COMMONWEALTH OF KENTUCKY

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PUBLIC SERVICE COMMISSION

BEFORE THE

PUBLIC SERVICE COMMISSION OF KENTUCKY

IN THE MATTER OF:

APPLICATION OF KENTUCKY POWER COMPANY)
FOR ADJUSTMENT OF ELECTRIC RATES) CASE NO. 2013-00197

KENTUCKY POWER COMPANY RESPONSE TO ATTORNEY GENERAL'S INITIAL SET OF DATA REQUESTS

VOLUME 2 0F 2

October 4, 2013

Kentucky Power Company

REQUEST

With regard to professional service expenses, please provide the following information:

a. In the same format and detail as required per the filing requirements, provide a breakout of professional services expenses (e.g., legal, engineering, accounting, other) included in the adjusted test year results.

b. Equivalent actual professional service expenses (by the categories identified in subpart a above) booked in each of the years 2010 through 2012.

c. For each of the expense category expenses from 2010 through the pro forma test year to be provided in response to subparts a and b above, provide the portions charged to O&M expense.

RESPONSE

a. Please see AG 1-26, Attachment 1.

b. Please see AG 1-26, Attachment 2.

c. Please see AG 1-26, Attachment 3.

WITNESS: Lila P Munsey

Total Professional Service Expenses	
Test Year 12 Months Ended March 31, 2013	
Category	**Total**
Professional Expenses General	8,825,919.86
Legal Services and Expenses	961,473.28
Trustee Fees	35,512.04
Outside Tax Services	274,102.42
Audit Fees Financial	272,199.62
Outside Engineering Services	2,054,839.83
Outside Services - Banking Fees	54,706.44
Outside Services - Software	107,193.69
Outside Services - Project Development	5.38
Grand Total	12,585,952.56

Total Professional Service Expenses			
	Year		
Category	2012	2011	2010
Professional Expenses General	9,715,311.39	7,138,964.07	5,794,221.85
Legal Services and Expenses	819,678.56	515,527.92	507,198.76
Trustee Fees	35,512.04	8,000.00	8,000.00
Outside Tax Services	275,810.91	45,662.71	70,623.92
Audit Fees Financial	262,091.19	279,444.96	3,454.53
Outside Engineering Services	1,496,509.31	345,790.30	6,189.13
Outside Services - Banking Fees	54,160.46	54,072.99	68,777.72
Outside Services - Software	100,151.67	72,975.79	35,295.68
Outside Services - Project Development		19.91	
Grand Total	12,759,225.53	8,460,458.65	6,493,761.59

Professional Service Expenses Charged to O&M Expense	
Test Year 12 Months Ended March 31, 2013	
Category	**Total**
Professional Expenses General	2,957,811.45
Legal Services and Expenses	667,887.50
Trustee Fees	35,511.85
Outside Tax Services	21,961.42
Audit Fees Financial	272,171.24
Outside Engineering Services	84,866.47
Outside Services - Banking Fees	54,706.44
Outside Services - Software	57,898.77
Outside Services - Project Development	5.38
Grand Total	4,152,820.52

Professional Service Expenses Charged to O&M Expense			
	Year		
Category	**2012**	**2011**	**2010**
Professional Expenses General	3,026,551.98	3,437,920.06	3,520,310.15
Legal Services and Expenses	519,109.47	463,954.66	503,313.85
Trustee Fees	35,511.85	8,000.00	8,000.00
Outside Tax Services	144,880.91	134,110.71	70,623.92
Audit Fees Financial	262,062.81	339,545.70	312,772.53
Outside Engineering Services	33,916.29	3,097.68	3,810.78
Outside Services - Banking Fees	54,160.46	54,072.99	68,777.72
Outside Services - Software	52,395.09	43,845.81	16,133.79
Outside Services - Project Development		19.91	
Grand Total	4,128,588.86	4,484,567.52	4,503,742.74

Kentucky Power Company

REQUEST

Using OAG Schedule 1 (Excel schedule) which is attached to these DRs, (found under the advanced tab below) provide Kentucky Power's payroll information, showing:

a. Schedule 1A and 1C - The amount and percent of payroll costs expensed and capitalized by the categories of payroll labor, benefits (if possible, payroll taxes, other payroll (if applicable), and non-regulated payroll (if applicable).

b. Schedule 1B - The amount and percent of payroll costs expensed and capitalized by primary account in total (although it is not necessary to show these payroll costs by categories of labor, benefits, other, and non-regulated).

c. Schedule 1A, 1B and 1C - Show the previous information for the periods: historic test period; change from historic test period in Case No. 2009- 0459; FYE September 30, 2012, FYE September 30, 2011 and FYE September 30, 2010.

0d. Schedule 1A, 1B and 1C - Explain the reasons for changes in the percent of payroll expensed and capitalized for each period and provide related supporting documentation and calculations.

e. Schedule 1A, 1B and 1C - Explain the reason for changes in the amount of payroll labor, benefits (for each of the benefits categories of pension/retirement, FAS 106, employee insurance ESOP, and other), payroll taxes, other payroll, and non-regulated payroll for each period, when the amount varies by 5% or more between each period and provide supporting documentation and calculations.

RESPONSE

a-e. The Company does not maintain its records in a manner that would allow it to provide the information in the format requested. Please see AG 1-27 Attachment 1, which provides for each identified period payroll costs by FERC line description and type. The attachment also provides benefit costs by type, and payroll tax costs by tax account.

The changes in payroll from 2006 through the test year ended March 31, 2013 are related to annual pay structure increases, the decrease in the number of employees, changes in salary and wage levels, except during the 2009 wage freeze, changes in incentive payouts and deferred compensation, and costs related to the 2010 severance plan.

Benefit costs are affected by salary changes, the decrease in the number of employees, and severance plans. Pension-related benefit costs are also affected by changes in the amortization of investment losses, favorable investment returns, changes in accounting requirements, declines in interest rates, and plan amendments.

Changes in payroll taxes are driven by changes in the number of employees, the amount those employees are paid, changes in state and federal tax rates, and changes in the laws affecting payroll taxes, including FICA.

WITNESS: Lila P Munsey

Response to AG 1-27

Kentucky Power Company
Case No. 2013-00197
Per Books Payroll labor, taxes and benefits by year

Line No. (1)	Description (2)	Case 2013-00197 April 2012 to March 2013 (3)	Compare Case 2013-00197 to Case 2009-00459 (4) (3)-(6)	(5) (4)/(6)	Case 2009-00459 October 2008 to September 2009 (6)	Compare Case 2013-00197 to Calendar Year 2012 (7) (3)-(9)	(8) (7)/(9)	2012 (9)	Compare Change from Calendar Year 2011 to Calendar Year 2012 (10) (9)-(12)	(11) (10)/(12)	2011 (12)	Compare Change from Calendar Year 2010 to Calendar Year 2011 (13) (12)-(15)	(14) (13)/(15)
1	**Payroll by FERC Line Description**	Per Books	Difference	%	Per Books	Difference	%	Per Books	Difference	%	Per Books	Difference	%
2	Administrative and General - Electric Maintenance	$ 636,343.67	$ (140,570.09)	-18%	$ 776,913.76	$ (49,615.59)	-7%	$ 685,959.26	$ 24,251.95	4%	$ 661,707.31	$ 8,293.22	1%
3	Administrative and General - Electric Operation	719,885.86	(378,561.33)	-34%	1,098,447.19	18,369.30	3%	701,516.56	(231,593.61)	-25%	933,110.17	(276,190.42)	-23%
4	Customer Accounts - Electric Operation	1,252,042.22	(224,914.41)	-15%	1,476,956.63	79,385.15	7%	1,172,657.07	(62,040.83)	-5%	1,234,697.90	(100,968.77)	-8%
5	Customer Service and Informational - Electric Operation	529,969.10	159,331.21	43%	370,637.89	16,361.37	3%	513,607.73	(23,420.90)	-4%	537,028.63	(8,798.58)	-2%
6	Distribution - Electric Maintenance	4,683,416.16	(1,614,314.70)	-26%	6,297,730.86	(452,294.15)	-9%	5,135,710.31	94,162.54	2%	5,041,547.77	(240,083.10)	-5%
7	Distribution - Electric Operation	2,927,408.98	832,673.17	40%	2,094,735.81	(331,416.20)	-10%	3,258,825.18	294,797.07	10%	2,964,028.11	(4,936,194.47)	-62%
8	Electric Plant - Construction	10,984,147.97	468,067.71	4%	10,516,080.26	51,151.45	0%	10,932,996.52	2,239,691.61	26%	8,693,304.91	(179,850.55)	-2%
9	Electric Plant - Plant Removal	2,356,731.74	79,203.08	3%	2,277,528.66	(58,059.38)	-2%	2,414,791.12	509,943.77	27%	1,904,847.35	104,149.95	6%
10	Other Accounts	3,754,301.57	430,189.83	13%	3,324,111.74	122,802.80	3%	3,631,498.77	301,541.75	9%	3,329,957.02	245,933.71	8%
11	Production - Electric Maintenance	4,354,512.09	251,406.08	6%	4,103,106.01	(167,818.86)	-4%	4,522,330.95	(763,288.17)	-14%	5,285,619.12	1,131,897.24	27%
12	Production - Electric Operation	3,840,927.46	(1,960,861.94)	-34%	5,801,789.40	(304,304.28)	-7%	4,145,231.74	(466,927.80)	-10%	4,612,159.54	(4,209,507.22)	-48%
13	Transmission - Electric Maintenance	737,193.01	(121,095.92)	-14%	858,288.93	13,164.91	2%	724,028.10	33,885.25	5%	690,142.85	(81,341.67)	-11%
14	Transmission - Electric Operation	294,212.42	(118,295.78)	-29%	412,508.20	(134,428.91)	-31%	428,641.33	130,608.57	44%	298,032.76	(897,099.09)	-75%
15	Grand Total Payroll (Line 15 = Line 27)	$ 37,071,092.25	$ (2,337,743.09)	-6%	$ 39,408,835.34	$ (1,196,702.39)	-3%	$38,267,794.64	$ 2,081,611.20	6%	$36,186,183.44	$ (9,439,759.74)	-21%
16	Expensed % of Grand Total Payroll ((Σ Lines 2-7, 11-14)/L15)	$ 19,975,910.97	54%		$ 23,291,114.68	59%		$21,288,508.23	56%		$22,258,074.16	62%	
17	Capitalized % of Grand Total Payroll (Line 8 / Line 15)	$ 10,984,147.97	30%		$ 10,516,080.26	27%		$10,932,996.52	29%		$ 8,693,304.91	24%	
18	Retirement % of Grand Total Payroll (Line 9 / Line 15)	$ 2,356,731.74	6%		$ 2,277,528.66	6%		$ 2,414,791.12	6%		$ 1,904,847.35	5%	
19	Other Accounts % of Grand Total Payroll (Line 10 / Line 15)	$ 3,754,301.57	10%		$ 3,324,111.74	8%		$ 3,631,498.77	10%		$ 3,329,957.02	9%	
20	**Payroll Cost by Type**												
21	Deferred Compensation	$ 8,706.42	$ (2,723.85)	-24%	$ 11,430.27	$ (2,067.67)	-19%	$ 10,774.09	$ (4,471.03)	-29%	$ 15,245.12	$ (244.21)	-2%
22	Long-Term Incentives	489,069.85	558,850.62	-801%	(69,780.77)	232,818.85	91%	256,251.00	(82,154.47)	-24%	338,405.47	146,246.84	76%
23	Other Payroll Costs	178,501.66	(15,752.77)	-8%	194,254.43	(33,456.20)	-16%	211,957.86	524,936.33	-168%	(312,978.47)	(1,493,550.89)	-127%
24	Payroll Labor	32,447,313.13	(4,221,386.21)	-12%	36,668,699.34	(1,027,871.97)	-3%	33,475,185.10	(502,106.05)	-1%	33,977,291.15	(58,386.17)	0%
25	Severance	169,563.85	169,563.85		0.00	(362,320.38)	-68%	531,884.23	582,521.71	-1150%	(50,637.48)	(7,363,554.76)	-101%
26	Short_term Incentives	3,777,937.34	1,173,705.27	45%	2,604,232.07	(3,805.02)	0%	3,781,742.36	1,562,884.71	70%	2,218,857.65	(670,270.55)	-23%
27	Grand Total Payroll (Line 27 = Line 15)	$ 37,071,092.25	$ (2,337,743.09)	-6%	$ 39,408,835.34	$ (1,196,702.39)	-3%	$38,267,794.64	$ 2,081,611.20	6%	$36,186,183.44	$ (9,439,759.74)	-21%
28	**Benefit Accounts**												
29	Workers Comp - Pre & Self Ins Prv	$ 485,977.85	$ 97,210.58	25%	$ 388,767.27	$ 401,045.01	472%	$ 84,932.84	$ (416,634.04)	-83%	$ 501,566.88	$ 330,677.56	194%
30	Fringe Ben Loading - Workers Comp	(264,927.60)	(143,991.86)	119%	(120,935.74)	(6,230.28)	2%	(258,697.32)	(83,916.10)	48%	(174,781.22)	(75,834.51)	77%
31	Pension & Group Ins Admin	23,628.77	11,616.77	97%	12,012.00	(8,230.15)	-26%	31,858.92	2,118.92	7%	29,740.00	12,742.00	75%
32	Pension Plan	3,448,185.09	1,539,085.92	81%	1,909,099.17	203,243.97	6%	3,244,941.12	350,941.08	12%	2,894,000.04	(101,603.16)	-3%
33	Group Life Ins Premiums	137,865.50	(15,398.75)	-10%	153,264.25	(3,871.32)	-3%	141,736.82	7,892.99	6%	133,843.83	(8,997.17)	-6%
34	Group Medical Ins Premiums	3,947,217.30	(852,850.98)	-18%	4,800,068.28	(42,796.65)	-1%	3,990,013.95	4,872.82	0%	3,985,141.13	(621,759.32)	-13%
35	Group LTD Insurance	12,368.98	(3,269.42)	-21%	15,638.40	(467.02)	-4%	12,836.00	(165,190.43)	-93%	178,026.43	(8,686.84)	-5%
36	Group Dental Ins Premiums	227,981.69	44,808.91	24%	183,172.78	(1,051.36)	0%	229,033.05	3,443.18	2%	225,589.87	(21,275.49)	-9%
37	Postretirement Benefits - OPEB	706,802.25	(3,009,612.48)	-81%	3,716,414.73	(735,698.79)	-51%	1,442,501.04	(944,966.98)	-40%	2,387,468.02	(959,370.01)	-29%
38	Savings Ptan Admin						-100%	58.85					
39	Savings Plan Contributions	1,474,480.57	(90,296.09)	-6%	1,564,776.66	(58,464.61)	-4%	1,532,945.18	92,754.66	6%	1,440,190.53	(88,910.79)	-6%
40	Fringe Ben Loading - Pension	(1,390,835.00)	(899,813.96)	183%	(491,021.05)	(42,216.94)	3%	(1,348,618.06)	(231,910.38)	21%	(1,116,707.68)	24,351.64	-2%
41	Fringe Ben Loading - Insurance	(2,029,017.81)	(200,332.56)	11%	(1,828,685.25)	(55,347.53)	3%	(1,973,670.28)	(139,797.21)	8%	(1,833,873.07)	25,623.90	-1%
42	Fringe Ben Loading - Savings	(625,013.28)	(42,197.69)	7%	(582,815.59)	(8,975.88)	1%	(616,037.40)	(103,321.84)	20%	(512,715.56)	6,311.62	-1%
43	Fringe Ben Loading - OPEB	(664,184.00)	184,773.43	-22%	(848,957.43)	211,580.44	-24%	(875,764.44)	(267,293.27)	44%	(608,471.17)	248,072.27	-29%
44	Postretirement Ben Medicare Subsidy	537,586.74	1,437,672.86	-160%	(900,086.12)	(14,839.26)	-3%	552,426.00	1,400,663.03	-165%	(848,237.03)	106,681.70	-11%
45	Total Payroll Benefits	$ 6,028,117.05	$ (1,942,595.32)	-24%	$ 7,970,712.37	$ (162,379.22)	-3%	$ 6,190,496.27	$ (490,284.73)	-7%	$ 6,680,781.00	$ (1,131,976.60)	-14%
46	**Payroll Tax Accounts**												
47	FICA	$ 2,614,336.23	$ (259,493.15)	-9%	$ 2,873,829.38	$ (141,613.62)	-5%	$ 2,755,949.85	$ 242,196.00	10%	$ 2,513,753.85	$ (686,383.08)	-21%
48	Fed Unemployment	34,282.18	6,637.80	24%	27,644.38	3,791.97	12%	30,490.21	(1,538.81)	-5%	32,029.02	999.55	3%
49	State Unemployment	37,530.89	(2,755.15)	-7%	40,286.04	5,270.80	16%	32,260.09	(1,074.52)	-3%	33,334.61	(13,565.41)	-29%
50	Fringe Ben Loading - FICA	(1,110,474.36)	7,780.65	-1%	(1,118,255.01)	(14,551.98)	1%	(1,095,922.38)	(142,225.55)	15%	(953,696.83)	(10,335.29)	1%
51	Fringe Ben Loading - FUT	(8,462.68)	3,332.03	-28%	(11,794.71)	(314.60)	4%	(8,148.08)	1,766.01	-18%	(9,914.09)	508.87	-5%
52	Fringe Ben Loading - SUT	(15,003.64)	(2,430.80)	19%	(12,572.84)	(393.53)	3%	(14,610.11)	1,427.14	-9%	(16,037.25)	(1,383.88)	9%
53	Total Payroll Taxes	$ 1,552,208.62	$ (246,928.63)	-14%	$ 1,799,137.25	$ (147,810.96)	-9%	$ 1,700,019.58	$ 100,550.27	6%	$ 1,599,469.31	$ (710,159.24)	-31%

Response to AG 1-27

Kentucky Power Company
Case No. 2013-00197
Per Books Payroll labor, taxes and benefits by year

Line No. (1)	Description (2)	2010 (15)	Compare Change from Calendar Year 2009 to Calendar Year 2010 (16) (15)-(18)	(17) (16)/(18)	2009 (18)	Compare Change from Calendar Year 2008 to Calendar Year 2009 (19) (18)-(21)	(20) (19)/(21)	2008 (21)	Compare Change from Calendar Year 2007 to Calendar Year 2008 (22) (21)-(24)	(23) (22)/(24)	2007 (24)		
1	**Payroll by FERC Line Description**	Per Books	Difference	%	Per Books	Difference	%	Per Books	Difference	%	Per Books		
2	Administrative and General - Electric Maintenance	$ 653,414.09	$ (162,748.39)	-20%	$ 816,162.48	$ 64,734.17	9%	$ 751,428.31	$ (130,063.50)	-15%	$ 881,491.81	O&M	
3	Administrative and General - Electric Operation	1,209,300.59	115,282.33	11%	1,094,018.26	78,069.11	8%	1,015,949.15	(51,178.58)	-5%	1,067,127.72	O&M	
4	Customer Accounts - Electric Operation	1,335,666.67	(97,394.54)	-7%	1,433,061.21	(169,172.72)	-11%	1,602,233.93	(188,164.30)	-11%	1,790,398.23	O&M	
5	Customer Service and Informational - Electric Operation	545,827.21	150,369.60	38%	395,457.61	15,822.88	4%	379,634.73	(79,138.76)	-17%	458,773.49	O&M	
6	Distribution - Electric Maintenance	5,281,630.87	(1,838,284.85)	-26%	7,119,915.72	1,940,505.24	37%	5,179,410.48	(190,863.02)	-4%	5,370,273.50	O&M	
7	Distribution - Electric Operation	7,900,222.58	6,055,055.36	328%	1,845,167.20	(845,683.09)	-31%	2,690,850.29	727,358.22	37%	1,963,492.07	O&M	
8	Electric Plant - Construction	8,873,155.46	(809,589.47)	-8%	9,682,744.93	(1,858,085.11)	-16%	11,540,830.04	1,317,571.64	13%	10,223,258.40	Capital	
9	Electric Plant - Plant Removal	1,800,697.40	(368,359.63)	-17%	2,169,057.03	(187,327.40)	-8%	2,356,384.43	154,153.16	7%	2,202,231.27	Retirement	
10	Other Accounts	3,084,023.31	(307,855.41)	-9%	3,391,878.72	(212,214.03)	-6%	3,604,092.75	288,571.63	9%	3,315,521.12	Other clearing acct	
11	Production - Electric Maintenance	4,153,721.88	194,890.08	5%	3,958,831.80	(743,141.67)	-16%	4,701,973.47	833,927.51	22%	3,868,045.96	O&M	
12	Production - Electric Operation	8,821,666.76	3,239,473.43	58%	5,582,193.33	(821,820.13)	-13%	6,404,013.46	789,686.26	14%	5,614,327.19	O&M	
13	Transmission - Electric Maintenance	771,484.52	(168,227.92)	-18%	939,712.44	(78,472.87)	-8%	1,018,185.31	(7,943.66)	-1%	1,026,128.97	O&M	
14	Transmission - Electric Operation	1,195,131.85	814,112.33	214%	381,019.52	(223,852.41)	-37%	604,871.93	(19,887.20)	-3%	624,759.13	O&M	
15	Grand Total Payroll (Line 15 = Line 27)	$45,625,943.18	$ 6,816,722.94	18%	$38,809,220.25	$ (3,040,638.04)	-7%	$41,849,858.28	$ 3,444,029.41	9%	$38,405,828.87		
16	Expensed % of Grand Total Payroll ((Σ Lines 2-7, 11-14)/L15)	$31,868,067.02	70%		$23,565,539.57	61%		$24,348,551.06	58%		$22,664,818.08		59%
17	Capitalized % of Grand Total Payroll (Line 8 / Line 15)	$ 8,873,155.46	19%		$ 9,682,744.93	25%		$11,540,830.04	28%		$10,223,258.40		27%
18	Retirement % of Grand Total Payroll (Line 9 / Line 15)	$ 1,800,697.40	4%		$ 2,169,057.03	6%		$ 2,356,384.43	6%		$ 2,202,231.27		6%
19	Other Accounts % of Grand Total Payroll (Line 10 / Line 15)	$ 3,084,023.31	7%		$ 3,391,878.72	9%		$ 3,604,092.75	9%		$ 3,315,521.12		9%
20	**Payroll Cost by Type**												
21	Deferred Compensation	$ 15,489.33	$ 1,324.56	9%	$ 14,164.77	$ 18,538.64	-424%	$ (4,373.87)	$ (4,366.50)	59247%	$ (7.37)		
22	Long-Term Incentives	192,158.63	(73,748.22)	-28%	265,906.85	480,142.73	-224%	(214,235.88)	(888,722.12)	-132%	674,486.24		
23	Other Payroll Costs	1,180,572.42	885,852.91	301%	294,719.51	103,049.28	54%	191,670.23	12,201.77	7%	179,468.47		
24	Payroll Labor	34,035,677.32	(3,595,596.21)	-10%	37,631,273.53	(4,542.98)	0%	37,635,816.51	4,081,865.82	12%	33,553,950.68		
25	Severance	7,312,917.28	7,312,917.28		0.00	0.83	-100%	(0.83)	(0.83)		0.00		
26	Short_term Incentives	2,889,128.20	2,285,972.61	379%	603,155.59	(3,637,826.54)	-86%	4,240,982.13	243,051.27	6%	3,997,930.86		
27	Grand Total Payroll (Line 27 = Line 15)	$45,625,943.18	$ 6,816,722.94	18%	$38,809,220.25	$ (3,040,638.04)	-7%	$41,849,858.28	$ 3,444,029.41	9%	$38,405,828.87		
28	**Benefit Accounts**												
29	Workers Comp - Pre & Self Ins Prv	$ 170,889.32	$ (407,219.95)	-70%	$ 578,109.27	$ 225,986.22	64%	$ 352,123.05	$ (43,106.86)	-11%	$ 395,229.91		
30	Fringe Ben Loading - Workers Comp	(98,946.71)	16,780.76	-15%	(115,727.47)	47,232.65	-29%	(162,960.12)	(39,519.08)	32%	(123,441.04)		
31	Pension & Group Ins Admin	16,998.00	4,944.00	41%	12,054.00	(1,931.00)	-14%	13,985.00	(2,791.55)	-17%	16,776.55		
32	Pension Plan	2,995,603.20	780,186.96	35%	2,215,416.24	1,225,172.27	124%	990,243.97	(23,807.94)	-2%	1,014,051.91		
33	Group Life Ins Premiums	142,841.00	(11,467.38)	-7%	154,308.38	6,949.30	5%	147,359.08	724.98	0%	146,634.10		
34	Group Medical Ins Premiums	4,606,900.45	(509,928.48)	-10%	5,116,828.93	897,979.00	21%	4,218,849.93	429,020.77	11%	3,789,829.16		
35	Group LTD Insurance	186,713.27	189,735.25	-6279%	(3,021.98)	(125,959.51)	-102%	122,937.53	(57,598.31)	-32%	180,535.84		
36	Group Dental Ins Premiums	246,865.36	73,965.86	43%	172,899.50	(97,767.50)	-36%	270,667.00	8,660.63	3%	262,006.37		
37	Postretirement Benefits - OPEB	3,346,838.03	(752,727.97)	-18%	4,099,566.00	1,518,304.03	59%	2,581,261.97	(69,568.06)	-3%	2,650,830.03		
38	Savings Plan Admin												
39	Savings Plan Contributions	1,529,101.32	(84,655.15)	-5%	1,613,756.46	86,184.48	6%	1,527,571.98	55,528.30	4%	1,472,043.69		
40	Fringe Ben Loading - Pension	(1,141,059.32)	(574,029.50)	101%	(567,029.82)	(191,157.96)	51%	(375,871.86)	(5,047.26)	1%	(370,824.60)		
41	Fringe Ben Loading - Insurance	(1,859,496.97)	(52,507.97)	3%	(1,806,989.00)	(43,556.60)	2%	(1,763,432.40)	(103,709.65)	6%	(1,659,722.75)		
42	Fringe Ben Loading - Savings	(519,027.18)	34,370.71	-6%	(553,397.89)	68,034.65	-11%	(621,432.54)	(47,468.38)	8%	(573,964.15)		
43	Fringe Ben Loading - OPEB	(856,543.44)	81,200.59	-9%	(937,744.03)	(272,315.20)	41%	(665,428.83)	11,003.91	-2%	(676,432.74)		
44	Postretirement Ben Medicare Subsidy	(954,918.73)	(87,538.09)	10%	(867,380.64)	95,465.30	-10%	(962,845.94)	(17,546.94)	2%	(945,299.00)		
45	Total Payroll Benefits	$ 7,812,757.60	$ (1,298,890.36)	-14%	$ 9,111,647.96	$ 3,438,620.12	61%	$ 5,673,027.84	$ 94,774.55	2%	$ 5,578,253.29		
46	**Payroll Tax Accounts**												
47	FICA	$ 3,200,136.93	$ 511,295.95	19%	$ 2,688,840.98	$ (351,319.86)	-12%	$ 3,040,160.84	$ 317,199.72	12%	$ 2,722,961.12		
48	Fed Unemployment	31,029.47	13,848.01	81%	17,181.46	(14,247.78)	-45%	31,429.24	731.67	2%	30,697.57		
49	State Unemployment	46,900.02	16,133.99	52%	30,766.03	1,534.33	5%	29,231.70	5,385.26	23%	23,846.44		
50	Fringe Ben Loading - FICA	(943,361.54)	114,113.72	-11%	(1,057,475.26)	128,344.29	-11%	(1,185,819.56)	(145,515.29)	14%	(1,040,304.26)		
51	Fringe Ben Loading - FUT	(10,422.96)	1,041.61	-9%	(11,464.57)	575.69	-5%	(12,040.27)	1,827.15	-13%	(13,867.42)		
52	Fringe Ben Loading - SUT	(14,653.37)	(2,410.65)	20%	(12,242.72)	(832.73)	7%	(11,410.00)	(923.05)	9%	(10,486.94)		
53	Total Payroll Taxes	$ 2,309,628.55	$ 654,022.64	40%	$ 1,655,605.91	$ (235,946.05)	-12%	$ 1,891,551.96	$ 178,705.46	10%	$ 1,712,846.50		

Kentucky Power Company

REQUEST

How much does Kentucky Power pay American Electric Power Service Corporation ("AEPSC") on an annual basis? Please provide a specific schedule of payments between January 1, 2010 and the present.

RESPONSE

Kentucky Power pays AEPSC for services provided on a monthly basis. AG 1-28 Attachment 1 details the monthly billings for services from January 1, 2010 through August 31, 2013.

WITNESS: Ranie K Wohnhas

AEPSC Billings to Kentucky Power Company

Year	Period	Total Amount Billed
2010	1	2,928,903
	2	2,634,464
	3	3,298,684
	4	2,819,429
	5	2,782,143
	6	5,892,158
	7	2,488,634
	8	2,854,249
	9	2,726,614
	10	2,813,307
	11	2,358,735
	12	3,465,818
2010 Total		37,063,139
2011	1	2,829,580
	2	2,430,530
	3	2,275,901
	4	2,736,447
	5	2,454,940
	6	2,922,180
	7	2,456,001
	8	2,688,753
	9	3,424,483
	10	2,508,675
	11	1,968,112
	12	3,199,696
2011 Total		31,895,297
2012	1	2,751,641
	2	2,155,874
	3	2,081,367
	4	2,298,090
	5	3,025,033
	6	2,850,027
	7	2,078,477
	8	2,464,976
	9	3,305,441
	10	3,193,904
	11	3,290,322
	12	5,465,401
2012 Total		34,960,554
2013	1	1,813,490
	2	2,739,676
	3	2,678,202
	4	2,591,235
	5	3,197,312
	6	2,399,513
	7	2,781,403
	8	2,993,301
2013 Total		21,194,133

Kentucky Power Company

REQUEST

Explain in detail any and all services or goods that American Electric Power Corporate Services Company provides Kentucky Power on an annual basis.

RESPONSE

AEPSC is a wholly-owned subsidiary of AEP and is the centralized service company for the AEP System. AEPSC provides services primarily to AEP's utility operating companies (utility affiliates), including Kentucky Power, under a Service Agreement between AEPSC and Kentucky Power dated June 15, 2000. AEPSC performs, at cost, various professional support services for Kentucky Power and the other affiliates. Among the services AEPSC performs for Kentucky Power and the other affiliates are management, accounting and financial reporting, tax, legal, engineering, treasury and cash management, regulatory and case management, insurance risk management, customer operations, generation, transmission, distribution, human resources, information technology, and supply chain services.

WITNESS: Ranie K. Wohnhas

Kentucky Power Company

REQUEST

Please provide the number AEPSC employees, who have provided services to Kentucky Power Company, in total and broken out by employee or service category for each month beginning January 1, 2012 through May 2013.

RESPONSE

The Company does not maintain the information in the detail necessary to provide the requested response. Please refer to AG 1-30 Attachment 1 for the total number of AEPSC employees who provided services to Kentucky Power by month during period requested, as well as a list of functions that were performed by AEPSC employees for Kentucky Power each month.

WITNESS: Ranie K. Wohnhas

AEPSC
Employees Providing Services to Kentucky Power
January 2012 - May 2013

	2012												2013				
	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Jan	Feb	Mar	Apr	May
Number of AEPSC Employees Providing Services to Kentucky Power	4,094	4,128	4,121	4,053	4,042	4,127	3,873	3,931	3,954	3,908	3,983	3,930	3,844	3,868	3,888	3,868	4,078

	2012												2013				
Services Provided During Month	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Jan	Feb	Mar	Apr	May
40 - DEV LOAD FORECAST-SHORT TERM	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X
42 - DEV GEN FUEL CONSUMP FORECST	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X
44 - EVAL/DEV DEMAND SIDE PROGS	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X
45 - EVAL/DEV SUPPLY RESOURCES/PLNS	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X
48 - EVAL/PLAN/SCH ENG DES PROJS	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X
49 - PRODUCE ENG DESIGN DOCS	X	X	X	X	X	X	X	X	X	X	X		X	X	X	X	X
50 - PROV FIELD LAB SUPPORT-NEW PLT										X				X		X	
53 - CONSTRUCT NEW GEN FACIL	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X
54 - MANAGE PROJECT-NEW PLANT	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X
55 - PROVIDE TECH SUPP-NEW PLANT	X	X		X	X		X	X	X	X	X	X	X	X	X	X	X
59 - DECOMMISSION FACILITY				X	X	X	X	X	X	X	X	X	X	X	X	X	X
83 - PERF LAB ANALYSES-COAL/WATER	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X
86 - MGE COAL OPERATIONS		X											X	X	X	X	X
89 - MGE/ADMINSTR TRNSPTN CNTRCTS	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X
90 - COORDINATE FUEL DELIVERY	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X
110 - OBTAIN/MGE PLANT LICENSES												X	X				
112 - SCHEDULE GENERATION	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X
118 - PLAN/SCH/COORD MAINT/MODS	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X
125 - PERF PRVNTVE MAINT-PLANT EQP	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X
126 - PERF CRRCTVE MAINT-PLANT EQP	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X
132 - EVAL/PLAN/SCH ENG/DESIGN PROJS	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X
133 - PROD ENG/DESGN DOCS-PLANT MODS	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X
134 - PROV TECH SUPP-PLANT MODS	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X
147 - PLAN/SUPP EMERG PREPAREDNESS						X											
154 - ENSURE SAFETY CMPLNC FOR DAMS	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X
155 - NERC Compliance Activities	X	X	X	X			X	X	X	X	X	X	X	X	X	X	X
169 - EVAL SUPP TRANS EQUIP MTL	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X
173 - ENG/DESIGN TRANS LN FACLITIES	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X
177 - CONSTRUCT TRANSN LN FACLITIES	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X
178 - Manage FMP or As Built Updates																X	X
180 - OPERATE TRANSN SYS FACILITIES	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X
181 - MGE/MONITOR/DISP TRANSN SYS	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X
190 - MAINTAIN TRANSN TOOLS	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X
191 - MAINTAIN TRANSN RIGHT-OF-WAY	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X
196 - COORD/PERF TRANSN RESTOR-STRM	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X
203 - PLAN DIST SYSTEM FACILITIES	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X
206 - EVAL/SUPP DISTN EQP/MATERIAL	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X
210 - ENG/DESIGN DISTN LN FACILITIES	X	X	X	X	X	X	X	X		X	X	X	X	X	X	X	X
214 - CONSTRUCT DIST LN FACILITIES							X					X	X	X	X	X	X
217 - OPERATE DISTN SYS FACILITIES	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X
218 - MGE/MONITOR/DISPATCH DISTN SYS	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X
219 - MANAGE JOINT FACILITY	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X
223 - TEST DISTN METERS-REG RQMTS														X			
225 - COORD/PERF UNDERGRND LOCATES	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X
228 - PERF ASSET REP NOT ASSOC W/INS	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X
230 - MAINTAIN DIST RIGHT-OF-WAY	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X
239 - Support Cust Inquiries/Reqsts	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X
248 - INSTALL/REMOVE METERS	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X
251 - READ BILLING METERS	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X
253 - MGE/SUPP CLLCTNS-ACTV DELINQS	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X
254 - MGE/SUPP CLLCTNS-INACTV DELINQ	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X
255 - MGE UNAUTHORIZED USE OF ENERGY		X							X								
256 - MGE/PART IN CUST ASST PROGS	X	X	X	X	X	X	X										
257 - PROCESS CUSTOMER PAYMENTS	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X
258 - PRINT/PACKAGE/DELIVER BILLS	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X

	2012												2013				
Services Provided During Month	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Jan	Feb	Mar	Apr	May
259 - MGE RESOLVE ACCT EXCEPTIONS	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X
260 - MGE/SUPP DISTRIBUTION BUSINESS	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X
261 - MGE/SUPP CUSTOMER SERV BUSINES	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X
263 - PERF STRATEGIC PLNG ANALYSIS	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X
264 - DEV ADM LNG RANGE BUS PLANS	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X
265 - EVALUATE M/A OPPORTUNITIES	X	X	X	X	X	X	X	X		X	X	X	X	X	X	X	
266 - EVAL DIVERSIFICATION OPPORS	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X
268 - PARTICIPATE IN PROC IMPRVMT	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X
269 - DEV/MEAS/ANALYZE ORG PERFMCE	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X
270 - PROV TECH ECONOMIC EVALUATN	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X
273 - CONDUCT RESEARCH/DEVELOPMENT	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X
280 - PREPARE RATE CASE FILINGS	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X
281 - RESP TO RATE CASE REQUESTS	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X
283 - PREPARE FUEL FILINGS	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X
286 - PREP OTH NON-RATE CASE FILNGS	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X
287 - PERF PRICING ANALYSES	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X
289 - MGE/PART IN LEGISLATVE AFFRS	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X
290 - MGE/PART IN REGULATORY AFFRS	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X
291 - RESP PSC/LEGSLTV CUST COMPLNTS	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X
292 - SUPP/PART-IND/PROF/TRADE ASSN	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X
293 - MGE/PART PUBLIC RELATIONS	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X
294 - MGE/PART COMMUNITY RELATIONS	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X
295 - MGE/PART EDUCATIONAL SVCS	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X
296 - MGE/PART VIDEO/PHOTO/DES SVCS	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X
297 - MGE/PART EMP COMMUNICATIONS	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X
302 - PERF INTERNAL AUDITS	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X
303 - PERF COORD EXTERNAL AUDITS	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X
304 - CNDCT COOE OF CONDUCT INVEST	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X
305 - Ethics&Compliance Investigatns								X			X	X		X	X		
308 - DEV/MGE/ADMINISTER STAFFING	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X
309 - DEV/MGE/ADM EEO/AA PROG/PLANS	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X
311 - DEV/MGE/ADMIN EMPLOYEE COMP	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X
312 - DEV/MGE/ADMIN BENEFIT PLANS	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X
313 - MGE DISABILITY/ABSENCE	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X
315 - DESIGN/DEV TRAINING/LEARNING	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X
316 - DELIVER TRAINING/LEARNING	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X
317 - PARTICIPATE IN TRNG/LEARNING	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X
319 - REVIEW/EVAL EMP PERFORMANCE	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X
320 - MGE/DEV/PROMOTE EMPL RELATIONS	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X
322 - DEV/MGE/ADMINSTR SAFETY PROGS	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X
323 - DEV/MGE/ADMINSTR IH PROGRAMS	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X
325 - PLAN/MGE/ADMINSTR LABOR RELNS	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X
328 - ADM/PART IN LABOR GRIEVANCES	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X
329 - PREP LNG TERM FINANCIAL PLANS	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X
333 - DEV/UPDATE/ADM ACCT POLICIES	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X
334 - MAINTN GENERAL LEDGER	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X
335 - ADM LEASES/RENTAL AGREEMTS	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X
336 - PERF FUEL ACCOUNTING	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X
338 - PROC OTH ACCTS RECEIVABLES	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X
339 - PROCESS INVOICES	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X
340 - PROC PAYRLL-EXEMPT/NON-EXEMPT	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X
341 - CDMPILE/VERIFY/ENTER TIME SHTS	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X
355 - PREP INT FIN RPTS STUDIES	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X
358 - PREP/FILE EXT/REG REPORTS	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X
360 - PERFORM OWNED ASSET ACCOUNTING	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X
363 - INTERVIEW/EVALUATE VENDORS	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X
364 - ADMIN MATL REQSTS- RFQ PROCESS	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	
365 - PREPARE/MGE BLANKET ORDERS	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X
366 - OROER MATLS/EQPMT/SUPPLIES	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X
367 - EXPEDITE ORDERS														X	X	X	X
369 - RECEIVE/INSPECT/STORE MATLS	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X
370 - ISSUE/TRANSFER SUPPLIES/TOOLS	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X
371 - DELIVER MATERIALS	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X
372 - PERF INVENTORY CONTROL	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X
373 - MGE TRANSFORMER INVENTORY	X	X	X							X							

	2012												2013				
Services Provided During Month	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Jan	Feb	Mar	Apr	May
374 - PROC/SELL SCRP/SALVG/RECYCBL	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X
376 - BID/AWARD/MGE CNTRCTS/SVC ORDS	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X
377 - INTERVW/EVAL CNTRCTRS/CNSLTNTS	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	
380 - PERF PERMT REG COMPLIANCE-WTR	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X
381 - PERF PERMT REG COMPLIANCE-AIR	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X
382 - PERF PERMT REG COMPLIANCE-WSTE	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X
386 - Provide Strategic Partner Svcs	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X
387 - Provide Change Agent Services	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X
388 - Provide Operational Services	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X
389 - Provide Employee Advocate Svcs	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X
395 - PROV IT APPLICATION SOLUTIONS	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X
404 - PLAN TELECOM SYSTEM	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X
405 - ENG/DESIGN TELECOM SYSTEMS	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X
406 - INST/REM TELECOM SYSTEM EQP	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X
407 - OPERATE TELECOM SYSTEM	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X
408 - TROUBLESHT/REPR TELECOM SYS														X	X	X	X
409 - PREVENT MAINT-TELECOM SYS/EQP	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X
412 - PURCHASE PROPERTY	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X
415 - MGE CAPITAL BLDG IMPROVMTS	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X
420 - MANAGE FOOD SERVICES	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X
421 - PROVIDE/MGE SECURITY SERVICES	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X
426 - MANAGE FOREST RESOURCES	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X
427 - PERFORM RESERVOIR MGMT	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X
428 - MGE CNSRVN/RCRTN/PRSRVTN PROGS	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X
432 - MANAGE FLEET	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X
436 - MGE PROPERTY CLAIMS								X	X	X	X	X	X	X	X	X	X
437 - MANAGE LIABILITY CLAIMS	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X
441 - PERF INFO RETRIEVAL SVCS	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X
442 - PROVIDE RECORDS DOCUMENT MGMT	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X
444 - PROV PRINTNG/REPRODTN/TYPSTTNG	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X
445 - HANDLE/DELIVER MAIL	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X
467 - PERF PREDICTIVE MAINT	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X
469 - ASSEMBLE/DEV SYS DATA/MODELS	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X
470 - ANLYZE/ASSESS INTERREG TRANSN	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X
471 - PERF TRANSN PLANNING STUDIES	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X
473 - ENG/DESIGN TRNS STA FACIL	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X
474 - CONSTRUCT TRNSN STA FACILITIES	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X
475 - ENG/DES DISTN STA FACILITIES	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X
476 - CONSTRUCT DIST STA FACILITIES	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X
477 - MAINTN CORP EXIST AEP SYS COS	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X
478 - PROV BD OF DIRECTORS SUPP	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X
479 - MGE/PROV CUST COMMUNICATIONS	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X
480 - DEV/MGE/PART IN RELOC EFFORT	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X
481 - MANAGE FINANCIAL RISK	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X
482 - MGE MTLS/SUPPLIES TRANSPTN	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X
483 - PERF ENVIRONMENTAL STEWARDSHIP	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X
521 - TRANSN LN FACLS DRWNGS-OH ONLY			X														
522 - TRANS ST FACILS DRWNGS-OH ONLY											X					X	X
525 - PROD ENG/DES DRWNGS-NEW PLT					X	X	X			X	X						
526 - PROD ENG/DES DRWNGS-PLT MODS	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X
533 - PROVIDE CAREER MGMT	X	X	X	X	X	X	X	X	X	X	X	X	X	X		X	X
534 - PROVIDE IT RESOURCES												X	X	X	X	X	X
548 - DEV/FACILITATE CHG MGT-DIVRSTY	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X
561 - PERF STA PREVENTV MAINT-TRANSN	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X
562 - PERF STA PREVENTV MAINT-DISTN	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X
563 - PERF STA CORRECTV MAINT-TRANSN	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X
564 - PERF STA CORRECTV MAINT-DISTN	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X
565 - PERF TRANSN LN PREVENTV MAINT	X	X	X	X													X
566 - PERF TRANSN LN CORRECTV MAINT	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	
609 - Perf Environmental Assessment	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X
611 - DVLP TARGTD COML/INDUS RCRUITM	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X
612 - CONDCT CMMNTY ECON DVLP EVALS	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X
617 - PLN/DVLP REG PRODUCTS/SVCS	X	X	X	X	X		X										
618 - PROMOTE REG PRODUCTS/SVCS	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X
619 - MANAGE THE MKTG PROCESS	X	X	X	X	X	X		X	X		X	X	X	X	X	X	X

	2012												2013				
Services Provided During Month	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Jan	Feb	Mar	Apr	May
621 - MANAGE CASH	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X
622 - MKT TRANS/ANCIL SVCS	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X
625 - PERF UNREG ENGY TRADNG ACTVTS	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X
626 - CONDCT UNREG BUSINESS DVLPMT	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X
628 - MANAGE INVESTMENTS	X	X	X	X													X
629 - PROVIDE ENGINEERING SVCS	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X
635 - PROC OUTAGE CLLS/COMM STATUS	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X
642 - PLAN/DEV ACCT MGMT-ASSGND CUST	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X
644 - PROV ENGY MGMT/TECH SUPP SVCS	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X
647 - PROVIDE END USER SUPPORT	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X
650 - PROV INDIVIDL SHAREHLDER SUPP	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X
651 - PROVIDE INSTITUTIONAL SUPPORT	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X
653 - PLAN/MGE EMP CAREER DEVELOPMT	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X
656 - COORD TAX COMPLIANCE	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X
657 - COORD TAX ACCTNG/REG SUPP	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X
658 - COORDINATE TAX PLNG/ANALYSIS	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X
661 - MGE/PARTICIPATE CORP FINANCING	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X
662 - MGE TRUST/INVESTMENTS	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X
664 - DEV/MGE/ADMINSTR SRV AGREEMTS													X	X			
666 - PERF SPILL CLEANUP/REMEDIATION	X	X	X	X	X		X										
668 - PROVIDE IT PLANNING	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X
670 - PROV ENHANCEMNTS/MODIFICATNS	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X
672 - PROVIDE IT TECHNICAL SUPPORT	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X
673 - PROV PAY/GEN BLDGS FIXED COSTS	X		X		X					X	X		X				
675 - PROV TRAVEL AND EVENT PLANNING	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X
676 - DEV/MONITR/ANLYZE BDGTS	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X
678 - DEV/MGE WORKFORCE CAPABILITY	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X
679 - DES/DEV/INTRO NEW SYS/APPLCTNS	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X
680 - PROVIDE IT ENGR/DESIGN SVCS	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X
681 - DEV/DEPLOY IT INFRASTRUCTURE	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X
682 - OPERATE IT	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X
683 - PERF IT PREVNTV MAINTENANCE	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X
687 - MGE/ADMNSTR FUEL/OTH REL PRCMT	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X
689 - TROUBLESHOOT/REPAIR IT SYS	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X
690 - SECURE DISTN R/W AND PERMITS		X				X	X	X	X	X	X	X	X	X	X	X	X
691 - SECURE TRANSN R/W AND PERMITS	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X
693 - OPER GAS PROCESSUNG PLANTS	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X
695 - MAINTN GAS PROCESSING PLANTS	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X
698 - PERF REG ENGY TRADNG ACTVITIES	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X
699 - PERF COAL TRADING ACTIVITIES	X	X	X	X	X	X											
700 - CONDUCT REG BUS DEVELOPMENT											X						
704 - REPAIR AND MAINTAIN BUILDINGS	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X
707 - PROVIDE TENANT SERVICES	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X
709 - Design and Manage Forms	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X
710 - Prov Office/Audio Visual Equip	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X
711 - Prov Office/Station Supplies	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X
712 - Manage Short Term Funding	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X
717 - Provide Continuity Planning	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X
718 - Mge/Part Env Pub Policy Issues	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X
719 - Mge/Part Public Policy Issues	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X
720 - Manage Operational Risk	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X
721 - Manage Demand Side Progs-Plans	X	X	X	X	X	X											
722 - Analyze Customer Choice Info	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X
801 - Provide Fuel Handling	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X
811 - Provide Fuel/Air Feed		X			X	X	X	X	X	X	X	X	X	X			X
812 - Provide Steam	X	X	X	X	X	X		X	X	X	X	X	X	X			X
821 - Prov Steam/H2O to Electric Con	X									X	X	X	X				X
822 - Provide Heat Rejection						X	X	X	X	X	X	X	X	X			X
823 - Provide Boiler H2O Feed		X	X	X	X	X	X	X	X	X	X	X	X	X			X
824 - Prov Aux/Emergency Power	X	X	X	X	X	X	X	X	X	X	X	X	X				
825 - Provide Compressed Air														X			
841 - Provide Fossil Plant Services	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X
953 - Dept Overheads																	X
974 - G/L JOURNAL EXP-IDENT USERS																X	X

Kentucky Power Company

REQUEST

Provide a copy of an example of a current residential bill based on the average residential usage, as well as on the following usage levels: 900 kWh, 1000 kWh, 1100 kWh, 1200 kWh, 1300 kWh, and 1400 kWh. The example should include any and all charges, whether customer charge, DSM, riders, trackers, taxes, etc. The bill should be indicative of the total amount charged to the customer for that billing cycle.

RESPONSE

Please see AG 1-31 Attachment 1.

WITNESS: Lila P Munsey

Residential Bill Charges	Rate	900 kWh	1000 kWh	1100 kWh	1200 kWh	1300 kWh	1374 kWh	1400 kWh
Service Charge ($/customer)	$8.00	$ 8.00	$ 8.00	$ 8.00	$ 8.00	$ 8.00	$ 8.00	$ 8.00
Energy Usage ($/kWh)	$0.0859	$ 77.31	$ 85.90	$ 94.49	$ 103.08	$ 111.67	$ 118.03	$ 120.26
Combined FAC & SS ($/kWh)	($0.0000361)	$ (0.03)	$ (0.04)	$ (0.04)	$ (0.04)	$ (0.05)	$ (0.05)	$ (0.05)
Capacity Charge ($/kWh)	$0.00097	$ 0.87	$ 0.97	$ 1.07	$ 1.16	$ 1.26	$ 1.33	$ 1.36
Demand-side Management ($/kWh)	$0.000826	$ 0.74	$ -	$ -	$ -	$ -	$ -	$ -
Home Energy Assistance Program ($/customer)		$ 0.15	$ 0.15	$ 0.15	$ 0.15	$ 0.15	$ 0.15	$ 0.15
		$ 87.04	$ 94.98	$ 103.67	$ 112.35	$ 121.03	$ 127.46	$ 129.72
Environmental Surchage (%)	-2.3607%	$ (2.05)	$ (2.24)	$ (2.45)	$ (2.65)	$ (2.86)	$ (3.01)	$ (3.06)
Total Monthly Bill		**$ 84.99**	**$ 92.74**	**$ 101.22**	**$ 109.70**	**$ 118.17**	**$ 124.45**	**$ 126.66**

* Monthly billilling amounts presented in table are exclusive of any school tax or franchise fees.
**Average Residential Usage for Test Year Ended March 31, 2013

KPSC Case No. 2013-00197
AG's First Set of Data Requests
Dated September 4, 2013
Item No. 31
Attachment 1
Page 1 of 1

Kentucky Power Company

REQUEST

Please provide copies of all Board of Director's minutes and internal management meeting minutes between January 1, 2010 and the present, inclusive, in which the subject of Kentucky Power Company's rates and specifically this rate application was discussed.

RESPONSE

The Company objects to this request to the extent the term "internal management meeting minutes" is ambiguous and overly broad. Without waiving this objection, the Company states as follows:

The Company's Board of Director's minutes between January 1, 2010 and the present do not discuss the subject of Kentucky Power Company's rates, nor specifically this rate application. There are no non-privileged internal management meeting minutes between January 1, 2010 and the present in which the subject of Kentucky Power Company's rates and specifically this rate application was discussed.

WITNESS: Gregory G Pauley

Kentucky Power Company

REQUEST

Please provide a list of any incentive compensation plans or programs, bonus plans or programs or other incentive award programs in effect at Kentucky Power Company for each year beginning January 1, 2010 through the present. For each program referenced above, which has been in effect during the period listed above, please provide a complete copy of the plan or program materials including but not limited to the following information:

a. The various goals on which incentive payments were to be determined and the actual achievement attained with specificity (the response should show the actual metrics and not only a reference that the goal was at target, not at target, at maximum, etc.) each calendar year 2010 through 2013, and including the test year;

b. The total Company amount of incentive compensation capitalized and the amount expensed for each calendar year 2010 through 2013, and including the test year;

c. The number of employees eligible under the plan for incentive compensation payment and the number of eligible employees that did not receive incentive compensation payment each calendar year 2010 through 2013, and including the test year; and

d. Any studies Kentucky Power Company has justifying or otherwise comparing its incentive/bonus program(s) to those allowed in other jurisdictions.

RESPONSE

The incentive compensation plans and programs in place at Kentucky Power Company from the period January 1, 2010 to present are listed below. Plan documents or program descriptions and the performance goals associated with each plan are provided, by year, in AG 1-33 Attachment 1. This response is being provided on the enclosed CD due to its voluminous nature.

2010 Incentive Compensation Plans and Programs

- **2010 AEP Annual Incentive Plan**

2011 Incentive Compensation Plans and Programs

- **2011 Annual Incentive Plan for Executive Council and Staff**
- **2011 Annual Incentive Compensation Plan for Generation**
- **2011 Annual Incentive Compensation Plan for Transmission**
- **2011 Annual Incentive Compensation Plan for AEP Utilities**

2012 Incentive Compensation Plans and Programs

- **2012 Annual Incentive Plan for Executive Council and Staff**
- **2012 Annual Incentive Compensation Plan for Generation**
- **2012 Annual Incentive Compensation Plan for Transmission**
- **2012 Annual Incentive Compensation Plan for AEP Utilities**

2013 Incentive Compensation Plans and Programs

- **2013 Annual Incentive Plan for Executive Council and Staff**
- **2013 Annual Incentive Compensation Plan for Generation**
- **2013 Annual Incentive Compensation Plan for Transmission**
- **2013 Annual Incentive Compensation Plan for AEP Utilities**

Incentive Compensation Plans and Programs Covering Multiple Years

- **AEP Long-Term Incentive Plan**
- **Annual Merit Based Salary Increase Program**

a. The actual performance and score achieved on each goal are combined within each plan and are not available in a separable form.

b. Incentive plan expense is aggregated and is not tracked by incentive plan. Therefore, the total Company amount of incentive compensation capitalized and the amount expensed is not available by incentive plan for any period.

c. Employee incentive compensation eligibility is aggregated and is, therefore, not available by incentive plan. In aggregate for 2012, there were 18,353 eligible annual incentive plan participants across the AEP system and 60 (0.33%) did not receive an award.

d. Please refer to the direct testimony of Mr. Carlin pp. 5-6, lines 21-10; pp. 16-17, lines 21-3; EXHIBIT ARC 2, 3 AND 4; pp. 17-18, lines 17-10; EXHIBIT ARC 5; and EXHIBIT ARC 8.

WITNESS: Andrew R Carlin

Kentucky Power Company

REQUEST

Internal Audits. Provide a list of internal audits completed, scheduled, or in progress at the Company for the years 2009-2013. For each, list the subject of the audit, date of audit, date of report, and title of report. Provide a copy of each of the completed studies for review on-site.

RESPONSE

Please see AG 1-34 Attachment 1.

WITNESS: Ranie K Wohnhas

Audit Name	Audit Date	Report Date	Report Title
Meter Inventory and Testing Controls Review	Jul-13	N/A	N/A - Audit in progress
Line Contractor Inspection Controls	Apr-13	8/14/2013	Distribution Line Contractor Inspection Controls Review
Contract Audit of Davis H. Elliot, Inc.	Jul-13	7/26/2013	Contract Audit of Davis H. Elliot, Inc.
Contract Audit of Pike Electric, Inc.	Apr-13	4/23/2013	Contract Audit of Pike Electric, Inc.
Storm Restoration Processes	Jan-13	4/19/2013	Review of Controls over Storm Restoration Costs
Coal Pile Inventories 2012	Apr-12	1/23/2013	2012 Coal Pile Inventories Audit Report
Coal Inventories 2011	Apr-11	1/23/2013	Report of Audit 2011 Coal Pile Inventories
Vegetation Management Inspection Process	Sep-11	1/30/2012	Vegetation Management Process Survey - Summary Memorandum
Kentucky Power Service Delivery Internal Controls Review	Dec-11	12/20/2011	Kentucky Power Service Delivery Internal Controls Review
Ashland Service Center 2011 Env. Health & Safety	January - March 2011	4/11/2011	Ashland Service Center 2011 Env. Health & Safety
APCo Generation Stores	Dec-10	3/30/2011	APCo Generation Stores
Hazard Service Center 2011 Safety & Health	January - March 2011	3/29/2011	Hazard Service Center 2011 Safety & Health Final Report
Coal Inventories 2010	Oct-10	2/3/2011	Report of Audit 2010 Coal Pile Inventories
Davis H Elliot Contract Compliance	Dec-10	12/16/2010	Davis H. Elliot Company – Contract Compliance Review
Pike Electric Contract Compliance	Sep-10	9/24/2010	Pike Electric Corporation – Contract Compliance Review
Pikeville Service Center ESH Audit	July - Sept. 2010	9/17/2010	Pikeville Service Center ESH Audit Report 2010
Coal Inventories, Consumption, & Receiving 2009	May-09	1/29/2010	Report of Audit 2009 Coal Pile Inventories
Big Sandy Plant 2009 Environmental Audit	July - Sept. 2009	10/7/2009	Big Sandy Plant 2009 Environmental Audit Report
Kuhlman Electric Contract Compliance	Jul-09	7/22/2009	Kuhlman Electric Corporation – Contract Compliance Review
Big Sandy 2009 Crane Follow-up	Mar-09	4/28/2009	Big Sandy 2009 Crane Follow-up
Trinity Coal Contract Delivery Shortfalls	Feb-09	2/26/2009	Trinity Coal Contract Delivery Shortfalls

AMERICAN ELECTRIC POWER

AUDIT SERVICES DEPARTMENT

Trinity Coal Contract Delivery Shortfalls

Report Issue Date: 02/26/09

Distribution: J. D. Henry
J. C. Dial

Project Number: GE00709

CC: M. G. Morris
N. K. Akins
T. K. Light
R. A. Mueller
R. D. Burnham

Trinity Coal Contract Delivery Shortfalls

Audit Services Department

REVIEW SUMMARY

WHY AUDIT SERVICES PERFORMED THIS REVIEW:

Kentucky Power Company entered into the coal purchase and sale agreements 03-30-07-900 and 03-30-07-905 on February 27, 2007 and November 6, 2007, respectively, with Trinity Coal Marketing, LLC (Trinity) for delivery of coal to the Big Sandy Plant. The approved source mines stated in the agreements are Falcon Resources Mine, Prater Branch Mine, Levisa Fork Mine, Bear Fork Mine, and Little Elk Mine. However, Little Elk does not use an AEP approved delivery point, and Bear Fork closed in 2007, so it no longer serves as a viable source. Delivery of the coal to Big Sandy is via railroad transportation (CSX). Terms for each of the contracts are as follows:

Agreement	2008 Obligation (Tons)	2008 Price (Railcar)	Term of Contract
03-30-07-900	240,000	$46.45	January 1, 2007 – December 31, 2010
03-30-07-905	120,000	$47.00	January 1, 2008 – December 31, 2012

The total coal burn at Big Sandy in 2008 was approximately 2.6 million tons; therefore, AEP relies on Trinity to provide approximately 14% of the total annual supply needs for Big Sandy.

Delivery shortages began in January 2008 and continued throughout the year. See chart below for the 2008 Big Sandy shortages relative to the two agreements:

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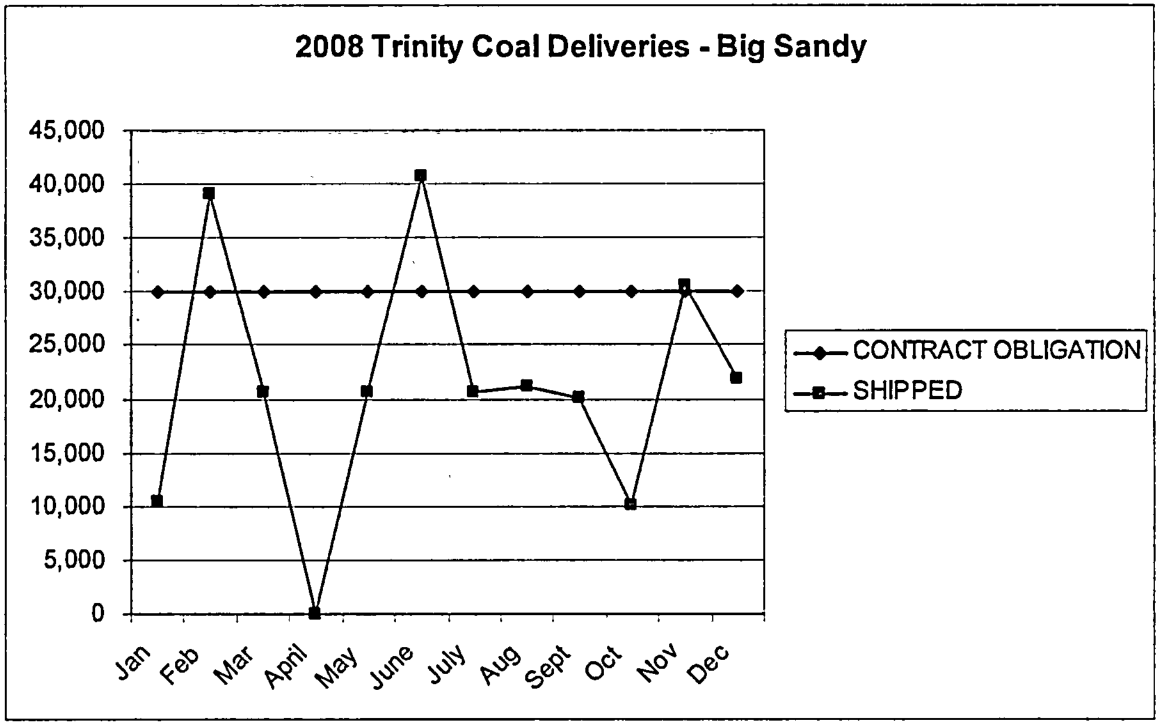
Trinity Coal Contract Delivery Shortfalls

Audit Services Department



Note: Approximately 30,000 tons was delayed at AEP's request during the first part of 2008 due to issues at Big Sandy.

Trinity has not claimed force majeure with regard to any of the monthly shortages for 2008; therefore, contractually, Trinity is responsible for either replacing the coal or reimbursing AEP for the additional cost incurred for obtaining the coal from another supplier. Due to the 2008 Trinity shortages, additional coal tons were purchased in the market, resulting in additional costs estimated to be approximately $5.3 million.

THE OBJECTIVES OF THIS REVIEW WERE:

The objectives of this audit were to:

- Determine the cause of the delivery shortages.
- Determine if AEP was treated comparable to other Trinity customers. That is, shortages were distributed evenly among customers.
- Determine if Trinity sold production into the market to capitalize on higher market prices.

THE SCOPE OF OUR REVIEW WAS AS FOLLOWS:

The following areas were reviewed to accomplish the objective stated above:

- 2007 actual tons produced were compared to the 2008 actual tons produced in order to determine whether production in 2008 was lower than historical production.
- The 2008 production plan was compared to the 2008 actual tons produced in order to determine whether the decrease in production was expected, and to the 2008 obligation in order to determine if Trinity oversold its planned production.
- The customer obligation, coal received, and pricing was reviewed in order to determine whether AEP was treated ratably among other customers who receive their coal from the Marnie and Banner delivery points.
- Coal agreements were reviewed in order to determine whether any new contracts were entered into during 2008, when the shortages began.
- For the months that Big Sandy did not receive any coal, the schedule was reviewed in order to determine if the rail transportation was scheduled timely.

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CONCLUSION

Audit Services verified that delivery shortages were caused by lower production in 2008 as compared to the 2008 plan attributable to mountaintop mining restrictions that lowered production under existing permits and also impacted the ability to obtain additional permits. Based on the 2007 actual tons produced and the mountaintop mining issue, it appears that Trinity's 2008 production plan may have been aggressive and assumed the mountaintop mining restrictions would be resolved. See table below for Trinity's production data for AEP approved mines and delivery points:

Mine	2007 Tons Produced	2008 Planned Tons	2008 Tons Produced	Decrease in Production vs Plan
Levisa Fork	944,980	1,510,000	1,013,423	496,577
Prater Branch	1,229,355	2,041,000	1,692,021	348,979
Bear Fork	132,526	0	0	0
Falcon Resources	1,101,118	1,003,700	540,078	463,622
Totals:	3,407,979	4,554,700	3,245,522	1,309,178

Additionally, the production shortages were distributed equitably among Trinity's customers, covering fourteen separate agreements. Specifically, Trinity delivered 77.3% of its contract obligations on average. AEP received 77.4% of its obligation under agreement 03-30-07-900 and 59.6% under agreement 03-30-07-905. However, for agreement 905, the delivery of approximately 30,000 tons was delayed at AEP's request due to operational issues at Big Sandy. If this coal had been delivered, AEP would have received approximately 84% of its coal under this agreement.

Further, Audit Services found no clear evidence of price majeure related to the shortages. For the customers who received more than a ratable percentage of their obligation, the price per ton ranged between $49 and $51, which is approximately $4 more per ton than AEP's prices.

Appendix 1

Classification of Audit Report Conclusions

Operational/Financial (Internal Controls Reviews):

Conclusion	Definition
[illegible]	Controls are appropriately designed and are operating effectively to manage risks. Control issues may exist, but are minor.
[illegible]	Medium-level control issues (either design or operating effectiveness) are present but do not compromise achievement of important control objectives.
Improvements in controls needed	High-level or medium-level control weaknesses are present that compromise achievement of one or more important control objectives but do not prevent the process or function from achieving its overall purpose. While important weaknesses exist, their impact on the management of risks is limited rather than widespread.
Major improvements in control needed	High-level control weaknesses exist across numerous control objectives that potentially prevent the process or function from achieving its overall purpose. The impact of weaknesses on management of risks is widespread rather than isolated either due to the number or nature of control weaknesses.

Classification of Audit Findings

Financial Audits:

Risk Significance	Risk Definition
High	Likelihood of the condition occurring must be more than remote **and** potential impact must be significant in relationship to the underlying financial information, overall objectives, or level of compliance of the function or process audited.
Medium	Likelihood of the condition occurring must be more than remote **or** potential impact must be significant in relationship to the underlying financial information, overall objectives, or level of compliance of the function or process audited.
[illegible]	Enhancement to a current process that would add value, but not necessarily have a significant impact to the company from a financial, compliance, effectiveness, or efficiency standpoint. Would entail process improvement or have a relatively small monetary impact.

BIG SANDY VERIFICATION ASSESSMENT

Completed March 23 – 25, 2009
By Jeffrey Armstrong, Audit Consultant

A site visit was made on March 23 – 25, 2009 to conduct a verification assessment of the Crane/Hoist program at the Big Sandy plant in Louisa, Kentucky. The purpose of the assessment was to confirm the implementation and effectiveness of the corrective action plans in response to the 2007 Safety and Health Audit. The assessment focused on the correction of the deficiencies noted in the audit report specified to the regulatory requirements regarding cranes and hoists; and the overall improvement of the crane and hoist compliance program. The corrective action assessment was conducted by reviewing required documentation such as:

- Preventative Maintenance Program
- Required Monthly Wire Rope Inspection (for cranes in regular use)
- Pre-use and Wire Rope Inspection (for cranes not in regular use – idle for greater than 30 days)
- Clearance Permit tags for cranes not meeting regulatory requirements
- Annual Inspection Reports generated by 3rd party inspection services
- Load testing data sheets for new and/or altered cranes
- Repair and Maintenance Records

Also, as part of the assessment, cranes/hoists at the facility were visually inspected and observations made regarding performance of the monthly wire rope inspections and preventative maintenance inspections.

At the conclusion of the site visit, a meeting was conducted with the Plant Manager and Maintenance Supervisor II to summarize the assessment and provide feedback as to the effectiveness of the implemented corrective actions, and the state of the crane/hoist compliance program. It is evident from the assessment that the crane/hoist compliance program has immensely improved as a result of the implementation of the corrective action plans. As a result of the corrective action plan implementation, overall conformance to the applicable standards has been achieved and is on-going. The level of documentation and tracking of Preventive Maintenance, inspections, repairs, frequency of use provides the Big Sandy plant with an increased level of evidence to confirm conformance with the standards.

Below is a summary of the improvements that have been noted.

1. Preventive Maintenance Program

Upon review of the 2008 and 2009 maintenance work orders regarding cranes and hoists, it is evident that a Preventive Maintenance program has been developed for the lifting units at the Big Sandy Plant. Inspection frequency has been established for the units based upon input from the 3rd party Crane contractor, and each crane has a PM file established in the site maintenance computer system which generates work orders based upon an established schedule.

A review of the maintenance work orders indicates maintenance employees are completing the specified PM's as directed on the work orders and documenting any deficiencies noted. Any unit with a deficiency that cannot be readily corrected is tagged out of service. There were four (4) units which had been documented to have been tagged out of service during a PM inspection. A visual confirmation of the tags was completed; and, noted that all four (4) units were, in fact, properly tagged.

2. Inventory of Cranes in Regular Use

A listing of the cranes considered to be in Regular Use has been developed. In an effort to control cost, the site has implemented the policy that the cranes considered to be in regular use, are those that must be maintained in an operation condition in order to ensure business continuity. Any issues noted with a crane in this category are promptly addressed and corrected.

Those cranes considered 'not in regular use' will be inspected and maintained; however, any deficiencies noted will result in the crane being removed from service until it is necessary to have the crane operational. The majority of these cranes are those that are used during outages or in the event of an equipment failure that would require crane use of the crane to remove and replace the failed equipment, and where there is no other means for completing the task.

By delineating the units necessary for operation, the plant is able to limit the cost of inspection, maintenance and repair of cranes; and, reduce the burden of ensuring complete and proper documentation is being maintained.

3. Monthly Wire Rope and Hook Inspection (documented/certified)

As previously stated in item number 2, the plant has identified the cranes considered to be in regular use; and therefore, required by the regulatory standard to have a monthly wire rope and hook inspection which is documented and certified. The inspections are being completed and documented as required. A work order is automatically generated monthly to ensure the inspection is completed.

At the time of the assessment, the monthly wire rope/hook inspections were being completed. The two maintenance employees tasked with completion of the inspections were observed. Interviews with these employees confirmed they had been trained in how to perform the inspections, and what types of deficiencies to look for during the inspection. During the observed inspections, there were two units that were noted to have damage to the wire ropes. The units were immediately tagged out of service, and the deficiencies were noted on the inspection work order form to ensure repairs are made prior to the unit being used.

4. Annual Inspection Documentation and Load Testing

During the initial audit in 2007 and 2008, there were noted issues and inconsistencies in the annual inspections completed by the 3rd party crane contractor. A new corporate preferred crane vendor is now being utilized to complete the annual inspections. The facility has also increased the oversight of the crane inspectors during the annual inspection process by meeting with the vendors each day prior to the beginning of the inspection and at the end of each day of the inspection to review the daily activities and any issues noted.

During the annual inspection completed in 2007, there were several cranes/hoists which had been installed but never load tested as required. All cranes identified as needing to be load tested have been tested in accordance with regulatory requirements. Load test certificates are maintained on-site and were reviewed during this assessment.

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AUDIT SERVICES DEPARTMENT

Kuhlman Electric Corporation – Contract Compliance Review

Report Issue Date: July 22, 2009

Project Number: AU03509

Distribution: Judson Schumacher
Tim Hostetler

cc: Mike Morris
Carl English
Susan Tomasky
Michael Heyeck
Rich Munczinski
John Harper
Wade Smith
Bernie M Pasternack
Dennis Warden
Daniel R Boezio
Russ Steward
Alice Bonning
Rich Mueller

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Kuhlman Electric Corporation - Contract Compliance Review – FINAL REPORT

Audit Services Department

REVIEW SUMMARY

- ***BACKGROUND:***

  Kuhlman provides medium power and instrument transformers primarily for AEP's Transmission organization. The following agreements and amendments constituted the basis for the review:

  - Contract # 8685610000X103, effective September 1, 2005
  - Contract # 8685610000X103 amendment 1, effective January 1, 2008
  - Contract # 8685610000X103 amendment 2, effective July 7, 2008
  - Contract # 0947710000X103, effective March 17, 2008
  - Monthly price adjustment letters from December 1, 2005 - November 30, 2008

  During the period December 2005 through November 2008, AEP paid approximately $41 million to Kuhlman under the above agreements. The review was conducted by Revenew International, LLC (Revenew) on behalf of AEP.

- ***THE OBJECTIVES OF THIS REVIEW WERE TO DETERMINE IF:***

  - Controls were in place to ensure the contract terms were applied appropriately; and that
  - Contract payments were accurate.

- ***THE SCOPE OF OUR REVIEW WAS AS FOLLOWS:***

  We reviewed the following scope areas in relation to the objectives noted above:

  - A sample of 60 Kuhlman invoices, totaling approximately $9.6 million which were issued during the period December 2005 through November 2008.

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Kuhlman Electric Corporation - Contract Compliance Review – FINAL REPORT

Audit Services Department

REVIEW SCORECARD

This scorecard summarizes our conclusions for each scope area covered in the review. The issues that relate to each scope area are referenced to the Audit Issues report section below. In summary, we achieved monetary recoveries of $433,734 on expenditures of approximately $41 million during the scope period. The overbillings were primarily related periodic price adjustments that were not performed in accordance with the terms of the agreements.

In our recent internal audit of "Controls over Supply Chain Procurement, Pricing, and Supplier Management Processes", control deficiencies were identified related to the above scope area "Controls were in place to ensure the contract terms were applied appropriately". Supply Chain Management is in the process of addressing the control deficiencies with respect to this scope area, and it is not included in the below scorecard.

SCOPE AREA	Issue(s) Present	CONCLUSION CLASSIFICATION
Contract payments were accurate	(1), (2), (3), (4)	Payments accurate with minor adjustments
OVERALL CONCLUSION FOR REVIEW		Payments accurate with minor adjustments

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ISSUES

This section of the report discusses the issues requiring action by management. The significance of each issue has been assessed per the 'AUDIT ISSUES' classification criteria in Appendix 1 at the end of this report. Low-risk issues are not included in this Audit Report, but have been communicated to management in a separate "Low-risk Issues" document. For each issue below, the responsible parties have agreed to implement or facilitate implementation of the resolution by the target date noted.

---

(1) Incorrect Application of Periodic Price Adjustments

- ***Comment*** - The contracts stipulate that AEP and Kuhlman shall discuss necessary price adjustments if Kuhlman's cost for core steel, copper, oil, or load tab changers increases or decreases by two percent or more on each transformer purchase. AEP's expectation was to keep Kuhlman whole on changes in material costs, not to increase or decrease Kuhlman's profit as a result of the price adjustments. During the scope period, Kuhlman applied these price adjustments to the total price of the transformers versus the **material cost only**. By applying the price adjustment to the total price, Kuhlman also escalated their profit. This practice was applied to all transformers in the sample and resulted in **extrapolated** net overbillings of approximately $1.4 million throughout the scope period.

  In addition, in late 2007 AEP agreed to pay Kuhlman a 20% premium for deliveries in excess of 24 units due to shortness in the market and Kuhlman not being able to participate in the spot market by fulfilling AEP's increased forecast. For these units, Kuhlman not only passed though the premium but also applied the price adjustments outlined above to the final price of the transformers. This resulted in overbillings of approximately $54,500.

- ***Risk*** – AEP may overpay for materials due to billings that are not in accordance with the contract or supporting documentation.

- ***Resolution*** –AEP Procurement and Transmission management personnel and Kuhlman settled the above issue for $400,000. Kuhlman agreed to issue credits to AEP to cover the settlement. AEP Procurement management will ensure that all credits are received from Kuhlman.

  An internal review was recently performed by AEP Audit Services which addresses control gaps that allowed these overbillings to occur. Going forward, Kuhlman has agreed to provide additional training to ensure that the periodic price adjustments are only applied to metal and oil component cost increases or decreases.

Significance: High
Target Date: September 30, 2009
Responsible Party: Judson Schumacher

(2) Slot and Volume Discounts Not Provided

- *Comment* – Five of the 60 invoices within the sample did not contain "slot" or volume discounts that were available under the terms of the contracts.

  Three purchases occurred where either the original purchase order requested delivery dates or Kuhlman's acknowledgement letter requested delivery dates were within the July through October "slot" period, qualifying the purchases for a two percent discount. Because Kuhlman actually shipped these orders before July they did not apply the discount. Also, a fourth purchase was found to be delivered within the slot period (although the purchase order requested date and the Kuhlman acknowledgement letter requested dates were not within the "slot" period) and the discount was not applied.

  Additionally, one purchase occurred where the order was for a transformer design that had shipped three times previously and the one percent volume / multiple order discount was not applied by Kuhlman.

  Based upon available documentation, the above errors resulted in extrapolated net overbillings of $101,150 throughout the scope period. During settlement meetings, both parties acknowledged that original agreed upon delivery dates are frequently adjusted.

- *Risk* – AEP may overpay for materials due to billings that are not in accordance with the contract or supporting documentation.

- *Resolution* –AEP Procurement and Transmission management personnel and Kuhlman agreed to settle the above issue for $3,136. Kuhlman will issue AEP a check in the amount of $33,734 to settle this issue along with issues three and four. AEP Procurement management will ensure that the check is received from Kuhlman by August 31, 2009.

  An internal review of the Procurement function was recently performed by AEP Audit Services which addresses control gaps that allowed the lost discounts to occur. Going forward, both parties will maintain adequate documentation regarding adjustments to the original requested delivery dates. Any changes to the delivery dates will be captured in purchase order change orders within Indus PassPort so that available "slot" discounts can be monitored.

Significance:	**Medium**
Target Date:	**August 31, 2009**
Responsible Party:	**Judson Schumacher**

(3) Charges for Load Tap Changers (LTC's)

- *Comment* – Three of the 60 invoices within the sample were noted where the sale price of the transformers was escalated based on changes in the cost of LTC's; however, LTC's are not components on these transformer models that were purchased. This resulted in actual overbillings of $17,730 on all M26, M35 and S30 transformers that were purchased throughout the scope period.

- *Risk* – AEP may overpay for materials due to billings that are not in accordance with the contract or supporting documentation.

- *Resolution* – AEP Procurement and Transmission management personnel and Kuhlman agreed to settle the above issue for $17,730. Kuhlman will issue AEP a check in the amount of $33,734 to settle this issue along with issues three and four. AEP Procurement management will ensure that the check is received from Kuhlman by August 31, 2009.

  An internal review of the Procurement function was recently performed by AEP Audit Services which addresses control gaps that allowed these overbillings to occur.

Significance:	**Medium**
Target Date:	**August 31, 2009**
Responsible Party:	**Judson Schumacher**

(4) Periodic Price Escalations Applied to Software and Grounding Revision Adders

- *Comment* – On nine of the 60 invoices within the sample, Kuhlman included either software and/or grounding revision adders in the total price of the transformers before applying periodic price adjustments (reference Issue One above). Prior to 2008, adders for items such as the Qualitrol DNP Software and Grounding Revisions were reflected as separate line items on invoices. In 2008, Kuhlman began adding the software, and occasionally, also the grounding revisions to the total price of the product. When Kuhlman later escalated the price of the product based on the changes in material costs, they would also escalate the cost of the adders. This resulted in extrapolated net overbillings of $12,868 throughout the scope period.

- *Risk* – AEP may overpay for materials due to billings that are not in accordance with the contract or supporting documentation.

- *Resolution* – AEP Procurement and Transmission management personnel and Kuhlman agreed to settle the above issue for $12,868. Kuhlman will issue AEP a check in the amount of $33,734 to settle this issue along with issues three and four. AEP Procurement management will ensure that the check is received from Kuhlman by August 31, 2009.

  An internal review of the Procurement function was recently performed by AEP Audit Services which addresses control gaps that allowed these overbillings to occur. Going forward, Kuhlman has agreed to list adders as separate line items on their invoices. They will also provide additional training to ensure that periodic price adjustments are only applied to metal and oil component costs.

Significance:	**Medium**
Target Date:	**August 31, 2009**
Responsible Party:	**Judson Schumacher**

Appendix 1

Classification of Audit Report Conclusions

Conclusion	Definition
Well-controlled	Controls are appropriately designed and are operating effectively to manage risks. Control issues may exist, but are minor.
Well-controlled with minor improvements needed	Medium-level control issues (either design or operating effectiveness) are present but do not compromise achievement of important control objectives.
Improvements in controls needed	High-level or medium-level control weaknesses are present that compromise achievement of one or more important control objectives but do not prevent the process or function from achieving its overall purpose. While important weaknesses exist, their impact on the management of risks is limited rather than widespread.
Major improvements in controls needed	High-level control weaknesses exist across numerous control objectives that potentially prevent the process or function from achieving its overall purpose. The impact of weaknesses on management of risks is widespread rather than isolated either due to the number or nature of control weaknesses.

Classification of Audit Issues

Risk Significance	Risk Definition
High	Likelihood of the condition occurring must be more than remote **and** potential impact must be significant in relationship to the underlying financial information, overall objectives, or level of compliance of the function or process audited.
Medium	Likelihood of the condition occurring must be more than remote **or** potential impact must be significant in relationship to the underlying financial information, overall objectives, or level of compliance of the function or process audited.
Low	Enhancement to a current process that would add value, but not necessarily have a significant impact to the company from a financial, compliance, effectiveness, or efficiency standpoint. Would entail process improvement or have a relatively small monetary impact.

AMERICAN
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POWER

Date: January 29, 2010

Subject: Report of Audit
2009 Coal Pile Inventories

From: J. R. Brooks

To: G. M. Barnett

We have completed our review of AEP's coal pile inventory results for inventories conducted during 2009. A total of 32 inventories were conducted at 21 plants and Cook Coal Terminal during the year. The purpose of our review was to:

- Review the System Power Plants' Spring and Fall coal inventory reports for completeness and propriety.
- Assess the reasonableness of book inventory number at time of survey, which is compared to physical inventory results to determine the coal inventory adjustment.
- Determine whether the coal inventory adjustments reported by the Power Plants were calculated accurately and in compliance with AEP System Accounting Bulletin No. 4. AEP System Accounting Bulletin No. 4 requires recording 100% of the difference between the physical inventory and the book inventory and performing another physical inventory within 6 months, if the difference, as a percent of consumed, is greater than +/- 2%.
- Determine that plants with a variance of +/- 2% investigated the variances and addressed any issues discovered.
- Verify that the accounting entries recording the financial adjustments were reasonable and complete.
- Observe the inventory volume and density measurement activities at three plants to evaluate compliance with AEP Circular Letter CI-O-CL-0084.

Two errors were noted during the review. One plant miscalculated the book inventory at the time of the survey, resulting in the overstatement of inventory by 40,500 tons. The plant utilized the inventory information from the wrong report in the fuel accounting system. Since the company implemented a new fuel accounting system (Comtrac) on May 1, 2009, this appears to be an isolated error. Plant management has been advised of which report should be used in the new system. The other error occurred when one plant miscalculated the surveyed inventory, resulting in a minor overstatement of inventory by 250 tons. Both plants issued a revised coal inventory report to correct the error prior to year-end.

In addition, management self-detected two errors. The Civil Lab entered incorrect density values on Tanners Creek's spring 2009 inventory report, resulting in the understatement of inventory by 36,129 tons. Similarly, the Civil Lab entered a volume of 631.837 cubic feet instead of 631,837 cubic feet on Glen Lynn's fall 2008 inventory report, resulting in the understatement of inventory by 25,122 tons. The Civil Lab's review process, which includes agreeing reported values to supporting documentation, is designed to detect these errors, but failed in both instances. Management is aware of the issues and has advised the lab to be more thorough in their review process. The Civil Lab and plant issued revised coal inventory reports, and the appropriate accounting adjustments were booked in the fall 2009.

Based on our review, we believe that the coal pile inventory results and adjustments are properly stated, in all material respects as of December 31, 2009.

c:			
	M. G. Morris	J. D. Henry	J. M. Buonaiuto
	R. A. Mueller	M. C. Mills	A. B. Reis
	B. X. Tierney	M. C. McCullough	D. L. Laws
	N. K. Akins	J. D. LaFleur	N. W. Felber
	T. K. Light	M. A. Gray	T. M. Dooley
	W. L. Sigmon	T. R. Zelina	F. E. Armatas
	S. N. Smith	M. W. Flynn	G. T. Gaffney
	M. A. Peifer	S. W. Burge	D. E. Richey
	G. C. Knight	P. W. Franklin	

Project # GE04609

Audit of Environmental & Asbestos Programs at the Big Sandy Plant, Louisa, KY

May – September, 2009

Jeff Armstrong

Brenda Carter

Carmen M. Ortega

Kirk Nofzinger

Gary Sommerville

1. SUMMARY/CONCLUSION

Environmental, Safety and Health Auditing (ESHA) conducted an audit of the Environmental and Asbestos Programs at Big Sandy Plant, Louisa, KY, during the period of May to September, 2009. The audit site visit occurred on the week of July 6-10, 2009.

In the audit team's judgment, improvements in controls are needed in the programs reviewed particularly in the Asbestos and NPDES programs. Three Control Findings and ten Compliance Findings were identified during this audit. Each of the Control Findings is believed to be significant.

ESHA last conducted audits involving Environmental and Asbestos Programs at this site in 2006 and 2007. All findings related to the Environmental Programs were closed and are not repeated in the current audit; however corrective actions established to remediate previous Asbestos Program audit findings have not been fully effective in eliminating compliance gaps as detailed in Control Finding #1. In addition, a deficiency in asbestos project documentation identified in the 2007 audit is repeated.

Improvement in Controls are Needed
(YELLOW)
The facility is acceptable but not remarkable with several minor exceptions or one significant exception to regulatory/company policy requirements being noted. The exceptions may be the result of (1) a failure to implement certain required aspects of the compliance program, (2) a weakness in the process used to address environmental compliance and (3) a lack of understanding of the regulatory requirements.

Programs applicable to this facility that were reviewed during the audit are evaluated by program area in the table below:

Status	Finding Present	Program	Status	Finding Present	Program
		Aboveground/Underground Storage Tanks (UST/AST)		X	National Pollutant Discharge Elimination System (NPDES)
		Air Permitting			PCBs
	X	Asbestos	NA		Risk Managements Plans (RMPs)
		Chlorofluorocarbons (CFCs)			Solid/Hazardous Waste
	X	Continuous Emission Monitoring (CEMS/COMS)			Spill Prevention Control & Countermeasure Plans (SPCC)
NA		Drinking Water		X	Storm Water
		Emergency Planning/Community Right-to-Know (EPCRA)			Toxic Release Inventory (TRI)
NA		Facility Response Plans		X	Universal Waste
	X	Groundwater			Used Oil
	X	Hazardous Materials Transportation (Hazmat/DOT)			
	X	**Control Findings: Asbestos, NPDES and SPCC**			

** Definition of color code can be found in Appendix B.*

The auditors note the following site conditions impacting the programs being audited:

Air Permitting:

Two Notices of Violation (NOV) have been received from Kentucky Department of Environmental Protection (KDEP) at Big Sandy Plant. The NOVs, received in December 2008, relate to Particulate Emissions exceedances, as detailed below:

- On December 23, 2008, an NOV was issued for combined stack emissions exceeding the particulate limit applicable to Big Sandy's Unit 1 and Unit 2, as demonstrated during the Particulate Emissions stack testing performed on Jul 8, 2008.
- On December 4, 2008, an NOV was issued to the facility for not operating below 110 percent of the average operating load maintained during the particulate emission test that demonstrated compliance with the particulate emission limit (i.e. <236.5 MWN), as required by 301 KAR 50:045 Section 5(2)

The facility was notified in June 2009 that both of these NOVs were referred to the KDEP Division of Enforcement At the time of the audit site visit, the facility is working with AEP Environmental Services, AEP Legal and the agency to achieve resolution.

Storm water:
As noted in Control Finding #2, the plant has experienced a number of storm water bypasses over the past three years. The number of bypasses has elicited concern from the KDEP during the past two wastewater inspections at the plant. Further KDEP has issued two letters to the plant, on September 15, 2008 and February 23, 2009, citing that the bypasses could "result in future non-compliance if not properly addressed." The KDEP has recommended that action be taken to address these spills and has recommended that "structures (flow pots, etc.) be installed in/on storm drains to help prevent a spill from entering or being discharged via a storm drain." The plant had not yet fully addressed the KYDEP concerns as of the date of audit site visit citing resource restraints as a contributing factor.

2. AUDIT SCOPE

The period of review for each program is generally inclusive of the time since the previous audit or the retention requirement by the applicable regulation. The period may be adjusted to accommodate time constraints and to address those programs having the greatest potential impact on a given facility.

Variations from scope: CEMS Program review was limited to the previous four quarters, 2^{nd} Quarter 2008 – 1^{st} Quarter 2009.

3. AUDIT RESULTS

SELF INITIATED COMPLIANCE IMPROVEMENT – *Action taken by site personnel prior to announcement of the audit site visit to pro-actively self-correct gaps identified in compliance processes and prevent their recurrence. Although the facility implemented a control to eliminate reoccurrence, some outstanding liability may still exist. No further corrective action is required.*	
Imprv. No.	**Description**
Hazardous Waste	
1	On December 29, 2006, an employee whose DOT Hazardous Materials Manifest Training had lapsed improperly signed a hazardous waste manifest (#000467739). To correct the deficiency, DOT HazMat training was provided to this employee on 1/11/07. Similarly, in December 24, 2008 a second employee signed a manifest (#000886078) without the proper training. It should be noted that the training was scheduled for this employee before the manifest was signed and was provided on 2/2/09. The facility recognized the deficiency and issued a memo to all plant employees in January 2009 reminding them that only trained personnel can sign manifests.
UST	
2	Testing of the UST Automatic Line Leak Detection (ALLD) system was not conducted within the 365 day annual interval as required by 40 CFR 280.44(a). The tests were conducted on 6/13/08 and 6/29/09. On 2/5/09, the plant scheduled the test with the external tank contractor to be conducted on 6/12/09. However, due to illness the contractor did not conduct the test on this date. Plant personnel immediately rescheduled the test date and the contractor completed the test on 6/29/09.

CONTROL FINDING – *A deficiency or weakness in the environmental management system where there is a potential for non-compliance. Corrective action is required.*				
Finding No.	**Status (Open/ Closed)**	**Description**	**Organization Responsible**	**Remediation**
Asbestos				
1	**Open**	The site process, implemented in 2007, to ensure contractor compliance with applicable requirements has improved. However, the process for project inspection and documentation is not sufficient to assure prompt detection and correction of deficiencies. Specifically, review of project documentation and interviews indicated that: • Air monitoring is not always being conducted as required and no negative exposure assessments are documented for work at Big Sandy Plant. • Documentation of project inspections conducted by the Contractor's Supervisor (the Abatement Safety Report or Abatement Removal Report) is not being completed concurrent with the inspections. These documents are not completed until after project conclusion, in some cases up to two months after the project was completed. Review of this documentation identified several instances of	**Plant**	In order to address this Finding, Big Sandy Plant (BSP) personnel are proceeding with the following steps: ➢ The plant Competent persons (CPs) met to develop a checklist which will prompt the contractor and the CPs to document all of the information required by the AEP Policy. The BSP currently has three CPs: Safety and Health Supervisor, Process Supervisor, and Maintenance Supervisor. This provides for more coverage of asbestos projects and for smooth transition due to planned retirement. A new checklist was developed on September 24, 2009. The new checklist will be completed concurrent with each asbestos abatement project and will be implemented during the next asbestos abatement project. ➢ S&H Supervisor met with the Asbestos Contractor on 9/8/09, to discuss audit findings and, specifically, the importance of documentation being accurate and complete before he leaves the site. The new checklist will be used and implemented during the next asbestos abatement project. ➢ Upon initiation of each project, one of the three CPs will meet with the contractor supervisor to review the checklist. Although a verbal conversation has historically occurred, this has not been adequately documented. The

CONTROL FINDING – *A deficiency or weakness in the environmental management system where there is a potential for non-compliance. Corrective action is required.*				
Finding No.	**Status (Open/ Closed)**	**Description**	**Organization Responsible**	**Remediation**
		contradictory information concerning project descriptions, work practices, and air monitoring among the documents related to a single project. As a result, it could not be determined if the documentation reflects actual site observations/conditions at the time the work was performed. • Review of project records by plant personnel is not conducted until one to four months after conclusion of the project. As a result, the delay in inspection documentation noted above was not identified during the plant reviews. In addition, reviews of documentation by plant personnel have failed to identify and correct errors in project execution (such as lack of required air monitoring), conflicts in the information presented and or the omission of required information (e.g., failure to document the waste quantities generated). See details in Appendix A.		conversation and documentation will address the activities and documentation that must be included for that project such as documentation of air monitoring. ➢ Review of contractor records will be conducted by one of the three CP during the first week of each month. The contractor will be apprised of the need to have the documentation available in a timely manner after each project. As it was determined that accessibility to contractor records was inhibiting the timely completion of this review, all CPs have been furnished with keys to the contractor's office as of 9/3/2009. The documentation review will be conducted using the form developed after the 2007 S&H audit and will include a review of documentation content as well as a completion to assure that the documentation accurately and consistently represent the activities conducted. All CPs share the responsibility of reviewing the contractor documentation the first week of the month. The Primary responsibility is with the S&H Supervisor. The first document review done since the audit site visit was conducted on 9/3/2009 by the S&H Supervisor. A copy of the checklist with notes was left for the contractor. A follow-up conversation was held with the contractor when he returned to BSP on 9/8/2009. Questions and comments were resolved. The ongoing process will be handled in the same manner in the future. To ensure that the review is conducted monthly, the S&H Supervisor will

CONTROL FINDING – *A deficiency or weakness in the environmental management system where there is a potential for non-compliance. Corrective action is required.*

Finding No.	Status (Open/ Closed)	Description	Organization Responsible	Remediation
				have a task added in Enviance by October 30, 2009. The responsibility for the completion of the Enviance task will be assigned to the S&H supervisor and will escalate to the other CPs.
NPDES				
2	**Open**	Actions to address the underlying causes of recurrent spills and bypasses of NPDES treatment systems should be developed and implemented. Thirteen spill and/or bypasses of NPDES treatment systems have occurred since September 2006 (see list in Appendix A). Although the plant has properly reported each instance to the Kentucky Department for Environmental Protection and initiated maintenance requests to address each situation, it does not appear that the actions taken to date have been effective in mitigating and preventing similar instances from recurring.	**Plant**	To address emergent bypass issues, the plant has purchased storm drain mats designed to seal the storm drain and prevent additional bypass water from entering the outfall. Plant personnel will also be trained to use these mats for work that may result in a bypass issue, such as ash piping work. These emergent issues have been addressed by Environmental and Lab Supervisor and should be completed by December 31, 2009. The plant will also address this item in the MESH action plan (old environmental excellence plan) The plant will seal off a storm drain underneath the Unit 1 flyash deck that has been the source of several of the bypass incidents. An REO engineer will be assigned to review past plant bypass incidents and recommend improvements to the plant which will be included in the next budgetary cycle. The plant has also repaired the leak in underground piping at the north end of Unit 1 which was a source of two bypass incidents.
SPCC				
3	**Open**	A determination of the underlying origin(s) of oil releases observed at the Unit 1 fuel oil collection tank vent line should be made and	**Plant**	The alarm for the chamber that alerts the operator of a possible vent release has been repaired. Also the name of the alarm was changed in early September 2009 to be more descriptive to the operator during

CONTROL FINDING – *A deficiency or weakness in the environmental management system where there is a potential for non-compliance. Corrective action is required.*				
Finding No.	**Status (Open/ Closed)**	**Description**	**Organization Responsible**	**Remediation**
		actions taken to prevent recurrence. On 7/6/2009, oil was observed flowing from the fuel oil collection tank vent line on the external wall of Unit 1. The oil was reaching the ground below the vent line which is within 15 yds. of a storm water drop inlet that flows to the Big Sandy River. In discussions with plant personnel, it was determined that a similar occurrence in April had alerted site personnel to problems involving the ignition oil valving and the high level alarm on the tank. Work orders to repair both were initiated in April; however, operations personnel indicated that the alarm system had again not sounded during the July event. Although the quantity and location of oil in this instance was not sufficient to trigger reporting requirements, there is significant potential for this situation to result in reportable spill event(s). It should be noted that plant personnel were in contact with AEP Engineering personnel shortly after the audit site visit and initial actions planned to determine the causes/corrections needed to		the next outage of sufficient duration when the control system can be reprogrammed. The plant has also developed an operating procedure for an operator to follow when the alarm is sounded. This was completed by the plant I&C and operations staff. The Environmental and Lab Supervisor will coordinate meeting with plant I&C and operations staff to determine how it could be assured that this alarm remains functional (i.e. alarm testing mechanisms, frequency of testing, preventive maintenance, etc), by October 30, 2009. Results will be implemented as soon as practicable upon determination. The plant will either install a tank to capture oil from the vent or plug the vent if engineering analysis proves this option meets safety and operating considerations. This will be completed by June 30, 2010.

CONTROL FINDING – *A deficiency or weakness in the environmental management system where there is a potential for non-compliance. Corrective action is required.*				
Finding No.	**Status (Open/ Closed)**	**Description**	**Organization Responsible**	**Remediation**
		prevent future releases. A corrective/preventive action process is needed to implement the recommendations made, verify the effectiveness of the corrective action and implement additional remediations, as necessary, to prevent further releases.		

COMPLIANCE FINDING – *A non-conformance with permit/regulatory requirements or company policy. Corrective action addressing the Finding is required.*				
Finding No.	**Status (Open/ Closed)**	**Description**	**Organization Responsible**	**Remediation**
Asbestos				
1	**Closed**	Air monitoring has not been performed during Class I or Class II work as required by Section 28 of the Kentucky AIM; nor were Negative Exposure Assessment(s) established for Class I, II, or III work to satisfy the requirements of Section 27 of the Kentucky AIM.	**Plant**	Plant Competent Persons will implement a daily check to ensure air monitoring (which could include negative air exposures, personal monitoring data, area monitoring) is being conducted as required by the Kentucky AIM. Any anomalies noted during this review will be documented in the daily journal for the project. Also, the monthly checklist already in use prompts for the review of the air monitoring data and negative air exposure data. The level of review and documentation required for the asbestos abatement projects was discussed with CPs on the September 24, 2009 as explained in Control Finding 1.

COMPLIANCE FINDING - *A non-conformance with permit/regulatory requirements or company policy. Corrective action addressing the Finding is required.*				
Finding No.	**Status (Open/ Closed)**	**Description**	**Organization Responsible**	**Remediation**
CEMS				
2	**Open**	Monitoring plan information submitted in US EPA's Emissions Collection and Monitoring Plan System (ECMPS) as required by 40 CFR 75.62 contains the following inaccuracies. • The seasonal indicator for unit 2's SCR control unit is being reported as yes, but the plant as has been operating SCR year round since 1/1/09 as required by NSR Consent Decree. • The descriptions of the NOx emission rate formulas (formula ID 104 and 404) indicate a fuel factor of 1800 is being used to calculate NOx emissions; however, the factor being used in the actual formulas is 1840. • The serial number for the right flow meter is being reported as 1500422, but the monitor's serial number is 1500442.	**Plant**	The Plant and AEP ES have reviewed the discrepancies noted, the following are next steps resulting from this review: ➢ The seasonal indicator will be updated in the Monitoring Plan by the plant CEMS coordinator. Since this change, by itself, does not trigger re-submittal of the Monitoring Plan, the updated information will be included with other updates requiring Monitoring Plan submittal in the future, in accordance with AEP Legal's advice and USEPA Guidance. The CEMS coordinator is responsible for assuring that future Monitoring Plan submittals include accurate and updated information. ➢ The correct fuel factor is being used in the calculation; however the description of the formula was still showing 1800. This has been corrected in the Monitoring Plan. ➢ The serial number for the right flow meter was a typo when it was entered into the Monitoring Plan. It has been corrected in the Monitoring Plan. An Enviance task will be created for the CEMS coordinator to annually review the monitoring plan to ensure accuracy and

COMPLIANCE FINDING - *A non-conformance with permit/regulatory requirements or company policy. Corrective action addressing the Finding is required.*				
Finding No.	**Status (Open/ Closed)**	**Description**	**Organization Responsible**	**Remediation**
				correct typos. The Enviance task will prompt the CEMS coordinator and will be created in Enviance by 11/2/09.
3	**Closed**	It could not be verified that the January 2009 Flow RATA data from the left (backup) stack monitor was submitted to USEPA with the first quarter 2009 ECMPS reports, as required by 40 CFR 75.64. The plant included that information with its report to the AEP central database for ECMPS submittal; however information available from USEPA's server indicates that the data has not been submitted.	**AEP ES**	The left Flow RATA data was in the EDR submitted by the plant, however the EPA's software, ECMPS, was not importing the left side RATA data. This has been corrected by the EPA's software company (PQA) and the quarterly EDR was resubmitted. Now that EPA has corrected the software error, AEP will rely on the data checking software in ECMPS to provide feedback to indicate any reporting errors of this type during the checks made prior to quarterly submittals by AEP ES.
4	**Closed**	The annual CEMS span and range evaluation was not performed or documented during 2008, as required by 40 CFR 75, Appendix A, Section 2.1. This evaluation is normally conducted by AEP Environmental Services on the plant's behalf.	**AEP ES**	Due to extenuating circumstances involving staff with responsibility for conducting span evaluations, these were not executed in 2008. This responsibility has been reassigned within AEP ES Air Quality Services and the annual span evaluation was completed by August 1, 2009.
DOT				
5	**Open**	Pickup truck (no. 477316), which was carrying one unmarked three-gallon gas can, was observed being driven offsite on the highway during the site visit. 49 CFR 173.6(c)(1), requires that non-bulk packaging	**.Plant**	The gas can was marked with a "Flammable Liquid" marking during the audit. The plant will order new gasoline and kerosene cans that are appropriately marked and are of metal construction. This

COMPLIANCE FINDING - *A non-conformance with permit/regulatory requirements or company policy. Corrective action addressing the Finding is required.*				
Finding No.	**Status (Open/ Closed)**	**Description**	**Organization Responsible**	**Remediation**
		must be marked with a common name or proper shipping name to identify the material it contains when being transported on public roadways.		will be completed by Environmental and Lab Supervisor and the Safety Supervisor by October 31, 2009.
Groundwater				
6	**Open**	The facility's May 2005 groundwater pollution prevention plan is not certified as required by 401 KAR 5:037 (2)(g). A certification signed by the person responsible for implementing the plan or a duly authorized representative who ensures that the plan complies with the requirements of the regulation is required for these plans. In addition, the assessment of the potential of contamination for underground pipelines, facility surface impoundments and aboveground storage tanks and the basis for the assessment (either geological assessment by a PG or analysis of ground water monitoring samples) should be included in the plan to substantiate the determination of "no reasonable means of contamination".	**Plant/AEP ES**	The plant is working with Environmental Services to revise the present groundwater plan. The Environmental and Lab Supervisor will ensure that the current corrections and revisions to the plan, as well as future revisions, are certified and are signed by the person responsible for implementing the plan (Plant Manager) or a duly authorized representative who ensures that the plan complies with the requirements (as determined by AEP ES). The current corrections and revisions will be completed by December 31, 2009.
NPDES				
7	**Closed**	The letter submitted to KDEP on November 28, 2006, correcting omission of the average and maximum daily flows from Outfall 004 for the September 2006 DMRs, signed by the responsible official (Plant Manager), did not include a certification statement as required by AEP's Environmental Policy EP-92-04	**Plant**	A letter of correction with the certification statement was sent to the Kentucky Division of Water on August 26, 2009 and signed by the plant manager. The Environmental and Lab Supervisor is now aware that this type of information

COMPLIANCE FINDING – *A non-conformance with permit/regulatory requirements, or company policy. Corrective action addressing the Finding is required.*				
Finding No.	**Status (Open/ Closed)**	**Description**	**Organization Responsible**	**Remediation**
		revised 8/20/07 and 40 CFR 122.41(k).		needs to be certified and will ensure that the certification language is included in future correspondence of this nature.
8	**Open**	Facility DMR and waste sludge removal records were not maintained as required by 40 CFR 122.41(j)(2). Specifically, the following records were not available at the facility • DMR field data that supported the reporting period from July 2006-January 31, 2008 was not available on site for review. • Sludge removal records were incomplete and did not include the amount of sludge removed nor document each withdrawal from the system for the five year period preceding the audit. • There was no documentation of field sample data for the December 2008 Outfall 004 Total Residual Chlorine monitoring data recorded in the DMR as "0".	**Plant**	In an effort to address this finding, the laboratory staff will benchmark and develop a better method of recording and storing environmental information. This will include record keeping and training for laboratory personnel. We will have a new system of recordkeeping of environmental records by March 31, 2010. Environmental and Lab Supervisor will lead this effort. Also, lab personnel are now obtaining sludge records directly from the waste hauler and giving the record to the Environmental and Lab Supervisor who files the record.
Stormwater				
9	**Open**	The Best Management Plan (BMP) required by the KPDES permit has not been re-submitted to the KDEP when modifications to the plan were made as required by KPDES permit KY0000221 Part V (3), (8) and (9). The following are examples of modifications that have been made and recorded in the BMP since 1998 for which resubmittal of the	**Plant**	The Environmental and Lab Supervisor is working with Environmental Services to revise the present BMP plan. Corrections and revisions to the plan should be complete by December 31, 2009. To prevent recurrence, the Environmental and Lab Supervisor will receive a copy of

COMPLIANCE FINDING - *A non-conformance with permit/regulatory requirements or company policy. Corrective action addressing the Finding is required.*				
Finding No.	**Status (Open/ Closed)**	**Description**	**Organization Responsible**	**Remediation**
		plan is required: • Addition of the plant heating steam to the miscellaneous discharge list in the Stormwater Runoff Section • Inclusion of construction activities such as stockpiled materials from the dredging of coal pile run off and bottom ash ponds • Additional description of the cooling tower emergency overflows and tower basin drains		capital and plant blanket projects annually and will submit any applicable projects to Environmental Services for their review and determination. Further, he will work with Environmental Services to assure that any changes determined to be included in the BMP plan are incorporated as required. This will be initiated as of January 1, 2010.
Universal Waste				
10	**Open**	Fifteen used fluorescent light bulbs accumulated under the plant's stack were not stored in a proper storage container and were not marked as universal wastes as required by 40 CFR §273.13(d)(1) and §273.33(d)(1).	**Plant**	The lighting wastes were placed in a storage container and marked as of September 18. The Environmental and Lab Supervisor will provide additional training to the plant to properly store Universal Wastes by December 31, 2009. All plant personnel will be trained.

OBSERVATION - *Identification of a practice that increases environmental liability or an area where current environmental practices can be improved even though no violation of regulatory or Company policy requirements has occurred. A response to an observation is required.*			
Obs. No.	**Description**	**Organization Responsible**	**Response**
Asbestos			
1	Project journal documentation developed and maintained by the contractor as records of asbestos abatement should be more detailed to provide adequate information to determine the	**Plant**	Plant Competent Persons will implement a daily check to ensure air monitoring is being conducted as required by the Kentucky AIM. Any anomalies noted

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OBSERVATION - *Identification of a practice that increases environmental liability or an area where current environmental practices can be improved even though no violation of regulatory or Company policy requirements has occurred. A response to an observation is required.*			
Obs. No.	**Description**	**Organization Responsible**	**Response**
	Class of work being performed, amounts of waste generated, and description of the work activities and practices.		during this review will be documented in the daily journal for the project. Also, the monthly checklist, conducted by the CP, and follow-up discussions with the contractor implemented on 9/3/2009 have already improved Contractor documentation.
Air Permitting			
2	The water spray system installed at the railcar rapid discharge bottom dumper (Station 11, Emission Unit 6) is not operational. This system is in place for controlling fugitive emissions from this source, in accordance with the operational requirements for Emission Unit 6 in the facility's Air Quality Permit (Number: V-06-053) Section B.1(ii). Although no instances of fugitive emissions were observed during the audit site visit, the facility should ensure that this emission control system is functional or establish alternative control measures, to suppress fugitive dust emissions when they occur during unit operation conformance with permit requirements.	**Plant**	The Environmental and Lab Supervisor issued a work request for repair of the sprays on July 10, 2009. This work will be completed by October 31, 2009. At present, railcar dumping is being observed for dusting during daylight hours. If dusting is observed unloading will be stopped and temporary measures for controlling dust will be enacted.
Groundwater			
3	Piezometers located at the base of the on-site dam used for testing groundwater levels were not secured either by restricting access to the area or by prohibiting foreign materials being introduced into the well standpipe. Some wells were observed to be open with no caps/covers. Maintaining the wells in this manner may offer an opportunity for the introduction of materials that	**Plant**	A means of capping these devices will be installed by June 2010. The Environmental and Lab Supervisor and Maintenance Supt. will be responsible to see that these devices are installed.

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OBSERVATION - *Identification of a practice that increases environmental liability or an area where current environmental practices can be improved even though no violation of regulatory or Company policy requirements has occurred. A response to an observation is required.*			
Obs. No.	**Description**	**Organization Responsible**	**Response**
	may lead to groundwater contamination. It is recommended that the wells be covered to help prevent unauthorized access.		
NPDES			
4	A procedure is needed to ensure that expired lab chemicals are not used and that laboratory personnel are aware of the potential consequences of using expired chemicals in analyses. Expired chemicals should be removed and fresh lab chemicals ordered in a timely manner to ensure that expired chemicals are not used for analytical purposes. The following lab reagents used in the analysis of KPDES-required samples were observed to have expired: • Sulfuric Acid used as a preservative in sample collection, expired 1/31/2009. • Buffer solution used in hardness testing, expired 05/14/01; • pH Buffer 10 used to monitor calibration for field analyses, expired 08/08/08. Laboratory personnel indicated that they planned to use the expired chemicals until the supply was exhausted.	**Plant**	The Chemists will provide additional training to the laboratory technicians by September 31, 2009, on the importance of using non-expired reagents for environmental analysis. We will also include a method of recording whether reagents have expired in the environmental records. This will be in conjunction with actions on item 8 on the compliance findings.
5	"BDL" was reported on the KPDES discharge monitoring reports when parameters were found to be below the level of detection for the analytical method being used. KDEP guidance recommends use of the less than (<) sign with the numerical detection limit when reporting analytical	**Plant**	The Environmental and Lab Supervisor began using the appropriate code for analysis that was below the level of detection. This was initiated on the July 2009 DMR.

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OBSERVATION - *Identification of a practice that increases environmental liability or an area where current environmental practices can be improved even though no violation of regulatory or Company policy requirements has occurred. A response to an observation is required.*			
Obs. No.	**Description**	**Organization Responsible**	**Response**
	results are below the detection level.		
Storm water			
6	Per the letter received from the Louisville, KY office of the Army Corp of Engineers, dated January 24, 2007, the Stormwater Compliance Certification should have been signed and returned when the relocation of Outfall 015 was completed. There was no record that the document had been signed and returned to the Army Corp of Engineers.	**AEP ES**	On July 15, 2009, Alan Wood, Manager Water and Ecological Resources, Services sent in the Compliance Certification notice to the Army Corp of Engineers office in Louisville KY as requested under the permit requirements. In it, he indicated the date the project work was completed (8/31/2007) and signed and dated the compliance certification 7/15/2009.
7	Sampling procedures and accessibility for obtaining samples of the storm water outfalls should be evaluated for safety concerns. The locations of these discharges are difficult to reach, posing potential for slips and falls. Potential exposure of employees to these risks has increased due to the frequency of bypass events experienced by the plant requiring samples to be obtained during various types of environmental conditions (e.g., weather, time of day, etc).	**Plant**	The Environmental and Lab Supervisor will add this item to the MESH action plan. The plant management staff is including budgeted funds for replacement of these outfalls over several years.

Appendix A

I. CONTROL FINDINGS

Asbestos

<u>Control Finding #1:</u>

The following Asbestos project gaps were noted:

- 1/15/09 and 2/10/09: Project Abatement reports indicated air samples were taken for these projects; however, no air monitoring report was noted. These projects were reviewed by the site on 5/20/09 with no issues noted. The plant review checklist indicated that air monitoring records were in the log book and documented negative exposure assessments were available. However, neither of these documents were available for review during the audit.

- 2/26/09: Project journal notes no removal/encapsulation only; The Abatement Removal report for this project indicates no removal/encapsulation only, no air monitoring, no disposal bags generated. However, the Abatement Safety Report for this project indicates material was removed wet, placed in the bags for disposal and air monitors were worn, but no there is no documentation related to air monitoring. The plant review checklist indicated that air monitoring records were in the log book and documented negative exposure assessments were available. However, neither of these documents were available for review during the audit.

- Projects on 5/19/09, 5/22/09, 5/23/09 and 5/24/09: Only a project journal page was available to review at the time of the on-site audit. There was no Abatement Report or Abatement Safety Report indicating the results of inspections conducted during the audit. This documentation was not created by the Contractor or reviewed by site personnel until July 27, 2009, after issues of missing documentation were noted during the audit site visit.

- Asbestos Checklists, which are completed by site personnel during review of contractor documentation, indicate Air Monitoring documentation was verified and/or documentation of a Negative Exposure Assessment was verified for projects in January 2009, February 2009, March 2009, and April 2009; during a phone call subsequent to the site visit, the Contractor Supervisor indicated that air monitoring was not always performed even though its performance was indicated on the Abatement Removal Report or Safety Report. It was further indicated that when air monitoring was not performed, it was because similar removal projects, which had monitoring data, had exposure levels below the PEL. However, MMI has not documented any negative exposure assessments for work at Big Sandy Plant.

- Asbestos Checklists, which are completed by site personnel during review of contractor documentation, indicates Elaine Martino was one of two AEP employees qualified and available on-site as Asbestos Contractor Supervisor for April 2009; however, Elaine Martino was not available on-site during month of April.

NPDES

Control Finding #2:

Big Sandy Bypasses/Upsets
4/2006-7/6/2009

	Description	Pollutant	Outfall	Discharged to	Amount
20-Sep-06	Leak from the Unit #1 Turbine room sump discharge pipe which released water into the storm drain that is routed to OO7.	Waste Water	7	Big Sandy River	2500 gal
2-Apr-07	Unit 1 turbine room sump discharge pipe discharged water into an unidentified storm drain.	Waste Water	7	Big Sandy River	200 gal
23-Apr-07	A leak developed in the underground water line and the water migrated to the ground level and into an unidentified storm drain.	Waste Water	Unknown	Big Sandy River	450 gal
7-May-07	Flyash slurry line from Unit 1 and 2 was leaking and water was leaking into a storm drain.	Waste Water	7	Big Sandy River	20 gal
27-Aug-07	Flyash slurry line from Unit 1 and 2 was leaking and water appeared to be leaking underground.	Waste Water	7	Big Sandy River	N/D
11-Oct-07	A leak from the bottom ash line from Unit 2 to the ash ponds .	Waste Water	7	Big Sandy River	500 gal
8-Mar-08	A flyash slurry line from Unit 1 and 2 was leaking.	Waste Water	7	Big Sandy River	100-300 gal
30-Mar-08	Bottom ash line from Unit #2 to the storage pond was found leaking	Waste Water	7	Big Sandy River	3000 gal

	Description	Pollutant	Outfall	Discharged to	Amount
	water.				
23-Apr-08	It was discovered that and underground line carrying water from the fire fighting system had ruptured and the resulting water was entering the storm drain at the NE end of Unit #1.	Waste Water	7	Big Sandy River	2500 gal
3 July 08	A water leak from a drinking water pipe line connected to a safety shower was discovered.	Waste Water	8	Big Sandy River	N/D
9 Jul 08	A reportable quantity of Sodium Hypochlorite (bleach) resulted from a failure of the bleach pump on Unit #2.	Bleach	7	Big Sandy River	1000-2500 gal
23 Oct 08	Water leak from the plant fire system's pipeline which resulted in fire system water entering the storm drain.	Waste Water			
28 Oct 08	A water blasting operation a contractor directed the filtered water to the storm drain.	Waste Water	7	Big Sandy River	75-130 gal

APPENDIX B

Conclusion	Definition
Well controlled	The facility is in compliance with applicable regulatory/policy requirements included in the audit scope. Isolated exceptions may be noted but they are minor in nature and do not materially impact the overall effectiveness of the compliance program. Systems are in place to identify and execute applicable requirements. Personnel are knowledgeable of processes and regulatory requirements.
Controlled but minor improvements needed	There is a high degree of compliance with regulatory/policy requirements. A few requirements are not satisfied as a result of isolated weaknesses in an overall effective program. Personnel are knowledgeable of regulatory requirements. No significant exceptions are noted.
Improvements in controls needed	The facility is acceptable but not remarkable with several minor exceptions or one significant exception to regulatory/company policy requirements being noted. The exceptions may be the result of (1) a failure to implement certain required aspects of the compliance program, (2) a weakness in the process used to address environmental compliance and (3) a lack of understanding of the regulatory requirements.
Major improvements in controls needed	More than one significant exception to applicable requirements, a pattern of nonconformance with applicable requirements, or the absence of required programs are noted. Personnel may not have a good understanding of the program requirements applicable to their facility or no systems are in place to monitor adequately and ensure environmental compliance.

AEP® Audit of selected Environmental, Safety and Health Programs at the

Pikeville Service Center

July – September 2010

Michelle L. Marsh

Nathaniel R. Francis

April D. Lilly

1. SUMMARY/CONCLUSION

> **Improvements in controls needed** – The facility is acceptable but not remarkable with several minor exceptions or one significant exception to regulatory/company policy requirements being noted. The exceptions may be the result of (1) a failure to implement certain required aspects of the compliance program, (2) a weakness in the process used to address safety and health compliance and (3) a lack of understanding of the regulatory requirements.

An audit of selected ESH programs was conducted during the period of July – September, 2010 at the Pikeville Service Center, Pikeville, KY. The audit site visit occurred on July 19 – July 23, 2010.

In the audit team's judgment, **Improvements in controls are needed** in the Pikeville Service Center compliance program for the selected ESH Programs identified as "yellow" below. Six (6) exceptions to governmental requirements and internal policies were identified. In addition, two (2) Control Findings were noted in the programs identified in the below table.

The ESH Programs reviewed during this audit are evaluated by program area in the table below. In addition to the programs noted, observations of overall safety practices during crew field projects were also conducted with the Distribution Line, Meter Revenue Operations, and Transmission – Protection and Control personnel located at this site.

Status	Finding Present	Program	Status	Finding Present	Program
	X	Asbestos			Machinery and Machine Guarding
		Confined Space Entry		X	MRO Safety Initiative
		Enclosed Space Entry		X	Material Handling (Cranes, Lifting Beams, Hoists, Slings, Wire Rope)
		Hand and Portable Powered Tools			OSHA Recordkeeping
		Hazard Communication			
		Control Finding: Asbestos and MRO Safety Initiative			

- *Definition of color code can be found in Appendix B.*

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2. AUDIT SCOPE

The period of review for each of the selected ESH programs is generally inclusive of the time since the previous audit or the retention requirement by the applicable regulation. The period may be adjusted to accommodate time constraints and to address those programs having the greatest potential impact on a given facility.

Variations from scope: None.

3. AUDIT RESULTS

SELF INITIATED COMPLIANCE IMPROVEMENT – *Action taken by site personnel prior to announcement of the audit site visit to pro-actively self-correct gaps identified in compliance processes and prevent their recurrence. Although the facility implemented a control to eliminate reoccurrence, some outstanding liability may still exist. No further corrective action is required.*	
Imprv. No.	**Description**
Asbestos	
1	**METER REVENUE OPERATIONS** During 2008, 83% (10 out of 12) of employees received Asbestos General Awareness training. However in 2009, 100% (14 out of 14) of employees and 93% (13 out of 14) in 2010 received the Asbestos General Awareness Training. This training has been included in the safety training matrix to be conducted annually. Per AEP Kentucky Asbestos Implementation Manual Section 15 A, all employees must receive this training annually if they work in areas where they could come in contact with ACM in the normal conduct of their job.
Material Handling (Cranes, Lifting Beams, Hoists, Slings, Wire Rope)	
2	**FLEET SERVICES** Prior to March 2010, the 5-Ton Bridge Crane located in the Fleet Garage was not inspected frequently as required by the AEP Lifting and Rigging Procedures and 29 CFR 1910.179(j)(2)(iv) and (m)(1). Specifically, daily and/or pre-use visual inspections were occurring on the hook and wire running ropes as required; however, per employee interviews, inspection documentation was not being maintained to confirm the hook has no more than 15% deviation in normal throat opening or 10 degrees of twist from center, nor that the chain and/or wire running ropes have exceeded nominal length and diameter for ropes. Beginning in March 2010, as a result of audits conducted at other Fleet Services locations, a documented inspection process was implemented to capture the requirements of the AEP Lifting and Rigging Procedures and 29 CFR 1910.179(j)(2)(iv) and (m)(1).

CONTROL FINDING – *A deficiency or weakness in the environmental management system where there is a potential for non-compliance. Corrective action is required.*				
Finding No.	**Status (Open/ Closed)**	**Description**	**Responsible Organization**	**Remediation**
Asbestos				
1	CLOSED	Asbestos abatement projects performed by external contractors are not being	▪ Station	Going forward, all asbestos abatement work will be coordinated by the Corporate

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CONTROL FINDING – *A deficiency or weakness in the environmental management system where there is a potential for non-compliance. Corrective action is required.*				
Finding No.	**Status (Open/ Closed)**	**Description**	**Responsible Organization**	**Remediation**
		overseen by a qualified AEP employee or third party contractor working on behalf of AEP as required by the AEP Asbestos Policy, Kentucky AIM Section 37. As a result, required inspections of contractor activities during and subsequent to the removals were not performed and the oversight duties required during the abatement activities as outlined in Section 37 of the AEP KY AIM was not implemented.		Industrial Hygiene (IH) Group; the Corporate IH Group will be responsible for determining the need for a Third Party Contractor. In the past, the Pikeville Station Department had been contacting the Regional Environmental Coordinator. However, the REC has requested that all future work be coordinated through Corporate IH. **Responsible Party:** Station Supervisor **Implementation Date:** 8/27/10
Meter Revenue Operations Safety Initiative				
2	OPEN	A standardized method for approving amendments to the MRO Safety Initiative (2008) and communicating approved changes to MRO personnel in each Operating Company is needed. The MRO Safety Initiative (the Initiative), conducted in 2008, issued a number of recommendations for communication and implementation by MRO groups throughout AEP. Currently, there is no clearly defined process for the reviewing and approving amendments to update the original Initiative recommendations	▪ Customer Services, Marketing, and Distribution Services (CMDS)	CMDS will work with the MRO Managers in the OPCOs to develop controls for amending the Initiative recommendations and communication related to the MRO Safety Initiative Recommendations. Up to now, approved revisions to the recommendations in the Initiative have been made and communicated (e.g., approval of new devices for reducing dog bites) but no formal action was taken to associate these changes back to the original Initiative. This will be changed by placing the Initiative and any approved revisions on the MRO Intranet Web site

CONTROL FINDING – *A deficiency or weakness in the environmental management system where there is a potential for non-compliance. Corrective action is required.*				
Finding No.	**Status (Open/ Closed)**	**Description**	**Responsible Organization**	**Remediation**
		and assure that those changes are adequately communicated throughout the MRO organization at all OPCos. As a result, some MRO OPCo groups have incorporated both approved and non-approved changes into their MRO Safety programs. Examples of these changes include substitution of EPD devices as a replacement for bite terminators and elimination of the Safe-Start program as HPI initiatives are increased, respectively.		or comparable location for ready access. Further CMDS, working with the OPCO MRO Managers, will develop a procedure for future adoption and communication of changes to the Initiative recommendations. Currently, it has not been determined whether current HPI activities and training are sufficient to replace those of Safe-Start as recommended by the Initiative. CMDS will review the information provided by each program and determine whether the required Safe-Start activities/training are appropriately replaced by similar HPI activities. If so, the approval process developed will be used to approve and communicate this change. **Implementation Dates:** ▪ A determination regarding the need for continued Safe-Start training will be made by November 5, 2010 and any changes to the policy documented by December 10, 2010. ▪ The procedure and web site documentation will be developed by October 1, 2010 and approved and

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CONTROL FINDING – *A deficiency or weakness in the environmental management system where there is a potential for non-compliance. Corrective action is required.*				
Finding No.	**Status (Open/ Closed)**	**Description**	**Responsible Organization**	**Remediation**
				implemented by December 10, 2010. **Responsible Party for Implementation of all actions:** Darren Shepard, CMDS Director of Consumer Technology & Programs.

COMPLIANCE FINDING - *A non-conformance with permit/regulatory requirements or company policy. Corrective action addressing the Finding is required.*				
Finding No.	**Status (Open/ Closed)**	**Description**	**Responsible Organization**	**Remediation**
Asbestos				
1	OPEN	Abatement activities conducted during the period between June 14 and November 7, 2007, for the removal of "pot-heads" with PACM cable wrap from overhead lines adjacent to the Landmark Inn in Pikeville, KY did not conform to the applicable regulatory and/or policy requirements. Examples include but are not limited to: • Distribution employees who performed the equipment removal had received only asbestos awareness training. Although the cable was cut in a manner to minimize disturbance of the PACM wrap, removal and wrapping of the materials requires a level of	▪ Distribution	Kentucky Power employees were working under the direction of the REC during the removal of the "Pot Heads" with the PACM cable wrap. Going forward, an outside contractor will be hired to perform all work in which asbestos is suspected. Additionally, Distribution Management has scheduled a meeting with the local Corporate Industrial Hygiene Representative (Mike Meade). Distribution Management has requested M. Meade provide an overview of the requirements for asbestos abatement activities and emphasis the

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COMPLIANCE FINDING – *A non-conformance with permit/regulatory requirements or company policy. Corrective action addressing the Finding is required.*				
Finding No.	**Status (Open/ Closed)**	**Description**	**Responsible Organization**	**Remediation**
		training beyond simple awareness training due to the potential for fiber release. • The removed materials were appropriately placed in a 6-mil asbestos transparent asbestos bag but were not adequately wetted to prevent the release of fibers during packaging and transport. Section 51 of the AEP KY AIM requires that *"All waste asbestos material must be kept wet, double bagged or wrapped in leak-tight, plastic (transparent preferred) while still wet, and properly labeled".* • Documentation of the project was not created and maintained as required by Section 62 of the AEP KY AIM. Distribution management should work with Corporate Industrial Hygiene for guidance in determining the level of training and related oversight activity necessary for performance of this type of work by employees in the future. See Appendix A for additional information.		need to contact the Corporate Industrial Hygiene Group for all work in which asbestos is suspected. This meeting is being conducted so that all Distribution personnel can be made aware of the requirement to utilize a contractor for all asbestos work. This meeting will be conducted by the end of October, 2010. **Responsible Party:** Manager Customer and Distribution Services
2	CLOSED	The two Forestry employees based at the Pikeville Service Center have not	▪ Forestry	All Forestry employees based in Kentucky have since received Asbestos

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COMPLIANCE FINDING - *A non-conformance with permit/regulatory requirements or company policy. Corrective action addressing the Finding is required.*				
Finding No.	**Status (Open/ Closed)**	**Description**	**Responsible Organization**	**Remediation**
		received General Asbestos Awareness training annually, as required per AEP KY AIM Section 15 Subpart A. Specifically, annual awareness training was not provided to these employees during the period from January 2007 – August 2010.		Awareness Training and it has been documented in KEY. Additionally, annual asbestos awareness training has been added to the KEY profile for each Forestry personnel. The KEY system will generate a reminder each year to complete the required training. **Responsible Party:** The Senior Utility Forester will be responsible for assuring annual training is completed. **Completion Date:** 8/27/10
Hand and Portable Powered Tools				
3	CLOSED	A "ring test" is not conducted before mounting abrasive wheels to bench grinders as required by 1910.243(c)(5)(i). Users are required to inspect and sound the wheels immediately before mounting. Fleet Services employees indicated that several new wheels have been installed due to frequent use of the shop bench grinder by other departments but indicated that they were not familiar with the "ring test" requirement. At the time of the audit site visit, the JET Electric Bench Grinder Model BG-10 had been tagged out (on 7/12/10) because the abrasive	▪ Fleet Services	A "ring test" inspection sheet has been attached to each grinder and is updated prior to replacement of the abrasive wheel. The inspection sheet prompts the Fleet Technician to complete a "ring test" prior to installation of the new abrasive wheel. **Responsible Party:** Fleet Supervisor **Completion Date:** 8/27/10

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COMPLIANCE FINDING - *A non-conformance with permit/regulatory requirements or company policy. Corrective action addressing the Finding is required.*				
Finding No.	**Status (Open/ Closed)**	**Description**	**Responsible Organization**	**Remediation**
		wheels needed to be replaced.		
Material Handling (Cranes, Lifting Beams, Hoists, Slings, Wire Rope)				
4	CLOSED	The three (3) cranes (5-Ton Monorail Crane, 1-Ton Monorail Crane, and 1-Ton Jib Crane) maintained by Station have not been inspected frequently, as required by the AEP Lifting and Rigging Procedures and 29 CFR 1910.179(j)(2) and (m)(1). Specifically, daily and/or pre-use visual inspections occur on the hooks and wire running ropes as required; however, per employee interviews, inspections do not include or document an examination to confirm the hook has no more than 15% deviation in normal throat opening or 10 degrees of twist from center, nor that the chain and/or wire running ropes have exceeded nominal length and diameter for ropes.	▪ Station	The Station Department has implemented written monthly crane inspections. ▪ All documentation will be maintained on file in the Station Department. ▪ Inspections will be completed during monthly Safety Meetings. ▪ The Station Group has adopted Fleet Service's forms to use with our cranes. ▪ Minimum checks on the hook and wire rope (or chain) will be documented and the inspection sheets will meet or exceed the requirements from the manufacturer's manual concerning monthly inspections. **Responsible Party:** Station Supervisor **Implementation Date:** September 2010
5	CLOSED	A preventive maintenance (PM) program, which meets the criteria established by the manufacturer(s), has not been established and implemented for each crane at the site as required by the AEP Lifting and Rigging Procedures and 29 CFR 1910.179(l).	▪ Fleet Services ▪ Station	<u>FLEET SERVICES</u> The Pikeville Service Center Fleet Supervisor contacted the manufacturer of the hoisting equipment used in conjunction with their 5 Ton Bridge Crane. Per the manufacturer, all preventative maintenance requirements are satisfied by the annual preventative

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COMPLIANCE FINDING – *A non-conformance with permit/regulatory requirements or company policy. Corrective action addressing the Finding is required.*				
Finding No.	**Status (Open/ Closed)**	**Description**	**Responsible Organization**	**Remediation**
				maintenance completed by Apex Systems Inc. of Roanoke, VA (this work is coordinated by WPS). **Responsible Party:** Fleet Supervisor **Completion Date:** 8/27/10 <u>**STATION**</u> Manuals have been collected for the R&M Electric Hoist Type F3M 5 Ton Crane and the CM Loadstart Model L1 Ton Crane. The appropriate maintenance guidelines, as outlined in the manuals, will be met with the implementation of the Monthly Inspections referenced in Compliance Finding #4. Per the manufacturer, all preventative maintenance requirements are satisfied by the monthly inspections and annual preventative maintenance completed by Apex Systems Inc. of Roanoke, VA (this work is coordinated by WPS). **Responsible Party:** Station Supervisor **Implementation Date:** September 2010
6	CLOSED	The below-the-hook lifting device designed and built by the Fleet Technician(s) does not meet the requirements of the AEP Lifting and	▪ Fleet Services	The below-the-hook lifting device designed and built by the Pikeville Service Center Fleet Technicians was disposed of 8/23/10. Additionally, all

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COMPLIANCE FINDING - *A non-conformance with permit/regulatory requirements or company policy. Corrective action addressing the Finding is required.*				
Finding No.	**Status (Open/ Closed)**	**Description**	**Responsible Organization**	**Remediation**
		Rigging Procedures Section 10.0 Below The Hook Devices; Subsection 10.2 Job-Built/Shop-Built Devices. See Appendix A for a photo of the lifting device.		Pikeville Service Center Fleet Services personnel were made aware of the requirements of the AEP Lifting and Rigging Procedures as it pertains to Job-Built/Shop-Built Devices. **Responsible Party:** Fleet Supervisor **Completion Date:** 8/23/10

Appendix A

I. COMPLIANCE FINDINGS

Asbestos

Compliance Finding #: 1

Distribution personnel did contact the Region Environmental Coordinator when the project was planned to determine how the pothead removal could be performed. The REC, believing that the PACM in question was encapsulated, advised Distribution to cut the cables on each end approximately 2 feet from the PACM cable-wrap, lower them to the ground, and place the entire piece of equipment (with PACM cable-wrapping in-tact) in a clear asbestos bag. Approximately a 1 foot piece of PACM cable-wrap was attached to each of the 3- 5 foot length of cables. No wetting occurred before removal or when the material was initially placed in the bag. The bags were then placed on an AEP service vehicle and driven to the Pikeville Service Center where the REC, who is trained as an Asbestos Building Inspector, was on-site. The REC removed the equipment from the bags, trimmed off the non-ACM cable, and wet the PACM cable-wrapping. He then replaced the material in the bags and transported the bags to the North Charleston Service Center for storage. The equipment was still on site at North Charleston when the Pikeville audit site visit was conducted.

Material Handling (Cranes, Lifting Beams, Hoists, Slings, Wire Rope)

Compliance Finding #: 6

The photo below is of the below-the-hook lifting device that was designed and built by the Fleet Technicians.

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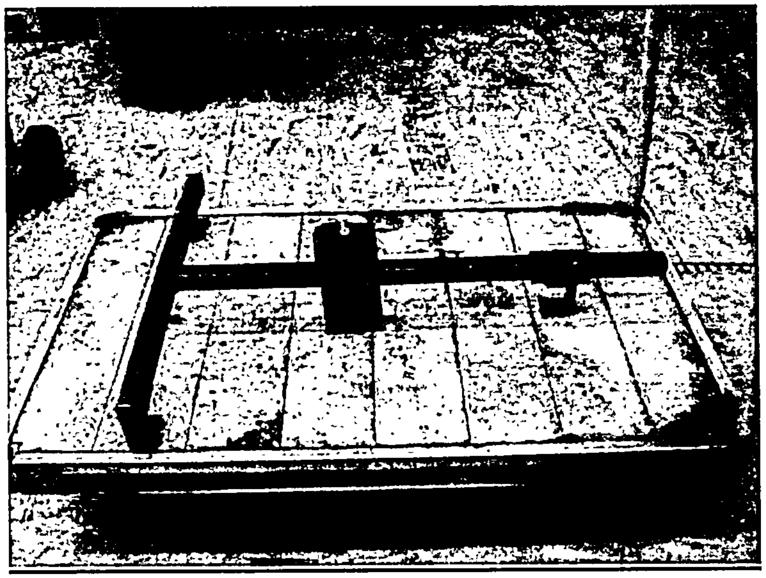

APPENDIX B

Conclusion	Definition
[illegible]	The facility is in compliance with applicable regulatory/policy requirements included in the audit scope. Isolated exceptions may be noted but they are minor in nature and do not materially impact the overall effectiveness of the compliance program. Systems are in place to identify and execute applicable requirements. Personnel are knowledgeable of processes and regulatory requirements.
[illegible] improvements needed	There is a high degree of compliance with regulatory/policy requirements. A few requirements are not satisfied as a result of isolated weaknesses in an overall effective program. Personnel are knowledgeable of regulatory requirements. No significant exceptions are noted.
Improvements in controls needed	The facility is acceptable but not remarkable with several minor exceptions or one significant exception to regulatory/company policy requirements being noted. The exceptions may be the result of (1) a failure to implement certain required aspects of the compliance program, (2) a weakness in the process used to address environmental compliance and (3) a lack of understanding of the regulatory requirements.
Major improvements in controls needed	More than one significant exception to applicable requirements, a pattern of nonconformance with applicable requirements, or the absence of required programs are noted. Personnel may not have a good understanding of the program requirements applicable to their facility or no systems are in place to monitor adequately and ensure environmental compliance.

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Pike Electric Corporation – Contract Compliance Review

Audit Services Department – FINAL REPORT

AMERICAN ELECTRIC POWER

AEP: America's Energy Partner℠

AUDIT SERVICES DEPARTMENT

Pike Electric Corporation – Contract Compliance Review

Report Issue Date: September 24, 2010

Project Number: AU04310

Distribution: Patrick Weyers

cc:
Mike Morris
Carl English
Bob Powers
Venita McCellon-Allen
Charles Patton
Paul Chodak
Joe Hamrock
Gregory Pauley
Wade Smith
Stuart Solomon
Craig Rhoades
Mark Coleman
Alice Bonning
Rich Mueller

REVIEW SUMMARY

- ***BACKGROUND:***

This review was initiated to verify contract compliance for Pike Electric Corporation (Pike). Pike provided construction and/or maintenance services for AEP distribution operations during the period reviewed. From January 2008 through December 2009, AEP paid approximately $77 million to Pike. Several agreements and the amendments to these agreements formed the contractual basis for the relationship.

The review was conducted by Revenew International, LLC (Revenew) on behalf of AEP during the third quarter of 2010.

- ***THE OBJECTIVES OF THIS REVIEW WERE TO DETERMINE IF:***

  - Controls were in place to ensure the contract terms were applied appropriately; and that
  - Contract payments were accurate.

- ***THE SCOPE OF OUR REVIEW WAS AS FOLLOWS:***

We reviewed the following scope areas in relation to the objectives noted above:

  - A sample of 130 Pike distribution operations invoices, totaling approximately $960,000, which were issued during the period January 2008 through December 2009.
  - Payroll tax reconciliations were performed for the years 2008 and 2009.

Pike Electric Corporation - Contract Compliance Review – FINAL REPORT

Audit Services Department

REVIEW SCORECARD

This scorecard summarizes our conclusions for each scope area covered in the review. In summary, only one minor issue related to labor classification billing errors was noted on expenditures of approximately $77 million during the audit scope period. The issue actually resulted in an underbilling by Pike of approximately $12,000. Pike did not request reimbursement from AEP for the issue noted.

SCOPE AREA	Issue(s) Present	CONCLUSION CLASSIFICATION
Controls were in place to ensure the contract terms were applied appropriately		WELL CONTROLLED
Contract payments were accurate		Payments Accurate
OVERALL CONCLUSION FOR REVIEW		WELL CONTROLLED and Payments Accurate

Appendix 1

Classification of Audit Report Conclusions

Conclusion	Definition
Well-controlled	Controls are appropriately designed and are operating effectively to manage risks. Control issues may exist, but are minor.
Well-controlled but minor improvements needed	Medium-level control issues (either design or operating effectiveness) are present but do not compromise achievement of important control objectives.
Improvements in controls needed	High-level or medium-level control weaknesses are present that compromise achievement of one or more important control objectives but do not prevent the process or function from achieving its overall purpose. While important weaknesses exist, their impact on the management of risks is limited rather than widespread.
Major improvements in controls needed	High-level control weaknesses exist across numerous control objectives that potentially prevent the process or function from achieving its overall purpose. The impact of weaknesses on management of risks is widespread rather than isolated either due to the number or nature of control weaknesses.

Classification of Audit Issues

Risk Significance	Risk Definition
High	Likelihood of the condition occurring must be more than remote **and** potential impact must be significant in relationship to the underlying financial information, overall objectives, or level of compliance of the function or process audited.
Medium	Likelihood of the condition occurring must be more than remote **or** potential impact must be significant in relationship to the underlying financial information, overall objectives, or level of compliance of the function or process audited.
Low	Enhancement to a current process that would add value, but not necessarily have a significant impact to the company from a financial, compliance, effectiveness, or efficiency standpoint. Would entail process improvement or have a relatively small monetary impact.

AMERICAN ELECTRIC POWER

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AUDIT SERVICES DEPARTMENT

Davis H. Elliot Company – Contract Compliance Review

Report Issue Date: December 16, 2010

Project Number: AU04810

Distribution: Patrick Weyers

cc:
Mike Morris
Carl English
Bob Powers
Venita McCellon-Allen
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Paul Chodak
Joe Hamrock
Gregory Pauley
Wade Smith
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Alice Bonning
Rich Mueller

Audit Services Department

REVIEW SUMMARY

- *BACKGROUND:* Davis H. Elliot Company (DHE) provides construction and/or maintenance services for AEP distribution operations. During the audit scope period of October 2006 through December 2009, AEP paid approximately $118 million to DHE. Several agreements formed the contractual basis for the relationship between AEP and DHE during the audit period.

  The review was conducted by Revenew International, LLC (Revenew) on behalf of AEP.

- *THE OBJECTIVES OF THIS REVIEW WERE TO DETERMINE IF:*

  - Controls were in place to ensure the contract terms were applied appropriately; and that
  - Contract payments were accurate.

- *THE SCOPE OF OUR REVIEW WAS AS FOLLOWS:*

  We reviewed the following scope areas in relation to the objectives noted above:

  - 235 DHE invoices, totaling approximately $2.3 million, which were issued during the period October 2006 through December 2009.

REVIEW SCORECARD

This scorecard summarizes our conclusions for each scope area covered in the review. In summary, we achieved monetary recoveries of $68,000 on expenditures of approximately $118 million during the audit scope period. **The two minor issues identified related to labor rate billings and annual worker's compensation reconciliations, both of which resulted in overbillings to AEP**

SCOPE AREA	Issue(s) Present	CONCLUSION CLASSIFICATION
Controls were in place to ensure the contract terms were applied appropriately	None	Well-Controlled
Contract payments were accurate	None	Payments Accurate
OVERALL CONCLUSION FOR REVIEW		Well-Controlled; Payments Accurate

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Appendix 1

Classification of Audit Report Conclusions

Conclusion	Definition
[illegible]	Controls are appropriately designed and are operating effectively to manage risks. Control issues may exist, but are minor.
[illegible]	Medium-level control issues (either design or operating effectiveness) are present but do not compromise achievement of important control objectives.
Improvements in controls needed	High-level or medium-level control weaknesses are present that compromise achievement of one or more important control objectives but do not prevent the process or function from achieving its overall purpose. While important weaknesses exist, their impact on the management of risks is limited rather than widespread.
Major impr[illegible]	High-level control weaknesses exist across numerous control objectives that potentially prevent the process or function from achieving its overall purpose. The impact of weaknesses on management of risks is widespread rather than isolated either due to the number or nature of control weaknesses.

Classification of Audit Issues

Risk Significance	Risk Definition
High	Likelihood of the condition occurring must be more than remote **and** potential impact must be significant in relationship to the underlying financial information, overall objectives, or level of compliance of the function or process audited.
Medium	Likelihood of the condition occurring must be more than remote **or** potential impact must be significant in relationship to the underlying financial information, overall objectives, or level of compliance of the function or process audited.
Low	Enhancement to a current process that would add value, but not necessarily have a significant impact to the company from a financial, compliance, effectiveness, or efficiency standpoint. Would entail process improvement or have a relatively small monetary impact.

AMERICAN ELECTRIC POWER

Date: February 3, 2011

Subject: Report of Audit
2010 Coal Pile Inventories

From: J. R. Brooks

To: G. M. Barnett

We have completed our review of AEP's coal pile inventory results for inventories conducted during 2010. A total of 39 inventories were conducted at 21 plants and Cook Coal Terminal during the year. The purpose of our review was to:

- Review the System Power Plants' Spring and Fall coal inventory reports for completeness and propriety.
- Assess the reasonableness of book inventory number at time of survey, which is compared to physical inventory results to determine the coal inventory adjustment.
- Determine whether the coal inventory adjustments reported by the Power Plants were calculated accurately and in compliance with AEP System Accounting Bulletin No. 4. AEP System Accounting Bulletin No. 4 requires recording 100% of the difference between the physical inventory and the book inventory and performing another physical inventory within 6 months, if the difference, as a percent of consumed, is greater than +/- 2%.
- Determine that plants with a variance of +/- 2% investigated the variances and addressed any issues discovered.
- Verify that the accounting entries recording the financial adjustments were reasonable and complete.
- Observe the inventory volume and density measurement activities at one plant to evaluate compliance with AEP Circular Letter CI-O-CL-0084.

One error was noted during the review. The Big Sandy Plant reported an incorrect book inventory at time of survey due to an error in the Comtrac inventory balance, which was not corrected until after the inventory report was issued. In addition, Fuel Emission & Logistics advised the plant that coal in the bunkers should not have been added to the as surveyed tons for comparison to the book inventory because once coal passes over the belt, it has been deducted from the Comtrac inventory balance as consumed. Due to the errors, inventory was overstated by 4,994 tons. A revised 0955A report was issued in January 2011. Since Kentucky requires that inventory adjustments be valued at $1 and passed through the fuel clause, the impact is immaterial to the financial statements. This results in the price per ton of the remaining inventory being increased.

In addition, management self-detected one error. The Clinch River Plant miscalculated book inventory at time of survey, resulting in an understatement of inventory of 1,007 tons. A revised 0955A report was issued in July 2010. Due to immateriality, no adjusting journal entry was made; the error was corrected in the fall 2010 survey.

Based on our review, we believe that the coal pile inventory results and adjustments are properly stated, in all material respects as of December 31, 2010.

c:

M. G. Morris	S. M. Debord	J. M. Buonaiuto
R. A. Mueller	M. C. Mills	A. B. Reis
B. X. Tierney	J. D. LaFleur	F. S. Travis
N. K. Akins	M. A. Peifer	J. W. Hoersdig
T. K. Light	D. V. Lee	T. M. Dooley
M. C. McCullough	G. C. Knight	G. T. Gaffney
W. L. Sigmon	P. W. Franklin	B. J. Frantz
T. V. Riordan	M. W. Flynn	
P. J. Amaya		

Project # GE07210

Audit of Selected Environmental Programs at the Hazard Service Center Hazard, Kentucky

January to March, 2011

Gary T Sommerville, CPEA

Kirk Nofzinger, CPEA

1. SUMMARY

An audit of selected ESH programs was conducted during the period of January to March, 2011 at the Hazard Service Center, Hazard, Kentucky. The audit site visit occurred on January 12 and 13, 2011. The ESH Programs reviewed during this audit and the associated program evaluations are summarized in the tables below. Please note that the conclusion classifications are defined in Appendix 1 located at the end of this report.

An environmental audit was last conducted at this site in May 2002. All issues from the 2002 audit have been closed and none of the issues are repeated in the current audit.

Well Controlled (Green)
Processes and controls are well designed and operating effectively with all (or virtually all) of the objectives achieved. For those limited areas where isolated exceptions are noted, the departures are determine to be occasional, outside of normal conditions and minor in comparison to the overall level of compliance achieved.

In the audit team's judgment, the Hazard SC compliance program for the selected ESH Programs reviewed is **Well Controlled.** No High/Medium Risk Comments were identified during the audit. Two low level issues were identified and corrective actions for both issues have been completed by site management.

Status*	Comment Present	Program	Status	Comment Present	Program
		Asbestos		x	PCBs
		Chlorofluorocarbons (CFCs)			Spill Prevention Control & Countermeasure Plans (SPCC)
NA		Drinking Water			Solid/Hazardous Waste
NA		Emergency Planning/Community Right-to-Know (EPCRA)			Universal Waste
		Emergency Generator		x	Used Oil
NA		Kentucky Groundwater Plan	NA		USTs
		Hazardous Materials Transportation (Hazmat/DOT)			

* *Definition of color code can be found in Appendix B.*

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APPENDIX B:

Classification of Audit Report Conclusions (Overall and Program specific)

Well Controlled	Processes and controls are well designed and operating effectively with all (or virtually all) of the objectives achieved. For those limited areas where isolated exceptions are noted, the departures are determine to be occasional, outside of normal conditions and minor in comparison to the overall level of compliance achieved.
Well Controlled with Minor Improvement Needed	There may be several minor exceptions to regulatory requirements or minor level control issues (either design or operating effectiveness) resulting in exceptions to requirements that do not compromise achievement of process objectives. The exceptions would **not** 1) result in serious injury or illness – damage beyond first aid is extremely remote; 2) cause a negative impact on the environment; 3) result in formal enforcement action or reputational harm.
Improvements in Controls Needed	One or more medium to high level compliance exceptions or control weaknesses exist that are more than isolated anomalies but do not prevent the process or function from achieving it's overall purpose. These may result in 1) significant departures from established criteria or lapses in program implementation; 2)potential to result in injury or illness that would **not** be serious; 3)limited impact to the environment; 4)potential for minimum to moderate enforcement action or reputational harm. (*This may be applied as a modifier to a specific program if the facility is believed to have a generally controlled overall ESH program).*
Requires Significant Improvement	High level compliance exception(s) or control weakness(es) exist that could result in either 1)death, severe injury, serious illness of employees or the public or place employees/public in serious imminent danger; 2) serious impact to the environment; 3) substantial enforcement action or reputational harm; or 4) interruption of facility operations.

Classification of Audit Comments

Low Risk	Isolated or minor exceptions to regulatory requirements or minor level control issues (either design or operating effectiveness) that do not compromise the achievement of process objectives. The exceptions would **not** 1) result in serious injury or illness – damage beyond first aid is extremely remote; 2) cause a negative impact on the environment; 3) result in formal enforcement action or reputational harm.
Medium Risk	An exception that can moderately impact overall ESH control or compliance objectives. These

	exceptions may result in one of the following: 1) significant departures from established criteria or lapses in program implementation; 2) potential to result in injury or illness but the injury or illness would not cause serious or lasting harm; 3)limited impact to the environment; or 4) potential for minimum to moderate enforcement action or reputational harm. Repeated exceptions from prior audits will cause the comment to fall into this category at a minimum.
High Risk	An exception that can result in serious impacts to overall ESH control or compliance objectives. These exceptions have the potential to result in one or a combination of the following: 1) death, severe injury, serious illness of employees or the public or place employees/public in serious imminent danger; 2) serious impact to the environment; 3) substantial enforcement action or reputational harm; or 4) interruption of facility operations.

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Audit Services Department

APCo Generation Stores

Date Issued: 3/30/2011

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Debra Osborne
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David Wickline
Alice Bonning
Richard Mueller

AMERICAN ELECTRIC POWER

Project Number: **GE08010**

APCo Generation Stores

BACKGROUND:

The Generation group categorized all AEP facilities into regions with a manager responsible for each facility within their region. There are currently 18 facilities aligned under APCo Generation. Additionally, for audit purposes, KPCo was included within this APCo Generation Stores engagement. The storeroom inventory values for these facilities as of January 11, 2011 are listed below and are grouped by the facilities visited and not visited.

Facilities Visited	Primary Fuel	MW Capacity	Storeroom Value	Facilities Not Visited	Primary Fuel	MW Capacity	Storeroom Value
Amos	Coal	2900	$ 34,434,776	Clinch River	Coal	705	$ 6,385,789
Mountaineer	Coal	1300	$ 20,355,236	Glen Lyn	Coal	335	$ 3,295,669
Sporn	Coal	1050	$ 18,169,538	Kanawha River	Coal	400	$ 2,932,692
Big Sandy	Coal	1060	$ 10,896,415	Smith Mountain	Hydro	586	$ 1,393,476
				Racine	Hydro	48	$ 713,876
				Claytor	Hydro	75	$ 432,941
				Twin Branch	Hydro	5	$ 236,094
				Central Machine Shop	N/A	N/A	$ 139,774
				Leesville	Hydro	50	$ 130,878
				Byllesby	Hydro	22	$ 127,656
				Marmet	Hydro	14	$ 98,088
				Reusens	Hydro	13	$ 71,732
Total – Facilities Visited			$ 83,855,965	Winfield	Hydro	15	$ 25,850
Total APCo & KPCo Generation			$ 99,868,471	Niagara	Hydro	2	$ 21,154
Percent Coverage			84%	London	Hydro	14	$ 6,837

APCo Generation Stores

OBJECTIVE:

The objective of this audit was to evaluate the effectiveness of APCo Generation storeroom controls and processes to determine whether plant transactions are recorded completely, accurately, timely, and are authorized by appropriate personnel.

SCOPE:

The scope of the audit included processes and controls in place at selected APCo Generation storerooms for the years 2010 and 2011 to date. Specific areas reviewed included:

- Cycle counts and corresponding adjustments
- Obsolete and scrap material
- Non-booked inventory
- Material receiving, issuance, and return process
- Capital spare parts identification and classification

The locations selected for review included four coal plants. These four facilities combined represent 84% of the APCo and KPCo Generation storeroom inventory dollars.

APCo Generation Stores

CONCLUSION:

This scorecard summarizes our conclusions for each scope area covered in the review. In addition, comments that relate to each scope area are referenced to the Comments, Risks and Resolutions section below. Please note that the conclusion classifications are defined in Appendix 1 located at the end of this report.

Scope Area	Comment Reference	Amos	Mountaineer	Sporn	Big Sandy
Cycle Counts and Corresponding Adjustments					
Obsolete and Scrap Material					
Non-booked Inventory	(2)				
Material Receiving, Issuance, and Return Process	(1)				
Capital Spare Parts Identification and Classification					
OVERALL CONCLUSION FOR REVIEW		Well Controlled with Minor Improvements Needed	Well Controlled with Minor Improvements Needed	Well Controlled	Well Controlled

<u>COMMENTS, RISKS, AND RESOLUTIONS</u>

In the following portion of the report, we have addressed the areas for improvement identified during our audit, their risk, and significance to the business. Also included are the planned action steps, responsible parties, and target dates for completion as provided by management. The significance level is based on our assessment of the combined impact and likelihood for each condition noted.

Low risk and operating efficiency comments have been communicated to plant and supply chain personnel in a separate "Low Risk Comments Memo."

1) Physical Access Controls over Storeroom Facilities

Comment – Access to the controlled stock at Mountaineer Plant appears to be excessive.

For cost efficiency purposes the storeroom at Mountaineer Plant is only staffed during the dayshift. During off-shifts all plant employees (but not contractors) have access to the storeroom through the use of their Company badge. Access to the storeroom is necessary during these off-shifts in order to maintain plant operations. When employees remove controlled stock items from the storeroom they are required to complete a log entry that storeroom personnel subsequently use to enter the transaction into inventory records. If items are removed and not entered on the log it would not be detected until the next physical inventory or until the item is needed and determined to be unavailable.

Additionally, during the dayshift, the logistics of the storeroom staff location and available entry points to the storeroom do not prevent someone from entering undetected and removing controlled stock items.

Risk – Inventory may be removed from the main storeroom without completion of the appropriate documentation and result in erroneous inventory balances. Undocumented inventory movement may also prompt added time expenditure during periodic inventory cycle counts in efforts to reconcile inventory report balances and physical cycle count balances.

Resolution – Supply Chain Management will collaborate with Mountaineer Plant Management to implement the following access control enhancements:

- Supply Chain will train and assign staff to the issue window area and move the entry point to the door directly in front of the issue window. The side door previously used to access the controlled stock area will be locked. This will eliminate undetected access during the dayshift. ***Target Date: June 30, 2011***
- Plant Management will evaluate access assignments to restrict access to selected supervisory personnel during the off-shift hours. ***Target Date: May 15, 2011***
- Supply Chain will also lock gates to the controlled stock area and will provide supervisory personnel who have been granted badge access the means to access locked areas for operational purposes during off-shift hours. ***Target Date: May 15, 2011***

<u>Significance:</u>	<u>Responsible Party:</u>	<u>Target Date:</u>
Medium	Diana Weaver, Terri Bowie, Charles Powell	See dates above

2) Unprocessed Non-booked Inventory

Comment – Processing of items identified during the non-booked inventory walkthrough at Amos Plant was not substantially completed within the required period.

Company policy requires that walkthroughs of facilities be performed at least annually to identify items that should be returned to stock. Walkthroughs are to be completed by September 30th and completion of accounting adjustments is required by December 31st. The walkthroughs performed at Amos Plant during 2010 were completed timely; however, 29 of 176 items identified during the walkthroughs were not entered into the stock records by the end of the year. These items had an estimated value of $155,000 and were resolved by Amos Plant storeroom and plant personnel subsequent to the audit field visit.

Risk – Failure to process non-booked inventory items identified during the non-booked inventory walkthrough in a timely manner, may misstate inventory balances reported in the financial statements.

Resolution – Supply Chain Management will provide additional oversight to assure that all non-booked inventory is resolved and that required adjustments are posted to Asset Suite prior to year-end. Additional oversight measures will include meeting with Plant Management quarterly to assure that non-booked inventory is being addressed and processed in a timely manner.

Significance:	Responsible Party:	Target Date:
Medium	Diana Weaver, Terri Bowie	March 31, 2011

Appendix 1

Classification of Audit Report Conclusions

Operational/Financial (Internal Controls Reviews):

Conclusion	Definition
[illegible]	Controls are appropriately designed and are operating effectively to manage risks. Control issues may exist, but are minor.
[illegible]	Medium-level control issues (either design or operating effectiveness) are present but do not compromise achievement of important control objectives.
Improvements in controls needed	High-level or medium-level control weaknesses are present that compromise achievement of one or more important control objectives but do not prevent the process or function from achieving its overall purpose. While important weaknesses exist, their impact on the management of risks is limited rather than widespread.
[illegible]	High-level control weaknesses exist across numerous control objectives that potentially prevent the process or function from achieving its overall purpose. The impact of weaknesses on management of risks is widespread rather than isolated either due to the number or nature of control weaknesses.

Classification of Audit Findings

Financial Audit Findings:

Risk Significance	Risk Definition
High	Likelihood of the condition occurring must be more than remote <u>**and**</u> potential impact must be significant in relationship to the underlying financial information, overall objectives, or level of compliance of the function or process audited.
Medium	Likelihood of the condition occurring must be more than remote <u>**or**</u> potential impact must be significant in relationship to the underlying financial information, overall objectives, or level of compliance of the function or process audited.
[illegible]	Enhancement to a current process that would add value, but not necessarily have a significant impact to the company from a financial, compliance, effectiveness, or efficiency standpoint. Would entail process improvement or have a relatively small monetary impact.

Audit of selected Environmental and Asbestos Programs at the Ashland Service Center Ashland, Kentucky

January to March 2011

Gary Sommerville, CPEA

Kirk Nofzinger, CPEA

1. SUMMARY

An audit of selected ESH programs was conducted during the period of January to March 2011 at the Ashland Service Center, Ashland, Kentucky. The audit site visit occurred on January 10-12, 2011. The ESH Programs reviewed during this audit and the associated program evaluations are summarized in the tables below. Please note that the conclusion classifications are defined in Appendix B at the end of this report.

An environmental audit was last conducted at this site in March 2000. All issues from the 2000 audit have been closed; however, the following issues were repeated during the current audit and are identified as yellow in the low level comment table.

Controlled but Minor Improvements Needed (Green)

There may be several minor exceptions to regulatory requirements or minor level control issues (either design or operating effectiveness) resulting in exceptions to requirements that do not compromise achievement of process objectives. The exceptions would not 1) result in serious injury or illness - damage beyond first aid is extremely remote; 2) cause a negative impact on the environment; 3) result in formal enforcement action or reputational harm.

In the audit team's judgment, the overall Ashland SC compliance program for the selected ESH Programs reviewed is **Well Controlled but Minor Improvements Needed.** One medium risk comment was identified related to oversight of asbestos abatement projects. Comments in the PCB and Used Oil programs were elevated to medium risk because they were repeated from the prior audit.

Status	Comment Present	Program	Status	Comment Present	Program
NA	x	Aboveground/Underground Storage Tanks (UST/AST)		x	PCBs
	x	Asbestos			Spill Prevention Control & Countermeasure Plans (SPCC)
		Chlorofluorocarbons (CFCs)		x	Solid/Hazardous Waste
NA		Drinking Water			Storm Water
		Emergency Planning/Community Right-to-Know (EPCRA)		x	Universal Waste
	x	Kentucky Groundwater Plan		x	Used Oil
		Hazardous Materials Transportation (Hazmat/DOT)			

- *Definition of color code can be found in Appendix B.*

2. AUDIT SCOPE

The period of review for each of the selected ESH programs is generally inclusive of the time since the previous audit or the retention requirement by the applicable regulation. The period may be adjusted to accommodate time constraints and to address those programs having the greatest potential impact on a given facility.

Variations from scope: **None.**

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3. COMMENTS, RISKS AND RESOLUTIONS:

In the following portion of the report, we have addressed the areas for improvement identified during the audit, their risk and significance to the business. Also included are the corrective action plans developed by responsible business unit management. *Low-risk compliance and operating efficiency comments are not included within the final report but have been documented and management has provided a response with corrective actions taken to address these comments.* All comments are being tracked to completion by Audit Services and are subject to review in future audits.

HIGH/MEDIUM RISK COMMENTS – *Weaknesses or deficiencies in the ESH management system or non-conformance with regulatory requirements or company policy that present more than an isolated or minor risk (see Appendix B). Corrective action is required and is tracked to completion by Audit Services.*

No., Status, and Significance	Comment/Risk	Responsible Organization	Corrective Action
Asbestos			
1 Closed MEDIUM RISK	Project management/oversight duties, outlined in Sections 4 and 36 of the AEP KY AIM are not being implemented for asbestos abatement projects. Interviews with site personnel indicated that multiple abatement jobs have been conducted by external contractors for Transmission Station and Information Technology (IT) however, none of these projects was overseen by a qualified individual working directly on AEP's behalf (either employee or third-party contractor) and supervisory activities including inspections of contractor site activities, confirmation of submittal of required notifications, and maintenance of required documentation were not	T-Station & IT	The Transmission Station and Information Technology managers have reviewed AEP's asbestos policies with their employees on February 28, 2011. They were instructed not to do "any" related asbestos work and that contract professionals must be involved in any abatement and disposal. Industrial Hygiene will be involved with determining the correct procedures for the abatement, oversee the abatement contractor and ensure all proper documentation is completed. Employees have also been instructed to contact their Region Environmental Coordinator to insure that proper notification and disposal procedures are followed.

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HIGH/MEDIUM RISK COMMENTS – *Weaknesses or deficiencies in the ESH management system or non-conformance with regulatory requirements or company policy that present more than an isolated or minor risk (see Appendix B). Corrective action is required and is tracked to completion by Audit Services.*

No., Status, and Significance	Comment/Risk	Responsible Organization	Corrective Action
	performed, therefore, the proper execution of required abatement practices could not be confirmed during the audit. Required documentation was available for only a single project performed Master Mechanical on behalf of the Station Department in 2010. **Risk:** Compliance Risk; Non-conformance to Company Policy; Failure to identify potential gaps in contractor abatement controls may result in compliance risk or add to the potential for exposure to ACM materials.		
PCBs			
2 Closed MEDIUM RISK	Documentation required by 40 CFR 761.125(b)(3) was not available to demonstrate the proper cleanup for three of 12 oil spills during the period between 2006 and 2010 that involved equipment assumed to be 50 to 499 ppm PCB. The spills, designated as #09-27, #09-31 and #09-32, occurred during an ice storm in 2009 and were cleaned-up by a spill contractor.	Distribution & REC	Spill reports have been completed for the three spills in question and placed in the file. All three spills were cleaned up by Weavertown Environmental. To prevent this problem from reoccurring, Weavertown has been supplied with spill reports and given instruction on how to fill them out and properly document and track debris from an assumed 50 to 499 ppm PCB spill. These documents will be inspected as they are received by the REC, to assure that they are

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HIGH/MEDIUM RISK COMMENTS – *Weaknesses or deficiencies in the ESH management system or non-conformance with regulatory requirements or company policy that present more than an isolated or minor risk (see Appendix B). Corrective action is required and is tracked to completion by Audit Services.*

No., Status, and Significance	Comment/Risk	Responsible Organization	Corrective Action
	(Repeat from 2000 Audit.) **Risk:** Compliance Risk		being completed correctly.
Used Oil			
3 Closed MEDIUM RISK	Nine drums in the PCB Long Term Storage Building were not labeled with the words "Used Oil" as required by 40 CFR 279.22. The drums were labeled with the words "oil", "dirty oil", or "scrap oil". **(Repeat from 2000 Audit.)** **Risk:** Compliance Risk	T-Station	The nine drums were properly labeled the next day and then bar-coded for TCI. They were picked up for recycling on the February 22, 2011, by TCI. Signs were prepared to remind and instruct employees on how to properly label used oil drums. These signs were placed in the PCB Long Term Storage Building and in the fleet garage. The REC also reviewed the requirements for managing used oil and labeling containers with the T-Station group.

LOW RISK COMMENTS – *Isolated or minor exceptions to regulatory and/or policy requirements or minor level control issues (either design or operating effectiveness) that do not compromise achievement of process objectives. Corrective action is required and is tracked to completion by Audit Services.*

No./Status	Comment	Responsible Organization	Corrective Action
Kentucky Groundwater Protection Plan			
Closed LOW RISK	The Ashland Groundwater Protection Plan was last reviewed on 8/17/2001. According to Kentucky groundwater rule 401 KYR 5: 037 Section 1(3), each groundwater protection plan	REC	Environmental Services will review and update the Groundwater Protection Plan by March 31, 2011. The Plan will be maintained in the storeroom office with

LOW RISK COMMENTS – *Isolated or* ***minor exceptions*** *to regulatory and/or policy requirements or minor level control issues (either design or operating effectiveness) that do not compromise achievement of process objectives. Corrective action is required and is tracked to completion by Audit Services.*

No./Status	Comment	Responsible Organization	Corrective Action
	shall be reviewed in its entirety every three (3) years, by the persons responsible for the plan, updated as necessary, and recertified. To the extent possible, the review shall include a reevaluation of the design and operation procedures for the pollution prevention practices previously selected for the plan to ensure that they are effective. Conditions at the site (transfer of gasoline, diesel and used oil) meet the requirements for maintaining a plan. **Risk:** Compliance Risk		the facility SPCC Plan. LE&RS will also create a task in Enviance by March 31, 2011, that will remind LE&RS and W&ERS that the plan must be reviewed every three years.
Hazardous Waste			
5 Closed LOW RISK	An exception report was not submitted to US EPA, as required by 40 CFR 262.42, when completed manifest #002251460FLE was not returned by the disposal vendor within 60 days of the shipment date. This manifest was for the single shipment of hazardous waste transported from the Service Center on September 14, 2009, when the service center was a small quantity generator of hazardous waste. **Risk:** Compliance Risk	Stores & REC	Going forward, entry will be made in the Enviance Quick Shipment System when waste is shipped and the system will automatically notify the REC to check on the manifest 10 days after the shipment is made. If not closed after 25 days and the manifest is not returned, the REC and his supervisor will be notified and they will contact the disposer to determine the status of the manifest.
Universal Wastes			
6	The length of time that universal waste had	Workplace	The Workplace Services employees have

LOW RISK COMMENTS – *Isolated or minor exceptions to regulatory and/or policy requirements or minor level control issues (either design or operating effectiveness) that do not compromise achievement of process objectives. Corrective action is required and is tracked to completion by Audit Services.*

No./Status	Comment	Responsible Organization	Corrective Action
Closed LOW RISK	been accumulated could not be demonstrated for one of the two containers of universal waste lamps stored by Workplace Services and one container of universal batteries stored by Information Technology, as required by 40 CFR 273.15. **Risk:** Compliance Risk	Services	been instructed to date the universal waste labels when they put them on the accumulation containers. The Workplace Supervisor or his/her designee will periodically inspect these containers to make sure this practice is being followed. The universal waste labeling requirements were reviewed during the January safety meeting for the KYPo Workplace services employees, by Tim Evans, Workplace services area supervisor. Although Workplaces services is not entirely sure they would require the option of storing universal waste longer than 12 months, if required, written justification will be routed through the local REC (Dan Dooley) for proper approvals.
USTs			
Closed LOW RISK	Test results of the Underground Storage Tank System annual line leak detector test were not submitted to KDEP within 30 days of the test as required by 401 KAR 42:040 Section 1(3). **Risk:** Compliance Risk	Workplace Services & REC	The line leak detector test was conducted on June 10, 2010. The system passed successfully and the results were sent to the Kentucky DEP when they were requested during an Underground Tank Inspection on September 7, 2010. When Workplace Services (WPS)

LOW RISK COMMENTS – *Isolated or **minor exceptions** to regulatory and/or policy requirements or minor level control issues (either design or operating effectiveness) that do not compromise achievement of process objectives. Corrective action is required and is tracked to completion by Audit Services.*			
No./Status	**Comment**	**Responsible Organization**	**Corrective Action**
			schedules the annual line leak detector test (about 11 months from the previous test) they will notify the REC by email the date when the test will take place. When the REC receives the email he/she will place a reminder on their Lotus Notes (LN) calendar to submit the tests results to Kentucky DEP within 30 days of the test. The contractor performing the test will be instructed by WPS send a copy of the test results to both the WPS building mechanic and the REC. The REC will then mail a copy of the tests results to Kentucky DEP within 30 days of the test.

APPENDIX B

Classification of Audit Report Conclusions (Overall and Program specific)

[illegible]	Processes and controls are well designed and operating effectively with all (or virtually all) of the objectives achieved. For those limited areas where isolated exceptions are noted, the departures are determine to be occasional, outside of normal conditions and minor in comparison to the overall level of compliance achieved.
[illegible]	There may be several minor exceptions to regulatory requirements or minor level control issues (either design or operating effectiveness) resulting in exceptions to requirements that do not compromise achievement of process objectives. The exceptions would <u>not</u> 1) result in serious injury or illness - damage beyond first aid is extremely remote; 2) cause a negative impact on the environment; 3) result in formal enforcement action or reputational harm.
Improvements in Controls Needed	One or more medium to high level compliance exceptions or control weaknesses exist that are more than isolated anomalies but do not prevent the process or function from achieving it's overall purpose. These may result in 1) significant departures from established criteria or lapses in program implementation; 2)potential to result in injury or illness that would <u>not</u> be serious; 3)limited impact to the environment; 4)potential for minimum to moderate enforcement action or reputational harm. (*This may be applied as a modifier to a specific program if the facility is believed to have a generally controlled <u>overall</u> ESH program).*
Requires Significant Improvement	High level compliance exception(s) or control weakness(es) exist that could result in either 1)death, severe injury, serious illness of employees or the public or place employees/public in serious imminent danger; 2) serious impact to the environment; 3) substantial enforcement action or reputational harm; or 4) interruption of facility operations.

Classification of Audit Comments

Low Risk	Isolated or minor exceptions to regulatory requirements or minor level control issues (either design or operating effectiveness) that do not compromise the achievement of process objectives. The exceptions would <u>not</u> 1) result in serious injury or illness - damage beyond first aid is extremely remote; 2) cause a negative impact on the environment; 3) result in formal enforcement action or reputational harm.
Medium Risk	An exception that can moderately impact overall ESH control or compliance objectives. These exceptions may result in one of the following: 1) significant departures from established criteria or lapses in program implementation; 2) potential to result in injury or illness but the injury or illness would not cause serious or lasting harm; 3)limited impact to the environment; or 4) potential for minimum to moderate enforcement action or reputational harm. <u>Repeated exceptions</u> from prior audits will cause the comment to fall into this category at a minimum.
High Risk	An exception that can result in serious impacts to overall ESH control or compliance objectives. These exceptions have the potential to result in one or a combination of the following: 1) death, severe injury, serious illness of employees or the public or place employees/public in serious imminent danger; 2) serious impact to the environment; 3) substantial enforcement action or reputational harm; or 4) interruption of facility operations.

Kentucky Power Service Delivery Internal Controls Review

Date Issued: 12/20/2011

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Project Number: **AU03611**

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AMERICAN® ELECTRIC POWER

Kentucky Power Service Delivery Internal Controls Review

BACKGROUND:
Kentucky Power Company provides electric service to approximately 174,000 customers in Kentucky. In order to provide this electric service, there are many tasks which are required to be performed by numerous employees across many different departments in the company. This review was initiated from Audit Services risk assessment to provide assurance that for these various processes, appropriate controls are in place and are functioning as designed.

OBJECTIVE:
The objective of this review was to ensure that controls have been adequately designed and are operating effectively with respect to selected activities related to providing electric service to retail customers.

SCOPE:
The scope of the review included the following areas related to providing electric service:

- Processing of orders related to activation and deactivation of electric service.
- Contribution-in-Aid of Construction (CIAC) billings and payments.
- Obtaining and recording of distribution easements.
- Work order review and closing.
- Storeroom activities related to receipting, issuance, return of material, and custodianship.

CONCLUSION:

This scorecard summarizes our conclusions for each scope area covered in the review. In addition, comments that relate to each scope area are referenced to the Comments, Risks and Resolutions section below. Please note that the conclusion classifications are defined in Appendix 1 located at the end of this report.

Scope Area	Comments Present	Conclusion Classification
Work Order Processes		Well Controlled
Store Rooms		Well Controlled
Contribution-in-Aid of Construction (CIAC)	1	Well Controlled – Minor Improvements Needed
Distribution Right-of-Way and Easements		Well Controlled
OPS Orders		Well Controlled
OVERALL CONCLUSION FOR REVIEW		Well Controlled – Minor Improvements Needed

COMMENTS, RISKS, AND RESOLUTIONS

In the following portion of the report, we have addressed the areas for improvement identified during our audit, their risk, and significance to the business. Also included are the planned actions steps, responsible parties, and target dates for completion as provided by management. The significance level is based on our assessment of the combined impact and likelihood for each condition noted.

Low-risk and operating efficiency comments were communicated to Kentucky Power and AEP Service Corporation management in a separate "Low Risk Comments Memo."

1) CIAC Requirements Not Always Entered to Design Work Requests

Comment – A review of 758 design work requests in which a CIAC payment had been made revealed that 267 (35%) did not reflect any CIAC requirements. It was subsequently determined that some technicians enter the CIAC requirements to the associated work request and not to the design work request. This procedure does not stop the design work request from being scheduled to be worked and could result in work being completed prior to payment of the CIAC amount.

Risk – Work may be completed prior to receiving the CIAC payment.

Resolution - The policy of setting the appropriate CIAC requirements in the DWMS Storms system will be reviewed with all personnel who create design work orders and CIAC quotes for customers.

Significance:	**Responsible Party:**	**Target Date:**
Medium Risk	Everett Phillips	January 16, 2012

Appendix 1

Classification of Audit Report Conclusions

Operational/Financial (Internal Controls Reviews):

Conclusion	Definition
[redacted]	Controls are appropriately designed and are operating effectively to manage risks. Control issues may exist, but are minor.
[redacted]	Medium-level control issues (either design or operating effectiveness) are present but do not compromise achievement of important control objectives.
Improvements in controls needed	High or medium-level control weaknesses are present that compromise achievement of one or more important control objectives but do not prevent the process or function from achieving its overall purpose. While important weaknesses exist, their impact on the management of risks is limited rather than widespread.
[redacted]	High-level control weaknesses exist across numerous control objectives that potentially prevent the process or function from achieving its overall purpose. The impact of weaknesses on management of risks is widespread rather than isolated either due to the number or nature of control weaknesses.

Classification of Audit Comments

Financial Audits:

Risk Significance	Risk Definition
[redacted]	Likelihood of the condition occurring must be more than remote **and** potential impact must be significant in relationship to the underlying financial information, overall objectives, or level of compliance of the function or process audited.
Medium	Likelihood of the condition occurring must be more than remote **or** potential impact must be significant in relationship to the underlying financial information, overall objectives, or level of compliance of the function or process audited.
Low	Enhancement to a current process that would add value, but not necessarily have a significant impact to the company from a financial, compliance, effectiveness, or efficiency standpoint. Would entail process improvement or have a relatively small monetary impact.

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Dated September 4, 2013
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AMERICAN ELECTRIC POWER

Date: January 23, 2012

Subject: Report of Audit
2011 Coal Pile Inventories

From: J. R. Brooks

To: G. M. Barnett

We have completed our review of AEP's coal pile inventory results for inventories conducted during 2011. A total of 34 inventories were conducted at 21 plants and Cook Coal Terminal during the year. The purpose of our review was to:

- Review the System Power Plants' Spring and Fall coal inventory reports for completeness and propriety.
- Assess the reasonableness of book inventory number at time of survey, which is compared to physical inventory results to determine the coal inventory adjustment.
- Determine whether the coal inventory adjustments reported by the Power Plants were calculated accurately and in compliance with AEP System Accounting Bulletin No. 4. AEP System Accounting Bulletin No. 4 requires recording 100% of the difference between the physical inventory and the book inventory and performing another physical inventory within 6 months, if the difference, as a percent of consumed, is greater than +/- 2%.
- Determine that plants with a variance of +/- 2% investigated the variances and addressed any issues discovered.
- Verify that the accounting entries recording the financial adjustments were reasonable and complete.
- Observe the inventory volume and density measurement activities at one plant to evaluate compliance with AEP Circular Letter CI-O-CL-0084.

Based on our review, we believe that the coal pile inventory results and adjustments are properly stated, in all material respects as of December 31, 2011.

c:

N. K. Akins
R. A. Mueller
B. X. Tierney
R. P. Powers
M. C. McCullough
T. K. Light
W. L. Sigmon
S. W. Burge
T. V. Riordan

S. M. Debord
M. C. Mills
J. D. LaFleur
D. V. Lee
G. C. Knight
P. W. Franklin
P. J. Amaya
M. W. Flynn

J. M. Buonaiuto
A. B. Reis
F. S. Travis
J. W. Hoersdig
T. M. Dooley
G. T. Gaffney
B. J. Frantz

Project # GE01911

Intra-System

AMERICAN® ELECTRIC POWER

To: Walter Sherry

From: Robert M. Wagner

cc: Craig Rhoades, Thomas Jobes, Kirk Cleveland, Rich Mueller

Date: 01/30/2012

Re: Vegetation Management Process Survey - Summary Memorandum

---

BACKGROUND: An AEP System-wide survey of the vegetation management inspection process was performed at the request of System Forestry Management as a follow-up to herbicide contractor billing issues at Public Service Company of Oklahoma. System Forestry Management's aim was to obtain a process comparison and to help determine if there are process gaps, improvement opportunities and best practices.

OBJECTIVE and SCOPE: The objective of this review was to determine if there are (1) process gaps (2) opportunities for improvement; and (3) best practices that System Forestry Management should address or consider. The review covered utility operating companies and transmission function vegetation management inspection processes and practices that were in place during 2011. The survey was completed during September and October 2011 by System Forestry Management personnel at the following business units:

- AEP Texas
- Southwestern Electric Power Company
- Indiana Michigan Power Company
- Public Service Company of Oklahoma
- AEP Ohio – Canton
- AEP Ohio – Columbus
- Appalachian Power Company
- Kentucky Power Company
- Transmission

The survey and other audit procedures focused on application of herbicides and tree growth regulator and tree trimming and removal. Initially, Audit Services summarized the survey results from respondents and provided them in a draft memo to System Forestry Management. Feedback received was reviewed and incorporated in the Review Summary below:

REVIEW SUMMARY: In the following portion of this memorandum, we have presented possible process gaps based on the initial survey responses and follow-up comments received. Other potential improvement opportunities and best practices noted in survey responses were presented to System Forestry Management in a separate observations document for their consideration and use.

1. Development of Expected Costs

Comment - Survey responses indicated that the expected cost by circuit, span or other area was not always computed. While most responses viewed development of expected costs as beneficial, they also noted that resources to do so are currently very limited.

Risk: Development of expected cost for the circuit, span or other area helps to assess the effectiveness and efficiency of vegetation control activities performed by contractors. If cost expectations are not sufficiently developed and used, contractors may overbill or perform unnecessary work.

Action Item to Consider - System Forestry Management should consider assessing the current methods used to develop expected costs for vegetation management work and determine if they provide for effective oversight of vendor work and billings.

2. Oversight of Field Activities

Comment - Oversight of vegetation management field activities may not be adequate for all AEP companies. Specifically, survey responses noted the following:

- Two companies indicated that field inspection was not performed until each job was completed or until the contractor invoice was received (i.e., no in-progress observation or inspection).
- System Forestry survey responses did not consistently indicate observation of spraying equipment calibration and herbicide mixing on a regular basis. Two companies noted observation of calibration and mixing, while other survey responses did not indicate observation of calibration or mixing.

Risk: If System Forestry field presence is not sufficient prior to billing, vendors may overbill and not be detected. Consequently, this may become the baseline for future cost analysis and planning (i.e., like a high bill becoming the baseline for high/low bill edits on a customer electric account). Also, if System Forestry personnel do not periodically observe the equipment calibration and product mixing, herbicide application may not be effective and subject to loss.

Action Item to Consider - Assess current methods used to observe work in progress and work that has been completed to determine if they provide enough field presence to detect ineffective or inefficient practices and to serve as a deterrent to inappropriate activities (e.g., excessive herbicide application or theft).

AMERICAN
ELECTRIC
POWER

Date: January 23, 2013

Subject: 2012 Coal Pile Inventories Audit Report

From: J. R. Brooks

To: G. M. Barnett

We have completed our review of AEP's coal pile inventory results for inventories conducted during 2012. A total of 33 inventories were conducted at 23 plants and Cook Coal Terminal during the year. The purpose of our review was to:

- Review the System Power Plants' Spring and Fall coal inventory reports for completeness and propriety.
- Assess the reasonableness of book inventory number at time of survey, which is compared to physical inventory results to determine the coal inventory adjustment.
- Determine whether the coal inventory adjustments reported by the Power Plants were calculated accurately and in compliance with AEP System Accounting Bulletin No. 4. AEP System Accounting Bulletin No. 4 requires recording 100% of the difference between the physical inventory and the book inventory and performing another physical inventory within 6 months, if the difference, as a percent of consumed, is greater than +/- 2%.
- Determine that plants with a variance of +/- 2% investigated the variances and addressed any issues discovered.
- Verify that the accounting entries recording the financial adjustments were reasonable and complete.

The coal pile survey for the Turk Plant was performed from December 28, 2012 through December 31, 2012 and resulted in a 15,569 ton shortage. The dollar amount associated with the adjustment was placed on the "Passed Adjustments" list for review and disposition by Financial Reporting in accordance with Accounting's Passed Journal Procedure.

Based on our review, we believe that the coal pile inventory results and adjustments are properly stated, in all material respects as of December 31, 2012.

c: N. K. Akins
R. A. Mueller
B. X. Tierney
R. P. Powers
M. C. McCullough
T. K. Light
W. L. Sigmon
S. W. Burge
T. V. Riordan
J. D. LaFleur
D. V. Lee
G. C. Knight
P. W. Franklin
P. J. Amaya
M. W. Flynn
J. M. Buonaiuto
A. B. Reis
F. S. Travis
J. W. Hoersdig
T. M. Dooley
G. T. Gaffney
B. J. Frantz

Project # GE02112

Intra-System

Audit Services Department

Review of Controls over Storm Restoration Costs

Date Issued: 4/19/13

Audit Team:

Callie Dunn
Jim Garrett
Jim Brooks

Distribution:

Craig Rhoades
Tom Kirkpatrick

CC:

Jim Nowak
Patrick Weyers
Matt Stinnett
Judson Schumacher
Ram Sastry
Bob Powers
Brian Tierney
Nick Akins
Rich Mueller
Albert M Smoak
Bruce Evans
Everett G Phillips
Barry Wiard
Philip A Wright
Steven Baker
Selwyn Dias
Venita McCellon-Allen
Wade Smith
Gregory Pauley
Paul Chodak
Charles Patton
Stuart Solomon
Pablo Vegas

AMERICAN ELECTRIC POWER

Project Number: AU00513

Review of Controls over Storm Restoration Costs

BACKGROUND:

In all jurisdictions, AEP's ability to recover significant storm restoration costs through applicable rate mechanisms can have significant impacts on the results of operations. Effective controls and processes are necessary in order to substantiate the validity and accuracy of costs AEP seeks to recover. AEP incurred $388 million in costs from storms over the past 3 years. As of December 31, 2012, AEP had $195 million in deferred storm related costs, not yet being recovered and $63 million in deferred storm related costs being recovered.

When AEP provides mutual assistance to another utility, well-controlled tracking of the costs incurred and the invoicing process can also have a significant impact on operations. In 2012, AEP provided an estimated $36.5 million in assistance to other utilities.

Although the key control objectives are similar for each of AEP's operating companies, the specific procedures followed in tracking costs and billings and verifying invoices for storm costs differs somewhat among the companies. Emergency Restoration Planning is the centralized group that assists the operating companies in obtaining resources and provides some overall procedural guidance. Procurement assists the operating companies in negotiating the related contracts.

OBJECTIVE:

The objective of this review was to evaluate the adequacy of controls over storm restoration costs.

SCOPE:

The scope of this review included the following:

- Providing Assistance, including:
  - Negotiating contracts and rates
  - Tracking time, location, and expenses for resources provided to others
  - Billing outside parties
- Receiving Assistance, including:
  - Negotiating contracts and rates
  - Tracking time, location, and expenses of outside parties
  - Verifying invoices received prior to payment

CONCLUSION:

This scorecard summarizes our conclusions for each scope area covered in the review. In addition, comments that relate to each scope area are referenced to the Comments, Risks and Resolutions section below. Please note that the conclusion classifications are defined in Appendix 1 located at the end of this report.

Scope Area	Comments Present	Conclusion Classification
Providing Assistance	None	Well-controlled
Receiving Assistance	1, 2	**Improvements in controls needed**
OVERALL CONCLUSION FOR REVIEW		**Improvements in controls needed**

COMMENTS, RISKS, AND RESOLUTIONS

In the following portion of the report, we have addressed the areas for improvement identified during our audit, their risks, and significance to the business. Also included are the planned action steps, responsible parties, and target dates for completion as provided by management. The significance level is based on our assessment of the combined impact and likelihood for each condition noted. The criteria for classification of issues and conclusions are contained in Appendix 1 at the end of this report.

Review of Controls over Storm Restoration Costs

1) Inconsistent Time Monitoring During a Storm

Comment – The hours worked associated with labor received from outside contractors and other utilities is not always monitored.

Labor usually represents more than half of the total costs of any given storm; therefore, it is important for AEP personnel to have processes in place to assure an accurate capture of the hours worked by all parties when performing storm work on AEP's behalf. AEP does not have formal guidelines established to direct operating companies in defining and monitoring time. This has resulted in inconsistent procedures among operating companies. The various procedures that are currently being followed do not provide adequate assurance that the time charged by contractors and outside utilities is accurate. Specifically, contractors and non-affiliated utilities are not always required to provide daily time sheets showing hours worked, and even when provided, these are not always signed and retained by AEP personnel. Also, there does not appear to be a common understanding among the operating companies as to what "hours worked" or "duty hours" represents, which could impact the reimbursable hours. In some cases this is interpreted as the total time between leaving and returning to the staging area, while in other cases it is being considered as the time between leaving and returning to the hotel.

Risk – Unless time is consistently reported and monitored there is the potential for erroneous charges to be billed and paid.

Resolution – Distribution Management has approval from Executive Management for a 3 year Storm Preparedness Strategy project. Resolution to the risks identified during this audit will be incorporated into the 3 year project. However, the risks and increased oversight of the current processes will be communicated to operating companies immediately.

Management will establish a common definition of "hours worked" or "duty hours", to be utilized by all operating companies in the absence of a specific overriding contractual agreement. Additionally, guidance will be provided to the operating companies identifying the minimum requirements regarding the monitoring of time reporting and retention of daily time sheets to support subsequent billings.

Significance:	Responsible Party:	Target Date:
Medium Risk	**Tom Kirkpatrick**	
Storm Response Team creates a consistent and standardized manual process for capturing labor of contractors during storms		12/31/2013
Storm Response Team creates consistent and standardized manual process for capturing labor of IOU crews during storms		6/30/2014
Potential Automation of labor units and costs monitoring control investigated and proposed if cost effective		9/30/2014

2) Invoice Submittal Process and Review

Comment – Controls over the receipt and payment of invoices from outside parties need to be enhanced.

The responsibility for review and approval of invoices from outside parties is not clearly defined. The operating companies indicated they rely on T&D Procurement (previously C&DS Contract Management) to review the accuracy of the rates in the invoice. Procurement maintains the accuracy of the rates within the Contract Administration Tracking System (CATS) and provides the established rates to the operating companies, but does not review the invoiced rates submitted outside of CATS. Although the Manager Emergency Restoration Planning performs a high level review of all invoices, he does not have the detailed information, or time, to validate them. Thus, in some cases the invoices from outside parties are not receiving the appropriate level of scrutiny prior to being paid.

Currently, invoices for storm work can be submitted to AEP by contractors via hardcopy, email or electronically through the Contract Administration Tracking System (CATS). Because each contractor can submit multiple invoices for storm assistance, through any of the three channels, the possibility of receiving and paying duplicate charges is increased. This opportunity for error is further increased by the fact that invoices submitted through CATS are assigned a unique invoice number for processing through accounts payable, thus preventing the detection of a duplicate invoice number. There is no subsequent comparison of the estimated and actual billings from each contractor, which would help to identify large variances.

Risk – Inaccurate and/or duplicate payments could occur.

Resolution – Distribution Management has approval from Executive Management for a 3 year Storm Preparedness Strategy project. Resolution to the risks identified during this audit will be incorporated into the 3 year project. However, the risks and increased oversight of the current processes will be communicated to operating companies immediately.

AEP Emergency Restoration Planning and AEP T&D Procurement personnel in conjunction with the Operating Companies will develop guidelines for invoice submission and review that clearly identify each group's responsibilities as well as requiring a variance analysis in order to detect significant variances from the original estimate and determine whether they are appropriate.

Review of Controls over Storm Restoration Costs

Significance:	Responsible Party:	Target Date:
Medium Risk T&D Procurement and Storm Response Team create consistent and standardized manual review based policy related to the submission and review of contractor invoices during storms.	**Craig Rhoades and Tom Kirkpatrick**	12/31/13

Appendix 1

Classification of Audit Report Conclusions

Operational/Financial (Internal Controls Reviews):

Conclusion	Definition
[illegible]	Controls are appropriately designed and are operating effectively to manage risks. Control issues may exist, but are minor.
[illegible]	Medium-level control issues (either design or operating effectiveness) are present but do not compromise achievement of important control objectives.
Improvements in controls needed	High or medium-level control weaknesses are present that compromise achievement of one or more important control objectives but do not prevent the process or function from achieving its overall purpose. While important weaknesses exist, their impact on the management of risks is limited rather than widespread.
[redacted]	High-level control weaknesses exist across numerous control objectives that potentially prevent the process or function from achieving its overall purpose. The impact of weaknesses on management of risks is widespread rather than isolated either due to the number or nature of control weaknesses.

Classification of Audit Comments

Financial Audits:

Risk Significance	Risk Definition
[redacted]	Likelihood of the condition occurring must be more than remote **and** potential impact must be significant in relationship to the underlying financial information, overall objectives, or level of compliance of the function or process audited.
Medium	Likelihood of the condition occurring must be more than remote **or** potential impact must be significant in relationship to the underlying financial information, overall objectives, or level of compliance of the function or process audited.
Low	Enhancement to a current process that would add value, but not necessarily have a significant impact to the company from a financial, compliance, effectiveness, or efficiency standpoint. Would entail process improvement or have a relatively small monetary impact.

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Audit Services Department

Distribution Line Contractor Inspection Controls Review

Date Issued: 08/14/2013

Audit Team:

Greg Taylor
Terry Youngman
Jim Brooks

Distribution:

Steven Baker
Selwyn Dias
Bruce Evans
Tom Kratt
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Gary Spitznogle
Philip Wright
Ranie Wohnhas
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CC:

Matthew Kyle
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Franklin Chambers
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Roger Heslep
David Isaacson
Jan Leeth
Austin McMillion
Joe Pemberton
Anthony Zeno
Leticia Gustafson
Shelia Hall
Rosemary Lane
Sandra Schlemmer
Candace Wilson
Nick Akins
Bob Powers
Brian Tierney
Paul Chodak
Venita McCellon-Allen
Charles Patton
Greg Pauley
Wade Smith
Stuart Solomon
Pablo Vegas
Rich Mueller

AEP AMERICAN ELECTRIC POWER

Project Number: AU02013

Distribution Line Contractor Inspection Controls Review

BACKGROUND:

The inspection process is a key control in determining whether overhead or underground line work performed by contractors is constructed in accordance with Distribution Standards and is accurately billed. Distribution Line Inspectors are specialized positions at the operating companies responsible for the pre and post-construction inspection process, which includes activities to ensure the actual work order charges reflect the project as actually built in the field (with changes from the original design shown as redlined). Management indicated that the number of Distribution Line Inspectors within the company decreased beginning in May 2010 as a result of the company's restructuring efforts, and subsequently, the positions have not been re-filled because they are not considered "field or customer contact" positions which can be readily replaced.

Based upon data obtained from distribution records, the following table summarizes the total contractor-constructed work orders and corresponding dollars by operating company for the period January 2012 through April 2013:

Operating Company	Total Work Orders	Total Work Order Dollars
Public Service of Oklahoma	3,857	$ 31,394,046
Indiana Michigan	1,866	$ 26,099,234
Kentucky Power Company	1,752	$ 14,370,449
Appalachian Power	4,735	$ 61,002,425
SWEPCO	1,837	$ 25,742,138
AEP Texas	3,420	$ 48,180,986
AEP Ohio	1,494	$ 49,722,592
Totals	**18,961**	**$ 256,511,870**

Distribution management personnel within the operating companies have expressed concerns that the current level of pre and post-construction inspections being performed may not be sufficient.

OBJECTIVES:

The objective of this review was to evaluate the adequacy and test the effectiveness of controls over the Distribution Line Contractor Inspection processes to determine if they provide reasonable assurance that contractor line work is adequately monitored.

SCOPE:

The scope of the review included the following areas related to the contractor inspection and review processes:

- Contractor Inspector Workload and Performance, including work order prioritization, work assignments and various work order metrics

Distribution Line Contractor Inspection Controls Review

- Work Order Redline Accuracy and Completeness , including material and corresponding labor charges, compatible unit reconciliations, and work order design versus actual
- Inspector/Contractor Resource Knowledge, including inspector and contractor training, technical skills and experience

CONCLUSION:

This scorecard summarizes our conclusions for each scope area covered in the review. In addition, comments that relate to each scope area are referenced to the Comments, Risks and Resolutions section below. Please note that the conclusion classifications are defined in Appendix 1 located at the end of this report.

Scope Area	Comments Present	Conclusion Classification
Contractor Inspector Workload and Performance	(1), (3)	**Improvements in Controls Needed**
Work Order Redline Accuracy and Completeness	(2)	**Improvements in Controls Needed**
Inspector/Contractor Resource Experience		Well Controlled
OVERALL CONCLUSION FOR REVIEW		**Improvements in Controls Needed**

COMMENTS, RISKS, AND RESOLUTIONS

In the following portion of the report, we have addressed the areas for improvement identified during our audit, their risk, and significance to the business. Also included are the planned action steps, responsible parties, and target dates for completion as provided by management. The significance level is based on our assessment of the combined impact and likelihood for each condition noted.

Low-risk and operating efficiency comments were communicated to the appropriate AEP Distribution management in a separate "Low Risk Comments Memo."

Distribution Line Contractor Inspection Controls Review

1) Absence of Process to Monitor Inspector Workloads, Performance, and Extent of Field Inspections

Comment - Management has not established targets or guidelines regarding the desired coverage to be achieved by the field inspection process. In addition, there is no process in place to effectively monitor inspector workloads or the actual number of work orders and the corresponding dollars that are field inspected.

The operating companies have information available concerning the total number of contractor work orders and the dollars associated with them. Although this information is available at a district level within the operating companies, the information is not maintained in a manner that permits it to be utilized to monitor the work load assigned to each inspector, especially when more than one inspector is assigned to a district (**Note:** Only AEP Texas provided requested work order information by inspector). The volume of jobs assigned to each inspector directly impacts the inspector's ability to oversee the contractors' work and verify the quality and quantity of work performed. Furthermore, while the operating companies did provide estimates of the total work orders and dollars covered by the field inspection process, there were large variances between the operating companies relative to their estimated coverage.

The chart below identifies the average number of contractor jobs assigned to each inspector by operating company during the January 2012 through April 2013 time period:

Operating Company	Total Inspectors	Avg WO's per Inspector	Avg Cost per WO
Public Service of Oklahoma	6	643	$ 8,139
Indiana Michigan	3	622	$ 13,986
Kentucky Power Company	3	584	$ 8,202
Appalachian Power	9	526	$ 12,883
AEP Texas	11	311	$ 14,088
SWEPCO	6	306	$ 14,013
AEP Ohio	9	166	$ 33,281
Totals and Averages	47	403	$ 13,528

Inspectors have other duties as well, so their total workload may not directly correlate to the numbers in the chart, however the comparison does highlight significant differences between companies. Within the operating companies, equally significant variances exist between districts. While it is recognized that each operating company may need to independently determine the resources it is willing to commit to the contractor inspection process, the lack of sufficient monitoring information makes it difficult for company management to evaluate the risk/benefit trade-off related to inspector resources.

Risk – Inspector resources may not be utilized in the most effective or efficient manner if workload and performance data is not readily available to management. Work order charges for labor and materials may not be accurate, resulting in potential contractor over/under-billings. Compatible/retirement units capitalized and billed may not reflect the actual work performed in the field.

Proposed Resolution - Management will establish targets, goals, and/or guidelines to provide expectations regarding field inspection metrics. Management will also develop a process that will enable them to monitor inspector workloads and performance, and to accurately measure the percentages of work orders and corresponding dollars being included in the field inspection process.

Significance:	Responsible Parties:	Target Date:
Medium Risk	Tom Kirkpatrick and Operating Company Vice Presidents of Distribution	October 1, 2013 (Est. Targets, Goals and Metrics) March 31, 2014 (New Process Implementation)

2) Incomplete Information Used to Evaluate the Effectiveness of the Redline Process

Comment – Redline Scorecard data was not captured for approximately 58% of the contractor-constructed work orders that were closed between January 1, 2012 and April 30, 2013. For the remaining 42% of these work orders, the data was not completely captured.

During the execution of distribution line related work, it is sometimes necessary to deviate from the original job design. This can result from numerous factors including, conditions encountered at the work location, omissions from the original job design, etc. When the actual work differs from the design specifications, there is a process for correcting the records to assure the appropriate amounts are capitalized and that contractors are paid accurately for the work performed in the field. This correction process is referred to as the "redlining process".

In 2007, the Distribution Expenditure Classification (DEC) team was created to review the entire work order process. They developed various reports, including the Redline Scorecard Report, to assist the operating companies in evaluating the effectiveness of the redline process. The Redline Scorecard Report provides valuable data relative to whether work orders were constructed by contractors versus company personnel; work orders were built as designed by Engineering; work orders contained correct material charges; and if the work orders had both material and corresponding labor charges. While most of the operating companies are at least partially capturing the Redline Scorecard data, APCO and KPCO Business Operations Support personnel indicated that a decision was made prior to January 2012 to discontinue capturing data for the Redline Scorecard Report.

In addition to the incomplete Redline Scorecard data noted above, there appear to be inconsistencies across the operating companies relative to the "Yes" or "No" responses provided for the Redline Scorecard Report parameters/fields. For instance, AEP Texas reported that approximately 99% of their contactor constructed work orders were built as designed during the January 2012 through April 2013 timeframe, compared to only 6% and 11% for Indiana Michigan and AEP Ohio respectively.

Risk – Management may not have the information or tools needed to assess the effectiveness of the redline process.

Proposed Resolution - Management will implement controls and guidelines to ensure that complete, consistent and accurate data is captured for the Redline Scorecard Report. Management will also add two data fields for the Redline Scorecard report to capture the inspector assigned to each work order and whether a field inspection was performed.

Significance:	Responsible Parties:	Target Date:
Medium Risk	Tom Kirkpatrick, Operating Company Vice Presidents of Distribution and Directors of Business Operation Support (East Operating Cos Only)	October 1, 2013 (Complete and Accurate Scorecard Data) March 31, 2014 (New Scorecard Fields Available)

3) Automated Work Order Audit Process Deficiencies

Comment – The Automated Work Order Audit process does not provide comprehensive coverage relative to the total number of work orders and dollars subjected to the audit process.

AEP's Field Accounting Policy for the Distribution Compatible Unit Work Order Closing Process, dated 10/23/2007, states that subsequent to the redline process, an Automated Work Order Audit within the Work Management System will be performed for each work order exceeding $10,000. The audit process determines if these work orders have both labor and materials charged to them, and identifies instances where differences between As Built and Actual material quantities are not within established tolerances. The policy further states that the $10,000 threshold was to be evaluated after 12 to 18 months to determine if the threshold should be increased or decreased.

For the period January 1, 2012 through April 30, 2013, the Automated Work Order Audit Process only provided coverage for approximately 13% of the total distribution work orders completed and a corresponding 66% of the total distribution work order dollars. If the monetary threshold were lowered to $5,000, versus $10,000, approximately 25% of the work orders and 80% of the corresponding dollars would be included in the Automated Work Order Process.

During January 2012 through April 2013, approximately 42% of distribution work orders subjected to the Automated Work Order Audit Process did not pass relative to the reconciliation of As-Built and Actual material quantities. A summary of the Automated Audit results by operating company is included in the table below:

Operating Company	Work Orders – Failing	Work Orders – Passing	Total Work Orders	Percentage of Work Order Failures
Appalachian Power Company	1,539	778	2,317	66.42%
AEP Ohio	1,532	972	2,504	61.18%
Kentucky Power Company	290	197	487	59.55%
Indiana Michigan	477	606	1,083	44.04%
SWEPCO	386	847	1,233	31.31%
AEP Texas *	580	1,693	2,273	25.52%
Public Service of Oklahoma *	79	1,625	1,704	4.64%
Totals	**4,883**	**6,718**	**11,601**	**42.09%**

* AEP Texas and PSO are the only companies that attempt to reconcile ASB and Actual quantities prior to the Automated Audit Process being performed.

Several possible explanations for a high percentage of work orders failing the system audits include: Materials are issued to a specific work order prior to construction and kept in Storeroom staging areas, but are used for unrelated work orders; field inspectors are not accurately identifying and recording As-Built quantities in the field; and As Built quantities are not processed accurately or completely during the work order closing process.

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Distribution Line Contractor Inspection Controls Review

Furthermore, Public Project Relocation (PPR) work orders are not included in the Automated Work Order Audit Process, although the policy stipulates that all actual cost billing work orders should be audited regardless of the amount, which would include PPR and third party actual cost billings. Although these work orders are not included in the automated work order audit, they are prone to scrutiny during the manual redline process. However, based upon a review of 25 PPR work orders having received redline reviews, 12 of these work orders still contained as-built versus actual material quantity variances totaling approximately $134,000, which equals approximately 2.5% of the total as-built cost of these 25 work orders. These variances were the result of the Information Services group not accurately and/or completely processing the As-Built quantities identified during the field inspection process. In addition, manual reconciliations of the As-Built versus Actual quantities were not performed after the work orders were updated with the As-Built quantities.

Risk – Work order charges for labor and materials may not be accurate, resulting in potential contractor over/under-billings. Compatible/retirement units capitalized and billed may not reflect the actual work performed in the field.

Proposed Resolution – Management will evaluate the cost/benefit of lowering the dollar value threshold for work orders included in the Automated Work Order Audit Process in order to achieve a higher percentage of both the work orders and dollars audited.

In addition, management will also determine if PPR work orders will be included in the Automated Work Order Audit Process. If the decision is made to continue suspending PPR work orders from the automated work order audit process, management will provide the necessary training, resources, and supervision to ensure redline activities are properly performed and that material count variances are reconciled for all work orders included in the redline process.

Significance:	Responsible Parties:	Target Date:
Medium Risk	Tom Kirkpatrick, Operating Company Vice Presidents of Distribution and Directors of Business Operation Support (East Operating Cos Only)	October 1, 2013

Distribution Line Contractor Inspection Controls Review

Appendix 1

Classification of Audit Report Conclusions

Operational/Financial (Internal Controls Reviews):

Conclusion	Definition
[illegible]	Controls are appropriately designed and are operating effectively to manage risks. Control issues may exist, but are minor.
[illegible]	Medium-level control issues (either design or operating effectiveness) are present but do not compromise achievement of important control objectives.
Improvements in controls needed	High or medium-level control weaknesses are present that compromise achievement of one or more important control objectives but do not prevent the process or function from achieving its overall purpose. While important weaknesses exist, their impact on the management of risks is limited rather than widespread.
[illegible]	High-level control weaknesses exist across numerous control objectives that potentially prevent the process or function from achieving its overall purpose. The impact of weaknesses on management of risks is widespread rather than isolated either due to the number or nature of control weaknesses.

Classification of Audit Comments

Financial Audits:

Risk Significance	Risk Definition
High	Likelihood of the condition occurring must be more than remote <u>and</u> potential impact must be significant in relationship to the underlying financial information, overall objectives, or level of compliance of the function or process audited.
Medium	Likelihood of the condition occurring must be more than remote <u>or</u> potential impact must be significant in relationship to the underlying financial information, overall objectives, or level of compliance of the function or process audited.
[illegible]	Enhancement to a current process that would add value, but not necessarily have a significant impact to the company from a financial, compliance, effectiveness, or efficiency standpoint. Would entail process improvement or have a relatively small monetary impact.

Audit Services Department

Contract Audit of Pike Electric, Inc.

Date Issued: April 23, 2013

Audit Team:

Tom Festi

Distribution:

Craig Rhoades
Tom Kirkpatrick
Patrick Weyers

CC:

Nick Akins
Bob Powers
Brian Tierney
Mark McCullough
Lisa Barton
Venita McCellon-Allen
Charles Patton
Pablo Vegas
Stuart Solomon
Gregory Pauley
Wade Smith
Matt Stinnett
Rich Mueller

AMERICAN ELECTRIC POWER

Project Number: AU3712

Contract Audit of Pike Electric, Inc.

BACKGROUND:

Pike Electric, Inc. (Pike) provides construction and maintenance services for electrical substation, overhead transmission and distribution lines, emergency storm restoration and other work at various AEP locations.

OBJECTIVES:

The examination's objective was to determine whether Pike's billings, totaling $98.8 million, complied with the contracts' terms. The payments to Pike were made under various contracts.

SCOPE:

We examined, on a sample basis, payments for work performed January 2010 through December 2011. To accomplish our objective, we examined documentation to determine whether:

- Contract payments were accurate,
- Billing markups were applied as appropriate,
- Equipment rates billed agreed with the contract established rates,
- Labor and equipment hours billed were properly supported by Pike's payroll /time reporting system.

Conclusion

In summary, we identified overbillings of $146,977. Pike has refunded $146,977 to correct the billings. The savings are 99% capital and 1% O&M. Please refer to the Comments and Resolutions section below for additional detail.

CONCLUSION (Contd.)

This scorecard summarizes our conclusions for each scope area covered in the review. Please note that the conclusion classifications are defined in Appendix 1 located at the end of this report.

Scope Areas	Comments Present	Conclusion Classification
1. Contract payments were accurate	1, 2	Improvements needed
2. Billing markups were applied as appropriate	1	Payments are accurate
3. Equipment rates billed agreed with contract established rates	-	Payments are accurate
4. Labor and equipment hours billed were properly supported by Pike's payroll / time reporting system.	-	Payments are accurate
OVERALL CONCLUSION FOR REVIEW		Payments are accurate, with minor improvements needed

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Contract Audit of Pike Electric, Inc.

(1) Federal (FUTA) and State (SUTA) Unemployment Payroll Tax and Worker's Compensation Reconciliations

- *Comment* – The contract states that the contractor shall not invoice for Federal Unemployment Insurance, State Unemployment Insurance, Social Security Tax, or worker's compensation at rates that exceed their actual cost. We found that Pike under billed FUT/SUT by $168,582 and over billed worker's compensation by $315,559 for a net over billing of $146,977.
- *Resolution* – Pike has refunded AEP the net over billing of $146,977. The savings are distributed $46,201 to APCO, $26,793 to KPCO, $18,459 to OPCO, $17,599 to AEP TX Central, $14,618 to PSO, $14,216 to SWEPCO, and $9,091 to Cardinal Op Co.

Significance:	**Low**
Target Date:	**Complete**
Responsible Party:	**Craig Rhoades**

(2) Meal Allowances and Associated Labor and Equipment Hours During Storm Repair

- *Comment* – We found instances where meal allowances and related labor and equipment billings did not always agree with the contract requirements indicating a potential over billing. During separate discussions with AEP management and Pike management, we were told it is not uncommon for employees to eat their lunch as they travel from one location to the next, rather than take a half hour for a sit down meal during storm restoration. As such, the view on the billings for meal allowances and related charges is that they were billed consistent with the way the work was performed.
- *Resolution* – To assure billing terms better match the work performed, Procurement and Distribution management have revised the Supplementary Terms & Conditions for Distribution Construction and Maintenance regarding meal allowances and their associated billings, as well as billable time for specialized equipment. The revised terms will be used on new contract awards. Additionally, existing blanket contracts will be amended to include the new terms.

Significance:	**Medium**
Target Date:	**07/31/2013 (for amending blankets)**
Responsible Party:	**Craig Rhoades**

Appendix One

Classification of Audit Report Conclusions

Conclusion	Definition
Payments are accurate	Payment issues may exist, but are minor.
Payments are accurate/minor improvements needed	Payment errors are 1.0% or less of contract spend and /or include mostly issues with payroll tax and insurance true-ups.
Improvements needed	Contract payment issues exist in multiple pay items <u>or</u> overbillings result from detectable billing errors that exceed 1% but are less than 5% of contract billings audited.
Major improvements needed	Contract payment errors are numerous and exist in multiple pay items. A significant portion of the over billings result from detectable payment errors. The errors are widespread rather than isolated either due to the number of payment errors, nature of payment errors, weaknesses, or significance of overpayments exceeding 5%.

Classification of Audit Comments

Risk Significance	Risk Definition
High	Identified billing errors must be more than remote <u>and</u> potential impact must be significant in relationship to the contract payments and underlying financial information, overall objectives, or level of compliance of the function or process audited.
Medium	Likelihood of the condition occurring must be more than remote <u>or</u> potential impact must be significant in relationship to the underlying financial information, overall objectives, or level of compliance of the function or process audited.
Low	Enhancement to a current process that would add value, but not necessarily have a significant impact to the company from a financial, compliance, effectiveness, or efficiency standpoint. Would entail process improvement or have a relatively small monetary impact.

Audit Services Department

Contract Audit of Davis H. Elliot, Inc.

Date Issued: July 26, 2013

Audit Team:

Tom Festi

Distribution:

Craig Rhoades
Tom Kirkpatrick
Patrick Weyers

CC:

Nick Akins
Bob Powers
Brian Tierney
Venita McCellon-Allen
Pablo Vegas
Stuart Solomon
Charles Patton
Greg Pauley
Matt Stinnett
Judd Schumacher
Rich Mueller

AMERICAN ELECTRIC POWER

Project Number: AU02913

BACKGROUND:

Davis H. Elliot, Inc. (Elliot) performs overhead and underground distribution line construction, maintenance, and locating services in various AEP service areas. Elliot also performed storm restoration services in various AEP service areas.

OBJECTIVES:

The examination's objective was to determine whether Elliot's billings, totaling $81 million, for the audit period January 1, 2010 through December 31, 2012 complied with the contracts' terms. The payments to Elliot were made under Contract Nos. 024070, 023150, 376644, 779943, 962823, and 025507.

SCOPE:

We examined, on a sample basis, payments for work performed January 1, 2010 through December 31, 2012. Elliot billings were for services provided to APCo, KPCo, PSO, SWEPCo, and OPCo service areas. To accomplish our objective, we examined documentation to determine whether:

- Contract payments were accurate,
- Billing markups were applied as appropriate,
- Labor and/or equipment rates billed agreed with the contract established rates,
- Labor and equipment hours billed were properly supported by Elliot's payroll /time reporting system.

Conclusion

In summary, billings were accurate with a minor adjustment of $42,852. The $42,852 is a net over collection (we found both over collections and under collections) resulting from reconciliation of payroll taxes, workers compensation, and base pay rates. Elliot's monitoring of the associated billing markups minimized the amount of the audit true-up. Elliot has refunded $42,852 to correct the billing errors. The savings are distributed 78% capital and 22% O&M.

CONCLUSION (Contd.)
This scorecard summarizes our conclusions for each scope area covered in the review. Please note that the conclusion classifications are defined in Appendix 1 located at the end of this report.

Scope Areas		Conclusion Classification
1. Contract payments were accurate		Payments are accurate with minor adjustments of $42,852
2. Billing markups were applied as appropriate		Payments are accurate
3. Labor and/or equipment rates billed agreed with contract established rates		Payments are accurate
4. Labor and equipment hours billed were properly supported by the contractor's payroll / time reporting system.		Payments are accurate
OVERALL CONCLUSION FOR REVIEW		Payments are accurate, with minor adjustments of $42,852

Appendix One

Classification of Audit Report Conclusions

Conclusion	Definition
Payments are accurate	Payment issues may exist, but are minor.
Payments are accurate, minor improvements needed	Payment errors are 1.0% or less of contract spend and /or include mostly issues with payroll tax and insurance true-ups.
Improvements needed	Contract payment issues exist in multiple pay items <u>or</u> overbillings result from detectable billing errors that exceed 1% but are less than 5% of contract billings audited.
Major improvements needed	Contract payment errors are numerous and exist in multiple pay items. A significant portion of the over billings result from detectable payment errors. The errors are widespread rather than isolated either due to the number of payment errors, nature of payment errors, weaknesses, or significance of overpayments exceeding 5%.

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Kentucky Power Company

REQUEST

Legal Settlements. List all amounts over $50,000 included in the test year which are the result of the settlements of claims against the Company.

RESPONSE

The test year does not include any such settlement.

WITNESS: Gregory G Pauley

Kentucky Power Company

REQUEST

Management & Performance Audit. Please provide a copy of the last management and performance audit report of the Company issued.

RESPONSE

Please see AG 1-36 Attachment 1.

WITNESS: Ranie K Wohnhas

I. Executive Summary

A. Background

Since 1996, the Commission staff has closely monitored AEP/Kentucky's system and the level of consumer complaints, with particular attention paid to the Hazard Service Area (HSA). Annual electric system inspections have noted various projects, such as sectionalizing, right-of-way clearing, and conductor change-outs, which have been completed or were in progress. The Commission's 2001 Inspection Report noted that the service interruptions reported in AEP/Kentucky's Year 2000 outage report are probable violations of 807 KAR 5:041, Section 5(1) (Maintenance and Continuity of Service). AEP/Kentucky has invested significant capital since 1996 in an effort to increase service reliability in its service territory, and specifically in the Hazard Service Area. As a result of AEP/Kentucky's efforts, the SAIDI index for the Hazard Service Area has improved somewhat in the period 1996 through 2001, but it is still significantly higher than the average for all of AEP/Kentucky.

The main focus of this project was to review AEP/Kentucky's management and operations efforts regarding the maintenance of service quality and service reliability to customers of the Hazard Service Area. A review of AEP/Kentucky's current initiatives was included in the evaluation. It is Schumaker & Company's understanding that both the Commission and AEP/Kentucky seek viable means by which the Hazard Service Area's distribution and transmission systems can be improved and adequately maintained, providing ratepayers with an acceptable, reliable electrical system in a cost-effective manner.

Chapter II – Report Summary provides a complete summary of the major findings and conclusions contained within this review.

B. Overall Assessment

Seven overall assessments need to be addressed between AEP/Kentucky and the Kentucky Public Service Commission if this report is to be successful at improving the service quality in the Hazard Service Area. These overall assessments are contained throughout the report; however, we felt that it is important to highlight these assessments, such that action is taken on these items to ensure the successful implementation of the remaining recommendations. These seven assessments are:

AEP/Kentucky Hazard Service Area is a more difficult area to serve than other service areas.

AEP/Kentucky Hazard Service Area is a more difficult service territory compared to other AEP/Kentucky services areas. The mountainous terrain and significant tree exposure make it a more difficult service territory to provide a comparable level of service than other areas of Kentucky. In Schumaker & Company's opinion, it is clear that the Hazard Service Area is a much more difficult area to serve than areas such as Pikeville or Ashland, or other areas of Kentucky for that matter.

AEP/Kentucky has not invested the financial resources in the HSA to provide comparable service.

AEP/Kentucky has not invested the operations and maintenance or capital resources to provide the Hazard Service Area with comparable service levels within other areas of Kentucky. Many of AEP/Kentucky responses to our suggestions that they need to be spending more money in certain areas was that they are spending all that is available. AEP/Kentucky comments to the draft report clearly indicate that they do not have the money to spend in the Hazard Service Area. This is an issue that must be addressed if service levels are to improve in the Hazard Service Area.

AEP/Kentucky has not quantified the financial resources required in the HSA to provide comparable service.

AEP/Kentucky has not quantified the level of operations and maintenance or capital expenditures that would be required to provide a comparable level of service quality in the Hazard Service Area. It will clearly cost more to provide the same level of service within the Hazard Service Area than other areas of Kentucky. Many of the recommendations (specifically, recommendations *II-1*, *II-2*, *II-4*, *II-5*, *V-1*, and *V-3*) contained within this report are designed to direct AEP/Kentucky to develop such a bottom-up estimate of the expected costs.

AEP/Kentucky has not sought rate relief, although their earnings have continually decreased over the last several years while service levels have not improved.

Within the Hazard Service Area, SAIFI, CAIDI, and SAIDI numbers have varied little over the last six years with the SAIFI and SAIDI numbers trending slightly down, but CAIDI remaining relatively unchanged. In almost all cases, the Hazard Service Area has the highest (worst) results within AEP/Kentucky.

AEP/Kentucky's last rate case was in 1991 and was settled. AEP/Kentucky has not had a fully litigated general rate case in many years (not since the 1980s). Although AEP/Kentucky's allowed rate of return was set at 16.5% at that time, AEP/Kentucky has not earned that level in many years, with the last several years being reported in the 8% to 9% range. AEP/Kentucky has been under a base rate moratorium since the settlement agreement was approved in Case No. 99-149 Joint Application of Kentucky Power Company, American Electric Power Company, Inc. and Central and Southwest Corporation Regarding a Proposed Merger, Order dated June 14, 1999. In the settlement agreement at page 3, the parties agreed. "Absent a force majeure, KPCO will not file a petition, which if approved, would have the effect, either directly or indirectly, of authorizing a general increase in basic rates and charges that would be effective prior to January 1, 2003 or three years from the effective date of the merger, whichever is later…" The moratorium ends in the summer of 2003.

Clearly, AEP/Kentucky needs to find a way to spend more on operations and maintenance or capital expenditures in the Hazard Service Area if they have any possibility of providing comparable service quality in that service area.

AEP/Kentucky needs to investigate all options for being able to commit more resources to the Hazard Service Area.

AEP/Kentucky is a regulated utility and is not striving to provide comparable service.

AEP/Kentucky operates as a regulated utility within the Commonwealth of Kentucky. As a regulated utility, its rates are set by the Kentucky Public Service Commission in a manner that should cover its costs of operations and provide an adequate return to its shareholders. In return, AEP/Kentucky has an obligation to provide service to residential, commercial, and industrial customers within its service territory. In essence, in exchange for its regulated monopoly status, AEP/Kentucky must provide equal service to all customers within its service territory (the franchise area), what some individuals would refer to as the "regulatory compact." The rates that have been set for providing this service are the same for each rate class throughout the AEP/Kentucky service territory. Given the uniformity of rates, it would be expected that AEP/Kentucky would strive to provide the same level of service throughout its service territory.

It would also be expected that AEP/Kentucky should strive to provide equal service for all customer classes within Kentucky and that rates should be adequate to permit AEP/Kentucky to provide such service. However, responses provided throughout the draft report indicated that AEP/Kentucky's viewpoint has strayed from the traditional "regulatory compact" for providing comparable service. By its own admission, AEP/Kentucky has decided to differentiate the level of service that is provided its customers based on various factors versus striving to provide the same level of service throughout its service territory.

Summary

This report identifies specific recommendations that should be implemented by AEP/Kentucky in responding to our overall assessments. AEP/Kentucky provided comments to these findings, conclusions, and recommendations throughout the development of this final report. These comments identified some differences of professional opinion and some misunderstandings of the issues in the final report. Although Schumaker & Company consultants tried to be clear in our development of this final report, the issues involved are complex and need to be addressed in a systematic manner over the next several years by all parties including the management of AEP/Kentucky and Kentucky Public Service Commission staff and Commissioners.

It is clear that improving service quality in the Hazard Service Area requires "money." The exact amount of additional money that will be required is something that the implementation of many of our recommendations will help identify. Depending on the amount of money involved, a method for making those financial resources available for the Hazard Service Area will need to be identified. These items will need to be worked out over the next year as KPSC staff monitors AEP/Kentucky's implementation of these recommendations.

The remainder of this chapter provides some background surrounding these investigations, summarizes all of the findings and conclusions contained within the report, and presents a summary of recommendations.

C. Report Background

The efficiency and effectiveness of the management of transmission and distribution assets within an electric utility directly translates into the electric system reliability experienced by customers. As such, based on generally accepted electric utility industry standards, an effective transmission and distribution operation should include the following characteristics:

- The decision-making process regarding the management of these transmission and distribution assets should be based on more than personal experience or prior practices and, as such, should incorporate the use of extensive quantitative data available from within the organizational information technology resources.
- The overall organization of the various functions related to electric distribution should be efficient and effective with clearly defined roles and responsibilities, staffing levels that are workload driven, and adequate consolidation of activities.
- The work management tools used for managing work activities should include planning, scheduling, and resource loading techniques and have a level of detail sufficient for adequate control.
- The facilities and equipment that are used by distribution personnel should be adequate and well maintained.
- There should be a well-developed maintenance management system to identify maintenance items, schedule maintenance work, record costs and durations of equipment failures, and record maintenance histories.
- There should be a well-developed preventative maintenance management system in place for major substation equipment to correct unfavorable station maintenance.
- There should be systematic procedures and practices in place for evaluating demand and energy forecasts and their impact on new facility requirements.

The processes used to manage the engineering and design of projects should identify responsibilities and authority, and should promote quality, cost-effective work.

Well planned and fully functional vegetation management and animal protection programs should be in place to minimize system service disruptions to the greatest extent possible.

Proper work management and manpower planning programs should be in place to facilitate the capability to utilize the existing workforce to the maximum extent possible at the greatest level of efficiency.

History

The concerns regarding the issue of AEP/Kentucky's electric service reliability in the Hazard Service Area first became a public issue as a result of electrical outages that occurred during a November 7, 1995 election. Electrical outages at several polling locations generated rumors of sabotage. AEP/Kentucky appeared before the Grand Jury to indicate that the outages were due to the failure of aging equipment, not sabotage. The Grand Jury was satisfied with AEP/Kentucky's response, but requested that the Kentucky Public Service Commission (KPSC) investigate the frequent and prolonged outages residents in the area experienced. In response to this request from the Grand Jury, the KPSC performed investigations and issued a May 23, 1996 Staff Report that addressed the issue.

This report initiated numerous activities by AEP/Kentucky to address the subject concerns, many of which were subsequently determined to be capital projects that had been planned prior to the Staff Report investigation. The report did review design characteristics of the distribution system and found them to be in need of improvement. In particular, problems were identified with heavily loaded feeders/substations and with effectively operating the 34.5 kV system. AEP/Kentucky maintains both 12 kV and 34.5 kV distribution lines as well as higher voltage transmission lines in this service area. The projects mentioned in the 1996 report were planned by the company in an effort to address the findings, but AEP was unable, at the time, to accelerate implementation of the Commission staff's recommendations. Over the course of time, these projects were completed as requested by the Commission staff.

Since 1996, the Commission staff has continued to closely monitor AEP/Kentucky's system and the level of consumer complaints. Annual electric system inspections have noted various projects, such as sectionalizing, right-of-way clearing, and conductor change-outs, which have been completed or were in progress. The Commission's 2001 Inspection Report noted that the service interruptions reported in AEP/Kentucky's Year 2000 outage report are probable violations of 807 KAR 5:041, Section 5(1) (Maintenance and Continuity of Service). AEP/Kentucky has invested significant capital since 1996 in an effort to increase service reliability in its service territory, and specifically in the Hazard Service Area. As a result of AEP/Kentucky's efforts, the SAIDI index for the Hazard Service Area has improved somewhat in the period 1996 through 2001, but it is still significantly higher than the average for all of AEP Kentucky, as demonstrated in *Exhibit I-1*.

Exhibit I-1
AEP/Kentucky Reliability Performance Statistics

Hazard Service Area

	No Exclusions			Major Storms Excluded		
Year	**SAIFI**	**CAIDI**	**SAIDI**	**SAIFI**	**CAIDI**	**SAIDI**
1996	2.60	4.00	10.400	2.60	4.00	10.400
1997	2.55	3.44	8.786	2.55	3.44	8.786
1998	2.98	6.05	18.047	2.48	3.93	9.731
1999	2.63	6.17	16.215	2.33	3.34	7.796
2000	2.40	4.44	10.647	2.02	3.91	7.879
2001	3.00	5.28	15.824	2.17	3.77	8.173

AEP/Kentucky Service Area

2001	2.16	4.51	9.75	1.66	3.29	5.47

The problems experienced by AEP/Kentucky ratepayers in the Hazard Service Area were particularly prevalent for the customers located near the City of Buckhorn, Kentucky. This area has a long history of service reliability problems, which were culminated in an outage on Christmas Day 2001, lasting most of the day. This event prompted the citizens of Buckhorn to develop a petition that was transmitted to the Kentucky Public Service Commission. This petition resulted in particular emphasis on the problems that were being experienced in the area and, to a large extent, resulted in the decision to perform this audit.

The Commission has acknowledged that the Hazard Service Area includes forested mountainous terrain, which presents difficult challenges to AEP/Kentucky for improving overall service quality. However, it is the stated belief of the Commission that there is room for significant improvement in service reliability for AEP/Kentucky's customers in the Hazard Service Area. The achievement of this objective is the specific focus of the audit.

AEP/Kentucky Background Information

AEP/Kentucky is a generation, transmission, and distribution company supplying electric power to retail customers in all or portions of the 20 eastern Kentucky counties as shown in *Exhibit I-2*:

Exhibit I-2
Counties in AEP/Kentucky Service Territory

Boyd	Floyd	Leslie	Morgan
Breathitt	Greenup	Letcher	Owsley
Carter	Johnson	Lewis	Perry
Clay	Knott	Magoffin	Pike
Elliot	Lawrence	Martin	Rowan

As of December 31, 2001, AEP/Kentucky served 172,120 total retail consumers. AEP/Kentucky's total utility operating revenue for the year ended December 31, 2001, was $1.659 billion with net utility operating income of $49.40 million. For the pay period ending December 31, 2001, AEP/Kentucky had 429 full-time employees.

In prior years, AEP/Kentucky was divided into three districts: Ashland, Hazard, and Pikeville. AEP/Kentucky currently has only one district operating in Kentucky, that being the Pikeville District, which is headquartered in Pikeville, Kentucky and is responsible for the operations of the Pikeville, Ashland, and Hazard, Kentucky Service Areas and the Logan, West Virginia Service Area. The Pikeville District Manager reports to the Charleston Region Vice President, located in Charleston, West Virginia. The Charleston Region includes AEP service territories in Kentucky, West Virginia, Virginia, and Tennessee.

Objectives and Scope of the Audit

The main focus of this project was to perform a review of AEP/Kentucky's management and operations efforts regarding the maintenance of service quality and service reliability to customers of the Hazard Service Area. A review of AEP/Kentucky's current initiatives was included in the evaluation. It is Schumaker & Company's understanding that both the Commission and AEP/Kentucky seek viable means by which the Hazard Service Area's distribution and transmission systems can be improved and adequately maintained providing ratepayers with an enhanced, reliable electrical system in a cost-effective manner.

Schumaker & Company understands that the Commission intended for this to be a focused review of service quality and reliability in the Hazard Service Area. However, it is important that such a review also encompass issues relating to the practices and provision of service throughout the entire AEP/Kentucky system.

The scope of this focused review encompassed, but was not limited to, the following task areas to a greater or lesser extent:

AEP/Kentucky's Transmission and Distribution (T&D) Organization
AEP/Kentucky's T&D System Capital Budgets and O&M Budgets and Expenditures
AEP/Kentucky's Reporting of System Reliability Information Procedures
AEP/Kentucky's T&D Planning
AEP/Kentucky's T&D System Design
AEP/Kentucky's T&D Protection Program
AEP/Kentucky's T&D Lightning Protection Program
AEP/Kentucky's T&D System Operations
AEP/Kentucky's Line Inspection and Maintenance and Repair Programs
AEP/Kentucky's T&D System Condition
AEP/Kentucky's Substation Evaluation
AEP/Kentucky's T&D System Staffing
AEP/Kentucky's Vegetation Management Program
AEP/Kentucky's Animal Protection Program
AEP/Kentucky's Work Management and Manpower Planning Practices

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Review Approach

Schumaker & Company performed a four-phase review process to address the KPSC's requirements. The major phases are listed below:

Phase I: Orientation and Project Planning
Phase II: Detailed Review
Phase III: Final Report Preparation
Phase IV: Action Plan Preparation

Based on the task areas reviewed, it was the intention of Schumaker & Company to evaluate the ability or inability of AEP/Kentucky to provide the same level of service to customers of the Hazard Service Area as provided to other AEP/Kentucky service areas. The review focused on determining what improvements, if any, could be made in the management and operations of the Hazard Service Area of AEP/Kentucky. In broad terms, the scope of "improvements" includes measures and strategies for:

Service and reliability improvements
Cost savings
Productivity gains
Efficiency increases
Addressing competition

Major Areas of Investigation

Our major areas of investigation were broken down into four review areas, specifically:

Asset Management – Decision Support Systems and Information Technology
Engineering Design
Electric Transmission and Distribution Operations
Vegetation Management and Animal Protection

Our principal objective in evaluating these AEP/Kentucky business and operations functions was to verify that the associated activities were being conducted in an effective and efficient manner, that the functions performed support the company's overall strategic goals, and that the established management controls and systems provide management with an adequate ability to ensure appropriate levels of service quality and reliability in the Hazard Service Area. The ultimate objective of this work plan was the identification of cost-effective improvements in management, design, and operations that will result in more cost-effective operation and/or better service to AEP/Kentucky customers in the Hazard Service Area.

In the course of conducting this audit the Schumaker & Company project team interviewed more than forty (40) individuals, the majority of whom were employees of AEP or AEP/Kentucky. Additionally, our consultants interviewed the Mayor of the City of Buckhorn, Kentucky to gain his perspective into the problems that had been experienced by its citizens. We also requested and reviewed over 160 documents that provided data on or information about AEP/Kentucky's organization and operations in the Hazard Service Area.

Report Layout

This report is organized into the following chapters:

Chapter I – Executive Summary
Chapter II – Project Summary
Chapter III – Asset Management – Decision Support Systems and Information Technology
Chapter IV – Engineering Design
Chapter V – Electric Transmission and Distribution Operations
Chapter VI – Vegetation Management and Animal Protection

Each of the four chapters focused on functional areas (Chapters III through VI) contain background and perspective information on the specific functional area, the resultant findings and conclusions, and associated recommendations.

Project Team

The names and positions of the Schumaker & Company project team consultants and the functional areas to which they were assigned are listed in *Exhibit I-3* below.

Exhibit I-3
Project Team Consultants

Consultant	Project Team Position	Functional Area Assigned
Dennis Schumaker, PMP, CMC	Engagement Manager	Asset Management
Siegfried Guggenmoos	Senior Consultant	Vegetation Management and Animal Protection
Martin Murphy, PE	Senior Consultant	Engineering Design. Electric Transmission and Distribution Operations
William Braatz, PE	Senior Engineer	Engineering Design
Kenneth Hobson, PE	Senior Engineer	Engineering Design

Schumaker & Company would also like to take this opportunity to express our profound appreciation to the Kentucky Public Service Commission Management Audit Branch management and staff who worked closely with our consulting team on the conduct of this project. Those managers and staff members include Messrs. Mike Nantz, John Rogness, Charles Bright, David White, and Aaron Greenwell. The insight, perspective, and guidance that were provided to our consulting team by these individuals was invaluable to us in our successful completion of this project.

D. Findings and Conclusions Summary

The following text contains a summary of our overall findings and conclusions for each of the four major areas of investigation. More detail and supporting information can be found in each of the individual chapters.

Chapter II – Asset Management – Decision Support Systems and Information Technology

Asset management can be thought of as a portfolio approach to managing the physical assets of an electric utility to maximize the overall asset performance and profitability while meeting regulatory obligations. During our investigations, we evaluated the current practices of AEP/Kentucky relative to the use of decision support systems and information technology in the management of electrical assets (both transmission and distribution) to determine (a) whether the processes used by AEP/Kentucky are consistent with currently accepted levels of technology for the electric utility industry in general, (b) whether these processes are properly designed to support the AEP/Kentucky organization in providing superior service to its customers, and (c) whether AEP/Kentucky attempts to tie expenditures to performance levels.

Although Schumaker & Company reviewed the activities of the Transmission Asset Management organization, it was determined early in our investigations that most of the issues or problems that caused our investigations stemmed from issues in distribution, rather than transmission, assets. Transmission assets account for only a small portion of the System Average Interruption Frequency Index (SAIFI) and System Average Interruption Duration Index (SAIDI) indicators. As a result, our investigations were primarily focused on distribution asset management activities.

Technology Systems

Over the last five years, AEP has made significant upgrades in their technology and systems that are involved in responding to customer outages and reporting on those results. The call center agent enters the information into the Trouble Entry & Reporting system (TERS), an internally developed system, implemented around 1995, that collects information on the outage and also supports the ongoing reporting of progress on outage restoration such that information can be relayed to the customer if they call in again or if additional customers affected by the same outage call in.

That trouble ticket then flows to the PowerOn software (implemented in 2002) where the tickets are analyzed and a failed device (transformer, fuse, breaker, etc.) is predicted. All of this information can be displayed on geographic maps, via an interface to the Small World system that was implemented in the last several years, in the Distribution Dispatch Center (DDC) in Roanoke, VA, and information on the "predicted" failed device can be relayed to the Servicer (a field technician who acts as the first responder to outage situations) who is dispatched to identify the outage cause. Once the outage is corrected, information is collected and summarized on a Trouble, Damage & Interruption Report that is then reviewed and entered into the Historical Outage Information System (HOIS). HOIS is an Oracle database that was implemented in 2001 to replace the previous Distribution Outage Reporting (DOR) system.

Outage Reporting and Monitoring (Call Center and Dispatch)

All initial customer calls on outages are handled in call centers, collectively called the Solutions Center. The Solutions Center is currently organized into an East and West configuration, although AEP is evolving toward a national virtual call center configuration, once the company's systems are capable of supporting such an operation. The Solutions Center is full service 7x24 for all customers. Throughout the management of an outage, AEP/Kentucky has the ability to keep the customer informed. Customer surveys that have been performed within the industry have repeatedly shown that the ability to keep the customer informed is one of the key capabilities that customers want during outages. AEP has vendors who do third-party customer satisfaction surveys. AEP also has a complaint tracking mechanism to monitor complaints.

Capital and Operations and Maintenance Budgeting

The budgeting process is predominately a top-down process. Asset Management is given a budget target for both transmission and distribution expenditures, which are developed by corporate based on the prior year's budget – with modifications for known savings or expenses that would be incremental in the next year. These budgeted amounts are initially divided among the Asset Management groups and the regions by the Asset Management organization. As such, budgets are not necessarily requirement based. Budgets are based more on prior year's expenditures, corporate goals, and other items that do not necessarily relate to what needs to be spent to provide improvements in service quality. This approach results in a setting of budgets such that field personnel are only left with deciding how "best" to spend the allotted dollars.

Reliability Programs

Asset Management manages several different reliability programs that specifically address the hardware aspects of reliability. Within the Asset Management organization various reliability programs exist that have been designed to ensure that certain ongoing preventative maintenance activities are performed. These programs include such things as: pole replacements, pole reinforcement, recloser replacement, lightning protection, animal mitigation, URD inspection and replacement, overhead circuit inspection and upgrade, pole ground-line treatment, small wire replacement, and maintenance. All of the above categories are divided on a regional basis by program.

Reliability programs are not specifically designed to make improvements in SAIFI, Customer Average Interruption Duration Index (CAIDI), and SAIDI by targeting improvements in frequency, duration, or number of customers. AEP/Kentucky has recently started trying to tie some of its reliability programs into improvements in SAIFI. In particular, a model has been developed based on theoretical assumptions that will require several years of analyzing actual field results to validate the model. However, this model does not address SAIDI or CAIDI considerations. There is more that needs to be done within AEP/Kentucky to begin to tie the result of its reliability programs into improvements in service quality.

Field crew staffing levels need to be approached from a response effectiveness analysis. Hazard Service Area staffing has been significantly reduced over the last five years. Although AEP/Kentucky has made many changes in the last five years that could support some of the reductions, such as the introduction of new computer systems, the most sensitive area with respect to system reliability is the Distribution Line area. One of the primary roles of Distribution Line personnel is to respond to outages. It has become even more important as response staff has been decreased.

Outage Results

Outages results are getting worse. The total number of customers impacted from January to July of 2001 compared to 2002 has increased by 55% and the customer minutes by 40%. Some of this increase might be explained by more accurate reporting as a result of the improved systems (specifically

PowerOn and HOIS). However, to the extent that this increase is not a result of improved reporting, it could be indicating that service levels are getting worse.

Chapter III – Engineering Design

The responsibility for the design engineering function is divided among the Charleston Region engineering groups located in Charleston, WV and Roanoke, VA; a Regional Engineer located at the Hazard Service Center; and Engineering Technicians located at the Hazard Service Center. The Station Resources group in Roanoke does substation design. The Technical Services group in Hazard does the design of the customer distribution line installation and upgrade projects.

Engineering Design Process

The design engineering function as it is performed by various groups within AEP for the benefit of the Hazard Service Area operations is commensurate with contemporary electric utility industry standards. The division of responsibilities between regional and local groups is properly structured to allow significant local input, while still adhering to regional goals and objectives. The number of engineers on staff in both the regional offices and the Hazard Service Center is appropriate in consideration of the normal workload. All of the engineering groups have access to the tools, information, and systems that they need to properly support the operation of the system.

Engineering Design Standards

AEP maintains a Central Standards Group, located in Columbus, OH, which is responsible for development and maintenance of company-wide standards for AEP in relation to the design engineering function. One person from the Central Standards Group is located in each of the regions to ensure that proper communication exists between the Engineers in the region and those of the Standards Group. The Central Standards Group engineer for the Hazard Service Area is located in Roanoke, VA. Engineering standards documentation is currently being updated with the intention of merging AEP standards and Central and Southwest (CSW) standards to create one unified set of standards for AEP nationwide.

The AEP Central Standards Group provides the engineering staff with a robust and up-to-date set of design standards to use in the completion of their work. The AEP Central Standards Group does a good job of maintaining and updating the engineering design standards, as witnessed by their current efforts to merge the design standards of AEP and CSW to have greater standardization and to avail themselves of the best of both sets of standards. These continuing efforts ensure that the engineering designs created by the AEP design engineering groups are based on the latest and most complete standards possible.

Chapter IV – Electric Transmission and Distribution Operations

The Transmission Line Operations organization and Distribution Line Operations organization of AEP/Kentucky are responsible for the construction, operation, maintenance, and repair of the AEP/Kentucky transmission and distribution grids, respectively. For the Hazard Service Area, the overall management of this function is located in Pikeville, KY, with local field management provided out of the Hazard and Whitesburg Service Centers. Dispatching for trouble and outage restoration is performed out of the centralized Distribution Dispatch Center (DDC) in Roanoke, VA.

Management and Organization

Our investigations revealed that the management of the Line Mechanics and Servicers is appropriate and adequate for the current staffing levels and workload. The organization and systems used to manage the Transmission and Distribution Line field operations forces are consistent with the requirements for proper management and control of an organization of that size and responsibility. The spans of control that were observed were well within accepted standards for an electric utility field operations organization. The systems and reports that were available as tools to the management of the operation were appropriate to support them in the performance of their assigned tasks.

Staffing Levels

The number of Servicers (those employees who handle distribution installation, maintenance, and restoration duties) assigned to the Hazard Service Area is not adequate to handle the current workload in an efficient manner. This results in two significant problems, specifically:

> The limited number of Servicers in the Hazard Service Area results in a reduced ability to restore service in a timely manner during storm situations. With the service restoration jobs divided among a smaller number of Servicers, response time and times to restoration will be longer than if a larger contingent of Servicers were available. While there certainly are practical and economic limits to the number of Servicers that should be in place, the number that currently exists is smaller than is needed to provide satisfactory restoration times. Additionally, when the Servicers are on vacation or out-of-town, the coverage of their responsibility often is transferred to a Line Mechanic. While the Line Mechanics have the technical capability to perform the required restoration work, their lack of daily familiarity with the tasks involved and with the geography of the area renders them less efficient than a Servicer in performing the same work. Additionally, situations were identified in which certain jobs or types of work were delayed until the Servicer returned to duty.
>
> The Servicers in the Hazard Service Area are working a large amount of overtime, which is attributable to the large number of after-hours callouts and a relatively small number of Servicers to handle the work load. Review of overtime data for the years 2000 through 2002 reveals that all of the Servicers in the Hazard Service Area have been working significant quantities of

overtime during this period. This is particularly true in the Perry County area, which includes the City of Hazard. Because this data reflects the number of hours that are paid for (rather than the number of hours that are actually worked), the numbers are somewhat inflated. However, even with this taken into consideration, the Servicers are still working very large amounts of overtime. When Servicers are working this much overtime, it would be expected that there would be a declining efficiency of the work as the number of hours worked increases. Additionally, at some point the number of hours worked becomes a concern relative to the safety of the workers. Having a larger number of Servicers assigned to the HSA would serve to reduce the amount of overtime worked by each of the individual Servicers, thereby reducing concerns with work performance and safety. Moreover, a larger number of Servicers would be expected to cut down on the amount of time that it takes to restore service in a storm situation due to an enhanced ability to spread the workload across more field personnel.

Radio Communications

Our investigations revealed that the current radio communications system does not provide adequate radio coverage in all areas of the HSA, leading to the presence of significant "dead spots" where radio communications between the field crews and the DDC and the Schedulers is impossible. Such significant radio communications dead spots were found to exist in two of the counties in the Hazard Service Area. This is a significant concern due to crew efficiency and safety considerations. However, a plan is in place to resolve these communications problems by the year 2004 through the construction of several new antenna facilities.

Tree-Related Outages

Most of the outages that are repaired by the Servicers are caused by trees. Interviews with several Servicers revealed that, in their collective opinion, trees are the single largest cause of outages experienced in the Hazard Service Area. This is particularly true in summer, because trees are in leaf and they have a greater tendency to fall or for branches to break off due to wind.

The rights of way that have been obtained by AEP/Kentucky in the Hazard Service Area are not wide enough in many cases to adequately prevent tree-related damage. Interviews with several of the Servicers revealed that, in their collective opinion, the insufficient width of many rights of way is the immediate cause of many of the service outages that they respond to. It was their opinion that widening the rights of way would eliminate a significant number of tree-caused outages.

Transmission and Distribution Operations

The design and operation of the transmission system does not have a deleterious effect on reliability in the Hazard Service Area. The transmission system is well designed and operated and is not a significant factor in the reliability problems that have been experienced in the Hazard Service Area. The problems that have been experienced are much more directly related to the distribution system, especially in relation to deficiencies in the widths of existing rights of way. This is primarily because the height at which the transmission lines are strung is high enough to allow them to avoid the majority of problems that occur due to tree-related damage. The distribution lines, being positioned at a lower elevation, are much more susceptible to tree-related incidents. The maintenance program for the substations that are located in the HSA is appropriate and consistent with industry standards.

The distribution and transmission dispatching functions are performed in a manner that is consistent with industry standards. The operations of the Roanoke Distribution Dispatch Center (DDC) were observed and found to be consistent with accepted industry standards. Centralization of the operation in Roanoke has strengthened the DDC's ability to respond to emergency situations. There is a significant emphasis placed on continually improving the dispatching process to provide better and more comprehensive support to the field crews.

Chapter V – Vegetation Management and Animal Protection

Following a merger in 2000, American Electric Power centralized the Forestry group, led by a manager in corporate headquarters, to deliver its vegetation management program. This is a positive move as decentralized programs are subject to changing local priorities and pressures and often see the vegetation management budget reassigned to other emerging priorities. Across the utility vegetation management industry, decentralized control of vegetation management funding decisions have a history of producing hotspotting programs; that is programs that are completely reactive rather than planned, managed programs. American Electric Power has taken advantage of one of the opportunities afforded by centralized control of the vegetation management program. It has entered into a sole source contract for all but the aerial components of vegetation management services. The contract is positive for American Electric Power in that it guarantees cost savings.

While there have been some tree-caused transmission outages over the last five years, they are infrequent. Tree-caused service interruptions are a distribution issue, accounting for more than 40% of all unplanned distribution outages in 2001 and 2002. The Hazard Service Area faces an enormous challenge in managing tree-caused service interruptions. Much of the Hazard Service Area is rural with a low customer density and a substantial percentage of the power lines running across forested country. Tree exposure on power lines is extremely high, estimated at greater than 90% in rural areas. The terrain is mountainous, making it difficult to detect and repair tree-caused outages.

Vegetation Management Program Practices

There are some very positive aspects to AEP/Kentucky's vegetation management program. System level guidelines, which encourage tree removals, herbicide use, and the elimination of branch overhangs, contribute positively to improving reliability and lowering maintenance costs. Forestry staff is very knowledgeable and competent. The competence is illustrated in the extensive use of herbicides; excellent control of power line incompatible species on herbicide-treated rights of way; herbicide maintenance cycles based on the objective of tapping into biological control, while recognizing the succession pressure for re-invasion;, a customer notification procedure that results in only 3% refusals for herbicide application; a species selective or prescriptive approach; an industry-leading tree removal rate; excellent pruning quality; and a willingness to examine and adopt alternative maintenance practices such as aerial trimming. The prescriptive approach reduces costs by avoiding or reducing the amount of work performed and fosters the establishment of a power line compatible vegetation community. The current pruning quality is so high as to leave no room for improvement in suppressing either the amount or rate of regrowth.

Tree-Related Outages

In spite of good policy, competent staff, and industry best practices, tree-related outages are increasing and a continuation of the current program will not reverse this trend. The pruning program is about two years behind, resulting in a very high need for hotspotting. As hotspotting is rightly recognized as being inordinately expensive, it is minimized. This focus on cost effectiveness, however, leaves the trees to grow into conductors and cause outages. As a result, tree-caused service interruptions from trees within the right of way have been increasing exponentially since 1996. While the use of herbicides and aerial pruning will lower maintenance costs over the long term, it should not be anticipated that the savings would be adequate to significantly impact the pruning maintenance cycle.

Funding

If AEP has the proper policies, staff, and vegetation management practices, then why is the vegetation management program not producing level or decreasing tree-related outages? Quite simply, the Hazard Service Area vegetation management program is under funded. The current condition of rights of way and evident maintenance cycles indicates under funding is not a recent but rather a long-standing condition. The extent of the under funding is not known, as there is no inventory of the tree workload. Tree-related service interruptions can be managed if vegetation management funding is responsive to the actual tree workload. There is a preferred way to determine the funding requirements. An inventory of the cyclical work, the amount of tree exposure, and derivation of the local tree growth and mortality rates must be undertaken and form the basis for budgeting. Any other approach to budgeting for vegetation management lacks the requisite rational foundation and, because tree workload expands exponentially, constitutes a costly, high risk guess. The present vegetation management budgeting process is largely top down driven. Local staff annually compiles a list of work required, but they indicate that funding is never sufficient to complete all the identified work. Thus, vegetation management funding is divorced from need. A budgeting process based on objective data and need, with flexibility to be responsive to unusual conditions such as drought or pest infestations, is required. In this regard, it is suggested that an inventory be used to establish maintenance cycles, their costs, the amount of backlog, a reasonable timeframe for the completion of the backlog, and the associated costs.

American Electric Power uses asset management strategies, which are useful in prioritizing where allocation of resources will provide the best return in line security. However, asset management strategies do not ensure funding of all the vegetation management work required in any given year.

Tree-caused outages are subdivided into those arising from trees either within or outside the right of way. Funding based on the actual tree workload will provide a pruning cycle that minimizes service interruptions from within right-of-way trees. A 10% to 15% reduction in SAIFI is a realistic outcome. Trees outside the right of way are the single largest cause of unplanned service interruptions. Some of these outages may be due to the in-growth of lateral branches, which the aerial trimming seeks to address, but typically these outages arise from tree failure. While the Forestry group is responsive to emergent conditions, such as increased tree mortality due to the southern pine bark beetle, there does not appear to be a recognition of or strategy to reduce the extent of tree exposure on lines. AEP Forestry practices in this regard are typical of the utility vegetation management industry and, thereby, are not responsive to the facts of remote, mountainous terrain with the exceptionally high tree exposure found in the Hazard Service Area. Remoteness, steep terrain, and the destructive nature of tree failures means outages from trees outside the right of way have long durations. Vegetation management practices cannot address the duration of such outages, but can influence frequency of occurrence. There are some AEP/Kentucky initiatives that serve to reduce the extent of tree exposure. Most significant is moving cross-country lines to the roadside. This significantly decreases the incidence of tree-caused outages by substantially reducing tree exposure on at least one side of the line. Better access will also facilitate locating and repairing tree-related outages, decreasing the outage duration.

With funding based on the actual tree workload, the AEP/Kentucky vegetation management program, as currently delivered, will improve system reliability and be cost effective. Further gains in reliability can be achieved via strategies that reduce the amount of tree exposure, particularly in locations where outage durations tend to be long.

Animal Control

Animal control practices are responsive and adequate to effectively manage animal-caused service interruptions.

E. Summary of Recommendations

The following pages contain a list of the recommendations contained within the report.

Recommendation Listing

Recommendation Number	Description	Page Number
Recommendation II-1	Develop a more appropriate approach to determining capital and operations and maintenance funding levels (Refer to Finding II-4, Finding II-6, and Finding II-7).	49
Recommendation II-2	Each circuit within the Hazard Service Area should be analyzed and a reliability improvement plan developed. (Refer to Finding II-6 and Finding II-7).	49
Recommendation II-3	Maintain historical information on operations and maintenance and capital planning processes. (Refer to Finding II-5).	50
Recommendation II-4	Develop a methodology for specifically tying capital and operations and maintenance investments to reliability indicators (Refer to Finding II-6 and Finding II-7).	50
Recommendation II-5	Use statistical methods for establishing field force staffing levels (Refer to Finding II-8).	50
Recommendation II-6	Closely monitor performance indices for adverse trends (Refer to Finding II-9).	51
Recommendation II-7	Develop a method for addressing momentary outages (Refer to Finding II-10).	51
Recommendation IV-1	Perform investigations to ensure that the new Severn Trent System software package has the capability to communicate all forms of jobs to the Servicers. (Refer to Finding IV-2).	85
Recommendation IV-2	Design the training program to be administered to the Servicers on the use of the new Severn Trent System in such a way as to ensure that the Servicers are able to avail themselves of the full capability of their laptop units and the software thereon. (Refer to Finding IV-3).	85

Recommendation Listing

Recommendation Number	Description	Page Number
Recommendation IV-3	Evaluate the Servicer workload and outage restoration statistics to determine the optimal number of Servicers that should be on staff in the Hazard Service Area. (Refer to Finding IV-4 and Finding IV-5).	86
Recommendation IV-4	Develop a software application that would allow the Distribution Line managers to track and monitor the number of overtime hours that are actually worked as opposed to those which are paid for. (Refer to Finding IV-6).	86
Recommendation IV-5	Continue with the established plan to improve the radio communications network in the Hazard Service Area (Refer to Finding IV-7).	86
Recommendation IV-6	Review the current policy on rights of way to determine if improvements could be made that would have a beneficial impact on service reliability in the Hazard Service Area. (Refer to Finding IV-9).	87
Recommendation IV-7	Develop and implement a feedback mechanism to inform the Servicers and field crews of the status of the Tree Condition Reports that they have submitted. (Refer to Finding IV-10).	87
Recommendation IV-8	Continue the efforts that have been undertaken to improve the quality and consistency of the data that is reported to the KPSC. (Refer to Finding IV-11).	87
Recommendation IV-9	Implement a full version of the PowerOn software in the Hazard Service Center for use in daily operations and storm restoration activities. (Refer to Finding IV-12).	87
Recommendation IV-10	Review the potential for utilizing the automated field crew routing optimization capability that is built into the Small World software application. (Refer to Finding IV-13).	88
Recommendation V-1	Determine the annual vegetation management workload increment. (Refer to Finding V-7).	108
Recommendation V-2	Establish pruning cycles based on measured average tree growth. (Refer to Finding V-4).	108
Recommendation V-3	Budget for vegetation management based on the annual workload increment. (Refer to Finding V-8 and Finding V-9).	109
Recommendation V-4	Use hotspotting to minimize tree-related outages until the system is on a sustainable pruning cycle. (Refer to Finding V-5).	109
Recommendation V-5	Develop and implement practices designed to manage tree-caused outages. (Refer to Finding V-6, Finding V-10, and Finding V-11).	110
Recommendation V-6	Introduce contractor agreements that ensure effective costs are competitive. (Refer to Finding V-3).	112

II. Asset Management

Asset management is a relative new term (concept) as applied to the electric utility industry. Over the last several years, much discussion has been held regarding new business models for the deregulated electric utility industry and the concept of "asset management" has evolved. Asset management can be thought of as a portfolio approach to managing the physical assets of an electric utility to maximize the overall asset performance and profitability while meeting regulatory obligations.

Schumaker & Company investigated and evaluated the current practices of AEP/Kentucky relative to the use of decision support systems and information technology in the management of electrical assets (both transmission and distribution) to determine (a) whether the processes used by AEP/Kentucky are consistent with currently accepted levels of technology for the electric utility industry in general, (b) whether these processes are properly designed to support the AEP/Kentucky organization in providing superior service to its customers, and (c) whether AEP/Kentucky attempts to tie expenditures to performance levels. Some of the activities that we performed included:

- Evaluated the decision support systems used by AEP/Kentucky in identifying construction and maintenance activities relative to transmission and distribution assets
- Assessed the use of internal data (contained within the various company databases) in supporting operations and providing adequate and timely information for rational management decision making regarding transmission and distribution assets
- Reviewed the current management and operational structure with regard to its effectiveness in supplying fully functional systems, effective technologies, and efficient services to users
- Reviewed the information systems that support the distribution operations, such as:
  - Transformer load management
  - Trouble reporting system
  - Workforce planning, scheduling, and control
  - Outage reporting
  - Materials management systems
  - Geographic information system (GIS)
  - Automated dispatching

A. Background and Perspective

AEP has two organizations in Columbus, OH that are responsible for asset management activities for the whole AEP region (AEP East and AEP West). One group, Transmission Asset Management, is organized as shown in *Exhibit II-1* and the other, Distribution Asset Management, is organized as shown in *Exhibit II-2*.

AEP has two organizations, with centralized management in Columbus, Ohio that are responsible for the strategic asset management activities. These strategic activities include coordinating and/or developing standard processes, analysis and overall direction of activities related to large scale distribution projects, budgeting & business rules, graphics, joint use, construction & material standards, work management and vegetation management.

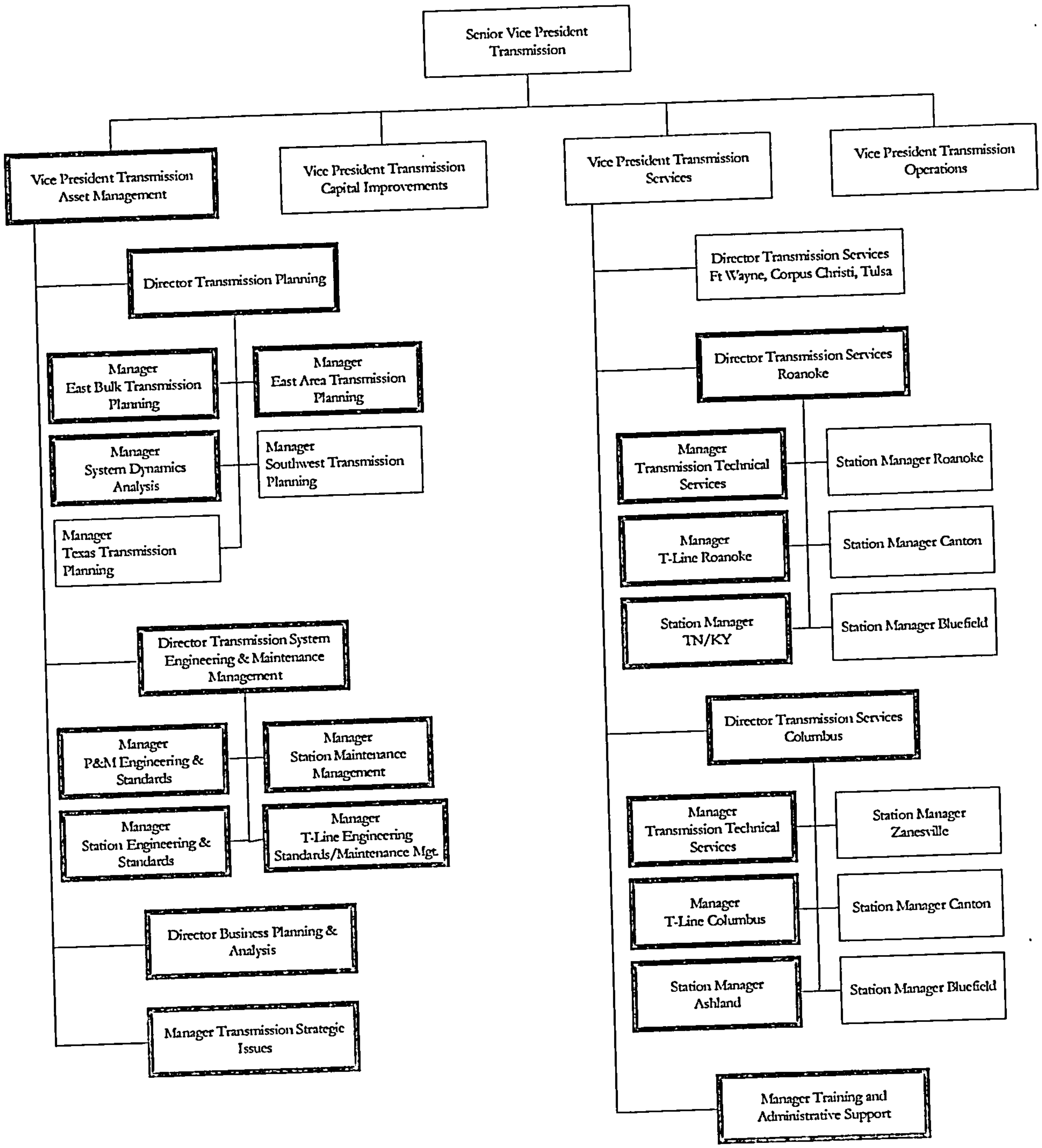
The distribution asset management organization has a significant number of personnel co-located in the regions in the areas of Asset Network & Planning, Asset Data & Application, Asset Standards, Asset Utilization, Work Management and Forestry.

The regions and Asset Management work in a matrix fashion in the various areas mentioned above for the purpose of continuously improving distribution's performance while balancing with customer needs. Examples of this include changes made in 2002 to the Asset Programs where overall funding in the Charleston region was increased for lightning mitigation, Forestry working closely with the line personnel to prioritize circuit clearing activities, establishment in 2003 of the Sectionalizing Program for the purpose of adding additional circuit sectionalizing devices and improve SAIFI & CAIDI, etc.

Organization and Management

Transmission Asset Management is responsible for transmission assets (69 kV and above in the Hazard Service Area) and all substations, whether they could be considered totally distribution or transmission substations.

Exhibit II-1
Transmission Asset Management Organization

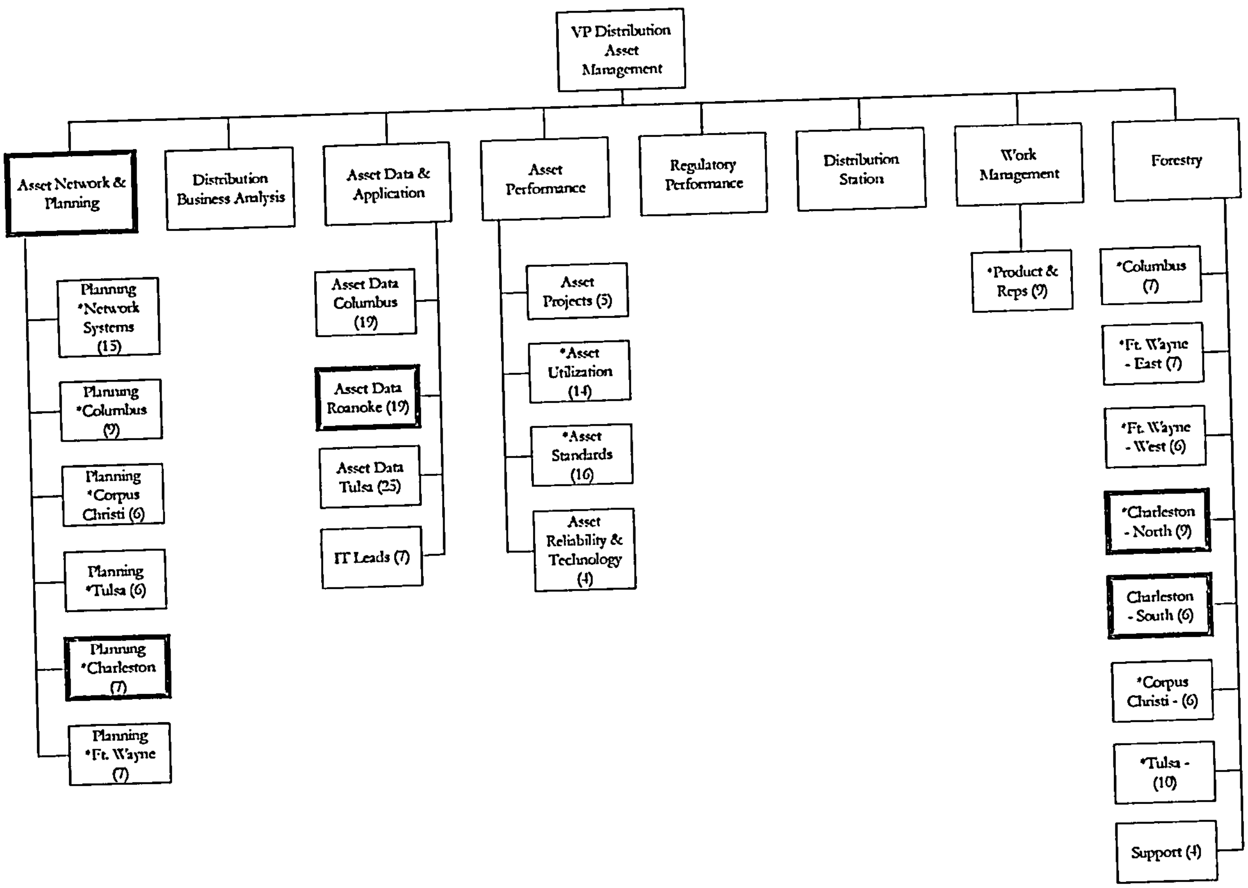


Bold boxes indicate management with most direct accountability for the Hazard Service Area

Although Schumaker & Company reviewed the activities of the Transmission Asset Management organization, it was determined early in our investigations that most of the issues or problems that resulted in our investigations stemmed from issues in distribution, rather than transmission, assets. Transmission assets account for only a small portion of the System Average Interruption Frequency Index (SAIFI) and System Average Interruption Duration Index (SAIDI) indicators. As a result, our investigations were primarily focused on distribution asset management activities.

Distribution Asset Management, which is responsible for all distribution assets, is organized as shown in *Exhibit II-2*. It is a part of the Distribution organization as shown in *Exhibit II-3*.

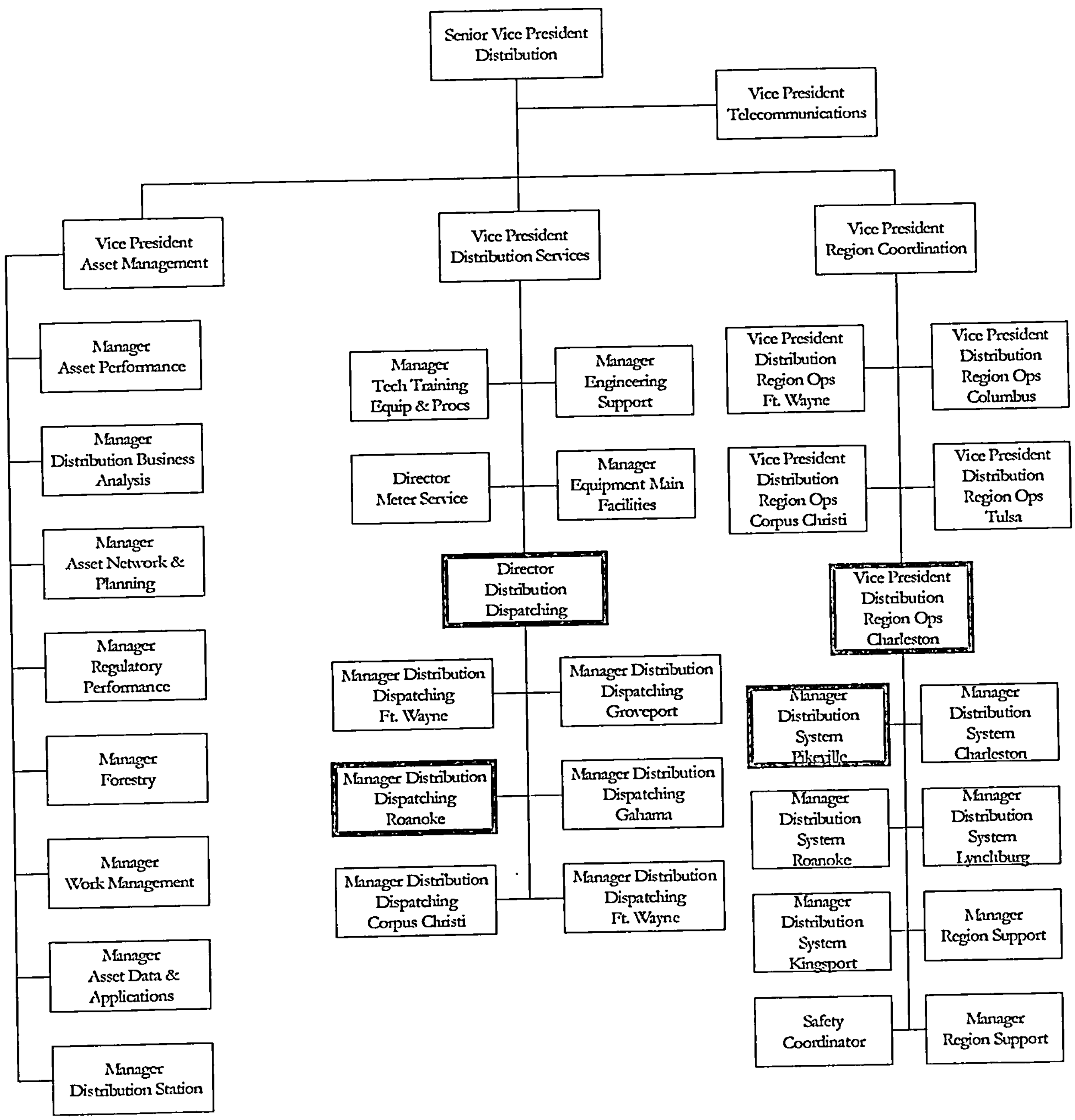
Exhibit II-2
Distribution Asset Management Organization



* Resources located throughout AEP
Bold boxes indicate management with most direct accountability for the Hazard Service Area

AEP/Kentucky is also within the regional organization structure being a part of the Charleston, WV region. Individuals at the region are also charged with asset management responsibilities. In particular the regions, in conjunction with the Asset Management Organization, are responsible for identifying projects within the region that support the overall asset management goals and objectives. The regional organization is shown in *Exhibit II-3.*

Exhibit II-3
Regional Distribution Organization



Asset Planning Engineering performs a formal annual review of the entire distribution system and develops plans for the future. The Regional Engineer works with day-to-day system operations. Asset Planning, which is a centralized operation from an overall point of view, is responsible for providing overall guidance. On a localized basis the Senior Engineer is responsible for his specific assigned area.

Distribution is organized into five regions:

Charleston, WV
Columbus, OH
Fort Wayne, IN
Tulsa, OK
Corpus Christi, TX

Each region has a Senior Planning Engineer (an additional Planning Engineers), who reports to the central Asset Management group, responsible for the actual work in their region (day-to-day planning activities). These Regional Engineers develop the details of a proposed project including:

Project description
Capital cost
Cost/benefit analysis

Capital Planning and Budgeting

The overall capital planning and budgeting process is shown graphically in *Exhibit II-4*. The left hand portion of *Exhibit II-4* represents the top-down portion of the capital planning and budgeting process whereas the remaining right hand portion of *Exhibit II-4* identifies how individual projects and work are identified to which these funds are applied. Some of the terms used within AEP include: BCR – Blanket Central Reserve, CPP – Capital Planning Projects, and CIP – Capital Improvement Projects.

The budgeting process is briefly discussed below at the highest level on a step-by-step basis:

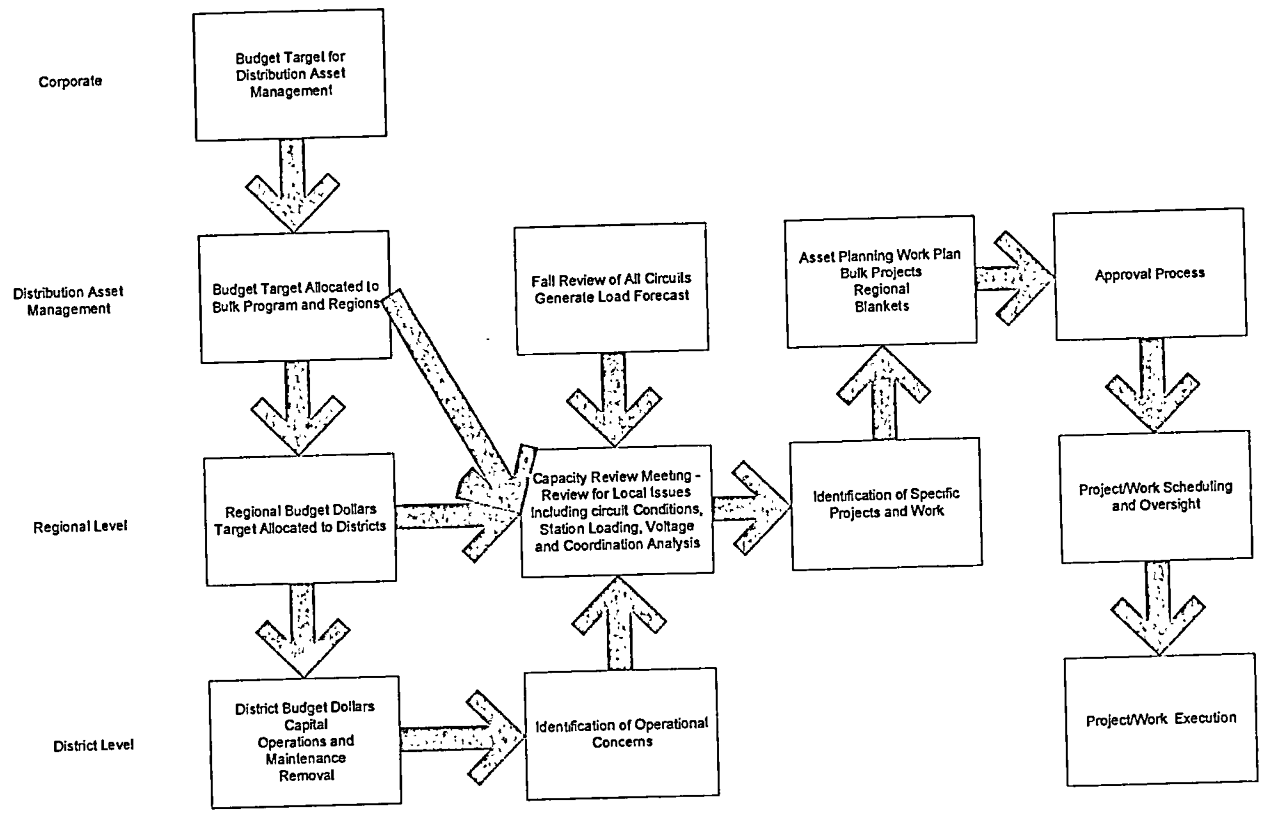
Step 1 – Corporate Planning and Budgeting in the early spring puts out a request for capital project needs from the field organizations. They identify at this point what last year's total budget was and what additional costs will be incurred this year. This is done both for O&M and Capital projects.

Step 2 – Early indication of the budget in mid- to late-spring

Step 3 – Distribution Asset Management (for AEP as a whole) splits this preliminary number into several distribution functional buckets, including:

- Capital projects – includes BCR and CPP projects which are longer-term in nature.
- VM – Vegetation Management
- Asset programs (Capital and O&M) – includes CIP

Exhibit II-4
Overall Planning Process



- Central organization funding – to support the AM organization for example
- Various blankets for such items as meters, transformers, etc.

Step 4 – A region-based budget which has 5 sub-buckets (for the five regions) that are divided according to historical dollars, customers, line miles, growth, etc. This is the region-based allocation.

Step 5 – Final budget – reconciliation.

Step 6 – Detailed budget development process

Step 7 – State-by-state check for continuity with past spending levels

Over the years the O&M budget tends to be very consistent while the capital budget will vary due to the specific projects that are approved. The factors that go into the decision process to authorize projects include the following:

1 – Capacity – probability of overload

2 – Reliability – current performance
3 – Customer satisfaction and complaints
4 – Environmental risk (where applicable)
5 – Safety risk (where applicable)

From a financial standpoint, Asset Management (both distribution and transmission) is given a budget target for both transmission and distribution expenditures, which are developed by corporate based on the prior year's budget – with modifications for known savings or expenses that would be incremental in the next year. This budget target is allocated to the bulk program and regions within the Asset Management organization. Each region then allocates these funds to the individual districts within their region.

The technical portion of the overall planning process begins with a review of data in the fall after the summer peak load. This review is undertaken in what is called a Demand Forecasting Meeting, in which various individuals such as Regional Engineers, Technicians, and Servicers meet to discuss issues. Similarly, in the spring, they perform a capacity review at the Capacity Planning Meeting, which results in the projects that are planned for the next 18 months.

Planning much of the bulk work plan of asset management is load-driven based on capacity planning. However, some projects (a small percentage) are driven totally by reliability considerations. According to AEP personnel, they also look at the impacts of improvements on reliability in terms of SAIFI and CAIDI, including the loading on components and estimates of ability to recover from an outage.

The bulk work plan (which is for all of AEP) is used by a central planning group (Distribution Asset Planning) for larger, longer-term projects such as distribution line reconductoring, rebuilds, etc. Generally projects greater than $125,000 are considered large projects and therefore are usually in the bulk work plan handled within Distribution Asset Management, whereas projects under $125,000 are usually handled in the regions. However, recently Distribution Asset Management has begun to include smaller projects, if the projects are forward thinking and improve the system and resolve longer-term issues.

The asset programs are also used for overall reliability programs that have been designed to ensure that ongoing preventative maintenance programs are performed within the regions. These programs include such items as: pole replacements, pole reinforcement, recloser replacement, lightning protection, animal mitigation, URD inspection and replacement, overhead circuit inspection and repair, pole ground-line treatment, and small wire replacement. All of the above categories are divided on a regional basis by program (i.e., transformers, vegetation mitigation, etc.). The regions may not reallocate funds which have been specifically budgeted for these preventative maintenance programs that are considered part of the bulk program (versus the regional budget). The regional budget is generally used for smaller, very reliability-driven projects or for daily repairs and improvements of a more immediate nature. The bulk work plan consists of individual projects that are justified based on specific system needs. The asset programs are targeted at the overall system and are intended to inspect, repair and replace a large number of components (such as poles and wire) for purpose of ensuring safety and the reliability of the system.

The bulk budget is segmented into categories by type of project. The work plan (of projects) for the year is subject to change throughout the year due to new or cancelled projects. Distribution Asset Planning breaks down this lump budgetary number into regional budgets that are based on the priority of the projects (which is apparently developed during the Capacity Review Meetings although Schumaker & Company has no written documentation to support this process) that are projected for each region. The Capacity Review Meetings are where potential projects are discussed. In these meeting planning engineers present areas of system needs and potential project improvements. Various departments participate in these meetings and provide feedback in the presented projects and also discuss alternatives. These departments may also introduce new system needs at this time. The documentation developed from this meeting is the preliminary work plan list. This list includes all potential projects discussed at the Capacity Review Meeting. In the following weeks this list is prioritized based on further project analysis. The final work plan is a ranked list of projects based on project justification (required projects as well as projects based on loading, voltage conditions, area growth, utilization rates, area reliability and contingency recovery).

The 2003 work plan, which was approved in June 2002, included the projects by region and the amount budgeted for those projects. Generally, these projects are for load and capacity at least one year down the road. This process has been in place for approximately two years.

Each of the individual projects in place has an individualized justification developed for it that is called a business case. This is done prior to initiation of the project, but after it has been approved as part of the work plan. Then the project is authorized for undertaking by management. The bases for the business case is developed and documented during the process of evaluating individual projects. It is this justification that determines which projects will be approved as part of the work plan. This documentation is later formalized and submitted with the project for authorization. At that time the project justification is reviewed to ensure the project plan is still appropriate.

Service Reliability

Within the electric utility industry, various methods of measuring electric utility service reliability have been used – from random sample customer surveys to quantitative indicators of service reliability. In brief, service reliability can be measured in two broad areas: hard service reliability indicators and soft service reliability indicators.

Hard Service Reliability Indicators

These reliability indicators are more technically based – based on statistics. Over the years, these indicators have evolved into various indicators. These Reliability Index Calculations were extracted from "IEEE Trial-Use Guide for Power Distribution Reliability Indices" (IEEE Std 1366 – 1998):

System Average Interruption Duration Index (SAIDI) – The average service interruption duration, measured on a system-wide basis. SAIDI equals the sum of all customer interruption durations divided by the total number of customers the utility serves during the reporting period.

$$\frac{\text{Sum of Customer Interruption Durations}}{\text{Total Number of Customers Served}} = \frac{\sum r_i N_i}{N_T}$$

System Average Interruption Frequency Index (SAIFI) – The average number of sustained outages per customer per year. SAIFI equals the total number of customer outages divided by the total number of customers the utility services during the reporting period.

$$\frac{\text{Total Number of Customer Interruptions}}{\text{Total Number of Customers Served}} = \frac{\sum N_i}{N_T}$$

Customer Average Interruption Duration Index (CAIDI) – The average time required to restore service to an average customer per sustained interruption. CAIDI equals the sum of all customer interruption durations divided by the total number of customer interruptions.

$$\frac{\text{Sum of Customer Interruption Durations}}{\text{Total Number of Customer Interruptions}} = \frac{\sum r_i N_i}{\sum N_i}$$

Where the values of the parameters in the above equations are as follows:

i = An interruption event
r_i = Restoration time for each interruption event
T = Total
ID_E = Number of interrupting device events
N_i = Number of interrupted customers for each interruption event during the reporting period
N_T = Total number of customers served for the area being indexed

Soft Service Reliability Indicators

Years ago, when electric utilities began to conduct customer surveys in an attempt to determine what "hard" service reliability was acceptable to customers, it was discovered that "soft" reliability indicators were perhaps just as important, if not more so, than "hard" indicators. Specifically the customer was more interested in being kept informed in the event of an outage than in some engineering based performance index. In short, if in the event of an outage the customer calls the call center and simple questions cannot be answered, customer satisfaction levels decrease. Examples of such simple questions include:

- What caused the outage? i.e., does the utility know what is going on?
- How soon will my power be restored? i.e., do I need to do something immediately to minimize the impact of the outage?

As a result, it is recognized within the electric utility industry that it is not just enough to concentrate on "hard" service indicators. Business processes and systems need to be developed that can also keep the customer informed throughout the outage restoration process.

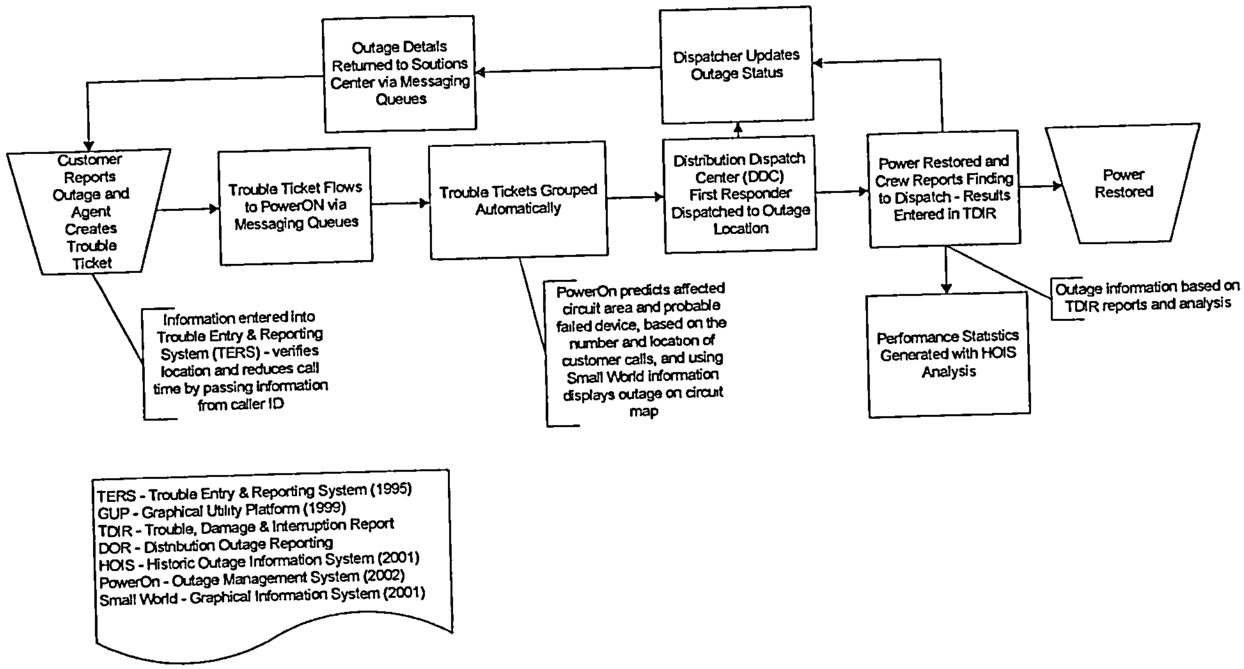
B. Findings and Conclusions

Finding II-1 Technology systems have been significantly upgraded in the last five years.

Outages are inevitable. It would be all but impossible to cost effectively design an electric network to prevent an outage from occurring. Therefore it is important that the "customer experience" from an inevitable outage be as painless and managed as economically as possible.

Over the last five years, AEP has made significant upgrades in their technology and systems that are involved in responding to customer outages and reporting on the progress of outage restoration. The specific systems that are involved in the area of asset management are shown in *Exhibit II-5*.

Exhibit II-5
Key Technology Systems Effecting Reliability



The identification of an outage usually begins with a customer calling the AEP Solutions Center (call center). The Solutions Center agent enters the information into the Trouble Entry & Reporting system (TERS). TERS is an internally developed system implemented around 1995, that collects information on the outage and also supports the ongoing reporting of progress on outage restoration such that information can be relayed to the customer if they call in again or if additional customers affected by the same outage call in.

That trouble ticket then flows to the PowerOn software. The trouble tickets generated as the result of an outage are grouped and analyzed by PowerOn, and a failed device (transformer, fuse, breaker, etc.) is "predicted." PowerOn "predicts" the affected circuit area and probable failed device based on the number and location of the customer calls. All of this information can be displayed on geographic maps, via an interface to the Small World system that was implemented in the last several years, in the Distribution Dispatch Center (DDC) in Roanoke, VA. This information on the "predicted" failed device can be relayed to the Servicer that is dispatched to identify and repair the outage cause. PowerOn is a purchased software package that was implemented in the last year (2002) in AEP/Kentucky.

Dispatchers in the DDC contact a Servicer within the affected area (county in the Hazard Service Area) to diagnose the outage at the circuit. Dispatchers remain in contact with the Servicer throughout the outage and are able to input status information into TERS such that customers can be informed of the status as needed. Once the outage is corrected, information is collected and summarized on a Trouble, Damage & Interruption Report that is then reviewed and entered into the Historical Outage Information System (HOIS). HOIS is an Oracle database that was implemented in 2001 to replace the previous Distribution Outage Reporting (DOR) system. HOIS supports various forms of reporting on historical results.

Throughout the above process, dispatchers can input status information into the TERS system such that the status information is available to relay to customers when they call in, to either report the same outage or inquire as to the status of the outage. Customer surveys have shown that the ability to keep the customer informed is one of the key capabilities that customers want during outages. Throughout the management of the outage, AEP/Kentucky has the ability to keep the customers informed.

Finding II-2 Call center operations for trouble reporting appear appropriate.

All initial customer calls on outages are handled in call centers, collectively called the Solutions Center. The AEP Solutions Center is currently organized into an East and West configuration. AEP is evolving toward a national virtual call center configuration, once the back office systems are capable of supporting such an operation, where a customer call that originates anywhere in the AEP service territory could be handled at any Solution Center location. The East is currently a virtual call center – that is any customer call can be answered by any of the following Solutions Center locations:

- Groveport with 150 to 180 total employees of all job classifications
- Fort Wayne with 60 to 80 total employees of all job classifications
- Hurricane, WV with 200 total employees of all job classifications
- Ashland, KY (will be phased out by the end of the 2002)

Common back office systems have been implemented throughout the East such that the virtual call center could be created. This virtual call center configuration allows AEP to handle more calls in the event of an emergency. There are two approaches used with virtual call center:

- Pre-call routing – All calls go to anyone
- Post-call routing – Used by AEP, where each customer has an assigned Home Center Site, which for AEP/Kentucky is Hurricane, WV; if there is no service representative available at Hurricane, the call can be routed to an available representative in another Solutions Center. As a result, a percentage of the calls received at a given Home Center site will be from a different area.

AEP targets a 60 second average speed of answer (ASA). Since they started virtual call routing in 1997, they have consistently achieved this goal. AEP attempts to route all calls to an agent. If agents are available at the home site, the caller is not requested to indicate the type of inquiry and is routed directly to an agent for processing. If all agents are busy at the home site, the caller is prompted for the type of call. The prompts include the ability for customers to be routed to the IVR for processing. The prompting is only four levels deep to minimize the confusion of the customer.

Although AEP's overall goal is to have all calls answered by a service representative instead of an automated system, such as an IVR system, AEP uses a third party application, which has a high capacity IVR system for customers to report the outages at the outset of a storm before the virtual call center has been ramped up. This reduces the number of customers that may receive a busy signal. The overflow system is activated to reduce the number of busy signals customers receive and is deactivated once the outage has been restored. When AEP activates the external IVR, it can control the number of calls that will go to the Solutions Center based on the geographic location of the caller. The geographical redirection of the caller is based on the area code and exchange of the calling party. This functionality reduces the number of non-outage callers that would be routed to the third party outage application in error. If the external service is activated, a portion of calls continues to be routed to the Hurricane Solution Center which could be answered locally or at another AEP solution center as described above. Calls not routed to the Hurricane Solution Center are routed to the third party application where customers can interactively report their power outage. AEP also has Internet-based outage reporting and service order capability. Outages are being reported on the Internet.

The Solutions Center is full service 7x24 for all customers. However, not all Solutions Center locations are open 7x24. Groveport and Hurricane are open 7x24, while Fort Wayne is open fewer hours. Most of the service representatives are full-time; however some are part-time (20 hours per week) and are used for load shaving purposes – i.e., they need them to work to handle large load periods. Turnover is approximately 21% per year – low for a call center environment. Service representatives do not have verbatim scripts – they have bullet items. The Solutions Center management records random callers and evaluates them based on rates involving caring, concern, grammar, tone, etc.

The call center work group organization is structured as follows:

Manager
Group Supervisor
Team Lead
Customer Service Associates

A work group is composed of anywhere from 16 to 18 agents (Customer Service Associates).

Although the Quality and Training Support group does live call monitoring, most of the live monitoring is done by Supervisors and Team Leads. Also the Manager and Director do spot live call sampling. Therefore, numerous opportunities for live monitoring exist. AEP has vendors who do third-party customer satisfaction surveys. AEP also has a complaint tracking mechanism to monitor complaints.

A call is only considered a complaint if AEP has had a prior opportunity to resolve the situation. Complaints would come in through the Solutions Center. The Customer Service Associate makes the determination as to whether a call is a report, inquiry, or complaint based mainly on the content of the call and the tone and level of agitation of the caller. The Solutions Center will try to handle the problem, but if the customer is still not satisfied, it will be escalated to a manager or higher, if necessary. Most calls that are escalated to a manager are classified as complaints. If the customer cannot be satisfied by the Customer Service Associate then the call would be considered as a complaint.

Finding II-3 Asset Management manages several different reliability programs that specifically address the hardware aspects of reliability.

Within the Asset Management organization various reliability programs exist that have been designed to ensure that certain ongoing preventative maintenance activities are performed. These programs include such things as:

- Pole replacement
- Pole reinforcement
- Recloser replacement
- Lightning protection
- Animal mitigation
- URD inspection and replacement
- Overhead circuit inspection and repair
- Pole ground-line treatment
- Small wire replacement
- Sectionalizing program (implemented after this report was drafted)

All of the above categories are divided on a regional basis by program (i.e., transformers, vegetation mitigation, etc.).

Capital and operations and maintenance funds are budgeted to each region for the above programs within the Distribution Asset Management organization based on prior year's expenditures and discussions with field personnel. The regions are allowed to reallocate money from any of these categories into other areas. The need to reallocate funds from one asset program to another is determined by a joint decision making process between the region and asset management at mid year which accounts for changes in projections such as pole inspection results, circuit inspection results, etc.. There is an exchange of information both up and down to complete the process as discussed previously. As yet, AEP/Kentucky does not have the capability of forecasting the impact of these expenditures on the changes in SAIFI. However, AEP has developed several models to attempt to quantify the impact of changes in expenditures on SAIFI performance. However, it will require several years of analyzing actual field results to validate the models.

Finding II-4 The budgeting process is predominately a top-down process.

Asset Management is given a budget target for both transmission and distribution expenditures, which are developed by corporate based on the prior year's budget – with modifications for known savings or expenses that would be incremental in the next year. These budgeted amounts are initially divided among the Asset Management groups and the regions by the Asset Management organization. Overall distribution budgets are allocated to regions based on line miles, customer counts and customer growth. The bulk work plan budget allocation is separate and independent of the region budget.

As such, budgets are not necessarily requirements based. Budgets are based more on prior year's expenditures, corporate goals, and other items that do not necessarily relate to what needs to be spent to provide improvements in service quality. This approach results in a setting of budgets such that field personnel are only left with deciding how "best" to spend the dollars. To put this in another context, if in *Exhibit II-4* the top down budget allowances are such that any bottoms-up projects identified by the districts cannot be included in the final budgets, it provides little incentive for district managers to push hard for projects that are known by them to be beneficial to the customers for reliability or other reasons. The key aspect of this whole process is the interaction that takes place in the Demand Forecasting Meetings and how projects are included within the final budgets. AEP/Kentucky has been unable to provide much written documentation (projects identified, project included, projects deferred, by year by budget) concerning this process and interaction.

Distribution Asset Management

Distribution Asset Management is given a budget target (capital, operations and maintenance, and removal) for distribution, which is developed by corporate based on the prior year's budget with modifications for known savings or expenses that would be incremental in the next year. Asset Management allocates these budget dollars to the bulk budget (typically projects greater than $125,000 and the preventative maintenance budgets or reliability programs) and regional budgets. The regional budget is used for customer service, service restoration, labor associated with asset programs, minor assets improvements, and highway relocation and therefore is divided into those categories. This regional budget is divided down to the Pikeville District level by the above categories.

Dollars are actually charged and budgeted to three categories:

Capital
Operations and maintenance (O&M)
Removal (small $ amount for pole removal, for example)

A large allocation ($3 million to $4 million) requires a Capital Allocation Proposal that includes a description of the project and details of the cost/benefit analysis. There are various levels of signoffs depending on the size of the project. Projects of $125,000 to $750,000 are funded under blanket allocation dollars and come out of the Asset Management budget. Projects of less than $125,000 are funded from either Distribution Asset Planning's or the region's budget. They are usually covered in what are called blanket budget accounts. Blanket budget accounts are created to handle many smaller projects. These can be done with only local approval under the blanket budget account. These total blankets are approved by the AEP Board, but local authorization to perform the project is acceptable.

Creating a budget does not authorize any expenditure of funds. Rather the projects must be authorized on an individual basis at some management level depending on their size.

Transmission Asset Management

Transmission Asset Management is given a budget target for transmission, which is developed by corporate based on the prior year's budget with modifications for known savings or expenses that would be incremental in the next year. Transmission asset management then aligns its projects to use the budget for the year. There are two groups that share the transmission budget allocation dollars:

- Capital projects
- Rehab projects

Transmission capital budget expenditures have been relatively stable over the past 3 to 5 years; however, the following two other categories can vary widely:

- Independent power producer connections
- Special projects (very large specialized projects)

Finding II-5 AEP/Kentucky was unable to readily provide historical information regarding planning and budgeting processes.

According to AEP/Kentucky, much of the decision making regarding projects takes place in the Capacity Review Meetings where potential projects are discussed. Various departments participate in these meetings and provide feedback in the presented projects and also discuss alternatives. The documentation developed from this meeting is the preliminary work plan list. This list includes all potential projects discussed at the Capacity Review Meeting. However, AEP/Kentucky was unable to provide us with these historical lists. Additionally, a request for the three prior year's transmission and distribution operations and maintenance and capital budgets was also difficult for AEP/Kentucky to develop. AEP/Kentucky had under gone a change in accounting systems during this time period which made it difficult for this information to be obtained.

Finding II-6 The capital and operations and maintenance budgeting processes by which funds were allocated to the Hazard Service Area have not resulted in improvements in reliability indicators or prevented extended outages.

As previously discussed, capital and operations and maintenance budgets are based primarily on the prior year's expenditures, corporate goals, and other items that do not necessarily relate to what needs to be spent to provide improvements in service quality. Capital and operations and maintenance expenditures for AEP/Kentucky have decreased significantly from 1999 as shown in *Exhibit II-6*. In essence, distribution capital and operations and maintenance expenditures are at almost the same level in 2001 as in 1996.

As shown in *Exhibit II-7*, the Buckhorn Area Improvement project, at $496,100, was a very significant project for the Hazard Service Area. It was by far the largest single project within the Hazard Service Area in the 2000-2002 timeframe. Schumaker & Company consultants were told that the Buckhorn area had been known to be a problem, i.e. it was not a surprise, and that it had been in the plan for several years, but was relegated to a future timeframe. Although it is difficult to determine the validity of these statements due to a lack of written historic documentation, it is understandable that it would not probably have been politically expeditious for Hazard Service Area personnel recommend a project the size of the Buckhorn Area Improvement during a time when funds were being constrained at the corporate level. Simply put, a $496,100 project in a $38 million total budget for AEP/Kentucky (or approximately $1 million for the Hazard Service Area) would probably have required significant justification on the grounds of improved reliability, cost and benefits, etc.

As is discussed in *Finding II-7*, AEP/Kentucky has only recently begun to tie some of its reliability programs to improvements in SAIFI, CAIDI, and SAIDI. Therefore, the tools to support the business justification of projects such as the Buckhorn Area Improvement did not exist within the Hazard Service Area let alone AEP/Kentucky. Without such tools, it is difficult for District management to be able to quantitatively justify large capital and operations and maintenance expenditures. However it should be understood that the funds were redirected once the affected customers complained to the Kentucky Public Service Commission.

Exhibit II-6
Transmission and Distribution Expenditures (1996-2001)

Transmission and Distribution	1996	1997	1998	1999	2000	2001
Distribution						
Capital	$21,549,800	$23,159,084	$17,987,868	$26,115,738	$22,558,353	$21,071,480
O&M	$16,453,642	$17,827,814	$21,633,952	$22,763,501	$17,052,323	$17,248,292
Total Distribution	$38,003,442	$40,986,898	$39,621,820	$48,879,239	$39,610,676	$38,319,772
Transmission						
Capital	$2,964,048	$40,973,981	$23,872,816	$29,359,675	$5,892,833	$13,686,830
O&M	$4,777,758	$4,424,148	$4,753,922	$3,543,039	$5,377,526	$4,973,664
Total Transmission	$7,741,806	$45,398,129	$28,626,738	$32,902,714	$11,270,359	$18,660,494
Total T & D	$45,745,248	$86,385,027	$68,248,558	$81,781,953	$50,881,035	$56,980,266

The Distribution capital expenditures for 1998 and 1999 are accurate from an accounting perspective, but not when the money was actually spent for work being performed. Due to the implementation of a new financial software release, People Soft 7.0 across AEP, during the 4th quarter of 1998. Any work orders that would have been closed during the 4th quarter were not closed until 1999. This results in a lower amount of capital being placed on the property records in the 1998 and a higher amount in 1999. This is shown as a 25% lower than average spending in 1998 and a 25% higher than average spending in 1999. The actual capital spending for 1998 and 1999 are closer to the average of these two years.

The primary reliability projects and related costs for the Hazard Service Area for the last several years are shown in *Exhibit II-7*.

Exhibit II-7
HSA Reliability Projects and Related Costs

	Operating Area	Costs	Year Approved
System Improvement			
Whitesburg Area Sectionalizing	Whitesburg	$82,063	2000
Bonnyman-Hazard Circuit Improvements	Hazard	$100,300	2002
Buckhorn Area Improvements	Hazard	$496,100	2002
Total System Improvement		$678,463	
Distribution Inspection and Maintenance			
Distribution Pole Replacements	Whitesburg and Hazard	$624,958	2000-2002
Distribution Reclosure Replacements	Whitesburg and Hazard	$777,197	2000-2002
Distribution Animal Guards Installments	Whitesburg and Hazard	$19,008	2000-2002
Distribution Reinforcements	Whitesburg and Hazard	$132,308	2000-2002
Lighting Arrestors	Whitesburg and Hazard	$7,227	2000-2002
Overhead Circuit Inspection	Whitesburg and Hazard	$327,771	2000-2002
Total Inspection and Maintenance		$1,888,469	
Vegetation Management	Whitesburg and Hazard	$4,033,202	2000-2002
Total		$6,600,134	

Despite the above referenced investments, the SAIFI, CAIDI, and SAIDI numbers, as shown in *Exhibit II-8* thru *Exhibit II-10*, have varied little over the last six years with the SAIFI and SAIDI numbers trending slightly down but CAIDI remaining relatively unchanged. In almost all cases, the Hazard Service Area has the highest (worst) results within AEP/Kentucky.

Exhibit II-8
SAIFI (Excluding Storms) Results for AEP/Kentucky

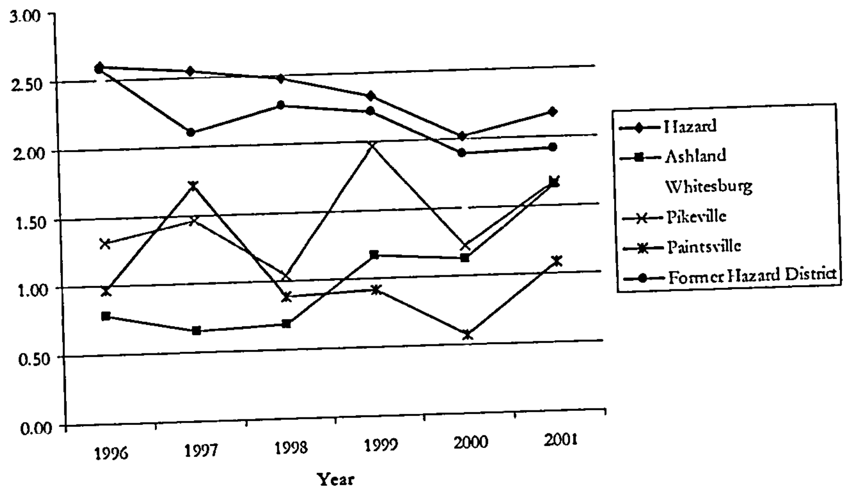


Exhibit II-9
SAIDI (Excluding Storms) Results for AEP/Kentucky

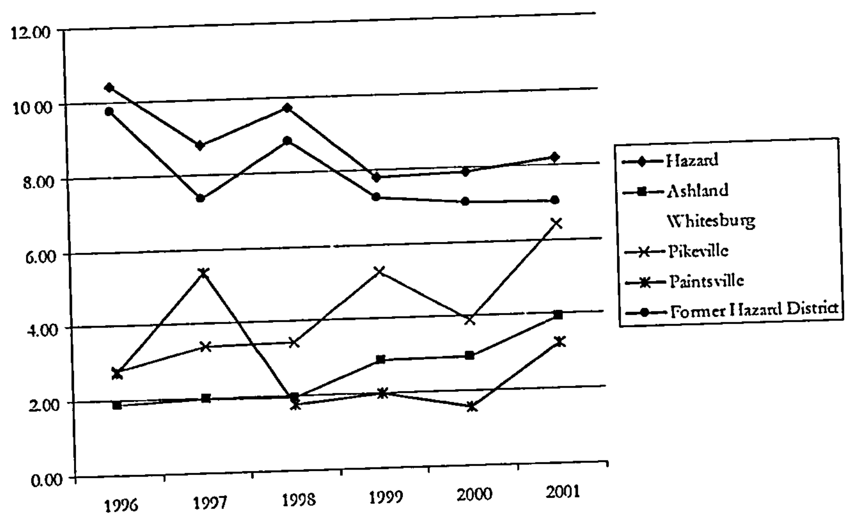
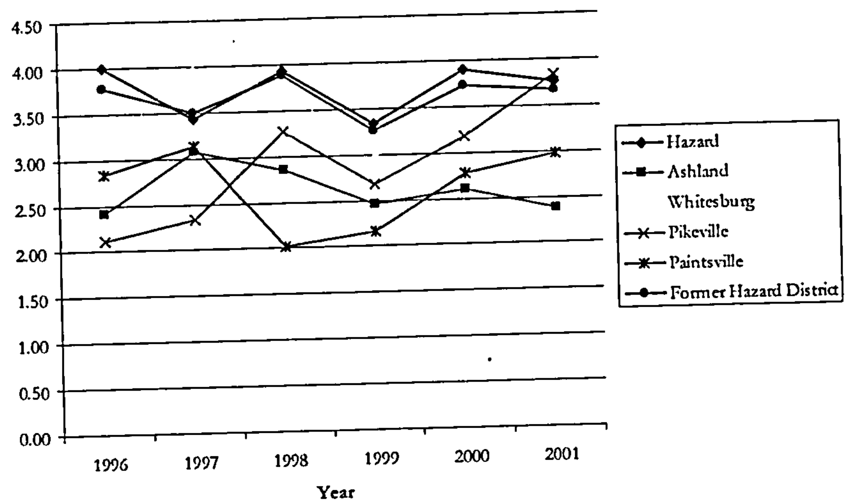


Exhibit II-10
CAIDI (Excluding Storms) Results for AEP/Kentucky



These numbers will probably appear worse in the future due to a change in the method of reporting these results (via the new Outage Management System).

Finding II-7 Reliability programs are not specifically designed to make specific improvements in SAIFI, CAIDI, and SAIDI by targeting improvement in frequency, duration, or number of customers.

AEP/Kentucky has attempted to tie some of its reliability programs into improvements in SAIFI. In particular, a model has been developed based on theoretical assumptions that will require several years of analyzing actual field results to validate the model. However, this model does not address SAIDI or CAIDI considerations. There is more that needs to be done within AEP/Kentucky to begin to tie the result of its reliability programs into improvements in service quality.

AEP/Kentucky internal studies have also identified the need for more proactive outage and circuit review and improvement projects for circuits with poor service reliability. AEP/Kentucky management recognizes that opportunities exist for reducing response times, improving restoration work practices, vegetation management, and further automating stations and systems with Supervisory Control and Data Acquisition (SCADA) systems. Some of the changes that have been made as a result of these internal studies include the Three Times Outage Report, which shows each isolating device that has locked out three times or more in the past twelve months. This information is used to eliminate the reoccurring outages that have affected customers most frequently. Examples of the proactive work that was targeted to improve the reliability of poor performing circuits are as follows:

The Three Times Outage Report captures any primary voltage sectionalizing device that has experienced three or more sustained outages in a rolling twelve-month period; the appropriate Regional Engineer or Forestry Specialist is responsible for initiating actions designed to prevent future outages at each device

Sorting of the area distribution circuits by SAIFI/CAIDI to create a worst performer list to provide first steps in identifying opportunities to improve the reliability of those circuits; examples of work that were performed include targeted widening of the right-of-way in the circuit breaker protection zone, installing fused cutouts on unprotected side taps, and upgrading the overall circuit sectionalizing schemes

Review of station breaker operations by reports derived from the Integrated Substation Information System (ISIS) to identify circuits that may have right-of-way issues in the circuit breaker protection zone ISIS is a record system that includes operation counts of circuit breakers inside the substation. These counter readings are obtained during scheduled substation inspections. For distribution circuits, the history of main circuit breaker operations can be reviewed (an unusually high number of operations) as an indicator of circuit problems within the breaker's protective zone. The causes of these operations would not be limited to trees and the circuit would be investigated for any obvious problems, including trees.

Tracking of devices in the abnormal equipment database to initiate actions to return equipment to service

A region-wide spreadsheet database of reliability related projects that are prioritized so the best projects can be completed, as funding is made available; this list can also be used to solicit funding from Asset Planning to obtain resources from outside the region/district base budgets

A just-completed 2003 right-of-way (ROW) maintenance plan for each operating area that was created through cooperation among local line supervision, regional engineering, and forestry personnel to target the worst performing circuits

A review of potentially overloaded primary stepdown transformers, the purpose of which is to prevent outages caused by transformer failures during the upcoming winter heating season

A review of the region's most unbalanced circuits on an amps/phase basis at the circuit breaker; the purpose of this effort is to improve the load balancing on the region's more heavily loaded station transformer banks and reduce the possibility of premature transformer failure.

The ability to tie the reliability programs into performance improvements in SAIFI, CAIDI, and SAIDI is highly dependent on having the performance data to analyze. Much of this performance data is available from the management and information systems that were discussed in *Finding II-1*. This data will need to be "mined" to makes this capability a reality. An example of the type of analysis that AEP/Kentucky should be undertaking with this information is presented in *Finding II-8*.

Finding II-8 Field crew staffing levels need to be approached from a response effectiveness analysis.

Hazard Service Area staffing has been significantly reduced over the last five years as shown in *Exhibit II-11*.

Exhibit II-11
Hazard Service Area Staffing Changes 1997 to 2001

Employee Group	End 1997	End 2001	Percentage Reduction
Supervisors Distribution Service	1	1	0%
Line Crew Supervisors	9	8	11%
Distribution Line	36	22	39%
Stores	4	4	0%
Customer Services, Billing & Collections, Meter Reading	25	13	48%
Marketing/Key Accounts	5	2	60%
Transmission/Station	9	1	89%
Metering	2	2	0%
Building Maintenance	3	1	66%
Fleet	4	2	50%
Communication	1	1	0%
Engineering/Technicians	12	8	33%
Community Service Manager	0	1	N/A
Total	111	66	41%

Although AEP/Kentucky has made many changes in the last five years that could support some of the reduction in numbers shown in *Exhibit II-11*, such as the introduction of new computer systems, the most sensitive area with respect to system reliability is the Distribution Line area. One of the primary roles of Distribution Line personnel is to respond to outages. It has become even more important as response staff has been decreased.

In particular, the first responder to an outage in AEP/Kentucky is a Servicer. As discussed later in this report, Servicers in the Hazard/Whitesburg area are currently working significant levels of overtime. Furthermore, according to AEP personnel, Servicers are able to completely handle (restore) service 75% of the time without having to call out other support – line crew personnel. Therefore the Servicer position is a key position relative to the impact on overall performance indicators, specifically CAIDI.

Electric utilities cannot directly "manage" SAIDI, SAIFI, and CAIDI. However, electric utilities can manage the individual parameters that go into making up these numbers. Specifically each of these indicators is a function of just three items:

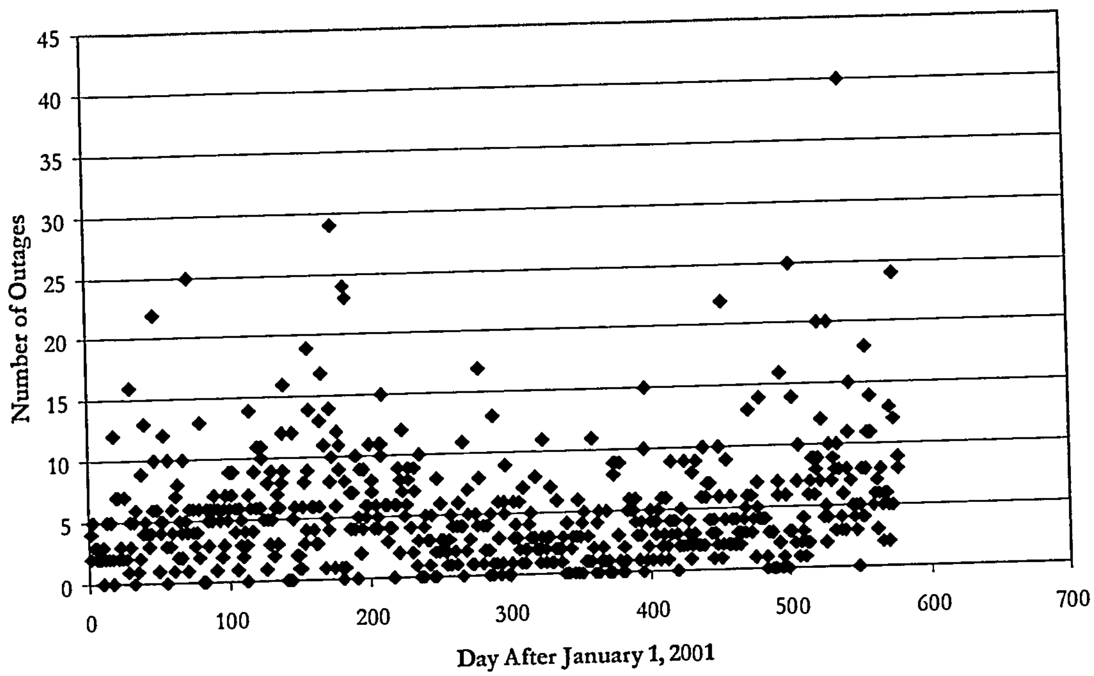
SAIFI
SAIDI = Function (frequency, duration, number of customers)
CAIDI

Frequency – frequency of occurrence
Duration – how long it takes to restore the outage
Number of customers – how many customers are affected by the outage

The important thing to take away from this function is that Servicers impact duration. If there are too few Servicers, then when multiple outages occur, the outages get stacked in a queue (the Servicer can only work on one outage at a time and the extra outages have to wait until the current one is restored), resulting in longer durations. There are also geographic challenges in the Hazard Service Area – such as long travel time to site, lack of river crossings or direct routes, etc. Additional Servicers could help lessen the impact of these factors.

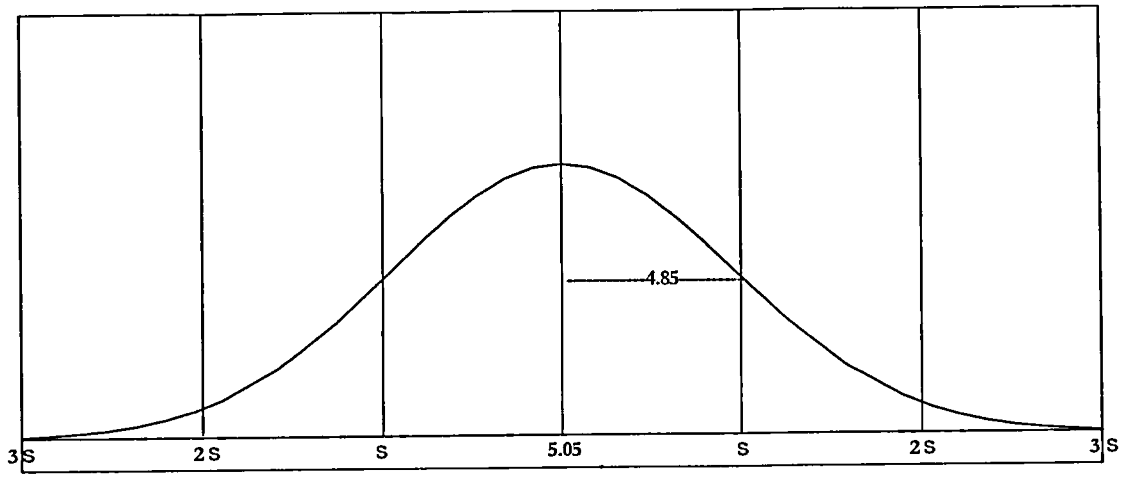
For a simple example of the type of analysis that could be done with the data that AEP/Kentucky already has available, outage information was obtained for the Hazard/Whitesburg area for the time period January 1, 2001 to August 1, 2002 (578 days). This information was analyzed by Schumaker & Company to create a representation of the number of outages that occur on any given day. The results are shown in the scatter diagram in *Exhibit II-12*.

Exhibit II-12
Number of Outages per Day



For illustrative purposes, if we assume that the above information is normally distributed, then it could be represented by a bell shaped curve as shown in *Exhibit II-13*, with an average of 5.05 and a standard deviation of 4.58. Translating these numbers into a more useful insight, a median of 5 means that for half the days in the year there are approximately 5 or fewer outages in the Hazard/Whitesburg area and for half the days there are more than 5 outages.

Exhibit II-13
Normal Distribution of Outages per Day



Furthermore, we know from a normal distribution that one standard deviation from the average contains 68.2% of the occurrences. From a more practical viewpoint, 84.15% of the time the Hazard/Whitesburg area experiences less than 10 outages in a day, as shown in *Exhibit II-14*.

Exhibit II-14
Normal Distribution Percentages

Standard Deviation from the Mean	Area Within Standard Deviation	Area in Upper and Lower Tails	Area to the Left of Right Standard Deviation
1	68.2%	31.7%	84.15%
2	95.4%	4.5%	97.75%
3	99.7%	.2%	99.99%

The fundamental question that needs to be decided is where on this distribution does the utility staff its field force level to cost effectively minimize the impact of the right hand side of the normal distribution curve to minimize CAIDI.

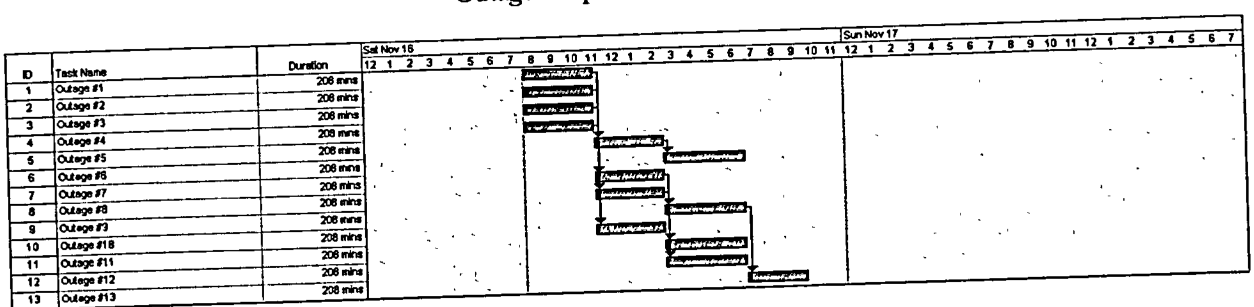
It can also be determined from the same information that the average restoration times are as shown in *Exhibit II-15*. As *Exhibit II-15* illustrates, restoration times are shorter on 34.5 kV/19.92 kV circuits as compared to 12.47 kV/7.2 kV circuits. It might be expected that on average 66 customers are out of service on 34.5 kV/19.92 kV circuits compared to 47 customers on 12.47 kV/7.2 kV circuits. Most likely, Servicers are being dispatched to 34.5 kV/19.92 kV circuits before 12.47 kV/7.2 kV circuits due to the higher customer counts.

Exhibit II-15
Outage Response Times

Distribution Voltage	Average Number of Customers Impacted	Average Number of Customer Minutes Out
34.5/19.92 kV	66.35	208.63
12.47/7.2 kV	46.95	254.41

Outages are not necessarily evenly spaced throughout the day. In particular, it is most likely on days that experience a higher number of outages that there is a precipitating event – i.e., thunderstorm, snow storm, or ice storm, etc. In those cases, the outages would most likely occur around the same time. This timing could lead to a stacking up of outages such that some outages would have to wait to be dispatched until a Servicer is released from another outage as illustrated in *Exhibit II-16*.

Exhibit II-16
Outage Response Scenarios



This finding and example illustrate how some of the information currently being collected could be used to begin to establish staffing levels from the bottom up. There are several other items that would need to be investigated and incorporated into the analysis before this "ground up" analysis would be complete. These items could also include:

- Goal on the distribution curve for designing staffing response – i.e., a 50%, 80%, etc., service level target
- Outage distribution by time of day
- Effective Servicer availabilities (incorporation of the impact of vacation and sickness, Servicers on disability, linemen serving as Servicers etc. into the actual Servicer availability on any given day, and callout turndown rates for each Servicer)

Finding II-9 Outages results are getting worse.

The results within the Hazard/Whitesburg area are shown in *Exhibit II-17* in terms of number of customers impacted and customer minutes.

Exhibit II-17
Outage Results

Timeframe	Number of Customers	Total Customer Minutes
January to July 2001	57,271	13,215,155
January to July 2002	88,882	18,463,101
Increase Over Prior Period	55%	40%
January to December 2001	86,297	20,128,592

The total number of customers impacted from January to July of 2001 compared to 2002 has increased by 55% and the customer minutes by 40%. Some of this increase might be explained by more accurate reporting as a result of the improved systems (specifically PowerOn and HOIS). However, to the extent that this increase is not a result of improved reporting, it could be indicating that service levels are getting worse.

Finding II-10 More analysis is needed of the data that is currently being collected from new systems to improve reliability.

SAIFI, SAIDI, and CAIDI are industry recognized ways of measuring electric system reliability. Each of these indexes requires that an outage be "identified" before it can be measured. This "identification" process to a large part depends on the customer calling AEP/Kentucky to report an outage – unless the outage causes a remotely monitored protection device to activate and lock out.

However, customers are also affected by momentary outages. Momentary outages are defined as outages that last less than five minutes. In many cases, these outages are self correcting – the tree branch that contacts the circuit is no longer in contact and the protection device resets, etc. It is difficult for utilities to measure these outages, because in many cases they occur and correct without the utility even being aware. However, more customers are now very aware of the impact of these outages by the flashing digital clocks that require resetting. In fact, customers can record these outages on their own to begin to develop a stronger case regarding unacceptable service quality from their utility. In essence, the customer could develop the data to show problems in service quality when the utility would have no information from which to refute the information.

The Institute of Electrical and Electronic Engineers (IEEE) has an indicator that attempts to measure the impact of these momentary outages. It is called MAIFIE or Momentary Average Interruption Event Frequency Index (Momentary Events) and is defined as shown below:

$$\frac{\text{Total Number of Customer Momentary Interruption Events}}{\text{Total Number of Customers Served}} = \frac{\sum ID_E N_i}{N_T}$$

However, without special equipment, this index is difficult to measure in that the data acquisition part is expensive – you have to have some way of knowing that a momentary outage occurred.

C. Recommendations

Recommendation II-1 **Develop a more appropriate approach to determining capital and operations and maintenance funding levels (Refer to *Finding II-4*, *Finding II-6*, and *Finding II-7*).**

At the current time, asset management decisions are driven primarily by load growth and the available capital and O&M funds. The available funds have been allocated based on a top-down development of the budget, with the Asset Management groups and regional personnel making the decisions on how to best use those funds. However, complete listings of annual work loads or field requirements have not been developed for the Whitesburg/Hazard area. These forecast workloads would include the results of proactive outage and circuit reviews for circuits with poor service reliability, tree inventories for all circuits, and complete inventories for all other reliability items currently being performed (pole replacements, small wire, etc.). It is this forecast workload data that would form the basis for the development of comprehensive bottom-up capital and O&M requirements. In the past year, AEP/Kentucky has begun to develop some of the information required for a bottom-up approach through the Three Times Outage Report and other items mentioned in *Finding II-7*.

This bottom-up workload forecast quantification would then need to be balanced against the top-down funding levels to identify shortfalls in the funding required to support the target level of service quality that is to be provided in the Whitesburg/Hazard area. Shortfalls would then need to be recognized as either workload that will need to be deferred (it does not go away, but most likely accumulates exponentially over time) or for which alternative sources of funding will be required – most likely through the regulatory process.

Recommendation II-2 **Each circuit within the Hazard Service Area should be analyzed and a reliability improvement plan developed. (Refer to *Finding II-6* and *Finding II-7*).**

As mentioned in *Finding II-6*, it was difficult to determine the extent to which the individual circuits within the Hazard Service Area had been analyzed relative to any of the following reliability issues:

- Outages (SAIDI, SAIFI, and CAIDI)
- Momentary outages (which are not reflected in any indicator at this time)

- Cold load pickup (the ability to reenergize a complete circuit instead of having to step the circuit back into service)
- The current status of vegetation along the circuit
- The condition of equipment

During the course of the project, Schumaker & Company consultants did perform a brief design review of several circuits to identify any obvious issues with specific circuits. However, it is our expectation that a formal written design review of all HSA circuits would be performed and updated on an annual basis. AEP/Kentucky had performed some aspects of such a review in the past in response to KPSC concerns, but we did not find evidence that all circuits had been reviewed in such a manner – as evidenced by the Buckhorn situation. A complete review of all circuits within the HSA needs to be performed and updated on an annual basis. This review should result in a written work product that can be reviewed by KPSC staff.

Recommendation II-3 **Maintain historical information on operations and maintenance and capital planning processes. (Refer to *Finding II-5*).**

AEP/Kentucky needs to maintain historical information on operations and maintenance and capital planning processes such that this information can be provided to the Kentucky Public Service Commission and the effectiveness of the planning processes can be measured.

Recommendation II-4 **Develop a methodology for specifically tying capital and operations and maintenance investments to reliability indicators (Refer to *Finding II-6* and *Finding II-7*).**

As mentioned in *Finding II-7*, AEP/Kentucky has attempted to tie some of its reliability programs to improvements in SAIFI. However, this model does not address SAIDI or CAIDI considerations. There is more that needs to be done within AEP/Kentucky to begin to tie the result of its reliability programs into improvements in service quality. The ability to tie the reliability programs into performance improvements in SAIFI, CAIDI, and SAIDI is highly dependent on having the appropriate performance data to analyze. Much of this performance data is available from the management and information systems that were discussed in *Finding II-1*. This data will need to be "mined" to makes this capability a reality.

Recommendation II-5 **Use statistical methods for establishing field force staffing levels (Refer to *Finding II-8*).**

One of the primary roles of field forces is to respond to outages. Field force levels have been reduced throughout the electric utility industry as a result of a combination of factors but, specifically:

- A reduction in major new construction projects
- A greater reliance on outside contractors for new construction that is undertaken

However, the need to be able to effectively respond to outages is a role that has not changed but has taken on a greater significance as staffing levels have been reduced. Field force proximity to where an outage occurs is a key factor in response time, necessitating that field forces be deployed in a manner to minimize response times.

Finding II-8 provided an illustration to demonstrate that a statistical approach to determining field force staffing levels could be used to correlate staffing levels with the ability to provide a certain level of response capability. This analysis needs to be completed based on the latest information available from AEP/Kentucky technology systems, including other factors discussed in the finding. This analysis should be conducted on an ongoing basis to determine the adequacy of staffing levels.

Recommendation II-6 Closely monitor performance indices for adverse trends (Refer to *Finding II-9*).

The performance indices within the Hazard/Whitesburg area have increased (gotten worse) in the last year in terms of number of customers impacted and customer minutes. Some of this increase might be explainable due to better reporting as a result of the improved systems (specifically PowerOn and HOIS). However, to the extent that this increase is not a result of the improved reporting, it is a cause for concern. One would expect that to the extent this increase is due to better reporting, the performance indices should "level off" if not come down in the next year (2003). As a result, these indices should be closely monitored and reported for the next several years.

Recommendation II-7 Develop a method for addressing momentary outages (Refer to *Finding II-10*).

SAIFI, SAIDI, and CAIDI are industry recognized ways of measuring electric system reliability; however each of these indices requires that an outage be "identified" before it can be measured. This identification process to a large part depends on the customer calling AEP/Kentucky to report an outage – unless the outage causes a remotely monitored protection device to activate and lock out. At least two ways of monitoring momentary outages exist:

- **Hardware related** – The identification and installation of some type of equipment that could be placed into the electrical network to report information on momentary outages.
- **Customer related** – AEP/Kentucky could provide customers with postage return cards that can be used to report momentary outages. If the message to the customer is that AEP/Kentucky is interested in knowing how well they are serving you, getting customers to participate in the process might offer other benefits.

III. Engineering

This chapter addresses American Electric Power (AEP)/Kentucky's design engineering activities.

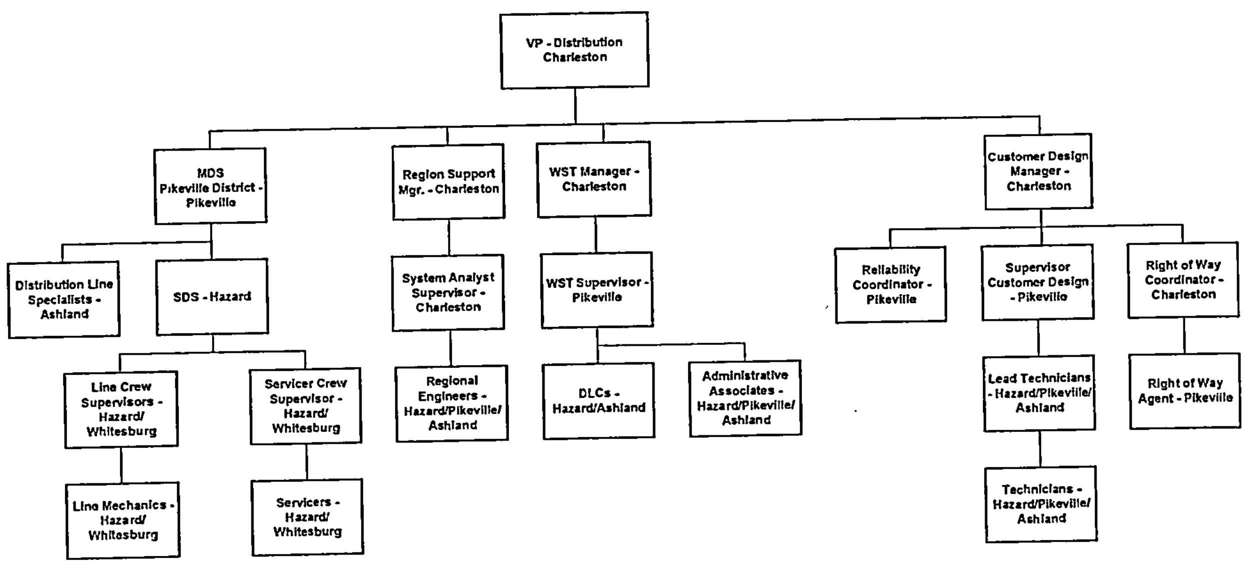
A. Background and Perspective

The responsibility for the design engineering function is divided among the Charleston Region engineering groups located in Charleston, WV and Roanoke, VA; a Regional Engineer located at the Hazard Service Center; and Engineering Technicians located at the Hazard Service Center. The Station Resources group in Roanoke does station design. The Technical Services group in Hazard does the design of the line-related projects.

Organization and Management

An organization chart showing the Regional Engineering group and Customer Design group to the Hazard Service Area level is included in *Exhibit III-1*.

Exhibit III-1
Charleston Region Engineering Groups Organization Chart



Regional Engineering Group

For Distribution Planning purposes there are five regions:

- Charleston, WV (includes AEP/Kentucky)
- Columbus, OH
- Fort Wayne, IN
- Tulsa, OK
- Corpus Christi, TX

Each region has a Senior Engineer assigned who reports to the Manager of Distribution Asset Planning inside the Asset Management organization and who is responsible for the actual work in their region (day-to-day planning activities). The Senior Engineer and his work team develops the details of a proposed project, including:

- Project description
- Capital cost
- Cost/benefit analysis

In relation to the overall planning process, the Regional Engineering staff and local service area operations staff review the operating data in the fall of each year after the summer peak load through an operational review, which is called the Demand Forecasting Meeting. This operational review leads to a forecasting meeting with Regional Engineers, Technicians, and Servicers. In the spring of each year, the same group performs a capacity review at the Capacity Planning Meeting, which results in the identification of those projects that are planned for completion in the next eighteen months.

In regard to reliability considerations, the Regional Engineering Group looks at the impacts of improvements on reliability in terms of SAIFI and CAIDI. This group also looks at the loading on components and estimates of the ability to recover from an outage. Much of Asset Management is load-driven based on capacity planning. However, some projects (a small percentage) are driven totally by reliability considerations.

The "bulk budget" (which is for all of AEP) is used by the Distribution Planning group for longer-term projects that are larger. The regional budget would generally be used for smaller, very reliability-driven projects. The regional budget is mostly intended for daily repairs and improvements of a more immediate nature. A large project is generally considered to be one that is over $125,000. However, there is now an ability to fund smaller projects out of the bulk budget, if the projects are forward thinking, improve the system, and resolve longer-term issues.

The bulk budget is divided into categories by type of project. The bulk budget is determined by the AEP corporate Asset Management organization, which gives them a total budgetary number for AEP as a whole. The work plan (of projects) for the year is subject to change throughout the year due to new or cancelled projects. The Distribution Asset Planning group then breaks down this lump budgetary number into regional budgets that are based on the priority of the projects that are forecast for each individual region. (See Chapter III – Asset Management for a more detailed discussion of the budget process.)

The 2003 work plan, which was approved in June 2002, included the projects by region and the amount budgeted for each project. Generally the Distribution Planning group is planning for load and capacity at least one year into the future. Each of the individual projects that have been identified has a justification developed for it that is called a "business case." The business case is done prior to initiation of the project, but after it has been approved as part of the work plan. At this point the project is "authorized" for undertaking by management.

The demand (load) forecast is developed by the Distribution Planning Group based on actual demands and loads including load growth projections. Potential sources of new demand are also obtained from Regional Engineers at the field level.

Regional Engineering Function in Hazard

The Regional Engineer located at the Hazard Service Center works with the day-to-day operations of the Hazard Service Area system. As such, the Regional Engineer is responsible for the coordination of engineering issues, power quality, over-current protection, low voltage, monitoring of power quality, power factor correction, reactive current, load current, and reliability. Additionally, this position is responsible for handling customer service complaints relevant to power quality or reliability. AEP recently transferred this responsibility to the Regional Engineers to standardize the manner in which this function is handled across the company and to improve the ability to respond directly to customer problems. The Regional Engineer also does initial studies of new or upgraded service additions.

Generally, projects that are over approximately $125,000 are Asset Management projects and are funded through that group. Projects that cost less than $125,000 are generally handled locally through various blanket budget allocations, which are a part of the established regional budgets. (See Chapter III – Asset Management for a more detailed discussion of the budget process.)

Three Regional Engineers in the Pikeville District organization are assigned to the Kentucky service territory of AEP. Two other Regional Engineers, who are also part of the Pikeville District organization, are physically located in and assigned to West Virginia. There are a total of 23 Regional Engineers assigned to the entire Charleston Region.

One of the primary reports that the Regional Engineer in Hazard uses is the Three Times Primary Device Outage Report, which lists those devices that have failed three or more times in the past year (12-month rolling average) including storm outages. This is a report that is combined for the Roanoke and Charleston Regions and is available on the Web. This report, formerly known in the old Transmission and Distribution Interruption Report (TDIR) program as the "Repeat Device Outage Report", has been in use for over 25 years. It was used on an informal basis by engineering and management to identify primary sectionalizing devices, which previously experienced repeated sustained outages in a defined reporting period. The Three Times Primary Device Outage Report as it currently exists, is now a formalized region-wide process to identify and mitigate repeat device outages. This new formalized report began in January 2002.

When a circuit shows up on the report that is within the Regional Engineer's service area, the Regional Engineer will research the reason for the problem. The report is by circuit and is updated on a monthly basis. The Regional Engineer in Hazard has refocused on this report in the past few months to better address reliability problems in the Hazard Service Area. While the Regional Engineer has a standardized deadline for responding to the items (in the assigned territory) that are listed in the report, response to the identified problems is usually immediate.

The Regional Engineer previously used the TDIR on a regular basis until it was phased out. The TDIR system is now only used for historical data, as no new data has been entered into it for the past year. The Regional Engineer now uses the Business Objects Report, which is produced by an engineer in Roanoke who is the Regional Team Leader for Reliability. This report provides the capability of searching the data based on a number of parameters, including SAIDI and SAIFI. It is part of the Enterprise Applications Solutions (EAS) software, which is currently in the final stages of implementation. Business Objects is a database-reporting tool that supports the EAS platform.

Regional Process Improvement Groups were formed in the February 2002 timeframe to look at how Regional Engineering can improve current processes. Five performance areas were studied under the System Analysis Performance Process, including:

New service
Power quality
System reliability
System analysis
Asset management

Other computer systems that are used on a regular basis by the Regional Engineer in Hazard include the following:

Marketing and Customer Service System (includes account history and status)

Order Processing system (OPS) (used for handling new service orders)

Numerous databases in Lotus Notes

Abnormal Equipment Database (The Distribution Dispatch Center (DDC) enters information on any equipment that is found to be defective into this database; the Regional Engineer can then assess the problem and produce a work order if required)

CYMEDIST (a CYME International package that produces the distribution system analysis tools utilized by AEP, contains engineering one-line diagrams of circuits, voltage drops, and short circuit calculations and CYME Link that pulls in circuit design data from the Small World Software)

Small World Software (used for storing circuit design and geographic information)

Integrated Station Information System (ISIS) (contains all substation operating data and note)

Distribution Estimating Tool (used for producing high level estimates of potential projects based on the construction units contained in LD Pro)

The Protection Verdict Over-current Protection Program (VPRO) (used for over-current protection design)

Design Engineering in Hazard

Design engineering related to service installations is done by a group of six Technicians located in the Hazard Service Center. These Technicians are responsible for performing field visits related to customer order requests that potentially require construction work, as well as identifying and implementing required reliability improvements. Additionally, they communicate with customers, provide cost estimates when required, and process field work orders. The Technicians in the Hazard Service Center handle the five-county area that comprises the Hazard Service Area. They can and do share the workload with the Technicians in the Pikeville office in cases when one of the offices is overloaded with work. For the past three years, six Technicians have been located at the Hazard Service Center; previously ten Technicians were in this center.

The specific job responsibilities of the Technicians located in the Hazard Service Center are as follows:

Two of the Technicians are assigned to larger jobs that require surveying and the placement of additional poles

Three of the Technicians, each assigned to a specific geographic area, work on smaller new service jobs that do not require surveying

One of the Technicians is a floater who helps out the others and also does jobs related to the replacement of reclosers and poles

A customer requesting new service would call the Solution Center where the order details are entered into the Order Processing System (OPS). The order is then transferred to a clerk in Hazard who would assign it, based on its size and content, to a specific Technician for completion of the design work.

The Technician performs a site inspection to determine what facilities would need to be added to provide service to the customer. The Technician then enters the job into LD Pro, the engineering computer aided design (CAD) system. If there is a reason for a hold, then a clerk would enter a "hold" into OPS. The LD Pro system then produces the work order for the line crew or Servicer to use in installing the requested service.

The Technicians in the Hazard Service Center previously handled customer service complaints relevant to power quality or reliability, but that responsibility was recently transferred to the Regional Engineer in Hazard. This change was made to standardize the manner in which this function is handled across the company and to improve the ability to respond directly to customer problems. If the Regional Engineer determines that a service upgrade is required, the Regional Engineer then transfers the requirements for an upgrade to the Technicians for design.

Engineering Standards

AEP maintains a Central Standards Group, located in Columbus, OH, which is responsible for development and maintenance of company-wide standards for AEP in relation to the design engineering function. Additionally, the Central Standards Group participates on several national committees of various national standards organizations to have input into the development of new or modified national standards.

One person from the Central Standards Group is located in each of the regions to ensure that proper communications exists between the Engineers in the region and those of the Standards Group. The Central Standards Group in Columbus consists of five people. In the regions there are four engineers located in the eastern portion of AEP and four engineers located in the western portion. The Central Standards Group engineer for the Hazard Service Area is located in Roanoke, VA.

The Central Standards Group is also responsible for the maintenance of the Compatible Units System (CUS), which is a listing of the standardized materials and quantities that are required to perform routine field jobs. CUS includes an estimate of the hours for installation and removal and some standard maintenance activities. This system is used to develop standard costs for materials and jobs for the company as a whole.

Transmission and distribution lines are designed and constructed to conform to the National Electrical Safety Code (NESC) standard that is in effect at the time of construction. It is the role of the designer to adapt the design at hand to the constraints that exist, while remaining in compliance with the standards. For example, distribution line strength and clearance variables must be incorporated as follows:

> *Line strength* – The NESC defines three grades of construction that can vary from span to span throughout the line, depending on the individual line structure's function and proximity to the public and other objects.
>
> *Conductor clearances* – Every overhead line must be located on a route, and on poles of sufficient height, such that conductors have adequate vertical and horizontal clearances from the ground, buildings, railroads, other structures, and other conductors.
>
> *Pole structures* – The selection process for pole structures requires that the most economical pole be used to support the expected loads on a given structure. The height of a pole is usually

based on clearance considerations. Loading on a pole (or structure) takes into consideration the worst case scenario of load factors including wind pressure, ice accumulation, and attached equipment loads (conductors and associated hardware), or a combination of these factors.

AEP has three general reasons for changing its company-wide standards, those being:

A manufacturer introduces a new or modified piece of equipment, resulting in the Central Standards Group performing a pilot testing program on that piece of equipment in the field through the installation of sample pieces of equipment

Feedback from the field on problems that have been encountered may result in an engineering standards change to resolve the problem

Changes in national industry standards (such as NESC standards) may result in a modification being made to the existing design standards

The Central Standards Group regularly interfaces with Dolen Labs, which is an equipment testing and research center. Dolen Labs is used on a regular basis for testing new equipment. Additionally, Dolen Labs performs testing on equipment that has been found to perform poorly.

The AEP Engineering Design Standards are maintained in both an on-line and a paper version. The Central Standards Group sends out email notifications to designated employees regarding changes that have been made to standards to make them aware of the changes that are posted on an internal website. It is the intention of the Central Standards Group to do mass releases of updates to the field for non-critical items. The Central Standards Group also provides standards documentation to contractors that are employed by AEP. There is a contract coordinator in Charleston that oversees the contractor relationships and contracts. The contractor's billing is generally based solely on the Compatible Units System.

Engineering standards documentation is currently being updated with the intention of merging the AEP standards and the Central and Southwest (CSW) standards to create one unified set of standards for AEP nationwide. This effort is also including input from the field forces into the newly created standards. The final result of the project will be the development of two separate manuals, specifically:

Engineering Standards, which contains both the Engineering Standards and the Construction Standards

Construction Standards, which contains only the Construction Standards

This division into separate volumes should make the documents easier to work with. The development project was completed in October, 2002. Training is currently being done by the Central Standards Group for the AEP Engineering and Construction groups across the company. It is anticipated that training will be done in AEP/Kentucky during the first half of 2003.

B. Findings and Conclusions

Finding III-1 The design engineering function as it is performed by various groups within AEP for the benefit of the Hazard Service Area operations is commensurate with contemporary electric utility industry standards.

The division of responsibilities between regional and local groups is properly structured to allow significant local input, while still adhering to the regional goals and objectives. The number of engineers on staff in both the regional offices and the Hazard Service Center is appropriate in consideration of the normal workload. All of the engineering groups have access to the tools, information, and systems that they need to properly support the operation of the system.

Finding III-2 The AEP Central Standards Group provides the engineering staff with a robust and up-to-date set of design standards to use in the completion of their work.

The AEP Central Standards Group does a good job of maintaining and updating the engineering design standards, as witnessed by their current efforts to merge the design standards of AEP and CSW to have greater standardization and to avail themselves of the best of both sets of standards. These continuing efforts ensure that the engineering designs created by the AEP design engineering groups are based on the latest and most complete standards possible.

C. Recommendations

None

IV. Transmission and Distribution Operations

This chapter addresses American Electric Power (AEP)/Kentucky's transmission and distribution operations activities.

A. Background and Perspective

The Distribution Line Operations Organization of AEP/Kentucky is responsible for the construction, operation, maintenance, and repair of the AEP/Kentucky distribution grid. For the Hazard Service Area, the management of this function is located in Pikeville, KY. A description of the organization and its functional responsibilities is included in the following text.

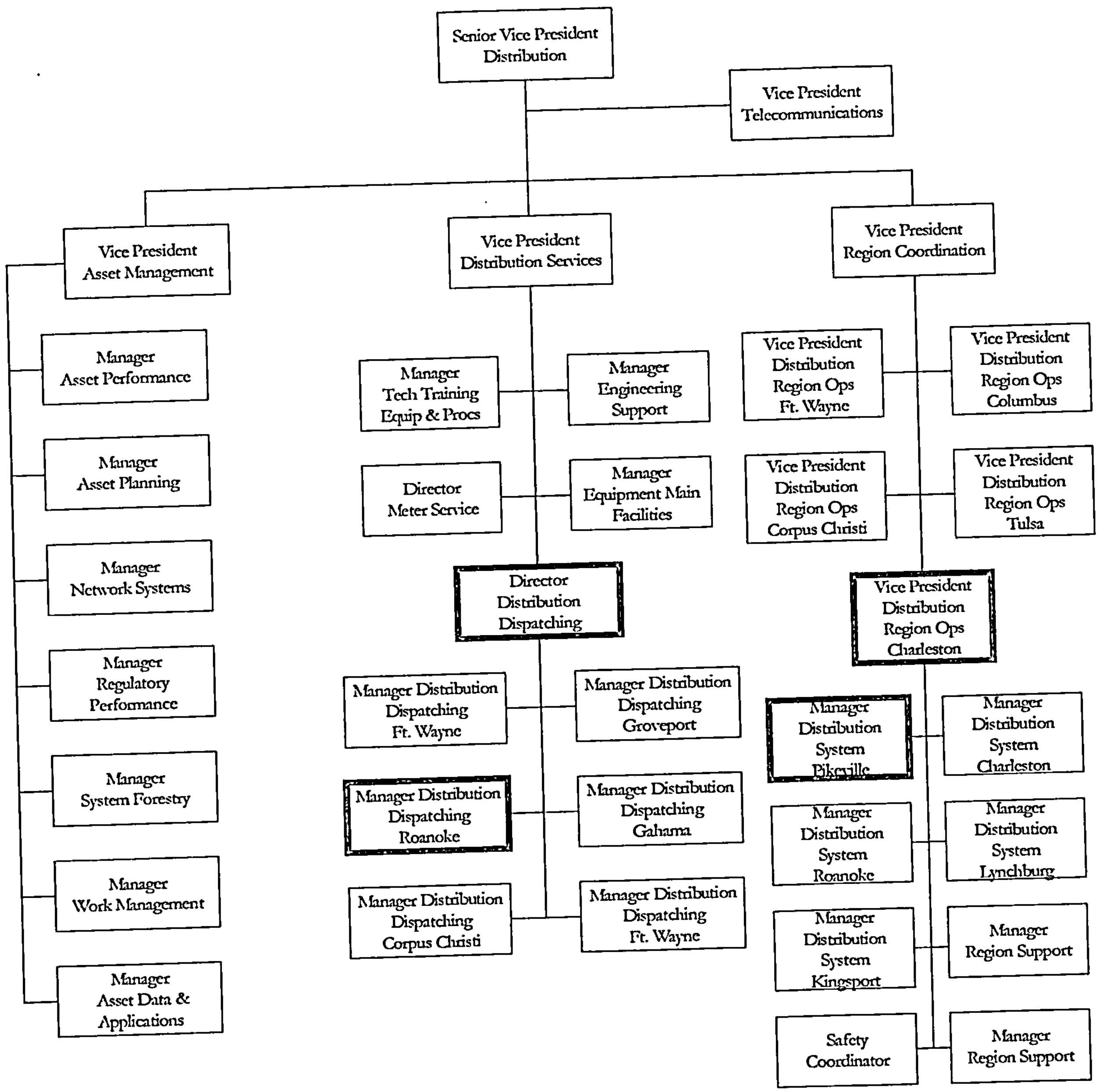
Distribution Line Operations Organization and Management

The Charleston Region Distribution Line organization is shown in

Exhibit IV-1 on the following page. The Manager – Distribution System, Pikeville manages the Distribution Line Operations group for the Pikeville District, which totals 132 people as follows:

- One (1) Manager of Distribution Service (MDS)
- One (1) Secretary
- Six (6) Supervisors of Distribution Service (SDS)
- Two (2) Line Specialists
- 24 Line Crew Supervisors (working Foremen)
- 98 Line Mechanics and Servicers

Exhibit IV-1
Regional Distribution Line Organization



In the Hazard Service Area (HSA), which includes the Hazard and Whitesburg areas, the following personnel (FTE equivalents) are on staff:

One and a half (1½) Supervisors of Distribution Service (SDS)
Eight Line Crew Supervisors (working foremen)
22 Line Mechanics and Servicers (16 Line Mechanics and 6 Servicers)

Each of the HSA line crews includes at least one supervisor (with supervisors doubled up at times to make the most efficient use of crews), with line crew composition as follows:

Three (3) 4-man crews
One (1) 5-man crew
One (1) split crew

The Distribution Operations organization is divided into two functional segments, specifically:

Line Crew Operations organization that is responsible for the construction of new distribution lines and facilities

Servicer organization that is responsible for performing troubleshooting, service restoration, upgrades, and installation work on the distribution system

The organization and operations of each of these groups is detailed in the following sections entitled Line Crew Operations and Servicers.

Line Crew Operations

Organization and Management

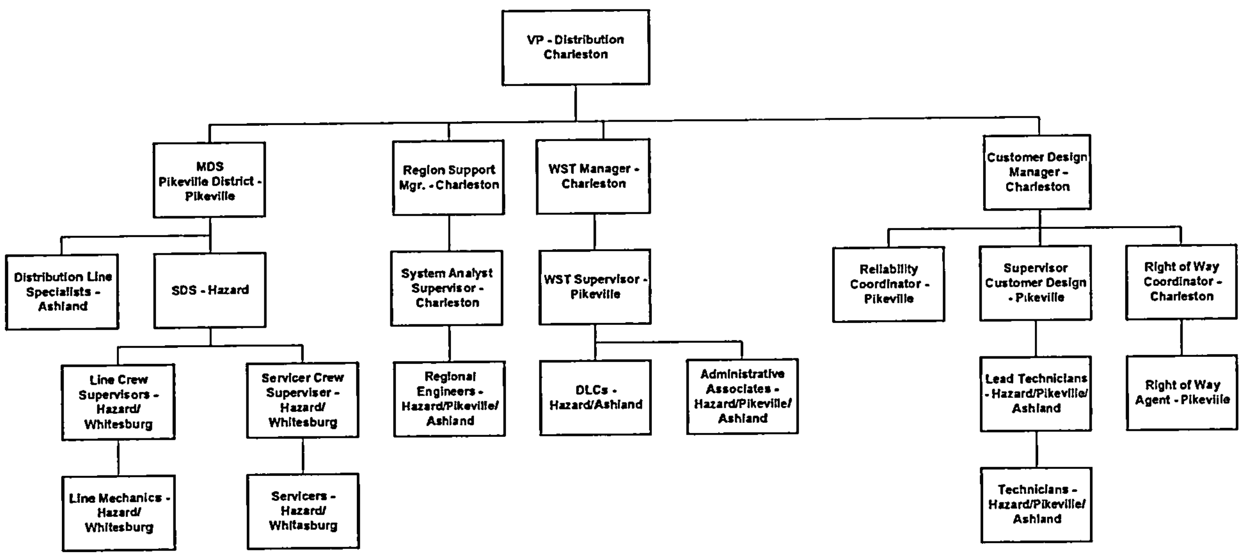
The Supervisor of Distribution Service (SDS) in Hazard is responsible for managing and scheduling eight Line Crew Supervisors and 22 Line Mechanics. Their primary responsibilities are the construction on new distribution lines and facilities and the setting of new poles. Most of these crews work out of the Hazard Service Center. One line crew and one pole setting crew work out of the Whitesburg Garage, where a small storeroom is also located. This storeroom is the responsibility of and maintained by the Hazard Storekeeper.

Line Mechanics are stratified into four major classifications according to their skill, experience, and training. A new employee would start out as an Apprentice with a Line Mechanic D classification and work up to Journeyman status as a Line Mechanic A. In the Hazard Service Area currently only two Line Mechanics are not in the top of the A class; they are in the second step of the A class. The experience levels of the Line Mechanics in the Hazard Service Area range from 6 years to 32 years with an average of approximately 22 years. AEP/Kentucky is monitoring the fact that there have not been many new entrants into the Line Mechanics ranks in the recent past and, as such, the work force is aging. This issue is being reviewed across AEP.

Work Management

Due to an identified need for better work planning, the position of District Line Coordinator (DLC) was established in the 1995 timeframe. These DLCs are responsible for the scheduling and coordination of work by the Distribution Line field crews within a specific service area. They perform this function through their activities as part of the Work Scheduling Team (WST), which is detailed in the following text. The DLCs are part of the Technical Services organization. This is a regional organization that also includes the Engineering Technicians who are responsible for performing the engineering design work that is done in Hazard. An organization chart that shows these groups to the Hazard Service Area level is shown on *Exhibit IV-2.*

Exhibit IV-2
AEP Distribution Organization – Charleston Region



Previous to this organizational change, the scheduling function was the responsibility of the SDSs. The establishment of the DLC position has allowed the SDSs to focus more on safety and quality considerations and less on the scheduling function. It has also allowed for better coordination with stockroom personnel. This is done by means of a weekly anticipated project schedule that is transmitted to the stockroom personnel the week before the work is scheduled. This allows the stockroom staff sufficient time to ensure that the equipment and materials required to complete the work are in stock. This is particularly important in the case of equipment that must be special ordered.

The DLC prioritizes the work based on an "A" through "I" priority code, with "A" being the highest priority projects. The line crews are generally shared with other areas for at least several weeks a year in order to balance the workload. This allocation of the field forces is done based on the results of a coordination phone call that is held on a weekly basis.

Work management is done through the use of Planning Scheduling Process (PSP) software, which is an old system that uses units that have been time studied and that have time estimates associated with units. All of the pending work is backlogged in PSP. The managers (MDS, SDSs, and DLCs) look at the current workload across the Pikeville District and distribute the personnel based on that information and historical workloads. The PSP software and its functionality are detailed in greater detail later in this section.

The Work Scheduling Team (WST) is responsible for analyzing the workload and making recommendations to the Manager of Distribution Service regarding crew allocation and project scheduling. It is the intention of AEP/Kentucky to try to do as much of the work as possible on an in-house basis, rather than relying on contractors. Most of the system improvement (asset) work is done in the fall and winter, with most installation and upgrade work done in the spring and summer.

There is one WST for the Pikeville District and one for each of the other three districts in the Charleston Region. The coordination among personnel is done through a weekly telephone call (Wednesday of each week) that includes the following personnel:

WST Supervisor of Distribution Service (SDS) from the Pikeville District level
Scheduling Supervisor from the Pikeville District level
DLC from Hazard Service Area
DLC from Pikeville Service Area
DLC from Ashland Service Area
DLC from Logan Service Area
Servicer Supervisor

This system of DLCs and coordination phone calls has been in place since the fall of 2000. For regular work there is a sharing of the work crews based on the WST recommendations. After the district call is completed, there is a regional phone call that takes place, with the WST Supervisor of Distribution Services or the Scheduling Supervisor serving as the representative for the Pikeville District. These calls deal only with the Distribution Line work load. The WST (through the DLC) attempts to give the work orders to the SDSs on Thursday for the next week's work, so that they can better plan the workload.

The Weekly Crew Plan, a homegrown database system that is about two months old, tracks the work to be done versus work completion, schedule targets, material considerations, and how well the crews in aggregate have done on a weekly basis. It replaced a typed manual report. It was developed by the Stores Supervisor and is shared with the Line Crew Supervisors to aid them in their planning and performance monitoring. There are also regional scorecards that track the progress of the Charleston Region as a whole.

Each district is budgeted for a certain number of employees. The funds for out-of-district crews are not cross-subsidized due to the fact that the expenses are all rolled up to the regional level. The costs of the individual projects are assigned to the individual districts.

Most of the work in the Hazard Service Area is residential in nature, although some work is done for large coal mines and is coordinated through the Business Services Engineer. Much of the residential work is comprised of installing service for mobile homes that are being relocated. While last year there were only 400 new customers added in the HSA, there was a significantly larger number of moves that were handled. There is not a lot of new residential construction and most of the work is driven by new service requests for new or relocated mobile homes.

Overtime is used primarily in emergency situations and is worked when there is a specific need. The overtime budget that is given to the district is based on the historical usage of overtime. This budget figure is based on only routine overtime, not on that overtime that is worked in emergency situations. For routine overtime, the responsible SDS would approve work that is determined to be necessary based on efficiency or service-related considerations.

The productivity of the line crews is only monitored on a cumulative basis. Management does not systematically track productivity on an individual crew basis. The productivity target is for an average of 20 hours of constructive work per week for all of their crews in aggregate. The SDSs are responsible for monitoring and supervising the crews on a daily basis.

Safety and Quality

The Line Crew Supervisors have first line responsibility for safety and quality. The SDS has a monthly meeting with them to review the results that were achieved in the previous month. Daily Safety Huddles (developed by the SDS) are held with the crews in the garage. Information on "near misses" (almost accidents) is shared across the district via Lotus Notes. When an accident does occur, the manager of the area will send around a voice mail to the other managers for information purposes. The Safety Coordinator then performs a detailed investigation of all accidents.

There is a regional safety organization that is comprised of three Safety Coordinators who are responsible for the Charleston Region. The safety documentation is contained in a database in Lotus Notes. A spreadsheet is used to track the progress of the safety program. There are safety programs that are AEP-wide, but the safety scheduling and program development functions are handled by the local SDSs. The Safety Coordinators keep track of the safety items to be covered in the programs.

AEP has a comprehensive "D-Line Training Program." This program evolved from the "Power Line Pro Training Program" that was developed by Tampa Electric, which was then tailored to the specific needs of AEP. Most of the training is focused on skills training for Line Mechanics and the application skills in how to use equipment. The instructors are veteran Line Mechanics who have been trained to be trainers on a full-time basis. There are 14 full-time instructors across AEP, with approximately two in each region. There are training centers in each of the five regions, including one for the Charleston Region in Cloverdale, VA. There is a separate Transmission Lineman training program that focuses on the high voltage lines (over 69 KV). There is very little cross-training between the T&D groups; however, more cross-training is done at the advanced levels.

Distribution Line personnel also have a standardized AEP training program. Line Mechanics must go to designated classes and pass two tests before they can be promoted to the next level. There is also a standard recertification class that all Line Mechanics must regularly complete. Prior to this structured training program, most of the training was done via on-the-job training. Advanced journeymen level training gives the Line Mechanics a chance to reinforce their skills through continuing education.

Budgeting

In terms of yearly budgetary goals established in Asset Management (AM), the budgeting system is set up on a monthly basis. Asset goals are established by AM for various types of equipment for each individual service area. The Engineering Department determines specifically where the new/upgraded equipment is to be installed. The District Manager is responsible for meeting these budgetary numbers. Pole replacement is currently a major emphasis in an effort to improve reliability. Poles are a longer term investment as they can cut the duration of outages. The poles that are replaced are generally in the 50-year old plus range. In the opinion of field personnel, the pole inspection and replacement programs, as well as the animal protection program, are beginning to pay dividends in terms of both cost savings and reliability. This topic is covered in more detail in Chapter III – Asset Management.

Bargaining Unit Relationship

The Distribution Line management in Pikeville believes that there is good communication and coordination with the union in the Hazard Service Area. IBEW Local 978 was established in the HSA in 1998. While there were some minor problems encountered at the time of startup, relations have smoothed out over the course of time. Hazard and Whitesburg comprise one bargaining unit. The Ashland and Pikeville service areas just became unionized in 2002.

Use of External Contractors

The Distribution Line organization, which makes use of external contractors on an as-needed basis, is currently using the services of four line construction contractors. These contractors are generally used on large job conversions, highway relocations, and specialized jobs (such as reconductoring work). Contractors bid for work on an AEP-wide basis. The regional organization coordinates and manages the contractor utilization.

Servicers

Organization and Management

A Servicer is generally an employee who has come up through the Line Mechanic ranks and has a significant amount of experience. The Servicers, who are on call 24 hours a day throughout the year, are responsible for performing troubleshooting, acting as first responder for outage repair and restoration, distribution system maintenance, upgrades, and installation work within specific geographical territories.

They generally function as single-person crews who work out of a bucket truck. The Servicers do not perform disconnections for non-payment as that is the responsibility of the meter readers.

There is one Servicer Supervisor for all of the Pikeville District, including the HSA. There are 26 Servicers (including employees doing Servicer work, but without the position title) in the Pikeville District, not counting those who work in the Ashland Service Area. The allocation of the Servicers in the Pikeville District includes the following:

Seven (7) in Hazard/Whitesburg
Four (4) in Logan
Five (5) in Williamson
Two (2) in Paintsville
Eight (8) in Pikeville (one of the Pikeville Servicers works the evening shift.)

In the Hazard Service Area seven employees perform the Servicer function, which breaks down to five assigned to Hazard and two assigned to Whitesburg. Of the seven employees, in Hazard there are two A Line Mechanics and in Whitesburg there is one who are currently doing Servicer work, but without the title. These Line Mechanics do get step-up pay to make them basically equivalent in pay scale to the Servicers. All of the Hazard/Whitesburg Servicers keep their trucks at home with two of them reporting to the Hazard Service Center on a daily basis due to their proximity to the center. Part of the reason that management is using A Line Mechanics in the Servicer role is that management does not know the long-term status of many of the seven employees who are currently on long-term disability (LTD) status.

It is management's current intention to transfer one or two additional Line Crew Supervisors (who currently oversee the work of the Line Mechanics) in the Hazard Service Area into the Servicer position, as there are currently more Crew Supervisors than are required, but a shortage of Servicers. There are currently eight Crew Supervisors in the Hazard Service Area with only fifteen Line Mechanics to supervise. This change will require union approval. The union contract has been in effect in Hazard since 1998. There is currently one Line Crew Supervisor who is acting as a Troubleshooter and performing Servicer work in the Jackson area.

Work Management

The Servicer Supervisor visits the Hazard Servicers approximately once every two weeks and talks to them on a regular basis via telephone. The Servicers in Hazard attend the regularly scheduled safety sessions with the Line Mechanics in the Hazard Service Center. Servicer management currently does not have an ability to track the number of hours that are actually spent on a callout job versus the number of hours that are paid for. However, they are able to distinguish between those overtime hours that are spent for routine work versus those that are spent for restoration and repair work.

The Servicers are set up to act as first responders for trouble calls on a geographical basis with well-defined boundaries. During normal working hours, the service territory boundaries become less strictly defined and are generally based on the work load for that specific day.

The Servicers submit a daily overtime sheet. Due to the distances involved, the SDSs in the HSA perform much of the day-to-day performance monitoring of the work of the Servicers. In the near future (currently scheduled for January 1, 2003), the day-to-day management of the HSA Servicers will revert to the local SDSs in Hazard. The Pikeville office will maintain the functional control of the Servicers. Overtime for Servicers is paid at a rate of time-and-a-half for time over their regular shift hours. After 16 straight hours the pay rate goes to double-time. It also goes to double-time on Sundays and holidays. Additionally, there are callout minimums as follows:

2 hour callout minimum for the period from the ending time of their regular shift to midnight
3 hour callout minimum for the period from midnight to 6:00 a.m.

Most of the overtime that is worked by the Servicers is due to emergency work. The routine work that they perform is generally a relatively small percentage of the overtime total.

There are five blanket accounts that the Servicers normally charge their time to, specifically:

Residential monthly for new service
Residential upgrade
Commercial/industrial monthly for new service
Commercial/industrial upgrade
Distribution system correction (AM projects)

Trouble time is differentiated from routine work time based on the charge numbers used. Travel time is incorporated into the time for the job to which the Servicer is traveling. The most frequently used charge numbers include the following:

214 – Routine work
233 – Routine trouble
234 – Major storm
227/228 – Routine maintenance

Based on the above charge accounts, the totals for trouble time versus routine time can be pulled from the PSP system in either detailed or summary fashion. The Servicer Manager and Manager – Distribution Service monitor this data on a regular basis.

Outage Restoration

Summer storms are generally very localized in nature, making them more difficult to predict. Snow storms are generally slower in coming but endure longer, often resulting in longer duration outages. The HSA does not experience very many trouble calls due only to rain. The wind generally causes more problems for them than rain does. In all of these storm situations, the majority of the outages are directly caused by damage due to trees and limbs falling or contacting the lines; the weather itself does a relatively small amount of damage. Lightning-related outages are a significant cause of outages, although not to the extent of tree-related outages. In response the company has gone to a heavier class of lightning arrester (called Scouts), added more lightning arresters, and gone to three grounds on all new poles (only on new construction, not retrofitting) to reduce the damage caused by lightning. In serious storm trouble situations, the Technicians (engineers) will first work to perform damage assessments, and then the Line Mechanics will be called out to begin performing line repairs.

In outage situations, the Distribution Dispatch Center (DDC) in Roanoke, VA will contact the designated Servicer for the specific geographic territory directly via pager, radio, land line, or cell phone. If they cannot reach that person or that person declines to respond, the DDC will either begin to work their callout listing or they will contact the designated Duty Supervisor for that day. The Duty Supervisor is a rotating Crew Supervisor that is on duty for one week on a 7x24 basis for the purpose of serving as the local coordinator for trouble or restoration activities. The Duty Supervisor can assist the DDC in finding employees to work trouble calls. When a situation goes beyond the ability of the Duty Supervisor, the SDSs and the local Work Scheduling Team will get involved. At that point the coordination of the dispatching effort will revert to local control. The DDC attempts to contact the employees in the local area in advance to inform them of approaching storms so that they can prepare.

The Servicers can generally handle approximately 90% of trouble calls that come in without assistance. If they cannot handle the outage or need equipment, the Servicer will call the DDC for assistance. The top rated A Line Mechanic acts as the backup if the Servicer is on vacation or otherwise unavailable. The contacts generally go out over cell phone, pager, land line, or company radio.

Software Applications

In autumn of 2001, AEP/Kentucky installed laptop computers in the bucket trucks that allow the Servicers to pick up most of their work assignments through a daily download from the Spectrum system, which downloads the job orders from the Order Processing System (OPS). Additionally using the laptops workers can access the LD Pro and Individual Out Wandering Around (IOWA) software, which provide access to computer-aided design (CAD) drawings and geographic location information respectively.

AEP is implementing the Severn Trent System (STS) software package, which is a wireless laptop scheduling and work monitoring system. It is scheduled to be fully implemented in the Charleston Region by mid-year 2003 (according to the current schedule). This enhanced wireless data communication system should enhance the ability to get the proper trouble information to Servicers in an efficient and expeditious manner. The implementation program is described in greater detail later in this section.

Servicer Scheduling Process

The routine work that is performed by the Servicers (such as new service installations, outdoor light installations, etc.) is scheduled by the Administrative Associates who are report to the DLC in the Hazard Service Center. The Administrative Associates work to schedule and ensure the completion of the work plans created by the WST. The Administrative Associates use a workflow application that is included in the Order Processing System (OPS) software to perform most of their scheduling functions. Each morning, the Administrative Associates go through the new service orders, upgrades, or outdoor light orders that were input to the system since the prior day's close of business. The Administrative Associate makes a determination, based on information provided by the customer, as to whether a Technician (engineer) is needed to inspect the site and/or perform design services. A Technician would be required on those jobs that require new poles to be placed or if there are other factors that would complicate the installation. If a Technician is required, the Administrative Associate schedules a Technician visit to the site within 48 hours of order receipt. The Administrative Associate will contact the customer on orders for new service, upgrades, and light installation to set up an appointment time. In the case of simple repairs or light repairs, they make contact with the customers as required, based on customer need.

If the customer facility is inspected and ready for a Servicer to be dispatched, the Administrative Associate enters the order and appointment time (if applicable) into the Access Scheduling Database, which is the primary tool for monitoring and scheduling work orders. The screens are color coded to ensure that the priority jobs are highlighted. As the Solutions Center can only see data in OPS (i.e., they cannot view the Access Scheduling Database), the Administrative Associate also enters the appointment times into OPS so that if a customer calls with a question concerning an appointment the Solutions Center representative will be able to respond accurately.

The orders are transmitted to Servicers in one of two ways:

Through the Spectrum System that downloads the orders into the Servicers' laptops when they log onto the local area network (LAN) in the Service Center or dial-in to the system.

Through hard copy print outs that are picked up at the Service Center by the Servicers (or faxed to their home bases). This method is used only for those orders in OPS that cannot be pushed into Spectrum. Such orders include:

- Combination accounts (those with both electric service and an outdoor light)
- Internal work
- Installation or removal of lights

The Servicers then prioritize their daily work assignments based on the immediacy of the jobs and the Servicers knowledge of his or her assigned service territory. They will then accordingly arrange the jobs on their laptops to set the day's work schedule. As new orders are entered into OPS throughout the day, the Administrativc Associate constantly monitors it to pick up and work on newly entered orders.

Each of the Servicers transmits a work order closeout sheet on a daily basis to the Administrative Associate showing those jobs from both the Spectrum and hard copy job listing that were completed that day. The Servicers close out their Spectrum jobs on their own laptops and then upload the information to the network to close out the job in OPS. On a daily basis the Administrative Associates verify that the jobs have been closed out properly in OPS. For those jobs that come out in hard copy only (those that are not in Spectrum), the Administrative Associate will close out the jobs in OPS.

If a Servicer cannot do a job at the appointed time or by the required date, he will call the Administrative Associate to have the job rescheduled with the customer. Delays generally occur due to trouble calls that arise during the course of a day or jobs that take longer than estimated. When a trouble call is received by the Servicer from the DDC, the Servicer will inform the Administrative Associate of their new schedule so that the customers may be contacted as required. The Administrative Associate does not get notification of trouble calls from the DDC directly. In general, the Servicers are not supposed to go home for the day until they finish all of their daily assigned jobs that have been designated as high priority jobs. The overtime that is accumulated as a result of finishing high priority jobs accounts for only a small percentage of the total overtime that is charged by Servicers.

Distribution Dispatch Process

Organization and Management

Outage reports and other trouble calls that are received from AEP/Kentucky customers in the HSA by the Solutions Center are transmitted to the Roanoke DDC for dispatch to the employee who is designated as first responder for the specific geographic area where the trouble is located. The Roanoke DDC dispatches for the entire AEP Charleston Region, which is composed of four districts. The Roanoke DDC, which has 30 dispatchers and other technical employees on its staff, is larger than that in Columbus, OH in terms of customers and geography. This staff is broken down as follows:

23 employees are either Switching or Trouble Dispatchers

3 Switching Coordinators (who set up planned outages and perform training for the field forces)

2 Electrical Engineers; one works with the Switching Coordinators to coordinate tap changes and mobile transformer installations and also works with loading issues on planned outages, while the other is a new position that works on training of the Trouble Dispatchers, improving the dispatch process, and problem areas on the system. The management of the DDC is currently working to get more training for and consistency among the Dispatchers.

1 Staff Associate (who works with time reporting and computer systems) will also take calls from the Solutions Center during storms and will do callbacks, as required.

1 Data Analyst located in Huntington, WV is responsible for scrubbing the data following outages to make sure that the outages and their restorations have been reported correctly

The DDC also has a dedicated technology support person that takes care of the servers and 25 workstations (not technically part of their group, but assigned to it on a full-time basis).

The DDC has been located in Roanoke since 1998 when it was originally established just for servicing central Virginia. The Kingsport, TN service territory was subsequently added. Then, on February 1st of 2002, the Pikeville District dispatching function was switched to Roanoke. Previously Pikeville did its own dispatching during the daytime hours. As of June 1st of 2002, the Roanoke DDC was assigned the centralized responsibility for all of the former Roanoke and Charleston Regions. The Roanoke DDC currently serves 1.1 million customers in Virginia, Tennessee, West Virginia, and Kentucky.

To maintain specific familiarity with Kentucky operations, as part of the transition of the dispatching function from Pikeville to Roanoke, two Switching Dispatchers who had Kentucky dispatching experience were transferred from Charleston, WV to the Roanoke DDC, with two more brought over at a later time. There was also a transfer of a Trouble Dispatcher from Pikeville. The current staff of Dispatchers, which is exempt-salaried and non-union, has an average of 5 to 10 years of dispatching experience. Transmission Dispatch, which is a separate group from the DDC, is also out of Roanoke.

The Dispatchers work 8 or 12 hour shifts, with shifts rotated on a continuous basis. The DDC has the most staffing from 3:00 p.m. to 7:00 p.m. each day, as this is the most frequent time for summer storms to occur and people are getting home from work and discovering that their power is out. After 11:00 p.m., they have three (3) Switching Dispatchers that work on both trouble and switching dispatching. Switching Dispatchers are senior positions, having worked up from a Trouble Dispatchers.

The Shift Lead position is responsible for looking at DDC current loading, especially in relation to the weather conditions, as well as handling coordination with the field. The Shift Lead position is currently shared among four people. DDC management has been rotating several people through the position to test them for their ability to handle the job and will soon make a final selection as to who will be assigned to this position in the long term. The Shift Lead is also assigned the responsibility for sending out text messages to predefined groups of people in the field on the status of outages and weather related issues.

Dispatching Process

Customer calls reporting outages or other problems are directed to the AEP call center which is referred to as the Solutions Center. The Solutions Center enters the tickets into the Trouble Entry & Reporting System (TERS) through a Virtual Agent graphical user interface (GUI) front end. TERS then transfers the data into the PowerOn system, which has an outage engine that predicts the source of the trouble and identifies the isolating device that has probably caused the outage. The Solutions Center will call the DDC directly in those situations that involve safety issues. The Dispatchers put comments into the PowerOn system, as well as an estimated time of restoration of service. They also input any comments that are received from the field crews. The Solutions Center can see the comments that have been entered into PowerOn and the estimated time of restoration, but they cannot see the PowerOn system as a whole. The field forces then get back in touch with the DDC to report the time of restoration, what was done, and any materials that were used. The Dispatchers then enter this data and close out the ticket. The field crews do not have to complete any paperwork to close out a service restoration job.

The Roanoke DDC is set up with the Pikeville/Charleston service territory (5 trouble pods) at one end and the Roanoke/Kingsport service territory (4 trouble pods) at the other. Additionally, there are five pods in the middle of the room that are set up so that they can be used by either area in a storm situation. The DDC management is currently rotating Dispatchers among geographic areas to get more people familiar with each area under non-storm conditions. Generally, one or two Trouble Dispatchers and one Switching Dispatcher would be part of this rotation at any given time. In putting Dispatchers on a new geographical territory, the main problem encountered is who to contact in the field and how to contact them. There is an established database of contact information in Lotus Notes, which they are working to improve and update.

In relation to crew assignment prioritization for restoration work, the first priority is to address potential safety hazards, followed by restoring service to the largest blocks of customers possible. The DDC management is currently in the process of developing maps that will help the Dispatchers in efficiently assigning the crews from a geographical perspective. Also the Dispatchers will frequently contact the crews for input on prioritizing unworked outages.

In a storm situation, the Dispatchers would first look at redeploying the field crews based on the geographic location of the outages. They would pre-assign the work to the crews when possible based on local knowledge. This pre-assignment could be done electronically from the field. Line Coordinators and SDSs in the field would be used to provide local knowledge in severe situations. In very bad situations the actual control of the restoration dispatching effort may be transferred to the local field office. However, as the DDC becomes more familiar with the geographic areas for which it is responsible, this option is not expected to be used frequently in the future.

The Roanoke DDC managers will call the designated Relief Dispatchers based on how long they have been off duty. All of the Dispatchers are equipped with pagers to facilitate contact in emergency situations. A portion of the Region Engineering staff is located in Roanoke and they provide support and assistance during storms. Also a portion of the Region Records and Graphics groups are located in Roanoke and they also provide assistance as required.

The DDC implemented PowerOn in April 2002 and they have been refining its usage since that time. The previously-used outage management system was GUP (Graphical User Platform), which was developed in-house at AEP. It had no outage assessment engine and the dispatcher had to manually determine the isolating device that was believed to be the source of the problem. The DDC has been on the Small World System since 1996. The Small World system automatically feeds data into PowerOn. The Small World System contains routing optimization capability that would provide assistance in optimizing service dispatches. To take advantage of this capability, AEP would have to implement some least cost algorithms for getting from specific places to other places; however, there is currently no schedule for performing this work due to other projects that must be completed.

In relation to the rationale for centralizing the DDC in Roanoke, a team performed an extensive nine-month study of consolidating to larger DDCs. The Roanoke location was chosen based on the availability of office space, the reliability of the power supply due to being located in downtown Roanoke, the existence of excellent communications links, the availability of SCADA support in the building, the presence of a backup generator with sufficient capacity, the presence of good technology support, and the cost of living in the area. The study team did benchmarking with other utilities, most of which were also centralizing their distribution trouble dispatching process. It has been found that it is beneficial to centralize the DDC operations from a technology and training point of view. The Roanoke DDC has 40 to 50 crew headquarters in their assigned service territory. An additional benefit to centralization was the ability to establish 24-hour coverage without handoffs from the local dispatch centers that handled the dispatch function during the day (as it had been done in the past). Centralization also allows a more professional approach to how to sectionalize and tie to other circuits. The local offices may or may not have had the expertise required to do it on a localized basis. Additionally, centralization also allows greater flexibility due to the ability to pool resources and the larger number of available staff members.

As of July 1, 2002 the responsibility for substation and step-down transformers was transferred from the Transmission Distribution Center (TDC) to the DDC. The support group for TDCs is located in Roanoke. The Roanoke DDC is responsible for the placement of mobile transformers and their transportation. For a bank distribution transformer, the DDC would contact the Transmission Line Operations Group to get the mobile delivered, and then the DDC would handle the switching arrangements that need to be made.

Materials Management

The Hazard Storeroom is responsible for the provision of materials to the crews that operate out of the Hazard and Whitesburg Service Centers. The Hazard Storekeeper reports to the Regional Stores Manager in Charleston. In addition to the Hazard Storekeeper, there are three full-time attendants who work in the Hazard Storeroom.

The Hazard Storeroom is replenished every other Monday out of the AEP Fort Wayne Distribution Center, which supplies all materials, other than poles and transformers. Poles and transformers are supplied directly by the vendors. Hazard is supplied out of Fort Wayne as it has the most efficient transportation access. If the Fort Wayne Distribution Center is out of an item, it can be supplied by one of the other AEP Distribution Centers. A Pony Express delivery system may be used to have material delivered when it is necessary on an expedited basis.

The Hazard Storeroom tries to maintain a five-to-six week supply of all inventoried items. The Storeroom maintains a "Quick Pick" area that contains the highest volume, low value items that are regularly used by field crews. In the Quick Pick area the Storeroom tries to maintain a two-week inventory supply and performs cycle counts of material in the Quick Pick area three times a week for the purpose of replenishing the supply. Quick Pick items are charged against a blanket account for capital expense. These items are generally not assigned to specific jobs when they are checked out, unless the quantity that is taken is large and for a specific job. Normally this Quick Pick supply is used primarily to restock the inventory levels on the trucks.

The Materials Management System (MMS) is a homegrown AEP mainframe system that is used for recording inventory transactions and monitoring inventory levels. Every Wednesday the Hazard Storekeeper receives a reorder report from MMS that shows the items that need to be replenished based on established minimum/maximum inventory levels. These inventory parameters are generally determined according to the following guidelines:

> Minimum inventory level = 4 week supply at historical usage rates
>
> Maximum inventory level = 5 week supply at historical usage rates
>
> Reorder quantity = Difference between the maximum and minimum levels with adjustments made based on quantities that may be available or on order

However, the Hazard Storekeeper has the capability to modify these parameters based on past experience and knowledge of any special situations that may exist.

Picked material is assigned to an operation and maintenance (O&M) account or a capital account (work order) depending on whether the material is to be used for restocking the inventory in the truck or is to be used on a specific project. The Servicers and Line Mechanics fill out an order or pick list to requisition material. The material orders for trucks are picked the day before and loaded onto the trucks during the morning of each day.

The material is assigned to the individual jobs (work orders) when the items are issued to that job. At this point they are no longer tracked by MMS and are not counted against the on-hand Storeroom inventory levels, causing AEP/Kentucky to essentially lose visibility of the item at this point. However, a spreadsheet is maintained of the reclosers and three-phase pad mount transformers that have been issued to a job but are still located in the Storeroom or yard.

All inventory items are cycle counted at least once a year according to a monthly schedule that is arranged by item class. This schedule is the standard for all AEP storerooms and is developed by the AEP Supply Chain Group. The poles are counted on a monthly basis. An AEP internal auditor comes to each state once per year, so with three storerooms in Kentucky, the Hazard facility is audited once every three years.

Shrinkage has never been a serious problem in the recent past at the Hazard and Whitesburg storerooms. When a problem is discovered it is investigated. These identified problems are usually determined to be the result of keypunch errors rather than loss or theft.

When the Technicians write up a job they get a Compatible Units Report from the Transmission and Distribution Information System (TDIS). This report is a list of the material that is required to complete the associated work order. This list is used by the Storeroom Attendants to pick the material for each of the projects. The Storeroom gets a report of the jobs to be completed from the Work Scheduling Team and the SDS. The Storeroom looks at the jobs to be completed the next day and picks the required material on a daily basis. The Compatible Units Document Order Number is entered into MMS after the items have been picked to relieve the inventory of the items for that work order. Therefore, there is a linkage between the Compatible Units Report from TDIS and MMS that allows whole jobs to be relieved from inventory.

There is an ability to allocate material to a work order in MMS, before it is picked, to allow MMS to calculate the availability of material properly. This is only done for regular inventory items. For special items they do not do allocations as the material is ordered on a special basis.

Field Operations Telecommunications System

AEP maintains a centralized Telecommunications Group (Telecom Group) located in Columbus, OH, with local field technicians in most of the service centers. The Telecom Group maintains a 7x24 Telecom Center at One Riverside Plaza in Columbus, OH that handles any outages of the system that occur during the daily operation of the system. The Telecom Group also maintains over 130 sites throughout the eastern network.

AEP started a telecommunications system upgrade project in 1992, but not in AEP/Kentucky as the local company chose not to participate. AEP/Kentucky was included in Phase II of the project, which started in the 1995/96 timeframe and was essentially completed in 2000. The Telecom Group has been doing cleanup work over the past two years, to resolve those minor problems that were discovered with the communications system. The work on Phase II in Kentucky was finished in 2000 and has been being fine tuned since that time. Four additional towers were approved in Kentucky as part of additional funding for Phase II, including:

Hazard tower site (servicing Hazard/mid- and north Perry County) – Work is completed

Richardson tower site (servicing Ulysses/Peach Orchard/Gallup and Lowmanville – Work is completed

Buckhorn translator site (servicing Buckhorn Lake area) – In the site acquisition stage

Salyersville translator site (servicing Salyersville) – In the site acquisition stage

Since 2000 and during the fine tuning effort, the Telecom Group has been investigating those problems that have been reported by field crews. When a problem is verified, the Telecom Group sends out testing crews to determine the locations where the signal strength problems do occur. They then perform modeling of where the antennas and transmitters should be located. As part of this effort the Telecom Group will meet with the SDSs and MDSs in the local area to get their input on the situation.

A comprehensive study was initiated by the Telecom Group in 2002 to identify those areas in the AEP/Kentucky service territory that were still in need of additional or enhanced telecommunications capability. This study identified a need for additional towers or translators in the following areas of Kentucky:

Southern Breathitt County (in the Hazard Service Area)
Evanston
Stinnett and Cutshin (in the Hazard Service Area)
Leatherwood and Slemp (in the Hazard Service Area)
Wheelwright and McDowell
Mouthcard and Paw Paw
Southeastern Martin County

The Phase III final plan of the project was approved and initiated in June/July of 2002, for the purpose of implementing the above identified facilities at an estimated cost of $2.775 million. The scheduled completion dates for the individual projects were prioritized by the field forces. Each of these projects is expected to take 1 to 1½ years to complete, mainly due to the time required for land acquisition. All of these new antennas and facilities planned for Kentucky as part of Phase III should be competed by 2004 or early 2005.

The Telecom Group maintains a Field Technician in the Hazard Service Center. Additionally, there is a Telecom Supervisor for eastern Kentucky located in Ashland, KY. There are numerous other Technicians in various locations across KY. The Technicians are assigned the responsibility of doing at least one inspection of each tower facility per quarter. If a problem occurs with an antenna in the Hazard Service Area, the Telecom Center dispatches its Hazard-based Technician to repair the problem. The sites are fully alarmed so that any problems can be detected remotely. Each of the antenna sites has an emergency generator with approximately two weeks of liquid propane (LP) gas to maintain operations in the event of a power outage.

The new mobile data communications systems that are to be installed in the trucks during 2003 as part of the STS software package implementation should actually be more efficient at receiving communications in poor reception areas, due to the fact that they will keep trying to reconnect on a regular basis and will do so automatically on the detection of a radio signal.

Work Management Systems

The Planning and Scheduling Process (PSP) system was implemented in the 1992-94 timeframe. It is a standard work management system (WMS) that assists in assigning the proper resources to work and scheduling it. PSP was developed in-house by AEP on a mainframe. It now has an Oracle database backend. It was originally used for all Distribution Line personnel. Currently it is used mostly by engineering, metering, and line departments. The management of each region can determine whether to use OPS or PSP for the engineering portion of the network design work. There is no automated link between PSP and OPS. The OPS system contains the original work request as entered by the Solutions Center. PSP is integrated with a PeopleSoft time and labor payroll system. Contractors use the PSP system for scheduling of work and closing out jobs but not for tracking crew hours.

The Compatible Units System (CUS) is integrated with PSP to enable the development of a time estimate for completing work. The number of hours is based on the number of hours that it would take one person to complete the work. Only the estimated labor hours, not the materials to be used on the specific job, are available from CUS. Local people match up the materials, vehicles, and resources required, then try to produce the best work schedule that they can for any given day. PSP maintains a backlog of work that can be designated for completion on a specific day. Crews fill out daily timesheets, which are then entered by an Administrative Assistant to close out the job. TDIS (estimating work order billing system) and CUS are used for producing the work orders.

Implementation of the STS software package is causing the phase-out of PSP. PSP will be phased out for the eastern regions by June/July of 2003. Severn Trent is being used in an attempt to implement one WMS for all parts of AEP. It is fourth generation software with more flexibility and more capability to manage the work projects. It is easier to develop interfaces to other software, which are frequently required. Severn Trent will also replace TDIS and CUS, but not OPS, as it is still part of the Customer Information System (CIS). There will be an interface between Severn Trent and OPS. It will not replace TERS. Severn Trent will be phased in over time due to the large number of systems that are being replaced.

The overall new system, which includes more than just the Severn Trent System, has:

Storms (work management system)

Auto-Scheduler (auto-routes the work directly to the truck and to schedule the crews)

Spectrum (an internal mobile application that is an AEP project that will be integrated with Storms and Auto-Scheduler)

There will be direct interfaces from OPS to STS (and then to Auto-Scheduler). Then, based on the type of work, it can be routed to an SDS or directly to a Servicer. The job will go to an SDS if it is a construction project. It will go to a Servicer if it is a trouble job. STS also has the capability for the new project to go to an SDS (to do the field inspection) and then to an engineer in the area.

Spectrum will communicate with the trucks through an 800 MHz wireless system that use the existing towers and telecommunications network. In the case of an outage, the trouble report will be routed to the outage management system, then to the Storms system, and then to the Servicer's laptop in his truck. This will become the primary means of communication from the DDC to the Servicers. Laptops in the trucks will have geographic information system (GIS) and other mapping software, such as the IOWA software that is used for locating rural addresses and trouble spots.

Spectrum will be used for entering time and project completion information for Servicers into a mobile laptop unit. The construction crews will enter their time into the Spectrum system directly. AEP/Kentucky will be the first or second company in the east to go live on Spectrum.

The Operational Data Store is being developed as a way to produce required reports (other than standard reports) in the field offices using an ad hoc report writer. The system currently uses PowerBuilder for the reporting from the STS, but PowerBuilder is too complex for the average user. There are a significant number of standardized reports that are built into STS. For reports other than those, the users will go to the Operational Data Store.

B. Findings and Conclusions

Finding IV-1 **Management of the Line Mechanics and Servicers is appropriate and adequate for the current staffing levels and workload.**

The organization and the systems used to manage the Distribution Line field operations forces are consistent with the requirements for proper management and control of an organization of that size and responsibility. The spans of control that were observed were well within accepted standards for an electric utility distribution field operation. The systems and reports that were available as tools to the management of the operation were appropriate to support them in the performance of their assigned tasks.

Finding IV-2 **The system used to communicate jobs to the Servicers is not comprehensive and requires the use of both the Spectrum System and hard copy printouts from the OPS application.**

The currently used Spectrum system is incapable of receiving all of the work orders in an automated manner from OPS. The remainder of the work orders must be printed out in hard copy from OPS and manually transmitted to the Servicers. This results in duplication of some orders in the two communication methods and more opportunities for confusion or error. It is believed that the new Severn Trent system (which is scheduled for implementation in the first half of 2003) will resolve this problem.

Finding IV-3 **The training that the Servicers were given in the use of laptop computers in their trucks and the associated software was inadequate and limits the benefits that AEP can gain from this technology.**

Observation of the Servicers using their laptop computers and discussions with them revealed that training that had been given to them in the use of the units and the included software had not been sufficient to enable them to use the equipment to its maximum capability. It was stated that the training lasted for only one-half of a day and was not sufficient to allow the Servicers to become comfortable and familiar with their units. This was particularly deleterious due to the fact that several of the Servicers were not very familiar with computer technology in general.

Finding IV-4 The Servicers in the Hazard Service Area are working a large amount of overtime.

The large amount of overtime is attributable to the large number of after-hours callouts and a relatively small number of Servicers to handle the work load. The number of overtime hours charged on an annual basis for the period of 2000 through 2002 year-to-date is presented on *Exhibit IV-3.*

Exhibit IV-3
HSA Servicer Overtime Hours

Service Location	Year 2000	Year 2001	Year 2002 (as of 10/3/02)
Knott	565.3	703.1	674.9
Leslie	484.5	563.7	501.5
So. Perry	502.8	473.8	463.6
No. Perry	1,430.7	1,416.8	1,272.7
Breathitt	408.1	562.2	551.0
Whitesburg	539.5	734.9	675.3
Totals	**3,930.9**	**4,454.5**	**4,139.0**

Review of this data reveals that all of the Servicers in the HSA have been working significant quantities of overtime during this period. This is particularly true in the Perry County area, which includes the City of Hazard. Because this data reflects the number of hours that are paid for (rather than the number of hours that are actually worked), the numbers are somewhat inflated. However, even with this taken into consideration, the Servicers are still working very large amounts of overtime. When Servicers are working this much overtime, it would be expected that there would be a declining efficiency of the work as the number of hours worked increases. Additionally, at some point the number of hours worked becomes a concern relative to the safety of the workers. Having a larger number of Servicers assigned to the Hazard Service Area would serve to reduce the amount of overtime worked by each of the individual Servicers, thereby reducing concerns with work performance and safety. Moreover, a larger number of Servicers would be expected to cut down on the amount of time that it takes to restore service in a storm situation due to an enhanced ability to spread the workload across more field personnel.

Finding IV-5 The limited number of Servicers in the Hazard Service Area results in a reduced ability to restore service in a timely manner during storm situations.

With the service restoration jobs divided over a smaller number of Servicers, response time and times to restoration will be longer than if a larger contingent of Servicers were available. While there certainly are practical and economic limits to the number of Servicers that should be in place, the number that currently exists is smaller than would be needed to provide satisfactory restoration times. Additionally, when the Servicers are on vacation or out-of-town, the coverage of their responsibility often is transferred to a Line Mechanic. While the Line Mechanics have the technical capability to perform the required restoration work, their lack of daily familiarity with the tasks involved and with the geography of the area renders them less efficient than a Servicer would be in performing the same work. Additionally, situations were identified in which certain jobs or types of work were delayed until such time that the Servicer returned to duty.

Finding IV-6 The company needs to establish an easy method for tracking the number of hours that are actually spent on a callout job versus the number of hours that are paid for.

The Distribution Line organization managers currently have no mechanism or system for tracking the number of hours that Servicers actually spend on completing service restoration work. The only numbers that are recorded are the number of hours of overtime that are paid for. Because the Servicers are paid for a certain minimum number of hours for any call out, it is impossible to determine the actual number of hours spent on various service restoration and repair jobs. Additionally, the amount of travel time is not captured as a separate data item. There is a capability to distinguish between those overtime hours that are spent for routine work versus those that are spent for storm work. The availability of actual hours worked data would enable the Distribution Line organization managers to make better judgments concerning deploying their forces in storm situations and permit better performance tracking capability. Additionally, this data could also assist in the identification of those geographic areas that are in need of more coverage.

Finding IV-7 Significant radio communications dead spots that exist in two of the counties in the Hazard Service Area disrupt the ability of the field crews to communicate with the DDC and the Schedulers.

The current radio communications system does not provide adequate radio coverage in all areas of the HSA, leading to the presence of significant "dead spots" where radio communications between the field crews and Dispatchers is impossible. This is a significant concern due to crew efficiency and safety considerations. However, a plan is in place to resolve these communications problems by the year 2004 through the construction of several new antenna facilities.

Finding IV-8 Most of the outages that are repaired by the Servicers are caused by trees, particularly in the summer.

Interviews with several Servicers revealed that, in their collective opinion, trees are the single largest cause of outages experienced in the Hazard Service Area. This is particularly true in summer, because trees are in leaf and they have a greater tendency to fall or for branches to break off due to wind. This topic is covered in more detail in Chapter VI – Vegetation Management and Animal Protection.

Finding IV-9 The rights of way that have been obtained by AEP/Kentucky in the Hazard Service Area are not wide enough in many cases to adequately prevent tree-related damage.

Interviews with several of the Servicers revealed that, in their collective opinion, the insufficient width of many rights of way results in many of the service outages that they respond to. It was their opinion that widening the rights of way would eliminate a significant number of tree-caused outages. This topic is covered in more detail in Chapter VI – Vegetation Management and Animal Protection.

Finding IV-10 The Tree Condition Reports completed by the Servicers to report vegetation that needs to be trimmed are limited in their effectiveness by the inconsistency of response.

Tree Condition Reports (which are a form of the Abnormal Equipment Report) are used by Servicers and Line Mechanics to report those field conditions that they identify that require tree trimming to avoid future problems with outages. After the form is completed and submitted, it is directed to one of two places:

- For small trimming jobs it is directed to the SDS for the HSA, which uses an Asplundh crew assigned to the SDS to handle the required trimming work
- Larger jobs that require more trimming are directed to the AEP/Kentucky Vegetation Management organization for the HSA for completion

While the reports handled by the SDS are followed up on with the Servicer who submitted the report, this does not necessarily happen with the larger jobs that are transmitted to the Vegetation Management organization. As such, the Servicers often are not informed as to when the trimming work is completed. This lack of a feedback loop discourages the Servicers from using the report, rendering it less effective than it could be.

Finding IV-11 Inconsistencies have been observed in the reporting of the number of customers affected by an outage, depending on the source of the data.

Due to using different sources of data and information, some of the numbers reported to the Kentucky Public Service Commission (KPSC) related to the number of customers who were affected by recent outages were not consistent. Work is currently ongoing within AEP/Kentucky to standardize its data base in order to gain consistency and accuracy in the numbers reported.

Finding IV-12 The lack of a full version of the PowerOn software in the Hazard Service Center limits the availability of useful information, particularly in storm situations.

The currently installed remote version of the PowerOn software is quite limited in its capabilities to allow access to data that is important in storm restoration efforts or in daily operations. The ability to access this greater range of data would be particularly important in the event of a severe storm in the HSA, where control of the restoration effort was transferred from the Roanoke DDC to the Hazard Service Center.

Finding IV-13 The automated routing optimization capability that is built into the Small World software package is not being utilized, nor are the capabilities that would be presented by the installation of GPS units in the Servicer and Line Mechanics trucks.

As this routing optimization capability feature is already included in the Small World application, it would be desirable in the future to take advantage of the capabilities provided therein. Several other utilities have adopted an automated field force routing system combined with on-board GPS units with great success. Such a technological advance would certainly be expected to enhance the ability of the DDC to direct the field forces in an optimal manner.

Finding IV-14 The Materials Management function properly supports the operations of the field forces.

The Materials Management function is managed and operated in an appropriate manner to properly support the materials requirements of the field crews. The inventory management computer system adequately provides the data that is necessary to properly manage the inventory/stores function. Statistics related to the performance of the materials management function are collected and monitored to ensure that performance and productivity are meeting established targets.

Finding IV-15 The maintenance program for the substations is appropriate and consistent with industry standards.

Observations were performed of the normal maintenance activities at two of the HSA substations. The substations were both found to be very weed-free and neatly kept. It was obvious that the maintenance was being performed in a very efficient method. The records of the maintenance performed were very comprehensive and detailed, detailing each maintenance activity performed and all of the various readings taken during the scheduled maintenance activities. There do not appear to be any problems with the operation and maintenance of the substations.

Finding IV-16 The design and operation of the transmission system does not have a deleterious effect on reliability in the Hazard Service Area.

The transmission system is well designed and operated and is not a significant factor in the reliability problems that have been experienced in the Hazard Service Area. The problems that have been experienced are much more directly related to the distribution system. This is primarily because the height at which the transmission lines are strung is high enough to allow them to avoid the majority of problems that occur due to tree-related damage. The distribution lines, being positioned at a lower elevation, are much more susceptible to tree-related incidents. Additionally, transmission line rights of way are generally wider than those which exist for distribution lines.

Finding IV-17 The distribution and transmission dispatching functions are performed in a manner that is consistent with industry standards.

The operations of the Roanoke DDC were observed and found to be consistent with accepted industry standards. Centralization of the operation in Roanoke has strengthened the DDC's ability to respond to emergency situations. There is a significant emphasis placed on continually improving the dispatching process to provide better and more comprehensive support to the field crews.

C. Recommendations

Recommendation IV-1 Perform investigations to ensure that the new Severn Trent System software package has the capability to communicate all forms of jobs to the Servicers. (Refer to *Finding IV-2*).

To avoid limitations of the current system in relation to not being able to transmit all types of jobs to the Servicers, testing should be completed during the implementation and testing phase of this systems implementation project to verify this capability. The resolution of this problem should be confirmed prior to implementation of the system to avoid any future problems with this important system requirement.

Recommendation IV-2 Design the training program to be administered to the Servicers on the use of the new Severn Trent System in such a way as to ensure that the Servicers are able to avail themselves of the full capability of their laptop units and the software thereon. (Refer to *Finding IV-3*).

Without proper training of the use of the new and existing software, the Servicers will not be able to use the computerized tools to their greatest impact and benefit. The training programs that are conducted during the implementation phase of the project should be specifically focused on instilling this knowledge in the Servicers. It should also be considered that the Servicers have varying levels of experience and comfort with personal computers. Therefore the training programs must address these individual needs if it is to be successful.

Recommendation IV-3 **Evaluate the Servicer workload and outage restoration statistics to determine the optimal number of Servicers that should be on staff in the Hazard Service Area. (Refer to *Finding IV-4* and *Finding IV-5*).**

It is very probable that the results of this evaluation will identify a need to increase the number of Servicers in the HSA. Increasing the number of HSA Servicers will have two very beneficial effects:

- The amount of overtime that is being worked by the individual Servicers should be reduced.
- The ability to respond to outage situations in a timely manner should be enhanced.

With a larger pool of trained and equipped employees, the workload related to service restoration would be shared over a larger number of people, thereby improving the efficiency and timeliness of the restoration process. Please note that this finding is very similar to one which is found in Chapter III – Asst Management.

Recommendation IV-4 **Develop a software application that would allow the Distribution Line managers to track and monitor the number of overtime hours that are actually worked as opposed to those which are paid for. (Refer to *Finding IV-6*).**

The availability of this actual hours worked data would enable the Distribution Line organization managers to make better judgments concerning deploying their forces in storm situations and permit better performance tracking capability.

Recommendation IV-5 **Continue with the established plan to improve the radio communications network in the Hazard Service Area (Refer to *Finding IV-7*).**

This improved radio communications capability should resolve the existent problems with poor radio communication capability in the HSA. This improved capability should, in turn, result in the Servicers and field crews becoming more efficient and safer.

Recommendation IV-6 **Review the current policy on rights of way to determine if improvements could be made that would have a beneficial impact on service reliability in the Hazard Service Area. (Refer to *Finding IV-9*).**

Upon completion of this review, if it is determined that significant benefits can be achieved through modifying the current policy on rights of way, this issue should be addressed by the management of AEP/Kentucky as a means of improving service reliability. The management of AEP/Kentucky should take a more aggressive stance in regard to attempting to obtain permission to increase the width of its rights of way in those situations where the current right of way is insufficient or has created problems in the past. This topic is covered in more detail in *Chapter V – Vegetation Management and Animal Protection* of this report.

Recommendation IV-7 **Develop and implement a feedback mechanism to inform the Servicers and field crews of the status of the Tree Condition Reports that they have submitted. (Refer to *Finding IV-10*).**

By implementing such a feedback loop, the Servicers will be better informed as to the status of the requested work and will be more encouraged to use the Tree Condition Reports for their intended purpose, thereby obviating potential problems before they can impact service reliability.

Recommendation IV-8 **Continue the efforts that have been undertaken to improve the quality and consistency of the data that is reported to the KPSC. (Refer to *Finding IV-11*).**

These efforts should result in more viable and accurate numbers being reported as bad data is being eliminated from the databases and the data is being consolidated into one data set.

Recommendation IV-9 **Implement a full version of the PowerOn software in the Hazard Service Center for use in daily operations and storm restoration activities. (Refer to *Finding IV-12*).**

A full version (as opposed to the remote version that is currently in place) of the PowerOn software should be implemented and will result in much greater localized information and capability. This will be particularly important in the event of a major storm restoration effort that is managed from the Hazard Service Center.

Recommendation IV-10 **Review the potential for utilizing the automated field crew routing optimization capability that is built into the Small World software application. (Refer to *Finding IV-13*).**

As this routing optimization capability feature is already included in the Small World application, it would be desirable in the future to take advantage of the capabilities provided therein. Several other utilities have adopted an automated field force routing system combined with on-board GPS units with great success. Such a technological advance would certainly be expected to enhance the ability of the DDC to direct the field forces in an optimal manner.

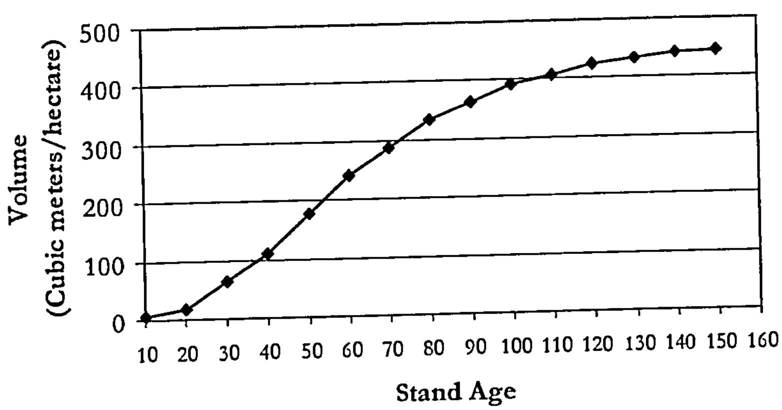
V. Vegetation Management and Animal Protection

This chapter addresses American Electric Power (AEP)/Kentucky's vegetation management and animal protection activities. Vegetation management is critical in providing reliable service to the customer. Tree-conductor contacts are the largest cause of unplanned service interruptions. AEP/Kentucky electric lines have a high exposure to trees. Animal-caused service interruptions, while not substantial, erode the quality of electric service and necessitate the installation of protective equipment.

A. Vegetation Management Concepts and Principles

The inventory of all trees that either have the potential to grow into a power line or on failure (breakage) to strike a conductor will be referred to as the utility forest. The utility forest has the same characteristics as any forest. The same patterns of biomass addition (tree growth) and tree mortality apply. Both of these are significant factors in power line security and both can be mathematically represented by geometric progressions, as illustrated in *Exhibit V-1*.

Exhibit V-1
Forest Biomass Addition
Timber Production
Spruce on Good Site



Adapted from: Freedman, Bill and Todd Keith, 1995. Planting Trees for Carbon Credits. Tree Canada Foundation.
1 cubic meter = 35.3 cubic feet.; 1 hectare = 2.47 acres

From a utility perspective, trees represent a liability in both the legal and financial sense. The fact that the utility forest changes by geometric progression is significant. It means the tree liability, if not managed, will grow exponentially.

Trees cause service interruptions by growing into energized conductors and establishing either a phase-to-phase or phase-to-ground fault. Trees also disrupt service when trees or branches fail, striking the line causing phase-to-phase faults, phase-to-ground faults or breaking the continuity of the circuit. As it is the two factors responsible for vegetation-related service interruptions, tree growth (biomass addition) and tree mortality, change by geometric progressions, the progression of tree-related outages is exponential. Failure to manage the tree liability leads to both exponentially expanding future costs and tree-related outages. Conversely, it is possible to simultaneously minimize vegetation management costs and tree-related outages.

It is not possible to totally eliminate the tree liability because the process of succession is a constant force for the re-establishment of trees from whence they were removed. The tree liability then, is like a debt that can never be completely paid. Under such circumstances, the best economy is found in maintaining the debt at the minimum level, thereby minimizing the annual accrued interest. However, irrespective of cost, minimizing the size of the tree liability or utility forest is rarely an option for utilities due to multiple stakeholders with an interest in the trees. What can be achieved, however, is equilibrium. The tree liability can be held constant at a point by annually addressing the workload increment. To continue the debt analogy, a debt is stabilized when the annual payments equal the interest that accrues through the year. The interest equivalent in the utility forest is comprised of annual tree growth and mortality. Actions that parallel the reduction in the debt principal are actions that actually decrease the number of trees in the utility forest. Such actions include removal of trees and brush by cutting or herbicide use.

When the pruning cycle removes the annual growth increment and the danger tree program removes trees as they become decadent, tree-related outages are stabilized. The residual level of tree-related outages reflects the interaction of several characteristics, including the size of the utility forest, chosen maintenance standards (such clear width), tree-conductor clearance, and tree species characteristics (such as mode of failure and decay). An expression of a managed tree liability, one where the annual workload increment is removed, is stable tree-related outages. Reducing tree-related outages below an achieved equilibrium necessitates actions that decrease the size of the utility forest. Actions are not limited to vegetation management. For example, increasing conductor height reduces the size of the utility forest as it reduces the number of trees capable of striking the line.

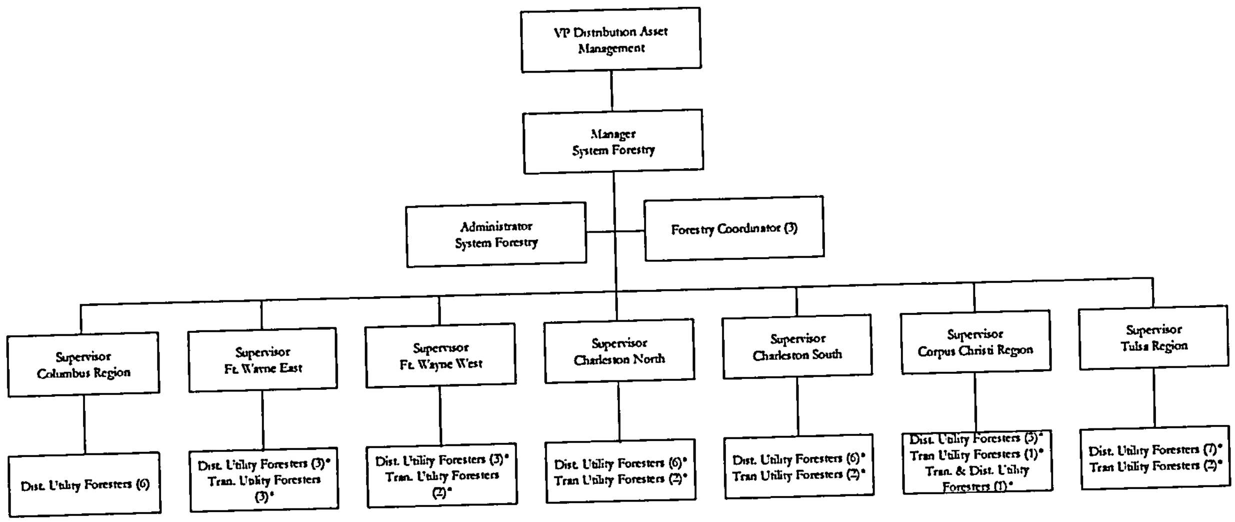
B. Background and Perspective

Organization

AEP's System Forestry (AEP Forestry) organization, which reports to the VP Distribution Asset Management, holds responsibility for vegetation management. Two foresters provide vegetation management services in the Hazard Service Area, one for the distribution system (Distribution Utility Forester) and another for the transmission system (Transmission Utility Forester). The Regional

Forester in the Charleston North Region supervises these foresters. The organization is shown in *Exhibit V-2.*

Exhibit V-2
AEP System Forestry Organization



* Resources located across each region

The System Forestry group was centralized in a 2000 reorganization stemming from a company merger.

Facilities

The distribution system is comprised of lines operated at 12 kV and 34.5 kV. The transmission voltages in the Hazard Service Area are 69 kV, 138 kV and 161 kV. Target easements are 40 feet for 12 kV lines, 50 feet for 34.5 kV lines and generally, 100 feet for the 69 kV, 138 kV, and 161 kV transmission lines. The target easements are not always achieved for distribution lines.

Clearance Standards

Trees that require pruning are cut to provide a minimum of 10 feet of clearance between conductors and the nearest tree part. Overhangs, however, are not tolerated regardless of clearance. Re-clearing is done to re-establish the original right-of-way. Where a transition from brush to large trees is evident, it is assumed that the large trees delineate the easement. Where no clear transition exists, vegetation management work planners and AEP Forestry staff assume the general easement widths, unless there is a known history with the landowner indicating otherwise. There is no set clear width (side clearance from tree boles at the right-of-way edge to the nearest conductor). There is no set distance for danger trees (trees outside the right-of-way that are diseased, cracked, leaning, subject to uprooting, or because of structural defects pose a threat to the power line). Identification of and removal of danger trees is based on whether or not they could strike the line on failure.

The right-of-way width and the conductor the furthest from the right-of-way centerline generally determine the clear width. For example, the clear width on 34.5 kV can be calculated as 21 feet (50 feet/2 – 8 feet (cross arm)/2 = 21 feet).

The clear width is considered when lines traverse slopes. The line may be installed off-center to provide a greater width on the uphill side. The clear width may be increased where the incidence of disease forces the labeling of an entire stand as danger trees. AEP/Kentucky is currently faced with increased pine mortality due to a bark beetle infestation.

Work Planning

The Distribution Utility Forester compiles the "wish list" of work for the following year considering:

Follow up required such as herbicide on areas recently cleared

Forecast of trim and re-clear based on history, visual field inspection, concerns expressed regarding reliability, and the number of customers on the circuit

The list is prioritized based on engineering and operations input

The Regional Forester checks to ensure the proposed work addresses lines that have the lowest reliability

The work plan may be modified through the year by input from operations, which is obtained on a weekly basis via the Complaints Database teleconference. Operations is another point of input regarding reliability. Other factors that may necessitate modifying the work plan include:

New capital work projects

The lack of availability or availability of specific crew types may alter the timing of work plan elements (i.e. aerial saw; aerial spray crew)

Response to the Kentucky Public Service Commission (KPSC)

Strikes

Unusual events like 9/11, which prevented any flying, grounding the aerial work crews

Hotspotting (where trees are in contact with conductors or the evidence of recent contact exists; addressing unplanned work as the need arises) done in response to Operations requests

Planning of the actual field work is done through contract work planners. The work planners are Asplundh Tree Expert Company (Asplundh) employees. The work planner position falls between a crew foreman and a general foreman.

In urban areas the work planner identifies the work to be done and notifies the landowner. Where the work is cross-country, the work planner notifies the landowners and the crew foreman determines the work to be done based on clearance requirements and general guidelines. The work planners mark the work on "pole maps." Upon completion of the work, the maps are returned to the Utility Forester. The circuits are then marked as completed in Right of Way Management (RWM), a web-based invoicing and record keeping database. There is no vegetation management layer in the Small World. As a result, records that tie work completed to geographic locations exist on paper only.

Utility Foresters audit the work for compliance with guidelines, completeness, quality, and accuracy of work units reported. All levels of AEP's Forestry group have specific audit frequency targets. When Forestry staff is particularly busy, the targeted amount of audits may not be met.

Hotspotting

Utilities commonly handle hotspot (where trees are making conductor contact) locations with a work effort separate from routine maintenance work. Such off-cycle work is generally referred to as hotspotting. There is a focused effort to minimize hotspotting due to associated higher unit costs. That hotspotting costs are frequently more than 100% higher than routine cycle pruning costs is illustrated in the Circuit Cost Summary report provided through AEP's RWM system. To facilitate the management of the amount of off-cycle work, hotspotting is listed as a separate line item in the budget and such work is tracked separately in RWM. *Exhibit V-3* provides the history of hotspotting in the Hazard Service Area.

Exhibit V-3
Hazard Service Area Hotspot History
(Distribution Only)

Year	Staff Hours	Cost
1997	25,103	$420,000
1998	8,673	$150,000
1999	14,104	$283,699
2000	21,250	$432,983
2001	6,311	$158,211
2002	NA	$120,462

Maintenance Cycles

Pruning cycles vary between two to three years in urban areas and three to eight years in rural areas. The pruning cycle is derived from the combination of the local Utility Forester's expertise, budget available, and emerging priorities. No growth studies have been undertaken by AEP/Kentucky to guide the derivation of maintenance cycles.

Pruning, tree and brush removal, and the identification and removal of danger trees are generally done in the same maintenance action. Exceptions occur for operations such as aerial pruning and danger tree removals in response to pest infestations. Aerial pruning is a discrete operation because the equipment requirements are completely different from that used for manual pruning and re-clearing. The Hazard Service Area is currently facing a Southern pine bark beetle epidemic that has resulted in stands of dead or decadent pines necessitating a more immediate, separate danger tree response.

Generally, within any utility pruning program, there are locations where trees will contact conductors before the next maintenance operation. Within the Hazard Service Area, locations where trees exist that grow considerably faster than the average (referred to as cycle busters), are targeted for tree replacement. Cycle buster species in the Hazard Service Area are silver maple (*Acer saccharinum*) and box elder (*Acer negundo*).

The herbicide program is planned as a follow up to cutting treatment, one to two years after re-clearing. While the first herbicide application following re-clearing is perceived to greatly diminish the stem count of incompatible species, subsequent herbicide applications are planned on a three-year cycle. The need for the herbicide application is monitored and the timing may be adjusted as required. AEP/Kentucky foresters indicated it is their experience that after multiple herbicide applications the cycle length is extended due to biological competition from low-growing power line compatible vegetation.

Tree Removals

AEP's *System Forestry Goals, Procedures & Guidelines for Distribution and Transmission Line Clearance Operations* document establishes a focus on tree removals unless the cost of such removals exceeds the cost of three pruning events. The guideline derives from financial analysis performed by Oklahoma Public Service.

The utility foresters exert influence on the work planners to ensure a strong focus on obtaining tree removals. *Exhibit V-4* provides the percent of total trees handled that are removed. The information is provided for the Hazard Service Area and AEP/Kentucky.

Exhibit V-4
Trees Removed of Trees Handled (Distribution Only)

	Hazard Service Area			AEP/Kentucky		
Year	Tree Trimming	Tree Removal	% Removals	Tree Trimming	Tree Removal	% Removals
1998	6,642	19,629	75%	53,078	63,959	55%
1999	9,630	33,658	78%	25,824	43,370	63%
2000	18,447*	33,622	65%	38,708	66,050	63%
2001	9,770	24,803	72%	23,579	47,988	67%
2002	7,035	16,894	71%	15,257	42,489	74%

* Aerial saw accounted for 10,880 trims

AEP Forestry has a tree replacement program that focuses on obtaining landowner agreement to remove cycle buster trees and replace them with low-growing, power line compatible tree species. Tree replacement is a separate line item in the budget. A financial analysis was undertaken to establish the merits of a tree replacement program.

Contracting

AEP has entered into an alliance agreement with Asplundh Tree Expert Company. The contract is essentially a sole source agreement with the exclusion of work performed from aircraft.

This contract that American Electric Power has entered into with Asplundh was piloted in American Electric Power's Charleston region. The agreement guarantees American Electric Power a specific minimum cost saving. At a certain percentage gain in productivity a pool of savings is triggered. In AEP/Kentucky the minimum guaranteed saving is 1% and the incentive pool begins to accumulate when productivity gains exceed 3%. The contractor is rewarded from the accumulated pool of savings based on key performance indicators, including productivity, safety, reliability, and mileage completed. In so far as the contractor fails to meet the conditions for the maximum incentive payment, the residual pool funds comprise further savings for American Electric Power.

Under the Alliance, AEP shares reports and information with Asplundh, and Asplundh has shared information with AEP. The Regional Forester believes the contractor has been more responsive under this contract. The contractor is free to adjust crew staffing and equipment because they need to meet certain productivity goals. The Regional Forester perceives specific benefits to arise from the Alliance. There is more stability in the work force because of the duration of the contract. This results in crew personnel being more experienced and familiar with the geographic area.

Productivity

Most of the vegetation management contract work is done on an hourly rate basis. Unit costs are derived from the RWM database/reporting system. Under the Alliance contract productivity information is shared with the contractor to focus improvement efforts that benefit both parties.

Budget

The budget determines the amount of tree work that can be completed. Local forestry staff develops a work plan based on their assessment of the work required in the following year. Funding is never sufficient to cover the locally perceived needs. A process of prioritizing what work will be done with the allocated resources is initiated by consulting the local Operations group and the Regional Forester. The Regional Forester has some flexibility in shifting funds to areas that have a particular need requiring resolution.

Exhibit V-5 provides a 6-year history of vegetation management funding both for the Hazard Service Area and AEP/Kentucky as a whole. The Hazard Service Area, since 1997, has received an increased share of the total AEP/Kentucky vegetation management budget.

Exhibit V-5
Vegetation Management Funding

Year	Hazard Whitesburg	% Change Relative to 1997	AEP/Kentucky	% Change Relative to 1997	Hazard Share of Total KY VM Budget
1997	$1,147,818		$4,099,999		28.00%
1998	$1,286,226	12.06%	$3,962,200	-3.36%	32.46%
1999	$1,367,653	19.15%	$3,088,468	-24.67%	44.28%
2000	$1,199,005	4.46%	$2,985,748	-27.18%	40.16%
2001	$1,109,587	-3.33%	$2,846,632	-30.57%	38.98%
2002	$1,152,638	0.42%	$3,202,100	-21.90%	36.00%

Decision Support

There is no inventory of the vegetation management work that needs to be done on an annual basis. Nor are there growth studies to guide the derivation of average pruning cycle lengths based on established clearance and tree re-growth rates.

Asset management approaches are used to prioritize where the largest return in reliability can be obtained for the dollar invested.

Productivity and mileage completed are key performance indicators in the Alliance contract. These are tracked in RWM, which provides both standardized reports and offers the flexibility for ad hoc reports. RWM provides unit costs, work units, herbicide usage, etc. from the foreman and circuit level up to the system level.

Animal Control

Birds and animals accounted for about 1% of unplanned outages in the Hazard Service Area over 1999-2001.

Targeting locations identified as experiencing animal caused outages, animal guards are installed on the primary bushings of overhead line transformers and other line equipment. In 2002 the installation of 217 animal guards at a cost of $3,348 is planned for the Hazard Service Area.

C. Findings and Conclusions

Finding V-1 Tree-caused outages are a distribution issue not a transmission issue.

The transmission system is not tree-free and some outages attributable to trees do occur, however, the number is very small. As shown in *Exhibit V-6*, the number of tree-caused outage incidents on distribution lines is substantially higher than those experienced on the transmission system.

Exhibit V-6
Tree-Related Outage Incidents - Hazard and Whitesburg

Cause Code	Years	Distribution Interruptions	Transmission Interruptions
Tree Inside ROW	1997-2001	1515	6
Tree Out of ROW	1997-2001	1806	0
Tree Removal	1997-2001	293	1
Total		3614	7

Finding V-2 Vegetation management methods, as employed, minimize both current and future vegetation management costs.

The vegetation management program as understood at the regional and local level has the potential to minimize both current and future maintenance costs. There is a strong, successful focus on tree removals. The rate of tree removal for AEP/Kentucky is much higher than is typical in the utility vegetation management industry. The high removal rate is particularly true for the Hazard Service Area (*Exhibit V-4*). From 1998 to present, in the Hazard Service Area, 71% of all trees handled were removed. This industry leading result will reduce future costs by avoiding the repetitive costs of pruning. The exceptional removal rate record is, however, marred. It is not known to what extent the high removal rate is an artifact of not handling the pruned trees often enough.

Some of the high removal rate may be attributable to the fact that the AEP/Kentucky service area is heavily treed and, under such conditions of tree abundance instead of scarcity, landowners may place less value on trees. Regardless, tree removals are not obtained without a focused effort to address the issue with landowners.

Pruning quality in the Hazard Service Area is very good. Pruning quality has a major impact on the rate of regrowth and, thereby, on the pruning maintenance cycle length and costs. Pruning quality is so good that there is no opportunity to further increase cycle length or suppress regrowth.

Herbicides are widely and effectively used in the AEP/Kentucky vegetation management program. Timely herbicide applications reduce current maintenance costs but, more significantly, by reducing the stem density of incompatible species while fostering a power line compatible vegetation community, substantially reduce future maintenance costs. Acceptance of herbicide use by landowners is high with only about a 3% refusal rate.

AEP/Kentucky's use of aerial spraying and aerial pruning are effective and serve to reduce maintenance costs.

AEP's prescriptive approach to vegetation management generally demonstrates a high level of professional skill and produces excellent results. This is particularly true for timely right-of-way interventions.

Finding V-3 The sole source Vegetation Management Alliance Agreement guarantees immediate savings benefits but sacrifices the ability to ascertain whether productivity and costs are competitive.

While the structure of the Alliance Agreement benefits American Electric Power, in entering into a sole source supplier agreement American Electric Power gives up the possibility of competitive contractor comparisons. If such comparisons were made in advance of entering into the Alliance Agreement and were the basis for selecting the contractor, then the process of ongoing monitoring of productivity is both informative and adequate.

Finding V-4 Maintenance cycles are too long and the timing of vegetation management activities is too late to avoid service interruptions from right-of-way trees.

Field examination of circuits where work is being done in the current (2002) year and where work is planned for next (2003) year revealed numerous locations where trees were either in the conductors or burning on the vegetation indicated that tree branches had made conductor contact. While no quantitative measure of the number of hotspots was undertaken, Schumaker & Company consultants found it not uncommon to encounter as many as five or six hotspots per mile of line. Schumaker & Company consultants also found that work planned for 2004 includes locations where the clearance between trees and conductors is inadequate to avoid burners occurring prior to pruning service delivery.

While it is agreed that a two to three year pruning cycle in urban areas might be expected to prevent trees from growing into conductors, there was insufficient detail in the AEP/Kentucky data records to definitively assess whether the two to three year cycle is being met. Based on the total 2499 miles of distribution line in the Hazard Service Area, a three year pruning cycle necessitates covering 833 miles per year. The AEP *Forestry 2002 Distribution Work Plan – Pikeville/Hazard* shows 233 miles of cutting work planned for the Hazard Service Area. The planned miles fall substantially short of the 833 miles required to achieve a 3 year pruning cycle.

There is one standard clearance obtained when pruning. It is 10 feet. Hence, there should be no difference in the length of the pruning cycle for urban and rural areas, unless tree species are vastly different or no tall-maturing trees are tolerated on the right-of-way in rural areas. It was observed by Schumaker & Company consultants that planted landscape trees did introduce some non-native species but most trees were naturally occurring, volunteer species. If tall-maturing trees were not tolerated in the right-of-way, then all growth requiring pruning would arise from lateral growth. A pruning cycle of three to eight years for lateral growth would be adequate to avoid conductor contact. AEP/Kentucky is quite successful in obtaining tree removals, concentrating trees requiring pruning to the vicinity of residences. In the Hazard Service Area, however, a large portion of the residences is in rural areas. Because people value trees, they resist removal of trees around residences. This has the effect of interjecting a shorter pruning cycle (two to three years) into the three to eight year rural maintenance cycle.

Other than the fact of different vertical and lateral growth rates, one might justify the different cycle lengths between urban and rural settings on the basis of human exposure to electrical hazards potential but not from a reliability perspective.

The implications of the high number of burners evident in current and next year planned work areas are that either AEP/Kentucky will need to use more costly hotspotting or customers must endure service interruptions.

Schumaker & Company consultants observed an herbicide application being made to dense and tall brush, ranging up to 25 feet in height. It was estimated by local forestry staff that the area had been cleared six years ago. However, this estimate suggests in excess of four feet of growth per year on yellow poplar (*Liriodendron tulipifera*). Both the density and height of the brush serve to drive up maintenance costs. Generally, the ideal timing for the herbicide application that both minimizes costs and optimizes efficacy of effecting a right-of-way species shift to power line compatible species will be one or two years after brush cutting.

Finding V-5 Because maintenance cycles are too long, the need for hotspotting is great, yet the use of hotspotting to maintain uninterrupted service is being constrained.

The extent of the need for hotspotting to maintain safe, reliable service is a reflection on the adequacy of the maintenance cycle.

AEP/Kentucky's use of hotspotting has been variable over the years of 1997 through 2002 (*Exhibit V-3*). Expenditures on hotspotting appear to be substantially higher than average every third year. Both the number of hotspots witnessed during the field tours and the increasing number of service interruptions arising from right-of-way trees (*Exhibit V-8*) indicates that, unless maintenance cycles are adjusted, there will be a need for a large expenditure hotspotting program in 2003.

From a financial perspective there is merit to minimizing hotspotting. This is recognized by AEP Forestry and hence, hotspotting is minimized. The recognition and intent are positive. However, the purpose of a hotspotting program is to address the safety and reliability problems associated with tree-conductor contacts arising between maintenance cycles. The product of overly long pruning cycles is the increased need for hotspotting. The way to minimize hotspotting without increasing unit costs or tree-related outages is via a pruning cycle based on standard clearance and tree growth rates. The combination of overly long pruning cycles and the minimization of hotspotting expenditures finds expression in higher rates of tree-caused service interruptions.

Finding V-6 Use of industry standard practices inadequately address the reliability risks associated with the very high extent of tree exposure.

AEP/Kentucky's service area has an extremely high concentration of trees. Much of the area is rural and the topography mountainous. As a result power lines run not alongside roads but cross-country, doubling the amount of tree exposure.

The extent of tree exposure and remote, rugged terrain impose a serious challenge to managing service reliability. Vegetation management practices used are typical of the utility vegetation management industry and, thereby, fail to recognize the abnormally high degree of tree risk.

Specifically, AEP/Kentucky's practices regarding the identification and removal of danger trees are typical of the utility vegetation management industry. With the exception of trees affected by a pest or pathogen, trees susceptible to failure and interfering with electrical service (danger trees) are generally identified and removed only during the routine maintenance cycle. The inadequacy of this approach is illustrated by the fact that failure of off right-of-way trees accounts for about 35% of the total hours of unplanned distribution service interruptions (*Exhibit V-9*).

AEP/Kentucky has a very high tree removal rate. While this record bodes well for reducing off right-of-way tree-caused outages, the benefits are obscured by the negative effects of an overly long maintenance cycle. However, while a reduced cycle length would contribute to improved service reliability, off right-of-way tree-caused outages will remain relatively high being positively correlated to the extent of tree exposure. The practices and strategies applied are designed to identify and mitigate against tree hazards but not to limit the extent of tree exposure.

The observed vegetation management practices and articulated strategies do not reflect recognition of the rates of, and influence of, innate tree mortality.

Finding V-7 The vegetation management workload, comprised of the inventory of trees, tree growth, and mortality rates, has not been quantified and is unknown.

The first requirement to successfully managing tree-conductor conflicts is to quantify the magnitude of the problem. AEP/Kentucky has not done so.

Determining the size of the tree liability requires an assessment of the size of the utility forest (all trees capable of contacting conductors) and its rate of change. Through a count of trees categorized by work type (i.e. trims or removals), a measure of brush and total tree exposure, determination of average annual growth and mortality rates, the annual amount of work necessary to hold the tree liability steady is derived. Without a measure of the annual vegetation management workload increment required to sustain the tree liability at equilibrium, the probability of successfully managing tree-related outages is virtually nonexistent.

Finding V-8 The vegetation management budget is not based on the annual work required to avoid service interruptions.

While it was stated by AEP management that vegetation management funding has been relatively stable, actual expenditures show a downward bias lacking cost of living increases (*Exhibit V-5*). The trend for decreasing maintenance spending is apparent in the AEP/Kentucky vegetation management budget, which was reduced by 30% in 2001 from 1997 levels. The Hazard and Whitesburg operating areas have to an extent been buffered from this decrease by receiving an increasing share of decreasing vegetation management funding for AEP/Kentucky as a whole. In the context of a shrinking funding allotment the Hazard Service Area cannot continue to receive an increasing share of these funds unless the need for vegetation management funds in the rest of the AEP/Kentucky service area is rapidly shrinking. If this is the case, then evidence for it should exist in substantial reductions in tree-related outages for the rest of AEP/Kentucky. Without evidence of a decreasing need for vegetation management outside the Hazard Service Area, one would expect over time the historical average share of funding to be re-established. In the return to the average, the Hazard Service Area would have to absorb its share of vegetation management budget reductions.

AEP/Kentucky's funding of vegetation management is not based on any measure of tree workload. Successful long-term vegetation management requires funding that permits removal of, as a minimum, the annual workload increment. Failing that, tree-related outages increase.

The pruning cycle afforded by the current budget is disconnected from the biological facts. It is easy to ignore these facts in the absence of scientifically sound, established tree growth rates.

Any approach to budgeting for vegetation management that is based not first and foremost on actual tree volumes and conditions, lacks the logical underpinnings for effective long-term management.

Finding V-9 Applying asset management strategies to prioritize maintenance reduces maintenance costs but does not ensure improved electric system reliability.

Asset management strategies are useful for prioritizing where to allocate resources for the maximum reliability benefit. These strategies are separate from the total resources allocated and, therefore, do not ensure the delivery of any specific standard of service.

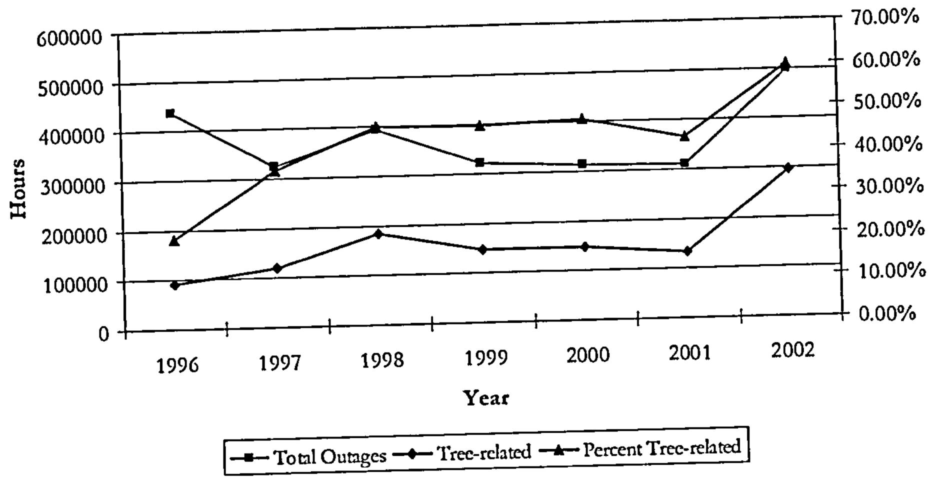
Asset management strategies as applied to vegetation management assure the optimum benefit for the dollar expensed and that may include getting more work done within the budget. For the approach to effectively address reliability problems there must be enough funds to complete as a minimum, the annual workload increment. That level of work completion would hold tree-related outages steady.

When funding for vegetation management is constrained such that the annual workload increment cannot be completed, system reliability will deteriorate. Asset management approaches may ameliorate the rate of deterioration but not the overall trend.

Finding V-10 Tree-related outages, the largest cause of unplanned service interruptions, are on an increasing trend that is not being addressed.

In the Hazard Service Area, tree-related outages are the single largest cause of unplanned outages. Over the period of 1998 to 2001 tree-related outages have accounted for 40% to 50% of all outages (*Exhibit V-7*) on a customer hour basis. Pro-rating the 2002 experience produces a jump to 60% of all outages.

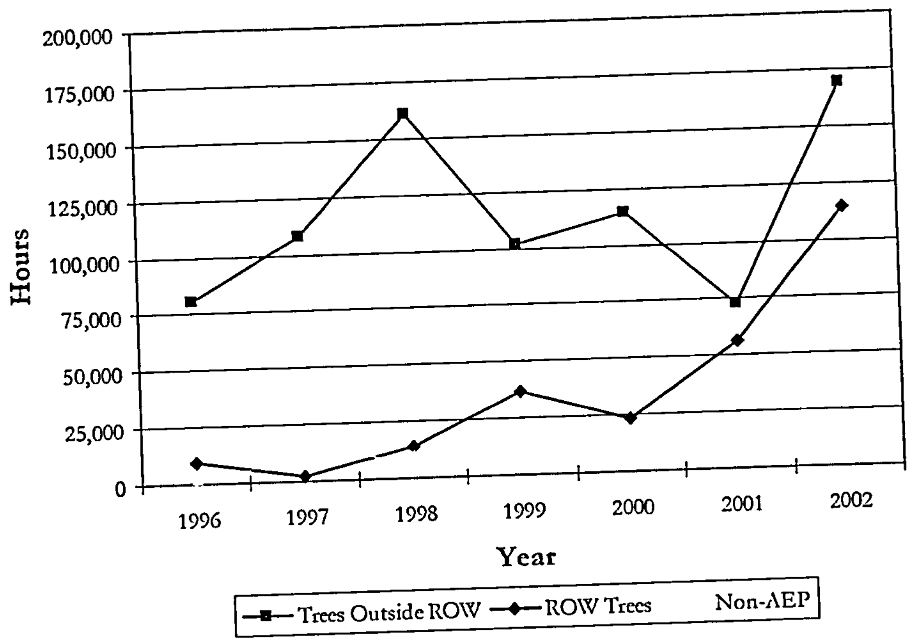
Exhibit V-7
Hazard Service Area
Unplanned Distribution Outages
(Major Storms Excluded)



* 2002 pro-rated

The outage history indicates that customers have been enduring more hours of service disruptions arising from on right-of-way of trees, which are trees requiring pruning. Within right of way tree-caused outages have been increasing essentially exponentially since 1997 (*Exhibit V-8*).

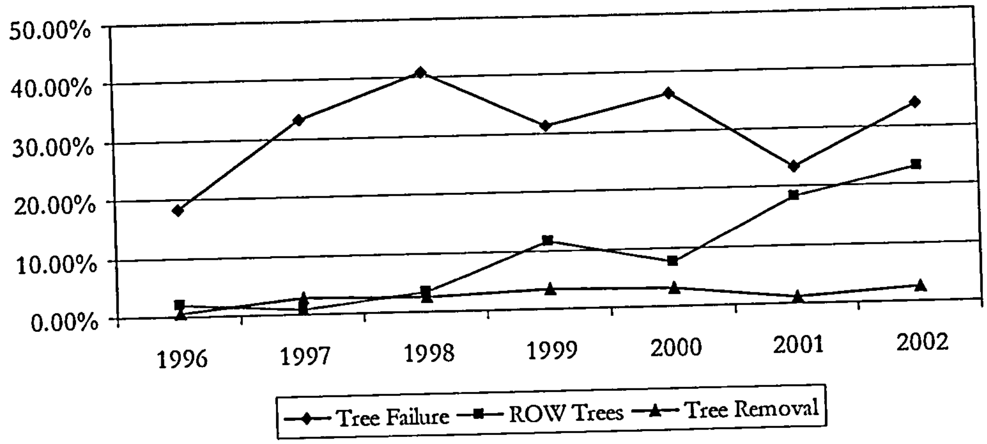
Exhibit V-8
Tree-Related Outages
by Tree Cause Code (Distribution)



* 2002 pro-rated

Right-of-way trees, which in 1997 accounted for less than 1% of unplanned outage hours, are predicted to account for more than 23% in 2002 (*Exhibit V-9*). Tree-caused outages due to non-AEP contractors have been fairly level. Tree failure of off right-of-way trees is the largest cause of service interruptions, ranging between 25% and 40% of all outages (*Exhibit V-9*). Tree removals in the Hazard Service Area were lower in 2001 than the preceding two years (*Exhibit V-4*). While data for 2002 is incomplete, pro-rating the trend found in the first 8 months suggests off right-of-way tree-related outages are increasing (*Exhibit V-8* and *Exhibit V-9*).

Exhibit V-9
Tree-related Outage Hours as a % of Total Unplanned Outages
(ROW Trees An Expanding Problem)

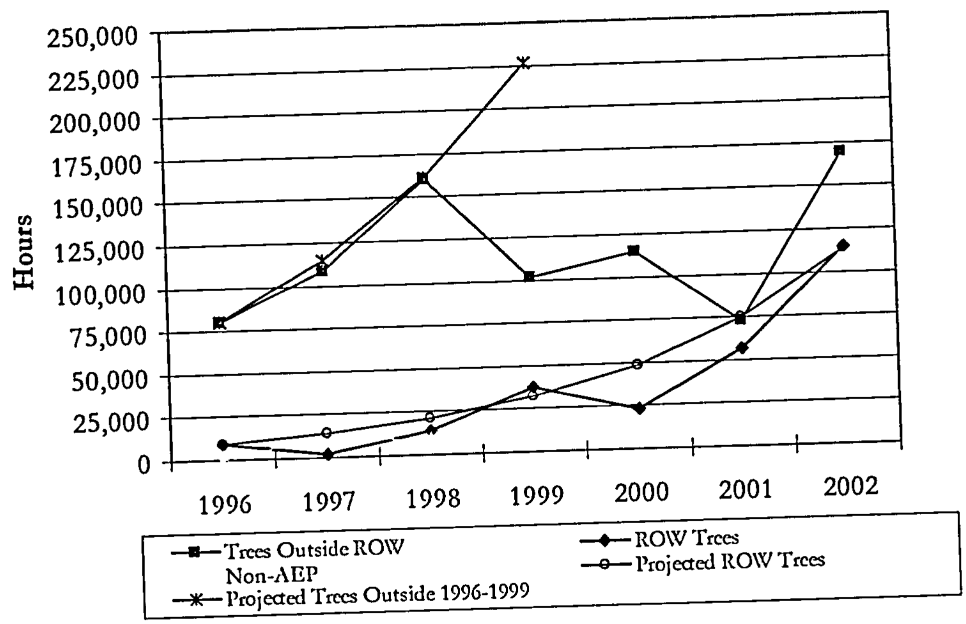


* 2002 pro-rated

The possibility exists that the influence of trees on reliability is not fully represented by the tree-caused outage codes. According to AEP/Kentucky documents another 6% of outages are ascribed to weather. AEP/Kentucky indicates that weather-related outages are mostly related to high wind and probably vegetation.

Tree-related outages caused by within right-of-way trees have been increasing exponentially since 1997 (*Exhibit V-10*). There is nothing in the vegetation management plan that would suggest this trend would change. The budget has not been increased to achieve a shorter pruning cycle and constrained hotspotting will contribute to perpetuate the established trend.

Exhibit V-10
Exponential Increase in ROW Tree-Caused Outages



* 2002 pro-rated

The focus on removals appears to have resulted in slight improvement in outages arising from off right-of-way trees until the current year. Both the (pro-rated) increase from 2001 to 2002 and the rate of increase from 1996 through 1998 show trees outside the right-of-way have the potential to add quickly and significantly to outages (*Exhibit V-10*).

To illustrate the potential for a rapid increase in tree-related outages from trees outside the right of way an algorithm was used to predict what those outages would have been for 1999 (Projected Trees Outside 1996-1999 in *Exhibit V-10*). The fact that the projected outages did not occur may be due to a lower frequency or intensity of minor storms and/or some action that proved to be an intervention. The intervention most probably was the over 70% increase in the rate of tree removals from 1998 to 1999 (*Exhibit V-4*). The nature of tree workload and tree-caused outage progression was revealed at the start of this section in *Vegetation Management Concepts and Principles* and illustrated in *Exhibit V-1*. Obtaining the best fit of such a geometric progression to the outage statistics for the years 1996 through 1998, the progression was extended for another year to forecast 1999 trees outside the right of way caused outages. While the projected level of outages did not occur, the projected curve (Projected Trees Outside 1996-1999 in *Exhibit V-10*) is revealing. Given we know the overall shape of the progression (as in *Exhibit V-1*), the projected outages segment reveals:

1) Work volume is well out to the right side of the graphic representation of the progression (see Exhibit V-1) where the exponential effects are large. This is to be expected because of the high degree of tree exposure for lines in the Hazard Service Area.
2) The rate of compounding is large as indicated by steepness of the slope for Projected Trees Outside 1996-1999. The steep slope is reflection of the degree of tree exposure but also provides information about tree failure rates, suggesting either high tree mortality or decadence and/or poor root support.

In a nutshell, what the Projected Trees Outside 1996-1999 curve reveals is trees outside the right of way caused outages are volatile, with a potential to significantly negatively impact overall reliability if there is not a focused management effort to contain them. Conversely, they are also very responsive to certain management actions (see sharp drop in Trees Outside ROW from 1998 to 1999 in *Exhibit V-10*).

There is no strategy specific neither to containing trees outside the right of way caused outages nor to making substantial outage reductions, in spite of the fact off right-of-way trees are the largest single contributor to service interruptions (*Exhibit V-9*). Rather there may be a tendency to discount outages from off right-of-way as beyond the control of the utility. This is not untypical in the utility industry as many utilities label such outages as non-preventable. However, to the customer experiencing a loss of service the relative location of the tree interrupting the service is immaterial.

Finding V-11 The articulated strategies for decreasing the impact of tree-conductor conflicts on reliability of service are inadequate.

Clear width has not been explored as a factor in improving reliability, other than accounting for the influence of slope where lines run across the slope. Outage statistics indicate tree failures outside the right-of-way account for about 35% of unplanned service interruptions (*Exhibit V-9*). No initiatives that specifically recognize and seek to address this substantial source of service interruptions were revealed.

Asset management strategies designed to improve SAIFI and SAIDI appear to focus on the circuit level. Focusing on the circuit level misses opportunities for improving reliability.

There are two factors that need to be examined in tree-related outages, those being controlling incidents and duration. While the asset management approach considers the number of customers affected by an interruption and, thereby, improving SAIDI, it does so only on the basis of the AEP Forestry standards. AEP/Kentucky Forestry has not extended the use of prescriptive treatments to address the specific areas (line segments) that have the greatest potential to negatively impact SAIDI. Application of a uniform standard fails to consider there may be portions of a circuit where a tree-related outage will take more time to locate and mitigate. If there is a probability that an outage incident on a particular portion of a circuit will have an above average negative affect on SAIDI, alternate, specific mitigation strategies are warranted.

Finding V-12 Animal protection practices are adequate.

Animal caused outages are a minor cause of unplanned service interruptions. AEP/Kentucky's approach to installing protective devices in response to emergent animal caused reliability problems is reasonable.

D. Recommendations

Recommendation V-1 Determine the annual vegetation management workload increment. (Refer to *Finding V-7*).

Trees represent a liability to utilities. Because vegetation is dynamic, there is an annual change in the tree workload inventory. To hold tree-related outages constant, the volume of annual vegetation management work completed must match the annual change in the tree workload inventory. Any portion of the annual work increment not completed enlarges by geometric progression. Failure to remove the annual workload increment results in both deteriorating reliability and increased future costs.

To prevent the escalation of costs and deteriorating reliability, the amount of annual vegetation management required (annual workload increment) must be quantified. It is a specific amount of work, representing a specific cost. Without quantification, there are only guesses.

Determining the annual workload increment necessitates a static snap shot of all current trims, removals, brush, and spray areas. In addition to this inventory, the rate of change needs to be quantified. It typically includes tree growth rates. The average rate of tree mortality over the utility forest should also be determined. As AEP/Kentucky has very high tree exposure, off right-of-way trees comprising 35% of unplanned distribution outages, tree mortality will figure prominently in managing tree-related outages.

Once this workload is determined, it would be useful to represent this information in a vegetation management layer in the Small World. This would provide a more useful representation of the information and eliminate the need to record the information on paper maps only.

Recommendation V-2 Establish pruning cycles based on measured average tree growth. (Refer to *Finding V-4*).

The field review suggests that current pruning cycles are one to two years behind. This observation is supported by the history of tree-related outages arising from trees within the right-of-way. Yet, AEP/Kentucky's experience shows it is feasible to reduce tree-related outages from within right-of-way trees to just a few percent of unplanned outages.

The present pruning cycle does not avoid tree-conductor contacts. Avoiding tree-conductor contacts should, however, be an objective of the pruning program for both safety and reliability reasons. A pruning cycle based on an inventory of trees requiring pruning and tree growth rates minimizes the number of tree-conductor contacts. Reducing outages from vegetation within the right-of-way to zero is not feasible for AEP/Kentucky because of the extremely fast growth rate of kudzu (Pueraria montana var. lobata). Typically within a maintained circuit there will be locations with exceptional growth that will require off-cycle pruning to avoid tree-conductor contacts. Such locations usually contain planted, introduced species. These locations require hotspotting and are the same ones targeted in the tree replacement program.

There are two possible ways to minimize within right-of-way tree-caused outages. The first is to establish a pruning cycle based on average tree growth. Flexibility is required to adjust the cycles up or down based on exceptional local conditions such as drought. The second approach is to substantially increase the use of hotspotting to prevent trees growing into conductors. The hotspotting approach escalates maintenance costs and is reactive. That is, hotspotting does not constitute management of the tree workload.

Recommendation V-3 **Budget for vegetation management based on the annual workload increment. (Refer to *Finding V-8* and *Finding V-9*).**

Successful vegetation management that manages tree-related outages can only derive from funding based on actual tree conditions. Funding based on any other premise is bound to fail the objective of providing safe, reliable, economic service. Paradoxically, because the tree workload expands exponentially, budgeting based on the actual tree workload is the path to simultaneously minimizing tree-related outages and costs.

Recommendation V-4 **Use hotspotting to minimize tree-related outages until the system is on a sustainable pruning cycle. (Refer to *Finding V-5*).**

Until the pruning cycle based on average tree growth is established across the entire Hazard Service Area, tree-conductor contacts will remain high. It may take a number of years to work across the whole Hazard Service Area establishing the shorter pruning cycle. In the interim, if tree-related outages are to be avoided, hotspotting must be substantially increased to prevent burners. The alternative is to maintain hotspotting at current levels, recognizing that while tree-caused outages will remain high, they will begin decreasing as more of the area is completed and maintained on the proper pruning cycle.

In areas where the new pruning cycle has been introduced, hotspotting should be used to maintain clearance at all cycle buster locations. The amount of hotspotting must be determined by the actual need in the field, unlike the current practice of ignoring hotspots because they occur in the next year's work plan. As the need for hotspotting cannot be entirely avoided, a target for the maximum amount of hotspotting should be set. However, the cap must be set based on real need. A cap of 2% to 5% is suggested as achievable with a proper pruning cycle.

Recommendation V-5 **Develop and implement practices designed to manage tree-caused outages. (Refer to *Finding V-6*, *Finding V-10*, and *Finding V-11*).**

The examination of tree-related outage history leads to a number of observations (*Exhibit V-9*).

- Within right-of-way trees account for about 20% of unplanned outages
- Within right-of-way tree-related outages have been increasing since 1997
- Reducing within right-of-way tree-related outages to less than 5% of the total is achievable
- Off right-of-way trees account for about 35% of unplanned outages

Reducing and managing within right-of-way tree-related outages could be achieved by the use of a growth-driven pruning cycle. The potential exists to reduce within right-of-way tree-related outages to below 5% of all unplanned outages.

Off right-of-way tree-related outages constitute an opportunity to substantially improve service reliability. Doing so will necessitate identification of portions of circuits where tree-related outages have above average negative effects on service reliability. Actions designed to address the location specific tree risks will need to be implemented.

An example is provided to illustrate that the potential for reducing off right-of-way tree-related outages does exist. To illustrate this potential for improving reliability, an analysis of the influence of right-of-way width follows. Assume a 34.5 kV line with the standard 50-foot right-of-way, as well as the following conditions:

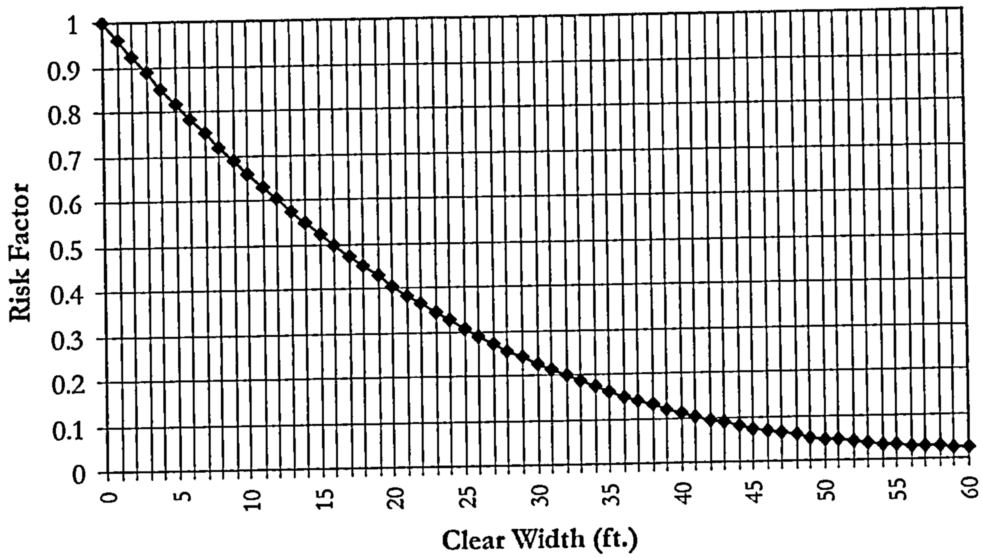
- Adjacent trees are 90 feet in height
- Average line height is 27 feet
- Tree density of adjacent trees is 220 trees/acre
- Cross arm length is 8 feet
- Tree removal costs average $50/tree

The current clear width is 21 feet (50 ft ROW/2 – 8 ft cross arm/2).

What would be the benefit and cost of increasing the right-of-way to 75 feet?

Exhibit V-11 shows the change in tree risk over a range of clear widths. There is a diminishing return in line security for the dollar invested in increasing clear width. At the current clear width of 21 feet, the tree risk factor is 0.385. Increasing the right-of-way width to 75 feet increases the clear width 33.5 feet. The risk factor associated with a 33 foot clear width is 0.186.

Exhibit V-11
Tree Risk Assessment
(Line Strike Probability for 90-foot Trees
Line Height at 27 Feet)



To facilitate assessment of the change in line security and the associated costs, information has been entered into a spreadsheet (*Exhibit V-12*). Increasing the right-of-way to 75 feet, under the assumed conditions, would reduce off right-of-way tree-related outages 52%.

Exhibit V-12
Change in Line Security
Cost Benefit Analysis

Line Segment Specific:		Acre/Mile	Trees/Mile	Cost/Mile	Line Security Improvement
Line Height	27				
Tree Height	90				
Trees/Acre	220				
Current Clear Width	21				
Current Risk Factor	0.385				
Increase Width	12.5	1.52	333		
New Risk Factor	0.186				52%
Removal Cost/Tree *	$8.00			$2,666.67	
Removal Cost/Tree **	$50.00			$16,666.67	

* Using feller bunches
** Chainsaw removals

The cost based on the assumed unit cost would be $16,667 per mile of right-of-way side. Where trees border both sides of the line, the cost will double. The cost of obtaining additional right-of-way has not been included.

While increasing the right-of-way width from 50 feet to 75 feet would produce a substantial reduction in tree-related outages, the cost is also substantial. Obviously, there would be merit in applying such an approach selectively to trouble spots that have a large influence on total customer minutes of outages.

Recommendation V-6 **Introduce contractor agreements that ensure effective costs are competitive. (Refer to *Finding V-3*).**

Consider means of assuring that contractor rates are competitive. It may require contracting with a minimum of two contractors for AEP's system.

The basis of competitive comparisons should be on the basis of effective costs, not merely on the basis of hourly labor and equipment rates offered. A measure of productivity needs to be applied as a modifier to hourly rates. AEP's RWM system can provide such a measure of productivity.

Kentucky Power Company

REQUEST

Officer Compensation. Please identify and provide a copy of all compensation surveys, studies of total compensation and payroll studies that the Company has used in the past five years, is currently using, and/or plans to use in 2013-2015 to evaluate whether the compensation levels of its executives are reasonable.

RESPONSE

Please refer to witness Carlin's Exhibits ARC-1, ARC-2, ARC-3, ARC-4, ARC-5, ARC-6, ARC-7 and ARC-8 for a listing and description of publicly available studies used during the test year as well as the Company's analysis. In addition, the Company is in possession of, and relies upon, other study and survey results which are copyrighted and subject to licensing agreements that prohibit the Company from filing them with the Commission or serving them on the parties to this proceeding.

WITNESS: Andrew R Carlin

Kentucky Power Company

REQUEST

Penalties and Fines. Provide for each year 2009 through 2012, 2013 year-to-date a list of any and all penalties and fines paid by the Company and a description of why the penalty/fine was paid.

RESPONSE

Penalties and fines are recorded in account 426.3, which is a "Below the Line" account which are not included in base rates. See AG 1-38 Attachment 1 which shows the penalties and fines recorded in account 426.3 by year by description.

WITNESS: Ranie K Wohnhas

Year	Amount	Description
2009	149	IRS
2009	1,110	State, Local and Property Taxes
Total 2009	$1,259	
2010	-333,340	Qtr FIN 48 St Accrd Penalties
2010	1,007	IRS
2010	149	State, Local and Property Taxes
Total 2010	($332,184)	
2011	3,211	FERC Violation Penalty Payment
2011	43	State, Local and Property Taxes
Total 2011	$3,254	
2012	759	FERC Violation Penalty Payment
2012	85	IRS
2012	-826	State, Local and Property Taxes
Total 2012	$18	
2013	2,296	FERC Violation Penalty Payment
2013	-37	US Treasury Penalty Refund
2013	784	State, Local and Property Taxes
Through 6/30/13	$3,043	
Grand Total	($324,610)	

Kentucky Power Company

REQUEST

Early Retirement Plan. Did the Company offer an early retirement plan during the period 2010-2013 year-to-date? If so, provide details including written descriptions provided to potentially eligible employees. Provide the details of impacts on annual expenses. Include a copy of any cost-benefit analyses associated with such early retirement programs. Also, describe any early retirement or employee severance plans being considered for the test year and indicate whether or not the program is reflected in the filing. If so, identify where.

RESPONSE

No, the Company did not offer an Early Retirement Plan during the period 2010 – 2013 year-to-date. During the Test Year 4/1/12 – 3/31/13 a severance plan was available. Please see attachment AG 1-39 which describes this plan. The plan was not reflected in the filing.

In regards to annual expense, employee reductions are reflected in the payroll adjustments in Section V workpapers 38 - 43 and 50 -55 which annualizes Kentucky Power employees as of March 31, 2013 as well as adjustments in workpapers 44 and 56 which removes severance expense from the test year.

WITNESS: Andrew R Carlin

About this Guide

As you end your employment at American Electric Power (AEP), use this AEP Severance Plan Guide to help make this time of change work best for you. This guide is designed to supplement the "Leaving AEP Guide," available from the HR Service Center. It should answer many of your questions and help you in your understanding of steps you will need to take to receive severance plan benefits, if eligible. **This guide assumes you have met the requirements for eligibility to receive an offer of severance plan benefits.**

Every effort has been made to ensure this information is accurate. However, the severance plan is governed by a legal document. If there is any difference between the information in this guide and the official severance plan document, the plan document will rule.

This guide is not intended to be a plan document, summary plan description (SPD), nor required notice with respect to any of the AEP System plans mentioned. AEP reserves the right to modify, amend, suspend or terminate the severance plan at any time. Refer to the applicable plan document if there are any questions relating to a specific plan or benefit.

Terminating With Severance Benefits

Completing the Severance Paperwork

As you receive your actual, or final, severance package, and if you elect to sign the Release, then you are eligible for the special benefits described in the Severance Plan relating to the: Severance Allowance, AEP Comprehensive Medical, and AEP Dental.

Final Severance Package

The actual, or final, Severance Release Agreement (Release) and Severance Benefit Election Form (if you are not retirement benefits eligible) is enclosed. Once you have reviewed and completed these forms and signed the Release, they should be returned in the self-addressed, return envelope provided along with a COBRA/ severance benefits premium payment check, ***if applicable*** (see COBRA).

If desired, you may overnight the documents, at your expense, to:

American Electric Power
Attn: HRSC Severance
33 Bullitt Ave SW
Roanoke, VA 24011-2404

Your lump-sum severance allowance will be issued, not earlier than eight days, nor later than 45 days, after receipt of your signed release. Applicable taxes (federal at the flat supplemental withholding rate, state, local and FICA) will be withheld at required levels.

Payment will be made by the same method you were receiving your regular pay check. If you were receiving your pay via Direct Deposit, your "Balance" Direct Deposit account should remain open until your severance allowance is paid in full. A direct deposit statement will be sent to your mailing address on file. If you were receiving your pay via check, the check will be sent to your mailing address on file. If you elect not to sign the Release, you will not be eligible for the severance allowance.

Severance Medical and Dental Contribution Rate

Not Retirement-Benefits Eligible - COBRA

If you are not retirement-benefits eligible, by completing the Severance Benefit Election Form, you may elect to continue your AEP medical and dental coverage under COBRA, but at a reduced rate equal to the active employee rate for up to 18 months. You should send the initial payment along with your signed Release and Severance Benefit Election Form before you can be enrolled in the medical and/or dental coverage.

The check or money order for the first COBRA/severance benefits premium payment should be payable to **American Electric Power** and mailed to:

American Electric Power
Attn: HR Service Center - COBRA
PO Box 2021
Roanoke, VA 24022-2121

If desired, you may overnight the payment to:

American Electric Power
Attn: HR Service Center - COBRA
33 Bullitt Ave SW
Roanoke, VA 24011-2404

Retirement-Benefits Eligible

If you are retirement-benefits eligible (i.e., age 55 or older with at least 10 years of AEP service at termination), by completing the benefit election form provided to you in your retirement packet, as well as your signed Severance and Release of All Claims Agreement, your AEP retiree medical and dental coverage will be continued at a reduced rate equal to the active employee rate for up to 18 months.

Electing Not to Sign the Severance Release Agreement (Release)

If you elect **not** to sign the Release, you will **not** be eligible for the severance allowance or severance benefits. If you are **not** retirement-benefits eligible, your medical and dental benefit options will be governed solely by the provisions of COBRA and subject to the full COBRA contribution rate of 102 percent. If you are retirement-benefits eligible, your medical and dental benefit options will be provided in accordance with the terms of the applicable benefit plans at the applicable retiree rate.

General Severance Benefits

If you are entitled to benefits under the AEP Severance Plan, your initial COBRA rate (or initial retiree contribution rate, if you are retirement-benefits eligible) shall be the contribution rate then charged by the AEP System Companies to similarly situated active employees/dependents, as adjusted from time to time. **This reduced rate for medical and dental coverage shall cease, however, at such time as you (or your surviving covered dependent(s) are *eligible for medical coverage* either through Medicare or some other public program or through subsequent employment, whichever comes first, whether or not you or your dependent(s) actually enroll for such medical coverage.** Since the benefit through the severance plan is merely a reduced rate for coverage, however, your eligibility for (but not enrolling in) this other coverage will not end the availability of your coverage through AEP. That may be continued until you experience a COBRA termination event (including if you would enroll in another group health plan that does not have a preexisting condition exclusion that applies to you) or an event that would end your retiree coverage (such as, if you ever waive your dental coverage, you will not be able to elect it at a later date). However, your cost for the continued medical and/or dental coverage would be at the full COBRA contribution rate of 102 percent or the applicable retiree contribution rate, if you are retirement-benefits eligible.

If you and your dependent(s) continue to be covered under COBRA medical, retiree medical or extended medical coverage provided by the AEP Severance Plan (points-based contribution rate available if you are at least age 50 with 10 years of service at termination, as described below), prescription drug and managed behavioral health benefits remain available. Access to the employee assistance plan (EAP), whether enrolled in a medical plan or not, ends at the end of the 18-month COBRA period.

If coverage has **not** ended sooner, your reduced rate for medical and dental coverage will terminate at the end of the 18 months <u>unless on your date of termination</u> you were:

- Retirement-benefits eligible (i.e., age 55 or older with at least 10 years of AEP service), or
- At least age 50 with 10 years of service.

If you are at least age 50 with at least 10 years of AEP service, you may continue medical coverage. Your contribution rate will be points-based which is determined by your age and years of service as of the date your employment ends. This **coverage may continue until you (or your surviving covered dependent(s) become eligible for medical coverage either through Medicare or some other public program, or through subsequent employment, or remarriage if a surviving spouse, whichever occurs first and whether or not you or your dependent(s) enrolls for such medical coverage.**

Educational Assistance

You will have no liability for repayment of previously paid educational assistance benefits. If you have completed your degree prior to ending employment, the three year waiting period for the additional 25% reimbursement is waived. The maximum payment of $5,250 applies.

Severance Related Outplacement Services

Outplacement service is available at AEP's expense through an AEP-contracted vendor to assist with career transitioning. This program is designed to prepare you to conduct an effective search for new employment and to help you assess, implement and manage your transition.

Any Questions, Contact

Should you have any questions about the content within this guide or need human resources assistance, contact the:

AEP HR Service Center
PO Box 2021
Roanoke, VA 24022-2121
Toll-Free Telephone: 1-888-237-2363

or if your question is related to Executive Benefits, contact:

AEP Executive Benefits
1 Riverside Plaza, 15th Floor
Columbus, OH 43215-2373
Telephone: 614-716-3417

Kentucky Power Company

REQUEST

Plant Held for Future Use ("PHFU"). Provide for each year 2009 through 2012, 2013 year-to-date and the test year a summary of all PHFU showing a description of the property, the date acquired, the date included in PHFU, the proposed site use and a date for any proposed plant to be constructed and put in service. Property Taxes. For each taxing district, please provide the data that tax bills are sent and when they are paid.

RESPONSE

Please see AG 1-40, Attachment 1 for the PHFU summary.

Please see AG 1-40, Attachment 2 for the requested property tax information.

WITNESS: Lila P Munsey

Kentucky Power Company
Account 1050001
Balance as of December, 2009

Company	Asset Location	Utility Account	Amount	Proposed Use Date	Date Acquired	Included In GL 105	Description
Kentucky Power - Gen	Carrs Site : KEP : 8500	31000 - Land - Coal Fired	6,778,355.00	unknown	1982	1982	Lewis County, KY - 4543.692 Acres
Kentucky Power - Transm	New Coalton 138KV Substation Site : KEP : 1117	35000 - Land	30,592.00	unknown	1982	1982	Boyd County, KY - 10.1 Acres
Kentucky Power - Distr	Ramey Substation : KEP : 4205	36000 - Land	627,603.73	2015	2008	2008	Boyd County, KY - 18.883 Acres
			7,436,550.73				

Kentucky Power Company
Account 1050001
Balance as of December, 2010

Company	Asset Location	Utility Account	Amount	Proposed Use Date	Date Acquired	Included In GL 105	Description
Kentucky Power - Gen	Carrs Site : KEP : 8500	31000 - Land - Coal Fired	6,778,355.00	unknown	1982	1982	Lewis County, KY - 4543.692 Acres
Kentucky Power - Transm	New Coalton 138KV Substation Site : KEP : 1117	35000 - Land	30,592.00	unknown	1982	1982	Boyd County, KY - 10.1 Acres
Kentucky Power - Distr	Ramey Substation : KEP : 4205	36000 - Land	627,603.73	2015	2008	2008	Boyd County, KY - 18.883 Acres
			7,436,550.73				

Kentucky Power Company
Account 1050001
Balance as of December, 2011

Company	Asset Location	Utility Account	Amount	Proposed Use Date	Date Acquired	Included in GL 105	Description
Kentucky Power - Gen	Carrs Site : KEP : 8500	31000 - Land - Coal Fired	6,778,355.00	unknown	1982	1982	Lewis County, KY - 4543.692 Acres
Kentucky Power - Transm	New Coalton 138KV Substation Site : KEP : 1117	35000 - Land	30,592.00	unknown	1982	1982	Boyd County, KY - 10.1 Acres
Kentucky Power - Distr	Ramey Substation : KEP : 4205	36000 - Land	627,603.73	2015	2008	2008	Boyd County, KY - 18.883 Acres
			7,436,550.73				

Kentucky Power Company
Account 1050001
Balance as of December, 2012

Company	Asset Location	Utility Account	Amount	Proposed Use Date	Date Acquired	Included in GL 105	Description
Kentucky Power - Gen	Carrs Site : KEP : 8500	31000 - Land - Coal Fired	6,778,355.00	unknown	1982	1982	Lewis County, KY - 4543.692 Acres
Kentucky Power - Transm	New Coalton 138KV Substation Site : KEP : 1117	35000 - Land	30,592.00	unknown	1982	1982	Boyd County, KY - 10.1 Acres
Kentucky Power - Distr	Ramey Substation : KEP : 4205	36000 - Land	627,603.73	2015	2008	2008	Boyd County, KY - 18.883 Acres
			7,436,550.73				

Kentucky Power Company
Account 1050001
Balance as of August, 2013

Company	Asset Location	Utility Account	Amount	Proposed Use Date	Date Acquired	Included In GL 105	Description
Kentucky Power - Gen	Carrs Site : KEP : 8500	31000 - Land - Coal Fired	6,778,355.00	unknown	1982	1982	Lewis County, KY - 4543.692 Acres
Kentucky Power - Transm	New Coalton 138KV Substation Site : KEP : 1117	35000 - Land	30,592.00	unknown	1982	1982	Boyd County, KY - 10.1 Acres
Kentucky Power - Distr	Ramey Substation : KEP : 4205	36000 - Land	627,603.73	2015	2008	2008	Boyd County, KY - 18.883 Acres
			7,436,550.73				

	Taxing District	Date Bill Received	Date Paid
2013 Stmt Year	KY-Boyd-Ashland ISD-Ashland	Not Yet Received	Not Yet Received
	KY-Lewis-Common SD	Not Yet Received	Not Yet Received
	KY-Boyd-Common SD-Cannonsburg FD	Not Yet Received	Not Yet Received
	KY-State	Not Yet Received	Not Yet Received
2012 Stmt Year	KY-Boyd-Ashland ISD-Ashland	11/27/2012	12/3/2012
	KY-Lewis-Common SD	11/27/2012	12/3/2012
	KY-Boyd-Common SD-Cannonsburg FD	11/27/2012	12/3/2012
	KY-State	8/23/2012	10/3/2012
2011 Stmt Year	KY-Boyd-Ashland ISD-Ashland	2/19/2013	3/4/2013
	KY-Lewis-Common SD	12/14/2011	1/2/2012
	KY-Boyd-Common SD-Cannonsburg FD	12/14/2011	1/2/2012
	KY-State	9/29/2011	10/27/2011
2010 Stmt Year	KY-Boyd-Ashland ISD-Ashland	4/13/2011	5/9/2011
	KY-Lewis-Common SD	3/24/2011	4/4/2011
	KY-Boyd-Common SD-Cannonsburg FD	3/24/2011	4/4/2011
	KY-State (protested notice)	9/20/2010	10/21/2010
	KY-State (final settled notice)	1/25/2011	1/29/2011
2009 Stmt Year	KY-Boyd-Ashland ISD-Ashland	1/20/2010	2/1/2010
	KY-Lewis-Common SD	11/30/2009	12/23/2009
	KY-Boyd-Common SD-Cannonsburg FD	11/30/2009	12/23/2009
	KY-State (protested notice)	8/31/2009	10/9/2009
	KY-State (final settled notice)	6/4/2010	6/5/2010

(Note: There is no set date for when bills are sent. The state bill is due 45 days after bill notification, local bills are due 30 days after the bill date)

Kentucky Power Company

REQUEST

Property Taxes. For each taxing district, for any given year, please indicate whether taxes are based on actual plant in service or whether it is based on an assessed value.

a. If the Company is taxed based on an assessed value, please indicate when the assessment is made relative to when the tax bill is issued (i.e. if tax bills are sent June 1, on what date is the assessment based on).

b. Property Taxes. Assume that new plant in service was placed into service on January 1, 2012 at a cost of $1,000,000: for each taxing district, please provide the tax rate per thousand dollars and provide a calculation of how much tax the Company would have to pay, the date that the tax bill would be sent and the date the payment would be due.

c. Property Taxes. Provide on a monthly basis the company's property taxes for the period 2009 through 2013 year-to-date and the test year.

RESPONSE

a. The Company is taxed based on an assessed value from the Kentucky Office of Property Valuation, Department of Revenue. The assessment has no specific date and is determined by the date the Dept. of Revenue sends their initial Notice of Assessment. The Company then has 45 days to either accept that value or contact the Department to reach a settlement. Normally, the settlement is reached in the fall of the same year that the tax return was filed. Once settled, the Department of Revenue issues a final Notice of Assessment, which includes the state portion of the tax bill. This bill is due 45 days after the date of the Notice of Assessment. When the final Notice of Assessment is issued, the Department of Revenue also issues the Certificate of Property Assessment to the counties so that they can issue their local tax bills to the Company. The local taxing authorities can issue their tax bills any time after that, with no set schedule, the Company may receive local tax bills from shortly after the state Final Notice until up to two to three years later. Once received, the Company has 30 days from the date of the bill to pay it.

b. Awaiting further information from the Attorney General.

c. Please see AG 1-41 Attachment 1.

WITNESS: Lila P Munsey

KPCO KY Property Tax Expense - 408 accounts

All States

Period: 2009-2013YTD

Sum of Act $		
Year	Month	Monthly Expense
2009	Jan	$724,420
	Feb	$724,420
	Mar	$724,420
	Apr	$554,221
	May	$753,865
	Jun	$753,846
	Jul	$753,846
	Aug	$753,846
	Sep	$754,717
	Oct	$767,019
	Nov	$754,043
	Dec	$753,855
2009 Total		$8,772,518
2010	Jan	$759,929
	Feb	$759,902
	Mar	$761,790
	Apr	$759,902
	May	$759,902
	Jun	$759,902
	Jul	$759,903
	Aug	$759,902
	Sep	-$718,857
	Oct	$759,902
	Nov	$760,100
	Dec	$759,878
2010 Total		$7,642,154
2011	Jan	$665,519
	Feb	-$80,611
	Mar	$707,570
	Apr	$707,584
	May	$707,570
	Jun	$732,360
	Jul	$707,570
	Aug	$998,177
	Sep	$649,851
	Oct	$1,584,110
	Nov	$795,377
	Dec	$785,871
2011 Total		$8,960,947

2012	Jan	$806,109	
	Feb	$741,170	
	Mar	$803,970	
	Apr	$803,970	Test Year
	May	$803,970	
	Jun	$803,970	
	Jul	$803,970	
	Aug	$803,970	
	Sep	$776,850	
	Oct	$803,970	
	Nov	$705,596	
	Dec	$699,603	
2012 Total		$9,357,118	
2013	Jan	$832,178	
	Feb	$832,789	
	Mar	$831,978	$9,502,813
	Apr	$869,219	
	May	$831,978	
	Jun	$821,934	
	Jul	$571,593	
	Aug	$1,122,713	
2013 Total		$6,714,381	
Grand Total		$41,447,118	

Kentucky Power Company

REQUEST

Rental Income. Please provide annual rental income for each year 2010 through 2012, 2013 year-to-date and the test year.

RESPONSE

Rental income for each year 2010 through 2012, plus 2013 year-to-date and the test year are as follows:

2010 = $4,603,988.21
2011 = $5,246,624.19
2012 = $7,006,536.71
2013 YTD = $4,456,779.98
Test Year = $7,037,976.65

WITNESS: Lila P Munsey

Kentucky Power Company

REQUEST

Research and Development. Identify the amount of research and development expense recorded during the test year and identify the account charged for each project. Provide a description of the project and any and all associated cost/benefit analysis. Also, identify whether the project is recurring in nature.

RESPONSE

The research and development expense for the test year was recorded in account 9302004 in the amount of $3,031.05. All associated expense was an allocation of general R&D and not project specific.

WITNESS: Lila P Munsey

Kentucky Power Company

REQUEST

Reserve Accounts. Provide the monthly balances in each reserve account (e.g., injuries and damages reserve account) for each year 2010 through 2012, 2013 year-to-date and the test year. This listing should include the monthly debits and credits to the reserve accounts.

RESPONSE

See AG 1-44 Attachment 1 for the total company reserve provisions recorded in account 228 for Kentucky Power Company for the years requested including the test year by month showing debits and credits.

WITNESS: Thomas E Mitchell

Sum of Sum Amount		Year Dr Cr													
		2 010			2,010 Total	2,011		2,011 Total	2,012		2,012 Total	2,013		2,013 Total	Grand Total
Account	Period	Beginning Balance	Cr	Dr		Cr	Dr		Cr	Dr		Cr.	Dr		
2282003	0	(61 505 76)			(61 505 76)										(61 505 76)
	1		(114 271.97)	117,853 42	3 581 45	(853 47)	5 644.17	4,790 70	(5 686 29)	0 00	(5 686 29)	(49 715 11)	0 00	(49 715 11)	(47 029 25)
	2		(33 996 12)	44,036.70	10 040 58	(561 83)	2,816 60	2,254 77		51,801.51	51 801.51		1,558.34	1,558.34	65 655.20
	3		(75 687.35)	73,114.18	(2 573 17)		4 870 30	4,870 30		27,100 54	27,100 54		2,636.39	2,636 39	32,034 06
	4		(72.078 79)	69,872.68	(2.206 11)	(7,298 68)	36 72	(7.261 96)	(708 72)	1,679 15	970 43	(129,207 27)	0 00	(129.207 27)	(137,704 91)
	5		(23 300 67)	26,416.12	3,115.25	(474 67)	26 62	(448 05)		1,012.78	1,012.78		9 308 48	9,308 48	12,988 46
	6		(40 769 57)	38,020 00	(2.749 57)	(6 572 08)	0 00	(6 572 08)	(24 498 93)	0 00	(24 498 93)	(14 729 31)	9 060 60	(5 668 71)	(39 489 27)
	7		(34 428 25)	33,467 45	(960 80)	(14 049 99)	5 080 36	(8 969 63)		2,023 44	2,023 44				(7 926 99)
	8		(10 834 85)	15,950 05	5 115.20	(26 792.16)	3 678.70	(23,113 46)	(112 86)	6,146.86	6 034 00				(11 954 26)
	9		(93 793 25)	83,091.54	(10 701 71)	(3 732 37)	33,828.33	30,095.96		3,381.31	3,381.31				22,775.56
	10		(7 914 85)	11,005 40	3 090 55	(16 489 36)	7,854.27	(8 635 09)		2,605 88	2,605.88				(2 938 66)
	11		(19 596 72)	21,956 80	2,359 88	(42,116 79)	1,750.19	(40 366 60)		5 383 16	5,383.16				(32 623 56)
	12		(11 253 05)	14 559 59	3 306 54	(5 051 43)	0 00	(5 051 43)		1,605 54	1,605 54				(139 35)
2282003 Total		(61 505 76)	(537 925 64)	549 343 73	(50 087 67)	(123 992 81)	65,566 26	(58 426 55)	(31 006 80)	102,740 17	71,733 37	(193 651 69)	22 563 81	(171 087 88)	(207 868 73)
2283000	0	(128 472.79)			(128 472.79)										(128 472 79)
	1		(166 67)		(166 67)	(83 33)		(83 33)	(83 33)		(83 33)				(333 33)
	2		(166 67)		(166 67)	(83 33)		(83 33)	(83 33)		(83 33)				(333 33)
	3		(86 61)	161.56	74 95				(60 33)	46 49	(13 84)	(973 74)		(973 74)	(912 63)
	4		(86 13)		(86 13)	(166 66)		(166 66)	(60 16)		(60 16)	(324 58)		(324 58)	(637 53)
	5		(86 13)		(86 13)	(83 33)		(83 33)	(60 16)		(60 16)	(324 58)		(324 58)	(554.20)
	6		(86 13)		(86 13)	(83 33)		(83 33)	(60 16)		(60 16)	(324 58)		(324 58)	(554 20)
	7		(86 13)		(86 13)	(83 33)		(83 33)	(60 16)		(60 16)				(229 62)
	8		(86 13)		(86 13)	(83 33)		(83 33)	(60 16)		(60 16)				(229 62)
	9		(86 13)		(86 13)	(83 33)		(83 33)	(60 16)		(60 16)				(229 62)
	10		(86 13)		(86 13)	(83 33)		(83 33)	(60 16)		(60 16)				(229 62)
	11		(86 13)		(86 13)	(83 33)		(83 33)	(60 16)		(60 16)				(229 62)
	12		(86 13)		(86 13)	(83 33)		(83 33)	(60 16)		(60 16)				(229 62)
2283000 Total		(128 472 79)	(1 195 12)	161 56	(129 506 35)	(999 96)		(999 96)	(768 43)	46 49	(721 94)	(1 947 48)		(1 947 48)	(133 175 73)
2283001	0	0 00			0 00										0 00
2283001 Total		0 00			0 00										0 00
2283002	0	(638 495 23)			(638 495.23)										(638 495 23)
	2						88,982.44	88 982.44		71,129.26	71,129.26		70,314 81	78,314 81	216,426 51
	3		(17,256 34)		(17,256 34)	(26 346 43)		(26 346 43)	(19 887 48)		(19 887 48)	(18 550 04)		(18 550 04)	(80 040 29)
	4		(129 37)		(129 37)										(129 37)
	5		(3 503 08)		(3 503 08)										(3 503 08)
	6		(3,751.22)	32,577.91	28,826.69	(10 512.67)		(10 512 67)		3,019 44	3 019 44		935 88	935 88	22,269 14
	7		(10 097 92)		(10 097 92)		113,478 54	113,478 54							103,380 62
	8		(2,918 08)		(2,918 08)										(2 918 08)
	9		(53 744 34)	35,310.40	(18 433 94)		158,722.56	158,722.55	(13,753 92)	43,605.15	29,852.23				168,140 84
	11		(2,308 56)		(2,308 56)										(2 308 56)
	12		(38 639 25)		(38 639 25)	(22 272 55)		(22 272 55)	(3 699 31)		(3 699 31)				(64 811 11)
2283002 Total		(638 495 23)	(132 346 16)	67,888 31	(702 953 08)	(59 131 65)	337,183 53	278 051 88	(37 340 71)	117,754 85	80 414 14	(16 550 04)	79,250 49	62,700 45	(281 786 61)
2283003	0	(5 007,379 01)			(5 007 379 01)										(5 007,379 01)
	1		(281,361 41)	228,157.00	(53,204 41)	(278,903 17)	237,997 13	(40 906 04)	(134 580 49)	254,634 00	120,053.51	(120,208 42)		(120,208 42)	(94,265 36)
	2		(281 361 41)	228,157 00	(53,204 41)	(461 899 33)	453,363.17	(8,535 16)	(134 580 49)	254,634 00	120 053.51		353,272 08	353,272 08	411,586 02
	3		(283 149 16)	344,545.57	81,396 39	(198 955 67)	238,447 01	39 491.34	(120,208 42)	530,122.68	409 914.26		142,009 87	142,009 87	852,811.86
	4		(278 903 17)	435,983 37	157,080.20	(198 955 67)	451,265.21	252,309 54	(120,208 42)	136,781.00	16,572.58		148,322.25	148,322.25	574,284.57
	5		(278 903 17)	189,716 00	(89 187 17)	(198 955 67)	11,382.00	(187 573 67)	(120 208 42)	136,781.00	16,572.58		125,024 51	125,024.51	(135 163 75)
	6		(278 903.17)	189,716 00	(89 187 17)	(282,492 80)	112,873 00	(149 619 80)	(120,208 42)	136,781.00	16,572.58		125,024 51	125 024.51	(97,209 88)
	7		(278 903 17)	189,716.00	(89 187 17)	(198 955 67)	214,364.00	15 408.33	(120,208 42)	136,781.00	16 572.58				(57,206 26)
	8		(278 903 17)	189,716 00	(89 187 17)	(198 955 67)	11,382.00	(187,573 67)	(120,208 42)	136,781.00	16,572.58				(260 188 26)
	9		(278 903 17)	189 716 00	(89 187 17)	(198 955 67)	112,873 00	(86 082 67)	(120 208 42)	136,781.00	16 572.58				(158 697.26)
	10		(278 903 17)	188,716 00	(89 187 17)	(198 955 67)	214,364 00	15,408.33	(120 208 42)	136,781.00	16 572.58				(57,206 26)
	11		(278 903.17)	189 716.00	(89 187 17)	(198 955 67)	112,873 00	(86 082 67)	(120 208 42)	136,781 00	16,572.58				(158 897 26)
	12		(278 903 17)	189 718 00	(89 187 17)	(198 955 67)	11,382.00	(187 573 67)	(120 208 42)	136,781 00	18 572 58				(260 188 26)
2283003 Total		(5 007 379 01)	(3 356 000 53)	2,754 570 94	(5 608 808 60)	(2,793 895 33)	2,182,565 52	(611 329 81)	(1 471 245 18)	2,270,419 68	799,174 50	(120 208 42)	893 653 22	773 444 80	(4 647 519 11)
2283005	0	(6 098 839 39)			(6 098 839 39)										(6 098 839 39)
	2									354,004 00	354,004 00				354,004.00
	3		(145 099 27)	1,061,035 04	915,935.77				(522 931 31)	284,769 69	(238 161 62)	(2,273 988 81)	767,896.00	(1 506 092 81)	(829 318 46)
	4					(812,016 15)	1,673,489 39	861,473.24				(38 787 67)		(38 787 67)	822,686 37
	5											(38 787 67)		(38,787 67)	(38,787 67)
	6											(38 787 67)		(38 787 87)	(38 787 87)
2283005 Total		(6 098 839 39)	(145 099 27)	1 061 035 04	(5 182 903 62)	(812 016 15)	1,673,489 39	861 473 24	(522 931 31)	638,773 69	115 842.38	(2 390 352 22)	767,896 00	(1 622 456 22)	(5 829 044 22)
2283006	0	0 00			0.00										0 00
	1		(297,405 00)	297,405.00	0.00				(255 500 00)		(255 500 00)	(356 918 67)		(356,918 67)	(612,416 67)
	2					(526,333 34)		(526 333 34)	(255 500 00)		(255 500 00)	(356,918 67)		(356 918 67)	(1 138 750 01)
	3			143,314.20	143,314.20	(197,166 67)		(197,166 67)	(300,235.28)		(300.235.28)	(300 645 91)		(300 645 91)	(654 733 66)
	4					(241,166 67)		(241 166 67)	(270 411 76)		(270 411 76)	(338 159 75)		(338 159 75)	(849 738 16)
	5						870,833.33	870,833.33	(270,411 76)		(270,411 76)	(338 159 75)		(338 159 75)	262,261 82
	6			143,314.20	143,314.20	(241,166 67)		(241,166 67)	(270 411 76)		(270 411 76)	(338 159 75)		(338 159 75)	(708 423 95)
	7						1,145,833.33	1,145 833.33	(270 411 76)		(270 411 76)				875,421.57
	8					(241,166 67)		(241 166 67)	(270 411 76)		(270 411 76)				(511 578 43)
	9			2,758,352.20	2,758,352.20	(241,166 67)		(241,166 67)		1,570,588.24	1,570,588.24				4,087,773.77
	10					(241,166 67)		(241,166 67)	(270 411 76)		(270 411 76)				(511 578 43)
	11						7,794,833.33	7,794 833.33	(270 411 76)		(270 411 76)				7,524,421.57
	12		(3 044 990 60)		(3 044 990 60)	(7 892,166 63)		(7 892,166 63)		1,133,529 36	1,133 529 36				(9 793 617 87)
2283006 Total		0 00	(3 342 385 60)	3 342,385 60	0 00	(9 811,499 99)	9 811,499 99	0.00	(2 704 117 60)	2,704,117 60	0 00	(2 028 958 50)		(2 028 958 50)	(2 028 958 50)
2283007	0	(674 441 30)			(674 441.30)										(674 441 30)
	1		(63 524 11)	10,200 00	(53 324 11)	(158 006 53)		(158 006 53)	(267 648 23)		(267 648 23)	(158,133 29)	83,655.15	(64,478 14)	(541,457 01)
	2		(58 400 00)	154,531 69	96,131 69	(5 650 04)	126 349 69	120 699 65	(16 620 00)	361,474.83	344 854.63	(114 817 67)	398,957 38	284,139 71	845 825 68
	3		(19 300 11)	108,231.77	88,931.66	(21,950 06)	251,386 11	229 436 05		134,564 05	134,564 05	(187,140 08)	106,805.21	(80 334 87)	372,596 89
	4		(123 831.81)	10,700 00	(113,131 81)	(169,439 12)	15 500 00	(153 939 12)	(82,864 05)		(82,864 05)	(118,385 21)	9 59	(118 375 62)	(468 310 60)
	5		(3 000 00)	6.63	(2,991.37)		8,760 01	8 760 01	(3 920 00)		(3 920 00)	(34 500 00)	14.06	(34 485 94)	(32,637 30)
	6		(29 568 00)	119 885.32	90,117.32	(90,220 00)	177 581 15	87,361 15	(13 500 00)	76,044 90	62,544.90	(6 110 09)	162,852.81	156,742.72	396,766 09
	7		(100,185.30)	13 800 00	(86 385 30)	(220 781 15)	31,590.00	(189,191 15)	(81,844 90)		(81 844 90)				(357,421.35)
	8		(45 600 11)		(45 600 11)	(10 300 00)		(10,300 00)	(24 840 00)		(24 840 00)				(80 740 11)
	9		(29 100.21)	108,495 06	79,394.85	(96 920 00)	214,416.70	117,496.70	(148 600 00)	161,140 34	12,540.34				209,431.89
	10		(112,995 14)		(112,995 14)	(306 176 70)	70 160 00	(236 016 70)	(166,380 34)	7,770 00	(158 610 34)				(507 822 16)
	11		(10,200 12)		(10,200 12)		10,460.00	10,460 00	(7,440 07)		(7 440 07)				(7,180 19)
	12			139 758.23	139 758 23	(28 610 00)	257,128 23	228 518.23	(7,370 06)	158 133 29	150 763.23				519 039 69
2283007 Total		(674 441 30)	(595,704 91)	665,410 70	(604 735 51)	(1,106 053 60)	1 163,331 89	57,278 29	(621 027 65)	899,127.21	78 099 56	(619 086 34)	762,294 20	143 207 86	(325 149 80)
2283013	0	(222,622 74)			(222,622.74)										(222,622 74)
	2		(91,722 06)		(91,722 06)										(91,722 06)
	3		(4 012 08)		(4 012 08)	(2 411 61)		(2,411 61)	(2,980 01)		(2,980 01)	(912 34)		(912 34)	(10 316.24)
	6		(5 515 79)		(5 515 79)	(5 394 24)		(5,394.24)		65,417 42	65,417.42		73,016 60	73,016 60	127,523.99
	7			10,299 69	10,299 69		65 468.10	65,468.10		68,958 02	68,958 02				144,725.81
	9		(7 770 84)	1,008 69	(6,781 95)	(4 078 57)		(4 078 57)	(72,275 62)		(72,275 62)				(83 118 14)
	12			600 49	600 49	(3 360 50)		(3 360 50)	(935 85)		(935 85)				(3 495 89)
2283013 Total		(222 622 74)	(109 020 77)	12,109 07	(319 534 44)	(15 245 12)	65,468 10	50 222 98	(78,191 51)	134,375 44	58 183 93	(912 34)	73 016 60	72,104 26	(139 023 27)
2283015	0	121,511 00			121 511.00										121,511.00
	3			359 00	359 00		345.25	345.25		349.50	349.50		196.50	196.50	1,250.25
	6			359 00	359 00		345.25	345.25		349.50	349.50		196.50	196 50	1,250.25
	9			359 00	359 00		345.25	345.25		349 50	349.50				1,053.75
	12		(122 653 00)	129,571 00	6 918 00	(130 541 75)	130 506 00	(35 75)	(131 554 50)	130 794 00	(760 50)				6,121 75
2283015 Total		121,511 00	(122 653 00)	130,648 00	129 506 00	(130,541 75)	131,541 75	1 000 00	(131 554 50)	131 642 50	288 00		393 00	393 00	131,187 00
2283016	0	(26,866 928 84)			(26 866 928 84)										(26 866 928 84)
	3			550,097.00	550,097.00		774,963 50	774,963 50		940,001 75	940,001 75		1,127,904.25	1,127,904.25	3,392,966.50
	6			550 097 00	550,097.00		774,963.50	774,963 50		940,001.75	940,001.75		1,127,904 25	1,127,904.25	3,392,966.50
	9			550,097 00	550,097 00		774,963.50	774,963.50		940,001 75	940 001 75				2,265,062.25
	12		(24 925 930 04)	25 218 637 84	290 707 80	(45 804 29)	1,905,122.75	1,859 318 46	(2 405 740 37)		(2,405 740 37)				(255 714 11)
2283016 Total		(26 866 928 84)	(24 925 930 04)	26 866 928 84	(24 925 930 04)	(45 804 29)	4 230,013.25	4,184,208 96	(2,405 740 37)	2 820,005 25	414 264 88		2 255 808 50	2 255 808 50	(18 071 647 70)
2283017	0	(15,266 079 00)			(15,266 079 00)										(15,266 079 00)
	3			304,957 00	304,957.00		179,125.50	179,125.50		265,713.51	265,713 51	(84 217.25)		(84,217 25)	665,578 76
	6			304,957.00	304,957 00		179,125 50	179,125.50		265,713.51	265,713.51	(84,217.25)		(84,217 25)	665 578 76
	9			304,957.00	304,957.00		179,125.50	179,125 50		265,713.51	265,713.51				749,796 01
	12		(16 032 268 00)	14 351,206 00	(1 681 060 00)	(20 115 347 00)	15 494 891 50	(4 620 455 50)	(4 529 000 20)	19,316,206 47	14 789,206 27				8 487,890 77
2283017 Total		(15 266 079 00)	(16 032 268 00)	15 266 079 00	(16 032 268 00)	(20,115 347 00)	16 032,268 00	(4 083 079 00)	(4 529 000 20)	20 115 347 00	15 586,346 80	(168 434 50)		(168 434 50)	(4 697 434 70)
2283018	0	5,000,070 70			5,000 070 78										5 000 070 70
	1			61,354 60	61,354.60		79,578.56	79,578 56	(43 336 17)		(43 336 17)	(46 035 50)		(46 035 50)	71,559 49
	2			61,354 60	61,354 60	(79 578 56)	165 058 00	65,481 44	(43 336 17)		(43 336 17)	(41,198 50)		(41 198 50)	82,301.37
	3		(111,229 43)	80,023 47	(31,205 96)		82,529 00	82,529 00	(298,178 70)		(298 178 70)	(41 089 08)	5,055 84	(36 033 24)	(282 858 90)
	4		(246 267 37)	79,576 56	(166 690 61)	(272,428 96)	70 686.42	(201,742 54)	(46 035 50)		(46 035 50)	(291 624 62)		(291 624 62)	(708 093 47)
	5			79,576 56	79,576.56		70,686.42	70,686 42	(46 035 50)		(46 035 50)	(41 089 08)		(41 089 08)	63,138 40
	6			79,576 56	79,576.56		70,686.42	70 686 42	(46 035 50)		(46 035 50)	(41 089 08)		(41 089 08)	83,138 40
	7			79,576 56	79 576 56		70,686 42	70 686 42	(46 035 50)		(46 035 50)				104,227 48
	8			79,576 56	79,576.56		70,686 42	70,686 42	(46 035 50)		(46 035 50)				104,227.48
	9			79,576 56	79,576.56		70,686.42	70,686.42	(46 035 50)		(46 035 50)				104,227 48
	10			79 576 56	79,576 56		70 686 42	70,686 42	(46 035 50)		(46 035 50)				104,227 48
	11			79,576 56	79,576 56		70,686.42	70 686 42	(46 035 50)		(46 035 50)				104,227 48
	12			79 576 56	79 576 56		70 686 42	70 686 42	(46 035 50)		(46 035 50)				104,227 48
2283018 Total		5,000,070 70	(357,496 80)	958 921 71	5 601,495 61	(352 005 52)	963,341 34	611,335 62	(799 170 54)		(799 170 54)	(522,125 86)	5 055 84	(497,070 02)	4,918 590 87
Grand Total		(49,843,182 36)	(49 658 025 84)	51,875 482 50	(47 825 725 70)	(35 366 533 17)	36 856 269 02	1,289 735 85	(13 530 094 80)	29 934 549 88	16,404,455 08	(8 042 227 39)	4 859 931 68	(1,182 295 73)	(31 313 830 50)

Kentucky Power Company

REQUEST

Revenues. Provide by month for each year 2010 through 2012, 2013 year-to-date and the test year, the revenues from customers.

RESPONSE

Please see response to AG 1-21.

WITNESS: Lila P Munsey

Kentucky Power Company

REQUEST

Other Revenues. Please provide the amount of Other Revenues by revenue type for each year 2010 through 2012, 2013 year-to-date and the test year.

RESPONSE

Please see AG 1-46 Attachment 1.

WITNESS: Lila P Munsey

Kentucky Power Corp Consol
Comparative Income Statement
December 2010

Run Date: 01/11/2011 14:26

X_OPR_COS	Rpt ID: GLR2100V Layout: GLR2100V	TWELVE MONTHS ENDED	
KYP_CORP_CO	V2099-01-01 Acct: PRPT_ACCOUNT BU: GL_PRPT_CONS	2010	2009
4560007	Oth Elect Rev - DSM Program	2,095,824.30	1,202,405.43
4560012	Oth Elect Rev - Nonaffiliated	12,701.71	(33,624.07)
4560015	Other Electric Revenues - ABD	242,569.97	2,055,113.78
4560016	Financial Trading Rev-Unreal	(108,999.26)	73,279.76
4560041	Miscellaneous Revenue-NonAffil	0.00	0.66
4560049	Merch Generation Finan -Realzd	12.32	(92.72)
4560050	Oth Elec Rev-Coal Trd Rlzd G-L	2,063,983.19	939,752.43
4560109	Interest Rate Swaps-Coal	(3,362.30)	(1,685.97)
4560111	MTM Aff GL Coal Trading	108,999.26	(73,279.76)
4560112	Realized GL Coal Trading-Affil	(945,770.68)	(266,378.44)
4561002	RTO Formation Cost Recovery	13,645.20	15,334.37
4561003	PJM Expansion Cost Recov	76,867.40	77,237.61
4561004	SECA Transmission Rev	176,533.95	0.00
4561005	PJM Point to Point Trans Svc	898,167.71	878,293.15
4561006	PJM Trans Owner Admin Rev	190,068.93	155,753.95
4561007	PJM Network Integ Trans Svc	4,136,354.87	3,882,391.23
4561019	Oth Elec Rev Trans Non Affil	64,536.00	66,096.00
4561028	PJM Pow Fac Cre Rev Whsl Cu-NA	401.16	0.00
4561029	PJM NITS Revenue Whsl Cus-NAff	224,408.47	0.00
4561030	PJM TO Serv Rev Whls Cus-NAff	6,999.18	0.00
4561058	NonAffil PJM Trans Enhncmt Rev	25,636.47	0.00
NonAff	Other Electric Revenues - NonAffiliated	9,279,577.85	8,970,597.41
4561031	GFA Trans Base Rev Unb - Aff	61,832.38	0.00
4561032	GFA Trans Ancillary Rev - Aff	1,979.42	0.00
4561033	PJM NITS Revenue - Affiliated	4,812,028.04	0.00
4561034	PJM TO Adm. Serv Rev - Aff	0.00	0.00
4561035	PJM Affiliated Trans NITS Cost	(4,147,559.79)	0.00
4561036	PJM Affiliated Trans TO Cost	0.00	0.00
4561059	Affil PJM Trans Enhancmnt Rev	57,673.03	0.00
4561060	Affil PJM Trans Enhancmnt Cost	(48,892.00)	0.00
Aff	Other Electric Revenues - Affiliated	737,061.08	0.00
	Other Electric Revenues	**10,016,638.93**	**8,970,597.41**

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Comparative Income Statement
December 2012

Run Date: 01/24/2013 11:23

X_OPR_COS	Rpt ID: GLR2100V Layout: GLR2100V	TWELVE MONTHS ENDED 2012	2011
KYP_CORP_CO	V2099-01-01 Acct: PRPT_ACCOUNT BU: GL_PRPT_CONS		
4560007	Oth Elect Rev - DSM Program	3,101,791.99	3,416,706.00
4560012	Oth Elect Rev - Nonaffiliated	0.00	4,150.10
4560015	Other Electric Revenues - ABD	242,813.87	246,345.04
4560041	Miscellaneous Revenue-NonAffil	0.00	1,000.00
4560049	Merch Generation Finan -Realzd	16.66	15.63
4560050	Oth Elec Rev-Coal Trd Rlzd G-L	(54,112.21)	(15,706.34)
4560109	Interest Rate Swaps-Coal	(626.99)	(4,396.61)
4561002	RTO Formation Cost Recovery	10,475.10	2,406.40
4561003	PJM Expansion Cost Recov	85,013.65	78,428.46
4561004	SECA Transmission Rev	227,184.25	0.00
4561005	PJM Point to Point Trans Svc	696,676.28	736,101.15
4561006	PJM Trans Owner Admin Rev	235,655.56	231,337.60
4561007	PJM Network Integ Trans Svc	10,054,585.47	6,207,450.54
4561019	Oth Elec Rev Trans Non Affil	59,064.00	64,020.00
4561028	PJM Pow Fac Cre Rev Whsl Cu-NA	8,462.96	9,440.70
4561029	PJM NITS Revenue Whsl Cus-NAff	2,550,125.16	2,344,767.44
4561030	PJM TO Serv Rev Whls Cus-NAff	36,386.50	40,878.52
4561058	NonAffil PJM Trans Enhncmt Rev	163,819.73	145,599.11
4561061	NAff PJM RTEP Rev for Whsl-FR	16,752.59	18,463.38
4561064	PROVISION PJM NITS WhslCus-NAf	(13,451.27)	39,295.49
4561065	PROVISION PJM NITS	40,505.59	78,590.97
NonAff	Other Electric Revenues - NonAffiliated	17,461,138.89	13,644,893.58
4561033	PJM NITS Revenue - Affiliated	40,000,571.34	40,137,444.20
4561034	PJM TO Adm. Serv Rev - Aff	419,468.35	418,671.49
4561035	PJM Affiliated Trans NITS Cost	(37,302,112.29)	(35,803,217.99)
4561036	PJM Affiliated Trans TO Cost	(387,045.44)	(391,387.87)
4561059	Affil PJM Trans Enhancmnt Rev	262,916.98	314,244.84
4561060	Affil PJM Trans Enhancmnt Cost	(245,122.34)	(279,650.70)
4561062	PROVISION PJM NITS Affil- Cost	554,107.04	(583,890.79)
4561063	PROVISION PJM NITS Affiliated	(280,093.53)	668,023.25
Aff	Other Electric Revenues - Affiliated	3,022,690.11	4,480,236.43
	Other Electric Revenues	**20,483,829.00**	**18,125,130.01**

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Comparative Income Statement
March 2013

Run Date: 04/06/2013 15:38

X_OPR_COS KYP_CORP_CO	Rpt ID: GLR2100V Layout: GLR2100V V2099-01-01 Acct: PRPT_ACCOUNT BU: GL_PRPT_CONS	TWELVE MONTHS ENDED 2013
4560007	Oth Elect Rev - DSM Program	3,195,075.47
4560012	Oth Elect Rev - Nonaffiliated	0.00
4560015	Other Electric Revenues - ABD	194,278.65
4560041	Miscellaneous Revenue-NonAffil	0.00
4560049	Merch Generation Finan -Realzd	2.31
4560050	Oth Elec Rev-Coal Trd Rlzd G-L	(27,842.79)
4560109	Interest Rate Swaps-Coal	0.00
4561002	RTO Formation Cost Recovery	10,846.19
4561003	PJM Expansion Cost Recov	85,721.55
4561004	SECA Transmission Rev	227,184.25
4561005	PJM Point to Point Trans Svc	681,555.00
4561006	PJM Trans Owner Admin Rev	222,366.92
4561007	PJM Network Integ Trans Svc	10,770,831.41
4561019	Oth Elec Rev Trans Non Affil	59,931.00
4561028	PJM Pow Fac Cre Rev Whsl Cu-NA	10,190.28
4561029	PJM NITS Revenue Whsl Cus-NAff	2,451,238.16
4561030	PJM TO Serv Rev Whls Cus-NAff	34,654.97
4561058	NonAffil PJM Trans Enhncmt Rev	168,402.48
4561061	NAff PJM RTEP Rev for Whsl-FR	16,201.26
4561064	PROVISION PJM NITS WhslCus-NAf	(7,578.22)
4561065	PROVISION PJM NITS	24,782.19
NonAff	Other Electric Revenues - NonAffiliated	18,117,841.08
4561033	PJM NITS Revenue - Affiliated	38,147,624.09
4561034	PJM TO Adm. Serv Rev - Aff	502,696.43
4561035	PJM Affiliated Trans NITS Cost	(36,116,142.19)
4561036	PJM Affiliated Trans TO Cost	(470,070.18)
4561059	Affil PJM Trans Enhancmnt Rev	252,251.35
4561060	Affil PJM Trans Enhancmnt Cost	(238,880.48)
4561062	PROVISION PJM NITS Affil- Cost	266,198.32
4561063	PROVISION PJM NITS Affiliated	(143,723.57)
Aff	Other Electric Revenues - Affiliated	2,199,953.77
	Other Electric Revenues	**20,317,794.85**

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Comparative Income Statement
August 2013

Run Date: 09/10/2013 18:24

X_OPR_COS	Rpt ID: GLR2100V Layout: GLR2100V	YEAR TO DATE
KYP_CORP_CO	V2099-01-01 Acct: PRPT_ACCOUNT BU: GL_PRPT_CONS	2013
4560007	Oth Elect Rev - DSM Program	1,589,799.83
4560015	Other Electric Revenues - ABD	233,882.23
4560041	Miscellaneous Revenue-NonAffil	0.00
4560049	Merch Generation Finan -Realzd	(1.68)
4560050	Oth Elec Rev-Coal Trd Rlzd G-L	31,558.76
4560109	Interest Rate Swaps-Coal	0.00
4561002	RTO Formation Cost Recovery	2,740.17
4561003	PJM Expansion Cost Recov	55,381.47
4561004	SECA Transmission Rev	0.00
4561005	PJM Point to Point Trans Svc	404,541.83
4561006	PJM Trans Owner Admin Rev	141,082.48
4561007	PJM Network Integ Trans Svc	8,338,139.49
4561019	Oth Elec Rev Trans Non Affil	38,307.00
4561028	PJM Pow Fac Cre Rev Whsl Cu-NA	5,479.62
4561029	PJM NITS Revenue Whsl Cus-NAff	1,522,803.42
4561030	PJM TO Serv Rev Whls Cus-NAff	23,455.28
4561058	NonAffil PJM Trans Enhncmt Rev	143,667.62
4561061	NAff PJM RTEP Rev for Whsl-FR	11,172.43
4561064	PROVISION PJM NITS WhslCus-NAf	(13,969.35)
4561065	PROVISION PJM NITS	(52,418.07)
NonAff	Other Electric Revenues - NonAffiliated	12,475,622.53
4561033	PJM NITS Revenue - Affiliated	23,790,070.00
4561034	PJM TO Adm. Serv Rev - Aff	288,432.34
4561035	PJM Affiliated Trans NITS Cost	(23,284,656.22)
4561036	PJM Affiliated Trans TO Cost	(280,140.35)
4561059	Affil PJM Trans Enhancmnt Rev	174,428.87
4561060	Affil PJM Trans Enhancmnt Cost	(170,707.48)
4561062	PROVISION PJM NITS Affil- Cost	665,777.62
4561063	PROVISION PJM NITS Affiliated	(204,076.41)
Aff	Other Electric Revenues - Affiliated	979,128.37
	Other Electric Revenues	**13,454,750.90**

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Kentucky Power Company

REQUEST

Late Payment Revenues. Provide the annual actual late payment revenues for each year 2010 through 2012, 2013 year-to-date and the test year.

RESPONSE

Please see AG 1-48 Attachment 1. Late payment revenues are titled "forfeited discounts" and recorded in account 4500000.

WITNESS: Lila P Munsey

Kentucky Power Company

REQUEST

Miscellaneous Revenues. Provide the annual actual miscellaneous revenues for each year 2010 through 2012, 2013 year-to-date and the test year.

RESPONSE

Please see AG 1-48 Attachment 1.

WITNESS: Lila P Munsey

Kentucky Power Corp Consol
Comparative Income Statement
December 2010

Run Date: 01/11/2011 14:26

X_OPR_COS	Rpt ID: GLR2100V Layout: GLR2100V	TWELVE MONTHS ENDED	
KYP_CORP_CO	V2099-01-01 Acct: PRPT_ACCOUNT BU: GL_PRPT_CONS	2010	2009
4500000	Forfeited Discounts	1,873,780.51	1,780,497.80
4510001	Misc Service Rev - Nonaffil	376,680.64	398,912.50
NonAff	Miscellaneous Revenues - NonAffiliated	2,250,461.15	2,179,410.30
Aff	Miscellaneous Revenues - Affiliated	0.00	0.00
	Miscellaneous Revenues	**2,250,461.15**	**2,179,410.30**

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Kentucky Power Corp Consol
Comparative Income Statement
December 2012

Run Date: 01/24/2013 11:23

X_OPR_COS	Rpt ID: GLR2100V Layout: GLR2100V	TWELVE MONTHS ENDED	
KYP_CORP_CO	V2099-01-01 Acct: PRPT_ACCOUNT BU: GL_PRPT_CONS	**2012**	**2011**
4500000	Forfeited Discounts	3,268,232.89	2,221,318.73
4510001	Misc Service Rev - Nonaffil	353,912.38	432,633.80
NonAff	Miscellaneous Revenues - NonAffiliated	3,622,145.27	2,653,952.53
Aff	Miscellaneous Revenues - Affiliated	0.00	0.00
	Miscellaneous Revenues	**3,622,145.27**	**2,653,952.53**

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Kentucky Power Corp Consol
Comparative Income Statement
March 2013

Run Date: 04/06/2013 15:38

X_OPR_COS	Rpt ID: GLR2100V Layout: GLR2100V	TWELVE MONTHS ENDED
KYP_CORP_CO	V2099-01-01 Acct: PRPT_ACCOUNT BU: GL_PRPT_CONS	2013
4500000	Forfeited Discounts	3,262,936.47
4510001	Misc Service Rev - Nonaffil	358,930.74
NonAff	Miscellaneous Revenues - NonAffiliated	3,621,867.21
Aff	Miscellaneous Revenues - Affiliated	0.00
	Miscellaneous Revenues	**3,621,867.21**

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Kentucky Power Corp Consol
Comparative Income Statement
August 2013

Run Date: 09/10/2013 18:24

X_OPR_COS KYP_CORP_CO	Rpt ID: GLR2100V Layout: GLR2100V V2099-01-01 Acct: PRPT_ACCOUNT BU: GL_PRPT_CONS	YEAR TO DATE 2013
4500000	Forfeited Discounts	2,328,708.95
4510001	Misc Service Rev - Nonaffil	275,941.52
NonAff	Miscellaneous Revenues - NonAffiliated	2,604,650.47
Aff	Miscellaneous Revenues - Affiliated	0.00
	Miscellaneous Revenues	**2,604,650.47**

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Kentucky Power Company

REQUEST

Trial Balance. Provide the trial balances for the years ending December 31, 2010 through 2012 and 2013 year-to-date.

RESPONSE

Please see Attachments 1 through 4 to this response for the trial balances for the years ending December 31, 2010, 2011, 2012 and year to date 2013 in respective order.

WITNESS: Ranie K Wohnhas

KYP CORP CONSOLIDATED
Trial Balance
For The Month Ended DECEMBER 31, 2010

Account Number	Description	Pr Yr Ending Balance	Yearly Activity	Debits	Credit	Current Yr Balance
1010001	Plant in Service	1,536,588,920 96	73,538,902.05	73,538,902.05	0 00	1,610,127,823 01
1011001	Capital Leases	3,378,618.12	3,814,780.12	3,814,780.12	0.00	7,193,398 24
1011006	Prov-Leased Assets	(1,627,324.89)	(154,014.71)	0 00	(154,014.71)	(1,781,339.60)
1011012	Accrued Capital Leases	1,513 60	(957.94)	0 00	(957.94)	555.68
1050001	Held For Fut Use	7,436,550.73	0.00	0.00	0.00	7,436,550.73
1060001	Const Not Classifd	61,640,980.60	(39,619,071.57)	0.00	(39,619,071.57)	22,021,909.03
1070001	CWIP - Project	28,408,870.43	5,684,105.94	5,684,105.94	0.00	34,092,976.37
1080001	A/P for Deprec of Plt	(493,467,052.47)	(28,417,323.89)	0.00	(28,417,323.89)	(521,884,376.36)
1080005	RWIP - Project Detail	3,767,366.28	(2,887,525.82)	0.00	(2,887,525.82)	879,840.43
1080011	Cost of Removal Reserve	(26,544,599 60)	(3,467,123.33)	0.00	(3,467,123 33)	(30,011,722.93)
1080013	ARO Removal Deprec - Accretion	1,565,334.08	471,317.27	471,317.27	0.00	2,036,651.35
1110001	A/P for Amort of Plt	(17,291,094.09)	(2,170,816.65)	0.00	(2,170,816.65)	(19,461,910.74)
1210001	Nonutility Property - Owned	964,528.00	0.00	0.00	0.00	964,528.00
1220001	Depr&Amrt of Nonutl Prop-Ownd	(188,276 67)	(6,669.72)	0.00	(6,669.72)	(194,946.59)
1240002	Oth Investments-Nonassociated	806.00	0 00	0.00	0.00	806.00
1240005	Spec Allowance Inv NOx	156.35	(105.68)	0.00	(105.68)	50.67
1240007	Deferred Compensation Benefits	129,390.01	(8,580.73)	0.00	(8,580.73)	120,809.28
1240029	Other Property - CPR	4,533,569.90	201,405.73	201,405.73	0.00	4,734,975.63
1240044	Spec Allowances Inv SO2	5,189.40	(5,156.23)	0.00	(5,156.23)	33.17
1240050	Spec Allowance Inventory CO2	372.99	(372.99)	0 00	(372.99)	0 00
1240092	Fbr Opt Lns-In Kind Sv-Invest	176,281.21	(4,275.21)	0.00	(4,275.21)	172,006 00
1310000	Cash	488,717 91	(207,745.61)	0.00	(207,745.61)	280,972.30
1340018	Spec Deposits - Elect Trading	618,024 64	763,129.38	763,129.38	0.00	1,381,154 02
1340043	Spec Deposit UBS Securities	10,898,806.90	(5,301,866.28)	0.00	(5,301,866.28)	5,596,940.62
1340048	Spec Deposits-Trading Contra	(6,406,127.00)	3,031,545 00	3,031,545.00	0.00	(3,374,582.00)
1340050	Spec Deposit Mizuho Securities	814,201.01	939,539.24	939,539.24	0.00	1,753,740.25
1350002	Petty Cash	4,999.72	(4,999.72)	0.00	(4,999.72)	0.00
1420001	Customer A/R - Electric	27,684,774.14	9,829,099.47	9,829,099.47	0.00	37,513,873.61
1420005	Employee Loans - Current	348 60	(348.60)	0 00	(348 60)	0.00
1420014	Customer A/R-System Sales	571,942.26	93,826 67	93,826 67	0.00	665,768 93
1420019	Transmission Sales Receivable	9,036.00	7,668 00	7,668.00	0.00	16,704.00
1420022	Cust A/R - Factored	(24,943,544 66)	(10,502,737.73)	0.00	(10,502,737.73)	(35,446,282.39)
1420023	Cust A/R-System Sales - MLR	7,687,473.43	1,088,145.38	1,088,145.38	0.00	8,775,618 81
1420024	Cust A/R-Options & Swaps - MLR	462,470.81	(100,217.89)	0.00	(100,217.89)	362,252 92
1420027	Low Inc Energy Asst Pr (LIEAP)	948,303.00	(354,711.00)	0.00	(354,711.00)	593,592.00
1420044	Customer A/R - Estimated	648,202.00	5,284,440 00	5,284,440 00	0.00	5,932,642.00
1420050	PJM AR Accrual	0.00	0.00	0.00	0.00	0.00
1420052	Gas Accruals	0.00	4,022.19	4,022.19	0.00	4,022.19
1420053	AR Coal Trading	0 00	295,983.53	295,983.53	0.00	295,983.53
1420054	Accrued Power Brokers	0 00	214,289.54	214,289.54	0.00	214,289.54
1420102	AR Peoplesoft Billing - Cust	0.00	480,008.08	480,008.08	0.00	480,008 08
1430019	Coal Trading	325,656.03	(325,656 03)	0.00	(325,656.03)	0.00
1430022	2001 Employee Biweekly Pay Cnv	100,857.22	(26,754 57)	0.00	(26,754.57)	74,102 65
1430023	A/R PeopleSoft Billing System	1,865,052.09	(1,865,052.09)	0.00	(1,865,052.09)	0.00
1430081	Damage Recovery - Third Party	83,410.65	(47,797.65)	0 00	(47,797.65)	35,613 00
1430083	Damage Recovery Offset Demand	(92,404.65)	39,727.65	39,727.65	0 00	(52,677.00)
1430086	AR Accrual NYMEX OTC Penults	2,763.16	(2,763.16)	0.00	(2,763.16)	0.00
1430087	PJM AR Accrual	257,295.97	(257,295.97)	0.00	(257,295.97)	0.00
1430089	A/R - Benefits Billing	456 68	3,762.78	3,762.78	0.00	4,219.46
1430090	Accrued Broker - Power	278,507.72	(278,507.72)	0.00	(278,507.72)	0.00
1430101	Other Accounts Rec - Misc	0.00	16,977.38	16,977.38	0 00	16,977.38
1430102	AR Peoplesoft Billing - Misc	0.00	151,756.45	151,756.45	0.00	151,756.45
1430123	Accounts Receivable - LT	21,531.64	(21,531.64)	0 00	(21,531.64)	0.00
1440002	Uncoll Accts-Other Receivables	(22,676.54)	16,476.57	16,476.57	0.00	(6,199.97)
1440003	Uncoll Accts-Power Trading	(828,642.09)	211,561.66	211,561.66	0.00	(617,080.43)
1450000	Corp Borrow Prg (NR-Assoc)	0.00	67,059,742.87	67,059,742.87	0.00	67,059,742.87
1460001	A/R Assoc Co - InterUnit G/L	5,069,525 01	7,115,821.36	7,115,821.36	0 00	12,185,346 37
1460002	A/R Assoc Co - Allowances	0.00	1,898,460.49	1,898,460.49	0.00	1,898,460 49
1460006	A/R Assoc Co - Intercompany	542,450.89	(168,047.16)	0.00	(168,047.16)	378,403.73
1460009	A/R Assoc Co - InterUnit A/P	0.02	29,438.41	29,438.41	0.00	29,438.43
1460011	A/R Assoc Co - Multi Pmts	577,998.36	868,174 66	868,174.66	0.00	1,446,173 02
1460012	A/R Assoc Co - Transmissn Agmt	659,338 00	(659,338.00)	0.00	(659,338.00)	0 00
1460019	A/R-Assoc Co-AEPSC-Agent	833,808 62	(456,567.62)	0.00	(456,567.62)	377,241.00
1460024	A/R Assoc Co - System Sales	160,835.94	(130,514.49)	0.00	(130,514.49)	30,321.45
1460025	Fleet - M4 - A/R	22,592.75	(6,763.85)	0.00	(6,763.85)	15,828 90
1510001	Fuel Stock - Coal	34,327,550.77	(19,454,623.89)	0.00	(19,454,623.69)	14,872,926 88
1510002	Fuel Stock - Oil	639,780.39	18,490.88	18,490.88	0.00	658,271.27
1510020	Fuel Stock Coal - Intransit	547,553 30	267,831.40	267,831.40	0.00	815,384.70
1520000	Fuel Stock Exp Undistributed	652,947.63	(359,972.81)	0 00	(359,972.81)	292,974.82
1540001	M&S - Regular	10,099,972.28	608,041.49	608,041.49	0.00	10,708,013.77
1540004	M&S - Exempt Material	42,091.14	3,507.09	3,507.09	0.00	45,598.23
1540012	Materials & Supplies - Urea	186,731.99	100,339 69	100,339 69	0.00	287,071.68
1540013	Transportation Inventory	47,100.45	25,650.58	25,650.58	0.00	72,751.03
1540023	M&S Inv - Urea In-Transit	776,458.16	276,004.56	276,004.56	0.00	1,052,462.72
1581000	SO2 Allowance Inventory	5,997,049.57	(1,114,633.59)	0.00	(1,114,633.59)	4,882,415.98
1581003	SO2 Allowance Inventory - Curr	7,048,319.82	4,979,642.42	4,979,642.42	0.00	12,027,962.24
1581006	An. NOx Comp Inv - Curr	46,975.70	137,230.70	137,230.70	0 00	184,206.40
1650001	Prepaid Insurance	367,942.24	(20,872.64)	0.00	(20,872.64)	347,069 60
165000209	Prepaid Taxes	374,877.41	(374,877.41)	0.00	(374,877.41)	0.00
165000210	Prepaid Taxes	0.00	399,674.78	399,674.78	0 00	399,674.78
1650009	Prepaid Carry Cost-Factored AR	19,411.28	4,641.18	4,641.18	0.00	24,052.44

KYP CORP CONSOLIDATED
Trial Balance
For The Month Ended DECEMBER 31, 2010

Account Number	Description	Pr Yr Ending Balance	Yearly Activity	Debits	Credit	Current Yr Balance
1650010	Prepaid Pension Benefits	14,836,181.16	3,188,294.80	3,188,294.80	0 00	18,024,475.96
165001110	Prepaid Sales Taxes	0.00	339,691.13	339,691.13	0.00	339,691.13
165001209	Prepaid Sales/Use Taxes	340,189.38	(340,189.38)	0.00	(340,189.38)	0 00
165001210	Prepaid Use Taxes	0.00	30,787.79	30,787.79	0.00	30,787.79
1650014	FAS 158 Qual Contra Asset	(14,836,181.16)	(3,188,294 80)	0.00	(3,188,294.80)	(18,024,475.96)
1650021	Prepaid Insurance - EIS	179,434.74	73,904.75	73,904.75	0 00	253,339 49
1650023	Prepaid Lease	0.00	2,928.12	2,928.12	0.00	2,928.12
1710046	Interest Receivable -FIT -LT	(634,767.00)	634,767 00	634,767.00	0 00	0 00
1710248	Interest Receivable -FIT -ST	796,514.00	(451,672.00)	0.00	(451,672.00)	344,842.00
1710448	Interest Receivable. -SIT -ST	137,084 00	(124,698.00)	0.00	(124,698.00)	12,388.00
1720000	Rents Receivable	2,073,414.74	170,050.13	170,050.13	0.00	2,243,464.87
1730000	Accrued Utility Revenues	21,157,586.17	10,070,958.07	10,070,958.07	0 00	31,228,544.24
1730002	Acrd Utility Rev-Factored-Assc	(16,351,881.44)	(11,053,270.59)	0 00	(11,053,270.59)	(27,405,152.03)
1740000	Misc Current & Accrued Assets	0.00	8 22	8.22	0.00	8.22
1750001	Curr. Unreal Gains - NonAffil	13,290,912.23	(4,333,679 96)	0.00	(4,333,679.96)	8,957,232 27
1750002	Long-Term Unreal Gns - Non Aff	9,834,007.87	(1,770,784.13)	0 00	(1,770,784.13)	8,063,223 74
1750003	Curr. Unrealized Gains Affil	399,292.00	(399,292 00)	0.00	(399,292.00)	0.00
1750009	S/T Option Premium Purchases	2,821.25	(2,821.25)	0.00	(2,821.25)	0 00
1750021	S/T Asset MTM Collateral	(427,357.00)	88,357.00	88,357.00	0.00	(339,000.00)
1750022	L/T Asset MTM Collateral	(336,181.00)	300,164.00	300,164.00	0.00	(36,017.00)
1760010	S/T Asset for Commodity Hedges	421,541.00	(342,687.00)	0 00	(342,687.00)	78,854.00
1760011	L/T Asset for Commodity Hedges	0.00	2,466 00	2,466.00	0.00	2,466 00
1810006	Unamort Debt Exp - Sr Unsec Nt	3,118,664 03	(304,461.48)	0.00	(304,461.48)	2,814,202.55
1823007	SFAS 112 Postemployment Benef	7,076,606 39	(620,470.77)	0.00	(620,470.77)	6,456,335 62
1823009	DSM Incentives	991,571.00	252,977.00	252,977.00	0.00	1,244,548.00
1823010	DSM Recovery	(14,670,635.00)	(2,274,581 00)	0.00	(2,274,581.00)	(16,945,216.00)
1823011	DSM Lost Revenues	3,650,578.00	367,941.00	367,941.00	0 00	4,018,519.00
1823012	DSM Program Costs	10,297,990.00	1,410,665.00	1,410,665.00	0.00	11,708,655 00
1823022	HRJ 765kV Post Service AFUDC	765,864 00	(33,408.00)	0.00	(33,408 00)	732,456.00
1823054	HRJ 765kV Depreciation Expense	119,353 00	(5,208.00)	0 00	(5,208 00)	114,145.00
1823077	Unreal Loss on Fwd Commitments	0.00	93,036.27	93,036.27	0 00	93,036.27
1823078	Deferred Storm Expense	24,355,055.00	(3,212,057.00)	0 00	(3,212,057.00)	21,142,998 00
1823115	Defd Equity Carry Chg-Non Fuel	(174,968 65)	22,428.00	22,428.00	0.00	(152,540 65)
1823116	BridgeCo TO Funding	336,498.65	(22,002.54)	0.00	(22,002.54)	314,496.11
1823119	PJM Integration Payments	616,302.14	(105,875.01)	0.00	(105,875 01)	510,427.13
1823120	Other PJM Integration	355,510 08	(23,245.65)	0.00	(23,245.65)	332,264.43
1823121	Carry Chgs-RTO Startup Costs	228,575.41	(24,738.13)	0.00	(24,738.13)	203,837.28
1823122	Alliance RTO Deferred Expense	176,119.60	(11,515 89)	0 00	(11,515.89)	164,603.71
1823165	REG ASSET FAS 158 QUAL PLAN	41,703,110.00	1,247,296.00	1,247,296.00	0.00	42,950,406.00
1823166	REG ASSET FAS 158 OPEB PLAN	15,266,079 00	766,189 00	766,189.00	0.00	16,032,268.00
1823167	REG Asset FAS 158 SERP Plan	(121,317.00)	(8,189 00)	0.00	(8,189.00)	(129,506.00)
1823188	Deferred Carbon Mgmt Research	200,000 00	75,002.00	75,002.00	0.00	275,002 00
1823301	SFAS 109 Flow Thru Defd FIT	79,448,610.56	3,733,947.73	3,733,947.73	0.00	83,182,558.29
1823302	SFAS 109 Flow Thru Defrd SIT	36,824,251.00	5,407,797.27	5,407,797.27	0.00	42,232,048.27
1830000	Prelimin Surv&Investgtn Chrgs	21,315,585.94	358,041.83	358,041.83	0 00	21,673,627.77
1860001	Allowances	0 00	323.09	323.09	0.00	323.09
186000309	Deferred Property Taxes	9,323,500.00	(9,323,500 00)	0.00	(9,323,500.00)	0 00
186000310	Deferred Property Taxes	0.00	7,970,436.00	7,970,436.00	0.00	7,970,436.00
1860007	Billings and Deferred Projects	1,102,111.92	(1,029,962.75)	0.00	(1,029,962.75)	72,149.17
1860077	Agency Fees - Factored A/R	825,908.49	431,120.20	431,120.20	0.00	1,257,028 69
1860136	NonTradition Option Premiums	24,847.27	(24,847.27)	0.00	(24,847.27)	0.00
1860153	Unamortized Credit Line Fees	94,643.74	216,971.96	216,971.96	0.00	311,615.70
1860160	Deferred Expenses - Current	1,873.14	(1,294 37)	0.00	(1,294.37)	578.77
1860166	Def Lease Assets - Non Taxable	0.00	26,580.31	26,580.31	0.00	26,580.31
1890004	Loss Rec Debt-Debentures	771,113.20	(33,648.60)	0.00	(33,648.60)	737,464 60
1900006	ADIT Federal - SFAS 133 Nonaff	252,948.30	(198,215 25)	0.00	(198,215.25)	54,733 05
1900015	ADIT-Fed-Hdg-CF-Int Rate	249,432.24	(32,534.64)	0.00	(32,534.64)	216,897.60
1901001	Accum Deferred FIT - Other	14,157,012.45	265,167.77	265,167.77	0.00	14,422,180.22
1902001	Accum Defd FIT - Oth Inc & Ded	607,057.99	(199,756.20)	0.00	(199,756.20)	407,301.79
1903001	Acc Dfd FIT - FAS109 Flow Thru	13,730,759.07	(64,399 81)	0.00	(64,399 81)	13,666,359.26
1904001	Accum Dfd FIT - FAS 109 Excess	429,831.75	(47,988.22)	0.00	(47,988.22)	381,843 53
	TOTAL ASSETS AND OTHER DEBITS	1,504,334,100.70	69,129,979.78	69,129,979.78	0.00	1,573,464,080.48
2010001	Common Stock Issued-Affiliated	(50,450,000.00)	0 00	0.00	0.00	(50,450,000.00)
2080000	Donations Recvd from Stckhldrs	(236,750,000.00)	0.00	0.00	0.00	(236,750,000.00)
2160001	Unapprp Retnd Erngs-Unrstrictd	(138,749,088.79)	(4,435,550.18)	0 00	(4,435,550.18)	(143,184,638.96)
2190010	OCI for Commodity Hedges	137,709.73	(89,391.00)	0.00	(89,391.00)	48,318.73
2190015	Accum OCI-Hdg-CF-Int Rate	463,231.96	(60,421.56)	0.00	(60,421.56)	402,810.40
2230000	Advances from Associated Co	(20,000,000.00)	0 00	0.00	0 00	(20,000,000.00)
2240006	Senior Unsecured Notes	(530,000,000.00)	0.00	0.00	0.00	(530,000,000.00)
2260006	Unam Disc LTD-Dr-Sr Unsec Note	1,278,225.00	(166,725.00)	0.00	(166,725 00)	1,111,500 00
4380001	Div Declrd - Common Stk - Asso	19,500,000.00	1,500,000.00	1,500,000 00	0 00	21,000,000.00
	TOTAL CAPITALIZATION	(956,569,922.10)	(3,252,087.74)	0.00	(3,252,087.74)	(959,822,009.83)
2270001	Obligatns Undr Cap Lse-Noncurr	(1,111,891 07)	(2,456,615.15)	0.00	(2,456,615.15)	(3,568,506.22)
2270003	Accrued Noncur Lease Oblig	(1,210.88)	933 05	933.05	0.00	(277.83)
2282003	Accm Prv I/D - Worker's Com	(61,505.76)	11,418.09	11,418 09	0.00	(50,087.67)
2283000	Accm Prv for Pensions&Benefits	(128,472.79)	(1,033.56)	0.00	(1,033.56)	(129,506 35)
2283002	Supplemental Savings Plan	(638,495.23)	(64,457.85)	0.00	(64,457.85)	(702,953 08)
2283003	SFAS 106 Post Retirement Benef	(5,007,379.01)	(601,429.59)	0.00	(601,429.59)	(5,608,808.60)
2283005	SFAS 112 Postemployment Benef	(6,098,839.39)	915,935.77	915,935.77	0.00	(5,182,903 82)
2283007	Perf Share Incentive Plan	(674,441.30)	69,705.79	69,705.79	0 00	(604,735.51)
2283013	Incentive Comp Deferral Plan	(222,622.74)	(96,911.70)	0.00	(96,911.70)	(319,534.44)

KYP CORP CONSOLIDATED
Trial Balance
For The Month Ended DECEMBER 31, 2010

Account Number	Description	Pr Yr Ending Balance	Yearly Activity	Debits	Credit	Current Yr Balance
2283015	FAS 158 SERP Payable Long Term	121,511.00	7,995.00	7,995 00	0.00	129,506.00
2283016	FAS 158 Qual Payable Long Term	(26,866,928 84)	1,940,998 80	1,940,998.80	0.00	(24,925,930.04)
2283017	FAS 158 OPEB Payable Long Term	(15,266,079 00)	(766,189.00)	0.00	(766,189 00)	(16,032,268 00)
2283018	SFAS 106 Med Part-D	5,000,070.70	601,424.91	601,424.91	0 00	5,601,495 61
2300001	Asset Retirement Obligations	(3,505,419 40)	(680,988.85)	0 00	(680,986 85)	(4,186,406.25)
2320001	Accounts Payable - Regular	(7,623,949.07)	4,292,290.41	4,292,290.41	0.00	(3,331,658 66)
2320002	Unvouchered Invoices	(19,565,728.50)	11,683,211.48	11,683,211.48	0.00	(7,882,515.02)
2320003	Retention	(191,541.57)	18,775.91	18,775.91	0 00	(172,765.66)
2320006	Allowance Settlements	(441,600.00)	(44,400.00)	0.00	(44,400.00)	(486,000 00)
2320011	Uninvoiced Fuel	(8,293,879.38)	(5,741,106.44)	0.00	(5,741,106 44)	(14,034,985.82)
2320050	Coal Trading	(284,612 50)	114,237.78	114,237.76	0.00	(170,374.74)
2320052	Accounts Payable - Purch Power	(3,256,899.27)	916,785.26	918,785.26	0 00	(2,340,114.01)
2320053	Elect Trad-Options&Swaps	(732,586.47)	162,523.08	162,523.08	0 00	(570,063.39)
2320054	Emission Allowance Trading	(2,257.34)	2,257.34	2,257.34	0.00	0.00
2320056	Gas Physicals	(156.72)	(291.44)	0.00	(291.44)	(448.18)
2320062	Broker Fees Payable	(11,607.94)	794.78	794.78	0.00	(10,813.18)
2320071	Gas Accruals GDA Trans-Payable	(1,348 53)	(1,590 86)	0.00	(1,590.86)	(2,939.39)
2320073	A/P Misc Dedic. Power	(11,272.50)	(1,558.50)	0.00	(1,556 50)	(12,831.00)
2320078	Corporate Credit Card Liab	(463,680.39)	350,867.50	350,867.50	0.00	(133,012.89)
2320077	INDUS Unvouchered Liabilities	(911,849.89)	(451,055.99)	0 00	(451,055.99)	(1,362,905.88)
2320079	Broker Commisn Spark/Merch Gen	(39.23)	38.23	38.23	0.00	(1.00)
2320081	AP Accrual NYMEX OTC & Penults	(9,389.47)	9,389.47	9,389.47	0 00	0.00
2320063	PJM Net AP Accrual	0 00	(1,746,196.91)	0.00	(1,746,196.91)	(1,746,196 91)
2320086	Accrued Broker - Power	(298,002.44)	(242,253.62)	0.00	(242,253.62)	(540,256.06)
2320090	MISO AP Accrual	(474,031.38)	(61,751.38)	0.00	(61,751.38)	(535,782.76)
2330000	Corp Borrow Program (NP-Assoc)	(485,336.84)	485,336 84	485,336 84	0 00	0.00
2340001	A/P Assoc Co - InterUnit G/L	(12,478,213.72)	(11,260,820.74)	0.00	(11,260,820.74)	(23,739,034 46)
2340005	A/P Assoc Co - Allowances	(6,338,684.45)	(5,164,376.51)	0.00	(5,164,376.51)	(11,503,060.96)
2340011	A/P-Assc Co-AEPSC-Agent	(4,464,362.00)	(2,584,093.00)	0.00	(2,584,093 00)	(7,048,455 00)
2340025	A/P Assoc Co - CM Bills	(39,405 61)	4,037.44	4,037.44	0.00	(35,366.17)
2340027	A/P Assoc Co - Intercompany	(586,843.51)	391,687.96	391,667.96	0.00	(195,155.55)
2340029	A/P Assoc Co - AEPSC Bills	(3,389,351.64)	315,665.29	315,665.29	0 00	(3,073,686.35)
2340030	A/P Assoc Co - InterUnit A/P	(29,896.81)	(140,575.74)	0.00	(140,575.74)	(170,474.55)
2340032	A/P Assoc Co - Multi Pmts	(383.29)	369.31	369.31	0.00	(13.98)
2340034	A/P Assoc Co - System Sales	(742.42)	(17,117.18)	0.00	(17,117.18)	(17,859.60)
2340035	Fleet - M4 - A/P	(12,713 64)	6,771.40	6,771.40	0.00	(5,942.24)
2340037	A/P Assoc-Global Borrowing Int	(87,500.00)	0.00	0.00	0 00	(87,500.00)
2340049	A/P Assoc -Realization Sharing	0.00	(1,051.00)	0 00	(1,051 00)	(1,051.00)
2350001	Customer Deposits-Active	(18,049,036.20)	(1,321,321.22)	0 00	(1,321,321.22)	(19,370,357.42)
2350003	Deposits - Trading Activity	(972,831.18)	275,644 64	275,644.64	0.00	(697,186.54)
2350005	Deposits - Trading Contra	763,538.00	(388,521.00)	0.00	(388,521 00)	375,017.00
2360001	Federal Income Tax	24,771,724 67	(31,666,630.52)	0.00	(31,666,630.52)	(6,694,905 85)
236000209	State Income Taxes	4,725,396.56	(4,725,396.56)	0.00	(4,725,396.56)	0.00
236000210	State Income Taxes	0.00	1,419,402.70	1,419,402.70	0.00	1,419,402.70
2360004	FICA	(170,270.83)	1,396.52	1,396.52	0.00	(168,874.31)
2360005	Federal Unemployment Tax	(5,059 02)	(2,144.51)	0.00	(2,144.51)	(7,203.53)
2360006	State Unemployment Tax	(4,809 54)	(4,775.95)	0.00	(4,775 95)	(9,585.49)
236000709	State Sales and Use Taxes	(65,729.17)	65,729.17	65,729.17	0 00	0.00
236000710	State Sales and Use Taxes	0.00	(65,517.10)	0.00	(65,517.10)	(65,517.10)
236000806	Real & Personal Property Taxes	(2,477,010.54)	2,340,749.59	2,340,749.59	0.00	(136,260.95)
236000809	Real & Personal Property Taxes	(9,323,500.00)	3,275,878.44	3,275,878.44	0.00	(6,047,621.56)
236000810	Real Personal Property Taxes	0.00	(7,970,436 00)	0.00	(7,970,436.00)	(7,970,436.00)
236001209	State Franchise Taxes	25,500.00	(25,500.00)	0.00	(25,500 00)	0.00
236001609	State Gross Receipts Tax	(41,747.00)	41,747.00	41,747.00	0.00	0.00
236001610	State Gross Receipts Tax	0 00	(64,716 00)	0 00	(64,716 00)	(64,716 00)
236003309	Pers Prop Tax-Cap Leases	2,776.35	565.28	565.28	0 00	3,341.63
236003310	Pers Prop Tax-Cap Leases	0.00	(106,300.00)	0.00	(106,300.00)	(106,300 00)
236003509	Real Prop Tax-Cap Leases	14,660.81	39 00	39.00	0.00	14,699.81
236003510	Real Prop Tax-Cap Leases	0.00	(13,785.17)	0.00	(13,785.17)	(13,785.17)
2360037	FICA - Incentive accrual	(40,894.76)	(174,243.77)	0.00	(174,243 77)	(215,136.53)
2360036	Reorg Payroll Tax Accrual	0 00	(46,661.65)	0.00	(46,661.65)	(48,661 65)
2360501	Fed Inc Tax-Short Term FIN48	(495,839 00)	(1,084,385.00)	0 00	(1,084,385.00)	(1,580,224 00)
2360502	State Inc Tax-Short Term FIN48	0.00	(431,674.00)	0 00	(431,674.00)	(431,674.00)
2360601	Fed Inc Tax-Long Term FIN48	(1,242,187.06)	504,241.00	504,241.00	0.00	(737,946.06)
2360602	State Inc Tax-Long Term FIN48	(965,474.00)	853,846 00	653,848.00	0 00	(111,626.00)
2360701	SEC Accum Defd FIT-Util FIN 48	1,809,347.00	560,143 00	580,143.00	0.00	2,389,490 00
2360702	SEC Accum Defd SIT - FIN 46	260,095.00	116,961 00	116,961.00	0.00	377,056 00
2370006	Interest Accrd-Sen Unsec Notes	(6,461,093.06)	(0.04)	0 00	(0 04)	(6,461,093.10)
2370007	Interest Accrd-Customer Depsts	(915,060.66)	(103,477.26)	0.00	(103,477.26)	(1,018,537.94)
2370016	Accrued Margin Interest	(2,466 69)	(545.44)	0.00	(545.44)	(3,012.13)
2370048	Acrd Int.- FIT Reserve - LT	0.00	(547,119 00)	0.00	(547,119 00)	(547,119.00)
2370348	Acrd Int. - SIT Reserve - LT	(388,706.00)	370,316.00	370,316.00	0 00	(18,390.00)
2410001	Federal Income Tax Withheld	(308,741.29)	94,324.21	94,324.21	0 00	(214,417.08)
2410002	State Income Tax Withheld	(180,727.34)	34,708.29	34,708.29	0.00	(146,019.05)
2410003	Local Income Tax Withheld	(24,296.58)	4,181.06	4,181.06	0.00	(20,115.52)
2410004	State Sales Tax Collected	(657,728 64)	(109,163.11)	0.00	(109,163.11)	(766,911.75)
2410005	FICA Tax Withheld	(124,630.26)	20,470.31	20,470.31	0 00	(104,159 95)
2410006	School District Tax Withheld	(878,196.08)	876,196 08	676,196.08	0.00	0 00
2410008	Franchise Fee Collected	(137,579.28)	(47,822 85)	0.00	(47,822.85)	(185,402.13)
2410009	KY Utility Gr Receipts Lic Tax	0.00	(1,239,874.24)	0.00	(1,239,874.24)	(1,239,874.24)
2420002	P/R Ded - Medical Insurance	(87,634 66)	2,324.38	2,324 38	0.00	(85,310.28)

KYP CORP CONSOLIDATED
Trial Balance
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Account Number	Description	Pr Yr Ending Balance	Yearly Activity	Debits	Credit	Current Yr Balance
2420003	P/R Ded - Dental Insurance	(7,238.32)	(185.60)	0.00	(185.60)	(7,423.92)
2420021	Vacation Pay - Next Year	(3,349,606.11)	395,260.05	395,260.05	0.00	(2,954,346.06)
2420027	FAS 112 CURRENT LIAB	(977,963.00)	(295,465.00)	0.00	(295,465.00)	(1,273,428.00)
2420044	P/R Withholdings	(27,682.89)	(20,706.10)	0.00	(20,706.10)	(48,388.99)
2420046	FAS 158 SERP Payable - Current	(194.00)	194.00	194.00	0.00	0.00
2420051	Non-Productive Payroll	(32,059.22)	(5,560.17)	0.00	(5,560.17)	(37,619.40)
2420053	Perf Share Incentive Plan	(62,724.11)	(48,534.08)	0.00	(48,534.08)	(111,258.19)
2420071	P/R Ded - Vision Plan	(4,296.21)	680.23	680.23	0.00	(3,615.98)
2420078	P/R Savings Plan - Incentive	(20,801.15)	(94,755.37)	0.00	(94,755.37)	(115,556.52)
2420083	Active Med and Dental IBNR	(505,228.00)	505,228.00	505,228.00	0.00	0.00
2420504	Accrued Lease Expense	(475.00)	475.00	475.00	0.00	0.00
2420511	Control Cash Disburse Account	(1,243,360.15)	621,367.32	621,367.32	0.00	(621,992.83)
2420512	Unclaimed Funds	(513.54)	(231.88)	0.00	(231.88)	(745.42)
2420514	Revenue Refunds Accrued	(2,428,009.03)	453,880.73	453,880.73	0.00	(1,974,128.30)
2420532	Adm Liab-Cur-S/Ins-W/C	(1,350,278.04)	741,312.03	741,312.03	0.00	(608,966.01)
2420542	Acc Cash Franchise Req	(81,474.54)	(18,400.16)	0.00	(18,400.16)	(97,874.70)
2420558	Admitted Liab NC-Self/Ins-W/C	(1,056,510.93)	(415,348.99)	0.00	(415,348.99)	(1,471,859.92)
242059209	Sales & Use Tax - Leased Equ	(3,454.50)	3,454.50	3,454.50	0.00	0.00
242059210	Sales Use Tax - Leased Equip	0.00	(75,772.66)	0.00	(75,772.66)	(75,772.66)
2420618	Accrued Payroll	(909,950.44)	390,941.19	390,941.19	0.00	(519,009.25)
2420623	Distr, Cust Ops & Reg Svcs ICP	(324,067.19)	(1,226,523.22)	0.00	(1,226,523.22)	(1,550,590.41)
2420624	Corp & Shrd Srv Incentive Plan	(38,330.00)	(149,030.00)	0.00	(149,030.00)	(187,360.00)
2420635	Generation Incentive Plan	(127,820.00)	(741,800.00)	0.00	(741,800.00)	(869,620.00)
2420643	Accrued Audit Fees	(15,300.75)	2,339.00	2,339.00	0.00	(12,961.75)
2420651	Reorg Severance Accrual	0.00	(20,006.40)	0.00	(20,006.40)	(20,006.40)
2420653	Reorg Misc HR Exp Accrual	0.00	(690,526.02)	0.00	(690,526.02)	(690,526.02)
2420656	Federal Mitigation Accru (NSR)	(457,034.90)	292,735.11	292,735.11	0.00	(164,299.79)
2420658	Accrued Prof. Tax Services	(42,482.00)	0.00	0.00	0.00	(42,482.00)
2420660	AEP Transmission ICP	(43,030.00)	(197,820.00)	0.00	(197,820.00)	(240,850.00)
2420661	Chief Admin Officer ICP	(4,230.00)	(16,330.00)	0.00	(16,330.00)	(20,560.00)
2420664	ST State Mitigation Def (NSR)	(345,407.30)	(106,776.01)	0.00	(106,776.01)	(452,183.31)
2430001	Oblig Under Cap Leases - Curr	(639,400.16)	(1,204,150.26)	0.00	(1,204,150.26)	(1,843,550.42)
2430003	Accrued Cur Lease Oblig	(302.72)	24.89	24.89	0.00	(277.83)
2440001	Curr. Unreal Losses - NonAffil	(8,456,385.99)	1,119,153.75	1,119,153.75	0.00	(7,337,232.24)
2440002	LT Unreal Losses - Non Affil	(6,097,603.01)	2,084,333.29	2,084,333.29	0.00	(4,013,269.72)
2440003	Curr. Unreal Losses - Affil	(108,999.26)	38,455.26	38,455.26	0.00	(72,544.00)
2440004	LT Unreal Losses - Affil	(297,632.00)	297,632.00	297,632.00	0.00	0.00
2440009	S/T Option Premium Receipts	(23,583.87)	(32,285.17)	0.00	(32,285.17)	(55,869.04)
2440010	L/T Option Premium Receipts	0.00	(6,526.89)	0.00	(6,526.89)	(6,526.89)
2440021	S/T Liability MTM Collateral	4,096,078.00	(2,438,688.00)	0.00	(2,438,688.00)	1,657,390.00
2440022	L/T Liability MTM Collateral	2,310,049.00	(592,857.00)	0.00	(592,857.00)	1,717,192.00
2450010	S/T Liability-Commodity Hedges	(697,404.62)	546,727.62	546,727.62	0.00	(150,677.00)
2450011	L/T Liability-Commodity Hedges	(16,187.00)	16,126.00	16,126.00	0.00	(61.00)
2520000	Customer Adv for Construction	(55,422.52)	(37,979.29)	0.00	(37,979.29)	(93,401.81)
2530000	Other Deferred Credits	(295,032.14)	280,653.75	280,653.75	0.00	(14,378.39)
2530022	Customer Advance Receipts	(1,816,076.08)	988,604.43	988,604.43	0.00	(827,471.65)
2530050	Deferred Rev -Pole Attachments	(49,051.52)	(48,199.71)	0.00	(48,199.71)	(97,251.23)
2530067	IPP - System Upgrade Credits	(236,193.37)	(7,770.35)	0.00	(7,770.35)	(243,963.72)
2530092	Fbr Opt Lns-In Kind Sv-Dfd Gns	(176,281.21)	4,275.21	4,275.21	0.00	(172,006.00)
2530101	MACSS Unidentified EOI Cash	(170.00)	170.00	170.00	0.00	0.00
2530112	Other Deferred Credits-Curr	(30,689.00)	(1,000,825.73)	0.00	(1,000,825.73)	(1,031,514.73)
2530113	State Mitigation Deferal (NSR)	(651,840.00)	325,919.96	325,919.98	0.00	(325,920.02)
2530114	Federl Mitigation Deferal(NSR)	(1,425,492.60)	0.00	0.00	0.00	(1,425,492.60)
2530137	Fbr Opt Lns-Sold-Defd Rev	(157,396.82)	13,555.80	13,555.80	0.00	(143,841.02)
2530148	Accrued Penalties-Tax Reserves	(333,340.00)	333,340.00	333,340.00	0.00	0.00
2540011	Over Recovered Fuel Cost	(1,786,709.88)	922,781.00	922,781.00	0.00	(863,928.88)
2540047	Unreal Gain on Fwd Commitments	(8,977,202.37)	3,132,846.46	3,132,846.48	0.00	(5,844,355.89)
2540105	Home Energy Assist Prgm - KPCO	(23,529.72)	(154,235.49)	0.00	(154,235.49)	(177,765.21)
2540173	Green Pricing Option	(520.00)	(64.00)	0.00	(64.00)	(584.00)
2543001	SFAS109 Flow Thru Def FIT Liab	(913,965.23)	379,197.00	379,197.00	0.00	(534,768.23)
2544001	SFAS 109 Exces Deferred FIT	(1,228,090.75)	137,109.22	137,109.22	0.00	(1,090,981.53)
2550001	Accum Deferred ITC - Federal	(1,697,364.00)	704,223.00	704,223.00	0.00	(993,141.00)
2811001	Acc Dfd FIT - Accel Amort Prop	(31,362,188.90)	1,559,985.00	1,559,985.00	0.00	(29,802,203.90)
2821001	Accum Defd FIT - Utility Prop	(162,185,879.69)	(6,262,892.18)	0.00	(6,262,892.18)	(168,446,771.87)
2823001	Acc Dfrd FIT FAS 109 Flow Thru	(51,641,596.78)	(777,440.15)	0.00	(777,440.15)	(52,419,036.93)
2824001	Acc Dfrd FIT - SFAS 109 Excess	798,259.00	(89,121.00)	0.00	(89,121.00)	709,138.00
2830006	ADIT Federal - SFAS 133 Nonaff	(178,797.73)	150,081.00	150,081.00	0.00	(28,716.73)
2831001	Accum Deferred FIT - Other	(21,654,672.13)	3,304,422.08	3,304,422.08	0.00	(18,350,250.05)
2832001	Accum Dfrd FIT - Oth Inc & Ded	(292,452.69)	258,434.75	258,434.75	0.00	(34,017.94)
2833001	Acc Dfd FIT FAS 109 Flow Thru	(40,623,807.62)	(3,271,304.77)	0.00	(3,271,304.77)	(43,895,112.39)
2833002	Acc Dfrd SIT FAS 109 Flow Thru	(36,824,251.00)	(5,407,797.27)	0.00	(5,407,797.27)	(42,232,048.27)
	LIABILITIES AND OTHER CREDITS	(523,828,628.42)	(54,531,567.12)	0.00	(54,531,567.12)	(578,360,195.55)
4030001	Depreciation Exp	47,381,452.77	1,341,010.19	1,341,010.19	0.00	48,722,462.96
4040001	Amort. of Plant	4,276,326.74	(483,647.69)	0.00	(483,647.69)	3,794,679.05
4060001	Amort of Plt Acq Adj	38,616.00	0.00	0.00	0.00	38,616.00
4073000	Regulatory Debits	311,514.72	0.00	0.00	0.00	311,514.72
4081002	FICA	2,688,840.98	511,295.95	511,295.95	0.00	3,200,136.93
4081003	Federal Unemployment Tax	17,181.46	13,848.01	13,848.01	0.00	31,029.47
408100505	Real & Personal Property Taxes	1,815.37	(1,815.37)	0.00	(1,815.37)	0.00
408100506	Real & Personal Property Taxes	(11,197.35)	11,197.35	11,197.35	0.00	0.00
408100507	Real & Personal Property Taxes	856,472.07	(856,472.07)	0.00	(856,472.07)	0.00

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Account Number	Description	Pr Yr Ending Balance	Yearly Activity	Debits	Credit	Current Yr Balance
408100508	Real & Personal Property Taxes	8,715,916.34	(10,193,953.02)	0 00	(10,193,953 02)	(1,478,036.68)
408100509	Real & Personal Property Taxes	198.37	8,985,601.63	8,985,601.63	0 00	8,985,800.00
408100510	Real Personal Property Taxes	0.00	198.39	198.39	0.00	198.39
408100608	State Gross Receipts Tax	(18,746 00)	16,746.00	18,748 00	0 00	0 00
408100609	State Gross Receipts Tax	223,151 00	(277,905.00)	0.00	(277,905 00)	(54,754.00)
406100610	State Gross Receipts Tax	0.00	268,158 00	268,158 00	0 00	268,156.00
4061007	State Unemployment Tax	30,766 03	16,133.99	16,133.99	0.00	46,900 02
406100800	State Franchise Taxes	0.00	(43,982 00)	0.00	(43,982.00)	(43,982.00)
408100808	State Franchise Taxes	(5,085.00)	5,085 00	5,085.00	0 00	0.00
408100809	State Franchise Taxes	73,550.00	(90,097.00)	0.00	(90,097.00)	(16,547.00)
408100810	State Franchise Taxes	0 00	38,300 00	38,300.00	0.00	38,300 00
408101409	Federal Excise Taxes	4,262.08	(4,262.08)	0.00	(4,262.08)	0 00
408101410	Federal Excise Taxes	0.00	2,098.40	2,098.40	0.00	2,098.40
408101709	St Lic/Rgstrtion Tax/Fees	225.00	(225 00)	0.00	(225.00)	0.00
408101710	St Lic-Rgstrtion Tax-Fees	0.00	255.25	255.25	0.00	255.25
406101808	St Publ Serv Comm Tax/Fees	335,182 84	(335,162.64)	0.00	(335,182.84)	0.00
406101809	St Publ Serv Comm Tax/Fees	374,877.36	0.05	0.05	0.00	374,877.41
406101810	St Publ Serv Comm Tax-Fees	0.00	399,674 76	399,674.76	0.00	399,674.76
408101900	State Sales and Use Taxes	(840,600 00)	840,600 00	640,600.00	0 00	0.00
406101908	State Sales and Use Taxes	243,262.02	(243,282.02)	0.00	(243,282.02)	0.00
408101909	State Sales and Usa Taxes	15,044.98	(13,531.64)	0.00	(13,531.64)	1,513.34
408101910	State Sales and Use Taxes	0.00	14,210.26	14,210.28	0.00	14,210.26
408102209	Municipal License Fees	100.00	(100.00)	0.00	(100.00)	0.00
408102210	Municipal License Fees	0.00	100.00	100.00	0.00	100.00
408102907	Real/Pers Prop Tax-Cap Leases	103.72	(103.72)	0.00	(103.72)	0.00
408102908	Real/Pers Prop Tax-Cap Leases	81.13	790.13	790.13	0 00	671.26
408102909	Real/Pers Prop Tax-Cap Leases	45,166 69	(44,845.78)	0.00	(44,845.78)	320 91
406102910	Real-Pers Prop Tax-Cap Leases	0.00	106,300.00	106,300.00	0.00	106,300.00
4061033	Fringe Benefit Loading - FICA	(1,057,475.26)	114,113.72	114,113.72	0.00	(943,361.54)
4081034	Fringe Benefit Loading - FUT	(11,464 57)	1,041.61	1,041.61	0.00	(10,422.96)
4081035	Fringe Benefit Loading - SUT	(12,242.72)	(2,410.65)	0.00	(2,410 65)	(14,653.37)
408103608	Real Prop Tax-Cap Leases	(864.43)	864.43	864.43	0.00	0.00
408103609	Real Prop Tax-Cap Leases	12,020 00	(12,020.00)	0.00	(12,020.00)	0.00
408103610	Real Prop Tax-Cap Leases	0.00	26,700 00	26,700.00	0.00	26,700.00
408200508	Real & Personal Property Taxes	55,000.00	(55,000.00)	0.00	(55,000 00)	0.00
408200509	Real & Personal Property Taxes	0.00	58,698.14	58,698.14	0.00	58,698.14
408201410	St Lic-Registration Tax-Fees	0.00	155.00	155.00	0.00	155.00
4091001	Income Taxes, UOI - Federal	(35,912,167.21)	50,579,420.32	50,579,420.32	0.00	14,667,253.11
409100206	Income Taxes, UOI - State	0 00	37,533.00	37,533.00	0 00	37,533 00
409100208	Income Taxes, UOI - State	(546,981.10)	546,981.10	546,981.10	0.00	0.00
409100209	Income Taxes, UOI - State	(4,016,443.10)	4,311,050.06	4,311,050 06	0.00	294,606.96
409100210	Income Taxes UOI - State	0.00	2,858,510.04	2,856,510.04	0.00	2,656,510.04
4092001	Inc Tax, Oth Inc&Ded-Federal	292,299 95	(374,704.54)	0.00	(374,704.54)	(62,404.59)
409200208	Inc Tax, Oth Inc & Ded - State	(5,460.84)	5,460.84	5,460.84	0.00	0 00
409200209	Inc Tax, Oth Inc & Ded - State	48,963 54	(72,342.94)	0.00	(72,342.94)	(23,379.40)
409200210	Inc Tax Oth Inc Ded - State	0 00	15,928.58	15,926 58	0 00	15,928.56
4101001	Prov Def I/T Util Op Inc-Fed	113,127,563.34	(49,717,506.30)	0.00	(49,717,506.30)	63,410,057.04
4102001	Prov Def I/T Oth I&D - Federal	943,257.72	(629,042.42)	0.00	(629,042.42)	314,215.30
4111001	Prv Def I/T-Cr Util Op Inc-Fed	(61,487,227.01)	(789,512.70)	0.00	(789,512.70)	(62,276,739.71)
4111005	Accretion Expense	1,274.82	(1,274.82)	0.00	(1,274.62)	0.00
4112001	Prv Def I/T-Cr Oth I&D-Fed	(1,971,828.14)	1,598,934.29	1,598,934.29	0.00	(372,893 85)
4114001	ITC Adj, Utility Oper - Fed	(621,958 00)	117,733.00	117,733.00	0.00	(704,223.00)
4116000	Gain From Disposition of Plant	(1,861.00)	(315.00)	0.00	(315.00)	(2,176 00)
4118002	Comp. Allow Gains Titla IV SO2	(38,629.72)	(1,785,635.15)	0.00	(1,765,635.15)	(1,824,264.87)
4180001	Non-Operatng Rental Income	(55,425 00)	(775.00)	0.00	(775.00)	(56,200 00)
4180005	Non-Opratng Rntal Inc-Depr	6,669.72	0.00	0.00	0.00	6,669.72
4190002	Int & Dividend Inc - Nonassoc	(34,461.46)	(7,646.35)	0.00	(7,646.35)	(42,107.81)
4190005	Interest Income - Assoc CBP	(23,712.20)	(27,001.44)	0.00	(27,001.44)	(50,713.64)
4191000	Allw Oth Fnds Usd Dmg Cnstr	(390,809.96)	(377,214.72)	0.00	(377,214.72)	(768,024 68)
4210000	Misc Non-Operating Income	0.00	105,822.61	105,822.61	0.00	105,822.61
4210002	Misc Non-Op Inc-NonAsc-Rents	(62,096.90)	(495.00)	0.00	(495.00)	(62,591.90)
4210005	Misc Non-Op Inc-NonAsc-Timber	(74,465 99)	(81,739.82)	0.00	(61,739.82)	(156,205 61)
4210007	Misc Non-Op Inc - NonAsc - Oth	(25,403.70)	1,662.43	1,662.43	0 00	(23,741.27)
4210009	Misc Non-Op Exp - NonAssoc	487.61	(470.69)	0.00	(470.69)	16.92
4210025	B/L MTM Assignments	(2,261,611.00)	1,066,680.00	1,066,680.00	0.00	(1,195,131.00)
4210026	B/L Affl MTM Assign	1,693,661.00	(1,048,681.00)	0.00	(1,048,681.00)	644,980 00
4210027	Realized Financial Assignments	115,703.17	244,597.67	244,597.67	0 00	360,300.84
4210028	Realized Affil Financial Assgn	452,446.83	(262,596.67)	0.00	(262,596.67)	189,850.16
4210031	Pwr Sales Outside Svc Territry	(4,456,040 88)	(344,994.06)	0.00	(344,994.06)	(4,601,034.94)
4210032	Pwr Purch Outside Svc Territry	3,682,350 84	754,061.93	754,061.93	0.00	4,436,412.77
4210033	Mark to Mkt Out Svc Territory	654,304 99	102,264.79	102,264.79	0.00	758,569.78
4210035	Gn/Ls MTM Emissions - Forwards	(2,167.23)	2,076.49	2,078.49	0.00	(88.74)
4210039	Carrying Charges	(160,080 59)	13,515.09	13,515 09	0.00	(146,565.50)
4210043	Realiz Sharing West Coast Pwr	2,216 00	42,856.55	42,856.55	0.00	45,072.55
4210045	UnReal Aff Fin Assign SNWA	(309,075.00)	(161,701.00)	0.00	(161,701.00)	(470,776.00)
4210046	Real Aff Fin Assign SNWA	(13,599.50)	84,712.38	84,712.38	0.00	71,112.88
4210049	Interest Rate Swaps-BTL Power	4,413.59	3,843.07	3,843.07	0.00	8,256 66
4210053	Specul. Allow. Gains-SO2	(14,314.83)	17,935.06	17,935 06	0.00	3,620.23
4210054	Specul. Allow. Gains-Seas NOx	0.00	(326.53)	0.00	(328.53)	(328.53)
4210056	Specul. Allow. Gains-CO2	(13.79)	13.79	13.79	0.00	0.00
4261000	Donations	144,413.67	142,687.19	142,687.19	0.00	287,101.06

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Account Number	Description	Pr Yr Ending Balance	Yearly Activity	Debits	Credit	Current Yr Balance
4263001	Penalties	1,258.48	(333,442.34)	0.00	(333,442.34)	(332,183 86)
4264000	Civic & Political Activities	94,759.99	219,494.55	219,494.55	0.00	314,254 54
4265002	Other Deductions - Nonassoc	9,728 30	68,675.38	68,675.38	0.00	78,403 68
4265004	Social & Service Club Dues	197,602.28	(110,486 58)	0.00	(110,486.58)	87,115.70
4265007	Regulatory Expenses	67.06	(67.06)	0.00	(67.06)	0 00
4265009	Factored Cust A/R Exp - Affil	1,183,340 64	(198,891.64)	0 00	(198,891 64)	964,448.80
4265010	Fact Cust A/R-Bad Debts-Affil	1,142,129.70	88,140 95	86,140 95	0.00	1,228,270.65
4265053	Specul. Allow Loss-SO2	(29.86)	4,733.18	4,733.18	0 00	4,703 32
4265054	Specul. Allow Loss-Seas NOx	843.75	(226.53)	0.00	(226.53)	617.22
4265056	Specul. Allow Loss-CO2	7,570 83	(7,035 06)	0.00	(7,035.06)	535.77
4270006	Int on LTD - Sen Unsec Notes	29,273,070.10	4,725,636.14	4,725,636.14	0 00	33,998,706.24
4280006	Amrtz Dscnt&Exp-Sn Unsec Note	457,097.61	14,088.67	14,088.67	0 00	471,186.48
4281004	Amrtz Loss Rcquired Debt-Dbnt	33,648 60	0 00	0.00	0.00	33,648 60
4300001	Interest Exp - Assoc Non-CBP	1,108,527.00	(58,527.00)	0 00	(58,527.00)	1,050,000.00
4300003	Int to Assoc Co - CBP	986,270.53	(976,694 00)	0 00	(976,694.00)	9,576.53
4310001	Other Interest Expense	1,180,970.97	(1,154,179.30)	0.00	(1,154,179.30)	26,791 87
4310002	Interest on Customer Deposits	1,003,483 03	111,770.35	111,770.35	0.00	1,115,253 38
4310007	Lines Of Credit	163,679.06	49,540 92	49,540.92	0.00	213,219.96
4310022	Interest Expense - Federal Tax	0.00	364,024.00	364,024.00	0.00	364,024.00
4310023	Interest Expense - State Tax	0 00	(245,618 00)	0.00	(245,616.00)	(245,618 00)
4320000	Allw Brrwed Fnds Used Cnstr-Cr	(394,309 98)	(199,932.24)	0.00	(199,932.24)	(594,242.22)
4400001	Residential Sales-W/Space Htg	(82,219,315 38)	(22,262,774.20)	0.00	(22,262,774.20)	(104,482,089 58)
4400002	Residential Sales-W/O Space Ht	(40,499,586.71)	(10,423,955.21)	0.00	(10,423,955.21)	(50,923,541.92)
4400005	Residential Fuel Rev	(69,543,621.84)	(988,360.46)	0.00	(986,360.46)	(70,531,982.30)
4420001	Commercial Sales	(55,196,538.14)	(11,506,025 09)	0.00	(11,506,025 09)	(66,702,563.23)
4420002	Industrial Sales (Excl Mines)	(49,066,656 99)	(8,683,394.45)	0.00	(8,683,394.45)	(57,750,051.44)
4420004	Ind Sales-NonAffil(Incl Mines)	(36,130,854.07)	(2,858,821.51)	0 00	(2,858,821.51)	(38,989,675.58)
4420006	Sales to Pub Auth - Schools	(9,853,396.63)	(2,299,096.12)	0.00	(2,299,096.12)	(12,152,492.75)
4420007	Sales to Pub Auth - Ex Schools	(9,650,887.88)	(1,993,913 86)	0.00	(1,993,913.86)	(11,644,801.74)
4420013	Commercial Fuel Rev	(41,265,450.48)	1,818,695.54	1,818,895.54	0.00	(39,446,554.94)
4420016	Industrial Fuel Rev	(93,255,195.45)	6,251,783.94	8,251,783.94	0.00	(87,003,411.51)
4440000	Public Street/Highway Lighting	(1,020,999 41)	(156,120.57)	0.00	(156,120.57)	(1,177,119 98)
4440002	Public St & Hwy Light Fuel Rev	(295,087.21)	19,906.30	19,906.30	0.00	(275,180.91)
4470001	Sales for Resale - Assoc Cos	110,966.78	(99,116.29)	0.00	(99,118 29)	11,850.49
4470002	Sales for Resale - NonAssoc	(13,226,315.51)	1,858,402.99	1,858,402.99	0 00	(11,367,912.52)
4470004	Sales for Resale-Nonaff-Ancill	(77,516.93)	66,860.24	66,860.24	0.00	(10,656 69)
4470005	Sales for Resale-Nonaff-Transm	(778,421.34)	441,778.63	441,778.63	0.00	(336,642.71)
4470006	Sales for Resale-Bookout Sales	(58,612,477.77)	(658,654.65)	0.00	(658,654.85)	(59,271,132.62)
4470010	Sales for Resale-Bookout Purch	52,258,646.07	(1,924,047.30)	0.00	(1,924,047.30)	50,334,600.77
4470027	Whsal/Muni/Pb Ath Fuel Rev	(2,797,470.37)	156,889.98	156,889.98	0.00	(2,640,580.39)
4470028	Sale/Resale - NA - Fuel Rev	(29,823,758.39)	2,591,045.04	2,591,045 04	0 00	(27,232,713.35)
4470033	Whsal/Muni/Pub Auth Base Rev	(3,371,619.29)	488,641.54	486,641.54	0.00	(2,882,977.75)
4470035	Sls for Rsl - Fuel Rev - Assoc	(565,476.47)	(157,260.74)	0.00	(157,260.74)	(722,737.21)
4470066	PWR Trding Trans Exp-NonAssoc	86,173.21	(53,166.21)	0.00	(53,166.21)	33,007.00
4470081	Financial Spark Gas - Realized	302,458 01	(351,591.33)	0.00	(351,591.33)	(49,133.32)
4470082	Financial Electric Realized	8,536,468.40	726,217.47	726,217.47	0 00	9,262,685.87
4470089	PJM Energy Sales Margin	2,594,532.57	(6,252,678.55)	0.00	(6,252,876.55)	(3,658,345.98)
4470091	PJM Explicit Congestion OSS	(15,272.11)	15,272.11	15,272.11	0.00	0.00
4470093	PJM Implicit Congestion-LSE	6,930,348.07	4,021,376.44	4,021,376.44	0.00	10,951,724 51
4470098	PJM Oper.Reserve Rev-OSS	(968,922.09)	(215,823.05)	0.00	(215,823.05)	(1,182,745.14)
4470099	Capacity Cr. Net Sales	(1,827,139.01)	(2,563,644.54)	0.00	(2,563,644.54)	(4,390,783.55)
4470100	PJM FTR Revenue-OSS	(1,881,491.13)	632,056.37	632,056.37	0 00	(1,249,434.76)
4470101	PJM FTR Revenue-LSE	(6,983,971.36)	(3,533,072.57)	0.00	(3,533,072.57)	(10,517,043.93)
4470103	PJM Energy Sales Cost	(22,577,419.79)	(14,454,183.89)	0.00	(14,454,183.89)	(37,031,603 68)
4470106	PJM Pt2Pt Trans.Purch-NonAff.	4,771.33	3,125.26	3,125.26	0.00	7,896.59
4470107	PJM NITS Purch-NonAff.	(11,341.00)	(11,282.71)	0.00	(11,282.71)	(22,623.71)
4470109	PJM FTR Revenue-Spec	366,396.93	(732,893.52)	0.00	(732,893.52)	(366,496.59)
4470110	PJM TO Admin. Exp.-NonAff.	(7,786 58)	18,140.69	18,140.69	0 00	10,352.11
4470112	Non-Trading Bookout Sales-OSS	(567,932.67)	(504,168.78)	0.00	(504,168.78)	(1,072,101.45)
4470115	PJM Meter Corrections-OSS	179,934.32	(119,965.04)	0.00	(119,965.04)	59,969.28
4470118	PJM Meter Corrections-LSE	6,441.65	(9,390.40)	0.00	(9,390.40)	(2,948.75)
4470124	PJM Incremental Spot-OSS	(4,186.17)	8,146.47	8,148.47	0.00	3,962.30
4470125	PJM Incremental Exp Cong-OSS	66,786 94	(66,786 94)	0.00	(66,786.94)	0.00
4470126	PJM Incremental Imp Cong-OSS	357,915.00	862,751.90	862,751.90	0.00	1,220,666.90
4470128	Sales for Res-Aff. Pool Energy	(64,074,464 94)	6,297,075.94	6,297,075.94	0.00	(57,777,389 00)
4470131	Non-Trading Bookout Purch-OSS	283,193.96	(140,675.38)	0.00	(140,675.38)	142,518 58
4470143	Financial Hedge Realized	(3,074,015.94)	2,551,286.35	2,551,288.35	0.00	(522,727.59)
4470144	Realiz.Sharing - 06 SIA	6,650.00	(19,376.45)	0.00	(19,376.45)	(12,726.45)
4470150	Transm. Rev.-Dedic. Whlsl/Muni	(670,582.04)	96,253.49	96,253.49	0 00	(574,328.55)
4470155	OSS Physical Margin Reclass	10,747,696 97	(2,655,921.08)	0 00	(2,655,921.08)	8,091,775.89
4470156	OSS Optim. Margin Reclass	(10,747,696 97)	2,655,921.08	2,655,921.08	0 00	(8,091,775.89)
4470166	Marginal Explicit Losses	(8,291.08)	8,291.08	8,291.08	0.00	0.00
4470167	MISO FTR Revenues OSS	(2,419.96)	(6,960.07)	0.00	(6,960.07)	(9,380.03)
4470168	Interest Rate Swaps-Power	36,079.12	31,508 85	31,508.85	0.00	67,587.97
4470169	Capacity Sales Trading	24,160.92	(76,320.99)	0.00	(76,320.99)	(52,160.07)
4470170	Non-ECR Auction Sales-OSS	(17,969,602.55)	5,335,317.17	5,335,317.17	0.00	(12,634,285.38)
4470174	PJM Whlse FTR Rev - OSS	(149,769 76)	(1,247,609.29)	0.00	(1,247,609.29)	(1,397,379 05)
4470175	OSS Sharing Reclass - Retail	0.00	2,048,078.21	2,048,078.21	0 00	2,048,078 21
4470176	OSS Sharing Reclass-Reduction	0.00	(2,048,078.21)	0.00	(2,048,078.21)	(2,048,078.21)
4470202	PJM OpRes-LSE-Credit	(2,513,816.71)	1,465,125.47	1,465,125.47	0 00	(1,048,691.24)
4470203	PJM OpRes-LSE-Charge	3,308,624 66	196,981.58	196,981.56	0 00	3,505,606.22

KYP CORP CONSOLIDATED
Trial Balance
For The Month Ended DECEMBER 31, 2010

Account Number	Description	Pr Yr Ending Balance	Yearly Activity	Debits	Credit	Current Yr Balance
4470204	PJM Spinning-Credit	(79,428.90)	79,428 90	79,428.90	0.00	0.00
4470205	PJM Spinning-Charge	13,438.41	(13,438.41)	0.00	(13,438.41)	0.00
4470206	PJM Trans loss credits-OSS	(1,100,276.32)	20,513.14	20,513.14	0.00	(1,079,763.18)
4470207	PJM transm loss charges - LSE	13,247,897.84	5,287,284.12	5,287,284.12	0.00	18,535,181.96
4470208	PJM Transm loss credits-LSE	(6,775,491.69)	(1,892,447.18)	0.00	(1,892,447.18)	(8,667,938 87)
4470209	PJM transm loss charges-OSS	2,092,503.68	362,423.95	362,423.95	0.00	2,454,927.83
4470214	PJM 30m Suppl Reserve CR OSS	(54,112.05)	(30,328.71)	0.00	(30,328.71)	(84,440.76)
4470215	PJM 30m Suppl Reserve CH OSS	14,307.37	(8,594.63)	0 00	(8,594 83)	5,712.54
4470216	PJM Explicit Loss not in ECR	188,437.65	(188,437.65)	0.00	(168,437.65)	0 00
4500000	Forfeited Discounts	(1,780,497.80)	(93,282.71)	0.00	(93,282.71)	(1,873,780.51)
4510001	Misc Service Rev - Nonaffil	(398,912.50)	22,231.86	22,231.86	0 00	(378,680.64)
4540001	Rent From Elect Property - Af	(246,818.52)	(4,818.95)	0 00	(4,818.95)	(251,637.47)
4540002	Rent From Elect Property-NAC	(4,270,659.12)	56,364 08	56,364 08	0.00	(4,214,295 04)
4540004	Rent From Elect Prop-ABD-Nonaf	(83,131.67)	(54,924.03)	0.00	(54,924.03)	(138,055.70)
4560007	Oth Elect Rev - DSM Program	(1,202,405.43)	(893,418 87)	0.00	(893,418 87)	(2,095,824.30)
4560012	Oth Elect Rev - Nonaffiliated	33,624.07	(46,325.78)	0.00	(46,325.78)	(12,701.71)
4560015	Other Electric Revenues - ABD	(2,055,113.78)	1,812,543 81	1,812,543 81	0.00	(242,569.97)
4560018	Financial Trading Rev-Unreal	(73,279.76)	182,279.02	182,279.02	0.00	108,999.26
4560041	Miscellaneous Revenue-NonAffil	(0.66)	0 68	0.66	0.00	0.00
4560049	Merch Generation Finan -Realzd	92.72	(105.04)	0.00	(105.04)	(12.32)
4560050	Oth Elec Rev-Coal Trd Rlzd G-L	(939,752.43)	(1,124,230 76)	0.00	(1,124,230.76)	(2,063,983.19)
4560109	Interest Rate Swaps-Coal	1,685.97	1,876.33	1,878.33	0 00	3,362.30
4560111	MTM Aff GL Coal Trading	73,279.76	(182,279.02)	0.00	(182,279.02)	(108,999.26)
4560112	Realized GL Coal Trading-Affil	268,378.44	679,392.24	679,392.24	0.00	945,770.68
4561002	RTO Formation Cost Recovery	(15,334.37)	1,689.17	1,689.17	0 00	(13,645.20)
4561003	PJM Expansion Cost Recov	(77,237.61)	370.21	370.21	0.00	(76,867.40)
4561004	SECA Transmission Rev	0.00	(176,533.95)	0.00	(178,533.95)	(176,533.95)
4561005	PJM Point to Point Trans Svc	(878,293.15)	(19,874.56)	0.00	(19,874.56)	(898,167.71)
4561006	PJM Trans Owner Admin Rev	(155,753 95)	(34,314.98)	0.00	(34,314.98)	(190,068 93)
4561007	PJM Network Integ Trans Svc	(3,882,391.23)	(253,963.64)	0.00	(253,963.64)	(4,136,354.87)
4561019	Oth Elec Rev Trans Non Affil	(66,096.00)	1,560.00	1,560.00	0.00	(64,536 00)
4561028	PJM Pow Fac Cre Rev Whsl Cu-NA	0.00	(401.16)	0.00	(401.16)	(401.16)
4561029	PJM NITS Revenue Whsl Cus-NAff	0.00	(224,408.47)	0.00	(224,408.47)	(224,408.47)
4561030	PJM TO Serv Rev Whls Cus-NAff	0.00	(6,999.18)	0.00	(6,999.18)	(6,999.18)
4561031	GFA Trans Base Rev Unb - Aff	0.00	(61,832.38)	0.00	(61,832.38)	(61,832.38)
4561032	GFA Trans Ancillary Rev - Aff	0 00	(1,979.42)	0.00	(1,979.42)	(1,979.42)
4561033	PJM NITS Revenue - Affiliated	0 00	(4,812,028.04)	0.00	(4,812,028.04)	(4,812,028.04)
4561035	PJM Affiliated Trans NITS Cost	0.00	4,147,559.79	4,147,559.79	0.00	4,147,559.79
4561058	NonAffil PJM Trans Enhncmt Rev	0.00	(25,636.47)	0.00	(25,636.47)	(25,636.47)
4561059	Affil PJM Trans Enhancmnt Rev	0.00	(57,673 03)	0.00	(57,673.03)	(57,673.03)
4561060	Affil PJM Trans Enhancmnt Cost	0.00	48,892.00	48,892.00	0 00	48,892.00
5000000	Oper Supervision & Engineering	4,926,633.52	(189,098.13)	0.00	(189,098.13)	4,737,535.39
5000001	Oper Super & Eng-RATA-Affil	20,220.70	31,713 66	31,713.66	0.00	51,934.36
5010000	Fuel	635,634.34	(33,294.83)	0.00	(33,294.83)	602,339 51
5010001	Fuel Consumed	165,606,308.71	3,704,335.83	3,704,335.83	0.00	169,310,644.54
5010003	Fuel - Procure Unload & Handle	2,420,141.08	969,017.45	969,017.45	0 00	3,389,156.53
5010005	Fuel - Deferred	11,739,874.12	(12,662,655.12)	0.00	(12,662,655.12)	(922,781.00)
5010013	Fuel Survey Activity	1.00	(1.00)	0.00	(1.00)	0 00
5010019	Fuel Oil Consumed	2,431,363 52	(807,034.09)	0.00	(807,034.09)	1,624,329.43
5020000	Steam Expenses	1,380,240.56	(504,346.68)	0.00	(504,346.68)	875,893.90
5020002	Urea Expense	3,364,726.29	718,088.17	718,088.17	0.00	4,082,814.46
5020008	Activated Carbon	0.00	2.78	2.78	0.00	2.78
5020025	Steam Exp Environmental	23.27	40.51	40.51	0.00	63.78
5050000	Electric Expenses	96,981.42	(60,164.89)	0.00	(60,164.89)	36,816 53
5060000	Misc Steam Power Expenses	3,234,644.14	8,245,043.74	6,245,043.74	0.00	9,479,687.88
5060002	Misc Steam Power Exp-Assoc	7,452.00	27,296.00	27,296.00	0.00	34,748.00
5060004	NSR Settlement Expense	(40,456.20)	7,752.33	7,752.33	0 00	(32,703 87)
5060006	Voluntary CO2 Compliance Exp	2,283.99	(13,156.49)	0.00	(13,158.49)	(10,872.50)
5060025	Misc Stm Pwr Exp Environmental	4.52	(9.04)	0.00	(9.04)	(4.52)
5090000	Allow Consum Title IV SO2	1,807,686.95	5,732,550.02	5,732,550.02	0.00	7,540,236.97
5090002	Allowance Expenses	0.00	0.76	0.76	0.00	0.76
5090005	An. NOx Cons. Exp	518,895.30	(207,122.60)	0.00	(207,122.60)	311,772.70
5100000	Maint Supv & Engineering	455,751.43	(19,094.24)	0.00	(19,094.24)	438,657.20
5110000	Maintenance of Structures	911,930.46	(191,723.62)	0.00	(191,723.62)	720,206.84
5120000	Maintenance of Boiler Plant	8,057,558.78	2,363,785.37	2,363,785.37	0.00	10,421,344.15
5130000	Maintenance of Electric Plant	1,890,814.20	3,207,872.23	3,207,872.23	0.00	5,098,686.43
5140000	Maintenance of Misc Steam Plt	817,264 59	74,377.27	74,377.27	0.00	691,641 86
5550001	Purch Pwr-NonTrading-Nonassoc	9,470,488.92	(3,645,519.85)	0.00	(3,645,519.85)	5,824,969 07
5550002	Purchased Power - Associated	332.08	(332.08)	0.00	(332.08)	0.00
5550004	Purchased Power-Pool Capacity	56,847,340.76	2,968,890.24	2,968,890.24	0.00	59,816,231.00
5550005	Purchased Power - Pool Energy	8,306,232.70	1,310,505.30	1,310,505.30	0.00	9,616,738.00
5550023	Purch Power Capacity -NA	484,175.25	319,566.00	319,566 00	0.00	803,741.25
5550027	Purch Pwr-Non-Fuel Portion-Aff	42,480,341.00	801,777.00	801,777.00	0.00	43,282,118 00
5550032	Gas-Conversion-Mone Plant	198,462.60	110,518.46	110,518.46	0.00	308,981.06
5550035	Normal Purchases (non-ECR)	(108,104.06)	108,104.06	108,104.06	0.00	0 00
5550036	PJM Emer.Energy Purch.	12,770.23	14,730.57	14,730.57	0.00	27,500.80
5550039	PJM Inadvertent Mtr Res-OSS	(1,664 95)	(13,356.50)	0.00	(13,358.50)	(15,023.45)
5550040	PJM Inadvertent Mtr Res-LSE	9,698.19	(156,914.89)	0.00	(158,914 89)	(149,216.70)
5550041	PJM Ancillary Serv.-Sync	33,687.88	(24,133.21)	0 00	(24,133.21)	9,554 67
5550046	Purch Power-Fuel Portion-Affil	59,555,306.94	(1,635,953.92)	0 00	(1,835,953.92)	57,919,353 02
5550074	PJM Reactive-Charge	2,365,380.54	(47,530 00)	0.00	(47,530.00)	2,317,850 54

KYP CORP CONSOLIDATED
Trial Balance
For The Month Ended DECEMBER 31, 2010

Account Number	Description	Pr Yr Ending Balance	Yearly Activity	Debits	Credit	Current Yr Balance
5550075	PJM Reactive-Credit	(2,255,634.58)	(7,448.98)	0.00	(7,448.98)	(2,263,083.56)
5550076	PJM Black Start-Charge	52,951.20	(11,143 57)	0.00	(11,143.57)	41,807.63
5550077	PJM Black Start-Credit	(23,463 03)	(936.77)	0.00	(936.77)	(24,399.80)
5550078	PJM Regulation-Charge	2,825,626.18	6,217.18	6,217.18	0 00	2,831,843.36
5550079	PJM Regulation-Credit	(858,835.34)	(107,770.97)	0.00	(107,770 97)	(966,606.31)
5550080	PJM Hourly Net Purch.-FERC	12,038,346.49	1,562,131.14	1,562,131.14	0 00	13,600,477.63
5550083	PJM Spinning Reserve-Charge	55,213 90	122,884 83	122,884.83	0.00	178,098.73
5550084	PJM Spinning Reserve-Credit	3,206 81	(44,596.78)	0.00	(44,596.78)	(41,389.97)
5550088	Normal Capacity Purchases	151,383 99	(151,383.99)	0.00	(151,383 99)	0 00
5550090	PJM 30m Suppl Rserv Charge LSE	31,441.52	46,006.57	46,006 57	0 00	77,448 09
5550093	Peak Hour Avail charge - LSE	(840,726.33)	840,726.33	840,726.33	0 00	0.00
5550094	Purchased Power - Fuel	9,428,359.86	4,466,783.17	4,466,783.17	0.00	13,895,143 03
5550096	Purch Power-Non Trad-Non-Fuel	284.39	(284.39)	0.00	(284 39)	0 00
5550099	PJM Purchases-non-ECR-Auction	11,123,939.35	(1,911,770 66)	0.00	(1,911,770 66)	9,212,168.69
5550100	Capacity Purchases-Auction	1,238,176.21	(276,874.50)	0 00	(276,874 50)	961,301.71
5550101	Purch Power-Pool Non-Fuel -Aff	817,312.39	709,884.61	709,884.61	0.00	1,527,197.00
5550102	Pur Power-Pool NonFuel-OSS-Aff	30,313,401.00	5,925,190.00	5,925,190.00	0.00	36,238,591.00
5550107	Capacity purchases - Trading	870,499 08	1,415,527.89	1,415,527.89	0.00	2,286,026.97
5560000	Sys Control & Load Dispatching	420,627.94	(41,907.60)	0.00	(41,907 60)	378,720.34
5570000	Other Expenses	2,714,754.75	(261,774.53)	0.00	(261,774.53)	2,452,980.22
5570007	Other Pwr Exp - Wholesale RECs	6,336 57	(223.77)	0 00	(223.77)	6,112 80
5570008	Other Pwr Exp - Voluntary RECs	460.68	(396.68)	0.00	(396 68)	64.00
5600000	Oper Supervision & Engineering	549,826.99	67,302.74	67,302.74	0 00	617,129.73
5610000	Load Dispatching	2,020.52	(2,020.52)	0.00	(2,020 52)	0.00
5611000	Load Dispatch - Reliability	10,064.03	4,088.89	4,088.89	0.00	14,152.92
5612000	Load Dispatch-Mntr&Op TransSys	750,573.60	58,307.45	58,307.45	0.00	808,881.05
5613000	Load Dispatch-Trans Srvc&Sched	1,666.42	(1,641.86)	0.00	(1,641.86)	24.56
5614000	PJM Admin-SSC&DS-OSS	82,301.86	13,160.42	13,160.42	0 00	95,462.28
5614001	PJM Admin-SSC&DS-Internal	985,722.66	217,070.25	217,070.25	0.00	1,202,792 91
5614007	RTO Admin Default LSE	18,532.76	(94,428.73)	0.00	(94,428.73)	(75,895.97)
5614008	PJM Admin Defaults OSS	2,928.03	(10,800 83)	0.00	(10,800.83)	(7,872.80)
5615000	Reliability,Plng&Stds Develop	42,904.59	49,238.50	49,238 50	0 00	92,143 09
5618000	PJM Admin-RP&SDS-OSS	16,123 84	5,930.19	5,930.19	0.00	22,054.03
5618001	PJM Admin-RP&SDS- Internal	189,312.48	85,887.89	85,887.89	0 00	275,200.37
5620001	Station Expenses - Nonassoc	209,552.82	(8,143.53)	0.00	(8,143.53)	201,409.29
5630000	Overhead Line Expenses	321,497.39	(200,389.31)	0.00	(200,389.31)	121,108 08
5650002	Transmssn Elec by Others-NAC	113,048 00	1,029.00	1,029 00	0.00	114,075.00
5650003	AEP Trans Equalization Agmt	(6,835,297.00)	821,477.00	821,477.00	0.00	(6,013,820.00)
5650012	PJM Trans Enhancement Charge	993,424.25	1,153,042.33	1,153,042.33	0.00	2,146,466 58
5650015	PJM TO Serv Exp - Aff	0 00	13,047.40	13,047.40	0.00	13,047.40
5650016	PJM NITS Expense - Affiliated	0.00	122,740.77	122,740.77	0.00	122,740.77
5650017	GFA Trans Exp Unb - Affiliate	0 00	53,803.46	53,803.46	0.00	53,803.46
5650018	PJM Trans Enhancement Credits	(132,740.71)	(118,742.16)	0.00	(118,742.16)	(251,482.87)
5660000	Misc Transmission Expenses	546,005.08	1,866,551.24	1,866,551.24	0.00	2,412,556.32
5670001	Rents - Nonassociated	8,863 43	(4,086.88)	0.00	(4,086.88)	4,776.55
5680000	Maint Supv & Engineering	111,517.73	15,936.74	15,936.74	0 00	127,454.47
5690000	Maintenance of Structures	13,556.04	19,317.17	19,317.17	0.00	32,873.21
5691000	Maint of Computer Hardware	46,128.20	1,532 66	1,532.66	0.00	47,660.86
5692000	Maint of Computer Software	260,106.72	(7,760.79)	0.00	(7,760.79)	252,345.93
5693000	Maint of Communication Equip	211,446.71	(2,055.98)	0.00	(2,055.98)	209,390.73
5700000	Maint of Station Equipment	788,987.01	(177,749.75)	0.00	(177,749.75)	611,237.26
5710000	Maintenance of Overhead Lines	1,868,950.96	(357,202.96)	0.00	(357,202.96)	1,511,748.00
5720000	Maint of Underground Lines	104 94	(106 80)	0.00	(106.80)	(1.86)
5730000	Maint of Misc Trnsmssion Plt	992.32	2,797.87	2,797.87	0.00	3,790.19
5757000	PJM Admin-MAM&SC- OSS	89,234.41	12,526.24	12,526.24	0.00	101,760.65
5757001	PJM Admin-MAM&SC- Internal	1,079,076.21	194,181.04	194,181.04	0.00	1,273,257.25
5800000	Oper Supervision & Engineering	821,457.57	(7,552.15)	0.00	(7,552.15)	813,905.42
5810000	Load Dispatching	3,743 66	(958.13)	0.00	(958.13)	2,785.53
5820000	Station Expenses	241,513.22	(37,070 80)	0.00	(37,070.80)	204,442.42
5830000	Overhead Line Expenses	1,196,627.96	(16,910.06)	0.00	(16,910.06)	1,179,717.90
5840000	Underground Line Expenses	91,618.15	42,310.76	42,310.76	0.00	133,928.91
5850000	Street Lighting & Signal Sys E	57,733.72	2,182.15	2,182.15	0.00	59,915 87
5860000	Meter Expenses	760,570.41	142,425.39	142,425 39	0.00	902,995.80
5870000	Customer Installations Exp	127,070.68	8,127.80	8,127.80	0 00	135,198.48
5880000	Miscellaneous Distribution Exp	2,706,033.68	7,715,244.21	7,715,244.21	0 00	10,421,277.89
5890001	Rents - Nonassociated	1,514,884.46	76,614.76	76,614.76	0 00	1,591,499.22
5890002	Rents - Associated	64,723.08	(34.26)	0.00	(34.26)	64,688.82
5900000	Maint Supv & Engineering	7,496.30	(5,016.44)	0.00	(5,016.44)	2,479.86
5910000	Maintenance of Structures	14,370 61	(2,139.57)	0.00	(2,139.57)	12,231.04
5920000	Maint of Station Equipment	916,709 00	(363,818.90)	0 00	(363,818.90)	552,890.10
5930000	Maintenance of Overhead Lines	20,152,131.31	106,955.65	106,955 65	0.00	20,259,086.96
5930001	Tree and Brush Control	160,206.22	73,580.57	73,580 57	0.00	233,786.79
5930010	Storm Expense Amortization	0.00	2,349,208 00	2,349,208.00	0.00	2,349,208.00
5930011	EMI Device Expense - Affiliate	0.00	30,106.63	30,106.63	0.00	30,106.63
5940000	Maint of Underground Lines	179,912.83	(65,804.93)	0.00	(65,804.93)	114,107.90
5950000	Maint of Lne Trnf,Rglators&Dvi	78,261.87	30,571.75	30,571.75	0.00	108,833 62
5960000	Maint of Strt Lghtng & Sgnal S	45,937.84	5,543.66	5,543 66	0.00	51,481.50
5970000	Maintenance of Meters	50,506.48	20,558.32	20,558.32	0 00	71,064.80
5980000	Maint of Misc Distribution Plt	502,102.79	(155,239.14)	0.00	(155,239.14)	346,863.65
9010000	Supervision - Customer Accts	388,255.94	(54,116.90)	0 00	(54,116.90)	334,139 04
9020000	Meter Reading Expenses	15,819.64	(3,856 89)	0.00	(3,856 89)	11,962.75

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Account Number	Description	Pr Yr Ending Balance	Yearly Activity	Debits	Credit	Current Yr Balance
9020001	Customer Card Reading	(12.50)	12.50	12.50	0.00	0.00
9020002	Meter Reading - Regular	603,118.74	(41,258.94)	0.00	(41,258.94)	561,859.80
9020003	Meter Reading - Large Power	41,119.83	6,454.16	6,454.18	0.00	47,573.99
9020004	Read-In & Read-Out Meters	53,716.75	(8,373.27)	0.00	(8,373.27)	45,343.48
9030000	Cust Records & Collection Exp	521,227.46	11,439.22	11,439.22	0.00	532,666.70
9030001	Customer Orders & Inquiries	2,653,726.52	(245,424.12)	0.00	(245,424.12)	2,408,302.40
9030002	Manual Billing	41,315.57	(8,090.36)	0.00	(8,090.36)	33,225.21
9030003	Postage - Customer Bills	763,677.27	(123,908.96)	0.00	(123,908.96)	639,768.31
9030004	Cashiering	121,956.17	6,104.39	6,104.39	0.00	128,060.56
9030005	Collection Agents Fees & Exp	103,626.53	(7,367.27)	0.00	(7,367.27)	96,259.26
9030006	Credit & Oth Collection Activi	970,332.91	37,495.78	37,495.78	0.00	1,007,826.87
9030007	Collectors	406,997.76	68,396.05	68,396.05	0.00	475,393.61
9030009	Data Processing	187,078.27	(43,680.14)	0.00	(43,680.14)	143,398.13
9040007	Uncoll Accts - Misc Receivable	9,395.16	813.01	813.01	0.00	10,208.17
9050000	Misc Customer Accounts Exp	11,052.84	19,677.34	19,677.34	0.00	30,730.18
9070000	Supervision - Customer Service	204,264.52	55,017.47	55,017.47	0.00	259,281.99
9070001	Supervision - DSM	4,444.51	(1,966.39)	0.00	(1,968.39)	2,478.12
9080000	Customer Assistance Expenses	448,097.68	34,861.54	34,861.54	0.00	482,959.22
9080009	Cust Assistance Expense - DSM	943,915.73	876,970.97	876,970.97	0.00	1,820,886.70
9090000	Information & Instruct Advrtis	210,254.21	(14,537.87)	0.00	(14,537.87)	195,716.34
9100000	Misc Cust Svc&Informational Ex	36,697.59	(4,326.63)	0.00	(4,326.63)	32,570.96
9110001	Supervision - Residential	0.00	57.81	57.81	0.00	57.81
9110002	Supervision - Comm & Ind	0.00	11.56	11.56	0.00	11.56
9130001	Advertising Exp - Residential	76.80	(76.80)	0.00	(76.80)	0.00
9200000	Administrative & Gen Salaries	6,732,281.08	783,160.89	783,160.89	0.00	7,515,441.97
9200003	Admin & Gen Salaries Trnsfr	0.00	46.34	46.34	0.00	46.34
9210001	Off Supl & Exp - Nonassociated	579,066.57	162,789.11	162,789.11	0.00	741,855.68
9210003	Office Supplies & Exp - Trnsf	0.00	43.35	43.35	0.00	43.35
9210004	Office Utilites	0.00	647.60	647.60	0.00	647.60
9210005	Cellular Phones and Pagers	20.58	(13.69)	0.00	(13.69)	6.89
9220000	Administrative Exp Trnsf - Cr	(6,270.73)	6,113.55	6,113.55	0.00	(157.18)
9220001	Admin Exp Trnsf to Cnstrctn	(411,899.93)	32,370.69	32,370.69	0.00	(379,529.24)
9220004	Admin Exp Trnsf to ABD	(9,865.77)	3,395.49	3,395.49	0.00	(6,470.28)
9220125	SSA Expense Transfers BL	(499,516.41)	(23,380.95)	0.00	(23,380.95)	(522,897.36)
9220127	SSA Expense Transfers IT	(53.00)	53.00	53.00	0.00	0.00
9230001	Outside Svcs Empl - Nonassoc	693,109.70	130,577.56	130,577.56	0.00	823,687.26
9230003	AEPSC Billed to Client Co	3,790,705.64	597,036.79	597,036.79	0.00	4,387,744.42
9240000	Property Insurance	406,398.71	100,350.51	100,350.51	0.00	506,749.22
9250000	Injuries and Damages	1,056,934.89	42,510.19	42,510.19	0.00	1,099,445.08
9250001	Safety Dinners and Awards	173.80	(173.80)	0.00	(173.80)	0.00
9250002	Emp Accdent Prvntion-Adm Exp	116,507.25	4,224.89	4,224.89	0.00	120,732.14
9250004	Injuries to Employees	295.76	22,268.72	22,268.72	0.00	22,564.48
9250006	Wrkrs Cmpnstn Pre&Slf Ins Prv	578,109.27	(407,219.95)	0.00	(407,219.95)	170,889.32
9250007	Prsnal Injries&Prop Dmage-Pub	285,902.06	(85,606.78)	0.00	(85,606.78)	200,295.28
9250010	Frg Ben Loading - Workers Comp	(115,727.47)	16,780.76	16,780.76	0.00	(98,946.71)
9260000	Employee Pensions & Benefits	9,672.75	(856.21)	0.00	(856.21)	8,816.54
9260001	Edit & Print Empl Pub-Salaries	17,741.95	5,869.03	5,869.03	0.00	23,610.98
9260002	Pension & Group Ins Admin	12,054.00	4,944.00	4,944.00	0.00	16,998.00
9260003	Pension Plan	2,215,416.24	780,186.96	780,186.96	0.00	2,995,603.20
9260004	Group Life Insurance Premiums	154,308.38	(11,467.38)	0.00	(11,467.38)	142,841.00
9260005	Group Medical Ins Premiums	5,116,828.93	(509,928.48)	0.00	(509,928.48)	4,606,900.45
9260006	Physical Examinations	125.00	(125.00)	0.00	(125.00)	0.00
9260007	Group L-T Disability Ins Prem	(3,021.98)	189,735.25	189,735.25	0.00	186,713.27
9260009	Group Dental Insurance Prem	172,899.50	73,965.86	73,965.86	0.00	246,865.36
9260010	Training Administration Exp	9,921.12	(5,410.48)	0.00	(5,410.48)	4,510.64
9260012	Employee Activities	895.42	836.52	836.52	0.00	1,731.94
9260014	Educational Assistance Pmts	23,179.38	1,808.00	1,808.00	0.00	24,987.38
9260021	Postretirement Benefits - OPEB	4,099,566.00	(752,727.97)	0.00	(752,727.97)	3,346,838.03
9260027	Savings Plan Contributions	1,613,756.46	(84,655.15)	0.00	(84,655.15)	1,529,101.32
9260036	Deferred Compensation	20,598.34	3,471.72	3,471.72	0.00	24,070.06
9260037	Supplemental Pension	2,799.85	(1,766.29)	0.00	(1,766.29)	1,033.56
9260050	Frg Ben Loading - Pension	(567,029.82)	(574,029.50)	0.00	(574,029.50)	(1,141,059.32)
9260051	Frg Ben Loading - Grp Ins	(1,806,989.00)	(52,507.97)	0.00	(52,507.97)	(1,859,496.97)
9260052	Frg Ben Loading - Savings	(553,397.89)	34,370.71	34,370.71	0.00	(519,027.18)
9260053	Frg Ben Loading - OPEB	(937,744.03)	81,200.59	81,200.59	0.00	(856,543.44)
9260055	IntercoFringeOffset- Don't Use	(989,279.95)	(112,728.42)	0.00	(112,728.42)	(1,102,008.37)
9260057	Postret Ben Medicare Subsidy	(867,380.64)	(87,538.09)	0.00	(87,538.09)	(954,916.73)
9260058	Frg Ben Loading - Accrual	124,125.02	(141,441.88)	0.00	(141,441.88)	(17,316.86)
9270000	Franchise Requirements	184,544.85	16,030.21	16,030.21	0.00	200,575.06
9280000	Regulatory Commission Exp	4.38	(12.02)	0.00	(12.02)	(7.66)
9280001	Regulatory Commission Exp-Adm	57.05	(61.71)	0.00	(61.71)	(4.66)
9280002	Regulatory Commission Exp-Case	(557.79)	88,828.12	88,828.12	0.00	88,270.33
9301001	Newspaper Advertising Space	272,547.03	(490,515.79)	0.00	(490,515.79)	(217,968.76)
9301002	Radio Station Advertising Time	1,500.00	(1,204.97)	0.00	(1,204.97)	295.03
9301006	Spec Corporate Comm Info Proj	0.00	0.08	0.08	0.00	0.08
9301008	Direct Mail and Handouts	561.79	(561.79)	0.00	(561.79)	0.00
9301009	Fairs, Shows, and Exhibits	522.45	(106.57)	0.00	(106.57)	415.88
9301010	Publicity	1,125.59	(351.99)	0.00	(351.99)	773.60
9301011	Dedications, Tours, & Openings	10.88	(3.39)	0.00	(3.39)	7.49
9301012	Public Opinion Surveys	32,805.31	(7,377.94)	0.00	(7,377.94)	25,427.37
9301013	Movies Slide Films & Speeches	23,151.09	(23,151.09)	0.00	(23,151.09)	0.00

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Account Number	Description	Pr Yr Ending Balance	Yearly Activity	Debits	Credit	Current Yr Balance
9301014	Video Communications	50.29	(20 94)	0.00	(20 94)	29.35
9301015	Other Corporate Comm Exp	66,630.40	(16,049 90)	0.00	(16,049 90)	50,580.50
9302000	Misc General Expenses	161,478.79	92,084.35	92,084.35	0.00	253,563.14
9302003	Corporate & Fiscal Expenses	28,091.18	(11,710.25)	0.00	(11,710.25)	16,380 94
9302004	Research, Develop&Demonstr Exp	4,945 82	10,568.38	10,568.38	0 00	15,514.20
9302007	Assoc Business Development Exp	313,101.83	(119,929 20)	0 00	(119,929.20)	193,172.63
9310000	Rents	1,679.25	4,600.75	4,600.75	0.00	6,280 00
9310001	Rents - Real Property	92,977.40	(2,593.13)	0.00	(2,593.13)	90,384.27
9310002	Rents - Personal Property	250,458.29	(108,153.69)	0 00	(108,153 69)	142,304.60
9350000	Maintenance of General Plant	767.49	(328.47)	0 00	(328.47)	439.02
9350001	Maint of Structures - Owned	391,495 81	129,721.72	129,721.72	0.00	521,217.33
9350002	Maint of Structures - Leased	69,861.05	11,652.72	11,652.72	0.00	81,513.77
9350006	Maint of Carrier Equipment	867.18	(867.18)	0.00	(867.18)	0.00
9350007	Maint of Radio Equip - Owned	55,562.53	(55,562.53)	0 00	(55,562.53)	0.00
9350012	Maint of Data Equipment	239 87	(126 64)	0.00	(126 64)	113.23
9350013	Maint of Cmmncation Eq-Unall	1,026,679 25	68,021 04	68,021.04	0 00	1,094,700.29
9350015	Maint of Office Furniture & Eq	32.50	227,919.16	227,919.16	0.00	227,951.66
9350016	Maintenance of Video Equipment	62.35	(62.35)	0.00	(62.35)	0.00
	NET INCOME - EARN FOR CMMN STK	(23,935,550.18)	(11,346,324.93)	0.00	(11,346,324.93)	(35,281,875.10)
	PREF STK DIVIDEND REQUIREMENT	0.00	0.00	0.00	0.00	0.00

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Account Number	Description	Pr Yr Ending Balance	Yearly Activity	Debits	Credit	Current Yr Balance
1010001	Plant In Service	1,610,127,823.01	26,940,608.44	26,940,608.44	0.00	1,637,068,431.45
1011001	Capital Leases	7,193,396.24	(1,465,281.68)	0.00	(1,465,281 68)	5,728,114.56
1011006	Prov-Leased Assets	(1,781,339.60)	(108,527.17)	0 00	(108,527.17)	(1,889,866.77)
1011012	Accrued Capital Leases	555.66	1,391.28	1,391.28	0 00	1,946.94
1050001	Held For Fut Use	7,436,550.73	0.00	0.00	0.00	7,436,550.73
1060001	Const Not Classifd	22,021,909 03	6,035,253.95	6,035,253.95	0 00	28,057,162.98
1070001	CWIP - Project	34,092,976.37	37,197,339.57	37,197,339 57	0.00	71,290,315.94
1080001	A/P for Deprec of Plt	(521,884,376.36)	(33,114,077.77)	0.00	(33,114,077.77)	(554,998,454.13)
1080005	RWIP - Project Detail	879,840.43	1,068,426.44	1,068,426.44	0 00	1,948,266.87
1080011	Cost of Removal Reserve	(30,011,722.93)	289,363.21	289,363 21	0 00	(29,722,359.72)
1080013	ARO Removal Deprec - Accretion	2,036,651.35	561,106.80	561,106.80	0.00	2,597,758.15
1110001	A/P for Amort of Plt	(19,461,910.74)	732,578.95	732,578.95	0.00	(18,729,331.79)
1210001	Nonutility Property - Owned	964,528.00	0 00	0.00	0 00	964,528.00
1220001	Depr&Amrt of Nonutl Prop-Ownd	(194,946.59)	(6,669.72)	0.00	(6,669.72)	(201,616.31)
1240002	Oth Investments-Nonassociated	806.00	0.00	0.00	0 00	806 00
1240005	Spec Allowance Inv NOx	50.67	(39.84)	0.00	(39.84)	10.83
1240007	Deferred Compensation Benefits	120,809.28	(10,822.34)	0.00	(10,822.34)	109,986.94
1240029	Other Property - CPR	4,734,975 63	0.00	0.00	0.00	4,734,975 63
1240044	Spec Allowances Inv SO2	33.17	(33.17)	0.00	(33.17)	0.00
1240092	Fbr Opt Lns-In Kind Sv-Invest	172,006 00	(4,395 00)	0 00	(4,395 00)	167,611.00
1310000	Cash	280,972.30	497,237.99	497,237.99	0.00	778,210.29
1340018	Spec Deposits - Elect Trading	1,381,154.02	402,808.54	402,808.54	0.00	1,783,962.56
1340043	Spec Deposit UBS Securities	5,596,940.62	1,086,367.74	1,086,367.74	0.00	6,683,308.36
1340048	Spec Deposits-Trading Contra	(3,374,582.00)	(1,866,294 00)	0.00	(1,866,294 00)	(5,240,876 00)
1340050	Spec Deposit Mizuho Securities	1,753,740.25	(1,570,765.95)	0 00	(1,570,765.95)	182,974 30
1410002	P/R Ded - Misc Loan Repayments	0.00	534.41	534.41	0 00	534.41
1420001	Customer A/R - Electric	37,513,873 61	(1,074,696.18)	0.00	(1,074,696.18)	36,439,177.43
1420014	Customer A/R-System Sales	665,768.93	(89,532.88)	0.00	(89,532.88)	576,236.05
1420019	Transmission Sales Receivable	16,704.00	(7,440.00)	0.00	(7,440 00)	9,264 00
1420022	Cust A/R - Factored	(35,446,282.39)	1,978,572.30	1,978,572.30	0.00	(33,467,710.09)
1420023	Cust A/R-System Sales - MLR	8,775,618 81	(1,563,859.19)	0.00	(1,563,859.19)	7,211,759 62
1420024	Cust A/R-Options & Swaps - MLR	362,252.92	124,059 07	124,059.07	0 00	486,311.99
1420027	Low Inc Energy Asst Pr (LIEAP)	593,592.00	563 00	563.00	0.00	594,155.00
1420044	Customer A/R - Estimated	5,932,642.00	(5,666,325.00)	0.00	(5,666,325.00)	266,317.00
1420050	PJM AR Accrual	0.00	450,300.49	450,300.49	0.00	450,300.49
1420052	Gas Accruals	4,022.19	1,339.49	1,339.49	0 00	5,361.68
1420053	AR Coal Trading	295,983.53	(140,652.11)	0.00	(140,652.11)	155,331.42
1420054	Accrued Power Brokers	214,289 54	(214,289.54)	0.00	(214,289.54)	0.00
1420102	AR Peoplesoft Billing - Cust	480,008 08	(268,787.78)	0.00	(268,787.78)	211,220.30
1430022	2001 Employee Biweekly Pay Cnv	74,102.65	(2,200 07)	0.00	(2,200 07)	71,902.58
1430081	Damage Recovery - Third Party	35,613.00	(17,567.82)	0.00	(17,567.82)	18,045.18
1430083	Damage Recovery Offset Demand	(52,677.00)	32,189 82	32,189 82	0.00	(20,487.18)
1430089	A/R - Benefits Billing	4,219.46	779 35	779.35	0 00	4,998.81
1430101	Other Accounts Rec - Misc	16,977.38	(16,977.38)	0.00	(16,977.38)	0.00
1430102	AR Peoplesoft Billing - Misc	151,756.45	(151,743 05)	0.00	(151,743.05)	13.40
1440002	Uncoll Accts-Other Receivables	(6,199.97)	6,199.97	6,199 97	0.00	0 00
1440003	Uncoll Accts-Power Trading	(617,080.43)	(5,645 63)	0.00	(5,645 63)	(622,726 06)
1450000	Corp Borrow Prg (NR-Assoc)	67,059,742.87	3,272,099 83	3,272,099.83	0.00	70,331,842.70
1460001	A/R Assoc Co - InterUnit G/L	12,185,346.37	(5,163,337.69)	0.00	(5,163,337.69)	7,022,008.68
1460002	A/R Assoc Co - Allowances	1,898,460.49	(1,898,460.49)	0.00	(1,898,460.49)	0.00
1460006	A/R Assoc Co - Intercompany	376,403.73	7,453.75	7,453.75	0.00	383,857.48
1460009	A/R Assoc Co - InterUnit A/P	29,438.43	(13,004.41)	0.00	(13,004.41)	16,434 02
1460011	A/R Assoc Co - Multi Pmts	1,446,173 02	(485,438.02)	0.00	(485,438.02)	960,735.00
1460019	A/R-Assoc Co-AEPSC-Agent	377,241.00	(377,241.00)	0.00	(377,241.00)	0.00
1460024	A/R Assoc Co - System Sales	30,321.45	(25,830.47)	0.00	(25,830.47)	4,490 98
1460025	Fleet - M4 - A/R	15,828 90	2,028.30	2,028.30	0.00	17,857.20
1510001	Fuel Stock - Coal	14,872,926.88	6,737,544 32	6,737,544.32	0.00	21,610,471.20
1510002	Fuel Stock - Oil	658,271.27	328,910.25	328,910.25	0 00	987,181.52
1510020	Fuel Stock Coal - Intransit	815,384.70	(815,384.70)	0.00	(815,384.70)	0 00
1520000	Fuel Stock Exp Undistributed	292,974.82	115,162.34	115,162.34	0.00	408,137.16
1540001	M&S - Regular	10,708,013.77	228,029.06	228,029.06	0.00	10,936,042.83
1540004	M&S - Exempt Material	45,598.23	5,895.07	5,895.07	0.00	51,493 30
1540012	Materials & Supplies - Urea	287,071.68	(9,504.26)	0 00	(9,504.26)	277,567.42
1540013	Transportation Inventory	72,751.03	11,454.92	11,454.92	0.00	84,205.95
1540023	M&S Inv - Urea In-Transit	1,052,462.72	722,982.89	722,982.89	0.00	1,775,445 61
1561000	SO2 Allowance Inventory	4,882,415.98	(1,356,487.58)	0.00	(1,356,487.58)	3,525,928.40
1581003	SO2 Allowance Inventory - Curr	12,027,962.24	1,490,710.98	1,490,710.98	0 00	13,518,673 22
1581006	An. NOx Comp Inv - Curr	184,206.40	(25,801.54)	0.00	(25,801.54)	158,404.86
1581009	CSAPR Current SO2 Inv	0.00	350,000.00	350,000.00	0.00	350,000.00
1650001	Prepaid Insurance	347,069.60	5,196.40	5,196.40	0.00	352,266 00
165000210	Prepaid Taxes	399,674.78	(399,674.78)	0.00	(399,674.78)	0.00
165000211	Prepaid Taxes	0 00	412,861.18	412,861.18	0.00	412,861.18
1650009	Prepaid Carry Cost-Factored AR	24,052.44	(3,695.11)	0.00	(3,695.11)	20,357.33
1650010	Prepaid Pension Benefits	18,024,475.96	7,640,999 96	7,640,999.96	0.00	25,665,475.92
165001110	Prepaid Sales Taxes	339,691.13	(339,691.13)	0.00	(339,691.13)	0.00

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Account Number	Description	Pr Yr Ending Balance	Yearly Activity	Debits	Credit	Current Yr Balance
165001111	Prepaid Sales Taxes	0.00	348,741.24	348,741.24	0.00	348,741.24
165001210	Prepaid Use Taxes	30,787.79	(30,787.79)	0.00	(30,787.79)	0.00
165001211	Prepaid Use Taxes	0.00	51,118.18	51,118.18	0.00	51,118.18
1650014	FAS 158 Qual Contra Asset	(18,024,475.96)	(7,640,999.96)	0 00	(7,640,999.96)	(25,665,475.92)
1650021	Prepaid Insurance - EIS	253,339.49	15,690.11	15,690.11	0.00	269,029.60
1650023	Prepaid Lease	2,928.12	2,526.36	2,526 36	0 00	5,454.48
1710000	Interest&Dividends Receivable	0.00	1,850,772.00	1,850,772.00	0.00	1,850,772.00
1710248	Interest Receivable -FIT -ST	344,842.00	(344,842.00)	0 00	(344,842.00)	0.00
1710448	Interest Receivable. -SIT -ST	12,386.00	(12,386 00)	0 00	(12,386 00)	0.00
1720000	Rents Receivable	2,243,464.87	264,231.67	264,231.67	0 00	2,507,696.54
1730000	Accrued Utility Revenues	31,228,544 24	(9,524,310.34)	0.00	(9,524,310.34)	21,704,233.90
1730002	Acrd Utility Rev-Factored-Assc	(27,405,152.03)	9,080,336.51	9,080,336 51	0.00	(18,324,815.52)
1740000	Misc Current & Accrued Assets	8.22	(8.22)	0 00	(8.22)	0.00
1750001	Curr. Unreal Gains - NonAffil	8,957,232.27	17,201.59	17,201.59	0 00	8,974,433.86
1750002	Long-Term Unreal Gns - Non Aff	8,063,223.74	467,237.07	467,237.07	0 00	8,530,460.81
1750021	S/T Asset MTM Collateral	(339,000.00)	(332,776.00)	0 00	(332,776.00)	(671,776.00)
1750022	L/T Asset MTM Collateral	(36,017.00)	(200,111.00)	0 00	(200,111.00)	(236,128.00)
1760010	S/T Asset for Commodity Hedges	78,854.00	6,868.00	6,868.00	0.00	85,722.00
1760011	L/T Asset for Commodity Hedges	2,466 00	3,059.00	3,059 00	0.00	5,525.00
1810006	Unamort Debt Exp - Sr Unsec Nt	2,814,202.55	(304,461.47)	0 00	(304,461.47)	2,509,741.08
1823007	SFAS 112 Postemployment Benef	8,456,335.62	(1,251,379 60)	0 00	(1,251,379 60)	5,204,956.02
1823009	DSM Incentives	1,244,548.00	408,249 00	408,249.00	0.00	1,652,797.00
1823010	DSM Recovery	(16,945,216 00)	(3,350,222.00)	0.00	(3,350,222.00)	(20,295,438.00)
1823011	DSM Lost Revenues	4,018,519 00	874,440 00	874,440.00	0.00	4,892,959.00
1823012	DSM Program Costs	11,708,655.00	2,200,998.41	2,200,998.41	0.00	13,909,653.41
1823022	HRJ 765kV Post Service AFUDC	732,456 00	(33,408.00)	0.00	(33,408 00)	699,048.00
1823054	HRJ 765kV Depreciation Expense	114,145 00	(5,208 00)	0.00	(5,208.00)	108,937.00
1823077	Unreal Loss on Fwd Commitments	93,036.27	(93,036.27)	0.00	(93,036.27)	0 00
1823078	Deferred Storm Expense	21,142,998.00	(4,698,444.00)	0 00	(4,698,444.00)	16,444,554 00
1823115	Defd Equity Carry Chg-Non Fuel	(152,540.65)	22,428.00	22,428.00	0.00	(130,112.65)
1823118	BridgeCo TO Funding	314,496.11	(23,783.56)	0.00	(23,783.56)	290,712.55
1823119	PJM Integration Payments	510,427.13	(113,897.25)	0 00	(113,897.25)	396,529.88
1823120	Other PJM Integration	332,264.43	(25,127.29)	0 00	(25,127.29)	307,137.14
1823121	Carry Chgs-RTO Startup Costs	203,837.28	(26,687.86)	0.00	(26,687.86)	177,149 42
1823122	Alliance RTO Deferred Expense	164,603.71	(12,448 08)	0 00	(12,448.08)	152,155 63
1823165	REG ASSET FAS 158 QUAL PLAN	42,950,406.00	3,456,791.00	3,456,791.00	0.00	46,407,197.00
1823166	REG ASSET FAS 158 OPEB PLAN	16,032,268 00	4,083,079.00	4,083,079 00	0.00	20,115,347.00
1823167	REG Asset FAS 158 SERP Plan	(129,506.00)	(1,000.00)	0.00	(1,000.00)	(130,506.00)
1823188	Deferred Carbon Mgmt Research	275,002.00	(49,996.00)	0.00	(49,996 00)	225,006.00
1823301	SFAS 109 Flow Thru Defd FIT	83,182,558.29	(593,655.87)	0.00	(593,655.87)	82,588,902.42
1823302	SFAS 109 Flow Thru Defrd SIT	42,232,048.27	(636,907.20)	0 00	(636,907.20)	41,595,141.07
1823306	Net CCS FEED Study Costs	0 00	905,127.70	905,127.70	0.00	905,127.70
1830000	Prelimin Surv&Investgtn Chrgs	21,673,627.77	(17,693,235.15)	0.00	(17,693,235.15)	3,980,392.62
1860001	Allowances	323.09	132.00	132.00	0.00	455 09
1860002	Deferred Expenses	0 00	2,747,820.17	2,747,820.17	0.00	2,747,820.17
186000310	Deferred Property Taxes	7,970,436.00	(7,970,436 00)	0.00	(7,970,436.00)	0.00
186000311	Deferred Property Taxes	0.00	10,031,245.00	10,031,245 00	0.00	10,031,245 00
1860007	Billings and Deferred Projects	72,149.17	(8,248.05)	0 00	(8,248.05)	63,901.12
1860077	Agency Fees - Factored A/R	1,257,028.69	(221,178.18)	0 00	(221,178.18)	1,035,850.51
1860153	Unamortized Credit Line Fees	311,615.70	407,480.23	407,480.23	0.00	719,095.93
1860160	Deferred Expenses - Current	578.77	1,429,635.40	1,429,635.40	0.00	1,430,214.17
1860166	Def Lease Assets - Non Taxable	26,580.31	(5,746.25)	0.00	(5,746.25)	20,834 06
1890004	Loss Rec Debt-Debentures	737,464.60	(33,648.60)	0.00	(33,648 60)	703,816 00
1900006	ADIT Federal - SFAS 133 Nonaff	54,733.05	129,511.66	129,511.66	0.00	184,244.71
1900015	ADIT-Fed-Hdg-CF-Int Rate	216,897.60	(32,534.64)	0.00	(32,534.64)	184,362.96
1901001	Accum Deferred FIT - Other	14,422,180.22	5,538,389 26	5,538,389.26	0.00	19,960,569.48
1902001	Accum Defd FIT - Oth Inc & Ded	407,301.79	233,329.62	233,329 62	0.00	640,631.41
1903001	Acc Dfd FIT - FAS109 Flow Thru	13,666,359.26	(610,585.28)	0.00	(610,585.28)	13,055,773.98
1904001	Accum Dfd FIT - FAS 109 Excess	381,843.53	(24,747.15)	0.00	(24,747.15)	357,096.38
	TOTAL ASSETS AND OTHER DEBITS	**1,573,464,080.48**	**29,128,370.73**	**29,128,370.73**	**0.00**	**1,602,592,451.21**
2010001	Common Stock Issued-Affiliated	(50,450,000.00)	0.00	0 00	0 00	(50,450,000.00)
2080000	Donations Recvd from Stckhldrs	(238,750,000 00)	0.00	0.00	0.00	(238,750,000.00)
2160001	Unapprp Retnd Erngs-Unrstrictd	(143,184,638 96)	(14,281,875.10)	0 00	(14,281,875.10)	(157,466,514.06)
2190010	OCI for Commodity Hedges	48,318.73	234,536.45	234,536.45	0.00	282,855.18
2190015	Accum OCI-Hdg-CF-Int Rate	402,810.40	(60,421.56)	0 00	(60,421.56)	342,388 84
2230000	Advances from Associated Co	(20,000,000 00)	0.00	0.00	0.00	(20,000,000 00)
2240006	Senior Unsecured Notes	(530,000,000.00)	0.00	0.00	0.00	(530,000,000 00)
2260006	Unam Disc LTD-Dr-Sr Unsec Note	1,111,500.00	(166,725 00)	0.00	(166,725.00)	944,775.00
4380001	Div Decld - Common Stk - Asso	21,000,000.00	7,000,000 00	7,000,000.00	0.00	28,000,000.00
	TOTAL CAPITALIZATION	**(959,822,009.83)**	**(7,274,485.21)**	**0.00**	**(7,274,485.21)**	**(967,096,495.04)**
2270001	Obligatns Undr Cap Lse-Noncurr	(3,568,506.22)	1,182,495.78	1,182,495.78	0.00	(2,386,010.44)
2270003	Accrued Noncur Lease Oblig	(277.83)	(1,279 71)	0.00	(1,279.71)	(1,557.54)
2282003	Accm Prv I/D - Worker's Com	(50,087.67)	(58,426.55)	0.00	(58,426 55)	(108,514 22)
2283000	Accm Prv for Pensions&Benefits	(129,506.35)	(999.96)	0.00	(999.96)	(130,506.31)
2283002	Supplemental Savings Plan	(702,953.08)	278,051 88	278,051.88	0.00	(424,901.20)

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Account Number	Description	Pr Yr Ending Balance	Yearly Activity	Debits	Credit	Current Yr Balance
2283003	SFAS 106 Post Retirement Benef	(5,608,808.60)	(611,329.81)	0 00	(611,329.81)	(6,220,138 41)
2283005	SFAS 112 Postemployment Benef	(5,182,903.62)	861,473.24	861,473 24	0.00	(4,321,430.38)
2283007	Perf Share Incentive Plan	(604,735 51)	57,276.29	57,276.29	0.00	(547,457.22)
2283013	Incentive Comp Deferral Plan	(319,534.44)	50,222.98	50,222.98	0 00	(269,311.46)
2283015	FAS 158 SERP Payable Long Term	129,506.00	1,000.00	1,000.00	0 00	130,506 00
2283016	FAS 158 Qual Payable Long Term	(24,925,930.04)	4,184,208.96	4,184,208.96	0.00	(20,741,721.08)
2283017	FAS 158 OPEB Payable Long Term	(16,032,268 00)	(4,083,079.00)	0 00	(4,083,079 00)	(20,115,347.00)
2283018	SFAS 106 Med Part-D	5,601,495.61	611,335.82	611,335.82	0.00	6,212,831.43
2300001	Asset Retirement Obligations	(4,186,406.25)	414,851.60	414,851.60	0.00	(3,771,554 65)
2320001	Accounts Payable - Regular	(3,331,658.66)	(5,435,857.70)	0.00	(5,435,857.70)	(8,767,516.36)
2320002	Unvouchered Invoices	(7,882,515.02)	1,156,859.81	1,156,859 81	0.00	(6,725,655.21)
2320003	Retention	(172,765.66)	(191,961.69)	0 00	(191,961.69)	(364,727.35)
2320006	Allowance Settlements	(486,000.00)	(454,100.00)	0.00	(454,100.00)	(940,100.00)
2320011	Uninvoiced Fuel	(14,034,985 82)	(984,529.44)	0 00	(984,529.44)	(15,019,515.26)
2320050	Coal Trading	(170,374.74)	6,923.26	6,923.26	0.00	(163,451.48)
2320052	Accounts Payable - Purch Power	(2,340,114.01)	1,054,902.35	1,054,902.35	0.00	(1,285,211.66)
2320053	Elect Trad-Options&Swaps	(570,063.39)	(299,924.21)	0.00	(299,924.21)	(869,987.60)
2320056	Gas Physicals	(448.16)	447.26	447.26	0.00	(0.90)
2320062	Broker Fees Payable	(10,813.18)	(713.16)	0 00	(713.16)	(11,526.34)
2320071	Gas Accruals GDA Trans-Payable	(2,939.39)	2,939.39	2,939 39	0.00	0.00
2320073	A/P Misc Dedic. Power	(12,831.00)	(6,904.50)	0.00	(6,904 50)	(19,735.50)
2320076	Corporate Credit Card Liab	(133,012.89)	77,355.88	77,355 88	0.00	(55,657.01)
2320077	INDUS Unvouchered Liabilities	(1,362,905.88)	866,580.31	866,580.31	0.00	(496,325.57)
2320079	Broker Commisn Spark/Merch Gen	(1.00)	(39.77)	0.00	(39.77)	(40.77)
2320083	PJM Net AP Accrual	(1,746,196 91)	1,746,196.91	1,746,196.91	0.00	0.00
2320084	Uninvoiced OVEC Purch Power	0.00	(275,079.47)	0.00	(275,079.47)	(275,079 47)
2320086	Accrued Broker - Power	(540,256.06)	(271,447.42)	0.00	(271,447.42)	(811,703.48)
2320090	MISO AP Accrual	(535,782.76)	266,081.85	266,081.85	0 00	(269,700.91)
2340001	A/P Assoc Co - InterUnit G/L	(23,739,034.46)	6,017,671.13	6,017,671.13	0.00	(17,721,363.34)
2340005	A/P Assoc Co - Allowances	(11,503,060.96)	(838,509.53)	0.00	(838,509.53)	(12,341,570.49)
2340011	A/P-Assc Co-AEPSC-Agent	(7,048,455.00)	5,328,870.00	5,328,870.00	0.00	(1,719,585.00)
2340025	A/P Assoc Co - CM Bills	(35,368.17)	25,238.86	25,238.86	0 00	(10,129.31)
2340027	A/P Assoc Co - Intercompany	(195,155.55)	406,316.04	406,316.04	0.00	211,160.49
2340029	A/P Assoc Co - AEPSC Bills	(3,073,686.35)	(123,055.91)	0.00	(123,055.91)	(3,196,742.26)
2340030	A/P Assoc Co - InterUnit A/P	(170,474.55)	(156,417.58)	0 00	(156,417.58)	(326,892.13)
2340032	A/P Assoc Co - Multi Pmts	(13.98)	(51.02)	0.00	(51.02)	(65.00)
2340034	A/P Assoc Co - System Sales	(17,859.60)	14,619.70	14,619.70	0.00	(3,239.90)
2340035	Fleet - M4 - A/P	(5,942.24)	(16,104.22)	0 00	(16,104.22)	(22,046.46)
2340037	A/P Assoc-Global Borrowing Int	(87,500.00)	0.00	0 00	0.00	(87,500.00)
2340049	A/P Assoc -Realization Sharing	(1,051.00)	471.00	471.00	0.00	(580.00)
2350001	Customer Deposits-Active	(19,370,357.42)	(2,458,336.84)	0 00	(2,458,336.84)	(21,828,694.26)
2350003	Deposits - Trading Activity	(697,186.54)	441,286.02	441,286.02	0.00	(255,900.52)
2350005	Deposits - Trading Contra	375,017.00	(364,499.00)	0.00	(364,499.00)	10,518.00
2360001	Federal Income Tax	(6,894,905 85)	1,379,122.49	1,379,122.49	0.00	(5,515,783.36)
236000209	State Income Taxes	0.00	63,670.00	63,670.00	0.00	63,670.00
236000210	State Income Taxes	1,419,402.70	(1,419,402.70)	0.00	(1,419,402.70)	0.00
236000211	State Income Taxes	0 00	(620,201.72)	0.00	(620,201.72)	(620,201.72)
2360004	FICA	(168,874.31)	45,805.07	45,805.07	0.00	(123,069.24)
2360005	Federal Unemployment Tax	(7,203.53)	(6,699.12)	0 00	(6,699.12)	(13,902.65)
2360006	State Unemployment Tax	(9,585.49)	3,341.81	3,341.61	0.00	(6,243.68)
236000710	State Sales and Use Taxes	(65,517.10)	65,517.10	65,517.10	0.00	0.00
236000711	State Sales and Use Taxes	0.00	(120,944.86)	0 00	(120,944.86)	(120,944.86)
236000808	Real & Personal Property Taxes	(136,260.95)	135,814.19	135,614.19	0.00	(448.76)
236000809	Real & Personal Property Taxes	(6,047,621.56)	6,015,907.06	6,015,907.06	0.00	(31,714.50)
236000810	Real Personal Property Taxes	(7,970,436.00)	5,604,707.32	5,604,707.32	0.00	(2,365,728.68)
236000811	Real Personal Property Taxes	0 00	(10,031,245.00)	0.00	(10,031,245.00)	(10,031,245.00)
236001211	State Franchise Taxes	0.00	8,908.00	6,908 00	0.00	8,908 00
236001610	State Gross Receipts Tax	(64,716.00)	64,716.00	64,716 00	0.00	0 00
236001611	State Gross Receipts Tax	0.00	(48,000.00)	0.00	(48,000.00)	(46,000.00)
236003309	Pers Prop Tax-Cap Leases	3,341.63	(3,323.65)	0.00	(3,323.65)	17.98
236003310	Pers Prop Tax-Cap Leases	(106,300.00)	2,183.67	2,183 67	0.00	(104,116.33)
236003311	Pers Prop Tax-Cap Leases	0.00	(77,647.73)	0.00	(77,647.73)	(77,647.73)
236003509	Real Prop Tax-Cap Leases	14,699.81	(14,389.07)	0.00	(14,389 07)	310.74
236003510	Real Prop Tax-Cap Leases	(13,785.17)	13,785.17	13,785.17	0.00	0 00
236003511	Real Prop Tax-Cap Leases	0 00	2,189.54	2,189 54	0.00	2,189.54
2360037	FICA - Incentive accrual	(215,138 53)	47,363.97	47,363 97	0.00	(167,774.56)
2360038	Reorg Payroll Tax Accrual	(46,661 65)	46,661.65	46,681.65	0.00	0.00
2360501	Fed Inc Tax-Short Term FIN48	(1,580,224.00)	1,580,224.00	1,580,224 00	0.00	0.00
2360502	State Inc Tax-Short Term FIN48	(431,674 00)	158,952.00	158,952.00	0.00	(272,722.00)
2360601	Fed Inc Tax-Long Term FIN48	(737,948.06)	(503,718.00)	0.00	(503,718.00)	(1,241,664.06)
2360602	State Inc Tax-Long Term FIN48	(111,626.00)	17,880.00	17,880.00	0.00	(93,746 00)
2360701	SEC Accum Defd FIT-Util FIN 48	2,389,490.00	(1,147,826.00)	0.00	(1,147,826.00)	1,241,664.00
2360702	SEC Accum Defd SIT - FIN 48	377,056.00	(178,861.00)	0 00	(178,861.00)	198,195.00
2370006	Interest Accrd-Sen Unsec Notes	(6,461,093.10)	(0.03)	0.00	(0.03)	(6,461,093.13)
2370007	Interest Accrd-Customer Depsts	(1,018,537.94)	(112,040.51)	0.00	(112,040.51)	(1,130,578.45)

KYP CORP CONSOLIDATED
Trial Balance
For The Month Ended DECEMBER 31, 2011

Account Number	Description	Pr Yr Ending Balance	Yearly Activity	Debits	Credit	Current Yr Balance
2370018	Accrued Margin Interest	(3,012.13)	247.97	247.97	0 00	(2,764.16)
2370048	Acrd Int.- FIT Reserve - LT	(547,119 00)	508,680.00	508,680 00	0.00	(38,439 00)
2370348	Acrd Int. - SIT Reserve - LT	(18,390 00)	10,605.00	10,605.00	0.00	(7,785.00)
2370448	Acrd Int. - SIT Reserve - ST	0.00	(72,817.00)	0.00	(72,817.00)	(72,817.00)
2410001	Federal Income Tax Withheld	(214,417.08)	44,823.16	44,823.16	0.00	(169,593.92)
2410002	State Income Tax Withheld	(146,019 05)	15,930.90	15,930 90	0 00	(130,088.15)
2410003	Local Income Tax Withheld	(20,115.52)	39 27	39 27	0 00	(20,076.25)
2410004	State Sales Tax Collected	(766,911.75)	(30,488 83)	0.00	(30,488 83)	(797,400.58)
2410005	FICA Tax Withheld	(104,159.95)	46,077.61	46,077.61	0.00	(58,082.34)
2410008	Franchise Fee Collected	(185,402 13)	(208,954.45)	0.00	(208,954.45)	(394,356.58)
2410009	KY Utility Gr Receipts Lic Tax	(1,239,874.24)	167,271.00	167,271.00	0 00	(1,072,603.24)
2420002	P/R Ded - Medical Insurance	(85,310.28)	(11,497.67)	0.00	(11,497.67)	(96,807.95)
2420003	P/R Ded - Dental Insurance	(7,423.92)	(452.74)	0.00	(452.74)	(7,876 66)
2420018	P/R Ded-Reg&Spec Life Ins Prem	0.00	(1.68)	0 00	(1.68)	(1.68)
2420021	Vacation Pay - Next Year	(2,954,346.06)	(290,166.97)	0.00	(290,166.97)	(3,244,513.03)
2420027	FAS 112 CURRENT LIAB	(1,273,428 00)	389,906.36	389,906.36	0 00	(883,521.64)
2420044	P/R Withholdings	(48,388.99)	5,742.49	5,742.49	0.00	(42,646.50)
2420051	Non-Productive Payroll	(37,619.40)	(9,349 07)	0.00	(9,349 07)	(46,968.46)
2420053	Perf Share Incentive Plan	(111,258.19)	(145,870.04)	0 00	(145,870.04)	(257,128 23)
2420071	P/R Ded - Vision Plan	(3,615.98)	2.07	2.07	0.00	(3,613.91)
2420076	P/R Savings Plan - Incentive	(115,556.52)	28,748.98	28,748.98	0.00	(86,807.54)
2420511	Control Cash Disburse Account	(621,992.83)	(2,715,121.16)	0 00	(2,715,121.16)	(3,337,113.99)
2420512	Unclaimed Funds	(745.42)	(1,236 51)	0.00	(1,236 51)	(1,981.93)
2420514	Revenue Refunds Accrued	(1,974,128.30)	204,460.53	204,460.53	0.00	(1,769,667.77)
2420532	Adm Liab-Cur-S/Ins-W/C	(608,966.01)	114,090.50	114,090.50	0.00	(494,875.51)
2420542	Acc Cash Franchise Req	(97,874.70)	14,243.28	14,243 28	0.00	(83,631.42)
2420558	Admitted Liab NC-Self/Ins-W/C	(1,471,859.92)	1,201.00	1,201.00	0.00	(1,470,658 92)
242059210	Sales Use Tax - Leased Equip	(75,772.66)	75,772.66	75,772.66	0.00	0.00
242059211	Sales Use Tax - Leased Equip	0 00	(2,054 61)	0 00	(2,054 61)	(2,054.61)
2420618	Accrued Payroll	(519,009.25)	(14,054 84)	0 00	(14,054 84)	(533,064.09)
2420623	Distr, Cust Ops & Reg Svcs ICP	(1,550,590.41)	488,108.24	488,108.24	0.00	(1,062,482.17)
2420624	Corp & Shrd Srv Incentive Plan	(187,360.00)	18,953 82	18,953.82	0 00	(168,406.18)
2420635	Generation Incentive Plan	(869,620.00)	(5,027.68)	0.00	(5,027.68)	(874,647.68)
2420643	Accrued Audit Fees	(12,961.75)	(8,673.16)	0.00	(8,673.16)	(21,634.91)
2420651	Reorg Severance Accrual	(20,006.40)	20,006.40	20,006.40	0.00	0.00
2420653	Reorg Misc HR Exp Accrual	(690,526.02)	690,526 02	690,526 02	0.00	0 00
2420656	Federal Mitigation Accru (NSR)	(164,299.79)	(1,214,284.58)	0 00	(1,214,284.58)	(1,378,584 37)
2420658	Accrued Prof. Tax Services	(42,482.00)	(88,448 00)	0.00	(88,448.00)	(130,930.00)
2420660	AEP Transmission ICP	(240,850.00)	10,872.67	10,872.67	0.00	(229,977.33)
2420661	Chief Admin Officer ICP	(20,560.00)	20,560.00	20,560.00	0.00	0.00
2420664	ST State Mitigation Def (NSR)	(452,183.31)	(128,976.34)	0.00	(128,976.34)	(581,159.65)
2430001	Oblig Under Cap Leases - Curr	(1,843,550.42)	391,313.07	391,313.07	0.00	(1,452,237.35)
2430003	Accrued Cur Lease Oblig	(277.83)	(111.57)	0 00	(111.57)	(389.40)
2440001	Curr. Unreal Losses - NonAffil	(7,337,232.24)	(1,851,195.58)	0.00	(1,851,195.58)	(9,188,427.82)
2440002	LT Unreal Losses - Non Affil	(4,013,269.72)	(773,533.06)	0.00	(773,533.06)	(4,786,802.78)
2440003	Curr. Unreal Losses - Affil	(72,544.00)	72,544.00	72,544 00	0 00	0.00
2440009	S/T Option Premium Receipts	(55,869.04)	50,379.74	50,379.74	0.00	(5,489.30)
2440010	L/T Option Premium Receipts	(6,526.89)	6,526.89	6,526.89	0.00	0.00
2440021	S/T Liability MTM Collateral	1,657,390.00	2,367,898.00	2,367,898.00	0.00	4,025,288 00
2440022	L/T Liability MTM Collateral	1,717,192.00	395,782.00	395,782.00	0.00	2,112,974.00
2450010	S/T Liability-Commodity Hedges	(150,677.00)	(309,692.00)	0.00	(309,692.00)	(460,369.00)
2450011	L/T Liability-Commodity Hedges	(61.00)	(60,424.00)	0.00	(60,424 00)	(60,485.00)
2520000	Customer Adv for Construction	(93,401.81)	402.67	402.67	0.00	(92,999.14)
2530000	Other Deferred Credits	(14,378.39)	(2,735,621.61)	0.00	(2,735,621.61)	(2,750,000.00)
2530022	Customer Advance Receipts	(827,471.65)	(1,074,318.79)	0 00	(1,074,318.79)	(1,901,790.44)
2530050	Deferred Rev -Pole Attachments	(97,251.23)	(56,134.39)	0.00	(56,134.39)	(153,385 62)
2530067	IPP - System Upgrade Credits	(243,963.72)	(8,025.98)	0.00	(8,025.98)	(251,989.70)
2530092	Fbr Opt Lns-In Kind Sv-Dfd Gns	(172,006 00)	4,395.00	4,395.00	0.00	(167,611.00)
2530112	Other Deferred Credits-Curr	(1,031,514.73)	39,125.55	39,125 55	0.00	(992,389.18)
2530113	State Mitigation Deferal (NSR)	(325,920.02)	325,920.02	325,920.02	0.00	0.00
2530114	Federl Mitigation Deferal(NSR)	(1,425,492.60)	1,425,492 60	1,425,492.60	0.00	0.00
2530137	Fbr Opt Lns-Sold-Defd Rev	(143,841.02)	13,555.80	13,555 80	0.00	(130,285.22)
2540011	Over Recovered Fuel Cost	(863,928.88)	(2,274,017.00)	0.00	(2,274,017.00)	(3,137,945.88)
2540047	Unreal Gain on Fwd Commitments	(5,844,355.89)	2,308,111.24	2,308,111.24	0 00	(3,536,244 65)
2540105	Home Energy Assist Prgm - KPCO	(177,765.21)	(88,636.59)	0.00	(88,636.59)	(266,401.80)
2540173	Green Pricing Option	(584 00)	(30.00)	0.00	(30 00)	(614 00)
2543001	SFAS109 Flow Thru Def FIT Liab	(534,768.23)	193,510.78	193,510.78	0 00	(341,257.45)
2544001	SFAS 109 Exces Deferred FIT	(1,090,981.53)	70,706.15	70,706.15	0 00	(1,020,275.38)
2550001	Accum Deferred ITC - Federal	(993,141.00)	359,377.18	359,377.18	0 00	(633,763 82)
2811001	Acc Dfd FIT - Accel Amort Prop	(29,802,203.90)	1,572,533.90	1,572,533.90	0.00	(28,229,670.00)
2821001	Accum Defd FIT - Utility Prop	(168,448,771.87)	(23,536,779.99)	0.00	(23,536,779 99)	(191,985,551.86)
2823001	Acc Dfrd FIT FAS 109 Flow Thru	(52,419,036.93)	580,033.28	580,033.28	0 00	(51,839,003 65)
2824001	Acc Dfrd FIT - SFAS 109 Excess	709,138.00	(45,959 00)	0.00	(45,959.00)	663,179 00
2830006	ADIT Federal - SFAS 133 Nonaff	(28,716.73)	(3,219 27)	0.00	(3,219 27)	(31,936.00)
2831001	Accum Deferred FIT - Other	(18,350,250.05)	(478,279 66)	0.00	(478,279.66)	(18,828,529.71)

KYP CORP CONSOLIDATED
Trial Balance
For The Month Ended DECEMBER 31, 2011

Account Number	Description	Pr Yr Ending Balance	Yearly Activity	Debits	Credit	Current Yr Balance
2832001	Accum Dfrd FIT - Oth Inc & Ded	(34,017.94)	(33,922.08)	0.00	(33,922.08)	(67,940.02)
2833001	Acc Dfd FIT FAS 109 Flow Thru	(43,895,112.39)	430,697.09	430,697.09	0.00	(43,464,415.30)
2833002	Acc Dfrd SIT FAS 109 Flow Thru	(42,232,048.27)	636,907.20	636,907.20	0.00	(41,595,141.07)
	LIABILITIES AND OTHER CREDITS	**(578,360,195.55)**	**(14,761,812.34)**	**0.00**	**(14,761,812.34)**	**(593,122,007.88)**
4030001	Depreciation Exp	48,722,462.96	1,109,817.41	1,109,817.41	0.00	49,832,280.37
4040001	Amort. of Plant	3,794,679.05	(221,178.83)	0.00	(221,178.83)	3,573,500.22
4060001	Amort of Plt Acq Adj	38,616.00	0.00	0.00	0.00	38,616.00
4073000	Regulatory Debits	311,514.72	0.00	0.00	0.00	311,514.72
4081002	FICA	3,200,138.93	(686,383.08)	0.00	(686,383.08)	2,513,753.85
4081003	Federal Unemployment Tax	31,029.47	999.55	999.55	0.00	32,029.02
408100506	Real & Personal Property Taxes	0.00	832.00	832.00	0.00	832.00
408100507	Real & Personal Property Taxes	0.00	984.57	984.57	0.00	984.57
408100508	Real & Personal Property Taxes	(1,478,036.68)	1,408,769.38	1,408,769.38	0.00	(69,267.32)
408100509	Real & Personal Property Taxes	8,985,800.00	(9,519,300.00)	0.00	(9,519,300.00)	(533,500.00)
408100510	Real Personal Property Taxes	198.39	9,439,524.75	9,439,524.75	0.00	9,439,723.14
408100511	Real Personal Property Taxes	0.00	197.47	197.47	0.00	197.47
408100609	State Gross Receipts Tax	(54,754.00)	54,754.00	54,754.00	0.00	0.00
408100610	State Gross Receipts Tax	268,158.00	(268,723.00)	0.00	(268,723.00)	(565.00)
408100611	State Gross Receipts Tax	0.00	243,944.00	243,944.00	0.00	243,944.00
4081007	State Unemployment Tax	46,900.02	(13,565.41)	0.00	(13,565.41)	33,334.61
408100800	State Franchise Taxes	(43,982.00)	43,982.00	43,982.00	0.00	0.00
408100809	State Franchise Taxes	(16,547.00)	16,547.00	16,547.00	0.00	0.00
408100810	State Franchise Taxes	38,300.00	(61,615.00)	0.00	(61,615.00)	(23,315.00)
408100811	State Franchise Taxes	0.00	29,392.00	29,392.00	0.00	29,392.00
408101410	Federal Excise Taxes	2,098.40	(2,098.40)	0.00	(2,098.40)	0.00
408101411	Federal Excise Taxes	0.00	2,315.26	2,315.26	0.00	2,315.26
408101710	St Lic-Rgstrtion Tax-Fees	255.25	(255.25)	0.00	(255.25)	0.00
408101711	St Lic-Rgstrtion Tax-Fees	0.00	272.25	272.25	0.00	272.25
408101809	St Publ Serv Comm Tax/Fees	374,877.41	(374,877.41)	0.00	(374,877.41)	0.00
408101810	St Publ Serv Comm Tax-Fees	399,674.76	0.02	0.02	0.00	399,674.78
408101811	St Publ Serv Comm Tax-Fees	0.00	412,861.20	412,861.20	0.00	412,861.20
408101909	State Sales and Use Taxes	1,513.34	(1,513.34)	0.00	(1,513.34)	0.00
408101910	State Sales and Use Taxes	14,210.28	(12,430.60)	0.00	(12,430.60)	1,779.68
408101911	State Sales and Use Taxes	0.00	14,295.82	14,295.82	0.00	14,295.82
408102210	Municipal License Fees	100.00	(100.00)	0.00	(100.00)	0.00
408102211	Municipal License Fees	0.00	200.00	200.00	0.00	200.00
408102908	Real/Pers Prop Tax-Cap Leases	871.26	(871.26)	0.00	(871.26)	0.00
408102909	Real/Pers Prop Tax-Cap Leases	320.91	3,071.09	3,071.09	0.00	3,392.00
408102910	Real-Pers Prop Tax-Cap Leases	106,300.00	(105,015.35)	0.00	(105,015.35)	1,284.65
408102911	Real-Pers Prop Tax-Cap Leases	0.00	79,000.00	79,000.00	0.00	79,000.00
4081033	Fringe Benefit Loading - FICA	(943,361.54)	(10,335.29)	0.00	(10,335.29)	(953,696.83)
4081034	Fringe Benefit Loading - FUT	(10,422.96)	508.87	508.87	0.00	(9,914.09)
4081035	Fringe Benefit Loading - SUT	(14,653.37)	(1,383.88)	0.00	(1,383.88)	(16,037.25)
408103609	Real Prop Tax-Cap Leases	0.00	14,760.50	14,760.50	0.00	14,760.50
408103610	Real Prop Tax-Cap Leases	26,700.00	(26,093.42)	0.00	(26,093.42)	606.58
408103611	Real Prop Tax-Cap Leases	0.00	24,750.00	24,750.00	0.00	24,750.00
408200509	Real & Personal Property Taxes	58,698.14	(58,698.14)	0.00	(58,698.14)	0.00
408200510	Real Personal Property Taxes	0.00	56,600.00	56,600.00	0.00	56,600.00
408201410	St Lic-Registration Tax-Fees	155.00	(155.00)	0.00	(155.00)	0.00
4091001	Income Taxes, UOI - Federal	14,667,253.11	(11,311,425.06)	0.00	(11,311,425.06)	3,355,828.05
409100206	Income Taxes, UOI - State	37,533.00	(37,533.00)	0.00	(37,533.00)	0.00
409100207	Income Taxes, UOI - State	0.00	(4,516.00)	0.00	(4,516.00)	(4,516.00)
409100208	Income Taxes, UOI - State	0.00	(2,648.00)	0.00	(2,648.00)	(2,648.00)
409100209	Income Taxes, UOI - State	294,606.96	(294,606.96)	0.00	(294,606.96)	0.00
409100210	Income Taxes UOI - State	2,858,510.04	(3,474,777.63)	0.00	(3,474,777.63)	(616,267.59)
409100211	Income Taxes UOI - State	0.00	3,812,469.75	3,812,469.75	0.00	3,812,469.75
4092001	Inc Tax, Oth Inc&Ded-Federal	(82,404.59)	763,103.32	763,103.32	0.00	680,698.73
409200209	Inc Tax, Oth Inc & Ded - State	(23,379.40)	23,379.40	23,379.40	0.00	0.00
409200210	Inc Tax Oth Inc Ded - State	15,926.58	(10,313.29)	0.00	(10,313.29)	5,615.29
409200211	Inc Tax Oth Inc Ded - State	0.00	105,504.97	105,504.97	0.00	105,504.97
4101001	Prov Def I/T Util Op Inc-Fed	63,410,057.04	1,637,215.24	1,637,215.24	0.00	65,047,272.28
4102001	Prov Def I/T Oth I&D - Federal	314,215.30	(251,766.66)	0.00	(251,766.66)	62,448.64
4111001	Prv Def I/T-Cr Util Op Inc-Fed	(62,276,739.71)	15,195,292.65	15,195,292.65	0.00	(47,081,447.06)
4112001	Prv Def I/T-Cr Oth I&D-Fed	(372,893.85)	111,037.67	111,037.67	0.00	(261,856.18)
4114001	ITC Adj, Utility Oper - Fed	(704,223.00)	344,845.82	344,845.82	0.00	(359,377.18)
4116000	Gain From Disposition of Plant	(2,176.00)	(559.00)	0.00	(559.00)	(2,735.00)
4118002	Comp. Allow Gains Title IV SO2	(1,824,264.87)	1,822,761.63	1,822,761.63	0.00	(1,503.24)
4171001	Exp of NonUtil Oper - Nonassoc	0.00	0.38	0.38	0.00	0.38
4180001	Non-Operatng Rental Income	(56,200.00)	200.00	200.00	0.00	(56,000.00)
4180005	Non-Opratng Rntal Inc-Depr	6,669.72	0.00	0.00	0.00	6,669.72
4190002	Int & Dividend Inc - Nonassoc	(42,107.81)	(1,832,132.76)	0.00	(1,832,132.76)	(1,874,240.57)
4190005	Interest Income - Assoc CBP	(50,713.64)	(267,162.96)	0.00	(267,162.96)	(317,876.60)
4191000	Allw Oth Fnds Usd Dmg Cnstr	(768,024.68)	(461,364.04)	0.00	(461,364.04)	(1,229,388.72)
4210000	Misc Non-Operating Income	105,822.61	(105,822.61)	0.00	(105,822.61)	0.00
4210002	Misc Non-Op Inc-NonAsc-Rents	(62,591.90)	1,643.00	1,643.00	0.00	(60,948.90)

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Account Number	Description	Pr Yr Ending Balance	Yearly Activity	Debits	Credit	Current Yr Balance
4210005	Misc Non-Op Inc-NonAsc-Timber	(156,205.81)	143,057.05	143,057.05	0.00	(13,148.76)
4210007	Misc Non-Op Inc - NonAsc - Oth	(23,741.27)	4,903.18	4,903.18	0.00	(18,838.09)
4210009	Misc Non-Op Exp - NonAssoc	16.92	(1,861.30)	0.00	(1,861.30)	(1,844.38)
4210025	B/L MTM Assignments	(1,195,131.00)	1,195,131.00	1,195,131.00	0.00	0.00
4210026	B/L Affl MTM Assign	644,980.00	(644,980.00)	0.00	(644,980.00)	0.00
4210027	Realized Financial Assignments	360,300.84	(360,300.84)	0.00	(360,300.84)	0.00
4210028	Realized Affil Financial Assgn	189,850.16	(189,850.16)	0.00	(189,850.16)	0.00
4210031	Pwr Sales Outside Svc Territry	(4,801,034.94)	4,152,512.75	4,152,512.75	0.00	(648,522.19)
4210032	Pwr Purch Outside Svc Territry	4,436,412.77	(3,781,606.49)	0.00	(3,781,606.49)	654,806.28
4210033	Mark to Mkt Out Svc Territory	756,569.78	(832,035.66)	0.00	(832,035.66)	(75,465.88)
4210035	Gn/Ls MTM Emissions - Forwards	(88.74)	1,195.63	1,195.63	0.00	1,106.89
4210039	Carrying Charges	(146,565.50)	14,566.82	14,566.82	0.00	(131,998.68)
4210043	Realiz Sharing West Coast Pwr	45,072.55	(47,214.55)	0.00	(47,214.55)	(2,142.00)
4210045	UnReal Aff Fin Assign SNWA	(470,776.00)	398,232.00	398,232.00	0.00	(72,544.00)
4210046	Real Aff Fin Assign SNWA	71,112.88	(29,824.62)	0.00	(29,824.62)	41,288.26
4210049	Interest Rate Swaps-BTL Power	8,256.66	1,440.95	1,440.95	0.00	9,697.61
4210053	Specul. Allow. Gains-SO2	3,620.23	(4,697.26)	0.00	(4,697.26)	(1,077.03)
4210054	Specul. Allow. Gains-Seas NOx	(328.53)	328.53	328.53	0.00	0.00
4261000	Donations	287,101.06	147,748.83	147,748.83	0.00	434,849.89
4263001	Penalties	(332,183.86)	335,438.61	335,438.61	0.00	3,254.75
4264000	Civic & Political Activities	314,254.54	14,604.34	14,604.34	0.00	328,858.88
4265002	Other Deductions - Nonassoc	78,403.68	(30,751.32)	0.00	(30,751.32)	47,652.36
4265004	Social & Service Club Dues	87,115.70	26,314.39	26,314.39	0.00	113,430.09
4265009	Factored Cust A/R Exp - Affil	984,448.80	110,658.52	110,658.52	0.00	1,095,107.32
4265010	Fact Cust A/R-Bad Debts-Affil	1,228,270.65	27,269.81	27,269.81	0.00	1,255,540.46
4265053	Specul. Allow Loss-SO2	4,703.32	(4,703.07)	0.00	(4,703.07)	0.25
4265054	Specul. Allow Loss-Seas NOx	617.22	(577.80)	0.00	(577.80)	39.42
4265056	Specul. Allow Loss-CO2	535.77	(535.77)	0.00	(535.77)	0.00
4270006	Int on LTD - Sen Unsec Notes	33,998,706.24	(0.01)	0.00	(0.01)	33,998,706.23
4280006	Amrtz Dscnt&Exp-Sn Unsec Note	471,186.48	(0.01)	0.00	(0.01)	471,186.47
4281004	Amrtz Loss Rcquired Debt-Dbnt	33,648.60	0.00	0.00	0.00	33,648.60
4300001	Interest Exp - Assoc Non-CBP	1,050,000.00	0.00	0.00	0.00	1,050,000.00
4300003	Int to Assoc Co - CBP	9,576.53	(9,264.38)	0.00	(9,264.38)	312.15
4310001	Other Interest Expense	26,791.67	(16,915.27)	0.00	(16,915.27)	9,876.40
4310002	Interest on Customer Deposits	1,115,253.38	121,513.66	121,513.66	0.00	1,236,767.04
4310007	Lines Of Credit	213,219.98	389,236.80	389,236.80	0.00	602,456.78
4310022	Interest Expense - Federal Tax	364,024.00	(529,811.00)	0.00	(529,811.00)	(165,787.00)
4310023	Interest Expense - State Tax	(245,618.00)	320,216.00	320,216.00	0.00	74,598.00
4320000	Allw Brrwed Fnds Used Cnstr-Cr	(594,242.22)	(306,047.65)	0.00	(306,047.65)	(900,289.87)
4400001	Residential Sales-W/Space Htg	(104,482,089.58)	(2,200,538.04)	0.00	(2,200,538.04)	(106,682,627.62)
4400002	Residential Sales-W/O Space Ht	(50,923,541.92)	(551,698.24)	0.00	(551,698.24)	(51,475,240.16)
4400005	Residential Fuel Rev	(70,531,982.30)	2,520,471.65	2,520,471.65	0.00	(68,011,510.65)
4420001	Commercial Sales	(66,702,563.23)	(2,962,867.48)	0.00	(2,962,867.48)	(69,665,430.71)
4420002	Industrial Sales (Excl Mines)	(57,750,051.44)	(2,609,157.33)	0.00	(2,609,157.33)	(60,359,208.77)
4420004	Ind Sales-NonAffil(Incl Mines)	(38,989,675.58)	(2,335,235.11)	0.00	(2,335,235.11)	(41,324,910.69)
4420006	Sales to Pub Auth - Schools	(12,152,492.75)	(754,674.71)	0.00	(754,674.71)	(12,907,167.46)
4420007	Sales to Pub Auth - Ex Schools	(11,644,801.74)	(1,194,428.06)	0.00	(1,194,428.06)	(12,839,229.80)
4420013	Commercial Fuel Rev	(39,446,554.94)	(659,023.02)	0.00	(659,023.02)	(40,105,577.96)
4420016	Industrial Fuel Rev	(87,003,411.51)	(7,176,077.62)	0.00	(7,176,077.62)	(94,179,489.13)
4440000	Public Street/Highway Lighting	(1,177,119.98)	(135,114.42)	0.00	(135,114.42)	(1,312,234.40)
4440002	Public St & Hwy Light Fuel Rev	(275,180.91)	(31,282.12)	0.00	(31,282.12)	(306,463.03)
4470001	Sales for Resale - Assoc Cos	11,850.49	(46,162.84)	0.00	(46,162.84)	(34,312.35)
4470002	Sales for Resale - NonAssoc	(11,367,912.52)	1,199,906.13	1,199,906.13	0.00	(10,168,006.39)
4470004	Sales for Resale-Nonaff-Ancill	(10,656.69)	10,656.69	10,656.69	0.00	0.00
4470005	Sales for Resale-Nonaff-Transm	(336,642.71)	336,642.71	336,642.71	0.00	0.00
4470006	Sales for Resale-Bookout Sales	(59,271,132.62)	18,791,483.82	18,791,483.82	0.00	(40,479,648.80)
4470010	Sales for Resale-Bookout Purch	50,334,600.77	(16,080,748.41)	0.00	(16,080,748.41)	34,253,852.36
4470027	Whsal/Muni/Pb Ath Fuel Rev	(2,840,580.39)	(14,143.53)	0.00	(14,143.53)	(2,854,723.92)
4470028	Sale/Resale - NA - Fuel Rev	(27,232,713.35)	5,420,393.34	5,420,393.34	0.00	(21,812,320.01)
4470033	Whsal/Muni/Pub Auth Base Rev	(2,882,977.75)	(530,763.84)	0.00	(530,763.84)	(3,413,741.59)
4470035	Sls for Rsl - Fuel Rev - Assoc	(722,737.21)	442,355.93	442,355.93	0.00	(280,381.28)
4470066	PWR Trding Trans Exp-NonAssoc	33,007.00	2,732.24	2,732.24	0.00	35,739.24
4470081	Financial Spark Gas - Realized	(49,133.32)	(12,022.40)	0.00	(12,022.40)	(61,155.72)
4470082	Financial Electric Realized	9,262,685.87	(4,550,911.73)	0.00	(4,550,911.73)	4,711,774.14
4470089	PJM Energy Sales Margin	(3,658,345.98)	(3,525,063.53)	0.00	(3,525,063.53)	(7,183,409.51)
4470093	PJM Implicit Congestion-LSE	10,951,724.51	(732,398.18)	0.00	(732,398.18)	10,219,326.33
4470098	PJM Oper.Reserve Rev-OSS	(1,182,745.14)	(172,133.71)	0.00	(172,133.71)	(1,354,878.85)
4470099	Capacity Cr. Net Sales	(4,390,783.55)	(431,700.73)	0.00	(431,700.73)	(4,822,484.28)
4470100	PJM FTR Revenue-OSS	(1,249,434.76)	404,195.17	404,195.17	0.00	(845,239.59)
4470101	PJM FTR Revenue-LSE	(10,517,043.93)	2,886,220.44	2,886,220.44	0.00	(7,630,823.49)
4470103	PJM Energy Sales Cost	(37,031,603.68)	(3,044,266.11)	0.00	(3,044,266.11)	(40,075,869.79)
4470106	PJM Pt2Pt Trans.Purch-NonAff.	7,896.59	(5,746.96)	0.00	(5,746.96)	2,149.63
4470107	PJM NITS Purch-NonAff.	(22,623.71)	24,153.32	24,153.32	0.00	1,529.61
4470109	PJM FTR Revenue-Spec	(366,496.59)	243,683.35	243,683.35	0.00	(122,813.24)
4470110	PJM TO Admin. Exp.-NonAff.	10,352.11	(7,499.46)	0.00	(7,499.46)	2,852.65

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Account Number	Description	Pr Yr Ending Balance	Yearly Activity	Debits	Credit	Current Yr Balance
4470112	Non-Trading Bookout Sales-OSS	(1,072,101.45)	1,058,879.74	1,058,879.74	0.00	(13,221.71)
4470115	PJM Meter Corrections-OSS	59,969.28	(389,593.83)	0.00	(389,593.83)	(329,624.55)
4470116	PJM Meter Corrections-LSE	(2,948.75)	(199,857.27)	0.00	(199,857.27)	(202,806.02)
4470124	PJM Incremental Spot-OSS	3,962.30	(5,579.16)	0.00	(5,579.16)	(1,616.86)
4470126	PJM Incremental Imp Cong-OSS	1,220,666.90	1,100,395 07	1,100,395.07	0.00	2,321,061.97
4470128	Sales for Res-Aff. Pool Energy	(57,777,389.00)	(9,392,912.95)	0.00	(9,392,912.95)	(67,170,301.95)
4470131	Non-Trading Bookout Purch-OSS	142,518.58	(128,273.08)	0 00	(128,273 08)	14,245.50
4470143	Financial Hedge Realized	(522,727.59)	(34,032.61)	0.00	(34,032.61)	(556,760 20)
4470144	Realiz.Sharing - 06 SIA	(12,726.45)	17,066.45	17,066.45	0 00	4,340.00
4470150	Transm. Rev.-Dedic. Whlsl/Muni	(574,328.55)	525,417.64	525,417.64	0.00	(48,910.91)
4470155	OSS Physical Margin Reclass	8,091,775 89	(3,038,135.79)	0.00	(3,038,135.79)	5,053,640.10
4470156	OSS Optim. Margin Reclass	(8,091,775.89)	3,038,135.79	3,038,135.79	0.00	(5,053,640.10)
4470167	MISO FTR Revenues OSS	(9,380.03)	(15,202.59)	0.00	(15,202.59)	(24,582.62)
4470168	Interest Rate Swaps-Power	67,587.97	61,801.40	61,801.40	0.00	129,389.37
4470169	Capacity Sales Trading	(52,160.07)	52,160.07	52,160.07	0.00	0 00
4470170	Non-ECR Auction Sales-OSS	(12,634,285.38)	(369,543.57)	0.00	(369,543.57)	(13,003,828.95)
4470174	PJM Whlse FTR Rev - OSS	(1,397,379 05)	775,590.92	775,590.92	0.00	(621,788.13)
4470175	OSS Sharing Reclass - Retail	2,048,078.21	(7,165,757.72)	0.00	(7,165,757.72)	(5,117,679.51)
4470176	OSS Sharing Reclass-Reduction	(2,048,078.21)	7,165,757.72	7,165,757.72	0 00	5,117,679.51
4470180	Trading intra-book Reclass	0.00	21,279.21	21,279.21	0 00	21,279.21
4470181	Auction intra-book Reclass	0.00	(21,279.21)	0.00	(21,279.21)	(21,279.21)
4470202	PJM OpRes-LSE-Credit	(1,048,691.24)	21,297.93	21,297.93	0 00	(1,027,393.31)
4470203	PJM OpRes-LSE-Charge	3,505,606.22	143,008.23	143,008.23	0.00	3,648,614.45
4470206	PJM Trans loss credits-OSS	(1,079,763.18)	(6,597.21)	0 00	(6,597.21)	(1,086,360.39)
4470207	PJM transm loss charges - LSE	18,535,181.96	(1,810,359.18)	0.00	(1,810,359.18)	16,724,822.78
4470208	PJM Transm loss credits-LSE	(8,667,938.87)	2,885,127.38	2,885,127.38	0 00	(5,782,811.49)
4470209	PJM transm loss charges-OSS	2,454,927.63	766,129 01	766,129.01	0.00	3,221,056.64
4470214	PJM 30m Suppl Reserve CR OSS	(84,440.76)	(202,925.37)	0.00	(202,925.37)	(287,366.13)
4470215	PJM 30m Suppl Reserve CH OSS	5,712.54	(5,712.54)	0.00	(5,712.54)	0 00
4500000	Forfeited Discounts	(1,873,780.51)	(347,538.22)	0.00	(347,538.22)	(2,221,318.73)
4510001	Misc Service Rev - Nonaffil	(376,680.64)	(55,953.16)	0.00	(55,953.16)	(432,633.80)
4540001	Rent From Elect Property - Af	(251,637.47)	(11,551.16)	0 00	(11,551.16)	(263,188.63)
4540002	Rent From Elect Property-NAC	(4,214,295.04)	(663,849.30)	0.00	(663,849.30)	(4,878,144.34)
4540004	Rent From Elect Prop-ABD-Nonaf	(138,055.70)	32,764.48	32,764.48	0.00	(105,291.22)
4560007	Oth Elect Rev - DSM Program	(2,095,824.30)	(1,320,881.70)	0.00	(1,320,881.70)	(3,416,706.00)
4560012	Oth Elect Rev - Nonaffiliated	(12,701.71)	8,551.61	8,551.61	0.00	(4,150.10)
4560015	Other Electric Revenues - ABD	(242,569.97)	(3,775 07)	0 00	(3,775 07)	(246,345 04)
4560016	Financial Trading Rev-Unreal	108,999.26	(108,999.26)	0.00	(108,999 26)	0.00
4560041	Miscellaneous Revenue-NonAffil	0.00	(1,000 00)	0.00	(1,000.00)	(1,000.00)
4560049	Merch Generation Finan -Realzd	(12.32)	(3.31)	0.00	(3.31)	(15.63)
4560050	Oth Elec Rev-Coal Trd Rlzd G-L	(2,063,983.19)	2,079,689 53	2,079,689.53	0.00	15,706.34
4560109	Interest Rate Swaps-Coal	3,362.30	1,034.31	1,034.31	0.00	4,396.61
4560111	MTM Aff GL Coal Trading	(108,999.26)	108,999.26	108,999 26	0.00	0.00
4560112	Realized GL Coal Trading-Affil	945,770.68	(945,770 68)	0.00	(945,770.68)	0 00
4561002	RTO Formation Cost Recovery	(13,645.20)	11,238.80	11,238.80	0.00	(2,406.40)
4561003	PJM Expansion Cost Recov	(76,867.40)	(1,561.06)	0.00	(1,561.06)	(78,428.46)
4561004	SECA Transmission Rev	(176,533.95)	176,533.95	176,533.95	0.00	0 00
4561005	PJM Point to Point Trans Svc	(898,167.71)	162,066.56	162,066.56	0.00	(736,101.15)
4561006	PJM Trans Owner Admin Rev	(190,068.93)	(41,268 67)	0.00	(41,268.67)	(231,337.60)
4561007	PJM Network Integ Trans Svc	(4,136,354.87)	(2,071,095.68)	0.00	(2,071,095 68)	(6,207,450.54)
4561019	Oth Elec Rev Trans Non Affil	(64,536.00)	516.00	516.00	0.00	(64,020.00)
4561028	PJM Pow Fac Cre Rev Whsl Cu-NA	(401.16)	(9,039 54)	0.00	(9,039.54)	(9,440.70)
4561029	PJM NITS Revenue Whsl Cus-NAff	(224,408.47)	(2,120,358.97)	0.00	(2,120,358.97)	(2,344,767.44)
4561030	PJM TO Serv Rev Whls Cus-NAff	(6,999.18)	(33,879 34)	0 00	(33,879.34)	(40,878 52)
4561031	GFA Trans Base Rev Unb - Aff	(61,832.38)	61,832.38	61,832.38	0.00	0.00
4561032	GFA Trans Ancillary Rev - Aff	(1,979.42)	1,979.42	1,979.42	0.00	0 00
4561033	PJM NITS Revenue - Affiliated	(4,812,028.04)	(35,325,416.16)	0 00	(35,325,416.16)	(40,137,444.20)
4561034	PJM TO Adm. Serv Rev - Aff	0.00	(418,671.49)	0.00	(418,671.49)	(418,671.49)
4561035	PJM Affiliated Trans NITS Cost	4,147,559.79	31,655,658.20	31,655,658.20	0.00	35,803,217.99
4561036	PJM Affiliated Trans TO Cost	0.00	391,387.87	391,387.87	0 00	391,387.87
4561058	NonAffil PJM Trans Enhncmt Rev	(25,636.47)	(119,962.64)	0.00	(119,962.64)	(145,599.11)
4561059	Affil PJM Trans Enhancmnt Rev	(57,673.03)	(256,571.81)	0.00	(256,571.81)	(314,244 84)
4561060	Affil PJM Trans Enhancmnt Cost	48,892.00	230,758.70	230,758.70	0.00	279,650.70
4561061	NAff PJM RTEP Rev for Whsl-FR	0.00	(18,463.38)	0.00	(18,463.38)	(18,463.38)
4561062	PRDVISION PJM NITS Affil- Cost	0.00	583,890.79	583,890.79	0.00	583,890.79
4561063	PROVISIDN PJM NITS Affiliated	0.00	(668,023.25)	0.00	(668,023.25)	(668,023.25)
4561064	PROVISION PJM NITS WhslCus-NAf	0.00	(39,295.49)	0.00	(39,295.49)	(39,295.49)
4561065	PROVISION PJM NITS	0.00	(78,590.97)	0.00	(78,590.97)	(78,590.97)
5000000	Oper Supervision & Engineering	4,737,535.39	(1,492,951.43)	0.00	(1,492,951.43)	3,244,583 96
5000001	Oper Super & Eng-RATA-Affil	51,934.36	(21,691.20)	0.00	(21,691.20)	30,243.16
5010000	Fuel	602,339.51	92,564.64	92,564 64	0.00	694,904.15
5010001	Fuel Consumed	169,310,644.54	15,052,031.33	15,052,031.33	0.00	184,362,675 87
5010003	Fuel - Procure Unload & Handle	3,389,158.53	(242,070.57)	0.00	(242,070.57)	3,147,087.96
5010005	Fuel - Deferred	(922,781.00)	3,196,798 00	3,196,798.00	0.00	2,274,017.00
5010013	Fuel Survey Activity	0.00	(1.00)	0.00	(1.00)	(1.00)

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Account Number	Description	Pr Yr Ending Balance	Yearly Activity	Debits	Credit	Current Yr Balance
5010019	Fuel Oil Consumed	1,624,329.43	1,602,320.19	1,602,320.19	0.00	3,226,649.62
5020000	Steam Expenses	875,893.90	355,505.14	355,505.14	0.00	1,231,399 04
5020002	Urea Expense	4,082,814.46	36,804.03	36,804.03	0 00	4,119,618.49
5020008	Activated Carbon	2.78	14 27	14.27	0.00	17.05
5020025	Steam Exp Environmental	63.78	(147.39)	0.00	(147.39)	(83 61)
5050000	Electric Expenses	36,818.53	434,102.13	434,102.13	0.00	470,918 66
5060000	Misc Steam Power Expenses	9,479,887.88	(4,270,477.95)	0.00	(4,270,477.95)	5,209,409.93
5060002	Misc Steam Power Exp-Assoc	34,748.00	4,793.00	4,793 00	0.00	39,541.00
5060004	NSR Settlement Expense	(32,703.87)	(199,568.29)	0.00	(199,568.29)	(232,272.16)
5060006	Voluntary CO2 Compliance Exp	(10,872.50)	13,761.72	13,761.72	0.00	2,889.22
5060025	Misc Stm Pwr Exp Environmental	(4.52)	4.52	4.52	0.00	0.00
5070000	Rents	0 00	4.00	4 00	0.00	4.00
5090000	Allow Consum Title IV SO2	7,540,236.97	4,846,163.12	4,846,163.12	0.00	12,386,400.09
5090002	Allowance Expenses	0.76	2.24	2.24	0.00	3.00
5090005	An. NOx Cons. Exp	311,772.70	722,845.24	722,845.24	0.00	1,034,617.94
5100000	Maint Supv & Engineering	436,657.20	1,613,603 00	1,613,603.00	0.00	2,050,260.19
5110000	Maintenance of Structures	720,206.84	509,428.72	509,428.72	0.00	1,229,635.56
5120000	Maintenance of Boiler Plant	10,421,344.15	(4,452,144.84)	0.00	(4,452,144.84)	5,969,199.31
5130000	Maintenance of Electric Plant	5,098,686.43	(3,972,026.75)	0.00	(3,972,026.75)	1,126,659 68
5140000	Maintenance of Misc Steam Plt	691,641.86	316,035.26	316,035.26	0.00	1,007,677.12
5550001	Purch Pwr-NonTrading-Nonassoc	5,824,969.07	2,017,573.11	2,017,573.11	0.00	7,842,542.18
5550004	Purchased Power-Pool Capacity	59,816,231.00	(4,959,094.00)	0 00	(4,959,094 00)	54,857,137.00
5550005	Purchased Power - Pool Energy	9,616,738.00	3,260,635.70	3,260,635.70	0.00	12,877,373.70
5550023	Purch Power Capacity -NA	803,741.25	(13,464.75)	0 00	(13,464.75)	790,276.50
5550027	Purch Pwr-Non-Fuel Portion-Aff	43,282,118.00	404,744 00	404,744.00	0.00	43,686,862.00
5550032	Gas-Conversion-Mone Plant	308,981.06	14,600.90	14,600.90	0.00	323,581.96
5550036	PJM Emer.Energy Purch.	27,500.80	(26,389.93)	0.00	(26,389.93)	1,110.87
5550039	PJM Inadvertent Mtr Res-OSS	(15,023.45)	62,372.72	62,372.72	0.00	47,349 27
5550040	PJM Inadvertent Mtr Res-LSE	(149,216.70)	414,556 56	414,556.56	0.00	265,339.86
5550041	PJM Ancillary Serv.-Sync	9,554.67	(1,610.04)	0.00	(1,610.04)	7,944.63
5550046	Purch Power-Fuel Portion-Affil	57,919,353.02	(3,524,764.17)	0.00	(3,524,764.17)	54,394,588 85
5550074	PJM Reactive-Charge	2,317,850.54	(1,111,623.42)	0.00	(1,111,623.42)	1,206,227.12
5550075	PJM Reactive-Credit	(2,263,083.56)	1,164,751.54	1,164,751.54	0.00	(1,098,332.02)
5550076	PJM Black Start-Charge	41,807.63	(4,672.87)	0.00	(4,672.87)	37,134 76
5550077	PJM Black Start-Credit	(24,399.80)	(1,098.54)	0.00	(1,098.54)	(25,498.34)
5550078	PJM Regulation-Charge	2,831,843.36	(306,318 87)	0.00	(306,318.87)	2,525,524.49
5550079	PJM Regulation-Credit	(966,606.31)	66,149.93	66,149.93	0.00	(900,456 38)
5550080	PJM Hourly Net Purch.-FERC	13,600,477.63	(2,187,438.16)	0.00	(2,187,438.16)	11,413,039.47
5550083	PJM Spinning Reserve-Charge	178,098.73	(66,222.84)	0.00	(66,222.84)	111,875.89
5550084	PJM Spinning Reserve-Credit	(41,389.97)	34,947.68	34,947.66	0.00	(6,442.31)
5550090	PJM 30m Suppl Rserv Charge LSE	77,448.09	272,335 57	272,335.57	0.00	349,783.68
5550094	Purchased Power - Fuel	13,895,143.03	(13,014,864.71)	0.00	(13,014,864.71)	880,278.32
5550099	PJM Purchases-non-ECR-Auction	9,212,168.69	839,806.47	839,806.47	0.00	10,051,975.16
5550100	Capacity Purchases-Auction	961,301.71	(128,301.71)	0.00	(128,301.71)	833,000.00
5550101	Purch Power-Pool Non-Fuel -Aff	1,527,197.00	972,261.00	972,261.00	0.00	2,499,458.00
5550102	Pur Power-Pool NonFuel-OSS-Aff	36,238,591.00	9,110,891.00	9,110,891.00	0.00	45,349,482.00
5550107	Capacity purchases - Trading	2,286,026.97	(724,394.51)	0.00	(724,394.51)	1,561,632.46
5560000	Sys Control & Load Dispatching	376,720.34	(58,474.62)	0.00	(58,474 62)	320,245.72
5570000	Other Expenses	2,452,980.22	(215,392.05)	0 00	(215,392.05)	2,237,588.17
5570007	Other Pwr Exp - Wholesale RECs	8,112.80	18,103.98	18,103.98	0.00	26,216.78
5570008	Other Pwr Exp - Voluntary RECs	64.00	(34.00)	0.00	(34.00)	30.00
5600000	Oper Supervision & Engineering	617,129.73	10,630.15	10,630.15	0.00	627,759.88
5611000	Load Dispatch - Reliability	14,152.92	(8,288.09)	0.00	(8,288.09)	5,864.83
5612000	Load Dispatch-Mntr&Op TransSys	808,881.05	17,481.35	17,481.35	0.00	826,362.40
5613000	Load Dispatch-Trans Srvc&Sched	24.56	(20.21)	0 00	(20.21)	4.35
5614000	PJM Admin-SSC&DS-OSS	95,462.28	(2,688.59)	0.00	(2,688.59)	92,773.69
5614001	PJM Admin-SSC&DS-Internal	1,202,792.91	(111,115.97)	0 00	(111,115.97)	1,091,676.94
5614007	RTO Admin Default LSE.	(75,895.97)	75,895.97	75,895.97	0 00	0.00
5614008	PJM Admin Defaults OSS	(7,872.80)	7,872.80	7,872.80	0.00	0 00
5615000	Reliability,Plng&Stds Develop	92,143.09	8,316.57	8,316 57	0.00	100,459.68
5618000	PJM Admin-RP&SDS-OSS	22,054 03	(695.51)	0.00	(695.51)	21,358.52
5618001	PJM Admin-RP&SDS- Internal	275,200.37	(24,211.53)	0 00	(24,211.53)	250,988 84
5620001	Station Expenses - Nonassoc	201,409.29	(38,579.79)	0.00	(38,579 79)	162,829.50
5630000	Overhead Line Expenses	121,108.08	34,005.55	34,005.55	0.00	155,113.63
5640000	Underground Line Expenses	0.00	3,933.43	3,933.43	0.00	3,933.43
5650002	Transmssn Elec by Others-NAC	114,075 00	168,622.14	168,622.14	0.00	282,697.14
5650003	AEP Trans Equalization Agmt	(8,013,820 00)	8,013,820.00	8,013,820.00	0 00	0 00
5650012	PJM Trans Enhancement Charge	2,146,466.58	472,972.66	472,972.66	0.00	2,619,439.24
5650015	PJM TO Serv Exp - Aff	13,047.40	(2,937.88)	0.00	(2,937.88)	10,109.52
5650016	PJM NITS Expense - Affiliated	122,740.77	195,671.43	195,671.43	0.00	318,412.20
5650017	GFA Trans Exp Unb - Affiliate	53,803.46	(53,803.46)	0 00	(53,803.46)	0.00
5650018	PJM Trans Enhancement Credits	(251,482.87)	251,482.87	251,482.87	0.00	0.00
5650020	PROVISION PJM NITS Affl Expens	0 00	(21,942.94)	0.00	(21,942.94)	(21,942.94)
5660000	Misc Transmission Expenses	2,412,556.32	(1,376,458 08)	0.00	(1,376,458.08)	1,036,098.24
5670001	Rents - Nonassociated	4,776.55	32.45	32.45	0.00	4,809 00

KYP CORP CONSOLIDATED
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Account Number	Description	Pr Yr Ending Balance	Yearly Activity	Debits	Credit	Current Yr Balance
5680000	Maint Supv & Engineering	127,454.47	18,134.06	18,134.06	0.00	145,588.53
5690000	Maintenance of Structures	32,873.21	(18,906.60)	0.00	(18,906.60)	13,966.61
5691000	Maint of Computer Hardware	47,660.86	5,198.69	5,198.69	0.00	52,859.55
5692000	Maint of Computer Software	252,345.93	(21,596.28)	0.00	(21,596.28)	230,749.65
5693000	Maint of Communication Equip	209,390.73	2,315.29	2,315.29	0.00	211,706.02
5700000	Maint of Station Equipment	611,237.26	203,380.01	203,380.01	0.00	814,617.27
5710000	Maintenance of Overhead Lines	1,511,748.00	242,970.80	242,970.80	0.00	1,754,718.80
5720000	Maint of Underground Lines	(1.86)	1.86	1.86	0.00	0.00
5730000	Maint of Misc Trnsmssion Plt	3,790.19	18,151.41	18,151.41	0.00	21,941.60
5757000	PJM Admin-MAM&SC- OSS	101,760.65	(3,997.68)	0.00	(3,997.68)	97,762.97
5757001	PJM Admin-MAM&SC- Internal	1,273,257.25	(131,273.14)	0.00	(131,273.14)	1,141,984.11
5800000	Oper Supervision & Engineering	813,905.42	(18,075.77)	0.00	(18,075.77)	795,829.65
5810000	Load Dispatching	2,785.53	(980.97)	0.00	(980.97)	1,804.56
5820000	Station Expenses	204,442.42	(1,149.15)	0.00	(1,149.15)	203,293.27
5830000	Overhead Line Expenses	1,179,717.90	(282,710.15)	0.00	(282,710.15)	897,007.75
5840000	Underground Line Expenses	133,928.91	9,711.07	9,711.07	0.00	143,639.98
5850000	Street Lighting & Signal Sys E	59,915.87	(15,231.98)	0.00	(15,231.98)	44,683.89
5860000	Meter Expenses	902,995.80	(37,758.22)	0.00	(37,758.22)	865,237.58
5870000	Customer Installations Exp	135,198.48	10,819.76	10,819.76	0.00	146,018.24
5880000	Miscellaneous Distribution Exp	10,421,277.89	(6,128,603.44)	0.00	(6,128,603.44)	4,292,674.45
5890001	Rents - Nonassociated	1,591,499.22	396,697.70	396,697.70	0.00	1,988,196.92
5890002	Rents - Associated	64,688.82	2,489.20	2,489.20	0.00	67,178.02
5900000	Maint Supv & Engineering	2,479.86	(2,433.12)	0.00	(2,433.12)	46.74
5910000	Maintenance of Structures	12,231.04	(3,353.79)	0.00	(3,353.79)	8,877.25
5920000	Maint of Station Equipment	552,890.10	467,109.68	467,109.68	0.00	1,019,999.78
5930000	Maintenance of Overhead Lines	20,259,086.96	8,246,509.71	8,246,509.71	0.00	28,505,596.67
5930001	Tree and Brush Control	233,786.79	9,353.56	9,353.56	0.00	243,140.35
5930010	Storm Expense Amortization	2,349,208.00	2,349,236.00	2,349,236.00	0.00	4,698,444.00
5930011	EMI Device Expense - Affiliate	30,106.63	(30,106.63)	0.00	(30,106.63)	0.00
5940000	Maint of Underground Lines	114,107.90	(44,604.89)	0.00	(44,604.89)	69,503.01
5950000	Maint of Lne Trnf,Rglators&Dvi	108,833.62	11,637.73	11,637.73	0.00	120,471.35
5960000	Maint of Strt Lghtng & Sgnal S	51,481.50	10,749.55	10,749.55	0.00	62,231.05
5970000	Maintenance of Meters	71,064.80	(14,882.82)	0.00	(14,882.82)	56,181.98
5980000	Maint of Misc Distribution Plt	346,863.65	(207,861.47)	0.00	(207,861.47)	139,002.18
9010000	Supervision - Customer Accts	334,139.04	(9,269.32)	0.00	(9,269.32)	324,869.72
9020000	Meter Reading Expenses	11,962.75	(2,133.83)	0.00	(2,133.83)	9,828.92
9020001	Customer Card Reading	0.00	1,598.15	1,598.15	0.00	1,598.15
9020002	Meter Reading - Regular	561,859.80	10,999.90	10,999.90	0.00	572,859.70
9020003	Meter Reading - Large Power	47,573.99	(4,734.86)	0.00	(4,734.86)	42,839.13
9020004	Read-In & Read-Out Meters	45,343.48	19,088.85	19,088.85	0.00	64,432.33
9030000	Cust Records & Collection Exp	532,666.70	4,652.20	4,652.20	0.00	537,318.90
9030001	Customer Orders & Inquiries	2,408,302.40	304,104.43	304,104.43	0.00	2,712,406.83
9030002	Manual Billing	33,225.21	9,330.74	9,330.74	0.00	42,555.95
9030003	Postage - Customer Bills	639,768.31	102,052.53	102,052.53	0.00	741,820.84
9030004	Cashiering	128,060.56	886.52	886.52	0.00	128,947.08
9030005	Collection Agents Fees & Exp	96,259.26	11,795.71	11,795.71	0.00	108,054.97
9030006	Credit & Oth Collection Activi	1,007,828.67	(93,861.13)	0.00	(93,861.13)	913,967.54
9030007	Collectors	475,393.81	112,312.62	112,312.62	0.00	587,706.43
9030009	Data Processing	143,398.13	9,327.60	9,327.60	0.00	152,725.73
9040007	Uncoll Accts - Misc Receivable	10,208.17	4,240.44	4,240.44	0.00	14,448.61
9050000	Misc Customer Accounts Exp	30,730.18	56,804.58	56,804.58	0.00	87,534.76
9070000	Supervision - Customer Service	259,281.99	68,221.56	68,221.56	0.00	327,503.55
9070001	Supervision - DSM	2,476.12	(457.91)	0.00	(457.91)	2,018.21
9080000	Customer Assistance Expenses	482,959.22	26,441.45	26,441.45	0.00	509,400.67
9080001	DSM-Customer Advisory Grp	0.00	742.50	742.50	0.00	742.50
9080009	Cust Assistance Expense - DSM	1,820,886.70	664,053.51	664,053.51	0.00	2,484,940.21
9090000	Information & Instruct Advrtis	195,716.34	(8,662.56)	0.00	(8,662.56)	187,053.78
9100000	Misc Cust Svc&Informational Ex	32,570.96	(7,722.09)	0.00	(7,722.09)	24,848.87
9110001	Supervision - Residential	57.81	(48.25)	0.00	(48.25)	9.56
9110002	Supervision - Comm & Ind	11.56	(8.15)	0.00	(8.15)	3.41
9120000	Demonstrating & Selling Exp	0.00	1.08	1.08	0.00	1.08
9200000	Administrative & Gen Salaries	7,515,441.97	(1,705,144.44)	0.00	(1,705,144.44)	5,810,297.53
9200003	Admin & Gen Salaries Trnsfr	46.34	(92.68)	0.00	(92.68)	(46.34)
9210001	Off Supl & Exp - Nonassociated	741,855.68	(190,509.51)	0.00	(190,509.51)	551,346.17
9210003	Office Supplies & Exp - Trnsf	43.35	(45.67)	0.00	(45.67)	(2.32)
9210004	Office Utilites	647.60	(647.60)	0.00	(647.60)	0.00
9210005	Cellular Phones and Pagers	6.89	(6.89)	0.00	(6.89)	0.00
9220000	Administrative Exp Trnsf - Cr	(157.18)	(140,159.95)	0.00	(140,159.95)	(140,317.13)
9220001	Admin Exp Trnsf to Cnstrction	(379,529.24)	15,664.24	15,664.24	0.00	(363,865.00)
9220004	Admin Exp Trnsf to ABD	(6,470.28)	2,982.92	2,982.92	0.00	(3,487.36)
9220125	SSA Expense Transfers BL	(522,897.36)	(102,294.53)	0.00	(102,294.53)	(625,191.89)
9230001	Outside Svcs Empl - Nonassoc	823,687.26	154,319.33	154,319.33	0.00	978,006.59
9230003	AEPSC Billed to Client Co	4,387,744.42	(523,613.41)	0.00	(523,613.41)	3,864,131.01
9240000	Property Insurance	506,749.22	134,308.55	134,308.55	0.00	641,057.77
9250000	Injuries and Damages	1,099,445.08	127,037.15	127,037.15	0.00	1,226,482.23

KYP CORP CONSOLIDATED
Trial Balance
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Account Number	Description	Pr Yr Ending Balance	Yearly Activity	Debits	Credit	Current Yr Balance
9250001	Safety Dinners and Awards	0.00	982.23	982.23	0.00	982.23
9250002	Emp Accdent Prvntion-Adm Exp	120,732.14	(111,223.94)	0.00	(111,223.94)	9,508 20
9250004	Injuries to Employees	22,564.48	52,329 80	52,329.80	0 00	74,894 28
9250006	Wrkrs Cmpnstn Pre&Slf Ins Prv	170,889.32	330,677.56	330,877.56	0.00	501,566.88
9250007	Prsnal Injries&Prop Dmage-Pub	200,295.28	(126,684.66)	0 00	(126,684.66)	73,610 62
9250010	Frg Ben Loading - Workers Comp	(98,946.71)	(75,834.51)	0.00	(75,834.51)	(174,781.22)
9260000	Employee Pensions & Benefits	8,816 54	250.59	250.59	0.00	9,067.13
9260001	Edit & Print Empl Pub-Salaries	23,610.98	13,457.40	13,457.40	0.00	37,068 38
9260002	Pension & Group Ins Admin	16,998.00	12,742.00	12,742.00	0 00	29,740.00
9260003	Pension Plan	2,995,603.20	(101,603.16)	0.00	(101,603.16)	2,894,000.04
9260004	Group Life Insurance Premiums	142,841.00	(8,997.17)	0.00	(8,997.17)	133,843.83
9260005	Group Medical Ins Premiums	4,606,900 45	(621,759.32)	0.00	(621,759.32)	3,985,141.13
9260007	Group L-T Disability Ins Prem	186,713.27	(8,686.84)	0.00	(8,686 84)	178,026.43
9260009	Group Dental Insurance Prem	246,865.36	(21,275.49)	0.00	(21,275.49)	225,589 87
9260010	Training Administration Exp	4,510 84	2,334.95	2,334.95	0 00	6,845.59
9260012	Employee Activities	1,731.94	4,085.05	4,085 05	0 00	5,816.99
9260014	Educational Assistance Pmts	24,987.38	(14,588.73)	0.00	(14,588.73)	10,398.65
9260021	Postretirement Benefits - OPEB	3,346,838.03	(959,370.01)	0.00	(959,370.01)	2,387,468.02
9260027	Savings Plan Contributions	1,529,101.32	(88,910.79)	0 00	(88,910.79)	1,440,190.53
9260036	Deferred Compensation	24,070.06	1,997.40	1,997.40	0.00	28,067.46
9260037	Supplemental Pension	1,033.56	(33.60)	0.00	(33.60)	999.96
9260050	Frg Ben Loading - Pension	(1,141,059.32)	24,351 64	24,351.84	0.00	(1,116,707.68)
9260051	Frg Ben Loading - Grp Ins	(1,859,496.97)	25,623.90	25,623.90	0.00	(1,833,873.07)
9260052	Frg Ben Loading - Savings	(519,027.18)	6,311.62	6,311.62	0.00	(512,715.56)
9260053	Frg Ben Loading - OPEB	(856,543.44)	248,072.27	248,072.27	0.00	(608,471.17)
9260055	IntercoFringeOffset- Don't Use	(1,102,008.37)	(23,908.93)	0.00	(23,908 93)	(1,125,917.30)
9260056	Fidelity Stock Option Admin	0 00	248.88	248.88	0 00	248 88
9260057	Postret Ben Medicare Subsidy	(954,918.73)	106,681.70	106,681.70	0.00	(848,237.03)
9260058	Frg Ben Loading - Accrual	(17,316.86)	3,828.98	3,828.98	0.00	(13,487.88)
9270000	Franchise Requirements	200,575.06	(10,455 69)	0.00	(10,455.69)	190,119.37
9280000	Regulatory Commission Exp	(7.66)	10 68	10.68	0.00	3 02
9280001	Regulatory Commission Exp-Adm	(4.66)	(16.79)	0 00	(16.79)	(21.45)
9280002	Regulatory Commission Exp-Case	88,270.33	(79,801.49)	0 00	(79,801.49)	8,468.84
9301000	General Advertising Expenses	0.00	5,561.61	5,561.61	0.00	5,561.61
9301001	Newspaper Advertising Space	(217,968.76)	232,871.94	232,871 94	0 00	14,903.18
9301002	Radio Station Advertising Time	295.03	2,474.97	2,474.97	0 00	2,770.00
9301003	TV Station Advertising Time	0.00	513.34	513.34	0.00	513 34
9301006	Spec Corporate Comm Info Proj	0.08	(0.08)	0.00	(0.08)	0.00
9301009	Fairs, Shows, and Exhibits	415.88	(415.88)	0.00	(415 88)	0.00
9301010	Publicity	773.60	76.48	76.46	0 00	850.06
9301011	Dedications, Tours, & Openings	7.49	(7.49)	0.00	(7.49)	0.00
9301012	Public Opinion Surveys	25,427.37	(4,069.71)	0.00	(4,069 71)	21,357.66
9301014	Video Communications	29.35	5.15	5.15	0.00	34.50
9301015	Other Corporate Comm Exp	50,580.50	(26,239.47)	0.00	(26,239.47)	24,341.03
9302000	Misc General Expenses	253,563.14	82,899 61	82,899 61	0.00	336,462.75
9302003	Corporate & Fiscal Expenses	16,380.94	7,810.61	7,810.61	0.00	24,191.55
9302004	Research, Develop&Demonstr Exp	15,514.20	3,360.16	3,360.16	0.00	18,874.36
9302006	Assoc Bus Dev - Materials Sold	0 00	15,340.61	15,340.61	0.00	15,340.61
9302007	Assoc Business Development Exp	193,172.63	(104,161.65)	0 00	(104,161.65)	89,010.98
9310000	Rents	6,280.00	(5,980.00)	0.00	(5,980.00)	300.00
9310001	Rents - Real Property	90,384.27	(3,581.87)	0.00	(3,581.87)	86,802.40
9310002	Rents - Personal Property	142,304 60	(103,318.68)	0 00	(103,318.68)	38,985.92
9350000	Maintenance of General Plant	439.02	(439.02)	0.00	(439.02)	0.00
9350001	Maint of Structures - Owned	521,217.33	100,947.49	100,947.49	0.00	622,164.82
9350002	Maint of Structures - Leased	81,513.77	25,207.96	25,207.96	0.00	106,721.73
9350007	Maint of Radio Equip - Owned	0.00	69.79	69.79	0 00	69.79
9350012	Maint of Data Equipment	113.23	(113.23)	0 00	(113.23)	0.00
9350013	Maint of Cmmncation Eq-Unall	1,094,700.29	(24,807.77)	0 00	(24,807.77)	1,069,892.52
9350015	Maint of Office Furniture & Eq	227,951.66	(225,765.23)	0.00	(225,765.23)	2,186.43
9350024	Maint of DA-AMI Comm Equip	0.00	183.23	183.23	0 00	183.23
	NET INCOME - EARN FOR CMMN STK	(35,281,875.10)	(7,092,073.19)	0.00	(7,092,073.19)	(42,373,948.29)
	PREF STK DIVIDEND REQUIREMENT	0.00	0.00	0.00	0.00	0.00

Kentucky Power Company
Trial Balance
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Account Number	Description	Pr Yr Ending Balance	Debits	Credit	Current Yr Balance
1010001	Plant in Service	1,637,068,431.45	40,989,688 65	0.00	1,678,058,120.10
1011001	Capital Leases	5,728,114.56	0.00	(616,224.61)	5,111,889.95
1011006	Prov-Leased Assets	(1,889,866.77)	0.00	(214,953 67)	(2,104,820.44)
1011012	Accrued Capital Leases	1,946.94	69,160.39	0.00	71,107.33
1050001	Held For Fut Use	7,436,550.73	0.00	0.00	7,436,550.73
1060001	Const Not Classifd	28,057,162.98	40,418,547.92	0.00	68,475,710 90
1070001	CWIP - Project	71,290,315.94	0.00	(27,009,024.03)	44,281,291.91
1080001	A/P for Deprec of Plt	(554,998,454.13)	0.00	(31,501,625.78)	(586,500,079.91)
1080005	RWIP - Project Detail	1,948,266.87	4,378,413.75	0.00	6,326,680.62
1080011	Cost of Removal Reserve	(29,722,359.72)	5,542,890.44	0.00	(24,179,469 28)
1080013	ARO Removal Deprec - Accretion	2,597,758.15	515,369.49	0.00	3,113,127.64
1110001	A/P for Amort of Plt	(18,729,331.79)	0.00	(2,165,009.35)	(20,894,341.14)
1210001	Nonutility Property - Owned	964,528 00	0 00	0.00	964,528 00
1220001	Depr&Amrt of Nonutl Prop-Ownd	(201,616.31)	0.00	(6,669.72)	(208,286.03)
1240002	Oth Investments-Nonassociated	806 00	0.00	0.00	806.00
1240005	Spec Allowance Inv NOx	10.83	0.00	(4.06)	6.77
1240007	Deferred Compensation Benefits	109,986.94	0.00	(12,679.27)	97,307.67
1240027	Other Property - RWIP	0.00	7,500.00	0.00	7,500.00
1240029	Other Property - CPR	4,734,975.63	0.00	0.00	4,734,975.63
1240092	Fbr Opt Lns-In Kind Sv-Invest	167,611.00	0.00	(4,997.00)	162,614 00
1310000	Cash	778,210.29	703,767.46	0.00	1,481,977.75
1340018	Spec Deposits - Elect Trading	1,783,962.56	0.00	(1,417,614.00)	366,348.56
1340043	Spec Deposit UBS Securities	6,683,308.36	0.00	(3,551,875.07)	3,131,433.29
1340048	Spec Deposits-Trading Contra	(5,240,876.00)	3,219,826.00	0.00	(2,021,050.00)
1340050	Spec Deposit Mizuho Securities	182,974.30	260,795.04	0.00	443,769.34
1410002	P/R Ded - Misc Loan Repayments	534.41	0.00	(534.41)	0.00
1420001	Customer A/R - Electric	36,439,177.43	0.00	(11,195,933.45)	25,243,243.98
1420014	Customer A/R-System Sales	576,236.05	22,102.25	0.00	598,338.30
1420019	Transmission Sales Receivable	9,264 00	1,332.00	0.00	10,596.00
1420022	Cust A/R - Factored	(33,467,710.09)	6,871,644.97	0.00	(26,596,065.12)
1420023	Cust A/R-System Sales - MLR	7,211,759 62	0.00	(3,268,504.54)	3,943,255.08
1420024	Cust A/R-Options & Swaps - MLR	486,311.99	0.00	(244,556.16)	241,755.83
1420027	Low Inc Energy Asst Pr (LIEAP)	594,155 00	40,989.27	0.00	635,144.27
1420044	Customer A/R - Estimated	266,317.00	5,120,144.50	0.00	5,386,461.50
1420050	PJM AR Accrual	450,300.49	1,696,787.33	0.00	2,147,087.82
1420052	Gas Accruals	5,361.68	40,333.06	0.00	45,694.74
1420053	AR Coal Trading	155,331.42	0.00	(117,553.98)	37,777.44
1420054	Accrued Power Brokers	0.00	31,236.28	0.00	31,236.28
1420102	AR Peoplesoft Billing - Cust	211,220.30	740,306.22	0.00	951,526 52
1430022	2001 Employee Biweekly Pay Cnv	71,902.58	0 00	(1,155.81)	70,746.77
1430081	Damage Recovery - Third Party	18,045.18	15,598 82	0.00	33,644.00
1430083	Damage Recovery Offset Demand	(20,487.18)	0.00	(26,109.82)	(46,597.00)
1430089	A/R - Benefits Billing	4,998.81	0.00	(3,323.28)	1,675.53
1430101	Other Accounts Rec - Misc	0 00	746.45	0.00	746.45
1430102	AR Peoplesoft Billing - Misc	13.40	90,430.48	0.00	90,443.88
1440002	Uncoll Accts-Other Receivables	0.00	0.00	(141,538.08)	(141,538.08)
1440003	Uncoll Accts-Power Trading	(622,726.06)	622,726.06	0.00	0.00
1450000	Corp Borrow Prg (NR-Assoc)	70,331,842.70	0.00	(70,331,842.70)	0.00
1460001	A/R Assoc Co - InterUnit G/L	7,022,008 68	0.00	(931,752.26)	6,090,256.42
1460002	A/R Assoc Co - Allowances	0 00	208,543.68	0.00	208,543.68
1460006	A/R Assoc Co - Intercompany	383,857.48	1,348,409.54	0.00	1,732,267.02
1460009	A/R Assoc Co - InterUnit A/P	16,434.02	0.00	(16,434 00)	0.02
1460011	A/R Assoc Co - Multi Pmts	960,735.00	230,878.36	0.00	1,191,613.36
1460024	A/R Assoc Co - System Sales	4,490.98	0.00	(741.21)	3,749.77
1460025	Fleet - M4 - A/R	17,857.20	0.00	(3,198 89)	14,658.31
1510001	Fuel Stock - Coal	21,610,471.20	44,984,814.48	0.00	66,595,285.68
1510002	Fuel Stock - Oil	987,181.52	0.00	(302,147.27)	685,034.25
1520000	Fuel Stock Exp Undistributed	408,137.16	1,458,719.38	0.00	1,866,856.54
1540001	M&S - Regular	10,936,042.83	412,780.58	0.00	11,348,823.41
1540004	M&S - Exempt Material	51,493.30	2,482.72	0.00	53,976.02
1540012	Materials & Supplies - Urea	277,567.42	88,465.46	0.00	366,032.88
1540013	Transportation Inventory	84,205.95	21,032.98	0.00	105,238 93
1540023	M&S Inv - Urea In-Transit	1,775,445.61	0.00	(741,201.26)	1,034,244.35
1581000	SO2 Allowance Inventory	3,525,928.40	0.00	(1,164,696.03)	2,361,232.37
1581003	SO2 Allowance Inventory - Curr	13,518,673.22	0.00	(1,743,980.86)	11,774,692.36
1581006	An. NOx Comp Inv - Curr	158,404.86	0.00	(130,133.39)	28,271.47
1581009	CSAPR Current SO2 Inv	350,000.00	0.00	0.00	350,000.00
1650001	Prepaid Insurance	352,266.00	14,405.17	0.00	366,671.17
165000211	Prepaid Taxes	412,861.18	0.00	(412,861.18)	0 00
165000212	Prepaid Taxes	0.00	515,095.27	0.00	515,095.27

Kentucky Power Company
Trial Balance
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Account Number	Description	Pr Yr Ending Balance	Debits	Credit	Current Yr Balance
1650009	Prepaid Carry Cost-Factored AR	20,357.33	0 00	(7,256.32)	13,101.01
1650010	Prepaid Pension Benefits	25,665,475.92	1,657,058.88	0.00	27,322,534.80
165001111	Prepaid Sales Taxes	348,741.24	0.00	(348,741.24)	0.00
165001112	Prepaid Sales Taxes	0.00	294,772.55	0.00	294,772.55
165001211	Prepaid Use Taxes	51,118.18	0.00	(51,118.18)	0.00
165001212	Prepaid Use Taxes	0.00	42,718.84	0.00	42,718.84
1650014	FAS 158 Qual Contra Asset	(25,665,475.92)	0.00	(1,657,058.88)	(27,322,534.80)
1650021	Prepaid Insurance - EIS	269,029.60	0.00	(855.93)	268,173.67
1650023	Prepaid Lease	5,454.48	63,807.81	0.00	69,262.29
1710000	Interest&Dividends Receivable	1,850,772.00	0.00	(1,850,772.00)	0.00
1710348	Interest Receivable -SIT -LT	0 00	1,285.00	0.00	1,285 00
1720000	Rents Receivable	2,507,696.54	482,056.26	0 00	2,989,752.80
1730000	Accrued Utility Revenues	21,704,233.90	0.00	(1,957,385.53)	19,746,848.37
1730002	Acrd Utility Rev-Factored-Assc	(18,324,815.52)	0.00	(605,093.32)	(18,929,908.84)
1750001	Curr. Unreal Gains - NonAffil	8,974,433.86	0.00	(2,575,210.14)	6,399,223.72
1750002	Long-Term Unreal Gns - Non Aff	8,530,460.81	0.00	(1,683,169.04)	6,847,291.77
1750021	S/T Asset MTM Collateral	(671,776.00)	425,457.00	0.00	(246,319.00)
1750022	L/T Asset MTM Collateral	(236,128.00)	229,650.00	0.00	(6,478.00)
1760010	S/T Asset for Commodity Hedges	85,722.00	0.00	(63,807.00)	21,915.00
1760011	L/T Asset for Commodity Hedges	5,525.00	35,316.00	0.00	40,841.00
1810006	Unamort Debt Exp - Sr Unsec Nt	2,509,741.08	0.00	(304,461.42)	2,205,279 66
1823007	SFAS 112 Postemployment Benef	5,204,956.02	24,755.98	0.00	5,229,712.00
1823009	DSM Incentives	1,652,797.00	477,003 00	0.00	2,129,800.00
1823010	DSM Recovery	(20,295,438.00)	0.00	(2,941,336.00)	(23,236,774.00)
1823011	DSM Lost Revenues	4,892,959.00	845,601.00	0.00	5,738,560.00
1823012	DSM Program Costs	13,909,653.41	3,048,083.13	0.00	16,957,736.54
1823022	HRJ 765kV Post Service AFUDC	699,048.00	0.00	(33,408.00)	665,640 00
1823054	HRJ 765kV Depreciation Expense	108,937.00	0.00	(5,208 00)	103,729.00
1823078	Deferred Storm Expense	16,444,554.00	7,447,556.00	0.00	23,892,110.00
1823115	Defd Equity Carry Chg-Non Fuel	(130,112.65)	22,428.00	0.00	(107,684.65)
1823118	BridgeCo TO Funding	290,712.55	0.00	(25,708.78)	265,003.77
1823119	PJM Integration Payments	396,529.88	0.00	(122,527.26)	274,002.62
1823120	Other PJM Integration	307,137.14	0.00	(27,161.24)	279,975.90
1823121	Carry Chgs-RTO Startup Costs	177,149.42	0.00	(28,791.43)	148,357.99
1823122	Alliance RTO Deferred Expense	152,155.63	0.00	(13,455.72)	138,699.91
1823165	REG ASSET FAS 158 QUAL PLAN	46,407,197.00	1,242,794.00	0.00	47,649,991.00
1823166	REG ASSET FAS 158 OPEB PLAN	20,115,347.00	0.00	(15,586,346.80)	4,529,000 20
1823167	REG Asset FAS 158 SERP Plan	(130,506.00)	0.00	(284.00)	(130,790.00)
1823188	Deferred Carbon Mgmt Research	225,006.00	0.00	(49,996 00)	175,010.00
1823301	SFAS 109 Flow Thru Defd FIT	82,588,902.42	3,722,129.71	0.00	86,311,032.13
1823302	SFAS 109 Flow Thru Defrd SIT	41,595,141.07	749,550.00	0.00	42,344,691.07
1823306	Net CCS FEED Study Costs	905,127.70	0.00	(32,269.39)	872,858.31
1830000	Prelimin Surv&Investgtn Chrgs	3,980,392.62	29,103,881.76	0.00	33,084,274.38
1860001	Allowances	455.09	0.00	(0.92)	454.17
1860002	Deferred Expenses	2,747,820.17	0.00	(2,747,820.17)	0 00
186000311	Deferred Property Taxes	10,031,245.00	0.00	(10,031,245.00)	0.00
186000312	Deferred Property Taxes	0.00	10,424,709.00	0.00	10,424,709.00
1860007	Billings and Deferred Projects	63,901.12	120,303.20	0.00	184,204.32
1860077	Agency Fees - Factored A/R	1,035,850.51	0.00	(125,331.05)	910,519.46
1860153	Unamortized Credit Line Fees	719,095.93	0.00	(176,946.02)	542,149 91
1860160	Deferred Expenses - Current	1,430,214.17	1,319,813.26	0.00	2,750,027.43
1860166	Def Lease Assets - Non Taxable	20,834 06	180,848.40	0.00	201,682.46
1890004	Loss Rec Debt-Debentures	703,816.00	0.00	(33,648.60)	670,167.40
1900006	ADIT Federal - SFAS 133 Nonaff	184,244.71	0.00	(92,759.41)	91,485.30
1900015	ADIT-Fed-Hdg-CF-Int Rate	184,362.96	0.00	(32,534.64)	151,828.32
1901001	Accum Deferred FIT - Other	19,960,569.48	0.00	(6,241,156.70)	13,719,412.78
1902001	Accum Defd FIT - Oth Inc & Ded	640,631.41	112,435.55	0.00	753,066.96
1903001	Acc Dfd FIT - FAS109 Flow Thru	13,055,773.98	266,794.07	0.00	13,322,568.05
1904001	Accum Dfd FIT - FAS 109 Excess	357,096.38	0.00	(15,755.93)	341,340.45
	TOTAL ASSETS AND OTHER DEBITS	1,602,592,451.21	16,279,277.65	0.00	1,618,871,728.86
2010001	Common Stock Issued-Affiliated	(50,450,000.00)	0.00	0.00	(50,450,000 00)
2080000	Donations Recvd from Stckhldrs	(238,750,000.00)	0.00	0.00	(238,750,000.00)
2160001	Unapprp Retnd Erngs-Unrstrictd	(157,466,514.06)	0.00	(14,373,948 29)	(171,840,462.36)
2190010	OCI for Commodity Hedges	282,855.18	0.00	(155,941.95)	126,913.23
2190015	Accum DCI-Hdg-CF-Int Rate	342,388.84	0.00	(60,421.56)	281,967.28
2230000	Advances from Associated Co	(20,000,000.00)	0.00	0.00	(20,000,000.00)
2240006	Senior Unsecured Notes	(530,000,000.00)	0.00	0.00	(530,000,000.00)
2260006	Unam Disc LTD-Dr-Sr Unsec Note	944,775.00	0.00	(166,725.00)	778,050 00
4380001	Div Declrd - Common Stk - Asso	28,000,000.00	4,000,000.00	0.00	32,000,000.00
	TOTAL CAPITALIZATION	(967,096,495.04)	0.00	(10,757,036.80)	(977,853,531.85)

Kentucky Power Company
Trial Balance
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Account Number	Description	Pr Yr Ending Balance	Debits	Credit	Current Yr Balance
2270001	Obligatns Undr Cap Lse-Noncurr	(2,386,010.44)	768,595.40	0 00	(1,617,415.04)
2270003	Accrued Noncur Lease Oblig	(1,557.54)	0.00	(55,328.31)	(56,885 85)
2282003	Accm Prv I/D - Worker's Com	(108,514.22)	71,733.37	0 00	(36,780.85)
2283000	Accm Prv for Pensions&Benefits	(130,506 31)	0.00	(721.94)	(131,228.25)
2283002	Supplemental Savings Plan	(424,901.20)	80,414.14	0.00	(344,487.06)
2283003	SFAS 106 Post Retirement Benef	(6,220,138.41)	799,174.50	0.00	(5,420,963.91)
2283005	SFAS 112 Postemployment Benef	(4,321,430.38)	115,842.38	0.00	(4,205,588.00)
2283007	Perf Share Incentive Plan	(547,457.22)	78,099.56	0 00	(469,357.66)
2283013	Incentive Comp Deferral Plan	(269,311.46)	58,183.93	0 00	(211,127.53)
2283015	FAS 158 SERP Payable Long Term	130,506.00	288.00	0.00	130,794.00
2283016	FAS 158 Qual Payable Long Term	(20,741,721.08)	414,264 88	0 00	(20,327,456.20)
2283017	FAS 158 OPEB Payable Long Term	(20,115,347.00)	15,586,346 80	0 00	(4,529,000.20)
2283018	SFAS 106 Med Part-D	6,212,831.43	0.00	(799,170.54)	5,413,660.89
2290006	Acc Prv for Potential Refund	0.00	0.00	(1,635,430.00)	(1,635,430.00)
2300001	Asset Retirement Obligations	(3,771,554.65)	0.00	(130,704.70)	(3,902,259.35)
2320001	Accounts Payable - Regular	(8,767,516.36)	1,284,691.94	0.00	(7,482,824.42)
2320002	Unvouchered Invoices	(6,725,655.21)	0.00	(3,399,611.93)	(10,125,267.14)
2320003	Retention	(364,727.35)	0.00	(164,409.51)	(529,136.86)
2320006	Allowance Settlements	(940,100.00)	940,100.00	0.00	0.00
2320011	Uninvoiced Fuel	(15,019,515.26)	4,841,048.81	0 00	(10,178,466.45)
2320050	Coal Trading	(163,451.48)	130,958.25	0.00	(32,493.23)
2320052	Accounts Payable - Purch Power	(1,285,211.66)	1,164,615.43	0.00	(120,596.23)
2320053	Elect Trad-Options&Swaps	(869,987.60)	236,458.64	0.00	(633,528.96)
2320056	Gas Physicals	(0.90)	0.90	0.00	(0.00)
2320062	Broker Fees Payable	(11,526.34)	9,588.16	0.00	(1,938.18)
2320073	A/P Misc Dedic. Power	(19,735.50)	4,063.50	0 00	(15,672.00)
2320076	Corporate Credit Card Liab	(55,657.01)	0.00	(67,376 98)	(123,033 99)
2320077	INDUS Unvouchered Liabilities	(496,325.57)	0.00	(58,377.76)	(554,703.33)
2320079	Broker Commisn Spark/Merch Gen	(40.77)	40.77	0.00	0.00
2320081	AP Accrual NYMEX OTC & Penults	0.00	0.00	(7,926 27)	(7,926.27)
2320084	Uninvoiced OVEC Purch Power	(275,079.47)	275,079.47	0 00	0.00
2320086	Accrued Broker - Power	(811,703.48)	583,003.43	0.00	(228,700.05)
2320090	MISO AP Accrual	(269,700.91)	0 00	(32,788.61)	(302,489.52)
2330000	Corp Borrow Program (NP-Assoc)	0.00	0.00	(13,358,855 63)	(13,358,855.63)
2340001	A/P Assoc Co - InterUnit G/L	(17,721,363.34)	1,475,328.55	0.00	(16,246,034.79)
2340005	A/P Assoc Co - Allowances	(12,341,570.49)	6,245,445.11	0.00	(6,096,125.38)
2340011	A/P-Assc Co-AEPSC-Agent	(1,719,585.00)	0.00	(11,270,805.36)	(12,990,390.36)
2340025	A/P Assoc Co - CM Bills	(10,129.31)	0.00	(7,778.50)	(17,907.81)
2340027	A/P Assoc Co - Intercompany	211,160.49	0.00	(438,003 20)	(226,842.71)
2340029	A/P Assoc Co - AEPSC Bills	(3,196,742.26)	0.00	(1,994,013.08)	(5,190,755.34)
2340030	A/P Assoc Co - InterUnit A/P	(326,892.13)	142,913.72	0.00	(183,978.41)
2340032	A/P Assoc Co - Multi Pmts	(65.00)	0.00	(312.70)	(377.70)
2340034	A/P Assoc Co - System Sales	(3,239.90)	3,065.40	0.00	(174.50)
2340035	Fleet - M4 - A/P	(22,046.46)	10,907.28	0.00	(11,139.18)
2340037	A/P Assoc-Global Borrowing Int	(87,500.00)	0.00	0.00	(87,500.00)
2340049	A/P Assoc -Realization Sharing	(580.00)	0.00	(874.00)	(1,454.00)
2350001	Customer Deposits-Active	(21,828,694.26)	0.00	(1,554,292.26)	(23,382,986.52)
2350003	Deposits - Trading Activity	(255,900.52)	89,063.23	0.00	(166,837.29)
2350005	Deposits - Trading Contra	10,518.00	54,341.00	0.00	64,859.00
2360001	Federal Income Tax	(5,515,783.36)	10,605,184.44	0 00	5,089,401.08
236000209	State Income Taxes	63,670.00	0.00	0.00	63,670.00
236000211	State Income Taxes	(620,201.72)	620,201.72	0.00	0.00
236000212	State Income Taxes	0.00	5,311.61	0.00	5,311.61
2360004	FICA	(123,069.24)	76,755.79	0.00	(46,313.45)
2360005	Federal Unemployment Tax	(13,902.65)	0.00	(3,703.37)	(17,606.02)
2360006	State Unemployment Tax	(6,243.68)	5,970.15	0.00	(273.53)
236000711	State Sales and Use Taxes	(120,944.86)	120,944.86	0.00	0.00
236000712	State Sales and Use Taxes	0.00	0.00	(252,612.46)	(252,612.46)
236000808	Real & Personal Property Taxes	(446.76)	446.76	0.00	0.00
236000809	Real & Personal Property Taxes	(31,714.50)	31,714.50	0.00	0.00
236000810	Real Personal Property Taxes	(2,365,728.68)	2,268,991.96	0.00	(96,736.72)
236000811	Real Personal Property Taxes	(10,031,245.00)	9,500,786.83	0.00	(530,458.17)
236000812	Real Personal Property Taxes	0.00	0.00	(10,424,508.70)	(10,424,508.70)
236001211	State Franchise Taxes	8,908.00	0.00	(8,908.00)	0 00
236001212	State Franchise Taxes	0.00	27,955.00	0.00	27,955.00
236001611	State Gross Receipts Tax	(48,000.00)	48,000.00	0.00	0.00
236001612	State Gross Receipts Tax	0.00	0.00	(33,000 00)	(33,000.00)
236003309	Pers Prop Tax-Cap Leases	17.98	0.00	(17.98)	0 00
236003310	Pers Prop Tax-Cap Leases	(104,116.33)	104,116.33	0.00	0 00
236003311	Pers Prop Tax-Cap Leases	(77,647.73)	67,379 56	0.00	(10,268.17)

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Account Number	Description	Pr Yr Ending Balance	Debits	Credit	Current Yr Balance
236003312	Pers Prop Tax-Cap Leases	0.00	0.00	(4,372.68)	(4,372.68)
236003509	Real Prop Tax-Cap Leases	310.74	0.00	(310.74)	0.00
236003511	Real Prop Tax-Cap Leases	2,189.54	0.00	(2,189.54)	0.00
2360037	FICA - Incentive accrual	(167,774.56)	0.00	(110,109.17)	(277,883.73)
2360038	Reorg Payroll Tax Accrual	0.00	0 00	(33,379.64)	(33,379.64)
2360502	State Inc Tax-Short Term FIN48	(272,722.00)	181,958.00	0.00	(90,764 00)
2360601	Fed Inc Tax-Long Term FIN48	(1,241,664.06)	75,113.00	0.00	(1,166,551.06)
2360602	State Inc Tax-Long Term FIN48	(93,746.00)	18,074.00	0.00	(75,672.00)
2360701	SEC Accum Defd FIT-Util FIN 48	1,241,664.00	0.00	(75,113.00)	1,166,551.00
2360702	SEC Accum Defd SIT - FIN 48	198,195.00	0.00	(24,567.00)	173,628.00
2360801	Federal Income Tax - IRS Audit	0.00	1.00	0.00	1.00
2360901	Accum Defd FIT- IRS Audit	0.00	0.00	(14,832.00)	(14,832.00)
2370006	Interest Accrd-Sen Unsec Notes	(6,461,093.13)	0.00	(0.04)	(6,461,093.17)
2370007	Interest Accrd-Customer Depsts	(1,130,578.45)	498,517.85	0.00	(632,060 60)
2370018	Accrued Margin Interest	(2,764.16)	170.91	0.00	(2,593.25)
2370048	Acrd Int.- FIT Reserve - LT	(38,439 00)	0.00	(5,767.00)	(44,206 00)
2370348	Acrd Int. - SIT Reserve - LT	(7,785.00)	7,785.00	0.00	0.00
2370448	Acrd Int. - SIT Reserve - ST	(72,817.00)	46,075.00	0.00	(26,742.00)
2410001	Federal Income Tax Withheld	(169,593.92)	169,593.92	0.00	0.00
2410002	State Income Tax Withheld	(130,088.15)	65,764.16	0.00	(64,323.99)
2410003	Local Income Tax Withheld	(20,076.25)	0.00	(692.91)	(20,769.16)
2410004	State Sales Tax Collected	(797,400.58)	154,872.53	0.00	(642,528.05)
2410005	FICA Tax Withheld	(58,082.34)	58,082.34	0.00	0.00
2410008	Franchise Fee Collected	(394,356.58)	31,682.48	0.00	(362,674.10)
2410009	KY Utility Gr Receipts Lic Tax	(1,072,603.24)	101,671.70	0.00	(970,931.54)
2420002	P/R Ded - Medical Insurance	(96,807.95)	4,488.87	0.00	(92,319.08)
2420003	P/R Ded - Dental Insurance	(7,876.66)	0.00	(1.12)	(7,877.78)
2420018	P/R Ded-Reg&Spec Life Ins Prem	(1.68)	1.68	0 00	0.00
2420021	Vacation Pay - Next Year	(3,244,513.03)	146,041.91	0.00	(3,098,471.12)
2420027	FAS 112 CURRENT LIAB	(883,521.64)	0.00	(140,598.36)	(1,024,120.00)
2420044	P/R Withholdings	(42,646.50)	1,973.19	0.00	(40,673.31)
2420046	FAS 158 SERP Payable - Current	0.00	0.00	(4.00)	(4.00)
2420051	Non-Productive Payroll	(46,968.46)	13,096.09	0.00	(33,872.37)
2420053	Perf Share Incentive Plan	(257,128.23)	98,994.94	0 00	(158,133.29)
2420071	P/R Ded - Vision Plan	(3,613.91)	153.86	0.00	(3,460 05)
2420076	P/R Savings Plan - Incentive	(86,807.54)	0.00	(59,429.75)	(146,237.29)
2420511	Control Cash Disburse Account	(3,337,113.99)	1,339,089.58	0.00	(1,998,024.41)
2420512	Unclaimed Funds	(1,981.93)	0.00	(1,674.61)	(3,656.54)
2420514	Revenue Refunds Accrued	(1,769,667.77)	0.00	(394,527.40)	(2,164,195.17)
2420532	Adm Liab-Cur-S/Ins-W/C	(494,875.51)	69,332.28	0.00	(425,543.23)
2420542	Acc Cash Franchise Req	(83,631.42)	3,238.51	0.00	(80,392.91)
2420558	Admitted Liab NC-Self/Ins-W/C	(1,470,658.92)	621,401.92	0.00	(849,257.00)
242059211	Sales Use Tax - Leased Equip	(2,054.61)	2,054.61	0.00	0.00
242059212	Sales Use Tax - Leased Equip	0.00	0.00	(14,374.41)	(14,374.41)
2420618	Accrued Payroll	(533,064.09)	0.00	(84,491.84)	(617,555.93)
2420623	Energy Delivery Incentive Plan	(1,062,482.17)	0.00	(949,712.26)	(2,012,194.43)
2420624	Corp & Shrd Srv Incentive Plan	(168,406.18)	0.00	(98,170.82)	(266,577.00)
2420635	Fossil and Hydro Gen ICP	(874,647.68)	0.00	(169,565.32)	(1,044,213.00)
2420643	Accrued Audit Fees	(21,634.91)	17,987.93	0.00	(3,646.98)
2420651	Reorg Severance Accrual	0.00	0.00	(462,555.99)	(462,555 99)
2420653	Reorg Misc HR Exp Accrual	0.00	0.00	(1,425.00)	(1,425.00)
2420656	Federal Mitigation Accru (NSR)	(1,378,584.37)	1,001,790.36	0.00	(376,794.01)
2420658	Accrued Prof. Tax Services	(130,930.00)	130,930.00	0 00	0.00
2420660	AEP Transmission ICP	(229,977.33)	0.00	(123,741.67)	(353,719.00)
2420664	ST State Mitigation Def (NSR)	(581,159.65)	123,871.70	0.00	(457,287.95)
2430001	Oblig Under Cap Leases - Curr	(1,452,237.35)	62,582.88	0.00	(1,389,654.47)
2430003	Accrued Cur Lease Oblig	(389.40)	0.00	(13,832.08)	(14,221.48)
2440001	Curr. Unreal Losses - NonAffil	(9,188,427.82)	4,439,565.06	0.00	(4,748,862.76)
2440002	LT Unreal Losses - Non Affil	(4,786,802.78)	586,606.71	0.00	(4,200,196.07)
2440009	S/T Option Premium Receipts	(5,489.30)	0.00	(3,601.96)	(9,091.26)
2440021	S/T Liability MTM Collateral	4,025,288.00	0.00	(2,398,845.00)	1,626,443.00
2440022	L/T Liability MTM Collateral	2,112,974.00	0.00	(1,530,429 00)	582,545.00
2450010	S/T Liability-Commodity Hedges	(460,369.00)	271,812.00	0.00	(188,557.00)
2450011	L/T Liability-Commodity Hedges	(60,485.00)	0.00	(22,246.00)	(82,731.00)
2520000	Customer Adv for Construction	(92,999.14)	29,821.40	0.00	(63,177.74)
2530000	Other Deferred Credits	(2,750,000.00)	2,750,000.00	0.00	0.00
2530022	Customer Advance Receipts	(1,901,790.44)	0.00	(732,707.09)	(2,634,497.53)
2530050	Deferred Rev -Pole Attachments	(153,385 62)	74,445.27	0.00	(78,940.35)
2530067	IPP - System Upgrade Credits	(251,989.70)	0.00	(8,290 02)	(260,279.72)
2530092	Fbr Opt Lns-In Kind Sv-Dfd Gns	(167,611.00)	4,997.00	0.00	(162,614 00)

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Account Number	Description	Pr Yr Ending Balance	Debits	Credit	Current Yr Balance
2530112	Other Deferred Credits-Curr	(992,389.18)	0.00	(120,937.54)	(1,113,326.72)
2530114	Federl Mitigation Deferal(NSR)	0.00	0.00	(754,941.55)	(754,941.55)
2530137	Fbr Opt Lns-Sold-Defd Rev	(130,285.22)	13,555.80	0.00	(116,729.42)
2540011	Over Recovered Fuel Cost	(3,137,945.88)	0.00	(4,790,377.00)	(7,928,322.88)
2540047	Unreal Gain on Fwd Commitments	(3,536,244.65)	0.00	(751,310.01)	(4,287,554.66)
2540071	KY Enhanced Reliability Liab	0.00	0 00	(215,164.00)	(215,164.00)
2540105	Home Energy Assist Prgm - KPCO	(266,401.80)	32,912.51	0.00	(233,489.29)
2540173	Green Pricing Option	(614.00)	0.00	0.00	(614.00)
2543001	SFAS109 Flow Thru Def FIT Liab	(341,257.45)	149,695.01	0.00	(191,562.44)
2544001	SFAS 109 Exces Deferred FIT	(1,020,275.38)	45,016.93	0.00	(975,258.45)
2550001	Accum Deferred ITC - Federal	(633,763.82)	278,005.00	0.00	(355,758.82)
2811001	Acc Dfd FIT - Accel Amort Prop	(28,229,670.00)	1,585,032.05	0.00	(26,644,637.95)
2821001	Accum Defd FIT - Utility Prop	(191,985,551.86)	0.00	(6,737,565.09)	(198,723,116.95)
2823001	Acc Dfrd FIT FAS 109 Flow Thru	(51,839,003.65)	0.00	(2,573,530.83)	(54,412,534.48)
2824001	Acc Dfrd FIT - SFAS 109 Excess	663,179.00	0.00	(29,261.00)	633,918.00
2830006	ADIT Federal - SFAS 133 Nonaff	(31,936.00)	8,789.90	0.00	(23,146.10)
2831001	Accum Deferred FIT - Other	(18,828,529.71)	294,927.82	0.00	(18,533,601.89)
2832001	Accum Dfrd FIT - Oth Inc & Ded	(67,940.02)	0.00	(7,912.45)	(75,852.47)
2833001	Acc Dfd FIT FAS 109 Flow Thru	(43,464,415.30)	0.00	(1,565,087.96)	(45,029,503.26)
2833002	Acc Dfrd SIT FAS 109 Flow Thru	(41,595,141.07)	0.00	(749,550.00)	(42,344,691.07)
	LIABILITIES AND OTHER CREDITS	(593,122,007.88)	3,082,264.07	0.00	(590,039,743.82)
4030001	Depreciation Exp	49,832,280.37	1,248,570.77	0 00	51,080,851.14
4030021	AEPSC Bell Howell Inserter	0.00	2,712.57	0.00	2,712.57
4040001	Amort. of Plant	3,573,500.22	0.00	(190,607.45)	3,382,892.77
4060001	Amort of Plt Acq Adj	38,616.00	0.00	0 00	38,616.00
4073000	Regulatory Debits	311,514.72	0.00	(22,428.00)	289,086.72
4081002	FICA	2,513,753.85	242,196.00	0.00	2,755,949.85
4081003	Federal Unemployment Tax	32,029.02	0.00	(1,538.81)	30,490.21
408100506	Real & Personal Property Taxes	832.00	0.00	(832.00)	0.00
408100507	Real & Personal Property Taxes	984.57	0.00	(984.57)	0.00
408100508	Real & Personal Property Taxes	(69,267.32)	68,820.56	0.00	(446.76)
408100509	Real & Personal Property Taxes	(533,500.00)	503,339.76	0 00	(30,160.24)
408100510	Real Personal Property Taxes	9,439,723.14	0.00	(9,538,097.42)	(98,374.28)
408100511	Real Personal Property Taxes	197.47	9,603,747.53	0.00	9,603,945.00
408100610	State Gross Receipts Tax	(565.00)	565.00	0.00	0.00
408100611	State Gross Receipts Tax	243,944.00	0.00	(213,832.00)	30,112.00
408100612	State Gross Receipts Tax	0.00	144,101.00	0.00	144,101.00
4081007	State Unemployment Tax	33,334.61	0.00	(1,074.52)	32,260.09
408100810	State Franchise Taxes	(23,315.00)	23,315.00	0.00	0.00
408100811	State Franchise Taxes	29,392.00	0.00	(51,586.00)	(22,194.00)
408100812	State Franchise Taxes	0.00	10,345.00	0.00	10,345.00
408101411	Federal Excise Taxes	2,315.26	0 00	(2,315.26)	0.00
408101412	Federal Excise Taxes	0.00	997.96	0.00	997.96
408101711	St Lic-Rgstrtion Tax-Fees	272.25	0.00	(272.25)	0.00
408101712	St Lic-Rgstrtion Tax-Fees	0.00	165.00	0.00	165.00
408101810	St Publ Serv Comm Tax-Fees	399,674 78	0.00	(399,674.78)	0.00
408101811	St Publ Serv Comm Tax-Fees	412,861.20	0 00	(0.02)	412,861.18
408101812	St Publ Serv Comm Tax-Fees	0.00	515,095.26	0.00	515,095.26
408101910	State Sales and Use Taxes	1,779.68	0.00	(1,779.68)	0.00
408101911	State Sales and Use Taxes	14,295.82	0.00	(13,048.70)	1,247.12
408101912	State Sales and Use Taxes	0.00	9,804.65	0.00	9,804 65
408102211	Municipal License Fees	200 00	0.00	(200.00)	0.00
408102212	Municipal License Fees	0.00	300.00	0.00	300.00
408102909	Real/Pers Prop Tax-Cap Leases	3,392.00	0.00	(3,374.02)	17.98
408102910	Real-Pers Prop Tax-Cap Leases	1,284.65	0.00	(103,338 46)	(102,053.81)
408102911	Real-Pers Prop Tax-Cap Leases	79,000.00	0 00	(140,822.48)	(61,822.48)
408102912	Real-Pers Prop Tax-Cap Leases	0.00	16,699.00	0 00	16,699.00
4081033	Fringe Benefit Loading - FICA	(953,696.83)	0.00	(142,225 55)	(1,095,922.38)
4081034	Fringe Benefit Loading - FUT	(9,914.09)	1,766.01	0.00	(8,148.08)
4081035	Fringe Benefit Loading - SUT	(16,037.25)	1,427.14	0.00	(14,610.11)
408103608	Real Prop Tax-Cap Leases	0.00	310.74	0 00	310.74
408103609	Real Prop Tax-Cap Leases	14,760.50	0.00	(14,760.50)	0.00
408103610	Real Prop Tax-Cap Leases	606.58	0.00	(606.58)	0.00
408103611	Real Prop Tax-Cap Leases	24,750.00	0.00	(22,492.56)	2,257.44
408103612	Real Prop Tax-Cap Leases	0.00	26,744.91	0 00	26,744.91
408200510	Real Personal Property Taxes	56,600.00	0.00	(56,600 00)	0.00
408200511	Real Personal Property Taxes	0.00	56,600 00	0.00	56,600.00
4091001	Income Taxes, UOI - Federal	3,355,828 05	6,809,929.85	0.00	10,165,757.90
409100200	Income Taxes, UOI - State	0.00	0.00	(498,211.00)	(498,211.00)
409100207	Income Taxes, UOI - State	(4,516.00)	4,516 00	0.00	0.00

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Account Number	Description	Pr Yr Ending Balance	Debits	Credit	Current Yr Balance
409100208	Income Taxes, UOI - State	(2,648.00)	2,648 00	0.00	0.00
409100210	Income Taxes UOI - State	(616,267.59)	616,267.59	0 00	0.00
409100211	Income Taxes UOI - State	3,812,469.75	0 00	(4,107,807.96)	(295,338.21)
409100212	Income Taxes UOI - State	0.00	3,109,464.36	0.00	3,109,464.36
4092001	Inc Tax, Oth Inc&Ded-Federal	680,698.73	0.00	(578,143.87)	102,554 86
409200210	Inc Tax Oth Inc Ded - State	5,615.29	0 00	(5,615.29)	0.00
409200211	Inc Tax Oth Inc Ded - State	105,504.97	0.00	(112,661.48)	(7,156.51)
409200212	Inc Tax Oth Inc Ded - State	0.00	22,944.03	0 00	22,944.03
4101001	Prov Def I/T Util Op Inc-Fed	65,047,272.28	0 00	(3,486,204.77)	61,561,067.51
4102001	Prov Def I/T Oth I&D - Federal	62,448.64	0.00	(53,651.39)	8,797.25
4111001	Prv Def I/T-Cr Util Op Inc-Fed	(47,081,447.06)	0.00	(4,295,558 21)	(51,377,005.27)
4112001	Prv Def I/T-Cr Oth I&D-Fed	(261,856.18)	148,535.83	0.00	(113,320.35)
4114001	ITC Adj, Utility Oper - Fed	(359,377.18)	81,372.18	0 00	(278,005.00)
4116000	Gain From Disposition of Plant	(2,735.00)	0.00	(375.00)	(3,110.00)
4118002	Comp. Allow Gains Title IV SO2	(1,503.24)	1,098.59	0.00	(404 65)
4118003	Comp. Allow. Gains-Seas NOx	0.00	0.00	(14,958.00)	(14,958.00)
4171001	Exp of NonUtil Oper - Nonassoc	0.38	0.00	(0.38)	0.00
4180001	Non-Operatng Rental Income	(56,000.00)	200.00	0.00	(55,800.00)
4180002	Non-Opratng Rntal Inc-Oper	0.00	330.20	0.00	330.20
4180005	Non-Opratng Rntal Inc-Depr	6,669.72	0.00	0.00	6,669.72
4190002	Int & Dividend Inc - Nonassoc	(1,874,240.57)	1,838,335.44	0.00	(35,905.13)
4190005	Interest Income - Assoc CBP	(317,876.60)	96,325.16	0.00	(221,551.44)
4191000	Allw Oth Fnds Usd Dmg Cnstr	(1,229,388.72)	0.00	(344,995.68)	(1,574,384.40)
4210002	Misc Non-Op Inc-NonAsc-Rents	(60,948.90)	0.00	(358.00)	(61,306.90)
4210003	Misc Non-Op Inc-NonAscRoylty	0.00	15.95	0.00	15.95
4210005	Misc Non-Op Inc-NonAsc-Timber	(13,148.76)	0.00	(42,888.81)	(56,037.57)
4210007	Misc Non-Op Inc - NonAsc - Oth	(18,838.09)	0.00	(25,845.68)	(44,683.77)
4210009	Misc Non-Op Exp - NonAssoc	(1,844.38)	4,585.44	0 00	2,741.06
4210031	Pwr Sales Outside Svc Territry	(648,522.19)	336,562.62	0.00	(311,959.57)
4210032	Pwr Purch Outside Svc Territry	654,806.28	0.00	(654,205.94)	600.34
4210033	Mark to Mkt Out Svc Territory	(75,465.88)	74,102.30	0.00	(1,363.58)
4210035	Gn/Ls MTM Emissions - Forwards	1,106 89	0.00	(1,106.89)	0.00
4210039	Carrying Charges	(131,998.68)	38,128.39	0.00	(93,870.29)
4210043	Realiz Sharing West Coast Pwr	(2,142.00)	1,528.00	0.00	(614.00)
4210045	UnReal Aff Fin Assign SNWA	(72,544.00)	72,544.00	0.00	0.00
4210046	Real Aff Fin Assign SNWA	41,288.26	0.00	(41,288 26)	0.00
4210049	Interest Rate Swaps-BTL Power	9,697.61	0 00	(8,366.51)	1,331.10
4210053	Specul. Allow. Gains-SO2	(1,077.03)	1,077.03	0 00	0.00
4261000	Donations	434,849.89	0.00	(112,279.46)	322,570.43
4263001	Penalties	3,254.75	0.00	(3,236.96)	17.79
4264000	Civic & Political Activities	328,858.88	0 00	(24,807.06)	304,051.82
4265002	Other Deductions - Nonassoc	47,652.36	0.00	(40,940.83)	6,711.53
4265004	Social & Service Club Dues	113,430 09	0.00	(53,571.04)	59,859 05
4265009	Factored Cust A/R Exp - Affil	1,095,107.32	0.00	(208,261.17)	886,846.15
4265010	Fact Cust A/R-Bad Debts-Affil	1,255,540.46	314,386.90	0.00	1,569,927.36
4265053	Specul. Allow Loss-SO2	0.25	0.00	(0.25)	0.00
4265054	Specul. Allow Loss-Seas NOx	39.42	0.00	(35.36)	4.06
4270006	Int on LTD - Sen Unsec Notes	33,998,706.23	0.01	0.00	33,998,706.24
4280006	Amrtz Dscnt&Exp-Sn Unsec Note	471,186.47	0.00	(0.05)	471,186.42
4281004	Amrtz Loss Rcquired Debt-Dbnt	33,648 60	0.00	0.00	33,648.60
4300001	Interest Exp - Assoc Non-CBP	1,050,000.00	0.00	0.00	1,050,000.00
4300003	Int to Assoc Co - CBP	312.15	821.32	0.00	1,133.47
4310001	Other Interest Expense	9,876.40	0.00	(1,474.73)	8,401.67
4310002	Interest on Customer Deposits	1,236,767.04	0.00	(520,561.28)	716,205.76
4310007	Lines Of Credit	602,456.78	0.00	(2,064.65)	600,392.13
4310022	Interest Expense - Federal Tax	(165,787.00)	169,289.00	0.00	3,502.00
4310023	Interest Expense - State Tax	74,598 00	0.00	(55,575.62)	19,022.38
4320000	Allw Brrwed Fnds Used Cnstr-Cr	(900,289.87)	0.00	(224,249.00)	(1,124,538 87)
4400001	Residential Sales-W/Space Htg	(106,682,627.62)	9,416,735.53	0.00	(97,265,892.09)
4400002	Residential Sales-W/O Space Ht	(51,475,240.16)	4,122,724.02	0.00	(47,352,516.14)
4400005	Residential Fuel Rev	(68,011,510.65)	6,830,753.84	0.00	(61,180,756.81)
4420001	Commercial Sales	(69,665,430.71)	4,595,079 85	0.00	(65,070,350.86)
4420002	Industrial Sales (Excl Mines)	(60,359,208.77)	9,854,846 89	0.00	(50,504,361.88)
4420004	Ind Sales-NonAffil(Incl Mines)	(41,324,910.69)	7,555,467.75	0.00	(33,769,442.94)
4420006	Sales to Pub Auth - Schools	(12,907,167.46)	1,121,641.04	0.00	(11,785,526.42)
4420007	Sales to Pub Auth - Ex Schools	(12,839,229.80)	763,328.20	0.00	(12,075,901.60)
4420013	Commercial Fuel Rev	(40,105,577.96)	3,320,399.08	0.00	(36,785,178.88)
4420016	Industrial Fuel Rev	(94,179,489.13)	10,478,340.12	0.00	(83,701,149.01)
4440000	Public Street/Highway Lighting	(1,312,234.40)	58,034.40	0.00	(1,254,200.00)
4440002	Public St & Hwy Light Fuel Rev	(306,463.03)	14,989 26	0.00	(291,473.77)

Kentucky Power Company
Trial Balance
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Account Number	Description	Pr Yr Ending Balance	Debits	Credit	Current Yr Balance
4470001	Sales for Resale - Assoc Cos	(34,312.35)	37,806.16	0 00	3,493 81
4470002	Sales for Resale - NonAssoc	(10,168,006.39)	866,004.98	0.00	(9,302,001.41)
4470006	Sales for Resale-Bookout Sales	(40,479,648.80)	22,022,326.15	0.00	(18,457,322.65)
4470007	Sales for Resale-Option Sales	0 00	0.00	(166.07)	(166.07)
4470010	Sales for Resale-Bookout Purch	34,253,852.36	0.00	(20,660,803 94)	13,593,048.42
4470011	Sales for Resale-Option Purch	0.00	110.24	0.00	110.24
4470027	Whsal/Muni/Pb Ath Fuel Rev	(2,654,723.92)	0 00	(127,198.19)	(2,781,922.11)
4470028	Sale/Resale - NA - Fuel Rev	(21,812,320.01)	5,728,996.74	0.00	(16,083,323.27)
4470033	Whsal/Muni/Pub Auth Base Rev	(3,413,741.59)	433,385.09	0.00	(2,980,356.50)
4470035	Sls for Rsl - Fuel Rev - Assoc	(280,381.28)	213,759.20	0.00	(66,622.08)
4470066	PWR Trding Trans Exp-NonAssoc	35,739.24	0.00	(27,219.91)	8,519 33
4470081	Financial Spark Gas - Realized	(61,155.72)	0.00	(113,302.09)	(174,457.81)
4470082	Financial Electric Realized	4,711,774.14	2,657,838.98	0.00	7,369,613.12
4470089	PJM Energy Sales Margin	(7,183,409.51)	5,881,091.67	0.00	(1,302,317.84)
4470093	PJM Implicit Congestion-LSE	10,219,326.33	0.00	(5,577,165.01)	4,642,161.32
4470098	PJM Oper.Reserve Rev-OSS	(1,354,878.85)	0.00	(1,791,054.87)	(3,145,933.72)
4470099	Capacity Cr. Net Sales	(4,822,484.28)	2,944,644.69	0.00	(1,877,839 59)
4470100	PJM FTR Revenue-OSS	(845,239.59)	613,021.43	0.00	(232,218.16)
4470101	PJM FTR Revenue-LSE	(7,630,823.49)	4,529,169.55	0.00	(3,101,653 94)
4470103	PJM Energy Sales Cost	(40,075,869.79)	5,777,970.41	0.00	(34,297,899.38)
4470106	PJM Pt2Pt Trans. Purch-NonAff.	2,149 63	21,579.68	0 00	23,729.31
4470107	PJM NITS Purch-NonAff.	1,529.61	4,309.68	0.00	5,839.29
4470109	PJM FTR Revenue-Spec	(122,813.24)	171,380.96	0 00	48,567.72
4470110	PJM TO Admin. Exp.-NonAff.	2,852.65	0.00	(4,359.24)	(1,506.59)
4470112	Non-Trading Bookout Sales-OSS	(13,221.71)	0.00	(397,078.34)	(410,300.05)
4470115	PJM Meter Corrections-OSS	(329,624.55)	0.00	(807,331.91)	(1,136,956.46)
4470116	PJM Meter Corrections-LSE	(202,806.02)	224,479.51	0.00	21,673.49
4470124	PJM Incremental Spot-OSS	(1,616.86)	1,617.16	0.00	0.30
4470126	PJM Incremental Imp Cong-OSS	2,321,061.97	0.00	(1,256,027.41)	1,065,034.56
4470128	Sales for Res-Aff. Pool Energy	(67,170,301.95)	34,657,507.95	0.00	(32,512,794 00)
4470131	Non-Trading Bookout Purch-OSS	14,245.50	0.00	(5,238.59)	9,006 91
4470141	PJM Contract Net Charge Credit	0.00	0.08	0.00	0 08
4470143	Financial Hedge Realized	(556,760.20)	232,413.82	0.00	(324,346 38)
4470144	Realiz. Sharing - 06 SIA	4,340.00	0.00	(2,733.00)	1,607.00
4470150	Transm. Rev.-Dedic. Whlsl/Muni	(48,910.91)	0.00	(39,698.44)	(88,609.35)
4470155	OSS Physical Margin Reclass	5,053,640.10	212,313.61	0.00	5,265,953.71
4470156	OSS Optim. Margin Reclass	(5,053,640.10)	0.00	(212,313.61)	(5,265,953.71)
4470167	MISO FTR Revenues OSS	(24,582.62)	24,582.62	0.00	0.00
4470168	Interest Rate Swaps-Power	129,389.37	0.00	(77,933.50)	51,455.87
4470170	Non-ECR Auction Sales-OSS	(13,003,828.95)	3,801,212.91	0.00	(9,202,616.04)
4470174	PJM Whlse FTR Rev - OSS	(621,788.13)	469,861.01	0.00	(151,927.12)
4470175	OSS Sharing Reclass - Retail	(5,117,679.51)	5,939,561.89	0 00	821,882.38
4470176	OSS Sharing Reclass-Reduction	5,117,679.51	0 00	(5,939,561.89)	(821,882.38)
4470180	Trading intra-book Reclass	21,279.21	0.00	(133,805.26)	(112,526.05)
4470181	Auction intra-book Reclass	(21,279.21)	133,805.26	0.00	112,526.05
4470202	PJM OpRes-LSE-Credit	(1,027,393.31)	0.00	(915,856.42)	(1,943,249.73)
4470203	PJM OpRes-LSE-Charge	3,648,614.45	0.00	(613,259 28)	3,035,355.17
4470206	PJM Trans loss credits-OSS	(1,086,360.39)	380,547.75	0.00	(705,812.64)
4470207	PJM transm loss charges - LSE	16,724,822.78	0 00	(6,807,405.35)	9,917,417.43
4470208	PJM Transm loss credits-LSE	(5,782,811.49)	2,958,724.66	0.00	(2,824,086.83)
4470209	PJM transm loss charges-OSS	3,221,056.64	0.00	(602,217.04)	2,618,839.60
4470214	PJM 30m Suppl Reserve CR OSS	(287,366.13)	36,690.71	0.00	(250,675.42)
4491003	Prov Rate Refund - Retail	0.00	1,635,430.00	0.00	1,635,430.00
4500000	Forfeited Discounts	(2,221,318.73)	0.00	(1,046,914.16)	(3,268,232.89)
4510001	Misc Service Rev - Nonaffil	(432,633.80)	78,721.42	0.00	(353,912.38)
4540001	Rent From Elect Property - Af	(263,188.63)	0.00	(6,853.27)	(270,041.90)
4540002	Rent From Elect Property-NAC	(4,878,144.34)	4,792,741.44	0 00	(85,402.90)
4540004	Rent From Elect Prop-ABD-Nonaf	(105,291.22)	13,170.89	0.00	(92,120 33)
4540005	Rent from Elec Prop-Pole Attch	0.00	0.00	(6,558,971.58)	(6,558,971.58)
4560007	Oth Elect Rev - DSM Program	(3,416,706.00)	314,914.01	0.00	(3,101,791.99)
4560012	Oth Elect Rev - Nonaffiliated	(4,150.10)	4,150.10	0.00	0.00
4560015	Other Electric Revenues - ABD	(246,345.04)	3,531.17	0.00	(242,813 87)
4560041	Miscellaneous Revenue-NonAffil	(1,000.00)	1,000.00	0.00	0.00
4560049	Merch Generation Finan -Realzd	(15.63)	0.00	(1.03)	(16 66)
4560050	Oth Elec Rev-Coal Trd Rlzd G-L	15,706.34	38,405.87	0 00	54,112.21
4560109	Interest Rate Swaps-Coal	4,396.61	0.00	(3,769.62)	626.99
4561002	RTO Formation Cost Recovery	(2,406.40)	0.00	(8,068.70)	(10,475.10)
4561003	PJM Expansion Cost Recov	(78,428.46)	0.00	(6,585.19)	(85,013.65)
4561004	SECA Transmission Rev	0.00	0.00	(227,184.25)	(227,184 25)
4561005	PJM Point to Point Trans Svc	(736,101.15)	39,424.87	0.00	(696,676.28)

Kentucky Power Company
Trial Balance
For The Month Ended DECEMBER 31, 2012

Account Number	Description	Pr Yr Ending Balance	Debits	Credit	Current Yr Balance
4561006	PJM Trans Owner Admin Rev	(231,337.60)	0.00	(4,317.96)	(235,655.56)
4561007	PJM Network Integ Trans Svc	(6,207,450.54)	0.00	(3,847,134.93)	(10,054,585.47)
4561019	Oth Elec Rev Trans Non Affil	(64,020.00)	4,956.00	0.00	(59,064.00)
4561028	PJM Pow Fac Cre Rev Whsl Cu-NA	(9,440.70)	977.74	0.00	(8,462.96)
4561029	PJM NITS Revenue Whsl Cus-NAff	(2,344,767.44)	0.00	(205,357.72)	(2,550,125.16)
4561030	PJM TO Serv Rev Whls Cus-NAff	(40,878.52)	4,492.02	0.00	(36,386.50)
4561033	PJM NITS Revenue - Affiliated	(40,137,444.20)	136,872.86	0.00	(40,000,571.34)
4561034	PJM TO Adm. Serv Rev - Aff	(418,671.49)	0.00	(796 86)	(419,468.35)
4561035	PJM Affiliated Trans NITS Cost	35,803,217.99	1,498,894.30	0.00	37,302,112.29
4561036	PJM Affiliated Trans TO Cost	391,387.87	0.00	(4,342.43)	387,045.44
4561058	NonAffil PJM Trans Enhncmt Rev	(145,599.11)	0.00	(18,220.62)	(163,819.73)
4561059	Affil PJM Trans Enhancmnt Rev	(314,244.84)	51,327.86	0.00	(262,916.98)
4561060	Affil PJM Trans Enhancmnt Cost	279,650.70	0.00	(34,528.36)	245,122.34
4561061	NAff PJM RTEP Rev for Whsl-FR	(18,463.38)	1,710.79	0.00	(16,752.59)
4561062	PROVISION PJM NITS Affil- Cost	583,890.79	0.00	(1,137,997.83)	(554,107.04)
4561063	PROVISION PJM NITS Affiliated	(668,023.25)	948,116.78	0.00	280,093.53
4561064	PROVISION PJM NITS WhslCus-NAf	(39,295.49)	52,746.76	0.00	13,451.27
4561065	PROVISION PJM NITS	(78,590.97)	38,085.38	0.00	(40,505.59)
5000000	Oper Supervision & Engineering	3,244,583.96	0 00	(1,204,750.97)	2,039,832.99
5000001	Oper Super & Eng-RATA-Affil	30,243.16	0.00	(5,743.16)	24,500.00
5010000	Fuel	694,904.15	0.00	(438,268 87)	256,635.28
5010001	Fuel Consumed	184,362,675.87	0.00	(101,151,057.38)	83,211,618.49
5010003	Fuel - Procure Unload & Handle	3,147,087.96	0.00	(1,299,481.18)	1,847,606.78
5010005	Fuel - Deferred	2,274,017.00	2,516,360.00	0.00	4,790,377.00
5010012	Ash Sales Proceeds	0.00	0.00	(205,759.32)	(205,759.32)
5010013	Fuel Survey Activity	(1.00)	2 00	0.00	1.00
5010019	Fuel Oil Consumed	3,226,649.62	30,231.19	0.00	3,256,880.81
5020000	Steam Expenses	1,231,399.04	0.00	(423,110.32)	808,288.72
5020002	Urea Expense	4,119,618.49	0.00	(2,168,764.49)	1,950,854.00
5020003	Trona Expense	0 00	16.21	0.00	16.21
5020008	Activated Carbon	17.05	0.00	(24.56)	(7.51)
5020025	Steam Exp Environmental	(83.61)	87.58	0.00	3.97
5050000	Electric Expenses	470,918.66	0.00	(175,838.96)	295,079.70
5060000	Misc Steam Power Expenses	5,209,409.93	365,699.24	0.00	5,575,109.17
5060002	Misc Steam Power Exp-Assoc	39,541.00	0.00	(5,909.00)	33,632.00
5060004	NSR Settlement Expense	(232,272.16)	142,672.34	0.00	(89,599.82)
5060006	Voluntary CO2 Compliance Exp	2,889.22	0.00	(2,889.22)	0.00
5070000	Rents	4.00	0.00	(4.00)	0.00
5090000	Allow Consum Title IV SO2	12,386,400 09	0.00	(3,590,141.50)	8,796,258.59
5090002	Allowance Expenses	3.00	0.00	(3.00)	0.00
5090005	An. NOx Cons. Exp	1,034,617.94	0.00	(957,282.13)	77,335.81
5100000	Maint Supv & Engineering	2,050,260.19	9,234.84	0.00	2,059,495.03
5110000	Maintenance of Structures	1,229,635.56	0.00	(655,708.62)	573,926.94
5120000	Maintenance of Boiler Plant	5,969,199.31	0.00	(416,390.18)	5,552,809.13
5130000	Maintenance of Electric Plant	1,126,659.68	270,217.38	0.00	1,396,877.06
5140000	Maintenance of Misc Steam Plt	1,007,677.12	0.00	(390,554.92)	617,122.20
5140025	Maint MiscStmPlt Environmental	0.00	2.30	0.00	2.30
5300000	Maint of Reactor Plant Equip	0.00	0.00	(0.62)	(0.62)
5550001	Purch Pwr-NonTrading-Nonassoc	7,842,542.18	0.00	(6,309,795.40)	1,532,746.78
5550004	Purchased Power-Pool Capacity	54,857,137.00	0.00	(32,410,547.00)	22,446,590 00
5550005	Purchased Power - Pool Energy	12,877,373.70	41,435,930.08	0.00	54,313,303.78
5550023	Purch Power Capacity -NA	790,276.50	0.00	(491,819.25)	298,457.25
5550027	Purch Pwr-Non-Fuel Portion-Aff	43,686,862.00	0.00	(2,560,393.00)	41,126,469 00
5550032	Gas-Conversion-Mone Plant	323,581.96	58,688.21	0.00	382,270.17
5550036	PJM Emer.Energy Purch.	1,110.87	0.00	(1,110.87)	0.00
5550039	PJM Inadvertent Mtr Res-OSS	47,349.27	0.00	(34,594.14)	12,755.13
5550040	PJM Inadvertent Mtr Res-LSE	265,339 86	0.00	(202,950.44)	62,389.42
5550041	PJM Ancillary Serv.-Sync	7,944.63	0.00	(5,371.27)	2,573.36
5550046	Purch Power-Fuel Portion-Affil	54,394,588.85	6,860,916.14	0.00	61,255,504.99
5550074	PJM Reactive-Charge	1,206,227.12	0.00	(1,198,554.14)	7,672.98
5550075	PJM Reactive-Credit	(1,098,332.02)	1,192,306.59	0.00	93,974.57
5550076	PJM Black Start-Charge	37,134.76	4,187.08	0.00	41,321.84
5550077	PJM Black Start-Credit	(25,498.34)	0.00	(5,369.72)	(30,868.06)
5550078	PJM Regulation-Charge	2,525,524.49	0.00	(1,156,600.97)	1,368,923.52
5550079	PJM Regulation-Credit	(900,456.38)	136,183.43	0.00	(764,272.95)
5550080	PJM Hourly Net Purch.-FERC	11,413,039.47	0.00	(4,304,052.97)	7,108,986 50
5550083	PJM Spinning Reserve-Charge	111,875.89	0.00	(103,974.97)	7,900.92
5550084	PJM Spinning Reserve-Credit	(6,442.31)	4,901.97	0.00	(1,540.34)
5550090	PJM 30m Suppl Rserv Charge LSE	349,783.66	0.00	(101,047.85)	248,735.81
5550094	Purchased Power - Fuel	880,278.32	0.00	(213,558.99)	666,719.33

Kentucky Power Company
Trial Balance
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Account Number	Description	Pr Yr Ending Balance	Debits	Credit	Current Yr Balance
5550099	PJM Purchases-non-ECR-Auction	10,051,975.16	0.00	(2,565,437.71)	7,486,537.45
5550100	Capacity Purchases-Auction	833,000.00	0.00	(722,710.23)	110,289.77
5550101	Purch Power-Pool Non-Fuel -Aff	2,499,458 00	5,048,628.00	0.00	7,548,086.00
5550102	Pur Power-Pool NonFuel-OSS-Aff	45,349,482.00	0.00	(3,930,985 23)	41,418,496.78
5550107	Capacity purchases - Trading	1,561,632.46	0.00	(1,102,365.07)	459,267.39
5560000	Sys Control & Load Dispatching	320,245.72	0.00	(148,892.95)	171,352.77
5570000	Other Expenses	2,237,588.17	0.00	(806,364.38)	1,431,223.79
5570007	Other Pwr Exp - Wholesale RECs	26,216.78	935.48	0.00	27,152 26
5570008	Other Pwr Exp - Voluntary RECs	30.00	0.00	(30 00)	0 00
5600000	Oper Supervision & Engineering	627,759.88	31,627.93	0 00	659,387.81
5611000	Load Dispatch - Reliability	5,864.83	0.00	(222.82)	5,642.01
5612000	Load Dispatch-Mntr&Op TransSys	826,362.40	0.00	(61,829.17)	764,533.23
5613000	Load Dispatch-Trans Srvc&Sched	4.35	0.00	(81.33)	(76.98)
5614000	PJM Admin-SSC&DS-OSS	92,773 69	0.00	(10,148.62)	82,625.07
5614001	PJM Admin-SSC&DS-Internal	1,091,676.94	0.00	(38,186.94)	1,053,490 00
5614007	PJM Admin Defaults LSE	0.00	24,603.14	0.00	24,603.14
5615000	Reliability,Plng&Stds Develop	100,459 66	36,430.61	0.00	136,890.27
5618000	PJM Admin-RP&SDS-OSS	21,358.52	0.00	(1,259.94)	20,098.58
5618001	PJM Admin-RP&SDS- Internal	250,988.84	0 00	(25,572.29)	225,416.55
5620001	Station Expenses - Nonassoc	162,829 50	25,601.77	0.00	188,431.27
5630000	Overhead Line Expenses	155,113.63	0.00	(1,796.45)	153,317.18
5640000	Underground Line Expenses	3,933.43	0.00	(3,933.43)	0.00
5650002	Transmssn Elec by Others-NAC	282,697.14	0.00	(123,001.55)	159,695.59
5650012	PJM Trans Enhancement Charge	2,619,439.24	468,533.40	0.00	3,087,972.64
5650015	PJM TO Serv Exp - Aff	10,109.52	0.00	(5,460.36)	4,649.16
5650016	PJM NITS Expense - Affiliated	318,412.20	738,013.81	0.00	1,056,426.01
5650019	Affil PJM Trans Enhncement Exp	0.00	32,994.90	0.00	32,994.90
5650020	PROVISION PJM NITS Affl Expens	(21,942.94)	41,779.20	0.00	19,836 26
5660000	Misc Transmission Expenses	1,036,098.24	172,068.59	0.00	1,208,166 83
5670001	Rents - Nonassociated	4,809 00	0 00	(4,422.56)	386.44
5670002	Rents - Associated	0.00	1,817.03	0.00	1,817.03
5680000	Maint Supv & Engineering	145,588.53	0 00	(9,282.53)	136,306 00
5690000	Maintenance of Structures	13,966.61	13,560.59	0.00	27,527.20
5691000	Maint of Computer Hardware	52,859.55	0.00	(8,437.60)	44,421.95
5692000	Maint of Computer Software	230,749.65	0.00	(26,660.93)	204,088.72
5693000	Maint of Communication Equip	211,706.02	0.00	(116,071.64)	95,634.38
5700000	Maint of Station Equipment	814,617.27	0.00	(250,220.92)	564,396.35
5710000	Maintenance of Overhead Lines	1,754,718.80	320,396.05	0.00	2,075,114 85
5730000	Maint of Misc Trnsmssion Plt	21,941.60	147,179.20	0.00	169,120.80
5757000	PJM Admin-MAM&SC- OSS	97,762.97	120.50	0.00	97,883.47
5757001	PJM Admin-MAM&SC- Internal	1,141,984.11	0.00	(45,545.49)	1,096,438.62
5800000	Oper Supervision & Engineering	795,829.65	0.00	(130,659 84)	665,169.81
5810000	Load Dispatching	1,804.56	488.94	0.00	2,293.50
5820000	Station Expenses	203,293.27	0.00	(23,438.64)	179,854.63
5830000	Overhead Line Expenses	897,007.75	0.00	(709,684.13)	187,323.62
5840000	Underground Line Expenses	143,639.98	0.00	(13,890.48)	129,749.50
5850000	Street Lighting & Signal Sys E	44,683 89	55,744.99	0.00	100,428.88
5860000	Meter Expenses	865,237.58	0.00	(345,768.76)	519,468.82
5870000	Customer Installations Exp	146,018.24	0.00	(16,292.36)	129,725.88
5880000	Miscellaneous Distribution Exp	4,292,674.45	1,115,305.43	0.00	5,407,979.88
5890001	Rents - Nonassociated	1,988,196.92	0.00	(361,424.60)	1,626,772.32
5890002	Rents - Associated	67,178.02	0.00	(11,938.69)	55,239.32
5900000	Maint Supv & Engineering	46.74	692.69	0.00	739.43
5910000	Maintenance of Structures	8,877.25	15,275.87	0.00	24,153.12
5920000	Maint of Station Equipment	1,019,999.78	0.00	(502,466.37)	517,533.41
5930000	Maintenance of Overhead Lines	28,505,596.67	0.00	(3,080,571.57)	25,425,025.10
5930001	Tree and Brush Control	243,140.35	116,525.24	0.00	359,665.59
5930010	Storm Expense Amortization	4,698,444.00	0.00	0.00	4,698,444.00
5940000	Maint of Underground Lines	69,503.01	22,654.67	0.00	92,157.68
5950000	Maint of Lne Trnf,Rglators&Dvi	120,471.35	0.00	(52,086.34)	68,385.01
5960000	Maint of Strt Lghtng & Sgnal S	62,231.05	0.00	(18,515.37)	43,715.68
5970000	Maintenance of Meters	56,181.98	0.00	(2,389.87)	53,792.11
5980000	Maint of Misc Distribution Plt	139,002.18	0.00	(53,494.02)	85,508.16
9010000	Supervision - Customer Accts	324,869.72	0.00	(52,427.71)	272,442.01
9020000	Meter Reading Expenses	9,828.92	0.00	(8,819.25)	1,009 67
9020001	Customer Card Reading	1,598.15	0.00	(1,597.76)	0.39
9020002	Meter Reading - Regular	572,859.70	0.00	(195,616.46)	377,243.24
9020003	Meter Reading - Large Power	42,839.13	0.00	(7,076.27)	35,762.86
9020004	Read-In & Read-Out Meters	64,432.33	0.00	(25,419 83)	39,012.50
9030000	Cust Records & Collection Exp	537,318 90	13,616.38	0.00	550,935.28

Kentucky Power Company
Trial Balance
For The Month Ended DECEMBER 31, 2012

Account Number	Description	Pr Yr Ending Balance	Debits	Credit	Current Yr Balance
9030001	Customer Orders & Inquiries	2,712,406.83	0 00	(361,170.29)	2,351,236.54
9030002	Manual Billing	42,555.95	6.60	0.00	42,562.55
9030003	Postage - Customer Bills	741,820.84	0.00	(173,857.71)	567,963.13
9030004	Cashiering	128,947.08	0.00	(3,908.55)	125,038.53
9030005	Collection Agents Fees & Exp	108,054.97	0 00	(8,067.81)	99,987.16
9030006	Credit & Oth Collection Activi	913,967.54	0.00	(88,091.07)	825,876.47
9030007	Collectors	587,706.43	24,618.68	0.00	612,325.11
9030009	Data Processing	152,725.73	3,255.17	0.00	155,980.90
9040007	Uncoll Accts - Misc Receivable	14,448 61	138,167.11	0.00	152,615.72
9050000	Misc Customer Accounts Exp	87,534.76	0.00	(71,271.10)	16,263.66
9070000	Supervision - Customer Service	327,503.55	0.00	(115,910.48)	211,593.07
9070001	Supervision - DSM	2,018.21	0.00	(1,999.54)	18.67
9080000	Customer Assistance Expenses	509,400.67	0.00	(25,717.00)	483,683.67
9080001	DSM-Customer Advisory Grp	742.50	0.00	(460.35)	282.15
9080004	Cust Assistnce Exp - DSM - Ind	0.00	0.64	0.00	0 64
9080009	Cust Assistance Expense - DSM	2,484,940.21	0.00	(377,050.56)	2,107,889.65
9090000	Information & Instruct Advrtis	187,053.78	0.00	(31,710.51)	155,343.27
9100000	Misc Cust Svc&Informational Ex	24,848.87	12,808.30	0.00	37,657.17
9100001	Misc Cust Svc & Info Exp - RCS	0.00	51.50	0 00	51.50
9110001	Supervision - Residential	9.56	0.00	(15.08)	(5.52)
9110002	Supervision - Comm & Ind	3.41	0.00	(3.41)	0 00
9120000	Demonstrating & Selling Exp	1.08	0.00	(1.08)	0 00
9120001	Demo & Selling Exp - Res	0 00	2.08	0.00	2.08
9200000	Administrative & Gen Salaries	5,810,297.53	912,863.77	0.00	6,723,161.30
9200003	Admin & Gen Salaries Trnsfr	(46.34)	46.34	0.00	0.00
9210001	Off Supl & Exp - Nonassociated	551,346.17	33,389.63	0.00	584,735.80
9210003	Office Supplies & Exp - Trnsf	(2.32)	9 09	0.00	6.77
9220000	Administrative Exp Trnsf - Cr	(140,317.13)	0.00	(10,881.79)	(151,198.92)
9220001	Admin Exp Trnsf to Cnstrction	(363,865.00)	0.00	(312,232.24)	(676,097.24)
9220004	Admin Exp Trnsf to ABD	(3,487.36)	0.00	(1,124.98)	(4,612.34)
9220125	SSA Expense Transfers BL	(625,191.89)	123,636.23	0.00	(501,555.66)
9230001	Outside Svcs Empl - Nonassoc	978,006.59	418,824.08	0 00	1,396,830.66
9230003	AEPSC Billed to Client Co	3,864,131.01	0.00	(600,956.43)	3,263,174.58
9240000	Property Insurance	641,057.77	0.00	(35,512.31)	605,545.46
9250000	Injuries and Damages	1,226,482.23	0.00	(90,727.28)	1,135,754.95
9250001	Safety Dinners and Awards	982.23	29.01	0.00	1,011.24
9250002	Emp Accdent Prvntion-Adm Exp	9,508.20	0.00	(327.79)	9,180.41
9250004	Injuries to Employees	74,894.28	0.00	(42,431.90)	32,462.38
9250006	Wrkrs Cmpnstn Pre&Slf Ins Prv	501,566.88	0.00	(416,634.04)	84,932.84
9250007	Prsnal Injries&Prop Dmage-Pub	73,610.62	0.00	(67,753.91)	5,856.71
9250010	Frg Ben Loading - Workers Comp	(174,781.22)	0.00	(83,916.10)	(258,697.32)
9260000	Employee Pensions & Benefits	9,067.13	0.00	(2,511.66)	6,555.47
9260001	Edit & Print Empl Pub-Salaries	37,068.38	0.00	(6,295.60)	30,772.78
9260002	Pension & Group Ins Admin	29,740.00	2,118.92	0.00	31,858.92
9260003	Pension Plan	2,894,000 04	350,941.08	0.00	3,244,941.12
9260004	Group Life Insurance Premiums	133,843.83	7,892.99	0.00	141,736.82
9260005	Group Medical Ins Premiums	3,985,141.13	4,872.82	0.00	3,990,013.95
9260007	Group L-T Disability Ins Prem	178,026.43	0.00	(165,190.43)	12,836.00
9260009	Group Dental Insurance Prem	225,589 87	3,443.18	0.00	229,033.05
9260010	Training Administration Exp	6,845.59	0.00	(7,552.02)	(706.43)
9260012	Employee Activities	5,816.99	0.00	(1,210.53)	4,606.46
9260014	Educational Assistance Pmts	10,398.65	2,493.85	0.00	12,892.50
9260021	Postretirement Benefits - OPEB	2,387,468.02	0.00	(944,966.98)	1,442,501.04
9260026	Savings Plan Administration	0.00	58.85	0.00	58 85
9260027	Savings Plan Contributions	1,440,190.53	92,754.66	0.00	1,532,945.18
9260036	Deferred Compensation	26,067.46	0.00	(2,614.10)	23,453.36
9260037	Supplemental Pension	999.96	0.00	(278.02)	721.94
9260050	Frg Ben Loading - Pension	(1,116,707.68)	0.00	(231,910.38)	(1,348,618.06)
9260051	Frg Ben Loading - Grp Ins	(1,833,873.07)	0.00	(139,797.21)	(1,973,670.28)
9260052	Frg Ben Loading - Savings	(512,715.56)	0.00	(103,321.84)	(616,037.40)
9260053	Frg Ben Loading - OPEB	(608,471.17)	0.00	(267,293 27)	(875,764.44)
9260055	IntercoFringeOffset- Don't Use	(1,125,917.30)	0.00	(36,684 95)	(1,162,602.25)
9260056	Fidelity Stock Option Admin	248.88	0.00	(248 88)	0.00
9260057	Postret Ben Medicare Subsidy	(848,237.03)	1,400,663.03	0.00	552,426.00
9260058	Frg Ben Loading - Accrual	(13,487.88)	25,388.31	0.00	11,900.43
9270000	Franchise Requirements	190,119.37	0.00	(44,223.88)	145,895.49
9280000	Regulatory Commission Exp	3 02	0.00	(6.49)	(3.47)
9280001	Regulatory Commission Exp-Adm	(21.45)	17.11	0.00	(4.34)
9280002	Regulatory Commission Exp-Case	8,468 84	147,485.11	0.00	155,953 95
9301000	General Advertising Expenses	5,561 61	2,763.52	0.00	8,325.13

Kentucky Power Company
Trial Balance
For The Month Ended DECEMBER 31, 2012

Account Number	Description	Pr Yr Ending Balance	Debits	Credit	Current Yr Balance
9301001	Newspaper Advertising Space	14,903.18	0.00	(1,702.37)	13,200.81
9301002	Radio Station Advertising Time	2,770.00	0.00	(20.00)	2,750.00
9301003	TV Station Advertising Time	513.34	0.00	(513.34)	0.00
9301006	Spec Corporate Comm Info Proj	0.00	0.28	0.00	0.28
9301010	Publicity	850.06	427.67	0.00	1,277.73
9301011	Dedications, Tours, & Openings	0.00	0.55	0.00	0.55
9301012	Public Opinion Surveys	21,357.66	0.00	(18,750.58)	2,607.08
9301014	Video Communications	34.50	0.00	(21.70)	12.80
9301015	Other Corporate Comm Exp	24,341.03	15,952.96	0.00	40,293.99
9302000	Misc General Expenses	336,462.75	0.00	(169,647.13)	166,815.62
9302003	Corporate & Fiscal Expenses	24,191.55	0.00	(3,703.78)	20,487.77
9302004	Research, Develop&Demonstr Exp	18,874.36	0.00	(15,876.59)	2,997.77
9302006	Assoc Bus Dev - Materials Sold	15,340.61	24,458.36	0.00	39,798.97
9302007	Assoc Business Development Exp	89,010.98	0.00	(28,641.21)	60,369.77
9302458	AEPSC Non Affliated expenses	0.00	33 57	0.00	33.57
9310000	Rents	300.00	0.00	(280.47)	19.53
9310001	Rents - Real Property	86,802.40	8,431.25	0.00	95,233.65
9310002	Rents - Personal Property	38,985.92	0.00	(10,131.11)	28,854.81
9350000	Maintenance of General Plant	0.00	6.31	0.00	6.31
9350001	Maint of Structures - Owned	622,164.82	0 00	(101,998.45)	520,166.37
9350002	Maint of Structures - Leased	106,721.73	0 00	(44,667.68)	62,054.05
9350007	Maint of Radio Equip - Owned	69.79	0 00	(69.79)	0.00
9350013	Maint of Cmmncation Eq-Unall	1,069,892.52	0 00	(73,692.16)	996,200.36
9350015	Maint of Office Furniture & Eq	2,186.43	0.00	(2,031.33)	155.10
9350023	Site Communications Services	0 00	170 66	0.00	170.66
9350024	Maint of DA-AMI Comm Equip	183.23	0.00	(100.86)	82.37
	NET INCOME - EARN FOR CMMN STK	(42,373,948.29)	0.00	(8,604,504.91)	(50,978,453.21)
	PREF STK DIVIDEND REQUIREMENT	0.00	0.00	0.00	0.00

Kentucky Power Company
Trial Balance
For The Month Ended AUGUST 31, 2013

Account Number	Description	Pr Yr Ending Balance	Yearly Activity	Debits	Credit	Current Yr Balance
1010001	Plant in Service	1,678,058,120.10	40,997,056.97	40,997,056 97	0.00	1,719,055,177.07
1011001	Capital Leases	5,111,889.95	590,161.60	590,161.60	0.00	5,702,051.55
1011006	Prov-Leased Assets	(2,104,820.44)	(500,019.19)	0.00	(500,019.19)	(2,604,839.63)
1011012	Accrued Capital Leases	71,107.33	(63,957.43)	0 00	(63,957.43)	7,149.90
1050001	Held For Fut Use	7,436,550.73	0 00	0 00	0.00	7,436,550.73
1060001	Const Not Classifd	68,475,710.90	(11,872,418.57)	0.00	(11,872,418.57)	56,603,292.33
1070001	CWIP - Project	44,281,291.91	9,681,209 54	9,681,209.54	0.00	53,962,501.45
1080001	A/P for Deprec of Plt	(586,500,079.91)	(23,058,839.47)	0 00	(23,058,839.47)	(609,558,919.38)
1080005	RWIP - Project Detail	6,326,680 62	598,496.29	598,496 29	0 00	6,925,176.91
1080011	Cost of Removal Reserve	(24,179,469 28)	(434,319.58)	0.00	(434,319.58)	(24,613,788.86)
1080013	ARD Removal Deprec - Accretion	3,113,127.64	354,101.07	354,101.07	0.00	3,467,228.71
1110001	A/P for Amort of Plt	(20,894,341.14)	(2,473,556.83)	0 00	(2,473,556.83)	(23,367,897.97)
1210001	Nonutility Property - Owned	964,528 00	0 00	0.00	0.00	964,528.00
1220001	Depr&Amrt of Nonutl Prop-Ownd	(208,286.03)	(4,446.48)	0 00	(4,446.48)	(212,732.51)
1240002	Oth Investments-Nonassociated	806.00	0.00	0.00	0.00	806.00
1240005	Spec Allowance Inv NOx	6.77	0.00	0.00	0.00	6.77
1240007	Deferred Compensation Benefits	97,307.67	0.00	0.00	0.00	97,307.67
1240027	Other Property - RWIP	7,500.00	(9,642.95)	0.00	(9,642.95)	(2,142.95)
1240028	Other Property - RETIRE	0.00	2,142.95	2,142.95	0 00	2,142.95
1240029	Other Property - CPR	4,734,975.63	(2,834,483.00)	0.00	(2,834,483 00)	1,900,492.63
1240092	Fbr Opt Lns-In Kind Sv-Invest	162,614.00	(3,786 00)	0.00	(3,786 00)	158,828.00
1310000	Cash	1,481,977.75	(813,055.66)	0 00	(813,055 66)	668,922.09
1340018	Spec Deposits - Elect Trading	366,348.56	(363,881.31)	0.00	(363,881.31)	2,467.25
1340043	Spec Deposit UBS Securities	3,131,433.29	(1,023,193 90)	0.00	(1,023,193.90)	2,108,239.39
1340048	Spec Deposits-Trading Contra	(2,021,050.00)	985,478 00	985,478.00	0 00	(1,035,572.00)
1340050	Spec Deposit Mizuho Securities	443,769.34	(137,159.75)	0.00	(137,159.75)	306,609.59
1420001	Customer A/R - Electric	25,243,243.98	4,394,861.39	4,394,861.39	0.00	29,638,105.37
1420014	Customer A/R-System Sales	598,338.30	(65,612.90)	0.00	(65,612.90)	532,725.40
1420019	Transmission Sales Receivable	10,596.00	(6,600 00)	0.00	(6,600.00)	3,996.00
1420022	Cust A/R - Factored	(26,596,065.12)	1,652,485.61	1,652,485.61	0.00	(24,943,579.51)
1420023	Cust A/R-System Sales - MLR	3,943,255.08	(1,200,814.48)	0 00	(1,200,814.48)	2,742,440.60
1420024	Cust A/R-Options & Swaps - MLR	241,755.83	(129,503.41)	0.00	(129,503.41)	112,252.42
1420027	Low Inc Energy Asst Pr (LIEAP)	635,144 27	(635,144.27)	0 00	(635,144 27)	0.00
1420044	Customer A/R - Estimated	5,386,461.50	(5,274,171.06)	0 00	(5,274,171.06)	112,290.44
1420048	Emission Allowance Trading	0 00	21,000 00	21,000.00	0.00	21,000.00
1420050	PJM AR Accrual	2,147,087.82	1,719,256.96	1,719,256.96	0.00	3,866,344.78
1420052	Gas Accruals	45,694 74	15,258.30	15,258.30	0 00	60,953.04
1420053	AR Coal Trading	37,777.44	17,330.60	17,330.60	0.00	55,108.04
1420054	Accrued Power Brokers	31,236.28	84,025.41	84,025.41	0.00	115,261.69
1420102	AR Peoplesoft Billing - Cust	951,526.52	(463,195 84)	0.00	(463,195.84)	488,330.68
1430022	2001 Employee Biweekly Pay Cnv	70,746.77	(3,388.59)	0.00	(3,388.59)	67,358.18
1430023	A/R PeopleSoft Billing System	0.00	18,548.80	18,548 80	0.00	18,548.80
1430081	Damage Recovery - Third Party	33,644.00	(24,403.50)	0 00	(24,403 50)	9,240.50
1430083	Damage Recovery Offset Demand	(46,597.00)	36,832.00	36,832.00	0.00	(9,765.00)
1430089	A/R - Benefits Billing	1,675.53	(193.42)	0.00	(193.42)	1,482.11
1430101	Other Accounts Rec - Misc	746.45	0.00	0.00	0 00	746.45
1430102	AR Peoplesoft Billing - Misc	90,443 88	(80,960.11)	0.00	(80,960.11)	9,483.77
1440002	Uncoll Accts-Other Receivables	(141,538.08)	123,259.32	123,259.32	0 00	(18,278.76)
1450000	Corp Borrow Prg (NR-Assoc)	0.00	19,581,843.31	19,581,843.31	0.00	19,581,843.31
1460001	A/R Assoc Co - InterUnit G/L	6,090,256.42	253,792.06	253,792.06	0.00	6,344,048.48
1460002	A/R Assoc Co - Allowances	208,543.68	(208,543.68)	0.00	(208,543.68)	0.00
1460006	A/R Assoc Co - Intercompany	1,732,267.02	(1,413,386.21)	0.00	(1,413,386.21)	318,880 81
1460009	A/R Assoc Co - InterUnit A/P	0.02	598.71	598.71	0.00	598.73
1460011	A/R Assoc Co - Multi Pmts	1,191,613.36	(497,888.66)	0 00	(497,888.66)	693,724.70
1460019	A/R-Assoc Co-AEPSC-Agent	0.00	(0.00)	0.00	(0.00)	(0 00)
1460024	A/R Assoc Co - System Sales	3,749.77	1,115.13	1,115.13	0.00	4,864.90
1460025	Fleet - M4 - A/R	14,658.31	9,613.06	9,613 06	0.00	24,271.37
1460045	A/R Assc Co-Realization Shamg	0.00	511.00	511.00	0.00	511.00
1510001	Fuel Stock - Coal	66,595,285.68	(15,761,785.77)	0 00	(15,761,785.77)	50,833,499.91
1510002	Fuel Stock - Oil	685,034.25	195,172.13	195,172.13	0.00	880,206.38
1520000	Fuel Stock Exp Undistributed	1,866,856.54	(153,237.91)	0.00	(153,237.91)	1,713,618.63
1540001	M&S - Regular	11,348,823.41	101,149.76	101,149.76	0.00	11,449,973.17
1540004	M&S - Exempt Material	53,976.02	3,917.15	3,917.15	0.00	57,893.17
1540012	Materials & Supplies - Urea	366,032.88	(221,596.75)	0 00	(221,596.75)	144,436.13
1540013	Transportation Inventory	105,238 93	0.00	0.00	0.00	105,238.93
1540023	M&S Inv - Urea In-Transit	1,034,244.35	34,029.18	34,029.18	0.00	1,068,273.53
1581000	SO2 Allowance Inventory	2,361,232.37	0.63	0 63	0.00	2,361,233 00
1581003	SO2 Allowance Inventory - Curr	11,774,692.36	(4,260,275.75)	0 00	(4,260,275.75)	7,514,416 61
1581006	An. NOx Comp Inv - Curr	28,271.47	(16,828.26)	0.00	(16,828.26)	11,443.21
1581009	CSAPR Current SO2 Inv	350,000.00	0.00	0.00	0.00	350,000.00
1650001	Prepaid Insurance	366,671.17	93,732.30	93,732 30	0.00	460,403.47
165000212	Prepaid Taxes	515,095.27	(515,095.27)	0.00	(515,095.27)	0.00
165000213	Prepaid Taxes	0.00	788,536 85	788,536.85	0.00	788,536 85
1650009	Prepaid Carry Cost-Factored AR	13,101.01	2,383.10	2,383.10	0.00	15,484.11
1650010	Prepaid Pension Benefits	27,322,534.80	(2,705,278.00)	0.00	(2,705,278.00)	24,617,256.80

Kentucky Power Company
Trial Balance
For The Month Ended AUGUST 31, 2013

Account Number	Description	PrYr Ending Balance	Yearly Activity	Debits	Credit	Current Yr Balance
165001112	Prepaid Sales Taxes	294,772.55	(294,772.55)	0.00	(294,772.55)	0.00
165001113	Prepaid Sales Taxes	0.00	337,550.54	337,550.54	0.00	337,550 54
165001212	Prepaid Use Taxes	42,718.84	(42,718.84)	0.00	(42,718.84)	0.00
165001213	Prepaid Use Taxes	0 00	43,468.45	43,468.45	0.00	43,468.45
1650014	FAS 158 Qual Contra Asset	(27,322,534.80)	2,705,278.00	2,705,278.00	0.00	(24,617,256.80)
1650021	Prepaid Insurance - EIS	268,173.67	308,502.76	308,502.76	0.00	576,678.43
1650023	Prepaid Lease	69,262.29	(69,262.29)	0.00	(69,262.29)	0.00
1710246	Interest Receivable -FIT -ST	0 00	862 00	862.00	0.00	862.00
1710348	Interest Receivable -SIT -LT	1,285.00	(743.00)	0.00	(743.00)	542.00
1720000	Rents Receivable	2,989,752.80	(1,206,966.84)	0.00	(1,206,966.84)	1,782,785.96
1730000	Accrued Utility Revenues	19,746,848.37	(5,160,308 80)	0.00	(5,160,308.80)	14,586,539 57
1730002	Acrd Utility Rev-Factored-Assc	(18,929,908.84)	1,756,401.80	1,756,401.80	0.00	(17,173,507.04)
174001112	Non-Highway Fuel Tx Credt-2012	0.00	748.00	748.00	0.00	748.00
1750001	Curr. Unreal Gains - NonAffil	6,399,223.72	(886,187.21)	0 00	(886,187.21)	5,513,036.51
1750002	Long-Term Unreal Gns - Non Aff	6,847,291.77	(2,312,203.50)	0 00	(2,312,203.50)	4,535,088.27
1750021	S/T Asset MTM Collateral	(246,319.00)	156,640.00	156,640.00	0.00	(89,679.00)
1750022	L/T Asset MTM Collateral	(6,478.00)	6,478 00	6,478 00	0 00	0 00
1760010	S/T Asset for Commodity Hedges	21,915.00	80,907.00	80,907.00	0 00	102,822.00
1760011	L/T Asset for Commodity Hedges	40,841.00	(39,197.00)	0.00	(39,197.00)	1,644.00
1810006	Unamort Debt Exp - Sr Unsec Nt	2,205,279.66	(202,974.28)	0.00	(202,974.28)	2,002,305.38
1823007	SFAS 112 Postemployment Benef	5,229,712.00	2,467,927.96	2,467,927.96	0 00	7,697,639.96
1823009	DSM Incentives	2,129,800.00	169,790.00	169,790.00	0.00	2,299,590.00
1823010	DSM Recovery	(23,236,774.00)	(2,218,982.00)	0.00	(2,218,982.00)	(25,455,756.00)
1823011	DSM Lost Revenues	5,738,560.00	2,815.00	2,815.00	0.00	5,741,375.00
1823012	DSM Program Costs	16,957,736 54	1,539,497.11	1,539,497.11	0.00	18,497,233.65
1823022	HRJ 765kV Post Service AFUDC	665,640.00	(22,272.00)	0.00	(22,272.00)	643,368.00
1823054	HRJ 765kV Depreciation Expense	103,729.00	(3,472.00)	0.00	(3,472.00)	100,257.00
1823078	Deferred Storm Expense	23,892,110.00	(3,132,296.00)	0.00	(3,132,296.00)	20,759,814.00
1823115	Defd Equity Carry Chg-Non Fuel	(107,684.65)	14,840.65	14,840.65	0.00	(92,844.00)
1823118	BridgeCo TO Funding	265,003.77	(34,606 23)	0 00	(34,606 23)	230,397.54
1823119	PJM Integration Payments	274,002.62	(87,192.95)	0 00	(87,192.95)	186,809.67
1823120	Other PJM Integration	279,975.90	(36,561.44)	0 00	(36,561.44)	243,414.46
1823121	Carry Chgs-RTO Startup Costs	148,357.99	21,956.09	21,956.09	0.00	170,314.08
1823122	Alliance RTO Deferred Expense	138,699.91	(18,112.54)	0.00	(18,112.54)	120,587.37
1823165	REG ASSET FAS 158 QUAL PLAN	47,649,991.00	(2,255,808 50)	0.00	(2,255,808.50)	45,394,182.50
1823166	REG ASSET FAS 158 OPEB PLAN	4,529,000.20	168,434.50	168,434.50	0.00	4,697,434.70
1823167	REG Asset FAS 158 SERP Plan	(130,790.00)	(393 00)	0.00	(393.00)	(131,183.00)
1823188	Deferred Carbon Mgmt Research	175,010.00	(66,664 00)	0.00	(66,664.00)	108,346.00
1823299	SFAS 106 Medicare Subsidy	0.00	2,455,027.07	2,455,027.07	0.00	2,455,027.07
1823301	SFAS 109 Flow Thru Defd FIT	86,311,032.13	(2,344,464.35)	0.00	(2,344,464.35)	83,966,567.78
1823302	SFAS 109 Flow Thru Defrd SIT	42,344,691.07	185,021.00	165,021.00	0 00	42,529,712.07
1823306	Net CCS FEED Study Costs	872,858.31	0.00	0 00	0.00	872,858.31
1830000	Prelimin Surv&Investgtn Chrgs	33,084,274.38	(652,114.91)	0 00	(652,114.91)	32,432,159.47
1840029	Transp-Assigned Vehicles	0.00	4,457.09	4,457.09	0.00	4,457.09
1860001	Allowances	454.17	0.00	0.00	0.00	454.17
186000312	Deferred Property Taxes	10,424,709 00	(7,092,716.00)	0 00	(7,092,716.00)	3,331,993.00
1860005	Unidentified Cash Receipts	0.00	(8.81)	0.00	(8.81)	(8.81)
1860007	Billings and Deferred Projects	184,204 32	(44,641.76)	0.00	(44,641.76)	139,562.56
1860077	Agency Fees - Factored A/R	910,519.46	(68,177.76)	0.00	(68,177.76)	842,341.70
186008113	Defd Property Tax - Cap Leases	0 00	5,756.00	5,756.00	0.00	5,756.00
1860153	Unamortized Credit Line Fees	542,149.91	125,723.02	125,723.02	0.00	667,872.93
1860160	Deferred Expenses - Current	2,750,027.43	(1,833,146.55)	0.00	(1,833,146.55)	916,880.88
1860166	Def Lease Assets - Non Taxable	201,682.46	(201,682.46)	0.00	(201,682.46)	0.00
1890004	Loss Rec Debt-Debentures	670,167.40	(22,432.40)	0.00	(22,432.40)	647,735.00
1900006	ADIT Federal - SFAS 133 Nonaff	91,485.30	(61,512.30)	0.00	(61,512.30)	29,973.00
1900015	ADIT-Fed-Hdg-CF-Int Rate	151,828.32	(21,689.76)	0.00	(21,689.76)	130,138.56
1901001	Accum Deferred FIT - Other	13,719,412.78	(2,622,710.33)	0.00	(2,622,710.33)	11,096,702.45
1902001	Accum Defd FIT - Oth Inc & Ded	753,066.96	0.00	0.00	0.00	753,066.96
1903001	Acc Dfd FIT - FAS109 Flow Thru	13,322,568.05	1,671,826.29	1,671,826.29	0.00	14,994,394.34
1904001	Accum Dfd FIT - FAS 109 Excess	341,340.45	(9,097.84)	0.00	(9,097.84)	332,242.61
	TOTAL ASSETS AND OTHER DEBITS	1,618,871,728.86	(13,708,946.65)	0.00	(13,708,946.65)	1,605,162,782.20
2010001	Common Stock Issued-Affiliated	(50,450,000.00)	0.00	0.00	0.00	(50,450,000.00)
2080000	Donations Recvd from Stckhldrs	(238,750,000.00)	0.00	0.00	0.00	(238,750,000.00)
2160001	Unapprp Retnd Ernngs-Unrstrictd	(171,840,462.36)	(18,978,453 21)	0.00	(18,978,453.21)	(190,818,915.56)
2190010	OCI for Commodity Hedges	126,913.23	(156,131.57)	0.00	(156,131.57)	(29,218.34)
2190015	Accum OCI-Hdg-CF-Int Rate	281,967.28	(40,281.04)	0.00	(40,281.04)	241,686.24
2230000	Advances from Associated Co	(20,000,000.00)	0.00	0.00	0.00	(20,000,000.00)
2240006	Senior Unsecured Notes	(530,000,000.00)	0.00	0.00	0.00	(530,000,000.00)
2260006	Unam Disc LTD-Dr-Sr Unsec Note	778,050.00	(111,150.00)	0.00	(111,150 00)	666,900.00
4380001	Div Declrd - Common Stk - Asso	32,000,000.00	(13,250,000.00)	0.00	(13,250,000.00)	18,750,000.00
	TOTAL CAPITALIZATION	(977,853,531.85)	(32,536,015.82)	0.00	(32,536,015.82)	(1,010,389,547.66)
2270001	Obligatns Undr Cap Lse-Noncurr	(1,617,415 04)	(277,999.19)	0.00	(277,999.19)	(1,895,414 23)
2270003	Accrued Noncur Lease Oblig	(56,885.85)	51,165.93	51,165.93	0.00	(5,719.92)
2282003	Accm Prv I/D - Worker's Com	(36,780.85)	(165,993.06)	0.00	(165,993.06)	(202,773.91)
2283000	Accm Prv for Pensions&Benefits	(131,228.25)	(2,596 64)	0.00	(2,596.64)	(133,824 89)

Kentucky Power Company
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Account Number	Description	Pr Yr Ending Balance	Yearly Activity	Debits	Credit	Current Yr Balance
2283002	Supplemental Savings Plan	(344,487.06)	62,700.45	62,700.45	0.00	(281,786.61)
2283003	SFAS 106 Post Retirement Benef	(5,420,963.91)	1,023,493.82	1,023,493.82	0.00	(4,397,470.09)
2283005	SFAS 112 Postemployment Benef	(4,205,588.00)	(1,700,031.96)	0.00	(1,700,031.96)	(5,905,619.96)
2283006	SFAS 87 - Pensions	0.00	(2,705,278.00)	0.00	(2,705,278.00)	(2,705,278.00)
2283007	Perf Share Incentive Plan	(469,357.66)	13,324.94	13,324.94	0.00	(456,032.72)
2283013	Incentive Comp Deferral Plan	(211,127.53)	141,615.90	141,615.90	0.00	(69,511.63)
2283015	FAS 158 SERP Payable Long Term	130,794.00	393.00	393.00	0.00	131,187.00
2283016	FAS 158 Qual Payable Long Term	(20,327,456.20)	2,255,808.50	2,255,808.50	0.00	(18,071,647.70)
2283017	FAS 158 OPEB Payable Long Term	(4,529,000.20)	(168,434.50)	0.00	(168,434.50)	(4,697,434.70)
2283018	SFAS 106 Med Part-D	5,413,660.89	(579,248.18)	0.00	(579,248.18)	4,834,412.71
2290006	Acc Prv for Potential Refund	(1,635,430.00)	1,635,430.00	1,635,430.00	0.00	0.00
2300001	Asset Retirement Obligations	(3,902,259.35)	(158,245.32)	0.00	(158,245.32)	(4,060,504.67)
2320001	Accounts Payable - Regular	(7,482,824.42)	2,641,382.56	2,641,382.56	0.00	(4,841,441.86)
2320002	Unvouchered Invoices	(10,125,267.14)	3,981,128.35	3,981,128.35	0.00	(6,144,138.79)
2320003	Retention	(529,136.86)	49,297.35	49,297.35	0.00	(479,839.51)
2320011	Uninvoiced Fuel	(10,178,466.45)	2,299,259.29	2,299,259.29	0.00	(7,879,207.16)
2320050	Coal Trading	(32,493.23)	4,749.71	4,749.71	0.00	(27,743.52)
2320052	Accounts Payable - Purch Power	(120,596.23)	274,535.22	274,535.22	0.00	153,938.99
2320053	Elect Trad-Options&Swaps	(633,528.96)	255,853.47	255,853.47	0.00	(377,675.49)
2320054	Emission Allowance Trading	0.00	(1,000.00)	0.00	(1,000.00)	(1,000.00)
2320056	Gas Physicals	(0.00)	0.00	0.00	0.00	(0.00)
2320062	Broker Fees Payable	(1,938.18)	(60.02)	0.00	(60.02)	(1,998.20)
2320073	A/P Misc Dedic. Power	(15,672.00)	2,683.50	2,683.50	0.00	(12,988.50)
2320076	Corporate Credit Card Liab	(123,033.99)	61,860.14	61,860.14	0.00	(61,173.85)
2320077	INDUS Unvouchered Liabilities	(554,703.33)	263,218.60	263,218.60	0.00	(291,484.73)
2320079	Broker Commisn Spark/Merch Gen	0.00	0.00	0.00	0.00	0.00
2320081	AP Accrual NYMEX OTC & Penults	(7,926.27)	7,926.27	7,926.27	0.00	0.00
2320083	PJM Net AP Accrual	0.00	(275,088.88)	0.00	(275,088.88)	(275,088.88)
2320086	Accrued Broker - Power	(228,700.05)	137,472.14	137,472.14	0.00	(91,227.91)
2320090	MISO AP Accrual	(302,489.52)	80,397.15	80,397.15	0.00	(222,092.37)
2320094	Customer A/P - REC Activity	0.00	(0.08)	0.00	(0.08)	(0.08)
2330000	Corp Borrow Program (NP-Assoc)	(13,358,855.63)	13,358,855.63	13,358,855.63	0.00	0.00
2340001	A/P Assoc Co - InterUnit G/L	(16,246,034.79)	(82,896.54)	0.00	(82,896.54)	(16,328,931.33)
2340005	A/P Assoc Co - Allowances	(6,096,125.38)	6,096,125.38	6,096,125.38	0.00	0.00
2340011	A/P-Assc Co-AEPSC-Agent	(12,990,390.36)	(2,132,709.50)	0.00	(2,132,709.50)	(15,123,099.86)
2340025	A/P Assoc Co - CM Bills	(17,907.81)	(186,509.64)	0.00	(186,509.64)	(204,417.45)
2340027	A/P Assoc Co - Intercompany	(226,842.71)	28,229.61	28,229.61	0.00	(198,613.10)
2340029	A/P Assoc Co - AEPSC Bills	(5,190,755.34)	2,213,984.65	2,213,984.65	0.00	(2,976,770.69)
2340030	A/P Assoc Co - InterUnit A/P	(183,978.41)	159,186.72	159,186.72	0.00	(24,791.69)
2340032	A/P Assoc Co - Multi Pmts	(377.70)	377.70	377.70	0.00	0.00
2340034	A/P Assoc Co - System Sales	(174.50)	174.48	174.48	0.00	(0.02)
2340035	Fleet - M4 - A/P	(11,139.18)	(7,532.45)	0.00	(7,532.45)	(18,671.63)
2340037	A/P Assoc-Global Borrowing Int	(87,500.00)	(175,000.00)	0.00	(175,000.00)	(262,500.00)
2340049	A/P Assoc -Realization Sharing	(1,454.00)	1,454.00	1,454.00	0.00	0.00
2350001	Customer Deposits-Active	(23,382,986.52)	(500,479.30)	0.00	(500,479.30)	(23,883,465.82)
2350003	Deposits - Trading Activity	(166,837.29)	(677,367.78)	0.00	(677,367.78)	(844,205.07)
2350005	Deposits - Trading Contra	64,859.00	(26,971.00)	0.00	(26,971.00)	37,888.00
2360001	Federal Income Tax	5,089,401.08	184,180.43	184,180.43	0.00	5,273,581.51
236000209	State Income Taxes	63,670.00	0.00	0.00	0.00	63,670.00
236000212	State Income Taxes	5,311.61	111,000.00	111,000.00	0.00	116,311.61
236000213	State Income Taxes	0.00	251,144.27	251,144.27	0.00	251,144.27
2360004	FICA	(46,313.45)	(39,421.24)	0.00	(39,421.24)	(85,734.69)
2360005	Federal Unemployment Tax	(17,606.02)	17,213.21	17,213.21	0.00	(392.81)
2360006	State Unemployment Tax	(273.53)	(647.86)	0.00	(647.86)	(921.39)
236000700	State Sales and Use Taxes	0.00	(445,100.00)	0.00	(445,100.00)	(445,100.00)
236000712	State Sales and Use Taxes	(252,612.46)	252,612.46	252,612.48	0.00	0.00
236000713	State Sales and Use Taxes	0.00	(93,946.86)	0.00	(93,946.86)	(93,946.86)
236000810	Real Personal Property Taxes	(96,736.72)	96,736.72	96,736.72	0.00	0.00
236000811	Real Personal Property Taxes	(530,458.17)	509,738.18	509,738.18	0.00	(20,719.99)
236000812	Real Personal Property Taxes	(10,424,508.70)	3,707.14	3,707.14	0.00	(10,420,801.56)
236001212	State Franchise Taxes	27,955.00	0.00	0.00	0.00	27,955.00
236001213	State Franchise Taxes	0.00	(3,782.00)	0.00	(3,782.00)	(3,782.00)
236001600	State Gross Receipts Tax	0.00	(71,358.33)	0.00	(71,358.33)	(71,358.33)
236001608	State Gross Receipts Tax	0.00	(14,471.31)	0.00	(14,471.31)	(14,471.31)
236001609	State Gross Receipts Tax	0.00	(30,479.90)	0.00	(30,479.90)	(30,479.90)
236001612	State Gross Receipts Tax	(33,000.00)	33,000.00	33,000.00	0.00	0.00
236001613	State Gross Receipts Tax	0.00	(16,000.00)	0.00	(16,000.00)	(16,000.00)
236002213	State License Registration Tax	0.00	25.00	25.00	0.00	25.00
236003311	Pers Prop Tax-Cap Leases	(10,268.17)	10,268.17	10,268.17	0.00	0.00
236003312	Pers Prop Tax-Cap Leases	(4,372.68)	4,609.20	4,609.20	0.00	236.52
236003313	Pers Prop Tax-Cap Leases	0.00	(17,300.00)	0.00	(17,300.00)	(17,300.00)
236003513	Real Prop Tax-Cap Leases	0.00	(18,000.00)	0.00	(18,000.00)	(18,000.00)
2360037	FICA - Incentive accrual	(277,883.73)	147,761.09	147,761.09	0.00	(130,122.64)
2360038	Reorg Payroll Tax Accrual	(33,379.84)	33,379.64	33,379.64	0.00	0.00
2360502	State Inc Tax-Short Term FIN48	(90,764.00)	0.00	0.00	0.00	(90,764.00)

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Account Number	Description	Pr Yr Ending Balance	Yearly Activity	Debits	Credit	Current Yr Balance
2360601	Fed Inc Tax-Long Term FIN48	(1,166,551.06)	632,529.01	632,529.01	0.00	(534,022.05)
2360602	State Inc Tax-Long Term FIN48	(75,672.00)	0.00	0.00	0.00	(75,672.00)
2360701	SEC Accum Defd FIT-Util FIN 48	1,166,551.00	(632,529.01)	0.00	(632,529.01)	534,021.99
2360702	SEC Accum Defd SIT - FIN 48	173,628.00	0.00	0.00	0.00	173,628.00
2360801	Federal Income Tax - IRS Audit	1.00	0.00	0.00	0.00	1.00
2360901	Accum Defd FIT- IRS Audit	(14,832.00)	(1,010,410.00)	0.00	(1,010,410.00)	(1,025,242.00)
2370006	Interest Accrd-Sen Unsec Notes	(6,461,093.17)	(5,650,958.36)	0.00	(5,650,958.36)	(12,112,051.53)
2370007	Interest Accrd-Customer Depsts	(632,060.60)	606,618.46	606,618.46	0.00	(25,442.14)
2370018	Accrued Margin Interest	(2,593.25)	2,304.61	2,304.61	0.00	(288.64)
2370048	Acrd Int.- FIT Reserve - LT	(44,206.00)	7,119.00	7,119.00	0.00	(37,087.00)
2370248	Acrd Int. - FIT Reserve - ST	0.00	179,933.00	179,933.00	0.00	179,933.00
2370448	Acrd Int. - SIT Reserve - ST	(26,742.00)	(2,558.00)	0.00	(2,558.00)	(29,300.00)
2410002	State Income Tax Withheld	(64,323.99)	2,030.83	2,030.83	0.00	(62,293.16)
2410003	Local Income Tax Withheld	(20,769.16)	6,193.20	6,193.20	0.00	(14,575.96)
2410004	State Sales Tax Collected	(642,528.05)	(5,736.01)	0.00	(5,736.01)	(648,264.06)
2410005	FICA Tax Withheld	0.00	0.01	0.01	0.00	0.01
2410008	Franchise Fee Collected	(362,674.10)	37,788.25	37,788.25	0.00	(324,885.85)
2410009	KY Utility Gr Receipts Lic Tax	(970,931.54)	143,031.05	143,031.05	0.00	(827,900.49)
2420002	P/R Ded - Medical Insurance	(92,319.08)	796.38	796.38	0.00	(91,522.70)
2420003	P/R Ded - Dental Insurance	(7,877.78)	337.45	337.45	0.00	(7,540.33)
2420016	P/R Ded-Crt Ordr/Grnshmt/Tx Lv	0.00	(10.00)	0.00	(10.00)	(10.00)
2420020	Vacation Pay - This Year	0.00	(1,625,705.02)	0.00	(1,625,705.02)	(1,625,705.02)
2420021	Vacation Pay - Next Year	(3,098,471.12)	1,539,964.12	1,539,964.12	0.00	(1,558,507.01)
2420027	FAS 112 CURRENT LIAB	(1,024,120.00)	(767,896.00)	0.00	(767,896.00)	(1,792,016.00)
2420044	P/R Withholdings	(40,673.31)	(2,365.40)	0.00	(2,365.40)	(43,038.71)
2420046	FAS 158 SERP Payable - Current	(4.00)	0.00	0.00	0.00	(4.00)
2420051	Non-Productive Payroll	(33,872.37)	(226,903.27)	0.00	(226,903.27)	(260,775.64)
2420053	Perf Share Incentive Plan	(158,133.29)	158,133.29	158,133.29	0.00	0.00
2420071	P/R Ded - Vision Plan	(3,460.05)	(85.41)	0.00	(85.41)	(3,545.46)
2420072	P/R - Payroll Adjustment	0.00	(62.53)	0.00	(62.53)	(62.53)
2420076	P/R Savings Plan - Incentive	(146,237.29)	80,204.99	80,204.99	0.00	(66,032.30)
2420087	Engage to Gain Incentive	0.00	(84,297.00)	0.00	(84,297.00)	(84,297.00)
2420504	Accrued Lease Expense	0.00	(2,918.87)	0.00	(2,918.87)	(2,918.87)
2420511	Control Cash Disburse Account	(1,998,024.41)	399,732.94	399,732.94	0.00	(1,598,291.47)
2420512	Unclaimed Funds	(3,656.54)	(49,610.63)	0.00	(49,610.63)	(53,267.17)
2420514	Revenue Refunds Accrued	(2,164,195.17)	(149,992.73)	0.00	(149,992.73)	(2,314,187.90)
2420532	Adm Liab-Cur-S/Ins-W/C	(425,543.23)	(55,312.16)	0.00	(55,312.16)	(480,855.39)
2420542	Acc Cash Franchise Req	(80,392.91)	21,725.07	21,725.07	0.00	(58,667.84)
2420558	Admitted Liab NC-Self/Ins-W/C	(849,257.00)	(339,422.45)	0.00	(339,422.45)	(1,188,679.45)
242059212	Sales Use Tax - Leased Equip	(14,374.41)	14,374.41	14,374.41	0.00	0.00
242059213	Sales Use Tax - Lease Equip	0.00	(448.70)	0.00	(448.70)	(448.70)
2420618	Accrued Payroll	(617,555.93)	(408,644.10)	0.00	(408,644.10)	(1,026,200.03)
2420623	Distr, Cust Ops & Reg Svcs ICP	(2,012,194.43)	1,043,456.37	1,043,456.37	0.00	(968,738.06)
2420624	Corp & Shrd Srv Incentive Plan	(266,577.00)	154,141.76	154,141.76	0.00	(112,435.24)
2420635	Generation Incentive Plan	(1,044,213.00)	633,534.34	633,534.34	0.00	(410,678.66)
2420643	Accrued Audit Fees	(3,646.98)	(69,201.57)	0.00	(69,201.57)	(72,848.55)
2420651	Reorg Severance Accrual	(462,555.99)	462,555.99	462,555.99	0.00	0.00
2420653	Reorg Misc HR Exp Accrual	(1,425.00)	0.00	0.00	0.00	(1,425.00)
2420656	Federal Mitigation Accru (NSR)	(376,794.01)	0.00	0.00	0.00	(376,794.01)
2420660	AEP Transmission ICP	(353,719.00)	194,723.51	194,723.51	0.00	(158,995.49)
2420664	ST State Mitigation Def (NSR)	(457,287.95)	60,509.58	60,509.58	0.00	(396,778.37)
2430001	Oblig Under Cap Leases - Curr	(1,389,654.47)	187,856.78	187,856.78	0.00	(1,201,797.69)
2430003	Accrued Cur Lease Oblig	(14,221.48)	12,791.50	12,791.50	0.00	(1,429.98)
2440001	Curr. Unreal Losses - NonAffil	(4,748,862.76)	1,252,050.61	1,252,050.61	0.00	(3,496,812.15)
2440002	LT Unreal Losses - Non Affil	(4,200,196.07)	1,274,668.16	1,274,668.16	0.00	(2,925,527.91)
2440009	S/T Option Premium Receipts	(9,091.26)	13,052.70	13,052.70	0.00	3,961.44
2440021	S/T Liability MTM Collateral	1,626,443.00	(788,977.00)	0.00	(788,977.00)	837,466.00
2440022	L/T Liability MTM Collateral	582,545.00	(332,648.00)	0.00	(332,648.00)	249,897.00
2450010	S/T Liability-Commodity Hedges	(188,557.00)	103,619.00	103,619.00	0.00	(84,938.00)
2450011	L/T Liability-Commodity Hedges	(82,731.00)	82,030.00	82,030.00	0.00	(701.00)
2520000	Customer Adv for Construction	(63,177.74)	(16,908.62)	0.00	(16,908.62)	(80,086.36)
2530022	Customer Advance Receipts	(2,634,497.53)	1,031,659.75	1,031,659.75	0.00	(1,602,837.78)
2530050	Deferred Rev -Pole Attachments	(78,940.35)	(217,827.90)	0.00	(217,827.90)	(296,768.25)
2530067	IPP - System Upgrade Credits	(260,279.72)	(5,694.92)	0.00	(5,694.92)	(265,974.64)
2530092	Fbr Opt Lns-In Kind Sv-Dfd Gns	(162,614.00)	3,786.00	3,786.00	0.00	(158,828.00)
2530112	Other Deferred Credits-Curr	(1,113,326.72)	891,710.55	891,710.55	0.00	(221,616.17)
2530114	Federl Mitigation Deferal(NSR)	(754,941.55)	0.00	0.00	0.00	(754,941.55)
2530137	Fbr Opt Lns-Sold-Defd Rev	(116,729.42)	9,037.20	9,037.20	0.00	(107,692.22)
2540011	Over Recovered Fuel Cost	(7,928,322.88)	1,788,183.00	1,788,183.00	0.00	(6,140,139.88)
2540047	Unreal Gain on Fwd Commitments	(4,287,554.66)	680,807.94	680,807.94	0.00	(3,606,746.72)
2540071	KY Enhanced Reliability Liab	(215,164.00)	215,164.00	215,164.00	0.00	0.00
2540105	Home Energy Assist Prgm - KPCO	(233,489.29)	(10,503.51)	0.00	(10,503.51)	(243,992.80)
2540173	Green Pricing Option	(614.00)	0.00	0.00	0.00	(614.00)
2543001	SFAS109 Flow Thru Def FIT Liab	(191,562.44)	82,567.36	82,567.36	0.00	(108,995.08)
2544001	SFAS 109 Exces Deferred FIT	(975,258.45)	25,993.84	25,993.84	0.00	(949,264.61)

Kentucky Power Company
Trial Balance
For The Month Ended AUGUST 31, 2013

Account Number	Description	Pr Yr Ending Balance	Yearly Activity	Debits	Credit	Current Yr Balance
2550001	Accum Deferred ITC - Federal	(355,758.82)	153,339 36	153,339.36	0.00	(202,419.46)
2811001	Acc Dfd FIT - Accel Amort Prop	(26,644,637.95)	1,050,000.00	1,050,000.00	0 00	(25,594,637.95)
2821001	Accum Defd FIT - Utility Prop	(198,723,116.95)	(9,383,553 68)	0 00	(9,383,553 68)	(208,106,670.63)
2823001	Acc Dfrd FIT FAS 109 Flow Thru	(54,412,534.48)	(165,734.49)	0.00	(165,734.49)	(54,578,268.97)
2824001	Acc Dfrd FIT - SFAS 109 Excess	633,918 00	(16,896 00)	0.00	(16,896.00)	617,022.00
2830006	ADIT Federal - SFAS 133 Nonaff	(23,148.10)	(22,560.71)	0.00	(22,560.71)	(45,708.81)
2831001	Accum Deferred FIT - Other	(18,533,601.89)	1,643,451.73	1,643,451.73	0.00	(16,890,150.16)
2832001	Accum Dfrd FIT - Oth Inc & Ded	(75,852.47)	(5,194.23)	0 00	(5,194.23)	(81,046.70)
2833001	Acc Dfd FIT FAS 109 Flow Thru	(45,029,503.26)	755,805.19	755,805.19	0.00	(44,273,698.07)
2833002	Acc Dfrd SIT FAS 109 Flow Thru	(42,344,691.07)	(185,021.00)	0.00	(185,021.00)	(42,529,712.07)
	LIABILITIES AND OTHER CREDITS	(590,039,743.82)	23,586,235.44	23,586,235.44	0.00	(566,453,508.37)
4030001	Depreciation Exp	51,080,851.14	(15,372,415.14)	0 00	(15,372,415.14)	35,708,436.00
4030021	AEPSC Bell Howell Inserter	2,712.57	(2,712.57)	0.00	(2,712.57)	0.00
4040001	Amort. of Plant	3,382,892.77	(909,335.94)	0.00	(909,335.94)	2,473,556.83
4060001	Amort of Plt Acq Adj	38,616 00	(12,872.00)	0.00	(12,872.00)	25,744.00
4073000	Regulatory Debits	289,086.72	(96,152.14)	0 00	(96,152.14)	192,934.58
4081002	FICA	2,755,949.85	(1,164,601.19)	0.00	(1,164,601.19)	1,591,348 66
4081003	Federal Unemployment Tax	30,490.21	(13,255.76)	0.00	(13,255.76)	17,234.45
408100508	Real & Personal Property Taxes	(446.76)	1,257.26	1,257.26	0.00	810.50
408100509	Real & Personal Property Taxes	(30,160.24)	30,160.24	30,160.24	0 00	0 00
408100510	Real Personal Property Taxes	(98,374.28)	150,973.16	150,973.16	0.00	52,598.88
408100511	Real Personal Property Taxes	9,603,945.00	(9,585,235.33)	0.00	(9,585,235.33)	18,709.67
408100512	Real Personal Property Taxes	0.00	6,626,480.30	6,626,480.30	0.00	6,626,480.30
408100600	State Gross Receipts Tax	0.00	71,358.33	71,358 33	0.00	71,358.33
408100611	State Gross Receipts Tax	30,112.00	(30,112.00)	0.00	(30,112.00)	0.00
408100612	State Gross Receipts Tax	144,101.00	(175,562.00)	0.00	(175,562.00)	(31,461.00)
408100613	State Gross Receipts Tax	0 00	48,973.00	48,973.00	0.00	48,973.00
4081007	State Unemployment Tax	32,260.09	6,241.56	6,241.56	0.00	38,501.65
408100811	State Franchise Taxes	(22,194.00)	22,194.00	22,194 00	0.00	0.00
408100812	State Franchise Taxes	10,345.00	(10,345.00)	0.00	(10,345 00)	0.00
408100813	State Franchise Taxes	0.00	3,782.00	3,782.00	0.00	3,782.00
408101412	Federal Excise Taxes	997.96	(997.96)	0.00	(997.96)	0 00
408101413	Federal Excise Taxes	0.00	2,489.24	2,489.24	0.00	2,489 24
408101712	St Lic-Rgstrtion Tax-Fees	165.00	(165.00)	0.00	(165.00)	0.00
408101713	St Lic Rgstrtion Tax-Fees	0.00	35.00	35 00	0.00	35 00
408101811	St Publ Serv Comm Tax-Fees	412,861.18	(412,861.18)	0.00	(412,861.18)	0 00
408101812	St Publ Serv Comm Tax-Fees	515,095.26	0.01	0.01	0.00	515,095.27
408101813	St Publ Serv Comm Tax-Fees	0.00	157,707.38	157,707.38	0.00	157,707.38
408101900	State Sales and Use Taxes	0.00	336,570.00	336,570.00	0.00	336,570.00
408101911	State Sales and Use Taxes	1,247.12	(1,247.12)	0.00	(1,247.12)	0 00
408101912	State Sales and Use Taxes	9,804.65	(8,696.00)	0.00	(8,696.00)	1,108 65
408101913	State Sales and Use Taxes	0 00	8,044.02	8,044.02	0.00	8,044.02
408102212	Municipal License Fees	300.00	(300.00)	0.00	(300.00)	0.00
408102213	Municipal License Fees	0.00	325.00	325.00	0.00	325 00
408102909	Real/Pers Prop Tax-Cap Leases	17.98	(17.98)	0 00	(17.98)	0.00
408102910	Real-Pers Prop Tax-Cap Leases	(102,053.81)	102,053.81	102,053 81	0.00	0.00
408102911	Real-Pers Prop Tax-Cap Leases	(61,822.48)	51,784.60	51,784.60	0.00	(10,037.88)
408102912	Real-Pers Prop Tax-Cap Leases	18,699.00	(20,422.98)	0.00	(20,422.98)	(3,723 98)
408102913	Real-Pers Prop Tax-Cap Leases	0.00	11,544.00	11,544.00	0.00	11,544 00
4081033	Fringe Benefit Loading - FICA	(1,095,922.38)	448,682.22	448,682.22	0.00	(647,240.16)
4081034	Fringe Benefit Loading - FUT	(8,148.08)	2,510.99	2,510.99	0.00	(5,637.09)
4081035	Fringe Benefit Loading - SUT	(14,610.11)	5,095.98	5,095.98	0.00	(9,514.13)
408103608	Real Prop Tax-Cap Leases	310.74	(310.74)	0 00	(310.74)	0.00
408103611	Real Prop Tax-Cap Leases	2,257.44	(2,257.44)	0.00	(2,257.44)	0.00
408103612	Real Prop Tax-Cap Leases	26,744 91	(26,744 91)	0 00	(26,744 91)	0.00
408103613	Real Prop Tax-Cap Leases	0.00	18,000.00	18,000.00	0.00	18,000.00
408200511	Real Personal Property Taxes	56,600.00	(56,600.00)	0.00	(56,600.00)	0.00
408200512	Real Personal Property Taxes	0.00	37,736.00	37,736.00	0.00	37,736.00
4091001	Income Taxes, UOI - Federal	10,165,757.90	(5,468,270.09)	0.00	(5,468,270.09)	4,697,487.81
409100200	Income Taxes, UOI - State	(498,211.00)	498,211.00	498,211.00	0.00	0.00
409100211	Income Taxes UOI - State	(295,338.21)	295,338.21	295,338.21	0.00	0.00
409100212	Income Taxes UOI - State	3,109,464.36	(3,109,464.36)	0.00	(3,109,464.36)	0.00
409100213	Income Taxes UOI - State	0.00	2,019,499.98	2,019,499.98	0.00	2,019,499.98
4092001	Inc Tax, Oth Inc&Ded-Federal	102,554.86	427,186.90	427,186.90	0.00	529,741.76
409200211	Inc Tax Oth Inc Ded - State	(7,156.51)	7,156.51	7,156 51	0.00	0 00
409200212	Inc Tax Oth Inc Ded - State	22,944.03	(22,944.03)	0.00	(22,944 03)	0.00
409200213	Inc Tax Oth Inc Ded - State	0.00	86,155.75	86,155.75	0.00	86,155.75
4101001	Prov Def I/T Util Op Inc-Fed	61,561,067.51	(34,911,938.79)	0.00	(34,911,938.79)	26,649,128.72
4102001	Prov Def I/T Oth I&D - Federal	8,797.25	(3,603.02)	0.00	(3,603.02)	5,194.23
4111001	Prv Def I/T-Cr Util Op Inc-Fed	(51,377,005.27)	31,441,248.38	31,441,248 38	0.00	(19,935,756 89)
4112001	Prv Def I/T-Cr Oth I&D-Fed	(113,320 35)	113,320.35	113,320.35	0.00	0.00
4114001	ITC Adj, Utility Oper - Fed	(278,005.00)	124,665.64	124,665.64	0 00	(153,339 36)
4116000	Gain From Disposition of Plant	(3,110.00)	754.00	754.00	0.00	(2,356.00)
4118002	Comp. Allow Gains Title IV SO2	(404.65)	240.42	240.42	0.00	(164.23)
4118003	Comp. Allow. Gains-Seas NOx	(14,958.00)	4,958 00	4,958 00	0.00	(10,000.00)

Kentucky Power Company
Trial Balance
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Account Number	Description	Pr Yr Ending Balance	Yearly Activity	Debits	Credit	Current Yr Balance
4118004	Comp. Allow. Gains-Ann NOx	0.00	(92,183.56)	0.00	(92,183.56)	(92,183.56)
4180001	Non-Operatng Rental Income	(55,800.00)	30,600.00	30,600 00	0.00	(25,200.00)
4180002	Non-Opratng Rntal Inc-Oper	330.20	(330.20)	0 00	(330 20)	0.00
4180003	Non-Opratng Rntal Inc-Maint	0.00	772.35	772.35	0.00	772.35
4180005	Non-Opratng Rntal Inc-Depr	6,669.72	(2,223 24)	0 00	(2,223.24)	4,446.48
4190002	Int & Dividend Inc - Nonassoc	(35,905.13)	(159,067.83)	0.00	(159,067.83)	(194,972.96)
4190005	Interest Income - Assoc CBP	(221,551.44)	199,853.17	199,853.17	0.00	(21,698.27)
4191000	Allw Oth Fnds Usd Dmg Cnstr	(1,574,384.40)	579,089.74	579,089.74	0 00	(995,294.66)
4210002	Misc Non-Op Inc-NonAsc-Rents	(61,306.90)	41,584.41	41,584.41	0.00	(19,722.49)
4210003	Misc Non-Op Inc-NonAscRoylty	15.95	(15.95)	0 00	(15.95)	0.00
4210005	Misc Non-Op Inc-NonAsc-Timber	(56,037.57)	38,723.86	38,723.86	0 00	(17,313.71)
4210007	Misc Non-Op Inc - NonAsc - Oth	(44,683.77)	34,011.76	34,011.76	0 00	(10,672.01)
4210009	Misc Non-Op Exp - NonAssoc	2,741.06	5,264.71	5,264.71	0 00	8,005.77
4210031	Pwr Sales Outside Svc Territy	(311,959.57)	310,692.13	310,692.13	0.00	(1,267.44)
4210032	Pwr Purch Outside Svc Territy	600.34	(61.01)	0.00	(61.01)	539.33
4210033	Mark to Mkt Out Svc Territory	(1,363.58)	1,363.58	1,363 58	0.00	0.00
4210039	Carrying Charges	(93,870.29)	40,612.13	40,612.13	0.00	(53,258.16)
4210043	Realiz Sharing West Coast Pwr	(614.00)	599.00	599.00	0.00	(15.00)
4210049	Interest Rate Swaps-BTL Power	1,331.10	(1,331.10)	0 00	(1,331.10)	0.00
4211000	Gain on Dspsition of Property	0 00	(1,768,047.94)	0.00	(1,768,047.94)	(1,768,047.94)
4212000	Loss on Dspsition of Property	0.00	7,425.00	7,425.00	0 00	7,425.00
4261000	Donations	322,570.43	(126,417.50)	0 00	(126,417.50)	196,152.93
4263001	Penalties	17.79	3,025.07	3,025.07	0 00	3,042.86
4264000	Civic & Political Activities	304,051.82	(130,512.75)	0.00	(130,512.75)	173,539.07
4265002	Other Deductions - Nonassoc	6,711.53	(4,372.42)	0.00	(4,372.42)	2,339.11
4265004	Social & Service Club Dues	59,859 05	(11,625.84)	0.00	(11,625.84)	48,233 21
4265009	Factored Cust A/R Exp - Affil	886,846.15	(304,269.52)	0.00	(304,269.52)	582,576.63
4265010	Fact Cust A/R-Bad Debts-Affil	1,569,927.36	(805,343.21)	0.00	(805,343 21)	764,584.15
4265033	Ohio Merger - Transition Costs	0 00	13,983.32	13,983.32	0 00	13,983.32
4265054	Specul. Allow Loss-Seas NOx	4 06	(4.06)	0 00	(4.06)	0.00
4270006	Int on LTD - Sen Unsec Notes	33,998,706.24	(11,332,902.08)	0.00	(11,332,902 08)	22,665,804.16
4280006	Amrtz Dscnt&Exp-Sn Unsec Note	471,186.42	(157,062.14)	0.00	(157,062.14)	314,124.28
4281004	Amrtz Loss Rcquired Debt-Dbnt	33,648.60	(11,216.20)	0.00	(11,216.20)	22,432.40
4300001	Interest Exp - Assoc Non-CBP	1,050,000.00	(350,000.00)	0.00	(350,000.00)	700,000.00
4300003	Int to Assoc Co - CBP	1,133.47	10,876.06	10,876.06	0.00	12,009.53
4310001	Other Interest Expense	8,401.67	12,770.12	12,770.12	0.00	21,171.79
4310002	Interest on Customer Deposits	716,205.76	(688,439.03)	0 00	(688,439 03)	27,766.73
4310007	Lines Of Credit	600,392.13	(180,922.69)	0.00	(180,922.69)	419,469.44
4310022	Interest Expense - Federal Tax	3,502.00	(11,483.00)	0.00	(11,483 00)	(7,981.00)
4310023	Interest Expense - State Tax	19,022.38	(15,721.38)	0.00	(15,721.38)	3,301.00
4320000	Allw Brrwed Fnds Used Cnstr-Cr	(1,124,538.87)	435,704.05	435,704.05	0.00	(688,834 82)
4400001	Residential Sales-W/Space Htg	(97,265,892.09)	28,143,487.75	28,143,487.75	0.00	(69,122,404.34)
4400002	Residential Sales-W/O Space Ht	(47,352,516.14)	14,985,029.80	14,985,029 80	0.00	(32,367,486.34)
4400005	Residential Fuel Rev	(61,180,756.81)	14,678,091.32	14,678,091.32	0.00	(46,502,665.49)
4420001	Commercial Sales	(65,070,350 86)	21,435,303.08	21,435,303 08	0 00	(43,635,047.78)
4420002	Industrial Sales (Excl Mines)	(50,504,361.88)	13,544,403.02	13,544,403.02	0.00	(36,959,958.86)
4420004	Ind Sales-NonAffil(Incl Mines)	(33,769,442.94)	14,297,363.14	14,297,363.14	0.00	(19,472,079.80)
4420006	Sales to Pub Auth - Schools	(11,785,526.42)	4,075,309 34	4,075,309.34	0.00	(7,710,217.08)
4420007	Sales to Pub Auth - Ex Schools	(12,075,901.60)	3,859,096.95	3,859,096.95	0 00	(8,216,804 65)
4420013	Commercial Fuel Rev	(36,785,178.88)	9,852,130.64	9,852,130.64	0.00	(26,933,048.24)
4420016	Industrial Fuel Rev	(83,701,149.01)	26,358,044.23	26,358,044.23	0.00	(57,343,104.78)
4440000	Public Street/Highway Lighting	(1,254,200.00)	406,245.84	406,245.84	0.00	(847,954.16)
4440002	Public St & Hwy Light Fuel Rev	(291,473.77)	98,569.91	98,569.91	0.00	(192,903 86)
4470001	Sales for Resale - Assoc Cos	3,493.81	(7,417.40)	0 00	(7,417.40)	(3,923.59)
4470002	Sales for Resale - NonAssoc	(9,302,001.41)	6,461,643.16	6,461,643.16	0.00	(2,840,358.25)
4470006	Sales for Resale-Bookout Sales	(18,457,322.65)	7,950,825 64	7,950,825.64	0.00	(10,506,497.01)
4470007	Sales for Resale-Option Sales	(166.07)	166 07	166 07	0 00	0.00
4470010	Sales for Resale-Bookout Purch	13,593,048.42	(6,116,861.67)	0.00	(6,116,861.67)	7,476,186.75
4470011	Sales for Resale-Option Purch	110.24	(110 24)	0.00	(110.24)	0.00
4470027	Whsal/Muni/Pb Ath Fuel Rev	(2,781,922.11)	938,184.26	938,184.26	0.00	(1,843,737.85)
4470028	Sale/Resale - NA - Fuel Rev	(16,083,323.27)	13,502,510.99	13,502,510.99	0.00	(2,580,812.28)
4470033	Whsal/Muni/Pub Auth Base Rev	(2,980,356.50)	1,898,575.57	1,898,575.57	0 00	(1,081,780.93)
4470035	Sls for Rsl - Fuel Rev - Assoc	(66,622.08)	1,381.61	1,381.61	0.00	(65,240.47)
4470066	PWR Trding Trans Exp-NonAssoc	8,519.33	(6,705.33)	0 00	(6,705.33)	1,814 00
4470081	Financial Spark Gas - Realized	(174,457.81)	(133,128.44)	0.00	(133,128.44)	(307,586.25)
4470082	Financial Electric Realized	7,369,613.12	(5,268,995.33)	0.00	(5,268,995.33)	2,100,617.79
4470089	PJM Energy Sales Margin	(1,302,317.84)	(4,988,913.43)	0.00	(4,988,913.43)	(6,291,231.27)
4470093	PJM Implicit Congestion-LSE	4,642,161.32	(878,457.05)	0.00	(878,457.05)	3,763,704.27
4470098	PJM Oper.Reserve Rev-OSS	(3,145,933.72)	2,131,692.89	2,131,692.89	0.00	(1,014,240.83)
4470099	Capacity Cr. Net Sales	(1,877,839.59)	1,578,979 94	1,578,979.94	0.00	(298,859.65)
4470100	PJM FTR Revenue-OSS	(232,218.16)	61,921.15	61,921.15	0.00	(170,297.01)
4470101	PJM FTR Revenue-LSE	(3,101,653 94)	716,191.47	716,191.47	0 00	(2,385,462.47)
4470103	PJM Energy Sales Cost	(34,297,899.38)	(4,589,775.56)	0 00	(4,589,775.56)	(38,887,674.94)
4470106	PJM Pt2Pt Trans.Purch-NonAff.	23,729.31	(22,464 94)	0 00	(22,464 94)	1,264.37
4470107	PJM NITS Purch-NonAff.	5,839.29	5,561.21	5,561.21	0.00	11,400.50

Kentucky Power Company
Trial Balance
For The Month Ended AUGUST 31, 2013

Account Number	Description	Pr Yr Ending Balance	Yearly Activity	Debits	Credit	Current Yr Balance
4470109	PJM FTR Revenue-Spec	48,567.72	(32,827.79)	0.00	(32,827.79)	15,739 93
4470110	PJM TO Admin. Exp.-NonAff.	(1,506.59)	1,829.08	1,829.08	0.00	322.49
4470112	Non-Trading Bookout Sales-OSS	(410,300.05)	412,327.52	412,327.52	0.00	2,027.47
4470115	PJM Meter Corrections-OSS	(1,136,956.46)	1,132,534.59	1,132,534.59	0.00	(4,421 87)
4470116	PJM Meter Corrections-LSE	21,673.49	(75,587.11)	0 00	(75,587.11)	(53,913 62)
4470124	PJM Incremental Spot-OSS	0.30	(0.16)	0.00	(0.16)	0.14
4470126	PJM Incremental Imp Cong-OSS	1,065,034.56	628,193.86	628,193 86	0.00	1,693,228.42
4470128	Sales for Res-Aff. Pool Energy	(32,512,794.00)	1,681,374.00	1,681,374.00	0.00	(30,831,420 00)
4470131	Non-Trading Bookout Purch-OSS	9,006.91	(9,187.00)	0.00	(9,187.00)	(180 09)
4470141	PJM Contract Net Charge Credit	0.08	61.46	61.46	0.00	61.54
4470143	Financial Hedge Realized	(324,346.38)	241,123.32	241,123.32	0.00	(83,223 06)
4470144	Realiz Sharing - 06 SIA	1,607.00	(2,703 00)	0.00	(2,703.00)	(1,096.00)
4470150	Transm. Rev.-Dedic. Whlsl/Muni	(88,609.35)	52,248.23	52,248 23	0.00	(36,361.12)
4470155	OSS Physical Margin Reclass	5,265,953.71	(4,431,853.63)	0 00	(4,431,853.63)	834,100.08
4470156	OSS Optim. Margin Reclass	(5,265,953.71)	4,431,853 63	4,431,853 63	0.00	(834,100.08)
4470168	Interest Rate Swaps-Power	51,455.87	(28,265.74)	0 00	(28,265.74)	23,190.13
4470170	Non-ECR Auction Sales-OSS	(9,202,616 04)	5,270,356.57	5,270,356.57	0.00	(3,932,259.47)
4470174	PJM Whlse FTR Rev - OSS	(151,927.12)	58,377.71	58,377.71	0.00	(93,549.41)
4470175	OSS Sharing Reclass - Retail	821,882.38	(1,494,577.41)	0.00	(1,494,577.41)	(672,695.03)
4470176	OSS Sharing Reclass-Reduction	(821,882.38)	1,494,577.41	1,494,577.41	0.00	672,695.03
4470180	Trading intra-book Reclass	(112,526.05)	129,414.31	129,414.31	0.00	16,888.26
4470181	Auction intra-book Reclass	112,526.05	(129,414.31)	0 00	(129,414.31)	(16,888.26)
4470202	PJM OpRes-LSE-Credit	(1,943,249.73)	(787,582.84)	0.00	(787,582.84)	(2,730,832.57)
4470203	PJM OpRes-LSE-Charge	3,035,355.17	(1,813,996.42)	0.00	(1,813,996.42)	1,221,358.75
4470206	PJM Trans loss credits-OSS	(705,812.64)	213,068 21	213,068.21	0.00	(492,744.43)
4470207	PJM transm loss charges - LSE	9,917,417.43	(3,572,988.82)	0.00	(3,572,988.82)	6,344,428.61
4470208	PJM Transm loss credits-LSE	(2,824,086.83)	1,411,868.79	1,411,868.79	0.00	(1,412,218.04)
4470209	PJM transm loss charges-OSS	2,618,839.60	(302,421.14)	0.00	(302,421.14)	2,316,418.46
4470214	PJM 30m Suppl Reserve CR OSS	(250,675.42)	28,743.81	28,743.81	0.00	(221,931.61)
4470220	PJM Regulation - OSS	0.00	(11,817.13)	0 00	(11,817.13)	(11,817.13)
4470221	PJM Spinning Reserve - OSS	0.00	(20,575.74)	0.00	(20,575.74)	(20,575.74)
4470222	PJM Reasctive - OSS	0.00	(273,908.77)	0.00	(273,908.77)	(273,908.77)
4491003	Prov Rate Refund - Retail	1,635,430.00	(2,113,757.00)	0.00	(2,113,757.00)	(478,327.00)
4500000	Forfeited Discounts	(3,268,232 89)	939,523.94	939,523.94	0 00	(2,328,708.95)
4510001	Misc Service Rev - Nonaffil	(353,912.38)	77,970.86	77,970.86	0 00	(275,941.52)
4540001	Rent From Elect Property - Af	(270,041.90)	95,233.65	95,233.65	0.00	(174,808.26)
4540002	Rent From Elect Property-NAC	(85,402.90)	31,799.95	31,799.95	0.00	(53,602.95)
4540004	Rent From Elect Prop-ABD-Nonaf	(92,120.33)	38,306.68	38,306.68	0.00	(53,813.65)
4540005	Rent from Elec Prop-Pole Attch	(6,558,971.58)	2,384,416.46	2,384,416.46	0.00	(4,174,555.12)
4560007	Oth Elect Rev - DSM Program	(3,101,791.99)	1,511,992.16	1,511,992.16	0.00	(1,589,799.83)
4560015	Other Electric Revenues - ABD	(242,813.87)	8,931.64	8,931.64	0.00	(233,882.23)
4560049	Merch Generation Finan -Realzd	(16.66)	18.34	18.34	0.00	1.68
4560050	Oth Elec Rev-Coal Trd Rlzd G-L	54,112.21	(85,670.97)	0.00	(85,670.97)	(31,558.76)
4560109	Interest Rate Swaps-Coal	626.99	(626.99)	0.00	(626.99)	0.00
4561002	RTO Formation Cost Recovery	(10,475.10)	7,734.93	7,734.93	0.00	(2,740.17)
4561003	PJM Expansion Cost Recov	(85,013.65)	29,632.18	29,632.18	0.00	(55,381.47)
4561004	SECA Transmission Rev	(227,184.25)	227,184.25	227,184.25	0.00	0.00
4561005	PJM Point to Point Trans Svc	(696,676.28)	292,134.45	292,134.45	0 00	(404,541.83)
4561006	PJM Trans Owner Admin Rev	(235,655.56)	94,573.08	94,573.08	0.00	(141,082.48)
4561007	PJM Network Integ Trans Svc	(10,054,585.47)	1,716,445.98	1,716,445.98	0 00	(8,338,139.49)
4561019	Oth Elec Rev Trans Non Affil	(59,064.00)	20,757.00	20,757.00	0.00	(38,307.00)
4561028	PJM Pow Fac Cre Rev Whsl Cu-NA	(8,462.96)	2,983.34	2,983.34	0 00	(5,479.62)
4561029	PJM NITS Revenue Whsl Cus-NAff	(2,550,125.16)	1,027,321.74	1,027,321.74	0 00	(1,522,803.42)
4561030	PJM TO Serv Rev Whls Cus-NAff	(36,386.50)	12,931.22	12,931.22	0 00	(23,455.28)
4561033	PJM NITS Revenue - Affiliated	(40,000,571.34)	16,210,501.34	16,210,501.34	0.00	(23,790,070.00)
4561034	PJM TO Adm. Serv Rev - Aff	(419,468.35)	131,036.01	131,036.01	0.00	(288,432.34)
4561035	PJM Affiliated Trans NITS Cost	37,302,112.29	(14,017,456.07)	0.00	(14,017,456.07)	23,284,656.22
4561036	PJM Affiliated Trans TO Cost	387,045.44	(106,905.09)	0.00	(106,905.09)	280,140.35
4561058	NonAffil PJM Trans Enhncmt Rev	(163,819.73)	20,152.11	20,152.11	0 00	(143,667.62)
4561059	Affil PJM Trans Enhancmnt Rev	(262,916 98)	88,488.11	88,488.11	0.00	(174,428.87)
4561060	Affil PJM Trans Enhancmnt Cost	245,122.34	(74,414.86)	0 00	(74,414 86)	170,707.48
4561061	NAff PJM RTEP Rev for Whsl-FR	(16,752.59)	5,580.16	5,580.16	0.00	(11,172.43)
4561062	PROVISION PJM NITS Affil- Cost	(554,107.04)	(111,670.58)	0.00	(111,670.58)	(665,777.62)
4561063	PROVISION PJM NITS Affiliated	280,093.53	(76,017.12)	0.00	(76,017.12)	204,076.41
4561064	PROVISION PJM NITS WhslCus-NAf	13,451.27	518.08	518 08	0 00	13,969.35
4561065	PROVISION PJM NITS	(40,505.59)	92,923.66	92,923.66	0.00	52,418.07
5000000	Oper Supervision & Engineering	2,039,832.99	(888,903.83)	0.00	(888,903.83)	1,150,929.16
5000001	Oper Super & Eng-RATA-Affil	24,500.00	3,500.00	3,500 00	0.00	28,000.00
5010000	Fuel	256,635.28	(77,920.99)	0.00	(77,920 99)	178,714.29
5010001	Fuel Consumed	83,211,618.49	(8,399,729.10)	0.00	(8,399,729.10)	74,811,889 39
5010003	Fuel - Procure Unload & Handle	1,847,606.78	471,877.60	471,877.60	0.00	2,319,484.38
5010005	Fuel - Deferred	4,790,377.00	(6,578,560.00)	0 00	(6,578,560.00)	(1,788,183.00)
5010012	Ash Sales Proceeds	(205,759.32)	196,434.34	196,434.34	0 00	(9,324.98)
5010013	Fuel Survey Activity	1.00	(1.00)	0 00	(1.00)	0.00
5010019	Fuel Oil Consumed	3,256,880 81	(1,647,020.79)	0 00	(1,647,020.79)	1,609,860 02

Kentucky Power Company
Trial Balance
For The Month Ended AUGUST 31, 2013

Account Number	Description	Pr Yr Ending Balance	Yearly Activity	Debits	Credit	Current Yr Balance
5020000	Steam Expenses	808,288.72	(282,523.07)	0.00	(282,523 07)	525,765.65
5020002	Urea Expense	1,950,854.00	(203,001.13)	0.00	(203,001.13)	1,747,852.87
5020003	Trona Expense	16.21	(16.21)	0.00	(16.21)	0.00
5020008	Activated Carbon	(7.51)	7.51	7.51	0.00	0.00
5020025	Steam Exp Environmental	3 97	(11.38)	0.00	(11.38)	(7.41)
5050000	Electric Expenses	295,079.70	12,464.56	12,464.56	0.00	307,544.26
5060000	Misc Steam Power Expenses	5,575,109.17	(2,916,653.56)	0.00	(2,916,653.56)	2,658,455 61
5060002	Misc Steam Power Exp-Assoc	33,632.00	(19,272 00)	0.00	(19,272.00)	14,360.00
5060004	NSR Settlement Expense	(89,599 82)	83,701.50	83,701.50	0.00	(5,898.32)
5060025	Misc Stm Pwr Exp Environmental	0.00	22.78	22.78	0.00	22.78
5070000 '	Rents	0.00	900.00	900.00	0.00	900 00
5090000	Allow Consum Title IV SO2	8,796,258.59	(4,535,983.93)	0 00	(4,535,983.93)	4,260,274.66
5090002	Allowance Expenses	0 00	0.90	0 90	0.00	0.90
5090005	An. NOx Cons. Exp	77,335.61	(69,019.43)	0 00	(69,019.43)	8,316 38
5100000	Maint Supv & Engineering	2,059,495.03	(780,817.71)	0.00	(780,817.71)	1,278,677.32
5110000	Maintenance of Structures	573,926.94	(237,762.41)	0 00	(237,762.41)	336,164.53
5120000	Maintenance of Boiler Plant	5,552,809.13	(2,100,638.55)	0 00	(2,100,638.55)	3,452,170.58
5120025	Maint of Blr Plt Environmental	0 00	8.77	8.77	0.00	8.77
5130000	Maintenance of Electric Plant	1,396,877.06	1,706,262.75	1,706,262.75	0.00	3,103,139 81
5140000	Maintenance of Misc Steam Plt	617,122.20	(224,570.60)	0.00	(224,570.60)	392,551.60
5140025	Maint MiscStmPlt Environmental	2.30	(4.60)	0.00	(4.60)	(2.30)
5170000	Oper Supervision & Engineering	0.00	1,073.95	1,073 95	0.00	1,073.95
5300000	Maint of Reactor Plant Equip	(0.62)	0.62	0 62	0.00	0.00
5550001	Purch Pwr-NonTrading-Nonassoc	1,532,746 78	(858,079.44)	0 00	(858,079.44)	674,667.34
5550004	Purchased Power-Pool Capacity	22,446,590.00	(4,852,025.00)	0.00	(4,852,025.00)	17,594,565.00
5550005	Purchased Power - Pool Energy	54,313,303.78	(6,715,549.64)	0.00	(6,715,549.64)	47,597,754.14
5550023	Purch Power Capacity -NA	298,457.25	(298,457.25)	0.00	(298,457.25)	0 00
5550027	Purch Pwr-Non-Fuel Portion-Aff	41,126,469.00	(10,282,344.00)	0.00	(10,282,344.00)	30,844,125.00
5550032	Gas-Conversion-Mone Plant	382,270.17	(80,737.39)	0 00	(80,737.39)	301,532.78
5550039	PJM Inadvertent Mtr Res-OSS	12,755.13	(21,058.37)	0.00	(21,058 37)	(8,303.24)
5550040	PJM Inadvertent Mtr Res-LSE	62,389.42	(79,413.33)	0.00	(79,413.33)	(17,023.91)
5550041	PJM Ancillary Serv.-Sync	2,573 38	(28 06)	0 00	(28.06)	2,545.30
5550046	Purch Power-Fuel Portion-Affil	61,255,504.99	(24,468,990.36)	0.00	(24,468,990.36)	36,786,514.63
5550074	PJM Reactive-Charge	7,672.98	(3,224.12)	0.00	(3,224.12)	4,448.86
5550075	PJM Reactive-Credit	93,974.57	(19,717.66)	0.00	(19,717.66)	74,256.91
5550076	PJM Black Start-Charge	41,321.84	2,870,083.35	2,670,083.35	0.00	2,911,405.19
5550077	PJM Black Start-Credit	(30,868.06)	23,206.83	23,206 83	0.00	(7,661.23)
5550078	PJM Regulation-Charge	1,368,923.52	(370,105.49)	0 00	(370,105.49)	998,818.03
5550079	PJM Regulation-Credit	(764,272.95)	465,167.50	465,167.50	0.00	(299,105.45)
5550080	PJM Hourly Net Purch.-FERC	7,108,986.50	(950,920.22)	0 00	(950,920.22)	6,158,066.28
5550083	PJM Spinning Reserve-Charge	7,900.92	27,449.58	27,449.58	0.00	35,350.50
5550084	PJM Spinning Reserve-Credit	(1,540.34)	(7,617.18)	0 00	(7,617.18)	(9,157.52)
5550090	PJM 30m Suppl Rserv Charge LSE	248,735.61	(4,390.80)	0.00	(4,390.80)	244,345.01
5550094	Purchased Power - Fuel	666,719.33	(330,593.57)	0.00	(330,593.57)	336,125.76
5550099	PJM Purchases-non-ECR-Auction	7,486,537.45	(4,426,992.85)	0.00	(4,426,992.85)	3,059,544.60
5550100	Capacity Purchases-Auction	110,289.77	(55,411.90)	0.00	(55,411.90)	54,877.87
5550101	Purch Power-Pool Non-Fuel -Aff	7,548,086.00	(1,138,569.00)	0.00	(1,138,569.00)	6,409,517.00
5550102	Pur Power-Pool NonFuel-OSS-Aff	41,418,496.78	(7,018,820.76)	0.00	(7,018,820.76)	34,399,676.02
5550107	Capacity purchases - Trading	459,267.39	(314,103.99)	0 00	(314,103.99)	145,163.40
5560000	Sys Control & Load Dispatching	171,352.77	(104,658.78)	0 00	(104,658.78)	66,693.99
5570000	Other Expenses	1,431,223.79	(594,806.78)	0.00	(594,806.78)	836,417.01
5570007	Other Pwr Exp - Wholesale RECs	27,152.26	(23,050.55)	0 00	(23,050.55)	4,101.71
5600000	Oper Supervision & Engineering	659,387.81	(122,791.85)	0.00	(122,791.85)	536,595.96
5611000	Load Dispatch - Reliability	5,642.01	603.26	603.26	0.00	6,245.27
5612000	Load Dispatch-Mntr&Op TransSys	764,533.23	(233,661.85)	0 00	(233,661.85)	530,871.38
5613000	Load Dispatch-Trans Srvc&Sched	(76.98)	78.98	76.98	0.00	0.00
5614000	PJM Admin-SSC&DS-OSS	82,625.07	129,330.44	129,330.44	0.00	211,955.51
5614001	PJM Admin-SSC&DS-Internal	1,053,490.00	(579,465.36)	0 00	(579,465.36)	474,024.64
5614007	RTO Admin Default LSE.	24,603.14	(32,661.63)	0.00	(32,661.63)	(8,058.49)
5615000	Reliability,Plng&Stds Develop	136,890.27	(41,774.19)	0.00	(41,774.19)	95,116.08
5618000	PJM Admin-RP&SDS-OSS	20,098 58	25,445.63	25,445.63	0.00	45,544.21
5618001	PJM Admin-RP&SDS- Internal	225,416 55	(110,145.22)	0.00	(110,145.22)	115,271.33
5620001	Station Expenses - N0nassoc	188,431.27	(50,853.23)	0 00	(50,853.23)	137,578.04
5630000	Overhead Line Expenses	153,317.18	(83,841.01)	0.00	(83,841.01)	69,476.17
5650002	Transmssn Elec by Others-NAC	159,695.59	(33,730.76)	0 00	(33,730.76)	125,964 83
5650012	PJM Trans Enhancement Charge	3,087,972.64	(717,103.02)	0.00	(717,103.02)	2,370,869.62
5650015	PJM TO Serv Exp - Aff	4,649.16	(3,786.34)	0.00	(3,786.34)	862.82
5650016	PJM NITS Expense - Affiliated	1,056,426.01	301,363.43	301,363.43	0.00	1,357,789.44
5650019	Affil PJM Trans Enhncement Exp	32,994.90	32,151.70	32,151.70	0.00	65,146.60
5650020	PROVISION PJM NITS Affl Expens	19,836.26	315,769.39	315,769.39	0.00	335,605 65
5660000	Misc Transmission Expenses	1,208,166.83	(544,014.34)	0 00	(544,014.34)	664,152.49
5670001	Rents - Nonassociated	386.44	5,952.69	5,952 69	0.00	6,339.13
5670002	Rents - Associated	1,817.03	(1,817.03)	0 00	(1,617.03)	0.00
5680000	Maint Supv & Engineering	136,306.00	(61,373.18)	0 00	(61,373.18)	74,932.82
5690000	Maintenance of Structures	27,527.20	(16,237.74)	0 00	(16,237.74)	11,289.46

Kentucky Power Company
Trial Balance
For The Month Ended AUGUST 31, 2013

Account Number	Description	Pr Yr Ending Balance	Yearly Activity	Debits	Credit	Current Yr Balance
5691000	Maint of Computer Hardware	44,421.95	(30,458.51)	0 00	(30,458.51)	13,963.44
5692000	Maint of Computer Software	204,088.72	(5,732.79)	0.00	(5,732.79)	198,355.93
5693000	Maint of Communication Equip	95,634 38	(79,456.54)	0 00	(79,456 54)	16,177.84
5700000	Maint of Station Equipment	564,396 35	(170,100.10)	0 00	(170,100.10)	394,296.25
5710000	Maintenance of Overhead Lines	2,075,114.85	(875,099.91)	0.00	(875,099.91)	1,200,014.94
5730000	Maint of Misc Trnsmssion Plt	169,120.80	(148,987.23)	0.00	(148,987.23)	20,133.57
5757000	PJM Admin-MAM&SC- OSS	97,883.47	118,514.53	118,514 53	0.00	216,398.00
5757001	PJM Admin-MAM&SC- Internal	1,096,438 62	(626,266.25)	0.00	(626,266.25)	470,172.37
5800000	Oper Supervision & Engineering	665,169 81	(174,774.28)	0.00	(174,774.28)	490,395.53
5810000	Load Dispatching	2,293 50	(163.24)	0.00	(163.24)	2,130.26
5820000	Station Expenses	179,854.63	(74,149.03)	0.00	(74,149 03)	105,705.60
5830000	Overhead Line Expenses	187,323.62	137,486.12	137,486.12	0.00	324,809.74
5840000	Underground Line Expenses	129,749.50	(36,969.85)	0.00	(36,969.85)	92,779.65
5850000	Street Lighting & Signal Sys E	100,428 88	(26,894 85)	0 00	(26,894.85)	73,534.03
5860000	Meter Expenses	519,468.82	(198,950.49)	0.00	(198,950.49)	320,518.33
5870000	Customer Installations Exp	129,725 88	(23,951.24)	0.00	(23,951.24)	105,774.64
5880000	Miscellaneous Distribution Exp	5,407,979 88	(2,703,963.34)	0.00	(2,703,963 34)	2,704,016.54
5890001	Rents - Nonassociated	1,626,772.32	(580,558.71)	0.00	(580,558.71)	1,046,213 61
5890002	Rents - Associated	55,239.32	(11,488.55)	0 00	(11,488.55)	43,750.78
5900000	Maint Supv & Engineering	739.43	45.80	45 80	0 00	785.23
5910000	Maintenance of Structures	24,153.12	(11,178.93)	0.00	(11,178.93)	12,974.19
5920000	Maint of Station Equipment	517,533.41	37,161.10	37,161.10	0.00	554,694.51
5930000	Maintenance of Overhead Lines	25,425,025.10	(7,927,140.63)	0 00	(7,927,140 63)	17,497,884.47
5930001	Tree and Brush Control	359,665.59	(109,944.09)	0.00	(109,944.09)	249,721.50
5930010	Storm Expense Amortization	4,698,444.00	(1,566,148 00)	0.00	(1,566,148.00)	3,132,296.00
5940000	Maint of Underground Lines	92,157.68	119,904.99	119,904.99	0.00	212,062.67
5950000	Maint of Lne Trnf,Rglators&Dvi	68,385.01	(39,854.45)	0.00	(39,854.45)	28,530.56
5960000	Maint of Strt Lghtng & Sgnal S	43,715.68	1,772.67	1,772 67	0.00	45,488 35
5970000	Maintenance of Meters	53,792.11	(17,393.36)	0.00	(17,393.36)	36,398.75
5980000	Maint of Misc Distribution Plt	85,508.16	(28,754.83)	0.00	(28,754.83)	56,753.33
9010000	Supervision - Customer Accts	272,442.01	(80,450.95)	0.00	(80,450.95)	191,991.06
9020000	Meter Reading Expenses	1,009.67	1,078.52	1,078.52	0.00	2,088.19
9020001	Customer Card Reading	0 39	(0.39)	0.00	(0.39)	0.00
9020002	Meter Reading - Regular	377,243.24	(114,239.78)	0.00	(114,239.78)	263,003.46
9020003	Meter Reading - Large Power	35,762.86	(8,930 69)	0.00	(8,930.69)	26,832.17
9020004	Read-In & Read-Out Meters	39,012.50	(12,282.46)	0.00	(12,282.46)	26,730 04
9030000	Cust Records & Collection Exp	550,935 28	(319,974.16)	0 00	(319,974.16)	230,961.12
9030001	Customer Orders & Inquiries	2,351,236.54	(1,005,323.81)	0 00	(1,005,323.81)	1,345,912.73
9030002	Manual Billing	42,562.55	(20,027.21)	0.00	(20,027.21)	22,535.34
9030003	Postage - Customer Bills	567,963.13	(9,347.75)	0 00	(9,347.75)	558,615 38
9030004	Cashiering	125,038 53	(36,345.80)	0.00	(36,345.80)	88,692.73
9030005	Collection Agents Fees & Exp	99,987.16	(82,585.97)	0.00	(82,585.97)	17,401.19
9030006	Credit & Oth Collection Activi	825,876.47	(316,794.26)	0.00	(316,794.26)	509,082.21
9030007	Collectors	612,325.11	(233,004.99)	0.00	(233,004.99)	379,320.12
9030009	Data Processing	155,980.90	(48,649.75)	0.00	(48,649.75)	107,331.15
9040007	Uncoll Accts - Misc Receivable	152,615.72	(270,626.09)	0 00	(270,626.09)	(118,010 37)
9050000	Misc Customer Accounts Exp	16,263 66	(2,422.34)	0.00	(2,422.34)	13,841.32
9070000	Supervision - Customer Service	211,593 07	(117,771.26)	0.00	(117,771.26)	93,821.81
9070001	Supervision - DSM	18 67	(20.62)	0.00	(20.62)	(1.95)
9080000	Customer Assistance Expenses	483,683 67	(174,966.91)	0.00	(174,966.91)	308,716.76
9080001	DSM-Customer Advisory Grp	282.15	312.81	312.81	0.00	594.96
9080004	Cust Assistnce Exp - DSM - Ind	0.64	(1.79)	0.00	(1.79)	(1.15)
9080009	Cust Assistance Expense - DSM	2,107,889 65	(481,127.11)	0.00	(481,127.11)	1,626,762.54
9090000	Information & Instruct Advrtis	155,343.27	(147,297.66)	0.00	(147,297.66)	8,045.61
9100000	Misc Cust Svc&Informational Ex	37,657.17	(18,178.51)	0.00	(18,178.51)	19,478 66
9100001	Misc Cust Svc & Info Exp - RCS	51.50	(51.50)	0.00	(51.50)	0 00
9110001	Supervision - Residential	(5.52)	5.52	5.52	0.00	0.00
9120000	Demonstrating & Selling Exp	0.00	15,144.37	15,144.37	0.00	15,144.37
9120001	Demo & Selling Exp - Res	2.08	(0.54)	0.00	(0.54)	1.54
9200000	Administrative & Gen Salaries	6,723,161.30	(263,956.97)	0.00	(263,956.97)	6,459,204.33
9210001	Off Supl & Exp - Nonassociated	584,735.80	411,331.96	411,331.96	0.00	996,067.75
9210003	Office Supplies & Exp - Trnsf	6.77	49.17	49.17	0.00	55.94
9220000	Administrative Exp Trnsf - Cr	(151,198 92)	(255,379.45)	0 00	(255,379.45)	(406,578.37)
9220001	Admin Exp Trnsf to Cnstrction	(676,097.24)	291,115 24	291,115.24	0.00	(384,982.00)
9220004	Admin Exp Trnsf to ABD	(4,612.34)	581.70	581.70	0.00	(4,030 64)
9220125	SSA Expense Transfers BL	(501,555.66)	501,555.66	501,555.66	0.00	0 00
9230001	Outside Svcs Empl - Nonassoc	1,396,830.66	231,838.22	231,838 22	0.00	1,628,668.88
9230003	AEPSC Billed to Client Co	3,263,174.58	(3,625,965 52)	0.00	(3,625,965.52)	(362,790.94)
9240000	Property Insurance	605,545.46	(212,955.34)	0.00	(212,955.34)	392,590.12
9250000	Injuries and Damages	1,135,754.95	(412,833.65)	0.00	(412,833.65)	722,921.30
9250001	Safety Dinners and Awards	1,011.24	255.82	255.82	0.00	1,267.06
9250002	Emp Accdent Prvntion-Adm Exp	9,180.41	(1,050.44)	0 00	(1,050.44)	8,129.97
9250004	Injuries to Employees	32,462.38	(32,452.82)	0.00	(32,452.82)	9.56
9250006	Wrkrs Cmpnstn Pre&Slf Ins Prv	84,932.84	845,282.43	845,282.43	0.00	930,215.27
9250007	Prsnal Injries&Prop Dmage-Pub	5,856.71	58,023 26	58,023.26	0.00	63,879.97

Kentucky Power Company
Trial Balance
For The Month Ended AUGUST 31, 2013

Account Number	Description	Pr Yr Ending Balance	Yearly Activity	Debits	Credit	Current Yr Balance
9250010	Frg Ben Loading - Workers Comp	(258,697.32)	54,811.56	54,811 56	0.00	(203,885.76)
9260000	Employee Pensions & Benefits	6,555.47	(3,144.21)	0.00	(3,144.21)	3,411.26
9260001	Edit & Print Empl Pub-Salaries	30,772.78	(23,933.93)	0.00	(23,933 93)	6,838 85
9260002	Pension & Group Ins Admin	31,858 92	(18,524 76)	0.00	(18,524.76)	13,334.16
9260003	Pension Plan	3,244,941.12	(539,663.12)	0.00	(539,663.12)	2,705,278 00
9260004	Group Life Insurance Premiums	141,736.82	(56,460.28)	0.00	(56,460 28)	85,276 54
9260005	Group Medical Ins Premiums	3,990,013.95	(1,402,233.27)	0.00	(1,402,233 27)	2,587,780.68
9260006	Physical Examinations	0.00	27.19	27.19	0.00	27.19
9260007	Group L-T Disability Ins Prem	12,836.00	(3,405.80)	0.00	(3,405 80)	9,430 20
9260009	Group Dental Insurance Prem	229,033.05	(69,788.49)	0.00	(69,788 49)	159,244.56
9260010	Training Administration Exp	(706.43)	1,819.01	1,819.01	0.00	1,112.58
9260012	Employee Activities	4,606.46	(2,565 44)	0 00	(2,565.44)	2,041.02
9260014	Educational Assistance Pmts	12,892.50	(8,131.33)	0 00	(8,131.33)	4,761.17
9260021	Postretirement Benefits - OPEB	1,442,501.04	(2,442,697.12)	0 00	(2,442,697.12)	(1,000,196.08)
9260026	Savings Plan Administration	58 85	(58 85)	0.00	(58.85)	0.00
9260027	Savings Plan Contributions	1,532,945.18	(651,661.20)	0.00	(651,661.20)	881,283.98
9260036	Deferred Compensation	23,453.36	(95,557.62)	0.00	(95,557.62)	(72,104.26)
9260037	Supplemental Pension	721.94	1,874.70	1,874.70	0.00	2,596.64
9260050	Frg Ben Loading - Pension	(1,348,618.06)	307,384.75	307,384.75	0 00	(1,041,233 31)
9260051	Frg Ben Loading - Grp Ins	(1,973,670.28)	694,761.08	694,761.08	0 00	(1,278,909.20)
9260052	Frg Ben Loading - Savings	(616,037.40)	260,354.40	260,354.40	0.00	(355,683.00)
9260053	Frg Ben Loading - OPEB	(875,764 44)	842,637.13	842,637.13	0.00	(33,127.31)
9260055	IntercoFringeOffset- Don't Use	(1,162,602.25)	575,921 38	575,921.38	0.00	(586,680.87)
9260057	Postret Ben Medicare Subsidy	552,426 00	(223,713.36)	0.00	(223,713.36)	328,712.64
9260058	Frg Ben Loading - Accrual	11,900.43	(135,129.32)	0.00	(135,129.32)	(123,228 89)
9260060	Amort-Post Retirement Benefit	0.00	144,413.38	144,413.38	0 00	144,413.38
9270000	Franchise Requirements	145,895.49	(49,815 69)	0.00	(49,815.69)	96,079 80
9280000	Regulatory Commission Exp	(3.47)	1,067.53	1,067.53	0 00	1,064.06
9280001	Regulatory Commission Exp-Adm	(4.34)	10.10	10.10	0.00	5.76
9280002	Regulatory Commission Exp-Case	155,953.95	3,047.21	3,047.21	0.00	159,001.16
9301000	General Advertising Expenses	8,325.13	(7,981.34)	0.00	(7,981.34)	343.79
9301001	Newspaper Advertising Space	13,200 81	6,533.42	6,533.42	0.00	19,734.23
9301002	Radio Station Advertising Time	2,750.00	(2,716 35)	0.00	(2,716 35)	33.65
9301006	Spec Corporate Comm Info Proj	0 28	(0.28)	0.00	(0.28)	0.00
9301010	Publicity	1,277.73	(487.64)	0.00	(487.64)	790.09
9301011	Dedications, Tours, & Openings	0.55	(0.55)	0.00	(0 55)	0.00
9301012	Public Opinion Surveys	2,607.08	(2,557.56)	0 00	(2,557.56)	49.52
9301014	Video Communications	12.80	(5.77)	0 00	(5.77)	7.03
9301015	Other Corporate Comm Exp	40,293.99	(26,816.91)	0 00	(26,816.91)	13,477.08
9302000	Misc General Expenses	166,815.62	(84,620.29)	0.00	(84,620 29)	82,195.33
9302003	Corporate & Fiscal Expenses	20,487.77	(8,407.54)	0.00	(8,407.54)	12,080 23
9302004	Research, Develop&Demonstr Exp	2,997.77	(852.05)	0.00	(852.05)	2,145.72
9302006	Assoc Bus Dev - Materials Sold	39,798.97	23,491.85	23,491.85	0.00	63,290.82
9302007	Assoc Business Development Exp	60,369.77	30,432.80	30,432.80	0.00	90,802.57
9302458	AEPSC Non Affliated expenses	33 57	(32.96)	0.00	(32.96)	0.61
9310000	Rents	19 53	1,343.72	1,343.72	0 00	1,363.25
9310001	Rents - Real Property	95,233 65	(33,599.06)	0.00	(33,599.06)	61,634.59
9310002	Rents - Personal Property	28,854.81	38,817.61	38,817.61	0.00	67,672.42
9350000	Maintenance of General Plant	6.31	(6.31)	0 00	(6.31)	0.00
9350001	Maint of Structures - Owned	520,166.37	(278,299.29)	0 00	(278,299.29)	241,867.08
9350002	Maint of Structures - Leased	62,054.05	(22,892.40)	0.00	(22,892.40)	39,161.65
9350003	Maint of Prprty Held Fture Use	0.00	0.04	0 04	0.00	0.04
9350013	Maint of Cmmcation Eq-Unall	996,200.36	(472,917.88)	0.00	(472,917.88)	523,282.48
9350015	Maint of Office Furniture & Eq	155.10	272,201.71	272,201.71	0.00	272,356.81
9350016	Maintenance of Video Equipment	0.00	653.60	653.60	0 00	653 60
9350019	Maint of Gen Plant-SCADA Equ	0.00	104.05	104.05	0.00	104.05
9350023	Site Communications Services	170 66	(170.66)	0.00	(170 66)	0.00
9350024	Maint of DA-AMI Comm Equip	82.37	2,892.61	2,892.61	0.00	2,974.98
	NET INCOME - EARN FOR CMMN STK	(50,978,453.21)	22,658,727.03	22,658,727.03	0.00	(28,319,726.18)
	PREF STK DIVIDEND REQUIREMENT	0.00	0.00	0.00	0.00	0.00

Kentucky Power Company

REQUEST

Please provide copies of any existing Labor Agreements and any source documents, work papers and underlying data being used in any current or future labor negotiations.

RESPONSE

Please see KPSC 1-49 for copies of existing Labor Agreements. There is no other non-privileged responsive information available.

WITNESS: Andrew R Carlin

Kentucky Power Company

REQUEST

Accounts Receivable. For each year 2010 through 2012, 2013 year-to-date and the test year, provide the monthly accounts receivable balance due from customers.

RESPONSE

Please see AG 1-51 Attachment 1.

WITNESS: Ranie K Wohnhas

Kentucky Power Company
Accounts Receivable - Customer

	2010	2011	2012	2013 YTD	Test Year	
January	16,613,559.53	14,842,901.42	14,725,796.39	10,790,363.75	Jan-13	10,790,363.75
February	20,847,029.96	19,260,937.00	13,272,816.50	14,229,676.98	Feb-13	14,229,676.98
March	15,426,778.12	12,842,014.49	7,738,654.13	14,939,789.51	Mar-13	14,939,789.51
April	12,471,023.83	14,723,418.44	13,445,911.57	12,286,794.46	Apr-12	13,445,911.57
May	15,667,539.60	13,456,670.92	12,389,782.86	9,926,511.96	May-12	12,389,782.86
June	15,336,374.74	13,261,804.34	8,234,975.36	15,459,580.18	Jun-12	8,234,975.36
July	17,532,620.72	23,992,981.47	14,424,477.55	14,239,196.44	Jul-12	14,424,477.55
August	11,923,278.22	13,234,678.03	10,934,070.14	12,805,228.95	Aug-12	10,934,070.14
September	11,032,612.12	8,778,878.71	10,892,774.55		Sep-12	10,892,774.55
October	10,760,762.26	10,975,794.44	11,141,092.41		Oct-12	11,141,092.41
November	14,020,296.93	14,189,373.17	12,441,648.64		Nov-12	12,441,648.64
December	19,408,473.22	12,937,724.89	12,676,052.64		Dec-12	12,676,052.64

Kentucky Power Company

REQUEST

Advertising. Provide the total advertising expense for each year 2010 through 2012, 2013 year-to-date and the test year.

RESPONSE

Advertising expense for the periods requested are as follows:

2010 = $455,426.00 (Includes $243,567 in advertising expense associated with required legal notice for Case No. 2009-00459.)

2011 = $211,207.54

2012 = $209,651.20

2013 YTD = $424,269.36 (Includes $348,764 in advertising expense associated with required legal notice for this case.)

Test Year = $170,955.46

WITNESS: Lila P Munsey

Kentucky Power Company

REQUEST

Questions 53-60 reference General Questions as to Application, Testimony and Proof of Publication

Please provide copies of all source documents, work papers, and other sources used in the development and preparation of the direct testimony of Alex E. Vaughan. Please also include electronic copies (Microsoft Excel) of the Exhibits provided with the Vaughan testimony, leaving all data and formulas intact.

RESPONSE

See KIUC 1-1 Attachments 31 and 32 for the workpapers of Alex E Vaughan.

See AG 1-53 Attachments 1-3 on the enclosed CD for the requested electronic copies of Company witness Vaughan's exhibits.

WITNESS: Alex E Vaughan

Kentucky Power Company

REQUEST

Please confirm that the Virginia State Corporation Commission has denied Appalachian Power Company's application for a fifty percent (50%) undivided interest in the Mitchell Unites. Please advise whether this denial has affected in any way the testimony of Mr. Vaughan, including but not limited to the limitations of the cost of service study as described by Mr. Vaughan at page 3, lines 9-18.

RESPONSE

Confirmed.

No, the Virginia SCC's order dated July 31, 2013 in Docket No. PUE-2012-00141 does not affect Company witness Vaughan's calculations of the Mitchell plant cost of service in this proceeding.

WITNESS: Alex E Vaughan

Kentucky Power Company

REQUEST

Please provide copies of all source documents, work papers, and other sources used in the development and preparation of the direct testimony of Ranie K. Wohnhas. Please also include electronic copies (Microsoft Excel) of the Exhibits provided with the Vaughan testimony, leaving all data and formulas intact.

RESPONSE

See the Company's response to KPSC 2-64, KIUC 1-1, and its supplemental response to KIUC 1-1.

WITNESS: Ranie K Wohnhas

Kentucky Power Company

REQUEST

Please reference the direct testimony of Ranie K. Wohnhas beginning at page 30. Please confirm that the Company voluntarily withdrew its application (Case No. 2011-00401) for environmental cost recovery relating to the proposed retrofit of the Big Sandy Unit 2 with a dry flue gas desulphurization unit ("DFGD") after hearing and the filing of post-hearing briefs in the matter.

RESPONSE

Confirmed.

WITNESS: Ranie K Wohnhas

Kentucky Power Company

REQUEST

Please reference generally the direct testimony of Ranie K. Wohnhas and the Notice of Filing of Proof of Publication by Kentucky Power Company, filed on July 24, 2013. Please answer the questions and provide the information requested below:

a. Please provide copies of all source documents, work papers, and other sources used in the development and preparation of the Tariff P.P.A. and the tables located on pages 17-19 of the Notice of Filing of Proof of Publication. Please include electronic copies (Microsoft Excel) of tables describing the effect of the proposed change in customer rates, leaving all data and formulas intact.

b. Please explain why the Transmission Adjustment proposed by Kentucky Power Company will result in increased rates for the residential class.

c. Please explain why the Transmission Adjustment proposed by Kentucky Power will result in increased rates for the Commercial and Industrial Power Time-of-Day class.

d. Please describe in detail the benefits of the Transmission Adjustment as proposed by Kentucky Power Company.

RESPONSE

a. There are no source documents or workpapers developed for preparation of the proposed Tariff P.P. A.

Please see AG 1-57 Attachment 1 on the enclosed CD for the Microsoft Excel version of the tables located on pages 17-19 of the Notice of Filing of Proof of Publication. These tables include columns that were hidden in the tables printed for the published notice. These columns show how the Company calculated the average customer usage values for the change in billed amount table and the increased revenue amount in the revenue table.

b. While the Transmission Adjustment reduces the overall revenue requirement by $3.79 million, the effect of the adjustment on the residential class is a small increase due to the low relative rate of return of the residential class.

c. The Transmission Adjustment proposed by the Company does not result in increased rates for the CIP-TOD class as can be seen in column 10 of page 1 of Company witness Stegall's Exhibit JMS 3.

d. Benefits of the Company's proposed Transmission Adjustment are:

- A $3.79 million reduction to the overall revenue requirement in this proceeding.
- Customers will pay the actual costs incurred by the Company for providing transmission service in the PJM RTO. Also, if approved in tandem with the Company's proposed PJM Rider, customers will not over or under pay for transmission service.
- Please see page 9, lines 3-17 of Company witness Vaughan's testimony.

WITNESS: Ranie K Wohnhas

Kentucky Power Company

REQUEST

Please reference page 1 of the Notice/Proof detailing the Tariff Changes. Please identify all relevant testimony, studies or data to support the increase in reconnection and disconnect charges as proposed by Kentucky Power Company.

RESPONSE

All of the calculations, assumptions and workpapers used to develop the proposed increase in non-recurring charges are included on pages 30 through 34 of witness Munsey's testimony and Exhibit LPM-5.

WITNESS: Lila P Munsey

Kentucky Power Company

REQUEST

Regarding Home Energy Assistance ("HEA"), please confirm that:

a. The $0.15 per month per meter charge relating to the HEA is charged directly to ratepayers;

b. None of the foregoing total in HEA is derived from shareholder contributions; and

c. Please provide an annual total in HEA for the years 2010 through the present.

RESPONSE

a. Confirmed.

b. Confirmed. By definition the $0.15 per month residential charge is not contributed by the Company's shareholder. The Company's shareholders match each $0.15 per residential meter per month payment with a $0.125 contribution.

c. Payments into the HEA program by residential customers and matching contributions by the Company's shareholder for the period January 2010 through August 2013 totaled:

- Jan. to Dec. 2010: $314,959.49 ($210,962.86 from customer; $103,996.63 from KPCo)
- Jan. to Dec. 2011: $469,066.66 ($255,854.53 from customer; $213,212.13 from KPCo)
- Jan. to Dec. 2012: $465,778.53 ($254,061.00 from customer; $211,717.53 from KPCo)
- Jan. to Aug. 2013: $309,429.42 ($168,779.68 from customer; $140,649.74 from KPCo)

Per Order in Case 2009-00459, the Company matching began in July 2010.

WITNESS: Lila P Munsey

Kentucky Power Company

REQUEST

Please reference Petition at pages 5-6, stating the reasons for Kentucky Power Company's request for a rate increase. Please confirm that the application presumes the Commission's approval of either (a) the Company's application for a fifty percent (50%) undivided interest in the Mitchell Units as filed in the Company's application in Case No. 2012-00578 or (b) the Commission's acceptance of the proposed partial Stipulation and Settlement Agreement in Case No. 2012-00578, to which the Attorney General was not a party.

RESPONSE

The application in this case was filed prior to the execution of the July 2, 2013 Stipulation and Settlement Agreement in Case No. 2012-00578. The application in this case is premised upon the Commission's approval of the December 19, 2012 application in Case No. 2012-00578 and not its approval of the July 2, 2013 Stipulation and Settlement Agreement in Case No. 2012-00578. The Company will withdraw its application in this case if the Commission approves the Stipulation and Settlement Agreement in Case No. 2012-00578 without modification.

WITNESS: Gregory G Pauley