN UNDERGROUND VAULTS & MAN	$	352.68	12
4412	03	ELEC VEHICLE BATERY CHARGER PROJECT-OPERTESTING ELEC VEHICLE CHARGING SYSTEM R &	$	140.04	12
4419	03	FAULT ANALY&LIGHTNING LOCATION SYS-OPER VERIFY USAGE & IDENTIFY SPECIFIC BENE TOAEP;	$	2,651.18	12
4420	03	EASTON DEVLP DSTRBN TSF SWITCH DEMO-OPERMERITS OF SOLID STATE DISTRIBUTION TSF SWIT	$	1,787.25	12
4421	03	PWR FREQ AC SPARKOVER VOLT MEASURE-OPER EXPER @ OSU TO DETER AIR GAP SPARK OVER V	$	34.46	12
4427	03	ALTERNTV DISTRIBUTION STRUCTURE - OPER EVAL TUBULAR STEEL POLE STRUCTURES FOR SYS	$	1,027.65	12
4428	03	PWR QAUAL INSTRUMENT LAB DEVELOP - OPER DEVEL DATA ON PROCESS EQUIP & PROVIDE CALI	$	3,066.84	12
4446	03	DISTRBN INFRASTRUCTER PLANNING DEMO-OPERDISTRIBUTION ASSET MGMT PLAN CAPABILITY R&	$	117.17	12
0817	04	MARKET RESEARCH - OPER ANALYZE CUSTOMER CHARACTERISTICS FOR ELECTRICAL U	$	3,378.87	12
0987	04	PHASE ANGLE & FREQ MEASUREMENTS - OPER INVESTIGATE PHASE ANGLE METHODS BETWEEN S	$	52.09	12
1083	04	POLYCHLORINATED BIPHENYLS - OPER INSPECT, TEST, & EVALUATE DISPOSAL OPTIONS & C	$	3,227.40	12
1246	04	EAST CENTRAL AREA RELIABILITY ACTV - OPEINVOLVEMENT WITH ECAR GEN/TRANSM STUDIESEXC	$	7,139.62	12
1247	04	NORTH AMER ELEC RELIABILITY ACTV - OPER INVOLVEMENT WITH NERC GEN/TRANSM ASSESS-MEN	$	5,358.66	12
1398	04	CADPAD/FEEDER DESIGN IMPLEMENTATION-OPERIMPLEMENT A DISTRIBUTION APPLICATION & DES	$	15,186.11	12
1446	04	WORK MANAGEMENT SYSTEM DEVELOPMENT-OPER REPLATFORM PTS TO CLIENT PLATFORM & IN-	$	1,505.68	12
1695	04	LOAAD ANALYSIS STUDIES - OPER DETERMINE LOAD CHARACTER OF END USERS, INDIVIDUAL	$	2,751.24	12
1701	04	SYSTEM PLANNING ENERGY RESOURCE - OPER	$	436.63	12
4375	04	SOLAR MAGNETIC DISTURBANCE SYSTEM - OPERMONITOR (GICS) IN TRANSFORMER & SHUNT REA	$	945.69	12
4401	04	EPIC IND MKT ASSESS&STRATEGIC ANLS-OPER DEV ELECTECHNLG MKT PLNS FOR IND & COMM SE	$	22.02	12
4406	04	EPRI VOLTAGE FLICKER PROJECT - OPER PARTICIPATION IN EPRI SPONSORED PROJ ON VOLTAG	$	6.77	12
4408	04	NATIONAL EARTH COMFORT PROGRAM - OPER PARTICIPATION IN GEOTHERMAL HEAT PUMP CON	$	6,704.33	12

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WO	CO	TITLE/DESCRIPTION		AMOUNT	FORM
4411	04	MAGNETIC FIELD SHIELDING CASE STUDY-OPERMEASUREMENTS IN UNDERGROUND VAULTS & MAN	$	1,474.33	12
4412	04	ELEC VEHICLE BATERY CHARGER PROJECT-OPERTESTING ELEC VEHICLE CHARGING SYSTEM R &	$	586.47	12
4419	04	FAULT ANALY&LIGHTNING LOCATION SYS-OPER VERIFY USAGE & IDENTIFY SPECIFIC BENE TOAEP;	$	11,060.95	12
4420	04	EASTON DEVLP DSTRBN TSF SWITCH DEMO-OPERMERITS OF SOLID STATE DISTRIBUTION TSF SWIT	$	7,496.70	12
4421	04	PWR FREQ AC SPARKOVER VOLT MEASURE-OPER EXPER @ OSU TO DETER AIR GAP SPARK OVER V	$	143.56	12
4427	04	ALTERNTV DISTRIBUTION STRUCTURE - OPER EVAL TUBULAR STEEL POLE STRUCTURES FOR SYS	$	4,284.26	12
4428	04	PWR QAUAL INSTRUMENT LAB DEVELOP - OPER DEVEL DATA ON PROCESS EQUIP & PROVIDE CALI	$	12,897.42	12
4446	04	DISTRBN INFRASTRUCTER PLANNING DEMO-OPERDISTRIBUTION ASSET MGMT PLAN CAPABILITY R&	$	495.92	12
0817	06	MARKET RESEARCH - OPER ANALYZE CUSTOMER CHARACTERISTICS FOR ELECTRICAL U	$	282.04	12
0987	06	PHASE ANGLE & FREQ MEASUREMENTS - OPER INVESTIGATE PHASE ANGLE METHODS BETWEEN S	$	4.37	12
1083	06	POLYCHLORINATED BIPHENYLS - OPER INSPECT, TEST, & EVALUATE DISPOSAL OPTIONS & C	$	269.78	12
1246	06	EAST CENTRAL AREA RELIABILITY ACTV - OPEINVOLVEMENT WITH ECAR GEN/TRANSM STUDIESEXC	$	588.41	12
1247	06	NORTH AMER ELEC RELIABILITY ACTV - OPER INVOLVEMENT WITH NERC GEN/TRANSM ASSESS-MEN	$	441.66	12
1398	06	CADPAD/FEEDER DESIGN IMPLEMENTATION-OPERIMPLEMENT A DISTRIBUTION APPLICATION & DES	$	1,271.20	12
1446	06	WORK MANAGEMENT SYSTEM DEVELOPMENT-OPER REPLATFORM PTS TO CLIENT PLATFORM & IN-	$	126.18	12
1695	06	LOAAD ANALYSIS STUDIES - OPER DETERMINE LOAD CHARACTER OF END USERS, INDIVIDUAL	$	230.46	12
1701	06	SYSTEM PLANNING ENERGY RESOURCE - OPER	$	36.60	12
4375	06	SOLAR MAGNETIC DISTURBANCE SYSTEM - OPERMONITOR (GICS) IN TRANSFORMER & SHUNT REA	$	79.25	12
4401	06	EPIC IND MKT ASSESS&STRATEGIC ANLS-OPER DEV ELECTECHNLG MKT PLNS FOR IND & COMM SE	$	1.82	12
4406	06	EPRI VOLTAGE FLICKER PROJECT - OPER PARTICIPATION IN EPRI SPONSORED PROJ ON VOLTAG	$	0.57	12
4408	06	NATIONAL EARTH COMFORT PROGRAM - OPER PARTICIPATION IN GEOTHERMAL HEAT PUMP CON	$	560.16	12
4411	06	MAGNETIC FIELD SHIELDING CASE STUDY-OPERMEASUREMENTS IN UNDERGROUND VAULTS & MAN	$	123.42	12
4412	06	ELEC VEHICLE BATERY CHARGER PROJECT-OPERTESTING ELEC VEHICLE CHARGING SYSTEM R &	$	49.49	12
4419	06	FAULT ANALY&LIGHTNING LOCATION SYS-OPER VERIFY USAGE & IDENTIFY SPECIFIC BENE TOAEP;	$	926.84	12
4420	06	EASTON DEVLP DSTRBN TSF SWITCH DEMO-OPERMERITS OF SOLID STATE DISTRIBUTION TSF SWIT	$	626.83	12
4421	06	PWR FREQ AC SPARKOVER VOLT MEASURE-OPER EXPER @ OSU TO DETER AIR GAP SPARK OVER V	$	12.10	12
4427	06	ALTERNTV DISTRIBUTION STRUCTURE - OPER EVAL TUBULAR STEEL POLE STRUCTURES FOR SYS	$	358.93	12
4428	06	PWR QAUAL INSTRUMENT LAB DEVELOP - OPER DEVEL DATA ON PROCESS EQUIP & PROVIDE CALI	$	1,071.31	12
4446	06	DISTRBN INFRASTRUCTER PLANNING DEMO-OPERDISTRIBUTION ASSET MGMT PLAN CAPABILITY R&	$	40.86	12
0817	07	MARKET RESEARCH - OPER ANALYZE CUSTOMER CHARACTERISTICS FOR ELECTRICAL U	$	5,834.09	12
0987	07	PHASE ANGLE & FREQ MEASUREMENTS - OPER INVESTIGATE PHASE ANGLE METHODS BETWEEN S	$	90.51	12
1083	07	POLYCHLORINATED BIPHENYLS - OPER INSPECT, TEST, & EVALUATE DISPOSAL OPTIONS & C	$	5,583.95	12
1246	07	EAST CENTRAL AREA RELIABILITY ACTV - OPEINVOLVEMENT WITH ECAR GEN/TRANSM STUDIESEXC	$	12,082.42	12
1247	07	NORTH AMER ELEC RELIABILITY ACTV - OPER INVOLVEMENT WITH NERC GEN/TRANSM ASSESS-MEN	$	9,068.49	12
1398	07	CADPAD/FEEDER DESIGN IMPLEMENTATION-OPERIMPLEMENT A DISTRIBUTION APPLICATION & DES	$	26,329.24	12
1446	07	WORK MANAGEMENT SYSTEM DEVELOPMENT-OPER REPLATFORM PTS TO CLIENT PLATFORM & IN-	$	2,615.99	12
1695	07	LOAAD ANALYSIS STUDIES - OPER DETERMINE LOAD CHARACTER OF END USERS, INDIVIDUAL	$	4,776.44	12
1701	07	SYSTEM PLANNING ENERGY RESOURCE - OPER	$	758.59	12
4375	07	SOLAR MAGNETIC DISTURBANCE SYSTEM - OPERMONITOR (GICS) IN TRANSFORMER & SHUNT REA	$	1,642.45	12
4401	07	EPIC IND MKT ASSESS&STRATEGIC ANLS-OPER DEV ELECTECHNLG MKT PLNS FOR IND & COMM SE	$	37.28	12
4406	07	EPRI VOLTAGE FLICKER PROJECT - OPER PARTICIPATION IN EPRI SPONSORED PROJ ON VOLTAG	$	11.75	12
4408	07	NATIONAL EARTH COMFORT PROGRAM - OPER PARTICIPATION IN GEOTHERMAL HEAT PUMP CON	$	11,594.23	12
4411	07	MAGNETIC FIELD SHIELDING CASE STUDY-OPERMEASUREMENTS IN UNDERGROUND VAULTS & MAN	$	2,555.60	12
4412	07	ELEC VEHICLE BATERY CHARGER PROJECT-OPERTESTING ELEC VEHICLE CHARGING SYSTEM R &	$	1,029.06	12
4419	07	FAULT ANALY&LIGHTNING LOCATION SYS-OPER VERIFY USAGE & IDENTIFY SPECIFIC BENE TOAEP;	$	19,209.13	12
4420	07	EASTON DEVLP DSTRBN TSF SWITCH DEMO-OPERMERITS OF SOLID STATE DISTRIBUTION TSF SWIT	$	12,970.26	12
4421	07	PWR FREQ AC SPARKOVER VOLT MEASURE-OPER EXPER @ OSU TO DETER AIR GAP SPARK OVER V	$	251.72	12
4427	07	ALTERNTV DISTRIBUTION STRUCTURE - OPER EVAL TUBULAR STEEL POLE STRUCTURES FOR SYS	$	7,438.75	12
4428	07	PWR QAUAL INSTRUMENT LAB DEVELOP - OPER DEVEL DATA ON PROCESS EQUIP & PROVIDE CALI	$	22,093.75	12
4446	07	DISTRBN INFRASTRUCTER PLANNING DEMO-OPERDISTRIBUTION ASSET MGMT PLAN CAPABILITY R&	$	839.28	12
0817	10	MARKET RESEARCH - OPER ANALYZE CUSTOMER CHARACTERISTICS FOR ELECTRICAL U	$	2,824.75	12
0987	10	PHASE ANGLE & FREQ MEASUREMENTS - OPER INVESTIGATE PHASE ANGLE METHODS BETWEEN S	$	43.65	12
1083	10	POLYCHLORINATED BIPHENYLS - OPER INSPECT, TEST, & EVALUATE DISPOSAL OPTIONS & C	$	2,701.96	12
1246	10	EAST CENTRAL AREA RELIABILITY ACTV - OPEINVOLVEMENT WITH ECAR GEN/TRANSM STUDIESEXC	$	5,923.51	12
1247	10	NORTH AMER ELEC RELIABILITY ACTV - OPER INVOLVEMENT WITH NERC GEN/TRANSM ASSESS-MEN	$	4,445.88	12
1398	10	CADPAD/FEEDER DESIGN IMPLEMENTATION-OPERIMPLEMENT A DISTRIBUTION APPLICATION & DES	$	12,732.33	12
1446	10	WORK MANAGEMENT SYSTEM DEVELOPMENT-OPER REPLATFORM PTS TO CLIENT PLATFORM & IN-	$	1,261.74	12
1695	10	LOAAD ANALYSIS STUDIES - OPER DETERMINE LOAD CHARACTER OF END USERS, INDIVIDUAL	$	2,305.02	12
1701	10	SYSTEM PLANNING ENERGY RESOURCE - OPER	$	365.90	12
4375	10	SOLAR MAGNETIC DISTURBANCE SYSTEM - OPERMONITOR (GICS) IN TRANSFORMER & SHUNT REA	$	792.68	12

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WO	CO	TITLE/DESCRIPTION	AMOUNT	FORM
4401	10	EPIC IND MKT ASSESS&STRATEGIC ANLS-OPER DEV ELECTECHNLG MKT PLNS FOR IND & COMM SE	$ 18.29	12
4406	10	EPRI VOLTAGE FLICKER PROJECT - OPER PARTICIPATION IN EPRI SPONSORED PROJ ON VOLTAG	$ 5.67	12
4408	10	NATIONAL EARTH COMFORT PROGRAM - OPER PARTICIPATION IN GEOTHERMAL HEAT PUMP CON	$ 5,608.19	12
4411	10	MAGNETIC FIELD SHIELDING CASE STUDY-OPERMEASUREMENTS IN UNDERGROUND VAULTS & MAN	$ 1,235.93	12
4412	10	ELEC VEHICLE BATERY CHARGER PROJECT-OPERTESTING ELEC VEHICLE CHARGING SYSTEM R &	$ 496.16	12
4419	10	FAULT ANALY&LIGHTNING LOCATION SYS-OPER VERIFY USAGE & IDENTIFY SPECIFIC BENE TOAEP;	$ 9,275.94	12
4420	10	EASTON DEVLP DSTRBN TSF SWITCH DEMO-OPERMERITS OF SOLID STATE DISTRIBUTION TSF SWIT	$ 6,286.76	12
4421	10	PWR FREQ AC SPARKOVER VOLT MEASURE-OPER EXPER @ OSU TO DETER AIR GAP SPARK OVER V	$ 121.06	12
4427	10	ALTERNTV DISTRIBUTION STRUCTURE - OPER EVAL TUBULAR STEEL POLE STRUCTURES FOR SYS	$ 3,591.15	12
4428	10	PWR QAUAL INSTRUMENT LAB DEVELOP - OPER DEVEL DATA ON PROCESS EQUIP & PROVIDE CALI	$ 10,756.16	12
4446	10	DISTRBN INFRASTRUCTER PLANNING DEMO-OPERDISTRIBUTION ASSET MGMT PLAN CAPABILITY R&	$ 411.45	12
8779	01	ELECTRIC PLANT METERS-AP,I&MP,KGP,OP,WP DATA PROCESSING SERVICES FOR ELECTRIC PLAN	$ 58.02	14
8779	02	ELECTRIC PLANT METERS-AP,I&MP,KGP,OP,WP DATA PROCESSING SERVICES FOR ELECTRIC PLAN	$ 1,222.77	14
8779	04	ELECTRIC PLANT METERS-AP,I&MP,KGP,OP,WP DATA PROCESSING SERVICES FOR ELECTRIC PLAN	$ 762.35	14
8779	06	ELECTRIC PLANT METERS-AP,I&MP,KGP,OP,WP DATA PROCESSING SERVICES FOR ELECTRIC PLAN	$ 57.94	14
8779	07	ELECTRIC PLANT METERS-AP,I&MP,KGP,OP,WP DATA PROCESSING SERVICES FOR ELECTRIC PLAN	$ 948.36	14
1095	42	ENVIRONMENTAL AUDIT PROG - COAL SERV REL TO ENVIRONMENTAL AUDIT PROGRAM FOR BE	$ 847.95	16
2429	42	SYS HUM RESOURCES IND HYGIENE AUTIT-COALSERV OF GNE NATURE REL TO IND HYGIENE AUDI	$ 121.76	16
1095	43	ENVIRONMENTAL AUDIT PROG - COAL SERV REL TO ENVIRONMENTAL AUDIT PROGRAM FOR BE	$ 625.83	16
2429	43	SYS HUM RESOURCES IND HYGIENE AUTIT-COALSERV OF GNE NATURE REL TO IND HYGIENE AUDI	$ 91.65	16
1095	44	ENVIRONMENTAL AUDIT PROG - COAL SERV REL TO ENVIRONMENTAL AUDIT PROGRAM FOR BE	$ 2,872.02	16
2429	44	SYS HUM RESOURCES IND HYGIENE AUTIT-COALSERV OF GNE NATURE REL TO IND HYGIENE AUDI	$ 424.15	16
1095	54	ENVIRONMENTAL AUDIT PROG - COAL SERV REL TO ENVIRONMENTAL AUDIT PROGRAM FOR BE	$ 213.40	16
2429	54	SYS HUM RESOURCES IND HYGIENE AUTIT-COALSERV OF GNE NATURE REL TO IND HYGIENE AUDI	$ 31.44	16
3711	02	COAL COMBUSTION RESIDUAL HANDLING-9 GEN	$ 1,275.62	17
3731	02	COAL COMBUSTION RESIDUAL SALES - 9 GEN	$ 7,877.37	17
3711	03	COAL COMBUSTION RESIDUAL HANDLING-9 GEN	$ 284.82	17
3731	03	COAL COMBUSTION RESIDUAL SALES - 9 GEN	$ 1,899.89	17
3711	04	COAL COMBUSTION RESIDUAL HANDLING-9 GEN	$ 230.74	17
3731	04	COAL COMBUSTION RESIDUAL SALES - 9 GEN	$ 1,404.12	17
3711	07	COAL COMBUSTION RESIDUAL HANDLING-9 GEN	$ 2,192.44	17
3731	07	COAL COMBUSTION RESIDUAL SALES - 9 GEN	$ 13,926.79	17
3711	10	COAL COMBUSTION RESIDUAL HANDLING-9 GEN	$ 682.58	17
3731	10	COAL COMBUSTION RESIDUAL SALES - 9 GEN	$ 4,268.37	17
3711	22	COAL COMBUSTION RESIDUAL HANDLING-9 GEN	$ 438.48	17
3731	22	COAL COMBUSTION RESIDUAL SALES - 9 GEN	$ 2,785.35	17
3711	31	COAL COMBUSTION RESIDUAL HANDLING-9 GEN	$ 525.06	17
3731	31	COAL COMBUSTION RESIDUAL SALES - 9 GEN	$ 3,465.28	17
3711	32	COAL COMBUSTION RESIDUAL HANDLING-9 GEN	$ 311.46	17
3731	32	COAL COMBUSTION RESIDUAL SALES - 9 GEN	$ 2,088.51	17
3711	73	COAL COMBUSTION RESIDUAL HANDLING-9 GEN	$ 1,120.16	17
3731	73	COAL COMBUSTION RESIDUAL SALES - 9 GEN	$ 7,307.98	17
1654	02	ASBESTOS CLAIMS DFNS COUNSEL - AP,KP,OP SUPPORT DFNS COUNSEL FOR VARIOUS WORK ASR	$ 885.63	18
1654	03	ASBESTOS CLAIMS DFNS COUNSEL - AP,KP,OP SUPPORT DFNS COUNSEL FOR VARIOUS WORK ASR	$ 202.06	18
1654	07	ASBESTOS CLAIMS DFNS COUNSEL - AP,KP,OP SUPPORT DFNS COUNSEL FOR VARIOUS WORK ASR	$ 771.55	18
4402	07	CYCLONE NOX CONTROL INTEREST GRP-OP,CSP EPRI TC PROG TO INCLUDE DATA GATHERING ANL	$ 19,408.19	24
4402	10	CYCLONE NOX CONTROL INTEREST GRP-OP,CSP EPRI TC PROG TO INCLUDE DATA GATHERING ANL	$ 11,663.78	24
4407	02	EPRI WEST VA GROUNDWATER STUDY - AP, OP EVAL GROUNDWTR QUAL & IDENTIFY POTENTIALEN	$ 11,707.51	25
4407	07	EPRI WEST VA GROUNDWATER STUDY - AP, OP EVAL GROUNDWTR QUAL & IDENTIFY POTENTIALEN	$ 9,438.51	25
8767	01	TRANSFORMER LOAD MONITORING-AP, KP, KGP DATA PROCESSING SERVICES FOR TRANSFORMER	$ 31.39	26
8767	02	TRANSFORMER LOAD MONITORING-AP, KP, KGP DATA PROCESSING SERVICES FOR TRANSFORMER	$ 598.51	26
8767	03	TRANSFORMER LOAD MONITORING-AP, KP, KGP DATA PROCESSING SERVICES FOR TRANSFORMER	$ 89.42	26
3578	06	SCET&D CONSTRUCTION OVERHEADS - OP, WP DISTRIBUTION OHIO EAST REGION	$ 2,068.52	31
3578	07	SCET&D CONSTRUCTION OVERHEADS - OP, WP DISTRIBUTION OHIO EAST REGION	$ 10,035.46	31
3579	04	SCET&D CONSTR O/H - CSP,I&M,OP,WP DISTRIBUTION NORTHERN DIVISION	$ 22,484.17	33
3579	06	SCET&D CONSTR O/H - CSP,I&M,OP,WP DISTRIBUTION NORTHERN DIVISION	$ 1,455.01	33
3579	07	SCET&D CONSTR O/H - CSP,I&M,OP,WP DISTRIBUTION NORTHERN DIVISION	$ 19,552.12	33
3579	10	SCET&D CONSTR O/H - CSP,I&M,OP,WP DISTRIBUTION NORTHERN DIVISION	$ 26,082.46	33
3582	07	SCET&D CONSTRUCTION OVERHEADS - CSP, OP DISTRIBUTION OHIO SOUTH REGION	$ 2,429.16	34
3582	10	SCET&D CONSTRUCTION OVERHEADS - CSP, OP DISTRIBUTION OHIO SOUTH REGION	$ 13,232.76	34

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WO	CO	TITLE/DESCRIPTION	AMOUNT	FORM
3588	01	SCET&D CONSTRUCTION OVERHEADS - AP, KGP DISTRIBUTION VIRGINIA/TENN REGION	$ 2,056.40	35
3588	02	SCET&D CONSTRUCTION OVERHEADS - AP, KGP DISTRIBUTION VIRGINIA/TENN REGION	$ 17,884.08	35
4432	01	138KV HPFF SEVICE AGED CABLE ANALY-OPER ANALYZE 138KV HPFF PIPE CABLES FR KING AV BRI	$ 11.30	37
4445	01	INEZ AREA NETWORKED MMS SCADS SYS - OPEREXPAND STA INTEGRATION TO NETWORK OF SIXIN	$ 236.91	37
4450	01	CONDUCTOR ANGLE METER - OPER DEV SYS TO MONITOR TRANSMISSION LINE CONDUCTO	$ 28.70	37
4432	02	138KV HPFF SEVICE AGED CABLE ANALY-OPER ANALYZE 138KV HPFF PIPE CABLES FR KING AV BRI	$ 1,068.35	37
4445	02	INEZ AREA NETWORKED MMS SCADS SYS - OPEREXPAND STA INTEGRATION TO NETWORK OF SIXIN	$ 12,516.81	37
4450	02	CONDUCTOR ANGLE METER - OPER DEV SYS TO MONITOR TRANSMISSION LINE CONDUCTO	$ 2,708.68	37
4432	03	138KV HPFF SEVICE AGED CABLE ANALY-OPER ANALYZE 138KV HPFF PIPE CABLES FR KING AV BRI	$ 252.94	37
4445	03	INEZ AREA NETWORKED MMS SCADS SYS - OPEREXPAND STA INTEGRATION TO NETWORK OF SIXIN	$ 2,726.07	37
4450	03	CONDUCTOR ANGLE METER - OPER DEV SYS TO MONITOR TRANSMISSION LINE CONDUCTO	$ 641.28	37
4432	04	138KV HPFF SEVICE AGED CABLE ANALY-OPER ANALYZE 138KV HPFF PIPE CABLES FR KING AV BRI	$ 872.00	37
4445	04	INEZ AREA NETWORKED MMS SCADS SYS - OPEREXPAND STA INTEGRATION TO NETWORK OF SIXIN	$ 9,719.83	37
4450	04	CONDUCTOR ANGLE METER - OPER DEV SYS TO MONITOR TRANSMISSION LINE CONDUCTO	$ 2,210.98	37
4432	06	138KV HPFF SEVICE AGED CABLE ANALY-OPER ANALYZE 138KV HPFF PIPE CABLES FR KING AV BRI	$ 37.74	37
4445	06	INEZ AREA NETWORKED MMS SCADS SYS - OPEREXPAND STA INTEGRATION TO NETWORK OF SIXIN	$ 488.51	37
4450	06	CONDUCTOR ANGLE METER - OPER DEV SYS TO MONITOR TRANSMISSION LINE CONDUCTO	$ 95.72	37
4432	07	138KV HPFF SEVICE AGED CABLE ANALY-OPER ANALYZE 138KV HPFF PIPE CABLES FR KING AV BRI	$ 1,196.63	37
4445	07	INEZ AREA NETWORKED MMS SCADS SYS - OPEREXPAND STA INTEGRATION TO NETWORK OF SIXIN	$ 13,892.37	37
4450	07	CONDUCTOR ANGLE METER - OPER DEV SYS TO MONITOR TRANSMISSION LINE CONDUCTO	$ 3,034.12	37
4432	10	138KV HPFF SEVICE AGED CABLE ANALY-OPER ANALYZE 138KV HPFF PIPE CABLES FR KING AV BRI	$ 335.98	37
4445	10	INEZ AREA NETWORKED MMS SCADS SYS - OPEREXPAND STA INTEGRATION TO NETWORK OF SIXIN	$ 4,514.08	37
4450	10	CONDUCTOR ANGLE METER - OPER DEV SYS TO MONITOR TRANSMISSION LINE CONDUCTO	$ 851.85	37
0715	02	FERC, PURCHASING PRACTICES - GEN & ROCK BIANNUAL UPDATES OF FUEL & ENERGY PRAC- TICE	$ 264.14	43
1245	02	ALLOW TRACKING SYS DEVELOP - GEN & ROCK REPORT CONTINUOUS EMISSION MNTR DATA TO EP	$ 15,443.60	43
1434	02	PROCESS IMPROVEMENT PROGRAM - GEN & ROCKMGMT, ADMIN AND ENG SERV NECESSARY TO C	$ 2,411.68	43
4393	02	BIOINDCTR APPL @ AEP STREAMS-GEN & ROCK RESEARCH ON BIO INDICATORS AT AEP WASTE-WA	$ 10.32	43
4413	02	OH RVR ECOLGCL RESEARCH PROGRAM-GEN&ROCKSTY FISH, MACROINVERTEBRATES, MUSSELS I	$ 1,362.68	43
4416	02	BIOMRKR STY FISH FR WSTWTR STRM-GEN&ROCKSTY USE OF BIOMARKERS TO ASSESS METAL TO	$ 7,986.29	43
4417	02	PULVERIZER DIAGNOSTIC EVAL-GEN & ROCK EVAL ON LINE DIAGNOSTIC SYS TO DETECT COAL P	$ 4,027.14	43
4447	02	OZONE MODELING & ECON IMPACT STUDY - GENEPRI PROJ TO PERFORM OZONE MODEL & ECON IM	$ 4,740.00	43
0715	03	FERC, PURCHASING PRACTICES - GEN & ROCK BIANNUAL UPDATES OF FUEL & ENERGY PRAC- TICE	$ 56.18	43
1245	03	ALLOW TRACKING SYS DEVELOP - GEN & ROCK REPORT CONTINUOUS EMISSION MNTR DATA TO EP	$ 3,416.30	43
1434	03	PROCESS IMPROVEMENT PROGRAM - GEN & ROCKMGMT, ADMIN AND ENG SERV NECESSARY TO C	$ 701.58	43
4393	03	BIOINDCTR APPL @ AEP STREAMS-GEN & ROCK RESEARCH ON BIO INDICATORS AT AEP WASTE-WA	$ 2.20	43
4413	03	OH RVR ECOLGCL RESEARCH PROGRAM-GEN&ROCKSTY FISH, MACROINVERTEBRATES, MUSSELS I	$ 302.37	43
4416	03	BIOMRKR STY FISH FR WSTWTR STRM-GEN&ROCKSTY USE OF BIOMARKERS TO ASSESS METAL TO	$ 1,757.60	43
4417	03	PULVERIZER DIAGNOSTIC EVAL-GEN & ROCK EVAL ON LINE DIAGNOSTIC SYS TO DETECT COAL P	$ 896.87	43
4447	03	OZONE MODELING & ECON IMPACT STUDY - GENEPRI PROJ TO PERFORM OZONE MODEL & ECON IM	$ 1,000.00	43
0715	04	FERC, PURCHASING PRACTICES - GEN & ROCK BIANNUAL UPDATES OF FUEL & ENERGY PRAC- TICE	$ 47.22	43
1245	04	ALLOW TRACKING SYS DEVELOP - GEN & ROCK REPORT CONTINUOUS EMISSION MNTR DATA TO EP	$ 2,718.83	43
1434	04	PROCESS IMPROVEMENT PROGRAM - GEN & ROCKMGMT, ADMIN AND ENG SERV NECESSARY TO C	$ 383.68	43
4393	04	BIOINDCTR APPL @ AEP STREAMS-GEN & ROCK RESEARCH ON BIO INDICATORS AT AEP WASTE-WA	$ 1.85	43
4413	04	OH RVR ECOLGCL RESEARCH PROGRAM-GEN&ROCKSTY FISH, MACROINVERTEBRATES, MUSSELS I	$ 239.53	43
4416	04	BIOMRKR STY FISH FR WSTWTR STRM-GEN&ROCKSTY USE OF BIOMARKERS TO ASSESS METAL TO	$ 1,407.49	43
4417	04	PULVERIZER DIAGNOSTIC EVAL-GEN & ROCK EVAL ON LINE DIAGNOSTIC SYS TO DETECT COAL P	$ 709.68	43
4447	04	OZONE MODELING & ECON IMPACT STUDY - GENEPRI PROJ TO PERFORM OZONE MODEL & ECON IM	$ 840.00	43
0715	07	FERC, PURCHASING PRACTICES - GEN & ROCK BIANNUAL UPDATES OF FUEL & ENERGY PRAC- TICE	$ 473.25	43
1245	07	ALLOW TRACKING SYS DEVELOP - GEN & ROCK REPORT CONTINUOUS EMISSION MNTR DATA TO EP	$ 27,827.38	43
1434	07	PROCESS IMPROVEMENT PROGRAM - GEN & ROCKMGMT, ADMIN AND ENG SERV NECESSARY TO C	$ 4,604.07	43
4393	07	BIOINDCTR APPL @ AEP STREAMS-GEN & ROCK RESEARCH ON BIO INDICATORS AT AEP WASTE-WA	$ 18.49	43
4413	07	OH RVR ECOLGCL RESEARCH PROGRAM-GEN&ROCKSTY FISH, MACROINVERTEBRATES, MUSSELS I	$ 2,456.08	43
4416	07	BIOMRKR STY FISH FR WSTWTR STRM-GEN&ROCKSTY USE OF BIOMARKERS TO ASSESS METAL TO	$ 14,373.50	43
4417	07	PULVERIZER DIAGNOSTIC EVAL-GEN & ROCK EVAL ON LINE DIAGNOSTIC SYS TO DETECT COAL P	$ 7,274.92	43
4447	07	OZONE MODELING & ECON IMPACT STUDY - GENEPRI PROJ TO PERFORM OZONE MODEL & ECON IM	$ 8,440.00	43
0715	10	FERC, PURCHASING PRACTICES - GEN & ROCK BIANNUAL UPDATES OF FUEL & ENERGY PRAC- TICE	$ 125.88	43
1245	10	ALLOW TRACKING SYS DEVELOP - GEN & ROCK REPORT CONTINUOUS EMISSION MNTR DATA TO EP	$ 7,416.34	43
1434	10	PROCESS IMPROVEMENT PROGRAM - GEN & ROCKMGMT, ADMIN AND ENG SERV NECESSARY TO C	$ 1,249.6[illegible]	43
4393	10	BIOINDCTR APPL @ AEP STREAMS-GEN & ROCK RESEARCH ON BIO INDICATORS AT AEP WASTE-WA	$ 4.92	43
4413	10	OH RVR ECOLGCL RESEARCH PROGRAM-GEN&ROCKSTY FISH, MACROINVERTEBRATES, MUSSELS I	$ 654.66	43

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WO	CO	TITLE/DESCRIPTION		AMOUNT	FORM
4416	10	BIOMRKR STY FISH FR WSTWTR STRM-GEN&ROCKSTY USE OF BIOMARKERS TO ASSESS METAL TO	$	3,829.17	43
4417	10	PULVERIZER DIAGNOSTIC EVAL-GEN & ROCK EVAL ON LINE DIAGNOSTIC SYS TO DETECT COAL P	$	1,940.62	43
4447	10	OZONE MODELING & ECON IMPACT STUDY - GENEPRI PROJ TO PERFORM OZONE MODEL & ECON IM	$	2,240.00	43
0715	73	FERC, PURCHASING PRACTICES - GEN & ROCK BIANNUAL UPDATES OF FUEL & ENERGY PRAC- TICE	$	157.37	43
1245	73	ALLOW TRACKING SYS DEVELOP - GEN & ROCK REPORT CONTINUOUS EMISSION MNTR DATA TO EP	$	9,251.31	43
1434	73	PROCESS IMPROVEMENT PROGRAM - GEN & ROCKMGMT, ADMIN AND ENG SERV NECESSARY TO C	$	1,611.44	43
4393	73	BIOINDCTR APPL @ AEP STREAMS-GEN & ROCK RESEARCH ON BIO INDICATORS AT AEP WASTE-WA	$	6.15	43
4413	73	OH RVR ECOLGCL RESEARCH PROGRAM-GEN&ROCKSTY FISH, MACROINVERTEBRATES, MUSSELS I	$	815.96	43
4416	73	BIOMRKR STY FISH FR WSTWTR STRM-GEN&ROCKSTY USE OF BIOMARKERS TO ASSESS METAL TO	$	4,769.51	43
4417	73	PULVERIZER DIAGNOSTIC EVAL-GEN & ROCK EVAL ON LINE DIAGNOSTIC SYS TO DETECT COAL P	$	2,436.24	43
4447	73	OZONE MODELING & ECON IMPACT STUDY - GENEPRI PROJ TO PERFORM OZONE MODEL & ECON IM	$	2,740.00	43
3263	06	DISTRIBUTION O&M - OP, WP DISTRIBUTION OHIO EAST REGION	$	3,254.13	48
3263	07	DISTRIBUTION O&M - OP, WP DISTRIBUTION OHIO EAST REGION	$	19,824.41	48
1384	01	OVER-THE-COUNTER CASH PROCESS PROJ-OPER DEVELOP OVER-THE-COUNTER CASH PROCESSIN	$	0.03	49
1384	03	OVER-THE-COUNTER CASH PROCESS PROJ-OPER DEVELOP OVER-THE-COUNTER CASH PROCESSIN	$	0.08	49
1384	04	OVER-THE-COUNTER CASH PROCESS PROJ-OPER DEVELOP OVER-THE-COUNTER CASH PROCESSIN	$	0.28	49
1384	06	OVER-THE-COUNTER CASH PROCESS PROJ-OPER DEVELOP OVER-THE-COUNTER CASH PROCESSIN	$	0.01	49
1384	07	OVER-THE-COUNTER CASH PROCESS PROJ-OPER DEVELOP OVER-THE-COUNTER CASH PROCESSIN	$	0.35	49
1384	10	OVER-THE-COUNTER CASH PROCESS PROJ-OPER DEVELOP OVER-THE-COUNTER CASH PROCESSIN	$	0.30	49
1480	02	TECHNICAL EDUCATION - GEN & AEG	$	17,801.41	50
1990	02	COMPUTER APPL GEN ADM ENG OPER-GEN&AEG	$	5,483.26	50
2215	02	INTERCONNECTIONS - GEN & AEG	$	1,226.83	50
1480	03	TECHNICAL EDUCATION - GEN & AEG	$	2,652.55	50
1990	03	COMPUTER APPL GEN ADM ENG OPER-GEN&AEG	$	810.82	50
2215	03	INTERCONNECTIONS - GEN & AEG	$	179.75	50
1480	04	TECHNICAL EDUCATION - GEN & AEG	$	11,110.76	50
1990	04	COMPUTER APPL GEN ADM ENG OPER-GEN&AEG	$	3,400.72	50
2215	04	INTERCONNECTIONS - GEN & AEG	$	754.47	50
1480	07	TECHNICAL EDUCATION - GEN & AEG	$	19,273.44	50
1990	07	COMPUTER APPL GEN ADM ENG OPER-GEN&AEG	$	5,952.27	50
2215	07	INTERCONNECTIONS - GEN & AEG	$	1,333.10	50
1480	10	TECHNICAL EDUCATION - GEN & AEG	$	9,353.29	50
1990	10	COMPUTER APPL GEN ADM ENG OPER-GEN&AEG	$	2,874.86	50
2215	10	INTERCONNECTIONS - GEN & AEG	$	641.15	50
1480	21	TECHNICAL EDUCATION - GEN & AEG	$	4,238.36	50
1990	21	COMPUTER APPL GEN ADM ENG OPER-GEN&AEG	$	1,324.02	50
2215	21	INTERCONNECTIONS - GEN & AEG	$	301.56	50
3273	01	DISTRIBUTION O&M - AP, KGP DISTRIBUTION VIRGINIA/TENN REGION	$	3,411.12	53
3273	02	DISTRIBUTION O&M - AP, KGP DISTRIBUTION VIRGINIA/TENN REGION	$	14,125.28	53
1473	02	FOSSIL/HYDRO CROSS TRAINING - 7 COS DEVELOPMENT EXPENSES ASSOC WITH FOSSIL/ HYDRO	$	6,813.45	56
2565	02	FOSSIL PLANT COAL ANALYSES - 9 COS ANALYZE COAL SAMPLES FOR ALL AEP POWER PLANTS	$	15,354.57	56
1473	03	FOSSIL/HYDRO CROSS TRAINING - 7 COS DEVELOPMENT EXPENSES ASSOC WITH FOSSIL/ HYDRO	$	2,083.08	56
2565	03	FOSSIL PLANT COAL ANALYSES - 9 COS ANALYZE COAL SAMPLES FOR ALL AEP POWER PLANTS	$	4,694.38	56
1473	04	FOSSIL/HYDRO CROSS TRAINING - 7 COS DEVELOPMENT EXPENSES ASSOC WITH FOSSIL/ HYDRO	$	1,996.29	56
2565	04	FOSSIL PLANT COAL ANALYSES - 9 COS ANALYZE COAL SAMPLES FOR ALL AEP POWER PLANTS	$	4,498.80	56
1473	07	FOSSIL/HYDRO CROSS TRAINING - 7 COS DEVELOPMENT EXPENSES ASSOC WITH FOSSIL/ HYDRO	$	12,238.07	56
2565	07	FOSSIL PLANT COAL ANALYSES - 9 COS ANALYZE COAL SAMPLES FOR ALL AEP POWER PLANTS	$	27,579.48	56
1473	10	FOSSIL/HYDRO CROSS TRAINING - 7 COS DEVELOPMENT EXPENSES ASSOC WITH FOSSIL/ HYDRO	$	3,992.60	56
2565	10	FOSSIL PLANT COAL ANALYSES - 9 COS ANALYZE COAL SAMPLES FOR ALL AEP POWER PLANTS	$	8,997.59	56
1473	22	FOSSIL/HYDRO CROSS TRAINING - 7 COS DEVELOPMENT EXPENSES ASSOC WITH FOSSIL/ HYDRO	$	3,558.60	56
2565	22	FOSSIL PLANT COAL ANALYSES - 9 COS ANALYZE COAL SAMPLES FOR ALL AEP POWER PLANTS	$	8,019.62	56
1473	70	FOSSIL/HYDRO CROSS TRAINING - 7 COS DEVELOPMENT EXPENSES ASSOC WITH FOSSIL/ HYDRO	$	2,039.68	56
2565	70	FOSSIL PLANT COAL ANALYSES - 9 COS ANALYZE COAL SAMPLES FOR ALL AEP POWER PLANTS	$	4,596.62	56
1473	71	FOSSIL/HYDRO CROSS TRAINING - 7 COS DEVELOPMENT EXPENSES ASSOC WITH FOSSIL/ HYDRO	$	5,641.72	56
2565	71	FOSSIL PLANT COAL ANALYSES - 9 COS ANALYZE COAL SAMPLES FOR ALL AEP POWER PLANTS	$	12,713.99	56
1473	73	FOSSIL/HYDRO CROSS TRAINING - 7 COS DEVELOPMENT EXPENSES ASSOC WITH FOSSIL/ HYDRO	$	5,034.13	56
2565	73	FOSSIL PLANT COAL ANALYSES - 9 COS ANALYZE COAL SAMPLES FOR ALL AEP POWER PLANTS	$	11,344.81	56
4423	07	PREVENT ACID DRAIN FR COAL CLEAN-CSP,OP USE FGD MATERIAL FR CONESVILLE TO PRE- VENT	$	8,640.13	59
4423	10	PREVENT ACID DRAIN FR COAL CLEAN-CSP,OP USE FGD MATERIAL FR CONESVILLE TO PRE- VENT	$	4,141.63	59
1429	01	EVALUATION OF SHARED SERVICES - OPER EVALUATE SVC GROUP TIME & DOLLARS TO BE SHARE	$	621.75	62

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WO	CO	TITLE/DESCRIPTION		AMOUNT	FORM
1802	01	CORPORATE PLAN & BUDGET - 1ST TIER COS SVCS REL TO CORPORATE PLANNING & BUDGET TO B	$	(18.06)	62
1429	02	EVALUATION OF SHARED SERVICES - OPER EVALUATE SVC GROUP TIME & DOLLARS TO BE SHARE	$	21,938.55	62
1802	02	CORPORATE PLAN & BUDGET - 1ST TIER COS SVCS REL TO CORPORATE PLANNING & BUDGET TO B	$	(637.34)	62
1429	03	EVALUATION OF SHARED SERVICES - OPER EVALUATE SVC GROUP TIME & DOLLARS TO BE SHARE	$	5,950.92	62
1802	03	CORPORATE PLAN & BUDGET - 1ST TIER COS SVCS REL TO CORPORATE PLANNING & BUDGET TO B	$	(172.88)	62
1429	04	EVALUATION OF SHARED SERVICES - OPER EVALUATE SVC GROUP TIME & DOLLARS TO BE SHARE	$	20,961.52	62
1802	04	CORPORATE PLAN & BUDGET - 1ST TIER COS SVCS REL TO CORPORATE PLANNING & BUDGET TO B	$	(608.96)	62
1429	06	EVALUATION OF SHARED SERVICES - OPER EVALUATE SVC GROUP TIME & DOLLARS TO BE SHARE	$	621.75	62
1802	06	CORPORATE PLAN & BUDGET - 1ST TIER COS SVCS REL TO CORPORATE PLANNING & BUDGET TO B	$	(18.06)	62
1429	07	EVALUATION OF SHARED SERVICES - OPER EVALUATE SVC GROUP TIME & DOLLARS TO BE SHARE	$	23,359.60	62
1802	07	CORPORATE PLAN & BUDGET - 1ST TIER COS SVCS REL TO CORPORATE PLANNING & BUDGET TO B	$	(678.62)	62
1429	10	EVALUATION OF SHARED SERVICES - OPER EVALUATE SVC GROUP TIME & DOLLARS TO BE SHARE	$	11,368.95	62
1802	10	CORPORATE PLAN & BUDGET - 1ST TIER COS SVCS REL TO CORPORATE PLANNING & BUDGET TO B	$	(330.29)	62
1429	21	EVALUATION OF SHARED SERVICES - OPER EVALUATE SVC GROUP TIME & DOLLARS TO BE SHARE	$	1,865.22	62
1802	21	CORPORATE PLAN & BUDGET - 1ST TIER COS SVCS REL TO CORPORATE PLANNING & BUDGET TO B	$	(54.19)	62
1429	58	EVALUATION OF SHARED SERVICES - OPER EVALUATE SVC GROUP TIME & DOLLARS TO BE SHARE	$	88.80	62
1802	58	CORPORATE PLAN & BUDGET - 1ST TIER COS SVCS REL TO CORPORATE PLANNING & BUDGET TO B	$	(2.58)	62
1429	59	EVALUATION OF SHARED SERVICES - OPER EVALUATE SVC GROUP TIME & DOLLARS TO BE SHARE	$	266.44	62
1802	59	CORPORATE PLAN & BUDGET - 1ST TIER COS SVCS REL TO CORPORATE PLANNING & BUDGET TO B	$	(7.75)	62
1429	60	EVALUATION OF SHARED SERVICES - OPER EVALUATE SVC GROUP TIME & DOLLARS TO BE SHARE	$	532.95	62
1802	60	CORPORATE PLAN & BUDGET - 1ST TIER COS SVCS REL TO CORPORATE PLANNING & BUDGET TO B	$	(15.48)	62
1429	69	EVALUATION OF SHARED SERVICES - OPER EVALUATE SVC GROUP TIME & DOLLARS TO BE SHARE	$	888.22	62
1802	69	CORPORATE PLAN & BUDGET - 1ST TIER COS SVCS REL TO CORPORATE PLANNING & BUDGET TO B	$	(25.80)	62
1429	74	EVALUATION OF SHARED SERVICES - OPER EVALUATE SVC GROUP TIME & DOLLARS TO BE SHARE	$	355.29	62
1802	74	CORPORATE PLAN & BUDGET - 1ST TIER COS SVCS REL TO CORPORATE PLANNING & BUDGET TO B	$	(10.32)	62
1956	03	DATA PROCESSING OPER DP	$	6,071.03	66
1956	06	DATA PROCESSING OPER DP	$	1,300.95	66
1956	07	DATA PROCESSING OPER DP	$	63,572.55	66
1956	10	DATA PROCESSING OPER DP	$	15,784.72	66
2654	02	RSO PERSONAL PROTECTIVE EQUIPMENT - OPERACQUIRE & DISTRIB EQUIPMENT USED BY RE- GIO	$	60.43	75
2654	03	RSO PERSONAL PROTECTIVE EQUIPMENT - OPERACQUIRE & DISTRIB EQUIPMENT USED BY RE- GIO	$	11.48	75
2654	04	RSO PERSONAL PROTECTIVE EQUIPMENT - OPERACQUIRE & DISTRIB EQUIPMENT USED BY RE- GIO	$	33.73	75
2654	07	RSO PERSONAL PROTECTIVE EQUIPMENT - OPERACQUIRE & DISTRIB EQUIPMENT USED BY RE- GIO	$	97.66	75
2654	10	RSO PERSONAL PROTECTIVE EQUIPMENT - OPERACQUIRE & DISTRIB EQUIPMENT USED BY RE- GIO	$	30.91	75
0193	10	ZIMMER PLANT COAL FIRED - CSP ATTEND OWNERS' MEETINGS OR ACTIVITIES FOR CSP NOT	$	6,085.33	99
0210	60	ANNUAL REPORT - AEP PLAN & PREPARE ANNUAL REPORT TO SHAREHOLDERS OF	$	98,665.70	99
0211	60	FINANCIAL REPORTS - AEP PREPARE ANNUAL & PERIODIC FINANCIAL REPORTS FOR AEP	$	36,276.75	99
0216	60	SALE OF COMMON STOCK - AEP FINANCE SERVICES IN CONNECTION WITH SALEOF AEP COM	$	31,149.08	99
0217	60	BOARD OF DIRECTOR EXPENSES - AEP PAY HOTEL, AIR, MEALS & OTHER EXP FOR ATTENDANC	$	1,508.08	99
0221	60	MERGERS AND ACQUISITIONS - AEPCO SERVICES RELATED TO POSSIBLE MERGERS ANDACQUI	$	16,606.17	99
0223	60	CORPORATE DIVERSIFICATION - AEPCO SERVICES RELATED TO POSSIBLE CORPORATE DIVERSI	$	23,960.82	99
0224	60	POLITICAL ACTION COMMITTEE - AEPCO SERVICES PERFORMED BY AEPSC EMPLOYEES REGAR	$	14,842.43	99
0226	60	UNREG ENER SVC CO (ESCO) PROJ - AEPCO ESCO TASK FORCE TO PROVIDE UNREGULATED ESC	$	22,828.01	99
0432	32	COAL TRANSPORTATION - OVEC TRANSPORT COAL	$	15,904.32	99
0434	32	BULK TRANSMISSION PLANNING - OVEC SERVICES IN CONNECTION WITH BULK TRANSMISSI	$	6,844.21	99
0465	22	CARDINAL UNIT #1, 2, 3, O & M - CARD ENGINEER SERVICE RELATED TO OPERATION & MAINTENAN	$	37,872.57	99
0471	NN	ECAR/DEVELOP BDP MODELS DEVELOP ECAR REDUCTIONS FROM BDP MODELS	$	18,657.32	99
0475	JJ	NPPC/DEVELOP BDP MODELS DEVELOP NPPC REDUCTIONS FROM BDP MODELS	$	918.33	99
0510	04	MISC NUCLEAR FUEL ACTIVITIES - I&MP NUCLEAR FUEL ACTIVITIES THAT BENEFIT MORE THAN	$	60,589.58	99
0581	04	UNIT 1 NUCLEAR FUEL CYCLE - I&MP ENSURE THE FUEL IS DELIVERED AND READY TO PRODUC	$	12,261.74	99
0634	44	MEIGS 2, 31, RACCOON 3 AMD TREATMENT-SOCREVIEW & EVALUATION OF AMD TREATMENT PLAN	$	1,006.38	99
0636	52	COAL MINE ADMINISTRATION - SIM	$	3,193.71	99
0638	44	ALL SERV PERFORMED MARTINKA MINE - SOC	$	48,859.20	99
0684	43	WINDSOR SYSTEM DRILLING PROGRAM - WC SYSTEM CORE DRILLING IN CONNECTION WITH WIND	$	11,226.96	99
0686	42	CENTRAL OHIO SYSTEM DRILLING PROGRAM-COCSYSTEM CORE DRILLING IN CONNECTION WITH CE	$	41,791.84	99
0701	04	ACQUISITION & SALE OF COAL LANDS - I&MP	$	708.55	99
0702	03	ACQUISITION & SALE OF COAL LANDS - KP	$	497.00	99
0711	10	ACQUISITION & SALE OF COAL LANDS - CSP	$	1,224.42	99
0743	43	LONGS RUN RETURN SHAFT ENG & PROJ MGT-WCCONSTRUCT LONGS RUN RETURN SHAFT, SITE D	$	131.68	99
0772	71	FUEL PROCUREMENT & TRANSPORTATION - AMOS	$	600.21	99

AMERICAN ELECTRIC POWER SERVICE CORPORATION
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WO	CO	TITLE/DESCRIPTION		AMOUNT	FORM
0777	70	FUEL PROCUREMENT & TRANSPORTATION-SPORN	$	18,021.69	99
0790	40	ALL SERVICES PERFORMED FOR CAC - CAC	$	1,756.70	99
0791	41	ALL SERVICES PERFORMED FOR CC - CC	$	7,898.35	99
0792	50	ALL SERVICES PERFORMED FOR PRC - PRC	$	102.26	99
0795	45	ALL SERVICES PERFORMED FOR SAC - SAC	$	1,649.25	99
0796	46	ALL SERVICES PERFORMED FOR CED - CED CHARGES APPLICABLE TO CENTRAL REBUILD SHOP	$	15,284.75	99
0799	51	ALL SERVICES PERFORMED FOR BHC - BHC	$	20,159.25	99
0843	10	DSM, LOW INCOME INSULATION - CSP STY OF USAGE AFTER WEATHERIZATION SERV PERFORM	$	1,223.12	99
0867	10	CATV ALL AMERICAN CABLEVISION - CSP FIELD INVENTORY COSTS CSP WO 9-626-161	$	-	99
0868	10	CATV US NETWORK CORPORATION - CSP ENGINEERING & INSPECTION CSP WO 9-626-17	$	3,484.43	99
0869	10	CATV COAXIAL COMMUNICATIONS - CSP ENGINEERING & INSPECTION CSP WO 9-626-181	$	436.63	99
0871	10	CATV WARNER CABLE - CSP ENGINEERING & INSPECTION CSP WO 9-626-178	$	1,613.69	99
0872	10	CATV ICG ACCESS SERVICES - CSP ENGINEERING & INSPECTION CSP WO 9-626-173	$	1,775.61	99
0874	10	CATV NEW MEDIA ENTERPRISES - CSP ENGINEERING & INSPECTION CSP WO 9-626-163	$	1,797.62	99
0988	04	COOK THERMAL HYDRAULIC ANALYSIS - I&MP DEVELOP THERMAL HYDRAULIC & SAFETY ANALYS	$	59,622.85	99
1004	04	CIVIC, POLITICAL & RELATED ACT - I&MP INCLUDE MEMBERSHIPS, CONTRIBUTIONS & OTHER OUT	$	437.07	99
1006	06	CIVIC, POLITICAL & RELATED ACT - WP INCLUDE MEMBERSHIPS, CONTRIBUTIONS & OTHER OUT-	$	1,479.38	99
1007	07	CIVIC, POLITICAL & RELATED ACT - OP INCLUDE MEMBERSHIPS, CONTRIBUTIONS & OTHER OUT-	$	134.89	99
1008	10	CIVIC, POLITICAL & RELATED ACT - CSP INCLUDE MEMBERSHIPS, CONTRIBUTIONS & OTHER OUT-	$	30,000.00	99
1056	01	ENVIRONMENTAL - KGP	$	1,444.54	99
1057	03	ENVIRONMENTAL - KP	$	25,733.16	99
1061	06	ENVIRONMENTAL - WP	$	5,304.10	99
1069	10	ENVIRONMENTAL - CSP	$	69,952.07	99
1092	07	KAMMER PLANT, S02 - OP GEP STACK HEIGHT S02 CONTROL FEASIBILITYSTUDY TO COMP	$	38,447.43	99
1097	54	LINTON RD RECLAMATION PROJECT - CCP ENG FOR RECLAMATION OF COAL REFUSE PILE LINTON	$	1,716.36	99
1101	02	GENERAL DSM ACTIVITY W VA - AP GEN DSM ACT TO ENCOURAGE SAFE, EFFICIENTAND ECON	$	124.44	99
1102	02	GENERAL DSM ACTIVITY VA - AP GEN DSM ACT TO ENCOURAGE SAFE, EFFICIENTAND ECONO	$	1,265.90	99
1103	04	GENERAL DSM ACTIVITY MICHIGAN - I&MP GEN DSM ACT TO ENCOURAGE SAFE, EFFICIENTAND EC	$	3,703.09	99
1105	03	GENERAL DSM ACTIVITY KENTUCKY - KP GEN DSM ACT TO ENCOURAGE SAFE, EFFICIENTAND EC	$	34,661.79	99
1107	07	GENERAL DSM ACTIVITY OHIO - OP GEN DSM ACT TO ENCOURAGE SAFE, EFFICIENTAND ECON	$	15,673.59	99
1108	10	GENERAL DSM ACTIVITY OHIO - CSP GEN DSM ACT TO ENCOURAGE SAFE, EFFICIENTAND ECON	$	5,718.14	99
1116	10	DSM NEIGHBORHOOD ENERGY WATCH,1992 - CSPRESIDENT ENER AUTITS & INSTL OF LOW COSTCO	$	1,073.01	99
1117	02	RESIDENT LOW INCOME WEATHERIZATION - AP DSM PROG TO WEATHERIZE LOW INCOME HOMES T	$	124.43	99
1122	02	COMM & IND FLUORESCENT LIGHTING - AP DSM PROG OFFER FINAN ASSIST FOR LIGHTINGAUDIT &	$	665.55	99
1123	02	COMM & IND FLUORESCENT LIGHTING PROG-AP DSM PROG OFFER FINAN ASSIST FOR LIGHTINGAUD	$	1,331.09	99
1125	02	STORAGE WATER HEATING - AP DSM PROG PROMOTING STOR WTR HEAT CONCEPTSHIFT O	$	87.50	99
1138	07	SMART ENERGY RATED HOME PROGRAM - OP MEASURE EFFIC OF A HOME'S THERMAL ENVEL-OP	$	(11,124.39)	99
1147	02	VA DSM HOME ENERGY FITNESS - AP IMPLEMENT & EVALUATE HEF PROGRAM IN APCOVA JURI	$	7,988.79	99
1148	03	KY DSM SMART FINANCING - KP PROVIDE FINANCING FOR COMMERCIAL & INDUSTRIAL CUST	$	41,040.55	99
1149	03	KY DSM SMART AUDITS - KP PROVIDE ENERGY EFFICIENCY AUDITS TO COMMERCIAL AND	$	17,503.05	99
1172	03	KY DSM MOBILE HOME NEW CONSTR - KP IMPLEMENT AND EVAL MOBILE HOME NEW CON- STRUC	$	6,144.78	99
1173	03	KY DSM MOBILE HOME HEAT PUMPS - KP IMPLEMENT AND EVAL HIGH EFFICIENCY MO- BILE HOM	$	19,701.76	99
1174	03	KY DSM HIGH EFFICIENCY HEAT PUMPS - KP IMPLEMENT AND EVAL RESIDENTIAL HIGH EF- FICIENC	$	16,464.05	99
1175	03	KY DSM COMPACT FLUOR BULBS - KP IMPLEMENT AND EVAL COMPACT FLUORESCENT BULB P	$	4,296.11	99
1176	03	KY DSM TARGETED ENER EFFICIENCY - KP IMPLEMENT AND EVAL TARGETED ENERGY EFFICIEN	$	2,459.22	99
1177	03	KY DSM HOME ENERGY FITNESS - KP IMPLEMENT AND EVAL HOME ENERGY FITNESS PROGRA	$	8,265.86	99
1202	02	FINANCE - AP	$	33,076.27	99
1203	04	FINANCE - I&MP	$	90,832.07	99
1205	01	FINANCE - KGP	$	1,050.13	99
1206	03	FINANCE - KP	$	19,431.30	99
1209	07	FINANCE - OP	$	37,417.65	99
1211	10	FINANCE - CSP	$	13,121.40	99
1220	21	FINANCE - AEG	$	312.38	99
1222	32	FINANCE - IKEC	$	5.87	99
1240	CN	CG & E/ZIMMER ROUTINE SERVICES AGREEMENTPERFORM ROUTINE WORK FOR THE WILLIAM H. ZI	$	5,149.30	99
1305	07	LONG-TERM FORECAST, ODOE - OP OPCO'S ANNUAL LONG-TERM FORECAST REPORT TO THE	$	43,819.73	99
1306	10	LONG-TERM FORECAST, ODOE - CSP CSPCO'S ANNUAL LONG-TERM FORECAST REPORTTO TH	$	44,115.37	99
1349	04	ELKHART HYDRO RELICENSING - I&M SERVICES ASSOC WITH RELICENSING ELKHART HYDRO PL	$	51,687.07	99
1370	04	TWIN BRANCH RELICENSING - I&MP RELICENSE THE TWIN BRANCH HYDRO PLANT	$	180.87	99
1403	02	EXECUTIVE GROUP OPERATIONS - AP	$	64,747.05	99

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WO	CO	TITLE/DESCRIPTION		AMOUNT	FORM
1404	04	EXECUTIVE GROUP OPERATIONS - I&MP	$	14,209.26	99
1406	03	EXECUTIVE GROUP OPERATIONS - KP	$	4,195.69	99
1407	01	EXECUTIVE GROUP OPERATIONS - KGP	$	62,554.93	99
1409	07	EXECUTIVE GROUP OPERATIONS - OP	$	5,726.04	99
1411	06	EXECUTIVE GROUP OPERATIONS - WP	$	270.62	99
1419	10	EXECUTIVE GROUP OPERATIONS - CSP	$	3,223.95	99
1432	04	ELECTRICORE PARTICIPATION - I & M PERFORM WORK TO MEET $50000 IN-KIND COM-MITMENT A	$	140.00	99
1439	07	DISPO TIDD PFBC DEMO PLANT - OP SERVICES ASSOC W/ACTV FOR PHASE II TASK 1.3.2 DISPO	$	12,202.86	99
1445	10	CONESVILLE RAIL UNLOADING FACILITY-CSP ACTIVITIES REQUIRED TO INSTALL A NEW RAIL UNLO	$	131.96	99
1447	07	TIDD PLT SITE UTIL & ASSET RECOVERY - OPREMOVAL & DISPOSAL OF THE ORIGINAL TIDD PLANT	$	3,665.18	99
1448	02	SMITH MTN RECREATION PLAN - AP SVCS REQ TO DEV A RECREATION PLAN FOR SMITH MTN	$	820.54	99
1453	03	BIG SANDY U-2 REHEATER 96 - KP SUPPORT OF SCHEDULED MAINTENANCE OUTAGE REPLACE	$	346.18	99
1456	04	LICENSE RENEWAL ENVIRONMENTAL PLAN - I&MPROGRAM FOR LICENSE RENEWAL OF THE COOK N	$	14,123.98	99
1464	75	GAVIN DEMOLITION OF ORIGINAL STACK-GAVINCOSTS ASSOC WITH THE DEMOLITION OF ORI- GINAL	$	42,687.07	99
1465	22	U-2 ELEVATOR INSTALLATION - CARD INSTALL ELEVATOR PLATE FORMS & MODIFY OTHER FOR	$	34,433.58	99
1475	22	CARDINAL U 2 ESP PLATE REPLACEMENT-CARD ENGINEERING RELATED EXPENSES TO ASSESS TH	$	5,043.35	99
1484	04	TANNERS CRK U 3 TURBINE GEN REPAIR - I&MACCUM COSTS ASSOC W/TANNERS CREEK U 3 TURBI	$	(37,549.35)	99
1485	10	YEARLING #83 STATION - CSP CONSTRUCT NEW STATION TO PROVIDE DUAL 38KV SERVICE	$	65,990.27	99
1488	04	RKP PLT MODIFY RVR MAKE-UP SYSTEM - I&M MODIFICATIONS OF THE RIVER MAKE-UP SYS- TEM AT	$	42,460.39	99
1489	73	EASEMENT DEVELOPMENT AK STEEL - ROCK ENG, DESIGN & SURVEY COSTS ASSOC WITH EASE	$	44,549.91	99
1491	10	LEASING COMPANY ASSETS TELECOMM - CSP USE OF CSPCO TELECOMM TOWERS BY OUTSIDE P	$	(709.71)	99
1493	07	LEASING COMPANY ASSETS TELECOMM - OP USE OF OPCO TELECOMM TOWERS BY OUTSIDE PA	$	28.00	99
1498	01	LEASING COMPANY ASSETS TELECOMM - KGP USE OF KGPCO TELECOMM TOWERS BY OUTSIDE P	$	4,265.49	99
1503	02	PUBLIC AFFAIRS - AP	$	3,221.44	99
1504	04	PUBLIC AFFAIRS - I&MP	$	4,206.38	99
1510	07	PUBLIC AFFAIRS - OP	$	6,522.31	99
1512	10	PUBLIC AFFAIRS - CSP	$	8,437.44	99
1564	02	ANNUAL & PERIODIC FINANCIAL REPORTS - AP	$	31,003.93	99
1565	04	ANNUAL & PERIODIC FINANCIAL REPORTS-I&MP	$	19,850.78	99
1567	01	ANNUAL & PERIODIC FINANCIAL REPORTS-KGP	$	3,555.58	99
1568	03	ANNUAL & PERIODIC FINANCIAL REPORTS - KP	$	21,394.69	99
1571	07	ANNUAL & PERIODIC FINANCIAL REPORTS - OP	$	22,413.22	99
1572	06	ANNUAL & PERIODIC FINANCIAL REPORTS - WP	$	3,574.71	99
1582	10	ANNUAL & PERIODIC FINANCIAL REPORTS-CSP	$	12,419.13	99
1584	21	ANNUAL & PERIODIC FINANCIAL REPORTS-AEG	$	9,067.08	99
1601	32	LEGAL - OVEC	$	18,107.15	99
1602	31	LEGAL - IKEC	$	1,032.12	99
1603	22	LEGAL - CARD	$	14,488.94	99
1610	01	LEGAL - KGP	$	23,524.29	99
1611	03	LEGAL - KP	$	91,611.09	99
1615	06	LEGAL - WP	$	37,968.77	99
1645	21	LEGAL - AEG	$	3,388.92	99
1676	04	TRANSMISSION PLANNING OPERATIONS - I&MP	$	85,191.95	99
1677	03	TRANSMISSION PLANNING OPERATIONS - KP	$	35,083.66	99
1702	02	SYSTEM PLANNING GENERAL - AP	$	69,363.95	99
1703	10	SYSTEM PLANNING GENERAL - CSP	$	23,345.54	99
1704	04	SYSTEM PLANNING GENERAL - I&MP	$	12,010.19	99
1705	03	SYSTEM PLANNING GENERAL - KP	$	2,913.11	99
1708	07	SYSTEM PLANNING GENERAL - OP	$	25,491.37	99
1709	06	SYSTEM PLANNING GENERAL - WP	$	3,719.02	99
1722	07	BULK TRANSMISSION PLANNING OPER - OP	$	4,203.45	99
1723	04	BULK TRANSMISSION PLANNING OPER - I&MP	$	5,121.77	99
1746	02	INGREGRATED RESOURCE PLANNING - AP	$	17,703.66	99
1748	04	INGREGRATED RESOURCE PLANNING - I&MP	$	979.46	99
1749	07	INGREGRATED RESOURCE PLANNING - OP	$	208.09	99
1750	10	INGREGRATED RESOURCE PLANNING - CSP	$	367.47	99
1784	07	CORPORATE SERVICES - OP GEN SERVICES RELATED TO CORPORATE SVCS FOR THE BEN	$	48,140.65	99
1806	02	OPERATING FORECAST - AP	$	14,775.32	99
1807	04	OPERATING FORECAST - I&MP	$	7,488.49	99
1809	01	OPERATING FORECAST - KGP	$	5,002.47	99

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WO	CO	TITLE/DESCRIPTION	AMOUNT	FORM
1810	03	OPERATING FORECAST - KP	$ 7,551.54	99
1813	07	OPERATING FORECAST - OP	$ 8,351.09	99
1814	06	OPERATING FORECAST - WP	$ 414.98	99
1822	10	OPERATING FORECAST - CSP	$ 15,594.86	99
1826	02	CONSTRUCTION BUDGET - AP	$ 349.76	99
1827	04	CONSTRUCTION BUDGET - I&MP	$ 294.70	99
1833	07	CONSTRUCTION BUDGET - OP	$ 158.51	99
1855	02	FINANCIAL FORECAST - AP	$ 58,540.69	99
1856	04	FINANCIAL FORECAST - I&M	$ 48,814.35	99
1858	01	FINANCIAL FORECAST - KGP	$ 13,079.04	99
1859	03	FINANCIAL FORECAST - KP	$ 60,440.67	99
1862	07	FINANCIAL FORECAST - OP	$ 98,475.04	99
1863	06	FINANCIAL FORECAST - WP	$ 789.63	99
1864	10	FINANCIAL FORECAST - CSP	$ 49,958.82	99
1873	21	OPERATING FORECAST - AEG	$ 769.63	99
1874	21	FINANCIAL FORECAST - AEPG	$ 9,942.66	99
1909	01	TREASURY OPERATIONS - KGP	$ 8,712.04	99
1914	06	TREASURY OPERATIONS - WP	$ 33,474.81	99
1927	21	TREASURY OPERATIONS - AEG	$ 1,058.95	99
1932	01	TAX OPERATIONS - KGP	$ 33,169.50	99
1935	06	TAX OPERATIONS - WP	$ 57,434.10	99
1940	01	INTERNAL AUDITS OPERATIONS - KGP	$ 11,924.78	99
1943	06	INTERNAL AUDITS OPERATIONS - WP	$ 839.92	99
1945	21	INTERNAL AUDITS OPERATIONS - AEPG	$ 67.89	99
1946	21	TAX AUDITS OPERATIONS - AEPG	$ 7,668.36	99
2058	02	FERC GENERAL RATE ACTIVITY - AP	$ 10,251.38	99
2059	07	FERC GENERAL RATE ACTIVITY - OP	$ 70,707.33	99
2060	10	FERC GENERAL RATE ACTIVITY - CSP	$ 10,044.17	99
2062	04	FERC GENERAL RATE ACTIVITY - I&MP	$ 13,974.51	99
2101	02	VIRGINIA STATE COMM FUEL COST REVIEW-AP SEMIANNUAL FUEL COST REVIEW	$ 13,946.01	99
2102	02	WVA STATE COMMISSION FUEL COST REVIEW-APQUARTERLY FUEL COST REVIEW	$ 7,408.04	99
2111	04	INDIANA STATE COMM FUEL COST REVIEW-I&MPQUARTERLY FUEL COST REVIEW	$ 10,786.44	99
2122	03	KENTUCKY STATE COMM FUEL COST REVIEW-KP SEMIANNUAL FUEL COST REVIEW	$ 27,166.73	99
2134	06	WVA STATE COMMISSION FUEL COST REVIEW-WPSEMIANNUAL FUEL COST REVIEW	$ 820.74	99
2168	02	REFUND ORDER, VA SCC CASE #PUE 900026-APREFUNDS ORDERED BY VA STATE COMMISSION CAS	$ 27.43	99
2205	01	GENERAL RATE ACTIVITY TENNESSEE - KGP	$ 52,600.89	99
2210	06	GENERAL RATE ACTIVITY WEST VIRGINIA - WP	$ 53,022.45	99
2284	02	AUTOMOTIVE - AP	$ 718.03	99
2285	03	AUTOMOTIVE - KP	$ 1,065.74	99
2286	04	AUTOMOTIVE - I&MP	$ 5,710.97	99
2288	06	AUTOMOTIVE - WP	$ 157.40	99
2289	07	AUTOMOTIVE - OP	$ 3,038.81	99
2290	10	AUTOMOTIVE - CSP	$ 197.21	99
2293	02	LAND MANAGEMENT OPERATIONS - AP	$ 4,886.27	99
2294	04	LAND MANAGEMENT OPERATIONS - I&MP	$ 25,267.90	99
2297	03	LAND MANAGEMENT OPERATIONS - KP	$ 8,106.43	99
2300	07	LAND MANAGEMENT OPERATIONS - OP	$ 49,808.56	99
2302	10	LAND MANAGEMENT OPERATIONS - CSP	$ 8,806.34	99
2350	21	PURCHASING - AEG	$ 5,748.51	99
2382	01	PURCHASING - KGP	$ 32,965.01	99
2387	06	PURCHASING - WP	$ 6,174.60	99
2401	01	SYS HUMAN RESOURCES EMP BENEFITS - KGP	$ 35,768.22	99
2406	06	SYS HUMAN RESOURCES EMP BENEFITS - WP	$ 9,050.65	99
2411	01	SYS HUM RESOURCES SAFETY & ACCD PREV-KGP	$ 25,611.25	99
2416	06	SYS HUM RESOURCES SAFETY & ACCD PREV-WP	$ 31,151.70	99
2431	01	SYS HUM RESOURCES EDUCATION & TRAIN-KGP	$ 27,271.90	99
2433	03	SYS HUM RESOURCES EDUCATION & TRAIN - KP	$ 32,745.05	99
2436	06	SYS HUM RESOURCES EDUCATION & TRAIN - WP	$ 2,861.24	99
2440	32	SYSTEM HUMAN RESOURCES OTHER - OVEC	$ 4,740.80	99
2441	01	SYSTEM HUMAN RESOURCES OTHER - KGP	$ 75,312.31	99

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WO	CO	TITLE/DESCRIPTION	AMOUNT	FORM
2446	06	SYSTEM HUMAN RESOURCES OTHER - WP	$ 7,988.24	99
2449	31	SYSTEM HUMAN RESOURCES OTHER - IKEC	$ 471.02	99
2522	01	CUSTOMER SERVICES - KGP	$ 2,435.77	99
2523	03	CUSTOMER SERVICES - KP	$ 50,333.70	99
2525	06	CUSTOMER SERVICES - WP	$ 13,669.20	99
2529	04	MARKETING SERVICES - I & M	$ 67,856.46	99
2530	01	MARKETING SERVICES - KGP	$ 12,267.65	99
2531	03	MARKETING SERVICES - KP	$ 33,119.49	99
2532	07	MARKETING SERVICES - OP	$ 91,669.58	99
2533	06	MARKETING SERVICES - WP	$ 2,563.41	99
2534	10	MARKETING SERVICES - CSP	$ 52,857.75	99
2557	44	DANVILLE SHAFT ELEV/WAIT ROOM-SOC ENG & DESIGN OF ELEVATOR AND WAITING ROOM @	$ 66,976.32	99
2558	44	PARKER RUN PREP PLT CONTRL CHANGEOUT-SOCREPLACEMENT OF COMPUTER & PLC APPARATU	$ 377.62	99
2559	43	WINDSOR REFUSE IMPOUNDMENT - WCCO PROVIDE FOR DISPOSAL OF FINE AND COARSE REFU	$ 9,738.43	99
2560	44	WATER SAMPLING & ANALYSIS - SOC ACTV ASSOC W/SAMPLING, ANALYSIS & RE- PORTING OF	$ 66,023.82	99
2561	49	REPLACEMENT OF NORTH DUMPER - CCT REPLACE END RINGS,SILL BEAMS & TRUNNIONSON TH	$ 50,553.51	99
2562	43	E MAINS INTAKE SHAFT/EMER HOIST - WCCO SHAFT FOR VENTILATION; HOIST FOR EMER ESCAPE	$ 36,695.67	99
2563	44	NW BLEEDER SHAFT FAN UPGRADE - SOC FAN WILL ALLOW DEVLOPMNT & EXTRACTION OFWEST	$ 42,245.29	99
2564	44	N MAINS DUAL COMPARTMENT SHAFT/FAN - SOCALLOW DEVELOPMNT & EXTRACTION OF COAL FR	$ 64,291.06	99
2566	44	C-BLOCK SHAFT&BLEEDER FAN INSTALL-SOCCO SUPPORT DVLPMT & EXTRCTN OF MEIGS MINE NO	$ 556.24	99
2567	44	THIRD NORTHEAST INTAKE SHAFT - SOCCO PREPARE, DESIGN & CONSTRUCT 10.5' INTAKESHAFT	$ 2,811.49	99
2601	02	VIRGINIA STATE COMMISSION REPORTS - AP	$ 49,961.37	99
2602	02	WVA STATE COMMISSION REPORTS - AP	$ 12,898.90	99
2603	04	MICHIGAN STATE COMMISSION REPORTS - I&MP	$ 524.07	99
2604	04	INDIANA STATE COMMISSION REPORTS - I&MP	$ 41,133.64	99
2606	03	KENTUCKY STATE COMMISSION REPORTS - KP	$ 63,525.60	99
2607	07	OHIO STATE COMMISSION REPORTS - OP	$ 2,847.97	99
2609	02	VASCC 10 YEAR OPERATING FORECAST - AP VIRGINIA STATE CORP COMM ANNUAL 10 YEAR OPER	$ 68,264.36	99
2612	01	TPSC DIRECTED MGMT AUDIT - KGP COST ASSOC WITH THE TENN PUBLIC SERVICE DIRECTED	$ 3,268.10	99
2613	02	MISC INCOME DEDUCTIONS REFUND EXP - AP LABOR RELATED TO DEV OF COMPUTER PROGM &PRI	$ 9,506.13	99
2642	02	SYSTEM TRANSACTIONS - AP	$ 385.22	99
2644	04	SYSTEM TRANSACTIONS - I&MP	$ 3,704.88	99
2647	07	SYSTEM TRANSACTIONS - OP	$ 58,383.09	99
2648	10	SYSTEM TRANSACTIONS - CSP	$ 249.77	99
2707	04	UNIT 2 UPRATE - I&M SERVICES PROVIDED TO ALLOW UNIT 2 TO OPERATE AT 3600 MW	$ 32,098.67	99
3014	02	SPORN PLANT CONSTRUCTION - AP	$ 342.12	99
3064	02	LONDON HYDROELECTRIC PLANT REHAB - KVP REHABILITATE & UPGRADE THE LONDON HYDRO PL	$ 502.30	99
3083	02	UNITS 1-3 SUPERHEATER REPLACEMENT - AP ENG, DESIGN, CONSTR TO REPLACE BOILER & SUPE	$ 26,372.73	99
3084	04	COOK U-1 GSU TRANSFORMER REPLACEMENT-I&MREPLACE COOK U-1 GSU TRANSFORMER & DIS- P	$ 24,821.03	99
3086	10	ST CLAIR TO EAST BROAD STREET FIBER-CSP INSTALL APPROX 15 MILES OF FIBER WHICH WILL CO	$ 54,422.31	99
3087	10	E BROAD TO BUCKEYE STEEL FIBER BUILD-CSPINSTALL APPROX 20 MILES OF FIBER WHICH WILL C	$ 16,748.83	99
3089	58	CHARLESTON/ROANOKE LIGHTWAVE - AEPC,LLC INSTALL INTERCONN FIBER OPTIC LINE BE- TWEEN	$ 7,868.17	99
3089	91	CHARLESTON/ROANOKE LIGHTWAVE - AEPC,LLC INSTALL INTERCONN FIBER OPTIC LINE BE- TWEEN	$ 818.74	99
3089	95	CHARLESTON/ROANOKE LIGHTWAVE - AEPC,LLC INSTALL INTERCONN FIBER OPTIC LINE BE- TWEEN	$ 968.50	99
3092	02	SMITH MNT GANTRY CRANE REHAB - AP PROCUREMENT OF MATERIALS AND SERVICES FOR TH	$ 24,778.98	99
3094	02	W VA CALL CENTER LIGHTWAVE SYSTEM - AP LIGHTWAVE SYSTEM TO SERVE W VA CALL CEN-TER I	$ 26,695.11	99
3142	25	ADMINISTRATIVE SERVICES - AEPRI SERVICES OF A GENERAL NATURE FOR THE BENEFIT OF	$ 53,274.07	99
3143	25	CHINA PUSHAN PROJECT - AEPRI EVAL INVESTMENT OPPORTUNITY IN 250 MW (2 X 125) COA	$ 35,863.58	99
3144	25	INDIA MANGALDRE PROJECT - AEPRI EVAL INVESTMENT OPPORTUNITY IN 1000 MW (4 X 250) GE	$ 87,315.81	99
3145	25	HAZELWOOD AUSTRIALA PROJECT - AEPRI EVAL INVESTMENT OPPORTUNITY IN HAZELWOODPOW	$ 8,887.44	99
3146	25	LAIBIN B PRE-BID ACTIVITIES - AEPRI SERVICES REQ TO PREPARE JOINT BID WITH FOR 350 MW P	$ 1,245.26	99
3152	74	MEXICO BUSINESS DEVELOPMENT - AEPR CHARGES INCURRED IN THE IDENTIFICATION OF INVE	$ 48,410.74	99
3154	74	INDIA BUSINESS DEVELOPMENT - AEPR CHARGES INCURRED IN THE IDENTIFICATION OF INVEST	$ 30,209.21	99
3156	74	ILLINOIS COAL 2000 - AEPR	$ 37,965.06	99
3158	74	IEP THIRD PARTY EXPENSES - AEPR CHARGES RELATED TO THE INDUSTRIAL EN- ERGY PART	$ 141.86	99
3160	74	IEP AK STEEL - AEPR ACCUM COSTS INCURRED IN THE SUPPORT OF THE IEP AK STEEL	$ 5,338.61	99
3162	74	CHINA REPRESENTATIVE OFFICE - AEPR COSTS ASSOC W/ESTABLISHING AND OPERAT- ING A RE	$ 24,118.70	99
3166	74	SOUTH AMER GEN BUSINESS DEVELOPMENT-AEPRCOST ASSOCIATED W/DEVELOP & EVAL BUSI- NE	$ 27,016.98	99
3167	74	LATIN AMER GEN BUSINESS DEVELOPMENT-AEPRCOST ASSOCIATED W/DEVELOP & EVAL BUSI- NE	$ 7,118.12	99
3177	74	PROJECT VIRGO - AEPR COSTS ASSOCIATED WITH PROJECT VIRGO--A CONFIDENTIAL PR	$ 54,450.20	99

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WO	CO	TITLE/DESCRIPTION		AMOUNT	FORM
3179	74	AUSTRALIAN SOUTHERN - AEPR	COSTS ASSOCIATED WITH THE BID & PROPOSALOF A SOUT	$ 8,805.07	99
3183	74	CHINA 2X1300 MW EVALUATION - AEPR	COSTS ASSOC W/TWO SUPERCRITICAL 1300MW COAL FI	$ 2,288.16	99
3199	72	ADMINISTRATIVE SERVICES - AEPI	SERVICES OF A GENERAL NATURE FOR THE BENEFIT OF A	$ 33,967.83	99
3238	03	TRANSMISSION OPERATIONS - KP	CENTRAL	$ 37,970.13	99
3243	03	TRANSMISSION OPERATIONS - KP	SOUTHERN	$ 49,675.99	99
3244	01	TRANSMISSION OPERATIONS - KGP	SOUTHERN	$ 3,936.65	99
3247	07	TRANSMISSION OPERATIONS - OP	WESTERN	$ 72,197.10	99
3259	07	DISTRIBUTION O&M - OP	DISTRIBUTION OHIO CENTRAL REGION	$ 24,618.35	99
3261	07	DISTRIBUTION O&M - OP	DISTRIBUTION OHIO EAST REGION	$ 39,877.52	99
3262	06	DISTRIBUTION O&M - WP	DISTRIBUTION OHIO EAST REGION	$ 7,235.22	99
3265	10	DISTRIBUTION O&M - CSP	DISTRIBUTION OHIO SOUTH REGION	$ 26,829.48	99
3266	07	DISTRIBUTION O&M - OP	DISTRIBUTION OHIO SOUTH REGION	$ 11,078.83	99
3268	03	DISTRIBUTION O&M - KP	DISTRIBUTION KENTUCKY REGION	$ 42,120.34	99
3269	02	DISTRIBUTION O&M - AP	DISTRIBUTION W VIRGINIA NORTH REGION	$ 22,666.92	99
3270	02	DISTRIBUTION O&M - AP	DISTRIBUTION W VIRGINIA SOUTH REGION	$ 43,053.25	99
3271	02	DISTRIBUTION O&M - AP	DISTRIBUTION VIRGINIA/TENN REGION	$ 4,676.35	99
3272	01	DISTRIBUTION O&M - KGP	DISTRIBUTION VIRGINIA/TENN REGION	$ 5,017.74	99
3274	02	DISTRIBUTION O&M - AP	DISTRIBUTION VIRGINIA CENTRAL REGION	$ 22,631.73	99
3290	01	TELECOMMUNICATIONS O&M - KGP		$ 963.45	99
3292	06	TELECOMMUNICATIONS O&M - WP		$ 1,515.02	99
3393	01	T & D MATERIAL DISTRIBUTION - KGP		$ 1,605.63	99
3394	02	T & D MATERIAL DISTRIBUTION - AP		$ 43,158.61	99
3395	03	T & D MATERIAL DISTRIBUTION - KP		$ 7,068.19	99
3396	04	T & D MATERIAL DISTRIBUTION - I&M		$ 12,427.55	99
3397	06	T & D MATERIAL DISTRIBUTION - WP		$ 1,207.43	99
3398	07	T & D MATERIAL DISTRIBUTION - OP		$ 19,936.28	99
3399	10	T & D MATERIAL DISTRIBUTION - CSP		$ 15,037.41	99
3481	02	TRANSMISSION MAINTENANCE- AP	CENTRAL	$ 1,563.96	99
3482	10	TRANSMISSION MAINTENANCE- CSP	CENTRAL	$ 16,152.40	99
3483	03	TRANSMISSION MAINTENANCE- KP	CENTRAL	$ 3,992.72	99
3484	07	TRANSMISSION MAINTENANCE- OP	CENTRAL	$ 46,279.36	99
3485	06	TRANSMISSION MAINTENANCE- WP	CENTRAL	$ 751.93	99
3487	02	TRANSMISSION MAINTENANCE- AP	SOUTHERN	$ 76,031.32	99
3488	03	TRANSMISSION MAINTENANCE- KP	SOUTHERN	$ 870.54	99
3492	07	TRANSMISSION MAINTENANCE- OP	WESTERN	$ 5,848.00	99
3577	06	SCET&D CONSTRUCTION OVERHEADS - WP	DISTRIBUTION OHIO EAST REGION	$ 15,897.25	99
3580	10	SCET&D CONSTRUCTION OVERHEADS - CSP	DISTRIBUTION OHIO SOUTH REGION	$ 82,055.59	99
3581	07	SCET&D CONSTRUCTION OVERHEADS - OP	DISTRIBUTION OHIO SOUTH REGION	$ 49,966.21	99
3583	03	SCET&D CONSTRUCTION OVERHEADS - KP	DISTRIBUTION KENTUCKY REGION	$ 37,787.56	99
3585	02	SCET&D CONSTRUCTION OVERHEADS - AP	DISTRIBUTION W VIRGINIA SOUTH REGION	$ 97,076.85	99
3586	02	SCET&D CONSTRUCTION OVERHEADS - AP	DISTRIBUTION VIRGINIA/TENN REGION	$ 82,145.04	99
3587	01	SCET&D CONSTRUCTION OVERHEADS - KGP	DISTRIBUTION VIRGINIA/TENN REGION	$ 28,906.76	99
3601	71	SCET&D CONSTRUCTION OVERHEADS - AMOS	FOSSIL AND HYDRO PRODUCTION	$ 2,574.09	99
3603	10	SCET&D CONSTRUCTION OVERHEADS - CSP	FOSSIL AND HYDRO PRODUCTION	$ 10,293.35	99
3604	04	SCET&D CONSTRUCTION OVERHEADS - I&M	FOSSIL AND HYDRO PRODUCTION	$ 41,437.22	99
3605	03	SCET&D CONSTRUCTION OVERHEADS - KP	FOSSIL AND HYDRO PRODUCTION	$ 11,941.36	99
3606	07	SCET&D CONSTRUCTION OVERHEADS - OP	FOSSIL AND HYDRO PRODUCTION	$ 68,908.46	99
3607	70	SCET&D CONSTRUCTION OVERHEADS - SPORN	FOSSIL AND HYDRO PRODUCTION	$ 4,257.36	99
3608	73	SCET&D CONSTRUCTION OVERHEADS - ROCK	FOSSIL AND HYDRO PRODUCTION	$ 1,583.42	99
3625	06	SCET&D CONSTRUCTION OVERHEADS - WP	TRANSMISSION CENTRAL REGION	$ 16,633.22	99
3652	71	PLANT CONSTR INSTALLATION O/H-AMOS JT	AMOS COMMON	$ 50,811.51	99
3653	71	PLANT CONSTR INTALLATION O/H-AMOS JT	AMOS PUTNAM COAL TERMINAL	$ 1,136.44	99
3654	71	PLANT CONSTR INSTALLATION O/H-AMOS JT	AMOS PUTNAM COAL TERMINAL COMMON	$ 12,376.41	99
3656	04	PLANT CONSTR INSTALLATION O/H - I&M	BREED	$ 9,520.70	99
3660	22	PLANT CONSTR INSTALLATION O/H - CARD	CARDINAL GENERAL	$ 85,536.75	99
3688	04	SCET&D CONSTRUCTION OVERHEADS - I & M	TELECOMMONICATIONS	$ 18,815.88	99
3689	03	SCET&D CONSTRUCTION OVERHEADS - KP	TELECOMMONICATIONS	$ 81,607.46	99
3690	01	SCET&D CONSTRUCTION OVERHEADS - KGP	TELECOMMONICATIONS	$ 642.22	99
3692	06	SCET&D CONSTRUCTION OVERHEADS - WP	TELECOMMONICATIONS	$ 2,848.36	99
3715	07	COAL COMBUSTION RESIDUAL HANDLING - OP		$ 2,449.42	99

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WO	CO	TITLE/DESCRIPTION	AMOUNT	FORM
3716	10	COAL COMBUSTION RESIDUAL HANDLING - CSP	$ 2,998.94	99
3732	02	CLINCH RIVER COAL COMBUST RESID SALES-AP	$ 16,320.78	99
3733	02	GLEN LYN COAL COMBUST RESID SALES - AP	$ 15,203.73	99
3734	02	KANAWHA RVR COAL COMBUST RESID SALES-AP	$ 9,590.72	99
3735	02	MOUNTAINEER COAL COMBUST RESID SALES-AP	$ 40,139.91	99
3736	03	BIG SANDY COAL COMBUST RESID SALES - KP	$ 8,342.58	99
3737	04	BREED COAL COMBUST RESID SALES - I&MP	$ (453.96)	99
3738	04	TANNERS CK COAL COMBUST RESID SALES-I&MP	$ 791.78	99
3739	07	GAVIN COAL COMBUST RESID SALES - OP	$ 72,943.05	99
3740	07	KAMMER COAL COMBUST RESID SALES - OP	$ 3,220.15	99
3741	07	MITCHELL COAL COMBUST RESID SALES - OP	$ 2,841.02	99
3742	07	MUSKINGUM COAL COMBUST RESID SALES - OP	$ 15,078.88	99
3743	10	CONESVILLE COAL COMBUST RESID SALES-CSP	$ 21,041.35	99
3744	10	PICWAY COAL COMBUST RESID SALES - CSP	$ 1,633.18	99
3745	22	CARDINAL COAL COMBUST RESID SALES-CARD	$ 12,929.76	99
3746	31	CLIFTY CK COAL COMBUST RESID SALES-IKEC	$ 1,570.59	99
3747	32	KYGER CK COAL COMBUST RESID SALES-OVEC	$ 1,452.64	99
3748	70	SPORN COAL COMBUST RESID SALES - SPORN	$ 7,038.13	99
3749	71	AMOS COAL COMBUST RESID SALES - AMOS	$ 29,765.11	99
3750	73	ROCKPORT COAL COMBUST RESID SALES - ROCK	$ 10,575.80	99
3752	02	CLINCH RVR COAL COMBUST BY-PROD SALES-AP	$ 22,441.38	99
3753	02	GLEN LYN COAL COMBUST BY-PROD SALES - AP	$ 8,957.80	99
3754	02	KANWHA RVR COAL COMBUST BY-PROD SALES-AP	$ 17,115.15	99
3755	02	MOUNTNEER COAL COMBUST BY-PROD SALES-AP	$ 21,328.52	99
3756	03	BIG SANDY COAL COMBUST BY-PORD SALES-KP	$ 525.06	99
3757	04	BREED COAL COMBUST BY-PROD SALES -I&MP	$ 946.33	99
3758	04	TANRS CK COAL COMBUST BY-PORD SALES-I&MP	$ 1,329.68	99
3759	07	GAVIN COAL COMBUST BY-PROD SALES - OP	$ 34,459.89	99
3760	07	KAMMER COAL COMBUST BY-PORD SALES - OP	$ 2,555.66	99
3761	07	MITCHELL COAL COMBUST BY-PROD SALES - OP	$ 658.69	99
3762	07	MSKNGUM COAL COMBUST BY-PROD SALES - OP	$ 34,054.34	99
3763	10	CNSVILLE COAL COMBUST BY-PROD SALES-CSP	$ 44,993.02	99
3764	10	PICWAY COAL COMBUST BY-PROD SALES - CSP	$ 6,823.72	99
3765	22	CARDINAL COAL COMBUST BY-PROD SALES-CARD	$ 2,474.08	99
3766	31	CLFTY CK COAL COMBUST BY-PROD SALES-IKEC	$ 15,861.46	99
3767	32	KYGER CK COAL COMBUST BY-PROD SALES-OVEC	$ 675.34	99
3768	70	SPORN COAL COMBUST BY-PROD SALES - SPORN	$ 1,574.22	99
3769	71	AMOS COAL COMBUST BY-PROD SALES - AMOS	$ 29,518.74	99
3770	73	ROCKPORT COAL COMBUST BY-PROD SALES-ROCK	$ 19,575.51	99
3826	03	BIG SANDY OPERATION - KP	$ 31,534.22	99
3828	02	CLINCH RIVER OPERATION - AP	$ 59,276.21	99
3829	10	CONESVILLE OPERATION - CSP	$ 85,903.69	99
3831	02	GLEN LYN OPERATION - AP	$ 43,501.56	99
3832	07	KAMMER OPERATION - OP	$ 42,765.17	99
3833	02	KANAWHA RIVER OPERATION - AP	$ 50,362.75	99
3834	07	MITCHELL OPERATION - OP	$ 70,760.20	99
3837	10	PICWAY OPERATION - CSP	$ 21,303.11	99
3838	73	ROCKPORT OPERATION - ROCK	$ 98,859.43	99
3839	70	SPORN OPERATION - SPORN JT	$ 45,781.95	99
3840	04	TANNERS CREEK OPERATION - I&M	$ 58,221.27	99
3841	04	BERRIEN SPRINGS OPERATION - I&M	$ 3,867.59	99
3842	04	BUCHANAN OPERATION - I&M	$ 3,350.33	99
3843	02	BUCK OPERATIONS - AP	$ 2,027.95	99
3844	02	BYLLESBY OPERATION - AP	$ 4,976.66	99
3845	02	CLAYTOR OPERATION - AP	$ 7,134.54	99
3846	04	CONSTANTINE OPERATION - I&M	$ 4,121.02	99
3847	04	ELKHART OPERATION - I&M	$ 2,645.62	99
3848	02	LEESVILLE OPERATION - AP	$ 7,023.25	99
3849	02	LONDON OPERATION - AP	$ 1,460.68	99
3850	02	MARMET OPERATION - AP	$ 1,652.10	99

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WO	CO	TITLE/DESCRIPTION		AMOUNT	FORM
3851	04	MOTTVILLE OPERATION - I&M		$ 1,804.00	99
3852	02	NIAGARA OPERATION - AP		$ 6,437.68	99
3853	07	RACINE OPERATION - OP		$ 3,166.33	99
3854	02	REUSENS OPERATION - AP		$ 4,156.23	99
3855	02	SMITH MOUNTAIN OPERATION - AP		$ 75,429.08	99
3856	04	TWIN BRANCH OPERATION - I&M		$ 15,868.42	99
3857	02	WINFIELD OPERATION - AP		$ 2,179.82	99
3860	71	PLANT CONSTR RETIREMENT O/H-AMOS JT	AMOS UNITS 1 AND 2	$ 66,228.64	99
3861	71	PLANT CONSTR RETIREMENT O/H-AMOS JT	AMOS UNIT 3	$ 36,199.68	99
3862	71	PLANT CONSTR RETIREMENT O/H-AMOS JT	AMOS COMMON	$ 1,845.63	99
3864	71	PLANT CONSTR RETIREMENT O/H-AMOS JT	AMOS PUTNAM COAL TERMINAL COMMON	$ 700.38	99
3865	03	PLANT CONSTR RETIREMENT O/H - KP	BIG SANDY	$ 39,438.60	99
3866	04	PLANT CONSTR RETIREMENT O/H - I&M	BREED	$ 4,889.10	99
3867	07	PLANT CONSTR RETIREMENT O/H - OP	CARDINAL UNIT 1	$ 33,823.53	99
3867	22	PLANT CONSTR RETIREMENT O/H - OP	CARDINAL UNIT 1	$ 4,404.43	99
3868	22	PLANT CONSTR RETIREMENT O/H - CARD	CARDINAL UNITS 2 AND 3	$ 1,588.95	99
3869	22	PLANT CONSTR RETIREMENT O/H - CARD	CARDINAL COMMON	$ 3,116.99	99
3870	22	PLANT CONSTR RETIREMENT O/H-CARD	GENERAL	$ 50,876.31	99
3872	10	PLANT CONSTR RETIREMENT O/H - CSP	CONSEVILLE UNIT 4	$ 198.55	99
3873	10	PLANT CONSTR RETIREMENT O/H - CSP	CONESVILLE UNITS 1,2,3,5 AND 6	$ 44,660.38	99
3874	07	PLANT CONSTR RETIREMENT O/H - OP	GAVIN	$ 46,880.39	99
3875	02	PLANT CONSTR RETIREMENT O/H - AP	GLEN LYN	$ 29,119.17	99
3876	07	PLANT CONSTR RETIREMENT O/H - OP	KAMMER	$ 49,171.01	99
3877	02	PLANT CONSTR RETIREMENT O/H - AP	KANAWHA RIVER	$ 29,111.07	99
3878	07	PLANT CONSTR RETIREMENT O/H - OP	MITCHELL	$ 40,418.31	99
3879	02	PLANT CONSTR RETIREMENT O/H - AP	MOUNTAINEER	$ 5,793.39	99
3881	10	PLANT CONSTR RETIREMENT O/H - CSP	PICWAY	$ 3,980.88	99
3882	73	PLANT CONSTR RETIREMENT O/H - ROCK	ROCKPORT	$ 7,874.63	99
3883	70	PLANT CONSTR RETIREMENT O/H-SPORN JT	SPORN UNITS 1 AND 3	$ 27,764.12	99
3885	04	PLANT CONSTR RETIREMENT O/H - I&M	TANNERS CREEK	$ 24,938.35	99
3903	71	AMOS PUTNAM COAL MAINT - AMOS JT		$ 76,535.46	99
3904	71	AMOS PUTNAM COAL MAINT - AMOS JT	COMMON	$ 67,177.55	99
3906	02	AMOS SIMULATOR MAINTENANCE - AMOS JT		$ 3,789.04	99
3910	04	BREED UNIT 1 MAINTENANCE - I&M		$ 1,754.56	99
3911	04	BREED COMMON MAINTENANCE - I&M		$ 55,300.29	99
3917	02	CLINCH RIVER UNIT 1 MAINTENANCE - AP		$ 30,970.80	99
3919	02	CLINCH RIVER UNIT 3 MAINTENANCE - AP		$ 19,671.67	99
3922	10	CONESVILLE UNIT 2 MAINTENANCE - CSP		$ 31,319.02	99
3923	10	CONESVILLE UNIT 3 MAINTENANCE - CSP		$ 51,836.49	99
3927	10	CONESVILLE U 1,2,3 COMMON MAINT - CSP		$ 86,197.29	99
3928	10	CONESVILLE U 1,2,3,4 COMM MAINT - CSP		$ 23,937.42	99
3929	10	CONESVILLE U 4 COMMON MAINTENANCE - CSP		$ 82,160.37	99
3942	02	KANAWHA RVR UNIT 1 MAINTENANCE - AP		$ 87,751.58	99
3943	02	KANAWHA RVR UNIT 2 MAINTENANCE - AP		$ 77,640.53	99
3957	10	PICWAY COMMON MAINTENANCE - CSP		$ 93,525.41	99
3963	70	SPORN UNIT 3 MAINTENANCE - SPORN JT		$ 85,759.56	99
3968	04	TANNER CREEK UNIT 2 MAINTENANCE - I&M		$ 93,593.65	99
3972	04	FOURTH STREET GAS TURBINE - I&M		$ 8,184.00	99
3975	04	BERRIEN SPRINGS MAINTENANCE - I&M		$ 6,984.31	99
3976	04	BUCHANAN MAINTENANCE - I&M		$ 50,846.09	99
3977	02	BUCK MAINTENANCE - AP		$ 31,183.69	99
3979	02	CLAYTOR MAINTENANCE - AP		$ 26,926.00	99
3980	04	CONSTANTINE MAINTENANCE - I&M		$ 16,143.47	99
3981	04	ELKHART MAINTENANCE - I&M		$ 26,608.67	99
3982	02	LEESVILLE MAINTENANCE - AP		$ 15,631.47	99
3983	02	LONDON MAINTENANCE - AP		$ 1,312.00	99
3984	02	MARMET MAINTENANCE - AP		$ 1,905.39	99
3985	04	MOTTVILLE MAINTENANCE - I&M		$ 31,342.93	99
3986	02	NIAGARA MAINTENANCE - AP		$ 32,232.70	99
3987	07	RACINE MAINTENANCE - OP		$ 23,451.26	99

AMERICAN ELECTRIC POWER SERVICE CORPORATION
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WO	CO	TITLE/DESCRIPTION		AMOUNT	FORM
3988	02	REUSENS MAINTENANCE - AP	$	39,597.41	99
3989	02	SMITH MOUNTAIN MAINTENANCE - AP	$	99,969.45	99
3990	04	TWIN BRANCH MAINTENANCE - I&M	$	7,317.54	99
3991	02	WINFIELD MAINTENANCE - AP	$	3,175.19	99
4036	07	KAMMER UNITS #1-#3 COAL SWITCH - OP BUILD COAL HANDLING FACILITIES PER CLEANAIR ACT C	$	64.03	99
4040	10	CONESVILLE UNITS #1-#3 GAS FIRING - CSP PROVIDE CO-FIRING (COAL & NATURAL GAS) FOR BOILE	$	817.95	99
4124	KK	DUKE POWER/COMPUTER STUDIES	$	918.33	99
4125	GG	GPU SERVICE CORP/COMPUTER STUDIES	$	1,836.60	99
4126	LG	LG & E/COMPUTER STUDIES	$	604.73	99
4127	CG	CG & E/COMPUTER STUDIES	$	777.50	99
4128	DA	DP & L/COMPUTER STUDIES	$	423.31	99
4129	PU	KENTUCKY UTILITIES/COMPUTER STUDIES	$	215.99	99
4131	PA	PENNSYLVANIA POWER/COMPUTER STUDIES	$	172.78	99
4132	SI	SOUTHERN INDIANA G & E/COMPUTER STUDIES	$	129.58	99
4133	TE	TOLEDO EDISON/COMPUTER STUDIES	$	345.56	99
4134	WP	WEST PENN POWER/COMPUTER STUDIES	$	928.96	99
4135	PE	POTOMAC EDISON/COMPUTER STUDIES	$	86.64	99
4136	MP	MONOGAHELA POWER/COMPUTER STUDIES	$	64.28	99
4137	OE	OHIO EDISON/COMPUTER STUDIES	$	1,295.61	99
4174	AO	AMP OHIO/NTSP LOAD FLOW STUDIES EVALUATE PERFORMANCE OF AMP OHIO'S NORTHERN	$	4,072.93	99
4177	07	CITY OF DOVER NORTH INTERTIE STATION-OP PROVIDE SERVICE TO CITY OF DOVER FOR PROPO	$	7,128.05	99
4178	AO	AMP OHIO LOAD FLOW STUDIES CONDUCT LOAD FLOW STUDIES FOR VARIOUS TRANSMISSI	$	640.66	99
4180	AC	ABB SYSTEM CONTROL PROVIDE SVC AS SUBCONTRACTOR ON THE ENERMGMT SYS PL	$	4,754.32	99
4182	NN	OPERATION OF ECAR-MET TRNSMSN SECUR CTR OPERATE ECAR-MET TRANSMISSION SECURITY C	$	784.10	99
4201	32	SCADA SOFTWARE MAINTENANCE - OVEC SUPERVISORY CONTROL & DATA ACQUISITION SYSTE	$	47,786.83	99
4210	32	ANNUAL DOE L-T FORECAST REPORT - OVEC ACTIVITIES RELATED TO LONG-TERM FORECASTREP	$	18,811.80	99
4215	32	ENVIRONMENT ACTIVITIES, AIR - OVEC PERFORM ENGINEER, LEGAL & TEST SERVICES RELATED	$	4,755.04	99
4217	32	ENVIRONMENT ACTIVITIES, WATER - OVEC PERFORM ENGINEER, LEGAL & TEST SERVICES RELATE	$	3,594.02	99
4221	31	ENVIRONMENT ACTIVITIES, SOLID WASTE-IKECPERFORM ENGINEER, LEGAL & TEST SERVICES RELA	$	1,229.23	99
4222	31	ENVIRONMENT ACTIVITIES, AIR - IKEC PERFORM ENGINEER, LEGAL & TEST SERVICES RELATED T	$	1,096.88	99
4231	32	SEASONAL LOSS STUDIES - OVEC TRANSMISSION LOSS STUDIES ASSOC W/POWER DELIVERI	$	58,883.21	99
4256	31	CLIFTY COAL HANDLING MODIFICATION - IKECMODIFY COAL HANDLING & BOILER FACILITIESTO COM	$	28,349.36	99
4257	32	ENVIRONMENTAL AUDIT PROGRAM - OVEC GEN SERV REL TO ENVIRON AUDIT PROGRAM FOR B	$	12,913.99	99
4258	31	ENVIRONMENTAL AUDIT PROGRAM - IKEC GEN SERV REL TO ENVIRON AUDIT PROGRAM FOR BE	$	64.00	99
4263	32	KYGER PLT NO. FLY ASH POND CLOSURE-OVEC DESIGN OF NORTH FLY ASH POND CLOSURE ANDDR	$	48,326.62	99
4264	32	NOX REDUCTION PILOT PROGRAM - OVEC ENG, INSTALL AND TEST OF NOX EMISSIONS CONTRO	$	899.00	99
4267	32	TOWER 80 DEARBORN/PIERCE 345KV LINE-OVECRELOCATION OF TOWER 80 PURSUANT TO A RE-QU	$	4,437.75	99
4269	32	SEWAGE HANDLING FACILITIES PIKETON-OVEC PUMP STATION AND PIPING RUNS FOR ROUTINGSEW	$	11,055.94	99
4270	31	CLIFTY CRK STATION CONVEYOR DAMAGE-IKEC REPAIR SECTION OF B 12 LUFFING CONVEYOR @ C	$	41.74	99
4271	32	COAL PILE VOLUMETRIC SURVEY - OVEC SEMI ANNUAL COAL PILE VOLUMETRIC SURVEYSTO BE	$	7,618.31	99
4272	31	COAL PILE VOLUMETRIC SURVEY - IKEC SEMI ANNUAL COAL PILE VOLUMETRIC SURVEYSTO BE C	$	16,300.81	99
4273	32	TRNSMSN LINE RELO KENTON CO, KY - OVEC RELO SECTION OF OVEC'S TRANSMISSION LINE	$	3,277.00	99
4340	02	TRANSTEXT PILOT PROGRAM - AP, CSP, I&MP SERVICES FOR TRANSTEXT PROGRAM; SEE W.O.0812	$	10,330.87	99
4340	04	TRANSTEXT PILOT PROGRAM - AP, CSP, I&MP SERVICES FOR TRANSTEXT PROGRAM; SEE W.O.0812	$	10,299.91	99
4340	10	TRANSTEXT PILOT PROGRAM - AP, CSP, I&MP SERVICES FOR TRANSTEXT PROGRAM; SEE W.O.0812	$	10,299.91	99
4358	07	ONCE THROUGH COOLING FISH STUDIES-CSP,OPFISH STUDIES AT CONESVILLE & MUSKINGUM RIVE	$	438.57	99
4358	10	ONCE THROUGH COOLING FISH STUDIES-CSP,OPFISH STUDIES AT CONESVILLE & MUSKINGUM RIVE	$	438.66	99
4398	02	SMITH MNTN LAKE STRIPED BASS STUDY - AP 3 YR RESEARCH PROJ TO DETERMN REASON FORDEC	$	329.78	99
4404	10	UNDERGROUND CABLE MONITOR - CSP PURCHASE & INSTALL THERMAL MONITOR SYS FOR MO	$	22,571.15	99
4430	02	LITE ASH COLLECTION - AP TEST & EVAL LITE ASH IN COMPRESSION MOLDPLASTIC COMPO	$	12,216.36	99
4438	10	NORVIK/HONDA FAST CHG LIFT TRUCK - CSP FAST CHARGE TECH FOR ELEC LIFT TRUCKS ATHOND	$	156.83	99
4453	75	MORPH&CARBON CHARACTER OF FLY ASH-GAVIN FUSION OF FLY ASH PARTICLES & CHARACTER-IZ	$	3,020.65	99
4454	75	FGD CENTRATE TO ABSORBERS - GAVIN TEST TO PUMP CENTRATE BACK TO FGD SYSTEMASOR	$	8,369.79	99
4704	59	BRIGHT SOLUTIONS - AEPES NON REGULATED MKT & ADM ACTV & CONSTR OFOUTDOOR LI	$	3,881.34	99
4705	56	AEPR PROJ MGMT CO LTD ADMIN & GEN SVCS	$	7,103.48	99
4708	58	FIBER OPTIC LINE E BROAD/CANTON-AEPC,LLCCONSTRUCTION OF FIBER OPTIC LINE FROM EAST B	$	-	99
4709	58	FIBER OPTIC LINE TO EAST BROAD-AEPC,LLC CONSTRUCTION OF FIBER OPTIC LINE CABLE FR 1 RIV	$	-	99
4711	86	AEP RESOURCES DELAWARE-ADMIN & GENERAL GENERAL SERVICES FOR THE BENEFIT OF AEP	$	6,258.60	99
4712	88	AEP RESOURCES GLOBAL HOLAND HOLDINGS BV GEN SVCS FOR THE BENEFIT OF AEPR GLOBAL HO	$	164.75	99
4713	89	AEP RESOURCES GLOBAL VENTURES BV GEN SVCS FOR THE BENEFIT OF AEPR GLOBAL VENTU	$	274.57	99

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WO	CO	TITLE/DESCRIPTION		AMOUNT	FORM
4714	90	AEP RESOURCES GLOBAL INVESTMENTS BV GEN SVCS FOR THE BENEFIT OF AEPR GLOBAL INVE	$	387.07	99
4715	58	LONGABERGER PROJECT - AEPC,LLC TRACK COSTS ASSOC W/ DESIGN & DEVELOPMNTOF A FI	$	2,666.32	99
4719	58	MCI CAPACITY REVENUE - AEPC	$	1,069.09	99
4725	58	ROANOKE CO LOCATION - AEPC,LLC LEASE/SUB LEASE OFFICE SPACE IN ROANOKE FOR THE F	$	107.60	99
4728	91	PRODUCT DEVELOPMENT - AEPC,LLC COSTS ASSOC W/EXPANDING PRODUCT LINES INAEPC T	$	10,539.74	99
4729	58	SALES ACTIVITIES - AEPC,LLC COSTS ASSOC W/FIBER CAPACITY SALES RE- LATED ACTIVITIE	$	2,971.00	99
4729	91	SALES ACTIVITIES - AEPC,LLC COSTS ASSOC W/FIBER CAPACITY SALES RE- LATED ACTIVITIE	$	1,689.98	99
4729	95	SALES ACTIVITIES - AEPC,LLC COSTS ASSOC W/FIBER CAPACITY SALES RE- LATED ACTIVITIE	$	2,907.98	99
4730	91	AEPC LLC ADMIN & GENERAL SERVICES	$	1,717.05	99
4731	95	SUB MEASUREMENT BOARD - AEPC,LLC COSTS ASSOCIATED WITH DEVELOPMENT OF A SUB M	$	1,928.30	99
4732	58	ENGINR & DESIGN ASSESSMENTS - AEPC,LLC ENGIN & DESIGN WORK ASSOCIATED WITH ESTIMA	$	1,782.76	99
4732	91	ENGINR & DESIGN ASSESSMENTS - AEPC,LLC ENGIN & DESIGN WORK ASSOCIATED WITH ESTIMA	$	7,615.95	99
4732	95	ENGINR & DESIGN ASSESSMENTS - AEPC,LLC ENGIN & DESIGN WORK ASSOCIATED WITH ESTIMA	$	5,316.21	99
4733	58	CCS DEVELOPMENT - AEPC,LLC DEVELOPMENT COST CUSTOMER COMMUNICATION SYSTEM	$	17,545.62	99
4733	91	CCS DEVELOPMENT - AEPC,LLC DEVELOPMENT COST CUSTOMER COMMUNICATION SYSTEM	$	10,006.04	99
4733	95	CCS DEVELOPMENT - AEPC,LLC DEVELOPMENT COST CUSTOMER COMMUNICATION SYSTEM	$	15,670.17	99
4734	91	AEP LLC REVENUE ON FIBER LINE - AEPC LLCREVENUE ASSOCIATED WITH AEPC LLC FIBER OPTIC L	$	1,291.27	99
4736	91	CHARLESTON FIBER RING BUILDOUT-AEPC,LLC COSTS RELATED TO CONSTR OF FIBER OPTIC RING	$	938.05	99
4737	91	COLS TO CANTON FIBER BUILD O&M-AEPC,LLC OPER/MAINT EXPENSES ASSOC/W THE COLUMBUST	$	1,948.61	99
4738	91	HUNTINGTON LIGHTWAVE TERMINAL - AEPC,LLCCONSTRUCTION EXPENDITURES ASSOC W/HUNT- IN	$	5,352.81	99
5023	69	N AMER ELEC RELIABILITY COUNCIL-AEPRESCOCOMPUTER CONSULTING SERVICES	$	36,422.70	99
5272	69	CIVIL LAB SERVICE AGREEMENT - AEPRESCO VARIOUS CIVIL LAB SERVICES PERFORMED UNDER	$	32,687.52	99
5273	69	ENVIRON LAB SERVICE AGREEMENT-AEPRESCO VARIOUS ENVIRONMENTAL LAB SERVICES PER- FO	$	182.36	99
5410	69	BURNS & ROE COMPANY - AEPRESCO CONTRACT SERVICES TO B&R TO PERFORM WORKON U	$	631.78	99
5412	69	ETRAN 500KV TRANSMISSION PROJ - AEPRESCOCONSULT SERV TO SICHUAN ELEC PWR ADMIN FO	$	2,392.58	99
5414	69	MEDICAL CENTER COMPANY - AEPRESCO ENG & CONSTR OF A 138KV DISTRIBUTION SUBSTATI	$	5,237.67	99
5415	69	AK STEEL CORPORATION - AEPRESCO ENGINEERING, PROCUREMENT & CONSTRUCTION OF 138	$	118.83	99
5425	69	TECHNEGLAS 40/13.2KV SUBSTATION-AEPRESCOPROVIDE TECHNEGLAS WITH A 40/13.2 KV SUBST	$	314.76	99
5426	69	OMEGA JV5 KV - AEPRESCO TERMINATE BELLEVILLE KV LINE THROUGH NEWKV CIRCUIT B	$	13,955.83	99
5430	69	GILBERT COMMONWLTH PFBC RPT-AEPRESCO PROVIDE INPUT TO GILBERT TO UPDATE DRAFTRE	$	12,142.75	99
5435	69	CPP TRANSIENT VOLTAGE STUDIES - AEPRESCOCALCULATE EXPECTED TRANSIENT VOLTAGE DUET	$	59.47	99
5437	69	EGAT 500KV TRANSMN LINE PROPOSL-AEPRESCOPREPARATION OF PROPOSAL FOR 500KV TRANS-	$	9,984.07	99
5438	69	BEI DEVELOPMENT PROJECT - AEPRESCO PRELIM ANALYSIS OF BEI PROJ, INCLUDING LEGAL, FI	$	73.28	99
5439	69	AMERICAN FLY ASH COMPANY - AEPRESCO GENARAL ADMIN OF LICENSE AGREEMENT ACTV ASS	$	865.44	99
5442	69	RADFORD RIGHT OF WAY ACQUISTION-AEPRESCOOBTAIN TRANSMN ROW FR TAP POINT GLEN LYN1	$	584.12	99
5445	69	SIERRA PACIFIC'S TRACY STA U 1-AEPRESCO COSTS ASSOC W/CONSULTING ACTV FOR DB RILEY	$	140.25	99
5446	69	WHEELING-PITTSBURH STEEL CORP - AEPRESCOUPGRADE PWR LINE CARRIER RELAY TIDD- WHE	$	838.80	99
5448	69	CCPA STATIC VAR SYS SIZING STY-AEPRESCO PERFORM SIZING STUDIES FOR COLUMBIANA COUN	$	7.03	99
5449	69	EGAT KHLONG NGAE 230KV TRANSM AEPRESCO PROPOSAL FOR 50HZ TRANSM LINE FR KHLONG N	$	3,042.85	99
5450	69	EGAT LAOS 230KV TRANSM LINE-AEPRESCO PROPOSAL FOR 50HZ TRANSM LINE FR LAOS BORDE	$	778.71	99
5451	69	HURST ENG TECHNICAL SUPPORT - AEPRESCO PROVIDE TECH SUPPORT SVCS PER LICENSING AG	$	293.17	99
5452	69	HURST ENG MARKETING SUPPORT - AEPRESCO PROVIDE MKTG SUPPORT SVCS PER LICENSING AG	$	10,972.95	99
5453	69	FLASHFILL ADMIN & GEN EXP - AEPRESCO ADMINISTRATIVE & GENERAL EXPENSES ASSOC WITH F	$	31,287.35	99
5454	69	FORT WAYNE COMM SCHOOLS - AEPRESCO CONSULT SVC TO EVAL ENER CONSUMPTION ANDPR	$	965.60	99
5456	69	ALLIED SIGNAL MICRO TURBINE-AEPRESCO EVALUATION OF BUSINESS DEVELOPMENT WITH AL	$	14,248.66	99
5457	69	EMI SIGNATURE ANALYSIS - AEPRESCO DEVELOP ONLINE DIAGNOSTIC SYSTEM FOR ROTATIN	$	46,039.55	99
5459	69	ALLIED PWR SERVICE JT VENTURE - AEPRESCOASSIST IN THE DEVELOPMENT OF A JOINT VENTUR	$	9,301.08	99
5463	69	ENTERGY CONTRACT - AEPRESCO ENGINEERING ASSESMENT OF UNBALANCED TRANSFO	$	17,760.85	99
5464	69	PROCURE SOFTWARE MARKETING - AEPRESCO CHGS REL TO MKTG OF PROCURE SOFTWARE FOR	$	57,548.59	99
5465	69	LTRAX SOFTWARE - AEPRESCO CHGS REL TO S/W MKTG, SALES & LICENSING USED FOR RE	$	207.69	99
5466	69	SUBSTA AUTOMATION DEVELOP/MKTG-AEPRESCO DEVELOP & MARKET INTEGRATED DISTRIBUTION	$	577.33	99
5467	69	COVOL EVALUATION - AEPRESCO EVALUATION OF COVOL SYNTHETIC FUEL PLANTAND RELA	$	8,149.88	99
5469	69	PANAMA DEVELOPMENT PROJECT - AEPRESCO COST ASSOC W/STRATEGIES FOR PROJECT DE- VE	$	25,689.00	99
5470	69	ARMCO, INC - AEPRESCO ENGIN A NEW 69/13.8 KV, 15 MVA SERVICE ENTRANCE SUBSTA	$	8,566.44	99
5471	69	DELIVR ORDER 19, NW RUSSIA PROJ-AEPRESCOINTEGRATED RESOURCE & INVEST PLAN IN RUSSI	$	2,971.76	99
5472	69	PGG RAILCAR UNLOADER - AEPRESCO TURNKEY CONSTRUCTION PROJECT WITH PGG INSOUTH	$	1,208.86	99
5474	69	UNION CARBIDE SUBSTATION - AEPRESCO NEW ELEC SUBSTATION & 13.8KV FEEDER CIR-CUTS IN	$	751.05	99
5475	69	STANDBY GENERATION PROGRAM - AEPRESCO COSTS ASSOC/W BIDDING & PROJ DEVELOP- MEN	$	4,831.60	99
5501	69	GREENSBORO CORP, DBA DECKR CONS-AEPRESCODEVELOP, MARKET & LICENSE AEPES' PROCESS	$	3,508.66	99
5502	69	S J ROTH ENTERPRISES, INC - AEPRESCO DEVELOP, MARKET & LICENSE AEPES' PROCESSTO PRO	$	23,962.54	99

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WO	CO	TITLE/DESCRIPTION		AMOUNT	FORM
5504	69	WESTERN ASH COMPANY - AEPRESCO DEVELOP, MARKET & LICENSE AEPES' PROCESSTO PRO	$	3,005.28	99
5597	69	FLASHFILL SELL & MKT SVC - AEPRESCO GEN SELL/MKT ACT ASSOC WITH MKT & LIC OFPROCESS	$	56,656.22	99
5598	69	FLASHFILL TECHNL DEVMNT EXP - AEPRESCO GEN TECHNL DEVMNT ACT ASSOC WITH DEVMNT OF	$	14,762.13	99
5908	69	SELLING & MARKETING - AEPRESCO TECHNICAL, CONSULTING & DEMONSTRATION & OTHER SE	$	88,736.89	99
5912	69	BURNS & ROE GENERAL SVCS - AEPRESCO GEN SVC ASSOC WITH AEPES EFFORTS TO WORKWIT	$	5.25	99
6026	02	NORTH CHARLESTON SERVICE CENTER - AP	$	12,974.18	99
6029	07	ZANESVILLE SERVICE BLDG RENOVATION - OP	$	1,052.37	99
6032	04	FT WAYNE NORTHEAST SERVICE CENTER - I&M	$	67,172.90	99
6035	04	WINCHESTER SERVICE BUILDING - I&M	$	26,208.53	99
6036	07	CANTON GENERAL OFFICE REMODELING - OP	$	35,026.66	99
6038	10	ATHENS DIVISION SERVICE CENTER - CSP	$	68,894.64	99
6039	10	SEAMAN SERVICE BUILDING - CSP DESIGN AND CONSTRUCTION OF NEW SERVICE CENTER BU	$	28,628.83	99
6041	02	LOGAN GARAGE FACILITY - AP	$	4,030.87	99
6042	03	COAL RUN SERVICE CENTER - KP SERVICES RELATED TO DESIGN AND CONSTR OFOFFICE SP	$	1,256.66	99
6044	02	NORTH CHARLESTON COMPLEX ANNEX ONE - AP RENOVATE THE ANNEX ONE BUILDING FORMERLY	$	248.55	99
6200	71	AMOS U-2 RETIRE TURBINE CONTROLS -AMOS	$	52,138.61	99
6205	71	AMOS U-1 RETIRE EXPANSION JOINT -AMOS EJ-103	$	75.00	99
6210	71	AMOS U-1CONDENSATE POLISH RESIN-AMOS	$	385.57	99
6211	71	AMOS U-1 RETIRE EXPANSION JOINT-AMOS	$	207.03	99
6216	71	AMOS U-1 REPLACE CONTROLS -AMOS	$	6,130.05	99
6222	04	BERRIEN SPRING U1-4 HYDRO REDEVL-I&M	$	6,029.42	99
6224	04	BREED U 1 DEMOLITION OF BREED PLANT-I&M	$	19,476.33	99
6233	22	CARD U-2 INSTALL DIVERSION GATES-CARD	$	94.31	99
6238	22	CARDINAL U1-3 REMOVE FLYASH LINES -CARD	$	32,403.97	99
6239	22	CARDINAL U1-3 INSTALL FLYASH LINES-CARD	$	69,027.28	99
6245	02	CLINCH RIVER U1-3REFURBISH ELEVATOR-AP	$	116.90	99
6247	02	CLINCH RIVER U1-3 REPLACE PLANT -AP	$	6,319.83	99
6250	02	CLINCH RIVER U 1-3 RETIRE #1 ELEV-AP	$	724.59	99
6251	02	CLINCH RIVER U 1-3 REFURB #1 ELEV-AP	$	2,656.56	99
6263	10	CONESVILLE U-4 SOLID CONTACT UNIT -CSP	$	(4,853.95)	99
6264	10	CONESVILLE U-4 TURBINE CONTROLS -CSP	$	137.73	99
6284	02	GLEN LYN U-6REPLACE FIRE PIPING-AP	$	3,652.51	99
6286	02	GLEN LYN U-5 RETUBE HEATER -AP	$	337.47	99
6290	02	GLEN LYN U 5 UPGRADE OIL LIGHTER-AP	$	(10.21)	99
6315	02	KANAWAH RVR U 1PURCHASE DETECTION-AP	$	182.36	99
6320	02	KANAWAH RVR COMMON RETIRE MIXER -AP	$	29.98	99
6321	02	KANAWAH RVR COMMON SYS CONVERSION-AP	$	2,988.47	99
6323	07	MITCHELL COMMONREBUILD PULVERIZER-OP	$	52.29	99
6324	07	MITCHELL COMMON RETIRE PULVERIZER-OP	$	(178.29)	99
6326	07	MITCHELL U 4 VALVE REPLACEMENT -OP	$	8,467.11	99
6330	07	MUSKINGUM U 4 RETIRE SAFETY VALVE-OP	$	972.93	99
6331	07	MUSKINGUM U 3 RETIRE TRASH RAKES-OP	$	687.86	99
6333	07	MUSKINGUM U 3 REPLACE OSCILLOGRAPH-OP	$	6,703.02	99
6335	07	MUSKINGUM U 3 RETIRE HOT/COLD BADK-OP	$	7,700.06	99
6337	07	MUSKINGUM U 5 REPLACE OSCILLOGRAPH-OP	$	1,098.69	99
6340	07	MUSKINGUM U 1 HOT/COLD HEAT BASKETS-OP	$	3,048.25	99
6343	07	MUSKINGUM U 3 RETIRE SAFETY VALVES-OP	$	911.47	99
6351	07	MUSKINGUM U 1 PURCH/INSTALL BUCKETS-OP	$	582.39	99
6357	07	MUSKINGUM U 5 RETIRE GAS FAN -OP	$	(48.22)	99
6360	07	MUSKINGUM U 5 RETIRE AIR HEATER -OP	$	(873.01)	99
6362	07	MUSKINGUM U 3 AIR HEATER BASKETS-OP	$	10,660.26	99
6363	07	MUSKINGUM U 5 RETIRE GAS DUCT -OP	$	119.73	99
6367	07	MUSKINGUM COMMON COAL PILE -OP	$	119.00	99
6369	07	MUSKINGUM U 3 PURCH/INST TURBINE-OP	$	2,134.25	99
6375	07	MUSKINGUM U 3 RETIRE SPILL STRIPS-OP	$	56.61	99
6384	04	BREED U 1 RETIRE ASBESTOS ABATEM-I&MP	$	510.20	99
6388	02	GREENLIGHTS SERVICE BUILDING-AP	$	32,032.72	99
6389	10	CONESVILLE U 5-6 WASTE DISP FACILITY-CSP	$	2,116.70	99
6392	22	SILO 6 COAL HANDLING SYSTEM UPGRADE-CARDCARDINAL 0	$	3,549.34	99
6396	22	SILO A COAL HANDLING UPGRADE - CARD CARDINAL 0	$	81.06	99

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WO	CO	TITLE/DESCRIPTION	AMOUNT	FORM
6402	07	INSTALL 20 OPEN BACK 90DEGR BURN ELBW-OPGAVIN	$ 2,603.24	99
6473	70	SPORN U-5 INSTALL DEMINERALIZER-SPORN	$ 4,742.23	99
6483	22	INST STEAM COIL AIR HEAT CONTRL SYS-CARDCARDINAL 1	$ 1,166.48	99
6484	22	REMV STEAM COIL AIR HEAT CONTRL SYS-CARDCARDINAL 1	$ (13.19)	99
6485	22	INST ACOUSTIC LEAK DETECTOR SYSTEM-CARD CARDINAL 1	$ 119.48	99
6488	22	INST COAL FEEDER WEIGHT CONTROLS-CARD CARDINAL 1	$ 2,766.08	99
6489	22	REMV COAL FEEDER WEIGHT CONTROLS-CARD CARDINAL 1	$ (200.63)	99
6491	22	REMV BOILDER SEAL SKIRT-CARD CARDINAL 1	$ (88.04)	99
6494	22	INST SECONDARY SPRHEAT INLET ALIGNM-CARDCARDINAL 1	$ 431.38	99
6496	22	INST NORTH CIRCULATING WATER PUMP-CARD CARDINAL 2	$ (636.25)	99
6497	22	RMV NORTH CIRCULATING WATER PUMP-CARD	$ (238.77)	99
6509	22	REMV #31 PULVERIZER ROTATING THROAT-CARDCARDINAL 3	$ 202.33	99
6510	71	INST PRIMARY AIR FAN DIRVES-AMOS JT AMOS 2	$ 4,250.58	99
6512	71	INST CAPAC DAMPER DRIVES ON PULV-AMOS JTAMOS 2	$ 12,791.31	99
6513	71	REMV CAPAC DAMPER DRIVES ON PULV-AMOS JTAMOS 2	$ 1,078.82	99
6514	71	INST PIPE INSUL FR BOILR TO TURB-AMOS JTAMOS 2	$ 3,402.94	99
6515	71	REMV PIPE INSUL FR BOILR TO TURB-AMOS JTAMOS 2	$ 27,181.19	99
6516	71	INST INSUL ON AUXIL STEAM HEADER-AMOS JTAMOS 2	$ 2,540.64	99
6517	71	REMV INSUL ON AUXIL STEAM HEADER-AMOS JTAMOS 2	$ 2,940.09	99
6518	71	INST TRANSFMR FIRE DECTION SYS-AMOS JT AMOS 2	$ 29,034.95	99
6519	71	REMV TRANSFMR FIRE DECTION SYS-AMOS JT AMOS 2	$ 1,123.08	99
6522	71	INST ROTATING THROAT #3-6 PULV-AMOS JT AMOS 3	$ 57.62	99
6528	71	INST COAL FEEDER SPEED DRIVES-AMOS JT AMOS 2	$ 39,566.40	99
6529	71	REMV COAL FEEDER SPEED DRIVES-AMOS JT AMOS 2	$ 3,807.52	99
6531	10	INST FORCED DRAFT FAN BEAR&OIL MNTR-CSP CONESVILLE 1	$ 180.30	99
6535	10	INSTALL COAL HANDLING CONTROLS - CSP CONESVILLE	$ 172.39	99
6554	10	PURCH MILL VENTURI OUTLET CLASSIF - CSP CONESVILLE 5	$ (607.25)	99
6560	10	REMV SCRUBBER LIGHTING - CSP CONESVILLE 6	$ 94.65	99
6563	10	INSTALL BLOW DOWN TANK - CSP CONESVILLE 6	$ 183.79	99
6565	07	INST 2ND & 7TH BUCKETS ON TURBINE - CSP MUSKINGUM 5	$ 174.44	99
6566	07	REMV 2ND & 7TH BUCKETS ON TURBINE - CSP MUSKINGUM 5	$ 36.91	99
6567	07	INST HIGH PRESS TURBINE EXHAUST VALV-CSPMUSKINGUM 3	$ 4,048.19	99
6568	07	REMV HIGH PRESS TURBINE EXHAUST VALV-CSPMUSKINGUM 3	$ 996.21	99
6569	22	INST SLURRY PUMPHSE ANNUNCIATOR - CARD CARDINAL 1	$ 2,999.14	99
6575	71	INST HOT/COLD AIR HEATER BASKETS-AMOS JTAMOS 3	$ 14,438.67	99
6577	03	MODIFICATIONS FLY ASH DAM PROJECT - KP BIG SANDY 0	$ 98.11	99
6578	03	INST COOLING TOWER FILL - KP BIG SANDY 2	$ 11,229.27	99
6580	03	INST LOW PRESS REHEAT OUTLET BANK - KP BIG SANDY 2	$ 888.12	99
6588	02	ASH DISPOSAL AREA CONSTRUCTION - AP CLINCH RIVER 0	$ 107.31	99
6589	02	ASH DISPOSAL AREA RENOVATION - AP CLINCH RIVER 0	$ 555.04	99
6590	02	INSTALL LOW NOX BURNERS - AP CLINCH RIVER	$ 42.00	99
6596	07	INST SPARE 2ND REHEAT ROTOR & NOZZLE-OP MITCHELL 2	$ (1,250.50)	99
6598	73	INST ROTATING THROATS 14 PULVRZR - ROCK ROCKPORT 2	$ 20,973.37	99
6599	73	REMV ROTATING THROATS 14 PULVRZR - ROCK ROCKPORT 2	$ 8,771.86	99
6602	70	INST RVR CELLS FOR LOADED FLEET-SPORN SPORN 0	$ 2,921.55	99
6603	70	REMV RVR CELLS FOR LOADED FLEET-SPORN SPORN 0	$ 1,914.18	99
6604	70	INST INTERMD PRESSURE NOZZLE - SPORN SPORN 4	$ 528.63	99
6606	70	INST FRONT/REAR RECIRCUL GAS DUCT-SPORN SPORN 5	$ 37,302.18	99
6607	70	REMV FRONT/REAR RECIRCUL GAS DUCT-SPORN SPORN 5	$ 54,740.43	99
6608	70	INST SECONDARY SPRHEAT OUTLET HEAD-SPORNSPORN 5	$ 75,114.58	99
6609	70	REM SECONDARY SPRHT OUTLET HEAD-SPORN SPORN 5	$ 91,131.94	99
6611	70	INST NEW WIND HIGH PRESSURE STATO-SPORN SPORN 5	$ 1,702.40	99
6613	04	INST HIGH PRESS INNER SHELL&NOZZLE-I&M TANNERS 3	$ 172.98	99
6617	04	INST PERFORMANCE MONITORING SYSTEM - I&MTANNERS CREEK 0	$ 1,259.95	99
6622	10	INST DRIVES ON CONDENSATE PUMPS - CSP CONESVILLE 5	$ 83,717.85	99
6623	10	REMV DRIVES ON CONDENSATE PUMPS - CSP CONESVILLE 5	$ 10,286.69	99
6624	10	INST DRIVES ON CONDENSATE PUMPS - CSP CONESVILLE 6	$ 79,883.19	99
6625	10	REMV DRIVES ON CONDENSATE PUMPS - CSP CONESVILLE 6	$ 17,878.05	99
6626	10	INST 2 FROZEN COAL FEEDER BREAKERS - CSPCONESVILLE 5,6	$ 78.42	99
6632	10	REMV LOW PRESS TURBINE ROTOR A-CSP CONESVILLE 5	$ 11,145.40	99

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WO	CO	TITLE/DESCRIPTION	AMOUNT	FORM
6633	10	PURCH/INST LOW PRESS TURBINE ROTOR A-CSPCONESVILLE 6	$ 80,777.47	99
6634	10	REMV LOW PRESS TURBINE ROTOR A-CSP CONESVILLE 6	$ 23,940.00	99
6644	71	INST STA 13 COAL HANDL LOGIC RVSN-AMOSJTAMOS 0	$ 9,029.11	99
6652	04	INST LOW NOX BURNERS - I&M TANNERS 3	$ 1,203.48	99
6654	04	RETUBE MAIN CONDENSER - I&M TANNERS 3	$ 3,153.32	99
6655	04	REMV TUBES MAIN CONDENSER - I&M TANNERS 3	$ 3,552.43	99
6665	70	REMV 6 ANNUNCIATOR PANELS - SPORN SPORN 1	$ 11,652.29	99
6666	70	INST STEAM COIL AIR PREHEAT EXPAN-SPORN SPORN 5	$ 30,984.47	99
6667	70	REMV STEAM COIL AIR PREHEAT EXPAN-SPORN SPORN 5	$ 24,911.32	99
6668	70	INST AC/DC DISTRIBUTION - SPORN SPORN 5	$ 4,885.16	99
6669	70	REMV AC/DC DISTRIBUTION - SPORN SPORN 5	$ 2,270.77	99
6670	70	INST DEC COMPUTER SYSTEM - SPORN SPORN 5	$ 3,302.38	99
6672	70	INST TURBINE OIL COOL CONT SYS - SPORN SPORN 5	$ 26,836.53	99
6673	70	REMV TURBINE OIL COOL CONT SYS - SPORN SPORN 5	$ 2,104.18	99
6674	70	INST PLANT BATTERIES - SPORN SPORN 5	$ 7,431.37	99
6675	70	REMV PLANT BATTERIES - SPORN SPORN 5	$ 1,280.63	99
6678	70	INST 4 GAS RECIRCUL DAMPERS - SPORN SPORN 5	$ 33,295.42	99
6679	70	REMV 4 GAS RECIRCUL DAMPERS - SPORN SPORN 5	$ 839.13	99
6680	70	INST BRUSH RIG HIGH/LOW PRESS GEN-SPORN SPORN 5	$ 5,524.84	99
6681	70	REMV BRUSH RIG HIGH/LOW PRESS GEN-SPORN SPORN 5	$ 1,360.68	99
6682	70	INST 4 COAL FEEDER HOUSINGS - SPORN SPORN 5	$ 40,767.92	99
6683	70	REMV 4 COAL FEEDER HOUSINGS - SPORN SPORN 5	$ 17,479.69	99
6684	70	INST KEY INTERLOCK SYSTEMS - SPORN SPORN 5	$ 10,736.00	99
6685	70	REMV KEY INTERLOCK SYSTEMS - SPORN SPORN 5	$ 4,840.42	99
6686	70	INST DOUBLE FLOW LOW PRESS TURB - SPORN SPORN 5	$ 757.13	99
6687	70	REMV DOUBLE FLOW LOW PRESS TURB - SPORN SPORN 5	$ 413.53	99
6688	70	INST DOUBL FLOW LOW PRES TURB RTR -SPORNSPORN 5	$ 28,094.31	99
6689	70	REMV DOUBL FLOW LOW PRES TURB RTR -SPORNSPORN 5	$ 18,746.42	99
6692	70	INST PROPORTIONING DAMPER CONTROLS-SPORNSPORN 5	$ 28,598.26	99
6693	70	REMV PROPORTIONING DAMPER CONTROLS-SPORNSPORN 5	$ 3,496.86	99
6695	70	REMV 7 ANNUNCIATIOR - SPORN SPORN 5	$ 5,931.14	99
6696	70	INST 6 SAFETY VALVES WITH 4 NEW - SPORN SPORN 1	$ 20,613.33	99
6697	70	REMV 6 SAFETY VALVES WITH 4 NEW - SPORN SPORN 1	$ 6,545.39	99
6698	70	INST TRANSFORMR RECTIFIER CONTROLS-SPORNSPORN 5	$ 48,323.54	99
6699	70	REMV TRANSFORMR RECTIFIER CONTROLS-SPORNSPORN 5	$ 2,642.82	99
6709	70	INST POWER RELIEF VALVE - SPORN SPORN 5	$ 13,172.74	99
6710	70	REMV POWER RELIEF VALVE - SPORN SPORN 5	$ 3,794.22	99
6712	70	REMV LOW NOX BURNER SYS - SPORN SPORN 2	$ 41,875.91	99
6713	70	INST LOW NOX BURNER SYS - SPORN SPORN 4	$ 91,113.16	99
6714	70	REMV LOW NOX BURNER SYS - SPORN SPORN 4	$ 14,030.87	99
6716	70	REMV 4 KV AUX BUS - SPORN SPORN 5	$ 102.14	99
6722	10	INST TUBES ON MAIN CONDENSER - CSP CONESVILLE 5	$ 39,322.49	99
6723	10	REMV TUBES ON MAIN CONDENSER - CSP CONESVILLE 5	$ 11,629.71	99
6730	22	INSTALL CONSTRUCTION ELEVATOR - CARD CARDINAL 1	$ 25,981.07	99
6731	70	INST INSUL ON SECONDARY AIR SYS - SPORN SPORN 5	$ 46,651.66	99
6732	70	REMV INSUL ON SECONDARY AIR SYS - SPORN SPORN 5	$ 92,852.03	99
6733	02	INST GENERATOR STATOR WINDING - AP GLEN LYN 5	$ 1,451.16	99
6735	02	INST MAIN STEAM TURBINE ROTOR/SHELL - APGLEN LYN 5	$ 61,066.55	99
6739	02	INST MAIN STEAM PIPING - AP GLEN LYN 5	$ 2,324.99	99
6740	02	REMV MAIN STEAM PIPING - AP GLEN LYN 5	$ 7.00	99
6744	02	INST ADJUSTABLE SPEED DRIVE FOR PUMP-AP MOUNTAINEER 1	$ 12,666.78	99
6746	02	EPA GREEN LIGHTS PROGRAM - AP GLEN LYN 0	$ 4,395.46	99
6747	22	INSTALL BOILER FEED PUMP ROTOR - CARD UNIT 1	$ 397.20	99
6749	22	INST MAIN TURB BYPOASS CONTROLS - CARD UNIT 1	$ 60.00	99
6750	22	REMV MAIN TURB BYPOASS CONTROLS - CARD UNIT 1	$ 112.55	99
6753	70	INST BOILER ROOM ROOF - SPORN JT UNIT 3	$ 60.00	99
6754	70	REMV BOILER ROOM ROOF - SPORN JT UNIT 3	$ 1,031.65	99
6755	02	INST COAL PILE DRAINAGE SYSTEM - AP GLEN LYN U-0	$ 544.69	99
6760	07	INSTALL PLANT AIR DRYER - OP MUSKINGUM 5	$ 39.69	99
6764	02	INST DIKE REPAIRS N BOTTOM ASH POND-AP GLEN LYN 0	$ 4,363.41	99

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WO	CO	TITLE/DESCRIPTION		AMOUNT	FORM
6765	02	UPGRADE CRUSHER AND CHUTE - AP GLEN LYN 0	$	42,132.42	99
6766	02	INST 6TH STAGE HEATER TUBES - AP GLEN LYN 5	$	455.86	99
6768	02	INST AIR FLOW MONITORING SYSTEM - AP CLINCH RIVER 3	$	2,736.09	99
6771	02	MODIFY CONT ROOM INSTRUMENTATION - AP GLEN LYN 5	$	(75.73)	99
6799	07	INST GENERATOR ROTOR - OP MITCHELL 2	$	(12.69)	99
6801	70	INST TRANSF RECTIFIER & RAPPER-SPORN JT SPORN 2	$	(17.10)	99
6802	70	REMV TRANSF RECTIFIER & RAPPER -SPORN JTSPORN 2	$	(293.76)	99
6803	70	INST 3 ANNUNICATIOR-SPORN JT SPORN 2	$	18,032.77	99
6804	70	REMV 3 ANNUNICATIOR-SPORN JT SPORN 2	$	(60.71)	99
6808	70	REMV 4 EXPANSION JOINT - SPORN JT SPORN 2	$	215.55	99
6809	70	INST PRIMARY AIR FAN HOUSINGS-SPORN JT SPORN 2	$	463.66	99
6812	22	INST ON LINE PERFORM MONITORING - CARD CARDINAL U 3	$	28,605.35	99
6814	07	INST HIGH PRESS TURBINE SAFE VALVES - OPMUSKINGUM RIVER U 2	$	17,119.60	99
6815	07	REMV HIGH PRESS TURBINE SAFE VALVES - OPMUSKINGUM RIVER U 2	$	8,916.82	99
6816	07	INST HIGH PRESS TURBINE SAFE VALVES - OPMUSKINGUM RIVER U 2	$	6,478.39	99
6817	07	REMV HIGH PRESS TURBINE SAFE VALVES - OPMUSKINGUM RIVER U 2	$	2,964.40	99
6818	70	INST ABOVE SEAT DRAIN VALVE - SPORN JT SPORN 2	$	14,403.44	99
6819	70	REMV ABOVE SEAT DRAIN VALVE - SPORN JT SPORN 2	$	1,356.89	99
6820	70	INST DISCHARGE ELECTRODES - SPORN JT SPORN 2	$	46,962.42	99
6821	70	REMV DISCHARGE ELECTRODES - SPORN JT SPORN 2	$	9,330.73	99
6822	70	INST SPEED DRIVES COAL FEEDER - SPORN JTSPORN 2	$	(32.25)	99
6823	70	REMV SPEED DRIVES COAL FEEDER - SPORN JTSPORN 2	$	581.40	99
6829	22	INST ACID CAUSTIC REGEN STATION - CARD CARDINAL U 3	$	(644.73)	99
6830	22	REMV ACID CAUSTIC REGEN STATION - CARD CARDINAL U 3	$	(72.10)	99
6831	22	INST DISSOLVED 02 ANALYZER - CARD CARDINAL U 1	$	244.91	99
6834	07	INST COMBUSTION CONT & OPER INTER - OP MUSKINGUM RVR 5	$	889.36	99
6835	07	INST VENT LOUVERS ON ELEV 18 - OP GAVIN 2	$	2,495.40	99
6837	70	INST LOW NOX BURNER SYSTEM - SPORN SPORN U 3	$	5,579.49	99
6839	10	INST SHELTERS OVER MONITOR EQUIP - CSP CONESVILLE U 3	$	210.23	99
6842	07	INST HIGH PRESS TURB BEARING - OP GAVIN 2	$	8,338.83	99
6843	07	REMV HIGH PRESS TURB BEARING - OP GAVIN 2	$	2,235.07	99
6845	07	INST COLD SIDE AIR HEAT BASKET - OP GAVIN 2	$	3,026.17	99
6846	07	REMV COLD SIDE AIR HEAT BASKET - OP GAVIN 2	$	0.99	99
6847	07	INST SECONDARY SPRHEAT ALIGN CAST - OP GAVIN 1	$	2,407.50	99
6848	07	REMV SECONDARY SPRHEAT ALIGN CAST - OP GAVIN 1	$	18.00	99
6849	07	INST SECONDARY SPRHEAT ALIGN CAST - OP GAVIN 2	$	2,555.59	99
6850	07	REMV SECONDARY SPRHEAT ALIGN CAST - OP GAVIN 2	$	2,477.48	99
6851	07	REMV FEMALE SUPERVISOR LOCKERROOM - OP GAVIN 0	$	5.25	99
6852	22	INST OUTDOOR MAIN&REHEAT STM PIPE - CARDCARD 1	$	15,541.70	99
6853	22	INST OUTDOOR MAIN&REHEAT STM PIPE - CARDCARD 1	$	3,668.62	99
6855	70	INST CONDENSATE CLEANUP SYS - SPORN JT SPORN 5	$	60,638.51	99
6856	70	REMV CONDENSATE CLEANUP SYS - SPORN JT SPORN 5	$	4,836.37	99
6857	70	INST EXPAN JOINTS GAS OUTLET - SPORN JT SPORN 5	$	671.83	99
6858	70	REMV EXPAN JOINTS GAS OUTLET - SPORN JT SPORN 5	$	1,297.38	99
6859	70	INST PRECIP OUTLET EXPAN JOINTS-SPORN JTSPORN 5	$	1,423.34	99
6860	70	REMV PRECIP OUTLET EXPAN JOINTS-SPORN JTSPORN 5	$	1,441.26	99
6861	70	INST EAST/WEST DUST EXPANSION - SPORN JTSPORN 5	$	1,389.58	99
6862	70	REMV EAST/WEST DUST EXPANSION - SPORN JTSPORN 5	$	566.89	99
6863	70	INST GAS OUTLET EXPAN 58 & 28 - SPORN JTSPORN 5	$	1,139.76	99
6864	70	REMV GAS OUTLET EXPAN 58 & 28 - SPORN JTSPORN 5	$	2,998.74	99
6865	70	INST LOW PRESS #3 HEAT TUBES - SPORN JT SPORN 5	$	4,374.34	99
6866	70	REMV LOW PRESS #3 HEAT TUBES - SPORN JT SPORN 5	$	2,662.96	99
6867	70	INST LOW PRESS #1 HEAT TUBES - SPORN JT SPORN 5	$	11,030.68	99
6868	70	REMV LOW PRESS #1 HEAT TUBES - SPORN JT SPORN 5	$	1,387.81	99
6869	70	INST LOW PRESS #2 HEAT TUBES - SPORN JT SPORN 5	$	5,000.50	99
6870	70	REMV LOW PRESS #2 HEAT TUBES - SPORN JT SPORN 5	$	2,441.47	99
6871	70	INST NOZZLE,DIAPHGRAMS, PACKING-SPORN JTSPORN 5	$	756.63	99
6873	07	INST VALVE CRV 201 - OP GAVIN 2	$	1,151.21	99
6874	07	REMV VALVE CRV 201 - OP GAVIN 2	$	124.23	99
6875	07	INST OXYGEN ANALYZER SYSTEM - OP MUSKINGUM RVR 2	$	31,222.62	99

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WO	CO	TITLE/DESCRIPTION		AMOUNT	FORM
6876	07	REMV OXYGEN ANALYZER SYSTEM - OP	MUSKINGUM RVR 2	$ 1,779.37	99
6877	07	INST SEAL SKIRT - OP	MUSKINGUM RVR 2	$ 52,575.05	99
6878	07	REMV SEAL SKIRT - OP	MUSKINGUM RVR 2	$ 22,086.91	99
6879	07	INST EXPANSION JOINT 2-1 - OP	MUSKINGUM RVR 2	$ 16,729.19	99
6880	07	REMV EXPANSION JOINT 2-1 - OP	MUSKINGUM RVR 2	$ 17,601.47	99
6881	07	INST HOTWELL PUMP #1 - OP	MUSKINGUM RVR 2	$ 14,850.99	99
6882	07	REMV HOTWELL PUMP #1 - OP	MUSKINGUM RVR 2	$ 4,401.51	99
6883	07	INST HOTWELL PUMP #2 - OP	MUSKINGUM RVR 2	$ 13,329.59	99
6884	07	REMV HOTWELL PUMP #2 - OP	MUSKINGUM RVR 2	$ 4,224.72	99
6886	02	INST BOILER BURNER TIPS&INSULATION - AP	GLEN LYN 5	$ 92.32	99
6889	02	REMV INSULATION ON BOILER WALLS - AP	GLEN LYN 5	$ 73.69	99
6892	07	INST AIR HEATER #2 INLET DAMPERS - OP	GAVIN 2	$ 1,528.96	99
6893	07	REMV AIR HEATER #2 INLET DAMPERS - OP	GAVIN 2	$ 1.62	99
6894	07	INST 35 CERAMIC COAL PIPE ELBOWS - OP	GAVIN 2	$ 22,769.24	99
6895	07	REMV 35 CERAMIC COAL PIPE ELBOWS - OP	GAVIN 2	$ 17,117.97	99
6898	07	INST PLATFORMS AIR HTR DMPR LINK - OP	GAVIN 2	$ 1,720.51	99
6899	07	REMV PLATFORMS AIR HTR DMPR LINK - OP	GAVIN 2	$ 4,375.95	99
6900	07	INST OIL LIGHTERS - OP	MUSKINGUM RVR 2	$ 96,960.52	99
6901	07	REMV OIL LIGHTERS - OP	MUSKINGUM RVR 2	$ 17,239.92	99
6902	07	INST LWR FURNANCE WALLS/FLOOR - OP	MUSKINGUM RVR 2	$ 50,392.02	99
6903	07	REMV LWR FURNANCE WALLS/FLOOR - OP	MUSKINGUM RVR 2	$ 67,083.75	99
6904	07	INST AIR HEATER BASKETS - OP	MUSKINGUM RVR 2	$ 80,178.02	99
6905	07	REMV AIR HEATER BASKETS - OP	MUSKINGUM RVR 2	$ 61,510.58	99
6906	04	INST LP GEN ROTOR, BEARINGS, SEAL - I&M	TANNERS CREEK 3	$ 10,876.14	99
6907	04	REMV LP GEN ROTOR, BEARINGS, SEAL - I&M	TANNERS CREEK 3	$ 957.85	99
6909	04	REMV WEDGES ON LP GENERATOR - I&M	TANNERS CREEK 3	$ 618.41	99
6910	04	INST IP TURBINE RTR W/BEARS & SEALS-I&M	TANNERS CREEK 3	$ 7,400.57	99
6911	04	REMV IP TURBINE RTR W/BEARS & SEALS-I&M	TANNERS CREEK 3	$ 310.87	99
6912	04	INST LP TURBINE RTR W/BEARS & SEALS-I&M	TANNERS CREEK 3	$ 9,292.52	99
6913	04	REMV LP TURBINE RTR W/BEARS & SEALS-I&M	TANNERS CREEK 3	$ (372.03)	99
6914	07	INST INLET NOZLE VANES - OP	MUSKINGUM RVR 2	$ 27,499.84	99
6916	02	REMV #52 WEST PULVERIZER GEAR - AP	GLEN LYN 5	$ 124.09	99
6917	04	INST TURBINE SUPERVISORY INSTRU - I&M	TANNERS CREEK 3	$ 4,520.22	99
6918	04	REMV TURBINE SUPERVISORY INSTRU - I&M	TANNERS CREEK 3	$ 345.71	99
6921	07	REMV INLET NOZZLE VANES - OP	MUSKINGUM RVR 2	$ 33,905.77	99
6922	71	INST EXPAN JT FR #2 AIR HEAT - AMOS JT	AMOS 2	$ 3,836.44	99
6924	71	INST EXPAN JT FR #1 AIR HEAT - AMOS JT	AMOS 2	$ 252.80	99
6926	71	INST INVERTER & ASSOC EQUIP - AMOS JT	AMOS 2	$ 8,084.76	99
6929	71	REMV LPA & LPB TURB ROTORS - AMOS JT	AMOS 2	$ 17,018.44	99
6930	22	INST AIR HEAT COLD EXPAN JT 3-1 - CARD	CARDINAL 3	$ 1,311.83	99
6931	22	REMV AIR HEAT COLD EXPAN JT 3-1 - CARD	CARDINAL 3	$ 71.50	99
6934	07	INST PURGE AIR SYSTEM - GAVIN	GAVIN 2	$ 29,034.30	99
6934	75	INST PURGE AIR SYSTEM - GAVIN	GAVIN 2	$ 18,021.44	99
6935	07	FLY ASH REMOVAL - GAVIN	GAVIN 2	$ 3,752.71	99
6935	75	FLY ASH REMOVAL - GAVIN	GAVIN 2	$ 756.41	99
6936	07	INST LIQUID COLLECTION DEVICES - GAVIN	GAVIN 2	$ 19,316.64	99
6936	75	INST LIQUID COLLECTION DEVICES - GAVIN	GAVIN 2	$ 12,288.70	99
6937	07	INST MIST ELIMINATORS - GAVIN	GAVIN 2	$ 8,447.97	99
6937	75	INST MIST ELIMINATORS - GAVIN	GAVIN 2	$ 4,759.15	99
6938	07	MISC PROJECTS TO COMPLETE R1R2 - GAVIN	GAVIN 0	$ 79,268.95	99
6938	75	MISC PROJECTS TO COMPLETE R1R2 - GAVIN	GAVIN 0	$ 13,289.52	99
6939	02	ELEC UPGRADE INSTALLATION - AP	BYLLESBY 0	$ 11,319.24	99
6945	07	REMV HIGH PRESS/REHEAT ROTOR ASSMB - OP	MUSKINGUM RVR 3	$ 64,693.94	99
6946	70	INST MAIN CONDENSER TUBES - SPORN JT	SPORN 3	$ 559.55	99
6947	22	INST SILCIA ANALYZER - CARD	CARDINAL 3	$ 38,634.62	99
6948	22	REMV SILCIA ANALYZER - CARD	CARDINAL 3	$ 3,476.62	99
6949	22	INST COAL HANDLING CONTROLS - CARD	CARDINAL 3	$ 31,699.07	99
6950	22	REMV COAL HANDLING CONTROLS - CARD	CARDINAL 3	$ 2,257.73	99
6951	22	INST EXPANSION JT 1-34 - CARD	CARDINAL 1	$ 4,617.78	99
6952	22	REMV EXPANSION JT 1-34 - CARD	CARDINAL 1	$ 2,787.44	99

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WO	CO	TITLE/DESCRIPTION	AMOUNT	FORM
6956	07	REMV PRIMARY FURNACE ROOF TUBING - OP MUSKINGUM RVR 2	$ 58,210.55	99
6957	02	INST HEADGATE - AP BUCK 0	$ 46,375.09	99
6959	07	INST REHEAT OUTLET HDR & LEG TUBES - OP MUSKINGUM RVR 3	$ 12,680.34	99
6960	07	REMV REHEAT OUTLET HDR & LEG TUBES - OP MUSKINGUM RVR 3	$ 7,451.97	99
6961	07	INST REHEAT OUTLET HDR & LEG TUBES - OP MUSKINGUM RVR 4	$ 2,574.47	99
6962	07	REMV REHEAT OUTLET HDR & LEG TUBES - OP MUSKINGUM RVR 4	$ 59.39	99
6964	07	REMV LWR FURN WALLS & FLOOR TUBES - OP MUSKINGUM RVR 2	$ 37,170.33	99
6967	07	INST REARWALL & ARCH - OP MUSKINGUM RVR 4	$ 54,485.02	99
6968	07	REMV REARWALL & ARCH - OP MUSKINGUM RVR 4	$ 25,466.57	99
6969	07	INST SECONDARY SPRHEAT OUTLET BANK - OP MUSKINGUM RVR 3	$ 9,736.26	99
6970	07	REMV SECONDARY SPRHEAT OUTLET BANK - OP MUSKINGUM RVR 3	$ 80.92	99
6971	07	INST SECONDARY SPRHEAT OUTLET BANK - OP MUSKINGUM RVR 4	$ 1,496.99	99
6972	07	REMV SECONDARY SPRHEAT OUTLET BANK - OP MUSKINGUM RVR 4	$ 1,719.88	99
6973	07	INST REHEAT INTERMED & OULTED HEAD - OP MUSKINGUM RVR 3	$ 10,280.27	99
6975	07	INST REHEAT INTERMED & OULTED HEAD - OP MUSKINGUM RVR 4	$ 934.97	99
6977	73	INST IP INNER CASE & ROTOR ASSEMBLY-ROCKROCKPORT 1	$ 91,105.99	99
6979	07	INST LWR FURN WALLS & FLOOR TUBING - OP MUSKINGUM RVR 1	$ 7,171.17	99
6982	02	REMV EQUIP ASSOC W/UPGRADE PROJ - AP SMITH MTN 4	$ 38,320.24	99
6983	02	REMV T&D EQ ASSOC W/UPGRADE PROJ - AP SMITH MTN 2	$ 939.70	99
6984	02	REMV T&D EQ ASSOC W/UPGRADE PROJ - AP SMITH MTN 4	$ 92.41	99
6988	22	INST PLANT BATTERIES - CARD CARDINAL 3	$ 2,836.65	99
6989	22	REMV PLANT BATTERIES - CARD CARDINAL 3	$ 595.41	99
6990	22	INST GLYCOL HEAT DRAIN PIPE & MOTOR-CARDCARDINAL 3	$ 11,431.64	99
6991	22	REMV GLYCOL HEAT DRAIN PIPE & MOTOR-CARDCARDINAL 3	$ 5,272.64	99
6992	22	INST ZEBRA MUSSEL CONTROL - CARD CARDINAL 3	$ 820.08	99
6993	22	INST ASH PIT SUMP PUMPS - CARD CARDINAL 3	$ 8,023.67	99
6994	22	REMV ASH PIT SUMP PUMPS - CARD CARDINAL 3	$ 3,404.24	99
6995	04	INST CYCLONE WTR INJ SYS FOR NOX - I&M TANNERS CREEK 4	$ 68,796.19	99
6998	70	INST LOW NOX BURNERS - SPORN JT SPRON 5	$ 2,747.78	99
7000	07	INST 2NDARY SPRHTR OUTLET BANKS - OP MUSKINGUM RIVER 5	$ 39,749.89	99
7001	07	REMV 2NDARY SPRHTR OUTLET BANKS - OP MUSKINGUM RIVER 5	$ 8,738.83	99
7002	10	INST SPRHEAT SAFETY VALVES - CSP CONSEVILLE 5	$ 12,500.29	99
7003	10	REMV SPRHEAT SAFETY VALVES - CSP CONSEVILLE 5	$ 2,034.17	99
7004	10	INST COAL HANDLING CONTROLS - CSP CONSEVILLE 5,6	$ 22,479.22	99
7005	10	REMV COAL HANDLING CONTROLS - CSP CONSEVILLE 5,6	$ 2,902.16	99
7006	10	INST CRUSHER BUILDING FEED CONTROLS-CSP CONSEVILLE 5,6	$ 61,608.84	99
7008	10	INST WASTE WATER PUMP BEARING - CSP CONSEVILLE 6	$ 798.80	99
7009	10	REMV WASTE WATER PUMP BEARING - CSP CONSEVILLE 6	$ 556.59	99
7010	10	INST SCRUB EXPAN JTS EJ6A-1&6B-1 - CSP CONSEVILLE 6	$ 32,883.02	99
7011	10	REMV SCRUB EXPAN JTS EJ6A-1&6B-1 - CSP CONSEVILLE 6	$ 19,756.57	99
7012	10	INST SCRUB EXPAN JTS EJ5A-1&5B-1 - CSP CONSEVILLE 6	$ 23,584.27	99
7013	10	REMV SCRUB EXPAN JTS EJ5A-1&5B-1 - CSP CONSEVILLE 6	$ 19,171.41	99
7014	10	INST PRIMARY PREHEAT COIL - CSP CONSEVILLE 5	$ 1,361.83	99
7015	10	REMV PRIMARY PREHEAT COIL - CSP CONSEVILLE 5	$ 1,008.79	99
7016	10	INST TURBINE DRAIN VALVES - CSP CONSEVILLE 5	$ 20,300.29	99
7017	10	REMV TURBINE DRAIN VALVES - CSP CONSEVILLE 5	$ 18,432.82	99
7018	10	INST TURBINE DRAIN VALVES - CSP CONSEVILLE 6	$ 25,494.63	99
7019	10	REMV TURBINE DRAIN VALVES - CSP CONSEVILLE 6	$ 5,510.75	99
7020	10	INST CAPITAL SPARE PARTS - CSP CONSEVILLE 6	$ 28,618.95	99
7021	10	REMV CAPITAL SPARE PARTS - CSP CONSEVILLE 6	$ 19,980.91	99
7022	07	INST SPRING HANGERS FOR STEAM PIPE - OP MUSKINGUM RIVER 2	$ 37,588.55	99
7023	07	REMV SPRING HANGERS FOR STEAM PIPE - OP MUSKINGUM RIVER 2	$ 21,069.88	99
7024	07	INST SPRING HANGERS STEAM PIPE - OP MUSKINGUM RVR 4	$ 2,235.75	99
7025	07	REMV SPRING HANGERS STEAM PIPE - OP MUSKINGUM RVR 4	$ 1,464.67	99
7026	07	RETUBE #7 FEEDWATER HEATER - OP MUSKINGUM RVR 4	$ 8,684.87	99
7027	07	RETIRE TUBES #7 FEEDWATER HEATER - OP MUSKINGUM RVR 4	$ 8,137.06	99
7028	07	INST ANNUNCIATOR PANELS - OP MUSKINGUM RVR 4	$ 14,637.20	99
7029	07	REMV ANNUNCIATOR PANELS - OP MUSKINGUM RVR 4	$ 1,879.60	99
7030	07	INST REHEAT INTERMED & OUTLET BANK - OP KAMMER 1	$ 344.22	99
7032	07	INST 2NDARY SPRHEAT OUTLET BANK/HEAD-OP KAMMER 1	$ 344.22	99

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WO	CO	TITLE/DESCRIPTION	AMOUNT	FORM
7034	07	INST 2NDARY SPRHEAT OUTLET BANK/HEAD-OP KAMMER 2	$ 11,336.98	99
7035	07	REMV 2NDARY SPRHEAT OUTLET BANK/HEAD-OP KAMMER 2	$ 1,311.70	99
7036	07	INST REHEAT INTERMED & OUTLET BANK - OP KAMMER 2	$ 9,112.62	99
7037	07	REMV REHEAT INTERMED & OUTLET BANK - OP KAMMER 2	$ 1,258.47	99
7038	07	INST 2NDARY SPRHEAT OUTLET BANK/HEAD-OP KAMMER 3	$ 1,377.67	99
7040	07	INST REHEAT INTERMED & OUTLET BANK - OP KAMMER 3	$ 1,177.73	99
7044	73	INST WATER FEED TO AK STEEL - ROCK ROCKPORT 1	$ 7,341.40	99
7045	73	INST 2NDARY SPRHEATER ALIGN CAST - ROCK ROCKPORT 1	$ 1,535.11	99
7046	73	REMV 2NDARY SPRHEATER ALIGN CAST - ROCK ROCKPORT 1	$ 107.10	99
7047	73	INST ECONOMIZER SUPPORT RODS - ROCK ROCKPORT 1	$ 437.28	99
7050	71	REMOVE BURNERS - AMOS JT AMOS 3	$ 3,777.91	99
7052	71	INST ASH HOPPER SEAL SKIRT - AMOS JT AMOS 3	$ 2,010.40	99
7053	71	REMV ASH HOPPER SEAL SKIRT - AMOS JT AMOS 3	$ 371.57	99
7054	02	INST CONDENSATE FLOW CONTROLS - AP CLINCH 2	$ 8,006.47	99
7055	02	REMV CONDENSATE FLOW CONTROLS - AP CLINCH 2	$ 7,622.37	99
7056	02	INST COOL TWR SOUTH HOTWTR HEADER - AP CLINCH 2	$ 3,776.32	99
7057	02	REMV COOL TWR SOUTH HOTWTR HEADER - AP CLINCH 2	$ 242.67	99
7059	02	REMV CRT SCREEN CONTROL SYSTEM - AP CLINCH 2	$ 7,219.43	99
7060	07	INST FOAM TANKS TURB ROOM FOAM SYS - OP GAVIN 0	$ 39,419.09	99
7061	07	REMV FOAM TANKS TURB ROOM FOAM SYS - OP GAVIN 0	$ 5,735.52	99
7064	07	INST CONDENSER TUBES - OP GAVIN 2	$ 32.40	99
7066	10	INST UNINTERRUPT POWER SUPPLY - CSP CONESVILLE 5	$ 32,587.34	99
7067	10	REMV UNINTERRUPT POWER SUPPLY - CSP CONESVILLE 5	$ 164.49	99
7068	10	INST 3 DRUM SAFETY VALVES - CSP CONESVILLE 1	$ 2,831.97	99
7070	10	INST 5 DRUM SAFETY VALVES - CSP CONESVILLE 6	$ 20,037.60	99
7071	10	REMV 5 DRUM SAFETY VALVES - CSP CONESVILLE 6	$ 5,705.85	99
7074	10	INST SCRUBBER GRATING - CSP CONESVILLE 6	$ 38,970.89	99
7076	10	INST CONTROL ROOM RECORDER - CSP CONESVILLE 5	$ 27,798.29	99
7077	10	REMV CONTROL ROOM RECORDER - CSP CONESVILLE 5	$ 2,751.02	99
7078	10	INST RECYCLE PUMP SUCTION VALVES - CSP CONESVILLE 5	$ 6,156.23	99
7079	10	REMV RECYCLE PUMP SUCTION VALVES - CSP CONESVILLE 5	$ 1,006.32	99
7080	10	INST RECYCLE PUMP SUCTION VALVES - CSP CONESVILLE 6	$ 4,895.47	99
7081	10	REMV RECYCLE PUMP SUCTION VALVES - CSP CONESVILLE 6	$ 955.19	99
7084	10	INST BOILER & STEAM TEMP CONTROL - CSP CONESVILLE 1	$ 2,692.39	99
7086	10	INST FORCED DRAFT FAN BEARING - CSP CONESVILLE 1	$ 498.63	99
7087	10	INST FURNACE TUBE PANELS - CSP CONESVILLE 5	$ 29,913.51	99
7088	10	REMV FURNACE TUBE PANELS - CSP CONESVILLE 5	$ 16,122.18	99
7089	10	INST FURNACE TUBE PANELS - CSP CONESVILLE 6	$ 31,161.94	99
7090	10	REMV FURNACE TUBE PANELS - CSP CONESVILLE 6	$ 37,260.75	99
7091	22	INST LOW NOX BURNERS - CARD CARDINAL 1	$ 18,785.36	99
7093	22	INST LOW NOX BURNERS - CARD CARDINAL 2	$ 6,089.86	99
7095	07	INST OSCILLOGRAH - OP MUSKINGUM RVR 3	$ 21,846.55	99
7096	07	REMV OSCILLOGRAH - OP MUSKINGUM RVR 3	$ 4,011.84	99
7097	07	INST PRECIPITATOR EXPAN JT 4-1 - OP MUSKINGUM RVR 4	$ 115.19	99
7098	07	REMV PRECIPITATOR EXPAN JT 4-1 - OP MUSKINGUM RVR 4	$ 1,378.33	99
7100	07	REMV #25 COAL SCALE - OP MUSKINGUM RVR 5	$ 731.75	99
7101	07	INST INLET NOZZLE VANES - OP MUSKINGUM RVR 3	$ 11,169.67	99
7102	07	REMV INLET NOZZLE VANES - OP MUSKINGUM RVR 3	$ 1,357.87	99
7103	07	INST INLET NOZZLE VANES - OP MUSKINGUM RVR 4	$ 1,168.10	99
7104	07	REMV INLET NOZZLE VANES - OP MUSKINGUM RVR 4	$ 190.06	99
7105	07	GENERATOR CHANGEOUT INSTALL - OP GAVIN 1	$ 96,777.45	99
7106	07	GENERATOR CHANGEOUT REMOVAL - OP GAVIN 1	$ 54,254.46	99
7107	07	INST AIR HEAT ROTORS & ELEMENTS - OP MITCHELL 2	$ 88,869.32	99
7108	07	REMV AIR HEAT ROTORS & ELEMENTS - OP MITCHELL 2	$ 161.03	99
7110	07	REMV AIR HEAT ROTORS & ELEMENTS - OP MITCHELL 1	$ 44,381.49	99
7111	70	INST FAULT MONITOR SYSTEM - SPORN JT SPORN 5	$ 20,851.02	99
7112	70	REMV FAULT MONITOR SYSTEM - SPORN JT SPORN 5	$ 4,079.93	99
7114	70	REMV HIGH PRESSURE TURB RTR - SPORN JT SPORN 5	$ 2,828.33	99
7115	70	INST HIGH PRESSURE TURB PACK - SPORN JT SPORN 5	$ 518.63	99
7117	70	INST FAULT MONITORING SYSTEM - SPORN JT SPORN 1	$ 34,537.98	99

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WO	CO	TITLE/DESCRIPTION	AMOUNT	FORM
7118	70	REMV FAULT MONITORING SYSTEM - SPORN JT SPORN 1	$ 13,182.11	99
7119	70	INST ROTATE EQUIP MONITOR - SPORN JT SPORN 1	$ 4,961.39	99
7120	10	INST SCRUBBER DAMPER DIRVE CHAINS - CSP CONESVILLE 6	$ 23,917.11	99
7121	10	REMV SCRUBBER DAMPER DIRVE CHAINS - CSP CONESVILLE 6	$ 5,878.41	99
7122	71	INST LOW NOX BURNER MODIFICATN - AMOS JTAMOS 2	$ 61,437.77	99
7123	07	INST BOILER FEED PUMP TURBINE RTR - OP KAMMER 1	$ 3,154.03	99
7125	07	INST 2NDARY AIR CONTROL DAMP DRIVE - OP KAMMER 1	$ 12,735.50	99
7126	07	REMV 2NDARY AIR CONTROL DAMP DRIVE - OP KAMMER 1	$ 5,448.59	99
7127	07	INST COAL FEEDER CONTROLS - OP KAMMER 1	$ 18,404.84	99
7129	07	INST BASEMENT FOAM SYSTEM & TANK - OP KAMMER 1	$ 8,747.43	99
7131	07	INST TRIP SEQUENCE SYSTEM - OP KAMMER 1	$ 34,982.63	99
7133	02	INST LOW NOX INSTRUMENTATION - AP CLINCH RVR 2	$ 53,410.52	99
7134	02	REMOVE CONTROL INSTRUMENTATION - AP CLINCH RVR 2	$ 14,582.09	99
7136	07	FLY ASH DAM RAISING - OP MUSKINGUM RVR 5	$ 4,320.61	99
7137	04	INST CURRENT BATTERIES - I&M TANNERS CREEK 1	$ 4,707.02	99
7138	04	REMV CURRENT BATTERIES - I&M TANNERS CREEK 1	$ 2,063.03	99
7139	04	INST CURRENT BATTERIES - I&M TANNERS CREEK 2	$ 2,340.81	99
7140	04	REMV CURRENT BATTERIES - I&M TANNERS CREEK 2	$ 797.24	99
7145	07	INST SOOTBLOWER CONTROLS - OP MITCHELL 1	$ 7,408.84	99
7146	07	REMV SOOTBLOWER CONTROLS - OP MITCHELL 1	$ 273.61	99
7149	07	INST PRECIPITATOR EXPAN JOINTS - OP MITCHELL 1	$ 65,888.13	99
7150	07	REMV PRECIPITATOR EXPAN JOINTS - OP MITCHELL 1	$ 17,610.65	99
7151	07	INST SIDEWALL CASING - OP MITCHELL 1	$ 2,666.12	99
7152	07	REMV SIDEWALL CASING - OP MITCHELL 1	$ 5,635.67	99
7153	07	INST LOW PRESSURE B TURBINE ROTOR - OP MITCHELL 1	$ 91,523.28	99
7154	07	REMV LOW PRESSURE B TURBINE ROTOR - OP MITCHELL 1	$ 51,099.12	99
7155	07	INST LOW PRESSURE HEATER #2 - OP KAMMER 1	$ 9,290.91	99
7156	07	REMV LOW PRESSURE HEATER #2 - OP KAMMER 1	$ 21,524.18	99
7157	07	INST AIR HEATER SEALS - OP KAMMER 1	$ 40,927.66	99
7158	07	REMV AIR HEATER SEALS - OP KAMMER 1	$ 8,761.26	99
7160	07	REMV HIGH PRESSURE GENERATOR FIELD - OP GAVIN 2	$ 36,058.26	99
7161	07	INST REHEAT STEAM LEAD INSULATION - OP GAVIN 2	$ 400.34	99
7163	70	INST EMER ACCESS ROAD&FENCE - SPORN JT SPORN 0	$ 362.64	99
7166	22	INST ACOUSTICAL DIFFUSER - CARD CARDINAL 3	$ 23,511.50	99
7168	10	REMV THROTTLE VALVE BODY - CSP CONESVILLE 1	$ 2,857.04	99
7169	70	INST STEAM COIL AIR PREHEATRS - SPORN JTSPORN 5	$ 28,177.48	99
7171	22	INST BRKR STA SCALP SCREEN & CRUSHR-CARDCARDINAL 3	$ 13,263.89	99
7172	22	REMV BRKR STA SCALP SCREEN & CRUSHR-CARDCARDINAL 3	$ 1,275.13	99
7173	07	INST PANEL ANNUNCATORS BETA SYSTEM - OP GAVIN 2	$ 1,872.61	99
7174	07	REMV PANEL ANNUNCATORS BETA SYSTEM - OP GAVIN 2	$ 2,797.72	99
7175	10	INST BOILER DAMPER CONTROL DRIVES - CSP CONESVILLE 5	$ 35,808.27	99
7176	10	REMV BOILER DAMPER CONTROL DRIVES - CSP CONESVILLE 5	$ 8,465.74	99
7177	07	INST I R SOOTBLOWERS - OP KAMMER 1	$ 8,619.87	99
7178	07	REMV I R SOOTBLOWERS - OP KAMMER 1	$ 3,531.42	99
7181	07	INST RH GENERATOR ROTOR CHANGEOUT - OP GAVIN 1	$ 20,798.36	99
7182	07	REMV RH GENERATOR ROTOR CHANGEOUT - OP GAVIN 1	$ 16,467.65	99
7183	10	INST BFP TURBINE SEALS - CSP CONESVILLE 5	$ 11.00	99
7185	03	INST EXTN FLY ASH RETENTION DAM - KP BIG SANDY 0	$ 10,839.50	99
7188	02	INST CONVEYOR FIRE PROCTECT - AP GLEN LYN 5/6	$ 40,073.11	99
7189	02	INST P.A. SYSTEM UPGRADE - AP GLEN LYN 5/6	$ 2,229.91	99
7192	02	FIBER OPTIC CABLE 138KV YARD - AP GLEN LYN 6	$ 379.84	99
7194	02	INST SCREW AIR COMPRESSOR REPLC - AP GLEN LYN 6	$ 16,623.03	99
7195	02	REMV SCREW AIR COMPRESSOR REPLC - AP GLEN LYN 6	$ 152.20	99
7196	02	INST CAR SHAKER REPLACEMENT - AP GLEN LYN 6	$ 9,209.18	99
7197	02	REMV CAR SHAKER REPLACEMENT - AP GLEN LYN 6	$ 3,396.39	99
7198	02	INST ELEC UPGRADE OFF BLDG - AP GLEN LYN 6	$ 16,767.05	99
7200	71	PLT CAP SPARE PART INST O/H-AMOS JT AMOS UNITS 1 AND 2	$ 72,424.78	99
7201	71	PLT CAP SPARE PART INST O/H-AMOS JT AMOS UNIT 3	$ 20,124.36	99
7205	03	PLT CAP SPARE PART INST O/H - KP BIG SANDY	$ 1,564.61	99
7206	22	PLT CAP SPARE PART INST O/H - CARD CARDINAL UNIT 1	$ 68.62	99

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WO	CO	TITLE/DESCRIPTION		AMOUNT	FORM
7207	02	PLT CAP SPARE PART INST O/H - AP	CLINCH RIVER	$ 620.93	99
7208	10	PLT CAP SPARE PART INST O/H - CSP	CONSEVILLE UNIT 4	$ 25.20	99
7209	10	PLT CAP SPARE PART INST O/H - CSP	CONESVILLE UNITS 1,2,3,5 AND 6	$ 979.15	99
7210	07	PLT CAP SPARE PART INST O/H - OP	GAVIN	$ 5,332.70	99
7211	02	PLT CAP SPARE PART INST O/H - AP	GLEN LYN	$ 1,511.12	99
7212	07	PLT CAP SPARE PART INST O/H - OP	KAMMER	$ 272.20	99
7214	07	PLT CAP SPARE PART INST O/H - OP	MITCHELL	$ 991.18	99
7215	02	PLT CAP SPARE PART INST O/H - AP	MOUNTAINEER	$ 3,699.27	99
7217	07	PLT CAP SPARE PART INST O/H - OP	MUSKINGUM 5	$ 1,302.66	99
7219	73	PLT CAP SPARE PART INST O/H - ROCK	ROCKPORT	$ 9,335.48	99
7220	70	PLT CAP SPARE PART INST O/H-SPORN JT	SPORN UNITS 1 AND 3	$ 6,571.15	99
7221	70	PLT CAP SPARE PART INST O/H-SPORN JT	SPORN UNITS 2, 4, AND 5	$ 41,260.58	99
7222	04	PLT CAP SPARE PART INST O/H - I&M	TANNERS CREEK	$ 9,140.34	99
7223	07	PLT CAP SPARE PART INST O/H - OP	GAVIN SCRUBBER	$ 415.02	99
7235	71	PLT CAP SPARE PART RTRM O/H-AMOS JT	AMOS UNITS 1 AND 2	$ 15,503.65	99
7236	71	PLT CAP SPARE PART RTRM O/H-AMOS JT	AMOS UNIT 3	$ 12,309.09	99
7240	03	PLT CAP SPARE PART RTRM O/H - KP	BIG SANDY	$ 170.97	99
7241	22	PLT CAP SPARE PART RTRM O/H - CARD	CARDINAL UNIT 1	$ 124.92	99
7242	02	PLT CAP SPARE PART RTRM O/H - AP	CLINCH RIVER	$ 210.26	99
7245	07	PLT CAP SPARE PART RTRM O/H - OP	GAVIN	$ 6,609.97	99
7246	02	PLT CAP SPARE PART RTRM O/H - AP	GLEN LYN	$ 1,463.51	99
7251	07	PLT CAP SPARE PART RTRM O/H - OP	MUSKINGUM 1-4	$ 27,227.31	99
7254	73	PLT CAP SPARE PART RTRM O/H - ROCK	ROCKPORT	$ 5,672.03	99
7255	70	PLT CAP SPARE PART RTRM O/H-SPORN JT	SPORN UNITS 1 AND 3	$ 5,298.89	99
7256	70	PLT CAP SPARE PART RTRM O/H-SPORN JT	SPORN UNITS 2, 4, AND 5	$ 24,776.00	99
7257	04	PLT CAP SPARE PART RTRM O/H - I&M	TANNERS CREEK	$ 4,587.92	99
7258	07	PLT CAP SPARE PART RTRM O/H - OP	GAVIN SCRUBBER	$ 532.78	99
7300	71	PERFORM COAL ANALYSIS RECD FUEL - AMOS	AMOS	$ 30,202.13	99
7301	71	PERFORM COAL ANALYSIS CONSUMED FUEL-AMOS	AMOS	$ 7,719.46	99
7302	03	PERFORM COAL ANALYSIS CONS/RECD FUEL-KP	BIG SANDY	$ 32,375.14	99
7303	22	PERFORM COAL ANALYS CONS/RECD FUEL-CARD	CARDINAL	$ 36,326.75	99
7304	02	PERFORM COAL ANALYSIS RECD FUEL - AP	CLINCH RIVER	$ 16,442.02	99
7305	02	PERFORM COAL ANALYSIS CONS FUEL - AP	CLINCH RIVER	$ 2,542.40	99
7306	10	PERFORM COAL ANALYSIS CONS/RECD FUEL-CSP	CONESVILLE	$ 46,296.33	99
7307	07	PERFORM COAL ANALYSIS CONS/RECD FUEL-OP	GAVIN	$ 28,240.75	99
7308	02	PERFORM COAL ANALYSIS RECD FUEL-AP	GLEN LYN	$ 15,699.06	99
7309	02	PERFORM COAL ANALYSIS CONS FUEL-AP	GLEN LYN	$ 9,318.89	99
7310	07	PERFORM COAL ANALYSIS RECD/CONS FUEL-OP	KAMMER	$ 14,664.96	99
7311	02	PERFORM COAL ANALYSIS RECD FUEL-AP	KANAWHA RIVER	$ 14,849.22	99
7312	02	PERFORM COAL ANALYSIS CONS FUEL-AP	KANAWHA RIVER	$ 4,272.73	99
7313	07	PERFORM COAL ANALYSIS CONS/RECD FUEL-OP	MITCHELL	$ 17,874.69	99
7314	02	PERFORM COAL ANALYSIS RECD FUEL-AP	MOUNTAINEER	$ 22,358.26	99
7315	02	PERFORM COAL ANALYSIS CONS FUEL-AP	MOUNTAINEER	$ 4,433.91	99
7316	07	PERFORM COAL ANALYSIS CONS/RECD FUEL-OP	MUSKINGUM RIVER	$ 26,018.85	99
7317	10	PERFORM COAL ANALYSIS CONS/RECD FUEL-CSP	PICWAY	$ 8,623.19	99
7318	73	PERFORM COAL ANALYS CONS/RECD FUEL-ROCK	ROCKPORT	$ 26,609.09	99
7319	70	PERFORM COAL ANALYSIS RECD FUEL-SPORN	SPORN	$ 27,932.38	99
7320	70	PERFORM COAL ANALYSIS CONS FUEL-SPORN	SPORN	$ 6,097.14	99
7321	04	PERFORM COAL ANALYSIS CONS/RECD FUEL-I&M	TANNER CREEK	$ 35,412.16	99
7401	02	REMV TRASH RAKES REPLACEMENT - AP	GLEN LYN 5	$ 1,649.12	99
7403	02	REMV HG CONTROL RM INST RPLCMT - AP	GLEN LYN 6	$ 40,136.88	99
7404	02	INST BOILER TUBE TEMP MONITOR - AP	GLEN LYN 6	$ 40,076.65	99
7405	02	REMV BOILER TUBE TEMP MONITOR - AP	GLEN LYN 6	$ 687.02	99
7406	02	FIRE PROTECITION UPGRADE - AP	GLEN LYN 5	$ 71,696.80	99
7407	02	INST ELEVATOR REPLACEMENT - AP	GLEN LYN 5	$ 626.26	99
7410	02	REMV 13.8KV SWITCHGEAR REPLACEMENT - AP	GLEN LYN 6	$ 3,460.68	99
7412	02	REMV PRECIPITATOR ROOF - AP	GLEN LYN 6	$ 95,412.78	99
7413	02	INST BOILER ROOM SUMP PUMP REPLCMT - AP	GLEN LYN 6	$ 28,979.72	99
7414	02	REMV BOILER ROOM SUMP PUMP REPLCMT - AP	GLEN LYN 6	$ 1,512.65	99
7415	02	INST PIPE HANGERS - AP	GLEN LYN 6	$ 12,520.96	99

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WO	CO	TITLE/DESCRIPTION		AMOUNT	FORM
7417	02	INST FD FAN INLET VANE REPLACE E&W - AP GLEN LYN 6		$ 2,478.26	99
7418	02	REMV FD FAN INLET VANE REPLACE E&W - AP GLEN LYN 6		$ 170.34	99
7419	02	INST COAL CONVEYOR #3 MODIFICATIONS-AP GLEN LYN 6		$ 70,292.94	99
7420	02	REMV COAL CONVEYOR #3 MODIFICATIONS-AP GLEN LYN 6		$ 1,322.10	99
7421	02	INST COAL BUNKERS 6A-6F MODIFICATION-AP GLEN LYN 6		$ 12,667.59	99
7422	02	REMV COAL BUNKERS 6A-6F MODIFICATION-AP GLEN LYN 6		$ 3,999.41	99
7423	02	INST HG INSTRUMENTS REPLACEMENT - AP GLEN LYN 6		$ 24,096.90	99
7425	02	INST URLITE BREAKERS 440V REPLCMNT - AP GLEN LYN 6		$ 47,763.11	99
7426	02	REMV URLITE BREAKERS 440V REPLCMNT - AP GLEN LYN 6		$ 2,614.91	99
7429	02	INST ELEC RECEPTACLES REPLACEMENT - AP GLEN LYN 6		$ 5,709.04	99
7433	02	INST INSULATION ON PIPING - AP GLEN LYN 6		$ 42,438.14	99
7434	02	REMV INSULATION ON PIPING - AP GLEN LYN 6		$ 59,744.37	99
7435	02	REMV UPGRADE CRUSHER & CHUTE - AP GLEN LYN 6		$ 326.04	99
7436	07	INST ROTATING THROAT ASSMB #1PULV - OP MUSKINGUM RVR 5		$ 366.49	99
7437	07	REMV ROTATING THROAT ASSMB #1PULV - OP MUSKINGUM RVR 5		$ 196.98	99
7438	73	INST BOILER FEED PUMP TURB ROTOR - ROCK ROCKPORT 1		$ 2,791.83	99
7441	10	INST PORTABLE WATER FILTERS - CSP CONESVILLE 0		$ 12,654.50	99
7444	02	INST ASH HOPPER DOG HOUSE - AP GLEN LYN 6		$ 10,675.22	99
7445	02	REMV ASH HOPPER DOG HOUSE - AP GLEN LYN 6		$ 6,841.67	99
7446	02	INST CONVEYOR FIRE PROTECTION - AP GLEN LYN 5/6		$ 366.49	99
7447	04	INST PENTHOUSE INNER CASING & INSUL-I&M TANNERS CREEK 4		$ 40,976.57	99
7449	04	SECENDARY,INTERMED,OUTLET BANKS,HEAD-I&MINSTALLATION	TANNERS CREEK 4	$ 20,178.79	99
7451	04	INST THRID PASS TUB PANELS - I&M TANNERS CREEK 4		$ 20,883.27	99
7452	04	REMV THRID PASS TUB PANELS - I&M TANNERS CREEK 4		$ 1,076.74	99
7453	07	INST REPLACE #2 ELEC FIRE PUMP - OP KAMMER 0		$ 2,287.44	99
7460	02	INST FEEDWTR MOTOR OPERATED VALVES - AP GLEN LYN 6		$ 5,494.92	99
7461	02	REMV FEEDWTR MOTOR OPERATED VALVES - AP GLEN LYN 6		$ 581.61	99
7462	07	INST LOW NOX BURNERS - 0P GAVIN 2		$ 4,090.11	99
7463	07	REMV LOW NOX BURNERS - 0P GAVIN 2		$ 169.57	99
7464	07	INST LOW NOX BURNERS - 0P GAVIN 1		$ 9,144.06	99
7466	02	INST COAL PILE TRESTLE - AP GLEN LYN 0		$ 245.48	99
7467	02	REMV COAL PILE TRESTLE - AP GLEN LYN 0		$ 12,620.05	99
7468	07	INST SULPHURIC ACID TANK - OP GAVIN 0		$ 7,590.10	99
7469	07	REMV SULPHURIC ACID TANK - OP GAVIN 0		$ 1,043.78	99
7471	04	REMV CHANGEOUT SEALS IN TOTAL - I&M TANNERS CREEK 4		$ 851.50	99
7472	10	INST EMER TRIP DEVICE #1 TURB - CSP CONESVILLE 1		$ 2,081.85	99
7473	10	REMV EMER TRIP DEVICE #1 TURB - CSP CONESVILLE 1		$ 2,306.43	99
7474	07	INST PA SYSTEM U3 - OP MUSKINGUM RVR 3		$ 407.97	99
7477	10	INST SURGE TANK/WASTE WATER PROBLEM-CSP CONESVILLE 0		$ 10,480.37	99
7481	04	REMV MAIN EXCITER REWIND - I&M TANNERS CREEK 4		$ 4,004.56	99
7486	02	PURCHASCE WTR SOFTNERS TREAT PLANT - AP GLEN LYN 0		$ 5,542.41	99
7489	07	INST SPRING HNAGERS - OP MUSKINGUM RVR 5		$ 2,343.75	99
7494	07	REMV SEAL SKIRT - OP MUSKINGUM RVR 5		$ 897.65	99
7499	07	INST EXPANSION JOINT #5-25 - OP MUSKINGUM RVR 5		$ 5,682.75	99
7505	07	INST BURNER TIP TEMP THERMOCOUPLES - OP MUSKINGUM RVR 5		$ 1,085.56	99
7517	07	INST EXPANSION JOINT #5-37A - OP MUSKINGUM RVR 5		$ 1,015.50	99
7521	07	INST INLET NOZZLE VANES TO PRECIP - OP MUSKINGUM RVR 3		$ 1,808.71	99
7522	07	REMV INLET NOZZLE VANES TO PRECIP - OP MUSKINGUM RVR 3		$ 2,270.55	99
7526	07	INST BURNER REGISTER CONTROLS - OP MUSKINGUM RVR 5		$ 9,093.22	99
7530	02	INST BARGE HAUL CONTROL SYSTEM - AP MOUNTAINEER 0		$ 19,282.64	99
7531	02	REMV BARGE HAUL CONTROL SYSTEM - AP MOUNTAINEER 0		$ 3,535.62	99
7532	02	STRUCTURAL MONITORING SYSTEM - AP SMITH MOUNTAIN 0		$ 79,417.13	99
7533	07	RETIRE GUNNITE FROM AIR HEAT TO STACK-OPMUSKINUM RVR 3		$ 6,370.29	99
7535	02	PURCH&INST 6 TANK PUMP CHECK VALVES - APGLEN LYN 5		$ 136.35	99
7539	70	INST SOOTBLOWER CONTROL SYSTEM-SPORN JT SPORN 4		$ 16,010.10	99
7542	07	INST FLY ASH PRECIP PIP SYS MODF - OP GAVIN 2		$ 381.67	99
7543	71	INST LPA & BPB TURBINE ROTORS - AMOS JT AMOS 3		$ 21,156.75	99
7544	71	REMV LPA & BPB TURBINE ROTORS - AMOS JT AMOS 3		$ 4,791.15	99
7545	07	INST BOTTOM ASH SUBPANEL RELO - OP GAVIN 2		$ 242.15	99
7547	03	INST LOW NOX BURNERS - KP BIG SANDY 1		$ 76,096.42	99

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WO	CO	TITLE/DESCRIPTION		AMOUNT	FORM
7548	03	REMV LOW NOX BURNERS - KP BIG SANDY 1	$	3,024.94	99
7549	22	INST LOW NOX BURNERS - CARD CARDINAL 3	$	23,939.88	99
7551	04	RELICENSING PROJECT - I&M MOTTVILLE HYDRO 0	$	8,996.56	99
7553	07	PURCHASE WDPF CABINET #4 - OP MITCHELL 1	$	5,240.84	99
7558	07	INST 2 PRV VALVES - OP MITCHELL 1	$	5,253.96	99
7562	07	INST FRONT SCREEN TUBE WALL - OP MITCHELL 1	$	13,968.85	99
7563	07	REMV FRONT SCREEN TUBE WALL - OP MITCHELL 1	$	421.55	99
7564	07	INST FEEDWATER REGULATOR - OP MITCHELL 1	$	2,331.44	99
7568	03	PURCHASE & INST COAL FEEDER - KP BIG SANDY 1	$	7,746.01	99
7569	02	MOVABLE SPILLWAY BULKHEAD FABRCTN - AP REUSENS 0	$	9,718.79	99
7571	02	REMV INSUL ON ESP ASH HOPPERS HEATER-AP GLEN LYN 6	$	275.35	99
7575	07	INST FORCED DRAFT FAN VANE DRIVES - OP MUSKINGUM RVR 5	$	1,103.82	99
7579	03	INST SOOTBLOWER CONTROL PANELS - KP BIG SANDY 1	$	6,332.97	99
7580	03	REMV SOOTBLOWER CONTROL PANELS - KP BIG SANDY 1	$	741.00	99
7590	03	INST AIR HEATER CLEANING DEVICE - KP BIG SANDY 1	$	281.81	99
7592	71	INST HP HEATER LEVEL ALARMS - AMOS JT AMOS 3	$	14,246.38	99
7595	71	INST COAL FEED SPEED DRIVE - AMOS JT AMOS 3	$	16,700.38	99
7599	71	INST TRNSFMR FIRE DETECT SYS - AMOS JT AMOS 3	$	3,198.76	99
7601	71	INST BATTERY CHARGER - AMOS JT AMOS 3	$	4,015.58	99
7602	71	INST INVERTER - AMOS JT AMOS 3	$	18,523.73	99
7606	71	INST EXHAUST HOOD PIPE LP1&2 - AMOS JT AMOS 3	$	2,047.39	99
7612	07	INST ROTATIONG THROAT - OP MUSKINGUM RVR 5	$	8,662.00	99
7613	07	REMV ROTATIONG THROAT - OP MUSKINGUM RVR 5	$	3,554.24	99
7616	07	INST SEWAGE TREATMENT SYS - OP MITCHELL 0	$	25,020.71	99
7617	07	REMV P A SYSTEM - OP MUSKINGUM RVR 3	$	71.48	99
7620	07	INST HP INNER CASING & ROTOR - OP GAVIN 1	$	48.44	99
7630	73	REMV COAL FEEDER PIPES - ROCK ROCKPORT 2	$	271.67	99
7632	73	REMV WATER LANCE SOOTBLOWERS - ROCK ROCKPORT 2	$	4,607.14	99
7634	71	REMV GEN & EXCITER RETAIN RINGS-AMOS JT AMOS 3	$	7,043.98	99
7635	07	INST HP GENERATOR ROTOR - OP GAVIN 2	$	(54,545.46)	99
7637	02	INST HP STATIC EXCITER - AP GLEN LYN 6	$	9,771.88	99
7643	22	INST PAVING U 1 & 2 PARKING LOT - CARD CARDINAL 1 & 2	$	26.68	99
7647	07	REMV GUNNITE ON DUCT - OP MUSKINGUM RVR 4	$	9,644.48	99
7649	02	COAL SIZING GRID FOR 8-1 CRUSHER - AP MOUNTAINEER 0	$	10,376.18	99
7651	22	INST PULVERIZER GEAR BOX - CARD CARDINAL 2	$	23,063.30	99
7652	22	REMV PULVERIZER GEAR BOX - CARD CARDINAL 2	$	11,273.37	99
7653	70	INST LOAD REJECT AUTO SYS - SPORN JT SPORN 2	$	5,119.42	99
7655	02	INST BARGE UNLOADER CONTROL SYS - AP KANAWHA RVR 0	$	15,725.67	99
7657	07	INST DUST COLLECTORS ON GAS FANS - OP KAMMER 2	$	2,637.95	99
7663	07	INST PENTHOUSE CASING & INSULATION - OP KAMMER 1	$	855.86	99
7665	07	INST PENTHOUSE CASING & INSULATION - OP KAMMER 2	$	4,203.16	99
7667	07	INST PENTHOUSE CASING & INSULATION - OP KAMMER 3	$	2,287.54	99
7673	22	REMV BOILER SEAL SKIRT - CARD CARDINAL 2	$	198.94	99
7674	04	INST LOW NOX BURNER SYS & INJECT AIR-I&MTANNERS CREEK	$	12,555.95	99
7680	75	INST ACOUSTIC EMISSN TEST SYS - GAVIN GAVIN 2	$	120.94	99
7700	04	LPG ROTOR COST POSSIBLE ROTOR GROUND-I&MTANNERS CREEK 3	$	8,884.30	99
7703	04	INST CONTROLS UPGRADE CRT - I&M TANNERS CREEK 2	$	397.39	99
7704	04	REMV CONTROLS UPGRADE CRT - I&M TANNERS CREEK 2	$	258.47	99
7705	04	INST TURBINE SUPERVISORY INSTRUMENT-I&M TANNERS CREEK 1	$	1,712.45	99
7707	04	INST PRIMARY AIR FAN UPGRADE - I&M TANNERS CREEK 1	$	3,866.95	99
7709	04	INST CONTROLS UPGRADE CRT - I&M TANNERS CREEK 1	$	5,975.24	99
7711	04	INST LOW NOX FLAME MONITOR CAMERAS - I&MTANNERS CREEK 1	$	2,115.15	99
7715	22	REPAIR 10/27/97 SLIDE AT DAM CONSTR-CARDCARDINAL 0	$	35,228.19	99
7717	22	REMV OUTDOOR STEAM PIPE INSUL - CARD CARDINAL 2	$	328.13	99
7719	02	INST CENTAC AIR COMPRESSOR - AP CLINCH RIVER 0	$	7,067.12	99
7725	10	INST SULFURIC ACID STORE/MIX TANKS - CSPPICWAY 0	$	8,454.59	99
7726	10	REMV SULFURIC ACID STORE/MIX TANKS - CSPPICWAY 0	$	3,105.74	99
7739	10	INST REMOTE RIS ANNUNCIATOR REPLCMNT-CSPCONESVILLE 4	$	3,239.23	99
7741	10	INST WATER TREATMENT SLAKERS - CSP CONESVILLE 4	$	1,499.26	99
7745	10	INST BURNER TILT LINKAGES/DRIVES - CSP CONESVILLE 4	$	3,912.96	99

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WO	CO	TITLE/DESCRIPTION		AMOUNT	FORM
7757	07	INST INSTRUMENT REGEN CABINETS & PIPE-OPMUSKINGUM RVR 5	$	734.39	99
7773	02	INST BOILER 51 ECON BANK REPLACEMENT-AP GLEN LYN 5	$	957.52	99
7775	04	INST RETUBE U1 CONDNSR W/ARSNC COPPR-I&MTANNERS CREEK 1	$	3,860.79	99
7776	04	REMV RETUBE U1 CONDNSR W/ARSNC COPPR-I&MTANNERS CREEK 1	$	3,754.26	99
8600	61	COMPUTER STUDIES DEFERRED FOR OUTSIDE BILLING	$	26,476.28	99
8601	02	IPE RUBBER GOODS TESTING - AP TESTING OF IPE RUBBER GOODS FOR APCO ANDTHIRD PAR	$	917.98	99
8602	10	IPE RUBBER GOODS TESTING - CSP TESTING OF IPE RUBBER GOODS FOR CSPCO AND THIRD	$	269.41	99
8603	04	IPE RUBBER GOODS TESTING - I&M TESTING OF IPE RUBBER GOODS FOR I&M AND THIRD PART	$	3,872.76	99
8604	03	IPE RUBBER GOODS TESTING - KP TESTING OF IPE RUBBER GOODS FOR KPCO ANDTHIRD PAR	$	446.32	99
8606	07	IPE RUBBER GOODS TESTING - OP TESTING OF IPE RUBBER GOODS FOR OPCO ANDTHIRD PA	$	459.90	99
8607	06	IPE RUBBER GOODS TESTING - WP TESTING OF IPE RUBBER GOODS FOR WPCO ANDTHIRD PA	$	107.60	99
8608	02	CWF PUBLIC COMM SYS INSTALLATION - AP SERVICES IN SUPPORT OF CWF COMM COMPANY PCS	$	77,196.46	99
8609	10	AMER PORT TELCOMM PUBL COMM SYS INST-CSPSERVICES IN SUPPORT OF APT PCS NETWORK	$	37,415.20	99
8610	10	AT&T WIRELESS PUBL COMM SYS INST - CSP SERVICES IN SUPPORT OF AT&T PCS NETWORK	$	282.81	99
8612	04	BONNEVILLE PWR ADMIN R/W EASEMENTS - I&MREVIEW THREE ENCROACHMENTS INVOLVING BONN	$	2,033.24	99
8618	02	ABD TRANSMISSION PRE PLANNING - AP	$	33,130.66	99
8619	02	ABD DISTRIBUTION PRE PLANNING - AP	$	13,281.99	99
8620	10	ABD TRANSMISSION PRE PLANNING - CSP	$	70,697.51	99
8621	10	ABD DISTRIBUTION PRE PLANNING - CSP	$	13,856.50	99
8622	04	ABD TRANSMISSION PRE PLANNING - I&M	$	96,905.32	99
8623	04	ABD DISTRIBUTION PRE PLANNING - I&M	$	12,011.49	99
8624	03	ABD TRANSMISSION PRE PLANNING - KP	$	25,819.89	99
8625	03	ABD DISTRIBUTION PRE PLANNING - KP	$	1,790.56	99
8627	01	ABD TRANSMISSION PRE PLANNING - KGP	$	510.59	99
8629	07	ABD TRANSMISSION PRE PLANNING - OP	$	87,453.46	99
8630	07	ABD DISTRIBUTION PRE PLANNING - OP	$	16,759.43	99
8631	06	ABD TRANSMISSION PRE PLANNING - WP	$	1,012.73	99
8632	06	ABD DISTRIBUTION PRE PLANNING - WP	$	1,165.83	99
8633	02	US CELLULAR - AP	$	479.87	99
8635	02	ROANOKE GAS METER READ SVC PILOT - AP	$	1,240.83	99
8638	02	ROANOKE GAS METER READING - AP	$	1,270.81	99
8639	10	CSP METER READING - CSP	$	508.93	99
8644	02	APCO PERSONAL COMMUNICATION SYS - AP	$	384.58	99
8649	07	OPCO PERSONAL COMMUNICATION SYS - OP	$	186.68	99
8653	07	SPRINT PCS ATTACHMENTS - OP	$	54.43	99
8654	07	NEXTEL PCS ATTACHMENTS - OP	$	2,730.87	99
8655	04	STEEL DYNAMICS - I&M	$	64,081.70	99
8656	04	GOULD INCORPORATED - I&M	$	14,037.30	99
8658	03	ASHLAND PETROLEUM - KP	$	4,170.97	99
8659	03	ASHLAND CHEMICAL- KP	$	1,205.60	99
8661	04	BORG WARNER - I&M	$	1,861.27	99
8662	10	AEP COMMUNICATIONS - CSP AEP COMMUNICATIONS IN ASSOCIATION WITH BLENDON SIT	$	17,882.16	99
8664	02	TRANSFORMER LEASE/ILLINOIS POWER - AP APCO TO LOAN 345/138 KV 450 MVA TRANS- FORMER	$	9,476.27	99
8670	10	BUCKEYE POWER - CSP TRANSMISSION WORK IN ASSOCIATION WITH SYSTEM PLANNIN	$	10,237.22	99
8671	07	CITY OF BRYAN - OP TRANSMISSION WORK IN ASSOCIATION WITH SYSTEM PLANNING	$	16,737.20	99
8672	10	LOAD RESEARCH SERVICES - CSP LOAD PROFILE SERVICES	$	410.50	99
8673	07	CINERGY TRANSFORMER INSPECTION - OP TRANSFORMER INSPECTION FOR CINERGY	$	1,510.71	99
8675	02	EMI TESTING - AP EMI TESTING FOR SHELL OIL APPLEGROVE, WVPERFORMED BY DOL	$	3,373.42	99
8676	02	TENNESSEE VALLEY AUTHORITY - AP INTERCONNECTION WORK RELATED TO SYSTEM PLANNI	$	1,336.85	99
8677	10	CITY COLS-HAP CREAMEAN STATION - CSP SYSTEM PLANNING RELATED	$	5,324.59	99
8679	07	SANCAST, INC OIL TESTING - OP	$	130.40	99
8680	10	NATIONWIDE INSURANCE COMPANY - CSP	$	1,210.31	99
8682	02	CFW WIRELESS PCS - AP PERSONAL COMM SVCS ASSOC/W W VA SITES FOR CFW WIREL	$	1,681.49	99
8683	07	OWENS CORNING - OP LEASE TRANSFORMER TO CUSTOMER DUE TO FAILURE	$	5,509.94	99
8684	10	ACCUTEMP PRODUCTS, INC - CSP METERING SERVICES	$	4,214.59	99
8688	07	VON ROLL, INC - OPCO INSTALL 8 ALARM POINTS FOR VON ROLL, INCOPCO #991-8131	$	1,655.83	99
8689	03	ASHLAND PETROLEUM - KP EMI SERVICES FOR ASHLAND PETROLEUM KP#930-9940	$	3,420.84	99
8690	02	CFW DANVILLE, NORTH - AP PERSONAL COMMUNICATIONS SERVICES FOR CFWCSA #96AP2	$	3,419.55	99
8691	07	ANCHOR HOCKING OIL TESTING - OP OIL TESTING AT THE DOLAN LAB OP #991-8066	$	378.87	99
8692	03	AK STEEL TRANSFORMER REPAIR - KP TRANSFORMER REPAIR SERVICE PERFORMED BY DOLAN	$	183.75	99

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WO	CO	TITLE/DESCRIPTION	AMOUNT	FORM
8695	10	WENDY'S INTERNATIONAL TRANSFMR MAINT-CSPTRANSFORMER MAINT PERFORMED BY DOLAN LAB	$ 690.84	99
8697	03	TENNECO STATION MAINT - KP STATION MAINT PERFORMED BY DOLAN LAB 95KP119 KP#93	$ 981.89	99
8698	07	ARMCO RESCO PROJECT GROUP - OP SELLING WIRE AND TRANSMISSION WORK OP #991-81	$ 162.39	99
8699	04	ALLIED SIGNAL - I&M TRANSMISSION WORK TO VERIFY RELAY SETTINGS I&M #996-514	$ 1,375.46	99
8801	04	AK STEEL - I&M OPERATION CONTROL EQUIPMENT AND METERINGTESTING I&M#996-5	$ 283.32	99
8802	02	CFW CATAWBA SITE - AP WO #994-1114	$ 5,828.89	99
8803	02	CFW BASSET FORKS SITE - AP WO #994-1118	$ 1,485.08	99
8804	02	CFW ROUTE 57 SITE - AP WO #994-1119	$ 940.51	99
8806	02	CFW CHESTERFIELD STIE - AP WO #994-1121	$ 1,464.17	99
8807	02	CFW ST ALBANS SITE - AP WO #994-1122	$ 4,135.53	99
8808	07	CLEVLAND PUBLIC POWER - OP EMERGENCY ASSISTANCE OPCO WO #991-8194	$ 515.24	99
8810	07	CLEVELAND PUBLIC POWER - OP BREAKER MAINTENANCE OPCO WO #991-8194	$ 4,977.89	99
8811	02	CFW MARMET - AP PERSONAL COMMUNICATION SERVICES APCO WO #994-1125	$ 189.09	99
8814	10	E MANUFACTURING - CSP TESTING SERVICES CSPCO WO #904-5137	$ 24.74	99
8815	03	INCO ALLOYS INTERNATIONAL INC - KP OIL SAMPLING KPCO WO #903-9943	$ 1,192.69	99
8816	02	CFW CITY FARM SITE LYNCHBURG, VA - AP PERSONAL COMMUNICATIONS SERVICES APCO WO	$ 4,500.95	99
8820	02	CFW CULLODEN - AP PERSONAL COMMUNICATIONS SERVICES APCO # 994-1140 STR	$ 218.89	99
8823	02	BLUE RIDGE POWER AGENCY - AP FACILITY ENGINEERING STY PERFORMED BY SYS PLANN	$ 9,709.60	99
8824	04	HOOSIER ENERGY FEASIBILITY STY - I&M FEASIBILITY STY PERFORMED BY SYSTEM PLANNING I	$ 603.42	99
8825	10	GALBREATH/LASALLE PARTNERS - CSP POWER QUALITY ASSISTANCE CSPCO #904-5148	$ 450.86	99
8826	02	CFW AEP DANVILLE SITE - AP PERSONAL COMMUNICATIONS SERVICES APCO #994-1148	$ 859.88	99
8827	07	LICKING RURAL ELECTRIFICATION, INC - OP SVCS & CONSTR FOR ESTABLISHMENT OF A DELIVERY	$ 1,388.13	99
8828	07	THE GERTENSLAGER COMPANY - OP STATION REBUILD PROJECT OPCO #991-8242	$ 894.82	99
8829	02	US CELLULAR CLEARBROOK SITE - AP PERSONAL COMMUNICATIONS SERVICES APCO #994-	$ 3,554.06	99
8830	03	ASHLAND PETROLEUM - KP CABLE INSPECTION KPCO #930-9948	$ 50.55	99
8831	10	NBB CONTROLS - CSP TESTING RADIO CONTROL ON A BUCKET TRUCK CSP WO # 904-51	$ 1,918.40	99
8835	10	TRANSDATA - CSP ANSI C-12.16 CERTIFICATION TESTING CSP#904-5167	$ 5,052.09	99
8836	02	CONSOLIDATED COAL COMPANY - AP EMI TESTING APCO#994-1158	$ 3,531.49	99
8837	07	ADAMS REC - OP SWITCH REPLACEMENT OPCO WO#991-8222	$ 358.43	99
8841	02	AEP ROANOKE TO LYNCHBURG FIBER PROJ-AP ENGINEER DESIGN WORK APCO #994-116	$ 1,402.55	99
8842	07	ARIEL CORPORATION - OP POWER QUALITY ASSISTANCE OPCO #991-8290	$ 1,476.51	99
8844	02	US CELLULAR RT 419 AT GRANDIN - AP ATTACHMENT TO AEP TRANSMISSION TOWER APCO #99	$ 299.85	99
8845	02	US CELLULAR RT 220 BUSINESS - AP ATTACHMENT TO AEP TRANSMISSION TOWER APCO #994-	$ 381.49	99
8846	10	GALBREATH/LASALLE PARTNERS - CSP METER INSTALLATION CSP#904-5174	$ 383.66	99
8848	07	CITY OF CLEVELAND - OP INFORMATION MEETINGS OPCO #991-8311	$ 401.21	99
8850	04	OMNISOURCE - I&M DESIGN AND BUILD 34 KV STATION I&M #996-5230	$ 1,236.74	99
8851	10	CENTURY ALUMINUM - CSP INSTALL, REMOVE AND RENT A TRANSFORMER CSP #904-5184	$ 2,175.27	99
9001	61	ACCOUNT DISTRIBUTION SYSTEM PROCESSING WO USED IF INVALID WO IS PASSED FROM PAS(P/R	$ 5,879.35	99
9107	07	CORRECT PRIOR PERIOD WORK ORDER CHARGES TO OHIO POWER COMPANY	$ (9,781.27)	99
9128	22	CORRECT PRIOR PERIOD WORK ORDER CHARGES TO CARDINAL OPERATING COMPANY	$ 9,781.27	99
9191	91	CORR PRIOP PERIOD WORK ORDER CHARGES TO AEPC, LLC	$ 83,016.62	99
9195	95	CORR PRIOP PERIOD WORK ORDER CHARGES TO UNASSIGNED COMPANY	$ (83,016.62)	99
			$22,485,704.44	

Schedule 28

AMERICAN ELECTRIC POWER SERVICE CORPORATION
BILLINGS OVER 100K BY WORK ORDERS
FOR THE YEAR ENDED 12/31/97

WO#	SERVICE ID	CO#	DESCRIPTION		AMOUNT	BASIS
1951	HRPAYROLAB	01	PAYROLL SERVICES - KP,WP,OP,CSP,CARD,SOCWC,COC,CED,CCP	GEN SVC RELATED TO PAYROL	$ 9,778 13	61
1951	HRPAYROLAB	02	PAYROLL SERVICES - KP,WP,OP,CSP,CARD,SOCWC,COC,CED,CCP	GEN SVC RELATED TO PAYROL	$ 420,307.38	61
1951	HRPAYROLAB	03	PAYROLL SERVICES - KP,WP,OP,CSP,CARD,SOCWC,COC,CED,CCP	GEN SVC RELATED TO PAYROL	$ 86,427.45	61
1951	HRPAYROLAB	04	PAYROLL SERVICES - KP,WP,OP,CSP,CARD,SOCWC,COC,CED,CCP	GEN SVC RELATED TO PAYROL	$ 320,392.62	61
1951	HRPAYROLAB	06	PAYROLL SERVICES - KP,WP,OP,CSP,CARD,SOCWC,COC,CED,CCP	GEN SVC RELATED TO PAYROL	$ 11,407.74	61
1951	HRPAYROLAB	07	PAYROLL SERVICES - KP,WP,OP,CSP,CARD,SOCWC,COC,CED,CCP	GEN SVC RELATED TO PAYROL	$ 329,643.21	61
1951	HRPAYROLAB	10	PAYROLL SERVICES - KP,WP,OP,CSP,CARD,SOCWC,COC,CED,CCP	GEN SVC RELATED TO PAYROL	$ 204,377.73	61
1951	HRPAYROLAB	22	PAYROLL SERVICES - KP,WP,OP,CSP,CARD,SOCWC,COC,CED,CCP	GEN SVC RELATED TO PAYROL	$ 25,944.00	61
1951	HRPAYROLAB	23	PAYROLL SERVICES - KP,WP,OP,CSP,CARD,SOCWC,COC,CED,CCP	GEN SVC RELATED TO PAYROL	$ 30,712.56	61
1951	HRPAYROLAB	42	PAYROLL SERVICES - KP,WP,OP,CSP,CARD,SOCWC,COC,CED,CCP	GEN SVC RELATED TO PAYROL	$ 24,445.29	61
1951	HRPAYROLAB	43	PAYROLL SERVICES - KP,WP,OP,CSP,CARD,SOCWC,COC,CED,CCP	GEN SVC RELATED TO PAYROL	$ 26,462.52	61
1951	HRPAYROLAB	44	PAYROLL SERVICES - KP,WP,OP,CSP,CARD,SOCWC,COC,CED,CCP	GEN SVC RELATED TO PAYROL	$ 100,001.31	61
1951	HRPAYROLAB	46	PAYROLL SERVICES - KP,WP,OP,CSP,CARD,SOCWC,COC,CED,CCP	GEN SVC RELATED TO PAYROL	$ 1,629.84	61
1951	HRPAYROLAB	49	PAYROLL SERVICES - KP,WP,OP,CSP,CARD,SOCWC,COC,CED,CCP	GEN SVC RELATED TO PAYROL	$ 3,952.93	61
1951	HRPAYROLAB	54	PAYROLL SERVICES - KP,WP,OP,CSP,CARD,SOCWC,COC,CED,CCP	GEN SVC RELATED TO PAYROL	$ 4,486.13	61
1951	HRPAYROLAB	69	PAYROLL SERVICES - KP,WP,OP,CSP,CARD,SOCWC,COC,CED,CCP	GEN SVC RELATED TO PAYROL	$ 539.11	61
1951	HRPAYROLAB	71	PAYROLL SERVICES - KP,WP,OP,CSP,CARD,SOCWC,COC,CED,CCP	GEN SVC RELATED TO PAYROL	$ 16,602.05	61
1951	HRPAYROLAB	73	PAYROLL SERVICES - KP,WP,OP,CSP,CARD,SOCWC,COC,CED,CCP	GEN SVC RELATED TO PAYROL	$ 12,577.34	61
1903	HRPAYROLAB	01	TREASURY OPERATIONS - OPER & AEG		$ 2,088.58	01
1903	HRPAYROLAB	02	TREASURY OPERATIONS - OPER & AEG		$ 39,963.22	01
1903	HRPAYROLAB	03	TREASURY OPERATIONS - OPER & AEG		$ 5,987.84	01
1903	HRPAYROLAB	04	TREASURY OPERATIONS - OPER & AEG		$ 24,937.21	01
1903	HRPAYROLAB	06	TREASURY OPERATIONS - OPER & AEG		$ 2,079.87	01
1903	HRPAYROLAB	07	TREASURY OPERATIONS - OPER & AEG		$ 43,217.97	01
1903	HRPAYROLAB	10	TREASURY OPERATIONS - OPER & AEG		$ 20,852.76	01
1903	HRPAYROLAB	21	TREASURY OPERATIONS - OPER & AEG		$ 9,434.70	01
1903	ACCLOSESAA	01	TREASURY OPERATIONS - OPER & AEG		$ 9,846.14	01
1903	ACCLOSESAA	02	TREASURY OPERATIONS - OPER & AEG		$ 188,398.04	01
1903	ACCLOSESAA	03	TREASURY OPERATIONS - OPER & AEG		$ 28,228.37	01
1903	ACCLOSESAA	04	TREASURY OPERATIONS - OPER & AEG		$ 117,561.14	01
1903	ACCLOSESAA	06	TREASURY OPERATIONS - OPER & AEG		$ 9,805.09	01
1903	ACCLOSESAA	07	TREASURY OPERATIONS - OPER & AEG		$ 203,741.88	01
1903	ACCLOSESAA	10	TREASURY OPERATIONS - OPER & AEG		$ 98,305.86	01
1903	ACCLOSESAA	21	TREASURY OPERATIONS - OPER & AEG		$ 44,477.87	01
1961	ACCLOSESAA	03	GENERAL ACCOUNTING OPERATIONS - OPER	ACCTG RESPONSIBILITIES OF A GENERAL NA- TURE FOR VARIO	$ 59,107.40	71
1961	ACCLOSESAA	06	GENERAL ACCOUNTING OPERATIONS - OPER	ACCTG RESPONSIBILITIES OF A GENERAL NA- TURE FOR VARIO	$ 20,040.61	71
1961	ACCLOSESAA	07	GENERAL ACCOUNTING OPERATIONS - OPER	ACCTG RESPONSIBILITIES OF A GENERAL NA- TURE FOR VARIO	$ 429,619.44	71
1961	ACCLOSESAA	10	GENERAL ACCOUNTING OPERATIONS - OPER	ACCTG RESPONSIBILITIES OF A GENERAL NA- TURE FOR VARIO	$ 206,968.03	71

AMERICAN ELECTRIC POWER SERVICE CORPORATION
BILLINGS OVER 100K BY WORK ORDERS
FOR THE YEAR ENDED 12/31/97

WO#	SERVICE ID	CO#		DESCRIPTION			AMOUNT	BASIS
1961	ACCLOSESAA	03	GENERAL ACCOUNTING OPERATIONS - OPER	ACCTG RESPONSIBILITIES OF A GENERAL NA-	TURE FOR VARIO	$	34,304.88	71
1961	ACCLOSESAA	06	GENERAL ACCOUNTING OPERATIONS - OPER	ACCTG RESPONSIBILITIES OF A GENERAL NA-	TURE FOR VARIO	$	11,631.22	71
1961	ACCLOSESAA	07	GENERAL ACCOUNTING OPERATIONS - OPER	ACCTG RESPONSIBILITIES OF A GENERAL NA-	TURE FOR VARIO	$	249,343.50	71
1961	ACCLOSESAA	10	GENERAL ACCOUNTING OPERATIONS - OPER	ACCTG RESPONSIBILITIES OF A GENERAL NA-	TURE FOR VARIO	$	120,120.58	71
1457	ACFINCONAB	01	SYS ACCTG APPL VISION STY - OPER & AEG	STUDY UNDERTAKEN TO ACCOMPLISH VARIOUS	ACCOUNTING PR	$	3,969.93	01
1457	ACFINCONAB	02	SYS ACCTG APPL VISION STY - OPER & AEG	STUDY UNDERTAKEN TO ACCOMPLISH VARIOUS	ACCOUNTING PR	$	76,919.08	01
1457	ACFINCONAB	03	SYS ACCTG APPL VISION STY - OPER & AEG	STUDY UNDERTAKEN TO ACCOMPLISH VARIOUS	ACCOUNTING PR	$	11,471.04	01
1457	ACFINCONAB	04	SYS ACCTG APPL VISION STY - OPER & AEG	STUDY UNDERTAKEN TO ACCOMPLISH VARIOUS	ACCOUNTING PR	$	47,885.86	01
1457	ACFINCONAB	06	SYS ACCTG APPL VISION STY - OPER & AEG	STUDY UNDERTAKEN TO ACCOMPLISH VARIOUS	ACCOUNTING PR	$	4,003.19	01
1457	ACFINCONAB	07	SYS ACCTG APPL VISION STY - OPER & AEG	STUDY UNDERTAKEN TO ACCOMPLISH VARIOUS	ACCOUNTING PR	$	83,495.80	01
1457	ACFINCONAB	10	SYS ACCTG APPL VISION STY - OPER & AEG	STUDY UNDERTAKEN TO ACCOMPLISH VARIOUS	ACCOUNTING PR	$	40,032.25	01
1457	ACFINCONAB	21	SYS ACCTG APPL VISION STY - OPER & AEG	STUDY UNDERTAKEN TO ACCOMPLISH VARIOUS	ACCOUNTING PR	$	18,167.35	01
1952	SCAPAYMTAA	01	ACCOUNTS PAYABLE OPERATIONS - AEP SYS	PROCESSING & PAYMENT OF AEP SYSTEM	INVOICES	$	13,048.30	64
1952	SCAPAYMTAA	02	ACCOUNTS PAYABLE OPERATIONS - AEP SYS	PROCESSING & PAYMENT OF AEP SYSTEM	INVOICES	$	304,690.94	64
1952	SCAPAYMTAA	03	ACCOUNTS PAYABLE OPERATIONS - AEP SYS	PROCESSING & PAYMENT OF AEP SYSTEM	INVOICES	$	150,677.48	64
1952	SCAPAYMTAA	04	ACCOUNTS PAYABLE OPERATIONS - AEP SYS	PROCESSING & PAYMENT OF AEP SYSTEM	INVOICES	$	161,660.46	64
1952	SCAPAYMTAA	06	ACCOUNTS PAYABLE OPERATIONS - AEP SYS	PROCESSING & PAYMENT OF AEP SYSTEM	INVOICES	$	18,755.78	64
1952	SCAPAYMTAA	07	ACCOUNTS PAYABLE OPERATIONS - AEP SYS	PROCESSING & PAYMENT OF AEP SYSTEM	INVOICES	$	468,990.69	64
1952	SCAPAYMTAA	10	ACCOUNTS PAYABLE OPERATIONS - AEP SYS	PROCESSING & PAYMENT OF AEP SYSTEM	INVOICES	$	281,574.34	64
1952	SCAPAYMTAA	21	ACCOUNTS PAYABLE OPERATIONS - AEP SYS	PROCESSING & PAYMENT OF AEP SYSTEM	INVOICES	$	987.85	64
1952	SCAPAYMTAA	22	ACCOUNTS PAYABLE OPERATIONS - AEP SYS	PROCESSING & PAYMENT OF AEP SYSTEM	INVOICES	$	42,641.94	64
1952	SCAPAYMTAA	23	ACCOUNTS PAYABLE OPERATIONS - AEP SYS	PROCESSING & PAYMENT OF AEP SYSTEM	INVOICES	$	1,975.70	64
1952	SCAPAYMTAA	42	ACCOUNTS PAYABLE OPERATIONS - AEP SYS	PROCESSING & PAYMENT OF AEP SYSTEM	INVOICES	$	48,357.90	64
1952	SCAPAYMTAA	43	ACCOUNTS PAYABLE OPERATIONS - AEP SYS	PROCESSING & PAYMENT OF AEP SYSTEM	INVOICES	$	56,359.17	64
1952	SCAPAYMTAA	44	ACCOUNTS PAYABLE OPERATIONS - AEP SYS	PROCESSING & PAYMENT OF AEP SYSTEM	INVOICES	$	161,084.11	64
1952	SCAPAYMTAA	46	ACCOUNTS PAYABLE OPERATIONS - AEP SYS	PROCESSING & PAYMENT OF AEP SYSTEM	INVOICES	$	1,975.70	64
1952	SCAPAYMTAA	48	ACCOUNTS PAYABLE OPERATIONS - AEP SYS	PROCESSING & PAYMENT OF AEP SYSTEM	INVOICES	$	35,147.02	64
1952	SCAPAYMTAA	49	ACCOUNTS PAYABLE OPERATIONS - AEP SYS	PROCESSING & PAYMENT OF AEP SYSTEM	INVOICES	$	14,292.44	64
1952	SCAPAYMTAA	51	ACCOUNTS PAYABLE OPERATIONS - AEP SYS	PROCESSING & PAYMENT OF AEP SYSTEM	INVOICES	$	987.85	64
1952	SCAPAYMTAA	54	ACCOUNTS PAYABLE OPERATIONS - AEP SYS	PROCESSING & PAYMENT OF AEP SYSTEM	INVOICES	$	10,442.50	64
1952	SCAPAYMTAA	70	ACCOUNTS PAYABLE OPERATIONS - AEP SYS	PROCESSING & PAYMENT OF AEP SYSTEM	INVOICES	$	20,287.65	64
1952	SCAPAYMTAA	71	ACCOUNTS PAYABLE OPERATIONS - AEP SYS	PROCESSING & PAYMENT OF AEP SYSTEM	INVOICES	$	22,872.80	64
1952	SCAPAYMTAA	73	ACCOUNTS PAYABLE OPERATIONS - AEP SYS	PROCESSING & PAYMENT OF AEP SYSTEM	INVOICES	$	18,450.76	64
1952	SCAPAYMTAA	75	ACCOUNTS PAYABLE OPERATIONS - AEP SYS	PROCESSING & PAYMENT OF AEP SYSTEM	INVOICES	$	318.79	64
1903	SCAPAYMTAA	01	TREASURY OPERATIONS - OPER & AEG			$	3,282.05	01
1903	SCAPAYMTAA	02	TREASURY OPERATIONS - OPER & AEG			$	62,799.35	01
1903	SCAPAYMTAA	03	TREASURY OPERATIONS - OPER & AEG			$	9,409.46	01
1903	SCAPAYMTAA	04	TREASURY OPERATIONS - OPER & AEG			$	39,187.05	01

AMERICAN ELECTRIC POWER SERVICE CORPORATION
BILLINGS OVER 100K BY WORK ORDERS
FOR THE YEAR ENDED 12/31/97

WO#	SERVICE ID	CO#	DESCRIPTION		AMOUNT	BASIS
1903	SCAPAYMTAA	06	TREASURY OPERATIONS - OPER & AEG	$	3,268.36	01
1903	SCAPAYMTAA	07	TREASURY OPERATIONS - OPER & AEG	$	67,913.96	01
1903	SCAPAYMTAA	10	TREASURY OPERATIONS - OPER & AEG	$	32,768.62	01
1903	SCAPAYMTAA	21	TREASURY OPERATIONS - OPER & AEG	$	14,825.96	01
1903	ACADMINSAA	01	TREASURY OPERATIONS - OPER & AEG	$	2,088.58	01
1903	ACADMINSAA	02	TREASURY OPERATIONS - OPER & AEG	$	39,963.22	01
1903	ACADMINSAA	03	TREASURY OPERATIONS - OPER & AEG	$	5,987.84	01
1903	ACADMINSAA	04	TREASURY OPERATIONS - OPER & AEG	$	24,937.21	01
1903	ACADMINSAA	06	TREASURY OPERATIONS - OPER & AEG	$	2,079.87	01
1903	ACADMINSAA	07	TREASURY OPERATIONS - OPER & AEG	$	43,217.97	01
1903	ACADMINSAA	10	TREASURY OPERATIONS - OPER & AEG	$	20,852.76	01
1903	ACADMINSAA	21	TREASURY OPERATIONS - OPER & AEG	$	9,434.70	01
1200	TRINTEXPAA	01	INTEREST ON BORROWED CAP-ASSOC,CG&E,DP&L	$	4,138.04	21
1200	TRINTEXPAA	02	INTEREST ON BORROWED CAP-ASSOC,CG&E,DP&L	$	118,168.47	21
1200	TRINTEXPAA	03	INTEREST ON BORROWED CAP-ASSOC,CG&E,DP&L	$	25,272.12	21
1200	TRINTEXPAA	04	INTEREST ON BORROWED CAP-ASSOC,CG&E,DP&L	$	134,250.87	21
1200	TRINTEXPAA	06	INTEREST ON BORROWED CAP-ASSOC,CG&E,DP&L	$	4,138.04	21
1200	TRINTEXPAA	07	INTEREST ON BORROWED CAP-ASSOC,CG&E,DP&L	$	113,933.80	21
1200	TRINTEXPAA	10	INTEREST ON BORROWED CAP-ASSOC,CG&E,DP&L	$	65,294.48	21
1200	TRINTEXPAA	21	INTEREST ON BORROWED CAP-ASSOC,CG&E,DP&L	$	7,735.49	21
1200	TRINTEXPAA	22	INTEREST ON BORROWED CAP-ASSOC,CG&E,DP&L	$	5,643.83	21
1200	TRINTEXPAA	23	INTEREST ON BORROWED CAP-ASSOC,CG&E,DP&L	$	399.02	21
1200	TRINTEXPAA	25	INTEREST ON BORROWED CAP-ASSOC,CG&E,DP&L	$	540.55	21
1200	TRINTEXPAA	31	INTEREST ON BORROWED CAP-ASSOC,CG&E,DP&L	$	2,799.46	21
1200	TRINTEXPAA	32	INTEREST ON BORROWED CAP-ASSOC,CG&E,DP&L	$	2,265.28	21
1200	TRINTEXPAA	42	INTEREST ON BORROWED CAP-ASSOC,CG&E,DP&L	$	3,732.58	21
1200	TRINTEXPAA	43	INTEREST ON BORROWED CAP-ASSOC,CG&E,DP&L	$	3,069.72	21
1200	TRINTEXPAA	44	INTEREST ON BORROWED CAP-ASSOC,CG&E,DP&L	$	12,002.23	21
1200	TRINTEXPAA	46	INTEREST ON BORROWED CAP-ASSOC,CG&E,DP&L	$	-	21
1200	TRINTEXPAA	48	INTEREST ON BORROWED CAP-ASSOC,CG&E,DP&L	$	1,866.29	21
1200	TRINTEXPAA	49	INTEREST ON BORROWED CAP-ASSOC,CG&E,DP&L	$	1,332.17	21
1200	TRINTEXPAA	54	INTEREST ON BORROWED CAP-ASSOC,CG&E,DP&L	$	933.19	21
1200	TRINTEXPAA	58	INTEREST ON BORROWED CAP-ASSOC,CG&E,DP&L	$	135.16	21
1200	TRINTEXPAA	59	INTEREST ON BORROWED CAP-ASSOC,CG&E,DP&L	$	270.31	21
1200	TRINTEXPAA	60	INTEREST ON BORROWED CAP-ASSOC,CG&E,DP&L	$	2,406.84	21
1200	TRINTEXPAA	69	INTEREST ON BORROWED CAP-ASSOC,CG&E,DP&L	$	5,605.30	21
1200	TRINTEXPAA	70	INTEREST ON BORROWED CAP-ASSOC,CG&E,DP&L	$	2,554.89	21
1200	TRINTEXPAA	71	INTEREST ON BORROWED CAP-ASSOC,CG&E,DP&L	$	3,494.46	21

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AMERICAN ELECTRIC POWER SERVICE CORPORATION
BILLINGS OVER 100K BY WORK ORDERS
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WO#	SERVICE ID	CO#	DESCRIPTION	AMOUNT	BASIS
1200	TRINTEXPAA	73	INTEREST ON BORROWED CAP-ASSOC,CG&E,DP&L	$ 6,686.45	21
1200	TRINTEXPAA	74	INTEREST ON BORROWED CAP-ASSOC,CG&E,DP&L	$ 939.57	21
1200	TRINTEXPAA	75	INTEREST ON BORROWED CAP-ASSOC,CG&E,DP&L	$ 4,537.01	21
1200	TRINTEXPAA	80	INTEREST ON BORROWED CAP-ASSOC,CG&E,DP&L	$ -	21
1906	ACCLOSES02	02	TREASURY OPERATIONS - AP	$ 407,156.49	99
1910	ACCLOSES03	03	TREASURY OPERATIONS - KP	$ 286,305.59	99
1907	ACCLOSES04	04	TREASURY OPERATIONS - I&MP	$ 209,601.34	99
1913	ACCLOSES07	07	TREASURY OPERATIONS - OP	$ 650,445.48	99
1915	ACCLOSES10	10	TREASURY OPERATIONS - CSP	$ 202,796.48	99
1930	ACTAXCMP02	02	TAX OPERATIONS - AP	$ 478,077.60	99
1933	ACTAXCMP03	03	TAX OPERATIONS - KP	$ 152,001.13	99
1931	ACTAXCMP04	04	TAX OPERATIONS - I&M	$ 301,559.00	99
1934	ACTAXCMP07	07	TAX OPERATIONS - OP	$ 249,613.38	99
1936	ACTAXCMP10	10	TAX OPERATIONS - CSP	$ 223,677.66	99
1960	FLACCTNGAA	02	FUEL ACCOUNTING OPERATIONS - AEP SYS MAINTAIN RECORDS REQUIRED TO RECORD INVENTORY & CON	$ 54,699.01	74
1960	FLACCTNGAA	03	FUEL ACCOUNTING OPERATIONS - AEP SYS MAINTAIN RECORDS REQUIRED TO RECORD INVENTORY & CON	$ 24,791.97	74
1960	FLACCTNGAA	04	FUEL ACCOUNTING OPERATIONS - AEP SYS MAINTAIN RECORDS REQUIRED TO RECORD INVENTORY & CON	$ 18,233.02	74
1960	FLACCTNGAA	07	FUEL ACCOUNTING OPERATIONS - AEP SYS MAINTAIN RECORDS REQUIRED TO RECORD INVENTORY & CON	$ 149,107.41	74
1960	FLACCTNGAA	10	FUEL ACCOUNTING OPERATIONS - AEP SYS MAINTAIN RECORDS REQUIRED TO RECORD INVENTORY & CON	$ 55,415.59	74
1960	FLACCTNGAA	22	FUEL ACCOUNTING OPERATIONS - AEP SYS MAINTAIN RECORDS REQUIRED TO RECORD INVENTORY & CON	$ 35,978.29	74
1960	FLACCTNGAA	70	FUEL ACCOUNTING OPERATIONS - AEP SYS MAINTAIN RECORDS REQUIRED TO RECORD INVENTORY & CON	$ 22,252.10	74
1960	FLACCTNGAA	71	FUEL ACCOUNTING OPERATIONS - AEP SYS MAINTAIN RECORDS REQUIRED TO RECORD INVENTORY & CON	$ 55,147.65	74
1960	FLACCTNGAA	73	FUEL ACCOUNTING OPERATIONS - AEP SYS MAINTAIN RECORDS REQUIRED TO RECORD INVENTORY & CON	$ 95,869.14	74
0209	TRINVSERAA	60	ANNUAL SHAREHOLDERS MEETING - AEP PLAN ACTUAL PRESENTATION FOR AEP, INC., SHAREHOLDERS ME	$ 118,397.45	99
0215	TRINVSERAA	60	SHAREHOLDER RELATIONS - AEP SERVICES IN CONNECTION WITH SHAREHOLDER RELATIONS	$ 440,384.39	99
1225	TRLTCAPMAA	01	FINANCE - OPER & AEG	$ 22,875.79	63
1225	TRLTCAPMAA	02	FINANCE - OPER & AEG	$ 672,711.63	63
1225	TRLTCAPMAA	03	FINANCE - OPER & AEG	$ 144,373.31	63
1225	TRLTCAPMAA	04	FINANCE - OPER & AEG	$ 756,184.09	63
1225	TRLTCAPMAA	06	FINANCE - OPER & AEG	$ 22,875.79	63
1225	TRLTCAPMAA	07	FINANCE - OPER & AEG	$ 689,098.29	63
1225	TRLTCAPMAA	10	FINANCE - OPER & AEG	$ 366,059.95	63
1225	TRLTCAPMAA	21	FINANCE - OPER & AEG	$ 49,811.19	63
1225	TRLTCAPMAA	23	FINANCE - OPER & AEG	$ 2,149.24	63
1225	TRLTCAPMAA	25	FINANCE - OPER & AEG	$ 3,247.96	63
1225	TRLTCAPMAA	42	FINANCE - OPER & AEG	$ 20,439.67	63
1225	TRLTCAPMAA	43	FINANCE - OPER & AEG	$ 16,954.09	63
1225	TRLTCAPMAA	44	FINANCE - OPER & AEG	$ 65,904.14	63

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AMERICAN ELECTRIC POWER SERVICE CORPORATION
BILLINGS OVER 100K BY WORK ORDERS
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WO#	SERVICE ID	CO#	DESCRIPTION		AMOUNT	BASIS
1225	TRLTCAPMAA	48	FINANCE - OPER & AEG	$	8,595.62	63
1225	TRLTCAPMAA	49	FINANCE - OPER & AEG	$	6,447.02	63
1225	TRLTCAPMAA	54	FINANCE - OPER & AEG	$	5,110.15	63
1225	TRLTCAPMAA	58	FINANCE - OPER & AEG	$	812.16	63
1225	TRLTCAPMAA	59	FINANCE - OPER & AEG	$	1,624.00	63
1225	TRLTCAPMAA	60	FINANCE - OPER & AEG	$	13,467.53	63
1225	TRLTCAPMAA	69	FINANCE - OPER & AEG	$	30,946.57	63
1225	TRLTCAPMAA	70	FINANCE - OPER & AEG	$	4,297.99	63
1225	TRLTCAPMAA	71	FINANCE - OPER & AEG	$	6,447.02	63
1225	TRLTCAPMAA	73	FINANCE - OPER & AEG	$	23,638.50	63
1225	TRLTCAPMAA	74	FINANCE - OPER & AEG	$	24,737.63	63
1225	TRLTCAPMAA	75	FINANCE - OPER & AEG	$	2,149.24	63
1958	ACPROPTYAA	03	OWNED ASSET ACCOUNTING OPERATIONS - OPERPERFORM ACCTG SVCS REL TO REQUIRED MAINTOF COMPA	$	260,250.01	68
1958	ACPROPTYAA	06	OWNED ASSET ACCOUNTING OPERATIONS - OPERPERFORM ACCTG SVCS REL TO REQUIRED MAINTOF COMPA	$	22,192.67	68
1958	ACPROPTYAA	07	OWNED ASSET ACCOUNTING OPERATIONS - OPERPERFORM ACCTG SVCS REL TO REQUIRED MAINTOF COMPA	$	999,716.68	68
1958	ACPROPTYAA	10	OWNED ASSET ACCOUNTING OPERATIONS - OPERPERFORM ACCTG SVCS REL TO REQUIRED MAINTOF COMPA	$	735,357.56	68
1852	ACBUDGETAB	01	FINANCIAL FORECAST - OPER, AEG	$	19,957.78	01
1852	ACBUDGETAB	02	FINANCIAL FORECAST - OPER, AEG	$	379,813.44	01
1852	ACBUDGETAB	03	FINANCIAL FORECAST - OPER, AEG	$	56,533.86	01
1852	ACBUDGETAB	04	FINANCIAL FORECAST - OPER, AEG	$	235,772.22	01
1852	ACBUDGETAB	06	FINANCIAL FORECAST - OPER, AEG	$	19,767.19	01
1852	ACBUDGETAB	07	FINANCIAL FORECAST - OPER, AEG	$	411,548.15	01
1852	ACBUDGETAB	10	FINANCIAL FORECAST - OPER, AEG	$	197,919.03	01
1852	ACBUDGETAB	21	FINANCIAL FORECAST - OPER, AEG	$	90,633.37	01
1903	ACGENERLAA	01	TREASURY OPERATIONS - OPER & AEG	$	51,408.86	01
1903	ACGENERLAA	02	TREASURY OPERATIONS - OPER & AEG	$	983,667.44	01
1903	ACGENERLAA	03	TREASURY OPERATIONS - OPER & AEG	$	147,386.50	01
1903	ACGENERLAA	04	TREASURY OPERATIONS - OPER & AEG	$	613,812.47	01
1903	ACGENERLAA	06	TREASURY OPERATIONS - OPER & AEG	$	51,194.54	01
1903	ACGENERLAA	07	TREASURY OPERATIONS - OPER & AEG	$	1,063,780.98	01
1903	ACGENERLAA	10	TREASURY OPERATIONS - OPER & AEG	$	513,276.46	01
1928	ACINCTAXAA	01	INCOME TAXES AND CREDITS - ASSOC	$	(3,428.00)	20
1928	ACINCTAXAA	02	INCOME TAXES AND CREDITS - ASSOC	$	(88,101.78)	20
1928	ACINCTAXAA	03	INCOME TAXES AND CREDITS - ASSOC	$	(8,621.66)	20
1928	ACINCTAXAA	04	INCOME TAXES AND CREDITS - ASSOC	$	(119,172.49)	20
1928	ACINCTAXAA	06	INCOME TAXES AND CREDITS - ASSOC	$	(3,428.00)	20
1928	ACINCTAXAA	07	INCOME TAXES AND CREDITS - ASSOC	$	(74,512.92)	20
1928	ACINCTAXAA	10	INCOME TAXES AND CREDITS - ASSOC	$	(48,286.66)	20

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AMERICAN ELECTRIC POWER SERVICE CORPORATION
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WO#	SERVICE ID	CO#	DESCRIPTION		AMOUNT	BASIS
1928	ACINCTAXAA	21	INCOME TAXES AND CREDITS - ASSOC		$ (8,284.82)	20
1928	ACINCTAXAA	22	INCOME TAXES AND CREDITS - ASSOC		$ 5,938.63	20
1928	ACINCTAXAA	23	INCOME TAXES AND CREDITS - ASSOC		$ (740.95)	20
1928	ACINCTAXAA	25	INCOME TAXES AND CREDITS - ASSOC		$ 1,428.67	20
1928	ACINCTAXAA	31	INCOME TAXES AND CREDITS - ASSOC		$ (4,115.71)	20
1928	ACINCTAXAA	32	INCOME TAXES AND CREDITS - ASSOC		$ (2,990.68)	20
1928	ACINCTAXAA	42	INCOME TAXES AND CREDITS - ASSOC		$ (4,499.56)	20
1928	ACINCTAXAA	43	INCOME TAXES AND CREDITS - ASSOC		$ (2,660.23)	20
1928	ACINCTAXAA	44	INCOME TAXES AND CREDITS - ASSOC		$ (13,168.09)	20
1928	ACINCTAXAA	46	INCOME TAXES AND CREDITS - ASSOC		$ -	20
1928	ACINCTAXAA	48	INCOME TAXES AND CREDITS - ASSOC		$ (2,249.81)	20
1928	ACINCTAXAA	49	INCOME TAXES AND CREDITS - ASSOC		$ (1,865.76)	20
1928	ACINCTAXAA	54	INCOME TAXES AND CREDITS - ASSOC		$ (1,124.88)	20
1928	ACINCTAXAA	58	INCOME TAXES AND CREDITS - ASSOC		$ 357.23	20
1928	ACINCTAXAA	59	INCOME TAXES AND CREDITS - ASSOC		$ 714.36	20
1928	ACINCTAXAA	60	INCOME TAXES AND CREDITS - ASSOC		$ (821.11)	20
1928	ACINCTAXAA	69	INCOME TAXES AND CREDITS - ASSOC		$ (4,936.69)	20
1928	ACINCTAXAA	70	INCOME TAXES AND CREDITS - ASSOC		$ 3,161.18	20
1928	ACINCTAXAA	71	INCOME TAXES AND CREDITS - ASSOC		$ 3,848.97	20
1928	ACINCTAXAA	73	INCOME TAXES AND CREDITS - ASSOC		$ (2,079.32)	20
1928	ACINCTAXAA	74	INCOME TAXES AND CREDITS - ASSOC		$ 687.72	20
1928	ACINCTAXAA	75	INCOME TAXES AND CREDITS - ASSOC		$ (4,910.12)	20
1928	ACINCTAXAA	80	INCOME TAXES AND CREDITS - ASSOC		$ -	20
1963	ACINTRPTAB	06	FINANCIAL REPORTING - OPER	FINAN REPORTING REQUIREMENTS FOR BENE- FITTING COS	$ 11,469.66	70
1963	ACINTRPTAB	07	FINANCIAL REPORTING - OPER	FINAN REPORTING REQUIREMENTS FOR BENE- FITTING COS	$ 241,988.23	70
1963	ACINTRPTAB	10	FINANCIAL REPORTING - OPER	FINAN REPORTING REQUIREMENTS FOR BENE- FITTING COS	$ 116,529.83	70
1903	ACPOLPLNAA	21	TREASURY OPERATIONS - OPER & AEG		$ 232,228.71	01
1903	ACPOLPLNAA	01	TREASURY OPERATIONS - OPER & AEG		$ 12,531.45	01
1903	ACPOLPLNAA	02	TREASURY OPERATIONS - OPER & AEG		$ 239,779.32	01
1903	ACPOLPLNAA	03	TREASURY OPERATIONS - OPER & AEG		$ 35,927.01	01
1903	ACPOLPLNAA	04	TREASURY OPERATIONS - OPER & AEG		$ 149,623.27	01
1903	ACPOLPLNAA	06	TREASURY OPERATIONS - OPER & AEG		$ 12,479.21	01
1903	ACPOLPLNAA	07	TREASURY OPERATIONS - OPER & AEG		$ 259,307.84	01
1903	ACPOLPLNAA	10	TREASURY OPERATIONS - OPER & AEG		$ 125,116.55	01
1903	ACPOLPLNAA	21	TREASURY OPERATIONS - OPER & AEG		$ 56,608.20	01
1561	ACSECRPTAB	01	ANNUAL & PERIODIC FINANCIAL RPT-OPER&AEG		$ 6,312.71	01
1561	ACSECRPTAB	02	ANNUAL & PERIODIC FINANCIAL RPT-OPER&AEG		$ 120,356.06	01
1561	ACSECRPTAB	03	ANNUAL & PERIODIC FINANCIAL RPT-OPER&AEG		$ 17,968.42	01

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WO#	SERVICE ID	CO#	DESCRIPTION			AMOUNT	BASIS
1561	ACSECRPTAB	04	ANNUAL & PERIODIC FINANCIAL RPT-OPER&AEG		$	74,885.29	01
1561	ACSECRPTAB	06	ANNUAL & PERIODIC FINANCIAL RPT-OPER&AEG		$	6,263.91	01
1561	ACSECRPTAB	07	ANNUAL & PERIODIC FINANCIAL RPT-OPER&AEG		$	130,285.53	01
1561	ACSECRPTAB	10	ANNUAL & PERIODIC FINANCIAL RPT-OPER&AEG		$	62,759.25	01
1561	ACSECRPTAB	21	ANNUAL & PERIODIC FINANCIAL RPT-OPER&AEG		$	28,589.43	01
1929	ACTAXCMPAB	01	TAX OPERATIONS - OPER, AEPG		$	17,978.42	01
1929	ACTAXCMPAB	02	TAX OPERATIONS - OPER, AEPG		$	343,627.91	01
1929	ACTAXCMPAB	03	TAX OPERATIONS - OPER, AEPG		$	51,441.01	01
1929	ACTAXCMPAB	04	TAX OPERATIONS - OPER, AEPG		$	214,267.85	01
1929	ACTAXCMPAB	06	TAX OPERATIONS - OPER, AEPG		$	17,883.99	01
1929	ACTAXCMPAB	07	TAX OPERATIONS - OPER, AEPG		$	371,693.38	01
1929	ACTAXCMPAB	10	TAX OPERATIONS - OPER, AEPG		$	179,278.21	01
1929	ACTAXCMPAB	21	TAX OPERATIONS - OPER, AEPG		$	81,256.40	01
1938	AUDITSVC02	02	INTERNAL AUDITS OPERATIONS - AP		$	172,549.66	99
1941	AUDITSVC03	03	INTERNAL AUDITS OPERATIONS - KP		$	141,014.51	99
1939	AUDITSVC04	04	INTERNAL AUDITS OPERATIONS - I&M		$	163,771.41	99
1942	AUDITSVC07	07	INTERNAL AUDITS OPERATIONS - OP		$	186,134.71	99
1944	AUDITSVC10	10	INTERNAL AUDITS OPERATIONS - CSP		$	106,838.80	99
1094	AUENVAUDAA	02	ENVIRONMENTAL AUDIT PROG - GEN	SERV REL TO ENVIRONMENTAL AUDIT PROGRAM FOR BENEFIT OF G	$	25,456.27	56
1094	AUENVAUDAA	03	ENVIRONMENTAL AUDIT PROG - GEN	SERV REL TO ENVIRONMENTAL AUDIT PROGRAM FOR BENEFIT OF G	$	7,782.74	56
1094	AUENVAUDAA	04	ENVIRONMENTAL AUDIT PROG - GEN	SERV REL TO ENVIRONMENTAL AUDIT PROGRAM FOR BENEFIT OF G	$	7,458.55	56
1094	AUENVAUDAA	07	ENVIRONMENTAL AUDIT PROG - GEN	SERV REL TO ENVIRONMENTAL AUDIT PROGRAM FOR BENEFIT OF G	$	45,723.92	56
1094	AUENVAUDAA	10	ENVIRONMENTAL AUDIT PROG - GEN	SERV REL TO ENVIRONMENTAL AUDIT PROGRAM FOR BENEFIT OF G	$	14,917.06	56
1094	AUENVAUDAA	22	ENVIRONMENTAL AUDIT PROG - GEN	SERV REL TO ENVIRONMENTAL AUDIT PROGRAM FOR BENEFIT OF G	$	13,295.63	56
1094	AUENVAUDAA	70	ENVIRONMENTAL AUDIT PROG - GEN	SERV REL TO ENVIRONMENTAL AUDIT PROGRAM FOR BENEFIT OF G	$	7,620.64	56
1094	AUENVAUDAA	71	ENVIRONMENTAL AUDIT PROG - GEN	SERV REL TO ENVIRONMENTAL AUDIT PROGRAM FOR BENEFIT OF G	$	21,078.37	56
1094	AUENVAUDAA	73	ENVIRONMENTAL AUDIT PROG - GEN	SERV REL TO ENVIRONMENTAL AUDIT PROGRAM FOR BENEFIT OF G	$	18,808.46	56
1443	AUDITSVCAA	01	CORPORATE COMPLIANCE PROGRAM - ALL	TRAINING, COMMUNICATING, MONITORING, ANDAUDITING RELAT	$	5,074.28	05
1443	AUDITSVCAA	02	CORPORATE COMPLIANCE PROGRAM - ALL	TRAINING, COMMUNICATING, MONITORING, ANDAUDITING RELAT	$	208,486.83	05
1443	AUDITSVCAA	03	CORPORATE COMPLIANCE PROGRAM - ALL	TRAINING, COMMUNICATING, MONITORING, ANDAUDITING RELAT	$	43,410.41	05
1443	AUDITSVCAA	04	CORPORATE COMPLIANCE PROGRAM - ALL	TRAINING, COMMUNICATING, MONITORING, ANDAUDITING RELAT	$	160,608.93	05
1443	AUDITSVCAA	06	CORPORATE COMPLIANCE PROGRAM - ALL	TRAINING, COMMUNICATING, MONITORING, ANDAUDITING RELAT	$	5,568.64	05
1443	AUDITSVCAA	07	CORPORATE COMPLIANCE PROGRAM - ALL	TRAINING, COMMUNICATING, MONITORING, ANDAUDITING RELAT	$	159,827.37	05
1443	AUDITSVCAA	10	CORPORATE COMPLIANCE PROGRAM - ALL	TRAINING, COMMUNICATING, MONITORING, ANDAUDITING RELAT	$	102,050.80	05
1443	AUDITSVCAA	22	CORPORATE COMPLIANCE PROGRAM - ALL	TRAINING, COMMUNICATING, MONITORING, ANDAUDITING RELAT	$	17,708.53	05
1443	AUDITSVCAA	23	CORPORATE COMPLIANCE PROGRAM - ALL	TRAINING, COMMUNICATING, MONITORING, ANDAUDITING RELAT	$	15,222.76	05
1443	AUDITSVCAA	42	CORPORATE COMPLIANCE PROGRAM - ALL	TRAINING, COMMUNICATING, MONITORING, ANDAUDITING RELAT	$	12,614.53	05
1443	AUDITSVCAA	43	CORPORATE COMPLIANCE PROGRAM - ALL	TRAINING, COMMUNICATING, MONITORING, ANDAUDITING RELAT	$	13,317.16	05

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WO#	SERVICE ID	CO#		DESCRIPTION	AMOUNT	BASIS
1443	AUDITSVCAA	44	CORPORATE COMPLIANCE PROGRAM - ALL	TRAINING, COMMUNICATING, MONITORING, ANDAUDITING RELAT	$ 50,176.79	05
1443	AUDITSVCAA	46	CORPORATE COMPLIANCE PROGRAM - ALL	TRAINING, COMMUNICATING, MONITORING, ANDAUDITING RELAT	$ 845.70	05
1443	AUDITSVCAA	48	CORPORATE COMPLIANCE PROGRAM - ALL	TRAINING, COMMUNICATING, MONITORING, ANDAUDITING RELAT	$ 19,308.21	05
1443	AUDITSVCAA	49	CORPORATE COMPLIANCE PROGRAM - ALL	TRAINING, COMMUNICATING, MONITORING, ANDAUDITING RELAT	$ 4,228.54	05
1443	AUDITSVCAA	54	CORPORATE COMPLIANCE PROGRAM - ALL	TRAINING, COMMUNICATING, MONITORING, ANDAUDITING RELAT	$ 2,042.73	05
1443	AUDITSVCAA	69	CORPORATE COMPLIANCE PROGRAM - ALL	TRAINING, COMMUNICATING, MONITORING, ANDAUDITING RELAT	$ 351.34	05
1443	AUDITSVCAA	71	CORPORATE COMPLIANCE PROGRAM - ALL	TRAINING, COMMUNICATING, MONITORING, ANDAUDITING RELAT	$ 13,873.80	05
1443	AUDITSVCAA	73	CORPORATE COMPLIANCE PROGRAM - ALL	TRAINING, COMMUNICATING, MONITORING, ANDAUDITING RELAT	$ 10,987.09	05
1937	AUDITSVCAB	01	INTERNAL AUDITS OPERATIONS - OPER, AEPG		$ 44,149.47	01
1937	AUDITSVCAB	02	INTERNAL AUDITS OPERATIONS - OPER, AEPG		$ 843,153.03	01
1937	AUDITSVCAB	03	INTERNAL AUDITS OPERATIONS - OPER, AEPG		$ 126,174.62	01
1937	AUDITSVCAB	04	INTERNAL AUDITS OPERATIONS - OPER, AEPG		$ 525,572.45	01
1937	AUDITSVCAB	06	INTERNAL AUDITS OPERATIONS - OPER, AEPG		$ 43,881.51	01
1937	AUDITSVCAB	07	INTERNAL AUDITS OPERATIONS - OPER, AEPG		$ 912,044.37	01
1937	AUDITSVCAB	10	INTERNAL AUDITS OPERATIONS - OPER, AEPG		$ 439,882.41	01
1937	AUDITSVCAB	21	INTERNAL AUDITS OPERATIONS - OPER, AEPG		$ 199,540.05	01
1096	AUDITSVCEA	01	ENVIRONMENTAL AUDIT PROG - OPER	SERV REL TO ENVIRONMENTAL AUDIT PROGRAM FOR BENEFIT OF O	$ 2,824.87	12
1096	AUDITSVCEA	02	ENVIRONMENTAL AUDIT PROG - OPER	SERV REL TO ENVIRONMENTAL AUDIT PROGRAM FOR BENEFIT OF O	$ 55,564.29	12
1096	AUDITSVCEA	03	ENVIRONMENTAL AUDIT PROG - OPER	SERV REL TO ENVIRONMENTAL AUDIT PROGRAM FOR BENEFIT OF O	$ 8,317.82	12
1096	AUDITSVCEA	04	ENVIRONMENTAL AUDIT PROG - OPER	SERV REL TO ENVIRONMENTAL AUDIT PROGRAM FOR BENEFIT OF O	$ 34,881.78	12
1096	AUDITSVCEA	06	ENVIRONMENTAL AUDIT PROG - OPER	SERV REL TO ENVIRONMENTAL AUDIT PROGRAM FOR BENEFIT OF O	$ 2,903.76	12
1096	AUDITSVCEA	07	ENVIRONMENTAL AUDIT PROG - OPER	SERV REL TO ENVIRONMENTAL AUDIT PROGRAM FOR BENEFIT OF O	$ 59,967.07	12
1096	AUDITSVCEA	10	ENVIRONMENTAL AUDIT PROG - OPER	SERV REL TO ENVIRONMENTAL AUDIT PROGRAM FOR BENEFIT OF O	$ 29,122.54	12
1393	CSSUPPRTAA	01	ORDER PROCESSING SYSTEM - OPER	CREATE AN ORDER ARCHITECTURE TO BE USED BY THREE DEVMNT	$ 2,493.89	03
1393	CSSUPPRTAA	02	ORDER PROCESSING SYSTEM - OPER	CREATE AN ORDER ARCHITECTURE TO BE USED BY THREE DEVMNT	$ 48,978.79	03
1393	CSSUPPRTAA	03	ORDER PROCESSING SYSTEM - OPER	CREATE AN ORDER ARCHITECTURE TO BE USED BY THREE DEVMNT	$ 9,494.96	03
1393	CSSUPPRTAA	04	ORDER PROCESSING SYSTEM - OPER	CREATE AN ORDER ARCHITECTURE TO BE USED BY THREE DEVMNT	$ 30,650.49	03
1393	CSSUPPRTAA	06	ORDER PROCESSING SYSTEM - OPER	CREATE AN ORDER ARCHITECTURE TO BE USED BY THREE DEVMNT	$ 2,332.09	03
1393	CSSUPPRTAA	07	ORDER PROCESSING SYSTEM - OPER	CREATE AN ORDER ARCHITECTURE TO BE USED BY THREE DEVMNT	$ 38,093.86	03
1393	CSSUPPRTAA	10	ORDER PROCESSING SYSTEM - OPER	CREATE AN ORDER ARCHITECTURE TO BE USED BY THREE DEVMNT	$ 34,534.39	03
2519	CSSUPPRTAA	01	CUSTOMER SERVICES - OPER		$ 54,408.90	03
2519	CSSUPPRTAA	02	CUSTOMER SERVICES - OPER		$ 1,070,523.75	03
2519	CSSUPPRTAA	03	CUSTOMER SERVICES - OPER		$ 207,512.50	03
2519	CSSUPPRTAA	04	CUSTOMER SERVICES - OPER		$ 669,863.70	03
2519	CSSUPPRTAA	06	CUSTOMER SERVICES - OPER		$ 50,967.84	03
2519	CSSUPPRTAA	07	CUSTOMER SERVICES - OPER		$ 832,308.42	03
2519	CSSUPPRTAA	10	CUSTOMER SERVICES - OPER		$ 754,977.64	03
1953	CSSUPPRTAA	03	CUSTOMER ACCTG OPERATIONS CANTON - OPER	ACCOUNTING & MAINTENANCE OF CUSTOMER ACCTG REC	$ 89,565.36	65

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WO#	SERVICE ID	CO#	DESCRIPTION		AMOUNT	BASIS
1953	CSSUPPRTAA	06	CUSTOMER ACCTG OPERATIONS CANTON - OPER ACCOUNTING & MAINTENANCE OF CUSTOMER ACCTG REC	$	22,205.16	65
1953	CSSUPPRTAA	07	CUSTOMER ACCTG OPERATIONS CANTON - OPER ACCOUNTING & MAINTENANCE OF CUSTOMER ACCTG REC	$	360,680.36	65
1967	ISBILPRTAA	01	CORPORATE SVCS BILLING OPERATION - OPER GEN SVCS RELATED TO CORPORATE SVCS BILL-ING OPER FOR	$	111,722.37	76
1967	ISBILPRTAA	02	CORPORATE SVCS BILLING OPERATION - OPER GEN SVCS RELATED TO CORPORATE SVCS BILL-ING OPER FOR	$	2,240,654.36	76
1967	ISBILPRTAA	03	CORPORATE SVCS BILLING OPERATION - OPER GEN SVCS RELATED TO CORPORATE SVCS BILL-ING OPER FOR	$	431,624.43	76
1967	ISBILPRTAA	06	CORPORATE SVCS BILLING OPERATION - OPER GEN SVCS RELATED TO CORPORATE SVCS BILL-ING OPER FOR	$	111,722.37	76
1967	ISBILPRTAA	07	CORPORATE SVCS BILLING OPERATION - OPER GEN SVCS RELATED TO CORPORATE SVCS BILL-ING OPER FOR	$	1,737,903.65	76
1967	ISBILPRTAA	10	CORPORATE SVCS BILLING OPERATION - OPER GEN SVCS RELATED TO CORPORATE SVCS BILL-ING OPER FOR	$	1,573,171.66	76
1955	ISBILPRTAA	01	D P OPER MACHINE ROOM CANTON - BILL PRINT	$	11,730.71	72
1955	ISBILPRTAA	02	D P OPER MACHINE ROOM CANTON - BILL PRINT	$	245,172.43	72
1955	ISBILPRTAA	03	D P OPER MACHINE ROOM CANTON - BILL PRINT	$	93,845.94	72
1955	ISBILPRTAA	04	D P OPER MACHINE ROOM CANTON - BILL PRINT	$	22,288.50	72
1955	ISBILPRTAA	06	D P OPER MACHINE ROOM CANTON - BILL PRINT	$	22,288.50	72
1955	ISBILPRTAA	07	D P OPER MACHINE ROOM CANTON - BILL PRINT	$	466,882.99	72
1955	ISBILPRTAA	10	D P OPER MACHINE ROOM CANTON - BILL PRINT	$	310,864.50	72
1957	TRREMITTAA	01	D P OPER REMITTANCE PROCESSING - OPER DP SUPPORT REL TO REMITTANCE PROCESSING PERFORMED F	$	(1,136.11)	03
1957	TRREMITTAA	02	D P OPER REMITTANCE PROCESSING - OPER DP SUPPORT REL TO REMITTANCE PROCESSING PERFORMED F	$	(32,071.60)	03
1957	TRREMITTAA	03	D P OPER REMITTANCE PROCESSING - OPER DP SUPPORT REL TO REMITTANCE PROCESSING PERFORMED F	$	69,658.36	03
1957	TRREMITTAA	04	D P OPER REMITTANCE PROCESSING - OPER DP SUPPORT REL TO REMITTANCE PROCESSING PERFORMED F	$	89,872.83	03
1957	TRREMITTAA	06	D P OPER REMITTANCE PROCESSING - OPER DP SUPPORT REL TO REMITTANCE PROCESSING PERFORMED F	$	17,124.19	03
1957	TRREMITTAA	07	D P OPER REMITTANCE PROCESSING - OPER DP SUPPORT REL TO REMITTANCE PROCESSING PERFORMED F	$	279,806.92	03
1957	TRREMITTAA	10	D P OPER REMITTANCE PROCESSING - OPER DP SUPPORT REL TO REMITTANCE PROCESSING PERFORMED F	$	252,577.53	03
1966	CSSWITCHAA	04	CORPORATE SVCS SWITCH HEATER BILL-OP, WPGEN SVCS RELATED TO CORPORATE SVCS WTR HEAT BILL FO	$	32,558.28	99J
1966	CSSWITCHAA	06	CORPORATE SVCS SWITCH HEATER BILL-OP, WPGEN SVCS RELATED TO CORPORATE SVCS WTR HEAT BILL FO	$	14,778.92	99J
1966	CSSWITCHAA	07	CORPORATE SVCS SWITCH HEATER BILL-OP, WPGEN SVCS RELATED TO CORPORATE SVCS WTR HEAT BILL FO	$	170,632.61	99J
1966	CSSWITCHAA	10	CORPORATE SVCS SWITCH HEATER BILL-OP, WPGEN SVCS RELATED TO CORPORATE SVCS WTR HEAT BILL FO	$	31,274.53	99J
1478	CSADMINSAA	01	PICA 97 CONFERENCE - OPER ORGANIZE POWER INDUSTRY COMPUTER APPLI- CATIONS CONFERENCE	$	3,990.64	12
1478	CSADMINSAA	02	PICA 97 CONFERENCE - OPER ORGANIZE POWER INDUSTRY COMPUTER APPLI- CATIONS CONFERENCE	$	75,962.40	12
1478	CSADMINSAA	03	PICA 97 CONFERENCE - OPER ORGANIZE POWER INDUSTRY COMPUTER APPLI- CATIONS CONFERENCE	$	11,347.76	12
1478	CSADMINSAA	04	PICA 97 CONFERENCE - OPER ORGANIZE POWER INDUSTRY COMPUTER APPLI- CATIONS CONFERENCE	$	47,263.77	12
1478	CSADMINSAA	06	PICA 97 CONFERENCE - OPER ORGANIZE POWER INDUSTRY COMPUTER APPLI- CATIONS CONFERENCE	$	3,968.65	12
1478	CSADMINSAA	07	PICA 97 CONFERENCE - OPER ORGANIZE POWER INDUSTRY COMPUTER APPLI- CATIONS CONFERENCE	$	82,349.70	12
1478	CSADMINSAA	10	PICA 97 CONFERENCE - OPER ORGANIZE POWER INDUSTRY COMPUTER APPLI- CATIONS CONFERENCE	$	39,693.43	12
2520	CSSUPPRT02	02	CUSTOMER SERVICES - AP	$	181,638.40	99
6043	CSSUPPRT02	02	WEST VIRGINIA CALL CENTER - AP DESIGN & CONSTRUCT CALL CENTER PER CIA #21515	$	146,784.36	99
2521	CSSUPPRT04	04	CUSTOMER SERVICES - I & M	$	179,246.66	99
2524	CSSUPPRT07	07	CUSTOMER SERVICES - OP	$	283,640.32	99
1954	CSSUPPRT10	10	CUSTOMER ACCOUNTING OPERATIONS COLS-CSP ACCOUNTING & MAINTENANCE OF CUSTOMER ACCTG REC	$	705,897.31	99

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WO#	SERVICE ID	CO#	DESCRIPTION			AMOUNT	BASIS
2526	CSSUPPRT10	10	CUSTOMER SERVICES - CSP		$	276,251.44	99
1957	TRREMITT01	01	D P OPER REMITTANCE PROCESSING - OPER	DP SUPPORT REL TO REMITTANCE PROCESSING PERFORMED F	$	15,392.01	03
1957	TRREMITT02	02	D P OPER REMITTANCE PROCESSING - OPER	DP SUPPORT REL TO REMITTANCE PROCESSING PERFORMED F	$	311,484.93	03
1957	TRREMITT03	03	D P OPER REMITTANCE PROCESSING - OPER	DP SUPPORT REL TO REMITTANCE PROCESSING PERFORMED F	$	59,871.43	03
1957	TRREMITT04	04	D P OPER REMITTANCE PROCESSING - OPER	DP SUPPORT REL TO REMITTANCE PROCESSING PERFORMED F	$	194,326.60	03
1957	TRREMITT06	06	D P OPER REMITTANCE PROCESSING - OPER	DP SUPPORT REL TO REMITTANCE PROCESSING PERFORMED F	$	14,815.90	03
1957	TRREMITT07	07	D P OPER REMITTANCE PROCESSING - OPER	DP SUPPORT REL TO REMITTANCE PROCESSING PERFORMED F	$	241,057.59	03
1957	TRREMITT10	10	D P OPER REMITTANCE PROCESSING - OPER	DP SUPPORT REL TO REMITTANCE PROCESSING PERFORMED F	$	220,122.30	03
1010	CSCIVPOLAB	01	CIVIC, POLITICAL & RELATED ACT-OPER&AEG	INCLUDE MEMBERSHIPS, CONTRIBUTIONS & OTHER OUT-OF-PO	$	12,955.65	62
1010	CSCIVPOLAB	02	CIVIC, POLITICAL & RELATED ACT-OPER&AEG	INCLUDE MEMBERSHIPS, CONTRIBUTIONS & OTHER OUT-OF-PO	$	402,793.87	62
1010	CSCIVPOLAB	03	CIVIC, POLITICAL & RELATED ACT-OPER&AEG	INCLUDE MEMBERSHIPS, CONTRIBUTIONS & OTHER OUT-OF-PO	$	82,438.40	62
1010	CSCIVPOLAB	04	CIVIC, POLITICAL & RELATED ACT-OPER&AEG	INCLUDE MEMBERSHIPS, CONTRIBUTIONS & OTHER OUT-OF-PO	$	466,130.55	62
1010	CSCIVPOLAB	06	CIVIC, POLITICAL & RELATED ACT-OPER&AEG	INCLUDE MEMBERSHIPS, CONTRIBUTIONS & OTHER OUT-OF-PO	$	12,955.65	62
1010	CSCIVPOLAB	07	CIVIC, POLITICAL & RELATED ACT-OPER&AEG	INCLUDE MEMBERSHIPS, CONTRIBUTIONS & OTHER OUT-OF-PO	$	403,066.36	62
1010	CSCIVPOLAB	10	CIVIC, POLITICAL & RELATED ACT-OPER&AEG	INCLUDE MEMBERSHIPS, CONTRIBUTIONS & OTHER OUT-OF-PO	$	216,778.70	62
1010	CSCIVPOLAB	21	CIVIC, POLITICAL & RELATED ACT-OPER&AEG	INCLUDE MEMBERSHIPS, CONTRIBUTIONS & OTHER OUT-OF-PO	$	37,550.31	62
1010	CSCIVPOLAB	58	CIVIC, POLITICAL & RELATED ACT-OPER&AEG	INCLUDE MEMBERSHIPS, CONTRIBUTIONS & OTHER OUT-OF-PO	$	346.14	62
1010	CSCIVPOLAB	59	CIVIC, POLITICAL & RELATED ACT-OPER&AEG	INCLUDE MEMBERSHIPS, CONTRIBUTIONS & OTHER OUT-OF-PO	$	1,038.45	62
1010	CSCIVPOLAB	60	CIVIC, POLITICAL & RELATED ACT-OPER&AEG	INCLUDE MEMBERSHIPS, CONTRIBUTIONS & OTHER OUT-OF-PO	$	7,343.18	62
1010	CSCIVPOLAB	69	CIVIC, POLITICAL & RELATED ACT-OPER&AEG	INCLUDE MEMBERSHIPS, CONTRIBUTIONS & OTHER OUT-OF-PO	$	17,943.92	62
1010	CSCIVPOLAB	74	CIVIC, POLITICAL & RELATED ACT-OPER&AEG	INCLUDE MEMBERSHIPS, CONTRIBUTIONS & OTHER OUT-OF-PO	$	1,384.68	62
1304	CSCIVPOLAB	01	MATCHING CONTRIBUTIONS - OPER & AEG	CHARITABLE CONTRIBUTIONS MADE ON BEHALF OF EMPLOYEES T	$	874.58	62
1304	CSCIVPOLAB	02	MATCHING CONTRIBUTIONS - OPER & AEG	CHARITABLE CONTRIBUTIONS MADE ON BEHALF OF EMPLOYEES T	$	27,412.39	62
1304	CSCIVPOLAB	03	MATCHING CONTRIBUTIONS - OPER & AEG	CHARITABLE CONTRIBUTIONS MADE ON BEHALF OF EMPLOYEES T	$	5,737.26	62
1304	CSCIVPOLAB	04	MATCHING CONTRIBUTIONS - OPER & AEG	CHARITABLE CONTRIBUTIONS MADE ON BEHALF OF EMPLOYEES T	$	31,339.98	62
1304	CSCIVPOLAB	06	MATCHING CONTRIBUTIONS - OPER & AEG	CHARITABLE CONTRIBUTIONS MADE ON BEHALF OF EMPLOYEES T	$	874.58	62
1304	CSCIVPOLAB	07	MATCHING CONTRIBUTIONS - OPER & AEG	CHARITABLE CONTRIBUTIONS MADE ON BEHALF OF EMPLOYEES T	$	27,552.40	62
1304	CSCIVPOLAB	10	MATCHING CONTRIBUTIONS - OPER & AEG	CHARITABLE CONTRIBUTIONS MADE ON BEHALF OF EMPLOYEES T	$	14,715.73	62
1304	CSCIVPOLAB	21	MATCHING CONTRIBUTIONS - OPER & AEG	CHARITABLE CONTRIBUTIONS MADE ON BEHALF OF EMPLOYEES T	$	2,540.59	62
1304	CSCIVPOLAB	58	MATCHING CONTRIBUTIONS - OPER & AEG	CHARITABLE CONTRIBUTIONS MADE ON BEHALF OF EMPLOYEES T	$	29.71	62
1304	CSCIVPOLAB	59	MATCHING CONTRIBUTIONS - OPER & AEG	CHARITABLE CONTRIBUTIONS MADE ON BEHALF OF EMPLOYEES T	$	88.91	62
1304	CSCIVPOLAB	60	MATCHING CONTRIBUTIONS - OPER & AEG	CHARITABLE CONTRIBUTIONS MADE ON BEHALF OF EMPLOYEES T	$	511.24	62
1304	CSCIVPOLAB	69	MATCHING CONTRIBUTIONS - OPER & AEG	CHARITABLE CONTRIBUTIONS MADE ON BEHALF OF EMPLOYEES T	$	1,213.97	62
1304	CSCIVPOLAB	74	MATCHING CONTRIBUTIONS - OPER & AEG	CHARITABLE CONTRIBUTIONS MADE ON BEHALF OF EMPLOYEES T	$	118.41	62
1311	CSCIVPOLAB	01	CONTRIBUTIONS BY AEPSC - OPER & AEG	CONTRIBUTIONS MADE TO LOCAL CHARITIES THROUGH AEPSC	$	8,985.26	62
1311	CSCIVPOLAB	02	CONTRIBUTIONS BY AEPSC - OPER & AEG	CONTRIBUTIONS MADE TO LOCAL CHARITIES THROUGH AEPSC	$	274,854.83	62
1311	CSCIVPOLAB	03	CONTRIBUTIONS BY AEPSC - OPER & AEG	CONTRIBUTIONS MADE TO LOCAL CHARITIES THROUGH AEPSC	$	53,735.10	62
1311	CSCIVPOLAB	04	CONTRIBUTIONS BY AEPSC - OPER & AEG	CONTRIBUTIONS MADE TO LOCAL CHARITIES THROUGH AEPSC	$	325,705.51	62

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1311	CSCIVPOLAB	06	CONTRIBUTIONS BY AEPSC - OPER & AEG CONTRIBUTIONS MADE TO LOCAL CHARITIES THROUGH AEPSC	$ 8,985.26	62
1311	CSCIVPOLAB	07	CONTRIBUTIONS BY AEPSC - OPER & AEG CONTRIBUTIONS MADE TO LOCAL CHARITIES THROUGH AEPSC	$ 272,616.23	62
1311	CSCIVPOLAB	10	CONTRIBUTIONS BY AEPSC - OPER & AEG CONTRIBUTIONS MADE TO LOCAL CHARITIES THROUGH AEPSC	$ 148,678.72	62
1311	CSCIVPOLAB	21	CONTRIBUTIONS BY AEPSC - OPER & AEG CONTRIBUTIONS MADE TO LOCAL CHARITIES THROUGH AEPSC	$ 25,933.67	62
1311	CSCIVPOLAB	58	CONTRIBUTIONS BY AEPSC - OPER & AEG CONTRIBUTIONS MADE TO LOCAL CHARITIES THROUGH AEPSC	$ 115.61	62
1311	CSCIVPOLAB	59	CONTRIBUTIONS BY AEPSC - OPER & AEG CONTRIBUTIONS MADE TO LOCAL CHARITIES THROUGH AEPSC	$ 346.82	62
1311	CSCIVPOLAB	60	CONTRIBUTIONS BY AEPSC - OPER & AEG CONTRIBUTIONS MADE TO LOCAL CHARITIES THROUGH AEPSC	$ 4,781.64	62
1311	CSCIVPOLAB	69	CONTRIBUTIONS BY AEPSC - OPER & AEG CONTRIBUTIONS MADE TO LOCAL CHARITIES THROUGH AEPSC	$ 12,398.12	62
1311	CSCIVPOLAB	74	CONTRIBUTIONS BY AEPSC - OPER & AEG CONTRIBUTIONS MADE TO LOCAL CHARITIES THROUGH AEPSC	$ 462.34	62
8667	DSDSNGENAA	01	ABD CONTRACT ADMIN & SOLICITATION - OPERDISTRIBUTION RELATED	$ 3,005.73	03
8667	DSDSNGENAA	02	ABD CONTRACT ADMIN & SOLICITATION - OPERDISTRIBUTION RELATED	$ 58,911.92	03
8667	DSDSNGENAA	03	ABD CONTRACT ADMIN & SOLICITATION - OPERDISTRIBUTION RELATED	$ 11,421.66	03
8667	DSDSNGENAA	04	ABD CONTRACT ADMIN & SOLICITATION - OPERDISTRIBUTION RELATED	$ 36,870.06	03
8667	DSDSNGENAA	06	ABD CONTRACT ADMIN & SOLICITATION - OPERDISTRIBUTION RELATED	$ 2,805.38	03
8667	DSDSNGENAA	07	ABD CONTRACT ADMIN & SOLICITATION - OPERDISTRIBUTION RELATED	$ 45,792.20	03
8667	DSDSNGENAA	10	ABD CONTRACT ADMIN & SOLICITATION - OPERDISTRIBUTION RELATED	$ 41,573.84	03
8785	DSDSNGENAA	01	ON-LINE METER INFORMATION SYSTEM - OPER DESIGN & IMPLEMENT AN ON-LINE METER INFORMATION SYS	$ 16,374.42	03
8785	DSDSNGENAA	02	ON-LINE METER INFORMATION SYSTEM - OPER DESIGN & IMPLEMENT AN ON-LINE METER INFORMATION SYS	$ 322,815.78	03
8785	DSDSNGENAA	03	ON-LINE METER INFORMATION SYSTEM - OPER DESIGN & IMPLEMENT AN ON-LINE METER INFORMATION SYS	$ 62,569.04	03
8785	DSDSNGENAA	04	ON-LINE METER INFORMATION SYSTEM - OPER DESIGN & IMPLEMENT AN ON-LINE METER INFORMATION SYS	$ 201,977.39	03
8785	DSDSNGENAA	06	ON-LINE METER INFORMATION SYSTEM - OPER DESIGN & IMPLEMENT AN ON-LINE METER INFORMATION SYS	$ 15,367.84	03
8785	DSDSNGENAA	07	ON-LINE METER INFORMATION SYSTEM - OPER DESIGN & IMPLEMENT AN ON-LINE METER INFORMATION SYS	$ 251,127.77	03
8785	DSDSNGENAA	10	ON-LINE METER INFORMATION SYSTEM - OPER DESIGN & IMPLEMENT AN ON-LINE METER INFORMATION SYS	$ 227,470.78	03
3267	DSDSNGENCO	07	DISTRIBUTION O&M - CSP, OP DISTRIBUTION OHIO SOUTH REGION	$ 70,989.55	52
3267	DSDSNGENCO	10	DISTRIBUTION O&M - CSP, OP DISTRIBUTION OHIO SOUTH REGION	$ 139,337.51	52
3264	DSDSNGENE1	04	DISTRIBUTION O & M -CSP, I&M, OP, WP DISTRIBUTION NORTHERN DIVISION	$ 121,175.72	51
3264	DSDSNGENE1	06	DISTRIBUTION O & M -CSP, I&M, OP, WP DISTRIBUTION NORTHERN DIVISION	$ 9,302.69	51
3264	DSDSNGENE1	07	DISTRIBUTION O & M -CSP, I&M, OP, WP DISTRIBUTION NORTHERN DIVISION	$ 137,252.11	51
3264	DSDSNGENE1	10	DISTRIBUTION O & M -CSP, I&M, OP, WP DISTRIBUTION NORTHERN DIVISION	$ 110,219.05	51
3275	DSDSNGENE2	01	DISTRIBUTION O&M-AP,CSP,KP,KGP,OP DISTRIBUTION SOUTHERN DIVISION COMMON	$ 5,270.64	54
3275	DSDSNGENE2	02	DISTRIBUTION O&M-AP,CSP,KP,KGP,OP DISTRIBUTION SOUTHERN DIVISION COMMON	$ 104,460.83	54
3275	DSDSNGENE2	03	DISTRIBUTION O&M-AP,CSP,KP,KGP,OP DISTRIBUTION SOUTHERN DIVISION COMMON	$ 20,085.15	54
3275	DSDSNGENE2	07	DISTRIBUTION O&M-AP,CSP,KP,KGP,OP DISTRIBUTION SOUTHERN DIVISION COMMON	$ 7,155.61	54
3275	DSDSNGENE2	10	DISTRIBUTION O&M-AP,CSP,KP,KGP,OP DISTRIBUTION SOUTHERN DIVISION COMMON	$ 14,044.44	54
3255	DSOPRMNTEN	01	DISTRIBUTION O&M - OPER DISTRIBUTION COMMON	$ 113,680.84	03
3255	DSOPRMNTEN	02	DISTRIBUTION O&M - OPER DISTRIBUTION COMMON	$ 2,239,028.03	03
3255	DSOPRMNTEN	03	DISTRIBUTION O&M - OPER DISTRIBUTION COMMON	$ 433,995.88	03
3255	DSOPRMNTEN	04	DISTRIBUTION O&M - OPER DISTRIBUTION COMMON	$ 1,400,966.72	03

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WO#	SERVICE ID	CO#	DESCRIPTION	AMOUNT	BASIS
3255	DSOPRMNTEN	06	DISTRIBUTION O&M - OPER DISTRIBUTION COMMON	$ 106,595.53	03
3255	DSOPRMNTEN	07	DISTRIBUTION O&M - OPER DISTRIBUTION COMMON	$ 1,740,769.23	03
3255	DSOPRMNTEN	10	DISTRIBUTION O&M - OPER DISTRIBUTION COMMON	$ 1,578,913.42	03
1435	DSTRANTXAA	01	TRANSTEXT IMPLEMENTATION PROGRAM - OPER IMPLEMENT SYS AS COMM PRODUCT TO RESI- DENTIAL CUST	$ 16,060.77	99C
1435	DSTRANTXAA	02	TRANSTEXT IMPLEMENTATION PROGRAM - OPER IMPLEMENT SYS AS COMM PRODUCT TO RESI- DENTIAL CUST	$ 123,131.87	99C
1435	DSTRANTXAA	03	TRANSTEXT IMPLEMENTATION PROGRAM - OPER IMPLEMENT SYS AS COMM PRODUCT TO RESI- DENTIAL CUST	$ 24,091.06	99C
1435	DSTRANTXAA	04	TRANSTEXT IMPLEMENTATION PROGRAM - OPER IMPLEMENT SYS AS COMM PRODUCT TO RESI- DENTIAL CUST	$ 18,737.47	99C
1435	DSTRANTXAA	06	TRANSTEXT IMPLEMENTATION PROGRAM - OPER IMPLEMENT SYS AS COMM PRODUCT TO RESI- DENTIAL CUST	$ 2,676.80	99C
1435	DSTRANTXAA	07	TRANSTEXT IMPLEMENTATION PROGRAM - OPER IMPLEMENT SYS AS COMM PRODUCT TO RESI- DENTIAL CUST	$ 32,121.44	99C
1435	DSTRANTXAA	10	TRANSTEXT IMPLEMENTATION PROGRAM - OPER IMPLEMENT SYS AS COMM PRODUCT TO RESI- DENTIAL CUST	$ 50,858.82	99C
3256	DSDSNGEN04	04	DISTRIBUTION O&M - I & M DISTRIBUTION MICHIANA REGION	$ 135,686.83	99
3257	DSDSNGEN04	04	DISTRIBUTION O&M - I & M DISTRIBUTION INDIANA REGION	$ 162,183.99	99
3258	DSDSNGEN07	07	DISTRIBUTION O&M - OP DISTRIBUTION OHIO WEST REGION	$ 158,238.61	99
3260	DSDSNGEN10	10	DISTRIBUTION O&M - CSP DISTRIBUTION COLUMBUS REGION	$ 128,375.62	99
3584	DSSCCOOH02	02	SCET&D CONSTRUCTION OVERHEADS - AP DISTRIBUTION W VIRGINIA NORTH REGION	$ 282,501.76	99
3589	DSSCCOOH02	02	SCET&D CONSTRUCTION OVERHEADS - AP DISTRIBUTION VIRGINIA CENTRAL REGION	$ 140,907.35	99
3571	DSSCCOOH04	04	SCET&D CONSTRUCTION OVERHEADS - I & M DISTRIBUTION MICHIANA REGION	$ 332,874.77	99
3572	DSSCCOOH04	04	SCET&D CONSTRUCTION OVERHEADS - I & M DISTRIBUTION INDIANA REGION	$ 298,026.72	99
8669	DSSCCOOH04	04	SYSTEM PLANNING PROJECT - I&M SYSTEM PLANNING PROJECTS TO BE PER- FORMED BY ABD	$ 132,432.25	99
3573	DSSCCOOH07	07	SCET&D CONSTRUCTION OVERHEADS - OP DISTRIBUTION OHIO WEST REGION	$ 316,448.90	99
3574	DSSCCOOH07	07	SCET&D CONSTRUCTION OVERHEADS - OP DISTRIBUTION OHIO CENTRAL REGION	$ 478,911.65	99
3576	DSSCCOOH07	07	SCET&D CONSTRUCTION OVERHEADS - OP DISTRIBUTION OHIO EAST REGION	$ 198,607.88	99
3575	DSSCCOOH10	10	SCET&D CONSTRUCTION OVERHEADS - CSP DISTRIBUTION COLUMBUS REGION	$ 913,650.81	99
3590	DSSCCOOHE2	01	SCET&D CONSTR O/H - AP,CSP,KP,KG;,OP DISTRIBUTION SOUTHERN DIVISION COMMON	$ 1,799.32	36
3590	DSSCCOOHE2	02	SCET&D CONSTR O/H - AP,CSP,KP,KG;,OP DISTRIBUTION SOUTHERN DIVISION COMMON	$ 77,155.85	36
3590	DSSCCOOHE2	03	SCET&D CONSTR O/H - AP,CSP,KP,KG;,OP DISTRIBUTION SOUTHERN DIVISION COMMON	$ 51,874.37	36
3590	DSSCCOOHE2	07	SCET&D CONSTR O/H - AP,CSP,KP,KG;,OP DISTRIBUTION SOUTHERN DIVISION COMMON	$ 1,541.58	36
3590	DSSCCOOHE2	10	SCET&D CONSTR O/H - AP,CSP,KP,KG;,OP DISTRIBUTION SOUTHERN DIVISION COMMON	$ 8,406.21	36
3570	DSSCCOOHEN	01	SCET&D CONSTRUCTION OVERHEADS - OPER DISTRIBUTION COMMON	$ 34,562.10	29
3570	DSSCCOOHEN	02	SCET&D CONSTRUCTION OVERHEADS - OPER DISTRIBUTION COMMON	$ 1,526,849.08	29
3570	DSSCCOOHEN	03	SCET&D CONSTRUCTION OVERHEADS - OPER DISTRIBUTION COMMON	$ 918,750.79	29
3570	DSSCCOOHEN	04	SCET&D CONSTRUCTION OVERHEADS - OPER DISTRIBUTION COMMON	$ 579,445.78	29
3570	DSSCCOOHEN	06	SCET&D CONSTRUCTION OVERHEADS - OPER DISTRIBUTION COMMON	$ 36,728.47	29
3570	DSSCCOOHEN	07	SCET&D CONSTRUCTION OVERHEADS - OPER DISTRIBUTION COMMON	$ 532,652.39	29
3570	DSSCCOOHEN	10	SCET&D CONSTRUCTION OVERHEADS - OPER DISTRIBUTION COMMON	$ 746,474.40	29
3255	DSADMINSAA	01	DISTRIBUTION O&M - OPER DISTRIBUTION COMMON	$ 42,046.34	03
3255	DSADMINSAA	02	DISTRIBUTION O&M - OPER DISTRIBUTION COMMON	$ 828,133.66	03
3255	DSADMINSAA	03	DISTRIBUTION O&M - OPER DISTRIBUTION COMMON	$ 160,519.03	03

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WO#	SERVICE ID	CO#	DESCRIPTION		AMOUNT	BASIS
3255	DSADMINSAA	04	DISTRIBUTION O&M - OPER	DISTRIBUTION COMMON	$ 518,165.77	03
3255	DSADMINSAA	06	DISTRIBUTION O&M - OPER	DISTRIBUTION COMMON	$ 39,425.74	03
3255	DSADMINSAA	07	DISTRIBUTION O&M - OPER	DISTRIBUTION COMMON	$ 643,846.15	03
3255	DSADMINSAA	10	DISTRIBUTION O&M - OPER	DISTRIBUTION COMMON	$ 583,981.68	03
1053	ENMISCSR02	02	ENVIRONMENTAL - AP		$ 208,350.41	99
1054	ENMISCSR04	04	ENVIRONMENTAL - I&MP		$ 195,644.10	99
1060	ENMISCSR07	07	ENVIRONMENTAL - OP		$ 310,522.29	99
1051	ENMISCSRAA	02	ENVIRONMENTAL - GEN		$ 1,330,638.23	02
1051	ENMISCSRAA	03	ENVIRONMENTAL - GEN		$ 273,486.89	02
1051	ENMISCSRAA	04	ENVIRONMENTAL - GEN		$ 757,233.10	02
1051	ENMISCSRAA	07	ENVIRONMENTAL - GEN		$ 1,073,684.73	02
1051	ENMISCSRAA	10	ENVIRONMENTAL - GEN		$ 646,846.54	02
4456	ENMISCSRAA	02	SNCR DEMONSTRATION ON CARDINAL 1 - GEN	DESIGN, PROCURE & INSTALL SNCR AT CARD 1: R&D #7427; LEA	$ 272,025.00	02
4456	ENMISCSRAA	03	SNCR DEMONSTRATION ON CARDINAL 1 - GEN	DESIGN, PROCURE & INSTALL SNCR AT CARD 1: R&D #7427; LEA	$ 56,079.00	02
4456	ENMISCSRAA	04	SNCR DEMONSTRATION ON CARDINAL 1 - GEN	DESIGN, PROCURE & INSTALL SNCR AT CARD 1: R&D #7427; LEA	$ 156,519.00	02
4456	ENMISCSRAA	07	SNCR DEMONSTRATION ON CARDINAL 1 - GEN	DESIGN, PROCURE & INSTALL SNCR AT CARD 1: R&D #7427; LEA	$ 219,294.00	02
4456	ENMISCSRAA	10	SNCR DEMONSTRATION ON CARDINAL 1 - GEN	DESIGN, PROCURE & INSTALL SNCR AT CARD 1: R&D #7427; LEA	$ 133,083.00	02
1091	ENMISCSRAA	02	ACID RAIN TECHNICAL SERVICES-GEN & ROCK	ACID RAIN EFFECTS ON ENVIRONMENT & ANALYSIS OF IMPAC	$ 56,944.12	43
1091	ENMISCSRAA	03	ACID RAIN TECHNICAL SERVICES-GEN & ROCK	ACID RAIN EFFECTS ON ENVIRONMENT & ANALYSIS OF IMPAC	$ 12,463.67	43
1091	ENMISCSRAA	04	ACID RAIN TECHNICAL SERVICES-GEN & ROCK	ACID RAIN EFFECTS ON ENVIRONMENT & ANALYSIS OF IMPAC	$ 10,052.96	43
1091	ENMISCSRAA	07	ACID RAIN TECHNICAL SERVICES-GEN & ROCK	ACID RAIN EFFECTS ON ENVIRONMENT & ANALYSIS OF IMPAC	$ 102,383.97	43
1091	ENMISCSRAA	10	ACID RAIN TECHNICAL SERVICES-GEN & ROCK	ACID RAIN EFFECTS ON ENVIRONMENT & ANALYSIS OF IMPAC	$ 27,266.66	43
1091	ENMISCSRAA	73	ACID RAIN TECHNICAL SERVICES-GEN & ROCK	ACID RAIN EFFECTS ON ENVIRONMENT & ANALYSIS OF IMPAC	$ 33,944.75	43
1437	ENMISCSRAA	01	EPRI ADMINISTRATION - OPER & AEG	ACTIVITIES OF RESEARCH ADMIN COMMITTEE RELATED TO EPRI MEM	$ 3,511.06	01
1437	ENMISCSRAA	02	EPRI ADMINISTRATION - OPER & AEG	ACTIVITIES OF RESEARCH ADMIN COMMITTEE RELATED TO EPRI MEM	$ 67,251.64	01
1437	ENMISCSRAA	03	EPRI ADMINISTRATION - OPER & AEG	ACTIVITIES OF RESEARCH ADMIN COMMITTEE RELATED TO EPRI MEM	$ 10,070.97	01
1437	ENMISCSRAA	04	EPRI ADMINISTRATION - OPER & AEG	ACTIVITIES OF RESEARCH ADMIN COMMITTEE RELATED TO EPRI MEM	$ 41,952.34	01
1437	ENMISCSRAA	06	EPRI ADMINISTRATION - OPER & AEG	ACTIVITIES OF RESEARCH ADMIN COMMITTEE RELATED TO EPRI MEM	$ 3,500.08	01
1437	ENMISCSRAA	07	EPRI ADMINISTRATION - OPER & AEG	ACTIVITIES OF RESEARCH ADMIN COMMITTEE RELATED TO EPRI MEM	$ 72,757.15	01
1437	ENMISCSRAA	10	EPRI ADMINISTRATION - OPER & AEG	ACTIVITIES OF RESEARCH ADMIN COMMITTEE RELATED TO EPRI MEM	$ 35,082.71	01
1437	ENMISCSRAA	21	EPRI ADMINISTRATION - OPER & AEG	ACTIVITIES OF RESEARCH ADMIN COMMITTEE RELATED TO EPRI MEM	$ 15,880.99	01
1011	EXSUPPRTAA	01	MISC NON-OPERATING EXPENSES-OPER & AEG	INCLUDE COUNTRY & SERVICE CLUB MEMBER- SHIPS & CHAM	$ 989.97	62
1011	EXSUPPRTAA	02	MISC NON-OPERATING EXPENSES-OPER & AEG	INCLUDE COUNTRY & SERVICE CLUB MEMBER- SHIPS & CHAM	$ 32,612.48	62
1011	EXSUPPRTAA	03	MISC NON-OPERATING EXPENSES-OPER & AEG	INCLUDE COUNTRY & SERVICE CLUB MEMBER- SHIPS & CHAM	$ 7,701.58	62
1011	EXSUPPRTAA	04	MISC NON-OPERATING EXPENSES-OPER & AEG	INCLUDE COUNTRY & SERVICE CLUB MEMBER- SHIPS & CHAM	$ 34,628.92	62
1011	EXSUPPRTAA	06	MISC NON-OPERATING EXPENSES-OPER & AEG	INCLUDE COUNTRY & SERVICE CLUB MEMBER- SHIPS & CHAM	$ 989.97	62
1011	EXSUPPRTAA	07	MISC NON-OPERATING EXPENSES-OPER & AEG	INCLUDE COUNTRY & SERVICE CLUB MEMBER- SHIPS & CHAM	$ 33,623.04	62
1011	EXSUPPRTAA	10	MISC NON-OPERATING EXPENSES-OPER & AEG	INCLUDE COUNTRY & SERVICE CLUB MEMBER- SHIPS & CHAM	$ 17,243.69	62

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AMERICAN ELECTRIC POWER SERVICE CORPORATION
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WO#	SERVICE ID	CO#	DESCRIPTION		AMOUNT	BASIS
1011	EXSUPPRTAA	21	MISC NON-OPERATING EXPENSES-OPER & AEG INCLUDE COUNTRY & SERVICE CLUB MEMBER- SHIPS & CHAM	$	2,913.78	62
1011	EXSUPPRTAA	58	MISC NON-OPERATING EXPENSES-OPER & AEG INCLUDE COUNTRY & SERVICE CLUB MEMBER- SHIPS & CHAM	$	77.22	62
1011	EXSUPPRTAA	59	MISC NON-OPERATING EXPENSES-OPER & AEG INCLUDE COUNTRY & SERVICE CLUB MEMBER- SHIPS & CHAM	$	231.64	62
1011	EXSUPPRTAA	60	MISC NON-OPERATING EXPENSES-OPER & AEG INCLUDE COUNTRY & SERVICE CLUB MEMBER- SHIPS & CHAM	$	688.03	62
1011	EXSUPPRTAA	69	MISC NON-OPERATING EXPENSES-OPER & AEG INCLUDE COUNTRY & SERVICE CLUB MEMBER- SHIPS & CHAM	$	1,390.21	62
1011	EXSUPPRTAA	74	MISC NON-OPERATING EXPENSES-OPER & AEG INCLUDE COUNTRY & SERVICE CLUB MEMBER- SHIPS & CHAM	$	308.84	62
1402	EXSUPPRTAA	01	EXECUTIVE GROUP OPERATIONS - OPER & AEG	$	61,312.98	01
1402	EXSUPPRTAA	02	EXECUTIVE GROUP OPERATIONS - OPER & AEG	$	1,158,600.16	01
1402	EXSUPPRTAA	03	EXECUTIVE GROUP OPERATIONS - OPER & AEG	$	171,090.33	01
1402	EXSUPPRTAA	04	EXECUTIVE GROUP OPERATIONS - OPER & AEG	$	714,689.36	01
1402	EXSUPPRTAA	06	EXECUTIVE GROUP OPERATIONS - OPER & AEG	$	60,298.93	01
1402	EXSUPPRTAA	07	EXECUTIVE GROUP OPERATIONS - OPER & AEG	$	1,258,196.55	01
1402	EXSUPPRTAA	10	EXECUTIVE GROUP OPERATIONS - OPER & AEG	$	602,810.94	01
1402	EXSUPPRTAA	21	EXECUTIVE GROUP OPERATIONS - OPER & AEG	$	280,064.71	01
1402	STRATDEVAA	01	EXECUTIVE GROUP OPERATIONS - OPER & AEG	$	23,843.94	01
1402	STRATDEVAA	02	EXECUTIVE GROUP OPERATIONS - OPER & AEG	$	450,566.73	01
1402	STRATDEVAA	03	EXECUTIVE GROUP OPERATIONS - OPER & AEG	$	66,535.13	01
1402	STRATDEVAA	04	EXECUTIVE GROUP OPERATIONS - OPER & AEG	$	277,934.75	01
1402	STRATDEVAA	06	EXECUTIVE GROUP OPERATIONS - OPER & AEG	$	23,449.59	01
1402	STRATDEVAA	07	EXECUTIVE GROUP OPERATIONS - OPER & AEG	$	489,298.66	01
1402	STRATDEVAA	10	EXECUTIVE GROUP OPERATIONS - OPER & AEG	$	234,426.48	01
1402	STRATDEVAA	21	EXECUTIVE GROUP OPERATIONS - OPER & AEG	$	108,914.06	01
1982	GSOFFICEAB	01	CORPORATE SERVICES-OPER GEN SERVICES RELATED TO CORPORATE SVCS FOR THE BENEFIT OF	$	8,324.11	12
1982	GSOFFICEAB	02	CORPORATE SERVICES-OPER GEN SERVICES RELATED TO CORPORATE SVCS FOR THE BENEFIT OF	$	156,628.89	12
1982	GSOFFICEAB	03	CORPORATE SERVICES-OPER GEN SERVICES RELATED TO CORPORATE SVCS FOR THE BENEFIT OF	$	23,259.83	12
1982	GSOFFICEAB	04	CORPORATE SERVICES-OPER GEN SERVICES RELATED TO CORPORATE SVCS FOR THE BENEFIT OF	$	96,953.84	12
1982	GSOFFICEAB	06	CORPORATE SERVICES-OPER GEN SERVICES RELATED TO CORPORATE SVCS FOR THE BENEFIT OF	$	8,176.74	12
1982	GSOFFICEAB	07	CORPORATE SERVICES-OPER GEN SERVICES RELATED TO CORPORATE SVCS FOR THE BENEFIT OF	$	169.973.44	12
1982	GSOFFICEAB	10	CORPORATE SERVICES-OPER GEN SERVICES RELATED TO CORPORATE SVCS FOR THE BENEFIT OF	$	81,800.59	12
2282	GSFLEETSAA	01	AUTOMOTIVE - OPER	$	13,339.61	12
2282	GSFLEETSAA	02	AUTOMOTIVE - OPER	$	259,689.14	12
2282	GSFLEETSAA	03	AUTOMOTIVE - OPER	$	38,836.27	12
2282	GSFLEETSAA	04	AUTOMOTIVE - OPER	$	162,554.28	12
2282	GSFLEETSAA	06	AUTOMOTIVE - OPER	$	13,569.43	12
2282	GSFLEETSAA	07	AUTOMOTIVE - OPER	$	280,648.01	12
2282	GSFLEETSAA	10	AUTOMOTIVE - OPER	$	135,985.67	12
1780	GSOFFICE02	02	CORPORATE SERVICES - AP GEN SERVICES RELATED TO CORPORATE SVCS FOR THE BENEFIT OF AP	$	334,246.62	99
1782	GSOFFICE03	03	CORPORATE SERVICES - KP GEN SERVICES RELATED TO CORPORATE SVCS FOR THE BENEFIT OF KP	$	439,124.28	99

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WO#	SERVICE ID	CO#	DESCRIPTION		AMOUNT	BASIS
1783	GSOFFICE04	04	CORPORATE SERVICES - I&M GEN SERVICES RELATED TO CORPORATE SVCS FOR THE BENEFIT OF I&	$	590,202.54	99
1050	GSOFFICE10	10	ADMIN SERVICES DEPT 37 CHARGES - CSPCO TO BILL COLS SOUTHERN PWR ADMIN CHARGES BASED ON NUM	$	116,438.94	99
0214	EXSUPPRTRR	60	ADMINISTRATIVE SERVICES - AEP	$	552,214.82	99
0222	PMPOWERMR	60	OFF SYSTEM RETAIL MARKETING - AEPCO DEV/IMPLMENT NATURAL GAS CAPABILITIES FOR SUPPORT ON S	$	365,710.58	99
2200	RGSUPPRT02	02	GENERAL RATE ACTIVITY WEST VIRGINIA - AP	$	147,839.84	99
2201	RGSUPPRT02	02	GENERAL RATE ACTIVITY VIRGINIA - AP	$	449,720.92	99
2292	GSBLDSVCAA	01	LAND MANAGEMENT OPERATIONS - OPER & AEG	$	3,399.81	01
2292	GSBLDSVCAA	02	LAND MANAGEMENT OPERATIONS - OPER & AEG	$	64,861.24	01
2292	GSBLDSVCAA	03	LAND MANAGEMENT OPERATIONS - OPER & AEG	$	9,711.74	01
2292	GSBLDSVCAA	04	LAND MANAGEMENT OPERATIONS - OPER & AEG	$	40,443.59	01
2292	GSBLDSVCAA	06	LAND MANAGEMENT OPERATIONS - OPER & AEG	$	3,375.70	01
2292	GSBLDSVCAA	07	LAND MANAGEMENT OPERATIONS - OPER & AEG	$	70,133.74	01
2292	GSBLDSVCAA	10	LAND MANAGEMENT OPERATIONS - OPER & AEG	$	33,847.82	01
2292	GSBLDSVCAA	21	LAND MANAGEMENT OPERATIONS - OPER & AEG	$	15,346.16	01
1130	GSBLDSVCAA	01	GRN LGHT(INT)-OPER,AEG,COC,KV,SIM,SOC,WCSYSTEM-WIDE PROJ TO COORDINATE RELAMPINGOF ALL FACILI	$	674.72	08
1130	GSBLDSVCAA	02	GRN LGHT(INT)-OPER,AEG,COC,KV,SIM,SOC,WCSYSTEM-WIDE PROJ TO COORDINATE RELAMPINGOF ALL FACILI	$	34,940.18	08
1130	GSBLDSVCAA	03	GRN LGHT(INT)-OPER,AEG,COC,KV,SIM,SOC,WCSYSTEM-WIDE PROJ TO COORDINATE RELAMPINGOF ALL FACILI	$	7,888.92	08
1130	GSBLDSVCAA	04	GRN LGHT(INT)-OPER,AEG,COC,KV,SIM,SOC,WCSYSTEM-WIDE PROJ TO COORDINATE RELAMPINGOF ALL FACILI	$	25,554.70	08
1130	GSBLDSVCAA	06	GRN LGHT(INT)-OPER,AEG,COC,KV,SIM,SOC,WCSYSTEM-WIDE PROJ TO COORDINATE RELAMPINGOF ALL FACILI	$	674.72	08
1130	GSBLDSVCAA	07	GRN LGHT(INT)-OPER,AEG,COC,KV,SIM,SOC,WCSYSTEM-WIDE PROJ TO COORDINATE RELAMPINGOF ALL FACILI	$	30,655.87	08
1130	GSBLDSVCAA	10	GRN LGHT(INT)-OPER,AEG,COC,KV,SIM,SOC,WCSYSTEM-WIDE PROJ TO COORDINATE RELAMPINGOF ALL FACILI	$	22,555.40	08
1130	GSBLDSVCAA	42	GRN LGHT(INT)-OPER,AEG,COC,KV,SIM,SOC,WCSYSTEM-WIDE PROJ TO COORDINATE RELAMPINGOF ALL FACILI	$	250.51	08
1130	GSBLDSVCAA	43	GRN LGHT(INT)-OPER,AEG,COC,KV,SIM,SOC,WCSYSTEM-WIDE PROJ TO COORDINATE RELAMPINGOF ALL FACILI	$	385.48	08
1130	GSBLDSVCAA	44	GRN LGHT(INT)-OPER,AEG,COC,KV,SIM,SOC,WCSYSTEM-WIDE PROJ TO COORDINATE RELAMPINGOF ALL FACILI	$	2,027.77	08
1130	GSBLDSVCAA	73	GRN LGHT(INT)-OPER,AEG,COC,KV,SIM,SOC,WCSYSTEM-WIDE PROJ TO COORDINATE RELAMPINGOF ALL FACILI	$	9,338.13	08
1893	RMANAGMTAA	01	RISK MGT - OPER,AEG,COC,KV,SIM,SOC,WC	$	4,805.37	08
1893	RMANAGMTAA	02	RISK MGT - OPER,AEG,COC,KV,SIM,SOC,WC	$	249,484.94	08
1893	RMANAGMTAA	03	RISK MGT - OPER,AEG,COC,KV,SIM,SOC,WC	$	56,653.07	08
1893	RMANAGMTAA	04	RISK MGT - OPER,AEG,COC,KV,SIM,SOC,WC	$	181,609.45	08
1893	RMANAGMTAA	06	RISK MGT - OPER,AEG,COC,KV,SIM,SOC,WC	$	4,805.37	08
1893	RMANAGMTAA	07	RISK MGT - OPER,AEG,COC,KV,SIM,SOC,WC	$	218,240.21	08
1893	RMANAGMTAA	10	RISK MGT - OPER,AEG,COC,KV,SIM,SOC,WC	$	160,767.09	08
1893	RMANAGMTAA	42	RISK MGT - OPER,AEG,COC,KV,SIM,SOC,WC	$	1,651.77	08
1893	RMANAGMTAA	43	RISK MGT - OPER,AEG,COC,KV,SIM,SOC,WC	$	2,612.84	08
1893	RMANAGMTAA	44	RISK MGT - OPER,AEG,COC,KV,SIM,SOC,WC	$	14,225.51	08
1893	RMANAGMTAA	73	RISK MGT - OPER,AEG,COC,KV,SIM,SOC,WC	$	66,202.60	08
1892	HRBENSERAB	01	EMPLOYEE BENEFITS ACCOUNTING - ALL	$	2,995.30	05
1892	HRBENSERAB	02	EMPLOYEE BENEFITS ACCOUNTING - ALL	$	124,313.50	05

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WO#	SERVICE ID	CO#	DESCRIPTION		AMOUNT	BASIS
1892	HRBENSERAB	03	EMPLOYEE BENEFITS ACCOUNTING - ALL	$	25,526.26	05
1892	HRBENSERAB	04	EMPLOYEE BENEFITS ACCOUNTING - ALL	$	95,563.76	05
1892	HRBENSERAB	06	EMPLOYEE BENEFITS ACCOUNTING - ALL	$	3,310.73	05
1892	HRBENSERAB	07	EMPLOYEE BENEFITS ACCOUNTING - ALL	$	94,037.12	05
1892	HRBENSERAB	10	EMPLOYEE BENEFITS ACCOUNTING - ALL	$	60,336.41	05
1892	HRBENSERAB	22	EMPLOYEE BENEFITS ACCOUNTING - ALL	$	10,662.47	05
1892	HRBENSERAB	23	EMPLOYEE BENEFITS ACCOUNTING - ALL	$	8,985.72	05
1892	HRBENSERAB	42	EMPLOYEE BENEFITS ACCOUNTING - ALL	$	7,473.34	05
1892	HRBENSERAB	43	EMPLOYEE BENEFITS ACCOUNTING - ALL	$	7,840.92	05
1892	HRBENSERAB	44	EMPLOYEE BENEFITS ACCOUNTING - ALL	$	29,621.94	05
1892	HRBENSERAB	46	EMPLOYEE BENEFITS ACCOUNTING - ALL	$	499.26	05
1892	HRBENSERAB	48	EMPLOYEE BENEFITS ACCOUNTING - ALL	$	11,349.90	05
1892	HRBENSERAB	49	EMPLOYEE BENEFITS ACCOUNTING - ALL	$	2,496.04	05
1892	HRBENSERAB	54	EMPLOYEE BENEFITS ACCOUNTING - ALL	$	1,182.21	05
1892	HRBENSERAB	69	EMPLOYEE BENEFITS ACCOUNTING - ALL	$	183.77	05
1892	HRBENSERAB	71	EMPLOYEE BENEFITS ACCOUNTING - ALL	$	7,149.80	05
1892	HRBENSERAB	73	EMPLOYEE BENEFITS ACCOUNTING - ALL	$	5,672.67	05
2400	HRBENSERAB	01	SYS HUMAN RESOURCES EMP BENEFITS - ALL	$	15,038.71	05
2400	HRBENSERAB	02	SYS HUMAN RESOURCES EMP BENEFITS - ALL	$	626,241.87	05
2400	HRBENSERAB	03	SYS HUMAN RESOURCES EMP BENEFITS - ALL	$	127,846.47	05
2400	HRBENSERAB	04	SYS HUMAN RESOURCES EMP BENEFITS - ALL	$	478,106.89	05
2400	HRBENSERAB	06	SYS HUMAN RESOURCES EMP BENEFITS - ALL	$	16,774.83	05
2400	HRBENSERAB	07	SYS HUMAN RESOURCES EMP BENEFITS - ALL	$	475,328.95	05
2400	HRBENSERAB	10	SYS HUMAN RESOURCES EMP BENEFITS - ALL	$	303,260.97	05
2400	HRBENSERAB	22	SYS HUMAN RESOURCES EMP BENEFITS - ALL	$	51,943.54	05
2400	HRBENSERAB	23	SYS HUMAN RESOURCES EMP BENEFITS - ALL	$	45,115.96	05
2400	HRBENSERAB	42	SYS HUMAN RESOURCES EMP BENEFITS - ALL	$	37,383.19	05
2400	HRBENSERAB	43	SYS HUMAN RESOURCES EMP BENEFITS - ALL	$	38,923.69	05
2400	HRBENSERAB	44	SYS HUMAN RESOURCES EMP BENEFITS - ALL	$	148,436.69	05
2400	HRBENSERAB	46	SYS HUMAN RESOURCES EMP BENEFITS - ALL	$	2,506.64	05
2400	HRBENSERAB	48	SYS HUMAN RESOURCES EMP BENEFITS - ALL	$	56,682.29	05
2400	HRBENSERAB	49	SYS HUMAN RESOURCES EMP BENEFITS - ALL	$	12,532.50	05
2400	HRBENSERAB	54	SYS HUMAN RESOURCES EMP BENEFITS - ALL	$	5,783.28	05
2400	HRBENSERAB	69	SYS HUMAN RESOURCES EMP BENEFITS - ALL	$	770.37	05
2400	HRBENSERAB	71	SYS HUMAN RESOURCES EMP BENEFITS - ALL	$	35,486.84	05
2400	HRBENSERAB	73	SYS HUMAN RESOURCES EMP BENEFITS - ALL	$	28,274.60	05
2425	HRBENSERAB	01	SYSTEM HUMAN RESOURCES OTHER - ALL	$	58,167.70	05
2425	HRBENSERAB	02	SYSTEM HUMAN RESOURCES OTHER - ALL	$	2,416,277.59	05

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WO#	SERVICE ID	CO#	DESCRIPTION	AMOUNT	BASIS
2425	HRBENSERAB	03	SYSTEM HUMAN RESOURCES OTHER - ALL	$ 495,270.55	05
2425	HRBENSERAB	04	SYSTEM HUMAN RESOURCES OTHER - ALL	$ 1,851,538.80	05
2425	HRBENSERAB	06	SYSTEM HUMAN RESOURCES OTHER - ALL	$ 64,546.13	05
2425	HRBENSERAB	07	SYSTEM HUMAN RESOURCES OTHER - ALL	$ 1,832,922.83	05
2425	HRBENSERAB	10	SYSTEM HUMAN RESOURCES OTHER - ALL	$ 1,172,203.27	05
2425	HRBENSERAB	22	SYSTEM HUMAN RESOURCES OTHER - ALL	$ 203,500.52	05
2425	HRBENSERAB	23	SYSTEM HUMAN RESOURCES OTHER - ALL	$ 174,503.10	05
2425	HRBENSERAB	42	SYSTEM HUMAN RESOURCES OTHER - ALL	$ 144,830.93	05
2425	HRBENSERAB	43	SYSTEM HUMAN RESOURCES OTHER - ALL	$ 151,463.61	05
2425	HRBENSERAB	44	SYSTEM HUMAN RESOURCES OTHER - ALL	$ 574,710.12	05
2425	HRBENSERAB	46	SYSTEM HUMAN RESOURCES OTHER - ALL	$ 9,695.48	05
2425	HRBENSERAB	48	SYSTEM HUMAN RESOURCES OTHER - ALL	$ 219,914.80	05
2425	HRBENSERAB	49	SYSTEM HUMAN RESOURCES OTHER - ALL	$ 48,474.12	05
2425	HRBENSERAB	54	SYSTEM HUMAN RESOURCES OTHER - ALL	$ 22,706.62	05
2425	HRBENSERAB	69	SYSTEM HUMAN RESOURCES OTHER - ALL	$ 3,316.98	05
2425	HRBENSERAB	71	SYSTEM HUMAN RESOURCES OTHER - ALL	$ 139,603.33	05
2425	HRBENSERAB	73	SYSTEM HUMAN RESOURCES OTHER - ALL	$ 110,968.98	05
2410	HRSAFETYAB	01	SYS HUM RESOURCES SAFETY & ACCD PREV-ALL	$ 6,369.89	05
2410	HRSAFETYAB	02	SYS HUM RESOURCES SAFETY & ACCD PREV-ALL	$ 265,138.31	05
2410	HRSAFETYAB	03	SYS HUM RESOURCES SAFETY & ACCD PREV-ALL	$ 54,134.85	05
2410	HRSAFETYAB	04	SYS HUM RESOURCES SAFETY & ACCD PREV-ALL	$ 201,962.86	05
2410	HRSAFETYAB	06	SYS HUM RESOURCES SAFETY & ACCD PREV-ALL	$ 7,121.19	05
2410	HRSAFETYAB	07	SYS HUM RESOURCES SAFETY & ACCD PREV-ALL	$ 201,788.30	05
2410	HRSAFETYAB	10	SYS HUM RESOURCES SAFETY & ACCD PREV-ALL	$ 128,465.29	05
2410	HRSAFETYAB	22	SYS HUM RESOURCES SAFETY & ACCD PREV-ALL	$ 21,831.30	05
2410	HRSAFETYAB	23	SYS HUM RESOURCES SAFETY & ACCD PREV-ALL	$ 19,109.33	05
2410	HRSAFETYAB	42	SYS HUM RESOURCES SAFETY & ACCD PREV-ALL	$ 15,802.23	05
2410	HRSAFETYAB	43	SYS HUM RESOURCES SAFETY & ACCD PREV-ALL	$ 16,422.59	05
2410	HRSAFETYAB	44	SYS HUM RESOURCES SAFETY & ACCD PREV-ALL	$ 62,823.85	05
2410	HRSAFETYAB	46	SYS HUM RESOURCES SAFETY & ACCD PREV-ALL	$ 1,061.77	05
2410	HRSAFETYAB	48	SYS HUM RESOURCES SAFETY & ACCD PREV-ALL	$ 23,976.37	05
2410	HRSAFETYAB	49	SYS HUM RESOURCES SAFETY & ACCD PREV-ALL	$ 5,308.44	05
2410	HRSAFETYAB	54	SYS HUM RESOURCES SAFETY & ACCD PREV-ALL	$ 2,433.68	05
2410	HRSAFETYAB	69	SYS HUM RESOURCES SAFETY & ACCD PREV-ALL	$ 310.26	05
2410	HRSAFETYAB	71	SYS HUM RESOURCES SAFETY & ACCD PREV-ALL	$ 15,334.89	05
2410	HRSAFETYAB	73	SYS HUM RESOURCES SAFETY & ACCD PREV-ALL	$ 12,232.15	05
2421	HRTRAINSAB	01	SYS HUM RESOURCES EDUCATION & TRAIN-ALL	$ 829.41	05
2421	HRTRAINSAB	02	SYS HUM RESOURCES EDUCATION & TRAIN-ALL	$ 34,457.70	05

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WO#	SERVICE ID	CO#	DESCRIPTION	AMOUNT	BASIS
2421	HRTRAINSAB	03	SYS HUM RESOURCES EDUCATION & TRAIN-ALL	$ 7,054.27	05
2421	HRTRAINSAB	04	SYS HUM RESOURCES EDUCATION & TRAIN-ALL	$ 26,252.64	05
2421	HRTRAINSAB	06	SYS HUM RESOURCES EDUCATION & TRAIN-ALL	$ 926.21	05
2421	HRTRAINSAB	07	SYS HUM RESOURCES EDUCATION & TRAIN-ALL	$ 26,340.95	05
2421	HRTRAINSAB	10	SYS HUM RESOURCES EDUCATION & TRAIN-ALL	$ 16,723.04	05
2421	HRTRAINSAB	22	SYS HUM RESOURCES EDUCATION & TRAIN-ALL	$ 2,785.71	05
2421	HRTRAINSAB	23	SYS HUM RESOURCES EDUCATION & TRAIN-ALL	$ 2,488.29	05
2421	HRTRAINSAB	42	SYS HUM RESOURCES EDUCATION & TRAIN-ALL	$ 2,055.87	05
2421	HRTRAINSAB	43	SYS HUM RESOURCES EDUCATION & TRAIN-ALL	$ 2,138.90	05
2421	HRTRAINSAB	44	SYS HUM RESOURCES EDUCATION & TRAIN-ALL	$ 8,179.98	05
2421	HRTRAINSAB	46	SYS HUM RESOURCES EDUCATION & TRAIN-ALL	$ 138.33	05
2421	HRTRAINSAB	48	SYS HUM RESOURCES EDUCATION & TRAIN-ALL	$ 3,124.38	05
2421	HRTRAINSAB	49	SYS HUM RESOURCES EDUCATION & TRAIN-ALL	$ 691.27	05
2421	HRTRAINSAB	54	SYS HUM RESOURCES EDUCATION & TRAIN-ALL	$ 318.02	05
2421	HRTRAINSAB	69	SYS HUM RESOURCES EDUCATION & TRAIN-ALL	$ 41.53	05
2421	HRTRAINSAB	71	SYS HUM RESOURCES EDUCATION & TRAIN-ALL	$ 2,055.01	05
2421	HRTRAINSAB	73	SYS HUM RESOURCES EDUCATION & TRAIN-ALL	$ 1,638.52	05
1467	HRTRAINSAB	01	POWER SYSTEM CONCEPTS COURSE - OPER, AEPSERVICES RELATED TO PARTICIPATION IN THEPOWER SYSTE	$ 6,120.14	01
1467	HRTRAINSAB	02	POWER SYSTEM CONCEPTS COURSE - OPER, AEPSERVICES RELATED TO PARTICIPATION IN THEPOWER SYSTE	$ 117,221.27	01
1467	HRTRAINSAB	03	POWER SYSTEM CONCEPTS COURSE - OPER, AEPSERVICES RELATED TO PARTICIPATION IN THEPOWER SYSTE	$ 17,434.10	01
1467	HRTRAINSAB	04	POWER SYSTEM CONCEPTS COURSE - OPER, AEPSERVICES RELATED TO PARTICIPATION IN THEPOWER SYSTE	$ 72,763.70	01
1467	HRTRAINSAB	06	POWER SYSTEM CONCEPTS COURSE - OPER, AEPSERVICES RELATED TO PARTICIPATION IN THEPOWER SYSTE	$ 6,100.74	01
1467	HRTRAINSAB	07	POWER SYSTEM CONCEPTS COURSE - OPER, AEPSERVICES RELATED TO PARTICIPATION IN THEPOWER SYSTE	$ 127,175.37	01
1467	HRTRAINSAB	10	POWER SYSTEM CONCEPTS COURSE - OPER, AEPSERVICES RELATED TO PARTICIPATION IN THEPOWER SYSTE	$ 61,030.33	01
1467	HRTRAINSAB	21	POWER SYSTEM CONCEPTS COURSE - OPER, AEPSERVICES RELATED TO PARTICIPATION IN THEPOWER SYSTE	$ 27,921.08	01
2402	HRBENSER02	02	SYS HUMAN RESOURCES EMP BENEFITS - AP	$ 650,640.25	99
2403	HRBENSER03	03	SYS HUMAN RESOURCES EMP BENEFITS - KP	$ 174,716.23	99
2404	HRBENSER04	04	SYS HUMAN RESOURCES EMP BENEFITS - I&MP	$ 411,169.89	99
2407	HRBENSER07	07	SYS HUMAN RESOURCES EMP BENEFITS - OP	$ 414,379.58	99
2408	HRBENSER10	10	SYS HUMAN RESOURCES EMP BENEFITS - CSP	$ 290,716.20	99
2442	HRBENSER02	02	SYSTEM HUMAN RESOURCES OTHER - AP	$ 1,037,875.11	99
2443	HRBENSER03	03	SYSTEM HUMAN RESOURCES OTHER - KP	$ 179,186.37	99
2444	HRBENSER04	04	SYSTEM HUMAN RESOURCES OTHER - I&MP	$ 1,232,363.51	99
2447	HRBENSER07	07	SYSTEM HUMAN RESOURCES OTHER - OP	$ 648,239.86	99
2448	HRBENSER10	10	SYSTEM HUMAN RESOURCES OTHER - CSP	$ 681,913.48	99
2412	HRSAFETY02	02	SYS HUM RESOURCES SAFETY & ACCD PREV-AP	$ 472,200.61	99
2413	HRSAFETY03	03	SYS HUM RESOURCES SAFETY & ACCD PREV-KP	$ 143,996.85	99
2414	HRSAFETY04	04	SYS HUM RESOURCES SAFETY&ACCD PREV-I&MP	$ 437,927.27	99

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WO#	SERVICE ID	CO#	DESCRIPTION	AMOUNT	BASIS
2417	HRSAFETY07	07	SYS HUM RESOURCES SAFETY & ACCD PREV-OP	$ 775,577.19	99
2418	HRSAFETY10	10	SYS HUM RESOURCES SAFETY & ACCD PREV-CSP	$ 523,043.72	99
2432	HRTRAINS02	02	SYS HUM RESOURCES EDUCATION & TRAIN - AP	$ 189,998.58	99
2434	HRTRAINS04	04	SYS HUM RESOURCES EDUCATION & TRAIN-I&MP	$ 489,760.85	99
2437	HRTRAINS07	07	SYS HUM RESOURCES EDUCATION & TRAIN - OP	$ 230,154.59	99
2438	HRTRAINS10	10	SYS HUM RESOURCES EDUCATION & TRAIN-CSP	$ 108,869.88	99
3285	TCCELLPHAA	01	TELECOMMUNICATONS O&M - OPER	$ 764.04	47
3285	TCCELLPHAA	02	TELECOMMUNICATONS O&M - OPER	$ 29,050.76	47
3285	TCCELLPHAA	03	TELECOMMUNICATONS O&M - OPER	$ 6,154.05	47
3285	TCCELLPHAA	04	TELECOMMUNICATONS O&M - OPER	$ 22,245.51	47
3285	TCCELLPHAA	06	TELECOMMUNICATONS O&M - OPER	$ 775.91	47
3285	TCCELLPHAA	07	TELECOMMUNICATONS O&M - OPER	$ 23,078.80	47
3285	TCCELLPHAA	10	TELECOMMUNICATONS O&M - OPER	$ 14,177.29	47
1965	ISCISSYSAA	06	D P OPER MACHINE ROOM COLS	$ 3,362.87	73
1965	ISCISSYSAA	07	D P OPER MACHINE ROOM COLS	$ 88,874.31	73
1965	ISCISSYSAA	10	D P OPER MACHINE ROOM COLS	$ 147,963.48	73
1989	ISCISSYSAA	01	COMPUTER APPL GEN ADM ENG OPER-OPER&AEG	$ 106,174.52	01
1989	ISCISSYSAA	02	COMPUTER APPL GEN ADM ENG OPER-OPER&AEG	$ 2,034,438.01	01
1989	ISCISSYSAA	03	COMPUTER APPL GEN ADM ENG OPER-OPER&AEG	$ 306,127.21	01
1989	ISCISSYSAA	04	COMPUTER APPL GEN ADM ENG OPER-OPER&AEG	$ 1,273,548.00	01
1989	ISCISSYSAA	06	COMPUTER APPL GEN ADM ENG OPER-OPER&AEG	$ 105,881.93	01
1989	ISCISSYSAA	07	COMPUTER APPL GEN ADM ENG OPER-OPER&AEG	$ 2,196,682.20	01
1989	ISCISSYSAA	10	COMPUTER APPL GEN ADM ENG OPER-OPER&AEG	$ 1,062,716.67	01
1989	ISCISSYSAA	21	COMPUTER APPL GEN ADM ENG OPER-OPER&AEG	$ 477,398.75	01
1989	ISCISSYSAA	01	COMPUTER APPL GEN ADM ENG OPER-OPER&AEG	$ 30,174.23	01
1989	ISCISSYSAA	02	COMPUTER APPL GEN ADM ENG OPER-OPER&AEG	$ 578,176.34	01
1989	ISCISSYSAA	03	COMPUTER APPL GEN ADM ENG OPER-OPER&AEG	$ 86,999.71	01
1989	ISCISSYSAA	04	COMPUTER APPL GEN ADM ENG OPER-OPER&AEG	$ 361,935.49	01
1989	ISCISSYSAA	06	COMPUTER APPL GEN ADM ENG OPER-OPER&AEG	$ 30,091.07	01
1989	ISCISSYSAA	07	COMPUTER APPL GEN ADM ENG OPER-OPER&AEG	$ 624,285.26	01
1989	ISCISSYSAA	10	COMPUTER APPL GEN ADM ENG OPER-OPER&AEG	$ 302,018.36	01
1989	ISCISSYSAA	21	COMPUTER APPL GEN ADM ENG OPER-OPER&AEG	$ 135,674.16	01
1300	ISCISSYSAA	01	MACSS - OPER DEVELOP A NEW MARKETING & CUSTOMER SERVICE SYSTEM (MACSS)	$ 364,328.23	03
1300	ISCISSYSAA	02	MACSS - OPER DEVELOP A NEW MARKETING & CUSTOMER SERVICE SYSTEM (MACSS)	$ 7,160,769.57	03
1300	ISCISSYSAA	03	MACSS - OPER DEVELOP A NEW MARKETING & CUSTOMER SERVICE SYSTEM (MACSS)	$ 1,388,125.16	03
1300	ISCISSYSAA	04	MACSS - OPER DEVELOP A NEW MARKETING & CUSTOMER SERVICE SYSTEM (MACSS)	$ 4,480,964.49	03
1300	ISCISSYSAA	06	MACSS - OPER DEVELOP A NEW MARKETING & CUSTOMER SERVICE SYSTEM (MACSS)	$ 340,943.12	03
1300	ISCISSYSAA	07	MACSS - OPER DEVELOP A NEW MARKETING & CUSTOMER SERVICE SYSTEM (MACSS)	$ 5,569,591.63	03

AMERICAN ELECTRIC POWER SERVICE CORPORATION
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WO#	SERVICE ID	CO#	DESCRIPTION	AMOUNT	BASIS
1300	ISCISSYSAA	10	MACSS - OPER DEVELOP A NEW MARKETING & CUSTOMER SERVICE SYSTEM (MACSS)	$ 5,048,346.72	03
3235	ISCISSYSAA	01	TRANSMISSION OPERATIONS - OPER COMMON	$ 7,374.17	37
3235	ISCISSYSAA	02	TRANSMISSION OPERATIONS - OPER COMMON	$ 695,609.53	37
3235	ISCISSYSAA	03	TRANSMISSION OPERATIONS - OPER COMMON	$ 164,685.09	37
3235	ISCISSYSAA	04	TRANSMISSION OPERATIONS - OPER COMMON	$ 567,794.32	37
3235	ISCISSYSAA	06	TRANSMISSION OPERATIONS - OPER COMMON	$ 24,580.03	37
3235	ISCISSYSAA	07	TRANSMISSION OPERATIONS - OPER COMMON	$ 779,180.70	37
3235	ISCISSYSA	10	TRANSMISSION OPERATIONS - OPER COMMON	$ 218,760.77	37
1468	ISSCSUPTAA	01	PROCUREMENT & SUPPLY CHAIN SVCS - OPER DEV NEW PROCUREMENT SYSTEM WHICH WILL INTERFACE WI	$ 43,203.47	01
1468	ISSCSUPTAA	02	PROCUREMENT & SUPPLY CHAIN SVCS - OPER DEV NEW PROCUREMENT SYSTEM WHICH WILL INTERFACE WI	$ 828,437.95	01
1468	ISSCSUPTAA	03	PROCUREMENT & SUPPLY CHAIN SVCS - OPER DEV NEW PROCUREMENT SYSTEM WHICH WILL INTERFACE WI	$ 124,453.64	01
1468	ISSCSUPTAA	04	PROCUREMENT & SUPPLY CHAIN SVCS - OPER DEV NEW PROCUREMENT SYSTEM WHICH WILL INTERFACE WI	$ 516,018.58	01
1468	ISSCSUPTAA	06	PROCUREMENT & SUPPLY CHAIN SVCS - OPER DEV NEW PROCUREMENT SYSTEM WHICH WILL INTERFACE WI	$ 43,115.76	01
1468	ISSCSUPTAA	07	PROCUREMENT & SUPPLY CHAIN SVCS - OPER DEV NEW PROCUREMENT SYSTEM WHICH WILL INTERFACE WI	$ 895,210.74	01
1468	ISSCSUPTAA	10	PROCUREMENT & SUPPLY CHAIN SVCS - OPER DEV NEW PROCUREMENT SYSTEM WHICH WILL INTERFACE WI	$ 432,511.00	01
1468	ISSCSUPTAA	21	PROCUREMENT & SUPPLY CHAIN SVCS - OPER DEV NEW PROCUREMENT SYSTEM WHICH WILL INTERFACE WI	$ 194,744.72	01
1989	ISADMSYSAB	01	COMPUTER APPL GEN ADM ENG OPER-OPER&AEG	$ 158,414.70	01
1989	ISADMSYSAB	02	COMPUTER APPL GEN ADM ENG OPER-OPER&AEG	$ 3,035,425.77	01
1989	ISADMSYSAB	03	COMPUTER APPL GEN ADM ENG OPER-OPER&AEG	$ 456,748.45	01
1989	ISADMSYSAB	04	COMPUTER APPL GEN ADM ENG OPER-OPER&AEG	$ 1,900,161.32	01
1989	ISADMSYSAB	06	COMPUTER APPL GEN ADM ENG OPER-OPER&AEG	$ 157,978.14	01
1989	ISADMSYSAB	07	COMPUTER APPL GEN ADM ENG OPER-OPER&AEG	$ 3,277,497.63	01
1989	ISADMSYSAB	10	COMPUTER APPL GEN ADM ENG OPER-OPER&AEG	$ 1,585,596.39	01
1989	ISADMSYSAB	21	COMPUTER APPL GEN ADM ENG OPER-OPER&AEG	$ 712,289.32	01
3685	TCSCCOOH8E	01	SCET&D CONSTRUCTION OVERHEADS - OPER TELECOMMUNICATIONS	$ 8,019.02	47
3685	TCSCCOOH8E	02	SCET&D CONSTRUCTION OVERHEADS - OPER TELECOMMUNICATIONS	$ 304,084.13	47
3685	TCSCCOOH8E	03	SCET&D CONSTRUCTION OVERHEADS - OPER TELECOMMUNICATIONS	$ 64,507.39	47
3685	TCSCCOOH8E	04	SCET&D CONSTRUCTION OVERHEADS - OPER TELECOMMUNICATIONS	$ 233,339.98	47
3685	TCSCCOOH8E	06	SCET&D CONSTRUCTION OVERHEADS - OPER TELECOMMUNICATIONS	$ 8,110.76	47
3685	TCSCCOOH8E	07	SCET&D CONSTRUCTION OVERHEADS - OPER TELECOMMUNICATIONS	$ 241,535.74	47
3685	TCSCCOOH8E	10	SCET&D CONSTRUCTION OVERHEADS - OPER TELECOMMUNICATIONS	$ 148,521.88	47
3285	TCSUPPRTAB	01	TELECOMMUNICATONS O&M - OPER	$ 10,753.81	47
3285	TCSUPPRTAB	02	TELECOMMUNICATONS O&M - OPER	$ 408,885.46	47
3285	TCSUPPRTAB	03	TELECOMMUNICATONS O&M - OPER	$ 86,617.40	47
3285	TCSUPPRTAB	04	TELECOMMUNICATONS O&M - OPER	$ 313,102.43	47
3285	TCSUPPRTAB	06	TELECOMMUNICATONS O&M - OPER	$ 10,920.80	47
3285	TCSUPPRTAB	07	TELECOMMUNICATONS O&M - OPER	$ 324,830.89	47
3285	TCSUPPRTAB	10	TELECOMMUNICATONS O&M - OPER	$ 199,543.35	47

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WO#	SERVICE ID	CO#	DESCRIPTION		AMOUNT	BASIS
1450	ISGENLEGAA	01	GEN LEDGER SYS ACCTG APPL - OPER & AEG DEV & IMPLEMENT G/L ACCTG APPLICATION FOR AEP SYSTEM C	$	56,305.08	01
1450	ISGENLEGAA	02	GEN LEDGER SYS ACCTG APPL - OPER & AEG DEV & IMPLEMENT G/L ACCTG APPLICATION FOR AEP SYSTEM C	$	1,078,603.21	01
1450	ISGENLEGAA	03	GEN LEDGER SYS ACCTG APPL - OPER & AEG DEV & IMPLEMENT G/L ACCTG APPLICATION FOR AEP SYSTEM C	$	162,001.78	01
1450	ISGENLEGAA	04	GEN LEDGER SYS ACCTG APPL - OPER & AEG DEV & IMPLEMENT G/L ACCTG APPLICATION FOR AEP SYSTEM C	$	674,290.50	01
1450	ISGENLEGAA	06	GEN LEDGER SYS ACCTG APPL - OPER & AEG DEV & IMPLEMENT G/L ACCTG APPLICATION FOR AEP SYSTEM C	$	56,135.81	01
1450	ISGENLEGAA	07	GEN LEDGER SYS ACCTG APPL - OPER & AEG DEV & IMPLEMENT G/L ACCTG APPLICATION FOR AEP SYSTEM C	$	1,165,473.91	01
1450	ISGENLEGAA	10	GEN LEDGER SYS ACCTG APPL - OPER & AEG DEV & IMPLEMENT G/L ACCTG APPLICATION FOR AEP SYSTEM C	$	563,138.83	01
1450	ISGENLEGAA	21	GEN LEDGER SYS ACCTG APPL - OPER & AEG DEV & IMPLEMENT G/L ACCTG APPLICATION FOR AEP SYSTEM C	$	253,729.05	01
1487	ISGENLEGAA	01	FINANCIAL INTEGRATION PROJECT - OPER DESIGN, BUILD & IMPLEMENT INTEGRATED DATA REPOSITORY A	$	37,004.81	01
1487	ISGENLEGAA	02	FINANCIAL INTEGRATION PROJECT - OPER DESIGN, BUILD & IMPLEMENT INTEGRATED DATA REPOSITORY A	$	710,386.94	01
1487	ISGENLEGAA	03	FINANCIAL INTEGRATION PROJECT - OPER DESIGN, BUILD & IMPLEMENT INTEGRATED DATA REPOSITORY A	$	107,022.60	01
1487	ISGENLEGAA	04	FINANCIAL INTEGRATION PROJECT - OPER DESIGN, BUILD & IMPLEMENT INTEGRATED DATA REPOSITORY A	$	445,154.33	01
1487	ISGENLEGAA	06	FINANCIAL INTEGRATION PROJECT - OPER DESIGN, BUILD & IMPLEMENT INTEGRATED DATA REPOSITORY A	$	36,971.79	01
1487	ISGENLEGAA	07	FINANCIAL INTEGRATION PROJECT - OPER DESIGN, BUILD & IMPLEMENT INTEGRATED DATA REPOSITORY A	$	766,860.62	01
1487	ISGENLEGAA	10	FINANCIAL INTEGRATION PROJECT - OPER DESIGN, BUILD & IMPLEMENT INTEGRATED DATA REPOSITORY A	$	371,139.98	01
1487	ISGENLEGAA	21	FINANCIAL INTEGRATION PROJECT - OPER DESIGN, BUILD & IMPLEMENT INTEGRATED DATA REPOSITORY A	$	166,302.47	01
1989	ISGENLEGAA	01	COMPUTER APPL GEN ADM ENG OPER-OPER&AEG	$	22,630.67	01
1989	ISGENLEGAA	02	COMPUTER APPL GEN ADM ENG OPER-OPER&AEG	$	433,632.25	01
1989	ISGENLEGAA	03	COMPUTER APPL GEN ADM ENG OPER-OPER&AEG	$	65,249.78	01
1989	ISGENLEGAA	04	COMPUTER APPL GEN ADM ENG OPER-OPER&AEG	$	271,451.62	01
1989	ISGENLEGAA	06	COMPUTER APPL GEN ADM ENG OPER-OPER&AEG	$	22,568.31	01
1989	ISGENLEGAA	07	COMPUTER APPL GEN ADM ENG OPER-OPER&AEG	$	468,213.95	01
1989	ISGENLEGAA	10	COMPUTER APPL GEN ADM ENG OPER-OPER&AEG	$	226,513.77	01
1989	ISGENLEGAA	21	COMPUTER APPL GEN ADM ENG OPER-OPER&AEG	$	101,755.62	01
1964	ISGENLEGAA	03	SYSTEMS & PROCEDURES OPERATIONS - OPER SUPPORT & MAINT FOR LOCALLY MAINTAINED COMPUTER AP	$	77,863.49	71
1964	ISGENLEGAA	06	SYSTEMS & PROCEDURES OPERATIONS - OPER SUPPORT & MAINT FOR LOCALLY MAINTAINED COMPUTER AP	$	26,387.17	71
1964	ISGENLEGAA	07	SYSTEMS & PROCEDURES OPERATIONS - OPER SUPPORT & MAINT FOR LOCALLY MAINTAINED COMPUTER AP	$	565,594.13	71
1964	ISGENLEGAA	10	SYSTEMS & PROCEDURES OPERATIONS - OPER SUPPORT & MAINT FOR LOCALLY MAINTAINED COMPUTER AP	$	272,553.91	71
3285	ISNETLANAA	01	TELECOMMUNICATONS O&M - OPER	$	5,093.62	47
3285	ISNETLANAA	02	TELECOMMUNICATONS O&M - OPER	$	193,671.74	47
3285	ISNETLANAA	03	TELECOMMUNICATONS O&M - OPER	$	41,027.00	47
3285	ISNETLANAA	04	TELECOMMUNICATONS O&M - OPER	$	148,303.37	47
3285	ISNETLANAA	06	TELECOMMUNICATONS O&M - OPER	$	5,172.72	47
3285	ISNETLANAA	07	TELECOMMUNICATONS O&M - OPER	$	153,858.65	47
3285	ISNETLANAA	10	TELECOMMUNICATONS O&M - OPER	$	94,515.24	47
3285	TCMOBRADAA	01	TELECOMMUNICATONS O&M - OPER	$	3,820.22	47
3285	TCMOBRADAA	02	TELECOMMUNICATONS O&M - OPER	$	145,253.81	47
3285	TCMOBRADAA	03	TELECOMMUNICATONS O&M - OPER	$	30,770.25	47

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WO#	SERVICE ID	CO#	DESCRIPTION	AMOUNT	BASIS
3285	TCMOBRADAA	04	TELECOMMUNICATONS O&M - OPER	$ 111,227.53	47
3285	TCMOBRADAA	06	TELECOMMUNICATONS O&M - OPER	$ 3,879.54	47
3285	TCMOBRADAA	07	TELECOMMUNICATONS O&M - OPER	$ 115,393.99	47
3285	TCMOBRADAA	10	TELECOMMUNICATONS O&M - OPER	$ 70,886.43	47
2551	ISRAILCRAA	02	RAILCAR MAINT MGMT SYSTEM - AP, I&M, OP COSTS ASSOC WITH RAILCAR MAINT SYSTEM ISD DEVELOPMENT	$ 30,523.24	99D
2551	ISRAILCRAA	04	RAILCAR MAINT MGMT SYSTEM - AP, I&M, OP COSTS ASSOC WITH RAILCAR MAINT SYSTEM ISD DEVELOPMENT	$ 208,139.05	99D
2551	ISRAILCRAA	07	RAILCAR MAINT MGMT SYSTEM - AP, I&M, OP COSTS ASSOC WITH RAILCAR MAINT SYSTEM ISD DEVELOPMENT	$ 52,034.82	99D
3285	TCTELEPHAA	01	TELECOMMUNICATONS O&M - OPER	$ 4,584.26	47
3285	TCTELEPHAA	02	TELECOMMUNICATONS O&M - OPER	$ 174,304.57	47
3285	TCTELEPHAA	03	TELECOMMUNICATONS O&M - OPER	$ 36,924.30	47
3285	TCTELEPHAA	04	TELECOMMUNICATONS O&M - OPER	$ 133,473.04	47
3285	TCTELEPHAA	06	TELECOMMUNICATONS O&M - OPER	$ 4,655.45	47
3285	TCTELEPHAA	07	TELECOMMUNICATONS O&M - OPER	$ 138,472.79	47
3285	TCTELEPHAA	10	TELECOMMUNICATONS O&M - OPER	$ 85,063.72	47
8702	ISAPAYSYAA	01	ACCOUNTS PAYABLE - ALL DATA PROCESSING SERVICES FOR ACCOUNTS PAYABLE COMPUTER SYS	$ 3,891.95	99F
8702	ISAPAYSYAA	02	ACCOUNTS PAYABLE - ALL DATA PROCESSING SERVICES FOR ACCOUNTS PAYABLE COMPUTER SYS	$ 88,804.56	99F
8702	ISAPAYSYAA	03	ACCOUNTS PAYABLE - ALL DATA PROCESSING SERVICES FOR ACCOUNTS PAYABLE COMPUTER SYS	$ 25,902.95	99F
8702	ISAPAYSYAA	04	ACCOUNTS PAYABLE - ALL DATA PROCESSING SERVICES FOR ACCOUNTS PAYABLE COMPUTER SYS	$ 66,699.71	99F
8702	ISAPAYSYAA	06	ACCOUNTS PAYABLE - ALL DATA PROCESSING SERVICES FOR ACCOUNTS PAYABLE COMPUTER SYS	$ 3,224.23	99F
8702	ISAPAYSYAA	07	ACCOUNTS PAYABLE - ALL DATA PROCESSING SERVICES FOR ACCOUNTS PAYABLE COMPUTER SYS	$ 80,763.38	99F
8702	ISAPAYSYAA	10	ACCOUNTS PAYABLE - ALL DATA PROCESSING SERVICES FOR ACCOUNTS PAYABLE COMPUTER SYS	$ 48,542.18	99F
8702	ISAPAYSYAA	21	ACCOUNTS PAYABLE - ALL DATA PROCESSING SERVICES FOR ACCOUNTS PAYABLE COMPUTER SYS	$ 403.03	99F
8702	ISAPAYSYAA	22	ACCOUNTS PAYABLE - ALL DATA PROCESSING SERVICES FOR ACCOUNTS PAYABLE COMPUTER SYS	$ 7,297.58	99F
8702	ISAPAYSYAA	23	ACCOUNTS PAYABLE - ALL DATA PROCESSING SERVICES FOR ACCOUNTS PAYABLE COMPUTER SYS	$ 806.10	99F
8702	ISAPAYSYAA	40	ACCOUNTS PAYABLE - ALL DATA PROCESSING SERVICES FOR ACCOUNTS PAYABLE COMPUTER SYS	$ -	99F
8702	ISAPAYSYAA	41	ACCOUNTS PAYABLE - ALL DATA PROCESSING SERVICES FOR ACCOUNTS PAYABLE COMPUTER SYS	$ -	99F
8702	ISAPAYSYAA	42	ACCOUNTS PAYABLE - ALL DATA PROCESSING SERVICES FOR ACCOUNTS PAYABLE COMPUTER SYS	$ 8,194.34	99F
8702	ISAPAYSYAA	43	ACCOUNTS PAYABLE - ALL DATA PROCESSING SERVICES FOR ACCOUNTS PAYABLE COMPUTER SYS	$ 9,711.14	99F
8702	ISAPAYSYAA	44	ACCOUNTS PAYABLE - ALL DATA PROCESSING SERVICES FOR ACCOUNTS PAYABLE COMPUTER SYS	$ 27,704.48	99F
8702	ISAPAYSYAA	45	ACCOUNTS PAYABLE - ALL DATA PROCESSING SERVICES FOR ACCOUNTS PAYABLE COMPUTER SYS	$ -	99F
8702	ISAPAYSYAA	46	ACCOUNTS PAYABLE - ALL DATA PROCESSING SERVICES FOR ACCOUNTS PAYABLE COMPUTER SYS	$ 806.10	99F
8702	ISAPAYSYAA	48	ACCOUNTS PAYABLE - ALL DATA PROCESSING SERVICES FOR ACCOUNTS PAYABLE COMPUTER SYS	$ 5,997.82	99F
8702	ISAPAYSYAA	49	ACCOUNTS PAYABLE - ALL DATA PROCESSING SERVICES FOR ACCOUNTS PAYABLE COMPUTER SYS	$ 2,418.20	99F
8702	ISAPAYSYAA	51	ACCOUNTS PAYABLE - ALL DATA PROCESSING SERVICES FOR ACCOUNTS PAYABLE COMPUTER SYS	$ 403.03	99F
8702	ISAPAYSYAA	54	ACCOUNTS PAYABLE - ALL DATA PROCESSING SERVICES FOR ACCOUNTS PAYABLE COMPUTER SYS	$ 1,702.79	99F
8702	ISAPAYSYAA	70	ACCOUNTS PAYABLE - ALL DATA PROCESSING SERVICES FOR ACCOUNTS PAYABLE COMPUTER SYS	$ 5,463.73	99F
8702	ISAPAYSYAA	71	ACCOUNTS PAYABLE - ALL DATA PROCESSING SERVICES FOR ACCOUNTS PAYABLE COMPUTER SYS	$ 6,539.14	99F
8702	ISAPAYSYAA	73	ACCOUNTS PAYABLE - ALL DATA PROCESSING SERVICES FOR ACCOUNTS PAYABLE COMPUTER SYS	$ 7,345.24	99f

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WO#	SERVICE ID	CO#	DESCRIPTION		AMOUNT	BASIS
8702	ISAPAYSYAA	75	ACCOUNTS PAYABLE - ALL DATA PROCESSING SERVICES FOR ACCOUNTS PAYABLE COMPUTER SYS	$	407.65	99F
8702	ISAPAYSYAA	76	ACCOUNTS PAYABLE - ALL DATA PROCESSING SERVICES FOR ACCOUNTS PAYABLE COMPUTER SYS	$	-	99F
1458	ISAPAYSYAA	01	SYS ACCTG APPL/AP, EDM, PURCH-OPER & AEGRE-ENG PAYABLES & REL PURCH ORDER PRO- CESS	$	53,712.15	01
1458	ISAPAYSYAA	02	SYS ACCTG APPL/AP, EDM, PURCH-OPER & AEGRE-ENG PAYABLES & REL PURCH ORDER PRO- CESS	$	1,028,212.90	01
1458	ISAPAYSYAA	03	SYS ACCTG APPL/AP, EDM, PURCH-OPER & AEGRE-ENG PAYABLES & REL PURCH ORDER PRO- CESS	$	154,155.49	01
1458	ISAPAYSYAA	04	SYS ACCTG APPL/AP, EDM, PURCH-OPER & AEGRE-ENG PAYABLES & REL PURCH ORDER PRO- CESS	$	641,918.04	01
1458	ISAPAYSYAA	06	SYS ACCTG APPL/AP, EDM, PURCH-OPER & AEGRE-ENG PAYABLES & REL PURCH ORDER PRO- CESS	$	53,513.09	01
1458	ISAPAYSYAA	07	SYS ACCTG APPL/AP, EDM, PURCH-OPER & AEGRE-ENG PAYABLES & REL PURCH ORDER PRO- CESS	$	1,111,745.74	01
1458	ISAPAYSYAA	10	SYS ACCTG APPL/AP, EDM, PURCH-OPER & AEGRE-ENG PAYABLES & REL PURCH ORDER PRO- CESS	$	536,589.88	01
1458	ISAPAYSYAA	21	SYS ACCTG APPL/AP, EDM, PURCH-OPER & AEGRE-ENG PAYABLES & REL PURCH ORDER PRO- CESS	$	242,506.06	01
3285	TCTRNPRTAA	01	TELECOMMUNICATONS O&M - OPER	$	5,602.99	47
3285	TCTRNPRTAA	02	TELECOMMUNICATONS O&M - OPER	$	213,038.92	47
3285	TCTRNPRTAA	03	TELECOMMUNICATONS O&M - OPER	$	45,129.70	47
3285	TCTRNPRTAA	04	TELECOMMUNICATONS O&M - OPER	$	163,133.71	47
3285	TCTRNPRTAA	06	TELECOMMUNICATONS O&M - OPER	$	5,689.99	47
3285	TCTRNPRTAA	07	TELECOMMUNICATONS O&M - OPER	$	169,244.52	47
3285	TCTRNPRTAA	10	TELECOMMUNICATONS O&M - OPER	$	103,966.77	47
1455	ISPGPIMSAA	02	AEPIMS - GEN DEV & IMPLEMENT SOFTWARE FOR THE AUTOMA-TED ENG PROCESS INFO MGT S	$	747,720.19	30
1455	ISPGPIMSAA	03	AEPIMS - GEN DEV & IMPLEMENT SOFTWARE FOR THE AUTOMA-TED ENG PROCESS INFO MGT S	$	586,933.98	30
1455	ISPGPIMSAA	04	AEPIMS - GEN DEV & IMPLEMENT SOFTWARE FOR THE AUTOMA-TED ENG PROCESS INFO MGT S	$	266,781.54	30
1455	ISPGPIMSAA	07	AEPIMS - GEN DEV & IMPLEMENT SOFTWARE FOR THE AUTOMA-TED ENG PROCESS INFO MGT S	$	364,064.96	30
1455	ISPGPIMSAA	10	AEPIMS - GEN DEV & IMPLEMENT SOFTWARE FOR THE AUTOMA-TED ENG PROCESS INFO MGT S	$	326,003.70	30
1266	PSCCCOAMAA	02	SYSTEM CONTROL CENTER DEVELOPMENT - GEN DEVELOP FUNCTIONAL & DESIGN REQUIREMENTSFOR CONT	$	735,372.22	02
1266	PSCCCOAMAA	03	SYSTEM CONTROL CENTER DEVELOPMENT - GEN DEVELOP FUNCTIONAL & DESIGN REQUIREMENTSFOR CONT	$	151,237.08	02
1266	PSCCCOAMAA	04	SYSTEM CONTROL CENTER DEVELOPMENT - GEN DEVELOP FUNCTIONAL & DESIGN REQUIREMENTSFOR CONT	$	419,213.10	02
1266	PSCCCOAMAA	07	SYSTEM CONTROL CENTER DEVELOPMENT - GEN DEVELOP FUNCTIONAL & DESIGN REQUIREMENTSFOR CONT	$	593,568.54	02
1266	PSCCCOAMAA	10	SYSTEM CONTROL CENTER DEVELOPMENT - GEN DEVELOP FUNCTIONAL & DESIGN REQUIREMENTSFOR CONT	$	357,877.48	02
1985	ISENGSUP02	02	COMPUTER APPL GEN ADM ENG OPERATION - AP	$	291,437.92	99
1987	ISENGSUP03	03	COMPUTER APPL GEN ADM ENG OPERATION - KP	$	347,378.72	99
1986	ISENGSUP04	04	COMPUTER APPL GEN ADM ENG OPERATION-I&MP	$	292,586.84	99
1988	ISENGSUP07	07	COMPUTER APPL GEN ADM ENG OPERATION - OP	$	254,575.19	99
1984	ISENGSUP10	10	COMPUTER APPL GEN ADM ENG OPERATION-CSP	$	721,794.72	99
3085	ISFIBLIN07	07	CANTON/COLUMBUS FIBER JOINT BUILD - OP INSTALL APPROX 140 MILES OF A FIBER OP- TIC INSTALLATION BE	$	55,386.46	99E
3085	ISFIBLIN10	10	CANTON/COLUMBUS FIBER JOINT BUILD - OP INSTALL APPROX 140 MILES OF A FIBER OP- TIC INSTALLATION BE	$	62,457.02	99E
1301	ISGENLEG10	10	ISD PROGRAMMING - CSP PROGRAMMING & MAINTENANCE OF NEW & EXISTING PROGRAMS	$	509,778.57	99
3286	TCMGTOPS02	02	TELECOMMUNICATIONS O&M - AP	$	794,358.10	99
3289	TCMGTOPS03	03	TELECOMMUNICATIONS O&M - KP	$	186,920.60	99
3288	TCMGTOPS04	04	TELECOMMUNICATIONS O&M - I&MP	$	296,829.85	99

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WO#	SERVICE ID	CO#	DESCRIPTION			AMOUNT	BASIS
3291	TCMGTOPS07	07	TELECOMMUNICATIONS O&M - OP		$	269,566.98	99
3287	TCMGTOPS10	10	TELECOMMUNICATIONS O&M - CSP		$	286,502.20	99
3686	TCSCCOOH02	02	SCET&D CONSTRUCTION OVERHEADS - AP	TELECOMMONICATIONS	$	306,594.79	99
3691	TCSCCOOH07	07	SCET&D CONSTRUCTION OVERHEADS - OP	TELECOMMONICATIONS	$	298,842.39	99
3687	TCSCCOOH10	10	SCET&D CONSTRUCTION OVERHEADS -CSP	TELECOMMONICATIONS	$	197,349.37	99
1989	ISPGSUPTAA	01	COMPUTER APPL GEN ADM ENG OPER-OPER&AEG		$	40,232.30	01
1989	ISPGSUPTAA	02	COMPUTER APPL GEN ADM ENG OPER-OPER&AEG		$	770,901.78	01
1989	ISPGSUPTAA	03	COMPUTER APPL GEN ADM ENG OPER-OPER&AEG		$	115,999.61	01
1989	ISPGSUPTAA	04	COMPUTER APPL GEN ADM ENG OPER-OPER&AEG		$	482,580.65	01
1989	ISPGSUPTAA	06	COMPUTER APPL GEN ADM ENG OPER-OPER&AEG		$	40,121.43	01
1989	ISPGSUPTAA	07	COMPUTER APPL GEN ADM ENG OPER-OPER&AEG		$	832,380.35	01
1989	ISPGSUPTAA	10	COMPUTER APPL GEN ADM ENG OPER-OPER&AEG		$	402,691.15	01
1989	ISPGSUPTAA	21	COMPUTER APPL GEN ADM ENG OPER-OPER&AEG		$	180,898.88	01
2632	ISPGSUPTAA	02	SYSTEM TRANSACTIONS - GEN		$	645,106.22	02
2632	ISPGSUPTAA	03	SYSTEM TRANSACTIONS - GEN		$	132,621.14	02
2632	ISPGSUPTAA	04	SYSTEM TRANSACTIONS - GEN		$	367,375.93	02
2632	ISPGSUPTAA	07	SYSTEM TRANSACTIONS - GEN		$	520,585.99	02
2632	ISPGSUPTAA	10	SYSTEM TRANSACTIONS - GEN		$	313,730.58	02
3285	TCEMSCDAAA	01	TELECOMMUNICATONS O&M - OPER		$	509.36	47
3285	TCEMSCDAAA	02	TELECOMMUNICATONS O&M - OPER		$	19,367.17	47
3285	TCEMSCDAAA	03	TELECOMMUNICATONS O&M - OPER		$	4,102.70	47
3285	TCEMSCDAAA	04	TELECOMMUNICATONS O&M - OPER		$	14,830.34	47
3285	TCEMSCDAAA	06	TELECOMMUNICATONS O&M - OPER		$	517.27	47
3285	TCEMSCDAAA	07	TELECOMMUNICATONS O&M - OPER		$	15,385.87	47
3285	TCEMSCDAAA	10	TELECOMMUNICATONS O&M - OPER		$	9,451.52	47
3285	TCADMINSAA	01	TELECOMMUNICATONS O&M - OPER		$	5,093.62	47
3285	TCADMINSAA	02	TELECOMMUNICATONS O&M - OPER		$	193,671.74	47
3285	TCADMINSAA	03	TELECOMMUNICATONS O&M - OPER		$	41,027.00	47
3285	TCADMINSAA	04	TELECOMMUNICATONS O&M - OPER		$	148,303.37	47
3285	TCADMINSAA	06	TELECOMMUNICATONS O&M - OPER		$	5,172.72	47
3285	TCADMINSAA	07	TELECOMMUNICATONS O&M - OPER		$	153,858.65	47
3285	TCADMINSAA	10	TELECOMMUNICATONS O&M - OPER		$	94,515.24	47
1428	ISYEAR2KAB	01	PROJECT 2000 - OPER	COSTS RELATED TO UPDATING ISD MAINFRAME EQUIP TO BE YEAR 2000 COM	$	9,009.22	62
1428	ISYEAR2KAB	02	PROJECT 2000 - OPER	COSTS RELATED TO UPDATING ISD MAINFRAME EQUIP TO BE YEAR 2000 COM	$	317,895.39	62
1428	ISYEAR2KAB	03	PROJECT 2000 - OPER	COSTS RELATED TO UPDATING ISD MAINFRAME EQUIP TO BE YEAR 2000 COM	$	86,230.73	62
1428	ISYEAR2KAB	04	PROJECT 2000 - OPER	COSTS RELATED TO UPDATING ISD MAINFRAME EQUIP TO BE YEAR 2000 COM	$	303,738.13	62
1428	ISYEAR2KAB	06	PROJECT 2000 - OPER	COSTS RELATED TO UPDATING ISD MAINFRAME EQUIP TO BE YEAR 2000 COM	$	9,009.22	62
1428	ISYEAR2KAB	07	PROJECT 2000 - OPER	COSTS RELATED TO UPDATING ISD MAINFRAME EQUIP TO BE YEAR 2000 COM	$	338,487.72	62

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WO#	SERVICE ID	CO#	DESCRIPTION		AMOUNT	BASIS
1428	ISYEAR2KAB	10	PROJECT 2000 - OPER	COSTS RELATED TO UPDATING ISD MAINFRAME EQUIP TO BE YEAR 2000 COM	$ 164,739.32	62
1428	ISYEAR2KAB	21	PROJECT 2000 - OPER	COSTS RELATED TO UPDATING ISD MAINFRAME EQUIP TO BE YEAR 2000 COM	$ 27,027.56	62
1428	ISYEAR2KAB	58	PROJECT 2000 - OPER	COSTS RELATED TO UPDATING ISD MAINFRAME EQUIP TO BE YEAR 2000 COM	$ 1,287.09	62
1428	ISYEAR2KAB	59	PROJECT 2000 - OPER	COSTS RELATED TO UPDATING ISD MAINFRAME EQUIP TO BE YEAR 2000 COM	$ 3,861.13	62
1428	ISYEAR2KAB	60	PROJECT 2000 - OPER	COSTS RELATED TO UPDATING ISD MAINFRAME EQUIP TO BE YEAR 2000 COM	$ 7,722.16	62
1428	ISYEAR2KAB	69	PROJECT 2000 - OPER	COSTS RELATED TO UPDATING ISD MAINFRAME EQUIP TO BE YEAR 2000 COM	$ 12,870.25	62
1428	ISYEAR2KAB	74	PROJECT 2000 - OPER	COSTS RELATED TO UPDATING ISD MAINFRAME EQUIP TO BE YEAR 2000 COM	$ 5,148.12	62
1486	ACABC&PMAA	01	ABMS ENHANCEMENTS - OPER		$ 24,447.94	47
1486	ACABC&PMAA	02	ABMS ENHANCEMENTS - OPER		$ 930,538.66	47
1486	ACABC&PMAA	03	ABMS ENHANCEMENTS - OPER		$ 197,871.24	47
1486	ACABC&PMAA	04	ABMS ENHANCEMENTS - OPER		$ 713,367.77	47
1486	ACABC&PMAA	06	ABMS ENHANCEMENTS - OPER		$ 24,939.98	47
1486	ACABC&PMAA	07	ABMS ENHANCEMENTS - OPER		$ 739,924.15	47
1486	ACABC&PMAA	10	ABMS ENHANCEMENTS - OPER		$ 455,667.58	47
1451	ISLAMSSYAB	01	LAMS SYSTEM ACCTG APPL - OPER & AEG	DEV & IMPLEMENT A COMPUTER SYSTEM TO SUPPORT ACCTG F	$ 44,106.68	01
1451	ISLAMSSYAB	02	LAMS SYSTEM ACCTG APPL - OPER & AEG	DEV & IMPLEMENT A COMPUTER SYSTEM TO SUPPORT ACCTG F	$ 844,729.79	01
1451	ISLAMSSYAB	03	LAMS SYSTEM ACCTG APPL - OPER & AEG	DEV & IMPLEMENT A COMPUTER SYSTEM TO SUPPORT ACCTG F	$ 126,692.68	01
1451	ISLAMSSYAB	04	LAMS SYSTEM ACCTG APPL - OPER & AEG	DEV & IMPLEMENT A COMPUTER SYSTEM TO SUPPORT ACCTG F	$ 527,527.32	01
1451	ISLAMSSYAB	06	LAMS SYSTEM ACCTG APPL - OPER & AEG	DEV & IMPLEMENT A COMPUTER SYSTEM TO SUPPORT ACCTG F	$ 43,963.76	01
1451	ISLAMSSYAB	07	LAMS SYSTEM ACCTG APPL - OPER & AEG	DEV & IMPLEMENT A COMPUTER SYSTEM TO SUPPORT ACCTG F	$ 913,280.01	01
1451	ISLAMSSYAB	10	LAMS SYSTEM ACCTG APPL - OPER & AEG	DEV & IMPLEMENT A COMPUTER SYSTEM TO SUPPORT ACCTG F	$ 440,861.71	01
1451	ISLAMSSYAB	21	LAMS SYSTEM ACCTG APPL - OPER & AEG	DEV & IMPLEMENT A COMPUTER SYSTEM TO SUPPORT ACCTG F	$ 199,098.09	01
1607	LGCONSUL02	02	LEGAL - AP		$ 448,498.81	99
1608	LGCONSUL04	04	LEGAL - I&MP		$ 422,841.72	99
1614	LGCONSUL07	07	LEGAL - OP		$ 430,956.06	99
1616	LGCONSUL10	10	LEGAL - CSP		$ 446,712.93	99
1604	LGCONSULAB	01	LEGAL - OPER & AEG		$ 42,404.31	01
1604	LGCONSULAB	02	LEGAL - OPER & AEG		$ 810,227.53	01
1604	LGCONSULAB	03	LEGAL - OPER & AEG		$ 121,278.26	01
1604	LGCONSULAB	04	LEGAL - OPER & AEG		$ 505,163.59	01
1604	LGCONSULAB	06	LEGAL - CPER & AEG		$ 42,167.89	01
1604	LGCONSULAB	07	LEGAL - OPER & AEG		$ 876,397.01	01
1604	LGCONSULAB	10	LEGAL - OPER & AEG		$ 422,714.84	01
1604	LGCONSULAB	21	LEGAL - OPER & AEG		$ 191,643.33	01
3141	MAAEPRES25	25	LOY YANG-AUSTRALIA PROJ - AEPR	EVAL OF INVESTMENT OPPORTUNITY IN THE LOY YAND PWR PROJ IN	$ 19,534.04	99G
4706	MAAEPRES58	58	GATEWAY 2000 PROJECT - AEPC,LLC	EVAL & DEV THE GATEWAY 2000 PROJECT UNDER AEP COMM, INC	$ 101,995.10	99H
4710	MAAEPRES58	58	GENERAL O&M COLUMBUS/CHARLESTON-AEPC,LLC	DESIGN, PURCHASE, INSTALL FIBER OPTIC LINE BETWEEN	$ 164,221.35	99I
4700	MAAEPRES58	58	AEP COMMUNICATIONS, INC - AEPC	TRACK COSTS ASSOC W/DEVELOP & EVAL BUSI-NESS WITHIN COMMU	$ 1,278,622.78	99

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WO#	SERVICE ID	CO#	DESCRIPTION		AMOUNT	BASIS
4703	MAAEPRES59	59	EXPANDED ENER PRODUCTS/SVC MKTG - AEPES SUPPORT EXPANDED ENERGY PRODUCTS/SERVICEMKTG AUT	$	2,955,173.20	99
4707	MAAEPRES59	59	PROJECT ACE - AEPES COSTS ASSOC WITH THE DEVELOPMENT & EVALOF A HIGHLY CONFIDENTIAL	$	266,622.82	99
4716	MAAEPRES59	59	ADMINISTRATIVE SUPPORT SERVICES - AEPES SERVICES OF A GENERAL NATURE RENDERED FOTHE BENEFIT	$	1,020,053.55	99
4717	MAAEPRES59	59	PRICING ANALYSIS - AEPES FORWARD PRICE CURVES, VALUATIONS, VOLA- TILITY SENSITIVITIES, LOAD	$	498,477.27	99
4718	MAAEPRES59	59	GAS TRADING - AEPES REVIEW WEATHER CONDITIONS, FORCASTS, CA-PACITY STORAGE, MKT REP	$	424,616.45	99
0227	MAAEPRESRR	60	PROJECT MAGIC - AEPCO ACCUMULATE COSTS RELATED TO PROJECT MAGIC	$	357,473.50	99
5271	MAAEPRES69	69	ELEC LAB SERVICE AGREEMENTS - AEPRESCO VARIOUS ELEC LAB SERVICES PERFORMED UNDER STANDAR	$	164,830.01	99
5423	MAAEPRES69	69	W VA PWR PLT GROUNDWTR QUAL STY-AEPRESCOINSTALL GROUNDWATER WELLS AT AMOS PLT, FLY ASH IM	$	106,821.61	99
5441	MAAEPRES69	69	CITY OF RADFORD T&D PROJECT - AEPRESCO AEPES TO PROVIDE SERVICES TO ADD 138KV TAP STATION, TR	$	116,986.14	99
5447	MAAEPRES69	69	PUSHAN CONSULTING AGREEMENT - AEPRESCO MGMT CONSULTING TO NANYANK GENEREL ELEC LIGHT CO O	$	149,322.72	99
5455	MAAEPRES69	69	AK STEEL ROCKPORT PLANT PROJ-AEPRESCO SVC REL TO CONSTR OF NEW SUBSTATION FACILITY AT RKP	$	286,128.25	99
5906	MAAEPRES69	69	ADMIN SUPPORT SERVICES - AEPRESCO SERVICES OF A GENERAL NATURE FOR THE BENEFIT OF AEPES, I	$	366,202.13	99
5997	MAAEPRES69	69	ADMIN SERVICES DEPT 37 CHGS-AEPRESCO TO BILL ENERGY SERVICES ADMIN CHARGES BASED ON NUMBE	$	115,067.82	99
5999	MAAEPRES69	69	BIDS & PROPOSALS - AEPRESCO PREPARE BIDS & PROPOSALS	$	152,800.51	99
8657	MAAEPRES69	69	CONSOLIDATED BILLING/MTR READ-AEPRESCO	$	210,601.32	99
3141	MAAEPRES74	74	LOY YANG-AUSTRALIA PROJ - AEPR EVAL OF INVESTMENT OPPORTUNITY IN THE LOY YAND PWR PROJ IN	$	440,924.68	99G
3149	MAAEPRES74	74	ADMINISTRATIVE SERVICES - AEPR SERVICES OF GENERAL NATURE RENDERED FOR THE BENEFIT OF AEP	$	1,444,216.18	99
3151	MAAEPRES74	74	AUSTRALIA BUSINESS DEVELOPMENT - AEPR CHARGES INCURRED IN THE IDENTIFICATION OF INVESTMENT O	$	129,671.24	99
3153	MAAEPRES74	74	CHINA BUSINESS DEVELOPMENT - AEPR CHARGES INCURRED IN THE IDENTIFICATION OF INVESTMENT OPP	$	161,373.68	99
3155	MAAEPRES74	74	UNITED STATES BUSINESS DEVELOPMENT-AEPR CHARGES INCURRED INVESTMENT OF OPPOR- TUNITIES IN P	$	482,946.05	99
3159	MAAEPRES74	74	IEP MARKETING AND DEVELOPMENT - AEPR DEVELOPMENT COSTS RELATED TO THE INDUS- TRIAL ENERGY P	$	222,629.05	99
3161	MAAEPRES74	74	CANADA BUSINESS DEVELOPMENT - AEPR COSTS ASSOCIATED WITHE DEVELOPING AND EVALUATING BUSI	$	260,728.78	99
3163	MAAEPRES74	74	ELECTRIC MARKET STUDY - AEPR ELEC MARKET STY CONDUCTED JOINTLY WITH COGENRIX AND SARGE	$	110,870.51	99
3164	MAAEPRES74	74	UK GENERAL BUSINESS DEVELOPMENT - AEPR COSTS ASSOC W/DEVEL & EVAL BUSINESS OPPORTUNITIES I	$	393,971.10	99
3165	MAAEPRES74	74	EUROPE GENERAL BUSINESS DEVELOPMENT-AEPRCOST ASSOCIATED W/DEVELOP & EVAL BUSI- NESS OPPOR	$	197,236.84	99
3168	MAAEPRES74	·74	ASIA GENERAL BUSINESS DEVELOPMENT-AEPR COST ASSOCIATED W/DEVELOP & EVAL BUSI- NESS OPPOR IN	$	385,772.94	99
3169	MAAEPRES74	74	PROJECT PATRIOT - AEPR SERVICES PERFORMED UNDER A CONFIDENT- IALITY AGREEMENT	$	186,270.68	99
3170	MAAEPRES74	74	PROJECT LION KING - AEPR PROJECT COST FOR EVALUATION & DEVELOP- MENT OF A CONFIDENTIAL	$	1,652,104.14	99
3171	MAAEPRES74	74	UPSHUR GENERATION PROJECT - AEPR COSTS ASSOC WITH EVAL OF THE UPSHUR GEN-ERATION PROJEC	$	125,919.06	99
3172	MAAEPRES74	74	YORKSHIRE GENERATION - AEPR COSTS FOR POSSIBLE GENERATION PROJECTS IN ENGLAND	$	126,064.80	99
3173	MAAEPRES74	74	PROJECT ACE EVALUATION - AEPR COSTS ASSOC W/THE EVALUATION & ANALYSIS OF PROJECT ACE STU	$	828,145.74	99
3174	MAAEPRES74	74	PROJECT EKIB - AEPR COSTS ASSOCIATED WITH EKIBASTUZ PROJECT	$	137,122.78	99
3175	MAAEPRES74	74	SINGAPORE BRANCH OFFICE - AEPR COSTS ASSOCIATED WITH ESTABLISHING & OPERATING A BRANCH	$	109,442.90	99
3176	MAAEPRES74	74	LONDON BRANCH OFFICE - AEPR COSTS ASSOCIATED WITH ESTABLISHING & OPERATING A BRANCH O	$	109,251.49	99
4701	MAAEPRES81	81	PUSHAN POWER PROJECT - AEP PUSH COSTS ASSOC W/LICENSING & CONSTRUCTION OF THE PUSHAN P	$	516,190.98	99
4702	MAAEPRES81	81	PUSHAN JOINT VENTURE COSTS - AEP PUSH COSTS INCURRED ON BEHALF OF NANYANG ELEC RELATED TO	$	187,474.11	99
4706	MAAEPRES91	91	GATEWAY 2000 PROJECT - AEPC,LLC EVAL & DEV THE GATEWAY 2000 PROJECT UNDER AEP COMM, INC	$	53,656.77	99H
4710	MAAEPRES91	91	GENERAL O&M COLUMBUS/CHARLESTON-AEPC,LLCDESIGN, PURCHASE, INSTALL FIBER OPTIC LINE BETWEEN	$	6,023.09	99i

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WO#	SERVICE ID	CO#	DESCRIPTION		AMOUNT	BASIS
4706	MAAEPRES95	95	GATEWAY 2000 PROJECT - AEPC,LLC EVAL & DEV THE GATEWAY 2000 PROJECT UNDER AEP COMM, INC	$	40,279.03	99H
4710	MAAEPRES95	95	GENERAL O&M COLUMBUS/CHARLESTON-AEPC,LLCDESIGN, PURCHASE, INSTALL FIBER OPTIC LINE BETWEEN	$	5,005.49	99I
4181	MAAEPRESXX	NN	DEVELOPMENT OF ECAR-MET TRNSMN SECUR CTRDEVELOP ECAR-MET TRANSMISSION SECURITY CENTER AT	$	165,920.01	99
1394	MKECODEVAA	01	EUROPEAN DEVELOPMENT PROGRAM - OPER ESTB ECON DEVMNT OFFICE TO ENCOURAGE MKTPARTICIPAT	$	1,666.01	03
1394	MKECODEVAA	02	EUROPEAN DEVELOPMENT PROGRAM - OPER ESTB ECON DEVMNT OFFICE TO ENCOURAGE MKTPARTICIPAT	$	32,886.31	03
1394	MKECODEVAA	03	EUROPEAN DEVELOPMENT PROGRAM - OPER ESTB ECON DEVMNT OFFICE TO ENCOURAGE MKTPARTICIPAT	$	6,373.72	03
1394	MKECODEVAA	04	EUROPEAN DEVELOPMENT PROGRAM - OPER ESTB ECON DEVMNT OFFICE TO ENCOURAGE MKTPARTICIPAT	$	20,574.85	03
1394	MKECODEVAA	06	EUROPEAN DEVELOPMENT PROGRAM - OPER ESTB ECON DEVMNT OFFICE TO ENCOURAGE MKTPARTICIPAT	$	1,565.43	03
1394	MKECODEVAA	07	EUROPEAN DEVELOPMENT PROGRAM - OPER ESTB ECON DEVMNT OFFICE TO ENCOURAGE MKTPARTICIPAT	$	25,605.31	03
1394	MKECODEVAA	10	EUROPEAN DEVELOPMENT PROGRAM - OPER ESTB ECON DEVMNT OFFICE TO ENCOURAGE MKTPARTICIPAT	$	23,148.05	03
2527	MKRESEARAA	01	MARKETING SERVICES - OPER	$	246,510.41	03
2527	MKRESEARAA	02	MARKETING SERVICES - OPER	$	4,850,438.73	03
2527	MKRESEARAA	03	MARKETING SERVICES - OPER	$	940,215.17	03
2527	MKRESEARAA	04	MARKETING SERVICES - OPER	$	3,035,079.00	03
2527	MKRESEARAA	06	MARKETING SERVICES - OPER	$	230,930.09	03
2527	MKRESEARAA	07	MARKETING SERVICES - OPER	$	3,771,760.93	03
2527	MKRESEARAA	10	MARKETING SERVICES - OPER	$	3,420,056.37	03
2528	MKRESEAR02	02	MARKETING SERVICES - AP	$	181,762.33	99
2527	MKRESEAR59	59	MARKETING SERVICES - OPER	$	4,652,433.28	03
2004	RGRATECS04	04	ELECTRIC POWER SUPPLY COST RECOVERY-I&MPMICHIGAN JURISDICTION	$	138,303.01	99
2133	RGRATECS07	07	OHIO STATE COMM FUEL COST REVIEW - OP SEMIANNUAL FUEL COST REVIEW	$	145,705.12	99
2135	RGRATECS10	10	OHIO STATE COMM FUEL COST REVIEW - CSP SEMIANNUAL FUEL COST REVIEW	$	109,101.27	99
2206	RGSUPPRT03	03	GENERAL RATE ACTIVITY KENTUCKY - KP	$	112,420.95	99
2203	RGSUPPRT04	04	GENERAL RATE ACTIVITY INDIANA - I&MP	$	155,294.26	99
2204	RGSUPPRT04	04	GENERAL RATE ACTIVITY MICHIGAN - I&MP	$	164,400.34	99
2209	RGSUPPRT07	07	GENERAL RATE ACTIVITY OHIO - OP	$	202,237.71	99
2216	RGSUPPRT10	10	GENERAL RATE ACTIVITY OHIO - CSP	$	193,877.06	99
2709	NUCLEARE04	04	GENERAL OPERATIONS - I&M SERVICES RELATED TO GENERAL OPERATIONS EXCLUDING FUEL RELAT	$	6,449,023.35	99
2711	NUCLEARE04	04	NUCLEAR RELOCATION EXPENSES - OP	$	651,804.61	99
0502	NUSCCOOH0·	04	SCET&D CONSTRUCTION O/H D.C. COOK - I&MP	$	245,199.55	99
4359	NUPRSREAAA	02	ADVANCED PRESSURIZED REACTOR DESIGN-GEN IDENTIFY FUTURE NUCLEAR PLANTS DESIGN PREFERENCE	$	62,833.40	02
4359	NUPRSREAAA	03	ADVANCED PRESSURIZED REACTOR DESIGN-GEN IDENTIFY FUTURE NUCLEAR PLANTS DESIGN PREFERENCE	$	12,919.36	02
4359	NUPRSREAAA	04	ADVANCED PRESSURIZED REACTOR DESIGN-GEN IDENTIFY FUTURE NUCLEAR PLANTS DESIGN PREFERENCE	$	35,815.18	02
4359	NUPRSREAAA	07	ADVANCED PRESSURIZED REACTOR DESIGN-GEN IDENTIFY FUTURE NUCLEAR PLANTS DESIGN PREFERENCE	$	50,670.15	02
4359	NUPRSREAAA	10	ADVANCED PRESSURIZED REACTOR DESIGN-GEN IDENTIFY FUTURE NUCLEAR PLANTS DESIGN PREFERENCE	$	30,588.23	02
2641	PMPOWERMAA	02	POWER TRADING - OPER REVIEW WEATHER CONDITIONS, FORECASTS, SYSTEM CONDITIONS,MKT	$	356,710.26	02
2641	PMPOWERMAA	03	POWER TRADING - OPER REVIEW WEATHER CONDITIONS, FORECASTS, SYSTEM CONDITIONS,MKT	$	73,537.20	02
2641	PMPOWERMAA	04	POWER TRADING - OPER REVIEW WEATHER CONDITIONS, FORECASTS, SYSTEM CONDITIONS,MKT	$	205,183.29	02

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2641	PMPOWERMAA	07	POWER TRADING - OPER REVIEW WEATHER CONDITIONS, FORECASTS, SYSTEM CONDITIONS,MKT	$	287,625.77	02
2641	PMPOWERMAA	10	POWER TRADING - OPER REVIEW WEATHER CONDITIONS, FORECASTS, SYSTEM CONDITIONS,MKT	$	174,513.63	02
1742	PSINTPLNAA	02	INTEGRATED RESOURCE PLANNING OPER - GEN	$	514,154.51	02
1742	PSINTPLNAA	03	INTEGRATED RESOURCE PLANNING OPER - GEN	$	105,638.35	02
1742	PSINTPLNAA	04	INTEGRATED RESOURCE PLANNING OPER - GEN	$	292,357.55	02
1742	PSINTPLNAA	07	INTEGRATED RESOURCE PLANNING OPER - GEN	$	414,637.03	02
1742	PSINTPLNAA	10	INTEGRATED RESOURCE PLANNING OPER - GEN	$	249,903.94	02
1744	PSINTPLNA	02	INGREGRTD RESOURCE PLN PROJ LOAD REQ-OPE	$	274,706.17	02
1744	PSINTPLNAA	03	INGREGRTD RESOURCE PLN PROJ LOAD REQ-OPE	$	56,470.34	02
1744	PSINTPLNAA	04	INGREGRTD RESOURCE PLN PROJ LOAD REQ-OPE	$	156,391.38	02
1744	PSINTPLNAA	07	INGREGRTD RESOURCE PLN PROJ LOAD REQ-OPE	$	221,702.84	02
1744	PSINTPLNAA	10	INGREGRTD RESOURCE PLN PROJ LOAD REQ-OPE	$	133,569.87	02
0647	FLCOALMNAA	42	COAL MINE ADMINISTRATION - COAL	$	667,736.97	16
0647	FLCOALMNAA	43	COAL MINE ADMINISTRATION - COAL	$	501,576.43	16
0647	FLCOALMNAA	44	COAL MINE ADMINISTRATION - COAL	$	2,283,289.26	16
0647	FLCOALMNAA	54	COAL MINE ADMINISTRATION - COAL	$	168,649.44	16
0687	FLBARGES48	48	LAKIN RIVER TRANSPORTATION HQ-I&MP/WATERTRANSPORT COAL FOR I&MP WATER TRANSPORTATION	$	642,889.17	99
0643	FLCOALMN42	42	COAL MINE ADMINISTRATION - COC	$	499,240.82	99
0646	FLCOALMN43	43	COAL MINE ADMINISTRATION - WC	$	1,227,067.37	99
0637	FLCOALMN44	44	COAL MINE ADMINISTRATION/MEIGS - SOC	$	1,989,684.25	99
0658	FLCOALMN54	54	COAL MINE ADMINISTRATION - CCP	$	243,839.78	99
0721	FLSOCOAL02	02	FUEL PROCUREMENT & TRANSPORTATION - AP	$	567,387.50	99
0723	FLSOCOAL03	03	FUEL PROCUREMENT & TRANSPORTATION - KP	$	176,558.53	99
0722	FLSOCOAL04	04	FUEL PROCUREMENT & TRANSPORTATION - I&MP	$	159,551.34	99
0725	FLSOCOAL07	07	FUEL PROCUREMENT & TRANSPORTATION - OP	$	375,677.89	99
0726	FLSOCOAL10	10	FUEL PROCUREMENT & TRANSPORTATION - CSP	$	268,605.20	99
0424	FLSOCOAL22	22	FUEL PROCUREMENT - CARD PROCURE FUEL FROM OUTSIDE SOURCES	$	121,825.57	99
0450	FLSOCOAL31	31	FUEL PROCUREMENT - IKEC PROCURE FUEL FROM OUTSIDE SOURCES	$	194,534.32	99
0433	FLSOCOAL32	32	FUEL PROCUREMENT - OVEC PROCURE FUEL FROM OUTSIDE SOURCES	$	213,602.40	99
0787	FLSOCOAL49	49	FUEL PROCUREMENT & TRANSPORTATION-OP/CCT	$	427,778.75	99
0770	FLSOCOAL73	73	FUEL PROCUREMENT & TRANSPORTATION - ROCK	$	120,305.50	99
1244	PSACIDRN07	07	ACID RAIN ALLOWANCE TRADING - OP COST REL TO DEVELOPING CRITERIA&PREPAR- ING PLANS ASSOC WI	$	162,543.88	99
3090	PSCAPITA02	02	SMITH MOUNTAIN U 2 & 4 UPGRADE/HYDRO-AP HYDRO ENG, DESIGN, CONSTR AND MANAGING OF SMITH MTN	$	598,348.03	99
3091	PSCAPITA02	02	SMITH MOUNTAIN U 2 & 4 UPGRADE/T&D - AP T&D ENG, DESIGN, CONSTR AND MANAGING OF SMITH MTN U 2 &	$	130,074.71	99
3602	PSCAPITA02	02	SCET&D CONSTRUCTION OVERHEADS - AP FOSSIL AND HYDRO PRODUCTION	$	142,504.97	99
3661	PSCAPITA02	02	PLANT CONSTR INSTALLATION O/H - AP CLINCH RIVER	$	528,954.63	99
3665	PSCAPITA02	02	PLANT CONSTR INSTALLATION O/H - AP GLEN LYN	$	1,320,282.84	99
3667	PSCAPITA02	02	PLANT CONSTR INSTALLATION O/H - AP KANAWHA RIVER	$	278,269.12	99

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WO#	SERVICE ID	CO#	DESCRIPTION		AMOUNT	BASIS
3669	PSCAPITA02	02	PLANT CONSTR INSTALLATION O/H - AP MOUNTAINEER	$	109,896.83	99
3871	PSCAPITA02	02	PLANT CONSTR RETIREMENT O/H - AP CLINCH RIVER	$	340,412.87	99
6885	PSCAPITA02	02	STABILITY IMPROVEMENTS - AP NIAGARA 0	$	233,198.15	99
6941	PSCAPITA02	02	ELEC UPGRADE INSTALLATION - AP BUCK 0	$	156,474.76	99
7058	PSCAPITA02	02	INST CRT SCREEN CONTROL SYSTEM - AP CLINCH 2	$	153,471.44	99
7135	PSCAPITA02	02	REMOVE SUPERHEATER BANKS & HEADERS - AP CLINCH RVR 2	$	147,371.78	99
7402	PSCAPITA02	02	INST HG CONTROL RM INST RPLCMT - AP GLEN LYN 6	$	292,380.09	99
7409	PSCAPITA02	02	INST 13.8KV SWITCHGEAR REPLACEMENT - AP GLEN LYN 6	$	142,903.06	99
7411	PSCAPITA02	02	INST PRECIPITATOR ROOF - AP GLEN LYN 6	$	322,109.35	99
3655	PSCAPITA03	03	PLANT CONSTR INSTALLATION O/H-KP BIG SANDY	$	288,126.67	99
3675	PSCAPITA04	04	PLANT CONSTR INSTALLATION O/H - I&M TANNERS CREEK	$	362,532.27	99
6826	PSCAPITA04	04	INST RVSE OSMOSIS WTR TREAT SYS - I&M TANNERS CREEK 0	$	141,407.18	99
3664	PSCAPITA07	07	PLANT CONSTR INSTALLATION O/H - OP GAVIN	$	988,958.36	99
3666	PSCAPITA07	07	PLANT CONSTR INSTALLATION O/H - OP KAMMER	$	354,220.55	99
3668	PSCAPITA07	07	PLANT CONSTR INSTALLATION O/H - OP MITCHELL	$	415,589.46	99
3670	PSCAPITA07	07	PLANT CONSTR INSTALLATION O/H - OP MUSKINGUM	$	807,159.54	99
3880	PSCAPITA07	07	PLANT CONSTR RETIREMENT O/H - OP MUSKINGUM	$	104,482.41	99
6833	PSCAPITA07	07	INST COMBUSTION CONT & OPER INTER - OP MUSKINGUM RIVER U 5	$	800,662.74	99
6944	PSCAPITA07	07	INST HIGH PRESS/REHEAT ROTOR ASSMB - OP MUSKINGUM RVR 3	$	166,709.37	99
6955	PSCAPITA07	07	INST PRIMARY FURNACE ROOF TUBING - OP MUSKINGUM RVR 2	$	266,922.94	99
6963	PSCAPITA07	07	INST LWR FURN WALLS & FLOOR TUBES - OP MUSKINGUM RVR 2	$	147,001.71	99
6965	PSCAPITA07	07	INST REARWALL & ARCH - OP MUSKINGUM RVR 3	$	106,021.42	99
6966	PSCAPITA07	07	REMV REARWALL & ARCH - OP MUSKINGUM RVR 3	$	101,356.60	99
7109	PSCAPITA07	07	INST AIR HEAT ROTORS & ELEMENTS - OP MITCHELL 1	$	158,947.65	99
7159	PSCAPITA07	07	INST HIGH PRESSURE GENERATOR FIELD - OP GAVIN 2	$	123,752.16	99
7216	PSCAPITA07	07	PLT CAP SPARE PART INST O/H - OP MUSKINGUM 1-4	$	103,012.97	99
3662	PSCAPITA10	10	PLANT CONSTR INSTALLATION O/H - CSP CONSEVILLE UNIT 4	$	117,398.72	99
3663	PSCAPITA10	10	PLANT CONSTR INSTALLATION O/H - CSP CONESVILLE UNITS 1,2,3,5 AND 6	$	628,883.44	99
3671	PSCAPITA10	10	PLANT CONSTR INSTALLATION O/H - CSP PICWAY	$	188,580.49	99
6631	PSCAPITA10	10	PURCH/INST LOW PRESS TURBINE ROTOR A-CSPCONESVILLE 5	$	120,091.73	99
3658	PSCAPITA22	22	PLANT CONSTR INSTALLATION O/H - CARD CARDINAL UNITS 2 AND 3	$	448,057.31	99
3659	PSCAPITA22	22	PLANT CONSTR INSTALLATION O/H - CARD CARDINAL COMMON	$	255,773.29	99
6813	PSCAPITA22	22	INST ON LINE PERFORM MONITORING - CARD CARDINAL U 2	$	177,886.73	99
6854	PSCAPITA22	22	FLY ASH RETENTION DAM CREST RAISING-CARDCARD 0	$	473,652.32	99
4274	PSCAPITA31	31	SO 3 FLUE GAS CONDITION SYS - IKEC TEST & INSTALL FLUE GAS CONDITIONING SYSTEM FOR CLIFTY CRE	$	110,570.98	99
6664	PSCAPITA70	70	INST 6 ANNUNCIATOR PANELS - SPORN SPORN 1	$	137,257.82	99M
6694	PSCAPITA70	70	INST 7 ANNUNCIATIOR - SPORN SPORN 5	$	140,508.44	99M
3673	PSCAPITA70	70	PLANT CONSTR INSTALLATION O/H-SPORN JT SPORN UNITS 1 AND 3	$	306,665.01	99

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WO#	SERVICE ID	CO#	DESCRIPTION		AMOUNT	BASIS
3674	PSCAPITA70	70	PLANT CONSTR INSTALLATION O/H-SPORN JT SPORN UNITS 2, 4, AND 5	$	1,196,381.55	99
3884	PSCAPITA70	70	PLANT CONSTR RETIREMENT O/H-SPORN JT SPORN UNITS 2, 4, AND 5	$	145,715.10	99
6711	PSCAPITA70	70	INST LOW NOX BURNER SYS - SPORN SPORN 2	$	322,330.11	99
6715	PSCAPITA70	70	INST 4 KV AUX BUS - SPORN SPORN 5	$	106,590.69	99
6726	PSCAPITA70	70	INST LOW NOX BURNER SYSTEM - SPORN SPORN 1	$	761,118.75	99
6727	PSCAPITA70	70	REMV LOW NOX BURNER SYSTEM - SPORN SPORN 1	$	187,501.39	99
3650	PSCAPITA71	71	PLANT CONSTR INSTALLATIN O/H-AMOS JT AMOS UNITS 1 AND 2	$	1,394,181.63	99
3651	PSCAPITA71	71	PLANT CONSTR INSTALLATION O/H-AMOS JT AMOS UNIT 3	$	259,146.72	99
6215	PSCAPITA71	71	AMOS U-3 RETIRE BEARING FAN -AMOS	$	105,585.96	99
6217	PSCAPITA71	71	AMOS U-2 REPLACE CONTROLS -AMOS	$	311,820.65	99
6928	PSCAPITA71	71	INST LPA & LPB TURB ROTORS - AMOS JT AMOS 2	$	213,395.33	99
7049	PSCAPITA71	71	INSTALL LOW NOX BURNERS - AMOS JT AMOS 3	$	220,028.59	99
7051	PSCAPITA71	71	INST SO3 GAS CONDITIONING SYS - AMOS JT AMOS 3	$	238,550.47	99
3672	PSCAPITA73	73	PLANT CONSTR INSTALLATION O/H - ROCK ROCKPORT	$	419,366.84	99
6978	PSCAPITA73	73	REMV IP INNER CASE & ROTOR ASSEMBLY-ROCKROCKPORT 1	$	142,733.47	99
7631	PSCAPITA73	73	INST WATER LANCE SOOTBLOWERS - ROCK ROCKPORT 2	$	100,373.88	99
1461	PSCAPITA75	75	GAVIN LANDFILL PHASE B - GAVIN ENGINEERING & SUPPORT SERVICES FOR PHASEB OF THE GAVIN LAND	$	565,628.02	99
1477	PSCAPITA75	75	GAVIN PHASE C LANDFILL - GAVIN ACCUM COST ASSOC W/PLAN, DESIGN & OTHER INCURRED PRIOR TO&A	$	396,051.85	99
0688	PSCREDRL44	44	MEIGS SYSTEM DRILLING PROGRAM - SOC SYSTEM CORE DRILLING IN CONNECTION WITH MEIGS MINE OPER	$	116,275.26	99
0758	PSCREDRL45	44	MEIGS MINE WATER DAMAGE - SOC COSTS ASSOC WITH MEIGS MINE WATER DAMAGEJULY 11, 1993 TO C	$	310,992.85	99
1479	PSOPRMNT02	02	GLEN LYN UNIT 6 STUDY TEAM - AP ACCUM COSTS ASSOC W/ ASSESSING SHORT ANDLONG TERM PLANS F	$	181,592.06	99
3835	PSOPRMNT02	02	MOUNTAINEER OPERATION - AP	$	101,741.33	99
3918	PSOPRMNT02	02	CLINCH RIVER UNIT 2 MAINTENANCE - AP	$	446,698.42	99
3920	PSOPRMNT02	02	CLINCH RIVER COMMON MAINTENANCE - AP	$	207,161.73	99
3935	PSOPRMNT02	02	GLEN LYN UNIT 5 MAINTENANCE - AP	$	242,430.58	99
3936	PSOPRMNT02	02	GLEN LYN UNIT 6 MAINTENANCE - AP	$	463,803.87	99
3937	PSOPRMNT02	02	GLEN LYN COMMON MAINTENANCE - AP	$	184,119.83	99
3944	PSOPRMNT02	02	KANAWHA RIVER COMMON MAINTENANCE - AP	$	470,368.72	99
3948	PSOPRMNT02	02	MOUNTAINEER UNIT 1 MAINTENANCE - AP	$	658,627.50	99
3949	PSOPRMNT02	02	MOUNTAINEER COMMON MAINTENANCE - AP	$	454,319.61	99
3978	PSOPRMNT02	02	BYLLESBY MAINTENANCE - AP	$	106,180.54	99
3907	PSOPRMNT03	03	BIG SANDY UNIT 1 MAINTENANCE - KP	$	277,469.41	99
3908	PSOPRMNT03	03	BIG SANDY UNIT 2 MAINTENANCE - KP	$	341,853.21	99
3909	PSOPRMNT03	03	BIG SANDY COMMON MAINTENANCE - KP	$	696,542.26	99
3967	PSOPRMNT04	04	TANNER CREEK UNIT 1 MAINTENANCE - I&M	$	239,531.93	99
3969	PSOPRMNT04	04	TANNER CREEK UNIT 3 MAINTENANCE - I&M	$	324,068.97	99
3970	PSOPRMNT04	04	TANNER CREEK UNIT 4 MAINTENANCE - I&M	$	775,868.60	99
3971	PSOPRMNT04	04	TANNERS CREEK COMMON MAINTENANCE - I&M	$	507,621.61	99

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WO#	SERVICE ID	CO#	DESCRIPTION		AMOUNT	BASIS
3830	PSOPRMNT07	07	GAVIN OPERATION - OP	$	151,220.95	99
3836	PSOPRMNT07	07	MUSKINGUM RIVER OPERATION - OP	$	114,818.90	99
3932	PSOPRMNT07	07	GAVIN UNIT 1 MAINTENANCE - OP	$	727,750.40	99
3933	PSOPRMNT07	07	GAVIN UNIT 2 MAINTENANCE - OP	$	2,060,540.58	99
3934	PSOPRMNT07	07	GAVIN COMMON MAINTENANCE - OP	$	983,071.83	99
3938	PSOPRMNT07	07	KAMMER UNIT 1 MAINTENANCE - OP	$	1,020,038.48	99
3939	PSOPRMNT07	07	KAMMER UNIT 2 MAINTENANCE - OP	$	241,965.98	99
3940	PSOPRMNT07	07	KAMMER UNIT 3 MAINTENANCE - OP	$	110,111.65	99
3941	PSOPRMNT07	07	KAMMER COMMON MAINTENANCE - OP	$	519,789.11	99
3945	PSOPRMNT07	07	MITCHELL UNIT 1 MAINTENANCE - OP	$	1,694,363.24	99
3946	PSOPRMNT07	07	MITCHELL UNIT 2 MAINTENANCE - OP	$	297,432.28	99
3947	PSOPRMNT07	07	MITCHELL COMMON MAINTENANCE - OP	$	305,488.09	99
3950	PSOPRMNT07	07	MUSKINGUM UNIT 1 MAINTENANCE - OP	$	101,280.65	99
3951	PSOPRMNT07	07	MUSKINGUM UNIT 2 MAINTENANCE - OP	$	2,293,481.73	99
3952	PSOPRMNT07	07	MUSKINGUM UNIT 3 MAINTENANCE - OP	$	1,635,958.19	99
3953	PSOPRMNT07	07	MUSKINGUM UNIT 4 MAINTENANCE - OP	$	1,009,704.39	99
3954	PSOPRMNT07	07	MUSKINGUM UNIT 5 MAINTENANCE - OP	$	327,725.88	99
3955	PSOPRMNT07	07	MUSKINGUM COMMON MAINTENANCE - OP	$	460,473.79	99
3921	PSOPRMNT10	10	CONESVILLE UNIT 1 MAINTENANCE - CSP	$	119,225.34	99
3924	PSOPRMNT10	10	CONESVILLE UNIT 4 MAINTENANCE - CSP	$	279,783.33	99
3925	PSOPRMNT10	10	CONESVILLE UNIT 5 MAINTENANCE - CSP	$	956,711.20	99
3926	PSOPRMNT10	10	CONESVILLE UNIT 6 MAINTENANCE - CSP	$	1,156,932.53	99
3930	PSOPRMNT10	10	CONESVILLE U 5,6 COMMON MAINT - CSP	$	474,688.10	99
3931	PSOPRMNT10	10	CONESVILLE TOTAL PLT COMMON MAINT - CSP	$	343,576.89	99
3956	PSOPRMNT10	10	PICWAY UNIT 5 MAINTENANCE - CSP	$	196,827.85	99
4429	PSOPRMNT10	10	ROBERTS/DAWSON MINE PROJECT - CSP	$	242,577.23	99
1959	PSOPRMNT22	22	ACCOUNTING OPERATIONS CARDINAL - CARD MAINTAIN RECORDS REQUIRED FOR THE ACCT &BILLING OF CA	$	107,581.17	99
3827	PSOPRMNT22	22	CARDINAL OPERATION - CARD	$	124,203.27	99
3912	PSOPRMNT22	22	CARDINAL UNIT 1 MAINTENANCE - CARD	$	266,127.20	99
3913	PSOPRMNT22	22	CARDINAL UNIT 2 MAINTENANCE - CARD	$	139,090.46	99
3914	PSOPRMNT22	22	CARDINAL UNIT 3 MAINTENANCE - CARD	$	2,015,571.42	99
3915	PSOPRMNT22	22	CARDINAL COMMON MAINTENANCE - CARD	$	317,271.71	99
3916	PSOPRMNT22	22	CARDINAL GENERAL MAINTENANCE - CARD	$	149,701.41	99
0431	PSOPRMNT31	31	O & M - IKEC SERVICES IN CONNECTION WITH GENERAL OPERATION & MAINTENANCE	$	455,695.06	99
0430	PSOPRMNT32	32	O & M - OVEC SERVICES IN CONNECTION WITH GENERAL OPERATION & MAINTENANCE	$	613,367.12	99
3961	PSOPRMNT70	70	SPORN UNIT 1 MAINTENANCE - SPORN JT	$	573,093.45	99
3962	PSOPRMNT70	70	SPORN UNIT 2 MAINTENANCE - SPORN JT	$	263,265.61	99
3964	PSOPRMNT70	70	SPORN UNIT 4 MAINTENANCE - SPORN JT	$	119,979.31	99

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WO#	SERVICE ID	CO#	DESCRIPTION		AMOUNT	BASIS
3965	PSOPRMNT70	70	SPORN UNIT 5 MAINTENANCE - SPORN JT	$	2,068,081.15	99
3966	PSOPRMNT70	70	SPORN COMMON MAINTENANCE - SPORN JT	$	484,746.62	99
3825	PSOPRMNT71	71	AMOS OPERATION - AMOS JT	$	101,389.75	99
3900	PSOPRMNT71	71	AMOS UNIT 1 MAINTENANCE - AMOS JT	$	401,365.56	99
3901	PSOPRMNT71	71	AMOS UNIT 2 MAINTENANCE - AMOS JT	$	2,877,925.36	99
3902	PSOPRMNT71	71	AMOS UNIT 3 MAINTENANCE - AMOS JT	$	944,374.33	99
3905	PSOPRMNT71	71	AMOS COMMON MAINTENANCE - AMOS JT	$	262,585.85	99
3958	PSOPRMNT73	73	ROCKPORT UNIT 1 MAINTENANCE - RKPT	$	1,351,018.33	99
3959	PSOPRMNT73	73	ROCKPORT UNIT 2 MAINTENANCE - RKPT	$	838,548.25	99
3960	PSOPRMNT73	73	ROCKPORT COMMON MAINTENANCE - RKPT	$	453,033.39	99
1466	PSPROBES71	71	PROJECT PROBE - AMOS SERVICES RELATED TO PROJECT PROBE AND THE RECRUITMENT OF PAR	$	123,949.41	99
3657	PSSCCOOH07	07	PLANT CONSTR INSTALLATION O/H - OP CARDINAL UNIT 1	$	111,947.06	99L
3657	PSSCCOOH22	22	PLANT CONSTR INSTALLATION O/H - OP CARDINAL UNIT 1	$	44,210.44	99L
7541	RMCLAIMS75	75	DAMAGE DUE TO FIRE OF 7/2/97 - GAVIN GAVIN 2	$	1,057,335.16	99
3600	PSSCCOOHAA	02	SCET&D CONSTRUCTION OVERHEADS - GEN FOSSIL AND HYDRO PRODUCTION	$	3,314,611.24	15
3600	PSSCCOOHAA	03	SCET&D CONSTRUCTION OVERHEADS - GEN FOSSIL AND HYDRO PRODUCTION	$	2,582,742.72	15
3600	PSSCCOOHAA	04	SCET&D CONSTRUCTION OVERHEADS - GEN FOSSIL AND HYDRO PRODUCTION	$	764,037.68	15
3600	PSSCCOOHAA	07	SCET&D CONSTRUCTION OVERHEADS - GEN FOSSIL AND HYDRO PRODUCTION	$	2,631,699.18	15
3600	PSSCCOOHAA	10	SCET&D CONSTRUCTION OVERHEADS - GEN FOSSIL AND HYDRO PRODUCTION	$	1,364,201.43	15
3600	PSSCCOOHAA	73	SCET&D CONSTRUCTION OVERHEADS - GEN FOSSIL AND HYDRO PRODUCTION	$	337,497.49	15
2649	PSFOSMNTAA	04	PLANT MAINTENANCE - CARD, CSP, I&M, OP, RKPT NORTHERN REGION (COMMON)	$	261,055.50	57
2649	PSFOSMNTAA	07	PLANT MAINTENANCE - CARD, CSP, I&M, OP, RKPT NORTHERN REGION (COMMON)	$	920,286.50	57
2649	PSFOSMNTAA	10	PLANT MAINTENANCE - CARD, CSP, I&M, OP, RKPT NORTHERN REGION (COMMON)	$	643,410.24	57
2649	PSFOSMNTAA	22	PLANT MAINTENANCE - CARD, CSP, I&M, OP, RKPT NORTHERN REGION (COMMON)	$	361,259.58	57
2649	PSFOSMNTAA	73	PLANT MAINTENANCE - CARD, CSP, I&M, OP, RKPT NORTHERN REGION (COMMON)	$	450,914.81	57
2650	PSFOSMNTAA	02	PLANT MAINTENANCE - AMOS JT, AP, KP, OP,SPORN JT SOUTHERN REGION (COMMON)	$	1,123,491.26	58
2650	PSFOSMNTAA	03	PLANT MAINTENANCE - AMOS JT, AP, KP, OP,SPORN JT SOUTHERN REGION (COMMON)	$	314,579.57	58
2650	PSFOSMNTAA	07	PLANT MAINTENANCE - AMOS JT, AP, KP, OP,SPORN JT SOUTHERN REGION (COMMON)	$	539,276.48	58
2650	PSFOSMNTAA	70	PLANT MAINTENANCE - AMOS JT, AP, KP, OP,SPORN JT SOUTHERN REGION (COMMON)	$	395,469.80	58
2650	PSFOSMNTAA	71	PLANT MAINTENANCE - AMOS JT, AP, KP, OP,SPORN JT SOUTHERN REGION (COMMON)	$	623,164.78	58
2651	PSFOSMNTAA	02	RSO TOOLS & EQUIP TOOLS & EQUIP CHGS USED BY NRSO & SRSO TO PERFORM PLANT WORK DU	$	139,058.26	75
2651	PSFOSMNTAA	03	RSO TOOLS & EQUIP TOOLS & EQUIP CHGS USED BY NRSO & SRSO TO PERFORM PLANT WORK DU	$	26,356.94	75
2651	PSFOSMNTAA	04	RSO TOOLS & EQUIP TOOLS & EQUIP CHGS USED BY NRSO & SRSO TO PERFORM PLANT WORK DU	$	76,502.82	75
2651	PSFOSMNTAA	07	RSO TOOLS & EQUIP TOOLS & EQUIP CHGS USED BY NRSO & SRSO TO PERFORM PLANT WORK DU	$	228,398.28	75
2651	PSFOSMNTAA	10	RSO TOOLS & EQUIP TOOLS & EQUIP CHGS USED BY NRSO & SRSO TO PERFORM PLANT WORK DU	$	69,337.17	75
0720	FLSOCOALAA	02	FUEL PROCURE & TRANSPORT - GEN,CARD,ROCK	$	575,923.41	13
0720	FLSOCOALAA	03	FUEL PROCURE & TRANSPORT - GEN,CARD,ROCK	$	142,511.95	13
0720	FLSOCOALAA	04	FUEL PROCURE & TRANSPORT - GEN,CARD,ROCK	$	103,203.64	13

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0720	FLSOCOALAA	07	FUEL PROCURE & TRANSPORT - GEN,CARD,ROCK	$	1,027,894.21	13
0720	FLSOCOALAA	10	FUEL PROCURE & TRANSPORT - GEN,CARD,ROCK	$	315,681.56	13
0720	FLSOCOALAA	22	FUEL PROCURE & TRANSPORT - GEN,CARD,ROCK	$	205,800.11	13
0720	FLSOCOALAA	73	FUEL PROCURE & TRANSPORT - GEN,CARD,ROCK	$	549,236.37	13
3751	FLSOCOALAA	02	COAL COMBUSTION BY-PRODUCT SALES - 9 GEN	$	65,257.96	17
3751	FLSOCOALAA	03	COAL COMBUSTION BY-PRODUCT SALES - 9 GEN	$	16,854.33	17
3751	FLSOCOALAA	04	COAL COMBUSTION BY-PRODUCT SALES - 9 GEN	$	11,490.66	17
3751	FLSOCOALAA	07	COAL COMBUSTION BY-PRODUCT SALES - 9 GEN	$	120,023.81	17
3751	FLSOCOALAA	10	COAL COMBUSTION BY-PRODUCT SALES - 9 GEN	$	36,003.84	17
3751	FLSOCOALAA	22	COAL COMBUSTION BY-PRODUCT SALES - 9 GEN	$	24,004.88	17
3751	FLSOCOALAA	31	COAL COMBUSTION BY-PRODUCT SALES - 9 GEN	$	30,331.91	17
3751	FLSOCOALAA	32	COAL COMBUSTION BY-PRODUCT SALES - 9 GEN	$	18,142.59	17
3751	FLSOCOALAA	73	COAL COMBUSTION BY-PRODUCT SALES - 9 GEN	$	63,715.46	17
0864	FGUTILIZAA	01	LOAD IMPACT PROFITABILITY STUDIES - OPERDEV LOAD CHARACTERISTICS & PERFORM ANALYSIS TO DETERM	$	2,037.91	01
0864	FGUTILIZAA	02	LOAD IMPACT PROFITABILITY STUDIES - OPERDEV LOAD CHARACTERISTICS & PERFORM ANALYSIS TO DETERM	$	38,942.27	01
0864	FGUTILIZAA	03	LOAD IMPACT PROFITABILITY STUDIES - OPERDEV LOAD CHARACTERISTICS & PERFORM ANALYSIS TO DETERM	$	5,867.85	01
0864	FGUTILIZAA	04	LOAD IMPACT PROFITABILITY STUDIES - OPERDEV LOAD CHARACTERISTICS & PERFORM ANALYSIS TO DETERM	$	24,396.41	01
0864	FGUTILIZAA	06	LOAD IMPACT PROFITABILITY STUDIES - OPERDEV LOAD CHARACTERISTICS & PERFORM ANALYSIS TO DETERM	$	2,026.69	01
0864	FGUTILIZAA	07	LOAD IMPACT PROFITABILITY STUDIES - OPERDEV LOAD CHARACTERISTICS & PERFORM ANALYSIS TO DETERM	$	42,006.88	01
0864	FGUTILIZAA	10	LOAD IMPACT PROFITABILITY STUDIES - OPERDEV LOAD CHARACTERISTICS & PERFORM ANALYSIS TO DETERM	$	20,355.71	01
0864	FGUTILIZAA	21	LOAD IMPACT PROFITABILITY STUDIES - OPERDEV LOAD CHARACTERISTICS & PERFORM ANALYSIS TO DETERM	$	9,133.03	01
1700	FGUTILIZAA	01	SYSTEM PLANNING GENERAL - OPER & AEG	$	8,283.68	01
1700	FGUTILIZAA	02	SYSTEM PLANNING GENERAL - OPER & AEG	$	158,015.22	01
1700	FGUTILIZAA	03	SYSTEM PLANNING GENERAL - OPER & AEG	$	23,622.68	01
1700	FGUTILIZAA	04	SYSTEM PLANNING GENERAL - OPER & AEG	$	98,416.71	01
1700	FGUTILIZAA	06	SYSTEM PLANNING GENERAL - OPER & AEG	$	8,223.85	01
1700	FGUTILIZAA	07	SYSTEM PLANNING GENERAL - OPER & AEG	$	170,968.21	01
1700	FGUTILIZAA	10	SYSTEM PLANNING GENERAL - OPER & AEG	$	82,424.18	01
1700	FGUTILIZAA	21	SYSTEM PLANNING GENERAL - OPER & AEG	$	37,462.42	01
2630	PSOPRMNTAA	02	PLANT O & M - GEN, AMOS JT, CARD, RKPT, SPORN JT	$	2,904,835.96	56
2630	PSOPRMNTAA	03	PLANT O & M - GEN, AMOS JT, CARD, RKPT, SPORN JT	$	888,103.07	56
2630	PSOPRMNTAA	04	PLANT O & M - GEN, AMOS JT, CARD, RKPT, SPORN JT	$	851,099.13	56
2630	PSOPRMNTAA	07	PLANT O & M - GEN, AMOS JT, CARD, RKPT, SPORN JT	$	5,217,594.84	56
2630	PSOPRMNTAA	10	PLANT O & M - GEN, AMOS JT, CARD, RKPT SPORN JT	$	1,702,196.34	56
2630	PSOPRMNTAA	22	PLANT O & M - GEN, AMOS JT, CARD, RKPT, SPORN JT	$	1,517,175.43	56
2630	PSOPRMNTAA	70	PLANT O & M - GEN, AMOS JT, CARD, RKPT, SPORN JT	$	869,602.08	56
2630	PSOPRMNTAA	71	PLANT O & M - GEN, AMOS JT, CARD, RKPT, SPORN JT	$	2,405,278.41	56
2630	PSOPRMNTAA	73	PLANT O & M - GEN, AMOS JT, CARD, RKPT, SPORN JT	$	2,146,248.03	56

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WO#	SERVICE ID	CO#	DESCRIPTION			AMOUNT	BASIS
8626	PSOPRMNTAA	02	BI WEELKY PAYROLL ACCRUAL-GEN,CARD,RKPT		$	26,882.01	56
8626	PSOPRMNTAA	03	BI WEELKY PAYROLL ACCRUAL-GEN,CARD,RKPT		$	8,218.67	56
8626	PSOPRMNTAA	04	BI WEELKY PAYROLL ACCRUAL-GEN,CARD,RKPT		$	7,876.29	56
8626	PSOPRMNTAA	07	BI WEELKY PAYROLL ACCRUAL-GEN,CARD,RKPT		$	48,284.93	56
8626	PSOPRMNTAA	10	BI WEELKY PAYROLL ACCRUAL-GEN,CARD,RKPT		$	15,752.55	56
8626	PSOPRMNTAA	22	BI WEELKY PAYROLL ACCRUAL-GEN,CARD,RKPT		$	14,040.23	56
8626	PSOPRMNTAA	70	BI WEELKY PAYROLL ACCRUAL-GEN,CARD,RKPT		$	8,047.47	56
8626	PSOPRMNTAA	71	BI WEELKY PAYROLL ACCRUAL-GEN,CARD,RKPT		$	22,258.93	56
8626	PSOPRMNTAA	73	BI WEELKY PAYROLL ACCRUAL-GEN,CARD,RKPT		$	19,861.85	56
0851	ENMISCSRAA	02	GLOBAL CLIMATE CHANGE ISSUE - GEN	ASSESS GLOBAL CLIMATE CHANGE ISSUE AND ITS POTENTIAL RAMI	$	55,275.32	02
0851	ENMISCSRAA	03	GLOBAL CLIMATE CHANGE ISSUE - GEN	ASSESS GLOBAL CLIMATE CHANGE ISSUE AND ITS POTENTIAL RAMI	$	11,363.86	02
0851	ENMISCSRAA	04	GLOBAL CLIMATE CHANGE ISSUE - GEN	ASSESS GLOBAL CLIMATE CHANGE ISSUE AND ITS POTENTIAL RAMI	$	31,494.90	02
0851	ENMISCSRAA	07	GLOBAL CLIMATE CHANGE ISSUE - GEN	ASSESS GLOBAL CLIMATE CHANGE ISSUE AND ITS POTENTIAL RAMI	$	44,589.81	02
0851	ENMISCSRAA	10	GLOBAL CLIMATE CHANGE ISSUE - GEN	ASSESS GLOBAL CLIMATE CHANGE ISSUE AND ITS POTENTIAL RAMI	$	26,886.40	02
2632	SOCCCOAMEN	02	SYSTEM TRANSACTIONS - GEN		$	2,750,189.67	02
2632	SOCCCOAMEN	03	SYSTEM TRANSACTIONS - GEN		$	565,384.84	02
2632	SOCCCOAMEN	04	SYSTEM TRANSACTIONS - GEN		$	1,566,181.61	02
2632	SOCCCOAMEN	07	SYSTEM TRANSACTIONS - GEN		$	2,219,340.25	02
2632	SOCCCOAMEN	10	SYSTEM TRANSACTIONS - GEN		$	1,337,482.98	02
1500	CCINTERNAB	01	PUBLIC AFFAIRS - OPER		$	67,154.21	12
1500	CCINTERNAB	02	PUBLIC AFFAIRS - OPER		$	1,307,648.15	12
1500	CCINTERNAB	03	PUBLIC AFFAIRS - OPER		$	195,462.55	12
1500	CCINTERNAB	04	PUBLIC AFFAIRS - OPER		$	818,434.33	12
1500	CCINTERNAB	06	PUBLIC AFFAIRS - OPER		$	68,324.60	12
1500	CCINTERNAB	07	PUBLIC AFFAIRS - OPER		$	1,413,056.25	12
1500	CCINTERNAB	10	PUBLIC AFFAIRS - OPER		$	684,800.32	12
1483	CCINTERNGA	01	TECHNL EDUCATION OPER IDEAS - OPER & AEG		$	3,737.46	01
1483	CCINTERNGA	02	TECHNL EDUCATION OPER IDEAS - OPER & AEG		$	70,479.72	01
1483	CCINTERNGA	03	TECHNL EDUCATION OPER IDEAS - OPER & AEG		$	10,483.75	01
1483	CCINTERNGA	04	TECHNL EDUCATION OPER IDEAS - OPER & AEG		$	43,696.05	01
1483	CCINTERNGA	06	TECHNL EDUCATION OPER IDEAS - OPER & AEG		$	3,668.06	01
1483	CCINTERNGA	07	TECHNL EDUCATION OPER IDEAS - OPER & AEG		$	76,286.89	01
1483	CCINTERNGA	10	TECHNL EDUCATION OPER IDEAS - OPER & AEG		$	36,753.73	01
1483	CCINTERNGA	21	TECHNL EDUCATION OPER IDEAS - OPER & AEG		$	16,900.25	01
1500	CCADMINSAA	01	PUBLIC AFFAIRS - OPER		$	13,990.46	12
1500	CCADMINSAA	02	PUBLIC AFFAIRS - OPER		$	272,426.70	12
1500	CCADMINSAA	03	PUBLIC AFFAIRS - OPER		$	40,721.36	12
1500	CCADMINSAA	04	PUBLIC AFFAIRS - OPER		$	170,507.15	12

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1500	CCADMINSAA	06	PUBLIC AFFAIRS - OPER	$	14,234.29	12
1500	CCADMINSAA	07	PUBLIC AFFAIRS - OPER	$	294,386.72	12
1500	CCADMINSAA	10	PUBLIC AFFAIRS - OPER	$	142,666.73	12
1500	PSEXECSPAA	01	PUBLIC AFFAIRS - OPER	$	12,125.07	12
1500	PSEXECSPAA	02	PUBLIC AFFAIRS - OPER	$	236,103.14	12
1500	PSEXECSPAA	03	PUBLIC AFFAIRS - OPER	$	35,291.85	12
1500	PSEXECSPAA	04	PUBLIC AFFAIRS - OPER	$	147,772.87	12
1500	PSEXECSPAA	06	PUBLIC AFFAIRS - OPER	$	12,336.39	12
1500	PSEXECSPAA	07	PUBLIC AFFAIRS - OPER	$	255,135.16	12
1500	PSEXECSPAA	10	PUBLIC AFFAIRS - OPER	$	123,644.50	12
3392	SCSUPPRTAA	01	T & D MATERIAL DISTRIBUTION - OPER	$	9,660.78	03
3392	SCSUPPRTAA	02	T & D MATERIAL DISTRIBUTION - OPER	$	190,667.97	03
3392	SCSUPPRTAA	03	T & D MATERIAL DISTRIBUTION - OPER	$	36,953.92	03
3392	SCSUPPRTAA	04	T & D MATERIAL DISTRIBUTION - OPER	$	119,289.76	03
3392	SCSUPPRTAA	06	T & D MATERIAL DISTRIBUTION - OPER	$	9,076.38	03
3392	SCSUPPRTAA	07	T & D MATERIAL DISTRIBUTION - OPER	$	148,297.90	03
3392	SCSUPPRTAA	10	T & D MATERIAL DISTRIBUTION - OPER	$	134,367.04	03
1962	SCSUPPRTAA	01	STORES ACCOUNTING OPERATIONS	$	2,423.00	69
1962	SCSUPPRTAA	02	STORES ACCOUNTING OPERATIONS	$	74,314.97	69
1962	SCSUPPRTAA	03	STORES ACCOUNTING OPERATIONS	$	34,979.46	69
1962	SCSUPPRTAA	04	STORES ACCOUNTING OPERATIONS	$	23,496.50	69
1962	SCSUPPRTAA	06	STORES ACCOUNTING OPERATIONS	$	4,041.64	69
1962	SCSUPPRTAA	07	STORES ACCOUNTING OPERATIONS	$	104,123.33	69
1962	SCSUPPRTAA	10	STORES ACCOUNTING OPERATIONS	$	36,756.90	69
1962	SCSUPPRTAA	22	STORES ACCOUNTING OPERATIONS	$	1,627.11	69
1962	SCSUPPRTAA	42	STORES ACCOUNTING OPERATIONS	$	3,729.08	69
1962	SCSUPPRTAA	43	STORES ACCOUNTING OPERATIONS	$	3,335.41	69
1962	SCSUPPRTAA	44	STORES ACCOUNTING OPERATIONS	$	10,578.78	69
1962	SCSUPPRTAA	48	STORES ACCOUNTING OPERATIONS	$	1,487.99	69
1962	SCSUPPRTAA	49	STORES ACCOUNTING OPERATIONS	$	1,487.99	69
1962	SCSUPPRTAA	54	STORES ACCOUNTING OPERATIONS	$	393.68	69
1962	SCSUPPRTAA	70	STORES ACCOUNTING OPERATIONS	$	1,374.08	69
1962	SCSUPPRTAA	71	STORES ACCOUNTING OPERATIONS	$	1,814.63	69
1962	SCSUPPRTAA	73	STORES ACCOUNTING OPERATIONS	$	1,007.00	69
8775	ISPURCSPAA	01	PURCHASING - ASSOC DATA PROCESSING SERVICES FOR VARIOUS PURCHASING REPORTS	$	16,649.32	99B
8775	ISPURCSPAA	02	PURCHASING - ASSOC DATA PROCESSING SERVICES FOR VARIOUS PURCHASING REPORTS		389,852.45	99B
8775	ISPURCSPAA	03	PURCHASING - ASSOC DATA PROCESSING SERVICES FOR VARIOUS PURCHASING REPORTS		115,715.01	99B
8775	ISPURCSPAA	04	PURCHASING - ASSOC DATA PROCESSING SERVICES FOR VARIOUS PURCHASING REPORTS		235,015.41	99B

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W/O#	SERVICE ID	CO#	DESCRIPTION		AMOUNT	BASIS
8775	ISPURCSPAA	06	PURCHASING - ASSOC	DATA PROCESSING SERVICES FOR VARIOUS PURCHASING REPORTS	$ 6,243.67	99B
8775	ISPURCSPAA	07	PURCHASING - ASSOC	DATA PROCESSING SERVICES FOR VARIOUS PURCHASING REPORTS	$ 443,601.71	99B
8775	ISPURCSPAA	10	PURCHASING - ASSOC	DATA PROCESSING SERVICES FOR VARIOUS PURCHASING REPORTS	$ 139,595.47	99B
8775	ISPURCSPAA	22	PURCHASING - ASSOC	DATA PROCESSING SERVICES FOR VARIOUS PURCHASING REPORTS	$ 82,573.10	99B
8775	ISPURCSPAA	31	PURCHASING - ASSOC	DATA PROCESSING SERVICES FOR VARIOUS PURCHASING REPORTS	$ 3,488.64	99B
8775	ISPURCSPAA	42	PURCHASING - ASSOC	DATA PROCESSING SERVICES FOR VARIOUS PURCHASING REPORTS	$ 114,464.65	99B
8775	ISPURCSPAA	43	PURCHASING - ASSOC	DATA PROCESSING SERVICES FOR VARIOUS PURCHASING REPORTS	$ 71,276.97	99B
8775	ISPURCSPAA	44	PURCHASING - ASSOC	DATA PROCESSING SERVICES FOR VARIOUS PURCHASING REPORTS	$ 175,335.31	99B
8775	ISPURCSPAA	46	PURCHASING - ASSOC	DATA PROCESSING SERVICES FOR VARIOUS PURCHASING REPORTS	$ 5,569.71	99B
8775	ISPURCSPAA	48	PURCHASING - ASSOC	DATA PROCESSING SERVICES FOR VARIOUS PURCHASING REPORTS	$ 29,136.51	99B
8775	ISPURCSPAA	49	PURCHASING - ASSOC	DATA PROCESSING SERVICES FOR VARIOUS PURCHASING REPORTS	$ 16,492.45	99B
8775	ISPURCSPAA	54	PURCHASING - ASSOC	DATA PROCESSING SERVICES FOR VARIOUS PURCHASING REPORTS	$ 10,406.09	99B
8775	ISPURCSPAA	69	PURCHASING - ASSOC	DATA PROCESSING SERVICES FOR VARIOUS PURCHASING REPORTS	$ 2,081.32	99B
8775	ISPURCSPAA	70	PURCHASING - ASSOC	DATA PROCESSING SERVICES FOR VARIOUS PURCHASING REPORTS	$ 56,865.56	99B
8775	ISPURCSPAA	71	PURCHASING - ASSOC	DATA PROCESSING SERVICES FOR VARIOUS PURCHASING REPORTS	$ 83,246.85	99B
8775	ISPURCSPAA	73	PURCHASING - ASSOC	DATA PROCESSING SERVICES FOR VARIOUS PURCHASING REPORTS	$ 72,998.03	99B
8775	ISPURCSPAA	75	PURCHASING - ASSOC	DATA PROCESSING SERVICES FOR VARIOUS PURCHASING REPORTS	$ 10,562.95	99B
8775	ISPURCSPAA	76	PURCHASING - ASSOC	DATA PROCESSING SERVICES FOR VARIOUS PURCHASING REPORTS	$ -	99B
2375	SCPRSERVAA	01	PURCHASING - OPER & AEG		$ 74,331.30	01
2375	SCPRSERVAA	02	PURCHASING - OPER & AEG		$ 1,418,742.45	01
2375	SCPRSERVAA	03	PURCHASING - OPER & AEG		$ 212,226.60	01
2375	SCPRSERVAA	04	PURCHASING - OPER & AEG		$ 884,072.24	01
2375	SCPRSERVAA	06	PURCHASING - OPER & AEG		$ 73,837.56	01
2375	SCPRSERVAA	07	PURCHASING - OPER & AEG		$ 1,534,782.18	01
2375	SCPRSERVAA	10	PURCHASING - OPER & AEG		$ 740,134.47	01
2375	SCPRSERVAA	21	PURCHASING - OPER & AEG		$ 336,009.85	01
6040	SCCAPITA10	10	CHILLICOTHE SERVICE CENTER - CSP		$ 215,456.37	99
2379	SCPRSERV02	02	PURCHASING - AP		$ 580,360.32	99
2383	SCPRSERV03	03	PURCHASING - KP		$ 131,239.66	99
2380	SCPRSERV04	04	PURCHASING - I&MP		$ 554,056.33	99
2386	SCPRSERV07	07	PURCHASING - OP		$ 408,520.15	99
2388	SCPRSERV10	10	PURCHASING - CSP		$ 358,181.66	99
1472	TSISOMIDEN	01	MIDWEST ISO DEVELOP & IMPLEMENT - OPER	ACTV ASSOC WITH MIDWEST INDEPENDENT SYS OPERATOR (MIS	$ 11,641.15	12
1472	TSISOMIDEN	02	MIDWEST ISO DEVELOP & IMPLEMENT - OPER	ACTV ASSOC WITH MIDWEST INDEPENDENT SYS OPERATOR (MIS	$ 229,378.40	12
1472	TSISOMIDEN	03	MIDWEST ISO DEVELOP & IMPLEMENT - OPER	ACTV ASSOC WITH MIDWEST INDEPENDENT SYS OPERATOR (MIS	$ 34,325.42	12
1472	TSISOMIDEN	04	MIDWEST ISO DEVELOP & IMPLEMENT - OPER	ACTV ASSOC WITH MIDWEST INDEPENDENT SYS OPERATOR (MIS	$ 144,039.81	12
1472	TSISOMIDEN	06	MIDWEST ISO DEVELOP & IMPLEMENT - OPER	ACTV ASSOC WITH MIDWEST INDEPENDENT SYS OPERATOR (MIS	$ 11,986.70	12
1472	TSISOMIDEN	07	MIDWEST ISO DEVELOP & IMPLEMENT - OPER	ACTV ASSOC WITH MIDWEST INDEPENDENT SYS OPERATOR (MIS	$ 247,484.42	12

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WO#	SERVICE ID	CO#	DESCRIPTION		AMOUNT	BASIS
1472	TSISOMIDEN	10	MIDWEST ISO DEVELOP & IMPLEMENT - OPER ACTV ASSOC WITH MIDWEST INDEPENDENT SYS OPERATOR (MIS	$	120,247.07	12
3093	TSCAPITA04	04	ROCKPORT INTERCONNECTION/AK STEEL - I&M INTERCONN FOR PKPT STA TO A LOCAL ELEC TO BE DETERMIN	$	100,611.94	99
3088	TSFIBLIN58	58	GENERAL O&M ROANOKE/CHARLESTON-AEPC,LLC INSTALL APPROX 150 MILES OF BIBER OPTIC GROUND WIRE	$	125,835.19	99K
3088	TSFIBLIN91	91	GENERAL O&M ROANOKE/CHARLESTON-AEPC,LLC INSTALL APPROX 150 MILES OF BIBER OPTIC GROUND WIRE	$	3,161.33	99K
3088	TSFIBLIN95	95	GENERAL O&M ROANOKE/CHARLESTON-AEPC,LLC INSTALL APPROX 150 MILES OF BIBER OPTIC GROUND WIRE	$	10,940.94	99K
3236	TSOPRMNT02	02	TRANSMISSION OPERATIONS - AP CENTRAL	$	110,476.19	99
3242	TSOPRMNT02	02	TRANSMISSION OPERATIONS - AP SOUTHERN	$	605,980.50	99
3246	TSOPRMNT04	04	TRANSMISSION OPERATIONS - I&MP WESTERN	$	255,849.72	99
3491	TSOPRMNT04	04	TRANSMISSION MAINTENANCE- I&MP WESTERN	$	120,021.40	99
3240	TSOPRMNT06	06	TRANSMISSION OPERATIONS - WP CENTRAL	$	231,224.52	99
3239	TSOPRMNT07	07	TRANSMISSION OPERATIONS - OP CENTRAL	$	269,113.45	99
3237	TSOPRMNT10	10	TRANSMISSION OPERATIONS - CSP CENTRAL	$	130,484.10	99
3629	TSSCCOOH01	01	SCET&D CONSTRUCTINO OVERHEADS - KGP TRANSMISSION SOUTHERN REGION	$	107,618.36	99
3621	TSSCCOOH02	02	SCET&D CONSTRUCTION OVERHEADS - AP TRANSMISSION CENTRAL REGION	$	234,029.16	99
3627	TSSCCOOH02	02	SCET&D CONSTRUCTION OVERHEADS - AP TRANSMISSION SOUTHERN REGION	$	3,387,943.34	99
3623	TSSCCOOH03	03	SCET&D CONSTRUCTION OVERHEADS - KP TRANSMISSION CENTRAL REGION	$	252,381.24	99
3628	TSSCCOOH03	03	SCET&D CONSTRUCTION OVERHEADS - KP TRANSMISSION SOUTHERN REGION	$	1,541,759.62	99
3631	TSSCCOOH04	04	SCET&D CONSTRUCTINO OVERHEADS - I&M TRANSMISSION WESTERN REGION	$	1,131,183.11	99
3624	TSSCCOOH07	07	SCET&D CONSTRUCTION OVERHEADS - 0P TRANSMISSION CENTRAL REGION	$	1,544,309.48	99
3632	TSSCCOOH07	07	SCET&D CONSTRUCTINO OVERHEADS - OP TRANSMISSION WESTERN REGION	$	266,115.61	99
3622	TSSCCOOH10	10	SCET&D CONSTRUCTION OVERHEADS - CSP TRANSMISSION CENTRAL REGION	$	1,368,542.62	99
1675	TSSTUDYX10	10	TRANSMISSION PLANNING OPERATIONS - CSP	$	129,648.57	99
3560	TSSCCOOHAA	01	SCET&D CONSTRUCTION OVERHEADS-OPER&ROCK SUBSTATION ENG & DESIGN AUTO DEVELOPMENT	$	10,084.31	19
3560	TSSCCOOHAA	02	SCET&D CONSTRUCTION OVERHEADS-OPER&ROCK SUBSTATION ENG & DESIGN AUTO DEVELOPMENT	$	278,213.64	19
3560	TSSCCOOHAA	03	SCET&D CONSTRUCTION OVERHEADS-OPER&ROCK SUBSTATION ENG & DESIGN AUTO DEVELOPMENT	$	248,983.51	19
3560	TSSCCOOHAA	04	SCET&D CONSTRUCTION OVERHEADS-OPER&ROCK SUBSTATION ENG & DESIGN AUTO DEVELOPMENT	$	145,721.01	19
3560	TSSCCOOHAA	06	SCET&D CONSTRUCTION OVERHEADS-OPER&ROCK SUBSTATION ENG & DESIGN AUTO DEVELOPMENT	$	7,604.68	19
3560	TSSCCOOHAA	07	SCET&D CONSTRUCTION OVERHEADS-OPER&ROCK SUBSTATION ENG & DESIGN AUTO DEVELOPMENT	$	142,394.07	19
3560	TSSCCOOHAA	10	SCET&D CONSTRUCTION OVERHEADS-OPER&ROCK SUBSTATION ENG & DESIGN AUTO DEVELOPMENT	$	98,735.95	19
3620	TSSCCOOHAA	01	SCET&D CONSTRUCTION OVERHEADS - OPER TRANSMISSION COMMON	$	82,101.16	19
3620	TSSCCOOHAA	02	SCET&D CONSTRUCTION OVERHEADS - OPER TRANSMISSION COMMON	$	2,077,761.68	19
3620	TSSCCOOHAA	03	SCET&D CONSTRUCTION OVERHEADS - OPER TRANSMISSION COMMON	$	1,916,114.43	19
3620	TSSCCOOHAA	04	SCET&D CONSTRUCTION OVERHEADS - OPER TRANSMISSION COMMON	$	974,976.22	19
3620	TSSCCOOHAA	06	SCET&D CONSTRUCTION OVERHEADS - OPER TRANSMISSION COMMON	$	48,478.13	19
3620	TSSCCOOHAA	07	SCET&D CONSTRUCTION OVERHEADS - OPER TRANSMISSION COMMON	$	1,105,477.28	19
3620	TSSCCOOHAA	10	SCET&D CONSTRUCTION OVERHEADS - OPER TRANSMISSION COMMON	$	741,587.53	19
3626	TSSCCOOHE5	02	SCET&D CONSTR O/H-AP,CSP,KP,OP,WP TRANSMISSION CENTRAL REGION	$	103,542.53	23
3626	TSSCCOOHE5	03	SCET&D CONSTR O/H-AP,CSP,KP,OP,WP TRANSMISSION CENTRAL REGION	$	215,863.20	23

WO#	SERVICE ID	CO#	DESCRIPTION		AMOUNT	BASIS
3626	TSSCCOOHE5	06	SCET&D CONSTR O/H-AP,CSP,KP,OP,WP TRANSMISSION CENTRAL REGION	$	14,808.08	23
3626	TSSCCOOHE5	07	SCET&D CONSTR O/H-AP,CSP,KP,OP,WP TRANSMISSION CENTRAL REGION	$	267,298.17	23
3626	TSSCCOOHE5	10	SCET&D CONSTR O/H-AP,CSP,KP,OP,WP TRANSMISSION CENTRAL REGION	$	241,444.86	23
3630	TSSCCOOHE6	01	SCET&D CONSTRUCTION OVERHEADS-AP,KP,KGP TRANSMISSION SOUTHERN REGION	$	24,025.45	27
3630	TSSCCOOHE6	02	SCET&D CONSTRUCTION OVERHEADS-AP,KP,KGP TRANSMISSION SOUTHERN REGION	$	485,645.40	27
3630	TSSCCOOHE6	03	SCET&D CONSTRUCTION OVERHEADS-AP,KP,KGP TRANSMISSION SOUTHERN REGION	$	334,024.94	27
3633	TSSCCOOHIO	04	SCET&D CONSTRUCTION OVERHEADS-I&M, OP TRANSMISSION WESTERN REGION	$	512,049.73	28
3633	TSSCCOOHIO	07	SCET&D CONSTRUCTION OVERHEADS-I&M, OP TRANSMISSION WESTERN REGION	$	161,037.68	28
0833	TSANALYSAA	01	ELEC & MAG FIELD INVESTIGATIONS-OPER&AEGINVESTIGATE CUSTOMER CONCERNS RELATED TOELECTRIC &	$	1,627.67	01
0833	TSANALYSAA	02	ELEC & MAG FIELD INVESTIGATIONS-OPER&AEGINVESTIGATE CUSTOMER CONCERNS RELATED TOELECTRIC &	$	31,011.62	01
0833	TSANALYSAA	03	ELEC & MAG FIELD INVESTIGATIONS-OPER&AEGINVESTIGATE CUSTOMER CONCERNS RELATED TOELECTRIC &	$	4,626.94	01
0833	TSANALYSAA	04	ELEC & MAG FIELD INVESTIGATIONS-OPER&AEGINVESTIGATE CUSTOMER CONCERNS RELATED TOELECTRIC &	$	19,285.39	01
0833	TSANALYSAA	06	ELEC & MAG FIELD INVESTIGATIONS-OPER&AEGINVESTIGATE CUSTOMER CONCERNS RELATED TOELECTRIC &	$	1,613.96	01
0833	TSANALYSAA	07	ELEC & MAG FIELD INVESTIGATIONS-OPER&AEGINVESTIGATE CUSTOMER CONCERNS RELATED TOELECTRIC &	$	33,575.47	01
0833	TSANALYSAA	10	ELEC & MAG FIELD INVESTIGATIONS-OPER&AEGINVESTIGATE CUSTOMER CONCERNS RELATED TOELECTRIC &	$	16,169.13	01
0833	TSANALYSAA	21	ELEC & MAG FIELD INVESTIGATIONS-OPER&AEGINVESTIGATE CUSTOMER CONCERNS RELATED TOELECTRIC &	$	7,374.68	01
3235	TSANALYSAA	01	TRANSMISSION OPERATIONS - OPER COMMON	$	1,474.83	37
3235	TSANALYSAA	02	TRANSMISSION OPERATIONS - OPER COMMON	$	139,121.91	37
3235	TSANALYSAA	03	TRANSMISSION OPERATIONS - OPER COMMON	$	32,937.02	37
3235	TSANALYSAA	04	TRANSMISSION OPERATIONS - OPER COMMON	$	113,558.86	37
3235	TSANALYSAA	06	TRANSMISSION OPERATIONS - OPER COMMON	$	4,916.01	37
3235	TSANALYSAA	07	TRANSMISSION OPERATIONS - OPER COMMON	$	155,836.14	37
3235	TSANALYSAA	10	TRANSMISSION OPERATIONS - OPER COMMON	$	43,752.15	37
3480	TSOPRMNTAA	01	TRANSMISSION MAINTENANCE- OPER COMMON	$	3,783.01	37
3480	TSOPRMNTAA	02	TRANSMISSION MAINTENANCE- OPER COMMON	$	356,872.15	37
3480	TSOPRMNTAA	03	TRANSMISSION MAINTENANCE- OPER COMMON	$	84,489.23	37
3480	TSOPRMNTAA	04	TRANSMISSION MAINTENANCE- OPER COMMON	$	291,298.31	37
3480	TSOPRMNTAA	06	TRANSMISSION MAINTENANCE- OPER COMMON	$	12,610.52	37
3480	TSOPRMNTAA	07	TRANSMISSION MAINTENANCE- OPER COMMON	$	399,747.21	37
3480	TSOPRMNTAA	10	TRANSMISSION MAINTENANCE- OPER COMMON	$	112,231.89	37
8668	TSOPRMNTAA	01	ABD CONTRACT ADMIN & SOLICITATION - OPERTRANSMISSION RELATED	$	652.48	37
8668	TSOPRMNTAA	02	ABD CONTRACT ADMIN & SOLICITATION - OPERTRANSMISSION RELATED	$	61,552.30	37
8668	TSOPRMNTAA	03	ABD CONTRACT ADMIN & SOLICITATION - OPERTRANSMISSION RELATED	$	14,572.46	37
8668	TSOPRMNTAA	04	ABD CONTRACT ADMIN & SOLICITATION - OPERTRANSMISSION RELATED	$	50,242.33	37
8668	TSOPRMNTAA	06	ABD CONTRACT ADMIN & SOLICITATION - OPERTRANSMISSION RELATED	$	2,175.02	37
8668	TSOPRMNTAA	07	ABD CONTRACT ADMIN & SOLICITATION - OPERTRANSMISSION RELATED	$	68,947.12	37
8668	TSOPRMNTAA	10	ABD CONTRACT ADMIN & SOLICITATION - OPERTRANSMISSION RELATED	$	19,357.45	37
3241	TSOPRMNTE5	02	TRANSMISSION OPERATIONS-AP,CSP,KP,OP,WP CENTRAL	$	38,284.07	39

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AMERICAN ELECTRIC POWER SERVICE CORPORATION
BILLINGS OVER 100K BY WORK ORDERS
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WO#	SERVICE ID	CO#	DESCRIPTION		AMOUNT	BASIS
3241	TSOPRMNTE5	03	TRANSMISSION OPERATIONS-AP,CSP,KP,OP,WP CENTRAL	$	25,384.02	39
3241	TSOPRMNTE5	06	TRANSMISSION OPERATIONS-AP,CSP,KP,OP,WP CENTRAL	$	11,651.66	39
3241	TSOPRMNTE5	07	TRANSMISSION OPERATIONS-AP,CSP,KP,OP,WP CENTRAL	$	242,604.23	39
3241	TSOPRMNTE5	10	TRANSMISSION OPERATIONS-AP,CSP,KP,OP,WP CENTRAL	$	98,206.93	39
3486	TSOPRMNTE5	02	TRANSMISSION MAINTENANCE-AP,CSP,KP,OP,WPCENTRAL	$	10,562.52	39
3486	TSOPRMNTE5	03	TRANSMISSION MAINTENANCE-AP,CSP,KP,OP,WPCENTRAL	$	7,003.46	39
3486	TSOPRMNTE5	06	TRANSMISSION MAINTENANCE-AP,CSP,KP,OP,WPCENTRAL	$	3,214.59	39
3486	TSOPRMNTE5	07	TRANSMISSION MAINTENANCE-AP,CSP,KP,OP,WPCENTRAL	$	66,934.09	39
3486	TSOPRMNTE5	10	TRANSMISSION MAINTENANCE-AP,CSP,KP,OP,WPCENTRAL	$	27,095.02	39
3245	TSOPRMNTE6	01	TRANSMISSION OPERATIONS - AP,KP,KGP SOUTHERN	$	2,912.04	42
3245	TSOPRMNTE6	02	TRANSMISSION OPERATIONS - AP,KP,KGP SOUTHERN	$	245,188.62	42
3245	TSOPRMNTE6	03	TRANSMISSION OPERATIONS - AP,KP,KGP SOUTHERN	$	43,097.31	42
3490	TSOPRMNTE6	01	TRANSMISSION MAINTENANCE- AP,KP,KGP SOUTHERN	$	3,173.98	42
3490	TSOPRMNTE6	02	TRANSMISSION MAINTENANCE- AP,KP,KGP SOUTHERN	$	267,247.27	42
3490	TSOPRMNTE6	03	TRANSMISSION MAINTENANCE- AP,KP,KGP SOUTHERN	$	46,974.63	42
3248	TSOPRMNTIO	04	TRANSMISSION OPERATIONS - I&M,OP WESTERN	$	186,332.02	46
3248	TSOPRMNTIO	07	TRANSMISSION OPERATIONS - I&M,OP WESTERN	$	77,968.86	46
3493	TSOPRMNTIO	04	TRANSMISSION MAINTENANCE- I&M,OP WESTERN	$	154,190.53	46
3493	TSOPRMNTIO	07	TRANSMISSION MAINTENANCE- I&M,OP WESTERN	$	64,519.51	46
3235	TSADMINSAA	01	TRANSMISSION OPERATIONS - OPER COMMON	$	2,738.98	37
3235	TSADMINSAA	02	TRANSMISSION OPERATIONS - OPER COMMON	$	258,369.25	37
3235	TSADMINSAA	03	TRANSMISSION OPERATIONS - OPER COMMON	$	61,168.75	37
3235	TSADMINSAA	04	TRANSMISSION OPERATIONS - OPER COMMON	$	210,895.03	37
3235	TSADMINSAA	06	TRANSMISSION OPERATIONS - OPER COMMON	$	9,129.72	37
3235	TSADMINSAA	07	TRANSMISSION OPERATIONS - OPER COMMON	$	289,409.97	37
3235	TSADMINSAA	10	TRANSMISSION OPERATIONS - OPER COMMON	$	81,254.00	37
3480	TSADMINSAA	01	TRANSMISSION MAINTENANCE- OPER COMMON	$	515.86	37
3480	TSADMINSAA	02	TRANSMISSION MAINTENANCE- OPER COMMON	$	48,664.38	37
3480	TSADMINSAA	03	TRANSMISSION MAINTENANCE- OPER COMMON	$	11,521.26	37
3480	TSADMINSAA	04	TRANSMISSION MAINTENANCE- OPER COMMON	$	39,722.50	37
3480	TSADMINSAA	06	TRANSMISSION MAINTENANCE- OPER COMMON	$	1,719.62	37
3480	TSADMINSAA	07	TRANSMISSION MAINTENANCE- OPER COMMON	$	54,510.98	37
3480	TSADMINSAA	10	TRANSMISSION MAINTENANCE- OPER COMMON	$	15,304.35	37
2212	RGSUPPRTEA	01	GENERAL RATE ACTIVITY - OPER	$	27,275.95	12
2212	RGSUPPRTEA	02	GENERAL RATE ACTIVITY - OPER	$	533,900.97	12
2212	RGSUPPRTEA	03	GENERAL RATE ACTIVITY - OPER	$	79,817.51	12
2212	RGSUPPRTEA	04	GENERAL RATE ACTIVITY - OPER	$	334,605.29	12
2212	RGSUPPRTEA	06	GENERAL RATE ACTIVITY - OPER	$	27,896.62	12

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AMERICAN ELECTRIC POWER SERVICE CORPORATION
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WO#	SERVICE ID	CO#	DESCRIPTION		AMOUNT	BASIS
2212	RGSUPPRTEA	07	GENERAL RATE ACTIVITY - OPER	$	576,521.65	12
2212	RGSUPPRTEA	10	GENERAL RATE ACTIVITY - OPER	$	279,735.57	12
1720	TSOPRPLNAA	02	BULK TRANSMISSION PLANNING OPER - GEN	$	108,266.34	02
1720	TSOPRPLNAA	03	BULK TRANSMISSION PLANNING OPER - GEN	$	22,143.25	02
1720	TSOPRPLNAA	04	BULK TRANSMISSION PLANNING OPER - GEN	$	60,879.69	02
1720	TSOPRPLNAA	07	BULK TRANSMISSION PLANNING OPER - GEN	$	86,988.90	02
1720	TSOPRPLNAA	10	BULK TRANSMISSION PLANNING OPER - GEN	$	52,218.44	02
1725	TSOPRPLNAA	02	TRANSMISSN PLANNNING OPERATIONS - GEN	$	100,709.50	02
1725	TSOPRPLNAA	03	TRANSMISSN PLANNNING OPERATIONS - GEN	$	20,696.29	02
1725	TSOPRPLNAA	04	TRANSMISSN PLANNNING OPERATIONS - GEN	$	57,274.31	02
1725	TSOPRPLNAA	07	TRANSMISSN PLANNNING OPERATIONS - GEN	$	81,275.69	02
1725	TSOPRPLNAA	10	TRANSMISSN PLANNNING OPERATIONS - GEN	$	48,943.60	02
1314	TSOPRPLNAA	01	LOAD RESEARCH - OPER DETERM CUSTOMER USE PATTERNS BASED ON TIME OF DAY, SEASON &	$	7,669.76	12
1314	TSOPRPLNAA	02	LOAD RESEARCH - OPER DETERM CUSTOMER USE PATTERNS BASED ON TIME OF DAY, SEASON &	$	149,850.47	12
1314	TSOPRPLNAA	03	LOAD RESEARCH - OPER DETERM CUSTOMER USE PATTERNS BASED ON TIME OF DAY, SEASON &	$	22,405.46	12
1314	TSOPRPLNAA	04	LOAD RESEARCH - OPER DETERM CUSTOMER USE PATTERNS BASED ON TIME OF DAY, SEASON &	$	93,875.91	12
1314	TSOPRPLNAA	06	LOAD RESEARCH - OPER DETERM CUSTOMER USE PATTERNS BASED ON TIME OF DAY, SEASON &	$	7,829.85	12
1314	TSOPRPLNAA	07	LOAD RESEARCH - OPER DETERM CUSTOMER USE PATTERNS BASED ON TIME OF DAY, SEASON &	$	161,858.06	12
1314	TSOPRPLNAA	10	LOAD RESEARCH - OPER DETERM CUSTOMER USE PATTERNS BASED ON TIME OF DAY, SEASON &	$	78,498.41	12
1670	TSOPRPLNAA	01	TRANSMISSION PLANNING OPERATIONS - OPER	$	30,060.59	12
1670	TSOPRPLNAA	02	TRANSMISSION PLANNING OPERATIONS - OPER	$	590,113.11	12
1670	TSOPRPLNAA	03	TRANSMISSION PLANNING OPERATIONS - OPER	$	88,379.91	12
1670	TSOPRPLNAA	04	TRANSMISSION PLANNING OPERATIONS - OPER	$	370,341.42	12
1670	TSOPRPLNAA	06	TRANSMISSION PLANNING OPERATIONS - OPER	$	30,840.70	12
1670	TSOPRPLNAA	07	TRANSMISSION PLANNING OPERATIONS - OPER	$	637,087.80	12
1670	TSOPRPLNAA	10	TRANSMISSION PLANNING OPERATIONS - OPER	$	309,215.88	12
2277	TSOPRPLNAA	01	LOAD RESEARCH & TRANSLATION ACTV - OPER SERVICES RELATED TO LOAD RESEARCH DATA PROCESSING	$	6,740.16	12
2277	TSOPRPLNAA	02	LOAD RESEARCH & TRANSLATION ACTV - OPER SERVICES RELATED TO LOAD RESEARCH DATA PROCESSING	$	132,685.67	12
2277	TSOPRPLNAA	03	LOAD RESEARCH & TRANSLATION ACTV - OPER SERVICES RELATED TO LOAD RESEARCH DATA PROCESSING	$	19,863.84	12
2277	TSOPRPLNAA	04	LOAD RESEARCH & TRANSLATION ACTV - OPER SERVICES RELATED TO LOAD RESEARCH DATA PROCESSING	$	71,470.53	12
2277	TSOPRPLNAA	06	LOAD RESEARCH & TRANSLATION ACTV - OPER SERVICES RELATED TO LOAD RESEARCH DATA PROCESSING	$	14,104.84	12
2277	TSOPRPLNAA	07	LOAD RESEARCH & TRANSLATION ACTV - OPER SERVICES RELATED TO LOAD RESEARCH DATA PROCESSING	$	286,402.04	12
2277	TSOPRPLNAA	10	LOAD RESEARCH & TRANSLATION ACTV - OPER SERVICES RELATED TO LOAD RESEARCH DATA PROCESSING	$	136,823.73	12
3235	TSOPRPLNAA	01	TRANSMISSION OPERATIONS - OPER COMMON	$	9,481.08	37
3235	TSOPRPLNAA	02	TRANSMISSION OPERATIONS - OPER COMMON	$	894,355.11	37
3235	TSOPRPLNAA	03	TRANSMISSION OPERATIONS - OPER COMMON	$	211,737.97	37
3235	TSOPRPLNAA	04	TRANSMISSION OPERATIONS - OPER COMMON	$	730,021.27	37
3235	TSOPRPLNAA	06	TRANSMISSION OPERATIONS - OPER COMMON	$	31,602.89	37

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AMERICAN ELECTRIC POWER SERVICE CORPORATION
BILLINGS OVER 100K BY WORK ORDERS
FOR THE YEAR ENDED 12/31/97

WO#	SERVICE ID	CO#	DESCRIPTION		AMOUNT	BASIS
3235	TSOPRPLNAA	07	TRANSMISSION OPERATIONS - OPER	COMMON	$ 1,001,803.75	37
3235	TSOPRPLNAA	10	TRANSMISSION OPERATIONS - OPER	COMMON	$ 281,263.84	37
1721	TSOPRPLNAK	02	TRANSMISSION PLANNING OPERATIONS - AP,KP		$ 169,268.04	06
1721	TSOPRPLNAK	03	TRANSMISSION PLANNING OPERATIONS - AP,KP		$ 34,890.11	06
1674	TSOPRPLNKA	01	TRANSMISSION PLANNING OPERATIONS-AP, KGP		$ 8,157.51	44
1674	TSOPRPLNKA	02	TRANSMISSION PLANNING OPERATIONS-AP, KGP		$ 154,326.03	44
1678	TSOPRPLNOW	06	TRANSMISSION PLANNING OPERATIONS - OP,WP		$ 6,575.14	45
1678	TSOPRPLNOW	07	TRANSMISSION PLANNING OPERATIONS - OP,WP		$ 139,538.85	45
					$ 433,369,765.26	
TOTAL 1997 AEPSC BILLINGS					$ 455,855,469.70	
TOTAL 1997 BILLINGS LESS THAT $100,000					$ 22,485,704.44	
PERCENTAGE OF 1997 BILLINGS ANALYZED					95.1%	

Synergics Savings

SYNERGIES SAVINGS INDEX

SYNERGIES SAVINGS AND COST ALLOCATION TEAM

Output Requirements

Analyze SYNERGIES ANALYSIS. Allocate labor and non-labor savings, cost to achieve, pre merger initiatives, and change in control for years 1999 through 2009 to AEP and CSW companies.

Based on the analysis, allocate the savings and costs to the benefiting subsidiaries by FERC account number. Provide the net savings information to the rate departments of AEP and CSW for jurisdictional allocation.

Team Members

AEP	Don Rennix	CSW	Russell Davis
	Greg Campbell		Francie Bourland
	Jerry Knorr		Terry Taylor

SUMMARY OF SYNERGY SAVINGS ALLOCATION PROCESS

The Synergies Analysis groups savings by functional area. Those savings result from labor reductions, corporate program savings and non-fuel purchasing economies. The Synergies Analysis provided the savings in a format that would facilitate allocating the savings to the appropriate companies. See section 3 for a graphical overview of the type of information provided.

The savings were categorized by labor and non-labor. The labor savings were further categorized by functional and sub functional areas. The non-labor savings were categorized by type of savings; professional services, administrative and general overheads, benefits, etc..

The information was analyzed and a work order was assigned to each category of savings. See section 8 for a list of work orders used. For explanation of the work order methodology refer to CSWS training manual in section 26. The next step assigned an allocation factor to each savings work order. Based on the information provided in the Synergies Analysis the most representative allocation factor was used. See section 9 for allocation factors utilized.

Each work order was assigned a FERC account number. See section 5 for FERC account numbers used.

The savings were then allocated to the companies by account and work order.

Costs to achieve and cost of change in control were allocated straight line over five years. Further allocation of the annual amount to individual companies was based on gross savings by company. The annual amount of pre-merger initiative costs were taken from the Synergies Analysis and allocated to individual companies based on gross saving by company.

See the next page for a technical description of the process.

SAVINGS ALLOCATION PROCESS

All savings categories and amounts were derived from the Synergies Analysis. These studies were broken into two categories, labor and non-labor. Within those categories, the distinction was given between direct regulated, direct non-regulated and service company savings. A further breakdown of the direct regulated savings was given by the classifications of: fuel, generation, transmission, distribution, customer accounts, customer service, sales, and administration and general. In addition to the above breakdown, the study provided savings by capital, operations and maintenance, and revenue requirement.

ANALYSIS OF LABOR SAVINGS

Scheduled labor savings dollars per the Synergies Analysis by category and sub-category. Determined direct regulated and service company labor savings. Based on the Synergies Analysis study, no labor savings were assigned to the direct non-regulated category.

Analysis of Service Company labor savings
Assigned work order to each sub-category of savings:

- Assigned service code to labor savings with two-digit function code, three-digit SAV designation, and three-digit acronym for labor sub-category.
- Assigned appropriate customer code to each labor savings sub-category based on analysis of companies benefiting from services provided by affected group.
- Assigned appropriate allocation factor to each service code based on analysis of services provided by functional group.

Labeled all labor savings with five-digit center code LABOR.
Assigned capital and operations and maintenance FERC accounts to each labor sub-category based on analysis of services provided by functional group.

Analysis of direct regulated labor savings
Assigned work order to each sub-category of savings:

- Assigned service code to labor savings with four-digit REGU designation and four-digit acronym for functional classification (e.g. distribution was given the designation DIST).
- Assigned appropriate customer code to each labor savings sub-category based on analysis of companies benefiting from services provided by affected group.
- Assigned appropriate allocation factor to each service code based on analysis of services provided by functional group.

Labeled all labor savings with five-digit center code LABOR.
Assigned capital and operations and maintenance FERC accounts to each labor sub-category based on analysis of cost and savings associated with a savings area.

ANALYSIS OF NON-LABOR SAVINGS

Scheduled non-labor savings dollars per the Synergies Analysis by category.
Determined direct regulated, direct non-regulated and service company non-labor savings.

Analysis of Service Company non-labor savings
Assigned work order to each category of savings:

- Assigned service code to non-labor savings with two-digit function code, three-digit SAV designation, and three-digit acronym for non-labor savings category. For categories covering a multiple of areas, each sub-category was assigned a two-digit function code representative of the functional group providing the specific service and a three-digit savings category code depicting the service provided. For example, the savings for professional services were split into legal, auditing, accounting and finance, engineering and other. The legal savings were given the function code of LG and savings category code of ATT (attorney).
- Assigned appropriate customer code to each non-labor savings category based on analysis of companies benefiting from services provided by affected group.

- Assigned appropriate allocation factor to each service code based on analysis of services provided by functional group.

Labeled non-labor savings with five-digit center code representative of category of savings (e.g. Corporate Facilities category was giving the center code FACIL).
Assigned capital and operations and maintenance FERC accounts to each non-labor sub-category based on analysis of services provided by functional group.

Analysis of direct regulated non-labor savings
Segregated non-labor savings by functional group within an area of savings.
Assigned work order to each category of savings:

- Assigned service code to non-labor savings with four-digit REGU designation and four-digit acronym for functional classification (e.g. distribution was given the designation DIST).
- Assigned appropriate customer code to each non-labor savings category based on analysis of regulated companies benefiting from services provided by functional group.
- Assigned appropriate allocation factor to each service code based on driver of cost and savings.

Labeled non-labor savings with five-digit center code representative of category of savings (e.g. Professional Services category was giving the center code PRSER).
Assigned capital and operations and maintenance FERC accounts to each non-labor sub-category based on analysis of cost and savings associated with a savings area.

Analysis of direct non-regulated non-labor savings
Assigned work order to each category of savings:

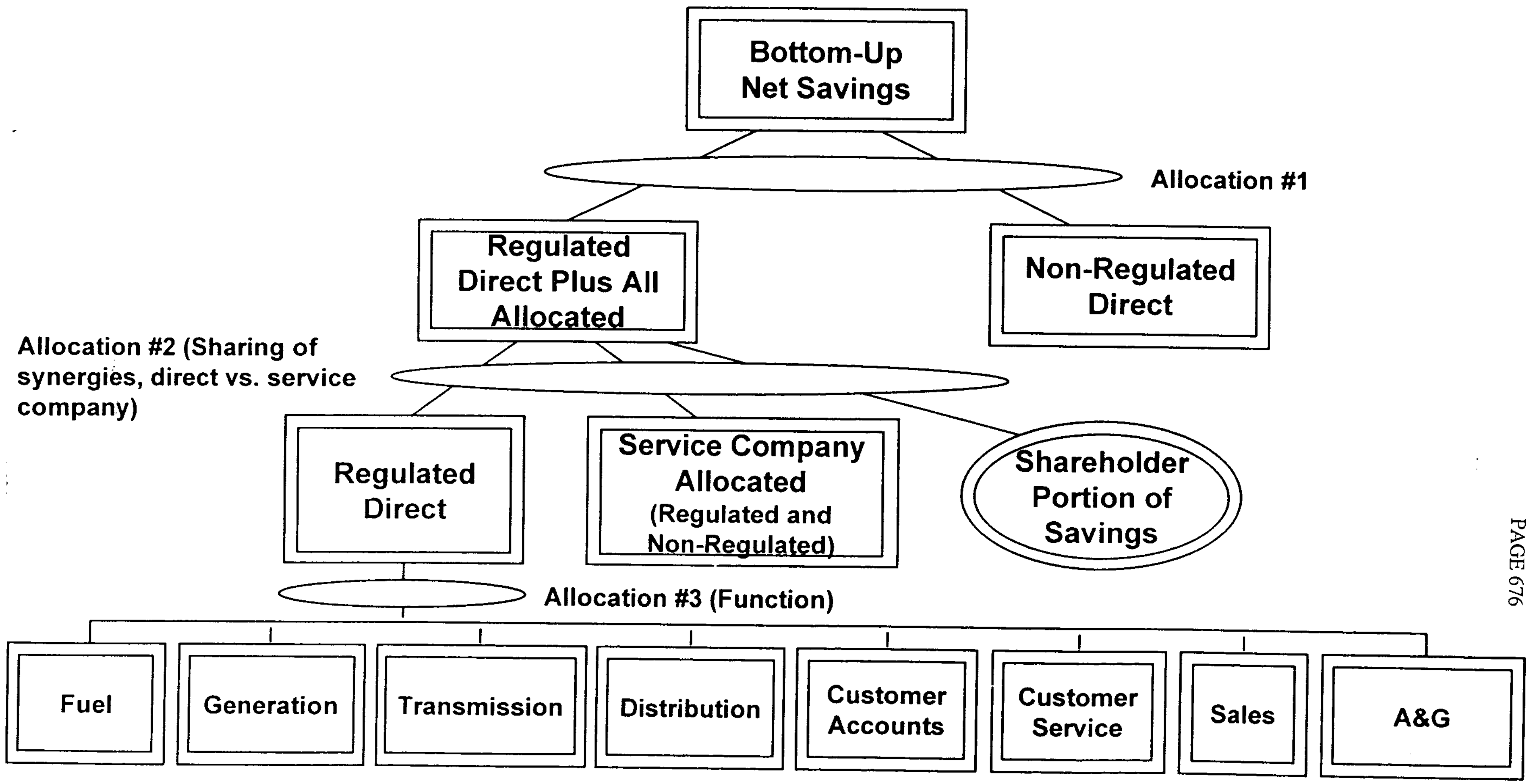
- Assigned service code to non-labor savings with four-digit NREG designation and four-digit acronym for non-labor savings category. For example, non-regulated savings related to credit line fees were given the savings category CRDT.
- Assigned appropriate customer code to each non-labor savings category based on analysis of non-regulated companies benefiting from the savings.
- Assigned appropriate allocation factor to each service code based on driver of cost and savings.

Labeled non-labor savings with five-digit center code representative of category of savings (e.g. Professional Services category was giving the center code PRSER).
Assigned FERC account 9302 to each non-labor sub-category.

ALLOCATION OF SAVINGS
Savings were allocated to subsidiaries and non-regulated customers based on the above process. Savings identified in two sections, direct and services.

ALLOCATION PROCESS

Three-Tiered Allocation Process Construct



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AEP AMERICAN ELECTRIC POWER

Central and South West

Application of Total Savings

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Application of Total Savings

Allocation ($000)	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	Total
Total Savings	(42,856)	92,579	162,046	204,245	222,559	235,088	246,677	251,707	258,800	334,493	1,965,338
Regulated Savings	(43,500)	89,557	158,043	199,584	217,753	230,136	241,570	246,423	253,286	327,209	1,920,062
Non-Regulated Savings	644	3,022	4,003	4,661	4,805	4,952	5,107	5,284	5,513	7,285	45,276
											1,965,338
Direct Savings	(6,947)	22,076	38,917	54,628	59,496	64,318	69,182	74,261	79,923	109,264	$ 565,118
Service Company	(36,553)	67,481	119,126	144,956	158,257	165,818	172,389	172,162	173,364	217,944	1,354,943
											1,920,062
Fuel Savings	27	112	147	164	169	174	179	184	192	253	1,601
Generation Savings	-2,645	8,860	16,681	20,938	23,357	25,745	28,138	30,610	33,307	45,862	230,850
Transmission Savings	-229	2,553	4,241	5,149	5,622	6,091	6,565	7,060	7,612	10,393	55,057
Distribution Savings	-777	3,720	6,654	8,254	9,140	10,016	10,897	11,811	12,817	17,605	90,136
Customer Accounts Savings	87	386	509	571	590	608	628	650	679	898	5,605
Cust Service Savings	-1,174	2,436	3,747	4,461	4,812	5,162	5,517	5,893	6,318	8,947	46,118
Sales Savings	-464	926	1,546	1,739	1,805	1,870	1,937	2,012	2,103	2,792	16,266
A&G	-1,771	3,084	5,392	13,352	14,002	14,653	15,321	16,043	16,895	22,515	119,486
											565,118
Capital Summary	24,154	55,270	68,886	64,032	63,392	48,472	49,771	45,080	44,779	60,818	524,655
Regulated Savings	24,134	55,313	68,953	64,093	63,537	48,662	49,986	45,286	45,041	61,041	526,046
Non-Regulated Savings	20	-43	-67	-62	-144	-191	-215	-206	-262	-223	-1,392
											524,655
Direct Savings	16,568	22,837	33,148	25,536	25,363	25,674	26,289	27,355	27,631	36,929	267,330
Service Company	7,565	32,476	35,805	38,557	38,174	22,988	23,697	17,931	17,410	24,112	258,716
											$526,046
Fuel Savings	1	-2	-2	-4	-7	-9	-10	-9	-11	-11	-64
Generation Savings	10,336	13,853	20,700	14,397	14,432	14,669	15,032	15,582	15,813	21,107	155,920
Transmission Savings	1,818	2,415	3,572	2,492	2,473	2,500	2,558	2,659	2,683	3,625	26,794
Distribution Savings	3,644	4,874	7,170	5,062	5,063	5,143	5,272	5,475	5,552	7,444	54,698
Customer Accounts Savings	12	7	5	0	-10	-15	-17	-16	-22	-14	-70
Cust. Service Savings	658	1,677	1,727	1,748	1,737	1,765	1,819	1,910	1,938	2,217	17,195
Sales Savings	47	126	152	143	120	110	109	120	107	183	1,218
A&G	53	-114	-176	1,698	1,555	1,510	1,526	1,635	1,572	2,378	11,638
											267,330

ALLOCATION TABLE #1 --> Regulated Direct, Regulated Service & Non-Regulated Service/Non-Regulated Direct

	Areas ($ in 000s)	RD, RS, NR-S	NR-D	Total
	Labor			
1	Corporate	100.00%	0.00%	100.0%
2	Generation Support	100.00%	0.00%	100.0%
3	Field	100.00%	0.00%	100.0%
	Total			
1	Facilities	100.00%	0.00%	100.0%
	Corporate & Administrative Programs			
7	Advertising/Public Relations	100.00%	0.00%	100.0%
4	Administrative & General Overhead	100.00%	0.00%	100.0%
7	Association Dues & Memberships	100.00%	0.00%	100.0%
14	Benefits	98.05%	1.95%	100.0%
8	Credit Facilities and Bank Fees	63.64%	36.36%	100.0%
13	Director's Fees	0.00%	100.00%	100.0%
6	Insurance	98.14%	1.86%	100.0%
11	Information Services	100.00%	0.00%	100.0%
9	Professional Services	78.13%	21.87%	100.0%
10	Research & Development	100.00%	0.00%	100.0%
7	Shareholder Services	100.00%	0.00%	100.0%
7	Telecom	100.00%	0.00%	100.0%
	Total			
	Purchasing Economies (Nonfuel)			
7	Procurement	100.00%	0.00%	100.0%
12	Contract Services	100.00%	0.00%	100.0%
7	Inventory Reduction	100.00%	0.00%	100.0%
	Total			
	Savings - Subtotal			
	Total Savings			
5	Cost to Achieve	97.70%	2.30%	100.0%
5	Premerger Initiatives	97.70%	2.30%	100.0%
	Net Savings			

ALLOCATION TABLE #1 --> INPUTS

	Criteria	RD, RS, NR-S	NR-D	Total		RD, RS, NR-S	NR-D	Total	
1	Corporate Employees	100.00%	0.00%	100.0%	Corporate Employees	787	0	787	C-1
2	Generation Employees	100.00%	0.00%	100.0%	Generation Employees	83	0	83	C-2
3	Field Employees	100.00%	0.00%	100.0%	Field Employees	191	0	191	C-3
4	# of Reduced Employees	100.00%	0.00%	100.0%	# of Reduced Employees	1,061	0	1,061	
5	Follows Total Savings	97.70%	2.30%	100.0%	Total Savings	2,351,301	55,445	2,406,746	M-1,5
6	Fixed Assets	98.14%	1.86%	100.0%	Fixed Assets	18,794,116	355,420	19,149,536	C-1,2
7	RD, RS, NR-S Only	100.00%	0.00%	100.0%					
8	Lines of Credit Allocation	63.64%	36.36%	100.0%	Lines of Credit Alloc	1,874,074	1,070,926	2,945,000	
9	Professional Services	78.13%	21.87%	100.0%	Professional Services	79,934,911	22,370,302	102,305,213	
10	R & D	100.00%	0.00%	100.0%	R & D	35,839	0	35,839	
11	IS	100.00%	0.00%	100.0%	IS	137,200,000	0	137,200,000	
12	Contract Services	100.00%	0.00%	100.0%	Contract Services	354,090,605	0	354,090,605	
13	100% NR-D	0.00%	100.00%	100.0%	NR-D	0	1	1	
14	# of Non-UMWA Employees	98.05%	1.95%	100.0%	# of Non-UMWA Employees	23,446	466	23,912	L-1
15	No Allocation	0.00%	0.00%	0.0%	No Allocation	0	0	1	

ALLOCATION TABLE #2 --> Direct/Service Company

	Areas ($ in 000s)	Direct	Service Company	Total
	Labor			
1	Corporate	2.03%	97.97%	100.0%
2	Generation Support	2.41%	97.59%	100.0%
3	Field	77.49%	22.51%	100.0%
	Total			
4	Facilities	0.00%	100.00%	100.0%
	Corporate & Administrative Programs			
4	Advertising/Public Relations	0.00%	100.00%	100.0%
6	Administrative & General Overhead	15.65%	84.35%	100.0%
5	Association Dues & Memberships	100.00%	0.00%	100.0%
11	Benefits	78.88%	21.12%	100.0%
13	Credit Facilities and Bank Fees	97.79%	2.21%	100.0%
14	Director's Fees	0.00%	0.00%	0.0%
7	Insurance	98.60%	1.40%	100.0%
4	Information Services	0.00%	100.00%	100.0%
8	Professional Services	61.88%	38.12%	100.0%
10	Research & Development	100.00%	0.00%	100.0%
4	Shareholder Services	0.00%	100.00%	100.0%
4	Telecom	0.00%	100.00%	100.0%
	Total			
	Purchasing Economies (Nonfuel)			
5	Procurement	100.00%	0.00%	100.0%
9	Contract Services	100.00%	0.00%	100.0%
5	Inventory Reduction	100.00%	0.00%	100.0%
	Total			
	Savings - Subtotal			
	Total Savings			
	Cost to Achieve			
12	Total Cost to Achieve	29.43%	70.57%	100.0%
12	Premerger Initiatives	29.43%	70.57%	100.0%
	Net Savings			

ALLOCATION TABLE #2 --> INPUTS

	Criteria	Direct	Service	Total	ALLOCATION % Direct	ALLOCATION % Service	ALLOCATION % Total	RATEPAYER ALLOCATION % Direct	RATEPAYER ALLOCATION % Service	RATEPAYER ALLOCATION % Total
1	Corporate Labor	16	771	787	2.03%	97.97%	100.0%	2.03%	97.97%	100.0%
2	Generation Labor	2	81	83	2.41%	97.59%	100.0%	2.41%	97.59%	100.0%
3	Field Labor	148	43	191	77.49%	22.51%	100.0%	77.49%	22.51%	100.0%
4	Non-Labor Service Company	0	1	1	0.00%	100.00%	100.0%	0.00%	100.00%	100.0%
5	Non-Labor Direct	1	0	1	100.00%	0.00%	100.0%	100.00%	0.00%	100.0%
6	# of Reduced Employees	166	895	1,061	15.65%	84.35%	100.0%	15.65%	84.35%	100.0%
7	Fixed Assets	18,530,933	263,183	18,794,116	98.60%	1.40%	100.0%	98.60%	1.40%	100.0%
8	Professional Services Alloc	49,461,499	30,473,412	79,934,911	61.88%	38.12%	100.0%	61.88%	38.12%	100.0%
9	Contract Services Alloc	354,093,605	0	354,090,605	100.00%	0.00%	100.0%	100.00%	0.00%	100.0%
10	R & D Alloc	35,839	0	35,839	100.00%	0.00%	100.0%	100.00%	0.00%	100.0%
11	# of Non-UMWA Employees	18,494	4,952	23,446	78.88%	21.12%	100.0%	78.88%	21.12%	100.0%
12	Follows Total Savings	692,042	1,659,259	2,351,301	29.43%	70.57%	100.0%	29.43%	70.57%	100.0%
13	Lines of Credit	1,832,714	41,360	1,874,074	97.79%	2.21%	100.0%	97.79%	2.21%	100.0%
14	No Allocation	0	0	1	0.00%	0.00%	0.0%	0.00%	0.00%	0.0%

Ratepayer/Shareholder Sharing Calcuations
% to Ratepayers calculated to equal: 1

ALLOCATION TABLE #3 --> Direct Categories

	Areas ($ in 000s)	Fuel	Generation	Transmission	Distribution	Cust. Accts	Cust. Service	Sales	A&G	TOTAL
	Labor									
6	Corporate	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	100.0%	0.0%	100.0%
7	Generation Support	0.0%	100.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	100.0%
8	Field	0.0%	0.0%	0.0%	0.0%	0.0%	100.0%	0.0%	0.0%	100.0%
	Total									
5	Facilities	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
	Corporate & Administrative Programs									
5	Advertising/Public Relations	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
12	Administrative & General Overhead	0.0%	1.2%	0.0%	0.0%	0.0%	89.2%	9.6%	0.0%	100.0%
2	Association Dues & Memberships	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	100.0%	100.0%
2	Benefits	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	100.0%	100.0%
2	Credit Facilities and Bank Fees	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	100.0%	100.0%
5	Director's Fees	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
2	Insurance	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	100.0%	100.0%
5	Information Services	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
9	Professional Services	1.6%	39.8%	22.9%	19.6%	5.2%	2.2%	1.3%	7.4%	100.0%
10	Research & Development	2.9%	47.0%	10.4%	23.5%	9.4%	6.6%	0.2%	0.0%	100.0%
5	Shareholder Services	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
	Total									
	Purchasing Economies (Nonfuel)									
1	Procurement	0.0%	66.5%	11.3%	22.2%	0.0%	0.0%	0.0%	0.0%	100.0%
11	Contract Services	0.0%	51.0%	13.6%	32.3%	0.8%	2.3%	0.0%	0.0%	100.0%
1	Inventory Reduction	0.0%	66.5%	11.3%	22.2%	0.0%	0.0%	0.0%	0.0%	100.0%
	Total									
	Savings - Subtotal									
	Total Savings									
	Cost to Achieve									
4	Total Cost to Achieve	0.3%	40.8%	9.7%	15.9%	1.0%	8.2%	2.9%	21.1%	100.0%
4	Premerger Initiatives	0.3%	40.8%	9.7%	15.9%	1.0%	8.2%	2.9%	21.1%	100.0%
	Net Savings									

ALLOCATION TABLE #3 -->

INPUTS

		Fuel	Generation	Transmission	Distribution	Cust. Accounts	Cust. Service	Sales	A&G	Total
1	96/97 Inventory	0	154,919,495	26,271,572	51,823,538	0	106,618	0	0	233,121,222
2	A & G	0	0	0	0	0	0	0	1	1
3	Gross Receipts	0	0	0	0	0	0	0	1	1
4	Follow Savings	1,961	282,698	67,422	110,380	6,864	56,476	19,919	146,322	692,042
5	No Allocation	0	0	0	0	0	0	0	0	1
6	Corporate Labor	0	0	0	0	0	0	16	0	16
7	Generation Labor	0	2	0	0	0	0	0	0	2
8	Field Labor	0	0	0	0	0	148	0	0	148
9	Professional Services	790,572	19,667,531	11,325,975	9,712,164	2,583,696	1,066,629	651,853	3,663,080	49,461,498
10	R & D	1,032	16,833	3,742	8,433	3,368	2,377	56	0	35,841
11	Contract Services	0	180,692,576	48,127,331	114,264,762	2,683,275	8,277,751	44,912	0	354,090,607
12	# of Reduced Employees	0	2	0	0	0	148	16	0	166

ALLOCATION %

		Fuel	Generation	Transmission	Distribution	Cust. Accts	Cust. Service	Sales	A&G	Total
1	M & S Inventory	0.0%	66.5%	11.3%	22.2%	0.0%	0.0%	0.0%	0.0%	100.0%
2	A & G	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	100.0%	100.0%
3	Gross Receipts	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	100.0%	100.0%
4	Follow Savings	0.3%	40.8%	9.7%	15.9%	1.0%	8.2%	2.9%	21.1%	100.0%
5	No Allocation	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
6	Corporate Labor	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	100.0%	0.0%	100.0%
7	Generation labor	0.0%	100.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	100.0%
8	Field labor	0.0%	0.0%	0.0%	0.0%	0.0%	100.0%	0.0%	0.0%	100.0%
9	Professional Services	1.6%	39.8%	22.9%	19.6%	5.2%	2.2%	1.3%	7.4%	100.0%
10	R & D	2.9%	47.0%	10.4%	23.5%	9.4%	6.6%	0.2%	0.0%	100.0%
11	Contract Services	0.0%	51.0%	13.6%	32.3%	0.8%	2.3%	0.0%	0.0%	100.0%
12	# of Reduced Employees	0.0%	1.2%	0.0%	0.0%	0.0%	89.2%	9.6%	0.0%	100.0%

AEP AMERICAN ELECTRIC POWER

Central and South West

Allocation #1

Regulated Direct/Regulated Service/Non-Regulated Service vs. Non-Reg Direct

Total Savings Detail - Regulated

Areas ($ in 000s)	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	Total	
Labor												
Corporate	17,124	60,990	77,031	81,498	86,094	90,826	95,700	100,725	105,908	140,934	856,831	
Generation Support	2,662	7,402	7,750	8,111	8,484	8,870	9,270	9,685	10,114	13,315	85,664	
Field Support	1,200	3,463	3,965	4,475	4,993	5,519	6,054	6,600	7,156	10,275	53,700	
Total	20,986	71,856	88,747	94,084	99,571	105,215	111,025	117,010	123,178	164,524	996,195	
Corporate Facilities	5,238	7,193	7,409	7,631	7,860	8,096	8,339	8,589	8,847	11,459	80,661	
Corporate & Administrative Programs:												
Advertising/Public Relations	1,191	1,667	1,750	1,838	1,930	2,026	2,128	2,234	2,346	3,109	20,219	
Administrative & General Overhead	1,868	6,353	7,176	7,391	7,613	7,841	8,076	8,319	8,568	11,098	74,302	
Association Dues & Memberships	274	376	388	399	411	424	436	449	463	599	4,220	
Benefits	0	0	0	8,856	9,647	10,456	11,282	12,126	12,990	17,570	82,927	
Credit Facilities	57	78	80	83	85	88	90	93	96	124	875	
Director's Fees	0	0	0	0	0	0	0	0	0	0	0	
Insurance	4,280	5,934	6,172	6,419	6,675	6,942	7,220	7,509	7,809	10,233	69,194	
Information Services	6,273	20,416	31,525	42,012	52,378	57,112	60,765	57,123	53,544	59,299	440,445	
Professional Services	9,780	13,692	14,376	15,095	15,850	16,642	17,474	18,348	19,265	25,539	166,061	
Regulatory Expense	0	0	0	0	0	0	0	0	0	0	0	
Research & Development	718	986	1,015	1,046	1,077	1,110	1,143	1,177	1,213	1,571	11,056	
Shareholder Services	597	820	845	870	897	923	951	980	1,009	1,307	9,200	
Telecom	1,893	2,599	2,677	2,758	2,840	2,925	3,013	3,104	3,197	4,140	29,146	
Total	26,930	52,921	66,004	86,766	99,403	106,489	112,579	111,462	110,499	134,589	907,643	
Purchasing Economies (Nonfuel):												
Procurement	9,335	15,321	19,063	22,802	26,538	30,276	34,019	37,774	41,542	57,606	294,276	
Contract Services	2,778	4,095	4,572	5,063	5,570	6,092	6,632	7,190	7,768	10,614	60,373	
Inventory Reduction	0	0	1,473	1,473	1,473	1,473	1,473	1,473	1,473	1,841	12,152	
Total	12,112	19,416	25,108	29,338	33,581	37,841	42,124	46,437	50,783	70,061	366,801	
Savings - Subtotal	65,267	151,386	187,268	217,819	240,415	257,641	274,067	283,498	293,307	380,633	2,351,301	
Total Savings	65,267	151,386	187,268	217,819	240,415	257,641	274,067	283,498	293,307	380,633	2,351,301	B-1
Cost to Achieve												
Total Cost to Achieve	107,255	57,582	21,971	7,448	7,623	7,787	7,887	7,553	7,553	9,707	242,366	
Premerger Initiatives	1,512	4,247	7,255	10,787	15,038	19,719	24,610	29,521	32,467	43,717	188.873	
Net Savings	-43,500	89,557	158,043	199,584	217,753	230,136	241,570	246,423	253,286	327,209	1,920,062	A-1

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Total O&M Savings - Regulated

Areas ($ in 000s)	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	Total
Labor											
Corporate	16,780	59,432	73,983	76,942	80,020	83,221	86,550	90,012	93,612	122,669	783,222
Generation	2,642	7,328	7,621	7,926	8,243	8,573	8,916	9,272	9,643	12,637	82,802
Field Support	1,064	2,951	3,069	3,191	3,319	3,452	3,590	3,733	3,883	5,664	33,916
Total	20,486	69,711	84,673	88,060	91,582	95,246	99,055	103,018	107,138	140,970	899,940
Corporate Facilities	5,238	7,193	7,409	7,631	7,860	8,096	8,339	8,589	8,847	11,459	80,661
Corporate & Administrative Programs:											
Advertising/Public Relations	1,191	1,667	1,750	1,838	1,930	2,026	2,128	2,234	2,346	3,109	20,219
Administrative & General Overhead	1,868	6,353	7,176	7,391	7,613	7,841	8,076	8,319	8,568	11,098	74,302
Association Dues & Memberships	274	376	388	399	411	424	436	449	463	599	4,220
Benefits	0	0	0	8,413	8,750	9,100	9,464	9,843	10,236	13,414	69,220
Credit Facilities	57	78	80	83	85	88	90	93	96	124	875
Director's Fees	0	0	0	0	0	0	0	0	0	0	0
Insurance	4,280	5,934	6,172	6,419	6,675	6,942	7,220	7,509	7,809	10,233	69,194
Information Services	4,614	9,689	11,306	11,898	12,522	13,181	13,875	14,608	15,381	20,263	127,338
Professional Services	9,780	13,692	14,376	15,095	15,850	16,642	17,474	18,348	19,265	25,539	166,061
Research & Development	718	986	1,015	1,046	1,077	1,110	1,143	1,177	1,213	1,571	11,056
Shareholder Services	597	820	845	870	897	923	951	980	1,009	1,307	9,200
Telecom	1,893	2,599	2,677	2,758	2,840	2,925	3,013	3,104	3,197	4,140	29,146
Total	25,271	42,194	45,786	56,210	58,650	61,202	63,871	66,663	69,583	91,397	580,829
Purchasing Economies (Nonfuel):											
Procurement	6798	9336	9616	9905	10202	10508	10823	11148	11482	14872	104,689
Contract Services	2568	3596	3776	3964	4163	4371	4589	4819	5060	6707	43,612
Inventory Reduction	0	0	0	0	0	0	0	0	0	0	0
Total	9366	12932	13392	13869	14364	14878	15412	15966	16542	21579	148,301
Savings - Subtotal	60,362	132,030	151,260	165,770	172,457	179,423	186,678	194,236	202,110	265,405	1,709,731
Total Savings	60,362	132,030	151,260	165,770	172,457	179,423	186,678	194,236	202,110	265,405	1,709,731
Cost to Achieve											
Total Cost to Achieve	107,255	57,582	21,971	7,448	7,623	7,787	7,887	7,553	7,553	9,707	242,366
Premeger Initiatives	1,661	4,073	6,586	9,299	12,123	15,053	18,049	21,180	21,973	27,466	137,463
Net O&M Savings	-48,554	70,375	122,704	149,023	152,711	156,583	160,742	165,503	172,584	228,232	1,329,902

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Revenue Requirement Savings - Regulated

Areas ($ in 000s)	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	Total
Labor											
Corporate	344	1,558	3,048	4,555	6,074	7,605	9,151	10,713	12,296	18,265	73,609
Generation	20	74	129	185	241	298	355	413	471	678	2,862
Field S pport	136	513	897	1,284	1,674	2,067	2,464	2,866	3,273	4,611	19,784
Total	500	2,145	4,074	6,024	7,989	9,970	11,969	13,992	16,040	23,553	96,255
Facilities and Other Capital	0	0	0	0	0	0	0	0	0	0	0
Corporate & Administrative Programs:											
Professional Services	0	0	0	0	0	0	0	0	0	0	0
Information Services	1,659	10,727	20,218	30,114	39,855	43,931	46,890	42,515	38,162	39,036	313,108
Benefits	0	0	0	443	897	1,356	1,818	2,284	2,753	4,156	13,707
Total	1,659	10,727	20,218	30,556	40,753	45,287	48,708	44,799	40,916	43,192	326,815
Purchasing Economies (Nonfuel):											
Procurement	2,537	5,985	9,447	12,897	16,336	19,768	23,196	26,627	30,060	42,735	189,587
Contract Services	209	499	796	1,099	1,407	1,721	2,042	2,371	2,708	3,906	16,761
Inventory Reduction	0	0	1,473	1,473	1,473	1,473	1,473	1,473	1,473	1,841	12,152
Total	2,746	6,485	11,716	15,469	19,216	22,962	26,712	30,471	34,242	48,482	218,500
Savings - Subtotal	4,905	19,356	36,008	52,049	67,958	78,219	87,389	89,261	91,197	115,228	641,570
Total Savings	4,905	19,356	36,008	52,049	67,958	78,219	87,389	89,261	91,197	115,228	641,570
Costs to Achieve	0	0	0	0	0	0	0	0	0	0	0
Premeger Initiatives	-149	174	669	1,488	2,915	4,666	6,561	8,341	10,494	16,251	51,410
Net Savings	5,054	19,182	35,339	50,562	65,043	73,553	80,828	80,920	80,703	98,976	590,160

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Capital Savings - Regulated

Areas ($ in 000s)	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	Total
Labor											
Corporate	1,964	6,957	8,660	9,006	9,367	9,741	10,131	10,536	10,958	14,359	91,679
Generation	112	311	323	336	349	363	378	393	409	536	3,511
Field Support	778	2,159	2,245	2,335	2,428	2,525	2,626	2,731	2,841	3,146	23,815
Total	2,855	9,426	11,228	11,677	12,144	12,630	13,135	13,661	14,207	18,041	119,005
Facilities and Other Capital	0	0	0	0	0	0	0	0	0	0	0
Corporate & Administrative Programs:											
Professional Services	0	0	0	0	0	0	0	0	0	0	0
Information Services	4,756	26,165	28,492	31,693	33,436	19,273	20,333	13,896	14,660	17,035	209,739
Benefits	0	0	0	2,527	2,628	2,734	2,843	2,957	3,075	4,029	20,793
Total	4,756	26,165	28,492	34,220	36,064	22,007	23,176	16,852	17,735	21,064	230,532
Purchasing Economies (Nonfuel):											
Procurement	14,478	19,883	20,479	21,094	21,726	22,378	23,050	23,741	24,453	31,673	222,955
Contract Services	1,194	1,672	1,756	1,844	1,936	2,033	2,134	2,241	2,353	3,119	20,282
Inventory Reduction	0	0	9,820	0	0	0	0	0	0	0	9,820
Total	15,672	21,555	32,055	22,937	23,662	24,411	25,184	25,982	26,806	34,792	253,056
Savings - Subtotal	23,283	57,146	71,775	68,835	71,871	59,048	61,495	56,495	58,748	73,897	602,594
Total Savings	23,283	57,146	71,775	68,835	71,871	59,048	61,495	56,495	58,748	73,897	602,594
Costs to Achieve	0	0	0	0	0	0	0	0	0	0	0
Premeger Initiatives	-851	1,833	2,822	4,741	8,334	10,386	11,509	11,209	13,707	12,856	76,547
Net Savings	24,134	55,313	68,953	64,093	63,537	48,662	49,986	45,286	45,041	61,041	526,046

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Total Savings Detail - Non-Regulated

Areas ($ in 000s)	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	Total
Labor											
Corporate	0	0	0	0	0	0	0	0	0	0	0
Generation Support	0	0	0	0	0	0	0	0	0	0	0
Field Support	0	0	0	0	0	0	0	0	0	0	0
Total	0	0	0	0	0	0	0	0	0	0	0
Corporate Facilities	0	0	0	0	0	0	0	0	0	0	0
Corporate & Administrative Programs:											
Advertising/Public Relations	0	0	0	0	0	0	0	0	0	0	0
Administrative & General Overhead	0	0	0	0	0	0	0	0	0	0	0
Association Dues & Memberships	0	0	0	0	0	0	0	0	0	0	0
Benefits	0	0	0	176	192	208	224	241	258	349	1,648
Credit Facilities	32	45	46	47	49	50	52	53	55	71	500
Director's Fees	358	492	507	522	537	554	570	587	605	784	5,516
Insurance	81	112	117	121	126	131	137	142	148	194	1,309
Information Services	0	0	0	0	0	0	0	0	0	0	0
Professional Services	2,737	3,832	4,023	4,224	4,436	4,657	4,890	5,135	5,392	7,147	46,473
Regulatory Expense	0	0	0	0	0	0	0	0	0	0	0
Research & Development	0	0	0	0	0	0	0	0	0	0	0
Shareholder Services	0	0	0	0	0	0	0	0	0	0	0
Total	3,208	4,480	4,693	5,091	5,340	5,600	5,873	6,158	6,457	8,544	55,445
Purchasing Economies (Nonfuel):											
Procurement	0	0	0	0	0	0	0	0	0	0	0
Contract Services	0	0	0	0	0	0	0	0	0	0	0
Inventory Reduction	0	0	0	0	0	0	0	0	0	0	0
Total	0	0	0	0	0	0	0	0	0	0	0
Savings - Subtotal	3,208	4,480	4,693	5,091	5,340	5,600	5,873	6,158	6,457	8,544	55,445
Total Savings	3,208	4,480	4,693	5,091	5,340	5,600	5,873	6,158	6,457	8,544	55,445 B-1
Cost to Achieve											
Total Cost to Achieve	2,529	1,358	518	176	180	184	186	178	178	229	5,715
Premerger Initiatives	36	100	171	254	355	465	580	696	766	1,031	4,454
Net Savings	644	3,022	4,003	4,661	4,805	4,952	5,107	5,284	5,513	7,285	45,276 A-1

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Total O&M Savings - Non-Regulated

Areas ($ in 000s)	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	Total
Labor											
Corporate	0	0	0	0	0	0	0	0	0	0	0
Generation	0	0	0	0	0	0	0	0	0	0	0
Field Support	0	0	0	0	0	0	0	0	0	0	0
Total	0	0	0	0	0	0	0	0	0	0	0
Corporate Facilities	0	0	0	0	0	0	0	0	0	0	0
Corporate & Administrative Programs:											
Advertising/Public Relations	0	0	0	0	0	0	0	0	0	0	0
Administrative & General Overhead	0	0	0	0	0	0	0	0	0	0	0
Association Dues & Memberships	0	0	0	0	0	0	0	0	0	0	0
Benefits	0	0	0	167	174	181	188	196	203	267	1,376
Credit Facilities	32	45	46	47	49	50	52	53	55	71	500
Director's Fees	358	492	507	522	537	554	570	587	605	784	5,516
Insurance	81	112	117	121	126	131	137	142	148	194	1,309
Information Services	0	0	0	0	0	0	0	0	0	0	0
Professional Services	2,737	3,832	4,023	4,224	4,436	4,657	4,890	5,135	5,392	7,147	46,473
Research & Development	0	0	0	0	0	0	0	0	0	0	0
Shareholder Services	0	0	0	0	0	0	0	0	0	0	0
Telecom	0	0	0	0	0	0	0	0	0	0	0
Total	3,208	4,480	4,693	5,082	5,322	5,573	5,837	6,113	6,402	8,462	55,173
Purchasing Economies (Nonfuel):											
Procurement	0	0	0	0	0	0	0	0	0	0	0
Contract Services	0	0	0	0	0	0	0	0	0	0	0
Inventory Reduction	0	0	0	0	0	0	0	0	0	0	0
Total	0	0	0	0	0	0	0	0	0	0	0
Savings - Subtotal	3,208	4,480	4,693	5,082	5,322	5,573	5,837	6,113	6,402	8,462	55,173
Total Savings	3,208	4,480	4,693	5,082	5,322	5,573	5,837	6,113	6,402	8,462	55,173
Cost to Achieve											
Total Cost to Achieve	2,529	1,358	518	176	180	184	186	178	178	229	5,715
Premeger Initiatives	39	96	155	219	286	355	426	499	518	648	3,241
Net O&M Savings	640	3,026	4,019	4,687	4,856	5,035	5,225	5,435	5,706	7,585	46,216

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Revenue Requirement Savings - Non-Regulated

Areas ($ in 000s)	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	Total
Labor											
Corporate	0	0	0	0	0	0	0	0	0	0	0
Generation	0	0	0	0	0	0	0	0	0	0	0
Field Support	0	0	0	0	0	0	0	0	0	0	0
Total	0	0	0	0	0	0	0	0	0	0	0
Facilities and Other Capital	0	0	0	0	0	0	0	0	0	0	0
Corporate & Administrative Programs:											
Professional Services	0	0	0	0	0	0	0	0	0	0	0
Information Services	0	0	0	0	0	0	0	0	0	0	0
Benefits	0	0	0	9	18	27	36	45	55	83	272
Total	0	0	0	9	18	27	36	45	55	83	272
Purchasing Economies (Nonfuel):											
Procurement	0	0	0	0	0	0	0	0	0	0	0
Contract Services	0	0	0	0	0	0	0	0	0	0	0
Inventory Reduction	0	0	0	0	0	0	0	0	0	0	0
Total	0	0	0	0	0	0	0	0	0	0	0
Savings - Subtotal	0	0	0	9	18	27	36	45	55	83	272
Total Savings	0	0	0	9	18	27	36	45	55	83	272
Costs to Achieve	0	0	0	0	0	0	0	0	0	0	0
Premeger Initiatives	-4	4	16	35	69	110	155	197	247	383	1,212
Net Savings	4	-4	-16	-26	-51	-83	-119	-151	-193	-301	-940

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Capital Savings - Non-Regulated

Areas ($ in 000s)	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	Total
Labor											
Corporate	0	0	0	0	0	0	0	0	0	0	0
Generation	0	0	0	0	0	0	0	0	0	0	0
Field Support	0	0	0	0	0	0	0	0	0	0	0
Total	0	0	0	0	0	0	0	0	0	0	0
Facilities and Other Capital	0	0	0	0	0	0	0	0	0	0	0
Corporate & Administrative Programs:											
Professional Services	0	0	0	0	0	0	0	0	0	0	0
Information Services	0	0	0	0	0	0	0	0	0	0	0
Benefits	0	0	0	50	52	54	57	59	61	80	413
Total	0	0	0	50	52	54	57	59	61	80	413
Purchasing Economies (Nonfuel):											
Procurement	0	0	0	0	0	0	0	0	0	0	0
Contract Services	0	0	0	0	0	0	0	0	0	0	0
Inventory Reduction	0	0	0	0	0	0	0	0	0	0	0
Total	0	0	0	0	0	0	0	0	0	0	0
Savings - Subtotal	0	0	0	50	52	54	57	59	61	80	413
Total Savings	0	0	0	50	52	54	57	59	61	80	413
Costs to Achieve	0	0	0	0	0	0	0	0	0	0	0
Premeger Initiatives	-20	43	67	112	197	245	271	264	323	303	1,805
Net Savings	20	-43	-67	-62	-144	-191	-215	-206	-262	-223	-1,392

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Allocation #2

Direct vs. ServiceCo

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Total Savings Detail - Direct

Areas ($ in 000s)	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	Total	
Labor												
Corporate	348	1,240	1,566	1,657	1,750	1,847	1,946	2,048	2,153	2,865	17,420	
Generation Support	64	178	187	195	204	214	223	233	244	321	2,064	
Field Support	930	2,684	3,073	3,468	3,869	4,276	4,691	5,114	5,545	7,962	41,610	
Total	1,342	4,102	4,825	5,320	5,824	6,337	6,860	7,395	7,942	11,148	61,094	
Corporate Facilities	0	0	0	0	0	0	0	0	0	0	0	
Corporate & Administrative Programs:												
Advertising/Public Relations	0	0	0	0	0	0	0	0	0	0	0	
Administrative & General Overhead	292	994	1,123	1,156	1,191	1,227	1,264	1,301	1,341	1,736	11,625	
Association Dues & Memberships	274	376	388	399	411	424	436	449	463	599	4,220	
Benefits	0	0	0	6,986	7,610	8,248	8,899	9,565	10,246	13,859	65,412	
Credit Facilities	56	76	79	81	83	86	88	91	94	122	855	
Director's Fees	0	0	0	0	0	0	0	0	0	0	0	
Insurance	4,220	5,851	6,085	6,329	6,582	6,845	7,119	7,404	7,700	10,090	68,225	
Information Services	0	0	0	0	0	0	0	0	0	0	0	
Professional Services	6,051	8,472	8,896	9,340	9,807	10,298	10,813	11,353	11,921	15,803	102,754	
Regulatory Expense	0	0	0	0	0	0	0	0	0	0	0	
Research & Development	718	986	1,015	1,046	1,077	1,110	1,143	1,177	1,213	1,571	11,056	
Shareholder Services	0	0	0	0	0	0	0	0	0	0	0	
Total	11,611	16,756	17,585	25,337	26,762	28,236	29,762	31,341	32,977	43,779	264,146	
Purchasing Economies (Nonfuel):												
Procurement	9,335	15,321	19,063	22,802	26,538	30,276	34,019	37,774	41,542	57,606	294,276	
Contract Services	2,778	4,095	4,572	5,063	5,570	6,092	6,632	7,190	7,768	10,614	60,373	
Inventory Reduction	0	0	1,473	1,473	1,473	1,473	1,473	1,473	1,473	1,841	12,152	
Total	12,112	19,416	25,108	29,338	33,581	37,841	42 124	46,437	50,783	70,061	366,801	
Savings - Subtotal	25,065	40,274	47,518	59,995	66,166	72,414	78,746	85,173	91,702	124,988	692,042	
Total Savings	25,065	40,274	47,518	59,995	66,166	72,414	78,746	85,173	91,702	124,988	692,042	B-2
Cost to Achieve												
Total Cost to Achieve	31,568	16,948	6,466	2,192	2,244	2,292	2,321	2,223	2,223	2,857	71,334	
Premerger Initiatives	445	1,250	2,135	3,175	4,426	5,804	7,243	8,689	9,556	12,867	55,590	
Net Savings	-6,947	22,076	38,917	54,628	59,496	64,318	69,182	74,261	79,923	109,264	565,118	A-1

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Total O&M Savings - Direct

Areas ($ in 000s)	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	Total
Labor											
Corporate	341	1,208	1,504	1,564	1,627	1,692	1,760	1,830	1,903	2,494	15,923
Generation	64	177	184	191	199	207	215	223	232	304	1,995
Field Support	824	2,286	2,378	2,473	2,572	2,675	2,782	2,893	3,009	4,389	26,280
Total	1,229	3,671	4,066	4,228	4,397	4,573	4,756	4,946	5,144	7,187	44,199
Corporate Facilities	0	0	0	0	0	0	0	0	0	0	0
Corporate & Administrative Programs:											
Advertising/Public Relations	0	0	0	0	0	0	0	0	0	0	0
Administrative & General Overhead	292	994	1,123	1,156	1,191	1,227	1,264	1,301	1,341	1,736	11,625
Association Dues & Memberships	274	376	388	399	411	424	436	449	463	599	4,220
Benefits	0	0	0	6,636	6,902	7,178	7,465	7,764	8,074	10,581	54,600
Credit Facilities	56	76	79	81	83	86	88	91	94	122	855
Director's Fees	0	0	0	0	0	0	0	0	0	0	0
Insurance	4,220	5,851	6,085	6,329	6,582	6,845	7,119	7,404	7,700	10,090	68,225
Information Services	0	0	0	0	0	0	0	0	0	0	0
Professional Services	6,051	8,472	8,896	9,340	9,807	10,298	10,813	11,353	11,921	15,803	102,754
Regulatory Expense	0	0	0	0	0	0	0	0	0	0	0
Research & Development	718	986	1,015	1,046	1,077	1,110	1,143	1,177	1,213	1,571	11,056
Shareholder Services	0	0	0	0	0	0	0	0	0	0	0
Total	11,611	16,756	17,585	24,988	26,054	27,167	28,328	29,540	30,805	40,501	253,334
Purchasing Economies (Nonfuel):											
Procurement	6,798	9,336	9,616	9,905	10,202	10,508	10,823	11,148	11,482	14,872	104,689
Contract Services	2,568	3,596	3,776	3,964	4,163	4,371	4,589	4,819	5,060	6,707	43,612
Inventory Reduction	0	0	0	0	0	0	0	0	0	0	0
Total	9,366	12,932	13,392	13,869	14,364	14,878	15,412	15,966	16,542	21,579	148,301
Savings - Subtotal	22,207	33,359	35,042	43,085	44,816	46,618	48,496	50,453	52,491	69,267	445,834
Total Savings	22,207	33,359	35,042	43,085	44,816	46,618	48,496	50,453	52,491	69,267	445,834
Cost to Achieve											
Total Cost to Achieve	31,568	16,948	6,466	2,192	2,244	2,292	2,321	2,223	2,223	2,857	71,334
Premeger Initiatives	489	1,199	1,938	2,737	3,568	4,430	5,312	6,234	6,467	8,084	40,459
Net O&M Savings	-9,850	15,212	26,638	38,156	39,004	39,896	40,863	41,996	43,801	58,327	334,042

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Revenue Requirement Savings - Direct

Areas ($ in 000s)	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	Total
Labor											
Corporate	7	32	62	93	123	155	186	218	250	371	1,496
Generation	0	2	3	4	6	7	9	10	11	16	69
Field Support	106	397	695	995	1,297	1,602	1,909	2,221	2,536	3,573	15,330
Total	113	431	760	1,092	1,426	1,763	2,104	2,449	2,798	3,960	16,896
Facilities and Other Capital	0	0	0	0	0	0	0	0	0	0	0
Corporate & Administrative Programs:											
Professional Services	0	0	0	0	0	0	0	0	0	0	0
Information Services	0	0	0	0	0	0	0	0	0	0	0
Benefits	0	0	0	349	708	1,070	1,434	1,801	2,172	3,278	10,812
Total	0	0	0	349	708	1,070	1,434	1,801	2,172	3,278	10,812
Purchasing Economies (Nonfuel):											
Procurement	2,537	5,985	9,447	12,897	16,336	19,768	23,196	26,627	30,060	42,735	189,587.47
Contract Services	209	499	796	1,099	1,407	1,721	2,042	2,371	2,708	3,906	16,761
Inventory Reduction	0	0	1,473	1,473	1,473	1,473	1,473	1,473	1,473	1,841	12,152
Total	2,746	6,485	11,716	15,469	19,216	22,962	26,712	30,471	34,242	48,482	218,500
Savings - Subtotal	2,859	6,915	12,476	16,910	21,350	25,795	30,250	34,721	39,211	55,721	246,208
Total Savings	2,859	6,915	12,476	16,910	21,350	25,795	30,250	34,721	39,211	55,721	246,208
Costs to Achieve	0	0	0	0	0	0	0	0	0	0	0
Premeger Initiatives	-44	51	197	438	858	1,373	1,931	2,455	3,089	4,783	15,131
Net Savings	2,903	6,864	12,279	16,472	20,492	24,422	28,319	32,266	36,122	50,938	231,077

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Capital Savings - Direct

Areas ($ in 000s)	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	Total
Labor											
Corporate	40	141	176	183	190	198	206	214	223	292	1,864
Generation	3	7	8	8	8	9	9	9	10	13	85
Field Support	603	1,673	1,740	1,809	1,882	1,957	2,035	2,116	2,201	2,438	18,453
Total	646	1,822	1,923	2,000	2,080	2,164	2,250	2,340	2,434	2,743	20,402
Facilities and Other Capital	0	0	0	0	0	0	0	0	0	0	0
Corporate & Administrative Programs:											
Professional Services	0	0	0	0	0	0	0	0	0	0	0
Information Services	0	0	0	0	0	0	0	0	0	0	0
Benefits	0	0	0	1,994	2,073	2,156	2,242	2,332	2,425	3,178	16,401
Total	0	0	0	1,994	2,073	2,156	2,242	2,332	2,425	3,178	16,401
Purchasing Economics (Nonfuel):											
Procurement	14,478	19,883	20,479	21,094	21,726	22,378	23,050	23,741	24,453	31,673	222,954.53
Contract Services	1,194	1,672	1,756	1,844	1,936	2,033	2,134	2,241	2,353	3,119	20,282
Inventory Reduction	0	0	9,820	0	0	0	0	0	0	0	9,820
Total	15,672	21,555	32,055	22,937	23,662	24,411	25,184	25,982	26,806	34,792	253,056
Savings - Subtotal	16,318	23,377	33,978	26,931	27,816	28,731	29,676	30,654	31,665	40,713	289,860
Total Savings	16,318	23,377	33,978	26,931	27,816	28,731	29,676	30,654	31,665	40,713	289,860
Costs to Achieve	0	0	0	0	0	0	0	0	0	0	0
Premeger Initiatives	-250	539	831	1,396	2,453	3,057	3,387	3,299	4,034	3,784	22,530
Net Savings	16,568	22,837	33,148	25,536	25,363	25,674	26,289	27,355	27,631	36,929	267,330

Total Savings Detail - Service Company

Areas ($ in 000s)	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	Total
Labor											
Corporate	16,776	59,751	75,465	79,841	84,344	88,979	93,755	98,677	103,755	138,069	839,411
Generation Support	2,598	7,224	7,564	7,915	8,280	8,657	9,047	9,452	9,871	12,994	83,600
Field Support	270	780	893	1,008	1,124	1,242	1,363	1,486	1,611	2,313	12,090
Total	19,644	67,754	83,921	88,764	93,748	98,879	104,165	109,615	115,236	153,376	935,100
Corporate Facilities	5,238	7,193	7,409	7,631	7,860	8,096	8,339	8,589	8,847	11,459	80,661
Corporate & Administrative Programs:											
Advertising/Public Relations	1,191	1,667	1,750	1,838	1,930	2,026	2,128	2,234	2,346	3,109	20,219
Administrative & General Overhead	1,576	5,359	6,053	6,235	6,422	6,614	6,813	7,017	7,228	9,361	62,677
Association Dues & Memberships	0	0	0	0	0	0	0	0	0	0	0
Benefits	0	0	0	1,871	2,038	2,208	2,383	2,561	2,744	3,711	17,515
Credit Facilities	1	2	2	2	2	2	2	2	2	3	19
Director's Fees	0	0	0	0	0	0	0	0	0	0	0
Insurance	60	83	86	90	93	97	101	105	109	143	969
Information Services	6,273	20,416	31,525	42,012	52,378	57,112	60,765	57,123	53,544	59,299	440,445
Professional Services	3,728	5,220	5,481	5,755	6,042	6,344	6,662	6,995	7,345	9,736	63,307
Regulatory Expense	0	0	0	0	0	0	0	0	0	0	0
Research & Development	0	0	0	0	0	0	0	0	0	0	0
Shareholder Services	597	820	845	870	897	923	951	980	1,009	1,307	9,200
Telecom	1,893	2,599	2,677	2,758	2,840	2,925	3,013	3,104	3,197	4,140	29,146
Total	15,319	36,165	48,419	61,429	72,641	78,253	82,817	80,121	77,522	90,810	643,497
Purchasing Economies (Nonfuel):											
Procurement	0	0	0	0	0	0	0	0	0	0	0
Contract Services	0	0	0	0	0	0	0	0	0	0	0
Inventory Reduction	0	0	0	0	0	0	0	0	0	0	0
Total	0	0	0	0	0	0	0	0	0	0	0
Savings - Subtotal	40,201	111,112	139,750	157,824	174,249	185,228	195,321	198,324	201,605	255,645	1,659,259
Total Savings	40,201	111,112	139,750	157,824	174,249	185,228	195,321	198,324	201,605	255,645	1,659,259 B-2
Cost to Achieve											
Total Cost to Achieve	75,687	40,634	15,504	5,256	5,380	5,495	5,566	5,330	5,330	6,850	171,032
Premerger Initiatives	1,067	2,997	5,119	7,612	10,612	13,915	17,367	20,832	22,911	30,850	133,283
Net Savings	-36,553	67,481	119,126	144,956	158,257	165,818	172,389	172,162	173,364	217,944	1,354,943 A-1

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Total O&M Savings - Service Company

Areas ($ in 000s)	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	Total
Labor											
Corporate	16,439	58,224	72,479	75,378	78,393	81,529	84,790	88,182	91,709	120,176	767,298
Generation	2,579	7,152	7,438	7,735	8,045	8,366	8,701	9,049	9,411	12,332	80,807
Field Support	240	664	691	718	747	777	808	841	874	1,275	7,636
Total	19,257	66,040	80,607	83,832	87,185	90,672	94,299	98,071	101,994	133,783	855,741
Corporate Facilities	5,238	7,193	7,409	7,631	7,860	8,096	8,339	8,589	8,847	11,459	80,661
Corporate & Administrative Programs:											
Advertising/Public Relations	1,191	1,667	1,750	1,838	1,930	2,026	2,128	2,234	2,346	3,109	20,219
Administrative & General Overhead	1,576	5,359	6,053	6,235	6,422	6,614	6,813	7,017	7,228	9,361	62,677
Association Dues & Memberships	0	0	0	0	0	0	0	0	0	0	0
Benefits	0	0	0	1,777	1,848	1,922	1,999	2,079	2,162	2,833	14,620
Credit Facilities	1	2	2	2	2	2	2	2	2	3	19
Director's Fees	0	0	0	0	0	0	0	0	0	0	0
Insurance	60	83	86	90	93	97	101	105	109	143	969
Information Services	4,614	9,689	11,306	11,898	12,522	13,181	13,875	14,608	15,381	20,263	127,338
Professional Services	3,728	5,220	5,481	5,755	6,042	6,344	6,662	6,995	7,345	9,736	63,307
Regulatory Expense	0	0	0	0	0	0	0	0	0	0	0
Research & Development	0	0	0	0	0	0	0	0	0	0	0
Shareholder Services	597	820	845	870	897	923	951	980	1,009	1,307	9,200
Telecom	1,893	2,599	2,677	2,758	2,840	2,925	3,013	3,104	3,197	4,140	29,146
Total	13,660	25,438	28,201	31,222	32,596	34,036	35,544	37,123	38,778	50,896	327,494
Purchasing Economies (Nonfuel):											
Procurement	0	0	0	0	0	0	0	0	0	0	0
Contract Services	0	0	0	0	0	0	0	0	0	0	0
Inventory Reduction	0	0	0	0	0	0	0	0	0	0	0
Total	0	0	0	0	0	0	0	0	0	0	0
Savings - Subtotal	38,155	98,671	116,217	122,685	127,641	132,804	138,182	143,784	149,619	196,138	1,263,897
Total Savings	38,155	98,671	116,217	122,685	127,641	132,804	138,182	143,784	149,619	196,138	1,263,897
Cost to Achieve											
Total Cost to Achieve	75,687	40,634	15,504	5,256	5,380	5,495	5,566	5,330	5,330	6,850	171,032
Premeger Initiatives	1,172	2,874	4,647	6,562	8,555	10,622	12,737	14,946	15,506	19,382	97,005
Net O&M Savings	-38,704	55,163	96,066	110,867	113,707	116,687	119,879	123,507	128,783	169,906	995,860

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Revenue Requirement Savings - Service

Areas ($ in 000s)	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	Total
Labor											
Corporate	337	1,527	2,986	4,463	5,951	7,450	8,964	10,495	12,046	17,893	72,112
Generation	19	72	126	180	235	290	346	403	460	662	2,793
Field Support	31	115	202	289	377	465	555	645	737	1,038	4,454
Total	387	1,714	3,314	4,932	6,562	8,206	9,865	11,543	13,242	19,593	79,360
Facilities and Other Capital	0	0	0	0	0	0	0	0	0	0	0
Corporate & Administrative Programs:											
Professional Services	0	0	0	0	0	0	0	0	0	0	0
Information Services	1,659	10,727	20,218	30,114	39,855	43,931	46,890	42,515	38,162	39,036	313,108
Benefits	0	0	0	94	190	286	384	482	582	878	2,895
Total	1,659	10,727	20,218	30,207	40,045	44,217	47,274	42,997	38,744	39,914	316,003
Purchasing Economies (Nonfuel):											
Procurement	0	0	0	0	0	0	0	0	0	0	0
Contract Services	0	0	0	0	0	0	0	0	0	0	0
Inventory Reduction	0	0	0	0	0	0	0	0	0	0	0
Total	0	0	0	0	0	0	0	0	0	0	0
Savings - Subtotal	2,046	12,441	23,532	35,139	46,607	52,423	57,139	54,541	51,986	59,507	395,362
Total Savings	2,046	12,441	23,532	35,139	46,607	52,423	57,139	54,541	51,986	59,507	395,362
Costs to Achieve	0	0	0	0	0	0	0	0	0	0	0
Premeger Initiatives	-105	123	472	1,050	2,057	3,293	4,630	5,886	7,406	11,468	36,279
Net Savings	2,151	12,318	23,060	34,089	44,550	49,131	52,509	48,655	44,580	48,039	359,083

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Capital Savings - Service

Areas ($ in 000s)	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	Total
Labor											
Corporate	1,924	6,815	8,484	8,823	9,176	9,543	9,925	10,322	10,735	14,067	89,816
Generation	109	303	315	328	341	355	369	384	399	523	3,426
Field Support	175	486	505	526	547	569	591	615	640	708	5,361
Total	2,209	7,605	9,305	9,677	10,064	10,467	10,885	11,321	11,773	15,298	98,603
Facilities and Other Capital	0	0	0	0	0	0	0	0	0	0	0
Corporate & Administrative Programs:											
Professional Services	0	0	0	0	0	0	0	0	0	0	0
Information Services	4,756	26,165	28,492	31,693	33,436	19,273	20,333	13,896	14,660	17,035	209,739
Benefits	0	0	0	534	555	577	600	624	649	851	4,392
Total	4,756	26,165	28,492	32,226	33,991	19,851	20,934	14,520	15,310	17,886	214,131
Purchasing Economies (Nonfuel):											
Procurement	0	0	0	0	0	0	0	0	0	0	0
Contract Services	0	0	0	0	0	0	0	0	0	0	0
Inventory Reduction	0	0	0	0	0	0	0	0	0	0	0
Total	0	0	0	0	0	0	0	0	0	0	0
Savings - Subtotal	6,965	33,770	37,797	41,903	44,055	30,317	31,819	25,841	27,083	33,184	312,734
Total Savings	6,965	33,770	37,797	41,903	44,055	30,317	31,819	25,841	27,083	33,184	312,734
Costs to Achieve	0	0	0	0	0	0	0	0	0	0	0
Premeger Initiatives	-600	1,293	1,991	3,346	5,881	7,329	8,122	7,910	9,673	9,072	54,018
Net Savings	7,565	32,476	35,805	38,557	38,174	22,988	23,697	17,931	17,410	24,112	258,716

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AEP AMERICAN ELECTRIC POWER

Central and South West

Allocation #3

Line of Business

Fuel, Generation, Transmission, Distribution, Customer Accounts, Customer Service, Sales, Gross Receipts

Total Savings Detail - Fuel

Areas ($ in 000s)	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	Total
Labor											
Corporate	0	0	0	0	0	0	0	0	0	0	0
Generation Support	0	0	0	0	0	0	0	0	0	0	0
Field Support	0	0	0	0	0	0	0	0	0	0	0
Total	0	0	0	0	0	0	0	0	0	0	0
Corporate Facilities	0	0	0	0	0	0	0	0	0	0	0
Corporate & Administrative Programs:											
Advertising/Public Relations	0	0	0	0	0	0	0	0	0	0	0
Administrative & General Overhead	0	0	0	0	0	0	0	0	0	0	0
Association Dues & Memberships	0	0	0	0	0	0	0	0	0	0	0
Benefits	0	0	0	0	0	0	0	0	0	0	0
Credit Facilities	0	0	0	0	0	0	0	0	0	0	0
Director's Fees	0	0	0	0	0	0	0	0	0	0	0
Insurance	0	0	0	0	0	0	0	0	0	0	0
Information Services	0	0	0	0	0	0	0	0	0	0	0
Professional Services	97	135	142	149	157	165	173	181	191	253	1,642
Regulatory Expense	0	0	0	0	0	0	0	0	0	0	0
Research & Development	21	28	29	30	31	32	33	34	35	45	318
Shareholder Services	0	0	0	0	0	0	0	0	0	0	0
Total	117	164	171	179	188	197	206	215	225	298	1,961
Purchasing Economies (Nonfuel):											
Procurement	0	0	0	0	0	0	0	0	0	0	0
Contract Services	0	0	0	0	0	0	0	0	0	0	0
Inventory Reduction	0	0	0	0	0	0	0	0	0	0	0
Total	0	0	0	0	0	0	0	0	0	0	0
Savings - Subtotal	117	164	171	179	188	197	206	215	225	298	1,961
Total Savings	117	164	171	179	188	197	206	215	225	298	1,961
Cost to Achieve											
Total Cost to Achieve	89	48	18	6	6	6	7	6	6	8	202
Premerger Initiatives	1	4	6	9	13	16	21	25	27	36	157
Net Savings	27	112	147	164	169	174	179	184	192	253	1,601

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Alloc.xls 10yr Summary - Fuel

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Total O&M Savings - Fuel

Areas ($ in 000s)	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	Total
Labor											
Corporate	0	0	0	0	0	0	0	0	0	0	0
Generation	0	0	0	0	0	0	0	0	0	0	0
Field Support	0	0	0	0	0	0	0	0	0	0	0
Total	0	0	0	0	0	0	0	0	0	0	0
Corporate Facilities	0	0	0	0	0	0	0	0	0	0	0
Corporate & Administrative Programs:											
Advertising/Public Relations	0	0	0	0	0	0	0	0	0	0	0
Administrative & General Overhead	0	0	0	0	0	0	0	0	0	0	0
Association Dues & Memberships	0	0	0	0	0	0	0	0	0	0	0
Benefits	0	0	0	0	0	0	0	0	0	0	0
Credit Facilities	0	0	0	0	0	0	0	0	0	0	0
Director's Fees	0	0	0	0	0	0	0	0	0	0	0
Insurance	0	0	0	0	0	0	0	0	0	0	0
Information Services	0	0	0	0	0	0	0	0	0	0	0
Professional Services	97	135	142	149	157	165	173	181	191	253	1,642
Regulatory Expense	0	0	0	0	0	0	0	0	0	0	0
Research & Development	21	28	29	30	31	32	33	34	35	45	318
Shareholder Services	0	0	0	0	0	0	0	0	0	0	0
Total	117	164	171	179	188	197	206	215	225	298	1,961
Purchasing Economies (Nonfuel):											
Procurement	0	0	0	0	0	0	0	0	0	0	0
Contract Services	0	0	0	0	0	0	0	0	0	0	0
Inventory Reduction	0	0	0	0	0	0	0	0	0	0	0
Total	0	0	0	0	0	0	0	0	0	0	0
Savings - Subtotal	117	164	171	179	188	197	206	215	225	298	1,961
Total Savings	117	164	171	179	188	197	206	215	225	298	1,961
Cost to Achieve											
Separation Costs - Merger											
Other Costs to Achieve											
Total Cost to Achieve	89	48	18	6	6	6	7	6	6	8	202
Premeger Initiatives	1	3	5	8	10	13	15	18	18	23	115
Net O&M Savings	27	112	148	165	171	177	184	191	201	267	1,644

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Revenue Requirement Savings - Fuel

Areas ($ in 000s)	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	Total
Labor											
Corporate	0	0	0	0	0	0	0	0	0	0	0
Generation	0	0	0	0	0	0	0	0	0	0	0
Field Support	0	0	0	0	0	0	0	0	0	0	0
Total	0	0	0	0	0	0	0	0	0	0	0
Facilities and Other Capital	0	0	0	0	0	0	0	0	0	0	0
Corporate & Administrative Programs:											
Professional Services	0	0	0	0	0	0	0	0	0	0	0
Information Services	0	0	0	0	0	0	0	0	0	0	0
Benefits	0	0	0	0	0	0	0	0	0	0	0
Total	0	0	0	0	0	0	0	0	0	0	0
Purchasing Economies (Nonfuel):											
Procurement	0	0	0	0	0	0	0	0	0	0	0
Contract Services	0	0	0	0	0	0	0	0	0	0	0
Inventory Reduction	0	0	0	0	0	0	0	0	0	0	0
Total	0	0	0	0	0	0	0	0	0	0	0
Savings - Subtotal	0	0	0	0	0	0	0	0	0	0	0
Total Savings	0	0	0	0	0	0	0	0	0	0	0
Costs to Achieve	0	0	0	0	0	0	0	0	0	0	0
Premeger Initiatives	0	0	1	1	2	4	5	7	9	14	43
Net Savings	0	0	-1	-1	-2	-4	-5	-7	-9	-14	-43

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Capital Savings - Fuel

Areas ($ in 000s)	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	Total	
Labor												
Corporate	0	0	0	0	0	0	0	0	0	0	0	
Generation	0	0	0	0	0	0	0	0	0	0	0	
Field Support	0	0	0	0	0	0	0	0	0	0	0	
Total	0	0	0	0	0	0	0	0	0	0	0	
Facilities and Other Capital	0	0	0	0	0	0	0	0	0	0	0	
Corporate & Administrative Programs:												
Professional Services	0	0	0	0	0	0	0	0	0	0	0	
Information Services	0	0	0	0	0	0	0	0	0	0	0	
Benefits	0	0	0	0	0	0	0	0	0	0	0	
Total	0	0	0	0	0	0	0	0	0	0	0	
Purchasing Economies (Nonfuel):												
Procurement	0	0	0	0	0	0	0	0	0	0	0	
Contract Services	0	0	0	0	0	0	0	0	0	0	0	
Inventory Reduction	0	0	0	0	0	0	0	0	0	0	0	
Total	0	0	0	0	0	0	0	0	0	0	0	
Savings - Subtotal	0	0	0	0	0	0	0	0	0	0	0	
Total Savings	0	0	0	0	0	0	0	0	0	0	0	
Costs to Achieve	0	0	0	0	0	0	0	0	0	0	0	
Premeger Initiatives	-1	2	2	4	7	9	10	9	11	11	64	
Net Savings	1	-2	-2	-4	-7	-9	-10	-9	-11	-11	-64	A-1

Total Savings Detail - Generation

Areas ($ in 000s)	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	Total
Labor											
Corporate	0	0	0	0	0	0	0	0	0	0	0
Generation Support	64	178	187	195	204	214	223	233	244	321	2,064
Field Support	0	0	0	0	0	0	0	0	0	0	0
Total	64	178	187	195	204	214	223	233	244	321	2,064
Corporate Facilities	0	0	0	0	0	0	0	0	0	0	0
Corporate & Administrative Programs:											
Advertising/Public Relations	0	0	0	0	0	0	0	0	0	0	0
Administrative & General Overhead	4	12	14	14	14	15	15	16	16	21	140
Association Dues & Memberships	0	0	0	0	0	0	0	0	0	0	0
Benefits	0	0	0	0	0	0	0	0	0	0	0
Credit Facilities	0	0	0	0	0	0	0	0	0	0	0
Director's Fees	0	0	0	0	0	0	0	0	0	0	0
Insurance	0	0	0	0	0	0	0	0	0	0	0
Information Services	0	0	0	0	0	0	0	0	0	0	0
Professional Services	2,406	3,369	3,537	3,714	3,900	4,095	4,299	4,514	4,740	6,284	40,858
Regulatory Expense	0	0	0	0	0	0	0	0	0	0	0
Research & Development	337	463	477	491	506	521	537	553	569	738	5,192
Shareholder Services	0	0	0	0	0	0	0	0	0	0	0
Total	2,747	3,844	4,028	4,219	4,420	4,631	4,851	5,083	5,326	7,042	46,191
Purchasing Economies (Nonfuel):											
Procurement	6,203	10,182	12,668	15,153	17,636	20,119	22,607	25,103	27,607	38,282	195,560
Contract Services	1,417	2,090	2,333	2,584	2,842	3,109	3,384	3,669	3,964	5,416	30,809
Inventory Reduction	0	0	979	979	979	979	979	979	979	1,224	8,076
Total	7,621	12,271	15,980	18,715	21,457	24,207	26,970	29,751	32,550	44,922	234,444
Savings - Subtotal	10,432	16,294	20,194	23,130	26,081	29,051	32,045	35,067	38,119	52,285	282,698
Total Savings	10,432	16,294	20,194	23,130	26,081	29,051	32,045	35,067	38,119	52,285	282,698 E-5
Cost to Achieve											
Total Cost to Achieve	12,895	6,923	2,642	896	917	936	948	908	908	1,167	29,140
Premerger Initiatives	182	511	872	1,297	1,808	2,371	2,959	3,549	3,904	5,256	22,708
Net Savings	-2,645	8,860	16,681	20,938	23,357	25,745	28,138	30,610	33,307	45,862	230,850 A-1

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Total O&M Savings - Generation

Areas ($ in 000s)	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	Total
Labor											
Corporate	0	0	0	0	0	0	0	0	0	0	0
Generation	64	177	184	191	199	207	215	223	232	304	1,995
Field Support	0	0	0	0	0	0	0	0	0	0	0
Total	64	177	184	191	199	207	215	223	232	304	1,995
Corporate Facilities	0	0	0	0	0	0	0	0	0	0	0
Corporate & Administrative Programs:											
Advertising/Public Relations	0	0	0	0	0	0	0	0	0	0	0
Administrative & General Overhead	4	12	14	14	14	15	15	16	16	21	140
Association Dues & Memberships	0	0	0	0	0	0	0	0	0	0	0
Benefits	0	0	0	0	0	0	0	0	0	0	0
Credit Facilities	0	0	0	0	0	0	0	0	0	0	0
Director's Fees	0	0	0	0	0	0	0	0	0	0	0
Insurance	0	0	0	0	0	0	0	0	0	0	0
Information Services	0	0	0	0	0	0	0	0	0	0	0
Professional Services	2,406	3,369	3,537	3,714	3,900	4,095	4,299	4,514	4,740	6,284	40,858
Regulatory Expense	0	0	0	0	0	0	0	0	0	0	0
Research & Development	337	463	477	491	506	521	537	553	569	738	5,192
Shareholder Services	0	0	0	0	0	0	0	0	0	0	0
Total	2,747	3,844	4,028	4,219	4,420	4,631	4,851	5,083	5,326	7,042	46,191
Purchasing Economies (Nonfuel):											
Procurement	4,518	6,204	6,390	6,582	6,779	6,983	7,192	7,408	7,630	9,883	69,570
Contract Services	1,311	1,835	1,927	2,023	2,124	2,230	2,342	2,459	2,582	3,423	22,255
Inventory Reduction	0	0	0	0	0	0	0	0	0	0	0
Total	5,828	8,039	8,317	8,605	8,904	9,213	9,534	9,867	10,212	13,306	91,826
Savings - Subtotal	8,639	12,059	12,528	13,015	13,522	14,050	14,601	15,174	15,770	20,652	140,012
Total Savings	8,639	12,059	12,528	13,015	13,522	14,050	14,601	15,174	15,770	20,652	140,012
Cost to Achieve											
Total Cost to Achieve	12,895	6,923	2,642	896	917	936	948	908	908	1,167	29,140
Premeger Initiatives	200	490	792	1,118	1,458	1,810	2,170	2,546	2,642	3,302	16,527
Net O&M Savings	-4,456	4,647	9,095	11,002	11,148	11,304	11,482	11,719	12,220	16,183	94,344

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Revenue Requirement Savings - Generation

Areas ($ in 000s)	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	Total
Labor											
Corporate	0	0	0	0	0	0	0	0	0	0	0
Generation	0	2	3	4	6	7	9	10	11	16	69
Field Support	0	0	0	0	0	0	0	0	0	0	0
Total	0	2	3	4	6	7	9	10	11	16	69
Facilities and Other Capital	0	0	0	0	0	0	0	0	0	0	0
Corporate & Administrative Programs:											
Professional Services	0	0	0	0	0	0	0	0	0	0	0
Information Services	0	0	0	0	0	0	0	0	0	0	0
Benefits	0	0	0	0	0	0	0	0	0	0	0
Total	0	0	0	0	0	0	0	0	0	0	0
Purchasing Economies (Nonfuel):											
Procurement	1,686	3,977	6,278	8,571	10,856	13,137	15,415	17,695	19,976	28,399	125,989
Contract Services	107	255	406	561	718	878	1,042	1,210	1,382	1,993	8,553
Inventory Reduction	0	0	979	979	979	979	979	979	979	1,224	8,076
Total	1,792	4,232	7,663	10,110	12,553	14,994	17,436	19,884	22,337	31,616	142,618
Savings - Subtotal	1,793	4,234	7,666	10,115	12,559	15,001	17,445	19,893	22,349	31,632	142,687
Total Savings	1,793	4,234	7,666	10,115	12,559	15,001	17,445	19,893	22,349	31,632	142,687
Costs to Achieve	0	0	0	0	0	0	0	0	0	0	0
Premeger Initiativ :s	-18	21	80	179	350	561	789	1,003	1,262	1,954	6,181
Net Savings	1,811	4,213	7,586	9,936	12,208	14,440	16,656	18,891	21,087	29,678	136,506

Capital Savings - Generation

Areas ($ in 000s)	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	Total
Labor											
Corporate	0	0	0	0	0	0	0	0	0	0	0
Generation	3	7	8	8	8	9	9	9	10	13	85
Field Support	0	0	0	0	0	0	0	0	0	0	0
Total	3	7	8	8	8	9	9	9	10	13	85
Facilities and Other Capital	0	0	0	0	0	0	0	0	0	0	0
Corporate & Administrative Programs:											
Professional Services	0	0	0	0	0	0	0	0	0	0	0
Information Services	0	0	0	0	0	0	0	0	0	0	0
Benefits	0	0	0	0	0	0	0	0	0	0	0
Total	0	0	0	0	0	0	0	0	0	0	0
Purchasing Economies (Nonfuel):											
Procurement	9,621	13,213	13,609	14,018	14,438	14,871	15,317	15,777	16,250	21,048	148,163
Contract Services	610	853	896	941	988	1,037	1,089	1,144	1,201	1,592	10,350
Inventory Reduction	0	0	6,526	0	0	0	0	0	0	0	6,526
Total	10,231	14,066	21,031	14,958	15,426	15,909	16,407	16,921	17,451	22,640	165,039
Savings - Subtotal	10,233	14,074	21,039	14,967	15,434	15,917	16,416	16,930	17,461	22,652	165,123
Total Savings	10,233	14,074	21,039	14,967	15,434	15,917	'6,416	16,930	17,461	22,652	165,123
Costs to Achieve	0	0	0	0	0	0	0	0	0	0	0
Premeger Initiatives	-102	220	339	570	1,002	1,249	1,384	1,348	1,648	1,546	9,203
Net Savings	10,336	13,853	20,700	14,397	14,432	14,669	15,032	15,582	15,813	21,107	155,920

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Total Savings Detail - Transmission

Areas ($ in 000s)	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	Total
Labor											
Corporate	0	0	0	0	0	0	0	0	0	0	0
Generation Support	0	0	0	0	0	0	0	0	0	0	0
Field Support	0	0	0	0	0	0	0	0	0	0	0
Total	0	0	0	0	0	0	0	0	0	0	0
Corporate Facilities	0	0	0	0	0	0	0	0	0	0	0
Corporate & Administrative Programs:											
Advertising/Public Relations	0	0	0	0	0	0	0	0	0	0	0
Administrative & General Overhead	0	0	0	0	0	0	0	0	0	0	0
Association Dues & Memberships	0	0	0	0	0	0	0	0	0	0	0
Benefits	0	0	0	0	0	0	0	0	0	0	0
Credit Facilities	0	0	0	0	0	0	0	0	0	0	0
Director's Fees	0	0	0	0	0	0	0	0	0	0	0
Insurance	0	0	0	0	0	0	0	0	0	0	0
Information Services	0	0	0	0	0	0	0	0	0	0	0
Professional Services	1,386	1,940	2,037	2,139	2,246	2,358	2,476	2,600	2,730	3,619	23,529
Regulatory Expense	0	0	0	0	0	0	0	0	0	0	0
Research & Development	75	103	106	109	112	116	119	123	127	164	1,154
Shareholder Services	0	0	0	0	0	0	0	0	0	0	0
Total	1,461	2,043	2,143	2,248	2,358	2,474	2,595	2,723	2,856	3,783	24,683
Purchasing Economies (Nonfuel):											
Procurement	1,052	1,727	2,148	2,570	2,991	3,412	3,834	4,257	4,682	6,492	33,163
Contract Services	378	557	621	688	757	828	901	977	1,056	1,443	8,206
Inventory Reduction	0	0	166	166	166	166	166	166	166	207	1,369
Total	1,429	2,283	2,936	3,424	3,914	4,406	4,901	5,400	5,903	8,142	42,739
Savings - Subtotal	2,890	4,326	5,079	5,672	6,272	6,880	7,496	8,123	8,760	11,925	67,422
Total Savings	2,890	4,326	5,079	5,672	6,272	6,880	7,496	8,123	8,760	11,925	67,422
Cost to Achieve											
Total Cost to Achieve	3,075	1,651	630	214	219	223	226	217	217	278	6,950
Premerger Initiatives	43	122	208	309	431	565	706	846	931	1,254	5,416
Net Savings	-229	2,553	4,241	5,149	5,622	6,091	6,565	7,060	7,612	10,393	55,057

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Total O&M Savings - Transmission

Areas ($ in 000s)	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	Total
Labor											
Corporate	0	0	0	0	0	0	0	0	0	0	0
Generation	0	0	0	0	0	0	0	0	0	0	0
Field Support	0	0	0	0	0	0	0	0	0	0	0
Total	0	0	0	0	0	0	0	0	0	0	0
Corporate Facilities	0	0	0	0	0	0	0	0	0	0	0
Corporate & Administrative Programs:											
Advertising/Public Relations	0	0	0	0	0	0	0	0	0	0	0
Administrative & General Overhead	0	0	0	0	0	0	0	0	0	0	0
Association Dues & Memberships	0	0	0	0	0	0	0	0	0	0	0
Benefits	0	0	0	0	0	0	0	0	0	0	0
Credit Facilities	0	0	0	0	0	0	0	0	0	0	0
Director's Fees	0	0	0	0	0	0	0	0	0	0	0
Insurance	0	0	0	0	0	0	0	0	0	0	0
Information Services	0	0	0	0	0	0	0	0	0	0	0
Professional Services	1,386	1,940	2,037	2,139	2,246	2,358	2,476	2,600	2,730	3,619	23,529
Regulatory Expense	0	0	0	0	0	0	0	0	0	0	0
Research & Development	75	103	106	109	112	116	119	123	127	164	1,154
Shareholder Services	0	0	0	0	0	0	0	0	0	0	0
Total	1,461	2,043	2,143	2,248	2,358	2,474	2,595	2,723	2,856	3,783	24,683
Purchasing Economies (Nonfuel):											
Procurement	766	1,052	1,084	1,116	1,150	1,184	1,220	1,256	1,294	1,676	11,798
Contract Services	349	489	513	539	566	594	624	655	688	912	5,928
Inventory Reduction	0	0	0	0	0	0	0	0	0	0	0
Total	1,115	1,541	1,597	1,655	1,715	1,778	1,843	1,911	1,982	2,588	17,726
Savings - Subtotal	2,576	3,584	3,740	3,903	4,074	4,252	4,439	4,634	4,838	6,370	42,409
Total Savings	2,576	3,584	3,740	3,903	4,074	4,252	4,439	4,634	4,838	6,370	42,409
Cost to Achieve											
Total Cost to Achieve	3,075	1,651	630	214	219	223	226	217	217	278	6,950
Premeger Initiatives	48	117	189	267	348	432	518	607	630	788	3,942
Net O&M Savings	-547	1,816	2,921	3,423	3,507	3,597	3,695	3,810	3,991	5,304	31,518

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Revenue Requirement Savings - Transmission

Areas ($ in 000s)	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	Total
Labor											
Corporate	0	0	0	0	0	0	0	0	0	0	0
Generation	0	0	0	0	0	0	0	0	0	0	0
Field Support	0	0	0	0	0	0	0	0	0	0	0
Total	0	0	0	0	0	0	0	0	0	0	0
Facilities and Other Capital	0	0	0	0	0	0	0	0	0	0	0
Corporate & Administrative Programs:											
Professional Services	0	0	0	0	0	0	0	0	0	0	0
Information Services	0	0	0	0	0	0	0	0	0	0	0
Benefits	0	0	0	0	0	0	0	0	0	0	0
Total	0	0	0	0	0	0	0	0	0	0	0
Purchasing Economies (Nonfuel):											
Procurement	286	675	1,065	1,453	1,841	2,228	2,614	3,001	3,388	4,816	21,366
Contract Services	28	68	108	149	191	234	278	322	368	531	2,278
Inventory Reduction	0	0	166	166	166	166	166	166	166	207	1,369
Total	314	742	1,339	1,769	2,198	2,628	3,058	3,489	3,922	5,554	25,013
Savings - Subtotal	314	742	1,339	1,769	2,198	2,628	3,058	3,489	3,922	5,554	25,013
Total Savings	314	742	1,339	1,769	2,198	2,628	3,058	3,489	3,922	5,554	25,013
Costs to Achieve	0	0	0	0	0	0	0	0	0	0	0
Premeger Initiatives	-4	5	19	43	84	134	188	239	301	466	1,474
Net Savings	319	737	1,320	1,726	2,115	2,494	2,870	3,250	3,621	5,088	23,539

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Capital Savings - Transmission

Areas ($ in 000s)	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	Total
Labor											
Corporate	0	0	0	0	0	0	0	0	0	0	0
Generation	0	0	0	0	0	0	0	0	0	0	0
Field Support	0	0	0	0	0	0	0	0	0	0	0
Total	0	0	0	0	0	0	0	0	0	0	0
Facilities and Other Capital	0	0	0	0	0	0	0	0	0	0	0
Corporate & Administrative Programs:											
Professional Services	0	0	0	0	0	0	0	0	0	0	0
Information Services	0	0	0	0	0	0	0	0	0	0	0
Benefits	0	0	0	0	0	0	0	0	0	0	0
Total	0	0	0	0	0	0	0	0	0	0	0
Purchasing Economies (Nonfuel):											
Procurement	1,632	2,241	2,308	2,377	2,448	2,522	2,598	2,675	2,756	3,569	25,126
Contract Services	162	227	239	251	263	276	290	305	320	424	2,757
Inventory Reduction	0	0	1,107	0	0	0	0	0	0	0	1,107
Total	1,794	2,468	3,653	2,628	2,712	2,798	2,888	2,980	3,076	3,993	28,989
Savings - Subtotal	1,794	2,468	3,653	2,628	2,712	2,798	2,888	2,980	3,076	3,993	28,989
Total Savings	1,794	2,468	3,653	2,628	2,712	2,798	2,888	2,980	3,076	3,993	28,989
Costs to Achieve	0	0	0	0	0	0	0	0	0	0	0
Premeger Initiatives	-24	53	81	136	239	298	330	321	393	369	2,195
Net Savings	1,818	2,415	3,572	2,492	2,473	2,500	2,558	2,659	2,683	3,625	26,794

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Total Savings Detail - Distribution

Areas ($ in 000s)	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	Total	
Labor												
Corporate	0	0	0	0	0	0	0	0	0	0	0	0.0%
Generation Support	0	0	0	0	0	0	0	0	0	0	0	0.0%
Field Support	0	0	0	0	0	0	0	0	0	0	0	0.0%
Total	0	0	0	0	0	0	0	0	0	0	0	0.0%
Corporate Facilities	0	0	0	0	0	0	0	0	0	0	0	0.0%
Corporate & Administrative Programs												
Advertising/Public Relations	0	0	0	0	0	0	0	0	0	0	0	0.0%
Administrative & General Overhead	0	0	0	0	0	0	0	0	0	0	0	0.0%
Association Dues & Memberships	0	0	0	0	0	0	0	0	0	0	0	0.0%
Benefits	0	0	0	0	0	0	0	0	0	0	0	0.0%
Credit Facilities	0	0	0	0	0	0	0	0	0	0	0	0.0%
Director's Fees	0	0	0	0	0	0	0	0	0	0	0	0.0%
Insurance	0	0	0	0	0	0	0	0	0	0	0	0.0%
Information Services	0	0	0	0	0	0	0	0	0	0	0	0.0%
Professional Services	1,188	1,664	1,747	1,834	1,926	2,022	2,123	2,229	2,341	3,103	20,177	18.3%
Regulatory Expense	0	0	0	0	0	0	0	0	0	0	0	0.0%
Research & Development	169	232	239	246	253	261	269	277	285	370	2,601	2.4%
Shareholder Services	0	0	0	0	0	0	0	0	0	0	0	0.0%
Total	1,357	1,896	1,986	2,080	2,179	2,283	2,392	2,506	2,626	3,473	22,778	20.6%
Purchasing Economies (Nonfuel).												
Procurement	2,075	3,406	4,238	5,069	5,899	6,730	7,563	8,397	9,235	12,806	65,418	59.3%
Contract Services	896	1,322	1,475	1,634	1,797	1,966	2,140	2,320	2,507	3,425	19,482	17.7%
Inventory Reduction	0	0	327	327	327	327	327	327	327	409	2,701	2.4%
Total	2,971	4,727	6,041	7,030	8,024	9,024	10,030	11,045	12,069	16,640	87,602	79.4%
Savings - Subtotal	4,329	6,623	8,026	9,110	10,203	11,307	12,422	13,551	14,695	20,113	110,380	
Total Savings	4,329	6,623	8,026	9,110	10,203	11,307	12,422	13,551	14,695	20,113	110,380	
Cost to Achieve												
Total Cost to Achieve	5,035	2,703	1,031	350	358	366	370	355	355	456	11,378	
Premerger Initiatives	71	199	341	506	706	926	1,155	1,386	1,524	2,052	8,867	
Net Savings	-777	3,720	6,654	8,254	9,140	10,016	10,897	11,811	12,817	17,605	90,136	A 1
									Check		90,136	

Total O&M Savings - Distribution

Areas ($ in 000s)	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	Total
Labor											
Corporate	0	0	0	0	0	0	0	0	0	0	0
Generation	0	0	0	0	0	0	0	0	0	0	0
Field Support	0	0	0	0	0	0	0	0	0	0	0
Total	0	0	0	0	0	0	0	0	0	0	0
Corporate Facilities	0	0	0	0	0	0	0	0	0	0	0
Corporate & Administrative Programs											
Advertising/Public Relations	0	0	0	0	0	0	0	0	0	0	0
Administrative & General Overhead	0	0	0	0	0	0	0	0	0	0	0
Association Dues & Memberships	0	0	0	0	0	0	0	0	0	0	0
Benefits	0	0	0	0	0	0	0	0	0	0	0
Credit Facilities	0	0	0	0	0	0	0	0	0	0	0
Director's Fees	0	0	0	0	0	0	0	0	0	0	0
Insurance	0	0	0	0	0	0	0	0	0	0	0
Information Services	1,188	1,664	1,747	1,834	1,926	2,022	2,123	2,229	2,341	3,103	20,177
Professional Services	0	0	0	0	0	0	0	0	0	0	0
Regulatory Expense	169	232	239	246	253	261	269	277	285	370	2,601
Research & Development	0	0	0	0	0	0	0	0	0	0	0
Shareholder Services											
Total	1,357	1,896	1,986	2,080	2,179	2,283	2,392	2,506	2,626	3,473	22,778
Purchasing Economies (Nonfuel)											
Procurement	1,511	2,075	2,138	2,202	2,268	2,336	2,406	2,478	2,553	3,306	23,273
Contract Services	829	1,160	1,218	1,279	1,343	1,410	1,481	1,555	1,633	2,164	14,074
Inventory Reduction	0	0	0	0	0	0	0	0	0	0	0
Total	2,340	3,236	3,356	3,481	3,611	3,746	3,887	4,033	4,185	5,470	37,346
Savings - Subtotal	3,697	5,131	5,342	5,561	5,790	6,029	6,279	6,539	6,811	8,943	60,124
Total Savings	3,697	5,131	5,342	5,561	5,790	6,029	6,279	6,539	6,811	8,943	60,124
Cost to Achieve											
Total Cost to Achieve	5,035	2,703	1,031	350	358	366	370	355	355	456	11,378
Premerger Initiatives	78	191	309	437	569	707	847	994	1,031	1,289	6,453
Net O&M Savings	-1,416	2,237	4,001	4,775	4,863	4,957	5,061	5,191	5,425	7,198	42,293

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Revenue Requirement Savings - Distribution

Areas ($ in 000s)	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	Total
Labor											
Corporate	0	0	0	0	0	0	0	0	0	0	0
Generation	0	0	0	0	0	0	0	0	0	0	0
Field Support	0	0	0	0	0	0	0	0	0	0	0
Total	0	0	0	0	0	0	0	0	0	0	0
Facilities and Other Capital	0	0	0	0	0	0	0	0	0	0	0
Corporate & Administrative Programs:											
Professional Services	0	0	0	0	0	0	0	0	0	0	0
Information Services	0	0	0	0	0	0	0	0	0	0	0
Benefits	0	0	0	0	0	0	0	0	0	0	0
Total	0	0	0	0	0	0	0	0	0	0	0
Purchasing Economies (Nonfuel):											
Procurement	564	1,331	2,100	2,867	3,632	4,394	5,157	5,919	6,682	9,500	42,146
Contract Services	68	161	257	355	454	555	659	765	874	1,261	5,409
Inventory Reduction	0	0	327	327	327	327	327	327	327	409	2,701
Total	631	1,492	2,684	3,549	4,413	5,277	6,143	7,012	7,884	11,170	50,256
Savings - Subtotal	631	1,492	2,684	3,549	4,413	5,277	6,143	7,012	7,884	11,170	50,256
Total Savings	631	1,492	2,684	3,549	4,413	5,277	6,143	7,012	7,884	11,170	50,256
Costs to Achieve	0	0	0	0	0	0	0	0	0	0	0
Premeger Initiatives	-7	8	31	70	137	219	308	392	493	763	2,413
Net Savings	638	1,484	2,653	3,479	4,276	5,058	5,835	6,620	7,391	10,407	47,843

Capital Savings - Distribution

Areas ($ in 000s)	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	Total
Labor											
Corporate	0	0	0	0	0	0	0	0	0	0	0
Generation	0	0	0	0	0	0	0	0	0	0	0
Field Support	0	0	0	0	0	0	0	0	0	0	0
Total	0	0	0	0	0	0	0	0	0	0	0
Facilities and Other Capital	0	0	0	0	0	0	0	0	0	0	0
Corporate & Administrative Programs:											
Professional Services	0	0	0	0	0	0	0	0	0	0	0
Information Services	0	0	0	0	0	0	0	0	0	0	0
Benefits	0	0	0	0	0	0	0	0	0	0	0
Total	0	0	0	0	0	0	0	0	0	0	0
Purchasing Economies (Nonfuel):											
Procurement	3,218	4,420	4,553	4,689	4,830	4,975	5,124	5,278	5,436	7,041	49,563
Contract Services	385	540	567	595	625	656	689	723	759	1,007	6,545
Inventory Reduction	0	0	2,183	0	0	0	0	0	0	0	2,183
Total	3,604	4,960	7,302	5,284	5,455	5,631	5,813	6,001	6,195	8,047	58,291
Savings - Subtotal	3,604	4,960	7,302	5,284	5,455	5,631	5,813	6,001	6,195	8,047	58,291
Total Savings	3,604	4,960	7,302	5,284	5,455	5,631	5,813	6,001	6,195	8,047	58,291
Costs to Achieve	0	0	0	0	0	0	0	0	0	0	0
Premeger Initiatives	-40	86	132	223	391	488	540	526	643	604	3,593
Net Savings	3,644	4,874	7,170	5,062	5,063	5,143	5,272	5,475	5,552	7,444	54,698

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Total Savings Detail - Customer Accounts

Areas ($ in 000s)	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	Total	
Labor												
Corporate	0	0	0	0	0	0	0	0	0	0	0	0.0%
Generation Support	0	0	0	0	0	0	0	0	0	0	0	0.0%
Field Support	0	0	0	0	0	0	0	0	0	0	0	0.0%
Total	0	0	0	0	0	0	0	0	0	0	0	0.0%
Corporate Facilities	0	0	0	0	0	0	0	0	0	0	0	0.0%
Corporate & Administrative Programs												
Advertising/Public Relations	0	0	0	0	0	0	0	0	0	0	0	0.0%
Administrative & General Overhead	0	0	0	0	0	0	0	0	0	0	0	0.0%
Association Dues & Memberships	0	0	0	0	0	0	0	0	0	0	0	0.0%
Benefits	0	0	0	0	0	0	0	0	0	0	0	0.0%
Credit Facilities	0	0	0	0	0	0	0	0	0	0	0	0.0%
Director's Fees	0	0	0	0	0	0	0	0	0	0	0	0.0%
Insurance	0	0	0	0	0	0	0	0	0	0	0	0.0%
Information Services	0	0	0	0	0	0	0	0	0	0	0	0.0%
Professional Services	316	443	465	488	512	538	565	593	623	825	5,367	78.2%
Regulatory Expense	0	0	0	0	0	0	0	0	0	0	0	0.0%
Research & Development	67	93	95	98	101	104	107	111	114	148	1,039	15.1%
Shareholder Services	0	0	0	0	0	0	0	0	0	0	0	0.0%
Total	384	535	560	586	614	642	672	704	737	973	6,406	93.3%
Purchasing Economies (Nonfuel):												
Procurement	0	0	0	0	0	0	0	0	0	0	0	0.0%
Contract Services	21	31	35	38	42	46	50	54	59	80	458	6.7%
Inventory Reduction	0	0	0	0	0	0	0	0	0	0	0	0.0%
Total	21	31	35	38	42	46	50	54	59	80	458	6.7%
Savings - Subtotal	405	566	595	625	656	688	722	758	796	1,053	6,864	
Total Savings	405	566	595	625	656	688	722	758	796	1,053	6,864	
Cost to Achieve												
Total Cost to Achieve	313	168	64	22	22	23	23	22	22	28	707	
Premerger Initiatives	4	12	21	31	44	58	72	86	95	128	551	
Net Savings	87	386	509	571	590	608	628	650	679	898	5,605	A-1
										Check	5,605	

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Total O&M Savings - Customer Accounts

Areas ($ in 000s)	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	Total
Labor											
Corporate	0	0	0	0	0	0	0	0	0	0	0
Generation	0	0	0	0	0	0	0	0	0	0	0
Field Support	0	0	0	0	0	0	0	0	0	0	0
Total	0	0	0	0	0	0	0	0	0	0	0
Corporate Facilities	0	0	0	0	0	0	0	0	0	0	0
Corporate & Administrative Programs											
Advertising/Public Relations	0	0	0	0	0	0	0	0	0	0	0
Administrative & General Overhead	0	0	0	0	0	0	0	0	0	0	0
Association Dues & Memberships	0	0	0	0	0	0	0	0	0	0	0
Benefits	0	0	0	0	0	0	0	0	0	0	0
Credit Facilities	0	0	0	0	0	0	0	0	0	0	0
Director's Fees	0	0	0	0	0	0	0	0	0	0	0
Insurance	0	0	0	0	0	0	0	0	0	0	0
Information Services	0	0	0	0	0	0	0	0	0	0	0
Professional Services	316	443	465	488	512	538	565	593	623	825	5,367
Regulatory Expense	0	0	0	0	0	0	0	0	0	0	0
Research & Development	67	93	95	98	101	104	107	111	114	148	1,039
Shareholder Services	0	0	0	0	0	0	0	0	0	0	0
Total	384	535	560	586	614	642	672	704	737	973	6,406
Purchasing Economies (Nonfuel)											
Procurement	0	0	0	0	0	0	0	0	0	0	0
Contract Services	19	27	29	30	32	33	35	37	38	51	330
Inventory Reduction	0	0	0	0	0	0	0	0	0	0	0
Total	19	27	29	30	32	33	35	37	38	51	330
Savings - Subtotal	403	562	589	616	645	675	707	740	775	1,024	6,737
Total Savings	403	562	589	616	645	675	707	740	775	1,024	6,737
Cost to Achieve											
Total Cost to Achieve	313	168	64	22	22	23	23	22	22	28	707
Premerger Initiatives	5	12	19	27	35	44	53	62	64	80	401
Net O&M Savings	85	382	505	567	587	609	631	656	689	915	5,628

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Revenue Requirement Savings - Customer Accounts

Areas ($ in 000s)	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	Total
Labor											
Corporate	0	0	0	0	0	0	0	0	0	0	0
Generation	0	0	0	0	0	0	0	0	0	0	0
Field Support	0	0	0	0	0	0	0	0	0	0	0
Total	0	0	0	0	0	0	0	0	0	0	0
Facilities and Other Capital	0	0	0	0	0	0	0	0	0	0	0
Corporate & Administrative Programs:											
Professional Services	0	0	0	0	0	0	0	0	0	0	0
Information Services	0	0	0	0	0	0	0	0	0	0	0
Benefits	0	0	0	0	0	0	0	0	0	0	0
Total	0	0	0	0	0	0	0	0	0	0	0
Purchasing Economics (Nonfuel):											
Procurement	0	0	0	0	0	0	0	0	0	0	0
Contract Services	2	4	6	8	11	13	15	18	21	30	127
Inventory Reduction	0	0	0	0	0	0	0	0	0	0	0
Total	2	4	6	8	11	13	15	18	21	30	127
Savings - Subtotal	2	4	6	8	11	13	15	18	21	30	127
Total Savings	2	4	6	8	11	13	15	18	21	30	127
Costs to Achieve	0	0	0	0	0	0	0	0	0	0	0
Premeger Initiatives	0	1	2	4	9	14	19	24	31	47	150
Net Savings	2	3	4	4	2	-1	-4	-6	-10	-18	-23

Capital Savings - Customer Accounts

Areas ($ in 000s)	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	Total
Labor											
Corporate	0	0	0	0	0	0	0	0	0	0	0
Generation	0	0	0	0	0	0	0	0	0	0	0
Field Support	0	0	0	0	0	0	0	0	0	0	0
Total	0	0	0	0	0	0	0	0	0	0	0
Facilities and Other Capital	0	0	0	0	0	0	0	0	0	0	0
Corporate & Administrative Programs:											
Professional Services	0	0	0	0	0	0	0	0	0	0	0
Information Services	0	0	0	0	0	0	0	0	0	0	0
Benefits	0	0	0	0	0	0	0	0	0	0	0
Total	0	0	0	0	0	0	0	0	0	0	0
Purchasing Economies (Nonfuel):											
Procurement	0	0	0	0	0	0	0	0	0	0	0
Contract Services	9	13	13	14	15	15	16	17	18	24	154
Inventory Reduction	0	0	0	0	0	0	0	0	0	0	0
Total	9	13	13	14	15	15	16	17	18	24	154
Savings - Subtotal	9	13	13	14	15	15	16	17	18	24	154
Total Savings	9	13	13	14	15	15	16	17	18	24	154
Costs to Achieve	0	0	0	0	0	0	0	0	0	0	0
Premeger Initiatives	-2	5	8	14	24	30	34	33	40	38	223
Net Savings	12	7	5	0	-10	-15	-17	-16	-22	-14	-70

Total Savings Detail - Customer Service

Areas ($ in 000s)	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	Total	
Labor												
Corporate	0	0	0	0	0	0	0	0	0	0	0	0.0%
Generation Support	0	0	0	0	0	0	0	0	0	0	0	0.0%
Field Support	930	2,684	3,073	3,468	3,869	4,276	4,691	5,114	5,545	7,962	41,610	73.7%
Total	930	2,684	3,073	3,468	3,869	4,276	4,691	5,114	5,545	7,962	41,610	73.7%
Corporate Facilities	0	0	0	0	0	0	0	0	0	0	0	0.0%
Corporate & Administrative Programs:												
Advertising/Public Relations	0	0	0	0	0	0	0	0	0	0	0	0.0%
Administrative & General Overhead	261	886	1,001	1,031	1,062	1,094	1,127	1,160	1,195	1,548	10,364	18.4%
Association Dues & Memberships	0	0	0	0	0	0	0	0	0	0	0	0.0%
Benefits	0	0	0	0	0	0	0	0	0	0	0	0.0%
Credit Facilities	0	0	0	0	0	0	0	0	0	0	0	0.0%
Director's Fees	0	0	0	0	0	0	0	0	0	0	0	0.0%
Insurance	0	0	0	0	0	0	0	0	0	0	0	0.0%
Information Services	0	0	0	0	0	0	0	0	0	0	0	0.0%
Professional Services	130	183	192	201	211	222	233	245	257	341	2,216	3.9%
Regulatory Expense	0	0	0	0	0	0	0	0	0	0	0	0.0%
Research & Development	48	65	67	69	71	74	76	78	80	104	733	1.3%
Shareholder Services	0	0	0	0	0	0	0	0	0	0	0	0.0%
Total	439	1,134	1,260	1,302	1,345	1,389	1,436	1,483	1,533	1,993	13,314	23.6%
Purchasing Economies (Nonfuel):												
Procurement	4	7	9	10	12	14	16	17	19	26	135	0.2%
Contract Services	65	96	107	118	130	142	155	168	182	248	1,411	2.5%
Inventory Reduction	0	0	1	1	1	1	1	1	1	1	6	0.0%
Total	69	103	116	129	143	157	171	186	201	275	1,552	2.7%
Savings - Subtotal	1,438	3,921	4,449	4,899	5,357	5,823	6,298	6,783	7,279	10,230	56,476	
Total Savings	1,438	3,921	4,449	4,899	5,357	5,823	6,298	6,783	7,279	10,230	56,476	E - 1
Cost to Achieve												
Total Cost to Achieve	2,576	1,383	528	179	183	187	189	181	181	233	5,821	
Premerger Initiatives	36	102	174	259	361	474	591	709	780	1,050	4,537	
Net Savings	-1,174	2,436	3,747	4,461	4,812	5,162	5,517	5,893	6,318	8,947	46,118	A - 1
										Check	46,118	

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Total O&M Savings - Customer Service

Areas ($ in 000s)	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	Total
Labor											
Corporate	0	0	0	0	0	0	0	0	0	0	0
Generation	0	0	0	0	0	0	0	0	0	0	0
Field Support	824	2,286	2,378	2,473	2,572	2,675	2,782	2,893	3,009	4,389	26,280
Total	824	2,286	2,378	2,473	2,572	2,675	2,782	2,893	3,009	4,389	26,280
Corporate Facilities	0	0	0	0	0	0	0	0	0	0	0
Corporate & Administrative Programs											
Advertising/Public Relations	0	0	0	0	0	0	0	0	0	0	0
Administrative & General Overhead	261	886	1,001	1,031	1,062	1,094	1,127	1,160	1,195	1,548	10,364
Association Dues & Memberships	0	0	0	0	0	0	0	0	0	0	0
Benefits	0	0	0	0	0	0	0	0	0	0	0
Credit Facilities	0	0	0	0	0	0	0	0	0	0	0
Director's Fees	0	0	0	0	0	0	0	0	0	0	0
Insurance	0	0	0	0	0	0	0	0	0	0	0
Information Services	0	0	0	0	0	0	0	0	0	0	0
Professional Services	130	183	192	201	211	222	233	245	257	341	2,216
Regulatory Expense	0	0	0	0	0	0	0	0	0	0	0
Research & Development	48	65	67	69	71	74	76	78	80	104	733
Shareholder Services	0	0	0	0	0	0	0	0	0	0	0
Total	439	1,134	1,260	1,302	1,345	1,389	1,436	1,483	1,533	1,993	13,314
Purchasing Economies (Nonfuel)											
Procurement	3	4	4	5	5	5	5	5	5	7	48
Contract Services	60	84	88	93	97	102	107	113	118	157	1,020
Inventory Reduction	0	0	0	0	0	0	0	0	0	0	0
Total	63	88	93	97	102	107	112	118	124	164	1,067
Savings - Subtotal	1,326	3,509	3,731	3,872	4,019	4,171	4,329	4,494	4,665	6,546	40,661
Total Savings	1,326	3,509	3,731	3,872	4,019	4,171	4,329	4,494	4,665	6,546	40,661
Cost to Achieve											
Total Cost to Achieve	2,576	1,383	528	179	183	187	189	181	181	233	5,821
Premeger Initiatives	40	98	158	223	291	362	434	509	528	660	3,302
Net O&M Savings	-1,290	2,028	3,045	3,470	3,544	3,623	3,707	3,804	3,956	5,653	31,538

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Revenue Requirement Savings - Customer Service

Areas ($ in 000s)	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	Total
Labor											
Corporate	0	0	0	0	0	0	0	0	0	0	0
Generation	0	0	0	0	0	0	0	0	0	0	0
Field Support	106	397	695	995	1,297	1,602	1,909	2,221	2,536	3,573	15,330
Total	106	397	695	995	1,297	1,602	1,909	2,221	2,536	3,573	15,330
Facilities and Other Capital	0	0	0	0	0	0	0	0	0	0	0
Corporate & Administrative Programs:											
Professional Services	0	0	0	0	0	0	0	0	0	0	0
Information Services	0	0	0	0	0	0	0	0	0	0	0
Benefits	0	0	0	0	0	0	0	0	0	0	0
Total	0	0	0	0	0	0	0	0	0	0	0
Purchasing Economies (Nonfuel):											
Procurement	1	3	4	6	7	9	11	12	14	20	87
Contract Services	5	12	19	26	33	40	48	55	63	91	392
Inventory Reduction	0	0	1	1	1	1	1	1	1	1	6
Total	6	14	24	32	41	50	59	68	78	112	484
Savings - Subtotal	112	412	718	1,027	1,338	1,652	1,968	2,289	2,614	3,684	15,814
Total Savings	112	412	718	1,027	1,338	1,652	1,968	2,289	2,614	3,684	15,814
Costs to Achieve	0	0	0	0	0	0	0	0	0	0	0
Premeger Initiatives	-4	4	16	36	70	112	158	200	252	390	1,235
Net Savings	115	408	702	991	1,268	1,540	1,811	2,089	2,362	3,294	14,579

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Capital - Customer Service

Areas ($ in 000s)	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	Total
Labor											
Corporate	0	0	0	0	0	0	0	0	0	0	0
Generation	0	0	0	0	0	0	0	0	0	0	0
Field Support	603	1,673	1,740	1,809	1,882	1,957	2,035	2,116	2,201	2,438	18,453
Total	603	1,673	1,740	1,809	1,882	1,957	2,035	2,116	2,201	2,438	18,453
Facilities and Other Capital	0	0	0	0	0	0	0	0	0	0	0
Corporate & Administrative Programs:											
Professional Services	0	0	0	0	0	0	0	0	0	0	0
Information Services	0	0	0	0	0	0	0	0	0	0	0
Benefits	0	0	0	0	0	0	0	0	0	0	0
Total	0	0	0	0	0	0	0	0	0	0	0
Purchasing Economies (Nonfuel):											
Procurement	7	9	9	10	10	10	11	11	11	14	102
Contract Services	28	39	41	43	45	48	50	52	55	73	474
Inventory Reduction	0	0	4	0	0	0	0	0	0	0	4
Total	35	48	55	53	55	58	60	63	66	87	581
Savings - Subtotal	638	1,721	1,794	1,862	1,937	2,015	2,095	2,180	2,267	2,525	19,034
Total Savings	638	1,721	1,794	1,862	1,937	2,015	2,095	2,180	2,267	2,525	19,034
Costs to Achieve	0	0	0	0	0	0	0	0	0	0	0
Premeger Initiatives	-20	44	68	114	200	249	276	269	329	309	1,839
Net Savings	658	1,677	1,727	1,748	1,737	1,765	1,819	1,910	1,938	2,217	17,195

Total Savings Detail - Sales

Areas ($ in 000s)	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	Total	
Labor												
Corporate	348	1,240	1,566	1,657	1,750	1,847	1,946	2,048	2,153	2,865	17,420	87.5%
Generation Support	0	0	0	0	0	0	0	0	0	0	0	0.0%
Field Support	0	0	0	0	0	0	0	0	0	0	0	0.0%
Total	348	1,240	1,566	1,657	1,750	1,847	1,946	2,048	2,153	2,865	17,420	87.5%
Corporate Facilities	0	0	0	0	0	0	0	0	0	0	0	0.0%
Corporate & Administrative Programs:												
Advertising Public Relations	0	0	0	0	0	0	0	0	0	0	0	0.0%
Administrative & General Overhead	28	96	108	111	115	118	122	125	129	167	1,120	5.6%
Association Dues & Memberships	0	0	0	0	0	0	0	0	0	0	0	0.0%
Benefits	0	0	0	0	0	0	0	0	0	0	0	0.0%
Credit Facilities	0	0	0	0	0	0	0	0	0	0	0	0.0%
Director's Fees	0	0	0	0	0	0	0	0	0	0	0	0.0%
Insurance	0	0	0	0	0	0	0	0	0	0	0	0.0%
Information Services	0	0	0	0	0	0	0	0	0	0	0	0.0%
Professional Services	80	112	117	123	129	136	142	150	157	208	1,354	6.8%
Regulatory Expense	0	0	0	0	0	0	0	0	0	0	0	0.0%
Research & Development	1	2	2	2	2	2	2	2	2	2	17	0.1%
Shareholder Services	0	0	0	0	0	0	0	0	0	0	0	0.0%
Total	109	209	227	236	246	256	266	277	288	378	2,492	12.5%
Purchasing Economies (Nonfuel):												
Procurement	0	0	0	0	0	0	0	0	0	0	0	0.0%
Contract Services	0	1	1	1	1	1	1	1	1	1	8	0.0%
Inventory Reduction	0	0	0	0	0	0	0	0	0	0	0	0.0%
Total	0	1	1	1	1	1	1	1	1	1	8	0.0%
Savings - Subtotal	458	1,449	1,794	1,894	1,997	2,103	2,213	2,326	2,442	3,245	19,919	
Total Savings	458	1,449	1,794	1,894	1,997	2,103	2,213	2,326	2,442	3,245	19,919	1 -)
Cost to Achieve												
Total Cost to Achieve	909	488	186	63	65	66	67	64	64	82	2,053	
Premerger Initiatives	13	36	61	91	127	167	208	250	275	370	1,600	
Net Savings	-464	926	1,546	1,739	1,805	1,870	1,937	2,012	2,103	2,792	16,266	A-1
										Check	16,266	

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Total O&M Savings - Sales

Areas ($ in 000s)	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	Total
Labor											
Corporate	341	1,208	1,504	1,564	1,627	1,692	1,760	1,830	1,903	2,494	15,923
Generation	0	0	0	0	0	0	0	0	0	0	0
Field Support	0	0	0	0	0	0	0	0	0	0	0
Total	341	1,208	1,504	1,564	1,627	1,692	1,760	1,830	1,903	2,494	15,923
Corporate Facilities	0	0	0	0	0	0	0	0	0	0	0
Corporate & Administrative Programs											
Advertising/Public Relations	0	0	0	0	0	0	0	0	0	0	0
Administrative & General Overhead	28	96	108	111	115	118	122	125	129	167	1,120
Association Dues & Memberships	0	0	0	0	0	0	0	0	0	0	0
Benefits	0	0	0	0	0	0	0	0	0	0	0
Credit Facilities	0	0	0	0	0	0	0	0	0	0	0
Director's Fees	0	0	0	0	0	0	0	0	0	0	0
Insurance	0	0	0	0	0	0	0	0	0	0	0
Information Services	0	0	0	0	0	0	0	0	0	0	0
Professional Services	80	112	117	123	129	136	142	150	157	208	1,354
Regulatory Expense	0	0	0	0	0	0	0	0	0	0	0
Research & Development	1	2	2	2	2	2	2	2	2	2	17
Shareholder Services	0	0	0	0	0	0	0	0	0	0	0
Total	109	209	227	236	246	256	266	277	288	378	2,492
Purchasing Economies (Nonfuel)											
Procurement	0	0	0	0	0	0	0	0	0	0	0
Contract Services	0	0	0	1	1	1	1	1	1	1	6
Inventory Reduction	0	0	0	0	0	0	0	0	0	0	0
Total	0	0	0	1	1	1	1	1	1	1	6
Savings - Subtotal	451	1,418	1,732	1,801	1,873	1,948	2,026	2,108	2,192	2,873	18,421
Total Savings	451	1,418	1,732	1,801	1,873	1,948	2,026	2,108	2,192	2,873	18,421
Cost to Achieve											
Total Cost to Achieve	909	488	186	63	65	66	67	64	64	82	2,053
Premeger Initiatives	14	35	56	79	103	128	153	179	186	233	1,165
Net O&M Savings	-472	895	1,490	1,659	1,706	1,755	1,807	1,864	1,942	2,558	15,203

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Revenue Requirement Savings - Sales

Areas ($ in 000s)	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	Total
Labor											
Corporate	7	32	62	93	123	155	186	218	250	371	1,496
Generation	0	0	0	0	0	0	0	0	0	0	0
Field Support	0	0	0	0	0	0	0	0	0	0	0
Total	7	32	62	93	123	155	186	218	250	371	1,496
Facilities and Other Capital	0	0	0	0	0	0	0	0	0	0	0
Corporate & Administrative Programs:											
Professional Services	0	0	0	0	0	0	0	0	0	0	0
Information Services	0	0	0	0	0	0	0	0	0	0	0
Benefits	0	0	0	0	0	0	0	0	0	0	0
Total	0	0	0	0	0	0	0	0	0	0	0
Purchasing Economies (Nonfuel):											
Procurement	0	0	0	0	0	0	0	0	0	0	0
Contract Services	0	0	0	0	0	0	0	0	0	0	2
Inventory Reduction	0	0	0	0	0	0	0	0	0	0	0
Total	0	0	0	0	0	0	0	0	0	0	2
Savings - Subtotal	7	32	62	93	124	155	186	218	250	372	1,499
Total Savings	7	32	62	93	124	155	186	218	250	372	1,499
Costs to Achieve	0	0	0	0	0	0	0	0	0	0	0
Premeger Initiatives	-1	1	6	13	25	40	56	71	89	138	436
Net Savings	8	30	56	80	99	115	131	147	161	234	1,063

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Capital Savings - Sales

Areas ($ in 000s)	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	Total
Labor											
Corporate	40	141	176	183	190	198	206	214	223	292	1,864
Generation	0	0	0	0	0	0	0	0	0	0	0
Field Support	0	0	0	0	0	0	0	0	0	0	0
Total	40	141	176	183	190	198	206	214	223	292	1,864
Facilities and Other Capital	0	0	0	0	0	0	0	0	0	0	0
Corporate & Administrative Programs:											
Professional Services	0	0	0	0	0	0	0	0	0	0	0
Information Services	0	0	0	0	0	0	0	0	0	0	0
Benefits	0	0	0	0	0	0	0	0	0	0	0
Total	0	0	0	0	0	0	0	0	0	0	0
Purchasing Economies (Nonfuel):											
Procurement	0	0	0	0	0	0	0	0	0	0	0
Contract Services	0	0	0	0	0	0	0	0	0	0	3
Inventory Reduction	0	0	0	0	0	0	0	0	0	0	0
Total	0	0	0	0	0	0	0	0	0	0	3
Savings - Subtotal	40	142	176	183	191	198	206	214	223	292	1,866
Total Savings	40	142	176	183	191	198	206	214	223	292	1,866
Costs to Achieve	0	0	0	0	0	0	0	0	0	0	0
Premeger Initiatives	-7	16	24	40	71	88	98	95	116	109	648
Net Savings	47	126	152	143	120	110	109	120	107	183	1,218

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Total Savings Detail - A&G

Areas ($ in 000s)	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	Total	
Labor												
Corporate	0	0	0	0	0	0	0	0	0	0	0	0.0%
Generation Support	0	0	0	0	0	0	0	0	0	0	0	0.0%
Field Support	0	0	0	0	0	0	0	0	0	0	0	0.0%
Total	0	0	0	0	0	0	0	0	0	0	0	0.0%
Corporate Facilities	0	0	0	0	0	0	0	0	0	0	0	0.0%
Corporate & Administrative Programs:												
Advertising/Public Relations	0	0	0	0	0	0	0	0	0	0	0	0.0%
Administrative & General Overhead	0	0	0	0	0	0	0	0	0	0	0	0.0%
Association Dues & Memberships	274	376	388	399	411	424	436	449	463	599	4,220	2.9%
Benefits	0	0	0	6,986	7,610	8,248	8,899	9,565	10,246	13,859	65,412	44.7%
Credit Facilities	56	76	79	81	83	86	88	91	94	122	855	0.6%
Director's Fees	0	0	0	0	0	0	0	0	0	0	0	0.0%
Insurance	4,220	5,851	6,085	6,329	6,582	6,845	7,119	7,404	7,700	10,090	68,225	46.6%
Information Services	0	0	0	0	0	0	0	0	0	0	0	0.0%
Professional Services	448	627	659	692	726	763	801	841	883	1,170	7,610	5.2%
Regulatory Expense	0	0	0	0	0	0	0	0	0	0	0	0.0%
Research & Development	0	0	0	0	0	0	0	0	0	0	0	0.0%
Shareholder Services	0	0	0	0	0	0	0	0	0	0	0	0.0%
Total	4,997	6,931	7,210	14,486	15,412	16,365	17,344	18,350	19,386	25,840	146,322	100.0%
Purchasing Economies (Nonfuel):												
Procurement	0	0	0	0	0	0	0	0	0	0	0	0.0%
Contract Services	0	0	0	0	0	0	0	0	0	0	0	0.0%
Inventory Reduction	0	0	0	0	0	0	0	0	0	0	0	0.0%
Total	0	0	0	0	0	0	0	0	0	0	0	0.0%
Savings - Subtotal	4,997	6,931	7,210	14,486	15,412	16,365	17,344	18,350	19,386	25,840	146,322	
Total Savings	4,997	6,931	7,210	14,486	15,412	16,365	17,344	18,350	19,386	25,840	146,322	
Cost to Achieve												
Total Cost to Achieve	6,674	3,583	1,367	464	474	485	491	470	470	604	15,082	
Premerger Initiatives	94	264	451	671	936	1,227	1,532	1,837	2,020	2,721	11,754	
Net Savings	-1,771	3,084	5,392	13,352	14,002	14,653	15,321	16,043	16,895	22,515	119,486	A-1
										Check	119,486	

Total O&M Savings - A&G

Areas ($ in 000s)	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	Total
Labor											
Corporate	0	0	0	0	0	0	0	0	0	0	0
Generation	0	0	0	0	0	0	0	0	0	0	0
Field Support	0	0	0	0	0	0	0	0	0	0	0
Total	0	0	0	0	0	0	0	0	0	0	0
Corporate Facilities	0	0	0	0	0	0	0	0	0	0	0
Corporate & Administrative Programs											
Advertising/Public Relations	0	0	0	0	0	0	0	0	0	0	0
Administrative & General Overhead	0	0	0	0	0	0	0	0	0	0	0
Association Dues & Memberships	274	376	388	399	411	424	436	449	463	599	4,220
Benefits	0	0	0	6,636	6,902	7,178	7,465	7,764	8,074	10,581	54,600
Credit Facilities	56	76	79	81	83	86	88	91	94	122	855
Director's Fees	0	0	0	0	0	0	0	0	0	0	0
Insurance	4,220	5,851	6,085	6,329	6,582	6,845	7,119	7,404	7,700	10,090	68,225
Information Services	0	0	0	0	0	0	0	0	0	0	0
Professional Services	448	627	659	692	726	763	801	841	883	1,170	7,610
Regulatory Expense	0	0	0	0	0	0	0	0	0	0	0
Research & Development	0	0	0	0	0	0	0	0	0	0	0
Shareholder Services	0	0	0	0	0	0	0	0	0	0	0
Total	4,997	6,931	7,210	14,137	14,705	15,295	15,910	16,549	17,214	22,562	135,510
Purchasing Economies (Nonfuel)											
Procurement	0	0	0	0	0	0	0	0	0	0	0
Contract Services	0	0	0	0	0	0	0	0	0	0	0
Inventory Reduction	0	0	0	0	0	0	0	0	0	0	0
Total	0	0	0	0	0	0	0	0	0	0	0
Savings - Subtotal	4,997	6,931	7,210	14,137	14,705	15,295	15,910	16,549	17,214	22,562	135,510
Total Savings	4,997	6,931	7,210	14,137	14,705	15,295	15,910	16,549	17,214	22,562	135,510
Cost to Achieve											
Total Cost to Achieve	6,674	3,583	1,367	464	474	485	491	470	470	604	15,082
Premeger Initiatives	103	253	410	579	754	937	1,123	1,318	1,367	1,709	8,554
Net O&M Savings	-1,780	3,094	5,433	13,095	13,476	13,874	14,296	14,761	15,376	20,249	111,873

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Revenue Requirement Savings - A&G

Areas ($ in 000s)	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	Total
Labor											
Corporate	0	0	0	0	0	0	0	0	0	0	0
Generation	0	0	0	0	0	0	0	0	0	0	0
Field Support	0	0	0	0	0	0	0	0	0	0	0
Total	0	0	0	0	0	0	0	0	0	0	0
Facilities and Other Capital	0	0	0	0	0	0	0	0	0	0	0
Corporate & Administrative Programs:											
Professional Services	0	0	0	0	0	0	0	0	0	0	0
Information Services	0	0	0	0	0	0	0	0	0	0	0
Benefits	0	0	0	349	708	1,070	1,434	1,801	2,172	3,278	10,812
Total	0	0	0	349	708	1,070	1,434	1,801	2,172	3,278	10,812
Purchasing Economies (Nonfuel):											
Procurement	0	0	0	0	0	0	0	0	0	0	0
Contract Services	0	0	0	0	0	0	0	0	0	0	0
Inventory Reduction	0	0	0	0	0	0	0	0	0	0	0
Total	0	0	0	0	0	0	0	0	0	0	0
Savings - Subtotal	0	0	0	349	708	1,070	1,434	1,801	2,172	3,278	10,812
Total Savings	0	0	0	349	708	1,070	1,434	1,801	2,172	3,278	10,812
Costs to Achieve	0	0	0	0	0	0	0	0	0	0	0
Premeger Initiatives	-9	11	42	93	181	290	408	519	653	1,011	3,199
Net Savings	9	-11	-42	257	526	779	1,026	1,282	1,519	2,267	7,613

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Capital Savings - A&G

Areas ($ in 000s)	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	Total
Labor											
Corporate	0	0	0	0	0	0	0	0	0	0	0
Generation	0	0	0	0	0	0	0	0	0	0	0
Field Support	0	0	0	0	0	0	0	0	0	0	0
Total	0	0	0	0	0	0	0	0	0	0	0
Facilities and Other Capital	0	0	0	0	0	0	0	0	0	0	0
Corporate & Administrative Programs:											
Professional Services	0	0	0	0	0	0	0	0	0	0	0
Information Services	0	0	0	0	0	0	0	0	0	0	0
Benefits	0	0	0	1,994	2,073	2,156	2,242	2,332	2,425	3,178	16,401
Total	0	0	0	1,994	2,073	2,156	2,242	2,332	2,425	3,178	16,401
Purchasing Economies (Nonfuel):											
Procurement	0	0	0	0	0	0	0	0	0	0	0
Contract Services	0	0	0	0	0	0	0	0	0	0	0
Inventory Reduction	0	0	0	0	0	0	0	0	0	0	0
Total	0	0	0	0	0	0	0	0	0	0	0
Savings - Subtotal	0	0	0	1,994	2,073	2,156	2,242	2,332	2,425	3,178	16,401
Total Savings	0	0	0	1,994	2,073	2,156	2,242	2,332	2,425	3,178	16,401
Costs to Achieve	0	0	0	0	0	0	0	0	0	0	0
Premerger Initiatives	-53	114	176	295	519	646	716	698	853	800	4,764
Net Savings	53	-114	-176	1,698	1,555	1,510	1,526	1,635	1,572	2,378	11,638

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FERC ACCOUNT NUMBERS USED IN ALLOCATION STUDY

For this study, each work order is assigned FERC accounts based on the service provided. By function two accounts are used, one for one for operations and one for maintenance, with the exception of production maintenance. Production maintenance costs are categorized by specific account based on the service provided.

Below is a list, by function, of the accounts used:

CATEGORY	OPERATIONS	MAINTENANCE
Fuel	501	-
Steam	506	514
Nuclear	524	532
Hydro	539	545
Other Production	549	554
Other Power Supply	557	-
Transmission	566	573
Distribution	588	598
Customer Accounts	905	-
Customer Service	910	-
Sales	916	-
A & G	930.2	935
Below the Line	426.5	-
Other Activity		
Capital	107	
Retirement	108	
Stores	163	
Deferred	186	

AMERICAN ELECTRIC POWER COMPANY
COMPANY CODES USED FOR ALLOCATING 1997 BILLINGS AND SYNERGY SAVINGS

CO CODE	DESCRIPTION	CO NO.	COMPANY NAME
AA	All Companies	01	Kingsport Power Company (KgPCo)
		02	Appalachian Power Company (APCo)
		03	Kentucky Power Company (KPCO)
		04	Indiana Michigan Power Company (I&M)
		06	Wheeling Power Company (WPCo)
		07	Ohio Power Company (OPCo)
		10	Columbus Southern Power Company (CSP)
		21	AEP Generating Company (AEG)
		22	Cardinal Operating Company
		23	Central Operating Company
		25	AEP Resources Int'l LTD
		26	AEP Resources LTD
		31	Indiana-Kentucky Power Company (IKEC)
		32	Ohio Valley Electric Corp. (OVEC)
		34	Buckeye Power Company
		40	Central Appalachian Coal Co. (CACCo)
		41	Central Coal Co. (CCCo / Sporn Mine)
		42	Central Ohio Coal Co. (COCCO / Muskingum Mine)
		43	Windsor Coal Co. (WCCo)
		44	Southern Ohio Coal Co. (SOCCo / Meigs Division)
		45	Southern Appalachian Coal Co. (SACCo)
		46	Cedar Coal Company
		48	Water Transportation Division (RTD)
		49	Cook Coal Terminal (CCT)
		50	Price River Coal Co.
		51	Blackhawk Coal Co.
		52	Simco, Inc.
		53	Colomet, Inc.
		54	Conesville Coal Prep Co. (CCPC)
		55	Southern Ohio Coal - Martinka Division
		56	AEPR Project Management Company
		57	AEPR Australia Pty LTD
		58	AEP Communications, Inc.
		59	AEP Energy Services, Inc.
		60	AEP Company, Inc.
		61	AEP Service Corp. (AEPSC)
		63	Franklin Real Estate Company
		64	Indiana Franklin Realty, Inc.
		66	AEP Power Marketing, Inc.
		67	West Virginia Power Company
		69	AEPR Service Company
		70	Sporn Plant Joint Books
		71	Amos Plant Joint Books
		72	AEP Investments, Inc.
		73	Rockport Plant Joint Books
		74	AEP Resources, Inc.
		75	Gavin FGD

AMERICAN ELECTRIC POWER COMPANY
COMPANY CODES USED FOR ALLOCATING 1997 BILLINGS AND SYNERGY SAVINGS

CO CODE	DESCRIPTION	CO NO.	COMPANY NAME
		76	Tidd Plant PFBC Project
		77	Sporn Plant - OPCo Share
		78	Amos Plant - OPCo Share
		81	AEP Pushan Power LDC
		83	AEPR Mauritius Company
		84	Rockport - I&M Share
		85	Rockport - AEG Share
		86	AEPR Delaware, Inc.
		87	Nanyang General Light Electric Co. LTD
		88	AEPR Global Holland Holding BV
		89	AEPR Global Ventures BV
		90	AEPR Global Investments BV
		91	AEP Communications, LLC
		98	Carolina Power & Light (CP&L)
		99	Yorkshire
		SEE	Seeboard
		CPL	Central Power & Light (CPL)
		CSE	CSW Energy
		DES	Enershop
		CSI	CSW International
		JFP	Joint Fuels Project (JFP)
		TOK	Transok
		DLL	CSW Leasing
		DCM	CSW Communications
		ESI	Energy Services Inc. (Boston)
		ECS	Energy Consulting SVCS
		LAB	External Lab Services
		PMI	Power Marketing Inc.
		PSO	Public Service of Oklahoma (PSO)
		DCR	CSW Corporation
		SEP	Southwestern Electric Power Co (SWEPCO)
		DCT	CSW Credit
		WTU	West Texas Utilities (WTU)
		DSV	CSW Services Support
AB	All Domestic Companies	01	Kingsport Power Company (KgPCo)
		02	Appalachian Power Company (APCo)
		03	Kentucky Power Company (KPCO)
		04	Indiana Michigan Power Company (I&M)
		06	Wheeling Power Company (WPCo)
		07	Ohio Power Company (OPCo)
		10	Columbus Southern Power Company (CSP)
		21	AEP Generating Company (AEG)
		22	Cardinal Operating Company
		23	Central Operating Company
		25	AEP Resources Int'l LTD
		26	AEP Resources LTD

AMERICAN ELECTRIC POWER COMPANY
COMPANY CODES USED FOR ALLOCATING 1997 BILLINGS AND SYNERGY SAVINGS

CO CODE	DESCRIPTION	CO NO.	COMPANY NAME
		31	Indiana-Kentucky Power Company (IKEC)
		32	Ohio Valley Electric Corp. (OVEC)
		34	Buckeye Power Company
		40	Central Appalachian Coal Co. (CACCo)
		41	Central Coal Co. (CCCo / Sporn Mine)
		42	Central Ohio Coal Co. (COCCO / Muskingum Mine)
		43	Windsor Coal Co. (WCCo)
		44	Southern Ohio Coal Co. (SOCCo / Meigs Division)
		45	Southern Appalachian Coal Co. (SACCo)
		46	Cedar Coal Company
		48	Water Transportation Division (RTD)
		49	Cook Coal Terminal (CCT)
		50	Price River Coal Co.
		51	Blackhawk Coal Co.
		52	Simco, Inc.
		53	Colomet, Inc.
		54	Conesville Coal Prep Co. (CCPC)
		55	Southern Ohio Coal - Martinka Division
		56	AEPR Project Management Company
		57	AEPR Australia Pty LTD
		58	AEP Communications, Inc.
		59	AEP Energy Services, Inc.
		60	AEP Company, Inc.
		61	AEP Service Corp. (AEPSC)
		63	Franklin Real Estate Company
		64	Indiana Franklin Realty, Inc.
		66	AEP Power Marketing, Inc.
		67	West Virginia Power Company
		69	AEPR Service Company
		70	Sporn Plant Joint Books
		71	Amos Plant Joint Books
		72	AEP Investments, Inc.
		73	Rockport Plant Joint Books
		74	AEP Resources, Inc.
		76	Tidd Plant PFBC Project
		77	Sporn Plant - OPCo Share
		78	Amos Plant - OPCo Share
		83	AEPR Mauritius Company
		84	Rockport - I&M Share
		85	Rockport - AEG Share
		86	AEPR Delaware, Inc.
		87	Nanyang General Light Electric Co. LTD
		88	AEPR Global Holland Holding BV
		89	AEPR Global Ventures BV
		90	AEPR Global Investments BV
		91	AEP Communications, LLC
		98	Carolina Power & Light (CP&L)

AMERICAN ELECTRIC POWER COMPANY
COMPANY CODES USED FOR ALLOCATING 1997 BILLINGS AND SYNERGY SAVINGS

CO CODE	DESCRIPTION	CO NO.	COMPANY NAME
		CPL	Central Power & Light (CPL)
		CSE	CSW Energy
		DES	Enershop
		CSI	CSW International
		JFP	Joint Fuels Project (JFP)
		TOK	Transok
		DLL	CSW Leasing
		DCM	CSW Communications
		ESI	Energy Services Inc. (Boston)
		ECS	Energy Consulting SVCS
		LAB	External Lab Services
		PMI	Power Marketing Inc.
		PSO	Public Service of Oklahoma (PSO)
		DCR	CSW Corporation
		SEP	Southwestern Electric Power Co (SWEPCO)
		DCT	CSW Credit
		WTU	West Texas Utilities (WTU)
		DSV	CSW Services Support
EA	All Electrics	01	Kingsport Power Company (KgPCo)
		02	Appalachian Power Company (APCo)
		03	Kentucky Power Company (KPCO)
		04	Indiana Michigan Power Company (I&M)
		06	Wheeling Power Company (WPCo)
		07	Ohio Power Company (OPCo)
		10	Columbus Southern Power Company (CSP)
		21	AEP Generating Company (AEG)
		22	Cardinal Operating Company
		23	Central Operating Company
		48	Water Transportation Division (RTD)
		49	Cook Coal Terminal (CCT)
		70	Sporn Plant Joint Books
		71	Amos Plant Joint Books
		73	Rockport Plant Joint Books
		CPL	Central Power & Light (CPL)
		PSO	Public Service of Oklahoma (PSO)
		SEP	Southwestern Electric Power Co (SWEPCO)
		WTU	West Texas Utilities (WTU)
AD	Electrics and Corportate Holding Companies	01	Kingsport Power Company (KgPCo)
		02	Appalachian Power Company (APCo)
		03	Kentucky Power Company (KPCO)
		04	Indiana Michigan Power Company (I&M)
		06	Wheeling Power Company (WPCo)
		07	Ohio Power Company (OPCo)
		10	Columbus Southern Power Company (CSP)
		21	AEP Generating Company (AEG)

AMERICAN ELECTRIC POWER COMPANY
COMPANY CODES USED FOR ALLOCATING 1997 BILLINGS AND SYNERGY SAVINGS

CO CODE	DESCRIPTION	CO NO.	COMPANY NAME
		22	Cardinal Operating Company
		23	Central Operating Company
		48	Water Transportation Division (RTD)
		49	Cook Coal Terminal (CCT)
		60	AEP Company, Inc.
		70	Sporn Plant Joint Books
		71	Amos Plant Joint Books
		73	Rockport Plant Joint Books
		CPL	Central Power & Light (CPL)
		CSE	CSW Energy
		PSO	Public Service of Oklahoma (PSO)
		DCR	CSW Corporation
		SEP	Southwestern Electric Power Co (SWEPCO)
		WTU	West Texas Utilities (WTU)
AF	4 CSW Electrics, CSW Comm & Enershop	CPL	Central Power & Light (CPL)
		DES	Enershop
		DCM	CSW Communications
		PSO	Public Service of Oklahoma (PSO)
		SEP	Southwestern Electric Power Co (SWEPCO)
		WTU	West Texas Utilities (WTU)
AZ	All Companies, excluding Service Corps	SEE	Seeboard
		CPL	Central Power & Light (CPL)
		CSE	CSW Energy
		DES	Enershop
		CSI	CSW International
		JFP	Joint Fuels Project (JFP)
		TOK	Transok
		DLL	CSW Leasing
		DCM	CSW Communications
		ESI	Energy Services Inc. (Boston)
		ECS	Energy Consulting SVCS
		LAB	External Lab Services
		PMI	Power Marketing Inc.
		PSO	Public Service of Oklahoma (PSO)
		DCR	CSW Corporation
		SEP	Southwestern Electric Power Co (SWEPCO)
		DCT	CSW Credit
		WTU	West Texas Utilities (WTU)
EN	Electric North	01	Kingsport Power Company (KgPCo)
		02	Appalachian Power Company (APCo)
		03	Kentucky Power Company (KPCO)
		04	Indiana Michigan Power Company (I&M)
		06	Wheeling Power Company (WPCo)
		07	Ohio Power Company (OPCo)

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AMERICAN ELECTRIC POWER COMPANY
COMPANY CODES USED FOR ALLOCATING 1997 BILLINGS AND SYNERGY SAVINGS

CO CODE	DESCRIPTION	CO NO.	COMPANY NAME
		10	Columbus Southern Power Company (CSP)
		21	AEP Generating Company (AEG)
		22	Cardinal Operating Company
		23	Central Operating Company
		48	Water Transportation Division (RTD)
		49	Cook Coal Terminal (CCT)
		70	Sporn Plant Joint Books
		71	Amos Plant Joint Books
		73	Rockport Plant Joint Books
ES	Electric South	CPL	Central Power & Light (CPL)
		PSO	Public Service of Oklahoma (PSO)
		SEP	Southwestern Electric Power Co (SWEPCO)
		WTU	West Texas Utilities (WTU)
AL	All Companies, excluding CSW Leasing	01	Kingsport Power Company (KgPCo)
		02	Appalachian Power Company (APCo)
		03	Kentucky Power Company (KPCO)
		04	Indiana Michigan Power Company (I&M)
		06	Wheeling Power Company (WPCo)
		07	Ohio Power Company (OPCo)
		10	Columbus Southern Power Company (CSP)
		21	AEP Generating Company (AEG)
		22	Cardinal Operating Company
		40	Central Appalachian Coal Co. (CACCo)
		41	Central Coal Co. (CCCo / Sporn Mine)
		42	Central Ohio Coal Co. (COCCO / Muskingum Mine)
		43	Windsor Coal Co. (WCCo)
		44	Southern Ohio Coal Co. (SOCCo / Meigs Division)
		45	Southern Appalachian Coal Co. (SACCo)
		46	Cedar Coal Company
		51	Blackhawk Coal Co.
		52	Simco, Inc.
		53	Colomet, Inc.
		54	Conesville Coal Prep Co. (CCPC)
		55	Southern Ohio Coal - Martinka Division
		56	AEPR Project Management Company
		57	AEPR Australia Pty LTD
		58	AEP Communications, Inc.
		59	AEP Energy Services, Inc.
		60	AEP Company, Inc.
		61	AEP Service Corp. (AEPSC)
		63	Franklin Real Estate Company
		64	Indiana Franklin Realty, Inc.
		66	AEP Power Marketing, Inc.
		67	West Virginia Power Company
		69	AEPR Service Company

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AMERICAN ELECTRIC POWER COMPANY
COMPANY CODES USED FOR ALLOCATING 1997 BILLINGS AND SYNERGY SAVINGS

CO CODE	DESCRIPTION	CO NO.	COMPANY NAME
		72	AEP Investments, Inc.
		74	AEP Resources, Inc.
		81	AEP Pushan Power LDC
		83	AEPR Mauritius Company
		86	AEPR Delaware, Inc.
		87	Nanyang General Light Electric Co. LTD
		91	AEP Communications, LLC
		SEE	Seeboard
		CPL	Central Power & Light (CPL)
		CSE	CSW Energy
		DES	Enershop
		CSI	CSW International
		JFP	Joint Fuels Project (JFP)
		TOK	Transok
		DCM	CSW Communications
		ESI	Energy Services Inc. (Boston)
		ECS	Energy Consulting SVCS
		LAB	External Lab Services
		PMI	Power Marketing Inc.
		PSO	Public Service of Oklahoma (PSO)
		DCR	CSW Corporation
		SEP	Southwestern Electric Power Co (SWEPCO)
		DCT	CSW Credit
		WTU	West Texas Utilities (WTU)
		DSV	CSW Services Support
AX	All Domestic Except CSW Leasing & CSW Credit	01	Kingsport Power Company (KgPCo)
		02	Appalachian Power Company (APCo)
		03	Kentucky Power Company (KPCO)
		04	Indiana Michigan Power Company (I&M)
		06	Wheeling Power Company (WPCo)
		07	Ohio Power Company (OPCo)
		10	Columbus Southern Power Company (CSP)
		21	AEP Generating Company (AEG)
		22	Cardinal Operating Company
		23	Central Operating Company
		25	AEP Resources Int'l LTD
		26	AEP Resources LTD
		31	Indiana-Kentucky Power Company (IKEC)
		32	Ohio Valley Electric Corp. (OVEC)
		34	Buckeye Power Company
		40	Central Appalachian Coal Co. (CACCo)
		41	Central Coal Co. (CCCo / Sporn Mine)
		42	Central Ohio Coal Co. (COCCO / Muskingum Mine)
		43	Windsor Coal Co. (WCCo)
		44	Southern Ohio Coal Co. (SOCCo / Meigs Division)
		45	Southern Appalachian Coal Co. (SACCo)

AMERICAN ELECTRIC POWER COMPANY
COMPANY CODES USED FOR ALLOCATING 1997 BILLINGS AND SYNERGY SAVINGS

CO CODE	DESCRIPTION	CO NO.	COMPANY NAME
		46	Cedar Coal Company
		48	Water Transportation Division (RTD)
		49	Cook Coal Terminal (CCT)
		50	Price River Coal Co.
		51	Blackhawk Coal Co.
		52	Simco, Inc.
		53	Colomet, Inc.
		54	Conesville Coal Prep Co. (CCPC)
		55	Southern Ohio Coal - Martinka Division
		56	AEPR Project Management Company
		57	AEPR Australia Pty LTD
		58	AEP Communications, Inc.
		59	AEP Energy Services, Inc.
		60	AEP Company, Inc.
		61	AEP Service Corp. (AEPSC)
		63	Franklin Real Estate Company
		64	Indiana Franklin Realty, Inc.
		66	AEP Power Marketing, Inc.
		67	West Virginia Power Company
		69	AEPR Service Company
		70	Sporn Plant Joint Books
		71	Amos Plant Joint Books
		72	AEP Investments, Inc.
		73	Rockport Plant Joint Books
		74	AEP Resources, Inc.
		76	Tidd Plant PFBC Project
		77	Sporn Plant - OPCo Share
		78	Amos Plant - OPCo Share
		83	AEPR Mauritius Company
		84	Rockport - I&M Share
		85	Rockport - AEG Share
		86	AEPR Delaware, Inc.
		87	Nanyang General Light Electric Co. LTD
		88	AEPR Global Holland Holding BV
		89	AEPR Global Ventures BV
		90	AEPR Global Investments BV
		91	AEP Communications, LLC
		98	Carolina Power & Light (CP&L)
		CPL	Central Power & Light (CPL)
		CSE	CSW Energy
		DES	Enershop
		CSI	CSW International
		JFP	Joint Fuels Project (JFP)
		TOK	Transok
		DCM	CSW Communications
		ESI	Energy Services Inc. (Boston)
		ECS	Energy Consulting SVCS

AMERICAN ELECTRIC POWER COMPANY
COMPANY CODES USED FOR ALLOCATING 1997 BILLINGS AND SYNERGY SAVINGS

CO CODE	DESCRIPTION	CO NO.	COMPANY NAME
		LAB	External Lab Services
		PMI	Power Marketing Inc.
		PSO	Public Service of Oklahoma (PSO)
		DCR	CSW Corporation
		SEP	Southwestern Electric Power Co (SWEPCO)
		WTU	West Texas Utilities (WTU)
		DSV	CSW Services Support
AY	All Except CSW Leasing & CSW Credit	01	Kingsport Power Company (KgPCo)
		02	Appalachian Power Company (APCo)
		03	Kentucky Power Company (KPCO)
		04	Indiana Michigan Power Company (I&M)
		06	Wheeling Power Company (WPCo)
		07	Ohio Power Company (OPCo)
		10	Columbus Southern Power Company (CSP)
		21	AEP Generating Company (AEG)
		22	Cardinal Operating Company
		23	Central Operating Company
		25	AEP Resources Int'l LTD
		26	AEP Resources LTD
		31	Indiana-Kentucky Power Company (IKEC)
		32	Ohio Valley Electric Corp. (OVEC)
		34	Buckeye Power Company
		40	Central Appalachian Coal Co. (CACCo)
		41	Central Coal Co. (CCCo / Sporn Mine)
		42	Central Ohio Coal Co. (COCCO / Muskingum Mine)
		43	Windsor Coal Co. (WCCo)
		44	Southern Ohio Coal Co. (SOCCo / Meigs Division)
		45	Southern Appalachian Coal Co. (SACCo)
		46	Cedar Coal Company
		48	Water Transportation Division (RTD)
		49	Cook Coal Terminal (CCT)
		50	Price River Coal Co.
		51	Blackhawk Coal Co.
		52	Simco, Inc.
		53	Colomet, Inc.
		54	Conesville Coal Prep Co. (CCPC)
		55	Southern Ohio Coal - Martinka Division
		56	AEPR Project Management Company
		57	AEPR Australia Pty LTD
		58	AEP Communications, Inc.
		59	AEP Energy Services, Inc.
		60	AEP Company, Inc.
		61	AEP Service Corp. (AEPSC)
		63	Franklin Real Estate Company
		64	Indiana Franklin Realty, Inc.
		66	AEP Power Marketing, Inc.

AMERICAN ELECTRIC POWER COMPANY
COMPANY CODES USED FOR ALLOCATING 1997 BILLINGS AND SYNERGY SAVINGS

CO CODE	DESCRIPTION	CO NO.	COMPANY NAME
		67	West Virginia Power Company
		69	AEPR Service Company
		70	Sporn Plant Joint Books
		71	Amos Plant Joint Books
		72	AEP Investments, Inc.
		73	Rockport Plant Joint Books
		74	AEP Resources, Inc.
		76	Tidd Plant PFBC Project
		77	Sporn Plant - OPCo Share
		78	Amos Plant - OPCo Share
		81	AEP Pushan Power LDC
		83	AEPR Mauritius Company
		84	Rockport - I&M Share
		85	Rockport - AEG Share
		86	AEPR Delaware, Inc.
		87	Nanyang General Light Electric Co. LTD
		88	AEPR Global Holland Holding BV
		89	AEPR Global Ventures BV
		90	AEPR Global Investments BV
		91	AEP Communications, LLC
		98	Carolina Power & Light (CP&L)
		99	Yorkshire
		SEE	Seeboard
		CPL	Central Power & Light (CPL)
		CSE	CSW Energy
		DES	Enershop
		CSI	CSW International
		JFP	Joint Fuels Project (JFP)
		TOK	Transok
		DCM	CSW Communications
		ESI	Energy Services Inc. (Boston)
		ECS	Energy Consulting SVCS
		LAB	External Lab Services
		PMI	Power Marketing Inc.
		PSO	Public Service of Oklahoma (PSO)
		DCR	CSW Corporation
		SEP	Southwestern Electric Power Co (SWEPCO)
		WTU	West Texas Utilities (WTU)
		DSV	CSW Services Support
GA	Generating All	02	Appalachian Power Company (APCo)
		03	Kentucky Power Company (KPCO)
		04	Indiana Michigan Power Company (I&M)
		07	Ohio Power Company (OPCo)
		10	Columbus Southern Power Company (CSP)
		21	AEP Generating Company (AEG)
		22	Cardinal Operating Company

AMERICAN ELECTRIC POWER COMPANY
COMPANY CODES USED FOR ALLOCATING 1997 BILLINGS AND SYNERGY SAVINGS

CO CODE	DESCRIPTION	CO NO.	COMPANY NAME
		23	Central Operating Company
		70	Sporn Plant Joint Books
		71	Amos Plant Joint Books
		73	Rockport Plant Joint Books
		CPL	Central Power & Light (CPL)
		PSO	Public Service of Oklahoma (PSO)
		SEP	Southwestern Electric Power Co (SWEPCO)
		WTU	West Texas Utilities (WTU)
E1	4 Companies - (CSP, I&M, OPCo, WPCo)	04	Indiana Michigan Power Company (I&M)
		06	Wheeling Power Company (WPCo)
		07	Ohio Power Company (OPCo)
		10	Columbus Southern Power Company (CSP)
E2	5 Companies - (APCo, CSP, KPCo, KgPCo, OPCo)	01	Kingsport Power Company (KgPCo)
		02	Appalachian Power Company (APCo)
		03	Kentucky Power Company (KPCO)
		07	Ohio Power Company (OPCo)
		10	Columbus Southern Power Company (CSP)
E3	3 Companies - (CSP, OPCo, WPCo)	06	Wheeling Power Company (WPCo)
		07	Ohio Power Company (OPCo)
		10	Columbus Southern Power Company (CSP)
E4	4 Companies - (CSP, KPCo, OPCo, WPCo)	03	Kentucky Power Company (KPCO)
		06	Wheeling Power Company (WPCo)
		07	Ohio Power Company (OPCo)
		10	Columbus Southern Power Company (CSP)
E5	Trans. Central - (APCo, CSP, KPCo, OPCo, WPCo)	02	Appalachian Power Company (APCo)
		03	Kentucky Power Company (KPCO)
		06	Wheeling Power Company (WPCo)
		07	Ohio Power Company (OPCo)
		10	Columbus Southern Power Company (CSP)
E6	Transmission South - (APCo, KPCo, KgPCo)	01	Kingsport Power Company (KgPCo)
		02	Appalachian Power Company (APCo)
		03	Kentucky Power Company (KPCO)
3C	3 Companies - (PSO, SWEPCO, WTU)	PSO	Public Service of Oklahoma (PSO)
		SEP	Southwestern Electric Power Co (SWEPCO)
		WTU	West Texas Utilities (WTU)
3S	3 Companies - (CPL, PSO, WTU)	CPL	Central Power & Light (CPL)
		PSO	Public Service of Oklahoma (PSO)
		WTU	West Texas Utilities (WTU)

AMERICAN ELECTRIC POWER COMPANY
COMPANY CODES USED FOR ALLOCATING 1997 BILLINGS AND SYNERGY SAVINGS

CO CODE	DESCRIPTION	CO NO.	COMPANY NAME
3W	3 Companies - (CPL, PSO, SWEPCO)	CPL	Central Power & Light (CPL)
		PSO	Public Service of Oklahoma (PSO)
		SEP	Southwestern Electric Power Co (SWEPCO)
4E	4 Companies - (CPL, PSO, SWEPCO, WTU)	CPL	Central Power & Light (CPL)
		PSO	Public Service of Oklahoma (PSO)
		SEP	Southwestern Electric Power Co (SWEPCO)
		WTU	West Texas Utilities (WTU)
8E	8 Companies	01	Kingsport Power Company (KgPCo)
		02	Appalachian Power Company (APCo)
		03	Kentucky Power Company (KPCO)
		04	Indiana Michigan Power Company (I&M)
		06	Wheeling Power Company (WPCo)
		07	Ohio Power Company (OPCo)
		10	Columbus Southern Power Company (CSP)
		21	AEP Generating Company (AEG)
AK	APCO / KPCo	02	Appalachian Power Company (APCo)
		03	Kentucky Power Company (KPCO)
.O	CSP / OPCo	07	Ohio Power Company (OPCo)
		10	Columbus Southern Power Company (CSP)
CP	CPL / PSO	CPL	Central Power & Light (CPL)
		PSO	Public Service of Oklahoma (PSO)
CS	CPL / SWEPCO	CPL	Central Power & Light (CPL)
		SEP	Southwestern Electric Power Co (SWEPCO)
CW	CPL / WTU	CPL	Central Power & Light (CPL)
		WTU	West Texas Utilities (WTU)
DA	CSW Energy, CSW Comm, CSW Int'l, Enershop	CSE	CSW Energy
		DES	Enershop
		CSI	CSW International
		DCM	CSW Communications
IO	Transmission West - (I&M / OPCo)	04	Indiana Michigan Power Company (I&M)
		07	Ohio Power Company (OPCo)
KA	KgPCo / APCo	01	Kingsport Power Company (KgPCo)
		02	Appalachian Power Company (APCo)
NB	Non-Billable		
JW	OPCo / WPCo	06	Wheeling Power Company (WPCo)

AMERICAN ELECTRIC POWER COMPANY
COMPANY CODES USED FOR ALLOCATING 1997 BILLINGS AND SYNERGY SAVINGS

CO CODE	DESCRIPTION	CO NO.	COMPANY NAME
		07	Ohio Power Company (OPCo)
PS	PSO / SWEPCO	PSO	Public Service of Oklahoma (PSO)
		SEP	Southwestern Electric Power Co (SWEPCO)
PW	PSO / WTU	PSO	Public Service of Oklahoma (PSO)
		WTU	West Texas Utilities (WTU)
SW	SWEPCO / WTU	SEP	Southwestern Electric Power Co (SWEPCO)
		WTU	West Texas Utilities (WTU)
TX	Texas Companies - (CPL, SWEPCO, WTU)	CPL	Central Power & Light (CPL)
		SEP	Southwestern Electric Power Co (SWEPCO)
		WTU	West Texas Utilities (WTU)
01	Kingsport Power Company (KgPCo)	01	Kingsport Power Company (KgPCo)
02	Appalachian Power Company (APCo)	02	Appalachian Power Company (APCo)
03	Kentucky Power Company (KPCO)	03	Kentucky Power Company (KPCO)
04	Indiana Michigan Power Company (I&M)	04	Indiana Michigan Power Company (I&M)
06	Wheeling Power Company (WPCo)	06	Wheeling Power Company (WPCo)
07	Ohio Power Company (OPCo)	07	Ohio Power Company (OPCo)
10	Columbus Southern Power Company (CSP)	10	Columbus Southern Power Company (CSP)
21	AEP Generating Company (AEG)	21	AEP Generating Company (AEG)
22	Cardinal Operating Company	22	Cardinal Operating Company
23	Central Operating Company	23	Central Operating Company
25	AEP Resources Int'l LTD	25	AEP Resources Int'l LTD
26	AEP Resources LTD	26	AEP Resources LTD
31	Indiana-Kentucky Power Company (IKEC)	31	Indiana-Kentucky Power Company (IKEC)
32	Ohio Valley Electric Corp. (OVEC)	32	Ohio Valley Electric Corp. (OVEC)
34	Buckeye Power Company	34	Buckeye Power Company
40	Central Appalachian Coal Co. (CACCo)	40	Central Appalachian Coal Co. (CACCo)

AMERICAN ELECTRIC POWER COMPANY
COMPANY CODES USED FOR ALLOCATING 1997 BILLINGS AND SYNERGY SAVINGS

CO CODE	DESCRIPTION	CO NO.	COMPANY NAME
41	Central Coal Co. (CCCo / Sporn Mine)	41	Central Coal Co. (CCCo / Sporn Mine)
42	Central Ohio Coal Co. (COCCO / Muskingum Mine)	42	Central Ohio Coal Co. (COCCO / Muskingum Mine)
43	Windsor Coal Co. (WCCo)	43	Windsor Coal Co. (WCCo)
44	Southern Ohio Coal Co. (SOCCo / Meigs Division)	44	Southern Ohio Coal Co. (SOCCo / Meigs Division)
45	Southern Appalachian Coal Co. (SACCo)	45	Southern Appalachian Coal Co. (SACCo)
46	Cedar Coal Company	46	Cedar Coal Company
48	Water Transportation Division (RTD)	48	Water Transportation Division (RTD)
49	Cook Coal Terminal (CCT)	49	Cook Coal Terminal (CCT)
50	Price River Coal Co.	50	Price River Coal Co.
51	Blackhawk Coal Co.	51	Blackhawk Coal Co.
52	Simco, Inc.	52	Simco, Inc.
53	Colomet, Inc.	53	Colomet, Inc.
54	Conesville Coal Prep Co. (CCPC)	54	Conesville Coal Prep Co. (CCPC)
55	Southern Ohio Coal - Martinka Division	55	Southern Ohio Coal - Martinka Division
56	AEPR Project Management Company	56	AEPR Project Management Company
57	AEPR Australia Pty LTD	57	AEPR Australia Pty LTD
58	AEP Communications, Inc.	58	AEP Communications, Inc.
59	AEP Energy Services, Inc.	59	AEP Energy Services, Inc.
60	AEP Company, Inc.	60	AEP Company, Inc.
61	AEP Service Corp. (AEPSC)	61	AEP Service Corp. (AEPSC)
63	Franklin Real Estate Company	63	Franklin Real Estate Company
64	Indiana Franklin Realty, Inc.	64	Indiana Franklin Realty, Inc.
66	AEP Power Marketing, Inc.	66	AEP Power Marketing, Inc.
67	West Virginia Power Company	67	West Virginia Power Company

AMERICAN ELECTRIC POWER COMPANY
COMPANY CODES USED FOR ALLOCATING 1997 BILLINGS AND SYNERGY SAVINGS

CO CODE	DESCRIPTION	CO NO.	COMPANY NAME
69	AEPR Service Company	69	AEPR Service Company
70	Sporn Plant Joint Books	70	Sporn Plant Joint Books
71	Amos Plant Joint Books	71	Amos Plant Joint Books
72	AEP Investments, Inc.	72	AEP Investments, Inc.
73	Rockport Plant Joint Books	73	Rockport Plant Joint Books
74	AEP Resources, Inc.	74	AEP Resources, Inc.
75	Gavin Scrubber Project	75	Gavin Scrubber Project
76	Tidd Plant PFBC Project	76	Tidd Plant PFBC Project
77	Sporn Plant - OPCo Share	77	Sporn Plant - OPCo Share
78	Amos Plant - OPCo Share	78	Amos Plant - OPCo Share
81	AEP Pushan Power LDC	81	AEP Pushan Power LDC
83	AEPR Mauritius Company	83	AEPR Mauritius Company
84	Rockport - I&M Share	84	Rockport - I&M Share
85	Rockport - AEG Share	85	Rockport - AEG Share
86	AEPR Delaware, Inc.	86	AEPR Delaware, Inc.
87	Nanyang General Light Electric Co. LTD	87	Nanyang General Light Electric Co. LTD
88	AEPR Global Holland Holding BV	88	AEPR Global Holland Holding BV
89	AEPR Global Ventures BV	89	AEPR Global Ventures BV
90	AEPR Global Investments BV	90	AEPR Global Investments BV
91	AEP Communications, LLC	91	AEP Communications, LLC
95	AEP Communications (Billing Error)	95	AEP Communications (Billing Error)
98	Carolina Power & Light (CP&L)	98	Carolina Power & Light (CP&L)
99	Yorkshire	99	Yorkshire

AMERICAN ELECTRIC POWER COMPANY
COMPANY CODES USED FOR ALLOCATING 1997 BILLINGS AND SYNERGY SAVINGS

CO CODE	DESCRIPTION	CO NO.	COMPANY NAME
BB	Seeboard	SEE	Seeboard
CC	Central Power & Light (CPL)	CPL	Central Power & Light (CPL)
EE	CSW Energy	CSE	CSW Energy
HH	Enershop	DES	Enershop
II	CSW International	CSI	CSW International
JJ	Joint Fuels Project (JFP)	JFP	Joint Fuels Project (JFP)
KK	Transok	TOK	Transok
LL	CSW Leasing	DLL	CSW Leasing
MM	CSW Communications	DCM	CSW Communications
NN	Energy Services Inc. (Boston)	ESI	Energy Services Inc. (Boston)
OA	Energy Consulting SVCS	ECS	Energy Consulting SVCS
OB	External Lab Services	LAB	External Lab Services
OO	Power Marketing Inc.	PMI	Power Marketing Inc.
PP	Public Service of Oklahoma (PSO)	PSO	Public Service of Oklahoma (PSO)
RR	CSW Corporation	DCR	CSW Corporation
SS	Southwestern Electric Power Co (SWEPCO)	SEP	Southwestern Electric Power Co (SWEPCO)
TT	CSW Credit	DCT	CSW Credit
WW	West Texas Utilities (WTU)	WTU	West Texas Utilities (WTU)
XX	Off-System Billing (Old AEP NN)		Nonaffiliated
ZZ	CSW Services Support	DSV	CSW Services Support
NA	All 1997 AEP Companies	01	Kingsport Power Company (KgPCo)
		02	Appalachian Power Company (APCo)
		03	Kentucky Power Company (KPCO)
		04	Indiana Michigan Power Company (I&M)
		06	Wheeling Power Company (WPCo)
		07	Ohio Power Company (OPCo)
		10	Columbus Southern Power Company (CSP)

AMERICAN ELECTRIC POWER COMPANY
COMPANY CODES USED FOR ALLOCATING 1997 BILLINGS AND SYNERGY SAVINGS

CO CODE	DESCRIPTION	CO NO.	COMPANY NAME
		21	AEP Generating Company (AEG)
		22	Cardinal Operating Company
		23	Central Operating Company
		25	AEP Resources Int'l LTD
		26	AEP Resources LTD
		31	Indiana-Kentucky Power Company (IKEC)
		32	Ohio Valley Electric Corp. (OVEC)
		34	Buckeye Power Company
		40	Central Appalachian Coal Co. (CACCo)
		41	Central Coal Co. (CCCo / Sporn Mine)
		42	Central Ohio Coal Co. (COCCO / Muskingum Mine)
		43	Windsor Coal Co. (WCCo)
		44	Southern Ohio Coal Co. (SOCCo / Meigs Division)
		45	Southern Appalachian Coal Co. (SACCo)
		46	Cedar Coal Company
		48	Water Transportation Division (RTD)
		49	Cook Coal Terminal (CCT)
		50	Price River Coal Co.
		51	Blackhawk Coal Co.
		52	Simco, Inc.
		53	Colomet, Inc.
		54	Conesville Coal Prep Co. (CCPC)
		55	Southern Ohio Coal - Martinka Division
		56	AEPR Project Management Company
		57	AEPR Australia Pty LTD
		58	AEP Communications, Inc.
		59	AEP Energy Services, Inc.
		60	AEP Company, Inc.
		61	AEP Service Corp. (AEPSC)
		63	Franklin Real Estate Company
		64	Indiana Franklin Realty, Inc.
		66	AEP Power Marketing, Inc.
		67	West Virginia Power Company
		69	AEPR Service Company
		70	Sporn Plant Joint Books
		71	Amos Plant Joint Books
		72	AEP Investments, Inc.
		73	Rockport Plant Joint Books
		74	AEP Resources, Inc.
		76	Tidd Plant PFBC Project
		77	Sporn Plant - OPCo Share
		78	Amos Plant - OPCo Share
		81	AEP Pushan Power LDC
		83	AEPR Mauritius Company
		84	Rockport - I&M Share
		85	Rockport - AEG Share
		86	AEPR Delaware, Inc.

AMERICAN ELECTRIC POWER COMPANY
COMPANY CODES USED FOR ALLOCATING 1997 BILLINGS AND SYNERGY SAVINGS

CO CODE	DESCRIPTION	CO NO.	COMPANY NAME
		87	Nanyang General Light Electric Co. LTD
		88	AEPR Global Holland Holding BV
		89	AEPR Global Ventures BV
		90	AEPR Global Investments BV
		91	AEP Communications, LLC
		98	Carolina Power & Light (CP&L)
		99	Yorkshire
NR		25	AEP Resources Int'l LTD
		58	AEP Communications, Inc.
		59	AEP Energy Services, Inc.
		60	AEP Company, Inc.
		67	West Virginia Power Company
		69	AEPR Service Company
		74	AEP Resources, Inc.
		81	AEP Pushan Power LDC
		83	AEPR Mauritius Company
		86	AEPR Delaware, Inc.
		87	Nanyang General Light Electric Co. LTD
		91	AEP Communications, LLC
		CSE	CSW Energy
		CSI	CSW International
		DCM	CSW Communications
		DCR	CSW Corporation
		DCT	CSW Credit
		DES	Enershop
		SEE	Seeboard
RO		1	Kingsport Power Company (KgPCo)
		2	Appalachian Power Company (APCo)
		3	Kentucky Power Company (KPCO)
		4	Indiana Michigan Power Company (I&M)
		6	Wheeling Power Company (WPCo)
		7	Ohio Power Company (OPCo)
		10	Columbus Southern Power Company (CSP)
		42	Central Ohio Coal Co. (COCCO / Muskingum Mine)
		43	Windsor Coal Co. (WCCo)
		44	Southern Ohio Coal Co. (SOCCo / Meigs Division)
		48	Water Transportation Division (RTD)
		49	Cook Coal Terminal (CCT)
		54	Conesville Coal Prep Co. (CCPC)
		CPL	Central Power & Light (CPL)
		PSO	Public Service of Oklahoma (PSO)
		SEP	Southwestern Electric Power Co (SWEPCO)
		WTU	West Texas Utilities (WTU)

AEP Operating Companies Allocation Percentages

AEP operating companies further allocate the service company bill to other companies, affiliated and non-affiliated. The schedule below shows, the operating companies (with company codes) who further allocate the service company bill. In addition it shows what companies (with company codes) are allocated, and their percentage of the allocation.

This allocation is done outside of the service company billing. It is used to facilitate jurisdictional allocations.

Cardinal Operating Company (23)	to	Ohio Power (07)	.456%
		Buckeye Power (34)	.544%
Amos Plant (71)	to	Ohio Power (07)	.274%
		Appalachian Power (02)	.726%
Sporn Plant (70)	to	Ohio Power (07)	.723%
		Appalachian Power (02)	.277%
Rockport (73)	to	Indiana Michigan Power (04)	.550%
		Kentucky Power (03)	.236%
		Carolina Power (98)	.214%
Central Operating (23)	to	Ohio Power (07)	.723%
		Appalachian Power (02)	.277%
AEP Generating (21)	to	Indiana Michigan Power (04)	.100%
		Kentucky Power (03)	.472%
		Carolina Power (98)	.428%
Rockport (84) I&M Share	to	Indiana Michigan Power (04)	100%
Rockport (85) AEG Share	to	Indiana Michigan Power (04)	.100%
		Kentucky Power (03)	.472%
		Carolina Power (98)	.428%
Sporn Plant (77)-Ohio Power Share	to	Ohio Power (07)	100%
Amos Plant (78))-Ohio Power Share	to	Ohio Power (07)	100%

SYNERGIES SAVINGS CENTER CATEGORIES

All savings identified in the Synergies Analysis were assigned a center. The center corresponds with the savings category in the Synergies Analysis

Savings Category	Center
Labor	LABOR
A&G Overheads	ADMIN
Advertising/PR	ADVER
Association Dues	DUESM
Benefits	BENFT
Directors Fees	DIREC
Telcomm	TCOMM
Insurance	INSUR
Credit Facilities	CREDT
Information Services	INSYS
Professional Services Direct Regulated	PRSER
Professional Services Non-Regulated	PROFS
Research and Development	RESRH
Shareholder Services	SHARE
Facilities	FACIL
Procurement	PROCU
Inventory	INVEN
Contract Services	CONSV

WORK ORDER DESCRIPTIONS USED FOR SAVINGS

WORK ORDER	CO CODE	ALLOCATION FACTOR	DESCRIPTION
SERVICE COMPANY			
ACSAVABC	AA	TGRUTIPLNT	Accounting corporate performance savings
ACSAVCLO	AA	#GLTRANSAC	Accounting general ledger and corporate acctg savings
ACSAVOTH	AA	TFIXASSET$	Accounting other savings
ACSAVPRP	AA	TGRUTIPLNT	Accounting property accounting savings
ACSAVTAX	AB	TTLASSETS$	Accounting tax savings
AUSAVAUD	AX	TTLASSETS$	Accounting audit savings
CCSAVPUB	AA	#EMPLOYEES	Corporate Communications public relations savings
DSSAVENG	AA	#ELULTCUST	Distribution engineering and support savings
DSSAVOTH	AA	#ELULTCUST	Distribution other savings
ENSAVAFF	AA	TTPKLOADLY	Environmental affairs savings
EXSAVMGT	AA	TCSWSB-INT	Executive management savings
EXSAVSTF	AA	TCSWSB-INT	Executive management staff savings
FLSAVPRO	AA	MMBTUBRALL	Fuel management and procurement savings
GSSAVFAC	AA	REALLOCPAY	General Services facilities maintenance savings
GSSAVFLT	AA	#VEHICLESS	General Services fleet savings
GSSAVOFF	AB	#EMPLOYEES	General Services office savings
GSSAVOTH	AB	#EMPLOYEES	General Services other savings
GSSAVREA	AA	TFIXASSET$	General Services real estate savings
GSSAVREC	AB	#EMPLOYEES	General Services records management savings
GSSAVSEC	AA	TFIXASSET$	General Services security savings
HRSAVBEN	AB	#EMPLOYEES	Human Resources benefits savings
HRSAVCOM	AB	#EMPLOYEES	Human Resources compensation savings
HRSAVDEV	AB	#EMPLOYEES	Human Resources management development savings
HRSAVOPD	AB	#EMPLOYEES	Human Resources organizational planning and design savings
HRSAVOTH	AB	#EMPLOYEES	Human Resources other
HRSAVPAY	AB	#EMPLOYEES	Human Resources payroll processing savings
HRSAVREL	AB	#EMPLOYEES	Human Resources employee relations savings
HRSAVSAF	AB	#EMPLOYEES	Human Resources safety savings
HRSAVSTF	AB	#EMPLOYEES	Human Resources staffing savings
ISSAVCTR	AA	#WORKSTATN	Information Services end user/information center savings
ISSAVDAT	AB	#EMPLOYEES	Information Services data base admin. and security savings
ISSAVDEV	AA	#ELULTCUST	Information Services applications system development savings
ISSAVDPR	AB	#EMPLOYEES	Information Services computer operations savings
ISSAVOTH	AB	#EMPLOYEES	Information Services other
LGSAVATT	AB	TTLASSETS$	Legal attorneys savings
LGSAVSTF	AB	TTLASSETS$	Legal attorneys staff savings
MKSAVADV	AA	#ELULTCUST	Marketing advertising savings
MKSAVFOR	AA	#ELULTCUST	Marketing load and sales forecasting savings
MKSAVOTH	AA	TTLASSETS$	Marketing other savings
MKSAVPLN	AA	TTLASSETS$	Marketing product and sales planning savings
MKSAVRAT	AA	#ELULTCUST	Marketing load research in rates savings
MKSAVRES	AA	TTLASSETS$	Marketing market and customer research savings
MKSAVRRP	AA	#ELULTCUST	Marketing rates and regulatory affairs/pricing savings
PASAVBUD	AA	TTLASSETS$	Planning and Analysis budget savings
PSSAVENG	AA	MWGENCAPAC	Production engineering savings

WORK ORDER DESCRIPTIONS USED FOR SAVINGS

WORK ORDER	CO CODE	ALLOCATION FACTOR	DESCRIPTION
PSSAVOTH	AA	MWGENCAPAC	Production other savings
PSSAVPLT	AA	MWGENCAPAC	Production plant administration savings
PSSAVSUP	AA	MWGENCAPAC	Production engineering support savings
RDSAVRES	AA	TTPKLOADLY	Research and Development savings
RGSAVGOV	AB	TTLASSETS$	Regulatory governmental affairs savings
RMSAVRMT	AA	TFIXASSET$	Risk Management savings
SCSAVAPR	AA	#VENDINVPT	Supply Chain accounts payable and receivable savings
SCSAVBUY	AA	#POWRITTEN	Supply Chain buyers savings
SCSAVICP	AA	#ELULTCUST	Supply Chain inventory control and planning savings
SCSAVMAT	AA	#ELULTCUST	Supply Chain materials management administration savings
SCSAVPUR	AA	#POWRITTEN	Supply Chain purchasing management and administration savings
STSAVCPP	AA	TTLASSETS$	Strategic corporate planning
TCSAVTEL	AB	#EMPLOYEES	Telecommunications savings
TRSAVCAS	AL	#BANKACCTS	Treasury cash management savings
TRSAVFLP	AA	TFIXASSET$	Treasury financial planning savings
TRSAVINT	AA	TCSWSB-INT	Treasury credit line fee savings
TRSAVINV	AA	TCSWSB-INT	Treasury investor relations savings
TSSAVBUL	AA	TTPKLOADLY	Transmission bulk system planning savings
TSSAVENG	AA	TPOLEMILES	Transmission engineering and support savings
TSSAVOTH	AA	TPOLEMILES	Transmission other savings
TSSAVPOW	AA	TTPKLOADLY	Transmission power marketing and sales savings
NON-REGULATED DIRECT			
NREGBENE	NR	#EMPLOYEES	Non-Regulated Direct benefits savings
NREGCRDT	NR	CREDITLINE	Non-Regulated credit line fee savings
NREGDIRE	60	DIRECT	Non-Regulated Direct
NREGDIRE	RR	DIRECT	Non-Regulated Direct
NREGINSU	NR	TFIXASSET$	Non-Regulated Direct insurance savings
NREGPROF	NR	PROFSERVIC	Non-Regulated Direct professional services savings
REGULATED DIRECT			
REGUADUE	AA	#ELULTCUST	Regulated Direct dues savings
REGUBENE	RO	#NUMAWEMPL	Regulated Direct benefits savings
REGUCRDT	RO	CREDITLINE	Regulated Direct credit line fee savings
REGUINSU	RO	TFIXASSET$	Regulated Direct insurance savings
REGUPROF	RO	#EMPLOYEES	Regulated Direct professional services savings
REGUCAAC	AA	#ELULTCUST	Regulated Direct customer accounts savings
REGUCSER	AA	#ELULTCUST	Regulated Direct customer service savings
REGUSALE	AA	#ELULTCUST	Regulated Direct customer sales savings
REGUDIST	AA	#ELULTCUST	Regulated Direct distribution savings
REGUFUEL	AA	MMBTUBRALL	Regulated Direct fuel savings
REGUGENE	04	MWGENCAPAC	Regulated Direct generation savings
REGUGENE	AA	MWGENCAPAC	Regulated Direct generation savings
REGUGENE	CC	MWGENCAPAC	Regulated Direct generation savings
REGUTRAN	AA	TPOLEMILES	Regulated Direct transmission savings

PROPOSED ALLOCATION FACTORS FOR AEPSC

DESCRIPTION	CALCULATION
1 NUMBER OF BANK ACCOUNTS	$\frac{\text{Number of Bank Accounts Per Company}}{\text{Total Number of Bank Accounts}}$
2 NUMBER OF CALL CENTER TELEPHONES	$\frac{\text{Number of Call Center Telephones Per Company}}{\text{Total Number of Call Center Telephones}}$
3 NUMBER OF CELL PHONES / PAGERS	$\frac{\text{Number of Cell Phones and Pagers Per Company}}{\text{Total Number of Cell Phones and Pagers}}$
4 NUMBER OF CHECKS PRINTED	$\frac{\text{Number of Checks Printed Per Company Per Month}}{\text{Total Number of Checks Printed Per Month}}$
5 NUMBER OF CIS CUSTOMER MAILINGS	$\frac{\text{Number of CIS Customer Mailings Per Company}}{\text{Total Number of CIS Customer Mailings}}$
6 NUMBER OF COMMERCIAL CUSTOMERS	$\frac{\text{Number of Commercial Customers Per Company}}{\text{Total Number of Commercial Customers}}$
7 NUMBER OF CREDIT CARDS	$\frac{\text{Number of Corporate Credit Cards Per Company}}{\text{Total Number of Corporate Credit Cards}}$
8 NUMBER OF ELECTRIC RETAIL CUSTOMERS	$\frac{\text{Number of Electric Retail Customers Per Company}}{\text{Total Number of Electric Retail Customers}}$
9 NUMBER OF EMPLOYEES	$\frac{\text{Number of Full-Time and Part-Time Employees Per Company}}{\text{Total Number of Full-Time and Part-Time Employees}}$
10 NUMBER OF GENERATING PLANT EMPLOYEES	$\frac{\text{Number of Generating Plant Employees Per Company}}{\text{Total Number of Generating Plant Employees}}$
11 NUMBER OF GL TRANSACTIONS	$\frac{\text{Number of Lines of Accounting Distribution Per Company}}{\text{Total Number of Lines of Accounting Distribution}}$
12 NUMBER OF HELP DESK CALLS	$\frac{\text{Number of Help Desk Calls Per Company}}{\text{Total Number of Help Desk Calls}}$

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PROPOSED ALLOCATION FACTORS FOR AEPSC

DESCRIPTION	CALCULATION
13 NUMBER OF INDUSTRIAL CUSTOMERS	Number of Industrial Customers / Total Number of Industrial Customers
14 NUMBER OF JCA TRANSACTIONS	Number of Lines of Accounting Distribution on Job Cost Accounting Sub-System Per Company / Total Number of Lines of Accounting Distribution on Job Cost Accounting Sub-System
15 NUMBER OF NON-UMWA EMPLOYEES	Number of Non-UMWA Employees Per Company / Total Number of Non-UMWA Employees
16 NUMBER OF PHONE CENTER CALLS	Number of Phone Calls Per Phone Center Per Company / Total Number of Phone Center Phone Calls
17 NUMBER OF PURCHASE ORDERS WRITTEN	Number of Purchase Orders Written Per Company / Total Number of Purchase Orders Written
18 NUMBER OF RADIOS (BASE/MOBILE/HANDHELD)	Number of Radios (Base/Mobile/Handheld) Per Company / Total Number of Radios (Base/Mobile/Handheld)
19 NUMBER OF RAILCARS	Number of Rail Cars Per Company / Total Number of Rail Cars
20 NUMBER OF REMITTANCE ITEMS	Number of Electric Bill Payments Processed Per Company Per Month (non-lockbox) / Total Number of Electric Bill Payments Processed Per Company Per Month
21 NUMBER OF REMOTE TERMINAL UNITS	Number of Remote Terminal Units Per Company / Total Number of Remote Terminal Units
22 NUMBER OF RENTED WATER HEATERS	Number of Rented Water Heaters Per Company / Total Number of Rented Water Heaters
23 NUMBER OF RESIDENTIAL CUSTOMERS	Number of Residential Customers Per Company / Total Number of Residential Customers
24 NUMBER OF ROUTERS	Number of Routers Per Company / Total Number of Routers

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PROPOSED ALLOCATION FACTORS FOR AEPSC

DESCRIPTION	CALCULATION
25 NUMBER OF SERVERS	Number of Servers Per Company / Total Number of Servers
26 NUMBER OF STORES TRANSACTIONS	Number of Stores Transactions Per Company / Total Number of Stores Transactions
27 NUMBER OF TELEPHONES	Number of Telephones Per Company (Includes all phone lines) / Total Number of Telephones (includes all phone lines)
28 NUMBER OF TRANSMISSION POLE MILES	Number of Transmission Pole Miles Per Company / Total Number of Transmission Pole Miles
29 NUMBER OF TRANSTEXT CUSTOMERS	Number of Transtext Customers Per Company / Total Number of Transtext Customers
30 NUMBER OF TRAVEL TRANSACTIONS	Number of Travel Transactions Per Company Per Month / Total Number of Travel Transactions Per Month
31 NUMBER OF VEHICLES	Number of Vehicles Per Company (Includes Fleet and Pool Cars) / Total Number of Vehicles Per Company (Includes Fleet and Pool Cars)
32 NUMBER OF VENDOR INVOICE PAYMENTS	Number of Vendor Invoice Payments Per Company Per Month / Total Number of Vendor Invoice Payments Per Month
33 NUMBER OF WORKSTATIONS	Number of Personal Computers Per Company / Total Number of Personal Computers
34 ACTIVE OWNED OR LEASED COMMUNICATION CHANNELS	Number of Active Owned Or Leased Communication Channels Per Company / Total Number of Active Owned Or Leased Communication Channels
35 AVG PEAK LOAD FOR PAST THREE YEARS	Average Peak Load for Past Three Years Per Company / Total of Average Peak Load for Past Three Years
36 COAL PLANT COMBINATION	The Sum of Each Coal Company's Gross Payroll, Original Cost of Fixed Assets Original Cost of Leased Assets, and Gross Revenues for Last Twelve Months / The Sum of the Same Factors for All Coal Companies

EXHIBIT GRK-1
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PROPOSED ALLOCATION FACTORS FOR AEPSC

DESCRIPTION	CALCULATION
37 AEPSC PAST 3 MONTHS TOTAL BILL DOLLARS	AEPSC Total Billed Amount for Past Three Months Per Company Total AEPSC Total Billed Amount for Past Three Months
38 AEPSC PRIOR MONTH TOTAL BILL DOLLARS	AEPSC Total Billed Amount for Prior Month Per Company AEPSC Total Billed Amount for Prior Month
39 DIRECT	100% to One Company
40 EQUAL SHARE RATIO	One (1) Total Number of Companies
41 FOSSIL PLANT COMBINATION	The Sum of (1) the Percentage Derived by Dividing the Total Megawatt Capability of All Fossil Generating Plants of Each Generating Company by the Total Megawatt Capability of All Fossil Plants Generating Plants of All Generating Companies (2) the Percentage Derived by Dividing the Total Scheduled Maintenance Outages of All Fossil Generating Plants of Each Generating Company For the Last Three Years by the Total Scheduled Maintenance of All Fossil Generating Plants at all Generating Companies During the Same Three Years Two (2)
42 FUNCTIONAL DEPARTMENT'S PAST 3 MONTHS TOTAL BILL DOLLARS	AEPSC Billed Amount for Past Three Months by Functional Category Per Company Total AEPSC Billed Amount for Past Three Months by Functional Category
43 KWH SALES	Number of KWH Sales Per Company Total Number of KWH Sales
44 LEVEL OF CONSTRUCTION – DISTRIBUTION	Construction Expenditures for All Distribution Plant Accounts Except Land and Land Rights, Services, Meters and Leased Property on Customers Premises, and Exclusive of Construction Expenditures Accumulated on Direct Work Orders for Which Charges by AEPSC Are Being Made Separately, for Each Operating Company During the Last Twelve Months The Sum of the Same Factors for All Companies
45 LEVEL OF CONSTRUCTION – PRODUCTION	Construction Expenditures for All Production Plant Accounts Except Land and Land Rights, Nuclear Accounts, and Exclusive of Construction Expenditures Accumulated on Direct Work Orders for Which Charges by AEPSC are Being Made Separately, for Each Operating Company During the Last Twelve Months The Sum of the Same Factors for All Companies

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PROPOSED ALLOCATION FACTORS FOR AEPSC

DESCRIPTION	CALCULATION
46 LEVEL OF CONSTRUCTION- TRANSMISSION	<u>Construction Expenditures for All Transmission Plant Accounts Except Land and Land Rights and Exclusive of Construction Expenditures Accumulated on Direct Work Orders for Which Charges by AEPSC are Being Made Separately, for Each Operating Company During the Last Twelve Months</u> The Sum of the Same Factors for All Companies
47 LEVEL OF CONSTRUCTION-TOTAL	<u>Construction Expenditures for ALL Plant Accounts Except Land and Land Rights, Line Transformers Services, Meters and Leased Property on Customers' Premises; and the Following General Plant Accounts: Structures and Improvements, Shop Equipment, Laboratory Equipment and Communication Equipment; And Exclusive of Construction Expenditures Accumulated on Direct Work Orders for Which Charges by AEPSC are Being Made Separately, for Each Operating Company During the Last Twelve Months</u> The Sum of the Same Factors for All Companies
48 MW GENERATING CAPABILITY	<u>Number of MWH Generation Capacity Per Company</u> Total Number of MWH Generation Capacity
49 MWH 'S GENERATION	<u>Number of MWH Generation Per Company</u> Total Number of MWH Generation
50 OVERHEAD CLEARING	<u>Budgeted AEPSC Payroll Dollars Billed Per Company</u> Total AEPSC Payroll Dollars Billed
51 PAST 3 MO. MMBTU'S BURNED(ALL FUEL TYPES)	<u>Past Three Months MMBTU's Burned Per Company (All Fuel Types)</u> Total Number of MMBTU's Burned for Past Three Months (All Fuel Types)
52 PAST 3 MO. MMBTU'S BURNED(COAL ONLY)	<u>Past Three Months MMBTU's Burned Per Company (Coal Only)</u> Total Number of MMBTU's Burned for Past Three Months (Coal Only)
53 PAST 3 MO. MMBTU'S BURNED(GAS TYPE ONLY)	<u>Past Three Months MMBTU's Burned Per Company (Gas Type Only)</u> Total Number of MMBTU's Burned for Past Three Months (Gas Type Only)
54 PAST 3 MO. MMBTU'S BURNED(OIL TYPE ONLY)	<u>Past Three Months MMBTU's Burned Per Company (Oil Type Only)</u> Total Number of MMBTU's Burned for Past Three Months (Oil Type Only)
55 PAST 3 MO. MMBTU'S BURNED(SOLID FUELS ONLY)	<u>Past Three Months MMBTU's Burned Per Company (Solid Fuels Only)</u> Total Number of MMBTU's Burned for Past Three Months (Solid Fuels Only)

EXHIBIT GRK-1
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PROPOSED ALLOCATION FACTORS FOR AEPSC

DESCRIPTION	CALCULATION
56 PEAK LOAD/AVG # CUST/KWH SALES	Average of Peak Load, # of Retail Customers, and KWH Sales to Retail Customers Per Company / Total of Average of Peak Load, # of Retail Customers, and KWH Sales to Retail Customers
57 TONS OF FUEL ACQUIRED	Number of Tons of Fuel Acquired Per Company / Total Number of Tons of Fuel Acquired
58 TOTAL ASSETS	Total Asset Amount Per Company / Total Asset Amount
59 TOTAL ASSETS LESS NUCLEAR PLANT	Total Asset Dollars Less Nuclear Per Company / Total Asset Dollars Less Nuclear
60 TOTAL AEPSC BILLING LESS INDIRECT COST & INTEREST	Total Billing Amount Less Indirect Cost and Interest Per Company / Total Billing Amount Less Indirect Cost and Interest
61 TOTAL FIXED ASSET	Total of Fixed Asset Amount Per Company / Total of Fixed Asset Amount
62 TOTAL GROSS REVENUE	Total Gross Revenue Previous Four Quarters Per Company / Total Gross Revenue Previous Four Quarters
63 TOTAL GROSS UTILITY PLANT(INCLUDES CWIP)	Gross Utility Plant Amount Per Company / Total Gross Utility Plant Amount
64 TOTAL PEAK LOAD (PRIOR YEAR)	Total Peak Load for Prior Year Per Company / Total Peak Load for Prior Year

EXHIBIT GRK-1
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AEP/CSW
ALLOCATION FACTORS USED IN ALLOCATIONS

ALLOCATION FACTOR	DESCRIPTION OF ALLOCATION FACTOR
#BANKACCTS	NUMBER OF BANK ACCOUNTS
#CELLPHONE	NUMBER OF CELL PHONES / PAGERS
#CKSPRINTD	NUMBER OF CHECKS PRINTED
#ELULTCUST	NUMBER OF ELECTRIC ULTIMATE CUSTOMERS
#EMPLOYEES	NUMBER OF EMPLOYEES
#GENPLTEMP	NUMBER OF GENERATING PLANT EMPLOYEES
#GLTRANSAC	NUMBER OF GENERAL LEDGER TRANSACTIONS
#NUMAWEMPL	NUMBER OF NON-UMAW EMPLOYEES
#OFROUTERS	NUMBER OF ROUTERS
#OFSERVERS	NUMBER OF SERVERS
#POWRITTEN	NUMBER OF PURCHASE ORDERS WRITTEN
#RADIOSMOB	NUMBER OF RADIOS (BASE/MOBILE/HANDHELD)
#RAILCARSS	NUMBER OF RAILCARS
#REMOTTERM	NUMBER OF REMOTE TERMINAL UNITS
#RENTHEATR	NUMBER OF RENTED WATER HEATERS
#TELEPHONE	NUMBER OF TELEPHONES
#TRANSTEXT	NUMBER OF TRANSTEXT CUSTOMERS
#TRAVELTRN	NUMBER OF TRAVEL TRANSACTIONS
#VEHICLESS	NUMBER OF VEHICLES
#VENDINVPT	NUMBER OF VENDOR INVOICE PAYMENTS
#WORKSTATN	NUMBER OF WORKSTATIONS
'AC'3MBILL	'AC' FUNCTION PAST 3 MONTHS TOTAL BILLING DOLLARS
ALCOMMCHAN	ACTIVE OWNED OR LEASED COMMUNICATION CHANNELS
'AU'3MBILL	'AU' FUNCTION PAST 3 MONTHS TOTAL BILLING DOLLARS
AVGPKLD3YR	AVERAGE PEAK LOAD FOR PAST THREE YEARS
COALCOMBIN	COAL COMBINATION
CSWS3MBILL	CSWS PAST 3 MONTHS TOTAL BILLING DOLLARS
CSWSPMBILL	CSWS PRIOR MONTH TOTAL BILLING DOLLARS
DLVLCONSTR	DISTRIBUTION LEVEL OF CONSTRUCTION
'DS'3MBILL	'DS' FUNCTION PAST 3 MONTHS TOTAL BILLING DOLLARS
'EN'3MBILL	'EN' FUNCTION PAST 3 MONTHS TOTAL BILLING DOLLARS
EVENSPREAD	EVEN SPREAD BY COMPANY
'EX'3MBILL	'EX' FUNCTION PAST 3 MONTHS TOTAL BILLING DOLLARS
FLVLCONSTR	FOSSIL LEVEL OF CONSTRUCTION
FOSPLCOMBI	FOSSIL PLANT COMBINATION
'GS'3MBILL	'GS' FUNCTION PAST 3 MONTHS TOTAL BILLING DOLLARS
'HR'3MBILL	'HR' FUNCTION PAST 3 MONTHS TOTAL BILLING DOLLARS
'IS'3MBILL	'IS' FUNCTION PAST 3 MONTHS TOTAL BILLING DOLLARS
'LG'3MBILL	'LG' FUNCTION PAST 3 MONTHS TOTAL BILLING DOLLARS
'MA'3MBILL	'MA' FUNCTION PAST 3 MONTHS TOTAL BILLING DOLLARS
'MK'3MBILL	'MK' FUNCTION PAST 3 MONTHS TOTAL BILLING DOLLARS
MMBTUBRALL	PAST 3 MONTHS MMBTU'S BURNED (ALL FUEL TYPES)
MMBTUBRCOA	PAST 3 MONTHS MMBTU'S BURNED (COAL ONLY)
MMBTUBRGAS	PAST 3 MONTHS MMBTU'S BURNED (GAS TYPE ONLY)
MWGENCAPAC	MW GENERATING CAPACITY
MWHGENERAT	MWH'S GENERATION

AEP/CSW
ALLOCATION FACTORS USED IN ALLOCATIONS

ALLOCATION FACTOR	DESCRIPTION OF ALLOCATION FACTOR
'NU'3MBILL	'NU' FUNCTION PAST 3 MONTHS TOTAL BILLING DOLLARS
OVERHEADCR	OVERHEAD CLEARING
OWNEDCAPAC	OWNED GENERATING CAPACITY
'PS'3MBILL	'PS' FUNCTION PAST 3 MONTHS TOTAL BILLING DOLLARS
'RG'3MBILL	'RG' FUNCTION PAST 3 MONTHS TOTAL BILLING DOLLARS
'SC'3MBILL	'SC' FUNCTION PAST 3 MONTHS TOTAL BILLING DOLLARS
TCSWSB-INT	TOTAL CSWS BILLING LESS INDIRECT COST AND INTEREST
TFIXASSET$	TOTAL FIXED ASSET DOLLARS
TGRUTIPLNT	TOTAL GROSS UTILITY PLANT (INCLUDES CWIP)
TLGROSSREV	TOTAL GROSS REVENUE
TLVLCONSTR	TRANSMISSION LEVEL OF CONSTRUCTION
TPOLEMILES	TRANSMISSION POLE MILES
'TS'3MBILL	'TS' FUNCTION PAST 3 MONTHS TOTAL BILLING DOLLARS
TTLASSETS$	TOTAL ASSET DOLLARS
TTPKLOADLY	TOTAL PEAK LOAD (PRIOR YEAR)

AEP/CSW
VOLUMES UTILIZED IN ALLOCATION OF SAVINGS AND REALLOCATION OF SERVICE CORP BILLING

ALLOCATION FACTOR	COMPANY	VOLUME
VOLUMES DERIVED FOR REALLOCATION OF SERVICE CORP BILLING		
#BANKACCTS	CPL	28
#BANKACCTS	CSE	12
#BANKACCTS	CSI	11
#BANKACCTS	DCM	5
#BANKACCTS	DCR	11
#BANKACCTS	DCT	3
#BANKACCTS	DES	2
#BANKACCTS	DSV	6
#BANKACCTS	ESI	2
#BANKACCTS	PSO	54
#BANKACCTS	SEE	4
#BANKACCTS	SEP	121
#BANKACCTS	WTU	72
#BANKACCTS	1	6
#BANKACCTS	2	23
#BANKACCTS	3	12
#BANKACCTS	4	17
#BANKACCTS	6	6
#BANKACCTS	7	30
#BANKACCTS	10	14
#BANKACCTS	34	2
#BANKACCTS	42	4
#BANKACCTS	43	4
#BANKACCTS	44	4
#BANKACCTS	53	1
#BANKACCTS	54	4
#BANKACCTS	56	2
#BANKACCTS	57	2
#BANKACCTS	58	2
#BANKACCTS	59	3
#BANKACCTS	60	2
#BANKACCTS	61	3
#BANKACCTS	63	1
#BANKACCTS	64	1
#BANKACCTS	66	1
#BANKACCTS	67	2
#BANKACCTS	69	3
#BANKACCTS	72	2
#BANKACCTS	74	8
#BANKACCTS	81	1
#BANKACCTS	83	1
#BANKACCTS	86	1
#BANKACCTS	87	1
#BANKACCTS	91	2
#BANKACCTS	98	1

AEP/CSW
VOLUMES UTILIZED IN ALLOCATION OF SAVINGS
AND REALLOCATION OF SERVICE CORP BILLING

ALLOCATION FACTOR	COMPANY	VOLUME
#CELLPHONE	CPL	1,071
#CELLPHONE	CSE	14
#CELLPHONE	DCM	38
#CELLPHONE	DSV	704
#CELLPHONE	ESI	5
#CELLPHONE	PSO	1,555
#CELLPHONE	SEP	1,372
#CELLPHONE	WTU	256
#CELLPHONE	1	35
#CELLPHONE	2	1,020
#CELLPHONE	3	630
#CELLPHONE	4	873
#CELLPHONE	6	18
#CELLPHONE	7	751
#CELLPHONE	10	585
#CELLPHONE	42	4
#CELLPHONE	43	11
#CELLPHONE	44	10
#CELLPHONE	48	21
#CELLPHONE	49	13
#CELLPHONE	54	1
#CELLPHONE	61	714
#CKSPRINTD	CPL	29,457
#CKSPRINTD	CSE	1,988
#CKSPRINTD	DCM	1,503
#CKSPRINTD	DES	545
#CKSPRINTD	DSV	12,300
#CKSPRINTD	PSO	21,174
#CKSPRINTD	SEP	17,863
#CKSPRINTD	WTU	14,505
#ELULTCUST	CPL	616,700
#ELULTCUST	PSO	475,800
#ELULTCUST	SEP	411,300
#ELULTCUST	WTU	186,300
#ELULTCUST	1	43,169
#ELULTCUST	2	873,619
#ELULTCUST	3	167,921
#ELULTCUST	4	545,026
#ELULTCUST	6	41,554
#ELULTCUST	7	676,092
#ELULTCUST	10	617,373
#EMPLOYEES	CPL	1,718
#EMPLOYEES	CSE	108
#EMPLOYEES	DCM	60
#EMPLOYEES	DES	29
#EMPLOYEES	DSV	1,429

AEP/CSW
VOLUMES UTILIZED IN ALLOCATION OF SAVINGS
AND REALLOCATION OF SERVICE CORP BILLING

ALLOCATION FACTOR	COMPANY	VOLUME
#EMPLOYEES	ESI	18
#EMPLOYEES	PSO	1,312
#EMPLOYEES	SEE	4,100
#EMPLOYEES	SEP	1,567
#EMPLOYEES	WTU	933
#EMPLOYEES	1	85
#EMPLOYEES	2	3,831
#EMPLOYEES	3	809
#EMPLOYEES	4	2,907
#EMPLOYEES	6	94
#EMPLOYEES	7	3,009
#EMPLOYEES	10	1,795
#EMPLOYEES	34	174
#EMPLOYEES	42	221
#EMPLOYEES	43	251
#EMPLOYEES	44	827
#EMPLOYEES	48	279
#EMPLOYEES	49	53
#EMPLOYEES	54	40
#EMPLOYEES	61	3,523
#EMPLOYEES	69	9
#EMPLOYEES	98	68
#GENPLTEMP	CPL	351
#GENPLTEMP	PSO	261
#GENPLTEMP	SEP	417
#GENPLTEMP	WTU	236
#GENPLTEMP	2	1,236
#GENPLTEMP	3	252
#GENPLTEMP	4	1,512
#GENPLTEMP	7	1,310
#GENPLTEMP	10	423
#GENPLTEMP	34	174
#GENPLTEMP	61	695
#GENPLTEMP	98	68
#GLTRANSAC	CPL	462,214
#GLTRANSAC	DCM	3,074
#GLTRANSAC	DCR	648
#GLTRANSAC	DCT	506
#GLTRANSAC	DLL	77
#GLTRANSAC	DSV	31,750
#GLTRANSAC	ESI	383
#GLTRANSAC	PSO	254,555
#GLTRANSAC	SEP	441,938
#GLTRANSAC	WTU	181,330
#GLTRANSAC	1	853
#GLTRANSAC	2	500,000

AEP/CSW
VOLUMES UTILIZED IN ALLOCATION OF SAVINGS
AND REALLOCATION OF SERVICE CORP BILLING

ALLOCATION FACTOR	COMPANY	VOLUME
#GLTRANSAC	3	100,000
#GLTRANSAC	4	500,000
#GLTRANSAC	6	1,000
#GLTRANSAC	7	684,280
#GLTRANSAC	10	459,150
#GLTRANSAC	25	68
#GLTRANSAC	26	7
#GLTRANSAC	42	545
#GLTRANSAC	43	531
#GLTRANSAC	44	803
#GLTRANSAC	48	501
#GLTRANSAC	49	273
#GLTRANSAC	54	318
#GLTRANSAC	56	17
#GLTRANSAC	57	12
#GLTRANSAC	58	186
#GLTRANSAC	59	220
#GLTRANSAC	60	134
#GLTRANSAC	61	49,968
#GLTRANSAC	63	36
#GLTRANSAC	64	35
#GLTRANSAC	69	664
#GLTRANSAC	72	22
#GLTRANSAC	74	552
#GLTRANSAC	81	62
#GLTRANSAC	83	9
#GLTRANSAC	86	17
#GLTRANSAC	91	4
#GLTRANSAC	98	160
#NUMAWEMPL	CPL	1,718
#NUMAWEMPL	CSE	108
#NUMAWEMPL	DCM	60
#NUMAWEMPL	DES	29
#NUMAWEMPL	DSV	1,429
#NUMAWEMPL	ESI	18
#NUMAWEMPL	PSO	1,312
#NUMAWEMPL	SEE	4,100
#NUMAWEMPL	SEP	1,567
#NUMAWEMPL	WTU	933
#NUMAWEMPL	1	85
#NUMAWEMPL	2	3,831
#NUMAWEMPL	3	809
#NUMAWEMPL	4	2,907
#NUMAWEMPL	6	94
#NUMAWEMPL	7	3,009
#NUMAWEMPL	10	1,795

AEP/CSW
VOLUMES UTILIZED IN ALLOCATION OF SAVINGS
AND REALLOCATION OF SERVICE CORP BILLING

ALLOCATION FACTOR	COMPANY	VOLUME
#NUMAWEMPL	34	174
#NUMAWEMPL	42	46
#NUMAWEMPL	43	40
#NUMAWEMPL	44	184
#NUMAWEMPL	48	106
#NUMAWEMPL	49	-
#NUMAWEMPL	54	13
#NUMAWEMPL	61	3,523
#NUMAWEMPL	69	9
#NUMAWEMPL	98	68
#OFROUTERS	CPL	80
#OFROUTERS	DCM	65
#OFROUTERS	PSO	20
#OFROUTERS	SEP	43
#OFROUTERS	WTU	55
#OFROUTERS	1	1
#OFROUTERS	2	118
#OFROUTERS	3	14
#OFROUTERS	4	49
#OFROUTERS	6	1
#OFROUTERS	7	53
#OFROUTERS	10	61
#OFROUTERS	61	25
#OFSERVERS	CPL	52
#OFSERVERS	DSV	44
#OFSERVERS	PSO	8
#OFSERVERS	SEP	28
#OFSERVERS	WTU	39
#OFSERVERS	1	6
#OFSERVERS	2	146
#OFSERVERS	3	34
#OFSERVERS	4	72
#OFSERVERS	6	6
#OFSERVERS	7	70
#OFSERVERS	10	40
#OFSERVERS	32	7
#OFSERVERS	61	324
#POWRITTEN	CPL	6,194
#POWRITTEN	CSE	79
#POWRITTEN	DCM	56
#POWRITTEN	DSV	314
#POWRITTEN	PSO	5,350
#POWRITTEN	SEP	8,672
#POWRITTEN	WTU	9,416
#POWRITTEN	1	920
#POWRITTEN	2	34,242

AEP/CSW
VOLUMES UTILIZED IN ALLOCATION OF SAVINGS
AND REALLOCATION OF SERVICE CORP BILLING

ALLOCATION FACTOR	COMPANY	VOLUME
#POWRITTEN	3	7,018
#POWRITTEN	4	19,258
#POWRITTEN	6	199
#POWRITTEN	7	38,011
#POWRITTEN	10	8,922
#POWRITTEN	34	2,104
#POWRITTEN	42	5,110
#POWRITTEN	43	6,662
#POWRITTEN	44	16,279
#POWRITTEN	48	2,668
#POWRITTEN	49	1,302
#POWRITTEN	54	1,105
#POWRITTEN	58	5
#POWRITTEN	59	1
#POWRITTEN	61	4,157
#POWRITTEN	69	23
#POWRITTEN	74	2
#POWRITTEN	98	945
#RADIOSMOB	CPL	1,202
#RADIOSMOB	PSO	1,271
#RADIOSMOB	SEP	1,570
#RADIOSMOB	WTU	683
#RADIOSMOB	1	14
#RADIOSMOB	2	1,836
#RADIOSMOB	3	335
#RADIOSMOB	4	937
#RADIOSMOB	6	103
#RADIOSMOB	7	1,204
#RADIOSMOB	10	1,085
#RADIOSMOB	42	245
#RADIOSMOB	43	31
#RADIOSMOB	44	137
#RADIOSMOB	48	101
#RADIOSMOB	49	47
#RADIOSMOB	54	21
#RADIOSMOB	61	139
#RAILCARSS	CPL	480
#RAILCARSS	PSO	754
#RAILCARSS	SEP	1,823
#RAILCARSS	2	326
#RAILCARSS	4	2,340
#RAILCARSS	7	794
#REMOTTERM	CPL	210
#REMOTTERM	PSO	153
#REMOTTERM	SEP	159
#REMOTTERM	WTU	125

AEP/CSW
VOLUMES UTILIZED IN ALLOCATION OF SAVINGS
AND REALLOCATION OF SERVICE CORP BILLING

ALLOCATION FACTOR	COMPANY	VOLUME
#REMOTTERM	1	14
#REMOTTERM	2	330
#REMOTTERM	3	43
#REMOTTERM	4	138
#REMOTTERM	6	5
#REMOTTERM	7	147
#REMOTTERM	10	89
#RENTHEATR	1	2
#RENTHEATR	2	31
#RENTHEATR	3	20
#RENTHEATR	4	15,541
#RENTHEATR	6	4,485
#RENTHEATR	7	52,037
#RENTHEATR	10	14,462
#TELEPHONE	CPL	2,187
#TELEPHONE	CSE	66
#TELEPHONE	DCM	75
#TELEPHONE	DES	14
#TELEPHONE	DSV	1,962
#TELEPHONE	ESI	23
#TELEPHONE	PSO	1,940
#TELEPHONE	SEP	1,706
#TELEPHONE	WTU	1,162
#TELEPHONE	1	130
#TELEPHONE	2	4,330
#TELEPHONE	3	1,280
#TELEPHONE	4	4,500
#TELEPHONE	6	200
#TELEPHONE	7	3,540
#TELEPHONE	10	1,860
#TELEPHONE	42	75
#TELEPHONE	43	50
#TELEPHONE	44	512
#TELEPHONE	48	56
#TELEPHONE	49	40
#TELEPHONE	54	13
#TELEPHONE	61	7,367
#TRANSTEXT	1	1,300
#TRANSTEXT	2	0,000
#TRANSTEXT	3	1,850
#TRANSTEXT	4	1,550
#TRANSTEXT	7	2,500
#TRANSTEXT	10	4,100
#VEHICLESS	CPL	762
#VEHICLESS	PSO	705
#VEHICLESS	SEP	596

AEP/CSW
VOLUMES UTILIZED IN ALLOCATION OF SAVINGS
AND REALLOCATION OF SERVICE CORP BILLING

ALLOCATION FACTOR	COMPANY	VOLUME
#VEHICLESS	WTU	378
#VEHICLESS	1	57
#VEHICLESS	2	2,039
#VEHICLESS	3	467
#VEHICLESS	4	1,237
#VEHICLESS	6	69
#VEHICLESS	7	1,576
#VEHICLESS	10	967
#VEHICLESS	42	118
#VEHICLESS	43	14
#VEHICLESS	44	79
#VEHICLESS	54	8
#VEHICLESS	61	548
#VENDINVPT	CPL	103,891
#VENDINVPT	DCM	189
#VENDINVPT	DES	135
#VENDINVPT	DSV	49,464
#VENDINVPT	ESI	50
#VENDINVPT	PSO	68,690
#VENDINVPT	SEP	68,101
#VENDINVPT	WTU	53,994
#VENDINVPT	1	5,561
#VENDINVPT	2	141,991
#VENDINVPT	3	41,187
#VENDINVPT	4	105,509
#VENDINVPT	6	4,949
#VENDINVPT	7	137,158
#VENDINVPT	10	68,696
#VENDINVPT	25	81
#VENDINVPT	34	6,721
#VENDINVPT	42	15,191
#VENDINVPT	43	17,524
#VENDINVPT	44	44,015
#VENDINVPT	48	10,194
#VENDINVPT	49	3,752
#VENDINVPT	54	3,123
#VENDINVPT	56	28
#VENDINVPT	58	528
#VENDINVPT	59	628
#VENDINVPT	60	893
#VENDINVPT	61	54,128
#VENDINVPT	63	224
#VENDINVPT	64	119
#VENDINVPT	69	1,487
#VENDINVPT	72	27
#VENDINVPT	74	784

AEP/CSW
VOLUMES UTILIZED IN ALLOCATION OF SAVINGS
AND REALLOCATION OF SERVICE CORP BILLING

ALLOCATION FACTOR	COMPANY	VOLUME
#VENDINVPT	81	37
#VENDINVPT	91	93
#VENDINVPT	98	2,643
#WORKSTATN	CPL	3,234
#WORKSTATN	CSE	58
#WORKSTATN	DCM	45
#WORKSTATN	DES	5
#WORKSTATN	DSV	3,074
#WORKSTATN	ESI	18
#WORKSTATN	PSO	1,638
#WORKSTATN	SEP	1,794
#WORKSTATN	WTU	800
#WORKSTATN	1	50
#WORKSTATN	2	2,500
#WORKSTATN	3	550
#WORKSTATN	4	2,600
#WORKSTATN	6	50
#WORKSTATN	7	1,400
#WORKSTATN	10	600
#WORKSTATN	61	3,200
ALCOMMCHAN	CPL	1,488
ALCOMMCHAN	CSE	12
ALCOMMCHAN	DCM	24
ALCOMMCHAN	DES	12
ALCOMMCHAN	DSV	199
ALCOMMCHAN	PSO	1,296
ALCOMMCHAN	SEE	12
ALCOMMCHAN	SEP	1,248
ALCOMMCHAN	WTU	768
ALCOMMCHAN	1	42
ALCOMMCHAN	2	5,711
ALCOMMCHAN	3	2,170
ALCOMMCHAN	4	1,683
ALCOMMCHAN	6	73
ALCOMMCHAN	7	2,851
ALCOMMCHAN	10	1,214
ALCOMMCHAN	58	9,408
ALCOMMCHAN	61	2,792
AVGPKLD3YR	CPL	3,880
AVGPKLD3YR	PSO	3,273
AVGPKLD3YR	SEP	3,844
AVGPKLD3YR	WTU	1,377
AVGPKLD3YR	1	296
AVGPKLD3YR	2	6,757
AVGPKLD3YR	3	1,399
AVGPKLD3YR	4	3,890

AEP/CSW
VOLUMES UTILIZED IN ALLOCATION OF SAVINGS
AND REALLOCATION OF SERVICE CORP BILLING

ALLOCATION FACTOR	COMPANY	VOLUME
AVGPKLD3YR	6	427
AVGPKLD3YR	7	5,569
AVGPKLD3YR	10	3,356
COALCOMBIN	42	183,077,870
COALCOMBIN	43	146,098,971
COALCOMBIN	44	751,835,107
COALCOMBIN	54	47,997,384
DLVLCONSTR	1	1,640,759
DLVLCONSTR	2	91,378,762
DLVLCONSTR	3	20,444,276
DLVLCONSTR	4	38,281,991
DLVLCONSTR	6	2,120,547
DLVLCONSTR	7	32,127,102
DLVLCONSTR	10	46,213,516
EVENSPREAD	CPL	1
EVENSPREAD	CSE	1
EVENSPREAD	CSI	1
EVENSPREAD	DCM	1
EVENSPREAD	DCR	1
EVENSPREAD	DCT	1
EVENSPREAD	DES	1
EVENSPREAD	DLL	1
EVENSPREAD	DSV	1
EVENSPREAD	ECS	1
EVENSPREAD	ESI	1
EVENSPREAD	JFP	1
EVENSPREAD	LAB	1
EVENSPREAD	PMI	1
EVENSPREAD	PSO	1
EVENSPREAD	SEE	1
EVENSPREAD	SEP	1
EVENSPREAD	TOK	1
EVENSPREAD	WTU	1
EVENSPREAD	1	1
EVENSPREAD	2	1
EVENSPREAD	3	1
EVENSPREAD	4	1
EVENSPREAD	5	1
EVENSPREAD	6	1
EVENSPREAD	7	1
EVENSPREAD	10	1
EVENSPREAD	21	1
EVENSPREAD	22	1
EVENSPREAD	23	1
EVENSPREAD	24	1
EVENSPREAD	25	1

AEP/CSW
VOLUMES UTILIZED IN ALLOCATION OF SAVINGS
AND REALLOCATION OF SERVICE CORP BILLING

ALLOCATION FACTOR	COMPANY	VOLUME
EVENSPREAD	26	1
EVENSPREAD	31	1
EVENSPREAD	32	1
EVENSPREAD	34	1
EVENSPREAD	42	1
EVENSPREAD	43	1
EVENSPREAD	44	1
EVENSPREAD	48	1
EVENSPREAD	49	1
EVENSPREAD	54	1
EVENSPREAD	56	1
EVENSPREAD	57	1
EVENSPREAD	58	1
EVENSPREAD	59	1
EVENSPREAD	60	1
EVENSPREAD	61	1
EVENSPREAD	66	1
EVENSPREAD	67	1
EVENSPREAD	69	1
EVENSPREAD	70	1
EVENSPREAD	71	1
EVENSPREAD	72	1
EVENSPREAD	73	1
EVENSPREAD	74	1
EVENSPREAD	76	1
EVENSPREAD	77	1
EVENSPREAD	78	1
EVENSPREAD	81	1
EVENSPREAD	83	1
EVENSPREAD	84	1
EVENSPREAD	85	1
EVENSPREAD	86	1
EVENSPREAD	87	1
EVENSPREAD	88	1
EVENSPREAD	89	1
EVENSPREAD	90	1
EVENSPREAD	91	1
EVENSPREAD	98	1
EVENSPREAD	99	1
FLVLCONSTR	2	43,799,753
FLVLCONSTR	3	22,757,446
FLVLCONSTR	4	14,357,555
FLVLCONSTR	7	41,058,896
FLVLCONSTR	10	23,542,788
FLVLCONSTR	98	1,014,836
FOSPLCOMBI	2	26

AEP/CSW
VOLUMES UTILIZED IN ALLOCATION OF SAVINGS
AND REALLOCATION OF SERVICE CORP BILLING

ALLOCATION FACTOR	COMPANY	VOLUME
FOSPLCOMBI	3	7
FOSPLCOMBI	4	10
FOSPLCOMBI	7	37
FOSPLCOMBI	10	13
FOSPLCOMBI	34	4
FOSPLCOMBI	98	2
MMBTUBRALL	CPL	55,065,651
MMBTUBRALL	PSO	49,254,074
MMBTUBRALL	SEP	69,592,254
MMBTUBRALL	WTU	17,440,714
MMBTUBRALL	2	79,338,658
MMBTUBRALL	3	30,268,299
MMBTUBRALL	4	38,897,348
MMBTUBRALL	7	119,488,100
MMBTUBRALL	10	35,319,010
MMBTUBRALL	98	9,680,414
MMBTUBRCOA	CPL	9,521,292
MMBTUBRCOA	PSO	21,264,110
MMBTUBRCOA	SEP	36,303,402
MMBTUBRCOA	WTU	7,098,169
MMBTUBRCOA	2	79,170,027
MMBTUBRCOA	3	30,235,094
MMBTUBRCOA	4	38,831,690
MMBTUBRCOA	7	119,198,158
MMBTUBRCOA	10	35,233,998
MMBTUBRCOA	98	9,670,182
MMBTUBRGAS	CPL	45,535,822
MMBTUBRGAS	PSO	27,687,072
MMBTUBRGAS	SEP	15,655,523
MMBTUBRGAS	WTU	10,334,823
MWGENCAPAC	CPL	3,846
MWGENCAPAC	PSO	3,898
MWGENCAPAC	SEP	4,433
MWGENCAPAC	WTU	1,384
MWGENCAPAC	2	5,860
MWGENCAPAC	3	1,674
MWGENCAPAC	4	4,575
MWGENCAPAC	7	8,512
MWGENCAPAC	10	2,595
MWGENCAPAC	98	556
OVERHEADCR	CPL	27,958,866
OVERHEADCR	CSE	728,337
OVERHEADCR	CSI	287,646
OVERHEADCR	DCM	492,214
OVERHEADCR	DCR	9,363,663
OVERHEADCR	DCT	322,178

AEP/CSW
VOLUMES UTILIZED IN ALLOCATION OF SAVINGS
AND REALLOCATION OF SERVICE CORP BILLING

ALLOCATION FACTOR	COMPANY	VOLUME
OVERHEADCR	DES	114,217
OVERHEADCR	DLL	21,334
OVERHEADCR	DSV	2,582,582
OVERHEADCR	ECS	978,875
OVERHEADCR	JFP	605
OVERHEADCR	LAB	147,771
OVERHEADCR	PSO	19,430,120
OVERHEADCR	SEE	2,224,962
OVERHEADCR	SEP	23,851,547
OVERHEADCR	WTU	11,985,853
TCSWSB-INT	CPL	74,136,816
TCSWSB-INT	CSE	2,121,521
TCSWSB-INT	CSI	647,130
TCSWSB-INT	DCM	3,856,188
TCSWSB-INT	DCR	28,152,777
TCSWSB-INT	DCT	1,140,469
TCSWSB-INT	DES	506,722
TCSWSB-INT	DLL	80,388
TCSWSB-INT	ECS	899,671
TCSWSB-INT	ESI	1,416,935
TCSWSB-INT	JFP	786,711
TCSWSB-INT	LAB	55,942
TCSWSB-INT	PMI	324,805
TCSWSB-INT	PSO	50,536,139
TCSWSB-INT	SEE	6,999,967
TCSWSB-INT	SEP	57,691,162
TCSWSB-INT	WTU	29,858,009
TCSWSB-INT	1	3,345,914
TCSWSB-INT	2	114,571,494
TCSWSB-INT	3	32,133,167
TCSWSB-INT	4	70,893,324
TCSWSB-INT	6	3,446,220
TCSWSB-INT	7	123,775,342
TCSWSB-INT	10	62,006,876
TCSWSB-INT	25	210,798
TCSWSB-INT	31	860,513
TCSWSB-INT	32	1,114,612
TCSWSB-INT	34	4,385,352
TCSWSB-INT	42	1,647,422
TCSWSB-INT	43	2,202,209
TCSWSB-INT	44	6,416,269
TCSWSB-INT	48	1,056,102
TCSWSB-INT	49	595,452
TCSWSB-INT	54	480,410
TCSWSB-INT	56	7,103
TCSWSB-INT	58	1,707,797

AEP/CSW
VOLUMES UTILIZED IN ALLOCATION OF SAVINGS
AND REALLOCATION OF SERVICE CORP BILLING

ALLOCATION FACTOR	COMPANY	VOLUME
TCSWSB-INT	59	5,176,989
TCSWSB-INT	60	2,114,228
TCSWSB-INT	69	2,301,524
TCSWSB-INT	72	33,968
TCSWSB-INT	74	7,783,718
TCSWSB-INT	75	2,130,857
TCSWSB-INT	81	703,665
TCSWSB-INT	86	6,259
TCSWSB-INT	88	165
TCSWSB-INT	89	275
TCSWSB-INT	90	387
TCSWSB-INT	91	187,776
TCSWSB-INT	98	3,707,894
TFIXASSET$	CPL	3,392,442
TFIXASSET$	CSE	160,547
TFIXASSET$	CSI	7,640
TFIXASSET$	DCM	20,222
TFIXASSET$	DES	97
TFIXASSET$	PSO	1,298,371
TFIXASSET$	SEE	1,049,237
TFIXASSET$	SEP	1,852,783
TFIXASSET$	WTU	667,366
TFIXASSET$	1	55,260
TFIXASSET$	2	3,009,240
TFIXASSET$	3	876,212
TFIXASSET$	4	2,599,958
TFIXASSET$	6	59,880
TFIXASSET$	7	2,607,099
TFIXASSET$	10	1,913,031
TFIXASSET$	42	14,513
TFIXASSET$	43	26,979
TFIXASSET$	44	194,862
TFIXASSET$	53	2,620
TFIXASSET$	54	317
TFIXASSET$	58	4,289
TFIXASSET$	67	10
TFIXASSET$	81	1,100
TFIXASSET$	87	32,136
TFIXASSET$	98	162,615
TGRUTIPLNT	CPL	5,116,570
TGRUTIPLNT	PSO	2,290,175
TGRUTIPLNT	SEE	1,677,099
TGRUTIPLNT	SEP	3,044,313
TGRUTIPLNT	WTU	1,088,141
TGRUTIPLNT	1	82,617
TGRUTIPLNT	2	4,840,536

AEP/CSW
VOLUMES UTILIZED IN ALLOCATION OF SAVINGS
AND REALLOCATION OF SERVICE CORP BILLING

ALLOCATION FACTOR	COMPANY	VOLUME
TGRUTIPLNT	3	1,282,178
TGRUTIPLNT	4	4,519,193
TGRUTIPLNT	6	94,028
TGRUTIPLNT	7	4,588,465
TGRUTIPLNT	10	2,953,665
TGRUTIPLNT	42	64,478
TGRUTIPLNT	43	61,084
TGRUTIPLNT	44	381,723
TGRUTIPLNT	54	770
TGRUTIPLNT	98	270,483
TLGROSSREV	CPL	1,300,125
TLGROSSREV	PSO	680,507
TLGROSSREV	SEP	764,957
TLGROSSREV	WTU	284,313
TLGROSSREV	1	82,522
TLGROSSREV	2	1,534,383
TLGROSSREV	3	335,311
TLGROSSREV	4	1,218,893
TLGROSSREV	6	84,529
TLGROSSREV	7	1,532,550
TLGROSSREV	10	1,085,601
TLGROSSREV	98	30,521
TLVLCONSTR	1	866,163
TLVLCONSTR	2	29,854,467
TLVLCONSTR	3	26,601,031
TLVLCONSTR	4	17,980,939
TLVLCONSTR	6	967,965
TLVLCONSTR	7	14,438,269
TLVLCONSTR	10	10,651,406
TPOLEMILES	CPL	4,794
TPOLEMILES	PSO	3,466
TPOLEMILES	SEP	3,284
TPOLEMILES	WTU	4,490
TPOLEMILES	1	52
TPOLEMILES	2	4,917
TPOLEMILES	3	1,156
TPOLEMILES	4	4,008
TPOLEMILES	6	183
TPOLEMILES	7	5,493
TPOLEMILES	10	1,545
TTLASSETS$	CPL	5,077,292
TTLASSETS$	CSE	360,266
TTLASSETS$	CSI	11,112
TTLASSETS$	DCM	31,909
TTLASSETS$	DCR	21,165
TTLASSETS$	DCT	561,381

AEP/CSW
VOLUMES UTILIZED IN ALLOCATION OF SAVINGS
AND REALLOCATION OF SERVICE CORP BILLING

ALLOCATION FACTOR	COMPANY	VOLUME
TTLASSETS$	DES	1,241
TTLASSETS$	DLL	60,610
TTLASSETS$	DSV	114,120
TTLASSETS$	PSO	1,584,425
TTLASSETS$	SEE	2,963,290
TTLASSETS$	SEP	2,251,070
TTLASSETS$	WTU	865,530
TTLASSETS$	1	73,096
TTLASSETS$	2	3,787,659
TTLASSETS$	3	1,023,392
TTLASSETS$	4	3,834,053
TTLASSETS$	6	84,152
TTLASSETS$	7	3,594,042
TTLASSETS$	10	2,534,196
TTLASSETS$	25	117
TTLASSETS$	42	42,925
TTLASSETS$	43	38,437
TTLASSETS$	44	333,036
TTLASSETS$	53	2,732
TTLASSETS$	54	1,827
TTLASSETS$	56	2
TTLASSETS$	57	504
TTLASSETS$	58	6,427
TTLASSETS$	59	706
TTLASSETS$	60	59,206
TTLASSETS$	61	211,103
TTLASSETS$	63	25
TTLASSETS$	64	1
TTLASSETS$	67	241
TTLASSETS$	69	16,354
TTLASSETS$	72	14,541
TTLASSETS$	74	2,976
TTLASSETS$	81	2,932
TTLASSETS$	83	29
TTLASSETS$	86	7
TTLASSETS$	87	35,785
TTLASSETS$	88	23
TTLASSETS$	89	23
TTLASSETS$	91	5,904
TTLASSETS$	98	159,717
TTLASSETS$	99	272,660
TTPKLOADLY	CPL	4,046
TTPKLOADLY	PSO	3,360
TTPKLOADLY	SEP	4,074
TTPKLOADLY	WTU	1,433
TTPKLOADLY	1	300

AEP/CSW
VOLUMES UTILIZED IN ALLOCATION OF SAVINGS
AND REALLOCATION OF SERVICE CORP BILLING

ALLOCATION FACTOR	COMPANY	VOLUME
TTPKLOADLY	2	6,857
TTPKLOADLY	3	1,417
TTPKLOADLY	4	3,926
TTPKLOADLY	6	430
TTPKLOADLY	7	5,519
TTPKLOADLY	10	3,354
SYSTEM GENERATED VOLUMES		
'AC'3MBILL	CPL	6,419,301
'AC'3MBILL	CSE	184,968
'AC'3MBILL	CSI	102,481
'AC'3MBILL	DCM	1,763,977
'AC'3MBILL	DCR	955,585
'AC'3MBILL	DCT	1,074,654
'AC'3MBILL	DES	59,467
'AC'3MBILL	DLL	48,037
'AC'3MBILL	DSV	2,190,603
'AC'3MBILL	ECS	(620)
'AC'3MBILL	ESI	13,748
'AC'3MBILL	JFP	6,728
'AC'3MBILL	LAB	2,630
'AC'3MBILL	NON	5,149
'AC'3MBILL	PMI	11,075
'AC'3MBILL	PSO	5,432,300
'AC'3MBILL	SEE	3,918,054
'AC'3MBILL	SEP	3,534,969
'AC'3MBILL	TOK	3,462
'AC'3MBILL	WTU	1,877,975
'AC'3MBILL	1	182,576
'AC'3MBILL	2	4,105,942
'AC'3MBILL	3	1,434,697
'AC'3MBILL	4	3,387,420
'AC'3MBILL	6	211,341
'AC'3MBILL	7	4,059,504
'AC'3MBILL	10	2,380,454
'AC'3MBILL	21	71,955
'AC'3MBILL	22	62,520
'AC'3MBILL	23	40,323
'AC'3MBILL	25	3,445
'AC'3MBILL	26	3,040
'AC'3MBILL	31	7,359
'AC'3MBILL	32	8,818
'AC'3MBILL	34	29,881
'AC'3MBILL	40	7
'AC'3MBILL	41	32
'AC'3MBILL	42	61,875

AEP/CSW
VOLUMES UTILIZED IN ALLOCATION OF SAVINGS
AND REALLOCATION OF SERVICE CORP BILLING

ALLOCATION FACTOR	COMPANY	VOLUME
'AC'3MBILL	43	66,425
'AC'3MBILL	44	289,425
'AC'3MBILL	45	6
'AC'3MBILL	46	62
'AC'3MBILL	48	76,659
'AC'3MBILL	49	51,205
'AC'3MBILL	50	-
'AC'3MBILL	51	82
'AC'3MBILL	52	12
'AC'3MBILL	53	(674)
'AC'3MBILL	54	7,251
'AC'3MBILL	56	478
'AC'3MBILL	57	594
'AC'3MBILL	58	13,016
'AC'3MBILL	59	45,857
'AC'3MBILL	60	27,024
'AC'3MBILL	61	(294,923)
'AC'3MBILL	63	(1,055)
'AC'3MBILL	64	(1,179)
'AC'3MBILL	66	1,744
'AC'3MBILL	67	519
'AC'3MBILL	69	14,916
'AC'3MBILL	70	74,932
'AC'3MBILL	71	74,798
'AC'3MBILL	72	4,955
'AC'3MBILL	73	55,895
'AC'3MBILL	74	33,370
'AC'3MBILL	76	3,043
'AC'3MBILL	77	3,043
'AC'3MBILL	78	3,043
'AC'3MBILL	81	7,627
'AC'3MBILL	83	1,748
'AC'3MBILL	84	3,043
'AC'3MBILL	85	3,043
'AC'3MBILL	86	1,745
'AC'3MBILL	87	10,103
'AC'3MBILL	88	3,049
'AC'3MBILL	89	3,049
'AC'3MBILL	90	3,043
'AC'3MBILL	91	3,043
'AC'3MBILL	98	110,199
'AC'3MBILL	99	82,905
'AU'3MBILL	CPL	1,415,574
'AU'3MBILL	CSE	98,647
'AU'3MBILL	CSI	2,278
'AU'3MBILL	DCM	87,262

AEP/CSW
VOLUMES UTILIZED IN ALLOCATION OF SAVINGS
AND REALLOCATION OF SERVICE CORP BILLING

ALLOCATION FACTOR	COMPANY	VOLUME
'AU'3MBILL	DCR	253,247
'AU'3MBILL	DCT	10,025
'AU'3MBILL	DES	21,395
'AU'3MBILL	DLL	1,082
'AU'3MBILL	DSV	70,312
'AU'3MBILL	ESI	12
'AU'3MBILL	PSO	446,386
'AU'3MBILL	SEE	52,919
'AU'3MBILL	SEP	633,455
'AU'3MBILL	WTU	274,760
'AU'3MBILL	1	16,592
'AU'3MBILL	2	1,072,507
'AU'3MBILL	3	391,641
'AU'3MBILL	4	1,066,907
'AU'3MBILL	6	19,099
'AU'3MBILL	7	1,055,160
'AU'3MBILL	10	701,585
'AU'3MBILL	25	23
'AU'3MBILL	34	120
'AU'3MBILL	42	8,955
'AU'3MBILL	43	8,056
'AU'3MBILL	44	68,870
'AU'3MBILL	48	193
'AU'3MBILL	49	36
'AU'3MBILL	53	559
'AU'3MBILL	54	401
'AU'3MBILL	57	103
'AU'3MBILL	58	1,317
'AU'3MBILL	59	144
'AU'3MBILL	60	12,141
'AU'3MBILL	61	42,491
'AU'3MBILL	63	4
'AU'3MBILL	67	49
'AU'3MBILL	69	3,359
'AU'3MBILL	72	2,981
'AU'3MBILL	74	609
'AU'3MBILL	81	52
'AU'3MBILL	83	5
'AU'3MBILL	86	1
'AU'3MBILL	87	7,338
'AU'3MBILL	88	4
'AU'3MBILL	89	4
'AU'3MBILL	91	1,210
'AU'3MBILL	98	35,410
'AU'3MBILL	99	4,871
'CU'3MBILL	CPL	4,148,743

AEP/CSW
VOLUMES UTILIZED IN ALLOCATION OF SAVINGS
AND REALLOCATION OF SERVICE CORP BILLING

ALLOCATION FACTOR	COMPANY	VOLUME
'CU'3MBILL	CSE	24,842
'CU'3MBILL	CSI	2,698
'CU'3MBILL	DCM	16,860
'CU'3MBILL	DCR	117,377
'CU'3MBILL	DCT	20,270
'CU'3MBILL	DES	4,354
'CU'3MBILL	DLL	335
'CU'3MBILL	ECS	3,750
'CU'3MBILL	ESI	7,088
'CU'3MBILL	JFP	3,279
'CU'3MBILL	LAB	233
'CU'3MBILL	PMI	1,354
'CU'3MBILL	PSO	3,779,688
'CU'3MBILL	SEP	3,360,538
'CU'3MBILL	WTU	1,737,198
'CU'3MBILL	1	245,079
'CU'3MBILL	2	5,187,812
'CU'3MBILL	3	1,059,711
'CU'3MBILL	4	3,327,489
'CU'3MBILL	6	253,509
'CU'3MBILL	7	4,442,630
'CU'3MBILL	10	4,474,860
'CU'3MBILL	25	878
'CU'3MBILL	31	3,587
'CU'3MBILL	32	4,646
'CU'3MBILL	34	18,283
'CU'3MBILL	42	6,868
'CU'3MBILL	43	9,181
'CU'3MBILL	44	26,751
'CU'3MBILL	48	4,403
'CU'3MBILL	49	2,482
'CU'3MBILL	54	2,002
'CU'3MBILL	56	29
'CU'3MBILL	58	7,120
'CU'3MBILL	59	21,584
'CU'3MBILL	60	8,814
'CU'3MBILL	69	9,595
'CU'3MBILL	72	141
'CU'3MBILL	74	32,452
'CU'3MBILL	86	25
'CU'3MBILL	88	-
'CU'3MBILL	89	-
'CU'3MBILL	90	1
'CU'3MBILL	91	782
'CU'3MBILL	98	15,833
'DS'3MBILL	CPL	1,031,864

AEP/CSW
VOLUMES UTILIZED IN ALLOCATION OF SAVINGS
AND REALLOCATION OF SERVICE CORP BILLING

ALLOCATION FACTOR	COMPANY	VOLUME
'DS'3MBILL	DSV	6,516
'DS'3MBILL	PSO	991,627
'DS'3MBILL	SEP	744,978
'DS'3MBILL	WTU	431,103
'DS'3MBILL	1	236,453
'DS'3MBILL	2	5,904,278
'DS'3MBILL	3	1,301,437
'DS'3MBILL	4	4,106,962
'DS'3MBILL	6	215,237
'DS'3MBILL	7	4,770,051
'DS'3MBILL	10	4,833,261
'DS'3MBILL	61	5,879
'EN'3MBILL	CPL	4,928,260
'EN'3MBILL	CSE	40,111
'EN'3MBILL	CSI	42,404
'EN'3MBILL	DCR	66
'EN'3MBILL	LAB	57,828
'EN'3MBILL	PSO	3,611,796
'EN'3MBILL	SEP	4,312,006
'EN'3MBILL	WTU	2,173,851
'EN'3MBILL	1	75,293
'EN'3MBILL	2	1,925,796
'EN'3MBILL	3	375,191
'EN'3MBILL	4	1,178,805
'EN'3MBILL	6	111,282
'EN'3MBILL	7	1,679,999
'EN'3MBILL	10	932,328
'EN'3MBILL	31	48,670
'EN'3MBILL	32	180,461
'EN'3MBILL	75	11,390
'EX'3MBILL	CPL	1,031,344
'EX'3MBILL	CSE	80,677
'EX'3MBILL	CSI	61,118
'EX'3MBILL	DCM	116,867
'EX'3MBILL	DCR	2,732,106
'EX'3MBILL	DCT	14,313
'EX'3MBILL	DES	152,402
'EX'3MBILL	DLL	1,008
'EX'3MBILL	ECS	11,291
'EX'3MBILL	ESI	17,784
'EX'3MBILL	JFP	9,873
'EX'3MBILL	LAB	701
'EX'3MBILL	PMI	4,076
'EX'3MBILL	PSO	699,671
'EX'3MBILL	SEE	439,389
'EX'3MBILL	SEP	907,126

AEP/CSW
VOLUMES UTILIZED IN ALLOCATION OF SAVINGS
AND REALLOCATION OF SERVICE CORP BILLING

ALLOCATION FACTOR	COMPANY	VOLUME
'EX'3MBILL	WTU	476,736
'EX'3MBILL	1	106,699
'EX'3MBILL	2	1,504,998
'EX'3MBILL	3	407,653
'EX'3MBILL	4	904,503
'EX'3MBILL	6	43,534
'EX'3MBILL	7	1,549,352
'EX'3MBILL	10	781,603
'EX'3MBILL	22	10,117
'EX'3MBILL	25	2,645
'EX'3MBILL	31	10,800
'EX'3MBILL	32	13,989
'EX'3MBILL	34	55,041
'EX'3MBILL	42	20,677
'EX'3MBILL	43	27,640
'EX'3MBILL	44	80,532
'EX'3MBILL	48	13,255
'EX'3MBILL	49	7,473
'EX'3MBILL	54	6,029
'EX'3MBILL	56	88
'EX'3MBILL	58	21,435
'EX'3MBILL	59	64,977
'EX'3MBILL	60	597,725
'EX'3MBILL	69	28,886
'EX'3MBILL	72	426
'EX'3MBILL	74	97,695
'EX'3MBILL	81	8,831
'EX'3MBILL	86	77
'EX'3MBILL	88	1
'EX'3MBILL	89	2
'EX'3MBILL	90	4
'EX'3MBILL	91	2,355
'EX'3MBILL	98	46,562
'GS'3MBILL	CPL	178,014
'GS'3MBILL	CSE	150,387
'GS'3MBILL	CSI	7,104
'GS'3MBILL	DCM	(16,706)
'GS'3MBILL	DCR	178,436
'GS'3MBILL	DCT	(5,519)
'GS'3MBILL	DES	(2,967)
'GS'3MBILL	DLL	(23)
'GS'3MBILL	DSV	4,545,143
'GS'3MBILL	ECS	(14,459)
'GS'3MBILL	ESI	(8,754)
'GS'3MBILL	JFP	(12,243)
'GS'3MBILL	LAB	(2,030)

AEP/CSW
VOLUMES UTILIZED IN ALLOCATION OF SAVINGS
AND REALLOCATION OF SERVICE CORP BILLING

ALLOCATION FACTOR	COMPANY	VOLUME
'GS'3MBILL	PMI	(3,026)
'GS'3MBILL	PSO	223,576
'GS'3MBILL	SEE	291,479
'GS'3MBILL	SEP	3,997
'GS'3MBILL	TOK	(1,266)
'GS'3MBILL	WTU	(70,238)
'GS'3MBILL	1	(27,805)
'GS'3MBILL	2	(721,993)
'GS'3MBILL	3	180,264
'GS'3MBILL	4	(17,393)
'GS'3MBILL	6	(25,439)
'GS'3MBILL	7	(1,157,560)
'GS'3MBILL	10	(690,043)
'GS'3MBILL	21	(1,325)
'GS'3MBILL	22	(104,480)
'GS'3MBILL	23	(583)
'GS'3MBILL	25	(2,754)
'GS'3MBILL	26	(44)
'GS'3MBILL	31	(16,154)
'GS'3MBILL	32	(21,205)
'GS'3MBILL	34	(16,157)
'GS'3MBILL	40	(34)
'GS'3MBILL	41	(149)
'GS'3MBILL	42	(18,292)
'GS'3MBILL	43	(48,183)
'GS'3MBILL	44	(138,917)
'GS'3MBILL	45	(32)
'GS'3MBILL	46	(300)
'GS'3MBILL	48	(27,029)
'GS'3MBILL	49	(12,774)
'GS'3MBILL	50	(1)
'GS'3MBILL	51	(387)
'GS'3MBILL	52	(59)
'GS'3MBILL	53	(94)
'GS'3MBILL	54	(9,178)
'GS'3MBILL	56	(195)
'GS'3MBILL	57	(67)
'GS'3MBILL	58	(36,123)
'GS'3MBILL	59	(102,422)
'GS'3MBILL	60	(20,982)
'GS'3MBILL	61	(300,107)
'GS'3MBILL	63	(31)
'GS'3MBILL	64	(22)
'GS'3MBILL	66	(56)
'GS'3MBILL	67	(67)
'GS'3MBILL	69	(31,483)

AEP/CSW
VOLUMES UTILIZED IN ALLOCATION OF SAVINGS
AND REALLOCATION OF SERVICE CORP BILLING

ALLOCATION FACTOR	COMPANY	VOLUME
'GS'3MBILL	70	(163,332)
'GS'3MBILL	71	(162,935)
'GS'3MBILL	72	(601)
'GS'3MBILL	73	(73,595)
'GS'3MBILL	74	(115,148)
'GS'3MBILL	75	1,057,335
'GS'3MBILL	76	(44)
'GS'3MBILL	77	(44)
'GS'3MBILL	78	(44)
'GS'3MBILL	81	(9,854)
'GS'3MBILL	83	(55)
'GS'3MBILL	84	(44)
'GS'3MBILL	85	(44)
'GS'3MBILL	86	(151)
'GS'3MBILL	87	(1,065)
'GS'3MBILL	88	(47)
'GS'3MBILL	89	(49)
'GS'3MBILL	90	(52)
'GS'3MBILL	91	(2,922)
'GS'3MBILL	98	(19,676)
'GS'3MBILL	99	3,031
'HR'3MBILL	CPL	2,510,421
'HR'3MBILL	CSE	89,212
'HR'3MBILL	CSI	48
'HR'3MBILL	DCM	1,091,628
'HR'3MBILL	DCR	845,086
'HR'3MBILL	DCT	75
'HR'3MBILL	DES	122,072
'HR'3MBILL	DLL	17
'HR'3MBILL	DSV	3,613,760
'HR'3MBILL	ECS	62
'HR'3MBILL	ESI	11,076
'HR'3MBILL	JFP	56
'HR'3MBILL	LAB	16
'HR'3MBILL	PMI	31
'HR'3MBILL	PSO	3,167,040
'HR'3MBILL	SEE	92,318
'HR'3MBILL	SEP	2,884,217
'HR'3MBILL	TOK	13
'HR'3MBILL	WTU	1,597,536
'HR'3MBILL	1	267,638
'HR'3MBILL	2	5,885,137
'HR'3MBILL	3	1,277,102
'HR'3MBILL	4	5,177,832
'HR'3MBILL	6	166,329
'HR'3MBILL	7	4,893,158

AEP/CSW
VOLUMES UTILIZED IN ALLOCATION OF SAVINGS
AND REALLOCATION OF SERVICE CORP BILLING

ALLOCATION FACTOR	COMPANY	VOLUME
'HR'3MBILL	10	3,322,483
'HR'3MBILL	21	13
'HR'3MBILL	22	13
'HR'3MBILL	23	13
'HR'3MBILL	25	25
'HR'3MBILL	26	13
'HR'3MBILL	31	569
'HR'3MBILL	32	5,195
'HR'3MBILL	34	102,298
'HR'3MBILL	42	9,356
'HR'3MBILL	43	2,222
'HR'3MBILL	44	43,151
'HR'3MBILL	48	69,609
'HR'3MBILL	49	(591)
'HR'3MBILL	54	4,928
'HR'3MBILL	56	13
'HR'3MBILL	57	13
'HR'3MBILL	58	107
'HR'3MBILL	59	297
'HR'3MBILL	60	129
'HR'3MBILL	61	(861,802)
'HR'3MBILL	66	13
'HR'3MBILL	67	13
'HR'3MBILL	69	5,416
'HR'3MBILL	70	13
'HR'3MBILL	71	13
'HR'3MBILL	72	15
'HR'3MBILL	73	13
'HR'3MBILL	74	439
'HR'3MBILL	76	13
'HR'3MBILL	77	13
'HR'3MBILL	78	13
'HR'3MBILL	81	51
'HR'3MBILL	83	13
'HR'3MBILL	84	13
'HR'3MBILL	85	13
'HR'3MBILL	86	13
'HR'3MBILL	87	13
'HR'3MBILL	88	13
'HR'3MBILL	89	13
'HR'3MBILL	90	13
'HR'3MBILL	91	23
'HR'3MBILL	98	40,116
'HR'3MBILL	99	27
'IS'3MBILL	CPL	5,787,093
'IS'3MBILL	CSE	123,285

AEP/CSW
VOLUMES UTILIZED IN ALLOCATION OF SAVINGS
AND REALLOCATION OF SERVICE CORP BILLING

ALLOCATION FACTOR	COMPANY	VOLUME
'IS'3MBILL	CSI	4,383
'IS'3MBILL	DCM	336,310
'IS'3MBILL	DCR	222,943
'IS'3MBILL	DCT	79,860
'IS'3MBILL	DES	53,350
'IS'3MBILL	DLL	8,500
'IS'3MBILL	DSV	1,700,608
'IS'3MBILL	ECS	4,890
'IS'3MBILL	ESI	13,817
'IS'3MBILL	JFP	3,066
'IS'3MBILL	LAB	426
'IS'3MBILL	NON	18,051
'IS'3MBILL	PMI	3,320
'IS'3MBILL	PSO	3,479,088
'IS'3MBILL	SEE	157,046
'IS'3MBILL	SEP	3,897,028
'IS'3MBILL	TOK	106,143
'IS'3MBILL	WTU	2,932,345
'IS'3MBILL	1	121,904
'IS'3MBILL	2	7,968,444
'IS'3MBILL	3	2,499,433
'IS'3MBILL	4	5,074,799
'IS'3MBILL	6	125,432
'IS'3MBILL	7	7,817,708
'IS'3MBILL	10	6,102,954
'IS'3MBILL	25	1,427
'IS'3MBILL	26	19
'IS'3MBILL	31	3,352
'IS'3MBILL	32	76,614
'IS'3MBILL	34	5,667
'IS'3MBILL	42	54,508
'IS'3MBILL	43	43,650
'IS'3MBILL	44	125,042
'IS'3MBILL	48	(3,542)
'IS'3MBILL	49	14,597
'IS'3MBILL	53	356
'IS'3MBILL	54	10,490
'IS'3MBILL	56	212
'IS'3MBILL	57	99
'IS'3MBILL	58	484,535
'IS'3MBILL	59	23,967
'IS'3MBILL	60	20,725
'IS'3MBILL	61	(3,095,709)
'IS'3MBILL	63	1,196
'IS'3MBILL	64	680
'IS'3MBILL	67	30

AEP/CSW
VOLUMES UTILIZED IN ALLOCATION OF SAVINGS
AND REALLOCATION OF SERVICE CORP BILLING

ALLOCATION FACTOR	COMPANY	VOLUME
'IS'3MBILL	69	18,006
'IS'3MBILL	72	2,229
'IS'3MBILL	74	36,154
'IS'3MBILL	81	511
'IS'3MBILL	83	28
'IS'3MBILL	86	73
'IS'3MBILL	87	4,682
'IS'3MBILL	88	2
'IS'3MBILL	89	3
'IS'3MBILL	90	1
'IS'3MBILL	91	1,966
'IS'3MBILL	98	158,415
'LG'3MBILL	CPL	1,515,221
'LG'3MBILL	CSE	917
'LG'3MBILL	CSI	(109)
'LG'3MBILL	DCM	(242)
'LG'3MBILL	DCR	4,797,436
'LG'3MBILL	DCT	(6,040)
'LG'3MBILL	DES	(12)
'LG'3MBILL	DLL	(657)
'LG'3MBILL	DSV	(3,196)
'LG'3MBILL	PSO	16,808
'LG'3MBILL	SEE	215,533
'LG'3MBILL	SEP	58,037
'LG'3MBILL	TOK	7,066
'LG'3MBILL	WTU	17,352
'LG'3MBILL	1	25,058
'LG'3MBILL	2	501,360
'LG'3MBILL	3	104,871
'LG'3MBILL	4	475,273
'LG'3MBILL	6	40,111
'LG'3MBILL	7	481,301
'LG'3MBILL	10	487,151
'LG'3MBILL	21	3,506
'LG'3MBILL	22	14,989
'LG'3MBILL	25	(1)
'LG'3MBILL	31	1,067
'LG'3MBILL	32	18,733
'LG'3MBILL	42	(421)
'LG'3MBILL	43	(377)
'LG'3MBILL	44	(3,272)
'LG'3MBILL	53	(26)
'LG'3MBILL	54	(17)
'LG'3MBILL	57	(5)
'LG'3MBILL	58	(63)
'LG'3MBILL	59	(6)

AEP/CSW
VOLUMES UTILIZED IN ALLOCATION OF SAVINGS
AND REALLOCATION OF SERVICE CORP BILLING

ALLOCATION FACTOR	COMPANY	VOLUME
'LG'3MBILL	60	150
'LG'3MBILL	61	(26,589)
'LG'3MBILL	63	-
'LG'3MBILL	67	(2)
'LG'3MBILL	69	(160)
'LG'3MBILL	72	(142)
'LG'3MBILL	74	(29)
'LG'3MBILL	81	71
'LG'3MBILL	83	-
'LG'3MBILL	86	-
'LG'3MBILL	87	(351)
'LG'3MBILL	88	-
'LG'3MBILL	89	-
'LG'3MBILL	91	(58)
'LG'3MBILL	98	(1,571)
'LG'3MBILL	99	6,642
'MA'3MBILL	CPL	11,588
'MA'3MBILL	DCM	1,364
'MA'3MBILL	DCR	6,509,355
'MA'3MBILL	ESI	1,280,539
'MA'3MBILL	NON	165,920
'MA'3MBILL	PSO	22,815
'MA'3MBILL	SEP	1,977,459
'MA'3MBILL	WTU	1,890
'MA'3MBILL	1	155
'MA'3MBILL	2	8,063
'MA'3MBILL	3	2,178
'MA'3MBILL	4	8,162
'MA'3MBILL	6	179
'MA'3MBILL	7	7,651
'MA'3MBILL	10	5,395
'MA'3MBILL	25	206,359
'MA'3MBILL	56	7,103
'MA'3MBILL	58	1,597,796
'MA'3MBILL	59	5,232,168
'MA'3MBILL	60	761,187
'MA'3MBILL	69	2,088,203
'MA'3MBILL	72	33,967
'MA'3MBILL	74	7,842,564
'MA'3MBILL	81	712,294
'MA'3MBILL	86	6,258
'MA'3MBILL	88	164
'MA'3MBILL	89	274
'MA'3MBILL	90	387
'MA'3MBILL	91	174,961
'MK'3MBILL	CPL	9,397,338

AEP/CSW
VOLUMES UTILIZED IN ALLOCATION OF SAVINGS
AND REALLOCATION OF SERVICE CORP BILLING

ALLOCATION FACTOR	COMPANY	VOLUME
'MK'3MBILL	CSE	6,242
'MK'3MBILL	CSI	22,179
'MK'3MBILL	DCM	125,262
'MK'3MBILL	DCR	49,156
'MK'3MBILL	DCT	(234,360)
'MK'3MBILL	DES	1,553
'MK'3MBILL	DLL	(25,302)
'MK'3MBILL	DSV	(135,770)
'MK'3MBILL	ESI	51,240
'MK'3MBILL	PSO	4,699,844
'MK'3MBILL	SEE	(1,268,231)
'MK'3MBILL	SEP	4,404,796
'MK'3MBILL	WTU	2,739,182
'MK'3MBILL	1	258,489
'MK'3MBILL	2	4,446,616
'MK'3MBILL	3	799,887
'MK'3MBILL	4	2,321,571
'MK'3MBILL	6	245,332
'MK'3MBILL	7	2,937,435
'MK'3MBILL	10	2,799,185
'MK'3MBILL	25	(47)
'MK'3MBILL	42	(17,920)
'MK'3MBILL	43	(16,046)
'MK'3MBILL	44	(139,032)
'MK'3MBILL	53	(1,140)
'MK'3MBILL	54	(762)
'MK'3MBILL	57	(209)
'MK'3MBILL	58	(2,682)
'MK'3MBILL	59	4,917,209
'MK'3MBILL	60	(24,716)
'MK'3MBILL	61	(65,103)
'MK'3MBILL	63	(10)
'MK'3MBILL	67	(100)
'MK'3MBILL	69	(6,826)
'MK'3MBILL	72	(6,070)
'MK'3MBILL	74	(1,241)
'MK'3MBILL	81	(1,253)
'MK'3MBILL	83	(11)
'MK'3MBILL	86	(2)
'MK'3MBILL	87	(14,938)
'MK'3MBILL	88	(8)
'MK'3MBILL	89	(8)
'MK'3MBILL	91	(2,464)
'MK'3MBILL	98	(66,670)
'MK'3MBILL	99	(116,720)
'NU'3MBILL	CPL	194,869

AEP/CSW
VOLUMES UTILIZED IN ALLOCATION OF SAVINGS
AND REALLOCATION OF SERVICE CORP BILLING

ALLOCATION FACTOR	COMPANY	VOLUME
'NU'3MBILL	PSO	19,082
'NU'3MBILL	SEP	23,136
'NU'3MBILL	WTU	8,138
'NU'3MBILL	1	1,703
'NU'3MBILL	2	38,942
'NU'3MBILL	3	8,047
'NU'3MBILL	4	7,533,370
'NU'3MBILL	6	2,442
'NU'3MBILL	7	31,343
'NU'3MBILL	10	19,048
'PS'3MBILL	CPL	5,289,199
'PS'3MBILL	CSE	51,257
'PS'3MBILL	CSI	83,789
'PS'3MBILL	DCM	10,592
'PS'3MBILL	DCR	1,896,827
'PS'3MBILL	DES	1,488
'PS'3MBILL	DSV	130,903
'PS'3MBILL	ECS	894,448
'PS'3MBILL	JFP	790,862
'PS'3MBILL	PMI	338,269
'PS'3MBILL	PSO	3,981,211
'PS'3MBILL	SEE	36,813
'PS'3MBILL	SEP	6,025,711
'PS'3MBILL	WTU	4,087,625
'PS'3MBILL	1	209,323
'PS'3MBILL	2	24,119,350
'PS'3MBILL	3	6,036,043
'PS'3MBILL	4	9,307,983
'PS'3MBILL	6	299,434
'PS'3MBILL	7	36,812,880
'PS'3MBILL	10	13,512,117
'PS'3MBILL	21	31
'PS'3MBILL	22	6,136,890
'PS'3MBILL	23	15
'PS'3MBILL	31	888,122
'PS'3MBILL	32	972,132
'PS'3MBILL	34	317,384
'PS'3MBILL	40	2,004
'PS'3MBILL	41	9,013
'PS'3MBILL	42	1,290,321
'PS'3MBILL	43	2,000,641
'PS'3MBILL	44	5,842,589
'PS'3MBILL	45	1,881
'PS'3MBILL	46	17,441
'PS'3MBILL	48	734,761
'PS'3MBILL	49	546,451

AEP/CSW
VOLUMES UTILIZED IN ALLOCATION OF SAVINGS
AND REALLOCATION OF SERVICE CORP BILLING

ALLOCATION FACTOR	COMPANY	VOLUME
'PS'3MBILL	50	116
'PS'3MBILL	51	23,005
'PS'3MBILL	52	3,643
'PS'3MBILL	54	455,778
'PS'3MBILL	60	246,236
'PS'3MBILL	61	114,705
'PS'3MBILL	70	9,611,773
'PS'3MBILL	71	9,574,570
'PS'3MBILL	73	4,324,459
'PS'3MBILL	75	1,053,603
'PS'3MBILL	98	314,852
'RG'3MBILL	CPL	3,229,471
'RG'3MBILL	CSE	28,548
'RG'3MBILL	CSI	413
'RG'3MBILL	DCM	34,247
'RG'3MBILL	DCR	822,153
'RG'3MBILL	DCT	1,647
'RG'3MBILL	DES	29,799
'RG'3MBILL	DLL	154
'RG'3MBILL	DSV	1,491,114
'RG'3MBILL	ECS	489
'RG'3MBILL	ESI	5,162
'RG'3MBILL	JFP	427
'RG'3MBILL	LAB	30
'RG'3MBILL	PMI	176
'RG'3MBILL	PSO	1,556,285
'RG'3MBILL	SEE	20,702
'RG'3MBILL	SEP	2,407,470
'RG'3MBILL	WTU	1,176,979
'RG'3MBILL	1	36,714
'RG'3MBILL	2	1,698,925
'RG'3MBILL	3	363,494
'RG'3MBILL	4	1,282,183
'RG'3MBILL	6	40,470
'RG'3MBILL	7	1,353,917
'RG'3MBILL	10	801,945
'RG'3MBILL	25	114
'RG'3MBILL	31	468
'RG'3MBILL	32	606
'RG'3MBILL	34	44,844
'RG'3MBILL	42	54,902
'RG'3MBILL	43	62,516
'RG'3MBILL	44	205,900
'RG'3MBILL	48	114,670
'RG'3MBILL	49	21,999
'RG'3MBILL	53	4

AEP/CSW
VOLUMES UTILIZED IN ALLOCATION OF SAVINGS
AND REALLOCATION OF SERVICE CORP BILLING

ALLOCATION FACTOR	COMPANY	VOLUME
'RG'3MBILL	54	10,024
'RG'3MBILL	56	3
'RG'3MBILL	57	-
'RG'3MBILL	58	941
'RG'3MBILL	59	2,818
'RG'3MBILL	60	1,258
'RG'3MBILL	61	(201,047)
'RG'3MBILL	63	-
'RG'3MBILL	67	-
'RG'3MBILL	69	3,478
'RG'3MBILL	72	44
'RG'3MBILL	74	4,241
'RG'3MBILL	81	382
'RG'3MBILL	83	-
'RG'3MBILL	86	3
'RG'3MBILL	87	65
'RG'3MBILL	88	-
'RG'3MBILL	89	-
'RG'3MBILL	90	-
'RG'3MBILL	91	112
'RG'3MBILL	98	18,917
'SC'3MBILL	CPL	744,575
'SC'3MBILL	CSE	22,256
'SC'3MBILL	DCM	31,444
'SC'3MBILL	DCR	695
'SC'3MBILL	DSV	350,915
'SC'3MBILL	PSO	582,806
'SC'3MBILL	SEP	681,535
'SC'3MBILL	WTU	482,890
'SC'3MBILL	1	87,768
'SC'3MBILL	2	2,144,852
'SC'3MBILL	3	444,987
'SC'3MBILL	4	1,470,658
'SC'3MBILL	6	36,429
'SC'3MBILL	7	1,933,663
'SC'3MBILL	10	1,235,520
'SC'3MBILL	21	6,262
'SC'3MBILL	34	60,808
'SC'3MBILL	42	147,686
'SC'3MBILL	43	192,541
'SC'3MBILL	44	470,488
'SC'3MBILL	48	77,108
'SC'3MBILL	49	37,629
'SC'3MBILL	54	31,936
'SC'3MBILL	58	144
'SC'3MBILL	59	28

AEP/CSW
VOLUMES UTILIZED IN ALLOCATION OF SAVINGS
AND REALLOCATION OF SERVICE CORP BILLING

ALLOCATION FACTOR	COMPANY	VOLUME
'SC'3MBILL	61	(74,169)
'SC'3MBILL	69	664
'SC'3MBILL	74	57
'SC'3MBILL	98	27,320
'SP'3MBILL	CPL	462,282
'SP'3MBILL	CSE	14,053
'SP'3MBILL	CSI	2,532
'SP'3MBILL	DCM	25,439
'SP'3MBILL	DCR	132,762
'SP'3MBILL	DCT	9,576
'SP'3MBILL	DES	3,388
'SP'3MBILL	DLL	556
'SP'3MBILL	DSV	161,686
'SP'3MBILL	ECS	(43)
'SP'3MBILL	ESI	10,291
'SP'3MBILL	JFP	5,203
'SP'3MBILL	LAB	429
'SP'3MBILL	PMI	2,291
'SP'3MBILL	PSO	308,603
'SP'3MBILL	SEE	41,496
'SP'3MBILL	SEP	351,426
'SP'3MBILL	TOK	758
'SP'3MBILL	WTU	184,151
'SP'3MBILL	1	19,341
'SP'3MBILL	2	674,510
'SP'3MBILL	3	185,522
'SP'3MBILL	4	473,494
'SP'3MBILL	6	20,251
'SP'3MBILL	7	666,660
'SP'3MBILL	10	398,118
'SP'3MBILL	21	543
'SP'3MBILL	22	39,442
'SP'3MBILL	23	267
'SP'3MBILL	25	210
'SP'3MBILL	26	20
'SP'3MBILL	31	6,189
'SP'3MBILL	32	8,323
'SP'3MBILL	34	6,505
'SP'3MBILL	40	12
'SP'3MBILL	41	56
'SP'3MBILL	42	14,356
'SP'3MBILL	43	19,669
'SP'3MBILL	44	59,324
'SP'3MBILL	45	11
'SP'3MBILL	46	110
'SP'3MBILL	48	10,382

AEP/CSW
VOLUMES UTILIZED IN ALLOCATION OF SAVINGS
AND REALLOCATION OF SERVICE CORP BILLING

ALLOCATION FACTOR	COMPANY	VOLUME
'SP'3MBILL	49	5,179
'SP'3MBILL	50	-
'SP'3MBILL	51	145
'SP'3MBILL	52	22
'SP'3MBILL	53	35
'SP'3MBILL	54	4,125
'SP'3MBILL	56	48
'SP'3MBILL	57	49
'SP'3MBILL	58	15,672
'SP'3MBILL	59	72,357
'SP'3MBILL	60	10,242
'SP'3MBILL	63	26
'SP'3MBILL	64	20
'SP'3MBILL	66	32
'SP'3MBILL	67	47
'SP'3MBILL	69	11,882
'SP'3MBILL	70	61,348
'SP'3MBILL	71	61,112
'SP'3MBILL	72	165
'SP'3MBILL	73	27,748
'SP'3MBILL	74	56,194
'SP'3MBILL	76	20
'SP'3MBILL	77	20
'SP'3MBILL	78	20
'SP'3MBILL	81	5,262
'SP'3MBILL	83	33
'SP'3MBILL	84	20
'SP'3MBILL	85	20
'SP'3MBILL	86	34
'SP'3MBILL	87	338
'SP'3MBILL	88	20
'SP'3MBILL	89	20
'SP'3MBILL	90	20
'SP'3MBILL	91	996
'SP'3MBILL	98	7,782
'SP'3MBILL	99	819
'TS'3MBILL	CPL	2,981,387
'TS'3MBILL	CSE	693,489
'TS'3MBILL	CSI	45,704
'TS'3MBILL	DCM	17,439
'TS'3MBILL	NON	19,575
'TS'3MBILL	PSO	2,211,894
'TS'3MBILL	SEP	4,230,383
'TS'3MBILL	WTU	1,727,337
'TS'3MBILL	1	303,346
'TS'3MBILL	2	12,317,320

AEP/CSW
VOLUMES UTILIZED IN ALLOCATION OF SAVINGS
AND REALLOCATION OF SERVICE CORP BILLING

ALLOCATION FACTOR	COMPANY	VOLUME
'TS'3MBILL	3	6,301,758
'TS'3MBILL	4	5,901,937
'TS'3MBILL	6	524,403
'TS'3MBILL	7	7,282,521
'TS'3MBILL	10	4,180,348
'TS'3MBILL	58	151,829
'TS'3MBILL	91	17,021
'ZZ'3MBILL	CPL	2,568,279
'ZZ'3MBILL	CSE	78,078
'ZZ'3MBILL	CSI	14,073
'ZZ'3MBILL	DCM	141,334
'ZZ'3MBILL	DCR	737,580
'ZZ'3MBILL	DCT	53,205
'ZZ'3MBILL	DES	18,827
'ZZ'3MBILL	DLL	3,091
'ZZ'3MBILL	DSV	(25,096,666)
'ZZ'3MBILL	ECS	(242)
'ZZ'3MBILL	ESI	57,172
'ZZ'3MBILL	JFP	28,911
'ZZ'3MBILL	LAB	2,386
'ZZ'3MBILL	NON	8,409
'ZZ'3MBILL	PMI	12,728
'ZZ'3MBILL	PSO	1,714,491
'ZZ'3MBILL	SEE	230,540
'ZZ'3MBILL	SEP	1,952,399
'ZZ'3MBILL	TOK	4,215
'ZZ'3MBILL	WTU	1,023,083
'ZZ'3MBILL	1	107,456
'ZZ'3MBILL	2	3,747,341
'ZZ'3MBILL	3	1,030,699
'ZZ'3MBILL	4	2,630,572
'ZZ'3MBILL	6	112,508
'ZZ'3MBILL	7	3,703,730
'ZZ'3MBILL	10	2,211,811
'ZZ'3MBILL	21	3,016
'ZZ'3MBILL	22	219,126
'ZZ'3MBILL	23	1,485
'ZZ'3MBILL	25	1,171
'ZZ'3MBILL	26	112
'ZZ'3MBILL	31	34,387
'ZZ'3MBILL	32	46,240
'ZZ'3MBILL	34	36,144
'ZZ'3MBILL	40	69
'ZZ'3MBILL	41	315
'ZZ'3MBILL	42	79,759
'ZZ'3MBILL	43	109,280

AEP/CSW
VOLUMES UTILIZED IN ALLOCATION OF SAVINGS
AND REALLOCATION OF SERVICE CORP BILLING

ALLOCATION FACTOR	COMPANY	VOLUME
'ZZ'3MBILL	44	329,584
'ZZ'3MBILL	45	64
'ZZ'3MBILL	46	614
'ZZ'3MBILL	48	57,682
'ZZ'3MBILL	49	28,773
'ZZ'3MBILL	50	1
'ZZ'3MBILL	51	810
'ZZ'3MBILL	52	127
'ZZ'3MBILL	53	197
'ZZ'3MBILL	54	22,915
'ZZ'3MBILL	56	270
'ZZ'3MBILL	57	272
'ZZ'3MBILL	58	87,067
'ZZ'3MBILL	59	401,990
'ZZ'3MBILL	60	56,904
'ZZ'3MBILL	63	144
'ZZ'3MBILL	64	109
'ZZ'3MBILL	66	180
'ZZ'3MBILL	67	260
'ZZ'3MBILL	69	66,016
'ZZ'3MBILL	70	340,830
'ZZ'3MBILL	71	339,517
'ZZ'3MBILL	72	918
'ZZ'3MBILL	73	154,161
'ZZ'3MBILL	74	312,194
'ZZ'3MBILL	75	85,539
'ZZ'3MBILL	76	109
'ZZ'3MBILL	77	109
'ZZ'3MBILL	78	109
'ZZ'3MBILL	81	29,235
'ZZ'3MBILL	83	182
'ZZ'3MBILL	84	109
'ZZ'3MBILL	85	109
'ZZ'3MBILL	86	190
'ZZ'3MBILL	87	1,879
'ZZ'3MBILL	88	112
'ZZ'3MBILL	89	112
'ZZ'3MBILL	90	112
'ZZ'3MBILL	91	5,538
'ZZ'3MBILL	98	43,238
'ZZ'3MBILL	99	4,564
CSWSPMBILL	CPL	53,844,834
CSWSPMBILL	CSE	1,686,975
CSWSPMBILL	CSI	391,102
CSWSPMBILL	DCM	3,783,081
CSWSPMBILL	DCR	20,250,817

AEP/CSW
VOLUMES UTILIZED IN ALLOCATION OF SAVINGS
AND REALLOCATION OF SERVICE CORP BILLING

ALLOCATION FACTOR	COMPANY	VOLUME
CSWSPMBILL	DCT	1,017,707
CSWSPMBILL	DES	465,120
CSWSPMBILL	DLL	36,800
CSWSPMBILL	DSV	(10,974,068)
CSWSPMBILL	ECS	899,566
CSWSPMBILL	ESI	1,459,178
CSWSPMBILL	JFP	836,165
CSWSPMBILL	LAB	62,652
CSWSPMBILL	NON	217,106
CSWSPMBILL	PMI	370,297
CSWSPMBILL	PSO	36,945,021
CSWSPMBILL	SEE	4,228,063
CSWSPMBILL	SEP	42,390,675
CSWSPMBILL	TOK	120,393
CSWSPMBILL	WTU	22,879,901
CSWSPMBILL	1	2,273,791
CSWSPMBILL	2	82,530,205
CSWSPMBILL	3	24,204,626
CSWSPMBILL	4	55,612,536
CSWSPMBILL	6	2,441,890
CSWSPMBILL	7	84,321,112
CSWSPMBILL	10	48,490,132
CSWSPMBILL	21	84,003
CSWSPMBILL	22	6,378,619
CSWSPMBILL	23	41,520
CSWSPMBILL	25	213,500
CSWSPMBILL	26	3,161
CSWSPMBILL	31	988,420
CSWSPMBILL	32	1,314,555
CSWSPMBILL	34	660,823
CSWSPMBILL	40	2,059
CSWSPMBILL	41	9,268
CSWSPMBILL	42	1,712,634
CSWSPMBILL	43	2,477,219
CSWSPMBILL	44	7,260,438
CSWSPMBILL	45	1,931
CSWSPMBILL	46	17,928
CSWSPMBILL	48	1,128,153
CSWSPMBILL	49	702,464
CSWSPMBILL	50	117
CSWSPMBILL	51	23,657
CSWSPMBILL	52	3,747
CSWSPMBILL	53	(780)
CSWSPMBILL	54	545,925
CSWSPMBILL	56	8,052
CSWSPMBILL	57	852

AEP/CSW
VOLUMES UTILIZED IN ALLOCATION OF SAVINGS
AND REALLOCATION OF SERVICE CORP BILLING

ALLOCATION FACTOR	COMPANY	VOLUME
CSWSPMBILL	58	2,342,113
CSWSPMBILL	59	10,680,971
CSWSPMBILL	60	1,696,841
CSWSPMBILL	61	(4,919,452)
CSWSPMBILL	63	274
CSWSPMBILL	64	(391)
CSWSPMBILL	66	1,914
CSWSPMBILL	67	749
CSWSPMBILL	69	2,211,955
CSWSPMBILL	70	9,925,565
CSWSPMBILL	71	9,887,076
CSWSPMBILL	72	39,031
CSWSPMBILL	73	4,488,681
CSWSPMBILL	74	8,299,554
CSWSPMBILL	75	2,207,868
CSWSPMBILL	76	3,142
CSWSPMBILL	77	3,142
CSWSPMBILL	78	3,142
CSWSPMBILL	81	753,212
CSWSPMBILL	83	1,945
CSWSPMBILL	84	3,142
CSWSPMBILL	85	3,142
CSWSPMBILL	86	8,270
CSWSPMBILL	87	8,064
CSWSPMBILL	88	3,313
CSWSPMBILL	89	3,422
CSWSPMBILL	90	3,531
CSWSPMBILL	91	202,568
CSWSPMBILL	98	730,731
CSWSPMBILL	99	(13,858)
CSWS3MBILL	CPL	53,844,834
CSWS3MBILL	CSE	1,686,975
CSWS3MBILL	CSI	391,102
CSWS3MBILL	DCM	3,783,081
CSWS3MBILL	DCR	20,250,817
CSWS3MBILL	DCT	1,017,707
CSWS3MBILL	DES	465,120
CSWS3MBILL	DLL	36,800
CSWS3MBILL	DSV	(10,974,068)
CSWS3MBILL	ECS	899,566
CSWS3MBILL	ESI	1,459,178
CSWS3MBILL	JFP	836,165
CSWS3MBILL	LAB	62,652
CSWS3MBILL	NON	217,106
CSWS3MBILL	PMI	370,297
CSWS3MBILL	PSO	36,945,021

AEP/CSW
VOLUMES UTILIZED IN ALLOCATION OF SAVINGS
AND REALLOCATION OF SERVICE CORP BILLING

ALLOCATION FACTOR	COMPANY	VOLUME
CSWS3MBILL	SEE	4,228,063
CSWS3MBILL	SEP	42,390,675
CSWS3MBILL	TOK	120,393
CSWS3MBILL	WTU	22,879,901
CSWS3MBILL	1	2,273,791
CSWS3MBILL	2	82,530,205
CSWS3MBILL	3	24,204,626
CSWS3MBILL	4	55,612,536
CSWS3MBILL	6	2,441,890
CSWS3MBILL	7	84,321,112
CSWS3MBILL	10	48,490,132
CSWS3MBILL	21	84,003
CSWS3MBILL	22	6,378,619
CSWS3MBILL	23	41,520
CSWS3MBILL	25	213,500
CSWS3MBILL	26	3,161
CSWS3MBILL	31	988,420
CSWS3MBILL	32	1,314,555
CSWS3MBILL	34	660,823
CSWS3MBILL	40	2,059
CSWS3MBILL	41	9,268
CSWS3MBILL	42	1,712,634
CSWS3MBILL	43	2,477,219
CSWS3MBILL	44	7,260,438
CSWS3MBILL	45	1,931
CSWS3MBILL	46	17,928
CSWS3MBILL	48	1,128,153
CSWS3MBILL	49	702,464
CSWS3MBILL	50	117
CSWS3MBILL	51	23,657
CSWS3MBILL	52	3,747
CSWS3MBILL	53	(780)
CSWS3MBILL	54	545,925
CSWS3MBILL	56	8,052
CSWS3MBILL	57	852
CSWS3MBILL	58	2,342,113
CSWS3MBILL	59	10,680,971
CSWS3MBILL	60	1,696,841
CSWS3MBILL	61	(4,919,452)
CSWS3MBILL	63	274
CSWS3MBILL	64	(391)
CSWS3MBILL	66	1,914
CSWS3MBILL	67	749
CSWS3MBILL	69	2,211,955
CSWS3MBILL	70	9,925,565
CSWS3MBILL	71	9,887,076

AEP/CSW
VOLUMES UTILIZED IN ALLOCATION OF SAVINGS
AND REALLOCATION OF SERVICE CORP BILLING

ALLOCATION FACTOR	COMPANY	VOLUME
CSWS3MBILL	72	39,031
CSWS3MBILL	73	4,488,681
CSWS3MBILL	74	8,299,554
CSWS3MBILL	75	2,207,868
CSWS3MBILL	76	3,142
CSWS3MBILL	77	3,142
CSWS3MBILL	78	3,142
CSWS3MBILL	81	753,212
CSWS3MBILL	83	1,945
CSWS3MBILL	84	3,142
CSWS3MBILL	85	3,142
CSWS3MBILL	86	8,270
CSWS3MBILL	87	6,064
CSWS3MBILL	88	3,313
CSWS3MBILL	89	3,422
CSWS3MBILL	90	3,531
CSWS3MBILL	91	202,568
CSWS3MBILL	98	730,731
CSWS3MBILL	99	(13,858)
VOLUMES DERIVED FOR SAVINGS ALLOCATION		
CREDITLINE	CPL	550,952
CREDITLINE	CSE	72,240
CREDITLINE	CSI	72,240
CREDITLINE	DCM	17,680
CREDITLINE	DCR	829,400
CREDITLINE	DCT	-
CREDITLINE	DES	1,840
CREDITLINE	PSO	240,933
CREDITLINE	SEE	23,200
CREDITLINE	SEP	345,434
CREDITLINE	WTU	105,081
CREDITLINE	1	13,755
CREDITLINE	2	123,926
CREDITLINE	3	95,389
CREDITLINE	4	93,206
CREDITLINE	6	13,755
CREDITLINE	7	123,926
CREDITLINE	10	89,538
CREDITLINE	25	4,585
CREDITLINE	58	11,463
CREDITLINE	59	9,170
CREDITLINE	60	78,075
CREDITLINE	63	-
CREDITLINE	64	-
CREDITLINE	69	4,585

AEP/CSW
VOLUMES UTILIZED IN ALLOCATION OF SAVINGS
AND REALLOCATION OF SERVICE CORP BILLING

ALLOCATION FACTOR	COMPANY	VOLUME
CREDITLINE	74	22,926
CREDITLINE	81	-
CREDITLINE	83	-
CREDITLINE	86	-
CREDITLINE	91	-
PROFSERVIC	CSE	1,582,000
PROFSERVIC	CSI	3,313,000
PROFSERVIC	DCM	1,195,746
PROFSERVIC	DCT	121,487
PROFSERVIC	DES	964,191
PROFSERVIC	25	310,546
PROFSERVIC	58	2,175,991
PROFSERVIC	59	3,813,334
PROFSERVIC	60	29,418
PROFSERVIC	63	1,611
PROFSERVIC	64	3,177
PROFSERVIC	69	2,381,884
PROFSERVIC	74	3,810,550
PROFSERVIC	81	944,243
PROFSERVIC	83	284,761
PROFSERVIC	86	1,997
PROFSERVIC	91	991,933
REALLOCPAY	CPL	24,975,161
REALLOCPAY	CSE	991,682
REALLOCPAY	CSI	227,797
REALLOCPAY	DCM	705,346
REALLOCPAY	DCR	5,256,169
REALLOCPAY	DCT	539,583
REALLOCPAY	DES	196,501
REALLOCPAY	DLL	37,108
REALLOCPAY	ECS	400,361
REALLOCPAY	ESI	328,435
REALLOCPAY	JFP	483,687
REALLOCPAY	LAB	54,416
REALLOCPAY	NON	123,173
REALLOCPAY	PMI	119,602
REALLOCPAY	PSO	16,345,817
REALLOCPAY	SEE	1,513,805
REALLOCPAY	SEP	19,955,859
REALLOCPAY	TOK	50,060
REALLOCPAY	WTU	11,079,628
REALLOCPAY	1	1,343,153
REALLOCPAY	2	51,878,317
REALLOCPAY	3	15,292,050
REALLOCPAY	4	33,635,814
REALLOCPAY	6	1,321,570

AEP/CSW
VOLUMES UTILIZED IN ALLOCATION OF SAVINGS
AND REALLOCATION OF SERVICE CORP BILLING

ALLOCATION FACTOR	COMPANY	VOLUME
REALLOCPAY	7	54,203,494
REALLOCPAY	10	29,932,537
REALLOCPAY	21	52,371
REALLOCPAY	22	4,128,442
REALLOCPAY	23	23,073
REALLOCPAY	25	108,912
REALLOCPAY	26	1,761
REALLOCPAY	31	638,349
REALLOCPAY	32	837,916
REALLOCPAY	34	469,049
REALLOCPAY	40	1,385
REALLOCPAY	41	5,915
REALLOCPAY	42	1,218,041
REALLOCPAY	43	1,739,404
REALLOCPAY	44	5,166,419
REALLOCPAY	45	1,283
REALLOCPAY	46	11,908
REALLOCPAY	48	796,397
REALLOCPAY	49	453,150
REALLOCPAY	50	85
REALLOCPAY	51	15,304
REALLOCPAY	52	2,359
REALLOCPAY	53	2,790
REALLOCPAY	54	371,910
REALLOCPAY	56	7,730
REALLOCPAY	57	2,985
REALLOCPAY	58	1,427,144
REALLOCPAY	59	4,047,574
REALLOCPAY	60	868,079
REALLOCPAY	63	1,275
REALLOCPAY	64	910
REALLOCPAY	66	2,216
REALLOCPAY	67	2,820
REALLOCPAY	69	1,246,040
REALLOCPAY	70	6,453,936
REALLOCPAY	71	6,438,238
REALLOCPAY	72	33,340
REALLOCPAY	73	2,908,081
REALLOCPAY	74	4,551,928
REALLOCPAY	75	1,498,212
REALLOCPAY	76	1,751
REALLOCPAY	77	1,751
REALLOCPAY	78	1,751
REALLOCPAY	81	390,099
REALLOCPAY	83	2,243
REALLOCPAY	84	1,751

AEP/CSW
VOLUMES UTILIZED IN ALLOCATION OF SAVINGS
AND REALLOCATION OF SERVICE CORP BILLING

ALLOCATION FACTOR	COMPANY	VOLUME
REALLOCPAY	85	1,751
REALLOCPAY	86	6,024
REALLOCPAY	87	32,072
REALLOCPAY	88	1,899
REALLOCPAY	89	1,978
REALLOCPAY	90	2,074
REALLOCPAY	91	119,381
REALLOCPAY	98	646,455
REALLOCPAY	99	58,684

AEP/CSW
SCHEDULE OF SYNERGIES ANALYSIS SAVINGS
BY CENTER AND YEAR

CENTER	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	TOTAL
ADMIN	(1,869,472.00)	(6,354,612.00)	(7,177,822.00)	(7,392,887.00)	(7,614,925.00)	(7,842,985.00)	(8,079,050.00)	(8,320,108.00)	(8,570,170.00)	(8,846,862.73)	(2,252,950.27)	(74,321,844.00)
ADVER	(1,191,000.00)	(1,667,000.00)	(1,750,000.00)	(1,838,000.00)	(1,930,000.00)	(2,026,000.00)	(2,128,000.00)	(2,234,000.00)	(2,346,000.00)	(2,477,960.32)	(631,039.68)	(20,219,000.00)
BENFT	-	-	-	(11,158,000.00)	(11,604,000.00)	(12,068,000.00)	(12,551,000.00)	(13,054,000.00)	(13,574,000.00)	(14,179,129.68)	(3,610,870.32)	(91,799,000.00)
CONSV	(3,762,000.00)	(5,267,000.00)	(5,531,000.00)	(5,809,000.00)	(6,099,000.00)	(6,402,000.00)	(6,724,000.00)	(7,061,000.00)	(7,413,000.00)	(7,833,192.04)	(1,994,807.96)	(63,896,000.00)
CREDT	(89,000.00)	(123,000.00)	(127,000.00)	(130,000.00)	(134,000.00)	(138,000.00)	(142,000.00)	(146,000.00)	(151,000.00)	(155,420..8)	(39,579.52)	(1,375,000.00)
DIREC	(358,000.00)	(492,000.00)	(507,000.00)	(522,000.00)	(537,000.00)	(554,000.00)	(570,000.00)	(587,000.00)	(605,000.00)	(624,870.02)	(159,129.98)	(5,516,000.00)
DUESM	(274,000.00)	(376,000.00)	(388,000.00)	(399,000.00)	(411,000.00)	(424,000.00)	(436,000.00)	(449,000.00)	(463,000.00)	(477,419.82)	(121,580.18)	(4,219,000.00)
FACIL	(5,237,551.00)	(7,192,902.00)	(7,408,689.00)	(7,630,950.00)	(7,859,879.00)	(8,095,675.00)	(8,338,545.00)	(8,588,701.00)	(8,846,362.00)	(9,133,144.85)	(2,325,855.15)	(80,658,254.00)
INSUR	(4,361,000.00)	(6,047,000.00)	(6,288,000.00)	(6,541,000.00)	(6,801,000.00)	(7,073,000.00)	(7,357,000.00)	(7,651,000.00)	(7,957,000.00)	(8,310,611.87)	(2,116,388.13)	(70,503,000.00)
INSYS	(9,372,000.00)	(35,854,000.00)	(39,798,000.00)	(43,591,000.00)	(45,958,000.00)	(32,453,000.00)	(34,209,000.00)	(28,505,000.00)	(30,043,000.00)	(29,729,147.66)	(7,570,852.34)	(337,083,000.00)
INVEN	-	-	(9,820,000.00)	-	-	-	-	-	-	-	-	(9,820,000.00)
LABOR	(23,340,997.00)	(79,136,003.00)	(95,901,998.00)	(99,736,001.00)	(103,726,999.00)	(107,877,001.00)	(112,191,003.00)	(116,678,001.00)	(121,345,998.00)	(126,736,234.01)	(32,274,766.99)	(1,018,945,002.00)
PROCU	(21,276,000.00)	(29,218,000.00)	(30,095,000.00)	(30,999,000.00)	(31,928,000.00)	(32,886,000.00)	(33,873,000.00)	(34,888,000.00)	(35,935,000.00)	(37,096,875.30)	(9,447,124.70)	(327,642,000.00)
PROFS	(2,737,000.00)	(3,832,000.00)	(4,023,000.00)	(4,224,000.00)	(4,436,000.00)	(4,657,000.00)	(4,890,000.00)	(5,135,000.00)	(5,392,000.00)	(5,696,359.74)	(1,450,640.26)	(46,473,000.00)
PRSER	(9,779,373.00)	(13,693,522.00)	(14,377,548.00)	(15,095,578.00)	(15,849,604.00)	(16,643,636.00)	(17,474,666.00)	(18,348,702.00)	(19,267,737.00)	(20,356,075.04)	(5,183,896.96)	(166,070,338.00)
RESRH	(718,000.00)	(986,000.00)	(1,015,000.00)	(1,045,000.00)	(1,076,000.00)	(1,110,000.00)	(1,143,000.00)	(1,178,000.00)	(1,212,000.00)	(1,252,131.13)	(318,868.87)	(11,054,000.00)
SHARE	(597,000.00)	(820,000.00)	(845,000.00)	(870,000.00)	(897,000.00)	(923,000.00)	(951,000.00)	(980,000.00)	(1,009,000.00)	(1,041,715.71)	(265,284.29)	(9,199,000.00)
TCOMM	(1,893,000.00)	(2,599,000.00)	(2,677,000.00)	(2,758,000.00)	(2,840,000.00)	(2,925,000.00)	(3,013,000.00)	(3,104,000.00)	(3,197,000.00)	(3,299,696.28)	(840,303.72)	(29,146,000.00)
TOTAL	(86,855,393.00)	(193,658,039.00)	(227,730,057.00)	(239,739,416.00)	(249,702,407.00)	(244,098,297.00)	(254,070,264.00)	(256,907,512.00)	(267,327,267.00)	(277,246,846.69)	(70,603,939.31)	(2,367,939,438.00)

AEP/CSW
SCHEDULE OF SYNERGIES ANALYSIS SAVINGS
BY WORK ORDER AND YEAR

WORK ORDER	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	TOTAL
ACSAVABCAA	(216,111.00)	(763,449.00)	(944,870.00)	(982,124.00)	(1,020,853.00)	(1,061,112.00)	(1,102,975.00)	(1,146,488.00)	(1,191,725.00)	(1,243,887.46)	(316,769.54)	(9,990,364.00)
ACSAVCLOAA	(1,280,334.00)	(3,525,147.00)	(4,235,272.00)	(4,409,041.00)	(4,589,941.00)	(4,778,426.00)	(4,974,910.00)	(5,179,427.00)	(5,392,516.00)	(5,639,549.97)	(1,436,173.03)	(45,440,737.00)
ACSAVOTHAA	(1,374,735.00)	(2,229,938.00)	(2,436,416.00)	(2,551,625.00)	(2,672,107.00)	(2,798,559.00)	(2,931,361.00)	(3,070,212.00)	(3,215,823.00)	(3,387,457.04)	(862,652.96)	(27,530,886.00)
ACSAVPRPAA	(261,420.00)	(923,414.00)	(1,142,578.00)	(1,187,600.00)	(1,234,404.00)	(1,283,058.00)	(1,333,648.00)	(1,386,231.00)	(1,440,898.00)	(1,503,927.44)	(382,991.56)	(12,080,170.00)
ACSAVTAXAB	(445,352.00)	(1,573,133.00)	(1,946,552.00)	(2,023,260.00)	(2,103,004.00)	(2,185,897.00)	(2,272,090.00)	(2,361,680.00)	(2,454,820.00)	(2,562,209.38)	(652,494.62)	(20,580,492.00)
AUSAVAUDAX	(575,924.00)	(2,034,352.00)	(2,517,234.00)	(2,616,429.00)	(2,719,549.00)	(2,826,742.00)	(2,938,203.00)	(3,054,057.00)	(3,174,501.00)	(3,313,370.89)	(843,786.11)	(26,614,148.00)
CCSAVPUBAA	(449,292.00)	(1,587,335.00)	(1,964,912.00)	(2,042,420.00)	(2,122,999.00)	(2,206,763.00)	(2,293,863.00)	(2,384,399.00)	(2,478,524.00)	(2,587,063.90)	(658,824.10)	(20,776,395.00)
DSSAVENGAA	(143,472.00)	(276,894.00)	(291,946.00)	(304,656.00)	(317,919.00)	(331,787.00)	(346,192.00)	(361,407.00)	(377,182.00)	(395,554.68)	(100,732.32)	(3,247,742.00)
DSSAVOTHAA	(56,012.00)	(160,766.00)	(169,883.00)	(176,360.00)	(183,092.00)	(190,080.00)	(197,221.00)	(204,844.00)	(212,620.00)	(221,486.93)	(56,404.07)	(1,828,769.00)
ENSAVAFFAA	(322,218.00)	(904,717.00)	(946,255.00)	(983,418.00)	(1,022,110.00)	(1,062,219.00)	(1,103,991.00)	(1,147,405.00)	(1,192,486.00)	(1,244,473.28)	(316,918.72)	(10,246,211.00)
EXSAVMGTAA	(483,832.00)	(1,712,659.00)	(2,129,200.00)	(2,214,084.00)	(2,302,365.00)	(2,394,174.00)	(2,489,650.00)	(2,588,938.00)	(2,692,177.00)	(2,811,390.65)	(715,951.35)	(22,534,421.00)
EXSAVSTFAA	(136,911.00)	(482,936.00)	(595,676.00)	(618,965.00)	(643,168.00)	(668,319.00)	(694,469.00)	(721,640.00)	(749,884.00)	(782,416.17)	(199,250.83)	(6,293,635.00)
FLSAVPROAA	(341,281.00)	(957,588.00)	(1,001,240.00)	(1,040,601.00)	(1,081,584.00)	(1,124,068.00)	(1,168,316.00)	(1,214,304.00)	(1,262,058.00)	(1,317,135.94)	(335,423.06)	(10,843,599.00)
GSSAVFACAA	(4,852,810.00)	(6,984,068.00)	(7,302,079.00)	(7,528,610.00)	(7,761,059.00)	(8,001,641.00)	(8,249,589.00)	(8,505,125.00)	(8,768,492.00)	(9,063,376.20)	(2,308,087.80)	(79,324,937.00)
GSSAVFLTAA	(73,870.00)	(260,882.00)	(322,653.00)	(335,353.00)	(348,555.00)	(362,278.00)	(376,546.00)	(391,376.00)	(406,794.00)	(424,567.30)	(108,120.70)	(3,410,995.00)
GSSAVOFFAB	(415,916.00)	(1,468,876.00)	(1,816,768.00)	(1,888,286.00)	(1,962,631.00)	(2,039,908.00)	(2,120,262.00)	(2,203,779.00)	(2,290,602.00)	(2,390,696.11)	(608,816.89)	(19,206,541.00)
GSSAVOTHAB	(67,553.00)	(238,508.00)	(294,802.00)	(306,388.00)	(318,431.00)	(330,949.00)	(343,964.00)	(357,491.00)	(371,553.00)	(387,760.54)	(98,747.46)	(3,116,147.00)
GSSAVREAAA	(25,312.00)	(89,405.00)	(110,614.00)	(114,973.00)	(119,503.00)	(124,211.00)	(129,108.00)	(134,198.00)	(139,489.00)	(145,589.14)	(37,075.86)	(1,169,478.00)
GSSAVRECAB	(93,839.00)	(331,360.00)	(409,708.00)	(425,824.00)	(442,575.00)	(459,987.00)	(478,093.00)	(496,910.00)	(516,471.00)	(539,021.33)	(137,267.67)	(4,331,056.00)
GSSAVSECAA	(25,863.00)	(91,356.00)	(113,043.00)	(117,499.00)	(122,130.00)	(126,944.00)	(131,950.00)	(137,153.00)	(142,562.00)	(148,798.77)	(37,893.23)	(1,195,192.00)
HRSAVBENAB	(388,650.00)	(1,372,795.00)	(1,698,523.00)	(4,076,444.00)	(4,238,013.00)	(4,406,328.00)	(4,581,522.00)	(4,763,680.00)	(4,952,933.00)	(5,171,867.44)	(1,317,072.56)	(36,967,828.00)
HRSAVCOMAB	(174,284.00)	(615,793.00)	(762,421.00)	(792,511.00)	(823,792.00)	(856,312.00)	(890,126.00)	(925,276.00)	(961,819.00)	(1,003,960.49)	(255,669.51)	(8,061,964.00)
HRSAVDEVAB	(227,863.00)	(805,074.00)	(996,686.00)	(1,036,013.00)	(1,076,897.00)	(1,119,398.00)	(1,163,592.00)	(1,209,530.00)	(1,257,289.00)	(1,312,364.93)	(334,208.07)	(10,538,915.00)
HRSAVOPDAB	(172,006.00)	(607,728.00)	(752,382.00)	(782,070.00)	(812,934.00)	(845,019.00)	(878,381.00)	(913,061.00)	(949,116.00)	(990,692.36)	(252,290.64)	(7,955,680.00)
HRSAVOTHAB	(430,738.00)	(1,521,865.00)	(1,884,090.00)	(1,958,433.00)	(2,035,722.00)	(2,116,065.00)	(2,199,609.00)	(2,286,452.00)	(2,376,735.00)	(2,480,849.55)	(631,775.45)	(19,922,334.00)
HRSAVPAYAB	(177,560.00)	(627,151.00)	(775,880.00)	(806,442.00)	(838,213.00)	(871,237.00)	(905,576.00)	(941,269.00)	(978,374.00)	(1,021,154.78)	(260,048.22)	(8,202,905.00)
HRSAVRELAB	(86,061.00)	(303,564.00)	(374,427.00)	(389,065.00)	(404,278.00)	(420,087.00)	(436,524.00)	(453,603.00)	(471,356.00)	(491,804.59)	(125,243.41)	(3,956,013.00)
HRSAVSAFAB	(167,159.00)	(590,558.00)	(731,007.00)	(759,841.00)	(789,815.00)	(820,976.00)	(853,377.00)	(887,056.00)	(922,070.00)	(962,445.69)	(245,097.31)	(7,729,402.00)
HRSAVSTFAB	(96,575.00)	(341,051.00)	(421,772.00)	(438,369.00)	(455,623.00)	(473,557.00)	(492,205.00)	(511,587.00)	(531,736.00)	(554,963.48)	(141,327.52)	(4,458,766.00)
ISSAVCTRAA	(1,533,385.00)	(6,175,611.00)	(7,770,567.00)	(8,106,971.00)	(8,458,005.00)	(8,824,987.00)	(9,210,362.00)	(9,611,390.00)	(10,030,513.00)	(10,257,121.04)	(2,612,087.96)	(82,591,000.00)
ISSAVDATAB	(1,284,347.00)	(6,593,883.00)	(8,608,058.00)	(9,061,087.00)	(9,538,174.00)	(10,040,396.00)	(10,569,854.00)	(11,127,617.00)	(11,714,786.00)	(12,416,397.65)	(3,161,971.35)	(94,116,571.00)
ISSAVDEVAA	(11,152,913.00)	(39,326,136.00)	(43,509,810.00)	(47,304,447.00)	(49,665,680.00)	(36,146,275.00)	(37,876,265.00)	(32,137,303.00)	(33,629,423.00)	(33,494,582.53)	(8,529,761.47)	(372,772,596.00)
ISSAVDPRAB	(915,208.00)	(3,232,810.00)	(4,000,156.00)	(4,157,788.00)	(4,321,657.00)	(4,491,998.00)	(4,669,120.00)	(4,853,225.00)	(5,044,622.00)	(5,265,300.65)	(1,340,866.35)	(42,292,751.00)
ISSAVOTHAB	(267,608.00)	(945,332.00)	(1,169,862.00)	(1,215,976.00)	(1,263,915.00)	(1,313,749.00)	(1,365,567.00)	(1,419,426.00)	(1,475,422.00)	(1,539,984.99)	(392,174.01)	(12,369,016.00)
LGSAVATTAB	(1,788,987.00)	(2,777,089.00)	(3,001,623.00)	(3,145,887.00)	(3,296,825.00)	(3,455,365.00)	(3,621,988.00)	(3,796,286.00)	(3,979,187.00)	(4,195,137.41)	(1,068,337.59)	(34,126,712.00)
LGSAVSTFAB	(170,714.00)	(603,394.00)	(747,667.00)	(777,232.00)	(807,971.00)	(839,929.00)	(873,160.00)	(907,706.00)	(943,623.00)	(985,053.39)	(250,854.61)	(7,907,304.00)
MKSAVADVAA	(1,243,239.00)	(1,851,534.00)	(1,978,355.00)	(2,075,355.00)	(2,176,711.00)	(2,282,438.00)	(2,394,552.00)	(2,511,064.00)	(2,633,993.00)	(2,778,553.89)	(707,589.11)	(22,633,384.00)
MKSAVFORAA	(72,199.00)	(254,963.00)	(315,285.00)	(327,691.00)	(340,586.00)	(353,990.00)	(367,927.00)	(382,413.00)	(397,471.00)	(414,830.80)	(105,641.20)	(3,332,997.00)
MKSAVOTHAA	(2,088,380.00)	(7,374,812.00)	(9,119,685.00)	(9,478,509.00)	(9,851,509.00)	(10,239,218.00)	(10,642,355.00)	(11,061,356.00)	(11,496,944.00)	(11,999,070.56)	(3,055,694.44)	(96,407,533.00)
MKSAVPLNAA	(253,799.00)	(896,423.00)	(1,108,978.00)	(1,152,657.00)	(1,198,063.00)	(1,245,263.00)	(1,294,341.00)	(1,345,351.00)	(1,398,384.00)	(1,459,524.21)	(371,683.79)	(11,724,467.00)
MKSAVRATAA	(74,488.00)	(262,087.00)	(321,435.00)	(333,822.00)	(346,688.00)	(360,050.00)	(373,941.00)	(388,366.00)	(403,356.00)	(420,589.33)	(107,107.67)	(3,391,930.00)
MKSAVRESAA	(279,827.00)	(988,364.00)	(1,222,750.00)	(1,270,914.00)	(1,320,982.00)	(1,373,026.00)	(1,427,143.00)	(1,483,391.00)	(1,541,867.00)	(1,609,285.79)	(409,822.21)	(12,927,372.00)
MKSAVRRPAA	(641,741.00)	(2,266,731.00)	(2,804,468.00)	(2,914,952.00)	(3,029,808.00)	(3,149,198.00)	(3,273,340.00)	(3,402,375.00)	(3,536,521.00)	(3,691,183.73)	(940,000.27)	(29,650,318.00)
NREGBENENR	-	-	-	(217,000.00)	(226,000.00)	(235,000.00)	(245,000.00)	(255,000.00)	(264,000.00)	(276,568.75)	(70,431.25)	(1,789,000.00)
NREGCRDTNR	(32,000.00)	(45,000.00)	(46,000.00)	(47,000.00)	(49,000.00)	(50,000.00)	(52,000.00)	(53,000.00)	(55,000.00)	(56,588.99)	(14,411.01)	(500,000.00)
NREGDIRERR	(179,000.00)	(246,000.00)	(253,500.00)	(261,000.00)	(268,500.00)	(277,000.00)	(285,000.00)	(293,500.00)	(302,500.00)	(312,435.01)	(79,564.99)	(2,758,000.00)

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AEP/CSW
SCHEDULE OF SYNERGIES ANALYSIS SAVINGS
BY WORK ORDER AND YEAR

WORK ORDER	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	TOTAL
NREGDIRE60	(179,000.00)	(246,000.00)	(253,500.00)	(261,000.00)	(268,500.00)	(277,000.00)	(285,000.00)	(293,500.00)	(302,500.00)	(312,435.01)	(79,564.99)	(2,758,000.00)
NREGINSUNR	(81,000.[illegible])	(113,000.00)	(117,000.00)	(122,000.00)	(126,000.00)	(131,000.00)	(137,000.00)	(142,000.00)	(148,000.00)	(154,623.45)	(39,376.55)	(1,311,000.00)
NREGPROFNR	(2,737,000.00)	(3,832,000.00)	(4,023,000.00)	(4,224,000.00)	(4,436,000.00)	(4,657,000.00)	(4,890,000.00)	(5,135,000.00)	(5,392,000.00)	(5,696,359.74)	(1,450,640.26)	(46,473,000.00)
PASAVBUDAA	(171,584.00)	(605,965.00)	(749,444.00)	(778,943.00)	(809,607.00)	(841,481.00)	(874,623.00)	(909,070.00)	(944,881.00)	(986,164.45)	(251,137.55)	(7,922,900.00)
PSSAVENGAA	(245,52[illegible].00)	(430,738.00)	(451,592.00)	(472,221.00)	(493,782.00)	(516,355.00)	(540,036.00)	(564,770.00)	(590,662.00)	(621,073.78)	(158,163.22)	(5,084,918.00)
PSSAVOTHAA	(693,3[illegible]7.00)	(1,937,393.00)	(2,021,794.00)	(2,101,764.00)	(2,185,049.00)	(2,271,400.00)	(2,361,346.00)	(2,454,856.00)	(2,551,960.00)	(2,664,049.64)	(678,429.36)	(21,921,428.00)
PSSAVPLTAA	(430,728.00)	(1,211,196.00)	(1,267,671.00)	(1,317,351.00)	(1,369,069.00)	(1,422,675.00)	(1,478,504.00)	(1,536,524.00)	(1,596,766.00)	(1,666,219.90)	(424,321.10)	(13,721,025.00)
PSSAVSUPAA	(948,101.00)	(2,662,609.00)	(2,785,114.00)	(2,894,465.00)	(3,008,312.00)	(3,126,325.00)	(3,249,235.00)	(3,376,976.00)	(3,509,614.00)	(3,662,572.01)	(932,713.99)	(30,156,040.00)
RDSAVRESAA	(33,176.00)	(93,096.00)	(97,345.00)	(101,172.00)	(105,155.00)	(109,285.00)	(113,586.00)	(118,057.00)	(122,699.00)	(128,052.13)	(32,609.87)	(1,054,233.00)
REGUADUEAA	(274,000.00)	(376,000.00)	(388,000.00)	(399,000.00)	(411,000.00)	(424,000.00)	(436,000.00)	(449,000.00)	(463,000.00)	(477,419.82)	(121,580.18)	(4,219,000.00)
REGUBENERO	-	-	-	(8,630,000.00)	(8,975,000.00)	(9,334,000.00)	(9,707,000.00)	(10,096,000.00)	(10,499,000.00)	(10,966,309.46)	(2,792,690.54)	(71,000,000.00)
REGUCAACAA	(411,000.00)	(576,000.00)	(602,000.00)	(630,000.00)	(660,000.00)	(690,000.00)	(723,000.00)	(758,000.00)	(793,000.00)	(835,285.44)	(212,714.56)	(6,891,000.00)
REGUCRDTRO	(56,000.00)	(76,000.00)	(79,000.00)	(81,000.00)	(83,000.00)	(86,000.00)	(88,000.00)	(91,000.00)	(94,000.00)	(97,237.43)	(24,762.57)	(856,000.00)
REGUCSERAA	(1,964,000.00)	(5,229,000.00)	(5,524,000.00)	(5,734,000.00)	(5,955,000.00)	(6,187,000.00)	(6,426,000.00)	(6,673,000.00)	(6,931,000.00)	(7,229,841.78)	(1,841,158.22)	(59,694,000.00)
REGUDISTAA	(7,300,000.00)	(10,091,000.00)	(12,645,000.00)	(10,845,000.00)	(11,245,000.00)	(11,660,000.00)	(12,092,000.00)	(12,540,000.00)	(13,007,000.00)	(13,542,304.23)	(3,448,695.77)	(118,416,000.00)
REGUFUELAA	(118,000.00)	(163,000.00)	(171,000.00)	(179,000.00)	(188,000.00)	(197,000.00)	(206,000.00)	(215,000.00)	(226,000.00)	(237,514.37)	(60,485.63)	(1,961,000.00)
REGUGENEAA	(18,803,000.00)	(25,937,000.00)	(33,362,000.00)	(27,769,000.00)	(28,735,000.00)	(29,737,000.00)	(30,776,000.00)	(31,855,000.00)	(32,972,000.00)	(34,246,702.86)	(8,721,297.14)	(302,914,000.00)
REGUGENECC	(35,500.00)	(98,000.00)	(103,000.00)	(106,500.00)	(110,500.00)	(115,500.00)	(119,500.00)	(124,000.00)	(129,000.00)	(134,697.75)	(34,302.25)	(1,110,500.00)
REGUGENE04	(35,500.00)	(98,000.00)	(103,000.00)	(106,500.00)	(110,500.00)	(115,500.00)	(119,500.00)	(124,000.00)	(129,000.00)	(134,697.75)	(34,302.25)	(1,110,500.00)
REGUINSURO	(4,220,000.00)	(5,851,000.00)	(6,085,000.00)	(6,329,000.00)	(6,582,000.00)	(6,845,000.00)	(7,119,000.00)	(7,404,000.00)	(7,700,000.00)	(8,042,013.40)	(2,047,986.60)	(68,225,000.00)
REGUPROFRO	(448,000.00)	(627,000.00)	(659,000.00)	(692,000.00)	(726,000.00)	(763,000.00)	(801,000.00)	(841,000.00)	(883,000.00)	(932,522.86)	(237,477.14)	(7,610,000.00)
REGUSALEAA	(490,000.00)	(1,559,000.00)	(1,907,000.00)	(1,984,000.00)	(2,064,000.00)	(2,147,000.00)	(2,233,000.00)	(2,322,000.00)	(2,415,000.00)	(2,521,796.87)	(642,203.13)	(20,285,000.00)
REGUTRANAA	(4,370,000.00)	(6,052,000.00)	(7,394,000.00)	(6,531,000.00)	(6,785,000.00)	(7,050,000.00)	(7,327,000.00)	(7,614,000.00)	(7,915,000.00)	(8,260,399.10)	(2,103,600.90)	(71,402,000.00)
RGSAVGOVAB	(725,552.00)	(1,283,929.00)	(1,420,685.00)	(1,468,858.00)	(1,518,698.00)	(1,570,264.00)	(1,623,622.00)	(1,678,828.00)	(1,735,949.00)	(1,800,659.40)	(458,557.60)	(15,285,602.00)
RMSAVRMTAA	(276,963.00)	(978,218.00)	(1,210,120.00)	(1,257,778.00)	(1,307,321.00)	(1,358,819.00)	(1,412,367.00)	(1,468,025.00)	(1,525,886.00)	(1,592,595.22)	(405,571.78)	(12,793,664.00)
SCSAVAPRAA	(539,371.00)	(1,904,641.00)	(2,355,084.00)	(2,447,729.00)	(2,544,032.00)	(2,644,133.00)	(2,748,216.00)	(2,856,395.00)	(2,968,856.00)	(3,098,492.92)	(789,065.08)	(24,896,015.00)
SCSAVBUYAA	(569,813.00)	(2,011,973.00)	(2,487,335.00)	(2,585,137.00)	(2,686,800.00)	(2,792,469.00)	(2,902,342.00)	(3,016,535.00)	(3,135,247.00)	(3,272,083.24)	(833,271.76)	(26,293,006.00)
SCSAVICPAA	(194,240.00)	(685,988.00)	(848,443.00)	(881,841.00)	(916,558.00)	(952,646.00)	(990,169.00)	(1,029,169.00)	(1,069,714.00)	(1,116,456.22)	(284,317.78)	(8,969,542.00)
SCSAVMATAA	(103,571.00)	(365,831.00)	(452,619.00)	(470,450.00)	(488,987.00)	(508,255.00)	(528,292.00)	(549,1[illegible]7.00)	(570,767.00)	(595,729.08)	(151,708.92)	(4,785,327.00)
SCSAVPURAA	(335,078.00)	(1,183,564.00)	(1,464,383.00)	(1,522,078.00)	(1,582,055.00)	(1,644,400.00)	(1,709,228.00)	(1,776,611.00)	(1,846,661.00)	(1,927,428.32)	(490,840.68)	(15,482,327.00)
STSAVCPPAA	(315,268.00)	(1,113,889.00)	(1,379,009.00)	(1,433,422.00)	(1,489,990.00)	(1,548,795.00)	(1,609,943.00)	(1,673,504.00)	(1,739,584.00)	(1,815,787.00)	(462,410.00)	(14,581,601.00)
TCSAVTELAB	(2,515,508.00)	(4,797,853.00)	(5,397,651.00)	(5,585,850.00)	(5,779,290.00)	(5,980,130.00)	(6,188,582.00)	(6,404,782.00)	(6,627,941.00)	(6,880,706.82)	(1,752,247.18)	(57,910,541.00)
TRSAVCASAL	(321,335.00)	(1,135,134.00)	(1,404,774.00)	(1,460,151.00)	(1,517,721.00)	(1,577,564.00)	(1,639,790.00)	(1,704,470.00)	(1,771,712.00)	(1,849,245.44)	(470,930.56)	(14,852,827.00)
TRSAVFLPAA	(161,686.00)	(571,176.00)	(706,880.00)	(734,749.00)	(763,720.00)	(793,837.00)	(825,151.00)	(857,702.00)	(891,542.00)	(930,561.38)	236,977.62)	(7,473,982.00)
TRSAVINTAA	(1,000.00)	(2,000.00)	(2,000.00)	(2,000.00)	(2,000.00)	(2,000.00)	(2,000.00)	(2,000.00)	(2,000.00)	(1,594.06)	(405.94)	(19,000.00)
TRSAVINVAA	(735,230.00)	(1,308,340.00)	(1,449,443.00)	(1,498,280.00)	(1,550,062.00)	(1,601,822.00)	(1,656,610.00)	(1,713,453.00)	(1,771,400.00)	(1,837,494.06)	(467,937.94)	(15,590,072.00)
TSSAVBULAA	(97,646.00)	(280,602.00)	(296,670.00)	(307,962.00)	(319,697.00)	(331,877.00)	(344,324.00)	(357,611.00)	(371,164.00)	(386,614.41)	(98,455.59)	(3,192,623.00)
TSSAVENGAA	(113,804.00)	(191,311.00)	(201,309.00)	(210,588.00)	(220,287.00)	(230,457.00)	(241,081.00)	(252,262.00)	(263,923.00)	(277,607.27)	(70,695.73)	(2,273,325.00)
TSSAVOTHAA	(58,429.00)	(167,464.00)	(176,849.00)	(183,605.00)	(190,628.00)	(197,919.00)	(205,368.00)	(213,323.00)	(221,438.00)	(230,691.81)	(58,748.19)	(1,904,463.00)
TSSAVPOWAA	(205,607.00)	(588,598.00)	(621,255.00)	(645,030.00)	(669,747.00)	(695,406.00)	(721,621.00)	(749,625.00)	(778,184.00)	(810,761.68)	(206,469.32)	(6,692,304.00)
TOTAL	(80,855,393.00)	(193,658,039.00)	(227,730,057.00)	(239,739,416.00)	(249,702,407.00)	(244,098,297.00)	(254,070,264.00)	(256,907,512.00)	(267,327,267.00)	(277,246,846.69)	(70,603,939.31)	(2,367,939,438.00)

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ANALYSIS OF SYNERGIES ANALYSIS SAVINGS
BY FERC AND YEAR

FERC	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	TOTAL
1070	(22,399,507.00)	(54,013,988.00)	(58,056,216.00)	(64,830,460.00)	(67,704,437.00)	(54,714,391.00)	(56,989,265.00)	(51,808,667.00)	(53,875,607.00)	(53,912,769.16)	(13,729,475.84)	(552,034,783.00)
1540	-	-	(9,820,000.00)	-	-	-	-	-	-	-	-	(9,820,000.00)
1630	(884,237.00)	(3,131,834.00)	(3,898,624.00)	(4,054,544.00)	(4,216,724.00)	(4,385,405.00)	(4,560,826.00)	(4,743,279.00)	(4,933,003.00)	(5,049,543.55)	(1,285,921.45)	(41,143,941.00)
4265	(718,460.00)	(1,259,813.00)	(1,393,446.00)	(1,440,800.00)	(1,489,799.00)	(1,540,501.00)	(1,592,963.00)	(1,647,251.00)	(1,703,423.00)	(1,767,084.60)	(450,007.40)	(15,003,548.00)
5010	(97,000.00)	(135,000.00)	(142,000.00)	(149,000.00)	(157,000.00)	(165,000.00)	(173,000.00)	(181,000.00)	(191,000.00)	(201,648.11)	(51,351.89)	(1,643,000.00)
5060	(4,094,388.00)	(9,271,929.00)	(9,663,667.00)	(10,071,558.00)	(10,497,561.00)	(10,940,815.00)	(11,404,286.00)	(11,886,928.00)	(12,389,844.00)	(12,975,447.50)	(3,304,339.50)	(106,500,763.00)
5120	(3,462,000.00)	(4,786,500.00)	(4,963,500.00)	(5,148,000.00)	(5,339,500.00)	(5,539,000.00)	(5,745,500.00)	(5,961,000.00)	(6,185,000.00)	(6,442,776.55)	(1,640,723.45)	(55,213,500.00)
5140	(3,462,000.00)	(4,786,500.00)	(4,963,500.00)	(5,148,000.00)	(5,339,500.00)	(5,539,000.00)	(5,745,500.00)	(5,961,000.00)	(6,185,000.00)	(6,442,776.55)	(1,640,723.45)	(55,213,500.00)
5240	(68,000.00)	(189,000.00)	(198,000.00)	(205,000.00)	(213,000.00)	(222,000.00)	(230,000.00)	(239,000.00)	(248,000.00)	(259,034.13)	(65,965.87)	(2,137,000.00)
5660	(628,913.00)	(1,138,432.00)	(1,189,698.00)	(1,244,191.00)	(1,300,908.00)	(1,359,905.00)	(1,421,747.00)	(1,486,772.00)	(1,554,668.00)	(1,633,905.19)	(416,091.81)	(13,375,231.00)
5730	(2,152,000.00)	(2,992,000.00)	(3,121,000.00)	(3,255,000.00)	(3,396,000.00)	(3,542,000.00)	(3,696,000.00)	(3,856,000.00)	(4,024,000.00)	(4,220,263.72)	(1,074,736.28)	(35,329,000.00)
5880	(972,913.00)	(1,432,562.00)	(1,502,754.00)	(1,576,517.00)	(1,653,849.00)	(1,734,804.00)	(1,820,277.00)	(1,909,623.00)	(2,003,511.00)	(2,113,831.67)	(538,310.33)	(17,258,952.00)
5980	(2,699,000.00)	(3,739,000.00)	(3,885,000.00)	(4,036,000.00)	(4,194,000.00)	(4,358,000.00)	(4,529,000.00)	(4,707,000.00)	(4,894,000.00)	(5,108,153.01)	(1,300,846.99)	(43,450,000.00)
9050	(335,000.00)	(470,000.00)	(494,000.00)	(518,000.00)	(544,000.00)	(571,000.00)	(600,000.00)	(630,000.00)	(661,000.00)	(698,196.60)	(177,803.40)	(5,699,000.00)
9100	(3,774,890.00)	(12,286,614.00)	(14,671,862.00)	(15,252,148.00)	(15,854,106.00)	(16,481,424.00)	(17,132,778.00)	(17,809,983.00)	(18,513,720.00)	(19,683,052.56)	(5,012,504.44)	(156,473,082.00)
9160	(1,640,000.00)	(3,083,000.00)	(3,479,000.00)	(3,637,000.00)	(3,802,000.00)	(3,973,000.00)	(4,153,000.00)	(4,340,000.00)	(4,536,000.00)	(4,765,430.94)	(1,213,569.06)	(38,622,000.00)
9300	(4,645,043.00)	(6,379,192.00)	(6,570,568.00)	(6,767,685.00)	(6,970,716.00)	(7,179,837.00)	-	-	-	-	-	(38,513,041.00)
9302	(34,374,042.00)	(83,935,675.00)	(99,058,222.00)	(111,713,513.00)	(116,303,307.00)	(121,089,215.00)	(133,475,122.00)	(138,899,009.00)	(144,546,491.00)	(151,040,410.00)	(38,464,091.00)	(1,172,899,097.00)
9350	(448,000.00)	(627,000.00)	(659,000.00)	(692,000.00)	(726,000.00)	(763,000.00)	(801,000.00)	(841,000.00)	(883,000.00)	(932,522.86)	(237,477.14)	(7,610,000.00)
TOTAL	(86,855,393.00)	(193,658,039.00)	(227,730,057.00)	(239,739,416.00)	(249,702,407.00)	(244,098,297.00)	(254,070,264.00)	(256,907,512.00)	(267,327,267.00)	(277,246,846.69)	(70,603,939.31)	(2,367,939,438.00)

SUMMARY OF SAVINGS BY YEAR

FOR THE YEAR 1999

(IN 000'S)

	DIRECT CAPITAL BALANCE SHEET SAVINGS		DIRECT SAVINGS			SERVICE CORP SAVINGS			TOTAL SAVINGS			ANNUAL PMI	5-YEAR ACCRUAL OF TOTAL CTA	5-YEAR ACCRUAL OF TOTAL CIC	NET SAVINGS	50% OF NET SAVINGS	REALLOC SERVICE CORP O&M	CUSTOMER IMPACT
	DIRECT	SERVICE	O&M	CAPITAL	TOTAL	O&M	CAPITAL	TOTAL	O&M	CAPITAL	TOTAL							
REGULATED:																		
CSW	6,137	2,396	8,465	1,075	9,541	12,473	704	13,177	20,938	1,779	22,717	(514)	(12,345)	(3,435)	6,423	(3,212)	3,578	6,789
AEP	10,181	4,525	13,742	1,784	15,525	24,087	1,329	25,416	37,829	3,113	40,942	(926)	(22,249)	(6,191)	11,576	(5,788)	(11,290)	(5,501)
Total	16,318	6,921	22,207	2,859	25,066	36,560	2,033	38,593	58,767	4,892	63,659	(1,439)	(34,594)	(9,626)	18,000	(9,000)	(7,712)	1,288
NON-REGULATED:																		
CSW	0	31	1,182	0	1,182	1,188	9	1,197	2,370	9	2,379	(54)	(1,293)	(360)	673	(336)	11,814	12,151
AEP	0	13	2,026	0	2,026	408	4	412	2,434	4	2,438	(55)	(1,325)	(369)	689	(345)	(4,726)	(4,381)
Total	0	44	3,208	0	3,208	1,597	13	1,610	4,805	13	4,818	(109)	(2,618)	(728)	1,362	(681)	7,088	7,769
COMBINED:																		
CSW	6,137	2,428	9,647	1,075	10,723	13,661	713	14,374	23,308	1,788	25,097	(567)	(13,638)	(3,795)	7,096	(3,548)	15,392	18,940
AEP	10,181	4,538	15,768	1,784	17,551	24,496	1,333	25,828	40,263	3,117	43,380	(981)	(23,574)	(6,560)	12,266	(6,133)	(16,016)	(9,883)
Total	16,318	6,966	25,415	2,859	28,274	38,157	2,046	40,203	63,572	4,905	68,477	(1,548)	(37,212)	(10,355)	19,362	(9,681)	(624)	9,057

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SUMMARY OF SAVINGS BY YEAR

FOR THE YEAR 2000

(IN 000'S)

	DIRECT CAPITAL BALANCE SHEET SAVINGS		DIRECT SAVINGS			SERVICE CORP SAVINGS			TOTAL SAVINGS			ANNUAL PMI	5-YEAR ACCRUAL OF TOTAL CTA	5-YEAR ACCRUAL OF TOTAL CIC	NET SAVINGS	50% OF NET SAVINGS	REALLOC SERVICE CORP O&M	CUSTOMER IMPACT
	DIRECT	SERVICE	O&M	CAPITAL	TOTAL	O&M	CAPITAL	TOTAL	O&M	CAPITAL	TOTAL							
REGULATED:																		
CSW	8,780	11,729	12,683	2,597	15,280	32,532	4,321	36,853	45,215	6,918	52,133	(1,454)	(16,595)	(4,618)	29,466	(14,733)	3,578	18,311
AEP	14,596	21,833	20,674	4,318	24,992	61,760	8,044	69,804	82,435	12,361	94,796	(2,644)	(30,176)	(8,397)	53,580	(26,790)	(11,290)	15,500
Total	23,376	33,563	33,357	6,915	40,272	94,293	12,365	106,657	127,650	19,280	146,929	(4,098)	(46,771)	(13,014)	83,046	(41,523)	(7,712)	33,811
NON-REGULATED:																		
CSW	0	143	1,650	0	1,650	3,415	53	3,467	5,065	53	5,117	(143)	(1,629)	(453)	2,892	(1,446)	11,814	13,261
AEP	0	64	2,832	0	2,832	966	24	990	3,798	24	3,821	(107)	(1,216)	(338)	2,160	(1,080)	(4,726)	(3,646)
Total	0	207	4,482	0	4,482	4,380	76	4,457	8,862	76	8,939	(249)	(2,845)	(792)	5,052	(2,526)	7,088	9,614
COMBINED:																		
CSW	8,780	11,872	14,333	2,597	16,930	35,947	4,374	40,321	50,280	6,971	57,251	(1,597)	(18,224)	(5,071)	32,359	(16,179)	15,392	31,571
AEP	14,596	21,898	23,506	4,318	27,824	62,726	8,067	70,794	86,233	12,385	98,618	(2,750)	(31,392)	(8,735)	55,740	(27,870)	(16,016)	11,854
Total	23,376	33,770	37,839	6,915	44,754	98,673	12,441	111,114	136,512	19,356	155,868	(4,347)	(49,616)	(13,806)	88,099	(44,049)	(624)	43,426

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SUMMARY OF SAVINGS BY YEAR

FOR THE YEAR 2001

(IN 000'S)

	DIRECT CAPITAL BALANCE SHEET SAVINGS		DIRECT SAVINGS			SERVICE CORP SAVINGS			TOTAL SAVINGS			ANNUAL PMI	5-YEAR ACCRUAL OF TOTAL CTA	5-YEAR ACCRUAL OF TOTAL CIC	NET SAVINGS	50% OF NET SAVINGS	REALLOC SERVICE CORP O&M	CUSTOMER IMPACT
	DIRECT	SERVICE	O&M	CAPITAL	TOTAL	O&M	CAPITAL	TOTAL	O&M	CAPITAL	TOTAL							
REGULATED:																		
CSW	12,770	13,044	13,319	4,689	18,007	38,310	8,122	46,431	51,628	12,810	64,439	(2,492)	(16,655)	(4,634)	40,656	(20,328)	3,578	23,906
AEP	21,209	24,482	21,724	7,787	29,512	72,641	15,243	87,883	94,365	23,030	117,395	(4,541)	(30,343)	(8,443)	74,068	(37,034)	(11,290)	25,745
Total	33,979	37,527	35,043	12,476	47,519	110,950	23,364	134,315	145,993	35,840	181,834	(7,033)	(46,998)	(13,078)	114,725	(57,362)	(7,712)	49,650
NON-REGULATED:																		
CSW	0	184	1,725	0	1,725	4,130	115	4,244	5,854	115	5,969	(231)	(1,543)	(429)	3,766	(1,883)	11,814	13,697
AEP	0	85	2,968	0	2,968	1,139	53	1,192	4,107	53	4,160	(161)	(1,075)	(299)	2,625	(1,312)	(4,726)	(3,414)
Total	0	269	4,693	0	4,693	5,269	168	5,436	9,962	168	10,129	(392)	(2,618)	(729)	6,391	(3,195)	7,088	10,284
COMBINED:																		
CSW	12,770	13,229	15,044	4,689	19,732	42,439	8,236	50,676	57,483	12,925	70,408	(2,723)	(18,198)	(5,064)	44,423	(22,211)	15,392	37,603
AEP	21,209	24,567	24,692	7,787	32,480	73,780	15,296	89,076	98,472	23,083	121,555	(4,702)	(31,418)	(8,742)	76,693	(38,347)	(16,016)	22,331
Total	33,979	37,796	39,736	12,476	52,212	116,219	23,532	139,751	155,955	36,008	191,963	(7,425)	(49,616)	(13,806)	121,116	(60,558)	(624)	59,934

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SUMMARY OF SAVINGS BY YEAR

FOR THE YEAR 2002

(IN 000'S)

	DIRECT CAPITAL BALANCE SHEET SAVINGS		DIRECT SAVINGS			SERVICE CORP SAVINGS			TOTAL SAVINGS			ANNUAL PMI	5-YEAR ACCRUAL OF TOTAL CTA	5-YEAR ACCRUAL OF TOTAL CIC	NET SAVINGS	50% OF NET SAVINGS	REALLOC SERVICE CORP O&M	CUSTOMER IMPACT
	DIRECT	SERVICE	O&M	CAPITAL	TOTAL	O&M	CAPITAL	TOTAL	O&M	CAPITAL	TOTAL							
REGULATED:																		
CSW	9,964	14,457	15,842	6,256	22,098	40,347	12,123	52,470	56,189	18,379	74,568	(3,693)	(16,597)	(4,618)	49,659	(24,829)	3,578	28,407
AEP	16,968	27,146	27,242	10,654	37,896	76,802	22,764	99,566	104,044	33,418	137,462	(6,809)	(30,597)	(8,514)	91,543	(45,771)	(11,290)	34,482
Total	26,932	41,602	43,084	16,910	59,994	117,149	34,887	152,036	160,233	51,797	212,030	(10,502)	(47,194)	(13,132)	141,202	(70,601)	(7,712)	62,889
NON-REGULATED:																		
CSW	50	205	1,971	9	1,980	4,335	172	4,507	6,305	181	6,486	(321)	(1,444)	(402)	4,320	(2,160)	11,814	13,974
AEP	0	95	3,111	0	3,111	1,205	80	1,285	4,316	80	4,396	(218)	(979)	(272)	2,928	(1,464)	(4,726)	(3,262)
Total	50	301	5,082	9	5,091	5,540	252	5,792	10,622	261	10,883	(539)	(2,422)	(674)	7,247	(3,624)	7,088	10,712
COMBINED:																		
CSW	10,014	14,662	17,813	6,265	24,078	44,681	12,295	56,976	62,494	18,560	81,054	(4,015)	(18,041)	(5,020)	53,978	(26,989)	15,392	42,381
AEP	16,968	27,241	30,353	10,654	41,007	78,007	22,844	100,851	108,360	33,498	141,858	(7,026)	(31,575)	(8,786)	94,471	(47,235)	(16,016)	31,220
Total	26,982	41,903	48,166	16,919	65,085	122,688	35,139	157,827	170,854	52,058	222,912	(11,041)	(49,616)	(13,806)	148,449	(74,224)	(624)	73,601

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SUMMARY OF SAVINGS BY YEAR

FOR THE YEAR 2003

(IN 000'S)

	DIRECT CAPITAL BALANCE SHEET SAVINGS		DIRECT SAVINGS			SERVICE CORP SAVINGS			TOTAL SAVINGS			ANNUAL PMI	5-YEAR ACCRUAL OF TOTAL CTA	5-YEAR ACCRUAL OF TOTAL CIC	NET SAVINGS	50% OF NET SAVINGS	REALLOC SERVICE CORP O&M	CUSTOMER IMPACT
	DIRECT	SERVICE	O&M	CAPITAL	TOTAL	O&M	CAPITAL	TOTAL	O&M	CAPITAL	TOTAL							
REGULATED:																		
CSW	10,289	15,203	16,480	7,898	24,377	41,980	16,084	58,064	58,460	23,981	82,441	(5,164)	(16,644)	(4,631)	56,002	(28,001)	3,578	31,578
AEP	17,526	28,535	28,335	13,452	41,788	79,899	30,188	110,087	108,235	43,640	151,875	(9,513)	(30,663)	(8,532)	103,168	(51,584)	(11,290)	40,294
Total	?7,815	43,737	44,815	21,350	66,165	121,880	46,272	168,152	166,695	67,622	234,317	(14,676)	(47,307)	(13,163)	159,170	(79,585)	(7,712)	71,873
NON-REGULATED:																		
CSW	52	216	2,060	18	2,078	4,510	228	4,738	6,570	246	6,816	(427)	(1,376)	(383)	4,630	(2,315)	11,814	14,129
AEP	0	101	3,262	0	3,262	1,255	107	1,362	4,517	107	4,623	(290)	(933)	(260)	3,141	(1,570)	(4,726)	(3,156)
Total	52	317	5,322	18	5,340	5,765	335	6,100	11,087	353	11,440	(717)	(2,310)	(643)	7,771	(3,885)	7,088	10,974
COMBINED:																		
CSW	10,341	15,419	18,540	7,916	26,455	46,490	16,312	62,802	65,030	24,228	89,257	(5,591)	(18,020)	(5,014)	60,632	(30,316)	15,392	45,708
AEP	17,526	28,636	31,597	13,452	45,050	81,154	30,295	111,449	112,752	43,747	156,499	(9,802)	(31,596)	(8,792)	106,309	(53,154)	(16,016)	37,139
Total	27,867	44,054	50,137	21,368	71,505	127,644	46,607	174,251	177,781	67,975	245,756	(15,393)	(49,616)	(13,806)	166,941	(83,470)	(624)	82,847

SUMMARY OF SAVINGS BY YEAR

FOR THE YEAR 2004

(IN 000'S)

	DIRECT CAPITAL BALANCE SHEET SAVINGS		DIRECT SAVINGS			SERVICE CORP SAVINGS			TOTAL SAVINGS			ANNUAL PMI	5-YEAR ACCRUAL OF TOTAL CTA	5-YEAR ACCRUAL OF TOTAL CIC	NET SAVINGS	50% OF NET SAVINGS	REALLOC SERVICE CORP O&M	CUSTOMER IMPACT
	DIRECT	SERVICE	O&M	CAPITAL	TOTAL	O&M	CAPITAL	TOTAL	O&M	CAPITAL	TOTAL							
REGULATED:																		
CSW	10,626	10,183	17,145	9,541	26,685	43,703	17,609	61,312	60,848	27,150	87,997	(6,747)	(4,146)	(1,154)	75,950	(37,975)	3,578	41,553
AEP	18,104	19,805	29,476	16,254	45,731	83,130	34,247	117,377	112,606	50,502	163,108	(12,506)	(7,686)	(2,139)	140,777	(70,389)	(11,290)	59,099
Total	28,730	2',988	46,621	25,795	72,416	126,833	51,856	178,689	173,454	77,651	251,105	(19,253)	(11,832)	(3,292)	216,727	(108,364)	(7,712)	100,652
NON-REGULATED:																		
CSW	54	223	2,154	27	2,181	4,677	386	5,063	6,831	413	7,244	(555)	(341)	(95)	6,252	(3,126)	11,814	14,940
AEP	0	104	3,419	0	3,419	1,295	180	1,475	4,714	180	4,894	(375)	(231)	(64)	4,224	(2,112)	(4,726)	(2,614)
Total	54	328	5,573	27	5,600	5,972	567	6,538	11,545	594	12,138	(931)	(572)	(159)	10,477	(5,238)	7,088	12,327
COMBINED:																		
CSW	10,680	10,407	19,298	9,568	28,866	48,380	17,995	66,376	67,678	27,563	95,242	(7,303)	(4,488)	(1,249)	82,202	(41,101)	15,392	56,493
AEP	18,104	19,909	32,896	16,254	49,150	84,424	34,428	118,852	117,320	50,682	168,002	(12,881)	(7,916)	(2,203)	145,001	(72,501)	(16,016)	56,485
Total	28,784	30,316	52,194	25,822	78,016	132,805	52,423	185,228	184,999	78,245	263,244	(20,184)	(12,404)	(3,452)	227,204	(113,602)	(624)	112,978

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SUMMARY OF SAVINGS BY YEAR

FOR THE YEAR 2005

(IN 000'S)

	DIRECT CAPITAL BALANCE SHEET SAVINGS		DIRECT SAVINGS			SERVICE CORP SAVINGS			TOTAL SAVINGS			ANNUAL PMI	5-YEAR ACCRUAL OF TOTAL CTA	5-YEAR ACCRUAL OF TOTAL CIC	NET SAVINGS	50% OF NET SAVINGS	REALLOC SERVICE CORP O&M	CUSTOMER IMPACT
	DIRECT	SERVICE	O&M	CAPITAL	TOTAL	O&M	CAPITAL	TOTAL	O&M	CAPITAL	TOTAL							
REGULATED:																		
CSW	10,975	10,690	17,835	11,187	29,023	45,479	19,199	64,677	63,314	30,386	93,700	(8,431)	0	0	85,269	(42,634)	3,578	46,212
AEP	18,701	20,782	30,662	19,063	49,724	86,493	37,321	123,814	117,155	56,383	173,538	(15,615)	0	0	157,923	(78,962)	(11,290)	67,672
Total	29,676	31,472	48,497	30,250	78,747	131,972	56,519	188,492	180,469	86,769	267,239	(24,047)	0	0	243,192	(121,596)	(7,712)	113,884
NON-REGULATED:																		
CSW	57	235	2,253	36	2,288	4,866	422	5,288	7,118	458	7,576	(682)	0	0	6,894	(3,447)	11,814	15,262
AEP	0	110	3,584	0	3,585	1,348	198	1,546	4,933	198	5,131	(462)	0	0	4,669	(2,334)	(4,726)	(2,392)
Total	57	345	5,837	36	5,873	6,214	620	6,834	12,051	656	12,707	(1,143)	0	0	11,563	(5,782)	7,088	12,870
COMBINED:																		
CSW	11,032	10,925	20,088	11,223	31,311	50,345	19,620	69,965	70,433	30,844	101,276	(9,113)	0	0	92,163	(46,082)	15,392	61,473
AEP	18,701	20,892	34,246	19,063	53,309	87,841	37,519	125,360	122,088	56,581	178,669	(16,077)	0	0	162,592	(81,296)	(16,016)	65,280
Total	29,733	31,817	54,334	30,286	84,620	138,186	57,139	195,325	192,520	87,425	279,945	(25,190)	0	0	254,755	(127,378)	(624)	126,754

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SUMMARY OF SAVINGS BY YEAR

FOR THE YEAR 2006

(IN 000'S)

	DIRECT CAPITAL BALANCE SHEET SAVINGS		DIRECT SAVINGS			SERVICE CORP SAVINGS			TOTAL SAVINGS			ANNUAL PMI	5-YEAR ACCRUAL OF TOTAL CTA	5-YEAR ACCRUAL OF TOTAL CIC	NET SAVINGS	50% OF NET SAVINGS	REALLOC SERVICE CORP O&M	CUSTOMER IMPACT
	DIRECT	SERVICE	O&M	CAPITAL	TOTAL	O&M	CAPITAL	TOTAL	O&M	CAPITAL	TOTAL							
REGULATED:																		
CSW	11,335	8,483	18,556	12,839	31,395	47,339	17,905	65,244	65,895	30,745	96,639	(10,081)	0	0	86,558	(43,279)	3,578	46,857
AEP	19,318	16,997	31,897	21,882	53,779	89,998	35,875	125,873	121,895	57,757	179,652	(18,741)	0	0	160,911	(80,456)	(11,290)	69,166
Total	30,653	25,480	50,453	34,721	85,174	137,337	53,781	191,117	187,790	88,502	276,291	(28,822)	0	0	247,469	(123,735)	(7,712)	116,023
NON-REGULATED:																		
CSW	59	245	2,355	45	2,400	5,055	517	5,572	7,410	562	7,972	(832)	0	0	7,140	(3,570)	11,814	15,385
AEP	0	115	3,758	0	3,758	1,398	243	1,641	5,156	243	5,399	(563)	0	0	4,836	(2,418)	(4,726)	(2,308)
Total	59	360	6,113	45	6,158	6,453	760	7,213	12,566	805	13,371	(1,395)	0	0	11,976	(5,988)	7,088	13,076
COMBINED:																		
CSW	11,394	8,728	20,911	12,884	33,795	52,394	18,423	70,817	73,304	31,307	104,611	(10,913)	0	0	93,699	(46,849)	15,392	62,241
AEP	19,318	17,112	35,655	21,882	57,537	91,396	36,118	127,514	127,051	58,000	185,051	(19,304)	0	0	165,747	(82,874)	(16,016)	66,858
Total	30,712	25,840	56,566	34,766	91,332	143,790	54,541	198,331	200,356	89,307	289,663	(30,217)	0	0	259,446	(129,723)	(624)	129,099

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SUMMARY OF SAVINGS BY YEAR

FOR THE YEAR 2007

(IN 000'S)

	DIRECT CAPITAL BALANCE SHEET SAVINGS		DIRECT SAVINGS			SERVICE CORP SAVINGS			TOTAL SAVINGS			ANNUAL PMI	5-YEAR ACCRUAL OF TOTAL CTA	5-YEAR ACCRUAL OF TOTAL CIC	NET SAVINGS	50% OF NET SAVINGS	REALLOC SERVICE CORP O&M	CUSTOMER IMPACT
	DIRECT	SERVICE	O&M	CAPITAL	TOTAL	O&M	CAPITAL	TOTAL	O&M	CAPITAL	TOTAL							
REGULATED:																		
CSW	11,708	8,893	19,307	14,498	33,805	49,265	17,070	66,335	68,572	31,568	100,140	(11,102)	0	0	89,038	(44,519)	3,578	48,097
AEP	19,957	17,810	33,184	24,713	57,897	93,645	34,187	127,832	126,829	58,900	185,730	(20,590)	0	0	165,139	(82,570)	(11,290)	71,280
Total	31,665	26,703	52,491	39,211	91,702	142,910	51,258	194,168	195,401	90,469	285,870	(31,692)	0	0	254,178	(127,089)	(7,712)	119,377
NON-REGULATED:																		
CSW	61	258	2,463	55	2,518	5,259	494	5,753	7,722	549	8,271	(917)	0	0	7,354	(3,677)	11,814	15,491
AEP	0	122	3,940	0	3,940	1,456	234	1,690	5,396	234	5,630	(624)	0	0	5,006	(2,503)	(4,726)	(2,223)
Total	61	380	6,403	55	6,458	6,714	728	7,443	13,117	783	13,901	(1,541)	0	0	12,360	(6,180)	7,088	13,268
COMBINED:																		
CSW	11,769	9,150	21,769	14,553	36,322	54,524	17,565	72,089	76,293	32,118	108,411	(12,019)	0	0	96,392	(48,196)	15,392	63,588
AEP	19,957	17,932	37,125	24,713	61,838	95,100	34,421	129,522	132,225	59,134	191,360	(21,214)	0	0	170,145	(85,073)	(16,016)	69,057
Total	31,726	27,083	58,894	39,266	98,160	149,625	51,986	201,611	208,519	91,252	299,771	(33,233)	0	0	266,538	(133,269)	(624)	132,645

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SUMMARY OF SAVINGS BY YEAR

FOR THE YEAR 2008

(IN 000'S)

	DIRECT CAPITAL BALANCE SHEET SAVINGS		DIRECT SAVINGS			SERVICE CORP SAVINGS			TOTAL SAVINGS			ANNUAL PMI	5-YEAR ACCRUAL OF TOTAL CTA	5-YEAR ACCRUAL OF TOTAL CIC	NET SAVINGS	50% OF NET SAVINGS	REALLOC SERVICE CORP O&M	CUSTOMER IMPACT
	DIRECT	SERVICE	O&M	CAPITAL	TOTAL	O&M	CAPITAL	TOTAL	O&M	CAPITAL	TOTAL							
REGULATED:																		
CSW	11,999	8,611	20,306	16,422	36,728	51,406	15,442	66,848	71,713	31,863	103,576	(11,810)	0	0	91,766	(45,883)	3,578	49,461
AEP	20,451	17,425	34,903	27,990	62,893	97,851	31,247	129,098	132,754	59,237	191,991	(21,891)	0	0	170,100	(85,050)	(11,290)	73,761
Total	32,449	26,037	55,209	44,411	99,621	149,257	46,689	195,947	204,467	91,101	295,567	(33,701)	0	0	261,867	(130,933)	(7,712)	123,221
NON-REGULATED:																		
CSW	64	276	2,590	66	2,656	5,517	494	6,011	8,107	560	8,667	(988)	0	0	7,679	(3,839)	11,814	15,654
AEP	0	137	4,155	0	4,156	1,556	245	1,801	5,711	245	5,956	(679)	0	0	5,277	(2,639)	(4,726)	(2,087)
Total	64	412	6,745	66	6,811	7,073	739	7,812	13,818	806	14,623	(1,667)	0	0	12,956	(6,478)	7,088	13,566
COMBINED:																		
CSW	12,062	8,887	22,896	16,488	39,384	56,923	15,936	72,859	79,819	32,424	112,243	(12,798)	0	0	99,445	(49,723)	15,392	65,114
AEP	20,451	17,562	39,059	27,990	67,048	99,407	31,492	130,899	138,465	59,482	197,948	(22,570)	0	0	175,378	(87,689)	(16,016)	71,673
Total	32,513	26,449	61,955	44,477	106,432	156,330	47,429	203,759	218,285	91,906	310,191	(35,368)	0	0	274,823	(137,411)	(624)	136,788

SUMMARY OF SAVINGS BY YEAR

FOR THE YEAR 2009

(IN 000'S)

	DIRECT CAPITAL BALANCE SHEET SAVINGS		DIRECT SAVINGS			SERVICE CORP SAVINGS			TOTAL SAVINGS			ANNUAL PMI	5-YEAR ACCRUAL OF TOTAL CTA	5-YEAR ACCRUAL OF TOTAL CIC	NET SAVINGS	50% OF NET SAVINGS	REALLOC SERVICE CORP O&M	CUSTOMER IMPACT
	DIRECT	SERVICE	O&M	CAPITAL	TOTAL	O&M	CAPITAL	TOTAL	O&M	CAPITAL	TOTAL							
REGULATED:																		
CSW	3,056	2,193	5,171	4,182	9,353	13,091	3,932	17,024	18,262	8,114	26,377	(3,132)	0	0	23,244	(11,622)	3,578	15,200
AEP	5,208	4,438	8,888	7,128	16,016	24,919	7,958	32,876	33,807	15,085	48,893	(5,806)	0	0	43,086	(21,543)	(11,290)	10,254
Total	8,264	6,631	14,060	11,310	25,369	38,010	11,890	49,900	52,070	23,200	75,269	(8,939)	0	0	66,331	(33,165)	(7,712)	25,453
NON-REGULATED:																		
CSW	16	70	660	17	676	1,405	126	1,531	2,064	143	2,207	(262)	0	0	1,945	(973)	11,814	12,787
AEP	0	35	1,058	0	1,058	396	62	459	1,454	62	1,517	(180)	0	0	1,337	(668)	(4,726)	(4,058)
Total	16	105	1,718	17	1,735	1,801	188	1,989	3,519	205	3,724	(442)	0	0	3,282	(1,641)	7,088	8,729
COMBINED:																		
CSW	3,072	2,263	5,831	4,199	10,029	14,496	4,058	18,554	20,327	8,257	28,584	(3,395)	0	0	25,189	(12,595)	15,392	27,987
AEP	5,208	4,472	9,947	7,128	17,075	25,315	8,020	33,335	35,262	15,148	50,410	(5,986)	0	0	44,423	(22,212)	(16,016)	6,196
Total	8,280	6,736	15,777	11,327	27,104	39,811	12,078	51,889	55,589	23,405	78,993	(9,381)	0	0	69,612	(34,806)	(624)	34,182

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AMERICAN ELECTRIC POWER COMPANY
ALLOCATION OF MERGER SAVINGS
TO NON-REGULATED SUBSIDIARIES

COMPANY	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	TOTAL
TOTAL SAVINGS												
25	(42)	(61)	(64)	(68)	(72)	(75)	(79)	(83)	(87)	(92)	(24)	(748)
26	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(1)
53	(2)	(5)	(6)	(6)	(6)	(6)	(7)	(7)	(7)	(7)	(2)	(61)
56	(1)	(5)	(6)	(6)	(7)	(7)	(7)	(8)	(8)	(8)	(2)	(65)
57	(1)	(5)	(6)	(6)	(7)	(7)	(7)	(8)	(8)	(8)	(2)	(65)
58	(308)	(458)	(492)	(519)	(546)	(578)	(606)	(638)	(667)	(707)	(180)	(5,699)
59	(582)	(910)	(995)	(1,059)	(1,119)	(1,194)	(1,255)	(1,326)	(1,383)	(1,473)	(375)	(11,671)
60	(223)	(349)	(376)	(391)	(406)	(424)	(438)	(455)	(470)	(489)	(124)	(4,145)
63	(1)	(3)	(3)	(4)	(4)	(4)	(4)	(5)	(5)	(5)	(1)	(38)
64	(1)	(3)	(3)	(3)	(3)	(4)	(4)	(4)	(4)	(4)	(1)	(34)
66	(1)	(2)	(3)	(3)	(3)	(3)	(3)	(4)	(4)	(4)	(1)	(31)
67	(1)	(5)	(6)	(6)	(6)	(7)	(7)	(7)	(8)	(8)	(2)	(63)
69	(337)	(510)	(549)	(581)	(612)	(649)	(681)	(717)	(750)	(792)	(202)	(6,379)
72	(6)	(16)	(19)	(20)	(21)	(22)	(23)	(24)	(24)	(25)	(6)	(206)
74	(592)	(921)	(1,003)	(1,063)	(1,121)	(1,190)	(1,250)	(1,318)	(1,375)	(1,459)	(372)	(11,664)
81	(129)	(189)	(202)	(213)	(224)	(237)	(249)	(262)	(274)	(290)	(74)	(2,343)
83	(36)	(52)	(55)	(58)	(61)	(64)	(67)	(70)	(74)	(78)	(20)	(635)
86	(1)	(3)	(4)	(4)	(4)	(4)	(4)	(4)	(5)	(5)	(1)	(38)
87	(15)	(37)	(43)	(45)	(47)	(49)	(51)	(53)	(55)	(57)	(14)	(464)
88	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(1)
89	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(1)
90	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(1)
91	(129)	(188)	(200)	(210)	(220)	(232)	(243)	(255)	(268)	(283)	(72)	(2,299)
99	(29)	(101)	(125)	(130)	(135)	(140)	(145)	(151)	(156)	(162)	(41)	(1,314)
TOTAL	(2,438)	(3,822)	(4,160)	(4,396)	(4,624)	(4,894)	(5,131)	(5,399)	(5,630)	(5,956)	(1,517)	(47,967)

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AMERICAN ELECTRIC POWER COMPANY
ALLOCATION OF MERGER SAVINGS
TO NON-REGULATED SUBSIDIARIES

AMORTIZATION OF COST TO ACHIEVE

COMPANY	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	TOTAL
25	23	19	17	15	14	4	0	0	0	0	0	92
26	0	0	0	0	0	0	0	0	0	0	0	0
53	1	2	1	1	1	0	0	0	0	0	0	7
56	1	2	2	1	1	0	0	0	0	0	0	7
57	1	2	2	1	1	0	0	0	0	0	0	7
58	167	146	127	116	110	27	0	0	0	0	0	693
59	316	290	257	236	226	56	0	0	0	0	0	1,381
60	121	111	97	87	82	20	0	0	0	0	0	518
63	0	1	1	1	1	0	0	0	0	0	0	4
64	0	1	1	1	1	0	0	0	0	0	0	4
66	0	1	1	1	1	0	0	0	0	0	0	3
67	1	2	2	1	1	0	0	0	0	0	0	7
69	183	162	142	129	123	31	0	0	0	0	0	771
72	3	5	5	4	4	1	0	0	0	0	0	23
74	322	293	259	237	226	56	0	0	0	0	0	1,393
81	70	60	52	48	45	11	0	0	0	0	0	286
83	20	17	14	13	12	3	0	0	0	0	0	79
86	1	1	1	1	1	0	0	0	0	0	0	4
87	8	12	11	10	9	2	0	0	0	0	0	53
88	0	0	0	0	0	0	0	0	0	0	0	0
89	0	0	0	0	0	0	0	0	0	0	0	0
90	0	0	0	0	0	0	0	0	0	0	0	0
91	70	60	52	47	44	11	0	0	0	0	0	284
99	16	32	32	29	27	7	0	0	0	0	0	143
TOTAL	1,325	1,216	1,075	979	933	231	0	0	0	0	0	5,759

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AMERICAN ELECTRIC POWER COMPANY
ALLOCATION OF MERGER SAVINGS
TO NON-REGULATED SUBSIDIARIES

COMPANY	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	TOTAL
PREMERGER INITIATIVES												
25	1	2	2	3	4	6	7	9	10	11	3	58
26	0	0	0	0	0	0	0	0	0	0	0	0
53	0	0	0	0	0	0	1	1	1	1	0	5
56	0	0	0	0	0	1	1	1	1	1	0	5
57	0	0	0	0	0	1	1	1	1	1	0	5
58	7	13	19	26	34	44	55	67	74	81	21	440
59	13	25	38	53	70	91	113	138	153	168	45	908
60	5	10	15	19	25	32	39	48	52	56	15	316
63	0	0	0	0	0	0	0	0	1	1	0	3
64	0	0	0	0	0	0	0	0	0	0	0	3
66	0	0	0	0	0	0	0	0	0	0	0	2
67	0	0	0	0	0	1	1	1	1	1	0	5
69	8	14	21	29	38	50	61	75	83	90	24	494
72	0	0	1	1	1	2	2	2	3	3	1	16
74	13	26	39	53	70	91	112	137	152	166	44	905
81	3	5	8	11	14	18	22	27	30	33	9	181
83	1	1	2	3	4	5	6	7	8	9	2	49
86	0	0	0	0	0	0	0	0	1	1	0	3
87	0	1	2	2	3	4	5	5	6	6	2	36
88	0	0	0	0	0	0	0	0	0	0	0	0
89	0	0	0	0	0	0	0	0	0	0	0	0
90	0	0	0	0	0	0	0	0	0	0	0	0
91	3	5	8	10	14	18	22	27	30	32	9	177
99	1	3	5	6	8	11	13	16	17	18	5	103
TOTAL	55	107	161	218	290	375	462	563	624	679	180	3,714

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AMERICAN ELECTRIC POWER COMPANY
ALLOCATION OF MERGER SAVINGS
TO NON-REGULATED SUBSIDIARIES

COMPANY	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	TOTAL
SAVINGS LESS COST TO ACHIEVE AND PRE-MERGER INITIATIVES												
25	(18)	(40)	(45)	(49)	(53)	(66)	(72)	(75)	(78)	(82)	(21)	(598)
26	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(1)
53	(1)	(3)	(4)	(4)	(5)	(6)	(6)	(6)	(6)	(7)	(2)	(49)
56	(1)	(3)	(4)	(5)	(5)	(6)	(7)	(7)	(7)	(7)	(2)	(53)
57	(1)	(3)	(4)	(5)	(5)	(6)	(7)	(7)	(7)	(7)	(2)	(53)
58	(134)	(300)	(345)	(378)	(402)	(506)	(552)	(572)	(593)	(626)	(159)	(4,566)
59	(253)	(595)	(699)	(771)	(823)	(1,046)	(1,142)	(1,188)	(1,229)	(1,305)	(331)	(9,381)
60	(97)	(228)	(264)	(285)	(298)	(371)	(399)	(408)	(418)	(433)	(110)	(3,310)
63	(0)	(2)	(2)	(3)	(3)	(4)	(4)	(4)	(4)	(4)	(1)	(31)
64	(0)	(2)	(2)	(2)	(3)	(3)	(3)	(4)	(4)	(4)	(1)	(28)
66	(0)	(2)	(2)	(2)	(2)	(3)	(3)	(3)	(3)	(3)	(1)	(25)
67	(1)	(3)	(4)	(5)	(5)	(6)	(6)	(6)	(7)	(7)	(2)	(51)
69	(146)	(333)	(386)	(423)	(450)	(568)	(620)	(643)	(666)	(702)	(178)	(5,115)
72	(2)	(10)	(13)	(15)	(15)	(19)	(21)	(21)	(22)	(22)	(6)	(167)
74	(257)	(602)	(705)	(774)	(824)	(1,043)	(1,137)	(1,180)	(1,222)	(1,293)	(327)	(9,366)
81	(56)	(124)	(142)	(155)	(165)	(208)	(226)	(234)	(244)	(257)	(65)	(1,876)
83	(16)	(34)	(39)	(42)	(45)	(56)	(61)	(63)	(66)	(69)	(17)	(507)
86	(0)	(2)	(2)	(3)	(3)	(4)	(4)	(4)	(4)	(4)	(1)	(31)
87	(6)	(24)	(30)	(33)	(34)	(43)	(46)	(47)	(49)	(50)	(13)	(375)
88	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(1)
89	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(1)
90	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(1)
91	(56)	(123)	(140)	(153)	(162)	(203)	(221)	(229)	(238)	(250)	(63)	(1,838)
99	(13)	(66)	(88)	(94)	(99)	(122)	(132)	(135)	(139)	(143)	(36)	(1,068)
TOTAL	(1,058)	(2,499)	(2,924)	(3,199)	(3,401)	(4,288)	(4,669)	(4,836)	(5,006)	(5,277)	(1,337)	(38,494)

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AMERICAN ELECTRIC POWER COMPANY
ALLOCATION OF MERGER SAVINGS
TO NON-REGULATED SUBSIDIARIES

COMPANY	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	TOTAL
AMORTIZATION OF CHANGE IN CONTROL												
25	6	5	5	4	4	1	0	0	0	0	0	26
26	0	0	0	0	0	0	0	0	0	0	0	0
53	0	0	0	0	0	0	0	0	0	0	0	2
56	0	0	0	0	0	0	0	0	0	0	0	2
57	0	0	0	0	0	0	0	0	0	0	0	2
58	47	41	35	32	31	8	0	0	0	0	0	193
59	88	81	72	66	63	16	0	0	0	0	0	384
60	34	31	27	24	23	6	0	0	0	0	0	144
63	0	0	0	0	0	0	0	0	0	0	0	1
64	0	0	0	0	0	0	0	0	0	0	0	1
66	0	0	0	0	0	0	0	0	0	0	0	1
67	0	0	0	0	0	0	0	0	0	0	0	2
69	51	45	40	36	34	9	0	0	0	0	0	214
72	1	1	1	1	1	0	0	0	0	0	0	6
74	90	82	72	66	63	16	0	0	0	0	0	388
81	19	17	15	13	13	3	0	0	0	0	0	80
83	5	5	4	4	3	1	0	0	0	0	0	22
86	0	0	0	0	0	0	0	0	0	0	0	1
87	2	3	3	3	3	1	0	0	0	0	0	15
88	0	0	0	0	0	0	0	0	0	0	0	0
89	0	0	0	0	0	0	0	0	0	0	0	0
90	0	0	0	0	0	0	0	0	0	0	0	0
91	20	17	14	13	12	3	0	0	0	0	0	79
99	4	9	9	8	8	2	0	0	0	0	0	40
TOTAL	369	338	299	272	260	64	0	0	0	0	0	1,603

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AMERICAN ELECTRIC POWER COMPANY
ALLOCATION OF MERGER SAVINGS
TO NON-REGULATED SUBSIDIARIES

COMPANY	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	TOTAL
NET SHAREHOLDERS SAVINGS												
25	(12)	(34)	(41)	(45)	(49)	(65)	(72)	(75)	(78)	(82)	(21)	(573)
26	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(1)
53	(0)	(3)	(4)	(4)	(4)	(6)	(6)	(6)	(6)	(7)	(2)	(47)
56	(0)	(3)	(4)	(4)	(5)	(6)	(7)	(7)	(7)	(7)	(2)	(51)
57	(0)	(3)	(4)	(4)	(5)	(6)	(7)	(7)	(7)	(7)	(2)	(51)
58	(87)	(259)	(310)	(346)	(371)	(498)	(552)	(572)	(593)	(626)	(159)	(4,373)
59	(165)	(514)	(628)	(705)	(760)	(1,030)	(1,142)	(1,188)	(1,229)	(1,305)	(331)	(8,997)
60	(63)	(197)	(237)	(260)	(275)	(366)	(399)	(408)	(418)	(433)	(110)	(3,166)
63	(0)	(2)	(2)	(2)	(3)	(4)	(4)	(4)	(4)	(4)	(1)	(30)
64	(0)	(1)	(2)	(2)	(2)	(3)	(3)	(4)	(4)	(4)	(1)	(27)
66	(0)	(1)	(2)	(2)	(2)	(3)	(3)	(3)	(3)	(3)	(1)	(24)
67	(0)	(3)	(4)	(4)	(4)	(6)	(6)	(6)	(7)	(7)	(2)	(49)
69	(95)	(288)	(347)	(387)	(416)	(560)	(620)	(643)	(666)	(702)	(178)	(4,901)
72	(2)	(9)	(12)	(13)	(14)	(19)	(21)	(21)	(22)	(22)	(6)	(160)
74	(168)	(521)	(633)	(708)	(761)	(1,027)	(1,137)	(1,180)	(1,222)	(1,293)	(327)	(8,978)
81	(36)	(107)	(128)	(142)	(152)	(204)	(226)	(234)	(244)	(257)	(65)	(1,796)
83	(10)	(29)	(35)	(39)	(41)	(55)	(61)	(63)	(66)	(69)	(17)	(486)
86	(0)	(2)	(2)	(2)	(3)	(3)	(4)	(4)	(4)	(4)	(1)	(30)
87	(4)	(21)	(27)	(30)	(32)	(42)	(46)	(47)	(49)	(50)	(13)	(360)
88	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(1)
89	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(1)
90	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(1)
91	(37)	(106)	(126)	(140)	(150)	(200)	(221)	(229)	(238)	(250)	(63)	(1,760)
99	(8)	(57)	(79)	(86)	(91)	(121)	(132)	(135)	(139)	(143)	(36)	(1,028)
TOTAL	(690)	(2,160)	(2,625)	(2,927)	(3,141)	(4,224)	(4,669)	(4,836)	(5,006)	(5,277)	(1,337)	(36,891)

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AMERICAN ELECTRIC POWER COMPANY
ALLOCATION OF MERGER SAVINGS
TO REGULATED SUBSIDIARIES

COMPANY	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	TOTAL
TOTAL SAVINGS												
01	(281)	(701)	(889)	(1,063)	(1,197)	(1,250)	(1,330)	(1,326)	(1,359)	(1,377)	(351)	(11,124)
02	(10,818)	(25,164)	(31,245)	(36,873)	(40,839)	(43,720)	(46,535)	(47,987)	(49,593)	(51,168)	(13,031)	(396,975)
03	(2,639)	(5,994)	(7,380)	(8,601)	(9,479)	(10,189)	(10,840)	(11,256)	(11,654)	(12,081)	(3,077)	(93,190)
04	(8,099)	(18,870)	(23,323)	(27,355)	(30,135)	(32,378)	(34,425)	(35,709)	(36,943)	(38,191)	(9,726)	(295,153)
06	(294)	(722)	(911)	(1,087)	(1,219)	(1,273)	(1,354)	(1,354)	(1,391)	(1,416)	(360)	(11,382)
07	(10,675)	(23,952)	(29,522)	(34,340)	(37,936)	(40,811)	(43,504)	(45,215)	(46,919)	(48,745)	(12,413)	(374,034)
10	(6,233)	(14,589)	(18,129)	(21,273)	(23,623)	(24,899)	(26,487)	(26,925)	(27,815)	(28,603)	(7,284)	(225,860)
21	(1)	(2)	(2)	(3)	(3)	(3)	(3)	(4)	(4)	(4)	(1)	(30)
22	(82)	(163)	(191)	(209)	(223)	(244)	(257)	(274)	(281)	(304)	(77)	(2,305)
23	(0)	(1)	(1)	(1)	(1)	(1)	(2)	(2)	(2)	(2)	(0)	(14)
31	(14)	(29)	(35)	(38)	(40)	(43)	(46)	(48)	(50)	(54)	(14)	(410)
32	(19)	(39)	(46)	(50)	(53)	(57)	(60)	(64)	(66)	(71)	(18)	(541)
34	(78)	(238)	(306)	(348)	(379)	(446)	(469)	(515)	(520)	(529)	(135)	(3,964)
40	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(1)
41	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(3)
42	(139)	(404)	(519)	(608)	(663)	(785)	(828)	(911)	(918)	(936)	(238)	(6,950)
43	(168)	(479)	(615)	(714)	(780)	(928)	(979)	(1,079)	(1,086)	(1,106)	(282)	(8,217)
44	(598)	(1,645)	(2,078)	(2,412)	(2,615)	(3,046)	(3,207)	(3,506)	(3,548)	(3,628)	(924)	(27,206)
45	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(1)
46	(0)	(0)	(1)	(1)	(1)	(1)	(1)	(1)	(1)	(1)	(0)	(7)
48	(119)	(354)	(453)	(564)	(613)	(716)	(755)	(828)	(838)	(858)	(219)	(6,318)
49	(33)	(94)	(121)	(138)	(151)	(181)	(191)	(211)	(212)	(216)	(55)	(1,600)
50	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)
51	(0)	(1)	(1)	(1)	(1)	(1)	(1)	(1)	(1)	(1)	(0)	(9)
52	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(1)
54	(29)	(85)	(108)	(128)	(139)	(164)	(173)	(191)	(192)	(196)	(50)	(1,456)
70	(128)	(254)	(298)	(326)	(347)	(381)	(400)	(427)	(439)	(474)	(121)	(3,594)
71	(128)	(253)	(297)	(325)	(346)	(379)	(399)	(426)	(437)	(472)	(120)	(3,582)
73	(58)	(114)	(134)	(147)	(157)	(172)	(181)	(193)	(198)	(214)	(54)	(1,623)
75	(6)	(25)	(33)	(38)	(42)	(48)	(52)	(56)	(58)	(65)	(16)	(440)
76	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(1)
77	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	[illegible]

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AMERICAN ELECTRIC POWER COMPANY
ALLOCATION OF MERGER SAVINGS
TO REGULATED SUBSIDIARIES

COMPANY	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	TOTAL
78	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(1)
84	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(1)
85	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(1)
98	(298)	(623)	(751)	(817)	(889)	(983)	(1,053)	(1,137)	(1,198)	(1,272)	(324)	(9,345)
XX	(1)	(2)	(3)	(4)	(4)	(5)	(5)	(6)	(6)	(6)	(2)	(43)
TOTAL	(40,942)	(94,797)	(117,395)	(137,462)	(151,875)	(163,107)	(173,539)	(179,652)	(185,729)	(191,991)	(48,893)	(1,485,382)

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AMERICAN ELECTRIC POWER COMPANY
ALLOCATION OF MERGER SAVINGS
TO REGULATED SUBSIDIARIES

COMPANY	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	TOTAL
AMORTIZATION OF COST TO ACHIEVE												
01	153	223	230	237	242	59	0	0	0	0	0	1,143
02	5,879	8,010	8,076	8,207	8,245	2,060	0	0	0	0	0	40,478
03	1,434	1,908	1,908	1,915	1,914	480	0	0	0	0	0	9,558
04	4,401	6,007	6,028	6,089	6,084	1,526	0	0	0	0	0	30,135
06	160	230	235	242	246	60	0	0	0	0	0	1,173
07	5,801	7,624	7,631	7,644	7,659	1,923	0	0	0	0	0	38,282
10	3,387	4,644	4,686	4,735	4,769	1,173	0	0	0	0	0	23,395
21	1	1	1	1	1	0	0	0	0	0	0	3
22	45	52	49	46	45	12	0	0	0	0	0	249
23	0	0	0	0	0	0	0	0	0	0	0	1
31	8	9	9	8	8	2	0	0	0	0	0	45
32	10	12	12	11	11	3	0	0	0	0	0	59
34	43	76	79	78	76	21	0	0	0	0	0	373
40	0	0	0	0	0	0	0	0	0	0	0	0
41	0	0	0	0	0	0	0	0	0	0	0	0
42	76	129	134	135	134	37	0	0	0	0	0	645
43	91	152	159	159	158	44	0	0	0	0	0	763
44	325	524	537	537	528	144	0	0	0	0	0	2,594
45	0	0	0	0	0	0	0	0	0	0	0	0
46	0	0	0	0	0	0	0	0	0	0	0	1
48	65	113	117	126	124	34	0	0	0	0	0	578
49	18	30	31	31	30	9	0	0	0	0	0	148
50	0	0	0	0	0	0	0	0	0	0	0	0
51	0	0	0	0	0	0	0	0	0	0	0	1
52	0	0	0	0	0	0	0	0	0	0	0	0
54	16	27	28	28	28	8	0	0	0	0	0	135
70	70	81	77	72	70	18	0	0	0	0	0	388
71	70	81	77	72	70	18	0	0	0	0	0	387
73	31	36	35	33	32	8	0	0	0	0	0	175
75	4	8	9	9	8	2	0	0	0	0	0	39
76	0	0	0	0	0	0	0	0	0	0	0	0
77	0	0	0	0	0	0	0	0	0	0	0	0

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AMERICAN ELECTRIC POWER COMPANY
ALLOCATION OF MERGER SAVINGS
TO REGULATED SUBSIDIARIES

COMPANY	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	TOTAL
78	0	0	0	0	0	0	0	0	0	0	0	0
84	0	0	0	0	0	0	0	0	0	0	0	0
85	0	0	0	0	0	0	0	0	0	0	0	0
98	162	198	194	182	180	46	0	0	0	0	0	962
XX	0	1	1	1	1	0	0	0	0	0	0	4
TOTAL	22,249	30,176	30,343	30,597	30,663	7,686	0	0	0	0	0	151,714

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AMERICAN ELECTRIC POWER COMPANY
ALLOCATION OF MERGER SAVINGS
TO REGULATED SUBSIDIARIES

COMPANY	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	TOTAL
PREMERGER INITIATIVES												
01	6	20	34	53	75	96	120	138	151	157	42	891
02	245	702	1,209	1,826	2,558	3,352	4,187	5,006	5,498	5,834	1,547	31,965
03	60	167	285	426	594	781	975	1,174	1,292	1,377	365	7,498
04	183	526	902	1,355	1,888	2,483	3,098	3,725	4,096	4,355	1,155	23,765
06	7	20	35	54	76	98	122	141	154	161	43	911
07	241	668	1,142	1,701	2,376	3,129	3,915	4,717	5,202	5,558	1,474	30,123
10	141	407	701	1,054	1,480	1,909	2,383	2,809	3,084	3,261	865	18,094
21	0	0	0	0	0	0	0	0	0	0	0	2
22	2	5	7	10	14	19	23	29	31	35	9	184
23	0	0	0	0	0	0	0	0	0	0	0	1
31	0	1	1	2	2	3	4	5	6	6	2	33
32	0	1	2	2	3	4	5	7	7	8	2	43
34	2	7	12	17	24	34	42	54	58	60	16	325
40	0	0	0	0	0	0	0	0	0	0	0	0
41	0	0	0	0	0	0	0	0	0	0	0	0
42	3	11	20	30	42	60	75	95	102	107	28	573
43	4	13	24	35	49	71	88	113	120	126	33	677
44	14	46	80	119	164	234	289	366	393	414	110	2,228
45	0	0	0	0	0	0	0	0	0	0	0	0
46	0	0	0	0	0	0	0	0	0	0	0	1
48	3	10	18	28	38	55	68	86	93	98	26	522
49	1	3	5	7	9	14	17	22	23	25	7	132
50	0	0	0	0	0	0	0	0	0	0	0	0
51	0	0	0	0	0	0	0	0	0	0	0	1
52	0	0	0	0	0	0	0	0	0	0	0	0
54	1	2	4	6	9	13	16	20	21	22	6	120
70	3	7	12	16	22	29	36	45	49	54	14	286
71	3	7	11	16	22	29	36	44	48	54	14	285
73	1	3	5	7	10	13	16	20	22	24	6	129
75	0	1	1	2	3	4	5	6	6	7	2	37
76	0	0	0	0	0	0	0	0	0	0	0	0
77	0	0	0	0	0	0	0	0	0	0	0	0

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AMERICAN ELECTRIC POWER COMPANY
ALLOCATION OF MERGER SAVINGS
TO REGULATED SUBSIDIARIES

COMPANY	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	TOTAL
78	0	0	0	0	0	0	0	0	0	0	0	0
84	0	0	0	0	0	0	0	0	0	0	0	0
85	0	0	0	0	0	0	0	0	0	0	0	0
98	7	17	29	40	56	75	95	119	133	145	38	754
XX	0	0	0	0	0	0	0	1	1	1	0	4
TOTAL	926	2,644	4,541	6,809	9,513	12,506	15,615	18,741	20,590	21,891	5,806	119,583

AMERICAN ELECTRIC POWER COMPANY
ALLOCATION OF MERGER SAVINGS
TO REGULATED SUBSIDIARIES

COMPANY	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	TOTAL
CUSTOMER EFFECT OF SAVINGS												
01	(61)	(229)	(313)	(387)	(440)	(548)	(605)	(594)	(604)	(610)	(155)	(4,545)
02	(2,347)	(8,226)	(10,980)	(13,420)	(15,018)	(19,154)	(21,174)	(21,491)	(22,048)	(22,667)	(5,742)	(162,266)
03	(573)	(1,959)	(2,594)	(3,130)	(3,486)	(4,464)	(4,932)	(5,041)	(5,181)	(5,352)	(1,356)	(38,067)
04	(1,757)	(6,168)	(8,196)	(9,955)	(11,082)	(14,185)	(15,664)	(15,992)	(16,424)	(16,918)	(4,285)	(120,627)
06	(64)	(236)	(320)	(396)	(448)	(558)	(616)	(606)	(618)	(627)	(159)	(4,649)
07	(2,316)	(7,830)	(10,375)	(12,498)	(13,950)	(17,880)	(19,795)	(20,249)	(20,859)	(21,593)	(5,470)	(152,814)
10	(1,352)	(4,769)	(6,371)	(7,742)	(8,687)	(10,908)	(12,052)	(12,058)	(12,366)	(12,671)	(3,209)	(92,186)
21	(0)	(1)	(1)	(1)	(1)	(1)	(2)	(2)	(2)	(2)	(0)	(12)
22	(18)	(53)	(67)	(76)	(82)	(107)	(117)	(123)	(125)	(135)	(34)	(936)
23	(0)	(0)	(0)	(0)	(0)	(1)	(1)	(1)	(1)	(1)	(0)	(6)
31	(3)	(10)	(12)	(14)	(15)	(19)	(21)	(22)	(22)	(24)	(6)	(167)
32	(4)	(13)	(16)	(18)	(19)	(25)	(27)	(29)	(29)	(31)	(8)	(220)
34	(17)	(78)	(107)	(127)	(139)	(195)	(214)	(231)	(231)	(234)	(59)	(1,633)
40	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)
41	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(1)
42	(30)	(132)	(182)	(221)	(244)	(344)	(377)	(408)	(408)	(415)	(105)	(2,866)
43	(37)	(157)	(216)	(260)	(287)	(407)	(445)	(483)	(483)	(490)	(124)	(3,388)
44	(130)	(538)	(730)	(878)	(961)	(1,334)	(1,459)	(1,570)	(1,577)	(1,607)	(407)	(11,192)
45	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)
46	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(3)
48	(26)	(116)	(159)	(205)	(225)	(314)	(344)	(371)	(373)	(380)	(96)	(2,609)
49	(7)	(31)	(42)	(50)	(55)	(79)	(87)	(94)	(94)	(96)	(24)	(660)
50	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)
51	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(3)
52	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(1)
54	(6)	(28)	(38)	(47)	(51)	(72)	(79)	(85)	(85)	(87)	(22)	(601)
70	(28)	(33)	(105)	(119)	(128)	(167)	(182)	(191)	(195)	(210)	(53)	(1,460)
71	(28)	(83)	(104)	(118)	(127)	(166)	(181)	(191)	(194)	(209)	(53)	(1,455)
73	(13)	(37)	(47)	(54)	(58)	(75)	(82)	(86)	(88)	(95)	(24)	(659)
75	(1)	(8)	(12)	(14)	(15)	(21)	(23)	(25)	(26)	(29)	(7)	(182)
76	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)
77	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)

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AMERICAN ELECTRIC POWER COMPANY
ALLOCATION OF MERGER SAVINGS
TO REGULATED SUBSIDIARIES

COMPANY	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	TOTAL
78	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)
84	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)
85	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)
98	(65)	(204)	(264)	(297)	(327)	(431)	(479)	(509)	(532)	(564)	(143)	(3,814)
XX	(0)	(1)	(1)	(1)	(2)	(2)	(2)	(2)	(3)	(3)	(1)	(18)
TOTAL	(8,883)	(30,988)	(41,255)	(50,028)	(55,849)	(71,458)	(78,962)	(80,456)	(82,570)	(85,050)	(21,543)	(607,042)

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AMERICAN ELECTRIC POWER COMPANY
ALLOCATION OF MERGER SAVINGS
TO REGULATED SUBSIDIARIES

AMORTIZATION OF CHANGE IN CONTROL

COMPANY	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	TOTAL
01	42	62	64	66	67	16	0	0	0	0	0	318
02	1,636	2,229	2,247	2,284	2,294	573	0	0	0	0	0	11,263
03	399	531	531	533	532	134	0	0	0	0	0	2,660
04	1,225	1,671	1,677	1,694	1,693	425	0	0	0	0	0	8,385
06	44	64	65	67	69	17	0	0	0	0	0	326
07	1,614	2,122	2,123	2,127	2,131	535	0	0	0	0	0	10,652
10	942	1,292	1,304	1,318	1,327	326	0	0	0	0	0	6,510
21	0	0	0	0	0	0	0	0	0	0	0	1
22	12	14	14	13	13	3	0	0	0	0	0	69
23	0	0	0	0	0	0	0	0	0	0	0	0
31	2	3	2	2	2	1	0	0	0	0	0	12
32	3	3	3	3	3	1	0	0	0	0	0	16
34	12	21	22	22	21	6	0	0	0	0	0	104
40	0	0	0	0	0	0	0	0	0	0	0	0
41	0	0	0	0	0	0	0	0	0	0	0	0
42	21	36	37	38	37	10	0	0	0	0	0	179
43	25	42	44	44	44	12	0	0	0	0	0	212
44	90	146	149	149	147	40	0	0	0	0	0	722
45	0	0	0	0	0	0	0	0	0	0	0	0
46	0	0	0	0	0	0	0	0	0	0	0	0
48	18	31	33	35	34	9	0	0	0	0	0	161
49	5	8	9	9	8	2	0	0	0	0	0	41
50	0	0	0	0	0	0	0	0	0	0	0	0
51	0	0	0	0	0	0	0	0	0	0	0	0
52	0	0	0	0	0	0	0	0	0	0	0	0
54	4	7	8	8	8	2	0	0	0	0	0	38
70	19	22	21	20	20	5	0	0	0	0	0	108
71	19	22	21	20	19	5	0	0	0	0	0	108
73	9	10	10	9	9	2	0	0	0	0	0	49
75	1	2	2	2	2	1	0	0	0	0	0	11
76	0	0	0	0	0	0	0	0	0	0	0	0
77	0	0	0	0	0	0	0	0	0	0	0	0

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AMERICAN ELECTRIC POWER COMPANY
ALLOCATION OF MERGER SAVINGS
TO REGULATED SUBSIDIARIES

COMPANY	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	TOTAL
78	0	0	0	0	0	0	0	0	0	0	0	0
84	0	0	0	0	0	0	0	0	0	0	0	0
85	0	0	0	0	0	0	0	0	0	0	0	0
98	45	55	54	51	50	13	0	0	0	0	0	268
XX	0	0	0	0	0	0	0	0	0	0	0	1
TOTAL	6,191	8,397	8,443	8,514	8,532	2,139	0	0	0	0	0	42,215

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AMERICAN ELECTRIC POWER COMPANY
ALLOCATION OF MERGER SAVINGS
TO REGULATED SUBSIDIARIES

COMPANY	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	TOTAL
SHAREHOLDER EFFECT OF MERGER												
01	(18)	(167)	(249)	(321)	(373)	(531)	(605)	(594)	(604)	(610)	(155)	(4,227)
02	(711)	(5,997)	(8,733)	(11,136)	(12,724)	(18,581)	(21,174)	(21,491)	(22,048)	(22,667)	(5,742)	(151,003)
03	(174)	(1,428)	(2,063)	(2,598)	(2,953)	(4,330)	(4,932)	(5,041)	(5,181)	(5,352)	(1,356)	(35,408)
04	(533)	(4,497)	(6,519)	(8,261)	(9,389)	(13,760)	(15,664)	(15,992)	(16,424)	(16,918)	(4,285)	(112,242)
06	(19)	(172)	(255)	(328)	(380)	(541)	(616)	(606)	(618)	(627)	(159)	(4,322)
07	(702)	(5,708)	(8,252)	(10,371)	(11,819)	(17,344)	(19,795)	(20,249)	(20,859)	(21,593)	(5,470)	(142,162)
10	(410)	(3,477)	(5,067)	(6,424)	(7,360)	(10,582)	(12,052)	(12,058)	(12,366)	(12,671)	(3,209)	(85,676)
21	(0)	(0)	(1)	(1)	(1)	(1)	(2)	(2)	(2)	(2)	(0)	(11)
22	(5)	(39)	(53)	(63)	(69)	(104)	(117)	(123)	(125)	(135)	(34)	(867)
23	(0)	(0)	(0)	(0)	(0)	(1)	(1)	(1)	(1)	(1)	(0)	(5)
31	(1)	(7)	(10)	(11)	(12)	(18)	(21)	(22)	(22)	(24)	(6)	(154)
32	(1)	(9)	(13)	(15)	(16)	(24)	(27)	(29)	(29)	(31)	(8)	(203)
34	(5)	(57)	(85)	(105)	(118)	(189)	(214)	(231)	(231)	(234)	(59)	(1,529)
40	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)
41	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(1)
42	(9)	(96)	(145)	(184)	(207)	(334)	(377)	(408)	(408)	(415)	(105)	(2,687)
43	(11)	(114)	(172)	(216)	(243)	(394)	(445)	(483)	(483)	(490)	(124)	(3,176)
44	(39)	(392)	(581)	(728)	(815)	(1,294)	(1,459)	(1,570)	(1,577)	(1,607)	(407)	(10,470)
45	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)
46	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(2)
48	(8)	(84)	(127)	(170)	(191)	(304)	(344)	(371)	(373)	(380)	(96)	(2,448)
49	(2)	(22)	(34)	(42)	(47)	(77)	(87)	(94)	(94)	(96)	(24)	(618)
50	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)
51	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(3)
52	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)
54	(2)	(20)	(30)	(39)	(43)	(70)	(79)	(85)	(85)	(87)	(22)	(563)
70	(8)	(60)	(83)	(98)	(108)	(162)	(182)	(191)	(195)	(210)	(53)	(1,352)
71	(8)	(60)	(83)	(98)	(108)	(161)	(181)	(191)	(134)	(209)	(53)	(1,347)
73	(4)	(27)	(38)	(44)	(49)	(73)	(82)	(86)	(88)	(95)	(24)	(610)
75	(0)	(6)	(9)	(12)	(13)	(21)	(23)	(25)	(26)	(29)	(7)	(171)
76	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)
77	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	[illegible]

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AMERICAN ELECTRIC POWER COMPANY
ALLOCATION OF MERGER SAVINGS
TO REGULATED SUBSIDIARIES

COMPANY	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	TOTAL
78	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)
84	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)
85	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)
98	(20)	(149)	(210)	(247)	(277)	(418)	(479)	(509)	(532)	(564)	(143)	(3,547)
XX	(0)	(1)	(1)	(1)	(1)	(2)	(2)	(2)	(3)	(3)	(1)	(17)
TOTAL	(2,693)	(22,592)	(32,812)	(41,514)	(47,317)	(69,319)	(78,962)	(80,456)	(82,570)	(85,050)	(21,543)	(564,828)

CENTRAL AND SOUTH WEST CORPORATION
ALLOCATION OF MERGER SAVINGS
TO NON-REGULATED SUBSIDIARIES

COMPANY	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	TOTAL
TOTAL SAVINGS												
CSE	(381)	(766)	(883)	(944)	(993)	(1,061)	(1,111)	(1,172)	(1,215)	(1,265)	(322)	(10,113)
CSI	(433)	(630)	(669)	(702)	(737)	(774)	(812)	(852)	(894)	(943)	(240)	(7,684)
DCM	(215)	(397)	(454)	(492)	(522)	(566)	(595)	(634)	(656)	(691)	(176)	(5,399)
DCR	(409)	(801)	(926)	(994)	(1,049)	(1,129)	(1,181)	(1,249)	(1,286)	(1,372)	(349)	(10,746)
DCT	(155)	(395)	(469)	(490)	(511)	(533)	(555)	(578)	(601)	(625)	(159)	(5,070)
DES	(136)	(215)	(235)	(252)	(266)	(284)	(299)	(316)	(329)	(346)	(88)	(2,767)
DLL	(14)	(38)	(46)	(47)	(49)	(51)	(53)	(56)	(58)	(60)	(15)	(488)
ESI	(20)	(57)	(71)	(80)	(86)	(97)	(102)	(110)	(113)	(119)	(30)	(885)
PMI	(4)	(8)	(10)	(11)	(12)	(13)	(14)	(15)	(15)	(17)	(4)	(124)
SEE	(611)	(1,809)	(2,202)	(2,471)	(2,587)	(2,731)	(2,850)	(2,986)	(3,100)	(3,225)	(821)	(25,394)
TOK	.(1)	(2)	(3)	(3)	(4)	(4)	(4)	(4)	(5)	(5)	(1)	(37)
TOTAL	(2,379)	(5,118)	(5,969)	(6,486)	(6,816)	(7,244)	(7,576)	(7,972)	(8,271)	(8,667)	(2,207)	(68,705)

AMORTIZATION OF COST TO ACHIEVE												
CSE	207	244	228	210	200	50	0	0	0	0	0	1,140
CSI	235	200	173	156	149	36	0	0	0	0	0	950
DCM	117	126	117	110	105	27	0	0	0	0	0	602
DCR	222	255	239	221	212	53	0	0	0	0	0	1,203
DCT	84	126	121	109	103	25	0	0	0	0	0	569
DES	74	68	61	56	54	13	0	0	0	0	0	326
DLL	8	12	12	11	10	2	0	0	0	0	0	55
ESI	11	18	18	18	17	5	0	0	0	0	0	87
PMI	2	3	3	3	2	1	0	0	0	0	0	13
SEE	332	576	569	550	522	129	0	0	0	0	0	2,678
TOK	1	1	1	1	1	0	0	0	0	0	0	4
TOTAL	1,293	1,629	1,543	1,444	1,376	341	0	0	0	0	0	7,626

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CENTRAL AND SOUTH WEST CORPORATION
ALLOCATION OF MERGER SAVINGS
TO NON-REGULATED SUBSIDIARIES

COMPANY	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	TOTAL
AMORTIZATION OF PRE-MERGER INITIATIVES												
CSE	9	21	34	47	62	81	100	122	135	144	38	794
CSI	10	18	26	35	46	59	73	89	99	108	29	590
DCM	5	11	18	24	33	43	54	66	73	79	21	426
DCR	9	22	36	49	66	87	106	130	143	156	41	846
DCT	4	11	18	24	32	41	50	60	67	71	19	397
DES	3	6	9	12	17	22	27	33	37	39	10	215
DLL	0	1	2	2	3	4	5	6	6	7	2	38
ESI	0	2	3	4	5	7	9	11	12	14	4	72
PMI	0	0	0	1	1	1	1	2	2	2	1	10
SEE	14	51	85	122	162	209	256	312	344	368	98	2,020
TOK	0	0	0	0	0	0	0	0	1	1	0	3
TOTAL	54	143	231	321	427	555	682	832	917	988	262	5,412
SAVINGS LESS COST TO ACHIEVE AND PRE-MERGER INITIATIVES												
CSE	(165)	(501)	(621)	(687)	(730)	(930)	(1,011)	(1,049)	(1,080)	(1,121)	(284)	(8,179)
CSI	(188)	(412)	(470)	(511)	(542)	(678)	(739)	(763)	(794)	(836)	(212)	(6,144)
DCM	(93)	(260)	(319)	(358)	(384)	(496)	(542)	(568)	(583)	(612)	(155)	(4,370)
DCR	(177)	(523)	(651)	(723)	(772)	(990)	(1,075)	(1,119)	(1,143)	(1,216)	(308)	(8,697)
DCT	(67)	(258)	(330)	(357)	(375)	(467)	(505)	(518)	(534)	(553)	(140)	(4,105)
DES	(59)	(140)	(165)	(183)	(196)	(249)	(272)	(283)	(293)	(307)	(78)	(2,225)
DLL	(6)	(25)	(32)	(35)	(36)	(45)	(49)	(50)	(51)	(53)	(13)	(395)
ESI	(9)	(37)	(50)	(58)	(63)	(85)	(93)	(99)	(100)	(105)	(27)	(726)
PMI	(2)	(5)	(7)	(8)	(9)	(12)	(13)	(13)	(14)	(15)	(4)	(101)
SEE	(265)	(1,183)	(1,548)	(1,798)	(1,903)	(2,393)	(2,594)	(2,675)	(2,756)	(2,857)	(724)	(20,696)
TOK	(0)	(2)	(2)	(2)	(3)	(3)	(4)	(4)	(4)	(4)	(1)	(30)
TOTAL	(1,032)	(3,346)	(4,195)	(4,721)	(5,013)	(6,348)	(6,895)	(7,140)	(7,354)	(7,679)	(1,945)	(55,668)

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CENTRAL AND SOUTH WEST CORPORATION
ALLOCATION OF MERGER SAVINGS
TO NON-REGULATED SUBSIDIARIES

COMPANY	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	TOTAL
AMORTIZATION OF CHANGE IN CONTROL												
CSE	58	68	64	58	56	14	0	0	0	0	0	317
CSI	65	56	48	43	41	10	0	0	0	0	0	264
DCM	33	35	33	30	29	7	0	0	0	0	0	168
DCR	62	71	67	62	59	15	0	0	0	0	0	335
DCT	24	35	34	30	29	7	0	0	0	0	0	158
DES	21	19	17	16	15	4	0	0	0	0	0	91
DLL	2	3	3	3	3	1	0	0	0	0	0	15
ESI	3	5	5	5	5	1	0	0	0	0	0	24
PMI	1	1	1	1	1	0	0	0	0	0	0	4
SEE	92	160	158	153	145	36	0	0	0	0	0	745
TOK	0	0	0	0	0	0	0	0	0	0	0	1
TOTAL	360	453	429	402	383	95	0	0	0	0	0	2,122
NET SHAREHOLDERS SAVINGS												
CSE	(108)	(433)	(557)	(629)	(675)	(916)	(1,011)	(1,049)	(1,080)	(1,121)	(284)	(7,862)
CSI	(122)	(356)	(422)	(468)	(501)	(668)	(739)	(763)	(794)	(836)	(212)	(5,879)
DCM	(61)	(224)	(286)	(328)	(355)	(489)	(542)	(568)	(583)	(612)	(155)	(4,203)
DCR	(116)	(453)	(584)	(662)	(713)	(975)	(1,075)	(1,119)	(1,143)	(1,216)	(308)	(8,362)
DCT	(44)	(223)	(296)	(326)	(347)	(460)	(505)	(518)	(534)	(553)	(140)	(3,947)
DES	(39)	(121)	(148)	(168)	(181)	(246)	(272)	(283)	(293)	(307)	(78)	(2,134)
DLL	(4)	(22)	(29)	(32)	(34)	(44)	(49)	(50)	(51)	(53)	(13)	(380)
ESI	(6)	(32)	(45)	(53)	(59)	(84)	(93)	(99)	(100)	(105)	(27)	(702)
PMI	(1)	(5)	(6)	(7)	(8)	(11)	(13)	(13)	(14)	(15)	(4)	(98)
SEE	(173)	(1,022)	(1,389)	(1,645)	(1,758)	(2,357)	(2,594)	(2,675)	(2,756)	(2,857)	(724)	(19,950)
TOK	(0)	(1)	(2)	(2)	(2)	(3)	(4)	(4)	(4)	(4)	(1)	(29)
TOTAL	(672)	(2,892)	(3,766)	(4,320)	(4,630)	(6,253)	(6,895)	(7,140)	(7,354)	(7,679)	(1,945)	(53,546)

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CENTRAL AND SOUTH WEST CORPORATION
ALLOCATION OF MERGER SAVINGS
TO REGULATED SUBSIDIARIES

TOTAL SAVINGS

COMPANY	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	TOTAL
CPL	(8,259)	(19,148)	(23,607)	(27,086)	(29,859)	(31,748)	(33,738)	(34,696)	(35,906)	(37,043)	(9,433)	(290,523)
ECS	(11)	(23)	(28)	(31)	(33)	(36)	(38)	(40)	(41)	(44)	(11)	(336)
JFP	(11)	(24)	(28)	(31)	(33)	(36)	(37)	(40)	(41)	(44)	(11)	(337)
LAB	(1)	(2)	(3)	(3)	(3)	(3)	(3)	(3)	(4)	(4)	(1)	(30)
PSO	(5,488)	(12,512)	(15,546)	(18,112)	(20,155)	(21,441)	(22,885)	(23,487)	(24,359)	(25,188)	(6,414)	(195,588)
SEP	(6,092)	(13,899)	(17,143)	(19,838)	(21,902)	(23,448)	(24,978)	(25,864)	(26,837)	(27,829)	(7,087)	(214,918)
WTU	(2,856)	(6,524)	(8,084)	(9,467)	(10,458)	(11,286)	(12,021)	(12,508)	(12,952)	(13,423)	(3,418)	(102,998)
TOTAL	(22,717)	(52,133)	(64,439)	(74,568)	(82,442)	(87,998)	(93,700)	(96,639)	(100,140)	(103,576)	(26,377)	(804,728)

AMORTIZATION OF COST TO ACHIEVE

COMPANY	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	209	TOTAL
CPL	4,488	6,095	6,102	6,029	6,028	1,496	0	0	0	0	0	30,237
ECS	6	7	7	7	7	2	0	0	0	0	0	35
JFP	6	8	7	7	7	2	0	0	0	0	0	36
LAB	1	1	1	1	1	0	0	0	0	0	0	3
PSO	2,982	3,983	4,018	4,031	4,069	1,010	0	0	0	0	0	20,094
SEP	3,310	4,424	4,431	4,415	4,422	1,105	0	0	0	0	0	22,108
WTU	1,552	2,077	2,089	2,107	2,111	532	0	0	0	0	0	10,468
TOTAL	12,345	16,595	16,655	16,597	16,644	4,146	0	0	0	0	0	82,982

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CENTRAL AND SOUTH WEST CORPORATION
ALLOCATION OF MERGER SAVINGS
TO REGULATED SUBSIDIARIES

AMORTIZATION OF PRE-MERGER INITIATIVES

COMPANY	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	TOTAL
CPL	187	534	913	1,341	1,870	2,434	3,036	3,619	3,981	4,224	1,120	23,260
ECS	0	1	1	2	2	3	3	4	5	5	1	27
JFP	0	1	1	2	2	3	3	4	5	5	1	27
LAB	0	0	0	0	0	0	0	0	0	0	0	2
PSO	124	349	601	897	1,262	1,644	2,059	2,450	2,700	2,872	762	15,721
SEP	138	388	663	982	1,372	1,798	2,248	2,698	2,975	3,173	842	17,276
WTU	65	182	313	469	655	865	1,082	1,305	1,436	1,531	406	8,307
TOTAL	514	1,454	2,492	3,693	5,164	6,747	8,431	10,081	11,102	11,810	3,132	64,620

TOTAL SAVINGS LESS COST TO ACHIEVE AND PRE-MERGER INITIATIVES

COMPANY	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	TOTAL
CPL	(3,584)	(12,519)	(16,593)	(19,716)	(21,960)	(27,818)	(30,702)	(31,077)	(31,925)	(32,820)	(8,313)	(237,026)
ECS	(5)	(15)	(20)	(22)	(24)	(31)	(34)	(36)	(37)	(39)	(10)	(273)
JFP	(5)	(16)	(20)	(22)	(24)	(31)	(34)	(36)	(37)	(39)	(10)	(273)
LAB	(0)	(1)	(2)	(2)	(2)	(3)	(3)	(3)	(3)	(3)	(1)	(24)
PSO	(2,381)	(8,180)	(10,927)	(13,184)	(14,824)	(18,787)	(20,826)	(21,037)	(21,658)	(22,316)	(5,653)	(159,773)
SEP	(2,644)	(9,087)	(12,049)	(14,440)	(16,108)	(20,545)	(22,730)	(23,166)	(23,862)	(24,656)	(6,245)	(175,534)
WTU	(1,239)	(4,265)	(5,682)	(6,891)	(7,691)	(9,889)	(10,939)	(11,203)	(11,516)	(11,893)	(3,012)	(84,222)
TOTAL	(9,858)	(34,084)	(45,292)	(54,278)	(60,634)	(77,105)	(85,269)	(86,557)	(89,038)	(91,766)	(23,244)	(657,126)

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CENTRAL AND SOUTH WEST CORPORATION
ALLOCATION OF MERGER SAVINGS
TO REGULATED SUBSIDIARIES

CUSTOMER ALLOCATION @ 50%

COMPANY	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	TOTAL
CPL	(1,792)	(6,259)	(8,296)	(9,858)	(10,980)	(13,909)	(15,351)	(15,538)	(15,963)	(16,410)	(4,157)	(118,513)
ECS	(2)	(8)	(10)	(11)	(12)	(16)	(17)	(18)	(18)	(20)	(5)	(137)
JFP	(2)	(8)	(10)	(11)	(12)	(16)	(17)	(18)	(18)	(20)	(5)	(137)
LAB	(0)	(1)	(1)	(1)	(1)	(1)	(1)	(2)	(2)	(2)	(0)	(12)
PSO	(1,191)	(4,090)	(5,463)	(6,592)	(7,412)	(9,394)	(10,413)	(10,518)	(10,829)	(11,158)	(2,826)	(79,887)
SEP	(1,322)	(4,544)	(6,025)	(7,220)	(8,054)	(10,273)	(11,365)	(11,583)	(11,931)	(12,328)	(3,123)	(87,767)
WTU	(620)	(2,133)	(2,841)	(3,446)	(3,846)	(4,944)	(5,470)	(5,601)	(5,758)	(5,946)	(1,506)	(42,111)
TOTAL	(4,929)	(17,042)	(22,646)	(27,139)	(30,317)	(38,552)	(42,634)	(43,279)	(44,519)	(45,883)	(11,622)	(328,563)

AMORTIZATION OF CHANGE IN CONTROL

COMPANY	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	TOTAL
CPL	1,249	1,696	1,698	1,678	1,677	416	0	0	0	0	0	8,414
ECS	2	2	2	2	2	0	0	0	0	0	0	10
JFP	2	2	2	2	2	0	0	0	0	0	0	10
LAB	0	0	0	0	0	0	0	0	0	0	0	1
PSO	830	1,108	1,118	1,122	1,132	281	0	0	0	0	0	5,591
SEP	921	1,231	1,233	1,229	1,230	307	0	0	0	0	0	6,152
WTU	432	578	581	586	587	148	0	0	0	0	0	2,913
TOTAL	3,435	4,618	4,634	4,618	4,631	1,154	0	0	0	0	0	23,091

CENTRAL AND SOUTH WEST CORPORATION
ALLOCATION OF MERGER SAVINGS
TO REGULATED SUBSIDIARIES

NET SHAREHOLDERS SAVINGS

COMPANY	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	TOTAL
CPL	(543)	(4,563)	(6,599)	(8,180)	(9,303)	(13,493)	(15,351)	(15,538)	(15,963)	(16,410)	(4,157)	(110,099)
ECS	(1)	(6)	(8)	(9)	(10)	(15)	(17)	(18)	(18)	(20)	(5)	(127)
JFP	(1)	(6)	(8)	(9)	(10)	(15)	(17)	(18)	(18)	(20)	(5)	(127)
LAB	(0)	(1)	(1)	(1)	(1)	(1)	(1)	(2)	(2)	(2)	(0)	(11)
PSO	(361)	(2,982)	(4,345)	(5,470)	(6,279)	(9,112)	(10,413)	(10,518)	(10,829)	(11,158)	(2,826)	(74,295)
SEP	(401)	(3,312)	(4,792)	(5,991)	(6,824)	(9,965)	(11,365)	(11,583)	(11,931)	(12,328)	(3,123)	(81,615)
WTU	(188)	(1,555)	(2,260)	(2,859)	(3,258)	(4,796)	(5,470)	(5,601)	(5,758)	(5,946)	(1,506)	(39,198)
TOTAL	(1,494)	(12,424)	(18,012)	(22,521)	(25,685)	(37,399)	(42,634)	(43,279)	(44,519)	(45,883)	(11,622)	(305,472)

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AMERICAN ELECTRIC POWER COMPANY
SUMMARY OF SAVINGS
BY SUBSIDIARY

(IN 000'S)

COMPANY	DIRECT SAVINGS			SERVICE COMPANY SAVINGS			TOTAL SAVINGS			ALLOCATION OF CTA	ALLOCATION OF PMI	ALLOCATION OF CIC	NET SAVINGS
1999	O&M	REV REQ	CAPITAL	O&M	REV REQ	CAPITAL	O&M	REV REQ	CAPITAL				
NON-REG													
25	(39)	0	0	(3)	(0)	(0)	(42)	(0)	(0)	23	1	6	(12)
26	0	0	0	(0)	(0)	(0)	(0)	(0)	(0)	0	0	0	(0)
53	0	0	0	(2)	(0)	(0)	(2)	(0)	(0)	1	0	0	(0)
56	0	0	0	(1)	(0)	(0)	(1)	(0)	(0)	1	0	0	(0)
57	0	0	0	(1)	(0)	(0)	(1)	(0)	(0)	1	0	0	(0)
58	(272)	0	0	(35)	(0)	(1)	(308)	(0)	(1)	167	7	47	(87)
59	(476)	0	0	(105)	(1)	(5)	(581)	(1)	(5)	316	13	88	(165)
60	(185)	0	0	(38)	(0)	(1)	(223)	(0)	(1)	121	5	34	(63)
63	0	0	0	(1)	(0)	(0)	(1)	(0)	(0)	0	0	0	(0)
64	0	0	0	(1)	(0)	(0)	(1)	(0)	(0)	0	0	0	(0)
66	0	0	0	(1)	(0)	(0)	(1)	(0)	(0)	0	0	0	(0)
67	(0)	0	0	(1)	(0)	(0)	(1)	(0)	(0)	1	0	0	(0)
69	(298)	0	0	(39)	(1)	(2)	(337)	(1)	(2)	183	8	51	(95)
72	0	0	0	(6)	(0)	(0)	(6)	(0)	(0)	3	0	1	(2)
74	(476)	0	0	(115)	(1)	(4)	(591)	(1)	(4)	322	13	90	(168)
81	(118)	0	0	(11)	(0)	(0)	(129)	(0)	(0)	70	3	19	(36)
83	(36)	0	0	(1)	(0)	(0)	(36)	(0)	(0)	20	1	5	(10)
86	(0)	0	0	(1)	(0)	(0)	(1)	(0)	(0)	1	0	0	(0)
87	(2)	0	0	(13)	(0)	(0)	(15)	(0)	(0)	8	0	2	(4)
88	0	0	0	(0)	(0)	(0)	(0)	(0)	(0)	0	0	0	(0)
89	0	0	0	(0)	(0)	(0)	(0)	(0)	(0)	0	0	0	(0)
90	0	0	0	(0)	(0)	(0)	(0)	(0)	(0)	0	0	0	(0)
91	(124)	0	0	(6)	(0)	(0)	(129)	(0)	(0)	70	3	20	(37)
99	0	0	0	(29)	(0)	(0)	(29)	(0)	(0)	16	1	4	(8)
TOTAL NON-REG	(2,026)	0	0	(408)	(4)	(13)	(2,434)	(4)	(13)	1,325	55	369	(690)
REGULATED													
01	(76)	(7)	(43)	(181)	(16)	(54)	(257)	(23)	(97)	153	6	42	(79)
02	(3,672)	(469)	(2,675)	(6,302)	(375)	(1,278)	(9,974)	(844)	(3,954)	5,879	245	1,636	(3,059)
03	(923)	(118)	(676)	(1,521)	(77)	(262)	(2,444)	(195)	(937)	1,434	60	399	(746)
04	(2,783)	(346)	(1,973)	(4,724)	(246)	(839)	(7,507)	(592)	(2,812)	4,401	183	1,225	(2,290)
06	(85)	(8)	(48)	(185)	(15)	(51)	(270)	(24)	(100)	160	7	44	(83)
07	(3,964)	(570)	(3,251)	(5,835)	(307)	(1,044)	(9,799)	(876)	(4,295)	5,801	241	1,614	(3,018)
10	(2,017)	(239)	(1,363)	(3,743)	(233)	(794)	(5,761)	(472)	(2,157)	3,387	141	942	(1,762)

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AMERICAN ELECTRIC POWER COMPANY
SUMMARY OF SAVINGS
BY SUBSIDIARY

(IN 000'S)

COMPANY	DIRECT SAVINGS			SERVICE COMPANY SAVINGS			TOTAL SAVINGS			ALLOCATION OF CTA	ALLOCATION OF PMI	ALLOCATION OF CIC	NET SAVINGS
	O&M	REV REQ	CAPITAL	O&M	REV REQ	CAPITAL	O&M	REV REQ	CAPITAL				
21	0	0	0	(1)	(0)	(0)	(1)	(0)	(0)	1	0	0	(0)
22	0	0	0	(81)	(1)	(3)	(81)	(1)	(3)	45	2	12	(23)
23	0	0	0	(0)	(0)	(0)	(0)	(0)	(0)	0	0	0	(0)
31	0	0	0	(14)	(0)	(0)	(14)	(0)	(0)	8	0	2	(4)
32	0	0	0	(19)	(0)	(1)	(19)	(0)	(1)	10	0	3	(5)
34	0	0	0	(75)	(4)	(13)	(75)	(4)	(13)	43	2	12	(22)
40	0	0	0	(0)	(0)	(0)	(0)	(0)	(0)	0	0	0	(0)
41	0	0	0	(0)	(0)	(0)	(0)	(0)	(0)	0	0	0	(0)
42	(8)	0	0	(124)	(7)	(25)	(132)	(7)	(25)	76	3	21	(39)
43	(12)	0	0	(148)	(9)	(30)	(159)	(9)	(30)	91	4	25	(48)
44	(63)	0	0	(511)	(24)	(82)	(574)	(24)	(82)	325	14	90	(169)
45	0	0	0	(0)	(0)	(0)	(0)	(0)	(0)	0	0	0	(0)
46	0	0	0	(0)	(0)	(0)	(0)	(0)	(0)	0	0	0	(0)
48	(6)	0	0	(107)	(5)	(18)	(114)	(5)	(18)	65	3	18	(34)
49	(1)	0	0	(30)	(2)	(6)	(31)	(2)	(6)	18	1	5	(9)
50	0	0	0	(0)	(0)	(0)	(0)	(0)	(0)	0	0	0	(0)
51	0	0	0	(0)	(0)	(0)	(0)	(0)	(0)	0	0	0	(0)
52	0	0	0	(0)	(0)	(0)	(0)	(0)	(0)	0	0	0	(0)
54	(1)	0	0	(27)	(1)	(5)	(28)	(1)	(5)	16	1	4	(8)
70	0	0	0	(127)	(1)	(4)	(127)	(1)	(4)	70	3	19	(36)
71	0	0	0	(127)	(1)	(4)	(127)	(1)	(4)	70	3	19	(36)
73	0	0	0	(57)	(1)	(2)	(57)	(1)	(2)	31	1	9	(16)
75	0	0	0	(6)	(0)	(1)	(6)	(0)	(1)	4	0	1	(2)
76	0	0	0	(0)	(0)	(0)	(0)	(0)	(0)	0	0	0	(0)
77	0	0	0	(0)	(0)	(0)	(0)	(0)	(0)	0	0	0	(0)
78	0	0	0	(0)	(0)	(0)	(0)	(0)	(0)	0	0	0	(0)
84	0	0	0	(0)	(0)	(0)	(0)	(0)	(0)	0	0	0	(0)
85	0	0	0	(0)	(0)	(0)	(0)	(0)	(0)	0	0	0	(0)
98	(130)	(27)	(152)	(139)	(2)	(8)	(269)	(29)	(161)	162	7	45	(84)
XX	0	0	0	(1)	(0)	(0)	(1)	(0)	(0)	0	0	0	(0)
TOTAL REG	(13,742)	(1,784)	(10,181)	(24,087)	(1,329)	(4,525)	(37,829)	(3,113)	(14,706)	22,249	926	6,191	(11,576)
TOTAL 1999	(15,768)	(1,784)	(10,181)	(24,496)	(1,333)	(4,538)	(40,263)	(3,117)	(14,719)	23,574	981	6,560	(12,266)

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AMERICAN ELECTRIC POWER COMPANY
SUMMARY OF SAVINGS
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(IN 000'S)

COMPANY	DIRECT SAVINGS			SERVICE COMPANY SAVINGS			TOTAL SAVINGS			ALLOCATION OF CTA	ALLOCATION OF PMI	ALLOCATION OF CIC	NET SAVINGS
2000	O&M	REV REQ	CAPITAL	O&M	REV REQ	CAPITAL	O&M	REV REQ	CAPITAL				
NON-REG													
25	(54)	0	0	(6)	(0)	(1)	(60)	(0)	(1)	19	2	5	(34)
26	0	0	0	(0)	(0)	(0)	(0)	(0)	(0)	0	0	0	(0)
53	0	0	0	(5)	(0)	(0)	(5)	(0)	(0)	2	0	0	(3)
56	0	0	0	(5)	(0)	(0)	(5)	(0)	(0)	2	0	0	(3)
57	0	0	0	(5)	(0)	(0)	(5)	(0)	(0)	2	0	0	(3)
58	(381)	0	0	(75)	(2)	(6)	(456)	(2)	(6)	146	13	41	(259)
59	(667)	0	0	(234)	(9)	(24)	(901)	(9)	(24)	290	25	81	(514)
60	(254)	0	0	(93)	(2)	(5)	(347)	(2)	(5)	111	10	31	(197)
63	0	0	0	(3)	(0)	(0)	(3)	(0)	(0)	1	0	0	(2)
64	0	0	0	(2)	(0)	(0)	(2)	(0)	(0)	1	0	0	(1)
66	0	0	0	(2)	(0)	(0)	(2)	(0)	(0)	1	0	0	(1)
67	(0)	0	0	(5)	(0)	(0)	(5)	(0)	(0)	2	0	0	(3)
69	(417)	0	0	(90)	(3)	(8)	(507)	(3)	(8)	162	14	45	(288)
72	0	0	0	(16)	(0)	(0)	(16)	(0)	(0)	5	0	1	(9)
74	(667)	0	0	(247)	(7)	(19)	(914)	(7)	(19)	293	26	82	(521)
81	(165)	0	0	(24)	(1)	(2)	(189)	(1)	(2)	60	5	17	(107)
83	(50)	0	0	(2)	(0)	(0)	(52)	(0)	(0)	17	1	5	(29)
86	(0)	0	0	(3)	(0)	(0)	(3)	(0)	(0)	1	0	0	(2)
87	(3)	0	0	(34)	(0)	(0)	(37)	(0)	(0)	12	1	3	(21)
88	0	0	0	(0)	(0)	(0)	(0)	(0)	(0)	0	0	0	(0)
89	0	0	0	(0)	(0)	(0)	(0)	(0)	(0)	0	0	0	(0)
90	0	0	0	(0)	(0)	(0)	(0)	(0)	(0)	0	0	0	(0)
91	(173)	0	0	(14)	(0)	(1)	(188)	(0)	(1)	60	5	17	(106)
99	0	0	0	(101)	(0)	(0)	(101)	(0)	(0)	32	3	9	(57)
TOTAL NON-REG	(2,832)	0	0	(966)	(24)	(64)	(3,798)	(24)	(64)	1,216	107	338	(2,160)
REGULATED													
01	(128)	(20)	(67)	(453)	(99)	(270)	(582)	(119)	(337)	223	20	62	(396)
02	(5,556)	(1,140)	(3,854)	(16,178)	(2,290)	(6,216)	(21,734)	(3,430)	(10,071)	8,010	702	2,229	(14,223)
03	(1,369)	(285)	(963)	(3,877)	(464)	(1,258)	(5,245)	(748)	(2,221)	1,908	167	531	(3,388)
04	(4,195)	(835)	(2,824)	(12,342)	(1,497)	(4,064)	(16,537)	(2,333)	(6,888)	6,007	526	1,671	(10,665)
06	(140)	(22)	(75)	(465)	(95)	(257)	(605)	(117)	(332)	230	20	64	(408)
07	(5,854)	(1,363)	(4,606)	(14,893)	(1,842)	(4,999)	(20,747)	(3,204)	(9,605)	7,624	668	2,122	(13,538)
10	(3,124)	(591)	(1,998)	(9,416)	(1,457)	(3,955)	(12,541)	(2,048)	(5,953)	4,644	407	1,292	(8,246)

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AMERICAN ELECTRIC POWER COMPANY
SUMMARY OF SAVINGS
BY SUBSIDIARY

(IN 000'S)

COMPANY	DIRECT SAVINGS			SERVICE COMPANY SAVINGS			TOTAL SAVINGS			ALLOCATION OF CTA	ALLOCATION OF PMI	ALLOCATION OF CIC	NET SAVINGS
	O&M	REV REQ	CAPITAL	O&M	REV REQ	CAPITAL	O&M	REV REQ	CAPITAL				
21	0	0	0	(2)	(0)	(0)	(2)	(0)	(0)	1	0	0	(1)
22	0	0	0	(158)	(5)	(14)	(158)	(5)	(14)	52	5	14	(92)
23	0	0	0	(1)	(0)	(0)	(1)	(0)	(0)	0	0	0	(1)
31	0	0	0	(29)	(1)	(2)	(29)	(1)	(2)	9	1	3	(17)
32	0	0	0	(38)	(1)	(3)	(38)	(1)	(3)	12	1	3	(22)
34	0	0	0	(219)	(19)	(51)	(219)	(19)	(51)	76	7	21	(135)
40	0	0	0	(0)	(0)	(0)	(0)	(0)	(0)	0	0	0	(0)
41	0	0	0	(0)	(0)	(0)	(0)	(0)	(0)	0	0	0	(0)
42	(12)	0	0	(358)	(35)	(96)	(369)	(35)	(96)	129	11	36	(229)
43	(16)	0	0	(419)	(43)	(117)	(436)	(43)	(117)	152	13	42	(271)
44	(88)	0	0	(1,438)	(119)	(323)	(1,526)	(119)	(323)	524	46	146	(930)
45	0	0	0	(0)	(0)	(0)	(0)	(0)	(0)	0	0	0	(0)
46	0	0	0	(0)	(0)	(0)	(0)	(0)	(0)	0	0	0	(0)
48	(9)	0	0	(318)	(27)	(75)	(326)	(27)	(75)	113	10	31	(200)
49	(2)	0	0	(83)	(9)	(24)	(85)	(9)	(24)	30	3	8	(53)
50	0	0	0	(0)	(0)	(0)	(0)	(0)	(0)	0	0	0	(0)
51	0	0	0	(1)	(0)	(0)	(1)	(0)	(0)	0	0	0	(0)
52	0	0	0	(0)	(0)	(0)	(0)	(0)	(0)	0	0	0	(0)
54	(1)	0	0	(76)	(7)	(20)	(77)	(7)	(20)	27	2	7	(48)
70	0	0	0	(246)	(8)	(22)	(246)	(8)	(22)	81	7	22	(143)
71	0	0	0	(245)	(8)	(21)	(245)	(8)	(21)	81	7	22	(143)
73	0	0	0	(111)	(4)	(10)	(111)	(4)	(10)	36	3	10	(65)
75	0	0	0	(23)	(2)	(5)	(23)	(2)	(5)	8	1	2	(14)
76	0	0	0	(0)	(0)	(0)	(0)	(0)	(0)	0	0	0	(0)
77	0	0	0	(0)	(0)	(0)	(0)	(0)	(0)	0	0	0	(0)
78	0	0	0	(0)	(0)	(0)	(0)	(0)	(0)	0	0	0	(0)
84	0	0	0	(0)	(0)	(0)	(0)	(0)	(0)	0	0	0	(0)
85	0	0	0	(0)	(0)	(0)	(0)	(0)	(0)	0	0	0	(0)
98	(180)	(62)	(209)	(370)	(11)	(31)	(550)	(73)	(240)	198	17	55	(352)
XX	0	0	0	(2)	(0)	(0)	(2)	(0)	(0)	1	0	0	(1)
TOTAL REG	(20,674)	(4,318)	(14,596)	(61,760)	(8,044)	(21,833)	(82,435)	(12,362)	(36,430)	30,176	2,644	8,397	(53,580)
TOTAL 2000	(23,506)	(4,318)	(14,596)	(62,726)	(8,068)	(21,898)	(86,233)	(12,386)	(36,494)	31,392	2,751	8,735	(55,741)

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AMERICAN ELECTRIC POWER COMPANY
SUMMARY OF SAVINGS
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COMPANY	DIRECT SAVINGS			SERVICE COMPANY SAVINGS			TOTAL SAVINGS			ALLOCATION OF CTA	ALLOCATION OF PMI	ALLOCATION OF CIC	NET SAVINGS
2001	O&M	REV REQ	CAPITAL	O&M	REV REQ	CAPITAL	O&M	REV REQ	CAPITAL				
NON-REG													
25	(57)	0	0	(7)	(0)	(1)	(64)	(0)	(1)	17	2	5	(41)
26	0	0	0	(0)	(0)	(0)	(0)	(0)	(0)	0	0	0	(0)
53	0	0	0	(6)	0	0	(6)	0	0	1	0	0	(4)
56	0	0	0	(6)	(0)	(0)	(6)	(0)	(0)	2	0	0	(4)
57	0	0	0	(6)	(0)	(0)	(6)	(0)	(0)	2	0	0	(4)
58	(400)	0	0	(87)	(5)	(8)	(487)	(5)	(8)	127	19	35	(310)
59	(700)	0	0	(275)	(20)	(32)	(975)	(20)	(32)	257	38	72	(628)
60	(262)	0	0	(110)	(4)	(6)	(372)	(4)	(6)	97	15	27	(237)
63	0	0	0	(3)	(0)	(0)	(3)	(0)	(0)	1	0	0	(2)
64	0	0	0	(3)	(0)	(0)	(3)	(0)	(0)	1	0	0	(2)
66	0	0	0	(3)	(0)	(0)	(3)	(0)	(0)	1	0	0	(2)
67	(0)	0	0	(6)	(0)	(0)	(6)	(0)	(0)	2	0	0	(4)
69	(437)	0	0	(106)	(6)	(10)	(543)	(6)	(10)	142	21	40	(347)
72	0	0	0	(19)	(0)	(0)	(19)	(0)	(0)	5	1	1	(12)
74	(700)	0	0	(287)	(16)	(25)	(987)	(16)	(25)	259	39	72	(633)
81	(173)	0	0	(28)	(1)	(2)	(201)	(1)	(2)	52	8	15	(128)
83	(52)	0	0	(3)	(0)	(0)	(55)	(0)	(0)	14	2	4	(35)
86	(0)	0	0	(3)	(0)	(0)	(4)	(0)	(0)	1	0	0	(2)
87	(3)	0	0	(40)	(0)	(0)	(43)	(0)	(0)	11	2	3	(27)
88	0	0	0	(0)	(0)	(0)	(0)	(0)	(0)	0	0	0	(0)
89	0	0	0	(0)	(0)	(0)	(0)	(0)	(0)	0	0	0	(0)
90	0	0	0	(0)	(0)	(0)	(0)	(0)	(0)	0	0	0	(0)
91	(182)	0	0	(17)	(0)	(1)	(199)	(0)	(1)	52	8	14	(126)
99	0	0	0	(125)	(0)	(0)	(125)	(0)	(0)	32	5	9	(79)
TOTAL NON-REG	(2,968)	0	0	(1,139)	(53)	(85)	(4,107)	(53)	(85)	1,075	161	299	(2,625)
REGULATED													
01	(137)	(34)	(92)	(535)	(184)	(296)	(672)	(218)	(387)	230	34	64	(561)
02	(5,844)	(2,049)	(5,582)	(19,032)	(4,321)	(6,939)	(24,875)	(6,370)	(12,521)	8,076	1,209	2,247	(19,714)
03	(1,436)	(516)	(1,405)	(4,548)	(880)	(1,414)	(5,984)	(1,396)	(2,818)	1,908	285	531	(4,656)
04	(4,405)	(1.508)	(4,107)	(14,567)	(2,843)	(4,567)	(18,972)	(4,351)	(8,674)	6,028	902	1,677	(14,715)
06	(149)	(38)	(103)	(548)	(175)	(282)	(697)	(213)	(385)	235	35	65	(575)
07	(6,139)	(2,476)	(6,745)	(17,421)	(3,486)	(5,599)	(23,560)	(5,963)	(12,344)	7,631	1,142	2,123	(18,626)
10	(3,295)	(1,051)	(2,863)	(11,072)	(2,711)	(4,354)	(14,367)	(3,762)	(7,216)	4,686	701	1,304	(11,438)

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AMERICAN ELECTRIC POWER COMPANY
SUMMARY OF SAVINGS
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(IN 000'S)

COMPANY	DIRECT SAVINGS			SERVICE COMPANY SAVINGS			TOTAL SAVINGS			ALLOCATION OF CTA	ALLOCATION OF PMI	ALLOCATION OF CIC	NET SAVINGS
	O&M	REV REQ	CAPITAL	O&M	REV REQ	CAPITAL	O&M	REV REQ	CAPITAL				
21	0	0	0	(2)	(0)	(0)	(2)	(0)	(0)	1	0	0	(2)
22	0	0	0	(180)	(11)	(18)	(180)	(11)	(18)	49	7	14	(121)
23	0	0	0	(1)	(0)	(0)	(1)	(0)	(0)	0	0	0	(1)
31	0	0	0	(33)	(2)	(3)	(33)	(2)	(3)	9	1	2	(22)
32	0	0	0	(43)	(2)	(4)	(43)	(2)	(4)	12	2	3	(29)
34	0	0	0	(266)	(40)	(64)	(266)	(40)	(64)	79	12	22	(193)
40	0	0	0	(0)	(0)	(0)	(0)	(0)	(0)	0	0	0	(0)
41	0	0	0	(0)	(0)	(0)	(0)	(0)	(0)	0	0	0	(0)
42	(12)	0	0	(432)	(75)	(121)	(444)	(75)	(121)	134	20	37	(328)
43	(17)	0	0	(506)	(92)	(148)	(523)	(92)	(148)	159	24	44	(388)
44	(91)	0	0	(1,732)	(255)	(409)	(1,824)	(255)	(409)	537	80	149	(1,311)
45	0	0	0	(0)	(0)	(0)	(0)	(0)	(0)	0	0	0	(0)
46	0	0	0	(1)	(0)	(0)	(1)	(0)	(0)	0	0	0	(0)
48	(9)	0	0	(385)	(59)	(95)	(394)	(59)	(95)	117	18	33	(286)
49	(2)	0	0	(100)	(19)	(30)	(102)	(19)	(30)	31	5	9	(76)
50	0	0	0	(0)	(0)	(0)	(0)	(0)	(0)	0	0	0	(0)
51	0	0	0	(1)	(0)	(0)	(1)	(0)	(0)	0	0	0	(0)
52	0	0	0	(0)	(0)	(0)	(0)	(0)	(0)	0	0	0	(0)
54	(1)	0	0	(92)	(15)	(25)	(93)	(15)	(25)	28	4	8	(68)
70	0	0	0	(280)	(18)	(29)	(280)	(18)	(29)	77	12	21	(188)
71	0	0	0	(279)	(18)	(29)	(279)	(18)	(29)	77	11	21	(187)
73	0	0	0	(126)	(8)	(13)	(126)	(8)	(13)	35	5	10	(85)
75	0	0	0	(29)	(4)	(6)	(29)	(4)	(6)	9	1	2	(21)
76	0	0	0	(0)	(0)	(0)	(0)	(0)	(0)	0	0	0	(0)
77	0	0	0	(0)	(0)	(0)	(0)	(0)	(0)	0	0	0	(0)
78	0	0	0	(0)	(0)	(0)	(0)	(0)	(0)	0	0	0	(0)
84	0	0	0	(0)	(0)	(0)	(0)	(0)	(0)	0	0	0	(0)
85	0	0	0	(0)	(0)	(0)	(0)	(0)	(0)	0	0	0	(0)
98	(187)	(115)	(313)	(426)	(23)	(38)	(613)	(138)	(351)	194	29	54	(474)
XX	0	0	0	(3)	(0)	(1)	(3)	(0)	(1)	1	0	0	(2)
TOTAL REG	(21,724)	(7,787)	(21,209)	(72,641)	(15,243)	(24,482)	(94,365)	(23,030)	(45,691)	30,343	4,541	8,443	(74,068)
TOTAL 2001	(24,692)	(7,787)	(21,209)	(73,780)	(15,296)	(24,567)	(98,472)	(23,083)	(45,776)	31,418	4,702	3,742	(76,693)

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AMERICAN ELECTRIC POWER COMPANY
SUMMARY OF SAVINGS
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(IN 000'S)

COMPANY	DIRECT SAVINGS			SERVICE COMPANY SAVINGS			TOTAL SAVINGS			ALLOCATION OF CTA	ALLOCATION OF PMI	ALLOCATION OF CIC	NET SAVINGS
2002	O&M	REV REQ	CAPITAL	O&M	REV REQ	CAPITAL	O&M	REV REQ	CAPITAL				
NON-REG													
25	(60)	0	0	(7)	(1)	(1)	(67)	(1)	(1)	15	3	4	(45)
26	0	0	0	(0)	(0)	(0)	(0)	(0)	(0)	0	0	0	(0)
53	0	0	0	(6)	0	0	(6)	0	0	1	0	0	(4)
56	0	0	0	(6)	(0)	(0)	(6)	(0)	(0)	1	0	0	(4)
57	0	0	0	(6)	(0)	(0)	(6)	(0)	(0)	1	0	0	(4)
58	(420)	0	0	(92)	(7)	(8)	(512)	(7)	(8)	116	26	32	(346)
59	(735)	0	0	(294)	(30)	(36)	(1,029)	(30)	(36)	236	53	66	(705)
60	(270)	0	0	(115)	(6)	(7)	(385)	(6)	(7)	87	19	24	(260)
63	0	0	0	(3)	(0)	(0)	(3)	(0)	(0)	1	0	0	(2)
64	0	0	0	(3)	(0)	(0)	(3)	(0)	(0)	1	0	0	(2)
66	0	0	0	(3)	(0)	(0)	(3)	(0)	(0)	1	0	0	(2)
67	(0)	0	0	(6)	(0)	(0)	(6)	(0)	(0)	1	0	0	(4)
69	(460)	0	(0)	(112)	(10)	(11)	(572)	(10)	(11)	129	29	36	(387)
72	0	0	0	(20)	(0)	(0)	(20)	(0)	(0)	4	1	1	(13)
74	(735)	0	0	(305)	(24)	(28)	(1,040)	(24)	(28)	237	53	66	(708)
81	(182)	0	0	(29)	(2)	(3)	(211)	(2)	(3)	48	11	13	(142)
83	(55)	0	0	(3)	(0)	(0)	(58)	(0)	(0)	13	3	4	(39)
86	(0)	0	0	(3)	(0)	(0)	(4)	(0)	(0)	1	0	0	(2)
87	(3)	0	0	(42)	(0)	(0)	(45)	(0)	(0)	10	2	3	(30)
88	0	0	0	(0)	(0)	(0)	(0)	(0)	(0)	0	0	0	(0)
89	0	0	0	(0)	(0)	(0)	(0)	(0)	(0)	0	0	0	(0)
90	0	0	0	(0)	(0)	(0)	(0)	(0)	(0)	0	0	0	(0)
91	(191)	0	0	(18)	(1)	(1)	(209)	(1)	(1)	47	10	13	(140)
99	0	0	0	(130)	0	0	(130)	0	0	29	6	8	(86)
TOTAL NON-REG	(3,111)	0	(0)	(1,205)	(80)	(95)	(4,316)	(80)	(96)	979	218	272	(2,927)
REGULATED													
01	(173)	(51)	(81)	(564)	(275)	(328)	(737)	(326)	(410)	237	53	66	(708)
02	(7,456)	(2,843)	(4,527)	(20,119)	(6,456)	(7,698)	(27,575)	(9,298)	(12,226)	8,207	1,826	2,284	(24,556)
03	(1,784)	(700)	(1,114)	(4,804)	(1,314)	(1,567)	(6,588)	(2,013)	(2,681)	1,915	426	533	(5,728)
04	(5,627)	(2,089)	(3,327)	(15,393)	(4,246)	(5,063)	(21,020)	(6,335)	(8,390)	6,089	1,355	1,694	(18,217)
06	(189)	(57)	(90)	(579)	(263)	(313)	(768)	(319)	(404)	242	54	67	(724)
07	(7,466)	(3,287)	(5,235)	(18,386)	(5,201)	(6,202)	(25,853)	(8,487)	(11,437)	7,644	1,701	2,127	(22,869)
10	(4,073)	(1,463)	(2,329)	(11,675)	(4,062)	(4,844)	(15,748)	(5,524)	(7,173)	4,735	1,054	1,318	(14,166)

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AMERICAN ELECTRIC POWER COMPANY
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(IN 000'S)

COMPANY	DIRECT SAVINGS			SERVICE COMPANY SAVINGS			TOTAL SAVINGS			ALLOCATION OF CTA	ALLOCATION OF PMI	ALLOCATION OF CIC	NET SAVINGS
	O&M	REV REQ	CAPITAL	O&M	REV REQ	CAPITAL	O&M	REV REQ	CAPITAL				
21	0	0	0	(2)	(0)	(0)	(2)	(0)	(0)	1	0	0	(2)
22	0	0	0	(191)	(17)	(21)	(191)	(17)	(21)	46	10	13	(139)
23	0	0	0	(1)	(0)	(0)	(1)	(0)	(0)	0	0	0	(1)
31	0	0	0	(35)	(3)	(3)	(35)	(3)	(3)	8	2	2	(25)
32	0	0	0	(46)	(4)	(4)	(46)	(4)	(4)	11	2	3	(33)
34	0	0	0	(289)	(59)	(71)	(289)	(59)	(71)	78	17	22	(232)
40	0	0	0	(0)	(0)	(0)	(0)	(0)	(0)	0	0	0	(0)
41	0	0	0	(0)	(0)	(0)	(0)	(0)	(0)	0	0	0	(0)
42	(29)	(3)	(5)	(466)	(110)	(131)	(495)	(113)	(136)	135	30	38	(405)
43	(32)	(3)	(4)	(545)	(134)	(160)	(577)	(137)	(164)	159	35	44	(476)
44	(162)	(12)	(20)	(1,864)	(374)	(446)	(2,025)	(386)	(466)	537	119	149	(1,606)
45	0	0	0	(0)	(0)	(0)	(0)	(0)	(0)	0	0	0	(0)
46	0	0	0	(1)	(0)	(0)	(1)	(0)	(0)	0	0	0	(0)
48	(48)	(7)	(11)	(421)	(88)	(105)	(469)	(95)	(117)	126	28	35	(376)
49	(2)	0	0	(108)	(28)	(33)	(110)	(28)	(33)	31	7	9	(92)
50	0	0	0	(0)	(0)	(0)	(0)	(0)	(0)	0	0	0	(0)
51	0	0	0	(1)	(0)	(0)	(1)	(0)	(0)	0	0	0	(1)
52	0	0	0	(0)	(0)	(0)	(0)	(0)	(0)	0	0	0	(0)
54	(6)	(1)	(1)	(98)	(22)	(27)	(105)	(23)	(28)	28	6	8	(85)
70	0	0	0	(298)	(27)	(32)	(298)	(27)	(32)	72	16	20	(217)
71	0	0	0	(298)	(27)	(32)	(298)	(27)	(32)	72	16	20	(216)
73	0	0	0	(135)	(12)	(15)	(135)	(12)	(15)	33	7	9	(98)
75	0	0	0	(32)	(6)	(7)	(32)	(6)	(7)	9	2	2	(25)
76	0	0	0	(0)	(0)	(0)	(0)	(0)	(0)	0	0	0	(0)
77	0	0	0	(0)	(0)	(0)	(0)	(0)	(0)	0	0	0	(0)
78	0	0	0	(0)	(0)	(0)	(0)	(0)	(0)	0	0	0	(0)
84	0	0	0	(0)	(0)	(0)	(0)	(0)	(0)	0	0	0	(0)
85	0	0	0	(0)	(0)	(0)	(0)	(0)	(0)	0	0	0	(0)
98	(194)	(140)	(223)	(448)	(34)	(41)	(642)	(174)	(264)	182	40	51	(544)
XX	0	0	0	(3)	(1)	(1)	(3)	(1)	(1)	1	0	0	(3)
TOTAL REG	(27,242)	(10,654)	(16,968)	(76,802)	(22,764)	(27,146)	(104,044)	(33,418)	(44,114)	30,597	6,809	8,514	(91,542)
TOTAL 2002	(30,353)	(10,654)	(16,968)	(78,007)	(22,844)	(27,241)	(108,360)	(33,498)	(44,210)	31,576	7,027	8,786	(94,469)

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AMERICAN ELECTRIC POWER COMPANY
SUMMARY OF SAVINGS
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(IN 000'S)

COMPANY	DIRECT SAVINGS			SERVICE COMPANY SAVINGS			TOTAL SAVINGS			ALLOCATION OF CTA	ALLOCATION OF PMI	ALLOCATION OF CIC	NET SAVINGS
2003	O&M	REV REQ	CAPITAL	O&M	REV REQ	CAPITAL	O&M	REV REQ	CAPITAL				
NON-REG													
25	(63)	0	0	(8)	(1)	(1)	(71)	(1)	(1)	14	4	4	(49)
26	0	0	0	(0)	(0)	(0)	(0)	(0)	(0)	0	0	0	(0)
53	0	0	0	(6)	0	0	(6)	0	0	1	0	0	(4)
56	0	0	0	(7)	(0)	(0)	(7)	(0)	(0)	1	0	0	(5)
57	0	0	0	(7)	(0)	(0)	(7)	(0)	(0)	1	0	0	(5)
58	(441)	0	0	(96)	(9)	(9)	(537)	(9)	(9)	110	34	31	(371)
59	(772)	0	0	(307)	(40)	(38)	(1,079)	(40)	(38)	226	70	63	(760)
60	(278)	0	0	(120)	(8)	(7)	(398)	(8)	(7)	82	25	23	(275)
63	0	0	0	(3)	(0)	(0)	(3)	(0)	(0)	1	0	0	(3)
64	0	0	0	(3)	(0)	(0)	(3)	(0)	(0)	1	0	0	(2)
66	0	0	0	(3)	(0)	(0)	(3)	(0)	(0)	1	0	0	(2)
67	(0)	0	0	(6)	(0)	(0)	(6)	(0)	(0)	1	0	0	(4)
69	(483)	0	(0)	(117)	(13)	(12)	(599)	(13)	(12)	123	38	34	(416)
72	0	0	0	(21)	(0)	(0)	(21)	(0)	(0)	4	1	1	(14)
74	(772)	0	0	(317)	(32)	(30)	(1,089)	(32)	(30)	226	70	63	(761)
81	(191)	0	0	(30)	(3)	(3)	(222)	(3)	(3)	45	14	13	(152)
83	(58)	0	0	(3)	(0)	(0)	(61)	(0)	(0)	12	4	3	(41)
86	(0)	0	0	(3)	(0)	(0)	(4)	(0)	(0)	1	0	0	(3)
87	(3)	0	0	(44)	(0)	(0)	(47)	(0)	(0)	9	3	3	(32)
88	0	0	0	(0)	(0)	(0)	(0)	(0)	(0)	0	0	0	(0)
89	0	0	0	(0)	(0)	(0)	(0)	(0)	(0)	0	0	0	(0)
90	0	0	0	(0)	(0)	(0)	(0)	(0)	(0)	0	0	0	(0)
91	(201)	0	0	(19)	(1)	(1)	(219)	(1)	(1)	44	14	12	(150)
99	0	0	0	(135)	0	0	(135)	0	0	27	8	8	(91)
TOTAL NON-REG	(3,262)	0	(0)	(1,255)	(107)	(101)	(4,517)	(107)	(101)	933	290	260	(3,141)
REGULATED													
01	(180)	(65)	(84)	(587)	(366)	(346)	(767)	(430)	(430)	242	75	67	(813)
02	(7,756)	(3,590)	(4,677)	(20,931)	(8,563)	(8,094)	(28,687)	(12,153)	(12,771)	8,245	2,558	2,294	(27,742)
03	(1,856)	(883)	(1,151)	(4,997)	(1,742)	(1,647)	(6,853)	(2,625)	(2,797)	1,914	594	532	(6,439)
04	(5,853)	(2,637)	(3,436)	(16,014)	(5,631)	(5,322)	(21,867)	(8,268)	(8,758)	6,084	1,888	1,693	(20,470)
06	(197)	(72)	(93)	(602)	(349)	(330)	(799)	(421)	(423)	246	76	69	(828)
07	(7,766)	(4,148)	(5,405)	(19,126)	(6,896)	(6,518)	(26,892)	(11,044)	(11,923)	7,659	2,376	2,131	(25,770)
10	(4,236)	(1,847)	(2,407)	(12,148)	(5,392)	(5,096)	(16,384)	(7,239)	(7,503)	4,769	1,480	1,327	(16,047)

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AMERICAN ELECTRIC POWER COMPANY
SUMMARY OF SAVINGS
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(IN 000'S)

COMPANY	DIRECT SAVINGS			SERVICE COMPANY SAVINGS			TOTAL SAVINGS			ALLOCATION OF CTA	ALLOCATION OF PMI	ALLOCATION OF CIC	NET SAVINGS
	O&M	REV REQ	CAPITAL	O&M	REV REQ	CAPITAL	O&M	REV REQ	CAPITAL				
21	0	0	0	(3)	(0)	(0)	(3)	(0)	(0)	1	0	0	(2)
22	0	0	0	(199)	(23)	(22)	(199)	(23)	(22)	45	14	13	(151)
23	0	0	0	(1)	(0)	(0)	(1)	(0)	(0)	0	0	0	(1)
31	0	0	0	(36)	(4)	(3)	(36)	(4)	(3)	8	2	2	(27)
32	0	0	0	(48)	(5)	(5)	(48)	(5)	(5)	11	3	3	(36)
34	0	0	0	(300)	(78)	(74)	(300)	(78)	(74)	76	24	21	(257)
40	0	0	0	(0)	(0)	(0)	(0)	(0)	(0)	0	0	0	(0)
41	0	0	0	(0)	(0)	(0)	(0)	(0)	(0)	0	0	0	(0)
42	(30)	(4)	(5)	(484)	(144)	(137)	(515)	(148)	(142)	134	42	37	(450)
43	(34)	(3)	(4)	(566)	(177)	(167)	(600)	(180)	(172)	158	49	44	(530)
44	(168)	(16)	(21)	(1,938)	(492)	(465)	(2,106)	(508)	(486)	528	164	147	(1,776)
45	0	0	0	(0)	(0)	(0)	(0)	(0)	(0)	0	0	0	(0)
46	0	0	0	(1)	(0)	(0)	(1)	(0)	(0)	0	0	0	(0)
48	(50)	(9)	(12)	(437)	(116)	(110)	(487)	(126)	(122)	124	38	34	(416)
49	(2)	0	0	(112)	(36)	(34)	(114)	(36)	(34)	30	9	8	(102)
50	0	0	0	(0)	(0)	(0)	(0)	(0)	(0)	0	0	0	(0)
51	0	0	0	(1)	(0)	(0)	(1)	(0)	(0)	0	0	0	(1)
52	0	0	0	(0)	(0)	(0)	(0)	(0)	(0)	0	0	0	(0)
54	(6)	(1)	(1)	(102)	(30)	(28)	(109)	(31)	(29)	28	9	8	(95)
70	0	0	0	(311)	(36)	(34)	(311)	(36)	(34)	70	22	20	(236)
71	0	0	0	(310)	(36)	(34)	(310)	(36)	(34)	70	22	19	(235)
73	0	0	0	(140)	(16)	(16)	(140)	(16)	(16)	32	10	9	(106)
75	0	0	0	(34)	(8)	(8)	(34)	(8)	(8)	8	3	2	(29)
76	0	0	0	(0)	(0)	(0)	(0)	(0)	(0)	0	0	0	(0)
77	0	0	0	(0)	(0)	(0)	(0)	(0)	(0)	0	0	0	(0)
78	0	0	0	(0)	(0)	(0)	(0)	(0)	(0)	0	0	0	(0)
84	0	0	0	(0)	(0)	(0)	(0)	(0)	(0)	0	0	0	(0)
85	0	0	0	(0)	(0)	(0)	(0)	(0)	(0)	0	0	0	(0)
98	(202)	(176)	(230)	(466)	(45)	(43)	(668)	(221)	(272)	180	56	50	(604)
XX	0	0	0	(3)	(1)	(1)	(3)	(1)	(1)	1	0	0	(3)
TOTAL REG	(28,335)	(13,452)	(17,526)	(79,899)	(30,188)	(28,535)	(108,235)	(43,640)	(46,060)	30,663	9,513	8,532	(103,167)
TOTAL 2003	(31,597)	(13,452)	(17,526)	(81,154)	(30,295)	(28,636)	(112,752)	(43,747)	(46,162)	31,596	9,803	8,792	(106,308)

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BY SUBSIDIARY

(IN 000'S)

COMPANY	DIRECT SAVINGS			SERVICE COMPANY SAVINGS			TOTAL SAVINGS			ALLOCATION OF CTA	ALLOCATION OF PMI	ALLOCATION OF CIC	NET SAVINGS
2004	O&M	REV REQ	CAPITAL	O&M	REV REQ	CAPITAL	O&M	REV REQ	CAPITAL				
NON-REG													
25	(66)	0	0	(8)	(2)	(1)	(74)	(2)	(1)	4	6	1	(65)
26	0	0	0	(0)	(0)	(0)	(0)	(0)	(0)	0	0	0	(0)
53	0	0	0	(6)	0	0	(6)	0	0	0	0	0	(6)
56	0	0	0	(7)	(0)	(0)	(7)	(0)	(0)	0	1	0	(6)
57	0	0	0	(7)	(0)	(0)	(7)	(0)	(0)	0	1	0	(6)
58	(463)	0	0	(98)	(16)	(9)	(562)	(16)	(9)	27	44	8	(498)
59	(811)	0	0	(316)	(68)	(39)	(1,126)	(68)	(39)	56	91	16	(1,030)
60	(287)	0	0	(124)	(13)	(7)	(411)	(13)	(7)	20	32	6	(366)
63	0	0	0	(4)	(1)	(0)	(4)	(1)	(0)	0	0	0	(4)
64	0	0	0	(3)	(0)	(0)	(3)	(0)	(0)	0	0	0	(3)
66	0	0	0	(3)	(0)	(0)	(3)	(0)	(0)	0	0	0	(3)
67	(0)	0	0	(7)	(0)	(0)	(7)	(0)	(0)	0	1	0	(6)
69	(507)	0	(0)	(121)	(21)	(12)	(627)	(21)	(13)	31	50	9	(560)
72	0	0	0	(21)	(0)	(0)	(21)	(0)	(0)	1	2	0	(19)
74	(811)	0	0	(327)	(53)	(31)	(1,137)	(53)	(31)	56	91	16	(1,027)
81	(201)	0	0	(31)	(5)	(3)	(232)	(5)	(3)	11	18	3	(204)
83	(60)	0	0	(3)	(0)	(0)	(64)	(0)	(0)	3	5	1	(55)
86	(0)	0	0	(4)	(0)	(0)	(4)	(0)	(0)	0	0	0	(3)
87	(3)	0	0	(45)	(0)	(0)	(49)	(0)	(0)	2	4	1	(42)
88	0	0	0	(0)	(0)	(0)	(0)	(0)	(0)	0	0	0	(0)
89	0	0	0	(0)	(0)	(0)	(0)	(0)	(0)	0	0	0	(0)
90	0	0	0	(0)	(0)	(0)	(0)	(0)	(0)	0	0	0	(0)
91	(211)	0	0	(19)	(1)	(1)	(230)	(1)	(1)	11	18	3	(200)
99	0	0	0	(140)	0	0	(140)	0	0	7	11	2	(121)
TOTAL NON-REG	(3,419)	0	(0)	(1,295)	(180)	(104)	(4,714)	(180)	(104)	231	375	64	(4,224)
REGULATED													
01	(187)	(78)	(87)	(612)	(373)	(215)	(799)	(451)	(303)	59	96	16	(1,079)
02	(8,068)	(4,338)	(4,832)	(21,787)	(9,527)	(5,509)	(29,855)	(13,865)	(10,341)	2,060	3,352	573	(37,734)
03	(1,931)	(1,067)	(1,188)	(5,197)	(1,995)	(1,154)	(7,128)	(3,061)	(2,342)	480	781	134	(8,794)
04	(6,089)	(3,187)	(3,550)	(16,665)	(6,437)	(3,722)	(22,754)	(9,624)	(7,272)	1,526	2,483	425	(27,945)
06	(205)	(87)	(96)	(628)	(354)	(205)	(832)	(440)	(301)	60	98	17	(1,099)
07	(8,078)	(5,010)	(5,580)	(19,896)	(7,828)	(4,527)	(27,973)	(12,838)	(10,107)	1,923	3,129	535	(35,224)
10	(4,406)	(2,233)	(2,487)	(12,653)	(5,607)	(3,242)	(17,059)	(7,840)	(5,730)	1,173	1,909	326	(21,490)

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AMERICAN ELECTRIC POWER COMPANY
SUMMARY OF SAVINGS
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(IN 000'S)

COMPANY	DIRECT SAVINGS			SERVICE COMPANY SAVINGS			TOTAL SAVINGS			ALLOCATION OF CTA	ALLOCATION OF PMI	ALLOCATION OF CIC	NET SAVINGS
	O&M	REV REQ	CAPITAL	O&M	REV REQ	CAPITAL	O&M	REV REQ	CAPITAL				
21	0	0	0	(3)	(1)	(0)	(3)	(1)	(0)	0	0	0	(3)
22	0	0	0	(205)	(39)	(23)	(205)	(39)	(23)	12	19	3	(211)
23	0	0	0	(1)	(0)	(0)	(1)	(0)	(0)	0	0	0	(1)
31	0	0	0	(37)	(6)	(4)	(37)	(6)	(4)	2	3	1	(37)
32	0	0	0	(49)	(8)	(5)	(49)	(8)	(5)	3	4	1	(49)
34	0	0	0	(312)	(134)	(77)	(312)	(134)	(77)	21	34	6	(385)
40	0	0	0	(0)	(0)	(0)	(0)	(0)	(0)	0	0	0	(0)
41	0	0	0	(0)	(0)	(0)	(0)	(0)	(0)	0	0	0	(0)
42	(32)	(5)	(5)	(503)	(246)	(142)	(534)	(251)	(148)	37	60	10	(678)
43	(35)	(4)	(5)	(588)	(301)	(174)	(623)	(305)	(179)	44	71	12	(801)
44	(175)	(19)	(22)	(2,012)	(839)	(485)	(2,187)	(858)	(507)	144	234	40	(2,629)
45	0	0	0	(0)	(0)	(0)	(0)	(0)	(0)	0	0	0	(0)
46	0	0	0	(1)	(0)	(0)	(1)	(0)	(0)	0	0	0	(1)
48	(52)	(11)	(12)	(454)	(199)	(115)	(506)	(210)	(127)	34	55	9	(618)
49	(2)	0	0	(117)	(62)	(36)	(119)	(62)	(36)	9	14	2	(156)
50	0	0	0	(0)	(0)	(0)	(0)	(0)	(0)	0	0	0	(0)
51	0	0	0	(1)	(0)	(0)	(1)	(0)	(0)	0	0	0	(1)
52	0	0	0	(0)	(0)	(0)	(0)	(0)	(0)	0	0	0	(0)
54	(7)	(1)	(2)	(106)	(50)	(29)	(113)	(52)	(31)	8	13	2	(142)
70	0	0	0	(319)	(61)	(35)	(319)	(61)	(35)	18	29	5	(329)
71	0	0	0	(318)	(61)	(35)	(318)	(61)	(35)	18	29	5	(327)
73	0	0	0	(144)	(28)	(16)	(144)	(28)	(16)	8	13	2	(148)
75	0	0	0	(35)	(14)	(8)	(35)	(14)	(8)	2	4	1	(42)
76	0	0	0	(0)	(0)	(0)	(0)	(0)	(0)	0	0	0	(0)
77	0	0	0	(0)	(0)	(0)	(0)	(0)	(0)	0	0	0	(0)
78	0	0	0	(0)	(0)	(0)	(0)	(0)	(0)	0	0	0	(0)
84	0	0	0	(0)	(0)	(0)	(0)	(0)	(0)	0	0	0	(0)
85	0	0	0	(0)	(0)	(0)	(0)	(0)	(0)	0	0	0	(0)
98	(210)	(213)	(237)	(484)	(77)	(44)	(694)	(289)	(281)	46	75	13	(849)
XX	0	0	0	(3)	(1)	(1)	(3)	(1)	(1)	0	0	0	(4)
TOTAL REG	(29,476)	(16,254)	(18,104)	(83,130)	(34,247)	(19,805)	(112,606)	(50,501)	(37,909)	7,686	12,506	2,139	(140,776)
TOTAL 2004	(32,896)	(16,254)	(18,104)	(84,424)	(34,427)	(19,909)	(117,320)	(50,681)	(38,013)	7,917	12,881	2,203	(145,000)

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AMERICAN ELECTRIC POWER COMPANY
SUMMARY OF SAVINGS
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(IN 000'S)

COMPANY	DIRECT SAVINGS			SERVICE COMPANY SAVINGS			TOTAL SAVINGS			ALLOCATION OF CTA	ALLOCATION OF PMI	ALLOCATION OF CIC	NET SAVINGS
2005	O&M	REV REQ	CAPITAL	O&M	REV REQ	CAPITAL	O&M	REV REQ	CAPITAL				
NON-REG													
25	(69)	0	0	(8)	(2)	(1)	(78)	(2)	(1)	0	7	0	(72)
26	0	0	0	(0)	(0)	(0)	(0)	(0)	(0)	0	0	0	(0)
53	0	0	0	(7)	0	0	(7)	0	0	0	1	0	(6)
56	0	0	0	(7)	(0)	(0)	(7)	(0)	(0)	0	1	0	(7)
57	0	0	0	(7)	(0)	(0)	(7)	(0)	(0)	0	1	0	(7)
58	(486)	0	0	(102)	(17)	(10)	(589)	(17)	(10)	0	55	0	(552)
59	(851)	0	0	(329)	(74)	(41)	(1,180)	(74)	(41)	0	113	0	(1,142)
60	(295)	0	0	(129)	(14)	(8)	(424)	(14)	(8)	0	39	0	(399)
63	0	0	0	(4)	(1)	(0)	(4)	(1)	(0)	0	0	0	(4)
64	0	0	0	(4)	(0)	(0)	(4)	(0)	(0)	0	0	0	(3)
66	0	0	0	(3)	(0)	(0)	(3)	(0)	(0)	0	0	0	(3)
67	(0)	0	0	(7)	(0)	(0)	(7)	(0)	(0)	0	1	0	(6)
69	(532)	0	(0)	(125)	(23)	(13)	(657)	(23)	(13)	0	61	0	(620)
72	0	0	0	(22)	(0)	(0)	(22)	(0)	(0)	0	2	0	(21)
74	(851)	0	0	(340)	(59)	(33)	(1,191)	(59)	(33)	0	112	0	(1,137)
81	(211)	0	0	(33)	(5)	(3)	(243)	(5)	(3)	0	22	0	(226)
83	(64)	0	0	(3)	(0)	(0)	(67)	(0)	(0)	0	6	0	(61)
86	(0)	0	0	(4)	(0)	(0)	(4)	(0)	(0)	0	0	0	(4)
87	(3)	0	0	(47)	(0)	(0)	(51)	(0)	(0)	0	5	0	(46)
88	0	0	0	(0)	(0)	(0)	(0)	(0)	(0)	0	0	0	(0)
89	0	0	0	(0)	(0)	(0)	(0)	(0)	(0)	0	0	0	(0)
90	0	0	0	(0)	(0)	(0)	(0)	(0)	(0)	0	0	0	(0)
91	(221)	0	0	(20)	(2)	(1)	(241)	(2)	(1)	0	22	0	(221)
99	0	0	0	(145)	0	0	(145)	0	0	0	13	0	(132)
TOTAL NON-REG	(3,584)	0	(0)	(1,348)	(198)	(110)	(4,933)	(198)	(110)	0	462	0	(4,669)
REGULATED													
01	(194)	(92)	(90)	(637)	(406)	(226)	(832)	(498)	(317)	0	120	0	(1,210)
02	(8,393)	(5,089)	(4,992)	(22,669)	(10,384)	(5,782)	(31,062)	(15,473)	(10,774)	0	4,187	0	(42,348)
03	(2,008)	(1,251)	(1,227)	(5,407)	(2,174)	(1,210)	(7,416)	(3,425)	(2,438)	0	975	0	(9,865)
04	(6,334)	(3,738)	(3,667)	(17,339)	(7,015)	(3,906)	(23,673)	(10,753)	(7,573)	0	3,098	0	(31,328)
06	(213)	(102)	(100)	(654)	(386)	(215)	(866)	(488)	(315)	0	122	0	(1,232)
07	(8,402)	(5,874)	(5,762)	(20,699)	(8,529)	(4,749)	(29,101)	(14,403)	(10,511)	0	3,915	0	(39,589)
10	(4,583)	(2,620)	(2,571)	(13,167)	(6,116)	(3,406)	(17,750)	(8,737)	(5,976)	0	2,383	0	(24,104)

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AMERICAN ELECTRIC POWER COMPANY
SUMMARY OF SAVINGS
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(IN 000'S)

COMPANY	DIRECT SAVINGS O&M	DIRECT SAVINGS REV REQ	DIRECT SAVINGS CAPITAL	SERVICE COMPANY SAVINGS O&M	SERVICE COMPANY SAVINGS REV REQ	SERVICE COMPANY SAVINGS CAPITAL	TOTAL SAVINGS O&M	TOTAL SAVINGS REV REQ	TOTAL SAVINGS CAPITAL	ALLOCATION OF CTA	ALLOCATION OF PMI	ALLOCATION OF CIC	NET SAVINGS
21	0	0	0	(3)	(1)	(0)	(3)	(1)	(0)	0	0	0	(3)
22	0	0	0	(213)	(43)	(24)	(213)	(43)	(24)	0	23	0	(234)
23	0	0	0	(1)	(0)	(0)	(1)	(0)	(0)	0	0	0	(1)
31	0	0	0	(39)	(7)	(4)	(39)	(7)	(4)	0	4	0	(41)
32	0	0	0	(51)	(9)	(5)	(51)	(9)	(5)	0	5	0	(55)
34	0	0	0	(324)	(145)	(81)	(324)	(145)	(81)	0	42	0	(427)
40	0	0	0	(0)	(0)	(0)	(0)	(0)	(0)	0	0	0	(0)
41	0	0	0	(0)	(0)	(0)	(0)	(0)	(0)	0	0	0	(0)
42	(33)	(6)	(6)	(522)	(267)	(149)	(556)	(272)	(154)	0	75	0	(754)
43	(37)	(5)	(5)	(611)	(326)	(182)	(648)	(331)	(187)	0	88	0	(891)
44	(183)	(23)	(22)	(2,092)	(910)	(507)	(2,275)	(933)	(529)	0	289	0	(2,919)
45	0	0	0	(0)	(0)	(0)	(0)	(0)	(0)	0	0	0	(0)
46	0	0	0	(1)	(0)	(0)	(1)	(0)	(0)	0	0	0	(1)
48	(54)	(13)	(13)	.(472)	(216)	(120)	(527)	(229)	(133)	0	68	0	(687)
49	(2)	0	0	(121)	(67)	(37)	(123)	(67)	(37)	0	17	0	(174)
50	0	0	0	(0)	(0)	(0)	(0)	(0)	(0)	0	0	0	(0)
51	0	0	0	(1)	(0)	(0)	(1)	(0)	(0)	0	0	0	(1)
52	0	0	0	(0)	(0)	(0)	(0)	(0)	(0)	0	0	0	(0)
54	(7)	(2)	(2)	(110)	(55)	(30)	(117)	(56)	(32)	0	16	0	(158)
70	0	0	0	(333)	(67)	(38)	(333)	(67)	(38)	0	36	0	(364)
71	0	0	0	(332)	(67)	(37)	(332)	(67)	(37)	0	36	0	(363)
73	0	0	0	(150)	(31)	(17)	(150)	(31)	(17)	0	16	0	(164)
75	0	0	0	(37)	(15)	(8)	(37)	(15)	-(8)	0	5	0	(47)
76	0	0	0	(0)	(0)	(0)	(0)	(0)	(0)	0	0	0	(0)
77	0	0	0	(0)	(0)	(0)	(0)	(0)	(0)	0	0	0	(0)
78	0	0	0	(0)	(0)	(0)	(0)	(0)	(0)	0	0	0	(0)
84	0	0	0	(0)	(0)	(0)	(0)	(0)	(0)	0	0	0	(0)
85	0	0	0	(0)	(0)	(0)	(0)	(0)	(0)	0	0	0	(0)
98	(218)	(249)	(244)	(503)	(83)	(46)	(721)	(332)	(291)	0	95	0	(959)
XX	0	0	0	(4)	(1)	(1)	(4)	(1)	(1)	0	0	0	(5)
TOTAL REG	(30,662)	(19,063)	(18,701)	(86,493)	(37,321)	(20,782)	(117,155)	(56,384)	(39,483)	0	15,615	0	(157,924)
TOTAL 2005	(34,246)	(19,063)	(18,701)	(87,841)	(37,519)	(20,892)	(122,088)	(56,582)	(39,593)	0	16,077	0	(162,593)

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AMERICAN ELECTRIC POWER COMPANY
SUMMARY OF SAVINGS
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(IN 000'S)

COMPANY	DIRECT SAVINGS			SERVICE COMPANY SAVINGS			TOTAL SAVINGS			ALLOCATION OF CTA	ALLOCATION OF PMI	ALLOCATION OF CIC	NET SAVINGS
2006	O&M	REV REQ	CAPITAL	O&M	REV REQ	CAPITAL	O&M	REV REQ	CAPITAL				
NON-REG													
25	(73)	0	0	(8)	(2)	(1)	(81)	(2)	(1)	0	9	0	(75)
26	0	0	0	(0)	(0)	(0)	(0)	(0)	(0)	0	0	0	(0)
53	0	0	0	(7)	0	0	(7)	0	0	0	1	0	(6)
56	0	0	0	(7)	(0)	(0)	(7)	(0)	(0)	0	1	0	(7)
57	0	0	0	(7)	(0)	(0)	(7)	(0)	(0)	0	1	0	(7)
58	(511)	0	0	(106)	(21)	(10)	(617)	(21)	(10)	0	67	0	(572)
59	(894)	0	0	(341)	(91)	(43)	(1,235)	(91)	(43)	0	138	0	(1,188)
60	(304)	0	0	(134)	(17)	(8)	(438)	(17)	(8)	0	48	0	(408)
63	0	0	0	(4)	(1)	(0)	(4)	(1)	(0)	0	0	0	(4)
64	0	0	0	(4)	(0)	(0)	(4)	(0)	(0)	0	0	0	(4)
66	0	0	0	(4)	(0)	(0)	(4)	(0)	(0)	0	0	0	(3)
67	(0)	0	0	(7)	(0)	(0)	(7)	(0)	(0)	0	1	0	(6)
69	(559)	0	(0)	(130)	(29)	(14)	(689)	(29)	(14)	0	75	0	(643)
72	0	0	0	(23)	(0)	(0)	(23)	(0)	(0)	0	2	0	(21)
74	(894)	0	0	(352)	(72)	(34)	(1,246)	(72)	(34)	0	137	0	(1,180)
81	(221)	0	0	(34)	(6)	(3)	(255)	(6)	(3)	0	27	0	(234)
83	(67)	0	0	(4)	(0)	(0)	(70)	(0)	(0)	0	7	0	(63)
86	(0)	0	0	(4)	(0)	(0)	(4)	(0)	(0)	0	0	0	(4)
87	(4)	0	0	(49)	(0)	(0)	(53)	(0)	(0)	0	5	0	(47)
88	0	0	0	(0)	(0)	(0)	(0)	(0)	(0)	0	0	0	(0)
89	0	0	0	(0)	(0)	(0)	(0)	(0)	(0)	0	0	0	(0)
90	0	0	0	(0)	(0)	(0)	(0)	(0)	(0)	0	0	0	(0)
91	(232)	0	0	(21)	(2)	(1)	(253)	(2)	(1)	0	27	0	(229)
99	0	0	0	(151)	0	0	(151)	0	0	0	16	0	(135)
TOTAL NON-REG	(3,758)	0	(0)	(1,398)	(243)	(115)	(5,156)	(243)	(115)	0	563	0	(4,836)
REGULATED													
01	(202)	(106)	(93)	(664)	(354)	(168)	(866)	(460)	(261)	0	138	0	(1,188)
02	(8,732)	(5,842)	(5,158)	(23,594)	(9,820)	(4,652)	(32,325)	(15,662)	(9,810)	0	5,006	0	(42,981)
03	(2,089)	(1,436)	(1,268)	(5,625)	(2,106)	(998)	(7,714)	(3,541)	(2,265)	0	1,174	0	(10,082)
04	(6,589)	(4,291)	(3,788)	(18,043)	(6,786)	(3,215)	(24,632)	(11,077)	(7,003)	0	3,725	0	(31,984)
06	(221)	(117)	(103)	(681)	(335)	(159)	(902)	(452)	(262)	0	141	0	(1,213)
07	(8,740)	(6,740)	(5,950)	(21,535)	(8,201)	(3,885)	(30,275)	(14,941)	(9,836)	0	4,717	0	(40,499)
10	(4,768)	(3,009)	(2,657)	(13,709)	(5,439)	(2,577)	(18,477)	(8,448)	(5,233)	0	2,809	0	(24,116)

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AMERICAN ELECTRIC POWER COMPANY
SUMMARY OF SAVINGS
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(IN 000'S)

COMPANY	DIRECT SAVINGS			SERVICE COMPANY SAVINGS			TOTAL SAVINGS			ALLOCATION OF CTA	ALLOCATION OF PMI	ALLOCATION OF CIC	NET SAVINGS
	O&M	REV REQ	CAPITAL	O&M	REV REQ	CAPITAL	O&M	REV REQ	CAPITAL				
21	0	0	0	(3)	(1)	(0)	(3)	(1)	(0)	0	0	0	(3)
22	0	0	0	(221)	(53)	(25)	(221)	(53)	(25)	0	29	0	(245)
23	0	0	0	(1)	(0)	(0)	(1)	(0)	(0)	0	0	0	(2)
31	0	0	0	(40)	(8)	(4)	(40)	(8)	(4)	0	5	0	(43)
32	0	0	0	(53)	(11)	(5)	(53)	(11)	(5)	0	7	0	(57)
34	0	0	0	(337)	(178)	(84)	(337)	(178)	(84)	0	54	0	(461)
40	0	0	0	(0)	(0)	(0)	(0)	(0)	(0)	0	0	0	(0)
41	0	0	0	(0)	(0)	(0)	(0)	(0)	(0)	0	0	0	(0)
42	(35)	(7)	(6)	(543)	(327)	(155)	(577)	(334)	(161)	0	95	0	(816)
43	(38)	(6)	(5)	(635)	(400)	(189)	(673)	(406)	(195)	0	113	0	(966)
44	(190)	(26)	(23)	(2,173)	(1,116)	(529)	(2,364)	(1,142)	(552)	0	366	0	(3,140)
45	0	0	0	(0)	(0)	(0)	(0)	(0)	(0)	0	0	0	(0)
46	0	0	0	(1)	(0)	(0)	(1)	(0)	(0)	0	0	0	(1)
48	(56)	(15)	(13)	(491)	(265)	(125)	(548)	(280)	(139)	0	86	0	(741)
49	(2)	0	0	(126)	(83)	(39)	(128)	(83)	(39)	0	22	0	(189)
50	0	0	0	(0)	(0)	(0)	(0)	(0)	(0)	0	0	0	(0)
51	0	0	0	(1)	(0)	(0)	(1)	(0)	(0)	0	0	0	(1)
52	0	0	0	(0)	(0)	(0)	(0)	(0)	(0)	0	0	0	(0)
54	(7)	(2)	(2)	(114)	(67)	(32)	(122)	(69)	(33)	0	20	0	(171)
70	0	0	0	(344)	(83)	(39)	(344)	(83)	(39)	0	45	0	(383)
71	0	0	0	(343)	(83)	(39)	(343)	(83)	(39)	0	44	0	(381)
73	0	0	0	(155)	(38)	(18)	(155)	(38)	(18)	0	20	0	(173)
75	0	0	0	(38)	(18)	(9)	(38)	(18)	(9)	0	6	0	(51)
76	0	0	0	(0)	(0)	(0)	(0)	(0)	(0)	0	0	0	(0)
77	0	0	0	(0)	(0)	(0)	(0)	(0)	(0)	0	0	0	(0)
78	0	0	0	(0)	(0)	(0)	(0)	(0)	(0)	0	0	0	(0)
84	0	0	0	(0)	(0)	(0)	(0)	(0)	(0)	0	0	0	(0)
85	0	0	0	(0)	(0)	(0)	(0)	(0)	(0)	0	0	0	(0)
98	(227)	(285)	(252)	(523)	(102)	(48)	(750)	(387)	(300)	0	119	0	(1,018)
XX	0	0	0	(4)	(2)	(1)	(4)	(2)	(1)	0	1	0	(5)
TOTAL REG	(31,897)	(21,882)	(19,318)	(89,998)	(35,875)	(16,997)	(121,895)	(57,757)	(36,315)	0	18,741	0	(160,911)
TOTAL 2006	(35,655)	(21,882)	(19,318)	(91,396)	(36,118)	(17,112)	(127,051)	(58,000)	(36,430)	0	19,304	0	(165,747)

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AMERICAN ELECTRIC POWER COMPANY
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(IN 000'S)

COMPANY	DIRECT SAVINGS			SERVICE COMPANY SAVINGS			TOTAL SAVINGS			ALLOCATION OF CTA	ALLOCATION OF PMI	ALLOCATION OF CIC	NET SAVINGS
2007	O&M	REV REQ	CAPITAL	O&M	REV REQ	CAPITAL	O&M	REV REQ	CAPITAL				
NON-REG													
25	(77)	0	0	(9)	(2)	(1)	(85)	(2)	(1)	0	10	0	(78)
26	0	0	0	(0)	(0)	(0)	(0)	(0)	(0)	0	0	0	(0)
53	0	0	0	(7)	0	0	(7)	0	0	0	1	0	(6)
56	0	0	0	(8)	(0)	(0)	(8)	(0)	(0)	0	1	0	(7)
57	0	0	0	(8)	0	0	(8)	0	0	0	1	0	(7)
58	(536)	0	0	(110)	(21)	(11)	(647)	(21)	(11)	0	74	0	(593)
59	(938)	0	0	(356)	(88)	(46)	(1,294)	(88)	(46)	0	153	0	(1,229)
60	(313)	0	0	(140)	(16)	(9)	(453)	(16)	(9)	0	52	0	(418)
63	0	0	0	(4)	(1)	(0)	(4)	(1)	(0)	0	1	0	(4)
64	0	0	0	(4)	(0)	(0)	(4)	(0)	(0)	0	0	0	(4)
66	0	0	0	(4)	(0)	(0)	(4)	(0)	(0)	0	0	0	(3)
67	(0)	0	0	(7)	0	0	(8)	0	0	0	1	0	(7)
69	(587)	0	(0)	(135)	(28)	(14)	(722)	(28)	(15)	0	83	0	(666)
72	0	0	0	(24)	(0)	(0)	(24)	(0)	(0)	0	3	0	(22)
74	(938)	0	0	(367)	(69)	(36)	(1,305)	(69)	(36)	0	152	0	(1,222)
81	(232)	0	0	(35)	(6)	(3)	(268)	(6)	(3)	0	30	0	(244)
83	(70)	0	0	(4)	(0)	(0)	(74)	(0)	(0)	0	8	0	(66)
86	(0)	0	0	(4)	(0)	(0)	(4)	(0)	(0)	0	1	0	(4)
87	(4)	0	0	(51)	(0)	(0)	(55)	(0)	(0)	0	6	0	(49)
88	0	0	0	(0)	(0)	(0)	(0)	(0)	(0)	0	0	0	(0)
89	0	0	0	(0)	(0)	(0)	(0)	(0)	(0)	0	0	0	(0)
90	0	0	0	(0)	(0)	(0)	(0)	(0)	(0)	0	0	0	(0)
91	(244)	0	0	(22)	(2)	(1)	(266)	(2)	(1)	0	30	0	(238)
99	0	0	0	(157)	0	0	(157)	0	0	0	17	0	(139)
TOTAL NON-REG	(3,940)	0	(0)	(1,456)	(234)	(122)	(5,396)	(234)	(122)	0	624	0	(5,006)
REGULATED													
01	(210)	(120)	(97)	(691)	(338)	(176)	(902)	(457)	(273)	0	151	0	(1,208)
02	(9,084)	(6,599)	(5,329)	(24,551)	(9,359)	(4,876)	(33,635)	(15,958)	(10,205)	0	5,498	0	(44,095)
03	(2,173)	(1,621)	(1,309)	(5,853)	(2,007)	(1,045)	(8,026)	(3,628)	(2,355)	0	1,292	0	(10,362)
04	(6,855)	(4,847)	(3,914)	(18,774)	(6,467)	(3,369)	(25,629)	(11,314)	(7,283)	0	4,096	0	(32,847)
06	(230)	(132)	(107)	(709)	(319)	(166)	(939)	(452)	(273)	0	154	0	(1,237)
07	(9,093)	(7,609)	(6,145)	(22,405)	(7,813)	(4,070)	(31,498)	(15,422)	(10,215)	0	5,202	0	(41,718)
10	(4,959)	(3,400)	(2,746)	(14,268)	(5,188)	(2,703)	(19,228)	(8,588)	(5,448)	0	3,084	0	(24,732)

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AMERICAN ELECTRIC POWER COMPANY
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COMPANY	DIRECT SAVINGS			SERVICE COMPANY SAVINGS			TOTAL SAVINGS			ALLOCATION OF CTA	ALLOCATION OF PMI	ALLOCATION OF CIC	NET SAVINGS
	O&M	REV REQ	CAPITAL	O&M	REV REQ	CAPITAL	O&M	REV REQ	CAPITAL				
21	0	0	0	(3)	(1)	(0)	(3)	(1)	(0)	0	0	0	(3)
22	0	0	0	(230)	(51)	(27)	(230)	(51)	(27)	0	31	0	(250)
23	0	0	0	(1)	(0)	(0)	(1)	(0)	(0)	0	0	0	(2)
31	0	0	0	(42)	(8)	(4)	(42)	(8)	(4)	0	6	0	(44)
32	0	0	0	(55)	(11)	(6)	(55)	(11)	(6)	0	7	0	(58)
34	0	0	0	(350)	(169)	(88)	(350)	(169)	(88)	0	58	0	(462)
40	0	0	0	(0)	(0)	(0)	(0)	(0)	(0)	0	0	0	(0)
41	0	0	0	(0)	(0)	(0)	(0)	(0)	(0)	0	0	0	(0)
42	(36)	(7)	(6)	(564)	(310)	(162)	(600)	(318)	(168)	0	102	0	(816)
43	(40)	(7)	(5)	(660)	(380)	(198)	(700)	(386)	(203)	0	120	0	(966)
44	(198)	(30)	(24)	(2,260)	(1,060)	(552)	(2,458)	(1,089)	(576)	0	393	0	(3,154)
45	0	0	0	(0)	(0)	(0)	(0)	(0)	(0)	0	0	0	(0)
46	0	0	0	(1)	(0)	(0)	(1)	(0)	(0)	0	0	0	(1)
48	(59)	(17)	(14)	(511)	(252)	(131)	(569)	(269)	(145)	0	93	0	(745)
49	(2)	0	0	(131)	(78)	(41)	(133)	(78)	(41)	0	23	0	(188)
50	0	0	0	(0)	(0)	(0)	(0)	(0)	(0)	0	0	0	(0)
51	0	0	0	(1)	(0)	(0)	(1)	(0)	(0)	0	0	0	(1)
52	0	0	0	(0)	(0)	(0)	(0)	(0)	(0)	0	0	0	(0)
54	(8)	(2)	(2)	(119)	(63)	(33)	(127)	(66)	(35)	0	21	0	(171)
70	0	0	0	(359)	(80)	(42)	(359)	(80)	(42)	0	49	0	(390)
71	0	0	0	(357)	(80)	(42)	(357)	(80)	(42)	0	48	0	(389)
73	0	0	0	(162)	(36)	(19)	(162)	(36)	(19)	0	22	0	(176)
75	0	0	0	(40)	(18)	(9)	(40)	(18)	(9)	0	6	0	(51)
76	0	0	0	(0)	(0)	(0)	(0)	(0)	(0)	0	0	0	(0)
77	0	0	0	(0)	(0)	(0)	(0)	(0)	(0)	0	0	0	(0)
78	0	0	0	(0)	(0)	(0)	(0)	(0)	(0)	0	0	0	(0)
84	0	0	0	(0)	(0)	(0)	(0)	(0)	(0)	0	0	0	(0)
85	0	0	0	(0)	(0)	(0)	(0)	(0)	(0)	0	0	0	(0)
98	(235)	(322)	(260)	(544)	(96)	(50)	(779)	(418)	(310)	0	133	0	(1,065)
XX	0	0	0	(4)	(2)	(1)	(4)	(2)	(1)	0	1	0	(5)
TOTAL REG	(33,184)	(24,713)	(19,957)	(93,645)	(34,187)	(17,810)	(126,829)	(58,900)	(37,767)	0	20,590	0	(165,139)
TOTAL 2007	(37,125)	(24,713)	(19,957)	(95,100)	(34,421)	(17,932)	(132,225)	(59,134)	(37,889)	0	21,214	0	(170,145)

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AMERICAN ELECTRIC POWER COMPANY
SUMMARY OF SAVINGS
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OMPANY	DIRECT SAVINGS O&M	DIRECT SAVINGS REV REQ	DIRECT SAVINGS CAPITAL	SERVICE COMPANY SAVINGS O&M	SERVICE COMPANY SAVINGS REV REQ	SERVICE COMPANY SAVINGS CAPITAL	TOTAL SAVINGS O&M	TOTAL SAVINGS REV REQ	TOTAL SAVINGS CAPITAL	ALLOCATION OF CTA	ALLOCATION OF PMI	ALLOCATION OF CIC	NET SAVINGS
008													
ON-REG													
25	(81)	0	0	(9)	(2)	(1)	(90)	(2)	(1)	0	11	0	(82)
26	0	0	0	(0)	(0)	(0)	(0)	(0)	(0)	0	0	0	(0)
53	0	0	0	(7)	0	0	(7)	0	0	0	1	0	(7)
56	0	0	0	(8)	(0)	(0)	(8)	(0)	(0)	0	1	0	(7)
57	0	0	0	(8)	0	0	(8)	0	0	0	1	0	(7)
58	(567)	0	0	(119)	(22)	(12)	(685)	(22)	(12)	0	81	0	(626)
59	(991)	0	0	(388)	(93)	(52)	(1,380)	(93)	(52)	0	168	0	(1,305)
60	(324)	0	0	(148)	(17)	(9)	(472)	(17)	(9)	0	56	0	(433)
63	0	0	0	(4)	(1)	(0)	(4)	(1)	(0)	0	1	0	(4)
64	0	0	0	(4)	(0)	(0)	(4)	(0)	(0)	0	0	0	(4)
66	0	0	0	(4)	(0)	(0)	(4)	(0)	(0)	0	0	0	(3)
67	(0)	0	0	(8)	0	0	(8)	0	0	0	1	0	(7)
69	(620)	0	(0)	(144)	(28)	(16)	(764)	(28)	(16)	0	90	0	(702)
72	0	0	0	(25)	(0)	(0)	(25)	(0)	(0)	0	3	0	(22)
74	(991)	0	0	(395)	(73)	(41)	(1,386)	(73)	(41)	0	166	0	(1,293)
81	(246)	0	0	(38)	(7)	(4)	(283)	(7)	(4)	0	33	0	(257)
83	(74)	0	0	(4)	(0)	(0)	(78)	(0)	(0)	0	9	0	(69)
86	(1)	0	0	(4)	(0)	(0)	(5)	(0)	(0)	0	1	0	(4)
87	(4)	0	0	(53)	0	0	(57)	0	0	0	6	0	(50)
88	0	0	0	(0)	(0)	(0)	(0)	(0)	(0)	0	0	0	(0)
89	0	0	0	(0)	(0)	(0)	(0)	(0)	(0)	0	0	0	(0)
90	0	0	0	(0)	(0)	(0)	(0)	(0)	(0)	0	0	0	(0)
91	(258)	0	0	(23)	(2)	(1)	(281)	(2)	(1)	0	32	0	(250)
99	0	0	0	(162)	1	0	(162)	1	0	0	18	0	(143)
TOTAL NON-REG	(4,155)	0	(0)	(1,556)	(245)	(137)	(5,711)	(245)	(137)	0	679	0	(5,277)
REGULATED													
01	(223)	(133)	(97)	(722)	(299)	(167)	(945)	(432)	(264)	0	157	0	(1,220)
02	(9,560)	(7,467)	(5,456)	(25,635)	(8,506)	(4,743)	(35,195)	(15,973)	(10,199)	0	5,834	0	(45,334)
03	(2,284)	(1,839)	(1,343)	(6,118)	(1,841)	(1,026)	(8,402)	(3,679)	(2,370)	0	1,377	0	(10,704)
04	(7,205)	(5,493)	(4,014)	(19,582)	(5,911)	(3,296)	(26,787)	(11,404)	(7,310)	0	4,355	0	(33,836)
06	(244)	(148)	(108)	(741)	(283)	(158)	(985)	(431)	(266)	0	161	0	(1,254)
07	(9,553)	(8,638)	(6,311)	(23,415)	(7,139)	(3,981)	(32,967)	(15,777)	(10,293)	0	5,558	0	(43,187)
10	(5,229)	(3,831)	(2,799)	(14,907)	(4,636)	(2,585)	(20,136)	(8,467)	(5,384)	0	3,261	0	(25,341)

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(IN 000'S)

COMPANY	DIRECT SAVINGS			SERVICE COMPANY SAVINGS			TOTAL SAVINGS			ALLOCATION OF CTA	ALLOCATION OF PMI	ALLOCATION OF CIC	NET SAVINGS
	O&M	REV REQ	CAPITAL	O&M	REV REQ	CAPITAL	O&M	REV REQ	CAPITAL				
21	0	0	0	(3)	(1)	(0)	(3)	(1)	(0)	0	0	0	(3)
22	0	0	0	(249)	(55)	(30)	(249)	(55)	(30)	0	35	0	(269)
23	0	0	0	(2)	(0)	(0)	(2)	(0)	(0)	0	0	0	(2)
31	0	0	0	(45)	(8)	(5)	(45)	(8)	(5)	0	6	0	(47)
32	0	0	0	(59)	(11)	(6)	(59)	(11)	(6)	0	8	0	(63)
34	0	0	0	(365)	(164)	(91)	(365)	(164)	(91)	0	60	0	(469)
40	0	0	0	(0)	(0)	(0)	(0)	(0)	(0)	0	0	0	(0)
41	0	0	0	(0)	(0)	(0)	(0)	(0)	(0)	0	0	0	(0)
42	(38)	(9)	(6)	(590)	(299)	(167)	(628)	(308)	(173)	0	107	0	(829)
43	(42)	(8)	(5)	(691)	(366)	(204)	(733)	(374)	(210)	0	126	0	(980)
44	(208)	(35)	(25)	(2,362)	(1,024)	(571)	(2,570)	(1,058)	(596)	0	414	0	(3,214)
45	0	0	0	(0)	(0)	(0)	(0)	(0)	(0)	0	0	0	(0)
46	0	0	0	(1)	(0)	(0)	(1)	(0)	(0)	0	0	0	(1)
48	(62)	(20)	(15)	(532)	(244)	(136)	(594)	(264)	(151)	0	98	0	(760)
49	(3)	0	0	(137)	(76)	(42)	(140)	(76)	(42)	0	25	0	(191)
50	0	0	0	(0)	(0)	(0)	(0)	(0)	(0)	0	0	0	(0)
51	0	0	0	(1)	(0)	(0)	(1)	(0)	(0)	0	0	0	(1)
52	0	0	0	(0)	(0)	(0)	(0)	(0)	(0)	0	0	0	(0)
54	(8)	(2)	(2)	(125)	(61)	(34)	(133)	(64)	(36)	0	22	0	(174)
70	0	0	0	(389)	(85)	(47)	(389)	(85)	(47)	0	54	0	(420)
71	0	0	0	(388)	(85)	(47)	(388)	(85)	(47)	0	54	0	(418)
73	0	0	0	(176)	(38)	(21)	(176)	(38)	(21)	0	24	0	(190)
75	0	0	0	(46)	(19)	(11)	(46)	(19)	(11)	0	7	0	(57)
76	0	0	0	(0)	(0)	(0)	(0)	(0)	(0)	0	0	0	(0)
77	0	0	0	(0)	(0)	(0)	(0)	(0)	(0)	0	0	0	(0)
78	0	0	0	(0)	(0)	(0)	(0)	(0)	(0)	0	0	0	(0)
84	0	0	0	(0)	(0)	(0)	(0)	(0)	(0)	0	0	0	(0)
85	0	0	0	(0)	(0)	(0)	(0)	(0)	(0)	0	0	0	(0)
98	(246)	(368)	(269)	(566)	(93)	(52)	(812)	(460)	(320)	0	145	0	(1,127)
XX	0	0	0	(4)	(2)	(1)	(4)	(2)	(1)	0	1	0	(6)
TOTAL REG	(34,903)	(27,989)	(20,451)	(97,851)	(31,247)	(17,425)	(132,754)	(59,237)	(37,876)	0	21,891	0	(170,100)
TOTAL 2008	(39,059)	(27,989)	(20,451)	(99,407)	(31,492)	(17,562)	(138,465)	(59,481)	(38,013)	)	22,570	0	(175,377)
		(67,048)			(130,899)			(197,947)					

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AMERICAN ELECTRIC POWER COMPANY
SUMMARY OF SAVINGS
BY SUBSIDIARY

(IN 000'S)

COMPANY	DIRECT SAVINGS			SERVICE COMPANY SAVINGS			TOTAL SAVINGS			ALLOCATION OF CTA	ALLOCATION OF PMI	ALLOCATION OF CIC	NET SAVINGS
2009	O&M	REV REQ	CAPITAL	O&M	REV REQ	CAPITAL	O&M	REV REQ	CAPITAL				
NON-REG													
25	(21)	0	0	(2)	(1)	(0)	(23)	(1)	(0)	0	3	0	(21)
26	0	0	0	(0)	(0)	(0)	(0)	(0)	(0)	0	0	0	(0)
53	0	0	0	(2)	0	0	(2)	0	0	0	0	0	(2)
56	0	0	0	(2)	(0)	(0)	(2)	(0)	(0)	0	0	0	(2)
57	0	0	0	(2)	0	0	(2)	0	0	0	0	0	(2)
58	(144)	0	0	(30)	(6)	(3)	(174)	(6)	(3)	0	21	0	(159)
59	(252)	0	0	(99)	(24)	(13)	(351)	(24)	(13)	0	45	0	(331)
60	(82)	0	0	(38)	(4)	(2)	(120)	(4)	(2)	0	15	0	(110)
63	0	0	0	(1)	(0)	(0)	(1)	(0)	(0)	0	0	0	(1)
64	0	0	0	(1)	(0)	(0)	(1)	(0)	(0)	0	0	0	(1)
66	0	0	0	(1)	(0)	(0)	(1)	(0)	(0)	0	0	0	(1)
67	(0)	0	0	(2)	0	0	(2)	0	0	0	0	0	(2)
69	(158)	0	(0)	(37)	(7)	(4)	(195)	(7)	(4)	0	24	0	(178)
72	0	0	0	(6)	(0)	(0)	(6)	(0)	(0)	0	1	0	(6)
74	(252)	0	0	(101)	(19)	(10)	(353)	(19)	(10)	0	44	0	(327)
81	(63)	0	0	(10)	(2)	(1)	(72)	(2)	(1)	0	9	0	(65)
83	(19)	0	0	(1)	(0)	(0)	(20)	(0)	(0)	0	2	0	(17)
86	(0)	0	0	(1)	(0)	(0)	(1)	(0)	(0)	0	0	0	(1)
87	(1)	0	0	(13)	0	0	(14)	0	0	0	2	0	(13)
88	0	0	0	(0)	(0)	(0)	(0)	(0)	(0)	0	0	0	(0)
89	0	0	0	(0)	(0)	(0)	(0)	(0)	(0)	0	0	0	(0)
90	0	0	0	(0)	(0)	(0)	(0)	(0)	(0)	0	0	0	(0)
91	(66)	0	0	(6)	(1)	(0)	(71)	(1)	(0)	0	9	0	(63)
99	0	0	0	(41)	0	0	(41)	0	0	0	5	0	(36)
TOTAL NON-REG	(1,058)	0	(0)	(396)	(62)	(35)	(1,454)	(62)	(35)	0	180	0	(1,337)
REGULATED													
01	(57)	(34)	(25)	(184)	(76)	(43)	(241)	(110)	(67)	0	42	0	(309)
02	(2,435)	(1,902)	(1,389)	(6,528)	(2,166)	(1,208)	(8,963)	(4,068)	(2,597)	0	1,547	0	(11,483)
03	(582)	(468)	(342)	(1,558)	(469)	(261)	(2,140)	(937)	(604)	0	365	0	(2,711)
04	(1,835)	(1,399)	(1,022)	(4,987)	(1,505)	(839)	(6,822)	(2,904)	(1,862)		1,155	0	(8,571)
06	(62)	(38)	(27)	(189)	(72)	(40)	(251)	(110)	(68)		43	0	(318)
07	(2,433)	(2,200)	(1,607)	(5,963)	(1,818)	(1,014)	(8,395)	(4,018)	(2,621)		1,474	0	(10,939)
10	(1,332)	(976)	(713)	(3,796)	(1,181)	(658)	(5,128)	(2,156)	(1,371)		865	0	(6,419)

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AMERICAN ELECTRIC POWER COMPANY
SUMMARY OF SAVINGS
BY SUBSIDIARY

(IN 000'S)

COMPANY	DIRECT SAVINGS O&M	DIRECT SAVINGS REV REQ	DIRECT SAVINGS CAPITAL	SERVICE COMPANY SAVINGS O&M	SERVICE COMPANY SAVINGS REV REQ	SERVICE COMPANY SAVINGS CAPITAL	TOTAL SAVINGS O&M	TOTAL SAVINGS REV REQ	TOTAL SAVINGS CAPITAL	ALLOCATION OF CTA	ALLOCATION OF PMI	ALLOCATION OF CIC	NET SAVINGS
21	0	0	0	(1)	(0)	(0)	(1)	(0)	(0)	0	0	0	(1)
22	0	0	0	(64)	(14)	(8)	(64)	(14)	(8)	0	9	0	(68)
23	0	0	0	(0)	(0)	(0)	(0)	(0)	(0)	0	0	0	(0)
31	0	0	0	(11)	(2)	(1)	(11)	(2)	(1)	0	2	0	(12)
32	0	0	0	(15)	(3)	(2)	(15)	(3)	(2)	0	2	0	(16)
34	0	0	0	(93)	(42)	(23)	(93)	(42)	(23)	0	16	0	(119)
40	0	0	0	(0)	(0)	(0)	(0)	(0)	(0)	0	0	0	(0)
41	0	0	0	(0)	(0)	(0)	(0)	(0)	(0)	0	0	0	(0)
42	(10)	(2)	(2)	(150)	(76)	(43)	(160)	(78)	(44)	0	28	0	(210)
43	(11)	(2)	(1)	(176)	(93)	(52)	(187)	(95)	(53)	0	33	0	(248)
44	(53)	(9)	(6)	(602)	(261)	(145)	(654)	(270)	(152)	0	110	0	(814)
45	0	0	0	(0)	(0)	(0)	(0)	(0)	(0)	0	0	0	(0)
46	0	0	0	(0)	(0)	(0)	(0)	(0)	(0)	0	0	0	(0)
48	(16)	(5)	(4)	(136)	(62)	(35)	(151)	(67)	(38)	0	26	0	(193)
49	(1)	0	0	(35)	(19)	(11)	(36)	(19)	(11)	0	7	0	(48)
50	0	0	0	(0)	(0)	(0)	(0)	(0)	(0)	0	0	0	(0)
51	0	0	0	(0)	(0)	(0)	(0)	(0)	(0)	0	0	0	(0)
52	0	0	0	(0)	(0)	(0)	(0)	(0)	(0)	0	0	0	(0)
54	(2)	(1)	(0)	(32)	(16)	(9)	(34)	(16)	(9)	0	6	0	(44)
70	0	0	0	(99)	(22)	(12)	(99)	(22)	(12)	0	14	0	(106)
71	0	0	0	(99)	(22)	(12)	(99)	(22)	(12)	0	14	0	(106)
73	0	0	0	(45)	(10)	(5)	(45)	(10)	(5)	0	6	0	(48)
75	0	0	0	(12)	(5)	(3)	(12)	(5)	(3)	0	2	0	(15)
76	0	0	0	(0)	(0)	(0)	(0)	(0)	(0)	0	0	0	(0)
77	0	0	0	(0)	(0)	(0)	(0)	(0)	(0)	0	0	0	(0)
78	0	0	0	(0)	(0)	(0)	(0)	(0)	(0)	0	0	0	(0)
84	0	0	0	(0)	(0)	(0)	(0)	(0)	(0)	0	0	0	(0)
85	0	0	0	(0)	(0)	(0)	(0)	(0)	(0)	0	0	0	(0)
98	(63)	(94)	(68)	(144)	(24)	(13)	(207)	(117)	(82)	0	38	0	(286)
XX	0	0	0	(1)	(0)	(0)	(1)	(0)	(0)	0	0	0	(1)
TOTAL REG	(8,888)	(7,128)	(5,208)	(24,919)	(7,958)	(4,438)	(33,807)	(15,085)	(9,646)	0	5,806	0	(43,086)
TOTAL 2009	(9,947)	(7,128)	(5,208)	(25,315)	(8,020)	(4,472)	(35,262)	(15,148)	(9,680)	0	5,986	0	(44,423)

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CENTRAL AND SOUTH WEST SERVICES, INC.
SUMMARY OF SAVINGS
BY CSW SUBSIDIARY

1999
(IN 000'S)

COMPANY	DIRECT SAVINGS			SERVICE COMPANY SAVINGS			TOTAL SAVINGS			ALLOCATION OF CTA	ALLOCATION OF PMI	ALLOCATION OF CIC	NET SAVINGS
	O&M	REV REQ	CAPITAL	O&M	REV REQ	CAPITAL	O&M	REV REQ	CAPITAL				
NON-REG													
CSE	(210)	0	0	(170)	(1)	(5)	(379)	(1)	(5)	207	9	58	(108)
CSI	(416)	0	0	(17)	(0)	(0)	(433)	(0)	(0)	235	10	65	(122)
DCM	(151)	0	0	(63)	(1)	(4)	(214)	(1)	(4)	117	5	33	(61)
DCR	(202)	0	0	(204)	(2)	(8)	(407)	(2)	(8)	222	9	62	(116)
DCT	(15)	0	0	(140)	(0)	(1)	(155)	(0)	(1)	84	4	24	(44)
DES	(120)	0	0	(16)	(0)	(1)	(136)	(0)	(1)	74	3	21	(39)
DLL	0	0	0	(14)	(0)	(0)	(14)	(0)	(0)	8	0	2	(4)
ESI	0	0	0	(20)	(0)	(1)	(20)	(0)	(1)	11	0	3	(6)
PMI	0	0	0	(4)	(0)	(0)	(4)	(0)	(0)	2	0	1	(1)
SEE	(67)	0	0	(541)	(3)	(10)	(608)	(3)	(10)	332	14	92	(173)
TOK	0	0	0	(1)	(0)	(0)	(1)	(0)	(0)	1	0	0	(0)
TOTAL NON-REG	(1,182)	0	0	(1,188)	(9)	(31)	(2,370)	(9)	(31)	1,293	54	360	(672)
REGULATED													
CPL	(2,942)	(330)	(1,881)	(4,735)	(252)	(858)	(7,677)	(582)	(2,739)	4,488	187	1,249	(2,335)
ECS	0	0	0	(10)	(0)	(0)	(10)	(0)	(0)	6	0	2	(3)
JFP	0	0	0	(11)	(0)	(0)	(11)	(0)	(0)	6	0	2	(3)
LAB	0	0	0	(1)	(0)	(0)	(1)	(0)	(0)	1	0	0	(0)
PSO	(2,135)	(297)	(1,693)	(2,869)	(188)	(639)	(5,004)	(484)	(2,332)	2,982	124	830	(1,552)
SEP	(2,298)	(310)	(1,770)	(3,307)	(176)	(601)	(5,605)	(487)	(2,371)	3,310	138	921	(1,722)
WTU	(1,091)	(139)	(792)	(1,539)	(88)	(298)	(2,630)	(226)	(1,090)	1,552	65	432	(807)
TOTAL REG	(8,465)	(1,075)	(6,137)	(12,473)	(704)	(2,396)	(20,938)	(1,779)	(8,533)	12,345	514	3,435	(6,423)
TOTAL 1999	(9,647)	(1,075)	(6,137)	(13,661)	(713)	(2,428)	(23,308)	(1,788)	(8,565)	13,638	568	3,795	(7,095)

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CENTRAL AND SOUTH WEST SERVICES, INC.
SUMMARY OF SAVINGS
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2000
(IN 000'S)

COMPANY	DIRECT SAVINGS O&M	DIRECT SAVINGS REV REQ	DIRECT SAVINGS CAPITAL	SERVICE COMPANY SAVINGS O&M	SERVICE COMPANY SAVINGS REV REQ	SERVICE COMPANY SAVINGS CAPITAL	TOTAL SAVINGS O&M	TOTAL SAVINGS REV REQ	TOTAL SAVINGS CAPITAL	ALLOCATION OF CTA	ALLOCATION OF PMI	ALLOCATION OF CIC	NET SAVINGS
NON-REG													
CSE	(294)	0	0	(463)	(9)	(24)	(757)	(9)	(24)	244	21	68	(433)
CSI	(583)	0	0	(47)	(0)	(1)	(629)	(0)	(1)	200	18	56	(356)
DCM	(212)	0	0	(178)	(8)	(21)	(389)	(8)	(21)	126	11	35	(224)
DCR	(279)	0	0	(506)	(16)	(44)	(784)	(16)	(44)	255	22	71	(453)
DCT	(21)	0	0	(373)	(1)	(2)	(394)	(1)	(2)	126	11	35	(223)
DES	(169)	0	0	(44)	(2)	(6)	(213)	(2)	(6)	68	6	19	(121)
DLL	0	0	0	(38)	(0)	(0)	(38)	(0)	(0)	12	1	3	(22)
ESI	0	0	0	(54)	(3)	(7)	(54)	(3)	(7)	18	2	5	(32)
PMI	0	0	0	(8)	(0)	(1)	(8)	(0)	(1)	3	0	1	(5)
SEE	(94)	0	0	(1,701)	(14)	(37)	(1,795)	(14)	(37)	576	51	160	(1,022)
TOK	0	0	0	(2)	(0)	(0)	(2)	(0)	(0)	1	0	0	(1)
TOTAL NON-REG	(1,650)	0	0	(3,415)	(53)	(143)	(5,065)	(53)	(143)	1,629	143	453	(2,892)
REGULATED													
CPL	(4,454)	(802)	(2,712)	(12,336)	(1,556)	(4,223)	(16,790)	(2,358)	(6,936)	6,095	534	1,696	(10,823)
ECS	0	0	0	(23)	(1)	(2)	(23)	(1)	(2)	7	1	2	(13)
JFP	0	0	0	(23)	(1)	(2)	(23)	(1)	(2)	8	1	2	(14)
LAB	0	0	0	(2)	(0)	(0)	(2)	(0)	(0)	1	0	0	(1)
PSO	(3,212)	(717)	(2,424)	(7,420)	(1,162)	(3,155)	(10,633)	(1,879)	(5,579)	3,983	349	1,108	(7,072)
SEP	(3,404)	(744)	(2,517)	(8,674)	(1,076)	(2,921)	(12,078)	(1,821)	(5,438)	4,424	388	1,231	(7,856)
WTU	(1,612)	(333)	(1,127)	(4,053)	(525)	(1,426)	(5,666)	(859)	(2,553)	2,077	182	578	(3,688)
TOTAL REG	(12,683)	(2,597)	(8,780)	(32,532)	(4,321)	(11,729)	(45,215)	(6,918)	(20,509)	16,595	1,454	4,618	(29,466)
TOTAL 2000	(14,333)	(2,597)	(8,780)	(35,947)	(4,374)	(11,872)	(50,280)	(6,971)	(20,652)	18,224	1,597	5,071	(32,359)

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CENTRAL AND SOUTH WEST SERVICES, INC.
SUMMARY OF SAVINGS
BY CSW SUBSIDIARY

2001
(IN 000'S)

COMPANY	DIRECT SAVINGS O&M	DIRECT SAVINGS REV REQ	DIRECT SAVINGS CAPITAL	SERVICE COMPANY SAVINGS O&M	SERVICE COMPANY SAVINGS REV REQ	SERVICE COMPANY SAVINGS CAPITAL	TOTAL SAVINGS O&M	TOTAL SAVINGS REV REQ	TOTAL SAVINGS CAPITAL	ALLOCATION OF CTA	ALLOCATION OF PMI	ALLOCATION OF CIC	NET SAVINGS
NON-REG													
CSE	(308)	0	0	(556)	(19)	(31)	(864)	(19)	(31)	228	34	64	(557)
CSI	(612)	0	0	(56)	(1)	(1)	(668)	(1)	(1)	173	26	48	(422)
DCM	(222)	0	0	(215)	(17)	(27)	(437)	(17)	(27)	117	18	33	(286)
DCR	(287)	0	0	(603)	(37)	(58)	(890)	(37)	(58)	239	36	67	(584)
DCT	(22)	0	0	(445)	(2)	(3)	(467)	(2)	(3)	121	18	34	(296)
DES	(177)	0	0	(53)	(4)	(7)	(231)	(4)	(7)	61	9	17	(148)
DLL	0	0	0	(45)	(0)	(0)	(45)	(0)	(0)	12	2	3	(29)
ESI	0	0	0	(66)	(6)	(9)	(66)	(6)	(9)	18	3	5	(45)
PMI	0	0	0	(10)	(1)	(1)	(10)	(1)	(1)	3	0	1	(6)
SEE	(97)	0	0	(2,076)	(29)	(46)	(2,173)	(29)	(46)	569	85	158	(1,389)
TOK	0	0	0	(3)	(0)	(0)	(3)	(0)	(0)	1	0	0	(2)
TOTAL NON-REG	(1,725)	0	0	(4,130)	(115)	(184)	(5,854)	(115)	(184)	1,543	231	429	(3,766)
REGULATED													
CPL	(4,679)	(1,441)	(3,926)	(14,566)	(2,921)	(4,691)	(19,245)	(4,362)	(8,617)	6,102	913	1,698	(14,895)
ECS	0	0	0	(26)	(2)	(3)	(26)	(2)	(3)	7	1	2	(18)
JFP	0	0	0	(27)	(2)	(2)	(27)	(2)	(2)	7	1	2	(18)
LAB	0	0	0	(2)	(0)	(0)	(2)	(0)	(0)	1	0	0	(2)
PSO	(3,376)	(1,294)	(3,524)	(8,704)	(2,171)	(3,487)	(12,081)	(3,465)	(7,011)	4,018	601	1,118	(9,809)
SEP	(3,571)	(1,350)	(3,677)	(10,194)	(2,027)	(3,256)	(13,766)	(3,377)	(6,933)	4,431	663	1,233	(10,816)
WTU	(1,692)	(603)	(1,643)	(4,789)	(1,000)	(1,606)	(6,481)	(1,603)	(3,248)	2,089	313	581	(5,101)
TOTAL REG	(13,319)	(4,689)	(12,770)	(38,310)	(8,122)	(13,044)	(51,628)	(12,811)	(25,814)	16,655	2,492	4,634	(40,658)
TOTAL 2001	(15,044)	(4,689)	(12,770)	(42,439)	(8,237)	(13,229)	(57,483)	(12,926)	(25,999)	18,198	2,723	5,064	(44,424)

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CENTRAL AND SOUTH WEST SERVICES, INC.
SUMMARY OF SAVINGS
BY CSW SUBSIDIARY

2002
(IN 000'S)

COMPANY	DIRECT SAVINGS			SERVICE COMPANY SAVINGS			TOTAL SAVINGS			ALLOCATION OF CTA	ALLOCATION OF PMI	ALLOCATION OF CIC	NET SAVINGS
	O&M	REV REQ	CAPITAL	O&M	REV REQ	CAPITAL	O&M	REV REQ	CAPITAL				
NON-REG													
CSE	(327)	(0)	(1)	(587)	(29)	(35)	(915)	(29)	(36)	210	47	58	(629)
CSI	(642)	0	0	(59)	(1)	(1)	(701)	(1)	(1)	156	35	43	(468)
DCM	(235)	(0)	(1)	(231)	(25)	(30)	(467)	(25)	(31)	110	24	30	(328)
DCR	(295)	0	0	(643)	(55)	(66)	(938)	(55)	(66)	221	49	62	(662)
DCT	(23)	0	0	(464)	(3)	(3)	(487)	(3)	(3)	109	24	30	(326)
DES	(187)	(0)	(0)	(58)	(7)	(8)	(245)	(7)	(9)	56	12	16	(168)
DLL	0	0	0	(47)	(0)	(0)	(47)	(0)	(0)	11	2	3	(32)
ESI	(1)	(0)	(0)	(71)	(9)	(10)	(71)	(9)	(11)	18	4	5	(53)
PMI	0	0	0	(10)	(1)	(1)	(10)	(1)	(1)	3	1	1	(7)
SEE	(260)	(9)	(47)	(2,161)	(41)	(49)	(2,421)	(50)	(97)	550	122	153	(1,645)
TOK	0	0	0	(3)	(0)	(0)	(3)	(0)	(0)	1	0	0	(2)
TOTAL NON-REG	(1,971)	(9)	(50)	(4,335)	(172)	(205)	(6,305)	(181)	(255)	1,444	321	402	(4,320)
REGULATED													
CPL	(5,484)	(1,934)	(3,081)	(15,310)	(4,358)	(5,196)	(20,794)	(6,292)	(8,277)	6,029	1,341	1,678	(18,038)
ECS	0	0	0	(28)	(2)	(3)	(28)	(2)	(3)	7	2	2	(20)
JFP	0	0	0	(29)	(2)	(3)	(29)	(2)	(3)	7	2	2	(21)
LAB	0	0	0	(3)	(0)	(0)	(3)	(0)	(0)	1	0	0	(2)
PSO	(3,984)	(1,712)	(2,727)	(9,172)	(3,244)	(3,869)	(13,156)	(4,957)	(6,596)	4,031	897	1,122	(12,062)
SEP	(4,278)	(1,791)	(2,853)	(10,743)	(3,026)	(3,609)	(15,021)	(4,817)	(6,462)	4,415	982	1,229	(13,211)
WTU	(2,097)	(818)	(1,303)	(5,063)	(1,490)	(1,777)	(7,159)	(2,308)	(3,079)	2,107	469	586	(6,305)
TOTAL REG	(15,842)	(6,256)	(9,964)	(40,347)	(12,123)	(14,457)	(56,189)	(18,379)	(24,420)	16,597	3,693	4,618	(49,659)
TOTAL 2002	(17,813)	(6,265)	(10,014)	(44,681)	(12,295)	(14,662)	(62,494)	(18,560)	(24,675)	18,041	4,014	5,020	**(53,979)**

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CENTRAL AND SOUTH WEST SERVICES, INC.
SUMMARY OF SAVINGS
BY CSW SUBSIDIARY

2003
(IN 000'S)

COMPANY	DIRECT SAVINGS O&M	DIRECT SAVINGS REV REQ	DIRECT SAVINGS CAPITAL	SERVICE COMPANY SAVINGS O&M	SERVICE COMPANY SAVINGS REV REQ	SERVICE COMPANY SAVINGS CAPITAL	TOTAL SAVINGS O&M	TOTAL SAVINGS REV REQ	TOTAL SAVINGS CAPITAL	ALLOCATION OF CTA	ALLOCATION OF PMI	ALLOCATION OF CIC	NET SAVINGS
NON-REG													
CSE	(343)	(0)	(1)	(611)	(38)	(36)	(954)	(39)	(38)	200	62	56	(675)
CSI	(674)	0	0	(61)	(1)	(1)	(735)	(1)	(1)	149	46	41	(501)
DCM	(247)	(0)	(1)	(241)	(34)	(32)	(488)	(34)	(33)	105	33	29	(355)
DCR	(304)	0	0	(671)	(74)	(70)	(975)	(74)	(70)	212	66	59	(713)
DCT	(25)	0	0	(482)	(4)	(4)	(507)	(4)	(4)	103	32	29	(347)
DES	(196)	(0)	(0)	(60)	(9)	(9)	(257)	(9)	(9)	54	17	15	(181)
DLL	0	0	0	(49)	(0)	(0)	(49)	(0)	(0)	10	3	3	(34)
ESI	(1)	(0)	(0)	(74)	(12)	(11)	(75)	(12)	(11)	17	5	5	(59)
PMI	0	0	0	(11)	(1)	(1)	(11)	(1)	(1)	2	1	1	(8)
SEE	(270)	(17)	(49)	(2,247)	(54)	(51)	(2,516)	(71)	(100)	522	162	145	(1,758)
TOK	0	0	0	(3)	(0)	(0)	(3)	(0)	(0)	1	0	0	(2)
TOTAL NON-REG	(2,060)	(18)	(52)	(4,510)	(228)	(216)	(6,570)	(246)	(268)	1,376	427	383	(4,630)
REGULATED													
CPL	(5,705)	(2,443)	(3,182)	(15,930)	(5,782)	(5,465)	(21,634)	(8,224)	(8,647)	6,028	1,870	1,677	(20,283)
ECS	0	0	0	(29)	(3)	(3)	(29)	(3)	(3)	7	2	2	(22)
JFP	0	0	0	(30)	(3)	(3)	(30)	(3)	(3)	7	2	2	(22)
LAB	0	0	0	(3)	(0)	(0)	(3)	(0)	(0)	1	0	0	(2)
PSO	(4,143)	(2,162)	(2,816)	(9,544)	(4,306)	(4,070)	(13,688)	(6,467)	(6,886)	4,069	1,262	1,132	(13,691)
SEP	(4,449)	(2,261)	(2,946)	(11,177)	(4,014)	(3,794)	(15,626)	(6,276)	(6,740)	4,422	1,372	1,230	(14,878)
WTU	(2,182)	(1,033)	(1,345)	(5,267)	(1,975)	(1,867)	(7,450)	(3,008)	([illegible],213)	2,111	655	587	(7,104)
TOTAL REG	(16,480)	(7,898)	(10,289)	(41,980)	(16,084)	(15,203)	(58,460)	(23,982)	(25,492)	16,644	5 164	4,631	(56,002)
TOTAL 2003	(18,540)	(7,916)	(10,341)	(46,490)	(16,312)	(15,419)	(65,030)	(24,228)	(25,760)	18,020	5,591	5,014	(60,632)

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CENTRAL AND SOUTH WEST SERVICES, INC.
SUMMARY OF SAVINGS
BY CSW SUBSIDIARY

2004
(IN 000'S)

COMPANY	DIRECT SAVINGS			SERVICE COMPANY SAVINGS			TOTAL SAVINGS			ALLOCATION OF CTA	ALLOCATION OF PMI	ALLOCATION OF CIC	NET SAVINGS
	O&M	REV REQ	CAPITAL	O&M	REV REQ	CAPITAL	O&M	REV REQ	CAPITAL				
NON-REG													
CSE	(360)	(1)	(1)	(634)	(66)	(38)	(995)	(66)	(39)	50	81	14	(916)
CSI	(708)	0	0	(63)	(2)	(1)	(771)	(2)	(1)	36	59	10	(668)
DCM	(259)	(0)	(1)	(249)	(57)	(33)	(509)	(58)	(34)	27	43	7	(489)
DCR	(313)	0	0	(691)	(125)	(72)	(1,004)	(125)	(72)	53	87	15	(975)
DCT	(26)	0	0	(501)	(6)	(4)	(527)	(6)	(4)	25	41	7	(460)
DES	(206)	(0)	(0)	(63)	(16)	(9)	(269)	(16)	(9)	13	22	4	(246)
DLL	0	0	0	(51)	(0)	(0)	(51)	(0)	(0)	2	4	1	(44)
ESI	(1)	(0)	(0)	(76)	(20)	(11)	(77)	(20)	(12)	5	7	1	(84)
PMI	0	0	0	(11)	(2)	(1)	(11)	(2)	(1)	1	1	0	(11)
SEE	(280)	(26)	(51)	(2,333)	(91)	(53)	(2,614)	(117)	(104)	129	209	36	(2,357)
TOK	0	0	0	(3)	(1)	(0)	(3)	(1)	(0)	0	0	0	(3)
TOTAL NON-REG	(2,154)	(27)	(54)	(4,677)	(386)	(223)	(6,831)	(413)	(277)	341	555	95	(6,253)
REGULATED													
CPL	(5,935)	(2,951)	(3,287)	(16,585)	(6,277)	(3,630)	(22,520)	(9,229)	(6,917)	1,496	2,434	416	(27,402)
ECS	0	0	0	(30)	(6)	(3)	(30)	(6)	(3)	2	3	0	(31)
JFP	0	0	0	(31)	(5)	(3)	(31)	(5)	(3)	2	3	0	(31)
LAB	0	0	0	(3)	(0)	(0)	(3)	(0)	(0)	0	0	0	(3)
PSO	(4,310)	(2,611)	(2,908)	(9,941)	(4,579)	(2,648)	(14,252)	(7,190)	(5,556)	1,010	1,644	281	(18,506)
SEP	(4,628)	(2,731)	(3,042)	(11,633)	(4,456)	(2,577)	(16,261)	(7,187)	(5,619)	1,105	1,798	307	(20,238)
WTU	(2,272)	(1,248)	(1,390)	(5,480)	(2,286)	(1,322)	(7,752)	(3,534)	(2,711)	532	865	148	(9,741)
TOTAL REG	(17,145)	(9,541)	(10,626)	(43,703)	(17,609)	(10,183)	(60,848)	(27,150)	(20,810)	4,146	6,747	1,154	(75,951)
TOTAL 2004	(19,298)	(9,568)	(10,680)	(48,380)	(17,995)	(10,407)	(67,678)	(27,563)	(21,087)	4,487	7,302	1,249	(82,204)

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CENTRAL AND SOUTH WEST SERVICES, INC.
SUMMARY OF SAVINGS
BY CSW SUBSIDIARY

2005
(IN 000'S)

COMPANY	DIRECT SAVINGS			SERVICE COMPANY SAVINGS			TOTAL SAVINGS			ALLOCATION OF CTA	ALLOCATION OF PMI	ALLOCATION OF CIC	NET SAVINGS
	O&M	REV REQ	CAPITAL	O&M	REV REQ	CAPITAL	O&M	REV REQ	CAPITAL				
NON-REG													
CSE	(378)	(1)	(1)	(660)	(72)	(40)	(1,038)	(72)	(41)	0	100	0	(1,011)
CSI	(743)	0	0	(66)	(3)	(1)	(809)	(3)	(1)	0	73	0	(739)
DCM	(272)	(1)	(1)	(260)	(63)	(35)	(532)	(63)	(36)	0	54	0	(542)
DCR	(323)	0	0	(721)	(138)	(77)	(1,044)	(138)	(77)	0	106	0	(1,075)
DCT	(27)	0	0	(521)	(7)	(4)	(548)	(7)	(4)	0	50	0	(505)
DES	(216)	(0)	(0)	(65)	(17)	(9)	(282)	(17)	(10)	0	27	0	(272)
DLL	0	0	0	(53)	(0)	(0)	(53)	(0)	(0)	0	5	0	(49)
ESI	(1)	(0)	(0)	(80)	(22)	(12)	(80)	(22)	(12)	0	9	0	(93)
PMI	0	0	0	(11)	(3)	(1)	(11)	(3)	(1)	0	1	0	(13)
SEE	(292)	(34)	(54)	(2,426)	(98)	(55)	(2,718)	(133)	(109)	0	256	0	(2,594)
TOK	0	0	0	(3)	(1)	(0)	(3)	(1)	(0)	0	0	0	(4)
TOTAL NON-REG	(2,253)	(36)	(57)	(4,866)	(422)	(235)	(7,118)	(458)	(292)	0	682	0	(6,895)
REGULATED													
CPL	(6,173)	(3,461)	(3,395)	(17,259)	(6,845)	(3,811)	(23,432)	(10,306)	(7,207)	0	3,036	0	(30,702)
ECS	0	0	0	(31)	(6)	(3)	(31)	(6)	(3)	0	3	0	(34)
JFP	0	0	0	(32)	(6)	(3)	(32)	(6)	(3)	0	3	0	(34)
LAB	0	0	0	(3)	(0)	(0)	(3)	(0)	(0)	0	0	0	(3)
PSO	(4,483)	(3,061)	(3,003)	(10,347)	(4,994)	(2,781)	(14,830)	(8,055)	(5,784)	0	2,059	0	(20,826)
SEP	(4,814)	(3,202)	(3,141)	(12,105)	(4,858)	(2,705)	(16,919)	(8,059)	(5,846)	0	2,248	0	(22,730)
WTU	(2,365)	(1,463)	(1,435)	(5,703)	(2,491)	(1,387)	(8,067)	(3,954)	(2,822)	0	1,082	0	(10,939)
TOTAL REG	(17,835)	(11,187)	(10,975)	(45,479)	(19,199)	(10,690)	(63,314)	(30,386)	(21,666)	0	8,431	0	(85,269)
TOTAL 2005	(20,088)	(11,223)	(11,032)	(50,345)	(19,621)	(10,925)	(70,433)	(30,844)	(21,957)	0	9,113	0	(92,164)

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CENTRAL AND SOUTH WEST SERVICES, INC.
SUMMARY OF SAVINGS
BY CSW SUBSIDIARY

2006
(IN 000'S)

COMPANY	DIRECT SAVINGS O&M	DIRECT SAVINGS REV REQ	DIRECT SAVINGS CAPITAL	SERVICE COMPANY SAVINGS O&M	SERVICE COMPANY SAVINGS REV REQ	SERVICE COMPANY SAVINGS CAPITAL	TOTAL SAVINGS O&M	TOTAL SAVINGS REV REQ	TOTAL SAVINGS CAPITAL	ALLOCATION OF CTA	ALLOCATION OF PMI	ALLOCATION OF CIC	NET SAVINGS
NON-REG													
CSE	(397)	(1)	(1)	(686)	(88)	(42)	(1,083)	(89)	(43)	0	122	0	(1,049)
CSI	(780)	0	0	(68)	(3)	(2)	(849)	(3)	(2)	0	89	0	(763)
DCM	(286)	(1)	(1)	(270)	(77)	(37)	(556)	(78)	(37)	0	66	0	(568)
DCR	(332)	0	0	(748)	(169)	(80)	(1,080)	(169)	(80)	0	130	0	(1,119)
DCT	(28)	0	0	(541)	(8)	(4)	(570)	(8)	(4)	0	60	0	(518)
DES	(227)	(0)	(0)	(68)	(21)	(10)	(295)	(21)	(10)	0	33	0	(283)
DLL	0	0	0	(55)	(0)	(0)	(55)	(0)	(0)	0	6	0	(50)
ESI	(1)	(0)	(0)	(83)	(27)	(13)	(83)	(27)	(13)	0	11	0	(99)
PMI	0	0	0	(12)	(3)	(1)	(12)	(3)	(1)	0	2	0	(13)
SEE	(304)	(43)	(56)	(2,520)	(120)	(57)	(2,824)	(162)	(113)	0	312	0	(2,675)
TOK	0	0	0	(3)	(1)	(0)	(3)	(1)	(0)	0	0	0	(4)
TOTAL NON-REG	(2,355)	(45)	(59)	(5,055)	(517)	(245)	(7,410)	(562)	(304)	0	832	0	(7,140)
REGULATED													
CPL	(6,422)	(3,972)	(3,507)	(17,965)	(6,336)	(3,002)	(24,388)	(10,308)	(6,509)	0	3,619	0	(31,077)
ECS	0	0	0	(33)	(8)	(4)	(33)	(8)	(4)	0	4	0	(36)
JFP	0	0	0	(33)	(7)	(3)	(33)	(7)	(3)	0	4	0	(36)
LAB	0	0	0	(3)	(1)	(0)	(3)	(1)	(0)	0	0	0	(3)
PSO	(4,664)	(3,513)	(3,102)	(10,773)	(4,536)	(2,149)	(15,437)	(8,050)	(5,251)	0	2,450	0	(21,037)
SEP	(5,008)	(3,674)	(3,244)	(12,598)	(4,585)	(2,172)	(17,605)	(8,259)	(5,416)	0	2,698	0	(23,166)
WTU	(2,462)	(1,679)	(1,483)	(5,934)	(2,433)	(1,153)	(8,396)	(4,112)	(2,635)	0	1,305	0	(11,203)
TOTAL REG	(18,556)	(12,839)	(11,335)	(47,339)	(17,905)	(8,483)	(65,895)	(30,744)	(19,818)	0	10,081	0	(86,557)
TOTAL 2006	(20,911)	(12,884)	(11,394)	(52,394)	(18,422)	(8,728)	(73,304)	(31,306)	(20,122)	0	10,913	0	(93,698)

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CENTRAL AND SOUTH WEST SERVICES, INC.
SUMMARY OF SAVINGS
BY CSW SUBSIDIARY

2007
(IN 000'S)

COMPANY	DIRECT SAVINGS O&M	DIRECT SAVINGS REV REQ	DIRECT SAVINGS CAPITAL	SERVICE COMPANY SAVINGS O&M	SERVICE COMPANY SAVINGS REV REQ	SERVICE COMPANY SAVINGS CAPITAL	TOTAL SAVINGS O&M	TOTAL SAVINGS REV REQ	TOTAL SAVINGS CAPITAL	ALLOCATION OF CTA	ALLOCATION OF PMI	ALLOCATION OF CIC	NET SAVINGS
NON-REG													
CSE	(416)	(1)	(2)	(713)	(84)	(44)	(1,130)	(85)	(45)	0	135	0	(1,080)
CSI	(819)	0	0	(71)	(3)	(2)	(890)	(3)	(2)	0	99	0	(794)
DCM	(300)	(1)	(1)	(281)	(74)	(38)	(582)	(75)	(39)	0	73	0	(583)
DCR	(342)	0	0	(780)	(163)	(85)	(1,123)	(163)	(85)	0	143	0	(1,143)
DCT	(30)	0	0	(563)	(8)	(4)	(593)	(8)	(4)	0	67	0	(534)
DES	(239)	(0)	(0)	(70)	(20)	(10)	(309)	(20)	(11)	0	37	0	(293)
DLL	0	0	0	(57)	(0)	(0)	(57)	(0)	(0)	0	6	0	(51)
ESI	(1)	(0)	(0)	(86)	(25)	(13)	(87)	(26)	(13)	0	12	0	(100)
PMI	0	0	0	(12)	(3)	(2)	(12)	(3)	(2)	0	2	0	(14)
SEE	(315)	(52)	(58)	(2,620)	(113)	(59)	(2,935)	(165)	(117)	0	344	0	(2,756)
TOK	0	0	0	(4)	(1)	(1)	(4)	(1)	(1)	0	1	0	(4)
TOTAL NON-REG	(2,463)	(55)	(61)	(5,259)	(494)	(258)	(7,722)	(549)	(318)	0	917	0	(7,354)
REGULATED													
CPL	(6,682)	(4,487)	(3,623)	(18,696)	(6,041)	(3,147)	(25,378)	(10,528)	(6,770)	0	3,981	0	(31,925)
ECS	0	0	0	(34)	(7)	(4)	(34)	(7)	(4)	0	5	0	(37)
JFP	0	0	0	(34)	(7)	(4)	(34)	(7)	(4)	0	5	0	(36)
LAB	0	0	0	(3)	(1)	(0)	(3)	(1)	(0)	0	0	0	(3)
PSO	(4,853)	(3,967)	(3,203)	(11,213)	(4,326)	(2,254)	(16,066)	(8,293)	(5,457)	0	2,700	0	(21,658)
SEP	(5,210)	(4,148)	(3,350)	(13,109)	(4,371)	(2,277)	(18,319)	(8,519)	(5,627)	0	2,975	0	(23,862)
WTU	(2,563)	(1,897)	(1,532)	(6,175)	(2,318)	(1,207)	(8,738)	(4,214)	(2,739)	0	1,436	0	(11,516)
TOTAL REG	(19,307)	(14,498)	(11,708)	(49,265)	(17,070)	(8,893)	(68,572)	(31,568)	(20,601)	0	11,102	0	(89,038)
TOTAL 2007	(21,769)	(14,553)	(11,769)	(54,524)	(17,564)	(9,150)	(76,293)	(32,117)	(20,919)	0	12,019	0	(96,392)

CENTRAL AND SOUTH WEST SERVICES, INC.
SUMMARY OF SAVINGS
BY CSW SUBSIDIARY

2008
(IN 000'S)

COMPANY	DIRECT SAVINGS O&M	DIRECT SAVINGS REV REQ	DIRECT SAVINGS CAPITAL	SERVICE COMPANY SAVINGS O&M	SERVICE COMPANY SAVINGS REV REQ	SERVICE COMPANY SAVINGS CAPITAL	TOTAL SAVINGS O&M	TOTAL SAVINGS REV REQ	TOTAL SAVINGS CAPITAL	ALLOCATION OF CTA	ALLOCATION OF PMI	ALLOCATION OF CIC	NET SAVINGS
NON-REG													
CSE	(439)	(2)	(2)	(743)	(81)	(45)	(1,183)	(83)	(47)	0	144	0	(1,121)
CSI	(865)	0	0	(75)	(3)	(2)	(940)	(3)	(2)	0	108	0	(836)
DCM	(317)	(1)	(1)	(299)	(74)	(41)	(616)	(75)	(42)	0	79	0	(612)
DCR	(353)	0	0	(846)	(173)	(96)	(1,199)	(173)	(96)	0	156	0	(1,216)
DCT	(32)	0	0	(586)	(7)	(4)	(618)	(7)	(4)	0	71	0	(553)
DES	(252)	(0)	(0)	(74)	(20)	(11)	(326)	(20)	(11)	0	39	0	(307)
DLL	0	0	0	(60)	(0)	(0)	(60)	(0)	(0)	0	7	0	(53)
ESI	(1)	(0)	(0)	(92)	(26)	(14)	(93)	(26)	(15)	0	14	0	(105)
PMI	0	0	0	(14)	(3)	(2)	(14)	(3)	(2)	0	2	0	(15)
SEE	(330)	(63)	(60)	(2,726)	(106)	(59)	(3,056)	(169)	(120)	0	368	0	(2,857)
TOK	0	0	0	(4)	(1)	(1)	(4)	(1)	(1)	0	1	0	(4)
TOTAL NON-REG	(2,590)	(66)	(64)	(5,517)	(494)	(276)	(8,107)	(560)	(339)	0	988	0	(7,679)
REGULATED													
CPL	(7,029)	(5,073)	(3,707)	(19,495)	(5,445)	(3,037)	(26,524)	(10,519)	(6,744)	0	4,224	0	(32,820)
ECS	0	0	0	(37)	(8)	(4)	(37)	(8)	(4)	0	5	0	(39)
JFP	0	0	0	(37)	(7)	(4)	(37)	(7)	(4)	0	5	0	(39)
LAB	0	0	0	(3)	(1)	(0)	(3)	(1)	(0)	0	0	0	(3)
PSO	(5,107)	(4,492)	(3,282)	(11,704)	(3,885)	(2,167)	(16,811)	(8,377)	(5,448)	0	2,872	0	(22,316)
SEP	(5,475)	(4,705)	(3,438)	(13,680)	(3,969)	(2,213)	(19,155)	(8,674)	(5,651)	0	3,173	0	(24,656)
WTU	(2,695)	(2,152)	(1,572)	(6,450)	(2,127)	(1,186)	(9,145)	(4,279)	(2,758)	0	1,531	0	(11,893)
TOTAL REG	(20,306)	(16,422)	(11,999)	(51,406)	(15,442)	(8,611)	(71,713)	(31,864)	(20,610)	0	11,810	0	(91,766)
TOTAL 2008	(22,896)	(16,488)	(12,062)	(56,923)	(15,936)	(8,887)	(79,819)	(32,424)	(20,949)	0	12,798	0	(99,445)
		(87,[illegible]58)			(131,469)			(218,727)					

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CENTRAL AND SOUTH WEST SERVICES, INC.
SUMMARY OF SAVINGS
BY CSW SUBSIDIARY

2009
(IN 000'S)

COMPANY	DIRECT SAVINGS			SERVICE COMPANY SAVINGS			TOTAL SAVINGS			ALLOCATION OF CTA	ALLOCATION OF PMI	ALLOCATION OF CIC	NET SAVINGS
	O&M	REV REQ	CAPITAL	O&M	REV REQ	CAPITAL	O&M	REV REQ	CAPITAL				
NON-REG													
CSE	(112)	(0)	(0)	(189)	(21)	(12)	(301)	(21)	(12)	0	38	0	(284)
CSI	(220)	0	0	(19)	(1)	(0)	(239)	(1)	(0)	0	29	0	(212)
DCM	(81)	(0)	(0)	(76)	(19)	(11)	(157)	(19)	(11)	0	21	0	(155)
DCR	(90)	0	0	(215)	(44)	(25)	(305)	(44)	(25)	0	41	0	(308)
DCT	(8)	0	0	(149)	(2)	(1)	(157)	(2)	(1)	0	19	0	(140)
DES	(64)	(0)	(0)	(19)	(5)	(3)	(83)	(5)	(3)	0	10	0	(78)
DLL	0	0	0	(15)	(0)	(0)	(15)	(0)	(0)	0	2	0	(13)
ESI	(0)	(0)	(0)	(23)	(7)	(4)	(24)	(7)	(4)	0	4	0	(27)
PMI	0	0	0	(3)	(1)	(0)	(3)	(1)	(0)	0	1	0	(4)
SEE	(84)	(16)	(15)	(694)	(27)	(15)	(778)	(43)	(30)	0	98	0	(724)
TOK	0	0	0	(1)	(0)	(0)	(1)	(0)	(0)	0	0	0	(1)
TOTAL NON-REG	(660)	(17)	(16)	(1,405)	(126)	(70)	(2,064)	(143)	(86)	0	262	0	(1,945)
REGULATED													
CPL	(1,790)	(1,292)	(944)	(4,965)	(1,387)	(773)	(6,755)	(2,679)	(1,717)	0	1,120	0	(8,313)
ECS	0	0	0	(9)	(2)	(1)	(9)	(2)	(1)	0	1	0	(10)
JFP	0	0	0	(9)	(2)	(1)	(9)	(2)	(1)	0	1	0	(10)
LAB	0	0	0	(1)	(0)	(0)	(1)	(0)	(0)	0	0	0	(1)
PSO	(1,301)	(1,144)	(836)	(2,981)	(989)	(552)	(4,281)	(2,133)	(1,387)	0	762	0	(5,653)
SEP	(1,394)	(1,198)	(875)	(3,484)	(1,011)	(564)	(4,878)	(2,209)	(1,439)	0	842	0	(6,245)
WTU	(686)	(548)	(400)	(1,643)	(542)	(302)	(2,329)	(1,090)	(702)	0	406	0	(3,012)
TOTAL REG	(5,171)	(4,182)	(3,056)	(13,091)	(3,932)	(2,193)	(18,262)	(8,114)	(5,249)	0	3,132	0	(23,244)
TOTAL 2009	(5,831)	(4,199)	(3,072)	(14,496)	(4,058)	(2,263)	(20,327)	(8,257)	(5,335)	0	3,395	0	(25,180)

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AMERICAN ELECTRIC POWER COMPANY
ALLOCATION OF SERVICES' CAPITAL REVENUE REQUIREMENT SAVINGS
BY AEP SUBSIDIARY

(IN 000'S)

COMPANY	O & M SAVINGS	CAPITAL SAVINGS	TOTAL SAVINGS	% OF SAVINGS	REV REQ ALLOCATION	O&M/REV SAV TOTAL
1999						
NON-REG						
25	(3)	(0)	(3)	0.873%	(0)	(3)
26	(0)	(0)	(0)	0.010%	(0)	(0)
53	(2)	(0)	(2)	0.013%	(0)	(2)
56	(1)	(0)	(1)	0.106%	(0)	(1)
57	(1)	(0)	(1)	0.020%	(0)	(1)
58	(35)	(1)	(36)	8.876%	(0)	(36)
59	(105)	(5)	(109)	35.757%	(1)	(106)
60	(38)	(1)	(39)	7.657%	(0)	(39)
63	(1)	(0)	(1)	0.521%	(0)	(1)
64	(1)	(0)	(1)	0.279%	(0)	(1)
66	(1)	(0)	(1)	0.014%	(0)	(1)
67	(1)	(0)	(1)	0.019%	(0)	(1)
69	(39)	(2)	(41)	13.037%	(1)	(40)
72	(6)	(0)	(6)	0.235%	(0)	(6)
74	(115)	(4)	(118)	28.637%	(1)	(116)
81	(11)	(0)	(11)	2.522%	(0)	(11)
83	(1)	(0)	(1)	0.014%	(0)	(1)
86	(1)	(0)	(1)	0.035%	(0)	(1)
87	(13)	(0)	(13)	0.129%	(0)	(13)
88	(0)	(0)	(0)	0.011%	(0)	(0)
89	(0)	(0)	(0)	0.011%	(0)	(0)
90	(0)	(0)	(0)	0.011%	(0)	(0)
91	(6)	(0)	(6)	0.894%	(0)	(6)
99	(29)	(0)	(29)	0.319%	(0)	(29)
TOTAL NON-REG	(408)	(13)	(421)	100.000%	(4)	(412)
REGULATED						
01	(181)	(54)	(235)	1.195%	(16)	(197)
02	(6,302)	(1,278)	(7,580)	28.253%	(375)	(6,677)
03	(1,521)	(262)	(1,783)	5.779%	(77)	(1,598)

AMERICAN ELECTRIC POWER COMPANY
ALLOCATION OF SERVICES' CAPITAL REVENUE REQUIREMENT SAVINGS
BY AEP SUBSIDIARY

(IN 000'S)

COMPANY	O & M SAVINGS	CAPITAL SAVINGS	TOTAL SAVINGS	% OF SAVINGS	REV REQ ALLOCATION	O&M/REV SAV TOTAL
04	(4,724)	(839)	(5,563)	18.547%	(246)	(4,971)
06	(185)	(51)	(237)	1.136%	(15)	(200)
07	(5,835)	(1,044)	(6,879)	23.077%	(307)	(6,142)
10	(3,743)	(794)	(4,538)	17.554%	(233)	(3,977)
21	(1)	(0)	(1)	0.001%	(0)	(1)
22	(81)	(3)	(84)	0.059%	(1)	(82)
23	(0)	(0)	(0)	0.000%	(0)	(0)
31	(14)	(0)	(15)	0.009%	(0)	(14)
32	(19)	(1)	(19)	0.012%	(0)	(19)
34	(75)	(13)	(87)	0.276%	(4)	(78)
40	(0)	(0)	(0)	0.000%	(0)	(0)
41	(0)	(0)	(0)	0.000%	(0)	(0)
42	(124)	(25)	(148)	0.542%	(7)	(131)
43	(148)	(30)	(178)	0.668%	(9)	(156)
44	(511)	(82)	(593)	1.813%	(24)	(535)
45	(0)	(0)	(0)	0.000%	(0)	(0)
46	(0)	(0)	(0)	0.000%	(0)	(0)
48	(107)	(18)	(126)	0.401%	(5)	(113)
49	(30)	(6)	(36)	0.136%	(2)	(32)
50	(0)	(0)	(0)	0.000%	(0)	(0)
51	(0)	(0)	(0)	0.000%	(0)	(0)
52	(0)	(0)	(0)	0.000%	(0)	(0)
54	(27)	(5)	(32)	0.112%	(1)	(28)
70	(127)	(4)	(131)	0.091%	(1)	(128)
71	(127)	(4)	(131)	0.091%	(1)	(128)
73	(57)	(2)	(59)	0.041%	(1)	(58)
75	(6)	(1)	(7)	0.020%	(0)	(6)
76	(0)	(0)	(0)	0.000%	(0)	(0)
77	(0)	(0)	(0)	0.000%	(0)	(0)
78	(0)	(0)	(0)	0.000%	(0)	(0)
84	(0)	(0)	(0)	0.000%	(0)	(0)
85	(0)	(0)	(0)	0.000%	(0)	(0)

AMERICAN ELECTRIC POWER COMPANY
ALLOCATION OF SERVICES' CAPITAL REVENUE REQUIREMENT SAVINGS
BY AEP SUBSIDIARY

(IN 000'S)

COMPANY	O & M SAVINGS	CAPITAL SAVINGS	TOTAL SAVINGS	% OF SAVINGS	REV REQ ALLOCATION	O&M/REV SAV TOTAL
98	(139)	(8)	(147)	0.181%	(2)	(141)
XX	(1)	(0)	(1)	0.002%	(0)	(1)
TOTAL REG	(24,087)	(4,525)	(28,612)	100.000%	(1,329)	(25,416)
TOTAL 1999	(24,496)	(4,538)	(29,033)		(1,333)	(25,829)

AMERICAN ELECTRIC POWER COMPANY
ALLOCATION OF SERVICES' CAPITAL REVENUE REQUIREMENT SAVINGS
BY AEP SUBSIDIARY

(IN 000'S)

COMPANY	O & M SAVINGS	CAPITAL SAVINGS	TOTAL SAVINGS	% OF SAVINGS	REV REQ ALLOCATION	O&M/REV SAV TOTAL
2000						
NON-REG						
25	(6)	(1)	(6)	0.852%	(0)	(6)
26	(0)	(0)	(0)	0.011%	(0)	(0)
53	(5)	(0)	(5)	0.003%	(0)	(5)
56	(5)	(0)	(5)	0.079%	(0)	(5)
57	(5)	(0)	(5)	0.009%	(0)	(5)
58	(75)	(6)	(80)	8.841%	(2)	(77)
59	(234)	(24)	(258)	37.036%	(9)	(243)
60	(93)	(5)	(98)	7.237%	(2)	(95)
63	(3)	(0)	(3)	0.369%	(0)	(3)
64	(2)	(0)	(3)	0.196%	(0)	(3)
66	(2)	(0)	(2)	0.009%	(0)	(2)
67	(5)	(0)	(5)	0.009%	(0)	(5)
69	(90)	(8)	(98)	12.138%	(3)	(93)
72	(16)	(0)	(16)	0.193%	(0)	(16)
74	(247)	(19)	(266)	29.333%	(7)	(254)
81	(24)	(2)	(25)	2.606%	(1)	(24)
83	(2)	(0)	(2)	0.009%	(0)	(2)
86	(3)	(0)	(3)	0.031%	(0)	(3)
87	(34)	(0)	(34)	0.066%	(0)	(34)
88	(0)	(0)	(0)	0.011%	(0)	(0)
89	(0)	(0)	(0)	0.011%	(0)	(0)
90	(0)	(0)	(0)	0.012%	(0)	(0)
91	(14)	(1)	(15)	0.846%	(0)	(15)
99	(101)	(0)	(101)	0.094%	(0)	(101)
TOTAL NON-REG	(966)	(64)	(1,030)	100.000%	(24)	(990)
REGULATED						
01	(453)	(270)	(723)	1.235%	(99)	(553)
02	(16,178)	(6,216)	(22,394)	28.472%	(2,290)	(18,468)
03	(3,877)	(1,258)	(5,135)	5.764%	(464)	(4,340)

AMERICAN ELECTRIC POWER COMPANY
ALLOCATION OF SERVICES' CAPITAL REVENUE REQUIREMENT SAVINGS
BY AEP SUBSIDIARY

(IN 000'S)

COMPANY	O & M SAVINGS	CAPITAL SAVINGS	TOTAL SAVINGS	% OF SAVINGS	REV REQ ALLOCATION	O&M/REV SAV TOTAL
04	(12,342)	(4,064)	(16,406)	18.615%	(1,497)	(13,839)
06	(465)	(257)	(722)	1.179%	(95)	(560)
07	(14,893)	(4,999)	(19,892)	22.898%	(1,842)	(16,735)
10	(9,416)	(3,955)	(13,371)	18.114%	(1,457)	(10,873)
21	(2)	(0)	(2)	0.001%	(0)	(2)
22	(158)	(14)	(171)	0.063%	(5)	(163)
23	(1)	(0)	(1)	0.000%	(0)	(1)
31	(29)	(2)	(31)	0.010%	(1)	(29)
32	(38)	(3)	(41)	0.013%	(1)	(39)
34	(219)	(51)	(270)	0.232%	(19)	(238)
40	(0)	(0)	(0)	0.000%	(0)	(0)
41	(0)	(0)	(0)	0.000%	(0)	(0)
42	(358)	(96)	(453)	0.438%	(35)	(393)
43	(419)	(117)	(537)	0.537%	(43)	(463)
44	(1,438)	(323)	(1,762)	1.481%	(119)	(1,557)
45	(0)	(0)	(0)	0.000%	(0)	(0)
46	(0)	(0)	(0)	0.000%	(0)	(0)
48	(318)	(75)	(392)	0.342%	(27)	(345)
49	(83)	(24)	(107)	0.110%	(9)	(92)
50	(0)	(0)	(0)	0.000%	(0)	(0)
51	(1)	(0)	(1)	0.000%	(0)	(1)
52	(0)	(0)	(0)	0.000%	(0)	(0)
54	(76)	(20)	(96)	0.090%	(7)	(83)
70	(246)	(22)	(267)	0.099%	(8)	(254)
71	(245)	(21)	(266)	0.098%	(8)	(253)
73	(111)	(10)	(121)	0.045%	(4)	(114)
75	(23)	(5)	(28)	0.022%	(2)	(25)
76	(0)	(0)	(0)	0.000%	(0)	(0)
77	(0)	(0)	(0)	0.000%	(0)	(0)
78	(0)	(0)	(0)	0.000%	(0)	(0)
84	(0)	(0)	(0)	0.000%	(0)	(0)
85	(0)	(0)	(0)	0.000%	(0)	(0)

AMERICAN ELECTRIC POWER COMPANY
ALLOCATION OF SERVICES' CAPITAL REVENUE REQUIREMENT SAVINGS
BY AEP SUBSIDIARY

(IN 000'S)

COMPANY	O & M SAVINGS	CAPITAL SAVINGS	TOTAL SAVINGS	% OF SAVINGS	REV REQ ALLOCATION	O&M/REV SAV TOTAL
98	(370)	(31)	(401)	0.140%	(11)	(381)
XX	(2)	(0)	(3)	0.002%	(0)	(2)
TOTAL REG	(61,760)	(21,833)	(83,594)	100.000%	(8,044)	(69,804)
TOTAL 2000	(62,726)	(21,898)	(84,624)		(8,068)	(70,794)

AMERICAN ELECTRIC POWER COMPANY
ALLOCATION OF SERVICES' CAPITAL REVENUE REQUIREMENT SAVINGS
BY AEP SUBSIDIARY

(IN 000'S)

COMPANY	O & M SAVINGS	CAPITAL SAVINGS	TOTAL SAVINGS	% OF SAVINGS	REV REQ ALLOCATION	O&M/REV SAV TOTAL
2001						
NON-REG						
25	(7)	(1)	(8)	0.850%	(0)	(7)
26	(0)	(0)	(0)	0.011%	(0)	(0)
53	(6)	0	(6)	0.000%	0	(6)
56	(6)	(0)	(6)	0.073%	(0)	(6)
57	(6)	(0)	(6)	0.005%	(0)	(6)
58	(87)	(8)	(94)	8.846%	(5)	(91)
59	(275)	(32)	(306)	37.285%	(20)	(295)
60	(110)	(6)	(116)	7.167%	(4)	(114)
63	(3)	(0)	(3)	0.346%	(0)	(3)
64	(3)	(0)	(3)	0.183%	(0)	(3)
66	(3)	(0)	(3)	0.008%	(0)	(3)
67	(6)	(0)	(6)	0.005%	(0)	(6)
69	(106)	(10)	(116)	11.986%	(6)	(112)
72	(19)	(0)	(19)	0.182%	(0)	(19)
74	(287)	(25)	(312)	29.469%	(16)	(303)
81	(28)	(2)	(30)	2.620%	(1)	(29)
83	(3)	(0)	(3)	0.008%	(0)	(3)
86	(3)	(0)	(3)	0.029%	(0)	(3)
87	(40)	(0)	(40)	0.045%	(0)	(40)
88	(0)	(0)	(0)	0.011%	(0)	(0)
89	(0)	(0)	(0)	0.012%	(0)	(0)
90	(0)	(0)	(0)	0.012%	(0)	(0)
91	(17)	(1)	(18)	0.836%	(0)	(18)
99	(125)	(0)	(125)	0.012%	(0)	(125)
TOTAL NON-REG	(1,139)	(85)	(1,224)	100.000%	(53)	(1,192)
REGULATED						
01	(535)	(296)	(831)	1.208%	(184)	(719)
02	(19,032)	(6,939)	(25,971)	28.344%	(4,321)	(23,352)
03	(4,548)	(1,414)	(5,962)	5.774%	(880)	(5,428)

AMERICAN ELECTRIC POWER COMPANY
ALLOCATION OF SERVICES' CAPITAL REVENUE REQUIREMENT SAVINGS
BY AEP SUBSIDIARY

(IN 000'S)

COMPANY	O & M SAVINGS	CAPITAL SAVINGS	TOTAL SAVINGS	% OF SAVINGS	REV REQ ALLOCATION	O&M/REV SAV TOTAL
04	(14,567)	(4,567)	(19,134)	18.654%	(2,843)	(17,411)
06	(548)	(282)	(830)	1.151%	(175)	(724)
07	(17,421)	(5,599)	(23,020)	22.872%	(3,486)	(20,907)
10	(11,072)	(4,354)	(15,425)	17.783%	(2,711)	(13,783)
21	(2)	(0)	(3)	0.001%	(0)	(2)
22	(180)	(18)	(198)	0.075%	(11)	(191)
23	(1)	(0)	(1)	0.000%	(0)	(1)
31	(33)	(3)	(36)	0.012%	(2)	(35)
32	(43)	(4)	(47)	0.016%	(2)	(46)
34	(266)	(64)	(330)	0.263%	(40)	(306)
40	(0)	(0)	(0)	0.000%	(0)	(0)
41	(0)	(0)	(0)	0.000%	(0)	(0)
42	(432)	(121)	(553)	0.492%	(75)	(507)
43	(506)	(148)	(653)	0.604%	(92)	(598)
44	(1,732)	(409)	(2,141)	1.670%	(255)	(1,987)
45	(0)	(0)	(0)	0.000%	(0)	(0)
46	(1)	(0)	(1)	0.000%	(0)	(1)
48	(385)	(95)	(480)	0.387%	(59)	(444)
49	(100)	(30)	(130)	0.124%	(19)	(119)
50	(0)	(0)	(0)	0.000%	(0)	(0)
51	(1)	(0)	(1)	0.000%	(0)	(1)
52	(0)	(0)	(0)	0.000%	(0)	(0)
54	(92)	(25)	(116)	0.101%	(15)	(107)
70	(280)	(29)	(309)	0.117%	(18)	(298)
71	(279)	(29)	(308)	0.117%	(18)	(297)
73	(126)	(13)	(139)	0.053%	(8)	(134)
75	(29)	(6)	(35)	0.026%	(4)	(33)
76	(0)	(0)	(0)	0.000%	(0)	(0)
77	(0)	(0)	(0)	0.000%	(0)	(0)
78	(0)	(0)	(0)	0.000%	(0)	(0)
84	(0)	(0)	(0)	0.000%	(0)	(0)
85	(0)	(0)	(0)	0.000%	(0)	(0)

AMERICAN ELECTRIC POWER COMPANY
ALLOCATION OF SERVICES' CAPITAL REVENUE REQUIREMENT SAVINGS
BY AEP SUBSIDIARY

(IN 000'S)

COMPANY	O & M SAVINGS	CAPITAL SAVINGS	TOTAL SAVINGS	% OF SAVINGS	REV REQ ALLOCATION	O&M/REV SAV TOTAL
98	(426)	(38)	(464)	0.154%	(23)	(449)
XX	(3)	(1)	(3)	0.003%	(0)	(3)
TOTAL REG	(72,641)	(24,482)	(97,123)	100.000%	(15,243)	(87,884)
TOTAL 2001	(73,780)	(24,567)	(98,347)		(15,296)	(89,076)

AMERICAN ELECTRIC POWER COMPANY
ALLOCATION OF SERVICES' CAPITAL REVENUE REQUIREMENT SAVINGS
BY AEP SUBSIDIARY

(IN 000'S)

COMPANY	O & M SAVINGS	CAPITAL SAVINGS	TOTAL SAVINGS	% OF SAVINGS	REV REQ ALLOCATION	O&M/REV SAV TOTAL
2002						
NON-REG						
25	(7)	(1)	(8)	0.846%	(1)	(8)
26	(0)	(0)	(0)	0.011%	(0)	(0)
53	(6)	0	(6)	-0.001%	0	(6)
56	(6)	(0)	(6)	0.069%	(0)	(6)
57	(6)	(0)	(6)	0.005%	(0)	(6)
58	(92)	(8)	(100)	8.829%	(7)	(99)
59	(294)	(36)	(330)	37.445%	(30)	(324)
60	(115)	(7)	(122)	7.093%	(6)	(121)
63	(3)	(0)	(4)	0.320%	(0)	(4)
64	(3)	(0)	(3)	0.169%	(0)	(3)
66	(3)	(0)	(3)	0.007%	(0)	(3)
67	(6)	(0)	(6)	0.004%	(0)	(6)
69	(112)	(11)	(124)	11.912%	(10)	(122)
72	(20)	(0)	(20)	0.177%	(0)	(20)
74	(305)	(28)	(333)	29.550%	(24)	(328)
81	(29)	(3)	(32)	2.631%	(2)	(31)
83	(3)	(0)	(3)	0.007%	(0)	(3)
86	(3)	(0)	(3)	0.029%	(0)	(3)
87	(42)	(0)	(42)	0.039%	(0)	(42)
88	(0)	(0)	(0)	0.011%	(0)	(0)
89	(0)	(0)	(0)	0.012%	(0)	(0)
90	(0)	(0)	(0)	0.012%	(0)	(0)
91	(18)	(1)	(19)	0.828%	(1)	(19)
99	(130)	0	(130)	-0.005%	0	(130)
TOTAL NON-REG	(1,205)	(95)	(1,300)	100.000%	(80)	(1,285)
REGULATED						
01	(564)	(328)	(892)	1.210%	(275)	(839)
02	(20,119)	(7,698)	(27,817)	28.360%	(6,456)	(26,575)
03	(4,804)	(1,567)	(6,370)	5.771%	(1,314)	(6,117)

AMERICAN ELECTRIC POWER COMPANY
ALLOCATION OF SERVICES' CAPITAL REVENUE REQUIREMENT SAVINGS
BY AEP SUBSIDIARY

(IN 000'S)

COMPANY	O & M SAVINGS	CAPITAL SAVINGS	TOTAL SAVINGS	% OF SAVINGS	REV REQ ALLOCATION	O&M/REV SAV TOTAL
04	(15,393)	(5,063)	(20,456)	18.653%	(4,246)	(19,639)
06	(579)	(313)	(892)	1.155%	(263)	(842)
07	(18,386)	(6,202)	(24,588)	22.846%	(5,201)	(23,587)
10	(11,675)	(4,844)	(16,519)	17.844%	(4,062)	(15,737)
21	(2)	(0)	(3)	0.001%	(0)	(3)
22	(191)	(21)	(212)	0.077%	(17)	(209)
23	(1)	(0)	(1)	0.000%	(0)	(1)
31	(35)	(3)	(38)	0.012%	(3)	(38)
32	(46)	(4)	(50)	0.016%	(4)	(50)
34	(289)	(71)	(360)	0.261%	(59)	(348)
40	(0)	(0)	(0)	0.000%	(0)	(0)
41	(0)	(0)	(0)	0.000%	(0)	(0)
42	(466)	(131)	(597)	0.482%	(110)	(575)
43	(545)	(160)	(705)	0.590%	(134)	(679)
44	(1,864)	(446)	(2,310)	1.642%	(374)	(2,238)
45	(0)	(0)	(0)	0.000%	(0)	(0)
46	(1)	(0)	(1)	0.000%	(0)	(1)
48	(421)	(105)	(526)	0.388%	(88)	(509)
49	(108)	(33)	(141)	0.122%	(28)	(136)
50	(0)	(0)	(0)	0.000%	(0)	(0)
51	(1)	(0)	(1)	0.000%	(0)	(1)
52	(0)	(0)	(0)	0.000%	(0)	(0)
54	(98)	(27)	(125)	0.099%	(22)	(121)
70	(298)	(32)	(331)	0.119%	(27)	(326)
71	(298)	(32)	(330)	0.119%	(27)	(325)
73	(135)	(15)	(149)	0.054%	(12)	(147)
75	(32)	(7)	(39)	0.027%	(6)	(38)
76	(0)	(0)	(0)	0.000%	(0)	(0)
77	(0)	(0)	(0)	0.000%	(0)	(0)
78	(0)	(0)	(0)	0.000%	(0)	(0)
84	(0)	(0)	(0)	0.000%	(0)	(0)
85	(0)	(0)	(0)	0.000%	(0)	(0)

AMERICAN ELECTRIC POWER COMPANY
ALLOCATION OF SERVICES' CAPITAL REVENUE REQUIREMENT SAVINGS
BY AEP SUBSIDIARY

(IN 000'S)

COMPANY	O & M SAVINGS	CAPITAL SAVINGS	TOTAL SAVINGS	% OF SAVINGS	REV REQ ALLOCATION	O&M/REV SAV TOTAL
98	(448)	(41)	(489)	0.150%	(34)	(482)
XX	(3)	(1)	(4)	0.003%	(1)	(4)
TOTAL REG	(76,802)	(27,146)	(103,948)	100.000%	(22,764)	(99,566)
TOTAL 2002	(78,007)	(27,241)	(105,248)		(22,844)	(100,851)

AMERICAN ELECTRIC POWER COMPANY
ALLOCATION OF SERVICES' CAPITAL REVENUE REQUIREMENT SAVINGS
BY AEP SUBSIDIARY

(IN 000'S)

COMPANY	O & M SAVINGS	CAPITAL SAVINGS	TOTAL SAVINGS	% OF SAVINGS	REV REQ ALLOCATION	O&M/REV SAV TOTAL
2003						
NON-REG						
25	(8)	(1)	(8)	0.845%	(1)	(8)
26	(0)	(0)	(0)	0.011%	(0)	(0)
53	(6)	0	(6)	-0.002%	0	(6)
56	(7)	(0)	(7)	0.067%	(0)	(7)
57	(7)	(0)	(7)	0.004%	(0)	(7)
58	(96)	(9)	(104)	8.830%	(9)	(105)
59	(307)	(38)	(345)	37.512%	(40)	(347)
60	(120)	(7)	(127)	7.075%	(8)	(128)
63	(3)	(0)	(4)	0.314%	(0)	(4)
64	(3)	(0)	(3)	0.165%	(0)	(3)
66	(3)	(0)	(3)	0.007%	(0)	(3)
67	(6)	(0)	(6)	0.003%	(0)	(6)
69	(117)	(12)	(129)	11.865%	(13)	(129)
72	(21)	(0)	(21)	0.174%	(0)	(21)
74	(317)	(30)	(347)	29.586%	(32)	(349)
81	(30)	(3)	(33)	2.635%	(3)	(33)
83	(3)	(0)	(3)	0.007%	(0)	(3)
86	(3)	(0)	(3)	0.029%	(0)	(3)
87	(44)	(0)	(44)	0.034%	(0)	(44)
88	(0)	(0)	(0)	0.011%	(0)	(0)
89	(0)	(0)	(0)	0.012%	(0)	(0)
90	(0)	(0)	(0)	0.012%	(0)	(0)
91	(19)	(1)	(20)	0.826%	(1)	(20)
99	(135)	0	(135)	-0.023%	0	(135)
TOTAL NON-REG	(1,255)	(101)	(1,356)	100.000%	(107)	(1,362)
REGULATED						
01	(587)	(346)	(932)	1.211%	(366)	(952)
02	(20,931)	(8,094)	(29,025)	28.365%	(8,563)	(29,494)
03	(4,997)	(1,647)	(6,644)	5.771%	(1,742)	(6,739)

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AMERICAN ELECTRIC POWER COMPANY
ALLOCATION OF SERVICES' CAPITAL REVENUE REQUIREMENT SAVINGS
BY AEP SUBSIDIARY

(IN 000'S)

COMPANY	O & M SAVINGS	CAPITAL SAVINGS	TOTAL SAVINGS	% OF SAVINGS	REV REQ ALLOCATION	O&M/REV SAV TOTAL
04	(16,014)	(5,322)	(21,336)	18.653%	(5,631)	(21,644)
06	(602)	(330)	(932)	1.156%	(349)	(951)
07	(19,126)	(6,518)	(25,644)	22.843%	(6,896)	(26,022)
10	(12,148)	(5,096)	(17,244)	17.860%	(5,392)	(17,540)
21	(3)	(0)	(3)	0.001%	(0)	(3)
22	(199)	(22)	(221)	0.077%	(23)	(223)
23	(1)	(0)	(1)	0.001%	(0)	(1)
31	(36)	(3)	(40)	0.012%	(4)	(40)
32	(48)	(5)	(52)	0.016%	(5)	(53)
34	(300)	(74)	(374)	0.260%	(78)	(379)
40	(0)	(0)	(0)	0.000%	(0)	(0)
41	(0)	(0)	(0)	0.000%	(0)	(0)
42	(484)	(137)	(621)	0.478%	(144)	(629)
43	(566)	(167)	(733)	0.586%	(177)	(743)
44	(1,938)	(465)	(2,403)	1.631%	(492)	(2,430)
45	(0)	(0)	(0)	0.000%	(0)	(0)
46	(1)	(0)	(1)	0.000%	(0)	(1)
48	(437)	(110)	(547)	0.386%	(116)	(554)
49	(112)	(34)	(147)	0.121%	(36)	(149)
50	(0)	(0)	(0)	0.000%	(0)	(0)
51	(1)	(0)	(1)	0.000%	(0)	(1)
52	(0)	(0)	(0)	0.000%	(0)	(0)
54	(102)	(28)	(130)	0.098%	(30)	(132)
70	(311)	(34)	(345)	0.120%	(36)	(347)
71	(310)	(34)	(344)	0.120%	(36)	(346)
73	(140)	(16)	(156)	0.054%	(16)	(157)
75	(34)	(8)	(42)	0.027%	(8)	(42)
76	(0)	(0)	(0)	0.000%	(0)	(0)
77	(0)	(0)	(0)	0.000%	(0)	(0)
78	(0)	(0)	(0)	0.000%	(0)	(0)
84	(0)	(0)	(0)	0.000%	(0)	(0)
85	(0)	(0)	(0)	0.000%	(0)	(0)

AMERICAN ELECTRIC POWER COMPANY
ALLOCATION OF SERVICES' CAPITAL REVENUE REQUIREMENT SAVINGS
BY AEP SUBSIDIARY

(IN 000'S)

COMPANY	O & M SAVINGS	CAPITAL SAVINGS	TOTAL SAVINGS	% OF SAVINGS	REV REQ ALLOCATION	O&M/REV SAV TOTAL
98	(466)	(43)	(509)	0.149%	(45)	(511)
XX	(3)	(1)	(4)	0.003%	(1)	(4)
TOTAL REG	(79,899)	(28,535)	(108,434)	100.000%	(30,188)	(110,087)
TOTAL 2003	(81,154)	(28,636)	(109,790)		(30,295)	(111,449)

AMERICAN ELECTRIC POWER COMPANY
ALLOCATION OF SERVICES' CAPITAL REVENUE REQUIREMENT SAVINGS
BY AEP SUBSIDIARY

(IN 000'S)

COMPANY	O & M SAVINGS	CAPITAL SAVINGS	TOTAL SAVINGS	% OF SAVINGS	REV REQ ALLOCATION	O&M/REV SAV TOTAL
2004						
NON-REG						
25	(8)	(1)	(9)	0.846%	(2)	(9)
26	(0)	(0)	(0)	0.011%	(0)	(0)
53	(6)	0	(6)	-0.003%	0	(6)
56	(7)	(0)	(7)	0.067%	(0)	(7)
57	(7)	(0)	(7)	0.003%	(0)	(7)
58	(98)	(9)	(108)	8.830%	(16)	(114)
59	(316)	(39)	(355)	37.509%	(68)	(383)
60	(124)	(7)	(132)	7.074%	(13)	(137)
63	(4)	(0)	(4)	0.316%	(1)	(4)
64	(3)	(0)	(4)	0.166%	(0)	(4)
66	(3)	(0)	(3)	0.006%	(0)	(3)
67	(7)	(0)	(7)	0.003%	(0)	(7)
69	(121)	(12)	(133)	11.907%	(21)	(142)
72	(21)	(0)	(22)	0.172%	(0)	(22)
74	(327)	(31)	(357)	29.577%	(53)	(380)
81	(31)	(3)	(34)	2.634%	(5)	(36)
83	(3)	(0)	(3)	0.007%	(0)	(3)
86	(4)	(0)	(4)	0.028%	(0)	(4)
87	(45)	(0)	(45)	0.027%	(0)	(45)
88	(0)	(0)	(0)	0.011%	(0)	(0)
89	(0)	(0)	(0)	0.012%	(0)	(0)
90	(0)	(0)	(0)	0.012%	(0)	(0)
91	(19)	(1)	(20)	0.825%	(1)	(21)
99	(140)	0	(140)	-0.041%	0	(140)
TOTAL NON-REG	(1,295)	(104)	(1,399)	100.000%	(180)	(1,475)
REGULATED						
01	(612)	(215)	(828)	1.088%	(373)	(985)
02	(21,787)	(5,509)	(27,296)	27.818%	(9,527)	(31,314)
03	(5,197)	(1,154)	(6,351)	5.824%	(1,995)	(7,192)

AMERICAN ELECTRIC POWER COMPANY
ALLOCATION OF SERVICES' CAPITAL REVENUE REQUIREMENT SAVINGS
BY AEP SUBSIDIARY

(IN 000'S)

COMPANY	O & M SAVINGS	CAPITAL SAVINGS	TOTAL SAVINGS	% OF SAVINGS	REV REQ ALLOCATION	O&M/REV SAV TOTAL
04	(16,665)	(3,722)	(20,387)	18.795%	(6,437)	(23,102)
06	(628)	(205)	(833)	1.033%	(354)	(982)
07	(19,896)	(4,527)	(24,422)	22.857%	(7,828)	(27,723)
10	(12,653)	(3,242)	(15,895)	16.372%	(5,607)	(18,260)
21	(3)	(0)	(3)	0.002%	(1)	(3)
22	(205)	(23)	(228)	0.115%	(39)	(244)
23	(1)	(0)	(1)	0.001%	(0)	(1)
31	(37)	(4)	(41)	0.018%	(6)	(43)
32	(49)	(5)	(54)	0.024%	(8)	(57)
34	(312)	(77)	(389)	0.391%	(134)	(446)
40	(0)	(0)	(0)	0.000%	(0)	(0)
41	(0)	(0)	(0)	0.000%	(0)	(0)
42	(503)	(142)	(645)	0.719%	(246)	(749)
43	(588)	(174)	(762)	0.879%	(301)	(889)
44	(2,012)	(485)	(2,497)	2.450%	(839)	(2,851)
45	(0)	(0)	(0)	0.000%	(0)	(0)
46	(1)	(0)	(1)	0.000%	(0)	(1)
48	(454)	(115)	(569)	0.580%	(199)	(653)
49	(117)	(36)	(152)	0.181%	(62)	(179)
50	(0)	(0)	(0)	0.000%	(0)	(0)
51	(1)	(0)	(1)	0.000%	(0)	(1)
52	(0)	(0)	(0)	0.000%	(0)	(0)
54	(106)	(29)	(135)	0.147%	(50)	(156)
70	(319)	(35)	(355)	0.179%	(61)	(381)
71	(318)	(35)	(354)	0.178%	(61)	(379)
73	(144)	(16)	(160)	0.081%	(28)	(172)
75	(35)	(8)	(43)	0.040%	(14)	(48)
76	(0)	(0)	(0)	0.000%	(0)	(0)
77	(0)	(0)	(0)	0.000%	(0)	(0)
78	(0)	(0)	(0)	0.000%	(0)	(0)
84	(0)	(0)	(0)	0.000%	(0)	(0)
85	(0)	(0)	(0)	0.000%	(0)	(0)

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AMERICAN ELECTRIC POWER COMPANY
ALLOCATION OF SERVICES' CAPITAL REVENUE REQUIREMENT SAVINGS
BY AEP SUBSIDIARY

(IN 000'S)

COMPANY	O & M SAVINGS	CAPITAL SAVINGS	TOTAL SAVINGS	% OF SAVINGS	REV REQ ALLOCATION	O&M/REV SAV TOTAL
98	(484)	(44)	(528)	0.224%	(77)	(561)
XX	(3)	(1)	(4)	0.004%	(1)	(5)
TOTAL REG	(83,130)	(19,805)	(102,935)	100.000%	(34,247)	(117,377)
TOTAL 2004	(84,424)	(19,909)	(104,334)		(34,427)	(118,851)

AMERICAN ELECTRIC POWER COMPANY
ALLOCATION OF SERVICES' CAPITAL REVENUE REQUIREMENT SAVINGS
BY AEP SUBSIDIARY

(IN 000'S)

COMPANY	O & M SAVINGS	CAPITAL SAVINGS	TOTAL SAVINGS	% OF SAVINGS	REV REQ ALLOCATION	O&M/REV SAV TOTAL
2005						
NON-REG						
25	(8)	(1)	(9)	0.845%	(2)	(10)
26	(0)	(0)	(0)	0.011%	(0)	(0)
53	(7)	0	(7)	-0.003%	0	(7)
56	(7)	(0)	(7)	0.065%	(0)	(7)
57	(7)	(0)	(7)	0.002%	(0)	(7)
58	(102)	(10)	(112)	8.831%	(17)	(120)
59	(329)	(41)	(371)	37.577%	(74)	(404)
60	(129)	(8)	(137)	7.056%	(14)	(143)
63	(4)	(0)	(4)	0.310%	(1)	(4)
64	(4)	(0)	(4)	0.163%	(0)	(4)
66	(3)	(0)	(3)	0.006%	(0)	(3)
67	(7)	(0)	(7)	0.002%	(0)	(7)
69	(125)	(13)	(139)	11.862%	(23)	(149)
72	(22)	(0)	(22)	0.169%	(0)	(23)
74	(340)	(33)	(373)	29.613%	(59)	(399)
81	(33)	(3)	(36)	2.638%	(5)	(38)
83	(3)	(0)	(3)	0.006%	(0)	(3)
86	(4)	(0)	(4)	0.028%	(0)	(4)
87	(47)	(0)	(47)	0.021%	(0)	(47)
88	(0)	(0)	(0)	0.011%	(0)	(0)
89	(0)	(0)	(0)	0.012%	(0)	(0)
90	(0)	(0)	(0)	0.012%	(0)	(0)
91	(20)	(1)	(21)	0.823%	(2)	(22)
99	(145)	0	(145)	-0.059%	0	(145)
TOTAL NON-REG	(1,348)	(110)	(1,458)	100.000%	(198)	(1,546)
REGULATED						
01	(637)	(226)	(863)	1.089%	(406)	(1,044)
02	(22,669)	(5,782)	(28,451)	27.824%	(10,384)	(33,053)
03	(5,407)	(1,210)	(6,618)	5.825%	(2,174)	(7,581)

AMERICAN ELECTRIC POWER COMPANY
ALLOCATION OF SERVICES' CAPITAL REVENUE REQUIREMENT SAVINGS
BY AEP SUBSIDIARY

(IN 000'S)

COMPANY	O & M SAVINGS	CAPITAL SAVINGS	TOTAL SAVINGS	% OF SAVINGS	REV REQ ALLOCATION	O&M/REV SAV TOTAL
04	(17,339)	(3,906)	(21,245)	18.796%	(7,015)	(24,354)
06	(654)	(215)	(869)	1.035%	(386)	(1,040)
07	(20,699)	(4,749)	(25,448)	22.852%	(8,529)	(29,228)
10	(13,167)	(3,406)	(16,573)	16.389%	(6,116)	(19,284)
21	(3)	(0)	(3)	0.002%	(1)	(3)
22	(213)	(24)	(237)	0.116%	(43)	(257)
23	(1)	(0)	(1)	0.001%	(0)	(2)
31	(39)	(4)	(43)	0.018%	(7)	(46)
32	(51)	(5)	(56)	0.024%	(9)	(60)
34	(324)	(81)	(405)	0.389%	(145)	(469)
40	(0)	(0)	(0)	0.000%	(0)	(0)
41	(0)	(0)	(0)	0.000%	(0)	(0)
42	(522)	(149)	(671)	0.715%	(267)	(789)
43	(611)	(182)	(793)	0.874%	(326)	(937)
44	(2,092)	(507)	(2,598)	2.438%	(910)	(3,002)
45	(0)	(0)	(0)	0.000%	(0)	(0)
46	(1)	(0)	(1)	0.000%	(0)	(1)
48	(472)	(120)	(593)	0.578%	(216)	(688)
49	(121)	(37)	(159)	0.180%	(67)	(189)
50	(0)	(0)	(0)	0.000%	(0)	(0)
51	(1)	(0)	(1)	0.000%	(0)	(1)
52	(0)	(0)	(0)	0.000%	(0)	(0)
54	(110)	(30)	(141)	0.146%	(55)	(165)
70	(333)	(38)	(370)	0.181%	(67)	(400)
71	(332)	(37)	(369)	0.180%	(67)	(399)
73	(150)	(17)	(167)	0.082%	(31)	(181)
75	(37)	(8)	(45)	0.040%	(15)	(52)
76	(0)	(0)	(0)	0.000%	(0)	(0)
77	(0)	(0)	(0)	0.000%	(0)	(0)
78	(0)	(0)	(0)	0.000%	(0)	(0)
84	(0)	(0)	(0)	0.000%	(0)	(0)
85	(0)	(0)	(0)	0.000%	(0)	(0)

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AMERICAN ELECTRIC POWER COMPANY
ALLOCATION OF SERVICES' CAPITAL REVENUE REQUIREMENT SAVINGS
BY AEP SUBSIDIARY

(IN 000'S)

COMPANY	O & M SAVINGS	CAPITAL SAVINGS	TOTAL SAVINGS	% OF SAVINGS	REV REQ ALLOCATION	O&M/REV SAV TOTAL
98	(503)	(46)	(550)	0.222%	(83)	(586)
XX	(4)	(1)	(4)	0.004%	(1)	(5)
TOTAL REG	(86,493)	(20,782)	(107,275)	100.000%	(37,321)	(123,814)
TOTAL 2005	(87,841)	(20,892)	(108,733)		(37,519)	(125,360)

AMERICAN ELECTRIC POWER COMPANY
ALLOCATION OF SERVICES' CAPITAL REVENUE REQUIREMENT SAVINGS
BY AEP SUBSIDIARY

(IN 000'S)

COMPANY	O & M SAVINGS	CAPITAL SAVINGS	TOTAL SAVINGS	% OF SAVINGS	REV REQ ALLOCATION	O&M/REV SAV TOTAL
2006						
NON-REG						
25	(8)	(1)	(9)	0.845%	(2)	(10)
26	(0)	(0)	(0)	0.011%	(0)	(0)
53	(7)	0	(7)	-0.004%	0	(7)
56	(7)	(0)	(7)	0.064%	(0)	(8)
57	(7)	(0)	(8)	0.001%	(0)	(8)
58	(106)	(10)	(116)	8.832%	(21)	(128)
59	(341)	(43)	(384)	37.613%	(91)	(433)
60	(134)	(8)	(142)	7.045%	(17)	(151)
63	(4)	(0)	(4)	0.308%	(1)	(5)
64	(4)	(0)	(4)	0.162%	(0)	(4)
66	(4)	(0)	(4)	0.006%	(0)	(4)
67	(7)	(0)	(7)	0.001%	(0)	(7)
69	(130)	(14)	(144)	11.858%	(29)	(159)
72	(23)	(0)	(23)	0.165%	(0)	(24)
74	(352)	(34)	(386)	29.628%	(72)	(424)
81	(34)	(3)	(37)	2.639%	(6)	(40)
83	(4)	(0)	(4)	0.006%	(0)	(4)
86	(4)	(0)	(4)	0.027%	(0)	(4)
87	(49)	(0)	(49)	0.015%	(0)	(49)
88	(0)	(0)	(0)	0.011%	(0)	(0)
89	(0)	(0)	(0)	0.012%	(0)	(0)
90	(0)	(0)	(0)	0.012%	(0)	(0)
91	(21)	(1)	(22)	0.821%	(2)	(23)
99	(151)	0	(151)	-0.079%	0	(151)
TOTAL NON-REG	(1,398)	(115)	(1,513)	100.000%	(243)	(1,641)
REGULATED						
01	(664)	(168)	(832)	0.987%	(354)	(1,018)
02	(23,594)	(4,652)	(28,246)	27.372%	(9,820)	(33,413)
03	(5,625)	(998)	(6,623)	5.869%	(2,106)	(7,731)

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AMERICAN ELECTRIC POWER COMPANY
ALLOCATION OF SERVICES' CAPITAL REVENUE REQUIREMENT SAVINGS
BY AEP SUBSIDIARY

(IN 000'S)

COMPANY	O & M SAVINGS	CAPITAL SAVINGS	TOTAL SAVINGS	% OF SAVINGS	REV REQ ALLOCATION	O&M/REV SAV TOTAL
04	(18,043)	(3,215)	(21,258)	18.916%	(6,786)	(24,829)
06	(681)	(159)	(840)	0.933%	(335)	(1,016)
07	(21,535)	(3,885)	(25,420)	22.859%	(8,201)	(29,735)
10	(13,709)	(2,577)	(16,286)	15.162%	(5,439)	(19,149)
21	(3)	(0)	(3)	0.002%	(1)	(4)
22	(221)	(25)	(246)	0.149%	(53)	(274)
23	(1)	(0)	(1)	0.001%	(0)	(2)
31	(40)	(4)	(44)	0.023%	(8)	(48)
32	(53)	(5)	(58)	0.031%	(11)	(64)
34	(337)	(84)	(421)	0.497%	(178)	(515)
40	(0)	(0)	(0)	0.000%	(0)	(0)
41	(0)	(0)	(0)	0.000%	(0)	(0)
42	(543)	(155)	(698)	0.911%	(327)	(870)
43	(635)	(189)	(824)	1.115%	(400)	(1,035)
44	(2,173)	(529)	(2,702)	3.110%	(1,116)	(3,289)
45	(0)	(0)	(0)	0.000%	(0)	(0)
46	(1)	(0)	(1)	0.000%	(0)	(1)
48	(491)	(125)	(616)	0.738%	(265)	(756)
49	(126)	(39)	(165)	0.230%	(83)	(208)
50	(0)	(0)	(0)	0.000%	(0)	(0)
51	(1)	(0)	(1)	0.001%	(0)	(1)
52	(0)	(0)	(0)	0.000%	(0)	(0)
54	(114)	(32)	(146)	0.186%	(67)	(181)
70	(344)	(39)	(384)	0.231%	(83)	(427)
71	(343)	(39)	(382)	0.230%	(83)	(426)
73	(155)	(18)	(173)	0.105%	(38)	(193)
75	(38)	(9)	(47)	0.052%	(18)	(56)
76	(0)	(0)	(0)	0.000%	(0)	(0)
77	(0)	(0)	(0)	0.000%	(0)	(0)
78	(0)	(0)	(0)	0.000%	(0)	(0)
84	(0)	(0)	(0)	0.000%	(0)	(0)
85	(0)	(0)	(0)	0.000%	(0)	(0)

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AMERICAN ELECTRIC POWER COMPANY
ALLOCATION OF SERVICES' CAPITAL REVENUE REQUIREMENT SAVINGS
BY AEP SUBSIDIARY

(IN 000'S)

COMPANY	O & M SAVINGS	CAPITAL SAVINGS	TOTAL SAVINGS	% OF SAVINGS	REV REQ ALLOCATION	O&M/REV SAV TOTAL
98	(523)	(48)	(571)	0.283%	(102)	(625)
XX	(4)	(1)	(5)	0.005%	(2)	(6)
TOTAL REG	(89,998)	(16,997)	(106,995)	100.000%	(35,875)	(125,873)
TOTAL 2006	(91,396)	(17,112)	(108,508)		(36,118)	(127,514)

AMERICAN ELECTRIC POWER COMPANY
ALLOCATION OF SERVICES' CAPITAL REVENUE REQUIREMENT SAVINGS
BY AEP SUBSIDIARY

(IN 000'S)

COMPANY	O & M SAVINGS	CAPITAL SAVINGS	TOTAL SAVINGS	% OF SAVINGS	REV REQ ALLOCATION	O&M/REV SAV TOTAL
2007						
NON-REG						
25	(9)	(1)	(10)	0.845%	(2)	(11)
26	(0)	(0)	(0)	0.011%	(0)	(0)
53	(7)	0	(7)	-0.005%	0	(7)
56	(8)	(0)	(8)	0.063%	(0)	(8)
57	(8)	0	(8)	0.000%	0	(8)
58	(110)	(11)	(121)	8.834%	(21)	(131)
59	(356)	(46)	(402)	37.684%	(88)	(444)
60	(140)	(9)	(148)	7.027%	(16)	(156)
63	(4)	(0)	(4)	0.303%	(1)	(5)
64	(4)	(0)	(4)	0.158%	(0)	(4)
66	(4)	(0)	(4)	0.005%	(0)	(4)
67	(7)	0	(7)	0.000%	0	(7)
69	(135)	(14)	(150)	11.812%	(28)	(163)
72	(24)	(0)	(24)	0.162%	(0)	(24)
74	(367)	(36)	(403)	29.666%	(69)	(436)
81	(35)	(3)	(39)	2.643%	(6)	(41)
83	(4)	(0)	(4)	0.005%	(0)	(4)
86	(4)	(0)	(4)	0.027%	(0)	(4)
87	(51)	(0)	(51)	0.008%	(0)	(51)
88	(0)	(0)	(0)	0.011%	(0)	(0)
89	(0)	(0)	(0)	0.012%	(0)	(0)
90	(0)	(0)	(0)	0.012%	(0)	(0)
91	(22)	(1)	(23)	0.818%	(2)	(24)
99	(157)	0	(156)	-0.100%	0	(156)
TOTAL NON-REG	(1,456)	(122)	(1,577)	100.000%	(234)	(1,690)
REGULATED						
01	(691)	(176)	(867)	0.988%	(338)	(1,029)
02	(24,551)	(4,876)	(29,426)	27.376%	(9,359)	(33,910)
03	(5,853)	(1,045)	(6,898)	5.870%	(2,007)	(7,860)

AMERICAN ELECTRIC POWER COMPANY
ALLOCATION OF SERVICES' CAPITAL REVENUE REQUIREMENT SAVINGS
BY AEP SUBSIDIARY

(IN 000'S)

COMPANY	O & M SAVINGS	CAPITAL SAVINGS	TOTAL SAVINGS	% OF SAVINGS	REV REQ ALLOCATION	O&M/REV SAV TOTAL
04	(18,774)	(3,369)	(22,143)	18.917%	(6,467)	(25,241)
06	(709)	(166)	(875)	0.934%	(319)	(1,028)
07	(22,405)	(4,070)	(26,475)	22.853%	(7,813)	(30,218)
10	(14,268)	(2,703)	(16,971)	15.175%	(5,188)	(19,456)
21	(3)	(0)	(3)	0.002%	(1)	(4)
22	(230)	(27)	(257)	0.150%	(51)	(281)
23	(1)	(0)	(2)	0.001%	(0)	(2)
31	(42)	(4)	(46)	0.023%	(8)	(50)
32	(55)	(6)	(61)	0.031%	(11)	(66)
34	(350)	(88)	(439)	0.495%	(169)	(520)
40	(0)	(0)	(0)	0.000%	(0)	(0)
41	(0)	(0)	(0)	0.000%	(0)	(0)
42	(564)	(162)	(726)	0.908%	(310)	(875)
43	(660)	(198)	(858)	1.110%	(380)	(1,040)
44	(2,260)	(552)	(2,812)	3.099%	(1,060)	(3,319)
45	(0)	(0)	(0)	0.000%	(0)	(0)
46	(1)	(0)	(1)	0.000%	(0)	(1)
48	(511)	(131)	(642)	0.736%	(252)	(762)
49	(131)	(41)	(172)	0.229%	(78)	(209)
50	(0)	(0)	(0)	0.000%	(0)	(0)
51	(1)	(0)	(1)	0.001%	(0)	(1)
52	(0)	(0)	(0)	0.000%	(0)	(0)
54	(119)	(33)	(152)	0.186%	(63)	(182)
70	(359)	(42)	(400)	0.234%	(80)	(439)
71	(357)	(42)	(399)	0.233%	(80)	(437)
73	(162)	(19)	(181)	0.106%	(36)	(198)
75	(40)	(9)	(49)	0.052%	(18)	(58)
76	(0)	(0)	(0)	0.000%	(0)	(0)
77	(0)	(0)	(0)	0.000%	(0)	(0)
78	(0)	(0)	(0)	0.000%	(0)	(0)
84	(0)	(0)	(0)	0.000%	(0)	(0)
85	(0)	(0)	(0)	0.000%	(0)	(0)

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AMERICAN ELECTRIC POWER COMPANY
ALLOCATION OF SERVICES' CAPITAL REVENUE REQUIREMENT SAVINGS
BY AEP SUBSIDIARY

(IN 000'S)

COMPANY	O & M SAVINGS	CAPITAL SAVINGS	TOTAL SAVINGS	% OF SAVINGS	REV REQ ALLOCATION	O&M/REV SAV TOTAL
98	(544)	(50)	(594)	0.282%	(96)	(640)
XX	(4)	(1)	(5)	0.005%	(2)	(6)
TOTAL REG	(93,645)	(17,810)	(111,455)	100.000%	(34,187)	(127,832)
TOTAL 2007	(95,100)	(17,932)	(113,033)		(34,421)	(129,521)
					(234)	
					(34,187)	

AMERICAN ELECTRIC POWER COMPANY
ALLOCATION OF SERVICES' CAPITAL REVENUE REQUIREMENT SAVINGS
BY AEP SUBSIDIARY

(IN 000'S)

COMPANY	O & M SAVINGS	CAPITAL SAVINGS	TOTAL SAVINGS	% OF SAVINGS	REV REQ ALLOCATION	O&M/REV SAV TOTAL
2008						
NON-REG						
25	(9)	(1)	(11)	0.846%	(2)	(12)
26	(0)	(0)	(0)	0.011%	(0)	(0)
53	(7)	0	(7)	-0.013%	0	(7)
56	(8)	(0)	(8)	0.052%	(0)	(8)
57	(8)	0	(8)	-0.008%	0	(8)
58	(119)	(12)	(131)	8.853%	(22)	(140)
59	(388)	(52)	(440)	38.123%	(93)	(482)
60	(148)	(9)	(157)	6.931%	(17)	(165)
63	(4)	(0)	(5)	0.277%	(1)	(5)
64	(4)	(0)	(4)	0.143%	(0)	(4)
66	(4)	(0)	(4)	0.001%	(0)	(4)
67	(8)	0	(8)	-0.008%	0	(8)
69	(144)	(16)	(160)	11.569%	(28)	(173)
72	(25)	(0)	(25)	0.136%	(0)	(25)
74	(395)	(41)	(436)	29.881%	(73)	(468)
81	(38)	(4)	(42)	2.664%	(7)	(44)
83	(4)	(0)	(4)	0.001%	(0)	(4)
86	(4)	(0)	(4)	0.023%	(0)	(4)
87	(53)	0	(53)	-0.047%	0	(53)
88	(0)	(0)	(0)	0.011%	(0)	(0)
89	(0)	(0)	(0)	0.012%	(0)	(0)
90	(0)	(0)	(0)	0.012%	(0)	(0)
91	(23)	(1)	(24)	0.803%	(2)	(25)
99	(162)	0	(162)	-0.273%	1	(162)
TOTAL NON-REG	(1,556)	(137)	(1,693)	100.000%	(245)	(1,801)
REGULATED						
01	(722)	(167)	(889)	0.958%	(299)	(1,021)
02	(25,635)	(4,743)	(30,379)	27.222%	(8,506)	(34,141)
03	(6,118)	(1,026)	(7,144)	5.890%	(1,841)	(7,958)

AMERICAN ELECTRIC POWER COMPANY
ALLOCATION OF SERVICES' CAPITAL REVENUE REQUIREMENT SAVINGS
BY AEP SUBSIDIARY

(IN 000'S)

COMPANY	O & M SAVINGS	CAPITAL SAVINGS	TOTAL SAVINGS	% OF SAVINGS	REV REQ ALLOCATION	O&M/REV SAV TOTAL
04	(19,582)	(3,296)	(22,878)	18.916%	(5,911)	(25,492)
06	(741)	(158)	(899)	0.906%	(283)	(1,024)
07	(23,415)	(3,981)	(27,396)	22.848%	(7,139)	(30,554)
10	(14,907)	(2,585)	(17,492)	14.837%	(4,636)	(19,543)
21	(3)	(0)	(4)	0.002%	(1)	(4)
22	(249)	(30)	(280)	0.175%	(55)	(304)
23	(2)	(0)	(2)	0.001%	(0)	(2)
31	(45)	(5)	(50)	0.027%	(8)	(54)
32	(59)	(6)	(66)	0.036%	(11)	(71)
34	(365)	(91)	(457)	0.525%	(164)	(529)
40	(0)	(0)	(0)	0.000%	(0)	(0)
41	(0)	(0)	(0)	0.000%	(0)	(0)
42	(590)	(167)	(757)	0.958%	(299)	(889)
43	(691)	(204)	(895)	1.172%	(366)	(1,057)
44	(2,362)	(571)	(2,933)	3.276%	(1,024)	(3,386)
45	(0)	(0)	(0)	0.000%	(0)	(0)
46	(1)	(0)	(1)	0.000%	(0)	(1)
48	(532)	(136)	(669)	0.782%	(244)	(777)
49	(137)	(42)	(180)	0.243%	(76)	(213)
50	(0)	(0)	(0)	0.000%	(0)	(0)
51	(1)	(0)	(1)	0.001%	(0)	(1)
52	(0)	(0)	(0)	0.000%	(0)	(0)
54	(125)	(34)	(159)	0.196%	(61)	(186)
70	(389)	(47)	(436)	0.272%	(85)	(474)
71	(388)	(47)	(435)	0.271%	(85)	(472)
73	(176)	(21)	(197)	0.123%	(38)	(214)
75	(46)	(11)	(56)	0.061%	(19)	(65)
76	(0)	(0)	(0)	0.000%	(0)	(0)
77	(0)	(0)	(0)	0.000%	(0)	(0)
78	(0)	(0)	(0)	0.000%	(0)	(0)
84	(0)	(0)	(0)	0.000%	(0)	(0)
85	(0)	(0)	(0)	0.000%	(0)	(0)

AMERICAN ELECTRIC POWER COMPANY
ALLOCATION OF SERVICES' CAPITAL REVENUE REQUIREMENT SAVINGS
BY AEP SUBSIDIARY

(IN 000'S)

COMPANY	O & M SAVINGS	CAPITAL SAVINGS	TOTAL SAVINGS	% OF SAVINGS	REV REQ ALLOCATION	O&M/REV SAV TOTAL
98	(566)	(52)	(618)	0.297%	(93)	(659)
XX	(4)	(1)	(6)	0.006%	(2)	(6)
TOTAL REG	(97,851)	(17,425)	(115,276)	100.000%	(31,247)	(129,098)
TOTAL 2008	(99,407)	(17,562)	(116,969)		(31,492)	(130,899)
					(245)	
					(31,247)	

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AMERICAN ELECTRIC POWER COMPANY
ALLOCATION OF SERVICES' CAPITAL REVENUE REQUIREMENT SAVINGS
BY AEP SUBSIDIARY

(IN 000'S)

COMPANY	O & M SAVINGS	CAPITAL SAVINGS	TOTAL SAVINGS	% OF SAVINGS	REV REQ ALLOCATION	O&M/REV SAV TOTAL
2009						
NON-REG						
25	(2)	(0)	(3)	0.846%	(1)	(3)
26	(0)	(0)	(0)	0.011%	(0)	(0)
53	(2)	0	(2)	-0.013%	0	(2)
56	(2)	(0)	(2)	0.052%	(0)	(2)
57	(2)	0	(2)	-0.008%	0	(2)
58	(30)	(3)	(33)	8.853%	(6)	(36)
59	(99)	(13)	(112)	38.123%	(24)	(123)
60	(38)	(2)	(40)	6.931%	(4)	(42)
63	(1)	(0)	(1)	0.277%	(0)	(1)
64	(1)	(0)	(1)	0.143%	(0)	(1)
66	(1)	(0)	(1)	0.001%	(0)	(1)
67	(2)	0	(2)	-0.008%	0	(2)
69	(37)	(4)	(41)	11.569%	(7)	(44)
72	(6)	(0)	(6)	0.136%	(0)	(6)
74	(101)	(10)	(111)	29.881%	(19)	(119)
81	(10)	(1)	(11)	2.664%	(2)	(11)
83	(1)	(0)	(1)	0.001%	(0)	(1)
86	(1)	(0)	(1)	0.023%	(0)	(1)
87	(13)	0	(13)	-0.047%	0	(13)
88	(0)	(0)	(0)	0.011%	(0)	(0)
89	(0)	(0)	(0)	0.012%	(0)	(0)
90	(0)	(0)	(0)	0.012%	(0)	(0)
91	(6)	(0)	(6)	0.803%	(1)	(6)
99	(41)	0	(41)	-0.273%	0	(41)
TOTAL NON-REG	(396)	(35)	(431)	100.000%	(62)	(459)
REGULATED						
01	(184)	(43)	(226)	0.958%	(76)	(260)
02	(6,528)	(1,208)	(7,736)	27.222%	(2,166)	(8,694)
03	(1,558)	(261)	(1,819)	5.890%	(469)	(2,027)

AMERICAN ELECTRIC POWER COMPANY
ALLOCATION OF SERVICES' CAPITAL REVENUE REQUIREMENT SAVINGS
BY AEP SUBSIDIARY

(IN 000'S)

COMPANY	O & M SAVINGS	CAPITAL SAVINGS	TOTAL SAVINGS	% OF SAVINGS	REV REQ ALLOCATION	O&M/REV SAV TOTAL
04	(4,987)	(839)	(5,826)	18.916%	(1,505)	(6,492)
06	(189)	(40)	(229)	0.906%	(72)	(261)
07	(5,963)	(1,014)	(6,977)	22.848%	(1,818)	(7,781)
10	(3,796)	(658)	(4,455)	14.837%	(1,181)	(4,977)
21	(1)	(0)	(1)	0.002%	(0)	(1)
22	(64)	(8)	(71)	0.175%	(14)	(77)
23	(0)	(0)	(0)	0.001%	(0)	(0)
31	(11)	(1)	(13)	0.027%	(2)	(14)
32	(15)	(2)	(17)	0.036%	(3)	(18)
34	(93)	(23)	(116)	0.525%	(42)	(135)
40	(0)	(0)	(0)	0.000%	(0)	(0)
41	(0)	(0)	(0)	0.000%	(0)	(0)
42	(150)	(43)	(193)	0.958%	(76)	(226)
43	(176)	(52)	(228)	1.172%	(93)	(269)
44	(602)	(145)	(747)	3.276%	(261)	(862)
45	(0)	(0)	(0)	0.000%	(0)	(0)
46	(0)	(0)	(0)	0.000%	(0)	(0)
48	(136)	(35)	(170)	0.782%	(62)	(198)
49	(35)	(11)	(46)	0.243%	(19)	(54)
50	(0)	(0)	(0)	0.000%	(0)	(0)
51	(0)	(0)	(0)	0.001%	(0)	(0)
52	(0)	(0)	(0)	0.000%	(0)	(0)
54	(32)	(9)	(40)	0.196%	(16)	(47)
70	(99)	(12)	(111)	0.272%	(22)	(121)
71	(99)	(12)	(111)	0.271%	(22)	(120)
73	(45)	(5)	(50)	0.123%	(10)	(54)
75	(12)	(3)	(14)	0.061%	(5)	(16)
76	(0)	(0)	(0)	0.000%	(0)	(0)
77	(0)	(0)	(0)	0.000%	(0)	(0)
78	(0)	(0)	(0)	0.000%	(0)	(0)
84	(0)	(0)	(0)	0.000%	(0)	(0)
85	(0)	(0)	(0)	0.000%	(0)	(0)

AMERICAN ELECTRIC POWER COMPANY
ALLOCATION OF SERVICES' CAPITAL REVENUE REQUIREMENT SAVINGS
BY AEP SUBSIDIARY

(IN 000'S)

COMPANY	O & M SAVINGS	CAPITAL SAVINGS	TOTAL SAVINGS	% OF SAVINGS	REV REQ ALLOCATION	O&M/REV SAV TOTAL
98	(144)	(13)	(157)	0.297%	(24)	(168)
XX	(1)	(0)	(1)	0.006%	(0)	(2)
TOTAL REG	(24,919)	(4,438)	(29,356)	100.000%	(7,958)	(32,876)
TOTAL 2009	(25,315)	(4,472)	(29,787)		(8,020)	(33,335)

CENTRAL AND SOUTH WEST SERVICES, INC.
ALLOCATION OF SERVICES' CAPITAL REVENUE REQUIREMENT SAVINGS
BY CSW SUBSIDIARY

1999
(IN 000'S)

COMPANY	O & M SAVINGS	CAPITAL SAVINGS	TOTAL SAVINGS	% OF SAVINGS	REV REQ ALLOCATION	O&M/REV SAV TOTAL
NON-REG						
CSE	(170)	(5)	(175)	16.142%	(1)	(171)
CSI	(17)	(0)	(17)	0.571%	(0)	(17)
DCM	(63)	(4)	(67)	13.484%	(1)	(64)
DCR	(204)	(8)	(213)	26.982%	(2)	(207)
DCT	(140)	(1)	(141)	1.800%	(0)	(140)
DES	(16)	(1)	(17)	3.682%	(0)	(16)
DLL	(14)	(0)	(14)	0.096%	(0)	(14)
ESI	(20)	(1)	(21)	4.554%	(0)	(20)
PMI	(4)	(0)	(4)	0.491%	(0)	(4)
SEE	(541)	(10)	(551)	32.038%	(3)	(544)
TOK	(1)	(0)	(1)	0.159%	(0)	(1)
TOTAL NON-REG	(1,188)	(31)	(1,220)	100.000%	(9)	(1,197)
REGULATED						
CPL	(4,735)	(858)	(5,594)	35.806%	(252)	(4,988)
ECS	(10)	(0)	(11)	0.016%	(0)	(11)
JFP	(11)	(0)	(12)	0.015%	(0)	(11)
LAB	(1)	(0)	(1)	0.001%	(0)	(1)
PSO	(2,869)	(639)	(3,508)	26.659%	(188)	(3,056)
SEP	(3,307)	(601)	(3,907)	25.060%	(176)	(3,483)
WTU	(1,539)	(298)	(1,837)	12.443%	(88)	(1,627)
TOTAL REG	(12,473)	(2,396)	(14,869)	100.000%	(704)	(13,177)
TOTAL 1999	(13,661)	(2,428)	(16,089)		(713)	(14,374)

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CENTRAL AND SOUTH WEST SERVICES, INC.
ALLOCATION OF SERVICES' CAPITAL REVENUE REQUIREMENT SAVINGS
BY CSW SUBSIDIARY

2000
(IN 000'S)

COMPANY	O & M SAVINGS	CAPITAL SAVINGS	TOTAL SAVINGS	% OF SAVINGS	REV REQ ALLOCATION	O&M/REV SAV TOTAL
NON-REG						
CSE	(463)	(24)	(487)	16.636%	(9)	(472)
CSI	(47)	(1)	(48)	0.616%	(0)	(47)
DCM	(178)	(21)	(198)	14.383%	(8)	(186)
DCR	(506)	(44)	(550)	30.836%	(16)	(522)
DCT	(373)	(2)	(375)	1.732%	(1)	(373)
DES	(44)	(6)	(50)	3.857%	(2)	(46)
DLL	(38)	(0)	(38)	0.075%	(0)	(38)
ESI	(54)	(7)	(61)	4.934%	(3)	(57)
PMI	(8)	(1)	(9)	0.563%	(0)	(8)
SEE	(1,701)	(37)	(1,739)	26.185%	(14)	(1,715)
TOK	(2)	(0)	(3)	0.183%	(0)	(2)
TOTAL NON-REG	(3,415)	(143)	(3,557)	100.000%	(53)	(3,468)
REGULATED						
CPL	(12,336)	(4,223)	(16,560)	36.006%	(1,556)	(13,892)
ECS	(23)	(2)	(25)	0.017%	(1)	(23)
JFP	(23)	(2)	(25)	0.015%	(1)	(24)
LAB	(2)	(0)	(2)	0.001%	(0)	(2)
PSO	(7,420)	(3,155)	(10,576)	26.899%	(1,162)	(8,583)
SEP	(8,674)	(2,921)	(11,595)	24.902%	(1,076)	(9,750)
WTU	(4,053)	(1,426)	(5,480)	12.159%	(525)	(4,579)
TOTAL REG	(32,532)	(11,729)	(44,262)	100.000%	(4,321)	(36,853)
TOTAL 2000	(35,947)	(11,872)	(47,819)		(4,374)	(40,321)

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CENTRAL AND SOUTH WEST SERVICES, INC.
ALLOCATION OF SERVICES' CAPITAL REVENUE REQUIREMENT SAVINGS
BY CSW SUBSIDIARY

2001
(IN 000'S)

COMPANY	O & M SAVINGS	CAPITAL SAVINGS	TOTAL SAVINGS	% OF SAVINGS	REV REQ ALLOCATION	O&M/REV SAV TOTAL
NON-REG						
CSE	(556)	(31)	(587)	16.590%	(19)	(575)
CSI	(56)	(1)	(58)	0.622%	(1)	(57)
DCM	(215)	(27)	(242)	14.518%	(17)	(232)
DCR	(603)	(58)	(662)	31.742%	(37)	(640)
DCT	(445)	(3)	(448)	1.677%	(2)	(447)
DES	(53)	(7)	(61)	3.871%	(4)	(58)
DLL	(45)	(0)	(46)	0.066%	(0)	(46)
ESI	(66)	(9)	(75)	4.994%	(6)	(71)
PMI	(10)	(1)	(11)	0.580%	(1)	(10)
SEE	(2,076)	(46)	(2,123)	25.152%	(29)	(2,105)
TOK	(3)	(0)	(3)	0.189%	(0)	(3)
TOTAL NON-REG	(4,130)	(184)	(4,314)	100.000%	(115)	(4,245)
REGULATED						
CPL	(14,566)	(4,691)	(19,257)	35.964%	(2,921)	(17,487)
ECS	(26)	(3)	(29)	0.020%	(2)	(28)
JFP	(27)	(2)	(29)	0.019%	(2)	(28)
LAB	(2)	(0)	(3)	0.001%	(0)	(3)
PSO	(8,704)	(3,487)	(12,191)	26.729%	(2,171)	(10,875)
SEP	(10,194)	(3,256)	(13,450)	24.959%	(2,027)	(12,222)
WTU	(4,789)	(1,606)	(6,395)	12.309%	(1,000)	(5,789)
TOTAL REG	(38,310)	(13,044)	(51,354)	100.000%	(8,122)	(46,432)
TOTAL 2001	(42,439)	(13,229)	(55,668)		(8,237)	(50,676)

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CENTRAL AND SOUTH WEST SERVICES, INC.
ALLOCATION OF SERVICES' CAPITAL REVENUE REQUIREMENT SAVINGS
BY CSW SUBSIDIARY

2002
(IN 000'S)

COMPANY	O & M SAVINGS	CAPITAL SAVINGS	TOTAL SAVINGS	% OF SAVINGS	REV REQ ALLOCATION	O&M/REV SAV TOTAL
NON-REG						
CSE	(587)	(35)	(622)	16.910%	(29)	(616)
CSI	(59)	(1)	(60)	0.628%	(1)	(60)
DCM	(231)	(30)	(261)	14.722%	(25)	(257)
DCR	(643)	(66)	(709)	32.229%	(55)	(699)
DCT	(464)	(3)	(467)	1.676%	(3)	(467)
DES	(58)	(8)	(66)	3.997%	(7)	(65)
DLL	(47)	(0)	(47)	0.065%	(0)	(47)
ESI	(71)	(10)	(81)	5.057%	(9)	(79)
PMI	(10)	(1)	(11)	0.589%	(1)	(11)
SEE	(2,161)	(49)	(2,210)	23.935%	(41)	(2,202)
TOK	(3)	(0)	(3)	0.191%	(0)	(3)
TOTAL NON-REG	(4,335)	(205)	(4,540)	100.000%	(172)	(4,507)
REGULATED						
CPL	(15,310)	(5,196)	(20,506)	35.945%	(4,358)	(19,667)
ECS	(28)	(3)	(31)	0.020%	(2)	(31)
JFP	(29)	(3)	(31)	0.019%	(2)	(31)
LAB	(3)	(0)	(3)	0.001%	(0)	(3)
PSO	(9,172)	(3,869)	(13,041)	26.763%	(3,244)	(12,416)
SEP	(10,743)	(3,609)	(14,352)	24.962%	(3,026)	(13,769)
WTU	(5,063)	(1,777)	(6,839)	12.290%	(1,490)	(6,553)
TOTAL REG	(40,347)	(14,457)	(54,803)	100.000%	(12,123)	(52,470)
TOTAL 2002	(44,681)	(14,662)	(59,343)		(12,295)	(56,976)

CENTRAL AND SOUTH WEST SERVICES, INC.
ALLOCATION OF SERVICES' CAPITAL REVENUE REQUIREMENT SAVINGS
BY CSW SUBSIDIARY

2003
(IN 000'S)

COMPANY	O & M SAVINGS	CAPITAL SAVINGS	TOTAL SAVINGS	% OF SAVINGS	REV REQ ALLOCATION	O&M/REV SAV TOTAL
NON-REG						
CSE	(611)	(36)	(647)	16.867%	(38)	(649)
CSI	(61)	(1)	(63)	0.631%	(1)	(63)
DCM	(241)	(32)	(273)	14.745%	(34)	(275)
DCR	(671)	(70)	(741)	32.503%	(74)	(745)
DCT	(482)	(4)	(486)	1.662%	(4)	(486)
DES	(60)	(9)	(69)	3.994%	(9)	(69)
DLL	(49)	(0)	(49)	0.062%	(0)	(49)
ESI	(74)	(11)	(85)	5.069%	(12)	(85)
PMI	(11)	(1)	(12)	0.594%	(1)	(12)
SEE	(2,247)	(51)	(2,298)	23.679%	(54)	(2,301)
TOK	(3)	(0)	(3)	0.193%	(0)	(4)
TOTAL NON-REG	(4,510)	(216)	(4,726)	100.000%	(228)	(4,738)
REGULATED						
CPL	(15,930)	(5,465)	(21,395)	35.948%	(5,782)	(21,711)
ECS	(29)	(3)	(32)	0.020%	(3)	(33)
JFP	(30)	(3)	(33)	0.019%	(3)	(33)
LAB	(3)	(0)	(3)	0.001%	(0)	(3)
PSO	(9,544)	(4,070)	(13,614)	26.770%	(4,306)	(13,850)
SEP	(11,177)	(3,794)	(14,972)	24.959%	(4,014)	(15,192)
WTU	(5,267)	(1,867)	(7,135)	12.282%	(1,975)	(7,243)
TOTAL REG	(41,980)	(15,203)	(57,183)	100.000%	(16,084)	(58,064)
TOTAL 2003	(46,490)	(15,419)	(61,909)		(16,312)	(62,802)

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CENTRAL AND SOUTH WEST SERVICES, INC.
ALLOCATION OF SERVICES' CAPITAL REVENUE REQUIREMENT SAVINGS
BY CSW SUBSIDIARY

2004
(IN 000'S)

COMPANY	O & M SAVINGS	CAPITAL SAVINGS	TOTAL SAVINGS	% OF SAVINGS	REV REQ ALLOCATION	O&M/REV SAV TOTAL
NON-REG						
CSE	(634)	(38)	(672)	17.004%	(66)	(700)
CSI	(63)	(1)	(65)	0.625%	(2)	(66)
DCM	(249)	(33)	(283)	14.823%	(57)	(307)
DCR	(691)	(72)	(764)	32.368%	(125)	(816)
DCT	(501)	(4)	(505)	1.627%	(6)	(507)
DES	(63)	(9)	(72)	4.030%	(16)	(78)
DLL	(51)	(0)	(51)	0.059%	(0)	(51)
ESI	(76)	(11)	(88)	5.094%	(20)	(96)
PMI	(11)	(1)	(12)	0.592%	(2)	(13)
SEE	(2,333)	(53)	(2,386)	23.586%	(91)	(2,425)
TOK	(3)	(0)	(4)	0.192%	(1)	(4)
TOTAL NON-REG	(4,677)	(223)	(4,901)	100.000%	(386)	(5,063)
REGULATED						
CPL	(16,585)	(3,630)	(20,215)	35.648%	(6,277)	(22,862)
ECS	(30)	(3)	(33)	0.032%	(6)	(36)
JFP	(31)	(3)	(34)	0.029%	(5)	(36)
LAB	(3)	(0)	(3)	0.002%	(0)	(3)
PSO	(9,941)	(2,648)	(12,589)	26.003%	(4,579)	(14,520)
SEP	(11,633)	(2,577)	(14,210)	25.305%	(4,456)	(16,089)
WTU	(5,480)	(1,322)	(6,802)	12.981%	(2,286)	(7,766)
TOTAL REG	(43,703)	(10,183)	(53,886)	100.000%	(17,609)	(61,312)
TOTAL 2004	(48,380)	(10,407)	(58,787)		(17,995)	(66,375)

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CENTRAL AND SOUTH WEST SERVICES, INC.
ALLOCATION OF SERVICES' CAPITAL REVENUE REQUIREMENT SAVINGS
BY CSW SUBSIDIARY

2005
(IN 000'S)

COMPANY	O & M SAVINGS	CAPITAL SAVINGS	TOTAL SAVINGS	% OF SAVINGS	REV REQ ALLOCATION	O&M/REV SAV TOTAL
NON-REG						
CSE	(660)	(40)	(700)	16.964%	(72)	(731)
CSI	(66)	(1)	(67)	0.627%	(3)	(69)
DCM	(260)	(35)	(295)	14.850%	(63)	(323)
DCR	(721)	(77)	(798)	32.643%	(138)	(859)
DCT	(521)	(4)	(525)	1.610%	(7)	(528)
DES	(65)	(9)	(75)	4.028%	(17)	(82)
DLL	(53)	(0)	(53)	0.056%	(0)	(53)
ESI	(80)	(12)	(92)	5.108%	(22)	(101)
PMI	(11)	(1)	(13)	0.597%	(3)	(14)
SEE	(2,426)	(55)	(2,480)	23.324%	(98)	(2,524)
TOK	(3)	(0)	(4)	0.194%	(1)	(4)
TOTAL NON-REG	(4,866)	(235)	(5,101)	100.000%	(422)	(5,288)
REGULATED						
CPL	(17,259)	(3,811)	(21,070)	35.651%	(6,845)	(24,103)
ECS	(31)	(3)	(35)	0.032%	(6)	(38)
JFP	(32)	(3)	(35)	0.030%	(6)	(37)
LAB	(3)	(0)	(3)	0.002%	(0)	(3)
PSO	(10,347)	(2,781)	(13,127)	26.011%	(4,994)	(15,340)
SEP	(12,105)	(2,705)	(14,810)	25.302%	(4,858)	(16,962)
WTU	(5,703)	(1,387)	(7,089)	12.972%	(2,491)	(8,193)
TOTAL REG	(45,479)	(10,690)	(56,169)	100.000%	(19,199)	(64,678)
TOTAL 2005	(50,345)	(10,925)	(61,270)		(19,621)	(69,966)

CENTRAL AND SOUTH WEST SERVICES, INC.
ALLOCATION OF SERVICES' CAPITAL REVENUE REQUIREMENT SAVINGS
BY CSW SUBSIDIARY

2006
(IN 000'S)

COMPANY	O & M SAVINGS	CAPITAL SAVINGS	TOTAL SAVINGS	% OF SAVINGS	REV REQ ALLOCATION	O&M/REV SAV TOTAL
NON-REG						
CSE	(686)	(42)	(728)	17.009%	(88)	(774)
CSI	(68)	(2)	(70)	0.626%	(3)	(72)
DCM	(270)	(37)	(307)	14.903%	(77)	(347)
DCR	(748)	(80)	(828)	32.730%	(169)	(917)
DCT	(541)	(4)	(545)	1.583%	(8)	(550)
DES	(68)	(10)	(78)	4.044%	(21)	(89)
DLL	(55)	(0)	(55)	0.053%	(0)	(56)
ESI	(83)	(13)	(95)	5.127%	(27)	(109)
PMI	(12)	(1)	(13)	0.599%	(3)	(15)
SEE	(2,520)	(57)	(2,577)	23.133%	(120)	(2,640)
TOK	(3)	(0)	(4)	0.195%	(1)	(4)
TOTAL NON-REG	(5,055)	(245)	(5,300)	100.000%	(517)	(5,572)
REGULATED						
CPL	(17,965)	(3,002)	(20,967)	35.387%	(6,336)	(24,301)
ECS	(33)	(4)	(36)	0.042%	(8)	(40)
JFP	(33)	(3)	(36)	0.039%	(7)	(40)
LAB	(3)	(0)	(3)	0.003%	(1)	(3)
PSO	(10,773)	(2,149)	(12,923)	25.336%	(4,536)	(15,310)
SEP	(12,598)	(2,172)	(14,770)	25.607%	(4,585)	(17,183)
WTU	(5,934)	(1,153)	(7,087)	13.586%	(2,433)	(8,367)
TOTAL REG	(47,339)	(8,483)	(55,822)	100.000%	(17,905)	(65,244)
TOTAL 2006	(52,394)	(8,728)	(61,122)		(18,422)	(70,816)

CENTRAL AND SOUTH WEST SERVICES, INC.
ALLOCATION OF SERVICES' CAPITAL REVENUE REQUIREMENT SAVINGS
BY CSW SUBSIDIARY

2007
(IN 000'S)

COMPANY	O & M SAVINGS	CAPITAL SAVINGS	TOTAL SAVINGS	% OF SAVINGS	REV REQ ALLOCATION	O&M/REV SAV TOTAL
NON-REG						
CSE	(713)	(44)	(757)	16.966%	(84)	(797)
CSI	(71)	(2)	(73)	0.628%	(3)	(74)
DCM	(281)	(38)	(320)	14.931%	(74)	(355)
DCR	(780)	(85)	(865)	33.019%	(163)	(943)
DCT	(563)	(4)	(567)	1.564%	(8)	(571)
DES	(70)	(10)	(81)	4.042%	(20)	(90)
DLL	(57)	(0)	(58)	0.050%	(0)	(58)
ESI	(86)	(13)	(99)	5.142%	(25)	(111)
PMI	(12)	(2)	(14)	0.604%	(3)	(15)
SEE	(2,620)	(59)	(2,679)	22.859%	(113)	(2,733)
TOK	(4)	(1)	(4)	0.196%	(1)	(5)
TOTAL NON-REG	(5,259)	(258)	(5,517)	100.000%	(494)	(5,753)
REGULATED						
CPL	(18,696)	(3,147)	(21,843)	35.389%	(6,041)	(24,737)
ECS	(34)	(4)	(38)	0.042%	(7)	(41)
JFP	(34)	(4)	(38)	0.039%	(7)	(41)
LAB	(3)	(0)	(3)	0.003%	(1)	(4)
PSO	(11,213)	(2,254)	(13,467)	25.344%	(4,326)	(15,539)
SEP	(13,109)	(2,277)	(15,386)	25.604%	(4,371)	(17,480)
WTU	(6,175)	(1,207)	(7,383)	13.578%	(2,318)	(8,493)
TOTAL REG	(49,265)	(8,893)	(58,158)	100.000%	(17,070)	(66,335)
TOTAL 2007	(54,524)	(9,150)	(63,675)		(17,564)	(72,088)

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CENTRAL AND SOUTH WEST SERVICES, INC.
ALLOCATION OF SERVICES' CAPITAL REVENUE REQUIREMENT SAVINGS
BY CSW SUBSIDIARY

2008
(IN 000'S)

COMPANY	O & M SAVINGS	CAPITAL SAVINGS	TOTAL SAVINGS	% OF SAVINGS	REV REQ ALLOCATION	O&M/REV SAV TOTAL
NON-REG						
CSE	(743)	(45)	(788)	16.443%	(81)	(824)
CSI	(75)	(2)	(76)	0.635%	(3)	(78)
DCM	(299)	(41)	(340)	15.003%	(74)	(373)
DCR	(846)	(96)	(942)	34.989%	(173)	(1,019)
DCT	(586)	(4)	(590)	1.372%	(7)	(593)
DES	(74)	(11)	(85)	4.001%	(20)	(94)
DLL	(60)	(0)	(60)	0.022%	(0)	(60)
ESI	(92)	(14)	(106)	5.195%	(26)	(117)
PMI	(14)	(2)	(15)	0.641%	(3)	(17)
SEE	(2,726)	(59)	(2,785)	21.491%	(106)	(2,832)
TOK	(4)	(1)	(4)	0.209%	(1)	(5)
TOTAL NON-REG	(5,517)	(276)	(5,792)	100.000%	(494)	(6,011)
REGULATED						
CPL	(19,495)	(3,037)	(22,532)	35.265%	(5,445)	(24,940)
ECS	(37)	(4)	(41)	0.050%	(8)	(44)
JFP	(37)	(4)	(41)	0.046%	(7)	(44)
LAB	(3)	(0)	(4)	0.003%	(1)	(4)
PSO	(11,704)	(2,167)	(13,871)	25.161%	(3,885)	(15,589)
SEP	(13,680)	(2,213)	(15,893)	25.703%	(3,969)	(17,649)
WTU	(6,450)	(1,186)	(7,636)	13.772%	(2,127)	(8,577)
TOTAL REG	(51,406)	(8,611)	(60,018)	100.000%	(15,442)	(66,848)
TOTAL 2008	(56,923)	(8,887)	(65,810)		(15,936)	(72,859)

CENTRAL AND SOUTH WEST SERVICES, INC.
ALLOCATION OF SERVICES' CAPITAL REVENUE REQUIREMENT SAVINGS
BY CSW SUBSIDIARY

2009
(IN 000'S)

COMPANY	O & M SAVINGS	CAPITAL SAVINGS	TOTAL SAVINGS	% OF SAVINGS	REV REQ ALLOCATION	O&M/REV SAV TOTAL
NON-REG						
CSE	(189)	(12)	(201)	4.187%	(21)	(210)
CSI	(19)	(0)	(19)	0.162%	(1)	(20)
DCM	(76)	(11)	(87)	3.821%	(19)	(95)
DCR	(215)	(25)	(240)	8.910%	(44)	(259)
DCT	(149)	(1)	(150)	0.349%	(2)	(151)
DES	(19)	(3)	(22)	1.019%	(5)	(24)
DLL	(15)	(0)	(15)	0.006%	(0)	(15)
ESI	(23)	(4)	(27)	1.323%	(7)	(30)
PMI	(3)	(0)	(4)	0.163%	(1)	(4)
SEE	(694)	(15)	(709)	5.473%	(27)	(721)
TOK	(1)	(0)	(1)	0.053%	(0)	(1)
TOTAL NON-REG	(1,405)	(70)	(1,475)	25.466%	(126)	(1,531)
REGULATED						
CPL	(4,965)	(773)	(5,738)	8.981%	(1,387)	(6,351)
ECS	(9)	(1)	(10)	0.013%	(2)	(11)
JFP	(9)	(1)	(10)	0.012%	(2)	(11)
LAB	(1)	(0)	(1)	0.001%	(0)	(1)
PSO	(2,981)	(552)	(3,532)	6.407%	(989)	(3,970)
SEP	(3,484)	(564)	(4,047)	6.546%	(1,011)	(4,495)
WTU	(1,643)	(302)	(1,945)	3.507%	(542)	(2,184)
TOTAL REG	(13,091)	(2,193)	(15,284)	25.466%	(3,932)	(17,024)
TOTAL 2009	(14,496)	(2,263)	(16,759)		(4,058)	(18,554)

AMERICAN ELECTRIC POWER COMPANY
ALLOCATION OF DIRECT CAPITAL REVENUE REQUIREMENT SAVINGS
BY AEP SUBSIDIARY

(IN 000'S)

COMPANY	O & M SAVINGS	CAPITAL SAVINGS	TOTAL SAVINGS	% OF SAVINGS	REV REQ ALLOCATION	O&M/REV SAV TOTAL
1999						
NON-REG						
25	(39)	0	(39)	0.000%	0	(39)
26	0	0	0	0.000%	0	0
53	0	0	0	0.000%	0	0
56	0	0	0	0.000%	0	0
57	0	0	0	0.000%	0	0
58	(272)	0	(272)	0.000%	0	(272)
59	(476)	0	(476)	0.000%	0	(476)
60	(185)	0	(185)	0.000%	0	(185)
63	0	0	0	0.000%	0	0
64	0	0	0	0.000%	0	0
66	0	0	0	0.000%	0	0
67	(0)	0	(0)	0.000%	0	(0)
69	(298)	0	(298)	0.000%	0	(298)
72	0	0	0	0.000%	0	0
74	(476)	0	(476)	0.000%	0	(476)
81	(118)	0	(118)	0.000%	0	(118)
83	(36)	0	(36)	0.000%	0	(36)
86	(0)	0	(0)	0.000%	0	(0)
87	(2)	0	(2)	0.000%	0	(2)
88	0	0	0	0.000%	0	0
89	0	0	0	0.000%	0	0
90	0	0	0	0.000%	0	0
91	(124)	0	(124)	0.000%	0	(124)
99	0	0	0	0.000%	0	0
TOTAL NON-REG	(2,026)	0	(2,026)	0.000%	0	(2,026)
REGULATED						
01	(76)	(43)	(119)	0.418%	(7)	(83)
02	(3,672)	(2,675)	(6,347)	26.277%	(469)	(4,141)
03	(923)	(676)	(1,599)	6.636%	(118)	(1,041)

AMERICAN ELECTRIC POWER COMPANY
ALLOCATION OF DIRECT CAPITAL REVENUE REQUIREMENT SAVINGS
BY AEP SUBSIDIARY

(IN 000'S)

COMPANY	O & M SAVINGS	CAPITAL SAVINGS	TOTAL SAVINGS	% OF SAVINGS	REV REQ ALLOCATION	O&M/REV SAV TOTAL
04	(2,783)	(1,973)	(4,755)	19.379%	(346)	(3,128)
06	(85)	(48)	(133)	0.473%	(8)	(94)
07	(3,964)	(3,251)	(7,215)	31.931%	(570)	(4,534)
10	(2,017)	(1,363)	(3,380)	13.389%	(239)	(2,256)
21	0	0	0	0.000%	0	0
22	0	0	0	0.000%	0	0
23	0	0	0	0.000%	0	0
31	0	0	0	0.000%	0	0
32	0	0	0	0.000%	0	0
34	0	0	0	0.000%	0	0
40	0	0	0	0.000%	0	0
41	0	0	0	0.000%	0	0
42	(8)	0	(8)	0.000%	0	(8)
43	(12)	0	(12)	0.000%	0	(12)
44	(63)	0	(63)	0.000%	0	(63)
45	0	0	0	0.000%	0	0
46	0	0	0	0.000%	0	0
48	(6)	0	(6)	0.000%	0	(6)
49	(1)	0	(1)	0.000%	0	(1)
50	0	0	0	0.000%	0	0
51	0	0	0	0.000%	0	0
52	0	0	0	0.000%	0	0
54	(1)	0	(1)	0.000%	0	(1)
70	0	0	0	0.000%	0	0
71	0	0	0	0.000%	0	0
73	0	0	0	0.000%	0	0
75	0	0	0	0.000%	0	0
76	0	0	0	0.000%	0	0
77	0	0	0	0.000%	0	0
78	0	0	0	0.000%	0	0
84	0	0	0	0.000%	0	0
85	0	0	0	0.000%	0	0

AMERICAN ELECTRIC POWER COMPANY
ALLOCATION OF DIRECT CAPITAL REVENUE REQUIREMENT SAVINGS
BY AEP SUBSIDIARY

(IN 000'S)

COMPANY	O & M SAVINGS	CAPITAL SAVINGS	TOTAL SAVINGS	% OF SAVINGS	REV REQ ALLOCATION	O&M/REV SAV TOTAL
98	(130)	(152)	(282)	1.497%	(27)	(157)
XX	0	0	0	0.000%	0	0
TOTAL REG	(13,742)	(10,181)	(23,923)	100.000%	(1,784)	(15,526)
TOTAL 1999	(15,768)	(10,181)	(25,949)		(1,784)	(17,552)

AMERICAN ELECTRIC POWER COMPANY
ALLOCATION OF DIRECT CAPITAL REVENUE REQUIREMENT SAVINGS
BY AEP SUBSIDIARY

(IN 000'S)

COMPANY	O & M SAVINGS	CAPITAL SAVINGS	TOTAL SAVINGS	% OF SAVINGS	REV REQ ALLOCATION	O&M/REV SAV TOTAL
2000						
NON-REG						
25	(54)	0	(54)	0.000%	0	(54)
26	0	0	0	0.000%	0	0
53	0	0	0	0.000%	0	0
56	0	0	0	0.000%	0	0
57	0	0	0	0.000%	0	0
58	(381)	0	(381)	0.000%	0	(381)
59	(667)	0	(667)	0.000%	0	(667)
60	(254)	0	(254)	0.000%	0	(254)
63	0	0	0	0.000%	0	0
64	0	0	0	0.000%	0	0
66	0	0	0	0.000%	0	0
67	(0)	0	(0)	0.000%	0	(0)
69	(417)	0	(417)	0.000%	0	(417)
72	0	0	0	0.000%	0	0
74	(667)	0	(667)	0.000%	0	(667)
81	(165)	0	(165)	0.000%	0	(165)
83	(50)	0	(50)	0.000%	0	(50)
86	(0)	0	(0)	0.000%	0	(0)
87	(3)	0	(3)	0.000%	0	(3)
88	0	0	0	0.000%	0	0
89	0	0	0	0.000%	0	0
90	0	0	0	0.000%	0	0
91	(173)	0	(173)	0.000%	0	(173)
99	0	0	0	0.000%	0	0
TOTAL NON-REG	(2,832)	0	(2,832)	0.000%	0	(2,832)
REGULATED						
01	(128)	(67)	(195)	0.461%	(20)	(148)
02	(5,556)	(3,854)	(9,410)	26.405%	(1,140)	(6,696)
03	(1,369)	(963)	(2,331)	6.596%	(285)	(1,653)

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AMERICAN ELECTRIC POWER COMPANY
ALLOCATION OF DIRECT CAPITAL REVENUE REQUIREMENT SAVINGS
BY AEP SUBSIDIARY

(IN 000'S)

COMPANY	O & M SAVINGS	CAPITAL SAVINGS	TOTAL SAVINGS	% OF SAVINGS	REV REQ ALLOCATION	O&M/REV SAV TOTAL
04	(4,195)	(2,824)	(7,019)	19.346%	(835)	(5,030)
06	(140)	(75)	(215)	0.511%	(22)	(162)
07	(5,854)	(4,606)	(10,460)	31.555%	(1,363)	(7,217)
10	(3,124)	(1,998)	(5,123)	13.692%	(591)	(3,716)
21	0	0	0	0.000%	0	0
22	0	0	0	0.000%	0	0
23	0	0	0	0.000%	0	0
31	0	0	0	0.000%	0	0
32	0	0	0	0.000%	0	0
34	0	0	0	0.000%	0	0
40	0	0	0	0.000%	0	0
41	0	0	0	0.000%	0	0
42	(12)	0	(12)	0.000%	0	(12)
43	(16)	0	(16)	0.000%	0	(16)
44	(88)	0	(88)	0.000%	0	(88)
45	0	0	0	0.000%	0	0
46	0	0	0	0.000%	0	0
48	(9)	0	(9)	0.000%	0	(9)
49	(2)	0	(2)	0.000%	0	(2)
50	0	0	0	0.000%	0	0
51	0	0	0	0.000%	0	0
52	0	0	0	0.000%	0	0
54	(1)	0	(1)	0.000%	0	(1)
70	0	0	0	0.000%	0	0
71	0	0	0	0.000%	0	0
73	0	0	0	0.000%	0	0
75	0	0	0	0.000%	0	0
76	0	0	0	0.000%	0	0
77	0	0	0	0.000%	0	0
78	0	0	0	0.000%	0	0
84	0	0	0	0.000%	0	0
85	0	0	0	0.000%	0	0

AMERICAN ELECTRIC POWER COMPANY
ALLOCATION OF DIRECT CAPITAL REVENUE REQUIREMENT SAVINGS
BY AEP SUBSIDIARY

(IN 000'S)

COMPANY	O & M SAVINGS	CAPITAL SAVINGS	TOTAL SAVINGS	% OF SAVINGS	REV REQ ALLOCATION	O&M/REV SAV TOTAL
98	(180)	(209)	(389)	1.435%	(62)	(242)
XX	0	0	0	0.000%	0	0
TOTAL REG	(20,674)	(14,596)	(35,271)	100.000%	(4,318)	(24,992)
TOTAL 2000	(23,506)	(14,596)	(38,103)		(4,318)	(27,824)

AMERICAN ELECTRIC POWER COMPANY
ALLOCATION OF DIRECT CAPITAL REVENUE REQUIREMENT SAVINGS
BY AEP SUBSIDIARY

(IN 000'S)

COMPANY	O & M SAVINGS	CAPITAL SAVINGS	TOTAL SAVINGS	% OF SAVINGS	REV REQ ALLOCATION	O&M/REV SAV TOTAL
2001						
NON-REG						
25	(57)	0	(57)	0.000%	0	(57)
26	0	0	0	0.000%	0	0
53	0	0	0	0.000%	0	0
56	0	0	0	0.000%	0	0
57	0	0	0	0.000%	0	0
58	(400)	0	(400)	0.000%	0	(400)
59	(700)	0	(700)	0.000%	0	(700)
60	(262)	0	(262)	0.000%	0	(262)
63	0	0	0	0.000%	0	0
64	0	0	0	0.000%	0	0
66	0	0	0	0.000%	0	0
67	(0)	0	(0)	0.000%	0	(0)
69	(437)	0	(437)	0.000%	0	(437)
72	0	0	0	0.000%	0	0
74	(700)	0	(700)	0.000%	0	(700)
81	(173)	0	(173)	0.000%	0	(173)
83	(52)	0	(52)	0.000%	0	(52)
86	(0)	0	(0)	0.000%	0	(0)
87	(3)	0	(3)	0.000%	0	(3)
88	0	0	0	0.000%	0	0
89	0	0	0	0.000%	0	0
90	0	0	0	0.000%	0	0
91	(182)	0	(182)	0.000%	0	(182)
99	0	0	0	0.000%	0	0
TOTAL NON-REG	(2,968)	0	(2,968)	0.000%	0	(2,968)
REGULATED						
01	(137)	(92)	(228)	0.433%	(34)	(170)
02	(5,844)	(5,582)	(11,426)	26.319%	(2,049)	(7,893)
03	(1,436)	(1,405)	(2,841)	6.622%	(516)	(1,952)

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AMERICAN ELECTRIC POWER COMPANY
ALLOCATION OF DIRECT CAPITAL REVENUE REQUIREMENT SAVINGS
BY AEP SUBSIDIARY

(IN 000'S)

COMPANY	O & M SAVINGS	CAPITAL SAVINGS	TOTAL SAVINGS	% OF SAVINGS	REV REQ ALLOCATION	O&M/REV SAV TOTAL
04	(4,405)	(4,107)	(8,512)	19.365%	(1,508)	(5,913)
06	(149)	(103)	(252)	0.485%	(38)	(187)
07	(6,139)	(6,745)	(12,884)	31.802%	(2,476)	(8,615)
10	(3,295)	(2,863)	(6,158)	13.497%	(1,051)	(4,346)
21	0	0	0	0.000%	0	0
22	0	0	0	0.000%	0	0
23	0	0	0	0.000%	0	0
31	0	0	0	0.000%	0	0
32	0	0	0	0.000%	0	0
34	0	0	0	0.000%	0	0
40	0	0	0	0.000%	0	0
41	0	0	0	0.000%	0	0
42	(12)	0	(12)	0.000%	0	(12)
43	(17)	0	(17)	0.000%	0	(17)
44	(91)	0	(91)	0.000%	0	(91)
45	0	0	0	0.000%	0	0
46	0	0	0	0.000%	0	0
48	(9)	0	(9)	0.000%	0	(9)
49	(2)	0	(2)	0.000%	0	(2)
50	0	0	0	0.000%	0	0
51	0	0	0	0.000%	0	0
52	0	0	0	0.000%	0	0
54	(1)	0	(1)	0.000%	0	(1)
70	0	0	0	0.000%	0	0
71	0	0	0	0.000%	0	0
73	0	0	0	0.000%	0	0
75	0	0	0	0.000%	0	0
76	0	0	0	0.000%	0	0
77	0	0	0	0.000%	0	0
78	0	0	0	0.000%	0	0
84	0	0	0	0.000%	0	0
85	0	0	0	0.000%	0	0

AMERICAN ELECTRIC POWER COMPANY
ALLOCATION OF DIRECT CAPITAL REVENUE REQUIREMENT SAVINGS
BY AEP SUBSIDIARY

(IN 000'S)

COMPANY	O & M SAVINGS	CAPITAL SAVINGS	TOTAL SAVINGS	% OF SAVINGS	REV REQ ALLOCATION	O&M/REV SAV TOTAL
98	(187)	(313)	(500)	1.477%	(115)	(302)
XX	0	0	0	0.000%	0	0
TOTAL REG	(21,724)	(21,209)	(42,934)	100.000%	(7,787)	(29,511)
TOTAL 2001	(24,692)	(21,209)	(45,902)		(7,787)	(32,479)

AMERICAN ELECTRIC POWER COMPANY
ALLOCATION OF DIRECT CAPITAL REVENUE REQUIREMENT SAVINGS
BY AEP SUBSIDIARY

(IN 000'S)

COMPANY	O & M SAVINGS	CAPITAL SAVINGS	TOTAL SAVINGS	% OF SAVINGS	REV REQ ALLOCATION	O&M/REV SAV TOTAL
2002						
NON-REG						
25	(60)	0	(60)	0.000%	0	(60)
26	0	0	0	0.000%	0	0
53	0	0	0	0.000%	0	0
56	0	0	0	0.000%	0	0
57	0	0	0	0.000%	0	0
58	(420)	0	(420)	0.000%	0	(420)
59	(735)	0	(735)	0.000%	0	(735)
60	(270)	0	(270)	0.000%	0	(270)
63	0	0	0	0.000%	0	0
64	0	0	0	0.000%	0	0
66	0	0	0	0.000%	0	0
67	(0)	0	(0)	0.000%	0	(0)
69	(460)	(0)	(460)	100.000%	0	(460)
72	0	0	0	0.000%	0	0
74	(735)	0	(735)	0.000%	0	(735)
81	(182)	0	(182)	0.000%	0	(182)
83	(55)	0	(55)	0.000%	0	(55)
86	(0)	0	(0)	0.000%	0	(0)
87	(3)	0	(3)	0.000%	0	(3)
88	0	0	0	0.000%	0	0
89	0	0	0	0.000%	0	0
90	0	0	0	0.000%	0	0
91	(191)	0	(191)	0.000%	0	(191)
99	0	0	0	0.000%	0	0
TOTAL NON-REG	(3,111)	(0)	(3,112)	100.000%	0	(3,111)
REGULATED						
01	(173)	(81)	(254)	0.480%	(51)	(224)
02	(7,456)	(4,527)	(11,983)	26.681%	(2,843)	(10,299)
03	(1,784)	(1,114)	(2,899)	6.566%	(700)	(2,484)

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AMERICAN ELECTRIC POWER COMPANY
ALLOCATION OF DIRECT CAPITAL REVENUE REQUIREMENT SAVINGS
BY AEP SUBSIDIARY

(IN 000'S)

COMPANY	O & M SAVINGS	CAPITAL SAVINGS	TOTAL SAVINGS	% OF SAVINGS	REV REQ ALLOCATION	O&M/REV SAV TOTAL
04	(5,627)	(3,327)	(8,953)	19.605%	(2,089)	(7,716)
06	(189)	(90)	(279)	0.531%	(57)	(245)
07	(7,466)	(5,235)	(12,701)	30.850%	(3,287)	(10,753)
10	(4,073)	(2,329)	(6,402)	13.727%	(1,463)	(5,535)
21	0	0	0	0.000%	0	0
22	0	0	0	0.000%	0	0
23	0	0	0	0.000%	0	0
31	0	0	0	0.000%	0	0
32	0	0	0	0.000%	0	0
34	0	0	0	0.000%	0	0
40	0	0	0	0.000%	0	0
41	0	0	0	0.000%	0	0
42	(29)	(5)	(34)	0.029%	(3)	(32)
43	(32)	(4)	(37)	0.025%	(3)	(35)
44	(162)	(20)	(181)	0.117%	(12)	(174)
45	0	0	0	0.000%	0	0
46	0	0	0	0.000%	0	0
48	(48)	(11)	(59)	0.068%	(7)	(55)
49	(2)	0	(2)	0.000%	0	(2)
50	0	0	0	0.000%	0	0
51	0	0	0	0.000%	0	0
52	0	0	0	0.000%	0	0
54	(6)	(1)	(8)	0.008%	(1)	(7)
70	0	0	0	0.000%	0	0
71	0	0	0	0.000%	0	0
73	0	0	0	0.000%	0	0
75	0	0	0	0.000%	0	0
76	0	0	0	0.000%	0	0
77	0	0	0	0.000%	0	0
78	0	0	0	0.000%	0	0
84	0	0	0	0.000%	0	0
85	0	0	0	0.000%	0	0

AMERICAN ELECTRIC POWER COMPANY
ALLOCATION OF DIRECT CAPITAL REVENUE REQUIREMENT SAVINGS
BY AEP SUBSIDIARY

(IN 000'S)

COMPANY	O & M SAVINGS	CAPITAL SAVINGS	TOTAL SAVINGS	% OF SAVINGS	REV REQ ALLOCATION	O&M/REV SAV TOTAL
98	(194)	(223)	(417)	1.313%	(140)	(334)
XX	0	0	0	0.000%	0	0
TOTAL REG	(27,242)	(16,968)	(44,210)	100.000%	(10,654)	(37,896)
TOTAL 2002	(30,353)	(16,968)	(47,322)		(10,654)	(41,007)

AMERICAN ELECTRIC POWER COMPANY
ALLOCATION OF DIRECT CAPITAL REVENUE REQUIREMENT SAVINGS
BY AEP SUBSIDIARY

(IN 000'S)

COMPANY	O & M SAVINGS	CAPITAL SAVINGS	TOTAL SAVINGS	% OF SAVINGS	REV REQ ALLOCATION	O&M/REV SAV TOTAL
2003						
NON-REG						
25	(63)	0	(63)	0.000%	0	(63)
26	0	0	0	0.000%	0	0
53	0	0	0	0.000%	0	0
56	0	0	0	0.000%	0	0
57	0	0	0	0.000%	0	0
58	(441)	0	(441)	0.000%	0	(441)
59	(772)	0	(772)	0.000%	0	(772)
60	(278)	0	(278)	0.000%	0	(278)
63	0	0	0	0.000%	0	0
64	0	0	0	0.000%	0	0
66	0	0	0	0.000%	0	0
67	(0)	0	(0)	0.000%	0	(0)
69	(483)	(0)	(483)	100.000%	0	(483)
72	0	0	0	0.000%	0	0
74	(772)	0	(772)	0.000%	0	(772)
81	(191)	0	(191)	0.000%	0	(191)
83	(58)	0	(58)	0.000%	0	(58)
86	(0)	0	(0)	0.000%	0	(0)
87	(3)	0	(3)	0.000%	0	(3)
88	0	0	0	0.000%	0	0
89	0	0	0	0.000%	0	0
90	0	0	0	0.000%	0	0
91	(201)	0	(201)	0.000%	0	(201)
99	0	0	0	0.000%	0	0
TOTAL NON-REG	(3,262)	(0)	(3,262)	100.000%	0	(3,262)
REGULATED						
01	(180)	(84)	(264)	0.481%	(65)	(244)
02	(7,756)	(4,677)	(12,433)	26.685%	(3,590)	(11,346)
03	(1,856)	(1,151)	(3,007)	6.565%	(883)	(2,739)

AMERICAN ELECTRIC POWER COMPANY
ALLOCATION OF DIRECT CAPITAL REVENUE REQUIREMENT SAVINGS
BY AEP SUBSIDIARY

(IN 000'S)

COMPANY	O & M SAVINGS	CAPITAL SAVINGS	TOTAL SAVINGS	% OF SAVINGS	REV REQ ALLOCATION	O&M/REV SAV TOTAL
04	(5,853)	(3,436)	(9,289)	19.605%	(2,637)	(8,490)
06	(197)	(93)	(290)	0.532%	(72)	(268)
07	(7,766)	(5,405)	(13,170)	30.838%	(4,148)	(11,914)
10	(4,236)	(2,407)	(6,643)	13.734%	(1,847)	(6,084)
21	0	0	0	0.000%	0	0
22	0	0	0	0.000%	0	0
23	0	0	0	0.000%	0	0
31	0	0	0	0.000%	0	0
32	0	0	0	0.000%	0	0
34	0	0	0	0.000%	0	0
40	0	0	0	0.000%	0	0
41	0	0	0	0.000%	0	0
42	(30)	(5)	(36)	0.029%	(4)	(34)
43	(34)	(4)	(38)	0.026%	(3)	(37)
44	(168)	(21)	(189)	0.118%	(16)	(184)
45	0	0	0	0.000%	0	0
46	0	0	0	0.000%	0	0
48	(50)	(12)	(62)	0.068%	(9)	(59)
49	(2)	0	(2)	0.000%	0	(2)
50	0	0	0	0.000%	0	0
51	0	0	0	0.000%	0	0
52	0	0	0	0.000%	0	0
54	(6)	(1)	(8)	0.008%	(1)	(8)
70	0	0	0	0.000%	0	0
71	0	0	0	0.000%	0	0
73	0	0	0	0.000%	0	0
75	0	0	0	0.000%	0	0
76	0	0	0	0.000%	0	0
77	0	0	0	0.000%	0	0
78	0	0	0	0.000%	0	0
84	0	0	0	0.000%	0	0
85	0	0	0	0.000%	0	0

AMERICAN ELECTRIC POWER COMPANY
ALLOCATION OF DIRECT CAPITAL REVENUE REQUIREMENT SAVINGS
BY AEP SUBSIDIARY

(IN 000'S)

COMPANY	O & M SAVINGS	CAPITAL SAVINGS	TOTAL SAVINGS	% OF SAVINGS	REV REQ ALLOCATION	O&M/REV SAV TOTAL
98	(202)	(230)	(432)	1.311%	(176)	(378)
XX	0	0	0	0.000%	0	0
TOTAL REG	(28,335)	(17,526)	(45,861)	100.000%	(13,452)	(41,787)
TOTAL 2003	(31,597)	(17,526)	(49,124)		(13,452)	(45,049)

AMERICAN ELECTRIC POWER COMPANY
ALLOCATION OF DIRECT CAPITAL REVENUE REQUIREMENT SAVINGS
BY AEP SUBSIDIARY

(IN 000'S)

COMPANY	O & M SAVINGS	CAPITAL SAVINGS	TOTAL SAVINGS	% OF SAVINGS	REV REQ ALLOCATION	O&M/REV SAV TOTAL
2004						
NON-REG						
25	(66)	0	(66)	0.000%	0	(66)
26	0	0	0	0.000%	0	0
53	0	0	0	0.000%	0	0
56	0	0	0	0.000%	0	0
57	0	0	0	0.000%	0	0
58	(463)	0	(463)	0.000%	0	(463)
59	(811)	0	(811)	0.000%	0	(811)
60	(287)	0	(287)	0.000%	0	(287)
63	0	0	0	0.000%	0	0
64	0	0	0	0.000%	0	0
66	0	0	0	0.000%	0	0
67	(0)	0	(0)	0.000%	0	(0)
69	(507)	(0)	(507)	100.000%	0	(507)
72	0	0	0	0.000%	0	0
74	(811)	0	(811)	0.000%	0	(811)
81	(201)	0	(201)	0.000%	0	(201)
83	(60)	0	(60)	0.000%	0	(60)
86	(0)	0	(0)	0.000%	0	(0)
87	(3)	0	(3)	0.000%	0	(3)
88	0	0	0	0.000%	0	0
89	0	0	0	0.000%	0	0
90	0	0	0	0.000%	0	0
91	(211)	0	(211)	0.000%	0	(211)
99	0	0	0	0.000%	0	0
TOTAL NON-REG	(3,419)	(0)	(3,419)	100.000%	0	(3,419)
REGULATED						
01	(187)	(87)	(274)	0.482%	(78)	(265)
02	(8,068)	(4,832)	(12,900)	26.689%	(4,338)	(12,406)
03	(1,931)	(1,188)	(3,119)	6.564%	(1,067)	(2,998)

AMERICAN ELECTRIC POWER COMPANY
ALLOCATION OF DIRECT CAPITAL REVENUE REQUIREMENT SAVINGS
BY AEP SUBSIDIARY

(IN 000'S)

COMPANY	O & M SAVINGS	CAPITAL SAVINGS	TOTAL SAVINGS	% OF SAVINGS	REV REQ ALLOCATION	O&M/REV SAV TOTAL
04	(6,089)	(3,550)	(9,639)	19.608%	(3,187)	(9,276)
06	(205)	(96)	(301)	0.533%	(87)	(291)
07	(8,078)	(5,580)	(13,658)	30.825%	(5,010)	(13,088)
10	(4,406)	(2,487)	(6,894)	13.740%	(2,233)	(6,640)
21	0	0	0	0.000%	0	0
22	0	0	0	0.000%	0	0
23	0	0	0	0.000%	0	0
31	0	0	0	0.000%	0	0
32	0	0	0	0.000%	0	0
34	0	0	0	0.000%	0	0
40	0	0	0	0.000%	0	0
41	0	0	0	0.000%	0	0
42	(32)	(5)	(37)	0.030%	(5)	(37)
43	(35)	(5)	(40)	0.026%	(4)	(39)
44	(175)	(22)	(197)	0.119%	(19)	(195)
45	0	0	0	0.000%	0	0
46	0	0	0	0.000%	0	0
48	(52)	(12)	(64)	0.068%	(11)	(63)
49	(2)	0	(2)	0.000%	0	(2)
50	0	0	0	0.000%	0	0
51	0	0	0	0.000%	0	0
52	0	0	0	0.000%	0	0
54	(7)	(2)	(8)	0.008%	(1)	(8)
70	0	0	0	0.000%	0	0
71	0	0	0	0.000%	0	0
73	0	0	0	0.000%	0	0
75	0	0	0	0.000%	0	0
76	0	0	0	0.000%	0	0
77	0	0	0	0.000%	0	0
78	0	0	0	0.000%	0	0
84	0	0	0	0.000%	0	0
85	0	0	0	0.000%	0	0

AMERICAN ELECTRIC POWER COMPANY
ALLOCATION OF DIRECT CAPITAL REVENUE REQUIREMENT SAVINGS
BY AEP SUBSIDIARY

(IN 000'S)

COMPANY	O & M SAVINGS	CAPITAL SAVINGS	TOTAL SAVINGS	% OF SAVINGS	REV REQ ALLOCATION	O&M/REV SAV TOTAL
98	(210)	(237)	(447)	1.309%	(213)	(422)
XX	0	0	0	0.000%	0	0
TOTAL REG	(29,476)	(18,104)	(47,580)	100.000%	(16,254)	(45,730)
TOTAL 2004	(32,896)	(18,104)	(50,999)		(16,254)	(49,150)

AMERICAN ELECTRIC POWER COMPANY
ALLOCATION OF DIRECT CAPITAL REVENUE REQUIREMENT SAVINGS
BY AEP SUBSIDIARY

(IN 000'S)

COMPANY	O & M SAVINGS	CAPITAL SAVINGS	TOTAL SAVINGS	% OF SAVINGS	REV REQ ALLOCATION	O&M/REV SAV TOTAL
2005						
NON-REG						
25	(69)	0	(69)	0.000%	0	(69)
26	0	0	0	0.000%	0	0
53	0	0	0	0.000%	0	0
56	0	0	0	0.000%	0	0
57	0	0	0	0.000%	0	0
58	(486)	0	(486)	0.000%	0	(486)
59	(851)	0	(851)	0.000%	0	(851)
60	(295)	0	(295)	0.000%	0	(295)
63	0	0	0	0.000%	0	0
64	0	0	0	0.000%	0	0
66	0	0	0	0.000%	0	0
67	(0)	0	(0)	0.000%	0	(0)
69	(532)	(0)	(532)	100.000%	0	(532)
72	0	0	0	0.000%	0	0
74	(851)	0	(851)	0.000%	0	(851)
81	(211)	0	(211)	0.000%	0	(211)
83	(64)	0	(64)	0.000%	0	(64)
86	(0)	0	(0)	0.000%	0	(0)
87	(3)	0	(3)	0.000%	0	(3)
88	0	0	0	0.000%	0	0
89	0	0	0	0.000%	0	0
90	0	0	0	0.000%	0	0
91	(221)	0	(221)	0.000%	0	(221)
99	0	0	0	0.000%	0	0
TOTAL NON-REG	(3,584)	(0)	(3,585)	100.000%	0	(3,584)
REGULATED						
01	(194)	(90)	(285)	0.483%	(92)	(286)
02	(8,393)	(4,992)	(13,385)	26.694%	(5,089)	(13,482)
03	(2,008)	(1,227)	(3,236)	6.563%	(1,251)	(3,259)

AMERICAN ELECTRIC POWER COMPANY
ALLOCATION OF DIRECT CAPITAL REVENUE REQUIREMENT SAVINGS
BY AEP SUBSIDIARY

(IN 000'S)

COMPANY	O & M SAVINGS	CAPITAL SAVINGS	TOTAL SAVINGS	% OF SAVINGS	REV REQ ALLOCATION	O&M/REV SAV TOTAL
04	(6,334)	(3,667)	(10,001)	19.609%	(3,738)	(10,072)
06	(213)	(100)	(313)	0.534%	(102)	(315)
07	(8,402)	(5,762)	(14,165)	30.813%	(5,874)	(14,276)
10	(4,583)	(2,571)	(7,154)	13.746%	(2,620)	(7,204)
21	0	0	0	0.000%	0	0
22	0	0	0	0.000%	0	0
23	0	0	0	0.000%	0	0
31	0	0	0	0.000%	0	0
32	0	0	0	0.000%	0	0
34	0	0	0	0.000%	0	0
40	0	0	0	0.000%	0	0
41	0	0	0	0.000%	0	0
42	(33)	(6)	(39)	0.030%	(6)	(39)
43	(37)	(5)	(42)	0.026%	(5)	(42)
44	(183)	(22)	(205)	0.120%	(23)	(206)
45	0	0	0	0.000%	0	0
46	0	0	0	0.000%	0	0
48	(54)	(13)	(67)	0.069%	(13)	(67)
49	(2)	0	(2)	0.000%	0	(2)
50	0	0	0	0.000%	0	0
51	0	0	0	0.000%	0	0
52	0	0	0	0.000%	0	0
54	(7)	(2)	(9)	0.008%	(2)	(9)
70	0	0	0	0.000%	0	0
71	0	0	0	0.000%	0	0
73	0	0	0	0.000%	0	0
75	0	0	0	0.000%	0	0
76	0	0	0	0.000%	0	0
77	0	0	0	0.000%	0	0
78	0	0	0	0.000%	0	0
84	0	0	0	0.000%	0	0
85	0	0	0	0.000%	0	0

AMERICAN ELECTRIC POWER COMPANY
ALLOCATION OF DIRECT CAPITAL REVENUE REQUIREMENT SAVINGS
BY AEP SUBSIDIARY

(IN 000'S)

COMPANY	O & M SAVINGS	CAPITAL SAVINGS	TOTAL SAVINGS	% OF SAVINGS	REV REQ ALLOCATION	O&M/REV SAV TOTAL
98	(218)	(244)	(462)	1.307%	(249)	(467)
XX	0	0	0	0.000%	0	0
TOTAL REG	(30,662)	(18,701)	(49,363)	100.000%	(19,063)	(49,725)
TOTAL 2005	(34,246)	(18,701)	(52,947)		(19,063)	(53,309)

AMERICAN ELECTRIC POWER COMPANY
ALLOCATION OF DIRECT CAPITAL REVENUE REQUIREMENT SAVINGS
BY AEP SUBSIDIARY

(IN 000'S)

COMPANY	O & M SAVINGS	CAPITAL SAVINGS	TOTAL SAVINGS	% OF SAVINGS	REV REQ ALLOCATION	O&M/REV SAV TOTAL
2006						
NON-REG						
25	(73)	0	(73)	0.000%	0	(73)
26	0	0	0	0.000%	0	0
53	0	0	0	0.000%	0	0
56	0	0	0	0.000%	0	0
57	0	0	0	0.000%	0	0
58	(511)	0	(511)	0.000%	0	(511)
59	(894)	0	(894)	0.000%	0	(894)
60	(304)	0	(304)	0.000%	0	(304)
63	0	0	0	0.000%	0	0
64	0	0	0	0.000%	0	0
66	0	0	0	0.000%	0	0
67	(0)	0	(0)	0.000%	0	(0)
69	(559)	(0)	(559)	100.000%	0	(559)
72	0	0	0	0.000%	0	0
74	(894)	0	(894)	0.000%	0	(894)
81	(221)	0	(221)	0.000%	0	(221)
83	(67)	0	(67)	0.000%	0	(67)
86	(0)	0	(0)	0.000%	0	(0)
87	(4)	0	(4)	0.000%	0	(4)
88	0	0	0	0.000%	0	0
89	0	0	0	0.000%	0	0
90	0	0	0	0.000%	0	0
91	(232)	0	(232)	0.000%	0	(232)
99	0	0	0	0.000%	0	0
TOTAL NON-REG	(3,758)	(0)	(3,758)	100.000%	0	(3,758)
REGULATED						
01	(202)	(93)	(296)	0.483%	(106)	(308)
02	(8,732)	(5,158)	(13,889)	26.699%	(5,842)	(14,574)
03	(2,089)	(1,268)	(3,357)	6.562%	(1,436)	(3,525)

AMERICAN ELECTRIC POWER COMPANY
ALLOCATION OF DIRECT CAPITAL REVENUE REQUIREMENT SAVINGS
BY AEP SUBSIDIARY

(IN 000'S)

COMPANY	O & M SAVINGS	CAPITAL SAVINGS	TOTAL SAVINGS	% OF SAVINGS	REV REQ ALLOCATION	O&M/REV SAV TOTAL
04	(6,589)	(3,788)	(10,377)	19.609%	(4,291)	(10,880)
06	(221)	(103)	(325)	0.535%	(117)	(338)
07	(8,740)	(5,950)	(14,690)	30.802%	(6,740)	(15,480)
10	(4,768)	(2,657)	(7,424)	13.751%	(3,009)	(7,777)
21	0	0	0	0.000%	0	0
22	0	0	0	0.000%	0	0
23	0	0	0	0.000%	0	0
31	0	0	0	0.000%	0	0
32	0	0	0	0.000%	0	0
34	0	0	0	0.000%	0	0
40	0	0	0	0.000%	0	0
41	0	0	0	0.000%	0	0
42	(35)	(6)	(40)	0.030%	(7)	(41)
43	(38)	(5)	(43)	0.026%	(6)	(44)
44	(190)	(23)	(214)	0.120%	(26)	(217)
45	0	0	0	0.000%	0	0
46	0	0	0	0.000%	0	0
48	(56)	(13)	(70)	0.069%	(15)	(72)
49	(2)	0	(2)	0.000%	0	(2)
50	0	0	0	0.000%	0	0
51	0	0	0	0.000%	0	0
52	0	0	0	0.000%	0	0
54	(7)	(2)	(9)	0.009%	(2)	(9)
70	0	0	0	0.000%	0	0
71	0	0	0	0.000%	0	0
73	0	0	0	0.000%	0	0
75	0	0	0	0.000%	0	0
76	0	0	0	0.000%	0	0
77	0	0	0	0.000%	0	0
78	0	0	0	0.000%	0	0
84	0	0	0	0.000%	0	0
85	0	0	0	0.000%	0	0

AMERICAN ELECTRIC POWER COMPANY
ALLOCATION OF DIRECT CAPITAL REVENUE REQUIREMENT SAVINGS
BY AEP SUBSIDIARY

(IN 000'S)

COMPANY	O & M SAVINGS	CAPITAL SAVINGS	TOTAL SAVINGS	% OF SAVINGS	REV REQ ALLOCATION	O&M/REV SAV TOTAL
98	(227)	(252)	(479)	1.305%	(285)	(512)
XX	0	0	0	0.000%	0	0
TOTAL REG	(31,897)	(19,318)	(51,215)	100.000%	(21,882)	(53,779)
TOTAL 2006	(35,655)	(19,318)	(54,974)		(21,882)	(57,537)

AMERICAN ELECTRIC POWER COMPANY
ALLOCATION OF DIRECT CAPITAL REVENUE REQUIREMENT SAVINGS
BY AEP SUBSIDIARY

(IN 000'S)

COMPANY	O & M SAVINGS	CAPITAL SAVINGS	TOTAL SAVINGS	% OF SAVINGS	REV REQ ALLOCATION	O&M/REV SAV TOTAL
2007						
NON-REG						
25	(77)	0	(77)	0.000%	0	(77)
26	0	0	0	0.000%	0	0
53	0	0	0	0.000%	0	0
56	0	0	0	0.000%	0	0
57	0	0	0	0.000%	0	0
58	(536)	0	(536)	0.000%	0	(536)
59	(938)	0	(938)	0.000%	0	(938)
60	(313)	0	(313)	0.000%	0	(313)
63	0	0	0	0.000%	0	0
64	0	0	0	0.000%	0	0
66	0	0	0	0.000%	0	0
67	(0)	0	(0)	0.000%	0	(0)
69	(587)	(0)	(587)	100.000%	0	(587)
72	0	0	0	0.000%	0	0
74	(938)	0	(938)	0.000%	0	(938)
81	(232)	0	(232)	0.000%	0	(232)
83	(70)	0	(70)	0.000%	0	(70)
86	(0)	0	(0)	0.000%	0	(0)
87	(4)	0	(4)	0.000%	0	(4)
88	0	0	0	0.000%	0	0
89	0	0	0	0.000%	0	0
90	0	0	0	0.000%	0	0
91	(244)	0	(244)	0.000%	0	(244)
99	0	0	0	0.000%	0	0
TOTAL NON-REG	(3,940)	(0)	(3,940)	100.000%	0	(3,940)
REGULATED						
01	(210)	(97)	(307)	0.484%	(120)	(330)
02	(9,084)	(5,329)	(14,414)	26.703%	(6,599)	(15,684)
03	(2,173)	(1,309)	(3,483)	6.561%	(1,621)	(3,795)

AMERICAN ELECTRIC POWER COMPANY
ALLOCATION OF DIRECT CAPITAL REVENUE REQUIREMENT SAVINGS
BY AEP SUBSIDIARY

(IN 000'S)

COMPANY	O & M SAVINGS	CAPITAL SAVINGS	TOTAL SAVINGS	% OF SAVINGS	REV REQ ALLOCATION	O&M/REV SAV TOTAL
04	(6,855)	(3,914)	(10,769)	19.612%	(4,847)	(11,702)
06	(230)	(107)	(337)	0.536%	(132)	(363)
07	(9,093)	(6,145)	(15,237)	30.789%	(7,609)	(16,701)
10	(4,959)	(2,746)	(7,705)	13.757%	(3,400)	(8,359)
21	0	0	0	0.000%	0	0
22	0	0	0	0.000%	0	0
23	0	0	0	0.000%	0	0
31	0	0	0	0.000%	0	0
32	0	0	0	0.000%	0	0
34	0	0	0	0.000%	0	0
40	0	0	0	0.000%	0	0
41	0	0	0	0.000%	0	0
42	(36)	(6)	(42)	0.030%	(7)	(44)
43	(40)	(5)	(45)	0.026%	(7)	(46)
44	(198)	(24)	(223)	0.121%	(30)	(228)
45	0	0	0	0.000%	0	0
46	0	0	0	0.000%	0	0
48	(59)	(14)	(73)	0.070%	(17)	(76)
49	(2)	0	(2)	0.000%	0	(2)
50	0	0	0	0.000%	0	0
51	0	0	0	0.000%	0	0
52	0	0	0	0.000%	0	0
54	(8)	(2)	(9)	0.009%	(2)	(10)
70	0	0	0	0.000%	0	0
71	0	0	0	0.000%	0	0
73	0	0	0	0.000%	0	0
75	0	0	0	0.000%	0	0
76	0	0	0	0.000%	0	0
77	0	0	0	0.000%	0	0
78	0	0	0	0.000%	0	0
84	0	0	0	0.000%	0	0
85	0	0	0	0.000%	0	0

AMERICAN ELECTRIC POWER COMPANY
ALLOCATION OF DIRECT CAPITAL REVENUE REQUIREMENT SAVINGS
BY AEP SUBSIDIARY

(IN 000'S)

COMPANY	O & M SAVINGS	CAPITAL SAVINGS	TOTAL SAVINGS	% OF SAVINGS	REV REQ ALLOCATION	O&M/REV SAV TOTAL
98	(235)	(260)	(495)	1.302%	(322)	(557)
XX	0	0	0	0.000%	0	0
TOTAL REG	(33,184)	(19,957)	(53,141)	100.000%	(24,713)	(57,897)
TOTAL 2007	(37,125)	(19,957)	(57,082)		(24,713)	(61,838)

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AMERICAN ELECTRIC POWER COMPANY
ALLOCATION OF DIRECT CAPITAL REVENUE REQUIREMENT SAVINGS
BY AEP SUBSIDIARY

(IN 000'S)

COMPANY	O & M SAVINGS	CAPITAL SAVINGS	TOTAL SAVINGS	% OF SAVINGS	REV REQ ALLOCATION	O&M/REV SAV TOTAL
2008						
NON-REG						
25	(81)	0	(81)	0.000%	0	(81)
26	0	0	0	0.000%	0	0
53	0	0	0	0.000%	0	0
56	0	0	0	0.000%	0	0
57	0	0	0	0.000%	0	0
58	(567)	0	(567)	0.000%	0	(567)
59	(991)	0	(991)	0.000%	0	(991)
60	(324)	0	(324)	0.000%	0	(324)
63	0	0	0	0.000%	0	0
64	0	0	0	0.000%	0	0
66	0	0	0	0.000%	0	0
67	(0)	0	(0)	0.000%	0	(0)
69	(620)	(0)	(620)	100.000%	0	(620)
72	0	0	0	0.000%	0	0
74	(991)	0	(991)	0.000%	0	(991)
81	(246)	0	(246)	0.000%	0	(246)
83	(74)	0	(74)	0.000%	0	(74)
86	(1)	0	(1)	0.000%	0	(1)
87	(4)	0	(4)	0.000%	0	(4)
88	0	0	0	0.000%	0	0
89	0	0	0	0.000%	0	0
90	0	0	0	0.000%	0	0
91	(258)	0	(258)	0.000%	0	(258)
99	0	0	0	0.000%	0	0
TOTAL NON-REG	(4,155)	(0)	(4,156)	100.000%	0	(4,155)
REGULATED						
01	(223)	(97)	(320)	0.475%	(133)	(356)
02	(9,560)	(5,456)	(15,016)	26.678%	(7,467)	(17,027)
03	(2,284)	(1,343)	(3,627)	6.569%	(1,839)	(4,123)

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AMERICAN ELECTRIC POWER COMPANY
ALLOCATION OF DIRECT CAPITAL REVENUE REQUIREMENT SAVINGS
BY AEP SUBSIDIARY

(IN 000'S)

COMPANY	O & M SAVINGS	CAPITAL SAVINGS	TOTAL SAVINGS	% OF SAVINGS	REV REQ ALLOCATION	O&M/REV SAV TOTAL
04	(7,205)	(4,014)	(11,219)	19.627%	(5,493)	(12,699)
06	(244)	(108)	(352)	0.527%	(148)	(392)
07	(9,553)	(6,311)	(15,864)	30.862%	(8,638)	(18,191)
10	(5,229)	(2,799)	(8,028)	13.687%	(3,831)	(9,060)
21	0	0	0	0.000%	0	0
22	0	0	0	0.000%	0	0
23	0	0	0	0.000%	0	0
31	0	0	0	0.000%	0	0
32	0	0	0	0.000%	0	0
34	0	0	0	0.000%	0	0
40	0	0	0	0.000%	0	0
41	0	0	0	0.000%	0	0
42	(38)	(6)	(44)	0.031%	(9)	(46)
43	(42)	(5)	(47)	0.027%	(8)	(49)
44	(208)	(25)	(233)	0.124%	(35)	(242)
45	0	0	0	0.000%	0	0
46	0	0	0	0.000%	0	0
48	(62)	(15)	(76)	0.071%	(20)	(82)
49	(3)	0	(3)	0.000%	0	(3)
50	0	0	0	0.000%	0	0
51	0	0	0	0.000%	0	0
52	0	0	0	0.000%	0	0
54	(8)	(2)	(10)	0.009%	(2)	(10)
70	0	0	0	0.000%	0	0
71	0	0	0	0.000%	0	0
73	0	0	0	0.000%	0	0
75	0	0	0	0.000%	0	0
76	0	0	0	0.000%	0	0
77	0	0	0	0.000%	0	0
78	0	0	0	0.000%	0	0
84	0	0	0	0.000%	0	0
85	0	0	0	0.000%	0	0

AMERICAN ELECTRIC POWER COMPANY
ALLOCATION OF DIRECT CAPITAL REVENUE REQUIREMENT SAVINGS
BY AEP SUBSIDIARY

(IN 000'S)

COMPANY	O & M SAVINGS	CAPITAL SAVINGS	TOTAL SAVINGS	% OF SAVINGS	REV REQ ALLOCATION	O&M/REV SAV TOTAL
98	(246)	(269)	(515)	1.314%	(368)	(614)
XX	0	0	0	0.000%	0	0
TOTAL REG	(34,903)	(20,451)	(55,354)	100.000%	(27,989)	(62,892)
TOTAL 2008	(39,059)	(20,451)	(59,510)		(27,989)	(67,048)
					0	
					(27,989)	

AMERICAN ELECTRIC POWER COMPANY
ALLOCATION OF DIRECT CAPITAL REVENUE REQUIREMENT SAVINGS
BY AEP SUBSIDIARY

(IN 000'S)

COMPANY	O & M SAVINGS	CAPITAL SAVINGS	TOTAL SAVINGS	% OF SAVINGS	REV REQ ALLOCATION	O&M/REV SAV TOTAL
2009						
NON-REG						
25	(21)	0	(21)	0.000%	0	(21)
26	0	0	0	0.000%	0	0
53	0	0	0	0.000%	0	0
56	0	0	0	0.000%	0	0
57	0	0	0	0.000%	0	0
58	(144)	0	(144)	0.000%	0	(144)
59	(252)	0	(252)	0.000%	0	(252)
60	(82)	0	(82)	0.000%	0	(82)
63	0	0	0	0.000%	0	0
64	0	0	0	0.000%	0	0
66	0	0	0	0.000%	0	0
67	(0)	0	(0)	0.000%	0	(0)
69	(158)	(0)	(158)	100.000%	0	(158)
72	0	0	0	0.000%	0	0
74	(252)	0	(252)	0.000%	0	(252)
81	(63)	0	(63)	0.000%	0	(63)
83	(19)	0	(19)	0.000%	0	(19)
86	(0)	0	(0)	0.000%	0	(0)
87	(1)	0	(1)	0.000%	0	(1)
88	0	0	0	0.000%	0	0
89	0	0	0	0.000%	0	0
90	0	0	0	0.000%	0	0
91	(66)	0	(66)	0.000%	0	(66)
99	0	0	0	0.000%	0	0
TOTAL NON-REG	(1,058)	(0)	(1,058)	100.000%	0	(1,058)
REGULATED						
01	(57)	(25)	(82)	0.475%	(34)	(91)
02	(2,435)	(1,389)	(3,824)	26.678%	(1,902)	(4,336)
03	(582)	(342)	(924)	6.569%	(468)	(1,050)

AMERICAN ELECTRIC POWER COMPANY
ALLOCATION OF DIRECT CAPITAL REVENUE REQUIREMENT SAVINGS
BY AEP SUBSIDIARY

(IN 000'S)

COMPANY	O & M SAVINGS	CAPITAL SAVINGS	TOTAL SAVINGS	% OF SAVINGS	REV REQ ALLOCATION	O&M/REV SAV TOTAL
04	(1,835)	(1,022)	(2,857)	19.627%	(1,399)	(3,234)
06	(62)	(27)	(90)	0.527%	(38)	(100)
07	(2,433)	(1,607)	(4,040)	30.862%	(2,200)	(4,632)
10	(1,332)	(713)	(2,044)	13.687%	(976)	(2,307)
21	0	0	0	0.000%	0	0
22	0	0	0	0.000%	0	0
23	0	0	0	0.000%	0	0
31	0	0	0	0.000%	0	0
32	0	0	0	0.000%	0	0
34	0	0	0	0.000%	0	0
40	0	0	0	0.000%	0	0
41	0	0	0	0.000%	0	0
42	(10)	(2)	(11)	0.031%	(2)	(12)
43	(11)	(1)	(12)	0.027%	(2)	(13)
44	(53)	(6)	(59)	0.124%	(9)	(62)
45	0	0	0	0.000%	0	0
46	0	0	0	0.000%	0	0
48	(16)	(4)	(19)	0.071%	(5)	(21)
49	(1)	0	(1)	0.000%	0	(1)
50	0	0	0	0.000%	0	0
51	0	0	0	0.000%	0	0
52	0	0	0	0.000%	0	0
54	(2)	(0)	(2)	0.009%	(1)	(3)
70	0	0	0	0.000%	0	0
71	0	0	0	0.000%	0	0
73	0	0	0	0.000%	0	0
75	0	0	0	0.000%	0	0
76	0	0	0	0.000%	0	0
77	0	0	0	0.000%	0	0
78	0	0	0	0.000%	0	0
84	0	0	0	0.000%	0	0
85	0	0	0	0.000%	0	0

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AMERICAN ELECTRIC POWER COMPANY
ALLOCATION OF DIRECT CAPITAL REVENUE REQUIREMENT SAVINGS
BY AEP SUBSIDIARY

(IN 000'S)

COMPANY	O & M SAVINGS	CAPITAL SAVINGS	TOTAL SAVINGS	% OF SAVINGS	REV REQ ALLOCATION	O&M/REV SAV TOTAL
98	(63)	(68)	(131)	1.314%	(94)	(156)
XX	0	0	0	0.000%	0	0
TOTAL REG	(8,888)	(5,208)	(14,097)	100.000%	(7,128)	(16,016)
TOTAL 2009	(9,947)	(5,208)	(15,155)		(7,128)	(17,074)

CENTRAL AND SOUTH WEST SERVICES, INC.
ALLOCATION OF DIRECT CAPITAL REVENUE REQUIREMENT SAVINGS
BY CSW SUBSIDIARY

1999
(IN 000'S)

COMPANY	O & M SAVINGS	CAPITAL SAVINGS	TOTAL SAVINGS	% OF CAP SAVINGS	REV REQ ALLOCATION	O&M/REV SAV TOTAL
NON-REG						
CSE	(210)	0	(210)	0.000%	0	(210)
CSI	(416)	0	(416)	0.000%	0	(416)
DCM	(151)	0	(151)	0.000%	0	(151)
DCR	(202)	0	(202)	0.000%	0	(202)
DCT	(15)	0	(15)	0.000%	0	(15)
DES	(120)	0	(120)	0.000%	0	(120)
DLL	0	0	0	0.000%	0	0
ESI	0	0	0	0.000%	0	0
PMI	0	0	0	0.000%	0	0
SEE	(67)	0	(67)	0.000%	0	(67)
TOK	0	0	0	0.000%	0	0
TOTAL NON-REG	(1,182)	0	(1,182)	0.000%	0	(1,182)
REGULATED						
CPL	(2,942)	(1,881)	(4,823)	30.657%	(330)	(3,271)
ECS	0	0	0	0.000%	0	0
JFP	0	0	0	0.000%	0	0
LAB	0	0	0	0.000%	0	0
PSO	(2,135)	(1,693)	(3,828)	27.586%	(297)	(2,431)
SEP	(2,298)	(1,770)	(4,069)	28.847%	(310)	(2,608)
WTU	(1,091)	(792)	(1,883)	12.909%	(139)	(1,229)
TOTAL REG	(8,465)	(6,137)	(14,602)	100.000%	(1,075)	(9,540)
TOTAL 1999	(9,647)	(6,137)	(15,784)		(1,075)	(10,722)
					0	
					(1,075)	

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CENTRAL AND SOUTH WEST SERVICES, INC.
ALLOCATION OF DIRECT CAPITAL REVENUE REQUIREMENT SAVINGS
BY CSW SUBSIDIARY

2000
(IN 000'S)

COMPANY	O & M SAVINGS	CAPITAL SAVINGS	TOTAL SAVINGS	% OF SAVINGS	REV REQ ALLOCATION	O&M/REV SAV TOTAL
NON-REG						
CSE	(294)	0	(294)	0.000%	0	(294)
CSI	(583)	0	(583)	0.000%	0	(583)
DCM	(212)	0	(212)	0.000%	0	(212)
DCR	(279)	0	(279)	0.000%	0	(279)
DCT	(21)	0	(21)	0.000%	0	(21)
DES	(169)	0	(169)	0.000%	0	(169)
DLL	0	0	0	0.000%	0	0
ESI	0	0	0	0.000%	0	0
PMI	0	0	0	0.000%	0	0
SEE	(94)	0	(94)	0.000%	0	(94)
TOK	0	0	0	0.000%	0	0
TOTAL NON-REG	(1,650)	0	(1,650)	0.000%	0	(1,650)
REGULATED						
CPL	(4,454)	(2,712)	(7,166)	30.894%	(802)	(5,256)
ECS	0	0	0	0.000%	0	0
JFP	0	0	0	0.000%	0	0
LAB	0	0	0	0.000%	0	0
PSO	(3,212)	(2,424)	(5,636)	27.603%	(717)	(3,929)
SEP	(3,404)	(2,517)	(5,921)	28.667%	(744)	(4,149)
WTU	(1,612)	(1,127)	(2,739)	12.835%	(333)	(1,945)
TOTAL REG	(12,683)	(8,780)	(21,462)	100.000%	(2,597)	(15,280)
TOTAL 2000	(14,333)	(8,780)	(23,112)		(2,597)	(16,930)

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CENTRAL AND SOUTH WEST SERVICES, INC.
ALLOCATION OF DIRECT CAPITAL REVENUE REQUIREMENT SAVINGS
BY CSW SUBSIDIARY

2001
(IN 000'S)

COMPANY	O & M SAVINGS	CAPITAL SAVINGS	TOTAL SAVINGS	% OF SAVINGS	REV REQ ALLOCATION	O&M/REV SAV TOTAL
NON-REG						
CSE	(308)	0	(308)	0.000%	0	(308)
CSI	(612)	0	(612)	0.000%	0	(612)
DCM	(222)	0	(222)	0.000%	0	(222)
DCR	(287)	0	(287)	0.000%	0	(287)
DCT	(22)	0	(22)	0.000%	0	(22)
DES	(177)	0	(177)	0.000%	0	(177)
DLL	0	0	0	0.000%	0	0
ESI	0	0	0	0.000%	0	0
PMI	0	0	0	0.000%	0	0
SEE	(97)	0	(97)	0.000%	0	(97)
TOK	0	0	0	0.000%	0	0
TOTAL NON-REG	(1,725)	0	(1,725)	0.000%	0	(1,725)
REGULATED						
CPL	(4,679)	(3,926)	(8,605)	30.741%	(1,441)	(6,120)
ECS	0	0	0	0.000%	0	0
JFP	0	0	0	0.000%	0	0
LAB	0	0	0	0.000%	0	0
PSO	(3,376)	(3,524)	(6,901)	27.599%	(1,294)	(4,671)
SEP	(3,571)	(3,677)	(7,248)	28.796%	(1,350)	(4,921)
WTU	(1,692)	(1,643)	(3,335)	12.864%	(603)	(2,295)
TOTAL REG	(13,319)	(12,770)	(26,088)	100.000%	(4,689)	(18,008)
TOTAL 2001	(15,044)	(12,770)	(27,813)		(4,689)	(19,733)

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CENTRAL AND SOUTH WEST SERVICES, INC.
ALLOCATION OF DIRECT CAPITAL REVENUE REQUIREMENT SAVINGS
BY CSW SUBSIDIARY

2002
(IN 000'S)

COMPANY	O & M SAVINGS	CAPITAL SAVINGS	TOTAL SAVINGS	% OF SAVINGS	REV REQ ALLOCATION	O&M/REV SAV TOTAL
NON-REG						
CSE	(327)	(1)	(329)	2.503%	(0)	(328)
CSI	(642)	0	(642)	0.000%	0	(642)
DCM	(235)	(1)	(236)	1.390%	(0)	(236)
DCR	(295)	0	(295)	0.000%	0	(295)
DCT	(23)	0	(23)	0.000%	0	(23)
DES	(187)	(0)	(187)	0.672%	(0)	(187)
DLL	0	0	0	0.000%	0	0
ESI	(1)	(0)	(1)	0.417%	(0)	(1)
PMI	0	0	0	0.000%	0	0
SEE	(260)	(47)	(307)	95.017%	(9)	(268)
TOK	0	0	0	0.000%	0	0
TOTAL NON-REG	(1,971)	(50)	(2,020)	100.000%	(9)	(1,980)
REGULATED						
CPL	(5,484)	(3,081)	(8,565)	30.922%	(1,934)	(7,419)
ECS	0	0	0	0.000%	0	0
JFP	0	0	0	0.000%	0	0
LAB	0	0	0	0.000%	0	0
PSO	(3,984)	(2,727)	(6,711)	27.370%	(1,712)	(5,696)
SEP	(4,278)	(2,853)	(7,131)	28.633%	(1,791)	(6,069)
WTU	(2,097)	(1,303)	(3,399)	13.074%	(818)	(2,915)
TOTAL REG	(15,842)	(9,964)	(25,806)	100.000%	(6,256)	(22,098)
TOTAL 2002	(17,813)	(10,014)	(27,826)		(6,265)	(24,078)

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CENTRAL AND SOUTH WEST SERVICES, INC.
ALLOCATION OF DIRECT CAPITAL REVENUE REQUIREMENT SAVINGS
BY CSW SUBSIDIARY

2003
(IN 000'S)

COMPANY	O & M SAVINGS	CAPITAL SAVINGS	TOTAL SAVINGS	% OF SAVINGS	REV REQ ALLOCATION	O&M/REV SAV TOTAL
NON-REG						
CSE	(343)	(1)	(345)	2.503%	(0)	(344)
CSI	(674)	0	(674)	0.000%	0	(674)
DCM	(247)	(1)	(248)	1.390%	(0)	(247)
DCR	(304)	0	(304)	0.000%	0	(304)
DCT	(25)	0	(25)	0.000%	0	(25)
DES	(196)	(0)	(197)	0.672%	(0)	(196)
DLL	0	0	0	0.000%	0	0
ESI	(1)	(0)	(1)	0.417%	(0)	(1)
PMI	0	0	0	0.000%	0	0
SEE	(270)	(49)	(319)	95.017%	(17)	(287)
TOK	0	0	0	0.000%	0	0
TOTAL NON-REG	(2,060)	(52)	(2,112)	100.000%	(18)	(2,078)
REGULATED						
CPL	(5,705)	(3,182)	(8,887)	30.926%	(2,443)	(8,147)
ECS	0	0	0	0.000%	0	0
JFP	0	0	0	0.000%	0	0
LAB	0	0	0	0.000%	0	0
PSO	(4,143)	(2,816)	(6,959)	27.369%	(2,162)	(6,305)
SEP	(4,449)	(2,946)	(7,395)	28.630%	(2,261)	(6,710)
WTU	(2,182)	(1,345)	(3,528)	13.075%	(1,033)	(3,215)
TOTAL REG	(16,480)	(10,289)	(26,769)	100.000%	(7,898)	(24,378)
TOTAL 2003	(18,540)	(10,341)	(28,880)		(7,916)	(26,456)

CENTRAL AND SOUTH WEST SERVICES, INC.
ALLOCATION OF DIRECT CAPITAL REVENUE REQUIREMENT SAVINGS
BY CSW SUBSIDIARY

2004
(IN 000'S)

COMPANY	O & M SAVINGS	CAPITAL SAVINGS	TOTAL SAVINGS	% OF SAVINGS	REV REQ ALLOCATION	O&M/REV SAV TOTAL
NON-REG						
CSE	(360)	(1)	(362)	2.503%	(1)	(361)
CSI	(708)	0	(708)	0.000%	0	(708)
DCM	(259)	(1)	(260)	1.390%	(0)	(260)
DCR	(313)	0	(313)	0.000%	0	(313)
DCT	(26)	0	(26)	0.000%	0	(26)
DES	(206)	(0)	(207)	0.672%	(0)	(206)
DLL	0	0	0	0.000%	0	0
ESI	(1)	(0)	(1)	0.417%	(0)	(1)
PMI	0	0	0	0.000%	0	0
SEE	(280)	(51)	(332)	95.017%	(26)	(306)
TOK	0	0	0	0.000%	0	0
TOTAL NON-REG	(2,154)	(54)	(2,208)	100.000%	(27)	(2,181)
REGULATED						
CPL	(5,935)	(3,287)	(9,222)	30.933%	(2,951)	(8,886)
ECS	0	0	0	0.000%	0	0
JFP	0	0	0	0.000%	0	0
LAB	0	0	0	0.000%	0	0
PSO	(4,310)	(2,908)	(7,218)	27.367%	(2,611)	(6,921)
SEP	(4,628)	(3,042)	(7,670)	28.624%	(2,731)	(7,359)
WTU	(2,272)	(1,390)	(3,661)	13.077%	(1,248)	(3,519)
TOTAL REG	(17,145)	(10,626)	(27,771)	100.000%	(9,541)	(26,686)
TOTAL 2004	(19,298)	(10,680)	(29,979)		(9,568)	(28,866)

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CENTRAL AND SOUTH WEST SERVICES, INC.
ALLOCATION OF DIRECT CAPITAL REVENUE REQUIREMENT SAVINGS
BY CSW SUBSIDIARY

2005
(IN 000'S)

COMPANY	O & M SAVINGS	CAPITAL SAVINGS	TOTAL SAVINGS	% OF SAVINGS	REV REQ ALLOCATION	O&M/REV SAV TOTAL
NON-REG						
CSE	(378)	(1)	(380)	2.503%	(1)	(379)
CSI	(743)	0	(743)	0.000%	0	(743)
DCM	(272)	(1)	(273)	1.390%	(1)	(273)
DCR	(323)	0	(323)	0.000%	0	(323)
DCT	(27)	0	(27)	0.000%	0	(27)
DES	(216)	(0)	(217)	0.672%	(0)	(217)
DLL	0	0	0	0.000%	0	0
ESI	(1)	(0)	(1)	0.417%	(0)	(1)
PMI	0	0	0	0.000%	0	0
SEE	(292)	(54)	(346)	95.017%	(34)	(326)
TOK	0	0	0	0.000%	0	0
TOTAL NON-REG	(2,253)	(57)	(2,309)	100.000%	(36)	(2,289)
REGULATED						
CPL	(6,173)	(3,395)	(9,569)	30.937%	(3,461)	(9,634)
ECS	0	0	0	0.000%	0	0
JFP	0	0	0	0.000%	0	0
LAB	0	0	0	0.000%	0	0
PSO	(4,483)	(3,003)	(7,487)	27.365%	(3,061)	(7,545)
SEP	(4,814)	(3,141)	(7,955)	28.620%	(3,202)	(8,015)
WTU	(2,365)	(1,435)	(3,800)	13.079%	(1,463)	(3,828)
TOTAL REG	(17,835)	(10,975)	(28,810)	100.000%	(11,187)	(29,022)
TOTAL 2005	(20,088)	(11,032)	(31,120)		(11,223)	(31,311)

CENTRAL AND SOUTH WEST SERVICES, INC.
ALLOCATION OF DIRECT CAPITAL REVENUE REQUIREMENT SAVINGS
BY CSW SUBSIDIARY

2006
(IN 000'S)

COMPANY	O & M SAVINGS	CAPITAL SAVINGS	TOTAL SAVINGS	% OF SAVINGS	REV REQ ALLOCATION	O&M/REV SAV TOTAL
NON-REG						
CSE	(397)	(1)	(398)	2.503%	(1)	(398)
CSI	(780)	0	(780)	0.000%	0	(780)
DCM	(286)	(1)	(287)	1.390%	(1)	(287)
DCR	(332)	0	(332)	0.000%	0	(332)
DCT	(28)	0	(28)	0.000%	0	(28)
DES	(227)	(0)	(228)	0.672%	(0)	(228)
DLL	0	0	0	0.000%	0	0
ESI	(1)	(0)	(1)	0.417%	(0)	(1)
PMI	0	0	0	0.000%	0	0
SEE	(304)	(56)	(360)	95.017%	(43)	(347)
TOK	0	0	0	0.000%	0	0
TOTAL NON-REG	(2,355)	(59)	(2,414)	100.000%	(45)	(2,400)
REGULATED						
CPL	(6,422)	(3,507)	(9,929)	30.940%	(3,972)	(10,395)
ECS	0	0	0	0.000%	0	0
JFP	0	0	0	0.000%	0	0
LAB	0	0	0	0.000%	0	0
PSO	(4,664)	(3,102)	(7,766)	27.364%	(3,513)	(8,177)
SEP	(5,008)	(3,244)	(8,251)	28.616%	(3,674)	(8,682)
WTU	(2,462)	(1,483)	(3,944)	13.080%	(1,679)	(4,141)
TOTAL REG	(18,556)	(11,335)	(29,891)	100.000%	(12,839)	(31,395)
TOTAL 2006	(20,911)	(11,394)	(32,304)		(12,884)	(33,795)

CENTRAL AND SOUTH WEST SERVICES, INC.
ALLOCATION OF DIRECT CAPITAL REVENUE REQUIREMENT SAVINGS
BY CSW SUBSIDIARY

2007
(IN 000'S)

COMPANY	O & M SAVINGS	CAPITAL SAVINGS	TOTAL SAVINGS	% OF SAVINGS	REV REQ ALLOCATION	O&M/REV SAV TOTAL
NON-REG						
CSE	(416)	(2)	(418)	2.503%	(1)	(418)
CSI	(819)	0	(819)	0.000%	0	(819)
DCM	(300)	(1)	(301)	1.391%	(1)	(301)
DCR	(342)	0	(342)	0.000%	0	(342)
DCT	(30)	0	(30)	0.000%	0	(30)
DES	(239)	(0)	(239)	0.672%	(0)	(239)
DLL	0	0	0	0.000%	0	0
ESI	(1)	(0)	(1)	0.417%	(0)	(1)
PMI	0	0	0	0.000%	0	0
SEE	(315)	(58)	(373)	95.017%	(52)	(368)
TOK	0	0	0	0.000%	0	0
TOTAL NON-REG	(2,463)	(61)	(2,524)	100.000%	(55)	(2,518)
REGULATED						
CPL	(6,682)	(3,623)	(10,305)	30.947%	(4,487)	(11,168)
ECS	0	0	0	0.000%	0	0
JFP	0	0	0	0.000%	0	0
LAB	0	0	0	0.000%	0	0
PSO	(4,853)	(3,203)	(8,056)	27.361%	(3,967)	(8,819)
SEP	(5,210)	(3,350)	(8,559)	28.610%	(4,148)	(9,357)
WTU	(2,563)	(1,532)	(4,094)	13.081%	(1,897)	(4,459)
TOTAL REG	(19,307)	(11,708)	(31,015)	100.000%	(14,498)	(33,805)
TOTAL 2007	(21,769)	(11,769)	(33,538)		(14,553)	(36,322)

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CENTRAL AND SOUTH WEST SERVICES, INC.
ALLOCATION OF DIRECT CAPITAL REVENUE REQUIREMENT SAVINGS
BY CSW SUBSIDIARY

2008
(IN 000'S)

COMPANY	O & M SAVINGS	CAPITAL SAVINGS	TOTAL SAVINGS	% OF SAVINGS	REV REQ ALLOCATION	O&M/REV SAV TOTAL
NON-REG						
CSE	(439)	(2)	(441)	2.503%	(2)	(441)
CSI	(865)	0	(865)	0.000%	0	(865)
DCM	(317)	(1)	(318)	1.390%	(1)	(318)
DCR	(353)	0	(353)	0.000%	0	(353)
DCT	(32)	0	(32)	0.000%	0	(32)
DES	(252)	(0)	(253)	0.672%	(0)	(253)
DLL	0	0	0	0.000%	0	0
ESI	(1)	(0)	(1)	0.417%	(0)	(1)
PMI	0	0	0	0.000%	0	0
SEE	(330)	(60)	(391)	95.017%	(63)	(393)
TOK	0	0	0	0.000%	0	0
TOTAL NON-REG	(2,590)	(64)	(2,653)	100.000%	(66)	(2,656)
REGULATED						
CPL	(7,029)	(3,707)	(10,736)	30.894%	(5,073)	(12,103)
ECS	0	0	0	0.000%	0	0
JFP	0	0	0	0.000%	0	0
LAB	0	0	0	0.000%	0	0
PSO	(5,107)	(3,282)	(8,389)	27.351%	(4,492)	(9,599)
SEP	(5,475)	(3,438)	(8,913)	28.651%	(4,705)	(10,180)
WTU	(2,695)	(1,572)	(4,267)	13.105%	(2,152)	(4,847)
TOTAL REG	(20,306)	(11,999)	(32,305)	100.000%	(16,422)	(36,728)
TOTAL 2008	(22,896)	(12,062)	(34,958)		(16,488)	(39,384)

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CENTRAL AND SOUTH WEST SERVICES, INC.
ALLOCATION OF DIRECT CAPITAL REVENUE REQUIREMENT SAVINGS
BY CSW SUBSIDIARY

2009
(IN 000'S)

COMPANY	O & M SAVINGS	CAPITAL SAVINGS	TOTAL SAVINGS	% OF SAVINGS	REV REQ ALLOCATION	O&M/REV SAV TOTAL
NON-REG						
CSE	(112)	(0)	(112)	2.503%	(0)	(112)
CSI	(220)	0	(220)	0.000%	0	(220)
DCM	(81)	(0)	(81)	1.390%	(0)	(81)
DCR	(90)	0	(90)	0.000%	0	(90)
DCT	(8)	0	(8)	0.000%	0	(8)
DES	(64)	(0)	(64)	0.672%	(0)	(64)
DLL	0	0	0	0.000%	0	0
ESI	(0)	(0)	(0)	0.417%	(0)	(0)
PMI	0	0	0	0.000%	0	0
SEE	(84)	(15)	(99)	95.017%	(16)	(100)
TOK	0	0	0	0.000%	0	0
TOTAL NON-REG	(660)	(16)	(676)	100.000%	(17)	(676)
REGULATED						
CPL	(1,790)	(944)	(2,734)	30.894%	(1,292)	(3,082)
ECS	0	0	0	0.000%	0	0
JFP	0	0	0	0.000%	0	0
LAB	0	0	0	0.000%	0	0
PSO	(1,301)	(836)	(2,136)	27.351%	(1,144)	(2,444)
SEP	(1,394)	(875)	(2,270)	28.651%	(1,198)	(2,592)
WTU	(686)	(400)	(1,087)	13.105%	(548)	(1,234)
TOTAL REG	(5,171)	(3,056)	(8,227)	100.000%	(4,182)	(9,353)
TOTAL 2009	(5,831)	(3,072)	(8,902)		(4,199)	(10,030)

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Service I.D. Training

Billing Training

Central & South West Services

Summer 1996

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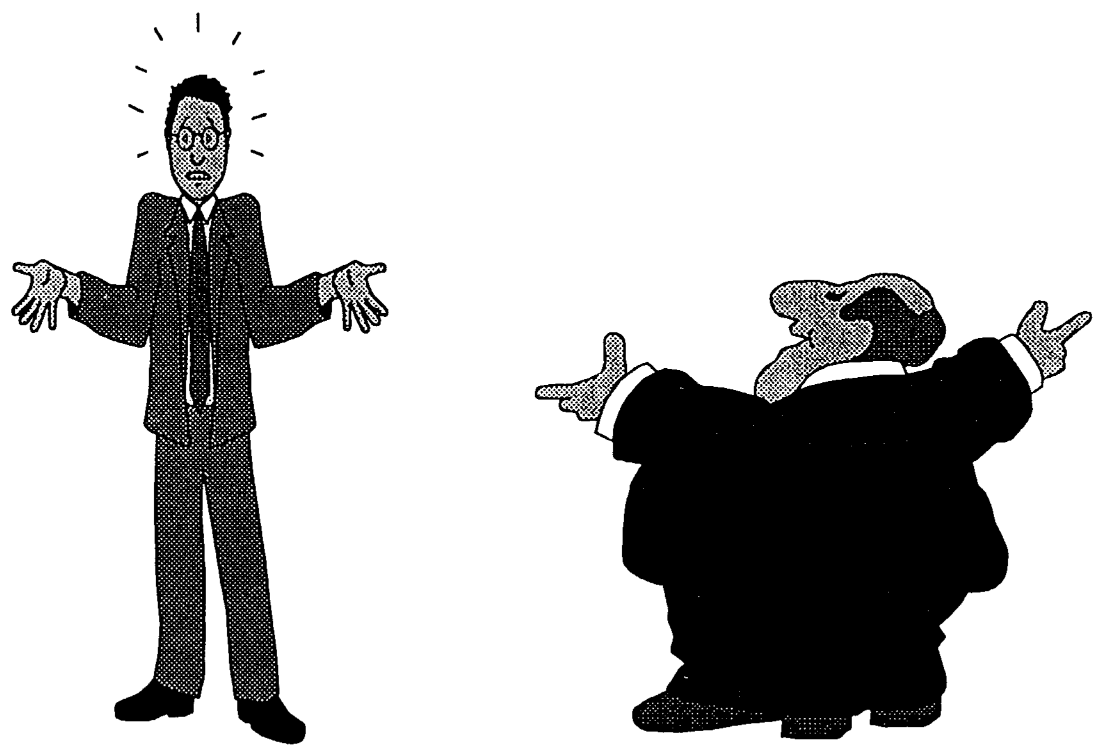
CSWS BILLING TRAINING
(PART I)

CSWS ACCOUNTING

SUMMER, 1996

CSWS BILLING TRAINING

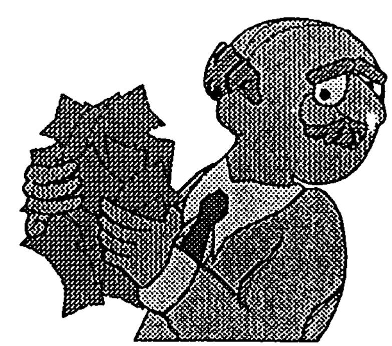
A One "Size" Fits all Class!



CSWS Billing Question #1

100% of CSWS cost is billed out each month. Who do we bill these cost to?

-
-
-
-
-

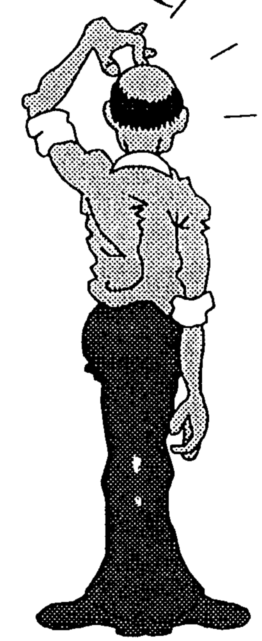


CSWS Billing Question #2

WHO decides what "$" amount each CSW subsidiary will pay for?

- »
- »
- »
- »

Hard Question ?



CSWS Billing Question # 3

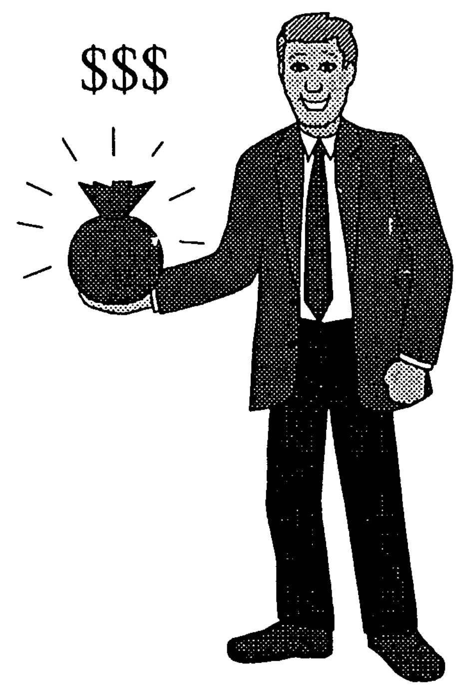
WHO pays for CSW subsidiaries' cost?

»

»

»

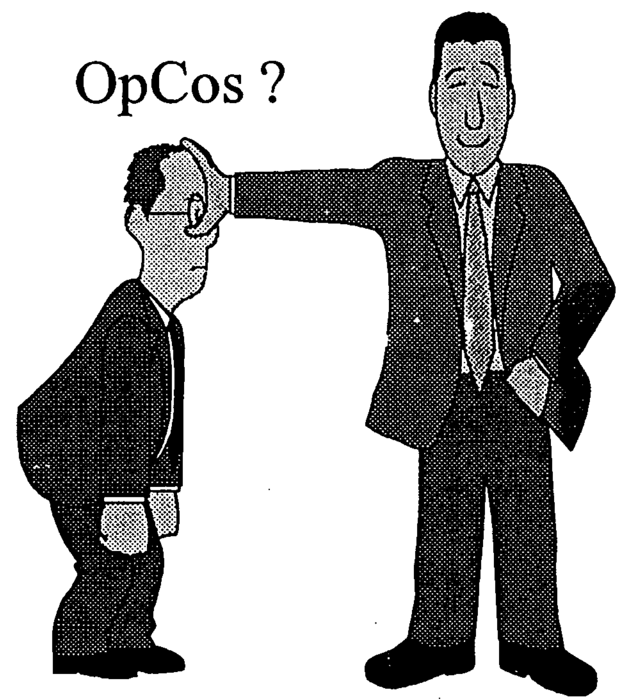
»



CSWS Billing Question # 4

WHO has to approve CSWS services provided to CSW Electric OpCos? How?

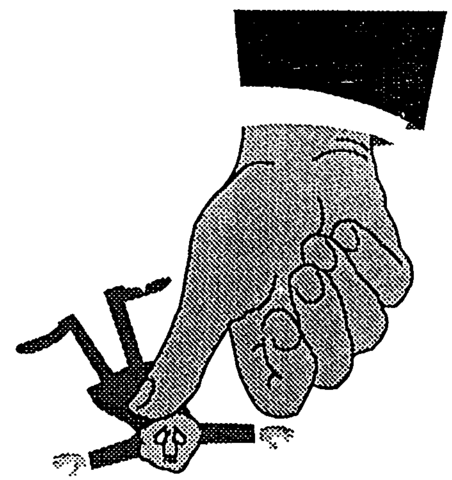
- »
- »
- »
- »
- »
- »



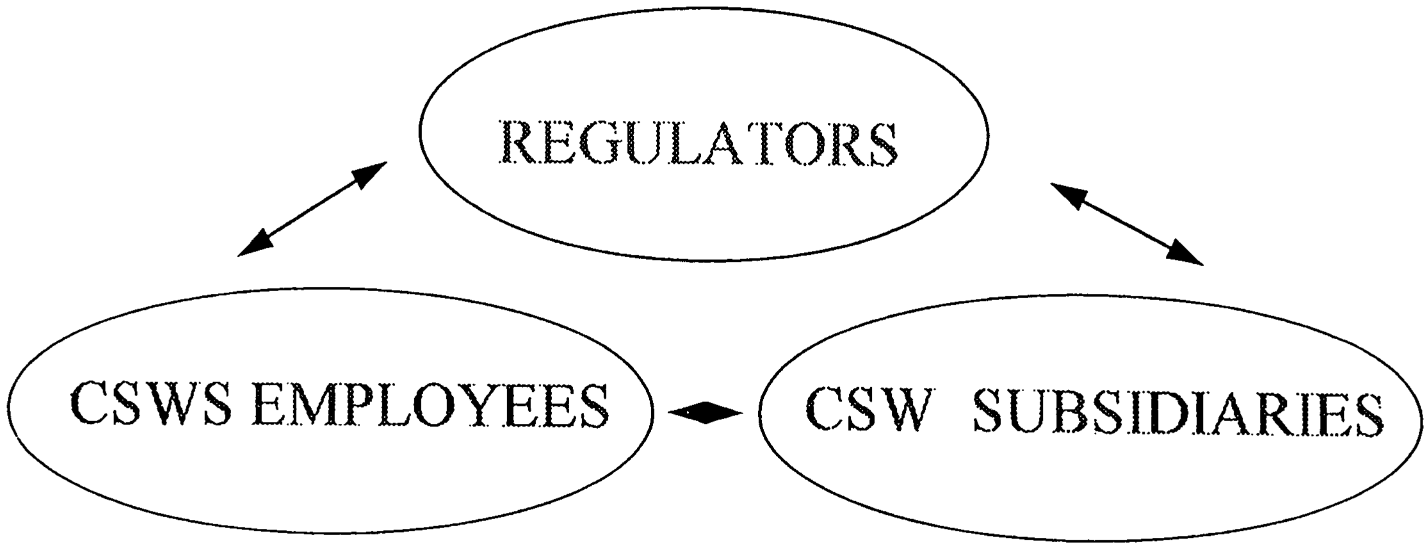
CSWS Billing Question # 5

What criteria do the regulators use to evaluate CSW Electric OpCos cost?

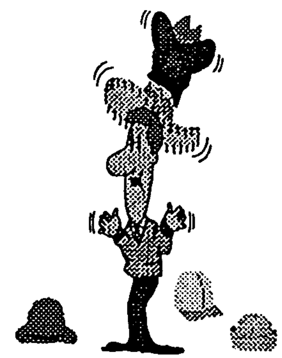
- »
- »
- »
- »
- »



A "Big Happy Family" ?



√ How Do We Find Balances Among these Three ?
√ How Can We Make them a Happy Family ?



What Does Each Group "NEED" ?

- CSWS EMPLOYEES:
  - Easier way to track their time and cost
- CSW SUBSIDIARIES:
  - To understand CSWS Bill
- REGULATORS:
  - To determine if costs are "Reasonable" and "Necessary"


NO
WHINING

"What" and "Who"

WHAT Are You Doing ?

WHO Are You Doing It For ?

CSWS EMPLOYEES

REGULATORS

CSW SUBSIDIARIES

“What” and “Who” and “Where”

WHAT Are You Doing ?

WHO Are You Doing It For ?

WHERE Do You Record “What” and “Who” ?

Accounting Code Fields

Corp.

Center

Account

Trans Type

"KUD"
Key User Defined
(WORK ORDER #)

DSV

Project

```
HV02                         CSWS STANDARD TIME REPORTING
                             BI-WEEKLY TIME / ACCOUNTING
PAYENDTE 06/01/1996 EMPLID 999555  Greenwell,Grace S.H.  CO CSS CENTER A2173  E
 COPY FROM EMPLID _______    DFLT/PREV DIST(D/P) _    PERSONAL MILEAGE _____

   CDE S  ACCOUNT  KUD          WO-PROJ    WSTP ACTIV TUD
   / CO  CENTR JOBCDE TX /       SUN   MON    TUE    WED    THU    FRI    SAT    TOT
 _ REG _ 9200 5000 EX1034
  / CSS A2173 ______ _ / WK1: _____  1.00   1.00   1.00   1.00   1.00  _____   5.00
                         WK2: _____ _____   1.00   1.00   1.00   1.00  _____   4.00
 _ REG _ 9200 5000 EX1970
  / CSS A2173 ______ _ / WK1: _____  7.00   7.00   7.00   7.00   7.00  _____  35.00
                         WK2: _____ _____   7.00   7.00   7.00   7.00  _____  28.00
 _ HOL _ 9200 5000 EX4019
  / CSS A2173 ______ _ / WK1: _____ _____  _____  _____  _____  _____  _____    .00
                         WK2: _____  8.00  _____  _____  _____  _____  _____   8.00
 _ ___ _ ____ ____ ______
  / ___ _____ ______ _ / WK1: _____ _____  _____  _____  _____  _____  _____    .00
                         WK2: _____ _____  _____  _____  _____  _____  _____    .00

 TOT HRS:  80.00  REG:  72.00  OT:    .00  OTHER:   8.00     < MEALS:    .00 >
 F1:MENU  F3:QUIT  F5:TOP  P6:BOTTOM  F7:PREV  F8:NEXT  F10:ADD SCREEN
 TIME HAS BEEN POSTED - NO UPDATES ALLOWED
USERID: DTSOC78      DATE: 06/11/1996      TIME: 09:25:15    SCREEN ID: HDTD01
```

```
HTC4                  CENTRAL AND SOUTH WEST
               Credit Card Accounting Distribution
Company: CSW Name: GRACE GREENWELL    Acct Nbr: 5473249050004316 Status: SG
CENTER   ACCOUNT T KUD        PROJECT    WK-ST/SB ACT       TUD
A2173   92107110 E EX1034
001                                                    AMOUNT:     209.46
A2173   92107110 E EX6453
002                                                    AMOUNT:      69.82

                                                       AMOUNT:

                                                       AMOUNT:

                                                       AMOUNT:

                                                       AMOUNT:

                                                       AMOUNT:
 RECEIPTS REQUIRED FOR PURCHASES OF $75 OR MORE
MEALS:        .00 LODGING     :       .00      DISTRIBUTION TOTAL:     279.28
OTHER:        .00 TRAVEL/MILES:    279.28     CREDIT CARD BALANCE:     279.28

Clear=Exit PF2=Menu PF3=Prev PF7=PgUp PF8=PgDn
```

Accounting Code Fields

Corp.	Center	Account	Trans Type

Project

"KUD"

~~EX 6453~~

~~EX 1034~~

"***SERVICE ID***"

SERVICE ID vs. WORK ORDER#

- Work Order # - Just a "DUMMY" number that captures costs

- **Service ID** - It's Smart; It makes sense;
  It records
  What I Do and
  Who I am doing it for!

SERVICE ID

A "10" Digit Code

WHAT	WHO
"8 Digits"	"2 Digits"
SERVICE CODE	**CUSTOMER CODE**

"Commercial Marketing Programs" MKCPROGM

CC	Bill 100% - CPL
PP	Bill 100% - PSO
WW	Bill 100% - WTU
??	Bill 100% - SWEP
4E	Bill 100% - 4 ELECS

SERVICE CODE (8 DIGITS)

SERVICE TITLE: COMMERCIAL MARKETING PROGRAMS
ATTRIBUTION BASIS: # OF COMMERCIAL CUSTOMERS

ATTRIBUTION BASIS:
"Number of Commercial Customers"

MKCPROGM

√ Attribution Basis of Number of Commercial Customers is now linked to "MKCPROGM" service code behind the scene

CUSTOMER CODE (2 DIGITS)

SERVICE: COMMERCIAL MARKETING PROGRAMS (MKCPROGM)

ATTRIBUTION BASIS: ***Number of Commercial Customers***

Direct Billing: 100% billed to only ONE CSW Subsidiary (Attribution Basis does NOT Apply)	
CC	Bill 100% - CPL
PP	Bill 100% - PSO
WW	Bill 100% - WTU
SS	Bill 100% - SWEP
Shared Billing: Bill to CSW Subsidiaries based on "# of Commercial Customers" (Attribution Basis DOES Apply)	
4E	Bill to 4 ELECS.
CW	Bill to CPL & WTU
SP	Bill to SEP & PSO

"SERVICE CODE" + "CUSTOMER CODE" = SERVICE ID

"COMMERCIAL MARKETING PROGRAMS"

MKCPROGM CC	(Direct Billing - 100% to CPL)
MKCPROGM PP	(Direct Billing - 100% to PSO)
MKCPROGM WW	(Direct Billing - 100% to WTU)
MKCPROGM 4E	(Shared Billing - Billed to 4 Electrics Based on " # of Commercial Customers)

√ IT'S MAGIC!

√ ONE SERVICE CODE CAN BE BILLED TO DIFFERENT CUSTOMERS

COMMERCIAL MARKETING PROGRAMS

	SERVICE ID ("What" and "Who")	WORK ORDER
Direct Billing - 100% to CPL	MKCPROGMCC	EX 1265
Direct Billing - 100% to PSO	MKCPROGMPP	EX 3954
Direct Billing - 100% to SEP	MKCPROGMSS	EX 2946
Direct Billing - 100% to WTU	MKCPROGMWW	EX 6849
Shared Billing - 4 Electrics	MKCPROGM4E	EX 3857
Shared Billing - CPL & WTU	MKCPROGMCW	EX 6393

CSWS Billing Reports to CSW Subsidiaries:

Marketing:

Commercial Marketing Programs $100,000.00

EX 1265	$25,000
EX 3954	10,000
EX 2946	20,000
EX 6849	35,000
EX 3857	5,000
EX 6393	5,000
	$100,000

CENTRAL AND SOUTH WEST SERVICES, INC.
SERVICES RENDERED FOR SWEP BY DSV
ACTUAL ACTIVE-INACTIVE WORK ORDERS FOR FEB, 1996

TYPE: A ADMIN AND GENERAL

ACCOUNT NUMBER	ACCOUNT TITLE	EX1970 13.4085%	EX4001 25.6799%	EX4004 16.7811%	EX4007 22.5311%	EX4011 25.6799%	EX4019 22.5311%	EX4021 16.7811%
92004000	COMP ABSENCE IN	75.75	523.90	1,022.95	1,255.16	1,616.16	1,574.95	28.26
92004100	COMPABSENCE OUT	-	-	-	-	-	(151,444.57)	-
92005000	A & G SALARIES	522.41	3,613.12	7,054.84	8,772.92	11,221.27	58,887.79	194.88
92009000	OTHER COMP	-	-	-	40.56	801.21	-	55.38
	***** SUBTOTAL	598.16	4,137.02	8,077.79	10,733.38	13,638.64	(90,981.83)	278.52
92101700	OTH UTILITY EXP	-	-	-	18,278.26	-	-	-
92102000	MEETING EXPENSE	-	110.36	71.71	16.35	147.90	-	-
92102300	SMALL EQUI?MENT	-	-	-	218.97	-	-	-
92107010	DUES-PROF	-	-	15.44	-	-	-	-
92107110	TRAVEL & LODGIN	-	178.42	163.68	(367.72)	1,005.72	6.44	194.25
92107600	SUPPLIES, MATRL	-	-	(3.76)	4,167.27	608.22	98.38	7.50
92107620	MATERIAL & OTHE	-	-	-	4,143.49	-	-	8.05
92107700	COMMUN OTHER	-	-	-	136.39	(58.59)	-	2.73
92107710	TELECOM-VOICE	-	-	-	13,671.32	45.59	-	-
92107742	TELECOM-MOB-CEL	-	-	-	(2.30)	-	-	-
92107810	TRAIN-INTERNAL	-	-	100.69	-	-	-	-
92109000	MISCELLANEOUS	-	-	131.26	(133.58)	72.30	-	-
	***** SUBTOTAL	-	288.78	479.02	40,128.45	1,821.14	104.82	212.53
92200100	CSWS EXP T CRED	-	-	-	(2,934.17)	-	(1,574.95)	-
92202000	CSWS EDP CHARGE	-	-	-	47.66	11,974.23	-	37.73
92203000	G&A OH TRANS IN	130.60	903.28	1,763.71	2,934.17	2,771.48	-	48.13
92203100	G&A OH TRAN OUT	-	-	-	(258,654.02)	-	-	-
92204000	CORP AIR EXP IN	-	-	1,661.33	-	-	-	-
	***** SUBTOTAL	130.60	903.28	3,425.04	(258,606.36)	14,745.71	(1,574.95)	85.86
92307430	OUTSIDE SERVICE	-	-	-	11,091.50	4,839.39	-	1,452.10
92307450	OS SERV TEMP PS	-	-	1.26	1,191.12	1,094.35	-	-
92309000	OS SERV OTH	-	140.47	-	309.67	1,520.31	-	-
	***** SUBTOTAL	-	140.47	1.26	12,592.29	7,454.05	-	1,452.10
92604000	PAYROLL BEN. IN	65.30	451.64	881.86	1,082.03	1,393.24	8,938.09	24.36
92604700	SYS EMPL OH	-	-	-	517.31	-	-	-
92606300	EMPLOYEE ACTIV	-	-	223.64	-	-	-	-
92609000	MISCELLANEOUS	-	-	-	1,351.77	-	-	6.84
	***** SUBTOTAL	65.30	451.64	1,105.50	2,951.11	1,393.24	8,938.09	31.20
93025100	CO MEM FEE DUES	-	-	50.04	-	-	-	-
93027300	CO RELOCAT EXP	-	-	-	-	(2,897.43)	(955.89)	-
	***** SUBTOTAL	-	-	50.04	-	(2,897.43)	(955.89)	-

WP/KNORR
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DFGL8[redacted] I
03/05/[redacted]

CENTRAL AND SOUTH[redacted] SERVICES, INC.
SERVICES RENDERED FOR SWEP BY DSV
ACTUAL ACTIVE-INACTIVE WORK ORDERS FOR FEB. 1996

[redacted]3
[redacted].19

TYPE: A ADMIN AND GENERAL

ACCOUNT NUMBER	ACCOUNT TITLE	EX1970 13.4085%	EX4001 25.6799%	EX4004 16.7811%	EX4007 22.5311%	EX4011 25.6799%	EX4019 22.5311%	EX4021 16.7811%
93104400	OFFSITE STORAGE	-	-	-	305.11	-	-	-
93104800	COMPUTER TIMESH	-	-	-	-	104.27	-	-
93105200	RENTS-OFFICE SP	-	-	-	52,902.46	-	-	9.22
93109000	RENTS - OTHER	-	-	-	9,920.03	-	-	-
	***** SUBTOTAL	-	-	-	63,127.60	104.27	-	9.22
93505100	MAINT/STRUCTURE	-	-	-	16,272.84	-	-	-
93505200	MAINT/FUR&EQUIP	-	-	-	921.06	-	-	-
93507200	MAINT/CO./VEHIC	-	-	7.62	131.19	-	-	-
93509000	MAINT/MISC	-	-	-	171.94	-	56.96	-
	***** SUBTOTAL	-	-	7.62	17,497.03	-	56.96	-
	WORK ORDER TOTALS	831.93	6,768.01	13,674.46	163,421.87	37,067.70	(66,666.03)	2,083.56

WP/KNORR
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6/12/96

CENTRAL AND SOUTH WEST SERVICES, INC.
SERVICES RENDERED FOR CPL
FOR THE MONTH OF JANUARY, 1997

SUMMARY OF SERVICES RENDERED

	CURRENT MONTH			YEAR TO DATE		
FUNCTION	ACTUAL	BUDGET	FAVORABLE <UNFAVR>	ACTUAL	BUDGET	FAVORABLE <UNFAVR>
INFORMATION SERVICES	$XXX,XXX.XX	$XXX,XXX	$XX,XXX.XX	$XXX,XXX.XX	$XXX,XXX	$XX,XXX.XX
HUMAN RESOURCES	$XXX,XXX.XX	$XXX,XXX	$XX,XXX.XX	$XXX,XXX.XX	$XXX,XXX	$XX,XXX.XX
MARKETING	$XXX,XXX.XX	$XXX,XXX	$XX,XXX.XX	$XXX,XXX.XX	$XXX,XXX	$XX,XXX.XX
ACCOUNTING	$XXX,XXX.XX	$XXX,XXX	$XX,XXX.XX	$XXX,XXX.XX	$XXX,XXX	$XX,XXX.XX
PRODUCTION	$XXX,XXX.XX	$XXX,XXX	$XX,XXX.XX	$XXX,XXX.XX	$XXX,XXX	$XX,XXX.XX
TRANSMISSION	$XXX,XXX.XX	$XXX,XXX	$XX,XXX.XX	$XXX,XXX.XX	$XXX,XXX	$XX,XXX.XX
STRATEGIC PLANNING	$XXX,XXX.XX	$XXX,XXX	$XX,XXX.XX	$XXX,XXX.XX	$XXX,XXX	$XX,XXX.XX
CORPORATE MANAGEMENT	$XXX,XXX.XX	$XXX,XXX	$XX,XXX.XX	$XXX,XXX.XX	$XXX,XXX	$XX,XXX.XX
PROJECTS: WORK 2000	$XXX,XXX.XX	$XXX,XXX	$XX,XXX.XX	$XXX,XXX.XX	$XXX,XXX	$XX,XXX.XX
SUPPLY CHAIN	$XXX,XXX.XX	$XXX,XXX	$XX,XXX.XX	$XXX,XXX.XX	$XXX,XXX	$XX,XXX.XX
	$XXX,XXX.XX	$XXX,XXX	$XX,XXX.XX	$XXX,XXX.XX	$XXX,XXX	$XX,XXX.XX
TOTAL SERVICES RENDERED	$X,XXX,XXX.XX	$X,XXX,XXX	$XX,XXX.XX	$X,XXX,XXX.XX	$X,XXX,XXX	$XXX,XXX.XX

CSWS BILLING TEAM

WP/KNORR
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CENTRAL AND SOUTH WEST SERVICES, INC.
SERVICES RENDERED FOR CPL
FOR THE MONTH OF JANUARY, 1997

SUMMARY OF HUMAN RESOURCES SERVICES

	CURRENT MONTH			YEAR TO DATE		
TYPE OF SERVICES	ACTUAL	BUDGET	FAVORABLE <UNFAVR>	ACTUAL	BUDGET	FAVORABLE <UNFAVR>
O & M SERVICE IDS:						
PAYROLL PROCESSING	$XXX,XXX.XX	$XXX,XXX	$XX,XXX.XX	$XXX,XXX.XX	$XXX,XXX	$XX,XXX.XX
BENEFITS PROCESSING	$XXX,XXX.XX	$XXX,XXX	$XX,XXX.XX	$XXX,XXX.XX	$XXX,XXX	$XX,XXX.XX
CLAIMS PROCESSING	$XXX,XXX.XX	$XXX,XXX	$XX,XXX.XX	$XXX,XXX.XX	$XXX,XXX	$XX,XXX.XX
	$XXX,XXX.XX	$XXX,XXX	$XX,XXX.XX	$XXX,XXX.XX	$XXX,XXX	$XX,XXX.XX
	$XXX,XXX.XX	$XXX,XXX	$XX,XXX.XX	$XXX,XXX.XX	$XXX,XXX	$XX,XXX.XX
	$XXX,XXX.XX	$XXX,XXX	$XX,XXX.XX	$XXX,XXX.XX	$XXX,XXX	$XX,XXX.XX
TOTAL O & M SERVICES	$XXX,XXX.XX	$XXX,XXX	$XX,XXX.XX	$XXX,XXX.XX	$XXX,XXX	$XX,XXX.XX
CAPITAL SERVICE IDS:						
THE "XXXX" PROJECT	$XXX,XXX.XX	$XXX,XXX	$XX,XXX.XX	$XXX,XXX.XX	$XXX,XXX	$XX,XXX.XX
	$XXX,XXX.XX	$XXX,XXX	$XX,XXX.XX	$XXX,XXX.XX	$XXX,XXX	$XX,XXX.XX
TOTAL CAPITAL SERVICES	$XXX,XXX.XX	$XXX,XXX	$XX,XXX.XX	$XXX,XXX.XX	$XXX,XXX	$XX,XXX.XX
TOTAL H/R SERVICES	$X,XXX,XXX.XX	$X,XXX,XXX	$XX,XXX.XX	$X,XXX,XXX.XX	$X,XXX,XXX	$XXX,XXX.XX

CENTRAL AND SOUTH WEST SERVICES, INC.
SERVICES RENDERED FOR CPL
FOR THE MONTH OF JANUARY, 1997

SUMMARY OF PAYROLL PROCESSING SERVICES

	CURRENT MONTH			YEAR TO DATE		
TYPE OF EXPENSE	ACTUAL	BUDGET	FAVORABLE <UNFAVR>	ACTUAL	BUDGET	FAVORABLE <UNFAVR>
SALARIES	$XXX,XXX.XX	$XXX,XXX	$XX,XXX.XX	$XXX,XXX.XX	$XXX,XXX	$XX,XXX.XX
TRAVEL	$XXX,XXX.XX	$XXX,XXX	$XX,XXX.XX	$XXX,XXX.XX	$XXX,XXX	$XX,XXX.XX
OUTSIDE SERVICES	$XXX,XXX.XX	$XXX,XXX	$XX,XXX.XX	$XXX,XXX.XX	$XXX,XXX	$XX,XXX.XX
	$XXX,XXX.XX	$XXX,XXX	$XX,XXX.XX	$XXX,XXX.XX	$XXX,XXX	$XX,XXX.XX
	$XXX,XXX.XX	$XXX,XXX	$XX,XXX.XX	$XXX,XXX.XX	$XXX,XXX	$XX,XXX.XX
OVERHEADS	$XXX,XXX.XX	$XXX,XXX	$XX,XXX.XX	$XXX,XXX.XX	$XXX,XXX	$XX,XXX.XX
COMPUTER RESOURCE CHARGE	$XXX,XXX.XX	$XXX,XXX	$XX,XXX.XX	$XXX,XXX.XX	$XXX,XXX	$XX,XXX.XX
	$XXX,XXX.XX	$XXX,XXX	$XX,XXX.XX	$XXX,XXX.XX	$XXX,XXX	$XX,XXX.XX
TOTAL PAYROLL PROCESSING	$X,XXX,XXX.XX	$X,XXX,XXX	$XX,XXX.XX	$X,XXX,XXX.XX	$X,XXX,XXX	$XXX,XXX.XX

CSWS BILLING TRAINING
(PART II)

CSWS ACCOUNTING
SUMMER, 1996

More On “Service ID”

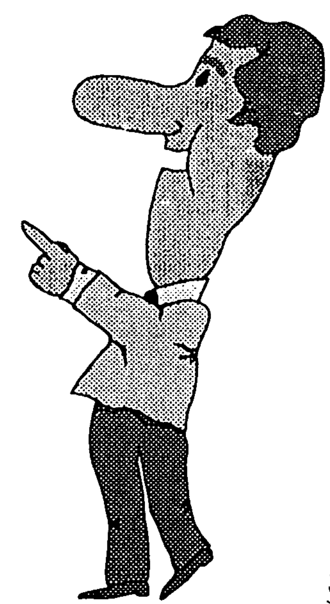
Purpose of Service IDs

Types of Cost

What Service ID to use

New Service ID Request

Service ID Owner



CSW/CSWS Employees Use Service IDs

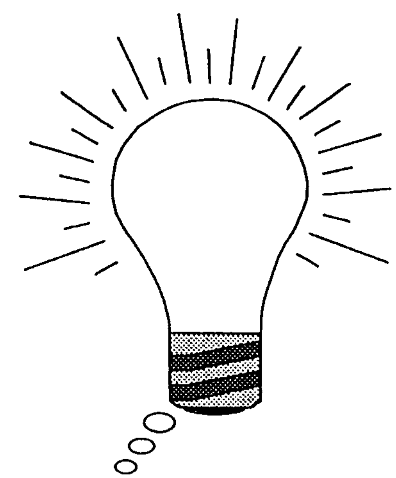
To ...

√ Budget Services

√ Capture Actual Charges

√ Bill the Charges to appropriate CSW Subsidiary(ies)

√ Track major activities, project & functional Services

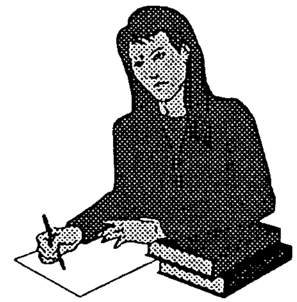


Not To ......

√ Track Detailed Tasks

Types of Cost

- Service Cost:
  - Cost incurred for providing functional or special project services



- Administrative Cost:
  - Cost not associated with specific functional or special project services (e.g. staff meeting, team building, safety meeting ... etc.)

team building

"Service IDs "

MARKETING PROGRAMS DEPARTMENT"

Service Cost:

MKCPROGMCC (Commercial Marketing Programs - 100% CPL)

MKCPROGM4E (Commercial Marketing Programs - Billed to 4 Electrics Based on "# of Commercial customers)

Administrative Cost:

MKADMINSAA (Marketing Administrative Cost - Bill to CSW Subsidiaries receiving marketing services)

What "Service IDs" Do I Use ?

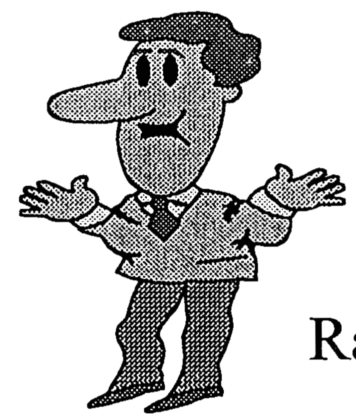
Your ***Functional Services*** - Ask your manager or budget coordinator ....

Special Assignment/Project - Ask the requester or project leader for service ID...

When Is A New "Service ID" Required ?

- If ....
  - √ No existing <u>Service Code</u> applies to the new service or project **Or** ....
  - √ No existing Service Code uses the <u>Attribution Formula</u> that is appropriate for the new service or project **Or** ....
  - √ <u>Regulatory</u> requirement

- New Service ID Questions- contact Raul Ortiz at (918) 594 - 2372



Raul

"SERVICE ID" SYSTEM

√ CICS on-line information screen "HSID" (8/1/96)

  – Help screen feature

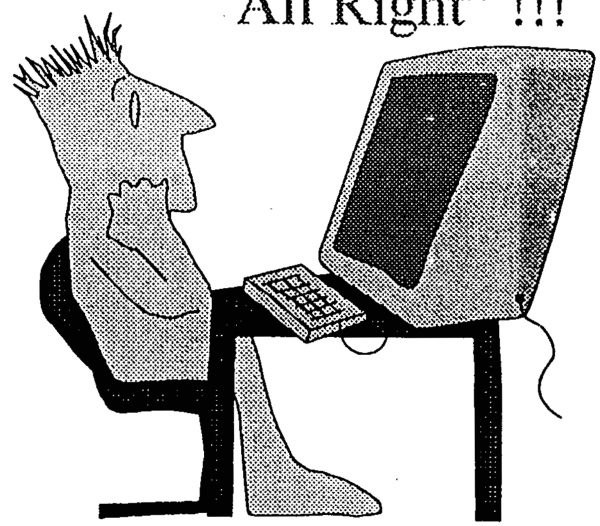
√ New service ID on-line request

  – On-line automatic approval

  – Help screen feature

  – Validation feature

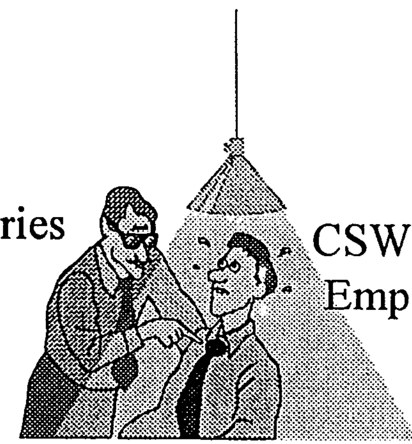
"All Right" !!!



Service ID Owners

- Monitor Service IDs ***charges*** incurred and question unusual charges
- Be available to help the Accounting department with ***billing questions***
- Monitor ***budget variances*** for their Service IDs

* CSW Subsidiaries
* Regulators



CSWS
Employees

CSWS Billing *Questions*

- Francie Bourland (918) 594 - 2061
- Grace Greenwell (918) 594 - 2296
- Terry Taylor (918) 594 - 2057
- Camille White (918) 594 - 2076

CSWS Service ID Training Appendix

1. CSWS 1997 Service Code Listing for Functional Services (partial)

2. CSWS 1997 Attribution Basis Listing (partial)

3. CSWS 1997 Customer Code Listing (partial)

4. CSWS 1996 Work Orders Used by Center (available on the LAN)

5. CSWS 1997 ~~Service ID and~~ Billing Method Guidelines

6. CSWS Service ID Request Form

NOTE:

Item # 1, 2, 3, and 4 are also available on the LAN

X:\\\ CN = CSWS_XCHANGE.CSWS.CSW\BILLING\

Item # 6 (Service ID Request Form)

Sign on to "CICS" and key in "HSID"

1. CSWS 1997 Service Code Listing for Functional Services (partial)

X:\\\ CN = CSWS_XCHANGE.CSWS.CSW\BILLING\

CSW/CSWS 1997 SERVICE CODE LISTING FOR FUNCTIONAL SERVICES

(PARTIAL LISTING)

SERVICE CODE	SERVICE CODE TITLE	ATTRIBUTION BASIS
ACADMINS	ACCOUNTING ADMINISTRATION	"AC" FUNCTION PAST 3 MONTHS TOTAL BILL $
ACAPAYMT	VENDOR PAYMENT SERVICE	# OF VENDOR INVOICE PAYMENTS
ACCLOSES	FINANCIAL CLOSING SERVICE	# OF GL TRANSACTIONS
ACEXRPT	EXTERNAL REPORTING	TOTAL ASSET $
ACFERCRP	FERC REPORTS	EVEN SPREAD BY COMPANY
ACINTRPT	INTERNAL REPORTING	TOTAL ASSET $
ACMGMTRP	MANAGERIAL (INTERNAL) REPORTS	TOTAL ASSET $
ACPROPTY	PROPERTY RECORDS SERVICE	# OF JCA TRANSACTIONS
ACRESCH	ACCOUNTING RESEARCH/CONSULTING	TOTAL ASSET $
ACRTCASE	RATE CASE SUPPORT	EVEN SPREAD BY COMPANY
ACSECRPT	SEC REPORTS	TOTAL ASSET $
ACSTATER	STATE REPORTS	TOTAL ASSET $
ACTAXCMP	FED/STATE/LOCAL TAX COMPLIANCE	"TX" PAST 3 MONTHS DIRECT BILL$???
ACTAXPLN	TAX PLANNING	"TX" PAST 3 MONTHS DIRECT BILL$???
ASADMINS	AUDITS ADMINISTRATION	"AS" FUNCTION FUNCTION PAST 3 MONTHS TOTAL BILL $
ASSERVIC	INTERNAL AUDITS	0
AVADMINS	AVIATION ADMINISTRATION	"AV" FUNCTION PAST 3 MONTHS TOTAL BILL $
AVF263SW	N263SW - FIXED COSTS (SWEP)	0
AVF295CP	N295CP - FIXED COSTS (CPL)	
AVF326PS	N326PS - FIXED COSTS (PSO)	
AVF466CS	N466CS - FIXED COSTS (DALLAS)	TOTAL CSWS BILLING LESS INDIR WO & INT.
AVFKA350	KING AIR 350 - FIXED COST	
AVN295CP	N295CP - VAR OPER EXP NON-BILL	0
AVN326PS	N326PS - VARIABLE COST (PSO) NON-BILL	
AVV263SW	N263SW - VARIABLE COST (SWEP)	
AVV294CS	N294CS - VARIABLE COSTS (WTU)	
AVV466CS	N466CS - VARIABLE COST (DALLAS) NON-BILL	
AVVKA350	KING AIR 350 - VARIABLE COST	
BENEFITS	OVERHEAD - BENEFITS	OVERHEAD CLEARING
CMADMINS	CORP. COMMUNICATION ADMINISTRATION	"CC" FUNCTION PAST 3 MONTHS TOTAL BILL $
CMEXTERN	EXTERNAL COMMUNICATION	# OF CUSTOMERS ???
CMINTERN	INTERNAL COMMUNICATION	# OF EMPLOYEES
ECADMINS	ENGINEERING & CONSTRUCTION ADMINISTRATION	"EC" PAST 3 MONTHS TOTAL BILL $
ECBUSDEV	ENG/CONST. BUSINESS DEVELOPMENT	TOTAL PEAK LOAD (LAST YEAR)
ECDRAFTD	DRAFTING/TECHNICAL DESIGN	TOTAL PEAK LOAD (LAST YEAR)
ECENGCON	ENGINEERING & CONSTRUCTION CONSULTING	TOTAL PEAK LOAD (LAST YEAR)
ENADMINS	ENVIRONMENTAL SERVICE ADMINISTRATIION	"EN" PAST 3 MONTHS TOTAL BILL $
ENAIREMI	AIR EMISSIONS MANAGEMENT	0
ENAIRPER	AIR PERMITTING	
ENCOMPAU	ENVIRONMENTAL COMPLIANCE AUDITING	
ENMINEPR	MINE PERMITTING	
ENMISCSR	MISCELLANEOUS ENVIRONMENTAL SERVICES	
ENOCCUPH	OCCUPATIONAL HEALTH/IH	
ENSPILLR	SPILLS/REMEDIATION	
ENWASMGT	WASTE MANAGEMENT	
ENWTRMGT	WATER MANAGEMENT	
ENWTRPER	WATER PERMITTING	
EXSUPPRT	EXECUTIVE SUPPORT	TO BE DETERMINED
FGADMINS	FOSSIL GENERATION ADMINISTRATION	"FG" PAST 3 MONTHS TOTAL BILL $
FGADMSVC	FOSSIL GENERATION ADMINISTRATIVE SERVICES	# OF GENERATING PLANT EMPLOYEES
FGMGTSVC	FOSSIL GENERATION MANAGEMENT SERVICES	MW GENERATING CAPABILITY
FGTECSVC	FOSSIL GENERATION TECHNICAL SERVICES	MWH 'S GENERATION
FUACCTNG	FUEL ACCOUNTING SERVICES	PAST 3 MONTHS MMBtu's BURNED(ALL FUEL TYPES)
FUADMINS	FUELS ADMINISTRATION	"FU" PAST 3 MONTHS TOTAL BILL $
FUGASFUE	GAS FUEL SERVICES	PAST 3 MONTHS MMBtu's BURNED(GAS TYPE ONLY)
FUOILFUE	OIL FUELS SERVICES	PAST 3 MONTHS MMBtu's BURNED(OIL TYPE ONLY)
FUPLANNA	FUEL PLANNING & ANALYSIS SERVICES	PAST 3 MONTHS MMBtu's BURNED(ALL FUEL TYPES)
FURECORD	FUEL ACCOUNTING SERV. - LAND RECORDS	JOINT PROJECTS WORKED ON FOR THE PERIOD ?
FUREGUIS	FUEL SERVICES - REGULATORY ISSUES	JOINT PROJECTS WORKED ON FOR THE PERIOD ?
FUSERVIC	FUELS SERVICES	PAST 3 MONTHS MMBtu's BURNED(ALL FUEL TYPES)
FUSOCOAL	SOLID FUEL SERVICES - COAL	PAST 3 MONTHS MMBtu's BURNED(COAL ONLY)
FUSOSERV	SOILD FUEL SERVICES	PAST 3 MONTHS MMBtu's BURNED(SOLID FUELS ONLY)
GSADMINS	GENERAL SERVICES ADMINISTRATION	"GS" FUNCTION FUNCTION PAST 3 MONTHS TOTAL BILL $
GSCOPYSV	COPY SERVICES	# OF EMPLOYEES
GSDOCUMT	DOCUMENTATION SERVICES	# OF EMPLOYEES
GSFLEETP	FLEET PROCUREMENT	# OF VEHICLE SPECIFICATIONS
GSFLEETS	FLEET SERVICES	# OF VEHICLES
GSFORMSM	FORMS MANAGEMENT	# OF EMPLOYEES
GSPRINTS	PRINT SERVICES	# OF EMPLOYEES
GSTRAVEL	TRAVEL SERVICES	# OF TRAVEL RESERVATIONS
HRADMINS	HR ADMINISTRATION	"HR" FUNCTION PAST 3 MONTHS TOTAL BILL $
HRBENSER	BENEFITS SERVICES	# OF BENEFITS TRANSACTIONS
HRCLAIMS	CLAIM PROCESSING	# OF CLAIM PROCESSING TRANSACTIONS
HRCONSUL	HR CONSULTING	# OF EMPLOYEES
HRCORMGT	CORPORATE MANAGEMENT CONFERENCE	# OF EMPLOYEES
HREVENTS	CORPORATE EVENT PLANNING	# OF EMPLOYEES

CSW/CSWS 1997 SERVICE CODE LISTING FOR FUNCTIONAL SERVICES		
(PARTIAL LISTING)		
SERVICE CODE	SERVICE CODE TITLE	ATTRIBUTION BASIS
HRPAYROL	PAYROLL SERVICES	# OF EMPLOYEES
HRSUPPRT	HR SUPPORT	# OF EMPLOYEES
HRTRAINS	HR TRAINING	# OF EMPLOYEES
INDUSSPT	INDUS SUPPORT	"PR" FUNCTION PAST 3 MONTHS TOTAL BILL $
ISADMINS	IS ADMINISTRATION	"IS" FUNCTION PAST 3 MONTHS TOTAL BILL $
ISADMSYS	IS ADMINISTATION SYSTEM	# OF EMPLOYEES
ISAPAYSM	IS A/P SYSTEM	# OF VENDOR INVOICE PAYMENTS
ISAPAYSY	IS ACCOUNTS PAYABLE SYSTEM	# OF VENDOR INVOICE PAYMENTS
ISBILPRT	IS BILL PRINTING & MAILING SERVICES	# OF CIS CUSTOMER MAILINGS
ISCALCTR	IS CALL CENTER	# OF AGENT SEATS/POSITIONS
ISCISSYS	IS CUSTOMER INFORMATION SYSTEM	# OF ELECTRIC ULTIMATE CUSTOMERS
ISCONSUL	IS CONSULTING	0
ISDISENG	IS DISTRIBUTION ENGINEERING SYSTEM	PEAK LOAD/AVG CUST/KWH SALES
ISENVIRN	IS ENVIRONMENTAL SYSTEM	
ISFINOTH	IS OTHER FINANCIAL SYSTEM	# OF GL TRANSACTIONS
ISFOSGEN .	IS FOSSIL / GENERATION SYSTEM	PEAK LOAD/AVG CUST/KWH SALES
ISFUELSY	IS FUELS SYSTEM	PEAK LOAD/AVG CUST/KWH SALES
ISGENLEG	IS GENERAL LEDGER SYSTEM	# OF TRANSACTIONS
ISHUMSYS	IS HUMAN SYSTEM	# OF EMPLOYEES
ISJCASYS	IS JOB COST ACCOUNTING SYSTEM	# OF JCA TRANSACTIONS
ISMARKET	IS MARKETING SYSTEMS	PEAK LOAD/AVG CUST/KWH SALES
ISMATPRO	IS MATERIAL PROCUREMENT SYSTEM	PEAK LOAD/AVG CUST/KWH SALES
ISMERCHD	IS MERCHANDISE SYSTEM	PEAK LOAD/AVG CUST/KWH SALES
ISMFBMRK	IS MAINFRAME BENCH MARKING CALLS	CRU BILLING FORMULA
ISMFCHGE	IS SECURITY & CHANGE CONTROL	CRU BILLING FORMULA
ISMFCICS	IS MAINFRAME CICS	CRU BILLING FORMULA
ISMFCMSS	IS MAINFRAME VM/CMS	CRU BILLING FORMULA
ISMFCOMM	IS MAINFRAME COMMUNICATIONS	CRU BILLING FORMULA
ISMFCPUS	IS MAINFRAME CENTRAL PROCESSING UNIT	CRU BILLING FORMULA
ISMFCTSV	IS MAINFRAME S&A CLIENT SERVICES	CRU BILLING FORMULA
ISMFDASD	IS DASD	CRU BILLING FORMULA
ISMFDBSP	IS MAINFRAME DATA BASE SYSTEM SUPPORT	CRU BILLING FORMULA
ISMFDIAS	IS MAINFRAME DIASTER RECOVERY	CRU BILLING FORMULA
ISMFDSKS	IS MAINFRAME DISK STORAGE	CRU BILLING FORMULA
ISMFHRDW	IS MAINFRAME HARDWARE	CRU BILLING FORMULA
ISMFMICO	IS MAINFRAME MICROFICHE	CRU BILLING FORMULA
ISMFMVSS	IS MAINFRAME MVS	CRU BILLING FORMULA
ISMFMVSW	IS MAINFRAME MVS SOFTWARE	CRU BILLING FORMULA
ISMFPNTR	IS MAINFRAME PRINTER	CRU BILLING FORMULA
ISMFPROD	IS MAINFRAME PRODUCTION	CRU BILLING FORMULA
ISSUPPMF	IS MAINFRAME - OTHER SUPPORT	
ISMFTAPE	IS MAINFRAME TAPE	CRU BILLING FORMULA
ISNETWRK	IS NETWORK	# OF WORKSTATIONS
ISPROENG	IS PRODUCTION ENGINEERING SYSTEM	PEAK LOAD/AVG CUST/KWH SALES
ISRATESS	IS RATES SYSTEM	PEAK LOAD/AVG CUST/KWH SALES
ISSHRHLD	IS SHAREHOLDER SYSTEM	TOTAL ASSET $
ISTREASR	IS TREASURY SYSTEM	TOTAL ASSET $
ISTRNSUB	IS TRANSMISSION & SUBSTATION SYSTEM	PEAK LOAD/AVG CUST/KWH SALES
ISWORK2K	IS WORK 2000 SYSTEM	# OF ELECTRIC ULTIMATE CUSTOMERS
ISWORKST	IS DESKTOP WORKSTATION	# OF WORKSTATIONS
LGADMINS	LEGAL ADMINISTRATION	"LG" FUNCTION PAST 3 MONTHS TOTAL BILL $
LGCONSUL	LEGAL CONSULTING SERVICES	0
LGCORSEC	CORP SECRETARY SERVICES	
LGEDMSOM	EDMS O & M SYSTEM	
LOSTTIME	OVERHEAD - LOST TIME	OVERHEAD CLEARING
MAADMINS	MERGER & ACQUISITION ADMINISTRATION	
MASERVIC	MERGER & ACQUISITION	0
MKADMINS	MARKETING ADMINISTRATION	"MK" FUNCTION PAST 3 MONTHS TOTAL BILL $
MKADPRME	ADVERTISING, PRODUCTION, MEDIA	# OF ELECTRIC ULTIMATE CUSTOMERS
MKADPROD	ADVERTISING, PRODUCTION	# OF ELECTRIC ULTIMATE CUSTOMERS
MKCOMMUN	COMMUNICATION	# OF EMPLOYEES
MKCOMPIN	COMPETITIVE INTELLIGENCE	AVG PEAK LOAD FOR WHOLESALE CUSTOMERS
MKCPROGM	COMMERCIAL MARKETING PORGRAMS	# OF COMMERCIAL CUSTOMERS
MKECODEV	ECONOMIC DEVELOPMENT	KWH SALES (ULTIMATE CUSTOMERS)
MKENERTR	ENERGY TRADING	AVG PEAK LOAD FOR WHOLESALE CUSTOMERS
MKGRAPHI	COMMUNICATION - GRAPHICS SUPPORT	# OF RESIDENTIAL CUSTOMERS
MKKEYACT	KEY ACCOUNT MANAGEMENT	# OF ELECTRIC ULTIMATE CUSTOMERS
MKMULTIM	COMMUNICATION - MULTIMEDIA	# OF RESIDENTIAL CUSTOMERS
MKPOWERM	POWER MARKETING	AVG PEAK LOAD FOR WHOLESALE CUSTOMERS
MKRATELR	MARKETING RATE LOAD RESEARCH	KWH SALES (ULTIMATE CUSTOMERS)
MKRATEPC	MARKETING RATE PRICING & COSTING	KWH SALES (ULTIMATE CUSTOMERS)
MKRATESP	MARKETING RATE SUPPORT	KWH SALES (ULTIMATE CUSTOMERS)
MKRESEAR	MARKET RESEARCH	# OF ELECTRIC ULTIMATE CUSTOMERS
MKRESSUP	RESEARCH SUPPORT	AVG PEAK LOAD FOR WHOLESALE CUSTOMERS
MKRPROGM	RESIDENTIAL MARKETING PROGRAMS	# OF RESIDENTIAL CUSTOMERS
MKTECHSP	MARKETING TECHNICAL SUPPORT	# OF ELECTRIC ULTIMATE CUSTOMERS

CSW/CSWS 1997 SERVICE CODE LISTING FOR FUNCTIONAL SERVICES		
(PARTIAL LISTING)		
SERVICE CODE	SERVICE CODE TITLE	ATTRIBUTION BASIS
MKTRAING	MARKETING TRAINING	# OF ELECTRIC ULTIMATE CUSTOMERS
MKVIDEOS	COMMUNICATION - VIDEO SUPPORT	# OF EMPLOYEES
NUCLEARE	NUCLEAR ENGINEERING	0
OCCPUANT	OCCUPANCY OVERHEAD	OVERHEAD CLEARING
OCCUBLDG	OCCUPANCY - BUILDING	OVERHEAD CLEARING
OCCUPCOM	OCCUPANCY - PC	OVERHEAD CLEARING
OCCUTELE	OCCUPANCY - TELEPHONE	OVERHEAD CLEARING
PAADMINS	P & A ADMINISTRATION	"PA" FUNCTION PAST 3 MONTHS TOTAL BILL $
PACAPSER	CAPITAL PLANNING SERVICE	TOTAL FIXED ASSET $
PAOMSERV	O&M PLANNING SERVICE	"CSWS" PAST 3 MONTHS TOTAL BILL $
PASTRATE	STRATEGIC PLANNING SERVICES	"CSWS" PAST 3 MONTHS TOTAL BILL $
PAYTAXES	OVERHEAD - PAYROLL TAX	OVERHEAD CLEARING
PIADMINS	SPI ADMINISTRATION	0
PIMGTCON	MANAGEMENT CONSULTING SERVICES	"SP" PAST 3 MONTHS TOTAL BILL $
PRADMINS	PROCUREMENT ADMINISTRATION	"PR" FUNCTION PAST 3 MONTHS TOTAL BILL $
PRSERVIC	PROCUREMENT SERVICES	PEAK LOAD/AVG CUST/KWH SALES
RGADMSUP	REGULATORY - ADMINISTRATIVE SUPPORT	TOTAL ASSET $
RGADMINS	REGULATORY ADMINISTRATION	"RG" FUNCTION PAST 3 MONTHS TOTAL BILL $
RGDOCACT	REGULATORY - DOCUMENTATION ACTIVITIES	TOTAL ASSET $
RGFEDGOV	REGULATORY - FED. GOVERNMENTAL AFFAIRS	TOTAL ASSET $
RGGENSUP	REGULATORY - GENERAL SUPPORT	TOTAL ASSET $
RGMGTCON	REGULATORY - MANAGEMENT & CONSULTING	TOTAL ASSET $
RGPOLCOM	REGULATORY - POLICY & COMPLIANCE	TOTAL ASSET $
RGSTGOVT	REGULATORY - STATE GOVERNMENTAL AFFAIRS	TOTAL ASSET $
RMANAGMT	RISK MANAGEMENT	TOTAL ASSET $
RMINSPRM	RISK MANAGEMENT INSURANCE PREMIUM	TOTAL ASSET $
RMSAFETY	RISK MANAGEMENT SAFETY	# OF EMPLOYEES
RMWKCOMP	RISK MANAGEMENT WORKER COMP.	# OF EMPLOYEES
STADMINS	STRATEGIC ADMINISTRATION	"ST" FUNCTION PAST 3 MONTHS TOTAL BILL $
STFINPLA	STRATEGIC & FINANCIAL PLANNING CONSULTING	"ST" FUNCTION PAST 3 MONTHS TOTAL BILL $
STMKTCON	STRATEGIC MARKETING CONSULTING	# CUSTOMERS ???
TCADMINS	TELECOM ADMINISTRATION	"TC" FUNCTION PAST 3 MONTHS TOTAL BILL $
TCCALCTR	TELECOM CALL CENTER	# OF AGENT SEATS/POSITIONS
TCCELLPH	TELECOM CELL PHONES AND PAGERS	# OF CELL PHONES / PAGERS
TCCONSUL	TELECOM CONSULTING	0
TCEMSCDA	TELECOM EMS / SCADA	# OF REMOTE TERMINAL UNITS
TCMOBRAD	TELECOM MOBILE RADIOS	# OF RADIOS(BASE/MOBILE/HANDHELD)
TCTELEPH	TELECOM TELEPHONY	# OF TELEPHONES
TDADMINS	T & S ADMINISTRATION	"TD" FUNCTION PAST 3 MONTHS TOTAL BILL $
TDASAPPX	ASAPP USERS GROUP	PEAK LOAD/AVG. # OF ULTIMATE CUSTOMERS
TDBIOMAS	BIOMASS RESEARCH	PEAK LOAD/AVG. # OF ULTIMATE CUSTOMERS
TDCAPITA	T& S SERVICES - CAPITAL	PEAK LOAD/AVG. # OF ULTIMATE CUSTOMERS
TDCATXXX	COMPETITIVE ASSESSMENT	PEAK LOAD/AVG. # OF ULTIMATE CUSTOMERS
TDCPLSPM	SUB PREDICTIVE MAIN	PEAK LOAD/AVG. # OF ULTIMATE CUSTOMERS
TDDOEEMF	DOE EMF STUDY	PEAK LOAD/AVG. # OF ULTIMATE CUSTOMERS
TDEIBURN	ELEC BURN STUDY	PEAK LOAD/AVG. # OF ULTIMATE CUSTOMERS
TDEPREMF	TAILORED COLLABORATION PROJ.	PEAK LOAD/AVG. # OF ULTIMATE CUSTOMERS
TDEPRIGN	OVERSIGHT UTIL OF EPRI R&D PROGRAM	PEAK LOAD/AVG. # OF ULTIMATE CUSTOMERS
TDEVSXXX	ELEC VEHICLE CON	PEAK LOAD/AVG. # OF ULTIMATE CUSTOMERS
TDMKTPRO	MARKET PROFITABILITY STUDY	PEAK LOAD/AVG. # OF ULTIMATE CUSTOMERS
TDRENMON	WIND & SOLAR RESOURCE MONITORING	0
TDRESEAR	S & A RESEARCH	PEAK LOAD/AVG. # OF ULTIMATE CUSTOMERS
TDRIOGRA	RIO GRANDE NOI FILING	0
TDTEAMUP	TEAM UP-PV	PEAK LOAD/AVG. # OF ULTIMATE CUSTOMERS
TDTSEXPE	T & S SERVICE - EXPENSE	0
TRADMINS	TREASURY ADMINISTRATION	"TR" FUNCTION FUNCTION PAST 3 MONTHS TOTAL BILL $
TRCSHMGT	CASH MANAGEMENT	# OF BANK ACCOUNTS
TRFINANL	FINANAL ANALYSIS CONSULTING	TOTAL ASSET $
TRINVREL	INVESTOR RELATION MANAGEMENT	TOTAL ASSET $
TRLTCAP	LONG TERM CAPITAL MANAGEMENT	TOTAL ASSET $
TRREMITP	REMITTANCE PROCESSING	# OF REMITTANCE ITEMS
TRSECADM	SECURITIES ADMINISTRATION	0
TRSTCAP	SHORT TERM CAPITAL MANAGEMENT	TOTAL ASSET $
TSSHRHLD	SHAREHOLDERS SERVICES	TOTAL CSWS BILLING LESS INDIR WO & INT.
0		

2. CSWS 1997 Attribution Basis Listing
(partial)

X:\\\ CN = CSWS_XCHANGE.CSWS.CSW\BILLING\

6/10/96
CSWS BILLING TEAM

(DRAFT)

CSW/CSWS 1997 ATTRIBUTION BASIS LISTING
(PARTIAL LISTING)
"AC" FUNCTION PAST 3 MONTHS TOTAL BILL$
"AS" FUNCTION PAST 3 MONTHS TOTAL BILL $
"AV" FUNCTION PAST 3 MONTHS TOTAL BILL $
"CC" FUNCTION PAST 3 MONTHS TOTAL BILL $
"CSWS" PAST 3 MONTHS TOTAL BILL $
"GS" FUNCTION PAST 3 MONTHS TOTAL BILL $
"HR" FUNCTION PAST 3 MONTHS TOTAL BILL $
"IS" FUNCTION PAST 3 MONTHS TOTAL BILL $
"LG" FUNCTION PAST 3 MONTHS TOTAL BILL $
"MK" FUNCTION PAST 3 MONTHS TOTAL BILL $
"PA" FUNCTION PAST 3 MONTHS TOTAL BILL $
"PR" FUNCTION PAST 3 MONTHS TOTAL BILL $
"RG" FUNCTION PAST 3 MONTHS TOTAL BILL $
"ST" FUNCTION PAST 3 MONTHS TOTAL BILL $
"TC" FUNCTION PAST 3 MONTH TOTAL BILL $
"TD" FUNCTION PAST 3 MONTHS TOTAL BILL $
"TR" FUNCTION PAST 3 MONTHS TOTAL BILL $
"TX" PAST 3 MO. DIRECT BILL$???
OF AGENT SEATS/POSITIONS
OF BANK ACCOUNTS
OF BENEFITS TRANSACTIONS
OF CELL PHONES / PAGERS
OF CIS CUSTOMER MAILINGS
OF CLAIM PROCESSING TRANSACTIONS
OF COMMERCIAL CUSTOMERS
OF CUSTOMERS ???
OF ELECTRIC ULTIMATE CUSTOMERS
OF EMPLOYEES
OF GENERATING PLANT EMPLOYEES
OF GL TRANSACTIONS
OF JCA TRANSACTIONS
OF RADIOS (BASE/MOBILE/HANDHELD)
OF REMITTANCE ITEMS
OF REMOTE TERMINAL UNITS
OF RESIDENTIAL CUSTOMERS
OF RESIDENTIAL CUSTOMERS
OF TELEPHONES
OF TRAVEL RESERVATIONS
OF ULTIMATE CUSTOMERS
OF VEHICLE SPECIFICATIONS
OF VEHICLES
OF VENDOR INVOICE PAYMENTS
OF WORKSTATIONS
AVG # OF ULTIMATE CUSTOMERS
AVG PEAK LOAD FOR PAST THREE YEARS
AVG PEAK LOAD FOR WHOLESALE CUSTOMERS
COMPUTER RESOURCE UNITS
CRU $ BILLED
CRU BILLING FORMULA
EVEN SPREAD BY COMPANY
JOINT PROJECTS WORKED ON FOR THE PERIOD
KWH SALES (ULTIMATE CUSTOMERS)
MONEY POOL INTEREST EXPENSE
MW GENERATING CAPABILITY
MWH 'S GENERATION
OVERHEAD CLEARING
PAST 3 MO. MMBtu's BURNED(ALL FUEL TYPES)
PAST 3 MO. MMBtu's BURNED(COAL ONLY)
PAST 3 MO. MMBtu's BURNED(GAS TYPE ONLY)
PAST 3 MO. MMBtu's BURNED(OIL TYPE ONLY)
PAST 3 MO. MMBtu's BURNED(SOLID FUELS ONLY)
PEAK LOAD/AVG # CUST/KWH SALES
PEAK LOAD/AVG # OF ULTIMATE CUSTOMERS
TOTAL ASSET $
TOTAL CSWS BILLING LESS INDIRECT COST & INTEREST
TOTAL FIXED ASSET $
TOTAL GROSS UTILITY PLANT(INCLUDES CWIP)
TOTAL PEAK LOAD (LAST YEAR)
ULTIMATE CUSTOMERS/KWH SALES

3. CSWS 1997 Customer Code Listing
(partial)

X:\\\ CN = CSWS_XCHANGE.CSWS.CSW\BILLING\

CENTRAL AND SOUTH WEST SERVICES, INC.
CUSTOMER CODES
(Draft)

DIRECT BILLING:

Code	Customer
BB	SEEBOARD
CC	CPL
EE	CSW ENERGY
HH	ENERSHOP
II	CSW INTERNATIONAL
JJ	JFP
KK	TRANSOK
LL	CSW LEASING
MM	CSW COMMUNICATIONS
PP	PSO
RR	CSW CORPORATION
SS	SWEPCO
TT	CSW CREDIT
WW	WTU
ZZ	CSW SERVICES SUPPORT

SHARED BILLING:

Code	Customer
CP	CPL AND PSO
CW	CPL AND WTU
CS	CPL AND SWEPCO
WP	WTU AND PSO
WS	WTU AND SWEPCO
SP	SWEPCO AND PSO (ALSO SOUTH WEST POWER POOL)
4E	4 ELECTRIC OPERATING COMPANIES
TX	CPL/SWEPCO/WTU (TEXAS COMPANIES)
AA	ALL COMPANIES
AB	ALL COMPANIES EXCLUDING SEEBOARD
AL	ALL COMPANIES EXCLUDING CSW LEASING
AX	ALL COMPANIES EXCLUDING CSW CREDIT, CSW LEASING AND SEEBOARD
AY	ALL COMPANIES EXCLUDING CSW CREDIT AND CSW LEASING
NB	NON-BILLABLE

4. CSWS 1996 Work Orders Used by Center (available on the LAN)

X:\\\ CN = CSWS_XCHANGE.CSWS.CSW\BILLING\

(EXAMPLE)

(CSWS '96 ACTUALS AND BUDGET BY CENTER BY WORK ORDER) CENTER A2184 NOT INCLUDED

CTR	CENTER NAME	W/O	F	W/O DESCRIPTION	1/96 - 3/96 ACTUAL	1996 BUDGET
A2101	ADMINISTRATION STAFF	EX1295	06A	SUPPLY CHAIN PROCESS IMPROVEMENT	2,080.52	0
A2101	ADMINISTRATION STAFF	EX1544	17A	CSWOS PAYROLL ADJUSTMENT	0.00	-906
A2101	ADMINISTRATION STAFF	EX4001	09A	INDIRECT-ADMINISTRATION	60,026.23	-102,292
A2101	ADMINISTRATION STAFF	EX4004	01A	S&A - EXECUTIVE VP	1,332.66	0
A2101	ADMINISTRATION STAFF	EX4007	16A	ADMIN. SUPPORT CLEARING	-77,706.68	0
A2101	ADMINISTRATION STAFF	EX4010	07A	S&A - SYSTEM OPERATIONS	-382.08	0
A2101	ADMINISTRATION STAFF	EX4011	09A	CLIENT SERVICES-INDIRECT	-11,716.33	0
A2101	ADMINISTRATION STAFF	EX4013	06A	INDIRECT - T&S ALL COMPANIES	-4,654.51	0
A2101	ADMINISTRATION STAFF	EX4014	06A	PRODUCTION SERVICES, V.P. PLANTS	-14,267.69	0
A2101	ADMINISTRATION STAFF	EX4019	16A	LOST TIME CLEARING	1,626.77	0
A2101	ADMINISTRATION STAFF	EX4033	02D	S&A - PWR ENGINEERING/ENVIROMENTAL	-43,494.83	0
A2101	ADMINISTRATION STAFF	EX4041	02A	S & A - ACCOUNTING SERVICES	-155,617.28	0
A2101	ADMINISTRATION STAFF	EX4042	09A	S&A - HUMAN RESOURCES	-12,133.31	0
A2101	ADMINISTRATION STAFF	EX4043	01A	S&A - INSURANCE	1,350.00	0
A2101	ADMINISTRATION STAFF	EX4045	01A	S&A - TAX	-171,924.43	0
A2101	ADMINISTRATION STAFF	EX4056	15A	CSW STRATEGIC PLANNING	-11,698.87	0
A2101	ADMINISTRATION STAFF	EX4058	07A	INDIRECT - RATES AND REGULATORY	-1,854.80	0
A2101	ADMINISTRATION STAFF	EX4079	15C	S&A - PSO	2,500.00	0
A2101	ADMINISTRATION STAFF	EX4081	15F	S&A - TRANSOK	700.00	0
A2101	ADMINISTRATION STAFF	EX4085	06A	S&A ACCOUNTING SERVICES	-9,688.27	0
A2101	ADMINISTRATION STAFF	EX4086	07A	MARKETING	-19,686.06	0
A2101	ADMINISTRATION STAFF	EX4088	09A	TELECOMMUNICATIONS PLANNING & PROJ.	-10,419.52	0
A2101	ADMINISTRATION STAFF	EX4089	06A	FUELS DIVISION - GENERAL	-4,959.77	0
A2101	ADMINISTRATION STAFF	EX4118	08A	MVS/XA SUPPORT	-31,801.43	0
A2101	ADMINISTRATION STAFF	EX4167	16A	CSWS PAYROLL ACCRUAL	-3,523.88	0
A2101	ADMINISTRATION STAFF	EX4237	15I	CSW ENERGY ADMINISTRATIVE EXPENSE	-3,719.73	0
A2101	ADMINISTRATION STAFF	EX4248	15A	CORPORATE ACTIVITIES	0.00	12,000
A2101	ADMINISTRATION STAFF	EX5021	09A	INDIRECT - TREASURY	-9,467.06	0
A2101	ADMINISTRATION STAFF	EX6408	01A	FEDERAL GOVERNMENT LOBBYING	-471.02	0
A2101	ADMINISTRATION STAFF	EX7220	09A	SYSTEMS ADMINISTRATION	-20,269.22	0
A2101	ADMINISTRATION STAFF	EX7222	09D	SYSTEMS ADMINISTRATION	-26,824.04	0
A2101	ADMINISTRATION STAFF	EX9728	15M	LAREDO TEAM SALARIES (18 MONTHS)	-24,000.00	0
A2101	ADMINISTRATION STAFF	IN9703	06A	FUELS SCHLEDULING MODEL EVALUATION	-1,255.41	0
A2101	ADMINISTRATION STAFF	IN9961	15E	RADIO IMPROVEMENT PROJECT-WTU	-8,274.46	0
A2111	HUMAN RESOURCE SERVICES STAFF	EX1058	17A	QUALITY JOB PREMIUMS-MOVING TO TUL	0.00	-872,153
A2111	HUMAN RESOURCE SERVICES STAFF	EX1544	17A	CSWOS PAYROLL ADJUSTMENT	0.00	-1,314
A2111	HUMAN RESOURCE SERVICES STAFF	EX1572	15A	CSW COMMON STOCK OFFERING	1,992.40	0
A2111	HUMAN RESOURCE SERVICES STAFF	EX4007	16A	ADMIN. SUPPORT CLEARING	1,055.68	0
A2111	HUMAN RESOURCE SERVICES STAFF	EX4011	09A	CLIENT SERVICES-INDIRECT	433.44	0
A2111	HUMAN RESOURCE SERVICES STAFF	EX4019	16A	LOST TIME CLEARING	5,500.00	0
A2111	HUMAN RESOURCE SERVICES STAFF	EX4040	01A	S&A - CONTROLLER	37,441.29	0
A2111	HUMAN RESOURCE SERVICES STAFF	EX4041	02A	S & A - ACCOUNTING SERVICES	5,499.19	0
A2111	HUMAN RESOURCE SERVICES STAFF	EX4042	09A	S&A - HUMAN RESOURCES	56,906.67	155,400
A2111	HUMAN RESOURCE SERVICES STAFF	EX4089	06A	FUELS DIVISION - GENERAL	3,268.89	0
A2111	HUMAN RESOURCE SERVICES STAFF	EX4090	07A	SYSTEM PROCESS IMPROVEMENT	22,495.74	0
A2111	HUMAN RESOURCE SERVICES STAFF	EX4095	17A	S&A - CSWS PRESIDENT	26,400.00	0
A2111	HUMAN RESOURCE SERVICES STAFF	EX4167	16A	CSWS PAYROLL ACCRUAL	-2,500.00	0
A2111	HUMAN RESOURCE SERVICES STAFF	EX4192	15D	SWEPCO - AUDIT COORDINATION	235.00	0
A2111	HUMAN RESOURCE SERVICES STAFF	EX4237	15I	CSW ENERGY ADMINISTRATIVE EXPENSE	6,567.69	0
A2111	HUMAN RESOURCE SERVICES STAFF	EX5020	09A	INDIRECT - GENERAL SERVICES	1,180.90	0
A2111	HUMAN RESOURCE SERVICES STAFF	EX5021	09A	INDIRECT - TREASURY	2,940.89	0
A2111	HUMAN RESOURCE SERVICES STAFF	EX9739	09D	SERVICE COMPANY RELOCATION COSTS	2,200.94	0
A2111	HUMAN RESOURCE SERVICES STAFF	IN9546	06A	WORK2000 CONSTRUCTION & TRANSITION	202.00	0
A2112	CLAIMS PROCESSING MANAGEMENT	EX1544	17A	CSWOS PAYROLL ADJUSTMENT	0.00	-1,296

5. CSWS 1997 Service ID and Billing Method Guidelines

Billing Method Guidelines

Contents

Billing Method Guidelines

Overview

Background

Central and South West Services, Inc. (CSWS) was organized under the Securities and Exchange Commission (SEC) regulations to provide certain services to CSW subsidiaries. Services may include:

- Engineering
- Financial
- Human Resources
- Information Services
- Legal
- Marketing
- Production
- Other

The SEC requires, when possible, that CSWS ***directly*** bill the CSW subsidiary that benefited from the service instead of attributing costs to several CSW subsidiaries.

Example:

Department Providing Service	Service Provided	Billing Method	Rationale
CSWS General Accounting	Accounting month-end closing directly for Central Power and Light (CP&L).	Direct	100 percent of the costs to provide these services are billed to CP&L.
CSWS General Accounting	Accounting research on an issue that impacts all CSW subsidiaries.	Attribution	Accounting costs are attributed to all CSW subsidiaries benefiting from these services.

Purpose of Billing Method Guidelines

The Billing Method guidelines were established to:

- Ensure that all CSWS expenses, including time and expense charges, are accurately and appropriately accounted for and billed, at cost, to the other CSW subsidiaries in a timely, cost-efficient manner.
- Provide a method for selecting Service IDs.
- Reduce and/or maintain the number of Service IDs and billing methods at an efficient and effective level.
- Develop standards to use, maintain and close Service IDs.

Guideline Responsibility

Establishing/Administering Guidelines

The CSWS Accounting department is responsible for establishing and administering the CSWS Service IDs and Billing Method Guidelines.

Compliance

CSWS Accounting can accept, reject, or request a correction and/or clarification of Service IDs that do not comply with the guidelines.

Billing Methodology: Attribution Basis and Service IDs

Billing Methodology

The combination of a Service ID and an attribution basis is used to direct bill or allocate costs to CSW subsidiaries for services provided. For a list of CSW subsidiaries, see Appendix B, p. 10.

What is an Attribution Basis

An attribution basis is assigned to a Service ID to determine how costs are attributed to CSW subsidiaries. Costs can be directly billed to a particular CSW subsidiary or can be allocated based on an attribution basis (Ex: number of employees, number of customers, kWh sales).

NOTE: An attribution basis must be authorized by the SEC before use.

Who Selects the Attribution Basis

The Service ID owner selects the appropriate attribution basis since he/she has the most knowledge as to the type of work being performed.

Guideline for Selecting an Attribution Basis

Selecting the appropriate attribution basis is crucial in justifying that CSWS costs are attributed both accurately and reasonably. Use the following guideline when selecting an attribution basis:

- Attribute costs to the CSW subsidiaries that benefit from the service provided in proportion to the factors driving the cost.

Continued on next page...

Examples

The following table provides three examples for selecting an attribution basis:

Service ID	Attribution Basis	Rationale/Driver
Marketing	Number of customers	Benefited customers served by each participating CSW subsidiary.
Human Resource Training Program	Number of employees	Training available to all CSW employe^es at each participating CSW subsidiary.
Benefits - Claims Processing	Number of claims	Employee claims are processed based on the number submitted by participating CSW subsidiaries.

What is a Service ID

Service IDs are codes used by CSWS employees to identify the services provided and the subsidiaries that benefited. A Service ID is required for every transaction since all CSWS charges must be billed to the CSW subsidiaries based on the level of service provided. Service IDs are used to:

- Budget and track actual costs.
- Accumulate costs on a special project or functional basis.

Service IDs are ***not*** intended to track detailed activities of projects or functions.

Selecting an appropriate Service ID to account for all CSWS cost is critical. All charges incurred by CSWS are billed to CSW subsidiaries and are subject to regulatory scrutiny and possible disallowance.

Continued on next page...

Types of Service IDs

The following table defines the various types of Service IDs used by CSWS:

Service ID Type	Definition	Attribution Method/Examples
Direct Costs	Costs incurred for a project or service that benefits only one CSW subsidiary.	Costs are incurred for the direct benefit of just one company. They are attributed 100% to that CSW subsidiary.
Shared Costs - Project	Costs incurred while providing services for a particular project that benefits more than one CSW subsidiary.	The attribution method depends on the service provided. Costs are attributed based on the most appropriate driver of the service provided. For example, a Service ID for a marketing program that benefits several companies is attributed based on the "number of customers" (the driver of the service) of each CSW subsidiary that benefits from the program.
Shared Costs - Functional Services	Costs incurred while providing general services that are related to a functional process, but that are not attributable to a particular project.	These Service ID costs are attributed to the CSW subsidiaries based on the driver that is most appropriate for the type of service provided.
Administrative Costs	Costs that are not associated with providing any particular services.	• Staff meeting • Team building • Status reports
Overhead Costs	Costs associated with overhead expenses.	• Administrative costs for the Building Services function. • Depreciation of office furniture and fixtures (including personal computers). • Telephone usage.

IMPORTANT: DEFAULT SERVICE ID Codes do not exist. You must select the appropriate Service ID for every transaction. All CSWS charges must be billed to the CSW subsidiaries based on the level of service provided.

Guidelines for requesting CSWS Service IDs

A request for a new Service ID may be appropriate when a new service or project is identified. However, in many situations, the cost of the new service or project may be captured using an existing Service ID.

The following table helps determine the situations under which a new Service ID is or is not appropriate:

A new Service ID...	If...
Is appropriate	A new service or project arises. OR There is a specific regulatory requirement that the service or project be tracked separately. (Ex: along jurisdictional or state lines.)
Is probably not appropriate	The total estimated annual cost of the service or project is less than $25,000.
Is not appropriate	An existing Service ID captures the service or project. AND There is no specific regulatory requirement that the service be tracked separately. ***Note: It may be appropriate to modify an existing Service ID title or description to encompass the new scope of the service or project.***

Continued on next page...

CSWS Service ID Roles

There are three roles involved in the Service ID process:

- Requester/Owner
- Service ID Approvers
- Service ID Administrator

The following table lists the responsibilities for each role:

Role	Responsibilities
Requester/Owner	1. Determine that an existing Service ID does not meet the need. 2. Complete a Service ID Request. 3. Revise requests that have been rejected by the Service ID Approver or Service ID Administrator pending correction or further clarification.
Service ID Approvers	Service IDs have the following approval levels: <u>**Service ID Amount**</u> — <u>**Approval Level**</u> $25,000 or less — CSWS manager Over $25,000 — CSWS department head Over $25,000 and billable 100% to a specific CSW subsidiary — Representative of that subsidiary Shared services totaling $500,000 — Representative of one of the benefiting subsidiaries
Service ID Administrator	Review the Service ID Request for compliance with the Service ID Guidelines, for completeness and reasonableness, and run all necessary compatibility edits. <u>**If a request**</u> — <u>**Then**</u> Is in compliance with Service ID guidelines — Approve the Service ID Request. Has errors or does not comply with the Service ID guidelines* — Communicate those deficiencies to the requester/owner. * Ex: Request is below the $25,000 threshold or has an inadequate Service ID description.

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Annual Charges/Billings

Some general rules:

- Submit a request for a new Service ID for new services or products when expected costs exceed $25,000.
- Combine small projects and services into one Service ID if possible.
- A request to establish a Service ID with estimated billings below the threshold must be justified and approved by CSWS Accounting.

Service ID Maintenance

Service Activity

- Service ID activity is reviewed annually to identify candidates for closure.

Annual Purging

- Service IDs with less than $25,000 activity and Service IDs open beyond the predetermined expiration dates may be closed.

Service ID Renewal

- Service ID owners will be notified that these Service IDs may be closed unless adequate justification is provided to keep them open.

Appendix B

CSW Subsidiaries

Subsidiary	Customer Code
Central Power and Light	CC
CSW Communications	MM
CSW Corporation	RR
CSW Credit	TT
CSW Energy	EE
CSW International	II
CSW Leasing	LL
Enershop	HH
Public Service Company of Oklahoma	PP
Seeboard	BB
Southwestern Electric Power Company	SS
Transok	KK
West Texas Utilities	WW

6. CSWS Service ID Request Form

SW System — Service ID Request

Service Code (8 digits): Service Code Title:

Service Code Description:

Total Expenditures Authorized $

Customer Code

Direct Billing: (100% billable to specific company)

☐ CC (CPL)	☐ LL (CSW Leasing)	☐ II (CSW Int'l)	☐ JJ (JFP)
☐ PP (PSO)	☐ RR (CSW Corp.)	☐ MM (CSW Comm.)	☐ ZZ (CSWS)
☐ WW (WTU)	☐ TT (CSW Credit)	☐ HH (ENERSHOP)	☐ OTHER:
☐ SS (SWEP)	☐ EE (CSW Energy)	☐ BB (SEEBOARD)	

WP/KNORR
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Shared Billing

Attribution Basis (Allocation)

Customer Code(s) (2 digits)

Non - Billable

Service ID Owner:	Phone: ( ) -	Center:	Date: / /
☐ O & M	☐ Capital	Budget Schedule No.	

If OPCO Capital provide OPCO JCA Work Order number (s)

CPL WO	WS	PSO WO	WS
SEP WO	WS	WTU WO	WS

Functional Category (2) Digits — Functional Owner Description:

Originator Signature:	Profs ID	Date	
CSWS Approval Signature:	Profs ID	Date	
CSW Subsidiary Approval: (if required)	Profs ID	Date	Company

FOR ACCOUNTING USE ONLY

Combo Name	Cost Category	Prepared by	Date

51-800mn REV. 6-96

SERVICE ID REQUEST INSTRUCTIONS

Service Code - unique 8 digit code provided by the user.

Service Code Title - name of product or service provided.

Service Code Description - detail description of product or service provided.

Total Expenditures Authorized - annual estimated dollar value of functional service or total estimated dollar value of special project.

Customer Code:

Direct Billing - used when billing a CSW subsidiary 100% of the product or service. Select appropriate customer code(s).

Shared Billing - used when a service benefits more than one CSW Subsidiary.

Attribution Basis - specify SEC approved attribution method.

Customer Code(s) - list combination(s) appropriate for CSW Subsidiaries benefiting from the service.

Non-Billable - used only when purchasing/developing CSW Service Company assets or capturing the cost of a deferred project.

Service ID Owner - name of person responsible for monitoring activity, analyzing charges, reviewing budget variances and answering questions related to service ID.

Phone - Service ID Owner's business phone number including 8+ or area code.

Center - Service ID Owner's responsibility center.

Date - current date.

O & M - denotes charges will be recorded as O&M expense on the CSW Subsidiaries' ledgers.

Capital - denotes charges will be capitalized investments on the CSW Subsidiaries' ledgers.

Budget Schedule # - schedule number assigned to capital project in CSW budget system.

SERVICE ID REQUEST INSTRUCTIONS (CONTINUED)

JCA Work Order - for services related to JCA work orders on the Electric Operating Companies ledgers, list JCA work order and work step for all appropriate companies.

Functional Category - specify the 2 digit code from standard list.

Functional Owner Description - full description of functional group from functional category list.

Approval/Authorization - A CSWS manager may authorize service request of $25,000 or less. Service request over $25,000 require the approval of a department head. Service ID request billable 100% to a specific subsidiary with amounts greater than $25,000 must be approved by the representative of that subsidiary. Shared services totaling $500,000 must be approved by the representative of one of the benefiting subsidiaries.

CENTRAL AND SOUTH WEST SERVICES, INC.
FUNCTIONAL CATEGORIES
(Draft)

Code	Functional Group
AC	CONTROLLER/ACCOUNTING
AS	AUDIT SERVICES
AV	AVIATION
CC	CORPORATE COMMUNICATIONS
EX	EXECUTIVE SUPPORT
GS	GENERAL SERVICES
HR	HUMAN RESOURCES
IS	INFORMATION SERVICES
LG	LEGAL SERVICES
MA	MERGERS AND ACQUISITIONS
MK	MARKETING SERVICES
PA	PLANNING AND ANALYSIS
PR	PROCUREMENT
PS	PRODUCTION SERVICES
RG	REGULATORY SERVICES
SP	SPECIAL PROJECTS
ST	STRATEGIC PLANNING
TC	TELECOMMUNICATIONS
TD	TRANSMISSION, DISTRIBUTION AND SUBSTATION
TR	TREASURY

COMMONWEALTH OF KENTUCKY

BEFORE THE

PUBLIC SERVICE COMMISSION OF KENTUCKY

IN THE MATTER OF:

JOINT APPLICATION OF KENTUCKY POWER COMPANY,)
AMERICAN ELECTRIC POWER COMPANY, INC.)
AND CENTRAL AND SOUTH WEST CORPORATION) CASE NO. 99-
REGARDING A PROPOSED MERGER)

WORKPAPERS OF

MARK A. BAILEY

FOR

APPLICANTS

APRIL 1999

TABLE OF CONTENTS

SMART MANAGING

BEST PRACTICES, CAREERS, AND IDEAS

Biggest Gainer: The Police

With crime rates falling, police forces scored the biggest four-year gain of all industries and services measured by the customer-satisfaction index.

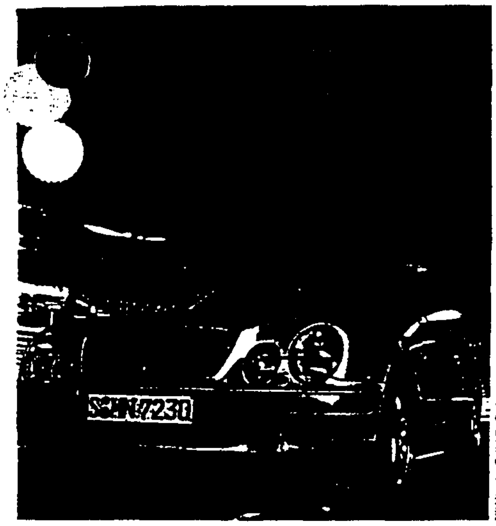
Now Are You SATISFIED?

THE 1998 AMERICAN CUSTOMER SATISFACTION INDEX

If your company blew away its revenue projections and handily beat its earnings estimates last year, congratulations. But don't get too cocky. At the root of every figure on an income statement are the customers who spend their money with you, and many are fickle enough to find someone else to serve their needs at any moment. Consider, then, how nice it would be to track your relations with customers continually, to know for sure where you stand with your most important stakeholders.

The American Customer Satisfaction Index (ACSI), which appears with accompanying articles in the following pages, is a good place to start. Based on a massive survey of how U.S. consumers rate a wide range of products and services, it can help managers in a number of ways. If you're looking for broad industry

PHOTOGRAPH BY MICHEAL MCLAUGHLIN



STEVE PIKE—MATRIX

No. 1: Mercedes-Benz

The cars are expensive, and there's a lot of breakable parts inside. But customers truly love them.

trends or are trying to understand how customer satisfaction can help determine your company's financial results or stock price, it's definitely worth a careful look.

To come up with the ratings, which appear exclusively in FORTUNE, the National Quality Research Center canvasses more than 50,000 U.S. consumers each year. Statisticians at the University of Michigan take over from there, measuring the responses according to six different quality indexes. Then they score each of close to 200 companies, along with some major government services, on a 100-point scale.

This year's results are notable for the long-term trends they reveal and for some big one-year swings. While the four-year decline in the overall index has stopped, only one industry group has seen its scores improve over the life of this measurement: the cops. Seems as if all that community policing, with more officers walking the street and keeping an eye on the neighborhood, is making residents happy in addition to lowering crime rates. Surprising losers are the personal computer makers, whose aggregate scores have fallen 10% in four years. Sure, the machines are more powerful than ever, but what good are they if you can't get through to the help lines? Only broadcast news fell further over the same time period—a full 20%—which shouldn't surprise anyone at all.

Mercedes-Benz tops the list of individual companies. The IRS brings up the rear for the fourth straight year, though it also posted the biggest one-year percentage gain (8%). McDonald's is the IRS's closest neighbor at the bottom, putting the falling golden arches below the worst of the utilities and all the garbage men. Tied (with General Public Utilities) for the biggest one-year loser award is American Airlines, which plummeted 12.7%. Like most carriers, American jacked up fares for business travelers, then packed them into crowded planes—moves certain to annoy some of its best customers. — *Ronald B. Lieber*

The 1998 Satisfaction Index

The average is up for the first time in four years, but customers are down on newscasting, computers, and hospitals.

Rank	Company or division	1997 score	Change from '96
1	Mercedes-Benz	87	N.C.
2	H.J. Heinz food processing	86	–4.4%
3	Colgate-Palmolive pet foods	85	N.A.
4	H.J. Heinz pet foods	85	N.A.
5	Mars food processing	85	–1.2%
6	Maytag	85	2.4%
7	Quaker Oats	85	3.7%
8	Cadillac[1]	84	–4.5%
9	Hershey Foods	84	–4.5%
10	Coca-Cola	84	–3.4%
11	Toyota	84	N.C.
12	Volvo	84	N.C.
13	Zenith Electronics	84	N.C.
14	Buick[1]	83	–1.2%
15	Cadbury Schweppes	83	–3.5%
16	Colgate-Palmolive personal-care products	83	1.2%
17	Nestlé food processing	83	1.2%
18	Nestlé pet foods	83	N.A.
19	Panasonic	83	3.8%
20	PepsiCo	83	–3.5%
21	Clorox	83	–1.2%
22	Dial	83	–2.4%
23	FedEx	82	–4.7%
24	Honda Motor	82	–1.2%
25	Kraft Foods	82	–3.5%
26	Nordstrom	82	–1.2%
27	Oldsmobile[1]	82	N.C.
28	Phillips Petroleum	82	3.8%
29	Pillsbury	82	–5.7%
30	Ralston Purina pet foods	82	N.A.
31	Sanyo Fisher	82	1.2%
32	Saturn	82	1.2%
33	Unilever	82	–1.2%
34	United Parcel Service[2]	82	–5.7%
35	Whirlpool	82	–3.5%
36	Anheuser-Busch	81	2.5%
37	Campbell Soup	81	–3.6%
38	General Mills	81	–5.8%
39	Kellogg	81	–4.7%
40	Levi Strauss	81	1.3%
41	Lincoln Mercury	81	1.3%
42	Mars pet foods	81	N.A.
43	Miller Brewing	81	3.8%
44	Mitsubishi Electric	81	–2.4%
45	Sara Lee food processing	81	8.0%
46	Shell	81	5.2%

3

American Airlines

American's score fell 12.7% as it took much of the blame for the industry's higher fares and overcrowded planes.


TONY SAVINO—SIPA

	Rank	Company or division	1997 score	Change from '96
	47	Sony	81	N.C.
	48	Procter & Gamble	81	-4.7%
	49	VF	81	1.3%
	50	Adolph Coors	80	1.3%
	51	AT&T	80	-3.6%
	52	BMW	80	-1.2%
	53	Chrysler	80	N.C.
	54	ConAgra	80	-2.4%
	55	GMC	80	N.A.
	56	Publix Super Markets	80	-2.4%
	57	RJR Nabisco	80	-5.9%
	58	Sara Lee apparel	80	-4.8%
	59	Tyson Foods	80	1.3%
	60	Amoco	79	-1.3%
	61	Dole Food	79	-7.1%
1	62	Duke Power	79	-4.8%
	63	JVC America	79	-1.3%
	64	Nissan	79	-1.3%
	65	Philips	79	-3.7%
	66	RCA	79	N.C.
	67	RJR Reynolds Tobacco	79	-6.0%
	68	Subaru	79	-4.8%
	69	Volkswagen	79	3.9%
	70	BellSouth	78	-6.0%
2	71	Central & South West	78	N.C.
	72	Chevrolet	78	-1.3%
2	73	Edison International	78	1.3%
	74	Exxon	78	-1.3%
	75	General Electric	78	-3.2%
	76	J.C. Penney	78	1.3%
	77	Mobil	78	N.C.
	78	Pontiac	78	N.C.
	79	Albertson's	77	N.C.
3	80	American Electric Power	77	-6.1%
	81	Chevron	77	1.3%
	82	Dayton Hudson[3] Target/Mervyn's	77	1.3%
	83	Dodge Plymouth	77	N.C.
	84	Ford	77	-1.3%
	85	Fruit of the Loom	77	-1.3%
	86	GTE[4] long distance	77	-5.6%
	87	Hyatt	77	N.C.
	88	Liz Claiborne	77	-4.9%
	89	Meijer grocery stores	77	-1.3%
	90	Philip Morris	77	-2.5%
	91	Promus	77	-7.2%
	92	Solid-waste disposal suburban	77	1.3%
	93	State Farm Insurance	77	-2.5%
	94	Texaco	77	-6.1%
3	95	Southern	77	-1.3%

Rank	Company or division	1997 score	Change from '96
96	Marriott hotels	76	-1.3%
97	Southwest Airlines	76	N.C.
98	Sprint	76	-5.0%
99	CMS Energy	75	-2.6%
100	DTE Energy	75	-3.8%
101	Hewlett-Packard	75	-2.6%
102	Hilton Hotels	75	N.C.
103	Meijer discount stores	75	-2.5%
104	New York Life Insurance	75	N.A.
105	Public Service Enterprise Group	75	-2.6%
106	Supervalu	75	-2.6%
107	May Department Stores	75	N.C.
108	Wal-Mart Stores Sam's Club	75	-8.6%
109	Winn-Dixie Stores	75	N.C.
110	Allstate	74	1.4%
111	American Stores	74	1.4%
112	Atlantic Richfield	74	2.8%
113	Dayton Hudson[3] department stores	74	-2.6%
114	Dillard Department Stores	74	N.C.
115	Dominion Resources	74	2.8%
116	Jeep Eagle	74	-2.6%
117	Mazda	74	-1.3%
118	Metropolitan Life Insurance	74	1.4%
119	Nike	74	-3.9%
120	Reebok International	74	-3.9%
121	Sears Roebuck	74	-1.3%
122	Kroger	74	-2.6%
123	Wal-Mart Stores discount stores	74	N.A.
124	Aetna Life & Casualty	73	N.C.
125	Ameritech	73	-5.2%
126	Federated Department Stores	73	2.8%
127	Food Lion	73	-3.9%
128	Montgomery Ward	73	1.4%
129	Safeway	73	N.C.
130	Solid-waste disposal central cities	73	-3.9%
131	Bell Atlantic[5]	72	-11.1%
132	Dell Computer	72	N.A.
133	Farmers Insurance Group	72	1.4%
134	Kmart	72	N.C.
135	MCI Communications	72	-7.7%
136	Pacific Telesis Group[6]	72	-10.0%
137	Consolidated Edison of New York	71	-4.1%
138	First Union	71	-2.7%
139	International Business Machines	71	-4.1%
140	Norwest	71	-6.6%
141	PG&E	71	-1.4%
142	SBC Communications[7]	71	-7.8%
143	US West	71	-4.1%
144	Wendy's International	71	-2.7%


HANS GISSINGER

McDonald's

Confused pricing and a tired menu contributed to an all-time-low ranking—just above the IRS and below the police.

WP/BAILEY
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Rank	Company or Division	1997 score	Change from '96	Rank	Company or Division	1997 score	Change from '96
145	Apple Computer	70	–7.9%	168	Prudential Insurance of America	68	–8.1%
146	Entergy	70	–6.7%	169	United Airlines	68	–2.9%
147	First Chicago NBD	70	N.A.	170	US Airways	68	3.0%
148	KeyCorp	70	–7.9%	171	Burger King	67	3.1%
149	Texas Utilities	70	–9.1%	172	Compaq Computer	67	–9.5%
150	U.S. Postal Service packages, express mail	70	–5.4%	173	Northeast Utilities	67	–6.9%
151	Army & Air Force Exchange Service	69	N.A.	174	Police suburban	67	6.3%
152	Banc One	69	–6.8%	175	Nynex	66	–12.0%
153	Delta Air Lines	69	3.0%	176	Packard Bell	66	–7.0%
154	FPL Group	69	–6.8%	177	Taco Bell	66	N.C.
155	General Public Utilities	69	–12.7%	178	BankAmerica	65	–3.0%
156	KFC	69	1.5%	179	Niagara Mohawk Power	65	1.6%
157	Little Caesars	69	N.C.	180	PECO Energy	65	–7.1%
158	PNC Bank	69	N.A.	181	Wells Fargo	65	–8.5%
159	U.S. Postal Service mail, counter services	69	–6.8%	182	Continental Airlines	64	–3.0%
160	Chase Manhattan	68	N.A.	183	Northwest Airlines	64	–4.5%
161	Citicorp	68	–2.9%	184	Ramada	64	–8.6%
162	Domino's Pizza	68	–2.9%	185	Pizza Hut	63	–4.5%
163	Great Atlantic & Pacific Tea	68	1.5%	186	Police central cities	63	6.8%
164	GTE[4] local service	68	N.A.	187	American Airlines	62	–12.7%
165	Houston Industries	68	N.A.	188	Unicom	62	–8.8%
166	Hyundai Motor	68	–1.4%	189	McDonald's	60	–4.8%
167	NationsBank	68	–6.8%	190	Internal Revenue Service	54	8.0%

N.C. No change. N.A. Not applicable. [1]Buick, Oldsmobile, and Cadillac were measured as a combined group in 1994 and 1995. In 1996 and 1997, each was measured separately. [2]Measurement made in 1997 before strike. [3]Dayton Hudson stores were split in 1996 to measure department stores and discount stores separately. [4]In 1997, local and long-distance telephone services were combined to measure as a single industry. Only GTE was offering both types of service broadly enough across U.S. to measure satisfaction with local and long-distance services. [5]Acquired Nynex since 1997 measurement. [6]Acquired by SBC Communications since 1997 measurement. [7]Acquired Pacific Telesis since 1997 measurement.

Your Customers Are Telling THE TRUTH

More managers are learning that tracking customers' moods helps them discover their company's basic problems and how to fix them.

This year's customer-satisfaction index highlights the enduring strength of established brands and underscores the pitiful state of American services. The top quartile is a roll call of well-established names—Heinz, Maytag, Kraft, Whirlpool, Nordstrom, Kellogg, Miller Brewing—while the bottom quartile is a lineup of harshly judged service companies. Airlines, for example, are widely viewed as hostile monopolies that delight in torturing their passengers. Banks going through mergers are driving customers out their doors. Many utilities, accustomed to regulated markets, haven't learned how to woo customers. Most fast food and its accompanying service are increasingly considered less than palatable.

Researchers have found a general correlation between delighted customers and above-average stock market returns (see following article), but while reading this ranking, you can't help noticing the exceptions. Many of the brands with top ratings, for example, are manufactured by companies with mediocre to poor financial results (Whirlpool, Nordstrom). Some of those airlines, banks, and utilities that alienate customers are minting money (Northwest Airlines, Wells Fargo).

Obvious question: Just how much attention should managers pay to studies, like the ACSI, that closely track customer attitudes? The answer: plenty. The ACSI, like other such surveys, has limitations. It's a fledgling, four-year-old effort that covers only products and services used by households, not other businesses. The research covers close to 200 U.S. companies and a few foreign concerns with big market shares, a small slice of the corporate landscape.

But these limitations shouldn't obscure the index's potential, as more and more enterprises are concluding. So far, about 25 companies have anted up the $25,000 required annually to gain access to the data the University of Michigan collects for this index. Andersen Consulting recently signed up as a sponsor because the firm regards the index as a useful management tool. Says partner Joseph O'Leary: "I tell clients it could help them assess where they are today vs. competitors, and in what direction they are moving." The European Union is also on the verge of adopting the ACSI modeling methodology, which means companies on the Continent will be urged to employ it.

What Customers Like

They're happier with manufacturers than with services.

Industry	Customer satisfaction score	Change from 1996
Beverages soft drinks	83	-3.5%
Pet foods	83	N.A.
Personal-care, cleaning products	82	2.5%
Food processing	81	-2.4%
Beverages beer	81	2.5%
Parcel delivery, express mail	80	-5.9%
Household appliances	80	-2.4%
Consumer electronics	80	-1.2%
Automobiles, vans, light trucks	79	N.C.
Gasoline	78	1.3%
Tobacco cigarettes	77	N.C.
Apparel sportswear	77	-1.3%
Insurance casualty, property	77	2.7%
Solid-waste disposal suburbs	77	1.3%
Telecommunications local & long distance	75	N.A.
Insurance life	75	1.4%
Apparel athletic shoes	74	-3.9%
Department & discount stores	74	-1.3%
Supermarkets	74	-1.3%
Electric service	73	-2.7%
Solid-waste disposal central cities	73	-3.9%
Commercial banks	72	-2.7%
Hotels	71	-1.4%
Motion pictures	71	-4.1%
Personal computers	70	-4.1%
Publishing newspapers	69	N.C.
U.S. Postal Service	69	-6.8%
Airlines scheduled	67	-2.9%
Hospitals	67	-5.6%
Local police suburbs	67	6.3%
Restaurants fast food, pizza, carryout	66	-5.7%
Local police central cities	63	6.8%
Broadcasting national news	62	-11.4%
Internal Revenue Service	54	8.0%

N.A. Not available. N.C. No change.

Industry type

Nondurables
Companies that make items that get used up quickly tend to score best. After all, how can you screw up ketchup?

Durables
With products that are supposed to last longer, like cars and computers, more can go wrong, and scores are lower.

Services
Customers tend to be least satisfied with service companies—mostly because downsizing has stressed out frontline workers.

ACSI's growing stature stems from managers' frustration with the uneven results of quality-improvement efforts that began in the 1980s. Frederick Reichheld of Bain & Co. and other researchers have proved that loyal customers—those who repeat purchases regularly—can substantially increase profits because they cost less to attract than new customers. But businesses have needed a credible, independent system for measuring the value of that loyal-customer asset over time and across business lines.

Economist Claes Fornell at Michigan's business school created just such an econometric model for Swedish companies in 1989. What set the Swedes' Customer Satisfaction Barometer (CSB) apart from other efforts was its ability to estimate what percentage of customers would repurchase a product or service. That information is crucial for planning because it enables companies to calculate future revenue streams and thus make rational investment decisions. After five years the Swedes were able to demonstrate a tantalizing correlation: Companies capable of increasing their quality index by one point every year for five years improved their average returns on assets during that period by 11.33%.

The American Society for Quality began searching in 1990 for a methodology to create a national index that could measure different kinds of businesses comparably. They selected the Swedish model as the best, which led them to Fornell. Today customers of ACSI are given customized computer software that quantifies results from telephone interviews with about 50,000 customers every year, plus a report that compares their company's results with those of competitors. More important, if clients plug in their own financial data—such as the average cost of each transaction and the average profit margin on each sale—they can obtain a dollar figure that represents the net present value of their retained-customer base. Net present value is based on future earnings, so the software disciplines managers to think hard about the effects of strategic choice.

The people who compile the index do not formally advise their clients on how to fix an ailing business, but their information helps diagnose problems. Take, for example, the experience of a real company that for reasons of confidentiality we'll call Company A. This is a service outfit that conducts millions of transactions every day at an average cost of less than $5 each. A manager can learn from ACSI that his quality-index number is far below those of two competitors because his company receives so many complaints. The net present value of Company A's customer base is a low $801 million. If the company could reduce the number of malcontents through better service and product—no easy task—its net present value would rise and perhaps overtake the $1.1 billion registered by Company B, which is smaller. Fornell warns, however, that these gains take time; a rise in net present value lags behind any increase in customer satisfaction because the satisfaction increase isn't worth much until it's established.

To fulfill its potential, an index like the ACSI should provide numbers that correlate more closely to overall economic performance. That, proponents of the index argue, will come with time. Fornell would like to see a "retained-customer asset" figure added to corporate balance sheets, because "intangible assets are crucial in today's economy." He thinks boards should insist on knowing the value of their company's customer bases and instruct CEOs to boost those values. Everyone says customers are important; as their importance becomes quantified, they will get more attention yet.

— *Linda Grant*

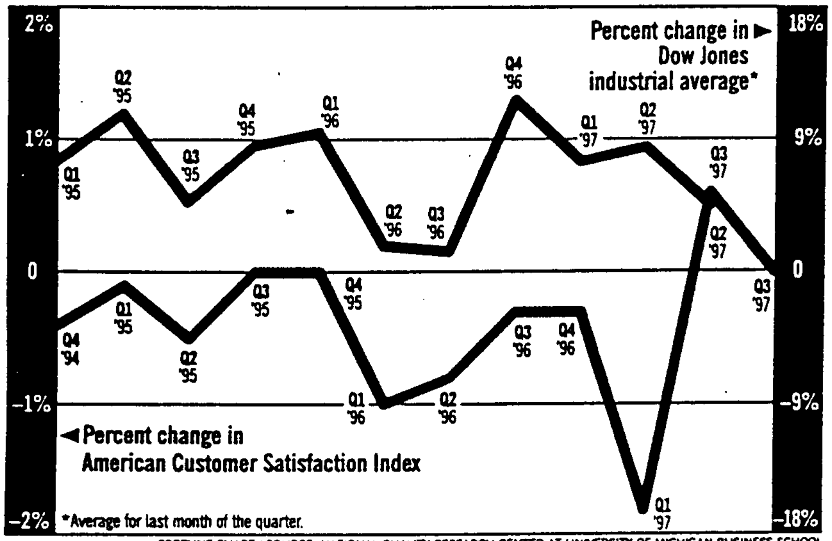
Last Again: The IRS

It actually annoyed fewer people than usual last year, tying for the biggest one-year gain of any individual entity on the list. But it still ranked last.

MARK WEISS

As Customers Go, So Goes THE DOW

When customer satisfaction scores have moved up or down in recent years, stocks have followed three months later. Just what's going on?



FORTUNE CHART / SOURCE: NATIONAL QUALITY RESEARCH CENTER AT UNIVERSITY OF MICHIGAN BUSINESS SCHOOL

Interest rates, inflation, consumer confidence—all have long been used to predict stock market performance (with limited success). What about customer satisfaction? Well, study the chart above. The American Customer Satisfaction Index and the Dow seem locked in a remarkably tight tango. Movement up or down by the ACSI appears to be mirrored by movements of the Dow in the following quarter. The tango sometimes gets a bit tangled, as you can see on closer examination. But the big picture still looks surprisingly clear: a stronger pattern of correlation than Dow watchers almost ever see.

Don't break the kids' piggy banks and call your broker just yet. Truth is, nobody's quite certain what's going on here. Experts readily agree that there may well be a correlation between customer satisfaction and the Dow, but with only 11 data points, the ACSI remains a mere infant in statistical terms. The index needs to be tested over time, in flat markets and down markets. It's also possible that the survey is picking up a Dow correlation other than customer satisfaction—general economic good times, perhaps, or that old standby, consumer confidence.

Still, there's an apparent correlation between the customer-satisfaction scores of individual companies and their stock performance. For the period the survey covers (the first quarter of 1995 through the third quarter of 1997), Campbell Soup, Heinz, and Procter & Gamble all rated in the top quartile in customer satisfaction, and these companies were stock performance stars. Companies in the bottom quartile of customer satisfaction tended to be losers in stock performance.

Bottom line: "I find it difficult to believe that the correlation will prove to be as strong as the chart shows," says Claes Fornell, a professor at the University of Michigan business school who created the index. "But I do think it will become a significant measure that says a lot about the future." —*Justin Martin*

Mirror Image: Follow Me

The Dow hasn't perfectly matched trends in customer satisfaction, but the pattern has easily been distinct enough to suggest a curious correlation.

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[illegible] [illegible]

[illegible]

[illegible] [illegible]

CASE NUMBER:

99-149

STITES & HARBISON PLLC
ATTORNEYS

August 1, 2005

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HAND DELIVERED

RECEIVED
AUG 1 2005
PUBLIC SERVICE COMMISSION

Ms. Beth O'Donnell
Executive Director
Public Service Commission of Kentucky
211 Sower Boulevard
P.O. Box 615
Frankfort, Kentucky 40602-0615

RE: P.S.C. Case No. 99-149 – Commission Order Dated June 14, 1999

Dear Ms. O'Donnell:

Please find enclosed and accept for filing an original and ten copies of Kentucky Power Company's revised Response to Item No. 15 that was filed May 16, 2005. Because 50 was used instead of 60 in computing the CAIDI the erroneous value was reported. The Company apologizes for any confusion or inconvenience.

Please call me if you have any questions.

Sincerely yours,

STITES & HARBISON, PLLC

Mark R. Overstreet

cc: Elizabeth E. Blackford (w/enclosure)
William H. Jones, Jr. (w/enclosure)
Michael L. Kurtz (w/enclosure)

KE057:KE131:12846:1:FRANKFORT

***** REVISED 7/29/2005 *****

Kentucky Power Company

REQUEST:

Provide annual Service Reliability Report addressing the duration and frequency of customer disruptions (CAIDI and SAIFI), including storms for calendar 2004. [Reference: Merger Agt., Attachment C, Pg. 1, Item 1]

RESPONSE:

The overall Customer Average Interruption Duration Index (CAIDI), including major events, for Kentucky Power Company (KPCo) customers during calendar 2004 was 6.52 hours per customer interrupted. The overall System Average Interruption Frequency Index (SAIFI), including major events, for KPCo customers during calendar 2004 was 3.27 interruptions per customer served.

Major events were declared during May 26 through June 5 for a series of severe thunderstorms and during September 16 – 20 for the remnants of Hurricane Ivan.

KPCo has previously reported on its changes in outage recording systems. Making comparisons to the 1995-1998 values is very difficult because of the numerous advancements in outage recording technology. The ultimate results are more accurate outage customer count and outage duration values.

***** The Company originally reported in its May 15, 2005 filing, the overall Customer Average Interruption Duration Index (CAIDI), including major events, for Kentucky Power customers during calendar year 2004 was 7.82 hours per customer interrupted. Upon review of reliability values, an error was discovered in the calculation. The correct CAIDI for calendar year 2004 is 6.52 hours, as shown above. The SAIFI number did not change.***

WITNESS: Errol K. Wagner

Ernie Fletcher
Governor

Commonwealth of Kentucky
Environmental and Public Protection Cabinet
Public Service Commission
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P.O. Box 615
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Telephone: (502) 564-3940
Fax: (502) 564-3460

LaJuana S. Wilcher
Secretary

July 16, 2004

Honorable Elizabeth E. Blackford
Assistant Attorney General
Office of the Attorney General Utility & Rate Intervention Division
1024 Capital Center Drive
Suite 200
Frankfort, KY 40601-8204

CERTIFICATE OF SERVICE

RE: Case No. 1999-00149
American Electric Power

I, Beth O'Donnell, Executive Director of the Public Service Commission, hereby certify that the enclosed attested copy of the Commission's Order in the above case was served upon the addressee by U.S. Mail on July 16, 2004.

Executive Director

TD/sa
Enclosure

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Director Regulatory Services
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Frankfort, KY 40602

This is the Service List for Case 1999-00149

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

JOINT APPLICATION OF KENTUCKY POWER COMPANY, AMERICAN ELECTRIC POWER COMPANY, INC. AND CENTRAL AND SOUTH WEST CORPORATION REGARDING A PROPOSED MERGER	)))))	CASE NO. 1999-00149

ORDER

On June 14, 2004, the Commission issued an Order granting the request of Kentucky Power Company d/b/a American Electric Power ("Kentucky Power") and modified our June 14, 1999 Order to the limited extent that the information required to be filed quarterly should be filed annually, and that all information required to be filed annually would be due March 31 of each year, beginning March 31, 2005. On June 29, 2004, Kentucky Power filed a petition for rehearing, asking that the Commission allow it to file the annual information no later than May 15 of each year.

Kentucky Power had previously requested the information be due on May 15, but in its June 14, 2004 Order, the Commission found that Kentucky Power had provided no explanation or rationale for the May 15 due date. In its petition for rehearing, Kentucky Power explained that much of the information necessary to make the filing will not be available until after March 31 of each year, specifically data contained in its filings with the Securities and Exchange Commission and Federal Energy Regulatory Commission.

Kentucky Power states that the May 15 filing date would allow it to make a single filing and avoid the necessity of requesting extensions of time to make the filing.[1]

The Commission finds that Kentucky Power has now provided sufficient justification in support of filing the information required by our June 14, 1999 Order no later than May 15 of each year. The Commission further finds it reasonable to amend our June 14, 2004 Order to permit the May 15 filing date, beginning May 15, 2005.

IT IS THEREFORE ORDERED that:

1. The Commission's June 14, 2004 Order is amended to require the annual filing of information to be due by May 15 of each year, beginning May 15, 2005.

2. All other provisions of the June 14, 2004 Order shall remain in full force and effect.

Done at Frankfort, Kentucky, this 16th day of July, 2004.

By the Commission

ATTEST:

Executive Director

[1] Petition for Rehearing at 1.

COMMONWEALTH OF KENTUCKY
BEFORE THE PUBLIC SERVICE COMMISSION OF KENTUCKY

RECEIVED
JUN 2 9 2004
PUBLIC SERVICE COMMISSION

IN THE MATTER OF :

JOINT APPLICATION OF KENTUCKY POWER COMPANY,) AMERICAN ELECTRIC POWER COMPANY, INC.) AND CENTRAL AND SOUTH WEST CORPORATION) REGARDING A PROPOSED MERGER) CASE NO. 99-149

Petition for Rehearing

Kentucky Power Company petitions the Public Service Commission of Kentucky pursuant to KRS 278.400 for rehearing of the Commission's June 14, 2004 Order in this matter and requests that the Commission modify its June 14, 2004 Order to permit the later filing of the information required by the Commission's June 14, 1999 Order. In support, Kentucky Power states:

1. Kentucky Power apologizes for failing to make clear to the Commission the basis for the Company's request to file the required financial information no later than May 15th of each year.

2. Kentucky Power requested a May 15th filing date because much of the information necessary to make the filing is not available until after March 31st of each year. Specifically, SEC Forms U-5S and U-13-60 are not due to be filed with the Securities and Exchange Commission until 120 days after the close of the calendar year (approximately April 30). In addition, FERC Form 1 will be due April 25, 2005 and April 18th of each year thereafter.

3. A May 15 filing date will permit Kentucky Power to make a single filing and will avoid the necessity of burdening the Commission with motions for extensions in which to file the information contained in the forms that will not be available until after March 31st of each year.

Wherefore, Kentucky Power Company respectfully requests that the Commission amend its June 14,2004 Order to permit Kentucky Power until and including May 15th of each year in which to make its annual filing of information as required by the Commission's June 14, 1999 Order in this matter.

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Kevin F. Duffy
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1 Riverside Plaza
Columbus, Ohio 43215-2373

COUNSEL FOR KENTUCKY POWER
COMPANY

CERTIFICATE OF SERVICE

I hereby certify that a copy of the foregoing was served by first class mail on this 29th day of June, 2004 upon:

Elizabeth E. Blackford
Assistant Attorney General
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Frankfort, Kentucky 40601

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Boehm, Kurtz & Lowry
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Mark R. Overstreet

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Ernie Fletcher
Governor

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Secretary

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June 14, 2004

Honorable Elizabeth E. Blackford
Assistant Attorney General
Office of the Attorney General Utility & Rate Intervention Division
1024 Capital Center Drive
Suite 200
Frankfort, KY 40601-8204

RE: Case No. 1999-00149

We enclose one attested copy of the Commission's Order in the above case.

Sincerely,

Beth O'Donnell
Executive Director

TD/sa
Enclosure

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Honorable Richard S. Taylor
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Errol K. Wagner
Director Regulatory Services
American Electric Power
101A Enterprise Drive
P. O. Box 5190
Frankfort, KY 40602

This is the Service List for Case 1999-00149

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

JOINT APPLICATION OF KENTUCKY POWER COMPANY, AMERICAN ELECTRIC POWER COMPANY, INC. AND CENTRAL AND SOUTH WEST CORPORATION REGARDING A PROPOSED MERGER	)	CASE NO. 1999-00149

ORDER

On March 24, 2004, Kentucky Power Company d/b/a American Electric Power ("Kentucky Power") filed its quarterly financial information as required by the Commission's June 14, 1999 Order in this proceeding. Included with its filing was a request that the information now filed quarterly be filed annually, and that the deadline for annual filings be extended to May 15 of each year. Kentucky Power served a copy of the request on all parties and no responses have been filed.

The June 14, 1999 Order required Kentucky Power to make annual and quarterly informational filings. On a quarterly basis, Kentucky Power must file: a report detailing its proportionate share of American Electric Power Company, Inc.'s ("AEP") total operating revenues, operating and maintenance expenses, and number of employees; and a report of the number of employees of AEP and each subsidiary on the basis of payroll assignment.

Based on a review of the information now being filed quarterly, the Commission finds that the information is still valuable, but our concerns will be adequately addressed if that information is filed annually. As to the due date for annual filings, the Commission notes that Kentucky Power provided no explanation or rationale for extending the filing date to May 15. Absent reasonable justification, this request should be denied. Further, we find that to improve administrative efficiency and the tracking of the information, the annual filings required by this docket should be made by March 31 of each year in conjunction with Kentucky Power's filing of its annual financial and statistical report.[1]

IT IS THEREFORE ORDERED that:

1. The June 14, 1999 Order is modified to the limited extent that the information required to be filed quarterly shall be filed annually, and all information required to be filed annually shall be due by March 31 of each year, beginning March 31, 2005.

2. Kentucky Power's request to file its annual information by May 15 of each year is denied.

3. All other provisions of the June 14, 1999 Order shall remain in full force and effect.

Done at Frankfort, Kentucky, this 14th day of June, 2004.

By the Commission

ATTEST:

Robert A. Amato

Deputy Executive Director

[1] In the event Kentucky Power is granted an extension to file its annual financial and statistical report, that extension will also apply to the annual reports required by this docket.

STITES & HARBISON PLLC

ATTORNEYS

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May 18, 2004

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HAND DELIVERY

Beth O' Donnell
Executive Director
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Frankfort, KY 40602-0615

RECEIVED
MAY 18 2004
PUBLIC SERVICE COMMISSION

RE: ***P.S.C. Case No. 99-149***

Dear Ms. O'Donnell:

Please accept for filing the original and four copies of the Supplemental Responses of Kentucky Power Company d/b/a American Electric Power to the Commission's June 14, 1999 Order in the above-referenced case. The Responses are for the year ended December 31, 2003 and the quarter ended March 31, 2004.

By copy of this letter I am providing the parties to the case with a copy of the Supplemental Response. If you have any questions, please do not hesitate to contact me.

Sincerely yours,

STITES & HARBISON PLLC

Mark R. Overstreet

cc: William H. Jones, Jr.
David F. Boehm
Elizabeth E. Blackford

KE057:KE131:10997:1:FRANKFORT

RECEIVED
MAY 18 2004
PUBLIC SERVICE COMMISSION

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the matter of:

JOINT APPLICATION OF KENTUCKY POWER	)
COMPANY, AMERICAN ELECTRIC POWER	)
COMPANY, INC. AND CENTRAL AND SOUTH	) CASE NO. 99-149
WEST CORPORATION REGARDING A	)
PROPOSED MERGER	)

****

RESPONSE OF KENTUCKY POWER COMPANY
d/b/a/
AMERICAN ELECTRIC POWER

Reporting Period: Year Ending December 31, 2003

And

Quarter Ending March 31, 2004

Filing Date: 18 May 2004

1

Kentucky Power Company
d/b/a
American Electric Power

REQUEST:

Furnish annual financial statements of AEP, including consolidating adjustments of AEP and its subsidiaries with a brief explanation of each adjustment and all periodic reports filed with the SEC. Including but not limited to the U5S and U-13-60 reports. All subsidiaries should prepare and have available monthly and annual financial information required to compile financial statements and to comply with other reporting requirements. The financial statements for any non-consolidated subsidiaries of AEP should be furnished to the Commission. [Reference: Merger Agt., Ky. PSC Order dated 6-14-99, pg 10 (Periodic Reports)]

RESPONSE:

Attached you will find a copy of AEP's combined 2003 Annual Reports and the SEC Form 10K (Attachment No. 1), Form U5S (Attachment No. 2), and Form U-13-60 (Attachment No. 3) also for the year 2003.

WITNESS: Errol K. Wagner

2

Kentucky Power Company
d/b/a
American Electric Power

REQUEST:

On an annual basis file a general description of the nature of inter-company transactions with specific identification of major transactions and a description of the basis upon which cost allocations and transfer pricing have been established. This report should discuss the use of the cost or market standard for the sale or transfer of assets, the allocation factors used, and the procedures used to determine these factors if they are different from the procedures used in prior years. [Reference: Merger Agt., Ky. PSC Order dated 6-14-99, pg. 11, Item 1]

RESPONSE:

A general description of the nature of inter-company transactions is contained in the Cost Allocation Manual (CAM) filed May 2001 as Attachment 1. There have been no changes to the procedures used to price inter-company transactions from those used in the prior year. Unless exempted, inter-company transactions conducted by or with Kentucky Power Company are priced at fully-allocated cost in accordance with Rules 90 and 91 prescribed by the Securities and Exchange Commission under the Public Utility Holiday Company Act of 1935.

WITNESS: Errol K. Wagner

Kentucky Power Transferees - 12 months ending 12/31/2003

	NAME	Eff Date	Job Title-New	Job Title-Old
Indiana Michigan Power Company				
	Rucker,Timothy T	2003-03-15	Instrument & Control Techn-Jr	Control Technician
AEP Service Corporation				
	Brown,Larry D	2003-08-02	Cust Solutions C&I Coord Sr	Distribution Line Coordinator
	Heighton,Clifford L	2003-12-20	Express Driver	Express Driver
	Hughes,Dale	2003-07-19	Property Damage Adjuster Ii	Distribution Line Specialist
	Vidas,Marian D	2003-07-19	Administrative Associate I	Administrative Associate I
	Workman,John E	2003-01-18	Area Supv Facility Mgmt	Building Maint Mechanic-A

Kentucky Power Company
d/b/a
American Electric Power

REQUEST:

On an annual basis file a report that identifies professional personnel transferred from Kentucky Power to AEP or any of the non-utility subsidiaries and describes the duties performed by each employee while employed by Kentucky Power and to be performed subsequent to transfer. [Reference: Merger Agt., Ky. PSC Order dated 6/14/99, Reporting Requirements, Pg. 11, Item 2.]

RESPONSE:

Attached is a list of Kentucky Power Company employees transferred from Kentucky Power Company during the twelve months ending December 31, 2003.

WITNESS: Errol K. Wagner

4

Kentucky Power Company
d/b/a
American Electric Power

REQUEST:

AEP should file on a quarterly basis a report detailing Kentucky Power's proportionate share of AEP's total operating revenues, operating and maintenance expenses, and number of employees. [Reference: Merger Agt., Ky. PSC Order dated 6/14/99, Reporting Requirements, Pg. 11, Item 2]

RESPONSE:

For 1st Quarter 2004:

Kentucky Power Company
Report Proportionate Share of AEP
(in millions, except number of employees)

Three Months Ended
March 31, 2004

	AEP	KPCO	SHARE
Revenues	3,341	107	3.2%
Operating/Maint. Exp.	2,232	41	1.8%
Number of Employees	19,946	393	2.0%

* See Response to Item No. 6

WITNESS: Errol K. Wagner

5

Kentucky Power Company
d/b/a
American Electric Power

REQUEST:

AEP should file any contracts or other agreements concerning the transfer of such assets or the pricing of inter-company transactions with the Commission at the time the transfer occurs. [Reference: Merger Agt., Ky. PSC Order dated 6/14/99, Reporting Requirements, Pg. 11 (Special Reports)]

RESPONSE:

1st Quarter 2004:

During the three month period ending March 31, 2004 there were 7 different transactions in which AEP/Kentucky sold assets to its affiliates. The assets transferred were various meters and transformers. The total dollar value of the assets transferred was $69,535. The smallest dollar value transferred was four meters at a value of $109. The largest dollar value transferred was 431 meters at a value of $42,440.

WITNESS: Errol K. Wagner

9

Kentucky Power Company
d/b/a
American Electric Power

REQUEST:

AEP should file a quarterly report of the number of employees of AEP and each subsidiary on the basis of payroll assignment. [Reference: Merger Agt., Ky. PSC Order dated 6/14/99, Reporting Requirements, Pg. 11, Item 1 (Special Reports)]

RESPONSE:

1st Quarter 2004:

Attached is the quarterly report of the number of employees of AEP and each subsidiary on the basis of payroll assignment for period ending March 31, 2004.

WITNESS: Errol K. Wagner

EMPLOYEE COUNT AS OF 03/31/2004

Co	Descr	Employee Count
E01	Kingsport Power Company	58
E02	Appalachian Power Company	2367
E03	Kentucky Power Company	393
E04	Indiana Michigan Power Company	2298
E06	Wheeling Power Company	58
E07	Ohio Power Company	2179
E10	Columbus Southern Power Co	1103
E16	Houston Pipe Line Company LP	268
E36	Louisiana Intrastate Gas Co	41
E39	Lig Liquids Company L.L.C.	22
E48	River Transportation Div I&MP	334
E54	Conesville Coal Prep Co	34
E59	AEP Energy Services	24
E61	AEP Service Corporation	6301
ECC	AEP Texas Central Company	1207
EEE	CSW Energy, Inc.	42
EEL	AEP Elmwood LLC	135
EMO	AEP MEMCO	387
EPP	Public Service Co. of OK	1067
ESS	SouthWestern Electric Power Co	1168
EWW	AEP Texas North Company	460
		19946

Kentucky Power Company
d/b/a
American Electric Power

REQUEST:

AEP should file an annual report containing the years of service at Kentucky Power and the salaries of professional employees transferred from Kentucky Power to AEP or its subsidiaries filed in conjunction with the annual transfer of employees report. [Reference: Merger Agt., Ky. PSC Order 6/14/99, Reporting Requirements, Pg. 12, Item 2]

RESPONSE:

Attached is the annual report for twelve months ending December 31, 2003 listing the years of service and the salaries of the professional employees transferred from Kentucky Power Company to AEP or one of its subsidiaries, filed in conjunction with Item No. 3.

WITNESS: Errol K. Wagner

Kentucky Power Transferees - 12 months ending 12/31/2003

	NAME	Eff Date	Total Years of Service	Annual Salary	
Indiana Michigan Power Company					
	Rucker,Timothy T	2003-03-15	23	$47,403.20	
AEP Service Corporation					
	Brown,Larry D	2003-08-02	34	$66,400.10	
	Heighton,Clifford L	2003-12-20	4	$36,857.60	
	Hughes,Dale	2003-07-19	36	$64,000.00	
	Vidas,Marian D	2003-07-19	14	$27,040.00	
	Workman,John E	2003-01-18	14	$60,200.00	

8

Kentucky Power Company
d/b/a
American Electric Power

REQUEST:

AEP should file an annual report of cost allocation factors in use, supplemented upon significant change. [Reference: Merger Agt., Ky. PSC Order dated 6/14/99, Reporting Requirements, Pg. 12 Item 3]

RESPONSE:

The cost allocation factors used by Kentucky Power Company and other AEP System companies are described in the Cost Allocation Manual (CAM) filed May 2001 as Attachment 1, Item No. 2. AEP received approval from the Securities and Exchange Commission on September 18, 2001 for eleven new cost allocation factors that are incorporated in the CAM. This information was filed with the Kentucky Commission in memo form on January 30, 2001 (Case No. 99-149).

WITNESS: Errol K. Wagner

6

Kentucky Power Company
d/b/a
American Electric Power

REQUEST:

AEP should file summaries of any cost allocation studies when conducted and the basis for the methods used to determine the cost allocation in effect. [Reference: Merger Agt., Ky. PSC Order dated 6/14/99, Reporting Requirements, Pg. 12, Item 4]

RESPONSE:

1st Quarter 2004:

Kentucky Power Company did not perform any cost allocation studies during the quarter ended March 31, 2004. The methods used by Kentucky Power Company for cost allocation are documented in the AEP Cost Allocation Manual.

WITNESS: Errol K. Wagner

10

Kentucky Power Company
d/b/a
American Electric Power

REQUEST:

AEP should file an annual report of the methods used to update or revise the cost allocation factors in use supplemented upon significant change. [Reference: Merger Agt., Ky. PSC Order dated 6/14/99, Reporting Requirements, Pg. 12, Item 5]

RESPONSE:

The methods used to update or revise the cost allocation factors used by Kentucky Power Company and other AEP System companies were not significantly changed during the year ended December 31, 2003. Allocation factors are revised periodically each year (e.g., monthly, quarterly, semi-annually and annually) based on the most current statistics available for each factor. The allocation factors in use are documented in the Cost Allocation Manual (CAM) filed May 2001 as Attachment 1, Item No. 2.

AEP received approval from the Securities and Exchange Commission on September 18, 2001 for eleven new cost allocation factors that are incorporated in the CAM. This information was filed with the Kentucky Commission in memo form on January 30, 2001 (Case No. 99-149).

WITNESS: Errol K. Wagner

11

Kentucky Power Company
d/b/a
American Electric Power

REQUEST:

AEP should file the current Articles of Incorporation and bylaws of affiliated companies in businesses related to the electric industry or that would be doing business with AEP. [Reference: Merger Agt., Ky. PSC Order dated 6/14/99, Reporting Requirements, Pg. 12, Item 6]

RESPONSE:

Please see the Company's response to Item No. 11 filed with the Commission on December 8, 2000.

WITNESS: Errol K. Wagner

12

Kentucky Power Company
d/b/a
American Electric Power

REQUEST:

AEP should file the current Articles of Incorporation of affiliated companies involved in non-related business. [Reference: Merger Agt., Ky. PSC Order dated 6/14/99, Reporting Requirements, Pg. 12, Item 7]

RESPONSE:

See the Company's response to Item No. 11 filed with the Commission on December 8, 2000.

WITNESS: Errol K. Wagner

13

Kentucky Power Company
d/b/a
American Electric Power

REQUEST:

To the extent that the merger is subject to conditions or changes not reviewed in this case, the Joint Applicants should amend their filing to allow the Commission and all parties an opportunity to review the revisions to ensure that Kentucky Power and its customers are not adversely affected and that any additional benefits flow through the favored nations clause. [Reference: Merger Agt., Ky. PSC Order dated 6/14/99, Reporting Requirements, Pgs. 12-13]

RESPONSE:

There were no changes during the period ending December 31, 2003 to the terms and conditions of the settlements in any jurisdiction that would adversely affect the settlement reached in the Commonwealth of Kentucky or cause additional benefits to flow through the favored nation clause.

WITNESS: Errol K. Wagner

14

Kentucky Power Company
d/b/a
American Electric Power

REQUEST:

The Joint Applicants should submit copies of final approval received from the FERC, SEC, FTC, DOJ, and all state regulatory commissions to the extent that these documents have not been provided. With each submittal, the Joint Applicants shall further state whether Paragraph 10 of the Settlement Agreement requires changes to the regulatory plan approved herein. [Reference: Merger Agt., Ky. PSC Order dated 6/14/99, Pg. 14 Item 7]

RESPONSE:

Please see the Company's response to Item No. 14 filed with the Commission on December 8, 2000.

WITNESS: Errol K. Wagner

15

Kentucky Power Company
d/b/a
American Electric Power

REQUEST:

Provide annual Service Reliability Report addressing the duration and frequency of customer disruptions (CAIDI and SAIFI), including storms for calendar 2003. [Reference: Merger Agt., Attachment C, Pg. 1, Item 1]

RESPONSE:

The overall Customer Average Interruption Duration Index (CAIDI), including major events, for Kentucky Power Company (KPCo) customers during calendar 2003 was 7.10 hours per customer interrupted. The overall System Average Interruption Frequency Index (SAIFI), including major events, for KPCo customers during calendar 2003 was 2.88 interruptions per customer served.

The high reliability indices are attributed to major events. A severe ice storm hit northern Kentucky in February. The outages attributed to that storm comprised 11.7% of the total annual outage cases, 14.4% of the total customers interrupted (SAIFI), and 50.5% of the total customer-minutes of interruption (which is used as the numerator in the CAIDI formula).

All reliability indices excluding major events were noticeably better in Y2003 than Y2002. The Y2003 CAIDI and SAIFI excluding major events were 2.88 hours per customer interrupted and 1.95 interruptions per customer served, respectively.

KPCo has previously reported on its changes in outage recording systems. Making comparisons to the 1995-1998 values is very difficult because of the numerous advancements in outage recording technology. The ultimate results are more accurate outage customer count and outage duration values.

WITNESS: Errol K. Wagner

16

Kentucky Power Company
d/b/a
American Electric Power

REQUEST:

Provide annual Call Center Performance Measures for those centers that handle Kentucky customer calls (Call Center Average Speed of Answer (ASA) Abandonment Rate, and Call Blockage), for calendar year 2003. [Reference: Merger Agt., Attachment C, Pg. 1, Item 2]

RESPONSE:

A summary of AEP's Call Center Performance Measures for Kentucky customer calls in calendar year 2003 is:

Measure	Value
Average Speed of Answer (ASA)	43 seconds
Abandonment Rate	4.76%
Call Blockage	0.35%

WITNESS: Errol K. Wagner

17

Kentucky Power Company
d/b/a
American Electric Power

REQUEST:

[AEP] Will continue to completely inspect its Kentucky electric facilities every two years and perform tree trimming, lightning arrestor replacement, animal guarding and pole and cross arm replacements. Provide data for calendar year 2003. [Reference: Merger Agt., Case No. 99-149, Attachment C, Page 1, Item 3]

RESPONSE:

In calendar year 2003, American Electric Power performed the work necessary to inspect the planned portion of its Kentucky electric facilities over the two-year period 2003-2004. AEP continues to perform tree trimming, lightning arrestor replacement, animal guarding, and pole and cross arm replacements as needed.

AEP provides the following statistics for work done in its Kentucky service territory in 2003:

- AEP previously sought and obtained approval from Mike Nantz to use circuit miles instead of poles as the measure for the two-year cycle inspection. The total circuit miles of conductor in Kentucky are 9,470 miles. These miles are contained in 196 distribution circuits. There were 71 complete circuits consisting of approximately 3,039 circuit miles inspected in 2003. We are on target to inspect all of the circuit miles for the two-year period 2003-2004.

- Inspected 11,491 poles as part of the ground-line treatment program. Poles were replaced or refurbished as necessary.

- Completed right-of-way maintenance work on 1,558 miles of distribution line.

AEP continues its asset management programs to review the performance of its facilities and to make prudent improvements to continue providing reliable and cost-effective electric service to its Kentucky customers.

WITNESS: Errol K. Wagner

18

Kentucky Power Company
d/b/a
American Electric Power

REQUEST:

AEP/Kentucky Power management will compile outage data detailing each circuit's reliability performance. In addition, by monitoring repeated outages on a regular basis, the Company will identify and resolve reliability problems, which may go unnoticed by using CAIDI and SAIFI results. This data will be coupled with feedback from district field personnel and supervision and management concerning other locations and situations where the impacts of outages are quantified. This process will be used to develop a comprehensive work plan each year, which focuses efforts to improve service reliability. The Company will undertake all reasonable expenditures to achieve the goal of limiting customer outages. [Reference: Merger Agt., Attachment C, Pg. 1, Item 4]

RESPONSE:

AEP/Kentucky continues to compile outage data detailing each circuit's reliability performance. Worst performing circuits are identified considering CAIDI, SAIFI, and repeat outages, as well as those with outage causes than can be addressed through existing asset improvement programs targeting animal, lightning, small conductor failure, and tree caused outages. This allows for the identification of areas needing reliability improvements and for the development of work plans to optimize system performance where within utility control.

Work plans are developed by combining reliability performance with input from field personnel to identify areas that do not satisfy ranking criteria alone. Work plans include ground line treatment of poles; improved fault isolation by installing additional sectionalizing devices; recloser maintenance; and system improvements required due to facility loading, voltage control, and reliability performance.

WITNESS: Errol K. Wagner

19

Kentucky Power Company
d/b/a
American Electric Power

REQUEST:

Plans to continue to maintain a high quality workforce to meet customers' needs. [Reference: Merger Agt, Attachment C, Pg. 2, Item 5]

RESPONSE:

The Company has maintained a high quality workforce which met the customers needs in providing electrical service.

WITNESS: Errol K. Wagner

20

Kentucky Power Company
d/b/a
American Electric Power

REQUEST:

AEP shall designate an employee who will act as a contact for State Commissions and consumer advocates seeking data and information regarding affiliate transactions and personnel transfers. Such employee shall be responsible for providing data and information requested by a State Commission for any and all transactions between the jurisdictional operating company and its affiliates, regardless of which affiliate(s) subsidiary(ies) or associate(s) of an AEP operating company from which the information is sought. [Reference: Merger Agt., Stipulation and Settlement, Pg. 11, Item Q]

RESPONSE:

Mr. Errol K. Wagner, AEP-Kentucky Regulatory Services Director, is the contact designee for the Kentucky Public Service Commissioners and Staff and the Kentucky Attorney General's Office regarding affiliate transactions and personnel transfers.

WITNESS: Errol K. Wagner

21

Kentucky Power Company
d/b/a
American Electric Power

REQUEST:

Please provide designated employee or agent within Kentucky who will act as a contact for retail customers regarding service and reliability concerns and provide a contact for retail consumers for information, questions and assistance. Such AEP/Kentucky Power representative shall be able to deal with billing, maintenance and service reliability issues. [Merger Agt., Stipulation and Settlement, Pg. 11, Item R]

RESPONSE:

The Company would prefer customers to initially call the Customer Solution Centers, whose representatives are capable of answering questions concerning service, reliability concerns and billing issues. However, the AEP-Kentucky Regulatory Services Department personnel, specifically the Regulatory Services Director, are also capable of dealing with billing, maintenance and service reliability issues.

WITNESS: Errol K. Wagner

22

Kentucky Power Company
d/b/a
American Electric Power

REQUEST:

AEP shall provide each signatory state a current list of employees or agents that are designated to work with each State Commission and consumer advocate concerning state regulatory matters, including, but not limited to, rate cases, consumer complaints, billing and retail competition issues. [Reference: Merger Agt., Stipulation and Settlement, Pg. 11, Item 5].

RESPONSE:

Mr. Errol K. Wagner, AEP-Kentucky Regulatory Services Director, and the AEP-Kentucky Regulatory Services Department staff are the designated employees to work with Kentucky Public Service Commission and the Kentucky Attorney General's Office concerning state regulatory matters, including, but not limited to rate cases, consumer complaints, billing and retail competition issues.

WITNESS: Errol K. Wagner

23

Kentucky Power Company
d/b/a
American Electric Power

REQUEST:

The Company further commits to maintain in Kentucky a sufficient management team to ensure that safe, reliable and efficient electric service is provided and to respond to the needs and inquiries of its Kentucky customers.
[Reference: Merger Agt., Attachment C, Pg. 2, Item 6a]

RESPONSE:

The Company has maintained a sufficient management team in Kentucky to ensure that safe, reliable and efficient electric service is provided and the Company has responded to the needs and inquiries of its customers.

WITNESS: Errol K. Wagner

24

Kentucky Power Company
d/b/a
American Electric Power

REQUEST:

AEP shall contract with an independent auditor who shall conduct biennial audits for ten years after merger consummation of affiliated transactions to determine compliance with the affiliate standards outlined in the Stipulation and Settlement Agreement. The results of such audits shall be filed with the State Commissions. Prior to the initial audit, AEP will conduct an informational meeting with State Commissions regarding how its affiliates and affiliate transactions will or have changed as a result of the proposed merger. [Reference: Stipulation and Settlement Agreement, Page 11, Section 8(V)]

RESPONSE:

Kentucky Power Company continues to adhere to all applicable affiliate standards. In light of the General Assembly's enactment of HB 897 (KRS278.2201 et seq.) in 2000, and the express terms of the Merger Settlement Agreement and the Order approving the agreement, the affiliate standards and requirements contained in the Merger Settlement Agreement have been superseded by statute. See, *Order, Joint Application of Kentucky Power Company, American Electric Power Company, Inc., and Central and South West Corporation Regarding a Proposed Merger, P.S.C. Case No. 99-149 at 8 (affiliate standards and guidelines set out in Merger Settlement Agreement to "remain in effect 'until new affiliate standards are imposed by either the Commission or by the General Assembly.'"*.) Accordingly, Kentucky Power Company will not be conducting a biennial audit of affiliated transactions as contemplated by the now superseded standards.

WITNESS: Errol K. Wagner

KPSC Case No. 99-149
Item No. 1
Attachment No. 1

2003 Annual Reports

American Electric Power Company, Inc.

AEP Generating Company

AEP Texas Central Company

AEP Texas North Company

Appalachian Power Company

Columbus Southern Power Company

Indiana Michigan Power Company

Kentucky Power Company

Ohio Power Company

Public Service Company of Oklahoma

Southwestern Electric Power Company

Audited Financial Statements and
Management's Discussion and Analysis

AEP AMERICAN ELECTRIC POWER

AEP: America's Energy Partner©

AMERICAN ELECTRIC POWER COMPANY, INC. AND SUBSIDIARY COMPANIES
INDEX TO ANNUAL REPORTS

GLOSSARY OF TERMS

When the following terms and abbreviations appear in the text of this report, they have the meanings indicated below.

Term	Meaning
2004 True-up Proceeding	A filing to be made after January 10, 2004 under the Texas Legislation to finalize the amount of stranded costs and other true-up items and the recovery of such amounts.
AEGCo	AEP Generating Company, an electric utility subsidiary of AEP.
AEP	American Electric Power Company, Inc.
AEP Consolidated	AEP and its majority owned consolidated subsidiaries and consolidated affiliates.
AEP Credit	AEP Credit, Inc., a subsidiary of AEP which factors accounts receivable and accrued utility revenues for affiliated domestic electric utility companies.
AEP East companies	APCo, CSPCo, I&M, KPCo and OPCo.
AEPES	AEP Energy Services, Inc., a subsidiary of AEPR.
AEPR	AEP Resources, Inc.
AEP System or the System	The American Electric Power System, an integrated electric utility system, owned and operated by AEP's electric utility subsidiaries.
AEPSC	American Electric Power Service Corporation, a service subsidiary providing management and professional services to AEP and its subsidiaries.
AEP System Power Pool or AEP Power Pool	Members are APCo, CSPCo, I&M, KPCo and OPCo. The Pool shares the generation, cost of generation and resultant wholesale system sales of the member companies.
AEP West companies	PSO, SWEPCo, TCC and TNC.
AFUDC	Allowance for funds used during construction, a noncash nonoperating income item that is capitalized and recovered through depreciation over the service life of domestic regulated electric utility plant.
ALJ	Administrative Law Judge.
Alliance RTO	Alliance Regional Transmission Organization, an ISO formed by AEP and four unaffiliated utilities (the FERC overturned earlier approvals of this RTO in December 2001).
Amos Plant	John E. Amos Plant, a 2,900 MW generation station jointly owned and operated by APCo and OPCo.
APB 18	Accounting Principles Board Opinion Number 18: The Equity Method of Accounting for Investments in Common Stock.
APCo	Appalachian Power Company, an AEP electric utility subsidiary.
Arkansas Commission	Arkansas Public Service Commission.
Buckeye	Buckeye Power, Inc., an unaffiliated corporation.
COLI	Corporate owned life insurance program.
Cook Plant	The Donald C. Cook Nuclear Plant, a two-unit, 2,110 MW nuclear plant owned by I&M.
CSPCo	Columbus Southern Power Company, an AEP electric utility subsidiary.
CSW	Central and South West Corporation, a subsidiary of AEP (Effective January 21, 2003, the legal name of Central and South West Corporation was changed to AEP Utilities, Inc.).
CSW Energy	CSW Energy, Inc., an AEP subsidiary which invests in energy projects and builds power plants.
CSW International	CSW International, Inc., an AEP subsidiary which invests in energy projects and entities outside the United States.
D.C. Circuit Court	The United States Court of Appeals for the District of Columbia Circuit.
DETM	Duke Energy Trading and Marketing L.L.C., a risk management counterparty.
DOE	United States Department of Energy.
ECOM	Excess Cost Over Market.
EITF	The Financial Accounting Standards Board's Emerging Issues Task Force.

EITF 02-3	Emerging Issues Task Force Issue No. 02-3: Issues Involved in Accounting for Derivative Contracts Held For Trading Purposes and Contracts Involved in Energy Trading and Risk Management Activities.
ERCOT	The Electric Reliability Council of Texas.
EWGs	Exempt Wholesale Generators.
FASB	Financial Accounting Standards Board.
Federal EPA	United States Environmental Protection Agency.
FERC	Federal Energy Regulatory Commission.
FIN 45	FASB Interpretation No. 45, "Guarantor's Accounting and Disclosure Requirements for Guarantees, Including Indirect Guarantees of Indebtedness of Others."
FIN 46	FASB Interpretation No. 46, "Consolidation of Variable Interest Entities."
FUCOs	Foreign Utility Companies.
GAAP	Generally Accepted Accounting Principles.
I&M	Indiana Michigan Power Company, an AEP electric utility subsidiary.
ICR	Interchange Cost Reconstruction.
IRS	Internal Revenue Service.
IURC	Indiana Utility Regulatory Commission.
ISO	Independent System Operator.
JMG	JMG Funding LP.
KPCo	Kentucky Power Company, an AEP electric utility subsidiary.
KPSC	Kentucky Public Service Commission.
KV	Kilovolt.
KWH	Kilowatthour.
LIG	Louisiana Intrastate Gas, an AEP subsidiary.
LPSC	Louisiana Public Service Commission.
Michigan Legislation	The Customer Choice and Electricity Reliability Act, a Michigan law which provides for customer choice of electricity supplier.
MISO	Midwest Independent System Operator (an independent operator of transmission assets in the Midwest).
MLR	Member Load Ratio, the method used to allocate AEP Power Pool transactions to its members.
Money Pool	AEP System's Money Pool.
MPSC	Michigan Public Service Commission.
MTM	Mark-to-Market.
MW	Megawatt.
MWH	Megawatthour.
NOx	Nitrogen oxide.
NOx Rule	A final rule issued by Federal EPA which requires NOx reductions in 22 eastern states including seven of the states in which AEP companies operate.
NRC	Nuclear Regulatory Commission.
OCC	The Corporation Commission of the State of Oklahoma.
Ohio Act	The Ohio Electric Restructuring Act of 1999.
Ohio EPA	Ohio Environmental Protection Agency.
OPCo	Ohio Power Company, an AEP electric utility subsidiary.
OVEC	Ohio Valley Electric Corporation, an electric utility company in which AEP and CSPCo own a 44.2% equity interest.
PCBs	Polychlorinated Biphenyls.
PJM	Pennsylvania – New Jersey – Maryland regional transmission organization.
PRP	Potentially Responsible Party.
PSO	Public Service Company of Oklahoma, an AEP electric utility subsidiary.
PTB	Price-to-Beat.
PUCO	The Public Utilities Commission of Ohio.
PUCT	The Public Utility Commission of Texas.

PUHCA	Public Utility Holding Company Act of 1935, as amended.
PURPA	The Public Utility Regulatory Policies Act of 1978.
RCRA	Resource Conservation and Recovery Act of 1976, as amended.
Registrant Subsidiaries	AEP subsidiaries who are SEC registrants; AEGCo, APCo, CSPCo, I&M, KPCo, OPCo, PSO, SWEPCo, TCC and TNC.
REP	Retail Electric Provider.
Risk Management Contracts	Trading and non-trading derivatives, including those derivatives designated as cash flow and fair value hedges, and non-derivative contracts held for trading purposes that were subject to mark-to-market accounting prior to January 1, 2003.
Rockport Plant	A generating plant, consisting of two 1,300 MW coal-fired generating units near Rockport, Indiana owned by AEGCo and I&M.
RTO	Regional Transmission Organization.
SEC	Securities and Exchange Commission.
SFAS	Statement of Financial Accounting Standards issued by the Financial Accounting Standards Board.
SFAS 71	Statement of Financial Accounting Standards No. 71, <u>Accounting for the Effects of Certain Types of Regulation</u>.
SFAS 101	Statement of Financial Accounting Standards No. 101, <u>Accounting for the Discontinuance of Application of Statement 71</u>.
SFAS 133	Statement of Financial Accounting Standards No. 133, <u>Accounting for Derivative Instruments and Hedging Activities</u>.
SFAS 143	Statement of Financial Accounting Standards No. 143, <u>Accounting for Asset Retirement Obligations</u>.
SFAS 149	Statement of Financial Accounting Standards No. 149, <u>Amendment of Statement 133 on Derivative Instruments and Hedging Activities</u>.
SFAS 150	Statement of Financial Accounting Standards No. 150, <u>Accounting for Certain Financial Instruments with Characteristics of both Liabilities and Equity</u>.
SNF	Spent Nuclear Fuel.
SPP	Southwest Power Pool.
STP	South Texas Project Nuclear Generating Plant, owned 25.2% by AEP Texas Central Company, an AEP electric utility subsidiary.
STPNOC	STP Nuclear Operating Company, a non-profit Texas corporation which operates STP on behalf of its joint owners including TCC.
Superfund	The Comprehensive Environmental, Response, Compensation and Liability Act.
SWEPCo	Southwestern Electric Power Company, an AEP electric utility subsidiary.
TCC	AEP Texas Central Company, an AEP electric utility subsidiary.
Tenor	Maturity of a contract.
Texas Legislation	Legislation enacted in 1999 to restructure the electric utility industry in Texas.
TNC	AEP Texas North Company, an AEP electric utility subsidiary.
TVA	Tennessee Valley Authority.
U.K.	The United Kingdom.
VaR	Value at Risk, a method to quantify risk exposure.
Virginia SCC	Virginia State Corporation Commission.
WVPSC	Public Service Commission of West Virginia.
WPCo	Wheeling Power Company, an AEP electric distribution subsidiary.
Zimmer Plant	William H. Zimmer Generating Station, a 1,300 MW coal-fired unit owned 25.4% by Columbus Southern Power Company, an AEP subsidiary.

FORWARD-LOOKING INFORMATION

This report made by AEP and certain of its subsidiaries contains forward-looking statements within the meaning of Section 21E of the Securities Exchange Act of 1934. Although AEP and each of its registrant subsidiaries believe that their expectations are based on reasonable assumptions, any such statements may be influenced by factors that could cause actual outcomes and results to be materially different from those projected. Among the factors that could cause actual results to differ materially from those in the forward-looking statements are:

- Electric load and customer growth.
- Weather conditions.
- Available sources and costs of fuels.
- Availability of generating capacity and the performance of AEP's generating plants.
- The ability to recover regulatory assets and stranded costs in connection with deregulation.
- New legislation and government regulation including requirements for reduced emissions of sulfur, nitrogen, mercury, carbon and other substances.
- Resolution of pending and future rate cases, negotiations and other regulatory decisions (including rate or other recovery for environmental compliance).
- Oversight and/or investigation of the energy sector or its participants.
- Resolution of litigation (including pending Clean Air Act enforcement actions and disputes arising from the bankruptcy of Enron Corp.).
- AEP's ability to reduce its operation and maintenance costs.
- The success of disposing of investments that no longer match AEP's corporate profile.
- AEP's ability to sell assets at attractive prices and on other attractive terms.
- International and country-specific developments affecting foreign investments including the disposition of any current foreign investments.
- The economic climate and growth in AEP's service territory and changes in market demand and demographic patterns.
- Inflationary trends.
- AEP's ability to develop and execute on a point of view regarding prices of electricity, natural gas, and other energy-related commodities.
- Changes in the creditworthiness and number of participants in the energy trading market.
- Changes in the financial markets, particularly those affecting the availability of capital and AEP's ability to refinance existing debt at attractive rates.
- Actions of rating agencies, including changes in the ratings of debt and preferred stock.
- Volatility and changes in markets for electricity, natural gas, and other energy-related commodities.
- Changes in utility regulation, including the establishment of a regional transmission structure.
- Accounting pronouncements periodically issued by accounting standard-setting bodies.
- The performance of AEP's pension plan.
- Prices for power that we generate and sell at wholesale.
- Changes in technology and other risks and unforeseen events, including wars, the effects of terrorism (including increased security costs), embargoes and other catastrophic events.

AEP COMMON STOCK AND DIVIDEND INFORMATION

The AEP common stock quarterly high and low sales prices, quarter-end closing price and the cash dividends paid per share are shown in the following table:

Quarter Ended	High	Low	Quarter-end Closing Price	Dividend
December 2003	$30.59	$26.69	$30.51	$0.35
September 2003	30.00	26.58	30.00	0.35
June 2003	31.51	22.56	29.83	0.35
March 2003	30.63	19.01	22.85	0.60
December 2002	$30.55	$15.10	$27.33	$0.60
September 2002	40.37	22.74	28.51	0.60
June 2002	48.80	39.00	40.02	0.60
March 2002	47.08	39.70	46.09	0.60

AEP common stock is traded principally on the New York Stock Exchange. At December 31, 2003, AEP had approximately 150,000 registered shareholders.

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AMERICAN ELECTRIC POWER COMPANY, INC.
AND SUBSIDIARY COMPANIES

AMERICAN ELECTRIC POWER COMPANY, INC. AND SUBSIDIARY COMPANIES
SELECTED CONSOLIDATED FINANCIAL DATA

	2003	2002	2001	2000	1999
OPERATIONS STATEMENTS DATA			(in millions)		
Total Revenues	$14,545	$13,308	$12,753	$10,743	$9,695
Operating Income	1,632	1,804	2,223	1,758	2,053
Income Before Discontinued Operations, Extraordinary Items and Cumulative Effect	522	485	960	177	865
Discontinued Operations Income (Loss)	(605)	(654)	41	134	116
Extraordinary Losses	-	-	(48)	(44)	(9)
Cumulative Effect of Accounting Changes Gain (Loss)	193	(350)	18	-	-
Net Income (Loss)	110	(519)	971	267	972
BALANCE SHEET DATA			(in millions)		
Property, Plant and Equipment	$36,033	$34,127	$32,993	$31,472	$30,476
Accumulated Depreciation and Amortization	14,004	13,539	12,655	12,398	11,895
Net Property, Plant and Equipment	$22,029	$20,588	$20,338	$19,074	$18,581
Total Assets	$36,744	$35,890	$40,432	$47,703	$36,297
Common Shareholders' Equity	7,874	7,064	8,229	8,054	8,673
Cumulative Preferred Stocks of Subsidiaries (a) (d)	137	145	156	161	182
Trust Preferred Securities (b)	-	321	321	334	335
Long-term Debt (a) (b)	14,101	10,190	9,409	8,980	9,471
Obligations Under Capital Leases (a)	182	228	451	614	610
COMMON STOCK DATA					
Earnings (Loss) per Common Share:					
Before Discontinued Operations, Extraordinary Items and Cumulative Effect	$1.35	$1.46	$2.98	$0.55	$2.69
Discontinued Operations	(1.57)	(1.97)	0.13	0.42	0.36
Extraordinary Losses	-	-	(0.16)	(0.14)	(0.02)
Cumulative Effect of Accounting Changes	0.51	(1.06)	0.06	-	-
Earnings (Loss) Per Share	$0.29	$(1.57)	$3.01	$0.83	$3.03
Average Number of Shares Outstanding (in millions)	385	332	322	322	321
Market Price Range:					
High	$31.51	$48.80	$51.20	$48.94	$48.19
Low	19.01	15.10	39.25	25.94	30.56
Year-end Market Price	30.51	27.33	43.53	46.50	32.13
Cash Dividends on Common (c)	$1.65	$2.40	$2.40	$2.40	$2.40
Dividend Payout Ratio(c)	569.0%	(152.9)%	79.7%	289.2%	79.2%
Book Value per Share	$19.93	$20.85	$25.54	$25.01	$26.96

(a) Including portion due within one year.
(b) See Note 17 of the Notes to Consolidated Financial Statements.
(c) Based on AEP historical dividend rate.
(d) Includes Cumulative Preferred Stocks of Subsidiaries Subject to Mandatory Redemption which are classified in 2003 as Non-Current Liabilities.

AMERICAN ELECTRIC POWER COMPANY, INC. AND SUBSIDIARY COMPANIES
MANAGEMENT'S FINANCIAL DISCUSSION AND ANALYSIS OF RESULTS OF OPERATIONS

American Electric Power Company, Inc. (AEP) is one of the largest investor owned electric public utility holding companies in the U.S. Our electric utility operating companies provide generation, transmission and distribution service to more than five million retail customers in Arkansas, Indiana, Kentucky, Louisiana, Michigan, Ohio, Oklahoma, Tennessee, Texas, Virginia and West Virginia.

We have a vast portfolio of assets including:

- 38,000 megawatts of generating capacity, the largest complement of generation in the U.S., the majority of which has a significant cost advantage in many of our market areas. Utility generating capacity of 4,500 megawatts located in Texas and approximately 280 megawatts of independent power generation located in Colorado and Florida are expected to be sold during 2004
- 39,000 miles of transmission lines, the backbone of the electric interconnection grid in the Eastern U.S.
- 210,000 miles of distribution lines that deliver electricity to customers
- Substantial coal transportation assets (7,000 railcars, 1,800 barges, 37 towboats and two coal handling terminals with 20 million tons of annual capacity)
- 6,400 miles of gas pipelines in Louisiana and Texas with 127 Bcf of gas storage facilities. We have entered into an agreement to sell 2,000 miles of pipeline and plan to sell 9 Bcf of storage located in Louisiana related to our disposal of LIG
- 4,000 megawatts of generating capacity in the U.K., a market which we plan to exit by the end of 2004

BUSINESS STRATEGY

We will continue to concentrate our efforts on our domestic utilities. Our objectives are to be an economical, reliable and safe provider of energy to the markets that we serve. We will achieve economic advantage by designing, building, improving and operating low cost efficient sources of power and maximizing the volumes of power delivered from these facilities. We will maintain and enhance our position as a safe and reliable provider of energy by making significant investments into environmental and reliability upgrades. We will seek to recover the cost of our new utility investments in a manner that results in reasonable rates for our customers and that provides a fair return for our shareholders through a stable stream of cash flows enabling us to pay competitive dividends.

We are addressing many challenges in our unregulated business. We have substantially reduced our trading activities that are not related to the sale of power from our owned-generation. We have written down the value of several investments to reflect deterioration in market conditions and sold or plan to sell assets that no longer fit our core business strategy. We have identified certain assets as "held-for-sale" and will move others to "held-for-sale" as we formalize and approve our plans for disposition. We will continue to operate HPL as we evaluate our future plans for this investment.

In summary our business strategy calls for us to:

Operations

- Invest in technology that improves the environment of the communities in which we operate
- Maximize the value of our transmission assets and protect our revenue stream through membership in PJM
- Continue maintaining and improving distribution service quality
- Optimize generation assets by increasing availability and consequently increasing sales
- Complete the sales of our non-core assets

Regulation

- Focus on the regulatory process to maximize our earnings while providing fair and reasonable rates to our customers
- Complete the sale of our generation assets in Texas and recognize and recover the associated stranded costs in compliance with the law
- Complete the integration of the operation of our transmission system into PJM consistent with applicable regulatory requirements

Financial

- Operate only those unregulated investments that are consistent with our energy expertise and risk tolerance and that provide reasonable prospects for a fair return and moderate growth
- Continue to improve credit quality and maintain acceptable levels of liquidity
- Achieve moderate but steady earnings growth

2003 OVERVIEW

2003 was a year of transition for AEP. We repositioned ourselves to take advantage of, and maximize, the value of our utility assets. At the same time we took significant strides to exit non-core investments.

Our utility operations had a year of continued improvement resulting from strong wholesale results and our efforts to control and reduce operating costs. We reduced our losses from unregulated investments by reducing transitional trading losses and cutting related administrative expenses.

During 2003 we further stabilized our financial strength by:

- Issuing approximately $1.1 billion in common stock
- Completing a cost reduction initiative which led to a $392 million decline in operations and maintenance expenses during 2003 as compared to 2002. Savings of approximately $139 million are attributable to our utility operations
- Minimizing future capital requirements associated with non-core assets
- Reducing our cash flow risk by limiting our trading activities to a level consistent with the scope of our generation fleet
- Stabilizing our credit ratings

We have redirected our business strategy by:

- Continuing to streamline our trading activities principally to support the sale of power from our core assets
- Actively pursuing the sale of all of our U.K. generation and our gas pipeline operations located in Louisiana; we expect each of these dispositions to be completed during 2004

OUTLOOK FOR 2004

We remain focused on the fundamental earning power of our utilities, and we are committed to strengthening our balance sheet. Our strategy for achieving these goals is well planned. We will:

- Continue to identify opportunities to further reduce both our operations and maintenance expenses and to efficiently manage our capital expenditures
- Seek rate changes that are fair and reasonable and that allow us to make the necessary operational and environmental improvements to our system
- Dispose of various unregulated assets to eliminate the negative earnings and cash consequences of these operations
- Use the proceeds from our dispositions to reduce debt and strengthen our capital structure
- Successfully operate certain unregulated investments such as our wind farms and our barge and river transport groups, which compliment our core capabilities
- Evaluate opportunities to hold and operate HPL under a revised business model that reduces commodity risk and earns reasonable returns for shareholders

Our objective is excellence in operations and results. There are, nevertheless, certain risks and challenges. We discuss these matters in detail in the Notes to Financial Statements and later in Management's Discussion and Analysis under the heading of Significant Factors. We will diligently resolve these matters by finding workable solutions that balance the interests of our customers, our employees and our investors.

RESULTS OF OPERATIONS

In 2003, AEP's principal operating business segments and their major activities were:

- Utility Operations:
  - Domestic generation of electricity for sale to retail and wholesale customers
  - Domestic electricity transmission and distribution
- Investments-Gas Operations:*
  - Gas pipeline and storage services
- Investments-UK Operations:**
  - International generation of electricity for sale to wholesale customers
  - Coal procurement and transportation to AEP plants and third parties
- Investments-Other:
  - Coal mining, bulk commodity barging operations and other energy supply related businesses

* Operations of Louisiana Intrastate Gas were classified as discontinued during 2003.
** UK Operations were classified as discontinued during 2003.

American Electric Power Company's consolidated Net Income (Loss) for the years ended December 31, 2003, 2002 and 2001 were as follows (Earnings and Average Shares Outstanding in millions):

	2003		2002		2001	
	Earnings	**EPS**	**Earnings**	**EPS**	**Earnings**	**EPS**
Utility Operations	$1,218	$3.17	$1,154	$3.47	$941	$2.92
Investments – Gas Operations	(290)	(.76)	(99)	(.29)	91	.28
Investments – UK Operations	-	-	-	-	-	-
Investments – Other	(277)	(.72)	(522)	(1.58)	-	-
All Other*	(129)	(.34)	(48)	(.14)	(72)	(.22)
Income Before Discontinued Operations, Extraordinary Items and Cumulative Effect	522	1.35	485	1.46	960	2.98
Investments – Gas Operations	(91)	(.24)	8	.02	(4)	(.01)
Investments – UK Operations	(507)	(1.32)	(472)	(1.42)	(41)	(.13)
Investments – Other	(7)	(.01)	(190)	(.57)	86	.27
Discontinued Operations	(605)	(1.57)	(654)	(1.97)	41	.13
Extraordinary Loss	-	-	-	-	(48)	(.16)
Cumulative Effect of Accounting Changes	193	.51	(350)	(1.06)	18	.06
Total Net Income (Loss)	$110	$.29	$(519)	$(1.57)	$971	$3.01
Average Shares Outstanding		385		332		322

* All Other includes the parent company interest income and expense, as well as other non-allocated costs.

2003 Compared to 2002

Income Before Discontinued Operations, Extraordinary Items and Cumulative Effect in 2003 increased compared to 2002 due to increased wholesale earnings, lower impairment and other charges, and reduced operations and maintenance expenses. This increase was offset, in part, by milder weather and continuing weakness in the economy. Our Net Income for 2003 of $110 million or $.29 per share includes a loss, net of taxes, on discontinued operations of $605 million and $193 million of income, net of taxes, from the cumulative effect of changing our accounting for asset retirement obligations and for certain trading activities. Our Net Loss for 2002 of $519 million or ($1.57) per share includes a loss, net of taxes, on discontinued operations of $654 million and a $350 million, net of tax, charge for implementing a newly issued accounting pronouncement related to the impairment of goodwill.

During the fourth quarter of 2003 we concluded that the U.K. operations and LIG were not part of our core business and we began actively marketing each of these investments. The U.K. operations consist of our generation and trading operations that sell to wholesale customers. LIG's operations include 2,000 miles of intrastate gas pipelines and 9 Bcf of natural gas storage capacity. In addition, we recognized that poor market conditions also affected our merchant generation, other gas pipeline and storage assets, goodwill associated with these investments and various other assets. Based on market factors, as measured by a combination of indicative bids from unrelated interested buyers, independent appraisals, and estimates of cash flows, we recognized impairment losses of $960 million, net of taxes.

Average shares outstanding increased to 385 million in 2003 from 332 million in 2002 due to a common stock issuance in March 2003. The additional average shares outstanding decreased our 2003 earnings per share by $0.04.

2002 Compared to 2001

Our Net Loss was $519 million or a loss of $1.57 per share in 2002 which was a $1.5 billion decline from 2001. Income Before Discontinued Operations, Extraordinary Items and Cumulative Effect was negatively affected by plant availability, lower wholesale prices, reduced trading activity and write-offs to reduce the valuation of the under-performing assets. In the fourth quarter 2002, we recognized impairments on under-performing assets and recorded losses, net of taxes, of $854 million. The losses in the fourth quarter 2002 were caused by the extended decline in domestic and international energy markets. In addition to the fourth quarter impairment losses, we had losses on discontinued operations of $654 million including U.K. operations, SEEBOARD, Citipower and other investments and a loss for transitional goodwill impairment of $350 million related to SEEBOARD and Citipower that resulted from the adoption of a newly issued accounting standard related to the impairment of goodwill.

Our results of operations are discussed below according to our operating segments.

Utility Operations

Summary of Selected Sales Data
For Utility Operations
For the Years Ended December 31, 2003, 2002 and 2001

	2003	2002	2001
Energy Summary		(in millions of KWH)	
Retail			
Residential	45,479	46,805	43,498
Commercial	37,104	36,487	35,589
Industrial	51,856	53,686	52,443
Miscellaneous	3,035	3,216	2,208
Total	137,474	140,194	133,738
Wholesale	72,977	70,661	79,288

	2003	2002	2001
Weather Summary		(in degree days)	
Eastern Region			
Actual – Heating	5,314	4,963	4,679
Normal – Heating*	5,182	5,177	5,232
Actual – Cooling	757	1,252	1,021
Normal – Cooling*	975	1,013	997
Western Region			
Actual – Heating	1,020	1,044	1,134
Normal – Heating*	1,062	1,034	1,060
Actual – Cooling	2,220	2,369	2,377
Normal – Cooling*	2,217	2,224	2,233

*Normal Heating/Cooling represents the 30-year average of degree days.

2003 Compared to 2002

Earnings from Utility Operations increased $64 million to $1,218 million in 2003. Decreased operating expenses were partially offset by decreases in revenues net of related fuel and purchased power.

Utility revenues net of related fuel and purchased power decreased as follows:

- Residential demand decreased principally as a consequence of milder weather, and industrial demand was down due to the continued slow economic recovery. The combination of these factors reduced revenues net of related fuel and purchased power by approximately $65 million.
- Reserves for final fuel factor decisions in Texas as well as other disallowances and associated rate reserves of $102 million and lower regulatory deferrals for ECOM-based stranded costs of $44 million reduced earnings. The provisions for stranded cost recovery in Texas recognize a regulatory asset or liability for the difference between the actual price received from the state-mandated auction of 15% of generation capacity and the earlier estimate of market price derived by a PUCT model.
- Fuel and purchased power costs increased by approximately $40 million due in part to nuclear plant outages.
- During the fourth quarter of 2002, we exited trading activities that were not related to the sale of power from our owned-generation. The loss of these contributions from exiting the related trading positions reduced utility earnings by approximately $70 million.

The decreases in utility revenues net of related fuel and purchased power were partially offset as follows:

- Off-system sales, including optimization activities, increased by approximately $160 million primarily due to increased prices and plant availability.
- Transmission revenues increased by approximately $45 million, due principally to increased wholesale power sales volumes.

Utility operating expenses decreased as follows:

- Maintenance and Other Operation expense decreased $139 million due to continuing efforts to reduce costs, primarily labor and insurance, despite severe storm damage in the Midwest.
- Taxes Other Than Income Taxes decreased $17 million primarily due to reduced gross receipts tax as a result of the sale of the Texas REPs.
- Depreciation and Amortization expense decreased $18 million due to the change in our accounting for asset retirement obligations. The accounting change caused similar offsetting increases in Maintenance and Other Operation expenses.

2002 Compared to 2001

Earnings from Utility Operations increased $213 million to $1,154 million in 2002 due to an $84 million gain on the sale of the Texas REPs and capital cost reductions of $104 million, partially offset by a reduction in operating income.

Capital costs decreased due to reductions in short-term interest rates, lower outstanding balances of short-term debt and the refinancing of long-term debt at favorable interest rates. These reductions were partially offset by an increase in the amount of long-term debt outstanding.

Increased operating expenses were partially offset by increases in revenues net of related fuel and purchased power.

Utility revenues net of related fuel and purchased power increased as follows:

- ECOM-based Texas stranded cost deferrals increased $262 million.
- Retail demand increased approximately $180 million due to increased usage by residential customers. Eastern region cooling degree days were up 23% over 2001.

The increases in utility revenues net of related fuel and purchased power were partially offset as follows:

- Off-system sales net of related fuel and purchased power decreased $126 million primarily due to lower plant availability, lower wholesale prices, the loss of certain municipal and co-op customers, and customers switching from FERC tariff-based to market-based rates.
- Trading operations, which decreased $214 million as a result of our previously announced plan to exit trading activities that are not related to the sale of power from our owned-generation.

Utility operating expenses increased as follows:

- Maintenance and Other Operation expense increased $102 million due to increased benefit costs of $48 million, increased post September 11 insurance cost of $35 million and increased nuclear maintenance and other expenses of $19 million.
- Depreciation and Amortization expense increased $46 million as a result of additional generation, transmission and distribution assets.
- Taxes Other Than Income Taxes increased $70 million due to increased property and payroll taxes.

Investments – Gas Operations

2003 Compared to 2002

The loss from our Gas Operations of $290 million increased $191 million from 2002. This increase is primarily due to impairments recorded to reflect the reduction in the value of our gas assets. In the fourth quarter 2003, we recognized impairments and other related charges of $228 million, net of tax, associated with HPL assets and goodwill based on market indicators supported by indicative bids received for LIG. These bids led us to conclude that purchasers were no longer willing to pay higher multiples for historic cash flows which included trading activities. Our previous operating strategy included higher risk tolerances associated with trading activities in order to achieve such operating results.

Partially offsetting the 2003 impairments, gas operations earnings have improved approximately $68 million from 2002 due to a $40 million decrease in losses associated with the options trading portfolio that we are no longer actively trading and exiting through a transition plan (our transition gas trading portfolio) and a $28 million reduction in operating expenses. These earnings improvements were partially offset by $15 million of losses due to unexpected late February 2003 sales to Entex, at fixed prices, when the Houston Ship Channel prices were at historic highs, a decrease in March deliveries due to unseasonably mild weather, and a decline in trading optimization of $28 million due to lower risk tolerances and limits compared to the previous year.

2002 Compared to 2001

The loss from our Gas Operations of $99 million increased $190 million from 2001. The increase is due to significant trading losses in 2002 compared with strong trading results in 2001.

Investments – UK Operations

2003 Compared to 2002

The loss from our UK Operations of $507 million for 2003 increased by $35 million from 2002 and was due primarily to $375 million, net of tax, of impairment and other related charges recorded during the fourth quarter. During 2003, we concluded that the UK Operations were not part of our core business and we began actively marketing our investment. As a result, we devalued our UK investment based on bids received from interested unrelated buyers. The loss includes $157 million of pre-tax losses associated with commitments for below market forward sales of power, which are beyond the date of the anticipated sale of these plants. We also experienced operating losses as a result of the deterioration of pretax trading margins of $83 million associated with U.K. power and $29 million associated with coal and freight.

2002 Compared to 2001

Our loss in 2002 from UK Operations of $472 million increased by $431 million from 2001. Our operations in the U.K. were dramatically expanded in December 2001 with the acquisition of two 2,000 MW generation stations. Goodwill and asset impairment charges of $414 million, net of tax, contributed to our 2002 losses. The oversupply conditions throughout 2002 worsened in the fourth quarter after the British government's decision to subsidize British Energy, a financially troubled, dominant generator of power in the U.K. This intervention in the competitive market kept inefficient generation in the marketplace. The write-down of our two U.K. power plants was the result of our analyses that indicated U.K. power prices would not recover to levels that would permit us to carry the plants at their original purchase prices. In addition to unfavorable U.K. power and coal markets, higher than anticipated operating costs contributed to the loss in 2002.

Investments – Other

2003 Compared to 2002

The loss from our Other investments decreased by $245 million to $277 million in 2003. The decrease was primarily due to asset impairment charges of $257 million, net of tax, compared to impairments of $392 million, net of tax, recorded in 2002. 2003 impairments included losses of $45 million, net of tax, for two of our independent generation facilities due to market conditions; $168 million, net of tax, for the Dow facility due to the current market conditions and litigation; and coal mining asset impairments of $44 million, net of tax, based on bids from unrelated parties. Additionally we incurred lower international development costs and reduced interest expenses during 2003.

2002 Compared to 2001

The loss from our Other investment operations of $522 million resulted from $392 million of asset impairment charges, net of tax. These write-downs in the fourth quarter of 2002 recognized the lower valuation in our investments in a utility in Brazil, AEP Communications and other under-performing assets. There were no such write-downs in 2001.

All Other

Our parent company's 2003 expenses increased $81 million over 2002 primarily from higher interest costs due to increased debt at the parent level and reduced reliance on short-term borrowings as well as the recognition of estimated losses from certain litigation contingencies. Expenses in 2002 declined $24 million from 2001 due to lower interest costs.

FINANCIAL CONDITION

We measure our financial condition by the strength of our balance sheet and the liquidity provided by our cash flows. During 2003 we improved our financial condition as a consequence of the following actions and events:

- We issued approximately $1.1 billion of new common equity
- We reduced our quarterly dividend in June 2003 to $.35 per share which reduced our annualized cash outflows by approximately $395 million
- We reduced short-term debt by $2.8 billion, restructured our lines of credit into two $750 million facilities, completed approximately $1.3 billion of optional long-term debt redemptions, paid-off $225 million of our Steelhead financing, and funded $1.4 billion of debt maturities
- We limited our energy trading activity to levels necessary to optimize earnings from sales of our owned-generation
- Despite downgrades of certain debt ratings during the first quarter and continued uncertainty in the industry, we have maintained stable credit ratings across the AEP System

Capitalization

	2003	2002	2001
Common Equity	35%	32 %	36%
Preferred Stock	1	1	1
Long-term Debt, including amounts due within one year	63	50	43
Short-term Debt	1	14	17
Minority Interest in Finance Subsidiary	-	3	3
Total Capitalization	100%	100%	100%

Our capital was affected by the following, during 2003:

- We recognized $960 million of impairment losses related to our unregulated investments while reducing our ratio of debt to total capital
- We substantially reduced our short-term debt commitments, thereby reducing refinancing and cash flow risks
- We improved our percentage of common equity outstanding to total capitalization, in part through the issuance of approximately $1.1 billion of new equity.

Liquidity

Liquidity, or access to cash, is an important factor in determining our financial stability due to volatility in wholesale power prices and the effects of credit rating downgrades. We are committed to preserving an adequate liquidity position.

Credit Facilities

We manage our liquidity by maintaining adequate external financing commitments. We had an available liquidity position of approximately $3.5 billion as illustrated in the table below:

	Amount (in millions)	Maturity
Commercial Paper Backup:		
Lines of Credit	$ 750	May 2004
Lines of Credit	1,000	May 2005
Lines of Credit	750	May 2006
Euro Revolving Credit Facility	189	October 2004
Letter of Credit Facility	200	September 2006
Total	2,889	
Available Cash and Temporary Investments	920*	
Total Liquidity Sources	3,809	
Less: AEP Commercial Paper Outstanding	282**	
Letters of Credit Outstanding	35	
Net Available Liquidity	$3,492	

* Available Cash and Temporary Investments of $920 million and $262 million in unavailable cash on hand make up the $1.2 billion Cash and Cash Equivalents balance on our Consolidated Balance Sheet at December 31, 2003.

** Amount does not include JMG Funding LP (JMG) commercial paper outstanding in the amount of $26 million. This commercial paper is specifically associated with the Gavin scrubber lease. This commercial paper does not reduce available liquidity to AEP.

Debt Covenants

Our revolving credit agreements require us to maintain our percentage of debt to total capitalization at a level that does not exceed 67.5%. The method for calculating our outstanding debt and other capital is contractually defined. At December 31, 2003, this percentage was 58.8%. Non-performance of these covenants may result in an event of default under these credit agreements. At December 31, 2003, we complied with the covenants contained in these credit agreements. In addition, the acceleration of the payment obligations of us, or certain of our subsidiaries, prior to maturity under any other agreement or instrument relating to debt outstanding in excess of $50 million would cause an event of default under these credit agreements and permit the lenders to declare the amounts outstanding thereunder payable.

Our commercial paper backup facilities generally prohibit new borrowings if we experience a material adverse change in our business or operations. We may, however, make new borrowings under these facilities if we experience a material adverse change so long as the proceeds of such borrowings are used to repay outstanding commercial paper.

Under an SEC order, AEP and its utility subsidiaries cannot incur additional indebtedness if the issuer's common equity would constitute less than 30% (25% for TCC due to its securitization bonds) of its capital. In addition, this order restricts AEP and the utility subsidiaries from issuing long-term debt unless that debt will be rated investment grade by at least one nationally recognized statistical rating organization.

Dividend Restrictions

Provisions within the Articles of Incorporation relating to the preferred stock of certain of our subsidiaries restrict the payment of cash dividends or other distributions on their common and preferred stock. PUHCA prohibits our subsidiaries from making loans or advances to the parent company, AEP. In addition, under PUHCA, AEP and its public utility subsidiaries can only pay dividends out of retained or current earnings.

Credit Ratings

We also manage our liquidity by continuing to maintain investment grade credit ratings and a stable credit outlook and are taking steps to improve our credit quality, including plans during 2004 to further reduce our outstanding debt through the use of proceeds from the planned dispositions. If we receive a downgrade in our credit ratings by these agencies, our borrowing costs could increase. The rating agencies currently have AEP and our rated subsidiaries on stable outlook. Current ratings for AEP are as follows:

	Moody's	S&P	Fitch
AEP Short-Term Debt	P-3	A-2	F-2
AEP Senior Unsecured Debt	Baa3	BBB	BBB

Cash Flow

Our cash flows are a major factor in managing and maintaining our liquidity strength.

	2003	2002 (in millions)	2001
Cash and Cash Equivalents at Beginning of Period	$1,199	$194	$232
Net Cash Flows From Operating Activities	2,308	2,067	2,818
Net Cash Flows Used For Investing Activities	(1,888)	(378)	(3,292)
Net Cash Flows (Used For) From Financing Activities	(437)	(681)	437
Effect of Exchange Rate Changes on Cash	-	(3)	(1)
Net Increase (Decrease) in Cash and Cash Equivalents	(17)	1,005	(38)
Cash and Cash Equivalents at End of Period	$1,182	$1,199	$194

Cash from operations, combined with a bank-sponsored receivables purchase agreement and short-term borrowings provide working capital and meet other short-term cash needs. We use our corporate borrowing program to meet the short-term borrowing needs of our subsidiaries. The corporate borrowing program includes a utility money pool which funds the utility subsidiaries and a non-utility money pool which funds the majority of the non-utility subsidiaries. In addition, we also fund, as direct borrowers, the short-term debt requirements of other subsidiaries that are not participants in the non-utility money pool for regulatory or operational reasons. As of December 31, 2003, we had credit facilities totaling $2.9 billion to support our commercial paper program. We generally use short-term borrowings to fund working capital needs, property acquisitions and construction until long-term funding mechanisms are arranged. Sources of long-term funding include issuance of common stock, preferred stock or long-term debt and sale-leaseback or leasing agreements. Money pool and external borrowings may not exceed SEC authorized limits.

Operating Activities

	2003	2002	2001
		(in millions)	
Net Income (Loss)	$110	$(519)	$971
Plus: Discontinued Operations	605	654	(41)
Income from Continuing Operations	715	135	930
Noncash Items Included in Earnings	1,798	2,734	976
Changes in Assets and Liabilities	(205)	(802)	912
Net Cash Flows From Operating Activities	$2,308	$2,067	$2,818

2003 Operating Cash Flow

Our cash flows from operating activities were $2.3 billion for 2003. We produced income from continuing operations of $715 million during the period. Income from continuing operations for 2003 included noncash items of $1.5 billion for depreciation, amortization, and deferred taxes, $193 million for the cumulative effects of accounting changes, and $720 million for impairment losses and other related charges. In addition, there is a current period impact for a net $122 million balance sheet change for risk management contracts that are marked-to-market. These contracts have an unrealized earnings impact as market prices move, and a cash impact upon settlement or upon disbursement or receipt of premiums. Changes in Assets and Liabilities represent those items that had a current period cash flow impact, such as changes in working capital, as well as items that represent future rights or obligations to receive or pay cash, such as regulatory assets and liabilities. The current period activity in these asset and liability accounts relates to a number of items; the most significant are presented below:

- The wholesale capacity auction true-up (ECOM) resulted in stranded cost deferrals of $218 million, which are not recoverable in cash until the conclusion of our Texas true-up proceeding. These proceedings are not expected to be finalized earlier than April 2005.
- Net changes in accounts receivable and accounts payable of $269 million related, in large part, to the settlement of risk management positions during 2002 and payments related to those settlements during 2003. These payments include $90 million in settlement of power and gas transactions to the Williams Companies. The earnings effects of substantially all payments were reflected in earlier periods.
- Increases in inventory levels of $71 million resulting primarily from higher procurement prices.
- Reserves for disallowed fuel costs, principally related to Texas, which will be a component of our 2004 final Texas true-up order of the PUCT.

2002 Operating Cash Flow

During 2002, our cash flows from operating activities were $2.1 billion. Income from continuing operations was $135 million during the period. Income from continuing operations for 2002 included noncash items of $1.4 billion for depreciation, amortization, and deferred taxes, $350 million related to the cumulative effect of an accounting change, and $639 million for impairment losses. There was a current period impact for a net $275 million balance sheet change for risk management contracts that were marked-to-market. These contracts have an unrealized earnings impact as market prices move, and a cash impact upon settlement or upon disbursement or receipt of premiums. The activity in the asset and liability accounts related to the wholesale capacity auction true-up asset (ECOM) of $262 million, deposits associated with risk management activities of $136 million, and seasonal increases in our fuel inventories.

2001 Operating Cash Flow

Our cash flows from operating activities were $2.8 billion for 2001. Income from continuing operations was $930 million during the period. Income from continuing operations for 2001 included noncash items of $1.5 billion for depreciation, amortization, and deferred taxes, and $18 million related to the cumulative effect of an accounting change. There was a current period impact for a net $294 million balance sheet change for risk management contracts that were marked-to-market. These contracts have an unrealized earnings impact as market prices move, and a cash impact upon settlement or upon disbursement or receipt of premiums. The activity in the asset and liability accounts was primarily attributable to increased levels of trading activities as compared to 2002 and 2003. During the fourth quarter of 2002 we exited trading that was not related to the sale of power from our owned-generation.

Investing Activities

	2003	2002 (in millions)	2001
Construction Expenditures	$(1,358)	$(1,685)	$(1,646)
Business Acquisitions/Sales Proceeds, net	82	1,263	(621)
Other	(612)	44	(1,025)
Net Cash Flows Used for Investing Activities	$(1,888)	$(378)	$(3,292)

Our cash flows used for investing activities increased $1.5 billion in 2003 from $378 million during the prior year. This increase was due to additional sales proceeds in 2002 related to SEEBOARD, CitiPower, and the Texas REPs as well as increased investments in our U.K. operations during 2003. These increases were partially offset by a reduction of our capital expenditures in 2003 as compared to 2002.

In 2002, our cash flows used for investing activities decreased $2.9 billion from 2001. This decrease resulted from the HPL and UK acquisitions during 2001 as well as the net increase in proceeds received from asset sales during 2002.

We forecast $5.8 billion of construction expenditures for 2004-2006.

Financing Activities

	2003	2002 (in millions)	2001
Issuances of Equity Securities (common stock/equity units)	$1,142	$990	$11
Issuances/Retirements of Debt, net	(727)	(868)	460
Retirement of Preferred Stock	(9)	(10)	(5)
Issuance/Retirement of Minority Interest	(225)	-	744
Dividends	(618)	(793)	(773)
Net Cash Flows (Used for) From Financing Activities	$(437)	$(681)	$437

Our cash flows used for financing activities decreased $244 million in 2003 from $681 million during the prior year. This decrease was due to additional proceeds from the issuance of common stock and the reduction of our common stock dividend in 2003.

In 2002 we used $681 million for financing activities compared to $437 million provided by the same activities in 2001. The increase in cash used pertained primarily to the debt retirements that occurred in 2002.

The following financing activities occurred during 2003 and 2002:

Common Stock and Equity Units:

- In March 2003, we issued 56 million shares of common stock at $20.95 per share through an equity offering and received net proceeds of $1.1 billion (net of issuance costs of $36 million). We used the proceeds to pay down both short-term and long-term debt with the balance being held in cash.

- In June 2002, we issued 16 million shares of common stock at $40.90 per share and 6.9 million equity units at $50 per unit and received combined net proceeds of $979 million. We used the proceeds to pay down short-term debt and establish a cash liquidity reserve fund.

Debt:

- We use our corporate borrowing program to meet the short-term borrowing needs of our subsidiaries. The corporate borrowing program includes a utility money pool which funds the utility subsidiaries and a non-utility money pool which funds the majority of the non-utility subsidiaries. In addition, we also fund, as direct borrowers, the short-term debt requirements of other subsidiaries that are not participants in the non-utility money pool for regulatory or operational reasons. As of December 31, 2003, we had credit facilities totaling $2.9 billion to support our commercial paper program. At December 31, 2003, we had $282 million outstanding in short-term borrowings supported by these credit facilities. In addition, JMG has commercial paper outstanding in the amount of $26 million. This commercial paper is specifically associated with the Gavin scrubber lease. This commercial paper does not reduce available liquidity.

- In February 2003, we issued over $2 billion of senior notes through our Ohio and Texas subsidiaries. The proceeds were used to repay the bank facility that was due to mature in April 2003, retire short-term debt and for other general corporate purposes. During the remainder of the year, our subsidiaries issued an additional $2.3 billion in senior notes and refinanced approximately $465 million in pollution control revenue bonds. The proceeds of these issuances were used to term-out short-term debt, fund long-term debt maturities and fund optional redemptions.

- In March 2003, AEP issued a $500 million senior unsecured note. The proceeds of this issuance were used to pay-down $225 million of the Steelhead financing and to prefund a portion of the AEP Resources bond that matured in December 2003.

- In May 2003, a third party exercised its option to call our $250 million of 5.50% putable callable notes, issued in May 2001, for purchase and remarketing. On May 15, 2003, AEP issued $300 million of 5.25% senior notes due 2015, a portion of which was an exchange for the $250 million putable callable notes due in 2003 that were outstanding at that time.

- AEP Credit extended its sale of receivables agreement from its May 28, 2003 expiration to July 25, 2003, when the agreement was renewed for an additional 364 days. The sale of receivables agreement, which expires on July 23, 2004, provides commitments of $600 million to purchase receivables from AEP Credit. At December 31, 2003, $385 million of commitments to purchase accounts receivable were outstanding under the receivables agreement. All receivables sold represent affiliate receivables. AEP Credit maintains a retained interest in the receivables sold and this interest is pledged as collateral for the collection of receivables sold. The fair value of the retained interest is based on book value due to the short-term nature of the accounts receivable less an allowance for anticipated uncollectible accounts.

- In September 2003, we closed on a $200 million revolving loan and letter of credit facility. The facility is available for the issuance of letters of credit and for general corporate purposes. The facility will expire in September 2006.

Minority Interest and Off-balance Sheet Arrangements

We enter into minority interest and off-balance sheet arrangements for various reasons including accelerating cash collections, reducing operational expenses and spreading risk of loss to third parties. The following identifies significant minority interest and off-balance sheet arrangements:

Minority Interest in Finance Subsidiary

We formed AEP Energy Services Gas Holding Co. II, LLC (SubOne) and Caddis Partners, LLC (Caddis) in August 2001. SubOne is a wholly-owned consolidated subsidiary that was capitalized with the assets of Houston Pipe Line Company and Louisiana Intrastate Gas Company and $321.4 million of AEP Energy Services Gas Holding Company

(AEP Gas Holding is a subsidiary of AEP and the parent of SubOne) preferred stock, that was convertible into our common stock at market price on a dollar-for-dollar basis. Caddis was capitalized with $2 million cash and a subscription agreement that represents an unconditional obligation to fund $83 million from SubOne for a managing member interest and $750 million from Steelhead Investors LLC (Steelhead) for a non-controlling preferred member interest. SubOne is the managing member of Caddis. As a result SubOne and all of its subsidiaries, including Caddis, HPL and LIG, are included in our Consolidated financial statements.

Steelhead is an unconsolidated special purpose entity and had an original capital structure of $750 million (currently approximately $525 million) of which 3% is equity from investors with no relationship to us or any of our subsidiaries and 97% is debt from a syndicate of banks. The $525 million invested in Caddis by Steelhead was loaned to SubOne. The loan to SubOne is due August 2006. Net proceeds from the planned sale of LIG will be used to reduce the outstanding balance of the loan from Caddis.

On July 1, 2003, due to the application of FIN 46, we deconsolidated Caddis, which included amounts previously reported as Minority Interest in Finance Subsidiary ($759 million at December 31, 2002 and $533 million at June 30, 2003). As a result, a $527 million note payable to Caddis is part of our Long-Term Debt at December 31, 2003. Application of FIN 46 is prospective and we, therefore, did not change the presentation of Minority Interest in Finance Subsidiary in periods prior to July 1, 2003.

On May 9, 2003, we reduced the outstanding balance of our note payable to Caddis by $225 million. Caddis used these proceeds to reduce the preferred interest in Caddis that was held by Steelhead. This payment eliminated the convertible preferred stock of AEP Gas Holding which under certain conditions had been convertible to AEP stock.

The credit agreement between Caddis and SubOne contains covenants that restrict certain incremental liens and indebtedness, asset sales, investments, acquisitions, and distributions. The credit agreement also contains covenants that impose minimum financial ratios. Non-performance of these covenants may result in an event of default under the credit agreement. Through December 31, 2003, SubOne has complied with the covenants contained in the credit agreement. In addition, the acceleration of our outstanding debt in excess of $50 million would be an event of default under the credit agreement.

SubOne has deposited $422 million in a cash reserve fund in order to comply with certain covenants in the credit agreement. Pursuant to the terms of the credit agreement, SubOne subsequently loaned these funds to affiliates, and we guaranteed the repayment obligations of these affiliates. These loans must be repaid in the event our credit ratings fall below investment grade.

Steelhead has certain rights as a preferred member in Caddis. Upon the occurrence of certain events, including a default in the payment of the preferred return, Steelhead's rights include forcing a liquidation of Caddis and acting as the liquidator. Liquidation of Caddis could negatively impact our liquidity.

AEP Credit

AEP Credit has a sale of receivables agreement with banks and commercial paper conduits. Under the sale of receivables agreement, AEP Credit sells an interest in the receivables it acquires to the commercial paper conduits and banks and receives cash. This transaction constitutes a sale of receivables in accordance with SFAS 140, allowing the receivables to be taken off of AEP Credit's balance sheet and allowing AEP Credit to repay any debt obligations. AEP has no ownership interest in the commercial paper conduits and does not consolidate these entities in accordance with GAAP. We continue to service the receivables. This off-balance sheet transaction was entered into to allow AEP Credit to repay its outstanding debt obligations, continue to purchase the AEP operating companies' receivables, and accelerate its cash collections.

AEP Credit extended its sale of receivables agreement to July 25, 2003 from its May 28, 2003 expiration date. The agreement was then renewed for an additional 364 days and now expires on July 23, 2004. This new agreement provides commitments of $600 million to purchase receivables from AEP Credit. At December 31, 2003, $385 million was outstanding. As collections from receivables sold occur and are remitted, the outstanding balance for sold receivables is reduced and as new receivables are sold, the outstanding balance of sold receivables increases. All of the receivables sold represented affiliate receivables. AEP Credit maintains a retained interest in the receivables sold and this interest is pledged as collateral for the collection of the receivables sold. The fair value of the retained interest is based on book value due to the short-term nature of the accounts receivables less an allowance for anticipated uncollectible accounts.

Rockport Plant Unit 2

AEGCo and I&M entered into a sale and leaseback transaction in 1989 with Wilmington Trust Company (Owner Trustee), an unrelated unconsolidated trustee for Rockport Plant Unit 2 (the plant). The Owner Trustee was capitalized with equity from six owner participants with no relationship to AEP or any of its subsidiaries and debt from a syndicate of banks and certain institutional investors. The future minimum lease payments for each respective company are $1.4 billion.

The FASB and other accounting constituencies continue to interpret the application of FIN 46 (revised December 2003) (FIN 46R). As a result, we are continuing to review the application of this new interpretation as it relates to the Rockport Plant Unit 2 transaction.

The gain from the sale was deferred and is being amortized over the term of the lease, which expires in 2022. The Owner Trustee owns the plant and leases it to AEGCo and I&M. The lease is accounted for as an operating lease with the payment obligations included in the lease footnote. The lease term is for 33 years with potential renewal options. At the end of the lease term, AEGCo and I&M have the option to renew the lease or the Owner Trustee can sell the plant. Neither AEGCo, I&M nor AEP has an ownership interest in the Owner Trustee and none of these entities guarantee its debt.

Railcars

In June 2003, we entered into an agreement with an unrelated, unconsolidated leasing company to lease 875 coal-transporting aluminum railcars. The lease has an initial term of five years and may be renewed for up to three additional five-year terms, for a maximum of twenty years. We intend to renew the lease for the full twenty years.

At the end of each lease term, we may (a) renew for another five-year term, not to exceed a total of twenty years, (b) purchase the railcars for the purchase price amount specified in the lease, projected at the lease inception to be the then fair market value, or (c) return the railcars and arrange a third party sale (return-and-sale option). The lease is accounted for as an operating lease with the future payment obligations included in the annual lease footnote. This operating lease agreement allows us to avoid a large initial capital expenditure, and to spread our railcar costs evenly over the expected twenty-year usage.

Under the lease agreement, the lessor is guaranteed that the sale proceeds under the return-and-sale option discussed above will equal at least a lessee obligation amount specified in the lease, which declines over time from approximately 86% to 77% of the projected fair market value of the equipment. At December 31, 2003, the maximum potential loss was approximately $31.5 million ($20.5 million net of tax) assuming the fair market value of the equipment is zero at the end of the current lease term. The railcars are subleased for one year to an unaffiliated company under an operating lease. The sublessee may renew the lease for up to four additional one-year terms. AEP has other railcar lease arrangements that do not utilize this type of financing structure.

Summary Obligation Information

Our contractual obligations include amounts reported on the Consolidated Balance Sheets and other obligations disclosed in the footnotes. The following table summarizes our contractual cash obligations at December 31, 2003:

	Payments Due by Period (in millions)				
Contractual Cash Obligations	**Less Than 1 year**	**2-3 years**	**4–5 years**	**After 5 years**	**Total**
Long-term Debt	$1,779	$3,460	$1,711	$7,151	$14,101
Short-term Debt	326	-	-	-	326
Preferred Stock Subject to Mandatory Redemption	-	-	21	55	76
Capital Lease Obligations	63	77	49	31	220
Unconditional Purchase Obligations (a)	1,720	2,132	1,101	1,785	6,738
Noncancellable Operating Leases	291	492	441	2,331	3,555
Total	$4,179	$6,161	$3,323	$11,353	$25,016

(a) Represents contractual obligations to purchase coal and natural gas as fuel for electric generation along with related transportation of the fuel.

Some of the transactions, described under "Minority Interest and Off-Balance Sheet Arrangements" above, include contractual cash obligations reported in the above table. The lease of Rockport Unit 2 and Railcars are reported in Noncancellable Operating Leases. The Minority Interest in Finance Subsidiary is reported in Long-term Debt.

In addition to the amounts disclosed in the contractual cash obligations table above, we make additional commitments in the normal course of business. These commitments include standby letters of credit, guarantees for the payment of obligation performance bonds, and other commitments. Our commitments outstanding at December 31, 2003 under these agreements are summarized in the table below:

	Amount of Commitment Expiration Per Period (in millions)				
Other Commercial Commitments	**Less Than 1 year**	**2-3 years**	**4–5 years**	**After 5 years**	**Total**
Standby Letters of Credit (a)	$175	$43	$-	$9	$227
Guarantees of the Performance of Outside Parties (b)	-	18	1	134	153
Guarantees of our Performance	1,083	107	-	8	1,198
Transmission Facilities for Third Parties (c)	99	110	54	-	263
Other Commercial Commitments (d)	14	14	-	-	28
Total Commercial Commitments	$1,371	$292	$55	$151	$1,869

(a) We have issued standby letters of credit to third parties. These letters of credit cover gas and electricity risk management contracts, construction contracts, insurance programs, security deposits, debt service reserves and credit enhancements for issued bonds. All of these letters of credit were issued in the ordinary course of business. The maximum future payments of these letters of credit are $227 million with maturities ranging from January 2004 to January 2011. As the parent of all of these subsidiaries, we hold all assets of the subsidiaries as collateral. There is no recourse to third parties in the event these letters of credit are drawn.

(b) These amounts are the balances drawn, not the maximum guarantee disclosed in Note 8.

(c) As construction agent for third party owners of transmission facilities, we have committed by contract terms to complete construction by dates specified in the contracts. Should we default on these obligations, financial payments could be required including liquidating damages of up to $8 million and other remedies required by contract terms.
(d) OPCo has entered into a 30-year power purchase agreement for electricity produced by an unaffiliated entity's three-unit natural gas fired plant. The plant was completed in 2002 and the agreement will terminate in 2032. Under the terms of the agreement, OPCo has the option to run the plant until December 31, 2005, taking 100% of the power generated and making monthly capacity payments. The capacity payments are fixed through December 2005 at $1.2 million per month. For the remainder of the 30-year contract term, OPCo will pay the variable costs to generate the electricity it purchases which could be up to 20% of the plant's capacity.

Expenditures for domestic electric utility construction are estimated to be $5.8 billion for the next three years. Approximately 80% of those construction expenditures is expected to be financed by internally generated funds.

Other

Power Generation Facility

We have agreements with Juniper Capital L.P. (Juniper) for Juniper to develop, construct, and finance a non-regulated merchant power generation facility (Facility) near Plaquemine, Louisiana and for Juniper to lease the Facility to us. The Facility is a "qualifying cogeneration facility" for purposes of PURPA. Construction of the Facility was begun by Katco Funding, Limited Partnership (Katco), an unrelated unconsolidated special purpose entity. Katco assigned its interest in the Facility to Juniper in June 2003.

Juniper is an unaffiliated limited partnership, formed to construct or otherwise acquire real and personal property for lease to third parties, to manage financial assets and to undertake other activities related to asset financing. Juniper arranged to finance the Facility with debt financing up to $494 million and equity up to $31 million from investors with no relationship to AEP or any of AEP's subsidiaries. Juniper will own the Facility and lease it to AEP after construction is completed.

At December 31, 2002, we would have reported the Facility and related obligations as an operating lease upon achieving commercial operation (COD). In the fourth quarter of 2003, we chose to not seek funding from Juniper for budgeted and approved pipeline construction costs related to the Facility. In order to continue reporting the Facility as an off-balance sheet financing, we were required to seek funding of our construction costs from Juniper. As a result, we recorded $496 million of construction work in progress (CWIP) and the related financing liability for the debt and equity as of December 31, 2003. At December 31, 2003, the lease of the Facility is reported as an owned asset under a lease financing transaction. Since the debt obligations of the Facility are recorded on our financial statements, the obligations under the lease agreement are excluded from the above table of future minimum lease payments.

We are the construction agent for Juniper. We expect to achieve COD in the spring of 2004, at which time the obligation to make payments under the lease agreement will begin to accrue and we will sublease the Facility to The Dow Chemical Company (Dow). If COD does not occur on or before March 14, 2004, Juniper has the right to terminate the project. In the event the project is terminated before COD, we have the option to either purchase the Facility for 100% of Juniper's acquisition cost (in general, the outstanding debt and equity associated with the Facility) or terminate the project and make a payment to Juniper for 89.9% of project costs (in general, the acquisition cost less certain financing costs).

The initial term of the lease agreement between Juniper and AEP commences on COD and continues for five years. The lease contains extension options, and if all extension options are exercised, the total term of the lease will be 30 years. AEP's lease payments to Juniper during the initial term and each extended term are sufficient for Juniper to make required debt payments under Juniper's debt financing associated with the Facility and provide a return on equity to the investors in Juniper. We have the right to purchase the Facility for the acquisition cost during the last month of the initial term or on any monthly rent payment date during any extended term. In addition, we may purchase the Facility from Juniper for the acquisition cost at any time during the initial term if we have arranged a sale of the Facility to an unaffiliated third party. A purchase of the Facility from Juniper by AEP should not alter Dow's rights to lease the Facility or our contract to purchase energy from Dow. If the lease were renewed for up to a 30-year lease term, we may further renew the lease at fair market value subject to Juniper's approval, purchase the Facility at its acquisition cost, or sell the Facility, on behalf of Juniper, to an independent third party. If the Facility is sold and the proceeds from the sale are insufficient to pay all of Juniper's acquisition costs, we may be required to make a payment (not to exceed $396 million) to Juniper of the excess of Juniper's acquisition costs over the proceeds from the sale, provided that we would not be required to make any payment if we have made the additional rental prepayment described below. We have guaranteed the performance of our subsidiaries to Juniper during the lease term. Because we now report the debt related to the Facility on our balance sheet, the fair value of the liability for our guarantee (the $396 million payment discussed above) is not separately reported.

At December 31, 2003, Juniper's acquisition costs for the Facility totaled $496 million, and total costs for the completed Facility are currently expected to be approximately $525 million. For the 30-year extended lease term, the base lease rental is a variable rate obligation indexed to three-month LIBOR. Consequently, as market interest rates increase, the base rental payments under the lease will also increase. Annual payments of approximately $18 million represent future minimum payments for interest on Juniper's financing structure during the initial term calculated using the indexed LIBOR rate (1.15% at December 31, 2003). An additional rental prepayment (up to $396 million) may be due on June 30, 2004 unless Juniper has refinanced its present debt financing on a long-term basis. Juniper is currently planning to refinance by June 30, 2004. The Facility is collateral for the debt obligation of Juniper. At December 31, 2003, we reflected $396 million of the $496 million recorded obligation as long-term debt due within one year. Our maximum required cash payment as a result of our financing transaction with Juniper is $396 million as well as interest payments during the lease term. Due to the treatment of the Facility as a financing of an owned asset, the recorded liability of $496 million is greater than our maximum possible cash payment obligation to Juniper.

Dow will use a portion of the energy produced by the Facility and sell the excess energy. OPCo has agreed to purchase up to approximately 800 MW of such excess energy from Dow. OPCo has also agreed to sell up to approximately 800 MW of energy to Tractebel Energy Marketing, Inc. (TEM) for a period of 20 years under a Power Purchase and Sale Agreement dated November 15, 2000 (PPA) at a price that is currently in excess of market. Beginning May 1, 2003, OPCo tendered replacement capacity, energy and ancillary services to TEM pursuant to the PPA that TEM rejected as non-conforming.

On September 5, 2003, TEM and AEP separately filed declaratory judgment actions in the United States District Court for the Southern District of New York. We allege that TEM has breached the PPA, and we are seeking a determination of our rights under the PPA. TEM alleges that the PPA never became enforceable, or alternatively, that the PPA has already been terminated as the result of AEP breaches. If the PPA is deemed terminated or found to be unenforceable by the court, we could be adversely affected to the extent we are unable to find other purchasers of the power with similar contractual terms to the extent we do not fully recover claimed termination value damages from TEM. The corporate parent of TEM has provided a limited guaranty.

On November 18, 2003, the above litigation was suspended pending final resolution in arbitration of all issues pertaining to the protocols relating to the dispatching, operation, and maintenance of the Facility and the sale and delivery of electric power products. In the arbitration proceedings, TEM basically argued that in the absence of mutually agreed upon protocols there was no commercially reasonable means to obtain or deliver the electric power products and therefore the PPA is not enforceable. TEM further argued that the creation of the protocols is not subject to arbitration. The arbitrator ruled in favor of TEM on February 11, 2004 and concluded that the "creation of protocols" was not subject to arbitration, but did not rule upon the merits of TEM's claim that the PPA is not enforceable.

If commercial operation is not achieved for purposes of the PPA by April 30, 2004, TEM may claim that it can terminate the PPA and is owed liquidating damages of approximately $17.5 million. TEM may also claim that we are not entitled to receive any termination value for the PPA.

The current litigation between TEM and ourselves, combined with a substantial oversupply of generation capacity in the markets where we would otherwise sell the power freed up by the TEM contract termination, triggered us to review the project for possible impairment of its reported values. We determined that the value of the Facility was impaired and recorded a $258 million pre-tax impairment in December 2003 on the CWIP.

SIGNIFICANT FACTORS

Possible Divestitures

We are firmly committed to continually evaluating the need to reallocate resources to areas that effectively match our investments with our business strategy, providing the greatest potential for financial returns. We are committed to disposing of investments that no longer meet these goals.

We are seeking to divest significant components of our non-regulated assets, including certain domestic and international unregulated generation, part of our gas pipeline and storage business, a coal business, independent power producers (IPPs) and a communications business. In June 2003, we began actively seeking buyers for 4,497 megawatts of unregulated generating capacity in Texas. The value received from this disposition will also be used to calculate our stranded costs in Texas (see Note 6). We are currently evaluating bids received during the fourth quarter of 2003 and are in negotiations to sell these assets.

During the second quarter of 2003, we also hired an advisor to evaluate our coal business, which has resulted in the receipt of non-binding bids. We are currently negotiating the anticipated sale of certain assets from this business. In the fourth quarter of 2003, in connection with the evaluation of this business, we recorded a $66.6 million pre-tax charge related to asset impairments, remediation accruals and other exit costs (see Note 10).

During the third quarter of 2003, management hired advisors to review business options regarding various investment components of our Gas Operations. We distributed an initial offering memorandum and request for proposal on the sale of our Louisiana Intrastate Gas and Jefferson Island Storage Facility operations during the fourth quarter of 2003. We are currently evaluating the proposals that we received. We are evaluating the merits of retaining our interest in Houston Pipe Line, which is part of Gas Operations. In connection with our review of the Gas Operations, we recorded $133.9 million in pre-tax charges related to LIG and $315 million in pre-tax charges related to HPL (see Note 10). We signed a sale agreement for the pipeline portion of LIG in the first quarter of 2004 and we expect the sale to close shortly with an immaterial impact on 2004 results of operations.

During the third quarter of 2003, we initiated an effort to sell four domestic IPP investments. Based on studies using current market assumptions, we believe that two of the facilities had declines in fair value that are other than temporary in nature. As a consequence, we recorded an impairment of $70 million pre-tax ($45.5 million net of tax) in the third quarter of 2003 (see Note 10). During the fourth quarter of 2003, we distributed an information memorandum related to the possible sale of our interest in these IPPs. We have received and are reviewing final bids and anticipate a sale of the four domestic IPP investments in 2004.

During the fourth quarter of 2003, we engaged an advisor for the disposition of our U.K. business and are planning to dispose of these assets in 2004. In connection with the evaluation of this business, we recorded a pre-tax charge of $577.4 million during the fourth quarter of 2003 based on indications of value received from potential buyers (see Note 10).

Management continues to have periodic discussions with various parties on business alternatives for certain of our other non-core investments.

The ultimate timing for a disposition of one or more of these assets will depend upon market conditions and the value of any buyer's proposal. We may realize losses from operations or upon disposition of these assets that, in the aggregate, could have a material impact on our results of operations, cash flows and financial condition.

Corporate Separation

In Texas, we are in the process of divesting our TCC generating assets in accordance with provisions of the Texas Legislation concerning stranded cost recovery (see Note 6). In order to sell these assets, we anticipate retiring TCC's first mortgage bonds by making open market purchases or defeasing the bonds. Once such generating assets are sold, which we expect to be finalized in 2004, we will effectively accomplish the structural separation requirements of the Texas Legislation for those assets.

In Ohio, the PUCO has encouraged utilities to file rate stabilization plans to provide rate certainty and stability for customers who do not choose alternative suppliers, for the period of January 1, 2006 through December 31, 2008, which is after the expiration of the current market development period. On February 9, 2004, CSPCo and OPCo filed such a rate stabilization plan with the PUCO. The plan, in part, provides that both CSPCo and OPCo will remain functionally separated. Approval of the rate stabilization plan is currently pending before the PUCO.

Unless otherwise directed by the PUCO in an order on the rate stabilization plan, CSPCo and OPCo will remain functionally separated through at least the end of the rate stabilization plan period, December 31, 2008, and therefore, are not planning to legally separate, or to change the affiliate pooling agreement for the AEP East companies, in the foreseeable future.

Management continues to evaluate the most appropriate approach for complying with the Texas Legislation's structural separation requirements for TNC, including appropriate regulatory approvals to implement its structural separation.

RTO Formation

The FERC's AEP-CSW merger approval and many of the settlement agreements with the state regulatory commissions to approve the AEP-CSW merger required the transfer of functional control of our subsidiaries' transmission systems to RTOs. Further, legislation in some of our states requires RTO participation.

In May 2002, we announced an agreement with PJM to pursue terms for participation in its RTO for AEP East companies with final agreements to be negotiated. In July 2002, FERC issued an order accepting our decision to participate in PJM, subject to specified conditions. AEP and other parties continue to work on the resolution of those conditions.

In December 2002, our subsidiaries that operate in the states of Indiana, Kentucky, Ohio and Virginia filed for state regulatory commission approval of their plans to transfer functional control of their transmission assets to PJM. Proceedings in Ohio remain pending.

In February 2003, the state of Virginia enacted legislation preventing APCo from joining an RTO prior to July 1, 2004 and thereafter only with the approval of the Virginia SCC, but required such transfers by January 1, 2005. In January 2004, APCo filed a cost/benefit study with the Virginia SCC covering the time period through 2014 as required by the Virginia SCC. The study results show a net benefit of approximately $98 million for APCo over the 11-year study period from AEP's participation in PJM.

In July 2003, the KPSC denied KPCo's request to join PJM based in part on a lack of evidence that it would benefit Kentucky retail customers. In December 2003, AEP filed with the KPSC a cost/benefit study showing a net benefit of approximately $13 million for KPCo over the five-year study period from AEP's participation in PJM. A hearing has been scheduled in April 2004.

In September 2003, the IURC issued an order approving I&M's transfer of functional control over its transmission facilities to PJM, subject to certain conditions included in the order. The IURC's order stated that AEP shall request and the IURC shall complete a review of Alliance formation costs before any deferral of the costs for future recovery.

In April 2003, FERC approved our transfer of functional control of the AEP East companies' transmission system to PJM. FERC also accepted our proposed rates for joining PJM, but set a number of rate issues for resolution through settlement proceedings or FERC hearings. Settlement discussions continue on certain rate matters.

On September 29 and 30, 2003, the FERC held a public inquiry regarding RTO formation, including delays in AEP's participation in PJM. In November 2003, the FERC issued an order preliminarily finding that AEP must fulfill its CSW merger commitment to join an RTO by fully integrating into PJM (transmission and markets) by October 1, 2004. The FERC set several issues for public hearing before an ALJ. Those issues include whether the laws, rules, or regulations of Virginia and Kentucky are preventing AEP from joining an RTO and whether the states' provisions meet either of the two exceptions under PURPA. The FERC directed the ALJ to issue his initial decision by March 15, 2004.

If AEP East companies do not obtain regulatory approval to join PJM, we are committed to reimburse PJM for certain project implementation costs (presently estimated at $24 million for AEP's share of the entire PJM integration project). AEP also has $28 million, at December 31, 2003, of deferred RTO formation/integration costs for which we plan to seek recovery in the future. See Note 4 for further discussion.

AEP West companies are members of ERCOT or SPP. In 2002, FERC conditionally accepted filings related to a proposed consolidation of MISO and SPP. State public utility commissions also regulate our SPP companies. The Louisiana and Arkansas commissions filed responses to the FERC's RTO order indicating that additional analysis was required. Subsequently, the proposed SPP/MISO combination was terminated. On October 15, 2003, SPP filed a proposal at FERC for recognition as an RTO. In February 2004, FERC granted RTO status to the SPP, subject to fulfilling specified requirements. Regulatory activities concerning various RTO issues are ongoing in Arkansas and Louisiana.

Management is unable to predict the outcome of these regulatory actions and proceedings or their impact on our transmission operations, results of operations and cash flows or the timing and operation of RTOs.

Pension Plans

We maintain qualified, defined benefit pension plans (Qualified Plans), which cover a substantial majority of non-union and certain union associates, and unfunded excess plans to provide benefits in excess of amounts permitted to be paid under the provisions of the tax law to participants in the Qualified Plans. Additionally, we have entered into individual retirement agreements with certain current and retired executives that provide additional retirement benefits.

Our net periodic pension expense was an income item for all pension plans approximating $3 million and $44 million for the years ended December 31, 2003 and 2002, respectively, and is calculated based upon a number of actuarial assumptions, including an expected long-term rate of return on the Qualified Plans' assets. In 2002 and 2003, the long-term return was assumed to be 9.00%, and for 2004, the long-term rate of return was lowered to 8.75%. In developing the expected long-term rate of return assumption, we evaluated input from actuaries and investment consultants, including their reviews of asset class return expectations as well as long-term inflation assumptions. Projected returns by such actuaries and consultants are based on broad equity and bond indices. We also considered historical returns of the investment markets as well as our 10-year average return, for the period ended December 2003, of approximately 10.0%. We anticipate that the investment managers we employ for the pension fund will continue to generate long-term returns of at least 8.75%.

The expected long-term rate of return on the Qualified Plan's assets is based on our targeted asset allocation and our expected investment returns for each investment category. Our assumptions are summarized in the following table:

	2003 Actual Asset Allocation	2004 Target Asset Allocation	Assumed/Expected Long-term Rate of Return
		(in percentage)	
Equity	71	70	10.5
Fixed Income	27	28	5
Cash and Cash Equivalents	2	2	2
Total	100	100	
Overall Expected Return (weighted average)			8.75

We regularly review the actual asset allocation and periodically rebalance the investments to our targeted allocation when considered appropriate. We believe that 8.75% is a reasonable long-term rate of return on the Qualified Plans' assets despite the recent market volatility in which the Qualified Plans' assets had a loss of 11.2% for the twelve months ended December 31, 2002, and a gain of 23.8% for the twelve months ended December 31, 2003. We will continue to evaluate the actuarial assumptions, including the expected rate of return, at least annually, and will adjust them as necessary.

We base our determination of pension expense or income on a market-related valuation of assets which reduces year-to-year volatility. This market-related valuation recognizes investment gains or losses over a five-year period from the year in which they occur. Investment gains or losses for this purpose are the difference between the expected return calculated using the market-related value of assets and the actual return based on the market-related value of assets. Since the market-related value of assets recognizes gains or losses over a five-year period, the future value of assets will be impacted as previously deferred gains or losses are recorded. As of December 31, 2003, we had cumulative losses of approximately $325 million which remain to be recognized in the calculation of the market-related value of assets. These unrecognized net actuarial losses result in increases in the future pension costs depending on several factors, including whether such losses at each measurement date exceed the corridor in accordance with SFAS No. 87, "Employers' Accounting for Pensions."

The discount rate that we utilize for determining future pension obligations is based on a review of long-term bonds that receive one of the two highest ratings given by a recognized rating agency. The discount rate determined on this basis has decreased from 6.75% at December 31, 2002, to 6.25% at December 31, 2003. Due to the effect of the unrecognized actuarial losses and based on an expected rate of return on the Qualified Plans' assets of 8.75%, a discount rate of 6.25% and various other assumptions, we estimate that the pension expense for all pension plans will approximate $41 million, $78 million and $103 million in 2004, 2005 and 2006, respectively. Future actual pension cost will depend on future investment performance, changes in future discount rates and various other factors related to the populations participating in the pension plans.

Lowering the expected long-term rate of return on the Qualified Plans' assets by 0.5% (from 9.0% to 8.5%) would have increased pension cost for 2003 by approximately $18 million (income of $3 million would have become $15 million in pension expense). Lowering the discount rate by 0.5% would have reduced pension income for 2003 by approximately $0.5 million.

The value of the Qualified Plans' assets has increased from $2.795 billion at December 31, 2002 to $3.180 billion at December 31, 2003. The Qualified Plans paid out $292 million in benefits to plan participants during 2003 (the nonqualified plans paid out $7 million in benefits). Our plans remain in an underfunded position (plan assets are less than projected benefit obligations) of $508 million at December 31, 2003. Due to the pension plans currently being underfunded, we recorded a charge to Other Comprehensive Income (OCI) of $585 million in 2002, and recorded a Deferred Income Tax Asset of $315 million, offset by a Minimum Pension Liability of $662 million and a reduction to prepaid costs and adjustment for unrecognized costs of $238 million. In 2003, the income recorded in OCI was $154 million, and the reduction in the Deferred Income Tax Asset was $76 million, offset by a reduction in Minimum Pension Liability of $234 million and a reduction to adjustment for unrecognized costs of $4 million. The charge to OCI does not affect earnings or cash flow. Due to the current underfunded status of the Qualified Plans, we expect to make cash contributions to the pension plans of approximately $41 million in 2004.

Certain of the defined benefit pension plans we sponsor and maintain contain a cash balance benefit feature. In recent years, cash balance benefit features have become a focus of scrutiny, as government regulators and courts consider how the Employee Retirement Income Security Act of 1974, as amended, the Age Discrimination in Employment Act, as amended, and other relevant federal employment laws apply to plans with such a cash balance plan feature. We believe that the defined benefit pension plans we sponsor and maintain are in substantial compliance with the applicable requirements of such laws.

Nuclear Plant Outages

In April 2003, engineers at STP, during inspections conducted regularly as part of refueling outages, found wall cracks in two bottom mounted instrument guide tubes of STP Unit 1. These tubes were repaired and the unit returned to service in August 2003. Our share of the cost of repair for this outage was approximately $6 million. We had commitments to provide power to customers during the outage. Therefore, we were subject to fluctuations in the market prices of electricity and purchased replacement energy.

In April 2003, both units of Cook Plant were taken offline due to an influx of fish in the plant's cooling water system which caused a reduction in cooling water to essential plant equipment. After repair of damage caused by the fish intrusion, Cook Plant Unit 1 returned to service in May and Unit 2 returned to service in June following completion of a scheduled refueling outage.

Litigation

Federal EPA Complaint and Notice of Violation

See discussion of the Federal EPA Complaint and Notice of Violation within "Significant Factors – Environmental Matters."

Enron Bankruptcy

On October 15, 2002, certain subsidiaries of AEP filed claims against Enron and its subsidiaries in the bankruptcy proceeding filed by the Enron entities which are pending in the U.S. Bankruptcy Court for the Southern District of New York. At the date of Enron's bankruptcy, certain subsidiaries of AEP had open trading contracts and trading accounts receivables and payables with Enron. In addition, on June 1, 2001, we purchased Houston Pipe Line Company (HPL) from Enron. Various HPL related contingencies and indemnities from Enron remained unsettled at the date of Enron's bankruptcy. The timing of the resolution of the claims by the Bankruptcy Court is not certain.

In connection with the 2001 acquisition of HPL, we acquired exclusive rights to use and operate the underground Bammel gas storage facility pursuant to an agreement with BAM Lease Company, a now-bankrupt subsidiary of Enron. This exclusive right to use the referenced facility is for a term of 30 years, with a renewal right for another 20 years and includes the use of the Bammel storage facility and the appurtenant pipelines. We have engaged in discussions with Enron concerning the possible purchase of the Bammel storage facility and related assets, the possible resolution of outstanding issues between AEP and Enron relating to our acquisition of HPL and the possible resolution of outstanding energy trading issues. We have considered the possible outcomes of these issues in our impairment analysis of HPL; however, actual results could differ from those estimates. We are unable to predict whether these discussions will lead to an agreement on these subjects. In January 2004, AEP and its subsidiaries filed an amended lawsuit against Enron and its subsidiaries in the U.S. Bankruptcy Court claiming that Enron does not have the right to reject the Bammel storage facility agreement or the cushion gas use agreement, described below. In February 2004 Enron filed Notices of Rejection regarding the cushion gas use agreement and other incidental agreements. We have objected to Enron's attempted rejection of these agreements. Management is unable to predict the outcome of these proceedings or the impact on results of operations, cash flows or financial condition.

We also entered into an agreement with BAM Lease Company which grants HPL the exclusive right to use approximately 65 billion cubic feet of cushion gas required for the normal operation of the Bammel gas storage facility. The Bammel Gas Trust (owned by Enron and Bank of America (BOA)) purports to have a lien on 55 billion cubic feet of this cushion gas. These banks claim to have certain rights to the cushion gas in certain events of default. In connection with our acquisition of HPL, the banks and Enron entered into an agreement granting HPL's exclusive use of 65 billion cubic feet of cushion gas. Enron and the banks released HPL from all prior and future liabilities and obligations in connection with the financing arrangement. After the Enron bankruptcy, HPL was informed by the banks of a purported default by Enron under the terms of the financing arrangement. In July 2002, the banks filed a lawsuit against HPL in the state court of Texas seeking a declaratory judgment that they have a valid and enforceable security interest in gas purportedly in the Bammel storage facility which would permit them to cause the withdrawal of up to 55 billion cubic feet of gas from the storage facility. In September 2002, HPL filed a general denial and certain counterclaims against the banks including that Enron was a necessary and indispensable party to the Texas state court proceeding initiated by BOA. HPL also filed a motion to dismiss, which was denied. In December 2003, the Texas state court granted partial summary judgment in favor of the banks. HPL appealed this decision. We have considered the possible outcomes of these issues in our impairment analysis of HPL; however, actual results could differ from those estimates. Management is unable to predict the outcome of this lawsuit or its impact on results of operations, cash flows and financial condition.

In October 2003, AEP Energy Services Gas Holding Company filed a lawsuit against BOA in the United States District Court for the Southern District of Texas. On January 8, 2004, this lawsuit was amended and seeks damages for BOA's breach of contract, negligent misrepresentation and fraud in connection with transactions surrounding our acquisition of HPL from Enron including entering into the Bammel storage facility lease arrangement with Enron and the cushion gas arrangements with BOA and Enron. BOA led a lending syndicate involving the 1997 gas monetization that Enron and its subsidiaries undertook and the leasing of the Bammel underground gas storage reservoir to HPL. The lawsuit asserts that BOA made misrepresentations and engaged in fraud to induce and promote the stock sale of HPL, that BOA directly benefited from the sale of HPL and that AEP undertook the stock purchase and entered into the Bammel storage facility lease arrangement with Enron and the cushion gas arrangement with Enron and BOA based on misrepresentations that BOA made about Enron's financial condition that BOA knew or should have known were false including that the 1997 gas monetization did not contravene or constitute a default of any federal, state, or local statute, rule, regulation, code or any law.

In September 2003, Enron filed a complaint in the Bankruptcy Court against AEPES challenging AEP's offsetting of receivables and payables and related collateral across various Enron entities and seeking payment of approximately $125 million plus interest in connection with gas related trading transactions. We will assert our right to offset trading payables owed to various Enron entities against trading receivables due to several AEP subsidiaries. Management is unable to predict the outcome of this lawsuit or its impact on our results of operations, cash flows or financial condition.

In December 2003, Enron filed a complaint in the Bankruptcy Court against AEPSC seeking approximately $93 million plus interest in connection with a transaction for the sale and purchase of physical power among Enron, AEP and Allegheny Energy Supply, LLC during November 2001. Enron's claim seeks to unwind the effects of the transaction. AEP believes it has several defenses to the claims in the action being brought by Enron. Management is unable to predict the outcome of this lawsuit or its impact on our results of operations, cash flows or financial condition.

During 2002 and 2001, we expensed a total of $53 million ($34 million net of tax) for our estimated loss from the Enron bankruptcy. The amount expensed was based on an analysis of contracts where AEP and Enron entities are counterparties, the offsetting of receivables and payables, the application of deposits from Enron entities and management's analysis of the HPL related purchase contingencies and indemnifications. As noted above, Enron has challenged our offsetting of receivables and payables and the Bammel storage facility lease agreement and cushion gas agreement. Management is unable to predict the final resolution of these disputes, however the impact on results of operations, cash flows and financial condition could be material.

Bank of Montreal Claim

In March 2003, Bank of Montreal (BOM) terminated all natural gas trading deals and claimed that we owed approximately $34 million. In April 2003, we filed a lawsuit against BOM claiming BOM had acted contrary to the appropriate trading contract and industry practice in terminating the contract and calculating termination and liquidation amounts and that BOM had acknowledged just prior to the termination and liquidation that it owed us approximately $68 million. We are claiming that BOM owes us at least $45 million. Although management is unable to predict the outcome of this matter, it is not expected to have a material impact on results of operations, cash flows or financial condition.

Arbitration of Williams Claim

In 2002, we filed a demand for arbitration with the American Arbitration Association to initiate formal arbitration proceedings in a dispute with the Williams Companies (Williams). The proceeding results from Williams' repudiation of its obligations to provide physical power deliveries to AEP and Williams' failure to provide the monetary security required for natural gas deliveries. AEP and Williams settled the dispute with AEP paying $90 million to Williams in June 2003. The settlement amount approximated the amount payable that, in the ordinary course of business, we recorded as part of our trading activity using MTM accounting. As a result, the resolution of this matter had an immaterial impact on results of operations and financial condition. See Note 7 for further discussion.

Arbitration of PG&E Energy Trading, LLC Claim

In January 2003, PG&E Energy Trading, LLC (PGET) claimed approximately $22 million was owed by AEP in connection with the termination and liquidation of all trading deals. In February 2003, PGET initiated arbitration proceedings. In July 2003, AEP and PGET agreed to a settlement with AEP paying approximately $11 million to PGET. The settlement amount approximated the amount payable that, in the ordinary course of business, we recorded as part of our trading activity using MTM accounting. As a result, the settlement payment did not have a material impact on results of operations, cash flows or financial condition.

Energy Market Investigations

AEP and other energy market participants received data requests, subpoenas and requests for information from the FERC, the SEC, the PUCT, the U.S. Commodity Futures Trading Commission (CFTC), the U.S. Department of Justice and the California attorney general during 2002. Management responded to the inquiries and provided the requested information and has continued to respond to supplemental data requests in 2003 and 2004.

In March 2003, we received a subpoena from the SEC as part of the SEC's ongoing investigation of energy trading activities. In August 2002, we had received an informal data request from the SEC seeking that we voluntarily provide information. The subpoena sought additional information and is part of the SEC's formal investigation. We responded to the subpoena and will continue to cooperate with the SEC.

On September 30, 2003, the CFTC filed a complaint against AEP and AEPES in federal district court in Columbus, Ohio. The CFTC alleges that AEP and AEPES provided false or misleading information about market conditions and prices of natural gas in an attempt to manipulate the price of natural gas in violation of the Commodity Exchange Act. The CFTC seeks civil penalties, restitution and disgorgement of benefits. The case is in the initial pleading stage with our response to the complaint currently due on May 18, 2004. Although management is unable to predict the outcome of this case, we recorded a provision in 2003 and the action is not expected to have a material effect on results of operations.

In January 2004, the CFTC issued a request for documents and other information in connection with a CFTC investigation of activities affecting the price of natural gas in the fall of 2003. We are responding to that request.

Management cannot predict what, if any further action, any of these governmental agencies may take with respect to these matters.

Shareholders' Litigation

In 2002, lawsuits alleging securities law violations, a breach of fiduciary duty for failure to establish and maintain adequate internal controls and violations of the Employee Retirement Income Security Act were filed against us, certain executives, members of the Board of Directors and certain investment banking firms. We intend to vigorously defend against these actions. See Note 7 for further discussion.

California Lawsuit

In 2002, the Lieutenant Governor of California filed a lawsuit in California Superior Court against forty energy companies, including AEP, and two publishing companies alleging violations of California law through alleged fraudulent reporting of false natural gas price and volume information with an intent to affect the market price of natural gas and electricity. AEP has been dismissed from the case. See Note 7 for further discussion.

Cornerstone Lawsuit

In the third quarter of 2003, Cornerstone Propane Partners filed an action in the United States District Court for the Southern District of New York against forty companies, including AEP and AEPES seeking class certification and alleging unspecified damages from claimed price manipulation of natural gas futures and options on the NYMEX from January 2000 through December 2002. Shortly thereafter, a similar action was filed in the same court against eighteen companies including AEP and AEPES making essentially the same claims as Cornerstone Propane Partners and also seeking class certification. These cases are in the initial pleading stage. Management believes that the cases are without merit and intends to vigorously defend against them.

TEM Litigation

See discussion of TEM litigation within the "Financial Condition – Other" section of Management's Financial Discussion and Analysis.

Texas Commercial Energy, LLP Lawsuit

Texas Commercial Energy, LLP (TCE), a Texas REP, filed a lawsuit against us and four AEP subsidiaries, certain unaffiliated energy companies and ERCOT alleging violations of the Sherman Antitrust Act, fraud, negligent misrepresentation, breach of fiduciary duty, breach of contract, civil conspiracy and negligence. The allegations, not all of which are made against the AEP companies, range from anticompetitive bidding to withholding power. TCE alleges that these activities resulted in price spikes requiring TCE to post additional collateral and ultimately forced it into bankruptcy when it was unable to raise prices to its customers due to fixed price contracts. The suit alleges over $500 million in damages for all defendants and seeks recovery of damages, exemplary damages and court costs. Management believes that the claims against us are without merit. We intend to vigorously defend against the claims. See Note 7 for further discussion.

COLI Litigation

A decision by the U.S. District Court for the Southern District of Ohio in February 2001 that denied AEP's deduction of interest claimed on AEP's consolidated federal income tax returns related to a COLI program resulted in a $319 million reduction in AEP's Net Income for 2000. We filed an appeal of the U.S. District Court's decision with the U.S. Court of Appeals for the 6th Circuit. In April 2003, the Appeals Court ruled against AEP. The U.S. Supreme Court has declined to hear this issue.

Snohomish Settlement

In February 2003, AEP and the Public Utility District No. 1 of Snohomish County, Washington (Snohomish) agreed to terminate their long-term contract signed in January 2001. Snohomish also agreed to withdraw its complaint before the FERC regarding this contract and paid $59 million to us. The settlement amount was less than the amount receivable that, in the ordinary course of business, we recorded using MTM accounting. As a result, we incurred a $10 million pre-tax loss.

Other Litigation

We are involved in a number of other legal proceedings and claims. While management is unable to predict the outcome of such litigation, it is not expected that the ultimate resolution of these matters will have a material adverse effect on results of operations, cash flows or financial condition.

Potential Uninsured Losses

Some potential losses or liabilities may not be insurable or the amount of insurance carried may not be sufficient to meet potential losses and liabilities, including, but not limited to, liabilities relating to damage to the Cook Plant or STP and costs of replacement power in the event of a nuclear incident at the Cook Plant or STP. Future losses or liabilities which are not completely insured, unless recovered from customers, could have a material adverse effect on results of operations, cash flows and financial condition.

Environmental Matters

There are new environmental control requirements that we expect will result in substantial capital investments and operational costs. The sources of these future requirements include:

- Legislative and regulatory proposals to adopt stringent controls on sulfur dioxide (SO_2), nitrogen oxide (NO_x) and mercury emissions from coal-fired power plants,
- New Clean Water Act rules to reduce the impacts of water intake structures on aquatic species at certain of our power plants, and
- Possible future requirements to reduce carbon dioxide emissions to address concerns about global climatic change.

In addition to achieving full compliance with all applicable legal requirements, we strive to go beyond compliance in an effort to be good environmental stewards. For example, we invest in research, through groups like the Electric

Power Research Institute, to develop, implement and demonstrate new emission control technologies. We plan to continue in a leadership role to protect and preserve the environment while providing vital energy commodities and services to customers at fair prices. We have a proven record of efficiently producing and delivering electricity and gas while minimizing the impact on the environment. We invested over $2 billion, from 1990 through 2003, to equip many of our facilities with pollution control technologies. We will continue to make investments to improve the air emissions from our generating stations because this is the most cost-effective generation source for our customers electricity needs.

The Current Air Quality Regulatory Framework

The Clean Air Act (CAA) is the legislation that establishes the federal regulatory authority and oversight for emissions from our fossil-fired generating plants. The states, with oversight and approval from the Federal EPA, administer and enforce these laws and related regulations.

Title I of the CAA

National Ambient Air Quality Standards: The Federal EPA periodically reviews the available scientific data for six pollutants and establishes a standard for concentration levels in ambient air for these substances to protect the public welfare and public health with an extra margin for safety. These requirements are known as "national ambient air quality standards" (NAAQS).

The states identify those areas within their state that meet the NAAQS (attainment areas) and those that do not (non-attainment areas). States must develop their individual state implementation plans (SIPs) with the intention of bringing non-attainment areas into compliance with the NAAQS. In developing a SIP each state must allow attainment areas to maintain compliance with the NAAQS. This is accomplished by controlling sources that emit one or more pollutants or precursors to those pollutants. The Federal EPA approves SIPs if they meet the minimum criteria in the CAA. Alternatively, the Federal EPA may prescribe a federal implementation plan if they conclude that a SIP is deficient. Additionally, the Federal EPA can impose sanctions, up to and including withholding of federal highway funds, in states that fail to submit an adequate SIP or a SIP that fails to bring non-attainment areas into NAAQS compliance within the time prescribed by the CAA.

The CAA also establishes visibility goals, which are known as the regional haze program, for certain federally designated areas, including national parks. States are required to develop and submit SIP provisions that will demonstrate reasonable progress toward preventing the impairment and remedying any existing impairment of visibility in these federally designated areas.

Each state's SIP must include requirements to control sources that emit pollutants in that state as well as requirements to control sources that significantly contribute to non-attainment areas in another state. If a state believes that its air quality is impacted by upwind sources outside their borders, that state can submit a petition that asks the Federal EPA to impose control requirements on specific sources in other states if those states' SIPs do not contain adequate requirements to control those sources. For example, the Federal EPA issued a NOx Rule in 1997, which affected 22 eastern states (including states in which AEP operates) and the District of Columbia. The NOx Rule asked these 23 jurisdictions to adopt requirements, for utility and industrial boilers and certain other emission sources, to employ cost-effective control technologies to reduce NOx emissions. The purpose of the request was to allow certain eastern states to reduce the contribution from these 23 jurisdictions to ozone non-attainment areas in certain eastern states.

The Federal EPA also granted four petitions filed by certain eastern states seeking essentially the same levels of control on emission sources outside of their states and issued a Section 126 Rule. All of the states in which we operate that were subject to the NOx Rule have submitted the required SIP revisions. In response, the Federal EPA issued the NOx Rule and the Section 126 Rule, which are discussed below.

The compliance date for the NOx Rule is May 31, 2004. In 2000, the Federal EPA also adopted a revised Section 126 Rule which granted petitions filed by four northeastern states. The revised Section 126 Rule imposes emissions reduction requirements comparable to the NOx Rule also beginning May 31, 2004, for most of our coal-fired generating units.

In 2000, the Texas Commission on Environmental Quality adopted rules requiring significant reductions in NOx emissions from utility sources, including TCC and SWEPCo. The compliance requirements began in May 2003 for TCC and begin in May 2005 for SWEPCo.

We are installing a variety of emission control technologies to improve NOx emissions standards and to comply with applicable state and federal NOx requirements. These include selective catalytic reduction (SCR) technology on certain units and other combustion control technologies on a larger number of units.

AEP's electric utility units are currently subject to SIP requirements that control SO_2 and particulate matter emissions in all states, and that control NOx emissions in certain states. Our generating plants comply with applicable SIP limits for SO_2, NOx and particulate matter.

Hazardous Air Pollutants: In 1990 Amendments to the CAA, Congress required the Federal EPA to identify the sources of 188 hazardous air pollutants (HAPs) and to develop regulations that prescribe a level of HAP emission reduction. These reductions must reflect the application of maximum achievable control technology (MACT). Congress also directed the Federal EPA to investigate HAP emissions from the electric utility sector and to submit a report to Congress. The Federal EPA's 1998 report to Congress identified mercury emissions from coal-fired electric utility units and nickel emissions from oil-fired utility units as sources of HAP emissions that warranted further investigation and possible control.

New Source Performance Standards and New Source Review: The Federal EPA establishes New Source Performance Standards (NSPS) for 28 categories of major stationary emission sources that reflect the best demonstrated level of pollution control. Sources that are constructed or modified after the effective date of an NSPS standard are required to meet those limitations. For example, many electric utility units are regulated under the NSPS for SO_2, NOx, and particulate matter. Similarly, each SIP must include regulations that require new sources, and major modifications at existing emission sources that result in a significant net increase in emissions, to submit a permit application and undergo a review of available technologies to control emissions of pollutants. These rules are called new source review (NSR) requirements.

Different NSR requirements apply in attainment and non-attainment areas.

In attainment areas:

- An air quality review must be performed, and
- The best available control technology must be employed to reduce new emissions.

In non-attainment areas,

- Requirements reflecting the lowest achievable emission rate are applied to new or modified sources, and
- All new emissions must be offset by reductions in emissions of the same pollutant from other sources within the same control area.

Neither the NSPS nor NSR requirements apply to certain activities, including routine maintenance, repair or replacement, changes in fuels or raw materials that a source is capable of accommodating, the installation of a pollution control project, and other specifically excluded activities.

Title IV of the CAA (Acid Rain)

The 1990 Amendments to the CAA included a market-based emission reduction program designed to reduce the amount of SO_2 emitted from electric utility units by approximately 50 percent from 1980 levels. This program also established a nationwide cap on utility SO_2 emissions of 8.9 million tons per year. The Federal EPA administers its SO_2 program through an allowance allocation and trading system. Allowances are allocated to specific units based on statutory formulas. Annually each utility unit must surrender one allowance for each ton of SO_2 that it emits. Emission sources that install controls and no longer need all of their allowances can bank those allowances for future use or trade them to other emission sources.

Title IV also contains requirements for utility sources to reduce NOx emissions through the use of available combustion controls. Units must meet NOx emission rates standards which are specific to that unit or units may participate in an annual averaging program for utility units that are under common control.

Future Reduction Requirements for SO_2, NOx, and Mercury

In 1997, the Federal EPA adopted new, more stringent NAAQS for fine particulate matter and ground-level ozone. The Federal EPA is in the process of developing final designations for fine particulate matter and ground-level ozone non-attainment areas. The Federal EPA has identified SO_2 and NOx emissions as precursors to the formation of fine particulate matter. NOx emissions are also identified as a precursor to the formation of ground-level ozone. As a result, requirements for future reductions in emissions of NOx and SO_2 from our generating units are highly probable. In addition, the Federal EPA has proposed a set of options for future mercury controls at coal-fired power plants.

Multi-emission control legislation, known as the Clear Skies Act, was introduced in Congress and is supported by the Bush Administration. This legislation would regulate NOx, SO_2, and mercury emissions from electric generating plants. We support enactment of this comprehensive, multi-emission legislation so that compliance planning can be coordinated and collateral emission reductions maximized. We believe the Bush Administration's Clear Skies Act would establish stringent emission reduction targets and achievable compliance timetables utilizing a cost-effective nationwide cap and trade program. Although the prospects for enactment of the Clear Skies Act are low, there are alternative regulatory approaches which will likely require us to substantially reduce SO_2, NOx and mercury emissions over the next ten years.

Regulatory Emissions Reductions

On January 30, 2004, the Federal EPA published two proposed rules that would collectively require reductions of approximately 70% in emissions of SO_2, NOx and mercury from coal-fired electric generating units by 2015 (2018 for mercury). This initiative has two major components:

- The Federal EPA proposed an interstate air quality rule for reducing SO_2 and NOx emissions across the eastern half of the United States (29 states and the District of Columbia) to address attainment of the fine particulate matter and ground-level ozone NAAQS. These reductions could also satisfy these states' obligations to make reasonable progress towards the national visibility goal under the regional haze program.
- The Federal EPA proposed to regulate mercury emissions from coal-fired electric generating units.

The interstate air quality rule would require affected states to include, in their SIPs, a program to reduce NOx and SO_2 emissions from coal-fired electric utility units. SO_2 and NOx emissions would be reduced in two phases, which would be implemented through a cap-and-trade program. Regional SO_2 emissions would be reduced to 3.9 million tons by 2010 and to 2.7 million tons by 2015. Regional NOx emissions would be reduced to 1.6 million tons by 2010 and to 1.3 million tons by 2015. Rules to implement the SO_2 and NOx trading programs have not yet been proposed.

To control and reduce mercury emissions, the Federal EPA published two alternative proposals. The first option requires the installation of MACT on a site-specific basis. Mercury emissions would be reduced from 48 tons to approximately 34 tons by 2008. The Federal EPA believes, and the industry concurs, that there are no commercially available mercury control technologies in the marketplace today that can achieve the MACT standards for bituminous coals, but certain units have achieved comparable levels of mercury reduction by installing conventional SO_2 (scrubbers) and NOx (SCR) emission reduction technologies. The proposed rule imposes significantly less stringent standards on generating plants that burn sub-bituminous coal or lignite, which standards potentially could be met without installation of mercury control technologies.

The Federal EPA recommends, and we support, a second mercury emission reduction option. The second option would permit mercury emission reductions to be achieved from existing sources through a national cap-and-trade approach. The cap-and-trade approach would include a two-phase mercury reduction program for coal-fired utilities. This approach would coordinate the reduction requirements for mercury with the SO_2 and NOx reduction requirements imposed on the same sources under the proposed interstate air quality rule. Coordination is significantly more cost-effective because technologies like scrubbers and SCRs, that can be used to comply with the more stringent SO_2 and NOx requirements, have also proven highly effective in reducing mercury emissions on certain coal-fired units that burn bituminous coal. The second option contemplates reducing mercury emissions from 48 million tons to 34 million tons by 2010 and to 15 million tons by 2018.

The Federal EPA's proposals are the beginning of a lengthy rulemaking process, which will involve supplemental proposals on many details of the new regulatory programs, written comments and public hearings, issuance of final rules, and potential litigation. In addition, states have substantial discretion in developing their rules to implement cap-and-trade programs, and will have 18 months after publication of the notice of final rulemaking to submit their revised SIPs. As a result, the ultimate requirements may not be known for several years and may depart significantly from the original proposed rules described here.

While uncertainty remains as to whether future emission reduction requirements will result from new legislation or regulation, it is certain under either outcome that we will invest in additional conventional pollution control technology on a major portion of our fleet of coal-fired power plants. Finalization of new requirements for further SO_2, NOx and/or mercury emission reductions will result in the installation of additional scrubbers, SCR systems and/or the installation of emerging technologies for mercury control.

Estimated Air Quality Environmental Investments

Each of the current and possible future environmental compliance requirements discussed above will require us to make significant additional investments, some of which are estimable. The proposed rules discussed above have not been adopted, will be subject to further revision, and will be the subject of a court challenge and further modifications.

All of our estimates are subject to significant uncertainties about the outcome of several interrelated assumptions and variables, including:

- Timing of implementation
- Required levels of reductions
- Allocation requirements of the new rules, and
- Our selected compliance alternatives.

As a result, we cannot estimate our compliance costs with certainty, and the actual costs to comply could differ significantly from the estimates discussed below.

All of the costs discussed below are incremental to our current investment base and operating cost structure. These expenditures for pollution control technologies, replacement generation and associated operating costs are recoverable from customers through regulated rates (in regulated jurisdictions) and should be recoverable through market prices (in deregulated jurisdictions). If not, those costs could adversely affect future results of operations and cash flows, and possibly financial condition.

Estimated Investments for NOx Compliance

We estimate that we will make future investments of approximately $600 million to comply with the Federal EPA's NOx Rule, the Texas Commission on Environmental Quality Rule and other final Federal EPA NOx-related requirements. Approximately $500 million of these investments are reflected in our estimated construction expenditures for 2004 – 2006. As of December 31, 2003, we have invested approximately $1.1 billion to comply with various NOx requirements.

Estimated Investments for SO2 Compliance

We are complying with Title IV SO_2 requirements by installing scrubbers, other controls and fuel switching at certain generating units. We also use SO_2 allowances that we:

- Receive in the annual allowance allocation by the Federal EPA,
- Obtain through participation in the annual allowance auction,
- Purchase in the allowance market, and
- Obtained as bonus allowances for installing controls early.

Decreasing SO_2 allowance allocations, a diminishing SO_2 allowance bank, and increasing allowance prices in the market will require us to install additional controls on certain of our generating units. We plan to install 3,500 MW of additional scrubbers over the next 4 years to comply with our Title IV SO_2 obligations. In total we estimate these additional capital costs to be approximately $1.2 billion. Of this total, we estimate that $900 million will be expended during 2004-2006 and this amount is included in our total estimated construction expenditures for 2004 – 2006.

Estimated Investments to Comply with Future Reduction Requirements

Our planning assumptions for the levels and timing of emissions reductions parallel the reduction levels and implementation time periods stated in the proposed rules issued by the Federal EPA in January 2004. We have also assumed that the Federal EPA will implement a mercury trading option and will design its proposed cap and trade mechanism for SO_2, NOx and mercury emissions in a manner similar to existing cap and trade programs. Based on these assumptions, compliance would require additional capital investment of approximately $1.7 billion by 2010, the end of the first phase for each proposed rule. We also estimate that we would incur increases in variable operation and maintenance expenses of $150 million for the periods by 2010, due to the costs associated with the maintenance of additional control systems, disposal of scrubber by-products and the purchase of reagents. We estimate that we will invest $200 million of this amount through 2006, and this amount is included in our total estimated construction expenditures for 2004 – 2006.

If the Federal EPA's preferred mercury trading option is not implemented, then any alternative mercury control program requiring adherence to MACT standards would also have implementation costs that could be significant. We cannot currently estimate the nature or amount of these costs. Furthermore, scrubber and SCR technologies could not be deployed at every bituminous-fired plant that AEP operates within the three-year compliance schedule provided under the proposed MACT rule. These MACT compliance costs, which we are not able to estimate, would be incremental to other cost estimates that we have discussed above.

Beyond 2010, we expect to incur additional costs for pollution control technology retrofits and associated operation and maintenance of the equipment. We cannot estimate these additional costs because of the uncertainties associated with the final control requirements and our associated compliance strategy, but these capital and operating costs will be significant.

New Source Review Litigation

Under the CAA, if a plant undertakes a major modification that directly results in an emissions increase, permitting requirements might be triggered and the plant may be required to install additional pollution control technology. This requirement does not apply to activities such as routine maintenance, replacement of degraded equipment or failed components, or other repairs needed for the reliable, safe and efficient operation of the plant.

The Federal EPA and a number of states have alleged APCo, CSPCo, I&M, OPCo and other unaffiliated utilities modified certain units at coal-fired generating plants in violation of the NSRs of the CAA. The Federal EPA filed its complaints against our subsidiaries in U.S. District Court for the Southern District of Ohio. The court also consolidated a separate lawsuit, initiated by certain special interest groups, with the Federal EPA case. The alleged modifications relate to costs that were incurred at our generating units over a 20-year period.

We are unable to estimate the loss or range of loss related to the contingent liability for civil penalties under the CAA proceedings. We are also unable to predict the timing of resolution of these matters due to the number of alleged violations and the significant number of issues yet to be determined by the Court. If we do not prevail, any capital and operating costs of additional pollution control equipment that may be required, as well as any penalties imposed, would adversely affect future results of operations, cash flows and possibly financial condition unless such costs can be recovered through regulated rates and market prices for electricity.

Superfund and State Remediation

By-products from the generation of electricity include materials such as ash, slag, sludge, low-level radioactive waste and SNF. Coal combustion by-products, which constitute the overwhelming percentage of these materials, are typically disposed of or treated in captive disposal facilities or are beneficially utilized. In addition, our generating plants and transmission and distribution facilities have used asbestos, PCBs and other hazardous and non-hazardous materials. We are currently incurring costs to safely dispose of these substances.

Superfund addresses clean-up of hazardous substances at disposal sites and authorized the Federal EPA to administer the clean-up programs. As of year-end 2003, subsidiaries of AEP are named by the Federal EPA as a PRP for five sites. There are six additional sites for which our subsidiaries have received information requests which could lead to PRP designation. Our subsidiaries have also been named potentially liable at six sites under state law. Liability has been resolved for a number of sites with no significant effect on results of operations. In those instances where we have been named a PRP or defendant, our disposal or recycling activities were in accordance with the then-applicable laws and regulations. Unfortunately, Superfund does not recognize compliance as a defense, but imposes strict liability on parties who fall within its broad statutory categories.

While the potential liability for each Superfund site must be evaluated separately, several general statements can be made regarding our potential future liability. Disposal of materials at a particular site is often unsubstantiated and the quantity of materials deposited at a site was small and often nonhazardous. Although superfund liability has been interpreted by the courts as joint and several, typically many parties are named as PRPs for each site and several of the parties are financially sound enterprises. Therefore, our present estimates do not anticipate material cleanup costs for identified sites for which we have been declared PRPs. If significant cleanup costs were attributed to our subsidiaries in the future under Superfund, results of operations, cash flows and possibly financial condition would be adversely affected unless the costs can be included in our electricity prices.

Global Climate Change

At the Third Conference of the Parties to the United Nations Framework Convention on Climate Change held in Kyoto, Japan in December 1997, more than 160 countries, including the U.S., negotiated a treaty requiring legally-binding reductions in emissions of greenhouse gases, chiefly CO_2, which many scientists believe are contributing to global climate change. The U.S. signed the Kyoto Protocol on November 12, 1998, but the treaty was not submitted to the Senate for its advice and consent by President Clinton. In March 2001, President Bush announced his opposition to the treaty. Ratification of the treaty by a majority of the countries' legislative bodies is required for it to be enforceable. Enforceability of the protocol is now contingent on ratification by Russia, which has expressed concerns about doing so.

On August 28, 2003, the Federal EPA issued a decision in response to a petition for rulemaking seeking reductions of CO_2 and other greenhouse gas emissions from mobile sources. The Federal EPA denied the petition and issued a memorandum stating that it does not have the authority under the Clean Air Act to regulate CO_2 or other greenhouse gas emissions that may affect global warming trends. The Circuit Court of Appeals for the District of Columbia is reviewing these actions.

We do not support the Kyoto Protocol but have been working with the Bush Administration on a voluntary program aimed at meeting the President's goal of reducing the greenhouse gas intensity of the economy by 18% by 2012. For many years, we have been a leader in pursuing voluntary actions to control greenhouse gas emissions. We expanded our commitment in this area in 2002 by joining the Chicago Climate Exchange, a pilot greenhouse gas emission reduction and trading program, under which we are obligated to reduce or offset 18 million tons of CO_2 emissions during 2003-2006.

We acquired 4,000 MW of coal-fired generation in the United Kingdom in December 2001. These assets may have future CO_2 emission control obligations beginning in 2005. We plan to dispose of our investment in this generation during 2004.

Costs for Spent Nuclear Fuel and Decommissioning

I&M, as the owner of the Cook Plant, and TCC, as a partial owner of STP, have a significant future financial commitment to safely dispose of SNF and to decommission and decontaminate the plants. The Nuclear Waste Policy Act of 1982 established federal responsibility for the permanent off-site disposal of SNF and high-level radioactive waste. By law I&M and TCC participate in the DOE's SNF disposal program which is described in Note 7. Since 1983 I&M has collected $316 million from customers for the disposal of nuclear fuel consumed at the Cook Plant. We deposited $117 million of these funds in external trust funds to provide for the future disposal of SNF and remitted $199 million to the DOE. TCC has collected and remitted to the DOE, $56 million for the future disposal of SNF since STP began operation in the late 1980s. Under the provisions of the Nuclear Waste Policy Act, collections from customers are to provide the DOE with money to build a permanent repository for spent fuel. However, in 1996, the DOE notified the companies that it would be unable to begin accepting SNF by the January 1998 deadline required by law. To date DOE has failed to comply with the requirements of the Nuclear Waste Policy Act.

As a result of DOE's failure to make sufficient progress toward a permanent repository or otherwise assume responsibility for SNF, AEP on behalf of I&M and STPNOC on behalf of TCC and the other STP owners, along with a number of unaffiliated utilities and states, filed suit in the D.C. Circuit Court requesting, among other things, that the D.C. Circuit Court order DOE to meet its obligations under the law. The D.C. Circuit Court ordered the parties to proceed with contractual remedies but declined to order DOE to begin accepting SNF for disposal. DOE estimates its planned site for the nuclear waste will not be ready until at least 2010. In 1998, AEP and I&M filed a complaint in the U.S. Court of Federal Claims seeking damages in excess of $150 million due to the DOE's partial material breach of its unconditional contractual deadline to begin disposing of SNF generated by the Cook Plant. Similar lawsuits were filed by other utilities. In August 2000, in an appeal of related cases involving other unaffiliated utilities, the U.S. Court of Appeals for the Federal Circuit held that the delays clause of the standard contract between utilities and the DOE did not apply to DOE's complete failure to perform its contract obligations, and that the utilities' suits against DOE may continue in court. On January 17, 2003, the U.S. Court of Federal Claims ruled in favor of I&M on the issue of liability. The case continues on the issue of damages owed to I&M by the DOE with a trial scheduled in March 2004. As long as the delay in the availability of a government approved storage repository for SNF continues, the cost of both temporary and permanent storage of SNF and the cost of decommissioning will continue to increase.

The cost to decommission nuclear plants is affected by both NRC regulations and the delayed SNF disposal program. Studies completed in 2003 estimate the cost to decommission the Cook Plant ranges from $821 million to $1.08 billion in 2003 non-discounted dollars. External trust funds have been established with amounts collected from customers to decommission the plant. At December 31, 2003, the total decommissioning trust fund balance for Cook Plant was $720 million which includes earnings on the trust investments. Studies completed in 1999 for STP estimate TCC's share of decommissioning cost to be $289 million in 1999 non-discounted dollars. Amounts collected from customers to decommission STP have been placed in an external trust. At December 31, 2003, the total decommissioning trust fund for TCC's share of STP was $125 million which includes earnings on the trust investments. Estimates from the decommissioning studies could continue to escalate due to the uncertainty in the SNF disposal program and the length of time that SNF may need to be stored at the plant site. I&M and TCC will work with regulators and customers to recover the remaining estimated costs of decommissioning Cook Plant and STP. However, our future results of operations, cash flows and possibly financial condition would be adversely affected if the cost of SNF disposal and decommissioning continues to increase and cannot be recovered.

Clean Water Act Regulation

On February 16, 2004, the Federal EPA signed a rule pursuant to the Clean Water Act that will require all large existing power plants to meet certain performance standards to reduce the mortality of juvenile and adult fish or other larger organisms pinned against a plant's cooling water intake screens. A subset of these plants that are located on sensitive water bodies will be required to meet additional performance standards for reducing the number of smaller organisms passing through the water screens and the cooling system. Sensitive water bodies are defined as oceans, estuaries, the Great Lakes, and small rivers with large plants. These rules will result in additional capital and operation and maintenance expenses to ensure compliance.

Other Environmental Concerns

We perform environmental reviews and audits on a regular basis for the purpose of identifying, evaluating and addressing environmental concerns and issues. In addition to the matters discussed above we are managing other environmental concerns which we do not believe are material or potentially material at this time. If they become significant or if any new matters arise that we believe could be material, they could have a material adverse effect on results of operations, cash flows and possibly financial condition.

Critical Accounting Policies

In the ordinary course of business, we use a number of estimates and assumptions relating to the reporting of results of operations and financial condition in the preparation of our financial statements in conformity with accounting principles generally accepted in the United States of America, including amounts related to legal matters and contingencies. Actual results can differ significantly from those estimates under different assumptions and conditions.

We believe that the following discussion addresses the most critical accounting policies, which are those that are most important to the portrayal of the financial condition and results and require management's most difficult, subjective and complex judgments, often as a result of the need to make estimates about the effect of matters that are inherently uncertain.

Revenue Recognition

Regulatory Accounting

Our consolidated financial statements reflect the actions of regulators that can result in the recognition of revenues and expenses in different time periods than enterprises that are not rate-regulated. We recognize regulatory assets (deferred expenses to be recovered in the future) and regulatory liabilities (deferred future revenue reductions or refunds) for the economic effects of regulation. Specifically, we match the timing of our expense recognition with the recovery of such expense in regulated revenues. Likewise, we match income with its passage to customers through regulated revenues in the same accounting period. We also record regulatory liabilities, for refunds, or probable refunds, to customers that have not yet been made.

When regulatory assets are probable of recovery through regulated rates, we record them as assets on the balance sheet. We test for probability of recovery whenever new events occur, for example, issuance of a regulatory commission order or passage of new legislation. If it is determined that recovery of a regulatory asset is no longer probable, we write-off that regulatory asset as a charge against earnings. A write-off of regulatory assets may also reduce future cash flows since there may be no recovery through regulated rates.

Traditional Electricity Supply and Delivery Activities

We recognize revenues on the accrual or settlement basis for normal retail and wholesale electricity supply sales and electricity transmission and distribution delivery services. That is, we recognize and record revenues when the energy is delivered to the customer and include estimated unbilled as well as billed amounts. In general, expenses are recorded when purchased electricity is received and when expenses are incurred.

Domestic Gas Pipeline and Storage Activities

We recognize revenues from domestic gas pipeline and storage services when gas is delivered to contractual meter points or when services are provided, with the exception of certain physical forward gas purchase and sale contracts that are derivatives and are required to be accounted for using mark-to-market accounting (Resale Gas Contracts).

Energy Marketing and Risk Management Activities

We engage in wholesale electricity, natural gas and coal marketing and risk management activities. Effective in October 2002, these activities were focused on wholesale markets where we own assets. Our activities include the purchase and sale of energy under forward contracts at fixed and variable prices and the buying and selling of financial energy contracts which include exchange traded futures and options, and over-the-counter options and swaps. Prior to October 2002, we recorded wholesale marketing and risk management activities using the mark-to-market method of accounting.

In October 2002, EITF 02-3 precluded mark-to-market accounting for risk management contracts that were not derivatives pursuant to SFAS 133. We implemented this standard for all non-derivative wholesale and risk management transactions occurring on or after October 25, 2002. For non-derivative risk management transactions entered into prior to October 25, 2002, we implemented this standard on January 1, 2003 and reported the effects of implementation as a cumulative effect of an accounting change.

After January 1, 2003, we use mark-to-market accounting for wholesale marketing and risk management transactions that are derivatives unless the derivative is designated for hedge accounting or the normal purchase and sale exemption. Revenues and expenses are recognized from wholesale marketing and risk management transactions that are not derivatives when the commodity is delivered.

See discussion of EITF 02-3 and Rescission of EITF 98-10 in Note 2.

Accounting for Derivative Instruments

For derivative contracts that are not designated as hedges or normal purchase and sale transactions we recognize unrealized gains and losses prior to settlement based on changes in fair value during the period in our results of operations. When we settle mark-to-market derivative contracts and realize gains and losses, we reverse previously recorded unrealized gains and losses from mark-to-market valuations.

We designate certain derivative instruments as hedges of forecasted transactions or future cash flows (cash flow hedges) or as a hedge of a recognized asset, liability or firm commitment (fair value hedge). We report changes in the fair value of these instruments on our balance sheet. We do not recognize changes in the fair value of the derivative instrument designated as a hedge in the current results of operations until earnings are impacted by the hedged item. We also recognize any changes in the fair value of the hedging instrument that are not offset by changes in the fair value of the hedged item immediately in earnings.

We measure the fair values of derivative instruments and hedge instruments accounted for using mark-to-market accounting based on exchange prices and broker quotes. If a quoted market price is not available, we estimate the fair value based on the best information available including valuation models that estimate future energy prices based on existing market and broker quotes, supply and demand market data, and other assumptions. We reduce fair values by estimated valuation adjustments for items such as discounting, liquidity and credit quality. There are inherent risks related to the underlying assumptions in models used to fair value open long-term derivative contracts. We have independent controls to evaluate the reasonableness of our valuation models. However, energy markets, especially electricity markets, are imperfect and volatile. Unforeseen events can and will cause reasonable price curves to differ from actual prices throughout a contract's term and at the time a contract settles. Therefore, there could be significant adverse or favorable effects on future results of operations and cash flows if market prices are not consistent with our approach at estimating current market consensus for forward prices in the current period. This is particularly true for long-term contracts.

We recognize all derivative instruments at fair value in our Consolidated Balance Sheets as either "Risk Management Assets" or "Risk Management Liabilities." We do not consider contracts that have been elected normal purchase or normal sale under SFAS 133 to be derivatives. Unrealized and realized gains and losses on all derivative instruments are ultimately included in Revenues in the Consolidated Statement of Operations on a net basis, with the exception of physically settled Resale Gas Contracts for the purchase of natural gas. The unrealized and realized gains and losses on these Resale Gas Contracts are presented as Purchased Gas for Resale in the Consolidated Statement of Operations.

Long-Lived Assets

Long-lived assets are evaluated periodically for impairment whenever events or changes in circumstances indicate that the carrying amount of any such assets may not be recoverable. If the carrying amount is not recoverable, an impairment is recorded to the extent that the fair value of the asset is less than its book value.

Pension Benefits

We sponsor pension and other retirement plans in various forms covering all employees who meet eligibility requirements. We use several statistical and other factors which attempt to anticipate future events in calculating the expense and liability related to our plans. These factors include assumptions about the discount rate, expected return on plan assets and rate of future compensation increases as estimated by management, within certain guidelines. In addition, our actuarial consultants use subjective factors such as withdrawal and mortality rates to estimate these factors. The actuarial assumptions used may differ materially from actual results due to changing market and economic conditions, higher or lower withdrawal rates or longer or shorter life spans of participants. These differences may result in a significant impact to the amount of pension expense recorded. See "Pension Plans" in Significant Factors section of Management's Financial Discussion and Analysis.

New Accounting Pronouncements

Effective July 1, 2003, we implemented FIN 46, "Consolidation of Variable Interest Entities." As a result of the implementation, we consolidated two entities, Sabine Mining Company ($77.8 million) and JMG ($469.6 million), which were previously off-balance sheet. These entities were consolidated with SWEPCo and OPCo, respectively. There is no change in net income due to the consolidations. In addition, we deconsolidated Cadis Partners, LLC and the trusts which hold mandatorily redeemable trust preferred securities which were previously reported as Minority Interest in Finance Subsidiary ($533 million) and Certain Subsidiary Obligated, Mandatorily Redeemable, Preferred Securities of Subsidiary Trusts Holding Solely Junior Subordinated Debentures of Such Subsidiaries ($321 million), respectively. As a result of the deconsolidation these amounts are now included in Long-term Debt. In December 2003, the FASB issued FIN 46R which replaces FIN 46. The FASB and other accounting constituencies continue to interpret the application of FIN 46R. As a result, we are continuing to review the application of this new interpretation and expect to adopt FIN 46R by March 31, 2004.

See Notes 1 and 2 to the consolidated financial statements for a discussion of significant accounting policies and additional impacts of new accounting pronouncements.

Other Matters

FERC Proposed Standard Market Design

In July 2002, the FERC issued its Standard Market Design (SMD) notice of proposed rulemaking, which sought to standardize the structure and operation of wholesale electricity markets across the country. Key elements of FERC's proposal included standard rules and processes for all users of the electricity transmission grid, new transmission rules and policies, and the creation of certain markets to be operated by independent administrators of the grid in all regions. The FERC issued a "white paper" on the proposal in April 2003, in response to the numerous comments that the FERC received on its proposal. Management does not know if or when the FERC will finalize a rule for SMD. Until any potential rule is finalized, management cannot predict its effect on cash flows and results of operations.

FERC Market Power Mitigation

A FERC order issued in November 2001 on AEP's triennial market based wholesale power rate authorization update required certain mitigation actions that AEP would need to take for sales/purchases within its control area and required AEP to post information on its website regarding its power system's status. As a result of a request for rehearing filed by AEP and other market participants, FERC issued an order delaying the effective date of the mitigation plan until after a planned technical conference on market power determination. In December 2003, the FERC issued a staff paper discussing alternatives and held a technical conference in January 2004. Management is unable to predict the timing of any further action by the FERC or its affect of future results of operations and cash flows.

Seasonality

The sale of electric power in our service territories is generally a seasonal business. In many parts of the country, demand for power peaks during the hot summer months, with market prices also peaking at that time. In other areas, power demand peaks during the winter. The pattern of this fluctuation may change due to the nature and location of our facilities and the terms of power contracts into which we enter. In addition, we have historically sold less power, and consequently earned less income, when weather conditions are milder. Unusually mild weather in the future could diminish our results of operations and may impact cash flows and financial condition.

Non-Core Investments

Additional market deterioration associated with our non-core wholesale investments (all operations outside our traditional domestic regulated utility operations), including our U.K. operations, merchant generation facilities, and certain gas storage and pipeline assets, could have an adverse impact on future results of operations and cash flows. Further changes in external market conditions could lead to additional write-offs and further divestitures of our wholesale investments, including, but not limited to, the U.K. operations, merchant generation facilities, and our gas storage and pipeline operations. See Note 10 for additional information regarding assets and investments currently recorded as held for sale.

Investments Limitations

Our investment, including guarantees of debt, in certain types of activities is limited by PUHCA. SEC authorization under PUHCA limits us to issuing and selling securities in an amount up to 100% of our average quarterly consolidated retained earnings balance for investment in EWGs and FUCOs. At December 31, 2003, our investment in EWGs and FUCOs was $1.7 billion, including guarantees of debt, compared to our limit of $2.1 billion.

SEC Rule 58, under the general rules and regulations of the PUHCA, permits us to invest up to 15% of consolidated capitalization (such amount was $3.4 billion at December 31, 2003) in energy-related companies, including marketing and/or risk management activities in electricity, gas and other energy commodities. As of December 31, 2003 AEP has invested $2.8 billion in these energy-related companies.

QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT RISK MANAGEMENT ACTIVITIES

Market Risks

As a major power producer and marketer of wholesale electricity and natural gas, we have certain market risks inherent in our business activities. These risks include commodity price risk, interest rate risk, foreign exchange risk and credit risk. They represent the risk of loss that may impact us due to changes in the underlying market prices or rates.

We have established policies and procedures which allow us to identify, assess, and manage market risk exposures in our day-to-day operations. Our risk policies have been reviewed with our Board of Directors and approved by our Risk Executive Committee. Our Chief Risk Officer administers our risk policies and procedures. The Risk Executive Committee establishes risk limits, approves risk policies, and assigns responsibilities regarding the oversight and management of risk and monitors risk levels. Members of this committee receive daily, weekly, and monthly reports regarding compliance with policies, limits and procedures. Our committee meets monthly and consists of the Chief Risk Officer, Chief Credit Officer, V.P. Market Risk Oversight, and senior financial and operating managers.

We actively participate in the Committee of Chief Risk Officers (CCRO) to develop standard disclosures for risk management activities around risk management contracts. The CCRO is composed of the chief risk officers of major electricity and gas companies in the United States. The CCRO adopted disclosure standards for risk management contracts to improve clarity, understanding and consistency of information reported. Implementation of the disclosures is voluntary. We support the work of the CCRO and have embraced the disclosure standards. The following tables provide information on our risk management activities.

Mark-to-Market Risk Management Contract Net Assets (Liabilities)

This table provides detail on changes in our mark-to-market (MTM) net asset or liability balance sheet position from one period to the next.

MTM Risk Management Contract Net Assets (Liabilities)
Year Ended December 31, 2003

	Utility Operations	Investments Gas Operations	Investments UK Operations	Consolidated
		(in millions)		
Beginning Balance December 31, 2002	$360	$(155)	$ 45	$250
(Gain) Loss from Contracts Realized/Settled During the Period (a)	(107)	175	(9)	59
Fair Value of New Contracts When Entered Into During the Period (b)	-	-	4	4
Net Option Premiums Paid/(Received) (c)	-	23	(14)	9
Change in Fair Value Due to Valuation Methodology Changes	-	1	-	1
Effect of EITF 98-10 Rescission (d)	(19)	1	(14)	(32)
Changes in Fair Value of Risk Management Contracts (e)	43	(40)	(134)	(131)
Changes in Fair Value of Risk Management Contracts Allocated to Regulated Jurisdictions (f)	9	-	-	9
UK Generation Hedges (g)	-	-	(124)	(124)
Total MTM Risk Management Contract Net Assets (Liabilities), excluding Cash Flow Hedges	$286	$5	$(246)	45
Net Cash Flow Hedge Contracts (h)				(134)
Net Risk Management Liabilities Held for Sale (i)				383
Ending Balance December 31, 2003				$294

(a) "(Gain) Loss from Contracts Realized/Settled During the Period" includes realized gains from risk management contracts and related derivatives that settled during 2003 and entered into prior to 2003.

(b) The "Fair Value of New Contracts When Entered Into During the Period" represents the fair value at inception of long-term contracts entered into with customers during 2003. Most of the fair value comes from longer term fixed price contracts with customers that seek to limit their risk against fluctuating energy prices. The contract prices are valued against market curves associated with the delivery location.

(c) "Net Option Premiums Paid/(Received)" reflects the net option premiums paid/(received) as they relate to unexercised and unexpired option contracts entered into in 2003.

(d) See Note 2 "New Accounting Pronouncements, Extraordinary Items and Cumulative Effect."

(e) "Changes in Fair Value of Risk Management Contracts" represents the fair value change in the risk management portfolio due to market fluctuations during the current period. Market fluctuations are attributable to various factors such as supply/demand, weather, storage, etc.

(f) "Change in Fair Value of Risk Management Contracts Allocated to Regulated Jurisdictions" relates to the net gains (losses) of those contracts that are not reflected in the Consolidated Statements of Operations. These net gains (losses) are recorded as regulatory liabilities/assets for those subsidiaries that operate in regulated jurisdictions.

(g) "UK Generation Hedges" represent amounts previously classified as hedges of forecasted U.K. power sales relating to the fourth quarter of 2004 and beyond. Given the expected disposition of our U.K. generation in 2004, the forecasted sales are no longer probable of occurring. Therefore, these amounts have been reclassified from hedge accounting to mark-to-market accounting.

(h) "Net Cash Flow Hedge Contracts" (pre-tax) are discussed in detail within the following pages.

(i) See Note 10 for discussion on Assets Held for Sale.

Detail on MTM Risk Management Contract Net Assets (Liabilities)
As of December 31, 2003

	Utility Operations	Investments Gas Operations	Investments UK Operations	Consolidated
		(in millions)		
Current Assets	$323	$417	$560	$1,300
Non Current Assets	279	215	274	768
Total Assets	$602	$632	$834	$ 2,068
Current Liabilities	$(216)	$(403)	$(646)	$(1,265)
Non Current Liabilities	(100)	(224)	(434)	(758)
Total Liabilities	$(316)	$(627)	$(1,080)	$(2,023)
Total Net Assets (Liabilities), excluding Cash Flow Hedges	$286	$5	$(246)	$45

Reconciliation of MTM Risk Management Contracts to
Consolidated Balance Sheets
As of December 31, 2003

	Risk Management Contracts*	Cash Flow Hedges	Assets Held for Sale	Consolidated
		(in millions)		
Current Assets	$1,300	$26	$(560)	$766
Non Current Assets	768	-	(274)	494
Total Assets	$2,068	$26	$(834)	$1,260
Current Liabilities	$(1,265)	$(148)	$782	$(631)
Non Current Liabilities	(758)	(12)	435	(335)
Total Liabilities	$(2,023)	$(160)	$1,217	$(966)
Total Net Assets (Liabilities)	$45	$(134)	$383	$294

* Excluding Cash Flow Hedges.

Maturity and Source of Fair Value of MTM Risk Management Contract Net Assets (Liabilities)

The table presenting maturity and source of fair value of MTM risk management contract net assets provides two fundamental pieces of information.

- The source of fair value used in determining the carrying amount of our total MTM asset or liability (external sources or modeled internally).
- The maturity, by year, of our net assets/liabilities, giving an indication of when these MTM amounts will settle and generate cash.

Maturity and Source of Fair Value of MTM
Risk Management Contract Net Assets (Liabilities)
Fair Value of Contracts as of December 31, 2003

	2004	2005	2006	2007	2008	After 2008 (c)	Total (d)
				(in millions)			
Utility Operations:							
Prices Actively Quoted – Exchange Traded Contracts	$44	$(4)	$(1)	$-	$-	$-	$39
Prices Provided by Other External Sources – OTC Broker Quotes (a)	78	38	29	13	6	-	164
Prices Based on Models and Other Valuation Methods (b)	(15)	7	15	19	16	41	83
Total	$107	$41	$43	$32	$22	$41	$286
Investments - Gas Operations:							
Prices Actively Quoted – Exchange Traded Contracts	$49	$14	$(1)	$-	$-	$-	$62
Prices Provided by Other External Sources – OTC Broker Quotes (a)	(27)	-	-	-	-	-	(27)
Prices Based on Models and Other Valuation Methods (b)	(8)	(7)	(6)	(1)	(3)	(5)	(30)
Total	$14	$7	$(7)	$(1)	$(3)	$(5)	$5
Investments - UK Operations:							
Prices Actively Quoted – Exchange Traded Contracts	$-	$-	$-	$-	$-	$-	$-
Prices Provided by Other External Sources – OTC Broker Quotes (a)	(60)	(101)	(46)	-	-	-	(207)
Prices Based on Models and Other Valuation Methods (b)	(26)	(9)	(2)	(2)	-	-	(39)
Total	$(86)	$(110)	$(48)	$(2)	$-	$-	$(246)
Consolidated:							
Prices Actively Quoted – Exchange Traded Contracts	$93	$10	$(2)	$-	$-	$-	$101
Prices Provided by Other External Sources – OTC Broker Quotes (a)	(9)	(63)	(17)	13	6	-	(70)
Prices Based on Models and Other Valuation Methods (b)	(49)	(9)	7	16	13	36	14
Total	$35	$(62)	$(12)	$29	$19	$36	$45

(a) Prices provided by other external sources – Reflects information obtained from over-the-counter brokers, industry services, or multiple-party on-line platforms.

(b) Modeled – In the absence of pricing information from external sources, modeled information is derived using valuation models developed by the reporting entity, reflecting when appropriate, option pricing theory, discounted cash flow concepts, valuation adjustments, etc. and may require projection of prices for underlying commodities beyond the period that prices are available from third-party sources. In addition, where external pricing information or market liquidity are limited, such valuations are classified as modeled.

(c) For Utility Operations, there is mark-to-market value in excess of 10 percent of our total mark-to-market value in individual periods beyond 2008. $17 million of this mark-to-market value is in 2009 and $16 million of this mark-to-market value is in 2010.

(d) Amounts exclude Cash Flow Hedges.

The determination of the point at which a market is no longer liquid for placing it in the Modeled category in the preceding table varies by market. The following table reports an estimate of the maximum tenors (contract maturities) of the liquid portion of each energy market.

Maximum Tenor of the Liquid Portion of Risk Management Contracts
As of December 31, 2003

Domestic	Transaction Class	Market/Region	Tenor (in months)
Natural Gas	Futures	NYMEX Henry Hub	72
	Physical Forwards	Gulf Coast, Texas	12
	Swaps	Gas East – Northeast, Mid-continent Gulf Coast, Texas	15
	Swaps	Gas West – Rocky Mountains, West Coast	15
	Exchange Option Volitility	NYMEX/Henry Hub	12
Power	Futures	Power East – PJM	24
	Physical Forwards	Power East – Cinergy	60
	Physical Forwards	Power East – PJM	48
	Physical Forwards	Power East – NYPP	24
	Physical Forwards	Power East – NEPOOL	12
	Physical Forwards	Power East – ERCOT	24
	Physical Forwards	Power East – TVA	48
	Physical Forwards	Power East – Com Ed	24
	Physical Forwards	Power East – Entergy	48
	Physical Forwards	Power West – PV, NP15, SP15, MidC, Mead	60
	Peak Power Volatility (Options)	Cinergy	12
	Peak Power Volatility (Options)	PJM	12
Crude Oil	Swaps	West Texas Intermediate	36
Emissions	Credits	SO2	24
Coal	Physical Forwards	PRB,NYMEX,CSX	24
International			
Power	Forwards and Options	United Kingdom	24
Coal	Forward Purchases and Sales	United Kingdom	15
	Swaps	Europe	36
Freight	Swaps	Europe	24

Cash Flow Hedges Included in Accumulated Other Comprehensive Income (Loss) on the Balance Sheet

We are exposed to market fluctuations in energy commodity prices impacting our power operations. We monitor these risks on our future operations and may employ various commodity instruments such as cash flow hedges to mitigate the impact of these fluctuations on the future cash flows from assets. We do not hedge all commodity price risk.

We employ fair value hedges and cash flow hedges to mitigate changes in interest rates or fair values on short and long-term debt when management deems it necessary. We do not hedge all interest rate risk.

We employ forward contracts as cash flow hedges to lock-in prices on certain transactions which have been denominated in foreign currencies where deemed necessary. International subsidiaries use currency swaps to hedge exchange rate fluctuations of debt denominated in foreign currencies. We do not hedge all foreign currency exposure.

The table provides detail on effective cash flow hedges under SFAS 133 included in the balance sheet. The data in the table will indicate the magnitude of SFAS 133 hedges we have in place (However, given that under SFAS 133 only cash flow hedges are recorded in Accumulated Other Comprehensive Income (AOCI), the table does not provide an all-encompassing picture of our hedging activity). The table further indicates what portions of these hedges are expected to be reclassified into net income in the next 12 months. The table also includes a roll-forward of the AOCI balance sheet account, providing insight into the drivers of the changes (new hedges placed during the period, changes in value of existing hedges and roll off of hedges).

Information on energy merchant activities is presented separately from interest rate, foreign currency risk management activities and other hedging activities. In accordance with GAAP, all amounts are presented net of related income taxes.

Cash Flow Hedges included in Accumulated Other Comprehensive Income (Loss) On the Balance Sheet as of December 31, 2003

	Accumulated Other Comprehensive Income (Loss) After Tax (a)	Portion Expected to be Reclassified to Earnings During the Next 12 Months (b)
	(in millions)	
Power and Gas	$(65)	$(58)
Foreign Currency	(20)	(20)
Interest Rate	(9)	(8)
Total	$(94)	$(86)

Total Accumulated Other Comprehensive Income (Loss) Activity Year Ended December 31, 2003

	Power and Gas	Foreign Currency	Interest Rate	Consolidated
		(in millions)		
Beginning Balance, December 31, 2002	$(3)	$(1)	$(12)	$(16)
Changes in Fair Value (c)	(64)	(19)	4	(79)
Reclassifications from AOCI to Net Income (d)	2	-	(1)	1
Ending Balance, December 31, 2003	$(65)	$(20)	$(9)	$(94)

(a) "Accumulated Other Comprehensive Income (Loss) After Tax" – Gains/losses are net of related income taxes that have not yet been included in the determination of net income; reported as a separate component of shareholders' equity on the balance sheet.

(b) "Portion Expected to be Reclassified to Earnings During the Next 12 Months" – Amount of gains or losses (realized or unrealized) from derivatives used as hedging instruments that have been deferred and are expected to be reclassified into net income during the next 12 months at the time the hedged transaction affects net income.

(c) "Changes in Fair Value" – Changes in the fair value of derivatives designated as cash flow hedges not yet reclassified into net income, pending the hedged items affecting net income. Amounts are reported net of related income taxes.

(d) "Reclassifications from AOCI to Net Income" – Gains or losses from derivatives used as hedging instruments in cash flow hedges that were reclassified into net income during the reporting period. Amounts are reported net of related income taxes above.

Credit Risk

We limit credit risk by assessing creditworthiness of potential counterparties before entering into transactions with them and continue to evaluate their creditworthiness after transactions have been initiated. Only after an entity has met our internal credit rating criteria will we extend unsecured credit. We use Moody's Investor Service, Standard and Poor's and qualitative and quantitative data to independently assess the financial health of counterparties on an ongoing basis. Our independent analysis, in conjunction with the rating agencies' information, is used to determine appropriate risk parameters. We also require cash deposits, letters of credit and parental/affiliate guarantees as security from counterparties depending upon credit quality in our normal course of business.

We have risk management contracts with numerous counterparties. Since open risk management contracts are valued based on changes in market prices of the related commodities, our exposures change daily. We believe that credit exposure with any one counterparty is not material to our financial condition at December 31, 2003. At December 31, 2003, our credit exposure net of credit collateral to sub investment grade counterparties was approximately 16%, expressed in terms of net MTM assets and net receivables. The increase in non-investment grade credit quality was largely due to an increase in coal and freight exposures related to our U.K. investments. As of December 31, 2003, the following table approximates our counterparty credit quality and exposure based on netting across commodities and instruments:

Counterparty Credit Quality:	Exposure Before Credit Collateral	Credit Collateral	Net Exposure	Number of Counterparties > 10%	Net Exposure of Counterparties > 10%
			(in millions)		
Investment Grade	$931	$29	$902	1	$135
Split Rating	47	-	47	1	40
Non-Investment Grade	276	136	140	2	71
No External Ratings:					
Internal Investment Grade	480	5	475	3	207
Internal Non-Investment Grade	185	48	137	2	51
Total	$1,919	$218	$1,701	9	$504

Generation Plant Hedging Information

This table provides information on operating measures regarding the proportion of output of our generation facilities (based on economic availability projections) economically hedged. This information is forward-looking and provided on a prospective basis through December 31, 2006. Please note that this table is a point-in-time estimate, subject to changes in market conditions and our decisions on how to manage operations and risk. "Estimated Plant Output Hedged," represents the portion of megawatt hours of future generation/production for which we have sales commitments or estimated requirement obligations to customers.

Generation Plant Hedging Information
Estimated Next Three Years
As of December 31, 2003

	2004	2005	2006
Estimated Plant Output Hedged	90%	92%	92%

VaR Associated with Risk Management Contracts

We use a risk measurement model, which calculates Value at Risk (VaR) to measure our commodity price risk in the risk management portfolio. The VaR is based on the variance - covariance method using historical prices to estimate volatilities and correlations and assumes a 95% confidence level and a one-day holding period. Based on this VaR analysis, at December 31, 2003, a near term typical change in commodity prices is not expected to have a material effect on our results of operations, cash flows or financial condition.

The following table shows the end, high, average, and low market risk as measured by VaR year-to-date:

VaR Model

December 31, 2003 (in millions)				December 31, 2002 (in millions)			
End	High	Average	Low	End	High	Average	Low
$11	$19	$ 7	$4	$5	$24	$12	$4

The high VaR for 2003 occurred in late February 2003 during a period when natural gas and power prices experienced high levels and extreme volatility. Within a few days, the VaR returned to levels more representative of the average VaR for the year.

Our VaR model results are adjusted using standard statistical treatments to calculate the CCRO VaR reporting metrics listed below.

CCRO VaR Metrics

	December 31, 2003	Average for Year-to-Date 2003	High for Year-to-Date 2003	Low for Year-to-Date 2003
		(in millions)		
95% Confidence Level, Ten-Day Holding Period	$41	$27	$71	$16
99% Confidence Level, One-Day Holding Period	$17	$11	$30	$ 7

We utilize a VaR model to measure interest rate market risk exposure. The interest rate VaR model is based on a Monte Carlo simulation with a 95% confidence level and a one-year holding period. The volatilities and correlations were based on three years of daily prices. The risk of potential loss in fair value attributable to our exposure to interest rates, primarily related to long-term debt with fixed interest rates, was $1.013 billion at December 31, 2003 and $527 million at December 31, 2002. We would not expect to liquidate our entire debt portfolio in a one-year holding period, therefore a near term change in interest rates should not materially affect our results of operations or consolidated financial position.

We are exposed to risk from changes in the market prices of coal and natural gas used to generate electricity where generation is no longer regulated or where existing fuel clauses are suspended or frozen. The protection afforded by fuel clause recovery mechanisms has either been eliminated by the implementation of customer choice in Ohio (effective January 1, 2001) and in the ERCOT area of Texas (effective January 1, 2002) or frozen by a settlement agreement in West Virginia. To the extent the fuel supply of the generating units in these states is not under fixed price long-term contracts we are subject to market price risk. We continue to be protected against market price changes by active fuel clauses in Oklahoma, Arkansas, Louisiana, Kentucky, Virginia and the SPP area of Texas. Fuel clauses are active again in Michigan and Texas, effective January 1, 2004 and March 1, 2004, respectively.

We employ risk management contracts including physical forward purchase and sale contracts, exchange futures and options, over-the-counter options, swaps, and other derivative contracts to offset price risk where appropriate. We engage in risk management of electricity, gas and to a lesser degree other commodities, principally coal and freight. As a result, we are subject to price risk. The amount of risk taken is controlled by risk management operations and our Chief Risk Officer and his staff. When risk management activities exceed certain pre-determined limits, the positions are modified or hedged to reduce the risk to be within the limits unless specifically approved by the Risk Executive Committee.

AMERICAN ELECTRIC POWER COMPANY, INC. AND SUBSIDIARY COMPANIES
CONSOLIDATED STATEMENTS OF OPERATIONS
For the Years Ended December 31, 2003, 2002 and 2001
(in millions, except per-share amounts)

	2003	2002	2001
REVENUES			
Utility Operations	$10,871	$10,446	$10,546
Gas Operations	3,097	2,071	1,797
Other	577	791	410
TOTAL	14,545	13,308	12,753
EXPENSES			
Fuel for Electric Generation	3,053	2,577	3,225
Purchased Electricity for Resale	707	532	296
Purchased Gas for Resale	2,850	1,946	1,443
Maintenance and Other Operation	3,673	4,065	3,666
Asset Impairments and Other Related Charges	650	318	-
Depreciation and Amortization	1,299	1,348	1,233
Taxes Other Than Income Taxes	681	718	667
TOTAL	12,913	11,504	10,530
OPERATING INCOME	1,632	1,804	2,223
Other Income	387	461	371
INTEREST AND OTHER CHARGES			
Investment Value Losses	70	321	-
Other Expenses	227	323	225
Interest	814	775	833
Preferred Stock Dividend Requirements of Subsidiaries	9	11	10
Minority Interest in Finance Subsidiary	19	35	13
TOTAL	1,139	1,465	1,081
INCOME BEFORE INCOME TAXES	880	800	1,513
Income Taxes	358	315	553
INCOME BEFORE DISCONTINUED OPERATIONS, EXTRAORDINARY ITEMS AND CUMULATIVE EFFECT	522	485	960
DISCONTINUED OPERATIONS (Net of Tax)	(605)	(654)	41
EXTRAORDINARY LOSS (Net of Tax)	-	-	(48)
CUMULATIVE EFFECT OF ACCOUNTING CHANGES (Net of Tax)			
Goodwill and Other Intangible Assets	-	(350)	18
Accounting for Risk Management Contracts	(49)	-	-
Asset Retirement Obligations	242	-	-
NET INCOME (LOSS)	$110	$(519)	$971
AVERAGE NUMBER OF SHARES OUTSTANDING	385	332	322
EARNINGS (LOSS) PER SHARE			
Income Before Discontinued Operations, Extraordinary Items and Cumulative Effect of Accounting Changes	$1.35	$1.46	$2.98
Discontinued Operations	(1.57)	(1.97)	0.13
Extraordinary Loss	-	-	(0.16)
Cumulative Effect of Accounting Changes	0.51	(1.06)	0.06
TOTAL EARNINGS PER SHARE (BASIC AND DILUTIVE)	$0.29	$(1.57)	$3.01
CASH DIVIDENDS PAID PER SHARE	$1.65	$2.40	$2.40

See Notes to Consolidated Financial Statements.

AMERICAN ELECTRIC POWER COMPANY, INC. AND SUBSIDIARY COMPANIES
CONSOLIDATED BALANCE SHEETS
ASSETS
December 31, 2003 and 2002

	2003	2002
	(in millions)	
CURRENT ASSETS		
Cash and Cash Equivalents	$1,182	$1,199
Accounts Receivable:		
Customers	1,155	1,553
Accrued Unbilled Revenues	596	551
Miscellaneous	83	93
Allowance for Uncollectible Accounts	(124)	(108)
Total Receivables	1,710	2,089
Fuel, Materials and Supplies	991	938
Risk Management Assets	766	850
Margin Deposits	119	110
Other	129	132
TOTAL	4,897	5,318
PROPERTY, PLANT AND EQUIPMENT		
Electric:		
Production	15,112	13,678
Transmission	6,130	5,866
Distribution	9,902	9,573
Other (including gas, coal mining and nuclear fuel)	3,584	3,656
Construction Work in Progress	1,305	1,354
TOTAL	36,033	34,127
Less: Accumulated Depreciation and Amortization	14,004	13,539
TOTAL-NET	22,029	20,588
OTHER NON-CURRENT ASSETS		
Regulatory Assets	3,548	2,688
Securitized Transition Assets	689	735
Spent Nuclear Fuel and Decommissioning Trusts	982	871
Investments in Power and Distribution Projects	212	283
Goodwill	78	241
Long-term Risk Management Assets	494	758
Other	733	792
TOTAL	6,736	6,368
Assets Held for Sale	3,082	3,601
Assets of Discontinued Operations	-	15
TOTAL ASSETS	$36,744	$35,890

See Notes to Consolidated Financial Statements.

AMERICAN ELECTRIC POWER COMPANY, INC. AND SUBSIDIARY COMPANIES
CONSOLIDATED BALANCE SHEETS
LIABILITIES AND SHAREHOLDERS' EQUITY
December 31, 2003 and 2002

	2003	2002
	(in millions)	
CURRENT LIABILITIES		
Accounts Payable	$1,337	$1,892
Short-term Debt	326	2,739
Long-term Debt Due Within One Year*	1,779	1,327
Risk Management Liabilities	631	961
Accrued Taxes	620	556
Accrued Interest	207	181
Customer Deposits	379	186
Other	703	814
TOTAL	5,982	8,656
NON-CURRENT LIABILITIES		
Long-term Debt*	12,322	8,863
Long-term Risk Management Liabilities	335	435
Deferred Income Taxes	3,957	3,916
Regulatory Liabilities and Deferred Investment Tax Credits	2,259	939
Asset Retirement Obligations and Nuclear Decommissioning Trusts	651	638
Employee Benefits and Pension Obligations	667	987
Deferred Gain on Sale and Leaseback – Rockport Plant Unit 2	176	185
Cumulative Preferred Stocks of Subsidiaries Subject to Mandatory Redemption	76	-
Deferred Credits and Other	508	1,691
TOTAL	20,951	17,654
Liabilities Held for Sale	1,876	1,279
Liabilities of Discontinued Operations	-	12
TOTAL LIABILITIES	28,809	27,601
Cumulative Preferred Stocks of Subsidiaries not Subject to Mandatory Redemption	61	-
Certain Subsidiary Obligated, Mandatorily Redeemable, Preferred Securities of Subsidiary Trusts Holding Solely Junior Subordinated Debentures of Such Subsidiaries	-	321
Minority Interest in Finance Subsidiary	-	759
Cumulative Preferred Stocks of Subsidiaries	-	145
Commitments and Contingencies		
COMMON SHAREHOLDERS' EQUITY		
Common Stock-Par Value $6.50:		
2003 / 2002		
Shares Authorized . . . . 600,000,000 / 600,000,000		
Shares Issued . . . . 404,016,413 / 347,835,212		
(8,999,992 shares were held in treasury at December 31, 2003 and 2002)	2,626	2,261
Paid-in Capital	4,184	3,413
Retained Earnings	1,490	1,999
Accumulated Other Comprehensive Income (Loss)	(426)	(609)
TOTAL	7,874	7,064
TOTAL LIABILITIES AND SHAREHOLDERS' EQUITY	$36,744	$35,890

* See Accompanying Schedules

See Notes to Consolidated Financial Statements.

AMERICAN ELECTRIC POWER COMPANY, INC. AND SUBSIDIARY COMPANIES
CONSOLIDATED STATEMENTS OF CASH FLOWS
For the Years Ended December 31, 2003, 2002 and 2001

	2003	2002 (in millions)	2001
OPERATING ACTIVITIES			
Net Income (Loss)	$110	$(519)	$971
Plus: Discontinued Operations	605	654	(41)
Income from Continuing Operations	715	135	930
Adjustments for Noncash Items:			
Depreciation and Amortization	1,299	1,375	1,267
Deferred Income Taxes	163	63	151
Deferred Investment Tax Credits	(33)	(31)	(29)
Pension and Postemployment Benefits Reserves	(74)	39	(234)
Cumulative Effect of Accounting Changes	(193)	350	(18)
Asset and Investment Value Impairments and Other Related Charges	720	639	-
Extraordinary Loss	-	-	48
Amortization of Deferred Property Taxes	(2)	(16)	43
Amortization of Cook Plant Restart Costs	40	40	40
Mark to Market of Risk Management Contracts	(122)	275	(294)
Changes in Certain Current Assets and Liabilities:			
Accounts Receivable, net	363	(238)	1,769
Fuel, Materials and Supplies	(71)	(102)	(82)
Accounts Payable	(632)	(21)	(469)
Taxes Accrued	87	(222)	(150)
Over/Under Fuel Recovery	138	13	340
Change in Other Assets	(162)	(78)	(171)
Change in Other Liabilities	72	(154)	(323)
Net Cash Flows From Operating Activities	2,308	2,067	2,818
INVESTING ACTIVITIES			
Construction Expenditures	(1,358)	(1,685)	(1,646)
Business Acquisitions	-	-	(1,269)
Investment in Discontinued Operations, net	(615)	-	(983)
Proceeds from Sale of Assets	82	1,263	648
Other	3	44	(42)
Net Cash Flows Used For Investing Activities	(1,888)	(378)	(3,292)
FINANCING ACTIVITIES			
Issuance of Common Stock	1,142	656	11
Issuance of Long-term Debt	4,761	2,893	2,787
Issuance of Minority Interest	-	-	744
Issuance of Equity Unit Senior Notes	-	334	-
Change in Short-term Debt, net	(2,781)	(1,248)	(778)
Retirement of Long-term Debt	(2,707)	(2,513)	(1,549)
Retirement of Preferred Stock	(9)	(10)	(5)
Retirement of Minority Interest	(225)	-	-
Dividends Paid on Common Stock	(618)	(793)	(773)
Net Cash Flows From (Used For) Financing Activities	(437)	(681)	437
Effect of Exchange Rate Change on Cash	-	(3)	(1)
Net Increase (Decrease) in Cash and Cash Equivalents	(17)	1,005	(38)
Cash and Cash Equivalents at Beginning of Period	1,199	194	232
Cash and Cash Equivalents at End of Period	$1,182	$1,199	$194
Net Increase (Decrease) in Cash and Cash Equivalents from Discontinued Operations	$(10)	$(116)	$29
Cash and Cash Equivalents from Discontinued Operations – Beginning of Period	23	139	110
Cash and Cash Equivalents from Discontinued Operations – End of Period	$13	$23	$139

See Notes to Consolidated Financial Statements.

AMERICAN ELECTRIC POWER COMPANY, INC. AND SUBSIDIARY COMPANIES
CONSOLIDATED STATEMENTS OF COMMON SHAREHOLDERS' EQUITY AND COMPREHENSIVE INCOME (LOSS)
(in millions)

	Common Stock Shares	Common Stock Amount	Paid-in Capital	Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Total
DECEMBER 31, 2000	331	$2,152	$2,915	$3,090	$(103)	$8,054
Issuance of Common Stock		1	9			10
Common Stock Dividends				(773)		(773)
Other			(18)	8		(10)
TOTAL						7,281
COMPREHENSIVE INCOME (LOSS)						
Other Comprehensive Income (Loss), Net of Taxes:						
Foreign Currency Translation Adjustments					(14)	(14)
Unrealized Losses on Cash Flow Hedges					(3)	(3)
Minimum Pension Liability					(6)	(6)
NET INCOME				971		971
TOTAL COMPREHENSIVE INCOME						948
DECEMBER 31, 2001	331	$2,153	$2,906	$3,296	$(126)	$8,229
Issuance of Common Stock	17	108	568			676
Common Stock Dividends				(793)		(793)
Common Stock Expense			(30)			(30)
Other			(31)	15		(16)
TOTAL						8,066
COMPREHENSIVE INCOME (LOSS)						
Other Comprehensive Income (Loss), Net of Taxes:						
Foreign Currency Translation Adjustments					117	117
Unrealized Losses on Cash Flow Hedges					(13)	(13)
Unrealized Losses on Securities Available for Sale					(2)	(2)
Minimum Pension Liability					(585)	(585)
NET LOSS				(519)		(519)
TOTAL COMPREHENSIVE INCOME (LOSS)						(1,002)
DECEMBER 31, 2002	348	$2,261	$3,413	$1,999	$(609)	$7,064
Issuance of Common Stock	56	365	812			1,177
Common Stock Dividends				(618)		(618)
Common Stock Expense			(35)			(35)
Other			(6)	(1)		(7)
TOTAL						7,581
COMPREHENSIVE INCOME (LOSS)						
Other Comprehensive Income (Loss), Net of Taxes:						
Foreign Currency Translation Adjustments					106	106
Unrealized Losses on Cash Flow Hedges					(78)	(78)
Unrealized Gains on Securities Available for Sale					1	1
Minimum Pension Liability					154	154
NET INCOME				110		110
TOTAL COMPREHENSIVE INCOME						293
DECEMBER 31, 2003	404	$2,626	$4,184	$1,490	$(426)	$7,874

See Notes to Consolidated Financial Statements.

AMERICAN ELECTRIC POWER COMPANY, INC. AND SUBSIDIARY COMPANIES
SCHEDULE OF CONSOLIDATED CUMULATIVE PREFERRED STOCKS OF SUBSIDIARIES
December 31, 2003 and 2002

	December 31, 2003			
	Call Price Per Share(a)	Shares Authorized(b)	Shares Outstanding(d)	Amount (in millions)
Not Subject to Mandatory Redemption:				
4.00% - 5.00%	\$102-\$110	1,525,903	607,940	\$61
Subject to Mandatory Redemption:				
5.90% - 5.92% (c)	\$100	1,950,000	278,100	28
6.25% - 6.875% (c)	\$100	1,650,000	482,450	48
Total Subject to Mandatory Redemption (c)				76
Total Preferred Stock				\$137 (e)

	December 31, 2002			
	Call Price Per Share(a)	Shares Authorized(b)	Shares Outstanding(d)	Amount (in millions)
Not Subject to Mandatory Redemption:				
4.00% - 5.00%	\$102-\$110	1,525,903	608,150	\$61
Subject to Mandatory Redemption:				
5.90% - 5.92% (c)	\$100	1,950,000	333,100	33
6.02% - 6.875% (c)	\$100	1,650,000	513,450	51
Total Subject to Mandatory Redemption (c)				84
Total Preferred Stock				\$145

(a) At the option of the subsidiary, the shares may be redeemed at the call price plus accrued dividends. The involuntary liquidation preference is \$100 per share for all outstanding shares.

(b) As of December 31, 2003, the subsidiaries had 13,780,352 shares of \$100 par value preferred stock, 22,200,000 shares of \$25 par value preferred stock and 7,768,561 shares of no par value preferred stock that were authorized but unissued.

(c) Shares outstanding and related amounts are stated net of applicable retirements through sinking funds (generally at par) and reacquisitions of shares in anticipation of future requirements. The subsidiaries reacquired enough shares in 1997 to meet all sinking fund requirements on certain series until 2008 and on certain series until 2009 when all remaining outstanding shares must be redeemed.

(d) The number of shares of preferred stock redeemed is 86,210 shares in 2003, 106,458 shares in 2002 and 50,000 shares in 2001.

(e) Due to the implementation of SFAS 150 in July 2003, Cumulative Preferred Stocks of Subsidiaries is no longer presented as one line item on the balance sheet. SFAS 150 has required us to present Cumulative Preferred Stocks of Subsidiaries Subject to Mandatory Redemption as a liability. Cumulative Preferred Stocks of Subsidiaries Not Subject to Mandatory Redemption will continue to be reported on the balance sheet in the "mezzanine" section.

AMERICAN ELECTRIC POWER COMPANY, INC. AND SUBSIDIARY COMPANIES
SCHEDULE OF CONSOLIDATED LONG-TERM DEBT
December 31, 2003 and 2002

Maturity	Weighted Average Interest Rate December 31, 2003	Interest Rates at December 31, 2003	Interest Rates at December 31, 2002	December 31, 2003 (in millions)	December 31, 2002 (in millions)
FIRST MORTGAGE BONDS (a)					
2003-2004	7.40%	6.125%-7.85%	6.00%-7.85%	$231	$648
2005-2008	6.90%	6.20%-8.00%	6.20%-8.00%	463	463
2022-2025	7.28%	6.875%-8.00%	6.875%-8.70%	246	773
INSTALLMENT PURCHASE CONTRACTS (b)(f)					
2003-2009	3.74%	2.15%-6.90%	3.75%-7.70%	395	396
2011-2030	4.92%	1.10%-8.20%	1.35%-8.20%	1,631	1,284
NOTES PAYABLE (c)(f)					
2003-2017	5.20%	1.537%-15.45%	6.225%-9.60%	1,518	214
SENIOR UNSECURED NOTES					
2003-2005	5.10%	2.43%-7.45%	2.12%-7.45%	1,359	1,834
2006-2015	5.49%	3.60%-6.91%	4.31%-6.91%	4,873	2,295
2032-2038	6.41%	5.625%-7.375%	6.00%-7.375%	1,765	690
JUNIOR DEBENTURES					
2025-2038	-	-	7.60%-8.72%	-	205
SECURITIZATION BONDS					
2005-2016	5.53%	3.54%-6.25%	3.54%-6.25%	746	797
NOTES PAYABLE TO TRUST (d)					
2037-2043	7.06%	5.25-8.00%	-	331	-
EQUITY UNIT SENIOR NOTES (e)					
2007	5.75%	5.75%	5.75%	345	345
OTHER LONG-TERM DEBT (g)				247	247
Equity Unit Contract Adjustment Payments				19	31
Unamortized Discount (net)				(68)	(32)
Total Long-term Debt Outstanding				14,101	10,190
Less Portion Due Within One Year				1,779	1,327
Long-term Portion				$12,322	$8,863

(a) First mortgage bonds are secured by first mortgage liens on electric property, plant and equipment.
(b) For certain series of installment purchase contracts, interest rates are subject to periodic adjustment. Certain series will be purchased on demand at periodic interest adjustment dates. Letters of credit from banks and standby bond purchase agreements support certain series.
(c) Notes payable represent outstanding promissory notes issued under term loan agreements and revolving credit agreements with a number of banks and other financial institutions. At expiration, all notes then issued and outstanding are due and payable. Interest rates are both fixed and variable. Variable rates generally relate to specified short-term interest rates.
(d) Notes Payable to Trust is a result of a deconsolidation of TCC, PSO and SWEPCo's trusts effective July 1, 2003 due to the implementation of FIN 46. See Notes 2 and 17 for further information.
(e) In May 2005, the interest rate on these Equity Unit Senior Notes can be reset through a remarketing.
(f) Installment Purchase Contracts and Notes Payable include $257 million and $185 million, respectively, due to the implementation of FIN 46 (see Note 2). Notes Payable includes $496 million of a merchant power generation facility which was consolidated as of December 31, 2003 (see Notes 10 and 16).
(g) Other long-term debt consists of a liability along with accrued interest for disposal of spent nuclear fuel (see Note 7) and a financing obligation under a sale and leaseback agreement.

LONG-TERM DEBT OUTSTANDING AT DECEMBER 31, 2003 IS PAYABLE AS FOLLOWS:

	2004	2005	2006	2007 (in millions)	2008	Later Years	TOTAL
Principal Amount	$1,779	$1,273	$2,187	$1,124	$587	$7,200	$14,150
Equity Unit Contract Adjustment Payments							19
Unamortized Discount							(68)
							$14,101

AMERICAN ELECTRIC POWER, INC. AND SUBSIDIARY COMPANIES
INDEX TO NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

1. ORGANIZATION AND SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

ORGANIZATION

Our principal business conducted by our eleven domestic electric utility operating companies is the generation, transmission and distribution of electric power. These companies are subject to regulation by the FERC under the Federal Power Act and maintain accounts in accordance with FERC and other regulatory guidelines. These companies are subject to further regulation with regard to rates and other matters by state regulatory commissions.

We also engage in wholesale electricity, natural gas and other commodity marketing and risk management activities in the United States and Europe. In addition, our domestic operations include non-regulated independent power and cogeneration facilities, coal mining and intra-state natural gas operations in Louisiana and Texas.

International operations include the generation and supply of power in the United Kingdom, and to a lesser extent in Mexico, Australia and China. These operations are either wholly-owned or partially-owned by our various subsidiaries.

We also conduct domestic barging operations, provide various energy related services and furnish communications-related services domestically.

During 2003 we announced plans to significantly restructure and dispose of many of our non-regulated operations. See Note 10 for a discussion of the impacts of these plans on our organization.

Certain previously reported amounts have been reclassified to conform to current classifications with no effect on net income or shareholders' equity.

SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

Rate Regulation

We are subject to regulation by the SEC under the PUHCA. The rates charged by the domestic utility subsidiaries are approved by the FERC and the state utility commissions. The FERC regulates wholesale electricity operations and transmission rates and the state commissions regulate retail rates. The prices charged by foreign subsidiaries located in China and Mexico are regulated by the authorities of those countries and are generally subject to price controls.

Principles of Consolidation

Our consolidated financial statements include AEP and its wholly-owned and majority-owned subsidiaries consolidated with their wholly-owned subsidiaries or substantially controlled variable interest entities. Intercompany items are eliminated in consolidation. Equity investments not substantially controlled that are 50% or less owned are accounted for using the equity method of accounting; equity earnings are included in Other Income. We also have generating units that are jointly owned with unaffiliated companies. The proportionate share of the operating costs associated with such facilities is included in our Consolidated Statements of Operations and the investments are reflected in our Consolidated Balance Sheets.

Accounting for the Effects of Cost-Based Regulation

As the owner of cost-based rate-regulated electric public utility companies, our consolidated financial statements reflect the actions of regulators that result in the recognition of revenues and expenses in different time periods than enterprises that are not rate-regulated. Regulatory assets (deferred expenses) and regulatory liabilities (future revenue reductions or refunds) are recorded to reflect the economic effects of regulation by matching expenses with their recovery through regulated revenues. We discontinued the application of SFAS 71 for the generation portion of our business as follows: in Ohio by OPCo and CSPCo in September 2000, in Virginia and West Virginia by APCo in June

2000, in Texas by TCC, TNC, and SWEPCo in September 1999, in Arkansas by SWEPCo in September 1999 and in the FERC jurisdiction for TNC in December 2003. During 2003, APCo reapplied SFAS 71 for West Virginia and SWEPCo reapplied SFAS 71 for Arkansas.

Use of Estimates

The preparation of these financial statements in conformity with accounting principles generally accepted in the United States of America requires management to make estimates and assumptions that affect the amounts reported in the financial statements and accompanying notes. These estimates include but are not limited to inventory valuation, allowance for doubtful accounts, goodwill and intangible asset impairment, unbilled electricity revenue, values of long-term energy contracts, the effects of regulation, long-lived asset recovery, the effects of contingencies and certain assumptions made in accounting for pension benefits. Actual results could differ from those estimates.

Property, Plant and Equipment

Domestic electric utility property, plant and equipment are stated at original purchase cost. Property, plant and equipment of the non-regulated operations and other investments are stated at their fair market value at acquisition (or as adjusted for any applicable impairments) plus the original cost of property acquired or constructed since the acquisition, less disposals. Additions, major replacements and betterments are added to the plant accounts. For cost-based rate-regulated operations, retirements from the plant accounts and associated removal costs, net of salvage, are deducted from accumulated depreciation. For non-regulated operations, retirements from the plant accounts and associated salvage are deducted from accumulated depreciation and removal costs are charged to expense. The costs of labor, materials and overhead incurred to operate and maintain plant are included in operating expenses. Assets are tested for impairment as required under SFAS 144 (see Note 10).

Allowance for Funds Used During Construction (AFUDC) and Interest Capitalization

AFUDC represents the estimated cost of borrowed and equity funds used to finance construction projects that is capitalized and recovered through depreciation over the service life of domestic regulated electric utility plant. For non-regulated operations, interest is capitalized during construction in accordance with SFAS 34, "Capitalization of Interest Costs." Capitalized interest is also recorded for domestic generating assets in Ohio, Texas and Virginia, effective with the discontinuance of SFAS 71 regulatory accounting. The amounts of AFUDC and interest capitalized were not material in 2003, 2002 and 2001.

Depreciation, Depletion and Amortization

We provide for depreciation of property, plant and equipment on a straight-line basis over the estimated useful lives of property, excluding coal-mining properties, generally using composite rates by functional class as follows:

Functional Class of Property	Annual Composite Depreciation Rates Ranges		
	2003	2002	2001
Production:			
Steam-Nuclear	2.5% to 3.4%	2.5% to 3.4%	2.5% to 3.4%
Steam-Fossil-Fired	2.3% to 4.6%	2.6% to 4.5%	2.5% to 4.5%
Hydroelectric-Conventional and Pumped Storage	1.9% to 3.4%	1.9% to 3.4%	1.9% to 3.4%
Transmission	1.7% to 2.8%	1.7% to 3.0%	1.7% to 3.1%
Distribution	3.3% to 4.2%	3.3% to 4.2%	2.7% to 4.2%
Other	1.8% to 16.7%	1.8% to 9.9%	1.8% to 15.0%

We provide for depreciation, depletion and amortization of coal-mining assets over each asset's estimated useful life or the estimated life of each mine, whichever is shorter, using the straight-line method for mining structures and equipment. We use either the straight-line method or the units-of-production method to amortize mine development costs and deplete coal rights based on estimated recoverable tonnages. We include these costs in the cost of coal charged to fuel expense. Average amortization rates for coal rights and mine development costs were $0.25 per ton in 2003, $0.32 per ton in 2002 and $2.06 per ton in 2001. In 2002, certain coal-mining assets were impaired by $60 million leading to the decline in amortization rates in 2003. In 2001, an AEP subsidiary sold coal mines in Ohio and West Virginia leading to the decline in amortization rates in 2002.

Valuation of Non-Derivative Financial Instruments

The book values of Cash and Cash Equivalents, Accounts Receivable, Short-term Debt and Accounts Payable approximate fair value because of the short-term maturity of these instruments. The book value of the pre-April 1983 spent nuclear fuel disposal liability approximates the best estimate of its fair value.

Cash and Cash Equivalents

Cash and cash equivalents include temporary cash investments with original maturities of three months or less.

Inventory

Except for PSO, TCC and TNC, the regulated domestic utility companies value fossil fuel inventories using a weighted average cost method. PSO, TCC and TNC, utilize the LIFO method to value fossil fuel inventories. For those domestic utilities whose generation is unregulated, inventory of coal and oil is carried at the lower of cost or market. Coal mine inventories are also carried at the lower of cost or market. Materials and supplies inventories are carried at average cost. Non-trading gas inventory is carried at the lower of cost or market. During 2003 a fair value hedging strategy was implemented for certain non-trading gas and coal inventory. Changes in the fair value of hedged inventory are recorded to the extent offsetting hedges are designated against that inventory.

Accounts Receivable

Customer accounts receivable primarily includes receivables from wholesale and retail energy customers, receivables from energy contract counterparties related to our risk management activities and customer receivables primarily related to other revenue-generating activities.

We recognize revenue from electric power and gas sales when we deliver power or gas to our customers. To the extent that deliveries have occurred but a bill has not been issued, we accrue and recognize, as Accrued Unbilled Revenues, an estimate of the revenues for energy delivered since the latest billings.

AEP Credit, Inc. factors accounts receivable for certain registrant subsidiaries. These subsidiaries include CSPCo, I&M, KPCo, OPCo, PSO, SWEPCo and a portion of APCo. Since APCo does not have regulatory authority to sell accounts receivable in all of its regulatory jurisdictions, only a portion of APCo's accounts receivable are sold to AEP Credit. AEP Credit has a sale of receivables agreement with banks and commercial paper conduits. Under the sale of receivables agreement, AEP Credit sells an interest in the receivables it acquires to the commercial paper conduits and banks and receives cash. This transaction constitutes a sale of receivables in accordance with SFAS 140, allowing the receivables to be taken off of the company's balance sheet. See Note 17 "Financing Activities" for further details.

Foreign Currency Translation

The financial statements of subsidiaries outside the U.S. which are included in our consolidated financial statements are measured using the local currency as the functional currency and translated into U.S. dollars in accordance with SFAS 52 "Foreign Currency Translation." Although the effects of foreign currency fluctuations are mitigated by the fact that expenses of foreign subsidiaries are generally incurred in the same currencies in which sales are generated, the reported results of operations of our foreign subsidiaries are affected by changes in foreign currency exchange rates and, as compared to prior periods, will be higher or lower depending upon a weakening or strengthening of the U.S. dollar. Revenues and expenses are translated at monthly average foreign currency exchange rates throughout the year. Assets and liabilities are translated into U.S. dollars at year-end foreign currency exchange rates. Accordingly, our consolidated common shareholders' equity will fluctuate depending on the relative strengthening or weakening of the U.S. dollar versus relevant foreign currencies. Currency translation gain and loss adjustments are recorded in shareholders' equity as Accumulated Other Comprehensive Income (Loss). The impact of the changes in exchange rates on cash, resulting from the translation of items at different exchange rates, is shown on our Consolidated

Statements of Cash Flows in Effect of Exchange Rate Change on Cash. Actual currency transaction gains and losses are recorded in income when they occur.

Deferred Fuel Costs

The cost of fuel consumed is charged to expense when the fuel is burned. Where applicable under governing state regulatory commission retail rate orders, fuel cost over-recoveries (the excess of fuel revenues billed to ratepayers over fuel costs incurred) are deferred as regulatory liabilities and under-recoveries (the excess of fuel costs incurred over fuel revenues billed to ratepayers) are deferred as regulatory assets. These deferrals are amortized when refunded or billed to customers in later months with the regulator's review and approval. The amounts of an over-recovery or under-recovery can also be affected by actions of regulators. When these actions become probable we adjust our deferrals to recognize these probable outcomes. The amount of under-recovered fuel costs deferred under fuel clauses as a regulatory asset was $51 million at December 31, 2003 and $148 million at December 31, 2002. The amount of over-recovered fuel costs deferred under fuel clauses as a regulatory liability was $132 million at December 31, 2003 and $90 million at December 31, 2002. See Note 5 "Effects of Regulation" for further information.

In general, changes in fuel costs in Kentucky for KPCo, the SPP area of Texas, Louisiana and Arkansas for SWEPCo, Oklahoma for PSO and Virginia for APCo are timely reflected in rates through the fuel cost adjustment clauses in place in those states. Where fuel clauses have been eliminated due to the transition to market pricing, (Ohio effective January 1, 2001 and in the Texas ERCOT area effective January 1, 2002) changes in fuel costs impact earnings. In other state jurisdictions, (Indiana, Michigan and West Virginia) where fuel clauses have been frozen or suspended for a period of years, fuel cost changes have also impacted earnings. The Michigan fuel clause suspension ended December 31, 2003, and the Indiana freeze is scheduled to end on March 1, 2004. Changes in fuel costs also impact earnings for certain of our Independent Power Producer generating units that do not have long-term contracts for their fuel supply. See Note 4, "Rate Matters" and Note 6, "Customer Choice and Industry Restructuring" for further information about fuel recovery.

Revenue Recognition

Regulatory Accounting

Our consolidated financial statements reflect the actions of regulators that can result in the recognition of revenues and expenses in different time periods than enterprises that are not rate-regulated. Regulatory assets (deferred expenses to be recovered in the future) and regulatory liabilities (deferred future revenue reductions or refunds) are recorded to reflect the economic effects of regulation by matching expenses with their recovery through regulated revenues in the same accounting period and by matching income with its passage to customers through regulated revenues in the same accounting period. Regulatory liabilities or regulatory assets are also recorded for unrealized gains or losses that occur due to changes in the fair value of physical and financial contracts that are derivatives and that are subject to the regulated ratemaking process.

When regulatory assets are probable of recovery through regulated rates, we record them as assets on the balance sheet. We test for probability of recovery whenever new events occur, for example, issuance of a regulatory commission order or passage of new legislation. If it is determined that recovery of a regulatory asset is no longer probable, we write off that regulatory asset as a charge against earnings. A write-off of regulatory assets may also reduce future cash flows since there may be no recovery through regulated rates.

Traditional Electricity Supply and Delivery Activities

Revenues are recognized on the accrual or settlement basis for normal retail and wholesale electricity supply sales and electricity transmission and distribution delivery services. The revenues are recognized in our statement of operations when the energy is delivered to the customer and include unbilled as well as billed amounts. In general, expenses are recorded when purchased electricity is received and when expenses are incurred.

Domestic Gas Pipeline and Storage Activities

Revenues are recognized from domestic gas pipeline and storage services when gas is delivered to contractual meter points or when services are provided, with the exception of certain physical forward gas purchase and sale contracts that are derivatives and that are accounted for using mark-to-market accounting (Resale Gas Contracts).

Energy Marketing and Risk Management Activities

We engage in wholesale electricity, natural gas and coal marketing and risk management activities. Effective in October 2002, these activities were focused on wholesale markets where we own assets. Our activities include the purchase and sale of energy under forward contracts at fixed and variable prices and the buying and selling of financial energy contracts which include exchange traded futures and options, and over-the-counter options and swaps. Prior to October 2002, we recorded wholesale marketing and risk management activities using the mark-to-market method of accounting.

In October 2002, EITF 02-3 precluded mark-to-market accounting for risk management contracts that were not derivatives pursuant to SFAS 133. We implemented this standard for all non-derivative wholesale and risk management transactions occurring on or after October 25, 2002. For non-derivative risk management transactions entered into prior to October 25, 2002, we implemented this standard on January 1, 2003 and reported the effects of implementation as a cumulative effect of an accounting change.

After January 1, 2003, we use mark-to-market accounting for wholesale marketing and risk management transactions that are derivatives unless the derivative is designated for hedge accounting or the normal purchase and sale exemption. Revenues and expenses are recognized from wholesale marketing and risk management transactions that are not derivatives when the commodity is delivered.

See discussion of EITF 02-3 and Rescission of EITF 98-10 in Note 2.

Accounting for Derivative Instruments

We use the mark-to-market method of accounting for derivative contracts. Unrealized gains and losses prior to settlement, resulting from revaluation of these contracts to fair value during the period, are recognized currently. When the derivative contracts are settled and gains and losses are realized, the previously recorded unrealized gains and losses from mark-to-market valuations are reversed.

Certain derivative instruments are designated as a hedge of a forecasted transaction or future cash flow (cash flow hedge) or as a hedge of a recognized asset, liability or firm commitment (fair value hedge). The gains or losses on derivatives designated as fair value hedges are recognized in Revenues in the Consolidated Statement of Operations in the period of change together with the offsetting losses or gains on the hedged item attributable to the risks being hedged. For derivatives designated as cash flow hedges, the effective portion of the derivative's gain or loss is initially reported as a component of Accumulated Other Comprehensive Income and subsequently reclassified into Revenues in the Consolidated Statement of Operations when the forecasted transaction affects earnings. The ineffective portion of the gain or loss is recognized in Revenues in the Consolidated Statement of Operations immediately (see Note 14).

The fair values of derivative instruments accounted for using mark-to-market accounting or hedge accounting are based on exchange prices and broker quotes. If a quoted market price is not available, the estimate of fair value is based on the best information available including valuation models that estimate future energy prices based on existing market and broker quotes and supply and demand market data and assumptions. The fair values determined are reduced by the appropriate valuation adjustments for items such as discounting, liquidity and credit quality. Credit risk is the risk that the counterparty to the contract will fail to perform or fail to pay amounts due. Liquidity risk represents the risk that imperfections in the market will cause the price to be less than or more than what the price should be based purely on supply and demand. There are inherent risks related to the underlying assumptions in models used to fair value open long-term risk management contracts. We have independent controls to evaluate the reasonableness of our valuation models. However, energy markets, especially electricity markets, are imperfect and volatile. Unforeseen events can and will cause reasonable price curves to differ from actual prices throughout a contract's term and at the time a contract settles. Therefore, there could be significant adverse or favorable effects on future results of operations and cash flows if market prices are not consistent with our approach at estimating current market consensus for forward prices in the current period. This is particularly true for long-term contracts.

We recognize all derivative instruments at fair value in our Consolidated Balance Sheets as either "Risk Management Assets" or "Risk Management Liabilities." We do not consider contracts that have been elected normal purchase or normal sale under SFAS 133 to be derivatives. Unrealized and realized gains and losses on all derivative instruments are ultimately included in Revenues in the Consolidated Statement of Operations on a net basis, with the exception of physically settled Resale Gas Contracts for the purchase of natural gas. The unrealized and realized gains and losses on these Resale Gas Contracts are presented as Purchased Gas for Resale in the Consolidated Statement of Operations.

Construction Projects for Outside Parties

Our entities engage in construction projects for outside parties that are accounted for on the percentage-of-completion method of revenue recognition. This method recognizes revenue in proportion to costs incurred compared to total estimated costs.

Debt Instrument Hedging and Related Activities

In order to mitigate the risks of market price and interest rate fluctuations, we enter into contracts to manage the exposure to unfavorable changes in the cost of debt to be issued. These anticipatory hedges are entered into in order to manage the change in interest rates between the time a debt offering is initiated and the issuance of the debt (usually a period of 60 days). Gains or losses from these transactions are deferred and amortized over the life of the debt issuance with the amortization included in interest charges. There were no such forward contracts outstanding at December 31, 2003 or 2002.

Maintenance

Maintenance costs are expensed as incurred. If it becomes probable that we will recover specifically incurred costs through future rates a regulatory asset is established to match the expensing of maintenance costs with their recovery in cost-based regulated revenues.

Other Income and Other Expenses

Non-operational revenue including the nonregulated business activities of our utilities, equity earnings of non-consolidated subsidiaries, gains on dispositions of property, interest and dividends, AFUDC and miscellaneous income, are reported in Other Income. Non-operational expenses including nonregulated business activities of our utilities, losses on dispositions of property, miscellaneous amortization, donations and various other non-operating and miscellaneous expenses, are reported in Other Expenses.

AEP Consolidated Other Income and Deductions:

	2003	December 31, 2002 (in millions)	2001
Other Income:			
Equity Earnings (Loss)	$10	$(15)	$30
Non-operational Revenue	129	201	184
Interest	42	26	48
Gain on Sale of Frontera	-	-	73
Gain on Sale of REPs (Mutual Energy Companies)	39	129	-
Other	167	120	36
Total Other Income	$387	$461	$371
Other Expenses:			
Property Taxes	$20	$20	$15
Non-operational Expenses	112	179	76
Fiber Optic and Datapult Exit Costs	-	-	49
Provision for Loss - Airplane	-	-	14
Other	95	124	71
Total Other Expenses	$227	$323	$225

Income Taxes and Investment Tax Credits

We use the liability method of accounting for income taxes. Under the liability method, deferred income taxes are provided for all temporary differences between the book and tax basis of assets and liabilities which will result in a future tax consequence.

When the flow-through method of accounting for temporary differences is reflected in regulated revenues (that is, when deferred taxes are not included in the cost of service for determining regulated rates for electricity), deferred income taxes are recorded and related regulatory assets and liabilities are established to match the regulated revenues and tax expense.

Investment tax credits have been accounted for under the flow-through method except where regulatory commissions have reflected investment tax credits in the rate-making process on a deferral basis. Investment tax credits that have been deferred are being amortized over the life of the regulated plant investment.

Excise Taxes

We act as an agent for some state and local governments and collect from customers certain excise taxes levied by those state or local governments on our customer. We do not recognize these taxes as revenue or expense.

Debt and Preferred Stock

Gains and losses from the reacquisition of debt used to finance domestic regulated electric utility plant are generally deferred and amortized over the remaining term of the reacquired debt in accordance with their rate-making treatment unless the debt is refinanced. If the reacquired debt, associated with the regulated business, is refinanced, the reacquisition costs attributable to the portions of the business that are subject to cost based regulatory accounting are generally deferred and amortized over the term of the replacement debt consistent with its recovery in rates. We report gains and losses on the reacquisition of debt for operations that are not subject to cost-based rate regulation in Other Income and Other Expenses.

Debt discount or premium and debt issuance expenses are deferred and amortized utilizing the effective interest rate method over the term of the related debt. The amortization expense is included in interest charges.

Where reflected in rates, redemption premiums paid to reacquire preferred stock of certain domestic utility subsidiaries are included in paid-in capital and amortized to retained earnings commensurate with their recovery in rates. The excess of par value over costs of preferred stock reacquired is credited to paid-in capital and amortized to retained earnings consistent with the timing of its inclusion in rates in accordance with SFAS 71.

Goodwill and Intangible Assets

When we acquire businesses we record the fair value of any acquired goodwill and other intangible assets. Purchased goodwill and intangible assets with indefinite lives are not amortized. We test acquired goodwill and other intangible assets with indefinite lives for impairment at least annually. Intangible assets with finite lives are amortized over their respective estimated lives to their estimated residual values.

The policies described above became effective with our adoption of a new accounting standard for goodwill (SFAS 142). For all business combinations with an acquisition date before July 1, 2001, we amortized goodwill and intangible assets with indefinite lives through December 2001, and then ceased amortization. The goodwill associated with those business combinations with an acquisition date before July 1, 2001 was amortized on a straight-line basis generally over 40 years except for the portion of goodwill associated with gas trading and marketing activities which was amortized on a straight-line basis over 10 years. Intangible assets with finite lives continue to be amortized over their respective estimated lives ranging from 2 to 10 years.

Nuclear Trust Funds

Nuclear decommissioning and spent nuclear fuel trust funds represent funds that regulatory commissions have allowed us to collect through rates to fund future decommissioning and spent fuel disposal liabilities. By rules or orders, the state jurisdictional commissions (Indiana, Michigan and Texas) and the FERC have established investment limitations and general risk management guidelines. In general, limitations include:

- Acceptable investments (rated investment grade or above)
- Maximum percentage invested in a specific type of investment
- Prohibition of investment in obligations of the applicable company or its affiliates

Trust funds are maintained for each regulatory jurisdiction and managed by investment managers external to AEP, who must comply with the guidelines and rules of the applicable regulatory authorities. The trust assets are invested in order to optimize the after-tax earnings of the trust, giving consideration to liquidity, risk, diversification, and other prudent investment objectives.

Securities held in trust funds for decommissioning nuclear facilities and for the disposal of spent nuclear fuel are included in Spent Nuclear Fuel and Decommissioning Trusts for amounts relating to the Cook Plant and are included in Assets Held for Sale for amounts relating to the Texas Plants. See "Assets Held for Sale" section of Note 10 for further information regarding the Texas Plants. These securities are recorded at market value. Securities in the trust funds have been classified as available-for-sale due to their long-term purpose. Unrealized gains and losses from securities in these trust funds are reported as adjustments to the regulatory liability account for the nuclear decommissioning trust funds and to regulatory assets or liabilities for the spent nuclear fuel disposal trust funds in accordance with their treatment in rates.

Comprehensive Income (Loss)

Comprehensive income (loss) is defined as the change in equity (net assets) of a business enterprise during a period from transactions and other events and circumstances from non-owner sources. It includes all changes in equity during a period except those resulting from investments by owners and distributions to owners. Comprehensive income (loss) has two components: net income (loss) and other comprehensive income (loss).

Components of Accumulated Other Comprehensive Income (Loss)

Accumulated Other Comprehensive Income (Loss) is included on the balance sheet in the equity section. The following table provides the components that constitute the balance sheet amount in Accumulated Other Comprehensive Income (Loss):

Components	December 31, 2003	2002 (in millions)	2001
Foreign Currency Translation Adjustments	$110	$4	$(113)
Unrealized Losses on Securities Available for Sale	(1)	(2)	-
Unrealized Losses on Cash Flow Hedges	(94)	(16)	(3)
Minimum Pension Liability	(441)	(595)	(10)
Total	$(426)	$(609)	$(126)

Stock Based Compensation Plans

At December 31, 2003, we have two stock-based employee compensation plans with outstanding stock options, which are described more fully in Note 12. No stock option expense is reflected in our earnings, as all options granted under these plans had exercise prices equal to or above the market value of the underlying common stock on the date of grant.

We also grant performance share units, phantom stock units, restricted shares and restricted stock units to employees, as well as stock units to non-employee members of the Board of Directors. The Deferred Compensation and Stock Plan for Non-Employee Directors permits directors to choose to defer up to 100 percent of their annual Board retainer in stock units, and the Stock Unit Accumulation Plan for Non-Employee Directors awards stock units to directors. Compensation cost is included in Net Income for the performance share units, phantom stock units, restricted shares, restricted stock units and the Director's stock units.

We do not currently intend to adopt the fair-value-based method of accounting for stock options. The following table shows the effect on our Net Income (Loss) and Earnings (Loss) per Share as if we had applied fair value measurement and recognition provisions of FASB Statement No. 123, "Accounting for Stock-Based Compensation," to stock-based employee compensation awards:

	Year Ended December 31, 2003	2002	2001
	(in millions, except per share data)		
Net Income (Loss), as reported	$110	$(519)	$971
Add: Stock-based compensation expense included in reported net income, net of related tax effects	2	(5)	3
Deduct: Stock-based employee compensation expense determined under fair value based method for all awards, net of related tax effects	(7)	(4)	(15)
Pro Forma Net Income (Loss)	$105	$(528)	$959
Earnings (Loss) per Share:			
Basic – as Reported	$0.29	$(1.57)	$3.01
Basic – Pro Forma (a)	$0.27	$(1.59)	$2.98
Diluted – as Reported	$0.29	$(1.57)	$3.01
Diluted – Pro Forma (a)	$0.27	$(1.59)	$2.97

(a) The pro forma amounts are not representative of the effects on reported net income for future years.

Earnings Per Share (EPS)

Basic earnings (loss) per common share is calculated by dividing net earnings (loss) available to common shareholders by the weighted average number of common shares outstanding during the period. Diluted earnings (loss) per common share is calculated by adjusting the weighted average outstanding common shares, assuming conversion of all potentially dilutive stock options and awards. The effects of stock options have not been included in the fiscal 2002 diluted loss per common share calculation as their effect would have been anti-dilutive.

The calculation of our basic and diluted earnings (loss) per common share (EPS) is based on weighted average common shares shown in the table below:

	2003	2002	2001
	(in millions – except per share amounts)		
Weighted Average Shares:			
Average Common Shares Outstanding	385	332	322
Assumed Conversion of Dilutive Stock Options (see Note 12)	-	-	1
Diluted Average Common Shares Outstanding	385	332	323

The assumed conversion of stock options does not affect net earnings (loss) for purposes of calculating diluted earnings per share. Our basic and diluted EPS are the same in 2003, 2002 and 2001 since the effect on weighted average common shares outstanding is minimal.

Had we reported net income in fiscal 2002, incremental shares attributable to the assumed exercise of outstanding stock options would have increased diluted common shares outstanding by 398,000 shares.

Options to purchase 5.6 million, 8.8 million and 0.7 million shares of common stock were outstanding at December 31, 2003, 2002 and 2001, respectively, but were not included in the computation of diluted earnings per share because the options' exercise prices were greater than the year-end market price of the common shares and, therefore, the effect would be antidilutive.

In addition, there is no effect on diluted earnings per share related to our equity units (issued in 2002) unless the market value of our common stock exceeds $49.08 per share. There were no dilutive effects from equity units at December 31, 2003 and 2002. If our common stock value exceeds $49.08 we would apply the treasury stock method to the equity units to calculate diluted earnings per share. This method of calculation theoretically assumes that the proceeds received as a result of the forward purchase contracts are used to repurchase outstanding shares. Also see Note 17.

Supplementary Information

	Year Ended December 31,		
	2003	2002	2001
		(in millions)	
AEP Consolidated Purchased Power – Ohio Valley Electric Corporation (44.2% owned by AEP System)	$147	$142	$127
Cash was paid for:			
Interest (net of capitalized amounts)	$741	$792	$972
Income Taxes	$163	$336	$569
Noncash Investing and Financing Activities:			
Acquisitions under Capital Leases	$25	$6	$17
Assumption of Liabilities Related to Acquisitions	$-	$1	$171
Increase in assets and liabilities resulting from:			
Consolidation of VIEs due to the adoption of FIN 46 (see Note 2)	$547	$-	$-
Consolidation of merchant power generation facility (see Note 16)	$496	$-	$-
Exchange of Communication Investment for Common Stock	$-	$-	$5

Power Projects

We own interests of 50% or less in domestic unregulated power plants with a capacity of 1,043 MW located in Colorado, Florida and Texas. In addition to the domestic projects, we have interests of 50% or less in international power plants totaling 1,113 MW (see Note 10, "Acquisitions, Dispositions, Discontinued Operations, Impairments, Assets Held for Sale and Assets Held and Used").

Investments in power projects that are 50% or less owned are accounted for by the equity method and reported in Investments in Power and Distribution Projects on our Consolidated Balance Sheets (see "Eastex" within the Dispositions section of Note 10). At December 31, 2003, five domestic power projects and three international power investments are accounted for under the equity method. The five domestic projects are combined cycle gas turbines that provide steam to a host commercial customer and are considered either Qualifying Facilities (QFs) or Exempt Wholesale Generators (EWGs) under PURPA. The three international power investments are classified as Foreign Utility Companies (FUCO) under the Energy Policies Act of 1992. Two of the international investments are power projects and the other international investment is a company which owns an interest in four additional power projects. All of the power projects accounted for under the equity method have unrelated third-party partners.

Seven of the above power projects have project-level financing, which is non-recourse to AEP. AEP or AEP subsidiaries have guaranteed $8 million of domestic partnership obligations for performance under power purchase agreements and for debt service reserves in lieu of cash deposits. In addition, AEP has issued letters of credit with maximum future payments of $23 million for domestic power projects and $69 million for international power investments.

Reclassifications

Certain prior period financial statement items have been reclassified to conform to current period presentation. Such reclassifications had no impact on previously reported Net Income (Loss).

2. NEW ACCOUNTING PRONOUNCEMENTS, EXTRAORDINARY ITEMS AND CUMULATIVE EFFECT OF ACCOUNTING CHANGES

NEW ACCOUNTING PRONOUNCEMENTS

SFAS 132 (revised 2003) "Employers' Disclosure about Pensions and Other Postretirement Benefits"

In December 2003 the FASB issued SFAS 132 (revised 2003), which requires additional footnote disclosures about pensions and postretirement benefits, some of which are effective beginning with the year-end 2003 financial statements. Other additional disclosures will begin with our 2004 quarterly financial statements or our 2004 year-end financial statements.

We will implement new quarterly disclosures when they become effective in the first quarter of 2004, including (a) the amount of net periodic benefit cost for each period for which an income statement is presented, showing separately each component thereof, and (b) the amount of employer contributions paid and expected to be paid during the current year, if significantly different from amounts disclosed at the most recent year-end.

We will implement the new year-end disclosure when it becomes effective in the fourth quarter of 2004, concerning information about foreign plans, if appropriate. See Note 11 for these additional 2003 disclosures.

SFAS 142 "Goodwill and Other Intangible Assets"

SFAS 142 requires that goodwill and intangible assets with indefinite useful lives no longer be amortized, and that goodwill and intangible assets be tested annually for impairment. The implementation of SFAS 142 resulted in a $350 million after tax net transitional loss in 2002 for the U.K. and Australian operations and is reported in our Consolidated Statements of Operations as a cumulative effect of accounting change. See Note 3 for further information on goodwill and other intangible assets.

SFAS 143 "Accounting for Asset Retirement Obligations"

We implemented SFAS 143, "Accounting for Asset Retirement Obligations," effective January 1, 2003, which requires entities to record a liability at fair value for any legal obligations for asset retirements in the period incurred. Upon establishment of a legal liability, SFAS 143 requires a corresponding asset to be established which will be depreciated over its useful life. SFAS 143 requires that a cumulative effect of change in accounting principle be recognized for the cumulative accretion and accumulated depreciation that would have been recognized had SFAS 143 been applied to existing legal obligations for asset retirements. In addition, the cumulative effect of change in accounting principle is favorably affected by the reversal of accumulated removal cost. These costs had previously been recorded for generation and did not qualify as a legal obligation although these costs were collected in depreciation rates by certain formerly regulated subsidiaries.

We completed a review of our asset retirement obligations and concluded that we have related legal liabilities for nuclear decommissioning costs for our Cook Plant and our partial ownership in the South Texas Project, as well as liabilities for the retirement of certain ash ponds, wind farms, the U.K. Plants, and certain coal mining facilities. Since we presently recover our nuclear decommissioning costs in our regulated cash flow and have existing balances recorded for such nuclear retirement obligations, we recognized the cumulative difference between the amount already provided through rates and the amount as measured by applying SFAS 143 as a regulatory asset or liability. Similarly, a regulatory asset was recorded for the cumulative effect of certain retirement costs for ash ponds related to our regulated operations. In 2003, we recorded an unfavorable cumulative effect of $45.4 million after tax for our non-regulated operations ($38.0 million related to Ash Ponds in the Utility Operations segment, $7.2 million related to U.K. Plants in the Investments – UK Operations segment and $0.2 million for Wind Mills in the Investments – Other segment).

Certain of our utility operating companies have collected removal costs from ratepayers for certain assets that do not have associated legal asset retirement obligations. To the extent that operating companies have now been deregulated we reversed the balance of such removal costs, totaling $287.2 million, after tax, which resulted in a net favorable cumulative effect in 2003. We have reclassified approximately $1.2 billion of removal costs for our utility operations from accumulated depreciation to Regulatory Liabilities and Deferred Investment Tax Credits in 2003 and to Deferred Credits and Other in 2002. In addition, $9 million is classified as held-for-sale related to the TCC generation assets as of December 31, 2003 and 2002.

The net favorable cumulative effect of the change in accounting principle for the year ended December 31, 2003 consists of the following:

	Pre-tax Income (Loss)	After-tax Income (Loss)
	(in millions)	
Ash Ponds	$(62.8)	$(38.0)
U.K. Plants, Wind Mills and Coal Operations	(11.3)	(7.4)
Reversal of Cost of Removal	472.6	287.2
Total	$398.5	$241.8

We have identified, but not recognized, asset retirement obligation liabilities related to electric transmission and distribution and gas pipeline assets, as a result of certain easements on property on which we have assets. Generally, such easements are perpetual and require only the retirement and removal of our assets upon the cessation of the property's use. The retirement obligation is not estimable for such easements since we plan to use our facilities indefinitely. The retirement obligation would only be recognized if and when we abandon or cease the use of specific easements.

The following is a reconciliation of the beginning and ending aggregate carrying amount of asset retirement obligations:

	Nuclear Decommissioning	Ash Ponds	U.K. Plants, Wind Mills and Coal Operations	Total
		(in millions)		
Asset Retirement Obligation Liability at January 1, 2003	$718.3	$69.8	$37.2	$825.3
Accretion Expense	52.6	5.6	2.3	60.5
Liabilities Incurred	-		8.3	8.3
Foreign Currency Translation	-	-	5.3	5.3
Asset Retirement Obligation Liability at December 31, 2003 including Held for Sale	770.9	75.4	53.1	899.4
Less Asset Retirement Obligation Liability Held for Sale:				
South Texas Project	(218.8)	-	-	(218.8)
U.K. Plants	-	-	(28.8)	(28.8)
Asset Retirement Obligation Liability at December 31, 2003	$552.1	$75.4	$24.3	$651.8

Accretion expense is included in Maintenance and Other Operation expense in our accompanying Consolidated Statements of Operations.

As of December 31, 2003 and 2002, the fair value of assets that are legally restricted for purposes of settling the nuclear decommissioning liabilities totaled $845 million and $716 million, respectively, of which $720 million and $618 million relating to the Cook Plant was recorded in Spent Nuclear Fuel and Decommissioning Trusts in our Consolidated Balance Sheets. The fair value of assets that are legally restricted for purposes of settling the nuclear decommissioning liabilities for the South Texas Project totaling $125 million and $98 million as of December 31, 2003 and 2002, respectively, was classified as Assets Held for Sale in our Consolidated Balance Sheets.

Pro forma net income and earnings per share are not presented for the years ended December 31, 2002 and 2001 because the pro forma application of SFAS 143 would result in pro forma net income and earnings per share not materially different from the actual amounts reported during those periods.

As of December 31, 2002 and 2001, the pro forma liability for asset retirement obligations which has been calculated as if SFAS 143 had been adopted at the beginning of each period was $825 million and $769 million, respectively.

SFAS 144 "Accounting for the Impairment or Disposal of Long-lived Assets"

In August 2001, the FASB issued SFAS 144, "Accounting for the Impairment or Disposal of Long-lived Assets" which sets forth the accounting to recognize and measure an impairment loss. This standard replaced, SFAS 121, "Accounting for Long-lived Assets and for Long-lived Assets to be Disposed Of." We adopted SFAS 144 effective January 1, 2002. See Note 10 for discussion of impairments recognized in 2003 and 2002.

SFAS 145 "Rescission of FASB Statements No. 4, 44 and 64, Amendment of FASB Statement No. 13, and Technical Corrections"

In April 2002, the FASB issued SFAS 145, "Rescission of FASB Statements No. 4, 44 and 64, Amendment of FASB Statement No. 13, and Technical Corrections" (SFAS 145). SFAS 145 rescinds SFAS 4, "Reporting Gains and Losses from Extinguishment of Debt," effective for fiscal years beginning after May 15, 2002. SFAS 4 required gains and losses from extinguishment of debt to be aggregated and classified as an extraordinary item if material. In 2003, we reclassified Extraordinary Losses (Net of Tax) on TCC's reacquired debt of $2 million for 2001 to Other Expenses.

SFAS 146 "Accounting for Costs Associated with Exit or Disposal Activities"

In June 2002, FASB issued SFAS 146 which addresses accounting for costs associated with exit or disposal activities. This statement supersedes previous accounting guidance, principally EITF No. 94-3, "Liability Recognition for Certain Employee Termination Benefits and Other Costs to Exit an Activity (including Certain Costs Incurred in a Restructuring)." Under EITF No. 94-3, a liability for an exit cost was recognized at the date of an entity's commitment to an exit plan. SFAS 146 requires that the liability for costs associated with an exit or disposal activity be recognized when the liability is incurred. SFAS 146 also establishes that the liability should initially be measured and recorded at fair value. The time at which we recognize future costs related to exit or disposal activities, including restructuring, as well as the amounts recognized may be affected by SFAS 146. We adopted the provisions of SFAS 146 for exit or disposal activities initiated after December 31, 2002.

SFAS 149 "Amendment of Statement 133 on Derivative Instruments and Hedging Activities"

On April 30, 2003, the FASB issued Statement No. 149, "Amendment of Statement 133 on Derivative Instruments and Hedging Activities" (SFAS 149). SFAS 149 amends SFAS 133 to clarify the definition of a derivative and the requirements for contracts to qualify for the normal purchase and sale exemption. SFAS 149 also amends certain other existing pronouncements. Effective July 1, 2003, we implemented SFAS 149 and the effect was not material to our results of operations, cash flows or financial condition.

SFAS 150 "Accounting for Certain Financial Instruments with Characteristics of Both Liabilities and Equity"

We implemented SFAS 150 effective July 1, 2003. SFAS 150 is the first phase of the FASB's project to eliminate from the balance sheet the "mezzanine" presentation of items with characteristics of both liabilities and equity, including: (1) mandatorily redeemable shares, (2) instruments other than shares that could require the issuer to buy back some of its shares in exchange for cash or other assets and (3) certain obligations that can be settled with shares. Measurement of these liabilities generally is to be at fair value, with the payment or accrual of "dividends" and other amounts to holders reported as interest cost.

Beginning with our third quarter 2003 financial statements, we present Cumulative Preferred Stocks of Subsidiaries Subject to Mandatory Redemption as a Non-Current Liability. Beginning July 1, 2003, we classify dividends on these mandatorily redeemable preferred shares as interest expense. In accordance with SFAS 150, dividends from prior periods remain classified as preferred stock dividends (a component of Preferred Stock Dividend Requirements of Subsidiaries).

FIN 45 "Guarantor's Accounting and Disclosure Requirements for Guarantees, Including Indirect Guarantees of Indebtedness of Others"

In November 2002, the FASB issued FIN 45 which clarifies the accounting to recognize liabilities related to issuing a guarantee, as well as additional disclosures of guarantees. We implemented FIN 45 as of January 1, 2003, and the effect was not material to our results of operations, cash flows or financial condition. See Note 8 for further disclosures.

FIN 46 (revised December 2003)"Consolidation of Variable Interest Entities" and FIN 46 "Consolidation of Variable Interest Entities"

We implemented FIN 46, "Consolidation of Variable Interest Entities," effective July 1, 2003. FIN 46 interprets the application of Accounting Research Bulletin No. 51, "Consolidated Financial Statements," to certain entities in which equity investors do not have the characteristics of a controlling financial interest or do not have sufficient equity at risk for the entity to finance its activities without additional subordinated financial support from other parties. Due to the prospective application of FIN 46, we did not reclassify prior period amounts.

On July 1, 2003, we deconsolidated Caddis Partners, LLC (Caddis). At December 31, 2002 $759 million was reported as a Minority Interest in Finance Subsidiary. At December 31, 2003 $527 million is reported as a note payable to Caddis, a component of Long-Term Debt. See Note 17 "Financing Activities" for further disclosures.

On July 1, 2003, we also deconsolidated the trusts which hold mandatorily redeemable trust preferred securities. Therefore, of the $321 million net amount reported as "Certain Subsidiary Obligated, Mandatorily Redeemable, Preferred Securities of Subsidiary Trusts Holding Solely Junior Subordinated Debentures of Such Subsidiaries" at December 31, 2002, $331 million is reported as Notes Payable to Trust (included in Long-term Debt) and $10 million is reported in Other Non-Current Assets at December 31, 2003.

Effective July 1, 2003, SWEPCo consolidated Sabine Mining Company (Sabine), a contract mining operation providing mining services to SWEPCo. Upon consolidation, SWEPCo recorded the assets and liabilities of Sabine ($77.8 million). Also, after consolidation, SWEPCo currently records all expenses (depreciation, interest and other operation expense) of Sabine and eliminates Sabine's revenues against SWEPCo's fuel expenses. There is no cumulative effect of accounting change recorded as a result of our requirement to consolidate, and there is no change in net income due to the consolidation of Sabine.

Effective July 1, 2003, OPCo consolidated JMG. Upon consolidation, OPCo recorded the assets and liabilities of JMG ($469.6 million). OPCo now records the depreciation, interest and other operating expenses of JMG and eliminates JMG's revenues against OPCo's operating lease expenses. There is no cumulative effect of accounting change recorded as a result of our requirement to consolidate JMG, and there is no change in net income due to the consolidation of JMG. See Note 16 "Leases" for further disclosures.

In December 2003, the FASB issued FIN 46 (revised December 2003) (FIN 46R) which replaces FIN 46. The FASB and other accounting constituencies continue to interpret the application of FIN 46R. As a result, we are continuing to review the application of this new interpretation and expect to adopt FIN 46R by March 31, 2004.

EITF 02-3 and Rescission of EITF 98-10

In October 2002, the Emerging Issues Task Force of the FASB reached a final consensus on Issue No. 02-3. EITF 02-3 rescinds EITF 98-10 and related interpretive guidance. Under EITF 02-3, mark-to-market accounting is precluded for risk management contracts that are not derivatives pursuant to SFAS 133. The consensus to rescind EITF 98-10 also eliminated the recognition of physical inventories at fair value other than as provided by GAAP. We have implemented this standard for all physical inventory and non-derivative risk management transactions occurring on or after October 25, 2002. For physical inventory and non-derivative risk management transactions entered into prior to October 25, 2002, we implemented this standard on January 1, 2003 and reported the effects of implementation as a cumulative effect of an accounting change. We recorded a $49 million loss, net of income tax, as a cumulative effect of accounting change.

Effective January 1, 2003, EITF 02-3 requires that gains and losses on all derivatives, whether settled financially or physically, be reported in the income statement on a net basis if the derivatives are held for risk management purposes. Previous guidance in EITF 98-10 permitted contracts that were not settled financially to be reported either gross or net in the income statement. Prior to the third quarter of 2002, we recorded and reported upon settlement, sales under forward risk management contracts as revenues; we also recorded and reported purchases under forward risk management contracts as purchased energy expenses. Effective July 1, 2002, we reclassified such forward risk management revenues and purchases on a net basis. The reclassification of such risk management activities to a net basis of reporting resulted in a substantial reduction in both revenues and purchased energy expense, but did not have any impact on our financial condition, results of operations or cash flows.

EITF 03-11 "Reporting Realized Gains and Losses on Derivative Instruments That Are Subject to FASB Statement No. 133 and Not "Held for Trading Purposes" as Defined in Issue No. 02-3"

In July 2003, the EITF reached consensus on Issue No. 03-11. The consensus states that realized gains and losses on derivative contracts not "held for trading purposes" should be reported either on a net or gross basis based on the relevant facts and circumstances. Reclassification of prior year amounts is not required. The adoption of EITF 03-11 did not have a material impact on our results of operations, financial position or cash flows.

FASB Staff Position No. 106-1, Accounting and Disclosure Requirements Related to the Medicare Prescription Drug Improvement and Modernization Act of 2003

On January 12, 2004, the FASB Staff issued FSP 106-1, which allows a one-time election to defer accounting for any effects of the prescription drug subsidy under the Medicare Prescription Drug Improvement and Modernization Act of 2003 (the Act), enacted on December 8, 2003. There are significant uncertainties as to whether our plan will be eligible for a subsidy under future federal regulations that have not yet been drafted. The method of accounting for any such subsidy and, therefore, the subsidy's possible reduction to our accumulated postretirement benefit obligation and periodic postretirement benefit costs has not been resolved by the FASB or other professional accounting standard setting authority. Accordingly, we elected to defer any potential effects of the Act until authoritative guidance on the accounting for the federal subsidy is issued. Our measurements of the accumulated postretirement benefit obligation and periodic postretirement benefit cost included in these financial statements do not reflect any potential effects of the Act. We cannot determine what impact, if any, new authoritative guidance on the accounting for the federal subsidy may have on our results of operations or financial condition.

Future Accounting Changes

The FASB's standard-setting process is ongoing. Until new standards have been finalized and issued by FASB, we cannot determine the impact on the reporting of our operations that may result from any such future changes.

CUMULATIVE EFFECT OF ACCOUNTING CHANGES

Accounting for Risk Management Contracts

EITF 02-3 rescinds EITF 98-10 and related interpretive guidance. We recorded a $49 million after tax charge against net income as Accounting for Risk Management Contracts in our Consolidated Statements of Operations in Cumulative Effect of Accounting Changes in the first quarter of 2003 ($12 million in Utility Operations, $22 million in Investments – Gas Operations and $15 million in Investments – UK Operations segments). This amount will be realized when the positions settle.

The FASB's Derivative Implementation Group (DIG) issued accounting guidance under SFAS 133 for certain derivative fuel supply contracts with volumetric optionality and derivative electricity capacity contracts. This guidance, effective in the third quarter of 2001, concluded that fuel supply contracts with volumetric optionality cannot qualify for a normal purchase or sale exclusion from mark-to-market accounting and provided guidance for determining when certain option-type contracts and forward contracts in electricity can qualify for the normal purchase or sale exclusion.

The effect of initially adopting the DIG guidance at July 1, 2001 was a favorable earnings mark-to-market after tax effect of $18 million (net of tax of $2 million). It was reported as a cumulative effect of an accounting change on our Consolidated Statements of Operations (included in Investments - Other segment).

Asset Retirement Obligations (SFAS 143)

In the first quarter of 2003, we recorded $242 million in after-tax income as a cumulative effect of accounting change for Asset Retirement Obligations.

Goodwill and Other Intangible Assets

SFAS 142 requires that goodwill and intangible assets with indefinite useful lives no longer be amortized and be tested annually for impairment. The implementation of SFAS 142 in 2002 resulted in a $350 million net transitional loss for our U.K. and Australian operations (included in the Investments – Other segment) and is reported in our Consolidated Statements of Operations as a cumulative effect of accounting change (see Note 3, "Goodwill and Other Intangible Assets" for further details).

See table below for details of the Cumulative Effect of Accounting Changes:

Description	Year Ended December 31, 2003	2002	2001
		(in millions)	
Accounting for Risk Management Contracts (EITF 02-3)	$(49)	$-	$-
Asset Retirement Obligations (SFAS 143)	242	-	-
Goodwill and Other Intangible Assets	-	(350)	-
Accounting for Risk Management Contracts (DIG Guidance)	-	-	18
Total	$193	$(350)	$18

EXTRAORDINARY ITEMS

In 2001, we recorded an extraordinary item for the discontinuance of regulatory accounting under SFAS 71 for the generation portion of our business in the Ohio state jurisdiction. OPCo and CSPCo recognized an extraordinary loss of $48 million (net of tax of $20 million) for unrecoverable Ohio Public Utility Excise Tax (commonly known as the Gross Receipts Tax – GRT) net of allowable Ohio coal credits. This loss resulted from regulatory decisions in connection with Ohio deregulation which stranded the recovery of the GRT. Effective with the liability affixing on May 1, 2001, CSPCo and OPCo recorded an extraordinary loss under SFAS 101. Both Ohio companies appealed to the Ohio Supreme Court the PUCO order on Ohio restructuring that the Ohio companies believe failed to provide for recovery for the final year of the GRT. In April 2002, the Ohio Supreme Court denied recovery of the final year of the GRT.

3. GOODWILL AND OTHER INTANGIBLE ASSETS

GOODWILL

The changes in our carrying amount of goodwill for the years ended December 31, 2003 and 2002 by operating segment are:

	Utility Operations	Investments Gas Operations	Investments UK Operations	Investments Other	AEP Consolidated
			(in millions)		
Balance at January 1, 2002 (including Assets Held for Sale)	$37.1	$340.1	$-	$14.9	$392.1
Goodwill acquired	-	-	2.3	-	2.3
Changes to Goodwill due to Purchase price adjustments	-	(33.8)	172.5	42.4	181.1
Impairment losses	-	-	(170.0)	(15.9)	(185.9)
Foreign currency exchange rate changes	-	-	6.4	-	6.4
Balance at December 31, 2002 (including Assets Held for Sale)	37.1	306.3	11.2	41.4	396.0
Less: Assets Held for Sale, Net (a)	-	(143.8)	(11.2)	-	(155.0)
Balance at December 31, 2002 (excluding Assets Held for Sale)	$37.1	$162.5	$-	$41.4	$241.0
Balance at January 1, 2003 (including Assets Held for Sale)	$37.1	$306.3	$11.2	$41.4	$396.0
Impairment losses	-	(291.4)	(12.2)	-	(303.6)
Foreign currency exchange rate changes	-	-	1.0	-	1.0
Balance at December 31, 2003 (including Assets Held for Sale)	37.1	14.9	-	41.4	93.4
Less: Assets Held for Sale, Net (a)	-	(14.9)	-	-	(14.9)
Balance at December 31, 2003 (excluding Assets Held for Sale)	$37.1	$-	$-	$41.4	$78.5

(a) On our Consolidated Balance Sheets, amounts related to entities classified as held for sale are excluded from Goodwill and are reported within Assets Held for Sale (see Note 10). The following entities classified as held for sale had goodwill or goodwill impairments during the years ended December 31, 2003 or 2002:

- Jefferson Island (Investments – Gas Operations segment) – $14.4 million and $143.3 million balances in goodwill at December 1, 2003 and 2002, respectively. During 2003, we recognized a goodwill impairment loss of $128.9 million.
- LIG Chemical (Investments – Gas Operations segment) – $0.5 million balance in goodwill at December 31, 2003 and 2002.
- U.K. Coal Trading (Investments – UK Operations segment) – $11.2 million balance in goodwill at December 31, 2002. In 2003, we recognized a goodwill impairment loss of $12.2 million related to the impairment study (impairment in 2003 was greater than December 31, 2002 balance due to changes in foreign currency translation rates).
- U.K. Generation (Investments – UK Operations segment) – No goodwill balances at December 31, 2003 or 2002. In 2002, we recognized a goodwill impairment loss of $166.0 million related to the impairment study.
- AEP Coal (Investments – Other segment) – No goodwill balances at December 31, 2003 or 2002. In 2002, we recognized a $3.6 million impairment loss related to the impairment study.

Accumulated amortization of goodwill was approximately $1 million and $9 million at December 31, 2003 and 2002, respectively. The decrease of $8 million between years is related to the impairment of goodwill on Houston Pipe Line Company and AEP Energy Services.

In the fourth quarter of 2003, we prepared our annual goodwill impairment tests. The fair values of the operations were estimated using cash flow projections and other market value indicators. As a result of the tests, we recognized a $162.5 million goodwill impairment loss related to Houston Pipe Line Company ($150.4 million) and AEP Energy Services ($12.1 million).

During 2002, changes to goodwill were due to purchase price adjustments of $6.7 million primarily related to our acquisition of Houston Pipe Line Company, MEMCO and Nordic Trading (see Note 10).

In the first quarter of 2002, we recognized a goodwill impairment loss of $12.3 million for all goodwill related to Gas Power Systems (see Note 10).

In the fourth quarter of 2002, we prepared our annual goodwill impairment tests. The fair values of the operations were estimated using cash flow projections. As a result of the tests, we recognized a goodwill impairment loss of $4.0 million related to Nordic Trading (see Note 10).

The transitional impairment loss related to SEEBOARD and CitiPower goodwill, which is reported as Cumulative Effect of Accounting Changes in 2002, is excluded from the above schedule.

The following tables show the transitional disclosures to adjust our reported net income (loss) and earnings (loss) per share to exclude amortization expense recognized in prior periods related to goodwill and intangible assets that are no longer being amortized.

Net Income (Loss)	**Year Ended December 31,**		
	2003	**2002**	**2001**
		(in millions)	
Reported Net Income (Loss)	$110	$(519)	$971
Add back: Goodwill amortization	-	-	39(a)
Add back: Amortization for intangibles with indefinite lives	-	-	8(b)
Adjusted Net Income (Loss)	$110	$(519)	$1,018

Earnings (Loss) Per Share (Basic and Dilutive)	**Year Ended December 31,**		
	2003	**2002**	**2001**
Reported Earnings (Loss) per Share	$0.29	$(1.57)	$3.01
Add back: Goodwill amortization	-	-	0.12(c)
Add back: Amortization for intangibles with indefinite lives	-	-	0.02(b)
Adjusted Earnings (Loss) per Share	$0.29	$(1.57)	$3.15

(a) This amount includes $34 million in 2001 related to SEEBOARD and CitiPower amortization expense included in Discontinued Operations on our Consolidated Statements of Operations.
(b) The amounts shown for 2001 relate to CitiPower amortization expense included in Discontinued Operations on our Consolidated Statements of Operations.
(c) This amount includes $0.10 in 2001 related to SEEBOARD and CitiPower amortization expense included in Discontinued Operations on our Consolidated Statements of Operations.

OTHER INTANGIBLE ASSETS

Acquired intangible assets subject to amortization are $34 million at December 31, 2003 and $37 million at December 31, 2002, net of accumulated amortization. The gross carrying amount, accumulated amortization and amortization life by major asset class are:

		December 31, 2003		December 31, 2002	
	Amortization Life	Gross Carrying Amount	Accumulated Amortization	Gross Carrying Amount	Accumulated Amortization
	(in years)	(in millions)		(in millions)	
Software and customer list (a)	2	$-	$-	$0.5	$0.2
Software acquired (b)	3	0.5	0.3	0.5	-
Patent	5	0.1	-	0.1	-
Easements	10	2.2	0.3	-	-
Trade name and administration of contracts	7	2.4	0.9	2.4	0.6
Purchased technology	10	10.9	2.2	10.3	1.0
Advanced royalties	10	29.4	7.7	29.4	4.7
Total		$45.5	$11.4	$43.2	$6.5

(a) This asset was disposed of in the second quarter of 2003.
(b) This asset relates to U.K. Generation Plants and is included in Assets Held for Sale on our Consolidated Balance Sheets.

Amortization of intangible assets was $5 million and $4 million for the twelve months ended December 31, 2003 and 2002, respectively. Our estimated aggregate amortization expense is $5 million for each year 2004 through 2007, $4 million for 2008 through 2010 and $3 million in 2011.

4. RATE MATTERS

In certain jurisdictions, we have agreed to base rate or fuel recovery limitations usually under terms of settlement agreements. See Note 5 for a discussion of those terms related to Nuclear Plant Restart and Merger with CSW.

Fuel in SPP Area of Texas

In 2001, the PUCT delayed the start of customer choice in the SPP area of Texas. In May 2003, the PUCT ordered that competition would not begin in the SPP areas before January 1, 2007. TNC filed with the PUCT in 2002 to determine the most appropriate method to reconcile fuel costs in TNC's SPP area. In April 2003, the PUCT issued an order adopting the methodology proposed in TNC's filing, with adjustments, for reconciling fuel costs in the SPP area. The adjustments removed $3.71 per MWH from reconcilable fuel expense. This adjustment will reduce revenues received by Mutual Energy SWEPCo who now serves TNC's SPP customers by approximately $400,000 annually. In October 2003, Mutual Energy SWEPCo agreed with the PUCT staff and the Office of Public Utility Counsel (OPC) to file a fuel reconciliation proceeding for the period January 2002 through December 2003 by March 31, 2004 and the PUCT ordered that the filing be made.

TNC Fuel Reconciliations

In June 2002, TNC filed with the PUCT to reconcile fuel costs, requesting to defer any unrecovered portion applicable to retail sales within its ERCOT service area for inclusion in the 2004 true-up proceeding. This reconciliation for the period of July 2000 through December 2001 will be the final fuel reconciliation for TNC's ERCOT service territory. At December 31, 2001, the deferred under-recovery balance associated with TNC's ERCOT service area was $27.5 million including interest. During the reconciliation period, TNC incurred $293.7 million of eligible fuel costs serving both ERCOT and SPP retail customers. TNC also requested authority to surcharge its SPP customers for under-recovered fuel costs. TNC's SPP customers will continue to be subject to fuel reconciliations until competition begins in the SPP area as described above. The under-recovery balance at December 31, 2001 for TNC's service within SPP was $0.7 million including interest.

In March 2003, the ALJ in this proceeding filed a Proposal for Decision (PFD) with a recommendation that TNC's under-recovered retail fuel balance be reduced. In March 2003, TNC established a reserve of $13 million based on the recommendations in the PFD. In May 2003, the PUCT reversed the ALJ on certain matters and remanded TNC's final fuel reconciliation to the ALJ to consider two issues. The issues are the sharing of off-system sales margins from AEP's trading activities with customers for five years per the PUCT's interpretation of the Texas AEP/CSW merger settlement and the inclusion of January 2002 fuel factor revenues and associated costs in the determination of the under-recovery. The PUCT proposed that the sharing of off-system sales margins for periods beyond the termination of the fuel factor should be recognized in the final fuel reconciliation proceeding. This would result in the sharing of margins for an additional three and one half years after the end of the Texas ERCOT fuel factor.

On December 3, 2003, the ALJ issued a PFD in the remand phase of the TNC fuel reconciliation recommending additional disallowances for the two remand issues. TNC filed responses to the PFD and the PUCT announced a final ruling in the fuel reconciliation proceeding on January 15, 2004 accepting the PFD. TNC is waiting for a written order, after which it will request a rehearing of the PUCT's ruling. While management believes that the Texas merger settlement only provided for sharing of margins during the period fuel and generation costs were regulated by the PUCT, an additional provision of $10 million was recorded in December 2003. Based on the decisions of the PUCT, TNC's final under-recovery including interest at December 31, 2003 was $6.2 million.

In February 2002, TNC received a final order from the PUCT in a previous fuel reconciliation covering the period July 1997 to June 2000 and reflected the order in its financial statements. This final order was appealed to the Travis County District Court. In May 2003, the District Court upheld the PUCT's final order. That order is currently on appeal to the Third Court of Appeals.

TCC Fuel Reconciliation

In December 2002, TCC filed its final fuel reconciliation with the PUCT to reconcile fuel costs to be included in its deferred over-recovery balance in the 2004 true-up proceeding. This reconciliation covers the period of July 1998 through December 2001. At December 31, 2001, the over-recovery balance for TCC was $63.5 million including interest. During the reconciliation period, TCC incurred $1.6 billion of eligible fuel and fuel-related expenses.

Based on the PUCT ruling in the TNC proceeding relating to similar issues, TCC established a reserve for potential adverse rulings of $81 million during 2003. In July 2003, the ALJ requested that additional information be provided in the TCC fuel reconciliation related to the impact of the TNC orders, referenced above, on TCC. On February 3, 2004, the ALJ issued a PFD recommending that the PUCT disallow $140 million in eligible fuel costs including some new items not considered in the TNC case, and other items considered but not disallowed in the TNC ruling. At this time, management is unable to predict the outcome of this proceeding. An adverse ruling from the PUCT, disallowing amounts in excess of the established reserve could have a material impact on future results of operations, cash flows and financial condition. Additional information regarding the 2004 true-up proceeding for TCC can be found in Note 6 "Customer Choice and Industry Restructuring."

SWEPCo Texas Fuel Reconciliation

In June 2003, SWEPCo filed with the PUCT to reconcile fuel costs in SPP. This reconciliation covers the period of January 2000 through December 2002. At December 31, 2002, SWEPCo's filing included a $2 million deferred over-recovery balance including interest. During the reconciliation period, SWEPCo incurred $435 million of Texas retail eligible fuel expense. In November 2003, intervenors and the PUCT Staff recommended fuel cost disallowances of more than $30 million. In December 2003, SWEPCo agreed to a settlement in principle with all parties in the fuel reconciliation. The settlement provides for a disallowance in fuel costs of $8 million which was recorded in December 2003. In addition, the settlement provides for the deferral as a regulatory asset of costs of a new lignite mining agreement in excess of a specified benchmark for lignite at SWEPCo's Dolet Hills Plant. The settlement provides for recovery of the deferred costs over a period ending in April 2011 as cost savings are realized under the new mining agreement. The settlement also will allow future recovery of litigation costs associated with the termination of a previous lignite mining agreement if future costs savings are adequate. The settlement will be filed with the PUCT for approval.

ERCOT Price-to-Beat (PTB) Fuel Factor Appeal

Several parties including the Office of Public Utility Counsel (OPC) and cities served by both TCC and TNC appealed the PUCT's December 2001 orders establishing initial PTB fuel factors for Mutual Energy CPL and Mutual Energy WTU. On June 25, 2003, the District Court ruled in both appeals. The Court ruled in the Mutual Energy WTU case that the PUCT lacked sufficient evidence to include unaccounted for energy in the fuel factor, and that the PUCT improperly shifted the burden of proof and the record lacked substantial evidence on the effect of loss of load due to retail competition on generation requirements. The Court upheld the initial PTB orders on all other issues. In the Mutual Energy CPL proceeding, the Court ruled that the PUCT improperly shifted the burden of proof and the record lacked substantial evidence on the effect of loss of load due to retail competition on generation requirements. The amount of unaccounted for energy built into the PTB fuel factors was approximately $2.7 million for Mutual Energy WTU. At this time, management is unable to estimate the potential financial impact related to the loss of load issue. The District Court decision was appealed to the Third Court of Appeals by Mutual Energy CPL, Mutual Energy WTU and other parties. Management believes, based on the advice of counsel, that the PUCT's original decision will ultimately be upheld. If the District Court's decisions are ultimately upheld, the PUCT could reduce the PTB fuel factors charged to retail customers in 2002 and 2003 resulting in an adverse effect on future results of operations and cash flows.

Unbundled Cost of Service (UCOS) Appeal

The UCOS proceeding established the regulated wires rates to be effective when retail electric competition began. TCC placed new transmission and distribution rates into effect as of January 1, 2002 based upon an order issued by the PUCT resulting from TCC's UCOS proceeding. TCC requested and received approval from the FERC of wholesale transmission rates determined in the UCOS proceeding. Regulated delivery charges include the retail transmission and distribution charge and, among other items, a nuclear decommissioning fund charge, a municipal franchise fee, a system benefit fund fee, a transition charge associated with securitization of regulatory assets and a credit for excess earnings. Certain rulings of the PUCT in the UCOS proceeding, including the initial determination of stranded costs, the requirement to refund TCC's excess earnings, regulatory treatment of nuclear insurance and distribution rates charged municipal customers, were appealed to the Travis County District Court by TCC and other parties to the proceeding. The District Court issued a decision on June 16, 2003, upholding the PUCT's UCOS order with one exception. The Court ruled that the refund of the 1999 through 2001 excess earnings, solely as a credit to non-bypassable transmission and distribution rates charged to REPs, discriminates against residential and small commercial customers and is unlawful. The distribution rate credit began in January 2002. This decision could potentially affect the PTB rates charged by Mutual Energy CPL and could result in a refund to certain of its customers. Mutual Energy CPL was a subsidiary of AEP until December 23, 2002 when it was sold. Management estimates that the effect of a decision to reduce the PTB rates for the period prior to the sale is approximately $11 million pre-tax. The District Court decision was appealed to the Third Court of Appeals by TCC and other parties. Based on advice of counsel, management believes that it will ultimately prevail on appeal. If the District Court's decision is ultimately upheld on appeal or the Court of Appeals reverses the District Court on issues adverse to TCC, it could have an adverse effect on future results of operations and cash flows.

TCC Rate Case

On June 26, 2003, the City of McAllen, Texas requested that TCC provide justification showing that its transmission and distribution rates should not be reduced. Other municipalities served by TCC passed similar rate review resolutions. In Texas, municipalities have original jurisdiction over rates of electric utilities within their municipal limits. Under Texas law, TCC must provide support for its rates to the municipalities. TCC filed the requested support for its rates based on a test year ending June 30, 2003 with all of its municipalities and the PUCT on November 3, 2003. TCC's proposal would decrease its wholesale transmission rates by $2 million or 2.5% and increase its retail energy delivery rates by $69 million or 19.2%. On February 9, 2004, eight intervening parties filed testimony recommending reductions to TCC's requested $67 million rate increase. The recommendations range from a decrease in existing rates of approximately $100 million to an increase in TCC's current rates of approximately $27 million. The PUCT Staff filed testimony, on February 17, 2004, recommending reductions to TCC's request of approximately $51 million. TCC's rebuttal testimony was filed on February 26, 2004. Hearings are scheduled for March 2004 with a PUCT decision expected in May 2004. Management is unable to predict the ultimate effect of this proceeding on TCC's rates or its impact on TCC's results of operations, cash flows and financial condition.

Louisiana Fuel Audit

The LPSC is performing an audit of SWEPCo's historical fuel costs. In addition, five SWEPCo customers filed a suit in the Caddo Parish District Court in January 2003 and filed a complaint with the LPSC. The customers claim that SWEPCo has over charged them for fuel costs since 1975. The LPSC consolidated the customer complaint and audit. In January 2004, a procedural schedule was issued requiring LPSC Staff and intervenor testimony to be filed in June 2004 and scheduling hearings for October 2004. Management believes that SWEPCo's fuel costs were proper and those costs incurred prior to 1999 have been approved by the LPSC. Management is unable to predict the outcome of these proceedings. If the actions of the LPSC or the Court result in a material disallowance of recovery of SWEPCo's fuel costs from customers, it could have an adverse impact on results of operations and cash flows.

Louisiana Compliance Filing

In October 2002, SWEPCo filed with the LPSC detailed financial information typically utilized in a revenue requirement filing, including a jurisdictional cost of service. This filing was required by the LPSC as a result of their order approving the merger between AEP and CSW. The LPSC's merger order also provides that SWEPCo's base rates are capped at the present level through mid 2005. The filing indicates that SWEPCo's current rates should not be reduced. In 2004 the LPSC required SWEPCo to file updated financial information with a test year ending December 31, 2003 before April 16, 2004. If, after review of the updated information, the LPSC disagrees with our conclusion, they could order SWEPCo to file all documents for a full cost of service revenue requirement review in order to determine whether SWEPCo's capped rates should be reduced which would adversely impact results of operations and cash flows.

FERC Wholesale Fuel Complaints

Certain TNC wholesale customers filed a complaint with FERC alleging that TNC had overcharged them through the fuel adjustment clause for certain purchased power costs since 1997.

Negotiations to settle the complaint and update the contracts resulted in new contracts. The FERC approved an offer of settlement regarding the fuel complaint and new contracts at market prices in December 2003. Since TNC had recorded a provision for refund in 2002, the effect of the settlement was a $4 million favorable adjustment recorded in December 2003.

Environmental Surcharge Filing

In September 2002, KPCo filed with the KPSC to revise its environmental surcharge tariff (annual revenue increase of approximately $21 million) to recover the cost of emissions control equipment being installed at the Big Sandy Plant. See NOx Reductions in Note 7.

In March 2003, the KPSC granted approximately $18 million of the request. Annual rate relief of $1.7 million became effective in May 2003 and an additional $16.2 million became effective in July 2003. The recovery of such amounts is intended to offset KPCo's cost of compliance with the Clean Air Act.

PSO Rate Review

In February 2003, the Director of the OCC filed an application requiring PSO to file all documents necessary for a general rate review. In October 2003, PSO filed financial information and supporting testimony in response to the OCC's requirements. PSO's response indicates that its annual revenues are $36 million less than costs. As a result, PSO is seeking OCC approval to increase its base rates by that amount, which is a 3.6% increase over PSO's existing revenues. Hearings are scheduled for October 2004. Management is unable to predict the ultimate effect of this review on PSO's rates or its impact on PSO's results of operations, cash flows and financial condition.

PSO Fuel and Purchased Power

PSO had a $44 million under-recovery of fuel costs resulting from a 2002 reallocation among AEP West companies of purchased power costs for periods prior to January 1, 2002. In July 2003, PSO filed with the OCC seeking recovery of the $44 million over an 18-month time period. In August 2003, the OCC Staff filed testimony recommending PSO be granted recovery of $42.4 million over three years. In September 2003, the OCC expanded the case to include a full review of PSO's 2001 fuel and purchased power practices. PSO filed its testimony in February 2004 and hearings will occur in June 2004. If the OCC determines as a result of the review that a portion of PSO's fuel and purchased power costs should not be recovered, there will be an adverse effect on PSO's results of operations, cash flows and possibly financial condition.

Virginia Fuel Factor Filing

APCo filed with the Virginia SCC to reduce its fuel factor effective August 1, 2003. The requested fuel rate reduction was approved by the Virginia SCC and is effective for 17 months (August 1, 2003 to December 31, 2004) and is estimated to reduce revenues by $36 million during that period. This fuel factor adjustment will reduce cash flows without impacting results of operations as any over-recovery or under-recovery of fuel costs would be deferred as a regulatory liability or a regulatory asset.

FERC Long-term Contracts

In 2002, the FERC set for hearing complaints filed by certain wholesale customers located in Nevada and Washington that sought to break long-term contracts which the customers alleged were "high-priced." At issue were long-term contracts entered into during the California energy price spike in 2000 and 2001. The complaints alleged that AEP sold power at unjust and unreasonable prices.

In February 2003, AEP and one of the customers agreed to terminate their contract. The customer withdrew its FERC complaint and paid $59 million to AEP. As a result of the contract termination, AEP reversed $69 million of unrealized mark-to-market gains previously recorded, resulting in a $10 million pre-tax loss.

In December 2002, a FERC ALJ ruled in favor of AEP and dismissed a complaint filed by two Nevada utilities. In 2000 and 2001, we agreed to sell power to the utilities for future delivery. In 2001, the utilities filed complaints asserting that the prices for power supplied under those contracts should be lowered because the market for power was allegedly dysfunctional at the time such contracts were executed. The ALJ rejected the utilities' complaint, held that the markets for future delivery were not dysfunctional, and that the utilities had failed to demonstrate that the public interest required that changes be made to the contracts. In June 2003, the FERC issued an order affirming the ALJ's decision. The utilities requested a rehearing which the FERC denied. The utilities' appeal of the FERC order is pending before the U.S. Court of Appeals for the Ninth Circuit. Management is unable to predict the outcome of this proceeding and its impact on future results of operations and cash flows.

RTO Formation/Integration Costs

With FERC approval, AEP East companies have been deferring costs incurred under FERC orders to form an RTO (the Alliance RTO) or join an existing RTO (PJM). In July 2003, the FERC issued an order approving our continued deferral of both our Alliance formation costs and our PJM integration costs including the deferral of a carrying charge. The AEP East companies have deferred approximately $28 million of RTO formation and integration costs and related carrying charges through December 31, 2003. As a result of the subsequent delay in the integration of AEP's East transmission system into PJM, FERC declined to rule, in its July order, on our request to transfer the deferrals to regulatory assets, and to maintain the deferrals until such time as the costs can be recovered from all users of AEP's East transmission system. The AEP East companies will apply for permission to transfer the deferred formation/integration costs to a regulatory asset prior to integration with PJM. In August 2003, the Virginia SCC filed a request for rehearing of the July order, arguing that FERC's action was an infringement on state jurisdiction, and that FERC should not have treated Alliance RTO startup costs in the same manner as PJM integration costs. On October 22, 2003, FERC denied the rehearing request.

In its July 2003 order, FERC indicated that it would review the deferred costs at the time they are transferred to a regulatory asset account and scheduled for amortization and recovery in the open access transmission tariff (OATT) to be charged by PJM. Management believes that the FERC will grant permission for the deferred RTO costs to be amortized and included in the OATT. Whether the amortized costs will be fully recoverable depends upon the state regulatory commissions' treatment of AEP East companies' portion of the OATT at the time they join PJM. Presently, retail base rates are frozen or capped and cannot be increased for retail customers of CSPCo, I&M and OPCo. APCo's Virginia retail base rates are capped with an opportunity for a one-time increase in non-generation rates after January 1, 2004. We intend to file an application with FERC seeking permission to delay the amortization of the deferred RTO formation/integration costs until they are recoverable from all users of the transmission system including retail customers. Management is unable to predict the timing of when AEP will join PJM and if upon joining PJM whether FERC will grant a delay of recovery until the rate caps and freezes end. If the AEP East companies do not obtain regulatory approval to join PJM, we are committed to reimburse PJM for certain project implementation costs (presently estimated at $24 million for the entire PJM integration project). Management intends to seek recovery of the deferred RTO formation/integration costs and project implementation cost reimbursements, if incurred. If the FERC ultimately decides not to approve a delay or the state commissions deny recovery, future results of operations and cash flows could be adversely affected.

In the first quarter of 2003, the state of Virginia enacted legislation preventing APCo from joining an RTO prior to July 1, 2004 and thereafter only with the approval of the Virginia SCC, but required such transfers by January 1, 2005. In January 2004, APCo filed with the Virginia SCC a cost/benefit study covering the time period through 2014 as required by the Virginia SCC. The study results show a net benefit of approximately $98 million for APCo over the 11-year study period from AEP's participation in PJM.

In July 2003, the KPSC denied KPCo's request to join PJM based in part on a lack of evidence that it would benefit Kentucky retail customers. In August 2003, KPCo sought and was granted a rehearing to submit additional evidence. In December 2003, AEP filed with the KPSC a cost/benefit study showing a net benefit of approximately $13 million for KPCo over the five-year study period from AEP's participation in PJM. A hearing has been scheduled in April 2004.

In September 2003, the IURC issued an order approving I&M's transfer of functional control over its transmission facilities to PJM, subject to certain conditions included in the order. The IURC's order stated that AEP shall request and the IURC shall complete a review of Alliance formation costs before any deferral of the costs for future recovery.

In November 2003, the FERC issued an order preliminarily finding that AEP must fulfill its CSW merger condition to join an RTO by integrating into PJM (transmission and markets) by October 1, 2004. The order was based on PURPA 205(a), which allows FERC to exempt electric utilities from state law or regulation in certain circumstances. The FERC set for public hearing before an ALJ several issues. Those issues include whether the laws, rules, or regulations of Virginia and Kentucky are preventing AEP from joining an RTO and whether the exceptions under PURPA apply. The FERC directed the ALJ to issue his initial decision by March 15, 2004.

FERC Order on Regional Through and Out Rates

In July 2003, the FERC issued an order directing PJM and the Midwest ISO to make compliance filings for their respective Open Access Transmission Tariffs to eliminate, by November 1, 2003, the transaction-based charges for through and out (T&O) transmission service on transactions where the energy is delivered within the proposed Midwest ISO and PJM expanded regions (RTO Footprint). In October 2003, the FERC postponed the November 1, 2003 deadline to eliminate T&O rates. The elimination of the T&O rates will reduce the transmission service revenues collected by the RTOs and thereby reduce the revenues received by transmission owners under the RTOs' revenue distribution protocols. The order provided that affected transmission owners could file to offset the elimination of these revenues by increasing rates or utilizing a transitional rate mechanism to recover lost revenues that result from the elimination of the T&O rates. The FERC also found that the T&O rates of some of the former Alliance RTO companies, including AEP, may be unjust, unreasonable, and unduly discriminatory or preferential for energy delivered in the RTO Footprint. FERC initiated an investigation and hearing in regard to these rates. We made a filing with the FERC to support the justness and reasonableness of our rates. We also made a joint filing with unaffiliated utilities proposing a regional revenue replacement mechanism for the lost revenues, in the event that FERC eliminated all T&O rates for delivery points within the RTO Footprint. In orders issued in November 2003, the FERC dismissed the joint filing, but adopted a new regional rate design substantially in the form proposed in the joint filing. The orders directed each transmission provider to file compliance rates to eliminate T&O rates prospectively within the region and simultaneously implement new seams elimination cost allocation (SECA) rates to mitigate the lost revenues for a two-year transition period beginning April 1, 2004. The FERC did not indicate the recovery method for the revenues after the two-year period. As required by the FERC, we filed compliance tariff changes in January 2004 to eliminate the T&O charges within the RTO Footprint. The SECA rate issues that remain unresolved have been set before an ALJ for settlement procedures, and the effective date of the T&O rate elimination and SECA rates were delayed until May 1, 2004. The November orders have been appealed by a number of parties. The AEP East companies received approximately $150 million of T&O rate revenues from transactions delivering energy to customers in the RTO Footprint for the twelve months ended June 30, 2003. At this time, management is unable to predict whether the new SECA rates will fully compensate the AEP East companies for their lost T&O rate revenues and, consequently, their impact on our future results of operations, cash flows and financial condition.

Indiana Fuel Order

On July 17, 2003, I&M filed a fuel adjustment clause application requesting authorization to implement the fixed fuel adjustment charge (fixed pursuant to a prior settlement of the Cook Nuclear Plant Outage) for electric service for the billing months of October 2003 through February 2004, and for approval of a new fuel cost adjustment credit for electric service to be applicable during the March 2004 billing month.

On August 27, 2003, the IURC issued an order approving the requested fixed fuel adjustment charge for October 2003 through February 2004. The order further stated that certain parties must negotiate the appropriate action on fuel to commence on March 1, 2004. Such negotiations are ongoing. The IURC deferred ruling on the March 2004 factor until after January 1, 2004.

Michigan 2004 Fuel Recovery Plan

The MPSC's December 16, 1999 order approved a Settlement Agreement regarding the extended outage of the Cook Plant and fixed I&M Power Supply Cost Recovery (PSCR) factors for the St. Joseph and Three Rivers rate areas through December 2003. In accordance with the settlement, PSCR Plan cases were not required to be filed through the 2003 plan year. As required, I&M filed its 2004 PSCR Plan with the MPSC on September 30, 2003 seeking new fuel and power supply recovery factors to be effective in 2004. The case has been scheduled for hearing. As allowed by Michigan law, the proposed factors were effective on January 1, 2004, subject to review and possible adjustment based on the results of the hearing.

5. EFFECTS OF REGULATION

Regulatory Assets and Liabilities

Regulatory assets and liabilities are comprised of the following items:

	December 31, 2003	December 31, 2002	Future Recovery/ Refund Period
	(in millions)		
Regulatory Assets:			
Income Tax-related Regulatory Assets, Net	$728	$639	Various Periods (a)
Transition Regulatory Assets	529	743	Up to 5 Years (a)
Regulatory Assets Designated for Securitization	1,253	331	(b)
Texas Wholesale Capacity Auction True-Up	480	262	(c)
Unamortized Loss on Reacquired Debt	116	83	Up to 40 Years (d)
Cook Nuclear Plant Restart Costs	-	40	N/A
Cook Nuclear Plant Refueling Outage Levelization	57	30	(e)
Deferred Fuel Costs	24	121	1 Year (a)
CSW Merger Costs	23	32	Up to 5 Years (a)
Deferred Fuel Costs (TNC)	27	27	(c)
DOE Decontamination and Decommissioning Assessment	21	26	Up to 5 Years (a)
Other	290	354	Various Periods (f)
Total Regulatory Assets	$3,548	$2,688	
Regulatory Liabilities:			
Asset Removal Costs	$1,233	$-	(h)
Deferred Investment Tax Credits	422	455	Up to 26 Years (a)
Excess ARO for Nuclear Decommissioning Liability	216	-	(g)
Deferred Over-Recovered Fuel Costs (TCC)	69	69	(c)
Deferred Over-Recovered Fuel Costs	63	21	(a)
Texas Retail Clawback	57	66	(c)
Other	199	328	Various Periods (f)
Total Regulatory Liabilities	$2,259	$939	

(a) Amount does not earn a return.
(b) Will be included in TCC's PUCT 2004 true-up proceeding and is designated for possible securitization during 2005.
(c) Amount will be included in TCC's and TNC's 2004 true-up proceedings for future recovery/payment over a time period to be determined in a future PUCT proceeding.
(d) Amount effectively earns a return.
(e) Amortized over the period beginning with the commencement of an outage and ending with the beginning of the next outage and does not earn a return.
(f) These regulatory assets and liabilities include items both earning and not earning a return.
(g) Amounts are accrued monthly and will be paid when the nuclear plant is decommissioned. This also earns a return.
(h) The liability for removal costs will be discharged as removal costs are incurred over the life of the plant.

Texas Restructuring Related Regulatory Assets and Liabilities

Regulatory Assets Designated for Securitization, Texas Wholesale Capacity Auction True-up regulatory assets, Deferred Over-Recovered Fuel Costs and Texas Retail Clawback regulatory liabilities are not being currently recovered from or returned to ratepayers. Management believes that the laws and regulations, established in Texas for industry restructuring, provide for the recovery from ratepayers of these net amounts. See Note 6 for a complete discussion of our plans to recover these regulatory assets, net of regulatory liabilities.

Nuclear Plant Restart

I&M completed the restart of both units of the Cook Plant in 2000. Settlement agreements in the Indiana and Michigan retail jurisdictions that addressed recovery of Cook Plant related outage restart costs were approved in 1999 by the IURC and MPSC.

The amount of deferrals amortized to other O&M expenses were $40 million in 2003, 2002 and 2001. Also pursuant to the settlement agreements, accrued fuel-related revenues of approximately $37 million in 2003 and $38 million in 2002 and 2001 were amortized as a reduction of revenues.

The amortization of O&M costs and fuel-related revenues deferred under Indiana and Michigan retail jurisdictional settlement agreements adversely affected results of operations through December 31, 2003 when the amortization period ended.

Merger with CSW

On June 15, 2000, AEP merged with CSW so that CSW became a wholly-owned subsidiary of AEP. The following table summarizes significant merger-related agreements:

Summary of key provisions of Merger Rate Agreements:

State/Company	Ratemaking Provisions
Texas – SWEPCo, TCC, TNC	$221 million rate reduction over 6 years. No base rate increases for 3 years post merger.
Indiana – I&M	$67 million rate reduction over 8 years. Extension of base rate freeze until January 1, 2005. Requires additional annual deposits of $6 million to the nuclear decommissioning trust fund for the years 2001 through 2003.
Michigan – I&M	Customer billing credits of approximately $14 million over 8 years. Extension of base rate freeze until January 1, 2005.
Kentucky – KPCo	Rate reductions of approximately $28 million over 8 years. No base rate increases for 3 years post merger.
Oklahoma – PSO	Rate reductions of approximately $28 million over 5 years. No base rate increase before January 1, 2003.
Arkansas – SWEPCo	Rate reductions of $6 million over 5 years. No base rate increase before June 15, 2003
Louisiana – SWEPCo	Rate reductions to share merger savings estimated to be $18 million over 8 years. Base rate cap until June 2005.

If actual merger savings are significantly less than the merger savings rate reductions required by the merger settlement agreements in the eight-year period following consummation of the merger, future results of operations, cash flows and possibly financial condition could be adversely affected.

See Note 7, "Commitments and Contingencies" for information on a court decision concerning the merger.

6. CUSTOMER CHOICE AND INDUSTRY RESTRUCTURING

Prior to 2003, retail customer choice began in four of the eleven state retail jurisdictions (Michigan, Ohio, Texas and Virginia) in which the AEP domestic electric utility companies operate. The following paragraphs discuss significant events related to customer choice and industry restructuring.

OHIO RESTRUCTURING

On June 27, 2002, the Ohio Consumers' Counsel, Industrial Energy Users–Ohio and American Municipal Power–Ohio filed a complaint with the PUCO alleging that CSPCo and OPCo have violated the PUCO's orders regarding implementation of their transition plan and violated the applicable law by failing to participate in an RTO.

The complainants seek, among other relief, an order from the PUCO:

- suspending collection of transition charges by CSPCo and OPCo until transfer of control of their transmission assets has occurred
- requiring the pricing of standard offer electric generation effective January 1, 2006 at the market price used by CSPCo and OPCo in their 1999 transition plan filings to estimate transition costs and
- imposing a $25,000 per company forfeiture for each day AEP fails to comply with its commitment to transfer control of transmission assets to an RTO

Due to FERC, state legislative and regulatory developments, CSPCo and OPCo have been delayed in the implementation of their RTO participation plans. We continue to pursue integration of CSPCo, OPCo and other AEP East companies into PJM. In this regard, on December 19, 2002, CSPCo and OPCo filed an application with the PUCO for approval of the transfer of functional control over certain of their transmission facilities to PJM. In February 2003, the PUCO consolidated the June 2002 complaint with our December application. CSPCo's and OPCo's motion to dismiss the complaint has been denied by the PUCO and the PUCO affirmed that ruling in rehearing. All further action in the consolidated case has been stayed "until more clarity is achieved regarding matters pending at the FERC and elsewhere." Management is currently unable to predict the timing of the AEP East companies' (including CSPCo and OPCo) participation in PJM, the outcome of these proceedings before the PUCO or their impact on results of operations and cash flows.

In October 2002, the PUCO initiated an investigation of the financial condition of Ohio's regulated public utilities. The PUCO's goal is to identify measures available to the PUCO to ensure that the regulated operations of Ohio's public utilities are not impacted by adverse financial consequences of parent or affiliate company unregulated operations and take appropriate corrective action, if necessary. The utilities and other interested parties were requested to provide comments and suggestions by November 12, 2002, with reply comments by November 22, 2002, on the type of information necessary to accomplish the stated goals, the means to gather the required information from the public utilities and potential courses of action that the PUCO could take. In January 2004, the PUCO staff issued a report recommending that the PUCO seek more authority from the Ohio Legislature on this issue. The PUCO has taken no further action in this proceeding. Management is unable to predict the outcome of the PUCO's investigation or its impact on results of operations, cash flows and business practices, if any.

On March 20, 2003, the PUCO commenced a statutorily required investigation concerning the desirability, feasibility and timing of declaring retail ancillary, metering or billing and collection service, supplied to customers within the certified territories of electric utilities, a competitive retail electric service. The PUCO sent out a list of questions and set June 6, 2003 and July 7, 2003 as the dates for initial responses and replies, respectively. CSPCo and OPCo filed comments and responses in compliance with the PUCO's schedule. Management is unable to predict the timing or the outcome of this proceeding or its impact on results of operations or cash flows.

The Ohio Act provides for a Market Development Period (MDP) during which retail customers can choose their electric power suppliers or receive Default Service at frozen generation rates from the incumbent utility. The MDP began on January 1, 2001 and is scheduled to terminate no later than December 31, 2005. The PUCO may terminate the MDP for one or more customer classes before that date if it determines either that effective competition exists in the incumbent utility's certified territory or that there is a twenty percent switching rate of the incumbent utility's load by customer class. Following the MDP, retail customers will receive distribution and transmission service from the incumbent utility whose distribution rates will be approved by the PUCO and whose transmission rates will be approved by the FERC. Retail customers will continue to have the right to choose their electric power suppliers or receive Default Service, which must be offered by the incumbent utility at market rates. On December 17, 2003, the PUCO adopted a set of rules concerning the method by which it will determine market rates for Default Service following the MDP. The rule provides for a Market Based Standard Service Offer which would be a variable rate based on a transparent forward market, daily market, and/or hourly market prices. The rule also requires a fixed-rate Competitive Bidding Process for residential and small nonresidential customers and permits a fixed-rate Competitive Bidding Process for large general service customers and other customer classes. Customers who do not switch to a competitive generation provider can choose between the Market Based Standard Service Offer or the Competitive Bidding Process. Customers who make no choice will be served pursuant to the Competitive Bidding Process.

On February 9, 2004, CSPCo and OPCo filed their rate stabilization plan with the PUCO addressing rates following the end of the MDP, which ends December 31, 2005. If approved by the PUCO, rates would be established pursuant to the plan for the period from January 1, 2006 through December 31, 2008 instead of the rates discussed in the previous paragraph. The plan is intended to provide rate stability and certainty for customers, facilitate the development of a competitive retail market in Ohio, provide recovery of environmental and other costs during the plan period and improve the environmental performance of AEP's generation resources that serve Ohio customers. The plan includes annual, fixed increases in the generation component of all customers' bills (3% annually for CSPCo and 7% annually for OPCo), and the opportunity for additional generation-related increases upon PUCO review and approval. For residential customers, however, if the temporary 5% generation rate discount provided by the Ohio Act were eliminated on June 30, 2004, the fixed increases would be 1.6% for CSPCo and 5.7% for OPCo. The generation-related increases under the plan would be subject to caps. The plan would maintain distribution rates through the end of 2008 for CSPCo and OPCo at the level effective on December 31, 2005. Such rates could be adjusted for specified reasons through a PUCO filing. Transmission charges can be adjusted to reflect applicable charges approved by the FERC related to open access transmission, net congestion, and ancillary services. The plan also provides for continued recovery of transition regulatory assets and deferral of regulatory assets in 2004 and 2005 for RTO costs and carrying costs on required environmental expenditures. A procedural schedule has not been established for this filing. Management cannot predict whether the plan will be approved as submitted, modified by the PUCO, or its impacts on results of operation and cash flows.

As provided in stipulation agreements approved by the PUCO in 2000, we are deferring customer choice implementation costs and related carrying costs that are in excess of $40 million. The agreements provide for the deferral of these costs as a regulatory asset until the next distribution base rate cases. The February 2004 filing provides for the continued deferral of customer choice implementation costs during the rate stabilization plan period. At December 31, 2003, we have incurred $66 million and deferred $26 million of such costs. Recovery of these regulatory assets will be subject to PUCO review in future Ohio filings for new distribution rates. If the rate stabilization plan is approved, it would defer recovery of these amounts until after the end of the rate stabilization period. Management believes that the customer choice implementation costs were prudently incurred and the deferred amounts should be recoverable in future rates. If the PUCO determines that any of the deferred costs are unrecoverable, it would have an adverse impact on future results of operations and cash flows.

TEXAS RESTRUCTURING

Texas Legislation enacted in 1999 provided the framework and timetable to allow retail electricity competition for all customers. On January 1, 2002, customer choice of electricity supplier began in the ERCOT area of Texas. Customer choice has been delayed in the SPP area of Texas until at least January 1, 2007.

The Texas Legislation, among other things:

- provides for the recovery of regulatory assets and other stranded costs through securitization and non-bypassable wires charges;
- requires each utility to structurally unbundle into a retail electric provider, a power generation company and a transmission and distribution (T&D) utility;
- provides for an earnings test for each of the years 1999 through 2001 and;
- provides for a 2004 true-up proceeding. See 2004 true-up proceeding discussion below.

The Texas Legislation required vertically integrated utilities to legally separate their generation and retail-related assets from their transmission and distribution-related assets. Prior to 2002, TCC and TNC functionally separated their operations to comply with the Texas Legislation requirements. AEP formed new subsidiaries to act as affiliated REPs for TCC and TNC effective January 1, 2002 (the start date of retail competition). In December 2002, AEP sold the affiliated REPs to an unaffiliated company.

In 1999, TCC filed with the PUCT to securitize $1.27 billion of its retail generation-related regulatory assets and $47 million in other qualified restructuring costs. The PUCT authorized the issuance of up to $797 million of securitization bonds ($949 million of generation-related regulatory assets and $33 million of qualified refinancing costs offset by $185 million of customer benefits for accumulated deferred income taxes). TCC issued its securitization bonds in February 2002. The amount not approved for securitization will be included in regulatory assets/stranded costs in TCC's 2004 true-up proceeding.

TEXAS 2004 TRUE-UP PROCEEDING

A 2004 true-up proceeding will determine the amount and recovery of:

- net stranded generating plant costs and generation-related regulatory assets (stranded costs),
- a true-up of actual market prices determined through legislatively-mandated capacity auctions to the power costs used in the PUCT's ECOM model for 2002 and 2003 (wholesale capacity auction true-up),
- final approved deferred fuel balance,
- unrefunded accumulated excess earnings,
- excess of price-to-beat revenues over market prices subject to certain conditions and limitations (retail clawback) and
- other restructuring true-up items

The PUCT adopted a rule in 2003 regarding the timing of the 2004 true-up proceedings scheduling TNC's filing in May 2004 and TCC's filing in September 2004 or 60 days after the completion of the sale of TCC's generation assets, if later.

Stranded Costs and Generation-Related Regulatory Assets

Restructuring legislation required utilities with stranded costs to use market-based methods to value certain generating assets for determining stranded costs. TCC is the only AEP subsidiary that has stranded costs under the Texas Legislation. We have elected to use the sale of assets method to determine the market value of all of our generation assets for stranded cost purposes. When completed, the sale of our generation assets will substantially complete the required separation of generation assets from transmission and distribution assets. For purposes of the 2004 true-up proceeding, the amount of stranded costs under this market valuation methodology will be the amount by which the book value of TCC's generating assets, including regulatory assets and liabilities that were not securitized, exceeds the market value of the generation assets as measured by the net proceeds from the sale of the assets. It is anticipated that any such sale will result in significant stranded costs for purposes of TCC's 2004 true-up proceeding.

In December 2002, TCC filed a plan of divestiture with the PUCT seeking approval of a sales process for all of its generating facilities. In March 2003, the PUCT dismissed TCC's divestiture filing, determining that it was more appropriate to address allowable valuation methods for the nuclear asset in a rulemaking proceeding. The PUCT approved a rule, in May 2003, which allows the market value obtained by selling nuclear assets to be used in determining stranded costs. Although the PUCT declined to review TCC's proposed sale of assets process, the PUCT has hired a consultant to advise TCC during the sale of the generation assets. TCC's sale of its generating assets will be subject to a review in the 2004 true-up proceeding.

In June 2003, we began actively seeking buyers for 4,497 megawatts of TCC's generating capacity in Texas. In order to sell these assets, we anticipate retiring TCC's first mortgage bonds by making open market purchases or defeasing the bonds. Bids were received for all of TCC's generating plants. In January 2004, TCC agreed to sell its 7.8% ownership interest in the Oklaunion Power Station to an unaffiliated third party for $43 million. The sale of TCC's remaining generation is pending. Additional regulatory approvals will be required to complete the sale of the generation assets, including NRC approval of the transfer of our interest in STP.

In the 2004 true-up proceeding, the amount of stranded costs under this market valuation methodology will be the amount by which the book value of TCC's generating assets, including regulatory assets and liabilities that were not securitized and reduced by mitigation including unrefunded excess earnings, exceeds the market value of the generation assets as measured by the net proceeds from the sale of the assets. It is anticipated that any such sale will result in significant stranded costs for purposes of TCC's 2004 true-up proceeding.

After the 2004 true-up proceeding, TCC may seek to issue securitization revenue bonds for its stranded costs and recover the costs of the securitization bonds through transmission and distribution rates. Based upon the Oklaunion sale and the bid information for the remaining generation, we recorded an impairment of generating assets of $938 million in December 2003 as a regulatory asset (see Note 10). The recovery of the regulatory asset will be subject to review and approval by the PUCT as a stranded cost in the 2004 true-up proceeding.

Wholesale Capacity Auction True-up

Texas Legislation also requires that electric utilities and their affiliated power generation companies (PGC) offer for sale at auction, in 2002 and 2003 and after, at least 15% of the PGC's Texas jurisdictional installed generation capacity in order to promote competitiveness in the wholesale market through increased availability of generation. Actual market power prices received in the state mandated auctions will be used to calculate the wholesale capacity auction true-up adjustment for TCC for the 2004 true-up proceeding.

TCC recorded a $480 million regulatory asset and related revenues which represent the quantifiable amount of the wholesale capacity auction true-up for the years 2002 and 2003. In TCC's UCOS proceeding, the PUCT estimated that TCC had negative stranded costs. In its true-up rule, the PUCT determined that the wholesale capacity auction true-up proceeds should be offset against negative stranded costs. However, in March 2003, the Texas Court of Appeals ruled that under the restructuring legislation, other 2004 true-up items, including the wholesale capacity auction true-up regulatory asset, could be recovered regardless of the level of stranded costs.

In the fourth quarter of 2003, the PUCT approved a true-up filing package containing calculation instructions similar to the methodology employed by TCC to calculate the amount recorded for recovery under its wholesale capacity auction true-up. The PUCT will review the $480 million wholesale capacity regulatory asset for recovery as part of the 2004 true-up proceeding.

Fuel Balance Recoveries

In 2002, TNC filed with the PUCT seeking to reconcile fuel costs and to establish its deferred unrecovered fuel balance applicable to retail sales within its ERCOT service area for inclusion in the 2004 true-up proceeding. In January 2004, the PUCT announced a final ruling in TNC's fuel reconciliation case that established TNC's unrecovered fuel balance, including interest for the ERCOT service territory, at $6.2 million. This balance will be included in TNC's 2004 true-up proceeding. TNC is waiting for a written order from the PUCT, after which it will request a rehearing.

In 2002, TCC filed with the PUCT to reconcile fuel costs and to establish its deferred over-recovery of fuel balance for inclusion in the 2004 true-up proceeding. In February 2004, an ALJ issued recommendations finding a $205 million over-recovery in this fuel proceeding. Management is unable to predict the amount of TCC's fuel over-recovery which will be included in its 2004 true-up proceeding.

See TCC Fuel Reconciliation and TNC Fuel Reconciliation in Note 4 "Rate Matters" for further discussion.

Unrefunded Excess Earnings

The Texas Legislation provides for the calculation of excess earnings for each year from 1999 through 2001. The total excess earnings determined for the three year period were $3 million for SWEPCo, $47 million for TCC and $19 million for TNC. TCC, TNC and SWEPCo challenged the PUCT's treatment of fuel-related deferred income taxes and appealed the PUCT's final 2000 excess earnings to the Travis County District Court which upheld the PUCT ruling. The District Court's ruling was appealed to the Third Court of Appeals. In August 2003, the Third Court of Appeals reversed the PUCT order and the District Court's judgment. The PUCT's request for rehearing of the Appeals Court's decision was denied and the PUCT chose not to appeal the ruling any further. Appeal of the same issue from the PUCT's 2001 order is pending before the District Court. Since an expense and regulatory liability had been accrued in prior years in compliance with the PUCT orders, the companies reversed a portion of their regulatory liability for the years 2000 and 2001 consistent with the Appeals Court's decision and credited amortization expense during the third quarter of 2003. Pre-tax amounts reversed by company were $5 million for TCC, $3 million for TNC and $1 million for SWEPCo.

In 2001, the PUCT issued an order requiring TCC to return estimated excess earnings by reducing distribution rates by approximately $55 million plus accrued interest over a five-year period beginning January 1, 2002. Since excess earnings amounts were expensed in 1999, 2000 and 2001, the order has no additional effect on reported net income but will reduce cash flows for the five-year refund period. The amount to be refunded is recorded as a regulatory liability. Management believes that TCC will have stranded costs and that it was inappropriate for the PUCT to order a refund prior to TCC's 2004 true-up proceeding. TCC appealed the PUCT's refund of excess earnings to the Travis County District Court. That court affirmed the PUCT's decision and further ordered that the refunds be provided to customers. TCC has appealed the decision to the Court of Appeals.

Retail Clawback

The Texas Legislation provides for the affiliated PTB REP serving residential and small commercial customers to refund to its T&D utility the excess of the PTB revenues over market prices (subject to certain conditions and a limitation of $150 per customer). This is the retail clawback. If, prior to January 1, 2004, 40% of the load for the residential or small commercial classes is served by competitive REPs, the retail clawback is not applicable for that class of customer. During 2003, TCC and TNC filed to notify the PUCT that competitive REPs serve over 40% of the load in the small commercial class. The PUCT approved TCC's and TNC's filings in December 2003. In 2002, AEP had accrued a regulatory liability of approximately $9 million for the small commercial retail clawback on its REP's books. When the PUCT certified that the REP's in TCC and TNC service territories had reached the 40% threshold, the regulatory liability was no longer required for the small commercial class and was reversed in December 2003. At December 31, 2003, the remaining retail clawback regulatory liability was $57 million.

When the 2004 true-up proceeding is completed, TCC intends to file to recover PUCT-approved stranded costs and other true-up amounts that are in excess of current securitized amounts, plus appropriate carrying charges and other true-up amounts, through non-bypassable competition transition charge in the regulated T&D rates. TCC may also seek to securitize certain of the approved stranded plant costs and regulatory assets that were not previously recovered through the non-bypassable transition charge. The annual costs of securitization are recovered through a non-bypassable rate surcharge collected by the T&D utility over the term of the securitization bonds.

In the event we are unable, after the 2004 true-up proceeding, to recover all or a portion of our stranded plant costs, generation-related regulatory assets, unrecovered fuel balances, wholesale capacity auction true-up regulatory assets, other restructuring true-up items and costs, it could have a material adverse effect on results of operations, cash flows and possibly financial condition.

MICHIGAN RESTRUCTURING

Customer choice commenced for I&M's Michigan customers on January 1, 2002. Effective with that date the rates on I&M's Michigan customers' bills for retail electric service were unbundled to allow customers the opportunity to evaluate the cost of generation service for comparison with other offers. I&M's total rates in Michigan remain unchanged and reflect cost of service. At December 31, 2003, none of I&M's customers have elected to change suppliers and no alternative electric suppliers are registered to compete in I&M's Michigan service territory.

Management has concluded that as of December 31, 2003 the requirements to apply SFAS 71 continue to be met since I&M's rates for generation in Michigan continue to be cost-based regulated.

ARKANSAS RESTRUCTURING

In February 2003, Arkansas repealed customer choice legislation originally enacted in 1999. Consequently, SWEPCo's Arkansas operations reapplied SFAS 71 regulatory accounting, which had been discontinued in 1999. The reapplication of SFAS 71 had an insignificant effect on results of operations and financial condition. As a result of reapplying SFAS 71, derivative contract gains/losses for transactions within AEP's traditional marketing area allocated to Arkansas will not affect income until settled. That is, such positions will be recorded on the balance sheet as either a regulatory asset or liability until realized.

WEST VIRGINIA RESTRUCTURING

APCo reapplied SFAS 71 for its West Virginia (WV) jurisdiction in the first quarter of 2003 after new developments during the quarter prompted an analysis of the probability of restructuring becoming effective.

In 2000, the WVPSC issued an order approving an electricity restructuring plan, which the WV Legislature approved by joint resolution. The joint resolution provided that the WVPSC could not implement the plan until the WV legislature made tax law changes necessary to preserve the revenues of state and local governments.

In the 2001 and 2002 legislative sessions, the WV Legislature failed to enact the required legislation that would allow the WVPSC to implement the restructuring plan. Due to this lack of legislative activity, the WVPSC closed two proceedings related to electricity restructuring during the summer of 2002.

In the 2003 legislative session, the WV Legislature failed to enact the required tax legislation. Also, legislation enacted in March 2003 clarified the jurisdiction of the WVPSC over electric generation facilities in WV. In March 2003, APCo's outside counsel advised us that restructuring in WV was no longer probable and confirmed facts relating to the WVPSC's jurisdiction and rate authority over APCo's WV generation. APCo has concluded that deregulation of the WV generation business is no longer probable and operations in WV meet the requirements to reapply SFAS 71.

Reapplying SFAS 71 in WV had an insignificant effect on results of operations and financial condition. As a result, derivative contract gains/losses related to transactions within AEP's traditional marketing area allocated to WV will not affect income until settled. That is, such positions will be recorded on the balance sheet as either a regulatory asset or liability until realized. Positions outside AEP's traditional marketing area will continue to be marked-to-market.

7. <u>COMMITMENTS AND CONTINGENCIES</u>

ENVIRONMENTAL

Federal EPA Complaint and Notice of Violation

The Federal EPA and a number of states have alleged APCo, CSPCo, I&M, OPCo and other unaffiliated utilities modified certain units at coal-fired generating plants in violation of the NSRs of the CAA. The Federal EPA filed its complaints against our subsidiaries in U.S. District Court for the Southern District of Ohio. The court also consolidated a separate lawsuit, initiated by certain special interest groups, with the Federal EPA case. The alleged modifications relate to costs that were incurred at our generating units over a 20-year period.

Under the Clean Air Act, if a plant undertakes a major modification that directly results in an emissions increase, permitting requirements might be triggered and the plant may be required to install additional pollution control technology. This requirement does not apply to activities such as routine maintenance, replacement of degraded equipment or failed components, or other repairs needed for the reliable, safe and efficient operation of the plant. The Clean Air Act authorizes civil penalties of up to $27,500 per day per violation at each generating unit ($25,000 per day prior to January 30, 1997). In 2001, the District Court ruled claims for civil penalties based on activities that occurred more than five years before the filing date of the complaints cannot be imposed. There is no time limit on claims for injunctive relief.

On August 7, 2003, the District Court issued a decision following a liability trial in a case pending in the Southern District of Ohio against Ohio Edison Company, an unaffiliated utility. The District Court held that replacements of major boiler and turbine components that are infrequently performed at a single unit, that are performed with the assistance of outside contractors, that are accounted for as capital expenditures, and that require the unit to be taken out of service for a number of months are not "routine" maintenance, repair, and replacement. The District Court also held that a comparison of past actual emissions to projected future emissions must be performed prior to any non-routine physical change in order to evaluate whether an emissions increase will occur, and that increased hours of operation that are the result of eliminating forced outages due to the repairs must be included in that calculation. Based on these holdings, the District Court ruled that all of the challenged activities in that case were not routine, and that the changes resulted in significant net increases in emissions for certain pollutants. A remedy trial is scheduled for July 2004.

Management believes that the Ohio Edison decision fails to properly evaluate and apply the applicable legal standards. The facts in our case also vary widely from plant to plant. Further, the Ohio Edison decision is limited to liability issues, and provides no insight as to the remedies that might ultimately be ordered by the Court.

On August 26, 2003, the District Court for the Middle District of South Carolina issued a decision on cross-motions for summary judgment prior to a liability trial in a case pending against Duke Energy Corporation, an unaffiliated utility. The District Court denied all the pending motions, but set forth the legal standards that will be applied at the trial in that case. The District Court determined that the Federal EPA bears the burden of proof on the issue of whether a practice is "routine maintenance, repair, or replacement" and on whether or not a "significant net emissions increase" results from a physical change or change in the method of operation at a utility unit. However, the Federal EPA must consider whether a practice is "routine within the relevant source category" in determining if it is "routine." Further, the Federal EPA must calculate emissions by determining first whether a change in the maximum achievable hourly emission rate occurred as a result of the change, and then must calculate any change in annual emissions holding hours of operation constant before and after the change. The Federal EPA has requested reconsideration of this decision, or in the alternative, certification of an interlocutory appeal to the Fourth Circuit Court of Appeals.

On June 24, 2003, the United States Court of Appeals for the 11th Circuit issued an order invalidating the administrative compliance order issued by the Federal EPA to the Tennessee Valley Authority for alleged Clean Air Act violations. The 11th Circuit determined that the administrative compliance order was not a final agency action, and that the enforcement provisions authorizing the issuance and enforcement of such orders under the Clean Air Act are unconstitutional.

On June 26, 2003, the United States Court of Appeals for the District of Columbia Circuit granted a petition by the Utility Air Regulatory Group (UARG), of which our subsidiaries are members, to reopen petitions for review of the 1980 and 1992 Clean Air Act rulemakings that are the basis for the Federal EPA claims in our case and other related cases. On August 4, 2003, UARG filed a motion to separate and expedite review of their challenges to the 1980 and 1992 rulemakings from other unrelated claims in the consolidated appeal. The Circuit Court denied that motion on September 30, 2003. The central issue in these petitions concerns the lawfulness of the emissions increase test, as currently interpreted and applied by the Federal EPA in its utility enforcement actions. A decision by the D. C. Circuit Court could significantly impact further proceedings in our case.

On August 27, 2003, the Administrator of the Federal EPA signed a final rule that defines "routine maintenance repair and replacement" to include "functionally equivalent equipment replacement." Under the new final rule, replacement of a component within an integrated industrial operation (defined as a "process unit") with a new component that is identical or functionally equivalent will be deemed to be a "routine replacement" if the replacement does not change any of the fundamental design parameters of the process unit, does not result in emissions in excess of any authorized limit, and does not cost more than twenty percent of the replacement cost of the process unit. The new rule is intended to have prospective effect, and will become effective in certain states 60 days after October 27, 2003, the date of its publication in the Federal Register, and in other states upon completion of state processes to incorporate the new rule into state law. On October 27, 2003 twelve states, the District of Columbia and several cities filed an action in the United States Court of Appeals for the District of Columbia Circuit seeking judicial review of the new rule. The UARG has intervened in this case. On December 24, 2003, the Circuit Court granted a motion from the petitioners to stay the effective date of this rule, which had been December 26, 2003.

We are unable to estimate the loss or range of loss related to the contingent liability for civil penalties under the CAA proceedings. We are also unable to predict the timing of resolution of these matters due to the number of alleged violations and the significant number of issues yet to be determined by the Court. If we do not prevail, any capital and operating costs of additional pollution control equipment that may be required, as well as any penalties imposed, would adversely affect future results of operations, cash flows and possibly financial condition unless such costs can be recovered through regulated rates and market prices for electricity.

In December 2000, Cinergy Corp., an unaffiliated utility, which operates certain plants jointly owned by CSPCo, reached a tentative agreement with the Federal EPA and other parties to settle litigation regarding generating plant emissions under the Clean Air Act. Negotiations are continuing between the parties in an attempt to reach final settlement terms. Cinergy's settlement could impact the operation of Zimmer Plant and W.C. Beckjord Generating Station Unit 6 (owned 25.4% and 12.5%, respectively, by CSPCo). Until a final settlement is reached, CSPCo will be unable to determine the settlement's impact on its jointly owned facilities and its future results of operations and cash flows.

NUCLEAR

Nuclear Plants

I&M owns and operates the two-unit 2,110 MW Cook Plant under licenses granted by the NRC. TCC owns 25.2% of the two-unit 2,500 MW STP. STPNOC operates STP on behalf of the joint owners under licenses granted by the NRC. The operation of a nuclear facility involves special risks, potential liabilities, and specific regulatory and safety requirements. Should a nuclear incident occur at any nuclear power plant facility in the U.S., the resultant liability could be substantial. By agreement I&M and TCC are partially liable together with all other electric utility companies that own nuclear generating units for a nuclear power plant incident at any nuclear plant in the U.S. In the event nuclear losses or liabilities are underinsured or exceed accumulated funds and recovery from customers is not possible, results of operations, cash flows and financial condition would be adversely affected.

Nuclear Incident Liability

The Price-Anderson Act establishes insurance protection for public liability arising from a nuclear incident at $10.6 billion and covers any incident at a licensed reactor in the U.S. Commercially available insurance provides $300 million of coverage. In the event of a nuclear incident at any nuclear plant in the U.S., the remainder of the liability would be provided by a deferred premium assessment of $101 million on each licensed reactor in the U.S. payable in annual installments of $10 million. As a result, I&M could be assessed $202 million per nuclear incident payable in annual installments of $20 million. TCC could be assessed $50 million per nuclear incident payable in annual installments of $5 million as its share of a STPNOC assessment. The number of incidents for which payments could be required is not limited. Under an industry-wide program insuring workers at nuclear facilities, I&M and TCC are also obligated for assessments of up to $6 million and $2 million, respectively, for potential claims. These obligations will remain in effect until December 31, 2007.

Insurance coverage for property damage, decommissioning and decontamination at the Cook Plant and STP is carried by I&M and STPNOC in the amount of $1.8 billion each. I&M and STPNOC jointly purchase $1 billion of excess coverage for property damage, decommissioning and decontamination. Additional insurance provides coverage for extra costs resulting from a prolonged accidental outage. I&M and STPNOC utilize an industry mutual insurer for the placement of this insurance coverage. Participation in this mutual insurer requires a contingent financial obligation of up to $43 million for I&M and $2 million for TCC which is assessable if the insurer's financial resources would be inadequate to pay for losses.

The current Price-Anderson Act expired in August 2002. Its contingent financial obligations still apply to reactors licensed by the NRC as of its expiration date. It is anticipated that the Price-Anderson Act will be renewed in 2004 with increases in required third party financial protection for nuclear incidents.

SNF Disposal

Federal law provides for government responsibility for permanent SNF disposal and assesses nuclear plant owners fees for SNF disposal. A fee of one mill per KWH for fuel consumed after April 6, 1983 at Cook Plant and STP is being collected from customers and remitted to the U.S. Treasury. Fees and related interest of $226 million for fuel consumed prior to April 7, 1983 at Cook Plant have been recorded as long-term debt. I&M has not paid the government the Cook Plant related pre-April 1983 fees due to continued delays and uncertainties related to the federal disposal program. At December 31, 2003, funds collected from customers towards payment of the pre-April 1983 fee and related earnings thereon are in external funds and exceed the liability amount. TCC is not liable for any assessments for nuclear fuel consumed prior to April 7, 1983 since the STP units began operation in 1988 and 1989.

Decommissioning and Low Level Waste Accumulation Disposal

Decommissioning costs are accrued over the service lives of the Cook Plant and STP. The licenses to operate the two nuclear units at Cook Plant expire in 2014 and 2017. In November 2003, I&M filed to extend the operating licenses of the two Cook Plant units for up to an additional 20 years. The review of the license extension application is expected to take at least two years. After expiration of the licenses, Cook Plant is expected to be decommissioned using the prompt decontamination and dismantlement (DECON) method. The estimated cost of decommissioning and low level radioactive waste accumulation disposal costs for Cook Plant ranges from $821 million to $1,080 million in 2003 nondiscounted dollars. The wide range is caused by variables in assumptions including the estimated length of time SNF may need to be stored at the plant site subsequent to ceasing operations. This, in turn, depends on future developments in the federal government's SNF disposal program. Continued delays in the federal fuel disposal program can result in increased decommissioning costs. I&M is recovering estimated Cook Plant decommissioning costs in its three rate-making jurisdictions based on at least the lower end of the range in the most recent decommissioning study at the time of the last rate proceeding. The amount recovered in rates for decommissioning the Cook Plant and deposited in the external fund was $27 million in 2003, 2002 and 2001.

The licenses to operate the two nuclear units at STP expire in 2027 and 2028. After expiration of the licenses, STP is expected to be decommissioned using the DECON method. TCC estimates its portion of the costs of decommissioning STP to be $289 million in 1999 nondiscounted dollars. TCC is accruing and recovering these decommissioning costs through rates based on the service life of STP at a rate of $8 million per year.

Decommissioning costs recovered from customers are deposited in external trusts. In 2003, 2002 and 2001, I&M deposited in its decommissioning trust an additional $12 million each year related to special regulatory commission approved funding for decommissioning of the Cook Plant. Trust fund earnings increase the fund assets and decrease the amount needed to be recovered from ratepayers. Decommissioning costs including interest, unrealized gains and losses and expenses of the trust funds are recorded in Other Operation expense for Cook Plant. For STP, nuclear decommissioning costs are recorded in Other Operation expense, interest income of the trusts are recorded in Nonoperating Income and interest expense of the trust funds are included in Interest Charges.

TCC's nuclear decommissioning trust asset and liability are included in held for sale amounts on the Consolidated Balance Sheets.

OPERATIONAL

Construction and Commitments

The AEP System has substantial construction commitments to support its operations. Aggregate construction expenditures for 2004-2006 for consolidated domestic and foreign operations are estimated to be $5.8 billion including amounts for proposed environmental rules.

Our subsidiaries have entered into long-term contracts to acquire fuel for electric generation. The longest contract extends to the year 2014. The contracts provide for periodic price adjustments and contain various clauses that would release the subsidiaries from their obligations under certain conditions.

The AEP System has unit contingent contracts to supply approximately 250 MW of capacity to unaffiliated entities through December 31, 2009. The commitment is pursuant to a unit power agreement requiring the delivery of energy only if the unit capacity is available.

Potential Uninsured Losses

Some potential losses or liabilities may not be insurable or the amount of insurance carried may not be sufficient to meet potential losses and liabilities, including, but not limited to, liabilities relating to damage to the Cook Plant or STP and costs of replacement power in the event of a nuclear incident at the Cook Plant or STP. Future losses or liabilities which are not completely insured, unless recovered from customers, could have a material adverse effect on results of operations, cash flows and financial condition.

Power Generation Facility

We have agreements with Juniper Capital L.P. (Juniper) for Juniper to develop, construct, and finance a non-regulated merchant power generation facility (Facility) near Plaquemine, Louisiana and for Juniper to lease the Facility to us. Juniper will own the Facility and lease it to AEP after construction is completed and we will sublease the Facility to The Dow Chemical Company (Dow).

Dow will use a portion of the energy produced by the Facility and sell the excess energy. OPCo has agreed to purchase up to approximately 800 MW of such excess energy from Dow. OPCo has also agreed to sell up to approximately 800 MW of energy to Tractebel Energy Marketing, Inc. (TEM) for a period of 20 years under a Power Purchase and Sale Agreement dated November 15, 2000 (PPA) at a price that is currently in excess of market. Beginning May 1, 2003, OPCo tendered replacement capacity, energy and ancillary services to TEM pursuant to the PPA that TEM rejected as non-conforming.

On September 5, 2003, TEM and AEP separately filed declaratory judgment actions in the United States District Court for the Southern District of New York. We allege that TEM has breached the PPA, and we are seeking a determination of our rights under the PPA. TEM alleges that the PPA never became enforceable or alternatively, that the PPA has already been terminated as the result of AEP breaches. If the PPA is deemed terminated or found to be unenforceable by the court, we could be adversely affected to the extent we are unable to find other purchasers of the power with similar contractual terms to the extent we do not fully recover claimed termination value damages from TEM. The corporate parent of TEM has provided a limited guaranty.

On November 18, 2003, the above litigation was suspended pending final resolution in arbitration of all issues pertaining to the protocols relating to the dispatching, operation, and maintenance of the Facility and the sale and delivery of electric power products. In the arbitration proceedings, TEM basically argued that in the absence of mutually agreed upon protocols there was no commercially reasonable means to obtain or deliver the electric power products and therefore the PPA is not enforceable. TEM further argued that the creation of the protocols is not subject to arbitration. The arbitrator ruled in favor of TEM on February 11, 2004 and concluded that the "creation of protocols" was not subject to arbitration, but did not rule upon the merits of TEM's claim that the PPA is not enforceable.

If commercial operation is not achieved for purposes of the PPA by April 30, 2004, TEM may claim that it can terminate the PPA and is owed liquidating damages of approximately $17.5 million. TEM may also claim that we are not entitled to receive any termination value for the PPA.

See further discussion in Notes 10 and 16.

Merger Litigation

In 2002, the U.S. Court of Appeals for the District of Columbia ruled that the SEC failed to prove that the June 15, 2000 merger of AEP with CSW meets the requirements of the PUHCA and sent the case back to the SEC for further review. Specifically, the court told the SEC to revisit its conclusion that the merger met PUHCA requirements that utilities be "physically interconnected" and confined to a "single area or region."

In its June 2000 approval of the merger, the SEC agreed with AEP that the companies' systems are integrated because they have transmission access rights to a single high-voltage line through Missouri and also met the PUCHA's single region requirement because it is now technically possible to centrally control the output of power plants across many states. In its ruling, the appeals court said that the SEC failed to support and explain its conclusions that the integration and single region requirements are satisfied.

Management believes that the merger meets the requirements of the PUHCA and expects the matter to be resolved favorably.

Enron Bankruptcy

On October 15, 2002, certain subsidiaries of AEP filed claims against Enron and its subsidiaries in the bankruptcy proceeding filed by the Enron entities which are pending in the U.S. Bankruptcy Court for the Southern District of New York. At the date of Enron's bankruptcy, certain subsidiaries of AEP had open trading contracts and trading accounts receivables and payables with Enron. In addition, on June 1, 2001, we purchased Houston Pipe Line Company (HPL) from Enron. Various HPL related contingencies and indemnities from Enron remained unsettled at the date of Enron's bankruptcy. The timing of the resolution of the claims by the Bankruptcy Court is not certain.

In connection with the 2001 acquisition of HPL, we acquired exclusive rights to use and operate the underground Bammel gas storage facility pursuant to an agreement with BAM Lease Company, a now-bankrupt subsidiary of Enron. This exclusive right to use the referenced facility is for a term of 30 years, with a renewal right for another 20 years and includes the use of the Bammel storage facility and the appurtenant pipelines. We have engaged in discussions with Enron concerning the possible purchase of the Bammel storage facility and related assets, the possible resolution of outstanding issues between AEP and Enron relating to our acquisition of HPL and the possible resolution of outstanding energy trading issues. We have considered the possible outcomes of these issues in our impairment analysis of HPL; however, actual results could differ from those estimates. We are unable to predict whether these discussions will lead to an agreement on these subjects. In January 2004, AEP and its subsidiaries filed an amended lawsuit against Enron and its subsidiaries in the U.S. Bankruptcy Court claiming that Enron does not have the right to reject the Bammel storage facility agreement or the cushion gas use agreement, described below. In February 2004 Enron filed Notices of Rejection regarding the cushion gas use agreement and other incidental agreements. We have objected to Enron's attempted rejection of these agreements. Management is unable to predict the outcome of these proceedings or the impact on results of operations, cash flows or financial condition.

We also entered into an agreement with BAM Lease Company which grants HPL the exclusive right to use approximately 65 billion cubic feet of cushion gas required for the normal operation of the Bammel gas storage facility. The Bammel Gas Trust (owned by Enron and Bank of America (BOA)) purports to have a lien on 55 billion cubic feet of this cushion gas. These banks claim to have certain rights to the cushion gas in certain events of default. In connection with our acquisition of HPL, the banks and Enron entered into an agreement granting HPL's exclusive use of 65 billion cubic feet of cushion gas. Enron and the banks released HPL from all prior and future liabilities and obligations in connection with the financing arrangement. After the Enron bankruptcy, HPL was informed by the banks of a purported default by Enron under the terms of the financing arrangement. In July 2002, the banks filed a lawsuit against HPL in the state court of Texas seeking a declaratory judgment that they have a valid and enforceable security interest in gas purportedly in the Bammel storage facility which would permit them to cause the withdrawal of up to 55 billion cubic feet of gas from the storage facility. In September 2002, HPL filed a general denial and certain counterclaims against the banks including that Enron was a necessary and indispensable party to the Texas state court proceeding initiated by BOA. HPL also filed a motion to dismiss, which was denied. In December 2003, the Texas state court granted partial summary judgment in favor of the banks. HPL appealed this decision. We have considered the possible outcomes of these issues in our impairment analysis of HPL; however, actual results could differ from those estimates. Management is unable to predict the outcome of this lawsuit or its impact on results of operations, cash flows and financial condition.

In October 2003, AEP Energy Services Gas Holding Company filed a lawsuit against BOA in the United States District Court for the Southern District of Texas. On January 8, 2004, this lawsuit was amended and seeks damages for BOA's breach of contract, negligent misrepresentation and fraud in connection with transactions surrounding our acquisition of HPL from Enron including entering into the Bammel storage facility lease arrangement with Enron and the cushion gas arrangements with BOA and Enron. BOA led a lending syndicate involving the 1997 gas monetization that Enron and its subsidiaries undertook and the leasing of the Bammel underground gas storage reservoir to HPL. The lawsuit asserts that BOA made misrepresentations and engaged in fraud to induce and promote the stock sale of HPL, that BOA directly benefited from the sale of HPL and that AEP undertook the stock purchase and entered into the Bammel storage facility lease arrangement with Enron and the cushion gas arrangement with Enron and BOA based on misrepresentations that BOA made about Enron's financial condition that BOA knew or should have known were false including that the 1997 gas monetization did not contravene or constitute a default of any federal, state, or local statute, rule, regulation, code or any law.

In September 2003, Enron filed a complaint in the Bankruptcy Court against AEPES challenging AEP's offsetting of receivables and payables and related collateral across various Enron entities and seeking payment of approximately $125 million plus interest in connection with gas related trading transactions. We will assert our right to offset trading payables owed to various Enron entities against trading receivables due to several AEP subsidiaries. Management is unable to predict the outcome of this lawsuit or its impact on our results of operations, cash flows or financial condition.

In December 2003, Enron filed a complaint in the Bankruptcy Court against AEPSC seeking approximately $93 million plus interest in connection with a transaction for the sale and purchase of physical power among Enron, AEP and Allegheny Energy Supply, LLC during November 2001. Enron's claim seeks to unwind the effects of the transaction. AEP believes it has several defenses to the claims in the action being brought by Enron. Management is unable to predict the outcome of this lawsuit or its impact on our results of operations, cash flows or financial condition.

During 2002 and 2001, we expensed a total of $53 million ($34 million net of tax) for our estimated loss from the Enron bankruptcy. The amount expensed was based on an analysis of contracts where AEP and Enron entities are counterparties, the offsetting of receivables and payables, the application of deposits from Enron entities and management's analysis of the HPL related purchase contingencies and indemnifications. As noted above, Enron has challenged our offsetting of receivables and payables and the Bammel storage facility lease agreement and cushion gas agreement. Management is unable to predict the final resolution of these disputes, however the impact on results of operations, cash flows and financial condition could be material.

Shareholder Lawsuits

In the fourth quarter of 2002 and the first quarter of 2003, lawsuits alleging securities law violations and seeking class action certification were filed in federal District Court, Columbus, Ohio against AEP, certain AEP executives, and in some of the lawsuits, members of the AEP Board of Directors and certain investment banking firms. The lawsuits claim that we failed to disclose that alleged "round trip" trades resulted in an overstatement of revenues, that we failed to disclose that our traders falsely reported energy prices to trade publications that published gas price indices and that we failed to disclose that we did not have in place sufficient management controls to prevent "round trip" trades or false reporting of energy prices. The plaintiffs seek recovery of an unstated amount of compensatory damages, attorney fees and costs. The Court has appointed a lead plaintiff who has filed a Consolidated Amended Complaint. We have filed a Motion to Dismiss the Consolidated Amended Complaint. The Motion has been briefed by the parties. Also, in the first quarter of 2003, a lawsuit making essentially the same allegations and demands was filed in state Common Pleas Court, Columbus, Ohio against AEP, certain executives, members of the Board of Directors and our independent auditor. We removed this case to federal District Court in Columbus and the Court has denied plaintiff's motion to remand the case to state court. We have moved to consolidate this case with the other pending cases. We intend to continue to vigorously defend against these actions.

In the fourth quarter of 2002, two shareholder derivative actions were filed in state court in Columbus, Ohio against AEP and its Board of Directors alleging a breach of fiduciary duty for failure to establish and maintain adequate internal controls over our gas trading operations. These cases have been stayed pending the outcome of our Motion to Dismiss the Consolidated Amended Complaint in the federal securities lawsuits. If these cases do proceed, we intend to vigorously defend against them. Also, in the fourth quarter of 2002 and the first quarter of 2003, three putative class action lawsuits were filed against AEP, certain executives and AEP's Employee Retirement Income Security Act (ERISA) Plan Administrator alleging violations of ERISA in the selection of AEP stock as an investment alternative and in the allocation of assets to AEP stock. The ERISA actions are pending in federal District Court, Columbus, Ohio. In these actions, the plaintiffs seek recovery of an unstated amount of compensatory damages, attorney fees and costs. We have filed a Motion to Dismiss these actions. The parties have fully briefed this Motion. We intend to continue to vigorously defend against these claims.

California Lawsuits

In November 2002, the Lieutenant Governor of California filed a lawsuit in Los Angeles County, California Superior Court against forty energy companies, including AEP, and two publishing companies alleging violations of California law through alleged fraudulent reporting of false natural gas price and volume information with an intent to affect the market price of natural gas and electricity. This case is in the initial pleading stage and all defendants have filed motions to dismiss. AEP has been dismissed from the case. The plaintiff had stated an intention to amend the complaint to add an AEP subsidiary as a defendant. The plaintiff amended the complaint but did not name any AEP company as a defendant. In November 2003, Texas-Ohio Energy, Inc. filed a lawsuit in the United States District Court for the Eastern District of California alleging that AEP and a large number of other energy companies conspired to manipulate natural gas prices in California in violation of federal and state antitrust and unfair competition laws. Certain of the other defendants in this case have filed a Notice of Potential Tag-Along Action with the Judicial Panel on Multi-District Litigation seeking to have this case transferred to the United States District Court for the District of Nevada where there are a number of other cases now pending that assert claims regarding the alleged manipulation of energy markets in California. None of the AEP companies is a party to these other pending cases. Once venue for the Texas-Ohio Energy, Inc. case is determined, we plan to move to dismiss the complaint and otherwise vigorously defend against these claims. In February 2004, two individuals on behalf of themselves and two businesses they own and another individual filed an action in state court in San Diego County, California against a large number of energy companies including AEPES. This action alleges violations of state antitrust and unfair competition laws based on alleged manipulation of gas price indices. This case is in the initial pleading states. We plan to vigorously defend against these claims.

Cornerstone Lawsuit

In the third quarter of 2003, Cornerstone Propane Partners filed an action in the United States District Court for the Southern District of New York against forty companies, including AEP and AEPES seeking class certification and alleging unspecified damages from claimed price manipulation of natural gas futures and options on the NYMEX from January 2000 through December 2002. Thereafter, two similar actions were filed in the same court against a number of companies including AEP and AEPES making essentially the same claims as Cornerstone Propane Partners and also seeking class certification. On December 5, 2003, the Court issued its initial Pretrial Order consolidating all related cases, appointing co-lead counsel and providing for the filing of an amended consolidated complaint. In January 2004, plaintiffs filed an amended consolidated complaint. We plan to move to dismiss the complaint and otherwise vigorously defend against these claims.

Texas Commercial Energy, LLP Lawsuit

Texas Commercial Energy, LLP (TCE), a Texas REP, filed a lawsuit in federal District Court in Corpus Christi, Texas, in July 2003, against us and four AEP subsidiaries, certain unaffiliated energy companies and ERCOT. The action alleges violations of the Sherman Antitrust Act, fraud, negligent misrepresentation, breach of fiduciary duty, breach of contract, civil conspiracy and negligence. The allegations, not all of which are made against the AEP companies, range from anticompetitive bidding to withholding power. TCE alleges that these activities resulted in price spikes requiring TCE to post additional collateral and ultimately forced it into bankruptcy when it was unable to raise prices to its customers due to fixed price contracts. The suit alleges over $500 million in damages for all defendants and seeks recovery of damages, exemplary damages and court costs. Two additional parties, Utility Choice, LLC and Cirro Energy Corporation, have sought leave to intervene as plaintiffs asserting similar claims. We filed a Motion to Dismiss in September 2003. In February 2004, TCE filed an amended complaint. We intend to file a motion to dismiss the amended complaint and otherwise vigorously defend against the claims.

Bank of Montreal Claim

In March 2003, Bank of Montreal (BOM) terminated all natural gas trading deals and claimed that we owed approximately $34 million. In April 2003, we filed a lawsuit in federal District Court in Columbus, Ohio against BOM claiming BOM had acted contrary to the appropriate trading contract and industry practice in terminating the contract and calculating termination and liquidation amounts and that BOM had acknowledged just prior to the termination and liquidation that it owed us approximately $68 million. We are claiming that BOM owes us at least $45 million. Although management is unable to predict the outcome of this matter, it is not expected to have a material impact on results of operations, cash flows or financial condition.

Arbitration of Williams Claim

In October 2002, we filed a demand for arbitration with the American Arbitration Association to initiate formal arbitration proceedings in a dispute with the Williams Companies (Williams). The proceeding resulted from Williams' repudiation of its obligations to provide physical power deliveries to AEP and Williams' failure to provide the monetary security required for natural gas deliveries by AEP. Consequently, both parties claimed default and terminated all outstanding natural gas and electric power trading deals among the various Williams and AEP affiliates. Williams claimed that we owed approximately $130 million in connection with the termination and liquidation of all trading deals. Williams and AEP settled the dispute and we paid $90 million to Williams in June 2003. The settlement amount approximated the amount payable that, in the ordinary course of business, we recorded as part of our trading activity using MTM accounting. As a result, the resolution of this matter did not have a material impact on results of operations or financial condition.

Arbitration of PG&E Energy Trading, LLC Claim

In January 2003, PG&E Energy Trading, LLC (PGET) claimed approximately $22 million was owed by AEP in connection with the termination and liquidation of all trading deals. In February 2003, PGET initiated arbitration proceedings. In July 2003, AEP and PGET agreed to a settlement and we paid approximately $11 million to PGET. The settlement amount approximated the amount payable that, in the ordinary course of business, we recorded as part of our trading activity using MTM accounting. As a result, the settlement payment did not have a material impact on results of operations, cash flows or financial condition.

Energy Market Investigation

AEP and other energy market participants received data requests, subpoenas and requests for information from the FERC, the SEC, the PUCT, the U.S. Commodity Futures Trading Commission (CFTC), the U.S. Department of Justice and the California attorney general during 2002. Management responded to the inquiries and provided the requested information and has continued to respond to supplemental data requests in 2003 and 2004.

In March 2003, we received a subpoena from the SEC as part of the SEC's ongoing investigation of energy trading activities. In August 2002, we had received an informal data request from the SEC asking that we voluntarily provide information. The subpoena sought additional information and is part of the SEC's formal investigation. We responded to the subpoena and will continue to cooperate with the SEC.

On September 30, 2003, the CFTC filed a complaint against AEP and AEPES in federal district court in Columbus, Ohio. The CFTC alleges that AEP and AEPES provided false or misleading information about market conditions and prices of natural gas in an attempt to manipulate the price of natural gas in violation of the Commodity Exchange Act. The CFTC seeks civil penalties, restitution and disgorgement of benefits. The case is in the initial pleading stage with our response to the complaint currently due on May 18, 2004. Although management is unable to predict the outcome of this case, it is not expected to have a material effect on results of operations due to a provision recorded in December 2003.

In January 2004, the CFTC issued a request for documents and other information in connection with a CFTC investigation of activities affecting the price of natural gas in the fall of 2003. We are responding to that request.

Management cannot predict what, if any further action, any of these governmental agencies may take with respect to these matters.

FERC Proposed Standard Market Design

In July 2002, the FERC issued its Standard Market Design (SMD) notice of proposed rulemaking, which sought to standardize the structure and operation of wholesale electricity markets across the country. Key elements of FERC's proposal included standard rules and processes for all users of the electricity transmission grid, new transmission rules and policies, and the creation of certain markets to be operated by independent administrators of the grid in all regions. The FERC issued a "white paper" on the proposal in April 2003, in response to the numerous comments that the FERC received on its proposal. Management does not know if or when the FERC will finalize a rule for SMD. Until any potential rule is finalized, management cannot predict its effect on cash flows and results of operations.

FERC Market Power Mitigation

A FERC order issued in November 2001 on AEP's triennial market based wholesale power rate authorization update required certain mitigation actions that AEP would need to take for sales/purchases within its control area and required AEP to post information on its website regarding its power system's status. As a result of a request for rehearing filed by AEP and other market participants, FERC issued an order delaying the effective date of the mitigation plan until after a planned technical conference on market power determination. In December 2003, the FERC issued a staff paper discussing alternatives and held a technical conference in January 2004. Management is unable to predict the timing of any further action by the FERC or its affect of future results of operations and cash flows.

8. GUARANTEES

There are no liabilities recorded for guarantees entered into prior to December 31, 2002 in accordance with FIN 45. There are certain immaterial liabilities recorded for guarantees entered into subsequent to December 31, 2002. There is no collateral held in relation to any guarantees and there is no recourse to third parties in the event any guarantees are drawn unless specified below.

LETTERS OF CREDIT

We have entered into standby letters of credit (LOC) with third parties. These LOCs cover gas and electricity risk management contracts, construction contracts, insurance programs, security deposits, debt service reserves and credit enhancements for issued bonds. All of these LOCs were issued by us in the ordinary course of business. At December 31, 2003, the maximum future payments for all the LOCs are approximately $227 million with maturities ranging from January 2004 to January 2011. Included in these amounts is TCC's LOC of approximately $43 million with a maturity date of November 3, 2005. As the parent of all these subsidiaries, we hold all assets of the subsidiaries as collateral. There is no recourse to third parties in the event these letters of credit are drawn.

We have guaranteed 50% of the principal and interest payments as well as 100% of a Power Purchase Agreement (PPA) of Fort Lupton, an IPP of which we are a 50% owner. In the event Fort Lupton does not make the required debt payments, we have a maximum future payment exposure of approximately $7 million, which expires May 2008.

In the event Fort Lupton is unable to perform under its PPA agreement, we have a maximum future payment exposure of approximately $15 million, which expires June 2019.

We have guaranteed 50% of a security deposit for gas transmission as well as 50% of a Power Purchase Agreement (PPA) of Orange Cogeneration (Orange), an IPP of which we are a 50% owner. In the event Orange fails to make payments in accordance with agreements for gas transmission, we have a maximum future payment exposure of approximately $1 million, which expires June 2023. In the event Orange is unable to perform under its PPA agreement, we have a maximum future payment exposure of approximately $1 million, which expires June 2016.

GUARANTEES OF THIRD-PARTY OBLIGATIONS

CSW Energy and CSW International

CSW Energy and CSW International have guaranteed 50% of the required debt service reserve of Sweeny Cogeneration (Sweeny), an IPP of which CSW Energy is a 50% owner. The guarantee was provided in lieu of Sweeny funding the debt reserve as a part of a financing. In the event that Sweeny does not make the required debt payments, CSW Energy and CSW International have a maximum future payment exposure of approximately $4 million, which expires June 2020.

AEP Utilities

AEP Utilities guaranteed 50% of the required debt service reserve for Polk Power Partners, an IPP of which CSW Energy owns 50%. In the event that Polk Power does not make the required debt payments, AEP Utilities has a maximum future payment exposure of approximately $5 million, which expires July 2010.

SWEPCo

In connection with reducing the cost of the lignite mining contract for its Henry W. Pirkey Power Plant, SWEPCo has agreed under certain conditions, to assume the capital lease obligations and term loan payments of the mining contractor, Sabine Mining Company (Sabine). In the event Sabine defaults under any of these agreements,

SWEPCo's total future maximum payment exposure is approximately $58 million with maturity dates ranging from June 2005 to February 2012.

As part of the process to receive a renewal of a Texas Railroad Commission permit for lignite mining, SWEPCo has agreed to provide guarantees of mine reclamation in the amount of approximately $85 million. Since SWEPCo uses self-bonding, the guarantee provides for SWEPCo to commit to use its resources to complete the reclamation in the event the work is not completed by a third party miner. At December 31, 2003, the cost to reclaim the mine in 2035 is estimated to be approximately $36 million. This guarantee ends upon depletion of reserves estimated at 2035 plus 6 years to complete reclamation.

On July 1, 2003, SWEPCo consolidated Sabine due to the application of FIN 46 (see Note 2). Upon consolidation, SWEPCo recorded the assets and liabilities of Sabine ($78 million). Also, after consolidation, SWEPCo currently records all expenses (depreciation, interest and other operation expense) of Sabine and eliminates Sabine's revenues against SWEPCo's fuel expenses. There is no cumulative effect of an accounting change recorded as a result of the requirement to consolidate, and there is no change in net income due to the consolidation of Sabine.

INDEMNIFICATIONS AND OTHER GUARANTEES

We entered into several types of contracts, which would require indemnifications. Typically these contracts include, but are not limited to, sale agreements, lease agreements, purchase agreements and financing agreements. Generally these agreements may include, but are not limited to, indemnifications around certain tax, contractual and environmental matters. With respect to sale agreements, our exposure generally does not exceed the sale price. We cannot estimate the maximum potential exposure for any of these indemnifications entered into prior to December 31, 2002 due to the uncertainty of future events. In 2003 we entered into several sale agreements discussed in Note 10. These sale agreements include indemnifications with a maximum exposure of approximately $57 million. There are no material liabilities recorded for any indemnifications entered into during 2003. There are no liabilities recorded for any indemnifications entered prior to December 31, 2002.

We lease certain equipment under a master operating lease. Under the lease agreement, the lessor is guaranteed to receive up to 87% of the unamortized balance of the equipment at the end of the lease term. If the fair market value of the leased equipment is below the unamortized balance at the end of the lease term, we have committed to pay the difference between the fair market value and the unamortized balance, with the total guarantee not to exceed 87% of the unamortized balance. At December 31, 2003, the maximum potential loss for these lease agreements was approximately $28 million assuming the fair market value of the equipment is zero at the end of the lease term.

See Note 16 "Leases" for disclosure of lease residual value guarantees.

9. SUSTAINED EARNINGS IMPROVEMENT INITIATIVE

In response to difficult conditions in our business, a Sustained Earnings Improvement (SEI) initiative was undertaken company-wide in the fourth quarter of 2002, as a cost-saving and revenue-building effort to build long-term earnings growth.

Termination benefits expense relating to 1,120 terminated employees totaling $75.4 million pre-tax was recorded in the fourth quarter of 2002. Of this amount, we paid $9.5 million to these terminated employees in the fourth quarter of 2002. No additional termination benefits expense related to the SEI initiative was recorded in 2003, and the remaining SEI related payments were made in 2003. The termination benefits expense is classified as Maintenance and Other Operation expense on our Consolidated Statements of Operations. We determined that the termination of the employees under our SEI initiative did not constitute a plan curtailment of any of our retirement benefit plans.

10. ACQUISITIONS, DISPOSITIONS, DISCONTINUED OPERATIONS, IMPAIRMENTS, ASSETS HELD FOR SALE AND ASSETS HELD AND USED

ACQUISITIONS

2002

Acquisition of Nordic Trading (Investments – UK Operations segment)

In January 2002 we acquired the trading operations, including key staff, of Enron's Norway and Sweden-based energy trading businesses (Nordic Trading). Results of operations are included in our Consolidated Statements of Operations from the date of acquisition. Subsequently in the fourth quarter of 2002, a decision was made to exit this non-core European trading business. The sale of Nordic Trading in the second quarter of 2003 is discussed in the "Dispositions" section of this note.

Acquisition of USTI (Investments – Other segment)

In January 2002, we acquired 100% of the stock of United Sciences Testing, Inc. (USTI) for $12.5 million. USTI provides equipment and services related to automated emission monitoring of combustion gases to both our affiliates and external customers. Results of operations are included in our Consolidated Statements of Operations from the date of acquisition.

2001

Houston Pipe Line Company (Investments – Gas Operations segment)

On June 1, 2001, through a wholly-owned subsidiary, we purchased Houston Pipe Line Company and Lodisco LLC for $727 million from Enron. The acquired assets include 4,200 miles of gas pipeline, a 30-year prepaid lease of a gas storage facility and certain gas marketing contracts. The purchase method of accounting was used to record the acquisition. During 2003 we recorded impairment and other losses for HPL and related gas operations of $315 million ($228 million net of tax).

U.K. Generation Plants (Investments – UK Operations segment)

In December 2001, we acquired 4,000 megawatts of coal-fired generation from Fiddler's Ferry, a four-unit, 2,000 MW station on the River Mersey in northwest England, and Ferrybridge, a four-unit, 2,000 MW station on the River Aire in northeast England and related coal stocks. These assets were acquired for a cash payment of $942.3 million and the assumption of certain liabilities. During 2003 these assets became held-for-sale and we reported the operations as discontinued. See U.K. Generation Plants in the "Discontinued Operations" section of this note for further information.

Other Acquisitions (Various segments)

We also purchased the following assets or acquired the following businesses from July 2001 through December 2001:

- Dolet Hills mining operations were purchased by SWEPCo, an AEP subsidiary, and SWEPCo also assumed the existing mine reclamation liabilities at its jointly owned lignite reserves in Louisiana.
- Quaker Coal Company as part of a bankruptcy proceeding settlement was acquired, including certain liabilities.

The acquisition includes property, coal reserves, mining operations and royalty interests in Colorado, Kentucky, Ohio, Pennsylvania and West Virginia. We continue to operate the mines and facilities. See AEP Coal in the "Assets Held for Sale" section of this note for further information on our decision to dispose of this investment.

- MEMCO Barge Line was acquired adding 1,200 hopper barges and 30 towboats to AEP's existing barging fleet. MEMCO added major barging operations on the Mississippi and Ohio rivers to AEP's barging operations on the Ohio and Kanawha rivers.
- A 20% equity interest in Caiua, a Brazilian electric operating company which is a subsidiary of Vale was acquired by converting a total of $66 million on an existing loan and accrued interest on that loan into Caiua equity. See Grupo Rede Investment in the "Dispositions" section of this note for further information.
- Indian Mesa Wind Project (referred to as "Desert Sky") consisting of 160 MW of wind generation located near Fort Stockton, Texas was purchased.
- Enron's London-based international coal trading group was acquired by purchasing existing contracts and hiring key staff.

Management recorded the assets acquired and liabilities assumed at their estimated fair values based on currently available information and on current assumptions as to future operations.

DISPOSITIONS

2003

C3 Communications (Investments – Other segment)

In February 2003, C3 Communications sold the majority of its assets for a sales price of $7.25 million. We provided for an $82 million pre-tax ($53 million after-tax) asset impairment in December 2002 and the effect of the sale on 2003 results of operations was not significant. The impairment is classified in Asset Impairments and Other Related Changes in our Consolidated Statements of Operations. See "Assets Held for Sale" section of this note for information on assets and liabilities held for sale at December 31, 2002 related to our "telecommunications" businesses.

Mutual Energy Companies (Utility Operations segment)

On December 23, 2002 we sold the general partner interests and the limited partner interests in Mutual Energy CPL L.P. and Mutual Energy WTU L.P. for a base purchase price paid in cash at closing and certain additional payments, including a net working capital payment. The buyer paid a base purchase price of $145.5 million which was based on a fair market value per customer established by an independent appraiser and an agreed customer count. We recorded a net gain totaling $83.7 million after-tax ($129 million pre-tax) in Other Income during 2002. We provided the buyer with a power supply contract for the two REPs and back-office services related to these customers for a two-year period. In addition, we retained the right to share in earnings from the two REPs above a threshold amount through 2006 in the event the Texas retail market develops increased earnings opportunities. No revenue was recorded in 2003 related to these sharing agreements. Under the Texas Legislation, REPs are subject to a clawback liability if customer change does not attain thresholds required by the legislation. We are responsible for a portion of such liability, if any, for the period we operated the REPs in the Texas competitive retail market (January 1, 2002 through December 23, 2002). In addition, we retained responsibility for regulatory obligations arising out of operations before closing. Our wholly-owned subsidiary Mutual Energy Service Company LLC (MESC) received an up-front payment of approximately $30 million from the buyer associated with the back-office service agreement, and MESC deferred its right to receive payment of an additional amount of approximately $9 million to secure certain contingent obligations. These prepaid service revenues were deferred on the books of MESC as of December 31, 2002 and are being amortized over the two-year term of the back office service agreement.

In February 2003, we completed the sale of MESC for $30.4 million dollars and realized a pre-tax gain of approximately $39 million, which included the recognition of the remaining balance of the original $30 million prepayment ($27 million), as no further service obligations existed for MESC.

Water Heater Assets (Utility Operations segment)

We sold our water heater rental program for $38 million and recorded a pre-tax loss of $3.9 million in the first quarter of 2003 based upon final terms of the sale agreement. We had provided for a $7.1 million pre-tax charge in the fourth quarter 2002 based on an estimated sales price ($3.2 million asset impairment charge and $3.9 million lease prepayment penalty). The impairment loss is included in Investment Value Losses in our Consolidated Statements of Operations. We operated a program to lease electric water heaters to residential and commercial customers until a decision was reached in the fourth quarter of 2002 to discontinue the program and offer the assets for sale. See the "Assets Held for Sale" section of this Note for assets and liabilities held for sale as of December 31, 2002.

AEP Gas Power Systems (Investments – Other segment)

In 2001, we acquired a 75% interest in a startup company, seeking to develop low-cost peaking generator sets powered by surplus jet turbine engines. In January 2003, AEP Gas Power Systems, LLC sold its assets. We recognized a goodwill impairment loss of $12.3 million pre-tax in the first quarter of 2002 due to technological and operational problems (also see Note 3). The impairment loss was recorded in Investment Value Losses on our Consolidated Statements of Operations. The fair values of the remaining assets and liabilities as of December 31, 2002 were excluded from held for sale on our Consolidated Balance Sheets as the impact was not significant. The effect of the asset sale on the first quarter 2003 results of operations was not significant.

Newgulf Facility (Investments – Other segment)

In 1995, we purchased an 85 MW gas-fired peaking electrical generation facility located near Newgulf, Texas (Newgulf). In October 2002, we began negotiations with a likely buyer of the facility. We estimated a pre-tax loss on sale of $11.8 million based on the indicative bid. This loss was recorded as Asset Impairments and Other Related Charges on our Consolidated Statements of Operations during the fourth quarter 2002. Newgulf's Property, Plant and Equipment, net of accumulated depreciation, was classified on our Consolidated Balance Sheets as held for sale at December 31, 2002. During the second quarter of 2003 we completed the sale of Newgulf and the impact on earnings in 2003 was not significant.

Nordic Trading (Investments – UK Operations segment)

In October 2002 we announced that our ongoing energy trading operations would be centered around our generation assets. As a result, we took steps to exit our coal, gas and electricity trading activities in Europe, except for those activities predominantly related to our U.K. generation operations. The Nordic Trading business acquired earlier in 2002 was made available for sale to potential buyers later in 2002. The estimated pre-tax loss on disposal recorded in 2002 of $5.3 million, consisted of impairment of goodwill of $4.0 million and impairment of assets of $1.3 million. The estimated loss of $5.3 million is included in Asset Impairments and Other Related Charges on our Consolidated Statements of Operations. Management's determination of a zero fair value was based on discussions with a potential buyer. The assets and liabilities of Nordic Trading have been classified on our Consolidated Balance Sheets as held for sale at December 31, 2002. The transfer of the Nordic Trading business, including the trading portfolio, to new owners was completed during the second quarter of 2003 and the impact on earnings during the second quarter of 2003 was not significant.

Eastex (Investments – Other segment)

In 1998, we began construction of a natural gas-fired cogeneration facility (Eastex) located near Longview, Texas and commercial operations commenced in December 2001. In June 2002, we requested that the FERC allow us to modify the FERC Merger Order and substitute Eastex as a required divestiture under the order, due to the fact that the agreed upon market-power related divestiture of a plant in Oklahoma was no longer feasible. The FERC approved the request at the end of September 2002. Subsequently, in the fourth quarter of 2002, we solicited bids for the sale of Eastex and several interested buyers were identified by December 2002. The estimated pre-tax loss on sale of $218.7 million pre-tax ($142 million after-tax), which was based on the estimated fair value of the facility and indicative bids by interested buyers, was recorded in Discontinued Operations in our Consolidated Statements of Operations during the fourth quarter 2002.

We completed the sale of Eastex during the third quarter of 2003 and the effect of the sale on third quarter 2003 results of operations was not significant. The results of operations of Eastex have been reclassified as Discontinued Operations in accordance with SFAS 144 for all years presented. The assets and liabilities of Eastex were reclassified on the Consolidated Balance Sheets from Assets Held for Sale and Liabilities Held for Sale to Discontinued Operations at December 31, 2002. See "Discontinued Operations" section of this note for additional information.

Grupo Rede Investment (Investments – Other segment)

In December 2002, we recorded an other than temporary impairment totaling \$141.0 million (\$217.0 million net of federal income tax benefit of \$76.0 million) of our 44% equity investment in Vale and our 20% equity interest in Caiua, both Brazilian electric operating companies (referred to as Grupo Rede). This amount is included in Investment Value Losses on our Consolidated Statements of Operations.

In December 2003 we transferred our share and investment in Vale to Grupo Rede for \$1 million. The effect of the transfer on fourth quarter results of operations was not significant.

Excess Equipment (Investments – Other segment)

In November 2002, as a result of a cancelled development project, we obtained title to a surplus gas turbine generator. We had been unsuccessful in finding potential buyers of the unit due to an over-supply of generation equipment available for sale during 2002. An estimated pre-tax loss on disposal of \$23.9 million was recorded in December 2002, based on market prices of similar equipment. The loss is included in Asset Impairments and Other Related Charges on our Consolidated Statements of Operations. The Other asset of \$12 million in 2002 was classified on our Consolidated Balance Sheets as held for sale at December 31, 2002.

We completed the sale of the surplus gas turbine generator in November 2003. The proceeds from the sale were \$8.7 million. A pre-tax loss of \$1.8 million was recorded in the fourth quarter of 2003.

Ft. Davis Wind Farm (Investments – Other segment)

In the 1990's, we developed a 6 MW facility wind energy project located on a lease site near Ft. Davis, Texas. In the fourth quarter of 2002 our engineering staff determined that operation of the facility was no longer technically feasible and the lease of the underlying site should not be renewed. Dismantling of the facility is expected to be completed during 2004. An estimated pre-tax loss on abandonment of \$4.7 million was recorded in December 2002. The loss was recorded in Asset Impairments and Other Related Charges on our Consolidated Statements of Operations.

2002

SEEBOARD (Investments – Other segment)

On June 18, 2002, through a wholly-owned subsidiary, we entered into an agreement, subject to European Union (EU) approval, to sell our consolidated subsidiary SEEBOARD, a U.K. electricity supply and distribution company. EU approval was received July 25, 2002 and the sale was completed on July 29, 2002. We received approximately \$941 million in net cash from the sale, subject to a working capital true up, and the buyer assumed SEEBOARD debt of approximately \$1.12 billion, resulting in a net loss of \$345 million at June 30, 2002. The results of operations of SEEBOARD have been classified as Discontinued Operations for all years presented. A net loss of \$22 million pre-tax (\$14 million after-tax) was classified as Discontinued Operations in the second quarter of 2002. The remaining \$323 million of the net loss has been classified as a transitional goodwill impairment loss from the adoption of SFAS 142 (see Notes 2 and 3) and has been reported as a Cumulative Effect of Accounting Change retroactive to January 1, 2002. A \$59 million pre-tax (\$38 million after-tax) reduction of the net loss was recognized in the second half of 2002 to reflect changes in exchange rates to closing, settlement of working capital true-up and selling expenses. The net total loss recognized on the disposal of SEEBOARD was \$286 million. Proceeds from the sale of SEEBOARD were used to pay down bank facilities and short-term debt. See "Discontinued Operations" section for the total revenues and pretax profit (loss) of the discontinued operations of SEEBOARD.

CitiPower (Investments – Other segment)

On July 19, 2002, through a wholly owned subsidiary, we entered into an agreement to sell CitiPower, a retail electricity and gas supply and distribution subsidiary in Australia. We completed the sale on August 30, 2002 and received net cash of approximately $175 million and the buyer assumed CitiPower debt of approximately $674 million. We recorded a pre-tax charge totaling $192 million ($125 million after-tax) as of June 30, 2002. The charge included a pre-tax impairment loss of $151 million ($98 million after-tax) on the remaining carrying value of an intangible asset related to a distribution license for CitiPower. The remaining $41 million pre-tax ($27 million after-tax) of net loss was classified as a transitional goodwill impairment loss from the adoption of SFAS 142 (see Notes 2 and 3) and was recorded as a Cumulative Effect of Accounting Change retroactive to January 1, 2002.

The loss on the sale of CitiPower increased $37 million pre-tax ($24 million after-tax) to $229 million pre-tax ($149 million after-tax; $122 million plus $27 million of cumulative effect) in the second half of 2002 based on actual closing amounts and exchange rates. See the "Discontinued Operations" section of this note for the total revenues and pretax profit (loss) of the discontinued operations of CitiPower.

2001

In March 2001, CSWE, a subsidiary company, completed the sale of Frontera, a generating plant that the FERC required to be divested in connection with the merger of AEP and CSW. The sale proceeds were $265 million and resulted in an after-tax gain of $46 million ($73 million pre-tax).

In July 2001, through a wholly-owned subsidiary, we sold our 50% interest in a 120-megawatt generating plant located in Mexico. The sale resulted in an after tax gain of approximately $11 million.

In July 2001, we sold coal mines in Ohio and West Virginia and agreed to purchase approximately 34 million tons of coal from the purchaser of the mines through 2008. The sale had a nominal impact on our results of operations and cash flows.

In December 2001, we completed the sale of our ownership interests in the Virginia and West Virginia PCS (Personal Communications Services) Alliances for stock, resulting in an after tax gain of approximately $7 million. Subsequently during 2002, due to decreasing market value of the shares received from the sale, we reduced the value of them to zero.

DISCONTINUED OPERATIONS

Management periodically assesses the overall AEP business model and makes decisions regarding our continued support and funding of our various businesses and operations. When it is determined that we will seek to exit a particular business or activity and we have met the accounting requirements for reclassification, we will reclassify the operations of those businesses or operations as discontinued operations. The assets and liabilities of these discontinued operations are classified as Assets and Liabilities Held for Sale until the time that they are sold. At the time they are sold they are reclassified to Assets and Liabilities of Discontinued Operations on the Consolidated Balance Sheets for all periods presented. Assets and liabilities that are held for sale, but do not qualify as a discontinued operations are reflected as Assets and Liabilities Held for Sale both while they are held for sale and after they have been sold, for all periods presented.

Certain of our operations were determined to be discontinued operations and have been classified as such in 2003, 2002 and 2001. Results of operations of these businesses have been reclassified as shown in the following table:

	SEE-BOARD	CitiPower	Eastex	Pushan Power Plant	LIG	U.K. Generation Plants	Total
2003 Revenue	$-	$-	$58	$60	$653	$125	$896
2003 Pretax Profit (Loss)	-	(20)	(23)	4	(122)	(713)	(874)
2003 Earnings (Loss) After Tax	16	(13)	(14)	4	(91)	(507)	(605)
2002 Revenue	694	204	73	57	507	251	1,786
2002 Pretax Profit (Loss)	180	(190)	(239)	(13)	14	(579)	(827)
2002 Earnings (Loss) After Tax	96	(123)	(156)	(7)	8	(472)	(654)
2001 Revenue	1,451	350	-	57	525	26	2,409
2001 Pretax Profit (Loss)	104	(4)	1	8	(6)	(48)	55
2001 Earnings (Loss) After Tax	88	(6)	-	4	(4)	(41)	41

Assets and liabilities of discontinued operations have been reclassified as follows:

	Eastex (in millions)
As of December 31, 2002	
Current Assets	$15
Total Assets of Discontinued Operations	$15
Current Liabilities	$8
Deferred Credits and Other	4
Total Liabilities of Discontinued Operations	$12

Pushan Power Plant (Investments – Other segment)

In the fourth quarter of 2002, we began active negotiations to sell our interest in the Pushan Power Plant (Pushan) in Nanyang, China to our minority interest partner and a purchase and sale agreement was signed in the fourth quarter of 2003. We expect to close on this transaction by mid 2004. An estimated pre-tax loss on disposal of $20 million pre-tax ($13 million after-tax) was recorded in December 2002, based on an indicative price expression. The estimated pre-tax loss on disposal is classified in Discontinued Operations in our Consolidated Statements of Operations.

Results of operations of Pushan have been reclassified as Discontinued Operations. The assets and liabilities of Pushan have been classified on our Consolidated Balance Sheets as held for sale. We have classified the assets and liabilities as held for sale for longer than 12 months, which is longer than originally expected, due to several unusual circumstances including the SARS outbreak and governmental delays.

Louisiana Intrastate Gas (LIG) (Investments – Gas Operations segment)

After announcing during 2003 that we would be divesting our non-core assets we began actively marketing LIG with the help of an investment advisor. After receiving and analyzing initial bids during the fourth quarter 2003 we recorded a $133.9 million pre-tax ($99 million after-tax) impairment loss; of this loss, $128.9 million pre-tax relates to the impairment of goodwill and $5 million pre-tax relates to other charges. In February 2004, we signed a definitive agreement to sell the pipeline portion of LIG. We anticipate the sale will be completed during the second quarter of 2004 and that the impact on results of operations in 2004 will not be significant. The assets and liabilities of LIG are classified as held for sale on our Consolidated Balance Sheets and the results of operations (including the above-mentioned impairments and other related charges) are classified in Discontinued Operations in our Consolidated Statements of Operations.

U.K. Generation Plants (Investments – UK Operations segment)

In December 2001, we acquired two coal-fired generation plants (U.K. Generation) in the U.K. for a cash payment of $942.3 million and assumption of certain liabilities. Subsequently and continuing through 2002, wholesale U.K. electric power prices declined sharply as a result of domestic over-capacity and static demand. External industry forecasts and our own projections made during the fourth quarter of 2002 indicated that this situation may extend many years into the future. As a result, the U.K. Generation fixed asset carrying value at year-end 2002 was substantially impaired. A December 2002 probability-weighted discounted cash flow analysis of the fair value of our U.K. Generation indicated a 2002 pre-tax impairment loss of $548.7 million ($414 million after-tax). This impairment loss is included in 2002 Discontinued Operations on our Consolidated Statements of Operations.

Management has retained an investment advisor to assist in determining the best methodology to exit the U.K. business. An information memorandum was distributed for the sale of our U.K. Generation and based on current information we recorded a $577 million pre-tax charge ($375 after-tax), including asset impairments of $420.7 million during the fourth quarter of 2003 to write down the value of the assets to their estimated realizable value. Additional charges of $156.7 million pre-tax were also recorded in December 2003 including $122.2 million related to the net loss on certain cash flow hedges previously recorded in Accumulated Other Comprehensive Income that has been reclassified into earnings as a result of management's determination that the hedged event is no longer probable of occurring and $34.5 million related to a first quarter 2004 sale of certain power contracts. The assets and liabilities of U.K. Generation have been classified as held for sale on our Consolidated Balance Sheets and the results of operations are included in Discontinued Operations on our Consolidated Statements of Operations. We anticipate the sale of the U.K. Generation plants during 2004.

ASSET IMPAIRMENTS, INVESTMENT VALUE LOSSES AND OTHER RELATED CHARGES

In 2003, AEP recorded pre-tax impairments of assets (including goodwill) and investments totaling $1.4 billion [consisting of approximately $650 million related to Asset Impairments ($610 million) and Other Related Charges ($40 million), $70 million related to Investment Value Losses, $711 million related to Discontinued Operations ($550 million of impairments and $161 million of other charges) and $6 million related to charges recorded for Excess Real Estate in Maintenance and Other Operation in the Consolidated Statements of Operations] that reflected downturns in energy trading markets, projected long-term decreases in electricity prices, our decision to exit non-core businesses and other factors.

In 2002, AEP recorded pre-tax impairments of assets (including goodwill) and investments totaling $1.7 billion (consisting of approximately $318 million related to Asset Impairments, $321 million related to Investment Value Losses, $938 million related to Discontinued Operations and $88 million related to charges recorded in other lines within the Consolidated Statements of Operations) that reflected downturns in energy trading markets, projected long-term decreases in electricity prices, and other factors. These impairments exclude the transitional goodwill impairment loss from adoption of SFAS 142 (see Notes 2 and 3).

The categories of impairments include:

	2003	2002 (in millions)	2001
Asset Impairments and Other Related Charges (Pre-tax)			
AEP Coal	$67	$60	$-
HPL and Other	315	-	-
Power Generation Facility	258	-	-
Blackhawk Coal Company	10	-	-
Ft. Davis Wind Farm	-	5	-
Texas Plants	-	38	-
Newgulf Facility	-	12	-
Excess Equipment	-	24	-
Nordic Trading	-	5	-
Excess Real Estate	-	16	-
Telecommunications – AEPC/C3	-	158	-
Total	$650	$318	$-
Investment Value Losses (Pre-tax)			
Independent Power Producers	$70	$-	$-
Water Heater Assets	-	3	-
South Coast Power Investment	-	63	-
Telecommunications – AFN	-	14	-
AEP Gas Power Systems	-	12	-
Grupo Rede Investment – Vale	-	217	-
Technology Investments	-	12	-
Total	$70	$321	$-
"Impairments and Other Related Charges" and "Operations" Included in Discontinued Operations (After-tax)			
Impairments and Other Related Charges:			
U.K. Generation Plants	$(375)	$(414)	$-
Louisiana Intrastate Gas	(99)	-	-
CitiPower	-	(122)	-
Eastex	-	(142)	-
SEEBOARD	-	24	-
Pushan	-	(13)	-
Total*	(474)	(667)	-
Operations:			
U.K. Generation Plants	(132)	(58)	(41)
Louisiana Intrastate Gas	8	8	(4)
CitiPower	(13)	(1)	(6)
Eastex	(14)	(14)	-
SEEBOARD	16	72	88
Pushan	4	6	4
Total	(131)	13	41
Total Discontinued Operations	$(605)	$(654)	$41

* See the "Dispositions" and "Discontinued Operations" sections of this note for the pre-tax impairment figures.

ASSETS HELD FOR SALE

Telecommunications (Investments – Other segment)

We developed businesses to provide telecommunication services to businesses and other telecommunication companies through broadband fiber optic networks. The businesses included AEP Communications, LLC (AEPC), C3 Communications, Inc. (C3), and a 50% share of AFN, LLC (AFN), a joint venture. Due to the difficult economic conditions in these businesses and the overall telecommunications industry, the AEP Board approved in December 2002 a plan to cease operations of these businesses. We took steps to market the assets of the businesses to potential interested buyers in the fourth quarter of 2002.

We completed the sale of substantially all the assets of C3 in the first quarter of 2003 as discussed in the "Dispositions" section of this note. AFN closed on the sale of substantially all of its assets in January 2004 with no significant additional effect on results of operations in 2004. The sale of remaining telecommunication assets is proceeding.

An estimated pre-tax impairment loss of $158.5 million ($76.3 million related to AEPC and $82.2 million related to C3) was recorded in December 2002 and is classified in Asset Impairments and Other Related Charges in our Consolidated Statements of Operations. An estimated pre-tax loss in value of the investment in AFN of $13.8 million was recorded in December 2002 and is classified in Investment Value Losses in our Consolidated Statements of Operations. The estimated losses were based on indicative bids by potential buyers. Property, Plant and Equipment, net of accumulated depreciation, of the telecommunication businesses have been classified on our Consolidated Balance Sheets as held for sale in 2002.

AEP Coal (Investments – Other segment)

In October 2001, we acquired out of bankruptcy certain assets and assumed certain liabilities of nineteen coal mine companies formerly known as "Quaker Coal" and renamed "AEP Coal." During 2002 the coal operations suffered from a decline in prices and adverse mining factors resulting in significantly reduced mine productivity and revenue. Based on an extensive review of economically accessible reserves and other factors, future mine productivity and production is expected to continue below historical levels. In December 2002, a probability-weighted discounted cash flow analysis of fair value of the mines was performed which indicated a 2002 pre-tax impairment loss of $59.9 million including a goodwill impairment of $3.6 million as discussed in Note 3. This impairment loss is included in Asset Impairments and Other Related Charges on our Consolidated Statements of Operations.

In 2003, as a result of management's decision to exit our non-core businesses, we retained an advisor to facilitate the sale of AEP Coal. In the fourth quarter of 2003, after considering the current bids and all other options, we recorded a $66.6 million pre-tax ($43.6 million after-tax) charge comprised of a $29.4 million asset impairment, a $25.2 million charge related to accelerated remediation cost accruals and $12 million charge (accrued at December 31, 2003) related to a royalty agreement. These impairment losses were included in Asset Impairments and Other Related Charges on our Consolidated Statements of Operations. The assets and liabilities of AEP Coal that are held for sale have been included in Assets and Liabilities Held for Sale in our Consolidated Balance Sheets at December 31, 2003 and 2002.

Texas Plants (Utility Operations segment)

In September 2002, AEP indicated to ERCOT its intent to deactivate 16 gas-fired power plants (8 TCC plants and 8 TNC plants). ERCOT subsequently conducted reliability studies, which determined that seven plants (4 TCC plants and 3 TNC plants) would be required to ensure reliability of the electricity grid. As a result of those studies, ERCOT and AEP mutually agreed to enter into reliability must run (RMR) agreements, which expired in December 2002, and were subsequently renewed through December 2003. However, certain contractual provisions provided ERCOT with a 90-day termination clause, if the contracted facility was no longer needed to ensure reliability of the electricity grid. With ERCOT's approval, AEP proceeded with its planned deactivation of the remaining nine plants. In August 2003, pursuant to contractual terms, ERCOT provided notification to AEP of its intent to cancel a RMR agreement at one of the TNC plants. Upon termination of the agreement, AEP proceeded with its planned deactivation of the plant. In December 2003, AEP and ERCOT mutually agreed to new RMR contracts at six plants (4 TCC plants and 2 TNC plants) through December 2004, subject to ERCOT's 90 day termination clause and the divestiture of the TCC facilities.

As a result of the decision to deactivate TNC plants, a write-down of utility assets of approximately $34.2 million (pre-tax) was recorded in Asset Impairments and Other Related Charges expense during the third quarter 2002 on our Consolidated Statements of Operations. The decision to deactivate the TCC plants resulted in a write-down of utility assets of approximately $95.6 million (pre-tax), which was deferred and recorded in Regulatory Assets during the third quarter 2002 in our Consolidated Balance Sheets.

During the fourth quarter of 2002, evaluations continued as to whether assets remaining at the deactivated plants, including materials, supplies and fuel oil inventories, could be utilized elsewhere within the AEP System. As a result of such evaluations, TNC recorded an additional asset impairment charge to Asset Impairments and Other Related Charges expense of $3.9 million (pre-tax) in the fourth quarter of 2002. In addition, TNC recorded related fuel inventory and materials and supplies write-downs of $2.6 million ($1.2 million in Fuel for Electric Generation and $1.4 million in Maintenance and Other Operation). Similarly, TCC recorded an additional asset impairment write-down of $6.7 million (pre-tax), which was deferred and recorded in Regulatory Assets in the fourth quarter of 2002. TCC also recorded related inventory write-downs of $14.9 million which was deferred and recorded in Regulatory Assets in the fourth quarter 2002.

The total Texas plant asset impairment of $38.1 million pre-tax in 2002 (all related to TNC) is included in Asset Impairments and Other Related Charges in our Consolidated Statements of Operations.

In December 2002, TCC filed a plan of divestiture with the PUCT proposing to sell all of its power generation assets, including the eight gas-fired generating plants that were either deactivated or designated as RMR status. During the fourth quarter of 2003, after receiving bids from interested buyers, we recorded a $938 million impairment loss and changed the classification of the plant assets from plant in service to Assets Held for Sale. In accordance with Texas legislation, the $938 million impairment was offset by the establishment of a regulatory asset, which is expected to be recovered through a wires charge, subject to the final outcome of the 2004 Texas true-up proceeding. See Texas Restructuring section of Note 6, "Customer Choice and Industry Restructuring," for further discussion of the divestiture plan, anticipated timeline and true-up proceeding.

The assets and liabilities of the entities held for sale at December 31, 2003 and 2002 are as follows:

December 31, 2003	Pushan Power Plant	U.K. Generation Plants	AEP Coal	Texas Plants	LIG	Total
			(in millions)			
Assets:						
Current Assets	$24	$1,245	$6	$57	$50	$1,382
Property, Plant and Equipment, Net	142	99	13	797	171	1,222
Regulatory Assets	-	-	-	49	-	49
Spent Nuclear Fuel and Decommissioning Trusts	-	-	-	125	-	125
Goodwill	-	-	-	-	15	15
Long-term Risk Management Assets	-	274	-	-	-	274
Other	-	6	-	-	9	15
Total Assets Held for Sale	$166	$1,624	$19	$1,028	$245	$3,082
Liabilities:						
Current Liabilities	$26	$988	$-	$-	$61	$1,075
Long-term Debt	20	-	-	-	-	20
Long-term Risk Management Liabilities	-	435	-	-	-	435
Regulatory Liabilities and Deferred Investment Tax Credits	-	-	-	9	-	9
Asset Retirement Obligations and Nuclear Decommissioning Trusts	-	29	-	219	-	248
Employee Benefits and Pension Obligations	-	12	-	-	-	12
Deferred Credits and Other	57	-	14	-	6	77
Total Liabilities Held for Sale	$103	$1,464	$14	$228	$67	$1,876

December 31, 2002	Pushan Power Plant	U.K. Generation Plants	AEP Coal	Texas Plants	LIG	Tele-Commun-ications	Nordic Trading	Newgulf Facility	Excess Equipment	Water Heater Program	Total
					(in millions)						
Assets:											
Current Assets	$19	$571	$4	$70	$62	$-	$35	$-	$-	$1	$762
Property, Plant and Equipment, Net	132	445	38	1,647	169	6	-	6	-	38	2,481
Spent Nuclear Fuel and Decommissioning Trusts	-	-	-	98	-	-	-	-	-	-	98
Goodwill	-	11	-	-	144	-	-	-	-	-	155
Long-term Risk Management Assets	-	61	-	-	-	-	5	-	-	-	66
Other	-	22	-	-	-	-	5	-	12	-	39
Total Assets Held for Sale	$151	$1,110	$42	$1,815	$375	$6	$45	$6	$12	$39	$3,601
Liabilities:											
Current Liabilities	$28	$992	$-	$-	$53	$-	$48	$-	$-	$-	$1,121
Long-term Debt	25	-	-	-	-	-	-	-	-	-	25
Deferred Income Taxes	-	-	-	-	-	-	-	-	-	-	-
Long-term Risk Management Liabilities	-	39	-	-	7	-	3	-	-	-	49
Deferred Credits and Other	26	24	15	9	10	-	-	-	-	-	84
Total Liabilities Held for Sale	$79	$1,055	$15	$9	$70	$-	$51	$-	$-	$-	$1,279

ASSETS HELD AND USED

In 2003 and 2002, we recorded the following impairments related to assets (including Goodwill) held and used to Asset Impairments and Other Related Charges on our Consolidated Statements of Operations as discussed below:

Excess Real Estate (Investments – Other segment)

In the fourth quarter of 2002, we began to market an under-utilized office building in Dallas, TX obtained through our merger with CSW. Sale of the facility was projected by the second quarter 2003 and an estimated pre-tax loss on disposal of $15.7 million was recorded in 2002, based on the option sale price. The estimated loss is included in Asset Impairments and Other Related Charges on our Consolidated Statements of Operations. The Property asset of $18 million in 2002 and $36 million in 2001 was previously classified on our Consolidated Balance Sheets as held for sale.

The sale of this office building was not completed by the end of 2003 and as a result the building no longer qualifies for held for sale status. In accordance with SFAS 144 the building will be moved to held and used status for all periods presented as of December 31, 2003. In December 2003 we recorded an additional pre-tax impairment of $6 million based on bids received to date. The impairment is recorded in Maintenance and Other Operation on our Consolidated Statements of Operations. The building will continue to be actively marketed.

HPL and Other (Investments – Gas Operations segment)

HPL owns, or leases, and operates natural gas gathering, transportation and storage operations in Texas. In 2003, management announced that we were in the process of divesting our non-core assets, which includes the assets within our Investments-Gas Operations segment. During the fourth quarter of 2003, based on a probability-weighted after-tax cash flow analysis of the fair value of HPL, we recorded an impairment of $300 million pre-tax ($218 million after-tax), with $150 million pre-tax related to goodwill, reflecting management's decision not to operate HPL as a major trading hub and market indicators supported by the LIG bid process. The cash flow analysis used management's estimate of the alternative likely outcomes of the uncertainties surrounding the continued use of the Bammel facility and other matters (see Note 7) and an after-tax risk free discount rate of 3.3% over the remaining life of the assets.

We also recorded a $15 million pre-tax charge ($10 million after-tax) in the fourth quarter 2003 included in Asset Impairments and Other Related Charges on our Consolidated Statements of Operations. This charge related to the effect of the write-off of certain HPL and LIG assets and the impairment of goodwill related to our former optimization strategy of LIG assets by AEP Energy Services.

Blackhawk Coal Company (Utility Operations segment)

Blackhawk Coal Company (Blackhawk) is a wholly-owned subsidiary of I&M and was formerly engaged in coal mining operations until they ceased due to gas explosions in the mine. During the fourth quarter of 2003, it was determined that the carrying value of the investment was impaired based on an updated valuation reflecting management's decision not to pursue development of potential gas reserves. As a result, a $10.4 million pre-tax charge was recorded to reduce the value of the coal and gas reserves to their estimated realizable value. This charge was recorded in Asset Impairments and Other Related Charges in our Consolidated Statements of Operations.

Power Generation Facility (Investments – Other segment)

We have agreements with Juniper Capital L.P. (Juniper) for Juniper to develop, construct, and finance a non-regulated merchant power generation facility (Facility) near Plaquemine, Louisiana and for Juniper to lease the Facility to us. Juniper will own the Facility and lease it to AEP after construction is completed and we will sublease the Facility to The Dow Chemical Company (Dow).

At December 31, 2002, we would have reported the Facility and related obligations as an operating lease upon achieving commercial operation. In the fourth quarter of 2003, we chose to not seek funding from Juniper for budgeted and approved pipeline construction costs related to the Facility. In order to continue reporting the Facility as an off-balance sheet financing, we were required to seek funding of our construction costs from Juniper. As a result, we recorded $496 million of construction work in progress (CWIP) and the related financing liability for the debt and equity as of December 31, 2003. At December 31, 2003, the lease of the Facility is reported as an owned asset under a lease financing transaction. Since the debt obligations of the Facility are recorded on our financial statements, the obligations under the lease agreement are excluded from the above table of future minimum lease payments.

The current litigation between TEM and ourselves, combined with a substantial oversupply of generation capacity in the markets where we would otherwise sell the power freed up by TEM contract termination, triggered us to review the project for possible impairment of its reported values. We determined that the value of the Facility was impaired and recorded a $258 million pre-tax impairment ($168 million after-tax) in December 2003 on the CWIP.

See further discussion in Notes 7 and 16.

INVESTMENT VALUE AND OTHER LOSSES

In 2003 and 2002, we recorded the following declines in fair value on investments:

Independent Power Producers (Investments – Other segment)

During the third quarter of 2003, we initiated an effort to sell four domestic Independent Power Producer (IPP) investments accounted for under the equity method. Based on indicative bids, it was determined that an other than temporary impairment existed on two of the equity investments. The impairment was the result of the measurement of fair value that was triggered by our recent decision to sell the assets. A $70.0 million pre-tax ($45.5 million net of tax) loss was recorded in September 2003 as a result of an other than temporary impairment of the equity interest. This loss of investment value is included in Investment Value Losses on our Consolidated Statements of Operations. We have received bids on the IPP investments and anticipate a final sale during the first half of 2004.

South Coast Power Investment (Investments – Other segment)

South Coast Power is a 50% owned joint venture that was formed in 1996 to build and operate a merchant closed-cycle gas turbine generator at Shoreham, U.K. South Coast Power is subject to the same adverse wholesale electric power rates described for U.K. Generation Plants above in "Discontinued Operations." A December 2002 projected cash flow estimate of the fair value of the investment indicated a 2002 pre-tax other than temporary impairment of the equity interest (which included the fair value of supply contracts held by South Coast Power and accounted for in accordance with SFAS 133) in the amount of $63.2 million. This loss of investment value is included in Investment Value Losses on our Consolidated Statements of Operations in 2002.

Technology Investments (Investments – Other segment)

We previously made investments totaling $11.7 million in four early-stage or startup technologies involving pollution control and procurement. An analysis in December 2002 of the viability of the underlying technologies and the projected performance of the investee companies indicated that the investments were unlikely to be recovered, and an other than temporary impairment of the entire amount of the equity interest under APB 18 was recorded. The loss of investment value is included in Investment Value Losses on our Consolidated Statements of Operations.

11. BENEFIT PLANS

In the U.S. we sponsor two qualified pension plans and two nonqualified pension plans. A substantial majority of our employees in the U.S. are covered by either one qualified plan or both a qualified and a nonqualified pension plan. Other postretirement benefit plans are sponsored by us to provide medical and death benefits for retired employees in the U.S.

We also have a foreign pension plan for employees of AEP Energy Services U.K. Generation Limited (Genco) in the U.K. The Genco pension plan had $7 million of accumulated benefit obligations in excess of plan assets at December 31, 2002. The plan was in an overfunded position at December 31, 2003.

The following tables provide a reconciliation of the changes in the plans' benefit obligations and fair value of assets over the two-year period ending at the plan's measurement date of December 31, 2003, and a statement of the funded status as of December 31 for both years:

	U.S. Pension Plans		U.S. Other Post Retirement Benefit Plans	
	2003	2002	2003	2002
Change in Benefit Obligation:	(in millions)			
Obligation at January 1	$3,583	$3,292	$1,877	$1,645
Service Cost	80	72	42	34
Interest Cost	233	241	130	114
Participant Contributions	-	-	14	13
Plan Amendments	-	(2)	-	-
Actuarial (Gain) Loss	91	258	192	152
Benefit Payments	(299)	(278)	(92)	(81)
Obligation at December 31	$3,688	$3,583	$2,163	$1,877
Change in Fair Value of Plan Assets:				
Fair Value of Plan Assets at January 1	$2,795	$3,438	$723	$711
Actual Return on Plan Assets	619	(371)	122	(57)
Company Contributions (a)	65	6	183	137
Participant Contributions	-	-	14	13
Benefit Payments (a)	(299)	(278)	(92)	(81)
Fair Value of Plan Assets at December, 31	$3,180	$2,795	$950	$723

Funded Status:

Funded Status at December 31	$(508)	$(788)	$(1,213)	$(1,154)
Unrecognized Net Transition (Asset) Obligation	2	(7)	206	233
Unrecognized Prior Service Cost	(12)	(13)	6	6
Unrecognized Actuarial (Gain) Loss	797	1,020	977	896
Net Asset (Liability) Recognized	$279	$212	$(24)	$(19)

(a) Our contributions and benefit payments include only those amounts contributed directly to or paid directly from plan assets.

Accumulated Benefit Obligation:	**2003**	**2002**
	(in millions)	
U.S. Qualified Pension Plans	$3,549	$3,456
U.S. Nonqualified Pension Plans	76	71

	U.S. Pension Plans		**U.S. Other Post Retirement Benefit Plans**	
	2003	**2002**	**2003**	**2002**
	(in millions)			
Prepaid Benefit Costs	$325	$255	$-	$-
Accrued Benefit Liability	(46)	(44)	(24)	(19)
Additional Minimum Liability	(723)	(944)	N/A	N/A
Unrecognized Prior Service Costs	39	45	N/A	N/A
Accumulated Other Comprehensive Income	684	900	N/A	N/A
Net Asset (Liability) Recognized	$279	$212	$(24)	$(19)
Increase (Decrease) in Minimum Liability Included in Other Comprehensive Income (Pre-tax)	$(216)	$894	N/A	N/A

N/A = Not Applicable

The asset allocations for our U.S. pension plans at the end of 2003 and 2002, and the target allocation for 2004, by asset category, are as follows:

Asset Category	**Target Allocation 2004**	**Percentage of Plan Assets at Yearend 2003**	**2002**
		(in percentage)	
Equity	70	71	67
Fixed Income	28	27	32
Cash and Cash Equivalents	2	2	1
Total	100	100	100

The asset allocations for our U.S. other postretirement benefit plans at the end of 2003 and 2002, and target allocation for 2004, by asset category, are as follows:

Asset Category	**Target Allocation 2004**	**Percentage of Plan Assets at Yearend 2003**	**2002**
		(in percentage)	
Equity	70	61	41
Fixed Income	28	36	38
Cash and Cash Equivalents	2	3	21
Total	100	100	100

Our investment strategy for our employee benefit trust funds is to use a diversified mixture of equity and fixed income securities to preserve the capital of the funds and to maximize the investment earnings in excess of inflation within acceptable levels of risk.

The value of our qualified plans' assets increased from $2.795 billion at December 31, 2002 to $3.180 billion at December 31, 2003. The qualified plans paid $292 million in benefits to plan participants during 2003 (nonqualified plans paid $7 million in benefits). The status of our plans remains in an underfunded position (plan assets are less than projected benefit obligations) of $508 million at December 31, 2003. Due to the pension plans currently being underfunded, we recorded income in Other Comprehensive Income (OCI) of $154 million, and a reduction in the Deferred Income Tax Asset of $76 million, offset by a reduction to Minimum Pension Liability of $234 million and a reduction in adjustments for unrecognized costs of $4 million. The charge to OCI does not affect earnings or cash flow. Also, due to the current underfunded status of our qualified plans, we expect to make cash contributions to our U.S. pension plans of approximately $41 million in 2004.

At December 31, 2003 and 2002, the projected benefit obligation, accumulated benefit obligation, and fair value of U.S. plan assets of the U.S. pension plans with an accumulated benefit obligation in excess of plan assets, were as follows:

	U.S. Plans	
End of Year	**2003**	**2002**
	(in millions)	
Projected Benefit Obligation	$3,688	$3,583
Accumulated Benefit Obligation	3,625	3,527
Fair Value of Plan Assets	3,180	2,795
Accumulated Benefit Obligation Exceeds the Fair Value of Plan Assets	445	732

We base our determination of pension expense or income on a market-related valuation of assets which reduces year-to-year volatility. This market-related valuation recognizes investment gains or losses over a five-year period from the year in which they occur. Investment gains or losses for this purpose are the difference between the expected return calculated using the market-related value of assets and the actual return based on the market-related value of assets. Since the market-related value of assets recognizes gains or losses over a five-year period, the future value of assets will be impacted as previously deferred gains or losses are recorded.

The weighted-average assumptions as of December 31, used in the measurement of our benefit obligations are shown in the following tables:

	U.S. Pension Plans		U.S. Other Postretirement Benefit Plans	
	2003	**2002**	**2003**	**2002**
	(in percentages)			
Discount Rate	6.25	6.75	6.25	6.75
Rate of Compensation Increase	3.7	3.7	N/A	N/A

In determining the discount rate in the calculation of future pension obligations we review the interest rates of long-term bonds that receive one of the two highest ratings given by a recognized rating agency. As a result of a decrease in this benchmark rate during 2003, we determined that a decrease in our discount rate from 6.75% at December 31, 2002 to 6.25% at December 31, 2003 was appropriate.

The rate of compensation increase assumed varies with the age of the employee, ranging from 3.5% per year to 8.5% per year, with an average increase of 3.7%.

Information about the expected cash flows for the U.S. pension (qualified and non-qualified) and other postretirement benefit plans is as follows:

	U.S. Pension Plans	U.S. Other Postretirement Benefit Plans
	(in millions)	
Employer Contributions		
2003	$65	$183
2004 (expected)	41	180

The table below reflects the total benefits expected to be paid from the plan or from our assets, including both our share of the benefit cost and the participants' share of the cost, which is funded by participant contributions to the plan. Future benefit payments are dependent on the number of employees retiring, whether the retiring employees elect to receive pension benefits as annuities or as lump sum distributions, future integration of the benefit plans with changes to Medicare and other legislation, future levels of interest rates, and variances in actuarial results. The estimated payments for pension benefits and other postretirement benefits are as follows:

	U.S. Pension Benefits	U.S. Other Postretirement Benefit Plans
	(in millions)	
2004	$293	$106
2005	300	114
2006	310	123
2007	325	132
2008	335	140
Years 2009 to 2013, in Total	1,840	836

The contribution to the pension fund is based on the minimum amount required by the U.S. Department of Labor or the amount of the pension expense for accounting purposes, whichever is greater. The contribution to the other postretirement benefit plans' trusts is generally based on the amount of the other postretirement benefit plans' expense for accounting purposes and is provided for in agreements with state regulatory authorities.

The following table provides the components of our net periodic benefit cost (credit) for the plans for fiscal years 2003, 2002 and 2001:

	U.S. Pension Plans			U.S. Other Postretirement Benefit Plans		
	2003	2002	2001	2003	2002	2001
	(in millions)					
Service Cost	$80	$72	$69	$42	$34	$30
Interest Cost	233	241	232	130	114	114
Expected Return on Plan Assets	(318)	(337)	(338)	(64)	(62)	(61)
Amortization of Transition (Asset) Obligation	(8)	(9)	(8)	28	29	30
Amortization of Prior-service Cost	(1)	(1)	-	-	-	-
Amortization of Net Actuarial (Gain) Loss	11	(10)	(24)	52	27	18
Net Periodic Benefit Cost (Credit)	(3)	(44)	(69)	188	142	131
Curtailment Loss	-	-	-	-	-	1
Net Periodic Benefit Cost (Credit) After Curtailments	$(3)	$(44)	$(69)	$188	$142	$132

The weighted-average assumptions as of January 1, used in the measurement of our benefit costs are shown in the following tables:

	U.S. Pension Plans			U.S. Other Postretirement Benefit Plans		
	2003	2002	2001	2003	2002	2001
	(in percentage)					
Discount Rate	6.75	7.25	7.50	6.75	7.25	7.50
Expected Return on Plan Assets	9.00	9.00	9.00	8.75	8.75	8.75
Rate of Compensation Increase	3.7	3.7	3.2	N/A	N/A	N/A

The expected return on plan assets for 2003 was determined by evaluating historical returns, the current investment climate, rate of inflation, and current prospects for economic growth. After evaluating the current yield on fixed income securities as well as other recent investment market indicators, the expected return on plan assets was reduced to 8.75% for 2004. The expected return on other postretirement benefit plan assets (a portion of which is subject to capital gains taxes as well as Unrelated Business Income Taxes) was reduced to 8.35%.

The assumptions used for other postretirement benefit plan measurement purposes are shown below:

Health Care Trend Rates:	2003	2002
	(in percentage)	
Initial	10.0	10.0
Ultimate	5.0	5.0
Year Ultimate Reached	2008	2008

Assumed health care cost trend rates have a significant effect on the amounts reported for the other postretirement benefit health care plans. A 1% change in assumed health care cost trend rates would have the following effects:

	1% Increase	1% Decrease
	(in millions)	
Effect on Total Service and Interest Cost Components of Net Periodic Postretirement Health Care Benefit Cost	$26	$(21)
Effect on the Health Care Component of the Accumulated Postretirement Benefit Obligation	315	(257)

We have not yet determined the impact of the Medicare Prescription Drug Improvement and Modernization Act of 2003 on our other postretirement benefit plans' accumulated benefit obligation and periodic benefit cost. See FASB Staff Position No. 106-1 in Note 2 for additional information on the potential impact on our results of operations, cash flows and financial condition.

AEP Savings Plans

We sponsor various defined contribution retirement savings plans eligible to substantially all non-United Mine Workers of America (UMWA) U.S. employees. These plans include features under Section 401(k) of the Internal Revenue Code and provide for company matching contributions. On January 1, 2003, the two major AEP Savings Plans merged into a single plan. Beginning in 2001, and continuing under the single merged plan, our contributions to the plans increased from 50% to 75% of the first 6% of eligible employee compensation. The cost for contributions to these plans totaled $57.0 million in 2003, $60.1 million in 2002 and $55.6 million in 2001.

Other UMWA Benefits

We provide UMWA pension, health and welfare benefits for certain unionized mining employees, retirees, and their survivors who meet eligibility requirements. UMWA trustees make final interpretive determinations with regard to all benefits. The pension benefits are administered by UMWA trustees and contributions are made to their trust funds.

The health and welfare benefits are administered by us and benefits are paid from our general assets. Contributions are expensed as paid as part of the cost of active mining operations and were not material in 2003, 2002 and 2001.

12. STOCK-BASED COMPENSATION

The American Electric Power System 2000 Long-Term Incentive Plan (the Plan) authorizes the use of 15,700,000 shares of AEP common stock for various types of stock-based compensation awards, including stock option awards, to key employees. The Plan was adopted in 2000 by the Board of Directors and shareholders.

Stock-based compensation awards granted by AEP include restricted stock units, restricted shares, performance share units and stock options. Restricted stock units vest, subject to the participant's continued employment, in approximately equal 1/3 increments on January 1st for three years following the grant date. Amounts equivalent to cash dividends on the units accrue as additional units. AEP awarded 105,910 restricted stock units, including dividends, in 2003, with a weighted-average grant-date fair value of $22.17 per unit. Compensation cost is recorded over the vesting period, based on the market value on the grant date. Expense associated with units that are forfeited is reversed in the period of forfeiture.

AEP awarded 300,000 restricted shares in January 2004, which vest over periods ranging from 1 to 8 years. Compensation cost will be recorded over the vesting period based on the market value of $30.76 per unit on the grant date.

Performance share units are equal in value to shares of AEP common stock but are subject to an attached performance factor ranging from 0% to 200%. The performance factor is determined at the end of the performance period based on performance measure(s) established for each grant at the beginning of the performance period by the Human Resources Committee of the Board of Directors. Performance share units are typically paid in cash at the end of a three-year vesting period, unless they are needed to satisfy a participant's stock ownership requirement, in which case they are mandatorily deferred as phantom stock units until the end of the participants AEP career. Phantom stock units have a value equivalent to AEP common stock and are typically paid in cash upon the participant's termination of employment. The compensation cost for performance share units is recorded over the vesting period and both the performance share and phantom stock unit liability is adjusted for changes in fair market value. Amounts equivalent to cash dividends on both performance share and phantom stock units accrue as additional units.

Under the Plan, the exercise price of all stock option grants must equal or exceed the market price of AEP's common stock on the date of grant, and in accordance with its policy, AEP does not record compensation expense. AEP generally grants options that have a ten-year life and vest, subject to the participant's continued employment, in approximately equal 1/3 increments on January 1 following the first, second and third anniversary of the grant date.

CSW maintained a stock option plan prior to the merger with AEP in 2000. Effective with the merger, all CSW stock options outstanding were converted into AEP stock options at an exchange ratio of one CSW stock option for 0.6 of an AEP stock option. The exercise price for each CSW stock option was adjusted for the exchange ratio. Outstanding CSW stock options will continue in effect until all options are exercised, cancelled or expired. Under the CSW stock option plan, the option price was equal to the fair market value of the stock on the grant date. All CSW options fully vested upon the completion of the merger and expire 10 years after their original grant date.

A summary of AEP stock option transactions in fiscal periods 2003, 2002 and 2001 is as follows:

	2003		2002		2001	
	Options (in thousands)	Weighted Average Exercise Price	Options (in thousands)	Weighted Average Exercise Price	Options (in thousands)	Weighted Average Exercise Price
Outstanding at beginning of year	8,787	$34	6,822	$37	6,610	$36
Granted	927	$28	2,923	$27	645	$45
Exercised	(23)	$27	(600)	$36	(216)	$38
Forfeited	(597)	$33	(358)	$41	(217)	$37
Outstanding at end of year	9,094	$33	8,787	$34	6,822	$37
Options exercisable at end of year	3,909	$36	2,481	$36	395	$43
Weighted average exercise price of options:						
-Granted above Market Price		N/A		$27		N/A
-Granted at Market Price		$28		$27		$45

The following table summarizes information about AEP stock options outstanding at December 31, 2003:

Options Outstanding

Range of Exercise Prices	Number Outstanding (in thousands)	Weighted Average Remaining Life (in years)	Weighted Average Exercise Price
$25.73 - $27.95	3,530	9.1	$27.28
$34.58 - $41.50	5,054	6.6	$35.74
$43.79 - $49.00	510	7.5	$45.98
	9,094	7.6	$33.03

Options Exercisable

Range of Exercise Prices	Number Outstanding (in thousands)	Weighted Average Exercise Price
$25.73 - $27.95	52	$27.06
$34.58 - $41.50	3,610	$35.78
$43.79 - $49.00	247	$46.57
	3,909	$36.35

The proceeds received from exercised stock options are included in common stock and paid-in capital.

The fair value of each option award is estimated on the date of grant using the Black-Scholes option-pricing model with the following weighted average assumptions used to estimate the fair value of AEP options granted:

	2003	2002	2001
Risk Free Interest Rate	3.92%	3.53%	4.87%
Expected Life	7 years	7 years	7 years
Expected Volatility	27.57%	29.78%	28.40%
Expected Dividend Yield	4.86%	6.15%	6.05%
Weighted average fair value of options:			
-Granted above Market Price	N/A	$4.58	N/A
-Granted at Market Price	$5.26	$4.37	$8.01

13. BUSINESS SEGMENTS

Our segments and their related business activities are as follows:

Utility Operations

- Domestic generation of electricity for sale to retail and wholesale customers
- Domestic electricity transmission and distribution

*Investments - Gas Operations**

- Gas pipeline and storage services

*Investments - UK Operations***

- International generation of electricity for sale to wholesale customers
- Coal procurement and transportation to AEP plants and third parties

Investments – Other

- Coal mining, bulk commodity barging operations and other energy supply businesses

* Operations of Louisiana Intrastate Gas were classified as discontinued during 2003.
** UK Operations were classified as discontinued during 2003.

The tables below present segment information for the twelve months ended December 31, 2003, 2002 and 2001. These amounts include certain estimates and allocations where necessary. Prior year amounts have been reclassified to conform to the current year's presentation.

		Investments					
	Utility Operations	Gas Operations	UK Operations	Other	All Other*	Reconciling Adjustments	Consolidated
2003				(in millions)			
Revenues from:							
External Customers	$10,871	$3,097	$-	$ 577	$-	$ -	$14,545
Other Operating Segments	-	192	-	96	11	(299)	-
Discontinued Operations, Net of Tax	-	(91)	(507)	(7)	-	-	(605)
Cumulative Effect of Accounting Changes, Net of Tax	237	(23)	(21)	-	-	-	193
Net Income (Loss)	1,455	(404)	(528)	(284)	(129)	-	110
Depreciation, Depletion and Amortization Expense	1,241	18	-	39	1	-	1,299
Total Assets	30,816	2,405	1,705	1,697	14,925	(14,804)	36,744
Assets Held for Sale	1,033	240	1,624	185	-	-	3,082
Investments in Equity Method Subsidiaries	-	36	38	87	-	-	161
Gross Property Additions	1,323	25	-	10	-	-	1,358

* All Other includes interest, litigation and other miscellaneous parent company expenses, as well as the operations of a service company subsidiary, which provides services at cost to the other operating segments.

2002	Utility Operations	Investments: Gas Operations	Investments: UK Operations	Investments: Other (in millions)	All Other*	Reconciling Adjustments	Consolidated
Revenues from:							
External Customers	$10,446	$2,071	$-	$791	$-	$ -	$13,308
Other Operating Segments	-	222	-	147	10	(379)	-
Discontinued Operations, Net of Tax	-	8	(472)	(190)	-	-	(654)
Cumulative Effect of Accounting Changes, Net of Tax	-	-	-	(350)	-	-	(350)
Net Income (Loss)	1,154	(91)	(472)	(1,062)	(48)	-	(519)
Depreciation, Depletion and Amortization Expense	1,268	13	-	67	-	-	1,348
Total Assets	29,431	3,912	1,215	1,947	18,388	(19,003)	35,890
Assets Held for Sale	1,866	375	1,150	210	-	-	3,601
Investments in Equity Method Subsidiaries	-	35	-	137	-	-	172
Gross Property Additions	1,517	47	-	25	96	-	1,685

* All Other includes interest, litigation and other miscellaneous parent company expenses, as well as the operations of a service company subsidiary, which provides services at cost to the other operating segments.

2001	Utility Operations	Investments: Gas Operations	Investments: UK Operations	Investments: Other (in millions)	All Other*	Reconciling Adjustments	Consolidated
Revenues from:							
External Customers	$10,546	$1,797	$-	$410	$-	$-	$12,753
Other Operating Segments	-	-	-	86	5	(91)	-
Discontinued Operations, Net of Tax	-	(4)	(41)	86	-	-	41
Extraordinary Items, Net of Tax	(48)	-	-	-	-	-	(48)
Cumulative Effect, Net of Tax	-	-	-	18	-	-	18
Net Income (Loss)	911	87	(41)	86	(72)	-	971
Depreciation, Depletion and Amortization Expense	1,193	15	-	25	-	-	1,233
Gross Property Additions	1,397	14	-	137	98	-	1,646

* All Other includes interest, litigation and other miscellaneous parent company expenses, as well as the operations of a service company subsidiary, which provides services at cost to the other operating segments.

14. DERIVATIVES, HEDGING AND FINANCIAL INSTRUMENTS

DERIVATIVES AND HEDGING

In the first quarter of 2001, we adopted SFAS 133, "Accounting for Derivative Instruments and Hedging Activities," as amended. We recorded a favorable transition adjustment to Accumulated Other Comprehensive Income (Loss) of $27 million at January 1, 2001 in connection with the adoption of SFAS 133. Derivatives included in the transition adjustment are interest rate swaps, foreign currency swaps and commodity swaps, options and futures. Most of the derivatives identified in the transition adjustment were designated as cash flow hedges and relate to foreign operations.

SFAS 133 requires recognition of all derivative instruments as either assets or liabilities in the statement of financial position at fair value. Our accounting for the changes in the fair value of a derivative instrument depends on whether it qualifies, and has been designated, as part of a hedging relationship and further, on the type of hedging relationship. We designate the hedging instrument, based on the exposure being hedged, as a fair value hedge, a cash flow hedge or a hedge of a net investment in a foreign operation. Certain qualifying derivative instruments have been designated as normal purchase or normal sale contracts, as provided in SFAS 133. These contracts are not reported at fair value, as otherwise required by SFAS 133.

For fair value hedges (i.e. hedging the exposure to changes in the fair value of an asset, liability or an identified portion thereof that is attributable to a particular risk), we recognize the gain or loss on the derivative instrument as well as the offsetting loss or gain on the hedged item associated with the hedged risk in Revenues in the Consolidated Statement of Operations during the period of change. For cash flow hedges (i.e. hedging the exposure to variability in expected future cash flows that is attributable to a particular risk), we initially report the effective portion of the gain or loss on the derivative instrument as a component of Other Accumulated Comprehensive Income and subsequently reclassify it to Revenues in the Consolidated Statement of Operations when the forecasted transaction affects earnings. The remaining gain or loss on the derivative instrument in excess of the cumulative change in the present value of future cash flows of the hedged item, if any, is recognized currently in Revenues during the period of change. For a hedge of a net investment in a foreign currency, we include the effective portion of the gain or loss in Other Accumulated Comprehensive Income as part of the cumulative translation adjustment. We recognize any ineffective portion of the gain or loss in Revenues immediately during the period of change.

We recognize all derivative instruments at fair value in our Consolidated Balance Sheets as either "Risk Management Assets" or "Risk Management Liabilities." We do not consider contracts that have been elected normal purchase or normal sale under SFAS 133 to be derivatives. Unrealized and realized gains and losses on all derivative instruments are ultimately included in Revenues in the Consolidated Statement of Operations on a net basis, with the exception of physically settled Resale Gas Contracts for the purchase of natural gas. The unrealized and realized gains and losses on these Resale Gas Contracts are presented as Purchased Gas for Resale in the Consolidated Statement of Operations.

Fair Value Hedging Strategies

We enter into natural gas forward and swap transactions to hedge natural gas inventory. The purpose of the hedging activity is to protect the natural gas inventory against changes in fair value due to changes in the spot gas prices. During the year ended December 31, 2003, we recognized a pre-tax loss of approximately $3.4 million within revenues related to hedge ineffectiveness and changes in time value excluded from the assessment of hedge ineffectiveness.

We enter into interest rate forward and swap transactions for interest rate risk exposure management purposes. The interest rate forward and swap transactions effectively modifies our exposure to interest risk by converting a portion of our fixed-rate debt to a floating rate. We do not hedge all interest rate exposure.

Cash Flow Hedging Strategies

We enter into forward contracts to protect against the reduction in value of forecasted cash flows resulting from transactions denominated in foreign currencies. When the dollar strengthens significantly against the foreign currencies, the decline in value of future foreign currency revenue is offset by gains in the value of the forward contracts designated as cash flow hedges. Conversely, when the dollar weakens, the increase in the value of future foreign currency cash flows is offset by losses in the value of forward contracts. We do not hedge all foreign currency exposure.

We enter into interest rate forward and swap transactions in order to manage interest rate risk exposure. These transactions effectively modify our exposure to interest risk by converting a portion of our floating-rate debt to a fixed rate. We do not hedge all interest rate exposure.

We enter into forward and swap transactions for the purchase and sale of electricity and natural gas to manage the variable price risk related to the forecasted purchase and sale of electricity. We closely monitor the potential impacts of commodity price changes and, where appropriate, enter into contracts to protect margins for a portion of future sales and generation revenues. We do not hedge all variable price risk exposure related to the forecasted purchase and sale of electricity.

Cash flow hedges included in Accumulated Other Comprehensive Income (Loss) on our Consolidated Balance Sheets at December 31, 2003 are:

	Hedging Assets	Hedging Liabilities	Accumulated Other Comprehensive Income (Loss) After Tax (in millions)	Portion Expected to Be Reclassified to Earnings during the Next 12 Months
Power and Gas	$21	$(121)	$(65)	$(58)
Interest Rate	-	(7)	(9)*	(8)
Foreign Currency	-	(30)	(20)	(20)
			$(94)	$(86)

* Includes $6 million loss recorded in an equity investment.

The net losses from cash flow hedges in Accumulated Other Comprehensive Income (Loss) at December 31, 2003 are expected to be reclassified to net income in the next twelve months as the items being hedged settle. The actual amounts reclassified from AOCI to Net Income can differ as a result of market price changes. The maximum term for which the exposure to the variability of future cash flows is being hedged is five years.

The following table represents the activity in Accumulated Other Comprehensive Income (Loss) for derivative contracts that qualify as cash flow hedges at December 31, 2003:

	(in millions)
Beginning Balance, January 1, 2003	$(16)
Changes in fair value	(79)
Reclasses from AOCI to net gain	1
Ending Balance, December 31, 2003	$(94)

Hedge of Net Investment in Foreign Operations

In 2001 and 2002, we used foreign denominated fixed-rate debt to protect the value of our investments in foreign subsidiaries in the U.K. Realized gains and losses from these hedges are not included in the income statement, but are shown in the cumulative translation adjustment account included in Other Accumulated Comprehensive Income.

During 2002, we recognized $64 million of net losses, included in the cumulative translation adjustment, related to the foreign denominated fixed-rate debt.

FINANCIAL INSTRUMENTS

The fair values of Long-term Debt and preferred stock subject to mandatory redemption are based on quoted market prices for the same or similar issues and the current dividend or interest rates offered for instruments with similar maturities. These instruments are not marked-to-market. The estimates presented are not necessarily indicative of the amounts that we could realize in a current market exchange.

The book values and fair values of significant financial instruments at December 31, 2003 and 2002 are summarized in the following tables.

	2003		2002	
	Book Value	Fair Value	Book Value	Fair Value
	(in millions)		(in millions)	
Long-term Debt	$14,101	$14,621	$10,190	$10,535
Cumulative Preferred Stocks of Subsidiaries Subject to Mandatory Redemption*	76	76	84	77
Trust Preferred Securities	-	-	321	324

* See Schedule of Consolidated Cumulative Preferred Stocks of Subsidiaries for the effect of SFAS 150 in 2003.

Other Financial Instruments - Nuclear Trust Funds Recorded at Market Value

The trust investments which are classified as available for sale for decommissioning and SNF disposal, reported in "Spent Nuclear Fuel and Decommissioning Trusts" and "Assets Held for Sale" on our Consolidated Balance Sheets, are recorded at market value in accordance with SFAS 115 "Accounting for Certain Investments in Debt and Equity Securities." At December 31, 2003 and 2002, the fair values of the trust investments were $1,107 million and $969 million, respectively, and had a cost basis of $995 million and $909 million, respectively. The change in market value in 2003, 2002, and 2001 was a net unrealized holding gain of $53 million and a net unrealized holding loss of $33 million and $11 million, respectively.

15. INCOME TAXES

The details of our consolidated income taxes before discontinued operations, extraordinary items, and cumulative effect as reported are as follows:

	Year Ended December 31,		
	2003	2002	2001
		(in millions)	
Federal:			
Current	$297	$307	$411
Deferred	34	(60)	54
Total	331	247	465
State and Local:			
Current	19	32	61
Deferred	1	28	34
Total	20	60	95
International:			
Current	7	8	(7)
Deferred	-	-	-
Total	7	8	(7)
Total Income Tax as Reported Before Discontinued Operations, Extraordinary Items and Cumulative Effect	$358	$315	$553

The following is a reconciliation of our consolidated difference between the amount of federal income taxes computed by multiplying book income before federal income taxes by the statutory tax rate and the amount of income taxes reported.

	Year Ended December 31,		
	2003	2002	2001
		(in millions)	
Net Income (Loss)	$110	$(519)	$971
Discontinued Operations (net of income tax of $312 million, $174 million and $14 million in 2003, 2002 and 2001, respectively)	605	654	(41)
Extraordinary Items (net of income tax of $20 million in 2001)	-	-	48
Cumulative Effect of Accounting Change (net of income tax of $138 million in 2003)	(193)	350	(18)
Preferred Stock Dividends	9	11	10
Income Before Preferred Stock Dividends of Subsidiaries	531	496	970
Income Taxes Before Discontinued Operations, Extraordinary Items and Cumulative Effect	358	315	553
Pre-Tax Income	$889	$811	$1,523
Income Taxes on Pre-Tax Income at Statutory Rate *(35%)*	$311	$284	$533
Increase (Decrease) in Income Taxes Resulting from the Following Items:			
Depreciation	40	32	48
Asset Impairments and Investment Value Losses	23	4	-
Investment Tax Credits (net)	(33)	(35)	(37)
Tax Effects of International Operations	8	27	(22)
Energy Production Credits	(15)	(14)	-
State Income Taxes	13	39	62
Other	11	(22)	(31)
Total Income Taxes as Reported Before Discontinued Operations, Extraordinary Items and Cumulative Effect	$358	$315	$553
Effective Income Tax Rate	40.3%	38.8%	36.3%

The following table shows our elements of the net deferred tax liability and the significant temporary differences.

	As of December 31,	
	2003	2002
	(in millions)	
Deferred Tax Assets	$3,354	$2,604
Deferred Tax Liabilities	(7,311)	(6,520)
Net Deferred Tax Liabilities	$(3,957)	$(3,916)
Property Related Temporary Differences	$(2,836)	$(3,195)
Amounts Due From Customers For Future Federal Income Taxes	(389)	(360)
Deferred State Income Taxes	(416)	(422)
Transition Regulatory Assets	(254)	(234)
Regulatory Assets Designated for Securitization	(281)	(310)
Deferred Income Taxes on Other Comprehensive Loss	306	326
All Other (net)	(87)	279
Net Deferred Tax Liabilities	$(3,957)	$(3,916)

We have settled with the IRS all issues from the audits of our consolidated federal income tax returns for the years prior to 1991. We have received Revenue Agent's Reports from the IRS for the years 1991 through 1996, and have filed protests contesting certain proposed adjustments. Returns for the years 1997 through 2000 are presently being audited by the IRS. Management is not aware of any issues for open tax years that upon final resolution are expected to have a material adverse effect on results of operations.

We join in the filing of a consolidated federal income tax return with our affiliated companies in the AEP System. The allocation of the AEP System's current consolidated federal income tax to the System companies is in accordance with SEC rules under the 1935 Act. These rules permit the allocation of the benefit of current tax losses to the System companies giving rise to them in determining their current tax expense. The tax loss of the System parent company, AEP Co., Inc., is allocated to its subsidiaries with taxable income. With the exception of the loss of the parent company, the method of allocation approximates a separate return result for each company in the consolidated group.

16. LEASES

Leases of property, plant and equipment are for periods up to 99 years and require payments of related property taxes, maintenance and operating costs. The majority of the leases have purchase or renewal options and will be renewed or replaced by other leases.

Lease rentals for both operating and capital leases are generally charged to operating expenses in accordance with rate-making treatment for regulated operations. Capital leases for non-regulated property are accounted for as if the assets were owned and financed. The components of rental costs are as follows:

	Year Ended December 31,		
	2003	2002	2001
		(in millions)	
Lease Payments on Operating Leases	$330	$346	$292
Amortization of Capital Leases	64	65	82
Interest on Capital Leases	9	14	22
Total Lease Rental Costs	$403	$425	$396

Property, plant and equipment under capital leases and related obligations recorded on the Consolidated Balance Sheets are as follows:

	December 31,	
	2003	2002
	(in millions)	
Property, Plant and Equipment Under Capital Leases		
Production	$37	$40
Distribution	15	15
Other	470	687
Total Property, Plant and Equipment	522	742
Accumulated Amortization	218	299
Net Property, Plant and Equipment Under Capital Leases	$304	$443
Obligations Under Capital Leases:		
Noncurrent Liability	$131	$170
Liability Due Within One Year	51	58
Total Obligations under Capital Leases	$182	$228

Future minimum lease payments consisted of the following at December 31, 2003:

	Capital Leases	Noncancelable Operating Leases
	(in millions)	
2004	$63	$291
2005	43	255
2006	34	237
2007	31	227
2008	18	214
Later Years	31	2,331
Total Future Minimum Lease Payments	220	$3,555
Less Estimated Interest Element	38	
Estimated Present Value of Future Minimum Lease Payments	$182	

Power Generation Facility

We have agreements with Juniper Capital L.P. (Juniper) for Juniper to develop, construct, and finance a non-regulated merchant power generation facility (Facility) near Plaquemine, Louisiana and for Juniper to lease the Facility to us. The Facility is a "qualifying cogeneration facility" for purposes of PURPA. Construction of the Facility was begun by Katco Funding, Limited Partnership (Katco), an unrelated unconsolidated special purpose entity. Katco assigned its interest in the Facility to Juniper in June 2003.

Juniper is an unaffiliated limited partnership, formed to construct or otherwise acquire real and personal property for lease to third parties, to manage financial assets and to undertake other activities related to asset financing. Juniper arranged to finance the Facility with debt financing up to $494 million and equity up to $31 million from investors with no relationship to AEP or any of AEP's subsidiaries. Juniper will own the Facility and lease it to AEP after construction is completed.

At December 31, 2002, we would have reported the Facility and related obligations as an operating lease upon achieving commercial operation (COD). In the fourth quarter of 2003, we chose to not seek funding from Juniper for budgeted and approved pipeline construction costs related to the Facility. In order to continue reporting the Facility as an off-balance sheet financing, we were required to seek funding of our construction costs from Juniper. As a result, we recorded $496 million of construction work in progress (CWIP) and the related financing liability for the debt and equity as of December 31, 2003. At December 31, 2003, the lease of the Facility is reported as an owned asset under a lease financing transaction. Since the debt obligations of the Facility are recorded on our financial statements, the obligations under the lease agreement are excluded from the above table of future minimum lease payments.

We are the construction agent for Juniper. We expect to achieve COD in the spring of 2004, at which time the obligation to make payments under the lease agreement will begin to accrue and we will sublease the Facility to The Dow Chemical Company (Dow). If COD does not occur on or before March 14, 2004, Juniper has the right to terminate the project. In the event the project is terminated before COD, we have the option to either purchase the Facility for 100% of Juniper's acquisition cost (in general, the outstanding debt and equity associated with the Facility) or terminate the project and make a payment to Juniper for 89.9% of project costs (in general, the acquisition cost less certain financing costs).

The initial term of the lease agreement between Juniper and AEP commences on COD and continues for five years. The lease contains extension options, and if all extension options are exercised, the total term of the lease will be 30 years. AEP's lease payments to Juniper during the initial term and each extended term are sufficient for Juniper to make required debt payments under Juniper's debt financing associated with the Facility and provide a return on equity to the investors in Juniper. We have the right to purchase the Facility for the acquisition cost during the last month of the initial term or on any monthly rent payment date during any extended term. In addition, we may purchase the Facility from Juniper for the acquisition cost at any time during the initial term if we have arranged a sale of the Facility to an unaffiliated third party. A purchase of the Facility from Juniper by AEP should not alter Dow's rights to lease the Facility or our contract to purchase energy from Dow. If the lease were renewed for up to a 30-year lease term, we may further renew the lease at fair market value subject to Juniper's approval, purchase the Facility at its acquisition cost, or sell the Facility, on behalf of Juniper, to an independent third party. If the Facility is sold and the proceeds from the sale are insufficient to pay all of Juniper's acquisition costs, we may be required to make a payment (not to exceed $396 million) to Juniper of the excess of Juniper's acquisition costs over the proceeds from the sale, provided that we would not be required to make any payment if we have made the additional rental prepayment described below. We have guaranteed the performance of our subsidiaries to Juniper during the lease term. Because we now report the debt related to the Facility on our balance sheet, the fair value of the liability for our guarantee (the $396 million payment discussed above) is not separately reported.

At December 31, 2003, Juniper's acquisition costs for the Facility totaled $496 million, and total costs for the completed Facility are currently expected to be approximately $525 million. For the 30-year extended lease term, the base lease rental is a variable rate obligation indexed to three-month LIBOR. Consequently, as market interest rates increase, the base rental payments under the lease will also increase. Annual payments of approximately $18 million represent future minimum payments for interest on Juniper's financing structure during the initial term calculated using the indexed LIBOR rate (1.15% at December 31, 2003). An additional rental prepayment (up to $396 million) may be due on June 30, 2004 unless Juniper has refinanced its present debt financing on a long-term basis. Juniper is currently planning to refinance by June 30, 2004. The Facility is collateral for the debt obligation of Juniper. At December 31, 2003, we reflected $396 million of the $496 million recorded obligation as long-term debt due within one year. Our maximum required cash payment as a result of our financing transaction with Juniper is $396 million as well as interest payments during the lease term. Due to the treatment of the Facility as a financing of an owned asset, the recorded liability of $496 million is greater than our maximum possible cash payment obligation to Juniper.

Dow will use a portion of the energy produced by the Facility and sell the excess energy. OPCo has agreed to purchase up to approximately 800 MW of such excess energy from Dow. OPCo has also agreed to sell up to approximately 800 MW of energy to Tractebel Energy Marketing, Inc. (TEM) for a period of 20 years under a Power Purchase and Sale Agreement dated November 15, 2000 (PPA) at a price that is currently in excess of market. Beginning May 1, 2003, OPCo tendered replacement capacity, energy and ancillary services to TEM pursuant to the PPA that TEM rejected as non-conforming.

See further discussion in Notes 7 and 10.

Gavin Lease

OPCo has entered into an agreement with JMG, an unrelated special purpose entity. JMG has a capital structure of which 3% is equity from investors with no relationship to AEP or any of its subsidiaries and 97% is debt from commercial paper, pollution control bonds and other bonds. JMG was formed to design, construct and lease the Gavin Scrubber for the Gavin Plant to OPCo. JMG owns the Gavin Scrubber and leases it to OPCo. Prior to July 1, 2003, the lease was accounted for as an operating lease. Payments under the lease agreement are based on JMG's cost of financing (both debt and equity) and include an amortization component plus the cost of administration. OPCo and AEP do not have an ownership interest in JMG and do not guarantee JMG's debt.

At any time during the lease, OPCo has the option to purchase the Gavin Scrubber for the greater of its fair market value or adjusted acquisition cost (equal to the unamortized debt and equity of JMG) or sell the Gavin Scrubber on behalf of JMG. The initial 15-year lease term is non-cancelable. At the end of the initial term, OPCo can renew the lease, purchase the Gavin Scrubber (terms previously mentioned), or sell the Gavin Scrubber on behalf of JMG. In case of a sale at less than the adjusted acquisition cost, OPCo must pay the difference to JMG.

On March 31, 2003, OPCo made a prepayment of $90 million under this lease structure. AEP recognizes lease expense on a straight-line basis over the remaining lease term, in accordance with SFAS 13 "Accounting for Leases." The asset will be amortized over the remaining lease term, which ends in the first quarter of 2010.

On July 1, 2003, OPCo consolidated JMG due to the application of FIN 46. Upon consolidation, OPCo recorded the assets and liabilities of JMG ($469.6 million). OPCo now records the depreciation, interest and other operating expenses of JMG and eliminates JMG's revenues against OPCo's operating lease expenses. There was no cumulative effect of an accounting change recorded as a result of our requirement to consolidate JMG, and there was no change in net income due to the consolidation of JMG. Since the debt obligations of JMG are now consolidated, the JMG lease is no longer accounted for on a consolidated basis as an operating lease and has been excluded from the above table of future minimum lease payments.

Rockport Lease

AEGCo and I&M entered into a sale and leaseback transaction in 1989 with Wilmington Trust Company (Owner Trustee) an unrelated unconsolidated trustee for Rockport Plant Unit 2 (the plant). Owner Trustee was capitalized with equity from six owner participants with no relationship to AEP or any of its subsidiaries and debt from a syndicate of banks and securities in a private placement to certain institutional investors. The future minimum lease payments for each respective company are $1.4 billion.

The FASB and other accounting constituencies continue to interpret the application of FIN 46R. As a result, we are continuing to review the application of this new interpretation as it relates to the Rockport Plant Unit 2 transaction.

The gain from the sale was deferred and is being amortized over the term of the lease, which expires in 2022. The Owner Trustee owns the plant and leases it to AEGCo and I&M. The lease is accounted for as an operating lease with the payment obligations included in the future minimum lease payments schedule earlier in this note. The lease term is for 33 years with potential renewal options. At the end of the lease term, AEGCo and I&M have the option to renew the lease or the Owner Trustee can sell the plant. Neither AEGCo, I&M nor AEP has an ownership interest in the Owner Trustee and do not guarantee its debt.

Railcar Lease

In June 2003, we entered into an agreement with an unrelated, unconsolidated leasing company to lease 875 coal-transporting aluminum railcars. The lease has an initial term of five years and may be renewed for up to three additional five-year terms, for a maximum of twenty years. We intend to renew the lease for the full twenty years. At the end of each lease term, we may (a) renew for another five-year term, not to exceed a total of twenty years, (b) purchase the railcars for the purchase price amount specified in the lease, projected at the lease inception to be the then fair market value, or (c) return the railcars and arrange a third party sale (return-and-sale option). The lease is accounted for as an operating lease with the future payment included in the future minimum lease payments schedule earlier in this note. This operating lease agreement allows us to avoid a large initial capital expenditure, and to spread our railcar costs evenly over the expected twenty-year usage.

Under the lease agreement, the lessor is guaranteed that the sale proceeds under the return-and-sale option discussed above will equal at least a lessee obligation amount specified in the lease, which declines over the term from approximately 86% to 77% of the projected fair market value of the equipment. At December 31, 2003, the maximum potential loss was approximately $31.5 million ($20.5 million net of tax) assuming the fair market value of the equipment is zero at the end of the current lease term. The railcars are subleased for one year to an unaffiliated company under an operating lease. The sublessee may renew the lease for up to four additional one-year terms. AEP has other rail car lease arrangements that do not utilize this type of structure.

17. FINANCING ACTIVITIES

Trust Preferred Securities

PSO, SWEPCo and TCC have wholly-owned business trusts that have issued trust preferred securities. The trusts which hold mandatorily redeemable trust preferred securities were deconsolidated effective July 1, 2003 due to the implementation of FIN 46. Therefore, $321 million ($75 million PSO, $110 million SWEPCo and $136 million TCC), previously reported at December 31, 2002 as Certain Subsidiary Obligated, Mandatorily Redeemable, Preferred Securities of Subsidiary Trusts Holding Solely Junior Subordinated Debentures of Such Subsidiaries, is now reported as two components on the Balance Sheet. The $10 million investment in the trust is now reported as Other within Other Non-Current Assets while the $331 million of subordinated debentures are now reported as Notes Payable to Trust within Long-term Debt.

The Junior Subordinated Debentures of PSO and TCC mature on April 30, 2037. In October 2003, SWEPCo refinanced its Junior Subordinated Debentures which are now due October 1, 2043. The following Trust Preferred Securities issued by the wholly-owned statutory business trusts of PSO, SWEPCo and TCC were outstanding at December 31, 2003 and 2002:

Business Trust	Security	Units Issued/ Outstanding at 12/31/03	Amount in Other at 12/31/03 (a) (in millions)	Amount in Notes Payable to Trust at 12/31/03 (b) (in millions)	Amount Reported Prior to FIN 46 at 12/31/02 (c) (in millions)	Description of Underlying Debentures of Registrant
CPL Capital I	8.00%, Series A	5,450,000	$5	$141	$136	TCC, $141 million, 8.00%, Series A
PSO Capital I	8.00%, Series A	3,000,000	2	77	75	PSO, $77 million, 8.00%, Series A
SWEPCo Capital I	7.875%, Series A	-	-	-	110	SWEPCo, $113 million, 7.875%, Series A
SWEPCo Capital I	5.25%, Series B	110,000	3	113	-	SWEPCo, $113 million, 5.25% five year fixed rate period, Series B
Total		8,560,000	$10	$331	$321	

(a) Amounts are in Other within Other Non-Current Assets.
(b) Amounts are in Notes Payable to Trust within Long-term Debt.
(c) Amounts reported on Balance Sheet prior to FIN 46.

Each of the business trusts is treated as a non-consolidated subsidiary of its parent company. The only assets of the business trusts are the subordinated debentures issued by their parent company as specified above. In addition to the obligations under their subordinated debentures, each of the parent companies has also agreed to a security obligation which represents a full and unconditional guarantee of its capital trust obligation.

Minority Interest in Finance Subsidiary

We formed AEP Energy Services Gas Holding Co. II, LLC (SubOne) and Caddis Partners, LLC (Caddis) in August 2001. SubOne is a wholly-owned consolidated subsidiary that was capitalized with the assets of Houston Pipe Line Company and Louisiana Intrastate Gas Company and $321.4 million of AEP Energy Services Gas Holding Company (AEP Gas Holding is a subsidiary of AEP and the parent of SubOne) preferred stock, that was convertible into AEP common stock at market price on a dollar-for-dollar basis. Caddis was capitalized with $2 million cash and a subscription agreement that represents an unconditional obligation to fund $83 million from SubOne for a managing member interest and $750 million from Steelhead Investors LLC (Steelhead) for a non-controlling preferred member interest. As managing member, SubOne consolidated Caddis. Steelhead is an unconsolidated special purpose entity and had an original capital structure of $750 million (currently approximately $525 million) of which 3% is equity from investors with no relationship to us or any of our subsidiaries and 97% is debt from a syndicate of banks. The $525 million invested in Caddis by Steelhead was loaned to SubOne. The loan to SubOne is due August 2006. Net proceeds from the proposed sale of LIG will be used to reduce the outstanding balance of the loan from Caddis (see Note 10 for additional information on LIG and HPL).

On July 1, 2003, due to the application of FIN 46, we deconsolidated Caddis, which included amounts previously reported as Minority Interest in Finance Subsidiary ($759 million at December 31, 2002 and $533 million at June 30, 2003). As a result, a note payable to Caddis is reported as a component of Long-term Debt ($527 million at December 31, 2003). Due to the prospective application of FIN 46, we did not change the presentation of Minority Interest in Finance Subsidiary in periods prior to July 1, 2003.

On May 9, 2003, SubOne borrowed $225 million from us and used the proceeds to reduce the outstanding balance of the loan from Caddis, which Caddis used to reduce the preferred interest held by Steelhead. This payment eliminated the convertible preferred stock of AEP Gas Holding which under certain conditions had been convertible to AEP common stock.

The credit agreement between Caddis and SubOne contains covenants that restrict certain incremental liens and indebtedness, asset sales, investments, acquisitions, and distributions. The credit agreement also contains covenants that impose minimum financial ratios. Non-performance of these covenants may result in an event of default under the credit agreement. Through December 31, 2003, SubOne has complied with the covenants contained in the credit agreement. In addition, the acceleration of outstanding debt in excess of $50 million would be an event of default under the credit agreement.

SubOne has deposited $422 million in a cash reserve fund in order to comply with certain covenants in the credit agreement. Pursuant to the terms of the credit agreement, SubOne subsequently loaned these funds to affiliates, and we guaranteed the repayment obligations of these affiliates. These loans must be repaid in the event our credit ratings fall below investment grade.

Steelhead has certain rights as a preferred member in Caddis. Upon the occurrence of certain events, including a default in the payment of the preferred return, Steelhead's rights include forcing a liquidation of Caddis and acting as the liquidator. Liquidation of Caddis could negatively impact our liquidity.

Caddis and SubOne are each a limited liability company, with a separate existence and identity from its members, and the assets of each are separate and legally distinct from us.

Equity Units

In June 2002, AEP issued 6.9 million equity units at $50 per unit and received proceeds of $345 million. Each equity unit consists of a forward purchase contract and a senior note.

The forward purchase contracts obligate the holders to purchase shares of AEP common stock on August 16, 2005. The purchase price per equity unit is $50. The number of shares to be purchased under the forward purchase contract will be determined under a formula based upon the average closing price of AEP common stock near the stock purchase date. Holders may satisfy their obligation to purchase AEP common stock under the forward purchase contracts by allowing the senior notes to be remarketed or by continuing to hold the senior notes and using other resources as consideration for the purchase of stock. If the holders elect to allow the notes to be remarketed, the proceeds from the remarketing will be used to purchase a portfolio of U.S. treasury securities that the holders will pledge to AEP in order to meet their obligations under the forward purchase contracts.

The senior notes have a principal amount of $50 each and mature on August 16, 2007. The senior notes are the collateral that secures the holders' requirement to purchase common stock under the forward purchase contracts.

AEP is making quarterly interest payments on the senior notes at an initial annual rate of 5.75%. The interest rate can be reset through a remarketing, which is initially scheduled for May 2005. AEP makes contract adjustment payments to the purchaser at the annual rate of 3.50% on the forward purchase contracts. The present value of the contract adjustment payments was recorded as a $31 million liability in Equity Unit Senior Notes offset by a charge to Paid-in Capital in June 2002. Interest payments on the senior notes are reported as interest expense. Accretion of the contract adjustment payment liability is reported as interest expense.

AEP applies the treasury stock method to the equity units to calculate diluted earnings per share. This method of calculation theoretically assumes that the proceeds received as a result of the forward purchase contract are used to repurchase outstanding shares.

Lines of Credit – AEP System

We use our corporate borrowing program to meet the short-term borrowing needs of our subsidiaries. The corporate borrowing program includes a utility money pool, which funds the utility subsidiaries, and a non-utility money pool, which funds the majority of the non-utility subsidiaries. In addition, we also fund, as direct borrowers, the short-term debt requirements of other subsidiaries that are not participants in the non-utility money pool for regulatory or operational reasons. As of December 31, 2003, we had credit facilities totaling $2.9 billion to support our commercial paper program. At December 31, 2003, AEP had $326 million outstanding in short-term borrowings of which $282 million was commercial paper supported by the revolving credit facilities. In addition, JMG has commercial paper outstanding in the amount of $26 million. This commercial paper is specifically associated with the Gavin scrubber lease identified in Note 16 "Leases". This commercial paper does not reduce available liquidity to AEP. The maximum amount of commercial paper outstanding during the year, which had a weighted average interest rate during 2003 of 1.98%, was $1.5 billion during January 2003. On December 11, 2002, Moody's Investor Services placed AEP's Prime-2 short-term rating for commercial paper under review for possible downgrade. On January 24, 2003, Standard & Poor's Rating Services placed AEP's A-2 short-term rating for commercial paper under review for possible downgrade. On February 10, 2003, Moody's Investor Services downgraded AEP's short-term rating for commercial paper to Prime-3 from Prime-2. On March 7, 2003, Standard & Poor's Rating Services reaffirmed AEP's A-2 short-term rating for commercial paper.

Outstanding Short-term Debt consisted of:

	December 31,	
	2003	2002
	(in millions)	
Balance Outstanding:		
Notes Payable	$18	$1,322
Commercial Paper - AEP	282	1,417
Commercial Paper - JMG	26	-
Total	$326	$2,739

Sale of Receivables – AEP Credit

AEP Credit has a sale of receivables agreement with banks and commercial paper conduits. Under the sale of receivables agreement, AEP Credit sells an interest in the receivables it acquires to the commercial paper conduits and banks and receives cash. This transaction constitutes a sale of receivables in accordance with SFAS 140, allowing the receivables to be taken off of AEP Credit's balance sheet and allowing AEP Credit to repay any debt obligations. AEP has no ownership interest in the commercial paper conduits and does not consolidate these entities in accordance with GAAP. We continue to service the receivables. We entered into this off-balance sheet transaction to allow AEP Credit to repay its outstanding debt obligations, continue to purchase the AEP operating companies' receivables, and accelerate its cash collections.

AEP Credit extended its sale of receivables agreement to July 25, 2003 from its May 28, 2003 expiration date. The agreement was then renewed for an additional 364 days and now expires on July 23, 2004. This new agreement provides commitments of $600 million to purchase receivables from AEP Credit. At December 31, 2003, $385 million was outstanding. As collections from receivables sold occur and are remitted, the outstanding balance for sold receivables is reduced and as new receivables are sold, the outstanding balance of sold receivables increases. All of the receivables sold represented affiliate receivables. AEP Credit maintains a retained interest in the receivables sold and this interest is pledged as collateral for the collection of the receivables sold. The fair value of the retained interest is based on book value due to the short-term nature of the accounts receivable less an allowance for anticipated uncollectible accounts.

AEP Credit purchases accounts receivable through purchase agreements with certain registrant subsidiaries and, until the first quarter of 2002, with non-affiliated companies. These subsidiaries include CSPCo, I&M, KPCo, OPCo, PSO, SWEPCo and a portion of APCo. Since APCo does not have regulatory authority to sell accounts receivable in all of its regulatory jurisdictions, only a portion of APCo's accounts receivable are sold to AEP Credit. As a result of the restructuring of electric utilities in the State of Texas, the purchase agreement between AEP Credit and Reliant

Energy, Incorporated was terminated as of January 25, 2002 and the purchase agreement between AEP Credit and Texas-New Mexico Power Company, the last remaining non-affiliated company, was terminated on February 7, 2002. In addition, the purchase agreements between AEP Credit and its Texas affiliates, AEP Texas Central Company (formerly Central Power and Light Company) and AEP Texas North Company (formerly West Texas Utilities Company), were terminated effective March 20, 2002.

Comparative accounts receivable information for AEP Credit:

	Year Ended December 31, 2003 (in millions)	2002
Proceeds from Sale of Accounts Receivable	$5,221	$5,513
Accounts Receivable Retained Interest Less Uncollectible Accounts and Amounts Pledged as Collateral	124	76
Deferred Revenue from Servicing Accounts Receivable	1	1
Loss on Sale of Accounts Receivable	7	4
Average Variable Discount Rate	1.33%	1.92%
Retained Interest if 10% Adverse Change in Uncollectible Accounts	122	74
Retained Interest if 20% Adverse Change in Uncollectible Accounts	121	72

Historical loss and delinquency amount for the AEP System's customer accounts receivable managed portfolio:

	Face Value Year Ended December 31, 2003 (in millions)	2002
Customer Accounts Receivable Retained	$1,155	$1,553
Accrued Unbilled Revenues Retained	596	551
Miscellaneous Accounts Receivable Retained	83	93
Allowance for Uncollectible Accounts Retained	(124)	(108)
Total Net Balance Sheet Accounts Receivable	1,710	2,089
Customer Accounts Receivable Securitized (Affiliate)	385	454
Total Accounts Receivable Managed	$2,095	$2,543
Net Uncollectible Accounts Written Off	$39	$48

Customer accounts receivable retained and securitized for the domestic electric operating companies are managed by AEP Credit. Miscellaneous accounts receivable have been fully retained and not securitized.

At December 31, 2003, delinquent customer accounts receivable for the electric utility affiliates that AEP Credit currently factors was $30 million.

18. UNAUDITED QUARTERLY FINANCIAL INFORMATION

Our unaudited quarterly financial information is as follows:

(In Millions – Except Per Share Amounts)	2003 Quarterly Periods Ended March 31	June 30	September 30	December 31
Revenues	$3,834	$3,451	$3,940	$3,320
Operating Income (Loss)	630	393	735	(126)
Income (Loss) Before Discontinued Operations, Extraordinary Items and Cumulative Effect	294	185	298	(255)
Net Income (Loss)	440	175	257	(762)
Earnings (Loss) per Share Before Discontinued Operations, Extraordinary Items and Cumulative Effect*	0.83	0.47	0.75	(0.65)
Earnings (Loss) per Share**	1.24	0.44	0.65	(1.93)

(In Millions – Except Per Share Amounts)	2002 Quarterly Periods Ended March 31	June 30	September 30	December 31
Revenues	$2,802	$3,395	$3,639	$3,472
Operating Income	420	433	781	170
Income (Loss) Before Discontinued Operations, Extraordinary Items and Cumulative Effect	134	167	385	(201)
Net Income (Loss)	(169)	62	425	(837)
Earnings (Loss) per Share Before Discontinued Operations, Extraordinary Items and Cumulative Effect***	0.42	0.51	1.14	(0.59)
Earnings (Loss) per Share****	(0.53)	0.19	1.25	(2.47)

* Amounts for 2003 do not add to $1.35 earnings per share before Discontinued Operations, Extraordinary Loss and Cumulative Effect due to rounding and the dilutive effect of shares issued in 2003.

** Amounts for 2003 do not add to $0.29 earnings per share due to rounding and the dilutive effect of shares issued in 2003.

***Amounts for 2002 do not add to $1.46 earnings per share before Discontinued Operations, Extraordinary Loss and Cumulative Effect due to rounding.

****Amounts for 2002 do not add to $(1.57) earnings per share due to rounding.

Income (Loss) Before Discontinued Operations, Extraordinary Items and Cumulative Effect for the fourth quarter 2003 ($255 million loss) and 2002 ($201 million loss) were significantly lower than the previous three quarters due to asset impairments, investment value losses and other related charges. These pre-tax writedowns ($650 million in the fourth quarter 2003 and $593 million in the fourth quarter 2002) were made to reflect impairments and discontinued operations as discussed in Note 10.

19. SUBSEQUENT EVENTS (UNAUDITED)

After December 31, 2003, we entered into separate agreements to dispose of the following investments:

Investment	Sales Price (in millions)	Date of Agreement
Oklaunion Power Station	$42.8	January 30, 2004
LIG Pipeline and its subsidiaries	$76.2	February 13, 2004
STP	$332.6	February 27, 2004

We anticipate these sales to be completed during 2004 and that the impact on results of operations will not be significant.

The Nanyang General Light (Pushan) investment was sold for $60.7 million on March 2, 2004. This sale had no significant impact on our results of operations.

On March 10, 2004, we entered into an agreement to sell four domestic Independent Power Producer (IPP) investments for a sales price of $156 million. We anticipate this sale to be completed during 2004 and to result in a pre-tax gain of approximately $100 million.

INDEPENDENT AUDITORS' REPORT

To the Shareholders and Board of Directors
of American Electric Power Company, Inc.:

We have audited the accompanying consolidated balance sheets of American Electric Power Company, Inc. and subsidiary companies as of December 31, 2003 and 2002, and the related consolidated statements of operations, cash flows and common shareholders' equity and comprehensive income, for each of the three years in the period ended December 31, 2003. These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements based on our audits.

We conducted our audits in accordance with auditing standards generally accepted in the United States of America. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, the consolidated financial statements referred to above present fairly, in all material respects, the financial position of American Electric Power Company, Inc. and subsidiary companies as of December 31, 2003 and 2002, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2003 in conformity with accounting principles generally accepted in the United States of America.

As discussed in Note 2 to the consolidated financial statements, the Company adopted SFAS 142, "Goodwill and Other Intangible Assets," effective January 1, 2002.

As discussed in Note 2 to the consolidated financial statements, the Company adopted SFAS 143, "Accounting for Asset Retirement Obligations" and EITF 02-3, "Issues Involved in Accounting for Derivative Contracts Held for Trading Purposes and Contracts Involved in Energy Trading and Risk Management Activities" effective January 1, 2003.

As discussed in Note 2 to the consolidated financial statements, the Company adopted FIN 46, "Consolidation of Variable Interest Entities" effective July 1, 2003.

/s/ Deloitte & Touche LLP

Columbus, Ohio
March 5, 2004

MANAGEMENT'S RESPONSIBILITY

The management of American Electric Power Company, Inc. (the Company) has prepared the financial statements and schedules herein and is responsible for the integrity and objectivity of the information and representations in this annual report, including the consolidated financial statements. These statements have been prepared in conformity with accounting principles generally accepted in the United States of America, using informed estimates where appropriate, to reflect the Company's financial condition and results of operations. The information in other sections of the annual report is consistent with these statements.

The Company's Board of Directors has oversight responsibilities for determining that management has fulfilled its obligation in the preparation of the financial statements and in the ongoing examination of the Company's established internal control structure over financial reporting. The Audit Committee, which consists solely of outside directors and which reports directly to the Board of Directors, meets regularly with management, Deloitte & Touche LLP - independent auditors and the Company's internal audit staff to discuss accounting, auditing and reporting matters. To ensure auditor independence, both Deloitte & Touche LLP and the internal audit staff have unrestricted access to the Audit Committee. The financial statements have been audited by Deloitte & Touche LLP, whose report appears on the previous page.

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AEP GENERATING COMPANY

AEP GENERATING COMPANY
SELECTED FINANCIAL DATA

	2003	2002	2001	2000	1999
			(in thousands)		
INCOME STATEMENTS DATA					
Operating Revenues	$233,165	$213,281	$227,548	$228,516	$217,189
Operating Expenses	225,991	207,152	220,571	220,092	211,849
Operating Income	7,174	6,129	6,977	8,424	5,340
Nonoperating Items, Net	3,340	3,681	3,484	3,429	3,659
Interest Charges	2,550	2,258	2,586	3,869	2,804
Net Income	$7,964	$7,552	$7,875	$7,984	6,195
BALANCE SHEETS DATA					
Electric Utility Plant	$674,055	$652,213	$648,254	$642,302	$640,093
Accumulated Depreciation	351,062	330,187	310,804	290,858	271,941
Net Electric Utility Plant	$322,993	$322,026	$337,450	$351,444	$368,152
TOTAL ASSETS	$380,045	$377,716	$387,688	$399,310	$421,764
Common Stock and Paid-in Capital	$24,434	$24,434	$24,434	$24,434	$30,235
Retained Earnings	21,441	18,163	13,761	9,722	3,673
Total Common Shareholder's Equity	$45,875	$42,597	$38,195	$34,156	$33,908
Long-term Debt (a)	$44,811	$44,802	$44,793	$44,808	$44,800
Obligations Under Capital Leases (a)	$269	$501	$311	$591	$867
TOTAL CAPITALIZATION AND LIABILITIES	$380,045	$377,716	$387,688	$399,310	$421,764

(a) Including portion due within one year.

AEP GENERATING COMPANY
MANAGEMENT'S NARRATIVE FINANCIAL DISCUSSION AND ANALYSIS

AEGCo, co-owner of the Rockport Plant, is engaged in the generation and wholesale sale of electric power to two affiliates, I&M and KPCo, under long-term agreements. I&M is the operator and the other co-owner of the Rockport Plant.

Operating revenues are derived from the sale of Rockport Plant energy and capacity to I&M and KPCo pursuant to FERC approved long-term unit power agreements. Under the terms of its unit power agreement, I&M agreed to purchase all of AEGCo's Rockport energy and capacity unless it is sold to other utilities or affiliates. I&M assigned 30% of its rights to energy and capacity to KPCo. This assignment expires December 31, 2004.

The unit power agreements provide for a FERC approved rate of return on common equity, a return on other capital (net of temporary cash investments) and recovery of costs including operation and maintenance, fuel and taxes. Under the terms of the unit power agreements, AEGCo accumulates all expenses monthly and prepares bills for its affiliates. In the month the expenses are incurred, AEGCo recognizes the billing revenues and establishes a receivable from the affiliated companies.

Results of Operations

2003 Compared to 2002

Net Income increased $412 thousand for the year 2003 compared with the year 2002. The fluctuations in Net Income are a result of terms in the unit power agreements which allow for the return on total capital of the Rockport Plant calculated and adjusted monthly.

Operating Income

Operating Income increased $1 million for the year 2003 compared with the year 2002 primarily due to:

- A $20 million increase in Operating Revenue as a result of increased recoverable expenses, primarily Fuel for Electric Generation, in accordance with the unit power agreements along with increased return on total capital.
- A $2 million decrease in Maintenance and Other Operation expense. This decrease is due primarily to the impact of cost reduction efforts instituted in the fourth quarter of 2002 and related employment termination benefits allocated to AEGCo in 2002.

The increase in Operating Income was partially offset by:

- A $20 million increase in Fuel for Electric Generation expense. This increase is primarily due to an increase in the average cost of coal and an 8% increase in MWH generation.

Off-Balance Sheet Arrangements

We enter into off-balance sheet arrangements for various reasons including accelerating cash collections, reducing operational expenses and spreading risk of loss to third parties. The following identifies significant off-balance sheet arrangements:

Rockport Plant Unit 2

AEGCo and I&M entered into a sale and leaseback transaction in 1989 with Wilmington Trust Company (Owner Trustee), an unrelated unconsolidated trustee for Rockport Plant Unit 2 (the plant). The Owner Trustee was capitalized with equity from six owner participants with no relationship to AEP or any of its subsidiaries and debt from a syndicate of banks and certain institutional investors. The future minimum lease payments for each respective company are $1.4 billion.

The FASB and other accounting constituencies continue to interpret the application of FIN 46 (revised December 2003) (FIN 46R). As a result, we are continuing to review the application of this new interpretation as it relates to the Rockport Plant Unit 2 transaction.

The gain from the sale was deferred and is being amortized over the term of the lease, which expires in 2022. The Owner Trustee owns the plant and leases it to AEGCo and I&M. The lease is accounted for as an operating lease with the payment obligations included in the lease footnote. The lease term is for 33 years with potential renewal options. At the end of the lease term, AEGCo and I&M have the option to renew the lease or the Owner Trustee can sell the plant. Neither AEGCo, I&M nor AEP has an ownership interest in the Owner Trustee and none of these entities guarantee its debt.

Summary Obligation Information

Our contractual obligations include amounts reported on the Consolidated Balance Sheets and other obligations disclosed in the footnotes. The following table summarizes our contractual cash obligations at December 31, 2003:

	Payments Due by Period (in millions)				
Contractual Cash Obligations	**Less Than 1 year**	**2-3 years**	**4–5 years**	**After 5 years**	**Total**
Long-term Debt	$-	$-	$-	$45	$45
Advances from Affiliates	37	-	-	-	37
Unconditional Purchase Obligations (a)	82	75	75	161	393
Noncancellable Operating Leases	74	148	148	1,033	1,403
Total	$193	$223	$223	$1,239	$1,878

(a) Represents contractual obligations to purchase coal as fuel for electric generation along with related transportation of the fuel.

Some of the transactions, described under "Off-Balance Sheet Arrangements" above, have been employed for a contractual cash obligation reported in the above table. The lease of Rockport Unit 2 is reported in Noncancellable Operating Leases.

Significant Factors

See the "Registrants' Combined Management's Discussion and Analysis" section beginning on page M-1 for additional discussion of factors relevant to us.

AEP GENERATING COMPANY
STATEMENTS OF INCOME
For the Years Ended December 31, 2003, 2002 and 2001

	2003	2002 (in thousands)	2001
OPERATING REVENUES	$233,165	$213,281	$227,548
OPERATING EXPENSES			
Fuel for Electric Generation	109,238	89,105	102,828
Rent – Rockport Plant Unit 2	68,283	68,283	68,283
Other Operation	10,399	12,924	11,025
Maintenance	10,346	9,418	8,853
Depreciation	22,686	22,560	22,423
Taxes Other Than Income Taxes	3,396	3,281	4,257
Income Taxes	1,643	1,581	2,902
TOTAL	225,991	207,152	220,571
OPERATING INCOME	7,174	6,129	6,977
Nonoperating Income	151	344	30
Nonoperating Expenses	361	199	16
Nonoperating Income Tax Credits	3,550	3,536	3,470
Interest Charges	2,550	2,258	2,586
NET INCOME	$7,964	$7,552	$7,875

STATEMENTS OF RETAINED EARNINGS
For the Years Ended December 31, 2003, 2002 and 2001

	2003	2002 (in thousands)	2001
BALANCE AT BEGINNING OF PERIOD	$18,163	$13,761	$9,722
Net Income	7,964	7,552	7,875
Cash Dividends Declared	4,686	3,150	3,836
BALANCE AT END OF PERIOD	$21,441	$18,163	$13,761

The common stock of AEGCo is wholly-owned by AEP.

See Notes to Respective Financial Statements beginning on page L-1.

AEP GENERATING COMPANY
BALANCE SHEETS
ASSETS
December 31, 2003 and 2002

	2003	2002
	(in thousands)	
ELECTRIC UTILITY PLANT		
Production	$645,251	$637,095
General	4,063	4,728
Construction Work in Progress	24,741	10,390
TOTAL	674,055	652,213
Accumulated Depreciation	351,062	330,187
TOTAL - NET	322,993	322,026
OTHER PROPERTY AND INVESTMENTS – Non-Utility Property, Net	119	119
CURRENT ASSETS		
Accounts Receivable – Affiliated Companies	24,748	18,454
Fuel	20,139	20,260
Materials and Supplies	5,419	4,913
TOTAL	50,306	43,627
DEFERRED DEBITS AND OTHER ASSETS		
Regulatory Assets:		
Unamortized Loss on Reacquired Debt	4,733	4,970
Asset Retirement Obligations	928	-
Deferred Charges	966	6,974
TOTAL	6,627	11,944
TOTAL ASSETS	$380,045	$377,716

See Notes to Respective Financial Statements beginning on page L-1.

AEP GENERATING COMPANY
BALANCE SHEETS
CAPITALIZATION AND LIABILITIES
December 31, 2003 and 2002

	2003	2002
	(in thousands)	
CAPITALIZATION		
Common Shareholder's Equity:		
Common Stock – Par Value $1,000 per share:		
Authorized and Outstanding – 1,000 Shares	$1,000	$1,000
Paid-in Capital	23,434	23,434
Retained Earnings	21,441	18,163
Total Common Shareholder's Equity	45,875	42,597
Long-term Debt	44,811	44,802
TOTAL	90,686	87,399
CURRENT LIABILITIES		
Advances from Affiliates	36,892	28,034
Accounts Payable:		
General	498	26
Affiliated Companies	15,911	15,907
Taxes Accrued	6,070	2,327
Interest Accrued	911	911
Obligations Under Capital Leases	87	200
Rent Accrued – Rockport Plant Unit 2	4,963	4,963
TOTAL	65,332	52,368
DEFERRED CREDITS AND OTHER LIABILITIES		
Deferred Income Taxes	24,329	29,002
Regulatory Liabilities:		
Asset Removal Costs	27,822	-
Deferred Investment Tax Credits	49,589	52,943
SFAS 109 Regulatory Liability, Net	15,505	16,670
Deferred Gain on Sale and Leaseback – Rockport Plant Unit 2	105,475	111,046
Obligations Under Capital Leases	182	301
Asset Retirement Obligations	1,125	-
Other	-	27,987
TOTAL	224,027	237,949
Commitments and Contingencies (Note 7)		
TOTAL CAPITALIZATION AND LIABILITIES	$380,045	$377,716

See Notes to Respective Financial Statements beginning on page L-1.

AEP GENERATING COMPANY
STATEMENTS OF CASH FLOWS
For the Years Ended December 31, 2003, 2002 and 2001

	2003	2002 (in thousands)	2001
OPERATING ACTIVITIES			
Net Income	$7,964	$7,552	$7,875
Adjustments to Reconcile Net Income to Net Cash Flows From Operating Activities:			
Depreciation	22,686	22,560	22,423
Deferred Income Taxes	(5,838)	(5,028)	(6,224)
Deferred Investment Tax Credits	(3,354)	(3,361)	(3,414)
Amortization of Deferred Gain on Sale and Leaseback – Rockport Plant Unit 2	(5,571)	(5,571)	(5,571)
Changes in Certain Assets and Liabilities:			
Accounts Receivable	(6,294)	4,037	1,224
Fuel, Materials and Supplies	(385)	(5,450)	(4,738)
Accounts Payable	476	6,697	(4,597)
Taxes Accrued	3,743	(2,450)	(216)
Deferred Property Taxes	(45)	190	(49)
Change in Other Assets	3,531	(5,401)	(520)
Change in Other Liabilities	1,007	(2,295)	(1,244)
Net Cash Flows From Operating Activities	17,920	11,480	4,949
INVESTING ACTIVITIES			
Construction Expenditures	(22,197)	(5,298)	(6,868)
Proceeds From Sale of Assets	105	-	-
Net Cash Flows Used For Investing Activities	(22,092)	(5,298)	(6,868)
FINANCING ACTIVITIES			
Change in Advances from Affiliates	8,858	(4,015)	3,981
Dividends Paid	(4,686)	(3,150)	(3,836)
Net Cash Flows From (Used For) Financing Activities	4,172	(7,165)	145
Net Decrease in Cash and Cash Equivalents	-	(983)	(1,774)
Cash and Cash Equivalents at Beginning of Period	-	983	2,757
Cash and Cash Equivalents at End of Period	$-	$-	$983

SUPPLEMENTAL DISCLOSURE:
Cash paid for interest net of capitalized amounts was $2,283,000, $2,019,000 and $1,509,000 and for income taxes was $6,483,000, $7,884,000 and $8,597,000 in 2003, 2002 and 2001, respectively.

See Notes to Respective Financial Statements beginning on page L-1.

AEP GENERATING COMPANY
STATEMENTS OF CAPITALIZATION
December 31, 2003 and 2002

		2003	2002
		(in thousands)	
COMMON SHAREHOLDER'S EQUITY		$45,875	$42,597
LONG-TERM DEBT:			
Installment Purchase Contracts – City of Rockport (a)			
Series	**Due Date**		
1995 A	2025 (b)	22,500	22,500
1995 B	2025 (b)	22,500	22,500
Unamortized Discount		(189)	(198)
TOTAL LONG-TERM DEBT		44,811	44,802
TOTAL CAPITALIZATION		$90,686	$87,399

(a) Installment purchase contracts were entered into in connection with the issuance of pollution control revenue bonds by the City of Rockport, Indiana. The terms of the installment purchase contracts require AEGCo to pay amounts sufficient to enable the payment of interest and principal on the related pollution control revenue bonds issued to refinance the construction costs of pollution control facilities at the Rockport Plant.

(b) These series have an adjustable interest rate that can be a daily, weekly, commercial paper or term rate as designated by AEGCo. Prior to July 13, 2001, AEGCo had selected a daily rate which ranged from 0.9% to 5.6% during 2001 and averaged 2.8% in 2001. Effective July 13, 2001, AEGCo selected a term rate of 4.05% for five years ending July 12, 2006.

See Notes to Respective Financial Statements beginning on page L-1.

AEP GENERATING COMPANY
INDEX TO NOTES TO RESPECTIVE FINANCIAL STATEMENTS

The notes to AEGCo's financial statements are combined with the notes to respective financial statements for other subsidiary registrants. Listed below are the notes that apply to AEGCo. The footnotes begin on page L-1.

INDEPENDENT AUDITORS' REPORT

To the Shareholder and Board of Directors
of AEP Generating Company:

We have audited the accompanying balance sheets and statements of capitalization of AEP Generating Company as of December 31, 2003 and 2002, and the related statements of income, retained earnings, and cash flows for each of the three years in the period ended December 31, 2003. These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements based on our audits.

We conducted our audits in accordance with auditing standards generally accepted in the United States of America. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, such financial statements present fairly, in all material respects, the financial position of AEP Generating Company as of December 31, 2003 and 2002, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2003 in conformity with accounting principles generally accepted in the United States of America.

/s/ Deloitte & Touche LLP

Columbus, Ohio
March 5, 2004

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AEP TEXAS CENTRAL COMPANY AND SUBSIDIARY

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AEP TEXAS CENTRAL COMPANY AND SUBSIDIARY
SELECTED CONSOLIDATED FINANCIAL DATA

	2003	2002	2001	2000	1999
			(in thousands)		
INCOME STATEMENTS DATA					
Operating Revenues	$1,747,511	$1,690,493	$1,738,837	$1,770,402	$1,482,475
Operating Expenses	1,425,971	1,296,760	1,443,106	1,463,304	1,188,490
Operating Income	321,540	393,733	295,731	307,098	293,985
Nonoperating Items, Net	29,819	8,079	2,815	7,235	2,596
Interest Charges	133,812	125,871	116,268	124,766	114,380
Income Before Cumulative Effect of Accounting Change	217,547	275,941	182,278	189,567	182,201
Cumulative Effect of Accounting Change (Net of Tax)	122	-	-	-	-
Net Income	217,669	275,941	182,278	189,567	182,201
Preferred Stock Dividend Requirements	241	241	242	241	6,931
Gain (Loss) on Reacquired Preferred Stock	-	4	-	-	(2,763)
Earnings Applicable To Common Stock	$217,428	$275,704	$ 182,036	$189,326	$ 172,507
BALANCE SHEETS DATA					
Electric Utility Plant	$2,425,038	$2,334,794	$2,231,287	$2,097,497	$1,996,374
Accumulated Depreciation and Amortization	695,359	662,345	616,526	570,522	598,275
Net Electric Utility Plant	$1,729,679	$1,672,449	$1,614,761	$1,526,975	$1,398,099
TOTAL ASSETS	$5,824,707	$5,453,960	$4,989,381	$5,556,275	$4,930,547
Common Stock and Paid-in Capital	$187,898	$187,898	$573,903	$573,904	$573,904
Retained Earnings	1,083,023	986,396	826,197	792,219	758,894
Accumulated Other Comprehensive Income (Loss)	(61,872)	(73,160)	-	-	-
Total Common Shareholder's Equity	$1,209,049	$1,101,134	$1,400,100	$1,366,123	$1,332,798
Cumulative Preferred Stock Not Subject to Mandatory Redemption	$5,940	$5,942	$5,952	$5,951	$5,951
Trust Preferred Securities (a)	$-	$136,250	$136,250	$148,500	$150,000
Long-term Debt (b)	$2,291,625	$1,438,565	$1,253,768	$1,454,559	$1,454,541
Obligations Under Capital Leases (b)	$1,043	$-	$-	$-	$-
TOTAL CAPITALIZATION AND LIABILITIES	$5,824,707	$5,453,960	$4,989,381	$5,556,275	$4,930,547

(a) See Note 16 of the Notes to Respective Financial Statements.
(b) Including portion due within one year.

AEP TEXAS CENTRAL COMPANY AND SUBSIDIARY
MANAGEMENT'S FINANCIAL DISCUSSION AND ANALYSIS

AEP Texas Central Company (TCC), formerly know as Central Power and Light Company (CPL), is a public utility engaged in the generation and purchase of electric power, and the subsequent sale, transmission and distribution of that power. As a power pool member with AEP West companies, we share in the revenues and expenses of the power pool's sales to neighboring utilities and power marketers. TCC also sells electric power at wholesale to other utilities, municipalities, rural electric cooperatives and retail electric providers (REPs) in Texas.

Power pool members are compensated for energy delivered to other members based upon the delivering members' incremental cost plus a portion of the savings realized by the purchasing member that avoids the use of more costly alternatives. The revenue and costs for sales to neighboring utilities and power marketers made by AEPSC on behalf of the AEP West companies are shared among the members based upon the relative magnitude of the energy each member provides to make such sales.

Power and gas risk management activities are conducted on our behalf by AEPSC. We share in the revenues and expenses associated with these risk management activities with other AEP registrant subsidiaries excluding AEGCo under existing power pool and system integration agreements. Risk management activities primarily involve the purchase and sale of electricity under physical forward contracts at fixed and variable prices and to a lesser extent gas. The electricity and gas contracts include physical transactions, over-the-counter options and swaps and exchange traded futures and options. The majority of the physical forward contracts are typically settled by entering into offsetting contracts.

Under our system integration agreement, revenues and expenses from the sales to neighboring utilities, power marketers and other power and gas risk management entities are shared among AEP East and West companies. Sharing in a calendar year is based upon the level of such activities experienced for the twelve months ended June 30, 2000, which immediately preceded the merger of AEP and CSW. This resulted in an AEP East and West companies' allocation of approximately 91% and 9%, respectively, for revenues and expenses. Allocation percentages in any given calendar year may also be based upon the relative generating capacity of the AEP East and West companies in the event the pre-merger activity level is exceeded. The capacity based allocation mechanism was triggered in June 2003, resulting in an allocation factor of approximately 70% and 30% for the AEP East and West companies, respectively, for the remainder of 2003.

Results of Operations

2003 Compared to 2002

Net Income decreased $58 million for 2003. The decrease is mainly due to an increased provision for refunds of $85 million ($55 million after tax) and a decrease in the recognition of non-cash earnings related to legislatively mandated capacity auctions and regulatory assets established in Texas of $29 million net of tax. Additionally, income from transactions with ERCOT increased significantly due mainly to Texas Restructuring Legislation.

Since REPs are the electricity suppliers to retail customers in the ERCOT area, we sell our generation to the REPs and other market participants and provide transmission and distribution services to retail customers of the REPs in our service territory. As a result of the provision of retail electric service by REPs, effective January 1, 2002, we no longer supply electricity directly to retail customers. The implementation of REPs as suppliers to retail customers has caused a shift in our sales as further described below.

In December 2002, AEP sold Mutual Energy CPL to an unrelated third party, who assumed the obligations of the affiliated REP including the provision of price-to-beat rates under the Texas Restructuring Legislation. Prior to the sale, during 2002, sales to Mutual Energy CPL were classified as Sales to AEP Affiliates. Subsequent to the sale, energy transactions and delivery charges with Mutual Energy CPL are classified as Electric Generation, Transmission and Distribution.

Operating Income

Operating Income decreased $72 million primarily due to:

- Increased provisions for rate refunds of $85 million due mainly to 2003 Texas fuel issues (see "TCC Fuel Reconciliation" in Note 4).
- Decreased revenues associated with establishing regulatory assets in Texas of $44 million or 17% in 2003 (see "Texas Restructuring" in Note 6). These revenues will not continue after 2003.
- Decreased system sales, including those to REPs, of $7 million due mainly to a decrease in the overall average price per KWH and higher KWH sales of 2%.
- Decreased revenues from ERCOT for various services, including balancing energy, of $7 million or 7%.
- The 2002 ICR adjustments which accounted for approximately $59 million of the decrease in revenue with an offsetting $51 million decrease in purchased power.
- Decreased retail revenues of $24 million driven by a 9% decrease in cooling degree-days offset by a slight increase in heating degree-days. Average price per KWH decreased 2%.
- Increases in fuel and purchased electricity on a net basis of $197 million to replace portions of the energy from the non-RMR mothballed plants and the unscheduled forced outage at the STP nuclear unit (See "Significant Factors" below). KWH purchased increased 47% while the cost increased 54%. Although the KWH generated decreased, fuel costs increased 16% due to higher per unit costs attributable mostly to natural gas.
- Increased Maintenance expense of $8 million due mainly to the STP Unit 2 forced outage in the first quarter of 2003 and the STP Unit 1 scheduled refueling outage and forced outage in the second and third quarters of 2003.

The decrease in Operating Income was partially offset by:

- Increased Reliability Must Run (RMR) revenues from ERCOT of $214 million which include both fuel recovery and a fixed cost component of $35 million (see "Texas Plants" in Note 10 for discussion of RMR facilities).
- Increased margins of $31 million resulting from risk management activities.
- Increased other operating revenue of $25 million comprised primarily of miscellaneous service revenue and fees as a result of the Texas Restructuring Legislation.
- Decreased Other Operation expense of $6 million due primarily to lower distribution and customer related expenses in 2003, offset in part by $16 million of accretion expense associated with the implementation of SFAS 143, as well as increased cost of $6 million related to 2003 ERCOT transmission charges.
- Decreased Depreciation and Amortization expense of $25 million due mainly to decreases resulting from ARO of $16 million (see Note 2) and reduced depreciable plant by $6 million due to the mothballing of certain generating units in 2002.
- Decreased Taxes Other Than Income Taxes of $3 million due mainly to reduce gross receipt taxes as a result of the sale of the Texas REPs, partially offset by higher property taxes.
- Decreased Income Taxes of $41 million due to decreased pre-tax operating income.

Other Impacts on Earnings

Nonoperating Income increased $1 million. While 2003 gains from risk management activities increased $33 million, they are almost totally offset by lower 2003 revenues of $33 million from third party non-utility energy related construction projects.

Nonoperating Expense decreased $25 million primarily due to lower non-utility expenses associated with energy related construction projects for third parties.

Nonoperating Income Tax Expense (Credit) increased $4 million due to increased pre-tax nonoperating income partially offset by changes related to consolidated tax savings.

Interest Charges increased $8 million primarily due to the replacement of lower cost short-term floating rate debt with longer-term higher cost fixed rate debt.

2002 Compared to 2001

In 2002, Net Income increased $94 million primarily due to $262 million of revenue associated with recognition of stranded costs in Texas offset in part by losses associated with the commencement of customer choice in Texas, which resulted in the loss of customers and reduced prices (see Note 6).

Operating Income

Operating Income increased $98 million primarily due to:

- Increased revenue associated with establishing regulatory assets in Texas of $262 million in 2002 (see "Texas Restructuring" in Note 6).
- Increased system sales, including those to REPs, of $84 million due mainly to the newly created affiliated REP, offset by retail fuel revenue, as a result of Texas Restructuring Legislation.
- Increase revenues of $73 million from ERCOT for various services, including balancing energy, as a result of Texas Restructuring Legislation.
- The 2002 ICR adjustments which accounted for approximately $59 million of the increase in revenue with an offsetting $51 million increase in purchased power (See "ICR Explanation" in Note 4 for discussion of the ICR adjustments).
- Decreased provisions for rate refunds of $3 million due mainly to a 2001 FERC transmission tariff refund.
- Increased RMR revenues from ERCOT of $28 million which include both fuel recovery and a fixed cost component (see "Texas Plants" in Note 10 for discussion of RMR facilities).
- Net decreases in fuel and purchased electricity on a combined basis of $198 million due to a decrease in both generation and the average cost of fuel, offset in part by increased KWH purchased. More KWH were purchased in part due to our ability to purchase power below our cost to produce. KWH purchased increased 5% while the total cost increased 26%. The KWH generated decreased by 27% and fuel costs decreased 50%.
- Decreased Other Operation expense of $17 million due to the elimination of factoring of accounts receivable, as well as lower ERCOT transmission charges.
- Decreased Maintenance expense of $8 million due mainly to two scheduled "18 months interval" refueling outages for STP during 2001 that increased maintenance expense above the 2002 level. Also contributing to the decrease in 2002 was an increase in maintenance expense for scheduled major overhauls of four power plants in 2001.

The increase in Operating Income was partially offset by:

- Decreased retail revenues due to the Texas Restructuring Legislation of $467 million in 2002 (see "Texas Restructuring" in Note 6).
- Decreased revenues of $54 million resulting from risk management activities.
- Increased Depreciation and Amortization expense of $46 million due mainly to the amortization of regulatory assets that were securitized in the first quarter of 2002 and being collected in revenue, offset by the elimination of excess earnings expense in 2002 under Texas Restructuring Legislation (See Note 6).
- Increased Taxes Other Than Income Taxes of $5 million due to higher local franchise taxes, offset by one-time 2001 assessments and decreased gross receipts tax due to deregulation.

Other Impacts on Earnings

Nonoperating Income increased $31 million primarily due to increased non-utility revenues associated with energy related construction projects for third parties offset in part by decreased interest income.

Nonoperating Expense increased $20 million primarily due to increased non-utility expenses associated with energy related construction projects for third parties offset in part by the extraordinary loss on reacquired debt in 2001, that was reclassified to Nonoperating Expense with the implementation of SFAS 145 (See Note 1).

Nonoperating Income Tax Expense (Credit) increased $5 million due to higher pre-tax nonoperating book income.

Interest Charges increased $10 million primarily due to higher levels of outstanding debt.

Cumulative Effect of Accounting Change

This amount represents the one-time after-tax effect of the application of EITF 02-3 (see Note 2).

Financial Condition

Credit Ratings

The rating agencies currently have us on stable outlook. Our current ratings are as follows:

	Moody's	S&P	Fitch
First Mortgage Bonds	Baa1	BBB	A
Senior Unsecured Debt	Baa2	BBB	A-

In February 2003, Moody's Investor Service (Moody's) completed their review of AEP and its rated subsidiaries. The results of that review included a downgrade of TCC's rating for unsecured debt from Baa1 to Baa2 and secured debt from A3 to Baa1. The completion of this review was a culmination of ratings action started during 2002. With the completion of the reviews, Moody's has placed AEP and its rated subsidiaries on stable outlook. In March 2003, S&P lowered AEP and our senior unsecured debt and first mortgage bonds ratings from BBB+ to BBB.

Cash Flow

Cash flows for the year ended December 31, 2003, 2002 and 2001 were as follows:

	2003	2002 (in thousands)	2001
Cash and cash equivalents at beginning of period	$85,420	$10,909	$14,253
Cash flow from (used for):			
Operating activities	367,223	147,493	469,920
Investing activities	(134,316)	(151,502)	(194,086)
Financing activities	(252,445)	78,520	(279,178)
Net increase (decrease) in cash and cash equivalents	(19,538)	74,511	(3,344)
Cash and cash equivalents at end of period	$65,882	$85,420	$10,909

Operating Activities

Cash flow from operating activities were $367 million primarily due to net income as explained above, changes to Accounts Receivable, Accounts Payable and Accrued Taxes, as well as, non-cash Depreciation and Amortization partially offset by the non-cash Texas Wholesale Clawback regulatory asset recorded in 2003.

Investing Activities

Investing expenditures in 2003 were $134 million due mostly to construction expenditures focused on improved service reliability projects for transmission and distribution systems.

Financing Activities

We obtained the additional funds needed for financing activities through new borrowings of $962 million in 2003. Current year debt proceeds replaced both short and long-term debt.

Summary Obligation Information

Our contractual obligations include amounts reported on the Consolidated Balance Sheets and other obligations disclosed in the footnotes. The following table summarizes our contractual cash obligations at December 31, 2003:

	Payments Due by Period (in thousands)				
Contractual Cash Obligations	**Less Than 1 year**	**2-3 years**	**4–5 years**	**After 5 years**	**Total**
Long-term Debt	$237,651	$524,838	$121,417	$1,407,719	$2,291,625
Unconditional Purchase Obligations (a)	53,749	82,203	60,648	133,608	330,208
Capital Lease Obligations	450	571	110	-	1,131
Noncancellable Operating Leases	6,112	11,104	8,347	11,272	36,835
Total	$297,962	$618,716	$190,522	$1,552,599	$2,659,799

(a) Represents contractual obligations to purchase coal and natural gas as fuel for electric generation along with related transportation costs.

In addition to the amounts disclosed in the contractual cash obligations table above, we make additional commitments in the normal course of business. These commitments include standby letters of credit and other commitments. Our commitments outstanding at December 31, 2003 under these agreements are summarized in the table below:

	Amount of Commitment Expiration Per Period (in thousands)				
Other Commercial Commitments	**Less Than 1 year**	**2-3 years**	**4–5 years**	**After 5 years**	**Total**
Standby Letters of Credit	$-	$43,000	$-	$-	$43,000
Transmission Facilities for Third Parties (a)	22,811	74,716	30,720	-	128,247
Total	$22,811	$117,716	$30,720	$-	$171,247

(a) As construction agent for third party owners of transmission facilities, we have committed by contract terms to complete construction by dates specified in the contracts.

Significant Factors

See the "Registrants' Combined Management's Discussion and Analysis" section beginning on page M-1 for additional discussion of factors relevant to us.

Quantitative And Qualitative Disclosures About Risk Management Activities

Market Risks

Our risk management policies and procedures are instituted and administered at the AEP consolidated level. See complete discussion within AEP's "Qualitative And Quantitative Disclosures About Risk Management Activities" section. The following tables provide information about our risk management activities' effect.

MTM Risk Management Contract Net Assets

This table provides detail on changes in our MTM net asset or liability balance sheet position from one period to the next.

MTM Risk Management Contract Net Assets
Year Ended December 31, 2003
(in thousands)

Domestic Power	
Beginning Balance December 31, 2002	$5,414
(Gain) Loss from Contracts Realized/Settled During the Period (a)	(2,033)
Fair Value of New Contracts When Entered Into During the Period (b)	-
Net Option Premiums Paid/(Received) (c)	(130)
Change in Fair Value Due to Valuation Methodology Changes	-
Effect of EITF 98-10 Rescission (d)	187
Changes in Fair Value of Risk Management Contracts (e)	8,504
Changes in Fair Value of Risk Management Contracts Allocated to Regulated Jurisdictions (f)	-
Total MTM Risk Management Contract Net Assets, Excluding Cash Flow Hedges	11,942
Net Cash Flow Hedge Contracts (g)	(2,812)
Ending Balance December 31, 2003	$9,130

(a)"(Gain) Loss from Contracts Realized/Settled During the Period" includes realized gains from risk management contracts and related derivatives that settled during 2003 that were entered into prior to 2003.

(b)The "Fair Value of New Contracts When Entered Into During the Period" represents the fair value of long-term contracts entered into with customers during 2003. The fair value is calculated as of the execution of the contract. Most of the fair value comes from longer term fixed price contracts with customers that seek to limit their risk against fluctuating energy prices. The contract prices are valued against market curves associated with the delivery location.

(c)"Net Option Premiums Paid/(Received)" reflects the net option premiums paid/(received) as they relate to unexercised and unexpired option contracts that were entered into in 2003.

(d)See Note 2 "New Accounting Pronouncements Extraordinary Items and Cumulative Effect of Accounting Changes."

(e)"Changes in Fair Value of Risk Management Contracts" represents the fair value change in the risk management portfolio due to market fluctuations during the current period. Market fluctuations are attributable to various factors such as supply/demand, weather, etc.

(f)"Change in Fair Value of Risk Management Contracts Allocated to Regulated Jurisdictions" relates to the net gains (losses) of those contracts that are not reflected in the Consolidated Statements of Income. These net gains (losses) are recorded as regulatory liabilities/assets for those subsidiaries that operate in regulated jurisdictions.

(g)"Net Cash Flow Hedge Contracts" (pre-tax) are discussed below in Accumulated Other Comprehensive Income (Loss).

Maturity and Source of Fair Value of MTM Risk Management Contract Net Assets

The table presenting maturity and source of fair value of MTM risk management contract net assets provides two fundamental pieces of information:

- The source of fair value used in determining the carrying amount of our total MTM asset or liability (external sources or modeled internally).
- The maturity, by year, of our net assets/liabilities, giving an indication of when these MTM amounts will settle and generate cash.

Maturity and Source of Fair Value of MTM
Risk Management Contract Net Assets
Fair Value of Contracts as of December 31, 2003

	2004	2005	2006	2007 (in thousands)	2008	After 2008	Total (c)
Prices Actively Quoted – Exchange Traded Contracts	$238	$(99)	$9	$61	$-	$-	$209
Prices Provided by Other External Sources – OTC Broker Quotes (a)	1,752	1,570	576	363	208	-	4,469
Prices Based on Models and Other Valuation Methods (b)	4,346	511	114	237	497	1,559	7,264
Total	$6,336	$1,982	$699	$661	$705	$1,559	$11,942

(a)"Prices Provided by Other External Sources – OTC Broker Quotes" reflects information obtained from over-the-counter brokers, industry services, or multiple-party on-line platforms.

(b)"Prices Based on Models and Other Valuation Methods" is in absence of pricing information from external sources, modeled information is derived using valuation models developed by the reporting entity, reflecting when appropriate, option pricing theory, discounted cash flow concepts, valuation adjustments, etc. and may require projection of prices for underlying commodities beyond the period that prices are available from third-party sources. In addition, where external pricing information or market liquidity are limited, such valuations are classified as modeled. The determination of the point at which a market is no longer liquid for placing it in the Modeled category varies by market.

(c)Amounts exclude Cash Flow Hedges.

Cash Flow Hedges Included in Accumulated Other Comprehensive Income (Loss) (AOCI) on the Balance Sheet

The table provides detail on effective cash flow hedges under SFAS 133 included in the balance sheet. The data in the table will indicate the magnitude of SFAS 133 hedges we have in place. (However, given that under SFAS 133 only cash flow hedges are recorded in AOCI, the table does not provide an all-encompassing picture of our hedging activity). The table also includes a roll-forward of the AOCI balance sheet account, providing insight into the drivers of the changes (new hedges placed during the period, changes in value of existing hedges and roll-off of hedges). In accordance with GAAP, all amounts are presented net of related income taxes.

Total Accumulated Other Comprehensive Income (Loss) Activity
Year Ended December 31, 2003

	Domestic Power (in thousands)
Beginning Balance December 31, 2002	$(36)
Changes in Fair Value (a)	(1,931)
Reclassifications from AOCI to Net Income (b)	139
Ending Balance December 31, 2003	$(1,828)

(a) "Changes in Fair Value" shows changes in the fair value of derivatives designated as hedging instruments in cash flow hedges during the reporting period not yet reclassified into net income, pending the hedged item's affecting net income. Amounts are reported net of related income taxes.

(b) "Reclassifications from AOCI to Net Income" represents gains or losses from derivatives used as hedging instruments in cash flow hedges that were reclassified into net income during the reporting period. Amounts are reported net of related income taxes above.

The portion of cash flow hedges in AOCI expected to be reclassified to earnings during the next twelve months is a $1,413 thousand loss.

Credit Risk

Our counterparty credit quality and exposure is generally consistent with that of AEP.

VaR Associated with Management Contracts

The following table shows the end, high, average, and low market risk as measured by VaR for year-to-date:

December 31, 2003 (in thousands)			
End	High	Average	Low
$189	$733	$307	$73

December 31, 2002 (in thousands)			
End	High	Average	Low
$115	$353	$126	$26

VaR Associated with Debt Outstanding

The risk of potential loss in fair value attributable to our exposure to interest rates, primarily related to long-term debt with fixed interest rates was $206 million and $65 million at December 31, 2003 and 2002, respectively. We would not expect to liquidate our entire debt portfolio in a one-year holding period, therefore a near term change in interest rates should not negatively affect our results of operation or consolidated financial position.

AEP TEXAS CENTRAL COMPANY AND SUBSIDIARY
CONSOLIDATED STATEMENTS OF INCOME
For the Years Ended December 31, 2003, 2002 and 2001

	2003	2002 (in thousands)	2001
OPERATING REVENUES			
Electric Generation, Transmission and Distribution	$1,593,943	$682,049	$1,697,075
Sales to AEP Affiliates	153,568	1,008,444	41,762
TOTAL	1,747,511	1,690,493	1,738,837
OPERATING EXPENSES			
Fuel for Electric Generation	89,389	88,488	492,057
Fuel from Affiliates for Electric Generation	195,527	157,346	-
Purchased Electricity for Resale	373,388	211,358	127,816
Purchased Electricity from AEP Affiliates	19,097	23,406	58,641
Other Operation	297,878	304,094	321,227
Maintenance	71,361	63,392	71,212
Depreciation and Amortization	189,130	214,162	168,341
Taxes Other Than Income Taxes	92,109	95,500	90,916
Income Taxes	98,092	139,014	112,896
TOTAL	1,425,971	1,296,760	1,443,106
OPERATING INCOME	321,540	393,733	295,731
Nonoperating Income	54,172	53,141	22,552
Nonoperating Expenses	17,273	41,910	21,486
Nonoperating Income Tax Expense (Credit)	7,080	3,152	(1,749)
Interest Charges	133,812	125,871	116,268
Income Before Cumulative Effect of Accounting Change	217,547	275,941	182,278
Cumulative Effect of Accounting Change (Net of Tax)	122	-	-
NET INCOME	217,669	275,941	182,278
Gain on Reacquired Preferred Stock	-	4	-
Preferred Stock Dividend Requirements	241	241	242
EARNINGS APPLICABLE TO COMMON STOCK	$217,428	$275,704	$182,036

The common stock of TCC is owned by a wholly-owned subsidiary of AEP.

See Notes to Respective Financial Statements beginning on page L-1.

AEP TEXAS CENTRAL COMPANY AND SUBSIDIARY
CONSOLIDATED STATEMENTS OF CHANGES IN COMMON SHAREHOLDER'S EQUITY AND COMPREHENSIVE INCOME
For the Years Ended December 31, 2003, 2002 and 2001
(in thousands)

	Common Stock	Paid-in Capital	Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Total
DECEMBER 31, 2000	$168,888	$405,015	$792,219	$-	$1,366,122
Common Stock Dividends Declared			(148,057)		(148,057)
Preferred Stock Dividends Declared			(242)		(242)
Other			(1)		(1)
TOTAL					1,217,822
COMPREHENSIVE INCOME					
NET INCOME			182,278		182,278
TOTAL COMPREHENSIVE INCOME					182,278
DECEMBER 31, 2001	$168,888	$405,015	$826,197	$-	$1,400,100
Redemption of Common Stock	(113,596)	(272,409)			(386,005)
Common Stock Dividends			(115,505)		(115,505)
Preferred Stock Dividends			(241)		(241)
Gain on Reacquired Preferred Stock			4		4
TOTAL					898,353
COMPREHENSIVE INCOME					
Other Comprehensive Income, Net of Taxes:					
Unrealized Loss on Cash Flow Hedges				(36)	(36)
Minimum Pension Liability				(73,124)	(73,124)
NET INCOME			275,941		275,941
TOTAL COMPREHENSIVE INCOME					202,781
DECEMBER 31, 2002	$55,292	$132,606	$986,396	$(73,160)	$1,101,134
Common Stock Dividends			(120,801)		(120,801)
Preferred Stock Dividends			(241)		(241)
TOTAL					980,092
COMPREHENSIVE INCOME					
Other Comprehensive Income (Loss), Net of Taxes:					
Unrealized Loss on Cash Flow Hedges				(1,792)	(1,792)
Minimum Pension Liability				13,080	13,080
NET INCOME			217,669		217,669
TOTAL COMPREHENSIVE INCOME					228,957
DECEMBER 31, 2003	$55,292	$132,606	$1,083,023	$(61,872)	$1,209,049

See Notes to Respective Financial Statements beginning on page L-1.

AEP TEXAS CENTRAL COMPANY AND SUBSIDIARY
CONSOLIDATED BALANCE SHEETS
ASSETS
December 31, 2003 and 2002

	2003	2002
	(in thousands)	
ELECTRIC UTILITY PLANT		
Production	$-	$-
Transmission	767,970	682,780
Distribution	1,376,761	1,296,731
General	221,354	202,418
Construction Work in Progress	58,953	152,865
TOTAL	2,425,038	2,334,794
Accumulated Depreciation and Amortization	695,359	662,345
TOTAL - NET	1,729,679	1,672,449
OTHER PROPERTY AND INVESTMENTS		
Non-Utility Property, Net	1,302	2,385
Other Investments	4,639	354
TOTAL	5,941	2,739
CURRENT ASSETS		
Cash and Cash Equivalents	65,882	85,420
Advances to Affiliates	60,699	-
Accounts Receivable:		
Customers	146,630	113,014
Affiliated Companies	78,484	121,324
Accrued Unbilled Revenues	23,077	27,150
Miscellaneous	-	529
Allowance for Uncollectible Accounts	(1,710)	(346)
Materials and Supplies	11,708	14,376
Risk Management Assets	22,051	22,493
Margin Deposits	3,230	121
Prepayments and Other Current Assets	6,770	2,012
TOTAL	416,821	386,093
DEFERRED DEBITS AND OTHER ASSETS		
Regulatory Assets:		
SFAS 109 Regulatory Asset, Net	3,249	9,950
Wholesale Capacity Auction True-up	480,000	262,000
Unamortized Loss on Reacquired Debt	9,086	8,661
Designated for Securitization	1,253,289	330,960
Deferred Debt – Restructuring	12,015	13,324
Other	133,913	170,101
Securitized Transition Assets	689,399	734,591
Long-term Risk Management Assets	7,627	4,392
Deferred Charges	55,554	43,890
TOTAL	2,644,132	1,577,869
Assets Held for Sale – Texas Generation Plants	1,028,134	1,814,810
TOTAL ASSETS	$5,824,707	$5,453,960

See Notes to Respective Financial Statements beginning on page L-1.

AEP TEXAS CENTRAL COMPANY AND SUBSIDIARY
CONSOLIDATED BALANCE SHEETS
CAPITALIZATION AND LIABILITIES
December 31, 2003 and 2002

	2003	2002
	(in thousands)	
CAPITALIZATION		
Common Shareholder's Equity:		
Common Stock – $25 Par Value:		
Authorized – 12,000,000 Shares		
Outstanding – 2,211,678 Shares	$55,292	$55,292
Paid-in Capital	132,606	132,606
Retained Earnings	1,083,023	986,396
Accumulated Other Comprehensive Income (Loss)	(61,872)	(73,160)
Total Common Shareholder's Equity	1,209,049	1,101,134
Cumulative Preferred Stock Not Subject to Mandatory Redemption	5,940	5,942
Total Shareholder's Equity	1,214,989	1,107,076
CPL – Obligated Mandatorily Redeemable Preferred Securities of Subsidiary Trust Holding Solely Junior Subordinated Debentures of TCC	-	136,250
Long-term Debt	2,053,974	1,209,434
TOTAL	3,268,963	2,452,760
CURRENT LIABILITIES		
Short-term Debt – Affiliates	-	650,000
Long-term Debt Due Within One Year	237,651	229,131
Advances from Affiliates	-	126,711
Accounts Payable:		
General	90,004	72,199
Affiliated Companies	74,209	36,242
Customer Deposits	1,517	666
Taxes Accrued	67,018	24,791
Interest Accrued	43,196	51,205
Risk Management Liabilities	17,888	19,811
Obligation Under Capital Leases	407	-
Other	23,248	36,698
TOTAL	555,138	1,247,454
DEFERRED CREDITS AND OTHER LIABILITIES		
Deferred Income Taxes	1,244,912	1,261,252
Long-term Risk Management Liabilities	2,660	1,713
Regulatory Liabilities:		
Asset Removal Costs	95,415	-
Deferred Investment Tax Credits	112,479	117,686
Deferred Fuel Costs	69,026	69,026
Retail Clawback	45,527	51,926
Other	56,984	76,547
Obligation Under Capital Leases	636	-
Deferred Credits and Other	144,833	166,711
TOTAL	1,772,472	1,744,861
Liabilities Held for Sale – Texas Generation Plants	228,134	8,885
Commitments and Contingencies (Note 7)		
TOTAL CAPITALIZATION AND LIABILITIES	$5,824,707	$5,453,960

See Notes to Respective Financial Statements beginning on page L-1.

AEP TEXAS CENTRAL COMPANY AND SUBSIDIARY
CONSOLIDATED STATEMENTS OF CASH FLOWS
For the Years Ended 2003, 2002 and 2001

	2003	2002 (in thousands)	2001
OPERATING ACTIVITIES			
Net Income	$217,669	$275,941	$182,278
Adjustments to Reconcile Net Income to Net Cash Flows From Operating Activities:			
Depreciation and Amortization	189,130	214,162	168,341
Deferred Income Taxes	19,393	113,655	(72,568)
Deferred Investment Tax Credits	(5,207)	(5,206)	(5,208)
Cumulative Effect of Accounting Change	(122)	-	-
Mark-to-Market of Risk Management Contracts	(6,341)	(1,558)	(12,048)
Wholesale Capacity Auction True-up	(218,000)	(262,000)	-
Changes in Certain Assets and Liabilities:			
Accounts Receivable, Net	15,190	(217,149)	52,862
Fuel, Materials and Supplies	15,850	(4,899)	(18,215)
Interest Accrued	(8,009)	27,490	(2,502)
Accounts Payable	55,772	(6,167)	(55,311)
Taxes Accrued	42,227	(58,721)	27,986
Fuel Recovery	-	16,455	179,866
Change in Other Assets	30,341	(534)	13,276
Change in Other Liabilities	19,330	56,024	11,163
Net Cash Flows From Operating Activities	367,223	147,493	469,920
INVESTING ACTIVITIES			
Construction Expenditures	(141,771)	(151,645)	(193,732)
Other	7,455	143	(354)
Net Cash Flows Used For Investing Activities	(134,316)	(151,502)	(194,086)
FINANCING ACTIVITIES			
Change in Short-term Debt - Affiliates	(650,000)	650,000	-
Issuance of Long-term Debt	953,136	797,335	260,162
Retirement of Long-term Debt	(247,127)	(639,492)	(475,606)
Change in Advances to/from Affiliates, Net	(187,410)	(227,566)	84,565
Retirement of Common Stock	-	(386,005)	-
Retirement of Preferred Stock	(2)	(6)	-
Dividends Paid on Common Stock	(120,801)	(115,505)	(148,057)
Dividends Paid on Cumulative Preferred Stock	(241)	(241)	(242)
Net Cash Flows From (Used For) Financing Activities	(252,445)	78,520	(279,178)
Net Increase (Decrease) in Cash and Cash Equivalents	(19,538)	74,511	(3,344)
Cash and Cash Equivalents at Beginning of Period	85,420	10,909	14,253
Cash and Cash Equivalents at End of Period	$65,882	$85,420	$10,909

SUPPLEMENTAL DISCLOSURE:
Cash paid for interest net of capitalized amounts was $129,491,000, $93,120,000 and $109,835,000 and for income taxes was $49,630,000, $95,600,000 and $161,529,000 in 2003, 2002 and 2001, respectively.

See Notes to Respective Financial Statements beginning on page L-1.

AEP TEXAS CENTRAL COMPANY AND SUBSIDIARY
CONSOLIDATED STATEMENTS OF CAPITALIZATION
December 31, 2003 and 2002

	2003	2002
	(in thousands)	
TOTAL COMMON SHAREHOLDER'S EQUITY (a)	$1,209,049	$1,101,134

PREFERRED STOCK – 3,035,000 authorized shares, $100 par value

Not Subject to Mandatory Redemption:

Series	Call Price December 31, 2003	Number of Shares Redeemed Year Ended December 31, 2003	2002	2001	Shares Outstanding December 31, 2003	2003	2002
4.00%	$105.75	11	100	-	41,927	4,192	4,194
4.20%	103.75	-	-	-	17,476	1,748	1,748
Total Preferred Stock						5,940	5,942

	2003	2002
TRUST PREFERRED SECURITIES:		
TCC-Obligated, Mandatorily Redeemable Preferred Securities of Subsidiary Trust Holding Solely Junior Subordinated Debentures of TCC, 8.00%, due April 30, 2037 (b)	-	136,250
LONG-TERM (See Schedule of Long-term Debt):		
First Mortgage Bonds	117,939	152,353
Securitization Bonds (a)	745,680	796,635
Note Payable to Trust (b)	140,889	-
Installment Purchase Contracts	489,585	489,577
Senior Unsecured Notes	797,532	-
Less Portion Due Within One year	(237,651)	(229,131)
Long-term Debt Excluding Portion Due Within One Year	2,053,974	1,209,434
TOTAL CAPITALIZATION	$3,268,963	$2,452,760

(a) In February 2002, TCC issued securitization bonds. $386 million of the proceeds was used to retire 4,543,857 shares of common stock.
(b) See Note 16 for discussion of Notes Payable to Trust.

See Notes to Respective Financial Statements beginning on page L-1.

AEP TEXAS CENTRAL COMPANY AND SUBSIDIARY
SCHEDULE OF LONG-TERM DEBT
December 31, 2003 and 2002

First Mortgage Bonds outstanding were as follows:

% Rate	Due	2003	2002
		(in thousands)	
6.875	2003 – February 1	$-	$16,418
7.25	2004 – October 1	27,400	27,400
7-1/8	2008 – February 1	18,581	18,581
7.50	2023 – April 1	-	17,996
6-5/8	2005 – July 1	71,958	71,958
Total		$117,939	$152,353

First Mortgage Bonds are secured by a first mortgage lien on electric utility plant. The indenture, as supplemented, relating to the first mortgage bonds contains maintenance and replacement provisions requiring the deposit of cash or bonds with the trustee, or in lieu thereof, certification of unfunded property additions. Interest payments are made semi-annually.

Securitization Bonds outstanding were as follows:

%Rate	Final Payment Date	Maturity Date	2003	2002
			(in thousands)	
3.54	1/15/2005	1/15/2007	$77,937	$128,950
5.01	1/15/2008	1/15/2010	154,507	154,507
5.56	1/15/2010	1/15/2012	107,094	107,094
5.96	7/15/2013	7/15/2015	214,927	214,927
6.25	1/15/2016	1/15/2017	191,857	191,857
Unamortized Discount			(642)	(700)
Total			$745,680	$796,635

In February 2002, CPL Transition Funding LLC, a special purpose subsidiary of TCC, issued $797 million of Securitization Bonds, Series 2002-1. The Securitization Bonds mature at different times through 2017 and have a weighted average interest rate of 5.4 percent.

Senior Unsecured Notes outstanding were as follows:

% Rate	Due	2003	2002
		(in thousands)	
5.50	2013 – February 15	$275,000	$-
6.65	2033 – February 15	275,000	-
3.00	2005 – February 15	150,000	-
(a)	2005 – February 15	100,000	-
Unamortized Discount		(2,468)	-
Total		$797,532	$-

(a) A floating interest rate is determined quarterly. The rate on December 31, 2003 was 2.43%.

Installment Purchase Contracts have been entered into in connection with the issuance of pollution control revenue bonds by governmental authorities as follows:

% Rate	Due	2003	2002
		(in thousands)	
Matagorda County Navigation District, Texas:			
6.00	2028 – July 1	$120,265	$120,265
6-1/8	2030 – May 1	60,000	60,000
3.75	2003 – November 1	-	111,700
2.15	2030 – May 1 (a)	111,700	-
4.00	2030 – May 1	-	50,000
4.55	2029 – November 1 (b)	100,635	100,635
2.35	2030 – May 1 (a)	50,000	-
Guadalupe-Blanco River Authority District, Texas:			
	2015 – November 1 (c)	40,890	40,890
Red River Authority of Texas:			
6.00	2020 – June 1	6,330	6,330
Unamortized Discount		(235)	(243)
Total		$489,585	$489,577

(a) Installment Purchase Contract provides for bonds to be tendered in 2004 for 2.15% and 2.35% series. Therefore, these installment purchase contracts have been classified for payment in 2004.
(b) Installment Purchase Contract provides for bonds to be tendered in 2006 for 4.55% series. Therefore, this installment purchase contract has been classified for payment in 2006.
(c) A floating interest rate is determined daily. The rate on December 31, 2003 was 1.30%.

Under the terms of the installment purchase contracts, TCC is required to pay amounts sufficient to enable the payment of interest on and the principal (at stated maturities and upon mandatory redemptions) of related pollution control revenue bonds issued to finance the construction of pollution control facilities at certain plants. Interest payments range from monthly to semi-annually.

Notes Payable to Trust was outstanding as follows:

% Rate	Due	2003	2002
		(in thousands)	
8.00	2037 – April 30	$140,889	$-

See Note 16 for discussion of Notes Payable to Trust.

At December 31, 2003, future annual long-term debt payments are as follows:

	Amount (in thousands)
2004	$237,651
2005	371,938
2006	152,900
2007	52,729
2008	68,688
Later Years	1,411,064
Total Principal Amount	2,294,970
Unamortized Discount	(3,345)
Total	$2,291,625

AEP TEXAS CENTRAL COMPANY AND SUBSIDIARY
INDEX TO NOTES TO RESPECTIVE FINANCIAL STATEMENTS

The notes to TCC's consolidated financial statements are combined with the notes to respective financial statements for other subsidiary registrants. Listed below are the notes that apply to TCC. The footnotes begin on page L-1.

INDEPENDENT AUDITORS' REPORT

To the Shareholders and Board of Directors
of AEP Texas Central Company:

We have audited the accompanying consolidated balance sheets and consolidated statements of capitalization of AEP Texas Central Company and subsidiary as of December 31, 2003 and 2002, and the related consolidated statements of income, changes in common shareholder's equity and comprehensive income and cash flows for each of the three years in the period ended December 31, 2003. These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements based on our audits.

We conducted our audits in accordance with auditing standards generally accepted in the United States of America. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, such consolidated financial statements present fairly, in all material respects, the financial position of AEP Texas Central Company and subsidiary as of December 31, 2003 and 2002, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2003 in conformity with accounting principles generally accepted in the United States of America.

As discussed in Note 2 to the consolidated financial statements, the Company adopted SFAS 143, "Accounting for Asset Retirement Obligations," effective January 1, 2003.

As discussed in Note 2 to the consolidated financial statements, the Company adopted FIN 46, "Consolidation of Variable Interest Entities," effective July 1, 2003.

/s/ Deloitte & Touche LLP

Columbus, Ohio
March 5, 2004

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AEP TEXAS NORTH COMPANY
SELECTED FINANCIAL DATA

	2003	2002	2001 (in thousands)	2000	1999
INCOME STATEMENTS DATA					
Operating Revenues	$465,946	$450,740	$556,458	$571,064	$445,709
Operating Expenses	397,919	442,869	523,068	518,723	391,910
Operating Income	68,027	7,871	33,390	52,341	53,799
Nonoperating Items, Net	9,685	(703)	2,195	(1,675)	2,488
Interest Charges	22,049	20,845	23,275	23,216	24,420
Income (Loss) Before Extraordinary Item and Cumulative Effect of Accounting Change	55,663	(13,677)	12,310	27,450	31,867
Extraordinary Loss	(177)	-	-	-	(5,461)
Cumulative Effect of Accounting Change	3,071	-	-	-	-
Net Income (Loss)	58,557	(13,677)	12,310	27,450	26,406
Gain on Reacquired Preferred Stock	3	-	-	-	-
Preferred Stock Dividend Requirements	104	104	104	104	104
Earnings (Loss) Applicable to Common Stock	$58,456	$(13,781)	$12,206	$27,346	$ 26,302
BALANCE SHEETS DATA					
Electric Utility Plant	$1,233,427	$1,201,747	$1,260,872	$1,229,339	$1,182,544
Accumulated Depreciation and Amortization	460,513	446,818	475,036	447,802	446,282
Net Electric Utility Plant	$772,914	$754,929	$785,836	$781,537	$736,262
TOTAL ASSETS	$1,009,509	$952,149	$936,001	$1,154,743	$910,770
Common Stock and Paid-in Capital	$139,565	$139,565	$139,565	$139,565	$139,565
Retained Earnings	125,428	71,942	105,970	122,588	113,242
Accumulated Other Comprehensive Income (Loss)	(26,718)	(30,763)	-	-	-
Total Common Shareholder's Equity	$238,275	$180,744	$245,535	$262,153	$252,807
Cumulative Preferred Stock Not Subject to Mandatory Redemption	$2,357	$2,367	$2,367	$2,367	$2,367
Long-term Debt (a)	$356,754	$132,500	$255,967	$255,843	$303,686
Obligations Under Capital Leases (a)	$473	$-	$-	$-	$-
TOTAL CAPITALIZATION AND LIABILITIES	$1,009,509	$952,149	$936,001	$1,154,743	$910,770

(a) Including portion due within one year.

AEP TEXAS NORTH COMPANY
MANAGEMENT'S NARRATIVE FINANCIAL DISCUSSION AND ANALYSIS

AEP Texas North Company (TNC), formerly known as West Texas Utilities Company (WTU), is a public utility engaged in the generation and purchase of electric power, and the subsequent sale, transmission and distribution of that power in west and central Texas. As a power pool member with AEP West companies, we share in the revenues and expenses of the power pool's sales to neighboring utilities and power marketers. TNC also sells electric power at wholesale to other utilities, municipalities, rural electric cooperatives and retail electric providers (REPs) in Texas.

Power pool members are compensated for energy delivered to other members based upon the delivering members' incremental cost plus a portion of the savings realized by the purchasing member that avoids the use of more costly alternatives. The revenue and costs for sales to neighboring utilities and power marketers made by AEPSC on behalf of the AEP West companies are shared among the members based upon the relative magnitude of the energy each member provides to make such sales.

Power and gas risk management activities are conducted on our behalf by AEPSC. We share in the revenues and expenses associated with these risk management activities with other AEP registrant subsidiaries excluding AEGCo under existing power pool and system integration agreements. Risk management activities primarily involve the purchase and sale of electricity under physical forward contracts at fixed and variable prices and to a lesser extent gas. The electricity and gas contracts include physical transactions, over-the-counter options and swaps and exchange traded futures and options. The majority of the physical forward contracts are typically settled by entering into offsetting contracts.

Under our system integration agreement, revenues and expenses from the sales to neighboring utilities, power marketers and other power and gas risk management entities are shared among AEP East and West companies. Sharing in a calendar year is based upon the level of such activities experienced for the twelve months ended June 30, 2000, which immediately preceded the merger of AEP and CSW. This resulted in an AEP East and West companies' allocation of approximately 91% and 9%, respectively, for revenues and expenses. Allocation percentages in any given calendar year may also be based upon the relative generating capacity of the AEP East and West companies in the event the pre-merger activity level is exceeded. The capacity based allocation mechanism was triggered in June 2003, resulting in an allocation factor of approximately 70% and 30% for the AEP East and West companies, respectively, for the remainder of 2003.

Results of Operations

2003 Compared to 2002

Net Income increased $72 million primarily due to a 2002 $43 million write-down ($28 million after tax) of gas power plants and increased risk management margins of $20 million in 2003. Transactions with ERCOT also significantly increased income in 2003.

Since REPs are the electricity suppliers to retail customers in the ERCOT area, we sell our generation to the REPs and other market participants and provide transmission and distribution services to retail customers of the REPs in our service territory. As a result of the provision of retail electric service by REPs effective January 1, 2002, we no longer supply electricity directly to retail customers. The implementation of REPs as suppliers to retail customers has caused a significant shift in our sales as further described below.

In December 2002, AEP sold Mutual Energy WTU to an unrelated third party, who assumed the obligations of the affiliated REP, including the provision of price-to-beat rates under the Texas Restructuring Legislation. Prior to the sale, during 2002, sales to Mutual Energy WTU were classified as Sales to AEP Affiliates. Subsequent to the sale, energy transactions and delivery charges with Mutual Energy WTU are classified as Electric Generation, Transmission and Distribution.

Operating Income

Operating Income increased by $60 million primarily due to:

- The 2002 asset impairment of $43 million. See Note 10 "Acquisitions, Dispositions, Impairments, Assets Held for Sale and Assets Held and Used."
- Increased Reliability Must Run (RMR) revenues from ERCOT of $44 million which include both fuel recovery and a fixed cost component of $13 million (see "Texas Plants" in Note 10 for discussion of RMR facilities).
- Increased revenues from risk management activities of $10 million.
- Increased revenues from ERCOT of $22 million or 91% for various services, due mainly to prior years adjustments made by ERCOT.
- Decreased fuel and purchased power on a net basis of $9 million. KWH generation decreased 27% mainly due to mothballing of plants while the per unit cost of fuel increased 14% due primarily to higher natural gas prices. KWH purchased declined 9%, but the average cost increased 2%.
- Reduced Other Operation expenses of $20 million due to several factors including $8 million of customer service, outside services, other administrative related expenses, ERCOT transmission charges of $4 million, distribution expenses of $2 million, and a $2 million write-down of material and supplies to market value related to the deactivation of several power plants in 2002.
- Decreased Maintenance expense of $3 million due primarily to the deactivation of several power plants in 2002 (See Note 10).
- Reduced Depreciation and Amortization of $7 million due to the 2002 impairment of several power plants resulting in approximately $4 million less depreciation expense. An additional decrease of $3 million relates to adjustments to prior years' excess earnings accruals under the Texas restructuring legislation due to a favorable Appeals Court ruling (See Note 6).
- Decrease of Taxes Other Than Income Taxes of $2 million is due to reduced gross receipts tax as a result of the sale of the Texas REPs.

The increase in Operating Income was partially offset by:

- Decreased system sales, including those to REP's, of $7 million due mainly to both lower KWH sales of 17% and a decrease in the overall average price per KWH.
- The 2002 ICR adjustments decreased revenue by approximately $24 million in 2003. This decrease was partially offset by a reduction in purchased power, due to these adjustments of $5 million.
- Decreased delivery revenues of $5 million, due partly to decreased cooling and heating degree-days.
- Reduced wholesale revenues of $8 million due to the loss of several large wholesale customers whose contracts expired and were not renewed.
- Increased provision for rate refunds of $20 million in 2003 due mainly to the final Texas fuel reconciliation (see "TNC Fuel Reconciliation" in Note 4).
- Increased Federal Income Taxes of $39 million due to the increase in pre-tax operating income.

Other Impacts on Earnings

Nonoperating Income increased $15 million primarily due to a $10 million increase in net revenue from risk management activities, while revenue from third party non-utility energy related construction projects increased $5 million.

Extraordinary (Loss) – (Net of Tax)

Extraordinary loss resulted from the cessation of SFAS 71 accounting for wholesale generation assets due to the FERC settlement case (see Note 2).

Cumulative Effect of Accounting Changes

The Cumulative Effect of Accounting Changes is due to a one-time after-tax impact of adopting SFAS 143 (see Note 2).

Financial Condition

Credit Ratings

The rating agencies currently have us on stable outlook. Our current ratings are as follows:

	Moody's	S&P	Fitch
First Mortgage Bonds	A3	BBB	A
Senior Unsecured Debt	Baa1	BBB	A-

In February 2003, Moody's Investor Service (Moody's) completed their review of AEP and its rated subsidiaries. TNC had its secured debt downgraded from A2 to A3 and unsecured debt downgraded from A3 to Baa1. The completion of this review was a culmination of ratings action started during 2002. In March 2003, S&P lowered AEP and our senior unsecured debt and mortgage bonds ratings from BBB+ to BBB.

Summary Obligation Information

Our contractual obligations include amounts reported on the Consolidated Balance Sheets and other obligations disclosed in the footnotes. The following table summarizes our contractual cash obligations at December 31, 2003:

	Payments Due by Period (in thousands)				
Contractual Cash Obligations	**Less Than 1 year**	**2-3 years**	**4-5 years**	**After 5 years**	**Total**
Long-term Debt	$42,505	$37,609	$8,151	$268,489	$356,754
Unconditional Purchase Obligations (a)	51,172	82,478	57,456	201,096	392,202
Capital Lease Obligations	223	275	9	2	509
Noncancellable Operating Leases	1,964	3,791	2,770	4,981	13,506
Total	$95,864	$124,153	$68,386	$474,568	$762,971

(a) Represents contractual obligations to purchase coal and natural gas as fuel for electric generation along with related transportation costs.

In addition to the amounts disclosed in the contractual cash obligations table above, we make additional commitments in the normal course of business. These commitments include standby letters of credit and other commitments. Our commitments outstanding at December 31, 2003 under these agreements are summarized in the table below:

	Amount of Commitment Expiration Per Period (in thousands)				
Other Commercial Commitments	**Less Than 1 year**	**2-3 years**	**4-5 years**	**After 5 years**	**Total**
Transmission Facilities for Third Parties (a)	$75,658	$15,621	$-	$-	$91,279

(a) As construction agent for third party owners of transmission facilities, we have committed by contract terms to complete construction by dates specified in the contracts.

Significant Factors

See the "Registrants' Combined Management's Discussion and Analysis" section beginning on page M-1 for additional discussion of factors relevant to us.

Quantitative And Qualitative Disclosures About Risk Management Activities

Market Risks

Our risk management policies and procedures are instituted and administered at the AEP consolidated level. See complete discussion within AEP's "Qualitative And Quantitative Disclosures About Risk Management Activities" section. The following tables provide information about our risk management activities' effects.

MTM Risk Management Contract Net Assets

This table provides detail on changes in our MTM net asset or liability balance sheet position from one period to the next.

MTM Risk Management Contract Net Assets
Year Ended December 31, 2003
(in thousands)

Domestic Power	
Beginning Balance December 31, 2002	$2,043
(Gain) Loss from Contracts Realized/Settled During the Period (a)	104
Fair Value of New Contracts When Entered Into During the Period (b)	-
Net Option Premiums Paid/(Received) (c)	(110)
Change in Fair Value Due to Valuation Methodology Changes	-
Effect of EITF 98-10 Rescission (d)	20
Changes in Fair Value of Risk Management Contracts (e)	3,203
Changes in Fair Value of Risk Management Contracts Allocated to Regulated Jurisdictions (f)	(640)
Total MTM Risk Management Contract Net Assets, Excluding Cash Flow Hedges	4,620
Net Cash Flow Hedge Contracts (g)	(926)
Ending Balance December 31, 2003	$3,694

(a)"(Gain) Loss from Contracts Realized/Settled During the Period" includes realized gains from risk management contracts and related derivatives that settled during 2003 that were entered into prior to 2003.
(b)The "Fair Value of New Contracts When Entered Into During the Period" represents the fair value of long-term contracts entered into with customers during 2003. The fair value is calculated as of the execution of the contract. Most of the fair value comes from longer term fixed price contracts with customers that seek to limit their risk against fluctuating energy prices. The contract prices are valued against market curves associated with the delivery location.
(c)"Net Option Premiums Paid/(Received)" reflects the net option premiums paid/(received) as they relate to unexercised and unexpired option contracts that were entered into in 2003.
(d)See Note 2 "New Accounting Pronouncements, Extraordinary Items and Cumulative Effect of Accounting Changes."
(e)"Changes in Fair Value of Risk Management Contracts" represents the fair value change in the risk management portfolio due to market fluctuations during the current period. Market fluctuations are attributable to various factors such as supply/demand, weather, etc.
(f)"Change in Fair Value of Risk Management Contracts Allocated to Regulated Jurisdictions" relates to the net gains (losses) of those contracts that are not reflected in the Consolidated Statements of Income. These net gains (losses) are recorded as regulatory liabilities/assets for those subsidiaries that operate in regulated jurisdictions.
(g)"Net Cash Flow Hedge Contracts" (pre-tax) are discussed below in Accumulated Other Comprehensive Income (Loss).

Maturity and Source of Fair Value of MTM Risk Management Contract Net Assets

The table presenting maturity and source of fair value of MTM risk management contract net assets provides two fundamental pieces of information:

- The source of fair value used in determining the carrying amount of our total MTM asset or liability (external sources or modeled internally).
- The maturity, by year, of our net assets/liabilities, giving an indication of when these MTM amounts will settle and generate cash.

Maturity and Source of Fair Value of MTM
Risk Management Contract Net Assets
Fair Value of Contracts as of December 31, 2003

	2004	2005	2006	2007	2008	After 2008	Total (c)
			(in thousands)				
Prices Actually Quoted – Exchange Traded Contracts	$96	$(40)	$4	$24	$-	$-	$84
Prices Provided by Other External Sources – OTC Broker Quotes (a)	932	631	231	146	84	-	2,024
Prices Based on Models and Other Valuation Methods (b)	1,323	223	45	95	199	627	2,512
Total	$2,351	$814	$280	$265	$283	$627	$4,620

(a) "Prices Provided by Other External Sources – OTC Broker Quotes" reflects information obtained from over-the-counter brokers, industry services, or multiple-party on-line platforms.

(b) "Prices Based on Models and Other Valuation Methods" is in absence of pricing information from external sources, modeled information is derived using valuation models developed by the reporting entity, reflecting when appropriate, option pricing theory, discounted cash flow concepts, valuation adjustments, etc. and may require projection of prices for underlying commodities beyond the period that prices are available from third-party sources. In addition, where external pricing information or market liquidity are limited, such valuations are classified as modeled. The determination of the point at which a market is no longer liquid for placing it in the Modeled category varies by market.

(c) Amounts exclude Cash Flow Hedges.

Cash Flow Hedges Included in Accumulated Other Comprehensive Income (Loss) (AOCI) on the Balance Sheet

The table provides detail on effective cash flow hedges under SFAS 133 included in the balance sheet. The data in the table will indicate the magnitude of SFAS 133 hedges we have in place. (However, given that under SFAS 133 only cash flow hedges are recorded in AOCI, the table does not provide an all-encompassing picture of our hedging activity). The table also includes a roll-forward of the AOCI balance sheet account, providing insight into the drivers of the changes (new hedges placed during the period, changes in value of existing hedges and roll-off of hedges). In accordance with GAAP, all amounts are presented net of related income taxes.

Total Accumulated Other Comprehensive Income (Loss) Activity
Year Ended December 31, 2003

	Domestic Power (in thousands)
Beginning Balance December 31, 2002	$(15)
Changes in Fair Value (a)	(641)
Reclassifications from AOCI to Net Income (b)	55
Ending Balance December 31, 2003	$(601)

(a) "Changes in Fair Value" shows changes in the fair value of derivatives designated as hedging instruments in cash flow hedges during the reporting period not yet reclassified into net income, pending the hedged item's affecting net income. Amounts are reported net of related income taxes.

(b) "Reclassifications from AOCI to Net Income" represents gains or losses from derivatives used as hedging instruments in cash flow hedges that were reclassified into net income during the reporting period. Amounts are reported net of related income taxes above.

The portion of cash flow hedges in AOCI expected to be reclassified to earnings during the next twelve months is a $435 thousand loss.

Credit Risk

Our counterparty credit quality and exposure is generally consistent with that of AEP.

VaR Associated with Risk Management Contracts

The following table shows the end, high, average, and low market risk as measured by VaR for year-to-date:

December 31, 2003 (in thousands)				December 31, 2002 (in thousands)			
End	High	Average	Low	End	High	Average	Low
$76	$294	$123	$29	$48	$146	$52	$11

VaR Associated with Debt Outstanding

The risk of potential loss in fair value attributable to our exposure to interest rates, primarily related to long-term debt with fixed interest rates was $33 million and $5 million at December 31, 2003 and 2002, respectively. We would not expect to liquidate our entire debt portfolio in a one-year holding period, therefore a near term change in interest rates should not negatively affect our results of operation or consolidated financial position.

AEP TEXAS NORTH COMPANY
STATEMENTS OF OPERATIONS
For the Years Ended December 31, 2003, 2002 and 2001

	2003	2002 (in thousands)	2001
OPERATING REVENUES			
Electric Generation, Transmission and Distribution	$410,793	$210,315	$537,777
Sales to AEP Affiliates	55,153	240,425	18,681
TOTAL	465,946	450,740	556,458
OPERATING EXPENSES			
Fuel for Electric Generation	39,082	36,081	177,140
Fuel from Affiliates for Electric Generation	44,197	64,385	-
Purchased Electricity for Resale	87,006	80,391	70,395
Purchased Electricity from AEP Affiliates	39,409	37,582	56,656
Other Operation	85,263	104,960	111,248
Asset Impairments	-	42,898	-
Maintenance	18,961	22,295	22,343
Depreciation and Amortization	36,242	43,620	50,705
Taxes Other Than Income Taxes	20,570	22,471	28,319
Income Tax Expense (Credit)	27,189	(11,814)	6,262
TOTAL	397,919	442,869	523,068
OPERATING INCOME	68,027	7,871	33,390
Nonoperating Income	68,451	53,884	12,199
Nonoperating Expenses	55,692	54,876	10,695
Nonoperating Income Tax Expense (Credit)	3,074	(289)	(691)
Interest Charges	22,049	20,845	23,275
Income (Loss) Before Extraordinary Items and Cumulative Effect of Accounting Changes	55,663	(13,677)	12,310
Extraordinary (Loss) – (Net of Tax)	(177)	-	-
Cumulative Effect of Accounting Changes (Net of Tax)	3,071	-	-
NET INCOME (LOSS)	58,557	(13,677)	12,310
Gain on Reacquired Preferred Stock	3	-	-
Preferred Stock Dividend Requirements	104	104	104
EARNINGS (LOSS) APPLICABLE TO COMMON STOCK	$58,456	$(13,781)	$12,206

The common stock of TNC is owned by a wholly-owned subsidiary of AEP.

See Notes to Respective Financial Statements beginning on page L-1.

AEP TEXAS NORTH COMPANY
STATEMENTS OF CHANGES IN COMMON SHAREHOLDER'S EQUITY AND COMPREHENSIVE INCOME
For the Years Ended December 31, 2003, 2002 and 2001
(in thousands)

	Common Stock	Paid-in Capital	Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Total
DECEMBER 31, 2000	$137,214	$2,351	$122,588	$-	$262,153
Common Stock Dividends Declared			(28,824)		(28,824)
Preferred Stock Dividends Declared			(104)		(104)
TOTAL					233,225
COMPREHENSIVE INCOME					
NET INCOME			12,310		12,310
TOTAL COMPREHENSIVE INCOME					12,310
DECEMBER 31, 2001	$137,214	$2,351	$105,970	$-	$245,535
Common Stock Dividends			(20,247)		(20,247)
Preferred Stock Dividends			(104)		(104)
TOTAL					225,184
COMPREHENSIVE INCOME					
Other Comprehensive Income, Net of Taxes:					
Unrealized Loss on Cash Flow Hedges				(15)	(15)
Minimum Pension Liability				(30,748)	(30,748)
NET INCOME (LOSS)			(13,677)		(13,677)
TOTAL COMPREHENSIVE INCOME					(44,440)
DECEMBER 31, 2002	$137,214	$2,351	$71,942	$(30,763)	$180,744
Common Stock Dividends			(4,970)		(4,970)
Preferred Stock Dividends			(104)		(104)
Gain on Reacquired Preferred Stock			3		3
TOTAL					175,673
COMPREHENSIVE INCOME					
Other Comprehensive Income (Loss), Net of Taxes:					
Unrealized Loss on Cash Flow Hedges				(586)	(586)
Minimum Pension Liability				4,631	4,631
NET INCOME			58,557		58,557
TOTAL COMPREHENSIVE INCOME					62,602
DECEMBER 31, 2003	$137,214	$2,351	$125,428	$(26,718)	$238,275

See Notes to Respective Financial Statements beginning on page L-1.

AEP TEXAS NORTH COMPANY
BALANCE SHEETS
ASSETS
December 31, 2003 and December 31, 2002

	2003	2002
	(in thousands)	
ELECTRIC UTILITY PLANT		
Production	$360,463	$353,087
Transmission	268,695	254,483
Distribution	456,278	445,486
General	117,792	111,679
Construction Work in Progress	30,199	37,012
TOTAL	1,233,427	1,201,747
Accumulated Depreciation and Amortization	460,513	446,818
TOTAL – NET	772,914	754,929
OTHER PROPERTY AND INVESTMENTS		
Non-Utility Property, Net	1,286	1,086
Other Investments	-	127
TOTAL	1,286	1,213
CURRENT ASSETS		
Cash and Cash Equivalents	2,863	1,219
Advances to Affiliates	41,593	-
Accounts Receivable:		
Customers	56,670	62,646
Affiliated Companies	28,910	43,632
Accrued Unbilled Revenues	4,871	6,829
Miscellaneous	3,411	14
Allowance for Uncollectible Accounts	(175)	(5,041)
Fuel Inventory	10,925	12,677
Materials and Supplies	8,866	9,574
Risk Management Assets	10,340	4,130
Margin Deposits	1,285	37
Prepayments and Other	1,834	1,033
TOTAL	171,393	136,750
DEFERRED DEBITS AND OTHER ASSETS		
Regulatory Assets:		
Deferred Fuel Costs	26,680	26,680
Deferred Debt – Restructuring	6,579	10,134
Unamortized Loss on Reacquired Debt	3,929	3,283
Other	3,332	5,000
Long-term Risk Management Assets	3,106	2,248
Deferred Charges	20,290	11,912
TOTAL	63,916	59,257
TOTAL ASSETS	$1,009,509	$952,149

See Notes to Respective Financial Statements beginning on page L-1.

AEP TEXAS NORTH COMPANY
BALANCE SHEETS
CAPITALIZATION AND LIABILITIES
December 31, 2003 and 2002

	2003	2002
	(in thousands)	
CAPITALIZATION		
Common Shareholder's Equity:		
Common Stock – $25 Par Value:		
Authorized – 7,800,000 Shares		
Outstanding – 5,488,560 Shares	$137,214	$137,214
Paid-in Capital	2,351	2,351
Retained Earnings	125,428	71,942
Accumulated Other Comprehensive Income (Loss)	(26,718)	(30,763)
Total Common Shareholder's Equity	238,275	180,744
Cumulative Preferred Stock Not Subject to Mandatory Redemption	2,357	2,367
Total Shareholder's Equity	240,632	183,111
Long-term Debt	314,249	132,500
TOTAL	554,881	315,611
CURRENT LIABILITIES		
Short-term Debt – Affiliates	-	125,000
Long-term Debt Due Within One Year	42,505	-
Advances from Affiliates	-	80,407
Accounts Payable:		
General	28,190	32,714
Affiliated Companies	40,601	76,217
Customer Deposits	161	117
Taxes Accrued	22,877	3,697
Interest Accrued	6,038	2,776
Risk Management Liabilities	8,658	3,801
Obligations Under Capital Leases	203	-
Other	9,419	17,414
TOTAL	158,652	342,143
DEFERRED CREDITS AND OTHER LIABILITIES		
Deferred Income Taxes	113,019	117,521
Long-term Risk Management Liabilities	1,094	557
Regulatory Liabilities:		
Asset Removal Costs	76,740	-
Deferred Investment Tax Credits	19,990	21,510
Retail Clawback	11,804	14,328
Excess Earnings	14,262	17,419
SFAS 109 Regulatory Liability, Net	13,655	12,280
Other	1,826	7,285
Obligations Under Capital Leases	270	-
Deferred Credits and Other	43,316	103,495
TOTAL	295,976	294,395
Commitments and Contingencies (Note 7)		
TOTAL CAPITALIZATION AND LIABILITIES	$1,009,509	$952,149

See Notes to Respective Financial Statements beginning on page L-1.

AEP TEXAS NORTH COMPANY
STATEMENTS OF CASH FLOWS
For the Years Ended December 31, 2003, 2002 and 2001

	2003	2002	2001
		(in thousands)	
OPERATING ACTIVITIES			
Net Income	$58,557	$(13,677)	$12,310
Adjustments to Reconcile Net Income to Net Cash Flows From Operating Activities:			
Depreciation and Amortization	36,242	43,620	50,705
Extraordinary (Loss) – Net of Tax	177	-	-
Write Down of Utility Plant Assets	-	38,154	-
Write Down of Wind Farm Assets	-	4,744	-
Deferred Income Taxes	(3,493)	(12,275)	(11,891)
Deferred Investment Tax Credits	(1,520)	(1,271)	(1,271)
Cumulative Effect of Accounting Changes	(3,071)	-	-
Mark-to-Market of Risk Management Contracts	(2,558)	(1,127)	(3,506)
Changes in Certain Assets and Liabilities:			
Accounts Receivable, Net	14,393	(80,900)	24,844
Fuel, Materials and Supplies	2,460	(2,754)	3,187
Accounts Payable	(40,140)	63,761	(42,604)
Taxes Accrued	19,180	(13,661)	(1,543)
Fuel Recovery	-	14,169	32,505
Change in Other Assets	(8,955)	(16,928)	(1,432)
Change in Other Liabilities	5,996	16,514	11,056
Net Cash Flows From Operating Activities	77,268	38,369	72,360
INVESTING ACTIVITIES			
Construction Expenditures	(46,683)	(43,563)	(39,662)
Other	688	150	(127)
Net Cash Flows Used For Investing Activities	(45,995)	(43,413)	(39,789)
FINANCING ACTIVITIES			
Change in Short-term Debt - Affiliates	(125,000)	125,000	-
Issuance of Long-term Debt	222,455	-	-
Retirement of Long-term Debt	-	(130,799)	-
Retirement of Preferred Stock	(10)	-	-
Change in Advances to/from Affiliates, Net	(122,000)	29,959	(8,130)
Dividends Paid on Common Stock	(4,970)	(20,247)	(28,824)
Dividends Paid on Cumulative Preferred Stock	(104)	(104)	(104)
Net Cash Flows From (Used For) Financing Activities	(29,629)	3,809	(37,058)
Net Increase (Decrease) in Cash and Cash Equivalents	1,644	(1,235)	(4,487)
Cash and Cash Equivalents at Beginning of Period	1,219	2,454	6,941
Cash and Cash Equivalents at End of Period	$2,863	$1,219	$2,454

SUPPLEMENTAL DISCLOSURE:

Cash paid for interest net of capitalized amounts was $16,384,000, $19,934,000 and $19,279,000 and for income taxes was $16,081,000, $15,544,000 and $21,997,000 in 2003, 2002 and 2001 respectively.

See Notes to Respective Financial Statements beginning on page L-1.

AEP TEXAS NORTH COMPANY
STATEMENTS OF CAPITALIZATION
December 31, 2003 and 2002

						2003	2002
						(in thousands)	
COMMON SHAREHOLDER'S EQUITY						$238,275	$180,744
PREFERRED STOCK: $100 par value – authorized shares 810,000							
Series	Call Price December 31, 2003	Number of Shares Redeemed Year Ended December 31, 2003	2002	2001	Shares Outstanding December 31, 2003		
Not Subject to Mandatory Redemption:							
4.40%	$107	102	-	-	23,570	2,357	2,367
LONG-TERM DEBT (See Schedule of Long-term Debt):							
First Mortgage Bonds						88,236	88,190
Installment Purchase Contracts						44,310	44,310
Senior Unsecured Notes						224,208	-
Less Portion Due Within One Year						(42,505)	-
Long-term Debt Excluding Portion Due Within One Year						314,249	132,500
TOTAL CAPITALIZATION						$554,881	$315,611

See Notes to Respective Financial Statements beginning on page L-1.

AEP TEXAS NORTH COMPANY
SCHEDULE OF LONG-TERM DEBT
December 31, 2003 and 2002

First Mortgage Bonds outstanding were as follows:

% Rate	Due	2003	2002
		(in thousands)	
7.00	2004 – October 1	$18,469	$18,469
6-1/8	2004 – February 1	24,036	24,036
6-3/8	2005 – October 1	37,609	37,609
7-3/4	2007 – June 1	8,151	8,151
Unamortized Discount		(29)	(75)
Total		$88,236	$88,190

First Mortgage Bonds are secured by a first mortgage lien on electric utility plant. The indenture, as supplemented, relating to the first mortgage bonds contains maintenance and replacement provisions requiring the deposit of cash or bonds with the trustee, or in lieu thereof, certification of unfunded property additions. Interest payments are made semi-annually.

Installment Purchase Contracts have been entered into, in connection with the issuance of pollution control revenue bonds by governmental authorities as follows:

% Rate	Due	2003	2002
		(in thousands)	
Red River Authority of Texas:			
6.00	2020 – June 1	$44,310	$44,310

Under the terms of the Installment Purchase Contracts, TNC is required to pay amounts sufficient to enable the payment of interest on and the principal of (at stated maturities and upon mandatory redemptions) related pollution control revenue bonds issued to finance the construction of pollution control facilities at certain plants. Interest payments are made semi-annually.

Senior Unsecured Notes outstanding were as follows:

% Rate	Due	2003	2002
		(in thousands)	
5.50	2013 – March 1	$225,000	$-
Unamortized Discount		(792)	-
Total		$224,208	$-

At December 31, 2003, future annual Long-term Debt payments are as follows:

	Amount (in thousands)
2004	$42,505
2005	37,609
2006	-
2007	8,151
2008	-
Later Years	269,310
Total Principal Amount	357,575
Unamortized Discount	(821)
Total	$356,754

AEP TEXAS NORTH COMPANY
INDEX TO NOTES TO RESPECTIVE FINANCIAL STATEMENTS

The notes to TNC's financial statements are combined with the notes to respective financial statements for other subsidiary registrants. Listed below are the notes that apply to TNC. The footnotes begin on page L-1.

INDEPENDENT AUDITORS' REPORT

To the Shareholders and Board of
Directors of AEP Texas North Company:

We have audited the accompanying balance sheets and statements of capitalization of AEP Texas North Company as of December 31, 2003 and 2002, and the related statements of operations, changes in common shareholder's equity and comprehensive income, and cash flows for each of the three years in the period ended December 31, 2003. These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements based on our audits.

We conducted our audits in accordance with auditing standards generally accepted in the United States of America. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, such financial statements present fairly, in all material respects, the financial position of AEP Texas North Company as of December 31, 2003 and 2002, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2003 in conformity with accounting principles generally accepted in the United States of America.

As discussed in Note 2 to the financial statements, the Company adopted SFAS 143, "Accounting for Asset Retirement Obligations," effective January 1, 2003.

/s/ Deloitte & Touche LLP

Columbus, Ohio
March 5, 2004

APPALACHIAN POWER COMPANY
AND SUBSIDIARIES

APPALACHIAN POWER COMPANY AND SUBSIDIARIES
SELECTED CONSOLIDATED FINANCIAL DATA

	2003	2002	2001 (in thousands)	2000	1999
INCOME STATEMENTS DATA					
Operating Revenues	$1,957,358	$1,814,470	$1,784,259	$1,759,253	$1,586,050
Operating Expenses	1,638,547	1,512,407	1,509,273	1,558,099	1,344,814
Operating Income	318,811	302,063	274,986	201,154	241,236
Nonoperating Items, Net	(826)	20,106	6,868	11,752	8,096
Interest Charges	115,202	116,677	120,036	148,000	128,840
Income Before Extraordinary Item and Cumulative Effect of Accounting Changes	202,783	205,492	161,818	64,906	120,492
Extraordinary Gain	-	-	-	8,938	-
Income Before Cumulative Effect of Accounting Changes	202,783	205,492	161,818	73,844	120,492
Cumulative Effect of Accounting Changes (Net of Tax)	77,257	-	-	-	-
Net Income	280,040	205,492	161,818	73,844	120,492
Preferred Stock Dividend Requirements (Including Capital Stock Expense)	3,495	2,898	2,011	2,504	2,706
Earnings Applicable to Common Stock	$276,545	$202,594	$159,807	$71,340	$117,786
BALANCE SHEETS DATA					
Electric Utility Plant	$6,140,931	$5,895,303	$5,664,657	$5,418,278	$5,262,951
Accumulated Depreciation and Amortization	2,321,360	2,330,012	2,207,072	2,103,471	1,998,112
Net Electric Utility Plant	$3,819,571	$3,565,291	$3,457,585	$3,314,807	$3,264,839
TOTAL ASSETS	$4,977,011	$4,722,442	$4,572,194	$6,657,920	$4,433,597
Common Stock and Paid-in Capital	$980,357	$977,700	$976,244	$975,676	$974,717
Retained Earnings	408,718	260,439	150,797	120,584	175,854
Accumulated Other Comprehensive Income (Loss)	(52,088)	(72,082)	(340)	-	-
Total Common Shareholder's Equity	$1,336,987	$1,166,057	$1,126,701	$1,096,260	$1,150,571
Cumulative Preferred Stock:					
Not Subject to Mandatory Redemption	$17,784	$17,790	$17,790	$17,790	$18,491
Subject to Mandatory Redemption	5,360	10,860	10,860	10,860	20,310
Total Cumulative Preferred Stock	$23,144	$28,650	$28,650	$28,650	$38,801
Long-term Debt (a)	$1,864,081	$1,893,861	$1,556,559	$1,605,818	$1,665,307
Obligations Under Capital Leases (a)	$25,352	$33,589	$46,285	$63,160	$64,645
TOTAL CAPITALIZATION AND LIABILITIES	$4,977,011	$4,722,442	$4,572,194	$6,657,920	$4,433,597

(a) Including portion due within one year.

APPALACHIAN POWER COMPANY AND SUBSIDIARIES
MANAGEMENT'S FINANCIAL DISCUSSION AND ANALYSIS

APCo is a public utility engaged in the generation and purchase of electric power, and the subsequent sale, transmission and distribution of that power to 929,000 retail customers in our service territory in southwestern Virginia and southern West Virginia. As a member of the AEP Power Pool, we share the revenues and the costs of the AEP Power Pool's sales to neighboring utilities and power marketers. We also sell power at wholesale to municipalities.

The cost of the AEP Power Pool's generating capacity is allocated among its members based on their relative peak demands and generating reserves through the payment of capacity charges and the receipt of capacity credits. AEP Power Pool members are also compensated for the out-of-pocket costs of energy delivered to the AEP Power Pool and charged for energy received from the AEP Power Pool. The AEP Power Pool calculates each member's prior twelve-month peak demand relative to the sum of the peak demands of all members as a basis for sharing revenues and costs. The result of this calculation is the member load ratio (MLR), which determines each member's percentage share of revenues and costs. In 2003 our relative share of the AEP Power Pool revenues and expenses increased over the prior period as a result of our reaching a new peak demand in January 2003, which increased our allocation factor.

Power and gas risk management activities are conducted on our behalf by AEPSC. We share in the revenues and expenses associated with these risk management activities with other AEP registrant subsidiaries excluding AEGCo under existing power pool and system integration agreements. Risk management activities primarily involve the purchase and sale of electricity under physical forward contracts at fixed and variable prices and to a lesser extent gas. The electricity and gas contracts include physical transactions, over-the-counter options and swaps and exchange traded futures and options. The majority of the physical forward contracts are typically settled by entering into offsetting contracts.

Under our system integration agreement, revenues and expenses from the sales to neighboring utilities, power marketers and other power and gas risk management entities are shared among AEP East and West companies. Sharing in a calendar year is based upon the level of such activities experienced for the twelve months ended June 30, 2000, which immediately preceded the merger of AEP and CSW. This resulted in an AEP East and West companies' allocation of approximately 91% and 9%, respectively, for revenues and expenses. Allocation percentages in any given calendar year may also be based upon the relative generating capacity of the AEP East and West companies in the event the pre-merger activity level is exceeded. The capacity based allocation mechanism was triggered in June 2003, resulting in an allocation factor of approximately 70% and 30% for the AEP East and West companies, respectively, for the remainder of 2003.

Results of Operations

Net Income for 2003 increased $75 million over the prior year period primarily due to the Cumulative Effect of Accounting Changes of $77 million recorded in 2003. See "Cumulative Effect of Accounting Changes" in Note 2 for further information.

Income Before Cumulative Effect of Accounting Changes decreased slightly from 2002 as improvements in Operating Income were offset by reduced gains from risk management activities included in Nonoperating Income (Expense). The improvement in Operating Income was driven by increased earnings on system sales and reduced employee related expenses partially offset by increased capacity charges included in Purchased Electricity from AEP Affiliates.

2003 Compared to 2002

Operating Income

Operating Income for 2003 increased by $17 million from 2002 primarily due to the following:

- An increase in system sales and transmission revenues totaling $93 million reflecting an increase in the volume of AEP Power Pool transactions, as well as our relative share based on the higher MLR.
- An increase of $36 million in Sales to AEP Affiliates due to strong wholesale sales by the AEP Power Pool.
- A decrease in Other Operation expense of $24 million due to severance expenses of $13 million incurred in 2002 related to the SEI initiative (see Note 9, "Sustained Earnings Improvement Initiative"), as well as reduced employee related expenses and insurance premiums in 2003. These decreases were partially offset

by an increase in transmission equalization charges due to the increase in APCo's MLR as described above.

- A decrease in Depreciation and Amortization expense of $14 million primarily due to reduced amortization of generation related regulatory assets due to the return to SFAS 71 for the West Virginia jurisdiction in the first quarter of 2003 (see Note 5, "Effects of Regulation").
- An increase in gains from risk management activities of $10 million.

The increase in Operating Income for 2003 was partially offset by:

- An increase in purchased power expenses and fuel expense of $150 million reflecting the $62 million increase in capacity charges resulting from the increase in APCo's MLR as described above, the increase in our relative share of the AEP Power Pool expenses and increased generation. Also, we accrued additional fuel expense to increase fuel costs to match fuel revenues billed to ratepayers (see "Deferred Fuel Costs" in Note 1, "Summary of Significant Accounting Policies").
- An increase in Maintenance expense of $13 million primarily due to increased maintenance of overhead lines required due to severe storm damage in the first quarter of 2003 and increased overhead line maintenance throughout the year.

Other Impacts on Earnings

Nonoperating income decreased $36 million in 2003 compared to 2002 primarily due to lower profit from power sold outside AEP's traditional marketing area resulting from AEP's plan to exit risk management activities in areas outside of its traditional market area. The decrease in nonoperating income was partially offset by a $12 million decrease in nonoperating income taxes resulting primarily from the reduced pre-tax nonoperating book income.

Cumulative Effect of Accounting Changes

The Cumulative Effect of Accounting Changes of $77 million is due to the implementation of SFAS 143 and EITF 02-03 (see "Cumulative Effect" section of Note 2).

2002 Compared to 2001

Net Income

Net Income for 2002 increased $44 million over the prior year due to higher retail sales resulting from weather related electricity demands and reductions in Maintenance expense. Most significantly the Mountaineer, Amos and Glen Lyn plants, down for boiler maintenance in 2001, were back online in 2002 resulting in increased availability of generation and decreased maintenance expense. In addition, net nonoperating income increased $10 million as a result of a reduction in incentive compensation partially offset by decreased gains from risk management activities.

Operating Income

Operating Income for 2002 increased $27 million compared to the prior year primarily due to the following:

- Retail sales increased $42 million primarily due to weather related electricity demands.
- An increase in Sales to AEP Affiliates of $15 million due to an increase in generation capacity and power available to be delivered to the AEP Power Pool.
- A decrease of $10 million in Maintenance expense due to the boiler maintenance incurred in 2001 as discussed above.
- A $97 million decrease in purchase power expense resulting from increased internal generation based on the higher plant availability partially offset by a $79 million increase in Fuel expense necessary to support the increased generation.
- A $5 million decrease in Taxes Other Than Income Taxes primarily due to the replacement of the municipal license tax imposed on APCo with the Virginia consumption tax that was imposed on the consumer.

These increases in Operating Income for 2002 were offset by:

- A net $32 million decrease in system sales partially offset by gains from risk management activities.
- An increase of $9 million in Other Operation expense mainly due to $13 million of severance expenses related to the SEI initiative, a reduction in gains recorded on the dispositions of SO2 emission allowances and increased insurance premiums and other employee benefit costs.
- An increase of $9 million in Depreciation and Amortization due to increased amortization for the net generation-related regulatory assets related to our West Virginia jurisdiction which were assigned to the distribution portion of our business and are being recovered through regulated rates.
- An increase of $18 million in Income Taxes due to an increase in pre-tax income.

Other Impacts on Earnings

Nonoperating income decreased $20 million for 2002, primarily due to a decrease in gains from risk management activities driven by a decline in market prices. Nonoperating Expenses decreased $30 million due to decreased incentives related to risk management activities.

Financial Condition

Credit Ratings

The rating agencies currently have us on stable outlook. Current ratings are as follows:

	Moody's	S&P	Fitch
First Mortgage Bonds	Baa1	BBB	A-
Senior Unsecured Debt	Baa2	BBB	BBB+

In February 2003, Moody's Investors Service (Moody's) completed their review of AEP and its rated subsidiaries. The results of that review included a downgrade of our rating for unsecured debt from Baa1 to Baa2 and a downgrade of secured ratings from A3 to Baa1. The completion of this review was a culmination of ratings action started during 2002. In March 2003, S&P lowered AEP and its subsidiaries senior unsecured ratings from BBB+ to BBB along with the first mortgage bonds of AEP subsidiaries.

Cash Flow

Cash flows for 2003, 2002 and 2001 were as follows:

	2003	2002 (in thousands)	2001
Cash and cash equivalents at beginning of period	$4,285	$13,663	$5,847
Cash flow from (used for):			
Operating activities	461,276	280,709	393,854
Investing activities	(286,608)	(275,475)	(313,298)
Financing activities	(133,072)	(14,612)	(72,740)
Net increase (decrease) in cash and cash equivalents	41,596	(9,378)	7,816
Cash and cash equivalents at end of period	$45,881	$4,285	$13,663

Operating Activities

Cash flow from operating activities in 2003 increased $181 million over the prior year primarily due to decreases in various accounts receivable balances in 2003 and changes in Federal and state income tax accruals.

Investing Activities

Construction expenditures in 2003 versus 2002 increased $12 million. The current year expenditures of $289 million were focused primarily on projects to improve service reliability for transmission and distribution, as well as environmental upgrades.

Financing Activities

In 2003, we issued two series of Senior Unsecured Notes, each in the amount of $200 million which were used to call First Mortgage Bonds and Senior Unsecured Notes and fund maturities. Additionally, we incurred obligations of $188 million in Installment Purchase Contracts to redeem higher costing Installment Purchase Contracts.

Summary Obligation Information

Our contractual obligations include amounts reported on the Consolidated Balance Sheets and other obligations disclosed in the footnotes. The following table summarizes our contractual cash obligations at December 31, 2003:

	Payments Due by Period (in thousands)				
Contractual Cash Obligations	**Less Than 1 year**	**2-3 years**	**4–5 years**	**After 5 years**	**Total**
Long-term Debt	$161,008	$677,521	$400,027	$625,525	$1,864,081
Advances from Affiliates	82,994	-	-	-	82,994
Preferred Stock Subject to Mandatory Redemption	-	-	5,360	-	5,360
Capital Lease Obligations	11,735	12,036	5,309	1,802	30,882
Unconditional Purchase Obligations (a)	311,826	351,760	90,163	-	753,749
Noncancellable Operating Leases	5,998	9,609	5,696	6,094	27,397
Total	$573,561	$1,050,926	$506,555	$633,421	$2,764,463

(a) Represents contractual obligations to purchase coal as fuel for electric generation along with related transportation of the fuel.

Significant Factors

See the "Registrants' Combined Management's Discussion and Analysis" section beginning on page M-1 for additional discussion of factors relevant to us.

Quantitative And Qualitative Disclosures About Risk Management Activities

Market Risks

Our risk management policies and procedures are instituted and administered at the AEP consolidated level. See complete discussion within AEP's "Qualitative And Quantitative Disclosures About Risk Management Activities" section. The following tables provide information about our risk management activities' effect on this specific registrant.

MTM Risk Management Contract Net Assets

This table provides detail on changes in our MTM net asset or liability balance sheet position from one period to the next.

MTM Risk Management Contract Net Assets
Year Ended December 31, 2003
(in thousands)

Domestic Power

Beginning Balance December 31, 2002	$96,852
(Gain) Loss from Contracts Realized/Settled During the Period (a)	(33,846)
Fair Value of New Contracts When Entered Into During the Period (b)	-
Net Option Premiums Paid/(Received) (c)	143
Change in Fair Value Due to Valuation Methodology Changes	-
Effect of EITF 98-10 Rescission (d)	(4,664)
Changes in Fair Value of Risk Management Contracts (e)	9,305
Changes in Fair Value Risk Management Contracts Allocated to Regulated Jurisdictions (f)	276
Total MTM Risk Management Contract Net Assets, Excluding Cash Flow Hedges	68,066
Net Cash Flow Hedge Contracts (g)	553
DETM Assignment (h)	(32,287)
Ending Balance December 31, 2003	$36,332

(a) "(Gain) Loss from Contracts Realized/Settled During the Period" includes realized gains from risk management contracts and related derivatives that settled during 2003 that were entered into prior to 2003.

(b) The "Fair Value of New Contracts When Entered Into During the Period" represents the fair value of long-term contracts entered into with customers during 2003. The fair value is calculated as of the execution of the contract. Most of the fair value comes from longer term fixed price contracts with customers that seek to limit their risk against fluctuating energy prices. The contract prices are valued against market curves associated with the delivery location.

(c) "Net Option Premiums Paid/(Received)" reflects the net option premiums paid/(received) as they relate to unexercised and unexpired option contracts that were entered into in 2003.

(d) See Note 2 "New Accounting Pronouncements, Extraordinary Items and Cumulative Effect of Accounting Changes."

(e) "Changes in Fair Value of Risk Management Contracts" represents the fair value change in the risk management portfolio due to market fluctuations during the current period. Market fluctuations are attributable to various factors such as supply/demand, weather, etc.

(f) "Change in Fair Value of Risk Management Contracts Allocated to Regulated Jurisdictions" relates to the net gains (losses) of those contracts that are not reflected in the Consolidated Statements of Operations. These net gains (losses) are recorded as regulatory liabilities/assets for those subsidiaries that operate in regulated jurisdictions.

(g) "Net Cash Flow Hedge Contracts" (pre-tax) are discussed below in Accumulated Other Comprehensive Income (Loss).

(h) See Note 17 "Related Party Transactions."

Maturity and Source of Fair Value of MTM Risk Management Contract Net Assets

The table presenting maturity and source of fair value of MTM risk management contract net assets provides two fundamental pieces of information:

- The source of fair value used in determining the carrying amount of our total MTM asset or liability (external sources or modeled internally).
- The maturity, by year, of our net assets/liabilities, giving an indication of when these MTM amounts will settle and generate cash.

Maturity and Source of Fair Value of MTM
Risk Management Contract Net Assets
Fair Value of Contracts as of December 31, 2003

	2004	2005	2006	2007	2008	After 2008	Total (c)
			(in thousands)				
Prices Actively Quoted – Exchange Traded Contracts	$1,219	$(245)	$29	$191	$-	$-	$1,194
Prices Provided by Other External Sources – OTC Broker Quotes (a)	23,753	8,514	8,350	3,395	1,703	-	45,715
Prices Based on Models and Other Valuation Methods (b)	(7)	36	3,313	3,829	3,521	10,465	21,157
Total	$24,965	$8,305	$11,692	$7,415	$5,224	$10,465	$68,066

(a) "Prices Provided by Other External Sources – OTC Broker Quotes" reflects information obtained from over-the-counter brokers, industry services, or multiple-party on-line platforms.
(b) "Prices Based on Models and Other Valuation Methods" is in absence of pricing information from external sources, modeled information is derived using valuation models developed by the reporting entity, reflecting when appropriate, option pricing theory, discounted cash flow concepts, valuation adjustments, etc. and may require projection of prices for underlying commodities beyond the period that prices are available from third-party sources. In addition, where external pricing information or market liquidity are limited, such valuations are classified as modeled. The determination of the point at which a market is no longer liquid for placing it in the Modeled category varies by market.
(c) Amounts exclude Cash Flow Hedges.

Cash Flow Hedges Included in Accumulated Other Comprehensive Income (Loss) (AOCI) on the Balance Sheet

The table provides detail on effective cash flow hedges under SFAS 133 included in the balance sheet. The data in the table will indicate the magnitude of SFAS 133 hedges we have in place. (However, given that under SFAS 133 only cash flow hedges are recorded in AOCI, the table does not provide an all-encompassing picture of our hedging activity). The table also includes a roll-forward of the AOCI balance sheet account, providing insight into the drivers of the changes (new hedges placed during the period, changes in value of existing hedges and roll-off of hedges). In accordance with GAAP, all amounts are presented net of related income taxes.

Total Accumulated Other Comprehensive Income (Loss) Activity
Year Ended December 31, 2003

	Domestic Power	Foreign Currency	Interest Rate	Consolidated
		(in thousands)		
Beginning Balance December 31, 2002	$(394)	$(190)	$(1,336)	$(1,920)
Changes in Fair Value (a)	272	-	(720)	(448)
Reclassifications from AOCI to Net Income (b)	481	7	311	799
Ending Balance December 31, 2003	$359	$(183)	$(1,745)	$(1,569)

(a) "Changes in Fair Value" shows changes in the fair value of derivatives designated as hedging instruments in cash flow hedges during the reporting period not yet reclassified into net income, pending the hedged item's affecting net income. Amounts are reported net of related income taxes.
(b) "Reclassifications from AOCI to Net Income" represents gains or losses from derivatives used as hedging instruments in cash flow hedges that were reclassified into net income during the reporting period. Amounts are reported net of related income taxes above.

The portion of cash flow hedges in AOCI expected to be reclassified to earnings during the next twelve months is a $1,325 thousand gain.

Credit Risk

Our counterparty credit quality and exposure is generally consistent with that of AEP.

VaR Associated with Risk Management Contracts

The following table shows the end, high, average, and low market risk as measured by VaR year-to-date:

December 31, 2003 (in thousands)			
End	High	Average	Low
$596	$2,314	$969	$230

December 31, 2002 (in thousands)			
End	High	Average	Low
$1,289	$3,948	$1,412	$286

VaR Associated with Debt Outstanding

The risk of potential loss in fair value attributable to our exposure to interest rates, primarily related to long-term debt with fixed interest rates was $102 million and $87 million at December 31, 2003 and 2002, respectively. We would not expect to liquidate our entire debt portfolio in a one-year holding period, therefore a near term change in interest rates should not negatively affect our results of operation or consolidated financial position.

APPALACHIAN POWER COMPANY AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF INCOME
For the Years Ended December 31, 2003, 2002 and 2001

	2003	2002 (in thousands)	2001
OPERATING REVENUES			
Electric Generation, Transmission and Distribution	$1,734,565	$1,627,993	$1,612,974
Sales to AEP Affiliates	222,793	186,477	171,285
TOTAL	1,957,358	1,814,470	1,784,259
OPERATING EXPENSES			
Fuel for Electric Generation	454,901	430,963	351,557
Purchased Electricity for Resale	66,084	57,091	42,092
Purchased Electricity from AEP Affiliates	351,210	234,597	346,878
Other Operation	245,308	269,426	260,518
Maintenance	135,596	122,209	132,373
Depreciation and Amortization	175,772	189,335	180,393
Taxes Other Than Income Taxes	90,087	95,249	99,878
Income Taxes	119,589	113,537	95,584
TOTAL	1,638,547	1,512,407	1,509,273
OPERATING INCOME	318,811	302,063	274,986
Nonoperating Income (Expense)	(5,661)	30,020	50,268
Nonoperating Expenses	9,534	12,525	42,261
Nonoperating Income Tax Expense (Credit)	(14,369)	(2,611)	1,139
Interest Charges	115,202	116,677	120,036
Income Before Cumulative Effect of Accounting Changes	202,783	205,492	161,818
Cumulative Effect of Accounting Changes (Net of Tax)	77,257	-	-
NET INCOME	280,040	205,492	161,818
Preferred Stock Dividend Requirements (Including Capital Stock Expense)	3,495	2,898	2,011
EARNINGS APPLICABLE TO COMMON STOCK	$276,545	$202,594	$159,807

The common stock of APCo is wholly-owned by AEP.

See Notes to Respective Financial Statements beginning on page L-1.

APPALACHIAN POWER COMPANY AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF CHANGES IN COMMON SHAREHOLDER'S EQUITY AND COMPREHENSIVE INCOME
For the Years Ended December 31, 2003, 2002 and 2001
(in thousands)

	Common Stock	Paid-in Capital	Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Total
DECEMBER 31, 2000	$260,458	$715,218	$120,584	$-	$1,096,260
Common Stock Dividends			(129,594)		(129,594)
Preferred Stock Dividends			(1,443)		(1,443)
Capital Stock Expense		568	(568)		-
TOTAL					965,223
COMPREHENSIVE INCOME					
Other Comprehensive Income (Loss), Net of Taxes:					
Unrealized Loss on Cash Flow Hedges				(340)	(340)
NET INCOME			161,818		161,818
TOTAL COMPREHENSIVE INCOME					161,478
DECEMBER 31, 2001	$260,458	$715,786	$150,797	$(340)	$1,126,701
Common Stock Dividends			(92,952)		(92,952)
Preferred Stock Dividends			(1,442)		(1,442)
Capital Stock Expense		1,456	(1,456)		-
TOTAL					1,032,307
COMPREHENSIVE INCOME					
Other Comprehensive Income (Loss), Net of Taxes:					
Unrealized Loss on Cash Flow Hedges				(1,580)	(1,580)
Minimum Pension Liability				(70,162)	(70,162)
NET INCOME			205,492		205,492
TOTAL COMPREHENSIVE INCOME					133,750
DECEMBER 31, 2002	$260,458	$717,242	$260,439	$(72,082)	$1,166,057
Common Stock Dividends			(128,266)		(128,266)
Preferred Stock Dividends			(1,001)		(1,001)
Capital Stock Expense		2,494	(2,494)		-
SFAS 71 Reapplication		163			163
TOTAL					1,036,953
COMPREHENSIVE INCOME					
Other Comprehensive Income, Net of Taxes:					
Unrealized Gain on Cash Flow Hedges				351	351
Minimum Pension Liability				19,643	19,643
NET INCOME			280,040		280,040
TOTAL COMPREHENSIVE INCOME					300,034
DECEMBER 31, 2003	$260,458	$719,899	$408,718	$(52,088)	$1,336,987

See Notes to Respective Financial Statements beginning on page L-1.

APPALACHIAN POWER COMPANY AND SUBSIDIARIES
CONSOLIDATED BALANCE SHEETS
ASSETS
December 31, 2003 and 2002

	2003	2002
	(in thousands)	
ELECTRIC UTILITY PLANT		
Production	$2,287,043	$2,245,945
Transmission	1,240,889	1,218,108
Distribution	2,006,329	1,951,804
General	294,786	272,901
Construction Work in Progress	311,884	206,545
TOTAL	6,140,931	5,895,303
Accumulated Depreciation and Amortization	2,321,360	2,330,012
TOTAL - NET	3,819,571	3,565,291
OTHER PROPERTY AND INVESTMENTS		
Non-Utility Property, Net	20,574	20,550
Other Investments	26,668	34,103
TOTAL	47,242	54,653
CURRENT ASSETS		
Cash and Cash Equivalents	45,881	4,285
Accounts Receivable:		
Customers	133,717	155,521
Affiliated Companies	137,281	122,665
Accrued Unbilled Revenues	35,020	30,948
Miscellaneous	3,961	5,374
Allowance for Uncollectible Accounts	(2,085)	(13,439)
Fuel Inventory	42,806	53,646
Materials and Supplies	71,978	59,886
Risk Management Assets	71,189	94,010
Margin Deposits	11,525	1,238
Prepayments and Other	13,301	12,386
TOTAL	564,574	526,520
DEFERRED DEBITS AND OTHER ASSETS		
Regulatory Assets:		
Transition Regulatory Assets	30,855	158,708
SFAS 109 Regulatory Asset, Net	325,889	209,884
Unamortized Loss on Reacquired Debt	19,005	9,147
Other Regulatory Assets	41,447	17,814
Long-term Risk Management Assets	70,900	115,748
Deferred Property Taxes	35,343	35,323
Other Deferred Charges	22,185	29,354
TOTAL	545,624	575,978
TOTAL ASSETS	$4,977,011	$4,722,442

See Notes to Respective Financial Statements beginning on page L-1.

APPALACHIAN POWER COMPANY AND SUBSIDIARIES
CONSOLIDATED BALANCE SHEETS
CAPITALIZATION AND LIABILITIES
December 31, 2003 and 2002

	2003	2002
	(in thousands)	
CAPITALIZATION		
Common Shareholder's Equity:		
Common Stock – No Par Value:		
Authorized – 30,000,000 Shares		
Outstanding – 13,499,500 Shares	$260,458	$260,458
Paid-in Capital	719,899	717,242
Retained Earnings	408,718	260,439
Accumulated Other Comprehensive Income (Loss)	(52,088)	(72,082)
Total Common Shareholder's Equity	1,336,987	1,166,057
Cumulative Preferred Stock Not Subject to Mandatory Redemption	17,784	17,790
Total Shareholder's Equity	1,354,771	1,183,847
Liability for Cumulative Preferred Stock Subject to Mandatory Redemption	5,360	10,860
Long-term Debt	1,703,073	1,738,854
TOTAL	3,063,204	2,933,561
CURRENT LIABILITIES		
Long-term Debt Due Within One Year	161,008	155,007
Advances from Affiliates	82,994	39,205
Accounts Payable:		
General	140,497	141,546
Affiliated Companies	81,812	98,374
Customer Deposits	33,930	26,186
Taxes Accrued	50,259	29,181
Interest Accrued	22,113	22,437
Risk Management Liabilities	51,430	69,001
Obligations Under Capital Leases	9,218	9,598
Other	60,289	70,234
TOTAL	693,550	660,769
DEFERRED CREDITS AND OTHER LIABILITIES		
Deferred Income Taxes	803,355	701,801
Regulatory Liabilities:		
Asset Removal Costs	92,497	-
Deferred Investment Tax Credits	30,545	33,691
WV Rate Stabilization Deferral	-	75,601
Over Recovery of Fuel Cost	68,704	-
Other Regulatory Liabilities	17,326	72
Long-term Risk Management Liabilities	54,327	44,517
Obligations Under Capital Leases	16,134	23,991
Asset Retirement Obligation	21,776	-
Deferred Credits and Other	115,593	248,439
TOTAL	1,220,257	1,128,112
Commitments and Contingencies (Note 7)		
TOTAL CAPITALIZATION AND LIABILITIES	$4,977,011	$4,722,442

See Notes to Respective Financial Statements beginning on page L-1.

APPALACHIAN POWER COMPANY AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF CASH FLOWS
For the Years Ended December 31, 2003, 2002 and 2001

	2003	2002	2001
		(in thousands)	
OPERATING ACTIVITIES			
Net Income	$280,040	$205,492	$161,818
Adjustments to Reconcile Net Income to Net Cash Flows From Operating Activities:			
Cumulative Effect of Accounting Changes	(77,257)	-	-
Depreciation and Amortization	175,772	189,335	180,505
Deferred Income Taxes	24,563	16,777	42,498
Deferred Investment Tax Credits	(3,146)	(4,637)	(4,765)
Deferred Power Supply Costs, Net	74,071	6,365	1,411
Mark to Market of Risk Management Contracts	56,409	(21,151)	(68,254)
Changes in Certain Assets and Liabilities:			
Accounts Receivable, Net	(6,825)	(83,453)	169,691
Fuel, Materials and Supplies	(1,252)	3,016	(19,957)
Accounts Payable	(17,611)	27,805	(45,073)
Taxes Accrued	21,078	(26,402)	(7,675)
Incentive Plan Accrued	(7,210)	(858)	(2,451)
Rate Stabilization Deferral	(75,601)	-	-
Change in Operating Reserves	(46,984)	(3,190)	(5,358)
Change in Other Assets	(17,813)	(43,338)	19,418
Change in Other Liabilities	83,042	14,948	(27,954)
Net Cash Flows From Operating Activities	461,276	280,709	393,854
INVESTING ACTIVITIES			
Construction Expenditures	(288,577)	(276,549)	(306,046)
Proceeds from Sale of Property and Other	1,969	1,074	(7,252)
Net Cash Flows Used For Investing Activities	(286,608)	(275,475)	(313,298)
FINANCING ACTIVITIES			
Issuance of Long-term Debt	580,649	647,401	124,588
Retirement of Long-term Debt	(622,737)	(315,007)	(175,000)
Retirement of Preferred Stock	(5,506)	-	-
Change in Short-term Debt (net)	-	-	(191,495)
Change in Advances from Affiliates, Net	43,789	(252,612)	300,204
Dividends Paid on Common Stock	(128,266)	(92,952)	(129,594)
Dividends Paid on Cumulative Preferred Stock	(1,001)	(1,442)	(1,443)
Net Cash Flows Used For Financing Activities	(133,072)	(14,612)	(72,740)
Net Increase (Decrease) in Cash and Cash Equivalents	41,596	(9,378)	7,816
Cash and Cash Equivalents at Beginning of Period	4,285	13,663	5,847
Cash and Cash Equivalents at End of Period	$45,881	$4,285	$13,663

SUPPLEMENTAL DISCLOSURE:
Cash paid for interest net of capitalized amounts was $108,045,000, $111,528,000 and $117,283,000 and for income taxes was $62,673,000, $125,120,000 and $56,981,000 in 2003, 2002 and 2001, respectively.

See Notes to Respective Financial Statements beginning on page L-1.

APPALACHIAN POWER COMPANY AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF CAPITALIZATION
December 31, 2003 and 2002

						2003	2002
						(in thousands)	
COMMON SHAREHOLDER'S EQUITY						$1,336,987	$1,166,057
PREFERRED STOCK:							
No Par Value - Authorized 8,000,000 shares							
Series	Call Price December 31, 2003 (a)	Number of Shares Redeemed Year Ended December 31, 2003	2002	2001	Shares Outstanding December 31, 2003		
Not Subject to Mandatory Redemption - $100 Par:							
4-1/2%	$110	60	6	-	177,839	17,784	17,790
Subject to Mandatory Redemption - $100 Par(b):							
5.90% (c)		25,000	-	-	22,100	2,210	4,710
5.92% (c)		30,000	-	-	31,500	3,150	6,150
Total						5,360	10,860
LONG-TERM DEBT (See Schedule of Long-term Debt):							
First Mortgage Bonds						340,269	489,697
Installment Purchase Contracts						276,477	235,027
Senior Unsecured Notes						1,244,813	1,166,609
Other Long-term Debt						2,522	2,528
Less Portion Due Within One Year						(161,008)	(155,007)
Long-term Debt Excluding Portion Due Within One Year						1,703,073	1,738,854
TOTAL CAPITALIZATION						$3,063,204	$2,933,561

(a) The cumulative preferred stock is callable at the price indicated plus accrued dividends. The involuntary liquidation preference is $100 per share. The aggregate involuntary liquidation price for all shares of cumulative preferred stock may not exceed $300 million. The unissued shares of the cumulative preferred stock may or may not possess mandatory redemption characteristics upon issuance.

(b) The sinking fund provisions of each series subject to mandatory redemption have been met by shares purchased in advance of the due date.

(c) Commencing in 2003 and continuing through 2007 APCo may redeem at $100 per share 25,000 shares of the 5.90% series and 30,000 shares of the 5.92% series outstanding under sinking fund provisions at its option and all outstanding shares must be redeemed in 2008. Shares previously redeemed may be applied to meet the sinking fund requirement.

See Notes to Respective Financial Statements beginning on page L-1.

APPALACHIAN POWER COMPANY AND SUBSIDIARIES
SCHEDULE OF LONG-TERM DEBT
December 31, 2003 and 2002

First Mortgage Bonds outstanding were as follows:

% Rate	Due	2003	2002
		(in thousands)	
6.00	2003 – November 1	$-	$30,000
7.70	2004 – September 1	21,000	21,000
7.85	2004 – November 1	50,000	50,000
8.00	2005 – May 1	50,000	50,000
6.89	2005 – June 22	30,000	30,000
6.80	2006 – March 1	100,000	100,000
8.50	2022 – December 1	-	70,000
7.80	2023 – May 1	-	30,237
7.15	2023 – November 1	-	20,000
7.125	2024 – May 1	45,000	45,000
8.00	2025 – June 1	45,000	45,000
Unamortized Discount		(731)	(1,540)
Total		$340,269	$489,697

First Mortgage Bonds are secured by a first mortgage lien on electric utility plant. Certain supplemental indentures to the first mortgage lien contain maintenance and replacement provisions requiring the deposit of cash or bonds with the trustee, or in lieu thereof, certification of unfunded property additions.

Installment Purchase Contracts have been entered into, in connection with the issuance of pollution control revenue bonds, by governmental authorities as follows:

	% Rate	Due	2003	2002
			(in thousands)	
Industrial Development Authority of Russell County, Virginia:				
	7.70	2007 – November 1	$-	$17,500
	(a)	2007 – November 1	17,500	-
	5.00	2021 – November 1	19,500	19,500
Putnam County, West Virginia:				
	(b)	2019 – June 1	40,000	-
	6.60	2019 – July 1	-	30,000
	5.45	2019 – June 1	40,000	40,000
	(c)	2019 – May 1	30,000	-
Mason County, West Virginia:				
	7-7/8	2013 – November 1	-	10,000
	6.85	2022 – June 1	-	40,000
	6.60	2022 – October 1	-	50,000
	6.05	2024 – December 1	30,000	30,000
	5.50	2022 – October 1	100,000	-
	Unamortized Discount		(523)	(1,973)
	Total		$276,477	$235,027

(a) Rate is an annual long-term fixed rate of 2.70% through November 1, 2006. After that date the rate may be daily, weekly, commercial paper, auction or other long-term rate as designated by APCo (fixed rate bonds).
(b) In December 2003 an auction rate was established. Auction rates are determined by standard procedures every 35 days. The rate on December 31, 2003 was 1.10%. The proceeds from the issuance were used to redeem the 5.45% Putnam County Installment Purchase Contracts on January 12, 2004.
(c) Rate is an annual long-term fixed rate of 2.80% through November 1, 2006. After that date the rate may be daily, weekly, commercial paper, auction or other long-term rate as designated by APCo (fixed rate bonds).

Under the terms of the installment purchase contracts, APCo is required to pay amounts sufficient to enable the payment of interest on and the principal of (at stated maturities and upon mandatory redemptions) related pollution control revenue bonds issued to finance the construction of pollution control facilities at certain plants.

Senior Unsecured Notes outstanding were as follows:

% Rate	Due	2003	2002
		(in thousands)	
(a)	2003 – August 20	$-	$125,000
7.45	2004 – November 1	50,000	50,000
4.80	2005 – June 15	450,000	450,000
4.32	2007 – November 12	200,000	200,000
3.60	2008 – May 15	200,000	-
6.60	2009 – May 1	150,000	150,000
5.95	2033 – May 15	200,000	-
7.20	2038 – March 31	-	100,000
7.30	2038 – June 30	-	100,000
Unamortized Discount		(5,187)	(8,391)
Total		$1,244,813	$1,166,609

(a) A floating interest rate was determined monthly. The rate on December 31, 2002 was 2.167%.

At December 31, 2003, future annual long-term debt payments are as follows:

	Amount (in thousands)
2004	$161,008
2005	530,010
2006	147,511
2007	200,013
2008	200,014
Later Years	631,966
Total Principal Amount	1,870,522
Unamortized Discount	(6,441)
Total	$1,864,081

APPALACHIAN POWER COMPANY AND SUBSIDIARIES
INDEX TO NOTES TO RESPECTIVE FINANCIAL STATEMENTS

The notes to APCo's consolidated financial statements are combined with the notes to respective financial statements for other subsidiary registrants. Listed below are the notes that apply to APCo. The footnotes begin on page L-1.

INDEPENDENT AUDITORS' REPORT

To the Shareholders and Board of
Directors of Appalachian Power Company:

We have audited the accompanying consolidated balance sheets and consolidated statements of capitalization of Appalachian Power Company and subsidiaries as of December 31, 2003 and 2002, and the related consolidated statements of income, changes in common shareholder's equity and comprehensive income and cash flows for each of the three years in the period ended December 31, 2003. These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements based on our audits.

We conducted our audits in accordance with auditing standards generally accepted in the United States of America. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, such consolidated financial statements present fairly, in all material respects, the financial position of Appalachian Power Company and subsidiaries as of December 31, 2003 and 2002, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2003 in conformity with accounting principles generally accepted in the United States of America.

As discussed in Note 2 to the consolidated financial statements, the Company adopted SFAS 143, "Accounting for Asset Retirement Obligations" and EITF 02-3, "Issues Involved in Accounting for Derivative Contracts Held for Trading Purposes and Contracts Involved in Energy Trading and Risk Management Activities," effective January 1, 2003.

/s/ Deloitte & Touche LLP

Columbus, Ohio
March 5, 2004

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COLUMBUS SOUTHERN POWER COMPANY
AND SUBSIDIARIES

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COLUMBUS SOUTHERN POWER COMPANY AND SUBSIDIARIES
SELECTED CONSOLIDATED FINANCIAL DATA

	2003	2002	2001 (in thousands)	2000	1999
INCOME STATEMENTS DATA					
Operating Revenues	$1,431,851	$1,400,160	$1,350,319	$1,304,409	$1,190,997
Operating Expenses	1,206,365	1,180,381	1,098,142	1,108,532	968,207
Operating Income	225,486	219,779	252,177	195,877	222,790
Nonoperating Items, Net	(1,391)	15,263	7,738	5,153	2,709
Interest Charges	50,948	53,869	68,015	80,828	75,229
Income Before Extraordinary Item and Cumulative Effect	173,147	181,173	191,900	120,202	150,270
Extraordinary Loss (Net of Tax)	-	-	(30,024)	(25,236)	-
Cumulative Effect of Accounting Changes (Net of Tax)	27,283	-	-	-	-
Net Income	200,430	181,173	161,876	94,966	150,270
Preferred Stock Dividend Requirements (including Capital Stock Expense)	1,016	1,365	1,890	1,783	2,131
Earnings Applicable to Common Stock	$199,414	$179,808	$159,986	$93,183	$148,139
BALANCE SHEETS DATA					
Electric Utility Plant	$3,570,443	$3,467,626	$3,354,320	$3,266,794	$3,151,619
Accumulated Depreciation	1,389,586	1,369,153	1,283,712	1,211,728	1,129,007
Net Electric Utility Plant	$2,180,857	$2,098,473	$2,070,608	$2,055,066	$2,022,612
TOTAL ASSETS	$2,838,366	$2,849,261	$2,815,708	$3,965,460	$2,890,610
Common Stock and Paid-in Capital	$617,426	$616,410	$615,395	$614,380	$613,899
Retained Earnings	326,782	290,611	176,103	99,069	246,584
Accumulated Other Comprehensive Income (Loss)	(46,327)	(59,357)	-	-	-
Total Common Shareholder's Equity	$897,881	$847,664	$791,498	$713,449	$860,483
Cumulative Preferred Stock - Subject to Mandatory Redemption (a)	$-	$-	$10,000	$15,000	$25,000
Long-term Debt (a)	$897,564	$621,626	$791,848	$899,615	$924,545
Obligations Under Capital Leases (a)	$15,618	$27,610	$34,887	$42,932	$40,270
TOTAL CAPITALIZATION AND LIABILITIES	$2,838,366	$2,849,261	$2,815,708	$3,965,460	$2,890,610

(a) Including portion due within one year.

COLUMBUS SOUTHERN POWER COMPANY AND SUBSIDIARIES
MANAGEMENT'S NARRATIVE FINANCIAL DISCUSSION AND ANALYSIS

CSPCo is a public utility engaged in the generation and purchase of electric power, and the subsequent sale, transmission and distribution of that power to 698,000 retail customers in central and southern Ohio. As a member of the AEP Power Pool, we share the revenues and the costs of the AEP Power Pool's sales to neighboring utilities and power marketers.

The cost of the AEP Power Pool's generating capacity is allocated among its members based on their relative peak demands and generating reserves through the payment of capacity charges and the receipt of capacity credits. AEP Power Pool members are also compensated for the out-of-pocket costs of energy delivered to the AEP Power Pool and charged for energy received from the AEP Power Pool. The AEP Power Pool calculates each member's prior twelve-month peak demand relative to the sum of the peak demands of all members as a basis for sharing revenues and costs. The result of this calculation is the member load ratio (MLR), which determines each member's percentage share of revenues and costs.

Power and gas risk management activities are conducted on our behalf by AEPSC. We share in the revenues and expenses associated with these risk management activities with other AEP registrant subsidiaries excluding AEGCo under existing power pool and system integration agreements. Risk management activities primarily involve the purchase and sale of electricity under physical forward contracts at fixed and variable prices and to a lesser extent gas. The electricity and gas contracts include physical transactions, over-the-counter options and swaps and exchange traded futures and options. The majority of the physical forward contracts are typically settled by entering into offsetting contracts.

Under our system integration agreement, revenues and expenses from the sales to neighboring utilities, power marketers and other power and gas risk management entities are shared among AEP East and West companies. Sharing in a calendar year is based upon the level of such activities experienced for the twelve months ended June 30, 2000, which immediately preceded the merger of AEP and CSW. This resulted in an AEP East and West companies' allocation of approximately 91% and 9%, respectively, for revenues and expenses. Allocation percentages in any given calendar year may also be based upon the relative generating capacity of the AEP East and West companies in the event the pre-merger activity level is exceeded. The capacity based allocation mechanism was triggered in June 2003, resulting in an allocation factor of approximately 70% and 30% for the AEP East and West companies, respectively, for the remainder of 2003.

Results of Operations

2003 Compared to 2002

The increase in Net Income of $19 million in 2003 compared to 2002 was primarily due to a $32 million increase in operating revenues, a $37 million decrease in income taxes (includes Operating Income Taxes and Nonoperating Income Tax Expense) and a $27 million net-of-tax Cumulative Effect of Accounting Changes, which were partially offset by a $48 million increase in fuel and purchased power expenses and a $34 million decrease in results from risk management activities.

Operating Income

Operating Income increased $6 million primarily due to:

- An increase of $27 million in Sales to AEP Affiliates and an increase of $34 million of wholesale sales to non-affiliates due primarily to an increase in sales of MWH.
- A decrease in Other Operation expense of $19 million primarily due to decreases in factored receivables expenses, AEP transmission equalization expenses and personal injuries and property damage expenses. Administrative and general salaries also decreased due to the impact of cost reduction efforts instituted in the fourth quarter of 2002 and related employment termination benefits recorded in 2002.
- Income Taxes decreased by $20 million primarily due to state income tax return and accrual adjustments.

The increase in Operating Income was partially offset by:

- A decrease of $34 million in retail revenues resulting from milder spring and summer weather and a sluggish economy. A decrease of 42% in cooling degree days from the prior year was partially offset by a 7% increase in heating degree days.
- An increase of $18 million in fuel expense due to a 3% increase in coal costs and a 6% increase in MWH of power generation.
- An increase of $27 million in Purchased Electricity from AEP Affiliates to support wholesale sales to non-affiliated entities.
- An increase of $15 million in Maintenance expense due primarily to boiler overhaul work from scheduled and forced outages and increased maintenance of overhead lines resulting from severe storm damage.

Other Impacts on Earnings

Nonoperating Income decreased $36 million primarily due to lower profit from power sold outside AEP's traditional marketing area resulting from AEP's plan to exit risk management activities in areas outside of its traditional market area.

Nonoperating Income Tax Credit increased due to a decrease in pre-tax nonoperating book income and changes related to consolidated tax savings.

Cumulative Effect of Accounting Changes

The Cumulative Effect of Accounting Changes is due to the one-time, after-tax impact of adopting SFAS 143 and implementing the requirements of EITF 02-3 (see Note 2).

Financial Condition

Credit Ratings

The rating agencies currently have us on stable outlook. Current ratings are as follows:

	Moody's	S&P	Fitch
First Mortgage Bonds	A3	BBB	A
Senior Unsecured Debt	A3	BBB	A-

In February 2003, Moody's Investors Service (Moody's) completed their review of AEP and its rated subsidiaries. The completion of this review was a culmination of ratings action started during 2002. In March 2003, S&P lowered AEP and its subsidiaries senior unsecured ratings from BBB+ to BBB along with the first mortgage bonds of AEP subsidiaries.

Summary Obligation Information

Our contractual obligations include amounts reported on the Consolidated Balance Sheets and other obligations disclosed in the footnotes. The following table summarizes our contractual cash obligations at December 31, 2003:

	Payments Due by Period (in thousands)				
Contractual Cash Obligations	**Less Than 1 year**	**2-3 years**	**4-5 years**	**After 5 years**	**Total**
Long-term Debt	$11,000	$36,000	$112,000	$738,564	$897,564
Advances from Affiliates	6,517	-	-	-	6,517
Capital Lease Obligations	4,959	6,701	3,823	2,096	17,579
Unconditional Purchase Obligations (a)	81,500	9,854	-	-	91,354
Noncancellable Operating Leases	5,078	7,438	3,814	2,726	19,056
Total	$109,054	$59,993	$119,637	$743,386	$1,032,070

(a) Represents contractual obligations to purchase coal as fuel for electric generation along with related transportation of the fuel.

Significant Factors

See the "Registrants' Combined Management's Discussion and Analysis" section beginning on page M-1 for additional discussion of factors relevant to us.

Quantitative And Qualitative Disclosures About Risk Management Activities

Market Risks

Our risk management policies and procedures are instituted and administered at the AEP consolidated level. See complete discussion within AEP's "Qualitative And Quantitative Disclosures About Risk Management Activities" section. The following tables provide information about our risk management activities' effect on this specific registrant.

MTM Risk Management Contract Net Assets

This table provides detail on changes in our MTM net asset or liability balance sheet position from one period to the next.

MTM Risk Management Contract Net Assets
Year Ended December 31, 2003
(in thousands)

<u>**Domestic Power**</u>

Beginning Balance December 31, 2002	$65,117
(Gain) Loss from Contracts Realized/Settled During the Period (a)	(23,010)
Fair Value of New Contracts When Entered Into During the Period (b)	-
Net Option Premiums Paid/(Received) (c)	81
Change in Fair Value Due to Valuation Methodology Changes	-
Effect of EITF 98-10 Rescission (d)	(3,135)
Changes in Fair Value of Risk Management Contracts (e)	(716)
Changes in Fair Value Risk Management Contracts Allocated to Regulated Jurisdictions (f)	-
Total MTM Risk Management Contract Net Assets, Excluding Cash Flow Hedges	38,337
Net Cash Flow Hedge Contracts (g)	311
DETM Assignment (h)	(18,185)
Ending Balance December 31, 2003	$20,463

(a)"(Gain) Loss from Contracts Realized/Settled During the Period" includes realized gains from risk management contracts and related derivatives that settled during 2003 that were entered into prior to 2003.

(b) The "Fair Value of New Contracts When Entered Into During the Period" represents the fair value of long-term contracts entered into with customers during 2003. The fair value is calculated as of the execution of the contract. Most of the fair value comes from longer term fixed price contracts with customers that seek to limit their risk against fluctuating energy prices. The contract prices are valued against market curves associated with the delivery location.

(c)"Net Option Premiums Paid/(Received)" reflects the net option premiums paid/(received) as they relate to unexercised and unexpired option contracts that were entered into in 2003.

(d) See Note 2 "New Accounting Pronouncements, Extraordinary Items and Cumulative Effect of Accounting Changes."

(e)"Changes in Fair Value of Risk Management Contracts" represents the fair value change in the risk management portfolio due to market fluctuations during the current period. Market fluctuations are attributable to various factors such as supply/demand, weather, etc.

(f)"Change in Fair Value of Risk Management Contracts Allocated to Regulated Jurisdictions" relates to the net gains (losses) of those contracts that are not reflected in the Consolidated Statements of Income. These net gains (losses) are recorded as regulatory liabilities/assets for those subsidiaries that operate in regulated jurisdictions.

(g)"Net Cash Flow Hedge Contracts" (pre-tax) are discussed below in Accumulated Other Comprehensive Income (Loss).

(h)See Note 17 "Related Party Transactions."

Maturity and Source of Fair Value of MTM Risk Management Contract Net Assets

The table presenting maturity and source of fair value of MTM risk management contract net assets provides two fundamental pieces of information:

- The source of fair value used in determining the carrying amount of our total MTM asset or liability (external sources or modeled internally).
- The maturity, by year, of our net assets/liabilities, giving an indication of when these MTM amounts will settle and generate cash.

Maturity and Source of Fair Value of MTM
Risk Management Contract Net Assets
Fair Value of Contracts as of December 31, 2003

	2004	2005	2006	2007	2008	After 2008	Total (c)
			(in thousands)				
Prices Actively Quoted – Exchange Traded Contracts	$687	$(138)	$16	$108	$-	$-	$673
Prices Provided by Other External Sources – OTC Broker Quotes (a)	13,378	4,795	4,703	1,911	959	-	25,746
Prices Based on Models and Other Valuation Methods (b)	(3)	20	1,866	2,157	1,984	5,894	11,918
Total	$14,062	$4,677	$6,585	$4,176	$2,943	$5,894	$38,337

(a) "Prices Provided by Other External Sources – OTC Broker Quotes" reflects information obtained from over-the-counter brokers, industry services, or multiple-party on-line platforms.

(b) "Prices Based on Models and Other Valuation Methods" if there is absence of pricing information from external sources, modeled information is derived using valuation models developed by the reporting entity, reflecting when appropriate, option pricing theory, discounted cash flow concepts, valuation adjustments, etc. and may require projection of prices for underlying commodities beyond the period that prices are available from third-party sources. In addition, where external pricing information or market liquidity are limited, such valuations are classified as modeled. The determination of the point at which a market is no longer liquid for placing it in the Modeled category varies by market.

(c) Amounts exclude Cash Flow Hedges.

Cash Flow Hedges Included in Accumulated Other Comprehensive Income (Loss) (AOCI) on the Balance Sheet

The table provides detail on effective cash flow hedges under SFAS 133 included in the balance sheet. The data in the table will indicate the magnitude of SFAS 133 hedges we have in place. (However, given that under SFAS 133 only cash flow hedges are recorded in AOCI, the table does not provide an all-encompassing picture of our hedging activity). The table also includes a roll-forward of the AOCI balance sheet account, providing insight into the drivers of the changes (new hedges placed during the period, changes in value of existing hedges and roll-off of hedges). In accordance with GAAP, all amounts are presented net of related income taxes.

Total Accumulated Other Comprehensive Income (Loss) Activity
Year Ended December 31, 2003

	Domestic Power (in thousands)
Beginning Balance December 31, 2002	$(267)
Changes in Fair Value (a)	194
Reclassifications from AOCI to Net Income (b)	275
Ending Balance December 31, 2003	$ 202

(a) "Changes in Fair Value" shows changes in the fair value of derivatives designated as hedging instruments in cash flow hedges during the reporting period not yet reclassified into net income, pending the hedged item's affecting net income. Amounts are reported net of related income taxes.
(b) "Reclassifications from AOCI to Net Income" represents gains or losses from derivatives used as hedging instruments in cash flow hedges that were reclassified into net income during the reporting period. Amounts are reported net of related income taxes above.

The portion of cash flow hedges in AOCI expected to be reclassified to earnings during the next twelve months is a $940 thousand gain.

Credit Risk

Our counterparty credit quality and exposure is generally consistent with that of AEP.

VaR Associated with Energy and Gas Risk Management Contracts

The following table shows the end, high, average, and low market risk as measured by VaR for year-to-date:

December 31, 2003 (in thousands)				December 31, 2002 (in thousands)			
End	High	Average	Low	End	High	Average	Low
$336	$1,303	$546	$130	$867	$2,654	$949	$192

VaR Associated with Debt Outstanding

The risk of potential loss in fair value attributable to our exposure to interest rates, primarily related to long-term debt with fixed interest rates was $98 million and $33 million at December 31, 2003 and 2002, respectively. We would not expect to liquidate our entire debt portfolio in a one-year holding period, therefore a near term change in interest rates should not negatively affect our results of operation or consolidated financial position.

COLUMBUS SOUTHERN POWER COMPANY AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF INCOME
For the Years Ended December 31, 2003, 2002 and 2001

	2003	2002 (in thousands)	2001
OPERATING REVENUES			
Electric Generation, Transmission and Distribution	$1,347,482	$1,342,958	$1,282,808
Sales to AEP Affiliates	84,369	57,202	67,511
TOTAL	1,431,851	1,400,160	1,350,319
OPERATING EXPENSES			
Fuel for Electric Generation	203,399	185,086	175,153
Purchased Electricity for Resale	17,730	15,023	10,957
Purchased Electricity from AEP Affiliates	337,323	310,605	292,199
Other Operation	218,466	237,802	219,497
Maintenance	75,319	60,003	62,454
Depreciation and Amortization	135,964	131,624	127,364
Taxes Other Than Income Taxes	133,754	136,024	111,481
Income Taxes	84,410	104,214	99,037
TOTAL	1,206,365	1,180,381	1,098,142
OPERATING INCOME	225,486	219,779	252,177
Nonoperating Income (Loss)	(7,489)	28,280	34,656
Nonoperating Expenses	4,650	6,228	22,995
Nonoperating Income Tax Expense (Credit)	(10,748)	6,789	3,923
Interest Charges	50,948	53,869	68,015
Income Before Extraordinary Item and Cumulative Effect of Accounting Changes	173,147	181,173	191,900
Extraordinary Loss – Discontinuance of Regulatory Accounting for Generation – Net of Tax (Note 2)	-	-	(30,024)
Cumulative Effect of Accounting Changes (Net of Tax)	27,283	-	-
NET INCOME	200,430	181,173	161,876
Preferred Stock Dividend Requirements (Including Capital Stock Expense)	1,016	1,365	1,890
EARNINGS APPLICABLE TO COMMON STOCK	$199,414	$179,808	$159,986

The common stock of CSPCo is wholly-owned by AEP.

See Notes to Respective Financial Statements beginning on Page L-1.

COLUMBUS SOUTHERN POWER COMPANY AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF CHANGES IN COMMON SHAREHOLDER'S EQUITY AND COMPREHENSIVE INCOME
For the Years Ended December 31, 2003, 2002 and 2001
(in thousands)

	Common Stock	Paid-in Capital	Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Total
DECEMBER 31, 2000	$41,026	$573,354	$99,069	$-	$713,449
Common Stock Dividends Declared			(82,952)		(82,952)
Preferred Stock Dividends Declared			(875)		(875)
Capital Stock Expense		1,015	(1,015)		-
TOTAL					629,622
COMPREHENSIVE INCOME					
NET INCOME			161,876		161,876
TOTAL COMPREHENSIVE INCOME					161,876
DECEMBER 31, 2001	$41,026	$574,369	$176,103	$-	$791,498
Common Stock Dividends Declared			(65,300)		(65,300)
Preferred Stock Dividends Declared			(350)		(350)
Capital Stock Expense		1,015	(1,015)		-
TOTAL					725,848
COMPREHENSIVE INCOME					
Other Comprehensive Income, Net of Taxes:					
Unrealized Loss on Cash Flow Power Hedges				(267)	(267)
Minimum Pension Liability				(59,090)	(59,090)
NET INCOME			181,173		181,173
TOTAL COMPREHENSIVE INCOME					121,816
DECEMBER 31, 2002	$41,026	$575,384	$290,611	$(59,357)	$847,664
Common Stock Dividends Declared			(163,243)		(163,243)
Capital Stock Expense		1,016	(1,016)		-
TOTAL					684,421
COMPREHENSIVE INCOME					
Other Comprehensive Income, Net of Taxes:					
Unrealized Gain on Cash Flow Power Hedges				469	469
Minimum Pension Liability				12,561	12,561
NET INCOME			200,430		200,430
TOTAL COMPREHENSIVE INCOME					213,460
DECEMBER 31, 2003	$41,026	$576,400	$326,782	$(46,327)	$897,881

See Notes to Respective Financial Statements beginning on page L-1.

COLUMBUS SOUTHERN POWER COMPANY AND SUBSIDIARIES
CONSOLIDATED BALANCE SHEETS
ASSETS
December 31, 2003 and 2002

	2003	2002
	(in thousands)	
ELECTRIC UTILITY PLANT		
Production	$1,610,888	$1,582,627
Transmission	425,512	413,286
Distribution	1,253,760	1,208,255
General	166,002	165,025
Construction Work in Progress	114,281	98,433
TOTAL	3,570,443	3,467,626
Accumulated Depreciation and Amortization	1,389,586	1,369,153
TOTAL - NET	2,180,857	2,098,473
OTHER PROPERTY AND INVESTMENTS		
Non-Utility Property, Net	22,417	23,680
Other Investments	8,663	12,079
TOTAL	31,080	35,759
CURRENT ASSETS		
Cash and Cash Equivalents	4,142	1,479
Advances to Affiliates, Net	-	31,257
Accounts Receivable:		
Customers	47,099	70,704
Affiliated Companies	68,168	54,518
Accrued Unbilled Revenues	23,723	12,671
Miscellaneous	5,257	867
Allowance for Uncollectible Accounts	(531)	(634)
Fuel	14,365	24,844
Materials and Supplies	44,377	40,339
Risk Management Assets	40,095	63,197
Margin Deposits	6,636	824
Prepayments and Other	12,444	6,635
TOTAL	265,775	306,701
DEFERRED DEBITS AND OTHER ASSETS		
Regulatory Assets:		
SFAS 109 Regulatory Assets, Net	16,027	26,290
Transition Regulatory Assets	188,532	204,961
Unamortized Loss on Reacquired Debt	13,659	5,978
Other	24,966	20,453
Long-term Risk Management Assets	39,932	77,810
Deferred Property Taxes	62,262	61,733
Deferred Charges	15,276	11,103
TOTAL	360,654	408,328
TOTAL ASSETS	$2,838,366	$2,849,261

See Notes to Respective Financial Statements beginning on page L-1.

COLUMBUS SOUTHERN POWER COMPANY AND SUBSIDIARIES
CONSOLIDATED BALANCE SHEETS
CAPITALIZATION AND LIABILITIES
December 31, 2003 and 2002

	2003	2002
	(in thousands)	
CAPITALIZATION		
Common Shareholder's Equity:		
Common Stock – No Par Value:		
Authorized – 24,000,000 Shares		
Outstanding – 16,410,426 Shares	$41,026	$41,026
Paid-in Capital	576,400	575,384
Retained Earnings	326,782	290,611
Accumulated Other Comprehensive Income (Loss)	(46,327)	(59,357)
Total Common Shareholder's Equity	897,881	847,664
Long-term Debt:		
Nonaffiliated	886,564	418,626
Affiliated	-	160,000
Total Long-term Debt	886,564	578,626
TOTAL	1,784,445	1,426,290
CURRENT LIABILITIES		
Short-term Debt – Affiliates	-	290,000
Long-term Debt Due Within One Year - Nonaffiliated	11,000	43,000
Advances from Affiliates, Net	6,517	-
Accounts Payable:		
General	58,220	89,736
Affiliated Companies	53,572	81,599
Customer Deposits	19,727	14,719
Taxes Accrued	132,853	112,172
Interest Accrued	16,528	9,798
Risk Management Liabilities	28,966	46,375
Obligations Under Capital Leases	4,221	5,967
Other	25,364	16,104
TOTAL	356,968	709,470
DEFERRED CREDITS AND OTHER LIABILITIES		
Deferred Income Taxes	458,498	437,771
Regulatory Liabilities:		
Asset Removal Costs	99,119	-
Deferred Investment Tax Credits	30,797	33,907
Long-term Risk Management Liabilities	30,598	29,926
Obligations Under Capital Leases	11,397	21,643
Asset Retirement Obligations	8,740	-
Deferred Credits and Other	57,804	190,254
TOTAL	696,953	713,501
Commitments and Contingencies (Note 7)		
TOTAL CAPITALIZATION AND LIABILITIES	$2,838,366	$2,849,261

See Notes to Respective Financial Statements beginning on page L-1.

COLUMBUS SOUTHERN POWER COMPANY AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF CASH FLOWS
For the Years Ended December 31, 2003, 2002 and 2001

	2003	2002 (in thousands)	2001
OPERATING ACTIVITIES			
Net Income	$200,430	$181,173	$161,876
Adjustments to Reconcile Net Income to Net Cash Flows From Operating Activities:			
Cumulative Effect of Accounting Changes	(27,283)	-	-
Depreciation and Amortization	135,964	131,753	128,500
Deferred Income Taxes	(4,514)	23,292	24,108
Deferred Investment Tax Credits	(3,110)	(3,269)	(4,058)
Mark-to-Market of Risk Management Contracts	41,830	(16,667)	(44,680)
Extraordinary Loss	-	-	30,024
Changes in Certain Assets and Liabilities:			
Accounts Receivable, Net	(5,590)	(9,576)	22,538
Fuel, Materials and Supplies	6,441	(6,180)	(7,780)
Accounts Payable	(59,543)	26,949	(16,249)
Taxes Accrued	20,681	(4,192)	(46,540)
Interest Accrued	6,730	(1,108)	(2,462)
Deferred Property Tax	(529)	(13,732)	22,920
Change in Other Assets	(20,563)	5,705	(14)
Change in Other Liabilities	(8,762)	(17,148)	(34,739)
Net Cash Flows From Operating Activities	282,182	297,000	233,444
INVESTING ACTIVITIES			
Construction Expenditures	(136,291)	(136,800)	(132,532)
Proceeds from Sale of Property	1,644	730	10,841
Net Cash Flows Used For Investing Activities	(134,647)	(136,070)	(121,691)
FINANCING ACTIVITIES			
Issuance of Long-term Debt – Affiliated	-	160,000	200,000
Issuance of Long-term Debt – Nonaffiliated	643,097	-	-
Change in Advances to/from Affiliates, Net	37,774	(212,641)	92,652
Retirement of Long-term Debt – Nonaffiliated	(212,500)	(133,343)	(314,733)
Retirement of Long-term Debt – Affiliated	(160,000)	(200,000)	-
Retirement of Cumulative Preferred Stock	-	(10,000)	(5,000)
Change in Short-term Debt – Affiliates	(290,000)	290,000	-
Dividends Paid on Common Stock	(163,243)	(65,300)	(82,952)
Dividends Paid on Cumulative Preferred Stock	-	(525)	(962)
Net Cash Flows Used For Financing Activities	(144,872)	(171,809)	(110,995)
Net Increase (Decrease) in Cash and Cash Equivalents	2,663	(10,879)	758
Cash and Cash Equivalents at Beginning of Period	1,479	12,358	11,600
Cash and Cash Equivalents at End of Period	$4,142	$1,479	$12,358

SUPPLEMENTAL DISCLOSURE:
Cash paid for interest net of capitalized amounts was $42,601,000, $53,514,000 and $68,596,000 and for income taxes was $63,907,000, $117,591,000 and $80,485,000 in 2003, 2002 and 2001, respectively. Non-cash acquisitions under capital leases was $1,019,000 in 2001. There were no non-cash capital lease acquisitions in 2003 or 2002.

See Notes to Respective Financial Statements beginning on page L-1.

COLUMBUS SOUTHERN POWER COMPANY AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF CAPITALIZATION
December 31, 2003 and 2002

	2003	2002
	(in thousands)	
COMMON SHAREHOLDER'S EQUITY	$897,881	$847,664
PREFERRED STOCK (a)		
LONG-TERM DEBT (See Schedule of Long-term Debt):		
First Mortgage Bonds	10,944	222,797
Installment Purchase Contracts	91,329	91,275
Senior Unsecured Notes	795,291	147,554
Notes – Affiliated	-	160,000
Less Portion Due Within One Year	(11,000)	(43,000)
Total Long-term Debt Excluding Portion Due Within One Year	886,564	578,626
TOTAL CAPITALIZATION	$1,784,445	$1,426,290

(a) At December 31, 2003 and 2002 there were no shares outstanding, 2,500,000 authorized shares at $100 par value and 7,000,000 authorized shares at $25 par value.

See Notes to Respective Financial Statements beginning on page L-1.

COLUMBUS SOUTHERN POWER COMPANY AND SUBSIDIARIES
SCHEDULE OF LONG-TERM DEBT
December 31, 2003 and 2002

First Mortgage Bonds outstanding were as follows:

% Rate	Due	2003	2002
		(in thousands)	
6.80	2003 – May 1	$-	$13,000
6.60	2003 – August 1	-	25,000
6.10	2003 – November 1	-	5,000
6.55	2004 – March 1	-	26,500
6.75	2004 – May 1	-	26,000
8.70	2022 – July 1	-	2,000
8.55	2022 – August 1	-	15,000
8.40	2022 – August 15	-	14,000
8.40	2022 – October 15	-	13,000
7.90	2023 – May 1	-	40,000
7.75	2023 – August 1	-	33,000
7.60	2024 – May 1 (a)	11,000	11,000
Unamortized Discount		(56)	(703)
Total		$10,944	$222,797

(a) This bond will be redeemed in May 2004 and has been classified for payment in 2004.

First Mortgage Bonds are secured by a first mortgage lien on electric utility plant. Certain supplemental indentures to the first mortgage lien contain maintenance and replacement provisions requiring the deposit of cash or bonds with the trustee, or in lieu thereof, certification of unfunded property additions. Interest payments are made semi-annually.

Installment Purchase Contracts have been entered into in connection with the issuance of pollution control revenue bonds by the Ohio Air Quality Development Authority:

% Rate	Due	2003	2002
		(in thousands)	
6.375	2020 - December 1	$48,550	$48,550
6.25	2020 - December 1	43,695	43,695
Unamortized Discount		(916)	(970)
Total		$91,329	$91,275

Under the terms of the Installment Purchase Contracts, CSPCo is required to pay amounts sufficient to enable the payment of interest on and the principal of (at stated maturities and upon mandatory redemptions) related pollution control revenue bonds issued to finance the construction of pollution control facilities at the Zimmer Plant. Interest payments are made semi-annually.

Senior Unsecured Notes outstanding were as follows:

% Rate	Due	2003	2002
		(in thousands)	
6.85	2005 – October 3	$36,000	$36,000
6.51	2008 – February 1	52,000	52,000
6.55	2008 – June 26	60,000	60,000
4.40	2010 – December 1	150,000	-
5.50	2013 – March 1	250,000	-
6.60	2033 – March 1	250,000	-
Unamortized Discount		(2,709)	(446)
Total		$795,291	$147,554

Notes Payable to parent company were as follows:

% Rate	Due	2003	2002
		(in thousands)	
6.501%	2006 – May 15	$ -	$160,000

At December 31, 2003, future annual long-term debt payments are as follows:

	Amount (in thousands)
2004	$11,000
2005	36,000
2006	-
2007	-
2008	112,000
Later Years	742,245
Total Principal Amount	901,245
Unamortized Discount	(3,681)
Total	$897,564

COLUMBUS SOUTHERN POWER COMPANY AND SUBSIDIARIES
INDEX TO NOTES TO RESPECTIVE FINANCIAL STATEMENTS

The notes to CSPCo's consolidated financial statements are combined with the notes to respective financial statements for other subsidiary registrants. Listed below are the notes that apply to CSPCo. The footnotes begin on page L-1.

INDEPENDENT AUDITORS' REPORT

To the Shareholder and Board of Directors
of Columbus Southern Power Company:

We have audited the accompanying consolidated balance sheets and consolidated statements of capitalization of Columbus Southern Power Company and subsidiaries as of December 31, 2003 and 2002, and the related consolidated statements of income, changes in common shareholder's equity and comprehensive income and cash flows for each of the three years in the period ended December 31, 2003. These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements based on our audits.

We conducted our audits in accordance with auditing standards generally accepted in the United States of America. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, such consolidated financial statements present fairly, in all material respects, the financial position of Columbus Southern Power Company and subsidiaries as of December 31, 2003 and 2002, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2003 in conformity with accounting principles generally accepted in the United States of America.

As discussed in Note 2 to the consolidated financial statements, the Company adopted SFAS 143, "Accounting for Asset Retirement Obligations" and EITF 02-3, "Issues Involved in Accounting for Derivative Contracts Held for Trading Purposes and Contracts Involved in Energy Trading and Risk Management Activities," effective January 1, 2003.

/s/ Deloitte & Touche LLP

Columbus, Ohio
March 5, 2004

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INDIANA MICHIGAN POWER COMPANY
AND SUBSIDIARIES

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INDIANA MICHIGAN POWER COMPANY AND SUBSIDIARIES
SELECTED CONSOLIDATED FINANCIAL DATA

	2003	2002	2001 (in thousands)	2000	1999
INCOME STATEMENTS DATA					
Operating Revenues	$1,595,596	$1,526,764	$1,526,997	$1,488,209	$1,351,666
Operating Expenses	1,409,529	1,375,575	1,367,292	1,522,911	1,243,014
Operating Income (Loss)	186,067	151,189	159,705	(34,702)	108,652
Nonoperating Items, Net	(13,465)	16,726	9,730	9,933	4,530
Interest Charges	83,054	93,923	93,647	107,263	80,406
Net Income (Loss) Before Cumulative Effect of Accounting Change	89,548	73,992	75,788	(132,032)	32,776
Cumulative Effect of Accounting Change (Net of Tax)	(3,160)	-	-	-	-
Net Income (Loss)	86,388	73,992	75,788	(132,032)	32,776
Preferred Stock Dividend Requirements (Including Capital Stock Expense)	2,509	4,601	4,621	4,624	4,885
Earnings (Loss) Applicable to Common Stock	$83,879	$69,391	$71,167	$(136,656)	$27,891
BALANCE SHEETS DATA					
Electric Utility Plant	$5,306,182	$5,029,958	$4,923,721	$4,871,473	$4,770,027
Accumulated Depreciation and Amortization	2,490,912	2,318,063	2,198,524	2,057,542	1,981,430
Net Electric Utility Plant	$2,815,270	$2,711,895	$2,725,197	$2,813,931	$2,788,597
TOTAL ASSETS	$4,659,071	$4,837,732	$4,632,510	$5,997,087	$4,788,177
Common Stock and Paid-in Capital	$915,278	$915,144	$789,800	$789,656	$789,323
Retained Earnings	187,875	143,996	74,605	3,443	166,389
Accumulated Other Comprehensive Income (Loss)	(25,106)	(40,487)	(3,835)	-	-
Total Common Shareholder's Equity	$1,078,047	$1,018,653	$860,570	$793,099	$955,712
Cumulative Preferred Stock:					
Not Subject to Mandatory Redemption	$8,101	$8,101	$8,736	$8,736	$9,248
Subject to Mandatory Redemption (a)	63,445	64,945	64,945	64,945	64,945
Total Cumulative Preferred Stock	$71,546	$73,046	$73,681	$73,681	$74,193
Long-term Debt (a)	$1,339,359	$1,617,062	$1,652,082	$1,388,939	$1,324,326
Obligations Under Capital Leases (a)	$37,843	$50,848	$61,933	$163,173	$187,965
TOTAL CAPITALIZATION AND LIABILITIES	$4,659,071	$4,837,732	$4,632,510	$5,997,087	$4,788,177

(a) Including portion due within one year.

INDIANA MICHIGAN POWER COMPANY AND SUBSIDIARIES
MANAGEMENT'S FINANCIAL DISCUSSION AND ANALYSIS

We are a public utility engaged in the generation and purchase of electric power, and the subsequent sale, transmission and distribution of that power to 575,000 retail customers in our service territory in northern and eastern Indiana and a portion of southwestern Michigan. As a member of the AEP Power Pool, we share the revenues and the costs of the AEP Power Pool's sales to neighboring utilities and power marketers. We also sell power at wholesale to municipalities and electric cooperatives.

The cost of the AEP Power Pool's generating capacity is allocated among its members based on their relative peak demands and generating reserves through the payment of capacity charges and the receipt of capacity revenues. AEP Power Pool members are also compensated for the out-of-pocket costs of energy delivered to the AEP Power Pool and charged for energy received from the AEP Power Pool. The AEP Power Pool calculates each member's prior twelve-month peak demand relative to the sum of the peak demands of all members as a basis for sharing revenues and costs. The result of this calculation is the member load ratio (MLR), which determines each member's percentage share of revenues and costs.

Power and gas risk management activities are conducted on our behalf by AEPSC. We share in the revenues and expenses associated with these risk management activities with other AEP registrant subsidiaries excluding AEGCo under existing power pool and system integration agreements. Risk management activities primarily involve the purchase and sale of electricity under physical forward contracts at fixed and variable prices and to a lesser extent gas. The electricity and gas contracts include physical transactions, over-the-counter options and swaps and exchange traded futures and options. The majority of the physical forward contracts are typically settled by entering into offsetting contracts.

Under our system integration agreement, revenues and expenses from the sales to neighboring utilities, power marketers and other power and gas risk management entities are shared among AEP East and West companies. Sharing in a calendar year is based upon the level of such activities experienced for the twelve months ended June 30, 2000, which immediately preceded the merger of AEP and CSW. This resulted in an AEP East and West companies' allocation of approximately 91% and 9%, respectively, for revenues and expenses. Allocation percentages in any given calendar year may also be based upon the relative generating capacity of the AEP East and West companies in the event the pre-merger activity level is exceeded. The capacity based allocation mechanism was triggered in June 2003, resulting in an allocation factor of approximately 70% and 30% for the AEP East and West companies, respectively, for the remainder of 2003.

Results of Operations

During 2003, Net Income increased $12 million including an unfavorable $3 million Cumulative Effect of Accounting Change (see Note 2). During 2003, Net Income Before Cumulative Effect of Accounting Change increased $15 million due to reduced financing costs and an improvement in Operating Income resulting from higher margins on wholesale sales and lower Other Operation expense.

During 2002, Net Income decreased by $2 million due to increased operations and maintenance costs incurred as part of planned and unplanned outages at Cook and Rockport plants.

2003 Compared to 2002

Operating Income

Operating Income increased $35 million primarily due to:

- Increased wholesale sales of $69 million including system and power optimization sales, transmission revenues and risk management activities reflecting availability of AEP's generation and market conditions.
- Increased Sales to AEP Affiliates of $35 million due to increased capacity revenue.
- Decreased Other Operations expense of $45 million due primarily to the impact of cost reduction efforts instituted in the fourth quarter of 2002 and related employment termination benefits of $15 million recorded in 2002.

The increase in Operating Income was partially offset by:

- Decreased retail revenues of $37 million due primarily to milder summer weather and economic pressures on industrial customers. Cooling degree days declined approximately 42% this year compared with last year. Industrial revenues dropped 3% from prior year.
- Increased Fuel for Electric Generation expense of $11 million reflecting an increase in the average cost of fuel and increased coal-fired generation in 2003 as Rockport's availability increased.
- Increased Purchased Electricity from AEP Affiliates of $41 million due to purchasing more power from the AEP Power Pool to support wholesale sales to unaffiliated entities.
- Increased Income Tax expense of $12 million reflecting an increase in pre-tax operating income partially offset by temporary differences accounted for on a flow-through basis and tax return adjustments.

Other Impacts on Earnings

Nonoperating Income decreased $30 million primarily due to lower margins for power sold outside of AEP's traditional market reflecting AEP's plan to exit those risk management activities.

Nonoperating Expenses increased $16 million primarily due to a $10 million write-down of western coal lands (see Note 10).

Nonoperating Income Taxes decreased $16 million reflecting the decrease in pre-tax nonoperating income.

Interest Charges decreased $11 million primarily due to a reduction in outstanding long-term debt of $255 million which was retired in May 2003 using lower rate short-term debt.

Cumulative Effect of Accounting Change

The Cumulative Effect of Accounting Change is due to the implementation of the requirements of EITF 02-3 (see Note 2).

<u>2002 Compared to 2001</u>

Operating Income

Operating Income decreased $9 million primarily due to:

- Decreased Sales to AEP Affiliates of $41 million reflecting less energy to sell due to outages. In 2002, both units of Cook plant were shut down for refueling and both Rockport units were down for planned boiler maintenance.
- Increased Other Operation expense of $14 million due to increased costs for pensions, insurance and other benefits.
- Increased Maintenance expense of $24 million reflecting two nuclear refueling outages in 2002.

The decrease in Operating Income was partially offset by:

- Increased Retail revenues of $35 million reflecting a 4% increase in sales.
- Decreased Fuel for Electric Generation expense of $11 million reflecting a decline in the average cost of fuel and decreased nuclear generation.
- An $8 million decrease in Taxes Other Than Income Taxes reflects a favorable tax law change in Indiana effective March 2002.
- Decreased Income Taxes of $15 million reflecting a decrease in pre-tax operating income.

Other Impacts on Earnings

Nonoperating Expenses decreased $10 million due to a decrease in trading overheads and traders' incentive compensation.

Financial Condition

Credit Ratings

The rating agencies currently have us on stable outlook. Current ratings are as follows:

	Moody's	S&P	Fitch
First Mortgage Bonds	Baa1	BBB	BBB+
Senior Unsecured Debt	Baa2	BBB	BBB

During the first quarter of 2003, Moody's Investors Service (Moody's), Standard & Poors (S&P) and Fitch Rating Service completed their reviews of AEP and its rated subsidiaries. The reviews resulted in downgrades of debt ratings. The completion of these reviews was a culmination of ratings action started during 2002.

Cash Flow

Cash flows for 2003, 2002 and 2001 were as follows:

	2003	2002 (in thousands)	2001
Cash and cash equivalents at beginning of period	$3,237	$16,804	$14,835
Cash flow from (used for):			
Operating activities	222,773	228,234	236,207
Investing activities	(182,703)	(165,725)	(182,594)
Financing activities	(39,393)	(76,076)	(51,644)
Net increase (decrease) in cash and cash equivalents	677	(13,567)	1,969
Cash and cash equivalents at end of period	$3,914	$3,237	$16,804

Operating Activities

Operating activities during 2003 provided $5 million less cash than during 2002 which was $8 million less than during 2001 largely due to working capital requirements and changes in mark-to-market of risk management contracts.

Investing Activities

Cash flows used for investing activities during 2003 were $183 million compared to $166 million during 2002. The primary reason for the year-over-year variance was increased construction expenditures of $17 million. Construction expenditures increased $76 million comparing 2002 with 2001. In 2001, we bought out nuclear fuel leases using $93 million of operating cash. Construction expenditures for the nuclear plant and transmission and distribution assets are to upgrade or replace equipment and improve reliability.

Financing Activities

Financing activities for 2003 used $39 million of cash from operations primarily to pay common dividends. During 2003, we redeemed $285 million of long-term debt using short-term debt and refinanced $65 million of our installment purchase contracts at lower fixed rates until October 2006.

During 2002, we redeemed $340 million of long-term debt and $145 million of short-term debt using cash from operations, a $125 million capital contribution from our parent company and proceeds from the issuance of $300 million of long-term debt.

During 2001, we issued $300 million of long-term debt to reduce short-term debt.

Financing Activity

Long-term debt issuances and retirements during 2003 were:

Issuances

Type of Debt	Principal Amount (in millions)	Interest Rate (%)	Due Date
Installment Purchase Contracts	$25	2.625(a)	2019
Installment Purchase Contracts	40	2.625(a)	2025

(a) Fixed Until October 1, 2006

Retirements

Type of Debt	Principal Amount (in millions)	Interest Rate (%)	Due Date
First Mortgage Bonds	$30	6.10	2003
First Mortgage Bonds	75	8.50	2022
First Mortgage Bonds	15	7.35	2023
Junior Debentures	40	8.00	2026
Junior Debentures	125	7.60	2038
Installment Purchase Contracts	25	7.00	2015
Installment Purchase Contracts	40	7.60	2016

Off-Balance Sheet Arrangements

We enter into off-balance sheet arrangements for various reasons including accelerating cash collections, reducing operational expenses and spreading risk of loss to third parties. The following identifies significant off-balance sheet arrangements:

Rockport Plant Unit 2

AEGCo and I&M entered into a sale and leaseback transaction in 1989 with Wilmington Trust Company (Owner Trustee), an unrelated unconsolidated trustee for Rockport Plant Unit 2 (the plant). The Owner Trustee was capitalized with equity from six owner participants with no relationship to AEP or any of its subsidiaries and debt from a syndicate of banks and certain institutional investors. The future minimum lease payments for each respective company are $1.4 billion.

The FASB and other accounting constituencies continue to interpret the application of FIN 46 (revised December 2003) (FIN 46R). As a result, we are continuing to review the application of this new interpretation as it relates to the Rockport Plant Unit 2 transaction.

The gain from the sale was deferred and is being amortized over the term of the lease, which expires in 2022. The Owner Trustee owns the plant and leases it to AEGCo and I&M. The lease is accounted for as an operating lease with the payment obligations included in the lease footnote. The lease term is for 33 years with potential renewal options. At the end of the lease term, AEGCo and I&M have the option to renew the lease or the Owner Trustee can sell the plant. Neither AEGCo, I&M nor AEP has an ownership interest in the Owner Trustee and none of these entities guarantee its debt.

Summary Obligation Information

Our contractual obligations include amounts reported on the Consolidated Balance Sheets and other obligations disclosed in the footnotes. The following table summarizes our contractual cash obligations at December 31, 2003:

	Payments Due by Period (in millions)				
Contractual Cash Obligations	**Less Than 1 year**	**2-3 years**	**4–5 years**	**After 5 years**	**Total**
Long-term Debt	$205	$365	$100	$669	$1,339
Advances from Affiliates	99	-	-	-	99
Preferred Stock Subject to Mandatory Redemption	-	-	16	47	63
Capital Lease Obligations	10	14	16	6	46
Unconditional Purchase Obligations (a)	107	89	82	161	439
Noncancellable Operating Leases	104	191	182	1,097	1,574
Total	$525	$659	$396	$1,980	$3,560

(a) Represents contractual obligations to purchase coal as fuel for electric generation along with related transportation of the fuel.

Some of the transactions, described under "Off-Balance Sheet Arrangements" above, have been employed for a contractual cash obligation reported in the above table. The lease of Rockport Unit 2 is reported in Noncancellable Operating Leases.

Significant Factors

See the "Registrants' Combined Management's Discussion and Analysis" section beginning on page M-1 for additional discussion of factors relevant to us.

Quantitative And Qualitative Disclosures About Risk Management Activities

Market Risks

Our risk management policies and procedures are instituted and administered at the AEP consolidated level. See complete discussion within AEP's "Qualitative And Quantitative Disclosures About Risk Management Activities" section. The following tables provide information about our risk management activities' effect on this specific registrant.

MTM Risk Management Contract Net Assets

This table provides detail on changes in our MTM net asset or liability balance sheet position from one period to the next.

MTM Risk Management Contract Net Assets
Year Ended December 31, 2003
(in thousands)

Domestic Power	
Beginning Balance December 31, 2002	$70,861
(Gain) Loss from Contracts Realized/Settled During the Period (a)	(18,666)
Fair Value of New Contracts When Entered Into During the Period (b)	-
Net Option Premiums Paid/(Received) (c)	88
Change in Fair Value Due to Valuation Methodology Changes	-
Effect of EITF 98-10 Rescission (d)	(4,861)
Changes in Fair Value of Risk Management Contracts (e)	765
Changes in Fair Value Risk Management Contracts Allocated to Regulated Jurisdictions (f)	(6,192)
Total MTM Risk Management Contract Net Assets, Excluding Cash Flow Hedges	41,995
Net Cash Flow Hedge Contracts (g)	341
DETM Assignment (h)	(19,932)
Ending Balance December 31, 2003	$22,404

(a)"(Gain) Loss from Contracts Realized/Settled During the Period" includes realized gains from risk management contracts and related derivatives that settled during 2003 that were entered into prior to 2003.

(b) The "Fair Value of New Contracts When Entered Into During the Period" represents the fair value of long-term contracts entered into with customers during 2003. The fair value is calculated as of the execution of the contract. Most of the fair value comes from longer term fixed price contracts with customers that seek to limit their risk against fluctuating energy prices. The contract prices are valued against market curves associated with the delivery location.

(c)"Net Option Premiums Paid/(Received)" reflects the net option premiums paid/(received) as they relate to unexercised and unexpired option contracts that were entered into in 2003.

(d) See Note 2 "New Accounting Pronouncements, Extraordinary Items and Cumulative Effect of Accounting Changes."

(e)"Changes in Fair Value of Risk Management Contracts" represents the fair value change in the risk management portfolio due to market fluctuations during the current period. Market fluctuations are attributable to various factors such as supply/demand, weather, etc.

(f)"Change in Fair Value of Risk Management Contracts Allocated to Regulated Jurisdictions" relates to the net gains (losses) of those contracts that are not reflected in the Consolidated Statements of Income. These net gains (losses) are recorded as regulatory liabilities/assets for those subsidiaries that operate in regulated jurisdictions.

(g)"Net Cash Flow Hedge Contracts" (pre-tax) are discussed below in Accumulated Other Comprehensive Income (Loss).

(h)See Note 17 "Related Party Transactions."

Maturity and Source of Fair Value of MTM Risk Management Contract Net Assets

The table presenting maturity and source of fair value of MTM risk management contract net assets provides two fundamental pieces of information:

- The source of fair value used in determining the carrying amount of our total MTM asset or liability (external sources or modeled internally).
- The maturity, by year, of our net assets/liabilities, giving an indication of when these MTM amounts will settle and generate cash.

Maturity and Source of Fair Value of MTM
Risk Management Contract Net Assets
Fair Value of Contracts as of December 31, 2003

	2004	2005	2006	2007	2008	After 2008	Total (c)
			(in thousands)				
Prices Actively Quoted – Exchange Traded Contracts	$753	$(151)	$18	$118	$-	$-	$738
Prices Provided by Other External Sources – OTC Broker Quotes (a)	14,786	5,256	5,154	2,095	1,051	-	28,342
Prices Based on Models and Other Valuation Methods (b)	(151)	23	2,045	2,364	2,174	6,460	12,915
Total	$15,388	$5,128	$7,217	$4,577	$3,225	$6,460	$41,995

(a) "Prices Provided by Other External Sources" reflects information obtained from over-the-counter brokers, industry services, or multiple-party on-line platforms.
(b) "Prices Based on Models and Other Valuation Methods" is in absence of pricing information from external sources, modeled information is derived using valuation models developed by the reporting entity, reflecting when appropriate, option pricing theory, discounted cash flow concepts, valuation adjustments, etc. and may require projection of prices for underlying commodities beyond the period that prices are available from third-party sources. In addition, where external pricing information or market liquidity are limited, such valuations are classified as modeled. The determination of the point at which a market is no longer liquid for placing it in the Modeled category varies by market.
(c) Amounts exclude Cash Flow Hedges.

Cash Flow Hedges Included in Accumulated Other Comprehensive Income (Loss) (AOCI) on the Balance Sheet

The table provides detail on effective cash flow hedges under SFAS 133 included in the balance sheet. The data in the table will indicate the magnitude of SFAS 133 hedges we have in place. (However, given that under SFAS 133 only cash flow hedges are recorded in AOCI, the table does not provide an all-encompassing picture of our hedging activity). The table also includes a roll-forward of the AOCI balance sheet account, providing insight into the drivers of the changes (new hedges placed during the period, changes in value of existing hedges and roll-off of hedges). In accordance with GAAP, all amounts are presented net of related income taxes.

Total Accumulated Other Comprehensive Income (Loss) Activity
Year Ended December 31, 2003

	Domestic Power (in thousands)
Beginning Balance December 31, 2002	$(286)
Changes in Fair Value (a)	209
Reclassifications from AOCI to Net Income (b)	299
Ending Balance December 31, 2003	$222

(a) "Changes in Fair Value" shows changes in the fair value of derivatives designated as hedging instruments in cash flow hedges during the reporting period not yet reclassified into net income, pending the hedged item's affecting net income. Amounts are reported net of related income taxes.
(b) "Reclassifications from AOCI to Net Income" represents gains or losses from derivatives used as hedging instruments in cash flow hedges that were reclassified into net income during the reporting period. Amounts are reported net of related income taxes above.

The portion of cash flow hedges in AOCI expected to be reclassified to earnings during the next twelve months is a $1,031 thousand gain.

Credit Risk

Our counterparty credit quality and exposure is generally consistent with that of AEP.

VaR Associated with Risk Management Contracts

The following table shows the end, high, average, and low market risk as measured by VaR for year-to-date:

December 31, 2003 (in thousands)				December 31, 2002 (in thousands)			
End	High	Average	Low	End	High	Average	Low
$368	$1,429	$598	$142	$927	$2,840	$1,016	$206

VaR Associated with Debt Outstanding

The risk of potential loss in fair value attributable to our exposure to interest rates, primarily related to long-term debt with fixed interest rates was $79 million and $85 million at December 31, 2003 and 2002, respectively. We would not expect to liquidate our entire debt portfolio in a one-year holding period, therefore a near term change in interest rates should not negatively affect our results of operation or consolidated financial position.

INDIANA MICHIGAN POWER COMPANY AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF INCOME
For the Years Ended December 31, 2003, 2002 and 2001

	2003	2002 (in thousands)	2001
OPERATING REVENUES			
Electric Generation, Transmission and Distribution	$1,346,393	$1,312,626	$1,271,958
Sales to AEP Affiliates	249,203	214,138	255,039
TOTAL	1,595,596	1,526,764	1,526,997
OPERATING EXPENSES			
Fuel for Electric Generation	250,890	239,455	250,098
Purchased Electricity for Resale	28,327	23,443	18,707
Purchased Electricity from AEP Affiliates	274,400	233,724	238,237
Other Operation	417,636	462,707	449,115
Maintenance	158,281	151,602	127,263
Depreciation and Amortization	171,281	168,070	164,230
Taxes Other Than Income Taxes	57,788	57,721	65,518
Income Taxes	50,926	38,853	54,124
TOTAL	1,409,529	1,375,575	1,367,292
OPERATING INCOME	186,067	151,189	159,705
Nonoperating Income	53,928	84,084	85,673
Nonoperating Expenses	77,171	61,374	70,900
Nonoperating Income Tax Expense (Credit)	(9,778)	5,984	5,043
Interest Charges	83,054	93,923	93,647
Net Income Before Cumulative Effect of Accounting Change	89,548	73,992	75,788
Cumulative Effect of Accounting Change (Net of Tax)	(3,160)	-	-
NET INCOME	86,388	73,992	75,788
Preferred Stock Dividend Requirements (Including Capital Stock Expense)	2,509	4,601	4,621
EARNINGS APPLICABLE TO COMMON STOCK	$83,879	$69,391	$71,167

The common stock of I&M is wholly-owned by AEP.

See Notes to Respective Financial Statements beginning on page L-1.

INDIANA MICHIGAN POWER COMPANY AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF CHANGES IN COMMON SHAREHOLDER'S EQUITY AND COMPREHENSIVE INCOME
For the Years Ended December 31, 2003, 2002 and 2001
(in thousands)

	Common Stock	Paid-in Capital	Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Total
DECEMBER 31, 2000	$56,584	$733,072	$3,443	$-	$793,099
Preferred Stock Dividends			(4,487)		(4,487)
Capital Stock Expense		144	(139)		5
					788,617
COMPREHENSIVE INCOME					
Other Comprehensive Income, Net of Taxes:					
Cash Flow Interest Rate Hedge				(3,835)	(3,835)
NET INCOME			75,788		75,788
TOTAL COMPREHENSIVE INCOME					71,953
DECEMBER 31, 2001	$56,584	$733,216	$74,605	$(3,835)	$860,570
Capital Contributions from Parent Company		125,000			125,000
Preferred Stock Dividends			(4,467)		(4,467)
Capital Stock Expense		344	(134)		210
					981,313
COMPREHENSIVE INCOME					
Other Comprehensive Income, Net of Taxes:					
Cash Flow Interest Rate Hedge				3,835	3,835
Unrealized Loss on Cash Flow Power Hedges				(286)	(286)
Minimum Pension Liability				(40,201)	(40,201)
NET INCOME			73,992		73,992
TOTAL COMPREHENSIVE INCOME					37,340
DECEMBER 31, 2002	$56,584	$858,560	$143,996	$(40,487)	$1,018,653
Common Stock Dividends			(40,000)		(40,000)
Preferred Stock Dividends			(2,375)		(2,375)
Capital Stock Expense		134	(134)		-
					976,278
COMPREHENSIVE INCOME					
Other Comprehensive Income, Net of Taxes:					
Unrealized Gain on Cash Flow Power Hedges				508	508
Minimum Pension Liability				14,873	14,873
NET INCOME			86,388		86,388
TOTAL COMPREHENSIVE INCOME					101,769
DECEMBER 31, 2003	$56,584	$858,694	$187,875	$(25,106)	$1,078,047

See Notes to Respective Financial Statements beginning on page L-1.

INDIANA MICHIGAN POWER COMPANY AND SUBSIDIARIES
CONSOLIDATED BALANCE SHEETS
ASSETS
December 31, 2003 and 2002

	2003	2002
	(in thousands)	
ELECTRIC UTILITY PLANT		
Production	$2,878,051	$2,768,463
Transmission	1,000,926	971,599
Distribution	958,966	921,835
General (including nuclear fuel)	274,283	220,137
Construction Work in Progress	193,956	147,924
TOTAL	5,306,182	5,029,958
Accumulated Depreciation and Amortization	2,490,912	2,318,063
TOTAL - NET	2,815,270	2,711,895
OTHER PROPERTY AND INVESTMENTS		
Nuclear Decommissioning and Spent Nuclear Fuel Disposal Trust Funds	982,394	870,754
Non-Utility Property, Net	52,303	69,252
Other Investments	43,797	51,689
TOTAL	1,078,494	991,695
CURRENT ASSETS		
Cash and Cash Equivalents	3,914	3,237
Advances to Affiliates	-	191,226
Accounts Receivable:		
Customers	61,084	92,929
Affiliated Companies	124,826	122,489
Accrued Unbilled Revenues	2,000	6,511
Miscellaneous	4,498	4,872
Allowance for Uncollectible Accounts	(531)	(578)
Fuel	33,968	32,731
Materials and Supplies	105,328	95,552
Risk Management Assets	44,071	67,985
Margin Deposits	7,245	890
Prepayments and Other	10,673	11,172
TOTAL	397,076	629,016
DEFERRED DEBITS AND OTHER ASSETS		
Regulatory Assets:		
SFAS 109 Regulatory Asset, Net	151,973	163,928
Deferred Fuel Costs	-	37,501
Cook Plant Restart Costs	-	40,000
Incremental Nuclear Refueling Outage Expenses, Net	57,326	29,572
Other	66,978	77,211
Long-term Risk Management Assets	43,768	83,265
Deferred Property Taxes	21,916	22,271
Deferred Charges and Other Assets	26,270	51,378
TOTAL	368,231	505,126
TOTAL ASSETS	$4,659,071	$4,837,732

See Notes to Respective Financial Statements beginning on page L-1.

INDIANA MICHIGAN POWER COMPANY AND SUBSIDIARIES
CONSOLIDATED BALANCE SHEETS
CAPITALIZATION AND LIABILITIES
December 31, 2003 and 2002

	2003	2002
	(in thousands)	
CAPITALIZATION		
Common Shareholder's Equity:		
Common Stock – No Par Value:		
Authorized – 2,500,000 Shares		
Outstanding – 1,400,000 Shares	$56,584	$56,584
Paid-in Capital	858,694	858,560
Retained Earnings	187,875	143,996
Accumulated Other Comprehensive Income (Loss)	(25,106)	(40,487)
Total Common Shareholder's Equity	1,078,047	1,018,653
Cumulative Preferred Stock – Not Subject to Mandatory Redemption	8,101	8,101
Total Shareholder's Equity	1,086,148	1,026,754
Liability for Cumulative Preferred Stock - Subject to Mandatory Redemption	63,445	64,945
Long-term Debt	1,134,359	1,587,062
TOTAL	2,283,952	2,678,761
CURRENT LIABILITIES		
Long-term Debt Due Within One Year	205,000	30,000
Advances from Affiliates	98,822	-
Accounts Payable:		
General	101,776	125,048
Affiliated Companies	47,484	93,608
Customer Deposits	21,955	16,660
Taxes Accrued	42,189	71,559
Interest Accrued	17,963	21,481
Risk Management Liabilities	31,898	48,568
Obligations Under Capital Leases	6,528	8,229
Other	57,675	76,162
TOTAL	631,290	491,315
DEFERRED CREDITS AND OTHER LIABILITIES		
Deferred Income Taxes	337,376	356,197
Regulatory Liabilities:		
Asset Removal Costs	263,015	-
Deferred Investment Tax Credits	90,278	97,709
Excess ARO for Nuclear Decommissioning	215,715	-
Other	61,268	65,983
Deferred Gain on Sale and Leaseback – Rockport Plant Unit 2	70,179	73,885
Long-term Risk Management Liabilities	33,537	32,261
Obligations Under Capital Leases	31,315	42,619
Asset Retirement Obligations	553,219	-
Nuclear Decommissioning	-	620,672
Deferred Credits and Other	87,927	378,330
TOTAL	1,743,829	1,667,656
Commitments and Contingencies (Note 7)		
TOTAL CAPITALIZATION AND LIABILITIES	$4,659,071	$4,837,732

See Notes to Respective Financial Statements beginning on page L-1.

INDIANA MICHIGAN POWER COMPANY AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF CASH FLOWS
For the Years Ended December 31, 2003, 2002 and 2001

	2003	2002	2001
		(in thousands)	
OPERATING ACTIVITIES			
Net Income	$86,388	$73,992	$75,788
Adjustments to Reconcile Net Income to Net Cash Flows From Operating Activities:			
Impairments	10,300	-	-
Cumulative Effect of Accounting Change	3,160	-	-
Depreciation and Amortization	171,281	168,070	166,360
Amortization (Deferral) of Incremental Nuclear Refueling Outage Expenses, Net	(27,754)	(26,577)	418
Unrecovered Fuel and Purchased Power Costs	37,501	37,501	37,501
Amortization of Nuclear Outage Costs	40,000	40,000	40,000
Deferred Income Taxes	(14,894)	(16,921)	(29,205)
Deferred Investment Tax Credits	(7,431)	(7,740)	(8,324)
Mark-to-Market of Risk Management Contracts	43,938	(9,517)	(62,647)
Changes in Certain Assets and Liabilities:			
Accounts Receivable, Net	34,346	(106,683)	62,769
Fuel, Materials and Supplies	(11,013)	(7,854)	(19,426)
Accounts Payable	(69,396)	87,934	(60,185)
Taxes Accrued	(29,370)	1,798	1,345
Change in Other Assets	(24,302)	(29,264)	2,622
Change in Other Liabilities	(19,981)	23,495	29,191
Net Cash Flows From Operating Activities	222,773	228,234	236,207
INVESTING ACTIVITIES			
Construction Expenditures	(184,188)	(167,484)	(91,052)
Buyout of Nuclear Fuel Leases	-	-	(92,616)
Other	1,485	1,759	1,074
Net Cash Flows Used For Investing Activities	(182,703)	(165,725)	(182,594)
FINANCING ACTIVITIES			
Capital Contributions from Parent	-	125,000	-
Issuance of Long-term Debt	64,434	288,732	297,656
Retirement of Cumulative Preferred Stock	(1,500)	(424)	-
Retirement of Long-term Debt	(350,000)	(340,000)	(44,922)
Change in Advances to/from Affiliates, Net	290,048	(144,917)	(299,891)
Dividends Paid on Common Stock	(40,000)	-	-
Dividends Paid on Cumulative Preferred Stock	(2,375)	(4,467)	(4,487)
Net Cash Flows Used For Financing Activities	(39,393)	(76,076)	(51,644)
Net Increase (Decrease) in Cash and Cash Equivalents	677	(13,567)	1,969
Cash and Cash Equivalents at Beginning of Period	3,237	16,804	14,835
Cash and Cash Equivalents at End of Period	$3,914	$3,237	$16,804

SUPPLEMENTAL DISCLOSURE:
Cash paid for interest net of capitalized amounts was $82,593,000, $89,984,000 and $92,140,000 and for income taxes was $94,440,000, $60,523,000 and $100,470,000 in 2003, 2002 and 2001, respectively. Non-cash acquisitions under capital leases were $1,023,000 and $22,218,000 in 2002 and 2001, respectively. There were no non-cash capital lease acquisitions in 2003.

See Notes to Respective Financial Statements beginning on page L-1.

INDIANA MICHIGAN POWER COMPANY AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF CAPITALIZATION
December 31, 2003 and 2002

Series	Call Price December 31, 2003 (a)	Number of Shares Redeemed Year Ended December 31, 2003	2002	2001	Shares Outstanding December 31, 2003	2003 (in thousands)	2002
COMMON SHAREHOLDER'S EQUITY						$1,078,047	$1,018,653
PREFERRED STOCK:							
$100 Par Value - Authorized 2,250,000 shares							
$25 Par Value - Authorized 11,200,000 shares							
Not Subject to Mandatory Redemption - $100 Par:							
4-1/8%	106.125	-	20	-	55,369	5,537	5,537
4.56%	102	-	-	-	14,412	1,441	1,441
4.12%	102.728	-	6,326	-	11,230	1,123	1,123
Total						8,101	8,101
Subject to Mandatory Redemption - $100 Par(b):							
5.90% (c)		-	-	-	152,000	15,200	15,200
6-1/4% (c)		-	-	-	192,500	19,250	19,250
6.30% (c)		-	-	-	132,450	13,245	13,245
6-7/8% (d)		15,000	-	-	157,500	15,750	17,250
Total						63,445	64,945
LONG-TERM DEBT (See Schedule of Long-term Debt):							
First Mortgage Bonds						54,725	174,245
Installment Purchase Contracts						310,676	310,336
Senior Unsecured Notes						747,873	747,027
Other Long-term Debt (e)						226,085	223,736
Junior Debentures						-	161,718
Less Portion Due Within One Year						(205,000)	(30,000)
Long-term Debt Excluding Portion Due Within One Year						1,134,359	1,587,062
TOTAL CAPITALIZATION						$2,283,952	$2,678,761

(a) The cumulative preferred stock is callable at the price indicated plus accrued dividends.
(b) Sinking fund provisions require the redemption of 67,500 shares in each of 2004, 2005, 2006 and 2007 and 52,500 shares in 2008. The sinking fund provisions of each series subject to mandatory redemption have been met by purchase of shares in advance of these due dates. Shares previously purchased may be applied to meet the sinking fund requirement.
(c) Commencing in 2004 and continuing through 2008 I&M may redeem, at $100 per share, 20,000 shares of the 5.90% series, 15,000 shares of the 6-1/4% series and 17,500 shares of the 6.30% series outstanding under sinking fund provisions at its option and all remaining outstanding shares must be redeemed not later than 2009. The series are callable beginning November 1, 2003 for the 5.90% series, December 1, 2003 for the 6-1/4% series and March 1, 2004 for the 6.30% series at $100 plus accrued dividends.
(d) Commencing in 2003 and continuing through the year 2007, a sinking fund will require the redemption of 15,000 shares each year and the redemption of the remaining shares outstanding on April 1, 2008, in each case at $100 per share. Callable at $100 per share plus accrued dividends beginning February 1, 2003.
(e) Represents a liability for SNF disposal including interest payable to the DOE. See Note 7.

See Notes to Respective Financial Statements beginning on page L-1.

INDIANA MICHIGAN POWER COMPANY AND SUBSIDIARIES
SCHEDULE OF LONG-TERM DEBT
December 31, 2003 and 2002

First Mortgage Bonds outstanding were as follows:

% Rate	Due	2003	2002
		(in thousands)	
6.10	2003 – November 1	$-	$30,000
8.50	2022 – December 15	-	75,000
7.35	2023 – October 1	-	15,000
7.20	2024 – February 1	30,000 (a)	30,000
7.50	2024 – March 1	25,000 (a)	25,000
Unamortized Discount		(275)	(755)
Total		$54,725	$174,245

(a) These bonds will be redeemed in April 2004 and have been classified for payment in 2004.

First Mortgage Bonds are secured by a first mortgage lien on electric utility plant. Certain supplemental indentures to the first mortgage lien contain maintenance and replacement provisions requiring the deposit of cash or bonds with the trustee, or in lieu thereof, certification of unfunded property additions. Interest payments are made semi-annually.

Installment Purchase Contracts have been entered in connection with the issuance of pollution control revenue bonds by governmental authorities as follows:

	% Rate	Due	2003	2002
			(in thousands)	
City of Lawrenceburg, Indiana:				
	7.00	2015 – April 1	$-	$25,000
	(a)	2019 – October 1	25,000	-
	5.90	2019 – November 1	52,000	52,000
City of Rockport, Indiana:				
	7.60	2016 – March 1	-	40,000
	(a)	2025 – April 1	40,000	-
	6.55	2025 – June 1	50,000	50,000
	(b)	2025 – June 1	50,000	50,000
	4.90(c)	2025 – June 1	50,000	50,000
City of Sullivan, Indiana:				
	5.95	2009 – May 1	45,000	45,000
	Unamortized Discount		(1,324)	(1,664)
	Total		$310,676	$310,336

(a) Rate is an annual long-term fixed rate of 2.625% through October 1, 2006. After that date the rate may be a daily or weekly reset rate, commercial paper, auction or other long-term rate as designated by I&M (fixed rate bonds).
(b) In 2001, an auction rate was established. Auction rates are determined by standard procedures every 35 days. The auction rate for 2003 ranged from 0.85% to 1.35% and averaged 1.05%. The auction rate for 2002 ranged from 1.3% to 1.7% and averaged 1.5%.
(c) Rate is fixed until June 1, 2007 (term rate bonds).

The terms of the installment purchase contracts require I&M to pay amounts sufficient for the cities to pay interest on and the principal of (at stated maturities and upon mandatory redemptions) related pollution control revenue bonds issued to finance the construction of pollution control facilities at certain generating plants. The fixed rate bonds due 2019 and 2025 are subject to mandatory tender for purchase on October 1, 2006. Consequently, the fixed rate bonds have been classified for repayment purposes in 2006. The term rate bonds due 2025 are subject to mandatory tender for purchase on the term maturity date (June 1, 2007). Accordingly, the term rate bonds have been classified for repayment purposes in 2007 (the term end date). Interest payments range from every 35 days to semi-annually.

Senior Unsecured Notes outstanding were as follows:

% Rate	Due	2003	2002
		(in thousands)	
6-7/8	2004 – July 1	$150,000	$150,000
6.125	2006 – December 15	300,000	300,000
6.45	2008 – November 10	50,000	50,000
6.375	2012 – November 1	100,000	100,000
6.00	2032 – December 31	150,000	150,000
Unamortized Discount		(2,127)	(2,973)
Total		$747,873	$747,027

Junior Debentures outstanding were as follows:

% Rate	Due	2003	2002
		(in thousands)	
8.00	2026 – March 31	$-	$40,000
7.60	2038 – June 30	-	125,000
Unamortized Discount		-	(3,282)
Total		$ -	$161,718

At December 31, 2003 future annual long-term debt payments are as follows:

	Amount (in thousands)
2004	$205,000
2005	-
2006	365,000
2007	50,000
2008	50,000
Later Years	673,085
Total Principal Amount	1,343,085
Unamortized Discount	(3,726)
Total	$1,339,359

INDIANA MICHIGAN POWER COMPANY AND SUBSIDIARIES
INDEX TO NOTES TO RESPECTIVE FINANCIAL STATEMENTS

The notes to I&M's consolidated financial statements are combined with the notes to respective financial statements for other subsidiary registrants. Listed below are the notes that apply to I&M. The footnotes begin on page L-1.

INDEPENDENT AUDITORS' REPORT

To the Shareholders and Board of
Directors of Indiana Michigan Power Company:

We have audited the accompanying consolidated balance sheets and consolidated statements of capitalization of Indiana Michigan Power Company and subsidiaries as of December 31, 2003 and 2002, and the related consolidated statements of income, changes in common shareholder's equity and comprehensive income and cash flows for each of the three years in the period ended December 31, 2003. These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements based on our audits.

We conducted our audits in accordance with auditing standards generally accepted in the United States of America. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, such consolidated financial statements present fairly, in all material respects, the financial position of Indiana Michigan Power Company and subsidiaries as of December 31, 2003 and 2002, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2003 in conformity with accounting principles generally accepted in the United States of America.

As discussed in Note 2 to the consolidated financial statements, the Company adopted SFAS 143, "Accounting for Asset Retirement Obligations" and EITF 02-3, "Issues Involved in Accounting for Derivative Contracts Held for Trading Purposes and Contracts Involved in Energy Trading and Risk Management Activities," effective January 1, 2003.

/s/ Deloitte & Touche LLP

Columbus, Ohio
March 5, 2004

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KENTUCKY POWER COMPANY
SELECTED FINANCIAL DATA

	2003	2002	2001	2000	1999
			(in thousands)		
INCOME STATEMENTS DATA					
Operating Revenues	$416,470	$378,683	$379,025	$389,875	$358,757
Operating Expenses	351,726	336,486	331,347	340,137	304,082
Operating Income	64,744	42,197	47,678	49,738	54,675
Nonoperating Items, Net	(2,660)	5,206	1,248	2,070	(327)
Interest Charges	28,620	26,836	27,361	31,045	28,918
Income Before Cumulative Effect of Accounting Change	33,464	20,567	21,565	20,763	25,430
Cumulative Effect of Accounting Change (Net of Tax)	(1,134)	-	-	-	-
Net Income	$32,330	$20,567	$21,565	$20,763	$25,430
BALANCE SHEETS DATA					
Electric Utility Plant	$1,349,746	$1,295,619	$1,128,415	$1,103,064	$1,079,048
Accumulated Depreciation and Amortization	381,876	373,638	360,319	338,270	318,799
Net Electric Utility Plant	$967,870	$921,981	$768,096	$764,794	$760,249
TOTAL ASSETS	$1,221,634	$1,188,342	$1,022,833	$1,516,921	$1,007,332
Common Stock and Paid-in Capital	$259,200	$259,200	$209,200	$209,200	$209,200
Retained Earnings	64,151	48,269	48,833	57,513	67,110
Accumulated Other Comprehensive Income (Loss)	(6,213)	(9,451)	(1,903)	-	-
Total Common Shareholder's Equity	$317,138	$298,018	$256,130	$266,713	$276,310
Long-term Debt (a)	$487,602	$466,632	$346,093	$330,880	$365,782
Obligations Under Capital Leases (a)	$5,292	$7,248	$9,583	$14,184	$15,141
TOTAL CAPITALIZATION AND LIABILITIES	$1,221,634	$1,188,342	$1,022,833	$1,516,921	$1,007,332

(a) Including portion due within one year.

KENTUCKY POWER COMPANY
MANAGEMENT'S NARRATIVE FINANCIAL DISCUSSION AND ANALYSIS

KPCo is a public utility engaged in the generation and purchase of electric power, and the subsequent sale, transmission and distribution of that power to 175,000 retail customers in our service territory in eastern Kentucky. As a member of the AEP Power Pool, we share the revenues and the costs of the AEP Power Pool's sales to neighboring utilities and power marketers. We also sell power at wholesale to municipalities.

The cost of the AEP Power Pool's generating capacity is allocated among its members based on their relative peak demands and generating reserves through the payment of capacity charges and the receipt of capacity credits. AEP Power Pool members are also compensated for the out-of-pocket costs of energy delivered to the AEP Power Pool and charged for energy received from the AEP Power Pool. The AEP Power Pool calculates each member's prior twelve-month peak demand relative to the sum of the peak demands of all members as a basis for sharing revenues and costs. The result of this calculation is the member load ratio (MLR), which determines each member's percentage share of revenues and costs.

Power and gas risk management activities are conducted on our behalf by AEPSC. We share in the revenues and expenses associated with these risk management activities with other AEP registrant subsidiaries excluding AEGCo under existing power pool and system integration agreements. Risk management activities primarily involve the purchase and sale of electricity under physical forward contracts at fixed and variable prices and to a lesser extent gas. The electricity and gas contracts include physical transactions, over-the-counter options and swaps and exchange traded futures and options. The majority of the physical forward contracts are typically settled by entering into offsetting contracts.

Under our system integration agreement, revenues and expenses from the sales to neighboring utilities, power marketers and other power and gas risk management entities are shared among AEP East and West companies. Sharing in a calendar year is based upon the level of such activities experienced for the twelve months ended June 30, 2000, which immediately preceded the merger of AEP and CSW. This resulted in an AEP East and West companies' allocation of approximately 91% and 9%, respectively, for revenues and expenses. Allocation percentages in any given calendar year may also be based upon the relative generating capacity of the AEP East and West companies in the event the pre-merger activity level is exceeded. The capacity based allocation mechanism was triggered in June 2003, resulting in an allocation factor of approximately 70% and 30% for the AEP East and West companies, respectively, for the remainder of 2003.

Results of Operations

2003 Compared to 2002

Net Income for 2003 increased $12 million over 2002 primarily due to improved earnings from system sales and transmission revenues, as well as decreased employee related expenses and maintenance expenses. These improvements were partially offset by net losses from risk management activities included in Nonoperating Income (Expense) that exceeded net gains from risk management activities included in Operating Income.

Operating Income

Operating Income for 2003 increased $23 million primarily due to:

- Increases in system sales and transmission revenues of $16 million and an increase in gains from risk management activities of $7 million.
- An increase in Sales to AEP Affiliates of $12 million due to strong wholesale sales by the AEP Power Pool.
- An increase in residential and commercial sales of $4 million over 2002 due to the rate increase in mid 2003 to recover the cost of emission control equipment (see Note 4, "Rate Matters").
- An $8 million decrease in Maintenance expense due to planned plant outages in 2002. Big Sandy plant Unit 2 was down for the entire fourth quarter of 2002 for planned boiler and electric plant maintenance. In addition, Big Sandy Unit 1 was down for two months in 2002 for boiler maintenance.
- A $6 million decrease in Other Operation expense primarily due to the impact of cost reduction efforts instituted in the fourth quarter of 2002 and related employment termination benefits recorded in 2002, partially offset by reduced gains from emission allowances.

The increases in Operating Income were partially offset by:

- A decline in industrial sales of $2 million reflecting the weak economy and the reduced usage by a major customer in 2003.
- An increase in fuel expense of $9 million due to increased generation based on the increased plant availability at Big Sandy in 2003.
- An increase in purchased power expense of $10 million necessary to support system sales and Sales to AEP Affiliates. In addition, energy purchases increased from the Rockport Plant based on plant availability, as required by the unit power agreement with AEGCo, an affiliated company. The unit power agreement with AEGCo provides for our purchase of 15% of the total output of the two unit 2,600-MW capacity Rockport Plant.
- An increase in Depreciation and Amortization of $6 million reflecting the completion and implementation of new capital projects in the third quarter of 2003, as well as the implementation of emission control equipment at the Big Sandy plant in the second quarter of 2003.
- An increase in Income Taxes of $3 million due to an increase in pre-tax book operating income partially offset by federal and state tax return adjustments.

Other Impacts on Earnings

Nonoperating income decreased $12 million in 2003 compared to 2002 primarily due to lower profit from power sold outside AEP's traditional marketing area resulting from AEP's plan to exit risk management activities in areas outside of its traditional market area. The decrease in nonoperating income was partially offset by a $4 million decrease in nonoperating income taxes resulting primarily from the reduced pre-tax nonoperating book income. Interest Charges increased $2 million primarily due to an increase in outstanding debt partially offset by lower market interest rates on newly issued debt.

Financial Condition

Credit Ratings

The rating agencies currently have us on stable outlook. Current ratings are as follows:

	Moody's	S&P	Fitch
Senior Unsecured Debt	Baa2	BBB	BBB

In February 2003, Moody's Investors Service (Moody's) completed their review of AEP and its rated subsidiaries. The completion of this review was a culmination of ratings action started during 2002.

Summary Obligation Information

Our contractual obligations include amounts reported on the Consolidated Balance Sheets and other obligations disclosed in the footnotes. The following table summarizes our contractual cash obligations at December 31, 2003:

	Payments Due by Period (in thousands)				
Contractual Cash Obligations	**Less Than 1 year**	**2-3 years**	**4–5 years**	**After 5 years**	**Total**
Long-term Debt	$-	$60,000	$352,964	$74,638	$487,602
Advances from Affiliates	38,096	-	-	-	38,096
Capital Lease Obligations	2,107	2,597	1,041	116	5,861
Unconditional Purchase Obligations (a)	39,658	16,636	-	-	56,294
Noncancellable Operating Leases	1,209	1,877	1,246	1,785	6,117
Total	$81,070	$81,110	$355,251	$76,539	$593,970

(a) Represents contractual obligations to purchase coal as fuel for electric generation along with related transportation of the fuel.

Significant Factors

See the "Registrants' Combined Management's Discussion and Analysis" section beginning on page M-1 for additional discussion of factors relevant to us.

Quantitative And Qualitative Disclosures About Risk Management Activities

Market Risks

Our risk management policies and procedures are instituted and administered at the AEP consolidated level. See complete discussion within AEP's "Qualitative And Quantitative Disclosures About Risk Management Activities" section. The following tables provide information about our risk management activities' effect on this specific registrant.

MTM Risk Management Contract Net Assets

This table provides detail on changes in our MTM net asset or liability balance sheet position from one period to the next.

MTM Risk Management Contract Net Assets
Year Ended December 31, 2003
(in thousands)

Domestic Power	
Beginning Balance December 31, 2002	$24,998
(Gain) Loss from Contracts Realized/Settled During the Period (a)	(6,682)
Fair Value of New Contracts When Entered Into During the Period (b)	-
Net Option Premiums Paid/(Received) (c)	32
Change in Fair Value Due to Valuation Methodology Changes	-
Effect of EITF 98-10 Rescission (d)	(1,744)
Changes in Fair Value of Risk Management Contracts (e)	461
Changes in Fair Value Risk Management Contracts Allocated to Regulated Jurisdictions (f)	(1,575)
Total MTM Risk Management Contract Net Assets, Excluding Cash Flow Hedges	15,490
Net Cash Flow Hedge Contracts (g)	126
DETM Assignment (h)	(7,349)
Ending Balance December 31, 2003	$8,267

(a)"(Gain) Loss from Contracts Realized/Settled During the Period" includes realized gains from risk management contracts and related derivatives that settled during 2003 that were entered into prior to 2003.

(b)The "Fair Value of New Contracts When Entered Into During the Period" represents the fair value of long-term contracts entered into with customers during 2003. The fair value is calculated as of the execution of the contract. Most of the fair value comes from longer term fixed price contracts with customers that seek to limit their risk against fluctuating energy prices. The contract prices are valued against market curves associated with the delivery location.

(c)"Net Option Premiums Paid/(Received)" reflects the net option premiums paid/(received) as they relate to unexercised and unexpired option contracts that were entered into in 2003.

(d) See Note 2 "New Accounting Pronouncements, Extraordinary Items and Cumulative Effect of Accounting Changes."

(e)"Changes in Fair Value of Risk Management Contracts" represents the fair value change in the risk management portfolio due to market fluctuations during the current period. Market fluctuations are attributable to various factors such as supply/demand, weather, etc.

(f)"Change in Fair Value of Risk Management Contracts Allocated to Regulated Jurisdictions" relates to the net gains (losses) of those contracts that are not reflected in the Statements of Income. These net gains (losses) are recorded as regulatory liabilities/assets for those subsidiaries that operate in regulated jurisdictions.

(g)"Net Cash Flow Hedge Contracts" (pre-tax) are discussed below in Accumulated Other Comprehensive Income (Loss).

(h)See Note 17 "Related Party Transactions."

Maturity and Source of Fair Value of MTM Risk Management Contract Net Assets

The table presenting maturity and source of fair value of MTM risk management contract net assets provides two fundamental pieces of information:

- The source of fair value used in determining the carrying amount of our total MTM asset or liability (external sources or modeled internally).
- The maturity, by year, of our net assets/liabilities, giving an indication of when these MTM amounts will settle and generate cash.

Maturity and Source of Fair Value of MTM
Risk Management Contract Net Assets
Fair Value of Contracts as of December 31, 2003

	2004	2005	2006	2007	2008	After 2008	Total (c)
			(in thousands)				
Prices Actively Quoted – Exchange Traded Contracts	$277	$(56)	$7	$43	$-	$-	$271
Prices Provided by Other External Sources – OTC Broker Quotes (a)	5,405	1,937	1,899	772	388	-	10,401
Prices Based on Models and Other Valuation Methods (b)	(1)	12	754	871	801	2,381	4,818
Total	$5,681	$1,893	$2,660	$1,686	$1,189	$2,381	$15,490

(a) "Prices Provided by Other External Sources – OTC Broker Quotes" reflects information obtained from over-the-counter brokers, industry services, or multiple-party on-line platforms.

(b) "Prices Based on Models and Other Valuation Methods" is in absence of pricing information from external sources, modeled information is derived using valuation models developed by the reporting entity, reflecting when appropriate, option pricing theory, discounted cash flow concepts, valuation adjustments, etc. and may require projection of prices for underlying commodities beyond the period that prices are available from third-party sources. In addition, where external pricing information or market liquidity are limited, such valuations are classified as modeled. The determination of the point at which a market is no longer liquid for placing it in the Modeled category varies by market.

(c) Amounts exclude Cash Flow Hedges.

Cash Flow Hedges Included in Accumulated Other Comprehensive Income (Loss) (AOCI) on the Balance Sheet

The table provides detail on effective cash flow hedges under SFAS 133 included in the balance sheet. The data in the table will indicate the magnitude of SFAS 133 hedges we have in place. (However, given that under SFAS 133 only cash flow hedges are recorded in AOCI, the table does not provide an all-encompassing picture of our hedging activity). The table also includes a roll-forward of the AOCI balance sheet account, providing insight into the drivers of the changes (new hedges placed during the period, changes in value of existing hedges and roll-off of hedges). In accordance with GAAP, all amounts are presented net of related income taxes.

Total Accumulated Other Comprehensive Income (Loss) Activity
Year Ended December 31, 2003

	Domestic Power	Interest Rate	Consolidated
		(in thousands)	
Beginning Balance December 31, 2002	$(103)	$425	$322
Changes in Fair Value (a)	75	-	75
Reclassifications from AOCI to Net Income (b)	110	(87)	23
Ending Balance December 31, 2003	$82	$338	$420

(a) "Changes in Fair Value" shows changes in the fair value of derivatives designated as hedging instruments in cash flow hedges during the reporting period not yet reclassified into net income, pending the hedged item's affecting net income. Amounts are reported net of related income taxes.

(b) "Reclassifications from AOCI to Net Income" represents gains or losses from derivatives used as hedging instruments in cash flow hedges that were reclassified into net income during the reporting period. Amounts are reported net of related income taxes above.

The portion of cash flow hedges in AOCI expected to be reclassified to earnings during the next twelve months is a $466 thousand gain.

Credit Risk

Our counterparty credit quality and exposure is generally consistent with that of AEP.

VaR Associated with Risk Management Contracts

The following table shows the end, high, average, and low market risk as measured by VaR for year-to-date:

December 31, 2003 (in thousands)				December 31, 2002 (in thousands)			
End	High	Average	Low	End	High	Average	Low
$136	$527	$220	$52	$333	$1,019	$364	$74

VaR Associated with Debt Outstanding

The risk of potential loss in fair value attributable to our exposure to interest rates, primarily related to long-term debt with fixed interest rates was $29 million and $30 million at December 31, 2003 and 2002, respectively. We would not expect to liquidate our entire debt portfolio in a one-year holding period, therefore a near term change in interest rates should not negatively affect our results of operation or financial position.

KENTUCKY POWER COMPANY
STATEMENTS OF INCOME
For the Years Ended December 31, 2003, 2002 and 2001

	2003	2002 (in thousands)	2001
OPERATING REVENUES			
Electric Generation, Transmission and Distribution	$376,662	$350,719	$336,659
Sales to AEP Affiliates	39,808	27,964	42,366
TOTAL	416,470	378,683	379,025
OPERATING EXPENSES			
Fuel for Electric Generation	74,148	65,043	70,635
Purchased Electricity for Resale	963	29	86
Purchased Electricity from AEP Affiliates	141,690	133,002	130,204
Other Operation	47,325	52,892	58,275
Maintenance	27,328	35,089	22,444
Depreciation and Amortization	39,309	33,233	32,491
Taxes Other Than Income Taxes	8,788	8,240	7,854
Income Taxes	12,175	8,958	9,358
TOTAL	351,726	336,486	331,347
OPERATING INCOME	64,744	42,197	47,678
Nonoperating Income (Expense)	(4,036)	7,950	10,979
Nonoperating Expenses	1,124	840	9,047
Nonoperating Income Tax Expense (Credit)	(2,500)	1,904	684
Interest Charges	28,620	26,836	27,361
Income Before Cumulative Effect of Accounting Change	33,464	20,567	21,565
Cumulative Effect of Accounting Change (Net of Tax)	(1,134)	-	-
NET INCOME	$32,330	$20,567	$21,565

The common stock of KPCo is wholly-owned by AEP.

See Notes to Respective Financial Statements beginning on page L-1.

KENTUCKY POWER COMPANY
STATEMENTS OF CHANGES IN COMMON SHAREHOLDER'S EQUITY AND COMPREHENSIVE INCOME
For the Years Ended December 31, 2003, 2002 and 2001
(in thousands)

	Common Stock	Paid-in Capital	Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Total
DECEMBER 31, 2000	$50,450	$158,750	$57,513	$-	$266,713
Common Stock Dividends			(30,245)		(30,245)
TOTAL					236,468
COMPREHENSIVE INCOME					
Other Comprehensive Income, Net of Taxes:					
Unrealized Loss on Cash Flow Hedges				(1,903)	(1,903)
NET INCOME			21,565		21,565
TOTAL COMPREHENSIVE INCOME					19,662
DECEMBER 31, 2001	$50,450	$158,750	$48,833	$(1,903)	$256,130
Capital Contribution from Parent		50,000			50,000
Common Stock Dividends			(21,131)		(21,131)
TOTAL					284,999
COMPREHENSIVE INCOME					
Other Comprehensive Income, Net of Taxes:					
Unrealized Gain on Cash Flow Hedges				2,225	2,225
Minimum Pension Liability				(9,773)	(9,773)
NET INCOME			20,567		20,567
TOTAL COMPREHENSIVE INCOME					13,019
DECEMBER 31, 2002	$50,450	$208,750	$48,269	$(9,451)	$298,018
Common Stock Dividends			(16,448)		(16,448)
TOTAL					281,570
COMPREHENSIVE INCOME					
Other Comprehensive Income, Net of Taxes:					
Unrealized Gain on Cash Flow Hedges				98	98
Minimum Pension Liability				3,140	3,140
NET INCOME			32,330		32,330
TOTAL COMPREHENSIVE INCOME					35,568
DECEMBER 31, 2003	$50,450	$208,750	$64,151	$(6,213)	$317,138

See Notes to Respective Financial Statements beginning on page L-1.

KENTUCKY POWER COMPANY
BALANCE SHEETS
ASSETS
December 31, 2003 and 2002

	2003	2002
	(in thousands)	
ELECTRIC UTILITY PLANT		
Production	$457,341	$275,121
Transmission	381,354	373,639
Distribution	425,688	414,281
General	68,041	67,449
Construction Work in Progress	17,322	165,129
TOTAL	1,349,746	1,295,619
Accumulated Depreciation and Amortization	381,876	373,638
TOTAL – NET	967,870	921,981
OTHER PROPERTY AND INVESTMENTS		
Non-Utility Property, Net	5,423	5,477
Other Investments	1,022	1,427
TOTAL	6,445	6,904
CURRENT ASSETS		
Cash and Cash Equivalents	886	2,304
Accounts Receivable:		
Customers	21,177	24,716
Affiliated Companies	25,327	23,802
Accrued Unbilled Revenues	5,534	5,301
Miscellaneous	97	217
Allowance for Uncollectible Accounts	(736)	(192)
Fuel	9,481	10,817
Materials and Supplies	16,585	16,127
Accrued Tax Benefit	-	1,253
Risk Management Assets	16,200	24,261
Margin Deposits	2,660	320
Prepayments and Other	1,696	1,866
TOTAL	98,907	110,792
DEFERRED DEBITS AND OTHER ASSETS		
Regulatory Assets:		
SFAS 109 Regulatory Asset, Net	99,828	87,261
Other Regulatory Assets	13,971	14,715
Long-term Risk Management Assets	16,134	29,871
Deferred Property Taxes	6,847	6,300
Other Deferred Charges	11,632	10,518
TOTAL	148,412	148,665
TOTAL ASSETS	$1,221,634	$1,188,342

See Notes to Respective Financial Statements beginning on page L-1.

KENTUCKY POWER COMPANY
BALANCE SHEETS
CAPATALIZATION AND LIABILITIES
December 31, 2003 and 2002

	2003	2002
	(in thousands)	
CAPITALIZATION		
Common Shareholder's Equity:		
Common Stock – $50 Par Value:		
Authorized – 2,000,000 Shares		
Outstanding – 1,009,000 Shares	$50,450	$50,450
Paid-in Capital	208,750	208,750
Retained Earnings	64,151	48,269
Accumulated Other Comprehensive Income (Loss)	(6,213)	(9,451)
Total Common Shareholder's Equity	317,138	298,018
Long-term Debt:		
Nonaffiliated	427,602	391,632
Affiliated	60,000	60,000
Total Long-term Debt	487,602	451,632
TOTAL	804,740	749,650
CURRENT LIABILITIES		
Long-term Debt Due Within One Year – Affiliated	-	15,000
Advances from Affiliates	38,096	23,386
Accounts Payable:		
General	22,802	46,515
Affiliated Companies	22,648	44,035
Customer Deposits	9,894	8,048
Taxes Accrued	7,329	-
Interest Accrued	6,915	6,471
Risk Management Liabilities	11,704	17,803
Obligations Under Capital Leases	1,743	2,155
Other	8,628	12,167
TOTAL	129,759	175,580
DEFERRED CREDITS AND OTHER LIABILITIES		
Deferred Income Taxes	212,121	178,313
Regulatory Liabilities:		
Asset Removal Costs	26,140	-
Deferred Investment Tax Credits	7,955	9,165
Other Regulatory Liabilities	10,591	12,152
Long-term Risk Management Liabilities	12,363	11,488
Obligations Under Capital Leases	3,549	5,093
Deferred Credits and Other	14,416	46,901
TOTAL	287,135	263,112
Commitments and Contingencies (Note 7)		
TOTAL CAPITALIZATION AND LIABILITIES	$1,221,634	$1,188,342

See Notes to Respective Financial Statements beginning on page L-1.

KENTUCKY POWER COMPANY
STATEMENTS OF CASH FLOWS
For the Years Ended December 31, 2003, 2002 and 2001

	2003	2002	2001
		(in thousands)	
OPERATING ACTIVITIES			
Net Income	$32,330	$20,567	$21,565
Adjustments to Reconcile Net Income to Net Cash Flows From Operating Activities:			
Cumulative Effect of Accounting Change	1,134	-	-
Depreciation and Amortization	39,309	33,233	32,491
Deferred Income Taxes	20,107	9,839	6,293
Deferred Investment Tax Credits	(1,210)	(1,240)	(1,251)
Deferred Fuel Costs, Net	233	2,998	(4,707)
Mark-to-Market of Risk Management Contracts	15,112	(12,267)	(1,454)
Changes in Certain Assets and Liabilities:			
Accounts Receivable, Net	2,445	(9,332)	24,799
Fuel, Materials and Supplies	878	882	(7,658)
Accounts Payable	(45,100)	44,529	(22,942)
Taxes Accrued	8,582	(11,558)	(1,580)
Change in Other Assets	(16,588)	(21,491)	(2,762)
Change in Other Liabilities	4,565	16,161	(9,446)
Net Cash Flows From Operating Activities	61,797	72,321	33,348
INVESTING ACTIVITIES			
Construction Expenditures	(81,707)	(178,700)	(37,206)
Proceeds from Sales of Property and Other	967	217	216
Net Cash Flow Used for Investing Activities	(80,740)	(178,483)	(36,990)
FINANCING ACTIVITIES			
Capital Contributions from Parent Company	-	50,000	-
Issuance of Long-term Debt – Nonaffiliated	74,263	274,964	-
Issuance of Long-term Debt – Affiliated	-	-	75,000
Retirement of Long-term Debt – Nonaffiliated	(40,000)	(154,500)	(60,000)
Retirement of Long-term Debt – Affiliated	(15,000)	-	-
Change in Advances to/from Affiliates, Net	14,710	(42,814)	18,564
Dividends Paid	(16,448)	(21,131)	(30,245)
Net Cash Flows From Financing Activities	17,525	106,519	3,319
Net Increase (Decrease) in Cash and Cash Equivalents	(1,418)	357	(323)
Cash and Cash Equivalents at Beginning of Period	2,304	1,947	2,270
Cash and Cash Equivalents at End of Period	$886	$2,304	$1,947

SUPPLEMENTAL DISCLOSURE:
Cash paid for interest net of capitalized amounts was $26,988,000, $25,176,000 and $27,090,000 in 2003, 2002 and 2001, respectively. Cash (received) paid for income taxes was $(17,574,000), $13,041,000 and $7,549,000 in 2003, 2002 and 2001, respectively. Noncash acquisitions under capital leases were $22,000 and $817,000 in 2002 and 2001, respectively. There were no non-cash capital lease acquisitions in 2003.

See Notes to Respective Financial Statements beginning on page L-1.

KENTUCKY POWER COMPANY
STATEMENTS OF CAPITALIZATION
December 31, 2003 and 2002

	2003	2002
	(in thousands)	
COMMON SHAREHOLDER'S EQUITY	$317,138	$298,018
LONG-TERM DEBT (See Schedule of Long-term Debt):		
Senior Unsecured Notes	427,602	352,508
Notes Payable	60,000	75,000
Junior Debentures	-	39,124
Less Portion Due Within One Year	-	(15,000)
Long-term Debt Excluding Portion Due Within One Year	487,602	451,632
TOTAL CAPITALIZATION	$804,740	$749,650

See Notes to Respective Financial Statements beginning on page L-1.

KENTUCKY POWER COMPANY
SCHEDULE OF LONG-TERM DEBT
December 31, 2003 and 2002

Senior Unsecured Notes outstanding were as follows:

% Rate	Due	2003	2002
		(in thousands)	
6.91	2007 – October 1	$48,000	$48,000
6.45	2008 – November 10	30,000	30,000
5.50	2007 – July 1	125,000	125,000
4.31	2007 – November 12	80,400	80,400
4.37	2007 – December 12	69,564	69,564
5.625	2032 – December 31	75,000	-
Unamortized Discount		(362)	(456)
Total		$427,602	$352,508

Notes Payable to parent company were as follows:

% Rate	Due	2003	2002
		(in thousands)	
4.336	2003 – May 15	$-	$15,000
6.501	2006 – May 15	60,000	60,000
Total		$60,000	$75,000

Junior Debentures outstanding were as follows:

% Rate	Due	2003	2002
		(in thousands)	
8.72	2025 – June 30	$-	$40,000
Unamortized Discount		-	(876)
Total		$ -	$39,124

Interest may be deferred and payment of principal and interest on the junior debentures is subordinated and subject in right to the prior payment in full of all senior indebtedness of the Company.

At December 31, 2003, future annual long-term debt payments are as follows:

	Amount (in thousands)
2004	$-
2005	-
2006	60,000
2007	322,964
2008	30,000
Later Years	75,000
Total Principal Amount	487,964
Unamortized Discount	(362)
Total	$487,602

KENTUCKY POWER COMPANY
INDEX TO NOTES TO RESPECTIVE FINANCIAL STATEMENTS

The notes to KPCo's financial statements are combined with the notes to respective financial statements for other subsidiary registrants. Listed below are the notes that apply to KPCo. The footnotes begin on page L-1.

INDEPENDENT AUDITORS' REPORT

To the Shareholder and Board of
Directors of Kentucky Power Company:

We have audited the accompanying balance sheets and statements of capitalization of Kentucky Power Company as of December 31, 2003 and 2002, and the related statements of income, changes in common shareholder's equity and comprehensive income and cash flows for each of the three years in the period ended December 31, 2003. These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements based on our audits.

We conducted our audits in accordance with auditing standards generally accepted in the United States of America. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, such financial statements present fairly, in all material respects, the financial position of Kentucky Power Company as of December 31, 2003 and 2002, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2003 in conformity with accounting principles generally accepted in the United States of America.

As discussed in Note 2 to the financial statements, the Company adopted EITF 02-3, "Issues Involved in Accounting for Derivative Contracts Held for Trading Purposes and Contracts Involved in Energy Trading and Risk Management Activities," effective January 1, 2003.

/s/ Deloitte & Touche LLP

Columbus, Ohio
March 5, 2004

OHIO POWER COMPANY CONSOLIDATED

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OHIO POWER COMPANY CONSOLIDATED
SELECTED CONSOLIDATED FINANCIAL DATA

	2003	2002	2001	2000	1999
			(in thousands)		
INCOME STATEMENTS DATA					
Operating Revenues	$2,244,653	$2,113,125	$2,098,105	$2,140,331	$1,978,826
Operating Expenses	1,884,986	1,814,796	1,857,395	1,913,504	1,689,997
Operating Income	359,667	298,329	240,710	226,827	288,829
Nonoperating Items, Net	(2,172)	5,376	18,686	(5,004)	7,000
Interest Charges	106,464	83,682	93,603	119,210	83,672
Income Before Extraordinary Item And Cumulative Effect	251,031	220,023	165,793	102,613	212,157
Extraordinary Loss (Net of Tax)	-	-	(18,348)	(18,876)	-
Cumulative Effect of Accounting Changes (Net of Tax)	124,632	-	-	-	-
Net Income	375,663	220,023	147,445	83,737	212,157
Preferred Stock Dividend Requirements	1,098	1,258	1,258	1,266	1,417
Earnings Applicable To Common Stock	$374,565	$218,765	$146,187	$82,471	$210,740
BALANCE SHEETS DATA					
Electric Utility Plant	$6,531,315	$5,685,826	$5,390,576	$5,577,631	$5,400,917
Accumulated Depreciation	2,485,947	2,469,837	2,360,857	2,678,606	2,540,445
Net Electric Utility Plant	$4,045,368	$3,215,989	$3,029,719	$2,899,025	$2,860,472
TOTAL ASSETS	$5,374,518	$4,554,023	$4,485,787	$6,279,499	$4,756,425
Common Stock and Paid-in Capital	$783,685	$783,684	$783,684	$783,684	$783,577
Retained Earnings	729,147	522,316	401,297	398,086	587,424
Accumulated Other Comprehensive Income (Loss)	(48,807)	(72,886)	(196)	-	-
Total Common Shareholder's Equity	$1,464,025	$1,233,114	$1,184,785	$1,181,770	$1,371,001
Cumulative Preferred Stock:					
Not Subject to Mandatory Redemption	$16,645	$16,648	$16,648	$16,648	$16,937
Subject to Mandatory Redemption (a)	7,250	8,850	8,850	8,850	8,850
Total Cumulative Preferred Stock	$23,895	$25,498	$25,498	$25,498	$25,787
Long-term Debt (a)	$2,039,940	$1,067,314	$1,203,841	$1,195,493	$1,151,511
Obligations Under Capital Leases (a)	$34,688	$65,626	$80,666	$116,581	$136,543
TOTAL CAPITALIZATION AND LIABILITIES	$5,374,518	$4,554,023	$4,485,787	$6,279,499	$4,756,425

(a) Including portion due within one year.

OHIO POWER COMPANY CONSOLIDATED
MANAGEMENT'S FINANCIAL DISCUSSION AND ANALYSIS

OPCo is a public utility engaged in the generation and purchase of electric power and the subsequent sale, transmission and distribution of that power to approximately 704,000 retail customers in the northwestern, east central, eastern and southern sections of Ohio. We also supply and market electric power at wholesale to other electric utility companies, municipalities and electric cooperatives. We, as a member of the AEP Power Pool, share in the revenues and the costs of the AEP Power Pool's wholesale sales to neighboring utilities.

The cost of the AEP Power Pool's generating capacity is allocated among its members based on their relative peak demands and generating reserves through the payment of capacity charges and the receipt of capacity credits. AEP Power Pool members are also compensated for the out-of-pocket costs of energy delivered to the AEP Power Pool and charged for energy received from the AEP Power Pool. The AEP Power Pool calculates each member's prior twelve-month peak demand relative to the sum of the peak demands of all members as a basis for sharing revenues and costs. The result of this calculation is the member load ratio (MLR), which determines each member's percentage share of revenues and costs.

Power and gas risk management activities are conducted on our behalf by AEPSC. We share in the revenues and expenses associated with these risk management activities with other AEP registrant subsidiaries excluding AEGCo under existing power pool and system integration agreements. Risk management activities primarily involve the purchase and sale of electricity under physical forward contracts at fixed and variable prices and to a lesser extent gas. The electricity and gas contracts include physical transactions, over-the-counter options and swaps and exchange traded futures and options. The majority of the physical forward contracts are typically settled by entering into offsetting contracts.

Under our system integration agreement, revenues and expenses from the sales to neighboring utilities, power marketers and other power and gas risk management entities are shared among AEP East and West companies. Sharing in a calendar year is based upon the level of such activities experienced for the twelve months ended June 30, 2000, which immediately preceded the merger of AEP and CSW. This resulted in an AEP East and West companies' allocation of approximately 91% and 9%, respectively, for revenues and expenses. Allocation percentages in any given calendar year may also be based upon the relative generating capacity of the AEP East and West companies in the event the pre-merger activity level is exceeded. The capacity based allocation mechanism was triggered in June 2003, resulting in an allocation factor of approximately 70% and 30% for the AEP East and West companies, respectively, for the remainder of 2003.

Effective July 1, 2003, we consolidated JMG Funding, LP (JMG) as a result of the implementation of FIN 46. OPCo now records the depreciation, interest and other operating expenses of JMG and eliminates JMG's revenues against OPCo's operating lease expenses. While there was no effect to net income as a result of consolidation, some individual income statement captions were affected. See Note 2, "New Accounting Pronouncements, Extraordinary Items and Cumulative Effect of Accounting Changes," and Note 15, "Leases," for further discussion of the effects of FIN 46.

Results of Operations

During 2003, Net Income increased $156 million including a $125 million Cumulative Effect of Accounting Changes in the first quarter of 2003 (see Note 2). Income Before Cumulative Effect of Accounting Changes increased $31 million primarily due to increased revenues which were allocated to us from sales made to third parties by the AEP Power Pool.

During 2002, Income Before Extraordinary Item increased $54 million due to reductions in operating expenses, predominantly fuel, and interest charges.

2003 Compared to 2002

Operating Income

Operating Income increased $61 million for the year 2003 compared with 2002 due to:

- A $22 million increase in revenues from non-affiliated system sales and a $119 million increase in Sales to AEP Affiliates. The increase in non-affiliated system sales is primarily the result of an 8.9% increase in the price per MWH in 2003. The increase in affiliated sales is the result of optimizing our generation capacity and selling our excess generated power to the AEP Power Pool.
- A $47 million decrease in Other Operation expense. This decrease was primarily due to a $23 million decrease in rent expense associated with the OPCo consolidation of JMG. OPCo now records the depreciation, interest and other expenses of JMG and eliminates operating lease expense against JMG's lease revenues (there was no change in overall net income due to the consolidation of JMG). In addition, operation expenses decreased due to a $7 million pre-tax adjustment to the workers' compensation reserve related to coal companies sold in July 2001, a $9 million decrease in expense related to post-employment benefits and an $8 million reduction in employee salary expenses.

The increase in Operating Income was partially offset by:

- An increase in Fuel for Electric Generation of $32 million as a result of a 9.7% increase in MWH generated.
- An increase in Purchased Electricity from AEP Affiliates of $20 million resulting from a 31% volume increase in MWHs purchased from the AEP Power Pool.
- A $30 million increase in Maintenance expenses. The increase in 2003 is primarily due to increased boiler overhaul costs for planned and forced outages coupled with increased expense in maintaining overhead lines due to storm damage in Southern Ohio.
- An increase in Depreciation and Amortization associated with the OPCo consolidation of JMG. Depreciation expense related to the assets owned by JMG are now consolidated with OPCo.
- An increase in Income Taxes of $32 million as a result of an increase in pre-tax operating book income and tax return adjustments.

Other Impacts of Earnings

Nonoperating Income decreased $34 million for the year 2003 compared to 2002 primarily due to lower profit from power sold outside AEP's traditional marketing area resulting from AEP's plan to exit risk management activities in areas outside of its traditional market area.

Nonoperating Income Tax Expense decreased $26 million as a result of a decrease in pre-tax nonoperating book income and changes related to consolidated tax savings.

Interest charges increased $23 million due primarily to the consolidation of JMG and its associated debt along with replacement of lower cost floating-rate short-term debt with higher cost fixed-rate longer-term debt.

Cumulative Effect of Accounting Changes

The Cumulative Effect of Accounting Changes is due to the one-time after-tax impact of adopting SFAS 143 and implementing the requirements of EITF 02-3 (see Note 2).

2002 Compared to 2001

Operating Income

Operating Income increased $58 million from the year 2001 to the year 2002 primarily due to:

- A $61 million increase in nonaffiliated revenues resulting from a 39% increase in cooling degree days during the summer months along with a 32% increase in the heating degree days during the fall season. This reflects a return to more normal weather conditions since 2001 weather was abnormally mild.
- A $102 million decrease in Fuel for Electric Generation expense. This reflects a reduction of 19% in average cost of fuel for generation, offset in part by a slight increase in MWH generated. The decrease in fuel costs are the result of purchasing coal at lower prices on the open market in 2002 instead of affiliated company coal.

The increase in Operating Income was partially offset by:

- A $46 million decrease in Sales to AEP Affiliates. This decrease is due to a 15% decrease in price, reflective of lower average fuel cost, while MWH sales rose slightly.
- A $13 million increase in Purchased Electricity for Resale and Purchased Electricity from AEP Affiliates expenses. This was the result of an 11% increase in MWH sales and an 18% increase of MWH purchased from affiliates, partially offset by a decrease in price.
- A $16 million increase in Taxes Other Than Income Taxes as a result of increases in state excise tax created from a change in the base tax calculation.
- A $12 million increase in both federal and state tax expenses. Federal taxes increased due to higher pre-tax operating income offset in part by changes in certain book/tax timing differences accounted for on a flow-thru basis. State taxes increased predominately as a result of the State of Ohio's tax legislation revision involving utility deregulation.

Other Impacts on Earnings

Nonoperating Expenses decreased $25 million during 2002 due to reductions in variable incentive compensation expenses associated with risk management activities.

Nonoperating Income Tax Expense increased $20 million as a result of a favorable tax benefit recognized in 2001 from the sale of the Ohio Coal companies.

Interest Charges decreased $10 million due primarily to a decrease in the outstanding balances of long-term debt, the refinancing of debt at favorable interest rates and a reduction in short-term interest rates.

Extraordinary Loss

In the second quarter of 2001, an extraordinary loss of $18 million net of tax was recorded to write-off prepaid Ohio excise taxes stranded by Ohio deregulation (see Note 2).

Financial Condition

Credit Ratings

The rating agencies currently have us on stable outlook. Current ratings are as follows:

	Moody's	S&P	Fitch
First Mortgage Bonds	A3	BBB	A-
Senior Unsecured Debt	A3	BBB	BBB+

In February 2003, Moody's Investor Service (Moody's) completed their review of AEP and its rated subsidiaries. The completion of this review was a culmination of ratings action started during 2002. In March 2003, S&P lowered AEP and its subsidiaries senior unsecured ratings from BBB+ to BBB along with the first mortgage bonds of AEP subsidiaries.

Cash Flow

Cash flows years ended December 31, 2003, 2002 and 2001 were as follows:

	2003	2002	2001
		(in thousands)	
Cash and cash equivalents at beginning of period	$5,285	$8,848	$31,393
Cash flows from (used for):			
Operating activities	373,443	478,973	86,756
Investing activities	(237,011)	(348,298)	(359,908)
Financing activities	(83,467)	(134,238)	250,607
Net increase (decrease) in cash and cash equivalents	52,965	(3,563)	(22,545)
Cash and cash equivalents at end of period	$58,250	$5,285	$8,848

Operating Activities

Cash flows from operating activities for the year 2003 decreased $106 million compared to the year 2002 as they were adversely impacted primarily by significant reductions of accounts payable balances partially associated with a wind down of risk management activities in the current year.

Cash flows from operating activities for the year 2002 compared to the year 2001 increased $392 million as they were adversely impacted primarily by significant increases in Employee Benefits and Other Noncurrent Liabilities.

Investing Activities

Cash flows used for investing activities were reduced in the year 2003 compared with the year 2002 due primarily to a $110 million decrease in construction expenditures.

Cash flows used for investing activities remained relatively consistent from the year 2001 to the year 2002.

Financing Activities

Cash flows used for financing activities for the year of 2003 compared to the year 2002 used $51 million less primarily due to the retirement and restructuring of our long-term and short-term debt during 2003. We retired $300 million of Long-term Debt to Affiliated Companies and $275 million of Short-term Debt to Affiliated Companies with the proceeds of two Senior Unsecured Notes at $250 million each. In addition we issued two series of Senior Unsecured Notes, each in the amount of $225 million in July 2003.

Cash flows used for financing activities for the year 2002 compared to the year 2001 increased $385 million. This is primarily due to a decrease in the change in Advances to/from Affiliates, net during 2002.

Summary Obligation Information

Our contractual obligations include amounts reported on the Consolidated Balance Sheets and other obligations disclosed in the footnotes. The following table summarizes our contractual cash obligations at December 31, 2003:

	Payments Due by Period (in millions)				
Contractual Cash Obligations	**Less Than 1 year**	**2-3 years**	**4-5 years**	**After 5 years**	**Total**
Long-term Debt	$432	$25	$73	$1,510	$2,040
Short-term Debt	26	-	-	-	26
Preferred Stock Subject to Mandatory Redemption	2	4	1	-	7
Capital Lease Obligations	11	16	9	5	41
Unconditional Purchase Obligations (a)	626	917	511	578	2,632
Noncancellable Operating Leases	13	23	22	67	125
Total	$1,110	$985	$616	$2,160	$4,871

(a) Represents contractual obligations to purchase coal as fuel for electric generation along with related transportation of the fuel.

In addition to the amounts disclosed in the contractual cash obligations table above, we make additional commitments in the normal course of business. These commitments include standby letters of credit and other commitments. Our commitments outstanding at December 31, 2003 under these agreements are summarized in the table below:

	Amount of Commitment Expiration Per Period (in millions)				
Other Commercial Commitments	**Less Than 1 year**	**2-3 years**	**4-5 years**	**After 5 years**	**Total**
Standby Letters of Credit (a)	$5	$-	$-	$-	$5
Other Commercial Commitments (b)	14	14	-	-	28
Total Commercial Commitments	$19	$14	$-	$-	$33

(a) We have issued standby letters of credit to third parties. These letters of credit cover gas and electricity risk management contracts, construction contracts, insurance programs, security deposits, debt service reserves and credit enhancements for issued bonds. All of these letters of credit were issued in the ordinary course of business. AEP holds all assets of OPCo as collateral. There is no recourse to third parties in the event these letters of credit are drawn.

(b) We have entered into a 30-year power purchase agreement for electricity produced by an unaffiliated entity's three-unit natural gas fired plant. The plant was completed in 2002 and the agreement will terminate in 2032. Under the terms of the agreement, we have the option to run the plant until December 31, 2005, taking 100% of the power generated and making monthly capacity payments. The capacity payments are fixed through December 2005 at $1.2 million per month. For the remainder of the 30-year contract term, we will pay the variable costs to generate the electricity it purchases which could be up to 20% of the plant's capacity.

Other

Power Generation Facility

AEP has agreements with Juniper Capital L.P. (Juniper) for Juniper to develop, construct, and finance a non-regulated merchant power generation facility (Facility) near Plaquemine, Louisiana and for Juniper to lease the Facility to AEP.

The Facility is a "qualifying cogeneration facility" for purposes of PURPA. Construction of the Facility was begun by Katco Funding, Limited Partnership (Katco), an unrelated unconsolidated special purpose entity. Katco assigned its interest in the Facility to Juniper in June 2003.

Juniper is an unaffiliated limited partnership, formed to construct or otherwise acquire real and personal property for lease to third parties, to manage financial assets and to undertake other activities related to asset financing. Juniper arranged to finance the Facility with debt financing up to $494 million and equity up to $31 million from investors with no relationship to AEP or any of AEP's subsidiaries. Juniper will own the Facility and lease it to AEP after construction is completed.

Another AEP subsidiary is the construction agent for Juniper. They expect to achieve COD in the spring of 2004, at which time the obligation to make payments under the lease agreement will begin to accrue and AEP will sublease the Facility to The Dow Chemical Company (Dow). If COD does not occur on or before March 14, 2004, Juniper has the right to terminate the project. In the event the project is terminated before COD, AEP has the option to either purchase the Facility for 100% of Juniper's acquisition cost (in general, the outstanding debt and equity associated with the Facility) or terminate the project and make a payment to Juniper for 89.9% of project costs (in general, the acquisition cost less certain financing costs).

The initial term of the lease agreement between Juniper and AEP commences on COD and continues for five years. The lease contains extension options, and if all extension options are exercised, the total term of the lease will be 30 years. AEP's lease payments to Juniper during the initial term and each extended term are sufficient for Juniper to make required debt payments under Juniper's debt financing associated with the Facility and provide a return on equity to the investors in Juniper. AEP has the right to purchase the Facility for the acquisition cost during the last month of the initial term or on any monthly rent payment date during any extended term. In addition, AEP may purchase the Facility from Juniper for the acquisition cost at any time during the initial term if AEP has arranged a sale of the Facility to an unaffiliated third party. A purchase of the Facility from Juniper by AEP should not alter Dow's rights to lease the Facility or our contract to purchase energy from Dow. If the lease were renewed for up to a 30-year lease term, AEP may further renew the lease at fair market value subject to Juniper's approval, purchase the Facility at its acquisition cost, or sell the Facility, on behalf of Juniper, to an independent third party. If the Facility is sold and the proceeds from the sale are insufficient to pay all of Juniper's acquisition costs, AEP may be required to make a payment (not to exceed $396 million) to Juniper of the excess of Juniper's acquisition costs over the proceeds from the sale, provided that AEP would not be required to make any payment if AEP has made the additional rental prepayment described below. AEP has guaranteed the performance of our subsidiaries to Juniper during the lease term. Because AEP now reports the debt related to the Facility on our balance sheet, the fair value of the liability for our guarantee (the $396 million payment discussed above) is not separately reported.

At December 31, 2003, Juniper's acquisition costs for the Facility totaled $496 million, and total costs for the completed Facility are currently expected to be approximately $525 million. For the 30-year extended lease term, the base lease rental is a variable rate obligation indexed to three-month LIBOR. Consequently, as market interest rates increase, the base rental payments under the lease will also increase. Annual payments of approximately $18 million represent future minimum payments for interest on Juniper's financing structure during the initial term calculated using the indexed LIBOR rate (1.15% at December 31, 2003). An additional rental prepayment (up to $396 million) may be due on June 30, 2004 unless Juniper has refinanced its present debt financing on a long-term basis. Juniper is currently planning to refinance by June 30, 2004. The Facility is collateral for the debt obligation of Juniper. At December 31, 2003, we reflected $396 million of the $496 million recorded obligation as long-term debt due within one year. Our maximum required cash payment as a result of our financing transaction with Juniper is $396 million as well as interest payments during the lease term. Due to the treatment of the Facility as a financing of an owned asset, the recorded liability of $496 million is greater than our maximum possible cash payment obligation to Juniper.

Dow will use a portion of the energy produced by the Facility and sell the excess energy. OPCo has agreed to purchase up to approximately 800 MW of such excess energy from Dow. OPCo has also agreed to sell up to approximately 800 MW of energy to Tractebel Energy Marketing, Inc. (TEM) for a period of 20 years under a Power Purchase and Sale Agreement dated November 15, 2000 (PPA) at a price that is currently in excess of market. Beginning May 1, 2003, OPCo tendered replacement capacity, energy and ancillary services to TEM pursuant to the PPA that TEM rejected as non-conforming.

OPCo entered into an agreement with an affiliate that eliminates OPCo's market exposure related to the PPA. AEP has guaranteed this affiliate's performance under the agreement.

On September 5, 2003, TEM and AEP separately filed declaratory judgment actions in the United States District Court for the Southern District of New York. AEP alleges that TEM has breached the PPA, and is seeking a determination of OPCo's rights under the PPA. TEM alleges that the PPA never became enforceable, or alternatively, that the PPA has already been terminated as the result of AEP breaches. If the PPA is deemed terminated or found to be unenforceable by the court, AEP could be adversely affected to the extent we are unable to find other purchasers of the power with similar contractual terms to the extent we do not fully recover claimed termination value damages from TEM. The corporate parent of TEM has provided a limited guaranty.

On November 18, 2003, the above litigation was suspended pending final resolution in arbitration of all issues pertaining to the protocols related to the dispatching, operation and maintenance of the Facility and the sale and delivery of electric power products. In the arbitration proceedings, TEM basically argued that in the absence of mutually agreed upon protocols there was no commercially reasonable means to obtain or deliver the electric power products and therefore the PPA is not enforceable. TEM further argued that the creation of the protocols is not subject to arbitration. The arbitrator ruled in favor of TEM on February 11, 2004 and concluded that the "creation of protocols" was not subject to arbitration, but did not rule upon the merits of TEM's claim that the PPA is not enforceable.

If commercial operation is not achieved for purposes of the PPA by April 30, 2004, TEM may claim that it can terminate the PPA and is owed liquidating damages of approximately $17.5 million. TEM may also claim that we are not entitled to receive any termination value for the PPA.

Significant Factors

See the "Registrants' Combined Management's Discussion and Analysis" section beginning on page M-1 for additional discussion of factors relevant to us.

Quantitative And Qualitative Disclosures About Risk Management Activities

Market Risks

Our risk management policies and procedures are instituted and administered at the AEP consolidated level. See complete discussion within AEP's "Qualitative And Quantitative Disclosures About Risk Management Activities" section. The following tables provide information about our risk management activities' effect on this specific registrant.

Roll-Forward of MTM Risk Management Contract Net Assets

This table provides detail on changes in our MTM net asset or liability balance sheet position from one period to the next.

MTM Risk Management Contract Net Assets
Year Ended December 31, 2003
(in thousands)

Domestic Power	
Beginning Balance December 31, 2002	$94,106
(Gain) Loss from Contracts Realized/Settled During the Period (a)	(38,249)
Fair Value of New Contracts When Entered Into During the Period (b)	-
Net Option Premiums Paid/(Received) (c)	106
Change in Fair Value Due to Valuation Methodology Changes	-
Effect of EITF 98-10 Rescission (d)	(4,159)
Changes in Fair Value of Risk Management Contracts (e)	2,134
Changes in Fair Value of Risk Management Contracts Allocated to Regulated Jurisdictions (f)	-
Total MTM Risk Management Contract Net Assets, Excluding Cash Flow Hedges	53,938
Net Cash Flow Hedge Contracts (g)	412
DETM Assignment (h)	(24,055)
Ending Balance December 31, 2003	$30,295

(a)"(Gain) Loss from Contracts Realized/Settled During the Period" includes realized gains from risk management contracts and related derivatives that settled during 2003 that were entered into prior to 2003.

(b) The "Fair Value of New Contracts When Entered Into During the Period" represents the fair value of long-term contracts entered into with customers during 2003. The fair value is calculated as of the execution of the contract. Most of the fair value comes from longer term fixed price contracts with customers that seek to limit their risk against fluctuating energy prices. The contract prices are valued against market curves associated with the delivery location.

(c)"Net Option Premiums Paid/(Received)" reflects the net option premiums paid/(received) as they relate to unexercised and unexpired option contracts that were entered into in 2003.

(d) See Note 2 "New Accounting Pronouncements, Extraordinary Items and Cumulative Effect of Accounting Changes."

(e)"Changes in Fair Value of Risk Management Contracts" represents the fair value change in the risk management portfolio due to market fluctuations during the current period. Market fluctuations are attributable to various factors such as supply/demand, weather, storage, etc.

(f)"Change in Fair Value of Risk Management Contracts Allocated to Regulated Jurisdictions" relates to the net gains (losses) of those contracts that are not reflected in the Consolidated Statements of Income. These net gains (losses) are recorded as regulatory liabilities/assets for those subsidiaries that operate in regulated jurisdictions.

(g)"Net Cash Flow Hedge Contracts" (pre-tax) are discussed below in Accumulated Other Comprehensive Income (Loss).

(h) See Note 17 "Related Party Transactions."

Maturity and Source of Fair Value of MTM Risk Management Contract Net Assets

The table presenting maturity and source of fair value of MTM risk management contract net assets provides two fundamental pieces of information:

- The source of fair value used in determining the carrying amount of our total MTM asset or liability (external sources or modeled internally).
- The maturity, by year, of our net assets/liabilities, giving an indication of when these MTM amounts will settle and generate cash.

Maturity and Source of Fair Value of MTM
Risk Management Contract Net Assets
Fair Value of Contracts as of December 31, 2003

	2004	2005	2006	2007	2008	After 2008	Total (c)
				(in thousands)			
Prices Actively Quoted – Exchange Traded Contracts	$908	$(183)	$22	$142	$-	$-	$889
Prices Provided by Other External Sources – OTC Broker Quotes (a)	20,921	6,344	6,221	2,530	1,269	-	37,285
Prices Based on Models and Other Valuation Methods (b)	(4)	26	2,468	2,853	2,623	7,798	15,764
Total	$21,825	$6,187	$8,711	$5,525	$3,892	$7,798	$53,938

(a) "Prices Provided by Other External Sources – OTC Broker Quotes" reflects information obtained from over-the-counter brokers, industry services, or multiple-party on-line platforms.

(b) "Prices Based on Models and Other Valuation Methods" is in absence of pricing information from external sources, modeled information is derived using valuation models developed by the reporting entity, reflecting when appropriate, option pricing theory, discounted cash flow concepts, valuation adjustments, etc. and may require projection of prices for underlying commodities beyond the period that prices are available from third-party sources. In addition, where external pricing information or market liquidity are limited, such valuations are classified as modeled. The determination of the point at which a market is no longer liquid for placing it in the Modeled category varies by market.

(c) Amounts exclude Cash Flow Hedges.

Cash Flow Hedges Included in Accumulated Other Comprehensive Income (Loss) (AOCI) on the Balance Sheet

The table provides detail on effective cash flow hedges under SFAS 133 included in the balance sheet. The data in the table will indicate the magnitude of SFAS 133 hedges we have in place. (However, given that under SFAS 133 only cash flow hedges are recorded in AOCI, the table does not provide an all-encompassing picture of our hedging activity). The table also includes a roll-forward of the AOCI balance sheet account, providing insight into the drivers of the changes (new hedges placed during the period, changes in value of existing hedges and roll-off of hedges). In accordance with GAAP, all amounts are presented net of related income taxes.

Total Accumulated Other Comprehensive Income (Loss) Activity
Year Ended December 31, 2003

	Domestic Power	Foreign Currency (in thousands)	Consolidated
Beginning Balance December 31, 2002	$(354)	$(384)	$(738)
Changes in Fair Value (a)	256	-	256
Reclassifications from AOCI to Net Income (b)	366	13	379
Ending Balance December 31, 2003	$268	$(371)	$(103)

(a) "Changes in Fair Value" shows changes in the fair value of derivatives designated as hedging instruments in cash flow hedges during the reporting period not yet reclassified into net income, pending the hedged item's affecting net income. Amounts are reported net of related income taxes.

(b) "Reclassifications from AOCI to Net Income" represents gains or losses from derivatives used as hedging instruments in cash flow hedges that were reclassified into net income during the reporting period. Amounts are reported net of related income taxes above.

The portion of cash flow hedges in AOCI expected to be reclassified to earnings during the next twelve months is a $1,231 thousand gain.

Credit Risk

Our counterparty credit quality and exposure is generally consistent with that of AEP.

VaR Associated with Risk Management Contracts

The following table shows the end, high, average, and low market risk as measured by VaR for year-to-date:

December 31, 2003 (in thousands)				December 31, 2002 (in thousands)			
End	High	Average	Low	End	High	Average	Low
$444	$1,724	$722	$172	$1,150	$3,521	$1,259	$255

VaR Associated with Debt Outstanding

The risk of potential loss in fair value attributable to our exposure to interest rates, primarily related to long-term debt with fixed interest rates was $214 million and $34 million at December 31, 2003 and 2002, respectively. We would not expect to liquidate our entire debt portfolio in a one-year holding period, therefore a near term change in interest rates *should not* negatively affect our results of operation or consolidated financial position.

OHIO POWER COMPANY CONSOLIDATED
CONSOLIDATED STATEMENTS OF INCOME
For the Years Ended December 31, 2003, 2002 and 2001

	2003	2002	2001
		(in thousands)	
OPERATING REVENUES			
Electric Generation, Transmission and Distribution	$1,660,375	$1,647,923	$1,586,739
Sales to AEP Affiliates	584,278	465,202	511,366
TOTAL	2,244,653	2,113,125	2,098,105
OPERATING EXPENSES			
Fuel for Electric Generation	616,680	584,730	686,568
Purchased Electricity for Resale	63,486	67,385	63,441
Purchased Electricity from AEP Affiliates	90,821	71,154	62,585
Other Operation	369,087	416,533	400,790
Maintenance	166,438	136,609	142,878
Depreciation and Amortization	257,417	248,557	239,982
Taxes Other Than Income Taxes	175,043	176,247	159,778
Income Taxes	146,014	113,581	101,373
TOTAL	1,884,986	1,814,796	1,857,395
OPERATING INCOME	359,667	298,329	240,710
Nonoperating Income	24,495	58,289	76,341
Nonoperating Expenses	34,282	34,903	60,035
Nonoperating Income Tax Expense (Credit)	(7,615)	18,010	(2,380)
Interest Charges	106,464	83,682	93,603
Income Before Extraordinary Item and Cumulative Effect	251,031	220,023	165,793
Extraordinary Loss (Net of Tax)	-	-	(18,348)
Cumulative Effect of Accounting Changes (Net of Tax)	124,632	-	-
NET INCOME	375,663	220,023	147,445
Preferred Stock Dividend Requirements	1,098	1,258	1,258
EARNINGS APPLICABLE TO COMMON STOCK	$374,565	$218,765	$146,187

The common stock of OPCo is wholly-owned by AEP.

See Notes to Respective Financial Statements beginning on page L-1.

OHIO POWER COMPANY CONSOLIDATED
CONSOLIDATED STATEMENTS OF CHANGES IN COMMON SHAREHOLDER'S EQUITY AND COMPREHENSIVE INCOME
For the Years Ended December 31, 2003, 2002 and 2001
(in thousands)

	Common Stock	Paid-in Capital	Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Total
DECEMBER 31, 2000	$321,201	$462,483	$398,086	$-	$1,181,770
Common Stock Dividends			(142,976)		(142,976)
Preferred Stock Dividends			(1,258)		(1,258)
TOTAL					1,037,536
COMPREHENSIVE INCOME					
Other Comprehensive Income (Loss)					
Net of Taxes:					
Unrealized Loss on Cash Flow Hedges				(196)	(196)
NET INCOME			147,445		147,445
TOTAL COMPREHENSIVE INCOME					147,249
DECEMBER 31, 2001	$321,201	$462,483	$401,297	$(196)	$1,184,785
Common Stock Dividends			(97,746)		(97,746)
Preferred Stock Dividends			(1,258)		(1,258)
TOTAL					1,085,781
COMPREHENSIVE INCOME					
Other Comprehensive Income (Loss)					
Net of Taxes:					
Unrealized Loss on Cash Flow Hedges				(542)	(542)
Minimum Pension Liability				(72,148)	(72,148)
NET INCOME			220,023		220,023
TOTAL COMPREHENSIVE INCOME					147,333
DECEMBER 31, 2002	$321,201	$462,483	$522,316	$(72,886)	$1,233,114
Common Stock Dividends			(167,734)		(167,734)
Preferred Stock Dividends			(1,098)		(1,098)
Capital Stock Gains		1			1
TOTAL					1,064,283
COMPREHENSIVE INCOME					
Other Comprehensive Income (Loss)					
Net of Taxes:					
Unrealized Gain on Cash Flow Hedges				635	635
Minimum Pension Liability				23,444	23,444
NET INCOME			375,663		375,663
TOTAL COMPREHENSIVE INCOME					399,742
DECEMBER 31, 2003	$321,201	$462,484	$729,147	$(48,807)	$1,464,025

See Notes to Respective Financial Statements beginning on page L-1.

OHIO POWER COMPANY CONSOLIDATED
CONSOLIDATED BALANCE SHEETS
ASSETS
December 31, 2003 and 2002

	2003	2002
	(in thousands)	
ELECTRIC UTILITY PLANT		
Production	$4,029,515	$3,116,825
Transmission	938,805	905,829
Distribution	1,156,886	1,114,600
General	245,434	260,153
Construction Work in Progress	160,675	288,419
Total	6,531,315	5,685,826
Accumulated Depreciation and Amortization	2,485,947	2,469,837
TOTAL – NET	4,045,368	3,215,989
OTHER PROPERTY AND INVESTMENTS		
Non-Utility Property, Net	29,291	29,037
Other	24,264	32,649
TOTAL	53,555	61,686
CURRENT ASSETS		
Cash and Cash Equivalents	58,250	5,285
Advances to Affiliates	67,918	-
Accounts Receivable:		
Customers	100,960	113,207
Affiliated Companies	120,532	124,244
Miscellaneous	736	1,174
Allowance for Uncollectible Accounts	(789)	(909)
Fuel	77,725	87,409
Materials and Supplies	92,136	85,379
Risk Management Assets	56,265	91,872
Margin Deposits	9,296	1,636
Prepayments and Other	33,104	10,683
TOTAL	616,133	519,980
DEFERRED DEBITS AND OTHER ASSETS		
Regulatory Assets:		
SFAS 109 Regulatory Asset, Net	169,605	165,106
Transition Regulatory Assets	310,035	375,409
Unamortized Loss on Reacquired Debt	10,172	4,899
Other	22,506	23,227
Long-term Risk Management Assets	52,825	103,230
Deferred Property Taxes	67,469	66,621
Deferred Charges and Other Assets	26,850	17,876
TOTAL	659,462	756,368
TOTAL ASSETS	$5,374,518	$4,554,023

See Notes to Respective Financial Statements beginning on page L-1.

OHIO POWER COMPANY CONSOLIDATED
CONSOLIDATED BALANCE SHEETS
CAPITALIZATION AND LIABILITIES
December 31, 2003 and 2002

	2003	2002
	(in thousands)	
CAPITALIZATION		
Common Shareholder's Equity:		
Common Stock – No Par Value:		
Authorized – 40,000,000 Shares		
Outstanding – 27,952,473 Shares	$321,201	$321,201
Paid-in Capital	462,484	462,483
Retained Earnings	729,147	522,316
Accumulated Other Comprehensive Income (Loss)	(48,807)	(72,886)
Total Common Shareholder's Equity	1,464,025	1,233,114
Cumulative Preferred Stock Not Subject to Mandatory Redemption	16,645	16,648
Total Shareholder's Equity	1,480,670	1,249,762
Liability for Cumulative Preferred Stock Subject to Mandatory Redemption	7,250	8,850
Long-term Debt:		
Nonaffiliated	1,608,086	677,649
Affiliated	-	240,000
Total Long-term Debt	1,608,086	917,649
TOTAL	3,096,006	2,176,261
Minority Interest	16,314	-
CURRENT LIABILITIES		
Short-term Debt – General	25,941	-
Short-term Debt – Affiliates	-	275,000
Long-term Debt Due Within One Year – Nonaffiliated	431,854	89,665
Long-term Debt Due Within One Year – Affiliated	-	60,000
Advances from Affiliates	-	129,979
Accounts Payable:		
General	104,874	170,563
Affiliated Companies	101,758	145,718
Customer Deposits	17,308	12,969
Taxes Accrued	132,793	111,778
Interest Accrued	45,679	18,809
Risk Management Liabilities	38,318	61,839
Obligations Under Capital Leases	9,624	14,360
Other	71,642	80,608
TOTAL	979,791	1,171,288
DEFERRED CREDITS AND OTHER LIABILITIES		
Deferred Income Taxes	933,582	794,387
Regulatory Liabilities:		
Asset Removal Costs	101,160	-
Deferred Investment Tax Credits	15,641	18,748
Other	3	1,237
Long-term Risk Management Liabilities	40,477	39,702
Deferred Credits	23,222	27,719
Obligations Under Capital Leases	25,064	51,266
Asset Retirement Obligations	42,656	-
Other	100,602	273,415
TOTAL	1,282,407	1,206,474
Commitments and Contingencies (Note 7)		
TOTAL CAPITALIZATION AND LIABILITIES	$5,374,518	$4,554,023

See Notes to Respective Financial Statements beginning on page L-1.

OHIO POWER COMPANY CONSOLIDATED
CONSOLIDATED STATEMENTS OF CASH FLOWS
For the Years Ended December 31, 2003, 2002 and 2001

	2003	2002 (in thousands)	2001
OPERATING ACTIVITIES			
Net Income	$375,663	$220,023	$147,445
Adjustments to Reconcile Net Income to Net Cash Flows From Operating Activities:			
Cumulative Effect of Accounting Changes	(124,632)	-	-
Depreciation and Amortization	257,417	248,557	252,123
Deferred Income Taxes	24,482	46,010	215,833
Deferred Investment Tax Credits	(3,107)	(3,177)	(3,289)
Extraordinary Loss	-	-	18,348
Mark-to-Market of Risk Management Contracts	60,064	(28,693)	(59,833)
Changes in Certain Assets and Liabilities:			
Accounts Receivable, Net	16,335	14,571	51,640
Fuel, Materials and Supplies	2,927	704	4,852
Accrued Utility Revenues	(20,301)	3,081	264
Prepayments and Other	(13,096)	8,783	12,017
Accounts Payable	(173,218)	8,704	9,887
Customer Deposits	4,339	7,517	(34,284)
Taxes Accrued	21,015	(14,992)	(96,331)
Interest Accrued	21,533	1,130	(2,779)
Employee Benefits and Other Noncurrent Liabilities	(75,822)	110,298	(392,026)
Deferred Property Taxes	(855)	(1,818)	21,652
Change in Other Assets	(23,302)	(7,441)	46,162
Change in Other Liabilities	24,001	(134,284)	(104,925)
Net Cash Flows From Operating Activities	373,443	478,973	86,756
INVESTING ACTIVITIES			
Construction Expenditures	(244,312)	(354,797)	(344,571)
Proceeds from Sale of Property and Other	7,301	6,499	16,778
Investment in Coal Companies	-	-	(32,115)
Net Cash Flows Used For Investing Activities	(237,011)	(348,298)	(359,908)
FINANCING ACTIVITIES			
Issuance of Long-term Debt	988,914	-	-
Issuance of Long-term Debt – Affiliated	-	-	300,000
Change in Advances to/from Affiliates, Net	(197,897)	(170,234)	392,699
Change in Short-term Debt, Net	(671)	-	-
Change in Short-term Debt – Affiliates Net	(275,000)	275,000	-
Retirement of Long-term Debt – Nonaffiliated	(128,378)	(140,000)	(297,858)
Retirement of Long-term Debt – Affiliated	(300,000)	-	-
Retirement of Cumulative Preferred Stock	(1,603)	-	-
Dividends Paid on Common Stock	(167,734)	(97,746)	(142,976)
Dividends Paid on Cumulative Preferred Stock	(1,098)	(1,258)	(1,258)
Net Cash Flows From (Used For) Financing Activities	(83,467)	(134,238)	250,607
Net Increase (Decrease) in Cash and Cash Equivalents	52,965	(3,563)	(22,545)
Cash and Cash Equivalents at Beginning of Period	5,285	8,848	31,393
Cash and Cash Equivalents at End of Period	$58,250	$5,285	$8,848

SUPPLEMENTAL DISCLOSURE:
Cash paid (received) for interest net of capitalized amounts was $77,170,000, $81,041,000 and $94,747,000 and for income taxes was $98,923,000, $105,058,000 and $(22,417,000) in 2003, 2002 and 2001, respectively.

Noncash acquisitions under capital leases were $106,000 and $2,380,000 in 2002 and 2001, respectively. There were no noncash capital lease acquisitions in 2003. Noncash activity in 2003 included an increase in assets and liabilities of $469.6 million resulting from the consolidation of JMG (see Note 2).

See Notes to Respective Financial Statements beginning on page L-1.

OHIO POWER COMPANY CONSOLIDATED
CONSOLIDATED STATEMENTS OF CAPITALIZATION
December 31, 2003 and 2002

						2003	2002
						(in thousands)	
COMMON SHAREHOLDER'S EQUITY						$1,464,025	$1,233,114
PREFERRED STOCK:							
$100 Par Value - Authorized 3,762,403 shares							
$25 Par Value - Authorized 4,000,000 shares							
Series	**Call Price December 31, 2003 (a)**	**Number of Shares Redeemed Year Ended December 31,**			**Shares Outstanding December 31, 2003**		
		2003	**2002**	**2001**			
Not Subject to Mandatory Redemption-$100 Par:							
4.08%	$103	-	-	-	14,595	1,460	1,460
4.20%	103.20	-	-	-	22,824	2,282	2,282
4.40%	104	-	-	-	31,512	3,151	3,151
4-1/2%	110	23	-	-	97,523	9,752	9,755
Total						16,645	16,648
Subject to Mandatory Redemption-$100 Par (b):							
5.90% (c)	$-	-	-	-	72,500	7,250	7,250
6.02%	-	11,000	-	-	-	-	1,100
6.35%	-	5,000	-	-	-	-	500
Total						7,250	8,850
LONG-TERM DEBT (See Schedule of Long-term Debt):							
First Mortgage Bonds						9,950	136,633
Installment Purchase Contracts						539,406	233,340
Senior Unsecured Notes						1,343,706	397,341
Notes Payable – Nonaffiliated						146,878	-
Notes Payable – Affiliated						-	300,000
Less Portion Due Within One Year						(431,854)	(149,665)
Long-term Debt Excluding Portion Due Within One Year						1,608,086	917,649
TOTAL CAPITALIZATION						$3,096,006	$2,176,261

(a) The cumulative preferred stock is callable at the price indicated plus accrued dividends.
(b) Sinking fund provisions require the redemption of 35,000 shares in 2003 and 57,500 shares in each of 2004, 2005, 2006 and 2007. The sinking fund provisions of each series subject to mandatory redemption have been met by purchase of shares in advance of the due dates. Shares previously purchased may be applied to the sinking fund requirement. At the company's option, all shares are redeemable at $100 per share plus accrued and unpaid dividends with at least 30 days notice beginning on or after November 1, 2003 for the 5.90% series, October 1, 2003 for the 6.02% series, and April 1, 2003 for the 6.35% series.
(c) Commencing in 2004 and continuing through the year 2008, a sinking fund for the 5.90% cumulative preferred stock will require the redemption of 22,500 shares each year and the redemption of the remaining shares outstanding on January 1, 2009, in each case at $100 per share. Shares previously redeemed may be applied to meet sinking fund requirements.

See Notes to Respective Financial Statements beginning on page L-1.

OHIO POWER COMPANY CONSOLIDATED
SCHEDULE OF LONG-TERM DEBT
December 31, 2003 and 2002

First Mortgage Bonds outstanding were as follows:

% Rate	Due	2003	2002
		(in thousands)	
6.75	2003 – April 1	$-	$29,850
6.55	2003 – October 1	-	27,315
6.00	2003 – November 1	-	12,500
6.15	2003 – December 1	-	20,000
7.75	2023 – April 1	-	5,000
7.375	2023 – October 1	-	20,250
7.10	2023 – November 1	-	12,000
7.30	2024 – April 1 (a)	10,000	10,000
Unamortized Discount		(50)	(282)
Total		$9,950	$136,633

(a) This bond will be redeemed in April 2004 and has been classified for payment in 2004.

First Mortgage Bonds are secured by a first mortgage lien on electric utility plant. Certain supplemental indentures to the first mortgage lien contain maintenance and replacement provisions requiring the deposit of cash or bonds with the trustee, or in lieu thereof, certification of unfunded property additions. Interest payments are made semi-annually.

Installment Purchase Contracts have been entered into in connection with the issuance of pollution control revenue bonds by governmental authorities as follows:

% Rate	Due	2003	2002
		(in thousands)	
Mason County, West Virginia:			
5.45	2016 – December 1	$50,000	$50,000
Marshall County, West Virginia:			
5.45	2014 – July 1	50,000	50,000
5.90	2022 – April 1	35,000	35,000
6.85	2022 – June 1	50,000 (a)	50,000
(b)	2022 – June 1	50,000	-
Ohio Air Quality Development Authority:			
5.15	2026 – May 1	50,000	50,000
5.5625	2022 – October 1	19,565 (c)	-
5.5625	2023 – January 1	19,565 (c)	-
(d)	2028 – April 1	40,000 (c)	-
(e)	2028 – April 1	40,000 (c)	-
6.3750	2029 – January 1	51,000 (c)	-
6.3750	2029 – April 1	51,000 (c)	-
(d)	2029 – April 1	18,000 (c)	-
(e)	2029 – April 1	18,000 (c)	-
Unamortized Discount		(2,724)	(1,660)
Total		$539,406	$233,340

(a) This amount was redeemed in January 2004 using the proceeds from the variable interest Marshall County Installment Purchase Contract issued in December 2003. As a result of the early redemption, this amount is shown as due within one year in the debt maturity schedule.
(b) A floating interest rate is determined daily. The rate on December 31, 2003 was 1.29%.
(c) Due to FIN 46, OPCo was required to consolidate JMG during the third quarter of 2003 (see Note 2). Prior to consolidation, payments for an operating lease were made to JMG based on JMG's cost of financing (both debt and equity). As a result of the consolidation, operating lease payments were not recognized and OPCo recorded JMG's debt along with other balance sheet and income statement items. See Note 15, "Leases," for further discussion of JMG.
(d) A floating interest rate is determined weekly. The rate on December 31, 2003 was 1.13%.
(e) A floating interest rate is determined weekly. The rate on December 31, 2003 was 1.20%

Under the terms of the installment purchase contracts, OPCo is required to pay amounts sufficient to enable the payment of interest on and the principal of (at stated maturities and upon mandatory redemptions) related pollution control revenue bonds issued to finance the construction of pollution control facilities at certain plants. Interest payments range from monthly to semi-annually.

Senior Unsecured Notes outstanding were as follows:

% Rate	Due	2003	2002
		(in thousands)	
6.75	2004 – July 1	$100,000	$100,000
7.00	2004 – July 1	75,000	75,000
6.73	2004 – November 1	48,000	48,000
6.24	2008 – December 4	37,225	37,225
7-3/8	2038 – June 30 (a)	140,000	140,000
5.50	2013 – February 15	250,000	-
4.85	2014 – January 15	225,000	-
6.60	2033 – February 15	250,000	-
6.375	2033 – July 15	225,000	-
Unamortized Discount		(6,519)	(2,884)
Total		$1,343,706	$397,341

(a) This note was redeemed on March 1, 2004 and has been classified for payment in 2004.

Notes Payable to parent company were as follows:

% Rate	Due	2003	2002
		(in thousands)	
4.336	2003 – May 15	$-	$60,000
6.501	2006 – May 15	-	240,000
Total		$-	$300,000

Notes Payable to third parties outstanding were as follows:

% Rate	Due	2003	2002
		(in thousands)	
6.81	2008 – March 31 (a)	$24,878 (d)	$-
6.27	2009 – March 31 (b)	41,000 (d)	-
7.49	2009 – April 15	70,000 (d)	-
7.21	2009 – June 15 (c)	11,000 (d)	-
Total		$146,878	$-

(a) The terms of this note require quarterly principal payments of $5,853,659 per year through 2007 with the remaining $1,463,415 due at maturity. These payments are reflected in the debt maturity schedule.
(b) The terms of this note require semi-annual principal payments of $3 million per year for the year 2004, $6.5 million per year for the years 2005 and 2006, $12 million per year for the years 2007 and 2008 with the remaining amount of $1 million due at maturity. These payments are reflected in the debt maturity schedule.
(c) The terms of this note require a principal payment of $4.5 million in 2008 and the remaining amount of $6.5 million due in the year of maturity which is reflected in the debt maturity schedule.
(d) Due to FIN 46, OPCo was required to consolidate JMG during the third quarter of 2003 (see Note 2). Prior to consolidation, payments for an operating lease were made to JMG based on JMG's cost of financing (both debt and equity). As a result of the consolidation, operating lease payments were not recognized and OPCo recorded JMG's debt along with other balance sheet and income statement items. See Note 15, "Leases," for further discussion of JMG.

At December 31, 2003, future annual long-term debt payments are as follows:

	Amount (in thousands)
2004	$431,854
2005	12,354
2006	12,354
2007	17,853
2008	55,188
Later Years	1,519,630
Total Principal Amount	2,049,233
Unamortized Discount	(9,293)
Total	$2,039,940

OHIO POWER COMPANY CONSOLIDATED
INDEX TO NOTES TO RESPECTIVE FINANCIAL STATEMENTS

The notes to OPCo's financial statements are combined with the notes to respective financial statements for other subsidiary registrants. Listed below are the notes that apply to OPCo. The footnotes begin on page L-1.

INDEPENDENT AUDITORS' REPORT

To the Shareholders and Board of
Directors of Ohio Power Company:

We have audited the accompanying consolidated balance sheets and consolidated statements of capitalization of Ohio Power Company Consolidated as of December 31, 2003 and 2002, and the related consolidated statements of income, changes in common shareholder's equity and comprehensive income and cash flows for each of the three years in the period ended December 31, 2003. These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements based on our audits.

We conducted our audits in accordance with auditing standards generally accepted in the United States of America. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, such consolidated financial statements present fairly, in all material respects, the financial position of Ohio Power Company Consolidated as of December 31, 2003 and 2002, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2003 in conformity with accounting principles generally accepted in the United States of America.

As discussed in Note 2 to the consolidated financial statements, the Company adopted SFAS 143, "Accounting for Asset Retirement Obligations," and EITF 02-3, "Issues Involved in Accounting for Derivative Contracts Held for Trading Purposes and Contracts Involved in Energy Trading and Risk Management Activities," effective January 1, 2003.

As discussed in Note 2 to the consolidated financial statements, the Company adopted FIN 46, "Consolidation of Variable Interest Entities," effective July 1, 2003.

/s/ Deloitte & Touche LLP

Columbus, Ohio
March 5, 2004

PUBLIC SERVICE COMPANY OF OKLAHOMA

PUBLIC SERVICE COMPANY OF OKLAHOMA
SELECTED FINANCIAL DATA

	2003	2002	2001	2000	1999
			(in thousands)		
INCOME STATEMENTS DATA					
Operating Revenues	$1,102,822	$793,647	$957,000	$956,398	$749,390
Operating Expenses	1,009,959	708,926	860,012	859,729	650,677
Operating Income	92,863	84,721	96,988	96,669	98,713
Nonoperating Items, Net	5,812	(3,239)	20	8,974	946
Interest Charges	44,784	40,422	39,249	38,980	38,151
Net Income	53,891	41,060	57,759	66,663	61,508
Preferred Stock Dividend Requirements	213	213	213	212	212
Gain on Reacquired Preferred Stock	-	1	-	-	-
Earnings Applicable to Common Stock	$53,678	$40,848	$57,546	$66,451	$61,296
BALANCE SHEETS DATA					
Electric Utility Plant	$2,806,396	$2,759,504	$2,695,099	$2,604,670	$2,459,705
Accumulated Depreciation and Amortization	1,069,216	1,037,222	989,426	963,176	935,946
Net Electric Utility Plant	$1,737,180	$1,722,282	$1,705,673	$1,641,494	$1,523,759
TOTAL ASSETS	$1,970,032	$1,979,323	$1,943,928	$2,325,500	$1,703,155
Common Stock and Paid-in Capital	$387,246	$337,246	$337,246	$337,246	$337,246
Retained Earnings	139,604	116,474	142,994	137,688	139,237
Accumulated Other Comprehensive Income (Loss)	(43,842)	(54,473)	-	-	-
Total Common Shareholder's Equity	$483,008	$399,247	$480,240	$474,934	$476,483
Cumulative Preferred Stock Not Subject to Mandatory Redemption	$5,267	$5,267	$5,267	$5,267	$5,270
Trust Preferred Securities (a)	$-	$75,000	$75,000	$75,000	$75,000
Long-term Debt (b)	$574,298	$545,437	$451,129	$470,822	$384,516
Obligations Under Capital Leases (b)	$1,010	$-	$-	$-	$-
TOTAL CAPITALIZATION AND LIABILITIES	$1,970,032	$1,979,323	$1,943,928	$2,325,500	$1,703,155

(a) See Note 16 of the Notes to Respective Financial Statements.
(b) Including portion due within one year.

PUBLIC SERVICE COMPANY OF OKLAHOMA
MANAGEMENT'S NARRATIVE FINANCIAL DISCUSSION AND ANALYSIS

Public Service Company of Oklahoma (PSO) is a public utility engaged in the generation and purchase of electric power, and the subsequent sale, transmission and distribution of that power to approximately 505,000 retail customers in eastern and southwestern Oklahoma. As a power pool member with AEP West companies, we share in the revenues and expenses of the power pool's sales to neighboring utilities and power marketers. PSO also sells electric power at wholesale to other utilities, municipalities and rural electric cooperatives.

Power pool members are compensated for energy delivered to other members based upon the delivering members' incremental cost plus a portion of the savings realized by the purchasing member that avoids the use of more costly alternatives. The revenue and costs for sales to neighboring utilities and power marketers made by AEPSC on behalf of the AEP West companies are shared among the members based upon the relative magnitude of the energy each member provides to make such sales.

Power and gas risk management activities are conducted on our behalf by AEPSC. We share in the revenues and expenses associated with these risk management activities with other AEP registrant subsidiaries excluding AEGCo under existing power pool and system integration agreements. Risk management activities primarily involve the purchase and sale of electricity under physical forward contracts at fixed and variable prices and to a lesser extent gas. The electricity and gas contracts include physical transactions, over-the-counter options and swaps and exchange traded futures and options. The majority of the physical forward contracts are typically settled by entering into offsetting contracts.

Under our system integration agreement, revenues and expenses from the sales to neighboring utilities, power marketers and other power and gas risk management entities are shared among AEP East and West companies. Sharing in a calendar year is based upon the level of such activities experienced for the twelve months ended June 30, 2000, which immediately preceded the merger of AEP and CSW. This resulted in an AEP East and West companies' allocation of approximately 91% and 9%, respectively, for revenues and expenses. Allocation percentages in any given calendar year may also be based upon the relative generating capacity of the AEP East and West companies in the event the pre-merger activity level is exceeded. The capacity based allocation mechanism was triggered in June 2003, resulting in an allocation factor of approximately 70% and 30% for the AEP East and West companies, respectively, for the remainder of 2003.

Results of Operations

2003 Compared to 2002

Net Income increased $13 million for the year. The increase for the year was due mainly to higher retail base revenue and wholesale margins. Significant fluctuations occurred in revenues, fuel and purchased power due to certain ICR adjustments in 2002 and changing natural gas prices; however, operating income was not significantly affected due to the functioning of the fuel adjustment clause in Oklahoma.

Operating Income

Operating Income increased $8 million primarily due to:

- Increased wholesale margins of $9 million due to an increase in our allocation percentage, in AEP's Power Pool, resulting from increased amounts of off-system sales.
- Increased retail base revenue of $6 million (2%), resulting mainly from a 6% increase in KWH sold. Cooling degree-days decreased 3% while heating degree-days increased 1%.
- Decreased Other Operation expense of $4 million which has several contributing factors including administrative and support expenses, outside services and related expenses.
- Decreased Taxes Other Than Income Taxes of $2 million due primarily to decreased franchise taxes.

The increase in Operating Income was partially offset by:

- Increased Maintenance expense of $5 million due mainly to increased plant maintenance and tree trimming.
- Increased Income Taxes of $13 million due to an increase in pre-tax operating income and increases in tax return and tax accrual adjustments.

Other Impacts on Earnings

Nonoperating Income increased $6 million primarily due to higher margins from risk management activities and gains on the disposition of excess land.

Nonoperating Expenses decreased $6 million due to the 2002 write-down of certain non-utility investments.

Interest Charges increased $4 million as a result of replacing floating rate short-term debt with long-term fixed rate unsecured debt.

Financial Condition

Credit Ratings

The rating agencies currently have us on stable outlook. Current ratings are as follows:

	Moody's	S&P	Fitch
First Mortgage Bonds	A3	BBB	A
Senior Unsecured Debt	Baa1	BBB	A-

In February 2003, Moody's Investor Service (Moody's) completed their review of AEP and its rated subsidiaries. The results of that review included a downgrade of our rating for unsecured debt from A2 to Baa1 and secured debt from A1 to A3. The completion of this review was a culmination of ratings action started during 2002. In March 2003, S&P lowered AEP and our senior unsecured debt and first mortgage bonds ratings from BBB+ to BBB.

Summary Obligation Information

Our contractual obligations include amounts reported on the Consolidated Balance Sheets and other obligations disclosed in the footnotes. The following table summarizes our contractual cash obligations at December 31, 2003:

	Payments Due by Period (in thousands)				
Contractual Cash Obligations	Less Than 1 year	2-3 years	4–5 years	After 5 years	Total
Long-term Debt	$83,700	$50,000	$1,000	$439,598	$574,298
Advances from Affiliates	32,864	-	-	-	32,864
Unconditional Purchase Obligation (a)	181,379	175,082	139,916	377,568	873,945
Capital Lease Obligations	492	562	50	-	1,104
Noncancellable Operating Leases	4,684	8,599	4,642	8,616	26,541
Total	$303,119	$234,243	$145,608	$825,782	$1,508,752

(a) Represents contractual obligations to purchase coal and natural gas as fuel for electric generation along with related transportation costs.

Significant Factors

See the "Registrants' Combined Management's Discussion and Analysis" section beginning on page M-1 for additional discussion of factors relevant to us.

Quantitative And Qualitative Disclosures About Risk Management Activities

Market Risks

Our risk management policies and procedures are instituted and administered at the AEP consolidated level. See complete discussion within AEP's "Qualitative And Quantitative Disclosures About Risk Management Activities" section. The following tables provide information about our risk management activities' effect on this specific registrant.

MTM Risk Management Contract Net Assets

This table provides detail on changes in our MTM net asset or liability balance sheet position from one period to the next.

MTM Risk Management Contract Net Assets
Year Ended December 31, 2003
(in thousands)

Domestic Power	
Beginning Balance December 31, 2002	$3,545
(Gain) Loss from Contracts Realized/Settled During the Period (a)	1,308
Fair Value of New Contracts When Entered Into During the Period (b)	-
Net Option Premiums Paid/(Received) (c)	(69)
Change in Fair Value Due to Valuation Methodology Changes	-
Effect of EITF 98-10 Rescission (d)	-
Changes in Fair Value of Risk Management Contracts (e)	-
Changes in Fair Value of Risk Management Contracts Allocated to Regulated Jurisdictions (f)	9,273
Total MTM Risk Management Contract Net Assets, Excluding Cash Flow Hedges	14,057
Net Cash Flow Hedge Contracts (g)	239
Ending Balance December 31, 2003	$14,296

(a)"(Gain) Loss from Contracts Realized/Settled During the Period" includes realized gains from risk management contracts and related derivatives that settled during 2003 that were entered into prior to 2003.

(b)The "Fair Value of New Contracts When Entered Into During the Period" represents the fair value of long-term contracts entered into with customers during 2003. The fair value is calculated as of the execution of the contract. Most of the fair value comes from longer term fixed price contracts with customers that seek to limit their risk against fluctuating energy prices. The contract prices are valued against market curves associated with the delivery location.

(c)"Net Option Premiums Paid/(Received)" reflects the net option premiums paid/(received) as they relate to unexercised and unexpired option contracts that were entered into in 2003.

(d)See Note 2 "New Accounting Pronouncements, Extraordinary Items and Cumulative Effect of Accounting Changes."

(e)"Changes in Fair Value of Risk Management Contracts" represents the fair value change in the risk management portfolio due to market fluctuations during the current period. Market fluctuations are attributable to various factors such as supply/demand, weather, storage, etc.

(f)"Change in Fair Value of Risk Management Contracts Allocated to Regulated Jurisdictions" relates to the net gains (losses) of those contracts that are not reflected in the Consolidated Statements of Income. These net gains (losses) are recorded as regulatory liabilities/assets for those subsidiaries that operate in regulated jurisdictions.

(g) "Net Cash Flow Hedge Contracts (pre-tax)" are discussed below in Accumulated Other Comprehensive Income (Loss).

Maturity and Source of Fair Value of MTM Risk Management Contract Net Assets

The table presenting maturity and source of fair value of MTM risk management contract net assets provides two fundamental pieces of information:

- The source of fair value used in determining the carrying amount of our total MTM asset or liability (external sources or modeled internally).
- The maturity, by year, of our net assets/liabilities, giving an indication of when these MTM amounts will settle and generate cash.

Maturity and Source of Fair Value of MTM
Risk Management Contract Net Assets
Fair Value of Contracts as of December 31, 2003

	2004	2005	2006	2007	2008	After 2008	Total (c)
			(in thousands)				
Prices Actively Quoted – Exchange Exchange Traded Contracts	$326	$(136)	$13	$83	$-	$-	$286
Prices Provided by Other External Sources – OTC Broker Quotes (a)	6,962	2,151	788	497	285	-	10,683
Prices Based on Models and Other Valuation Methods (b)	(883)	676	155	325	680	2,135	3,088
Total	$6,405	$2,691	$956	$905	$965	$2,135	$14,057

(a) "Prices Provided by Other External Sources – OTC Broker Quotes reflects information obtained from over-the-counter brokers, industry services, or multiple-party on-line platforms.

(b) "Prices Based on Models and Other Valuation Methods" is in absence of pricing information from external sources, modeled information is derived using valuation models developed by the reporting entity, reflecting when appropriate, option pricing theory, discounted cash flow concepts, valuation adjustments, etc. and may require projection of prices for underlying commodities beyond the period that prices are available from third-party sources. In addition, where external pricing information or market liquidity are limited, such valuations are classified as modeled. The determination of the point at which a market is no longer liquid for placing it in the Modeled category varies by market.

(c) Amounts exclude Cash Flow Hedges.

Cash Flow Hedges Included in Accumulated Other Comprehensive Income (Loss) (AOCI) on the Balance Sheet

The table provides detail on effective cash flow hedges under SFAS 133 included in the balance sheet. The data in the table will indicate the magnitude of SFAS 133 hedges we have in place. (However, given that under SFAS 133 only cash flow hedges are recorded in AOCI, the table does not provide an all-encompassing picture of our hedging activity). The table also includes a roll-forward of the AOCI balance sheet account, providing insight into the drivers of the changes (new hedges placed during the period, changes in value of existing hedges and roll off of hedges). In accordance with GAAP, all amounts are presented net of related income taxes.

Total Accumulated Other Comprehensive Income (Loss) Activity
Year Ended December 31, 2003

	Domestic Power (in thousands)
Beginning Balance December 31, 2002	$(42)
Changes in Fair Value (a)	18
Reclassifications from AOCI to Net Income (b)	180
Ending Balance December 31, 2003	$156

(a) "Changes in Fair Value" shows changes in the fair value of derivatives designated as hedging instruments in cash flow hedges during the reporting period not yet reclassified into net income, pending the hedged item's affecting net income. Amounts are reported net of related income taxes.

(b) "Reclassifications from AOCI to Net Income" represents gains or losses from derivatives used as hedging instruments in cash flow hedges that were reclassified into net income during the reporting period. Amounts are reported net of related income taxes above.

The portion of cash flow hedges in AOCI expected to be reclassified to earnings during the next twelve months is a $724 thousand gain.

Credit Risk

Our counterparty credit quality and exposure is generally consistent with that of AEP.

VaR Associated with Risk Management Contracts

The following table shows the end, high, average, and low market risk as measured by VaR for year-to-date:

December 31, 2003 (in thousands)				December 31, 2002 (in thousands)			
End	High	Average	Low	End	High	Average	Low
$258	$1,004	$420	$100	$136	$415	$148	$30

VaR Associated with Debt Outstanding

The risk of potential loss in fair value attributable to our exposure to interest rates, primarily related to long-term debt with fixed interest rates was $66 million and $70 million at December 31, 2003 and 2002, respectively. We would not expect to liquidate our entire debt portfolio in a one-year holding period, therefore a near term change in interest rates should not negatively affect our results of operation or consolidated financial position.

PUBLIC SERVICE COMPANY OF OKLAHOMA
STATEMENTS OF INCOME
For the Years Ended December 31, 2003, 2002 and 2001

	2003	2002 (in thousands)	2001
OPERATING REVENUES			
Electric Generation, Transmission and Distribution	$1,079,692	$784,208	$920,229
Sales to AEP Affiliates	23,130	9,439	36,771
TOTAL	1,102,822	793,647	957,000
OPERATING EXPENSES			
Fuel for Electric Generation	526,563	246,199	461,470
Purchased Electricity for Resale	35,685	47,507	24,187
Purchased Electricity from AEP Affiliates	109,639	89,454	43,758
Other Operation	129,246	133,538	137,678
Maintenance	53,076	48,060	46,188
Depreciation and Amortization	86,455	85,896	80,245
Taxes Other Than Income Taxes	32,287	34,077	31,973
Income Taxes	37,008	24,195	34,513
TOTAL	1,009,959	708,926	860,012
OPERATING INCOME	92,863	84,721	96,988
Nonoperating Income	8,026	1,920	2,112
Nonoperating Expense	1,385	6,971	1,740
Nonoperating Income Tax Expense (Credit)	829	(1,812)	352
Interest Charges	44,784	40,422	39,249
NET INCOME	53,891	41,060	57,759
Gain on Reacquired Preferred Stock	-	1	-
Preferred Stock Dividend Requirements	213	213	213
EARNINGS APPLICABLE TO COMMON STOCK	$53,678	$40,848	$57,546

The common stock of PSO is owned by a wholly-owned subsidiary of AEP.

See Notes to Respective Financial Statements beginning on page L-1.

PUBLIC SERVICE COMPANY OF OKLAHOMA
STATEMENTS OF CHANGES IN COMMON SHAREHOLDER'S EQUITY AND COMPREHENSIVE INCOME
For the Years Ended December 31, 2003, 2002 and 2001
(in thousands)

	Common Stock	Paid-in Capital	Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Total
DECEMBER 31, 2000	$157,230	$180,016	$137,688	$-	$474,934
Common Stock Dividends Declared			(52,240)		(52,240)
Preferred Stock Dividends Declared			(213)		(213)
TOTAL					422,481
COMPREHENSIVE INCOME					
NET INCOME			57,759		57,759
TOTAL COMPREHENSIVE INCOME					57,759
DECEMBER 31, 2001	$157,230	$180,016	$142,994	$-	$480,240
Gain on Reacquired Preferred Stock			1		1
Common Stock Dividends			(67,368)		(67,368)
Preferred Stock Dividends			(213)		(213)
TOTAL					412,660
COMPREHENSIVE INCOME					
Other Comprehensive Income, (Loss) Net of Taxes:					
Unrealized Loss on Cash Flow Hedges				(42)	(42)
Minimum Pension Liability				(54,431)	(54,431)
NET INCOME			41,060		41,060
TOTAL COMPREHENSIVE INCOME					(13,413)
DECEMBER 31, 2002	$157,230	$180,016	$116,474	$(54,473)	$399,247
Capital Contribution from Parent		50,000			50,000
Common Stock Dividends			(30,000)		(30,000)
Preferred Stock Dividends			(213)		(213)
Distribution of Investment in AEMT, Inc. Preferred Shares to Parent			(548)		(548)
TOTAL					418,486
COMPREHENSIVE INCOME					
Other Comprehensive Income Net of Taxes:					
Unrealized Gain on Cash Flow Hedges				198	198
Minimum Pension Liability				10,433	10,433
NET INCOME			53,891		53,891
TOTAL COMPREHENSIVE INCOME					64,522
DECEMBER 31, 2003	$157,230	$230,016	$139,604	$(43,842)	$483,008

See Notes to Respective Financial Statements beginning on page L-1.

PUBLIC SERVICE COMPANY OF OKLAHOMA
BALANCE SHEETS
ASSETS
December 31, 2003 and 2002

	2003	2002
	(in thousands)	
ELECTRIC UTILITY PLANT		
Production	$1,065,408	$1,040,520
Transmission	451,292	432,846
Distribution	1,031,229	990,947
General	203,756	206,747
Construction Work in Progress	54,711	88,444
TOTAL	2,806,396	2,759,504
Accumulated Depreciation and Amortization	1,069,216	1,037,222
TOTAL - NET	1,737,180	1,722,282
OTHER PROPERTY AND INVESTMENTS		
Non-Utility Property, Net	4,631	4,833
Other Investments	2,320	550
TOTAL	6,951	5,383
CURRENT ASSETS		
Cash and Cash Equivalents	14,258	16,774
Accounts Receivable:		
Customers	28,515	30,130
Affiliated Companies	19,852	14,139
Miscellaneous	-	1,557
Allowance for Uncollectible Accounts	(37)	(84)
Fuel Inventory	18,331	19,973
Materials and Supplies	38,125	37,375
Regulatory Asset for Under-recovered Fuel Costs	24,170	76,470
Risk Management Assets	18,586	3,841
Margin Deposits	4,351	91
Prepayments and Other	2,655	2,644
TOTAL	168,806	202,910
DEFERRED DEBITS AND OTHER ASSETS		
Regulatory Assets:		
Unamortized Loss on Required Debt	14,357	11,138
Other	14,342	15,012
Long-term Risk Management Assets	10,379	4,481
Deferred Charges	18,017	18,117
TOTAL	57,095	48,748
TOTAL ASSETS	$1,970,032	$1,979,323

See Notes to Respective Financial Statements beginning on page L-1.

PUBLIC SERVICE COMPANY OF OKLAHOMA
BALANCE SHEETS
CAPITALIZATION AND LIABILITIES
December 31, 2003 and 2002

	2003	2002
	(in thousands)	
CAPITALIZATION		
Common Shareholder's Equity:		
Common Stock – $15 Par Value:		
Authorized Shares: 11,000,000		
Issued Shares: 10,482,000		
Outstanding Shares: 9,013,000	$157,230	$157,230
Paid-in Capital	230,016	180,016
Retained Earnings	139,604	116,474
Accumulated Other Comprehensive Income (Loss)	(43,842)	(54,473)
Total Common Shareholder's Equity	483,008	399,247
Cumulative Preferred Stock Not Subject to Mandatory Redemption	5,267	5,267
Total Shareholder's Equity	488,275	404,514
PSO – Obligated, Mandatorily Redeemable Preferred Securities of Subsidiary Trust Holding Solely Junior Subordinated Debentures of PSO	-	75,000
Long-term Debt	490,598	445,437
TOTAL	978,873	924,951
CURRENT LIABILITIES		
Long-term Debt Due Within One Year	83,700	100,000
Advances from Affiliates	32,864	86,105
Accounts Payable:		
General	48,808	61,169
Affiliated Companies	57,206	78,076
Customer Deposits	26,547	21,789
Taxes Accrued	27,157	6,854
Interest Accrued	3,706	6,979
Risk Management Liabilities	11,067	3,260
Obligations Under Capital Leases	452	-
Other	35,234	24,957
TOTAL	326,741	389,189
DEFERRED CREDITS AND OTHER LIABILITIES		
Deferred Income Taxes	335,434	341,396
Long-Term Risk Management Liabilities	3,602	1,581
Regulatory Liabilities:		
Asset Removal Costs	214,033	-
Deferred Investment Tax Credits	30,411	32,201
SFAS 109 Regulatory Liability, Net	24,937	27,893
Other	15,406	4,391
Obligations Under Capital Leases	558	-
Deferred Credits and Other	40,037	257,721
TOTAL	664,418	665,183
Commitments and Contingencies (Note 7)		
TOTAL CAPITALIZATION AND LIABILITIES	$1,970,032	$1,979,323

See Notes to Respective Financial Statements beginning on page L-1.

PUBLIC SERVICE COMPANY OF OKLAHOMA
STATEMENTS OF CASH FLOWS
For the Years Ended December 31, 2003, 2002 and 2001

	2003	2002 (in thousands)	2001
OPERATING ACTIVITIES			
Net Income	$53,891	$41,060	$57,759
Adjustments to Reconcile Net Income to Net Cash Flows From Operating Activities:			
Depreciation and Amortization	86,455	85,896	80,245
Deferred Income Taxes	(14,641)	75,659	(17,751)
Deferred Investment Tax Credits	(1,790)	(1,791)	(1,791)
Changes in Certain Assets and Liabilities:			
Accounts Receivable, Net	(2,588)	(3,737)	21,405
Fuel, Materials and Supplies	892	996	(589)
Accounts Payable	(33,231)	25,629	(55,319)
Taxes Accrued	20,303	(11,296)	16,491
Fuel Recovery	52,300	(85,190)	51,987
Changes in Other Assets	(10,421)	1,796	(11,929)
Changes in Other Liabilities	14,987	(6,928)	9,351
Net Cash Flows From Operating Activities	166,157	122,094	149,859
INVESTING ACTIVITIES			
Construction Expenditures	(86,815)	(89,365)	(124,520)
Proceeds from Sale of Property and Other	2,862	963	(359)
Net Cash Flows Used For Investing Activities	(83,953)	(88,402)	(124,879)
FINANCING ACTIVITIES			
Capital Contributions from Parent	50,000	-	-
Issuance of Long-term Debt	148,734	187,850	-
Retirement of Long-term Debt	(200,000)	(106,000)	(20,000)
Change in Advances to/from Affiliates, Net	(53,241)	(36,982)	41,967
Dividends Paid on Common Stock	(30,000)	(67,368)	(52,240)
Dividends Paid on Cumulative Preferred Stock	(213)	(213)	(213)
Net Cash Flows Used For Financing Activities	(84,720)	(22,713)	(30,486)
Net Increase (Decrease) in Cash and Cash Equivalents	(2,516)	10,979	(5,506)
Cash and Cash Equivalents at Beginning of Period	16,774	5,795	11,301
Cash and Cash Equivalents at End of Period	$14,258	$16,774	$5,795

SUPPLEMENTAL DISCLOSURE:
Cash paid (received) for interest net of capitalized amounts was $44,703,000, $38,620,000 and $38,250,000 and for income taxes was $36,470,000, (38,943,000) and $38,653,000 in 2003, 2002 and 2001, respectively.

There was a non-cash distribution of $548,000 in preferred shares in AEMT, Inc. to PSO's Parent Company in 2003.

See Notes to Respective Financial Statements beginning on page L-1.

PUBLIC SERVICE COMPANY OF OKLAHOMA
STATEMENTS OF CAPITALIZATION
December 31, 2003 and 2002

	2003	2002
	(in thousands)	
TOTAL COMMON SHAREHOLDER'S EQUITY	$483,008	$399,247

PREFERRED STOCK: Cumulative $100 par value – authorized shares 700,000, redeemable at the option of PSO upon 30 days notice.

Series	Call Price December 31, 2003	Number of Shares Redeemed Year Ended December 31, 2003	2002	2001	Shares Outstanding December 31, 2003	2003	2002
Not Subject to Mandatory Redemption:							
4.00%	$105.75	2	6	-	44,598	4,460	4,460
4.24%	103.19	-	1	-	8,069	807	807
Total						5,267	5,267

	2003	2002
TRUST PREFERRED SECURITIES:		
PSO-Obligated, Mandatorily Redeemable Preferred Securities of Subsidiary Trust Holding Solely Junior Subordinated Debentures of PSO, 8.00%, Due April 30, 2037 (a)	-	75,000
LONG-TERM DEBT (See Schedule of Long-term Debt):		
First Mortgage Bonds	99,864	298,079
Installment Purchase Contracts	47,358	47,358
Note Payable to Trust (a)	77,320	-
Senior Unsecured Notes	349,756	200,000
Less Portion Due Within One Year	(83,700)	(100,000)
Long-term Debt Excluding Portion Due Within One Year	490,598	445,437
TOTAL CAPITALIZATION	$978,873	$924,951

(a) See Note 16 for discussion of Notes Payable to Trust.

See Notes to Respective Financial Statements beginning on page L-1.

PUBLIC SERVICE COMPANY OF OKLAHOMA
SCHEDULE OF LONG-TERM DEBT
December 31, 2003 and 2002

First Mortgage Bonds outstanding were as follows:

% Rate	Due	2003	2002
		(in thousands)	
6.25	2003 – April 1	$-	$ 35,000
7.25	2003 – July 1	-	65,000
7.38	2004 – December 1	50,000	50,000
6.50	2005 – June 1	50,000	50,000
7.38	2023 – April 1	-	100,000
Unamortized Discount		(136)	(1,921)
Total		$99,864	$298,079

First Mortgage Bonds are secured by a first mortgage lien on electric utility plant. The indenture, as supplemented, relating to the first mortgage bonds contains maintenance and replacement provisions requiring the deposit of cash or bonds with the trustee, or in lieu thereof, certification of unfunded property additions. Interest payments are made semi-annually.

Installment Purchase Contracts have been entered into in connection with the issuance of pollution control revenue bonds by governmental authorities as follows:

% Rate	Due	2003	2002
		(in thousands)	
Oklahoma Environmental Finance Authority (OEFA):			
5.90	2007 - December 1	$1,000	$1,000
Oklahoma Development Finance Authority (ODFA):			
4.875	2014 - June 1 (a)	33,700	33,700
Red River Authority of Texas:			
6.00	2020 – June 1	12,660	12,660
Unamortized Discount		(2)	(2)
Total		$47,358	$47,358

(a) These bonds will be remarketed on June 1, 2004.

Under the terms of the installment purchase contracts, PSO is required to pay amounts sufficient to enable the payment of interest on and the principal of (at stated maturities and upon mandatory redemptions) related pollution control revenue bonds issued to finance the construction of pollution control facilities at certain plants. Interest payments are made semi-annually.

Senior Unsecured Notes outstanding were as follows:

% Rate	Due	2003	2002
		(in thousands)	
4.85	2010 – September 15	$150,000	$-
6.00	2032 – December 31	200,000	200,000
Unamortized Discount		(244)	-
Total		$349,756	$200,000

Notes Payable to Trust was outstanding as follows:

% Rate	Due	2003	2002
		(in thousands)	
8.00	2037 – April 30	$77,320	$-

See Note 16 for discussion of Notes Payable to Trust.

At December 31, 2003, future annual long-term debt payments are as follows:

	Amount (in thousands)
2004	$83,700
2005	50,000
2006	-
2007	1,000
2008	-
Later Years	439,980
Total Principal Amount	574,680
Unamortized Discount	(382)
Total	$574,298

PUBLIC SERVICE COMPANY OF OKLAHOMA
INDEX TO NOTES TO RESPECTIVE FINANCIAL STATEMENTS

The notes to PSO's consolidated financial statements are combined with the notes to respective financial statements for other subsidiary registrants. Listed below are the notes that apply to PSO. The footnotes begin on page L-1.

INDEPENDENT AUDITORS' REPORT

To the Shareholders and Board of
Directors of Public Service Company of Oklahoma:

We have audited the accompanying balance sheets and statements of capitalization of Public Service Company of Oklahoma as of December 31, 2003 and 2002, and the related statements of income, changes in common shareholder's equity and comprehensive income and cash flows for each of the three years in the period ended December 31, 2003. These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements based on our audits.

We conducted our audits in accordance with auditing standards generally accepted in the United States of America. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, such financial statements present fairly, in all material respects, the financial position of Public Service Company of Oklahoma as of December 31, 2003 and 2002, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2003 in conformity with accounting principles generally accepted in the United States of America.

As discussed in Note 2 to the financial statements, the Company adopted FIN 46, "Consolidation of Variable Interest Entities," effective July 1, 2003.

/s/ Deloitte & Touche LLP

Columbus, Ohio
March 5, 2004

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SOUTHWESTERN ELECTRIC POWER COMPANY CONSOLIDATED

SOUTHWESTERN ELECTRIC POWER COMPANY CONSOLIDATED
SELECTED CONSOLIDATED FINANCIAL DATA

	2003	2002	2001	2000	1999
			(in thousands)		
INCOME STATEMENTS DATA					
Operating Revenues	$1,146,842	$1,084,720	$1,101,326	$1,118,274	$971,527
Operating Expenses	996,706	942,251	955,119	989,996	824,465
Operating Income	150,136	142,469	146,207	128,278	147,062
Nonoperating Items, Net	4,767	(309)	741	3,851	(1,965)
Interest Charges	63,779	59,168	57,581	59,457	58,892
Minority Interest	(1,500)	-	-	-	-
Income Before Extraordinary Item And Cumulative Effect	89,624	82,992	89,367	72,672	86,205
Extraordinary Loss	-	-	-	-	(3,011)
Cumulative Effect of Accounting Changes	8,517	-	-	-	-
Net Income	98,141	82,992	89,367	72,672	83,194
Preferred Stock Dividend Requirements	229	229	229	229	229
Earnings Applicable to Common Stock	$97,912	$82,763	$89,138	$72,443	$82,965
BALANCE SHEETS DATA					
Electric Utility Plant	$3,799,460	$3,596,174	$3,460,764	$3,319,024	$3,231,431
Accumulated Depreciation and Amortization	1,617,846	1,477,875	1,342,003	1,259,509	1,196,629
Net Electric Utility Plant	$2,181,614	$2,118,299	$2,118,761	$2,059,515	$2,034,802
TOTAL ASSETS	$2,581,963	$2,428,138	$2,509,291	$2,855,885	$2,294,375
Common Stock and Paid-in Capital	$380,663	$380,663	$380,663	$380,663	$380,663
Retained Earnings	359,907	334,789	308,915	293,989	283,546
Accumulated Other Comprehensive Income (Loss)	(43,910)	(53,683)	-	-	-
Total Common Shareholder's Equity	$696,660	$661,769	$689,578	$674,652	$664,209
Cumulative Preferred Stock Not Subject to Mandatory Redemption	$4,700	$4,701	$4,701	$4,701	$4,703
Trust Preferred Securities (a)	$-	$110,000	$110,000	$110,000	$110,000
Long-term Debt (b)	$884,308	$693,448	$645,283	$645,963	$541,568
Obligations Under Capital Leases (b)	$21,542	-	-	-	-
TOTAL CAPITALIZATION AND LIABILITIES	$2,581,963	$2,428,138	$2,509,291	$2,855,885	$2,294,375

(a) See Note 16 of the Notes to Respective Financial Statements.
(b) Including portion due within one year.

SOUTHWESTERN ELECTRIC POWER COMPANY CONSOLIDATED
MANAGEMENT'S FINANCIAL DISCUSSION AND ANALYSIS

Southwestern Electric Power Company (SWEPCo) is a public utility engaged in the generation and purchase of electric power, and the subsequent sale, transmission and distribution of that power to approximately 439,000 retail customers in our service territory in northeastern Texas, northwestern Louisiana and western Arkansas. As a power pool member with AEP West companies, we share in the revenues and expenses of the power pool's sales to neighboring utilities and power marketers. SWEPCo also sells electric power at wholesale to other utilities, municipalities and electric cooperatives.

Power pool members are compensated for energy delivered to other members based upon the delivering members' incremental cost plus a portion of the savings realized by the purchasing member that avoids the use of more costly alternatives. The revenue and costs for sales to neighboring utilities and power marketers made by AEPSC on behalf of the AEP West companies are shared among the members based upon the relative magnitude of the energy each member provides to make such sales.

Power and gas risk management activities are conducted on our behalf by AEPSC. We share in the revenues and expenses associated with these risk management activities with other AEP registrant subsidiaries excluding AEGCo under existing power pool and system integration agreements. Risk management activities primarily involve the purchase and sale of electricity under physical forward contracts at fixed and variable prices and to a lesser extent gas. The electricity and gas contracts include physical transactions, over-the-counter options and swaps and exchange traded futures and options. The majority of the physical forward contracts are typically settled by entering into offsetting contracts.

Under our system integration agreement, revenues and expenses from the sales to neighboring utilities, power marketers and other power and gas risk management entities are shared among AEP East and West companies. Sharing in a calendar year is based upon the level of such activities experienced for the twelve months ended June 30, 2000, which immediately preceded the merger of AEP and CSW. This resulted in an AEP East and West companies' allocation of approximately 91% and 9%, respectively, for revenues and expenses. Allocation percentages in any given calendar year may also be based upon the relative generating capacity of the AEP East and West companies in the event the pre-merger activity level is exceeded. The capacity based allocation mechanism was triggered in June 2003, resulting in an allocation factor of approximately 70% and 30% for the AEP East and West companies, respectively, for the remainder of 2003.

Results of Operations

2003 Compared to 2002

During 2003, Net Income increased $15 million primarily due to an $8 million increase in Operating Income and the adoption of SFAS 143, which resulted in Cumulative Effect of Accounting Changes of $9 million in the first quarter of 2003. Significant fluctuations occurred in revenues, fuel and purchased power due to certain ICR adjustments in 2002; however, income is generally not affected due to the functioning of fuel adjustment clauses in the retail jurisdictions.

Operating Income

Operating Income increased by $8 million primarily due to:

- A $12 million increase in wholesale margins due to an increase in our allocation of overall AEP System sales percentages resulting from increased amounts of off-system sales.
- A $12 million increase in retail base revenues due to increased customers and their average usage, offset in part by milder weather. Cooling and heating degree-days declined 6%.
- A $7 million increase in income from risk management activities.
- A decrease of $16 million in Other Operation expense primarily due to decreases in customer services, outside services and other administrative expenses.

The increase in Operating Income was partially offset by:

- A $9 million decrease in wholesale base margins primarily due to decreased demand from wholesale customers.
- A $4 million decrease in capacity revenues due to the elimination of the requirement under the Texas Restructuring legislation to sell capacity. See Note 6.
- A $21 million increase in Income Taxes due to increases in pre-tax operating income, federal and state tax return and tax accrual adjustments and changes to certain book/tax timing differences accounted for on a flow-through basis.

Other Impacts on Earnings

Nonoperating Income Tax Credit increased by $5 million due to changes in certain book/tax timing differences accounted for on a flow-through basis, changes in consolidated tax savings and tax return and tax accrual adjustments.

Interest Charges increased $5 million primarily due to higher levels of outstanding debt, consolidation of Sabine Mining Company and in financing activity at Dolet Hills.

Minority Interest expense of $2 million is a result of consolidating Sabine Mining Company during the third quarter of 2003, due to the implementation of FIN 46. See Notes 2 and 8 for additional discussion.

Cumulative Effect of Accounting Changes

The Cumulative Effect of Accounting Changes is due to the one-time, after-tax impact of adopting SFAS 143 and implementing the requirements of EITF 02-3 (see Note 2).

<u>2002 Compared to 2001</u>

During 2002, Net Income decreased $6 million primarily resulting from reduced margins from risk management activities. Significant fluctuations occurred in revenues, fuel and purchased power due to certain ICR adjustments in 2002; however, income is generally not affected due to the functioning of fuel adjustment clauses in the retail jurisdictions.

Operating Income

Operating Income decreased by $4 million primarily due to:

- A $4 million decrease in retail base revenues mainly due to decreased KWH sales of 6% resulting from the loss of a large industrial customer in 2002.
- A $15 million decrease in income from risk management activities.
- An increase of $18 million in Other Operation expense primarily due to the acquisition of Dolet Hills Lignite Company.
- A $3 million increase in Depreciation and Amortization due primarily to the Dolet Hills acquisition.

The decrease in Operating Income was partially offset by:

- An increase of $13 million in other revenue primarily from the Dolet Hills Acquisition.
- An increase of $7 million in capacity revenues, due to the requirement under the Texas Restructuring legislation to sell capacity.
- An $8 million decrease in Maintenance expense due to less storm damage and reduced tree trimming expense in 2002.
- A decrease in Income Taxes of $8 million due to a decrease in pre-tax income.

Financial Condition

Credit Ratings

The rating agencies currently have us on stable outlook. Current ratings are as follows:

	Moody's	S&P	Fitch
First Mortgage Bonds	A3	BBB	A
Senior Unsecured Debt	Baa1	BBB	A-

In February 2003, Moody's Investors Service (Moody's) completed their review of AEP and its rated subsidiaries. The results of that review included a downgrade of our rating for unsecured debt from A2 to Baa1 and secured debt from A1 to A3. The completion of this review was a culmination of ratings action started during 2002. In March 2003, S&P lowered AEP and our senior unsecured debt and first mortgage bonds ratings from BBB+ to BBB.

Cash Flow

Cash flows for the years ended December 31, 2003, 2002 and 2001 were as follows:

	2003	2002	2001
Cash and cash equivalents at beginning of period	$2,069	$5,415	$1,907
Cash flows from (used for):			
Operating activities	248,094	210,563	169,610
Investing activities	(110,849)	(110,641)	(197,852)
Financing activities	(127,590)	(103,268)	31,750
Net increase (decrease) in cash and cash equivalents	9,655	(3,346)	3,508
Cash and cash equivalents at end of period	$11,724	$2,069	$5,415

Operating Activities

Cash flows from operating activities were $248 million during 2003 primarily due to net income, Accounts Receivables, Accounts Payable and Accrued Taxes.

Investing Activities

Cash spent on investing activities during 2003 were comparable to 2002. In 2003, construction expenditures were primarily related to projects for improved transmission and distribution service reliability.

Financing Activities

Cash flows used for financing activities increased by $24 million during 2003 in comparison to 2002. During 2003 we paid $16 million more in common stock dividends than in 2002. During the first quarter of 2003 we retired $55 million of first mortgage bonds at maturity. In April 2003, we issued $100 million of senior unsecured debt due 2015 at a coupon of 5.375%. In May 2003, one of our mining subsidiaries issued $44 million of notes due in 2011 at a coupon of 4.47%. The loan was used primarily to reduce a note to us with an interest rate of 8.06%. During the fourth quarter of 2003, we had an early redemption of $45 million of first mortgage bonds due in 2023.

Summary Obligation Information

Our contractual obligations include amounts reported on the Consolidated Balance Sheets and other obligations disclosed in the footnotes. The following table summarizes our contractual cash obligations at December 31, 2003:

Contractual Cash Obligations	Payments Due by Period (in millions) Less Than 1 year	2-3 years	4–5 years	After 5 years	Total
Long-term Debt	$142,714	$226,628	$123,263	$391,703	$884,308
Unconditional Purchase Obligations (a)	185,425	329,513	85,800	171,601	772,339
Capital Lease Obligations	4,737	9,174	8,799	4,380	27,090
Noncancellable Operating Leases	5,522	12,864	14,669	17,849	50,904
Total	$338,398	$578,179	$232,531	$585,533	$1,734,641

(a) Represents contractual obligations to purchase coal and natural gas as fuel for electric generation along with related transportation costs.

In connection with reducing the cost of the lignite mining contract for its Henry W. Pirkey Power Plant, we have agreed under certain conditions, to assume the obligations under capital lease obligations and term loan payments of the mining contractor, Sabine Mining Company (Sabine). In the event Sabine defaults under any of these agreements, our total future maximum payment exposure is approximately $58 million with maturity dates ranging from June 2005 to February 2012.

As part of the process to receive a renewal of a Texas Railroad Commission permit for lignite mining, we have agreed to provide guarantees of mine reclamation in the amount of approximately $85 million. Since we use self-bonding, the guarantee provides for us to commit to use its resources to complete the reclamation in the event the work is not completed by a third party miner. At December 31, 2003, the cost to reclaim the mine in 2035 is estimated to be approximately $36 million. This guarantee ends upon depletion of reserves estimated at 2035 plus 6 years to complete reclamation.

On July 1, 2003, we consolidated Sabine due to the application of FIN 46 (see Note 2). Upon consolidation, we recorded the assets and liabilities of Sabine ($78 million). Also, after consolidation, we currently record all expenses (depreciation, interest and other operation expense) of Sabine and eliminate Sabine's revenues against our fuel expenses. There is no cumulative effect of an accounting change recorded as a result of the requirement to consolidate, and there is no change in net income due to the consolidation of Sabine.

Significant Factors

See the "Registrants' Combined Management's Discussion and Analysis" section beginning on page M-1 for additional discussion of factors relevant to us.

Quantitative And Qualitative Disclosures About Risk Management Activities

Market Risks

Our risk management policies and procedures are instituted and administered at the AEP consolidated level. See complete discussion within AEP's "Qualitative And Quantitative Disclosures About Risk Management Activities" section. The following tables provide information about our risk management activities' effect on this specific registrant.

MTM Risk Management Contract Net Assets

This table provides detail on changes in our MTM net asset or liability balance sheet position from one period to the next.

MTM Risk Management Contract Net Assets
Year Ended December 31, 2003
(in thousands)

Domestic Power

Beginning Balance December 31, 2002	$4,050
(Gain) Loss from Contracts Realized/Settled During the Period (a)	820
Fair Value of New Contracts When Entered Into During the Period (b)	-
Net Option Premiums Paid/(Received) (c)	(32)
Change in Fair Value Due to Valuation Methodology Changes	-
Effect of EITF 98-10 Rescission (d)	151
Changes in Fair Value of Risk Management Contracts (e)	4,002
Changes in Fair Value of Risk Management Contracts Allocated to Regulated Jurisdictions (f)	7,615
Total MTM Risk Management Contract Net Assets, Excluding Cash Flow Hedges	16,606
Net Cash Flow Hedge Contracts (g)	(741)
Ending Balance December 31, 2003	$15,865

(a) "(Gain) Loss from Contracts Realized/Settled During the Period" includes realized gains from risk management contracts and related derivatives that settled during 2003 that were entered into prior to 2003.
(b) The "Fair Value of New Contracts When Entered Into During the Period" represents the fair value of long-term contracts entered into with customers during 2003. The fair value is calculated as of the execution of the contract. Most of the fair value comes from longer term fixed price contracts with customers that seek to limit their risk against fluctuating energy prices. The contract prices are valued against market curves associated with the delivery location.
(c) "Net Option Premiums Paid/(Received)" reflects the net option premiums paid/(received) as they relate to unexercised and unexpired option contracts that were entered into in 2003.
(d) See Note 2 "New Accounting Pronouncements, Extraordinary Items and Cumulative Effect of Accounting Changes."
(e) "Changes in Fair Value of Risk Management Contracts" represents the fair value change in the risk management portfolio due to market fluctuations during the current period. Market fluctuations are attributable to various factors such as supply/demand, weather, etc.
(f) "Change in Fair Value of Risk Management Contracts Allocated to Regulated Jurisdictions" relates to the net gains (losses) of those contracts that are not reflected in the Consolidated Statements of Income. These net gains (losses) are recorded as regulatory liabilities/assets for those subsidiaries that operate in regulated jurisdictions.
(g) "Net Cash Flow Hedge Contracts (pre-tax) are discussed below in Accumulated Other Comprehensive Income (Loss).

Maturity and Source of Fair Value of MTM Risk Management Contract Net Assets

The table presenting maturity and source of fair value of MTM risk management contract net assets provides two fundamental pieces of information:

- The source of fair value used in determining the carrying amount of our total MTM asset or liability (external sources or modeled internally).
- The maturity, by year, of our net assets/liabilities, giving an indication of when these MTM amounts will settle and generate cash.

Maturity and Source of Fair Value of MTM Risk Management Contract Net Assets Fair Value of Contracts as of December 31, 2003

	2004	2005	2006	2007	2008	After 2008	Total (c)
			(in thousands)				
Prices Actively Quoted – Exchange Traded Contracts	$384	$(160)	$15	$98	$-	$-	$337
Prices Provided by Other External Sources – OTC Broker Quotes (a)	8,198	2,533	928	585	336	-	12,580
Prices Based on Models and Other Valuation Methods (b)	(970)	776	183	383	800	2,517	3,689
Total	$7,612	$3,149	$1,126	$1,066	$1,136	$2,517	$16,606

(a) "Prices Provided by Other External Sources – OTC Broker Quotes" reflects information obtained from over-the-counter brokers, industry services, or multiple-party on-line platforms.

(b) "Prices Based on Models and Other Valuation Methods" is in absence of pricing information from external sources, modeled information is derived using valuation models developed by the reporting entity, reflecting when appropriate, option pricing theory, discounted cash flow concepts, valuation adjustments, etc. and may require projection of prices for underlying commodities beyond the period that prices are available from third-party sources. In addition, where external pricing information or market liquidity are limited, such valuations are classified as modeled. The determination of the point at which a market is no longer liquid for placing it in the Modeled category varies by market.

(c) Amounts exclude Cash Flow Hedges.

Cash Flow Hedges Included in Accumulated Other Comprehensive Income (Loss) (AOCI) on the Balance Sheet

The table provides detail on effective cash flow hedges under SFAS 133 included in the balance sheet. The data in the table will indicate the magnitude of SFAS 133 hedges we have in place. (However, given that under SFAS 133 only cash flow hedges are recorded in AOCI, the table does not provide an all-encompassing picture of our hedging activity). The table also includes a roll-forward of the AOCI balance sheet account, providing insight into the drivers of the changes (new hedges placed during the period, changes in value of existing hedges and roll-off of hedges). In accordance with GAAP, all amounts are presented net of related income taxes.

Total Accumulated Other Comprehensive Income (Loss) Activity Years Ended December 31, 2003

	Domestic Power (in thousands)
Beginning Balance December 31, 2002	$(48)
Changes in Fair Value (a)	21
Reclassifications from AOCI to Net Income (b)	211
Ending Balance December 31, 2003	$184

(a) "Changes in Fair Value" shows changes in the fair value of derivatives designated as hedging instruments in cash flow hedges during the reporting period not yet reclassified into net income, pending the hedged item's affecting net income. Amounts are reported net of related income taxes.

(b) "Reclassifications from AOCI to Net Income" represents gains or losses from derivatives used as hedging instruments in cash flow hedges that were reclassified into net income during the reporting period. Amounts are reported net of related income taxes above.

The portion of cash flow hedges in AOCI expected to be reclassified to earnings during the next twelve months is an $853 thousand gain.

Credit Risk

Our counterparty credit quality and exposure is generally consistent with that of AEP.

VaR Associated with Risk Management Contracts

The following table shows the end, high, average, and low market risk as measured by VaR for year-to-date:

December 31, 2003 (in thousands)			
End	High	Average	Low
$304	$1,182	$495	$118

December 31, 2002 (in thousands)			
End	High	Average	Low
$155	$474	$170	$34

VaR Associated with Debt Outstanding

The risk of potential loss in fair value attributable to our exposure to interest rates, primarily related to long-term debt with fixed interest rates was $57 million and $70 million at December 31, 2003 and 2002, respectively. We would not expect to liquidate our entire debt portfolio in a one-year holding period, therefore a near term change in interest rates should not negatively affect our results of operation or consolidated financial position.

SOUTHWESTERN ELECTRIC POWER COMPANY CONSOLIDATED
CONSOLIDATED STATEMENTS OF INCOME
For the Years Ended December 31, 2003, 2002 and 2001

	2003	2002	2001
		(in thousands)	
OPERATING REVENUES			
Electric Generation, Transmission and Distribution	$1,077,988	$1,012,421	$1,022,089
Sales to AEP Affiliates	68,854	72,299	79,237
TOTAL	1,146,842	1,084,720	1,101,326
OPERATING EXPENSES			
Fuel for Electric Generation	441,445	388,334	457,613
Purchased Electricity for Resale	34,850	44,119	18,164
Purchased Electricity from AEP Affiliates	47,914	42,022	15,858
Other Operation	173,349	189,024	171,314
Maintenance	70,443	66,855	74,677
Depreciation and Amortization	121,072	122,969	119,543
Taxes Other Than Income Taxes	53,165	55,232	55,834
Income Taxes	54,468	33,696	42,116
TOTAL	996,706	942,251	955,119
OPERATING INCOME	150,136	142,469	146,207
Nonoperating Income	3,978	3,260	4,512
Nonoperating Expenses	2,607	1,797	3,229
Nonoperating Income Tax Expense (Credit)	(3,396)	1,772	542
Interest Charges	63,779	59,168	57,581
Minority Interest	(1,500)	-	-
Income Before Cumulative Effect of Accounting Changes	89,624	82,992	89,367
Cumulative Effect of Accounting Changes (Net of Tax)	8,517	-	-
NET INCOME	98,141	82,992	89,367
Preferred Stock Dividend Requirements	229	229	229
EARNINGS APPLICABLE TO COMMON STOCK	$97,912	$82,763	$89,138

The common stock of SWEPCo is owned by a wholly-owned subsidiary of AEP.

See Notes to Respective Financial Statements beginning on page L-1.

SOUTHWESTERN ELECTRIC POWER COMPANY CONSOLIDATED
CONSOLIDATED STATEMENTS OF CHANGES IN COMMON SHAREHOLDER'S EQUITY AND COMPREHENSIVE INCOME
For the Years Ended December 31, 2003, 2002 and 2001
(in thousands)

	Common Stock	Paid-in Capital	Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Total
DECEMBER 31, 2000	$135,660	$245,003	$293,989	$-	$674,652
Common Stock Dividends			(74,212)		(74,212)
Preferred Stock Dividends			(229)		(229)
TOTAL					600,211
COMPREHENSIVE INCOME					
NET INCOME			89,367		89,367
TOTAL COMPREHENSIVE INCOME					89,367
DECEMBER 31, 2001	$135,660	$245,003	$308,915	$-	$689,578
Common Stock Dividends			(56,889)		(56,889)
Preferred Stock Dividends			(229)		(229)
TOTAL					632,460
COMPREHENSIVE INCOME					
Other Comprehensive Income, Net of Taxes:					
Unrealized Gain on Cash Flow Power Hedges				(48)	(48)
Minimum Pension Liability				(53,635)	(53,635)
NET INCOME			82,992		82,992
TOTAL COMPREHENSIVE INCOME					29,309
DECEMBER 31, 2002	$135,660	$245,003	$334,789	$(53,683)	$661,769
Common Stock Dividends			(72,794)		(72,794)
Preferred Stock Dividends			(229)		(229)
TOTAL					588,746
COMPREHENSIVE INCOME					
Other Comprehensive Income, Net of Taxes:					
Unrealized Gain on Cash Flow Hedges				232	232
Minimum Pension Liability				9,541	9,541
NET INCOME			98,141		98,141
TOTAL COMPREHENSIVE INCOME					107,914
DECEMBER 31, 2003	$135,660	$245,003	$359,907	$(43,910)	$696,660

See Notes to Respective Financial Statements beginning on page L-1.

SOUTHWESTERN ELECTRIC POWER COMPANY CONSOLIDATED
CONSOLIDATED BALANCE SHEETS
ASSETS
December 31, 2003 and 2002

	2003	2002
	(in thousands)	
ELECTRIC UTILITY PLANT		
Production	$1,622,498	$1,503,722
Transmission	615,158	575,003
Distribution	1,078,368	1,063,564
General	423,427	378,130
Construction Work in Progress	60,009	75,755
TOTAL	3,799,460	3,596,174
Accumulated Depreciation and Amortization	1,617,846	1,477,875
TOTAL - NET	2,181,614	2,118,299
OTHER PROPERTY AND INVESTMENTS		
Non-Utility Property, Net	3,808	4,203
Other Investments	4,710	1,775
TOTAL	8,518	5,978
CURRENT ASSETS		
Cash and Cash Equivalents	11,724	2,069
Advances to Affiliates	66,476	-
Accounts Receivable:		
Customers	41,474	61,478
Affiliated Companies	10,394	19,253
Miscellaneous	4,682	881
Allowance for Uncollectible Accounts	(2,093)	(2,128)
Fuel Inventory	63,881	61,741
Materials and Supplies	33,775	33,539
Regulatory Asset for Under-recovered Fuel Costs	11,394	2,865
Risk Management Assets	19,715	4,388
Margin Deposits	5,123	105
Prepayments and Other	19,078	17,746
TOTAL	285,623	201,937
DEFERRED DEBITS AND OTHER ASSETS		
Regulatory Assets:		
SFAS 109 Regulatory Asset, Net	3,235	19,855
Unamortized Loss on Required Debt	19,331	17,031
Other	15,859	12,347
Long-term Risk Management Assets	12,178	5,119
Deferred Charges	55,605	47,572
TOTAL	106,208	101,924
TOTAL ASSETS	$2,581,963	$2,428,138

See Notes to Respective Financial Statements beginning on page L-1.

SOUTHWESTERN ELECTRIC POWER COMPANY CONSOLIDATED
CONSOLIDATED BALANCE SHEETS
CAPITALIZATION AND LIABILITIES
December 31, 2003 and 2002

	2003	2002
	(in thousands)	
CAPITALIZATION		
Common Shareholder's Equity:		
Common Stock – $18 Par Value:		
Authorized – 7,600,000 Shares		
Outstanding – 7,536,640 Shares	$135,660	$135,660
Paid-in Capital	245,003	245,003
Retained Earnings	359,907	334,789
Accumulated Other Comprehensive Income (Loss)	(43,910)	(53,683)
Total Common Shareholder's Equity	696,660	661,769
Cumulative Preferred Stock Not Subject to Mandatory Redemption	4,700	4,701
Total Shareholder's Equity	701,360	666,470
SWEPCo – Obligated, Mandatorily Redeemable Preferred Securities of Subsidiary Trust Holding Solely Junior Subordinated Debentures of SWEPCo	-	110,000
Long-term Debt	741,594	637,853
TOTAL	1,442,954	1,414,323
Minority Interest	1,367	-
CURRENT LIABILITIES		
Long-term Debt Due Within One Year	142,714	55,595
Advances from Affiliates	-	23,239
Accounts Payable:		
General	37,646	62,139
Affiliated Companies	35,138	58,773
Customer Deposits	24,260	20,110
Taxes Accrued	28,691	19,081
Interest Accrued	16,852	17,051
Risk Management Liabilities	11,361	3,724
Obligations Under Capital Leases	3,159	-
Regulatory Liability for Over-recovered Fuel	4,178	17,226
Other	53,753	34,565
TOTAL	357,752	311,503
DEFERRED CREDITS AND OTHER LIABILITIES		
Deferred Income Taxes	349,064	341,064
Long-term Risk Management Liabilities	4,667	1,806
Reclamation Reserve	16,512	13,826
Regulatory Liabilities:		
Asset Removal Costs	236,409	-
Deferred Investment Tax Credits	39,864	44,190
Excess Earnings	2,600	3,700
Other	18,779	3,394
Asset Retirement Obligations	8,429	-
Obligations Under Capital Leases	18,383	-
Deferred Credits and Other	85,183	294,332
TOTAL	779,890	702,312
Commitments and Contingencies (Note 7)		
TOTAL CAPITALIZATION AND LIABILITIES	$2,581,963	$2,428,138

See Notes to Respective Financial Statements beginning on page L-1.

SOUTHWESTERN ELECTRIC POWER COMPANY CONSOLIDATED
CONSOLIDATED STATEMENTS OF CASH FLOWS
For the Years Ended December 31, 2003, 2002 and 2001

	2003	2002 (in thousands)	2001
OPERATING ACTIVITIES			
Net Income	$98,141	$82,992	$89,367
Adjustments to Reconcile Net Income to Net Cash Flows From Operating Activities:			
Depreciation and Amortization	121,072	122,969	119,543
Deferred Income Taxes	9,942	(3,134)	(31,396)
Deferred Investment Tax Credits	(4,326)	(4,524)	(4,453)
Cumulative Effect of Accounting Changes	(8,517)	-	-
Mark-to-Market of Risk Management Contracts	(12,403)	(1,151)	(10,695)
Changes in Certain Assets and Liabilities:			
Accounts Receivable, Net	27,527	(24,371)	(11,447)
Fuel, Materials and Supplies	4,165	(10,541)	(19,578)
Accounts Payable	(51,687)	11,633	(34,489)
Taxes Accrued	8,446	(17,441)	25,298
Fuel Recovery	(21,577)	17,713	34,423
Change in Other Assets	16,268	24,257	1,323
Change in Other Liabilities	61,043	12,161	11,714
Net Cash Flows From Operating Activities	248,094	210,563	169,610
INVESTING ACTIVITIES			
Construction Expenditures	(121,124)	(111,775)	(111,725)
Investment in Mining Operations	-	-	(85,716)
Proceeds from Sale of Assets and Other	10,275	1,134	(411)
Net Cash Flows Used For Investing Activities	(110,849)	(110,641)	(197,852)
FINANCING ACTIVITIES			
Issuance of Long-term Debt	254,630	198,573	-
Retirement of Long-term Debt	(219,482)	(150,595)	(595)
Change in Advances to/from Affiliates, Net	(89,715)	(94,128)	106,786
Dividends Paid on Common Stock	(72,794)	(56,889)	(74,212)
Dividends Paid on Cumulative Preferred Stock	(229)	(229)	(229)
Net Cash Flows From (Used For) Financing Activities	(127,590)	(103,268)	31,750
Net Increase (Decrease) in Cash and Cash Equivalents	9,655	(3,346)	3,508
Cash and Cash Equivalents at Beginning of Period	2,069	5,415	1,907
Cash and Cash Equivalents at End of Period	$11,724	$2,069	$5,415

SUPPLEMENTAL DISCLOSURE:
Cash paid for interest net of capitalized amounts was $57,775,000, $49,008,000 and $51,126,000 and for income taxes was $33,616,000, $60,451,000 and $49,901,000 in 2003, 2002 and 2001, respectively.

Noncash activity in 2003 included an increase in assets and liabilities of $78 million resulting from the consolidation of Sabine Mining Company (see Note 2).

See Notes to Respective Financial Statements beginning on page L-1.

SOUTHWESTERN ELECTRIC POWER COMPANY CONSOLIDATED
CONSOLIDATED STATEMENTS OF CAPITALIZATION
December 31, 2003 and 2002

	2003	2002
	(in thousands)	
COMMON SHAREHOLDER'S EQUITY	$696,660	$661,769

PREFERRED STOCK: $100 par value – authorized shares 1,860,000

Series	Call Price December 31, 2003	Number of Shares Redeemed Year Ended December 31, 2003	2002	2001	Shares Outstanding December 31, 2003	2003	2002
Not Subject to Mandatory Redemption:							
4.28%	$103.90	-	-	-	7,386	740	740
4.65%	$102.75	-	-	-	1,907	190	190
5.00%	$109.00	12	-	-	37,703	3,770	3,771
Total Preferred Stock						4,700	4,701

	2003	2002
TRUST PREFERRED SECURITIES:		
SWEPCo-Obligated, Mandatorily Redeemable Preferred Securities of Subsidiary Trust Holding Solely Junior Subordinated Debentures of SWEPCo, 7.875%, due April 30, 2037 (a)	-	110,000
LONG-TERM DEBT (See Schedule of Long-term Debt):		
First Mortgage Bonds	215,712	315,420
Installment Purchase Contracts	178,531	179,183
Senior Unsecured Notes	299,216	198,845
Notes Payable to Trust (a)	113,009	-
Notes Payable	77,840	-
Less Portion Due Within One Year	(142,714)	(55,595)
Long-term Debt Excluding Portion Due Within One Year	741,594	637,853
TOTAL CAPITALIZATION	$1,442,954	$1,414,323

(a) See Note 16 for Notes Payable to Trust.

See Notes to Respective Financial Statements beginning on page L-1.

SOUTHWESTERN ELECTRIC POWER COMPANY CONSOLIDATED
SCHEDULE OF LONG-TERM DEBT
December 31, 2003 and 2002

First Mortgage Bonds outstanding were as follows:

% Rate	Due	2003	2002
		(in thousands)	
6-5/8	2003 – February 1	$-	$55,000
7-3/4	2004 – June 1	40,000	40,000
6.20	2006 – November 1	5,360	5,505
6.20	2006 – November 1	1,000	1,000
7.00	2007 – September 1	90,000	90,000
7-1/4	2023 – July 1	-	45,000
6-7/8	2025 – October 1 (a)	80,000	80,000
Unamortized Discount		(648)	(1,085)
Total		$215,712	$315,420

(a) This bond was redeemed on March 1, 2004 and has been classified for payment in 2004.

First Mortgage Bonds are secured by a first mortgage lien on electric utility plant. The indenture, as supplemented, relating to the first mortgage bonds contains maintenance and replacement provisions requiring the deposit of cash or bonds with the trustee, or in lieu thereof, certification of unfunded property additions.

Installment Purchase Contracts have been entered into in connection with the issuance of pollution control revenue bonds by governmental authorities as follows:

	% Rate	Due	2003	2002
			(in thousands)	
Desoto County:				
	7.60	2019 – January 1	$53,500	$53,500
Sabine River Authority of Texas:				
	6.10	2018 – April 1	81,700	81,700
Titus County:				
	6.90	2004 – November 1	12,290	12,290
	6.00	2008 – January 1	12,170	12,620
	8.20	2011 – August 1	17,125	17,125
	Unamortized Premium		1,746	1,948
	Total		$178,531	$179,183

Under the terms of the installment purchase contracts, SWEPCo is required to pay amounts sufficient to enable the payment of interest on and the principal of (at stated maturities and upon mandatory redemptions) related pollution control revenue bonds issued to finance the construction of pollution control facilities at certain plants.

Senior Unsecured Notes outstanding were as follows:

%Rate	Due	2003	2002
		(in thousands)	
4.50	2005 – July 1	$200,000	$200,000
5.38	2015 – April 15	100,000	-
Unamortized Discount		(784)	(1,155)
Total		$299,216	$198,845

Notes Payable to Trust was outstanding as follows:

%Rate	Due	2003	2002
		(in thousands)	
5.25% (a)	2043 – October 1	$113,403	$-
Unamortized Discount		(394)	-
Total		$113,009	$-

(a) The 5.25% interest rate is thru September 10, 2008 after which they become floating rate bonds if the notes are not remarketed.

See Note 16 for discussion of Notes Payable to Trust.

Notes Payable outstanding were as follows:

%Rate	Due	2003	2002
		(in thousands)	
Sabine Mining Company (a):			
6.36	2007 – February 22	$4,000	$-
(b)	2008 – June 30	13,500	-
7.03	2012 – February 22	20,000	-
Dolet Hills Lignite Company:			
4.47	2011 – May 16	40,340	-
Total		$77,840	$-

(a) Sabine Mining Company was consolidated during the third quarter of 2003 due to the implementation of FIN 46.
(b) A floating interest rate is determined quarterly. The rate on December 31, 2003 was 1.54%.

At December 31, 2003 future annual long-term debt payments are as follows:

	Amount (in thousands)
2004	$142,714
2005	210,424
2006	16,204
2007	104,862
2008	18,401
Later Years	391,783
Total Principal Amount	884,388
Unamortized Discount	(80)
Total	$884,308

SOUTHWESTERN ELECTRIC POWER COMPANY CONSOLIDATED
INDEX TO NOTES TO RESPECTIVE FINANCIAL STATEMENTS

The notes to SWEPCo's consolidated financial statements are combined with the notes to respective financial statements for other subsidiary registrants. Listed below are the notes that apply to SWEPCo. The footnotes begin on page L-1.

INDEPENDENT AUDITORS' REPORT

To the Shareholders and Board of
Directors of Southwestern Electric Power Company:

We have audited the accompanying consolidated balance sheets and consolidated statements of capitalization of Southwestern Electric Power Company Consolidated as of December 31, 2003 and 2002, and the related consolidated statements of income, changes in common shareholder's equity and comprehensive income and cash flows for each of the three years in the period ended December 31, 2003. These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements based on our audits.

We conducted our audits in accordance with auditing standards generally accepted in the United States of America. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, such consolidated financial statements present fairly, in all material respects, the financial position of Southwestern Electric Power Company Consolidated as of December 31, 2003 and 2002, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2003 in conformity with accounting principles generally accepted in the United States of America.

As discussed in Note 2 to the consolidated financial statements, the Company adopted SFAS 143, "Accounting for Asset Retirement Obligations," effective January 1, 2003.

As discussed in Note 2 to the consolidated financial statements, the Company adopted FIN 46, "Consolidation of Variable Interest Entities," effective July 1, 2003.

/s/ Deloitte & Touche LLP

Columbus, Ohio
March 5, 2004

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NOTES TO RESPECTIVE FINANCIAL STATEMENTS

The notes to respective financial statements that follow are a combined presentation for AEP's subsidiary registrants. The following list indicates the registrants to which the footnotes apply:

1.	Organization and Summary of Significant Accounting Policies	AEGCo, APCo, CSPCo, I&M, KPCo, OPCo, PSO, SWEPCo, TCC, TNC
2.	New Accounting Pronouncements, Extraordinary Items and Cumulative Effect of Accounting Changes	AEGCo, APCo, CSPCo, I&M, KPCo, OPCo, PSO, SWEPCo, TCC, TNC
3.	Goodwill and Other Intangible Assets	SWEPCo
4.	Rate Matters	APCo, CSPCo, I&M, KPCo, OPCo, PSO, SWEPCo, TCC, TNC
5.	Effects of Regulation	AEGCo, APCo, CSPCo, I&M, KPCo, OPCo, PSO, SWEPCo, TCC, TNC
6.	Customer Choice and Industry Restructuring	APCo, CSPCo, I&M, OPCo, SWEPCo, TCC, TNC
7.	Commitments and Contingencies	AEGCo, APCo, CSPCo, I&M, KPCo, OPCo, PSO, SWEPCo, TCC, TNC
8.	Guarantees	AEGCo, APCo, CSPCo, I&M, KPCo, OPCo, PSO, SWEPCo, TCC, TNC
9.	Sustained Earnings Improvement Initiative	AEGCo, APCo, CSPCo, I&M, KPCo, OPCo, PSO, SWEPCo, TCC, TNC
10.	Acquisitions, Dispositions, Impairments, Assets Held for Sale and Assets Held and Used	APCo, CSPCo, I&M, KPCo, OPCo, SWEPCo, TCC, TNC
11.	Benefit Plans	AEGCo, APCo, CSPCo, I&M, KPCo, OPCo, PSO, SWEPCo, TCC, TNC
12.	Business Segments	AEGCo, APCo, CSPCo, I&M, KPCo, OPCo, PSO, SWEPCo, TCC, TNC
13.	Derivatives, Hedging and Financial Instruments	AEGCo, APCo, CSPCo, I&M, KPCo, OPCo, PSO, SWEPCo, TCC, TNC
14.	Income Taxes	AEGCo, APCo, CSPCo, I&M, KPCo, OPCo, PSO, SWEPCo, TCC, TNC
15.	Leases	AEGCo, APCo, CSPCo, I&M, KPCo, OPCo, PSO, SWEPCo, TCC, TNC
16.	Financing Activities	AEGCo, APCo, CSPCo, I&M, KPCo, OPCo, PSO, SWEPCo, TCC, TNC
17.	Related Party Transactions	AEGCo, APCo, CSPCo, I&M, KPCo, OPCo, PSO, SWEPCo, TCC, TNC
18.	Jointly Owned Electric Utility Plant	CSPCo, PSO, SWEPCo, TCC, TNC
19.	Unaudited Quarterly Financial Information	AEGCo, APCo, CSPCo, I&M, KPCo, OPCo, PSO, SWEPCo, TCC, TNC
20.	Subsequent Events (Unaudited)	TCC

1. ORGANIZATION AND SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

ORGANIZATION

The principal business conducted by AEP's ten domestic electric utility operating companies is the generation, transmission and distribution of electric power. These companies are subject to regulation by the FERC under the Federal Power Act and maintain accounts in accordance with FERC and other regulatory guidelines. These companies are subject to further regulation with regard to rates and other matters by state regulatory commissions.

With the exception of AEGCo, AEP's registrant subsidiaries engage in wholesale marketing and risk management activities in the United States. In addition, I&M provides barging services to both affiliated and nonaffiliated companies.

See Note 10 for additional information regarding asset impairments and assets and liabilities held for sale related to our Texas generation plants.

Certain previously reported amounts have been reclassified to conform to current classifications with no effect on net income or shareholders' equity.

SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

Rate Regulation

AEP and its subsidiaries are subject to regulation by the SEC under the PUHCA. The rates charged by the utility subsidiaries are approved by the FERC and the state utility commissions. The FERC regulates wholesale electricity operations and transmission rates and the state commissions regulate retail rates.

Principles of Consolidation

The consolidated financial statements for APCo, CSPCo, I&M, OPCO, SWEPCo and TCC include the registrant and its wholly-owned subsidiaries and/or substantially controlled variable interest entities. Intercompany items are eliminated in consolidation. Equity investments not substantially controlled that are 50% or less owned are accounted for using the equity method of accounting; equity earnings are included in Nonoperating Income.

Accounting for the Effects of Cost-Based Regulation

As cost-based rate-regulated electric public utility companies, the consolidated financial statements reflect the actions of regulators that result in the recognition of revenues and expenses in different time periods than enterprises that are not rate-regulated. Regulatory assets (deferred expenses) and regulatory liabilities (future revenue reductions or refunds) are recorded to reflect the economic effects of regulation by matching expenses with their recovery through regulated revenues. The following subsidiaries discontinued the application of SFAS 71 for the generation portion of their business as follows: in Ohio by OPCo and CSPCo in September 2000, in Virginia and West Virginia by APCo in June 2000, in Texas by TCC, TNC, and SWEPCo in September 1999, in Arkansas by SWEPCo in September 1999 and in the FERC jurisdiction for TNC in December 2003. During 2003, APCo reapplied SFAS 71 for West Virginia and SWEPCo reapplied SFAS 71 for Arkansas.

Use of Estimates

The preparation of these financial statements in conformity with accounting principles generally accepted in the United States of America requires management to make estimates and assumptions that affect the amounts reported in the financial statements and accompanying notes. These estimates include but are not limited to inventory valuation, allowance for doubtful accounts, unbilled electricity revenue, values of long-term energy contracts, the effects of regulation, long-lived asset recovery, the effects of contingencies and certain assumptions made in accounting for pension benefits. Actual results could differ from those estimates.

Property, Plant and Equipment

Domestic electric utility property, plant and equipment are stated at original purchase cost. Property, plant and equipment of the non-regulated operations and other investments are stated at their fair market value at acquisition (or as adjusted for any applicable impairments) plus the original cost of property acquired or constructed since the acquisition, less disposals. Additions, major replacements and betterments are added to the plant accounts. For cost-based rate-regulated operations, retirements from the plant accounts and associated removal costs, net of salvage, are deducted from accumulated depreciation. For non-regulated operations, retirements from the plant accounts and associated salvage are deducted from accumulated depreciation and removal costs are charged to expense. The costs of labor, materials and overhead incurred to operate and maintain plant are included in operating expenses. Assets are tested for impairment as required under SFAS 144 (see Note 10).

Allowance for Funds Used During Construction (AFUDC) and Interest Capitalization

AFUDC represents the estimated cost of borrowed and equity funds used to finance construction projects that is capitalized and recovered through depreciation over the service life of domestic regulated electric utility plant. For non-regulated operations, interest is capitalized during construction in accordance with SFAS 34, "Capitalization of Interest Costs." Capitalized interest is also recorded for domestic generating assets in Ohio, Texas and Virginia, effective with the discontinuance of SFAS 71 regulatory accounting. The amounts of AFUDC and interest capitalized were not material in 2003, 2002 and 2001.

Depreciation, Depletion and Amortization

We provide for depreciation of property, plant and equipment on a straight-line basis over the estimated useful lives of property, excluding coal-mining properties, through the use of composite rates by functional class. The following table provides the annual composite depreciation rates by functional class generally used by the AEP registrant subsidiaries for the year 2003:

	Nuclear	Steam	Hydro	Transmission	Distribution	General
AEGCo	- %	3.5%	- %	- %	- %	16.7%
APCo	-	3.3	2.7	2.2	3.3	9.3
CSPCo	-	3.0	-	2.3	3.6	9.9
I&M	3.4	4.6	3.4	1.9	4.2	11.8
KPCo	-	3.8	-	1.7	3.5	7.1
OPCo	-	2.8	2.7	2.3	4.0	10.5
PSO	-	2.7	-	2.3	3.4	9.7
SWEPCo	-	3.3	-	2.8	3.6	8.0
TCC	2.5	2.3	1.9	2.3	3.5	8.1
TNC	-	2.6	-	3.1	3.3	10.2

The annual composite depreciation rates by functional class generally used by the AEP registrant subsidiaries for the years 2002 and 2001 were as follows:

	Nuclear	Steam	Hydro	Transmission	Distribution	General
AEGCo	- %	3.5%	- %	- %	- %	2.8%
APCo	-	3.4	2.9	2.2	3.3	3.1
CSPCo	-	3.2	-	2.3	3.6	3.2
I&M	3.4	4.5	3.4	1.9	4.2	3.8
KPCo	-	3.8	-	1.7	3.5	2.5
OPCo	-	3.4	2.7	2.3	4.0	2.7
PSO	-	2.7	-	2.3	3.4	6.3
SWEPCo	-	3.4	-	2.7	3.6	4.7
TCC	2.5	2.6	1.9	2.3	3.5	4.0
TNC	-	2.8	-	3.1	3.3	6.8

We provide for depreciation, depletion and amortization of coal-mining assets over each asset's estimated useful life or the estimated life of each mine, whichever is shorter, using the straight-line method for mining structures and equipment. We use either the straight-line method or the units-of-production method to amortize mine development costs and deplete coal rights based on estimated recoverable tonnages. We include these costs in the cost of coal charged to fuel expense. Average amortization rates for coal rights and mine development costs related to SWEPCo were $0.41 per ton in 2003, 2002 and 2001 and related to OPCo were $3.46 per ton in 2001. In 2001, OPCo sold coal mines in Ohio and West Virginia.

Valuation of Non-Derivative Financial Instruments

The book values of Cash and Cash Equivalents, Accounts Receivable, Short-term Debt and Accounts Payable approximate fair value because of the short-term maturity of these instruments. The book value of the pre-April 1983 spent nuclear fuel disposal liability for I&M approximates the best estimate of its fair value.

Cash and Cash Equivalents

Cash and cash equivalents include temporary cash investments with original maturities of three months or less.

Inventory

Except for PSO, TCC and TNC, the regulated domestic utility companies value fossil fuel inventories using a weighted average cost method. PSO, TCC and TNC, utilize the LIFO method to value fossil fuel inventories. For those domestic utilities whose generation is unregulated, inventory of coal and oil is carried at the lower of cost or market. Coal mine inventories are also carried at the lower of cost or market. Materials and supplies inventories are carried at average cost.

Accounts Receivable

Customer accounts receivable primarily includes receivables from wholesale and retail energy customers, receivables from energy contract counterparties related to our risk management activities and customer receivables primarily related to other revenue-generating activities.

Revenue is recognized from electric power sales when power is delivered to customers. To the extent that deliveries have occurred but a bill has not been issued, AEP and its registrant subsidiaries accrue and recognize, as Accrued Unbilled Revenues, an estimate of the revenues for energy delivered since the latest billings.

AEP Credit, Inc. factors accounts receivable for certain registrant subsidiaries. These subsidiaries include CSPCo, I&M, KPCo, OPCo, PSO, SWEPCo and a portion of APCo. Since APCo does not have regulatory authority to sell accounts receivable in all of its regulatory jurisdictions, only a portion of APCo's accounts receivable are sold to AEP Credit. AEP Credit has a sale of receivables agreement with banks and commercial paper conduits. Under the sale of receivables agreement, AEP Credit sells an interest in the receivables it acquires to the commercial paper conduits and banks and receives cash. This transaction constitutes a sale of receivables in accordance with SFAS 140, allowing the receivables to be taken off of the company's balance sheet. See Note 16 for further details.

Deferred Fuel Costs

The cost of fuel consumed is charged to expense when the fuel is burned. Where applicable under governing state regulatory commission retail rate orders, fuel cost over-recoveries (the excess of fuel revenues billed to ratepayers over fuel costs incurred) are deferred as regulatory liabilities and under-recoveries (the excess of fuel costs incurred over fuel revenues billed to ratepayers) are deferred as regulatory assets. These deferrals are amortized when refunded or billed to customers in later months with the regulator's review and approval. The amounts of over-recovery or under-recovery can also be affected by actions of regulators. When these actions become probable we adjust our deferrals to recognize these probable outcomes. For the Texas companies, TCC & TNC, their deferred fuel balances will be included in their 2004 True Up Proceeding (see Note 6 "Customer Choice and Industry Restructuring"). See Note 5 "Effects of Regulation" for the amount of deferred fuel costs by registrant subsidiary.

In general, changes in fuel costs in Kentucky for KPCo, the SPP area of Texas, Louisiana and Arkansas for SWEPCo, Oklahoma for PSO and Virginia for APCo are timely reflected in rates through the fuel cost adjustment clauses in place in those states. Where fuel clauses have been eliminated due to the transition to market pricing, (Ohio effective January 1, 2001 and in the Texas ERCOT area effective January 1, 2002) changes in fuel costs impact earnings. In other state jurisdictions, (Indiana, Michigan and West Virginia) where fuel clauses have been frozen or suspended for a period of years, fuel cost changes have also impacted earnings. The Michigan fuel clause suspension ended December 31, 2003, and the Indiana freeze is scheduled to end on March 1, 2004. See Note 4, "Rate Matters" and Note 6, "Customer Choice and Industry Restructuring" for further information about fuel recovery.

Revenue Recognition

Regulatory Accounting

The consolidated financial statements of the registrant subsidiary companies with cost-based rate-regulated operations (I&M, KPCo, PSO, and a portion of APCo, OPCo, CSPCo, TCC, TNC and SWEPCo), reflect the actions of regulators that can result in the recognition of revenues and expenses in different time periods than enterprises that are not rate regulated. In accordance with SFAS 71, regulatory assets (deferred expenses to be recovered in the future) and regulatory liabilities (deferred future revenue reductions or refunds) are recorded to reflect the economic effects of regulation by matching expenses with their recovery through regulated revenues in the same accounting period and by matching income with its passage to customers through regulated revenues in the same accounting period. Regulatory liabilities (unrealized gains) or regulatory assets (unrealized losses) are also recorded for changes in the fair value of physical and financial contracts that meet the definition of a derivative as defined in SFAS 133 and are subject to the regulated ratemaking process.

When regulatory assets are probable of recovery through regulated rates, certain registrant subsidiaries record them as assets on the balance sheet. Registrant subsidiaries test for probability of recovery whenever new events occur, for example a regulatory commission order or passage of new legislation. If registrant subsidiaries determine that recovery of a regulatory asset is no longer probable, they write off that regulatory asset as a charge against net income. A write off of regulatory assets may also reduce future cash flows since there may be no recovery through regulated rates.

Traditional Electricity Supply and Delivery Activities

Revenues are recognized on the accrual or settlement basis for normal retail and wholesale electricity supply sales and electricity transmission and distribution delivery services. The revenues are recognized and recorded when the energy is delivered to the customer and include estimated unbilled as well as billed amounts. In general, expenses are recorded when purchased electricity is received and when expenses are incurred.

Energy Marketing and Risk Management Activities

Registrant subsidiaries engage in wholesale electricity, natural gas and coal marketing and risk management activities. Effective in October 2002, these activities were focused on wholesale markets where registrant subsidiaries own assets. Registrant subsidiaries activities include the purchase and sale of energy under forward contracts at fixed and variable prices and the buying and selling of financial energy contracts which include exchange traded futures and options, and over-the-counter options and swaps. Prior to October 2002, registrant subsidiaries recorded wholesale marketing and risk management activities using the mark-to-market method of accounting.

In October 2002, EITF 02-3 precluded mark-to-market accounting for risk management contracts that were not derivatives pursuant to SFAS 133. Registrant subsidiaries implemented this standard for all non-derivative wholesale and risk management transactions occurring on or after October 25, 2002. For non-derivative risk management transactions entered into prior to October 25, 2002, registrant subsidiaries implemented this standard on January 1, 2003 and reported the effects of implementation as a cumulative effect of an accounting change.

After January 1, 2003, registrant subsidiaries use mark-to-market accounting for wholesale marketing and risk management transactions that are derivatives unless the derivative is designated for hedge accounting or the normal purchase and sale exemption. Revenues and expenses are recognized from wholesale marketing and risk management transactions that are not derivatives when the commodity is delivered.

See discussion of EITF 02-3 and rescission of EITF 98-10 in Note 2.

All of the registrant subsidiaries except AEGCo participate in wholesale marketing and risk management activities in electricity and gas. For I&M, KPCo, PSO and a portion of TNC and SWEPCo, when the contract settles the total gain or loss is realized in revenues. Where the revenues are recorded on the income statement depends on whether the contract is subject to the regulated ratemaking process. For contracts subject to the regulated ratemaking process the total gain or loss realized for sales and the cost of purchased energy are included in revenues on a net basis. Prior to settlement, changes in the fair value of physical and financial forward sale and purchase contracts subject to the regulated ratemaking process are deferred as regulatory liabilities (gains) or regulatory assets (losses). For contracts not subject to the ratemaking process only the difference between the accumulated unrealized net gains or losses recorded in prior periods and the cash proceeds are recognized in the income statement as nonoperating income. Prior to settlement, changes in the fair value of physical and financial forward sale and purchase contracts not subject to the ratemaking process are included in nonoperating income on a net basis. Unrealized mark-to-market gains and losses are included in the balance sheets as Risk Management Assets or Liabilities as appropriate.

For APCo, CSPCo and OPCo, depending on whether the delivery point for the electricity is in the traditional marketing area or not determines where the contract is reported in the income statement. Physical forward risk management sale and purchase contracts with delivery points in the traditional marketing area are included in revenues on a net basis. Prior to settlement, changes in the fair value of physical forward sale and purchase contracts in the traditional marketing area are also included in revenues on a net basis. Physical forward sale and purchase contracts for delivery outside of the traditional marketing area are included in nonoperating income when the contract settles. Prior to settlement, changes in the fair value of physical forward sale and purchase contracts with delivery points outside of the traditional marketing area are included in nonoperating income on a net basis.

Accounting for Derivative Instruments

For derivative contracts that are not designated as hedges or normal purchase and sale transactions registrant subsidiaries recognize unrealized gains and losses prior to settlement based on changes in fair value during the period in our results of operations. When registrant subsidiaries settle mark-to-market derivative contracts and realize gains and losses, registrant subsidiaries reverse previously recorded unrealized gains and losses from mark-to-market valuations.

Certain derivative instruments are designated as a hedge of a forecasted transaction or future cash flow (cash flow hedge) or as a hedge of a recognized asset, liability or firm commitment (fair value hedge). The gains or losses on derivatives designated as fair value hedges are recognized in Revenues in the Consolidated Statement of Operations in the period of change together with the offsetting losses or gains on the hedged item attributable to the risks being hedged. For derivatives designated as cash flow hedges, the effective portion of the derivative's gain or loss is initially reported as a component of Accumulated Other Comprehensive Income and subsequently reclassified into Revenues in the Consolidated Statement of Operations when the forecasted transaction affects earnings. The ineffective portion of the gain or loss is recognized in Revenues in the Consolidated Statement of Operations immediately (see Note 13).

Registrant subsidiaries measure the fair values of derivative instruments and hedge instruments accounted for using mark-to-market accounting based on exchange prices and broker quotes. If a quoted market price is not available, registrant subsidiaries estimate the fair value based on the best information available including valuation models that estimate future energy prices based on existing market and broker quotes, supply and demand market data, and other assumptions. Registrant subsidiaries reduce fair values by estimated valuation adjustments for items such as discounting, liquidity and credit quality. There are inherent risks related to the underlying assumptions in models used to fair value open long-term derivative contracts. Registrant subsidiaries have independent controls to evaluate the reasonableness of our valuation models. However, energy markets, especially electricity markets, are imperfect and volatile. Unforeseen events can and will cause reasonable price curves to differ from actual prices throughout a contract's term and at the time a contract settles. Therefore, there could be significant adverse or favorable effects on future results of operations and cash flows if market prices are not consistent with our approach at estimating current market consensus for forward prices in the current period. This is particularly true for long-term contracts.

Registrant subsidiaries recognize all derivative instruments at fair value in our balance sheets as either Risk Management Assets or Risk Management Liabilities. Registrant subsidiaries do not consider contracts that have been elected normal purchase or normal sale under SFAS 133 to be derivatives. Unrealized and realized gains and losses on all derivative instruments are ultimately included in revenues in the income statement on a net basis.

Debt Instrument Hedging and Related Activities

In order to mitigate the risks of market price and interest rate fluctuations, registrant subsidiaries enter into contracts to manage the exposure to unfavorable changes in the cost of debt to be issued. These anticipatory hedges are entered into in order to manage the change in interest rates between the time a debt offering is initiated and the issuance of the debt (usually a period of 60 days). Gains or losses from these transactions are deferred and amortized over the life of the debt issuance with the amortization included in interest charges. There were no such forward contracts outstanding at December 31, 2003 or 2002.

Levelization of Nuclear Refueling Outage Costs

In order to match costs with regulated revenues, incremental operation and maintenance costs associated with periodic refueling outages at I&M's Cook Plant are deferred and amortized over the period beginning with the commencement of an outage and ending with the beginning of the next outage.

Maintenance Costs

Maintenance costs are expensed as incurred. If it becomes probable that registrant subsidiaries will recover specifically incurred costs through future rates a regulatory asset is established to match the expensing of maintenance costs with their recovery in cost-based regulated revenues.

Income Taxes and Investment Tax Credits

Registrant Subsidiaries use the liability method of accounting for income taxes. Under the liability method, deferred income taxes are provided for all temporary differences between the book cost and tax basis of assets and liabilities which will result in a future tax consequence.

The flow-through method of accounting for temporary differences is reflected in regulated revenues (that is, when deferred taxes are not included in the cost of service for determining regulated rates for electricity), deferred income taxes are recorded and related regulatory assets and liabilities are established to match the regulated revenues and tax expense.

Investment tax credits have been accounted for under the flow-through method except where regulatory commissions have reflected investment tax credits in the rate-making process on a deferral basis. Investment tax credits that have been deferred are being amortized over the life of the regulated plant investment.

Excise Taxes

Registrant subsidiaries, as agents for some state and local governments collect from customers certain excise taxes levied by those state or local governments on our customers. We do not record these taxes as revenue or expense.

Debt and Preferred Stock

Gains and losses from the reacquisition of debt used to finance domestic regulated electric utility plant are generally deferred and amortized over the remaining term of the reacquired debt in accordance with their ratemaking treatment unless the debt is refinanced. If the reacquired debt, associated with the regulated business, is refinanced, the reacquisition costs attributable to the portions of the business that are subject to cost based regulatory accounting are generally deferred and amortized over the term of the replacement debt consistent with its recovery in rates. We report gains and losses on the reacquisition of debt for operations that are not subject to cost-based rate regulation in Nonoperating Income or Nonoperating Expenses.

Debt discount or premium and debt issuance expenses are deferred and amortized utilizing the effective interest rate method over the term of the related debt. The amortization expense is included in interest charges.

Where reflected in rates, redemption premiums paid to reacquire preferred stock of certain domestic utility subsidiaries are included in paid-in capital and amortized to retained earnings commensurate with their recovery in rates. The excess of par value over costs of preferred stock reacquired is credited to paid-in capital and amortized to retained earnings consistent with the timing of its inclusion in rates in accordance with SFAS 71.

Goodwill and Intangible Assets

In the first quarter of fiscal 2002, AEP's registrant subsidiaries adopted SFAS No. 142, "Goodwill and Other Intangible Assets" which revises the accounting for purchased goodwill and other intangible assets. Under SFAS No. 142, purchased goodwill and intangible assets with indefinite lives are no longer amortized, but instead tested for impairment at least annually. Intangible assets with finite lives, requires that they be amortized over their respective estimated lives to the estimated residual values. The AEP registrant subsidiaries have no recorded goodwill and intangible assets with indefinite lives as of December 31, 2003 and 2002. SWEPCo is the only AEP registrant with an intangible asset with a finite life on its books. See Note 3 for further information about SWEPCo's intangible asset.

Nuclear Trust Funds

Nuclear decommissioning and spent nuclear fuel trust funds represent funds that regulatory commissions have allowed us to collect through rates to fund future decommissioning and spent fuel disposal liabilities. By rules or orders, the state jurisdictional commissions (Indiana, Michigan and Texas) and the FERC have established investment limitations and general risk management guidelines. In general, limitations include:

- Acceptable investments (rated investment grade or above)
- Maximum percentage invested in a specific type of investment
- Prohibition of investment in obligations of the applicable company or its affiliates

Trust funds are maintained for each regulatory jurisdiction and managed by investment managers external to AEP subsidiaries, who must comply with the guidelines and rules of the applicable regulatory authorities. The trust assets are invested in order to optimize the after-tax earnings of the trust, giving consideration to liquidity, risk, diversification, and other prudent investment objectives.

Securities held in trust funds for decommissioning nuclear facilities and for the disposal of spent nuclear fuel are included in Nuclear Decommissioning and Spent Nuclear Fuel Disposal Trust Funds for amounts relating to the Cook Plant and are included in Assets Held for Sale for amounts relating to the Texas Plants. See "Assets Held for Sale" section of Note 10 for further information regarding the Texas Plants. These securities are recorded at market value. Securities in the trust funds have been classified as available-for-sale due to their long-term purpose. Unrealized gains and losses from securities in these trust funds are reported as adjustments to the regulatory liability account for the nuclear decommissioning trust funds and to regulatory assets or liabilities for the spent nuclear fuel disposal trust funds in accordance with their treatment in rates.

Comprehensive Income (Loss)

Comprehensive income (loss) is defined as the change in equity (net assets) of a business enterprise during a period from transactions and other events and circumstances from non-owner sources. It includes all changes in equity during a period except those resulting from investments by owners and distributions to owners. Comprehensive income (loss) has two components: net income (loss) and other comprehensive income (loss).

There were no material differences between net income and comprehensive income for AEGCo.

Components of Accumulated Other Comprehensive Income (Loss)

Accumulated Other Comprehensive Income (Loss) is included on the balance sheet in the equity section. Accumulated Other Comprehensive Income (Loss) for AEP registrant subsidiaries as of December 31, 2003 and 2002 is shown in the following table.

Components	December 31, 2003	December 31, 2002
	(in thousands)	
Cash Flow Hedges:		
APCo	$(1,569)	$(1,920)
CSPCo	202	(267)
I&M	222	(286)
KPCo	420	322
OPCo	(103)	(738)
PSO	156	(42)
SWEPCo	184	(48)
TCC	(1,828)	(36)
TNC	(601)	(15)
Minimum Pension Liability:		
APCo	$(50,519)	$(70,162)
CSPCo	(46,529)	(59,090)
I&M	(25,328)	(40,201)
KPCo	(6,633)	(9,773)
OPCo	(48,704)	(72,148)
PSO	(43,998)	(54,431)
SWEPCo	(44,094)	(53,635)
TCC	(60,044)	(73,124)
TNC	(26,117)	(30,748)

Earnings Per Share (EPS)

AEGCo, APCo, CSPCo, I&M, KPCo, OPCo, PSO, SWEPCo, TCC and TNC are wholly-owned subsidiaries of AEP and are not required to report EPS.

Supplementary Information

The amounts of power purchased by the registrant subsidiaries from Ohio Valley Electric Corporation, which is 44.2% owned by the AEP System, for the years ended December 31, 2003, 2002 and 2001 were:

	APCo	CSPCo	I&M	OPCo
		(in thousands)		
Year Ended December 31, 2003	$55,219	$15,259	$25,659	$50,995
Year Ended December 31, 2002	53,386	14,885	23,282	50,135
Year Ended December 31, 2001	45,542	12,626	20,723	47,757

Reclassification

Certain prior period financial statement items have been reclassified to conform to current period presentation. Such reclassifications had no impact on previously reported Net Income (Loss).

2. NEW ACCOUNTING PRONOUNCEMENTS, EXTRAORDINARY ITEMS AND CUMULATIVE EFFECT OF ACCOUNTING CHANGES

NEW ACCOUNTING PRONOUNCEMENTS

SFAS 132 (revised 2003) "Employers' Disclosure about Pensions and Other Postretirement Benefits"

In December 2003 the FASB issued SFAS 132 (revised 2003), which requires additional footnote disclosures about pensions and postretirement benefits, some of which are effective beginning with the year-end 2003 financial statements. Other additional disclosures will begin with APCo, CSPCo, I&M, KPCo, OPCo, PSO, SWEPCo, TCC and TNC's 2004 quarterly financial statements.

APCo, CSPCo, I&M, KPCo, OPCo, PSO, SWEPCo, TCC and TNC will implement new quarterly disclosures when they become effective in the first quarter of 2004, including (a) the amount of net periodic benefit cost for each period for which an income statement is presented, showing separately each component thereof, and (b) the amount of employer contributions paid and expected to be paid during the current year, if significantly different from amounts disclosed at the most recent year-end. See Note 11 for these additional 2003 disclosures.

SFAS 142 "Goodwill and Other Intangible Assets"

SFAS 142 requires that goodwill and intangible assets with indefinite useful lives no longer be amortized, and that goodwill and intangible assets be tested annually for impairment. See Note 3 for further information on goodwill and other intangible assets.

SFAS 143 "Accounting for Asset Retirement Obligations"

We implemented SFAS 143, "Accounting for Asset Retirement Obligations," effective January 1, 2003, which requires entities to record a liability at fair value for any legal obligations for asset retirements in the period incurred. Upon establishment of a legal liability, SFAS 143 requires a corresponding asset to be established which will be depreciated over its useful life. SFAS 143 requires that a cumulative effect of change in accounting principle be recognized for the cumulative accretion and accumulated depreciation that would have been recognized had SFAS 143 been applied to existing legal obligations for asset retirements. In addition, the cumulative effect of change in accounting principle is favorably affected by the reversal of accumulated removal cost. These costs had previously been recorded for generation and did not qualify as a legal obligation although these costs were collected in depreciation rates by certain formerly regulated subsidiaries.

We completed a review of our asset retirement obligations and concluded that we have related legal liabilities for nuclear decommissioning costs for I&M's Cook Plant and TCC's partial ownership in the South Texas Project, as well as liabilities for the retirement of certain ash ponds. Since we presently recover our nuclear decommissioning costs in our regulated cash flow and have existing balances recorded for such nuclear retirement obligations, we recognized the cumulative difference between the amount already provided through rates and the amount as measured by applying SFAS 143, as a regulatory asset or liability. Similarly, a regulatory asset was recorded for the cumulative effect of certain retirement costs for ash ponds related to our regulated operations. In 2003, we recorded an unfavorable cumulative effect for the non-regulated operations. See the table later in this section for a summary by registrant subsidiary of the cumulative effect of changes in accounting principles for the year ended December 31, 2003.

Certain of AEP's registrant subsidiaries have collected removal costs from ratepayers for certain assets that do not have associated legal asset retirement obligations. To the extent that such registrant subsidiaries have now been deregulated, the registrant subsidiaries reversed the balance of such removal costs which resulted in a net favorable cumulative effect in 2003. The following is a summary by registrant subsidiary of the removal costs reclassified from Accumulated Depreciation and Amortization to Asset Removal Costs in 2003 and to Deferred Credits and Other in 2002 (Other on AEGCo's 2002 Balance Sheet):

	December 31, 2003	December 31, 2002
	(in millions)	
AEGCo	$ 27.8	$ 28.0
APCo	92.5	94.6
CSPCo	99.1	96.0
I&M	263.0	250.5
KPCo	26.1	23.7
OPCo	101.2	97.0
PSO	214.0	202.6
SWEPCo	236.4	219.5
TCC (a)	104.8	97.5
TNC	76.7	75.0

(a) Includes $9 million classified as Liabilities Held for Sale - Texas Generation Plants on TCC's Consolidated Balance Sheets as of December 31, 2003 and 2002.

The following is a summary by registrant subsidiary of the cumulative effect of change in accounting principle, as a result of SFAS 143, for the year ended December 31, 2003:

	Pre-tax Income (Loss)		After-tax Income (Loss)	
	(in millions)			
	Ash Ponds	Reversal of Cost of Removal	Ash Ponds	Reversal of Cost of Removal
AEGCo	$ -	$ -	$ -	$ -
APCo	(18.2)	146.5	(11.4)	91.7
CSPCo	(7.8)	56.8	(4.7)	33.9
I&M	-	-	-	-
KPCo	-	-	-	-
OPCo	(36.8)	250.4	(21.9)	149.3
PSO	-	-	-	-
SWEPCo	-	13.0	-	8.4
TCC	-	-	-	-
TNC	-	4.7	-	3.1

We have identified, but not recognized, asset retirement obligation liabilities related to electric transmission and distribution as a result of certain easements on property on which we have assets. Generally, such easements are perpetual and require only the retirement and removal of our assets upon the cessation of the property's use. The retirement obligation is not estimable for such easements since we plan to use our facilities indefinitely. The retirement obligation would only be recognized if and when we abandon or cease the use of specific easements.

The following is a reconciliation of beginning and ending aggregate carrying amounts of asset retirement obligations by registrant subsidiary following the adoption of SFAS 143:

	Balance At January 1, 2003	Accretion	Liabilities Incurred	Balance at December 31, 2003
		(in millions)		
AEGCo (a)	$1.1	$-	$-	$1.1
APCo (a)	20.1	1.6	-	21.7
CSPCo (a)	8.1	0.6	-	8.7
I&M (b)	516.1	37.1	-	553.2
OPCo (a)	39.5	3.2	-	42.7
SWEPCo (d)	-	0.3	8.1	8.4
TCC (c)	203.2	15.6	-	218.8

(a) Consists of asset retirement obligations related to ash ponds.
(b) Consists of asset retirement obligations related to ash ponds ($1.1 million at December 31, 2003) and nuclear decommissioning costs for the Cook Plant ($552.1 million at December 31, 2003).
(c) Consists of asset retirement obligations related to nuclear decommissioning costs for STP included in Liabilities Held for Sale – Texas Generation Plants on TCC's Consolidated Balance Sheets.
(d) Consists of asset retirement obligations related to Sabine Mining which is now being consolidated under FIN 46 (see FIN 46 "Consolidation of Variable Interest Entities" later in this note).

Accretion expense is included in Other Operation expense in the respective income statements of the individual subsidiary registrants.

As of December 31, 2003 and 2002, the fair value of assets that are legally restricted for purposes of settling the nuclear decommissioning liabilities totaled $845 million ($720 million for I&M and $125 million for TCC) and $716 million ($618 million for I&M and $98 million for TCC), respectively, recorded in Nuclear Decommissioning and Spent Nuclear Fuel Disposal Trust Funds on I&M's Consolidated Balance Sheets and in Assets Held for Sale-Texas Generation Plants on TCC's Consolidated Balance Sheets.

Pro forma net income has not been presented for the years ended December 31, 2002 and 2001 because the pro forma application of SFAS 143 would result in pro forma net income not materially different from the actual amounts reported for those periods.

The following is a summary by registrant subsidiary of the pro forma liability for asset retirement obligations which has been calculated as if SFAS 143 had been adopted as of the beginning of each period presented:

	December 31,		
	2002	**2001**	**2000**
		(in millions)	
AEGCo	$ 1.1	$ 1.0	$0.9
APCo	20.1	18.7	17.3
CSPCo	8.1	7.5	6.9
I&M	516.1	481.4	449.1
KPCo	-	-	-
OPCo	39.5	36.5	33.8
PSO	-	-	-
SWEPCo	-	-	-
TCC	203.2	188.8	175.4
TNC	-	-	-

SFAS 144 "Accounting for the Impairment or Disposal of Long-lived Assets"

In August 2001, the FASB issued SFAS 144, "Accounting for the Impairment or Disposal of Long-lived Assets" which sets forth the accounting to recognize and measure an impairment loss. This standard replaced, SFAS 121, "Accounting for Long-lived Assets and for Long-lived Assets to be Disposed Of." All of the registrant subsidiaries adopted SFAS 144 effective January 1, 2002. See Note 10 for discussion of impairments recognized in 2003 and 2002.

SFAS 145 "Rescission of FASB Statements No. 4, 44 and 64, Amendment of FASB Statement No. 13, and Technical Corrections"

In April 2002, the FASB issued SFAS 145, "Rescission of FASB Statements No. 4, 44 and 64, Amendment of FASB Statement No. 13, and Technical Corrections" (SFAS 145). SFAS 145 rescinds SFAS 4, "Reporting Gains and Losses from Extinguishment of Debt," effective for fiscal years beginning after May 15, 2002. SFAS 4 required gains and losses from extinguishment of debt to be aggregated and classified as an extraordinary item if material. In 2003, TCC reclassified Extraordinary Losses (Net of Tax) on its reacquired debt of $2 million for 2001 to Nonoperating Expenses and Nonoperating Income Tax Expense.

SFAS 146 "Accounting for Costs Associated with Exit or Disposal Activities"

In June 2002, FASB issued SFAS 146 which addresses accounting for costs associated with exit or disposal activities. This statement supersedes previous accounting guidance, principally EITF No. 94-3, "Liability Recognition for Certain Employee Termination Benefits and Other Costs to Exit an Activity (including Certain Costs Incurred in a Restructuring)." Under EITF No. 94-3, a liability for an exit cost was recognized at the date of an entity's commitment to an exit plan. SFAS 146 requires that the liability for costs associated with an exit or disposal activity be recognized when the liability is incurred. SFAS 146 also establishes that the liability should initially be measured and recorded at fair value. The time at which we recognize future costs related to exit or disposal activities, including restructuring, as well as the amounts recognized may be affected by SFAS 146. The registrant subsidiaries adopted the provisions of SFAS 146 for exit or disposal activities initiated after December 31, 2002.

SFAS 149 "Amendment of Statement 133 on Derivative Instruments and Hedging Activities"

On April 30, 2003, the FASB issued Statement No. 149, "Amendment of Statement 133 on Derivative Instruments and Hedging Activities" (SFAS 149). SFAS 149 amends SFAS 133 to clarify the definition of a derivative and the requirements for contracts to qualify as "normal purchase/normal sale." SFAS 149 also amends certain other existing pronouncements. Effective July 1, 2003, registrant subsidiaries implemented SFAS 149 and the effect was not material to our results of operations, cash flows or financial condition.

SFAS 150 "Accounting for Certain Financial Instruments with Characteristics of Both Liabilities and Equity"

We implemented SFAS 150 effective July 1, 2003. SFAS 150 is the first phase of the FASB's project to eliminate from the balance sheet the "mezzanine" presentation of items with characteristics of both liabilities and equity, including: (1) mandatorily redeemable shares, (2) instruments other than shares that could require the issuer to buy back some of its shares in exchange for cash or other assets and (3) certain obligations that can be settled with shares. Measurement of these liabilities generally is to be at fair value, with the payment or accrual of "dividends" and other amounts to holders reported as interest cost.

Beginning with our third quarter 2003 financial statements, we present Cumulative Preferred Stocks Subject to Mandatory Redemption as Liability for Cumulative Preferred Stock Subject to Mandatory Redemption. Beginning July 1, 2003, we classify dividends on these mandatorily redeemable preferred shares as Interest Charges. In accordance with SFAS 150, dividends from prior periods remain classified as Preferred Stock Dividends.

FIN 45 "Guarantor's Accounting and Disclosure Requirements for Guarantees, Including Indirect Guarantees of Indebtedness of Others"

In November 2002, the FASB issued FIN 45 which clarifies the accounting to recognize a liability related to issuing a guarantee, as well as additional disclosures of guarantees. We implemented FIN 45 as of January 1, 2003, and the effect was not material to our results of operations, cash flows or financial condition. See Note 8 for further disclosures.

FIN 46 (revised December 2003) "Consolidation of Variable Interest Entities" and FIN 46 "Consolidation of Variable Interest Entities"

We implemented FIN 46, "Consolidation of Variable Interest Entities," effective July 1, 2003. FIN 46 interprets the application of Accounting Research Bulletin No. 51, "Consolidated Financial Statements," to certain entities in which equity investors do not have the characteristics of a controlling financial interest or do not have sufficient equity at risk for the entity to finance its activities without additional subordinated financial support from other parties. Due to the prospective application of FIN 46, we did not reclassify prior period amounts.

On July 1, 2003, we deconsolidated the trusts which hold mandatorily redeemable trust preferred securities. Therefore, of the $321 million net amount ($75 million PSO, $110 million SWEPCo and $136 million TCC), reported as "Certain Subsidiary Obligated, Mandatorily Redeemable, Preferred Securities of Subsidiary Trusts Holding Solely Junior Subordinated Debentures of Such Subsidiaries" at December 31, 2002, $331 million ($77 million PSO, $113 million SWEPCo and $141 million TCC) is reported as a component of Long-term Debt and $10 million ($2 million PSO, $3 million SWEPCo and $5 million TCC) is reported in Other Investments within Other Property and Investments at December 31, 2003.

Effective July 1, 2003, SWEPCo consolidated Sabine Mining Company (Sabine), a contract mining operation providing mining services to SWEPCo. Upon consolidation, SWEPCo recorded the assets and liabilities of Sabine ($78 million). Also, after consolidation, SWEPCo currently records all expenses (depreciation, interest and other operation expense) of Sabine and eliminates Sabine's revenues against SWEPCo's fuel expenses. There is no cumulative effect of an accounting change recorded as a result of our requirement to consolidate, and there is no change in net income due to the consolidation of Sabine.

Effective July 1, 2003, OPCo consolidated JMG. Upon consolidation, OPCo recorded the assets and liabilities of JMG ($469.6 million). OPCo now records the depreciation, interest and other operating expenses of JMG and eliminates JMG's revenues against OPCo's operating lease expenses. There is no cumulative effect of an accounting change recorded as a result of our requirement to consolidate JMG, and there is no change in net income due to the consolidation of JMG. See Note 15 "Leases" for further disclosures.

In December 2003, the FASB issued FIN 46 (revised December 2003) (FIN 46R) which replaces FIN 46. The FASB and other accounting constituencies continue to interpret the application of FIN 46R. As a result, we are continuing to review the application of this new interpretation and expect to adopt FIN 46R by March 31, 2004.

EITF 02-3 and the Rescission of EITF 98-10

In October 2002, the Emerging Issues Task Force of the FASB reached a final consensus on Issue No. 02-3. EITF 02-3 rescinds EITF 98-10 and related interpretive guidance. Under EITF 02-3, mark-to-market accounting is precluded for risk management contracts that are not derivatives pursuant to SFAS 133. The consensus to rescind EITF 98-10 also eliminated the recognition of physical inventories at fair value other than as provided by GAAP. Registrant subsidiaries have implemented this standard for all physical inventory and non-derivative risk management transactions occurring on or after October 25, 2002. For physical inventory and non-derivative risk management transactions entered into prior to October 25, 2002, registrant subsidiaries implemented this standard on January 1, 2003 and reported the effects of implementation as a cumulative effect of an accounting change (see "Cumulative Effect of Accounting Change" for a summary by registrant subsidiary).

Effective January 1, 2003, EITF 02-3 requires that gains and losses on all derivatives, whether settled financially or physically, be reported in the income statement on a net basis if the derivatives are held for risk management purposes. Previous guidance in EITF 98-10 permitted contracts that were not settled financially to be reported either gross or net in the income statement. Prior to the third quarter of 2002, the registrant subsidiaries recorded and reported upon settlement, sales under forward risk management contracts as revenues. Registrant subsidiaries also recorded and reported purchases under forward risk management contracts as purchased energy expenses. Effective July 1, 2002, the registrant subsidiaries reclassified such forward risk management revenues and purchases on a net basis. The reclassification of such risk management activities to a net basis of reporting resulted in a substantial reduction in both revenues and purchased energy expense, but did not have any impact on financial condition, results of operations or cash flows.

EITF 03-11 "Reporting Realized Gains and Losses on Derivative Instruments That Are Subject to FASB Statement No. 133 and Not "Held for Trading Purposes" as Defined in Issue No. 02-3"

In July 2003, the EITF reached consensus on Issue No. 03-11. The consensus states that realized gains and losses on derivative contracts not "held for trading purposes" should be reported either on a net or gross basis based on the relevant facts and circumstances. Reclassification of prior year amounts is not required. The adoption of EITF 03-11 did not have a material impact on our results of operations, financial position or cash flows.

FASB Staff Position No. 106-1, Accounting and Disclosure Requirements Related to the Medicare Prescription Drug Improvement and Modernization Act of 2003

On January 12, 2004, the FASB Staff issued FSP 106-1, which allows a one-time election to defer accounting for any effects of the prescription drug subsidy under the Medicare Prescription Drug Improvement and Modernization Act of 2003 (the Act), enacted on December 8, 2003. There are significant uncertainties as to whether AEP's plan will be eligible for a subsidy under future federal regulations that have not yet been drafted. The method of accounting for any such subsidy and, therefore, the subsidy's possible reduction to the accumulated postretirement benefit obligation and periodic postretirement benefit costs has not been resolved by the FASB or other professional accounting standard setting authority. Accordingly, any potential effects of the Act were deferred until authoritative guidance on the accounting for the federal subsidy is issued. Measurements of the accumulated postretirement benefit obligation and periodic postretirement benefit cost included in these financial statements do not reflect any potential effects of the Act. APCo, CSPCo, I&M, KPCo, OPCo, PSO, SWEPCo, TCC and TNC cannot determine what impact, if any, new authoritative guidance on the accounting for the federal subsidy may have on our results of operations or financial condition.

Future Accounting Changes

The FASB's standard-setting process is ongoing. Until new standards have been finalized and issued by FASB, we cannot determine the impact on the reporting of our operations that may result from any such future changes.

CUMULATIVE EFFECT OF ACCOUNTING CHANGE

Accounting for Risk Management Contracts

EITF 02-3 rescinds EITF 98-10 and related interpretive guidance. Certain registrant subsidiaries have recorded after tax charges against net income as Accounting for Risk Management Contracts in our Consolidated Statements of Operations in Cumulative Effect of Accounting Changes in the first quarter of 2003. This amount will be realized when the positions settle.

The FASB's Derivative Implementation Group (DIG) issued accounting guidance under SFAS 133 for certain derivative fuel supply contracts with volumetric optionality and derivative electricity capacity contracts. This guidance, effective in the third quarter of 2001, concluded that fuel supply contracts with volumetric optionality cannot qualify for a normal purchase or sale exclusion from mark-to-market accounting and provided guidance for determining when certain option-type contracts and forward contracts in electricity can qualify for the normal purchase or sale exclusion.

Asset Retirement Obligations (SFAS 143)

In the first quarter of 2003, certain of the registrant subsidiaries recorded in after-tax income a cumulative effect of accounting change for Asset Retirement Obligations.

The following is a summary by registrant subsidiary of the cumulative effect of changes in accounting principles recorded in 2003 for the adoptions of SFAS 143 and EITF 02-3 (no effect on AEGCo or PSO):

	SFAS 143 Cumulative Effect		EITF 02-3 Cumulative Effect	
	Pre-tax Income (Loss)	After-tax Income (Loss)	Pre-tax Income (Loss)	After-tax Income (Loss)
	(in millions)		(in millions)	
APCo	$128.3	$ 80.3	$ (4.7)	$ (3.0)
CSPCo	49.0	29.3	(3.1)	(2.0)
I&M	-	-	(4.9)	(3.2)
KPCo	-	-	(1.7)	(1.1)
OPCo	213.6	127.3	(4.2)	(2.7)
SWEPCo	13.0	8.4	0.2	0.1
TCC	-	-	0.2	0.1
TNC	4.7	3.1	-	-

EXTRAORDINARY ITEMS

In 2003 an extraordinary item of $177,000, net of tax of $95,000, was recorded at TNC for the discontinuance of regulatory accounting under SFAS 71 in compliance with a FERC Order dated December 24, 2003 approving a Settlement. AEP's registrant subsidiaries had no extraordinary items in 2002. In 2001 an extraordinary item was recorded for the discontinuance of regulatory accounting under SFAS 71 for the generation portion of the business in the Ohio state jurisdiction. OPCo and CSPCo recognized an extraordinary loss of $48 million (net of tax of $20 million) for unrecoverable Ohio Public Utility Excise Tax (commonly known as the Gross Receipts Tax – GRT) net of allowable Ohio coal credits. This loss resulted from regulatory decisions in connection with Ohio deregulation which stranded the recovery of the GRT. Effective with the liability affixing on May 1, 2001, CSPCo and OPCo recorded an extraordinary loss under SFAS 101. Both Ohio companies appealed to the Ohio Supreme Court the PUCO order on Ohio restructuring that the Ohio companies believe failed to provide for recovery for the final year of the GRT. In April 2002, the Ohio Supreme Court denied recovery of the final year of the GRT.

3. GOODWILL AND OTHER INTANGIBLE ASSETS

Goodwill

There is no goodwill carried by any of the AEP registrant subsidiaries.

Acquired Intangible Assets

SWEPCo's acquired intangible asset subject to amortization is $21.7 million at December 31, 2003 and $24.7 million at December 31, 2002, net of accumulated amortization. The gross carrying amount, accumulated amortization and amortization life are:

		December 31, 2003		December 31, 2002	
	Amortization Life	Gross Carrying Amount	Accumulated Amortization	Gross Carrying Amount	Accumulated Amortization
	(in years)	(in millions)		(in millions)	
Advanced royalties	10	$29.4	$7.7	$29.4	$4.7

Amortization of the intangible asset was $3.0 million for the twelve months ended December 31, 2003 and 2002. SWEPCo's estimated aggregate amortization expense is $3 million for each year 2004 through 2010 and $1 million in 2011.

4. RATE MATTERS

In certain jurisdictions, we have agreed to base rate or fuel recovery limitations usually under terms of settlement agreements. See Note 5 for a discussion of those terms related to Nuclear Plant Restart and Merger with CSW.

Fuel in SPP Area of Texas – Affecting SWEPCo and TNC

In 2001, the PUCT delayed the start of customer choice in the SPP area of Texas. In May 2003, the PUCT ordered that competition would not begin in the SPP areas before January 1, 2007. TNC filed with the PUCT in 2002 to determine the most appropriate method to reconcile fuel costs in TNC's SPP area. In April 2003, the PUCT issued an order adopting the methodology proposed in TNC's filing, with adjustments, for reconciling fuel costs in the SPP area. The adjustments removed $3.71 per MWH from reconcilable fuel expense. This adjustment will reduce revenues received by Mutual Energy SWEPCo who now serves TNC's SPP customers by approximately $400,000 annually. In October 2003, Mutual Energy SWEPCo agreed with the PUCT staff and the Office of Public Utility Counsel (OPC) to file a fuel reconciliation proceeding for the period January 2002 through December 2003 by March 31, 2004 and the PUCT ordered that the filing be made.

TNC Fuel Reconciliation – Affecting TNC

In June 2002, TNC filed with the PUCT to reconcile fuel costs, requesting to defer any unrecovered portion applicable to retail sales within its ERCOT service area for inclusion in the 2004 true-up proceeding. This reconciliation for the period of July 2000 through December 2001 will be the final fuel reconciliation for TNC's ERCOT service territory. At December 31, 2001, the deferred under-recovery balance associated with TNC's ERCOT service area was $27.5 million including interest. During the reconciliation period, TNC incurred $293.7 million of eligible fuel costs serving both ERCOT and SPP retail customers. TNC also requested authority to surcharge its SPP customers for under-recovered fuel costs. TNC's SPP customers will continue to be subject to fuel reconciliations until competition begins in the SPP area as described above. The under-recovery balance at December 31, 2001 for TNC's service within SPP was $0.7 million including interest.

In March 2003, the ALJ in this proceeding filed a Proposal for Decision (PFD) with a recommendation that TNC's under-recovered retail fuel balance be reduced. In March 2003, TNC established a reserve of $13 million based on the recommendations in the PFD. In May 2003, the PUCT reversed the ALJ on certain matters and remanded TNC's final fuel reconciliation to the ALJ to consider two issues. The issues are the sharing of off-system sales margins from AEP's trading activities with customers for five years per the PUCT's interpretation of the Texas AEP/CSW merger settlement and the inclusion of January 2002 fuel factor revenues and associated costs in the determination of the under-recovery. The PUCT proposed that the sharing of off-system sales margins for periods beyond the termination of the fuel factor should be recognized in the final fuel reconciliation proceeding. This would result in the sharing of margins for an additional three and one half years after the end of the Texas ERCOT fuel factor.

On December 3, 2003, the ALJ issued a PFD in the remand phase of the TNC fuel reconciliation recommending additional disallowances for the two remand issues. TNC filed responses to the PFD and the PUCT announced a final ruling in the fuel reconciliation proceeding on January 15, 2004 accepting the PFD. TNC is waiting for a written order, after which it will request a rehearing of the PUCT's ruling. While management believes that the Texas merger settlement only provided for sharing of margins during the period fuel and generation costs were regulated by the PUCT, an additional provision of $10 million was recorded in December 2003. Based on the decisions of the PUCT, TNC's final under-recovery including interest at December 31, 2003 was $6.2 million.

In February 2002, TNC received a final order from the PUCT in a previous fuel reconciliation covering the period July 1997 to June 2000 and reflected the order in its financial statements. This final order was appealed to the Travis County District Court. In May 2003, the District Court upheld the PUCT's final order. That order is currently on appeal to the Third Court of Appeals.

TCC Fuel Reconciliation - Affecting TCC

In December 2002, TCC filed its final fuel reconciliation with the PUCT to reconcile fuel costs to be included in its deferred over-recovery balance in the 2004 true-up proceeding. This reconciliation covers the period of July 1998 through December 2001. At December 31, 2001, the over-recovery balance for TCC was $63.5 million including interest. During the reconciliation period, TCC incurred $1.6 billion of eligible fuel and fuel-related expenses.

Based on the PUCT ruling in the TNC proceeding relating to similar issues, TCC established a reserve for potential adverse rulings of $81 million during 2003. In July 2003, the ALJ requested that additional information be provided in the TCC fuel reconciliation related to the impact of the TNC orders, referenced above, on TCC. On February 3, 2004, the ALJ issued a PFD recommending that the PUCT disallow $140 million in eligible fuel costs including some new items not considered in the TNC case, and other items considered but not disallowed in the TNC ruling. At this time, management is unable to predict the outcome of this proceeding. An adverse ruling from the PUCT, disallowing amounts in excess of the established reserve could have a material impact on future results of operations, cash flows and financial condition. Additional information regarding the 2004 true-up proceeding for TCC can be found in Note 6 "Customer Choice and Industry Restructuring."

SWEPCo Texas Fuel Reconciliation – Affecting SWEPCo

In June 2003, SWEPCo filed with the PUCT to reconcile fuel costs in SPP. This reconciliation covers the period of

January 2000 through December 2002. At December 31, 2002, SWEPCo's filing included a $2 million deferred over-recovery balance including interest. During the reconciliation period, SWEPCo incurred $435 million of Texas retail eligible fuel expense. In November 2003, intervenors and the PUCT Staff recommended fuel cost disallowances of more than $30 million. In December 2003, SWEPCo agreed to a settlement in principle with all parties in the fuel reconciliation. The settlement provides for a disallowance in fuel costs of $8 million which was recorded in December 2003. In addition, the settlement provides for the deferral as a regulatory asset of costs of a new lignite mining agreement in excess of a specified benchmark for lignite at SWEPCo's Dolet Hills Plant. The settlement provides for recovery of those deferred costs over a period ending in April 2011 as cost savings are realized under the new mining agreement. The settlement also will allow future recovery of litigation costs associated with the termination of a previous lignite mining agreement if future costs savings are adequate. The settlement will be filed with the PUCT for approval.

ERCOT Price-to-Beat Fuel Factor Appeal – Affecting TCC and TNC

Several parties including the OPC and cities served by both TCC and TNC appealed the PUCT's December 2001 orders establishing initial PTB fuel factors for Mutual Energy CPL and Mutual Energy WTU. On June 25, 2003, the District Court ruled in both appeals. The Court ruled in the Mutual Energy WTU case that the PUCT lacked sufficient evidence to include unaccounted for energy in the fuel factor, and that the PUCT improperly shifted the burden of proof and the record lacked substantial evidence on the effect of loss of load due to retail competition on generation requirements. The Court upheld the initial PTB orders on all other issues. In the Mutual Energy CPL proceeding, the Court ruled that the PUCT improperly shifted the burden of proof and the record lacked substantial evidence on the effect of loss of load due to retail competition on generation requirements. The amount of unaccounted for energy built into the PTB fuel factors was approximately $2.7 million for Mutual Energy WTU. At this time, management is unable to estimate the potential financial impact related to the loss of load issue. The District Court decision was appealed to the Third Court of Appeals by Mutual Energy CPL, Mutual Energy WTU and other parties. Management believes, based on the advice of counsel, that the PUCT's original decision will ultimately be upheld. If the District Court's decisions are ultimately upheld, the PUCT could reduce the PTB fuel factors charged to retail customers in 2002 and 2003 resulting in an adverse effect on future results of operations and cash flows.

Unbundled Cost of Service (UCOS) Appeal – Affecting TCC

The UCOS proceeding established the regulated wires rates to be effective when retail electric competition began. TCC placed new transmission and distribution rates into effect as of January 1, 2002 based upon an order issued by the PUCT resulting from TCC's UCOS proceeding. TCC requested and received approval from the FERC of wholesale transmission rates determined in the UCOS proceeding. Regulated delivery charges include the retail transmission and distribution charge and, among other items, a nuclear decommissioning fund charge, a municipal franchise fee, a system benefit fund fee, a transition charge associated with securitization of regulatory assets and a credit for excess earnings. Certain rulings of the PUCT in the UCOS proceeding, including the initial determination of stranded costs, the requirement to refund TCC's excess earnings, regulatory treatment of nuclear insurance and distribution rates charged municipal customers, were appealed to the Travis County District Court by TCC and other parties to the proceeding. The District Court issued a decision on June 16, 2003, upholding the PUCT's UCOS order with one exception. The Court ruled that the refund of the 1999 through 2001 excess earnings, solely as a credit to non-bypassable transmission and distribution rates charged to REPs, discriminates against residential and small commercial customers and is unlawful. The distribution rate credit began in January 2002. This decision could potentially affect the PTB rates charged by Mutual Energy CPL and could result in a refund to certain of its customers. Mutual Energy CPL was a subsidiary of AEP until December 23, 2002 when it was sold. Management estimates that the effect of a decision to reduce the PTB rates for the period prior to the sale is approximately $11 million pre-tax. The District Court decision was appealed to the Third Court of Appeals by TCC and other parties. Based on advice of counsel, management believes that it will ultimately prevail on appeal. If the District Court's decision is ultimately upheld on appeal or the Court of Appeals reverses the District Court on issues adverse to TCC, it could have an adverse effect on future results of operations and cash flows.

TCC Rate Case – Affecting TCC

On June 26, 2003, the City of McAllen, Texas requested that TCC provide justification showing that its transmission and distribution rates should not be reduced. Other municipalities served by TCC passed similar rate review resolutions. In Texas, municipalities have original jurisdiction over rates of electric utilities within their municipal limits. Under Texas law, TCC must provide support for its rates to the municipalities. TCC filed the requested support for its rates based on a test year ending June 30, 2003 with all of its municipalities and the PUCT on November 3, 2003. TCC's proposal would decrease its wholesale transmission rates by $2 million or 2.5% and increase its retail energy delivery rates by $69 million or 19.2%. On February 9, 2004, eight intervening parties filed testimony recommending reductions to TCC's requested $67 million rate increase. The recommendations range from a decrease in existing rates of approximately $100 million to an increase in TCC's current rates of approximately $27 million. The PUCT Staff filed testimony, on February 17, 2004, recommending reductions to TCC's request of approximately $51 million. TCC's rebuttal testimony was filed on February 26, 2004. Hearings are scheduled for March 2004 with a PUCT decision expected in May 2004. Management is unable to predict the ultimate effect of this proceeding on TCC's rates or its impact on TCC's results of operations, cash flows and financial condition.

Louisiana Fuel Audit – Affecting SWEPCO

The LPSC is performing an audit of SWEPCo's historical fuel costs. In addition, five SWEPCo customers filed a suit in the Caddo Parish District Court in January 2003 and filed a complaint with the LPSC. The customers claim that SWEPCo has over charged them for fuel costs since 1975. The LPSC consolidated the customer complaint and audit. In January 2004, a procedural schedule was issued requiring LPSC Staff and intervenor testimony to be filed in June 2004 and scheduling hearings for October 2004. Management believes that SWEPCo's fuel costs were proper and those costs incurred prior to 1999 have been approved by the LPSC. Management is unable to predict the outcome of these proceedings. If the actions of the LPSC or the Court result in a material disallowance of recovery of SWEPCo's fuel costs from customers, it could have an adverse impact on results of operations and cash flows.

Louisiana Compliance Filing – Affecting SWEPCo

In October 2002, SWEPCo filed with the LPSC detailed financial information typically utilized in a revenue requirement filing, including a jurisdictional cost of service. This filing was required by the LPSC as a result of their order approving the merger between AEP and CSW. The LPSC's merger order also provides that SWEPCo's base rates are capped at the present level through mid 2005. The filing indicates that SWEPCo's current rates should not be reduced. In 2004 the LPSC required SWEPCo to file updated financial information with a test year ending December 31, 2003 before April 16, 2004. If, after review of the updated information, the LPSC disagrees with our conclusion, they could order SWEPCo to file all documents for a full cost of service revenue requirement review in order to determine whether SWEPCo's capped rates should be reduced which would adversely impact results of operations and cash flows.

FERC Wholesale Fuel Complaints – Affecting TNC

Certain TNC wholesale customers filed a complaint with FERC alleging that TNC had overcharged them through the fuel adjustment clause for certain purchased power costs since 1997.

Negotiations to settle the complaint and update the contracts resulted in new contracts. The FERC approved an offer of settlement regarding the fuel complaint and new contracts at market prices in December 2003. Since TNC had recorded a provision for refund in 2002, the effect of the settlement was a $4 million favorable adjustment recorded in December 2003. See Note 2 for a discussion of TNC's discontinuance of SFAS 71 accounting for its FERC jurisdictional customers.

Environmental Surcharge Filing – Affecting KPCo

In September 2002, KPCo filed with the KPSC to revise its environmental surcharge tariff (annual revenue increase of approximately $21 million) to recover the cost of emissions control equipment being installed at the Big Sandy Plant. See NOx Reductions in Note 7.

In March 2003, the KPSC granted approximately $18 million of the request. Annual rate relief of $1.7 million became effective in May 2003 and an additional $16.2 million became effective in July 2003. The recovery of such amounts is intended to offset KPCo's cost of compliance with the Clean Air Act.

PSO Rate Review – Affecting PSO

In February 2003, the Director of the OCC filed an application requiring PSO to file all documents necessary for a general rate review. In October 2003, PSO filed financial information and supporting testimony in response to the OCC's requirements. PSO's response indicates that its annual revenues are $36 million less than costs. As a result, PSO is seeking OCC approval to increase its base rates by that amount, which is a 3.6% increase over PSO's existing revenues. Hearings are scheduled for October 2004. Management is unable to predict the ultimate effect of this review on PSO's rates or its impact on PSO's results of operations, cash flows and financial condition.

PSO Fuel and Purchased Power – Affecting PSO

PSO had a $44 million under-recovery of fuel costs resulting from a 2002 reallocation among AEP West companies of purchased power costs for periods prior to January 1, 2002. In July 2003, PSO filed with the OCC seeking recovery of the $44 million over an 18-month time period. In August 2003, the OCC Staff filed testimony recommending PSO be granted recovery of $42.4 million over three years. In September 2003, the OCC expanded the case to include a full review of PSO's 2001 fuel and purchased power practices. PSO filed its testimony in February 2004 and hearings will occur in June 2004. If the OCC determines as a result of the review that a portion of PSO's fuel and purchased power costs should not be recovered, there will be an adverse effect on PSO's results of operations, cash flows and possibly financial condition.

Merger Mitigation Sales – Affecting PSO, SWEPCo, TCC and TNC

As a condition of AEP/CSW merger approval at the FERC, the AEP West companies were required to mitigate market power concerns in SPP by divesting 300 MW of SPP capacity and selling 300 MW of SPP capacity at auction on an interim basis until the divestiture is completed. The margins from the interim sales were to be shared with customers in accordance with the existing margin sharing if they were positive on an annual basis and customers were to be held harmless if the margins on an annual basis were negative. Consequently, for proper accounting, the margins were deferred until year-end.

On September 1, 2003, AEP sold its share of the Eastex plant located in SPP. As a result of the sale, AEP satisfied the 300 MW FERC divestiture requirement in SPP. Based on the advice of counsel, management has concluded that it is no longer required to make the agreed upon 300 MW interim merger mitigation sale. The AEP West companies had $8.7 million of net merger mitigation sales losses deferred. Since these sales are no longer required, the final adjustment to the accrual occurred in September 2003. The amounts of revenues reversed were $8.6 million by PSO, $0.7 million by TCC and $1.2 million by TNC. SWEPCo recorded its gain of $1.8 million as revenues.

Virginia Fuel Factor Filing – Affecting APCo

APCo filed with the Virginia SCC to reduce its fuel factor effective August 1, 2003. The requested fuel rate reduction was approved by the Virginia SCC and is effective for 17 months (August 1, 2003 to December 31, 2004) and is estimated to reduce revenues by $36 million during that period. This fuel factor adjustment will reduce cash flows without impacting results of operations as any over-recovery or under-recovery of fuel costs would be deferred as a regulatory liability or a regulatory asset.

FERC Long-term Contracts – Affecting AEP East and AEP West companies

In 2002, the FERC set for hearing complaints filed by certain wholesale customers located in Nevada and Washington that sought to break long-term contracts which the customers alleged were "high-priced." At issue were long-term contracts entered into during the California energy price spike in 2000 and 2001. The complaints alleged that AEP sold power at unjust and unreasonable prices.

In February 2003, AEP and one of the customers agreed to terminate their contract. The customer withdrew its FERC complaint and paid $59 million to AEP. As a result of the contract termination, AEP reversed $69 million of unrealized mark-to-market gains previously recorded, resulting in a $10 million pre-tax loss.

In December 2002, a FERC ALJ ruled in favor of AEP and dismissed a complaint filed by two Nevada utilities. In 2000 and 2001, we agreed to sell power to the utilities for future delivery. In 2001, the utilities filed complaints asserting that the prices for power supplied under those contracts should be lowered because the market for power was allegedly dysfunctional at the time such contracts were executed. The ALJ rejected the utilities' complaint, held that the markets for future delivery were not dysfunctional, and that the utilities had failed to demonstrate that the public interest required that changes be made to the contracts. In June 2003, the FERC issued an order affirming the ALJ's decision. The utilities requested a rehearing which the FERC denied. The utilities' appeal of the FERC order is pending before the U.S. Court of Appeals for the Ninth Circuit. Management is unable to predict the outcome of this proceeding and its impact on future results of operations and cash flows.

RTO Formation/Integration Costs – Affecting APCo, CSPCo, I&M, KPCo, and OPCo

With FERC approval, AEP East companies have been deferring costs incurred under FERC orders to form an RTO (the Alliance RTO) or join an existing RTO (PJM). In July 2003, the FERC issued an order approving our continued deferral of both our Alliance formation costs and our PJM integration costs including the deferral of a carrying charge. The AEP East companies have deferred approximately $28 million of RTO formation and integration costs and related carrying charges through December 31, 2003. Amounts per company are as follows:

Company	**(in millions)**
APCo	$7.8
CSPCo	3.3
I&M	6.0
KPCo	1.8
OPCo	8.6

As a result of the subsequent delay in the integration of AEP's East transmission system into PJM, FERC declined to rule, in its July 2003 order, on our request to transfer the deferrals to regulatory assets, and to maintain the deferrals until such time as the costs can be recovered from all users of AEP's East transmission system. The AEP East companies will apply for permission to transfer the deferred formation/integration costs to a regulatory asset prior to integration with PJM. In August 2003, the Virginia SCC filed a request for rehearing of the July 2003 order, arguing that FERC's action was an infringement on state jurisdiction, and that FERC should not have treated Alliance RTO startup costs in the same manner as PJM integration costs. On October 22, 2003, FERC denied the rehearing request.

In its July 2003 order, FERC indicated that it would review the deferred costs at the time they are transferred to a regulatory asset account and scheduled for amortization and recovery in the open access transmission tariff (OATT) to be charged by PJM. Management believes that the FERC will grant permission for the deferred RTO costs to be amortized and included in the OATT. Whether the amortized costs will be fully recoverable depends upon the state regulatory commissions' treatment of AEP East companies' portion of the OATT at the time they join PJM. Presently, retail base rates are frozen or capped and cannot be increased for retail customers of CSPCo, I&M and OPCo. APCo's Virginia retail base rates are capped with an opportunity for a one-time increase in non-generation rates after January 1, 2004. We intend to file an application with FERC seeking permission to delay the amortization of the deferred RTO formation/integration costs until they are recoverable from all users of the transmission system including retail customers. Management is unable to predict the timing of when AEP will join PJM and if upon joining PJM whether FERC will grant a delay of recovery until the rate caps and freezes end. If the AEP East companies do not obtain regulatory approval to join PJM, we are committed to reimburse PJM for certain project implementation costs (presently estimated at $24 million for the entire PJM integration project). If incurred, PJM project implementation costs will be allocated among the AEP East companies. Management intends to seek recovery of the deferred RTO formation/integration costs and project implementation cost reimbursements, if incurred. If the FERC ultimately decides not to approve a delay or the state commissions deny recovery, future results of operations and cash flows could be adversely affected.

In the first quarter of 2003, the state of Virginia enacted legislation preventing APCo from joining an RTO prior to July 1, 2004 and thereafter only with the approval of the Virginia SCC, but required such transfers by January 1, 2005. In January 2004, APCo filed with the Virginia SCC a cost/benefit study covering the time period through 2014 as required by the Virginia SCC. The study results show a net benefit of approximately $98 million for APCo over the 11-year study period from AEP's participation in PJM.

In July 2003, the KPSC denied KPCo's request to join PJM based in part on a lack of evidence that it would benefit Kentucky retail customers. In August 2003, KPCo sought and was granted a rehearing to submit additional evidence. In December 2003, AEP filed with the KPSC a cost/benefit study showing a net benefit of approximately $13 million for KPCo over the five-year study period from AEP's participation in PJM. A hearing has been scheduled in April 2004.

In September 2003, the IURC issued an order approving I&M's transfer of functional control over its transmission facilities to PJM, subject to certain conditions included in the order. The IURC's order stated that AEP shall request and the IURC shall complete a review of Alliance formation costs before any deferral of the costs for future recovery.

In November 2003, the FERC issued an order preliminarily finding that AEP must fulfill its CSW merger condition to join an RTO by integrating into PJM (transmission and markets) by October 1, 2004. The order was based on PURPA 205(a), which allows FERC to exempt electric utilities from state law or regulation in certain circumstances. The FERC set several issues for public hearing before an ALJ. Those issues include whether the laws, rules, or regulations of Virginia and Kentucky are preventing AEP from joining an RTO and whether the exceptions under PURPA apply. The FERC directed the ALJ to issue an initial decision by March 15, 2004.

FERC Order on Regional Through and Out Rates – Affecting APCo, CSPCo, I&M, KPCo and OPCo

In July 2003, the FERC issued an order directing PJM and the Midwest ISO to make compliance filings for their respective Open Access Transmission Tariffs to eliminate, by November 1, 2003, the transaction-based charges for through and out (T&O) transmission service on transactions where the energy is delivered within the proposed Midwest ISO and PJM expanded regions (RTO Footprint). In October 2003, the FERC postponed the November 1, 2003 deadline to eliminate T&O rates. The elimination of the T&O rates will reduce the transmission service revenues collected by the RTOs and thereby reduce the revenues received by transmission owners under the RTOs' revenue distribution protocols. The order provided that affected transmission owners could file to offset the elimination of these revenues by increasing rates or utilizing a transitional rate mechanism to recover lost revenues that result from the elimination of the T&O rates. The FERC also found that the T&O rates of some of the former Alliance RTO companies, including AEP, may be unjust, unreasonable, and unduly discriminatory or preferential for energy delivered in the RTO Footprint. FERC initiated an investigation and hearing in regard to these rates. We made a filing with the FERC to support the justness and reasonableness of our rates. We also made a joint filing with unaffiliated utilities proposing a regional revenue replacement mechanism for the lost revenues, in the event that FERC eliminated all T&O rates for delivery points within the RTO Footprint. In orders issued in November 2003, the FERC dismissed the joint filing, but adopted a new regional rate design substantially in the form proposed in the joint filing. The orders, directed each transmission provider to file compliance rates to eliminate T&O rates prospectively within the region and simultaneously implement a new seams elimination cost allocation (SECA) rates to mitigate the lost revenues for a two-year transition period beginning April 1, 2004. The FERC did not indicate the recovery method for the revenues after the two-year period. As required by the FERC, we filed compliance tariff changes in January 2004 to eliminate the T&O charges within the RTO Footprint. The SECA rate issues that remain unresolved have been set before an ALJ for settlement procedures, and the effective date of the T&O rate elimination and SECA rates were delayed until May 1, 2004. The November 2003 orders have been appealed by a number of parties. The AEP East companies received approximately $150 million of T&O rate revenues from transactions delivering energy to customers in the RTO Footprint for the twelve months ended June 30, 2003. At this time, management is unable to predict whether the new SECA rates will fully compensate the AEP East companies for their lost T&O rate revenues and, consequently, their impact on our future results of operations, cash flows and financial condition.

Indiana Fuel Order – Affecting I&M

On July 17, 2003, I&M filed a fuel adjustment clause application requesting authorization to implement the fixed fuel adjustment charge (fixed pursuant to a prior settlement of the Cook Nuclear Plant Outage) for electric service for the billing months of October 2003 through February 2004, and for approval of a new fuel cost adjustment credit for electric service to be applicable during the March 2004 billing month.

On August 27, 2003, the IURC issued an order approving the requested fixed fuel adjustment charge for October 2003 through February 2004. The order further stated that certain parties must negotiate the appropriate action on fuel to commence on March 1, 2004. Such negotiations are ongoing. The IURC deferred ruling on the March 2004 factor until after January 1, 2004.

Michigan 2004 Fuel Recovery Plan – Affecting I&M

The MPSC's December 16, 1999 order approved a Settlement Agreement regarding the extended outage of the Cook Plant and fixed I&M Power Supply Cost Recovery (PSCR) factors for the St. Joseph and Three Rivers rate areas through December 2003. In accordance with the settlement, PSCR Plan cases were not required to be filed through the 2003 plan year. As required, I&M filed its 2004 PSCR Plan with the MPSC on September 30, 2003 seeking new fuel and power supply recovery factors to be effective in 2004. The case has been scheduled for hearing. As allowed by Michigan law, the proposed factors were effective on January 1, 2004, subject to review and possible adjustment based on the results of the hearing.

	KPCo 2003	KPCo 2002	KPCo Recovery/Refund Period	OPCo 2003	OPCo 2002	OPCo Recovery/Refund Period
	(in thousands)					
Regulatory Assets:						
SFAS 109 Regulatory Asset, Net	$99,828	$87,261	Various Periods (a)	$169,605	$165,106	Various Periods (a)
Transition Regulatory Assets				310,035	375,409	4 years (a)
Unamortized Loss on Reacquired Debt	1,088	152	Up to 29 Years (b)	10,172	4,899	Up to 34 Years (b)
Other	12,883	14,563	Various Periods (a)	22,506	23,227	Various Periods (a)
Total Regulatory Assets	$113,799	$101,976		$512,318	$568,641	
Regulatory Liabilities:						
Asset Removal Costs	$26,140	$-	(c)	$101,160	$-	(c)
Deferred Investment Tax Credits	7,955	9,165	Up to 17 Years (a)	15,641	18,748	Up to 17 Years (a)
Unrealized Gain on Forward Commitments	9,174	10,967	Various Periods (a)			
Other	1,417	1,185	Various Periods (a)	3	1,237	Various Periods (a)
Total Regulatory Liabilities	$44,686	$21,317		$116,804	$19,985	

(a) Amount does not earn a return.
(b) Amount effectively earns a return.
(c) The liability for removal costs will be discharged as removal costs are incurred over the life of the plant.

	PSO 2003	PSO 2002	PSO Recovery/Refund Period	SWEPCo 2003	SWEPCo 2002	SWEPCo Recovery/Refund Period
	(in thousands)					
Regulatory Assets:						
SFAS 109 Regulatory Asset, Net				$3,235	$19,855	Various Periods (b)
Under-recovered Fuel Costs	$24,170	$76,470	1 Year (a)	11,394	2,865	1 Year (a)
Unamortized Loss on Reacquired Debt	14,357	11,138	Up to 12 Years (b)	19,331	17,031	Up to 40 Years (b)
Other	14,342	15,012	Various Periods (c)	15,859	12,347	Various Periods (c)
Total Regulatory Assets	$52,869	$102,620		$49,819	$52,098	
Regulatory Liabilities:						
Asset Removal Costs	$214,033	$-	(e)	$236,409	$-	(e)
Deferred Investment Tax Credits	30,411	32,201	Up to 26 Years (d)	39,864	44,190	Up to 14 Years (d)
SFAS 109 Regulatory Liability, Net	24,937	27,893	Various Periods (b)			
Over-Recovered Fuel Costs				4,178	17,226	1 Year (a)
Excess Earnings				2,600	3,700	(d)
Unrealized Gains on Forward Commitments	15,406	4,360	Various Periods (c)	11,793	1,992	Various Periods (c)
Other	-	31	Various Periods (c)	6,986	1,402	Various Periods (c)
Total Regulatory Liabilities	$284,787	$64,485		$301,830	$68,510	

(a) Deferred fuel for PSO's Oklahoma jurisdiction & SWEPCo's Arkansas and Louisiana jurisdictions does not earn a return. Texas jurisdictional amounts do earn a return.
(b) Amount effectively earns a return.
(c) Amounts are both earning and not earning a return.
(d) Amount does not earn a return.
(e) The liability for removal costs will be discharged as removal costs are incurred over the life of the plant.

	TCC			TNC		
	2003	2002	Recovery/Refund Period	2003	2002	Recovery/Refund Period
	(in thousands)					
Regulatory Assets:						
SFAS 109 Regulatory Asset, Net	$3,249	$9,950	Various Periods (a)			
Designated For Securitization	1,253,289	330,960	(b)			
Deferred Fuel Costs				$26,680	$26,680	(c)
Wholesale Capacity Auction True-up	480,000	262,000	(c)			
Unamortized Loss on Reacquired Debt	9,086	8,661	Up to 34 Years (a)	3,929	3,283	Up to 17 Years (a)
Deferred Debt – Restructuring	12,015	13,324	Up to 14 Years (a)	6,579	10,134	Up to 14 Years (a)
DOE Decontamination and Decommissioning Assessment	3,268	3,170	1 Year (d)			
Other	130,645	166,931	Various Periods (e)	3,332	5,000	Various Periods (e)
Total Regulatory Assets	$1,891,552	$794,996		$40,520	$45,097	
Regulatory Liabilities:						
Asset Removal Costs	$95,415	$-	(f)	$76,740	$-	(f)
Deferred Investment Tax Credits	112,479	117,686	Up to 25 Years (d)	19,990	21,510	Up to 19 Years (d)
Deferred Fuel Costs	69,026	69,026	(c)			
Retail Clawback	45,527	51,926	(c)	11,804	14,328	(c)
Over – Recovery of Transition Charges	22,499	20,870	Up to 13 Years (a)			
Purchased Power Conservation	9,234	9,560	Various Periods (e)			
Excess Earnings	25,246	46,111	(b)	14,262	17,419	Up to 30 Years (a)
SFAS 109 Regulatory Liability, Net				13,655	12,280	Various Periods (a)
Other	5	6	Various Periods (e)	1,826	7,285	Various Periods (e)
Total Regulatory Liabilities	$379,431	$315,185		$138,277	$72,822	

(a) Amount earns a return.
(b) Will be included in TCC's PUCT 2004 true-up proceedings and is designated for possible securitization during 2005.
(c) Amount will be included in TCC's and TNC's 2004 true-up proceedings for future recovery/payment over a time period to be determined in a future PUCT proceeding.
(d) Amount does not earn a return.
(e) Amounts are both earning and not earning a return.
(f) The liability for removal costs will be discharged as removal costs are incurred over the life of the plant.

Texas Restructuring Related Regulatory Assets and Liabilities

Regulatory assets Designated for Securitization, Wholesale Capacity Auction True-up regulatory assets, Deferred Fuel Costs and Retail Clawback regulatory liabilities are not being currently recovered from or returned to ratepayers. Management believes that the laws and regulations, established in Texas for industry restructuring, provide for the recovery from ratepayers of these net amounts. See Note 6 for a complete discussion of our plans to recover these regulatory assets, net of regulatory liabilities.

Nuclear Plant Restart

I&M completed the restart of both units of the Cook Plant in 2000. Settlement agreements in the Indiana and Michigan retail jurisdictions that addressed recovery of Cook Plant related outage costs were approved in 1999 by the IURC and MPSC.

The amount of deferrals amortized to other O&M expenses were $40 million in 2003, 2002 and 2001. Also pursuant to the settlement agreements, accrued fuel-related revenues of approximately $37 million in 2003 and $38 million in 2002 and 2001 were amortized as a reduction of revenues.

The amortization of O&M costs and fuel-related revenues deferred under Indiana and Michigan retail jurisdictional settlement agreements adversely affected results of operations through December 31, 2003 when the amortization period ended.

Merger with CSW

On June 15, 2000, AEP merged with CSW so that CSW became a wholly-owned subsidiary of AEP. In connection with the merger, non-recoverable merger costs were expensed in 2003, 2002 and 2001. Such costs included transaction and transition costs not recoverable from ratepayers. Also included in the merger costs were non-recoverable change in control payments. Merger transaction and transition costs recoverable from ratepayers were deferred pursuant to state regulator approved settlement agreements through December 31, 2003. The deferred merger costs are being amortized over five to eight year recovery periods, depending on the specific terms of the settlement agreements, with the amortization included in depreciation and amortization expense.

The following tables show the deferred merger cost and amortization expense of the applicable subsidiary registrants:

	Merger Cost Deferral December 31, 2003	Amortization Expense for the Year Ended December 31, 2003
	(in millions)	
I&M	$6.7	$1.7
KPCo	2.4	0.6
PSO	3.2	1.9
SWEPCo	2.7	1.2
TCC	6.5	2.6
TNC	1.9	0.8

	Merger Cost Deferral December 31, 2002	Amortization Expense for the Year Ended December 31, 2002
	(in millions)	
I&M	$8.2	$1.7
KPCo	2.9	0.6
PSO	5.0	1.6
SWEPCo	3.9	1.1
TCC	9.1	2.6
TNC	2.7	0.8

	Merger Cost Deferral December 31, 2001	Amortization Expense for the Year Ended December 31, 2001
	(in millions)	
I&M	$9.1	$1.7
KPCo	3.2	0.6
PSO	6.6	1.2
SWEPCo	5.0	1.1
TCC	11.8	2.6
TNC	3.5	0.8

Merger transition costs are expected to continue to be incurred for several years after the merger and will be expensed or deferred for amortization as appropriate. As hereinafter summarized, the state settlement agreements provide for, among other things, a sharing of net merger savings with certain regulated customers over periods of up to eight years through rate reductions which began in the third quarter of 2000.

Summary of key provisions of Merger Rate Agreements:

State/Company	Ratemaking Provisions
Texas – SWEPCo, TCC, TNC	$221 million rate reduction over 6 years. No base rate increases for 3 years post merger.
Indiana – I&M	$67 million rate reduction over 8 years. Extension of base rate freeze until January 1, 2005. Requires additional annual deposits of $6 million to the nuclear decommissioning trust fund for the years 2001 through 2003.
Michigan – I&M	Customer billing credits of approximately $14 million over 8 years. Extension of base rate freeze until January 1, 2005.
Kentucky – KPCo	Rate reductions of approximately $28 million over 8 years. No base rate increases for 3 years post merger.
Oklahoma – PSO	Rate reductions of approximately $28 million over 5 years. No base rate increase before January 1, 2003.
Arkansas – SWEPCo	Rate reductions of $6 million over 5 years. No base rate increase before June 15, 2003.
Louisiana – SWEPCo	Rate reductions to share merger savings estimated to be $18 million over 8 years. Base rate cap until June 2005.

If actual merger savings are significantly less than the merger savings rate reductions required by the merger settlement agreements in the eight-year period following consummation of the merger, future results of operations, cash flows and possibly financial condition could be adversely affected.

See Note 7, "Commitments and Contingencies" for information on a court decision concerning the merger.

6. CUSTOMER CHOICE AND INDUSTRY RESTRUCTURING

Prior to 2003, retail customer choice began in four of the eleven state retail jurisdictions (Michigan, Ohio, Texas and Virginia) in which the AEP domestic electric utility companies operate. The following paragraphs discuss significant events occurring related to customer choice and industry restructuring.

OHIO RESTRUCTURING – Affecting CSPCo and OPCo

On June 27, 2002, the Ohio Consumers' Counsel, Industrial Energy Users–Ohio and American Municipal Power–Ohio filed a complaint with the PUCO alleging that CSPCo and OPCo have violated the PUCO's orders regarding implementation of their transition plan and violated the applicable law by failing to participate in an RTO.

The complainants seek, among other relief, an order from the PUCO:

- suspending collection of transition charges by CSPCo and OPCo until transfer of control of their transmission assets has occurred
- requiring the pricing of standard offer electric generation effective January 1, 2006 at the market price used by CSPCo and OPCo in their 1999 transition plan filings to estimate transition costs and
- imposing a $25,000 per company forfeiture for each day AEP fails to comply with its commitment to transfer control of transmission assets to an RTO

Due to FERC, state legislative and regulatory developments, CSPCo and OPCo have been delayed in the implementation of their RTO participation plans. We continue to pursue integration of CSPCo, OPCo and other AEP East companies into PJM. In this regard, on December 19, 2002, CSPCo and OPCo filed an application with the PUCO for approval of the transfer of functional control over certain of their transmission facilities to PJM. In February 2003, the PUCO consolidated the June 2002 complaint with our December application. CSPCo's and OPCo's motion to dismiss the complaint has been denied by the PUCO and the PUCO affirmed that ruling in rehearing. All further action in the consolidated case has been stayed "until more clarity is achieved regarding matters pending at the FERC and elsewhere." Management is currently unable to predict the timing of the AEP East companies' (including CSPCo and OPCo) participation in PJM, the outcome of these proceedings before the PUCO or their impact on results of operations and cash flows.

In October 2002, the PUCO initiated an investigation of the financial condition of Ohio's regulated public utilities. The PUCO's goal is to identify measures available to the PUCO to ensure that the regulated operations of Ohio's public utilities are not impacted by adverse financial consequences of parent or affiliate company unregulated operations and take appropriate corrective action, if necessary. The utilities and other interested parties were requested to provide comments and suggestions by November 12, 2002, with reply comments by November 22, 2002, on the type of information necessary to accomplish the stated goals, the means to gather the required information from the public utilities and potential courses of action that the PUCO could take. In January 2004, the PUCO staff issued a report recommending that the PUCO seek more authority from the Ohio Legislature on this issue. The PUCO has taken no further action in this proceeding. Management is unable to predict the outcome of the PUCO's investigation or its impact on results of operations, cash flows and business practices, if any.

On March 20, 2003, the PUCO commenced a statutorily required investigation concerning the desirability, feasibility and timing of declaring retail ancillary, metering or billing and collection service, supplied to customers within the certified territories of electric utilities, a competitive retail electric service. The PUCO sent out a list of questions and set June 6, 2003 and July 7, 2003 as the dates for initial responses and replies, respectively. CSPCo and OPCo filed comments and responses in compliance with the PUCO's schedule. Management is unable to predict the timing or the outcome of this proceeding or its impact on results of operations or cash flows.

The Ohio Act provides for a Market Development Period (MDP) during which retail customers can choose their electric power suppliers or receive Default Service at frozen generation rates from the incumbent utility. The MDP began on January 1, 2001 and is scheduled to terminate no later than December 31, 2005. The PUCO may terminate the MDP for one or more customer classes before that date if it determines either that effective competition exists in the incumbent utility's certified territory or that there is a twenty percent switching rate of the incumbent utility's load by customer class. Following the MDP, retail customers will receive distribution and transmission service from the incumbent utility whose distribution rates will be approved by the PUCO and whose transmission rates will be approved by the FERC. Retail customers will continue to have the right to choose their electric power suppliers or receive Default Service, which must be offered by the incumbent utility at market rates. On December 17, 2003, the PUCO adopted a set of rules concerning the method by which it will determine market rates for Default Service following the MDP. The rule provides for a Market Based Standard Service Offer which would be a variable rate based on a transparent forward market, daily market, and/or hourly market prices. The rule also requires a fixed-rate Competitive Bidding Process for residential and small nonresidential customers and permits a fixed-rate Competitive Bidding Process for large general service customers and other customer classes. Customers who do not switch to a competitive generation provider can choose between the Market Based Standard Service Offer or the Competitive Bidding Process. Customers who make no choice will be served pursuant to the Competitive Bidding Process.

On February 9, 2004, CSPCo and OPCo filed their rate stabilization plan with the PUCO addressing rates following the end of the MDP, which ends December 31, 2005. If approved by the PUCO, rates would be established pursuant to the plan for the period from January 1, 2006 through December 31, 2008 instead of the rates discussed in the previous paragraph. The plan is intended to provide rate stability and certainty for customers, facilitate the development of a competitive retail market in Ohio, provide recovery of environmental and other costs during the plan period and improve the environmental performance of AEP's generation resources that serve Ohio customers. The plan includes annual, fixed increases in the generation component of all customers' bills (3% annually for CSPCo and 7% annually for OPCo), and the opportunity for additional generation-related increases upon PUCO review and approval. For residential customers, however, if the temporary 5% generation rate discount provided by the Ohio Act were eliminated on June 30, 2004, the fixed increases would be 1.6% for CSPCo and 5.7% for OPCo. The generation-related increases under the plan would be subject to caps. The plan would maintain distribution rates through the end of 2008 for CSPCo and OPCo at the level effective on December 31, 2005. Such rates could be adjusted for specified reasons through a PUCO filing. Transmission charges can be adjusted to reflect applicable charges approved by the FERC related to open access transmission, net congestion, and ancillary services. The plan also provides for continued recovery of transition regulatory assets and deferral of regulatory assets in 2004 and 2005 for RTO costs and carrying costs on required environmental expenditures. A procedural schedule has not been established for this filing. Management cannot predict whether the plan will be approved as submitted, modified by the PUCO, or its impacts on results of operation and cash flows.

As provided in stipulation agreements approved by the PUCO in 2000, CSPCo and OPCo are deferring customer choice implementation costs and related carrying costs that are in excess of $20 million per company. The agreements provide for the deferral of these costs as a regulatory asset until the company's next distribution base rate case. The February 2004 filing provides for the continued deferrals of customer choice implementation costs during the rate stabilization plan period. At December 31, 2003, CSPCo has incurred $32 million and deferred $12 million and OPCo has incurred $34 million and deferred $14 million of such costs. Recovery of these regulatory assets will be subject to PUCO review in each company's future Ohio filings for new distribution rates. If the rate stabilization plan is approved, it would defer recovery of these amounts until after the end of the rate stabilization period. Management believes that the customer choice implementation costs were prudently incurred and the deferred amounts should be recoverable in future rates. If the PUCO determines that any of the deferred costs are unrecoverable, it would have an adverse impact on future results of operations and cash flows.

TEXAS RESTRUCTURING – Affecting SWEPCo, TCC and TNC

Texas Legislation enacted in 1999 provided the framework and timetable to allow retail electricity competition for all customers. On January 1, 2002, customer choice of electricity supplier began in the ERCOT area of Texas. Customer choice has been delayed in the SPP area of Texas until at least January 1, 2007.

The Texas Legislation, among other things:

- provides for the recovery of regulatory assets and other stranded costs through securitization and non-bypassable wires charges;
- requires each utility to structurally unbundle into a retail electric provider, a power generation company and a transmission and distribution (T&D) utility;
- provides for an earnings test for each of the years 1999 through 2001 and;
- provides for a 2004 true-up proceeding. See 2004 true-up proceeding discussion below.

The Texas Legislation required vertically integrated utilities to legally separate their generation and retail-related assets from their transmission and distribution-related assets. Prior to 2002, TCC and TNC functionally separated their operations to comply with the Texas Legislation requirements. AEP formed new subsidiaries to act as affiliated REPs for TCC and TNC effective January 1, 2002 (the start date of retail competition). In December 2002, AEP sold the affiliated REPs to an unaffiliated company.

In 1999, TCC filed with the PUCT to securitize $1.27 billion of its retail generation-related regulatory assets and $47 million in other qualified restructuring costs. The PUCT authorized the issuance of up to $797 million of securitization bonds ($949 million of generation-related regulatory assets and $33 million of qualified refinancing costs offset by $185 million of customer benefits for accumulated deferred income taxes). TCC issued its securitization bonds in February 2002. The amount not approved for securitization will be included in regulatory assets/stranded costs in TCC's 2004 true-up proceeding.

TEXAS 2004 TRUE-UP PROCEEDING

A 2004 true-up proceeding will determine the amount and recovery of:

- net stranded generating plant costs and generation-related regulatory assets (stranded costs),
- a true-up of actual market prices determined through legislatively-mandated capacity auctions to the power costs used in the PUCT's ECOM model for 2002 and 2003 (wholesale capacity auction true-up),
- final approved deferred fuel balance,
- unrefunded accumulated excess earnings,
- excess of price-to-beat revenues over market prices subject to certain conditions and limitations (retail clawback) and
- other restructuring true-up items

The PUCT adopted a rule in 2003 regarding the timing of the 2004 true-up proceedings scheduling TNC's filing in May 2004 and TCC's filing in September 2004 or 60 days after the completion of the sale of TCC's generation assets, if later.

Stranded Costs and Generation-Related Regulatory Assets

Restructuring legislation required utilities with stranded costs to use market-based methods to value certain generating assets for determining stranded costs. TCC is the only AEP subsidiary that has stranded costs under the Texas Legislation. We have elected to use the sale of assets method to determine the market value of all of our generation assets for stranded cost purposes. When completed, the sale of our generation assets will substantially complete the required separation of generation assets from transmission and distribution assets. For purposes of the 2004 true-up proceeding, the amount of stranded costs under this market valuation methodology will be the amount by which the book value of TCC's generating assets, including regulatory assets and liabilities that were not securitized, exceeds the market value of the generation assets as measured by the net proceeds from the sale of the assets. It is anticipated that any such sale will result in significant stranded costs for purposes of TCC's 2004 true-up proceeding.

In December 2002, TCC filed a plan of divestiture with the PUCT seeking approval of a sales process for all of its generating facilities. In March 2003, the PUCT dismissed TCC's divestiture filing, determining that it was more appropriate to address allowable valuation methods for the nuclear asset in a rulemaking proceeding. The PUCT approved a rule, in May 2003, which allows the market value obtained by selling nuclear assets to be used in determining stranded costs. Although the PUCT declined to review TCC's proposed sale of assets process, the PUCT has hired a consultant to advise TCC during the sale of the generation assets. TCC's sale of its generating assets will be subject to a review in the 2004 true-up proceeding.

In June 2003, we began actively seeking buyers for 4,497 megawatts of TCC's generating capacity in Texas. In order to sell these assets, TCC anticipates retiring first mortgage bonds by making open market purchases or defeasing the bonds. Bids were received for all of TCC's generating plants. In January 2004, TCC agreed to sell its 7.8% ownership interest in the Oklaunion Power Station to an unaffiliated third party for $43 million. The sale of TCC's remaining generation is pending. Additional regulatory approvals will be required to complete the sale of the generation assets including NRC approval of the transfer of our interest in STP.

In the 2004 true-up proceeding, the amount of stranded costs under this market valuation methodology will be the amount by which the book value of TCC's generating assets, including regulatory assets and liabilities that were not securitized and reduced by mitigation including unrefunded excess earnings, exceeds the market value of the generation assets as measured by the net proceeds from the sale of the assets. It is anticipated that any such sale will result in significant stranded costs for purposes of TCC's 2004 true-up proceeding.

After the 2004 true-up proceeding, TCC may seek to issue securitization revenue bonds for its stranded costs and recover the costs of the securitization bonds through transmission and distribution rates. Based upon the Oklaunion sale and the bid information for the remaining generation, we recorded an impairment of generating assets of $938 million in December 2003 as a regulatory asset (see Note 10). The recovery of the regulatory asset will be subject to review and approval by the PUCT as a stranded cost in the 2004 true-up proceeding.

Wholesale Capacity Auction True-up

Texas Legislation also requires that electric utilities and their affiliated power generation companies (PGC) offer for sale at auction, in 2002 and 2003 and after, at least 15% of the PGC's Texas jurisdictional installed generation capacity in order to promote competitiveness in the wholesale market through increased availability of generation. Actual market power prices received in the state mandated auctions will be used to calculate the wholesale capacity auction true-up adjustment for TCC for the 2004 true-up proceeding.

TCC recorded a $480 million regulatory asset and related revenues which represent the quantifiable amount of the wholesale capacity auction true-up for the years 2002 and 2003. In TCC's UCOS proceeding, the PUCT estimated that TCC had negative stranded costs. In its true-up rule, the PUCT determined that the wholesale capacity auction true-up proceeds should be offset against negative stranded costs. However, in March 2003, the Texas Court of Appeals ruled that under the restructuring legislation, other 2004 true-up items, including the wholesale capacity auction true-up regulatory asset, could be recovered regardless of the level of stranded costs.

In the fourth quarter of 2003, the PUCT approved a true-up filing package containing calculation instructions similar to the methodology employed by TCC to calculate the amount recorded for recovery under its wholesale capacity auction true-up. The PUCT will review the $480 million wholesale capacity regulatory asset for recovery as part of the 2004 true-up proceeding.

Fuel Balance Recoveries

In 2002, TNC filed with the PUCT seeking to reconcile fuel costs and to establish its deferred unrecovered fuel balance applicable to retail sales within its ERCOT service area for inclusion in the 2004 true-up proceeding. In January 2004, the PUCT announced a final ruling in TNC's fuel reconciliation case that established TNC's unrecovered fuel balance, including interest for the ERCOT service territory, at $6.2 million. This balance will be included in TNC's 2004 true-up proceeding. TNC is waiting for a written order from the PUCT, after which it will request a rehearing.

In 2002, TCC filed with the PUCT to reconcile fuel costs and to establish its deferred over-recovery of fuel balance for inclusion in the 2004 true-up proceeding. In February 2004, an ALJ issued recommendations finding a $205 million over recovery in this fuel proceeding. Management is unable to predict the amount of TCC's fuel over-recovery which will be included in its 2004 true-up proceeding.

See TCC Fuel Reconciliation and TNC Fuel Reconciliation in Note 4 "Rate Matters" for further discussion.

Unrefunded Excess Earnings

The Texas Legislation provides for the calculation of excess earnings for each year from 1999 through 2001. The total excess earnings determined for the three year period were $3 million for SWEPCo, $47 million for TCC and $19 million for TNC. TCC, TNC and SWEPCo challenged the PUCT's treatment of fuel-related deferred income taxes and appealed the PUCT's final 2000 excess earnings to the Travis County District Court which upheld the PUCT ruling. The District Court's ruling was appealed to the Third Court of Appeals. In August 2003, the Third Court of Appeals reversed the PUCT order and the District Court judgment. The PUCT's request for rehearing of the Appeals Court's decision was denied and the PUCT chose not to appeal the ruling any further. Appeal of the same issue from the PUCT's 2001 order is pending before the District Court. Since an expense and regulatory liability had been accrued in prior years in compliance with the PUCT orders, the companies reversed a portion of their regulatory liability for the years 2000 and 2001 consistent with the Appeals Court's decision and credited amortization expense during the third quarter of 2003. Pre-tax amounts reversed by company were $5 million for TCC, $3 million for TNC and $1 million for SWEPCo.

In 2001, the PUCT issued an order requiring TCC to return estimated excess earnings by reducing distribution rates by approximately $55 million plus accrued interest over a five-year period beginning January 1, 2002. Since excess earnings amounts were expensed in 1999, 2000 and 2001, the order has no additional effect on reported net income but will reduce cash flows for the five-year refund period. The amount to be refunded is recorded as a regulatory liability. Management believes that TCC will have stranded costs and that it was inappropriate for the PUCT to order a refund prior to TCC's 2004 true-up proceeding. TCC appealed the PUCT's refund of excess earnings to the Travis County District Court. That court affirmed the PUCT's decision and further ordered that the refunds be provided to customers. TCC has appealed the decision to the Court of Appeals.

Retail Clawback

The Texas Legislation provides for the affiliated PTB REP serving residential and small commercial customers to refund to its T&D utility the excess of the PTB revenues over market prices (subject to certain conditions and a limitation of $150 per customer). This is the retail clawback. If, prior to January 1, 2004, 40% of the load for the residential or small commercial classes is served by competitive REPs, the retail clawback is not applicable for that class of customer. During 2003, TCC and TNC filed to notify the PUCT that competitive REPs serve over 40% of the load in the small commercial class. The PUCT approved TCC's and TNC's filings in December 2003. In 2002, AEP had accrued a regulatory liability of approximately $9 million for the small commercial retail clawback on its REP's books. When the PUCT certified that the REP's in TCC and TNC service territories had reached the 40% threshold, the regulatory liability was no longer required for the small commercial class and was reversed in December 2003. At December 31, 2003, the remaining retail clawback liability was $45.5 million for TCC and $11.8 million for TNC.

When the 2004 true-up proceeding is completed, TCC intends to file to recover PUCT-approved stranded costs and other true-up amounts that are in excess of current securitized amounts, plus appropriate carrying charges and other true-up amounts, through non-bypassable competition transition charge in the regulated T&D rates. TCC may also seek to securitize certain of the approved stranded plant costs and regulatory assets that were not previously recovered through the non-bypassable transition charge. The annual costs of securitization are recovered through a non-bypassable rate surcharge collected by the T&D utility over the term of the securitization bonds.

In the event we are unable, after the 2004 true-up proceeding, to recover all or a portion of our stranded plant costs, generation-related regulatory assets, unrecovered fuel balances, wholesale capacity auction true-up regulatory assets, other restructuring true-up items and costs, it could have a material adverse effect on results of operations, cash flows and possibly financial condition.

MICHIGAN RESTRUCTURING – Affecting I&M

Customer choice commenced for I&M's Michigan customers on January 1, 2002. Effective with that date the rates on I&M's Michigan customers' bills for retail electric service were unbundled to allow customers the opportunity to evaluate the cost of generation service for comparison with other offers. I&M's total rates in Michigan remain unchanged and reflect cost of service. At December 31, 2003, none of I&M's customers have elected to change suppliers and no alternative electric suppliers are registered to compete in I&M's Michigan service territory.

Management has concluded that as of December 31, 2003 the requirements to apply SFAS 71 continue to be met since I&M's rates for generation in Michigan continue to be cost-based regulated.

ARKANSAS RESTRUCTURING – Affecting SWEPCo

In February 2003, Arkansas repealed customer choice legislation originally enacted in 1999. Consequently, SWEPCo's Arkansas operations reapplied SFAS 71 regulatory accounting, which had been discontinued in 1999.

The reapplication of SFAS 71 had an insignificant effect on results of operations and financial condition. As a result of reapplying SFAS 71, derivative contract gains/losses for transactions within AEP's traditional marketing area allocated to Arkansas will not affect income until settled. That is, such positions will be recorded on the balance sheet as either a regulatory asset or liability until realized.

WEST VIRGINIA RESTRUCTURING – Affecting APCo

APCo reapplied SFAS 71 for its West Virginia (WV) jurisdiction in the first quarter of 2003 after new developments during the quarter prompted an analysis of the probability of restructuring becoming effective.

In 2000, the WVPSC issued an order approving an electricity restructuring plan, which the WV Legislature approved by joint resolution. The joint resolution provided that the WVPSC could not implement the plan until the WV legislature made tax law changes necessary to preserve the revenues of state and local governments.

In the 2001 and 2002 legislative sessions, the WV Legislature failed to enact the required legislation that would allow the WVPSC to implement the restructuring plan. Due to this lack of legislative activity, the WVPSC closed two proceedings related to electricity restructuring during the summer of 2002.

In the 2003 legislative session, the WV Legislature failed to enact the required tax legislation. Also, legislation enacted in March 2003 clarified the jurisdiction of the WVPSC over electric generation facilities in WV. In March 2003, APCo's outside counsel advised us that restructuring in WV was no longer probable and confirmed facts relating to the WVPSC's jurisdiction and rate authority over APCo's WV generation. APCo has concluded that deregulation of the WV generation business is no longer probable and operations in WV meet the requirements to reapply SFAS 71.

Reapplying SFAS 71 in WV had an insignificant effect on results of operations and financial condition. As a result, derivative contract gains/losses related to transactions within AEP's traditional marketing area allocated to WV will not affect income until settled. That is, such positions will be recorded on the balance sheet as either a regulatory asset or liability until realized. Positions outside AEP's traditional marketing area will continue to be marked-to-market.

7. COMMITMENTS AND CONTINGENCIES

ENVIRONMENTAL

Federal EPA Complaint and Notice of Violation – Affecting APCo, CSPCo, I&M, and OPCo

The Federal EPA and a number of states alleged APCo, CSPCo, I&M, OPCo and other unaffiliated utilities modified certain units at coal-fired generating plants in violation of the NSRs of the CAA. The Federal EPA filed its complaints against AEP subsidiaries in U.S. District Court for the Southern District of Ohio. The court also consolidated a separate lawsuit, initiated by certain special interest groups, with the Federal EPA case. The alleged modifications relate to costs that were incurred at the generating units over a 20-year period.

Under the Clean Air Act, if a plant undertakes a major modification that directly results in an emissions increase, permitting requirements might be triggered and the plant may be required to install additional pollution control technology. This requirement does not apply to activities such as routine maintenance, replacement of degraded equipment or failed components, or other repairs needed for the reliable, safe and efficient operation of the plant. The Clean Air Act authorizes civil penalties of up to $27,500 per day per violation at each generating unit ($25,000 per day prior to January 30, 1997). In 2001, the District Court ruled claims for civil penalties based on activities that occurred more than five years before the filing date of the complaints cannot be imposed. There is no time limit on claims for injunctive relief.

On August 7, 2003, the District Court issued a decision following a liability trial in a case pending in the Southern District of Ohio against Ohio Edison Company, an unaffiliated utility. The District Court held that replacements of major boiler and turbine components that are infrequently performed at a single unit, that are performed with the assistance of outside contractors, that are accounted for as capital expenditures, and that require the unit to be taken out of service for a number of months are not "routine" maintenance, repair, and replacement. The District Court also held that a comparison of past actual emissions to projected future emissions must be performed prior to any non-routine physical change in order to evaluate whether an emissions increase will occur, and that increased hours of operation that are the result of eliminating forced outages due to the repairs must be included in that calculation. Based on these holdings, the District Court ruled that all of the challenged activities in that case were not routine, and that the changes resulted in significant net increases in emissions for certain pollutants. A remedy trial is scheduled for July 2004.

Management believes that the Ohio Edison decision fails to properly evaluate and apply the applicable legal standards. The facts in the AEP case also vary widely from plant to plant. Further, the Ohio Edison decision is limited to liability issues, and provides no insight as to the remedies that might ultimately be ordered by the Court.

On August 26, 2003, the District Court for the Middle District of South Carolina issued a decision on cross-motions for summary judgment prior to a liability trial in a case pending against Duke Energy Corporation, an unaffiliated utility. The District Court denied all the pending motions, but set forth the legal standards that will be applied at the trial in that case. The District Court determined that Federal EPA bears the burden of proof on the issue of whether a practice is "routine maintenance, repair, or replacement" and on whether or not a "significant net emissions increase" results from a physical change or change in the method of operation at a utility unit. However, the Federal EPA must consider whether a practice is "routine within the relevant source category" in determining if it is "routine." Further, the Federal EPA must calculate emissions by determining first whether a change in the maximum achievable hourly emission rate occurred as a result of the change, and then must calculate any change in annual emissions holding hours of operation constant before and after the change. The Federal EPA has requested reconsideration of this decision, or in the alternative, certification of an interlocutory appeal to the Fourth Circuit Court of Appeals.

On June 24, 2003, the United States Court of Appeals for the 11th Circuit issued an order invalidating the administrative compliance order issued by the Federal EPA to the Tennessee Valley Authority for similar alleged violations. The 11th Circuit determined that the administrative compliance order was not a final agency action, and that the enforcement provisions authorizing the issuance and enforcement of such orders under the Clean Air Act are unconstitutional.

On June 26, 2003, the United States Court of Appeals for the District of Columbia Circuit granted a petition by the Utility Air Regulatory Group (UARG), of which the AEP subsidiaries are members, to reopen petitions for review of the 1980 and 1992 Clean Air Act rulemakings that are the basis for the Federal EPA claims in the AEP case and other related cases. On August 4, 2003, UARG filed a motion to separate and expedite review of their challenges to the 1980 and 1992 rulemakings from other unrelated claims in the consolidated appeal. The Circuit Court denied that motion on September 30, 2003. The central issue in these petitions concerns the lawfulness of the emissions increase test, as currently interpreted and applied by the Federal EPA in its utility enforcement actions. A decision by the D. C. Circuit Court could significantly impact further proceedings in the AEP case.

On August 27, 2003, the Administrator of the Federal EPA signed a final rule that defines "routine maintenance repair and replacement" to include "functionally equivalent equipment replacement." Under the new final rule, replacement of a component within an integrated industrial operation (defined as a "process unit") with a new component that is identical or functionally equivalent will be deemed to be a "routine replacement" if the replacement does not change any of the fundamental design parameters of the process unit, does not result in emissions in excess of any authorized limit, and does not cost more than twenty percent of the replacement cost of the process unit. The new rule is intended to have prospective effect, and will become effective in certain states 60 days after October 27, 2003, the date of its publication in the Federal Register, and in other states upon completion of state processes to incorporate the new rule into state law. On October 27, 2003 twelve states, the District of Columbia and several cities filed an action in the United States Court of Appeals for the District of Columbia Circuit seeking judicial review of the new rule. The UARG has intervened in this case. On December 24, 2003, the Circuit Court granted a motion from the petitioners to stay the effective date of this rule, which had been December 26, 2003.

Management is unable to estimate the loss or range of loss related to the contingent liability for civil penalties under the CAA proceedings. Management is also unable to predict the timing of resolution of these matters due to the number of alleged violations and the significant number of issues yet to be determined by the Court. If the AEP System companies do not prevail, any capital and operating costs of additional pollution control equipment that may be required, as well as any penalties imposed, would adversely affect future results of operations, cash flows and possibly financial condition unless such costs can be recovered through regulated rates and market prices for electricity.

In December 2000, Cinergy Corp., an unaffiliated utility, which operates certain plants jointly owned by CSPCo, reached a tentative agreement with the Federal EPA and other parties to settle litigation regarding generating plant emissions under the Clean Air Act. Negotiations are continuing between the parties in an attempt to reach final settlement terms. Cinergy's settlement could impact the operation of Zimmer Plant and W.C. Beckjord Generating Station Unit 6 (owned 25.4% and 12.5%, respectively, by CSPCo). Until a final settlement is reached, CSPCo will be unable to determine the settlement's impact on its jointly owned facilities and its future results of operations and cash flows.

NUCLEAR

Nuclear Plants – Affecting I&M and TCC

I&M owns and operates the two-unit 2,110 MW Cook Plant under licenses granted by the NRC. TCC owns 25.2% of the two-unit 2,500 MW STP. STPNOC operates STP on behalf of the joint owners under licenses granted by the NRC. The operation of a nuclear facility involves special risks, potential liabilities, and specific regulatory and safety requirements. Should a nuclear incident occur at any nuclear power plant facility in the U.S., the resultant liability could be substantial. By agreement I&M and TCC are partially liable together with all other electric utility companies that own nuclear generating units for a nuclear power plant incident at any nuclear plant in the U.S. In the event nuclear losses or liabilities are underinsured or exceed accumulated funds and recovery from customers is not possible, results of operations, cash flows and financial condition would be adversely affected.

Nuclear Incident Liability – Affecting I&M and TCC

The Price-Anderson Act establishes insurance protection for public liability arising from a nuclear incident at $10.6 billion and covers any incident at a licensed reactor in the U.S. Commercially available insurance provides $300 million of coverage. In the event of a nuclear incident at any nuclear plant in the U.S., the remainder of the liability would be provided by a deferred premium assessment of $101 million on each licensed reactor in the U.S. payable in annual installments of $10 million. As a result, I&M could be assessed $202 million per nuclear incident payable in annual installments of $20 million. TCC could be assessed $50 million per nuclear incident payable in annual installments of $5 million as its share of a STPNOC assessment. The number of incidents for which payments could be required is not limited. Under an industry-wide program insuring workers at nuclear facilities, I&M and TCC are also obligated for assessments of up to $6 million and $2 million, respectively, for potential claims. These obligations will remain in effect until December 31, 2007.

Insurance coverage for property damage, decommissioning and decontamination at the Cook Plant and STP is carried by I&M and STPNOC in the amount of $1.8 billion each. I&M and STPNOC jointly purchase $1 billion of excess coverage for property damage, decommissioning and decontamination. Additional insurance provides coverage for extra costs resulting from a prolonged accidental outage. I&M and STPNOC utilize an industry mutual insurer for the placement of this insurance coverage. Participation in this mutual insurer requires a contingent financial obligation of up to $43 million for I&M and $2 million for TCC which is assessable if the insurer's financial resources would be inadequate to pay for losses.

The current Price-Anderson Act expired in August 2002. Its contingent financial obligations still apply to reactors licensed by the NRC as of its expiration date. It is anticipated that the Price-Anderson Act will be renewed in 2004 with increases in required third party financial protection for nuclear incidents.

SNF Disposal – Affecting I&M and TCC

Federal law provides for government responsibility for permanent SNF disposal and assesses nuclear plant owners fees for SNF disposal. A fee of one mill per KWH for fuel consumed after April 6, 1983 at Cook Plant and STP is being collected from customers and remitted to the U.S. Treasury. Fees and related interest of $226 million for fuel consumed prior to April 7, 1983 at Cook Plant have been recorded as long-term debt. I&M has not paid the government the Cook Plant related pre-April 1983 fees due to continued delays and uncertainties related to the federal disposal program. At December 31, 2003, funds collected from customers towards payment of the pre-April 1983 fee and related earnings thereon are in external funds and exceed the liability amount. TCC is not liable for any assessments for nuclear fuel consumed prior to April 7, 1983 since the STP units began operation in 1988 and 1989.

Decommissioning and Low Level Waste Accumulation Disposal – Affecting I&M and TCC

Decommissioning costs are accrued over the service lives of the Cook Plant and STP. The licenses to operate the two nuclear units at Cook Plant expire in 2014 and 2017. In November 2003, I&M filed to extend the operating licenses of the two Cook Plant units for up to an additional 20 years. The review of the license extension application is expected to take at least two years. After expiration of the licenses, Cook Plant is expected to be decommissioned using the prompt decontamination and dismantlement (DECON) method. The estimated cost of decommissioning and low level radioactive waste accumulation disposal costs for Cook Plant ranges from $821 million to $1,080 million in 2003 nondiscounted dollars. The wide range is caused by variables in assumptions including the estimated length of time SNF may need to be stored at the plant site subsequent to ceasing operations. This, in turn, depends on future developments in the federal government's SNF disposal program. Continued delays in the federal fuel disposal program can result in increased decommissioning costs. I&M is recovering estimated Cook Plant decommissioning costs in its three rate-making jurisdictions based on at least the lower end of the range in the most recent decommissioning study at the time of the last rate proceeding. The amount recovered in rates for decommissioning the Cook Plant and deposited in the external fund was $27 million in 2003, 2002 and 2001.

The licenses to operate the two nuclear units at STP expire in 2027 and 2028. After expiration of the licenses, STP is expected to be decommissioned using the DECON method. TCC estimates its portion of the costs of decommissioning STP to be $289 million in 1999 nondiscounted dollars. TCC is accruing and recovering these decommissioning costs through rates based on the service life of STP at a rate of $8 million per year.

Decommissioning costs recovered from customers are deposited in external trusts. In 2003, 2002 and 2001, I&M deposited in its decommissioning trust an additional $12 million each year related to special regulatory commission approved funding for decommissioning of the Cook Plant. Trust fund earnings increase the fund assets and decrease the amount needed to be recovered from ratepayers. Decommissioning costs including interest, unrealized gains and losses and expenses of the trust funds are recorded in Other Operation expense for Cook Plant. For STP, nuclear decommissioning costs are recorded in Other Operation expense, interest income of the trusts are recorded in Nonoperating Income and interest expense of the trust funds are included in Interest Charges.

TCC's nuclear decommissioning trust asset and liability are included in held for sale amounts on its Consolidated Balance Sheet.

OPERATIONAL

Construction and Commitments – Affecting AEGCo, APCo, CSPCo, I&M, KPCo, OPCo, PSO, SWEPCo, TCC and TNC

The AEP System has substantial construction commitments to support its operations. The following table shows the estimated construction expenditures by company for 2004 – 2006 including amounts for proposed environmental rules:

	(in millions)
AEGCo	$73.3
APCo	1,307.2
CSPCo	391.4
I&M	645.1
KPCo	153.3
OPCo	1,686.4
PSO	296.2
SWEPCo	414.3
TCC	531.2
TNC	179.9

AEP subsidiaries have entered into long-term contracts to acquire fuel for electric generation. The expiration date of the longest fuel contract is 2007 for APCo, 2005 for CSPCo, 2007 for I&M, 2005 for KPCo, 2012 for OPCo, 2014 for PSO and 2006 for SWEPCo. The contracts provide for periodic price adjustments and contain various clauses that would release us from our obligations under certain conditions.

I&M has unit contingent contracts to supply approximately 250 MW of capacity to unaffiliated entities through December 31, 2009. The commitment is pursuant to a unit power agreement requiring the delivery of energy only if the unit capacity is available.

Potential Uninsured Losses *– Affecting AEGCo, APCo, CSPCo, I&M, KPCo, OPCo, PSO, SWEPCo, TCC and TNC*

Some potential losses or liabilities may not be insurable or the amount of insurance carried may not be sufficient to meet potential losses and liabilities, including, but not limited to, liabilities relating to damage to the Cook Plant or STP and costs of replacement power in the event of a nuclear incident at the Cook Plant or STP. Future losses or liabilities which are not completely insured, unless recovered from customers, could have a material adverse effect on results of operations, cash flows and financial condition.

Power Generation Facility – Affecting OPCo

AEP has agreements with Juniper Capital L.P. (Juniper) for Juniper to develop, construct, and finance a non-regulated merchant power generation facility (Facility) near Plaquemine, Louisiana and lease the Facility to AEP. Juniper will own the Facility and lease it to AEP after construction is completed. AEP will sublease the Facility to The Dow Chemical Company (Dow).

Dow will use a portion of the energy produced by the Facility and sell the excess energy. OPCo has agreed to purchase up to approximately 800 MW of such excess energy from Dow. OPCo has also agreed to sell up to approximately 800 MW of energy to Tractebel Energy Marketing, Inc. (TEM) for a period of 20 years under a Power Purchase and Sale Agreement dated November 15, 2000 (PPA) at a price which is currently in excess of market. Beginning May 1, 2003, OPCo tendered replacement capacity, energy and ancillary services to TEM pursuant to the PPA which TEM rejected as non-conforming.

OPCo has entered an agreement with an affiliate that eliminates OPCo's market exposure related to the PPA. AEP has guaranteed this affiliate's performance under the agreement.

On September 5, 2003, TEM and AEP separately filed declaratory judgment actions in the United States District Court for the Southern District of New York. AEP alleges that TEM has breached the PPA, and is seeking a determination of OPCo's rights under the PPA. TEM alleges that the PPA never became enforceable or alternatively, that the PPA has already been terminated as the result of AEP breaches. If the PPA is deemed terminated or found to be unenforceable by the court, AEP could be adversely affected to the extent we are unable to find other purchasers of the power with similar contractual terms to the extent we do not fully recover claimed termination value damages from TEM. The corporate parent of TEM has provided a limited guaranty.

On November 18, 2003, the above litigation was suspended pending final resolution in arbitration of all issues pertaining to the protocols relating to the dispatching, operation and maintenance of the Facility and the sale and delivery of electric power products. In the arbitration proceedings, TEM basically argued that in the absence of mutually agreed upon protocols there was no commercially reasonable means to obtain or deliver the electric power products and therefore the PPA is not enforceable. TEM further argued that the creation of the protocols is not subject to arbitration. The arbitrator ruled in favor of TEM, on February 11, 2004, and concluded that the "creation of protocols" was not subject to arbitration, but did not rule upon the merits of TEM's claim that the PPA is not enforceable.

If commercial operation is not achieved for purposes of the PPA by April 30, 2004, TEM may claim that it can terminate the PPA and is owed liquidating damages of approximately $17.5 million. TEM may also claim that AEP is not entitled to receive any termination value for the PPA.

Merger Litigation – Affecting AEGCo, APCo, CSPCo, I&M, KPCo, OPCo, PSO, SWEPCo, TCC and TNC

In 2002, the U.S. Court of Appeals for the District of Columbia ruled that the SEC failed to prove that the June 15, 2000 merger of AEP with CSW meets the requirements of the PUHCA and sent the case back to the SEC for further review. Specifically, the court told the SEC to revisit its conclusion that the merger met PUHCA requirements that utilities be "physically interconnected" and confined to a "single area or region."

In its June 2000 approval of the merger, the SEC agreed with AEP that the companies' systems are integrated because they have transmission access rights to a single high-voltage line through Missouri and also met the PUCHA's single region requirement because it is now technically possible to centrally control the output of power plants across many states. In its ruling, the appeals court said that the SEC failed to support and explain its conclusions that the integration and single region requirements are satisfied.

Management believes that the merger meets the requirements of the PUHCA and expects the matter to be resolved favorably.

Enron Bankruptcy –Affecting APCo, CSPCo, I&M, KPCo and OPCo

On October 15, 2002, certain subsidiaries of AEP filed claims against Enron and its subsidiaries in the bankruptcy proceeding filed by the Enron entities which are pending in the U.S. Bankruptcy Court for the Southern District of New York. At the date of Enron's bankruptcy, certain subsidiaries of AEP had open trading contracts and trading accounts receivables and payables with Enron. In addition, on June 1, 2001, AEP purchased Houston Pipe Line Company (HPL) from Enron. Various HPL related contingencies and indemnities from Enron remained unsettled at the date of Enron's bankruptcy. The timing of the resolution of the claims by the Bankruptcy Court is not certain.

In September 2003, Enron filed a complaint in the Bankruptcy Court against AEPES challenging AEP's offsetting of receivables and payables and related collateral across various Enron entities and seeking payment of approximately $125 million plus interest in connection with gas related trading transactions. We will assert our right to offset trading payables owed to various Enron entities against trading receivables due to several AEP subsidiaries. Management is unable to predict the outcome of this lawsuit or its impact on results of operations, cash flows or financial condition.

In December 2003, Enron filed a complaint in the Bankruptcy Court against AEPSC seeking approximately $93 million plus interest in connection with a transaction for the sale and purchase of physical power among Enron, AEP and Allegheny Energy Supply, LLC during November 2001. Enron's claim seeks to unwind the effects of the transaction. AEP believes it has several defenses to the claims in the action being brought by Enron. Management is unable to predict the outcome of this lawsuit or its impact on results of operations, cash flows or financial condition.

During 2002 and 2001, AEP expensed a total of $53 million ($34 million net of tax) for our estimated loss from the Enron bankruptcy. The amounts for certain subsidiaries were:

Registrant	Amounts Expensed	Amounts Net of Tax
	(in millions)	
APCo	$5.3	$3.4
CSPCo	2.7	1.8
I&M	2.8	1.8
KPCo	1.1	0.7
OPCo	3.6	2.3

The amount expensed was based on an analysis of contracts where AEP and Enron entities are counterparties, the offsetting of receivables and payables, the application of deposits from Enron entities and management's analysis of the HPL related purchase contingencies and indemnifications. As noted above, Enron has challenged the offsetting of receivables and payables. Management is unable to predict the final resolution of these disputes, however the impact on results of operations, cash flows and financial condition could be material.

Texas Commercial Energy, LLP Lawsuit – Affecting TCC and TNC

Texas Commercial Energy, LLP (TCE), a Texas REP, filed a lawsuit in federal District Court in Corpus Christi, Texas, in July 2003, against AEP and four AEP subsidiaries, including TCC and TNC, certain unaffiliated energy companies and ERCOT. The action alleges violations of the Sherman Antitrust Act, fraud, negligent misrepresentation, breach of fiduciary duty, breach of contract, civil conspiracy and negligence. The allegations, not all of which are made against the AEP companies, range from anticompetitive bidding to withholding power. TCE alleges that these activities resulted in price spikes requiring TCE to post additional collateral and ultimately forced it into bankruptcy when it was unable to raise prices to its customers due to fixed price contracts. The suit alleges over $500 million in damages for all defendants and seeks recovery of damages, exemplary damages and court costs. Two additional parties, Utility Choice, LLC and Cirro Energy Corporation, have sought leave to intervene as plaintiffs asserting similar claims. AEP and its subsidiaries filed a Motion to Dismiss in September 2003. In February 2004, TCE filed an amended complaint. AEP and its subsidiaries intend to file a motion to dismiss the amended complaint and otherwise vigorously defend against the claims.

Energy Market Investigation – Affecting AEP System

AEP and other energy market participants received data requests, subpoenas and requests for information from the FERC, the SEC, the PUCT, the U.S. Commodity Futures Trading Commission (CFTC), the U.S. Department of Justice and the California attorney general during 2002. Management responded to the inquiries and provided the requested information and has continued to respond to supplemental data requests in 2003 and 2004.

In March 2003, we received a subpoena from the SEC as part of the SEC's ongoing investigation of energy trading activities. In August 2002, we had received an informal data request from the SEC asking that we voluntarily provide information. The subpoena sought additional information and is part of the SEC's formal investigation. We responded to the subpoena and will continue to cooperate with the SEC.

On September 30, 2003, the CFTC filed a complaint against AEP and AEPES in federal district court in Columbus, Ohio. The CFTC alleges that AEP and AEPES provided false or misleading information about market conditions and prices of natural gas in an attempt to manipulate the price of natural gas in violation of the Commodity Exchange Act. The CFTC seeks civil penalties, restitution and disgorgement of benefits. The case is in the initial pleading stage with our response to the complaint currently due on May 18, 2004. Although management is unable to predict the outcome of this case, it is not expected to have a material effect on results of operations due to a provision recorded in December 2003.

In January 2004, the CFTC issued a request for documents and other information in connection with a CFTC investigation of activities affecting the price of natural gas in the fall of 2003. We are responding to that request.

Management cannot predict what, if any further action, any of these governmental agencies may take with respect to these matters.

FERC Proposed Standard Market Design – Affecting AEP System

In July 2002, the FERC issued its Standard Market Design (SMD) notice of proposed rulemaking which sought to standardize the structure and operation of wholesale electricity markets across the country. Key elements of FERC's proposal included standard rules and processes for all users of the electricity transmission grid, new transmission rules and policies, and the creation of certain markets to be operated by independent administrators of the grid in all regions. The FERC issued a "white paper" on the proposal in April 2003, in response to the numerous comments FERC received on its proposal. Management does not know if or when the FERC will finalize a rule for SMD. Until the potential rule is finalized, management cannot predict its effect on cash flows and results of operations.

FERC Market Power Mitigation – Affecting AEP System

A FERC order issued in November 2001 on AEP's triennial market based wholesale power rate authorization update required certain mitigation actions that AEP would need to take for sales/purchases within its control area and required AEP to post information on its website regarding its power system's status. As a result of a request for rehearing filed by AEP and other market participants, FERC issued an order delaying the effective date of the mitigation plan until after a planned technical conference on market power determination. In December 2003, the FERC issued a staff paper discussing alternatives and held a technical conference in January 2004. Management is unable to predict the timing of any further action by the FERC or its affect of future results of operations and cash flows.

8. GUARANTEES

There are no liabilities recorded for guarantees entered into prior to December 31, 2002 by registrant subsidiaries in accordance with FIN 45. There are certain immaterial liabilities recorded for guarantees entered into subsequent to December 31, 2002. There is no collateral held in relation to any guarantees and there is no recourse to third parties in the event any guarantees are drawn unless specified below.

Letters of Credit

Certain registrant subsidiaries have entered into standby letters of credit (LOC) with third parties. These LOCs cover gas and electricity risk management contracts, construction contracts, insurance programs, security deposits, debt service reserves, and credit enhancements for issued bonds. All of these LOCs were issued in the registrant subsidiaries' ordinary course of business. At December 31, 2003, the maximum future payments of the LOCs include $43 million, $1 million, $5 million and $4 million for TCC, I&M, OPCo and SWEPCo, respectively, with maturities ranging from March 2004 to November 2005. AEP holds all assets of the subsidiaries as collateral. There is no recourse to third parties in the event these letters of credit are drawn.

SWEPCo

In connection with reducing the cost of the lignite mining contract for its Henry W. Pirkey Power Plant, SWEPCo has agreed under certain conditions, to assume the obligations under capital lease obligations and term loan payments of the mining contractor, Sabine Mining Company (Sabine). In the event Sabine defaults under any of these agreements, SWEPCo's total future maximum payment exposure is approximately $58 million with maturity dates ranging from June 2005 to February 2012.

As part of the process to receive a renewal of a Texas Railroad Commission permit for lignite mining, SWEPCo has agreed to provide guarantees of mine reclamation in the amount of approximately $85 million. Since SWEPCo uses self-bonding, the guarantee provides for SWEPCo to commit to use its resources to complete the reclamation in the event the work is not completed by a third party miner. At December 31, 2003, the cost to reclaim the mine in 2035 is estimated to be approximately $36 million. This guarantee ends upon depletion of reserves estimated at 2035 plus 6 years to complete reclamation.

On July 1, 2003, SWEPCo consolidated Sabine due to the application of FIN 46 (see Note 2). Upon consolidation, SWEPCo recorded the assets and liabilities of Sabine ($78 million). Also, after consolidation, SWEPCo currently records all expenses (depreciation, interest and other operation expense) of Sabine and eliminates Sabine's revenues against SWEPCo's fuel expenses. There is no cumulative effect of an accounting change recorded as a result of the requirement to consolidate, and there is no change in net income due to the consolidation of Sabine.

Indemnifications and Other Guarantees

All of the registrant subsidiaries enter into certain types of contracts, which would require indemnifications. Typically these contracts include, but are not limited to, sale agreements, lease agreements, purchase agreements and financing agreements. Generally these agreements may include, but are not limited to, indemnifications around certain tax, contractual and environmental matters. With respect to sale agreements, exposure generally does not exceed the sale price. Registrant subsidiaries cannot estimate the maximum potential exposure for any of these indemnifications entered into prior to December 31, 2002 due to the uncertainty of future events. In 2003 registrant subsidiaries entered into sale agreements which included indemnifications with a maximum exposure that was not significant for any individual registrant subsidiary. There are no material liabilities recorded for any indemnifications entered into during 2003. There are no liabilities recorded for any indemnifications entered prior to December 31, 2002.

Certain registrant subsidiaries lease certain equipment under a master operating lease. Under the lease agreement, the lessor is guaranteed to receive up to 87% of the unamortized balance of the equipment at the end of the lease term. If the fair market value of the leased equipment is below the unamortized balance at the end of the lease term, we have committed to pay the difference between the fair market value and the unamortized balance, with the total guarantee not to exceed 87% of the unamortized balance. At December 31, 2003, the maximum potential loss by subsidiary for these lease agreements assuming the fair market value of the equipment is zero at the end of the lease term is as follows:

Subsidiary	Maximum Potential Loss (in millions)
APCo	$ 1
CSPCo	1
I&M	2
KPCo	1
OPCo	3
PSO	4
SWEPCo	4
TCC	6
TNC	2

See Note 15 "Leases" for disclosure of lease residual value guarantees.

9. SUSTAINED EARNINGS IMPROVEMENT INITIATIVE

In response to difficult conditions in AEP's business, a Sustained Earnings Improvement (SEI) initiative was undertaken company-wide in the fourth quarter of 2002, as a cost-saving and revenue-building effort to build long-term earnings growth.

The registrant subsidiaries recorded termination benefits expense relating to 389 terminated employees totaling $57.9 million pre-tax in the fourth quarter of 2002. Of this amount, the registrant subsidiaries paid $5.0 million to these terminated employees in the fourth quarter of 2002. No additional termination benefits expense related to the SEI initiative was recorded in 2003, and the remaining SEI related payments were made in 2003. The termination benefits expense is classified as Other Operation expense on the registrant subsidiaries' statements of operations. We determined that the termination of the employees under our SEI initiative did not constitute a plan curtailment of any of our retirement benefit plans.

The following table shows the staff reductions, termination benefits expense and the remaining termination benefits expense accrual as of December 31, 2002:

	Total Number of Terminated Employees	Total Expense Recorded in 2002 (in millions)	Total Termination Benefits Accrued at 12/31/02 (in millions)
AEGCo	-	$ 0.3	$ 0.3
APCo	93	13.1	12.2
CSPCo	19	5.0	4.5
I&M	146	15.0	13.1
KPCo	16	2.6	2.5
OPCo	33	7.5	7.1
PSO	17	3.1	3.0
SWEPCo	8	3.3	3.1
TCC	37	6.0	5.5
TNC	20	2.0	1.6

10. ACQUISITIONS, DISPOSITIONS, IMPAIRMENTS, ASSETS HELD FOR SALE AND ASSETS HELD AND USED

ACQUISITIONS

2001

SWEPCo purchased the Dolet Hills mining operations and assumed the existing mine reclamation liabilities at its jointly owned lignite reserves in Louisiana during 2001. Management recorded the assets acquired and liabilities assumed at their estimated fair values in accordance with APB Opinion No. 16 and SFAS 141 as appropriate based on currently available information and on current assumptions as to future operations.

DISPOSITIONS

2003

Water Heater Assets – APCo, CSPCo, I&M, KPCo and OPCo

APCo, CSPCo, I&M, KPCo and OPCo participated in a program to lease electric water heaters to residential and commercial customers until a decision was reached in the fourth quarter of 2002 to discontinue the program and offer the assets for sale. We sold our water heater rental program and recorded a pre-tax loss in the first quarter of 2003 based upon final terms of the sale agreement. We provided for pre-tax charges in the fourth quarter 2002 based on an estimated sales price. See below for amounts by company:

Subsidiary Company	Asset Impairment Charge Recorded in Fourth Quarter 2002 (Pre-tax)	Lease Prepayment Penalty Recorded in Fourth Quarter 2002 (Pre-tax)	Loss on Sale Recorded in First Quarter 2003 (Pre-tax)
		(in millions)	
APCo	$0.050	$0.062	$0.056
CSPCo	0.615	0.758	0.740
I&M	0.643	0.792	0.787
KPCo	0.011	0.011	0.011
OPCo	1.757	2.163	2.165

Ft. Davis Wind Farm – TNC

In the 1990's TNC developed a 6MW facility wind energy project located on a lease site near Ft. Davis, Texas. In the fourth quarter of 2002 TNC's engineering staff determined that operation of the facility was no longer technically feasible and the lease of the underlying site should not be renewed. Dismantling of the facility is expected to be completed during 2004. An estimated pre-tax loss on abandonment of $4.7 million was recorded in December 2002. The loss was recorded in Asset Impairments on TNC's Statements of Operations.

2001

Coal Mines – OPCo

In July 2001, OPCo sold coal mines in Ohio and West Virginia and agreed to purchase approximately 34 million tons of coal from the purchaser of the mines through 2008. The sale had a nominal impact on OPCo's results of operations and cash flows.

ASSETS HELD FOR SALE

Texas Plants – TCC and TNC

In September 2002, AEP indicated to ERCOT its intent to deactivate 16 gas-fired power plants (8 TCC plants and 8 TNC plants). ERCOT subsequently conducted reliability studies, which determined that seven plants (4 TCC plants and 3 TNC plants) would be required to ensure reliability of the electricity grid. As a result of those studies, ERCOT and AEP mutually agreed to enter into reliability must run (RMR) agreements, which expired in December 2002, and were subsequently renewed through December 2003. However, certain contractual provisions provided ERCOT with a 90-day termination clause, if the contracted facility was no longer needed to ensure reliability of the electricity grid. With ERCOT's approval, AEP proceeded with its planned deactivation of the remaining nine plants. In August 2003, pursuant to contractual terms, ERCOT provided notification to AEP of its intent to cancel a RMR agreement at one of the TNC plants. Upon termination of the agreement, AEP proceeded with its planned deactivation of the plant. In December 2003, AEP and ERCOT mutually agreed to new RMR contracts at six plants (4 TCC plants and 2 TNC plants) through December 2004, subject to ERCOT's 90-day termination clause and the divestiture of the TCC facilities.

As a result of the decision to deactivate TNC plants, a write-down of utility assets of approximately $34.2 million (pre-tax) was recorded in Asset Impairments expense during the third quarter 2002 on TNC's Statements of Operations. The decision to deactivate the TCC plants resulted in a write-down of utility assets of approximately $95.6 million (pre-tax), which was deferred and recorded in Regulatory Assets during the third quarter 2002 in TCC's Consolidated Balance Sheets.

During the fourth quarter 2002, evaluations continued as to whether assets remaining at the deactivated plants, including materials, supplies and fuel oil inventories, could be utilized elsewhere within the AEP System. As a result of such evaluations, TNC recorded an additional asset impairment charge to Asset Impairments expense of $3.9 million (pre-tax) in the fourth quarter 2002. In addition, TNC recorded related inventory write-downs of $2.6 million ($1.2 million of fuel inventory in Fuel for Electric Generation expense and $1.4 million of materials and supplies recorded in Other Operation expense). Similarly, TCC recorded an additional asset impairment write-down of $6.7 million (pre-tax), which was deferred and recorded in Regulatory Assets Designated for Securitization in the fourth quarter 2002. TCC also recorded related inventory write-downs of $14.9 million which was deferred and recorded in Regulatory Assets in the fourth quarter 2002.

The total Texas plant asset impairment of $38.1 million in 2002 related to TNC is included in Asset Impairments expense in TNC's Statements of Operations.

In December 2002, TCC filed a plan of divestiture with the PUCT proposing to sell all of its power generation assets, including the eight gas-fired generating plants that were either deactivated or designated as RMR status. During the fourth quarter of 2003, after receiving bids from interested buyers, TCC recorded a $938 million impairment loss and changed the classification of the plant assets from plant in service to assets held for sale. In accordance with Texas legislation, the $938 million impairment was offset by the establishment of a regulatory asset, which is expected to be recovered through a wires charge, subject to the final outcome of the 2004 Texas true-up proceeding. See Texas Restructuring section of Note 6 "Customer Choice and Industry Restructuring" for further discussion of the divestiture plan, anticipated timeline and true-up proceeding.

The assets and liabilities of the entities held for sale at December 31, 2003 and 2002 are as follows:

December 31, 2003	Texas Plants (TCC) (in millions)
Assets:	
Current Assets	$57
Property, Plant and Equipment, Net	797
Regulatory Assets	49
Nuclear Decommissioning Trust Fund	125
Total Assets Held for Sale	$1,028
Liabilities:	
Regulatory Liabilities – Other	$9
Other Noncurrent Liabilities	219
Total Liabilities Held for Sale	$228

December 31, 2002	Texas Plants (TCC) (in millions)
Assets:	
Current Assets	$70
Property, Plant and Equipment, Net	1,647
Nuclear Decommissioning Trust Fund	98
Total Assets Held for Sale	$1,815
Liabilities:	
Deferred Credits and Other	$9
Total Liabilities Held for Sale	$9

ASSETS HELD AND USED

Blackhawk Coal Company – I&M

Blackhawk Coal Company (Blackhawk) is a wholly-owned subsidiary of I&M and was formerly engaged in coal mining operations until they ceased due to gas explosions in the mine. During the fourth quarter of 2003, it was determined that the value of the investment needed to be written down based on an updated valuation reflecting management's decision not to pursue development of potential gas reserves. As a result, a $10.4 million charge was recorded to reduce the value of the coal and gas reserves to their estimated realizable value. This charge was recorded in Nonoperating Expenses in I&M's Consolidated Statements of Income.

11. BENEFIT PLANS

APCo, CSPCo, I&M, KPCo, OPCo, PSO, SWEPCo, TCC and TNC participate in AEP sponsored U.S. qualified pension plans and nonqualified pension plans. A substantial majority of employees are covered by either one qualified plan or both a qualified and a nonqualified pension plan. In addition, APCo, CSPCo, I&M, KPCo, OPCo, PSO, SWPECo, TCC and TNC participate in other postretirement benefit plans sponsored by AEP to provide medical and death benefits for retired employees in the U.S.

The following tables provide a reconciliation of the changes in the plans' benefit obligations and fair value of assets over the two-year period ending at the plan's measurement date of December 31, 2003, and a statement of the funded status as of December 31 for both years:

	U.S. Pension Plans		U.S. Other Post Retirement Benefit Plans	
	2003	2002	2003	2002
	(in millions)			
Change in Benefit Obligation:				
Obligation at January 1	$3,583	$3,292	$1,877	$1,645
Service Cost	80	72	42	34
Interest Cost	233	241	130	114
Participant Contributions	-	-	14	13
Plan Amendments	-	(2)	-	-
Actuarial (Gain) Loss	91	258	192	152
Benefit Payments	(299)	(278)	(92)	(81)
Obligation at December 31	$3,688	$3,583	$2,163	$1,877
Change in Fair Value of Plan Assets:				
Fair Value of Plan Assets at January 1	$2,795	$3,438	$723	$711
Actual Return on Plan Assets	619	(371)	122	(57)
Company Contributions (a)	65	6	183	137
Participant Contributions	-	-	14	13
Benefit Payments (a)	(299)	(278)	(92)	(81)
Fair Value of Plan Assets at December, 31	$3,180	$2,795	$950	$723
Funded Status:				
Funded Status at December 31	$(508)	$(788)	$(1,213)	$(1,154)
Unrecognized Net Transition (Asset) Obligation	2	(7)	206	233
Unrecognized Prior Service Cost	(12)	(13)	6	6
Unrecognized Actuarial (Gain) Loss	797	1,020	977	896
Net Asset (Liability) Recognized	$279	$212	$(24)	$(19)

(a) AEP contributions and benefit payments include only those amounts contributed directly to or paid directly from plan assets.

Accumulated Benefit Obligation:	2003	2002
	(in millions)	
U.S. Qualified Pension Plans	$3,549	$3,456
U.S. Nonqualified Pension Plans	76	71

	U.S. Pension Plans		U.S. Other Post Retirement Benefit Plans	
	2003	2002	2003	2002
	(in millions)			
Prepaid Benefit Costs	$325	$255	$-	$-
Accrued Benefit Liability	(46)	(44)	(24)	(19)
Additional Minimum Liability	(723)	(944)	N/A	N/A
Unrecognized Prior Service Costs	39	45	N/A	N/A
Accumulated Other Comprehensive Income	684	900	N/A	N/A
Net Asset (Liability) Recognized	$279	$212	$(24)	$(19)
Increase (Decrease) in Minimum Liability Included in Other Comprehensive Income (Pre-tax)	$(216)	$894	N/A	N/A

N/A = Not Applicable

The asset allocations for the U.S. pension plans at the end of 2003 and 2002, and the target allocation for 2004, by asset category, are as follows:

Asset Category	Target Allocation 2004	Percentage of Plan Assets at Yearend 2003	2002
		(in percentage)	
Equity	70	71	67
Fixed Income	28	27	32
Cash and Cash Equivalents	2	2	1
Total	100	100	100

The asset allocations for the U.S. other postretirement benefit plans at the end of 2003 and 2002, and target allocation for 2004, by asset category, are as follows:

Asset Category	Target Allocation 2004	Percentage of Plan Assets at Yearend 2003	2002
		(in percentage)	
Equity	70	61	41
Fixed Income	28	36	38
Cash and Cash Equivalents	2	3	21
Total	100	100	100

AEP's investment strategy for the employee benefit trust funds is to use a diversified mixture of equity and fixed income securities to preserve the capital of the funds and to maximize the investment earnings in excess of inflation within acceptable levels of risk.

The value of the AEP qualified plans' assets increased from $2.795 billion at December 31, 2002 to $3.180 billion at December 31, 2003. The qualified plans paid $292 million in benefits to plan participants during 2003 (nonqualified plans paid $7 million in benefits). AEP's plans remain in an underfunded position (plan assets are less than projected benefit obligations) of $508 million at December 31, 2003. Due to the pension plans currently being underfunded, AEP recorded income in Other Comprehensive Income (OCI) of $154 million, and a reduction in the Deferred Income Tax Asset of $76 million, offset by a reduction to Minimum Pension Liability of $234 million and a reduction in adjustments for unrecognized costs of $4 million. The charge to OCI does not affect earnings or cash flow. Also, due to the current underfunded status of AEP's qualified plans, AEP expects to make cash contributions to the U.S. pension plans of approximately $41 million in 2004.

At December 31, 2003 and 2002, the projected benefit obligation, accumulated benefit obligation, and fair value of U.S. plan assets of the U.S. pension plans with an accumulated benefit obligation in excess of plan assets, were as follows:

	U.S. Plans	
End of Year	**2003**	**2002**
	(in millions)	
Projected Benefit Obligation	$3,688	$3,583
Accumulated Benefit Obligation	3,625	3,527
Fair Value of Plan Assets	3,180	2,795
Accumulated Benefit Obligation Exceeds the Fair Value of Plan Assets	445	732

AEP bases its determination of pension expense or income on a market-related valuation of assets which reduces year-to-year volatility. This market-related valuation recognizes investment gains or losses over a five-year period from the year in which they occur. Investment gains or losses for this purpose are the difference between the expected return calculated using the market-related value of assets and the actual return based on the market-related value of assets. Since the market-related value of assets recognizes gains or losses over a five-year period, the future value of assets will be impacted as previously deferred gains or losses are recorded.

The weighted-average assumptions as of December 31, used in the measurement of AEP's benefit obligations are shown in the following tables:

	U.S. Pension Plans		U.S. Other Postretirement Benefit Plans	
	2003	**2002**	**2003**	**2002**
		(in percentage)		
Discount Rate	6.25	6.75	6.25	6.75
Rate of Compensation Increase	3.7	3.7	N/A	N/A

In determining the discount rate in the calculation of future pension obligations AEP reviews the interest rates of long-term bonds that receive one of the two highest ratings given by a recognized rating agency. As a result of a decrease in this benchmark rate during 2003, AEP determined that a decrease in its discount rate from 6.75% at December 31, 2002 to 6.25% at December 31, 2003 was appropriate.

The rate of compensation increase assumed varies with the age of the employee, ranging from 3.5% per year to 8.5% per year, with an average increase of 3.7%.

Information about the expected cash flows for the U.S. pension (qualified and non-qualified) and other postretirement benefit plans is as follows:

	U.S. Pension Plans	U.S. Other Postretirement Benefit Plans
	(in millions)	
Employer Contributions		
2003	$65	$183
2004 (expected)	41	180

The table below reflects the total benefits expected to be paid from the plan or from AEP assets, including both AEP's share of the benefit cost and the participants' share of the cost, which is funded by participant contributions to the plan. Future benefit payments are dependent on the number of employees retiring, whether the retiring employees elect to receive pension benefits as annuities or as lump sum distributions, future integration of the benefit plans with changes to Medicare and other legislation, future levels of interest rates, and variances in actuarial results. The estimated payments for pension benefits and other postretirement benefits are as follows:

	U.S. Pension Benefits	U.S. Other Postretirement Benefit Plans
	(in millions)	
2004	$293	$106
2005	300	114
2006	310	123
2007	325	132
2008	335	140
Years 2009 to 2013, in Total	1,840	836

The contribution to the pension fund is based on the minimum amount required by the U.S. Department of Labor or the amount of the pension expense for accounting purposes, whichever is greater. The contribution to the other postretirement benefit plans' trusts is generally based on the amount of the other postretirement benefit plans' expense for accounting purposes and is provided for in agreements with state regulatory authorities.

The following table provides the components of AEP's net periodic benefit cost (credit) for the plans for fiscal years 2003, 2002 and 2001:

	U.S. Pension Plans			U.S. Other Postretirement Benefit Plans		
	2003	2002	2001	2003	2002	2001
	(in millions)					
Service Cost	$80	$72	$69	$42	$34	$30
Interest Cost	233	241	232	130	114	114
Expected Return on Plan Assets	(318)	(337)	(338)	(64)	(62)	(61)
Amortization of Transition (Asset) Obligation	(8)	(9)	(8)	28	29	30
Amortization of Prior-service Cost	(1)	(1)	-	-	-	-
Amortization of Net Actuarial (Gain) Loss	11	(10)	(24)	52	27	18
Net Periodic Benefit Cost (Credit)	(3)	(44)	(69)	188	142	131
Curtailment Loss	-	-	-	-	-	1
Net Periodic Benefit Cost (Credit) After Curtailments	$(3)	$(44)	$(69)	$188	$142	$132

The following table provides the net periodic benefit cost (credit) for the plans by the following AEP registrant subsidiaries for fiscal years 2003, 2002 and 2001:

	Pension Plans			Other Postretirement Benefit Plans		
	2003	2002	2001	2003	2002	2001
	(thousands)					
APCo	$(5,202)	$(9,988)	$(13,645)	$33,618	$25,107	$22,810
CSPCo	(5,399)	(8,328)	(10,624)	14,684	11,494	10,328
I&M	(812)	(4,206)	(7,805)	22,999	17,608	15,077
KPCo	(566)	(1,406)	(1,922)	4,043	2,986	2,438
OPCo	(6,621)	(11,360)	(14,879)	28,143	22,608	34,444
PSO	(291)	(3,819)	(2,480)	9,885	8,436	6,187
SWEPCo	1,012	(2,245)	(3,051)	10,264	8,371	6,399
TCC	(123)	(4,786)	(3,411)	12,951	10,733	8,214
TNC	606	(1,104)	(1,644)	5,875	4,798	3,729

The weighted-average assumptions as of January 1, used in the measurement of AEP's benefit costs are shown in the following tables:

	U.S. Pension Plans			U.S. Other Postretirement Benefit Plans		
	2003	2002	2001	2003	2002	2001
	(in percentage)					
Discount Rate	6.75	7.25	7.50	6.75	7.25	7.50
Expected Return on Plan Assets	9.00	9.00	9.00	8.75	8.75	8.75
Rate of Compensation Increase	3.7	3.7	3.2	N/A	N/A	N/A

The expected return on plan assets for 2003 was determined by evaluating historical returns, the current investment climate, rate of inflation, and current prospects for economic growth. After evaluating the current yield on fixed income securities as well as other recent investment market indicators, the expected return on plan assets was reduced to 8.75% for 2004. The expected return on other postretirement benefit plan assets (a portion of which is subject to capital gains taxes as well as unrelated business income taxes) was reduced to 8.35%.

The assumptions used for other postretirement benefit plan measurement purposes are shown below:

Health Care Trend Rates:	2003	2002
	(in percentage)	
Initial	10.0	10.0
Ultimate	5.0	5.0
Year Ultimate Reached	2008	2008

Assumed health care cost trend rates have a significant effect on the amounts reported for the other postretirement benefit health care plans. A 1% change in assumed health care cost trend rates would have the following effects:

	1% Increase	1% Decrease
	(in millions)	
Effect on Total Service and Interest Cost Components of Net Periodic Postretirement Health Care Benefit Cost	$26	$(21)
Effect on the Health Care Component of the Accumulated Postretirement Benefit Obligation	315	(257)

AEP has not yet determined the impact of the Medicare Prescription Drug Improvement and Modernization Act of 2003 on its other postretirement benefit plans' accumulated benefit obligation and periodic benefit cost. See FASB Staff Position No. 106-1 in Note 2 for additional information on the potential impact on AEP's results of operations, cash flows and financial condition.

Retirement Savings Plan

APCo, CSPCo, I&M, KPCo, OPCo, PSO, SWEPCo, TCC and TNC participate in an AEP sponsored defined contribution retirement savings plan eligible to substantially all non-United Mine Workers of America (UMWA) employees. This plan includes features under Section 401(k) of the Internal Revenue Code and provides for company matching contributions. Prior to January 1, 2003, APCo, CSPCo, I&M, KPCo, OPCo, PSO, SWEPCo, TCC and TNC participated in two large AEP sponsored defined contribution retirement savings plans. Beginning in 2001 and continuing with the single merged plan, contributions to the plans increased from 50% to 75% of the first 6% of eligible employee compensation.

The following table provides the cost for contributions to the retirement savings plans by the following AEP registrant subsidiaries for fiscal years 2003, 2002 and 2001:

	2003	2002	2001
		(in thousands)	
APCo	$6,450	$ 6,722	$7,031
CSPCo	2,745	2,784	2,789
I&M	7,616	8,039	7,833
KPCo	1,042	1,043	1,016
OPCo	5,719	5,785	6,398
PSO	2,350	2,260	2,235
SWEPCo	3,418	3,170	2,896
TCC	2,757	3,054	3,046
TNC	1,332	1,574	1,558

Other UMWA Benefits

OPCo provides UMWA pension, health and welfare benefits for certain unionized mining employees, retirees, and their survivors who meet eligibility requirements. UWMA trustees make final interpretive determinations with regard to all benefits. The pension benefits are administered by UMWA trustees and contributions are made to their trust funds. The health and welfare benefits are administered by AEP and benefits are paid from AEP's general assets. Contributions are expensed as paid as part of the cost of active mining operations and were not material in 2003, 2002 and 2001. In July 2001, OPCo sold certain coal mines in Ohio and West Virginia.

12. BUSINESS SEGMENTS

All of AEP's registrant subsidiaries have one reportable segment. The one reportable segment is a vertically integrated electricity generation, transmission and distribution business except AEGCo, an electricity generation business. All of the registrants' other activities are insignificant. The registrant subsidiaries' operations are managed on an integrated basis because of the substantial impact of bundled cost-based rates and regulatory oversight on the business process, cost structures and operating results.

13. DERIVATIVES, HEDGING AND FINANCIAL INSTRUMENTS

Derivatives and Hedging

In the first quarter of 2001, we adopted SFAS 133, "Accounting for Derivative Instruments and Hedging Activities," as amended. Registrant Subsidiaries recorded a transition adjustment to Accumulated Other Comprehensive Income (Loss) on January 1, 2001 in connection with the adoption of SFAS 133. Derivatives included in the transition adjustment are interest rate swaps, foreign currency swaps and commodity swaps, options and futures.

SFAS 133 requires recognition of all derivative instruments as either assets or liabilities in the statement of financial position at fair value. Registrant subsidiaries accounting for the changes in the fair value of a derivative instrument depends on whether it qualifies, and has been designated, as part of a hedging relationship and further, on the type of hedging relationship. Registrant subsidiaries designate the hedging instrument, based on the exposure being hedged, as a fair value hedge or a cash flow hedge. Certain qualifying derivative instruments have been designated as normal purchase or normal sale contracts, as provided in SFAS 133. These contracts are not reported at fair value, as otherwise required by SFAS 133.

For fair value hedges (i.e. hedging the exposure to changes in the fair value of an asset, liability or an identified portion thereof that is attributable to a particular risk), registrant subsidiaries recognize the gain or loss on the derivative instrument as well as the offsetting loss or gain on the hedged item associated with the hedged risk in Revenues in the Consolidated Statements of Operations during the period of change. For cash flow hedges (i.e., hedging the exposure to variability in expected future cash flows that is attributable to a particular risk), registrant subsidiaries initially report the effective portion of the gain or loss on the derivative instrument as a component of Other Accumulated Comprehensive Income and subsequently reclassify it to Revenues in the Consolidated Statements of Operations when the forecasted transaction affects earnings. The remaining gain or loss on the derivative instrument in excess of the cumulative change in the present value of future cash flows of the hedged item, if any, is recognized currently in revenues during the period of change. Registrant subsidiaries recognize any ineffective portions of in revenues immediately during the period of change.

Fair Value Hedging Strategies

Certain registrant subsidiaries enter into interest rate forward and swap transactions for interest rate risk exposure management purposes. The interest rate forward and swap transactions effectively modifies our exposure to interest risk by converting a portion of our fixed-rate debt to a floating rate. Registrant subsidiaries do not hedge all interest rate exposure.

Cash Flow Hedging Strategies

Certain registrant subsidiaries enter into forward contracts to protect against the reduction in value of forecasted cash flows resulting from transactions denominated in foreign currencies. When the dollar strengthens significantly against the foreign currencies, the decline in value of future foreign currency revenue is offset by gains in the value of the forward contracts designated as cash flow hedges. Conversely, when the dollar weakens, the increase in the value of future foreign currency cash flows is offset by losses in the value of forward contracts. Registrant subsidiaries do not hedge all foreign currency exposure.

Certain registrant subsidiaries enter into interest rate forward and swap transactions in order to manage interest rate risk exposure. These transactions effectively modify our exposure to interest risk by converting a portion of our floating-rate debt to a fixed rate. Registrant subsidiaries do not hedge all interest rate exposure.

Registrant subsidiaries enter into forward and swap transactions for the purchase and sale of electricity to manage the variable price risk related to the forecasted purchase and sale of electricity. We closely monitor the potential impact of commodity price changes and, where appropriate, enter into contracts to protect margin for a portion of future sales and generation revenues. Registrant Subsidiaries do not hedge all variable price risk exposure related to the forecasted purchase and sale of electricity.

The following table represents the activity in Accumulated Other Comprehensive Income (Loss) related to the effect of adopting SFAS 133 for derivative contracts that qualify as cash flow hedges at December 31, 2003:

	(in thousands)
APCo	
Beginning Balance, January 1, 2003	$(1,920)
Effective portion of changes in fair value	(448)
Reclasses from AOCI to net income	799
Ending Balance, December 31, 2003	$(1,569)
CSPCo	
Beginning Balance, January 1, 2003	$(267)
Effective portion of changes in fair value	194
Reclasses from AOCI to net income	275
Ending Balance, December 31, 2003	$202
I&M	
Beginning Balance, January 1, 2003	$(286)
Effective portion of changes in fair value	209
Reclasses from AOCI to net income	299
Ending Balance, December 31, 2003	$222

KPCo	
Beginning Balance, January 1, 2003	$322
Effective portion of changes in fair value	75
Reclasses from AOCI to net income	23
Ending Balance, December 31, 2003	$420
OPCo	
Beginning Balance, January 1, 2003	$(738)
Effective portion of changes in fair value	256
Reclasses from AOCI to net income	379
Ending Balance, December 31, 2003	$(103)
PSO	
Beginning Balance, January 1, 2003	$(42)
Effective portion of changes in fair value	18
Reclasses from AOCI to net income	180
Ending Balance, December 31, 2003	$156
SWEPCo	
Beginning Balance, January 1, 2003	$(48)
Effective portion of changes in fair value	21
Reclasses from AOCI to net income	211
Ending Balance, December 31, 2003	$184
TCC	
Beginning Balance, January 1, 2003	$(36)
Effective portion of changes in fair value	(1,931)
Reclasses from AOCI to net income	139
Ending Balance, December 31, 2003	$(1,828)
TNC	
Beginning Balance, January 1, 2003	$(15)
Effective portion of changes in fair value	(641)
Reclasses from AOCI to net income	55
Ending Balance, December 31, 2003	$(601)

The following table approximates net gain (losses) from cash flow hedges in Accumulated Other Comprehensive Income (Loss) at December 31, 2003 that are expected to be reclassified to net income in the next twelve months as the items being hedged settle. The actual amounts reclassified from AOCI to Net Income can differ as a result of market price changes. The maximum term for which the exposure to the variability of future cash flows is being hedged is five years.

	(in thousands)
APCo	$1,325
CSPCo	940
I&M	1,031
KPCo	466
OPCo	1,231
PSO	724
SWEPCo	853
TCC	(1,413)
TNC	(435)

Financial Instruments

Market Valuation of Non-Derivative Financial Instrument

The fair values of Long-term Debt and preferred stock subject to mandatory redemption are based on quoted market prices for the same or similar issues and the current dividend or interest rates offered for instruments with similar maturities. These instruments are not marked-to-market. The estimates presented are not necessarily indicative of the amounts that could be realized in a current market exchange. The book values and fair values of significant financial instruments for registrant subsidiaries at December 31, 2003 and 2002 are summarized in the following tables.

	2003		2002	
	Book Value	Fair Value	Book Value	Fair Value
	(in thousands)		(in thousands)	
AEGCo				
Long-term Debt	$44,811	$47,882	$44,802	$48,103
APCo				
Long-term Debt	$1,864,081	$1,926,518	$1,893,861	$1,953,087
Cumulative Preferred Stock Subject to Mandatory Redemption (a)	5,360	5,287	10,860	9,774
CSPCo				
Long-term Debt	$897,564	$938,595	$621,626	$643,715
I&M				
Long-term Debt	$1,339,359	$1,400,937	$1,617,062	$1,673,363
Cumulative Preferred Stock Subject to Mandatory Redemption (a)	63,445	63,293	64,945	58,948
KPCo				
Long-term Debt	$427,602	$439,636	$466,632	$475,455
OPCo				
Long-term Debt	$2,039,940	$2,117,131	$1,067,314	$1,095,197
Cumulative Preferred Stock Subject to Mandatory Redemption (a)	7,250	7,214	8,850	7,965
PSO				
Long-term Debt	$574,298	$589,956	$545,437	$570,761
Trust Preferred Securities (b)	-	-	75,000	75,900
SWEPCo				
Long-term Debt	$884,308	$917,982	$693,448	$727,085
Trust Preferred Securities (b)	-	-	110,000	110,880
TCC				
Long-term Debt	$2,291,625	$2,393,468	$1,438,565	$1,522,373
Trust Preferred Securities (b)	-	-	136,250	136,959
TNC				
Long-term Debt	$356,754	$374,420	$132,500	$144,060

(a) See Registrants Statements of Capitalization for the effect of SFAS 150 in 2003.
(b) See Note 16 on Trust Preferred Securities.

Other Financial Instruments - Nuclear Trust Funds Recorded at Market Value

The trust investments are classified as available for sale for decommissioning (I&M, TCC) and SNJ disposal for I&M. I&M reports trusts in "Nuclear Decommissioning and Spent Nuclear Fuel Disposal Trust Funds" on the Consolidated Balance Sheets. TCC reports trusts in "Assets Held for Sale – Texas Generating Plants" on their Consolidated Balance Sheets. The following table provides fair values, cost basis and net unrealized gains or losses at December 31:

	I&M (in thousands)		TCC (in thousands)	
	2003	**2002**	**2003**	**2002**
Fair Value	$982,400	$870,700	$125,400	$98,400
Cost Basis	$900,000	$823,900	$94,800	$84,600

	2003	2002 (in thousands)	2001	2003	2002 (in thousands)	2001
Net Unrealized Holding Gain (Loss)	$35,500	$(25,400)	$(8,300)	$16,700	$(7,500)	$(3,000)

14. INCOME TAXES

The details of the registrant subsidiaries income taxes before extraordinary items and cumulative effect of accounting changes as reported are as follows:

	AEGCo	APCo	CSPCo (in thousands)	I&M	KPCo
Year Ended December 31, 2003					
Charged (Credited) to Operating Expenses (net):					
Current	$7,481	$84,449	$83,469	$58,190	$(7,840)
Deferred	(5,838)	37,024	3,982	66	21,183
Deferred Investment Tax Credits	-	(1,884)	(3,041)	(7,330)	(1,168)
Total	1,643	119,589	84,410	50,926	12,175
Charged (Credited) to Nonoperating Income (net):					
Current	(196)	(646)	(2,183)	5,283	(1,382)
Deferred	-	(12,461)	(8,496)	(14,960)	(1,076)
Deferred Investment Tax Credits	(3,354)	(1,262)	(69)	(101)	(42)
Total	(3,550)	(14,369)	(10,748)	(9,778)	(2,500)
Total Income Tax as Reported	$(1,907)	$105,220	$73,662	$41,148	$9,675

Year Ended December 31, 2003	OPCo	PSO	SWEPCo (in thousands)	TCC	TNC
Charged (Credited) to Operating Expenses (net):					
Current	$116,316	$55,834	$51,564	$88,530	$33,822
Deferred	32,191	(17,036)	7,230	14,769	(5,113)
Deferred Investment Tax Credits	(2,493)	(1,790)	(4,326)	(5,207)	(1,520)
Total	146,014	37,008	54,468	98,092	27,189
Charged (Credited) to Nonoperating Income (net):					
Current	708	(1,566)	(6,108)	2,456	1,454
Deferred	(7,709)	2,395	2,712	4,624	1,620
Deferred Investment Tax Credits	(614)	-	-	-	-
Total	(7,615)	829	(3,396)	7,080	3,074
Total Income Tax as Reported	$138,399	$37,837	$51,072	$105,172	$30,263

Year Ended December 31, 2002	AEGCo	APCo	CSPCo (in thousands)	I&M	KPCo
Charged (Credited) to Operating Expenses (net):					
Current	$6,607	$99,140	$81,538	$66,063	$680
Deferred	(5,028)	17,626	25,771	(19,870)	9,451
Deferred Investment Tax Credits	2	(3,229)	(3,095)	(7,340)	(1,173)
Total	1,581	113,537	104,214	38,853	8,958
Charged (Credited) to Nonoperating Income (net):					
Current	(173)	(354)	9,442	3,435	1,583
Deferred	-	(849)	(2,479)	2,949	388
Deferred Investment Tax Credits	(3,363)	(1,408)	(174)	(400)	(67)
Total	(3,536)	(2,611)	6,789	5,984	1,904
Total Income Tax as Reported	$(1,955)	$110,926	$111,003	$44,837	$10,862

Year Ended December 31, 2002	OPCo	PSO	SWEPCo (in thousands)	TCC	TNC
Charged (Credited) to Operating Expenses (net):					
Current	$86,026	$(49,673)	$41,354	$30,494	$109
Deferred	30,048	75,659	(3,134)	113,726	(10,652)
Deferred Investment Tax Credits	(2,493)	(1,791)	(4,524)	(5,206)	(1,271)
Total	113,581	24,195	33,696	139,014	(11,814)
Charged (Credited) to Nonoperating Income (net):					
Current	2,732	(1,812)	1,772	3,223	1,334
Deferred	15,962	-	-	(71)	(1,623)
Deferred Investment Tax Credits	(684)	-	-	-	-
Total	18,010	(1,812)	1,772	3,152	(289)
Total Income Tax as Reported	$131,591	$22,383	$35,468	$142,166	$(12,103)

Year Ended December 31, 2001	AEGCo	APCo	CSPCo (in thousands)	I&M	KPCo
Charged (Credited) to Operating Expenses (net):					
Current	$9,126	$71,623	$88,013	$107,286	$7,726
Deferred	(6,224)	27,198	14,923	(45,785)	2,812
Deferred Investment Tax Credits	-	(3,237)	(3,899)	(7,377)	(1,180)
Total	2,902	95,584	99,037	54,124	9,358
Charged (Credited) to Nonoperating Income (net):					
Current	(56)	(19,165)	(13,803)	(10,590)	(2,726)
Deferred	-	21,832	17,885	16,580	3,481
Deferred Investment Tax Credits	(3,414)	(1,528)	(159)	(947)	(71)
Total	(3,470)	1,139	3,923	5,043	684
Total Income Tax as Reported	$(568)	$96,723	$102,960	$59,167	$10,042

Year Ended December 31, 2001	OPCo	PSO	SWEPCo (in thousands)	TCC	TNC
Charged (Credited) to Operating Expenses (net):					
Current	$(62,298)	$53,030	$77,965	$190,672	$19,424
Deferred	166,166	(16,726)	(31,396)	(72,568)	(11,891)
Deferred Investment Tax Credits	(2,495)	(1,791)	(4,453)	(5,208)	(1,271)
Total	101,373	34,513	42,116	112,896	6,262
Charged (Credited) to Nonoperating Income (net):					
Current	(21,600)	352	542	(1,749)	(691)
Deferred	20,014	-	-	-	-
Deferred Investment Tax Credits	(794)	-	-	-	-
Total	(2,380)	352	542	(1,749)	(691)
Total Income Tax as Reported	$98,993	$34,865	$42,658	$111,147	$5,571

Shown below is a reconciliation for each registrant subsidiary of the difference between the amount of federal income taxes computed by multiplying book income before federal income taxes by the statutory rate, and the amount of income taxes reported.

	AEGCo	APCo	CSPCo	I&M	KPCo
Year Ended December 31, 2003			(in thousands)		
Net Income	$7,964	$280,040	$200,430	$86,388	$32,330
Cumulative Effect of Accounting Change	-	(77,257)	(27,283)	3,160	1,134
Income Taxes	(1,907)	105,220	73,662	41,148	9,675
Pre-Tax Income	$6,057	$308,003	$246,809	$130,696	$43,139
Income Tax on Pre-Tax Income at Statutory Rate *(35%)*	$2,120	$107,801	$86,383	$45,744	$15,099
Increase (Decrease) in Income Tax Resulting from the Following Items:					
Depreciation	371	9,263	2,220	19,288	1,538
Nuclear Fuel Disposal Costs	-	-	-	(6,465)	-
Allowance for Funds Used During Construction	(1,053)	(2,048)	(232)	(4,127)	(851)
Rockport Plant Unit 2 Investment Tax Credit	374	-	-	397	-
Removal Costs	-	(2,280)	(7)	(693)	(735)
Investment Tax Credits (net)	(3,354)	(3,146)	(3,110)	(7,431)	(1,210)
State Income Taxes	372	1,123	(3,074)	4,634	(58)
Other	(737)	(5,493)	(8,518)	(10,199)	(4,108)
Total Income Taxes as Reported	$(1,907)	$105,220	$73,662	$41,148	$9,675
Effective Income Tax Rate	N.M.	34.2%	29.8%	31.5%	22.4%

	OPCo	PSO	SWEPCo	TCC	TNC
Year Ended December 31, 2003			(in thousands)		
Net Income	$375,663	$53,891	$98,141	$217,669	$58,557
Cumulative Effect of Accounting Change	(124,632)	-	(8,517)	(122)	(3,071)
Extraordinary Loss	-	-	-	-	177
Income Taxes	138,399	37,837	51,072	105,172	30,263
Pre-Tax Income	$389,430	$91,728	$140,696	$322,719	$85,926
Income Tax on Pre-Tax Income at Statutory Rate *(35%)*	$136,301	$32,105	$49,244	$112,952	$30,074
Increase (Decrease) in Income Tax Resulting from the Following Items:					
Depreciation	4,388	1,166	834	486	286
Investment Tax Credits (net)	(3,107)	(1,791)	(4,326)	(5,207)	(1,521)
State Income Taxes	4,717	2,886	9,723	(10,434)	3,078
Other	(3,900)	3,471	(4,403)	7,375	(1,654)
Total Income Taxes as Reported	$138,399	$37,837	$51,072	$105,172	$30,263
Effective Income Tax Rate	35.5%	41.2%	36.3%	32.6%	35.2%

Year Ended December 31, 2002	AEGCo	APCo	CSPCo (in thousands)	I&M	KPCo
Net Income	$7,552	$205,492	$181,173	$73,992	$20,567
Income Taxes	(1,955)	110,926	111,003	44,837	10,862
Pre-Tax Income	$5,597	$316,418	$292,176	$118,829	$31,429
Income Tax on Pre-Tax Income at Statutory Rate *(35%)*	$1,959	$110,746	$102,262	$41,590	$11,000
Increase (Decrease) in Income Tax Resulting from the Following Items:					
Depreciation	286	3,082	2,899	21,812	2,057
Nuclear Fuel Disposal Costs	-	-	-	(3,087)	-
Allowance for Funds Used During Construction	(1,136)	-	-	(3,453)	-
Rockport Plant Unit 2 Investment Tax Credit	374	-	-	-	-
Removal Costs	-	-	-	-	(735)
Investment Tax Credits (net)	(3,361)	(4,637)	(3,270)	(7,740)	(1,240)
State Income Taxes	335	6,469	11,387	124	1,058
Other	(412)	(4,734)	(2,275)	(4,409)	(1,278)
Total Income Taxes as Reported	$(1,955)	$110,926	$111,003	$44,837	$10,862
Effective Income Tax Rate	N.M.	35.1%	38.0%	37.7%	34.6%

Year Ended December 31, 2002	OPCo	PSO	SWEPCo (in thousands)	TCC	TNC
Net Income (Loss)	$220,023	$41,060	$82,992	$275,941	$(13,677)
Income Taxes	131,591	22,383	35,468	142,166	(12,103)
Pre-Tax Income (Loss)	$351,614	$63,443	$118,460	$418,107	$(25,780)
Income Tax on Pre-Tax Income (Loss) at Statutory Rate *(35%)*	$123,065	$22,205	$41,461	$146,337	$(9,023)
Increase (Decrease) in Income Tax Resulting from the Following Items:					
Depreciation	4,227	(583)	(2,790)	(295)	(32)
Investment Tax Credits (net)	(3,177)	(1,791)	(4,524)	(5,207)	(1,271)
State Income Taxes	18,051	2,639	3,987	2,202	(1,577)
Other	(10,575)	(87)	(2,666)	(871)	(200)
Total Income Taxes as Reported	$131,591	$22,383	$35,468	$142,166	$(12,103)
Effective Income Tax Rate	37.4%	35.3%	29.9%	34.0%	46.9%

Year Ended December 31, 2001	AEGCo	APCo	CSPCo (in thousands)	I&M	KPCo
Net Income	$7,875	$161,818	$161,876	$75,788	$21,565
Extraordinary Loss	-	-	30,024	-	-
Income Taxes	(568)	96,723	102,960	59,167	10,042
Pre-Tax Income	$7,307	$258,541	$294,860	$134,955	$31,607
Income Tax on Pre-Tax Income at Statutory Rate *(35%)*	$2,557	$90,489	$103,201	$47,234	$11,062
Increase (Decrease) in Income Tax Resulting from the Following Items:					
Depreciation	230	2,977	2,757	21,224	1,581
Nuclear Fuel Disposal Costs	-	-	-	(3,292)	-
Allowance for Funds Used During Construction	(1,078)	-	-	(1,606)	-
Rockport Plant Unit 2 Investment Tax Credit	374	-	-	-	-
Removal Costs	-	-	-	-	(420)
Investment Tax Credits (net)	(3,414)	(4,765)	(4,058)	(8,324)	(1,252)
State Income Taxes	1,050	9,613	5,727	6,137	318
Other	(287)	(1,591)	(4,667)	(2,206)	(1,247)
Total Income Taxes as Reported	$(568)	$96,723	$102,960	$59,167	$10,042
Effective Income Tax Rate	N.M.	37.4%	34.9%	43.8%	31.8%

Year Ended December 31, 2001	OPCo	PSO	SWEPCo (in thousands)	TCC	TNC
Net Income	$147,445	$57,759	$89,367	$182,278	$12,310
Extraordinary Loss	18,348	-	-	-	-
Income Taxes	98,993	34,865	42,658	111,147	5,571
Pre-Tax Income	$264,786	$92,624	$132,025	$293,425	$17,881
Income Tax on Pre-Tax Income at Statutory Rate *(35%)*	$92,675	$32,418	$46,209	$102,699	$6,258
Increase (Decrease) in Income Tax Resulting from the Following Items:					
Depreciation	7,972	1,127	(501)	8,477	1,463
Investment Tax Credits (net)	(3,289)	(1,791)	(4,453)	(5,207)	(1,271)
State Income Taxes	9,752	5,137	5,451	9,652	1,283
Other	(8,117)	(2,026)	(4,048)	(4,474)	(2,162)
Total Income Taxes as Reported	$98,993	$34,865	$42,658	$111,147	$5,571
Effective Income Tax Rate	37.4%	37.6%	32.3%	37.9%	31.2%

The following tables show the elements of the net deferred tax liability and the significant temporary differences for each registrant subsidiary:

December 31, 2003	AEGCo	APCo	CSPCo	I&M	KPCo
			(in thousands)		
Deferred Tax Assets	$79,545	$237,873	$122,453	$695,037	$44,413
Deferred Tax Liabilities	(103,874)	(1,041,228)	(580,951)	(1,032,413)	(256,534)
Net Deferred Tax Liabilities	$(24,329)	$(803,355)	$(458,498)	$(337,376)	$(212,121)
Property Related Temporary Differences	$(62,271)	$(623,126)	$(357,980)	$(74,501)	$(151,404)
Amounts Due From Customers For Future Federal Income Taxes	6,949	(94,457)	(5,575)	(37,233)	(23,203)
Deferred State Income Taxes	(4,350)	(87,484)	(26,972)	(45,736)	(33,535)
Transition Regulatory Assets	-	(10,799)	(66,002)	-	-
Deferred Income Taxes on Other Comprehensive Loss	-	28,047	24,946	13,519	3,345
Net Deferred Gain on Sale and Leaseback-Rockport Plant Unit 2	36,916	-	-	24,563	-
Accrued Nuclear Decommissioning Expense	-	-	-	(173,054)	-
Deferred Fuel and Purchased Power	-	24,047	(273)	(19)	496
Deferred Cook Plant Restart Costs	-	-	-	(20,064)	-
Nuclear Fuel	-	-	-	(7,027)	-
All Other (Net)	(1,573)	(39,583)	(26,642)	(17,824)	(7,820)
Net Deferred Tax Liabilities	$(24,329)	$(803,355)	$(458,498)	$(337,376)	$(212,121)

December 31, 2003	OPCo	PSO	SWEPCo	TCC	TNC
		(in thousands)			
Deferred Tax Assets	$192,026	$164,801	$163,457	$298,648	$67,794
Deferred Tax Liabilities	(1,125,608)	(500,235)	(512,521)	(1,543,560)	(180,813)
Net Deferred Tax Liabilities	$(933,582)	$(335,434)	$(349,064)	$(1,244,912)	$(113,019)
Property Related Temporary Differences	$(721,118)	$(297,809)	$(307,023)	$(698,554)	$(118,876)
Amounts Due From Customers For Future Federal Income Taxes	(55,143)	8,728	(5,800)	(191,615)	9,979
Deferred State Income Taxes	(80,573)	(56,413)	(33,651)	(42,044)	(2,946)
Transition Regulatory Assets	(109,150)	-	-	(68,076)	-
Accrued Nuclear Decommissioning Expense	-	-	-	(1,470)	-
Nuclear Fuel	-	-	-	(7,240)	-
Deferred Income Taxes on Other Comprehensive Loss	26,280	23,607	23,644	33,316	14,387
Deferred Fuel and Purchased Power	12	(8,460)	(10,996)	(1,738)	(10,143)
Regulatory Assets Designated for Securitization	-	-	-	(281,260)	-
All Other (Net)	6,110	(5,087)	(15,238)	13,769	(5,420)
Net Deferred Tax Liabilities	$(933,582)	$(335,434)	$(349,064)	$(1,244,912)	$(113,019)

December 31, 2002	AEGCo	APCo	CSPCo	I&M	KPCo
		(in thousands)			
Deferred Tax Assets	$82,889	$247,080	$106,597	$436,361	$45,231
Deferred Tax Liabilities	(111,891)	(948,881)	(544,368)	(792,558)	(223,544)
Net Deferred Tax Liabilities	$(29,002)	$(701,801)	$(437,771)	$(356,197)	$(178,313)
Property Related Temporary Differences	$(74,291)	$(555,806)	$(331,166)	$(343,362)	$(127,069)
Amounts Due From Customers For Future Federal Income Taxes	7,626	(58,246)	(8,895)	(38,752)	(20,488)
Deferred State Income Taxes	(5,119)	(77,693)	(23,448)	(52,528)	(28,722)
Transition Regulatory Assets	-	(28,735)	(71,752)	-	-
Deferred Income Taxes on Other Comprehensive Loss	-	38,823	31,961	21,800	5,089
Net Deferred Gain on Sale and Leaseback-Rockport Plant Unit 2	38,866	-	-	25,860	-
Accrued Nuclear Decommissioning Expense	-	-	-	65,856	-
Deferred Fuel and Purchased Power	-	(1,878)	(273)	(13,144)	415
Deferred Cook Plant Restart Costs	-	-	-	(14,000)	-
Nuclear Fuel	-	-	-	(5,153)	-
All Other (Net)	3,916	(18,266)	(34,198)	(2,774)	(7,538)
Net Deferred Tax Liabilities	$(29,002)	$(701,801)	$(437,771)	$(356,197)	$(178,313)

December 31, 2002	OPCo	PSO	SWEPCo	TCC	TNC
		(in thousands)			
Deferred Tax Assets	$189,281	$141,571	$158,925	$164,343	$62,211
Deferred Tax Liabilities	(983,668)	(482,967)	(499,989)	(1,425,595)	(179,732)
Net Deferred Tax Liabilities	$(794,387)	$(341,396)	$(341,064)	$(1,261,252)	$(117,521)
Property Related Temporary Differences	$(620,019)	$(303,888)	$(315,821)	$(709,246)	$(127,038)
Amounts Due From Customers For Future Federal Income Taxes	(53,256)	9,490	(4,078)	(198,595)	5,726
Deferred State Income Taxes	(46,990)	(57,911)	(48,372)	(66,333)	(4,080)
Transition Regulatory Assets	(131,833)	-	-	-	-
Accrued Nuclear Decommissioning Expense	-	-	-	(1,117)	-
Nuclear Fuel	-	-	-	(7,023)	-
Deferred Income Taxes on Other Comprehensive Loss	39,246	29,332	28,906	39,394	16,565
Deferred Fuel and Purchased Power	540	(28,696)	3,192	2,655	(9,933)
Regulatory Assets Designated For Securitization	-	-	-	(310,410)	-
All Other (Net)	17,925	10,277	(4,891)	(10,577)	1,239
Net Deferred Tax Liabilities	$(794,387)	$(341,396)	$(341,064)	$(1,261,252)	$(117,521)

Registrant subsidiaries have settled with the IRS all issues from the audits of our consolidated federal income tax returns for the years prior to 1991. Registrant Subsidiaries have received Revenue Agent's Reports from the IRS for the years 1991 through 1996, and have filed protests contesting certain proposed adjustments. Returns for the years 1997 through 2000 are presently being audited by the IRS. Management is not aware of any issues for open tax years that upon final resolution are expected to have a material adverse effect on results of operations.

Registrant Subsidiaries join in the filing of a consolidated federal income tax return with the AEP System. The allocation of the AEP System's current consolidated federal income tax to the System companies is in accordance with SEC rules under the 1935 Act. These rules permit the allocation of the benefit of current tax losses to the System companies giving rise to them in determining their current tax expense. The tax loss of the System parent company, AEP Co., Inc., is allocated to its subsidiaries with taxable income. With the exception of the loss of the parent company, the method of allocation approximates a separate return result for each company in the consolidated group.

15. LEASES

Leases of property, plant and equipment are for periods up to 99 years and require payments of related property taxes, maintenance and operating costs. The majority of the leases have purchase or renewal options and will be renewed or replaced by other leases.

Lease rentals for both operating and capital leases are generally charged to operating expenses in accordance with rate-making treatment for regulated operations. Capital leases for non-regulated property are accounted for as if the assets were owned and financed. The components of rental costs are as follows:

	AEGCo	APCo	CSPCo	I&M	KPCo	OPCo
Year Ended December 31, 2003			(in thousands)			
Lease Payments on						
Operating Leases	$76,322	$6,148	$5,277	$110,714	$1,258	$27,337
Amortization of Capital Leases	269	9,217	4,898	7,370	1,951	9,437
Interest on Capital Leases	-	1,123	899	1,276	148	2,472
Total Lease Rental Costs	$76,591	$16,488	$11,074	$119,360	$3,357	$39,246

	PSO	SWEPCo	TCC	TNC
Year Ended December 31, 2003		(in thousands)		
Lease Payments on				
Operating Leases	$4,883	$4,708	$6,360	$2,132
Amortization of Capital Leases	174	1,434	161	83
Interest on Capital Leases	17	899	16	9
Total Lease Rental Costs	$5,074	$7,041	$6,537	$2,224

	AEGCo	APCo	CSPCo	I&M	KPCo	OPCo
Year Ended December 31, 2002			(in thousands)			
Lease Payments on						
Operating Leases	$76,143	$6,634	$5,209	$110,833	$1,597	$68,816
Amortization of Capital Leases	238	9,729	6,010	8,319	2,171	12,637
Interest on Capital Leases	19	2,240	1,717	2,221	469	4,501
Total Lease Rental Costs	$76,400	$18,603	$12,936	$121,373	$4,237	$85,954

	PSO	SWEPCo	TCC	TNC
Year Ended December 31, 2002		(in thousands)		
Lease Payments on				
Operating Leases	$4,403	$3,240	$7,184	$1,981
Amortization of Capital Leases	-	-	-	-
Interest on Capital Leases	-	-	-	-
Total Lease Rental Costs	$4,403	$3,240	$7,184	$1,981

	AEGCo	APCo	CSPCo	I&M	KPCo	OPCo
Year Ended December 31, 2001			(in thousands)			
Lease Payments on						
Operating Leases	$76,262	$6,142	$7,063	$104,574	$1,191	$63,913
Amortization of Capital Leases	281	12,099	7,206	17,933	2,740	14,443
Interest on Capital Leases	55	3,789	2,396	4,424	808	5,818
Total Lease Rental Costs	$76,598	$22,030	$16,665	$126,931	$4,739	$84,174

Year Ended December 31, 2001	PSO	SWEPCo (in thousands)	TCC	TNC
Lease Payments on				
Operating Leases	$4,010	$2,277	$5,948	$1,534
Amortization of Capital Leases	-	-	-	-
Interest on Capital Leases	-	-	-	-
Total Lease Rental Costs	$4,010	$2,277	$5,948	$1,534

Property, plant and equipment under capital leases and related obligations recorded on the Consolidated Balance Sheets are as follows:

Year Ended December 31, 2003	AEGCo	APCo	CSPCo (in thousands)	I&M	KPCo
Property, Plant and Equipment Under Capital Leases					
Production	$865	$2,758	$7,104	$4,492	$1,138
Distribution	-	-	-	14,589	-
Other	-	55,640	25,345	52,536	11,562
Total Property, Plant and Equipment	865	58,398	32,449	71,617	12,700
Accumulated Amortization	596	33,036	16,828	33,774	7,408
Net Property, Plant and Equipment Under Capital Leases	$269	$25,362	$15,621	$37,843	$5,292
Obligations Under Capital Leases:					
Noncurrent Liability	$182	$16,134	$11,397	$31,315	$3,549
Liability Due Within One Year	87	9,218	4,221	6,528	1,743
Total Obligations Under Capital Leases	$269	$25,352	$15,618	$37,843	$5,292

Year Ended December 31, 2003	OPCo	PSO	SWEPCo (in thousands)	TCC	TNC
Property, Plant and Equipment Under Capital Leases					
Production	$21,099	$-	$-	$-	$-
Distribution	-	-	-	-	-
Other	53,752	1,176	52,695	1,204	556
Total Property, Plant and Equipment	74,851	1,176	52,695	1,204	556
Accumulated Amortization	40,565	166	31,153	160	83
Net Property, Plant and Equipment Under Capital Leases	$34,286	$1,010	$21,542	$1,044	$473
Obligations Under Capital Leases:					
Noncurrent Liability	$25,064	$558	$18,383	$636	$270
Liability Due Within One Year	9,624	452	3,159	407	203
Total Obligations Under Capital Leases	$34,688	$1,010	$21,542	$1,043	$473

Year Ended December 31, 2002	AEGCo	APCo	CSPCo	I&M	KPCo
			(in thousands)		
Property, Plant and Equipment Under Capital Leases					
Production	$1,793	$3,368	$6,380	$5,728	$1,138
Distribution	-	-	-	14,589	-
Other:					
Mining Assets and Other	-	67,395	46,791	70,140	14,258
Total Property, Plant and Equipment	1,793	70,763	53,171	90,457	15,396
Accumulated Amortization	1,294	37,452	26,551	41,141	8,168
Net Property, Plant and Equipment Under Capital Leases	$499	$33,311	$26,620	$49,316	$7,228
Obligations Under Capital Leases:					
Noncurrent Liability	$301	$23,991	$21,643	$42,619	$5,093
Liability Due Within One Year	200	9,598	5,967	8,229	2,155
Total Obligations Under Capital Leases	$501	$33,589	$27,610	$50,848	$7,248

Year Ended December 31, 2002	OPCo	SWEPCo
	(in thousands)	
Property, Plant and Equipment Under Capital Leases		
Production	$21,360	$-
Distribution	-	-
Other:		
Mining Assets and Other	103,018	45,699
Total Property, Plant and Equipment	124,378	45,699
Accumulated Amortization	63,810	45,699
Net Property, Plant and Equipment Under Capital Leases	$60,568	$-
Obligations Under Capital Leases:		
Noncurrent Liability	$51,266	$-
Liability Due Within One Year	14,360	-
Total Obligations Under Capital Leases	$65,626	$-

Future minimum lease payments consisted of the following at December 31, 2003:

	APCo	CSPCo	I&M	KPCo	OPCo
			(in thousands)		
Capital Leases					
2004	$11,735	$4,959	$10,050	$2,107	$11,046
2005	6,853	4,025	7,478	1,640	8,093
2006	5,183	2,676	6,239	957	7,536
2007	2,664	1,773	12,616	785	5,582
2008	2,645	2,050	3,669	256	3,677
Later Years	1,802	2,096	5,994	116	4,627
Total Future Minimum Lease Payments	30,882	17,579	46,046	5,861	40,561
Less Estimated Interest Element	5,530	1,961	8,203	569	5,874
Estimated Present Value of Future Minimum Lease Payments	$25,352	$15,618	$37,843	$5,292	$34,687

	PSO	SWEPCo	TCC	TNC
	(in thousands)			
Capital Leases				
2004	$492	$4,737	$450	$223
2005	368	4,641	373	188
2006	194	4,533	198	87
2007	46	4,410	86	8
2008	4	4,389	24	1
Later Years	-	4,380	-	2
Total Future Minimum Lease Payments	1,104	27,090	1,131	509
Less Estimated Interest Element	94	5,548	88	36
Estimated Present Value of Future Minimum Lease Payments	$1,010	$21,542	$1,043	$473

	AEGCo	APCo	CSPCo	I&M	KPCo	OPCo
	(in thousands)					
Noncancellable Operating Leases						
2004	$73,854	$5,998	$5,078	$103,909	$1,209	$12,655
2005	73,854	5,154	4,920	97,447	1,084	11,886
2006	73,854	4,455	2,518	93,993	793	11,576
2007	73,854	3,302	2,205	91,328	771	11,132
2008	73,854	2,394	1,609	90,749	475	10,787
Later Years	1,033,956	6,094	2,726	1,096,567	1,785	66,918
Total Future Minimum Lease Payments	$1,403,226	$27,397	$19,056	$1,573,993	$6,117	$124,954

	PSO	SWEPCo	TCC	TNC
	(in thousands)			
Noncancellable Operating Leases				
2004	$4,684	$5,522	$6,112	$1,964
2005	4,520	6,020	5,886	1,945
2006	4,079	6,844	5,218	1,846
2007	3,424	7,218	4,397	1,532
2008	1,218	7,451	3,950	1,238
Later Years	8,616	17,849	11,272	4,981
Total Future Minimum Lease Payments	$26,541	$50,904	$36,835	$13,506

Gavin Lease

OPCo has entered into an agreement with JMG, an unrelated special purpose entity. JMG has a capital structure of which 3% is equity from investors with no relationship to AEP or any of its subsidiaries and 97% is debt from commercial paper, pollution control bonds and other bonds. JMG was formed to design, construct and lease the Gavin Scrubber for the Gavin Plant to OPCo. JMG owns the Gavin Scrubber and leases it to OPCo. Prior to July 1, 2003, the lease was accounted for as an operating lease. Payments under the lease agreement are based on JMG's cost of financing (both debt and equity) and include an amortization component plus the cost of administration. OPCo and AEP do not have an ownership interest in JMG and do not guarantee JMG's debt.

At any time during the lease, OPCo has the option to purchase the Gavin Scrubber for the greater of its fair market value or adjusted acquisition cost (equal to the unamortized debt and equity of JMG) or sell the Gavin Scrubber on behalf of JMG. The initial 15-year lease term is non-cancelable. At the end of the initial term, OPCo can renew the lease, purchase the Gavin Scrubber (terms previously mentioned), or sell the Gavin Scrubber on behalf of JMG. In case of a sale at less than the adjusted acquisition cost, OPCo must pay the difference to JMG.

On March 31, 2003, OPCo made a prepayment of $90 million under this lease structure. AEP recognizes lease expense on a straight-line basis over the remaining lease term, in accordance with SFAS 13 "Accounting for Leases." The asset will be amortized over the remaining lease term, which ends in the first quarter of 2010.

On July 1, 2003, OPCo consolidated JMG due to the application of FIN 46. Upon consolidation, OPCo recorded the assets and liabilities of JMG ($469.6 million). OPCo now records the depreciation, interest and other operating expenses of JMG and eliminates JMG's revenues against OPCo's operating lease expenses. There was no cumulative effect of an accounting change recorded as a result of AEP's requirement to consolidate JMG, and there was no change in net income due to the consolidation of JMG. Since the debt obligations of JMG are now consolidated, the JMG lease is no longer accounted for on a consolidated basis as an operating lease and has been excluded from the above table of future minimum lease payments.

Rockport Lease

AEGCo and I&M entered into a sale and leaseback transaction in 1989 with Wilmington Trust Company (Owner Trustee) an unrelated unconsolidated trustee for Rockport Plant Unit 2 (the plant). The Owner Trustee was capitalized with equity from six owner participants with no relationship to AEP or any of its subsidiaries and debt from a syndicate of banks and securities in a private placement to certain institutional investors. The future minimum lease payments for each respective company are $1.4 billion.

The FASB and other accounting constituencies continue to interpret the application of FIN 46 (revised December 2003) (FIN 46R). As a result, AEGCo and I&M are continuing to review the application of this new interpretation as it relates to the Rockport Plant Unit 2 transaction.
The gain from the sale was deferred and is being amortized over the term of the lease, which expires in 2022. The Owner Trustee owns the plant and leases it to AEGCo and I&M. The lease is accounted for as an operating lease with the payment obligations included in the future minimum lease payments schedule earlier in this note. The lease term is for 33 years with potential renewal options. At the end of the lease term, AEGCo and I&M have the option to renew the lease or the Owner Trustee can sell the plant. Neither AEGCo, I&M nor AEP has an ownership interest in the Owner Trustee and do not guarantee its debt.

16. FINANCING ACTIVITIES

Trust Preferred Securities

PSO, SWEPCo and TCC have wholly-owned business trusts that have issued trust preferred securities. The trusts which hold mandatorily redeemable trust preferred securities were deconsolidated effective July 1, 2003 due to the implementation of FIN 46. Therefore, $321 million ($75 million PSO, $110 million SWEPCo and $136 million TCC), previously reported at December 31, 2002 as Certain Subsidiary Obligated, Mandatorily Redeemable, Preferred Securities of Subsidiary Trusts Holding Solely Junior Subordinated Debentures of Such Subsidiaries, is now reported as two components on the Balance Sheet. The investment in the trust is now reported as Other Investments within Other Property and Investments of $10 million ($2 million PSO, $3 million SWEPCo and $5 million TCC) and the subordinated debentures are now reported as Notes Payable to Trust within Long-term Debt of $331 million ($77 million PSO, $113 million SWEPCo and $141 million TCC).

The Junior Subordinated Debentures of PSO and TCC mature on April 30, 2037. In October 2003, SWEPCo refinanced its Junior Subordinated Debentures which are now due October 1, 2043. The following Trust Preferred Securities issued by the wholly-owned statutory business trusts of PSO, SWEPCo and TCC were outstanding at December 31, 2003 and 2002:

Business Trust	Security	Units Issued/ Outstanding at 12/31/03	Amount in Other Investments at 12/31/03 (a) (in millions)	Amount in Notes Payable to Trust at 12/31/03 (b) (in millions)	Amount Reported Prior to FIN 46 at 12/31/02 (c) (in millions)	Description of Underlying Debentures of Registrant
CPL Capital I	8.00%, Series A	5,450,000	$5	$141	$136	TCC, $141 million, 8.00%, Series A
PSO Capital I	8.00%, Series A	3,000,000	2	77	75	PSO, $77 million, 8.00%, Series A
SWEPCo Capital I	7.875%, Series A	-	-	-	110	SWEPCo, $113 million, 7.875%, Series A
SWEPCo Capital I	5.25%, Series B	110,000	3	113	-	SWEPCo, $113 million, 5.25% five year fixed rate period, Series B
		8,560,000	$10	$331	$321	

(a) Amounts are in Other Investments within Other Property and Investments.
(b) Amounts are in Notes Payable to Trust within Long-term Debt.
(c) Amounts reported on Balance Sheet prior to FIN 46.

Each of the business trusts is treated as a non-consolidated subsidiary of its parent company. The only assets of the business trusts are the subordinated debentures issued by their parent company as specified above. In addition to the obligations under their subordinated debentures, each of the parent companies has also agreed to a security obligation which represents a full and unconditional guarantee of its capital trust obligation.

Lines of Credit – AEP System

The AEP System uses a corporate borrowing program to meet the short-term borrowing needs of its subsidiaries. The corporate borrowing program includes a utility money pool, which funds the utility subsidiaries, and a non-utility money pool, which funds the majority of the non-utility subsidiaries. In addition, the AEP System also funds, as direct borrowers, the short-term debt requirements of other subsidiaries that are not participants in the non-utility money pool for regulatory or operational reasons. The AEP System Corporate Borrowing Program operates in accordance with the terms and conditions outlined by the SEC. AEP has authority from the SEC through March 31, 2006 for short-term borrowings sufficient to fund the utility money pool and the non-utility money pool as well as its own requirements in an amount not to exceed $7.2 billion. Utility money pool participants include AEGCo, APCo, CSPCo, I&M, KPCo, OPCo, PSO, SWEPCo, TCC and TNC (domestic utility companies). The following are the SEC-authorized limits for short-term borrowings for the domestic utility companies as of December 31, 2003:

	Authorized (in millions)
AEP Generating Company	$125
AEP Texas Central Company (a)	438
AEP Texas North Company (a)	275
Appalachian Power Company	600
Columbus Southern Power Company (a)	150
Indiana Michigan Power Company	500
Kentucky Power Company	200
Ohio Power Company (a)	200
Public Service Company of Oklahoma	300
Southwestern Electric Power Company	350

(a) Short-term borrowing limits for these domestic utility companies are reduced by long-term debt issued commencing with the SEC order dated December 18, 2002, which authorized financing transactions through March 31, 2006.

As of December 31, 2003, AEP had credit facilities totaling $2.9 billion to support its commercial paper program. At December 31, 2003, AEP had $326 million outstanding in short-term borrowings of which $282 million was commercial paper supported by the revolving credit facilities. In addition, JMG has commercial paper outstanding in the amount of $26 million. This commercial paper is specifically associated with the Gavin scrubber lease identified in Note 15 "Leases". This commercial paper does not reduce available liquidity to AEP. The maximum amount of commercial paper outstanding during the year, which had a weighted average interest rate during 2003 of 1.98%, was $1.5 billion during January 2003. On December 11, 2002, Moody's Investor Services placed AEP's Prime-2 short-term rating for commercial paper under review for possible downgrade. On January 24, 2003, Standard & Poor's Rating Services placed AEP's A-2 short-term rating for commercial paper under review for possible downgrade. On February 10, 2003, Moody's Investor Services downgraded AEP's short-term rating for commercial paper to Prime-3 from Prime-2. On March 7, 2003, Standard & Poor's Rating Services reaffirmed AEP's A-2 short-term rating for commercial paper.

Net interest income (expense) recorded by each registrant subsidiary related to amounts advanced to (borrowed from) the AEP money pool were:

	Year Ended December 31,		
	2003	**2002**	**2001**
		(in millions)	
AEGCo	$(0.3)	$(0.2)	$(0.7)
APCo	1.4	(4.1)	(9.9)
CSPCo	-	(1.1)	(4.9)
I&M	1.5	1.0	(12.6)
KPCo	(0.9)	(1.6)	(2.3)
OPCo	(1.6)	(5.7)	(13.2)
PSO	(1.1)	(4.1)	(5.8)
SWEPCo	0.1	(2.8)	(2.3)
TCC	-	(6.3)	(11.1)
TNC	(0.3)	(3.2)	(3.0)

Outstanding short-term debt for AEP Consolidated consisted of:

	Year Ended December 31,	
	2003	**2002**
	(in millions)	
Balance Outstanding:		
Notes Payable	$18	$1,322
Commercial Paper – AEP	282	1,417
Commercial Paper – JMG	26	-
Total	$326	$2,739

Sale of Receivables – AEP Credit

AEP Credit has a sale of receivables agreement with banks and commercial paper conduits. Under the sale of receivables agreement, AEP Credit sells an interest in the receivables it acquires to the commercial paper conduits and banks and receives cash. This transaction constitutes a sale of receivables in accordance with SFAS 140, allowing the receivables to be taken off of AEP Credit's balance sheet and allowing AEP Credit to repay any debt obligations. AEP has no ownership interest in the commercial paper conduits and does not consolidate these entities in accordance with GAAP. We continue to service the receivables. This off-balance sheet transaction was entered into to allow AEP Credit to repay its outstanding debt obligations, continue to purchase the AEP operating companies' receivables, and accelerate its cash collections.

AEP Credit extended its sale of receivables agreement to July 25, 2003 from its May 28, 2003 expiration date. The agreement was then renewed for an additional 364 days and now expires on July 23, 2004. This new agreement provides commitments of $600 million to purchase receivables from AEP Credit. At December 31, 2003, $385 million was outstanding. As collections from receivables sold occur and are remitted, the outstanding balance for sold receivables is reduced and as new receivables are sold, the outstanding balance of sold receivables increases. All of the receivables sold represented affiliate receivables. AEP Credit maintains a retained interest in the receivables sold and this interest is pledged as collateral for the collection of the receivables sold. The fair value of the retained interest is based on book value due to the short-term nature of the accounts receivable less an allowance for anticipated uncollectible accounts.

AEP Credit purchases accounts receivable through purchase agreements with certain registrant subsidiaries and, until the first quarter of 2002, with non-affiliated companies. These subsidiaries include CSPCo, I&M, KPCo, OPCo, PSO, SWEPCo and a portion of APCo. Since APCo does not have regulatory authority to sell accounts receivable in all of its regulatory jurisdictions, only a portion of APCo's accounts receivable are sold to AEP Credit. As a result of the restructuring of electric utilities in the State of Texas, the purchase agreement between AEP Credit and Reliant Energy, Incorporated was terminated as of January 25, 2002 and the purchase agreement between AEP Credit and Texas-New Mexico Power Company, the last remaining non-affiliated company, was terminated on February 7, 2002. In addition, the purchase agreements between AEP Credit and its Texas affiliates, AEP Texas Central Company (formerly Central Power and Light Company) and AEP Texas North Company (formerly West Texas Utilities Company) were terminated effective March 20, 2002.

Comparative accounts receivable information for AEP Credit:

	Year Ended December 31, 2003	2002
	(in millions)	
Proceeds from Sale of Accounts Receivable	$5,221	$5,513
Accounts Receivable Retained Interest Less Uncollectible Accounts and Amounts Pledged as Collateral	124	76
Deferred Revenue from Servicing Accounts Receivable	1	1
Loss on Sale of Accounts Receivable	7	4
Average Variable Discount Rate	1.33%	1.92%
Retained Interest if 10% Adverse Change in Uncollectible Accounts	122	74
Retained Interest if 20% Adverse Change in Uncollectible Accounts	121	72

Historical loss and delinquency amount for the AEP System's customer accounts receivable managed portfolio:

	Face Value Year Ended December 31, 2003	2002
	(in millions)	
Customer Accounts Receivable Retained	$1,155	$1,553
Accrued Unbilled Revenues Retained	596	551
Miscellaneous Accounts Receivable Retained	83	93
Allowance for Uncollectible Accounts Retained	(124)	(108)
Total Net Balance Sheet Accounts Receivable	1,710	2,089
Customer Accounts Receivable Securitized (Affiliate)	385	454
Total Accounts Receivable Managed	$2,095	$2,543
Net Uncollectible Accounts Written Off	$39	$48

Customer accounts receivable retained and securitized for the domestic electric operating companies are managed by AEP Credit. Miscellaneous accounts receivable have been fully retained and not securitized.

At December 31, 2003, delinquent customer accounts receivable for the electric utility affiliates that AEP Credit currently factors was $30 million.

Under the factoring arrangement, participating registrant subsidiaries sell, without recourse, certain of their customer accounts receivable and accrued unbilled revenue balances to AEP Credit and are charged a fee based on AEP Credit financing costs, uncollectible accounts experience for each company's receivables and administrative costs. The costs of factoring customer accounts receivable are reported as an operating expense. The amount of factored accounts receivable and accrued unbilled revenues for each registrant subsidiary was as follows:

	December 31,	
	2003	2002
	(in millions)	
APCo	$60.2	$67.6
CSPCo	100.2	114.3
I&M	93.0	103.7
KPCo	30.4	29.5
OPCo	99.3	109.8
PSO	99.6	83.7
SWEPCo	64.4	65.2

The fees paid by the registrant subsidiaries to AEP Credit for factoring customer accounts receivable were:

	Year Ended December 31,		
	2003	2002	2001
		(in millions)	
APCo	$3.4	$ 4.8	$ 5.2
CSPCo	9.8	15.8	15.2
I&M	6.1	7.4	8.5
KPCo	2.4	2.7	2.7
OPCo	8.7	11.4	12.8
PSO	5.8	7.2	9.6
SWEPCo	4.9	5.4	7.4
TCC	-	2.2	14.7
TNC	-	1.4	3.8

17. RELATED PARTY TRANSACTIONS

AEP System Power Pool

APCo, CSPCo, I&M, KPCo and OPCo are parties to the Interconnection Agreement, dated July 6, 1951, as amended (the Interconnection Agreement), defining how they share the costs and benefits associated with their generating plants. This sharing is based upon each company's "member-load-ratio," which is calculated monthly on the basis of each company's maximum peak demand in relation to the sum of the maximum peak demands of all five companies during the preceding 12 months. In addition, since 1995, APCo, CSPCo, I&M, KPCo and OPCo have been parties to the AEP System Interim Allowance Agreement which provides, among other things, for the transfer of SO2 Allowances associated with transactions under the Interconnection Agreement. As part of AEP's restructuring settlement agreement filed with FERC, under certain conditions CSPCo and OPCo would no longer be parties to the Interconnection Agreement and certain other modifications to its terms would also be made.

Power and Gas and risk management activities are conducted by the AEP Power Pool and shared among the parties under the System Integration Agreement. Risk management activities involve the purchase and sale of electricity and gas under physical forward contracts at fixed and variable prices and the risk management of electricity and to a lesser extent gas contracts including exchange traded futures and options and over-the-counter options and swaps. The majority of these transactions represent physical forward contracts in the AEP System's traditional marketing area and are typically settled by entering into offsetting contracts. In addition, the AEP Power Pool enters into transactions for the purchase and sale of electricity and gas options, futures and swaps, and for the forward purchase and sale of electricity outside of the AEP System's traditional marketing area.

AEP West Companies

PSO, SWEPCo, TCC, TNC operating companies of the west zone and AEPSC are parties to a Restated and Amended Operating Agreement originally dated as of January 1, 1997 (CSW Operating Agreement). The CSW Operating Agreement requires the AEP West operating companies to maintain specified annual planning reserve margins and requires the operating companies that have capacity in excess of the required margins to make such capacity available for sale to other operating companies as capacity commitments. The CSW Operating Agreement also delegates to AEPSC the authority to coordinate the acquisition, disposition, planning, design and construction of generating units and to supervise the operation and maintenance of a central control center. As part of AEP's restructuring settlement agreement filed with the FERC, under certain conditions TCC and TNC would no longer be parties to the CSW Operating Agreement.

AEP's System Integration Agreement provides for the integration and coordination of AEP's east and west zone operating subsidiaries, joint dispatch of generation within the AEP System, and the distribution, between the two operating zones, of costs and benefits associated with the System's generating plants. It is designed to function as an umbrella agreement in addition to the AEP Interconnection Agreement and the CSW Operating Agreement, each of which will continue to control the distribution of costs and benefits within each zone.

The following table shows the revenues derived from sales to the pools and direct sales to affiliates for years ended December 31, 2003, 2002 and 2001:

Related Party Revenues		APCo	CSPCo	I&M (in thousands)	KPCo	OPCo	AEGCo
2003	Sales to East System Pool	$130,921	$59,113	$228,667	$32,827	$503,334	$-
	Sales to West System Pool	27	9	17	6	21	-
	Direct Sales To East Affiliates	60,638	-	-	-	50,764	232,955
	Direct Sales To West Affiliates	27,951	16,428	17,674	6,425	21,759	-
	Other	3,256	8,819	2,845	550	8,400	-
	Total Revenues	$222,793	$84,369	$249,203	$39,808	$584,278	$232,955
2002	Sales to East System Pool	$106,651	$42,986	$197,525	$22,369	$397,248	$-
	Sales to West System Pool	18,300	12,107	13,036	4,717	16,265	-
	Direct Sales To East Affiliates	58,213	-	-	-	50,599	213,071
	Direct Sales To West Affiliates	-	-	-	-	-	-
	Other	3,313	2,109	3,577	878	1,090	-
	Total Revenues	$186,477	$57,202	$214,138	$27,964	$465,202	$213,071
2001	Sales to East System Pool	$91,977	$44,185	$239,277	$34,735	$431,637	$-
	Sales to West System Pool	24,892	13,971	15,596	6,117	19,797	-
	Direct Sales To East Affiliates	54,777	-	-	-	55,450	227,338
	Direct Sales To West Affiliates	(3,133)	(1,705)	(1,905)	(744)	(2,590)	-
	Other	2,772	11,060	2,071	2,258	7,072	-
	Total Revenues	$171,285	$67,511	$255,039	$42,366	$511,366	$227,338

Related Party Revenues		PSO	SWEPCo	TCC	TNC
			(in thousands)		
2003	Sales to East System Pool	$-	$-	$-	$-
	Sales to West System Pool	793	600	15,157	651
	Direct Sales To East Affiliates	1,159	706	677	6
	Direct Sales To West Affiliates	17,855	64,802	23,248	1,929
	Other	3,323	2,746	114,486	52,567
	Total Revenues	$23,130	$68,854	$153,568	$55,153
2002	Sales to East System Pool	$-	$-	$-	$-
	Sales to West System Pool	674	1,334	18,416	1,280
	Direct Sales To East Affiliates	611	270	366	(23)
	Direct Sales To West Affiliates	6,047	75,674	956,751	228,404
	Other	2,107	(4,979)	32,911	10,764
	Total Revenues	$9,439	$72,299	$1,008,444	$240,425
2001	Sales to East System Pool	$4	$-	$-	$-
	Sales to West System Pool	3,317	8,073	19,865	322
	Direct Sales To East Affiliates	2,833	3,238	3,697	1,228
	Direct Sales To West Affiliates	30,668	67,930	12,617	9,350
	Other	(51)	(4)	5,583	7,781
	Total Revenues	$36,771	$79,237	$41,762	$18,681

The following table shows the purchased power expense incurred from purchases from the pools and affiliates for the years ended December 31, 2003, 2002, and 2001:

Related Party Purchases		APCo	CSPCo	I&M	KPCo	OPCo
				(in thousands)		
2003	Purchases from East System Pool	$348,899	$335,916	$109,826	$71,259	$88,962
	Purchases from West System Pool	-	-	-	-	-
	Direct Purchases from East Affiliates	1,546	936	164,069	70,249	1,234
	Direct Purchases from West Affiliates	765	471	505	182	625
	Total Purchases	$351,210	$337,323	$274,400	$141,690	$90,821
2002	Purchases from East System Pool	$233,677	$309,999	$83,918	$68,846	$70,338
	Purchases from West System Pool	337	219	237	86	297
	Direct Purchases from East Affiliates	583	387	149,569	64,070	519
	Direct Purchases from West Affiliates	-	-	-	-	-
	Total Purchases	$234,597	$310,605	$233,724	$133,002	$71,154
2001	Purchases from East System Pool	$346,582	$292,034	$79,030	$61,816	$62,350
	Purchases from West System Pool	296	165	185	72	235
	Direct Purchases from East Affiliates	-	-	159,022	68,316	-
	Direct Purchases from West Affiliates	-	-	-	-	-
	Total Purchases	$346,878	$292,199	$238,237	$130,204	$62,585

Related Party Purchases		PSO	SWEPCo	TCC	TNC
			(in thousands)		
2003	Purchases from East System Pool	$639	$-	$-	$-
	Purchases from West System Pool	704	741	289	15,467
	Direct Purchases from East Affiliates	46,384	28,376	10,238	4,677
	Direct Purchases from West Affiliates	61,912	18,087	8,570	19,265
	Other	-	710	-	-
	Total Purchases	$109,639	$47,914	$19,097	$39,409
2002	Purchases from East System Pool	$343	$-	$-	$-
	Purchases from West System Pool	874	(456)	1,366	15,475
	Direct Purchases from East Affiliates	29,029	17,242	8,236	2,669
	Direct Purchases from West Affiliates	59,208	25,236	13,804	19,438
	Total Purchases	$89,454	$42,022	$23,406	$37,582
2001	Purchases from East System Pool	$1,327	$-	$-	$4
	Purchases from West System Pool	5,877	3,810	415	11,689
	Direct Purchases from East Affiliates	1,951	2,352	12,657	4,614
	Direct Purchases from West Affiliates	34,603	9,696	45,569	40,349
	Total Purchases	$43,758	$15,858	$58,641	$56,656

The above summarized related party revenues and expenses are reported in their entirety, without elimination, and are presented as operating revenues affiliated and purchased power affiliated on the statements of operations of each AEP Power Pool member. Since all of the above pool members are included in AEP's consolidated results, the above summarized related party transactions are eliminated in total in AEP's consolidated revenues and expenses.

AEP System Transmission Pool

APCo, CSPCo, I&M, KPCo and OPCo are parties to the Transmission Agreement, dated April 1, 1984, as amended (the Transmission Agreement), defining how they share the costs associated with their relative ownership of the extra-high-voltage transmission system (facilities rated 345 kV and above) and certain facilities operated at lower voltages (138 kV and above). Like the Interconnection Agreement, this sharing is based upon each company's "member-load-ratio."

The following table shows the net (credits) or charges allocated among the parties to the Transmission Agreement during the years ended December 31, 2003, 2002 and 2001:

	2003	2002	2001
		(in thousands)	
APCo	$-	$(13,400)	$(3,100)
CSPCo	38,200	42,200	40,200
I&M	(39,800)	(36,100)	(41,300)
KPCo	(5,600)	(5,400)	(4,600)
OPCo	7,200	12,700	8,800

PSO, SWEPCo, TCC, TNC and AEPSC are parties to a Transmission Coordination Agreement originally dated as of January 1, 1997 (TCA). The TCA established a coordinating committee, which is charged with the responsibility of overseeing the coordinated planning of the transmission facilities of the west zone operating subsidiaries, including the performance of transmission planning studies, the interaction of such subsidiaries with independent system operators (ISO) and other regional bodies interested in transmission planning and compliance with the terms of the Open Access Transmission Tariff (OATT) filed with the FERC and the rules of the FERC relating to such tariff.

Under the TCA, the west zone operating subsidiaries have delegated to AEPSC the responsibility of monitoring the reliability of their transmission systems and administering the OATT on their behalf. The TCA also provides for the allocation among the west zone operating subsidiaries of revenues collected for transmission and ancillary services provided under the OATT.

The following table shows the net (credits) or charges allocated among parties to the Transmission Agreement during the years ended December 31, 2003, 2002 and 2001:

	2003	2002	2001
		(in thousands)	
PSO	$4,200	$4,200	$4,000
SWEPCo	5,000	5,000	5,400
TCC	(3,600)	(3,600)	(3,900)
TNC	(5,600)	(5,600)	(5,500)

AEP's System Transmission Integration Agreement provides for the integration and coordination of the planning, operation and maintenance of the transmission facilities of AEP's east and west zone operating subsidiaries. Like the System Integration Agreement, the System Transmission Integration Agreement functions as an umbrella agreement in addition to the AEP Transmission Agreement and the Transmission Coordination Agreement. The System Transmission Integration Agreement contains two service schedules that govern:

- The allocation of transmission costs and revenues
- The allocation of third-party transmission costs and revenues and System dispatch costs

The Transmission Integration Agreement anticipates that additional service schedules may be added as circumstances warrant.

AEP Coal, Inc.

AEP Coal, Inc. and CSPCo are parties to a 2003 coal purchase agreement, dated October 15, 2002. The agreement provides for the sale of up to 960,000 tons of coal mined by AEP Coal to be delivered (at CSP's expense) to the Conesville Plant for a price ranging from $23.15 per ton to $26.15 per ton plus quality adjustments. In 2002, AEP Coal, Inc. and CSPCo were parties to a 2002 coal purchase agreement, dated February 1, 2002. The agreement provided for the sale of up to 785,000 tons of coal mined by AEP Coal to be delivered (at CSP's expense) to the Conesville Plant for a price ranging from $24.00 per ton to $27.00 per ton plus quality adjustments. During 2003 and 2002, AEP Coal derived revenues from sales to CSPCo of $23.9 million and $21 million, respectively.

AEP Coal, Inc. and CSPCo are parties to a 1998 coal transloading agreement, dated June 12, 1998. Pursuant to the agreement, AEP Coal transfers coal from railcars into trucks at AEP Coal's Muskie Transloading Facility and delivers the coal via trucks to CSPCo's Conesville Preparation Plant or CSPCo's Power Plant for a rate of $1.25 per ton and $1.03 per ton, respectively. During 2003 and 2002, AEP Coal derived revenues from sales to CSPCo of $3.4 million and $3.5 million, respectively.

AEP East Companies

Effective October 31, 2003, AEPES assigned to AEPSC, as agent for the AEP East operating companies, approximately $97 million (negative value) associated with its natural gas contracts with DETM. The assignment was executed in order to consolidate DETM positions within AEP. Concurrently, in order to ensure that there would be no financial impact to the operating companies as a result of the assignment, AEPES and AEPSC entered into agreements requiring AEPES to reimburse AEPSC for any related cash settlements and all income related to the assigned contracts. There is no impact to the AEP consolidated financial statements. The following table represents registrant subsidiary liabilities at December 31, 2003 in thousands:

APCo	$(32,287)
CSPCo	(18,185)
I&M	(19,932)
KPCo	(7,349)
OPCo	(24,055)
Total	$(101,808)

Unit Power Agreements and Other

A unit power agreement between AEGCo and I&M (the I&M Power Agreement) provides for the sale by AEGCo to I&M of all the power (and the energy associated therewith) available to AEGCo at the Rockport Plant unless it is sold to another utility. I&M is obligated, whether or not power is available from AEGCo, to pay as a demand charge for the right to receive such power (and as an energy charge for any associated energy taken by I&M) such amounts, as when added to amounts received by AEGCo from any other sources, will be at least sufficient to enable AEGCo to pay all its operating and other expenses, including a rate of return on the common equity of AEGCo as approved by FERC. The I&M Power Agreement will continue in effect until the expiration of the lease term of Unit 2 of the Rockport Plant unless extended in specified circumstances.

Pursuant to an assignment between I&M and KPCo, and a unit power agreement between KPCo and AEGCo, AEGCo sells KPCo 30% of the power (and the energy associated therewith) available to AEGCo from both units of the Rockport Plant. KPCo has agreed to pay to AEGCo in consideration for the right to receive such power the same amounts which I&M would have paid AEGCo under the terms of the I&M Power Agreement for such entitlement. The KPCo unit power agreement expires on December 31, 2004.

APCo and OPCo, jointly own two power plants. The costs of operating these facilities are apportioned between the owners based on ownership interests. Each company's share of these costs is included in the appropriate expense accounts on each company's consolidated statements of income. Each company's investment in these plants is included in electric utility plant on its consolidated balance sheets.

I&M provides barging and other transportation services to affiliates. I&M records revenues from barging services as nonoperating income. The affiliates record costs paid to I&M for barging services as fuel expense or operation expense. The amount of affiliated revenues and affiliated expenses were:

	Year Ended December 31,		
	2003	**2002**	**2001**
Company		**(in millions)**	
I&M – revenues	$31.9	$34.3	$30.2
AEGCo – expense	8.1	7.8	8.5
APCo – expense	12.3	12.8	11.5
KEPCo – expense	0.1	-	-
OPCo – expense	4.3	7.9	10.2
MEMCo – expense (Non-Utility subsidiary of AEP)	7.1	5.7	-
AEP Energy Services (Non-Utility subsidiary of AEP)	-	0.1	-

In conjunction with a 500 MW agreement between OPCo and National Power Cooperative, Inc (NPC), AEPES entered into a fuel management agreement with those two parties to manage and procure fuel needs for the plant, which is owned by NPC. The plant went into service in July 2002. Because APCo, CSPCo, I&M, KPCo and OPCo purchase 100% of the available generating capacity from the plant, they also share in paying fuel expense to AEPES. The related purchases from AEPES were as follows:

	Year Ended December 31,	
	2003	2002
	(in thousands)	
KPCo	$363	$150
I&M	1,000	418
CSPCo	936	387
OPCo	1,234	519
APCo	1,546	583
Total	$5,079	$2,057

There was no activity in 2001.

HPL purchases physical gas in the spot market, which in turn, is sold to certain operating companies at cost for their fuel requirements. The related sales are as follows:

	Year Ended December 31,	
	2003	2002
	(in thousands)	
TCC	$195,527	$157,346
TNC	44,197	64,385

There was no activity in 2001.

AEPSC provides certain managerial and professional services to AEP System companies. The costs of the services are billed to its affiliated companies by AEPSC on a direct-charge basis, whenever possible, and on reasonable bases of proration for shared services. The billings for services are made at cost and include no compensation for the use of equity capital, which is furnished to AEPSC by AEP Co., Inc. Billings from AEPSC are capitalized or expensed depending on the nature of the services rendered. AEPSC and its billings are subject to the regulation of the SEC under the PUHCA.

18. JOINTLY OWNED ELECTRIC UTILITY PLANT

CSPCo, PSO, SWEPCo, TCC and TNC have generating units that are jointly owned with affiliated and unaffiliated companies. Each of the participating companies is obligated to pay its share of the costs of any such jointly owned facilities in the same proportion as its ownership interest. Each AEP registrant subsidiary's proportionate share of the operating costs associated with such facilities is included in its statements of operations and the investments are reflected in its balance sheets under utility plant as follows:

		Company's Share December 31,			
		2003		2002	
	Percent of Ownership	Utility Plant in Service	Construction Work in Progress	Utility Plant in Service	Construction Work in Progress
		(in thousands)		(in thousands)	
CSPCo					
W.C. Beckjord Generating Station (Unit No. 6)	12.5	$15,455	$127	$15,487	$49
Conesville Generating Station (Unit No. 4)	43.5	82,115	722	81,960	279
J.M. Stuart Generating Station	26.0	204,820	50,326	197,276	44,865
Wm. H. Zimmer Generating Station	25.4	707,281	31,249	705,620	14,077
Transmission	(a)	62,061	742	61,187	2,281
Total		$1,071,732	$83,166	$1,061,530	$61,551
PSO					
Oklaunion Generating Station (Unit No. 1)	15.6	$85,064	$518	$83,562	$777
SWEPCo					
Dolet Hills Generating Station (Unit No. 1)	40.2	$236,116	$2,304	$235,366	$1,313
Flint Creek Generating Station (Unit No. 1)	50.0	93,309	737	91,567	1,052
Pirkey Generating Station (Unit No. 1)	85.9	454,303	3,125	451,136	2,197
Total		$783,728	$6,166	$778,069	$4,562
TCC (b)					
Oklaunion Generating Station (Unit No. 1)	7.8	$38,798	$252	$38,055	$369
South Texas Project Generation Station (Units No. 1 and 2)	25.2	2,386,579	934	2,364,359	43,887
Total		$2,425,377	$1,186	$2,402,414	$44,256
TNC					
Oklaunion Generating Station (Unit No. 1)	54.7	$285,314	$1,351	$277,946	$3,650

(a) Varying percentages of ownership.
(b) Included in Assets Held for Sale - Texas Generation Plants on TCC's Consolidated Balance Sheets.

The accumulated depreciation with respect to each AEP registrant subsidiary's share of jointly owned facilities is shown below:

	December 31, 2003	December 31, 2002
	(in thousands)	
CSPCo	$435,249	$436,683
PSO	50,968	49,085
SWEPCo	465,871	450,057
TCC (a)	991,665	927,193
TNC	103,642	102,542

(a) Included in Assets Held for Sale - Texas Generation Plants on TCC's Consolidated Balance Sheets.

19. UNAUDITED QUARTERLY FINANCIAL INFORMATION

The unaudited quarterly financial information for each AEP registrant subsidiary follows:

Quarterly Periods Ended	AEGCo	APCo	CSPCo	I&M	KPCo
		(in thousands)			
March 31, 2003					
Operating Revenues	$60,428	$536,228	$359,205	$418,598	$112,094
Operating Income	1,851	112,684	55,151	58,990	19,834
Income Before Extraordinary Items and Cumulative Effect of Accounting Changes	1,796	79,153	38,359	30,687	11,021
Net Income	1,796	156,410	65,642	27,527	9,887
June 30, 2003					
Operating Revenues	$59,568	$444,751	$333,071	$376,906	$95,464
Operating Income	1,514	49,056	43,417	19,229	10,964
Income (Loss) Before Extraordinary Items and Cumulative Effect of Accounting Changes	1,768	14,636	29,331	(1,191)	4,095
Net Income (Loss)	1,768	14,636	29,331	(1,191)	4,095
September 30, 2003					
Operating Revenues	$59,008	$483,611	$397,655	$423,004	$103,693
Operating Income	1,809	67,134	71,193	56,242	13,097
Income Before Extraordinary Items and Cumulative Effect of Accounting Changes	2,021	45,715	62,825	37,116	6,501
Net Income	2,021	45,715	62,825	37,116	6,501
December 31, 2003					
Operating Revenues	$54,161	$492,768	$341,920	$377,088	$105,219
Operating Income	2,000	89,937	55,725	51,606	20,849
Income Before Extraordinary Items and Cumulative Effect of Accounting Changes	2,379	63,279	42,632	22,936	11,847
Net Income	2,379	63,279	42,632	22,936	11,847

Quarterly Periods Ended	OPCo	PSO	SWEPCo	TCC	TNC
			(in thousands)		
March 31, 2003					
Operating Revenues	$590,631	$242,662	$255,278	$428,358	$116,262
Operating Income	98,870	13,146	26,044	92,010	9,865
Income Before Extraordinary Items and Cumulative Effect of Accounting Changes	68,350	691	10,491	64,437	6,765
Net Income	192,982	691	19,008	64,559	9,836
June 30, 2003					
Operating Revenues	$539,386	$277,236	$281,306	$482,446	$136,806
Operating Income	79,831	28,715	35,588	96,603	23,243
Income Before Extraordinary Items and Cumulative Effect of Accounting Changes	56,277	17,927	20,590	63,587	17,922
Net Income	56,277	17,927	20,590	63,587	17,922
September 30, 2003					
Operating Revenues	$565,318	$358,575	$361,622	$485,129	$114,455
Operating Income	93,798	43,527	59,229	84,502	17,419
Income Before Extraordinary Items and Cumulative Effect of Accounting Changes	70,367	38,090	42,181	66,221	17,347
Net Income	70,367	38,090	42,181	66,221	17,347
December 31, 2003					
Operating Revenues	$549,318	$224,349	$248,636	$351,578	$98,423
Operating Income	87,168	7,475	29,275	48,425	17,500
Income (Loss) Before Extraordinary Items and Cumulative Effect of Accounting Changes	56,037	(2,817)	16,362	23,302	13,629
Net Income (Loss)	56,037	(2,817)	16,362	23,302	13,452

Quarterly Periods Ended	AEGCo	APCo	CSPCo	I&M	KPCo
			(in thousands)		
March 31, 2002					
Operating Revenues	$49,875	$462,605	$314,826	$352,235	$99,185
Operating Income	1,767	81,554	45,548	30,363	15,484
Income Before Extraordinary Items and Cumulative Effect of Accounting Changes	1,893	55,341	33,858	11,058	10,246
Net Income	1,893	55,341	33,858	11,058	10,246
June 30, 2002					
Operating Revenues	$53,356	$432,015	$343,813	$369,043	$92,164
Operating Income	1,504	65,224	58,040	19,865	9,550
Income Before Extraordinary Items and Cumulative Effect of Accounting Changes	1,718	46,608	51,721	7,494	5,246
Net Income	1,718	46,608	51,721	7,494	5,246
September 30, 2002					
Operating Revenues	$55,988	$464,409	$421,892	$414,414	$97,811
Operating Income	1,436	81,365	89,033	57,004	11,119
Income Before Extraordinary Items and Cumulative Effect of Accounting Changes	1,947	53,947	76,117	35,312	5,994
Net Income	1,947	53,947	76,117	35,312	5,994
December 31, 2002					
Operating Revenues	$54,062	$455,441	$319,629	$391,072	$89,523
Operating Income	1,422	73,920	27,158	43,957	6,044
Income (Loss) Before Extraordinary Items and Cumulative Effect of Accounting Changes	1,994	49,596	19,477	20,128	(919)
Net Income (Loss)	1,994	49,596	19,477	20,128	(919)

Quarterly Periods Ended	OPCo	PSO	SWEPCo	TCC	TNC
		(in thousands)			
March 31, 2002					
Operating Revenues	$520,652	$148,986	$222,259	$278,910	$103,626
Operating Income	83,716	8,410	22,469	55,445	11,145
Income (Loss) Before Extraordinary Items and Cumulative Effect of Accounting Changes	64,051	(1,648)	8,159	24,445	3,992
Net Income (Loss)	64,051	(1,648)	8,159	24,445	3,992
June 30, 2002					
Operating Revenues	$521,365	$158,330	$263,074	$360,391	$104,452
Operating Income	61,046	20,201	31,988	64,319	5,547
Income Before Extraordinary Items and Cumulative Effect of Accounting Changes	55,348	11,620	18,155	33,535	675
Net Income	55,348	11,620	18,155	33,535	675
September 30, 2002					
Operating Revenues	$557,574	$230,098	$362,423	$546,260	$152,667
Operating Income (Loss)	97,210	50,710	60,254	118,204	(308)
Income (Loss) Before Extraordinary Items and Cumulative Effect of Accounting Changes	80,258	41,002	45,794	93,383	(4,193)
Net Income (Loss)	80,258	41,002	45,794	93,383	(4,193)
December 31, 2002					
Operating Revenues	$513,534	$256,233	$236,964	$504,932	$89,995
Operating Income (Loss)	56,357	5,400	27,758	155,765	(8,513)
Income (Loss) Before Extraordinary Items and Cumulative Effect of Accounting Changes	20,366	(9,914)	10,884	124,578	(14,151)
Net Income (Loss)	20,366	(9,914)	10,884	124,578	(14,151)

For each of the AEP registrant subsidiaries, there were no significant, non-recurring events in the fourth quarter of 2003 or 2002.

20. SUBSEQUENT EVENTS (UNAUDITED)

After December 31, 2003 we entered into separate agreements to dispose of the following investments:

Investment	Sales Price (in millions)	Date of Agreement
Oklaunion Power Station (TCC's 7.8% ownership interest)	$42.8	January 30, 2004
STP (TCC's 25.2% ownership interest)	$332.6	February 27, 2004

We anticipate these sales to be completed during 2004 and that the impact on results of operations will not be significant.

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REGISTRANTS' COMBINED MANAGEMENT'S DISCUSSION AND ANALYSIS

The following is a combined presentation of certain components of the registrants' management's discussion and analysis. The information in this section completes the information necessary for management's discussion and analysis of financial condition and results of operations and is meant to be read with (i) Management's Financial Discussion and Analysis, (ii) financial statements, (iii) footnotes and (iv) the schedules of each individual registrant.

Source of Funding

Short-term funding for AEP's electric subsidiaries comes from AEP's commercial paper program and revolving credit facilities. Proceeds are loaned to the subsidiaries through intercompany notes. AEP and its subsidiaries also operate a money pool to minimize the AEP System's external short-term funding requirements and sell accounts receivable to provide liquidity for certain electric subsidiaries. The electric subsidiaries generally use short-term funding sources (the money pool or receivables sales) to provide for interim financing of capital expenditures that exceed internally generated funds and periodically reduce their outstanding short-term debt through issuances of long-term debt, sale-leaseback, leasing arrangements and additional capital contributions from their parent company.

Sale of Receivables Through AEP Credit

AEP Credit has a sale of receivables agreement with banks and commercial paper conduits. Under the sale of receivables agreement, AEP Credit sells an interest in the receivables it acquires to the commercial paper conduits and banks and receives cash. This transaction constitutes a sale of receivables in accordance with SFAS 140, allowing the receivables to be removed from of AEP Credit's balance sheet and allowing AEP Credit to repay any debt obligations. AEP has no ownership interest in the commercial paper conduits and does not consolidate these entities in accordance with GAAP. The electric subsidiaries continue to service the receivables. This off-balance sheet transaction was entered into to allow AEP Credit to repay its outstanding debt obligations, continue to purchase the AEP operating companies' receivables, and accelerate its cash collections.

AEP Credit extended its sale of receivables agreement to July 25, 2003 from its May 28, 2003 expiration date. The agreement was then renewed for an additional 364 days and now expires on July 23, 2004. This new agreement provides commitments of $600 million to purchase receivables from AEP Credit. At December 31, 2003, $385 million was outstanding. As collections from receivables sold occur and are remitted, the outstanding balance for sold receivables is reduced and as new receivables are sold, the outstanding balance of sold receivables increases. All of the receivables sold represented affiliate receivables. AEP Credit maintains a retained interest in the receivables sold and this interest is pledged as collateral for the collection of the receivables sold. The fair value of the retained interest is based on book value due to the short-term nature of the accounts receivable less an allowance for anticipated uncollectible accounts.

AEP Credit purchases accounts receivable through purchase agreements with certain registrant subsidiaries. These subsidiaries include CSPCo, I&M, KPCo, OPCo, PSO, SWEPCo and a portion of APCo. Since APCo does not have regulatory authority to sell accounts receivable in all of its regulatory jurisdictions, only a portion of APCo's accounts receivable are sold to AEP Credit. In addition, the purchase agreements between AEP Credit and TCC and TNC were terminated effective March 20, 2002.

Budgeted Construction Expenditures

Construction expenditures for certain registrant subsidiaries for the next three years are:

	Projected Construction Expenditures (in millions)	Construction Expenditures Financed With Internal Funds
APCo	$1,307	70%
I&M	645	100
OPCo	1,686	60
SWEPCo	414	100
TCC	531	100

Significant Factors

Possible Divestitures

AEP's management is firmly committed to continually evaluating the need to reallocate resources to areas that effectively match investments with our business strategy, providing the greatest potential for financial returns and to disposing of investments that no longer meet these goals.

TCC is seeking to divest significant components of its non-regulated domestic generation assets. In June 2003, TCC began actively seeking buyers for 4,497 megawatts of its generating capacity in Texas. The value received from this disposition will also be used to calculate stranded costs in Texas (see Note 6). Management is currently evaluating bids received during the fourth quarter of 2003 and is in negotiations to sell these assets. See Note 10 for discussion of impairments recorded related to the generating units in Texas. The ultimate sale of these assets may have a material impact on results of operations, cash flows and financial condition if losses are not recovered through the 2004 true-up proceeding in Texas.

Management continues to have periodic discussions with various parties on business alternatives for certain other investments. The ultimate timing for a disposition of one or more of these assets will depend upon market conditions and the value of any buyer's proposal.

Corporate Separation

In compliance with certain provisions in the Texas and Ohio restructuring laws, AEP filed in 2001 for regulatory approvals related to efforts at that time to separate regulated and unregulated operations, and amend certain affiliate pooling arrangements. Although certain regulatory approvals have been obtained, with the changes in the regulatory environment and AEP's business strategy, management continues to evaluate corporate separation plans.

In Texas, TCC is in the process of divesting its generating assets in accordance with provisions of the Texas Legislation concerning stranded cost recovery (see Note 6). In order to sell these assets, TCC anticipates retiring first mortgage bonds by making open market purchases or defeasing the bonds. Once such generating assets are sold, which management expect to be finalized in 2004, TCC will effectively accomplish the structural separation requirements of the Texas Legislation for those assets.

In Ohio, the PUCO has encouraged utilities to file rate stabilization plans to provide rate certainty and stability for customers who do not choose alternative suppliers, for the period of January 1, 2006 through December 31, 2008, which is after the expiration of the current market development period. On February 9, 2004, CSPCo and OPCo filed such a rate stabilization plan with the PUCO. The plan, in part, provides that both CSPCo and OPCo will remain functionally separated. Approval of the rate stabilization plan is currently pending before the PUCO.

Unless otherwise directed by the PUCO in an order on the rate stabilization plan, CSPCo and OPCo will remain functionally separated through at least the end of the rate stabilization plan period, December 31, 2008, and therefore, are not planning to legally separate, or to change the affiliate pooling agreement for the AEP East companies, in the foreseeable future.

Management continues to evaluate the most appropriate approach for complying with the Texas Legislation's structural separation requirements for TNC, including appropriate regulatory approvals to implement its structural separation.

RTO Formation

The FERC's AEP-CSW merger approval and many of the settlement agreements with the state regulatory commissions to approve the AEP-CSW merger required the transfer of functional control of our subsidiaries' transmission systems to RTOs. Further, legislation in some of AEP's states requires RTO participation.

In May 2002, AEP announced an agreement with PJM to pursue terms for participation in its RTO for AEP East companies with final agreements to be negotiated. In July 2002, FERC issued an order accepting our decision to participate in PJM, subject to specified conditions. AEP and other parties continue to work on the resolution of those conditions.

In December 2002, AEP's subsidiaries that operate in the states of Indiana, Kentucky, Ohio and Virginia filed for state regulatory commission approval of their plans to transfer functional control of their transmission assets to PJM. Proceedings in Ohio remain pending.

In February 2003, the state of Virginia enacted legislation preventing APCo from joining an RTO prior to July 1, 2004 and thereafter only with the approval of the Virginia SCC, but required such transfers by January 1, 2005. In January 2004, APCo filed a cost/benefit study with the Virginia SCC covering the time period through 2014 as required by the Virginia SCC. The study results show a net benefit of approximately $98 million for APCo over the 11-year study period from AEP's participation in PJM.

In July 2003, the KPSC denied KPCo's request to join PJM based in part on a lack of evidence that it would benefit Kentucky retail customers. In December 2003, AEP filed with the KPSC a cost/benefit study showing a net benefit of approximately $13 million for KPCo over the five-year study period from AEP's participation in PJM. A hearing has been scheduled in April 2004.

In September 2003, the IURC issued an order approving I&M's transfer of functional control over its transmission facilities to PJM, subject to certain conditions included in the order. The IURC's order stated that AEP shall request and the IURC shall complete a review of Alliance formation costs before any deferral of the costs for future recovery.

In April 2003, FERC approved our transfer of functional control of the AEP East companies' transmission system to PJM. FERC also accepted our proposed rates for joining PJM, but set a number of rate issues for resolution through settlement proceedings or FERC hearings. Settlement discussions continue on certain rate matters.

On September 29 and 30, 2003, the FERC held a public inquiry regarding RTO formation, including delays in AEP's participation in PJM. In November 2003, the FERC issued an order preliminarily finding that AEP must fulfill its CSW merger commitment to join an RTO by fully integrating into PJM (transmission and markets) by October 1, 2004. The FERC set several issues for public hearing before an ALJ. Those issues include whether the laws, rules, or regulations of Virginia and Kentucky are preventing AEP from joining an RTO and whether the states' provisions meet either of the two exceptions under PURPA. The FERC directed the ALJ to issue his initial decision by March 15, 2004.

If AEP East companies do not obtain regulatory approval to join PJM, they are committed to reimburse PJM for certain project implementation costs (presently estimated at $24 million for AEP's share of the entire PJM integration project). These costs, if incurred, will be allocated to the AEP East companies. AEP East companies also plan to seek recovery of deferred RTO formation/integration costs in the future. At December 31, 2003, the deferred amounts per company are as follows:

Company	(in millions)
APCo	$7.8
CSPCo	3.3
I&M	6.0
KPCo	1.8
OPCo	8.6

See Note 4 for further discussion.

AEP West companies are members of ERCOT or SPP. In 2002, FERC conditionally accepted filings related to a proposed consolidation of MISO and SPP. State public utility commissions also regulate AEP's SPP companies. The Louisiana and Arkansas commissions filed responses to the FERC's RTO order indicating that additional analysis was required. Subsequently, the proposed SPP/MISO combination was terminated. On October 15, 2003, SPP filed a proposal at the FERC for recognition as an RTO. In February 2004, the FERC granted RTO status to the SPP, subject to fulfilling specified requirements. Regulatory activities concerning various RTO issues are ongoing in Arkansas and Louisiana.

Management is unable to predict the outcome of these regulatory actions and proceedings or their impact on transmission operations, results of operations and cash flows or the timing and operation of RTOs.

Pension Plans

AEP maintains qualified defined benefit pension plans (Qualified Plans), which cover a substantial majority of non-union and certain union associates, and unfunded excess plans to provide benefits in excess of amounts permitted to be paid under the provisions of the tax law to participants in the Qualified Plans. Additionally, AEP has entered into individual retirement agreements with certain current and retired executives that provide additional retirement benefits.

AEP's net periodic pension expense was an income item for all pension plans approximating $3 million and $44 million for the years ended December 31, 2003 and 2002, respectively, and is calculated based upon a number of actuarial assumptions, including an expected long-term rate of return on the Qualified Plans' assets. In 2002 and 2003, the long-term return was assumed to be 9.00%, and for 2004, the long-term rate of return was lowered to 8.75%. In developing the expected long-term rate of return assumption, AEP evaluated input from actuaries and investment consultants, including their reviews of asset class return expectations as well as long-term inflation assumptions. Projected returns by such actuaries and consultants are based on broad equity and bond indices. AEP also considered historical returns of the investment markets as well as the 10-year average return, for the period ended December 2003, of approximately 10.0%. AEP anticipates that the investment managers it employs for the pension fund will continue to generate long-term returns of at least 8.75%.

The expected long-term rate of return on the Qualified Plan's assets is based on AEP's targeted asset allocation and expected investment returns for each investment category. AEP's assumptions are summarized in the following table:

	2003 Actual Asset Allocation	2004 Target Asset Allocation	Assumed/Expected Long-term Rate of Return
		(in percentage)	
Equity	71	70	10.5
Fixed Income	27	28	5
Cash and Cash Equivalents	2	2	2
Total	100	100	
Overall Expected Return (weighted average)			8.75

AEP regularly reviews the actual asset allocation and periodically rebalances the investments to its targeted allocation when considered appropriate. AEP believes that 8.75% is a reasonable long-term rate of return on the Qualified Plans' assets despite the recent market volatility in which the Qualified Plans' assets had a loss of 11.2% for the twelve months ended December 31, 2002, and a gain of 23.8% for the twelve months ended December 31, 2003. AEP will continue to evaluate the actuarial assumptions, including the expected rate of return, at least annually, and will adjust them as necessary.

AEP bases its determination of pension expense or income on a market-related valuation of assets which reduces year-to-year volatility. This market-related valuation recognizes investment gains or losses over a five-year period from the year in which they occur. Investment gains or losses for this purpose are the difference between the expected return calculated using the market-related value of assets and the actual return based on the market-related value of assets. Since the market-related value of assets recognizes gains or losses over a five-year period, the future value of assets will be impacted as previously deferred gains or losses are recorded. As of December 31, 2003, AEP has cumulative losses of approximately $325 million which remain to be recognized in the calculation of the market-related value of assets. These unrecognized net actuarial losses result in increases in the future pension costs depending on several factors, including whether such losses at each measurement date exceed the corridor in accordance with SFAS No. 87, "Employers' Accounting for Pensions."

The discount rate that AEP utilizes for determining future pension obligations is based on a review of long-term bonds that receive one of the two highest ratings given by a recognized rating agency. The discount rate determined on this basis has decreased from 6.75% at December 31, 2002, to 6.25% at December 31, 2003. Due to the effect of the unrecognized actuarial losses and based on an expected rate of return on the Qualified Plans' assets of 8.75%, a discount rate of 6.25% and various other assumptions, AEP estimates that the pension expense for all pension plans will approximate $41 million, $78 million and $103 million in 2004, 2005 and 2006, respectively. Future actual pension cost will depend on future investment performance, changes in future discount rates and various other factors related to the populations participating in the pension plans.

Lowering the expected long-term rate of return on the Qualified Plans' assets by 0.5% (from 9.0% to 8.5%) would have increased pension cost for 2003 by approximately $18 million (income of $3 million would have become $15 million in pension expense). Lowering the discount rate by 0.5% would have reduced pension income for 2003 by approximately $0.5 million.

The value of the Qualified Plans' assets has increased from $2.795 billion at December 31, 2002 to $3.180 billion at December 31, 2003. The Qualified Plans paid out $292 million in benefits to plan participants during 2003 (the nonqualified plans paid out $7 million in benefits). AEP's pension plans remain in an underfunded position (plan assets are less than projected benefit obligations) of $508 million at December 31, 2003. Due to the pension plans currently being underfunded, AEP recorded a charge to Other Comprehensive Income (OCI) of $585 million in 2002, and recorded a Deferred Income Tax Asset of $315 million, offset by a Minimum Pension Liability of $662 million and a reduction to prepaid costs and adjustment for unrecognized costs of $238 million. In 2003, the income recorded in OCI was $154 million, and the reduction in the Deferred Income Tax Asset was $76 million, offset by a reduction in Minimum Pension Liability of $234 million and a reduction to adjustment for unrecognized costs of $4 million. The charge to OCI does not affect earnings or cash flow. AEP's plans are in compliance with the laws and regulations governing such plans including the Employee Retirement Income Security Act of 1974, as amended. Due to the current underfunded status of the Qualified Plans, AEP expects to make cash contributions to the pension plans of approximately $41 million in 2004.

Certain of the defined benefit pension plans AEP sponsors and maintains contain a cash balance benefit feature. In recent years, cash balance benefit features have become a focus of scrutiny, as government regulators and courts consider how the Employee Retirement Income Security Act of 1974, as amended, the Age Discrimination in Employment Act, as amended, and other relevant federal employment laws apply to plans with such a cash balance plan feature. AEP believes that the defined benefit pension plans it sponsors and maintains are in substantial compliance with the applicable requirements of such laws.

See Note 11 of the Notes to Respective Financial Statements for additional information related to the impact of pension plans on individual AEP registrant subsidiaries.

Nuclear Plant Outages

In April 2003, engineers at STP, during inspections conducted regularly as part of refueling outages, found wall cracks in two bottom mounted instrument guide tubes of STP Unit 1. These tubes were repaired and the unit returned to service in August 2003. TCC's share of the cost of repair for this outage was approximately $6 million. TCC had commitments to provide power to customers during the outage. Therefore, TCC was subject to fluctuations in the market prices of electricity and purchased replacement energy.

In April 2003, both units of Cook Plant were taken offline due to an influx of fish in the plant's cooling water system which caused a reduction in cooling water to essential plant equipment. After repair of damage caused by the fish intrusion, Cook Plant Unit 1 returned to service in May and Unit 2 returned to service in June following completion of a scheduled refueling outage.

Litigation

Federal EPA Complaint and Notice of Violation

See discussion of New Source Review Litigation under "Environmental Matters".

Enron Bankruptcy

On October 15, 2002, certain subsidiaries of AEP filed claims against Enron and its subsidiaries in the bankruptcy proceeding filed by the Enron entities which are pending in the U.S. Bankruptcy Court for the Southern District of New York. At the date of Enron's bankruptcy, certain subsidiaries of AEP had open trading contracts and trading accounts receivables and payables with Enron. In addition, on June 1, 2001, AEP purchased Houston Pipe Line Company (HPL) from Enron. Various HPL related contingencies and indemnities from Enron remained unsettled at the date of Enron's bankruptcy. The timing of the resolution of the claims by the Bankruptcy Court is not certain.

In September 2003, Enron filed a complaint in the Bankruptcy Court against AEPES challenging AEP's offsetting of receivables and payables and related collateral across various Enron entities and seeking payment of approximately $125 million plus interest in connection with gas related trading transactions. AEP will assert its right to offset trading payables owed to various Enron entities against trading receivables due to several AEP subsidiaries. Management is unable to predict the outcome of this lawsuit or its impact on results of operations, cash flows or financial condition.

In December 2003, Enron filed a complaint in the Bankruptcy Court against AEPSC seeking approximately $93 million plus interest in connection with a transaction for the sale and purchase of physical power among Enron, AEP and Allegheny Energy Supply, LLC during November 2001. Enron's claim seeks to unwind the effects of the transaction. AEP believes it has several defenses to the claims in the action being brought by Enron. Management is unable to predict the outcome of this lawsuit or its impact on results of operations, cash flows or financial condition.

During 2002 and 2001, AEP subsidiaries expensed a total of $53 million ($34 million net of tax) for their estimated loss from the Enron bankruptcy. The amounts for certain subsidiaries were:

Registrant	Amounts Expensed	Amounts Net of Tax
	(in millions)	
APCo	$5.3	$3.4
CSPCo	2.7	1.8
I&M	2.8	1.8
KPCo	1.1	0.7
OPCo	3.6	2.3

The amounts expensed were based on an analysis of contracts where AEP and Enron entities are counterparties, the offsetting of receivables and payables, the application of deposits from Enron entities and management's analysis of the HPL related purchase contingencies and indemnifications. As noted above, Enron has challenged the offsetting of receivables and payables. Management is unable to predict the final resolution of these disputes, however the impact on results of operations, cash flows and financial condition could be material.

Energy Market Investigations

AEP and other energy market participants received data requests, subpoenas and requests for information from the FERC, the SEC, the PUCT, the U.S. Commodity Futures Trading Commission (CFTC), the U.S. Department of Justice and the California attorney general during 2002. Management responded to the inquiries and provided the requested information and has continued to respond to supplemental data requests in 2003 and 2004.

In March 2003, AEP received a subpoena from the SEC as part of the SEC's ongoing investigation of energy trading activities. In August 2002, AEP received an informal data request from the SEC seeking that AEP voluntarily provide information. The subpoena sought additional information and is part of the SEC's formal investigation. AEP responded to the subpoena and will continue to cooperate with the SEC.

On September 30, 2003, the CFTC filed a complaint against AEP and AEPES in federal district court in Columbus, Ohio. The CFTC alleges that AEP and AEPES provided false or misleading information about market conditions and prices of natural gas in an attempt to manipulate the price of natural gas in violation of the Commodity Exchange Act. The CFTC seeks civil penalties, restitution and disgorgement of benefits. The case is in the initial pleading stage with our response to the complaint currently due on May 18, 2004. Although management is unable to predict the outcome of this case, AEP recorded a provision in 2003 and the action is not expected to have a material effect on results of operations.

In January 2004, the CFTC issued a request for documents and other information in connection with a CFTC investigation of activities affecting the price of natural gas in the fall of 2003. AEP is responding to that request.

Management cannot predict what, if any further action, any of these governmental agencies may take with respect to these matters.

TEM Litigation

See discussion of TEM litigation within OPCo's Management's Financial Discussion and Analysis.

Texas Commercial Energy, LLP Lawsuit

Texas Commercial Energy, LLP (TCE), a Texas REP, filed a lawsuit against AEP and four of its subsidiaries including TCC and TNC, certain unaffiliated energy companies and ERCOT alleging violations of the Sherman Antitrust Act, fraud, negligent misrepresentation, breach of fiduciary duty, breach of contract, civil conspiracy and negligence. The allegations, not all of which are made against the AEP companies, range from anticompetitive bidding to withholding power. TCE alleges that these activities resulted in price spikes requiring TCE to post additional collateral and ultimately forced it into bankruptcy when it was unable to raise prices to its customers due to fixed price contracts. The suit alleges over $500 million in damages for all defendants and seeks recovery of damages, exemplary damages and court costs. Management believes that the claims against AEP and its subsidiaries are without merit. Management intends to vigorously defend against the claims. See Note 7 for further discussion.

COLI Litigation

A decision by the U.S. District Court for the Southern District of Ohio in February 2001 that denied AEP's deduction of interest claimed on AEP's consolidated federal income tax returns related to a COLI program resulted in a $319 million reduction in AEP's Net Income for 2000.

The earnings reductions for affected registrant subsidiaries were as follows:

	(in millions)
APCo	$82
CSPCo	41
I&M	66
KPCo	8
OPCo	118

AEP filed an appeal of the U.S. District Court's decision with the U.S. Court of Appeals for the 6th Circuit. In April 2003, the Appeals Court ruled against AEP. The U.S. Supreme Court has declined to hear this issue.

Other Litigation

AEP subsidiaries are involved in a number of other legal proceedings and claims. While management is unable to predict the outcome of such litigation, it is not expected that the ultimate resolution of these matters will have a material adverse effect on results of operations, cash flows or financial condition.

Potential Uninsured Losses

Some potential losses or liabilities may not be insurable or the amount of insurance carried may not be sufficient to meet potential losses and liabilities, including, but not limited to, liabilities relating to damage to the Cook Plant or STP and costs of replacement power in the event of a nuclear incident at the Cook Plant or STP. Future losses or liabilities which are not completely insured, unless recovered from customers, could have a material adverse effect on results of operations, cash flows and financial condition.

Environmental Matters

There are new environmental control requirements that management expects will result in substantial capital investments and operational costs. The sources of these future requirements include:

- Legislative and regulatory proposals to adopt stringent controls on sulfur dioxide (SO_2), nitrogen oxide (NO_x) and mercury emissions from coal-fired power plants,

- New Clean Water Act rules to reduce the impacts of water intake structures on aquatic species at certain of our power plants, and
- Possible future requirements to reduce carbon dioxide emissions to address concerns about global climatic change.

In addition to achieving full compliance with all applicable legal requirements, AEP subsidiaries strive to go beyond compliance in an effort to be good environmental stewards. For example, AEP subsidiaries invest in research, through groups like the Electric Power Research Institute, to develop, implement and demonstrate new emission control technologies. AEP subsidiaries plan to continue in a leadership role to protect and preserve the environment while providing vital energy commodities and services to customers at fair prices. AEP subsidiaries have a proven record of efficiently producing and delivering electricity while minimizing the impact on the environment. The AEP System has invested over $2 billion, from 1990 through 2003, to equip many of its facilities with pollution control technologies. The AEP System will continue to make investments to improve the air emissions from its generating stations because this is the most cost-effective generation source for its customers electricity needs.

The Current Air Quality Regulatory Framework

The Clean Air Act (CAA) is the legislation that establishes the federal regulatory authority and oversight for emissions from fossil-fired generating plants. The states, with oversight and approval from the Federal EPA, administer and enforce these laws and related regulations.

Title I of the CAA

National Ambient Air Quality Standards: The Federal EPA periodically reviews the available scientific data for six pollutants and establishes a standard for concentration levels in ambient air for these substances to protect the public welfare and public health with an extra margin for safety. These requirements are known as "national ambient air quality standards" (NAAQS).

The states identify those areas within their state that meet the NAAQS (attainment areas) and those that do not (non-attainment areas). States must develop their individual state implementation plans (SIPs) with the intention of bringing non-attainment areas into compliance with the NAAQS. In developing a SIP each state must allow attainment areas to maintain compliance with the NAAQS. This is accomplished by controlling sources that emit one or more pollutants or precursors to those pollutants. The Federal EPA approves SIPs if they meet the minimum criteria in the CAA. Alternatively, the Federal EPA may prescribe a federal implementation plan if they conclude that a SIP is deficient. Additionally, the Federal EPA can impose sanctions, up to and including withholding of federal highway funds, in states that fail to submit an adequate SIP or a SIP that fails to bring non-attainment areas into NAAQS compliance within the time prescribed by the CAA.

The CAA also establishes visibility goals, which are known as the regional haze program, for certain federally designated areas, including national parks. States are required to develop and submit SIP provisions that will demonstrate reasonable progress toward preventing the impairment and remedying any existing impairment of visibility in these federally designated areas.

Each state's SIP must include requirements to control sources that emit pollutants in that state as well as requirements to control sources that significantly contribute to non-attainment areas in another state. If a state believes that its air quality is impacted by upwind sources outside their borders, that state can submit a petition that asks the Federal EPA to impose control requirements on specific sources in other states if those states' SIPs do not contain adequate requirements to control those sources. For example, the Federal EPA issued a NOx Rule in 1997, which affected 22 eastern states (including states in which AEP subsidiaries operate) and the District of Columbia. The NOx Rule asked these 23 jurisdictions to adopt requirements, for utility and industrial boilers and certain other emission sources, to employ cost-effective control technologies to reduce NOx emissions. The purpose of the request was to allow certain eastern states to reduce the contribution from these 23 jurisdictions to ozone non-attainment areas in certain eastern states.

The Federal EPA also granted four petitions filed by certain eastern states seeking essentially the same levels of control on emission sources outside of their states and issued a Section 126 Rule. All of the states in which we operate that were subject to the NOx Rule have submitted the required SIP revisions. In response, the Federal EPA issued the NOx Rule and the Section 126 Rule, which are discussed below.

The compliance date for the NOx Rule is May 31, 2004. In 2000, the Federal EPA also adopted a revised Section 126 Rule which granted petitions filed by four northeastern states. The revised Section 126 Rule imposes emissions reduction requirements comparable to the NOx Rule also beginning May 31, 2004, for most of our coal-fired generating units.

In 2000, the Texas Commission on Environmental Quality adopted rules requiring significant reductions in NOx emissions from utility sources, including TCC and SWEPCo. The compliance requirements began in May 2003 for TCC and begin in May 2005 for SWEPCo.

AEP subsidiaries are installing a variety of emission control technologies to improve NOx emissions standards and to comply with applicable state and federal NOx requirements. These include selective catalytic reduction (SCR) technology on certain units and other combustion control technologies on a larger number of units.

AEP's electric utility units are currently subject to SIP requirements that control SO_2 and particulate matter emissions in all states, and that control NOx emissions in certain states. The AEP System's generating plants comply with applicable SIP limits for SO_2, NOx and particulate matter.

Hazardous Air Pollutants: In 1990 Amendments to the CAA, Congress required the Federal EPA to identify the sources of 188 hazardous air pollutants (HAPs) and to develop regulations that prescribe a level of HAP emission reduction. These reductions must reflect the application of maximum achievable control technology (MACT). Congress also directed the Federal EPA to investigate HAP emissions from the electric utility sector and to submit a report to Congress. The Federal EPA's 1998 report to Congress identified mercury emissions from coal-fired electric utility units and nickel emissions from oil-fired utility units as sources of HAP emissions that warranted further investigation and possible control.

New Source Performance Standards and New Source Review: The Federal EPA establishes New Source Performance Standards (NSPS) for 28 categories of major stationary emission sources that reflect the best demonstrated level of pollution control. Sources that are constructed or modified after the effective date of an NSPS standard are required to meet those limitations. For example, many electric utility units are regulated under the NSPS for SO_2, NOx, and particulate matter. Similarly, each SIP must include regulations that require new sources, and major modifications at existing emission sources that result in a significant net increase in emissions, to submit a permit application and undergo a review of available technologies to control emissions of pollutants. These rules are called new source review (NSR) requirements.

Different NSR requirements apply in attainment and non-attainment areas.

In attainment areas:

- An air quality review must be performed, and
- The best available control technology must be employed to reduce new emissions.

In non-attainment areas,

- Requirements reflecting the lowest achievable emission rate are applied to new or modified sources, and
- All new emissions must be offset by reductions in emissions of the same pollutant from other sources within the same control area.

Neither the NSPS nor NSR requirements apply to certain activities, including routine maintenance, repair or replacement, changes in fuels or raw materials that a source is capable of accommodating, the installation of a pollution control project, and other specifically excluded activities.

Title IV of the CAA (Acid Rain)

The 1990 Amendments to the CAA included a market-based emission reduction program designed to reduce the amount of SO_2 emitted from electric utility units by approximately 50 percent from 1980 levels. This program also established a nationwide cap on utility SO_2 emissions of 8.9 million tons per year. The Federal EPA administers its SO_2 program through an allowance allocation and trading system. Allowances are allocated to specific units based on statutory formulas. Annually each utility unit must surrender one allowance for each ton of SO_2 that it emits. Emission sources that install controls and no longer need all of their allowances can bank those allowances for future use or trade them to other emission sources.

Title IV also contains requirements for utility sources to reduce NOx emissions through the use of available combustion controls. Units must meet NOx emission rates standards which are specific to that unit or units may participate in an annual averaging program for utility units that are under common control.

Future Reduction Requirements for SO_2, NOx, and Mercury

In 1997, the Federal EPA adopted new, more stringent NAAQS for fine particulate matter and ground-level ozone. The Federal EPA is in the process of developing final designations for fine particulate matter and ground-level ozone non-attainment areas. The Federal EPA has identified SO_2 and NOx emissions as precursors to the formation of fine particulate matter. NOx emissions are also identified as a precursor to the formation of ground-level ozone. As a result, requirements for future reductions in emissions of NOx and SO_2 from the AEP System's generating units are highly probable. In addition, the Federal EPA has proposed a set of options for future mercury controls at coal-fired power plants.

Multi-emission control legislation, known as the Clear Skies Act, was introduced in Congress and is supported by the Bush Administration. This legislation would regulate NOx, SO_2, and mercury emissions from electric generating plants. AEP supports enactment of this comprehensive, multi-emission legislation so that compliance planning can be coordinated and collateral emission reductions maximized. Management believes the Bush Administration's Clear Skies Act would establish stringent emission reduction targets and achievable compliance timetables utilizing a cost-effective nationwide cap and trade program. Although the prospects for enactment of the Clear Skies Act are low, there are alternative regulatory approaches which will likely require the AEP System to substantially reduce SO_2, NOx and mercury emissions over the next ten years.

Regulatory Emissions Reductions

On January 30, 2004, the Federal EPA published two proposed rules that would collectively require reductions of approximately 70% in emissions of SO_2, NOx and mercury from coal-fired electric generating units by 2015 (2018 for mercury). This initiative has two major components:

- The Federal EPA proposed an interstate air quality rule for reducing SO_2 and NOx emissions across the eastern half of the United States (29 states and the District of Columbia) to address attainment of the fine particulate matter and ground-level ozone NAAQS. These reductions could also satisfy these states' obligations to make reasonable progress towards the national visibility goal under the regional haze program.
- The Federal EPA proposed to regulate mercury emissions from coal-fired electric generating units.

The interstate air quality rule would require affected states to include, in their SIPs, a program to reduce NOx and SO_2 emissions from coal-fired electric utility units. SO_2 and NOx emissions would be reduced in two phases, which would be implemented through a cap-and-trade program. Regional SO_2 emissions would be reduced to 3.9 million tons by 2010 and to 2.7 million tons by 2015. Regional NOx emissions would be reduced to 1.6 million tons by 2010 and to 1.3 million tons by 2015. Rules to implement the SO_2 and NOx trading programs have not yet been proposed.

To control and reduce mercury emissions, the Federal EPA published two alternative proposals. The first option requires the installation of MACT on a site-specific basis. Mercury emissions would be reduced from 48 tons to approximately 34 tons by 2008. The Federal EPA believes, and the industry concurs, that there are no commercially available mercury control technologies in the marketplace today that can achieve the MACT standards for bituminous coals, but certain units have achieved comparable levels of mercury reduction by installing conventional SO_2 (scrubbers) and NOx (SCR) emission reduction technologies. The proposed rule imposes significantly less stringent standards on generating plants that burn sub-bituminous coal or lignite, which standards potentially could be met without installation of mercury control technologies.

The Federal EPA recommends, and AEP supports, a second mercury emission reduction option. The second option would permit mercury emission reductions to be achieved from existing sources through a national cap-and-trade approach. The cap-and-trade approach would include a two-phase mercury reduction program for coal-fired utilities. This approach would coordinate the reduction requirements for mercury with the SO_2 and NOx reduction requirements imposed on the same sources under the proposed interstate air quality rule. Coordination is significantly more cost-effective because technologies like scrubbers and SCRs, that can be used to comply with the more stringent SO_2 and NOx requirements, have also proven highly effective in reducing mercury emissions on certain coal-fired units that burn bituminous coal. The second option contemplates reducing mercury emissions from 48 million tons to 34 million tons by 2010 and to 15 million tons by 2018.

The Federal EPA's proposals are the beginning of a lengthy rulemaking process, which will involve supplemental proposals on many details of the new regulatory programs, written comments and public hearings, issuance of final rules, and potential litigation. In addition, states have substantial discretion in developing their rules to implement cap-and-trade programs, and will have 18 months after publication of the notice of final rulemaking to submit their revised SIPs. As a result, the ultimate requirements may not be known for several years and may depart significantly from the original proposed rules described here.

While uncertainty remains as to whether future emission reduction requirements will result from new legislation or regulation, it is certain under either outcome that AEP subsidiaries will invest in additional conventional pollution control technology on a major portion of their coal-fired power plants. Finalization of new requirements for further SO_2, NOx and/or mercury emission reductions will result in the installation of additional scrubbers, SCR systems and/or the installation of emerging technologies for mercury control.

Estimated Air Quality Environmental Investments

Each of the current and possible future environmental compliance requirements discussed above will require significant additional investments, some of which are estimable. The proposed rules discussed above have not been adopted, will be subject to further revision, and will be the subject of a court challenge and further modifications.

All of management's estimates are subject to significant uncertainties about the outcome of several interrelated assumptions and variables, including:

- Timing of implementation
- Required levels of reductions
- Allocation requirements of the new rules, and
- Selected compliance alternatives.

As a result, management cannot estimate compliance costs with certainty, and the actual costs to comply could differ significantly from the estimates discussed below.

All of the costs discussed below are incremental to the AEP subsidiaries' current investment base and operating cost structure. These expenditures for pollution control technologies, replacement generation and associated operating costs are recoverable from customers through regulated rates (in regulated jurisdictions) and should be recoverable through market prices (in deregulated jurisdictions). If not, those costs could adversely affect future results of operations, cash flows and possibly financial condition.

Estimated Investments for NOx Compliance

Management estimates that AEP subsidiaries will make future investments of approximately $600 million to comply with the Federal EPA's NOx Rule, the Texas Commission on Environmental Quality Rule and other final Federal EPA NOx-related requirements. Approximately $500 million of these investments are reflected in the estimated construction expenditures for 2004 – 2006. As of December 31, 2003, the AEP System has invested approximately $1.1 billion to comply with various NOx requirements. Estimated future compliance costs, amounts in the 2004 – 2006 construction budget and amounts spent by subsidiaries are as follows:

	Future Estimated Compliance Investment	Investment Amount in 2004 – 2006 Budget	Amount Spent
		(in millions)	
AEGCo	$10	$9	$12
APCo	151	151	307
CSPCo	63	29	71
I&M	10	9	17
KPCo	11	1	179
OPCo	305	273	442
PSO	8	8	-
SWEPCo	18	12	23
TCC	-	-	5

Estimated Investments for SO2 Compliance

The AEP System is complying with Title IV SO_2 requirements by installing scrubbers, other controls and fuel switching at certain generating units. AEP subsidiaries also use SO_2 allowances that were:

- Received in the annual allowance allocation by the Federal EPA,
- Obtained through participation in the annual allowance auction,
- Purchased in the allowance market, and
- Obtained as bonus allowances for installing controls early.

Decreasing SO_2 allowance allocations, a diminishing SO_2 allowance bank, and increasing allowance prices in the market will require the installation of additional controls on certain generating units. AEP subsidiaries plan to install 3,500 MW of additional scrubbers over the next 4 years to comply with our Title IV SO_2 obligations. In total management estimates these additional capital costs to be approximately $1.2 billion. Of this total, approximately $900 million will be expended during 2004-2006 and this amount is included in total estimated construction expenditures for 2004 – 2006. The following table shows the estimated additional capital costs and amounts included in the 2004 – 2006 budget for additional scrubbers by subsidiary:

	Cost of Additional Scrubbers	Amount in 2004 – 2006 Construction Budget
	(in millions)	
APCo	$367	$307
OPCo	753	542
SWEPCo	27	21
TNC	16	16

AEP does not support the Kyoto Protocol but has been working with the Bush Administration on a voluntary program aimed at meeting the President's goal of reducing the greenhouse gas intensity of the economy by 18% by 2012. For many years, AEP has been a leader in pursuing voluntary actions to control greenhouse gas emissions. AEP expanded its commitment in this area in 2002 by joining the Chicago Climate Exchange, a pilot greenhouse gas emission reduction and trading program, under which AEP's subsidiaries are obligated to reduce or offset 18 million tons of CO_2 emissions during 2003-2006.

Costs for Spent Nuclear Fuel and Decommissioning

I&M, as the owner of the Cook Plant, and TCC, as a partial owner of STP, have a significant future financial commitment to safely dispose of SNF and to decommission and decontaminate the plants. The Nuclear Waste Policy Act of 1982 established federal responsibility for the permanent off-site disposal of SNF and high-level radioactive waste. By law I&M and TCC participate in the DOE's SNF disposal program which is described in Note 7. Since 1983 I&M has collected $316 million from customers for the disposal of nuclear fuel consumed at the Cook Plant. We deposited $117 million of these funds in external trust funds to provide for the future disposal of SNF and remitted $199 million to the DOE. TCC has collected and remitted to the DOE, $56 million for the future disposal of SNF since STP began operation in the late 1980s. Under the provisions of the Nuclear Waste Policy Act, collections from customers are to provide the DOE with money to build a permanent repository for spent fuel. However, in 1996, the DOE notified the companies that it would be unable to begin accepting SNF by the January 1998 deadline required by law. To date, the DOE has failed to comply with the requirements of the Nuclear Waste Policy Act.

As a result of DOE's failure to make sufficient progress toward a permanent repository or otherwise assume responsibility for SNF, AEP on behalf of I&M and STPNOC on behalf of TCC and the other STP owners, along with a number of unaffiliated utilities and states, filed suit in the D.C. Circuit Court requesting, among other things, that the D.C. Circuit Court order DOE to meet its obligations under the law. The D.C. Circuit Court ordered the parties to proceed with contractual remedies but declined to order DOE to begin accepting SNF for disposal. DOE estimates its planned site for the nuclear waste will not be ready until at least 2010. In 1998, AEP and I&M filed a complaint in the U.S. Court of Federal Claims seeking damages in excess of $150 million due to the DOE's partial material breach of its unconditional contractual deadline to begin disposing of SNF generated by the Cook Plant. Similar lawsuits were filed by other utilities. In August 2000, in an appeal of related cases involving other unaffiliated utilities, the U.S. Court of Appeals for the Federal Circuit held that the delays clause of the standard contract between utilities and the DOE did not apply to DOE's complete failure to perform its contract obligations, and that the utilities' suits against DOE may continue in court. On January 17, 2003, the U.S. Court of Federal Claims ruled in favor of I&M on the issue of liability. The case continues on the issue of damages owed to I&M by the DOE with a trial scheduled in March 2004. As long as the delay in the availability of a government approved storage repository for SNF continues, the cost of both temporary and permanent storage of SNF and the cost of decommissioning will continue to increase.

The cost to decommission nuclear plants is affected by both NRC regulations and the delayed SNF disposal program. Studies completed in 2003 estimate the cost to decommission the Cook Plant ranges from $821 million to $1.08 billion in 2003 non-discounted dollars. External trust funds have been established with amounts collected from customers to decommission the plant. At December 31, 2003, the total decommissioning trust fund balance for Cook Plant was $720 million which includes earnings on the trust investments. Studies completed in 1999 for STP estimate TCC's share of decommissioning cost to be $289 million in 1999 non-discounted dollars. Amounts collected from customers to decommission STP have been placed in an external trust. At December 31, 2003, the total decommissioning trust fund for TCC's share of STP was $125 million which includes earnings on the trust investments. Estimates from the decommissioning studies could continue to escalate due to the uncertainty in the SNF disposal program and the length of time that SNF may need to be stored at the plant site. I&M and TCC will work with regulators and customers to recover the remaining estimated costs of decommissioning Cook Plant and STP. However, future results of operations, cash flows and possibly financial condition would be adversely affected if the cost of SNF disposal and decommissioning continues to increase and cannot be recovered.

Clean Water Act Regulation

On February 16, 2004, the Federal EPA signed a rule pursuant to the Clean Water Act that will require all large existing power plants to meet certain performance standards to reduce the mortality of juvenile and adult fish or other larger organisms pinned against a plant's cooling water intake screens. A subset of these plants that are located on sensitive water bodies will be required to meet additional performance standards for reducing the number of smaller organisms passing through the water screens and the cooling system. Sensitive water bodies are defined as oceans, estuaries, the Great Lakes, and small rivers with large plants. These rules will result in additional capital and operation and maintenance expenses to ensure compliance.

Other Environmental Concerns

We perform environmental reviews and audits on a regular basis for the purpose of identifying, evaluating and addressing environmental concerns and issues. In addition to the matters discussed above, the AEP subsidiaries are managing other environmental concerns which are not believed to be material or potentially material at this time. If they become significant or if any new matters arise that could be material, they could have a material adverse effect on results of operations, cash flows and possibly financial condition.

Critical Accounting Policies

In the ordinary course of business, we use a number of estimates and assumptions relating to the reporting of results of operations and financial condition in the preparation of our financial statements in conformity with accounting principles generally accepted in the United States of America. Actual results could differ significantly from those estimates under different assumptions and conditions. We believe that the following discussion addresses the most critical accounting policies, which are those that are most important to the portrayal of the financial condition and results and require management's most difficult, subjective and complex judgments, often as a result of the need to make estimates about the effect of matters that are inherently uncertain.

Revenue Recognition

Regulatory Accounting

The consolidated financial statements of the registrant subsidiary companies with cost-based rate-regulated operations (I&M, KPCo, PSO, and a portion of APCo, OPCo, CSPCo, TCC, TNC and SWEPCo), reflect the actions of regulators that can result in the recognition of revenues and expenses in different time periods than enterprises that are not rate regulated. In accordance with SFAS 71, regulatory assets (deferred expenses to be recovered in the future) and regulatory liabilities (deferred future revenue reductions or refunds) are recorded to reflect the economic effects of regulation by matching expenses with their recovery through regulated revenues in the same accounting period and by matching income with its passage to customers through regulated revenues in the same accounting period. Regulatory liabilities (unrealized gains) or regulatory assets (unrealized losses) are also recorded for changes in the fair value of physical and financial contracts that meet the definition of a derivative as defined in SFAS 133 and are subject to the regulated ratemaking process.

When regulatory assets are probable of recovery through regulated rates, certain registrant subsidiaries record them as assets on the balance sheet. Registrant subsidiaries test for probability of recovery whenever new events occur, for example a regulatory commission order or passage of new legislation. If registrant subsidiaries determine that recovery of a regulatory asset is no longer probable, they write off that regulatory asset as a charge against net income. A write off of regulatory assets may also reduce future cash flows since there may be no recovery through regulated rates.

Traditional Electricity Supply and Delivery Activities

Revenues are recognized on the accrual or settlement basis for normal retail and wholesale electricity supply sales and electricity transmission and distribution delivery services. The revenues are recognized and recorded when the energy is delivered to the customer and include estimated unbilled as well as billed amounts. In general, expenses are recorded when purchased electricity is received and when expenses are incurred.

FASB and other accounting constituencies continue to interpret the application of FIN 46R. As a result, we are continuing to review the application of this new interpretation and expect to adopt FIN 46R by March 31, 2004.

See Notes 1 and 2 of the Notes to Respective Financial Statements for a discussion of significant accounting policies and additional impacts of new accounting pronouncements.

Other Matters

FERC Proposed Standard Market Design

In July 2002, the FERC issued its Standard Market Design (SMD) notice of proposed rulemaking, which sought to standardize the structure and operation of wholesale electricity markets across the country. Key elements of FERC's proposal included standard rules and processes for all users of the electricity transmission grid, new transmission rules and policies, and the creation of certain markets to be operated by independent administrators of the grid in all regions. The FERC issued a "white paper" on the proposal in April 2003, in response to the numerous comments that the FERC received on its proposal. Management does not know if or when the FERC will finalize a rule for SMD. Until any potential rule is finalized, management cannot predict its effect on cash flows and results of operations.

FERC Market Power Mitigation

A FERC order issued in November 2001 on AEP's triennial market based wholesale power rate authorization update required certain mitigation actions that AEP would need to take for sales/purchases within its control area and required AEP to post information on its website regarding its power system's status. As a result of a request for rehearing filed by AEP and other market participants, FERC issued an order delaying the effective date of the mitigation plan until after a planned technical conference on market power determination. In December 2003, the FERC issued a staff paper discussing alternatives and held a technical conference in January 2004. Management is unable to predict the timing of any further action by the FERC or its affect of future results of operations and cash flows.

Seasonality

The sale of electric power in AEP subsidiaries' service territories is generally a seasonal business. In many parts of the country, demand for power peaks during the hot summer months, with market prices also peaking at that time. In other areas, power demand peaks during the winter. The pattern of this fluctuation may change due to the nature and location of the AEP System's facilities and the terms of power contracts into which AEP enters. In addition, AEP subsidiaries have historically sold less power, and consequently earned less income, when weather conditions are milder. Unusually mild weather in the future could diminish results of operations and may impact cash flows and financial condition.

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File No. 30-150

SECURITIES AND EXCHANGE COMMISSION
Washington, D.C.

FORM U5S
ANNUAL REPORT

For the year ended December 31, 2003

Filed Pursuant to the Public Utility Holding Company Act of 1935
by

FILED
MAY 18 2004
PUBLIC SERVICE
COMMISSION

AMERICAN ELECTRIC POWER COMPANY, INC.
1 Riverside Plaza, Columbus, Ohio 43215

KPSC Case No. 99-149
Item No. 1
Attachment No. 2

AMERICAN ELECTRIC POWER COMPANY, INC.

FORM U5S – ANNUAL REPORT
For the Year Ended December 31, 2003

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PUBLIC SERVICE COMMISSION

ITEM 1. SYSTEM COMPANIES AND INVESTMENTS THEREIN AS OF DECEMBER 31, 2003

COMPANY NAME	PERCENTAGE OF VOTING SECURITIES OWNED BY IMMEDIATE PARENT	PERCENTAGE OF VOTING SECURITIES OWNED BY OTHER ENTITY	NUMBER OF COMMON SHARES OWNED	ISSUER'S BOOK VALUE EQUITY (IN 000'S)	OWNER'S BOOK VALUE EQUITY (IN 000'S)
00. American Electric Power Company, Inc. [Note A]					
01. American Electric Power Service Corporation [Note B]	100%		23,500	$ (80,674)	$ 1,450
01. AEP C&I Company, LLC [Note W]	100%		Uncertified	394	394
02. AEP Texas Commercial & Industrial Retail GP, LLC [Note W]	100%		Uncertified	(65)	(65)
03. AEP Texas Commercial & Industrial Retail Limited Partnership [Note W]	0.50%	99.50%	Partnership	17,980	90
02. AEP Texas Commercial & Industrial Retail Limited Partnership [Note W]	99.50%	0.50%	Partnership	17,980	17,980
02. AEP Gas Power GP, LLC [Note G]	100%		Uncertified	(13,763)	(13,763)
03. AEP Gas Power Systems, LLC [Note G]	75%	25%	Uncertified	1,188	1,093
02. REP Holdco, LLC [Note W]	100%		3,000	2,718	2,718
03. Mutual Energy SWEPCO, LLC [Note W]	99.50%	0.50%	Uncertified	(43)	(43)
03. REP General Partner LLC [Note W]	100%		Uncertified	1,099	1,099
04. Mutual Energy SWEPCO, LLC [Note W]	0.50%	99.50%	Uncertified	(43)	-
01. AEP Coal, Inc. [Note L]	100%		Uncertified	(79,394)	(79,394)
02. Snowcap Coal Company, Inc. [Note L]	100%		Uncertified	-	-
02. AEP Kentucky Coal, LLC [Note L]	100%		Uncertified	-	-
02. AEP Ohio Coal, LLC [Note L]	100%		Uncertified	-	-
02. AEP West Virginia Coal, Inc. [Note L]	100%		Uncertified	-	-
02. Leesville Land, LLC [Note L]	100%		Uncertified	-	-
02. Springdale Land, LLC [Note L]	100%		Uncertified	-	-
01. AEP Communications, Inc. [Note C]	100%		100	(168,243)	(168,679)
02. AEP Communications, LLC [Note C]	100%		100	(173,307)	(173,307)
03. C3 Networks Limited Partnership [Note C]	49.75%	49.75%	Partnership	-	-
04. C3 Networks & Communications Limited Partnership [Note C]	99.50%	0.50%	Partnership	-	-
03. American Fiber Touch, LLC [Note C]	50%	50%	Uncertified	22,658	22,658
03. AEP Fiber Venture, LLC [Note C]	100%		Uncertified	-	-
04. AFN Communications, LLC [Note C]	48%	52%	5,008	-	-
01. AEP Generating Company [Note J]	100%		1,000	45,875	45,875
01. AEP Desert Sky LP, LLC [Note X]	100%		Uncertified	858	784
02. AEP Desert Sky GP, LLC [Note X]	100%		Uncertified	4,799	4,799
01. AEP Desert Sky LP II, LLC [Note X]	100%		Uncertified	58,229	58,229
03. Desert Sky Wind Farm LP [Note X]	1%	99%	Uncertified	588	588
01. AEP Investments, Inc. [Note F]	100%		100	5,604	5,604
02. AEP EmTech, LLC [Note DD]	100%		Uncertified	-	-
03. Altra Energy Technologies, Inc. [Note DD]	5%	95%	N/A	-	-
03. Amperion, Inc. [Note DD]	38.30%	61.70%	N/A	-	-
03. Universal Supercapacitors, LLC	50.00%	50.00%	Uncertified	-	-
03. Integrated Fuel Cell Technologies, Inc. [DD]	0.10%	99.90%	Uncertified	-	40
03. Distribution Vision 2010, LLC	20.00%	80.00%	Uncertified	-	79
02. AEP Transportation, LLC [Note H]	100%		Uncertified	-	-
02. Pacific Hydro Limited [Note H]	20%	80%	Uncertified	-	54,887
02. Dynelec, Inc.	1.17%	98.83%	Uncertified	-	-
02. Energy Trading Platform Holding Company, Inc. [Note W]	16.70%	83.30%	Uncertified	-	-
02. Intercontinental Exchange Inc. [Note W]	5.30%	94.70%	Uncertified	-	5,057
02. Pantellos Corporation [Note DD]	5.40%	94.60%	Uncertified	-	-
02. PowerSpan Corp [Note DD]	9.80%	90.20%	Uncertified	-	-
02. AEMT, Inc.	27.00%	63.00%	Uncertified	-	-
02. Enerwise Global Technologies, Inc.	5.00%	95.00%	Uncertified	-	-
02. Powerware Solutions, Inc. [Note DD]	4.00%	96.00%	Uncertified	-	1,089
02. PHPK Technologies, Inc. [Note DD]	40.40%	59.60%	Uncertified	-	2,306
01. Mutual Energy L.L.C. [Note W]	100%		Uncertified	6,948	6,948
02. AEP Ohio Retail Energy, LLC [Note W]	100%		Uncertified	-	-

ITEM 1. SYSTEM COMPANIES AND INVESTMENTS THEREIN AS OF DECEMBER 31, 2003

COMPANY NAME	PERCENTAGE OF VOTING SECURITIES OWNED BY IMMEDIATE PARENT	PERCENTAGE OF VOTING SECURITIES OWNED BY OTHER ENTITY	NUMBER OF COMMON SHARES OWNED	ISSUER'S BOOK VALUE EQUITY (IN 000'S)	OWNER'S BOOK VALUE EQUITY (IN 000'S)
01. AEP Power Marketing, Inc. [Note W]	100%		100	$ 14,639	$ 14,639
02. AEP Coal Marketing, LLC [Note W]	100%		Uncertified	-	-
02 AEP Emissions Marketing, LLC [Note W]	100%		Uncertified	-	-
01. AEP T&D Services, LLC [Note BB]	100%		Uncertified	(99)	(99)
01. AEP Pro Serv, Inc. [Note I]	100%		110	19,413	19,416
02. Diversified Energy Contractors Company, LLC [Note I]	100%		1,000	16,286	11,052
03. DECCO II LLC [Note I]	100%		1,000	-	-
04. Diversified Energy Contractors, LP [Note I]	0.99%	99.01%	Partnership	(53)	(53)
03. Diversified Energy Contractors, LP [Note I]	99.01%	0.99%	Partnership	(5,215)	(5,215)
02. United Sciences Testing, Inc.	100%		Uncertified	-	-
01. AEP Texas POLR, LLC [Note W]	100%		Uncertified	(6,608)	(6,608)
02. AEP Texas POLR GP, LLC [Note W]	100%		Uncertified	(33)	(33)
03. POLR Power, L.P. [Note W]	0.50%	99.50%	Partnership	(10,215)	(51)
02. POLR Power, L.P. [Note W]	99.50%	0.50%	Partnership	(10,215)	-
01. AEP Resources, Inc. [Note H]	100%		100	29,941	29,941
02. AEP Delaware Investment Company [Note H]	100%		100	199,550	199,550
03. AEP Holdings I CV [Note H]	8%	92%	Uncertified	(929,347)	(123,058)
04. AEPR Global Investments B.V. [Note H]	100%		10	(929,451)	(929,451)
05. AEPR Global Holland Holding B.V. [Note H]	100%		Uncertified	(553,758)	(553,758)
05. AEP Energy Services UK Generation Limited [Note H]	100%		Uncertified	(379,024)	(379,024)
03. AEP Holdings II CV [Note H]	88%	12%	Partnership	284,526	255,661
04. AEP Energy Services Limited [Note H]	100%		Uncertified	(174,668)	(174,668)
05. AEP Energy Services Trading Limited [Note H]	100%		Uncertified	-	-
04. AEPR Global Energy B.V.	100%		Uncertified	-	-
05. AEP Energy Ventures B.V.	100%		Uncertified	-	-
06. CompresionBajio S de R.L. de C.V. [Note H]	50%	50%	Uncertified	4,290	4,290
04. AEPR Global Ventures B.V. [Note H]	100%		Uncertified	2,063	2,063
05. Operaciones Azteca VIII, S. de R.L. de C.V. [Note H]	50%	50%	Uncertified	-	-
05. Servicios Azteca VIII, S. de R.L. de C.V. [Note H]	50%	50%	Uncertified	(236)	(236)
05. AEP Energy Services Austria GmbH	100%		Uncertified	14	14
05. AEP Energy Services (Australia) Pty Ltd	100%		Uncertified	80	80
05. AEP Energy Services GmbH [Note H]	100%		Uncertified	27	27
05. AEP Energy Services (Switzerland) Pty Ltd	100%		Uncertified	12	12
05. AEP Energy Services Norway AS	100%		Uncertified	-	-
04. Intergen Denmark, Aps [Note H]	50%	50%	Partnership	33,985	33,985
05. Intergen Denmark Finance Aps [Note H]	100%		Partnership	-	-
05. Intergen Mexico, B.V. [Note H]	100%		Partnership	-	-
06. Intergen Aztec Energy VIII B.V. [Note H]	100%		Partnership	-	-
07. Intergen Aztec Energy VI B.V. [Note H]	100%		Partnership	-	-
07. Energia Azteca VIII S. de R.L. de C.V. [Note H]	100%		Partnership	-	-
02. AEP Delaware Investment Company II [Note H]	100%		1,000	86,199	86,199
03. AEP Holdings II CV [Note H]	12%	88%	Uncertified	284,526	28,865
04. AEP Energy Services Limited [Note H]	100%		Uncertified	(174,688)	(174,668)
05. AEP Energy Services Trading Limited [Note H]	100%		Uncertified	-	-
04. AEPR Global Ventures B.V. [Note H]	100%		Uncertified	2,063	2,063
05. Operaciones Azteca VIII, S. de R.L. de C.V. [Note H]	50%	50%	Uncertified	-	-
05. Servicios Azteca VIII, S. de R.L. de C.V. [Note H]	50%	50%	Uncertified	(236)	(236)
05. AEP Energy Services Austria GmbH	100%		Uncertified	14	14
05. AEP Energy Services (Australia) Pty Ltd	100%		Uncertified	80	80
05. AEP Energy Services GmbH [Note H]	100%		Uncertified	27	27
05. AEP Energy Services (Switzerland) Pty Ltd	100%		Uncertified	12	12
05. AEP Energy Norway AS	100%		Uncertified	-	-

ITEM 1. SYSTEM COMPANIES AND INVESTMENTS THEREIN AS OF DECEMBER 31, 2003

COMPANY NAME	PERCENTAGE OF VOTING SECURITIES OWNED BY IMMEDIATE PARENT	PERCENTAGE OF VOTING SECURITIES OWNED BY OTHER ENTITY	NUMBER OF COMMON SHARES OWNED	ISSUER'S BOOK VALUE EQUITY (IN 000'S)	OWNER'S BOOK VALUE EQUITY (IN 000'S)
04. Intergen Denmark, Aps [Note H]	50%	50%	Partnership	$ 33,985	$ 33,985
05. Intergen Denmark Finance Aps [Note H]	50%	50%	Partnership	-	-
05. Intergen Mexico, B.V. [Note H]	100%		Partnership	-	-
06. Intergen Aztec Energy VIII B.V. [Note H]	100%		Partnership	-	-
07. Intergen Aztec Energy VI B.V. [Note H]	100%		Partnership	-	-
07. Energia Azteca VIII S. de R.L. de C.V. [Note H]	100%		Partnership	-	-
04. AEPR Global Energy B.V.	100%		Uncertified	-	-
05. AEPR Energy Ventures B.V.	100%		Uncertified	-	-
06. Compresion Bajio S de R.L. de C.V. [Note H]	50%	50%	Uncertified	4,290	4,290
03. NGLE International, Limited [Note H]	100%		Uncertified	31,218	31,218
04. NGLE Pushan Power, LDC [Note H]	99%	1%	99	31,219	30,907
05. Nanyang General Light Electric Co., Ltd. [Note H]	70%	30%	Uncertified	82,365	57,655
04. NGLE Project Management Company, Limited [Note H]	100%		Uncertified	312	312
05. NGLE Pushan Power, LDC [Note H]	1%	99%	99	31,219	312
06. Nanyang General Light Electric Co., Ltd. [Note H]	70%	30%	Uncertified	82,365	57,655
02. AEP Memco LLC [Note Y]	100%		Uncertified	132,628	132,628
03. AEP Elmwood LLC [Note Y]	100%		Uncertified	-	-
04. Conlease, Inc. [Note Y]	100%		Uncertified	-	-
04. International Marine Terminals [Note Y]	33-1/3%	66-2/3%	Uncertified	-	-
02. AEP Resources Australia Holdings Pty Ltd [Note H]	100%		1	(49,960)	(49,960)
02. AEP Resources Australia Pty., Ltd. [Note H]	100%		3,753,752	45,425	45,425
02. AEP Resources Limited [Note H]	100%		1	837	837
02. AEP Energy Services, Inc. [Note D]	100%		200	(82,158)	(82,158)
03. AEP Energy Services Gas Holding Company [Note CC]	100%		10	9,702	9,702
04. AEP Energy Services Gas Holding Company II, LLC [Note CC]	100%		Uncertified	397,535	397,535
05. Caddis Partners, LLC [Note CC]	100%		Uncertified	-	-
05. AEP Energy Services Ventures III, Inc. [Note CC]	100%		10	176,624	176,624
05. HPL Holdings Inc. [Note CC]	100%		100	559,138	559,138
06. AEP Gas Marketing, LP [Note CC]	99.50%	0.50%	Partnership	(1,829)	(1,818)
06. HPL GP, LLC [Note CC]	100%		5	(987)	(987)
07. HPL Resources Company LP [Note CC]	0.50%	99.50%	Uncertified	(2)	-
07. AEP Gas Marketing, LP [Note CC]	0.50%	99.50%	Partnership	(1,829)	(11)
07. Houston Pipe Line Company LP [Note CC]	0.50%	99.50%	Partnership	534,822	(970)
08. AEP Houston Pipe Line Company, LLC [Note CC]	100.00%		Uncertified	-	-
08. Mid-Texas Pipeline Company [Note CC]	50%	50%	Partnership	67,437	33,718
06. HPL Resources Company LP [Note CC]	99.50%	0.50%	Partnership	(2)	(2)
06. Houston Pipe Line Company LP [Note CC]	99.50%	0.50%	Partnership	534,822	535,792
07. Mid-Texas Pipeline Company [Note CC]	50%	50%	Partnership	67,437	33,718
07. AEP Houston Pipe Line Company, LLC [Note CC]	100%		Uncertified	-	-
05. AEP Energy Services Investments, Inc. [Note CC]	100%		100	97,211	97,211
06. LIG Pipeline Company [Note CC]	100%		100	97,151	97,151
07. LIG, Inc. [Note CC]	100%		100	9,688	9,688
08. Louisiana Intrastate Gas Company, L.L.C. [Note CC]	10%	90%	100	97,225	9,722
09. LIG Chemical Company [Note CC]	100%		100	(16,099)	(16,099)
10. LIG Liquids Company, L.L.C. [Note CC]	10%	90%	10	16,288	1,629
09. LIG Liquids Company, L.L.C. [Note CC]	90%	10%	90	16,288	14,659
09. Tuscaloosa Pipeline Company [Note CC]	100%		100	640	640
07. Louisiana Intrastate Gas Company, L.L.C. [[Note CC]	90%	10%	900	97,225	87,503
08. LIG Chemical Company [Note CC]	100%		900	(16,099)	(16,099)
09. LIG Liquids Company, L.L.C. [Note CC]	10%	90%	90	16,288	1,629
08. LIG Liquids Company, L.L.C. [Note CC]	90%	10%	810	16,288	14,659
08. Tuscaloosa Pipeline Company [Note CC]	100%		900	640	640
05. AEP Energy Services Ventures, Inc. [Note CC]	100%		100	(56,846)	(56,846)

ITEM 1. SYSTEM COMPANIES AND INVESTMENTS THEREIN AS OF DECEMBER 31, 2003

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06. AEP Acquisition, LLC [Note CC]	50%	50%	Uncertified	$ (129,058)	$ (64,529)
07. Jefferson Island Storage & Hub L.L.C. [Note CC]	100%		50	78,220	78,220
05. AEP Energy Services Ventures II, Inc. [Note CC]	100%		10	(56,235)	(56,235)
06. AEP Acquisition, LLC [Note CC]	50%	50%	Uncertified	(129,058)	(64,529)
07. Jefferson Island Storage & Hub L.L.C. [Note CC]	100%		50	78,220	78,220
02. Ventures Lease Co., LLC [Note Q]	100%		Uncertified	(170,158)	(170,158)
02. AEPR Ohio, LLC	100%		Uncertified	(518,103)	(518,103)
03. AEP Delaware Investment Company III [Note H]	100%		Uncertified	(518,444)	(518,444)
04. AEP Holdings I CV [Note H]	92%	8%	Uncertified	(929,347)	(806,289)
05. AEPR Global Investments BV [Note H]	100%		Uncertified	(929,451)	(929,451)
06. AEPR Global Holland Holding BV [Note H]	100%		Uncertified	(553,758)	(553,758)
06. AEP Energy Services UK Generation Limited [Note H]	100%		Uncertified	(379,024)	(379,024)
01. Appalachian Power Company [Note J]	98.7% Com	1.3% Prf	13,499,500	1,336,988	1,389,075
02. Cedar Coal Co. [Note K]	100%		2,000	4,448	5,947
02. Central Appalachian Coal Company [Note K]	100%		3,000	882	882
02. Central Coal Company [Note K]	50%	50%	1,500	604	604
02. Southern Appalachian Coal Company [Note K]	100%		6,950	10,772	10,772
01. Columbus Southern Power Company [Note J]	100%		16,410,426	897,946	897,946
02. Colomet, Inc. [Note T]	100%		1,500	4,543	4,543
02. Conesville Coal Preparation Company [Note M]	100%		100	1,674	1,674
02. Simco Inc. [Note N]	100%		90,000	498	498
02. Ohio Valley Electric Corporation [Note E]	4.30%	39.90%	4,300	430	430
03. Indiana-Kentucky Electric Corporation [Note E]	100%		17,000	-	-
01. Franklin Real Estate Company [Note T]	100%		100	30	28
02. Indiana Franklin Realty, Inc. [Note T]	100%		10	1	1
01. Indiana Michigan Power Company [Note J]	100%		1,400,000	1,078,048	1,103,154
02. Blackhawk Coal Company [Note K]	100%		39,521	43,589	43,748
02. Price River Coal Company [Note K]	100%		1,091	27	27
01. Kentucky Power Company [Note J]	100%		1,009,000	317,138	323,351
01. Kingsport Power Company [Note J]	100%		410,000	25,375	27,008
01. Ohio Power Company [Note J]	99.2% Com	0.8% Prf	27,952,473	1,464,025	1,464,025
02. Cardinal Operating Company [Note E]	50%	50%	250	29,899	14,949
02. Central Coal Company [Note K]	50%	50%	1,500	603	603
01. Ohio Valley Electric Corporation [Note E]	39.90%	4.30%	39,900	-	4,082
02. Indiana-Kentucky Electric Corporation [Note E]	100%		17,000	-	-
01. Wheeling Power Company [Note J]	100%		150,000	33,751	36,202
01. AEP Utilities, Inc. [Note O]	100%		100	2,433,048	2,612,748
02. AEP Texas Central Company [Note J]	100%		2,211,678	1,209,049	1,209,049
03. AEP Texas Central Transition Funding LLC [Note AA]	100%		Uncertified	4,066	4,066
02. Public Service Company of Oklahoma [Note J]	100%		9,013,000	483,008	483,008
02. Southwestern Electric Power Company [Note J]	100.00%		7,536,640	696,660	696,660
03. The Arklahoma Corporation [Note P]	47.60%	52.40%	238	350	350
03. Southwest Arkansas Utilities Corporation [Note T]	100%		100	10	10
03. Dolet Hills Lignite Company, LLC [Note L]	100%		Uncertified	15,224	15,224
02. AEP Texas North Company [Note J]	100%		5,488,560	238,275	238,275
02. AEP Credit, Inc. [Note R]	100%		246	27,043	27,043
02. C3 Communications, Inc. [Note C]	100%		1,000	(185,690)	(185,690)
03. C3 Networks GP, L.L.C. [Note C]	100%		Uncertified	-	-
04. C3 Networks & Communications Limited Partnership [Note C]	0.50%	99.50%	Partnership	-	-
04. C3 Networks Limited Partnership [Note C]	0.50%	49.75%	Partnership	-	-
05. C3 Networks & Communications Limited Partnership [Note C]	99.50%	0.50%	Partnership	-	-
03. C3 Networks Limited Partnership [Note C]	49.75%	49.75%	Partnership	-	-
04. C3 Networks & Communications Limited Partnership [Note C]	99.50%	0.50%	Partnership	-	-

ITEM 1. SYSTEM COMPANIES AND INVESTMENTS THEREIN AS OF DECEMBER 31, 2003

COMPANY NAME	PERCENTAGE OF VOTING SECURITIES OWNED BY IMMEDIATE PARENT	PERCENTAGE OF VOTING SECURITIES OWNED BY OTHER ENTITY	NUMBER OF COMMON SHARES OWNED	ISSUER'S BOOK VALUE EQUITY (IN 000'S)	OWNER'S BOOK VALUE EQUITY (IN 000'S)
03. CSWC License, Inc. [Note C]	100%		Uncertified	$ -	$ -
02. CSW Energy, Inc. [Note S]	100%		1,000	(1,579)	(1,579)
03. AEP Wind Holding, LLC	100%		Uncertified	10,199	10,199
04. AEP Wind GP, LLC [Note X]	100%		Uncertified	1,390	1,390
04. Trent Wind Farm, LP [Note X]	1.00%	99.00%	Partnership	609	609
04. AEP Wind LP II, LLC [Note X]	100%		Uncertified	8,196	8,196
05. Trent Wind Farm, LP [Note X]	99%	1%	Partnership	60,316	60,316
04. Golden Prairie Holding Company LLC	100%		Uncertified	-	-
05. Golden Prairie Wind Farm LLC	100%		Uncertified	-	-
04. AEP Properties, LLC	100%		Uncertified	1,217	1,217
04. AEP Wind Energy, LLC	100%		Uncertified	-	-
03. AEP Wind LP, LLC [Note X]	100%		9	129,427	129,427
03. CSW Development-I, Inc. [Note S]	100%		1,000	58,088	58,088
04. Polk Power GP II, Inc. [Note S]	50%	50%	500	964	964
05. Polk Power GP, Inc. [Note S]	100%		1,000	605	605
06. Polk Power Partners, LP [Note S]	1%	49.50%	Partnership	625	625
07. Mulberry Holdings, Inc. [Note N]	100%		Uncertified	-	-
04. CSW Mulberry II, Inc. [[Note S]	100%		1,000	28,019	28,019
05. CSW Mulberry, Inc. [Note S]	100%		1,000	28,019	28,019
04. Polk Power Partners, LP [Note S]	49.50%	1%	Partnership	28,616	28,616
05. Mulberry Holdings, Inc. [Note N]	100%		Uncertified	-	-
04. Noah I Power GP, Inc. [Note S]	100%		1,000	28	28
05. Noah I Power Partners, LP [Note S]	1%	95%	Partnership	202	202
06. Brush Cogeneration Partners [Note S]	50%	50%	Partnership	-	-
04. Noah I Power Partners, LP [Note S]	95%	1%	Partnership	19,209	19,209
05. Brush Cogeneration Partners [Note S]	50%	50%	Partnership	21,583	21,583
04. Orange Cogeneration GP II, Inc. [Note S]	50%	50%	500	91	91
05. Orange Cogeneration G.P., Inc. [Note S]	100%		1,000	182	182
06. Orange Cogeneration Limited Partnership [Note S]	1.00%	49.50%	Partnership	81	81
07. Orange Cogen Funding Corp. [Note S]	100%		1,000	1	1
08. Orange Holdings, Inc. [Note N]	100%		Uncertified	-	-
04. CSW Orange II, Inc. [Note S]	100%		1,000	10,545	10,545
05. CSW Orange, Inc. [Note S]	100%		1,000	10,545	10,545
06. Orange Cogeneration Limited Partnership [Note S]	49.50%	1%	Partnership	4,005	4,005
07. Orange Cogen Funding Corp. [Note S]	100%		Uncertified	-	-
08. Orange Holdings, Inc. [Note N]	100%		Uncertified	-	-
03. CSW Ft. Lupton, Inc. [Note S]	100%		1,000	104,500	104,500
04. Thermo Cogeneration Partnership, L.P. [Note S]	50%	50%	Partnership	10,320	10,320
04. Cogeneration Holdings LLC [Note S]	50%	50%	Uncertified	9,909	9,909
03. Newgulf Power Venture, Inc. [Note S]	100%		1,000	3,580	3,850
03. CSW Sweeny GP I, Inc. [Note S]	100%		1,000	609	609
04. CSW Sweeny GP II, Inc. [Note S]	100%		1,000	940	940
05. Sweeny Cogeneration Limited Partnership [Note S]	1%	49%	Partnership	542	542
03. CSW Sweeny LP I, Inc. [Note S]	100%		1,000	27,028	27,028
04. CSW Sweeny LP II, Inc. [Note S]	100%		1,000	35,549	35,549
05. Sweeney Cogeneration Limited Partnership [Note S]	49%	1%	Partnership	26,559	26,559
03. CSW Power Marketing, Inc. [Note N]	100%		Uncertified	-	-
03. CSW Services International, Inc. [Note I]	100%		Uncertified	-	-
02. CSW International, Inc. [Note H]	100%		1,000	5,020	5,020
03. CSW International Two, Inc. [Note H]	100%		1,000	-	-
04. CSW UK Holdings [Note H]	100%		427,275,004	-	-
05. CSWI Europe Limited [Note H]	100%		1,000	(33,627)	(33,627)

ITEM 1. SYSTEM COMPANIES AND INVESTMENTS THEREIN AS OF DECEMBER 31, 2003

COMPANY NAME	PERCENTAGE OF VOTING SECURITIES OWNED BY IMMEDIATE PARENT	PERCENTAGE OF VOTING SECURITIES OWNED BY OTHER ENTITY	NUMBER OF COMMON SHARES OWNED	ISSUER'S BOOK VALUE EQUITY (IN 000'S)	OWNER'S BOOK VALUE EQUITY (IN 000'S)
06. South Coast Power Limited [Note H]	50%	50%	1	$ -	$ -
06. Shoreham Operations Company Limited [Note H]	50%	50%	2	-	-
05. CSW UK Finance Company [Note H]	90%	10	Uncertified	-	-
.04 CSW UK Finance Company	10%	90%	Uncertified	-	-
04. CSW UK Investments Limited [Note H]	100%		Uncertified	-	-
03. CSW International, Inc. (a Cayman Island Company) [Note H]	100%		1,000	(41,982)	(41,982)
04. CSW Vale L.L.C. [Note H]	99%	1%	Uncertified	(41,562)	(41,562)
03. CSW Vale L.L.C. [Note H]	1%	99%	Uncertified	(420)	(420)
03. CSW International Energy Development Ltd. [Note H]	100%		Uncertified	-	-
04. Tenaska CSW International Ltd. [Note H]	50%	50%	1,000	-	-
02. CSW Energy Services, Inc. [Note I]	100%		Uncertified	-	-
03. Nuvest, L.L.C. [Note U]	92.90%	7.10%	Uncertified	-	-
04. National Temporary Services, Inc. [Note U]	100%		Uncertified	-	-
05. Octagon, Inc. [Note U]	100%		Uncertified	-	-
04. Numanco, L.L.C. [Note U]	100%		Uncertified	-	-
05. NuSun, Inc. [Note U]	100%		Uncertified	-	-
06. Sun Technical Services, Inc. [Note U]	100%		Uncertified	-	-
06. Calibration and Testing Corporation [Note U]	100%		Uncertified	-	-
05. ESG, L.L.C. [Note U]	50%	50%	Uncertified	-	-
05. Numanco Services, LLC [U]	100%		Uncertified	-	-
Notes:					
A. Public utility holding company.					
B. Management, professional and technical services.					
C. Telecommunications.					
D. Broker and market energy commodities.					
E. Generation.					
F. Investor in companies developing energy-related ideas, products and technologies.					
G. Distributed generation products.					
H. International energy-related investments, trading and other projects.					
I. Non-regulated energy-related services and products.					
J. Domestic electric utility.					
K. Coal mining (inactive).					
L. Coal mining (active).					
M. Coal preparation.					
N. Inactive.					
O. Subsidiary public utility holding company.					
P. Electric transmission.					
Q. Leasing.					
R. Accounts receivable factoring.					
S. Independent power.					
T. Real estate.					
U. Staff augmentation to power plants.					
V. Retail energy sales.					
W. Marketing of natural gas, electricity or energy-related products.					
X. Wind Power Generation.					
Y. Barging Services					
AA. Finance Subsidiary					
BB. Energy services including operations, supply chain, transmission and distribution					
CC. Gas pipeline and processing					
DD. Domestic energy-related investments, trading and other projects					

ITEM 1. SYSTEM COMPANIES AND INVESTMENTS THEREIN AS OF DECEMBER 31, 2003

COMPANY NAME	PERCENTAGE OF VOTING SECURITIES OWNED BY IMMEDIATE PARENT	PERCENTAGE OF VOTING SECURITIES OWNED BY OTHER ENTITY	NUMBER OF COMMON SHARES OWNED	ISSUER'S BOOK VALUE EQUITY (IN 000'S)	OWNER'S BOOK VALUE EQUITY (IN 000'S)
CHANGES					
Name Changes	**Date**				
a. From AEP Resources International, Limited To NGLE International, Limited	12/15/2003				
b. From AEP Resources Project Management Company, Limited To NGLE Project Management Company, Limited	12/15/2003				
c. From AEP UK Holding, LLC To AEP Transportation, LLC	12/22/2003				
d. Central and South West, Inc. to AEP Utilities, Inc.	1/21/2003				
e. Houston Pipe Line Company, LLC to AEP Houston Pipe Line, LLC	3/7/2003				
f. CPL Transition Funding LLC to AEP Texas Central Transition Funding LLC	6/30/2003				
Formations	**Jurisdiction**	**Date**			
AEP Wind Energy, LLC	Delaware	4/22/2003			
AEP Coal Marketing, LLC	Delaware	1/22/2003			
AEP Emissions Marketing, LLC	Delaware	1/22/2003			
AEP Houston Pipe Line Company, LLC	Delaware	3/7/2003			
AEP Transportation, LLC f/k/a AEP UK Holding, LLC	Delaware	1/23/2003			
AEP Wind Holding, LLC	Delaware	1/23/2003			
Leesville Land, LLC	Delaware	2/11/2003			
Springdale Land, LLC	Delaware	2/11/2003			
AEP Wind Energy, LLC	Delaware	4/22/2003			
Changes in Status	**Type of change**	**Date**			
AEP Energy Services (Austria) Gmbh	Dissolved	9/2/2003			
AEP Funding Limited	Dissolved	3/31/2003			
CSW Power do Brasil Ltda.	Dissolved	5/9/2003			
Enershop Inc.	Dissolved	6/30/2003			
CSW Development 3, Inc.	Dissolved	2/7/2003			
CSW Development II, Inc.	Dissolved	2/7/2003			
CSW International (U.K.), Inc.	Dissolved	2/7/2003			
CSW Nevada, Inc.	Dissolved	12/31/2003			
CSW Northwest GP, Inc.	Dissolved	12/31/2003			
CSW Northwest LP, Inc.	Dissolved	12/31/2003			
CSWI Netherlands, Inc.	Dissolved	12/31/2003			
Energy Trading Platform Holding Company	Dissolved	12/31/2003			
Envirotherm, Inc.	Dissolved	2/7/2003			
Mutual Energy Service Company, LLC	Sold	3/1/2003			
AEP Energy Services Norway AS	Sold	4/25/2003			
AEP Energy Services (Switzerland) Gmbh	Dissolved	12/3/2003			
AEP Ohio Commercial & Industrial Retail Company, LLC	Dissolved	12/12/2003			
AEP Resources Do Brasil Ltda.	Sold	10/17/2003			
AEP Retail Energy, LLC	Dissolved	12/12/2003			
Caiua-Servicos de Electricidade	Sold	10/17/2003			
CSW Eastex GP I, Inc.	Dissolved	12/12/2003			
CSW Eastex GP II, Inc.	Dissolved	12/31/2003			
CSW Eastex LP I, Inc.	Dissolved	12/31/2003			
CSW Eastex LP II, Inc.	Dissolved	12/31/2003			
CSWC Southwest Holdings, Inc.	Dissolved	12/31/2003			
CSWC Telechoice Management, Inc.	Dissolved	12/12/2003			
Eastex Cogeneration Limited Partnership	Dissolved	12/12/2003			
Empressa de Electricidade Vale de Paranapanema S.A.	Sold	10/17/2003			
Industry And Energy Associates LLC	Sold	10/20/2003			
IPS Eastex, L.L.C.	Dissolved	12/31/2003			
Southwestern Wholesale Electric Company	Dissolved	12/5/2003			

ITEM 2. ACQUISITIONS OR SALES OF UTILITY ASSETS

Acquisition of Utility Assets:

Name of Company	Consideration	Brief Description of Transaction	Location	Exemption
None				

Sale of Utility Assets:

Name of Company	Consideration	Brief Description of Transaction	Location	Exemption
Columbus Southern Power Company	$1,284,000.00	Sale of two transformers and facilities at OSU 138 KV Substation *	Columbus, Ohio	Rule 44
AEP Texas Central Company	1,250,000.00	Sale of 5,000 poles	Texas	Rule 44
AEP Texas Central Company	3,740,125.38	Sale of Dupont-Victoria Substation	Victoria County, Texas	Rule 44
Indiana Michigan Power Company	5,611,275.00	Sale of 24,939 poles	Michigan and Indiana	Rule 44

* Equipment sold for a total purchase price of $3,852,000 in 2001. Payments of one-third each were received in 2001 and 2002, and the final one-third payment was received in 2003.

ITEM 3. ISSUE, SALE, PLEDGE, GUARANTEE OR ASSUMPTION OF SYSTEM SECURITIES

Name of Issuer and Description of Issues (1)	Date and Form of Transactions (2)	Consideration (in thousands) (3)	Authorization or Exemption (4)
Appalachian Power Company (APCo):			
Senior Unsecured Notes,			
3.60% Series, Due 2008	04/30/03 – Public Offering	$198,566	Rule 52
5.95% Series, Due 2033	04/30/03 – Public Offering	197,678	Rule 52
Columbus Southern Power Company (CSPCo):			
Senior Unsecured Notes,			
5.50% Series, Due 2013	02/11/03 – Public Offering	247,718	Rule 52
6.60% Series, Due 2033	02/11/03 – Public Offering	246,633	Rule 52
4.40% Series, Due 2010	11/20/03 – Public Offering	148,564	Rule 52
CSW Energy (Trent Wind Farm)(CSWE):			
Note Payable,			
Variable Note, Due 2011	11/18/03 – Private Offering	74,250	Rule 52
Dolet Hills Lignite Co. LLC (DHLC):			
Note Payable,			
4.47% Note, Due 2011	05/16/03 – Private Offering	44,324	Rule 52
Kentucky Power Company (KPCo):			
Senior Unsecured Notes,			
5.625% Series, Due 2032	06/10/03 – Public Offering	74,169	Rule 52
Ohio Power Company (OPCo):			
Senior Unsecured Notes,			
5.50% Series, Due 2013	02/11/03 – Public Offering	247,728	Rule 52
6.60% Series, Due 2033	02/11/03 – Public Offering	246,648	Rule 52
4.85% Series, Due 2014	07/08/03 – Public Offering	223,153	Rule 52
6.375% Series, Due 2033	07/08/03 – Public Offering	220,986	Rule 52
Public Service of Oklahoma (PSO):			
Senior Unsecured Notes,			
4.85% Series, Due 2010	09/10/03 – Public Offering	148,607	Rule 52

ITEM 3. ISSUE, SALE, PLEDGE, GUARANTEE OR ASSUMPTION OF SYSTEM SECURITIES (CONTINUED)

Name of Issuer and Description of Issues (1)	Date and Form of Transactions (2)	Consideration (in thousands) (3)	Authorization or Exemption (4)
Sabine Mining Company (Sabine):			
Notes Payable,			
6.36% Note, Due 2007	07/01/03 – Private Offering	$4,000	Rule 52
Variable Note, Due 2008	07/01/03 – Private Offering	15,000	Rule 52
7.03% Note, Due 2012	07/01/03 – Private Offering	20,000	Rule 52

GUARANTEE:

At December 31, 2003, American Electric Power Company, Inc. had outstanding parental guaranties of approximately $2.1 billion.

Note: We have not reported transactions previously reported on form U-6B2.

ITEM 4. ACQUISITION, REDEMPTION OR RETIREMENT OF SYSTEM SECURITIES

Name of Issuer and Title of Issue (1)	Name of Company Acquiring, Redeeming or Retiring Securities (2)	Consideration (in thousands) (3)	Extinguished (EXT) or Held (H) for Further Disposition (4)	Authorization or Exemption (5)
American Electric Power Company (AEP):				
Senior Unsecured Notes				
6.125% Series Due 2006	AEP	$49,140	EXT	Rule 42
5.50% Series Due 2003	AEP	250,000	EXT	Rule 42
AEP Desert Sky (AEPDS):				
Note Payable				
Variable Series Due 2017	AEPDS	6,459	EXT	Rule 42
AEP Texas Central Company (TCC):				
Cumulative Preferred Stock				
$100 Par Value				
4.00% Series	TCC	1	EXT	Rule 42
First Mortgage Bonds				
6.875% Series Due 2003	TCC	16,418	EXT	Rule 42
7.50% Series Due 2023	TCC	17,996	EXT	Rule 42
AEP Texas North Company (TNC):				
Cumulative Preferred Stock				
$100 Par Value				
4.40% Series	TNC	7	EXT	Rule 42
AEP Resources, Inc.(AEPR):				
Senior Unsecured Notes Payable				
6-1/2% Series Due 2003	AEPR	350,000	EXT	Rule 42
American Electric Power Service Corp (AEPSC):				
Mortgage Notes				
9.60% Series Due 2008	AEPSC	2,000	EXT	Rule 42
6.355% Series Due 2003	AEPSC	10,000	EXT	Rule 42
Appalachian Power Company (APCo):				
Cumulative Preferred Stock				
No Par Value				
4-1/2% Series	APCo	3	EXT	Rule 42
5.90% Series	APCo	2,500	EXT	Rule 42
5.92% Series	APCo	3,000	EXT	Rule 42
First Mortgage Bonds				
8.50% Series Due 2022	APCo	70,000	EXT	Rule 42
7.80% Series Due 2023	APCo	31,416	EXT	Rule 42
7.15% Series Due 2023	APCo	20,000	EXT	Rule 42
6.00% Series Due 2003	APCo	30,000	EXT	Rule 42

ITEM 4. ACQUISITION, REDEMPTION OR RETIREMENT OF SYSTEM SECURITIES (CONTINUED)

Name of Issuer and Title of Issue (1)	Name of Company Acquiring, Redeeming or Retiring Securities (2)	Consideration (in thousands) (3)	Extinguished (EXT) or Held (H) for Further Disposition (4)	Authorization or Exemption (5)
Appalachian Power Company (APCo) (Continued):				
Senior Unsecured Notes				
7.20% Series Due 2038	APCo	$100,000	EXT	Rule 42
7.30% Series Due 2038	APCo	100,000	EXT	Rule 42
Variable Series Due 2003	APCo	125,000	EXT	Rule 42
Columbus Southern Power Company (CSPCo):				
First Mortgage Bonds				
8.70% Series Due 2022	CSPCo	2,087	EXT	Rule 42
8.55% Series Due 2022	CSPCo	15,642	EXT	Rule 42
8.40% Series Due 2022	CSPCo	14,588	EXT	Rule 42
8.40% Series Due 2022	CSPCo	13,546	EXT	Rule 42
6.80% Series Due 2003	CSPCo	13,000	EXT	Rule 42
6.55% Series Due 2004	CSPCo	26,500	EXT	Rule 42
6.75% Series Due 2004	CSPCo	26,000	EXT	Rule 42
7.90% Series Due 2023	CSPCo	41,580	EXT	Rule 42
7.75% Series Due 2023	CSPCo	34,409	EXT	Rule 42
6.60% Series Due 2003	CSPCo	25,000	EXT	Rule 42
6.10% Series Due 2003	CSPCo	5,000	EXT	Rule 42
CPL Transition Funding (CPLTF):				
Securitization Bonds				
3.54% Series Due 2005	CPLTF	51,013	EXT	Rule 42
Dolet Hills Lignite Company (DHLC):				
Note Payable				
4.47% Series Due 2011	DHLC	3,984	EXT	Rule 42
Indiana Michigan Power Company (I&M):				
Cumulative Preferred Stock				
$100 Par Value				
6-7/8% Series	I&M	1,500	EXT	Rule 42
First Mortgage Bonds				
6.10% Series Due 2003	I&M	30,000	EXT	Rule 42
8.50% Series Due 2022	I&M	75,000	EXT	Rule 42
7.35% Series Due 2023	I&M	15,000	EXT	Rule 42
Junior Debentures				
8.00% Series Due 2026	I&M	40,000	EXT	Rule 42
7.60% Series Due 2038	I&M	125,000	EXT	Rule 42
JMG Funding Corporation (JMG):				
Note Payable				
6.81% Series Due 2008	JMG	1,463	EXT	Rule 42

ITEM 4. ACQUISITION, REDEMPTION OR RETIREMENT OF SYSTEM SECURITIES (CONTINUED)

Name of Issuer and Title of Issue (1)	Name of Company Acquiring, Redeeming or Retiring Securities (2)	Consideration (in thousands) (3)	Extinguished (EXT) or Held (H) for Further Disposition (4)	Authorization or Exemption (5)
Kentucky Power Company (KPCo):				
Junior Debentures				
8.72% Series Due 2025	KPCo	$40,000	EXT	Rule 42
Ohio Power Company (OPCo):				
Preferred Stock				
$100 Par Value				
4-1/2% Series	OPCo	1	EXT	Rule 42
6.02% Series	OPCo	1,100	EXT	Rule 42
6.35% Series	OPCo	500	EXT	Rule 42
First Mortgage Bonds				
6.75% Series Due 2003	OPCo	29,850	EXT	Rule 42
6.55% Series Due 2003	OPCo	27,315	EXT	Rule 42
6.00% Series Due 2003	OPCo	12,500	EXT	Rule 42
6.15% Series Due 2003	OPCo	20,000	EXT	Rule 42
7.75% Series Due 2023	OPCo	5,194	EXT	Rule 42
7.375% Series Due 2023	OPCo	20,997	EXT	Rule 42
7.10% Series Due 2023	OPCo	12,426	EXT	Rule 42
Public Service Company of Oklahoma (PSO):				
First Mortgage Bonds				
6.25% Series Due 2003	PSO	35,000	EXT	Rule 42
7.25% Series Due 2003	PSO	65,000	EXT	Rule 42
7.375% Series Due 2023	PSO	102,970	EXT	Rule 42
Sabine Mining Company (Sabine):				
Notes Payable				
Variable Series Due 2008	Sabine	1,500	EXT	Rule 42
Southwestern Electric Power Company (SWEPCo):				
Preferred Stock				
$100 Par Value				
5.0% Series	SWEPCo	1	EXT	Rule 42
First Mortgage Bonds				
6-1/5% Series Due 2006	SWEPCo	145	EXT	Rule 42
6-5/8% Series Due 2003	SWEPCo	55,000	EXT	Rule 42
7-1/4% Series Due 2023	SWEPCo	46,377	EXT	Rule 42

ITEM 4. ACQUISITION, REDEMPTION OR RETIREMENT OF SYSTEM SECURITIES (CONTINUED)

Name of Issuer and Title of Issue (1)	Name of Company Acquiring, Redeeming or Retiring Securities (2)	Consideration (in thousands) (3)	Extinguished (EXT) or Held (H) for Further Disposition (4)	Authorization or Exemption (5)
Southwestern Electric Power Company (SWEPCo):				
Trust Preferred Securities 7-875% Series Due 2037	SWEPCo	113,402	EXT	Rule 42

Note: We have not reported transactions previously reported on form U-6B2.

ITEM 5. INVESTMENTS IN SECURITIES OF NONSYSTEM COMPANIES AS OF DECEMBER 31, 2003.

1. Aggregate amount of investments in persons operating in the retail service area of AEP or of its subsidiaries.

Name of Company (1)	Aggregate Amount of Investments in Persons (Entities), Operating in Retail Service Area of Owner (2)	Number of Persons (Entities) (3)	Description of Persons (Entities) (4)
Appalachian Power Company	$1,291	10	Economic and Industrial Development Corporations
Wheeling Power Company	13	1	Industrial Development Corporation

2. Subsidiaries owned not included in 1 above.

None

ITEM 6. OFFICERS AND DIRECTORS
PART I as of December 31, 2003

The following are the abbreviations to be used for principal business address and positions.

Principal Business Address	Code
1 Riverside Plaza Columbus, OH 43215	(a)
155 W. Nationwide Blvd, Ste 500 Columbus, OH 43215	(b)
700 Morrison Road Gahanna, OH 43230	(c)
P.O. Box 60 Fort Wayne, IN 46801	(d)
40 Franklin Road Roanoke, VA 24022	(e)
Pushan Power Plant, Admin. Bldg. Nanyang City, Henan Province China 473000	(f)
Walker House P.O. Box 908GT George Town, Grand Cayman Cayman Islands	(g)
400 W. 15th Street Austin, TX 78701	(h)
1105 North Market Street Wilmington, DE 19801	(i)
624 Bourke Street, Level 15 Melbourne, Victoria 3000 Australia	(j)
29/30 St. James=s Street, London SW1A 1HB, Great Britain	(k)
P.O. Box B Brilliant, OH 43913	(l)
248 South Lake Drive Prestonburg, KY 41653	(n)
1 Atlantic Quay Glasgow, Scotland	(m)
222 Bayou Road Belle Chasse, LA 70037	(o)
P.O. Box 127, Convent, LA 70723	(p)
Herengracht 548 Rokin 55, 1012 KK Amsterdam The Netherlands	(q)
Suite 400, Deseret Building Salt Lake City, UT 84111	(r)
Ste 5B,Level 66,MLC Cntr,Martin Plc, Sydney NSW 2000, Australia	(s)
P.O. Box 1328 Fayettesville, AR 72702	(t)
5475 William Flynn Highway Gibsonia, PA 15044	(u)
16090 Swingley Ridge Rd.#600 Chesterfield, MO 63017	(v)
P.O. Box 468 Piketon, Ohio 45661	(w)
Basin Road S.,Portslade,Brighton East Sussex BN41 1WF GB	(y)
474 Flinders Street Melbourne, Victoria 3000 Australia	(aa)
1201 Louisiana St., Suite 1200 Houston, TX 77002	(bb)
Av Dr. Churcrizaldan, 920-8E 13 Andares, Market Place Tower 04583-404-Sao Paulo-SP-Brazil	(cc)
50 Berkeley Street, 6th Fl. Mayfair, London W1J8AP GB	(ff)
1616 Woodall Rodgers Freeway Dallas, TX 75202	(ll)
Torre Chapultepec Piso 13 Ruben Dario, No.281, Bosques de Chapultepec 11580 Mexico, D.F.	(pp)
Williams Tower 2, W. 2nd Street Tulsa, OK 74121	(qq)
428 Travis Street Shreveport, LA 71101	(rr)

Code	Position
AGC	Associate General Counsel
AS	Assistant Secretary
AT	Assistant Treasurer
B	Board of Managers
C	Controller
CAO	Chief Accounting Officer
CB	Chairman of the Board
CCO	Chief Credit Officer
CEO	Chief Executive Officer
CFO	Chief Financial Officer
CIO	Chief Information Officer
CSO	Chief Security Officer
CNO	Chief Nuclear Officer
COO	Chief Operating Officer
CRO	Chief Risk Officer
D	Director
DC	Deputy Controller
DGC	Deputy General Counsel
EVP	Executive Vice President
GC	General Counsel
GM	General Manager
MD	Managing Director
P	President
S	Secretary
SVP	Senior Vice President
T	Treasurer
VCB	Vice Chairman of the Board
VP	Vice President

The officer=s or director=s principal business address is the same as indicated in the Company heading unless another address is provided with the individual=s name.

American Electric Power Company, Inc.

Name and Principal Address(a)	Position
E. R. Brooks	D
3919 Crescent Drive	
Granbury, TX 76049	
Donald M. Carlton	D
8501 Mo-Pac Blvd.	
Austin, TX 78720	
John P. DesBarres	D
P.O. Box 189	
Park City, UT 84060	
E. Linn Draper, Jr.	D,CB,P,CEO
Robert W. Fri	D
6001 Overlea Road	
Bethesda, MD 20816	
William R. Howell	D
42113 N. 105th Street	
Scottsdale, AZ 85262	
Lester A Hudson, Jr.	D
MSC#1223	
Queens University	
1900 Selwyn Ave.	
Charlotte, NC 28274	
Leonard J. Kujawa	D
2660 Peachtree Rd. N.W	
Atlanta, GA 30305	
Richard L. Sandor	D
111 W. Jackson Blvd., 14th FL.	
Chicago, IL 60604	
Thomas V. Shockley, III	D,VCB
Donald G. Smith	D
P.O. Box 13948	
Roanoke, VA 24038	
Linda Gillespie Stuntz	D
555 Eleventh St. N.W.	
Washington, DC 20004	
Kathryn D. Sullivan	D
795 Old Oak Trace	
Columbus, OH 43235	
Henry W. Fayne	VP
Susan Tomasky	VP,S,CFO
Joseph M. Buonaiuto	C,CAO
Leonard V. Assante	DC
Thomas G. Berkemeyer	AS
Jeffrey D. Cross	AS
Wendy G. Hargus (11)	AT

AEP Acquisition, L.L.C.

Name and Principal Address(a)	Position
Holly Keller Koeppel (b)	P
Thomas V. Shockley,III	CB
Jeffrey D. Cross	VP
Armando A. Pena	VP
Stephen P. Smith	T
Joseph M. Buonaiuto	C
Timothy A. King	S

AEP Coal, Inc.

Name and Principal Address(a)	Position
Michael J. Beyer (b)	D,P
Jeffrey D. Cross	D,VP
Armando A. Pena	D,VP
Susan Tomasky	D,VP
Nelson L. Kidder (n)	VP
David G. Zatezalo (n)	VP
Timothy A. King	S

AEP Coal Marketing, Inc.

Name and Principal Address(a)	Position
Jeffrey D. Cross	B,VP
Holly Keller Koeppel (b)	B,P
Armando A. Pena	B,VP
Charles E. Zebula (b)	B,VP
C. R. Boyle, III (b)	VP
Ronald A. Erd	VP
Kevin McGowan (b)	VP
Stephen P. Smith	T
Joseph M. Buonaiuto	C
Timothy A. King	S

AEP Communications, Inc.

Name and Principal Address(a)	Position
Jeffrey D. Cross	D
E. Linn Draper, Jr.	D,CB,CEO
Henry W. Fayne	D,VP
Armando A. Pena	D,VP
Thomas V. Shockley, III	D,VP
Susan Tomasky	D,P
Gregory S. Campbell (b)	VP
Holly Keller Koeppel (b)	VP
Stephen P. Smith	T
Joseph M. Buonaiuto	C,CAO
Leonard V. Assante	DC
Timothy A. King	S

ITEM 6. OFFICERS AND DIRECTORS
PART I (Continued)

AEP Communications, LLC

Name and Principal Address(a)	Position
Holly Keller Koeppel (b)	B,VP
Armando A. Pena	B
Susan Tomasky	B,P
Stephen P. Smith	T
Timothy A. King	S

AEP Credit, Inc.

Name and Principal Address(a)	Position
E. Linn Draper, Jr.	D,CB,CEO,P
Henry W. Fayne	D,VP
Thomas M. Hagan	D
L. T. McDowell 13303 Peyton Drive Dallas, TX 75240	D
Armando A. Pena	D
Thomas V. Shockley, III	D
Susan Tomasky	D,VP
Joseph M. Buonaiuto	C,CAO
Leonard V. Assante	DC
Timothy A. King	S

AEP C&I Company, LLC

Name and Principal Address(a)	Position
Jeffrey D. Cross	B,VP
Holly Keller Koeppel (b)	B,VP
Armando A. Pena	B,VP
Thomas V. Shockley,III	B,CB,P
Stephen P. Smith	T
Timothy A. King	S

AEP Delaware Investment Company

Name and Principal Address(i)	Position
Sean Breiner	D
Jeffrey D. Cross (a)	D,VP
Timothy A. King (a)	D,S
John A. Oscar,Jr.	D
Armando A. Pena (a)	D,P
Mark A. Pyle (a)	D
Stephen P. Smith (a)	T
Joseph M. Buonaiuto (a)	C

AEP Delaware Investment Company II

Name and Principal Address(i)	Position
Sean Breiner	D
Jeffrey D. Cross (a)	D,VP
Timothy A. King (a)	D,S
John A. Oscar,Jr.	D
Armando A. Pena (a)	D,P
Mark A. Pyle (a)	D
Lonnie L. Dieck (b)	VP
Holly Keller Koeppel (b)	VP
Randy G. Ryan (b)	VP
Stephen P. Smith (a)	T
Joseph M. Buonaiuto(a)	C

AEP Delaware Investment Company III

Name and Principal Address(i)	Position
Sean Breiner	D
Jeffrey D. Cross (a)	D,VP
Timothy A. King (a)	D,S
John A. Oscar,Jr.	D
Armando A. Pena (a)	D,P
Mark A. Pyle (a)	D
Stephen P. Smith (a)	T
Joseph M. Buonaiuto(a)	C

AEP Desert Sky GP, LLC

Name and Principal Address(a)	Position
Jeffrey D. Cross	B,VP
Holly Keller Koeppel (b)	B,VP
Armando A. Pena	B,VP
Thomas V. Shockley,III	B,CB,P
Ronald A. Erd	VP
A. Wade Smith	VP
Stephen P. Smith	T
Joseph M. Buonaiuto	C
Timothy A. King	S

AEP Desert Sky LP, LLC

Name and Principal Address(a)	Position
Jeffrey D. Cross	B,VP
Holly Keller Koeppel (b)	B,VP
Armando A. Pena	B,VP
Thomas V. Shockley,III	B,CB,P
Ronald A. Erd	VP
A. Wade Smith	VP
Stephen P. Smith	T
Joseph M. Buonaiuto	C
Timothy A. King	S

AEP Desert Sky LP II, LLC

Name and Principal Address(a)	Position
Jeffrey D. Cross	B,VP
Holly Keller Koeppel (b)	B,VP
Armando A. Pena	B,VP
Thomas V. Shockley,III	B,CB,P
Ronald A. Erd	VP
A. Wade Smith	VP
Stephen P. Smith	T
Joseph M. Buonaiuto	C
Timothy A. King	S

AEP Elmwood LLC

Name and Principal Address(o)	Position
Holly Keller Koeppel(b)	B,VP
Armando A. Pena (a)	B
Mark K. Knoy (v)	P
Michael J. Beyer (b)	VP
Stephen P. Smith (a)	T
Joseph M. Buonaiuto (a)	C
Timothy A. King (a)	S

AEP Emissions Marketing, LLC

Name and Principal Address(a)	Position
Jeffrey D. Cross	B,VP
Holly Keller Koeppel (b)	B,P
Armando A. Pena	B,VP
Charles E. Zebula (b)	B,VP
C. R. Boyle, III (b)	VP
Ronald A. Erd	VP
Kevin J. McGowan (b)	VP
Stephen P. Smith	T
Joseph M. Buonaiuto	C
Timothy A. King	S

ITEM 6. OFFICERS AND DIRECTORS
PART I (Continued)

AEP EmTech, LLC

Name and Principal Address(a)	Position
Henry W. Fayne	B
Thomas V. Shockley,III	B
Susan Tomasky	B
Paul Chodak III	P
Jeffrey D. Cross	VP
Thomas L. Jones	VP
Holly Keller Koeppel (b)	VP
John H. Provanzana	VP
Stephen P. Smith	T
Timothy A. King	S

AEP Energy Services Gas Holding Company

Name and Principal Address(a)	Position
Jeffrey D. Cross	D,VP
E. Linn Draper, Jr.	D,CB,CEO
Holly Keller Koeppel (b)	D,VP
Armando A. Pena	D,VP
Thomas V. Shockley,III	D,P
Susan Tomasky	D
Ronald A. Erd	VP
Stephen P. Smith	T
Joseph M. Buonaiuto	C
Timothy A. King	S

AEP Energy Services Gas Holding Company II, LLC

Name and Principal Address(a)	Position
None	

AEP Energy Services GmbH
(IN LIQUIDATION 2/3/03)

Name and Principal Address(ff)	*Position*
Armando A. Pena (a)	*LIQUIDATOR*

AEP Energy Services Investments, Inc.

Name and Principal Address(i)	Position
Sean A. Breiner	D
Jeffrey D. Cross (a)	D,VP
Timothy A. King (a)	D,S
John A. Oscar,Jr.	D
Armando A. Pena (a)	D,VP
Mark A. Pyle (a)	D
Thomas V. Shockley,III(a)	P
Stephen P. Smith (a)	T
Joseph M. Buonaiuto (a)	C

AEP Energy Services Limited

Name and Principal Address(ff)	Position
Jeffrey D. Cross (a)	D
Ronald A. Erd (a)	D
Holly Keller Koeppel (b)	D
Armando A. Pena (a)	D
Stuart W. Staley	MD
John David Young	D
Wendy Hargus (11)	T
Linda M. Pszon	S

AEP Energy Services Trading Limited

Name and Principal Address(ff)	Position
Stuart W. Staley	D
John David Young	D
Armando A. Pena (a)	T
Linda M. Pszon	S

AEP Energy Services(Australia)Pty Ltd

Name and Principal Address(s)	Position
Jeffrey D. Cross (a)	D
Ronald A. Erd (a)	D
Paul Robert Rainey 600 Bourke Street, Melbourn, Victoria, 3000 Australia	D,S
John David Young (ff)	D
Armando A. Pena (a)	T
Linda M. Pszon (ff)	S

AEP Energy Services, Inc.

Name and Principal Address(a)	Position
Jeffrey D. Cross	D
E. Linn Draper, Jr.	D,CB,CEO
Henry W. Fayne	D,VP
Holly Keller Koeppel (b)	D,P
Armando A. Pena	D,VP
Thomas V. Shockley, III	D,VP
Susan Tomasky	D,VP
Ronald A. Erd	VP
Nelson L. Kidder (n)	VP
Donald B. Simpson (b)	VP
David G Zatezalo (n)	VP
Stephen P. Smith	T
Joseph M. Buonaiuto	C,CAO
Leonard V. Assante	DC
Timothy A. King	S

AEP Energy Services UK Generation Limited

Name and Principal Address(ff)	Position
Paul E. Connon	D
Jeffrey D. Cross (a)	D
Holly Keller Koeppel (b)	D
Armando A. Pena (a)	D
Surinder S. Toor	D
Wendy G. Hargus (11)	T
Linda M. Pszon	S

AEP Energy Services Ventures, Inc.

Name and Principal Address(i)	Position
Sean A. Breiner	D
Jeffrey D. Cross (a)	D,VP
Timothy A. King (a)	D,S
John A. Oscar,Jr.	D
Armando A. Pena (a)	D,VP
Mark A. Pyle (a)	D
Thomas V. Shockley,III(a)	P
Stephen P. Smith (a)	T
Joseph M. Buonaiuto (a)	C

ITEM 6. OFFICERS AND DIRECTORS
PART I (Continued)

AEP Energy Services Ventures II, Inc.

Name and Principal Address(i)	Position
Sean A. Breiner	D
Jeffrey D. Cross (a)	D,VP
Timothy A. King (a)	D,S
John A. Oscar,Jr.	D
Armando A. Pena (a)	D,VP
Mark A. Pyle (a)	D
Thomas V. Shockley,III(a)	P
Stephen P. Smith (a)	T
Joseph M. Buonaiuto (a)	C

AEP Energy Services Ventures III, Inc.

Name and Principal Address(i)	Position
Sean A. Breiner	D
Jeffrey D. Cross (a)	D,VP
Timothy A. King (a)	D,S
John A. Oscar,Jr.	D
Armando A. Pena (a)	D,VP
Mark A. Pyle (a)	D
Thomas V. Shockley,III(a)	P
Stephen P. Smith (a)	T
Joseph M. Buonaiuto (a)	C

AEP Fiber Venture, LLC

Name and Principal Address(a)	Position
Holly Keller Koeppel (b)	B,VP
Armando A. Pena	B,VP
Susan Tomasky	B,P
Jeffrey D. Cross	VP
Stephen P. Smith	T
Timothy A. King	S

AEP Gas Marketing LP

Name and Principal Address(bb)	Position
Holly Keller Koeppel (b)	P
Jeffrey D. Cross (a)	VP
Jim Deidiker	VP
Edward D. Gottlob	VP
Armando A. Pena (a)	VP
Stephen Schneider	VP
Joseph M. Buonaiuto (a)	C
Stephen P. Smith	T
Timothy A. King (a)	S

AEP Gas Power GP, LLC

Name and Principal Address(a)	Position
Jeffrey D. Cross	B,VP
Armando A. Pena	B
Robert P. Powers	B,VP
Thomas V. Shockley,III	B,CB,P
Stephen P. Smith	T
Timothy A. King	S

AEP Gas Power Systems, LLC

Name and Principal Address(a)	Position
Charles C. Cooper 430 Telser Road Lake Zurich, IL 60047-1588	B
Daniel O. Dickinson 430 Telser Road Lake Zurich, IL 60047-1588	B
Robert P. Powers	B
Michael W. Rencheck	B
Mark W. Marano	P,CEO
Armando A. Pena	T
Timothy A. King	S

AEP Generating Company

Name and Principal Address(a)	Position
Jeffrey D. Cross	D
E. Linn Draper, Jr.	D,CB,CEO
Henry W. Fayne	D,P
Thomas M. Hagan	D,VP
Armando A. Pena	D,VP
Robert P. Powers	D,VP
Thomas V. Shockley, III	D,VP
Susan Tomasky	D,VP
William L. Sigmon,Jr. (b)	VP
Stephen P. Smith (a)	T
Joseph M. Buonaiuto	C,CAO
Leonard V. Assante	DC
Timothy A. King	S

AEP Houston Pipe Line Company, LLC

Name and Principal Address(bb)	Position
Jeffrey D. Cross (a)	B,VP
Holly Keller Koeppel (b)	B,P
Armando A. Pena (a)	B,VP
Thomas V. Shockley,III (a)	B
C. R. Boyle, III (b)	VP
Jim Deidiker	VP
Ronald A. Erd (a)	VP
Edward D. Gottlob	VP
Stephen Schneider	VP
Stephen P. Smith (a)	T
Joseph M. Buonaiuto (a)	C
Timothy A. King (a)	S

AEP Investments, Inc.

Name and Principal Address(a)	Position
Jeffrey D. Cross	D
E. Linn Draper, Jr.	D,CB,CEO
Henry W. Fayne	D,VP
Armando A. Pena	D,VP
Thomas V. Shockley, III	D,VP
Susan Tomasky	D,P
Michelle S. Kalnas	VP
Holly Keller Koeppel (b)	VP
Stephen P. Smith	T
Joseph M. Buonaiuto	C,CAO
Leonard V. Assante	DC
Timothy A. King	S

AEP Kentucky Coal, L.L.C.

Name and Principal Address(n)	Position
Jeffrey D. Cross (a)	B,VP
Armando A. Pena (a)	B,VP
David G. Zatezalo	B,P
Nelson L. Kidder	VP
Susan Tomasky (a)	VP
Stephen P. Smith (a)	T
Timothy A. King (a)	S

ITEM 6. OFFICERS AND DIRECTORS
PART I (Continued)

AEP MEMCo LLC

Name and Principal Address(v)	Position
Holly Keller Koeppel (b)	B,VP
Armando A. Pena (a)	B
Mark K. Knoy	P
Michael J. Beyer (b)	VP
Joseph M. Buonaiuto (a)	C
Stephen P. Smith (a)	T
Timothy A. King (a)	S

AEP Ohio Coal, L.L.C.

Name and Principal Address(a)	Position
Jeffrey D. Cross	B,VP
Armando A. Pena	B,VP
David G. Zatezalo (n)	B,P
Nelson L. Kidder (n)	VP
Susan Tomasky	VP
Stephen P. Smith	T
Timothy A. King	S

AEP Ohio Retail Energy, LLC

Name and Principal Address(a)	Position
Jeffrey D. Cross	B,VP
Holly Keller Koeppel (b)	B,VP
Armando A. Pena	B
Thomas V. Shockley,III	B,CB,P
Stephen P. Smith	T
Timothy A. King	S

AEP Power Marketing, Inc.

Name and Principal Address(a)	Position
Jeffrey D. Cross	D
E. Linn Draper, Jr.	D,CB,CEO
Henry W. Fayne	D,VP
Armando A. Pena	D,VP
Susan Tomasky	D,VP
Thomas V. Shockley,III	P
Joseph M. Buonaiuto	C,CAO
Stephen P. Smith	T
Timothy A. King	S

AEP Pro Serv, Inc.

Name and Principal Address(a)	Position
Jeffrey D. Cross	D
E. Linn Draper, Jr.	D,CB,CEO
Henry W. Fayne	D,VP
Armando A. Pena	D,VP
Robert P. Powers	D,VP
Michael W. Rencheck	D,P
Thomas V. Shockley, III	D,VP
Susan Tomasky	D,VP
Mark W. Marano	SVP
Robert T. Burns	VP
Mark A. Gray	VP
John A. Mazzone (b)	VP
Stephen P. Smith	T
Joseph M. Buonaiuto	C,CAO
Leonard V. Assante	DC
Timothy A. King	S

AEP Properties, L.L.C.

Name and Principal Address(a)	Position
Ronald A. Erd	B
A. Wade Smith	B
Richard P. Walker (ll)	B

AEP Resources Australia Holdings Pty Ltd

Name and Principal Address(j)	Position
Herbert L. Hogue (a)	D
Holly Keller Koeppel (b)	D
Armando A. Pena (a)	D,T
Paul Robert Rainey	D,S
Jeffrey D. Cross (a)	S

AEP Resources Australia Pty., Ltd.

Name and Principal Address(j)	Position
Jeffrey D. Cross (a)	D,S
Armando A. Pena (a)	D,T
Paul Robert Rainey	D,S
Timothy A. King (a)	S

AEP Resources, Inc.

Name and Principal Address(a)	Position
Jeffrey D. Cross	D
E. Linn Draper, Jr.	D,CB,CEO
Henry W. Fayne	D,VP
Armando A. Pena	D,VP
Thomas V. Shockley, III	D,VP
Susan Tomasky	D,P
Ronald A. Erd	VP
Holly Keller Koeppel (b)	VP
James H. Sweeney	VP
Stephen P. Smith	T
Joseph M. Buonaiuto	C,CAO
Leonard V. Assante	DC
Timothy A. King	S

AEP Resources Limited

Name and Principal Address(k)	Position
Jeffrey D. Cross (a)	D
Holly Keller Koeppel (b)	D
Armando A. Pena (a)	D
Wendy G. Hargus (ll)	T
Timothy A. King (a)	S
Linda M. Pszon (ff)	S

ITEM 6. OFFICERS AND DIRECTORS
PART I (Continued)

AEP Texas Central Company

Name and Principal Address(a)	Position
Jeffrey D. Cross	D
E. Linn Draper, Jr.	D,CB,CEO
Henry W. Fayne	D,P
Thomas M. Hagan	D,VP
Armando A. Pena	D,VP
Robert P. Powers	D,VP
Thomas V. Shockley,III	D,VP
Susan Tomasky	D,VP
Charles H. Adami (11)	VP
Stephen W. Burge (b)	VP
Glenn M. Files	VP
Harry Gordon, Jr. 539 N. Carancahua Corpus Christi, TX 78401	VP
Michelle S. Kalnas	VP
Mano K. Nazar One Cook Place Bridgman, MI 41906	VP
Charles R. Patton (h)	VP
Julio C. Reyes (h)	VP
Marsha P. Ryan	VP
William L. Sigmon,Jr.(b)	VP
Richard P. Verret (c)	VP
Stephen P. Smith	T
Joseph M. Buonaiuto	C,CAO
Leonard V. Assante	DC
Timothy A. King	S

AEP Texas Commercial & Industrial Retail GP, LLC

Name and Principal Address(a)	Position
Jeffrey D. Cross	B,VP
Holly Keller Koeppel (b)	B,VP
Armando A. Pena	B
Thomas V. Shockley,III	B,CB,P
Stephen P. Smith	T
Timothy A. King	S

AEP Texas Commercial & Industrial Retail Limited Partnership

Name and Principal Address(h)	Position
Thomas V. Shockley,III(a)	P
Jeffrey D. Cross (a)	VP
Holly Keller Koeppel(b)	VP
Armando A. Pena (a)	VP
Brian X. Tierney (b)	VP
Charles E. Zebula (b)	VP
Stephen P. Smith (a)	T
Timothy A. King (a)	S

AEP Texas North Company

Name and Principal Address(a)	Position
Jeffrey D. Cross	D
E. Linn Draper, Jr.	D,CB,CEO
Henry W. Fayne	D,P
Thomas M. Hagan	D,VP
Armando A. Pena	D,VP
Robert P. Powers	D,VP
Thomas V. Shockley,III	D,VP
Susan Tomasky	D,VP
Charles H. Adami (11)	VP
Stephen W. Burge (b)	VP
Glenn M. Files	VP
Harry Gordon, Jr. 539 N. Carancahua Corpus Christi, TX 78401	VP
Michelle S. Kalnas	VP
Charles R. Patton (h)	VP
Julio C. Reyes (h)	VP
Marsha P. Ryan	VP
William L. Sigmon,Jr. (b)	VP
Richard P. Verret (c)	VP
Stephen P. Smith	T
Joseph M. Buonaiuto	C,CAO
Leonard V. Assante	DC
Timothy A. King	S

AEP Texas POLR GP, LLC

Name and Principal Address(h)	Position
Jeffrey D. Cross (a)	B,VP
Holly Keller Koeppel(b)	B,VP
Armando A. Pena (a)	B
Thomas V. Shockley,III(a)	B,CB,P
Stephen P. Smith (a)	T
Timothy A. King (a)	S

AEP Texas POLR, LLC

Name and Principal Address(a)	Position
Jeffrey D. Cross	B,VP
Holly Keller Koeppel (b)	B,VP
Armando A. Pena	B
Thomas V. Shockley,III	B,CB,P
Stephen P. Smith	T
Timothy A. King	S

AEP Transportation, LLC

Name and Principal Address(a)	Position
Jeffrey D. Cross	B,VP
Holly Keller Koeppel (b)	B,P
Armando A. Pena	B,VP
Charles E. Zebula (b)	B,VP
C. R. Boyle, III (b)	VP
Ronald A. Erd	VP
Stephen P. Smith	T
Joseph M. Buonaiuto	C
Timothy A. King	S

AEP T&D Services, LLC

Name and Principal Address(a)	Position
Jeffrey D. Cross	B,VP
Glenn M. Files	B,P
Thomas L. Kirkpatrick	B
Armando A. Pena	B
Richard P. Verret (c)	B,VP
Dale E. Cory 1331 Goodale Blvd. Columbus, OH 43212	VP
G. Michael Taylor	VP
Stephen P. Smith	T
Timothy A. King	S

ITEM 6. OFFICERS AND DIRECTORS
PART I (Continued)

AEP Utilities, Inc. (was Central and South West Corporation)

Name and Principal Address(a)	Position
Jeffery D. Cross	D
E. Linn Draper, Jr.	D,CB,CEO,P
Henry W. Fayne	D,VP
Thomas M. Hagan	D
Armando A. Pena	D
Robert P. Powers	D
Thomas V. Shockley,III	D,VCB,COO
Susan Tomasky	D
Joseph M. Buonaiuto	C,CAO
Stephen P. Smith	T
Leonard V. Assante	DC
Timothy A. King	S

AEP West Virginia Coal, Inc.

Name and Principal Address(a)	Position
Jeffrey D. Cross	D,VP
Armando A. Pena	D,VP
Susan Tomasky	D,VP
David G. Zatezalo (n)	D,P
Nelson L. Kidder (n)	VP
Stephen P. Smith	T
Timothy A. King	S

AEP Wind Energy, LLC

Name and Principal Address(a)	Position
Jeffrey D. Cross	B,VP
Holly Keller Koeppel (b)	B,VP
Armando A. Pena	B,VP
Thomas V. Shockley,III	B,P
Ronald A. Erd	VP
Stephen P. Smith	T
Joseph M. Buonaiuto	C
Timothy A. King	S

AEP Wind GP, LLC

Name and Principal Address(a)	Position
Thomas V. Shockley,III	P
Jeffrey D. Cross	VP
Ronald A. Erd	VP
Holly Keller Koeppel (b)	VP
Armando A. Pena	VP
A. Wade Smith	VP
Stephen P. Smith	T
Joseph M. Buonaiuto	C
Timothy A. King	S

AEP Wind Holding, LLC

Name and Principal Address(a)	Position
Jeffrey D. Cross	B,VP
Holly Keller Koeppel (b)	B,VP
Armando A. Pena	B,VP
Thomas V. Shockley,III	B,P
Ronald A. Erd	VP
Stephen P. Smith	T
Joseph M. Buonaiuto	C
Timothy A. King	S

AEP Wind LP, LLC

Name and Principal Address(a)	Position
Thomas V. Shockley,III	P
Jeffrey D. Cross	VP
Ronald A. Erd	VP
Holly Keller Koeppel (b)	VP
Armando A. Pena	VP
A. Wade Smith	VP
Stephen P. Smith	T
Joseph M. Buonaiuto	C
Timothy A. King	S

AEP Wind LP II, LLC

Name and Principal Address(a)	Position
Jeffrey D. Cross	B,VP
Holly Keller Koeppel (b)	B,VP
Armando A. Pena	B,VP
Thomas V. Shockley,III	B,CB,P
Ronald A. Erd	VP
A. Wade Smith	VP
Stephen P. Smith	T
Joseph M. Buonaiuto	C
Timothy A. King	S

AEPR Energy Ventures B.V.

Name and Principal Address(q)	Position
Jeffrey D. Cross (a)	MD
Armando A. Pena (a)	MD

AEPR Global Energy B.V.

Name and Principal Address(q)	Position
Jeffrey D. Cross (a)	MD
Armando A. Pena (a)	MD

AEPR Global Holland Holding B.V.

Name and Principal Address(q)	Position
AEP Resources, Inc. (a)	MD
Jeffrey D. Cross (a)	MD
Ronald A. Erd (a)	MD
Armando A. Pena (a)	MD
John David Young (ff)	MD

AEPR Global Investments B.V.

Name and Principal Address(q)	Position
Jeffrey D. Cross (a)	MD
Ronald A. Erd (a)	MD
Armando A. Pena (a)	MD
John David Young (ff)	MD

AEPR Global Ventures B.V.

Name and Principal Address(q)	Position
Jeffrey D. Cross (a)	MD
Ronald A. Erd (a)	MD
Armando A. Pena (a)	MD
John David Young (ff)	MD

AEPR Ohio, LLC

Name and Principal Address(a)	Position
Jeffrey D. Cross	B,VP
Armando A. Pena	B,VP
Thomas V. Shockley, III	B,CB,P
Stephen P. Smith	T
Timothy A. King	S

ITEM 6. OFFICERS AND DIRECTORS
PART I (Continued)

American Electric Power Service Corporation

Name and Principal Address(a)	Position
Jeffrey D. Cross	D,SVP,GC,AS
E. Linn Draper, Jr.	D,CB,P,CEO
Henry W. Fayne	D,EVP
Thomas M. Hagen	D,EVP
Holly Keller Koeppel (b)	D,EVP
Robert P. Powers	D,EVP
Thomas V. Shockley, III	D,VCB,COO
Susan Tomasky	D,EVP,AS
Melinda S. Ackerman	SVP
Nicholas J. Ashooh	SVP
J. C. Baker	SVP
A. Christopher Bakken,III	SVP
One Cook Place	
Bridgman, MI 49106	
C. R. Boyle, III (b)	SVP
Joseph M. Buonaiuto	SVP,C,CAO
Glenn M. Files	SVP
Joseph Hamrock	SVP,CIO
Dale E. Heydlauff	SVP
Michelle S. Kalnas	SVP
Mark W. Marano	SVP
R. E. Munczinski	SVP
Mano K. Nazar	SVP,CNO
One Cook Place	
Bridgman, MI 41906	
Andrew W. Patterson	SVP
Armando A. Pena	SVP
Michael W. Rencheck	SVP
Marsha P. Ryan	SVP
William L. Sigmon,Jr.(b)	SVP
Scott N. Smith	SVP,CRO
Stephen P. Smith	SVP,T
Brian X. Tierney (b)	SVP
Richard P. Verret (c)	SVP
Charles E. Zebula (b)	SVP
Nicholas K. Akins	VP
Leonard V. Assante	VP
Michael J. Assante	VP,CSO
Mark A. Bailey (c)	VP
Keith Barnett (b)	VP
Thomas A. Barry (b)	VP
Robert W. Bradish (b)	VP
Edward J. Brady	VP
Bruce H. Braine	VP
Stephen W. Burge (b)	VP
Robert T. Burns	VP
Todd D Busby (b)	VP
G. A. Clark	VP
110 W. Michigan Ave,	
Lansing, MI 48933	
Robert G. Cohn (b)	VP
Martin L. Cuilla (b)	VP
W. N. D=Onofrio	VP
John L. Dickerman	VP
Lonni L. Dieck (b)	VP
Diane M. Fitzgerald	VP
8523 Livingston Hills	
Bridgman, MI 49106	
Mark A. Gray	VP
Greg B. Hall (b)	VP
James G. Haunty (c)	VP
Wendy G. Hargus (11)	VP,AT
John D. Harper (c)	VP
Timothy G. Harshbarger	VP
Joseph R. Hartsoe	VP
801 Pennsylvania Ave.NW	
Washington, DC 20004	
Stephan T. Haynes (b)	VP
Frank Hilton (b)	VP,CCO
Anthony P. Kavanagh	VP
801 Pennsylvania Ave.NW	
Washington, DC 20004	
Nelson L. Kidder (n)	VP
Ray A. King (c)	VP
Thomas L. Kirkpatrick	VP
Preston S. Kissman	VP
Jeffery LaFleur (b)	VP
Timothy K. Light (b)	VP
Michael D. Martin	VP
Mark C. McCullough (b)	VP
Kevin J. McGowan (b)	VP
John M. McManus	VP
D. Michael Miller	VP,DGC
Scott P. Moore	VP
Richard A. Mueller	VP
Donald M. Norman (b)	VP
Gary M. Prescott	VP,DGC
Craig T. Rhoades	VP
Daniel J. Rogier	VP
William L. Scott	VP
Scott D. Slisher (b)	VP
O. J. Sever	VP
Stuart Solomon	VP
Laura J. Thomas (b)	VP
David B. Trego	VP
David C. Warner (b)	VP
Mark A. Welch	VP
Timothy A. King	S
Thomas G. Berkemeyer	AS,AGC

Appalachian Power Company

Name and Principal Address(a)	Position
Jeffrey D. Cross	D
E. Linn Draper, Jr.	D,CB,CEO
Henry W. Fayne	D,P
Thomas M. Hagan	D,VP
Armando A. Pena	D,VP
Robert P. Powers	D,VP
Thomas V. Shockley,III	D,VP
Susan Tomasky	D,VP
R. D. Carson, Jr.	VP
1051 East Cary Street	
Richmond, VA 23219	
Mark E. Dempsey	VP
707 Virginia Street, East	
Charleston, WV 25301	
Glenn M. Files	VP
Gene M. Jensen	VP
P.O. Box 1986	
Charleston, WV 25312	
Michelle S. Kalnas	VP
Holly Keller Koeppel (b)	VP
Mark C. McCullough (b)	VP
Marsha P. Ryan	VP
William L. Sigmon,Jr. (b)	VP
Richard P. Verret (c)	VP
William F. Vineyard (b)	VP
Joseph M. Buonaiuto	C,CAO
Stephen P. Smith	T
Leonard V. Assante	DC
Timothy A. King	S

ITEM 6. OFFICERS AND DIRECTORS
PART I (Continued)

Blackhawk Coal Company

Name and Principal Address(r)	Position
Jeffrey D. Cross (a)	D
E. Linn Draper, Jr. (a)	D,CB,CEO
Henry W. Fayne (a)	D,VP
Armando A. Pena (a)	D,VP
Thomas V. Shockley,III(a)	D,VP
Susan Tomasky (a)	D,VP
Gerald M. Dimmerling 377 Highway 522 Mansfield, LA 71052	P
Stephen P. Smith (a)	T
Joseph M. Buonaiuto (a)	C,CAO
Leonard V. Assante (a)	DC
Timothy A. King (a)	S

C3 Communications, Inc.

Name and Principal Address(a)	Position
Jeffrey D. Cross	D
E. Linn Draper, Jr.	D,CB,CEO
Henry W. Fayne	D,VP
Holly Keller Koeppel (b)	D,VP
Armando A. Pena	D,VP
Thomas V. Shockley, III	D,VP
Susan Tomasky	D,P
Stephen P. Smith	T
Joseph M. Buonaiuto	C,CAO
Leonard V. Assante	DC
Timothy A. King	S

C3 Networks & Communications Limited Partnership

Name and Principal Address(a)	Position
Susan Tomasky	P
Jeffrey D. Cross	VP
Holly Keller Koeppel (b)	VP
Armando A. Pena	VP
Stephen P. Smith	T
Timothy A. King	S

C3 Networks GP, L.L.C.

Name and Principal Address(a)	Position
Jeffrey D. Cross	B,VP
Holly Keller Koeppel (b)	B,VP
Armando A. Pena	B,VP
Susan Tomasky	B,P
Stephen P. Smith	T
Timothy A. King	S

C3 Networks Limited Partnership

Name and Principal Address(a)	Position
Susan Tomasky	P
Jeffrey D. Cross	VP
Holly Keller Koeppel (b)	VP
Armando A. Pena	VP
Stephen P. Smith	T
Timothy A. King	S

Cardinal Operating Company

Name and Principal Address(l)	Position
Anthony J. Ahern 6677 Busch Blvd. Columbus, OH 43226	D,VP
J. C. Baker (a)	D
E. Linn Draper, Jr. (a)	D,P
Henry W. Fayne (a)	D,VP
Ralph E. Luffler P.O. Box 250 Lancaster, OH 43130-0250	D,VP
Steven K. Nelson P.O. Box 280 Coshocton, OH 43812	D,VP
Patrick W. O=Loughlin 6677 Busch Blvd. Columbus, OH 43226	D,VP
Michael W. Rencheck (a)	D,VP
William L. Sigmon, Jr.(b)	D,VP
Michael L. Sims 3888 Stillwell Beckett Rd. Oxford, OH 45056	D
Joseph M. Buonaiuto (a)	C
Timothy A. King (a)	S

Cedar Coal Co.

Name and Principal Address(e)	Position
Jeffrey D. Cross (a)	D
E. Linn Draper, Jr. (a)	D,CB,CEO
Henry W. Fayne (a)	D,VP
Armando A. Pena (a)	D,VP
Thomas V. Shockley,III(a)	D,VP
Susan Tomasky (a)	D,VP
Gerald M. Dimmerling 377 Highway 522 Mansfield, LA 71052	P
Stephen P. Smith (a)	T
Joseph M. Buonaiuto (a)	C,CAO
Leonard V. Assante (a)	DC
Timothy A. King (a)	S

Central Appalachian Coal Company

Name and Principal Address(e)	Position
Jeffrey D. Cross (a)	D
E. Linn Draper, Jr. (a)	D,CB,CEO
Henry W. Fayne (a)	D,VP
Armando A. Pena (a)	D,VP
Thomas V. Shockley,III(a)	D,VP
Susan Tomasky (a)	D,VP
Gerald M. Dimmerling 377 Highway 522 Mansfield, LA 71052	P
Stephen P. Smith (a)	T
Joseph M. Buonaiuto (a)	C,CAO
Leonard V. Assante (a)	DC
Timothy A. King (a)	S

Central Coal Company

Name and Principal Address(e)	Position
Jeffrey D. Cross (a)	D
E. Linn Draper, Jr. (a)	D,CB,CEO
Henry W. Fayne (a)	D,VP
Armando A. Pena (a)	D,VP
Thomas V. Shockley,III(a)	D,VP
Susan Tomasky (a)	D,VP
David G. Zatezalo (n)	P
Nelson L. Kidder (n)	VP
Stephen P. Smith (a)	T
Joseph M. Buonaiuto (a)	C,CAO
Leonard V. Assante (a)	DC
Timothy A. King (a)	S

ITEM 6. OFFICERS AND DIRECTORS
PART I (Continued)

Colomet, Inc.

Name and Principal Address(a)	Position
Jeffrey D. Cross	D
E. Linn Draper, Jr.	D,P,CEO
Henry W. Fayne	D,VP
Thomas M. Hagan	D,VP
Armando A. Pena	D,VP
Thomas V. Shockley, III	D,VP
Susan Tomasky	D,VP
Glenn M. Files	VP
Richard P. Verret (c)	VP
Stephen P. Smith	T
Joseph M. Buonaiuto	C,CAO
Leonard V. Assante	DC
Timothy A. King	S

Columbus Southern Power Company

Name and Principal Address(a)	Position
Jeffrey D. Cross	D
E. Linn Draper, Jr.	D,CB,CEO
Henry W. Fayne	D,P
Thomas M. Hagan	D,VP
Armando A. Pena	D,VP
Robert P. Powers	D,VP
Thomas V. Shockley,III	D,VP
Susan Tomasky	D,VP
Karl G. Boyd (d)	VP
David M. Fenstermaker (c)	VP
Glenn M. Files	VP
Jane A. Harf 88 East Broad Street,8th Fl. Columbus, OH 43215	VP
Michelle S. Kalnas	VP
Holly Keller Koeppel (b)	VP
Jeffrey D. LaFleur (b)	VP
Marsha P. Ryan	VP
William L. Sigmon,Jr. (b)	VP
Richard P. Verret (c)	VP
William F. Vineyard (b)	VP
Stephen P. Smith	T
Joseph M. Buonaiuto	C,CAO
Leonard V. Assante	DC
Timothy A. King	S

Conesville Coal Preparation Company

Name and Principal Address(a)	Position
Jeffrey D. Cross	D
E. Linn Draper, Jr.	D,CB,CEO
Henry W. Fayne	D,VP
Armando A. Pena	D,VP
Thomas V. Shockley,III	D,VP
Susan Tomasky	D,VP
Jeffrey D. LaFleur (b)	P
Stephen P. Smith	T
Joseph M. Buonaiuto	C,CAO
Leonard V. Assante	DC
Timothy A. King	S

Conlease, Inc.

Name and Principal Address (p)	Position
Holly Keller Koeppel (b)	D,VP
Armando A. Pena (a)	D,VP
Mark K. Knoy (v)	P
Michael J. Beyer (b)	VP
Stephen P. Smith (a)	T
Joseph M. Buonaiuto (a)	C
Timothy A. King (a)	S

CSW Development-I, Inc.

Name and Principal Address(a)	Position
Jeffrey D. Cross	D,VP
Holly Keller Koeppel (b)	D,P
Armando A. Pena	D,VP
Ronald A. Erd	VP
Joseph M. Buonaiuto	C
Timothy A. King	S
Wendy G. Hargus (ll)	T

CSW Energy Services, Inc.

Name and Principal Address(a)	Position
Jeffrey D. Cross	D
Holly Keller Koeppel (b)	D,P
Armando A. Pena	D,VP
Thomas V. Shockley, III	D
Stephen P. Smith	T
Joseph M. Buonaiuto	C,CAO
Timothy A. King	S

CSW Energy, Inc.

Name and Principal Address(a)	Position
Jeffrey D. Cross	D
E. Linn Draper, Jr.	D,CB,CEO
Henry W. Fayne	D,VP
Holly Keller Koeppel (b)	D,VP
Armando A. Pena	D,VP
Thomas V. Shockley, III	D,P
Susan Tomasky	D,VP
Stephen P. Smith	T
Joseph M. Buonaiuto	C,CAO
Leonard V. Assante	DC
Timothy A. King	S

CSW Ft. Lupton, Inc.

Name and Principal Address(a)	Position
Jeffrey D. Cross	D,VP
Holly Keller Koeppel (b)	D,P
Armando A. Pena	D,VP
Ronald A. Erd	VP
Wendy G. Hargus (ll)	T
Joseph M. Buonaiuto	C
Timothy A. King	S

CSW International Two, Inc.

Name and Principal Address(a)	Position
Jeffrey D. Cross	D,VP
Timothy A. King	D,S
Armando A. Pena	D,P
Mark A. Pyle	D
Holy Keller Koeppel (b)	VP
Bradford R. Signet	VP
Stephen P. Smith	T
Joseph M. Buonaiuto	C

ITEM 6. OFFICERS AND DIRECTORS
PART I (Continued)

CSW International, Inc.(a Delaware Corp.)

Name and Principal Address(a)	Position
Jeffrey D. Cross	D
E. Linn Draper, Jr.	D,CB,CEO
Henry W. Fayne	D,VP
Armando A. Pena	D,VP
Thomas V. Shockley, III	D,P
Susan Tomasky	D,VP
Holly Keller Koeppel (b)	VP
Stephen P. Smith	T
Joseph M. Buonaiuto	C,CAO
Leonard V. Assante	DC
Timothy A. King	S

CSW International, Inc.(a Cayman Corp.)

Name and Principal Address(a)	Position
Holly Keller Koeppel (b)	D,P
Jeffrey D. Cross	D,VP
Armando A. Pena	D,VP
Susan Tomasky	D
Wendy G. Hargus (11)	T
Timothy A. King	S

CSW Mulberry II, Inc.

Name and Principal Address(a)	Position
Jeffrey D. Cross	D,VP
Holly Keller Koeppel (b)	D,P
Armando A. Pena	D,VP
Ron A. Erd	VP
Wendy G. Hargus (11)	T
Joseph M. Buonaiuto	C
Timothy A. King	S

CSW Mulberry, Inc.

Name and Principal Address(a)	Position
Jeffrey D. Cross	D,VP
Holly Keller Koeppel (b)	D,P
Armando A. Pena	D,VP
Ron A. Erd	VP
Wendy G. Hargus (11)	T
Joseph M. Buonaiuto	C
Timothy A. King	S

CSW Orange II, Inc.

Name and Principal Address(a)	Position
Jeffrey D. Cross	D,VP
Holly Keller Koeppel (b)	D,P
Armando A. Pena	D,VP
Ronald A. Erd	VP
Wendy G. Hargus (11)	T
Joseph M. Buonaiuto	C
Timothy A. King	S

CSW Orange, Inc.

Name and Principal Address(a)	Position
Jeffrey D. Cross	D,VP
Holly Keller Koeppel (b)	D,P
Armando A. Pena	D,VP
Ronald A. Erd	VP
Wendy G. Hargus (11)	T
Joseph M. Buonaiuto	C
Timothy A. King	S

CSW Power Marketing, Inc.

Name and Principal Address(a)	Position
Jeffrey D. Cross	D,VP
Holly Keller Koeppel (b)	D,P
Armando A. Pena	D
Ronald A. Erd	VP
Wendy G. Hargus (11)	T
Joseph M. Buonaiuto	C
Timothy A. King	S

CSW Services International, Inc.

Name and Principal Address(a)	Position
Jeffrey D. Cross	D,VP
Holly Keller Koeppel (b)	D,P
Armando A. Pena	D,VP
Ronald A. Erd	VP
Wendy G. Hargus (11)	T
Joseph M. Buonaiuto	C
Timothy A. King	S

CSW Sweeny GP II, Inc.

Name and Principal Address(a)	Position
Jeffrey D. Cross	D,VP
Holly Keller Koeppel (b)	D,P
Armando A. Pena	D,VP
Ronald A. Erd	VP
Wendy G. Hargus (11)	T
Joseph M. Buonaiuto	C
Timothy A. King	S

CSW Sweeny GP I, Inc.

Name and Principal Address(a)	Position
Jeffrey D. Cross	D,VP
Holly Keller Koeppel (b)	D,P
Armando A. Pena	D,VP
Ronald A. Erd	VP
Wendy G. Hargus (11)	T
Joseph M. Buonaiuto	C
Timothy A. King	S

CSW Sweeny LP II, Inc.

Name and Principal Address(a)	Position
Jeffrey D. Cross	D,VP
Holly Keller Koeppel (b)	D,P
Armando A. Pena	D,VP
Ronald A. Erd	VP
Wendy G. Hargus (11)	T
Joseph M. Buonaiuto	C
Timothy A. King	S

CSW Sweeny LP I, Inc.

Name and Principal Address(a)	Position
Jeffrey D. Cross	D,VP
Holly Keller Koeppel (b)	D,P
Armando A. Pena	D,VP
Ronald A. Erd	VP
Wendy G. Hargus (11)	T
Joseph M. Buonaiuto	C
Timothy A. King	S

ITEM 6. OFFICERS AND DIRECTORS
PART I (Continued)

CSW UK Finance Company

Name and Principal Address(ff)	Position
E. Linn Draper,Jr.(a)	D
Holly Keller Koeppel (b)	D
Armando A. Pena (a)	D
Thomas V. Shockley,III(a)	D
Bradford R. Signet (a)	D
Susan Tomasky (a)	D
Stephen P. Smith (a)	T
Jeffrey D. Cross (a)	S

CSW UK Holdings

Name and Principal Address(ff)	Position
E. Linn Draper,Jr.(a)	D
Holly Keller Koeppel (b)	D
Armando A. Pena (a)	D
Thomas V. Shockley,III(a)	D
Bradford R. Signet (a)	D
Susan Tomasky (a)	D
Stephen P. Smith (a)	T
Jeffrey D. Cross (a)	S

CSW UK Investments Limited

Name and Principal Address(ff)	Position
E. Linn Draper,Jr.(a)	D
Holly Keller Koeppel (b)	D
Armando A. Pena (a)	D
Thomas V. Shockley,III(a)	D
Bradford R. Signet (a)	D
Susan Tomasky (a)	D
Stephen P. Smith (a)	T
Jeffrey D. Cross (a)	S

CSW Vale L.L.C.

Name and Principal Address(a)	Position
Jeffrey D. Cross	D,VP
Holly Keller Koeppel (b)	D,P
Armando A. Pena	D,VP
Susan Tomasky	D
Joesph M. Buonaiuto	C
Timothy A. King	S
Wendy G. Hargus (11)	T

CSWC License, Inc.

Name and Principal Address(a)	Position
Holly Keller Koeppel (b)	D,VP
Armando A. Pena	D,VP,T
Thomas V. Shockley,III	D
Susan Tomasky	P
Jeffrey D. Cross	VP
Joseph M. Buonaiuto	C
Timothy A. King	S

CSWI Europe Limited

Name and Principal Address(ff)	Position
Paul E. Connon	D
Holly Keller Koeppel(b)	D
Stephen P. Smith (a)	T
Timothy A. King (a)	S

DECCO II, LLC

Name and Principal Address(a)	Position
Michael W. Rencheck	CEO
Jeffrey D. Cross	VP
Armando A. Pena	VP
Stephen P. Smith	T
Joseph M. Buonaiuto	C
Timothy A. King	S

Diversified Energy Contractors Company, LLC

Name and Principal Address(a)	Position
Michael W. Rencheck	CEO
Jeffrey D. Cross	VP
John A. Mazzone (b)	VP
Armando A. Pena	VP
Stephen P. Smith	T
Joseph M. Buonaiuto	C
Timothy A. King	S

Dolet Hills Lignite Company, LLC

Name and Principal Address(rr)	Position
Jeffrey D. Cross (a)	B,VP
E. Linn Draper, Jr. (a)	B,CB,CEO
Armando A. Pena (a)	B,VP
Thomas V. Shockley,III(a)	B
Gerald M. Dimmerling 377 Highway 522 Mansfield, LA 71052	P
Stephen W. Burge (b)	VP
Stephen P. Smith (a)	T
Timothy A. King (a)	S

Franklin Real Estate Company

Name and Principal Address(a)	Position
Jeffrey D. Cross	D
E. Linn Draper, Jr.	D,CEO,P
Henry W. Fayne	D,VP
Thomas M. Hagan	D,VP
Armando A. Pena	D,VP
Thomas V. Shockley,III	D,VP
Susan Tomasky	D,VP
Glenn M. Files	VP
Richard P. Verret	VP
Stephen P. Smith	T
Joseph M. Buonaiuto	C,CAO
Leonard V. Assante	DC
Timothy A. King	S

Golden Prairie Holding Company LLC

Name and Principal Address(a)	Position
Michael J. Kelley	B,T
Holly Keller Koeppel (b)	B,CB,P
Timothy K. Light (b)	B,VP

Golden Prairie Wind Farm LLC

Name and Principal Address(a)	Position
Holly Keller Koeppel (b)	B,CB,P
Michael J. Kelley	B,T
Timothy K. Light (b)	B,VP

ITEM 6. OFFICERS AND DIRECTORS
PART I (Continued)

Houston Pipe Line Company LP

Name and Principal Address(bb)	Position
Holly Keller Koeppel (b)	P
Jeffrey D. Cross (a)	VP
Jim Deidiker	VP
Edward D. Gottlob	VP
Armando A. Pena (a)	VP
Stephen Schneider	VP
Stephen P. Smith (a)	T
Joseph M. Buonaiuto (a)	C
Timothy A. King (a)	S

HPL GP, LLC

Name and Principal Address(a)	Position
Jeffrey D. Cross	B,VP
Holly Keller Koeppel (b)	B,P
Armando A. Pena	B,VP
Thomas V. Shockley, III	B
C. R. Boyle, III (b)	VP
Jim Deidiker (bb)	VP
Ronald A. Erd	VP
Stephen Schneider (bb)	VP
Stephen P. Smith	T
Joseph M. Buonaiuto	C
Timothy A. King	S

HPL Holdings, Inc.

Name and Principal Address(i)	Position
Sean Breiner	D
Jeffrey D. Cross (a)	D,VP
Timothy A. King (a)	D,S
John A. Oscar,Jr.	D
Armando A. Pena (a)	D,VP
Mark A. Pyle (a)	D
Stephen P. Smith (a)	T
Thomas V. Shockley,III(a)	P
Holley Keller Koeppel (b)	VP
Joseph M. Buonaiuto (a)	C

HPL Resources Company LP

Name and Principal Address(bb)	Position
Thomas V. Shockley,III(a)	P
Jeffrey D. Cross (a)	VP
Edward D. Gottlob	VP
Holly Keller Koeppel (b)	VP
Armando A. Pena (a)	VP
Stephen Schneider	VP
Stephen P. Smith (a)	T
Joseph M. Buonaiuto (a)	C
Timothy A. King (a)	S

Indiana-Kentucky Electric Corporation

Name and Principal Address(w)	Position
William S. Doty 20 NW Fourth Street Evensville, IN 47741	D
E. Linn Draper, Jr. (a)	D,P
Ronald G. Jochum 20 NW Fourth Street Evansville, IN 47741	D
Thomas J. Kalup 4350 Northern Pike Monroeville, PA 15146	D
Marc E. Lewis (d)	D
John R. Sampson 101 W. Ohio Street, Ste 1320 Indianapolis, IN 46204	D
Stanley F. Szwed 76 S. Main Street Akron, OH 44308	D
David L. Hart (a)	VP
David E. Jones	VP
Armando A. Pena (a)	VP
John D. Brodt	S,T

Indiana Franklin Realty, Inc.

Name and Principal Address(d)	Position
Jeffrey D. Cross (a)	D
E. Linn Draper, Jr. (a)	D,CEO,P
Henry W. Fayne (a)	D,VP
Thomas M. Hagan (a)	D,VP
Armando A. Pena (a)	D,VP
Thomas V. Shockley,III(a)	D,VP
Susan Tomasky (a)	D,VP
Glenn M. Files (a)	VP
Richard P. Verret (c)	VP
Stephen P. Smith (a)	T
Joseph M. Buonaiuto (a)	C,CAO
Leonard V. Assante (a)	DC
Timothy A. King (a)	S

Indiana Michigan Power Company

Name and Principal Address(a)	Position
Karl G. Boyd (d)	D
E. Linn Draper, Jr.	D,CB,CEO
John E. Ehler (d)	D
Henry W. Fayne	D,P
Thomas M. Hagan	D,VP
Patrick C. Hale 2791 North U.S. HWY 231 Rockport, IN 47635	D
David L. Lahrman (d)	D
Marc E. Lewis (d)	D
Susanne M. Moorman (d)	D
Robert P. Powers	D,VP
John R. Sampson 101 W. Ohio Street, Ste 1320 Indianapolis, IN 46204	D,VP
Thomas V. Shockley,III	D,VP
Susan Tomasky	D,VP
Karl G. Boyd (d)	VP
Glenn M. Files	VP
Joseph N. Jensen One Cook Place Bridgman, MI 49106	VP
Michelle S. Kalnas	VP
Holly Keller Koeppel (b)	VP
Mark C. McCullough (b)	VP
Mano K. Nazar One Cook Place Bridgeman, MI 41906	VP
Armando A. Pena	VP
Marsha P. Ryan	VP
William L. Sigmon,Jr. (b)	VP
Richard P. Verret (c)	VP
William F. Vineyard (b)	VP
Stephen P. Smith	T
Joseph M. Buonaiuto	C,CAO
Leonard V. Assante	DC
Timothy A. King	S

ITEM 6. OFFICERS AND DIRECTORS
PART I (Continued)

Jefferson Island Storage & Hub L.L.C.

Name and Principal Address(bb)	Position
Jeffrey D. Cross (a)	B,VP
Holly Keller Koeppel(b)	B,P
Armando A. Pena (a)	B,VP
Thomas V. Shockley,III(a)	B,CB
C. R. Boyle, III (b)	VP
Jim Deidiker	VP
Ronald A. Erd (a)	VP
Edward D. Gottlob	VP
Stephen Schneider	VP
Stephen P. Smith (a)	T
Joseph M. Buonaiuto (a)	C
Timothy A. King (a)	S

Kentucky Power Company

Name and Principal Address(a)	Position
Jeffrey D. Cross	D
E. Linn Draper, Jr.	D,CB,CEO
Henry W. Fayne	D,P
Thomas M. Hagan	D,VP
Armando A. Pena	D,VP
Robert P. Powers	D,VP
Thomas V. Shockley,III	D,VP
Susan Tomasky	D,VP
Glenn M. Files	VP
Gene M. Jensen	VP
P.O. Box 1986	
Charleston, WV 25312	
Michelle S. Kalnas	VP
Holly Keller Koeppel (b)	VP
Jeffery D. LaFleur (b)	VP
T. C. Mosher	VP
101 Enterprise Drive	
Frankfort, KY 40601	
Marsha P. Ryan	VP
William L. Sigmon,Jr. (b)	VP
Richard P. Verret (c)	VP
Joseph M. Buonaiuto	C,CAO
Leonard V. Assante	DC
Stephen P. Smith	T
Timothy A. King	S

Kingsport Power Company

Name and Principal Address(a)	Position
Jeffrey D. Cross	D
E. Linn Draper, Jr.	D,CB,CEO
Henry W. Fayne	D,P
Thomas M. Hagan	D,VP
Armando A. Pena	D,VP
Robert P. Powers	D,VP
Thomas V. Shockley,III	D,VP
Susan Tomasky	D,VP
R. D. Carson, Jr.	VP
1051 East Cary Street, 7th Fl.	
Richmond, VA 23219	
Glenn M. Files	VP
Gene M. Jensen	VP
P.O. Box 1986	
Charleston, WV 25312	
Michelle S. Kalnas	VP
Holley Keller Koeppel (b)	VP
Marsha P. Ryan	VP
Richard P. Verret (c)	VP
Stephen P. Smith	T
Joseph M. Buonaiuto	C,CAO
Leonard V. Assante	DC
Timothy A. King	S

Leesville Land, LLC

Name and Principal Address(a)	Position
Jeffrey D. Cross	B,VP
Holly Keller Koeppel (b)	B
David G. Zatezalo (n)	B,P
Nelson L. Kidder (n)	VP
Armando A. Pena	VP,T
Susan Tomasky	VP
Timothy A. King	S

LIG Chemical Company

Name and Principal Address(bb)	Position
Jeffrey D. Cross (a)	D,VP
Holly Keller Koeppel (b)	D,P
Armando A. Pena (a)	D,VP
Thomas V. Shockley,III(a)	D,CB
C. R. Boyle, III (b)	VP
Jim Deidiker	VP
Ronald A. Erd (a)	VP
Edward D. Gottlob	VP
Stephen Schneider	VP
Stephen P. Smith (a)	T
Joseph M. Buonaiuto (a)	C
Timothy A. King (a)	S

LIG Liquids Company, L.L.C.

Name and Principal Address(bb)	Position
Jeffrey D. Cross (a)	D,VP
Holly Keller Koeppel (b)	D,P
Armando A. Pena (a)	D,VP
Thomas V. Shockley,III(a)	D,CB
C. R. Boyle, III (b)	VP
Jim Deidiker	VP
Ronald A. Erd (a)	VP
Edward D. Gottlob	VP
Stephen Schneider	VP
Stephen P. Smith (a)	T
Joseph M. Buonaiuto (a)	C
Timothy A. King (a)	S

LIG Pipeline Company

Name and Principal Address(bb)	Position
Jeffrey D. Cross (a)	D,VP
Holly Keller Koeppel (b)	D,P
Armando A. Pena (a)	D,VP
Thomas V. Shockley,III(a)	D,CB
C. R. Boyle, III (b)	VP
Ronald A. Erd (a)	VP
Edward D. Gottlob	VP
Stephen Schneider	VP
Joseph M. Buonaiuto (a)	C
Timothy A. King (a)	S

ITEM 6. OFFICERS AND DIRECTORS
PART I (Continued)

LIG, Inc.

Name and Principal Address(bb)	Position
Jeffrey D. Cross (a)	D,VP
Holly Keller Koeppel(b)	D,P
Armando A. Pena (a)	D,VP
Thomas V. Shockley,III(a)	D,CB
C. R. Boyle, III (b)	VP
Ronald A. Erd (a)	VP
Edward D. Gottlob	VP
Stephen Schneider	VP
Stephen P. Smith (a)	T
Joseph M. Buonaiuto (a)	C
Timothy A. King (a)	S

Louisiana Intrastate Gas Company, L.L.C.

Name and Principal Address(bb)	Position
Jeffrey D. Cross (a)	B,VP
Holly Keller Koeppel(b)	B,P
Armando A. Pena (a)	B,VP
Thomas V. Shockley,III(a)	B,CB
C. R. Boyle, III (b)	VP
Jim Deidiker	VP
Ronald A. Erd (a)	VP
Edward D. Gottlob	VP
Stephen Schneider	VP
Stephen P. Smith (a)	T
Joseph M. Buonaiuto (a)	C
Timothy A. King (a)	S

Mulberry Holdings, Inc.

Name and Principal Address(a)	Position
Jeffrey D. Cross	D,VP
Holly Keller Koeppel (b)	D,P
Armando A. Pena	D,VP
Ronald A. Erd	VP
Wendy G. Hargus (11)	T
Joseph M. Buonaiuto	C
Timothy A. King	S

Mutual Energy L.L.C.

Name and Principal Address(a)	Position
Thomas V. Shockley,III	CB,P
Jeffrey D. Cross	VP
Holly Keller Koeppel (b)	VP
Stephen P. Smith	T
Timothy A. King	S

Nanyang General Light Electric Co., Ltd.

Name and Principal Address(f)	Position
Qin Qigen	D,VCB
Jeffrey D. Cross (a)	D,S
Lonni L. Dieck (b)	D
Bernard Hu 2648 Durfee Ave., #B El Monte, CA 91732	D
Holly Keller Koeppel (b)	D
Ralph E. Life (b)	D
Armando A. Pena (a)	D,CB
William L. Sigmon,Jr. (b)	D
Lu Ming Tao	D
Hao Zhengshan	D

Newgulf Power Venture, Inc.

Name and Principal Address(a)	Position
Jeffrey D. Cross	D,VP
Holly Keller Koeppel (b)	D,P
Armando A. Pena	D,VP
Ronald A. Erd	VP
Wendy G. Hargus (11)	T
Joseph M. Buonaiuto	C
Timothy A. King	S

NGLE Pushan Power, LDC

Name and Principal Address(g)	Position
Jeffrey D. Cross (a)	D,VP
Bernard Hu 2648 Durfee Ave., #B El Monte, CA 91732	D
Holly Keller Koeppel (b)	D,P
Armando A. Pena (a)	D,VP
Lonni L. Dieck (b)	VP
Wendy G. Hargus (11)	T
Walkers SPV Limited	S

Noah I Power GP, Inc.

Name and Principal Address(a)	Position
Jeffrey D. Cross	D,VP
Holly Keller Koeppel (b)	D,P
Armando A. Pena	D,VP
Ronald A. Erd	VP
Wendy G. Hargus (11)	T
Joseph M. Buonaiuto	C
Timothy A. King	S

Ohio Power Company

Name and Principal Address(a)	Position
Jeffrey D. Cross	D
E. Linn Draper, Jr.	D,CB,CEO
Henry W. Fayne	D,P
Thomas M. Hagan	D,VP
Armando A. Pena	D,VP
Robert P. Powers	D,VP
Thomas V. Shockley,III	D,VP
Susan Tomasky	D,VP
Karl G. Boyd (d)	VP
David M. Fenstermaker (c)	VP
Glenn M. Files	VP
Jane A. Harf 88 East Broad Street 8th Fl. Columbus, OH 43215	VP
Michelle S. Kalnas	VP
Holly Keller Koeppel (b)	VP
Jeffrey D. LaFleur (b)	VP
Mark C. McCullough (b)	VP
Marsha P. Ryan	VP
William L. Sigmon,Jr.(b)	VP
Richard P. Verret (c)	VP
Stephen P. Smith	T
Joseph M. Buonaiuto	C,CAO
Leonard V. Assante	DC
Timothy A. King	S

ITEM 6. OFFICERS AND DIRECTORS
PART I (Continued)

Ohio Valley Electric Corporation

Name and Principal Address(w)	Position
David C. Benson 4350 Northern Pike Monroeville, PA 15146	D
H. Peter Burg 76 South Main Street Akron, OH 44308	D
William S. Doty 20 NW Fourth Street Evansville, IN 47741	D
E. Linn Draper, Jr. (a)	D,P
Henry W. Fayne (a)	D
James P. Garlick 4350 Northern Pike Monroeville, PA 15146	D
Thomas J. Kalup 4350 Northern Pike Monroeville, PA 15146	D
Holly Keller Koeppel (b)	D
Guy L. Pipitone 76 South Main Street Akron, OH 44308	D
John C. Procario 139 East Fourth Street Cincinnati, OH 45202	D
Thomas V. Shockley,III(a)	D
A. Roger Smith 220 West Main Street Louisville, KY 40202	D
Stanley F. Szwed 76 S. Main Street Akron, OH 44308	D
Paul W. Thompson 220 West Main Street Louisville, KY 40202	D
W. Steven Wolff 1065 Woodman Drive Dayton, OH 45432	D
David L. Hart (a)	VP
David E. Jones	VP
Armando A. Pena (a)	VP
John D. Brodt	S,T

Operaciones Azteca VIII, S. de R.L. de C.V.

Name and Principal Address(pp)	Position
A. Wade Smith (a)	D
James H. Sweeney (a)	D
Robert H. Warburton 15 Wayside Rd. Burlington, MA 01803	D
Neil Smith 15 Wayside Road Burlington, MA 01803	CB
Carlos de Maria y Campos Segura Torre del Bosqu Blvd. Manuel Avila Camacho 24, Piso 7, Col. Lomas de Chapultepec 11000 Mexico, D.F.	S

Orange Cogen Funding Corp.

Name and Principal Address(a)	Position
Holly Keller Koeppel (b)	D,CEO
John O=Rourke (bb)	D,P
A. Wade Smith	D
Douglas E. Stockton (bb)	D
Faye L. Stallings (bb)	CFO
Timothy A. King	S

Orange Cogeneration GP II, Inc.

Name and Principal Address(a)	Position
Holly Keller Koeppel (b)	D,CEO
John O=Rourke (bb)	D,P
A. Wade Smith	D,GM
Douglas E. Stockton (bb)	D
Faye L. Stallings (bb)	CFO
David L. Siddall (bb)	S

Orange Cogeneration G.P., Inc.

Name and Principal Address(a)	Position
Holly Keller Koeppel (b)	D,CEO
John O=Rourke (bb)	D,P
A. Wade Smith	D,GM
Douglas E. Stockton (bb)	D
Faye L. Stallings (bb)	CFO
David L. Siddall (bb)	S

Orange Holdings, Inc.

Name and Principal Address(a)	Position
Jeffrey D. Cross	D,VP
Holly Keller Koeppel (b)	D,P
Armando A. Pena	D,VP
Wendy G. Hargus (11)	T
Joseph M. Buonaiuto	C
Timothy A. King	S

Pacific Hydro Limited

Name and Principal Address(aa)	Position
Michael C. Fitzpatrick	D
Jeffrey Harding	D
Michael J. Hutchinson	D
Holly Keller Koeppel(b)	D
John L. C. McInnes	D
Philip van der Riet	D
Peter F. Westaway	D
Bernard Wheelahan	D,CB
Neil L. Williams	S

Polk Power GP II, Inc.

Name and Principal Address(a)	Position
Holly Keller Koeppel (b)	D,P
John O=Rourke (bb)	D,CEO
A. Wade Smith	D,GM
Douglas E. Stockton (bb)	D
Faye L. Stallings (bb)	CFO
Timothy A. King	S

Polk Power GP, Inc.

Name and Principal Address(a)	Position
Holly Keller Koeppel (b)	D,P
John O=Rourke (bb)	D,CEO
A. Wade Smith	D,GM
Douglas E. Stockton (bb)	D
Faye L. Stallings (bb)	CFO
Timothy A. King	S

ITEM 6. OFFICERS AND DIRECTORS
PART I (Continued)

POLR Power, L.P.

Name and Principal Address (h)	Position
Thomas V. Shockley, III (a)	P
Jeffrey D. Cross (a)	VP
Holly Keller Koeppel (b)	VP
Stephen P. Smith (a)	T
Timothy A. King (a)	S

Price River Coal Company, Inc.

Name and Principal Address (a)	Position
Jeffrey D. Cross	D
E. Linn Draper, Jr.	D, CB, CEO
Henry W. Fayne	D, VP
Armando A. Pena	D, VP
Thomas V. Shockley, III	D, VP
Susan Tomasky	D, VP
Gerald M. Dimmerling 377 Highway 522 Mansfield, LA 71052	P
Stephen P. Smith	T
Joseph M. Buonaiuto	C, CAO
Leonard V. Assante	DC
Timothy A. King	S

Public Service Company of Oklahoma

Name and Principal Address (a)	Position
Jeffrey D. Cross	D
E. Linn Draper, Jr.	D, CB, CEO
Henry W. Fayne	D, P
Thomas M. Hagan	D, VP
Armando A. Pena	D, VP
Robert P. Powers	D, VP
Thomas V. Shockley, III	D, VP
Susan Tomasky	D, VP
Charles H. Adami (ll)	VP
Stephen W. Burge (b)	VP
Glenn M. Files	VP
Michelle S. Kalnas	VP
Gary C. Knight 3600 S. Elwood Ave. Tulsa, OK 74102	VP
Holly Keller Koeppel (b)	VP
Marsha P. Ryan	VP
William L. Sigmon, Jr. (b)	VP
Kimberly L. Smith 212 E. 6th Street Tulsa, OK 74119	VP
Richard P. Verret (c)	VP
Stephen P. Smith	T
Joseph M. Buonaiuto	C, CAO
Leonard V. Assante	DC
Timothy A. King	S

REP General Partner L.L.C.

Name and Principal Address (h)	Position
Jeffrey D. Cross (a)	B, VP
Holly Keller Koeppel (b)	B, VP
Armando A. Pena (a)	B, VP
Thomas V. Shockley, III (a)	B, P
Stephen P. Smith (a)	T
Timothy A. King (a)	S

REP Holdco, LLC

Name and Principal Address (qq)	Position
Jeffrey D. Cross (a)	D, VP
Holly Keller Koeppel (b)	D, VP
Armando A. Pena (a)	D, VP
Thomas V. Shockley, III (a)	D, CB, P
Stephen P. Smith (a)	T
Joseph M. Buonaiuto (a)	C
Timothy A. King (a)	S

Servicios Azteca VIII, S.de R.L. de C.V.

Name and Principal Address (pp)	Position
A. Wade Smith (a)	D
James H. Sweeney (a)	D
Neil Smith 15 Wayside Road Burlington, MA 01803	CB
Carlos de Maria y Campos Segura Torre del Bosqu Blvd. Manuel Avila Camacho 24, Piso 7, Col. Lomas de Chapultepec 11000 Mexico, D.F.	S

Shoreham Operations Company Limited

Name and Principal Address (y)	Position
Ronald A. Erd (a)	D
E. S. Golland	D
Stuart W. Staley (ff)	D
Surinder S. Toor (ff)	D
C. D. MacKendrick	S

Simco Inc.

Name and Principal Address (a)	Position
Jeffrey D. Cross	D
E. Linn Draper, Jr.	D, CB, CEO
Henry W. Fayne	D, VP
Armando A. Pena	D, VP
Thomas V. Shockley, III	D, VP
Susan Tomasky	D, VP
David G. Zatezalo (n)	P
Nelson L. Kidder (n)	VP
Stephen P. Smith	T
Joseph M. Buonaiuto	C, CAO
Leonard V. Assante	DC
Timothy A. King	S

Snowcap Coal Company, Inc.

Name and Principal Address (a)	Position
David M. Cohen (b)	D, VP, S
Scott H. Finch	D, T
David G. Zatezalo (n)	D, P
Nelson L. Kidder (n)	VP

ITEM 6. OFFICERS AND DIRECTORS
PART I (Continued)

South Coast Power Limited

Name and Principal Address (m)	Position
Ronald A. Erd (a)	D
Stuart W. Staley (ff)	D
Surinder S. Toor (ff)	D
Charles MacKendrick (y)	S

Southern Appalachian Coal Company

Name and Principal Address (a)	Position
Jeffrey D. Cross	D
E. Linn Draper, Jr.	D, CB, CEO
Henry W. Fayne	D, VP
Armando A. Pena	D, VP
Thomas V. Shockley, III	D, VP
Susan Tomasky	D, VP
Gerald M. Dimmerling 377 Highway 522 Mansfield, LA 71052	P
Stephen P. Smith	T
Joseph M. Buonaiuto	C, CAO
Leonard V. Assante	DC
Timothy A. King	S

Southwestern Arkansas Utilities Corporation

Name and Principal Address (t)	Position
Charles E. Clinehens, Jr.	D, S, T
Thomas H. Deweese	D, P
Phillip A. Watkins	D, VP

Southwestern Electric Power Company

Name and Principal Address (a)	Position
Jeffrey D. Cross	D
E. Linn Draper, Jr.	D, CB, CEO
Henry W. Fayne	D, P
Thomas M. Hagan	D, VP
Armando A. Pena	D, VP
Robert P. Powers	D, VP
Thomas V. Shockley, III	D, VP
Susan Tomasky	D, VP
Stephen W. Burge (b)	VP
Brian Bond (rr)	VP
Gary M. Dimmerling 377 Highway 522 Mansfield, LA 71052	VP
Glenn M. Files	VP
Paul W. Franklin (ll)	VP
Michelle S. Kalnas	VP
Charles R. Patton (h)	VP
Julio C. Reyes (h)	VP
Marsha P. Ryan	VP
William L. Sigmon, Jr. (b)	VP
Kimberly L. Smith (t)	VP
Richard P. Verret (c)	VP
Stephen P. Smith	T
Joseph M. Buonaiuto	C, CAO
Leonard V. Assante	DC
Timothy A. King	S

Springdale Land, LLC

Name and Principal Address (a)	Position
Jeffrey D. Cross	B, VP
Holly Keller Koeppel (b)	B
David G. Zatezalo (n)	B, P
Nelson L. Kidder (n)	VP
Armando A. Pena	VP
Susan Tomasky	VP
Stephen P. Smith	T
Timothy A. King	S

Tuscaloosa Pipeline Company

Name and Principal Address (bb)	Position
Jeffrey D. Cross (a)	D, VP
Holly Keller Koeppel (b)	D, P
Armando A. Pena (a)	D, VP
Thomas V. Shockley, III (a)	D, CB
C. R. Boyle, III (b)	VP
Jim Deidiker	VP
Donald A. Erd (a)	VP
Edward D. Gottlob	VP
Stephen Schneider	VP
Joseph M. Buonaiuto (a)	C
Timothy A. King (a)	S

United Sciences Testing, Inc.

Name and Principal Address (u)	Position
Mark A. Gray (a)	D, VP
John D. Harper (c)	D
Mark W. Marano (a)	D, P
Robert P. Powers (a)	D, CB
Michael W. Rencheck (a)	D, CEO
Jeffrey D. Cross (a)	VP
Stephen P. Smith (a)	T
Joseph M. Buonaiuto (a)	C
Timothy A. King (a)	S

Universal Supercapacitors, LLC

Name and Principal Address (a)	Position
Paul Chodak III	B
Holly Keller Koeppel (b)	B
Sergey V. Litvinenko 53 Leninsky Prospect 117927 Moscow, Russia	B
Alexander V. Novikov 53 Leninsky Prospect 117927 Moscow, Russia	B
John H. Provanzana	B
Sergey N. Razumov Troitsk, Moscow Region 142190 Russia	B

Ventures Lease Co., LLC

Name and Principal Address (a)	Position
Jeffrey D. Cross	B, VP
Armando A. Pena	B, P
Stephen P. Smith	T
Timothy A. King	S

ITEM 6. OFFICERS AND DIRECTORS
PART I (Continued)

Wheeling Power Company

Name and Principal Address(a)	Position
Jeffrey D. Cross	D
E. Linn Draper, Jr.	D,CB,CEO
Henry W. Fayne	D,P
Thomas M. Hagan	D,VP
Armando A. Pena	D,VP
Robert P. Powers	D,VP
Thomas V. Shockley,III	D,VP
Susan Tomasky	D,VP
Mark E. Dempsey 707 Virginia Street, East Charleston, WV 25301	VP
Glenn M. Files	VP
Gene M. Jensen P.O. Box 1986 Charleston, WV 25312	VP
Michelle S. Kalnas	VP
Holly Keller Koeppel (b)	VP
Marsha P. Ryan	VP
Richard P. Verret (c)	VP
Stephen P. Smith	T
Joseph M. Buonaiuto	C,CAO
Leonard V. Assante	DC
Timothy A. King	S

ITEM 6. (CONTINUED)

Part II. Each officer and director with a financial connection within the provisions of Section 17(c) of the Act is as follows:

Name of Officer or Director (1)	Name and Location of Financial Institution (2)	Position Held in Financial Institution (3)	Applicable Exemption Rule (4)
William R. Howell	Deutsche Bank Trust Corp. New York, N.Y.	Director	70(b)
L.A. Hudson, Jr.	Deutsche Bank Trust Company Americas New York, N.Y.	Director	70(a)
	American National Bankshares, Inc. Danville, Virginia	Director	70(a)
	American National Bank & Trust Co. Danville, Virginia	Director	70(a)
M.P. Ryan	US Bank Columbus, Ohio	Advisory Director	70(f)
Richard L. Sandor	Bear Stearns Financial Products, Inc. Chicago, Illinois	Director	70(b)
	Bear Stearns Trading Risk Management Inc. Chicago, Illinois	Director	70(b)
Sean Breiner	Wilmington Trust Company SP Services Inc. Wilmington, DE	Assistant Vice President	70(a)
John A. Oscar, Jr.	Wilmington Trust Company SP Services Inc Wilmington, DE	Assistant Vice President	70(a)
	Medvine, Inc. Vineland, NJ	Director Assistant Treasurer	70(a)

ITEM 6. (continued)

Part III. The disclosures made in the System companies' most recent proxy statement and annual report on Form 10-K with respect to items (a) through (f) follow:

(a) COMPENSATION OF DIRECTORS AND EXECUTIVE OFFICERS OF SYSTEM COMPANIES

Executive Compensation

The following table shows for 2003, 2002 and 2001 the compensation earned by the chief executive officer and the four other most highly compensated executive officers (as defined by regulations of the Securities and Exchange Commission) of AEP at December 31, 2003.

Summary Compensation Table

		Annual Compensation		Long-Term Compensation		
				Awards	Payouts	
Name and Principal Position	Year	Salary ($)(1)	Bonus ($)(2)	Securities Underlying Options(#)	LTIP Payouts($)(3)	All Other Compensation ($)(4)
E. Linn Draper, Jr. —	2003	1,094,192	980,031	0	0	63,429
	2002	1,054,038	0	350,000	0	135,417
	2001	913,500	682,090	0	311,253	123,217
Thomas V. Shockley, III	2003	667,558	291,475	49,000	0	45,845
	2002	642,461	49,116	150,000	0	122,141
	2001	592,269	353,788	0	79,781	145,400
Henry W. Fayne —	2003	501,923	256,225	25,000	0	39,150
	2002	481,846	49,116	88,000	0	80,830
	2001	421,615	305,861	0	83,697	75,955
Susan Tomasky —	2003	476,827	256,137	25,000	0	37,208
	2002	451,731	49,116	88,000	0	79,373
	2001	411,577	300,365	0	54,455	73,853
Thomas M. Hagan —	2003	421,615	237,850	25,000	0	29,326
	2002	345,517	0	88,000	0	59,976

Notes to Summary Compensation Table

(1) Amounts in the *Salary* column reflect an additional day of pay earned in 2003 and 2002 related to the number of calendar workdays and holidays in each year and AEP's use of bi-weekly pay periods.

(2) Amounts in the *Bonus* column reflect awards under the Senior Officer Annual Incentive Compensation Plan (SOIP) for 2001 and 2003. Payments pursuant to the

SOIP are made in the first quarter of the succeeding fiscal year for performance in the year indicated. No SOIP awards were made for 2002. In addition, Messrs. Fayne and Shockley and Ms. Tomasky received payments of $49,116 each in February 2002 in recognition of their efforts in connection with a management reorganization.

(3) Amounts in the *Long-Term Compensation — Payouts* column reflect performance share units earned under the AEP 2000 Long-Term Incentive Plan for three-year performance periods concluding at the end of the year shown. See below under *Long-Term Incentive Plans — Awards in 2003* and page 33 for additional information.

(4) Amounts in the *All Other Compensation* column include (i) AEP's matching contributions under the AEP Retirement Savings Plan and the AEP Supplemental Retirement Savings Plan, a non-qualified plan designed to supplement the AEP Savings Plan; (ii) subsidiary companies director fees; and (iii) imputed interest on a pay advance provided in 2001 to employees impacted by a change in payroll schedule that shifted pay one week in arrears. Detail of the 2003 amounts in the *All Other Compensation* column is shown below.

Item	Dr. Draper	Mr. Shockley	Mr. Fayne	Ms. Tomasky	Mr. Hagan
Savings Plan Matching Contributions	$5,611	$9,000	$5,555	$5,724	$9,050
Supplemental Savings Plan Matching Contributions	39,389	20,895	16,921	15,620	9,826
Subsidiaries Directors Fees	17,400	15,950	16,200	15,400	10,450
Imputed Interest on Pay Advance	1,029	—	474	464	—

(5) No 2001 compensation information is reported for Mr. Hagan because he was not an executive officer in that year.

Compensation of Directors

Annual Retainers and Meeting Fees. Directors who are officers of AEP or employees of any of its subsidiaries do not receive any compensation, other than their regular salaries and the accident insurance coverage described below, for attending meetings of AEP's Board of Directors. For a portion of 2003, the other members of the Board received an annual retainer of $35,000 for their services, an additional annual retainer of $5,000 for each Committee that they chaired (except for the Chairman of the Audit Committee, who received an annual retainer of $15,000), a fee of $1,200 for each meeting of the Board and of any Committee that they attended, and a fee of $1,200 per day for any inspection trip or conference. Members of the Audit Committee (other than the Chairman) also received an annual retainer of $10,000.

In October 2003, based upon the recommendation of the Committee on Directors and Corporate Governance and based on competitive data, the Board of Directors adopted changes to the cash and equity compensation to be paid to members of the Board of Directors and committees of the Board of Directors. These changes were adopted in order to bring the compensation packages of AEP's board members more in line with compensation paid to directors of comparable companies, recognize the increased workload and responsibilities of board and committee members, and enable AEP to attract qualified directors when needed. The new board compensation is as follows:

- Each non-employee director will receive an annual retainer of $60,000, the chair of the Audit Committee will receive an additional annual retainer of $15,000 and other members of the Audit Committee will receive an additional annual retainer of $10,000, each of these cash retainers is paid in quarterly increments;
- The presiding director will receive an additional annual retainer of $15,000, paid in quarterly increments;
- Each non-employee director will receive $60,000 in AEP stock units payable quarterly pursuant to the Stock Unit Accumulation Plan described below; and
- Directors no longer receive fees for meetings they attend.

During this transitional year, directors received an annual retainer in the amount of $41,250 and 1,692 AEP stock units under the Stock Unit Accumulation Plan. In addition, members of the Human Resources Committee (HR Committee) received the $1,200 meeting fee for their attendance at each special meeting relating to the search for a new Chief Executive Officer.

Deferred Compensation and Stock Plan. The Deferred Compensation and Stock Plan for Non-Employee Directors permits non-employee directors to choose to receive up to 100 percent of their annual Board cash retainer in units that are equivalent in value to shares of AEP Common Stock (Stock Units), deferring receipt by the non-employee director until termination of service or for a period that results in payment commencing not later than five years thereafter. AEP Stock Units are credited to directors when the retainer becomes payable, based on the closing price of the Common Stock on the payment date. Amounts equivalent to cash dividends on the Stock Units accrue as additional Stock Units. Payments with respect to the accumulated Stock Units are made in cash.

Stock Unit Accumulation Plan. The Stock Unit Accumulation Plan for Non-Employee Directors annually had awarded 1,200 Stock Units to each non-employee director as of the first day of the month in which the non-employee director becomes a member of the Board. As mentioned earlier, this Plan was amended to award $60,000 annually in Stock Units. These Stock Units will be credited to directors quarterly, based on the closing price of the Common Stock on the payment date. $15,000 in Stock Units was credited on December 31, 2003. Amounts equivalent to cash dividends on the Stock Units accrue as additional Stock Units. Stock Units are paid to the director in cash upon termination of service unless the director has elected to defer payment for a period that results in payment commencing not later than five years thereafter.

Insurance. AEP maintains a group 24-hour accident insurance policy to provide a $1,000,000 accidental death benefit for each director. The current policy, effective

September 1, 2001 through September 1, 2004, has a premium of $31,050. In addition, AEP pays each non-employee director an amount to provide for the federal and state income taxes incurred in connection with the maintenance of this coverage ($557 for 2003).

(b) INTEREST IN THE SECURITIES OF SYSTEM COMPANIES INCLUDING OPTIONS OR OTHER RIGHTS TO ACQUIRE SECURITIES (OWNERSHIP OF SECURITIES)

The following table sets forth the beneficial ownership of AEP Common Stock and stock-based units as of January 1, 2004 for all nominees to the Board of Directors, each of the persons named in the Summary Compensation Table and all such directors and executive officers as a group. Unless otherwise noted, each person had sole voting and investment power over the number of shares of AEP Common Stock and stock-based units of AEP set forth across from his or her name. Fractions of shares and units have been rounded to the nearest whole number.

Name	Shares	Stock Units(a)	Options Exercisable Within 60 Days	Total
E. R. Brooks	21,205	4,925	—	26,130
D. M. Carlton	7,432	4,925	—	12,357
J. P. DesBarres	5,000(c)	6,211	—	11,211
E. L. Draper, Jr.	5,693(b)(c)	125,233	816,666	947,592
H. W. Fayne	6,844(b)(d)	13,143	229,333	249,320
R. W. Fri	3,000	6,965	—	9,965
T. M. Hagan	14,110(b)	149	91,833	106,092
W. R. Howell	1,692	8,190	—	9,882
L. A. Hudson, Jr.	1,853(e)	9,379	—	11,232
L. J. Kujawa	2,328(e)	12,491	—	14,819
M. G. Morris	300,000(g)	—	—	300,000
R. L. Sandor	1,092	6,558	—	7,650
T. V. Shockley, III	45,323 (b)(d)(e)	—	300,000	345,323
D. G. Smith	2,500	7,506	—	10,006
K. D. Sullivan	—	11,334	—	11,334
S. Tomasky	1,967(b)	6,502	229,333	237,802
All directors, nominees and executive officers as a group (18 persons)	506,228(d)(f)	225,254	1,859,230	2,590,622

Notes on Stock Ownership

(a) This column includes amounts deferred in stock units and held under AEP's various director and officer benefit plans.

(b) Includes the following numbers of share equivalents held in the AEP Retirement Savings Plan: Dr. Draper, 4,938; Mr. Fayne, 6,152; Mr. Shockley, 7,530; Ms. Tomasky, 1,967; Mr. Hagan, 3,617; and all directors and executive officers as a group, 25,072.

September 1, 2001 through September 1, 2004, has a premium of $31,050. In addition, AEP pays each non-employee director an amount to provide for the federal and state income taxes incurred in connection with the maintenance of this coverage ($557 for 2003).

(b) INTEREST IN THE SECURITIES OF SYSTEM COMPANIES INCLUDING OPTIONS OR OTHER RIGHTS TO ACQUIRE SECURITIES (OWNERSHIP OF SECURITIES)

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M. G. Morris	300,000(g)	—	—	300,000
R. L. Sandor	1,092	6,558	—	7,650
T. V. Shockley, III	45,323(b)(d)(e)	—	300,000	345,323
D. G. Smith	2,500	7,506	—	10,006
K. D. Sullivan	—	11,334	—	11,334
S. Tomasky	1,967(b)	6,502	229,333	237,802
All directors, nominees and executive officers as a group (18 persons)	506,228(d)(f)	225,254	1,859,230	2,590,622

Notes on Stock Ownership

(a) This column includes amounts deferred in stock units and held under AEP's various director and officer benefit plans.

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(c) Includes the following numbers of shares held in joint tenancy with a family member: Mr. DesBarres, 5,000; and Dr. Draper, 755.
(d) Does not include, for Messrs. Fayne and Shockley and Ms. Tomasky, 85,231 shares in the American Electric Power System Educational Trust Fund over which Messrs. Fayne and Shockley and Ms. Tomasky share voting and investment power as trustees (they disclaim beneficial ownership). The amount of shares shown for all directors and executive officers as a group includes these shares.
(e) Includes the following numbers of shares held by family members over which beneficial ownership is disclaimed: Dr. Hudson, 750; Mr. Kujawa, 28; and Mr. Shockley, 496.
(f) Represents less than 1% of the total number of shares outstanding.
(g) Consists of restricted shares with different vesting schedules.

(c) CONTRACTS AND TRANSACTIONS WITH SYSTEM COMPANIES

None

(d) INDEBTEDNESS TO SYSTEM COMPANIES

None

(e) PARTICIPATION IN BONUS AND PROFIT-SHARING ARRANGEMENTS AND OTHER BENEFITS

Long-Term Incentive Plans — Awards In 2003

The performance share units set forth in the tables below were awarded in January 2003 and December 2003, respectively, pursuant to the Company's 2000 Long-Term Incentive Plan. Performance share units are equivalent to shares of AEP Common Stock. Dividends are reinvested in additional performance share units for the same performance and vesting period using the closing price of the AEP Common Stock on the dividend payment date. The value of the January 2003 performance share unit awards is dependent on the Company's total shareholder return for the applicable performance period relative to the S&P electric utilities, the market price of AEP Common Stock at the end of the performance period, the value of dividends paid during the performance period and the AEP Common Stock price on each dividend payment date. The value of the December 2003 performance share unit awards is dependent on AEP's earnings per share target versus a target established by the HR Committee in addition to each of the factors described above. The number of performance share units earned can vary between 0% and 200% of the initial award plus reinvested dividends.

The number of common stock equivalent units that may be earned at threshold, target and maximum performance levels, excluding any reinvested dividends, is shown in the table below. The HR Committee may, in its discretion, reduce the number of performance share unit targets otherwise earned. In accordance with the performance goals established for the periods set forth below, the threshold, target and maximum awards are equal to 20%, 100% and 200%, respectively, of the performance share unit awards.

Deferral of earned performance share units into phantom stock units (equivalent to shares of AEP Common Stock) is mandatory until the officer has met his or her stock ownership requirements. Once their stock ownership requirement is met, officers may elect to continue to defer earned performance share units or to receive subsequently earned awards in cash and/or Common Stock.

JANUARY 2003 AWARD

Name	Number of Performance Share Units	Performance Period Until Maturation or Payout	Estimated Future Payouts of Performance Share Units Under Non-Stock Price-Based Plan Threshold (#)	Target (#)	Maximum (#)
E. L. Draper, Jr.	40,236	2003-2005	8,047	40,236	80,472
T. V. Shockley, III	15,956	2003-2005	3,191	15,956	31,912
H. W. Fayne	11,074	2003-2005	2,215	11,074	22,148
S. Tomasky	10,520	2003-2005	2,104	10,520	21,040
T. M. Hagan	9,302	2003-2005	1,860	9,302	18,604

DECEMBER 2003 AWARD

Name	Number of Performance Share Units	Performance Period Until Maturation or Payout	Estimated Future Payouts of Performance Share Units Under Non-Stock Price-Based Plan Threshold (#)	Target (#)	Maximum (#)
E. L. Draper, Jr.	-0-	12/10/03–12/31/04	0	0	0
T. V. Shockley, III	41,400	12/10/03–12/31/04	8,280	41,400	82,800
H. W. Fayne	21,200	12/10/03–12/31/04	4,240	21,200	42,400
S. Tomasky	21,200	12/10/03–12/31/04	4,240	21,200	42,400
T. M. Hagan	21,200	12/10/03–12/31/04	4,240	21,200	42,400

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(1) Any performance shares earned for the December 2003 award will vest on December 31, 2006.

Retirement Benefits

AEP maintains qualified and nonqualified defined benefit ERISA pension plans for eligible employees. The tax-qualified plans are the American Electric Power System Retirement Plan (AEP Retirement Plan) and the Central and South West Corporation Cash Balance Retirement Plan (CSW Cash Balance Plan). The nonqualified plans are the American Electric Power System Excess Benefit Plan (AEP Excess Benefit Plan) (together with the AEP Retirement Plan, the AEP Plans) and the Central and South West Corporation Special Executive Retirement Plan (CSW SERP) (together with the CSW Cash Balance Plan, the CSW Plans), each of which provides (i) benefits that cannot be payable under the respective tax-qualified plans because of maximum limitations imposed on such plans by the Internal Revenue Code and (ii) benefits pursuant to individual agreements with certain AEP employees. The CSW Plans continue as separate plans for those AEP System employees who were participants in the CSW Cash Balance Plan as of December 31, 2000. Each of the executive officers named in the Summary Compensation Table (other than Mr. Shockley and Mr. Hagan) participates in the AEP Plans. Mr. Shockley and Mr. Hagan participate in the CSW Plans.

The benefit formula generally used to calculate benefit additions under the pension plans for all plan participants (including the executive officers named in the Summary Compensation Table) is a cash balance formula. When the cash balance formula was added to each plan, an opening balance was established for employees then participating under each plan's prior benefit formula (as further described below), using a number of factors as set forth in the appropriate plan. Under the cash balance formula, each participant has an account established (for record keeping purposes only) to which dollar amount credits are allocated each year based on a percentage of the participant's eligible pay not in excess of $1,000,000. The applicable percentage is determined by the participant's age and years of vesting service as of December 31 of each year (or as of the participant's termination date, if earlier). The following table shows the applicable percentage used to determine the annual dollar amount credits based on the sum of age and years of service indicated:

Sum of Age Plus Years of Service	Applicable Percentage
Less than 30	3.0%
30-39	3.5%
40-49	4.5%
50-59	5.5%
60-69	7.0%
70 or more	8.5%

All dollar amount balances in the cash balance accounts of participants earn a fixed rate of interest that is also credited annually. The interest rate for a particular year is the Applicable Interest Rate set in accordance with Section 417(e)(3)(A)(ii) of the Internal Revenue Code and is currently the average interest rate on 30-year Treasury securities for the month of November of the prior year. For 2003, the interest rate was 4.96%. Interest continues to be credited as long as the participant's balance remains in the plan.

The CSW SERP also provides that the cash balance account of participants who at termination of employment hold the office of Vice President or higher of an employer participating in the CSW Plans will be no less than (i) the sum of the Applicable Percentages from the foregoing table generally for each year that the participant earned credited service under the CSW Cash Balance Plan, multiplied by (ii) the participant's final average pay. "Final average pay" generally is the average annual compensation during the 36 consecutive months of highest pay during the 120 months prior to retirement.

Under the cash balance formula, an amount equal to the vested balance (including tax-qualified and nonqualified benefits) then credited to the account is payable to the participant in the form of an immediate or deferred lump-sum or an annuity or, with respect to the nonqualified benefits, in installments. Benefits (from both the tax-qualified and nonqualified plans) under the cash balance formula are not subject to reduction for Social Security benefits or other offset amounts, except that Dr. Draper has an individual agreement which provides that his supplemental retirement benefits are reduced by pension entitlements, if any, from plans sponsored by prior employers. The estimated annual benefit that would be payable as a single life annuity under the cash balance formula to each of the executive officers named in the Summary Compensation Table at age 65 is:

Name	Annual Benefit
E. L. Draper, Jr.	$ 536,200
T. V. Shockley, III	218,400
H. W. Fayne	263,300
S. Tomasky	296,500
T. M. Hagan	112,400

These amounts are based on the following assumptions:

- The amounts shown in the *Salary* column of the Summary Compensation Table are used for calendar year 2003 and all subsequent years, assuming no salary changes. The portion of the *Bonus* column attributable to the Senior Officer Annual Incentive Compensation Plan is used for 2004 and annual incentive awards at the 2003 target level are used for all subsequent years beyond 2004. For Dr. Draper, the annual salary rate reflected in the *Salary* column for calendar year 2003 is used for the period from January 1, 2004 through April 30, 2004, the approximate date as of which he is expected to retire.

- Conversion of the lump-sum cash balance to a single life annuity at age 65, based on an interest rate of 5.12% and the 1994 Group Annuity Reserving Table published by the Internal Revenue Service.

- Dr. Draper and Ms. Tomasky have individual agreements with AEP that credit them with years of service in addition to their years of service with AEP as follows: Dr. Draper, 24 years; and Ms. Tomasky, 20 years. As mentioned above, the agreement for Dr. Draper provides that his supplemental retirement benefits are reduced by pension entitlements, if any, from plans sponsored by prior employers.

In addition, employees who have continuously participated in the AEP Plans since December 31, 2000 remain eligible for a pension benefit using the final average pay formula that was in place before the implementation of the cash balance formula described above. Employees that are eligible for both formulas will receive their benefits under the formula that provides the higher benefit, given the participant's choice of the form of benefit (single life annuity, lump sum, etc.). Participants that remain eligible to receive the final average pay formula will continue to accrue pension benefits under that formula until December 31, 2010, at which time each participant's final average pay benefit payable at the participant's normal retirement age (the later of age 65 or 5 years of service) will be frozen and unaffected by the participant's subsequent service or compensation. After December 31, 2010, each participant's frozen final average pay benefit will be the minimum benefit a participant can receive from the AEP Plans at the participant's normal retirement age.

Final average pay under the AEP Plans is computed using the highest average 36 consecutive months of the salary and bonus out of the participant's most recent 10 years of service. The information used to compute the final average pay benefit for executive officers named in the Summary Compensation Table above, other than Mr. Shockley and Mr. Hagan, is consistent with that shown in the *Salary* column of the Summary Compensation Table and that portion of the *Bonus* column attributable to the Senior Officer Annual Incentive Compensation Plan.

The following table shows the approximate annual annuities that would be payable to executive officers and other management employees under the final average pay formula of the AEP Plans, assuming termination of employment on December 31, 2003 after various periods of service and with benefits commencing at age 65.

AEP Plans Pension Plan Table

Highest Average Annual Earnings	Years of Accredited Service					
	15	20	25	30	35	40
$ 400,000	$ 92,850	$ 123,800	$ 154,750	$ 185,700	$ 216,650	$ 243,250
500,000	116,850	155,800	194,750	233,700	272,650	305,900
600,000	140,850	187,800	234,750	281,700	328,650	368,550
800,000	188,850	251,800	314,750	377,700	440,650	493,850
1,000,000	236,850	315,800	394,750	473,700	552,650	619,150
1,200,000	284,850	379,800	474,750	569,700	664,650	744,450
2,000,000	476,850	635,800	794,750	953,700	1,112,650	1,245,650
2,500,000	596,850	795,800	994,750	1,193,700	1,392,650	1,558,900

The amounts shown in the table are the straight life annuities payable under the final average pay formula of the AEP Plans without reduction for any optional features that may be elected at the participant's expense. Retirement benefits listed in the table are not subject to any further deduction for Social Security or other offset amounts. The retirement annuity is reduced 3% per year for each year prior to age 62 in the event of a termination of employment after age 55 and the participant's election to commence benefits between ages 55 and 62. If an employee terminates employment after age 55 and commences benefits at or after age 62, there is no reduction in the retirement annuity.

Under the AEP Plans, as of December 31, 2003, for the executive officers named in the Summary Compensation Table (except for Mr. Shockley and Mr. Hagan as discussed below in connection with the CSW Plans), the number of years of service applicable for the final average pay formula were as follows: Dr. Draper, 35.9 years; Mr. Fayne, 29.1 years; and Ms. Tomasky, 25.5 years. The years of service for Dr. Draper and Ms. Tomasky include years of service provided by their respective agreements with AEP as described above in connection with the cash balance formula. The agreement for Dr. Draper provides that his supplemental retirement benefits are reduced by pension entitlements, if any, from plans sponsored by prior employers.

Under the CSW Plans, certain employees who were 50 or over and had completed at least 10 years of service as of July, 1997, remain eligible for benefits under the prior pension formulas that are based on career average pay and final average pay. Of the executive officers named in the Summary Compensation Table, Mr. Shockley and Mr. Hagan are eligible to participate in the CSW Plans and have a choice upon their termination of employment to elect their benefit based on the cash balance formula or the prior pension formulas.

The following table shows the approximate annual annuities that would be payable to employees in certain higher salary classifications under the prior benefit formulas provided through the CSW Plans, assuming termination of employment on December 31, 2003 after various periods of service and with benefits commencing at age 65, and prior to reduction by up to 50 percent of the participant's Social Security benefit.

CSW Plans Pension Plan Table

Highest Average	Years of Accredited Service			
Annual Earnings	15	20	25	30 or more
$ 400,000	$ 100,000	$ 133,333	$ 166,667	$ 200,000
500,000	125,000	166,667	208,333	250,000
600,000	150,000	200,000	250,000	300,000
700,000	175,000	233,333	291,667	350,000
800,000	200,000	266,667	333,333	400,000
900,000	225,000	300,000	375,000	450,000
1,000,000	250,000	333,333	416,667	500,000
1,200,000	300,000	400,000	500,000	600,000

Under the CSW Plans, the annual normal retirement benefit payable from the final average pay formula is based on 1 $^2/3$% of "Average Compensation" times the number of years of credited service (up to a maximum of 30 years), reduced by no more than 50 percent of the participant's age 62 or later Social Security benefit and then adjusted annually based on changes in the consumer price index. "Average Compensation" equals the average annual compensation, reported as *Salary* in the Summary Compensation Table, during the 36 consecutive months of highest pay during the 120 months prior to retirement. Mr. Shockley and Mr. Hagan each have an agreement entered into with CSW prior to its merger with AEP under which each is entitled to a retirement benefit that will bring his credited years of service to 30 if he remains employed with AEP until age 60 or thereafter. Mr. Shockley's years of credited service and age, as of December 31, 2003, are 20 and 58. Mr. Hagan's years of credited service and age, as of December 31, 2003, are 23 and 59.

In addition to the benefits described above, Mr. Fayne is the only executive officer named in the Summary Compensation Table who is eligible for certain supplemental retirement benefits if his pension benefits are adversely affected by amendments to the AEP Retirement Plan made as a result of the Tax Reform Act of 1986. Such benefits, if any, will be equal to any reduction occurring because of such amendments. If Mr. Fayne's employment had terminated by December 31, 2003, he would not be eligible for any additional annual supplemental benefit.

AEP also made available a voluntary deferred-compensation program in 1986, which permitted certain members of AEP System management to defer receipt of a portion of their salaries. Under this program, a participant was able to annually defer up to 10% of his or her salary over a four-year period, and receive supplemental retirement or survivor benefit payments over a 15-year period. The amount of supplemental retirement payments received is dependent upon the amount deferred, age at the time the deferral election was made, and number of years until the participant retires. Mr. Fayne is the only executive officer named in the Summary Compensation Table who participated in this program. He deferred $9,000 of his salary annually over a four-year period and, as a result, qualified for supplemental retirement payments of $95,400 per year for fifteen years assuming he would retire at age 65.

Change-In-Control Agreements

AEP has change-in-control agreements with its executives, including all of the executive officers named in the Summary Compensation Table. If there is a "change-in-control" of AEP and the executive officer's employment is terminated (i) by AEP without "cause" or (ii) by the officer because of a detrimental change in responsibilities, a required relocation or a reduction in salary or benefits, these agreements provide for:

- A lump sum payment equal to three times the officer's annual base salary plus target annual incentive under the Senior Officer Annual Incentive Compensation Plan.

- Maintenance for a period of three additional years of all medical and dental insurance benefits substantially similar to those benefits to which the officer was entitled immediately prior to termination, reduced to the extent comparable benefits are otherwise received.

- Outplacement services not to exceed a cost of $30,000 or use of an office and secretarial services for up to one year.

- Three years of service credited for purposes of determining non-qualified retirement benefits, with such credited service proportionately reduced to zero if termination occurs between ages 62 and 65.

- Payment, if required, to make the officer whole for any excise tax imposed by Section 4999 of the Internal Revenue Code.

Under these agreements, "change-in-control" means:

- The acquisition by any person of the beneficial ownership of securities representing 25% or more of AEP's voting stock;
- A change in the composition of a majority of the Board of Directors under certain circumstances within any two-year period; or
- Approval by the shareholders of the liquidation of AEP, disposition of all or substantially all of the assets of AEP or, under certain circumstances, a merger of AEP with another corporation.

(f) RIGHTS TO INDEMNITY

The Directors and officers of AEP and its subsidiaries are insured, subject to certain exclusions, against losses resulting from any claim or claims made against them while acting in their capacities as directors and officers. The American Electric Power System companies are also insured, subject to certain exclusions and deductibles, to the extent that they have indemnified their directors and officers for any such losses. Such insurance, effective January 1, 2004 through December 31, 2004, is provided by: Associated Electric & Gas Insurance Services, Energy Insurance Mutual, Zurich American Insurance Company, National Union Fire Insurance Company of PA, Federal Insurance Company, Liberty Mutual Insurance Company, Houston Casualty Company, Twin City Fire Insurance Company, Landmark American Insurance Company, Quanta Reinsurance U.S. Ltd., AXIS Reinsurance Company, Starr Excess International and Oil Casualty Insurance, Ltd. The total cost of this insurance is $8,720,200.

Fiduciary liability insurance provides coverage for AEP System companies, their directors and officers, and any employee deemed to be a fiduciary or trustee, for breach of fiduciary responsibility, obligation, or duties as imposed under the Employee Retirement Income Security Act of 1974. This coverage, provided by Associated Electric & Gas Insurance Services, Federal Insurance Company, Zurich American Insurance Company and Energy Insurance Mutual, was renewed, effective July 1, 2003 through June 30, 2004, for a cost of $1,190,750.

ITEM 7. CONTRIBUTIONS AND PUBLIC RELATIONS

Expenditures, disbursements or payments during the year, in money, goods or services directly or indirectly to or for the account of:

(1) Any political party, candidate for public office or holder of such office, or any committee or agent thereof.

NONE

(2) Any citizens group or public relations counsel.

Calendar Year 2003

Name of Company	Name or Number of Recipients or Beneficiaries	Primary Purpose of Entity	Purpose of Contribution	Accounts Charged	Amoun
CSW Energy, Inc.	American Wind Energy	Legislative Affairs	Annual Dues	930.2	$2,50
CSW Energy, Inc.	American Wind Energy	Legislative Affairs	Legislative Dues	426.1	24,00
CSW Energy, Inc.	Utility Wind Interest Group	Legislative Affairs	Annual Dues	930.2	3,75
Indiana Michigan Power Company	Access Indiana Information Network	Legislative Affairs	Registration Fees	426.4	52
Indiana Michigan Power Company	Business Speakers Bureau	Legislative Affairs	PAC Event Speaker	426.4	99
Indiana Michigan Power Company	Country Club of Lansing	Senate Democratic Caucus	Sponsorship Dinner	426.4	1,65
Indiana Michigan Power Company	Granholm-Cherry Inaugral CMT	Legislative Affairs	Sponsorship	426.4	10,00
Indiana Michigan Power Company	Hoaglin Fine Catering	Catering Services	2003 Legislative Reception	426.4	1,09

ITEM 7. CONTRIBUTIONS AND PUBLIC RELATIONS (CONTINUED)

(2) Any citizens group or public relations counsel. (CONTINUED)

Calendar Year 2003

Name of Company	Name or Number of Recipients or Beneficiaries	Primary Purpose of Entity	Purpose of Contribution	Accounts Charged	Amount
Indiana Michigan Power Company	Martins Catering	Catering Services,	PAC event	426.4	$303
Indiana Michigan Power Company	Indiana Night – NCSL	Legislative Affairs	Reception	426.4	411
Indiana Michigan Power Company	Michigan Chamber Pac II	Legislative Affairs	Sponsorship	426.4	700
Indiana Michigan Power Company	Muchmore Harrington & Smalley	Legislative Affairs	Legislative Services	426.4	42,865
Indiana Michigan Power Company	Vectren	Legislative Affairs	Sponsorship	426.1	1,000
Kentucky Power Company	NCSL – Kentucky Night 2003	Legislative Affairs	Reception	426.4	1,049
Kentucky Power Company	Home Builders Association of Kentucky	Legislative Affairs	Registration Fees	426.4	140
Kentucky Power Company	Kentucky State Treasurer	Legislative Affairs	Registration Fees	426.4	250

ITEM 8. SERVICE, SALES AND CONSTRUCTION CONTRACTS

Part I. Contracts for services, including engineering or construction services, or goods supplied or sold between System companies are as follows:

Calendar Year 2003

Nature of Trasactions (1)	Company Performing Service (2)	Company Receiving Service (3)	Compensation (4)	Date of Contract (5)	In Effect on December 31, 2003 (Yes/No) (6)
Accounts Receivable Factoring	AEP Credit, Inc.	Appalachian Power Company	$3,401	12/31/01	Yes
Accounts Receivable Factoring	AEP Credit, Inc.	Columbus Southern Power Company	9,792	12/31/01	Yes
Accounts Receivable Factoring	AEP Credit, Inc.	Indiana Michigan Power Company	6,104	12/31/01	Yes
Accounts Receivable Factoring	AEP Credit, Inc.	Kentucky Power Company	2,374	12/31/01	Yes
Accounts Receivable Factoring	AEP Credit, Inc.	Kingsport Power Company	481	12/31/01	Yes
Accounts Receivable Factoring	AEP Credit, Inc.	Ohio Power Company	8,748	12/31/01	Yes
Accounts Receivable Factoring	AEP Credit, Inc.	Public Service Company of Oklahoma	5,841	12/31/01	Yes
Accounts Receivable Factoring	AEP Credit, Inc.	Southwestern Electric Power Company	4,906	12/31/01	Yes
Barging	AEP Memco LLC	Indiana Michigan Power Company	10,561	1/1/03	Yes
Barging	AEP Memco LLC	Indiana - Kentucky Electric Corporation	8,841	4/01/03	Yes

ITEM 8. SERVICE, SALES AND CONSTRUCTION CONTRACTS (CONTINUED)

Part I. Contracts for services, including engineering or construction services, or goods supplied or sold between System companies (CONTINUED)

Nature of Trasactions (1)	Company Performing Service (2)	Company Receiving Service (3)	Compensation (4)	Date of Contract (5)	In Effect on December 31, 2003 (Yes/No) (6)
Barging	Indiana Michigan Power Company	Ohio Power Company	$4,313	5/1/86	Yes
Barging	Indiana Michigan Power Company	Appalachian Power Company	12,321	5/1/86	Yes
Barging	Indiana Michigan Power Company	AEP Generating Company	8,108	5/1/86	Yes
Barging	Indiana Michigan Power Company	Kentucky Power Company	74	5/1/96	Yes
Barging	Indiana Michigan Power Company	AEP Memco LLC	7,054	1/1/02	Yes
Barging	Indiana Michigan Power Company	AEP Energy Services, Inc.	53	1/1/02	No
Coal Washing	Conesville Coal Preparation Company	Columbus Southern Power Company	9,196	11/5/84	Yes
Communication Services	AEP Communications LLC	Appalachian Power Company	3,202	3/4/98	Yes
Communication Services	AEP Communications LLC	Kentucky Power Company	212	11/18/97	Yes
Communication Services	AEP Communications LLC	Indiana Michigan Power Company	1,758	10/24/98	Yes
Communication Services	AEP Communications LLC	Wheeling Power Company	956	11/18/97	Yes
Communication Services	AEP Communications LLC	Ohio Power Company	1,156	2/12/98	Yes

ITEM 8. SERVICE, SALES AND CONSTRUCTION CONTRACTS (CONTINUED)

Part I. Contracts for services, including engineering or construction services, or goods supplied or sold between System companies (CONTINUED)

Nature of Trasactions (1)	Company Performing Service (2)	Company Receiving Service (3)	Compensation (4)	Date of Contract (5)	In Effect on December 31, 2003 (Yes/No) (6)
Communication Services	AEP Communications LLC	Columbus Southern Power Company	$1,073	2/12/98	Yes
Environmental Services	AEP Pro Serv, Inc.	Eastex Cogeneration LP	1	8/23/01	No
Leasing Agreement for Coal Conveyor System	Simco, Inc.	Conesville Coal Preparation Company	172	5/1/91	Yes
Maintenance Services	Appalachian Power Company	Ohio Valley Electric Corporation	1,302	1/1/79	Yes
Maintenance Services	Appalachian Power Company	Indiana-Kentucky Electric Corporation	216	1/1/79	Yes
Machine Shop Services	Appalachian Power Company	System Operating Companies	8,752	12/8/78	Yes
Machine Shop Services	AEP Pro Serv, Inc.	CSW Energy, Inc.	6	5/1/02	No
Machine Shop Services	AEP Pro Serv, Inc.	CSW Energy, Inc.	2	5/3/02	No
Maintenance Services	AEP Pro Serv, Inc.	CSW Energy, Inc.	121	Various	No
Project & Administrative Services	AEP Pro Serv, Inc.	Nanyang General Light Electric Company, Ltd	396	1/1/03	Yes
Project & Administrative Services	AEP Pro Serv, Inc.	Sweeny Cogeneration LP	1,031	3/25/03	Yes

ITEM 8. SERVICE, SALES AND CONSTRUCTION CONTRACTS (CONTINUED)

Part I. Contracts for services, including engineering or construction services, or goods supplied or sold between System companies (CONTINUED)

Nature of Trasactions (1)	Company Performing Service (2)	Company Receiving Service (3)	Compensation (4)	Date of Contract (5)	In Effect on December 31, 2003 (Yes/No) (6)
Project and Administrative Services	AEP Pro Serv, Inc.	Louisiana Intrastate Gas Company, LLC	$2	1/19/01	No
Project and Administrative Services	Kingsport Power Company	AEP Communications LLC	(32)	3/4/98	Yes
Project and Administrative Services	Appalachian Power Company	AEP Communications LLC	1,381	3/4/98	Yes
Project and Administrative Services	Kentucky Power Company	AEP Communications LLC	25	3/4/98	Yes
Project and Administrative Services	Indiana Michigan Power Company	AEP Communications LLC	763	10/24/98	Yes
Project and Administrative Services	Wheeling Power Company	AEP Communications LLC	937	11/18/97	Yes
Project and Administrative Services	Ohio Power Company	AEP Communications LLC	(87)	2/12/98	Yes
Project and Administrative Services	Columbus Southern Power Company	AEP Communications LLC	117	2/12/98	Yes
Simulator Training Services	Appalachian Power Company	System Operating Companies	1,086	12/12/87	Yes

ITEM 8. SERVICE, SALES AND CONSTRUCTION CONTRACTS (CONTINUED)

Transactions between AEP System companies pursuant to the Affiliated Transactions Agreement dated December 31, 1996 are reported in Exhibit F of this U5S.

Part II. Contracts to purchase services or goods between any System company and (1) any affiliate company (other than a System company) or (2) any other company in which any officer or director of the System company, receiving service under the contract, is a partner or owns 5 percent or more of any class of equity securities. - NONE.

Part III. Employment of any other person, by any System company, for the performance on a continuing basis, of management, supervisory or financial advisory services. - NONE.

ITEM 9. WHOLESALE GENERATORS AND FOREIGN UTILITY COMPANIES

Part I.

The following table shows the required information for investment in wholesale generation and foreign utility companies as of December 31, 2003:

(a) Company name, business address, facilities and interest held;
(b) Capital invested, recourse debt, guarantees and transfer of assets between affiliates;
(c) Debt to equity ratio and earnings;
(d) Contracts for service, sales or construction with affiliates.

Foreign Utility Companies:

(a) AEPR Global Holland Holding B.V
Herengracht 548
1017 CG Amsterdam, The Netherlands
(b) Capital Invested - $734 million. Recourse debt – NONE. Guarantees – NONE.
Asset Transfers – NONE.
(c) Earnings – $(249) million,
(d) NONE

(a) AEP Energy Services UK Generation Limited
50 Berkeley Street
Mayfair London W1J89AP, Great Britain
(b) Capital invested - $409 million. Recourse debt – NONE. Guarantees – NONE.
Asset transfers – NONE.
(c) Earnings – $(142) million.
(d) NONE

(a) Nanyang General Light Electric Co., Ltd.
Dayuan Zhuan Village
Pushan Town, Nanyang City
People's Republic of China
Owns and operates a two unit electric generating plant in China. AEP owns 70%.
(b) Capital invested $44 million. Recourse debt – NONE. Guarantees – NONE.
Asset transfers – NONE.
(c) Debt to equity ratio – 0.8:1. Earnings - $12 million.
(d) Nanyang has contracts with AEP Pro Serv, Inc. for consulting and administrative service which resulted in a fee of $396,000.

(a) Pacific Hydro Limited
Level 8
474 Flinders Street
Melbourne, Victoria
3000 Australia
Develops and owns hydroelectric facilities in the Asia Pacific region.
AEP owns 20%.
(b) Capital invested - $20 million. Recourse Debt – NONE. Guarantees – NONE.
Assets transferred – NONE.
(c) Noncurrent liabilities to equity ratio – 0.7:1.
Earnings - $19 million.
(d) NONE

ITEM 9. WHOLESALE GENERATORS AND FOREIGN UTILITY COMPANIES (Continued)

Part I. (Continued)

(a) AEP Energy Services Limited
29/30 St. James's Street
London SW1A 1HB
Great Britain
AEP owns 100%.
(b) Capital invested - $71 million. Recourse debt – NONE. Guarantees – NONE.
Assets transferred – NONE.
(c) Earnings - $(137) million.
(d) NONE

(a) InterGen Denmark, Aps
Torre Chapultepec,
Piso 13,
Ruben Dario 281, Col.
Bosques de
Chapultepec, Mexico, D.F. 11520.
Construction and operation of a 600 megawatt natural gas-fired, combined cycle plant. AEP owns 50%.
(b) Capital invested - $54 million. Recourse debt - NONE. Guarantees – NONE.
Asset transfers – NONE.
(c) Debt to equity ratio – 7.0:1. Earnings – $(16) million.
(d) NONE

(a) South Coast Power Limited
Shoreham, East Sussex
United Kingdom
(b) Capital invested - NONE. Recourse debt – NONE. Guarantees – NONE.
Asset transfers – NONE.
(c) Earnings - $1 million.
(d) NONE

Exempt Wholesale Generators:

(a) Desert Sky Wind Farm L.P.
1 Riverside Plaza
Columbus, Ohio
Operation of Windfarm in Texas.
(b) Capital invested - $20 million. Recourse debt – NONE. Guarantees – NONE.
Asset transfer – NONE.
(c) Debt to equity ratio – 1.9:1. Earnings - $2 million.
(d) NONE

(a) Trent Windfarm L.P.
1 Riverside Plaza
Columbus, Ohio
Operation of Windfarm in Texas.
(b) Capital invested - $48 million. Recourse debt – NONE. Guarantees – NONE.
Asset transfer – NONE.
(c) Debt to equity ratio – 1.2:1. Earnings - $9 million.
(d) NONE

ITEM 9. WHOLESALE GENERATORS AND FOREIGN UTILITY COMPANIES (Continued)

Part II.

See Exhibit's G and H

Part III.

American Electric Power Company, Inc.'s aggregate investment in foreign utility companies is $1.3 billion and in exempt wholesale generators is $68 million which is 17.9% of its investment in domestic public utility subsidiary companies.

ITEM 10. FINANCIAL STATEMENTS AND EXHIBITS

FINANCIAL STATEMENTS	Section and Page No.
Consent of Independent Public Accountants	A
Consolidating Statements of Income	B-1 to B-26
Consolidating Balance Sheets	B-27 to B-74
Consolidating Statements of Cash Flows	B-75 to B-90
Consolidating Statements of Retained Earnings	B-91 to B-96
Notes to Consolidating Financial Statements	C
Financial Statements of Subsidiaries Not Consolidated:	
Ohio Valley Electric Corporation	D-1 to D-3

EXHIBITS

Exhibit A – 10-K File References for Each American Electric Power Company, Inc. Registrant	E
Exhibit B & C – 10-K Exhibit Index	**
Exhibit D – Tax Allocation Agreement	**
Exhibit E – Chart of Accounts/Personnel Policies	**
Exhibit F – Intercompany Billings	**
Exhibit G – Organizational Chart For: - Exempt Wholesale Generators - Foreign Utility Companies	**
Exhibit H – Unaudited Financial Statements For: - Exempt Wholesale Generators - Foreign Utility Companies	**

** These Exhibits are included only the in copy filed with the Securities and Exchange Commission.

*** Filed confidentially pursuant to Rule 104(b) of the PUHCA.

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SIGNATURE

The undersigned system company has duly caused this annual report to be signed on its behalf by the undersigned, thereunto duly authorized, pursuant to the requirements of the Public Utility Holding Company Act of 1935.

AMERICAN ELECTRIC POWER COMPANY, INC.

By /s/ Stephen P. Smith
Stephen P. Smith
Treasurer

April 30, 2004

INDEPENDENT AUDITORS' CONSENT

We consent to the incorporation by reference in this American Electric Power Company, Inc. Annual Report on Form U5S to the Securities and Exchange Commission, filed pursuant to the Public Utility Holding Company Act of 1935, for the year ended December 31, 2003, of our reports dated March 5, 2004, included in or incorporated by reference in the combined Annual Report on Form 10-K to the Securities and Exchange Commission of American Electric Power Company, Inc. and subsidiaries (which expresses an unqualified opinion and includes explanatory paragraphs referring to the Company's adoption of Statement of Financial Accounting Standards (SFAS) 142, "Goodwill and Other Intangible Assets," SFAS 143, "Accounting for Asset Retirement Obligations," Emerging Issues Task Force (EITF) 02-3, "Issues Involved in Accounting for Derivative Contracts Held for Trading Purposes and Contracts Involved in Energy Trading and Risk Management Activities," and Financial Interpretation Number (FIN) 46, "Consolidation of Variable Interest Entities"), AEP Generating Company, AEP Texas Central Company and subsidiaries (which expresses an unqualified opinion and includes explanatory paragraphs regarding the Company's adoption of SFAS 143 and FIN 46), AEP Texas North Company (which expresses an unqualified opinion and includes an explanatory paragraph regarding the Company's adoption of SFAS 143), Appalachian Power Company and subsidiaries (which expresses an unqualified opinion and includes an explanatory paragraph regarding the Company's adoption of SFAS 143 and EITF 02-3), Columbus Southern Power Company and subsidiaries (which expresses an unqualified opinion and includes an explanatory paragraph regarding the Company's adoption of SFAS 143 and EITF 02-3), Indiana Michigan Power Company and subsidiaries (which expresses an unqualified opinion and includes an explanatory paragraph regarding the Company's adoption of SFAS 143 and EITF 02-3), Kentucky Power Company (which expresses an unqualified opinion and includes an explanatory paragraph regarding the Company's adoption of EITF 02-3), Ohio Power Company Consolidated (which expresses an unqualified opinion and includes explanatory paragraphs regarding the Company's adoption of SFAS 143, EITF 02-3 and FIN 46), Public Service Company of Oklahoma Consolidated (which expresses an unqualified opinion and includes an explanatory paragraph regarding the Company's adoption of FIN 46), and Southwestern Electric Power Company and subsidiaries (which expresses an unqualified opinion and includes explanatory paragraphs regarding the Company's adoption of SFAS 143, and FIN 46) for the year ended December 31, 2003.

/s/ Deloitte & Touche LLP

Columbus, Ohio
April 30, 2004

Item 10 - Consolidating Statements of Income

AMERICAN ELECTRIC POWER COMPANY, INC.
AND SUBSIDIARY COMPANIES
CONSOLIDATING STATEMENT OF INCOME
FOR THE YEAR ENDED DECEMBER 31, 2003

Note - Totals and subtotals may be off due to rounding

DESCRIPTION	AMERICAN ELECTRIC POWER COMPANY CONSOLIDATED	SEC REPORTING ADJUSTMENTS	AMERICAN ELECTRIC POWER COMPANY ELIMINATIONS
REVENUES			
SALES TO NON AFFILIATES	$14,545,054,495.23	($847,192,934.00)	($160,248,881.25)
SALES TO AFFILIATES	36,782.36	0.00	(2,757,824,609.89)
TOTAL REVENUES	14,545,091,277.59	(847,192,934.00)	(2,918,073,491.14)
EXPENSES			
FUEL FOR ELECTRIC GENERATION	3,052,652,491.47	181,800,000.00	(303,177,110.56)
PURCHASED ELECTRICITY FOR RESALE	706,531,493.06	(3,760,930,000.00)	(5,226,951.07)
PURCHASED GAS FOR RESALE	2,850,275,000.00	2,850,275,000.00	0.00
PURCHASE POWER AFFILIATED	0.00	0.00	(1,651,316,467.89)
OTHER OPERATION	2,864,929,091.86	(169,403,602.69)	(786,582,092.37)
MAINTENANCE	808,469,478.49	(72,687,000.00)	(79,062,223.84)
ASSET IMPAIRMENTS AND OTHER RELATED CHARGES	650,158,000.00	650,158,000.00	0.00
DEPRECIATION AND AMORTIZATION	1,299,528,694.14	(37,725,000.00)	(8,653,441.20)
TAXES OTHER THAN INCOME TAXES	680,850,971.12	(550,000.00)	(40,221,167.42)
INCOME TAXES	0.00	(586,436,094.90)	(3,841,142.00)
TOTAL EXPENSES	12,913,395,220.14	(945,498,697.59)	(2,878,080,596.35)
OPERATING INCOME	1,631,696,057.44	98,305,763.59	(39,992,894.80)
OTHER INCOME (EXPENSE)	387,122,002.79	1,485,485,144.55	(349,445,665.22)
INTEREST AND OTHER CHARGES			
INVESTMENT VALUE GAINS (LOSSES)	(70,000,000.00)	(70,000,000.00)	0.00
OTHER INCOME (EXPENSE)	(227,123,635.05)	33,430,173.50	38,755,495.78
NONOPERATING INCOME TAX CREDITS (EXPENSE)	0.00	(549,376,104.56)	11,162,312.00
INTEREST EXPENSE (INCOME)	813,660,544.71	(16,252,000.00)	(115,938,120.93)
PREFERRED STOCK DIVIDEND REQUIREMENTS OF SUBSIDIARIES (INCLUDING CAPITAL STOCK EXPENSE)	8,903,507.37	8,903,507.37	0.00
MINORITY INTEREST IN FINANCE SUBSIDIARY (EXPENSE)	(18,569,365.54)	(18,569,365.54)	0.00
TOTAL INTEREST EXPENSE AND OTHER CHARGES (INCOME)	1,138,257,052.66	597,166,803.97	(165,855,928.71)
INCOME BEFORE INCOME TAXES	880,561,007.57	986,624,104.17	(223,582,631.30)
INCOME TAXES			
INCOME TAXES	832,249,171.90	832,249,171.90	0.00
NONOPERATING INCOME TAX CREDITS (EXPENSE)	474,104,088.56	474,104,088.56	0.00
TOTAL INCOME TAXES	358,145,083.34	358,145,083.34	0.00
INCOME BEFORE DISCONTINUED OPERATIONS, EXTRAORDINARY ITEMS AND CUMULATIVE EFFECT	522,415,924.23	628,479,020.83	(223,582,631.30)
DISCONTINUED OPERATIONS (NET OF TAX)	(605,202,563.00)	(605,202,563.00)	0.00
EXTRAORDINARY ITEMS (NET OF TAX)	0.00	176,775.00	0.00
CUMULATIVE EFFECT OF ACCOUNTING CHANGES (NET OF TAX)	192,521,480.13	(32,356,740.20)	0.00
NET INCOME	$109,734,841.36	($8,903,507.37)	($223,582,631.30)
PREFERRED STOCK DIVIDEND REQUIREMENTS OF SUBSIDIARIES (INCLUDING CAPITAL STOCK EXPENSE)	0.00	(8,903,507.37)	0.00
NET INCOME APPLICABLE TO COMMON STOCK	$109,734,841.36	($0.00)	($223,582,631.30)

Item 10 - Consolidating Statements of Income

AMERICAN ELECTRIC POWER COMPANY, INC.
AND SUBSIDIARY COMPANIES
CONSOLIDATING STATEMENT OF INCOME
FOR THE YEAR ENDED DECEMBER 31, 2003

Note - Totals and subtotals may be off due to rounding

DESCRIPTION	AMERICAN ELECTRIC POWER COMPANY	AMERICAN ELECTRIC POWER SERVICE CORPORATION	AEP TEXAS POLR, LLC
REVENUES			
SALES TO NON AFFILIATES	$0.00	$6,674,628.58	$8,694,202.35
SALES TO AFFILIATES	11,352,440.77	782,185,868.87	0.00
TOTAL REVENUES	11,352,440.77	788,860,497.45	8,694,202.35
EXPENSES			
FUEL FOR ELECTRIC GENERATION	0.00	2,442,434.76	0.00
PURCHASED ELECTRICITY FOR RESALE	0.00	860,437.07	0.00
PURCHASED GAS FOR RESALE	0.00	0.00	0.00
PURCHASE POWER AFFILIATED	0.00	0.00	5,117,114.49
OTHER OPERATION	32,146,080.07	646,846,471.46	13,075,955.63
MAINTENANCE	426.16	79,062,223.84	2.53
ASSET IMPAIRMENTS AND OTHER RELATED CHARGES	0.00	0.00	0.00
DEPRECIATION AND AMORTIZATION	146,738.09	8,618,050.25	1,586.76
TAXES OTHER THAN INCOME TAXES	0.00	40,227,458.74	262,547.43
INCOME TAXES	1,940,624.00	(2,681,030.00)	0.00
TOTAL EXPENSES	34,233,868.32	775,376,046.12	18,457,206.83
OPERATING INCOME	(22,881,427.55)	13,484,451.33	(9,763,004.48)
OTHER INCOME (EXPENSE)	312,845,519.27	569,280.79	9,018.32
INTEREST AND OTHER CHARGES			
INVESTMENT VALUE GAINS (LOSSES)	0.00	0.00	0.00
OTHER INCOME (EXPENSE)	(44,534,759.08)	(8,931,701.78)	(500.00)
NONOPERATING INCOME TAX CREDITS (EXPENSE)	490,342.00	0.00	3,528,862.00
INTEREST EXPENSE (INCOME)	139,526,828.47	5,122,030.33	203,690.26
PREFERRED STOCK DIVIDEND REQUIREMENTS OF SUBSIDIARIES (INCLUDING CAPITAL STOCK EXPENSE)	0.00	0.00	0.00
MINORITY INTEREST IN FINANCE SUBSIDIARY (EXPENSE)	0.00	0.00	0.00
TOTAL INTEREST EXPENSE AND OTHER CHARGES (INCOME)	183,571,245.55	14,053,732.11	(3,324,671.74)
INCOME BEFORE INCOME TAXES	106,392,846.17	0.01	(6,429,314.42)
INCOME TAXES			
INCOME TAXES	0.00	0.00	0.00
NONOPERATING INCOME TAX CREDITS (EXPENSE)	0.00	0.00	0.00
TOTAL INCOME TAXES	0.00	0.00	0.00
INCOME BEFORE DISCONTINUED OPERATIONS, EXTRAORDINARY ITEMS AND CUMULATIVE EFFECT	106,392,846.17	0.01	(6,429,314.42)
DISCONTINUED OPERATIONS (NET OF TAX)	0.00	0.00	0.00
EXTRAORDINARY ITEMS (NET OF TAX)	0.00	0.00	0.00
CUMULATIVE EFFECT OF ACCOUNTING CHANGES (NET OF TAX)	0.00	0.00	0.00
NET INCOME	$106,392,846.17	$0.01	($6,429,314.42)
PREFERRED STOCK DIVIDEND REQUIREMENTS OF SUBSIDIARIES (INCLUDING CAPITAL STOCK EXPENSE)	0.00	0.00	0.00
NET INCOME APPLICABLE TO COMMON STOCK	$106,392,846.17	$0.01	($6,429,314.42)

Item 10 - Consolidating Statements of Income

AMERICAN ELECTRIC POWER COMPANY, INC.
AND SUBSIDIARY COMPANIES
CONSOLIDATING STATEMENT OF INCOME
FOR THE YEAR ENDED DECEMBER 31, 2003

Note - Totals and subtotals may be off due to rounding

DESCRIPTION	AEP MONEY POOL	AEP GENERATING COMPANY	CENTRAL COAL COMPANY
REVENUES			
SALES TO NON AFFILIATES	$0.00	$210,000.00	$0.00
SALES TO AFFILIATES	0.00	232,955,270.00	0.00
TOTAL REVENUES	0.00	233,165,270.00	0.00
EXPENSES			
FUEL FOR ELECTRIC GENERATION	0.00	109,238,056.44	0.00
PURCHASED ELECTRICITY FOR RESALE	0.00	0.00	0.00
PURCHASED GAS FOR RESALE	0.00	0.00	0.00
PURCHASE POWER AFFILIATED	0.00	0.00	0.00
OTHER OPERATION	(0.02)	78,682,524.86	0.00
MAINTENANCE	0.00	10,345,839.38	0.00
ASSET IMPAIRMENTS AND OTHER RELATED CHARGES	0.00	0.00	0.00
DEPRECIATION AND AMORTIZATION	0.00	22,686,032.78	0.00
TAXES OTHER THAN INCOME TAXES	0.00	3,396,081.01	0.00
INCOME TAXES	0.00	1,642,997.00	0.00
TOTAL EXPENSES	(0.02)	225,991,531.46	0.00
OPERATING INCOME	0.02	7,173,738.54	0.00
OTHER INCOME (EXPENSE)	0.00	150,498.73	433,962.59
INTEREST AND OTHER CHARGES			
INVESTMENT VALUE GAINS (LOSSES)	0.00	0.00	0.00
OTHER INCOME (EXPENSE)	(0.00)	(361,264.29)	(438,437.57)
NONOPERATING INCOME TAX CREDITS (EXPENSE)	0.00	3,550,415.00	4,381.00
INTEREST EXPENSE (INCOME)	0.00	2,549,792.48	(93.99)
PREFERRED STOCK DIVIDEND REQUIREMENTS OF SUBSIDIARIES (INCLUDING CAPITAL STOCK EXPENSE)	0.00	0.00	0.00
MINORITY INTEREST IN FINANCE SUBSIDIARY (EXPENSE)	0.00	0.00	0.00
TOTAL INTEREST EXPENSE AND OTHER CHARGES (INCOME)	0.00	(639,358.23)	433,962.58
INCOME BEFORE INCOME TAXES	0.02	7,963,595.50	0.01
INCOME TAXES			
INCOME TAXES	0.00	0.00	0.00
NONOPERATING INCOME TAX CREDITS (EXPENSE)	0.00	0.00	0.00
TOTAL INCOME TAXES	0.00	0.00	0.00
INCOME BEFORE DISCONTINUED OPERATIONS, EXTRAORDINARY ITEMS AND CUMULATIVE EFFECT	0.02	7,963,595.50	0.01
DISCONTINUED OPERATIONS (NET OF TAX)	0.00	0.00	0.00
EXTRAORDINARY ITEMS (NET OF TAX)	0.00	0.00	0.00
CUMULATIVE EFFECT OF ACCOUNTING CHANGES (NET OF TAX)	0.00	0.00	0.00
NET INCOME	$0.02	$7,963,595.50	$0.01
PREFERRED STOCK DIVIDEND REQUIREMENTS OF SUBSIDIARIES (INCLUDING CAPITAL STOCK EXPENSE)	0.00	0.00	0.00
NET INCOME APPLICABLE TO COMMON STOCK	$0.02	$7,963,595.50	$0.01

Item 10 - Consolidating Statements of Income

AMERICAN ELECTRIC POWER COMPANY, INC.
AND SUBSIDIARY COMPANIES
CONSOLIDATING STATEMENT OF INCOME
FOR THE YEAR ENDED DECEMBER 31, 2003

Note - Totals and subtotals may be off due to rounding

DESCRIPTION	AEP T&D SERVICES, LLC	INDIANA FRANKLIN REALTY, INC.	FRANKLIN REAL ESTATE COMPANY
REVENUES			
SALES TO NON AFFILIATES	$880,774.91	$0.00	$0.00
SALES TO AFFILIATES	0.00	0.00	0.00
TOTAL REVENUES	880,774.91	0.00	0.00
EXPENSES			
FUEL FOR ELECTRIC GENERATION	0.00	0.00	0.00
PURCHASED ELECTRICITY FOR RESALE	0.00	0.00	0.00
PURCHASED GAS FOR RESALE	0.00	0.00	0.00
PURCHASE POWER AFFILIATED	0.00	0.00	0.00
OTHER OPERATION	820,201.86	0.01	0.01
MAINTENANCE	7,083.84	0.00	0.00
ASSET IMPAIRMENTS AND OTHER RELATED CHARGES	0.00	0.00	0.00
DEPRECIATION AND AMORTIZATION	4,453.46	0.00	0.00
TAXES OTHER THAN INCOME TAXES	(688.53)	0.00	0.00
INCOME TAXES	0.00	0.00	0.00
TOTAL EXPENSES	831,050.63	0.01	0.01
OPERATING INCOME	49,724.28	(0.01)	(0.01)
OTHER INCOME (EXPENSE)	(1.71)	0.00	0.00
INTEREST AND OTHER CHARGES			
INVESTMENT VALUE GAINS (LOSSES)	0.00	0.00	0.00
OTHER INCOME (EXPENSE)	(130.00)	0.00	0.00
NONOPERATING INCOME TAX CREDITS (EXPENSE)	(15,748.00)	0.00	0.00
INTEREST EXPENSE (INCOME)	5,458.98	0.00	0.00
PREFERRED STOCK DIVIDEND REQUIREMENTS OF SUBSIDIARIES (INCLUDING CAPITAL STOCK EXPENSE)	0.00	0.00	0.00
MINORITY INTEREST IN FINANCE SUBSIDIARY (EXPENSE)	0.00	0.00	0.00
TOTAL INTEREST EXPENSE AND OTHER CHARGES (INCOME)	21,336.98	0.00	0.00
INCOME BEFORE INCOME TAXES	28,385.59	(0.01)	(0.01)
INCOME TAXES			
INCOME TAXES	0.00	0.00	0.00
NONOPERATING INCOME TAX CREDITS (EXPENSE)	0.00	0.00	0.00
TOTAL INCOME TAXES	0.00	0.00	0.00
INCOME BEFORE DISCONTINUED OPERATIONS, EXTRAORDINARY ITEMS AND CUMULATIVE EFFECT	28,385.59	(0.01)	(0.01)
DISCONTINUED OPERATIONS (NET OF TAX)	0.00	0.00	0.00
EXTRAORDINARY ITEMS (NET OF TAX)	0.00	0.00	0.00
CUMULATIVE EFFECT OF ACCOUNTING CHANGES (NET OF TAX)	0.00	0.00	0.00
NET INCOME	$28,385.59	($0.01)	($0.01)
PREFERRED STOCK DIVIDEND REQUIREMENTS OF SUBSIDIARIES (INCLUDING CAPITAL STOCK EXPENSE)	0.00	0.00	0.00
NET INCOME APPLICABLE TO COMMON STOCK	$28,385.59	($0.01)	($0.01)

Item 10 - Consolidating Statements of Income

AMERICAN ELECTRIC POWER COMPANY, INC.
AND SUBSIDIARY COMPANIES
CONSOLIDATING STATEMENT OF INCOME
FOR THE YEAR ENDED DECEMBER 31, 2003

Note - Totals and subtotals may be off due to rounding

DESCRIPTION	APPALACHIAN POWER COMPANY CONSOLIDATED	COLUMBUS SOUTHERN POWER COMPANY CONSOLIDATED	INDIANA MICHIGAN POWER COMPANY CONSOLIDATED
REVENUES			
SALES TO NON AFFILIATES	$1,734,564,772.25	$1,347,482,630.68	$1,346,393,152.14
SALES TO AFFILIATES	222,793,068.84	84,368,806.72	249,202,841.44
TOTAL REVENUES	1,957,357,841.09	1,431,851,437.40	1,595,595,993.58
EXPENSES			
FUEL FOR ELECTRIC GENERATION	454,900,802.64	203,398,808.79	250,890,406.52
PURCHASED ELECTRICITY FOR RESALE	66,083,737.33	17,730,168.40	28,327,208.05
PURCHASED GAS FOR RESALE	0.00	0.00	0.00
PURCHASE POWER AFFILIATED	351,210,023.69	337,322,906.72	274,400,173.37
OTHER OPERATION	245,308,300.39	218,466,440.10	417,635,835.94
MAINTENANCE	135,595,517.13	75,319,430.65	158,280,616.40
ASSET IMPAIRMENTS AND OTHER RELATED CHARGES	0.00	0.00	0.00
DEPRECIATION AND AMORTIZATION	175,771,879.00	135,964,381.81	171,281,007.92
TAXES OTHER THAN INCOME TAXES	90,087,499.26	133,753,570.01	57,787,478.37
INCOME TAXES	119,589,105.99	84,409,962.71	50,926,310.10
TOTAL EXPENSES	1,638,546,865.41	1,206,365,669.20	1,409,529,036.66
OPERATING INCOME	318,810,975.67	225,485,768.20	186,066,956.92
OTHER INCOME (EXPENSE)	(5,660,921.99)	(7,488,973.13)	53,928,104.98
INTEREST AND OTHER CHARGES			
INVESTMENT VALUE GAINS (LOSSES)	0.00	0.00	0.00
OTHER INCOME (EXPENSE)	(9,534,194.27)	(4,650,608.99)	(77,170,790.28)
NONOPERATING INCOME TAX CREDITS (EXPENSE)	14,368,862.00	10,748,643.71	9,777,424.00
INTEREST EXPENSE (INCOME)	115,201,622.63	50,948,011.09	83,053,952.92
PREFERRED STOCK DIVIDEND REQUIREMENTS OF SUBSIDIARIES (INCLUDING CAPITAL STOCK EXPENSE)	0.00	0.00	0.00
MINORITY INTEREST IN FINANCE SUBSIDIARY (EXPENSE)	0.00	0.00	0.00
TOTAL INTEREST EXPENSE AND OTHER CHARGES (INCOME)	110,366,954.90	44,849,976.37	150,447,319.19
INCOME BEFORE INCOME TAXES	202,783,098.79	173,146,818.70	89,547,742.71
INCOME TAXES			
INCOME TAXES	0.00	0.00	0.00
NONOPERATING INCOME TAX CREDITS (EXPENSE)	0.00	0.00	0.00
TOTAL INCOME TAXES	0.00	0.00	0.00
INCOME BEFORE DISCONTINUED OPERATIONS, EXTRAORDINARY ITEMS AND CUMULATIVE EFFECT	202,783,098.79	173,146,818.70	89,547,742.71
DISCONTINUED OPERATIONS (NET OF TAX)	0.00	0.00	0.00
EXTRAORDINARY ITEMS (NET OF TAX)	0.00	0.00	0.00
CUMULATIVE EFFECT OF ACCOUNTING CHANGES (NET OF TAX)	77,256,443.43	27,283,164.83	(3,159,518.00)
NET INCOME	$280,039,542.22	$200,429,983.53	$86,388,224.71
PREFERRED STOCK DIVIDEND REQUIREMENTS OF SUBSIDIARIES (INCLUDING CAPITAL STOCK EXPENSE)	3,494,210.07	1,015,380.36	2,509,062.40
NET INCOME APPLICABLE TO COMMON STOCK	$276,545,332.15	$199,414,603.17	$83,879,162.31

Item 10 - Consolidating Statements of Income

AMERICAN ELECTRIC POWER COMPANY, INC.
AND SUBSIDIARY COMPANIES
CONSOLIDATING STATEMENT OF INCOME
FOR THE YEAR ENDED DECEMBER 31, 2003

Note - Totals and subtotals may be off due to rounding

DESCRIPTION	KENTUCKY POWER COMPANY	KINGSPORT POWER COMPANY	OHIO POWER COMPANY CONSOLIDATED
REVENUES			
SALES TO NON AFFILIATES	$376,662,163.69	$86,522,806.23	$1,660,374,867.60
SALES TO AFFILIATES	39,808,381.73	49,326.36	584,278,164.02
TOTAL REVENUES	416,470,545.42	86,572,132.59	2,244,653,031.62
EXPENSES			
FUEL FOR ELECTRIC GENERATION	74,148,004.24	0.00	616,679,836.32
PURCHASED ELECTRICITY FOR RESALE	962,715.53	0.00	63,485,751.63
PURCHASED GAS FOR RESALE	0.00	0.00	0.00
PURCHASE POWER AFFILIATED	141,690,132.64	60,637,688.99	90,821,164.40
OTHER OPERATION	47,325,335.43	7,105,836.22	369,086,535.21
MAINTENANCE	27,327,889.82	2,791,275.19	166,437,853.87
ASSET IMPAIRMENTS AND OTHER RELATED CHARGES	0.00	0.00	0.00
DEPRECIATION AND AMORTIZATION	39,308,876.20	3,632,150.71	257,417,401.15
TAXES OTHER THAN INCOME TAXES	8,788,583.51	3,504,714.82	175,043,400.86
INCOME TAXES	12,174,770.00	2,703,911.00	146,014,148.26
TOTAL EXPENSES	351,726,307.38	80,375,576.94	1,884,986,091.70
OPERATING INCOME	64,744,238.04	6,196,555.65	359,666,939.92
OTHER INCOME (EXPENSE)	(4,036,662.28)	37,526.79	24,494,888.63
INTEREST AND OTHER CHARGES			
INVESTMENT VALUE GAINS (LOSSES)	0.00	0.00	0.00
OTHER INCOME (EXPENSE)	(1,124,174.04)	(65,350.41)	(34,281,765.05)
NONOPERATING INCOME TAX CREDITS (EXPENSE)	2,500,135.00	75,280.00	7,614,796.00
INTEREST EXPENSE (INCOME)	28,619,742.22	1,515,115.41	106,464,124.05
PREFERRED STOCK DIVIDEND REQUIREMENTS OF SUBSIDIARIES (INCLUDING CAPITAL STOCK EXPENSE)	0.00	0.00	0.00
MINORITY INTEREST IN FINANCE SUBSIDIARY (EXPENSE)	0.00	0.00	0.00
TOTAL INTEREST EXPENSE AND OTHER CHARGES (INCOME)	27,243,781.26	1,505,185.82	133,131,093.10
INCOME BEFORE INCOME TAXES	33,463,794.50	4,728,896.62	251,030,735.45
INCOME TAXES			
INCOME TAXES	0.00	0.00	0.00
NONOPERATING INCOME TAX CREDITS (EXPENSE)	0.00	0.00	0.00
TOTAL INCOME TAXES	0.00	0.00	0.00
INCOME BEFORE DISCONTINUED OPERATIONS, EXTRAORDINARY ITEMS AND CUMULATIVE EFFECT	33,463,794.50	4,728,896.62	251,030,735.45
DISCONTINUED OPERATIONS (NET OF TAX)	0.00	0.00	0.00
EXTRAORDINARY ITEMS (NET OF TAX)	0.00	0.00	0.00
CUMULATIVE EFFECT OF ACCOUNTING CHANGES (NET OF TAX)	(1,133,544.00)	0.00	124,631,674.07
NET INCOME	$32,330,250.50	$4,728,896.62	$375,662,409.52
PREFERRED STOCK DIVIDEND REQUIREMENTS OF SUBSIDIARIES (INCLUDING CAPITAL STOCK EXPENSE)	0.00	0.00	1,098,049.97
NET INCOME APPLICABLE TO COMMON STOCK	$32,330,250.50	$4,728,896.62	$374,564,359.55

Item 10 - Consolidating Statements of Income

AMERICAN ELECTRIC POWER COMPANY, INC.
AND SUBSIDIARY COMPANIES
CONSOLIDATING STATEMENT OF INCOME
FOR THE YEAR ENDED DECEMBER 31, 2003

Note - Totals and subtotals may be off due to rounding

DESCRIPTION	WHEELING POWER COMPANY	AEP INVESTMENTS, INC.	AEP RESOURCES, INC.
REVENUES			
SALES TO NON AFFILIATES	$84,773,885.75	$0.00	$4,126,400,943.29
SALES TO AFFILIATES	1,158,950.52	0.00	197,355,528.65
TOTAL REVENUES	85,932,836.27	0.00	4,323,756,471.94
EXPENSES			
FUEL FOR ELECTRIC GENERATION	0.00	0.00	56,099,840.75
PURCHASED ELECTRICITY FOR RESALE	76,740.62	0.00	3,755,189,754.41
PURCHASED GAS FOR RESALE	0.00	0.00	0.00
PURCHASE POWER AFFILIATED	50,764,075.60	0.00	0.00
OTHER OPERATION	6,321,141.32	3,741,922.71	519,753,777.50
MAINTENANCE	2,942,835.58	2.52	78,219,677.55
ASSET IMPAIRMENTS AND OTHER RELATED CHARGES	0.00	0.00	0.00
DEPRECIATION AND AMORTIZATION	2,455,010.36	58,865.57	67,919,398.10
TAXES OTHER THAN INCOME TAXES	5,249,534.30	519.00	845,844.04
INCOME TAXES	6,833,045.00	0.00	(6,084,255.00)
TOTAL EXPENSES	74,642,382.78	3,801,309.81	4,471,944,037.34
OPERATING INCOME	11,290,453.49	(3,801,309.81)	(148,187,565.40)
OTHER INCOME (EXPENSE)	230,497.64	(3,704,778.74)	(1,326,658,194.88)
INTEREST AND OTHER CHARGES			
INVESTMENT VALUE GAINS (LOSSES)	0.00	0.00	0.00
OTHER INCOME (EXPENSE)	(357,944.97)	(5,027.00)	(43,814,587.88)
NONOPERATING INCOME TAX CREDITS (EXPENSE)	482,893.00	2,738,118.00	488,925,864.55
INTEREST EXPENSE (INCOME)	1,370,906.80	245,455.58	91,689,075.61
PREFERRED STOCK DIVIDEND REQUIREMENTS OF SUBSIDIARIES (INCLUDING CAPITAL STOCK EXPENSE)	0.00	0.00	0.00
MINORITY INTEREST IN FINANCE SUBSIDIARY (EXPENSE)	0.00	0.00	0.00
TOTAL INTEREST EXPENSE AND OTHER CHARGES (INCOME)	1,245,958.77	(2,487,635.42)	(353,422,201.06)
INCOME BEFORE INCOME TAXES	10,274,992.36	(5,018,453.13)	(1,121,423,559.22)
INCOME TAXES			
INCOME TAXES	0.00	0.00	0.00
NONOPERATING INCOME TAX CREDITS (EXPENSE)	0.00	0.00	0.00
TOTAL INCOME TAXES	0.00	0.00	0.00
INCOME BEFORE DISCONTINUED OPERATIONS, EXTRAORDINARY ITEMS AND CUMULATIVE EFFECT	10,274,992.36	(5,018,453.13)	(1,121,423,559.22)
DISCONTINUED OPERATIONS (NET OF TAX)	0.00	0.00	0.00
EXTRAORDINARY ITEMS (NET OF TAX)	0.00	0.00	0.00
CUMULATIVE EFFECT OF ACCOUNTING CHANGES (NET OF TAX)	0.00	0.00	0.00
NET INCOME	$10,274,992.36	($5,018,453.13)	($1,121,423,559.22)
PREFERRED STOCK DIVIDEND REQUIREMENTS OF SUBSIDIARIES (INCLUDING CAPITAL STOCK EXPENSE)	0.00	0.00	0.00
NET INCOME APPLICABLE TO COMMON STOCK	$10,274,992.36	($5,018,453.13)	($1,121,423,559.22)

Item 10 - Consolidating Statements of Income

AMERICAN ELECTRIC POWER COMPANY, INC.
AND SUBSIDIARY COMPANIES
CONSOLIDATING STATEMENT OF INCOME
FOR THE YEAR ENDED DECEMBER 31, 2003

Note - Totals and subtotals may be off due to rounding

DESCRIPTION	AEP COMMUNICATIONS, INC.	AEP UTILITIES INCORPORATED CONSOLIDATED	AEP C&I COMPANY, LLC
REVENUES			
SALES TO NON AFFILIATES	$5,792,235.73	$4,251,562,709.68	$153,619,517.72
SALES TO AFFILIATES	4,009,031.25	326,557,709.60	2,036,067.37
TOTAL REVENUES	9,801,266.98	4,578,120,419.28	155,655,585.09
EXPENSES			
FUEL FOR ELECTRIC GENERATION	0.00	1,406,231,411.57	0.00
PURCHASED ELECTRICITY FOR RESALE	0.00	534,309,788.93	3,302,370.61
PURCHASED GAS FOR RESALE	0.00	0.00	0.00
PURCHASE POWER AFFILIATED	0.00	215,342,482.24	123,028,769.70
OTHER OPERATION	9,460,784.28	834,782,459.63	32,047,277.06
MAINTENANCE	(350,259.92)	222,510,625.79	7.58
ASSET IMPAIRMENTS AND OTHER RELATED CHARGES	0.00	0.00	0.00
DEPRECIATION AND AMORTIZATION	1,359,351.43	442,140,297.87	5,809.43
TAXES OTHER THAN INCOME TAXES	58,925.86	198,644,581.49	1,513,252.93
INCOME TAXES	(368,701.00)	204,011,619.67	10,621.17
TOTAL EXPENSES	10,160,100.65	4,057,973,267.19	159,908,108.47
OPERATING INCOME	(358,833.67)	520,147,152.09	(4,252,523.38)
OTHER INCOME (EXPENSE)	1,559,663.24	226,800,500.04	1,610,025.09
INTEREST AND OTHER CHARGES			
INVESTMENT VALUE GAINS (LOSSES)	0.00	0.00	0.00
OTHER INCOME (EXPENSE)	5,994,396.05	(80,279,291.81)	476,370.63
NONOPERATING INCOME TAX CREDITS (EXPENSE)	2,020,521.00	5,756,832.96	3,866,582.00
INTEREST EXPENSE (INCOME)	12,816,209.53	295,524,089.54	961,827.30
PREFERRED STOCK DIVIDEND REQUIREMENTS OF SUBSIDIARIES (INCLUDING CAPITAL STOCK EXPENSE)	0.00	0.00	0.00
MINORITY INTEREST IN FINANCE SUBSIDIARY (EXPENSE)	0.00	0.00	0.00
TOTAL INTEREST EXPENSE AND OTHER CHARGES (INCOME)	4,801,292.48	370,046,548.39	(3,381,125.33)
INCOME BEFORE INCOME TAXES	(3,600,462.92)	376,901,103.74	738,627.04
INCOME TAXES			
INCOME TAXES	0.00	0.00	0.00
NONOPERATING INCOME TAX CREDITS (EXPENSE)	0.00	0.00	0.00
TOTAL INCOME TAXES	0.00	0.00	0.00
INCOME BEFORE DISCONTINUED OPERATIONS, EXTRAORDINARY ITEMS AND CUMULATIVE EFFECT	(3,600,462.92)	376,901,103.74	738,627.04
DISCONTINUED OPERATIONS (NET OF TAX)	0.00	0.00	0.00
EXTRAORDINARY ITEMS (NET OF TAX)	0.00	(176,775.00)	0.00
CUMULATIVE EFFECT OF ACCOUNTING CHANGES (NET OF TAX)	0.00	0.00	0.00
NET INCOME	($3,600,462.92)	$376,724,328.74	$738,627.04
PREFERRED STOCK DIVIDEND REQUIREMENTS OF SUBSIDIARIES (INCLUDING CAPITAL STOCK EXPENSE)	0.00	786,804.57	0.00
NET INCOME APPLICABLE TO COMMON STOCK	($3,600,462.92)	$375,937,524.17	$738,627.04

Item 10 - Consolidating Statements of Income

AMERICAN ELECTRIC POWER COMPANY, INC.
AND SUBSIDIARY COMPANIES
CONSOLIDATING STATEMENT OF INCOME
FOR THE YEAR ENDED DECEMBER 31, 2003

Note - Totals and subtotals may be off due to rounding

DESCRIPTION	AEP DESERT SKY LP, LLC	AEP DESERT SKY LP II, LLC	AEP COAL, INC
REVENUES			
SALES TO NON AFFILIATES	$0.00	$17,626,688.33	$129,081,078.44
SALES TO AFFILIATES	0.00	0.00	40,879,321.30
TOTAL REVENUES	0.00	17,626,688.33	169,960,399.74
EXPENSES			
FUEL FOR ELECTRIC GENERATION	0.00	0.00	0.00
PURCHASED ELECTRICITY FOR RESALE	0.00	0.00	0.00
PURCHASED GAS FOR RESALE	0.00	0.00	0.00
PURCHASE POWER AFFILIATED	0.00	0.00	0.00
OTHER OPERATION	615,687.36	3,376,175.38	162,472,621.74
MAINTENANCE	2.53	1,725,191.78	0.00
ASSET IMPAIRMENTS AND OTHER RELATED CHARGES	0.00	0.00	0.00
DEPRECIATION AND AMORTIZATION	3,459.10	9,052,662.39	6,014,127.14
TAXES OTHER THAN INCOME TAXES	0.00	1,692,601.50	693,415.04
INCOME TAXES	(455,690.00)	(8,747,177.00)	(22,218,411.00)
TOTAL EXPENSES	163,458.98	7,099,454.05	146,961,752.92
OPERATING INCOME	(163,458.98)	10,527,234.28	22,998,646.82
OTHER INCOME (EXPENSE)	(3.43)	66,916.76	(62,705,804.93)
INTEREST AND OTHER CHARGES			
INVESTMENT VALUE GAINS (LOSSES)	0.00	0.00	0.00
OTHER INCOME (EXPENSE)	(200.00)	(146,773.37)	(18,975.00)
NONOPERATING INCOME TAX CREDITS (EXPENSE)	0.00	0.00	106,028.00
INTEREST EXPENSE (INCOME)	431,338.54	7,590,629.75	1,761,923.39
PREFERRED STOCK DIVIDEND REQUIREMENTS OF SUBSIDIARIES (INCLUDING CAPITAL STOCK EXPENSE)	0.00	0.00	0.00
MINORITY INTEREST IN FINANCE SUBSIDIARY (EXPENSE)	0.00	0.00	0.00
TOTAL INTEREST EXPENSE AND OTHER CHARGES (INCOME)	431,538.54	7,737,403.12	1,674,870.39
INCOME BEFORE INCOME TAXES	(595,000.95)	2,856,747.92	(41,382,028.50)
INCOME TAXES			
INCOME TAXES	0.00	0.00	0.00
NONOPERATING INCOME TAX CREDITS (EXPENSE)	0.00	0.00	0.00
TOTAL INCOME TAXES	0.00	0.00	0.00
INCOME BEFORE DISCONTINUED OPERATIONS, EXTRAORDINARY ITEMS AND CUMULATIVE EFFECT	(595,000.95)	2,856,747.92	(41,382,028.50)
DISCONTINUED OPERATIONS (NET OF TAX)	0.00	0.00	0.00
EXTRAORDINARY ITEMS (NET OF TAX)	0.00	0.00	0.00
CUMULATIVE EFFECT OF ACCOUNTING CHANGES (NET OF TAX)	0.00	0.00	0.00
NET INCOME	($595,000.95)	$2,856,747.92	($41,382,028.50)
PREFERRED STOCK DIVIDEND REQUIREMENTS OF SUBSIDIARIES (INCLUDING CAPITAL STOCK EXPENSE)	0.00	0.00	0.00
NET INCOME APPLICABLE TO COMMON STOCK	($595,000.95)	$2,856,747.92	($41,382,028.50)

Item 10 - Consolidating Statements of Income

AMERICAN ELECTRIC POWER COMPANY, INC.
AND SUBSIDIARY COMPANIES
CONSOLIDATING STATEMENT OF INCOME
FOR THE YEAR ENDED DECEMBER 31, 2003

Note - Totals and subtotals may be off due to rounding

DESCRIPTION	AEP POWER MARKETING, INC	AEP PRO SERV, INC	MUTUAL ENERGY LLC
REVENUES			
SALES TO NON AFFILIATES	$45,147,061.58	$157,048,687.57	$12,983,503.98
SALES TO AFFILIATES	(22,081,764.69)	398,326.79	554,052.71
TOTAL REVENUES	23,065,296.89	157,447,014.36	13,537,556.69
EXPENSES			
FUEL FOR ELECTRIC GENERATION	0.00	0.00	0.00
PURCHASED ELECTRICITY FOR RESALE	0.00	0.00	2,359,771.55
PURCHASED GAS FOR RESALE	0.00	0.00	0.00
PURCHASE POWER AFFILIATED	0.00	0.00	981,936.05
OTHER OPERATION	452,895.18	163,620,794.34	7,769,733.27
MAINTENANCE	2.53	165.48	2,292.12
ASSET IMPAIRMENTS AND OTHER RELATED CHARGES	0.00	0.00	0.00
DEPRECIATION AND AMORTIZATION	0.00	1,707,866.58	357,729.24
TAXES OTHER THAN INCOME TAXES	0.00	50,988.62	21,830.30
INCOME TAXES	0.00	575,386.00	0.00
TOTAL EXPENSES	452,897.70	165,955,201.02	11,493,292.53
OPERATING INCOME	22,612,399.19	(8,508,186.66)	2,044,264.16
OTHER INCOME (EXPENSE)	238.16	(848,595.35)	39,449,818.87
INTEREST AND OTHER CHARGES			
INVESTMENT VALUE GAINS (LOSSES)	0.00	0.00	0.00
OTHER INCOME (EXPENSE)	(50.00)	(62,246.44)	(1,298.76)
NONOPERATING INCOME TAX CREDITS (EXPENSE)	(7,882,925.00)	3,327,227.34	(13,770,742.00)
INTEREST EXPENSE (INCOME)	89,942.08	269,605.65	(110,612.97)
PREFERRED STOCK DIVIDEND REQUIREMENTS OF SUBSIDIARIES (INCLUDING CAPITAL STOCK EXPENSE)	0.00	0.00	0.00
MINORITY INTEREST IN FINANCE SUBSIDIARY (EXPENSE)	0.00	0.00	0.00
TOTAL INTEREST EXPENSE AND OTHER CHARGES (INCOME)	7,972,917.08	(2,995,375.25)	13,661,427.79
INCOME BEFORE INCOME TAXES	14,639,720.26	(6,361,406.77)	27,832,655.25
INCOME TAXES			
INCOME TAXES	0.00	0.00	0.00
NONOPERATING INCOME TAX CREDITS (EXPENSE)	0.00	0.00	0.00
TOTAL INCOME TAXES	0.00	0.00	0.00
INCOME BEFORE DISCONTINUED OPERATIONS, EXTRAORDINARY ITEMS AND CUMULATIVE EFFECT	14,639,720.26	(6,361,406.77)	27,832,655.25
DISCONTINUED OPERATIONS (NET OF TAX)	0.00	0.00	0.00
EXTRAORDINARY ITEMS (NET OF TAX)	0.00	0.00	0.00
CUMULATIVE EFFECT OF ACCOUNTING CHANGES (NET OF TAX)	0.00	0.00	0.00
NET INCOME	$14,639,720.26	($6,361,406.77)	$27,832,655.25
PREFERRED STOCK DIVIDEND REQUIREMENTS OF SUBSIDIARIES (INCLUDING CAPITAL STOCK EXPENSE)	0.00	0.00	0.00
NET INCOME APPLICABLE TO COMMON STOCK	$14,639,720.26	($6,361,406.77)	$27,832,655.25

Item 10 - Consolidating Statements of Income

AEP UTILITIES, INC. AND SUBSIDIARY COMPANIES
CONSOLIDATING STATEMENT OF INCOME
FOR THE YEAR ENDED DECEMBER 31, 2003

Note - Totals and subtotals may be off due to rounding

DESCRIPTION	AEP UTILITIES INCORPORATED CONSOLIDATED	SEC REPORTING ADJUSTMENTS	AEP UTILITIES INCORPORATED ELIMINATIONS	AEP UTILITIES INCORPORATED
OPERATING REVENUES				
SALES TO NONAFFILIATES	$4,251,562,709.68	$357,627.00	$0.00	$0.00
SALES TO AFFILIATES	326,557,709.60	0.00	(17,539,146.25)	0.00
TOTAL OPERATING REVENUES	4,578,120,419.28	357,627.00	(17,539,146.25)	0.00
OPERATING EXPENSES				
FUEL FOR ELECTRIC GENERATION	1,406,231,411.57	239,724,031.05	(236,980.50)	0.00
FUEL FROM AFFILIATES FOR ELECTRIC GENERATION	0.00	(239,724,031.05)	0.00	0.00
PURCHASED ELECTRICITY FOR RESALE	534,309,788.93	0.00	0.00	0.00
PURCHASED ELECTRICITY FROM AEP AFFILIATES	215,342,482.24	0.00	(1,287,626.33)	0.00
OTHER OPERATION	834,782,459.63	(17,657,397.31)	(16,014,539.42)	2,691,066.55
MAINTENANCE	222,510,625.79	0.00	0.00	0.31
DEPRECIATION AND AMORTIZATION	442,140,297.87	0.00	0.00	430,774.24
TAXES OTHER THAN INCOME TAXES	198,644,581.49	0.00	0.00	(20,240.78)
INCOME TAXES	204,011,619.67	6,305,259.00	0.00	12,191,837.12
TOTAL OPERATING EXPENSES	4,057,973,267.19	(11,352,138.31)	(17,539,146.25)	15,293,437.44
NET OPERATING INCOME	520,147,152.09	11,709,765.31	0.00	(15,293,437.44)
NONOPERATING INCOME (EXPENSE)	226,800,500.04	(1,627,244.49)	(392,485,985.94)	391,307,967.87
NONOPERATING EXPENSE (EXPENSE)	(80,279,291.81)	127,790.27	0.00	(55,300.42)
NONOPERATING INCOME TAX EXPENSE (EXPENSE)	5,756,832.96	0.00	0.00	(10,860.00)
INTEREST CHARGES	295,524,089.54	0.00	0.00	10,845.71
MINORITY INTEREST (EXPENSE)	0.00	1,499,454.22	0.00	0.00
INCOME BEFORE EXTRAORDINARY ITEMS AND CUMULATIVE EFFECT OF ACCOUNTING CHANGE	376,901,103.74	11,709,765.31	(392,485,985.94)	375,937,524.29
EXTRAORDINARY ITEMS (NET OF TAX)	(176,775.00)	0.00	0.00	0.00
CUMULATIVE EFFECT OF ACCOUNTING CHANGES (NET OF TAX)	0.00	(11,709,765.31)	0.00	0.00
NET INCOME	376,724,328.74	0.00	(392,485,985.94)	375,937,524.29
PREFERRED STOCK DIVIDEND REQUIREMENT	786,804.57	0.00	0.00	0.00
GAIN ON REACQUIRED STOCK	0.00	(3,000.00)	0.00	0.00
EARNINGS APPLICABLE TO COMMON STOCK	$375,937,524.17	($3,000.00)	($392,485,985.94)	$375,937,524.29

Item 10 - Consolidating Statements of Income

AEP UTILITIES, INC. AND SUBSIDIARY COMPANIES
CONSOLIDATING STATEMENT OF INCOME
FOR THE YEAR ENDED DECEMBER 31, 2003

Note - Totals and subtotals may be off due to rounding

DESCRIPTION	AEP CREDIT INCORPORATED	ENERSHOP INCORPORATED	CSW LEASING INCORPORATED	AEP TEXAS CENTRAL COMPANY CONSOLIDATED
OPERATING REVENUES				
SALES TO NONAFFILIATES	$0.00	$0.00	$0.00	$1,593,943,051.34
SALES TO AFFILIATES	41,647,399.67	0.00	0.00	153,567,925.89
TOTAL OPERATING REVENUES	41,647,399.67	0.00	0.00	1,747,510,977.23
OPERATING EXPENSES				
FUEL FOR ELECTRIC GENERATION	0.00	0.00	0.00	89,388,738.79
FUEL FROM AFFILIATES FOR ELECTRIC GENERATION	0.00	0.00	0.00	195,526,909.89
PURCHASED ELECTRICITY FOR RESALE	0.00	0.00	0.00	373,388,438.20
PURCHASED ELECTRICITY FROM AEP AFFILIATES	0.00	0.00	0.00	19,097,154.27
OTHER OPERATION	31,978,071.62	313,000.75	3,223.25	297,877,813.88
MAINTENANCE	0.00	0.00	0.00	71,361,397.46
DEPRECIATION AND AMORTIZATION	0.00	643.17	0.00	189,129,688.49
TAXES OTHER THAN INCOME TAXES	0.00	2,876.86	0.00	92,109,013.35
INCOME TAXES	2,105,671.00	0.00	0.00	98,092,094.86
TOTAL OPERATING EXPENSES	34,083,742.62	316,520.77	3,223.25	1,425,971,249.19
NET OPERATING INCOME	7,563,657.05	(316,520.77)	(3,223.25)	321,539,728.04
NONOPERATING INCOME (EXPENSE)	528.99	(868,617.06)	3,027.65	54,172,131.35
NONOPERATING EXPENSE (EXPENSE)	(55,543.87)	(26,226.24)	0.00	(17,272,617.49)
NONOPERATING INCOME TAX EXPENSE (EXPENSE)	27,107.46	596,367.00	68.00	(7,079,713.00)
INTEREST CHARGES	3,180,105.27	369,766.39	0.00	133,811,944.23
MINORITY INTEREST (EXPENSE)	0.00	0.00	0.00	0.00
INCOME BEFORE EXTRAORDINARY ITEMS AND CUMULATIVE EFFECT OF ACCOUNTING CHANGE	4,355,644.36	(984,763.46)	(127.60)	217,547,584.67
EXTRAORDINARY ITEMS (NET OF TAX)	0.00	0.00	0.00	0.00
CUMULATIVE EFFECT OF ACCOUNTING CHANGES (NET OF TAX)	0.00	0.00	0.00	121,663.00
NET INCOME	4,355,644.36	(984,763.46)	(127.60)	217,669,247.67
PREFERRED STOCK DIVIDEND REQUIREMENT	0.00	0.00	0.00	241,143.84
GAIN ON REACQUIRED STOCK	0.00	0.00	0.00	0.00
EARNINGS APPLICABLE TO COMMON STOCK	$4,355,644.36	($984,763.46)	($127.60)	$217,428,103.83

Item 10 - Consolidating Statements of Income

AEP UTILITIES, INC. AND SUBSIDIARY COMPANIES
CONSOLIDATING STATEMENT OF INCOME
FOR THE YEAR ENDED DECEMBER 31, 2003

Note - Totals and subtotals may be off due to rounding

DESCRIPTION	PUBLIC SERVICE COMPANY OF OKLAHOMA	AEP TEXAS NORTH COMPANY	CSW ENERGY INCORPORATED	SOUTHWESTERN ELECTRIC POWER COMPANY CONSOLIDATED
OPERATING REVENUES				
SALES TO NONAFFILIATES	$1,079,691,666.53	$410,792,929.49	$83,808,270.16	$1,077,987,452.20
SALES TO AFFILIATES	23,130,878.60	55,153,103.55	1,743,210.08	68,854,339.06
TOTAL OPERATING REVENUES	1,102,822,545.13	465,946,033.04	85,551,480.24	1,146,841,791.26
OPERATING EXPENSES				
FUEL FOR ELECTRIC GENERATION	526,563,209.83	39,081,559.06	70,265,934.36	441,444,918.99
FUEL FROM AFFILIATES FOR ELECTRIC GENERATION	0.00	44,197,121.16	0.00	0.00
PURCHASED ELECTRICITY FOR RESALE	35,685,334.60	87,006,267.19	3,379,928.92	34,849,820.02
PURCHASED ELECTRICITY FROM AEP AFFILIATES	109,638,951.04	39,409,314.14	570,236.68	47,914,452.44
OTHER OPERATION	129,246,159.58	85,262,658.59	20,282,053.08	173,348,856.94
MAINTENANCE	53,075,868.59	18,960,588.99	8,339,480.42	70,443,258.96
DEPRECIATION AND AMORTIZATION	86,455,283.19	36,242,340.81	7,644,382.26	121,071,613.63
TAXES OTHER THAN INCOME TAXES	32,287,344.31	20,569,914.80	567,562.74	53,165,407.44
INCOME TAXES	37,008,213.88	27,189,059.43	(33,317,977.23)	54,467,946.88
TOTAL OPERATING EXPENSES	1,009,960,365.03	397,918,824.16	77,731,601.22	996,706,275.30
NET OPERATING INCOME	92,862,180.10	68,027,208.88	7,819,879.02	150,135,515.96
NONOPERATING INCOME (EXPENSE)	8,025,692.70	68,450,614.31	(37,040,622.45)	3,977,784.02
NONOPERATING EXPENSE (EXPENSE)	(1,385,020.23)	(55,691,273.49)	(2,878,054.81)	(2,606,751.11)
NONOPERATING INCOME TAX EXPENSE (EXPENSE)	(828,723.00)	(3,074,271.00)	(582,800.89)	3,396,162.00
INTEREST CHARGES	44,783,779.26	22,049,407.38	11,037,186.14	63,779,160.38
MINORITY INTEREST (EXPENSE)	0.00	0.00	0.00	(1,499,454.22)
INCOME BEFORE EXTRAORDINARY ITEMS AND CUMULATIVE EFFECT OF ACCOUNTING CHANGE	53,890,350.31	55,662,871.32	(43,718,785.27)	89,624,096.27
EXTRAORDINARY ITEMS (NET OF TAX)	0.00	(176,775.00)	0.00	0.00
CUMULATIVE EFFECT OF ACCOUNTING CHANGES (NET OF TAX)	0.00	3,070,844.47	0.00	8,517,257.84
NET INCOME	53,890,350.31	58,556,940.79	(43,718,785.27)	98,141,354.11
PREFERRED STOCK DIVIDEND REQUIREMENT	212,606.61	104,044.56	0.00	229,009.56
GAIN ON REACQUIRED STOCK	0.00	3,000.00	0.00	0.00
EARNINGS APPLICABLE TO COMMON STOCK	$53,677,743.70	$58,455,896.23	($43,718,785.27)	$97,912,344.55

Item 10 - Consolidating Statements of Income

AEP UTILITIES, INC. AND SUBSIDIARY COMPANIES
CONSOLIDATING STATEMENT OF INCOME
FOR THE YEAR ENDED DECEMBER 31, 2003

Note - Totals and subtotals may be off due to rounding

DESCRIPTION	CSW INTERNATIONAL INCORPORATED	C3 COMMUNICATIONS INCORPORATED	CSW ENERGY SERVICES INCORPORATED
OPERATING REVENUES			
SALES TO NONAFFILIATES	$0.00	$1,149,753.68	$3,831,959.28
SALES TO AFFILIATES	0.00	0.00	(1.00)
TOTAL OPERATING REVENUES	0.00	1,149,753.68	3,831,958.28
OPERATING EXPENSES			
FUEL FOR ELECTRIC GENERATION	0.00	0.00	0.00
FUEL FROM AFFILIATES FOR ELECTRIC GENERATION	0.00	0.00	0.00
PURCHASED ELECTRICITY FOR RESALE	0.00	0.00	0.00
PURCHASED ELECTRICITY FROM AEP AFFILIATES	0.00	0.00	0.00
OTHER OPERATION	6,162,415.24	2,265,269.96	119,023,806.92
MAINTENANCE	0.00	330,029.79	1.26
DEPRECIATION AND AMORTIZATION	0.00	0.00	1,165,572.08
TAXES OTHER THAN INCOME TAXES	0.00	(37,349.93)	52.70
INCOME TAXES	0.00	(5,515.27)	(24,970.00)
TOTAL OPERATING EXPENSES	6,162,415.24	2,552,434.55	120,164,462.97
NET OPERATING INCOME	(6,162,415.24)	(1,402,680.87)	(116,332,504.69)
NONOPERATING INCOME (EXPENSE)	10,455,718.24	4,615,018.37	117,814,486.49
NONOPERATING EXPENSE (EXPENSE)	(139,915.00)	(294,396.42)	(1,983.00)
NONOPERATING INCOME TAX EXPENSE (EXPENSE)	12,488,955.39	14,547.00	809,994.00
INTEREST CHARGES	458,503.29	11,039,831.13	5,003,560.36
MINORITY INTEREST (EXPENSE)	0.00	0.00	0.00
INCOME BEFORE EXTRAORDINARY ITEMS AND CUMULATIVE EFFECT OF ACCOUNTING CHANGE	16,183,840.10	(8,107,343.05)	(2,713,567.56)
EXTRAORDINARY ITEMS (NET OF TAX)	0.00	0.00	0.00
CUMULATIVE EFFECT OF ACCOUNTING CHANGES (NET OF TAX)	0.00	0.00	0.00
NET INCOME	16,183,840.10	(8,107,343.05)	(2,713,567.56)
PREFERRED STOCK DIVIDEND REQUIREMENT	0.00	0.00	0.00
GAIN ON REACQUIRED STOCK	0.00	0.00	0.00
EARNINGS APPLICABLE TO COMMON STOCK	$16,183,840.10	($8,107,343.05)	($2,713,567.56)

Item 10 - Consolidating Statements of Income

AEP TEXAS CENTRAL COMPANY AND SUBSIDIARY
CONSOLIDATING STATEMENT OF INCOME
FOR THE YEAR ENDED DECEMBER 31, 2003

Note - Totals and subtotals may be off due to rounding

DESCRIPTION	AEP TEXAS CENTRAL COMPANY CONSOLIDATED	SEC REPORTING ADJUSTMENTS	AEP TEXAS CENTRAL COMPANY ELIMINATIONS
OPERATING REVENUES			
ELECTRIC GENERATION, TRANSMISSION AND DISTRIBUTION	$1,593,943,051.34	($187,174.00)	$0.00
SALES TO AEP AFFILIATES	153,567,925.89	0.00	(398,667.00)
TOTAL OPERATING REVENUES	1,747,510,977.23	(187,174.00)	(398,667.00)
OPERATING EXPENSES			
FUEL FOR ELECTRIC GENERATION	89,388,738.79	(195,526,909.89)	0.00
FUEL FROM AFFILIATES FOR ELECTRIC GENERATION	195,526,909.89	195,526,909.89	0.00
PURCHASED ELECTRICITY FOR RESALE	373,388,438.20	0.00	0.00
PURCHASED ELECTRICITY FROM AEP AFFILIATES	19,097,154.27	0.00	0.00
OTHER OPERATION	297,877,813.88	0.00	(398,667.00)
MAINTENANCE	71,361,397.46	0.00	0.00
DEPRECIATION AND AMORTIZATION	189,129,688.49	0.00	0.00
TAXES OTHER THAN INCOME TAXES	92,109,013.35	0.00	0.00
INCOME TAXES	98,092,094.86	(65,511.00)	0.00
TOTAL OPERATING EXPENSES	1,425,971,249.19	(65,511.00)	(398,667.00)
OPERATING INCOME	321,539,728.04	(121,663.00)	0.00
NONOPERATING INCOME (EXPENSE)	54,172,131.35	54,333.77	(79,566.86)
NONOPERATING EXPENSES (EXPENSE)	(17,272,617.49)	(54,333.77)	0.00
NONOPERATING INCOME TAX EXPENSE (EXPENSE)	(7,079,713.00)	0.00	0.00
INTEREST CHARGES	133,811,944.23	0.00	0.00
INCOME BEFORE CUMULATIVE EFFECT OF ACCOUNTING CHANGE	217,547,584.67	(121,663.00)	(79,566.86)
CUMULATIVE EFFECT OF ACCOUNTING CHANGE (NET OF TAX)	121,663.00	121,663.00	0.00
NET INCOME	217,669,247.67	0.00	(79,566.86)
PREFERRED STOCK DIVIDEND REQUIREMENTS	241,143.84	0.00	0.00
EARNINGS APPLICABLE TO COMMON STOCK	$217,428,103.83	$0.00	($79,566.86)

Item 10 - Consolidating Statements of Income

AEP TEXAS CENTRAL COMPANY AND SUBSIDIARY
CONSOLIDATING STATEMENT OF INCOME
FOR THE YEAR ENDED DECEMBER 31, 2003

Note - Totals and subtotals may be off due to rounding

DESCRIPTION	AEP TEXAS CENTRAL COMPANY	AEP TEXAS CENTRAL COMPANY SEC
OPERATING REVENUES		
ELECTRIC GENERATION, TRANSMISSION AND DISTRIBUTION	$1,506,393,546.51	$87,736,678.83
SALES TO AEP AFFILIATES	148,728,436.92	5,238,155.97
TOTAL OPERATING REVENUES	1,655,121,983.43	92,974,834.80
OPERATING EXPENSES		
FUEL FOR ELECTRIC GENERATION	284,915,648.68	0.00
FUEL FROM AFFILIATES FOR ELECTRIC GENERATION	0.00	0.00
PURCHASED ELECTRICITY FOR RESALE	373,388,438.20	0.00
PURCHASED ELECTRICITY FROM AEP AFFILIATES	19,097,154.27	0.00
OTHER OPERATION	297,744,074.03	532,406.85
MAINTENANCE	71,361,397.46	0.00
DEPRECIATION AND AMORTIZATION	142,308,344.23	46,821,344.26
TAXES OTHER THAN INCOME TAXES	92,109,013.35	0.00
INCOME TAXES	98,157,605.86	0.00
TOTAL OPERATING EXPENSES	1,379,081,676.08	47,353,751.11
OPERATING INCOME	276,040,307.35	45,621,083.69
NONOPERATING INCOME (EXPENSE)	53,868,053.27	329,311.17
NONOPERATING EXPENSES (EXPENSE)	(17,218,283.72)	0.00
NONOPERATING INCOME TAX EXPENSE (EXPENSE)	(7,079,713.00)	0.00
INTEREST CHARGES	87,941,116.23	45,870,828.00
INCOME BEFORE CUMULATIVE EFFECT OF ACCOUNTING CHANGE	217,669,247.67	79,566.86
CUMULATIVE EFFECT OF ACCOUNTING CHANGE (NET OF TAX)	0.00	0.00
NET INCOME	217,669,247.67	79,566.86
PREFERRED STOCK DIVIDEND REQUIREMENTS	241,143.84	0.00
EARNINGS APPLICABLE TO COMMON STOCK	$217,428,103.83	$79,566.86

Item 10 - Consolidating Statements of Income

APPALACHIAN POWER COMPANY AND SUBSIDIARIES
CONSOLIDATING STATEMENT OF INCOME
FOR THE YEAR ENDED DECEMBER 31, 2003

Note - Totals and subtotals may be off due to rounding

DESCRIPTION	APPALACHIAN POWER COMPANY CONSOLIDATED	SEC REPORTING ADJUSTMENTS	APPALACHIAN POWER COMPANY ELIMINATIONS	APPALACHIAN POWER COMPANY
OPERATING REVENUES				
ELECTRIC GENERATION, TRANSMISSION AND DISTRIBUTION	$1,734,564,772.25	($2,094,011.00)	$0.00	$1,736,658,783.25
SALES TO AEP AFFILIATES	222,793,068.84	0.00	0.00	222,793,068.84
TOTAL OPERATING REVENUES	1,957,357,841.09	(2,094,011.00)	0.00	1,959,451,852.09
OPERATING EXPENSES				
FUEL FOR ELECTRIC GENERATION	454,900,802.64	0.00	0.00	454,900,802.64
PURCHASED ELECTRICITY FOR RESALE	66,083,737.33	0.00	0.00	66,083,737.33
PURCHASED ELECTRICITY FROM AEP AFFILIATES	351,210,023.69	0.00	0.00	351,210,023.69
OTHER OPERATION	245,308,300.39	128,341,689.43	0.00	116,966,610.96
MAINTENANCE	135,595,517.13	0.00	0.00	135,595,517.13
DEPRECIATION AND AMORTIZATION	175,771,879.00	0.00	0.00	175,771,879.00
TAXES OTHER THAN INCOME TAXES	90,087,499.26	0.00	0.00	90,087,499.26
INCOME TAXES	119,589,105.99	(48,786,795.00)	0.00	168,375,900.99
TOTAL OPERATING EXPENSES	1,638,546,865.41	79,554,894.43	0.00	1,558,991,970.98
OPERATING INCOME	318,810,975.67	(81,648,905.43)	0.00	400,459,881.10
NONOPERATING INCOME (EXPENSE)	(5,660,921.99)	7,568,755.58	(4,796,006.46)	(14,261,339.71)
NONOPERATING EXPENSES (EXPENSE)	(9,534,194.27)	(811,121.58)	3,229,308.70	(8,153,293.43)
NONOPERATING INCOME TAX CREDIT (EXPENSE)	14,368,862.00	(2,365,172.00)	0.00	17,199,072.00
INTEREST CHARGES	115,201,622.63	0.00	0.00	115,204,777.77
INCOME BEFORE CUMULATIVE EFFECT OF ACCOUNTING CHANGES	202,783,098.79	(77,256,443.43)	(1,566,697.76)	280,039,542.20
CUMULATIVE EFFECT OF ACCOUNTING CHANGES (NET OF TAX)	77,256,443.43	77,256,443.43	0.00	0.00
NET INCOME	280,039,542.22	0.00	(1,566,697.76)	280,039,542.20
PREFERRED STOCK DIVIDEND REQUIREMENTS	3,494,210.07	0.00	0.00	3,494,210.07
EARNINGS APPLICABLE TO COMMON STOCK	$276,545,332.15	$0.00	($1,566,697.76)	$276,545,332.13

Item 10 - Consolidating Statements of Income

APPALACHIAN POWER COMPANY AND SUBSIDIARIES
CONSOLIDATING STATEMENT OF INCOME
FOR THE YEAR ENDED DECEMBER 31, 2003

Note - Totals and subtotals may be off due to rounding

DESCRIPTION	CENTRAL APPALACHIAN COAL COMPANY	SOUTHERN APPALACHIAN COAL COMPANY	CEDAR COAL COMPANY
OPERATING REVENUES			
ELECTRIC GENERATION, TRANSMISSION AND DISTRIBUTION	$0.00	$0.00	$0.00
SALES TO AEP AFFILIATES	0.00	0.00	0.00
TOTAL OPERATING REVENUES	0.00	0.00	0.00
OPERATING EXPENSES			
FUEL FOR ELECTRIC GENERATION	0.00	0.00	0.00
PURCHASED ELECTRICITY FOR RESALE	0.00	0.00	0.00
PURCHASED ELECTRICITY FROM AEP AFFILIATES	0.00	0.00	0.00
OTHER OPERATION	0.00	0.00	0.00
MAINTENANCE	0.00	0.00	0.00
DEPRECIATION AND AMORTIZATION	0.00	0.00	0.00
TAXES OTHER THAN INCOME TAXES	0.00	0.00	0.00
INCOME TAXES	0.00	0.00	0.00
TOTAL OPERATING EXPENSES	0.00	0.00	0.00
OPERATING INCOME	0.00	0.00	0.00
NONOPERATING INCOME (EXPENSE)	271,704.51	1,486,069.91	4,069,894.18
NONOPERATING EXPENSES (EXPENSE)	(61,219.49)	(827,796.42)	(2,910,072.05)
NONOPERATING INCOME TAX CREDIT (EXPENSE)	(95,147.00)	(214,147.00)	(155,744.00)
INTEREST CHARGES	(238.99)	(1,114.52)	(1,801.63)
INCOME BEFORE CUMULATIVE EFFECT OF ACCOUNTING CHANGES	115,577.01	445,241.01	1,005,879.76
CUMULATIVE EFFECT OF ACCOUNTING CHANGES (NET OF TAX)	0.00	0.00	0.00
NET INCOME	115,577.01	445,241.01	1,005,879.76
PREFERRED STOCK DIVIDEND REQUIREMENTS	0.00	0.00	0.00
EARNINGS APPLICABLE TO COMMON STOCK	$115,577.01	$445,241.01	$1,005,879.76

Item 10 - Consolidating Statements of Income

COLUMBUS SOUTHERN POWER COMPANY AND SUBSIDIARIES
CONSOLIDATING STATEMENT OF INCOME
FOR THE YEAR ENDED DECEMBER 31, 2003

Note - Totals and subtotals may be off due to rounding

DESCRIPTION	COLUMBUS SOUTHERN POWER COMPANY CONSOLIDATED	SEC REPORTING ADJUSTMENTS	COLUMBUS SOUTHERN POWER COMPANY ELIMINATIONS	COLUMBUS SOUTHERN POWER COMPANY
OPERATING REVENUES				
ELECTRIC GENERATION, TRANSMISSION AND DISTRIBUTION	$1,347,482,630.68	($1,407,676.00)	($9,196,483.88)	$1,348,890,306.68
SALES TO AEP AFFILIATES	84,368,806.72	0.00	(172,100.00)	82,353,392.72
TOTAL OPERATING REVENUES	1,431,851,437.40	(1,407,676.00)	(9,368,583.88)	1,431,243,699.40
OPERATING EXPENSES				
FUEL FOR ELECTRIC GENERATION	203,398,808.79	0.00	(127,819.21)	203,526,628.00
PURCHASED ELECTRICITY FOR RESALE	17,730,168.40	0.00	0.00	17,730,168.40
PURCHASED ELECTRICITY FROM AEP AFFILIATES	337,322,906.72	0.00	0.00	337,322,906.72
OTHER OPERATION	218,466,440.10	49,036,164.83	(7,151,008.53)	169,425,561.89
MAINTENANCE	75,319,430.65	0.00	(1,772,196.68)	75,319,430.17
DEPRECIATION AND AMORTIZATION	135,964,381.81	0.00	(86,436.24)	135,822,582.21
TAXES OTHER THAN INCOME TAXES	133,753,570.01	0.00	(230,600.22)	133,451,449.24
INCOME TAXES	84,409,962.71	(20,207,894.00)	0.00	104,571,276.71
TOTAL OPERATING EXPENSES	1,206,365,669.20	28,828,270.83	(9,368,060.88)	1,177,170,003.34
OPERATING INCOME	225,485,768.20	(30,235,946.83)	(523.00)	254,073,696.05
NONOPERATING INCOME (EXPENSE)	(7,488,973.13)	4,885,042.13	(1,073,012.97)	(11,453,405.02)
NONOPERATING EXPENSES (EXPENSE)	(4,650,608.99)	(342,300.13)	523.00	(4,254,946.73)
NONOPERATING INCOME TAX CREDIT (EXPENSE)	10,748,643.71	(1,589,960.00)	0.00	12,970,691.71
INTEREST CHARGES	50,948,011.09	0.00	0.00	50,906,052.76
INCOME BEFORE CUMULATIVE EFFECT OF ACCOUNTING CHANGE	173,146,818.70	(27,283,164.83)	(1,073,012.97)	200,429,983.25
CUMULATIVE EFFECT OF ACCOUNTING CHANGES (NET OF TAX)	27,283,164.83	27,283,164.83	0.00	0.00
NET INCOME	200,429,983.53	0.00	(1,073,012.97)	200,429,983.25
PREFERRED STOCK DIVIDEND REQUIREMENTS	1,015,380.36	0.00	0.00	1,015,380.36
EARNINGS APPLICABLE TO COMMON STOCK	$199,414,603.17	$0.00	($1,073,012.97)	$199,414,602.89

Item 10 - Consolidating Statements of Income

COLUMBUS SOUTHERN POWER COMPANY AND SUBSIDIARIES
CONSOLIDATING STATEMENT OF INCOME
FOR THE YEAR ENDED DECEMBER 31, 2003

Note - Totals and subtotals may be off due to rounding

DESCRIPTION	SIMCO INCORPORATED	COLOMET INCORPORATED	CONESVILLE COAL PREPARATION COMPANY
OPERATING REVENUES			
ELECTRIC GENERATION, TRANSMISSION AND DISTRIBUTION	$0.00	$0.00	$9,196,483.88
SALES TO AEP AFFILIATES	172,100.00	2,015,414.00	0.00
TOTAL OPERATING REVENUES	172,100.00	2,015,414.00	9,196,483.88
OPERATING EXPENSES			
FUEL FOR ELECTRIC GENERATION	0.00	0.00	0.00
PURCHASED ELECTRICITY FOR RESALE	0.00	0.00	0.00
PURCHASED ELECTRICITY FROM AEP AFFILIATES	0.00	0.00	0.00
OTHER OPERATION	2,654.06	4,712.60	7,148,355.26
MAINTENANCE	0.00	0.00	1,772,197.15
DEPRECIATION AND AMORTIZATION	59,238.00	141,799.60	27,198.24
TAXES OTHER THAN INCOME TAXES	5,700.48	302,120.77	224,899.74
INCOME TAXES	29,538.00	0.00	17,042.00
TOTAL OPERATING EXPENSES	97,130.54	448,632.97	9,189,692.39
OPERATING INCOME	74,969.46	1,566,781.03	6,791.49
NONOPERATING INCOME (EXPENSE)	6,259.43	81,850.94	64,292.36
NONOPERATING EXPENSES (EXPENSE)	(523.00)	(50,368.00)	(2,994.13)
NONOPERATING INCOME TAX CREDIT (EXPENSE)	(4,958.00)	(627,130.00)	0.00
INTEREST CHARGES	(41.72)	43,910.33	(1,910.28)
INCOME BEFORE CUMULATIVE EFFECT OF ACCOUNTING CHANGE	75,789.61	927,223.64	70,000.00
CUMULATIVE EFFECT OF ACCOUNTING CHANGES (NET OF TAX)	0.00	0.00	0.00
NET INCOME	75,789.61	927,223.64	70,000.00
PREFERRED STOCK DIVIDEND REQUIREMENTS	0.00	0.00	0.00
EARNINGS APPLICABLE TO COMMON STOCK	$75,789.61	$927,223.64	$70,000.00

Item 10 - Consolidating Statements of Income

INDIANA MICHIGAN POWER COMPANY AND SUBSIDAIRIES
CONSOLIDATING STATEMENT OF INCOME
FOR THE YEAR ENDED DECEMBER 31, 2003

Note - Totals and subtotals may be off due to rounding

DESCRIPTION	INDIANA MICHIGAN POWER COMPANY CONSOLIDATED	SEC REPORTING ADJUSTMENTS	INDIANA MICHIGAN POWER COMPANY ELIMINATIONS	INDIANA MICHIGAN POWER COMPANY
OPERATING REVENUES				
ELECTRIC GENERATION, TRANSMISSION AND DISTRIBUTION	$1,346,393,152.14	$0.00	$0.00	$1,346,393,152.14
SALES TO AEP AFFILIATES	249,202,841.44	0.00	0.00	249,202,841.44
TOTAL OPERATING REVENUES	1,595,595,993.58	0.00	0.00	1,595,595,993.58
OPERATING EXPENSES				
FUEL FOR ELECTRIC GENERATION	250,890,406.52	0.00	0.00	250,890,406.52
PURCHASED ELECTRICITY FOR RESALE	28,327,208.05	0.00	0.00	28,327,208.05
PURCHASED ELECTRICITY FROM AEP AFFILIATES	274,400,173.37	0.00	0.00	274,400,173.37
OTHER OPERATION	417,635,835.94	0.00	0.00	417,635,835.93
MAINTENANCE	158,280,616.40	0.00	0.00	158,280,616.40
DEPRECIATION AND AMORTIZATION	171,281,007.92	0.00	0.00	171,281,007.92
TAXES OTHER THAN INCOME TAXES	57,787,478.37	0.00	0.00	57,787,478.37
INCOME TAXES	50,926,310.10	0.00	0.00	50,926,310.10
TOTAL OPERATING EXPENSES	1,409,529,036.66	0.00	0.00	1,409,529,036.66
OPERATING INCOME	186,066,956.92	0.00	0.00	186,066,956.92
NONOPERATING INCOME (EXPENSE)	53,928,104.98	24,463,995.47	6,164,161.58	31,587,375.35
NONOPERATING EXPENSES (EXPENSE)	(77,170,790.28)	(19,603,198.47)	241,892.75	(56,159,601.08)
NONOPERATING INCOME TAX CREDIT (EXPENSE)	9,777,424.00	(1,701,279.00)	0.00	7,948,857.00
INTEREST CHARGES	83,053,952.92	0.00	0.00	83,055,363.52
INCOME BEFORE CUMULATIVE EFFECT OF ACCOUNTING CHANGE	89,547,742.71	3,159,518.00	6,406,054.33	86,388,224.68
CUMULATIVE EFFECT OF ACCOUNTING CHANGES (NET OF TAX)	(3,159,518.00)	(3,159,518.00)	0.00	0.00
NET INCOME	86,388,224.71	0.00	6,406,054.33	86,388,224.68
PREFERRED STOCK DIVIDEND REQUIREMENTS	2,509,062.40	0.00	0.00	2,509,062.40
EARNINGS APPLICABLE TO COMMON STOCK	$83,879,162.31	$0.00	$6,406,054.33	$83,879,162.28

Item 10 - Consolidating Statements of Income

INDIANA MICHIGAN POWER COMPANY AND SUBSIDAIRIES
CONSOLIDATING STATEMENT OF INCOME
FOR THE YEAR ENDED DECEMBER 31, 2003

Note - Totals and subtotals may be off due to rounding

DESCRIPTION	PRICE RIVER COAL COMPANY	BLACKHAWK COAL COMPANY
OPERATING REVENUES		
ELECTRIC GENERATION, TRANSMISSION AND DISTRIBUTION	$0.00	$0.00
SALES TO AEP AFFILIATES	0.00	0.00
TOTAL OPERATING REVENUES	0.00	0.00
OPERATING EXPENSES		
FUEL FOR ELECTRIC GENERATION	0.00	0.00
PURCHASED ELECTRICITY FOR RESALE	0.00	0.00
PURCHASED ELECTRICITY FROM AEP AFFILIATES	0.00	0.00
OTHER OPERATION	0.00	0.00
MAINTENANCE	0.00	0.00
DEPRECIATION AND AMORTIZATION	0.00	0.00
TAXES OTHER THAN INCOME TAXES	0.00	0.00
INCOME TAXES	0.00	0.00
TOTAL OPERATING EXPENSES	0.00	0.00
OPERATING INCOME	(0.00)	0.00
NONOPERATING INCOME (EXPENSE)	0.00	(8,287,427.42)
NONOPERATING EXPENSES (EXPENSE)	0.00	(1,649,883.48)
NONOPERATING INCOME TAX CREDIT (EXPENSE)	0.00	3,529,846.00
INTEREST CHARGES	0.00	(1,410.60)
INCOME BEFORE CUMULATIVE EFFECT OF ACCOUNTING CHANGE	0.00	(6,406,054.30)
CUMULATIVE EFFECT OF ACCOUNTING CHANGES (NET OF TAX)	0.00	0.00
NET INCOME	0.00	(6,406,054.30)
PREFERRED STOCK DIVIDEND REQUIREMENTS	0.00	0.00
EARNINGS APPLICABLE TO COMMON STOCK	$0.00	($6,406,054.30)

Item 10 - Consolidating Statements of Income

OHIO POWER COMPANY CONSOLIDATED
CONSOLIDATING STATEMENT OF INCOME
FOR THE YEAR ENDED DECEMBER 31, 2003

Note - Totals and subtotals may be off due to rounding

DESCRIPTION	OHIO POWER COMPANY CONSOLIDATED	SEC REPORTING ADJUSTMENTS	OHIO POWER COMPANY ELIMINATIONS
OPERATING REVENUES			
ELECTRIC GENERATION, TRANSMISSION AND DISTRIBUTION	$1,660,374,867.60	($1,867,531.00)	$0.00
SALES TO AEP AFFILIATES	584,278,164.02	0.00	(31,597,338.10)
TOTAL OPERATING REVENUES	2,244,653,031.62	(1,867,531.00)	(31,597,338.10)
OPERATING EXPENSES			
FUEL FOR ELECTRIC GENERATION	616,679,836.32	0.00	0.00
PURCHASED ELECTRICITY FOR RESALE	63,485,751.63	0.00	0.00
PURCHASED ELECTRICITY FROM AEP AFFILIATES	90,821,164.40	0.00	0.00
OTHER OPERATION	369,086,535.21	213,641,327.27	(31,597,338.10)
MAINTENANCE	166,437,853.87	0.00	0.00
DEPRECIATION AND AMORTIZATION	257,417,401.15	0.00	0.00
TAXES OTHER THAN INCOME TAXES	175,043,400.86	0.00	0.00
INCOME TAXES	146,014,148.26	(86,959,751.00)	0.00
TOTAL OPERATING EXPENSES	1,884,986,091.70	126,681,576.27	(31,597,338.10)
OPERATING INCOME	359,666,939.92	(128,549,107.27)	0.00
NONOPERATING INCOME (EXPENSE)	24,494,888.63	8,280,786.21	0.00
NONOPERATING EXPENSES (EXPENSE)	(34,281,765.05)	(2,254,031.21)	0.00
NONOPERATING INCOME TAX CREDIT (EXPENSE)	7,614,796.00	(2,109,365.00)	0.00
INTEREST CHARGES	106,464,124.05	0.00	0.00
INCOME BEFORE CUMULATIVE EFFECT OF ACCOUNTING CHANGES	251,030,735.45	(124,631,717.27)	0.00
CUMULATIVE EFFECT OF ACCOUNTING CHANGES (NET OF TAX)	124,631,674.07	124,631,717.27	0.00
NET INCOME	375,662,409.52	0.00	0.00
PREFERRED STOCK DIVIDEND REQUIREMENT	1,098,049.97	0.00	0.00
EARNINGS APPLICABLE TO COMMON STOCK	$374,564,359.55	$0.00	$0.00

Item 10 - Consolidating Statements of Income

OHIO POWER COMPANY CONSOLIDATED
CONSOLIDATING STATEMENT OF INCOME
FOR THE YEAR ENDED DECEMBER 31, 2003

Note - Totals and subtotals may be off due to rounding

DESCRIPTION	OHIO POWER COMPANY	JMG FUNDING LP
OPERATING REVENUES		
ELECTRIC GENERATION, TRANSMISSION AND DISTRIBUTION	$1,662,242,398.60	$0.00
SALES TO AEP AFFILIATES	584,278,164.02	31,597,338.10
TOTAL OPERATING REVENUES	2,246,520,562.62	31,597,338.10
OPERATING EXPENSES		
FUEL FOR ELECTRIC GENERATION	616,679,836.32	0.00
PURCHASED ELECTRICITY FOR RESALE	63,485,751.63	0.00
PURCHASED ELECTRICITY FROM AEP AFFILIATES	90,821,164.40	0.00
OTHER OPERATION	176,994,183.30	10,048,362.74
MAINTENANCE	166,437,853.87	0.00
DEPRECIATION AND AMORTIZATION	247,461,862.04	9,955,539.11
TAXES OTHER THAN INCOME TAXES	175,043,400.86	0.00
INCOME TAXES	232,973,899.26	
TOTAL OPERATING EXPENSES	1,769,897,951.68	20,003,901.85
OPERATING INCOME	476,622,610.94	11,593,436.25
NONOPERATING INCOME (EXPENSE)	16,213,935.25	167.17
NONOPERATING EXPENSES (EXPENSE)	(32,027,733.84)	0.00
NONOPERATING INCOME TAX CREDIT (EXPENSE)	9,724,161.00	0.00
INTEREST CHARGES	94,870,520.63	11,593,603.42
INCOME BEFORE CUMULATIVE EFFECT OF ACCOUNTING CHANGES	375,662,452.72	
CUMULATIVE EFFECT OF ACCOUNTING CHANGES (NET OF TAX)	(43.20)	0.00
NET INCOME	375,662,409.52	0.00
PREFERRED STOCK DIVIDEND REQUIREMENT	1,098,049.97	0.00
EARNINGS APPLICABLE TO COMMON STOCK	$374,564,359.55	$0.00

Item 10 - Consolidating Statements of Income

SOUTHWESTERN ELECTRIC POWER COMPANY CONSOLIDATED
CONSOLIDATING STATEMENT OF INCOME
FOR THE YEAR ENDED DECEMBER 31, 2003

Note - Totals and subtotals may be off due to rounding

DESCRIPTION	SOUTHWESTERN ELECTRIC POWER COMPANY CONSOLIDATED	SEC REPORTING ADJUSTMENTS	SOUTHWESTERN ELECTRIC POWER COMPANY ELIMINATIONS
OPERATING REVENUES			
ELECTRIC GENERATION, TRANSMISSION AND DISTRIBUTION	$1,077,987,452.20	($150,836.00)	$0.00
SALES TO AEP AFFILIATES	68,854,339.06	0.00	(60,698,754.67)
TOTAL OPERATING REVENUES	1,146,841,791.26	(150,836.00)	(60,698,754.67)
OPERATING EXPENSES			
FUEL FOR ELECTRIC GENERATION	441,444,918.99	0.00	(11,958,974.74)
PURCHASED ELECTRICITY FOR RESALE	34,849,820.02	0.00	0.00
PURCHASED ELECTRICITY FROM AEP AFFILIATES	47,914,452.44	0.00	0.00
OTHER OPERATION	173,348,856.94	12,952,638.84	(39,043,947.32)
MAINTENANCE	70,443,258.96	0.00	0.00
DEPRECIATION AND AMORTIZATION	121,071,613.63	0.00	(8,116,474.34)
TAXES OTHER THAN INCOME TAXES	53,165,407.44	0.00	(1,579,358.07)
INCOME TAXES	54,467,946.88	(4,586,217.00)	0.00
TOTAL OPERATING EXPENSES	996,706,275.30	8,366,421.84	(60,698,754.47)
OPERATING INCOME	150,135,515.96	(8,517,257.84)	(0.20)
NONOPERATING INCOME (EXPENSE)	3,977,784.02	1,506,667.79	(4,716,674.17)
NONOPERATING EXPENSES (EXPENSE)	(2,606,751.11)	(7,213.57)	0.00
NONOPERATING INCOME TAX CREDIT (EXPENSE)	3,396,162.00	0.00	0.00
INTEREST CHARGES	63,779,160.38	0.00	(1,855,197.15)
MINORITY INTEREST (EXPENSE)	(1,499,454.22)	(1,499,454.22)	0.00
INCOME BEFORE CUMULATIVE EFFECT OF ACCOUNTING CHANGE	89,624,096.27	(8,517,257.84)	(2,861,477.22)
CUMULATIVE EFFECT OF ACCOUNTING CHANGE (NET OF TAX)	8,517,257.84	8,517,257.84	0.00
NET INCOME	98,141,354.11	0.00	(2,861,477.22)
PREFERRED STOCK DIVIDEND REQUIREMENTS	229,009.56	0.00	0.00
EARNINGS APPLICABLE TO COMMON STOCK	$97,912,344.55	$0.00	($2,861,477.22)

Item 10 - Consolidating Statements of Income

SOUTHWESTERN ELECTRIC POWER COMPANY CONSOLIDATED
CONSOLIDATING STATEMENT OF INCOME
FOR THE YEAR ENDED DECEMBER 31, 2003

Note - Totals and subtotals may be off due to rounding

DESCRIPTION	SOUTHWESTERN ELECTRIC POWER COMPANY	DOLET HILLS LIGNITE COMPANY	SABINE MINING COMPANY
OPERATING REVENUES			
ELECTRIC GENERATION, TRANSMISSION AND DISTRIBUTION	$1,045,164,278.57	$32,016,774.73	$957,234.90
SALES TO AEP AFFILIATES	68,854,339.06	32,016,774.73	28,681,979.94
TOTAL OPERATING REVENUES	1,114,018,617.63	64,033,549.46	29,639,214.84
OPERATING EXPENSES			
FUEL FOR ELECTRIC GENERATION	453,403,893.73	0.00	0.00
PURCHASED ELECTRICITY FOR RESALE	34,849,820.02	0.00	0.00
PURCHASED ELECTRICITY FROM AEP AFFILIATES	47,914,452.44	0.00	0.00
OTHER OPERATION	132,351,956.12	46,740,436.24	20,347,773.06
MAINTENANCE	70,443,258.96	0.00	0.00
DEPRECIATION AND AMORTIZATION	114,836,893.98	10,391,199.46	3,959,994.53
TAXES OTHER THAN INCOME TAXES	51,853,677.61	2,186,149.70	704,938.20
INCOME TAXES	57,448,650.88	795,541.00	809,972.00
TOTAL OPERATING EXPENSES	963,102,603.74	60,113,326.40	25,822,677.79
OPERATING INCOME	150,916,013.89	3,920,223.06	3,816,537.05
NONOPERATING INCOME (EXPENSE)	6,975,452.05	212,338.35	0.00
NONOPERATING EXPENSES (EXPENSE)	(2,352,713.82)	(154,833.33)	(91,990.39)
NONOPERATING INCOME TAX CREDIT (EXPENSE)	2,976,722.00	419,440.00	0.00
INTEREST CHARGES	60,374,120.03	3,035,145.06	2,225,092.44
MINORITY INTEREST (EXPENSE)	0.00	0.00	0.00
INCOME BEFORE CUMULATIVE EFFECT OF ACCOUNTING CHANGE	98,141,354.10	1,362,023.02	1,499,454.22
CUMULATIVE EFFECT OF ACCOUNTING CHANGE (NET OF TAX)	0.00	0.00	0.00
NET INCOME	98,141,354.10	1,362,023.02	1,499,454.22
PREFERRED STOCK DIVIDEND REQUIREMENTS	229,009.56	0.00	0.00
EARNINGS APPLICABLE TO COMMON STOCK	$97,912,344.54	$1,362,023.02	$1,499,454.22

Item 10 - Consolidating Balance Sheets

AMERICAN ELECTRIC POWER COMPANY, INC.
AND SUBSIDIARY COMPANIES
CONSOLIDATING BALANCE SHEET
DECEMBER 31, 2003

Note - Totals and subtotals may be off due to rounding

DESCRIPTION	AMERICAN ELECTRIC POWER COMPANY CONSOLIDATED	SEC REPORTING ADJUSTMENTS	AMERICAN ELECTRIC POWER COMPANY ELIMINATIONS	AMERICAN ELECTRIC POWER COMPANY
ASSETS				
CURRENT AND ACCRUED ASSETS				
CASH AND CASH EQUIVALENTS	$1,182,143,529.95	($13,163,000.00)	$0.00	$874,882,360.38
ADVANCES TO AFFILIATES	(0.00)	(3,326,573.62)	(2,552,889,525.31)	1,877,368,555.65
ACCOUNTS RECEIVABLE - CUSTOMERS	1,155,243,672.78	564,697,990.96	244,169,524.97	0.00
ACCOUNTS RECEIVABLE - AFFILIATED COMPANIES	0.00	(6,623,442.40)	(1,472,642,506.35)	35,599,750.45
ACCOUNTS RECEIVABLE - ACCRUED UNBILLED REVENUES	596,246,280.67	(29,779,121.00)	145,622,068.67	0.00
ACCOUNTS RECEIVABLE - MISCELLANEOUS	83,386,023.37	(735,931,237.66)	(9,759,718.12)	10,235,271.19
ACCOUNTS RECEIVABLE - ALLOWANCE FOR UNCOLLECTIBLE ACCOUNTS	(123,937,047.57)	0.00	0.00	0.00
FUEL INVENTORY	516,346,182.67	(284,144,038.00)	(3,243,735.91)	0.00
MATERIALS & SUPPLIES	475,040,881.60	(830,000.00)	1,983,490.88	0.00
RISK MANAGEMENT ASSETS	766,383,790.69	(560,283,000.00)	(11,583,450.00)	4,741,666.00
MARGIN DEPOSITS	119,117,000.00	81,754,150.66	0.00	0.00
PREPAYMENTS	88,174,361.00	(13,750,000.00)	(568,449.06)	2,477,262.55
OTHER	39,487,147.92	(316,699,029.66)	(9,469,005.84)	0.00
TOTAL CURRENT ASSETS	4,897,631,823.07	(1,318,077,300.72)	(3,668,381,306.07)	2,805,304,866.22
ELECTRIC UTILITY PLANT				
TOTAL ELECTRIC UTILITY PLANT	36,032,486,862.27	(2,324,221,268.27)	31,888.92	1,490,374.58
ACCUMULATED DEPRECIATION AND AMORTIZATION	(14,004,035,037.48)	1,211,237,078.77	0.00	(146,738.09)
ELECTRIC UTILITY PLANT - NET	22,028,451,824.80	(1,112,984,189.51)	31,888.92	1,343,636.49
OTHER PROPERTY AND INVESTMENTS				
NUCLEAR DECOMMISSIONING AND SPENT NUCLEAR FUEL DISPOSAL TRUST FUNDS	0.00	(982,394,078.70)	0.00	0.00
NON-UTILITY PROPERTY, NET	(0.00)	(130,249,808.38)	0.00	0.00
OTHER INVESTMENTS	(0.00)	(102,951,465.54)	0.00	0.00
TOTAL OTHER PROPERTY AND INVESTMENTS	(0.00)	(1,215,595,352.62)	0.00	0.00
INVESTMENTS IN POWER AND DISTRIBUTION PROJECTS	211,850,592.72	14,944,000.00	(7,815,934,503.58)	7,818,808,133.58
REGULATORY ASSETS	3,901,486,743.39	21,455,094.31	0.00	0.00
FAS 109 DEFERRED FIT RECLASS	(353,853,385.00)	(86,009,596.00)	3,866,018.00	2,143,686.00
NET REGULATORY ASSETS	3,547,633,358.39	(64,554,501.69)	3,866,018.00	2,143,686.00
SECURITIZED TRANSITION ASSETS	689,399,000.00	689,399,000.00	0.00	0.00
TOTAL GOODWILL	78,431,224.39	(15,000,000.00)	0.00	37,060,693.00
INTANGIBLE ASSETS	0.00	(34,166,945.96)	0.00	0.00
LONG-TERM RISK MANAGEMENT ASSETS	494,003,225.68	(274,252,000.00)	(9,612,040.00)	0.00
SPENT NUCLEAR FUEL AND DECOMMISSIONING TRUSTS	982,395,000.00	982,395,000.00	0.00	0.00
OTHER DEFERRED DEBITS	362,704,783.90	25,871,000.00	(28,247,987.01)	16,543,452.56
PREFERRED STOCK DIVIDEND REQUIREMENT OF SUBSIDIARIES	(8,903,507.37)	0.00	(8,116,702.80)	0.00
TOTAL OTHER DEFERRED DEBITS	353,801,276.53	25,871,000.00	(36,364,689.81)	16,543,452.56
OTHER ASSETS				
TOTAL OTHER INVESTMENTS	243,263,414.99	(580,853,534.46)	(732,222,899.57)	693,312,196.63
TOTAL OTHER SPECIAL FUNDS	(492.15)	(125,383,921.30)	0.00	0.00
CLEARING ACCOUNTS	8,616,552.93	0.00	0.00	148.92
UNAMORTIZED DEBT EXPENSE	126,640,653.39	0.00	0.00	9,516,620.91
TOTAL OTHER ASSETS	732,321,405.68	(680,366,455.76)	(768,587,589.38)	719,372,419.02
ASSETS HELD FOR SALE	3,081,420,763.58	3,081,420,763.58	0.00	0.00
TOTAL ASSETS	$36,743,538,218.31	$53,162,017.32	($12,258,617,532.11)	$11,384,033,434.31

Item 10 - Consolidating Balance Sheets

AMERICAN ELECTRIC POWER COMPANY, INC.
AND SUBSIDIARY COMPANIES
CONSOLIDATING BALANCE SHEET
DECEMBER 31, 2003

Note - Totals and subtotals may be off due to rounding

DESCRIPTION	AMERICAN ELECTRIC POWER COMPANY CONSOLIDATED	SEC REPORTING ADJUSTMENTS	AMERICAN ELECTRIC POWER COMPANY ELIMINATIONS	AMERICAN ELECTRIC POWER COMPANY
LIABILITIES AND SHAREHOLDERS' EQUITY				
CURRENT LIABILITIES				
LONG-TERM DEBT DUE WITHIN ONE YEAR	$1,778,855,672.16	($4,936,000.00)	$0.00	$10,864,980.40
SHORT-TERM DEBT	326,110,594.37	(9,217,000.00)	0.00	281,824,000.00
ADVANCES FROM AFFILIATES	24,488.96	41,152,737.28	(2,552,889,524.91)	615,164,169.95
ACCOUNTS PAYABLE - GENERAL	1,329,122,768.00	(205,632,000.00)	0.00	102,213.89
ACCOUNTS PAYABLE - AFFILIATED COMPANIES	7,810,543.62	0.00	(1,082,755,921.35)	27,192,233.60
CUSTOMER DEPOSITS	379,427,662.35	0.00	0.00	0.00
TAXES ACCRUED	619,994,801.24	12,237,000.00	(173,903.00)	858,226.00
INTEREST ACCRUED	207,373,909.25	(832,000.00)	(9,759,717.64)	18,094,228.16
RISK MANAGEMENT LIABILITIES	631,417,738.05	(782,392,000.00)	(11,583,450.00)	0.00
OBLIGATIONS UNDER CAPITAL LEASES	50,990,653.15	0.00	0.00	0.00
DIVIDENDS DECLARED	1,554,469.73	0.00	0.00	0.00
OTHER	649,484,904.31	(83,718,000.00)	(12,712,741.75)	46,776,183.63
TOTAL CURRENT LIABILITIES	5,982,168,205.18	(1,033,337,262.72)	(3,669,875,258.64)	1,000,876,235.63
LONG-TERM RISK MANAGEMENT LIABILITIES	335,252,271.27	(434,717,000.00)	(9,612,040.00)	1,191,714.00
DEFERRED INCOME TAXES	6,875,408,172.72	(1,000,000.00)	(13,001,629.00)	4,629,131.00
DEFERRED FIT & SIT RECLASS	(2,918,581,864.87)	0.00	3,866,018.00	(524,783.00)
NET DEFERRED INCOME TAXES	3,956,826,307.85	(1,000,000.00)	(9,135,611.00)	4,104,348.00
DEFERRED INVESTMENT TAX CREDITS	0.00	(422,035,653.00)	(7,179,522.00)	0.00
ASSET REMOVAL COSTS	0.00	(582,397,338.00)	0.00	0.00
LONG-TERM DEBT	12,321,669,165.90	(20,918,000.00)	(705,493,166.00)	2,077,054,552.59
OVER-RECOVERY OF FUEL COST	0.00	(133,221,888.17)	0.00	0.00
OTHER REGULATORY LIABILTIES	0.00	(1,112,872,030.57)	0.00	0.00
UNAMORTIZED GAIN ON REACQUIRED DEBT	(0.00)	(301,163.17)	0.00	0.00
SFAS 109 REGULATORY LIABILITY, NET	0.00	(15,504,774.00)	0.00	0.00
TOTAL REGULATORY LIABILITIES	(0.00)	(1,261,899,855.91)	0.00	0.00
TOTAL OTHER DEFERRED CREDITS	(0.00)	(208,077,036.18)	(8,366,885.23)	0.00
DEFERRED CREDITS AND REGULATORY LIABILITIES	(0.01)	(1,469,976,892.09)	(8,366,885.23)	0.00
CUSTOMER ADVANCES FOR CONSTRUCTION	0.00	(4,563,230.63)	0.00	0.00
DEFERRED GAIN ON SALE/LEASEBACK	175,653,947.00	(153,584.00)	0.00	0.00
UNREALIZED GAIN ON FORWARD COMMITMENTS	0.00	(17,282,832.10)	0.00	0.00
DEFERRED CREDITS AND OTHER	507,777,607.80	507,777,607.80	0.00	0.00
REGULATORY LIABILITIES AND DEFERRED INVESTMENT TAX CREDITS	2,259,110,905.01	2,259,110,905.01	0.00	0.00
OTHER NONCURRENT LIABILITIES				
OBLIGATIONS UNDER CAPITAL LEASES	(0.00)	(130,929,334.91)	(26,727,717.52)	0.00
ACCUMULATED PROVISIONS - RATE REFUND	0.00	(112,780,000.00)	0.00	0.00
ASSET RETIREMENT OBLIGATIONS AND NUCLEAR DECOMMSSIONING TRUSTS	650,810,645.39	23,293,691.21	0.00	0.00
ACCUMULATED PROVISIONS - MISCELLANEOUS	354.61	(1,035,860,050.67)	0.00	0.00
TOTAL OTHER NONCURRENT LIABILITIES	650,810,999.99	(1,256,275,694.37)	(26,727,717.52)	0.00
EMPLOYEE BENEFITS AND PENSION OBLIGATIONS	667,238,000.00	667,238,000.00	0.00	0.00
CUMULATIVE PREFERRED STOCKS OF SUBSIDIARIES SUBJECT TO MANDATORY REDEMPTION	76,055,000.00	0.00	0.00	0.00
CUMULATIVE PREFERRED STOCK OF SUBSIDIARIES NOT SUBJECT TO MANDATORY REDEMPTION	60,794,000.00	0.00	0.00	0.00
COMMON SHAREHOLDERS' EQUITY				
COMMON STOCK	2,626,106,684.50	0.00	(738,722,314.43)	2,626,106,684.50
PREMIUM ON CAPITAL STOCK	0.00	(3,078,712,964.32)	(263,880,640.79)	3,342,414,929.23
PAID-IN CAPITAL	4,183,712,284.87	3,323,551,843.57	(5,737,031,250.15)	842,465,913.67
RETAINED EARNINGS	1,489,818,784.90	0.00	(1,082,593,126.35)	1,489,819,056.68
ACCUMULATED OTHER COMPREHENSIVE INCOME (LOSS)	(425,463,000.00)	(242,838,879.25)	0.00	0.00
COMMON SHAREHOLDERS' EQUITY	7,874,174,754.27	2,000,000.00	(7,822,227,331.72)	8,300,806,584.08
MINORITY INTEREST	0.00	(16,314,062.62)	0.00	0.00
LIABILITIES HELD FOR SALE	1,876,007,054.04	1,876,007,054.04	0.00	0.00
TOTAL LIABILITIES AND SHAREHOLDERS' EQUITY	$36,743,538,218.31	$53,162,017.32	($12,258,617,532.11)	$11,384,033,434.31

Item 10 - Consolidating Balance Sheets

AMERICAN ELECTRIC POWER COMPANY, INC.
AND SUBSIDIARY COMPANIES
CONSOLIDATING BALANCE SHEET
DECEMBER 31, 2003

Note - Totals and subtotals may be off due to rounding

DESCRIPTION	AMERICAN ELECTRIC POWER SERVICE CORPORATION	AEP TEXAS POLR, LLC	AEP MONEY POOL	AEP GENERATING COMPANY
ASSETS				
CURRENT AND ACCRUED ASSETS				
CASH AND CASH EQUIVALENTS	$1,620,780.82	$32,307.61	$0.00	$0.00
ADVANCES TO AFFILIATES	0.00	2,123,784.59	0.00	0.00
ACCOUNTS RECEIVABLE - CUSTOMERS	34,506.21	13,860,385.18	0.00	0.00
ACCOUNTS RECEIVABLE - AFFILIATED COMPANIES	183,880,115.56	17,837.62	65,127,883.78	24,748,031.64
ACCOUNTS RECEIVABLE - ACCRUED UNBILLED REVENUES	0.00	0.00	0.00	0.00
ACCOUNTS RECEIVABLE - MISCELLANEOUS	7,387,243.48	575.19	0.00	0.00
ACCOUNTS RECEIVABLE - ALLOWANCE FOR UNCOLLECTIBLE ACCOUNTS	0.00	(13,666,029.53)	0.00	0.00
FUEL INVENTORY	0.00	0.00	(0.00)	20,139,220.44
MATERIALS & SUPPLIES	0.00	0.00	0.00	5,418,466.76
RISK MANAGEMENT ASSETS	0.00	0.00	0.00	0.00
MARGIN DEPOSITS	0.00	0.00	0.00	0.00
PREPAYMENTS	2,702,506.73	0.00	0.00	0.00
OTHER	15,483,500.30	0.00	0.00	0.00
TOTAL CURRENT ASSETS	211,108,653.10	2,368,860.66	65,127,883.78	50,305,718.83
ELECTRIC UTILITY PLANT				
TOTAL ELECTRIC UTILITY PLANT	332,510,394.31	7,933.80	0.00	674,054,374.71
ACCUMULATED DEPRECIATION AND AMORTIZATION	(174,465,146.83)	(1,586.76)	0.00	(351,061,609.66)
ELECTRIC UTILITY PLANT - NET	158,045,247.48	6,347.04	0.00	322,992,765.06
OTHER PROPERTY AND INVESTMENTS				
NUCLEAR DECOMMISSIONING AND SPENT NUCLEAR FUEL DISPOSAL TRUST FUNDS	0.00	0.00	0.00	0.00
NON-UTILITY PROPERTY, NET	0.00	0.00	0.00	119,589.14
OTHER INVESTMENTS	0.00	0.00	0.00	0.00
TOTAL OTHER PROPERTY AND INVESTMENTS	0.00	0.00	0.00	119,589.14
INVESTMENTS IN POWER AND DISTRIBUTION PROJECTS	0.00	0.00	0.00	0.00
REGULATORY ASSETS	2,246,120.39	0.00	0.00	5,660,896.15
FAS 109 DEFERRED FIT RECLASS	(9,293,001.00)	0.00	0.00	0.00
NET REGULATORY ASSETS	(7,046,880.61)	0.00	0.00	5,660,896.15
SECURITIZED TRANSITION ASSETS	0.00	0.00	0.00	0.00
TOTAL GOODWILL	0.00	0.00	0.00	0.00
INTANGIBLE ASSETS	0.00	0.00	0.00	0.00
LONG-TERM RISK MANAGEMENT ASSETS	0.00	0.00	0.00	0.00
SPENT NUCLEAR FUEL AND DECOMMISSIONING TRUSTS	0.00	0.00	0.00	0.00
OTHER DEFERRED DEBITS	878,249.38	0.61	2,287,714.64	523,707.38
PREFERRED STOCK DIVIDEND REQUIREMENT OF SUBSIDIARIES	0.00	0.00	0.00	0.00
TOTAL OTHER DEFERRED DEBITS	878,249.38	0.61	2,287,714.64	523,707.38
OTHER ASSETS				
TOTAL OTHER INVESTMENTS	108,519,737.38	0.00	0.00	0.00
TOTAL OTHER SPECIAL FUNDS	0.00	0.00	0.00	0.00
CLEARING ACCOUNTS	0.00	0.00	0.00	0.00
UNAMORTIZED DEBT EXPENSE	26,067.89	0.00	0.00	442,379.08
TOTAL OTHER ASSETS	109,424,054.65	0.61	2,287,714.64	966,086.46
ASSETS HELD FOR SALE	0.00	0.00	0.00	0.00
TOTAL ASSETS	$471,531,074.63	$2,375,208.31	$67,415,598.42	$380,045,055.64

Item 10 - Consolidating Balance Sheets

AMERICAN ELECTRIC POWER COMPANY, INC.
AND SUBSIDIARY COMPANIES
CONSOLIDATING BALANCE SHEET
DECEMBER 31, 2003

Note - Totals and subtotals may be off due to rounding

DESCRIPTION	AMERICAN ELECTRIC POWER SERVICE CORPORATION	AEP TEXAS POLR, LLC	AEP MONEY POOL	AEP GENERATING COMPANY
LIABILITIES AND SHAREHOLDERS' EQUITY				
CURRENT LIABILITIES				
LONG-TERM DEBT DUE WITHIN ONE YEAR	$2,000,000.00	$0.00	$0.00	$0.00
SHORT-TERM DEBT	0.00	0.00	0.00	0.00
ADVANCES FROM AFFILIATES	117,116,333.17	10,068,256.61	18,752,273.28	36,891,737.11
ACCOUNTS PAYABLE - GENERAL	23,685,339.64	1,367.68	0.00	498,599.57
ACCOUNTS PAYABLE - AFFILIATED COMPANIES	75,296,900.44	41,042.18	48,663,325.10	15,910,829.12
CUSTOMER DEPOSITS	0.00	115,687.00	0.00	0.00
TAXES ACCRUED	(15,927,070.00)	(221,498.00)	0.00	6,069,751.94
INTEREST ACCRUED	4,123,566.66	0.00	0.00	911,250.00
RISK MANAGEMENT LIABILITIES	0.00	0.00	0.00	0.00
OBLIGATIONS UNDER CAPITAL LEASES	14,512,740.14	0.00	0.00	86,778.80
DIVIDENDS DECLARED	0.00	0.00	0.00	0.00
OTHER	129,984,638.87	218,653.52	0.00	4,963,305.52
TOTAL CURRENT LIABILITIES	350,792,448.92	10,223,508.99	67,415,598.38	65,332,252.06
LONG-TERM RISK MANAGEMENT LIABILITIES	0.00	0.00	0.00	0.00
DEFERRED INCOME TAXES	46,886,129.00	2,777.00	0.00	94,135,552.00
DEFERRED FIT & SIT RECLASS	(118,819,947.00)	(1,243,259.00)	0.00	(69,806,845.00)
NET DEFERRED INCOME TAXES	(71,933,818.00)	(1,240,482.00)	0.00	24,328,707.00
DEFERRED INVESTMENT TAX CREDITS	749,470.00	0.00	0.00	49,588,612.00
ASSET REMOVAL COSTS	0.00	0.00	0.00	0.00
LONG-TERM DEBT	40,000,000.00	0.00	0.00	44,810,865.94
OVER-RECOVERY OF FUEL COST	0.00	0.00	0.00	0.00
OTHER REGULATORY LIABILTIES	0.00	0.00	0.00	27,822,062.00
UNAMORTIZED GAIN ON REACQUIRED DEBT	0.00	0.00	0.00	0.00
SFAS 109 REGULATORY LIABILITY, NET	0.00	0.00	0.00	15,504,774.00
TOTAL REGULATORY LIABILITIES	0.00	0.00	0.00	43,326,836.00
TOTAL OTHER DEFERRED CREDITS	3,974,172.92	0.00	0.01	0.00
DEFERRED CREDITS AND REGULATORY LIABILITIES	3,974,172.92	0.00	0.01	43,326,836.00
CUSTOMER ADVANCES FOR CONSTRUCTION	0.00	0.00	0.00	0.00
DEFERRED GAIN ON SALE/LEASEBACK	0.00	0.00	0.00	105,475,421.99
UNREALIZED GAIN ON FORWARD COMMITMENTS	0.00	0.00	0.00	0.00
DEFERRED CREDITS AND OTHER	0.00	0.00	0.00	0.00
REGULATORY LIABILITIES AND DEFERRED INVESTMENT TAX CREDITS	0.00	0.00	0.00	0.00
OTHER NONCURRENT LIABILITIES				
OBLIGATIONS UNDER CAPITAL LEASES	22,373,464.60	0.00	0.00	182,195.41
ACCUMULATED PROVISIONS - RATE REFUND	0.00	0.00	0.00	0.00
ASSET RETIREMENT OBLIGATIONS AND NUCLEAR DECOMMSSIONING TRUSTS	0.00	0.00	0.00	1,125,272.65
ACCUMULATED PROVISIONS - MISCELLANEOUS	206,248,935.18	0.00	0.00	0.00
TOTAL OTHER NONCURRENT LIABILITIES	228,622,399.78	0.00	0.00	1,307,468.06
EMPLOYEE BENEFITS AND PENSION OBLIGATIONS	0.00	0.00	0.00	0.00
CUMULATIVE PREFERRED STOCKS OF SUBSIDIARIES SUBJECT TO MANDATORY REDEMPTION	0.00	0.00	0.00	0.00
CUMULATIVE PREFERRED STOCK OF SUBSIDIARIES NOT SUBJECT TO MANDATORY REDEMPTION	0.00	0.00	0.00	0.00
COMMON SHAREHOLDERS' EQUITY				
COMMON STOCK	1,350,000.00	0.00	0.00	1,000,000.00
PREMIUM ON CAPITAL STOCK	0.00	0.00	0.00	0.00
PAID-IN CAPITAL	(82,023,599.00)	0.00	0.00	23,434,000.00
RETAINED EARNINGS	0.01	(6,607,818.69)	0.03	21,440,892.59
ACCUMULATED OTHER COMPREHENSIVE INCOME (LOSS)	0.00	0.00	0.00	0.00
COMMON SHAREHOLDERS' EQUITY	(80,673,598.99)	(6,607,818.69)	0.03	45,874,892.59
MINORITY INTEREST	0.00	0.00	0.00	0.00
LIABILITIES HELD FOR SALE	0.00	0.00	0.00	0.00
TOTAL LIABILITIES AND SHAREHOLDERS' EQUITY	$471,531,074.63	$2,375,208.31	$67,415,598.42	$380,045,055.64

Item 10 - Consolidating Balance Sheets

AMERICAN ELECTRIC POWER COMPANY, INC.
AND SUBSIDIARY COMPANIES
CONSOLIDATING BALANCE SHEET
DECEMBER 31, 2003

Note - Totals and subtotals may be off due to rounding

DESCRIPTION	CENTRAL COAL COMPANY	AEP T&D SERVICES, LLC	INDIANA FRANKLIN REALTY, INC.	FRANKLIN REAL ESTATE COMPANY
ASSETS				
CURRENT AND ACCRUED ASSETS				
CASH AND CASH EQUIVALENTS	$0.00	$0.00	$0.00	$0.00
ADVANCES TO AFFILIATES	575,865.68	0.00	0.00	240,169.54
ACCOUNTS RECEIVABLE - CUSTOMERS	0.00	0.00	0.00	0.00
ACCOUNTS RECEIVABLE - AFFILIATED COMPANIES	132.00	10,358.44	33,447.01	(211,825.99)
ACCOUNTS RECEIVABLE - ACCRUED UNBILLED REVENUES	0.00	0.00	0.00	0.00
ACCOUNTS RECEIVABLE - MISCELLANEOUS	0.00	152,261.99	0.00	98,813.78
ACCOUNTS RECEIVABLE - ALLOWANCE FOR UNCOLLECTIBLE ACCOUNTS	0.00	0.00	0.00	0.00
FUEL INVENTORY	0.00	0.00	0.00	0.00
MATERIALS & SUPPLIES	0.00	0.01	0.00	0.00
RISK MANAGEMENT ASSETS	0.00	0.00	0.00	0.00
MARGIN DEPOSITS	0.00	0.00	0.00	0.00
PREPAYMENTS	0.00	3,448.66	0.00	0.00
OTHER	0.00	481.00	0.00	0.00
TOTAL CURRENT ASSETS	575,997.68	166,550.10	33,447.01	127,157.33
ELECTRIC UTILITY PLANT				
TOTAL ELECTRIC UTILITY PLANT	715,282.00	23,450.51	0.00	0.00
ACCUMULATED DEPRECIATION AND AMORTIZATION	(14,436.00)	(4,453.46)	0.00	0.00
ELECTRIC UTILITY PLANT - NET	700,846.00	18,997.05	0.00	0.00
OTHER PROPERTY AND INVESTMENTS				
NUCLEAR DECOMMISSIONING AND SPENT NUCLEAR FUEL DISPOSAL TRUST FUNDS	0.00	0.00	0.00	0.00
NON-UTILITY PROPERTY, NET	0.00	0.00	0.00	0.00
OTHER INVESTMENTS	0.00	0.00	0.00	0.00
TOTAL OTHER PROPERTY AND INVESTMENTS	0.00	0.00	0.00	0.00
INVESTMENTS IN POWER AND DISTRIBUTION PROJECTS	0.00	0.00	0.00	1,000.00
REGULATORY ASSETS	0.00	0.00	0.00	0.00
FAS 109 DEFERRED FIT RECLASS	0.00	0.00	0.00	0.00
NET REGULATORY ASSETS	0.00	0.00	0.00	0.00
SECURITIZED TRANSITION ASSETS	0.00	0.00	0.00	0.00
TOTAL GOODWILL	0.00	0.00	0.00	0.00
INTANGIBLE ASSETS	0.00	0.00	0.00	0.00
LONG-TERM RISK MANAGEMENT ASSETS	0.00	0.00	0.00	0.00
SPENT NUCLEAR FUEL AND DECOMMISSIONING TRUSTS	0.00	0.00	0.00	0.00
OTHER DEFERRED DEBITS	0.00	8.92	0.00	0.00
PREFERRED STOCK DIVIDEND REQUIREMENT OF SUBSIDIARIES	0.00	0.00	0.00	0.00
TOTAL OTHER DEFERRED DEBITS	0.00	8.92	0.00	0.00
OTHER ASSETS				
TOTAL OTHER INVESTMENTS	0.00	0.00	11.00	11.00
TOTAL OTHER SPECIAL FUNDS	0.00	0.00	0.00	0.00
CLEARING ACCOUNTS	0.00	0.00	0.00	0.00
UNAMORTIZED DEBT EXPENSE	0.00	0.00	0.00	0.00
TOTAL OTHER ASSETS	0.00	8.92	11.00	11.00
ASSETS HELD FOR SALE	0.00	0.00	0.00	0.00
TOTAL ASSETS	$1,276,843.68	$185,556.07	$33,458.01	$128,168.33

Item 10 - Consolidating Balance Sheets

AMERICAN ELECTRIC POWER COMPANY, INC.
AND SUBSIDIARY COMPANIES
CONSOLIDATING BALANCE SHEET
DECEMBER 31, 2003

Note - Totals and subtotals may be off due to rounding

DESCRIPTION	CENTRAL COAL COMPANY	AEP T&D SERVICES, LLC	INDIANA FRANKLIN REALTY, INC.	FRANKLIN REAL ESTATE COMPANY
LIABILITIES AND SHAREHOLDERS' EQUITY				
CURRENT LIABILITIES				
LONG-TERM DEBT DUE WITHIN ONE YEAR	$0.00	$0.00	$0.00	$0.00
SHORT-TERM DEBT	0.00	0.00	0.00	0.00
ADVANCES FROM AFFILIATES	0.00	223,852.95	17,221.37	0.00
ACCOUNTS PAYABLE - GENERAL	0.00	57.44	0.00	249.00
ACCOUNTS PAYABLE - AFFILIATED COMPANIES	137,428.15	52,036.29	119.09	102.79
CUSTOMER DEPOSITS	0.00	0.00	0.00	0.00
TAXES ACCRUED	6,490.00	(13,813.00)	0.00	195.00
INTEREST ACCRUED	0.00	0.00	0.00	0.00
RISK MANAGEMENT LIABILITIES	0.00	0.00	0.00	0.00
OBLIGATIONS UNDER CAPITAL LEASES	0.00	0.00	0.00	0.00
DIVIDENDS DECLARED	0.00	0.00	0.00	0.00
OTHER	82,907.78	13,810.90	15,103.56	48,856.18
TOTAL CURRENT LIABILITIES	226,825.93	275,944.58	32,444.02	49,402.97
LONG-TERM RISK MANAGEMENT LIABILITIES	0.00	0.00	0.00	0.00
DEFERRED INCOME TAXES	34,643.00	6,648.00	0.00	0.00
DEFERRED FIT & SIT RECLASS	(717,517.00)	(484.00)	0.00	0.00
NET DEFERRED INCOME TAXES	(682,874.00)	6,164.00	0.00	0.00
DEFERRED INVESTMENT TAX CREDITS	0.00	0.00	0.00	0.00
ASSET REMOVAL COSTS	0.00	0.00	0.00	0.00
LONG-TERM DEBT	0.00	0.00	0.00	0.00
OVER-RECOVERY OF FUEL COST	0.00	0.00	0.00	0.00
OTHER REGULATORY LIABILTIES	0.00	0.00	0.00	0.00
UNAMORTIZED GAIN ON REACQUIRED DEBT	0.00	0.00	0.00	0.00
SFAS 109 REGULATORY LIABILITY, NET	0.00	0.00	0.00	0.00
TOTAL REGULATORY LIABILITIES	0.00	0.00	0.00	0.00
TOTAL OTHER DEFERRED CREDITS	0.00	0.00	14.00	48,796.50
DEFERRED CREDITS AND REGULATORY LIABILITIES	0.00	0.00	14.00	48,796.50
CUSTOMER ADVANCES FOR CONSTRUCTION	0.00	0.00	0.00	0.00
DEFERRED GAIN ON SALE/LEASEBACK	0.00	0.00	0.00	0.00
UNREALIZED GAIN ON FORWARD COMMITMENTS	0.00	0.00	0.00	0.00
DEFERRED CREDITS AND OTHER	0.00	0.00	0.00	0.00
REGULATORY LIABILITIES AND DEFERRED INVESTMENT TAX CREDITS	0.00	0.00	0.00	0.00
OTHER NONCURRENT LIABILITIES				
OBLIGATIONS UNDER CAPITAL LEASES	0.00	0.00	0.00	0.00
ACCUMULATED PROVISIONS - RATE REFUND	0.00	0.00	0.00	0.00
ASSET RETIREMENT OBLIGATIONS AND NUCLEAR DECOMMSSIONING TRUSTS	0.00	0.00	0.00	0.00
ACCUMULATED PROVISIONS - MISCELLANEOUS	527,720.72	2,769.27	0.00	0.00
TOTAL OTHER NONCURRENT LIABILITIES	527,720.72	2,769.27	0.00	0.00
EMPLOYEE BENEFITS AND PENSION OBLIGATIONS	0.00	0.00	0.00	0.00
CUMULATIVE PREFERRED STOCKS OF SUBSIDIARIES SUBJECT TO MANDATORY REDEMPTION	0.00	0.00	0.00	0.00
CUMULATIVE PREFERRED STOCK OF SUBSIDIARIES NOT SUBJECT TO MANDATORY REDEMPTION	0.00	0.00	0.00	0.00
COMMON SHAREHOLDERS' EQUITY				
COMMON STOCK	3,000.00	0.00	1,000.00	10,000.00
PREMIUM ON CAPITAL STOCK	0.00	0.00	0.00	0.00
PAID-IN CAPITAL	1,202,171.00	(1,032.00)	0.00	0.00
RETAINED EARNINGS	0.03	(98,289.78)	(0.01)	19,968.86
ACCUMULATED OTHER COMPREHENSIVE INCOME (LOSS)	0.00	0.00	0.00	0.00
COMMON SHAREHOLDERS' EQUITY	1,205,171.03	(99,321.78)	999.99	29,968.86
MINORITY INTEREST	0.00	0.00	0.00	0.00
LIABILITIES HELD FOR SALE	0.00	0.00	0.00	0.00
TOTAL LIABILITIES AND SHAREHOLDERS' EQUITY	$1,276,843.68	$185,556.07	$33,458.01	$128,168.33

Item 10 - Consolidating Balance Sheets

AMERICAN ELECTRIC POWER COMPANY, INC.
AND SUBSIDIARY COMPANIES
CONSOLIDATING BALANCE SHEET
DECEMBER 31, 2003

Note - Totals and subtotals may be off due to rounding

DESCRIPTION	APPALACHIAN POWER COMPANY CONSOLIDATED	COLUMBUS SOUTHERN POWER COMPANY CONSOLIDATED	INDIANA MICHIGAN POWER COMPANY CONSOLIDATED	KENTUCKY POWER COMPANY
ASSETS				
CURRENT AND ACCRUED ASSETS				
CASH AND CASH EQUIVALENTS	$45,880,666.27	$4,142,432.16	$3,913,780.56	$886,067.16
ADVANCES TO AFFILIATES	0.00	0.00	0.00	0.00
ACCOUNTS RECEIVABLE - CUSTOMERS	133,716,961.09	47,098,947.82	61,083,821.63	21,177,464.00
ACCOUNTS RECEIVABLE - AFFILIATED COMPANIES	137,281,246.61	68,168,358.88	124,826,019.97	25,327,057.84
ACCOUNTS RECEIVABLE - ACCRUED UNBILLED REVENUES	35,020,281.49	23,722,456.95	2,000,068.39	5,533,840.37
ACCOUNTS RECEIVABLE - MISCELLANEOUS	3,961,188.95	5,256,826.22	4,498,304.57	97,063.93
ACCOUNTS RECEIVABLE - ALLOWANCE FOR UNCOLLECTIBLE ACCOUNTS	(2,085,327.62)	(531,483.10)	(531,487.62)	(736,031.99)
FUEL INVENTORY	42,806,440.47	14,364,800.66	33,967,999.70	9,481,117.33
MATERIALS & SUPPLIES	71,977,745.12	44,376,806.74	105,328,541.58	16,584,927.95
RISK MANAGEMENT ASSETS	71,189,275.85	40,095,004.24	44,071,259.67	16,199,996.44
MARGIN DEPOSITS	11,524,954.90	6,636,268.45	7,245,494.99	2,659,669.31
PREPAYMENTS	6,782,863.88	8,341,261.47	5,731,502.81	669,689.75
OTHER	6,517,480.00	4,102,393.00	4,941,140.00	1,026,407.00
TOTAL CURRENT ASSETS	564,573,777.02	265,774,073.48	397,076,446.26	98,907,269.08
ELECTRIC UTILITY PLANT				
TOTAL ELECTRIC UTILITY PLANT	6,140,930,644.39	3,570,443,772.21	5,306,182,181.52	1,349,746,447.93
ACCUMULATED DEPRECIATION AND AMORTIZATION	(2,321,359,209.92)	(1,389,586,507.63)	(2,490,912,459.57)	(381,876,499.59)
ELECTRIC UTILITY PLANT - NET	3,819,571,434.47	2,180,857,264.58	2,815,269,721.95	967,869,948.33
OTHER PROPERTY AND INVESTMENTS				
NUCLEAR DECOMMISSIONING AND SPENT NUCLEAR FUEL DISPOSAL TRUST FUNDS	0.00	0.00	982,394,078.70	0.00
NON-UTILITY PROPERTY, NET	20,574,430.78	22,417,574.08	52,302,710.78	5,423,079.77
OTHER INVESTMENTS	26,064,029.59	8,232,793.95	43,796,994.81	1,021,507.17
TOTAL OTHER PROPERTY AND INVESTMENTS	46,638,460.37	30,650,368.03	1,078,493,784.29	6,444,586.94
INVESTMENTS IN POWER AND DISTRIBUTION PROJECTS	603,868.00	430,000.00	0.00	0.00
REGULATORY ASSETS	446,327,739.76	255,480,401.79	349,254,126.72	121,642,709.67
FAS 109 DEFERRED FIT RECLASS	(29,131,302.00)	(12,296,669.00)	(72,977,329.00)	(7,843,401.00)
NET REGULATORY ASSETS	417,196,437.76	243,183,732.79	276,276,797.72	113,799,308.67
SECURITIZED TRANSITION ASSETS	0.00	0.00	0.00	0.00
TOTAL GOODWILL	0.00	0.00	0.00	0.00
INTANGIBLE ASSETS	0.00	0.00	0.00	0.00
LONG-TERM RISK MANAGEMENT ASSETS	70,899,438.64	39,932,076.92	43,768,348.63	16,134,242.13
SPENT NUCLEAR FUEL AND DECOMMISSIONING TRUSTS	0.00	0.00	0.00	0.00
OTHER DEFERRED DEBITS	49,647,884.72	71,551,108.63	36,204,045.08	13,948,213.25
PREFERRED STOCK DIVIDEND REQUIREMENT OF SUBSIDIARIES	0.00	0.00	0.00	0.00
TOTAL OTHER DEFERRED DEBITS	49,647,884.72	71,551,108.63	36,204,045.08	13,948,213.25
OTHER ASSETS				
TOTAL OTHER INVESTMENTS	0.00	0.00	0.00	0.00
TOTAL OTHER SPECIAL FUNDS	0.00	0.00	0.00	0.00
CLEARING ACCOUNTS	158,833.16	57.87	0.00	0.00
UNAMORTIZED DEBT EXPENSE	7,721,257.00	5,986,961.53	11,981,425.14	4,530,228.54
TOTAL OTHER ASSETS	57,527,974.89	77,538,128.03	48,185,470.22	18,478,441.79
ASSETS HELD FOR SALE	0.00	0.00	0.00	0.00
TOTAL ASSETS	$4,977,011,391.15	$2,838,365,643.83	$4,659,070,569.07	$1,221,633,796.94

Item 10 - Consolidating Balance Sheets

AMERICAN ELECTRIC POWER COMPANY, INC.
AND SUBSIDIARY COMPANIES
CONSOLIDATING BALANCE SHEET
DECEMBER 31, 2003

Note - Totals and subtotals may be off due to rounding

DESCRIPTION	APPALACHIAN POWER COMPANY CONSOLIDATED	COLUMBUS SOUTHERN POWER COMPANY CONSOLIDATED	INDIANA MICHIGAN POWER COMPANY CONSOLIDATED	KENTUCKY POWER COMPANY
LIABILITIES AND SHAREHOLDERS' EQUITY				
CURRENT LIABILITIES				
LONG-TERM DEBT DUE WITHIN ONE YEAR	$161,008,387.76	$11,000,000.00	$205,000,000.00	$0.00
SHORT-TERM DEBT	0.00	0.00	0.00	0.00
ADVANCES FROM AFFILIATES	82,994,492.48	6,516,507.98	98,821,518.88	38,095,519.39
ACCOUNTS PAYABLE - GENERAL	140,497,345.72	58,219,859.77	101,776,021.61	22,802,341.50
ACCOUNTS PAYABLE - AFFILIATED COMPANIES	81,812,226.37	53,571,895.14	47,483,810.79	22,647,841.61
CUSTOMER DEPOSITS	33,929,606.82	19,727,363.58	21,954,513.91	9,894,337.18
TAXES ACCRUED	50,258,565.75	132,853,280.48	42,189,106.92	7,329,064.07
INTEREST ACCRUED	22,112,796.08	16,528,117.07	17,962,933.11	6,915,363.28
RISK MANAGEMENT LIABILITIES	51,429,954.00	28,966,379.38	31,898,490.87	11,703,584.83
OBLIGATIONS UNDER CAPITAL LEASES	9,217,759.36	4,220,839.94	6,527,938.79	1,742,670.84
DIVIDENDS DECLARED	186,190.92	(0.00)	1,089,389.03	0.00
OTHER	60,102,649.59	25,364,137.62	56,586,413.96	8,628,745.47
TOTAL CURRENT LIABILITIES	693,549,974.85	356,968,380.96	631,290,137.87	129,759,468.17
LONG-TERM RISK MANAGEMENT LIABILITIES	54,326,567.66	30,597,885.62	33,537,420.82	12,362,838.56
DEFERRED INCOME TAXES	1,008,854,037.88	546,259,293.00	940,358,147.00	247,385,404.06
DEFERRED FIT & SIT RECLASS	(205,498,809.48)	(87,760,993.00)	(602,982,549.00)	(35,264,271.00)
NET DEFERRED INCOME TAXES	803,355,228.40	458,498,300.00	337,375,598.00	212,121,133.06
DEFERRED INVESTMENT TAX CREDITS	30,544,863.00	30,796,639.00	90,278,100.00	7,954,776.00
ASSET REMOVAL COSTS	92,497,334.00	99,118,885.00	263,014,780.00	26,140,023.00
LONG-TERM DEBT	1,703,072,765.43	886,564,409.59	1,134,358,851.38	487,601,625.00
OVER-RECOVERY OF FUEL COST	68,704,458.11	0.00	0.00	1,418,030.00
OTHER REGULATORY LIABILTIES	0.00	0.00	276,948,842.49	9,173,641.46
UNAMORTIZED GAIN ON REACQUIRED DEBT	43,054.00	0.00	34,223.72	0.00
SFAS 109 REGULATORY LIABILITY, NET	0.00	0.00	0.00	0.00
TOTAL REGULATORY LIABILITIES	68,747,512.11	0.00	276,983,066.21	10,591,671.46
TOTAL OTHER DEFERRED CREDITS	13,041,424.25	15,864,536.26	27,878,885.11	365,734.36
DEFERRED CREDITS AND REGULATORY LIABILITIES	81,788,936.36	15,864,536.26	304,861,951.32	10,957,405.82
CUSTOMER ADVANCES FOR CONSTRUCTION	0.00	250,000.00	4,263,378.85	49,851.78
DEFERRED GAIN ON SALE/LEASEBACK	88,288.00	0.00	70,178,525.01	0.00
UNREALIZED GAIN ON FORWARD COMMITMENTS	17,282,832.10	0.00	0.00	0.00
DEFERRED CREDITS AND OTHER	0.00	0.00	0.00	0.00
REGULATORY LIABILITIES AND DEFERRED INVESTMENT TAX CREDITS	0.00	0.00	0.00	0.00
OTHER NONCURRENT LIABILITIES				
OBLIGATIONS UNDER CAPITAL LEASES	16,134,017.39	11,396,660.35	31,315,130.69	3,548,992.91
ACCUMULATED PROVISIONS - RATE REFUND	0.00	0.00	0.00	0.00
ASSET RETIREMENT OBLIGATIONS AND NUCLEAR DECOMMSSIONING TRUSTS	21,776,104.85	8,739,918.67	553,219,318.01	0.00
ACCUMULATED PROVISIONS - MISCELLANEOUS	102,462,814.22	41,689,669.16	55,783,588.26	13,999,494.26
TOTAL OTHER NONCURRENT LIABILITIES	140,372,936.45	61,826,248.18	640,318,036.96	17,548,487.17
EMPLOYEE BENEFITS AND PENSION OBLIGATIONS	0.00	0.00	0.00	0.00
CUMULATIVE PREFERRED STOCKS OF SUBSIDIARIES SUBJECT TO MANDATORY REDEMPTION	5,360,000.00	0.00	63,445,000.00	0.00
CUMULATIVE PREFERRED STOCK OF SUBSIDIARIES NOT SUBJECT TO MANDATORY REDEMPTION	17,783,900.00	0.00	8,101,100.00	0.00
COMMON SHAREHOLDERS' EQUITY				
COMMON STOCK	260,457,768.00	41,026,065.00	56,583,866.43	50,450,000.00
PREMIUM ON CAPITAL STOCK	0.00	0.00	0.00	0.00
PAID-IN CAPITAL	719,899,208.64	576,399,735.58	858,694,392.60	208,750,000.00
RETAINED EARNINGS	408,718,478.89	326,781,977.65	187,875,312.84	64,150,582.93
ACCUMULATED OTHER COMPREHENSIVE INCOME (LOSS)	(52,087,690.64)	(46,327,419.00)	(25,105,883.00)	(6,212,394.55)
COMMON SHAREHOLDERS' EQUITY	1,336,987,764.89	897,880,359.23	1,078,047,688.86	317,138,188.38
MINORITY INTEREST	0.00	0.00	0.00	0.00
LIABILITIES HELD FOR SALE	0.00	0.00	0.00	0.00
TOTAL LIABILITIES AND SHAREHOLDERS' EQUITY	$4,977,011,391.15	$2,838,365,643.83	$4,659,070,569.07	$1,221,633,796.94

Item 10 - Consolidating Balance Sheets

AMERICAN ELECTRIC POWER COMPANY, INC.
AND SUBSIDIARY COMPANIES
CONSOLIDATING BALANCE SHEET
DECEMBER 31, 2003

Note - Totals and subtotals may be off due to rounding

DESCRIPTION	KINGSPORT POWER COMPANY	OHIO POWER COMPANY CONSOLIDATED	WHEELING POWER COMPANY	AEP INVESTMENTS, INC.
ASSETS				
CURRENT AND ACCRUED ASSETS				
CASH AND CASH EQUIVALENTS	$127,580.55	$58,250,285.59	$205,027.27	$80,225.49
ADVANCES TO AFFILIATES	0.00	67,918,020.70	1,226,515.89	0.00
ACCOUNTS RECEIVABLE - CUSTOMERS	2,073,503.63	100,959,701.41	5,837,715.17	0.00
ACCOUNTS RECEIVABLE - AFFILIATED COMPANIES	316,158.42	120,531,929.50	306,602.12	0.00
ACCOUNTS RECEIVABLE - ACCRUED UNBILLED REVENUES	690,520.70	0.00	2,318,153.48	0.00
ACCOUNTS RECEIVABLE - MISCELLANEOUS	10,369.54	736,175.32	6,411.81	568,207.00
ACCOUNTS RECEIVABLE - ALLOWANCE FOR UNCOLLECTIBLE ACCOUNTS	(5,793.79)	(789,244.62)	(112,784.90)	(550,000.00)
FUEL INVENTORY	0.00	77,725,300.56	0.00	0.00
MATERIALS & SUPPLIES	145,822.97	92,135,723.09	99,457.88	0.00
RISK MANAGEMENT ASSETS	0.00	56,265,271.44	0.00	0.00
MARGIN DEPOSITS	0.00	9,296,461.69	0.00	0.00
PREPAYMENTS	1,016,986.80	10,033,003.21	183,602.12	8,359.00
OTHER	162,779.00	23,070,436.00	206,876.00	0.00
TOTAL CURRENT ASSETS	4,537,927.82	616,133,063.88	10,277,576.84	106,791.49
ELECTRIC UTILITY PLANT				
TOTAL ELECTRIC UTILITY PLANT	103,956,347.62	6,531,314,842.29	111,841,131.94	393,065.36
ACCUMULATED DEPRECIATION AND AMORTIZATION	(39,808,999.60)	(2,485,946,974.37)	(48,126,022.15)	(87,697.33)
ELECTRIC UTILITY PLANT - NET	64,147,348.02	4,045,367,867.92	63,715,109.79	305,368.03
OTHER PROPERTY AND INVESTMENTS				
NUCLEAR DECOMMISSIONING AND SPENT NUCLEAR FUEL DISPOSAL TRUST FUNDS	0.00	0.00	0.00	0.00
NON-UTILITY PROPERTY, NET	104,715.06	29,290,897.77	16,811.00	0.00
OTHER INVESTMENTS	190,587.50	23,617,149.88	28,402.64	0.00
TOTAL OTHER PROPERTY AND INVESTMENTS	295,302.56	52,908,047.65	45,213.64	0.00
INVESTMENTS IN POWER AND DISTRIBUTION PROJECTS	0.00	646,814.00	0.00	36,332,221.90
REGULATORY ASSETS	6,047,997.42	528,709,342.44	10,603,434.53	0.00
FAS 109 DEFERRED FIT RECLASS	(413,527.00)	(16,391,744.00)	(268,418.00)	0.00
NET REGULATORY ASSETS	5,634,470.42	512,317,598.44	10,335,016.53	0.00
SECURITIZED TRANSITION ASSETS	0.00	0.00	0.00	0.00
TOTAL GOODWILL	0.00	0.00	0.00	0.00
INTANGIBLE ASSETS	0.00	0.00	0.00	0.00
LONG-TERM RISK MANAGEMENT ASSETS	0.00	52,824,714.92	0.00	0.00
SPENT NUCLEAR FUEL AND DECOMMISSIONING TRUSTS	0.00	0.00	0.00	0.00
OTHER DEFERRED DEBITS	375,104.61	83,829,359.11	1,912,996.68	21,358,217.03
PREFERRED STOCK DIVIDEND REQUIREMENT OF SUBSIDIARIES	0.00	0.00	0.00	0.00
TOTAL OTHER DEFERRED DEBITS	375,104.61	83,829,359.11	1,912,996.68	21,358,217.03
OTHER ASSETS				
TOTAL OTHER INVESTMENTS	0.00	0.00	0.00	10,942,380.58
TOTAL OTHER SPECIAL FUNDS	0.00	0.00	0.00	0.00
CLEARING ACCOUNTS	0.00	0.01	0.00	0.00
UNAMORTIZED DEBT EXPENSE	2,777.70	10,489,950.22	2,777.77	0.00
TOTAL OTHER ASSETS	377,882.31	94,319,309.33	1,915,774.45	32,300,597.61
ASSETS HELD FOR SALE	0.00	0.00	0.00	0.00
TOTAL ASSETS	$74,992,931.12	$5,374,517,416.14	$86,288,691.25	$69,044,979.04

Item 10 - Consolidating Balance Sheets

AMERICAN ELECTRIC POWER COMPANY, INC.
AND SUBSIDIARY COMPANIES
CONSOLIDATING BALANCE SHEET
DECEMBER 31, 2003

Note - Totals and subtotals may be off due to rounding

DESCRIPTION	KINGSPORT POWER COMPANY	OHIO POWER COMPANY CONSOLIDATED	WHEELING POWER COMPANY	AEP INVESTMENTS, INC.
LIABILITIES AND SHAREHOLDERS' EQUITY				
CURRENT LIABILITIES				
LONG-TERM DEBT DUE WITHIN ONE YEAR	$20,000,000.00	$431,853,659.00	$20,000,000.00	$0.00
SHORT-TERM DEBT	0.00	25,940,955.49	0.00	0.00
ADVANCES FROM AFFILIATES	3,407,788.16	0.00	0.00	10,356,561.62
ACCOUNTS PAYABLE - GENERAL	284,539.47	104,873,746.12	232,478.93	14,850.00
ACCOUNTS PAYABLE - AFFILIATED COMPANIES	6,157,408.25	101,758,140.78	5,051,225.36	58,265,441.71
CUSTOMER DEPOSITS	1,706,672.45	17,308,672.65	827,331.72	0.00
TAXES ACCRUED	1,526,283.12	132,792,835.06	3,555,435.33	(70,497.00)
INTEREST ACCRUED	899,178.07	45,678,727.12	577,566.19	0.00
RISK MANAGEMENT LIABILITIES	0.00	38,318,638.79	0.00	0.00
OBLIGATIONS UNDER CAPITAL LEASES	321,360.42	9,623,896.48	291,766.63	0.00
DIVIDENDS DECLARED	0.00	102,240.39	0.00	0.00
OTHER	1,239,758.44	71,539,599.75	1,427,025.71	56,606.29
TOTAL CURRENT LIABILITIES	35,542,988.38	979,791,111.64	31,962,829.87	68,622,962.62
LONG-TERM RISK MANAGEMENT LIABILITIES	0.00	40,476,845.18	0.00	0.00
DEFERRED INCOME TAXES	14,183,936.00	1,090,202,075.16	19,468,992.00	(504,610.00)
DEFERRED FIT & SIT RECLASS	(3,235,753.00)	(156,619,782.24)	(5,146,430.00)	(4,677,056.05)
NET DEFERRED INCOME TAXES	10,948,183.00	933,582,292.92	14,322,562.00	(5,181,666.05)
DEFERRED INVESTMENT TAX CREDITS	578,524.00	15,640,519.00	340,443.00	0.00
ASSET REMOVAL COSTS	325,484.00	101,159,548.00	141,284.00	0.00
LONG-TERM DEBT	0.00	1,608,085,249.04	0.00	0.00
OVER-RECOVERY OF FUEL COST	0.00	0.00	0.00	0.00
OTHER REGULATORY LIABILTIES	0.00	3,288.73	0.00	0.00
UNAMORTIZED GAIN ON REACQUIRED DEBT	0.00	0.00	0.00	0.00
SFAS 109 REGULATORY LIABILITY, NET	0.00	0.00	0.00	0.00
TOTAL REGULATORY LIABILITIES	0.00	3,288.73	0.00	0.00
TOTAL OTHER DEFERRED CREDITS	113,809.19	23,222,475.75	111,662.01	0.00
DEFERRED CREDITS AND REGULATORY LIABILITIES	113,809.19	23,225,764.48	111,662.01	0.00
CUSTOMER ADVANCES FOR CONSTRUCTION	0.00	0.00	0.00	0.00
DEFERRED GAIN ON SALE/LEASEBACK	65,296.00	0.00	0.00	0.00
UNREALIZED GAIN ON FORWARD COMMITMENTS	0.00	0.00	0.00	0.00
DEFERRED CREDITS AND OTHER	0.00	0.00	0.00	0.00
REGULATORY LIABILITIES AND DEFERRED INVESTMENT TAX CREDITS	0.00	0.00	0.00	0.00
OTHER NONCURRENT LIABILITIES				
OBLIGATIONS UNDER CAPITAL LEASES	332,106.09	25,063,582.41	518,198.03	0.00
ACCUMULATED PROVISIONS - RATE REFUND	0.00	0.00	0.00	0.00
ASSET RETIREMENT OBLIGATIONS AND NUCLEAR DECOMMSSIONING TRUSTS	0.00	42,656,340.00	0.00	0.00
ACCUMULATED PROVISIONS - MISCELLANEOUS	1,711,675.27	100,601,508.71	5,140,547.92	0.00
TOTAL OTHER NONCURRENT LIABILITIES	2,043,781.36	168,321,431.12	5,658,745.95	0.00
EMPLOYEE BENEFITS AND PENSION OBLIGATIONS	0.00	0.00	0.00	0.00
CUMULATIVE PREFERRED STOCKS OF SUBSIDIARIES SUBJECT TO MANDATORY REDEMPTION	0.00	7,250,000.00	0.00	0.00
CUMULATIVE PREFERRED STOCK OF SUBSIDIARIES NOT SUBJECT TO MANDATORY REDEMPTION	0.00	16,645,400.00	0.00	0.00
COMMON SHAREHOLDERS' EQUITY				
COMMON STOCK	4,100,000.00	321,201,454.00	2,428,460.00	100.00
PREMIUM ON CAPITAL STOCK	0.00	0.00	0.00	9,900.00
PAID-IN CAPITAL	13,800,000.00	462,483,651.86	15,595,573.00	40,066,111.09
RETAINED EARNINGS	9,108,473.19	729,146,667.84	18,177,675.41	(34,472,428.62)
ACCUMULATED OTHER COMPREHENSIVE INCOME (LOSS)	(1,633,608.00)	(48,806,581.56)	(2,450,544.00)	0.00
COMMON SHAREHOLDERS' EQUITY	25,374,865.20	1,464,025,192.14	33,751,164.41	5,603,682.47
MINORITY INTEREST	0.00	16,314,062.62	0.00	0.00
LIABILITIES HELD FOR SALE	0.00	0.00	0.00	0.00
TOTAL LIABILITIES AND SHAREHOLDERS' EQUITY	$74,992,931.13	$5,374,517,416.14	$86,288,691.25	$69,044,979.04

Item 10 - Consolidating Balance Sheets

AMERICAN ELECTRIC POWER COMPANY, INC.
AND SUBSIDIARY COMPANIES
CONSOLIDATING BALANCE SHEET
DECEMBER 31, 2003

Note - Totals and subtotals may be off due to rounding

DESCRIPTION	AEP RESOURCES, INC.	AEP COMMUNICATIONS, INC.	AEP UTILITIES INCORPORATED CONSOLIDATED	AEP C&I COMPANY, LLC
ASSETS				
CURRENT AND ACCRUED ASSETS				
CASH AND CASH EQUIVALENTS	$57,049,002.63	$0.00	$129,782,942.65	$32,265.98
ADVANCES TO AFFILIATES	229,081,580.48	1,147,801.63	233,070,918.52	46,361,054.34
ACCOUNTS RECEIVABLE - CUSTOMERS	17,762,271.02	0.00	(91,822,041.42)	34,441,612.54
ACCOUNTS RECEIVABLE - AFFILIATED COMPANIES	93,113,583.95	446,137.97	494,670,329.62	20,116,870.07
ACCOUNTS RECEIVABLE - ACCRUED UNBILLED REVENUES	336,299,012.58	0.00	62,190,798.22	12,339,100.90
ACCOUNTS RECEIVABLE - MISCELLANEOUS	606,683,303.18	11,412,624.70	121,732,542.38	1,191,775.54
ACCOUNTS RECEIVABLE - ALLOWANCE FOR UNCOLLECTIBLE ACCOUNTS	(47,817,622.41)	(9,604,168.51)	(23,153,255.85)	(22,670,403.08)
FUEL INVENTORY	506,077,697.58	0.00	93,137,113.44	0.00
MATERIALS & SUPPLIES	5,864,314.63	2,320,463.05	129,635,120.96	0.00
RISK MANAGEMENT ASSETS	1,004,488,321.21	0.00	70,691,758.14	0.00
MARGIN DEPOSITS	0.00	0.00	0.00	0.00
PREPAYMENTS	31,574,775.54	0.01	31,638,120.69	0.00
OTHER	295,408,597.90	346.00	14,017,092.99	717,654.24
TOTAL CURRENT ASSETS	3,135,584,838.28	5,723,204.85	1,265,591,440.34	92,529,930.53
ELECTRIC UTILITY PLANT				
TOTAL ELECTRIC UTILITY PLANT	1,306,419,865.56	14,737,368.20	12,692,836,758.28	542,760.09
ACCUMULATED DEPRECIATION AND AMORTIZATION	(170,043,280.03)	(143,675.30)	(5,322,076,807.01)	(5,809.43)
ELECTRIC UTILITY PLANT - NET	1,136,376,585.53	14,593,692.90	7,370,759,951.27	536,950.66
OTHER PROPERTY AND INVESTMENTS				
NUCLEAR DECOMMISSIONING AND SPENT NUCLEAR FUEL DISPOSAL TRUST FUNDS	0.00	0.00	0.00	0.00
NON-UTILITY PROPERTY, NET	0.00	0.00	0.00	0.00
OTHER INVESTMENTS	0.00	0.00	0.00	0.00
TOTAL OTHER PROPERTY AND INVESTMENTS	0.00	0.00	0.00	0.00
INVESTMENTS IN POWER AND DISTRIBUTION PROJECTS	71,984,503.85	52,891,934.48	31,142,620.49	0.00
REGULATORY ASSETS	0.00	0.00	2,154,058,880.21	0.00
FAS 109 DEFERRED FIT RECLASS	0.00	0.00	(125,238,102.00)	0.00
NET REGULATORY ASSETS	0.00	0.00	2,028,820,778.21	0.00
SECURITIZED TRANSITION ASSETS	0.00	0.00	0.00	0.00
TOTAL GOODWILL	53,708,031.39	0.00	2,662,500.00	0.00
INTANGIBLE ASSETS	3,556,975.07	0.00	21,736,066.16	0.00
LONG-TERM RISK MANAGEMENT ASSETS	510,274,747.58	0.00	33,425,251.75	0.00
SPENT NUCLEAR FUEL AND DECOMMISSIONING TRUSTS	0.00	0.00	0.00	0.00
OTHER DEFERRED DEBITS	11,905,899.21	170,525.17	53,249,605.08	(4,000.02)
PREFERRED STOCK DIVIDEND REQUIREMENT OF SUBSIDIARIES	0.00	0.00	(786,804.57)	0.00
TOTAL OTHER DEFERRED DEBITS	11,905,899.21	170,525.17	52,462,800.51	(4,000.02)
OTHER ASSETS				
TOTAL OTHER INVESTMENTS	2,707,703.55	(56,538,926.00)	797,396,734.88	0.00
TOTAL OTHER SPECIAL FUNDS	0.00	0.00	125,383,429.15	0.00
CLEARING ACCOUNTS	27,153.38	0.00	11,687,875.88	0.00
UNAMORTIZED DEBT EXPENSE	8,079,606.60	666,882.04	67,193,718.97	0.00
TOTAL OTHER ASSETS	22,720,362.75	(55,701,518.79)	1,054,124,559.39	(4,000.02)
ASSETS HELD FOR SALE	0.00	0.00	0.00	0.00
TOTAL ASSETS	$4,934,206,044.45	$17,507,313.44	$11,808,263,167.62	$93,062,881.17

Item 10 - Consolidating Balance Sheets

AMERICAN ELECTRIC POWER COMPANY, INC.
AND SUBSIDIARY COMPANIES
CONSOLIDATING BALANCE SHEET
DECEMBER 31, 2003

Note - Totals and subtotals may be off due to rounding

DESCRIPTION	AEP RESOURCES, INC.	AEP COMMUNICATIONS, INC.	AEP UTILITIES INCORPORATED CONSOLIDATED	AEP C&I COMPANY, LLC
LIABILITIES AND SHAREHOLDERS' EQUITY				
CURRENT LIABILITIES				
LONG-TERM DEBT DUE WITHIN ONE YEAR	$400,367,264.10	$0.00	$513,710,800.68	$0.00
SHORT-TERM DEBT	9,217,090.88	0.00	18,345,548.00	0.00
ADVANCES FROM AFFILIATES	844,725,973.48	92,185,472.61	347,809,521.73	27,022,035.12
ACCOUNTS PAYABLE - GENERAL	819,964,997.05	27,256.88	225,052,317.85	2,571,754.87
ACCOUNTS PAYABLE - AFFILIATED COMPANIES	260,725,919.54	1,225,589.31	155,582,539.32	67,807,808.99
CUSTOMER DEPOSITS	220,258,672.17	1,300.00	52,485,476.96	984,027.91
TAXES ACCRUED	55,699,330.44	(1,540,684.23)	173,168,685.74	(273,774.11)
INTEREST ACCRUED	18,036,689.91	0.00	64,598,382.56	94,884.92
RISK MANAGEMENT LIABILITIES	1,183,366,738.21	0.00	50,982,438.10	0.00
OBLIGATIONS UNDER CAPITAL LEASES	190,685.31	26,569.86	4,220,302.13	0.00
DIVIDENDS DECLARED	0.00	0.00	176,649.39	0.00
OTHER	129,830,441.92	697,335.08	171,851,126.07	1,885,054.33
TOTAL CURRENT LIABILITIES	3,942,383,803.02	92,622,839.51	1,777,983,788.52	100,091,792.03
LONG-TERM RISK MANAGEMENT LIABILITIES	589,954,994.27	0.00	12,022,577.16	0.00
DEFERRED INCOME TAXES	235,555,617.22	10,181,050.00	2,573,021,589.40	9,058.00
DEFERRED FIT & SIT RECLASS	(938,049,078.03)	(53,223,461.00)	(569,164,461.00)	(8,610,804.00)
NET DEFERRED INCOME TAXES	(702,493,460.81)	(43,042,411.00)	2,003,857,128.40	(8,601,746.00)
DEFERRED INVESTMENT TAX CREDITS	0.00	0.00	202,743,229.00	0.00
ASSET REMOVAL COSTS	0.00	0.00	0.00	0.00
LONG-TERM DEBT	957,767,719.84	99,855,600.11	3,895,446,089.03	0.00
OVER-RECOVERY OF FUEL COST	0.00	0.00	63,099,400.06	0.00
OTHER REGULATORY LIABILTIES	0.00	0.00	798,924,195.89	0.00
UNAMORTIZED GAIN ON REACQUIRED DEBT	0.00	0.00	223,885.45	0.00
SFAS 109 REGULATORY LIABILITY, NET	0.00	0.00	0.00	0.00
TOTAL REGULATORY LIABILITIES	0.00	0.00	862,247,481.40	0.00
TOTAL OTHER DEFERRED CREDITS	47,834,041.88	10,162,201.04	66,937,011.58	1,178,864.35
DEFERRED CREDITS AND REGULATORY LIABILITIES	47,834,041.88	10,162,201.04	929,184,492.98	1,178,864.35
CUSTOMER ADVANCES FOR CONSTRUCTION	0.00	0.00	0.00	0.00
DEFERRED GAIN ON SALE/LEASEBACK	0.00	0.00	0.00	0.00
UNREALIZED GAIN ON FORWARD COMMITMENTS	0.00	0.00	0.00	0.00
DEFERRED CREDITS AND OTHER	0.00	0.00	0.00	0.00
REGULATORY LIABILITIES AND DEFERRED INVESTMENT TAX CREDITS	0.00	0.00	0.00	0.00
OTHER NONCURRENT LIABILITIES				
OBLIGATIONS UNDER CAPITAL LEASES	211,369.25	26,728,878.78	19,846,727.28	0.00
ACCUMULATED PROVISIONS - RATE REFUND	0.00	0.00	112,780,000.00	0.00
ASSET RETIREMENT OBLIGATIONS AND NUCLEAR DECOMMSSIONING TRUSTS	0.00	0.00	0.00	0.00
ACCUMULATED PROVISIONS - MISCELLANEOUS	49,990,839.89	422,839.76	403,087,489.88	0.00
TOTAL OTHER NONCURRENT LIABILITIES	50,202,209.14	27,151,718.54	535,714,217.16	0.00
EMPLOYEE BENEFITS AND PENSION OBLIGATIONS	0.00	0.00	0.00	0.00
CUMULATIVE PREFERRED STOCKS OF SUBSIDIARIES SUBJECT TO MANDATORY REDEMPTION	0.00	0.00	0.00	0.00
CUMULATIVE PREFERRED STOCK OF SUBSIDIARIES NOT SUBJECT TO MANDATORY REDEMPTION	0.00	0.00	18,263,600.00	0.00
COMMON SHAREHOLDERS' EQUITY				
COMMON STOCK	300.00	100.00	1.00	0.00
PREMIUM ON CAPITAL STOCK	9,900.00	9,900.00	148,975.88	0.00
PAID-IN CAPITAL	2,035,591,842.17	23,982,725.00	844,503,947.54	(5,727,771.11)
RETAINED EARNINGS	(1,987,045,305.05)	(193,235,359.76)	1,588,395,120.94	6,121,741.90
ACCUMULATED OTHER COMPREHENSIVE INCOME (LOSS)	0.00	0.00	0.00	0.00
COMMON SHAREHOLDERS' EQUITY	48,556,737.12	(169,242,634.76)	2,433,048,045.36	393,970.79
MINORITY INTEREST	0.00	0.00	0.00	0.00
LIABILITIES HELD FOR SALE	0.00	0.00	0.00	0.00
TOTAL LIABILITIES AND SHAREHOLDERS' EQUITY	$4,934,206,044.45	$17,507,313.44	$11,808,263,167.62	$93,062,881.17

Item 10 - Consolidating Balance Sheets

AMERICAN ELECTRIC POWER COMPANY, INC.
AND SUBSIDIARY COMPANIES
CONSOLIDATING BALANCE SHEET
DECEMBER 31, 2003

Note - Totals and subtotals may be off due to rounding

DESCRIPTION	AEP DESERT SKY LP, LLC	AEP DESERT SKY LP II, LLC	AEP COAL, INC	AEP POWER MARKETING, INC
ASSETS				
CURRENT AND ACCRUED ASSETS				
CASH AND CASH EQUIVALENTS	$0.00	$14,991,266.62	$2,627,260.97	$0.00
ADVANCES TO AFFILIATES	60,386,697.71	0.00	0.00	0.00
ACCOUNTS RECEIVABLE - CUSTOMERS	0.00	0.00	0.00	0.00
ACCOUNTS RECEIVABLE - AFFILIATED COMPANIES	406,975.47	57,362,933.20	3,962,495.04	23,154,475.01
ACCOUNTS RECEIVABLE - ACCRUED UNBILLED REVENUES	0.00	0.00	0.00	0.00
ACCOUNTS RECEIVABLE - MISCELLANEOUS	0.00	1,798,919.42	11,687,508.64	19,051,440.87
ACCOUNTS RECEIVABLE - ALLOWANCE FOR UNCOLLECTIBLE ACCOUNTS	0.00	0.00	0.00	0.00
FUEL INVENTORY	0.00	0.00	6,034,266.41	0.00
MATERIALS & SUPPLIES	0.00	0.00	0.00	0.00
RISK MANAGEMENT ASSETS	0.00	0.00	0.00	30,507,687.70
MARGIN DEPOSITS	0.00	0.00	0.00	0.00
PREPAYMENTS	(0.00)	220,690.11	655,568.77	0.00
OTHER	0.00	0.00	0.00	0.00
TOTAL CURRENT ASSETS	60,793,673.18	74,373,809.35	24,967,099.83	72,713,603.58
ELECTRIC UTILITY PLANT				
TOTAL ELECTRIC UTILITY PLANT	100,239.23	180,228,580.98	35,660,277.75	18.56
ACCUMULATED DEPRECIATION AND AMORTIZATION	(3,459.10)	(17,930,644.68)	(20,906,905.06)	0.00
ELECTRIC UTILITY PLANT - NET	96,780.13	162,297,936.30	14,753,372.69	18.56
OTHER PROPERTY AND INVESTMENTS				
NUCLEAR DECOMMISSIONING AND SPENT NUCLEAR FUEL DISPOSAL TRUST FUNDS	0.00	0.00	0.00	0.00
NON-UTILITY PROPERTY, NET	0.00	0.00	0.00	0.00
OTHER INVESTMENTS	0.00	0.00	0.00	0.00
TOTAL OTHER PROPERTY AND INVESTMENTS	0.00	0.00	0.00	0.00
INVESTMENTS IN POWER AND DISTRIBUTION PROJECTS	0.00	0.00	0.00	0.00
REGULATORY ASSETS	0.00	0.00	0.00	0.00
FAS 109 DEFERRED FIT RECLASS	0.00	0.00	0.00	0.00
NET REGULATORY ASSETS	0.00	0.00	0.00	0.00
SECURITIZED TRANSITION ASSETS	0.00	0.00	0.00	0.00
TOTAL GOODWILL	0.00	0.00	0.00	0.00
INTANGIBLE ASSETS	0.00	0.00	0.00	0.00
LONG-TERM RISK MANAGEMENT ASSETS	0.00	0.00	0.00	10,608,445.11
SPENT NUCLEAR FUEL AND DECOMMISSIONING TRUSTS	0.00	0.00	0.00	0.00
OTHER DEFERRED DEBITS	765,558.30	(765,558.30)	0.00	(0.00)
PREFERRED STOCK DIVIDEND REQUIREMENT OF SUBSIDIARIES	0.00	0.00	0.00	0.00
TOTAL OTHER DEFERRED DEBITS	765,558.30	(765,558.30)	0.00	(0.00)
OTHER ASSETS				
TOTAL OTHER INVESTMENTS	0.00	0.00	0.00	0.00
TOTAL OTHER SPECIAL FUNDS	0.00	0.00	0.00	0.00
CLEARING ACCOUNTS	0.00	0.00	0.00	0.00
UNAMORTIZED DEBT EXPENSE	0.00	0.00	0.00	0.00
TOTAL OTHER ASSETS	765,558.30	(765,558.30)	0.00	(0.00)
ASSETS HELD FOR SALE	0.00	0.00	0.00	0.00
TOTAL ASSETS	$61,656,011.60	$235,906,187.35	$39,720,472.52	$83,322,067.25

Item 10 - Consolidating Balance Sheets

AMERICAN ELECTRIC POWER COMPANY, INC.
AND SUBSIDIARY COMPANIES
CONSOLIDATING BALANCE SHEET
DECEMBER 31, 2003

Note - *Totals and subtotals may be off due to rounding*

DESCRIPTION	AEP DESERT SKY LP, LLC	AEP DESERT SKY LP II, LLC	AEP COAL, INC	AEP POWER MARKETING, INC
LIABILITIES AND SHAREHOLDERS' EQUITY				
CURRENT LIABILITIES				
LONG-TERM DEBT DUE WITHIN ONE YEAR	$0.00	$7,986,580.22	$0.00	$0.00
SHORT-TERM DEBT	0.00	0.00	0.00	0.00
ADVANCES FROM AFFILIATES	19,527,579.83	60,386,697.71	70,547,472.54	11,130,290.62
ACCOUNTS PAYABLE - GENERAL	0.00	193,345.26	3,964,462.09	16,629,141.41
ACCOUNTS PAYABLE - AFFILIATED COMPANIES	44,718,575.35	9,255,896.01	4,044,794.06	1,852,266.38
CUSTOMER DEPOSITS	0.00	0.00	0.00	234,000.00
TAXES ACCRUED	(3,806,193.00)	1,396,439.00	3,869,525.62	3,571,932.00
INTEREST ACCRUED	0.00	944,370.61	0.00	0.00
RISK MANAGEMENT LIABILITIES	0.00	3,785,728.00	0.00	24,941,235.87
OBLIGATIONS UNDER CAPITAL LEASES	0.00	0.00	0.00	0.00
DIVIDENDS DECLARED	0.00	0.00	0.00	0.00
OTHER	0.00	3,950,000.00	22,184,960.85	1,884,150.98
TOTAL CURRENT LIABILITIES	60,439,962.18	87,899,056.81	104,611,215.16	60,243,017.26
LONG-TERM RISK MANAGEMENT LIABILITIES	0.00	835,402.00	0.00	4,275,066.00
DEFERRED INCOME TAXES	374,545.00	42,124,735.00	12,353,074.00	4,164,941.00
DEFERRED FIT & SIT RECLASS	(16,174.00)	(1,601,222.00)	(51,019,240.07)	(238.00)
NET DEFERRED INCOME TAXES	358,371.00	40,523,513.00	(38,666,166.07)	4,164,703.00
DEFERRED INVESTMENT TAX CREDITS	0.00	0.00	0.00	0.00
ASSET REMOVAL COSTS	0.00	0.00	0.00	0.00
LONG-TERM DEBT	0.00	105,962,603.94	0.00	0.00
OVER-RECOVERY OF FUEL COST	0.00	0.00	0.00	0.00
OTHER REGULATORY LIABILTIES	0.00	0.00	0.00	0.00
UNAMORTIZED GAIN ON REACQUIRED DEBT	0.00	0.00	0.00	0.00
SFAS 109 REGULATORY LIABILITY, NET	0.00	0.00	0.00	0.00
TOTAL REGULATORY LIABILITIES	0.00	0.00	0.00	0.00
TOTAL OTHER DEFERRED CREDITS	0.00	0.00	120,092.80	0.00
DEFERRED CREDITS AND REGULATORY LIABILITIES	0.00	0.00	120,092.80	0.00
CUSTOMER ADVANCES FOR CONSTRUCTION	0.00	0.00	0.00	0.00
DEFERRED GAIN ON SALE/LEASEBACK	0.00	0.00	0.00	0.00
UNREALIZED GAIN ON FORWARD COMMITMENTS	0.00	0.00	0.00	0.00
DEFERRED CREDITS AND OTHER	0.00	0.00	0.00	0.00
REGULATORY LIABILITIES AND DEFERRED INVESTMENT TAX CREDITS	0.00	0.00	0.00	0.00
OTHER NONCURRENT LIABILITIES				
OBLIGATIONS UNDER CAPITAL LEASES	0.00	0.00	0.00	0.00
ACCUMULATED PROVISIONS - RATE REFUND	0.00	0.00	0.00	0.00
ASSET RETIREMENT OBLIGATIONS AND NUCLEAR DECOMMSSIONING TRUSTS	0.00	0.00	0.00	0.00
ACCUMULATED PROVISIONS - MISCELLANEOUS	0.00	848,771.68	53,049,811.15	0.00
TOTAL OTHER NONCURRENT LIABILITIES	0.00	848,771.68	53,049,811.15	0.00
EMPLOYEE BENEFITS AND PENSION OBLIGATIONS	0.00	0.00	0.00	0.00
CUMULATIVE PREFERRED STOCKS OF SUBSIDIARIES SUBJECT TO MANDATORY REDEMPTION	0.00	0.00	0.00	0.00
CUMULATIVE PREFERRED STOCK OF SUBSIDIARIES NOT SUBJECT TO MANDATORY REDEMPTION	0.00	0.00	0.00	0.00
COMMON SHAREHOLDERS' EQUITY				
COMMON STOCK	0.00	0.00	100.00	100.00
PREMIUM ON CAPITAL STOCK	0.00	0.00	0.00	0.00
PAID-IN CAPITAL	16,174.00	(3,019,908.00)	0.00	0.00
RETAINED EARNINGS	841,504.42	2,856,747.92	(79,394,580.52)	14,639,180.99
ACCUMULATED OTHER COMPREHENSIVE INCOME (LOSS)	0.00	0.00	0.00	0.00
COMMON SHAREHOLDERS' EQUITY	857,678.42	(163,160.08)	(79,394,480.52)	14,639,280.99
MINORITY INTEREST	0.00	0.00	0.00	0.00
LIABILITIES HELD FOR SALE	0.00	0.00	0.00	0.00
TOTAL LIABILITIES AND SHAREHOLDERS' EQUITY	$61,656,011.60	$235,906,187.35	$39,720,472.52	$83,322,067.25

Item 10 - Consolidating Balance Sheets

AMERICAN ELECTRIC POWER COMPANY, INC.
AND SUBSIDIARY COMPANIES
CONSOLIDATING BALANCE SHEET
DECEMBER 31, 2003

Note - Totals and subtotals may be off due to rounding

DESCRIPTION	AEP PRO SERV, INC	MUTUAL ENERGY LLC
ASSETS		
CURRENT AND ACCRUED ASSETS		
CASH AND CASH EQUIVALENTS	$802,277.24	$0.00
ADVANCES TO AFFILIATES	28,279,811.44	8,435,322.76
ACCOUNTS RECEIVABLE - CUSTOMERS	0.00	151,308.56
ACCOUNTS RECEIVABLE - AFFILIATED COMPANIES	69,044.57	0.00
ACCOUNTS RECEIVABLE - ACCRUED UNBILLED REVENUES	289,099.92	0.00
ACCOUNTS RECEIVABLE - MISCELLANEOUS	22,510,151.45	0.00
ACCOUNTS RECEIVABLE - ALLOWANCE FOR UNCOLLECTIBLE ACCOUNTS	(1,683,414.55)	0.00
FUEL INVENTORY	(0.00)	0.00
MATERIALS & SUPPLIES	(0.01)	0.00
RISK MANAGEMENT ASSETS	0.00	0.00
MARGIN DEPOSITS	0.00	0.00
PREPAYMENTS	453,167.96	0.00
OTHER	0.00	0.00
TOTAL CURRENT ASSETS	50,720,138.02	8,586,631.32
ELECTRIC UTILITY PLANT		
TOTAL ELECTRIC UTILITY PLANT	2,540,129.83	0.00
ACCUMULATED DEPRECIATION AND AMORTIZATION	(763,194.69)	0.00
ELECTRIC UTILITY PLANT - NET	1,776,935.14	0.00
OTHER PROPERTY AND INVESTMENTS		
NUCLEAR DECOMMISSIONING AND SPENT NUCLEAR FUEL DISPOSAL TRUST FUNDS	0.00	0.00
NON-UTILITY PROPERTY, NET	0.00	0.00
OTHER INVESTMENTS	0.00	0.00
TOTAL OTHER PROPERTY AND INVESTMENTS	0.00	0.00
INVESTMENTS IN POWER AND DISTRIBUTION PROJECTS	0.00	0.00
REGULATORY ASSETS	0.00	0.00
FAS 109 DEFERRED FIT RECLASS	0.00	0.00
NET REGULATORY ASSETS	0.00	0.00
SECURITIZED TRANSITION ASSETS	0.00	0.00
TOTAL GOODWILL	0.00	0.00
INTANGIBLE ASSETS	8,873,904.73	0.00
LONG-TERM RISK MANAGEMENT ASSETS	0.00	0.00
SPENT NUCLEAR FUEL AND DECOMMISSIONING TRUSTS	0.00	0.00
OTHER DEFERRED DEBITS	471,698.23	227,980.66
PREFERRED STOCK DIVIDEND REQUIREMENT OF SUBSIDIARIES	0.00	0.00
TOTAL OTHER DEFERRED DEBITS	471,698.23	227,980.66
OTHER ASSETS		
TOTAL OTHER INVESTMENTS	0.00	0.00
TOTAL OTHER SPECIAL FUNDS	0.00	0.00
CLEARING ACCOUNTS	(3,257,516.30)	0.00
UNAMORTIZED DEBT EXPENSE	0.00	0.00
TOTAL OTHER ASSETS	(2,785,818.07)	227,980.66
ASSETS HELD FOR SALE	0.00	0.00
TOTAL ASSETS	$58,585,159.81	$8,814,611.98

Item 10 - Consolidating Balance Sheets

AMERICAN ELECTRIC POWER COMPANY, INC.
AND SUBSIDIARY COMPANIES
CONSOLIDATING BALANCE SHEET
DECEMBER 31, 2003

Note - Totals and subtotals may be off due to rounding

DESCRIPTION	AEP PRO SERV, INC	MUTUAL ENERGY LLC
LIABILITIES AND SHAREHOLDERS' EQUITY		
CURRENT LIABILITIES		
LONG-TERM DEBT DUE WITHIN ONE YEAR	$0.00	$0.00
SHORT-TERM DEBT	0.00	0.00
ADVANCES FROM AFFILIATES	0.00	0.00
ACCOUNTS PAYABLE - GENERAL	12,871,798.03	490,684.22
ACCOUNTS PAYABLE - AFFILIATED COMPANIES	1,060,931.82	250,137.40
CUSTOMER DEPOSITS	0.00	0.00
TAXES ACCRUED	14,720,920.11	(80,833.00)
INTEREST ACCRUED	487,573.15	0.00
RISK MANAGEMENT LIABILITIES	0.00	0.00
OBLIGATIONS UNDER CAPITAL LEASES	7,344.45	0.00
DIVIDENDS DECLARED	0.00	0.00
OTHER	4,500,647.90	2,083,532.15
TOTAL CURRENT LIABILITIES	33,649,215.46	2,743,520.77
LONG-TERM RISK MANAGEMENT LIABILITIES	0.00	0.00
DEFERRED INCOME TAXES	(308,211.00)	31,248.00
DEFERRED FIT & SIT RECLASS	(7,556,998.00)	(907,728.00)
NET DEFERRED INCOME TAXES	(7,865,209.00)	(876,480.00)
DEFERRED INVESTMENT TAX CREDITS	0.00	0.00
ASSET REMOVAL COSTS	0.00	0.00
LONG-TERM DEBT	7,500,000.01	0.00
OVER-RECOVERY OF FUEL COST	0.00	0.00
OTHER REGULATORY LIABILTIES	0.00	0.00
UNAMORTIZED GAIN ON REACQUIRED DEBT	0.00	0.00
SFAS 109 REGULATORY LIABILITY, NET	0.00	0.00
TOTAL REGULATORY LIABILITIES	0.00	0.00
TOTAL OTHER DEFERRED CREDITS	5,590,199.40	0.00
DEFERRED CREDITS AND REGULATORY LIABILITIES	5,590,199.40	0.00
CUSTOMER ADVANCES FOR CONSTRUCTION	0.00	0.00
DEFERRED GAIN ON SALE/LEASEBACK	0.00	0.00
UNREALIZED GAIN ON FORWARD COMMITMENTS	0.00	0.00
DEFERRED CREDITS AND OTHER	0.00	0.00
REGULATORY LIABILITIES AND DEFERRED INVESTMENT TAX CREDITS	0.00	0.00
OTHER NONCURRENT LIABILITIES		
OBLIGATIONS UNDER CAPITAL LEASES	5,729.24	0.00
ACCUMULATED PROVISIONS - RATE REFUND	0.00	0.00
ASSET RETIREMENT OBLIGATIONS AND NUCLEAR DECOMMSSIONING TRUSTS	0.00	0.00
ACCUMULATED PROVISIONS - MISCELLANEOUS	291,929.96	0.00
TOTAL OTHER NONCURRENT LIABILITIES	297,659.20	0.00
EMPLOYEE BENEFITS AND PENSION OBLIGATIONS	0.00	0.00
CUMULATIVE PREFERRED STOCKS OF SUBSIDIARIES SUBJECT TO MANDATORY REDEMPTION	0.00	0.00
CUMULATIVE PREFERRED STOCK OF SUBSIDIARIES NOT SUBJECT TO MANDATORY REDEMPTION	0.00	0.00
COMMON SHAREHOLDERS' EQUITY		
COMMON STOCK	110,000.00	0.00
PREMIUM ON CAPITAL STOCK	0.00	0.00
PAID-IN CAPITAL	21,078,555.41	0.00
RETAINED EARNINGS	(1,775,260.67)	6,947,571.21
ACCUMULATED OTHER COMPREHENSIVE INCOME (LOSS)	0.00	0.00
COMMON SHAREHOLDERS' EQUITY	19,413,294.74	6,947,571.21
MINORITY INTEREST	0.00	0.00
LIABILITIES HELD FOR SALE	0.00	0.00
TOTAL LIABILITIES AND SHAREHOLDERS' EQUITY	$58,585,159.81	$8,814,611.98

Item 10 - Consolidating Balance Sheets

AEP UTILITIES, INCORPORATED
CONSOLIDATING BALANCE SHEET
DECEMBER 31, 2003

Note - Totals and subtotals may be off due to rounding

DESCRIPTION	AEP UTILITIES INCORPORATED CONSOLIDATED	SEC REPORTING ADJUSTMENTS	AEP UTILITIES INCORPORATED ELIMINATIONS	AEP UTILITIES INCORPORATED
ASSETS:				
CURRENT AND ACCRUED ASSETS				
CASH AND CASH EQUIVALENTS	$129,782,942.65	$0.00	$0.00	$24,365,423.45
ADVANCES TO AFFILIATES	233,070,918.52	0.00	0.00	0.00
ACCOUNTS RECEIVABLE - CUSTOMERS	(91,822,041.42)	(86,670,996.71)	106,666,935.86	0.00
ACCOUNTS RECEIVABLE - AFFILIATED COMPANIES	494,670,329.62	0.00	(202,279,955.01)	678,331.67
ACCOUNTS RECEIVABLE - ACCRUED UNBILLED REVENUES	62,190,798.22	34,243,095.12	0.00	0.00
ACCOUNTS RECEIVABLE - MISCELLANEOUS	121,732,542.38	86,670,996.71	0.00	13,639.03
ACCOUNTS RECEIVABLE - ALLOWANCE FOR UNCOLLECTIBLE ACCOUNTS	(23,153,255.85)	0.00	0.00	0.00
FUEL INVENTORY	93,137,113.44	0.00	0.00	0.00
MATERIALS & SUPPLIES	129,635,120.96	35,244,199.00	0.00	0.00
REGULATORY ASSET FOR UNDER-RECOVERED FUEL COST	0.00	(35,564,491.32)	0.00	0.00
RISK MANAGEMENT ASSETS	70,691,758.14	0.00	0.00	0.00
MARGIN DEPOSITS	0.00	(13,989,459.94)	0.00	0.00
PREPAYMENTS	31,638,120.69	0.00	(281,290.64)	(615,067.43)
OTHER	14,017,092.99	13,989,459.94	0.00	0.00
TOTAL CURRENT ASSETS	1,265,591,440.34	33,922,802.80	(95,894,309.79)	24,442,326.72
ELECTRIC UTILITY PLANT				
TOTAL ELECTRIC UTILITY PLANT	12,692,836,758.28	2,267,407,476.78	0.00	1,229,419.27
ACCUMULATED DEPRECIATION AND AMORTIZATION	(5,322,076,807.01)	(1,437,575,286.56)	0.00	(202,330.24)
ELECTRIC UTILITY PLANT - NET	7,370,759,951.27	829,832,190.22	0.00	1,027,089.03
OTHER PROPERTY AND INVESTMENTS				
NON-UTILITY PROPERTY, NET	0.00	(11,027,324.15)	0.00	0.00
OTHER INVESTMENTS	0.00	(11,478,125.42)	0.00	0.00
TOTAL OTHER PROPERTY AND INVESTMENTS	0.00	(22,505,449.57)	0.00	0.00
INVESTMENTS IN POWER AND DISTRIBUTION PROJECTS	31,142,620.49	0.00	(2,590,732,522.41)	2,590,732,522.42
REGULATORY ASSETS	2,154,058,880.21	86,868,170.17	0.00	0.00
FAS 109 DEFERRED FIT RECLASS	(125,238,102.00)	(57,242,684.00)	0.00	0.00
NET REGULATORY ASSETS	2,028,820,778.21	29,625,486.17	0.00	0.00
GOODWILL	2,662,500.00	0.00	0.00	0.00
INTANGIBLE ASSETS	21,736,066.16	0.00	0.00	0.00
LONG-TERM RISK MANAGEMENT ASSETS	33,425,251.75	0.00	0.00	0.00
OTHER ASSETS				
TOTAL OTHER INVESTMENTS	797,396,734.88	11,478,125.42	0.00	25,035,346.11
TOTAL OTHER SPECIAL FUNDS	125,383,429.15	125,383,429.15	0.00	0.00
CLEARING ACCOUNTS	11,687,875.88	0.00	0.00	0.00
UNAMORTIZED DEBT EXPENSE	67,193,718.97	0.00	0.00	0.00
PREFERRED STOCK DIVIDEND REQUIREMENT OF SUBSIDIARIES	(786,804.57)	0.00	(786,804.57)	0.00
OTHER DEFERRED DEBITS	53,249,605.08	0.00	(2,702,220.08)	1,148,893.75
TOTAL OTHER ASSETS	1,054,124,559.39	136,861,554.57	(3,489,024.65)	26,184,239.86
ASSETS HELD FOR SALE - TEXAS GENERATION PLANT	0.00	(1,028,134,000.00)	0.00	0.00
TOTAL ASSETS	$11,808,263,167.62	($20,397,415.81)	($2,690,115,856.85)	$2,642,386,178.03

Item 10 - Consolidating Balance Sheets

AEP UTILITIES, INCORPORATED
CONSOLIDATING BALANCE SHEET
DECEMBER 31, 2003

Note - Totals and subtotals may be off due to rounding

DESCRIPTION	AEP UTILITIES INCORPORATED CONSOLIDATED	SEC REPORTING ADJUSTMENTS	AEP UTILITIES INCORPORATED ELIMINATIONS	AEP UTILITIES INCORPORATED
CAPITALIZATION AND LIABILITIES:				
CURRENT LIABILITIES				
LONG-TERM DEBT DUE WITHIN ONE YEAR	$513,710,800.68	$0.00	$0.00	$0.00
SHORT-TERM DEBT	18,345,548.00	0.00	0.00	0.00
ADVANCES FROM AFFILIATES	347,809,521.73	0.00	0.00	0.00
ACCOUNTS PAYABLE - GENERAL	225,052,317.85	0.00	0.00	134,134.99
ACCOUNTS PAYABLE - AFFILIATED COMPANIES	155,582,539.32	34,243,095.12	(95,551,686.89)	2,553,123.22
CUSTOMER DEPOSITS	52,485,476.96	0.00	0.00	0.00
TAXES ACCRUED	173,168,685.74	0.00	0.00	7,833,087.24
INTEREST ACCRUED	64,598,382.56	(5,942,632.51)	0.00	0.00
RISK MANAGEMENT LIABILITIES	50,982,438.10	0.00	0.00	0.00
OBLIGATIONS UNDER CAPITAL LEASES	4,220,302.13	0.00	0.00	0.00
OVER-RECOVERY OF FUEL COST	0.00	(4,177,623.56)	0.00	0.00
DIVIDENDS DECLARED	176,649.39	0.00	(268,284.66)	0.00
OTHER	171,851,126.07	10,375,595.36	0.00	8,115,036.29
TOTAL CURRENT LIABILITIES	1,777,983,788.52	34,498,434.41	(95,819,971.55)	18,635,381.74
LONG-TERM RISK MANAGEMENT LIABILITIES	12,022,577.16	0.00	0.00	0.00
DEFERRED INCOME TAXES	2,573,021,589.40	0.00	0.00	3,494,336.91
DEFERRED FIT & SIT RECLASS	(569,164,461.00)	0.00	0.00	(676.00)
NET DEFERRED INCOME TAXES	2,003,857,128.40	0.00	0.00	3,493,660.91
DEFERRED INVESTMENT TAX CREDITS	202,743,229.00	0.00	0.00	0.00
SFAS 109 REGULATORY LIABILITY, NET	0.00	(38,593,140.00)	0.00	0.00
ASSET REMOVAL COSTS	0.00	(622,596,063.00)	0.00	0.00
LONG-TERM DEBT	3,895,446,089.03	0.00	0.00	0.00
OVER-RECOVERY OF FUEL COST	63,099,400.06	(5,926,679.93)	0.00	0.00
OTHER REGULATORY LIABILTIES	798,924,195.89	631,959,255.00	0.00	0.00
UNAMORTIZED GAIN REACQUIRED DEBT	223,885.45	0.00	0.00	0.00
TOTAL REGULATORY LIABILITIES	862,247,481.40	626,032,575.07	0.00	0.00
TOTAL OTHER DEFERRED CREDITS	66,937,011.58	(6,648,213.33)	(3,563,362.88)	7,509,958.83
TOTAL DEFERRED CREDITS & REGULATORY LIABILITIES	929,184,492.98	619,384,361.74	(3,563,362.88)	7,509,958.83
CUSTOMER ADVANCES FOR CONSTRUCTION	0.00	(2,360,191.42)	0.00	0.00
OBLIGATIONS UNDER CAPITAL LEASES	19,846,727.28	0.00	0.00	0.00
ACCUMULATED PROVISIONS - RATE REFUND	112,780,000.00	0.00	0.00	0.00
ACCUMULATED PROVISIONS - MISCELLANEOUS	403,087,489.88	227,199,539.07	0.00	(731.06)
ASSET RETIREMENT OBLIGATIONS	0.00	(8,429,166.00)	0.00	0.00
TOTAL OTHER NONCURRENT LIABILITIES	535,714,217.16	216,410,181.65	0.00	(731.06)
CUMULATIVE PREFERRED STOCK OF SUBSIDIARIES SUBJECT TO MANDATORY REDEMPTION	0.00	0.00	0.00	0.00
CUMULATIVE PREFERRED STOCK OF SUBSIDIARIES NOT SUBJECT TO MANDATORY REDEMPTION	18,263,600.00	0.00	0.00	0.00
COMMON STOCK				
COMMON STOCK	1.00	0.00	(485,400,464.53)	1.00
PREMIUM ON CAPITAL STOCK	148,975.88	148,975.92	(148,975.92)	148,975.88
PAID-IN CAPITAL	844,503,947.54	(176,491,855.92)	(908,174,107.12)	1,024,203,809.67
RETAINED EARNINGS	1,588,395,120.94	0.00	(1,197,008,974.85)	1,588,395,121.06
ACCUMULATED OTHER COMPREHENSIVE INCOME (LOSS)	0.00	176,342,880.00	0.00	0.00
COMMON SHAREHOLDER'S EQUITY	2,433,048,045.36	0.00	(2,590,732,522.42)	2,612,747,907.61
MINORITY INTEREST	0.00	(1,367,190.61)	0.00	0.00
LIABILITIES HELD FOR SALE - TEXAS GENERATION PLANTS	0.00	(228,134,000.00)	0.00	0.00
TOTAL CAPITALIZATION AND LIABILITIES	$11,808,263,167.62	($20,397,415.81)	($2,690,115,856.85)	$2,642,386,178.03

Item 10 - Consolidating Balance Sheets

AEP UTILITIES, INCORPORATED
CONSOLIDATING BALANCE SHEET
DECEMBER 31, 2003

Note - Totals and subtotals may be off due to rounding

DESCRIPTION	AEP CREDIT INCORPORATED	ENERSHOP INCORPORATED	CSW LEASING INCORPORATED	AEP TEXAS CENTRAL COMPANY CONSOLIDATED
ASSETS:				
CURRENT AND ACCRUED ASSETS				
CASH AND CASH EQUIVALENTS	$0.00	$0.00	$0.00	$65,882,383.28
ADVANCES TO AFFILIATES	0.00	0.00	0.00	60,698,653.80
ACCOUNTS RECEIVABLE - CUSTOMERS	(385,107,182.58)	0.00	0.00	146,630,328.79
ACCOUNTS RECEIVABLE - AFFILIATED COMPANIES	554,121,467.15	0.00	0.00	78,484,461.21
ACCOUNTS RECEIVABLE - ACCRUED UNBILLED REVENUES	0.00	0.00	0.00	23,076,876.57
ACCOUNTS RECEIVABLE - MISCELLANEOUS	0.00	0.00	0.00	0.00
ACCOUNTS RECEIVABLE - ALLOWANCE FOR UNCOLLECTIBLE ACCOUNT	(13,166,951.44)	0.00	0.00	(1,709,988.26)
FUEL INVENTORY	0.00	0.00	0.00	0.30
MATERIALS & SUPPLIES	0.00	0.00	0.00	11,709,156.27
REGULATORY ASSET FOR UNDER-RECOVERED FUEL COST	0.00	0.00	0.00	0.00
RISK MANAGEMENT ASSETS	0.00	0.00	0.00	22,050,547.90
MARGIN DEPOSITS	0.00	0.00	0.00	3,229,459.28
PREPAYMENTS	350,000.00	0.00	0.00	6,757,510.78
OTHER	0.00	0.00	0.00	12,075.00
TOTAL CURRENT ASSETS	156,197,333.13	0.00	0.00	416,821,464.92
ELECTRIC UTILITY PLANT				
TOTAL ELECTRIC UTILITY PLANT	8,031.46	0.00	0.00	2,425,038,000.00
ACCUMULATED DEPRECIATION AND AMORTIZATION	0.00	0.00	0.00	(695,358,935.97)
ELECTRIC UTILITY PLANT - NET	8,031.46	0.00	0.00	1,729,679,064.03
OTHER PROPERTY AND INVESTMENTS				
NON-UTILITY PROPERTY, NET	0.00	0.00	0.00	1,302,074.99
OTHER INVESTMENTS	0.00	0.00	0.00	4,639,200.00
TOTAL OTHER PROPERTY AND INVESTMENTS	0.00	0.00	0.00	5,941,274.99
INVESTMENTS IN POWER AND DISTRIBUTION PROJECTS	0.00	0.00	0.00	0.00
REGULATORY ASSETS	0.00	0.00	0.00	1,922,455,792.59
FAS 109 DEFERRED FIT RECLASS	0.00	0.00	0.00	(30,905,150.00)
NET REGULATORY ASSETS	0.00	0.00	0.00	1,891,550,642.59
GOODWILL	0.00	0.00	0.00	0.00
INTANGIBLE ASSETS	0.00	0.00	0.00	0.00
LONG-TERM RISK MANAGEMENT ASSETS	0.00	0.00	0.00	7,627,391.95
OTHER ASSETS				
TOTAL OTHER INVESTMENTS	0.00	0.00	0.00	689,399,160.00
TOTAL OTHER SPECIAL FUNDS	0.00	0.00	0.00	0.00
CLEARING ACCOUNTS	0.00	0.00	0.00	9,162,796.15
UNAMORTIZED DEBT EXPENSE	0.00	0.00	0.00	40,355,271.70
PREFERRED STOCK DIVIDEND REQUIREMENT OF SUBSIDIARIES	0.00	0.00	0.00	0.00
OTHER DEFERRED DEBITS	0.00	0.00	0.00	6,035,972.18
TOTAL OTHER ASSETS	0.00	0.00	0.00	744,953,200.04
ASSETS HELD FOR SALE - TEXAS GENERATION PLANT	0.00	0.00	0.00	1,028,134,000.00
TOTAL ASSETS	$156,205,364.59	$0.00	$0.00	$5,824,707,038.51

Item 10 - Consolidating Balance Sheets

AEP UTILITIES, INCORPORATED
CONSOLIDATING BALANCE SHEET
DECEMBER 31, 2003

Note - Totals and subtotals may be off due to rounding

DESCRIPTION	AEP CREDIT INCORPORATED	ENERSHOP INCORPORATED	CSW LEASING INCORPORATED	AEP TEXAS CENTRAL COMPANY CONSOLIDATED
CAPITALIZATION AND LIABILITIES:				
CURRENT LIABILITIES				
LONG-TERM DEBT DUE WITHIN ONE YEAR	$0.00	$0.00	$0.00	$237,651,004.00
SHORT-TERM DEBT	0.00	0.00	0.00	0.00
ADVANCES FROM AFFILIATES	102,206,885.63	0.00	0.00	0.00
ACCOUNTS PAYABLE - GENERAL	17,605,426.77	0.00	0.00	90,003,762.18
ACCOUNTS PAYABLE - AFFILIATED COMPANIES	1,561,198.01	0.00	0.00	74,209,243.66
CUSTOMER DEPOSITS	0.00	0.00	0.00	1,517,146.16
TAXES ACCRUED	(980,023.66)	0.00	0.00	67,017,583.55
INTEREST ACCRUED	118,575.00	0.00	0.00	43,196,060.74
RISK MANAGEMENT LIABILITIES	0.00	0.00	0.00	17,888,265.90
OBLIGATIONS UNDER CAPITAL LEASES	0.00	0.00	0.00	406,834.52
OVER-RECOVERY OF FUEL COST	0.00	0.00	0.00	0.00
DIVIDENDS DECLARED	268,284.67	0.00	0.00	40,195.58
OTHER	0.00	0.01	0.00	23,207,572.16
TOTAL CURRENT LIABILITIES	120,780,346.42	0.01	0.00	555,137,668.44
LONG-TERM RISK MANAGEMENT LIABILITIES	0.00	0.00	0.00	2,659,930.24
DEFERRED INCOME TAXES	(4,272,227.00)	0.00	0.00	1,506,888,537.00
DEFERRED FIT & SIT RECLASS	0.00	0.00	0.00	(261,976,194.00)
NET DEFERRED INCOME TAXES	(4,272,227.00)	0.00	0.00	1,244,912,343.00
DEFERRED INVESTMENT TAX CREDITS	0.00	0.00	0.00	112,478,774.00
SFAS 109 REGULATORY LIABILITY, NET	0.00	0.00	0.00	0.00
ASSET REMOVAL COSTS	0.00	0.00	0.00	95,414,745.00
LONG-TERM DEBT	0.00	0.00	0.00	2,053,974,012.58
OVER-RECOVERY OF FUEL COST	0.00	0.00	0.00	69,026,079.99
OTHER REGULATORY LIABILTIES	0.00	0.00	0.00	102,506,263.58
UNAMORTIZED GAIN REACQUIRED DEBT	0.00	0.00	0.00	5,258.50
TOTAL REGULATORY LIABILITIES	0.00	0.00	0.00	171,537,602.07
TOTAL OTHER DEFERRED CREDITS	12,654,322.75	0.00	0.00	5,487,416.56
TOTAL DEFERRED CREDITS & REGULATORY LIABILITIES	12,654,322.75	0.00	0.00	177,025,018.63
CUSTOMER ADVANCES FOR CONSTRUCTION	0.00	0.00	0.00	2,065,500.00
OBLIGATIONS UNDER CAPITAL LEASES	0.00	0.00	0.00	635,714.96
ACCUMULATED PROVISIONS - RATE REFUND	0.00	0.00	0.00	82,597,000.00
ACCUMULATED PROVISIONS - MISCELLANEOUS	0.00	0.00	0.00	54,682,880.65
ASSET RETIREMENT OBLIGATIONS	0.00	0.00	0.00	0.00
TOTAL OTHER NONCURRENT LIABILITIES	0.00	0.00	0.00	139,981,095.61
CUMULATIVE PREFERRED STOCK OF SUBSIDIARIES SUBJECT TO MANDATORY REDEMPTION	0.00	0.00	0.00	0.00
CUMULATIVE PREFERRED STOCK OF SUBSIDIARIES NOT SUBJECT TO MANDATORY REDEMPTION	0.00	0.00	0.00	5,940,300.00
COMMON STOCK				
COMMON STOCK	1,000.00	0.00	0.00	55,291,944.53
PREMIUM ON CAPITAL STOCK	0.00	0.00	0.00	0.00
PAID-IN CAPITAL	27,041,922.42	0.00	0.00	132,606,982.69
RETAINED EARNINGS	(0.00)	(0.00)	(0.00)	1,083,022,567.79
ACCUMULATED OTHER COMPREHENSIVE INCOME (LOSS)	0.00	0.00	0.00	(61,872,344.00)
COMMON SHAREHOLDER'S EQUITY	27,042,922.42	(0.00)	(0.00)	1,209,049,151.01
MINORITY INTEREST	0.00	0.00	0.00	0.00
LIABILITIES HELD FOR SALE - TEXAS GENERATION PLANTS	0.00	0.00	0.00	228,134,000.00
TOTAL CAPITALIZATION AND LIABILITIES	$156,205,364.59	$0.00	($0.00)	$5,824,707,038.51

Item 10 - Consolidating Balance Sheets

AEP UTILITIES, INCORPORATED
CONSOLIDATING BALANCE SHEET
DECEMBER 31, 2003

Note - Totals and subtotals may be off due to rounding

DESCRIPTION	PUBLIC SERVICE COMPANY OF OKLAHOMA	AEP TEXAS NORTH COMPANY	CSW ENERGY INCORPORATED	SOUTHWESTERN ELECTRIC POWER COMPANY CONSOLIDATED
ASSETS:				
CURRENT AND ACCRUED ASSETS				
CASH AND CASH EQUIVALENTS	$14,257,894.39	$2,862,572.24	$8,922,544.67	$11,724,352.26
ADVANCES TO AFFILIATES	0.00	41,593,327.78	64,303,296.81	66,475,640.13
ACCOUNTS RECEIVABLE - CUSTOMERS	28,515,138.85	56,670,028.92	0.00	41,473,705.45
ACCOUNTS RECEIVABLE - AFFILIATED COMPANIES	19,851,869.43	28,909,712.82	4,386,475.30	10,393,624.25
ACCOUNTS RECEIVABLE - ACCRUED UNBILLED REVENUES	0.00	4,870,826.53	0.00	0.00
ACCOUNTS RECEIVABLE - MISCELLANEOUS	0.00	3,410,673.07	1,836,780.85	4,682,309.38
ACCOUNTS RECEIVABLE - ALLOWANCE FOR UNCOLLECTIBLE ACCOUNT	(36,898.68)	(175,175.18)	0.00	(2,092,942.10)
FUEL INVENTORY	18,331,016.19	10,925,299.22	0.00	63,880,797.74
MATERIALS & SUPPLIES	38,125,104.02	8,865,753.45	(0.02)	33,775,398.67
REGULATORY ASSET FOR UNDER-RECOVERED FUEL COST	24,170,491.32	0.00	0.00	11,394,000.00
RISK MANAGEMENT ASSETS	18,586,392.40	10,340,274.72	0.00	19,714,543.12
MARGIN DEPOSITS	4,351,145.41	1,286,116.95	0.00	5,122,738.30
PREPAYMENTS	2,643,823.44	1,834,000.55	629,497.98	19,073,635.00
OTHER	10,708.00	0.00	0.00	4,850.00
TOTAL CURRENT ASSETS	168,806,684.77	171,393,411.08	80,078,595.60	285,622,652.21
ELECTRIC UTILITY PLANT				
TOTAL ELECTRIC UTILITY PLANT	2,806,395,932.79	1,233,426,999.54	148,768,348.40	3,799,459,946.09
ACCUMULATED DEPRECIATION AND AMORTIZATION	(1,069,215,752.81)	(460,512,708.70)	(41,365,428.09)	(1,617,846,204.00)
ELECTRIC UTILITY PLANT - NET	1,737,180,179.98	772,914,290.84	107,402,920.31	2,181,613,742.10
OTHER PROPERTY AND INVESTMENTS				
NON-UTILITY PROPERTY, NET	4,631,397.63	1,285,840.98	0.00	3,808,010.55
OTHER INVESTMENTS	2,320,006.00	2.00	0.00	4,518,917.42
TOTAL OTHER PROPERTY AND INVESTMENTS	6,951,403.63	1,285,842.98	0.00	8,326,927.97
INVESTMENTS IN POWER AND DISTRIBUTION PROJECTS	0.00	0.00	30,951,236.78	191,383.70
REGULATORY ASSETS	28,698,988.40	40,520,303.95	0.00	75,515,625.10
FAS 109 DEFERRED FIT RECLASS	0.00	0.00	0.00	(37,090,268.00)
NET REGULATORY ASSETS	28,698,988.40	40,520,303.95	0.00	38,425,357.10
GOODWILL	0.00	0.00	0.00	0.00
INTANGIBLE ASSETS	0.00	0.00	0.00	21,736,066.16
LONG-TERM RISK MANAGEMENT ASSETS	10,379,202.93	3,106,370.16	134,784.00	12,177,502.71
OTHER ASSETS				
TOTAL OTHER INVESTMENTS	0.00	0.00	71,484,103.35	0.00
TOTAL OTHER SPECIAL FUNDS	0.00	0.00	0.00	0.00
CLEARING ACCOUNTS	540,691.80	153,725.85	1,831.74	1,828,830.34
UNAMORTIZED DEBT EXPENSE	14,552,614.41	2,295,453.06	2,930,297.79	5,820,310.78
PREFERRED STOCK DIVIDEND REQUIREMENT OF SUBSIDIARIES	0.00	0.00	0.00	0.00
OTHER DEFERRED DEBITS	2,922,390.29	17,839,990.98	528,370.13	26,219,904.39
TOTAL OTHER ASSETS	18,015,696.50	20,289,169.89	74,944,603.01	33,869,045.51
ASSETS HELD FOR SALE - TEXAS GENERATION PLANT	0.00	0.00	0.00	0.00
TOTAL ASSETS	$1,970,032,156.21	$1,009,509,388.90	$293,512,139.70	$2,581,962,677.45

Item 10 - Consolidating Balance Sheets

AEP UTILITIES, INCORPORATED
CONSOLIDATING BALANCE SHEET
DECEMBER 31, 2003

Note - Totals and subtotals may be off due to rounding

DESCRIPTION	PUBLIC SERVICE COMPANY OF OKLAHOMA	AEP TEXAS NORTH COMPANY	CSW ENERGY INCORPORATED	SOUTHWESTERN ELECTRIC POWER COMPANY CONSOLIDATED
CAPITALIZATION AND LIABILITIES:				
CURRENT LIABILITIES				
LONG-TERM DEBT DUE WITHIN ONE YEAR	$83,700,000.00	$42,505,000.00	$7,140,586.00	$142,714,210.68
SHORT-TERM DEBT	0.00	0.00	0.00	0.00
ADVANCES FROM AFFILIATES	32,864,368.16	0.00	98,868,873.33	0.00
ACCOUNTS PAYABLE - GENERAL	48,808,315.63	28,189,890.39	2,110,957.36	37,645,508.97
ACCOUNTS PAYABLE - AFFILIATED COMPANIES	57,205,814.00	40,600,638.32	2,050,651.97	35,138,037.99
CUSTOMER DEPOSITS	26,547,008.92	161,386.96	0.00	24,259,934.92
TAXES ACCRUED	27,156,879.29	22,876,901.47	(31,245.38)	28,690,883.86
INTEREST ACCRUED	3,706,437.55	6,037,537.73	630,630.00	16,851,774.05
RISK MANAGEMENT LIABILITIES	11,067,058.39	8,658,146.73	2,007,517.00	11,361,450.08
OBLIGATIONS UNDER CAPITAL LEASES	451,935.63	202,774.11	0.00	3,158,757.87
OVER-RECOVERY OF FUEL COST	0.00	0.00	0.00	4,177,623.56
DIVIDENDS DECLARED	53,151.22	26,039.16	0.00	57,263.42
OTHER	35,180,337.68	9,394,003.03	686,861.13	53,696,014.94
TOTAL CURRENT LIABILITIES	326,741,306.47	158,652,317.89	113,464,831.41	357,751,460.34
LONG-TERM RISK MANAGEMENT LIABILITIES	3,601,851.16	1,093,647.92	0.00	4,667,147.84
DEFERRED INCOME TAXES	425,322,931.00	153,953,354.00	56,923,442.49	429,778,451.00
DEFERRED FIT & SIT RECLASS	(89,889,186.00)	(40,934,693.00)	7,975,877.00	(80,714,472.00)
NET DEFERRED INCOME TAXES	335,433,745.00	113,018,661.00	64,899,319.49	349,063,979.00
DEFERRED INVESTMENT TAX CREDITS	30,410,644.00	19,989,507.00	0.00	39,864,304.00
SFAS 109 REGULATORY LIABILITY, NET	24,937,751.00	13,655,389.00	0.00	0.00
ASSET REMOVAL COSTS	214,032,762.00	76,739,857.00	0.00	236,408,699.00
LONG-TERM DEBT	490,597,772.92	314,249,126.46	107,051,654.10	741,594,997.01
OVER-RECOVERY OF FUEL COST	0.00	0.00	0.00	0.00
OTHER REGULATORY LIABILTIES	15,406,284.00	27,857,434.27	0.00	21,194,959.04
UNAMORTIZED GAIN REACQUIRED DEBT	0.00	34,560.93	0.00	184,066.02
TOTAL REGULATORY LIABILITIES	15,406,284.00	27,891,995.20	0.00	21,379,025.06
TOTAL OTHER DEFERRED CREDITS	246,925.96	1,399,883.32	13,502,955.86	32,967,177.65
TOTAL DEFERRED CREDITS & REGULATORY LIABILITIES	15,653,209.96	29,291,878.52	13,502,955.86	54,346,202.71
CUSTOMER ADVANCES FOR CONSTRUCTION	294,691.42	0.00	0.00	0.00
OBLIGATIONS UNDER CAPITAL LEASES	557,776.36	270,031.50	0.00	18,383,204.46
ACCUMULATED PROVISIONS - RATE REFUND	0.00	21,621,000.00	0.00	8,562,000.00
ACCUMULATED PROVISIONS - MISCELLANEOUS	39,495,938.08	20,296,069.27	1,219,978.66	60,165,014.45
ASSET RETIREMENT OBLIGATIONS	0.00	0.00	0.00	8,429,166.00
TOTAL OTHER NONCURRENT LIABILITIES	40,348,405.86	42,187,100.77	1,219,978.66	95,539,384.91
CUMULATIVE PREFERRED STOCK OF SUBSIDIARIES SUBJECT TO MANDATORY REDEMPTION	0.00	0.00	0.00	0.00
CUMULATIVE PREFERRED STOCK OF SUBSIDIARIES NOT SUBJECT TO MANDATORY REDEMPTION	5,266,700.00	2,357,000.00	0.00	4,699,600.00
COMMON STOCK				
COMMON STOCK	157,230,000.00	137,214,000.00	1,000.00	135,659,520.00
PREMIUM ON CAPITAL STOCK	0.00	0.00	0.00	0.00
PAID-IN CAPITAL	230,015,879.19	2,350,434.87	88,480,323.68	245,003,620.64
RETAINED EARNINGS	139,604,354.66	125,428,607.47	(95,107,923.50)	359,906,742.39
ACCUMULATED OTHER COMPREHENSIVE INCOME (LOSS)	(43,842,226.00)	(26,718,139.00)	0.00	(43,910,171.00)
COMMON SHAREHOLDER'S EQUITY	483,008,007.85	238,274,903.34	(6,626,599.81)	696,659,712.03
MINORITY INTEREST	0.00	0.00	0.00	1,367,190.61
LIABILITIES HELD FOR SALE - TEXAS GENERATION PLANTS	0.00	0.00	0.00	0.00
TOTAL CAPITALIZATION AND LIABILITIES	$1,970,032,156.21	$1,009,509,388.90	$293,512,139.70	$2,581,962,677.45

Item 10 - Consolidating Balance Sheets

AEP UTILITIES, INCORPORATED
CONSOLIDATING BALANCE SHEET
DECEMBER 31, 2003

Note - Totals and subtotals may be off due to rounding

DESCRIPTION	CSW INTERNATIONAL INCORPORATED	C3 COMMUNICATIONS INCORPORATED	CSW ENERGY SERVICES INCORPORATED
ASSETS:			
CURRENT AND ACCRUED ASSETS			
CASH AND CASH EQUIVALENTS	$2,332,801.50	$58,828.18	($623,857.33)
ADVANCES TO AFFILIATES	0.00	0.00	0.00
ACCOUNTS RECEIVABLE - CUSTOMERS	0.00	0.00	0.00
ACCOUNTS RECEIVABLE - AFFILIATED COMPANIES	56,820.03	28,848.77	38,674.00
ACCOUNTS RECEIVABLE - ACCRUED UNBILLED REVENUES	0.00	0.00	0.00
ACCOUNTS RECEIVABLE - MISCELLANEOUS	5,950,271.21	21,680.44	19,146,191.69
ACCOUNTS RECEIVABLE - ALLOWANCE FOR UNCOLLECTIBLE ACCOUNT	(5,950,242.47)	(21,057.72)	0.00
FUEL INVENTORY	0.00	0.00	0.00
MATERIALS & SUPPLIES	0.00	0.00	1,915,509.57
REGULATORY ASSET FOR UNDER-RECOVERED FUEL COST	0.00	0.00	0.00
RISK MANAGEMENT ASSETS	0.00	0.00	0.00
MARGIN DEPOSITS	0.00	0.00	0.00
PREPAYMENTS	17,500.21	45,586.13	1,182,924.67
OTHER	0.00	0.04	0.00
TOTAL CURRENT ASSETS	2,407,150.48	133,885.84	21,659,442.60
ELECTRIC UTILITY PLANT			
TOTAL ELECTRIC UTILITY PLANT	0.00	(131.37)	11,102,735.31
ACCUMULATED DEPRECIATION AND AMORTIZATION	0.00	0.00	(160.64)
ELECTRIC UTILITY PLANT - NET	0.00	(131.37)	11,102,574.67
OTHER PROPERTY AND INVESTMENTS			
NON-UTILITY PROPERTY, NET	0.00	0.00	0.00
OTHER INVESTMENTS	0.00	0.00	0.00
TOTAL OTHER PROPERTY AND INVESTMENTS	0.00	0.00	0.00
INVESTMENTS IN POWER AND DISTRIBUTION PROJECTS	0.00	0.00	0.00
REGULATORY ASSETS	0.00	0.00	0.00
FAS 109 DEFERRED FIT RECLASS	0.00	0.00	0.00
NET REGULATORY ASSETS	0.00	0.00	0.00
GOODWILL	0.00	0.00	2,662,500.00
INTANGIBLE ASSETS	0.00	0.00	0.00
LONG-TERM RISK MANAGEMENT ASSETS	0.00	0.00	0.00
OTHER ASSETS			
TOTAL OTHER INVESTMENTS	0.00	0.00	0.00
TOTAL OTHER SPECIAL FUNDS	0.00	0.00	0.00
CLEARING ACCOUNTS	0.00	0.00	0.00
UNAMORTIZED DEBT EXPENSE	0.00	919,667.92	320,103.31
PREFERRED STOCK DIVIDEND REQUIREMENT OF SUBSIDIARIES	0.00	0.00	0.00
OTHER DEFERRED DEBITS	(20,883.49)	833,300.00	443,886.93
TOTAL OTHER ASSETS	(20,883.49)	1,752,967.92	763,990.24
ASSETS HELD FOR SALE - TEXAS GENERATION PLANT	0.00	0.00	0.00
TOTAL ASSETS	$2,386,266.99	$1,886,722.39	$36,188,507.50

Item 10 - Consolidating Balance Sheets

AEP UTILITIES, INCORPORATED
CONSOLIDATING BALANCE SHEET
DECEMBER 31, 2003

Note - Totals and subtotals may be off due to rounding

DESCRIPTION	CSW INTERNATIONAL INCORPORATED	C3 COMMUNICATIONS INCORPORATED	CSW ENERGY SERVICES INCORPORATED
CAPITALIZATION AND LIABILITIES:			
CURRENT LIABILITIES			
LONG-TERM DEBT DUE WITHIN ONE YEAR	$0.00	$0.00	$0.00
SHORT-TERM DEBT	0.00	0.00	18,345,548.00
ADVANCES FROM AFFILIATES	42,518,442.70	43,041,340.68	28,309,611.23
ACCOUNTS PAYABLE - GENERAL	27,031.57	0.00	527,290.00
ACCOUNTS PAYABLE - AFFILIATED COMPANIES	1,633,960.62	1,509,498.68	428,964.60
CUSTOMER DEPOSITS	0.00	0.00	0.00
TAXES ACCRUED	22,513,672.34	(1,477,570.71)	(431,482.26)
INTEREST ACCRUED	0.00	0.00	0.00
RISK MANAGEMENT LIABILITIES	0.00	0.00	0.00
OBLIGATIONS UNDER CAPITAL LEASES	0.00	0.00	0.00
OVER-RECOVERY OF FUEL COST	0.00	0.00	0.00
DIVIDENDS DECLARED	0.00	0.00	0.00
OTHER	13,385,620.84	8,353,316.15	9,456,768.49
TOTAL CURRENT LIABILITIES	80,078,728.07	51,426,584.80	56,636,700.06
LONG-TERM RISK MANAGEMENT LIABILITIES	0.00	0.00	0.00
DEFERRED INCOME TAXES	3,535.00	381,303.00	547,926.00
DEFERRED FIT & SIT RECLASS	(89,104,187.00)	(4,322,813.00)	(10,198,117.00)
NET DEFERRED INCOME TAXES	(89,100,652.00)	(3,941,510.00)	(9,650,191.00)
DEFERRED INVESTMENT TAX CREDITS	0.00	0.00	0.00
SFAS 109 REGULATORY LIABILITY, NET	0.00	0.00	0.00
ASSET REMOVAL COSTS	0.00	0.00	0.00
LONG-TERM DEBT	0.00	139,797,839.96	48,180,686.00
OVER-RECOVERY OF FUEL COST	0.00	0.00	0.00
OTHER REGULATORY LIABILTIES	0.00	0.00	0.00
UNAMORTIZED GAIN REACQUIRED DEBT	0.00	0.00	0.00
TOTAL REGULATORY LIABILITIES	0.00	0.00	0.00
TOTAL OTHER DEFERRED CREDITS	480,325.62	263,999.00	2,635,622.24
TOTAL DEFERRED CREDITS & REGULATORY LIABILITIES	480,325.62	263,999.00	2,635,622.24
CUSTOMER ADVANCES FOR CONSTRUCTION	0.00	0.00	0.00
OBLIGATIONS UNDER CAPITAL LEASES	0.00	0.00	0.00
ACCUMULATED PROVISIONS - RATE REFUND	0.00	0.00	0.00
ACCUMULATED PROVISIONS - MISCELLANEOUS	0.00	28,800.77	0.00
ASSET RETIREMENT OBLIGATIONS	0.00	0.00	0.00
TOTAL OTHER NONCURRENT LIABILITIES	0.00	28,800.77	0.00
CUMULATIVE PREFERRED STOCK OF SUBSIDIARIES SUBJECT TO MANDATORY REDEMPTION	0.00	0.00	0.00
CUMULATIVE PREFERRED STOCK OF SUBSIDIARIES NOT SUBJECT TO MANDATORY REDEMPTION	0.00	0.00	0.00
COMMON STOCK			
COMMON STOCK	1,000.00	1,000.00	1,000.00
PREMIUM ON CAPITAL STOCK	0.00	0.00	0.00
PAID-IN CAPITAL	179,466,937.42	0.00	0.00
RETAINED EARNINGS	(168,540,072.12)	(185,689,992.14)	(61,615,309.80)
ACCUMULATED OTHER COMPREHENSIVE INCOME (LOSS)	0.00	0.00	0.00
COMMON SHAREHOLDER'S EQUITY	10,927,865.30	(185,688,992.14)	(61,614,309.80)
MINORITY INTEREST	0.00	0.00	0.00
LIABILITIES HELD FOR SALE - TEXAS GENERATION PLANTS	0.00	0.00	0.00
TOTAL CAPITALIZATION AND LIABILITIES	$2,386,266.99	$1,886,722.39	$36,188,507.50

Item 10 - Consolidating Balance Sheets

AEP TEXAS CENTRAL COMPANY AND SUBSIDIARY
CONSOLIDATING BALANCE SHEET
DECEMBER 31, 2003

Note - Totals and subtotals may be off due to rounding

DESCRIPTION	AEP TEXAS CENTRAL COMPANY CONSOLIDATED	SEC REPORTING ADJUSTMENTS	AEP TEXAS CENTRAL COMPANY ELIMINATIONS
ASSETS:			
ELECTRIC UTILITY PLANT			
TOTAL ELECTRIC UTILITY PLANT	$2,425,038,000.00	($2,206,275,866.07)	$0.00
ACCUMULATED DEPRECIATION AND AMORTIZATION	(695,358,935.97)	1,492,248,937.00	0.00
ELECTRIC UTILITY PLANT - NET	1,729,679,064.03	(714,026,929.07)	0.00
OTHER PROPERTY AND INVESTMENTS			
NON-UTILITY PROPERTY, NET	1,302,074.99	0.00	0.00
INVESTMENT IN SUBSIDIARIES AND ASSOCIATES	0.00	0.00	(4,066,241.86)
OTHER INVESTMENTS	4,639,200.00	4,639,200.00	0.00
TOTAL OTHER PROPERTY AND INVESTMENTS	5,941,274.99	4,639,200.00	(4,066,241.86)
CURRENT ASSETS			
CASH AND CASH EQUIVALENTS	65,882,383.28	0.00	0.00
ADVANCES TO AFFILIATES	60,698,653.80	0.00	0.00
ACCOUNTS RECEIVABLE - CUSTOMERS	146,630,328.79	50,988,548.24	0.00
ACCOUNTS RECEIVABLE - AFFILIATED COMPANIES	78,484,461.21	0.00	(14,801,842.28)
ACCOUNTS RECEIVABLE - ACCRUED UNBILLED REVENUES	23,076,876.57	0.00	0.00
ACCOUNTS RECEIVABLE - MISCELLANEOUS	0.00	(50,988,548.24)	0.00
ACCOUNTS RECEIVABLE - ALLOWANCE FOR UNCOLLECTIBLE ACCOUNTS	(1,709,988.26)	0.00	0.00
FUEL INVENTORY	0.30	0.00	0.00
MATERIALS AND SUPPLIES	11,709,156.27	(35,244,199.00)	0.00
RISK MANAGEMENT ASSETS	22,050,547.90	0.00	0.00
MARGIN DEPOSITS	3,229,459.28	3,229,459.28	0.00
PREPAYMENTS	6,757,510.78	0.00	0.00
OTHER	12,075.00	(3,229,459.28)	0.00
TOTAL CURRENT ASSETS	416,821,464.92	(35,244,199.00)	(14,801,842.28)
DEFERRED DEBITS AND OTHER ASSETS			
REGULATORY ASSETS	1,922,455,792.59	(48,701,070.85)	0.00
FAS 109 DEFERRED FIT RECLASS	(30,905,150.00)	0.00	0.00
CLEARING ACCOUNTS	9,162,796.15	0.00	0.00
UNAMORTIZED DEBT EXPENSE	40,355,271.70	0.00	0.00
TOTAL OTHER SPECIAL FUNDS	0.00	(125,383,429.15)	0.00
TOTAL OTHER INVESTMENTS	689,399,160.00	(4,639,200.00)	0.00
LONG-TERM RISK MANAGEMENT ASSETS	7,627,391.95	0.00	0.00
OTHER DEFERRED DEBITS	6,035,972.18	0.00	(0.04)
TOTAL DEFERRED DEBITS AND OTHER ASSETS	2,644,131,234.58	(178,723,700.00)	(0.04)
ASSETS HELD FOR SALE	1,028,134,000.00	1,028,134,000.00	0.00
TOTAL ASSETS	$5,824,707,038.51	$104,778,371.93	($18,868,084.18)

Item 10 - Consolidating Balance Sheets

AEP TEXAS CENTRAL COMPANY AND SUBSIDIARY
CONSOLIDATING BALANCE SHEET
DECEMBER 31, 2003

Note - Totals and subtotals may be off due to rounding

DESCRIPTION	AEP TEXAS CENTRAL COMPANY CONSOLIDATED	SEC REPORTING ADJUSTMENTS	AEP TEXAS CENTRAL COMPANY ELIMINATIONS
CAPITALIZATION AND LIABILITIES:			
CAPITALIZATION			
COMMON STOCK	$55,291,944.53	$0.00	$0.00
PREMIUM ON CAPITAL STOCK	0.00	(15,041.22)	0.00
PAID-IN CAPITAL	132,606,982.69	61,887,385.22	(3,986,675.00)
RETAINED EARNINGS	1,083,022,567.79	0.00	(79,566.86)
ACCUMULATED OTHER COMPREHENSIVE INCOME	(61,872,344.00)	(61,872,344.00)	0.00
COMMON SHAREHOLDERS' EQUITY	1,209,049,151.01	0.00	(4,066,241.86)
CUMULATIVE PREFERRED STOCK NOT SUBJECT TO MANDATORY REDEMPTION	5,940,300.00	0.00	0.00
LONG-TERM DEBT	2,053,974,012.58	0.00	0.00
TOTAL CAPITALIZATION	3,268,963,463.59	0.00	(4,066,241.86)
CURRENT LIABILITIES			
LONG-TERM DEBT DUE WITHIN ONE YEAR	237,651,004.00	0.00	0.00
ACCOUNTS PAYABLE - GENERAL	90,003,762.18	0.00	0.00
ACCOUNTS PAYABLE - AFFILIATED COMPANIES	74,209,243.66	0.00	(14,801,842.32)
CUSTOMER DEPOSITS	1,517,146.16	0.00	0.00
TAXES ACCRUED	67,017,583.55	0.00	0.00
INTEREST ACCRUED	43,196,060.74	1,287,875.00	0.00
RISK MANAGEMENT LIABILITIES	17,888,265.90	0.00	0.00
OBLIGATIONS UNDER CAPITAL LEASES	406,834.52	0.00	0.00
DIVIDENDS DECLARED	40,195.58	0.00	0.00
OTHER	23,207,572.16	0.00	0.00
TOTAL CURRENT LIABILITIES	555,137,668.44	1,287,875.00	(14,801,842.32)
DEFERRED CREDITS AND OTHER LIABILITIES			
DEFERRED INCOME TAXES	1,506,888,537.00	0.00	0.00
DEFERRED FIT & SIT RECLASS	(261,976,194.00)	0.00	0.00
LONG-TERM RISK MANAGEMENT LIABILITIES	2,659,930.24	0.00	0.00
ASSET REMOVAL COSTS	95,414,745.00	95,414,745.00	0.00
DEFERRED INVESTMENT TAX CREDITS	112,478,774.00	0.00	0.00
OBLIGATIONS UNDER CAPITAL LEASES	635,714.96	0.00	0.00
OVER-RECOVERY OF FUEL COST	69,026,079.99	(1,287,875.00)	0.00
OTHER REGULATORY LIABILTIES	102,506,263.58	0.00	0.00
UNAMORT GAIN ON REACQUIRED DEBT	5,258.50	0.00	0.00
CUSTOMER ADVANCES FOR CONSTRUCTION	2,065,500.00	0.00	0.00
ACCUMULATED PROVISIONS - RATE REFUND	82,597,000.00	0.00	0.00
ACCUMULATED PROVISIONS - MISCELLANEOUS	54,682,880.65	(218,770,373.07)	0.00
OTHER DEFERRED CREDITS	5,487,416.56	0.00	0.00
TOTAL DEFERRED CREDITS AND OTHER LIABILITIES	1,772,471,906.48	(124,643,503.07)	0.00
LIABILITIES HELD FOR SALE - TEXAS GENERATION PLANTS	228,134,000.00	228,134,000.00	0.00
TOTAL CAPITALIZATION & LIABILITIES	$5,824,707,038.51	$104,778,371.93	($18,868,084.18)

Item 10 - Consolidating Balance Sheets

AEP TEXAS CENTRAL COMPANY AND SUBSIDIARY
CONSOLIDATING BALANCE SHEET
DECEMBER 31, 2003

Note - Totals and subtotals may be off due to rounding

DESCRIPTION	AEP TEXAS CENTRAL COMPANY	AEP TEXAS CENTRAL COMPANY SEC
ASSETS:		
ELECTRIC UTILITY PLANT		
TOTAL ELECTRIC UTILITY PLANT	$4,631,313,866.07	$0.00
ACCUMULATED DEPRECIATION AND AMORTIZATION	(2,187,607,872.97)	0.00
ELECTRIC UTILITY PLANT - NET	2,443,705,993.10	0.00
OTHER PROPERTY AND INVESTMENTS		
NON-UTILITY PROPERTY, NET	1,302,074.99	0.00
INVESTMENT IN SUBSIDIARIES AND ASSOCIATES	4,066,241.86	0.00
OTHER INVESTMENTS	0.00	0.00
TOTAL OTHER PROPERTY AND INVESTMENTS	5,368,316.85	0.00
CURRENT ASSETS		
CASH AND CASH EQUIVALENTS	5,693,508.30	60,188,874.98
ADVANCES TO AFFILIATES	60,698,653.80	0.00
ACCOUNTS RECEIVABLE - CUSTOMERS	95,641,780.55	0.00
ACCOUNTS RECEIVABLE - AFFILIATED COMPANIES	78,542,599.71	14,743,703.78
ACCOUNTS RECEIVABLE - ACCRUED UNBILLED REVENUES	23,076,876.57	0.00
ACCOUNTS RECEIVABLE - MISCELLANEOUS	50,988,548.24	0.00
ACCOUNTS RECEIVABLE - ALLOWANCE FOR UNCOLLECTIBLE ACCOUNTS	(1,709,988.26)	0.00
FUEL INVENTORY	0.30	0.00
MATERIALS AND SUPPLIES	46,953,355.27	0.00
RISK MANAGEMENT ASSETS	22,050,547.90	0.00
MARGIN DEPOSITS	0.00	0.00
PREPAYMENTS	6,755,684.03	1,826.75
OTHER	3,241,534.28	0.00
TOTAL CURRENT ASSETS	391,933,100.69	74,934,405.51
DEFERRED DEBITS AND OTHER ASSETS		
REGULATORY ASSETS	1,971,156,863.44	0.00
FAS 109 DEFERRED FIT RECLASS	(30,905,150.00)	0.00
CLEARING ACCOUNTS	9,162,796.15	0.00
UNAMORTIZED DEBT EXPENSE	13,344,803.70	27,010,468.00
TOTAL OTHER SPECIAL FUNDS	125,383,429.15	0.00
TOTAL OTHER INVESTMENTS	4,639,234.00	689,399,126.00
LONG-TERM RISK MANAGEMENT ASSETS	7,627,391.95	0.00
OTHER DEFERRED DEBITS	6,035,972.22	0.00
TOTAL DEFERRED DEBITS AND OTHER ASSETS	2,106,445,340.62	716,409,594.00
ASSETS HELD FOR SALE	0.00	0.00
TOTAL ASSETS	$4,947,452,751.25	$791,343,999.51

Item 10 - Consolidating Balance Sheets

AEP TEXAS CENTRAL COMPANY AND SUBSIDIARY
CONSOLIDATING BALANCE SHEET
DECEMBER 31, 2003

Note - Totals and subtotals may be off due to rounding

DESCRIPTION	AEP TEXAS CENTRAL COMPANY	AEP TEXAS CENTRAL COMPANY SEC
CAPITALIZATION AND LIABILITIES:		
CAPITALIZATION		
COMMON STOCK	$55,291,944.53	$0.00
PREMIUM ON CAPITAL STOCK	15,041.22	0.00
PAID-IN CAPITAL	70,719,597.47	3,986,675.00
RETAINED EARNINGS	1,083,022,567.79	79,566.86
ACCUMULATED OTHER COMPREHENSIVE INCOME	0.00	0.00
COMMON SHAREHOLDERS' EQUITY	1,209,049,151.01	4,066,241.86
CUMULATIVE PREFERRED STOCK NOT SUBJECT TO MANDATORY REDEMPTION	5,940,300.00	0.00
LONG-TERM DEBT	1,356,845,147.58	697,128,865.00
TOTAL CAPITALIZATION	2,571,834,598.59	701,195,106.86
CURRENT LIABILITIES		
LONG-TERM DEBT DUE WITHIN ONE YEAR	189,100,000.00	48,551,004.00
ACCOUNTS PAYABLE - GENERAL	90,003,762.18	0.00
ACCOUNTS PAYABLE - AFFILIATED COMPANIES	88,952,947.48	58,138.50
CUSTOMER DEPOSITS	1,517,146.16	0.00
TAXES ACCRUED	67,017,583.55	0.00
INTEREST ACCRUED	22,867,463.46	19,040,722.28
RISK MANAGEMENT LIABILITIES	17,888,265.90	0.00
OBLIGATIONS UNDER CAPITAL LEASES	406,834.52	0.00
DIVIDENDS DECLARED	40,195.58	0.00
OTHER	23,207,572.16	0.00
TOTAL CURRENT LIABILITIES	501,001,770.98	67,649,864.78
DEFERRED CREDITS AND OTHER LIABILITIES		
DEFERRED INCOME TAXES	1,506,888,537.00	0.00
DEFERRED FIT & SIT RECLASS	(261,976,194.00)	0.00
LONG-TERM RISK MANAGEMENT LIABILITIES	2,659,930.24	0.00
ASSET REMOVAL COSTS	0.00	0.00
DEFERRED INVESTMENT TAX CREDITS	112,478,774.00	0.00
OBLIGATIONS UNDER CAPITAL LEASES	635,714.96	0.00
OVER-RECOVERY OF FUEL COST	70,313,954.99	0.00
OTHER REGULATORY LIABILTIES	80,007,235.71	22,499,027.87
UNAMORT GAIN ON REACQUIRED DEBT	5,258.50	0.00
CUSTOMER ADVANCES FOR CONSTRUCTION	2,065,500.00	0.00
ACCUMULATED PROVISIONS - RATE REFUND	82,597,000.00	0.00
ACCUMULATED PROVISIONS - MISCELLANEOUS	273,453,253.72	0.00
OTHER DEFERRED CREDITS	5,487,416.56	0.00
TOTAL DEFERRED CREDITS AND OTHER LIABILITIES	1,874,616,381.68	22,499,027.87
LIABILITIES HELD FOR SALE - TEXAS GENERATION PLANTS	0.00	0.00
TOTAL CAPITALIZATION & LIABILITIES	$4,947,452,751.25	$791,343,999.51

Item 10 - Consolidating Balance Sheets

APPALACHIAN POWER COMPANY AND SUBSIDIARIES
CONSOLIDATING BALANCE SHEET
DECEMBER 31, 2003

Note - Totals and subtotals may be off due to rounding

DESCRIPTION	APPALACHIAN POWER COMPANY CONSOLIDATED	SEC REPORTING ADJUSTMENTS	APPALACHIAN POWER COMPANY ELIMINATIONS	APPALACHIAN POWER COMPANY
ASSETS:				
ELECTRIC UTILITY PLANT				
TOTAL ELECTRIC UTILITY PLANT	$6,140,930,644.39	$0.00	$0.00	$6,140,930,644.39
ACCUMULATED DEPRECIATION AND AMORTIZATION	(2,321,359,209.92)	92,497,334.00	0.00	(2,413,856,543.92)
ELECTRIC UTILITY PLANT - NET	3,819,571,434.47	92,497,334.00	0.00	3,727,074,100.47
OTHER PROPERTY AND INVESTMENTS				
NON-UTILITY PROPERTY, NET	20,574,430.78	0.00	0.00	20,481,580.78
INVESTMENTS IN SUBSIDIARIES AND ASSOCIATES	603,868.00	0.00	(17,600,574.94)	18,204,442.94
OTHER INVESTMENTS	26,064,029.59	0.00	0.00	23,078,230.59
TOTAL OTHER PROPERTY AND INVESTMENTS	47,242,328.37	0.00	(17,600,574.94)	61,764,254.31
CURRENT ASSETS				
CASH AND CASH EQUIVALENTS	45,880,666.27	0.00	0.00	45,880,666.27
ADVANCES TO AFFILIATES	0.00	(23,453,681.22)	0.00	0.00
ACCOUNTS RECEIVABLE - CUSTOMERS	133,716,961.09	16,033,933.67	0.00	117,683,027.42
ACCOUNTS RECEIVABLE - AFFILIATED COMPANIES	137,281,246.61	0.00	(5,073,517.21)	141,104,655.71
ACCOUNTS RECEIVABLE - ACCRUED UNBILLED REVENUES	35,020,281.49	0.00	0.00	35,020,281.49
ACCOUNTS RECEIVABLE - MISCELLANEOUS	3,961,188.95	(16,033,933.67)	0.00	17,036,971.62
ACCOUNTS RECEIVABLE - ALLOWANCE FOR UNCOLLECTIBLE ACCOUNTS	(2,085,327.62)	0.00	0.00	(2,085,327.62)
FUEL INVENTORY	42,806,440.47	0.00	0.00	42,806,440.47
MATERIALS AND SUPPLIES	71,977,745.12	0.00	0.00	71,977,745.12
RISK MANAGEMENT ASSETS	71,189,275.85	0.00	0.00	71,189,275.85
MARGIN DEPOSITS	11,524,954.90	11,524,954.90	0.00	0.00
PREPAYMENTS	6,782,863.88	0.00	0.00	6,782,863.88
OTHER CURRENT ASSETS	6,517,480.00	(11,524,954.90)	0.00	17,962,388.90
TOTAL CURRENT ASSETS	564,573,777.02	(23,453,681.22)	(5,073,517.21)	565,358,989.12
DEFERRED DEBITS AND OTHER ASSETS				
REGULATORY ASSETS	446,327,739.76	0.00	0.00	446,327,739.76
FAS 109 DEFERRED FIT RECLASS	(29,131,302.00)	0.00	0.00	(29,131,302.00)
LONG-TERM RISK MANAGEMENT ASSETS	70,899,438.64	0.00	0.00	70,899,438.64
CLEARING ACCOUNTS	158,833.16	0.00	0.00	158,833.16
UNAMORTIZED DEBT EXPENSE	7,721,257.00	0.00	0.00	7,721,257.00
OTHER DEFERRED CHARGES	49,647,884.72	0.00	(0.03)	49,647,884.75
TOTAL DEFERRED DEBITS AND OTHER ASSETS	545,623,851.29	0.00	(0.03)	545,623,851.31
TOTAL ASSETS	$4,977,011,391.15	$69,043,652.78	($22,674,092.18)	$4,899,821,195.21

Item 10 - Consolidating Balance Sheets

APPALACHIAN POWER COMPANY AND SUBSIDIARIES
CONSOLIDATING BALANCE SHEET
DECEMBER 31, 2003

Note - Totals and subtotals may be off due to rounding

DESCRIPTION	APPALACHIAN POWER COMPANY CONSOLIDATED	SEC REPORTING ADJUSTMENTS	APPALACHIAN POWER COMPANY ELIMINATIONS	APPALACHIAN POWER COMPANY
CAPITALIZATION AND LIABILITIES:				
CAPITALIZATION				
COMMON STOCK	$260,457,768.00	$0.00	($209,950.00)	$260,457,768.00
PREMIUM ON CAPITAL STOCK	0.00	(762,543.38)	(8,900,000.01)	762,543.38
PAID-IN CAPITAL	719,899,208.64	52,850,234.02	(5,318,393.00)	668,548,415.62
RETAINED EARNINGS	408,718,478.89	0.00	(3,172,231.96)	408,718,478.87
ACCUMULATED OTHER COMPREHENSIVE INCOME (LOSS)	(52,087,690.64)	(52,087,690.64)	0.00	0.00
COMMON SHAREHOLDER'S EQUITY	1,336,987,764.89	0.00	(17,600,574.97)	1,338,487,205.87
CUMULATIVE PREFERRED STOCK				
NOT SUBJECT TO MANDATORY REDEMPTION	17,783,900.00	0.00	0.00	17,783,900.00
LIABILITY FOR CUMULATIVE PREFERRED STOCK				
SUBJECT TO MANDATORY REDEMPTION	5,360,000.00	5,360,000.00	0.00	0.00
LONG-TERM DEBT	1,703,072,765.43	(5,360,000.00)	0.00	1,708,432,765.43
TOTAL CAPITALIZATION	3,063,204,430.32	0.00	(17,600,574.97)	3,064,703,871.30
CURRENT LIABILITIES				
LONG-TERM DEBT DUE WITHIN ONE YEAR	161,008,387.76	0.00	0.00	161,008,387.76
ADVANCES FROM AFFILIATES	82,994,492.48	(23,453,681.22)	0.00	106,448,173.70
ACCOUNTS PAYABLE - GENERAL	140,497,345.72	0.00	0.00	140,497,345.72
ACCOUNTS PAYABLE - AFFILIATED COMPANIES	81,812,226.37	0.00	(5,073,517.21)	81,973,069.72
CUSTOMER DEPOSITS	33,929,606.82	0.00	0.00	33,929,606.82
TAXES ACCRUED	50,258,565.75	0.00	0.00	50,120,834.75
INTEREST ACCRUED	22,112,796.08	0.00	0.00	22,112,796.08
RISK MANAGEMENT LIABILITIES	51,429,954.00	0.00	0.00	51,429,954.00
OBLIGATIONS UNDER CAPITAL LEASES	9,217,759.36	0.00	0.00	9,217,759.36
DIVIDENDS DECLARED	186,190.92	0.00	0.00	186,190.92
OTHER	60,102,649.59	0.00	0.00	58,753,448.90
TOTAL CURRENT LIABILITIES	693,549,974.85	(23,453,681.22)	(5,073,517.21)	715,677,567.73
DEFERRED CREDITS AND OTHER LIABILITIES				
DEFERRED INCOME TAXES	1,008,854,037.88	0.00	0.00	1,007,387,625.88
DEFERRED FIT & SIT RECLASS	(205,498,809.48)	0.00	0.00	(193,911,621.48)
ASSET REMOVAL COSTS	92,497,334.00	92,497,334.00	0.00	0.00
DEFERRED INVESTMENT TAX CREDITS	30,544,863.00	0.00	0.00	30,544,863.00
OVER-RECOVERY OF FUEL COST	68,704,458.11	0.00	0.00	68,704,458.11
UNREALIZED GAIN ON FORWARD COMMITMENTS	17,282,832.10	0.00	0.00	17,282,832.10
UNAMORTIZED GAIN ON REACQUIRED DEBT	43,054.00	0.00	0.00	43,054.00
LONG-TERM RISK MANAGEMENT LIABILITIES	54,326,567.66	0.00	0.00	54,326,567.66
OBLIGATIONS UNDER CAP LEASE	16,134,017.39	0.00	0.00	16,134,017.39
ASSET RETIREMENT OBLIGATIONS	21,776,104.85	21,776,104.85	0.00	0.00
ACCUMULATED PROVISIONS - MISCELLANEOUS	102,462,814.22	(21,776,104.85)	0.00	105,953,247.28
DEFERRED GAINS ON SALE/LEASEBACK	88,288.00	0.00	0.00	88,288.00
OTHER DEFERRED CREDITS	13,041,424.25	0.00	0.00	12,886,424.25
TOTAL DEFERRED CREDITS AND OTHER LIABILITIES	1,220,256,985.97	92,497,334.00	0.00	1,119,439,756.18
TOTAL CAPITALIZATION AND LIABILITIES	$4,977,011,391.15	$69,043,652.78	($22,674,092.18)	$4,899,821,195.21

Item 10 - Consolidating Balance Sheets

APPALACHIAN POWER COMPANY AND SUBSIDIARIES
CONSOLIDATING BALANCE SHEET
DECEMBER 31, 2003

Note - Totals and subtotals may be off due to rounding

DESCRIPTION	CENTRAL APPALACHIAN COAL COMPANY	SOUTHERN APPALACHIAN COAL COMPANY	CEDAR COAL COMPANY
ASSETS:			
ELECTRIC UTILITY PLANT			
TOTAL ELECTRIC UTILITY PLANT	$0.00	$0.00	$0.00
ACCUMULATED DEPRECIATION AND AMORTIZATION	0.00	0.00	0.00
ELECTRIC UTILITY PLANT - NET	0.00	0.00	0.00
OTHER PROPERTY AND INVESTMENTS			
NON-UTILITY PROPERTY, NET	0.00	92,850.00	0.00
INVESTMENTS IN SUBSIDIARIES AND ASSOCIATES	0.00	0.00	0.00
OTHER INVESTMENTS	113,467.00	1,436,169.00	1,436,163.00
TOTAL OTHER PROPERTY AND INVESTMENTS	113,467.00	1,529,019.00	1,436,163.00
CURRENT ASSETS			
CASH AND CASH EQUIVALENTS	0.00	0.00	0.00
ADVANCES TO AFFILIATES	1,755,084.92	7,813,474.51	13,885,121.79
ACCOUNTS RECEIVABLE - CUSTOMERS	0.00	0.00	0.00
ACCOUNTS RECEIVABLE - AFFILIATED COMPANIES	237,736.71	0.00	1,012,371.40
ACCOUNTS RECEIVABLE - ACCRUED UNBILLED REVENUES	0.00	0.00	0.00
ACCOUNTS RECEIVABLE - MISCELLANEOUS	92,416.00	1,695,943.00	1,169,792.00
ACCOUNTS RECEIVABLE - ALLOWANCE FOR UNCOLLECTIBLE ACCOUNTS	0.00	0.00	0.00
FUEL INVENTORY	0.00	0.00	0.00
MATERIALS AND SUPPLIES	0.00	0.00	0.00
RISK MANAGEMENT ASSETS	0.00	0.00	0.00
MARGIN DEPOSITS	0.00	0.00	0.00
PREPAYMENTS	0.00	0.00	0.00
OTHER CURRENT ASSETS	0.00	0.00	80,046.00
TOTAL CURRENT ASSETS	2,085,237.63	9,509,417.51	16,147,331.19
DEFERRED DEBITS AND OTHER ASSETS			
REGULATORY ASSETS	0.00	0.00	0.00
FAS 109 DEFERRED FIT RECLASS	0.00	0.00	0.00
LONG-TERM RISK MANAGEMENT ASSETS	0.00	0.00	0.00
CLEARING ACCOUNTS	0.00	0.00	0.00
UNAMORTIZED DEBT EXPENSE	0.00	0.00	0.00
OTHER DEFERRED CHARGES	0.00	0.00	0.00
TOTAL DEFERRED DEBITS AND OTHER ASSETS	0.00	0.00	0.00
TOTAL ASSETS	$2,198,704.63	$11,038,436.51	$17,583,494.19

Item 10 - Consolidating Balance Sheets

APPALACHIAN POWER COMPANY AND SUBSIDIARIES
CONSOLIDATING BALANCE SHEET
DECEMBER 31, 2003

Note - Totals and subtotals may be off due to rounding

DESCRIPTION	CENTRAL APPALACHIAN COAL COMPANY	SOUTHERN APPALACHIAN COAL COMPANY	CEDAR COAL COMPANY
CAPITALIZATION AND LIABILITIES:			
CAPITALIZATION			
COMMON STOCK	$3,000.00	$6,950.00	$200,000.00
PREMIUM ON CAPITAL STOCK	0.00	8,900,000.01	0.00
PAID-IN CAPITAL	449,990.00	0.00	3,368,962.00
RETAINED EARNINGS	428,746.01	1,864,897.01	878,588.96
ACCUMULATED OTHER COMPREHENSIVE INCOME (LOSS)	0.00	0.00	0.00
COMMON SHAREHOLDER'S EQUITY	881,736.01	10,771,847.02	4,447,550.96
CUMULATIVE PREFERRED STOCK NOT SUBJECT TO MANDATORY REDEMPTION	0.00	0.00	0.00
LIABILITY FOR CUMULATIVE PREFERRED STOCK SUBJECT TO MANDATORY REDEMPTION	0.00	0.00	0.00
LONG-TERM DEBT	0.00	0.00	0.00
TOTAL CAPITALIZATION	881,736.01	10,771,847.02	4,447,550.96
CURRENT LIABILITIES			
LONG-TERM DEBT DUE WITHIN ONE YEAR	0.00	0.00	0.00
ADVANCES FROM AFFILIATES	0.00	0.00	0.00
ACCOUNTS PAYABLE - GENERAL	0.00	0.00	0.00
ACCOUNTS PAYABLE - AFFILIATED COMPANIES	142,659.62	207,074.49	4,562,939.75
CUSTOMER DEPOSITS	0.00	0.00	0.00
TAXES ACCRUED	83,222.00	(80,038.00)	134,547.00
INTEREST ACCRUED	0.00	0.00	0.00
RISK MANAGEMENT LIABILITIES	0.00	0.00	0.00
OBLIGATIONS UNDER CAPITAL LEASES	0.00	0.00	0.00
DIVIDENDS DECLARED	0.00	0.00	0.00
OTHER	569,903.00	132,978.00	646,319.69
TOTAL CURRENT LIABILITIES	795,784.62	260,014.49	5,343,806.44
DEFERRED CREDITS AND OTHER LIABILITIES			
DEFERRED INCOME TAXES	58,100.00	171,463.00	1,236,849.00
DEFERRED FIT & SIT RECLASS	(1,026,296.00)	(773,424.00)	(9,787,468.00)
ASSET REMOVAL COSTS	0.00	0.00	0.00
DEFERRED INVESTMENT TAX CREDITS	0.00	0.00	0.00
OVER-RECOVERY OF FUEL COST	0.00	0.00	0.00
UNREALIZED GAIN ON FORWARD COMMITMENTS	0.00	0.00	0.00
UNAMORTIZED GAIN ON REACQUIRED DEBT	0.00	0.00	0.00
LONG-TERM RISK MANAGEMENT LIABILITIES	0.00	0.00	0.00
OBLIGATIONS UNDER CAP LEASE	0.00	0.00	0.00
ASSET RETIREMENT OBLIGATIONS	0.00	0.00	0.00
ACCUMULATED PROVISIONS - MISCELLANEOUS	1,489,380.00	453,536.00	16,342,755.79
DEFERRED GAINS ON SALE/LEASEBACK	0.00	0.00	0.00
OTHER DEFERRED CREDITS	0.00	155,000.00	0.00
TOTAL DEFERRED CREDITS AND OTHER LIABILITIES	521,184.00	6,575.00	7,792,136.79
TOTAL CAPITALIZATION AND LIABILITIES	$2,198,704.63	$11,038,436.51	$17,583,494.19

Item 10 - Consolidating Balance Sheets

COLUMBUS SOUTHERN POWER COMPANY AND SUBSIDIARIES
CONSOLIDATING BALANCE SHEET
DECEMBER 31, 2003

Note - Totals and subtotals may be off due to rounding

DESCRIPTION	COLUMBUS SOUTHERN POWER COMPANY CONSOLIDATED	SEC REPORTING ADJUSTMENTS	COLUMBUS SOUTHERN POWER COMPANY ELIMINATIONS	COLUMBUS SOUTHERN POWER COMPANY
ASSETS:				
ELECTRIC UTILITY PLANT				
TOTAL ELECTRIC UTILITY PLANT	$3,570,443,772.21	$0.00	$0.00	$3,557,784,306.94
ACCUMULATED DEPRECIATION AND AMORTIZATION	(1,389,586,507.63)	99,118,885.00	0.00	(1,485,433,455.31)
ELECTRIC UTILITY PLANT - NET	2,180,857,264.58	99,118,885.00	0.00	2,072,350,851.63
OTHER PROPERTY AND INVESTMENTS				
NON-UTILITY PROPERTY, NET	22,417,574.08	0.00	0.00	21,793,822.70
INVESTMENTS IN SUBSIDIARIES AND ASSOCIATES	430,000.00	0.00	(9,603,038.46)	10,033,038.46
OTHER INVESTMENTS	8,232,793.95	0.00	0.00	8,140,857.95
TOTAL OTHER PROPERTY AND INVESTMENTS	31,080,368.03	0.00	(9,603,038.46)	39,967,719.11
CURRENT ASSETS				
CASH AND CASH EQUIVALENTS	4,142,432.16	0.00	0.00	4,140,432.16
ADVANCES TO AFFILIATES, NET	0.00	(2,376,280.91)	0.00	0.00
ACCOUNTS RECEIVABLE - CUSTOMERS	47,098,947.82	12,959,165.57	0.00	34,135,691.82
ACCOUNTS RECEIVABLE - AFFILIATED COMPANIES	68,168,358.88	0.00	(221,595.17)	68,167,673.55
ACCOUNTS RECEIVABLE - ACCRUED UNBILLED REVENUES	23,722,456.95	0.00	0.00	23,722,456.95
ACCOUNTS RECEIVABLE - MISCELLANEOUS	5,256,826.22	(12,959,165.57)	0.00	18,194,150.08
ACCOUNTS RECEIVABLE - ALLOWANCE FOR UNCOLLECTIBLE ACCOUNTS	(531,483.10)	0.00	0.00	(531,483.10)
FUEL INVENTORY	14,364,800.66	0.00	0.00	14,364,800.66
MATERIALS AND SUPPLIES	44,376,806.74	0.00	0.00	43,062,755.57
RISK MANAGEMENT ASSETS	40,095,004.24	0.00	0.00	40,095,004.24
MARGIN DEPOSITS	6,636,268.45	6,636,268.45	0.00	0.00
PREPAYMENTS	8,341,261.47	0.00	0.00	8,341,131.47
OTHER CURRENT ASSETS	4,102,393.00	(6,636,268.45)	0.00	10,710,143.45
TOTAL CURRENT ASSETS	265,774,073.48	(2,376,280.91)	(221,595.17)	264,402,756.85
DEFERRED DEBITS AND OTHER ASSETS				
REGULATORY ASSETS	255,480,401.79	0.00	0.00	255,480,401.79
FAS 109 DEFERRED FIT RECLASS	(12,296,669.00)	0.00	0.00	(12,296,669.00)
LONG-TERM RISK MANAGEMENT ASSETS	39,932,076.92	0.00	0.00	39,932,076.92
CLEARING ACCOUNTS	57.87	0.00	0.00	57.87
UNAMORTIZED DEBT EXPENSE	5,986,961.53	0.00	0.00	5,986,961.53
OTHER DEFERRED DEBITS	71,551,108.63	0.00	0.01	71,428,726.46
TOTAL DEFERRED DEBITS AND OTHER ASSETS	360,653,937.74	0.00	0.01	77,415,745.86
TOTAL ASSETS	$2,838,365,643.83	$96,742,604.09	($9,824,633.61)	$2,737,252,883.16

Item 10 - Consolidating Balance Sheets

COLUMBUS SOUTHERN POWER COMPANY AND SUBSIDIARIES
CONSOLIDATING BALANCE SHEET
DECEMBER 31, 2003

Note - Totals and subtotals may be off due to rounding

DESCRIPTION	COLUMBUS SOUTHERN POWER COMPANY CONSOLIDATED	SEC REPORTING ADJUSTMENTS	COLUMBUS SOUTHERN POWER COMPANY ELIMINATIONS	COLUMBUS SOUTHERN POWER COMPANY
CAPITALIZATION AND LIABILITIES:				
CAPITALIZATION				
COMMON STOCK	$41,026,065.00	$0.00	($1,609,000.00)	$41,026,065.00
PREMIUM ON CAPITAL STOCK	0.00	(257,892,417.79)	(30,000.00)	257,892,417.79
PAID-IN CAPITAL	576,399,735.58	304,219,836.79	(668,589.30)	272,245,567.79
RETAINED EARNINGS	326,781,977.65	0.00	(4,473,147.15)	326,781,977.38
ACCUMULATED OTHER COMPREHENSIVE INCOME (LOSS)	(46,327,419.00)	(46,327,419.00)	0.00	0.00
COMMON SHAREHOLDER'S EQUITY	897,880,359.23	0.00	(6,780,736.45)	897,946,027.96
LONG-TERM DEBT	886,564,409.59	0.00	(2,822,302.00)	886,564,409.59
TOTAL CAPITALIZATION	1,784,444,768.82	0.00	(9,603,038.45)	1,784,510,437.55
CURRENT LIABILITIES				
LONG-TERM DEBT DUE WITHIN ONE YEAR - NONAFFILIATED	11,000,000.00	0.00	0.00	11,000,000.00
ADVANCES FROM AFFILIATES, NET	6,516,507.98	(2,376,280.91)	0.00	7,913,350.83
ACCOUNTS PAYABLE - GENERAL	58,219,859.77	0.00	0.00	57,992,150.33
ACCOUNTS PAYABLE - AFFILIATED COMPANIES	53,571,895.14	0.00	(221,595.17)	53,603,514.24
CUSTOMER DEPOSITS	19,727,363.58	0.00	0.00	19,727,363.58
TAXES ACCRUED	132,853,280.48	0.00	0.00	132,574,795.91
INTEREST ACCRUED	16,528,117.07	0.00	0.00	16,477,117.07
RISK MANAGEMENT LIABILITIES	28,966,379.38	0.00	0.00	28,966,379.38
OBLIGATIONS UNDER CAPITAL LEASES	4,220,839.94	0.00	0.00	4,220,839.94
DIVIDENDS DECLARED	(0.00)	0.00	0.00	(0.00)
OTHER	25,364,137.62	0.00	0.00	25,006,558.27
TOTAL CURRENT LIABILITIES	356,968,380.96	(2,376,280.91)	(221,595.17)	357,482,069.55
DEFERRED CREDITS AND OTHER LIABILITIES				
DEFERRED INCOME TAXES	546,259,293.00	0.00	0.00	545,238,093.00
DEFERRED FIT & SIT RECLASS	(87,760,993.00)	0.00	0.00	(86,118,764.00)
ASSET REMOVAL COSTS	99,118,885.00	99,118,885.00	0.00	0.00
ACCUMULATED PROVISIONS - MISC	41,689,669.16	(8,739,918.67)	0.00	47,314,088.84
DEFERRED INVESTMENT TAX CREDITS	30,796,639.00	0.00	0.00	30,789,093.00
LONG-TERM RISK MANAGEMENT LIABILITIES	30,597,885.62	0.00	0.00	30,597,885.62
CUSTOMER ADVANCES FOR CONSTRUCTION	250,000.00	0.00	0.00	250,000.00
OBLIGATIONS UNDER CAPITAL LEASES	11,396,660.35	0.00	0.00	11,396,660.35
ASSET RETIREMENT OBLIGATIONS	8,739,918.67	8,739,918.67	0.00	0.00
OTHER DEFERRED CREDITS	15,864,536.26	0.00	0.00	15,793,319.26
TOTAL DEFERRED CREDITS AND OTHER LIABILITIES	696,952,494.06	99,118,885.00	0.00	595,260,376.07
TOTAL CAPITALIZATION AND LIABILITIES	$2,838,365,643.83	$96,742,604.09	($9,824,633.61)	$2,737,252,883.16

Item 10 - Consolidating Balance Sheets

COLUMBUS SOUTHERN POWER COMPANY AND SUBSIDIARIES
CONSOLIDATING BALANCE SHEET
DECEMBER 31, 2003

Note - Totals and subtotals may be off due to rounding

DESCRIPTION	SIMCO INCORPORATED	COLOMET INCORPORATED	CONESVILLE COAL PREPARATION COMPANY
ASSETS:			
ELECTRIC UTILITY PLANT			
TOTAL ELECTRIC UTILITY PLANT	$1,821,376.18	$9,078,866.95	$1,759,222.15
ACCUMULATED DEPRECIATION AND AMORTIZATION	(1,636,239.29)	(206,922.12)	(1,428,775.91)
ELECTRIC UTILITY PLANT - NET	185,136.89	8,871,944.83	330,446.24
OTHER PROPERTY AND INVESTMENTS			
NON-UTILITY PROPERTY, NET	0.00	623,751.38	0.00
INVESTMENTS IN SUBSIDIARIES AND ASSOCIATES	0.00	0.00	0.00
OTHER INVESTMENTS	0.00	0.00	91,936.00
TOTAL OTHER PROPERTY AND INVESTMENTS	0.00	623,751.38	91,936.00
CURRENT ASSETS			
CASH AND CASH EQUIVALENTS	0.00	0.00	2,000.00
ADVANCES TO AFFILIATES, NET	333,003.98	0.00	2,043,276.93
ACCOUNTS RECEIVABLE - CUSTOMERS	0.00	0.00	4,090.43
ACCOUNTS RECEIVABLE - AFFILIATED COMPANIES	14,300.00	343.68	207,636.81
ACCOUNTS RECEIVABLE - ACCRUED UNBILLED REVENUES	0.00	0.00	0.00
ACCOUNTS RECEIVABLE - MISCELLANEOUS	0.00	2,260.00	19,581.71
ACCOUNTS RECEIVABLE - ALLOWANCE FOR UNCOLLECTIBLE ACCOUNTS	0.00	0.00	0.00
FUEL INVENTORY	0.00	0.00	0.00
MATERIALS AND SUPPLIES	0.00	0.00	1,314,051.17
RISK MANAGEMENT ASSETS	0.00	0.00	0.00
MARGIN DEPOSITS	0.00	0.00	0.00
PREPAYMENTS	0.00	0.00	130.00
OTHER CURRENT ASSETS	0.00	0.00	28,518.00
TOTAL CURRENT ASSETS	347,303.98	2,603.68	3,619,285.05
DEFERRED DEBITS AND OTHER ASSETS			
REGULATORY ASSETS	0.00	0.00	0.00
FAS 109 DEFERRED FIT RECLASS	0.00	0.00	0.00
LONG-TERM RISK MANAGEMENT ASSETS	0.00	0.00	0.00
CLEARING ACCOUNTS	0.00	0.00	0.00
UNAMORTIZED DEBT EXPENSE	0.00	0.00	0.00
OTHER DEFERRED DEBITS	0.00	122,382.16	(0.00)
TOTAL DEFERRED DEBITS AND OTHER ASSETS	0.00	122,382.16	(0.00)
TOTAL ASSETS	$532,440.87	$9,620,682.04	$4,041,667.28

Item 10 - Consolidating Balance Sheets

COLUMBUS SOUTHERN POWER COMPANY AND SUBSIDIARIES
CONSOLIDATING BALANCE SHEET
DECEMBER 31, 2003

Note - Totals and subtotals may be off due to rounding

DESCRIPTION	SIMCO INCORPORATED	COLOMET INCORPORATED	CONESVILLE COAL PREPARATION COMPANY
CAPITALIZATION AND LIABILITIES:			
CAPITALIZATION			
COMMON STOCK	$9,000.00	$1,500,000.00	$100,000.00
PREMIUM ON CAPITAL STOCK	0.00	30,000.00	0.00
PAID-IN CAPITAL	268,589.30	0.00	334,331.00
RETAINED EARNINGS	220,020.95	3,013,143.48	1,239,982.99
ACCUMULATED OTHER COMPREHENSIVE INCOME (LOSS)	0.00	0.00	0.00
COMMON SHAREHOLDER'S EQUITY	497,610.25	4,543,143.48	1,674,313.99
LONG-TERM DEBT	0.00	2,822,302.00	0.00
TOTAL CAPITALIZATION	497,610.25	7,365,445.48	1,674,313.99
CURRENT LIABILITIES			
LONG-TERM DEBT DUE WITHIN ONE YEAR - NONAFFILIATED	0.00	0.00	0.00
ADVANCES FROM AFFILIATES, NET	0.00	979,438.06	0.00
ACCOUNTS PAYABLE - GENERAL	0.00	0.00	227,709.44
ACCOUNTS PAYABLE - AFFILIATED COMPANIES	0.00	319.51	189,656.55
CUSTOMER DEPOSITS	0.00	0.00	0.00
TAXES ACCRUED	11,061.62	213,353.00	54,069.95
INTEREST ACCRUED	0.00	0.00	51,000.00
RISK MANAGEMENT LIABILITIES	0.00	0.00	0.00
OBLIGATIONS UNDER CAPITAL LEASES	0.00	0.00	0.00
DIVIDENDS DECLARED	0.00	0.00	0.00
OTHER	0.00	0.00	357,579.35
TOTAL CURRENT LIABILITIES	11,061.62	1,193,110.57	880,015.30
DEFERRED CREDITS AND OTHER LIABILITIES			
DEFERRED INCOME TAXES	71,385.00	990,909.00	(41,094.00)
DEFERRED FIT & SIT RECLASS	(55,162.00)	0.00	(1,587,067.00)
ASSET REMOVAL COSTS	0.00	0.00	0.00
ACCUMULATED PROVISIONS - MISC	0.00	0.00	3,115,498.99
DEFERRED INVESTMENT TAX CREDITS	7,546.00	0.00	0.00
LONG-TERM RISK MANAGEMENT LIABILITIES	0.00	0.00	0.00
CUSTOMER ADVANCES FOR CONSTRUCTION	0.00	0.00	0.00
OBLIGATIONS UNDER CAPITAL LEASES	0.00	0.00	0.00
ASSET RETIREMENT OBLIGATIONS	0.00	0.00	0.00
OTHER DEFERRED CREDITS	0.00	71,217.00	0.00
TOTAL DEFERRED CREDITS AND OTHER LIABILITIES	23,769.00	1,062,126.00	1,487,337.99
TOTAL CAPITALIZATION AND LIABILITIES	$532,440.87	$9,620,682.04	$4,041,667.28

Item 10 - Consolidating Balance Sheets

INDIANA MICHIGAN POWER COMPANY AND SUBSIDIARIES
CONSOLIDATING BALANCE SHEET
DECEMBER 31, 2003

Note - Totals and subtotals may be off due to rounding

DESCRIPTION	INDIANA MICHIGAN POWER COMPANY CONSOLIDATED	SEC REPORTING ADJUSTMENTS	INDIANA MICHIGAN POWER COMPANY ELIMINATIONS
ASSETS:			
ELECTRIC UTILITY PLANT			
TOTAL ELECTRIC UTILITY PLANT	$5,306,182,181.52	$0.00	$0.00
ACCUMULATED DEPRECIATION AND AMORTIZATION	(2,490,912,459.57)	263,014,780.00	0.00
NET ELECTRIC UTILITY PLANT	2,815,269,721.95	263,014,780.00	0.00
OTHER PROPERTY AND INVESTMENTS			
NUCLEAR DECOMMISSIONING AND SPENT NUCLEAR FUEL DISPOSAL TRUST FUNDS	982,394,078.70	0.00	0.00
NON-UTILITY PROPERTY, NET	52,302,710.78	0.00	0.00
INVESTMENTS IN SUBSIDIARIES & ASSOCIATES	0.00	0.00	(43,774,895.50)
TOTAL OTHER INVESTMENTS	43,796,994.81	0.00	0.00
TOTAL OTHER PROPERTY AND INVESTMENTS	1,078,493,784.29	0.00	(43,774,895.50)
CURRENT ASSETS			
CASH AND CASH EQUIVALENTS	3,913,780.56	0.00	0.00
ADVANCES TO AFFILIATES	0.00	(15,322,775.15)	0.00
ACCOUNTS RECEIVABLE - CUSTOMERS	61,083,821.63	8,153,247.25	0.00
ACCOUNTS RECEIVABLE- AFFILIATED COMPANIES	124,826,019.97	0.00	(897,402.14)
ACCOUNTS RECEIVABLE - ACCRUED UNBILLED REVENUES	2,000,068.39	0.00	0.00
ACCOUNTS RECEIVABLE - MISCELLANEOUS	4,498,304.57	(8,153,247.25)	0.00
ACCOUNTS RECEIVABLE - ALLOWANCE FOR UNCOLLECTIBLE ACCOUNTS	(531,487.62)	0.00	0.00
FUEL	33,967,999.70	0.00	0.00
MATERIALS AND SUPPLIES	105,328,541.58	0.00	0.00
RISK MANAGEMENT ASSETS	44,071,259.67	0.00	0.00
MARGIN DEPOSITS	7,245,494.99	7,245,494.99	0.00
PREPAYMENTS	5,731,502.81	0.00	0.00
OTHER	4,941,140.00	(7,245,494.99)	0.00
TOTAL CURRENT ASSETS	397,076,446.26	(15,322,775.15)	(897,402.14)
DEFERRED DEBITS AND OTHER ASSETS			
REGULATORY ASSETS	349,254,126.72	0.00	0.00
FAS 109 DEFERRED FIT RECLASS	(72,977,329.00)	0.00	0.00
LONG-TERM ENERGY TRADING CONTRACTS	43,768,348.63	0.00	0.00
UNAMORTIZED DEBT EXPENSE	11,981,425.14	0.00	0.00
OTHER DEFERRED DEBITS	36,204,045.08	0.00	(0.02)
TOTAL DEFERRED DEBITS AND OTHER ASSETS	368,230,616.57	0.00	(0.02)
TOTAL ASSETS	$4,659,070,569.06	$247,692,004.85	($44,672,297.66)

tem 10 - Consolidating Balance Sheets

NDIANA MICHIGAN POWER COMPANY AND SUBSIDIARIES
CONSOLIDATING BALANCE SHEET
DECEMBER 31, 2003

Note - Totals and subtotals may be off due to rounding

DESCRIPTION	INDIANA MICHIGAN POWER COMPANY CONSOLIDATED	SEC REPORTING ADJUSTMENTS	INDIANA MICHIGAN POWER COMPANY ELIMINATIONS
CAPITALIZATION AND LIABILITIES:			
CAPITALIZATION			
COMMON STOCK	$56,583,866.43	$0.00	($39,548,275.00)
PREMIUM ON CAPITAL STOCK	0.00	(4,318,031.53)	0.00
PAID-IN CAPITAL	858,694,392.60	29,423,914.53	(1,303,000.00)
RETAINED EARNINGS	187,875,312.84	0.00	(2,923,620.52)
ACCUMULATED OTHER COMPREHENSIVE INCOME (LOSS)	(25,105,883.00)	(25,105,883.00)	0.00
COMMON SHAREHOLDER'S EQUITY	1,078,047,688.86	0.00	(43,774,895.52)
CUMULATIVE PREFERRED STOCK - NOT SUBJECT TO MANDATORY REDEMPTION	8,101,100.00	0.00	0.00
LIABILITY FOR CUMULATIVE PREFERRED STOCK - SUBJECT TO MANDATORY REDEMPTION	63,445,000.00	63,445,000.00	0.00
LONG-TERM DEBT	1,134,358,851.38	(63,445,000.00)	0.00
TOTAL CAPITALIZATION	2,283,952,640.25	0.00	(43,774,895.52)
CURRENT LIABILITIES			
LONG-TERM DEBT DUE WITHIN ONE YEAR	205,000,000.00	0.00	0.00
ADVANCES FROM AFFILIATES	98,821,518.88	(15,322,775.15)	0.00
ACCOUNTS PAYABLE - GENERAL	101,776,021.61	0.00	0.00
ACCOUNTS PAYABLE - AFFILIATED COMPANIES	47,483,810.79	0.00	(897,402.14)
CUSTOMER DEPOSITS	21,954,513.91	0.00	0.00
TAXES ACCRUED	42,189,106.92	0.00	0.00
INTEREST ACCRUED	17,962,933.11	0.00	0.00
RISK MANAGEMENT LIABILITIES	31,898,490.87	0.00	0.00
OBLIGATIONS UNDER CAPITAL LEASES	6,527,938.79	0.00	0.00
DIVIDENDS DECLARED	1,089,389.03	0.00	0.00
OTHER	56,586,413.96	0.00	0.00
TOTAL CURRENT LIABILITIES	631,290,137.87	(15,322,775.15)	(897,402.14)
DEFERRED CREDITS AND OTHER LIABILITIES			
DEFERRED INCOME TAXES	940,358,147.00	0.00	0.00
DEFERRED FIT & SIT RECLASS	(602,982,549.00)	0.00	0.00
ASSET REMOVAL COSTS	263,014,780.00	263,014,780.00	0.00
DEFERRED INVESTMENT TAX CREDITS	90,278,100.00	0.00	0.00
OTHER REGULATORY LIABILTIES	276,948,842.49	0.00	0.00
OBLIGATIONS UNDER CAPITAL LEASES	31,315,130.69	0.00	0.00
ASSET RETIREMENT OBLIGATIONS	553,219,318.01	553,219,318.01	0.00
NUCLEAR DECOMMSSIONING	0.00	0.00	0.00
ACCUMULATED PROVISIONS - MISCELLANEOUS	55,783,588.26	(553,219,318.01)	0.00
UNAMORTIZED GAIN REACQUIRED DEBT	34,223.72	0.00	0.00
LONG-TERM RISK MANAGEMENT LIABILITIES	33,537,420.82	0.00	0.00
CUSTOMER ADVANCES FOR CONSTRUCTION	4,263,378.85	0.00	0.00
DEFERRED GAINS ON SALE/LEASEBACK	70,178,525.01	0.00	0.00
OTHER DEFERRED CREDITS	27,878,885.11	0.00	0.00
TOTAL DEFERRED CREDITS AND OTHER LIABILITIES	1,743,827,790.95	263,014,780.00	0.00
TOTAL CAPITALIZATION AND LIABILITIES	$4,659,070,569.07	$247,692,004.85	($44,672,297.66)

Item 10 - Consolidating Balance Sheets

INDIANA MICHIGAN POWER COMPANY AND SUBSIDIARIES
CONSOLIDATING BALANCE SHEET
DECEMBER 31, 2003

Note - Totals and subtotals may be off due to rounding

DESCRIPTION	INDIANA MICHIGAN POWER COMPANY	PRICE RIVER COAL COMPANY	BLACKHAWK COAL COMPANY
ASSETS:			
ELECTRIC UTILITY PLANT			
TOTAL ELECTRIC UTILITY PLANT	$5,306,182,181.52	$0.00	$0.00
ACCUMULATED DEPRECIATION AND AMORTIZATION	(2,753,927,239.57)	0.00	0.00
NET ELECTRIC UTILITY PLANT	2,552,254,941.95	0.00	0.00
OTHER PROPERTY AND INVESTMENTS			
NUCLEAR DECOMMISSIONING AND SPENT NUCLEAR FUEL DISPOSAL TRUST FUNDS	982,394,078.70	0.00	0.00
NON-UTILITY PROPERTY, NET	37,302,710.78	0.00	15,000,000.00
INVESTMENTS IN SUBSIDIARIES & ASSOCIATES	43,774,895.50	0.00	0.00
TOTAL OTHER INVESTMENTS	40,451,246.81	0.00	3,345,748.00
TOTAL OTHER PROPERTY AND INVESTMENTS	1,103,922,931.79	0.00	18,345,748.00
CURRENT ASSETS			
CASH AND CASH EQUIVALENTS	3,913,780.56	0.00	0.00
ADVANCES TO AFFILIATES	0.00	0.00	15,322,775.15
ACCOUNTS RECEIVABLE - CUSTOMERS	52,930,574.38	0.00	0.00
ACCOUNTS RECEIVABLE- AFFILIATED COMPANIES	125,618,607.28	27,275.00	77,539.83
ACCOUNTS RECEIVABLE - ACCRUED UNBILLED REVENUES	2,000,068.39	0.00	0.00
ACCOUNTS RECEIVABLE - MISCELLANEOUS	9,552,654.69	0.00	3,098,897.13
ACCOUNTS RECEIVABLE - ALLOWANCE FOR UNCOLLECTIBLE ACCOUNTS	(531,487.62)	0.00	0.00
FUEL	33,966,439.65	0.00	1,560.05
MATERIALS AND SUPPLIES	105,328,541.58	0.00	0.00
RISK MANAGEMENT ASSETS	44,071,259.67	0.00	0.00
MARGIN DEPOSITS	0.00	0.00	0.00
PREPAYMENTS	5,731,502.81	0.00	0.00
OTHER	12,177,434.99	0.00	9,200.00
TOTAL CURRENT ASSETS	394,759,376.39	27,275.00	18,509,972.16
DEFERRED DEBITS AND OTHER ASSETS			
REGULATORY ASSETS	349,254,126.72	0.00	0.00
FAS 109 DEFERRED FIT RECLASS	(72,977,329.00)	0.00	0.00
LONG-TERM ENERGY TRADING CONTRACTS	43,768,348.63	0.00	0.00
UNAMORTIZED DEBT EXPENSE	11,981,425.14	0.00	0.00
OTHER DEFERRED DEBITS	36,204,045.09	0.00	0.00
TOTAL DEFERRED DEBITS AND OTHER ASSETS	368,230,616.58	0.00	0.00
TOTAL ASSETS	$4,419,167,866.71	$27,275.00	$36,855,720.16

Item 10 - Consolidating Balance Sheets

INDIANA MICHIGAN POWER COMPANY AND SUBSIDIARIES
CONSOLIDATING BALANCE SHEET
DECEMBER 31, 2003

Note - Totals and subtotals may be off due to rounding

DESCRIPTION	INDIANA MICHIGAN POWER COMPANY	PRICE RIVER COAL COMPANY	BLACKHAWK COAL COMPANY
CAPITALIZATION AND LIABILITIES:			
CAPITALIZATION			
COMMON STOCK	$56,583,866.43	$27,275.00	$39,521,000.00
PREMIUM ON CAPITAL STOCK	4,318,031.53	0.00	0.00
PAID-IN CAPITAL	829,429,120.07	0.00	1,144,358.00
RETAINED EARNINGS	187,875,312.81	0.00	2,923,620.54
ACCUMULATED OTHER COMPREHENSIVE INCOME (LOSS)	0.00	0.00	0.00
COMMON SHAREHOLDER'S EQUITY	1,078,206,330.83	27,275.00	43,588,978.54
CUMULATIVE PREFERRED STOCK - NOT SUBJECT TO MANDATORY REDEMPTION	8,101,100.00	0.00	0.00
LIABILITY FOR CUMULATIVE PREFERRED STOCK - SUBJECT TO MANDATORY REDEMPTION	0.00	0.00	0.00
LONG-TERM DEBT	1,197,803,851.38	0.00	0.00
TOTAL CAPITALIZATION	2,284,111,282.22	27,275.00	43,588,978.54
CURRENT LIABILITIES			
LONG-TERM DEBT DUE WITHIN ONE YEAR	205,000,000.00	0.00	0.00
ADVANCES FROM AFFILIATES	114,144,294.03	0.00	0.00
ACCOUNTS PAYABLE - GENERAL	101,776,021.61	0.00	0.00
ACCOUNTS PAYABLE - AFFILIATED COMPANIES	47,465,121.87	0.00	916,091.06
CUSTOMER DEPOSITS	21,954,513.91	0.00	0.00
TAXES ACCRUED	40,932,133.92	0.00	1,256,973.00
INTEREST ACCRUED	17,962,933.11	0.00	0.00
RISK MANAGEMENT LIABILITIES	31,898,490.87	0.00	0.00
OBLIGATIONS UNDER CAPITAL LEASES	6,527,938.79	0.00	0.00
DIVIDENDS DECLARED	1,089,389.03	0.00	0.00
OTHER	56,547,992.50	0.00	38,421.46
TOTAL CURRENT LIABILITIES	645,298,829.65	0.00	2,211,485.52
DEFERRED CREDITS AND OTHER LIABILITIES			
DEFERRED INCOME TAXES	938,420,807.00	0.00	1,937,340.00
DEFERRED FIT & SIT RECLASS	(590,759,292.00)	0.00	(12,223,257.00)
ASSET REMOVAL COSTS	0.00	0.00	0.00
DEFERRED INVESTMENT TAX CREDITS	90,278,100.00	0.00	0.00
OTHER REGULATORY LIABILTIES	276,948,842.49	0.00	0.00
OBLIGATIONS UNDER CAPITAL LEASES	31,315,130.69	0.00	0.00
ASSET RETIREMENT OBLIGATIONS	0.00	0.00	0.00
NUCLEAR DECOMMSSIONING	0.00	0.00	0.00
ACCUMULATED PROVISIONS - MISCELLANEOUS	607,815,069.17	0.00	1,187,837.10
UNAMORTIZED GAIN REACQUIRED DEBT	34,223.72	0.00	0.00
LONG-TERM RISK MANAGEMENT LIABILITIES	33,537,420.82	0.00	0.00
CUSTOMER ADVANCES FOR CONSTRUCTION	4,263,378.85	0.00	0.00
DEFERRED GAINS ON SALE/LEASEBACK	70,178,525.01	0.00	0.00
OTHER DEFERRED CREDITS	27,725,549.11	0.00	153,336.00
TOTAL DEFERRED CREDITS AND OTHER LIABILITIES	1,489,757,754.85	0.00	(8,944,743.90)
TOTAL CAPITALIZATION AND LIABILITIES	$4,419,167,866.71	$27,275.00	$36,855,720.16

Item 10 - Consolidating Balance Sheets

OHIO POWER COMPANY CONSOLIDATED
CONSOLIDATING BALANCE SHEET
DECEMBER 31, 2003

Note - Totals and subtotals may be off due to rounding

DESCRIPTION	OHIO POWER COMPANY CONSOLIDATED	SEC REPORTING ADJUSTMENTS	OHIO POWER COMPANY ELIMINATIONS
ASSETS:			
ELECTRIC UTILITY PLANT			
TOTAL ELECTRIC UTILITY PLANT	$6,531,314,842.29	$0.00	$0.00
ACCUMULATED DEPRECIATION AND AMORTIZATION	(2,485,946,974.37)	101,159,548.00	0.00
ELECTRIC UTILITY PLANT - NET	4,045,367,867.92	101,159,548.00	0.00
OTHER PROPERTY AND INVESTMENTS			
NON-UTILITY PROPERTY, NET	29,290,897.77	0.00	0.00
INVESTMENTS IN SUBSIDIARIES & ASSOCIATES	646,814.00	0.00	0.00
TOTAL OTHER INVESTMENTS	23,617,149.88	0.00	0.00
TOTAL OTHER PROPERTY AND INVESTMENTS	53,554,861.65	0.00	0.00
CURRENT ASSETS			
CASH AND CASH EQUIVALENTS	58,250,285.59	0.00	0.00
ADVANCES TO AFFILIATES	67,918,020.70	0.00	0.00
ACCOUNTS RECEIVABLE - CUSTOMERS	100,959,701.41	23,060,143.88	0.00
ACCOUNTS RECEIVABLE - AFFILIATED COMPANIES	120,531,929.50	0.00	0.00
ACCOUNTS RECEIVABLE - MISCELLANEOUS	736,175.32	(23,060,143.88)	0.00
ACCOUNTS RECEIVABLE - ALLOWANCE FOR UNCOLLECTIBLE ACCOUNTS	(789,244.62)	0.00	0.00
FUEL INVENTORY	77,725,300.56	0.00	0.00
MATERIALS AND SUPPLIES	92,135,723.09	0.00	0.00
RISK MANAGEMENT ASSETS	56,265,271.44	0.00	0.00
ACCRUED UNBILLED REVENUES	0.00	(17,220,879.00)	0.00
MARGIN DEPOSITS	9,296,461.69	9,296,461.69	0.00
PREPAYMENTS	10,033,003.21	0.00	(16,506,225.00)
OTHER	23,070,436.00	7,924,417.31	0.00
TOTAL CURRENT ASSETS	616,133,063.88	0.00	(16,506,225.00)
DEFERRED DEBITS AND OTHER ASSETS			
REGULATORY ASSETS	528,709,342.44	0.00	0.00
FAS 109 DEFERRED FIT RECLASS	(16,391,744.00)	0.00	0.00
CLEARING ACCOUNTS	0.01	0.00	0.00
LONG-TERM RISK MANAGEMENT ASSETS	52,824,714.92	0.00	0.00
UNAMORTIZED DEBT EXPENSE	10,489,950.22	0.00	0.00
OTHER DEFERRED DEBITS	83,829,359.11	0.00	(39,416,939.00)
TOTAL DEFERRED CHARGES	659,461,622.69	0.00	(39,416,939.00)
TOTAL ASSETS	$5,374,517,416.14	$101,159,548.00	($55,923,164.00)

Item 10 - Consolidating Balance Sheets

OHIO POWER COMPANY CONSOLIDATED
CONSOLIDATING BALANCE SHEET
DECEMBER 31, 2003

Note - Totals and subtotals may be off due to rounding

DESCRIPTION	OHIO POWER COMPANY CONSOLIDATED	SEC REPORTING ADJUSTMENTS	OHIO POWER COMPANY ELIMINATIONS
CAPITALIZATION AND LIABILITIES:			
CAPITALIZATION			
COMMON STOCK	$321,201,454.00	$0.00	$0.00
PREMIUM ON CAPITAL STOCK	0.00	(728,972.21)	0.00
PAID-IN CAPITAL	462,483,651.86	49,535,553.77	(16,314,062.62)
RETAINED EARNINGS	729,146,667.84	0.00	0.00
ACCUMULATED OTHER COMPREHENSIVE INCOME	(48,806,581.56)	(48,806,581.56)	0.00
COMMON SHAREHOLDER'S EQUITY	1,464,025,192.14	0.00	(16,314,062.62)
CUMULATIVE PREFERRED STOCK NOT SUBJECT TO MANDATORY REDEMPTION	16,645,400.00	0.00	0.00
LIABILITY FOR CUMULATIVE PREFERRED STOCK SUBJECT TO MANDATORY REDEMPTION	7,250,000.00	7,250,000.00	0.00
LONG-TERM DEBT - NONAFFILIATED	1,608,085,249.04	(7,250,000.00)	0.00
TOTAL CAPITALIZATION	3,096,005,841.18	0.00	(16,314,062.62)
MINORITY INTEREST	16,314,062.62	16,314,062.62	0.00
CURRENT LIABILITIES			
LONG-TERM DEBT DUE WITHIN ONE YEAR - NONAFFILIATED	431,853,659.00	0.00	0.00
SHORT-TERM DEBT - GENERAL	25,940,955.49	0.00	0.00
ADVANCES FROM AFFILIATES	0.00	0.00	0.00
ACCOUNTS PAYABLE - GENERAL	104,873,746.12	0.00	0.00
ACCOUNTS PAYABLE - AFFILIATES	101,758,140.78	0.00	(55,923,164.00)
CUSTOMER DEPOSITS	17,308,672.65	0.00	0.00
TAXES ACCRUED	132,792,835.06	0.00	0.00
INTEREST ACCRUED	45,678,727.12	0.00	0.00
RISK MANAGEMENT LIABILITIES	38,318,638.79	0.00	0.00
OBLIGATIONS UNDER CAPITAL LEASES	9,623,896.48	0.00	0.00
DIVIDENDS DECLARED	102,240.39	0.00	0.00
OTHER CURRENT LIABILITIES	71,539,599.75	0.00	0.00
TOTAL CURRENT LIABILITIES	979,791,111.64	0.00	(55,923,164.00)
DEFERRED CREDITS AND REGULATORY LIABILITIES			
DEFERRED INCOME TAXES	1,090,202,075.16	0.00	0.00
DEFERRED FIT & DSIT RECLASS	(156,619,782.24)	0.00	0.00
ASSET REMOVAL COSTS	101,159,548.00	101,159,548.00	0.00
DEFERRED INVESTMENT TAX CREDITS	15,640,519.00	0.00	0.00
OTHER REGULATORY LIABILTIES	3,288.73	0.00	0.00
ACCUMULATED PROVISIONS - MISCELLANEOUS	100,601,508.71	(42,656,340.00)	0.00
OBLIGATIONS UNDER CAPITAL LEASES	25,063,582.41	0.00	0.00
ASSET RETIREMENT OBLIGATIONS	42,656,340.00	42,656,340.00	0.00
LONG-TERM RISK MANAGEMENT LIABILITIES	40,476,845.18	0.00	0.00
OTHER DEFERRED CREDITS	23,222,475.75	(16,314,062.62)	16,314,062.62
TOTAL DEFERRED CREDITS AND REGULATORY LIABILITIES	1,282,406,400.70	84,845,485.38	16,314,062.62
TOTAL CAPITALIZATION AND LIABILITIES	$5,374,517,416.14	$101,159,548.00	($55,923,164.00)

Item 10 - Consolidating Balance Sheets

OHIO POWER COMPANY CONSOLIDATED
CONSOLIDATING BALANCE SHEET
DECEMBER 31, 2003

Note - Totals and subtotals may be off due to rounding

DESCRIPTION	OHIO POWER COMPANY	JMG FUNDING LP
ASSETS:		
ELECTRIC UTILITY PLANT		
TOTAL ELECTRIC UTILITY PLANT	$5,844,174,108.83	$687,140,733.46
ACCUMULATED DEPRECIATION AND AMORTIZATION	(2,421,875,305.21)	(165,231,217.16)
ELECTRIC UTILITY PLANT - NET	3,422,298,803.62	521,909,516.30
OTHER PROPERTY AND INVESTMENTS		
NON-UTILITY PROPERTY, NET	29,290,897.77	0.00
INVESTMENTS IN SUBSIDIARIES & ASSOCIATES	646,814.00	0.00
TOTAL OTHER INVESTMENTS	23,617,149.88	0.00
TOTAL OTHER PROPERTY AND INVESTMENTS	53,554,861.65	0.00
CURRENT ASSETS		
CASH AND CASH EQUIVALENTS	56,067,591.37	2,182,694.22
ADVANCES TO AFFILIATES	67,918,020.70	0.00
ACCOUNTS RECEIVABLE - CUSTOMERS	77,899,557.53	0.00
ACCOUNTS RECEIVABLE - AFFILIATED COMPANIES	120,531,929.50	0.00
ACCOUNTS RECEIVABLE - MISCELLANEOUS	23,764,296.48	32,022.72
ACCOUNTS RECEIVABLE - ALLOWANCE FOR UNCOLLECTIBLE ACCOUNTS	(789,244.62)	0.00
FUEL INVENTORY	77,725,300.56	0.00
MATERIALS AND SUPPLIES	92,135,723.09	0.00
RISK MANAGEMENT ASSETS	56,265,271.44	0.00
ACCRUED UNBILLED REVENUES	17,220,879.00	0.00
MARGIN DEPOSITS	0.00	0.00
PREPAYMENTS	26,539,228.21	0.00
OTHER	15,146,018.69	0.00
TOTAL CURRENT ASSETS	630,424,571.94	2,214,716.94
DEFERRED DEBITS AND OTHER ASSETS		
REGULATORY ASSETS	528,709,342.44	0.00
FAS 109 DEFERRED FIT RECLASS	(16,391,744.00)	0.00
CLEARING ACCOUNTS	0.01	0.00
LONG-TERM RISK MANAGEMENT ASSETS	52,824,714.92	0.00
UNAMORTIZED DEBT EXPENSE	10,489,950.22	0.00
OTHER DEFERRED DEBITS	123,246,298.11	0.00
TOTAL DEFERRED CHARGES	698,878,561.69	0.00
TOTAL ASSETS	$4,805,156,798.90	$524,124,233.24

Item 10 - Consolidating Balance Sheets

OHIO POWER COMPANY CONSOLIDATED
CONSOLIDATING BALANCE SHEET
DECEMBER 31, 2003

Note - Totals and subtotals may be off due to rounding

DESCRIPTION	OHIO POWER COMPANY	JMG FUNDING LP
CAPITALIZATION AND LIABILITIES:		
CAPITALIZATION		
COMMON STOCK	$321,201,454.00	$0.00
PREMIUM ON CAPITAL STOCK	728,972.21	0.00
PAID-IN CAPITAL	412,948,098.09	16,314,062.62
RETAINED EARNINGS	729,146,667.84	0.00
ACCUMULATED OTHER COMPREHENSIVE INCOME	0.00	0.00
COMMON SHAREHOLDER'S EQUITY	1,464,025,192.14	16,314,062.62
CUMULATIVE PREFERRED STOCK NOT SUBJECT TO MANDATORY REDEMPTION	16,645,400.00	0.00
LIABILITY FOR CUMULATIVE PREFERRED STOCK SUBJECT TO MANDATORY REDEMPTION	0.00	0.00
LONG-TERM DEBT - NONAFFILIATED	1,221,349,806.12	393,985,442.92
TOTAL CAPITALIZATION	2,702,020,398.26	410,299,505.54
MINORITY INTEREST	0.00	0.00
CURRENT LIABILITIES		
LONG-TERM DEBT DUE WITHIN ONE YEAR - NONAFFILIATED	423,000,000.00	8,853,659.00
SHORT-TERM DEBT - GENERAL	0.00	25,940,955.49
ADVANCES FROM AFFILIATES	0.00	0.00
ACCOUNTS PAYABLE - GENERAL	104,873,746.12	0.00
ACCOUNTS PAYABLE - AFFILIATES	101,758,140.78	55,923,164.00
CUSTOMER DEPOSITS	17,308,672.65	0.00
TAXES ACCRUED	132,792,835.06	0.00
INTEREST ACCRUED	40,357,768.58	5,320,958.54
RISK MANAGEMENT LIABILITIES	38,318,638.79	0.00
OBLIGATIONS UNDER CAPITAL LEASES	9,623,896.48	0.00
DIVIDENDS DECLARED	102,240.39	0.00
OTHER CURRENT LIABILITIES	53,753,609.08	17,785,990.67
TOTAL CURRENT LIABILITIES	921,889,547.94	113,824,727.70
DEFERRED CREDITS AND REGULATORY LIABILITIES		
DEFERRED INCOME TAXES	1,090,202,075.16	0.00
DEFERRED FIT & DSIT RECLASS	(156,619,782.24)	0.00
ASSET REMOVAL COSTS	0.00	0.00
DEFERRED INVESTMENT TAX CREDITS	15,640,519.00	0.00
OTHER REGULATORY LIABILTIES	3,288.73	0.00
ACCUMULATED PROVISIONS - MISCELLANEOUS	143,257,848.71	0.00
OBLIGATIONS UNDER CAPITAL LEASES	25,063,582.41	0.00
ASSET RETIREMENT OBLIGATIONS	0.00	0.00
LONG-TERM RISK MANAGEMENT LIABILITIES	40,476,845.18	0.00
OTHER DEFERRED CREDITS	23,222,475.75	0.00
TOTAL DEFERRED CREDITS AND REGULATORY LIABILITIES	1,181,246,852.70	0.00
TOTAL CAPITALIZATION AND LIABILITIES	$4,805,156,798.90	$524,124,233.24

Item 10 - Consolidating Balance Sheets

SOUTHWESTERN ELECTRIC POWER COMPANY CONSOLIDATED
CONSOLIDATING BALANCE SHEET
DECEMBER 31, 2003

Note - Totals and subtotals may be off due to rounding

DESCRIPTION	SOUTHWESTERN ELECTRIC POWER COMPANY CONSOLIDATED	SEC REPORTING ADJUSTMENTS	SOUTHWESTERN ELECTRIC POWER COMPANY ELIMINATIONS
ASSETS:			
ELECTRIC UTILITY PLANT			
TOTAL ELECTRIC UTILITY PLANT	$3,799,459,946.09	$0.00	$0.00
ACCUMULATED DEPRECIATION AND AMORTIZATION	(1,617,846,204.00)	236,408,699.00	0.00
ELECTRIC UTILITY PLANT - NET	2,181,613,742.10	236,408,699.00	0.00
OTHER PROPERTY AND INVESTMENTS			
NON-UTILITY PROPERTY, NET	3,808,010.55	0.00	0.00
INVESTMENTS IN SUBSIDIARIES AND ASSOCIATES	191,383.70	0.00	(15,223,869.28)
TOTAL OTHER INVESTMENTS	4,518,917.42	0.00	(4,179,728.00)
TOTAL OTHER PROPERTY AND INVESTMENTS	8,518,311.67	0.00	(19,403,597.28)
CURRENT ASSETS			
CASH AND CASH EQUIVALENTS	11,724,352.26	0.00	0.00
ADVANCES TO AFFILIATES	66,475,640.13	0.00	(1,820,038.80)
ACCOUNTS RECEIVABLE - CUSTOMERS	41,473,705.45	15,050,164.44	0.00
ACCOUNTS RECEIVABLE - AFFILIATED COMPANIES	10,393,624.25	0.00	(8,989,201.98)
ACCOUNTS RECEIVABLE - ACCRUED UNBILLED REVENUES	0.00	(22,099,134.95)	0.00
ACCOUNTS RECEIVABLE - MISCELLANEOUS	4,682,309.38	(15,050,164.44)	0.00
ACCOUNTS RECEIVABLE - ALLOWANCE FOR UNCOLLECTIBLE ACCOUNTS	(2,092,942.10)	0.00	0.00
FUEL INVENTORY	63,880,797.74	0.00	0.00
MATERIALS AND SUPPLIES	33,775,398.67	0.00	0.00
REGULATORY ASSET FOR UNDER-RECOVERED FUEL COSTS	11,394,000.00	11,394,000.00	0.00
RISK MANAGEMENT ASSETS	19,714,543.12	0.00	0.00
MARGIN DEPOSITS	5,122,738.30	5,122,738.30	0.00
PREPAYMENTS	19,073,635.00	0.00	0.00
OTHER	4,850.00	(5,122,738.30)	0.00
TOTAL CURRENT ASSETS	285,622,652.21	(10,705,134.95)	(10,809,240.78)
DEFERRED DEBITS AND OTHER ASSETS			
REGULATORY ASSETS	75,515,625.10	0.00	0.00
FAS 109 DEFERRED FIT RECLASS	(37,090,268.00)	0.00	0.00
CLEARING ACCOUNTS	1,828,830.34	0.00	0.00
UNAMORTIZED DEBT EXPENSE	5,820,310.78	0.00	0.00
LONG-TERM RISK MANAGEMENT ASSETS	12,177,502.71	0.00	0.00
OTHER DEFERRED DEBITS	47,955,970.55	0.00	(4,249,437.99)
TOTAL DEFERRED CHARGES	106,207,971.48	0.00	(4,249,437.99)
TOTAL ASSETS	$2,581,962,677.45	$225,703,564.05	($34,462,276.05)

Item 10 - Consolidating Balance Sheets

SOUTHWESTERN ELECTRIC POWER COMPANY CONSOLIDATED
CONSOLIDATING BALANCE SHEET
DECEMBER 31, 2003

Note - Totals and subtotals may be off due to rounding

DESCRIPTION	SOUTHWESTERN ELECTRIC POWER COMPANY CONSOLIDATED	SEC REPORTING ADJUSTMENTS	SOUTHWESTERN ELECTRIC POWER COMPANY ELIMINATIONS
CAPITALIZATION AND LIABILITIES:			
CAPITALIZATION			
COMMON STOCK	$135,659,520.00	$0.00	($1,000.00)
PREMIUM ON CAPITAL STOCK	0.00	(3,620.64)	0.00
PAID-IN CAPITAL	245,003,620.64	43,913,791.64	(4,242,153.08)
RETAINED EARNINGS	359,906,742.39	0.00	(2,719,344.68)
ACCUMULATED OTHER COMPREHENSIVE INCOME (LOSS)	(43,910,171.00)	(43,910,171.00)	0.00
COMMON SHAREHOLDER'S EQUITY	696,659,712.03	0.00	(6,962,497.76)
CUMULATIVE PREFERRED STOCK NOT SUBJECT TO MANDATORY REDEMPTION	4,699,600.00	0.00	0.00
LONG-TERM DEBT	741,594,997.01	0.00	(9,628,562.12)
TOTAL CAPITALIZATION	1,442,954,309.04	0.00	(16,591,059.88)
MINORITY INTEREST	1,367,190.61	1,367,190.61	0.00
CURRENT LIABILITIES			
LONG-TERM DEBT DUE WITHIN 1 YR	142,714,210.68	0.00	0.00
ADVANCES FROM AFFILIATES	0.00	0.00	(1,820,038.80)
ACCOUNTS PAYABLE - GENERAL	37,645,508.97	0.00	0.00
ACCOUNTS PAYABLE - AFFILIATED COMPANIES	35,138,037.99	(22,099,134.95)	(8,989,201.98)
CUSTOMER DEPOSITS	24,259,934.92	0.00	0.00
TAXES ACCRUED	28,690,883.86	0.00	0.00
INTEREST ACCRUED	16,851,774.05	1,821.51	0.00
RISK MANAGEMENT LIABILITIES	11,361,450.08	0.00	0.00
OBLIGATIONS UNDER CAPITAL LEASES	3,158,757.87	0.00	0.00
OVER-RECOVERY OF FUEL COST	4,177,623.56	11,392,178.49	0.00
DIVIDENDS DECLARED	57,263.42	0.00	0.00
OTHER	53,696,014.94	(10,375,595.36)	(8,429,166.00)
TOTAL CURRENT LIABILITIES	357,751,460.34	(21,080,730.31)	(19,238,406.78)
DEFERRED CREDITS AND OTHER LIABILITIES			
DEFERRED INCOME TAXES	429,778,451.00	0.00	0.00
DEFERRED FIT & SIT RECLASS	(80,714,472.00)	0.00	0.00
LONG-TERM RISK MANAGEMENT LIABILITIES	4,667,147.84	0.00	0.00
ASSET REMOVAL COSTS	236,408,699.00	236,408,699.00	0.00
DEFERRED INVESTMENT TAX CREDITS	39,864,304.00	0.00	0.00
OTHER REGULATORY LIABILTIES	21,194,959.04	0.00	0.00
UNAMORTIZED GAIN ON REACQUIRED DEBT	184,066.02	0.00	0.00
ASSET RETIREMENT OBLIGATIONS	8,429,166.00	8,429,166.00	0.00
OBLIGATIONS UNDER CAPITAL LEASES	18,383,204.46	0.00	0.00
ACCUMULATED PROVISIONS - RATE REFUND	8,562,000.00	0.00	0.00
ACCUMULATED PROVISIONS - MISCELLANEOUS	60,165,014.45	(8,429,166.00)	0.00
OTHER DEFERRED CREDITS	32,967,177.65	9,008,404.75	1,367,190.61
TOTAL DEFERRED CREDITS AND OTHER LIABILITIES	779,889,717.46	245,417,103.75	1,367,190.61
TOTAL CAPITALIZATION & LIABILITIES	$2,581,962,677.45	$225,703,564.05	($34,462,276.05)

Item 10 - Consolidating Balance Sheets

SOUTHWESTERN ELECTRIC POWER COMPANY CONSOLIDATED
CONSOLIDATING BALANCE SHEET
DECEMBER 31, 2003

Note - Totals and subtotals may be off due to rounding

DESCRIPTION	SOUTHWESTERN ELECTRIC POWER COMPANY	DOLET HILLS LIGNITE COMPANY	SABINE MINING COMPANY
ASSETS:			
ELECTRIC UTILITY PLANT			
TOTAL ELECTRIC UTILITY PLANT	$3,605,376,479.75	$54,461,471.86	$139,621,994.48
ACCUMULATED DEPRECIATION AND AMORTIZATION	(1,744,363,068.12)	(18,616,481.57)	(91,275,353.31)
ELECTRIC UTILITY PLANT - NET	1,861,013,411.64	35,844,990.29	48,346,641.17
OTHER PROPERTY AND INVESTMENTS			
NON-UTILITY PROPERTY, NET	3,808,010.55	0.00	0.00
INVESTMENTS IN SUBSIDIARIES AND ASSOCIATES	15,415,252.98	0.00	0.00
TOTAL OTHER INVESTMENTS	4,518,917.42	0.00	4,179,728.00
TOTAL OTHER PROPERTY AND INVESTMENTS	23,742,180.95	0.00	4,179,728.00
CURRENT ASSETS			
CASH AND CASH EQUIVALENTS	8,760,167.09	150,500.00	2,813,685.17
ADVANCES TO AFFILIATES	65,384,536.69	2,911,142.24	0.00
ACCOUNTS RECEIVABLE - CUSTOMERS	26,422,790.18	0.00	750.83
ACCOUNTS RECEIVABLE - AFFILIATED COMPANIES	10,405,276.25	3,019,117.62	5,958,432.36
ACCOUNTS RECEIVABLE - ACCRUED UNBILLED REVENUES	22,099,134.95	0.00	0.00
ACCOUNTS RECEIVABLE - MISCELLANEOUS	14,868,300.38	2,580,558.72	2,283,614.72
ACCOUNTS RECEIVABLE - ALLOWANCE FOR UNCOLLECTIBLE ACCOUNTS	(2,092,942.10)	0.00	0.00
FUEL INVENTORY	51,307,459.16	4,119,657.33	8,453,681.25
MATERIALS AND SUPPLIES	29,403,398.67	4,372,000.00	0.00
REGULATORY ASSET FOR UNDER-RECOVERED FUEL COSTS	0.00	0.00	0.00
RISK MANAGEMENT ASSETS	19,714,543.12	0.00	0.00
MARGIN DEPOSITS	0.00	0.00	0.00
PREPAYMENTS	18,723,501.18	289,290.93	60,842.89
OTHER	5,127,588.30	0.00	0.00
TOTAL CURRENT ASSETS	270,123,753.88	17,442,266.84	19,571,007.22
DEFERRED DEBITS AND OTHER ASSETS			
REGULATORY ASSETS	75,515,625.10	0.00	0.00
FAS 109 DEFERRED FIT RECLASS	(37,090,268.00)	0.00	0.00
CLEARING ACCOUNTS	1,828,830.34	0.00	0.00
UNAMORTIZED DEBT EXPENSE	5,141,732.59	352,488.25	326,089.94
LONG-TERM RISK MANAGEMENT ASSETS	12,177,502.71	0.00	0.00
OTHER DEFERRED DEBITS	2,541,629.38	34,130,513.16	15,533,266.00
TOTAL DEFERRED CHARGES	60,115,052.12	34,483,001.41	15,859,355.94
TOTAL ASSETS	$2,214,994,398.59	$87,770,258.54	$87,956,732.33

Item 10 - Consolidating Balance Sheets

SOUTHWESTERN ELECTRIC POWER COMPANY CONSOLIDATED
CONSOLIDATING BALANCE SHEET
DECEMBER 31, 2003

Note - Totals and subtotals may be off due to rounding

DESCRIPTION	SOUTHWESTERN ELECTRIC POWER COMPANY	DOLET HILLS LIGNITE COMPANY	SABINE MINING COMPANY
CAPITALIZATION AND LIABILITIES:			
CAPITALIZATION			
COMMON STOCK	$135,659,520.00	$0.00	$1,000.00
PREMIUM ON CAPITAL STOCK	3,620.64	0.00	0.00
PAID-IN CAPITAL	201,089,829.00	4,907,153.08	(665,000.00)
RETAINED EARNINGS	359,906,742.37	688,154.09	2,031,190.61
ACCUMULATED OTHER COMPREHENSIVE INCOME (LOSS)	0.00	0.00	0.00
COMMON SHAREHOLDER'S EQUITY	696,659,712.01	5,595,307.17	1,367,190.61
CUMULATIVE PREFERRED STOCK NOT SUBJECT TO MANDATORY REDEMPTION	4,699,600.00	0.00	0.00
LONG-TERM DEBT	673,583,566.92	43,139,992.21	34,500,000.00
TOTAL CAPITALIZATION	1,374,942,878.93	48,735,299.38	35,867,190.61
MINORITY INTEREST	0.00	0.00	0.00
CURRENT LIABILITIES			
LONG-TERM DEBT DUE WITHIN 1 YR	132,885,000.00	6,829,210.68	3,000,000.00
ADVANCES FROM AFFILIATES	0.00	1,820,038.80	0.00
ACCOUNTS PAYABLE - GENERAL	35,889,323.37	98,422.00	1,657,763.60
ACCOUNTS PAYABLE - AFFILIATED COMPANIES	66,125,081.60	101,293.32	0.00
CUSTOMER DEPOSITS	24,259,934.92	0.00	0.00
TAXES ACCRUED	29,174,084.25	(1,943,546.60)	1,460,346.21
INTEREST ACCRUED	16,254,044.14	40,071.70	555,836.70
RISK MANAGEMENT LIABILITIES	10,790,450.08	0.00	571,000.00
OBLIGATIONS UNDER CAPITAL LEASES	328,977.87	0.00	2,829,780.00
OVER-RECOVERY OF FUEL COST	(7,214,554.93)	0.00	0.00
DIVIDENDS DECLARED	57,263.42	0.00	0.00
OTHER	56,875,959.75	11,629,566.67	3,995,249.88
TOTAL CURRENT LIABILITIES	365,425,564.47	18,575,056.57	14,069,976.39
DEFERRED CREDITS AND OTHER LIABILITIES			
DEFERRED INCOME TAXES	420,106,254.00	4,069,987.00	5,602,210.00
DEFERRED FIT & SIT RECLASS	(80,151,123.00)	(122,502.00)	(440,847.00)
LONG-TERM RISK MANAGEMENT LIABILITIES	4,215,147.84	0.00	452,000.00
ASSET REMOVAL COSTS	0.00	0.00	0.00
DEFERRED INVESTMENT TAX CREDITS	39,864,304.00	0.00	0.00
OTHER REGULATORY LIABILTIES	21,194,959.04	0.00	0.00
UNAMORTIZED GAIN ON REACQUIRED DEBT	184,066.02	0.00	0.00
ASSET RETIREMENT OBLIGATIONS	0.00	0.00	0.00
OBLIGATIONS UNDER CAPITAL LEASES	338,932.46	0.00	18,044,272.00
ACCUMULATED PROVISIONS - RATE REFUND	8,562,000.00	0.00	0.00
ACCUMULATED PROVISIONS - MISCELLANEOUS	37,999,554.59	16,512,417.59	14,082,208.27
OTHER DEFERRED CREDITS	22,311,860.23	0.00	279,722.06
TOTAL DEFERRED CREDITS AND OTHER LIABILITIES	474,625,955.18	20,459,902.59	38,019,565.33
TOTAL CAPITALIZATION & LIABILITIES	$2,214,994,398.59	$87,770,258.54	$87,956,732.33

Item 10 - Consolidating Statements of Cash Flows

AMERICAN ELECTRIC POWER COMPANY, INC.
AND SUBSIDIARY COMPANIES
CONSOLIDATING STATEMENT OF CASH FLOWS
FOR THE YEAR ENDED DECEMBER 31, 2003
(IN THOUSANDS)

Note - Totals and subtotals may be off due to rounding

	AMERICAN ELECTRIC POWER COMPANY CONSOLIDATED	SEC REPORTING ADJUSTMENTS/ ELIMINATIONS	AMERICAN ELECTRIC POWER COMPANY
OPERATING ACTIVITIES			
NET INCOME (LOSS)	$109,735	($231,699)	$106,393
PLUS: DISCONTINUED OPERATIONS	605,379	605,379	0
INCOME FROM CONTINUING OPERATIONS	715,114	373,680	106,393
ADJUSTMENTS FOR NONCASH ITEMS			
DEPRECIATION AND AMORTIZATION	1,299,428	(8,753)	147
DEFERRED INCOME TAXES	162,844	(15,669)	0
DEFERRED INVESTMENT TAX CREDITS	(33,326)	1,026	0
CUMULATIVE EFFECT OF ACCOUNTING CHANGES	(192,763)	0	0
ASSET AND INVESTMENT VALUE IMPAIRMENTS AND OTHER RELATED CHARGES	720,074	0	0
AMORTIZATION OF DEFERRED PROPERTY TAXES	(2,019)	(222)	0
AMORTIZATION OF COOK PLANT RESTART COSTS	40,000	0	0
PENSION AND POSTEMPLOYMENT BENEFITS RESERVES	(74,000)	(74,000)	0
MARK-TO-MARKET OF RISK MANAGEMENT CONTRACTS	(121,565)	(2,535)	0
EQUITY (EARNINGS) / LOSS - CONSOLIDATING SUBSIDIARIES	0	218,692	(218,692)
CHANGES IN CERTAIN CURRENT ASSETS AND LIABILITIES			
ACCOUNTS RECEIVABLE, NET	362,644	(405,002)	16,693
ACCRUED UTILITY REVENUES	0	20,301	0
PREPAYMENTS AND OTHER	0	13,096	0
FUEL, MATERIALS AND SUPPLIES	(71,038)	8,050	0
ACCOUNTS PAYABLE	(631,923)	321,706	(14,555)
INTEREST ACCRUED	0	(28,263)	0
CUSTOMER DEPOSITS	0	(4,339)	0
INCENTIVE PLAN ACCRUED	0	7,210	0
EMPLOYEE BENEFITS AND OTHER NONCURRENT LIABILITIES	0	75,822	0
TAXES ACCRUED	86,629	136	(10,491)
FUEL RECOVERY	137,987	0	0
ROCKPORT PLANT UNIT 2	0	5,571	0
RATE STABILIZATION DEFERRAL	0	75,601	0
CHANGE IN OPERATING RESERVES	0	46,984	0
DEFERRAL OF INCREMENTAL NUCLEAR REFUELING OUTAGE EXPENSES	0	27,754	0
CHANGE IN OTHER ASSETS	(162,409)	(510,613)	19,236
CHANGE IN OTHER LIABILITIES	72,067	(741,680)	617,471
NET CASH FLOWS FROM (USED FOR) OPERATING ACTIVITIES	2,307,743	(595,447)	516,202
INVESTING ACTIVITIES			
CONSTRUCTION EXPENDITURES	(1,358,401)	(15,603)	0
INVESTMENT IN DISCONTINUED OPERATIONS, NET	(614,978)	0	0
INVESTMENT IN SUBSIDIARIES	(0)	(489,843)	502,118
PROCEEDS FROM SALE OF ASSETS	81,768	7,325	0
OTHER	3,723	(13,004)	0
NET CASH FLOWS FROM (USED FOR) INVESTING ACTIVITIES	(1,887,888)	(511,125)	502,118
FINANCING ACTIVITIES			
ISSUANCE OF COMMON STOCK	1,142,206	0	1,142,206
CAPITAL CONTRIBUTION FROM PARENT	0	(1,118,564)	12,264
ISSUANCE OF LONG-TERM DEBT	4,761,086	(499)	757,022
CHANGE IN SHORT-TERM DEBT, NET	(2,781,148)	787,052	(2,132,328)
CHANGE IN SHORT-TERM DEBT - AFFILIATES	0	565,000	0
CHANGE IN ADVANCES FROM AFFILIATES, NET	0	(197,282)	0
RETIREMENT OF LONG-TERM DEBT	(2,707,134)	(124,392)	(311,215)
RETIREMENT OF LONG-TERM DEBT AFFILIATES	0	475,000	0
RETIREMENT OF PREFERRED STOCK	(9,122)	(500)	0
RETIREMENT OF MINORITY INTEREST	(225,000)	0	0
DIVIDENDS PAID ON CUMULATIVE PREFERRED STOCK	0	4,474	0
DIVIDENDS PAID ON COMMON STOCK	(618,053)	726,373	(618,053)
NET CASH FLOWS FROM (USED FOR) FINANCING ACTIVITIES	(437,164)	1,116,662	(1,150,103)
NET INCREASE (DECREASE) IN CASH AND CASH EQUIVALENTS	(17,309)	10,090	(131,783)
CASH AND CASH EQUIVALENTS AT BEGINNING OF PERIOD	1,199,449	(23,253)	1,006,665
CASH AND CASH EQUIVALENTS AT END OF PERIOD	1,182,140	(13,163)	874,882
NET INCREASE (DECREASE) IN CASH AND CASH EQUIVALENTS FROM DISCONTINUED OPERATIONS	(10,090)	(10,090)	0
CASH AND CASH EQUIVALENTS FROM DISCONTINUED OPERATIONS - BEGINNING OF PERIOD	23,253	23,253	0
CASH AND CASH EQUIVALENTS FROM DISCONTINUED OPERATIONS - END OF PERIOD	$13,163	$13,163	$0

Item 10 - Consolidating Statements of Cash Flows

AMERICAN ELECTRIC POWER COMPANY, INC.
AND SUBSIDIARY COMPANIES
CONSOLIDATING STATEMENT OF CASH FLOWS
FOR THE YEAR ENDED DECEMBER 31, 2003
(IN THOUSANDS)

Note - Totals and subtotals may be off due to rounding

	AMERICAN ELECTRIC POWER SERVICE CORPORATION	AEP TEXAS POLR, LLC	AEP MONEY POOL
OPERATING ACTIVITIES			
NET INCOME (LOSS)	$0	($6,429)	$0
PLUS: DISCONTINUED OPERATIONS	0	0	0
INCOME FROM CONTINUING OPERATIONS	0	(6,429)	0
ADJUSTMENTS FOR NONCASH ITEMS			
DEPRECIATION AND AMORTIZATION	8,618	2	0
DEFERRED INCOME TAXES	(36,937)	(1,240)	0
DEFERRED INVESTMENT TAX CREDITS	(51)	0	0
CUMULATIVE EFFECT OF ACCOUNTING CHANGES	0	0	0
ASSET AND INVESTMENT VALUE IMPAIRMENTS AND OTHER RELATED CHARGES	0	0	0
AMORTIZATION OF DEFERRED PROPERTY TAXES	0	0	0
AMORTIZATION OF COOK PLANT RESTART COSTS	0	0	0
PENSION AND POSTEMPLOYMENT BENEFITS RESERVES			
MARK-TO-MARKET OF RISK MANAGEMENT CONTRACTS	0	0	0
EQUITY (EARNINGS) / LOSS - CONSOLIDATING SUBSIDIARIES	0	0	0
CHANGES IN CERTAIN CURRENT ASSETS AND LIABILITIES			
ACCOUNTS RECEIVABLE, NET	304,552	8,533	(48,046)
ACCRUED UTILITY REVENUES	0	0	0
PREPAYMENTS AND OTHER	0	0	0
FUEL, MATERIALS AND SUPPLIES	13	0	0
ACCOUNTS PAYABLE	(67,897)	(568)	31,581
INTEREST ACCRUED	0	0	0
CUSTOMER DEPOSITS	0	0	0
INCENTIVE PLAN ACCRUED	0	0	0
EMPLOYEE BENEFITS AND OTHER NONCURRENT LIABILITIES	0	0	0
TAXES ACCRUED	8,799	(192)	0
FUEL RECOVERY	0	0	0
ROCKPORT PLANT UNIT 2	0	0	0
RATE STABILIZATION DEFERRAL	0	0	0
CHANGE IN OPERATING RESERVES	0	0	0
DEFERRAL OF INCREMENTAL NUCLEAR REFUELING OUTAGE EXPENSES	0	0	0
CHANGE IN OTHER ASSETS	6,793	(0)	(2,288)
CHANGE IN OTHER LIABILITIES	(100,511)	(2,260)	0
NET CASH FLOWS FROM (USED FOR) OPERATING ACTIVITIES	123,379	(2,155)	(18,752)
INVESTING ACTIVITIES			
CONSTRUCTION EXPENDITURES	46,012	0	0
INVESTMENT IN DISCONTINUED OPERATIONS, NET	0	0	0
INVESTMENT IN SUBSIDIARIES	0	0	0
PROCEEDS FROM SALE OF ASSETS	0	0	0
OTHER	0	0	0
NET CASH FLOWS FROM (USED FOR) INVESTING ACTIVITIES	46,012	0	0
FINANCING ACTIVITIES			
ISSUANCE OF COMMON STOCK	0	0	0
CAPITAL CONTRIBUTION FROM PARENT	0	0	0
ISSUANCE OF LONG-TERM DEBT	0	0	0
CHANGE IN SHORT-TERM DEBT, NET	(155,669)	3,156	18,752
CHANGE IN SHORT-TERM DEBT - AFFILIATES	0	0	0
CHANGE IN ADVANCES FROM AFFILIATES, NET	0	0	0
RETIREMENT OF LONG-TERM DEBT	(15,100)	0	0
RETIREMENT OF LONG-TERM DEBT AFFILIATES	0	0	0
RETIREMENT OF PREFERRED STOCK	0	0	0
RETIREMENT OF MINORITY INTEREST	0	0	0
DIVIDENDS PAID ON CUMULATIVE PREFERRED STOCK	0	0	0
DIVIDENDS PAID ON COMMON STOCK	0	0	0
NET CASH FLOWS FROM (USED FOR) FINANCING ACTIVITIES	(170,769)	3,156	18,752
NET INCREASE (DECREASE) IN CASH AND CASH EQUIVALENTS	(1,378)	1,002	0
CASH AND CASH EQUIVALENTS AT BEGINNING OF PERIOD	2,998	(969)	0
CASH AND CASH EQUIVALENTS AT END OF PERIOD	1,620	33	0
NET INCREASE (DECREASE) IN CASH AND CASH EQUIVALENTS FROM DISCONTINUED OPERATIONS	0	0	0
CASH AND CASH EQUIVALENTS FROM DISCONTINUED OPERATIONS - BEGINNING OF PERIOD	0	0	0
CASH AND CASH EQUIVALENTS FROM DISCONTINUED OPERATIONS - END OF PERIOD	$0	$0	$0

Item 10 - Consolidating Statements of Cash Flows

AMERICAN ELECTRIC POWER COMPANY, INC.
AND SUBSIDIARY COMPANIES
CONSOLIDATING STATEMENT OF CASH FLOWS
FOR THE YEAR ENDED DECEMBER 31, 2003
(IN THOUSANDS)

Note - Totals and subtotals may be off due to rounding

	AEP GENERATING COMPANY	CENTRAL COAL COMPANY	AEP T&D SERVICES, LLC
OPERATING ACTIVITIES			
NET INCOME (LOSS)	$7,964	$0	$28
PLUS: DISCONTINUED OPERATIONS	0	0	0
INCOME FROM CONTINUING OPERATIONS	7,964	0	28
ADJUSTMENTS FOR NONCASH ITEMS			
DEPRECIATION AND AMORTIZATION	22,686	0	4
DEFERRED INCOME TAXES	(5,838)	(110)	9
DEFERRED INVESTMENT TAX CREDITS	(3,354)	0	0
CUMULATIVE EFFECT OF ACCOUNTING CHANGES	0	0	0
ASSET AND INVESTMENT VALUE IMPAIRMENTS AND OTHER RELATED CHARGES	0	0	0
AMORTIZATION OF DEFERRED PROPERTY TAXES	(45)	0	0
AMORTIZATION OF COOK PLANT RESTART COSTS	0	0	0
PENSION AND POSTEMPLOYMENT BENEFITS RESERVES			
MARK-TO-MARKET OF RISK MANAGEMENT CONTRACTS	0	0	0
EQUITY (EARNINGS) / LOSS - CONSOLIDATING SUBSIDIARIES	0	0	0
CHANGES IN CERTAIN CURRENT ASSETS AND LIABILITIES			
ACCOUNTS RECEIVABLE, NET	(6,294)	20	105
ACCRUED UTILITY REVENUES	0	0	0
PREPAYMENTS AND OTHER	0	0	0
FUEL, MATERIALS AND SUPPLIES	(385)	0	0
ACCOUNTS PAYABLE	476	118	(37)
INTEREST ACCRUED	0	0	0
CUSTOMER DEPOSITS	0	0	0
INCENTIVE PLAN ACCRUED	0	0	0
EMPLOYEE BENEFITS AND OTHER NONCURRENT LIABILITIES	0	0	0
TAXES ACCRUED	3,743	3	(92)
FUEL RECOVERY	0	0	0
ROCKPORT PLANT UNIT 2	(5,571)	0	0
RATE STABILIZATION DEFERRAL	0	0	0
CHANGE IN OPERATING RESERVES	0	0	0
DEFERRAL OF INCREMENTAL NUCLEAR REFUELING OUTAGE EXPENSES	0	0	0
CHANGE IN OTHER ASSETS	3,531	(55)	(5)
CHANGE IN OTHER LIABILITIES	1,007	223	(11)
NET CASH FLOWS FROM (USED FOR) OPERATING ACTIVITIES	17,920	200	2
INVESTING ACTIVITIES			
CONSTRUCTION EXPENDITURES	(22,197)	0	0
INVESTMENT IN DISCONTINUED OPERATIONS, NET	0	0	0
INVESTMENT IN SUBSIDIARIES	0	0	0
PROCEEDS FROM SALE OF ASSETS	105	0	0
OTHER	0	0	0
NET CASH FLOWS FROM (USED FOR) INVESTING ACTIVITIES	(22,092)	0	0
FINANCING ACTIVITIES			
ISSUANCE OF COMMON STOCK	0	0	0
CAPITAL CONTRIBUTION FROM PARENT	0	0	0
ISSUANCE OF LONG-TERM DEBT	0	0	0
CHANGE IN SHORT-TERM DEBT, NET	0	(200)	(2)
CHANGE IN SHORT-TERM DEBT - AFFILIATES	0	0	0
CHANGE IN ADVANCES FROM AFFILIATES, NET	8,858	0	0
RETIREMENT OF LONG-TERM DEBT	0	0	0
RETIREMENT OF LONG-TERM DEBT AFFILIATES	0	0	0
RETIREMENT OF PREFERRED STOCK	0	0	0
RETIREMENT OF MINORITY INTEREST	0	0	0
DIVIDENDS PAID ON CUMULATIVE PREFERRED STOCK	0	0	0
DIVIDENDS PAID ON COMMON STOCK	(4,686)	0	0
NET CASH FLOWS FROM (USED FOR) FINANCING ACTIVITIES	4,172	(200)	(2)
NET INCREASE (DECREASE) IN CASH AND CASH EQUIVALENTS	0	0	(0)
CASH AND CASH EQUIVALENTS AT BEGINNING OF PERIOD	0	0	0
CASH AND CASH EQUIVALENTS AT END OF PERIOD	0	0	(0)
NET INCREASE (DECREASE) IN CASH AND CASH EQUIVALENTS FROM DISCONTINUED OPERATIONS	0	0	0
CASH AND CASH EQUIVALENTS FROM DISCONTINUED OPERATIONS - BEGINNING OF PERIOD	0	0	0
CASH AND CASH EQUIVALENTS FROM DISCONTINUED OPERATIONS - END OF PERIOD	$0	$0	$0

Item 10 - Consolidating Statements of Cash Flows

AMERICAN ELECTRIC POWER COMPANY, INC.
AND SUBSIDIARY COMPANIES
CONSOLIDATING STATEMENT OF CASH FLOWS
FOR THE YEAR ENDED DECEMBER 31, 2003
(IN THOUSANDS)

Note - Totals and subtotals may be off due to rounding

	INDIANA FRANKLIN REALTY, INC.	FRANKLIN REAL ESTATE COMPANY	APPALACHIAN POWER COMPANY CONSOLIDATED
OPERATING ACTIVITIES			
NET INCOME (LOSS)	$0	$0	$280,040
PLUS: DISCONTINUED OPERATIONS	0	0	0
INCOME FROM CONTINUING OPERATIONS	0	0	280,040
ADJUSTMENTS FOR NONCASH ITEMS			
DEPRECIATION AND AMORTIZATION	0	0	175,772
DEFERRED INCOME TAXES	0	0	24,563
DEFERRED INVESTMENT TAX CREDITS	0	0	(3,146)
CUMULATIVE EFFECT OF ACCOUNTING CHANGES	0	0	(77,257)
ASSET AND INVESTMENT VALUE IMPAIRMENTS AND OTHER RELATED CHARGES	0	0	0
AMORTIZATION OF DEFERRED PROPERTY TAXES	0	0	0
AMORTIZATION OF COOK PLANT RESTART COSTS	0	0	0
PENSION AND POSTEMPLOYMENT BENEFITS RESERVES			
MARK-TO-MARKET OF RISK MANAGEMENT CONTRACTS	0	0	56,409
EQUITY (EARNINGS) / LOSS - CONSOLIDATING SUBSIDIARIES	0	0	0
CHANGES IN CERTAIN CURRENT ASSETS AND LIABILITIES			
ACCOUNTS RECEIVABLE, NET	78	214	(6,825)
ACCRUED UTILITY REVENUES	0	0	0
PREPAYMENTS AND OTHER	0	0	0
FUEL, MATERIALS AND SUPPLIES	0	0	(1,252)
ACCOUNTS PAYABLE	(97)	(80)	(17,611)
INTEREST ACCRUED	0	0	0
CUSTOMER DEPOSITS	0	0	0
INCENTIVE PLAN ACCRUED	0	0	(7,210)
EMPLOYEE BENEFITS AND OTHER NONCURRENT LIABILITIES	0	0	0
TAXES ACCRUED	0	1	21,078
FUEL RECOVERY	0	0	74,071
ROCKPORT PLANT UNIT 2	0	0	0
RATE STABILIZATION DEFERRAL	0	0	(75,601)
CHANGE IN OPERATING RESERVES	0	0	(46,984)
DEFERRAL OF INCREMENTAL NUCLEAR REFUELING OUTAGE EXPENSES	0	0	0
CHANGE IN OTHER ASSETS	0	0	(17,813)
CHANGE IN OTHER LIABILITIES	(131)	(603)	83,042
NET CASH FLOWS FROM (USED FOR) OPERATING ACTIVITIES	(151)	(468)	461,276
INVESTING ACTIVITIES			
CONSTRUCTION EXPENDITURES	0	0	(288,577)
INVESTMENT IN DISCONTINUED OPERATIONS, NET	0	0	0
INVESTMENT IN SUBSIDIARIES	0	0	0
PROCEEDS FROM SALE OF ASSETS	0	0	1,969
OTHER	0	0	0
NET CASH FLOWS FROM (USED FOR) INVESTING ACTIVITIES	0	0	(286,608)
FINANCING ACTIVITIES			
ISSUANCE OF COMMON STOCK	0	0	0
CAPITAL CONTRIBUTION FROM PARENT	0	0	0
ISSUANCE OF LONG-TERM DEBT	0	0	580,649
CHANGE IN SHORT-TERM DEBT, NET	30	(194)	0
CHANGE IN SHORT-TERM DEBT - AFFILIATES	0	0	0
CHANGE IN ADVANCES FROM AFFILIATES, NET	0	0	43,789
RETIREMENT OF LONG-TERM DEBT	0	0	(622,737)
RETIREMENT OF LONG-TERM DEBT AFFILIATES	0	0	0
RETIREMENT OF PREFERRED STOCK	0	0	(5,506)
RETIREMENT OF MINORITY INTEREST	0	0	0
DIVIDENDS PAID ON CUMULATIVE PREFERRED STOCK	0	0	(1,001)
DIVIDENDS PAID ON COMMON STOCK	0	0	(128,266)
NET CASH FLOWS FROM (USED FOR) FINANCING ACTIVITIES	30	(194)	(133,072)
NET INCREASE (DECREASE) IN CASH AND CASH EQUIVALENTS	(120)	(662)	41,596
CASH AND CASH EQUIVALENTS AT BEGINNING OF PERIOD	120	662	4,285
CASH AND CASH EQUIVALENTS AT END OF PERIOD	(0)	(0)	45,881
NET INCREASE (DECREASE) IN CASH AND CASH EQUIVALENTS FROM DISCONTINUED OPERATIONS	0	0	0
CASH AND CASH EQUIVALENTS FROM DISCONTINUED OPERATIONS - BEGINNING OF PERIOD	0	0	0
CASH AND CASH EQUIVALENTS FROM DISCONTINUED OPERATIONS - END OF PERIOD	$0	$0	$0

Item 10 - Consolidating Statements of Cash Flows

AMERICAN ELECTRIC POWER COMPANY, INC.
AND SUBSIDIARY COMPANIES
CONSOLIDATING STATEMENT OF CASH FLOWS
FOR THE YEAR ENDED DECEMBER 31, 2003
(IN THOUSANDS)

Note - Totals and subtotals may be off due to rounding

	COLUMBUS SOUTHERN POWER COMPANY CONSOLIDATED	INDIANA MICHIGAN POWER COMPANY CONSOLIDATED	KENTUCKY POWER COMPANY
OPERATING ACTIVITIES			
NET INCOME (LOSS)	$200,430	$86,388	$32,330
PLUS: DISCONTINUED OPERATIONS	0	0	0
INCOME FROM CONTINUING OPERATIONS	200,430	86,388	32,330
ADJUSTMENTS FOR NONCASH ITEMS			
DEPRECIATION AND AMORTIZATION	135,964	171,281	39,309
DEFERRED INCOME TAXES	(4,514)	(14,894)	20,107
DEFERRED INVESTMENT TAX CREDITS	(3,110)	(7,431)	(1,210)
CUMULATIVE EFFECT OF ACCOUNTING CHANGES	(27,283)	3,160	1,134
ASSET AND INVESTMENT VALUE IMPAIRMENTS AND OTHER RELATED CHARGES	0	10,300	0
AMORTIZATION OF DEFERRED PROPERTY TAXES	(529)	0	0
AMORTIZATION OF COOK PLANT RESTART COSTS	0	40,000	0
PENSION AND POSTEMPLOYMENT BENEFITS RESERVES			
MARK-TO-MARKET OF RISK MANAGEMENT CONTRACTS	41,830	43,938	15,112
EQUITY (EARNINGS) / LOSS - CONSOLIDATING SUBSIDIARIES	0	0	0
CHANGES IN CERTAIN CURRENT ASSETS AND LIABILITIES			
ACCOUNTS RECEIVABLE, NET	(5,590)	34,346	2,445
ACCRUED UTILITY REVENUES	0	0	0
PREPAYMENTS AND OTHER	0	0	0
FUEL, MATERIALS AND SUPPLIES	6,441	(11,013)	878
ACCOUNTS PAYABLE	(59,543)	(69,396)	(45,100)
INTEREST ACCRUED	6,730	0	0
CUSTOMER DEPOSITS	0	0	0
INCENTIVE PLAN ACCRUED	0	0	0
EMPLOYEE BENEFITS AND OTHER NONCURRENT LIABILITIES	0	0	0
TAXES ACCRUED	20,681	(29,370)	8,582
FUEL RECOVERY	0	37,501	233
ROCKPORT PLANT UNIT 2	0	0	0
RATE STABILIZATION DEFERRAL	0	0	0
CHANGE IN OPERATING RESERVES	0	0	0
DEFERRAL OF INCREMENTAL NUCLEAR REFUELING OUTAGE EXPENSES	0	(27,754)	0
CHANGE IN OTHER ASSETS	(20,563)	(24,302)	(16,588)
CHANGE IN OTHER LIABILITIES	(8,762)	(19,981)	4,565
NET CASH FLOWS FROM (USED FOR) OPERATING ACTIVITIES	282,182	222,773	61,797
INVESTING ACTIVITIES			
CONSTRUCTION EXPENDITURES	(136,291)	(184,188)	(81,707)
INVESTMENT IN DISCONTINUED OPERATIONS, NET	0	0	0
INVESTMENT IN SUBSIDIARIES	0	0	0
PROCEEDS FROM SALE OF ASSETS	1,644	0	967
OTHER	0	1,485	0
NET CASH FLOWS FROM (USED FOR) INVESTING ACTIVITIES	(134,647)	(182,703)	(80,740)
FINANCING ACTIVITIES			
ISSUANCE OF COMMON STOCK	0	0	0
CAPITAL CONTRIBUTION FROM PARENT	0	0	0
ISSUANCE OF LONG-TERM DEBT	643,097	64,434	74,263
CHANGE IN SHORT-TERM DEBT, NET	0	0	0
CHANGE IN SHORT-TERM DEBT - AFFILIATES	(290,000)	0	0
CHANGE IN ADVANCES FROM AFFILIATES, NET	37,774	290,048	14,710
RETIREMENT OF LONG-TERM DEBT	(212,500)	(350,000)	(40,000)
RETIREMENT OF LONG-TERM DEBT AFFILIATES	(160,000)	0	(15,000)
RETIREMENT OF PREFERRED STOCK	0	(1,500)	0
RETIREMENT OF MINORITY INTEREST	0	0	0
DIVIDENDS PAID ON CUMULATIVE PREFERRED STOCK	0	(2,375)	0
DIVIDENDS PAID ON COMMON STOCK	(163,243)	(40,000)	(16,448)
NET CASH FLOWS FROM (USED FOR) FINANCING ACTIVITIES	(144,872)	(39,393)	17,525
NET INCREASE (DECREASE) IN CASH AND CASH EQUIVALENTS	2,663	677	(1,418)
CASH AND CASH EQUIVALENTS AT BEGINNING OF PERIOD	1,479	3,237	2,304
CASH AND CASH EQUIVALENTS AT END OF PERIOD	4,142	3,914	886
NET INCREASE (DECREASE) IN CASH AND CASH EQUIVALENTS FROM DISCONTINUED OPERATIONS	0	0	0
CASH AND CASH EQUIVALENTS FROM DISCONTINUED OPERATIONS - BEGINNING OF PERIOD	0	0	0
CASH AND CASH EQUIVALENTS FROM DISCONTINUED OPERATIONS - END OF PERIOD	$0	$0	$0

Item 10 - Consolidating Statements of Cash Flows

AMERICAN ELECTRIC POWER COMPANY, INC.
AND SUBSIDIARY COMPANIES
CONSOLIDATING STATEMENT OF CASH FLOWS
FOR THE YEAR ENDED DECEMBER 31, 2003
(IN THOUSANDS)

Note - Totals and subtotals may be off due to rounding

	KINGSPORT POWER COMPANY	OHIO POWER COMPANY CONSOLIDATED	WHEELING POWER COMPANY
OPERATING ACTIVITIES			
NET INCOME (LOSS)	$4,729	$375,663	$10,275
PLUS: DISCONTINUED OPERATIONS	0	0	0
INCOME FROM CONTINUING OPERATIONS	4,729	375,663	10,275
ADJUSTMENTS FOR NONCASH ITEMS			
DEPRECIATION AND AMORTIZATION	3,632	257,417	2,455
DEFERRED INCOME TAXES	511	24,482	697
DEFERRED INVESTMENT TAX CREDITS	(64)	(3,107)	(34)
CUMULATIVE EFFECT OF ACCOUNTING CHANGES	0	(124,632)	0
ASSET AND INVESTMENT VALUE IMPAIRMENTS AND OTHER RELATED CHARGES	0	0	0
AMORTIZATION OF DEFERRED PROPERTY TAXES	0	(855)	(18)
AMORTIZATION OF COOK PLANT RESTART COSTS	0	0	0
PENSION AND POSTEMPLOYMENT BENEFITS RESERVES			
MARK-TO-MARKET OF RISK MANAGEMENT CONTRACTS	0	60,064	0
EQUITY (EARNINGS) / LOSS - CONSOLIDATING SUBSIDIARIES	0	0	0
CHANGES IN CERTAIN CURRENT ASSETS AND LIABILITIES			
ACCOUNTS RECEIVABLE, NET	478	16,335	909
ACCRUED UTILITY REVENUES	0	(20,301)	0
PREPAYMENTS AND OTHER	0	(13,096)	0
FUEL, MATERIALS AND SUPPLIES	22	2,927	35
ACCOUNTS PAYABLE	(10,194)	(173,218)	(6,555)
INTEREST ACCRUED	0	21,533	0
CUSTOMER DEPOSITS	0	4,339	0
INCENTIVE PLAN ACCRUED	0	0	0
EMPLOYEE BENEFITS AND OTHER NONCURRENT LIABILITIES	0	(75,822)	0
TAXES ACCRUED	1,187	21,015	1,800
FUEL RECOVERY	0	0	0
ROCKPORT PLANT UNIT 2	0	0	0
RATE STABILIZATION DEFERRAL	0	0	0
CHANGE IN OPERATING RESERVES	0	0	0
DEFERRAL OF INCREMENTAL NUCLEAR REFUELING OUTAGE EXPENSES	0	0	0
CHANGE IN OTHER ASSETS	44	(23,302)	4,682
CHANGE IN OTHER LIABILITIES	(227)	24,001	(6,153)
NET CASH FLOWS FROM (USED FOR) OPERATING ACTIVITIES	118	373,443	8,091
INVESTING ACTIVITIES			
CONSTRUCTION EXPENDITURES	(4,121)	(244,312)	(5,472)
INVESTMENT IN DISCONTINUED OPERATIONS, NET	0	0	0
INVESTMENT IN SUBSIDIARIES	0	0	0
PROCEEDS FROM SALE OF ASSETS	0	7,301	314
OTHER	0	0	0
NET CASH FLOWS FROM (USED FOR) INVESTING ACTIVITIES	(4,121)	(237,011)	(5,158)
FINANCING ACTIVITIES			
ISSUANCE OF COMMON STOCK	0	0	0
CAPITAL CONTRIBUTION FROM PARENT	0	0	0
ISSUANCE OF LONG-TERM DEBT	0	988,914	0
CHANGE IN SHORT-TERM DEBT, NET	8,196	(671)	1,168
CHANGE IN SHORT-TERM DEBT - AFFILIATES	0	(275,000)	0
CHANGE IN ADVANCES FROM AFFILIATES, NET	0	(197,897)	0
RETIREMENT OF LONG-TERM DEBT	0	(128,378)	0
RETIREMENT OF LONG-TERM DEBT AFFILIATES	0	(300,000)	0
RETIREMENT OF PREFERRED STOCK	0	(1,603)	0
RETIREMENT OF MINORITY INTEREST	0	0	0
DIVIDENDS PAID ON CUMULATIVE PREFERRED STOCK	0	(1,098)	0
DIVIDENDS PAID ON COMMON STOCK	(4,000)	(167,734)	(4,000)
NET CASH FLOWS FROM (USED FOR) FINANCING ACTIVITIES	4,196	(83,467)	(2,832)
NET INCREASE (DECREASE) IN CASH AND CASH EQUIVALENTS	192	52,965	101
CASH AND CASH EQUIVALENTS AT BEGINNING OF PERIOD	(65)	5,285	104
CASH AND CASH EQUIVALENTS AT END OF PERIOD	127	58,250	205
NET INCREASE (DECREASE) IN CASH AND CASH EQUIVALENTS FROM DISCONTINUED OPERATIONS	0	0	0
CASH AND CASH EQUIVALENTS FROM DISCONTINUED OPERATIONS - BEGINNING OF PERIOD	0	0	0
CASH AND CASH EQUIVALENTS FROM DISCONTINUED OPERATIONS - END OF PERIOD	$0	$0	$0

Item 10 - Consolidating Statements of Cash Flows

AMERICAN ELECTRIC POWER COMPANY, INC.
AND SUBSIDIARY COMPANIES
CONSOLIDATING STATEMENT OF CASH FLOWS
FOR THE YEAR ENDED DECEMBER 31, 2003
(IN THOUSANDS)

Note - Totals and subtotals may be off due to rounding

	AEP INVESTMENTS, INC.	AEP RESOURCES, INC.	AEP COMMUNICATIONS, INC.
OPERATING ACTIVITIES			
NET INCOME (LOSS)	($5,018)	($1,121,424)	($3,600)
PLUS: DISCONTINUED OPERATIONS	0	0	0
INCOME FROM CONTINUING OPERATIONS	(5,018)	(1,121,424)	(3,600)
ADJUSTMENTS FOR NONCASH ITEMS			
DEPRECIATION AND AMORTIZATION	59	30,194	1,359
DEFERRED INCOME TAXES	(531)	82,744	7,231
DEFERRED INVESTMENT TAX CREDITS	0	0	0
CUMULATIVE EFFECT OF ACCOUNTING CHANGES	0	43,610	0
ASSET AND INVESTMENT VALUE IMPAIRMENTS AND OTHER RELATED CHARGES	0	573,148	0
AMORTIZATION OF DEFERRED PROPERTY TAXES	0	0	484
AMORTIZATION OF COOK PLANT RESTART COSTS	0	0	0
PENSION AND POSTEMPLOYMENT BENEFITS RESERVES			
MARK-TO-MARKET OF RISK MANAGEMENT CONTRACTS	0	(292,897)	0
EQUITY (EARNINGS) / LOSS - CONSOLIDATING SUBSIDIARIES	0	0	0
CHANGES IN CERTAIN CURRENT ASSETS AND LIABILITIES			
ACCOUNTS RECEIVABLE, NET	86	290,857	5,820
ACCRUED UTILITY REVENUES	0	0	0
PREPAYMENTS AND OTHER	0	0	0
FUEL, MATERIALS AND SUPPLIES	0	(105,376)	15
ACCOUNTS PAYABLE	57,646	(335,097)	(14,145)
INTEREST ACCRUED	0	0	0
CUSTOMER DEPOSITS	0	0	0
INCENTIVE PLAN ACCRUED	0	0	0
EMPLOYEE BENEFITS AND OTHER NONCURRENT LIABILITIES	0	0	0
TAXES ACCRUED	(473)	(55,517)	(5,628)
FUEL RECOVERY	0	0	0
ROCKPORT PLANT UNIT 2	0	0	0
RATE STABILIZATION DEFERRAL	0	0	0
CHANGE IN OPERATING RESERVES	0	0	0
DEFERRAL OF INCREMENTAL NUCLEAR REFUELING OUTAGE EXPENSES	0	0	0
CHANGE IN OTHER ASSETS	(22,874)	719,450	2,520
CHANGE IN OTHER LIABILITIES	2,205	111,553	(1,826)
NET CASH FLOWS FROM (USED FOR) OPERATING ACTIVITIES	31,099	(58,755)	(7,772)
INVESTING ACTIVITIES			
CONSTRUCTION EXPENDITURES	0	(25,315)	0
INVESTMENT IN DISCONTINUED OPERATIONS, NET	0	(646,602)	0
INVESTMENT IN SUBSIDIARIES	(4,993)	(7,500)	0
PROCEEDS FROM SALE OF ASSETS	0	8,200	0
OTHER	(35,517)	23,979	3,790
NET CASH FLOWS FROM (USED FOR) INVESTING ACTIVITIES	(40,510)	(647,238)	3,790
FINANCING ACTIVITIES			
ISSUANCE OF COMMON STOCK	0	0	0
CAPITAL CONTRIBUTION FROM PARENT	7,107	1,097,285	0
ISSUANCE OF LONG-TERM DEBT	0	0	0
CHANGE IN SHORT-TERM DEBT, NET	2,377	(18,148)	29,350
CHANGE IN SHORT-TERM DEBT - AFFILIATES	0	0	0
CHANGE IN ADVANCES FROM AFFILIATES, NET	0	0	0
RETIREMENT OF LONG-TERM DEBT	0	(139,944)	(25,000)
RETIREMENT OF LONG-TERM DEBT AFFILIATES	0	0	0
RETIREMENT OF PREFERRED STOCK	0	0	0
RETIREMENT OF MINORITY INTEREST	0	(225,000)	0
DIVIDENDS PAID ON CUMULATIVE PREFERRED STOCK	0	0	0
DIVIDENDS PAID ON COMMON STOCK	0	0	0
NET CASH FLOWS FROM (USED FOR) FINANCING ACTIVITIES	9,484	714,194	4,350
NET INCREASE (DECREASE) IN CASH AND CASH EQUIVALENTS	73	8,200	368
CASH AND CASH EQUIVALENTS AT BEGINNING OF PERIOD	7	48,849	(368)
CASH AND CASH EQUIVALENTS AT END OF PERIOD	80	57,049	0
NET INCREASE (DECREASE) IN CASH AND CASH EQUIVALENTS FROM DISCONTINUED OPERATIONS	0	0	0
CASH AND CASH EQUIVALENTS FROM DISCONTINUED OPERATIONS - BEGINNING OF PERIOD	0	0	0
CASH AND CASH EQUIVALENTS FROM DISCONTINUED OPERATIONS - END OF PERIOD	$0	$0	$0

Item 10 - Consolidating Statements of Cash Flows

AMERICAN ELECTRIC POWER COMPANY, INC.
AND SUBSIDIARY COMPANIES
CONSOLIDATING STATEMENT OF CASH FLOWS
FOR THE YEAR ENDED DECEMBER 31, 2003
(IN THOUSANDS)

Note - Totals and subtotals may be off due to rounding

	AEP UTILITIES INCORPORATED CONSOLIDATED	AEP C&I COMPANY, LLC	AEP DESERT SKY LP, LLC
OPERATING ACTIVITIES			
NET INCOME (LOSS)	$375,937	$739	($595)
PLUS: DISCONTINUED OPERATIONS	0	0	0
INCOME FROM CONTINUING OPERATIONS	375,937	739	(595)
ADJUSTMENTS FOR NONCASH ITEMS			
DEPRECIATION AND AMORTIZATION	442,140	6	3
DEFERRED INCOME TAXES	121,520	(23,326)	106
DEFERRED INVESTMENT TAX CREDITS	(12,845)	0	0
CUMULATIVE EFFECT OF ACCOUNTING CHANGES	(11,710)	0	0
ASSET AND INVESTMENT VALUE IMPAIRMENTS AND OTHER RELATED CHARGES	70,000	0	0
AMORTIZATION OF DEFERRED PROPERTY TAXES	(833)	0	0
AMORTIZATION OF COOK PLANT RESTART COSTS	0	0	0
PENSION AND POSTEMPLOYMENT BENEFITS RESERVES	0		
MARK-TO-MARKET OF RISK MANAGEMENT CONTRACTS	(31,813)	0	0
EQUITY (EARNINGS) / LOSS - CONSOLIDATING SUBSIDIARIES	0	0	0
CHANGES IN CERTAIN CURRENT ASSETS AND LIABILITIES			
ACCOUNTS RECEIVABLE, NET	177,577	46,612	(307)
ACCRUED UTILITY REVENUES	0	0	0
PREPAYMENTS AND OTHER	0	0	0
FUEL, MATERIALS AND SUPPLIES	24,868	2,529	0
ACCOUNTS PAYABLE	(239,486)	(29,204)	44,465
INTEREST ACCRUED	0	0	0
CUSTOMER DEPOSITS	0	0	0
INCENTIVE PLAN ACCRUED	0	0	0
EMPLOYEE BENEFITS AND OTHER NONCURRENT LIABILITIES	0	0	0
TAXES ACCRUED	131,381	(44,760)	(3,445)
FUEL RECOVERY	26,182	0	0
ROCKPORT PLANT UNIT 2	0	0	0
RATE STABILIZATION DEFERRAL	0	0	0
CHANGE IN OPERATING RESERVES	0	0	0
DEFERRAL OF INCREMENTAL NUCLEAR REFUELING OUTAGE EXPENSES	0	0	0
CHANGE IN OTHER ASSETS	(224,440)	2,110	6,416
CHANGE IN OTHER LIABILITIES	128,860	24,207	(46,931)
NET CASH FLOWS FROM (USED FOR) OPERATING ACTIVITIES	977,338	(21,087)	(287)
INVESTING ACTIVITIES			
CONSTRUCTION EXPENDITURES	(396,630)	0	0
INVESTMENT IN DISCONTINUED OPERATIONS, NET	31,624	0	0
INVESTMENT IN SUBSIDIARIES	836	(618)	0
PROCEEDS FROM SALE OF ASSETS	14,805	0	0
OTHER	22,990	0	0
NET CASH FLOWS FROM (USED FOR) INVESTING ACTIVITIES	(326,375)	(618)	0
FINANCING ACTIVITIES			
ISSUANCE OF COMMON STOCK	0	0	0
CAPITAL CONTRIBUTION FROM PARENT	(3,651)	(6,872)	0
ISSUANCE OF LONG-TERM DEBT	1,653,206	0	0
CHANGE IN SHORT-TERM DEBT, NET	(1,372,397)	23,490	287
CHANGE IN SHORT-TERM DEBT - AFFILIATES	0	0	0
CHANGE IN ADVANCES FROM AFFILIATES, NET	0	0	0
RETIREMENT OF LONG-TERM DEBT	(738,609)	0	0
RETIREMENT OF LONG-TERM DEBT AFFILIATES	0	0	0
RETIREMENT OF PREFERRED STOCK	(13)	0	0
RETIREMENT OF MINORITY INTEREST	0	0	0
DIVIDENDS PAID ON CUMULATIVE PREFERRED STOCK	0	0	0
DIVIDENDS PAID ON COMMON STOCK	(183,996)	0	0
NET CASH FLOWS FROM (USED FOR) FINANCING ACTIVITIES	(645,460)	16,618	287
NET INCREASE (DECREASE) IN CASH AND CASH EQUIVALENTS	5,503	(5,087)	(0)
CASH AND CASH EQUIVALENTS AT BEGINNING OF PERIOD	124,279	5,120	0
CASH AND CASH EQUIVALENTS AT END OF PERIOD	129,782	33	(0)
NET INCREASE (DECREASE) IN CASH AND CASH EQUIVALENTS FROM DISCONTINUED OPERATIONS	0	0	0
CASH AND CASH EQUIVALENTS FROM DISCONTINUED OPERATIONS - BEGINNING OF PERIOD	0	0	0
CASH AND CASH EQUIVALENTS FROM DISCONTINUED OPERATIONS - END OF PERIOD	$0	$0	$0

Item 10 - Consolidating Statements of Cash Flows

AMERICAN ELECTRIC POWER COMPANY, INC.
AND SUBSIDIARY COMPANIES
CONSOLIDATING STATEMENT OF CASH FLOWS
FOR THE YEAR ENDED DECEMBER 31, 2003
(IN THOUSANDS)

Note - Totals and subtotals may be off due to rounding

	AEP DESERT SKY LP II, LLC	AEP COAL, INC	AEP POWER MARKETING, INC
OPERATING ACTIVITIES			
NET INCOME (LOSS)	$2,857	($41,382)	$14,640
PLUS: DISCONTINUED OPERATIONS	0	0	0
INCOME FROM CONTINUING OPERATIONS	2,857	(41,382)	14,640
ADJUSTMENTS FOR NONCASH ITEMS			
DEPRECIATION AND AMORTIZATION	9,053	6,014	0
DEFERRED INCOME TAXES	1,968	(19,224)	4,165
DEFERRED INVESTMENT TAX CREDITS	0	0	0
CUMULATIVE EFFECT OF ACCOUNTING CHANGES	215	0	0
ASSET AND INVESTMENT VALUE IMPAIRMENTS AND OTHER RELATED CHARGES	0	66,626	0
AMORTIZATION OF DEFERRED PROPERTY TAXES	0	0	0
AMORTIZATION OF COOK PLANT RESTART COSTS	0	0	0
PENSION AND POSTEMPLOYMENT BENEFITS RESERVES			
MARK-TO-MARKET OF RISK MANAGEMENT CONTRACTS	0	0	(11,900)
EQUITY (EARNINGS) / LOSS - CONSOLIDATING SUBSIDIARIES	0	0	0
CHANGES IN CERTAIN CURRENT ASSETS AND LIABILITIES			
ACCOUNTS RECEIVABLE, NET	(57,916)	5,477	(42,206)
ACCRUED UTILITY REVENUES	0	0	0
PREPAYMENTS AND OTHER	0	0	0
FUEL, MATERIALS AND SUPPLIES	0	(1,654)	0
ACCOUNTS PAYABLE	8,048	(2,971)	18,480
INTEREST ACCRUED	0	0	0
CUSTOMER DEPOSITS	0	0	0
INCENTIVE PLAN ACCRUED	0	0	0
EMPLOYEE BENEFITS AND OTHER NONCURRENT LIABILITIES	0	0	0
TAXES ACCRUED	1,396	153	3,572
FUEL RECOVERY	0	0	0
ROCKPORT PLANT UNIT 2	0	0	0
RATE STABILIZATION DEFERRAL	0	0	0
CHANGE IN OPERATING RESERVES	0	0	0
DEFERRAL OF INCREMENTAL NUCLEAR REFUELING OUTAGE EXPENSES	0	0	0
CHANGE IN OTHER ASSETS	(4,487)	(7,664)	(0)
CHANGE IN OTHER LIABILITIES	46,260	(6,352)	2,118
NET CASH FLOWS FROM (USED FOR) OPERATING ACTIVITIES	7,393	(976)	(11,130)
INVESTING ACTIVITIES			
CONSTRUCTION EXPENDITURES	0	0	0
INVESTMENT IN DISCONTINUED OPERATIONS, NET	0	0	0
INVESTMENT IN SUBSIDIARIES	0	0	0
PROCEEDS FROM SALE OF ASSETS	0	6,072	0
OTHER	0	0	0
NET CASH FLOWS FROM (USED FOR) INVESTING ACTIVITIES	0	6,072	0
FINANCING ACTIVITIES			
ISSUANCE OF COMMON STOCK	0	0	0
CAPITAL CONTRIBUTION FROM PARENT	0	0	0
ISSUANCE OF LONG-TERM DEBT	0	0	0
CHANGE IN SHORT-TERM DEBT, NET	998	(6,694)	11,130
CHANGE IN SHORT-TERM DEBT - AFFILIATES	0	0	0
CHANGE IN ADVANCES FROM AFFILIATES, NET	0	0	0
RETIREMENT OF LONG-TERM DEBT	(6,759)	0	0
RETIREMENT OF LONG-TERM DEBT AFFILIATES	0	0	0
RETIREMENT OF PREFERRED STOCK	0	0	0
RETIREMENT OF MINORITY INTEREST	0	0	0
DIVIDENDS PAID ON CUMULATIVE PREFERRED STOCK	0	0	0
DIVIDENDS PAID ON COMMON STOCK	0	0	0
NET CASH FLOWS FROM (USED FOR) FINANCING ACTIVITIES	(5,761)	(6,694)	11,130
NET INCREASE (DECREASE) IN CASH AND CASH EQUIVALENTS	1,631	(1,598)	(0)
CASH AND CASH EQUIVALENTS AT BEGINNING OF PERIOD	13,360	4,225	0
CASH AND CASH EQUIVALENTS AT END OF PERIOD	14,991	2,627	(0)
NET INCREASE (DECREASE) IN CASH AND CASH EQUIVALENTS FROM DISCONTINUED OPERATIONS	0	0	0
CASH AND CASH EQUIVALENTS FROM DISCONTINUED OPERATIONS - BEGINNING OF PERIOD	0	0	0
CASH AND CASH EQUIVALENTS FROM DISCONTINUED OPERATIONS - END OF PERIOD	$0	$0	$0

Item 10 - Consolidating Statements of Cash Flows

AMERICAN ELECTRIC POWER COMPANY, INC.
AND SUBSIDIARY COMPANIES
CONSOLIDATING STATEMENT OF CASH FLOWS
FOR THE YEAR ENDED DECEMBER 31, 2003
(IN THOUSANDS)

Note - Totals and subtotals may be off due to rounding

	AEP PRO SERV, INC	MUTUAL ENERGY LLC
OPERATING ACTIVITIES		
NET INCOME (LOSS)	($6,361)	$27,833
PLUS: DISCONTINUED OPERATIONS	0	0
INCOME FROM CONTINUING OPERATIONS	(6,361)	27,833
ADJUSTMENTS FOR NONCASH ITEMS		
DEPRECIATION AND AMORTIZATION	1,708	358
DEFERRED INCOME TAXES	661	(3,634)
DEFERRED INVESTMENT TAX CREDITS	0	0
CUMULATIVE EFFECT OF ACCOUNTING CHANGES	0	0
ASSET AND INVESTMENT VALUE IMPAIRMENTS AND OTHER RELATED CHARGES	0	0
AMORTIZATION OF DEFERRED PROPERTY TAXES	0	0
AMORTIZATION OF COOK PLANT RESTART COSTS	0	0
PENSION AND POSTEMPLOYMENT BENEFITS RESERVES		
MARK-TO-MARKET OF RISK MANAGEMENT CONTRACTS	0	227
EQUITY (EARNINGS) / LOSS - CONSOLIDATING SUBSIDIARIES	0	0
CHANGES IN CERTAIN CURRENT ASSETS AND LIABILITIES		
ACCOUNTS RECEIVABLE, NET	18,235	5,457
ACCRUED UTILITY REVENUES	0	0
PREPAYMENTS AND OTHER	0	0
FUEL, MATERIALS AND SUPPLIES	86	2,778
ACCOUNTS PAYABLE	(21,530)	(7,162)
INTEREST ACCRUED	0	0
CUSTOMER DEPOSITS	0	0
INCENTIVE PLAN ACCRUED	0	0
EMPLOYEE BENEFITS AND OTHER NONCURRENT LIABILITIES	0	0
TAXES ACCRUED	15,796	(2,727)
FUEL RECOVERY	0	0
ROCKPORT PLANT UNIT 2	0	0
RATE STABILIZATION DEFERRAL	0	0
CHANGE IN OPERATING RESERVES	0	0
DEFERRAL OF INCREMENTAL NUCLEAR REFUELING OUTAGE EXPENSES	0	0
CHANGE IN OTHER ASSETS	2,645	(54,842)
CHANGE IN OTHER LIABILITIES	(39,723)	1,706
NET CASH FLOWS FROM (USED FOR) OPERATING ACTIVITIES	(28,483)	(30,006)
INVESTING ACTIVITIES		
CONSTRUCTION EXPENDITURES	0	0
INVESTMENT IN DISCONTINUED OPERATIONS, NET	0	0
INVESTMENT IN SUBSIDIARIES	0	0
PROCEEDS FROM SALE OF ASSETS	0	33,066
OTHER	0	0
NET CASH FLOWS FROM (USED FOR) INVESTING ACTIVITIES	0	33,066
FINANCING ACTIVITIES		
ISSUANCE OF COMMON STOCK	0	0
CAPITAL CONTRIBUTION FROM PARENT	12,431	0
ISSUANCE OF LONG-TERM DEBT	0	0
CHANGE IN SHORT-TERM DEBT, NET	8,070	11,099
CHANGE IN SHORT-TERM DEBT - AFFILIATES	0	0
CHANGE IN ADVANCES FROM AFFILIATES, NET	0	0
RETIREMENT OF LONG-TERM DEBT	7,500	0
RETIREMENT OF LONG-TERM DEBT AFFILIATES	0	0
RETIREMENT OF PREFERRED STOCK	0	0
RETIREMENT OF MINORITY INTEREST	0	0
DIVIDENDS PAID ON CUMULATIVE PREFERRED STOCK	0	0
DIVIDENDS PAID ON COMMON STOCK	0	(14,000)
NET CASH FLOWS FROM (USED FOR) FINANCING ACTIVITIES	28,001	(2,901)
NET INCREASE (DECREASE) IN CASH AND CASH EQUIVALENTS	(482)	159
CASH AND CASH EQUIVALENTS AT BEGINNING OF PERIOD	1,284	(159)
CASH AND CASH EQUIVALENTS AT END OF PERIOD	802	(0)
NET INCREASE (DECREASE) IN CASH AND CASH EQUIVALENTS FROM DISCONTINUED OPERATIONS	0	0
CASH AND CASH EQUIVALENTS FROM DISCONTINUED OPERATIONS - BEGINNING OF PERIOD	0	0
CASH AND CASH EQUIVALENTS FROM DISCONTINUED OPERATIONS - END OF PERIOD	$0	$0

Item 10 - Consolidating Statements of Cash Flows

AEP UTILITIES, INC. AND SUBSIDIARY COMPANIES
CONSOLIDATING STATEMENT OF CASH FLOWS
FOR THE YEAR ENDED DECEMBER 31, 2003
(IN THOUSANDS)

Note - Totals and subtotals may be off due to rounding

	AEP UTILITIES INCORPORATED CONSOLIDATED	AEP UTILITIES INCORPORATED ELIMINATIONS	AEP UTILITIES INCORPORATED
OPERATING ACTIVITIES			
NET INCOME (LOSS)	$375,937	($393,273)	$375,938
PLUS: DISCONTINUED OPERATIONS	0	0	0
INCOME FROM CONTINUING OPERATIONS	375,937	(393,273)	375,938
ADJUSTMENTS FOR NONCASH ITEMS			
DEPRECIATION AND AMORTIZATION	442,140	0	431
EXTRAORDINARY LOSS - NET OF TAX	0	(177)	0
DEFERRED INCOME TAXES	121,520	0	8,389
DEFERRED INVESTMENT TAX CREDITS	(12,845)	(2)	0
PENSION AND POSTEMPLOYMENT BENEFITS RESERVES	0		
CUMULATIVE EFFECT OF ACCOUNTING CHANGES	(11,710)	0	0
ASSET AND INVESTMENT VALUE IMPAIRMENTS AND OTHER RELATED CHARGES	70,000	0	0
AMORTIZATION OF DEFERRED PROPERTY TAXES	(833)	0	0
AMORTIZATION OF COOK PLANT RESTART COSTS	0	0	0
MARK-TO-MARKET OF RISK MANAGEMENT CONTRACTS	(31,813)	(10,511)	0
WHOLESALE CAPACITY AUCTION TRUE-UP	0	218,000	0
EQUITY (EARNINGS) / LOSS - CONSOLIDATING SUBSIDIARIES	0	392,486	(392,486)
CHANGES IN CERTAIN CURRENT ASSETS AND LIABILITIES			
ACCOUNTS RECEIVABLE, NET	177,577	136,202	(5,893)
FUEL, MATERIALS AND SUPPLIES	24,868	(1)	0
ACCOUNTS PAYABLE	(239,486)	(139,309)	(16,758)
INTEREST ACCRUED	0	8,009	0
TAXES ACCRUED	131,381	1	11,154
FUEL RECOVERY	26,182	(4,541)	0
CHANGE IN OTHER ASSETS	(224,440)	(227,824)	2,945
CHANGE IN OTHER LIABILITIES	128,860	(214,551)	165,989
NET CASH FLOWS FROM (USED FOR) OPERATING ACTIVITIES	977,339	(235,491)	149,708
INVESTING ACTIVITIES			
CONSTRUCTION EXPENDITURES	(396,630)	0	(237)
INVESTMENT IN DISCONTINUED OPERATIONS, NET	31,624	0	0
INVESTMENT IN SUBSIDIARIES	836	18,467	(18,467)
PROCEEDS FROM SALE OF ASSETS	14,805	0	0
OTHER	22,990	0	0
NET CASH FLOWS FROM (USED FOR) INVESTING ACTIVITIES	(326,375)	18,467	(18,704)
FINANCING ACTIVITIES			
ISSUANCE OF COMMON STOCK	0	0	0
CAPITAL CONTRIBUTION FROM PARENT	(3,651)	(11,294)	55,758
ISSUANCE OF LONG-TERM DEBT	1,653,206	1	0
CHANGE IN SHORT-TERM DEBT, NET	(1,372,397)	(1,227,450)	21,596
CHANGE IN SHORT-TERM DEBT AFFILIATES	0	775,000	0
CHANGE IN ADVANCES FROM AFFILIATES, NET	0	452,366	0
RETIREMENT OF LONG-TERM DEBT	(738,609)	0	0
RETIREMENT OF PREFERRED STOCK	(13)	(1)	0
RETIREMENT OF MINORITY INTEREST	0	0	0
DIVIDENDS PAID ON CUMULATIVE PREFERRED STOCK	(0)	787	0
DIVIDENDS PAID ON COMMON STOCK	(183,996)	227,619	(183,997)
NET CASH FLOWS FROM (USED FOR) FINANCING ACTIVITIES	(645,461)	217,028	(106,643)
NET INCREASE (DECREASE) IN CASH AND CASH EQUIVALENTS	5,503	4	24,361
CASH AND CASH EQUIVALENTS AT BEGINNING OF PERIOD	124,279	0	5
CASH AND CASH EQUIVALENTS AT END OF PERIOD	129,782	4	24,366
NET INCREASE (DECREASE) IN CASH AND CASH EQUIVALENTS FROM DISCONTINUED OPERATIONS	0	0	0
CASH AND CASH EQUIVALENTS FROM DISCONTINUED OPERATIONS - BEGINNING OF PERIOD	0	0	0
CASH AND CASH EQUIVALENTS FROM DISCONTINUED OPERATIONS - END OF PERIOD	$0	$0	$0

Item 10 - Consolidating Statements of Cash Flows

AEP UTILITIES, INC. AND SUBSIDIARY COMPANIES
CONSOLIDATING STATEMENT OF CASH FLOWS
FOR THE YEAR ENDED DECEMBER 31, 2003
(IN THOUSANDS)

Note - Totals and subtotals may be off due to rounding

	AEP CREDIT INCORPORATED	ENERSHOP INCORPORATED	CSW LEASING INCORPORATED
OPERATING ACTIVITIES			
NET INCOME (LOSS)	$4,356	($985)	($0)
PLUS: DISCONTINUED OPERATIONS	0	0	0
INCOME FROM CONTINUING OPERATIONS	4,356	(985)	(0)
ADJUSTMENTS FOR NONCASH ITEMS			
DEPRECIATION AND AMORTIZATION	0	1	0
EXTRAORDINARY LOSS - NET OF TAX	0	0	0
DEFERRED INCOME TAXES	5,120	(54)	0
DEFERRED INVESTMENT TAX CREDITS	0	0	0
PENSION AND POSTEMPLOYMENT BENEFITS RESERVES			
CUMULATIVE EFFECT OF ACCOUNTING CHANGES	0	0	0
ASSET AND INVESTMENT VALUE IMPAIRMENTS AND OTHER RELATED CHARGES	0	0	0
AMORTIZATION OF DEFERRED PROPERTY TAXES	0	0	0
AMORTIZATION OF COOK PLANT RESTART COSTS	0	0	0
MARK-TO-MARKET OF RISK MANAGEMENT CONTRACTS	0	0	0
WHOLESALE CAPACITY AUCTION TRUE-UP	0	0	0
EQUITY (EARNINGS) / LOSS - CONSOLIDATING SUBSIDIARIES	0	0	0
CHANGES IN CERTAIN CURRENT ASSETS AND LIABILITIES			
ACCOUNTS RECEIVABLE, NET	(44,884)	744	0
FUEL, MATERIALS AND SUPPLIES	0	0	0
ACCOUNTS PAYABLE	(13,530)	(182)	(6)
INTEREST ACCRUED	0	0	0
TAXES ACCRUED	(4,284)	168	15,599
FUEL RECOVERY	0	0	0
CHANGE IN OTHER ASSETS	(358)	449	0
CHANGE IN OTHER LIABILITIES	(5,021)	19,909	44,749
NET CASH FLOWS FROM (USED FOR) OPERATING ACTIVITIES	(58,601)	20,051	60,343
INVESTING ACTIVITIES			
CONSTRUCTION EXPENDITURES	0	0	0
INVESTMENT IN DISCONTINUED OPERATIONS, NET	0	0	0
INVESTMENT IN SUBSIDIARIES	0	0	0
PROCEEDS FROM SALE OF ASSETS	0	0	0
OTHER	0	0	0
NET CASH FLOWS FROM (USED FOR) INVESTING ACTIVITIES	0	0	0
FINANCING ACTIVITIES			
ISSUANCE OF COMMON STOCK	0	0	0
CAPITAL CONTRIBUTION FROM PARENT	(1,184)	(1)	(60,349)
ISSUANCE OF LONG-TERM DEBT	0	0	0
CHANGE IN SHORT-TERM DEBT, NET	59,784	(6,003)	0
CHANGE IN SHORT-TERM DEBT AFFILIATES	0	0	0
CHANGE IN ADVANCES FROM AFFILIATES, NET	0	0	0
RETIREMENT OF LONG-TERM DEBT	0	(15,000)	0
RETIREMENT OF PREFERRED STOCK	0	0	0
RETIREMENT OF MINORITY INTEREST	0	0	0
DIVIDENDS PAID ON CUMULATIVE PREFERRED STOCK	0	0	0
DIVIDENDS PAID ON COMMON STOCK	0	985	(38)
NET CASH FLOWS FROM (USED FOR) FINANCING ACTIVITIES	58,601	(20,020)	(60,387)
NET INCREASE (DECREASE) IN CASH AND CASH EQUIVALENTS	(1)	31	(44)
CASH AND CASH EQUIVALENTS AT BEGINNING OF PERIOD	0	(32)	44
CASH AND CASH EQUIVALENTS AT END OF PERIOD	(1)	(1)	0
NET INCREASE (DECREASE) IN CASH AND CASH EQUIVALENTS FROM DISCONTINUED OPERATIONS	0	0	0
CASH AND CASH EQUIVALENTS FROM DISCONTINUED OPERATIONS - BEGINNING OF PERIOD	0	0	0
CASH AND CASH EQUIVALENTS FROM DISCONTINUED OPERATIONS - END OF PERIOD	$0	$0	$0

Item 10 - Consolidating Statements of Cash Flows

AEP UTILITIES, INC. AND SUBSIDIARY COMPANIES
CONSOLIDATING STATEMENT OF CASH FLOWS
FOR THE YEAR ENDED DECEMBER 31, 2003
(IN THOUSANDS)

Note - Totals and subtotals may be off due to rounding

	AEP TEXAS CENTRAL COMPANY CONSOLIDATED	PUBLIC SERVICE COMPANY OF OKLAHOMA	AEP TEXAS NORTH COMPANY
OPERATING ACTIVITIES			
NET INCOME (LOSS)	$217,669	$53,891	$58,557
PLUS: DISCONTINUED OPERATIONS	0	0	0
INCOME FROM CONTINUING OPERATIONS	217,669	53,891	58,557
ADJUSTMENTS FOR NONCASH ITEMS			
DEPRECIATION AND AMORTIZATION	189,130	86,455	36,242
EXTRAORDINARY LOSS - NET OF TAX	0	0	177
DEFERRED INCOME TAXES	19,393	(14,641)	(3,493)
DEFERRED INVESTMENT TAX CREDITS	(5,207)	(1,790)	(1,520)
PENSION AND POSTEMPLOYMENT BENEFITS RESERVES			
CUMULATIVE EFFECT OF ACCOUNTING CHANGES	(122)	0	(3,071)
ASSET AND INVESTMENT VALUE IMPAIRMENTS AND OTHER RELATED CHARGES	0	0	0
AMORTIZATION OF DEFERRED PROPERTY TAXES	0	0	0
AMORTIZATION OF COOK PLANT RESTART COSTS	0	0	0
MARK-TO-MARKET OF RISK MANAGEMENT CONTRACTS	(6,341)	0	(2,558)
WHOLESALE CAPACITY AUCTION TRUE-UP	(218,000)	0	0
EQUITY (EARNINGS) / LOSS - CONSOLIDATING SUBSIDIARIES	0	0	0
CHANGES IN CERTAIN CURRENT ASSETS AND LIABILITIES			
ACCOUNTS RECEIVABLE, NET	15,190	(2,588)	14,393
FUEL, MATERIALS AND SUPPLIES	15,850	892	2,460
ACCOUNTS PAYABLE	55,772	(33,231)	(40,140)
INTEREST ACCRUED	(8,009)	0	0
TAXES ACCRUED	42,227	20,303	19,180
FUEL RECOVERY	0	52,300	0
CHANGE IN OTHER ASSETS	30,341	(10,421)	(8,955)
CHANGE IN OTHER LIABILITIES	19,330	14,987	5,996
NET CASH FLOWS FROM (USED FOR) OPERATING ACTIVITIES	367,223	166,157	77,268
INVESTING ACTIVITIES			
CONSTRUCTION EXPENDITURES	(141,771)	(86,815)	(46,683)
INVESTMENT IN DISCONTINUED OPERATIONS, NET	0	0	0
INVESTMENT IN SUBSIDIARIES	0	0	0
PROCEEDS FROM SALE OF ASSETS	7,455	2,862	688
OTHER	0	0	0
NET CASH FLOWS FROM (USED FOR) INVESTING ACTIVITIES	(134,316)	(83,953)	(45,995)
FINANCING ACTIVITIES			
ISSUANCE OF COMMON STOCK	0	0	0
CAPITAL CONTRIBUTION FROM PARENT	0	50,000	0
ISSUANCE OF LONG-TERM DEBT	953,136	148,734	222,455
CHANGE IN SHORT-TERM DEBT, NET	0	0	0
CHANGE IN SHORT-TERM DEBT AFFILIATES	(650,000)	0	(125,000)
CHANGE IN ADVANCES FROM AFFILIATES, NET	(187,410)	(53,241)	(122,000)
RETIREMENT OF LONG-TERM DEBT	(247,127)	(200,000)	0
RETIREMENT OF PREFERRED STOCK	(2)	0	(10)
RETIREMENT OF MINORITY INTEREST	0	0	0
DIVIDENDS PAID ON CUMULATIVE PREFERRED STOCK	(241)	(213)	(104)
DIVIDENDS PAID ON COMMON STOCK	(120,801)	(30,000)	(4,970)
NET CASH FLOWS FROM (USED FOR) FINANCING ACTIVITIES	(252,445)	(84,720)	(29,629)
NET INCREASE (DECREASE) IN CASH AND CASH EQUIVALENTS	(19,538)	(2,516)	1,644
CASH AND CASH EQUIVALENTS AT BEGINNING OF PERIOD	85,420	16,774	1,219
CASH AND CASH EQUIVALENTS AT END OF PERIOD	65,882	14,258	2,863
NET INCREASE (DECREASE) IN CASH AND CASH EQUIVALENTS FROM DISCONTINUED OPERATIONS	0	0	0
CASH AND CASH EQUIVALENTS FROM DISCONTINUED OPERATIONS - BEGINNING OF PERIOD	0	0	0
CASH AND CASH EQUIVALENTS FROM DISCONTINUED OPERATIONS - END OF PERIOD	$0	$0	$0

Item 10 - Consolidating Statements of Cash Flows

AEP UTILITIES, INC. AND SUBSIDIARY COMPANIES
CONSOLIDATING STATEMENT OF CASH FLOWS
FOR THE YEAR ENDED DECEMBER 31, 2003
(IN THOUSANDS)

Note - Totals and subtotals may be off due to rounding

	CSW ENERGY INCORPORATED	SOUTHWESTERN ELECTRIC POWER COMPANY CONSOLIDATED	CSW INTERNATIONAL INCORPORATED
OPERATING ACTIVITIES			
NET INCOME (LOSS)	($43,719)	$98,141	$16,184
PLUS: DISCONTINUED OPERATIONS	0	0	0
INCOME FROM CONTINUING OPERATIONS	(43,719)	98,141	16,184
ADJUSTMENTS FOR NONCASH ITEMS			
DEPRECIATION AND AMORTIZATION	7,644	121,072	0
EXTRAORDINARY LOSS - NET OF TAX	0	0	0
DEFERRED INCOME TAXES	66,501	9,942	1,825
DEFERRED INVESTMENT TAX CREDITS	0	(4,326)	0
PENSION AND POSTEMPLOYMENT BENEFITS RESERVES			
CUMULATIVE EFFECT OF ACCOUNTING CHANGES	0	(8,517)	0
ASSET AND INVESTMENT VALUE IMPAIRMENTS AND OTHER RELATED CHARGES	70,000	0	0
AMORTIZATION OF DEFERRED PROPERTY TAXES	0	0	0
AMORTIZATION OF COOK PLANT RESTART COSTS	0	0	0
MARK-TO-MARKET OF RISK MANAGEMENT CONTRACTS	0	(12,403)	0
WHOLESALE CAPACITY AUCTION TRUE-UP	0	0	0
EQUITY (EARNINGS) / LOSS - CONSOLIDATING SUBSIDIARIES	0	0	0
CHANGES IN CERTAIN CURRENT ASSETS AND LIABILITIES			
ACCOUNTS RECEIVABLE, NET	(4,663)	27,527	34,251
FUEL, MATERIALS AND SUPPLIES	0	4,165	0
ACCOUNTS PAYABLE	67,591	(51,687)	(59,330)
INTEREST ACCRUED	0	0	0
TAXES ACCRUED	8,389	8,446	5,054
FUEL RECOVERY	0	(21,577)	0
CHANGE IN OTHER ASSETS	(7,238)	16,268	(19,815)
CHANGE IN OTHER LIABILITIES	8,030	61,043	5,403
NET CASH FLOWS FROM (USED FOR) OPERATING ACTIVITIES	172,536	248,094	(16,428)
INVESTING ACTIVITIES			
CONSTRUCTION EXPENDITURES	0	(121,124)	0
INVESTMENT IN DISCONTINUED OPERATIONS, NET	31,624	0	0
INVESTMENT IN SUBSIDIARIES	836	0	0
PROCEEDS FROM SALE OF ASSETS	0	3,800	0
OTHER	16,515	6,475	0
NET CASH FLOWS FROM (USED FOR) INVESTING ACTIVITIES	48,975	(110,849)	0
FINANCING ACTIVITIES			
ISSUANCE OF COMMON STOCK	0	0	0
CAPITAL CONTRIBUTION FROM PARENT	(12,609)	0	(23,972)
ISSUANCE OF LONG-TERM DEBT	74,250	254,630	0
CHANGE IN SHORT-TERM DEBT, NET	(279,776)	0	40,903
CHANGE IN SHORT-TERM DEBT AFFILIATES	0	0	0
CHANGE IN ADVANCES FROM AFFILIATES, NET	0	(89,715)	0
RETIREMENT OF LONG-TERM DEBT	(10,000)	(219,482)	0
RETIREMENT OF PREFERRED STOCK	0	0	0
RETIREMENT OF MINORITY INTEREST	0	0	0
DIVIDENDS PAID ON CUMULATIVE PREFERRED STOCK	0	(229)	0
DIVIDENDS PAID ON COMMON STOCK	0	(72,794)	0
NET CASH FLOWS FROM (USED FOR) FINANCING ACTIVITIES	(228,135)	(127,590)	16,931
NET INCREASE (DECREASE) IN CASH AND CASH EQUIVALENTS	(6,625)	9,655	502
CASH AND CASH EQUIVALENTS AT BEGINNING OF PERIOD	15,544	2,069	1,830
CASH AND CASH EQUIVALENTS AT END OF PERIOD	8,919	11,724	2,332
NET INCREASE (DECREASE) IN CASH AND CASH EQUIVALENTS FROM DISCONTINUED OPERATIONS	0	0	0
CASH AND CASH EQUIVALENTS FROM DISCONTINUED OPERATIONS - BEGINNING OF PERIOD	0	0	0
CASH AND CASH EQUIVALENTS FROM DISCONTINUED OPERATIONS - END OF PERIOD	$0	$0	$0

AEP UTILITIES, INC. AND SUBSIDIARY COMPANIES
CONSOLIDATING STATEMENT OF CASH FLOWS
FOR THE YEAR ENDED DECEMBER 31, 2003
(IN THOUSANDS)

Note - Totals and subtotals may be off due to rounding

	C3 COMMUNICATIONS INCORPORATED	CSW ENERGY SERVICES INCORPORATED
OPERATING ACTIVITIES		
NET INCOME (LOSS)	($8,107)	($2,714)
PLUS: DISCONTINUED OPERATIONS	0	0
INCOME FROM CONTINUING OPERATIONS	(8,107)	(2,714)
ADJUSTMENTS FOR NONCASH ITEMS		
DEPRECIATION AND AMORTIZATION	0	1,166
EXTRAORDINARY LOSS - NET OF TAX	0	0
DEFERRED INCOME TAXES	28,991	(452)
DEFERRED INVESTMENT TAX CREDITS	0	0
PENSION AND POSTEMPLOYMENT BENEFITS RESERVES		
CUMULATIVE EFFECT OF ACCOUNTING CHANGES	0	0
ASSET AND INVESTMENT VALUE IMPAIRMENTS AND OTHER RELATED CHARGES	0	0
AMORTIZATION OF DEFERRED PROPERTY TAXES	(833)	0
AMORTIZATION OF COOK PLANT RESTART COSTS	0	0
MARK-TO-MARKET OF RISK MANAGEMENT CONTRACTS	0	0
WHOLESALE CAPACITY AUCTION TRUE-UP	0	0
EQUITY (EARNINGS) / LOSS - CONSOLIDATING SUBSIDIARIES	0	0
CHANGES IN CERTAIN CURRENT ASSETS AND LIABILITIES		
ACCOUNTS RECEIVABLE, NET	943	6,354
FUEL, MATERIALS AND SUPPLIES	0	1,502
ACCOUNTS PAYABLE	(3,848)	(4,827)
INTEREST ACCRUED	0	0
TAXES ACCRUED	4,619	524
FUEL RECOVERY	0	0
CHANGE IN OTHER ASSETS	1,089	(922)
CHANGE IN OTHER LIABILITIES	(332)	3,328
NET CASH FLOWS FROM (USED FOR) OPERATING ACTIVITIES	22,522	3,958
INVESTING ACTIVITIES		
CONSTRUCTION EXPENDITURES	0	0
INVESTMENT IN DISCONTINUED OPERATIONS, NET	0	0
INVESTMENT IN SUBSIDIARIES	0	0
PROCEEDS FROM SALE OF ASSETS	0	0
OTHER	0	0
NET CASH FLOWS FROM (USED FOR) INVESTING ACTIVITIES	0	0
FINANCING ACTIVITIES		
ISSUANCE OF COMMON STOCK	0	0
CAPITAL CONTRIBUTION FROM PARENT	0	0
ISSUANCE OF LONG-TERM DEBT	0	0
CHANGE IN SHORT-TERM DEBT, NET	12,031	6,518
CHANGE IN SHORT-TERM DEBT AFFILIATES	0	0
CHANGE IN ADVANCES FROM AFFILIATES, NET	0	0
RETIREMENT OF LONG-TERM DEBT	(35,000)	(12,000)
RETIREMENT OF PREFERRED STOCK	0	0
RETIREMENT OF MINORITY INTEREST	0	0
DIVIDENDS PAID ON CUMULATIVE PREFERRED STOCK	0	0
DIVIDENDS PAID ON COMMON STOCK	0	0
NET CASH FLOWS FROM (USED FOR) FINANCING ACTIVITIES	(22,969)	(5,482)
NET INCREASE (DECREASE) IN CASH AND CASH EQUIVALENTS	(447)	(1,524)
CASH AND CASH EQUIVALENTS AT BEGINNING OF PERIOD	505	901
CASH AND CASH EQUIVALENTS AT END OF PERIOD	58	(623)
NET INCREASE (DECREASE) IN CASH AND CASH EQUIVALENTS FROM DISCONTINUED OPERATIONS	0	0
CASH AND CASH EQUIVALENTS FROM DISCONTINUED OPERATIONS - BEGINNING OF PERIOD	0	0
CASH AND CASH EQUIVALENTS FROM DISCONTINUED OPERATIONS - END OF PERIOD	$0	$0

Item 10 - Consolidating Statements of Retained Earnings

AMERICAN ELECTRIC POWER COMPANY, INC.
AND SUBSIDIARY COMPANIES
STATEMENT OF RETAINED EARNINGS
FOR THE YEAR ENDED DECEMBER 31, 2003

Note - Totals and subtotals may be off due to rounding

DESCRIPTION	AMERICAN ELECTRIC POWER COMPANY CONSOLIDATED	AMERICAN ELECTRIC POWER COMPANY ELIMINATIONS	AMERICAN ELECTRIC POWER COMPANY	AMERICAN ELECTRIC POWER SERVICE CORPORATION	AEP TEXAS POLR, LLC
BALANCE AT DECEMBER 31, 2002	$1,998,738,032.96	($1,707,389,642.71)	$2,002,080,274.40	($0.01)	($178,504.87)
NET INCOME (LOSS)	109,734,841.36	(231,699,334.10)	106,392,846.17	0.01	(6,429,314.42)
TOTAL	2,108,472,874.32	(1,939,088,976.82)	2,108,473,120.56	(0.01)	(6,607,819.30)
DEDUCTIONS:					
COMMON STOCK DIVIDENDS	618,052,809.55	(726,374,634.54)	618,052,809.55	0.00	0.00
PREFERRED STOCK DIVIDENDS	(0.00)	(4,474,076.85)	0.00	0.00	0.00
OTHER	601,279.87	(125,647,139.08)	601,254.33	(0.01)	(0.61)
TOTAL DEDUCTIONS	618,654,089.42	(856,495,850.47)	618,654,063.88	(0.01)	(0.61)
BALANCE AT DECEMBER 31, 2003	$1,489,818,784.90	($1,082,593,126.35)	$1,489,819,056.68	$0.01	($6,607,818.69)

AMERICAN ELECTRIC POWER COMPANY, INC.
AND SUBSIDIARY COMPANIES
STATEMENT OF RETAINED EARNINGS
FOR THE YEAR ENDED DECEMBER 31, 2003

Note - Totals and subtotals may be off due to rounding

DESCRIPTION	AEP MONEY POOL	AEP GENERATING COMPANY	CENTRAL COAL COMPANY	AEP T&D SERVICES, LLC	INDIANA FRANKLIN REALTY, INC.
BALANCE AT DECEMBER 31, 2002	$0.01	$18,163,297.09	$0.02	($126,675.37)	$0.00
NET INCOME (LOSS)	0.02	7,963,595.50	0.01	28,385.59	(0.01)
TOTAL	0.03	26,126,892.59	0.03	(98,289.78)	(0.01)
DEDUCTIONS:					
COMMON STOCK DIVIDENDS	0.00	4,686,000.00	0.00	0.00	0.00
PREFERRED STOCK DIVIDENDS	0.00	0.00	0.00	0.00	0.00
OTHER	0.00	0.00	0.00	0.00	0.00
TOTAL DEDUCTIONS	0.00	4,686,000.00	0.00	0.00	0.00
BALANCE AT DECEMBER 31, 2003	$0.03	$21,440,892.59	$0.03	($98,289.78)	($0.01)

AMERICAN ELECTRIC POWER COMPANY, INC.
AND SUBSIDIARY COMPANIES
STATEMENT OF RETAINED EARNINGS
FOR THE YEAR ENDED DECEMBER 31, 2003

Note - Totals and subtotals may be off due to rounding

DESCRIPTION	FRANKLIN REAL ESTATE COMPANY	APPALACHIAN POWER COMPANY CONSOLIDATED	COLUMBUS SOUTHERN POWER COMPANY CONSOLIDATED	INDIANA MICHIGAN POWER COMPANY CONSOLIDATED	KENTUCKY POWER COMPANY
BALANCE AT DECEMBER 31, 2002	$19,968.87	$260,439,456.01	$290,610,579.41	$143,996,166.53	$48,268,596.38
NET INCOME (LOSS)	(0.01)	280,039,542.22	200,429,983.53	86,388,224.71	32,330,250.50
TOTAL	19,968.86	540,478,998.23	491,040,562.94	230,384,391.24	80,598,846.88
DEDUCTIONS:					
COMMON STOCK DIVIDENDS	0.00	128,266,309.27	163,243,204.94	40,000,015.97	16,448,263.95
PREFERRED STOCK DIVIDENDS	0.00	1,001,275.90	0.00	2,374,750.98	0.00
OTHER	0.00	2,492,934.17	1,015,380.35	134,311.45	0.00
TOTAL DEDUCTIONS	0.00	131,760,519.34	164,258,585.29	42,509,078.40	16,448,263.95
BALANCE AT DECEMBER 31, 2003	$19,968.86	$408,718,478.89	$326,781,977.65	$187,875,312.84	$64,150,582.93

Item 10 - Consolidating Statements of Retained Earnings

AMERICAN ELECTRIC POWER COMPANY, INC.
AND SUBSIDIARY COMPANIES
STATEMENT OF RETAINED EARNINGS
FOR THE YEAR ENDED DECEMBER 31, 2003

Note - Totals and subtotals may be off due to rounding

DESCRIPTION	KINGSPORT POWER COMPANY	OHIO POWER COMPANY CONSOLIDATED	WHEELING POWER COMPANY	AEP INVESTMENTS, INC.	AEP RESOURCES, INC.
BALANCE AT DECEMBER 31, 2002	$8,379,585.78	$522,316,153.93	$11,902,685.06	($29,453,975.51)	($781,690,091.62)
NET INCOME (LOSS)	4,728,896.62	375,662,409.52	10,274,992.36	(5,018,453.13)	(1,121,423,559.22)
TOTAL	13,108,482.40	897,978,563.45	22,177,677.41	(34,472,428.64)	(1,903,113,650.84)
DEDUCTIONS:					
COMMON STOCK DIVIDENDS	4,000,009.20	167,733,845.64	4,000,002.00	0.00	0.00
PREFERRED STOCK DIVIDENDS	0.00	1,098,049.97	0.00	0.00	0.00
OTHER	0.00	0.00	0.00	(0.02)	83,931,654.22
TOTAL DEDUCTIONS	4,000,009.20	168,831,895.62	4,000,002.00	(0.02)	83,931,654.22
BALANCE AT DECEMBER 31, 2003	$9,108,473.19	$729,146,667.84	$18,177,675.41	($34,472,428.62)	($1,987,045,305.05)

AMERICAN ELECTRIC POWER COMPANY, INC.
AND SUBSIDIARY COMPANIES
STATEMENT OF RETAINED EARNINGS
FOR THE YEAR ENDED DECEMBER 31, 2003

Note - Totals and subtotals may be off due to rounding

DESCRIPTION	AEP COMMUNICATIONS, INC.	AEP UTILITIES INCORPORATED CONSOLIDATED	AEP C&I COMPANY, LLC	AEP DESERT SKY LP, LLC	AEP DESERT SKY LP II, LLC
BALANCE AT DECEMBER 31, 2002	($189,634,901.83)	$1,434,527,437.70	$5,383,114.56	$8,139,770.98	($6,703,265.60)
NET INCOME (LOSS)	(3,600,462.92)	375,937,524.17	738,627.04	(595,000.95)	2,856,747.92
TOTAL	(193,235,364.75)	1,810,464,961.87	6,121,741.60	7,544,770.03	(3,846,517.68)
DEDUCTIONS:					
COMMON STOCK DIVIDENDS	0.00	183,996,983.57	0.00	0.00	0.00
PREFERRED STOCK DIVIDENDS	0.00	(0.00)	0.00	0.00	0.00
OTHER	(4.99)	38,072,857.36	(0.29)	6,703,265.61	(6,703,265.60)
TOTAL DEDUCTIONS	(4.99)	222,069,840.93	(0.29)	6,703,265.61	(6,703,265.60)
BALANCE AT DECEMBER 31, 2003	($193,235,359.76)	$1,588,395,120.94	$6,121,741.90	$841,504.42	$2,856,747.92

AMERICAN ELECTRIC POWER COMPANY, INC.
AND SUBSIDIARY COMPANIES
STATEMENT OF RETAINED EARNINGS
FOR THE YEAR ENDED DECEMBER 31, 2003

Note - Totals and subtotals may be off due to rounding

DESCRIPTION	AEP COAL, INC	AEP POWER MARKETING, INC	AEP PRO SERV, INC	MUTUAL ENERGY LLC
BALANCE AT DECEMBER 31, 2002	($38,012,552.02)	($539.27)	$4,586,179.10	($6,885,084.04)
NET INCOME (LOSS)	(41,382,028.50)	14,639,720.26	(6,361,406.76)	27,832,655.25
TOTAL	(79,394,580.52)	14,639,180.99	(1,775,227.66)	20,947,571.21
DEDUCTIONS:				
COMMON STOCK DIVIDENDS	0.00	0.00	0.00	14,000,000.00
PREFERRED STOCK DIVIDENDS	0.00	0.00	0.00	0.00
OTHER	0.00	0.00	33.00	(0.00)
TOTAL DEDUCTIONS	0.00	0.00	33.00	14,000,000.00
BALANCE AT DECEMBER 31, 2003	($79,394,580.52)	$14,639,180.99	($1,775,260.67)	$6,947,571.21

Item 10 - Consolidating Statements of Retained Earnings

AEP UTILITIES, INCORPORATED
AND SUBSIDIARY COMPANIES
STATEMENT OF RETAINED EARNINGS
FOR THE YEAR ENDED DECEMBER 31, 2003

Note - Totals and subtotals may be off due to rounding

DESCRIPTION	AEP UTILITIES INCORPORATED CONSOLIDATED	AEP UTILITIES INCORPORATED ELIMINATIONS	AEP UTILITIES INCORPORATED	AEP CREDIT INCORPORATED	ENERSHOP INCORPORATED
BALANCE AT DECEMBER 31, 2002	$1,434,527,437.70	($972,441,952.54)	$1,434,527,435.74	$0.00	($19,852,749.72)
NET INCOME (LOSS)	375,937,524.17	(393,272,790.51)	375,937,524.29	4,355,644.36	(984,763.46)
TOTAL	1,810,464,961.87	(1,365,714,743.05)	1,810,464,960.03	4,355,644.36	(20,837,513.18)
DEDUCTIONS:					
COMMON STOCK DIVIDENDS	183,996,983.57	(227,619,576.58)	183,996,983.57	0.00	(984,763.46)
PREFERRED STOCK DIVIDENDS	(0.00)	(786,804.57)	0.00	0.00	0.00
OTHER	38,072,857.36	59,700,612.95	38,072,855.40	4,355,644.37	(19,852,749.72)
TOTAL DEDUCTIONS	222,069,840.93	(168,705,768.20)	222,069,838.97	4,355,644.37	(20,837,513.18)
BALANCE AT DECEMBER 31, 2003	$1,588,395,120.94	($1,197,008,974.85)	$1,588,395,121.06	($0.00)	($0.00)

AEP UTILITIES, INCORPORATED
AND SUBSIDIARY COMPANIES
STATEMENT OF RETAINED EARNINGS
FOR THE YEAR ENDED DECEMBER 31, 2003

Note - Totals and subtotals may be off due to rounding

DESCRIPTION	CSW LEASING INCORPORATED	AEP TEXAS CENTRAL COMPANY CONSOLIDATED	PUBLIC SERVICE COMPANY OF OKLAHOMA CONSOLIDATED	AEP TEXAS NORTH COMPANY CONSOLIDATED	CSW ENERGY INCORPORATED
BALANCE AT DECEMBER 31, 2002	($44,711,370.12)	$986,395,393.85	$116,476,481.36	$71,942,097.47	($51,388,235.11)
NET INCOME (LOSS)	(127.60)	217,669,247.67	53,890,350.31	58,556,940.79	(43,718,785.27)
TOTAL	(44,711,497.72)	1,204,064,641.52	170,366,831.68	130,499,038.25	(95,107,020.38)
DEDUCTIONS:					
COMMON STOCK DIVIDENDS	37,942.30	120,801,410.04	29,999,950.76	4,970,439.94	0.00
PREFERRED STOCK DIVIDENDS	0.00	241,143.84	212,606.61	104,044.56	0.00
OTHER	(44,749,440.02)	(480.15)	549,919.65	(4,053.72)	903.11
TOTAL DEDUCTIONS	(44,711,497.72)	121,042,073.73	30,762,477.02	5,070,430.78	903.11
BALANCE AT DECEMBER 31, 2003	($0.00)	$1,083,022,567.79	$139,604,354.66	$125,428,607.47	($95,107,923.49)

AEP UTILITIES, INCORPORATED
AND SUBSIDIARY COMPANIES
STATEMENT OF RETAINED EARNINGS
FOR THE YEAR ENDED DECEMBER 31, 2003

Note - Totals and subtotals may be off due to rounding

DESCRIPTION	SOUTHWESTERN ELECTRIC POWER COMPANY CONSOLIDATED	CSW INTERNATIONAL INCORPORATED	C3 COMMUNICATIONS INCORPORATED	CSW ENERGY SERVICES INCORPORATED
BALANCE AT DECEMBER 31, 2002	$334,788,640.33	($184,723,912.22)	($177,582,649.10)	($58,901,742.24)
NET INCOME (LOSS)	98,141,354.11	16,183,840.10	(8,107,343.05)	(2,713,567.56)
TOTAL	432,929,994.44	(168,540,072.12)	(185,689,992.15)	(61,615,309.80)
DEDUCTIONS:				
COMMON STOCK DIVIDENDS	72,794,597.00	0.00	0.00	0.00
PREFERRED STOCK DIVIDENDS	229,009.56	0.00	0.00	0.00
OTHER	(354.51)	0.00	0.00	0.00
TOTAL DEDUCTIONS	73,023,252.05	0.00	0.00	0.00
BALANCE AT DECEMBER 31, 2003	$359,906,742.39	($168,540,072.12)	($185,689,992.15)	($61,615,309.80)

Item 10 - Consolidating Statements of Retained Earnings

AEP TEXAS CENTRAL COMPANY AND SUBSIDIARY
STATEMENT OF RETAINED EARNINGS
FOR THE YEAR ENDED DECEMBER 31, 2003

Note - Totals and subtotals may be off due to rounding

DESCRIPTION	AEP TEXAS CENTRAL COMPANY CONSOLIDATED	AEP TEXAS CENTRAL COMPANY ELIMINATIONS	AEP TEXAS CENTRAL COMPANY	AEP TEXAS CENTRAL COMPANY SEC
BALANCE AT DECEMBER 31, 2002	$986,395,393.85	$0.00	$0.00	$986,395,393.85
NET INCOME (LOSS)	217,669,247.67	(79,566.86)	217,669,247.67	79,566.86
TOTAL	1,204,064,641.52	(79,566.86)	217,669,247.67	986,474,960.71
DEDUCTIONS:				
COMMON STOCK DIVIDENDS	120,801,410.04	0.00	120,801,410.04	0.00
PREFERRED STOCK DIVIDENDS	241,143.84	0.00	241,143.84	0.00
CAPITAL STOCK EXPENSE	(480.15)	0.00	(986,395,874.00)	986,395,393.85
TOTAL DEDUCTIONS	121,042,073.73	0.00	(865,353,320.12)	986,395,393.85
BALANCE AT DECEMBER 31, 2003	$1,083,022,567.79	($79,566.86)	$1,083,022,567.79	$79,566.86

APPALACHIAN POWER COMPANY AND SUBSIDIARIES
STATEMENT OF RETAINED EARNINGS
FOR THE YEAR ENDED DECEMBER 31, 2003

Note - Totals and subtotals may be off due to rounding

DESCRIPTION	APPALACHIAN POWER COMPANY CONSOLIDATED	APPALACHIAN POWER COMPANY ELIMINATIONS	APPALACHIAN POWER COMPANY
BALANCE AT DECEMBER 31, 2002	$260,439,456.01	($1,605,534.20)	$260,439,456.01
NET INCOME (LOSS)	280,039,542.22	(1,566,697.76)	280,039,542.20
TOTAL	540,478,998.23	(3,172,231.96)	540,478,998.21
DEDUCTIONS:			
COMMON STOCK DIVIDENDS	128,266,309.27	0.00	128,266,309.27
PREFERRED STOCK DIVIDENDS	1,001,275.90	0.00	1,001,275.90
CAPITAL STOCK EXPENSE	2,492,934.17	(0.00)	2,492,934.17
TOTAL DEDUCTIONS	131,760,519.34	(0.00)	131,760,519.34
BALANCE AT DECEMBER 31, 2003	$408,718,478.89	($3,172,231.96)	$408,718,478.87

APPALACHIAN POWER COMPANY AND SUBSIDIARIES
STATEMENT OF RETAINED EARNINGS
FOR THE YEAR ENDED DECEMBER 31, 2003

Note - Totals and subtotals may be off due to rounding

DESCRIPTION	CENTRAL APPALACHIAN COAL COMPANY	SOUTHERN APPALACHIAN COAL COMPANY	CEDAR COAL COMPANY
BALANCE AT DECEMBER 31, 2002	$313,168.99	$1,419,656.00	($127,290.80)
NET INCOME (LOSS)	115,577.01	445,241.01	1,005,879.76
TOTAL	428,746.01	1,864,897.01	878,588.96
DEDUCTIONS:			
COMMON STOCK DIVIDENDS	0.00	0.00	0.00
PREFERRED STOCK DIVIDENDS	0.00	0.00	0.00
CAPITAL STOCK EXPENSE	0.00	0.00	0.00
TOTAL DEDUCTIONS	0.00	0.00	0.00
BALANCE AT DECEMBER 31, 2003	$428,746.01	$1,864,897.01	$878,588.96

Item 10 - Consolidating Statements of Retained Earnings

COLUMBUS SOUTHERN POWER COMPANY AND SUBSIDIARIES
STATEMENT OF RETAINED EARNINGS
FOR THE YEAR ENDED DECEMBER 31, 2003

Note - Totals and subtotals may be off due to rounding

DESCRIPTION	COLUMBUS SOUTHERN POWER COMPANY CONSOLIDATED	COLUMBUS SOUTHERN POWER COMPANY ELIMINATIONS	COLUMBUS SOUTHERN POWER COMPANY
BALANCE AT DECEMBER 31, 2002	$290,610,579.41	($3,400,134.19)	$290,610,579.42
NET INCOME (LOSS)	200,429,983.53	(1,073,012.97)	200,429,983.25
TOTAL	491,040,562.94	(4,473,147.16)	491,040,562.68
DEDUCTIONS:			
COMMON STOCK DIVIDENDS	163,243,204.94	0.00	163,243,204.94
CAPITAL STOCK EXPENSE	1,015,380.35	(0.01)	1,015,380.36
TOTAL DEDUCTIONS	164,258,585.29	(0.01)	164,258,585.30
BALANCE AT DECEMBER 31, 2003	$326,781,977.65	($4,473,147.15)	$326,781,977.38

COLUMBUS SOUTHERN POWER COMPANY AND SUBSIDIARIES
STATEMENT OF RETAINED EARNINGS
FOR THE YEAR ENDED DECEMBER 31, 2003

Note - Totals and subtotals may be off due to rounding

DESCRIPTION	SIMCO INCORPORATED	COLOMET INCORPORATED	CONESVILLE COAL PREPARATION COMPANY
BALANCE AT DECEMBER 31, 2002	$144,231.34	$2,085,919.84	$1,169,983.00
NET INCOME (LOSS)	75,789.61	927,223.64	70,000.00
TOTAL	220,020.95	3,013,143.48	1,239,982.99
DEDUCTIONS:			
COMMON STOCK DIVIDENDS	0.00	0.00	0.00
CAPITAL STOCK EXPENSE	0.00	0.00	0.00
TOTAL DEDUCTIONS	0.00	0.00	0.00
BALANCE AT DECEMBER 31, 2003	$220,020.95	$3,013,143.48	$1,239,982.99

INDIANA MICHIGAN POWER COMPANY AND SUBSIDIARIES
STATEMENT OF RETAINED EARNINGS
FOR THE YEAR ENDED DECEMBER 31, 2003

Note - Totals and subtotals may be off due to rounding

DESCRIPTION	INDIANA MICHIGAN POWER COMPANY CONSOLIDATED	INDIANA MICHIGAN POWER COMPANY ELIMINATIONS	INDIANA MICHIGAN POWER COMPANY	PRICE RIVER COAL COMPANY	BLACKHAWK COAL COMPANY
BALANCE AT DECEMBER 31, 2002	$143,996,166.53	($9,329,674.83)	$143,996,166.52	$0.00	$9,329,674.85
NET INCOME (LOSS)	86,388,224.71	6,406,054.33	86,388,224.68	0.00	(6,406,054.30)
TOTAL	230,384,391.24	(2,923,620.50)	230,384,391.20	0.00	2,923,620.54
DEDUCTIONS:					
COMMON STOCK DIVIDENDS	40,000,015.97	0.00	40,000,015.97	0.00	0.00
PREFERRED STOCK DIVIDENDS	2,374,750.98	0.00	2,374,750.98	0.00	0.00
CAPITAL STOCK EXPENSE	134,311.45	0.02	134,311.44	0.00	0.00
TOTAL DEDUCTIONS	42,509,078.40	0.02	42,509,078.39	0.00	0.00
BALANCE AT DECEMBER 31, 2003	$187,875,312.84	($2,923,620.52)	$187,875,312.81	$0.00	$2,923,620.54

Item 10 - Consolidating Statements of Retained Earnings

OHIO POWER COMPANY CONSOLIDATED
STATEMENT OF RETAINED EARNINGS
FOR THE YEAR ENDED DECEMBER 31, 2003

Note - Totals and subtotals may be off due to rounding

DESCRIPTION	OHIO POWER COMPANY CONSOLIDATED	OHIO POWER COMPANY ELIMINATIONS	OHIO POWER COMPANY	JMG FUNDING LP
BALANCE AT DECEMBER 31, 2002	$522,316,153.93	$0.00	$522,316,153.93	$0.00
NET INCOME (LOSS)	375,662,409.52	0.00	375,662,409.52	0.00
TOTAL	897,978,563.45	0.00	897,978,563.45	0.00
DEDUCTIONS:				
COMMON STOCK DIVIDENDS	167,733,845.64	0.00	167,733,845.64	0.00
PREFERRED STOCK DIVIDENDS	1,098,049.97	0.00	1,098,049.97	0.00
TOTAL DEDUCTIONS	168,831,895.61	0.00	168,831,895.61	0.00
BALANCE AT DECEMBER 31, 2003	$729,146,667.84	$0.00	$729,146,667.84	$0.00

SOUTHWESTERN ELECTRIC POWER COMPANY CONSOLIDATED
STATEMENT OF RETAINED EARNINGS
FOR THE YEAR ENDED DECEMBER 31, 2003

Note - Totals and subtotals may be off due to rounding

DESCRIPTION	SOUTHWESTERN ELECTRIC POWER COMPANY CONSOLIDATED	SOUTHWESTERN ELECTRIC POWER COMPANY ELIMINATIONS	SOUTHWESTERN ELECTRIC POWER COMPANY	DOLET HILLS LIGNITE COMPANY	SABINE MINING COMPANY
BALANCE AT DECEMBER 31, 2002	$334,788,640.33	($1,316,742.00)	$334,788,640.34	$1,316,741.99	$0.00
NET INCOME (LOSS)	98,141,354.11	(2,861,477.22)	98,141,354.10	1,362,023.02	1,499,454.22
TOTAL	432,929,994.44	(4,178,219.22)	432,929,994.43	2,678,765.01	1,499,454.22
DEDUCTIONS:					
COMMON STOCK DIVIDENDS	72,794,597.00	(5,530,507.48)	72,794,597.00	1,990,610.92	3,539,896.56
PREFERRED STOCK DIVIDENDS	229,009.56	0.00	229,009.56	0.00	0.00
CAPITAL STOCK EXPENSE	(354.51)	4,071,632.94	(354.50)	0.00	(4,071,632.95)
TOTAL DEDUCTIONS	73,023,252.05	(1,458,874.54)	73,023,252.06	1,990,610.92	(531,736.39)
BALANCE AT DECEMBER 31, 2003	$359,906,742.39	($2,719,344.68)	$359,906,742.37	$688,154.09	$2,031,190.61

Notes to Consolidating Financial Statements

Notes to financial statements are incorporated herein by reference to the 2003 Annual Report on Form 10-K filed by the respective companies reporting to the Securities and Exchange Commission pursuant to Section 13 or 15 (d) of the Securities Exchange Act of 1934.

Item 10 - Financial Statements of Subsidiares Not Consolidated

OHIO VALLEY ELECTRIC CORPORATION
STATEMENT OF INCOME
FOR THE YEAR ENDED DECEMBER 31, 2003
(IN THOUSANDS)
(UNAUDITED)

DESCRIPTION	OHIO VALLEY ELECTRIC CORPORATION
OPERATING REVENUES	$453,903
OPERATING EXPENSES	
FUEL FOR ELECTRIC GENERATION	81,424
PURCHASED ELECTRICITY FOR RESALE	220,718
OTHER OPERATION	93,126
MAINTENANCE	22,801
DEPRECIATION	4,185
TAXES OTHER THAN FEDERAL INCOME TAXES	835
FEDERAL INCOME TAXES	1,544
TOTAL OPERATING EXPENSES	424,633
OPERATING INCOME	29,270
NONOPERATING INCOME (LOSS)	(322)
INCOME BEFORE INTEREST CHARGES	28,948
NET INTEREST CHARGES	27,096
NET INCOME	$1,852

OHIO VALLEY ELECTRIC COMPANY
STATEMENT OF RETAINED EARNINGS
FOR THE YEAR ENDED DECEMBER 31, 2003
(IN THOUSANDS)
(UNAUDITED)

Note - Totals and subtotals may be off due to rounding

DESCRIPTION	OHIO VALLEY ELECTRIC CORPORATION
BALANCE AT DECEMBER 31, 2002	$1,888
NET INCOME	1,852
CASH DIVIDENDS DECLARED	1,800
BALANCE AT DECEMBER 31, 2003	$1,940

Item 10 - Financial Statements of Subsidiares Not Consolidated

OHIO VALLEY ELECTRIC CORPORATION
BALANCE SHEET
DECEMBER 31, 2003
(IN THOUSANDS)
(UNAUDITED)

DESCRIPTION	OHIO VALLEY ELECTRIC CORPORATION
ASSETS:	
CURRENT AND ACCRUED ASSETS	
CASH AND CASH EQUIVALENTS	$11,656
ACCOUNTS RECEIVABLE	117,422
COAL IN STORAGE - AT AVERAGE COST	9,424
MATERIALS & SUPPLIES - AT AVERAGE COST	8,685
PREPAYMENTS AND OTHER	3,989
TOTAL CURRENT ASSETS	151,176
ELECTRIC UTILITY PLANT	
TOTAL ELECTRIC UTILITY PLANT	505,084
ACCUMULATED DEPRECIATION AND AMORTIZATION	(311,990)
	193,094
CONSTRUCTION WORK IN PROGRESS	13,886
ELECTRIC UTILITY PLANT - NET	206,980
INVESTMENTS AND OTHER	167,020
REGULATORY ASSETS	42,028
DEFERRED CHARGES	23,469
TOTAL ASSETS	$590,673
CAPITALIZATION AND LIABILITIES:	
CURRENT LIABILITIES	
SHORT-TERM DEBT	$50,000
ACCOUNTS PAYABLE	40,612
TAXES ACCRUED	29,478
INTEREST ACCRUED AND OTHER	10,565
TOTAL CURRENT LIABILITIES	130,655
REGULATORY LIABILITIES	41,816
DEFERRED CREDITS	41,262
LONG-TERM DEBT	365,000
COMMON STOCK	10,000
RETAINED EARNINGS	1,940
COMMON SHAREHOLDER'S EQUITY	11,940
TOTAL CAPITALIZATION AND LIABILITIES	$590,673

Item 10 - Financial Statements of Subsidiares Not Consolidated

OHIO VALLEY ELECTRIC CORPORATION
STATEMENT OF CASH FLOWS
FOR THE YEAR ENDED DECEMBER 31, 2003
(IN THOUSANDS)
(UNAUDITED)

DESCRIPTION	OHIO VALLEY ELECTRIC CORPORATION
OPERATING ACTIVITIES	
NET INCOME	$1,852
ADJUSTMENTS FOR NONCASH ITEMS	
DEPRECIATION	4,185
AMORTIZATION OF DEBT EXPENSE	5,617
DEFERRED TAXES	(27,116)
DEFERRED INVESTMENT TAX CREDITS	(7,217)
CHANGES IN CERTAIN CURRENT ASSETS AND LIABILITIES	
ACCOUNTS RECEIVABLE, NET	(92,286)
FUEL, MATERIALS AND SUPPLIES	8,047
ACCOUNTS PAYABLE	16,632
TAXES ACCRUED	16,115
OTHER (NET)	65,517
NET CASH FLOWS FROM OPERATING ACTIVITIES	(8,654)
INVESTING ACTIVITIES	
CONSTRUCTION EXPENDITURES	(46,197)
ADVANCES TO SUBSIDIARIES FOR CONSTRUCTION	(11,816)
NET CASH FLOWS USED FOR INVESTING ACTIVITIES	(58,013)
FINANCING ACTIVITIES	
ISSUANCE OF LONG-TERM DEBT	56,772
RETIREMENT OF LONG-TERM DEBT	(27,734)
CHANGES IN SHORT-TERM DEBT	40,000
DIVIDENDS PAID ON COMMON STOCK	(1,800)
NET CASH USED FOR FINANCING ACTIVITIES	67,238
NET DECREASE IN CASH AND CASH EQUIVALENTS	571
CASH AND CASH EQUIVALENTS AT BEGINNING OF PERIOD	11,085
CASH AND CASH EQUIVALENTS AT END OF PERIOD	$11,656

EXHIBIT A

Incorporation by Reference
Form 10K
Annual Report

	Year	File Number
AEP	2003	1-3525
AEGCo	2003	0-18135
APCo	2003	1-3457
TCC	2003	0-346
TNC	2003	0-340
CSP	2003	1-2680
I&M	2003	1-3570
KPCo	2003	1-6858
OPCo	2003	1-6543
PSO	2003	0-343
SWEPCo	2003	1-3146

KPSC Case No. 99-149
Item No. 1
Attachment No. 3

UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549

FORM U-13-60

ANNUAL REPORT

FOR THE PERIOD

Beginning January 1, 2003 and Ending December 31, 2003

TO THE

U.S. SECURITIES AND EXCHANGE COMMISSION

OF

AMERICAN ELECTRIC POWER SERVICE CORPORATION
(Exact Name of Reporting Company)

FILED
MAY 18 2004
PUBLIC SERVICE
COMMISSION

A Subsidiary Service Company
("Mutual" or "Subsidiary")

Date of Incorporation December 17, 1937 If not Incorporated, Date of Organization ________.

State or Sovereign Power under which Incorporated or Organized New York

Location of Principal Executive Offices of Reporting Company Columbus, Ohio

Name, title, and address of officer to whom correspondence concerning this report should be addressed:

S. S. Bennett	Assistant Controller	1 Riverside Plaza Columbus, Ohio 43215
(Name)	(Title)	(Address)

Name of Principal Holding Company under which Reporting Company is organized:

AMERICAN ELECTRIC POWER COMPANY, INC.

INSTRUCTIONS FOR USE OF FORM U-13-60

1. Time of Filing. Rule 94 provides that on or before the first day of May in each calendar year, each mutual service company and each subsidiary service company as to which the Commission shall have made a favorable finding pursuant to Rule 88, and every service company whose application for approval or declaration pursuant to Rule 88 is pending shall file with the Commission an annual report on Form U-13-60 and in accordance with the Instructions for that form.

2. Number of Copies. Each annual report shall be filed in duplicate. The company should prepare and retain at least one extra copy for itself in case correspondence with reference to the report becomes necessary.

3. Period Covered by Report. The first report filed by any company shall cover the period from the date the Uniform System of Accounts was required to be made effective as to that company under Rules 82 and 93 to the end of that calendar year. Subsequent reports should cover a calendar year.

4. Report Format. Reports shall be submitted on the forms prepared by the Commission. If the space provided on any sheet of such form is inadequate, additional sheets may be inserted of the same size as a sheet of the form or folded to each size.

5. Money Amounts Displayed. All money amounts required to be shown in financial statements may be expressed in whole dollars, in thousands of dollars or in hundred thousands of dollars, as appropriate and subject to provisions of Regulation S-X (210.3-01(b)).

6. Deficits Displayed. Deficits and other like entries shall be indicated by the use of either brackets or a parenthesis with corresponding reference in footnotes. (Regulation S-X,210.3-01(c))

7. Major Amendments or Corrections. Any company desiring to amend or correct a major omission or error in a report after it has been filed with the Commission shall submit an amended report including only those pages, schedules, and entries that are to be amended or corrected. A cover letter shall be submitted requesting the Commission to incorporate the amended report changes and shall be signed by a duly authorized officer of the company.

8. Definitions. Definitions contained in Instruction 01-8 to the Uniform System of Accounts for Mutual Service Companies and Subsidiary Service Companies, Public Utility Holding Company Act of 1935, as amended February 2, 1979 shall be applicable to words or terms used specifically within this Form U-13-60.

9. Organization Chart. The service company shall submit with each annual report a copy of its current organization chart.

10. Methods of Allocation. The service company shall submit with each annual report a listing of the currently effective methods of allocation being used by the service company and on file with the Securities and Exchange Commission pursuant to the Public Utility Holding Company Act of 1935.

11. Annual Statement of Compensation for Use of Capital Billed. The service company shall submit with each annual report a copy of the annual statement supplied to each associate company in support of the amount of compensation for use of capital billed during the calendar year.

LISTING OF SCHEDULES AND ANALYSIS OF ACCOUNTS

LISTING OF SCHEDULES AND ANALYSIS OF ACCOUNTS

ANNUAL REPORT OF American Electric Power Service Corporation

For the Year Ended December 31, 2003

SCHEDULE I - COMPARATIVE BALANCE SHEET
(In Thousands)

Instructions: Give balance sheet of the Company as of December 31 of the current and prior year.

ACCOUNT	ASSETS AND OTHER DEBITS	AS OF DECEMBER 31 2003	2002
	SERVICE COMPANY PROPERTY		
101-106	Service company property (Schedule II)	$ 307,649	$ 349,559
107	Construction work in progress (Schedule II)	23,743	52,829
	Total Property	331,392	402,388
108-111	Less: Accumulated provision for depreciation and amortization of service company property (Schedule III)	174,465	183,942
	Net Service Company Property	156,927	218,446
	INVESTMENTS		
123	Investments in associate companies (Schedule IV)	-	-
124	Other investments (Schedule IV)	108,520	101,462
	Total Investments	108,520	101,462
	CURRENT AND ACCRUED ASSETS		
131	Cash	-	2,544
134	Special deposits	1,244	84
135	Working funds	376	371
136	Temporary cash investments (Schedule IV)	-	-
141	Notes receivable	1	54
143	Accounts receivable	7,421	13,113
144	Accumulated provision for uncollectible accounts	-	(408)
145	Advances to Affiliates		-
146	Accounts receivable from associate companies (Schedule V)	183,880	483,095
152	Fuel stock expenses undistributed (Schedule VI)	-	-
154	Materials and supplies	-	13
163	Stores expense undistributed (Schedule VII)	-	-
165	Prepayments	2,703	4,781
174	Miscellaneous current and accrued assets (Schedule VIII)	-	-
	Total Current and Accrued Assets	195,625	503,647
	DEFERRED DEBITS		
181	Unamortized debt expense	2,135	2,562
184	Clearing accounts	-	952
186	Miscellaneous deferred debits (Schedule IX)	2,134	3,548
188	Research, development, or demonstration expenditures (Sch. X)	-	-
190	Accumulated deferred income taxes	118,820	156,092
	Total Deferred Debits	123,089	163,154
	TOTAL ASSETS AND OTHER DEBITS	$ 584,161	$ 986,709

Note: Unamortized debt expense includes unamortized loss on reacquired debt of $2,135,193 at December 31, 2003 and $2,562,232 at December 31, 2002.

ANNUAL REPORT OF American Electric Power Service Corporation

For the Year Ended December 31, 2003

SCHEDULE I - COMPARATIVE BALANCE SHEET
(In Thousands)

Instructions: Give balance sheet of the Company as of December 31 of the current and prior year.

ACCOUNT	LIABILITIES AND PROPRIETARY CAPITAL	AS OF DECEMBER 31 2003	2002
	PROPRIETARY CAPITAL		
201	Common stock issued (Schedule XI)	$ 1,450	$ 1,450
211	Miscellaneous paid-in-capital (Schedule XI)	(82,123)	(126,763)
215	Appropriated retained earnings (Schedule XI)	-	-
216	Unappropriated retained earnings (Schedule XI)	-	-
	Total Proprietary Capital	(80,673)	(125,313)
	LONG-TERM DEBT		
223	Advances from associate companies (Schedule XII)	-	1,100
224	Other long-term debt (Schedule XII)	42,000	54,000
225	Unamortized premium on long-term debt	-	-
226	Unamortized discount on long-term debt-debit	-	-
	Total Long-Term Debt	42,000	55,100
	OTHER NONCURRENT LIABILITIES		
227	Obligations under capital leases - Noncurrent	22,373	22,383
224.6	Other	190,780	283,228
	Total Other Noncurrent Liabilities	213,153	305,611
	CURRENT AND ACCRUED LIABILITIES		
228	Accumulated provision for pensions and benefits	-	-
231	Notes payable	-	-
232	Accounts payable	23,685	19,397
233	Notes payable to associate companies (Schedule XIII)	117,116	272,785
234	Accounts payable to associate companies (Schedule XIII)	75,297	147,482
236	Taxes accrued	(15,927)	(24,726)
237	Interest accrued	4,124	3,744
241	Tax collections payable	422	2,828
242	Miscellaneous current and accrued liabilities (Schedule XIII)	129,548	196,064
243	Obligations under capital leases - Current	14,513	15,701
	Total Current and Accrued Liabilities	348,778	633,275
	DEFERRED CREDITS		
253	Other deferred credits	13,267	11,109
255	Accumulated deferred investment tax credits	750	800
	Total Deferred Credits	14,017	11,909
282	**ACCUMULATED DEFERRED INCOME TAXES**	46,886	106,127
	TOTAL LIABILITIES AND PROPRIETARY CAPITAL	$ 584,161	$ 986,709

Note: Long term debt includes $2,000,000 due within one year at December 31, 2003 and $12,000,000 at December 31, 2002 (See note 7, Schedule XIV). "Other" Other noncurrent liabilities exclude Accrued Deferred Compensation Benefits amounts due within one year of $512,619 at December 31, 2003 and $701,060 at December 31, 2002.

ANNUAL REPORT OF American Electric Power Service Corporation

For the Year Ended December 31, 2003

SCHEDULE II - SERVICE COMPANY PROPERTY
(In Thousands)

ACCOUNT DESCRIPTION	BALANCE AT BEGINNING OF YEAR	ADDITIONS	RETIREMENTS OR SALES	OTHER CHANGES (1)	BALANCE AT CLOSE OF YEAR
301 Organization	$ -	$ -	$ -	$ -	$ -
303 Miscellaneous Intangible Plant	39,751	(25,517)	-	-	14,234
304 Land and Land Rights	11,489	-	(924)	-	10,565
305 Structures and Improvements	166,256	7,447		(6,437)	167,266
306 Leasehold Improvements	5,259	43	(37)	-	5,265
307 Equipment (2)	18,245	1,032	-	-	19,277
308 Office Furniture and Equipment	16,964	4	-	-	16,968
309 Automobiles, Other Vehicles and Related Garage Equipment	194	-	-	-	194
310 Aircraft and Airport Equipment	-	-	-	-	-
311 Other Service Company Property	91,401	24,830	(47,568)	5,217	73,880
SUB-TOTALS	349,559	7,839	(48,529)	(1,220)	307,649
107 Construction Work in Progress (3)	52,829	(29,086)	-	-	23,743
TOTALS	$ 402,388	$ (21,247)	$ (48,529)	$ (1,220)	$ 331,392

ANNUAL REPORT OF American Electric Power Service Corporation

For the Year Ended December 31, 2003

SCHEDULE II - SERVICE COMPANY PROPERTY
(In Thousands)

FOOTNOTES

(1) *Provide an explanation of those changes considered material:*

Account 305 Structures and Improvements: In accordance with FASB No. 144 "Accounting for the Impairment or Disposal of Long-Lived Assets", a Dallas, Texas, office building was written-down by $6,399,000 to closely approximate its current appraised market value.

(2) *Subaccounts are required for each class of equipment owned. The service company shall provide a listing by subaccount of equipment additions during the year and the balance at the close of the year:*

Subaccount Description	Additions	Balance At Close Of Year
Account 307 - Equipment:		
Data Processing Equipment	$ -	$ 14,286
Communications Equipment	1,032	4,991
TOTALS	$ 1,032	$ 19,277

(3) *Describe Construction Work in Progress*:

Capitalized Software	$ 12,828
General and Miscellaneous Equipment	5,865
Office Buildings - Owned - Miscellanous Improvements	5,050
TOTALS	$ 23,743

ANNUAL REPORT OF American Electric Power Service Corporation

For the Year Ended December 31, 2003

SCHEDULE III - ACCUMULATED PROVISION FOR DEPRECIATION AND AMORTIZATION OF SERVICE COMPANY PROPERTY

(In Thousands)

ACCOUNT DESCRIPTION	BALANCE AT BEGINNING OF YEAR	ADDITIONS	RETIREMENTS OR SALES	OTHER CHANGES (1)	BALANCE AT CLOSE OF YEAR
301 Organization	$ -	$ -	$ -	$ -	$ -
303 Miscellaneous Intangible Plant	7,480	1,179	-	1,020	9,679
304 Land and Land Rights	-	(11)	11	-	-
305 Structures and Improvements	90,242	4,572	(6,446)	3,614	91,982
306 Leasehold Improvements	3,922	456	(37)	(1,440)	2,901
307 Equipment	14,287	660	-	2,742	17,689
308 Office Furniture and Equipment	14,044	1,455	-	(347)	15,152
309 Automobiles, Other Vehicles and Related Garage Equipment	340	19	-	(169)	190
310 Aircraft and Airport Equipment	-	-	-	-	-
311 Other Service Company Property	53,627	22,627	(43,689)	4,354	36,919
SUB-TOTALS	183,942	30,957	(50,161)	9,774	174,512
108 Retirement Work in Progress	-	-	-	(47)	(47)
TOTALS	$ 183,942	$ 30,957	$ (50,161)	$ 9,727	$ 174,465

(1) Provide an explanation of those changes considered material:

ANNUAL REPORT OF American Electric Power Service Corporation

For the Year Ended December 31, 2003

SCHEDULE IV - INVESTMENTS
(In Thousands)

Instructions: Complete the following schedule concerning investments.

Under Account 124 "Other Investments", state each investment separately, with description, including the name of issuing company, number of shares or principal amount, etc.

Under Account 136, "Temporary Cash Investments", list each investment separately.

ACCOUNT DESCRIPTION	BALANCE AT BEGINNING OF YEAR	BALANCE AT CLOSE OF YEAR
Account 123 - Investment in Associate Companies		
Investment in Common Stock of Subs	$ -	$ -
SUB-TOTALS	-	-
Account 124 - Other Investments		
Cash Surrender Value of Life Insurance Policies (net of policy loans and accrued interest)	19,916	15,987
Umbrella Trust	63,092	75,351
COLI Tax and Interest	18,454	17,182
SUB-TOTALS	101,462	108,520
Account 136 - Temporary Cash Investments	-	-
TOTALS	$ 101,462	$ 108,520

ANNUAL REPORT OF American Electric Power Service Corporation

For the Year Ended December 31, 2003

SCHEDULE V - ACCOUNTS RECEIVABLE FROM ASSOCIATE COMPANIES
(In Thousands)

Instructions: Complete the following schedule listing accounts receivable from each associate company. Where the service company has provided accommodation or convenience payments for associate companies, a separate listing of total payments for each associate company by subaccount should be provided.

ACCOUNT DESCRIPTION	BALANCE AT BEGINNING OF YEAR	BALANCE AT CLOSE OF YEAR
Account Balances by Associate Company		
AEP C&I Company, LLC	$ 13	$ 4
AEP Coal Co.	395	193
AEP Coal Marketing LLC	-	32
AEP Communications, Inc.	173	2
AEP Communications, LLC	1,815	5
AEP Credit, Inc.	172	25
AEP Delaware Investment Company	15	10
AEP Delaware Investment Company II	100	7
AEP Desert Sky LP, LLC	253	85
AEP Desert Sky GP, LLC	1	4
AEP Elmwood LLC	6	1
AEP Emissions Marketing, LLC	-	1
AEP EmTech LLC	450	506
AEP Energy Services Gas Holding Company	4,522	159
AEP Energy Services Gas Holdings II LLC	11	5
AEP Energy Services Limited	1,722	822
AEP Energy Services UK Generation Limited	270	734
AEP Energy Services Ventures, Inc.	4	1
AEP Energy Services Ventures II, Inc.	1	-
AEP Energy Services, Inc.	21,657	2,028
AEP Fiber Venture, LLC	22	50
AEP Gas Marketing LP	25	-
AEP Gas Power GP, LLC	41	3
AEP Gas Power System GP, LLC	1	-
AEP Generating Company	592	184
AEP Holdings I CV	2	-
AEP Investments, Inc.	149	13
AEP MEMCo LLC	190	373
AEP Ohio Commercial & Industrial Retail Company, LLC	2	-
AEP Ohio Retail Energy, LLC	13	-
AEP Power Marketing, Inc.	1	1
AEP Pro Serv, Inc.	5,688	864
AEP Pushan Power, LDC	6	17
AEP Resources Australia Holdings Pty, Ltd	-	2
AEP Resources Australia Pty., Ltd	-	(4)
AEP Resources Limited	1	-

ANNUAL REPORT OF American Electric Power Service Corporation

For the Year Ended December 31, 2003

SCHEDULE V - ACCOUNTS RECEIVABLE FROM ASSOCIATE COMPANIES
(In Thousands)

Instructions: Complete the following schedule listing accounts receivable from each associate company. Where the service company has provided accommodation or convenience payments for associate companies, a separate listing of total payments for each associate company by subaccount should be provided.

	BALANCE AT BEGINNING OF YEAR	BALANCE AT CLOSE OF YEAR
AEP Resources, Inc.	$ 1,885	$ (95)
AEP Retail Energy, LLC	1	-
AEP System Pool	(1,269)	4,399
AEP T & D Services, LLC	58	30
AEP Texas Central Company	34,572	13,378
AEP Texas Commercial & Industrial Retail GP, LLC	52	2
AEP Texas Commercial & Industrial Retail Limited Partnership	10	45
AEP Texas North Company	13,290	4,185
AEP Texas POLR, LLC	1	-
AEP Utilities Inc.	24,438	120
AEP Wind Holding, LLC	-	96
AEPR Ohio, LLC	13	2,928
American Electric Power Company, Inc.	12,149	4,813
Appalachian Power Company	70,481	41,911
Blackhawk Coal Company	37	8
C3 Communications, Inc.	729	365
C3 Networks GP, LLC	-	306
Cardinal Operating Company	3,940	574
Cedar Coal Co.	2	-
Central Coal Company	4	8
Colomet, Inc.	14	-
Columbus Southern Power Company	69,857	32,389
Conesville Coal Preparation Company	412	164
CSW Energy Services, Inc.	295	39
CSW Energy, Inc.	3,209	768
CSW International, Inc.	10,182	16
CSW Leasing, Inc.	(1)	-
CSW Power Marketing, Inc.	613	925
CSW Services International Inc.	289	6
Desert Sky Wind Farm LP	30	9
Diversified Energy Contractors Company, LLC	(1)	9
Dolet Hills Lignite Company, LLC	344	89
EnerShop Inc.	27	-
Houston Pipe Line Company LP	2,094	1,540
HPL GP, LLC	4	9
HPL Holdings, Inc	3	1
HPL Resources Company LP	3	3

ANNUAL REPORT OF American Electric Power Service Corporation

For the Year Ended December 31, 2003

SCHEDULE V - ACCOUNTS RECEIVABLE FROM ASSOCIATE COMPANIES
(In Thousands)

Instructions: Complete the following schedule listing accounts receivable from each associate company. Where the service company has provided accommodation or convenience payments for associate companies, a separate listing of total payments for each associate company by subaccount should be provided.

	BALANCE AT BEGINNING OF YEAR	BALANCE AT CLOSE OF YEAR
Indiana Michigan Power Company	$ 42,950	$ 13,511
Industry and Energy Associates LLC	174	-
Jefferson Island Storage & Hub L. L. C.	5	-
Kentucky Power Company	25,750	6,348
Kingsport Power Company	1,667	327
LIG Chemical Company	2	1
LIG Liquids Company, L.L.C.	17	8
LIG, Inc.	(1)	-
Louisiana Intrastate Gas Company, L.L.C	129	49
Mutual Energy L.L.C.	4	22
Mutual Energy Service Company, L.L.C.	695	
Mutual Energy SWEPCO L.P.	-	3
Newgulf Power Venture	28	-
Ohio Power Company	68,815	25,007
Ohio Power Company/Cook Coal Terminal	1,028	5,384
POLR Power, L.P.	21	3
Public Service Company of Oklahoma	21,193	7,554
REP General Partner L.L.C.	21	-
REP Holdco Inc.	575	2
Seeboard plc	37	9
Simco, Inc.	1	-
Southern Appalachian Coal Company	(10)	-
Southwestern Electric Power Company	29,983	9,741
Sweeny Cogeneration LP	-	3
Trent Wind Farm LP	914	153
Tuscaloosa Pipeline Company	(1)	-
United Sciences Testing, Inc.	589	145
Ventures Lease Co., LLC	24	61
Wheeling Power Company	2,405	382
TOTALS	$ 483,095	$ 183,880

ANNUAL REPORT OF American Electric Power Service Corporation

For the Year Ended December 31, 2003

SCHEDULE V - ACCOUNTS RECEIVABLE FROM ASSOCIATE COMPANIES
(In Thousands)

Instructions: Complete the following schedule listing accounts receivable from each associate company. Where the service company has provided accommodation or convenience payments for associate companies, a separate listing of total payments for each associate company by subaccount should be provided.

ANALYSIS OF CONVENIENCE OR ACCOMMODATION PAYMENTS:	TOTAL PAYMENTS
BY COMPANY:	
AEP Communications, Inc.	$ 1
AEP Communications, LLC	277
AEP Credit, Inc.	903
AEP EmTech LLC	160
AEP Energy Services Gas Holding Company	601
AEP Investments, Inc.	2
AEP Memco LLC	1
AEP Pro Serv, Inc.	516
AEP Resources, Inc.	38
AEP Texas Central Company	54,096
AEP Texas North Company	27,042
AEP T & D Services, LLC	1
AEPES General and Administrative	870
American Electric Power Company, Inc.	10
Appalachian Power Company	426,670
C3 Communications, Inc.	16
Cardinal Operating Company	(141)
Columbus Southern Power Company	252,571
Conesville Coal Preparation Company	117
CSW Energy Services, Inc.	9
CSW Energy, Inc.	36
Houston Pipe Line Company LP	345
Indiana Michigan Power Company	351,798
Kentucky Power Company	94,892
Kingsport Power Company	584
Louisiana Intrastate Gas Company, LLC	5
Mutual Energy Service Company, LLC	65
Ohio Power Company	709,827
Ohio Power Company/Cook Coal Terminal	34
Public Service Company of Oklahoma	49,750
Rep General Partner, LLC	15

ANNUAL REPORT OF American Electric Power Service Corporation

For the Year Ended December 31, 2003

SCHEDULE V - ACCOUNTS RECEIVABLE FROM ASSOCIATE COMPANIES
(In Thousands)

Instructions: Complete the following schedule listing accounts receivable from each associate company. Where the service company has provided accommodation or convenience payments for associate companies, a separate listing of total payments for each associate company by subaccount should be provided.

ANALYSIS OF CONVENIENCE OR ACCOMMODATION PAYMENTS:	TOTAL PAYMENTS
Southwestern Electric Power Company	$ 58,373
Trent Wind Farm LP	17
Wheeling Power Company	207
TOTAL	$ 2,029,708

FOR:	
Interchange Power Pool & Transmission Agreements	$ 1,887,755
Insurance	152
Employee Benefit Plans	1,976
Membership Dues	450
Maintenance	8,355
Construction Work in Progress	41,802
Educational Programs	80
Leases and Rents	3,671
Outside Services	64,325
Postage & Shipping	117
Telephone Service	1,919
Taxes	298
Office Supplies & Expense	8,758
Miscellaneous	10,050
TOTAL	$ 2,029,708

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For the Year Ended December 31, 2003

SCHEDULE VI - FUEL STOCK EXPENSES UNDISTRIBUTED
(In Thousands)

Instructions: Report the amount of labor and expenses incurred with respect to fuel stock expenses during the year and indicate amount attributable to each associate company. Under the section headed "Summary" listed below give and overall report of the fuel functions performed by the service company.

ACCOUNT DESCRIPTION	LABOR	EXPENSES	TOTAL
Account 152 - Fuel Stock Expenses Undistributed			
Associate Companies			
AEP Coal Co.	$ 67	$ 90	$ 157
AEP Energy Services, Inc.	29	25	54
AEP Pro Serv, Inc.	0	1	1
AEP Texas Central Company	134	171	305
AEP Texas North Company	105	127	232
Appalachian Power Company	695	876	1,571
Blackhawk Coal Company	0	40	40
Cardinal Operating Company	113	141	254
Columbus Southern Power Company	323	405	728
Conesville Coal Preparation Company	6	6	12
CSW Energy, Inc.	0	2	2
Indiana Michigan Power Company	641	793	1,434
Kentucky Power Company	108	133	241
Ohio Power Company	1,064	1,361	2,425
Public Service Company of Oklahoma	250	300	550
Southwestern Electric Power Company	$ 661	$ 814	$ 1,475
TOTALS	$ 4,196	$ 5,285	$ 9,481

Summary: The service company provides overall management of fuel supply and transportation procurement, as well as general administration.

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For the Year Ended December 31, 2003

SCHEDULE VII - STORES EXPENSE UNDISTRIBUTED
(In Thousands)

Instructions: Report the amount of labor and expenses incurred with respect to stores expense during the year and indicate amount attributable to each associate company.

ACCOUNT DESCRIPTION	LABOR	EXPENSES	TOTAL
Account 163 - Billable Stores Expense Undistributed			
Associate Companies			
AEP Communications, LLC	$ -	$ 1	$ 1
AEP Energy Services Gas Holding Company	2	1	3
AEP Energy Services, Inc	11	25	36
AEP Energy Services Limited	2	4	6
AEP Desert Sky LP, LLC	-	1	1
AEP Generating Company	1	2	3
AEPR Ohio, LLC	-	1	1
AEP Resources, Inc.	-	1	1
AEP Texas Central Company	676	858	1,534
AEP Texas North Company	389	480	869
American Electric Power Company, Inc.	5	10	15
Appalachian Power Company	1,058	938	1,996
Cardinal Operating Company	125	138	263
Columbus Southern Power Company	460	607	1,067
Conesville Coal Preparation Company	1	1	2
Cook Coal Terminal	1	2	3
CSW Energy, Inc.	2	3	5
Indiana Michigan Power Company	601	809	1,410
Indiana Michigan River Transportation- Lakin	1	3	4
Kentucky Power Company	179	245	424
Kingsport Power Company	11	18	29
Ohio Power Company	1,187	1,533	2,720
Public Service Company of Oklahoma	559	707	1,266
Southwestern Electric Power Company	560	698	1,258
Wheeling Power Company	24	36	60
TOTALS	$ 5,855	$ 7,122	$ 12,977

ANNUAL REPORT OF American Electric Power Service Corporation

For the Year Ended December 31, 2003

SCHEDULE VIII - MISCELLANEOUS CURRENT AND ACCRUED ASSETS
(In Thousands)

Instructions: Provide detail of items in this account. Items less than $10,000 may be grouped, showing the number of items in each group.

ACCOUNT DESCRIPTION	BALANCE AT BEGINNING OF YEAR	BALANCE AT CLOSE OF YEAR
Account 174 - Miscellaneous Current and Accrued Assets	$ -	$ -
TOTALS	$ -	$ -

ANNUAL REPORT OF American Electric Power Service Corporation

For the Year Ended December 31, 2003

SCHEDULE IX - MISCELLANEOUS DEFERRED DEBITS
(In Thousands)

Instructions: Provide detail of items in this account. Items less than $10,000 may be grouped by class showing the number of items in each class.

ACCOUNT DESCRIPTION	BALANCE AT BEGINNING OF YEAR	BALANCE AT CLOSE OF YEAR
Account 186 - Miscellaneous Deferred Debits		
Regulatory Asset - Taxes	$ 379	$ 152
Unbilled Charges	3,169	1,982
TOTALS	$ 3,548	$ 2,134

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For the Year Ended December 31, 2003

SCHEDULE X - RESEARCH, DEVELOPMENT OR DEMONSTRATION EXPENDITURES
(In Thousands)

Instructions: Provide a description of each material research, development, or demonstration project which incurred costs by the service corporation during the year.

ACCOUNT DESCRIPTION		AMOUNT
Account 188 - Billable Research, Development, or Demonstration Expenditures		
Transmission and Distribution	$	2,590
Steam Power		8,060
Hydro		174
Nuclear		10
General Activities		6,545
TOTAL	$	17,379

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For the Year Ended December 31, 2003

SCHEDULE XI - PROPRIETARY CAPITAL
(Dollars in thousands except per share amounts)

ACCOUNT NUMBER	CLASS OF STOCK	NUMBER OF SHARES AUTHORIZED	PAR OR STATED VALUE PER SHARE	OUTSTANDING CLOSE OF PERIOD NO. OF SHARES	OUTSTANDING CLOSE OF PERIOD TOTAL AMOUNT
Account 201	**Common Stock Issued**	20,000	$ 100	13,500	$ 1,350
Account 201	**Common Stock Issued**	10,000	$ 10	10,000	100
TOTAL					$ 1,450

Instructions: Classify amounts in each account with brief explanation, disclosing the general nature of transactions which give rise to the reported amounts.

ACCOUNT DESCRIPTION	AMOUNT
Account 211 - Miscellaneous Paid-In Capital	
Other Comprehensive Income - Minimum Pension Liability	$ (82,123)
Account 215 - Appropriated Retained Earnings	-
TOTAL	$ (82,123)

Instructions: Give particulars concerning net income or (loss) during the year, distinguishing between compensation for the use of capital owed or net loss remaining from servicing nonassociates per the General Instructions of the Uniform System of Accounts. For dividends paid during the year in cash or otherwise, provide rate percentage, amount of dividend, date declared and date paid.

ACCOUNT DESCRIPTION	BALANCE AT BEGINNING OF YEAR	NET INCOME OR (LOSS)	DIVIDENDS PAID	BALANCE AT CLOSE OF YEAR
Account 216 - Unappropriated Retained Earnings	$ -	$ -	$ -	$ -
TOTALS	$ -	$ -	$ -	$ -

For the Year Ended December 31, 2003

SCHEDULE XII - LONG-TERM DEBT
(In Thousands)

Instructions: Advances from associate companies should be reported separately for advances on notes, and advances on open accounts. Names of associate companies from which advances were received shall be shown under the class and series of obligation column. For Account 224 - Other long-term debt, provide the name of creditor company or organization, terms of the obligation, date of maturity, interest rate, and the amount authorized and outstanding.

NAME OF CREDITOR	TERM OF OBLIGATION CLASS & SERIES OF OBLIGATION	DATE OF MATURITY	INTEREST RATE	AMOUNT AUTHORIZED	BALANCE AT BEGINNING OF YEAR	ADDITIONS	DEDUCTIONS (1)	BALANCE AT CLOSE OF YEAR
Account 223 - Advances From Associate Companies				$ 1,100	$ 1,100	$ -	$ 1,100	$ -
Account 224 - Other Long-Term Debt:								
Connecticut Bank & Trust Company (as Trustee), Series E Mortgage Notes		12/15/2008	9.600	70,000	44,000	-	2,000	42,000
Suntrust Bank		10/14/2003	6.355	10,000	10,000	-	10,000	-
SUBTOTALS				80,000	54,000	-	12,000	42,000
TOTALS				$ 81,100	$ 55,100	$ -	$ 13,100	$ 42,000

(1) Give an explanation of deductions:

Account 223 - AEPSC repaid this advance to American Electric Power Company, Inc. in December 2003.
Account 224 - Loan Payments. See Note 7, Schedule XIV for further explanation of dates of maturity.

SCHEDULE XIII - CURRENT AND ACCRUED LIABILITIES
(In Thousands)

Instructions: Provide balance of notes and accounts payable to each associate company. Give description and amount of miscellaneous current and accrued liabilites. Items less than $10,000 may be grouped, showing the number of items in each group.

ACCOUNT DESCRIPTION	BALANCE AT BEGINNING OF YEAR	BALANCE AT CLOSE OF YEAR
Account 233 - Notes Payable to Associate Companies		
American Electric Power Company, Inc.	$ 272,785	$ 117,116
TOTALS	$ 272,785	$ 117,116
Account 234 - Accounts Payable to Associate Companies		
AEP Communications, LLC	$ 343	$ -
AEP Credit, Inc.	41	-
AEP EmTech LLC	30	-
AEP Energy Services Gas Holding Company	198	-
AEP Energy Services Limited	21	-
AEP Fiber Venture, LLC	-	85
AEP Investments, Inc.	16	-
AEP Pro Serv, Inc.	2,048	68
AEP Resources, Inc.	269	2,033
AEP Texas Central Company	2,676	459
AEP Texas North Company	956	43
AEPES General and Administrative	2,210	536
American Electric Power Company, Inc.	10,850	5,628
Appalachian Power Company	20,987	3,319
Blackhawk Coal Company	-	78
C3 Communications, Inc.	31	29
C3 Networks GP, LLC	-	353
Cardinal Operating Company	299	9
Cedar Coal Co.	24	818
Central and South West Corporation	90	-
Columbus Southern Power Company	12,093	2,522
Conesville Coal Preparation Company	16	-
CSW Energy Services, Inc.	57	-
CSW Energy, Inc.	151	28
Datapult, LLC	107	-
Dolet Hills Lignite Company, LLC	16	-
Houston Pipe Line Company LP	-	588
Indiana Michigan Power Company	25,822	18,278
Kentucky Power Company	3,686	1,648
Kingsport Power Company	1,131	2
Louisiana Intrastate Gas Company, L.L.C.	-	61
Memco Consolidated	-	340

ANNUAL REPORT OF American Electric Power Service Corporation

For the Year Ended December 31, 2003

SCHEDULE XIII - CURRENT AND ACCRUED LIABILITIES
(In Thousands)

Instructions: Provide balance of notes and accounts payable to each associate company. Give description and amount of miscellaneous current and accrued liabilites. Items less than $10,000 may be grouped, showing the number of items in each group.

ACCOUNT DESCRIPTION	BALANCE AT BEGINNING OF YEAR	BALANCE AT CLOSE OF YEAR
Account 234 - Accounts Payable to Associate Companies (con't)		
Mutual Energy Service Company, L.L.C.	$ 42	$ -
Ohio Power Company	56,362	36,171
Ohio Power Company/Cook Coal Terminal	24	174
Public Service Company of Oklahoma	2,731	578
Southwestern Electric Power Company	2,484	1,392
Trent Wind Farm LP	957	-
Wheeling Power Company	682	57
Miscellaneous	32	-
TOTALS	$ 147,482	$ 75,297

ANNUAL REPORT OF American Electric Power Service Corporation

For the Year Ended December 31, 2003

SCHEDULE XIII - CURRENT AND ACCRUED LIABILITIES
(In Thousands)

Instructions: Provide balance of notes and accounts payable to each associate company. Give description and amount of miscellaneous current and accrued liabilites. Items less than $10,000 may be grouped, showing the number of items in each group.

	BALANCE AT BEGINNING OF YEAR	BALANCE AT CLOSE OF YEAR
Account 242 - Miscellaneous Current and Accrued Liabilities		
Accrued Payroll	$ 12,174	$ 13,046
Control Cash Disbursements Account	17,111	8,319
Control Payroll Disbursement Account	2,860	70
Deferred Compensation Benefits	701	513
Employee Benefits	13,412	1,936
Incentive Pay	64,481	58,279
Real and Personal Property Taxes	356	184
Rent on John E. Dolan Engineering Laboratory	704	660
Rent on Personal Property	1,400	1,012
Severance Pay	37,556	217
Vacation Pay	44,124	44,014
Workers' Compensation	1,351	1,302
Misc. Current and Accrued Liabilities	(166)	(4)
TOTALS	$ 196,064	$ 129,548

SCHEDULE XIV – NOTES TO FINANCIAL STATEMENTS

Instructions: The space below is provided for important notes regarding the financial statements or any account thereof. Furnish particulars as to any significant contingent assets or liabilities existing at the end of the year. Notes relating to financial statements shown elsewhere in this report may be indicated here by reference.

1. ORGANIZATION AND SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

ORGANIZATION

American Electric Power Service Corporation (the Company or AEPSC) is a wholly-owned subsidiary of American Electric Power Company, Inc. (AEP), a public utility holding company. We provide certain managerial and professional services including administrative and engineering services to the affiliated companies in the American Electric Power System (AEP System) and periodically to unaffiliated companies.

SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

Regulation

As a subsidiary of AEP, we are subject to regulation by the Securities and Exchange Commission (SEC) under the Public Utility Holding Company Act of 1935 (1935 Act).

Basis of Accounting

Our accounting conforms to the Uniform System of Accounts for Mutual and Subsidiary Service Companies prescribed by the SEC pursuant to the 1935 Act. As a cost-based rate-regulated entity, our financial statements reflect the actions of regulators that result in the recognition of revenues and expenses in different time periods than enterprises that are not rate regulated. In accordance with Statement of Financial Accounting Standards No. 71, "Accounting for the Effects of Certain Types of Regulation" (SFAS 71), the financial statements include regulatory assets (deferred expenses) and regulatory liabilities (deferred revenues) recorded in accordance with regulatory actions to match expenses and revenues in cost-based rates. Regulatory assets are expected to be recovered in future periods through billings to client companies and regulatory liabilities are expected to reduce future billings. We have reviewed all the evidence currently available and concluded that we continue to meet the requirements to apply SFAS 71.

Among other things, application of SFAS 71 requires that our billing rates be cost-based regulated. In the event a portion of our business were to no longer meet those requirements, net regulatory assets would have to be written off for that portion of the business and long-term assets would have to be tested for possible impairment. If net regulatory assets were written off, the amounts would be recoverable from affiliated companies.

Recognized regulatory assets and liabilities are comprised of the following:

	December 31, 2003	December 31, 2002	Recovery/Refund Period
	(in thousands)		
Regulatory Assets:			
Unamortized Loss on Reacquired Debt	$2,109	$2,531	Up to 5 Years (a)
SFAS 109 Regulatory Asset	137	380	Various Periods (b)
Total Regulatory Assets	$2,246	$2,911	
Regulatory Liabilities:			
Deferred Amounts Due to Affiliates for Income Tax Benefits	$9,293	$5,864	Various Periods (b)
Deferred Investment Tax Credits	749	800	Up to 15 Years (b)
Total Regulatory Liabilities	$10,042	$6,664	

(a) Amount effectively earns a return.
(b) Amount does not earn a return.

Use of Estimates

The preparation of these financial statements in conformity with accounting principles generally accepted in the United States of America requires in certain instances the use of management's estimates. Actual results could differ from those estimates.

Operating Revenues and Expenses

Services rendered to both affiliated and unaffiliated companies are provided at cost. The charges for services include no compensation for the use of equity capital, all of which is furnished by AEP. The costs of the services are determined on a direct charge basis to the extent practicable and on reasonable basis of proration for indirect costs.

Income Taxes and Investment Tax Credits

We follow the liability method of accounting for income taxes. Under the liability method, deferred income taxes are provided for all temporary differences between the book cost and tax basis of assets and liabilities which will result in a future tax consequence.

When the flow-through method of accounting for temporary differences is reflected in billings (that is, when deferred taxes are not included in the cost of determining regulated billings for services), deferred income taxes are recorded and related regulatory assets and liabilities are established.

Investment tax credits have been accounted for under the flow-through method unless they have been deferred in accordance with regulatory treatment. Investment tax credits that have been deferred are being amortized over the life of the related investment.

SCHEDULE XIV – NOTES TO FINANCIAL STATEMENTS

Property

Property is stated at original cost. Land, structures and structural improvements are generally subject to first mortgage liens. Depreciation is provided on a straight-line basis over the estimated useful lives of the property. The annual composite depreciation rate was 9% and 10% for the years ended December 31, 2003 and 2002, respectively.

We transferred capitalized software costs of $87 million and $128 million in 2003 and 2002, respectively, to other AEP affiliated companies.

Investments

Investments include the cash surrender value of trust owned life insurance policies held under a grantor trust to provide funds for non-qualified deferred compensation plans sponsored by us.

Debt

With SEC staff approval, gains and losses on reacquired debt are deferred and amortized over the term of the replacement debt.

Debt issuance expenses are amortized over the term of the related debt, with the amortization included in interest charges.

Comprehensive Income (Loss)

Comprehensive Income (Loss) is defined as the change in equity (net assets) of a business enterprise during a period from transactions and other events and circumstances from non-owner sources. It includes all changes in equity during a period except those resulting from investments by owners and distributions to owners. Comprehensive Income (Loss) has two components, Net Income and Other Comprehensive Income (Loss) (OCI). Accumulated OCI is included on the balance sheet in the equity section.

Accumulated Other Comprehensive Loss related to the Minimum Pension Liability as of December 31, 2003 and 2002 was $82.1 million and $126.8 million, respectively.

Guarantees

We lease certain equipment under a master operating lease administered by AEP. Under the lease agreement, the lessor is guaranteed to receive up to 87% of the unamortized balance of the equipment at the end of the lease term. If the fair market value of the leased equipment is below the unamortized balance at the end of the lease term, we have committed to pay the difference between the fair market value and the unamortized balance, with the total guarantee not to exceed 87% of the unamortized balance. At December 31, 2003, the maximum potential loss for these lease agreements was approximately $0.9 million assuming the fair market value of the equipment is zero at the end of the lease term.

Reclassification

Certain prior year amounts were reclassified to conform with current year presentation. Such reclassifications had no impact on previously reported Net Income.

2. NEW ACCOUNTING PRONOUNCEMENTS

SFAS 143 "Accounting for Asset Retirement Obligations"

We implemented SFAS 143, "Accounting for Asset Retirement Obligations" (SFAS 143), effective January 1, 2003, which requires entities to record a liability at fair value for any legal obligations for asset retirements in the period incurred. Upon establishment of a legal liability, SFAS 143 requires a corresponding asset to be established which will be depreciated over its useful life. SFAS 143 requires that a cumulative effect of change in accounting principle be recognized for the cumulative accretion and accumulated depreciation that would have been recognized had SFAS 143 been applied to existing legal obligations for asset retirements. We completed a review of our asset retirement obligations and concluded that we have no legal asset retirement obligations.

SFAS 144 "Accounting for the Impairment or Disposal of Long-lived Assets"

In August 2001, the Financial Accounting Standards Board (FASB) issued SFAS 144, "Accounting for the Impairment or Disposal of Long-lived Assets" (SFAS 144) which sets forth the accounting to recognize and measure an impairment loss. This standard replaced SFAS 121, "Accounting for Long-lived Assets and for Long-lived Assets to be Disposed Of." We adopted SFAS 144 effective January 1, 2002. See Note 12 for discussion of impairments recognized in 2003 and 2002.

SFAS 146 "Accounting for Costs Associated with Exit or Disposal Activities"

In June 2002, FASB issued SFAS 146, "Accounting for Costs Associated with Exit or Disposal Activities" (SFAS 146) which addresses accounting for costs associated with exit or disposal activities. This statement supersedes previous accounting guidance, principally Emerging Issues Task Force No. (EITF) 94-3, "Liability Recognition for Certain Employee Termination Benefits and Other Costs to Exit an Activity (including Certain Costs Incurred in a Restructuring)." Under EITF No. 94-3, a liability for an exit cost was recognized at the date of an entity's commitment to an exit plan. SFAS 146 requires that the liability for costs associated with an exit or disposal activity be recognized when the liability is incurred. SFAS 146 also establishes that the liability should initially be measured and recorded at fair value. The time at which we recognize future costs related to exit or disposal activities, including restructuring, as well as the amounts recognized may be affected by SFAS 146. We adopted the provisions of SFAS 146 for exit or disposal activities initiated after December 31, 2002 with no material impact on our results of operations, cash flows or financial condition.

FIN 45 "Guarantor's Accounting and Disclosure Requirements for Guarantees, Including Indirect Guarantees of Indebtedness of Others"

In November 2002, the FASB issued FASB Interpretation No. 45, "Guarantor's Accounting and Disclosure Requirements for Guarantees, Including Indirect Guarantees of Indebtedness of Others" (FIN 45) which clarifies the accounting to recognize a liability, related to issuing a guarantee, as well as additional disclosures of guarantees. We implemented FIN 45 as of January 1, 2003, and the effect was not material to our results of operations, cash flows or financial condition.

Future Accounting Changes

The FASB's standard-setting process is ongoing. Until new standards have been finalized and issued by FASB, we cannot determine the impact on the reporting of our operations that may result from any such future changes.

3. COMMITMENTS AND CONTINGENCIES

On October 15, 2002, certain subsidiaries of AEP filed claims against Enron and its subsidiaries in the bankruptcy proceeding filed by the Enron entities which are pending in the U.S. Bankruptcy Court for the Southern District of New York. At the date of Enron's bankruptcy, certain subsidiaries of AEP had open trading contracts and trading accounts receivables and payables with Enron. The timing of the resolution of the claims by the Bankruptcy Court is not certain.

In December 2003, Enron filed a complaint in the Bankruptcy Court against us seeking approximately $93 million plus interest in connection with a transaction for the sale and purchase of physical power among Enron, AEP and Allegheny Energy Supply, LLC during November 2001. Enron's claim seeks to unwind the effects of the transaction. AEP believes it has several defenses to the claims in the action being brought by Enron. Management is unable to predict the outcome of this lawsuit or its impact on our results of operations, cash flows or financial condition.

We are involved in a number of other legal proceedings and claims. While management is unable to predict the outcome of litigation, any potential liability which may result would be recoverable from affiliated companies.

4. BENEFIT PLANS

We participate in two qualified pension plans and two nonqualified pension plans which cover all employees. Net pension costs (credits) for the years ended December 31, 2003 and 2002 were $12.4 million and $3.1 million, respectively.

Postretirement benefits other than pensions are provided for retired employees for medical and death benefits under an AEP System plan. Our portion of annual postretirement benefit expenses for 2003 and 2002 were $39.8 million and $26.1 million, respectively.

The qualified plans remain in an underfunded position (plan assets are less than projected benefit obligations) at December 31, 2003. The value of the qualified plan's assets have increased at December 31, 2003 as compared to December 31, 2002, therefore, we recorded other comprehensive income (OCI) of $44.6 million. The amount recorded as OCI does not affect earnings or cash flow. We expect to make cash contributions to our qualified plans of approximately $19.5 million in 2004. Other Comprehensive Income (Loss) of $(116.7) million was recorded in 2002.

A defined contribution employee savings plan required that we make contributions to the plan resulting in annual defined contribution employee savings plan expenses of $19.1 million and $21.3 million 2003 and 2002, respectively.

5. FINANCIAL INSTRUMENTS

The carrying amount of cash and cash equivalents, accounts receivable and accounts payable approximates fair value because of the short-term maturities of these instruments. The fair value of long-term debt, excluding advances from AEP, was $51.2 million and $62.6 million at December 31, 2003 and 2002, respectively. The balances are based on quoted market prices for similar issues and the current interest rates offered for debt of the same remaining maturities. The carrying amount for long-term debt, excluding advances from Parent Company, was $42.0 million at December 31, 2003, and $54.0 million at December 31, 2002.

We are subject to market risk as a result of changes in interest rates primarily due to short-term and long-term borrowings used to fund its business operations. The debt portfolio has fixed and variable interest rates with terms from one day to five years at December 31, 2003. A near term change in interest rates should not materially affect results of operations or financial position since we would not expect to liquidate its entire debt portfolio in a one year holding period.

6. INCOME TAXES

The details of income taxes are as follows:

	Year Ended December 31	
	2003	2002
	(in thousands)	
Current, net	$(9,923)	$(58,814)
Deferred, net	7,293	60,292
Deferred Investment Tax Credits, net	(51)	(51)
Total Income Tax Expense (Credit)	$(2,681)	$ 1,427

The following is a reconciliation of the difference between the amount of federal income taxes computed by multiplying book income before federal income taxes by the statutory rate, and the total amount of income taxes:

	Year Ended December 31,	
	2003	2002
	(in thousands)	
Net Income	$ -	$ -
Plus: Income Tax Expense (Credit)	(2,681)	1,427
Pre-Tax Income (Loss)	$(2,681)	$1,427
Income Tax on Pre-Tax Income (Loss) at Statutory Rate (35%)	$ (938)	$ 499
Increase (Decrease) in Income Tax Resulting From the Following Items:		
Trust Owned Life Insurance	(3,230)	3,706
Corporate Owned Life Insurance	(188)	(741)
State and Local Income Taxes	1,876	(4,163)
Other	(201)	2,126
Total Income Tax Expense (Credit)	$(2,681)	$1,427
Effective Income Tax Rate	N.M.	N.M.

The following table shows the elements of the net deferred tax asset and the significant temporary differences:

	December 31,	
	2003	2002
	(in thousands)	
Deferred Tax Assets	$118,820	$156,092
Deferred Tax Liabilities	(46,886)	(61,897)
Net Deferred Tax Assets	$71,934	$94,195
Property Related Temporary Differences	$(11,395)	$(20,573)
Deferred and Accrued Compensation	22,707	43,635
Capitalized Software Cost	(9,951)	(22,935)
Deferred Income Taxes on Other Comprehensive Income	44,220	62,860
Accrued Pension Expense	10,597	10,729
Accrued Vacation Pay	12,674	8,888
Post-Retirement Benefits	1,846	12,798
Deferred State Income Taxes	4,072	(204)
Amounts Due to Affiliates for Future Income Taxes	1,779	1,991
All Other, net	(4,615)	(2,994)
Net Deferred Tax Assets	$71,934	$94,195

We join in the filing of a consolidated federal income tax return with its affiliates in the AEP System. The allocation of the AEP System's current consolidated federal income tax to the AEP System companies is in accordance with SEC rules under the 1935 Act. These rules permit the allocation of the benefit of current tax losses utilized to the AEP System companies giving rise to them in determining their current tax expense. The tax loss of the AEP System parent company, AEP, is allocated to its subsidiaries with taxable income. With the exception of the loss of the parent company, the method of allocation approximates a separate return result for each company in the consolidated group.

The AEP System has settled with the IRS all issues from the audits of the consolidated federal income tax returns for the years prior to 1991. The AEP System has received Revenue Agent's Reports from the IRS for the years 1991 through 1996, and has filed protests contesting certain proposed adjustments. Returns for the years 1997 through 2000 are presently being audited by the IRS. Management is not aware of any issues for open tax years that upon final resolution are expected to have a material adverse effect on results of operations.

7. LEASES

Leases of structures, improvements, office furniture and miscellaneous equipment are for periods of up to 30 years and require payments of related property taxes, maintenance and operating costs. The majority of the leases have purchase or renewal options and will be renewed or replaced by other leases.

SCHEDULE XIV – NOTES TO FINANCIAL STATEMENTS

The components of lease rental expense are as follows:

	Year Ended December 31, 2003	2002
	(in thousands)	
Lease Payments on Operating Leases	$30,515	$18,451
Amortization of Capital Leases	21,165	18,986
Interest on Capital Leases	1,974	2,250
Total Lease Rental Expense	$53,654	$39,687

Property under capital leases and related obligations recorded on the Balance Sheets is as follows:

	December 31, 2003	2002
	(in thousands)	
Property Under Capital Leases:		
Structures and Improvements	$11,754	$11,754
Office Furniture and Miscellaneous Equipment	61,938	79,525
Total Property Under Capital Leases	73,692	91,279
Accumulated Amortization	36,787	53,628
Net Property Under Capital Leases	$36,905	$37,651
Obligations Under Capital Leases*:		
Noncurrent Liability	$22,373	$22,383
Liability Due Within One Year	14,513	15,701
Total Obligations Under Capital Leases	$36,886	$38,084

* Represents the present value of future minimum lease payments.

Property under operating leases and related obligations is not included in the Balance Sheets.

SCHEDULE XIV – NOTES TO FINANCIAL STATEMENTS

Future minimum lease payments consisted of the following at December 31, 2003:

	Capital Leases	Operating Leases
	(in thousands)	
2004	$16,457	$17,220
2005	8,992	9,631
2006	5,903	4,012
2007	2,813	3,144
2008	1,394	1,902
Later Years	11,686	1,093
Total Future Minimum Lease Rentals	47,245	$37,002
Less Estimated Interest Element	10,359	
Estimated Present Value of Future Minimum Lease Rentals	$36,886	

8. LONG-TERM DEBT

Long-term debt was outstanding as follows:

	Interest Rate	December 31, 2003	December 31, 2002
		(in thousands)	
Mortgage Notes:			
Series E (a)	9.60%	$42,000	$44,000
Notes Payable to Banks:			
Due October 2003	6.355%	-	10,000
Advances from Parent Company	(b)	-	1,100
		42,000	55,100
Less Portion Due Within One Year		2,000	12,000
Total		$40,000	$43,100

(a) Due in annual installments of $2.0 million until 2007 and the balance in December 2008.
(b) The advances from AEP are non-interest bearing and have no due date.

Long-term debt outstanding at December 31, 2003 is payable as follows:

	Principal Amount (in thousands)
2004	$2,000
2005	2,000
2006	2,000
2007	2,000
2008	34,000
Total	$42,000

9. SEGMENT INFORMATION

We have one reportable segment. We provide certain managerial and professional services including administrative and engineering services. For the years ended December 31, 2003 and 2002, all of our revenues are derived from managerial and professional services including administrative and engineering services in the United States.

10. SHORT-TERM DEBT BORROWINGS

In June 2000 the AEP System established a Money Pool, to coordinate short-term borrowings for certain subsidiaries, primarily the domestic electric utility operating companies. The operation of the Money Pool is designed to match on a daily basis the available cash and borrowing requirements of the participants, thereby minimizing the need for short-term borrowings from external sources and increasing the interest income for participants with available cash. Participants with excess cash loan funds to the Money Pool reducing the amount of external funds AEP needs to borrow to meet the short-term cash requirements of other participants whose short-term cash requirements are met through advances from the Money Pool. AEP borrows the funds on a daily basis, when necessary, to meet the net cash requirements of the Money Pool participants. A weighted average daily interest rate which is calculated based on the outstanding short-term debt borrowings made by AEP is applied to each Money Pool participant's daily outstanding investment or debt position to determine interest income or interest expense. The Money Pool participants include interest income in nonoperating income and interest expense in interest charges. As a result of becoming a Money Pool participant, we retired our short-term debt. At December 31, 2003 and 2002, we were a net borrower and reported our debt position as Advances from Affiliates on our balance sheets.

We incurred interest expense of $1.1 million and $3.8 million for amounts borrowed from the Money Pool in 2003 and 2002.

SCHEDULE XIV – NOTES TO FINANCIAL STATEMENTS

11. SUSTAINED EARNINGS INITIATIVE

In response to difficult conditions in AEP's business, a Sustained Earnings Improvement (SEI) initiative was undertaken company-wide in the fourth quarter of 2002, as a cost-saving and revenue-building effort to build long-term earnings growth.

Termination benefits expense relating to 701 terminated AEPSC employees totaling $48 million pre-tax was recorded in the fourth quarter of 2002 and was allocated among all AEP subsidiaries. As of December 31, 2002, total termination benefits accrued were $42 million. No additional termination benefits expense related to the SEI initiative was recorded in 2003, and the remaining SEI related payments were made in 2003. Management determined that the termination of the employees under the SEI initiative did not constitute a curtailment under the provisions of SFAS No. 88 "Employers' Accounting for Settlements and Curtailments of Defined Benefit Pension Plans and for Termination Benefits".

12. ASSET IMPAIRMENTS

In the fourth quarter of 2002, AEP began to market an under-utilized office building in Dallas, Texas obtained through the merger with CSW. In 2003 and 2002, we recorded estimated pre-tax losses on disposal of $6.4 million and $15.7 million, respectively, based on the estimated sale price. The estimated losses are included in Asset Impairments on our Statements of Operations. This office building will continue to be actively marketed and the status is considered held and used for all periods presented.

ANNUAL REPORT OF American Electric Power Service Corporation

For the Year Ended December 31, 2003

SCHEDULE XV - COMPARATIVE INCOME STATEMENT
(In Thousands)

ACCOUNT	DESCRIPTION	CURRENT YEAR	PRIOR YEAR
	INCOME		
454	Rents from electric properties - NAC	$ 282	$ 26
456	Other electric revenues	35	-
457	Services rendered to associate companies	1,104,701	1,370,537
458	Services rendered to non associate companies	6,358	20,105
419	Interest income - other	25	165
421	Miscellaneous income or loss	1,832	978
	TOTAL INCOME	1,113,233	1,391,811
	EXPENSES		
500-559	Power production	148,606	161,741
560-579	Transmission	34,519	34,222
580-599	Distribution	52,908	51,512
780-860	Trading	612	10,751
901-903	Customer accounts expense	113,428	127,068
904	Uncollectible - Misc. Receivable	231	10
905	Miscellaneous customer accounts	707	2,948
906-917	Customer service & information	12,607	10,558
920	Salaries and wages	300,421	372,865
921	Office supplies and expenses	70,605	109,168
922	Administrative expense transferred - credit	(276,594)	(310,907)
923	Outside services employed	43,374	83,773
924	Property insurance	217	223
925	Injuries and damages	7,988	10,601
926	Employee pensions and benefits	97,056	123,884
928	Regulatory commission expense	-	53
930.1	General advertising expenses	2,174	1,703
930.2	Miscellaneous general expenses	7,370	7,718
931	Rents	76,307	63,317
935	Maintenance of structures and equipment	30,278	35,968
402	Maintenance Expense	-	31
403-405	Depreciation and amortization expense	8,618	30,463
408	Taxes other than income taxes	40,228	50,078
409	Income taxes	34,307	(103,044)
410	Provision for deferred income taxes	113,850	190,302
411	Provision for deferred income taxes - credit	(150,838)	(85,831)
411.7	Loss from disposition of plant	6,399	15,730
416	Expense - sports lighting	760	857
417	Administrative - business venture	132	119
418	Non-Operating rental income	522	161
426.1	Donations	2,952	2,979
426.3 - 426.5	Other deductions	5,853	6,695
427	Interest on long-term debt	4,850	5,044
428	Amortization of debt discount and expense	427	427
430	Interest on debt to associate companies	1,079	3,753
431	Other interest expense	937	912
432	Borrowed funds - construction - credit	(2,172)	(2,984)
	TOTAL EXPENSE - INCOME STATEMENT	790,718	1,012,868
	COST OF SERVICE - BALANCE SHEET		
107	Construction work in progress	237,572	312,790
108	Retirement work in progress	4,173	8,417
120	Nuclear fuel	-	-
121	Nonutility Property	19	-
122	Depr & Amort of Nonutil Prop	55	-
124	Investments	53	46
151	Fuel stock	2,938	5,421
152	Fuel stock expense undistributed	9,481	5,570
163	Stores expense undistributed	12,977	13,413
182	Regulatory Assets	625	(24)
183	Preliminary survey and investigation charges	-	-
184	Clearing accounts	-	857
186	Miscellaneous deferred debits	37,243	11,934
188	Research, development, or demonstration expenses	17,379	20,519
	TOTAL COST OF SERVICE - BALANCE SHEET	322,515	378,943
	NET INCOME OR (LOSS)	$ -	$ -

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For the Year Ended December 31, 2003

ANALYSIS OF BILLING - ASSOCIATE COMPANIES - ACCOUNT 457
(In Thousands)

NAME OF ASSOCIATE COMPANY	DIRECT COSTS CHARGED 457 .1	INDIRECT COSTS CHARGED 457 .2	COMPENSATION FOR USE OF CAPITAL 457 .3	TOTAL AMOUNT BILLED
AEP C&I Company, LLC	$ 68	$ 8	$ -	$ 76
AEP Coal Company	2,905	474	-	3,379
AEP Coal Marketing LLC	390	59	-	449
AEP Communications, Inc.	26	7	-	33
AEP Communications, LLC	897	196	(1)	1,092
AEP Credit, Inc.	349	97	-	446
AEP Delaware Investment Company	25	4	-	29
AEP Delaware Investment Company II	13	6	-	19
AEP Desert Sky GP, LLC	3	1	-	4
AEP Desert Sky LP, LLC	704	118	-	822
AEP Elmwood LLC	11	3	-	14
AEP EmTech LLC	1,701	909	(1)	2,609
AEP Energy Services Gas Holding Company	2,242	325	1	2,568
AEP Energy Services Gas Holdings II LLC	4	1	-	5
AEP Energy Services General and Administrative	26,164	4,725	(29)	30,860
AEP Energy Services Limited	5,239	610	(1)	5,848
AEP Energy Services UK Generation Limited	449	14	-	463
AEP Energy Services Ventures, Inc.	10	1	-	11
AEP Energy Services Ventures II Inc	1	-	-	1
AEP Fiber Venture, LLC	3	115	-	118
AEP Gas Power GP, LLC	68	15	-	83
AEP Gas Power System, LLC	1	-	-	1
AEP Generating Company	1,613	267	-	1,880
AEP Investments, Inc.	160	26	-	186
AEP Memco LLC	270	39	-	.309
AEP Ohio Commercial & Industrial Retail Company, LLC	3	1	-	4
AEP Ohio Retail Energy, LLC	15	2	-	17
AEP Pro Serv, Inc.	19,613	3,138	(10)	22,741
AEP Pushan Power, LDC	196	24	-	220
AEP Resources Australia Holdings Pty., Ltd	6	2	-	8
AEP Resources Australia Pty., Ltd.	17	2	-	19
AEP Resources International, Limited	12	1	-	13
AEP Resources, Inc.	1,672	289	(3)	1,958
AEP Retail Energy, LLC	6	1	-	7
AEPR Ohio, LLC	2,534	335	-	2,869
AEP System Pool	52,196	4,366	-	56,562
AEP T&D Services, LLC	241	57	-	298
AEP Texas Central Company	94,775	21,017	(31)	115,761
AEP Texas Commercial & Industrial Retail Limited Partnersl	545	60	-	605
AEP Texas Commercial & Industrial Retail GP, LLC	69	13	-	82
AEP Texas North Company	35,645	8,659	(13)	44,291
AEP Texas POLR, LLC	6	1	-	7
AEP Utilities, Inc.	677	58	-	735
AEP Wind Holding, LLC	82	14	-	96
American Electric Power Company, Inc.	10,790	1,519	(4)	12,305
American Fiber Network, LLC	1	-	-	1
Appalachian Power Company	145,534	30,044	(52)	175,526
Blackhawk Coal Company	97	13	-	110
C3 Communications, Inc.	1,155	451	(1)	1,605
Cardinal Operating Company	15,215	2,510	(6)	17,719
Cedar Coal Company	2	-	-	2
Central Appalachian Coal Company	2	-	-	2
Central Coal Company	19	9	-	28
Colomet, Inc.	126	16	-	142
Columbus Southern Power Company	78,166	16,090	(27)	94,229
Conesville Coal Preparation Company	346	81	-	427
CSW Energy, Inc.	4,904	1,139	(6)	6,037

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For the Year Ended December 31, 2003

ANALYSIS OF BILLING - ASSOCIATE COMPANIES - ACCOUNT 457
(In Thousands)

NAME OF ASSOCIATE COMPANY	DIRECT COSTS CHARGED 457.1	INDIRECT COSTS CHARGED 457.2	COMPENSATION FOR USE OF CAPITAL 457.3	TOTAL AMOUNT BILLED
CSW Energy Services, Inc.	523	77	(1)	599
CSW International, Inc.	353	59	-	412
CSW Leasing, Inc.	5	1	-	6
CSW Power Marketing, Inc.	261	50	-	311
CSW Services International Inc.	153	35	-	188
Desert Sky Wind Farm LP	109	8	-	117
Diversified Energy Contractors Company, LLC	5	1	-	6
Dolet Hills Lignite Company, LLC	1,329	167	-	1,496
EnerShop Inc.	15	5	-	20
Franklin Real Estate Company	2	-	-	2
HPL GP, LLC	4	1	-	5
HPL Holdings, Inc.	3	-	-	3
Houston Pipeline Company LP	2,737	469	-	3,206
Indiana Franklin Reality, Inc.	1	-	-	1
Indiana Michigan Power Company	101,112	20,412	(37)	121,487
Industry and Energy Associates LLC	1	-	-	1
Jefferson Island Storage & Hub LLC	4	1	-	5
Kentucky Power Company	28,641	6,368	(16)	34,993
Kingsport Power Company	3,312	732	(1)	4,043
LIG Chemical Company	6	1	-	7
LIG Liquids Company LLC	8	2	-	10
LIG Pipeline Company	3	-	-	3
LIG, Inc.	4	1	-	5
Louisiana Intrastate Gas Company, LLC	395	53	-	448
Memco Consolidated	8	1	-	9
Mutual Energy L.L.C.	748	330	(1)	1,077
Mutual Energy Service Company, L.L.C.	846	122	-	968
Mutual Energy SWEPCO L. P.	57	7	-	64
Mutual Energy WTU L. P.	3	-	-	3
Mutual Energy CPL L.P.	8	1	-	9
Nanyang General Light Electric Co., Ltd.	3	-	-	3
Newgulf Power Venture	80	7	-	87
Nuvest, L.L.C.	13	3	-	16
Ohio Power Company	133,148	26,732	(44)	159,836
POLR Power, L. P.	73	12	-	85
Public Liability Company	1	-	-	1
Public Service Company of Oklahoma	60,357	12,720	(20)	73,057
Rep General Partner L.L.C.	163	14	-	177
Rep Holdco Inc.	128	26	-	154
Seeboard PLC	7	1	-	8
Simco, Inc.	2	-	-	2
Southern Appalachian Coal Company	1	-	-	1
Southwestern Electric Power Company	73,356	16,417	(26)	89,747
Sweeny Cogeneration LP	2	1	-	3
Trent Wind Farm LP	823	111	-	934
Tuscaloosa Pipeline Company	2	1	-	3
United Sciences Testing, Inc,	1,126	499	-	1,625
Ventures Lease Co., LLC	32	5	-	37
Wheeling Power Company	3,012	672	(1)	3,683
Unbilled Revenues	7	-	-	7
Internal Support Adjustments	9,547	(9,547)	-	-
TOTALS	$ 930,522	$ 174,510	$ (331)	$ 1,104,701

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For the Year Ended December 31, 2003

ANALYSIS OF BILLING - NONASSOCIATE COMPANIES - ACCOUNT 458
(In Thousands)

NAME OF NONASSOCIATE COMPANY	DIRECT COST CHARGED 458.1	INDIRECT COST CHARGED 458.2	COMPENSATION FOR USE OF CAPITAL 458.3	TOTAL COST	EXCESS OR DEFICIENCY 458.4	TOTAL AMOUNT BILLED
Bridgeco	$ (49)	$ 33	$ -	$ (16)	$ -	$ (16)
Cinergy	30	6	-	36	-	36
CLECO	41	3	-	44	-	44
CG&E/Zimmer Services Agreement	2	1	-	3	-	3
East Central Area Reliability	156	27	-	183	-	183
Indiana Kentucky Electric Corporation	836	160	-	996	-	996
Ohio Valley Electric Company	4,363	749	-	5,112	-	5,112
TOTALS	$ 5,379	$ 979	$ -	$ 6,358	$ -	$ 6,358

Instruction: Provide a brief description of the services rendered to each nonassociate company:
Engineering, Computer and Environmental Laboratory services.

For the Year Ended December 31, 2003

SCHEDULE XVI - ANALYSIS OF CHARGES FOR SERVICE - ASSOCIATE AND NONASSOCIATE COMPANIES
(In Thousands)

Instruction: Total cost of service will equal for associate and nonassociate companies the total amount billed under their separate analysis of billing schedules.

		ASSOCIATE COMPANY CHARGES			NONASSOCIATE COMPANY CHARGES			TOTAL CHARGES FOR SERVICE		
ACCOUNT	DESCRIPTION OF ITEMS	DIRECT COST	INDIRECT COST	TOTAL	DIRECT COST	INDIRECT COST	TOTAL	DIRECT COST	INDIRECT COST	TOTAL
COST OF SERVICE - INCOME STATEMENT										
454	Rents from electric properties - NAC	$ (282)	$ -	$ (282)	$ -	$ -	$ -	$ (282)	$ -	$ (282)
456	Other electric revenues	(26)	(9)	(35)	-	-	-	(26)	(9)	(35)
421	Miscellaneous income or loss	(1,925)	93	(1,832)	-	-	-	(1,925)	93	(1,832)
500-559	Power production	127,704	19,084	146,788	1,570	248	1,818	129,274	19,332	148,606
560-579	Transmission	26,810	7,520	34,330	139	50	189	26,949	7,570	34,519
580-599	Distribution	40,406	12,502	52,908	-	-	-	40,406	12,502	52,908
750-867	Trading	537	75	612	-	-	-	537	75	612
901-903	Customer accounts expense	90,635	22,793	113,428	-	-	-	90,635	22,793	113,428
904	Uncollectible - Misc. Receivable	229	2	231	-	-	-	229	2	231
905	Customer assistance	466	241	707	-	-	-	466	241	707
906-917	Customer service & information	9,276	3,331	12,607	-	-	-	9,276	3,331	12,607
920	Salaries and wages	245,619	52,136	297,755	2,256	410	2,666	247,875	52,546	300,421
921	Office supplies and expenses	60,417	9,744	70,161	348	96	444	60,765	9,840	70,605
922	Administrative expense transferred - credit	(276,594)	-	(276,594)	-	-	-	(276,594)	-	(276,594)
923	Outside service employed	37,580	4,553	42,133	1,065	176	1,241	38,645	4,729	43,374
924	Property insurance	217	-	217	-	-	-	217	-	217
925	Injuries and damages	7,847	141	7,988	-	-	-	7,847	141	7,988
926	Employee pensions and benefits	96,333	723	97,056	-	-	-	96,333	723	97,056
928	Regulatory commission expense	-	-	-	-	-	-	-	-	-
930.1	General advertising expense	1,793	381	2,174	-	-	-	1,793	381	2,174
930.2	Miscellaneous general expense	6,400	970	7,370	-	-	-	6,400	970	7,370
931	Rents	75,516	791	76,307	-	-	-	75,516	791	76,307
935	Maintenance of structures and equipment	24,954	5,324	30,278	-	-	-	24,954	5,324	30,278
403-405	Depreciation and amortization expense	8,585	33	8,618	-	-	-	8,585	33	8,618
408	Taxes other than income taxes	40,228	-	40,228	-	-	-	40,228	-	40,228
409	Income taxes	34,307	-	34,307	-	-	-	34,307	-	34,307
410	Provision for deferred income taxes	113,850	-	113,850	-	-	-	113,850	-	113,850
411	Provision for deferred income taxes - credit	(150,838)	-	(150,838)	-	-	-	(150,838)	-	(150,838)
411.7	Loss from Disposition of Plant	6,399	-	6,399	-	-	-	6,399	-	6,399
416	Sports lighting	716	44	760	-	-	-	716	44	760
417	Administrative - business venture	107	25	132	-	-	-	107	25	132
418	Non-Operating rental income	342	180	522	-	-	-	342	180	522
419	Interest income - other	(25)	-	(25)	-	-	-	(25)	-	(25)
426.1	Donations	2,550	402	2,952	-	-	-	2,550	402	2,952
426.3-426.5	Other deductions	5,070	783	5,853	-	-	-	5,070	783	5,853
427	Interest on long-term debt	4,850	-	4,850	-	-	-	4,850	-	4,850
428	Amortization of debt discount and expense	427	-	427	-	-	-	427	-	427
430	Interest on debt to associate companies	1,079	-	1,079	-	-	-	1,079	-	1,079
431	Other interest expense	937	-	937	-	-	-	937	-	937
432	Borrowed funds - construction - credit	(2,172)	-	(2,172)	-	-	-	(2,172)	-	(2,172)
TOTAL COST OF SERVICE - INCOME STATEMENT		640,324	141,862	782,186	5,378	980	6,358	645,702	142,842	788,544

SCHEDULE XVI - ANALYSIS OF CHARGES FOR SERVICE - ASSOCIATE AND NONASSOCIATE COMPANIES
(In Thousands)

Instruction: Total cost of service will equal for associate and nonassociate companies the total amount billed under their separate analysis of billing schedules.

		ASSOCIATE COMPANY CHARGES			NONASSOCIATE COMPANY CHARGES			TOTAL CHARGES FOR SERVICE		
ACCOUNT	DESCRIPTION OF ITEMS	DIRECT COST	INDIRECT COST	TOTAL	DIRECT COST	INDIRECT COST	TOTAL	DIRECT COST	INDIRECT COST	TOTAL
COST OF SERVICE - BALANCE SHEET										
107	Construction work in progress	215,521	22,051	237,572	-	-	-	215,521	22,051	237,572
108	Retirement work in progress	4,827	(654)	4,173	-	-	-	4,827	(654)	4,173
121	Non-Utility Property	16	3	19	-	-	-	16	3	19
122	Depreciation & amortization of non-utility property	43	12	55	-	-	-	43	12	55
124	Investments	37	16	53	-	-	-	37	16	53
151	Fuel stock	2,656	282	2,938	-	-	-	2,656	282	2,938
152	Fuel stock expense undistributed	8,011	1,470	9,481	-	-	-	8,011	1,470	9,481
163	Stores expense undistributed	11,310	1,667	12,977	-	-	-	11,310	1,667	12,977
182	Regulatory assets	574	51	625	-	-	-	574	51	625
186	Miscellaneous deferred debits	33,214	4,029	37,243	-	-	-	33,214	4,029	37,243
188	Research, development, or demonstration expense	13,658	3,721	17,379	-	-	-	13,658	3,721	17,379
TOTAL COST OF SERVICE - BALANCE SHEET		289,867	32,648	322,515	-	-	-	289,867	32,648	322,515
TOTAL COST OF SERVICE		$ 930,191	$ 174,510	$ 1,104,701	$ 5,378	$ 980	$ 6,358	$ 935,569	$ 175,490	$ 1,111,059

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SCHEDULE XVII - SCHEDULE OF EXPENSE DISTRIBUTION BY DEPARTMENT OR SERVICE FUNCTION
(In Thousands)

Instruction: Indicate each department or service function. (See Instruction 01-3 General Structure of Accounting System: Uniform System of Accounts).

ACCOUNT	DESCRIPTION OF ITEMS	TOTAL AMOUNT	OVERHEAD	DEPARTMENT OR SERVICE FUNCTION: AUDIT SERVICES	COMMERCIAL OPERATIONS	CORPORATE ACCOUNTING	CORPORATE COMMUN.	CORPORATE PLAN. & BUDG.	CORPORATE PLAN. & STRAT.	CUSTOMER OPERATIONS	DISTRIBUTION
454	Rents from electric properties - NAC	$ (282)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
456	Other electric revenues	(35)	(9)	-	-	-	-	-	-	(33)	7
419	Interest income - other	(25)	-	-	-	-	-	-	-	-	-
421	Miscellaneous income or loss	(1,832)	93	-	-	(1)	-	-	-	(504)	(3)
500-559	Power production	148,606	19,332	1	12,688	3,271	(2)	1	51	(18)	479
560-579	Transmission	34,519	7,570	-	14	9	(1)	14	-	12	1,256
580-599	Distribution	52,908	12,502	(1)	(3)	(8)	(2)	(2)	25	2,968	28,320
780-860	Trading	612	75	-	-	-	-	-	-	-	544
901-903	Customer accounts expense	113,428	22,793	(1)	(6)	2,335	(3)	-	4	84,179	275
904	Uncollectible - Misc. Receivable	231	2	-	-	(1)	-	-	-	3	-
905	Miscellaneous customer accounts	707	241	-	-	-	-	-	-	463	-
906-917	Customer service & information	12,607	3,331	-	(1)	2	42	9	-	3,776	(3)
920	Salaries and wages	300,421	52,546	4,162	6,772	28,310	5,830	10,047	3,365	2,891	2,710
921	Office supplies and expenses	70,605	9,840	416	375	(1,293)	755	747	553	600	3,833
922	Administrative expense transferred - credit	(276,594)	-	701	1,304	(397,411)	974	1,361	475	18,394	11,729
923	Outside services employed	43,374	4,729	439	243	4,190	943	473	3,412	147	392
924	Property insurance	217	-	-	-	-	-	-	-	-	1
925	Injuries and damages	7,988	141	-	-	-	-	-	-	-	227
926	Employee pensions and benefits	97,056	723	22	20	(15,053)	597	25	25	120	51
928	Regulatory commission expense	-	-	-	-	-	-	-	-	-	-
930.1	General advertising expenses	2,174	381	-	-	11	1,312	-	-	(1)	21
930.2	Miscellaneous general expenses	7,370	970	19	10	91	17	50	(189)	76	320
931	Rents	76,307	791	1	14	222	8	8	5	55	1,099
935	Maintenance of structures and equipment	30,278	5,324	-	(1)	(3,196)	(1)	(1)	-	(7)	16,037
403-405	Depreciation and amortization expense	8,618	33	-	-	-	-	-	-	-	-
408	Taxes other than income taxes	40,228	-	231	1,139	4,789	378	597	191	4,184	2,967
409	Income taxes	34,307	-	-	-	34,307	-	-	-	-	-
410	Provision for deferred income taxes	113,850	-	-	-	113,850	-	-	-	-	-
411	Provision for deferred income taxes - credit	(150,838)	-	-	-	(150,838)	-	-	-	-	-
411.7	Loss from disposition of plant	6,399	-	-	-	-	-	-	-	-	-
416	Expense - sports lighting	760	44	-	-	12	-	-	-	681	-
417	Administrative - business venture	132	25	-	-	1	-	-	-	-	-
418	Non-Operating rental income	522	180	-	-	-	-	-	-	(1)	-
426.1	Donations	2,952	402	4	-	6	7	-	-	3	-
426.3 - 426.5	Other deductions	5,853	783	-	25	10	487	-	-	10	4
427	Interest on long-term debt	4,850	-	-	-	-	-	-	-	-	-
428	Amortization of debt discount and expense	427	-	-	-	-	-	-	-	-	-
430	Interest on debt to associate companies	1,079	-	-	-	-	-	-	-	-	-
431	Other interest expense	937	-	-	-	14	-	-	-	-	-
432	Borrowed funds - construction - credit	(2,172)	-	-	-	(127)	-	-	-	-	-
107	Construction work in progress	237,572	22,051	(1)	270	1,627	43	309	1,516	890	13,865
108	Retirement work in progress	4,173	(654)	-	-	-	-	1	-	4	600
121	Nonutility Property	19	3	-	-	-	-	-	-	-	-
122	Depr & Amort of Nonutil Prop	55	12	-	-	-	-	1	-	-	-
124	Investments	53	16	-	-	-	-	-	-	-	-
151	Fuel stock	2,938	282	-	-	-	-	-	-	-	(1)
152	Fuel stock expense undistributed	9,481	1,470	-	1,191	1,039	-	-	-	(2)	(2)
163	Stores expense undistributed	12,977	1,667	-	-	546	-	(1)	(1)	(2)	-
182	Regulatory Assets	625	51	-	(1)	-	563	-	-	10	-
184	Clearing accounts	-		-	-	-	-	-	-	-	-
186	Miscellaneous deferred debits	37,243	4,029	(1)	67	86	140	23	66	54	11,433
188	Research, development, or demonstration expenses	17,379	3,721	-	(1)	(2)	-	5	3	(5)	23
	TOTAL COST OF SERVICE	$ 1,111,059	$ 175,490	$ 5,992	$ 24,119	$ (373,202)	$ 12,085	$ 13,667	$ 9,501	$ 118,947	$ 96,184

ANNUAL REPORT OF American Electric Power Service Corporation

For the Year Ended December 31, 2003

SCHEDULE XVII - SCHEDULE OF EXPENSE DISTRIBUTION BY DEPARTMENT OR SERVICE FUNCTION
(In Thousands)

Instruction: Indicate each department or service function. (See Instruction 01-3 General Structure of Accounting System: Uniform System of Accounts).

		DEPARTMENT OR SERVICE FUNCTION									
ACCOUNT	DESCRIPTION OF ITEMS	ENER. DELIV. & EXT. AFFAIRS	ENG. TECH. & ENVIRO. SERV.	EXECUTIVE GROUP	FOSSIL & HYDRO GEN.	GENERAL SERVICES	GENERATION BUS. SERVICES	GOV. & ENVIRO. AFFAIRS	HUMAN RESOURCES	INFORMATION TECHNOLOGY	LEGAL
454	Rents from electric properties - NAC	$ -	$ -	$ -	$ -	$ (280)	$ -	$ -	$ -	$ (2)	$ -
456	Other electric revenues	-	-	-	-	-	-	-	-	-	-
419	Interest income - other	-	-	-	-	-	-	-	-	(13)	-
421	Miscellaneous income or loss	(1)	(4)	-	(1)	(1,257)	-	-	(1)	(139)	(10)
500-559	Power production	38,543	48,351	723	17,164	235	939	9	115	2,749	380
560-579	Transmission	87	932	107	-	47	126	(1)	(2)	1,994	3
580-599	Distribution	(2)	1,462	152	(3)	38	188	(1)	1	5,995	(6)
780-860	Trading	(7)	-	-	-	-	-	-	-	(1)	-
901-903	Customer accounts expense	395	(34)	(4)	(6)	8	1,914	(3)	(5)	1,316	(10)
904	Uncollectible - Misc. Receivable	-	-	-	-	-	-	-	-	227	-
905	Miscellaneous customer accounts	-	-	-	4	-	-	-	-	(1)	-
906-917	Customer service & Information	47	(4)	-	(1)	-	38	1	17	4,121	22
920	Salaries and wages	19,368	18,926	7,457	667	11,187	56	3,677	21,952	58,091	17,102
921	Office supplies and expenses	2,616	3,655	2,571	566	4,635	192	537	2,085	29,824	1,979
922	Administrative expense transferred - credit	4,570	14,787	1,923	1,403	7,686	3,241	806	7,300	19,049	3,651
923	Outside services employed	770	2,119	3,229	52	4,289	343	66	1,403	9,939	3,871
924	Property insurance	-	-	-	-	-	-	-	-	-	-
925	Injuries and damages	9	10	-	-	-	-	-	1,937	1	107
926	Employee pensions and benefits	65	93	126	13	44	-	-	109,705	149	25
928	Regulatory commission expense	-	-	-	-	-	-	-	-	-	-
930.1	General advertising expenses	-	(1)	-	-	40	9	-	11	62	322
930.2	Miscellaneous general expenses	543	45	71	-	38	47	766	4	105	978
931	Rents	3,525	168	333	8	32,901	53	1	45	36,995	12
935	Maintenance of structures and equipment	12	52	(1)	-	5,630	(1)	(1)	-	6,422	(2)
403-405	Depreciation and amortization expense	3	-	-	-	8,582	-	-	-	-	-
408	Taxes other than income taxes	2,469	6,556	212	1,137	4,540	250	240	(1,658)	5,456	717
409	Income taxes	-	-	-	-	-	-	-	-	-	-
410	Provision for deferred income taxes	-	-	-	-	-	-	-	-	-	-
411	Provision for deferred income taxes - credit	-	-	-	-	-	-	-	-	-	-
411.7	Loss from disposition of plant	-	-	-	-	6,399	-	-	-	-	-
416	Expense - sports lighting	-	-	-	-	-	-	-	-	23	-
417	Administrative - business venture	-	1	2	-	-	-	-	-	4	-
418	Non-Operating rental income	-	-	-	-	344	-	-	-	(1)	-
426.1	Donations	142	1	-	-	1	-	662	200	-	1,500
426.3 - 426.5	Other deductions	255	88	139	-	134	23	3,527	4	16	339
427	Interest on long-term debt	-	-	-	-	-	-	-	-	-	-
428	Amortization of debt discount and expense	-	-	-	-	-	-	-	-	-	-
430	Interest on debt to associate companies	-	-	-	-	-	-	-	-	34	-
431	Other interest expense	-	-	-	-	-	-	-	1	-	-
432	Borrowed funds - construction - credit	-	-	-	-	-	-	-	-	1	-
107	Construction work in progress	3,496	32,927	992	3,223	1,438	16	(3)	1	106,620	38
108	Retirement work in progress	23	3,653	-	71	40	-	-	-	4	14
121	Nonutility Property	-	16	-	-	-	-	-	-	-	-
122	Depr & Amort of Nonutil Prop	-	-	-	-	42	-	-	-	-	-
124	Investments	-	2	1	-	33	-	-	-	-	1
151	Fuel stock	9	372	-	2,275	-	-	-	3	(1)	-
152	Fuel stock expense undistributed	3,922	1,428	32	44	-	-	-	(5)	141	126
163	Stores expense undistributed	14	-	-	6	-	1	-	(1)	(2)	(1)
182	Regulatory Assets	10	-	-	-	-	-	-	-	(8)	-
184	Clearing accounts	-	-	-	-	-	-	-	-	-	-
186	Miscellaneous deferred debits	7,580	5,814	(1)	11	778	3	-	11	245	2,677
188	Research, Development, or Demonstration Exp.	13	543	17	163	11	12,538	4	(1)	(40)	49
	TOTAL COST OF SERVICE	$ 88,476	$ 141,958	$ 18,081	$ 26,796	$ 87,583	$ 19,976	$ 10,287	$ 143,122	$ 289,375	$ 33,884

ANNUAL REPORT OF American Electric Power Service Corporation

For the Year Ended December 31, 2003

SCHEDULE XVII - SCHEDULE OF EXPENSE DISTRIBUTION BY DEPARTMENT OR SERVICE FUNCTION
(In Thousands)

Instruction: Indicate each department or service function. (See Instruction 01-3 General Structure of Accounting System: Uniform System of Accounts).

ACCOUNT	DESCRIPTION OF ITEMS	DEPARTMENT OR SERVICE FUNCTION NUCLEAR	PLAN. & BUS. DEVELOPMENT	PUBLIC POLICY	RISK MANAGEMENT	SUPPLY CHAIN	TRANSMISSION	TREASURY
454	Rents from electric properties - NAC	$ -	$ -	$ -	$ -	$ -	$ -	$ -
456	Other electric revenues	-	-	-	-	-	-	-
419	Interest income - other	-	-	-	(11)	-	-	(1)
421	Miscellaneous income or loss	-	-	(1)	-	(1)	(2)	-
500-559	Power production	527	9	(1)	1,932	11	1,117	-
560-579	Transmission	-	209	167	(1)	108	21,869	-
580-599	Distribution	-	184	3	(1)	(30)	1,129	-
780-860	Trading	-	-	-	1	-	-	-
901-903	Customer accounts expense	(1)	59	(3)	258	(8)	(23)	(1)
904	Uncollectible - Misc. Receivable	-	-	-	-	-	-	-
905	Miscellaneous customer accounts	-	-	-	-	-	-	-
906-917	Customer service & information	-	23	1,189	-	(1)	(3)	2
920	Salaries and wages	699	1,110	7,791	6,404	2,712	203	6,386
921	Office supplies and expenses	96	36	1,068	713	1,565	608	2,033
922	Administrative expense transferred - credit	257	464	2,082	862	1,674	15,332	792
923	Outside services employed	88	195	784	672	497	11	78
924	Property insurance	-	-	-	216	-	-	-
925	Injuries and damages	-	-	-	5,543	11	2	-
926	Employee pensions and benefits	-	1	15	230	14	31	15
928	Regulatory commission expense	-	-	-	-	-	-	-
930.1	General advertising expenses	-	-	7	-	-	-	-
930.2	Miscellaneous general expenses	4	2,412	1	13	14	822	143
931	Rents	-	1	2	26	6	24	6
935	Maintenance of structures and equipment	-	-	9	(1)	-	-	4
403-405	Depreciation and amortization expense	-	-	-	-	-	-	-
408	Taxes other than income taxes	17	158	522	426	727	3,672	311
409	Income taxes	-	-	-	-	-	-	-
410	Provision for deferred income taxes	-	-	-	-	-	-	-
411	Provision for deferred income taxes - credit	-	-	-	-	-	-	-
411.7	Loss from disposition of plant	-	-	-	-	-	-	-
416	Expense - sports lighting	-	-	-	-	-	-	-
417	Administrative - business venture	-	4	8	-	-	87	-
418	Non-Operating rental income	-	-	-	-	-	-	-
426.1	Donations	-	-	22	-	-	2	-
426.3 - 426.5	Other deductions	5	-	4	-	-	-	-
427	Interest on long-term debt	-	-	-	-	-	-	4,850
428	Amortization of debt discount and expense	-	-	-	-	-	-	427
430	Interest on debt to associate companies	-	-	-	-	-	-	1,045
431	Other interest expense	-	-	-	-	-	-	922
432	Borrowed funds - construction - credit	-	-	-	-	-	-	(2,046)
107	Construction work in progress	11	275	83	107	818	46,959	1
108	Retirement work in progress	-	-	1	-	4	412	-
121	Nonutility Property	-	-	-	-	-	-	-
122	Depr & Amort of Nonutil Prop	-	-	-	-	-	-	-
124	Investments	-	-	-	-	-	-	-
151	Fuel stock	-	-	-	-	-	(1)	-
152	Fuel stock expense undistributed	-	-	3	94	-	(2)	2
163	Stores expense undistributed	-	-	-	-	10,753	(2)	-
182	Regulatory Assets	-	-	-	-	-	-	-
184	Clearing accounts	-	-	-	-	-	-	-
186	Miscellaneous deferred debits	-	2	708	-	54	3,429	35
188	Research, Development, or Demonstration Exp.	22	-	(1)	-	(1)	317	1
	TOTAL COST OF SERVICE	$ 1,725	$ 5,142	$ 14,463	$ 17,483	$ 18,927	$ 95,993	$ 15,005

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For the Year Ended December 31, 2003

DEPARTMENTAL ANALYSIS OF SALARIES
(In Thousands except Number of Personnel)

NAME OF DEPARTMENT *Indicate each department or service function.*	DEPARTMENTAL SALARY EXPENSE INCLUDED IN AMOUNTS BILLED TO TOTAL AMOUNT	PARENT COMPANY	OTHER ASSOCIATES	NON ASSOCIATES	NUMBER OF PERSONNEL END OF YEAR
Service Groups (Overheads)	$ 51,865	$ 925	$ 50,530	$ 410	-
Audit Services	1,932	70	1,862	-	34
Commercial Operations	37,971	3	37,955	13	358
Corporate Accounting	16,593	351	16,242	-	360
Corporate Communications	3,397	191	3,206	-	59
Corporate Planning & Budgeting	5,532	209	5,323	-	94
Corporate Planning & Stategy	1,937	66	1,871	-	1
Customer Operations	45,171	57	45,114	-	1,109
Distribution	35,277	16	35,261	-	468
Energy Delivery & External Affairs	1,827	29	1,798	-	32
Engineering Technical & Environmental Services	73,586	51	71,667	1,868	959
Executive Group	1,631	66	1,335	230	22
Fossil & Hydro Generation	13,808	43	13,650	115	233
General Services	2,185	9	2,176	-	226
Generation Business Services	2,850	5	2,845	-	72
Governmental & Environmental Affairs	2,544	81	2,463	-	33
Human Resources	6,377	13	6,364	-	263
Information Technology	20,564	48	20,516	-	848
Legal	7,991	527	7,457	7	96
Nuclear	193	4	189	-	1
Planning & Business Development	1,746	-	1,746	-	21
Public Policy	4,561	8	4,552	1	67
Risk Management	4,226	12	4,207	7	102
Supply Chain	7,944	30	7,896	18	132
Transmission	46,090	2	46,078	10	622
Treasury	2,666	171	2,477	18	33
TOTALS	$ 400,464	$ 2,987	$ 394,780	$ 2,697	6,245

These amounts include charges to accounts throughout the Income Statement, including billable Balance Sheet accounts. Therefore, these amounts cannot be identified in total with any particular line on Schedule XV, but are distributed among various lines.

ANNUAL REPORT OF American Electric Power Service Corporation

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OUTSIDE SERVICES EMPLOYED
(In Thousands)

Instructions: Provide a breakdown of outside services employed. If the aggregate amount paid to any one payee and included within one category is less than $100,000, only the aggregate number and amount of all such payments included within the subaccount need be shown. Provide a brief description of the service rendered by each vendor listed.

FROM WHOM PURCHASED	SERVICE PROVIDED	AMOUNT
A & A Transfer Company	Tenant Services	$ 116
A. C. Coy Company	IT Support	152
A. T. Kearney, Inc.	Consulting Services	1,314
Abilene, City Of	Consulting Services	157
Accenture LLP	Consulting Services	234
Accountemps	Temporary Office & Accounting Services	742
Active Development Group, Inc.	IT Support	199
Advanced Programming Resources, Inc.	Develop IT Processes & Systems	133
AEC Cadcon - Tecworks, Inc.	IT Support	200
AEP Pro Serv, Inc.	Engineering Services	614
Aerotek, Inc.	Engineering Services	291
Alliance One	Collection Services	196
Alliance Participants Admin. & Startup	Maintain Facilities	122
Allied Interstate, Inc.	Collection Services	257
Alstom Usa, Inc.	IT Support	599
Amanda Graphics	Engineering Services	126
American Building Maintenance Co.	Housekeeping Support	199
American Payment Systems, Inc.	Process Customer Payments	1,317
Analysts International Corp.	IT Support	553
Applied Performance Technologies, Inc.	IT Support	115
ASAP Software Express, Inc.	Software Licence	192
Aspect Communications Corp.	Maintain Communication Systems	466
AYCO Company, LP	Human Resources Services	342
Banctec Service Corporation	Collection Services	267
Bank One Commercial Card Activity	Various Services	1,130
Barbara Boggs Associates, Inc.	Consulting Services	402
Battelle, Inc.	Research & Development	136
Bell & Howell Company	Collection Services	147
Bentley Systems, Inc.	Software Maintenance	239
Bindview Corp.	Software Licence	2,593
Bloomberg, LP	IT Support	106
Blue Ridge Service Corp.	Housekeeping Support	536
BMC Software, Inc.	Software Maintenance	2,037
Bracewell & Patterson LLC	Legal Services	225
Business Objects	Software Maintenance	607
Cambridge Energy	Manage & Participate in Public Policy Issues	328
Candle Corp.	Software Maintenance	373
Capital Recovery Service	Collection Services	187
Cardinal Solutions Group	Develop IT Processes & Systems	111
CBCS	Collection Services	193
CDS/Muery Services	Manage Property	561
Ceramphysics, Inc.	Research & Development	120
Charles River Associates, Inc.	Consulting Services	608
Checkfree Services Corp.	Collection Services	120
Cisco Systems, Inc.	Maintain Communication Systems	500
Citibank NA	Financial Services	753
Civil Design Services	Construct Faclities	242
Clark Thomas & Winters	Legal Services	123
CNP Houston Electric LLC	Maintain Facilities	757
Commercial Movers, Inc.	Tenant Services	171

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For the Year Ended December 31, 2003

OUTSIDE SERVICES EMPLOYED
(In Thousands)

Instructions: Provide a breakdown of outside services employed. If the aggregate amount paid to any one payee and included within one category is less than $100,000, only the aggregate number and amount of all such payments included within the subaccount need be shown. Provide a brief description of the service rendered by each vendor listed.

FROM WHOM PURCHASED	SERVICE PROVIDED	AMOUNT
Commonwealth Associates, Inc.	Engineering Services	109
Compaq Computer Corp.	Develop & Deploy IT Infrastructure	418
Computer Associates International, Inc.	Software Maintenance	2,017
Computer Network Technology	Maintain Information Systems	184
Compuware Corp.	Software Licence	1,182
Contract Counsel	Legal Services	172
Courion Corp.	IT Support	273
Covansys	IT Support	166
CQG	IT Support	388
Credit Suisse First Boston	Consulting Services	1,500
Data Dynamics, Inc.	IT Support	268
Davies Consulting, Inc.	Maintain Facilities	167
Dell Computer Corp.	Develop & Deploy IT Infrastructure	1,585
Deloitte & Touche LLP	Auditing/Consulting Services	6,986
Designeers-Midwest	Engineering Services	157
Doble Engineering Co.	Maintain Facilities	275
Dymacol Corp.	Collection Services	120
Eaton Systems Consulting, Inc.	IT Support	164
Edison Electric Institute	Support & Participate in Industry	108
EMC Corp.	Develop & Deploy IT Infrastructure	1,129
ENSR Corp.	Perform Permit & Regulatory Compliance	186
Enterprise For Education, Inc.	Educational Services	130
Enterprise Management Group	Consulting Services	4,281
EPRI Solutions	Research & Development	6,806
Equifax Credit Information Service	Collection Services	549
Ernst & Young	Develop & Deploy IT Infrastructure	1,831
Event Marketing Strategies	Consulting Services	221
Everest Data Research, Inc.	IT Support	449
Everest Technologies, Inc.	Maintain Information Systems	378
Evolve Software, Inc.	Software Maintenance	163
Excelergy Corp.	IT Support	424
Expert Technical Consultants, Inc.	IT Support	526
Flairsoft Ltd.	Maintain Facilities	106
Franklin Computer Services Group, Inc.	IT Support	105
Franklin Imaging	Maintain Facilities	132
Frontier Associates LLC	Consulting Services	105
Fulbright & Jaworski LLP	Legal Services	295
GE Network Solutions	Consulting Services	276
General Research	Engineering Services	1,005
Gentry, John M	Engineering Services	151
Geospatial Innovations, Inc.	Engineering Services	159
Grosh Consulting	IT Support	390
Heller, Ehrman, White, & Mcauliffe LLP	Legal Services	410
Hewlett-Packard Co.	Develop & Deploy IT Infrastructure	474
Hitachi Credit America Corp.	Software Licence	323
Hoffman, William D.	IT Support	117
Hogan & Hartson, LLP	Legal Services	277
Huntington National Bank	Financial Services	226
Hyperion Solutions	IT Support	140
iGate Mastech	IT Support	101

ANNUAL REPORT OF American Electric Power Service Corporation

For the Year Ended December 31, 2002

OUTSIDE SERVICES EMPLOYED
(In Thousands)

Instructions: Provide a breakdown of outside services employed. If the aggregate amount paid to any one payee and included within one category is less than $100,000, only the aggregate number and amount of all such payments included within the subaccount need be shown. Provide a brief description of the service rendered by each vendor listed.

FROM WHOM PURCHASED	SERVICE PROVIDED	AMOUNT
iImagine IT, Inc.	IT Support	128
IKON, Inc.	Office & Document Services	134
Indecon, Inc.	IT Support	1,030
Indus International	IT Support	1,334
Informatica Corp.	Software Maintenance	199
Information Security Technology, Inc.	Software Maintenance	392
Info-Scape Ltd.	IT Support	194
In-Plant Techniques Corp.	Office & Document Services	361
Integral Solutions	Consulting Services	253
Integrity Interactive Corp.	Training Services	185
Interactive Business Systems, Inc.	IT Support	157
International Business Machines Corp.	Develop & Deploy IT Infrastructure	6,869
Interstate Gas Supply, Inc.	Software Licence	477
Iron Mountain Off-Site Data Protection	IT Support	135
IST, Inc.	Consulting Services	1,785
Itron, Inc.	Maintain Facilities	792
ITS Technologies, Inc.	Engineering Services	440
J. D. Services, Inc.	Engineering Services	246
Jones, Day, Reavis, & Pogue	Legal Services	1,547
Keane, Inc.	IT Support	214
Kelly Services, Inc.	Temporary Office & Accounting Services	906
Key Personnel	Temporary Office & Accounting Services	368
Key Bank	Financial Services	796
Kforce.com	IT Support	954
King Business Interiors, Inc.	Tenant Services	503
Knack Technology LLC	IT Support	201
Lakeside Building Maintenance	Housekeeping Support	129
Lee Hecht Harrison LLC	Consulting Services	589
LexisNexis	Software Licence	273
Lifecare.com, Inc.	Human Resources Services	113
Lucent Technologies	Software Maintenance	142
Lumeta Corp.	Maintain Information Systems	118
M/A-Com, Inc.	Engineering Services	227
M3I Systems, Inc.	Software Maintenance	185
Manifest Solutions Corp.	IT Support	604
Manpower, Inc.	Temporary Office & Accounting Services	122
Mapinfo Corp.	Software Licence	142
Market Strategies, Inc.	Consulting Services	1,106
Maxim Group	IT Support	427
Maximation, Inc.	IT Support	769
McAllen, City Of	Consulting Services	381
McAulay Firm	Consulting Services	272
Medium Term Finance	Financial Services	325
Mellon Bank NA	Financial Services	115
Merant	Software Maintenance	118
Mercer Management Consulting	Consulting Services	777
Merrill Communications LLC	Consulting Services	117
Mitem Corp.	Software Maintenance	126
Mueller, Howard	Research & Development	123
National Records Centers, Inc.	Office & Document Services	227

ANNUAL REPORT OF American Electric Power Service Corporation

For the Year Ended December 31, 2003

OUTSIDE SERVICES EMPLOYED
(In Thousands)

Instructions: Provide a breakdown of outside services employed. If the aggregate amount paid to any one payee and included within one category is less than $100,000, only the aggregate number and amount of all such payments included within the subaccount need be shown. Provide a brief description of the service rendered by each vendor listed.

FROM WHOM PURCHASED	SERVICE PROVIDED	AMOUNT
National Theatre For Children	Educational Services	696
NBBJ Dugan & Meyers LLC	Manage Property	119
NCO Financial Systems, Inc.	Collection Services	127
Necho Systems Corp.	Software Maintenance	149
NETg, Inc.	Software Maintenance	149
Network & Security Technologies	IT Support	181
New Energy Associates LLC	Software Maintenance	192
NSI Consulting & Development, Inc.	Manage Property	629
Odyssey Consulting Services, Inc.	Consulting Services	511
OEUI	Customer Communications	230
Officeteam	Temporary Office & Accounting Services	306
Ohio Equities, LLC	Maintain Facilities	806
Ohio State University	Training Services	181
Olsten Staffing Services, Inc.	Temporary Office & Accounting Services	308
Onsite Companies	Maintain Facilities	345
Open Link Operating Partnership LP	Software Maintenance	570
Optimum Technology	IT Support	108
Oracle Corp.	Software Maintenance	1,721
Origin Technology In Business	IT Support	295
OSI Outsourcing Services, Inc.	Collection Services	3,546
Ossid, Inc.	Develop & Deploy IT Infrastructure	171
Pacific Telematics, Inc.	IT Support	128
Paros Business Partners, Inc.	IT Support	229
Peace Software	Software Licence	142
PeopleSoft USA, Inc.	Software Maintenance	1,697
PJM Interconnection LLC	Analyze & Assess Interregional Transmission System	10,508
Platts	Consulting Services	273
Porter, Wright, Morris, & Arthur	Legal Services	178
Power Costs, Inc.	Software Maintenance	351
Powerplan Consultants, Inc.	Software Maintenance	179
Practical Solutions, Inc.	Financial Services	694
Preng & Associates, Inc.	Human Resources Services	118
PriceWaterhouseCoopers LLP	Consulting Services	751
Princeton Softech, Inc.	Software Maintenance	130
Protec Group, Inc.	IT Support	627
Provide Technologies LLC	IT Support	452
Public Utilities Commission Of Ohio	Manage & Participate in Regulatory Affairs	138
PVS International, Inc.	IT Support	328
Quality Software Construction, Inc.	IT Support	150
Quick Solutions, Inc.	IT Support	377
R. Dorsey & Company, Inc.	IT Support	217
Raft International (UK) Ltd.	IT Support	697
Rapidigm	IT Support	333
Renaissance Worldwide IT	IT Support	340
Risk Management Alternatives, Inc.	Collection Services	836
Robert Half International, Inc.	Consulting Services	348
Robin Enterprises Co.	Consulting Services	272
Russell Reynolds Assoc., Inc.	Consulting Services	838
S/D Engineers, Inc.	Engineering Services	398
SAS Institute, Inc.	Software Maintenance	979

ANNUAL REPORT OF American Electric Power Service Corporation

For the Year Ended December 31, 2003

OUTSIDE SERVICES EMPLOYED
(In Thousands)

Instructions: Provide a breakdown of outside services employed. If the aggregate amount paid to any one payee and included within one category is less than $100,000, only the aggregate number and amount of all such payments included within the subaccount need be shown. Provide a brief description of the service rendered by each vendor listed.

FROM WHOM PURCHASED	SERVICE PROVIDED	AMOUNT
Savvy Engineering LLC	Maintain Facilities	118
Scientech, Inc.	Engineering Services	144
Scientific Applications & Research	Research & Development	150
Search Engine	IT Support	305
Serena Software, Inc.	Software Maintenance	102
Serviceware Technologies, Inc.	Software Maintenance	184
Severn Trent Systems	IT Support	528
Siemens Financial Services, Inc.	Software Licence	1,647
Simpson Thacher & Bartlett	Legal Services	1,070
Sirva Relocation	Human Resources Services	734
Sodexho Marriott Services	Food & Catering Services	645
Softbase Systems, Inc.	Software Licence	150
Software AG of North America	Software Maintenance	567
Solarc	Software Maintenance	327
Solomon Associates, Inc.	Maintain Facilities	143
Solutions Consulting	Consulting Services	401
Sourceone Financial LLC	IT Support	170
Southwest Power Pool	Analyze & Assess Interregional Transmission System	626
Steptoe & Johnson LLP	Legal Services	525
Stone & Webster Consultants	Consulting Services	106
Storage Technology Corp.	Develop & Deploy IT Infrastructure	120
Strategic Resources, Inc.	IT Support	117
Summit Solutions, Inc.	Consulting Services	146
Sun Technical Services, Inc.	Consulting Services	5,930
Swafford Consulting, Inc.	IT Support	156
Technolytics	Consulting Services	217
Teksystems	Consulting Services	884
Temporaries Plus, Inc.	IT Support	113
Texas Press Service, Inc.	Consulting Services	230
Thomas Glover Associates, Inc.	IT Support	121
Thomson Financial Corporate Group	Consulting Services	162
Thyssenkrupp Elevator	Maintain Facilities	329
Tibco Software, Inc.	Software Maintenance	108
Tiro Group	Research & Development	102
Towers Perrin	Human Resources Services	126
TQS Research, Inc.	Consulting Services	107
Trammell Crow Company	Security Services	395
Travel Solutions, Inc.	Travel Services	102
Trusecure	IT Support	111
Twenty First Century	Consulting Services	588
Ubics, Inc.	IT Support	175
UMS Group	Consulting Services	1,386
United Construction Co., Inc.	Facilities Construction	1,039
United Parcel Service	Delivery Service	595
Vaisala-Gai, Inc.	Engineering Services	131
Van Ness Feldman	Legal Services	288
Varo Engineers, Ltd.	Engineering Services	257
Veritas Software Corp.	Software Maintenance	103
Vigilinx, Inc.	IT Support	256
Vinson & Associates	Temporary Office & Accounting Services	545

ANNUAL REPORT OF American Electric Power Service Corporation

For the Year Ended December 31, 2003

OUTSIDE SERVICES EMPLOYED
(In Thousands)

Instructions: Provide a breakdown of outside services employed. If the aggregate amount paid to any one payee and included within one category is less than $100,000, only the aggregate number and amount of all such payments included within the subaccount need be shown. Provide a brief description of the service rendered by each vendor listed.

FROM WHOM PURCHASED	SERVICE PROVIDED	AMOUNT
Vintimilla, Luis C.	Consulting Services	164
Vredenburg	Develop & Deploy IT Infrastructure	454
Wackenhut Corp.	Security Services	1,056
Web Envision of Ohio	IT Support	136
Webmethods, Inc.	Software Maintenance	449
Wonderlic, Inc.	Human Resources Services	115
Worksuite LLC	Software Maintenance	205
World Travel BTI	Travel Services	248
Xerox Corp.	Printing Services	567
Others (2,425 under $100,000)	Various Services	12,441
TOTAL		$ 161,903

These amounts include charges to accounts throughout the Income Statement, including billable Balance Sheet accounts. Therefore, these amounts cannot be identified in total with any particular line on Schedule XV, but are distributed among various lines.

ANNUAL REPORT OF American Electric Power Service Corporation

For the Year Ended December 31, 2003

EMPLOYEE PENSIONS AND BENEFITS - ACCOUNT 926
(In Thousands)

Instructions: Provide a listing of each pension plan and benefit program provided by the service company. Such listing should be limited to $25,000.

DESCRIPTION	AMOUNT
Deferred Compensation Benefits	$ (320)
Dental Insurance	3,220
Employee Awards and Events Program	824
Employee Educational Assistance	778
Employees Newspaper and Magazine	748
Group Life Insurance	665
Long-Term Disability	5,539
Medical	41,320
Other Postretirement Benefits	38,387
Post Employment Benefits	2,096
Retirement Plan	(9,542)
Savings Plan	15,282
Supplemental Pension Plan	(3,475)
Training and Other Employee Benefit Expenses	876
Salaries, Salary Related Expenses and Overheads	442
Miscellaneous	216
TOTAL	$ 97,056

ANNUAL REPORT OF American Electric Power Service Corporation

For the Year Ended December 31, 2003

GENERAL ADVERTISING EXPENSES - ACCOUNT 930.1
(In Thousands)

Instructions: Provide a listing of the amount included in Account 930.1, "General Advertising Expenses", classifying the items according to the nature of the advertising and as defined in the account definiation. If a particular class includes an amount in excess of $3,000 applicable to a single payee, show separately the name of the payee and the aggregate amount applicable thereto.

DESCRIPTION	NAME OF PAYEE	AMOUNT
General Advertising Expenses	American Red Cross	$ 15
	Cirque de Soleil	4
	Cleveland Indians	27
	Columbus Blue Jackets	55
	Columbus Clippers	9
	Columbus Monthly	3
	Herald-Dispatch	4
	International Sports Properties Inc.	11
	Interspace Services Inc.	25
	Isherwood Production Limited	5
	Nationwide Advertising Service	3
	Ohio Newspaper Services Inc.	185
	Ohio State University	51
	WOSU/Ohio State University	14
	Others	31
	SUBTOTAL	442
Newspaper Advertising Space	Corpus Christi Caller Times	17
	Great Lakes Publishing	3
	Ohio Newspaper Services Inc.	200
	Our Texas Magazine	9
	Texas Press Clipping Service	169
	Others	23
	SUBTOTAL	421
TV Station Advertising Time	KULP	7
	Others	8
	SUBTOTAL	15
Newspaper Advertising Prod. Exp.	Video Duplication Services, Inc.	1
	SUBTOTAL	1

ANNUAL REPORT OF American Electric Power Service Corporation

For the Year Ended December 31, 2003

GENERAL ADVERTISING EXPENSES - ACCOUNT 930.1
(In Thousands)

Instructions: Provide a listing of the amount included in Account 930.1, "General Advertising Expenses", classifying the items according to the nature of the advertising and as defined in the account definiation. If a particular class includes an amount in excess of $3,000 applicable to a single payee, show separately the name of the payee and the aggregate amount applicable thereto.

DESCRIPTION	NAME OF PAYEE	AMOUNT
Special Corporate Communication Projects	Class Acts Columbus Inc.	3
	Kessler Sign Co.	3
	Ohio Vallley Greyhounds	3
	Webb, Jon Photography, Inc.	4
	Others	13
	SUBTOTAL	26
Special Advertising Space & Production Expenses	Wern-Rausch-Locke	9
	Others	2
		11
	SUBTOTAL	
Direct Mail And Handouts	Columbus Consumer Services Inc.	3
	Robin Enterprises Co.	19
	Vincent Graphics Inc.	16
	Others	(2)
	SUBTOTAL	36
Fairs, Shows, and Exhibits	Bank One Commercial Card Activity	9
	Eagle Exhibit Services, Inc.	5
	Live Technologies, Inc.	9
	Others	10
	SUBTOTAL	33
Publicity	DJRBI LLC	14
	National Press Foundation	3
	PR Newswire, Inc	21
	Branding Charges	155
	Others	19
	SUBTOTAL	212
Dedications, Tours, & Openings	Sodexho Inc. & Affiliates	3
	SUBTOTAL	3

ANNUAL REPORT OF American Electric Power Service Corporation

For the Year Ended December 31, 2003

GENERAL ADVERTISING EXPENSES - ACCOUNT 930.1
(In Thousands)

Instructions: Provide a listing of the amount included in Account 930.1, "General Advertising Expenses", classifying the items according to the nature of the advertising and as defined in the account definiation. If a particular class includes an amount in excess of $3,000 applicable to a single payee, show separately the name of the payee and the aggregate amount applicable thereto.

DESCRIPTION	NAME OF PAYEE	AMOUNT
Customer Surveys	Market Strategies	42
	SUBTOTAL	42
Video Communications	Curtis Elliott Designs	3
	Others	3
	SUBTOTAL	6
Other Corporate Communications	Bank One Commercial Card Activity	10
	Cirque de Soleil, Inc.	6
	Enterprise For Education	130
	IS Talent	6
	Kentucky Need Project	5
	Louisiana State University	4
	Midland Theatre Association	5
	Moore Syndication, Inc.	58
	Premiums & Promotions, Inc.	4
	Quadrant Productions	4
	Sodexho, Inc. & Affiliates	4
	Work+Play, Inc.	7
	Others	47
	SUBTOTAL	290
Salaries, salary related expenses, overheads and other expenses		636
	SUBTOTAL	636
	TOTAL	$ 2,174

ANNUAL REPORT OF American Electric Power Service Corporation

For the Year Ended December 31, 2003

MISCELLANEOUS GENERAL EXPENSES - ACCOUNT 930.2
(In Thousands)

Instructions: Provide a listing of the amount included in Account 930.2, "Miscellaneous General Expenses" classifying such expenses according to their nature. Payments and expenses permitted by Section 321 (b)(2) of the Federal Election Campaign Act, as amended by Public Law 94-283 in 1976 (2 U.S.C. 441(b)(2)) shall be separately classified.

DESCRIPTION	AMOUNT
Salaries, Salary Related Expenses and Overheads	$ 3,110
Membership Fees and Dues	1,896
Implement Community Economic Developmental Programs	1,219
Professional Software Services	438
Design, Develop and Introduce New Applications	140
Maintain General Ledger	136
Develop, Measure and Analyze Organizational Performance	119
Provide IT Techical Suppport	115
Directors' Fees and Expenses	110
Provide IndividualShareholder Support	55
Sales and Use Tax Accrual	46
Install and Remove Telecommunications Equipment	46
Engineer and Design Transmission Station Facilities	37
Engineer and Design Transmission Line Facilities	28
Engineer and Design Telecommunications System	28
Adjustment for Provision for Uncollectible Accounts	(408)
Miscellaneous	255
TOTAL	$ 7,370

RENTS - ACCOUNT 931
(In Thousands)

Instructions: Provide a listing of the amount included in Account 931, "Rents", classifying such expenses by major groupings of property, as defined in the account definition of the Uniform System of Accounts.

TYPE OF PROPERTY	AMOUNT
Office Space	$ 31,773
Computer Software	261
Computer Equipment	40,303
Office Equipment	1,314
Telecommunications Equipment	1,185
Miscellaneous	1,471
TOTAL	$ 76,307

TAXES OTHER THAN INCOME TAXES - ACCOUNT 408
(In Thousands)

Instructions: Provide an analysis of Account 408 "Taxes Other Than Income Taxes". Separate the analysis into two groups: (1) other than U.S. Government taxes, and (2) U.S. Government taxes. Specify each of the various kinds of taxes and show the amounts thereof. Provide a subtotal for each class of tax.

DESCRIPTION	AMOUNT
Taxes Other Than U.S. Government Taxes	
State Unemployment Taxes	$ 1,014
Property, Franchise, Ad Valorem and Other Taxes	6,229
SUB-TOTAL	7,243
U.S. Government Taxes	
Social Security Taxes	32,570
Federal Unemployment Taxes	415
SUB-TOTAL	32,985
TOTAL	$ 40,228

ANNUAL REPORT OF American Electric Power Service Corporation

For the Year Ended December 31, 2003

DONATIONS - ACCOUNT 426.1
(In Thousands)

Instructions: Provide a listing of the amount included in Account 426.1, "Donations", classifying such expenses by its purpose. The aggregate number and amount of all items of less than $3,000 may be shown in lieu of details.

NAME OF RECIPIENT	PURPOSE OF DONATION		AMOUNT
AEP UNCF	Education	$	8
Alliance	Community		5
Annapolis Center	Community		10
Annual Emancipiation Day Celebration Inc.	Community		3
Ashland Alliance Inc.	Community		4
Aspen Institute	Community		18
B R E A D Organization	Community		5
Ball State University Foundation	Education		5
Balletmet	Community		5
Biomedical Research Foundation	Education		15
Brown University	Education		3
Business & Industrial Development Corp.	Community		6
Camp Invention	Community		5
Canal Winchester First	Community		6
CIGRE	Education		3
Columbus Childrens Theatre	Community		10
Columbus Downtown	Community		50
Columbus State Community College	Education		47
Columbus Symphony Orchestra	Community		65
Columbus Zoo	Community		40
Congressional Black Caucus	Community		4
Cornerstone Alliance	Community		18
Council for Ethics	Community		5
Directions for Youth	Community		13
DRWV Foundation	Community		10
Eastland-Fairfield Career	Community		8
Economic Development Corp.	Community		5
Educational Council	Education		5
Ferrum College	Education		5
Friends of Nature Foundation	Community		10
Girl Scouts Seal of Ohio Council Inc	Community		11
Global 3E	Community		750
Grant County Economic Growth Council	Community		3
Greater Columbus Chamber of Commerce	Community		44
Greater Columbus Habitat for Humanity	Community		20
Greater Indianapolis	Community		12
Greater Kingsville Economic	Community		5
Harvard University	Education		51
Heritage Day Health Centers	Community		15

ANNUAL REPORT OF American Electric Power Service Corporation

For the Year Ended December 31, 2003

DONATIONS - ACCOUNT 426.1
(In Thousands)

Instructions: Provide a listing of the amount included in Account 426.1, "Donations", classifying such expenses by its purpose. The aggregate number and amount of all items of less than $3,000 may be shown in lieu of details.

NAME OF RECIPIENT	PURPOSE OF DONATION	AMOUNT
Hope Street Kids	Community	10
Huckleberry House	Community	11
Huntington Area Development Council	Community	3
I Know I Can	Community	7
IH 35 South Economic	Community	3
Institute For Public Relations	Community	8
Jackson County Development Authority	Community	3
Juvenile Diabetes Foundation	Community	3
Kent State University	Education	4
Kentucky State University	Education	3
Keystone Center	Community	53
Law Enforcement Foundation Inc.	Community	3
Lindenwood University	Education	5
Manhattan College	Education	3
Michigan Economic Development Foundation	Community	10
Monteith, Sherri A	Community	4
Muncie-Delaware County	Community	5
National Academy of Engineering	Education	5
National Association of Manufacturers	Community	10
National Fuel Funds Network	Community	11
National Governors Association	Community	37
National Wild Turkey Federation	Community	10
Nature Conservancy	Community	60
Need Project	Community	20
New York Financial Writers Association	Community	3
Ohio Erie to Trail Fund	Community	5
Ohio River Valley Water	Community	10
Ohio State University Foundation	Education	7
Ohio Valley Industrial	Community	4
Ohio-West Virginia YMCA	Community	11
Oklahoma Institute for Child Advocacy	Community	100
Penn High School	Education	5
Programme for Belize	Community	12
Protec	Community	3
Rag Coal International Ag	Community	4
Resources for the Future	Community	50
Robotics Team of Central Ohio	Education	4
Rutgers University Foundation	Education	4

ANNUAL REPORT OF American Electric Power Service Corporation

For the Year Ended December 31, 2003

DONATIONS - ACCOUNT 426.1
(In Thousands)

Instructions: Provide a listing of the amount included in Account 426.1, "Donations", classifying such expenses by its purpose. The aggregate number and amount of all items of less than $3,000 may be shown in lieu of details.

NAME OF RECIPIENT	PURPOSE OF DONATION	AMOUNT
Salvation Army Inc.	Community	30
Science & Mathematics Network	Education	5
Science Olympiad	Education	3
Shreveport Airport Authority	Community	5
Simon Kenton Council	Community	3
Southeast Coalition for Kids	Community	5
Southern Governors Association	Community	20
St Clairsville Area Soccer Association	Community	5
Stark Development Board	Community	5
Teach for America	Education	10
Tech Corps Ohio	Education	5
Texas A & M University-Kingsville	Education	4
Texas Economic Development Corp.	Community	10
Thurber House	Community	6
United Negro College Fund	Education	26
United Way	Community	356
United Way of Northwest Louisiana	Community	5
University of Notre Dame	Education	3
University of Texas At Austin	Education	30
Up On The Roof	Community	6
Utilitree Carbon Company	Community	100
Utility Business Education Coalition	Community	25
Virginia Military Institute	Education	3
Virginia Tech Foundation Inc.	Education	8
Wexner Center for the Arts	Community	5
Wildlife Habitat Council	Community	4
Wilds	Community	5
Williams College	Education	3
Womens Fund of Central Ohio	Community	5
World of Children Inc.	Community	5
Ymca of Central Ohio	Community	15
Employees and Others (Salaries, salary related expenses, overheads and other expenses)	Various	126
Others (less than $3,000)		286
TOTAL		$ 2,952

ANNUAL REPORT OF American Electric Power Service Corporation

For the Year Ended December 31, 2003

OTHER DEDUCTIONS - ACCOUNTS 426.3 - 426.5
(In Thousands)

Instructions: Provide a listing of the amount included in Accounts 426.3 through 426.5, "Other Deductions", classifying such expenses according to their nature.

DESCRIPTION	NAME OF PAYEE	AMOUNT
Expenditures for Certain Civic, Political & Related Activities	Company employee and administrative costs for civic, political and related activities	$ 3,467
Other Miscellaneous Deductions	Various	2,386
TOTAL		$ 5,853

ANNUAL REPORT OF American Electric Power Service Corporation

For the Year Ended December 31, 2003

SCHEDULE XVIII - NOTES TO STATEMENT OF INCOME

Instructions: The space below is provided for important notes regarding the statement of income or any account thereof. Furnish particulars as to any significant increase in services rendered or expenses incurred during the year. Notes related to financial statements shown elsewhere in this report may be indicated here by reference.

1) Page 21 "Analysis of Billing - Associate Companies" captures the category "Compensation for Use of Capital". The following items are included in this category (in thousands):

Interest on Long Term Debt - Notes	$	530
Interest to Associate Companies - Money Pool		1,089
Lines of Credit		221
Allowance for Borrowed Funds Used During Construction		(2,172)
Total Compensation for Use of Capital	$	(332)

2) See Notes to Financial Statements on Page 19.

ANNUAL REPORT OF American Electric Power Service Corporation

For Year Ended December 31, 2003

ORGANIZATION CHART

Chairman, Chief Executive Officer & President

Vice Chairman & Chief Operating Officer

- Transmission
- Distribution
- Customer Operations
- Planning & Business Development
- Energy Delivery & External Affairs
- Commercial Operations
- Engineering Technical & Environmental Services
- Fossil & Hydro Generation
- Nuclear
- Generation Business Services

Policy, Finance and Strategic Planning

- Corporate Communications
- Governmental & Environmental Affairs
- Public Policy
- Legal
- Risk Management
- Audit Services NOTE
- Treasury
- Corporate Planning & Strategy
- Corporate Accounting
- Corporate Planning & Budgeting

Shared Services

- Human Resources
- Information Technology
- Supply Chain
- General Services

NOTE:

Audit Services reports to the Audit Committee of the Board of Directors of American Electric Power Company, Inc. and administratively to the Chairman, Chief Executive Officer & President.

ANNUAL REPORT OF American Electric Power Service Corporation

For the Year Ended December 31, 2003

METHODS OF ALLOCATION

Service Billings

1 Number of Bank Accounts
2 Number of Call Center Telephones
3 Number of Cell Phones/Pagers
4 Number of Checks Printed
5 Number of Customer Information System Customer Mailings
6 Number of Commercial Customers (Ultimate)
7 Number of Credit Cards
8 Number of Electric Retail Customers (Ultimate)
9 Number of Employees
10 Number of Generating Plant Employees
11 Number of General Ledger Transactions
12 Number of Help Desk Calls
13 Number of Industrial Customers (Ultimate)
14 Number of Job Cost Accounting Transactions
15 Number of Non-UMWA Employees
16 Number of Phone Center Calls
17 Number of Purchase Orders Written
18 Number of Radios (Base/Mobile/Handheld)
19 Number of Railcars
20 Number of Remittance Items
21 Number of Remote Terminal Units
22 Number of Rented Water Heaters
23 Number of Residential Customers (Ultimate)
24 Number of Routers
25 Number of Servers
26 Number of Stores Transactions
27 Number of Telephones
28 Number of Transmission Pole Miles
29 Number of Transtext Customers
30 Number of Travel Transactions
31 Number of Vehicles
32 Number of Vendor Invoice Payments
33 Number of Workstations
34 Active Owned or Leased Communication Channels
35 Avg. Peak Load for past Three Years
36 Coal Company Combination
37 AEPSC past 3 Months Total Bill Dollars
38 AEPSC Prior Month Total Bill Dollars
39 Direct
40 Equal Share Ratio
41 Fossil Plant Combination
42 Functional Department's Past 3 Months Total Bill Dollars
43 KWH Sales (Ultimate Customers)
44 Level of Construction - Distribution
45 Level of Construction - Production
46 Level of Construction - Transmission
47 Level of Construction - Total
48 MW Generating Capability
49 MWH's Generation
50 Current Year Budgeted Salary Dollars
51 Past 3 Mo. MMBTU's Burned (All Fuel Types)
52 Past 3 Mo. MMBTU's Burned (Coal Only)
53 Past 3 Mo. MMBTU's Burned (Gas Type Only)
54 Past 3 Mo. MMBTU's Burned (Oil Type Only)

METHODS OF ALLOCATION

Service Billings

55 Past 3 Mo. MMBTU's Burned (Solid Fuels Only)
56 Peak Load / Avg. No. Cust / KWH Sales Combination
57 Tons of Fuel Acquired
58 Total Assets
59 Total Assets less Nuclear Plant
60 AEPSC Annual Costs Billed (Less Interest And/or Income Taxes as Applicable)
61 Total Fixed Assets
62 Total Gross Revenue
63 Total Gross Utility Plant (Including CWIP)
64 Total Peak Load (Prior Year)
65 Hydro MW Generating Capability
66 Number of Forrest Acres
67 Number of Dams
68 Number of Plant Licenses Obtained
69 Number of Nonelectric OAR Invoices
70 Number of Transformer Transactions
71 Tons of FGD Material
72 Tons of Limestone Received
73 Total Assets, Total Revenues, Total Payroll
74 Total Leased Assets
75 Number of Banking Transactions

Convenience Billings

Specific Identification Ratio
(based on known and pertinent factors)
Asset Ratio
Expense Budget Ratio
Contribution Ratio
Equal Share Ratio
Gross Annual Payroll Dollars Ratio
Coal Production Ratio
Kilowatt Hours Sales (KWH) Ratio
Number of Employees Ratio
Number of Customers Ratio
Number of Vehicles Ratio

ANNUAL REPORT OF American Electric Power Service Corporation

For the Year Ended December 31, 2003

ANNUAL STATEMENT OF COMPENSATION FOR USE OF CAPITAL BILLED

Since this U-13-60 report is distributed to the appropriate members of AEP's management each year, the following information is supplied to each associate company in support of the amount of compensation for use of capital billed during 2003:

In accordance with Instruction 01-12 of the Securities and Exchange Commission's Uniform System of Accounts for Mutual Service Companies and Subsidiary Service Companies, American Electric Power Service Corporation submits the following information on the billing of interest on borrowed funds to associated companies for the year 2003:

A. Amount of interest billed to associate companies is contained on page 21, Analysis of Billing.

B. The basis for billing of interest to the associated companies is based on the Service Company's prior year Attribution Basis "AEPSC Annual Cost Billed ."

ANNUAL REPORT OF American Electric Power Service Corporation

For the Year Ended December 31, 2003

ADDENDUM A - SALE OF COMPUTER SOFTWARE AND SUPPORT TO NONASSOCIATE COMPANIES

Instructions: In accordance with SEC Release No. 70-10092, American Electric Power Service Corporation will report to the Commission via an Addendum to the U-13-60 for the period July 1 - December 31 the amounts billed to nonassociate companies for the license or sale of specialized computer programs and the support services to the licenses and entities that have purchased this software.

This is to certify that American Electric Power Service Corporation, in accordance with the terms and conditions of, and for the purposes represented by, the application or declaration herein, the order of the Securities and Exchange Commission with respect thereto, dated December 30, 2002, provides the following information for each computer software license, lease or sale for the period July 1 through December 31: a) details of the product sold or licensed; b) the name of the licensee or buyer, and; c) the amount of revenue received by American Electric Power Service Corporation.

There was no computer software licensed, leased or sold during the period July 1, 2003 through December 31, 2003.

ANNUAL REPORT OF American Electric Power Service Corporation

For the Year Ended December 31, 2003

SIGNATURE CLAUSE

Pursuant to the requirements of the Public Utility Holding Company Act of 1935 and the rules and regulations of the Securities and Exchange Commission issued thereunder, the undersigned company has duly caused this report to be signed on its behalf by the undersigned officer thereunto duly authorized.

American Electric Power Service Corporation
(Name of Reporting Company)

Sandra S Bennett
(Signature of Signing Officer)

Sandra S. Bennett Assistant Controller
(Printed Name and Title of Signing Officer)

Date: 5-3-04

STITES & HARBISON PLLC
ATTORNEYS

421 West Main Street
Post Office Box 634
Frankfort, KY 40602-0634
(502) 223-3477
(502) 223-4124 Fax
www.stites.com

RECEIVED

MAR 24 2004

PUBLIC SERVICE COMMISSION

March 24, 2004

Mark R. Overstreet
(502) 209-1219
(502) 223-4387 FAX
moverstree@stites.com

HAND DELIVERED

Thomas M. Dorman
Executive Director
Public Service Commission of Kentucky
211 Sower Boulevard
P.O. Box 615
Frankfort, Kentucky 40602-0615

RE: ***P.S.C. Case No. 99-149 (Merger of American Electric Power Company and Central and South West Corporation)***

Dear Mr. Dorman:

Please accept for filing the original and four copies of the Supplemental Responses of Kentucky Power Company d/b/a American Electric Power to the Commission's June 14, 1999 Order in the above-referenced case. The Responses are for the quarter ended December 31. 2003.

The Company requests the Commission to reconsider that potion of its June 14, 2004 Order requiring the Company to make quarterly filings. The Company believes that in light of the passage of time the parties and Commission may no longer require quarterly filings. If the Commission and the parties believe they would be equally well served by annual filings, the Company requests the Order be amended to delete the requirement for quarterly filings. Finally, the Company requests that any annual filing be due on or before May 15th of each year.

By copy of this letter I am providing the parties to the case with a copy of the Supplemental Response. If you have any questions, please do not hesitate to contact me.

Sincerely yours,

STITES & HARBISON PLLC

Mark R. Overstreet

Enclosures

cc: David F. Boehm
William H. Jones, Jr.
Elizabeth Blackford

KE057:KE131:10729:1:FRANKFORT

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the matter of:

JOINT APPLICATION OF KENTUCKY POWER	)
COMPANY, AMERICAN ELECTRIC POWER	)
COMPANY, INC. AND CENTRAL AND SOUTH	) CASE NO. 99-149
WEST CORPORATION REGARDING A	)
PROPOSED MERGER	)

****

RESPONSE OF KENTUCKY POWER COMPANY
d/b/a/
AMERICAN ELECTRIC POWER

Reporting Period: 4th Quarter Ending December 31, 2003

Filing Date: 23 March 2004

Kentucky Power Company
d/b/a
American Electric Power

REQUEST:

Furnish annual financial statements of AEP, including consolidating adjustments of AEP and its subsidiaries with a brief explanation of each adjustment and all periodic reports filed with the SEC. Including but not limited to the U5S and U-13-60 reports. All subsidiaries should prepare and have available monthly and annual financial information required to compile financial statements and to comply with other reporting requirements. The financial statements for any non-consolidated subsidiaries of AEP should be furnished to the Commission. [Reference: Merger Agt., Ky. PSC Order dated 6-14-99, pg 10 (Periodic Reports)]

RESPONSE:

Please see the Company's response to Item No. 1 filed with the Commission on May 16, 2003.

WITNESS: Errol K. Wagner

2

Kentucky Power Company
d/b/a
American Electric Power

REQUEST:

On an annual basis file a general description of the nature of inter-company transactions with specific identification of major transactions and a description of the basis upon which cost allocations and transfer pricing have been established. This report should discuss the use of the cost or market standard for the sale or transfer of assets, the allocation factors used, and the procedures used to determine these factors if they are different from the procedures used in prior years. [Reference: Merger Agt., Ky. PSC Order dated 6-14-99, pg. 11, Item 1]

RESPONSE:

Please see the Company's response to Item No. 2 filed with the Commission on May 16, 2003.

WITNESS: Errol K. Wagner

3

Kentucky Power Company
d/b/a
American Electric Power

REQUEST:

On an annual basis file a report that identifies professional personnel transferred from Kentucky Power to AEP or any of the non-utility subsidiaries and describes the duties performed by each employee while employed by Kentucky Power and to be performed subsequent to transfer. [Reference: Merger Agt., Ky. PSC Order dated 6/14/99, Reporting Requirements, Pg. 11, Item 2.]

RESPONSE:

Please see the Company's response to Item No. 3 filed with the Commission on May 16, 2003.

WITNESS: Errol K. Wagner

4

Kentucky Power Company
d/b/a
American Electric Power

REQUEST:

AEP should file on a quarterly basis a report detailing Kentucky Power's proportionate share of AEP's total operating revenues, operating and maintenance expenses, and number of employees. [Reference: Merger Agt., Ky. PSC Order dated 6/14/99, Reporting Requirements, Pg. 11, Item 2]

RESPONSE:

For 4th Quarter 2003:

Kentucky Power Company
Report Proportionate Share of AEP
(in millions, except number of employees)

	Three Months Ended December 31, 2003				Twelve Months Ended December 31, 2003		
	AEP	KP CO	SHARE		AEP	KPCo	SHARE
Revenues	2,687	95	3.5%		14,545	377	2.6%
Operating/Maint. Exp.	1,625	39	2.4%		10,283	152	1.5%
Number of Employees*	19,905	394	2.0%				

* See Response to Item No. 6

WITNESS: Errol K. Wagner

5

Kentucky Power Company
d/b/a
American Electric Power

REQUEST:

AEP should file any contracts or other agreements concerning the transfer of such assets or the pricing of inter-company transactions with the Commission at the time the transfer occurs. [Reference: Merger Agt., Ky. PSC Order dated 6/14/99, Reporting Requirements, Pg. 11 (Special Reports)]

RESPONSE:

4th Quarter 2003:

During the three month period ending December 31, 2003 there were 7 different transactions in which AEP/Kentucky sold assets to its affiliates. The assets transferred were various meters and transformers. The total dollar value of the assets transferred was $85,850. The smallest dollar value transferred was two meters at a value of $70. The largest dollar value transferred was 755 meters at a value of $58,459.

WITNESS: Errol K. Wagner

9

Kentucky Power Company
d/b/a
American Electric Power

REQUEST:

AEP should file a quarterly report of the number of employees of AEP and each subsidiary on the basis of payroll assignment. [Reference: Merger Agt., Ky. PSC Order dated 6/14/99, Reporting Requirements, Pg. 11, Item 1 (Special Reports)]

RESPONSE:

Please see the attached page for the 4th Quarter 2003.

WITNESS: Errol K. Wagner

KENTUCKY POWER COMPANY
d/b/a/
AMERICAN ELECTRIC POWER

EMPLOYEE COUNT AS OF 12/31/2003

Co	Descr	Employee Count
E01	Kingsport Power Company	57
E02	Appalachian Power Company	2376
E03	Kentucky Power Company	394
E04	Indiana Michigan Power Company	2306
E06	Wheeling Power Company	57
E07	Ohio Power Company	2155
E10	Columbus Southern Power Co	1090
E16	Houston Pipe Line Company LP	268
E36	Louisiana Intrastate Gas Co	61
E39	Lig Liquids Company L.L.C.	27
E48	River Transportation Div I&MP	334
E54	Conesville Coal Prep Co	35
E59	AEP Energy Services	1
E61	AEP Service Corporation	6264
ECC	AEP Texas Central Company	1203
EEE	CSW Energy, Inc.	43
EEL	AEP Elmwood LLC	145
EMO	AEP MEMCO	380
EPP	Public Service Co. of OK	1068
ESS	SouthWestern Electric Power Co	1169
EWW	AEP Texas North Company	472
	TOTAL	19905

7

Kentucky Power Company
d/b/a
American Electric Power

REQUEST:

AEP should file an annual report containing the years of service at Kentucky Power and the salaries of professional employees transferred from Kentucky Power to AEP or its subsidiaries filed in conjunction with the annual transfer of employees report. [Reference: Merger Agt., Ky. PSC Order 6/14/99, Reporting Requirements, Pg. 12, Item 2]

RESPONSE:

Please see the Company's response to Item No. 7 filed with the Commission on May 16, 2003.

WITNESS: Errol K. Wagner

8

Kentucky Power Company
d/b/a
American Electric Power

REQUEST:

AEP should file an annual report of cost allocation factors in use, supplemented upon significant change. [Reference: Merger Agt., Ky. PSC Order dated 6/14/99, Reporting Requirements, Pg. 12 Item 3]

RESPONSE:

Please see the Company's response to Item No. 8 filed with the Commission on May 16, 2003.

WITNESS: Errol K. Wagner

6

AVERY®

RECYCLED PAPER MADE FROM 20% POST CONSUMER CONTENT

Kentucky Power Company
d/b/a
American Electric Power

REQUEST:

AEP should file summaries of any cost allocation studies when conducted and the basis for the methods used to determine the cost allocation in effect. [Reference: Merger Agt., Ky. PSC Order dated 6/14/99, Reporting Requirements, Pg. 12, Item 4]

RESPONSE:

4th Quarter 2003:

Kentucky Power Company did not perform any cost allocation studies during the quarter ended December 31, 2003. The methods used by Kentucky Power Company for cost allocation are documented in the AEP Cost Allocation Manual.

WITNESS: Errol K. Wagner

10

Kentucky Power Company
d/b/a
American Electric Power

REQUEST:

AEP should file an annual report of the methods used to update or revise the cost allocation factors in use supplemented upon significant change. [Reference: Merger Agt., Ky. PSC Order dated 6/14/99, Reporting Requirements, Pg. 12, Item 5]

RESPONSE:

Please see the Company's response to Item no. 10 filed with the Commission on May 16, 2003.

WITNESS: Errol K. Wagner

11

Kentucky Power Company
d/b/a
American Electric Power

REQUEST:

AEP should file the current Articles of Incorporation and bylaws of affiliated companies in businesses related to the electric industry or that would be doing business with AEP. [Reference: Merger Agt., Ky. PSC Order dated 6/14/99, Reporting Requirements, Pg. 12, Item 6]

RESPONSE:

Please see the Company's response to Item No. 11 filed with the Commission on December 8, 2000.

WITNESS: Errol K. Wagner

12

Kentucky Power Company
d/b/a
American Electric Power

REQUEST:

AEP should file the current Articles of Incorporation of affiliated companies involved in non-related business. [Reference: Merger Agt., Ky. PSC Order dated 6/14/99, Reporting Requirements, Pg. 12, Item 7]

RESPONSE:

See the Company's response to Item No. 11 filed with the Commission on December 8, 2000.

WITNESS: Errol K. Wagner

13

Kentucky Power Company
d/b/a
American Electric Power

REQUEST:

To the extent that the merger is subject to conditions or changes not reviewed in this case, the Joint Applicants should amend their filing to allow the Commission and all parties an opportunity to review the revisions to ensure that Kentucky Power and its customers are not adversely affected and that any additional benefits flow through the favored nations clause. [Reference: Merger Agt., Ky. PSC Order dated 6/14/99, Reporting Requirements, Pgs. 12-13]

RESPONSE:

Please see the Company's response to Item No. 13 filed with the Commission on May 16, 2003.

WITNESS: Errol K. Wagner

14

Kentucky Power Company
d/b/a
American Electric Power

REQUEST:

The Joint Applicants should submit copies of final approval received from the FERC, SEC, FTC, DOJ, and all state regulatory commissions to the extent that these documents have not been provided. With each submittal, the Joint Applicants shall further state whether Paragraph 10 of the Settlement Agreement requires changes to the regulatory plan approved herein. [Reference: Merger Agt., Ky. PSC Order dated 6/14/99, Pg. 14 Item 7]

RESPONSE:

See the Company's response to Item No. 14 filed with the Commission on December 8, 2000.

WITNESS: Errol K. Wagner

15

Kentucky Power Company
d/b/a
American Electric Power

REQUEST:

Provide annual Service Reliability Report addressing the duration and frequency of customer disruptions (CAIDI and SAIFI), including storms for calendar 2002. [Reference: Merger Agt., Attachment C, Pg. 1 Item l]

RESPONSE:

Please see the Company's response to Item No. 15 filed with the Commission on May 16, 2003.

WITNESS: Errol K. Wagner

16

Kentucky Power Company
d/b/a
American Electric Power

REQUEST:

Provide annual Call Center Performance Measures for those centers that handle Kentucky customer calls (Call Center Average Speed of Answer (ASA) Abandonment Rate, and Call Blockage), for calendar year 2002. [Reference: Merger Agt., Attachment C, Pg. 1, Item 2]

RESPONSE:

Please see the Company's response to Item No. 16 filed with the Commission on May 16, 2003.

WITNESS: Errol K. Wagner

17

Kentucky Power Company
d/b/a
American Electric Power

REQUEST:

Will continue to completely inspect its Kentucky electric facilities every two years and perform tree trimming, lightning arrestor replacement, animal guarding and pole and cross arm replacements. Provide data for calendar year 2002. [Reference: Merger Agt., Case 99-149, Attachment C, Page l, Item 3]

RESPONSE:

Please see the Company's response to Item No. 17 filed with the Commission on May 16, 2003.

WITNESS: Errol K. Wagner

18

Kentucky Power Company
d/b/a
American Electric Power

REQUEST:

**AEP/Kentucky Power management will compile outage data detailing each circuit's reliability performance. In addition, by monitoring repeated outages on a regular basis, the Company will identify and resolve reliability problems, which may go unnoticed by using CAIDI and SAIFI results. This data will be coupled with feedback from district field personnel and supervision and management concerning other locations and situations where the impacts of outages are quantified. This process will be used to develop a comprehensive work plan each year, which focuses efforts to improve service reliability. The Company will undertake all reasonable expenditures to achieve the goal of limiting customer outages.
[Reference: Merger Agt., Attachment C, Pg. 1, Item 4]**

RESPONSE:

Please see the Company's response to Item No. 18 filed with the Commission on May 16, 2003.

WITNESS: Errol K. Wagner

19

Kentucky Power Company
d/b/a
American Electric Power

REQUEST:

Plans to continue to maintain a high quality workforce to meet customers' needs. [Reference: Merger Agt, Attachment C, Pg. 2, Item 5]

RESPONSE:

Please see the Company's response to Item No. 19 filed with the Commission on May 16, 2003.

WITNESS: Errol K. Wagner

20

Kentucky Power Company
d/b/a
American Electric Power

REQUEST:

AEP shall designate an employee who will act as a contact for State Commissions and consumer advocates seeking data and information regarding affiliate transactions and personnel transfers. Such employee shall be responsible for providing data and information requested by a State Commission for any and all transactions between the jurisdictional operating company and its affiliates, regardless of which affiliate(s) subsidiary(ies) or associate(s) of an AEP operating company from which the information is sought. [Reference: Merger Agt., Stipulation and Settlement, Pg. 11, Item Q]

RESPONSE:

Mr. Errol K. Wagner, AEP-Kentucky Regulatory Services Director, is the contact designee for the Kentucky Public Service Commissioners and Staff and the Kentucky Attorney General's Office regarding affiliate transactions and personnel transfers.

WITNESS: Errol K. Wagner

21

Kentucky Power Company
d/b/a
American Electric Power

REQUEST:

Please provide designated employee or agent within Kentucky who will act as a contact for retail customers regarding service and reliability concerns and provide a contact for retail consumers for information, questions and assistance. Such AEP/Kentucky Power representative shall be able to deal with billing, maintenance and service reliability issues. [Merger Agt., Stipulation and Settlement, Pg. 11, Item R]

RESPONSE:

The Company would prefer customers to initially call the Customer Solution Centers, whose representatives are capable of answering questions concerning service, reliability concerns and billing issues. However, the AEP-Kentucky Regulatory Services Department, specifically the Regulatory Services Director, are also capable of dealing with billing, maintenance and service reliability issues.

WITNESS: Errol K. Wagner

22

Kentucky Power Company
d/b/a
American Electric Power

REQUEST:

AEP shall provide each signatory state a current list of employees or agents that are designated to work with each State Commission and consumer advocate concerning state regulatory matters, including, but not limited to, rate cases, consumer complaints, billing and retail competition issues. [Reference: Merger Agt., Stipulation and Settlement, Pg. 11, Item 5.]

RESPONSE:

Mr. Errol K. Wagner, AEP-Kentucky Regulatory Services Director, and the AEP-Kentucky Regulatory Services Department staff are the designated employees to work with Kentucky Public Service Commission and the Kentucky Attorney General's Office concerning state regulatory matters, including, but not limited to rate cases, consumer complaints, billing and retail competition issues.

WITNESS: Errol K. Wagner

23

Kentucky Power Company
d/b/a
American Electric Power

REQUEST:

The Company further commits to maintain in Kentucky a sufficient management team to ensure that safe, reliable and efficient electric service is provided and to respond to the needs and inquiries of its Kentucky customers.
[Reference: Merger Agt., Attachment C, Pg. 2, Item 6a]

RESPONSE:

Please see the Company's response to Item No. 23 filed with the Commission on May 16, 2003.

WITNESS: Errol K. Wagner

24

Kentucky Power Company
d/b/a
American Electric Power

REQUEST:

AEP shall contract with an independent auditor who shall conduct biennial audits for ten years after merger consummation of affiliated transactions to determine compliance with the affiliate standards outlined in the Stipulation and Settlement Agreement. The results of such audits shall be filed with the State Commissions. Prior to the initial audit, AEP will conduct an informational meeting with State Commissions regarding how its affiliates and affiliate transactions will or have changed as a result of the proposed merger.
[Reference: Stipulation and Settlement Agreement, Page 11, Section 8(V)]

RESPONSE:

Please see the Company's response to Item No. 24 filed with the Commission on May 16, 2003.

WITNESS: Errol K. Wagner

STITES & HARBISON PLLC

ATTORNEYS

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(502) 209-1219
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November 21, 2003

HAND DELIVERED

RECEIVED
NOV 21 2003
PUBLIC SERVICE COMMISSION

Thomas M. Dorman
Executive Director
Public Service Commission of Kentucky
211 Sower Boulevard
P.O. Box 615
Frankfort, Kentucky 40602-0615

RE: ***P.S.C.. Case No. 99-149*** (Merger of American Electric Power Company and Central and South West Corporation)

Dear Mr. Dorman:

Please find enclosed and accept for filing the supplementary Responses of Kentucky Power Company d/b/a American Electric Power to the Data Requests set forth in the Commission's Order dated June 14, 1999 in the above-styled action. The Responses are for the period ended September 30, 2003.

Copies of this letter and the supplementary Responses have been served this day on the persons listed below.

If you have any questions, please do not hesitate to contact me.

Sincerely yours,

STITES & HARBISON PLLC

Mark R. Overstreet

cc: David F. Boehm
William H. Jones, Jr.
Elizabeth E. Blackford

KE057:KE131:10173:1:FRANKFORT

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the matter of:

JOINT APPLICATION OF KENTUCKY POWER COMPANY, AMERICAN ELECTRIC POWER COMPANY, INC. AND CENTRAL AND SOUTH WEST CORPORATION REGARDING A PROPOSED MERGER	**) CASE NO. 99-149**

****

RESPONSE OF KENTUCKY POWER COMPANY
d/b/a/
AMERICAN ELECTRIC POWER

Reporting Period: Quarter Ending September 30, 2003

Filing Date: 21 November 2003

Kentucky Power Company
d/b/a
American Electric Power

REQUEST:

Furnish annual financial statements of AEP, including consolidating adjustments of AEP and its subsidiaries with a brief explanation of each adjustment and all periodic reports filed with the SEC. Including but not limited to the U5S and U-13-60 reports. All subsidiaries should prepare and have available monthly and annual financial information required to compile financial statements and to comply with other reporting requirements. The financial statements for any non-consolidated subsidiaries of AEP should be furnished to the Commission. [Reference: Merger Agt., Ky. PSC Order dated 6-14-99, pg 10 (Periodic Reports)]

RESPONSE:

Please see the Company's response to Item No. 1 filed with the Commission on May 16, 2003.

WITNESS: Errol K. Wagner

2

Kentucky Power Company
d/b/a
American Electric Power

REQUEST:

On an annual basis file a general description of the nature of inter-company transactions with specific identification of major transactions and a description of the basis upon which cost allocations and transfer pricing have been established. This report should discuss the use of the cost or market standard for the sale or transfer of assets, the allocation factors used, and the procedures used to determine these factors if they are different from the procedures used in prior years. [Reference: Merger Agt., Ky. PSC Order dated 6-14-99, pg. 11, Item 1]

RESPONSE:

Please see the Company's response to Item No. 2 filed with the Commission on May 16, 2003.

WITNESS: Errol K. Wagner

3

Kentucky Power Company
d/b/a
American Electric Power

REQUEST:

On an annual basis file a report that identifies professional personnel transferred from Kentucky Power to AEP or any of the non-utility subsidiaries and describes the duties performed by each employee while employed by Kentucky Power and to be performed subsequent to transfer. [Reference: Merger Agt., Ky. PSC Order dated 6/14/99, Reporting Requirements, Pg. 11, Item 2.]

RESPONSE:

Please see the Company's response to Item No. 3 filed with the Commission on May 16, 2003.

WITNESS: Errol K. Wagner

4

Kentucky Power Company
d/b/a
American Electric Power

REQUEST:

AEP should file on a quarterly basis a report detailing Kentucky Power's proportionate share of AEP's total operating revenues, operating and maintenance expenses, and number of employees. [Reference: Merger Agt., Ky. PSC Order dated 6/14/99, Reporting Requirements, Pg. 11, Item 2]

RESPONSE:

For 3rd Quarter 2003:

Kentucky Power Company
Report Proportionate Share of AEP
(in millions, except number of employees)

	Three Months September 30, 2003				Year-To Date September 30, 2003		
	AEP	KPCO	SHARE		AEP	KPCo	SHARE
Revenues	4,109	94	2.3%		11,858	282	2.4%
Operating/Maint. Exp.	2,927	41	1.4%		8,658	113	1.3%
Number of Employees	20,022	397	2.0%				

* See Response to Item No. 6

WITNESS: Errol K. Wagner

Kentucky Power Company
d/b/a
American Electric Power

REQUEST:

AEP should file any contracts or other agreements concerning the transfer of such assets or the pricing of inter-company transactions with the Commission at the time the transfer occurs. [Reference: Merger Agt., Ky. PSC Order dated 6/14/99, Reporting Requirements, Pg. 11 (Special Reports)]

RESPONSE:

3rd Quarter 2003:

During the three-month period ending September 30, 2003 there were 6 different transactions in which AEP/Kentucky sold assets to its affiliates. The assets transferred were various meters and transformers. The total dollar value of the assets transferred was $60,438. The smallest dollar value transferred was nine meters at a value of $273. The largest dollar value transferred was 735 meters at a value of $29,675.

WITNESS: Errol K. Wagner

9

Kentucky Power Company
d/b/a
American Electric Power

REQUEST:

AEP should file a quarterly report of the number of employees of AEP and each subsidiary on the basis of payroll assignment. [Reference: Merger Agt., Ky. PSC Order dated 6/14/99, Reporting Requirements, Pg. 11, Item 1 (Special Reports)]

RESPONSE:

Please see the attached page for 3rd Quarter 2003.

WITNESS: Errol K. Wagner

EMPLOYEE COUNT AS OF 09/30/2003

Co	Descr	Employee Count
E01	Kingsport Power Company	57
E02	Appalachian Power Company	2402
E03	Kentucky Power Company	397
E04	Indiana Michigan Power Company	2319
E06	Wheeling Power Company	57
E07	Ohio Power Company	2176
E10	Columbus Southern Power Co	1099
E16	Houston Pipe Line Company LP	263
E36	Louisiana Intrastate Gas Co	61
E39	Lig Liquids Company L.L.C.	27
E48	River Transportation Div I&MP	336
E54	Conesville Coal Prep Co	35
E59	AEP Energy Services	1
E61	AEP Service Corporation	6311
E69	AEP Pro Serv	1
ECC	AEP Texas Central Company	1207
EEE	CSW Energy, Inc.	45
EEL	AEP Elmwood LLC	152
EMO	AEP MEMCO	358
EPP	Public Service Co. of OK	1062
ESS	SouthWestern Electric Power Co	1173
EWW	AEP Texas North Company	483
	TOTAL	20022

7

Kentucky Power Company
d/b/a
American Electric Power

REQUEST:

AEP should file an annual report containing the years of service at Kentucky Power and the salaries of professional employees transferred from Kentucky Power to AEP or its subsidiaries filed in conjunction with the annual transfer of employees report. [Reference: Merger Agt., Ky. PSC Order 6/14/99, Reporting Requirements, Pg. 12, Item 2]

RESPONSE:

Please see the Company's response to Item No. 7 filed with the Commission on May 16, 2003.

WITNESS: Errol K. Wagner

8

Kentucky Power Company
d/b/a
American Electric Power

REQUEST:

AEP should file an annual report of cost allocation factors in use, supplemented upon significant change. [Reference: Merger Agt., Ky. PSC Order dated 6/14/99, Reporting Requirements, Pg. 12 Item 3]

RESPONSE:

Please see the Company's response to Item No. 8 filed with the Commission on May 16, 2003.

WITNESS: Errol K. Wagner

6

Kentucky Power Company
d/b/a
American Electric Power

REQUEST:

AEP should file summaries of any cost allocation studies when conducted and the basis for the methods used to determine the cost allocation in effect. [Reference: Merger Agt., Ky. PSC Order dated 6/14/99, Reporting Requirements, Pg. 12, Item 4]

RESPONSE:

3rd Quarter 2003:

Kentucky Power Company did not perform any cost allocation studies during the quarter ended September 30, 2003. The methods used by Kentucky Power Company for cost allocation are documented in the AEP Cost Allocation Manual.

WITNESS: Errol K. Wagner

10

Kentucky Power Company
d/b/a
American Electric Power

REQUEST:

AEP should file an annual report of the methods used to update or revise the cost allocation factors in use supplemented upon significant change. [Reference: Merger Agt., Ky. PSC Order dated 6/14/99, Reporting Requirements, Pg. 12, Item 5]

RESPONSE:

Please see the Company's response to Item No. 10 filed with the Commission on May 16, 2003.

WITNESS: Errol K. Wagner

11

Kentucky Power Company
d/b/a
American Electric Power

REQUEST:

AEP should file the current Articles of Incorporation and bylaws of affiliated companies in businesses related to the electric industry or that would be doing business with AEP. [Reference: Merger Agt., Ky. PSC Order dated 6/14/99, Reporting Requirements, Pg. 12, Item 6]

RESPONSE:

Please see the Company's response to Item No. 11 filed with the Commission on December 8, 2000.

WITNESS: Errol K. Wagner

12

Kentucky Power Company
d/b/a
American Electric Power

REQUEST:

AEP should file the current Articles of Incorporation of affiliated companies involved in non-related business. [Reference: Merger Agt., Ky. PSC Order dated 6/14/99, Reporting Requirements, Pg. 12, Item 7]

RESPONSE:

See the Company's response to Item No. 11 filed with the Commission on December 8, 2000.

WITNESS: Errol K. Wagner

13

Kentucky Power Company
d/b/a
American Electric Power

REQUEST:

To the extent that the merger is subject to conditions or changes not reviewed in this case, the Joint Applicants should amend their filing to allow the Commission and all parties an opportunity to review the revisions to ensure that Kentucky Power and its customers are not adversely affected and that any additional benefits flow through the favored nations clause. [Reference: Merger Agt., Ky. PSC Order dated 6/14/99, Reporting Requirements, Pgs. 12-13]

RESPONSE:

Please see the Company's response to Item No. 13 filed with the Commission on May 16, 2003.

WITNESS: Errol K. Wagner

14

Kentucky Power Company
d/b/a
American Electric Power

REQUEST:

The Joint Applicants should submit copies of final approval received from the FERC, SEC, FTC, DOJ, and all state regulatory commissions to the extent that these documents have not been provided. With each submittal, the Joint Applicants shall further state whether Paragraph 10 of the Settlement Agreement requires changes to the regulatory plan approved herein. [Reference: Merger Agt., Ky. PSC Order dated 6/14/99, Pg. 14 Item 7]

RESPONSE:

Please see the Company's response to Item No. 14 filed with the Commission on December 8, 2000.

WITNESS: Errol K. Wagner

15

Kentucky Power Company
d/b/a
American Electric Power

REQUEST:

Provide annual Service Reliability Report addressing the duration and frequency of customer disruptions (CAIDI and SAIFI), including storms for calendar 2001. [Reference: Merger Agt., Attachment C, Pg. 1 Item l]

RESPONSE:

Please see the Company's response to Item No. 15 filed with the Commission on May 16, 2003.

WITNESS: Errol K. Wagner

16

Kentucky Power Company
d/b/a
American Electric Power

REQUEST:

Provide annual Call Center Performance Measures for those centers that handle Kentucky customer calls (Call Center Average Speed of Answer (ASA) Abandonment Rate, and Call Blockage), for calendar year (XXXX). [Reference: Merger Agt., Attachment C, Pg. 1, Item 2]

RESPONSE:

Please see the Company's response to Item No. 16 filed with the Commission on May 16, 2003.

WITNESS: Errol K. Wagner

17

Kentucky Power Company
d/b/a
American Electric Power

REQUEST:

Will continue to completely inspect its Kentucky electric facilities every two years and perform tree trimming, lightning arrestor replacement, animal guarding and pole and cross arm replacements. Provide data for calendar year (XXXX). [Reference: Merger Agt., Case 99-149, Attachment C, Page l, Item 3]

RESPONSE:

Please see the Company's response to Item No. 17 filed with the Commission on May 16, 2003.

WITNESS: Errol K. Wagner

18

Kentucky Power Company
d/b/a
American Electric Power

REQUEST:

AEP/Kentucky Power management will compile outage data detailing each circuit's reliability performance. In addition, by monitoring repeated outages on a regular basis, the Company will identify and resolve reliability problems, which may go unnoticed by using CAIDI and SAIFI results. This data will be coupled with feedback from district field personnel and supervision and management concerning other locations and situations where the impacts of outages are quantified. This process will be used to develop a comprehensive work plan each year, which focuses efforts to improve service reliability. The Company will undertake all reasonable expenditures to achieve the goal of limiting customer outages.
[Reference: Merger Agt., Attachment C, Pg. 1, Item 4]

RESPONSE:

Please see the Company's response to Item No. 18 filed with the Commission on May 16, 2003.

WITNESS: Errol K. Wagner

19

Kentucky Power Company
d/b/a
American Electric Power

REQUEST:

Plans to continue to maintain a high quality workforce to meet customers' needs. [Reference: Merger Agt, Attachment C, Pg. 2, Item 5]

RESPONSE:

Please see the Company's response to Item No. 19 filed with the Commission on May 16, 2003.

WITNESS: Errol K. Wagner

20

Kentucky Power Company
d/b/a
American Electric Power

REQUEST:

AEP shall designate an employee who will act as a contact for State Commissions and consumer advocates seeking data and information regarding affiliate transactions and personnel transfers. Such employee shall be responsible for providing data and information requested by a State Commission for any and all transactions between the jurisdictional operating company and its affiliates, regardless of which affiliate(s) subsidiary(ies) or associate(s) of an AEP operating company from which the information is sought. [Reference: Merger Agt., Stipulation and Settlement, Pg. 11, Item Q]

RESPONSE:

Mr. Errol K. Wagner, AEP-Kentucky Regulatory Services Director, is the contact designee for the Kentucky Public Service Commissioners and Staff and the Kentucky Attorney General's Office regarding affiliate transactions and personnel transfers.

WITNESS: Errol K. Wagner

21

Kentucky Power Company
d/b/a
American Electric Power

REQUEST:

Please provide designated employee or agent within Kentucky who will act as a contact for retail customers regarding service and reliability concerns and provide a contact for retail consumers for information, questions and assistance. Such AEP/Kentucky Power representative shall be able to deal with billing, maintenance and service reliability issues. [Merger Agt., Stipulation and Settlement, Pg. 11, Item R]

RESPONSE:

The Company would prefer customers to initially call the Customer Solution Centers, whose representatives are capable of answering questions concerning service, reliability concerns and billing issues. However, the AEP-Kentucky Regulatory Services Department, specifically the Regulatory Services Director, are also capable of dealing with billing, maintenance and service reliability issues.

WITNESS: Errol K. Wagner

22

Kentucky Power Company
d/b/a
American Electric Power

REQUEST:

AEP shall provide each signatory state a current list of employees or agents that are designated to work with each State Commission and consumer advocate concerning state regulatory matters, including, but not limited to, rate cases, consumer complaints, billing and retail competition issues. [Reference: Merger Agt., Stipulation and Settlement, Pg. 11, Item 5.]

RESPONSE:

Mr. Errol K. Wagner, AEP-Kentucky Regulatory Services Director, and the AEP-Kentucky Regulatory Services Department staff are the designated employees to work with Kentucky Public Service Commission and the Kentucky Attorney General's Office concerning state regulatory matters, including, but not limited to rate cases, consumer complaints, billing and retail competition issues.

WITNESS: Errol K. Wagner

23

Kentucky Power Company
d/b/a
American Electric Power

REQUEST:

**The Company further commits to maintain in Kentucky a sufficient management team to ensure that safe, reliable and efficient electric service is provided and to respond to the needs and inquiries of its Kentucky customers.
[Reference: Merger Agt., Attachment C, Pg. 2, Item 6a]**

RESPONSE:

Please see the Company's response to Item No. 23 filed with the Commission on May 16, 2003.

WITNESS: **Errol K. Wagner**

24

Kentucky Power Company
d/b/a
American Electric Power

REQUEST:

AEP shall contract with an independent auditor who shall conduct biennial audits for ten years after merger consummation of affiliated transactions to determine compliance with the affiliate standards outlined in the Stipulation and Settlement Agreement. The results of such audits shall be filed with the State Commissions. Prior to the initial audit, AEP will conduct an informational meeting with State Commissions regarding how its affiliates and affiliate transactions will or have changed as a result of the proposed merger. [Reference: Stipulation and Settlement Agreement, Page 11, Section 8(V)]

RESPONSE:

Please see the Company's response to Item No. 24 filed with the Commission on May 16, 2003.

WITNESS: Errol K. Wagner

STITES & HARBISON PLLC

ATTORNEYS

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Frankfort, KY 40602-0634
[502] 223-3477
[502] 223-4124 Fax
www.stites.com

Mark R. Overstreet
(502) 209-1219
(502) 223-4387 FAX
moverstreet@stites.com

August 20, 2003

HAND DELIVERED

RECEIVED

AUG 20 2003

PUBLIC SERVICE COMMISSION

Thomas M. Dorman
Executive Director
Public Service Commission of Kentucky
211 Sower Boulevard
P.O. Box 615
Frankfort, Kentucky 40602-0615

RE: ***P.S.C. Case No. 99-149*** (Merger of American Electric Power Company and Central and South West Corporation)

Dear Mr. Dorman:

Please find enclosed and accept for filing the supplementary Responses of Kentucky Power Company d/b/a American Electric Power to the Data Requests set forth in the Commission's Order dated June 14, 1999 in the above-styled action. The Responses are for the period ended June 30, 2003.

Copies of this letter and the supplementary Responses have been served this day on the persons listed below.

If you have any questions, please do not hesitate to contact me.

Sincerely yours,

STITES & HARBISON PLLC

Mark R. Overstreet

cc: David F. Boehm
Elizabeth E. Blackford
William H. Jones, Jr.

KE057:KE131:9724:1:FRANKFORT

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

RECEIVED

AUG 20 2003

PUBLIC SERVICE
COMMISSION

In the matter of:

JOINT APPLICATION OF KENTUCKY POWER COMPANY, AMERICAN ELECTRIC POWER COMPANY, INC. AND CENTRAL AND SOUTH WEST CORPORATION REGARDING A PROPOSED MERGER	) CASE NO. 99-149

****

RESPONSE OF KENTUCKY POWER COMPANY
d/b/a/
AMERICAN ELECTRIC POWER

Reporting Period: Quarter Ending June 30, 2003

Filing Date: 20 August 2003

1

Kentucky Power Company
d/b/a
American Electric Power

REQUEST:

Furnish annual financial statements of AEP, including consolidating adjustments of AEP and its subsidiaries with a brief explanation of each adjustment and all periodic reports filed with the SEC. Including but not limited to the U5S and U-13-60 reports. All subsidiaries should prepare and have available monthly and annual financial information required to compile financial statements and to comply with other reporting requirements. The financial statements for any non-consolidated subsidiaries of AEP should be furnished to the Commission. [Reference: Merger Agt., Ky. PSC Order dated 6-14-99, pg 10 (Periodic Reports)]

RESPONSE:

Please see the Company's response to Item No. 1 filed with the Commission on May 16, 2003.

WITNESS: Errol K. Wagner

2

Kentucky Power Company
d/b/a
American Electric Power

REQUEST:

On an annual basis file a general description of the nature of inter-company transactions with specific identification of major transactions and a description of the basis upon which cost allocations and transfer pricing have been established. This report should discuss the use of the cost or market standard for the sale or transfer of assets, the allocation factors used, and the procedures used to determine these factors if they are different from the procedures used in prior years. [Reference: Merger Agt., Ky. PSC Order dated 6-14-99, pg. 11, Item 1]

RESPONSE:

Please see the Company's response to Item No. 2 filed with the Commission on May 16, 2003.

WITNESS: Errol K. Wagner

3

Kentucky Power Company
d/b/a
American Electric Power

REQUEST:

On an annual basis file a report that identifies professional personnel transferred from Kentucky Power to AEP or any of the non-utility subsidiaries and describes the duties performed by each employee while employed by Kentucky Power and to be performed subsequent to transfer. [Reference: Merger Agt., Ky. PSC Order dated 6/14/99, Reporting Requirements, Pg. 11, Item 2.]

RESPONSE:

Please see the Company's response to Item No. 3 filed with the Commission on May 16, 2003.

WITNESS: Errol K. Wagner

4

Kentucky Power Company
d/b/a
American Electric Power

REQUEST:

AEP should file on a quarterly basis a report detailing Kentucky Power's proportionate share of AEP's total operating revenues, operating and maintenance expenses, and number of employees. [Reference: Merger Agt., Ky. PSC Order dated 6/14/99, Reporting Requirements, Pg. 11, Item 2]

RESPONSE:

For 2nd Quarter 2003:

Kentucky Power Company
Report Proportionate Share of AEP
(in millions, except number of employees)

	Three Months June 30, 2003				Year-to-Date June 30, 2003		
	AEP	KPCO	SHARE		AEP	KPCo	SHARE
Revenues	3,669	84	2.3%		7,749	189	2.4%
Operating/Maint. Exp.	2,754	35	1.3%		5,731	74	1.3%
Number of Employees as of 6/30/03*	20245	400	2.0%				

* See Response to Item No. 6

WITNESS: Errol K. Wagner

5

Kentucky Power Company
d/b/a
American Electric Power

REQUEST:

AEP should file any contracts or other agreements concerning the transfer of such assets or the pricing of inter-company transactions with the Commission at the time the transfer occurs. [Reference: Merger Agt., Ky. PSC Order dated 6/14/99, Reporting Requirements, Pg. 11 (Special Reports)]

RESPONSE:

2nd Quarter 2003:

During the three month period ending June 30, 2003 there were five different transactions in which AEP/Kentucky sold assets to its affiliates. The assets transferred were various meters and transformers. The total dollar value of the assets transferred was $89,179.81. The smallest dollar value transferred was 21 meters at a value of $573.13. The largest dollar value transferred was 123 meters at a value of $45,939.23.

WITNESS: Errol K. Wagner

9

Kentucky Power Company
d/b/a
American Electric Power

REQUEST:

AEP should file a quarterly report of the number of employees of AEP and each subsidiary on the basis of payroll assignment. [Reference: Merger Agt., Ky. PSC Order dated 6/14/99, Reporting Requirements, Pg. 11, Item 1 (Special Reports)]

RESPONSE:

2nd Quarter 2003:

Attached is the quarterly report of the number of employees of AEP and each subsidiary on the basis of payroll assignment for period ending June 2003.

WITNESS: Errol K. Wagner

EMPLOYEE COUNT AS OF 06/30/2003

Co	Descr	Employee Count
E01	Kingsport Power Company	55
E02	Appalachian Power Company	2418
E03	Kentucky Power Company	400
E04	Indiana Michigan Power Company	2354
E06	Wheeling Power Company	58
E07	Ohio Power Company	2197
E10	Columbus Southern Power Co	1107
E16	Houston Pipe Line Company LP	261
E36	Louisiana Intrastate Gas Co	70
E39	Lig Liquids Company L.L.C.	33
E48	River Transportation Div I&MP	348
E54	Conesville Coal Prep Co	35
E59	AEP Energy Services	4
E61	AEP Service Corporation	6379
E69	AEP Pro Serv, Inc.	1
ECC	AEP Texas Central Company	1215
EEE	CSW Energy, Inc.	61
EEL	AEP Elmwood LLC	159
EMO	AEP MEMCO	355
EPP	Public Service Co. of OK	971
ESS	SouthWestern Electric Power Co	1184
EWW	AEP Texas North Company	580
	TOTAL	20245

7

Kentucky Power Company
d/b/a
American Electric Power

REQUEST:

AEP should file an annual report containing the years of service at Kentucky Power and the salaries of professional employees transferred from Kentucky Power to AEP or its subsidiaries filed in conjunction with the annual transfer of employees report. [Reference: Merger Agt., Ky. PSC Order 6/14/99, Reporting Requirements, Pg. 12, Item 2]

RESPONSE:

Please see the Company's response to Item No. 7 filed with the Commission on May 16, 2003.

WITNESS: **Errol K. Wagner**

8

Kentucky Power Company
d/b/a
American Electric Power

REQUEST:

AEP should file an annual report of cost allocation factors in use, supplemented upon significant change. [Reference: Merger Agt., Ky. PSC Order dated 6/14/99, Reporting Requirements, Pg. 12 Item 3]

RESPONSE:

Please see the Company's response to Item No. 8 filed with the Commission on May 16, 2003.

WITNESS: Errol K. Wagner

6

Kentucky Power Company
d/b/a
American Electric Power

REQUEST:

AEP should file summaries of any cost allocation studies when conducted and the basis for the methods used to determine the cost allocation in effect. [Reference: Merger Agt., Ky. PSC Order dated 6/14/99, Reporting Requirements, Pg. 12, Item 4]

RESPONSE:

2nd Quarter 2003:

Kentucky Power Company did not perform any cost allocation studies during the quarter ended June 30, 2003. The methods used by Kentucky Power Company for cost allocation are documented in the AEP Cost Allocation Manual.

WITNESS: Errol K. Wagner

10

Kentucky Power Company
d/b/a
American Electric Power

REQUEST:

AEP should file an annual report of the methods used to update or revise the cost allocation factors in use supplemented upon significant change. [Reference: Merger Agt., Ky. PSC Order dated 6/14/99, Reporting Requirements, Pg. 12, Item 5]

RESPONSE:

Please see the Company's response to Item no. 10 filed with the Commission on May 16, 2003.

WITNESS: Errol K. Wagner

11

Kentucky Power Company
d/b/a
American Electric Power

REQUEST:

AEP should file the current Articles of Incorporation and bylaws of affiliated companies in businesses related to the electric industry or that would be doing business with AEP. [Reference: Merger Agt., Ky. PSC Order dated 6/14/99, Reporting Requirements, Pg. 12, Item 6]

RESPONSE:

Please see the Company's response to Item No. 11 filed with the Commission on December 8, 2000.

WITNESS: Errol K. Wagner

12

Kentucky Power Company
d/b/a
American Electric Power

REQUEST:

AEP should file the current Articles of Incorporation of affiliated companies involved in non-related business. [Reference: Merger Agt., Ky. PSC Order dated 6/14/99, Reporting Requirements, Pg. 12, Item 7]

RESPONSE:

See the Company's response to Item No. 11 filed with the Commission on December 8, 2000.

WITNESS: Errol K. Wagner

13

Kentucky Power Company
d/b/a
American Electric Power

REQUEST:

To the extent that the merger is subject to conditions or changes not reviewed in this case, the Joint Applicants should amend their filing to allow the Commission and all parties an opportunity to review the revisions to ensure that Kentucky Power and its customers are not adversely affected and that any additional benefits flow through the favored nations clause. [Reference: Merger Agt., Ky. PSC Order dated 6/14/99, Reporting Requirements, Pgs. 12-13]

RESPONSE:

Please see the Company's response to Item No. 13 filed with the Commission on May 16, 2003.

WITNESS: Errol K. Wagner

14

Kentucky Power Company
d/b/a
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REQUEST:

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WITNESS: Errol K. Wagner

15

Kentucky Power Company
d/b/a
American Electric Power

REQUEST:

Provide annual Service Reliability Report addressing the duration and frequency of customer disruptions (CAIDI and SAIFI), including storms for calendar 2002. [Reference: Merger Agt., Attachment C, Pg. 1 Item l]

RESPONSE:

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WITNESS: Errol K. Wagner

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d/b/a
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WITNESS: Errol K. Wagner

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Kentucky Power Company
d/b/a
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REQUEST:

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WITNESS: Errol K. Wagner

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d/b/a
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[Reference: Merger Agt., Attachment C, Pg. 1, Item 4]

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WITNESS: Errol K. Wagner

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Kentucky Power Company
d/b/a
American Electric Power

REQUEST:

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RESPONSE:

Please see the Company's response to Item No. 19 filed with the Commission on May 16, 2003.

WITNESS: Errol K. Wagner