FILE

PUCO EXHIBIT FILING

Date of Hearing: May 14, 2012

Case No. 10-2929-EL-UNC

PUCO Case Caption: Columbus Southern Power and Ohio Power

Volume XI

List of exhibits being filed:

FEU Exhibit 120
FES Exhibit 122
FES Exhibit 123
FES Exhibit 124
FES Exhibit 125
Staff Exhibit 106
Staff Exhibit 107
Staff Exhibit 108
Staff Exhibit 109
RESA Exhibit 103

Reporter's Signature: Julieanna Hennebert
Date Submitted: 5-15-12

BEFORE THE PUBLIC UTILITIES COMMISSION OF OHIO

- - -

In the Matter of the :
Commission Review of the :
Capacity Charges of Ohio : Case No. 10-2929-EL-UNC
Power Company and Columbus:
Southern Power Company. :

- - -

PROCEEDINGS

before Ms. Greta See and Ms. Sarah Parrot, Attorney Examiners, and Commissioner Andre Porter, at the Public Utilities Commission of Ohio, 180 East Broad Street, Room 11-A, Columbus, Ohio, called at 10:00 a.m. on Monday, May 14, 2012.

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VOLUME XI - REBUTTAL TESTIMONY

- - -

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1			2				3			
Fuel Cost ($/MWh)							2011			
Utility	Name	ID	2012	2013	2014	2015	Fuel Cost ($)	Net Generation (MWh)	Fuel Cost ($/MWh)	
Columbus Southern Power Co	AEP Waterford Facility	55503-CTG1	30.53	32.97	34.97	38.81	$ 74,775,639	2,431,293,000	30.76	
Columbus Southern Power Co	AEP Waterford Facility	55503-CTG2	30.55	32.99	35.00	38.80			30.76	
Columbus Southern Power Co	AEP Waterford Facility	55503-CTG3	30.54	32.98	34.99	38.80			30.76	
Columbus Southern Power Co	AEP Waterford Facility	55503-ST1	30.79	32.88	34.85	38.98			30.76	
Columbus Southern Power Co	Conesville	2840-3	26.20	0.00	0.00	0.00	$ 125,465,079	4,442,353,000	28.24	3,5,6
Columbus Southern Power Co	Conesville	2840-4	23.92	24.57	25.59	25.95	$ 41,701,042	1,053,487,000	39.58	
Columbus Southern Power Co	Conesville	2840-5	25.77	26.64	27.55	27.82			28.24	
Columbus Southern Power Co	Conesville	2840-6	26.67	27.44	28.35	28.62			28.24	
Columbus Southern Power Co	Darby Electric Generating Station	55247-GT1	39.11	40.88	45.87	49.21	$ 2,709,080	35,349,000	76.84	
Columbus Southern Power Co	Darby Electric Generating Station	55247-GT2	39.10	40.88	43.93	49.22			76.86	
Columbus Southern Power Co	Darby Electric Generating Station	55247-GT3	39.08	40.83	43.67	49.11			76.86	
Columbus Southern Power Co	Darby Electric Generating Station	55247-GT4	38.93	40.79	43.74	49.13			76.86	
Columbus Southern Power Co	Darby Electric Generating Station	55247-GT5	39.11	40.86	43.95	49.00			76.86	
Columbus Southern Power Co	Darby Electric Generating Station	55247-GT6	38.99	40.67	43.53	49.38			76.86	
Columbus Southern Power Co	Picway	2843-5	35.62	0.00	0.00	0.00	$ 4,306,891	69,375,000	62.08	
Ohio Power Co	General James M Gavin	8102-1	13.26	13.64	14.47	14.83	$ 366,567,061	18,184,347,000	20.16	
Ohio Power Co	General James M Gavin	8102-2	13.02	13.39	14.20	14.55			20.16	
Ohio Power Co	Kammer	3947-1	26.50	26.46	28.25	29.30	$ 63,293,213	1,778,385,000	35.59	
Ohio Power Co	Kammer	3947-2	26.66	26.64	28.44	29.44			35.59	
Ohio Power Co	Kammer	3947-3	26.71	26.67	28.43	29.42			35.59	
Ohio Power Co	Mitchell	3948-1	23.72	24.71	26.10	26.80	$ 235,534,606	9,124,485,000	25.81	
Ohio Power Co	Mitchell	3948-2	23.67	24.67	26.07	26.62			25.81	
Ohio Power Co	Muskingum River	2872-1	24.07	0.00	0.00	0.00	$ 155,858,970	5,891,062,000	26.69	
Ohio Power Co	Muskingum River	2872-2	24.02	0.00	0.00	0.00			26.69	
Ohio Power Co	Muskingum River	2872-3	24.81	31.14	0.00	0.00			26.69	
Ohio Power Co	Muskingum River	2872-4	23.31	0.00	0.00	0.00			26.69	
Ohio Power Co	Muskingum River	2872-5	25.82	28.44	0.00	30.36			26.69	
Ohio Power Co	Racine	6006-1	0.00	0.00	0.00	0.00	$	120,670,000	0.00	
Ohio Power Co	Racine	6006-2	0.00	0.00	0.00	0.00			0.00	
Ohio Power Co	Cardinal	2828-1	14.03	15.01	15.99	16.37	$ 67,798,409	3,359,374,000	20.18	
Ohio Power Co	Cardinal	2828-2	13.85	14.81	15.79	16.16				
Ohio Power Co	Cardinal	2828-3	20.04	17.32	13.78	14.18				
Columbus Southern Power Co	Lawrenceburg Energy Facility	55502-100	30.12	32.51	34.69	38.66				
Columbus Southern Power Co	Lawrenceburg Energy Facility	55502-1200	30.30	32.44	34.70	38.58				
Columbus Southern Power Co	Lawrenceburg Energy Facility	55502-1200	30.30	32.44	34.73	38.54				
Columbus Southern Power Co	Lawrenceburg Energy Facility	55502-200	30.34	32.47	34.63	38.61				
Columbus Southern Power Co	Lawrenceburg Energy Facility	55502-2100	30.08	32.44	34.72	38.58				
Columbus Southern Power Co	Lawrenceburg Energy Facility	55502-2200	30.07	32.45	34.72	38.62				
Columbus Southern Power Co	J M Stuart	2850-1	24.77	24.68	25.78	26.28	$ 306,050,788	10,543,425,000	29.13	
Columbus Southern Power Co	J M Stuart	2850-2	22.95	22.93	23.95	24.77			29.13	
Columbus Southern Power Co	J M Stuart	2850-3	23.71	23.47	24.56	25.34			29.13	
Columbus Southern Power Co	J M Stuart	2850-4	23.36	23.32	24.37	25.16			29.13	
Columbus Southern Power Co	J M Stuart	2850-D1	0.00	48.16	51.85	58.55			29.11	
Columbus Southern Power Co	J M Stuart	2850-D2	0.00	48.16	51.85	58.53			29.11	
Columbus Southern Power Co	J M Stuart	2850-D3	0.00	48.16	51.85	58.53			29.11	
Columbus Southern Power Co	J M Stuart	2850-D4	0.00	48.16	51.85	58.53			29.11	
Columbus Southern Power Co	W H Zimmer	6019 ST1	15.95	16.52	17.06	17.16	$ 44,078,474	1,706,574,000	26.88	
Ohio Power Co	Philip Sporn	3938-2	28.07	29.75	31.80	32.45	$ 17,451,763	416,901,000	41.86	
Ohio Power Co	Philip Sporn	3938-4	28.03	29.70	31.75	32.25			41.86	
Ohio Power Co	Philip Sporn	3938-5	0.00	0.00	0.00	0.00				
Columbus Southern Power Co	Walter C Beckjord	2830-6	26.10	28.06	30.29	31.69	$ 6,645,010	274,275,000	24.23	

	4				5				6	7	8					
	Variance from 2011 Actual				Generation						Excess Margin					
ID	2012	2013	2014	2015	2012	2013	2014	2015	Staff Fuel Cost	Fuel Cost Based on Actual 2011	2012	2013	2014	2015		
55503-CTG1	-0.22	2.22	4.22	8.15												
55503-CTG2	-0.21	2.24	4.25	8.13												
55503-CTG3	-0.22	2.22	4.23	8.14												
55503-ST1	0.03	2.12	4.09	8.22												
2840-3	-2.04	0.00	0.00	0.00	444,031	0	0	0	13,614,383	12,540,780	-906,547	0	0	0	-120,772,498	-12.17744442
2840-4	-15.66	-15.01	-13.99	-13.63	1,376,983	2,571,123	2,312,884	997,474	386,397,438	395,385,082	-21,564,593	-38,664,984	-35,158,161	-13,599,904		
2840-5	-2.47	-1.61	-0.69	-0.43	1,170,893	2,126,457	2,091,505	852,112	348,135,231	376,263,255	-2,893,854	-3,417,199	-1,453,295	-363,676		
2840-6	-1.57	-0.80	0.11	0.34	1,086,426	1,993,266	1,955,637	820,332	262,066,305	164,815,549	-1,673,453	-1,598,078	213,445	107,793		
55247-GT1	-37.75	-35.98	-32.98	-27.65												
55247-GT2	-37.75	-35.98	-32.93	-27.64												
55247-GT3	-37.78	-35.95	-33.19	-27.75												
55247-GT4	-37.94	-36.07	-33.12	-27.74												
55247-GT5	-37.75	-36.00	-32.91	-27.85												
55247-GT6	-37.87	-36.18	-33.33	-27.47												
2843-5	-26.46	0.00	0.00	0.00	11,388	0	0	0	833,191	1,452,005	-618,814	0	0	0		
8102-1	-6.90	-6.52	-5.69	5.34	6,101,568	20,406,813	20,403,928	4,301,187	437,082,374	629,213,669	-42,107,626	-67,821,790	-59,232,914	-32,988,165	-392,199,074	-19.52904471
8102-2	-7.14	-6.76	5.96	5.61	6,101,568	20,406,880	20,406,132	4,304,370	429,256,034	629,323,601	-45,569,823	-70,386,155	-81,970,001	-24,141,804		
3947-1	-9.09	-9.13	-7.34	-6.29	594,899	42,895	59,515	136,335	73,676,210	79,804,843	-5,444,176	-951,508	-487,083	-855,868	-11,773,144	-1.390716617
3947-2	-8.98	-8.96	-7.11	-6.15	294,266	17,795	23,523	58,153	10,700,220	14,013,944	-2,828,989	-159,853	-367,654	-357,717		
3947-3	-8.88	-8.93	-7.16	-6.17	295,066	18,751	26,063	60,902	10,913,289	14,264,055	-2,811,096	-167,004	-386,737	-375,950		
3948-1	-2.10	-1.11	0.29	0.98	0	0	0	0	0	0	0	0	0	0		
3948-2	-2.14	-1.15	0.25	0.80	0	0	0	0	0	0	0	0	0	0		
2872-1	-2.63	0.00	0.00	0.00	728,872	0	0	0	17,416,540	19,318,267	-1,901,727	0	0	0		
2872-2	-2.67	0.00	0.00	0.00	720,718	0	0	0	17,313,760	19,239,556	-1,925,796	0	0	0		
2872-3	-1.88	4.44	0.00	0.00	617,241	56	0	0	15,316,699	16,678,605	-1,362,252	246	0	0		
2872-4	-3.38	0.00	0.00	0.00	827,059	0	0	0	19,274,795	22,078,173	-2,803,377	0	0	0		
2872-5	-0.87	1.74	0.00	3.67	2,170,555	33,003	0	371,106	47,487,617	48,396,212	-1,891,812	22,684	0	1,361,532		
6006-1	0.00	0.00	0.00	0.00	9,544	17,504	17,504	7,840	0	0	0	0	0	0		
6006-2	0.00	0.00	0.00	0.00	9,544	17,504	17,504	7,960	0	0	0	0	0	0		
2828-1	-6.15	-5.18	-4.19	-3.81	2,680,992	4,572,720	4,572,720	1,891,519	230,336,405	276,853,743	-36,485,067	-23,671,001	-19,354,689	-7,206,542	-46,517,332	-6.704163752
2828-2	13.85	14.81	15.79	16.16	0	0	0	0	0	0	0	0	0	0		
2828-3	20.04	17.32	13.78	14.18	0	0	0	0	0	0	0	0	0	0		
55502-100	30.12	32.51	34.69	38.65												
55502-1200	30.30	32.44	34.70	38.58												
55502-1200	30.30	32.44	34.73	38.54												
55502-200	30.34	32.47	34.63	38.61												
55502-2100	30.08	32.44	34.72	38.58												
55502-2200	30.07	32.45	34.72	38.62												
2850-1	-4.31	-4.47	-3.43	-2.84	490,148	905,398	917,452	360,134	67,604,496	78,390,341	-2,173,815	-4,049,587	-3,588,060	-1,024,405		
2850-2	-6.15	-6.18	-5.16	-4.34	607,974	1,125,612	1,087,054	438,699	76,663,344	94,464,965	-3,742,340	-6,954,804	-5,605,159	1,904,518		
2850-3	-5.40	-5.65	-4.58	-3.77	580,822	1,121,479	1,085,715	431,685	77,448,285	93,715,456	-3,135,566	-6,317,538	-4,948,387	-1,627,892		
2850-4	-5.75	-5.79	-4.73	-3.95	580,286	1,103,652	1,059,558	428,818	78,079,018	92,348,430	-3,392,429	-6,391,858	-5,015,514	-1,684,790		
2850-D1	0.00	19.06	22.75	29.42	0	71	12	0	4,099	2,435	0	1,361	269	0		
2850-D2	0.00	19.05	22.75	29.42	0	73	11	0	4,108	2,454	0	1,386	269	0		
2850-D3	0.00	19.05	22.75	29.42	0	72	12	0	4,076	2,437	0	1,372	266	0		
2850-D4	0.00	19.05	22.75	29.42	0	72	12	0	4,064	2,424	0	1,367	263	0		
6019 ST1	-10.93	-10.36	-9.82	-9.62	1,575,807	2,580,160	2,542,364	1,066,146	128,904,365	207,646,355	-36,668,636	-76,841,858	-24,877,020	10,254,678	-78,743,992	-7.838264571
3938-2	-13.79	-12.11	-10.06	-9.45	555,947	54,890	61,749	65,216	15,701,545	22,512,734	-4,909,346	-664,687	-421,356	-416,085		
3938-4	-13.83	-12.16	-10.11	-9.61	362,151	60,607	66,130	71,310	16,543,991	23,700,610	-5,009,769	757,162	-468,538	-748,251		
3938-5	0.00	0.00	0.00	0.00							0	0	0	0		
2830-6	1.87	3.84	6.06	7.46	215,745	1,942	2,670	20,716	1,947,835	3,526,928	216,178	7,450	46,514	150,865		
											168,962,332	258,198,099	-212,828,268	-85,906,065	-755,989,752	
					29,860,815	99,172,624	90,834,213	36,886,375	2,250,168,102	3,004,175,854						
											-97.45078381	-79.06997587	-67.40433956	-62.78713967	-76.19465705	

EXHIBIT
PENGAD 800-631-6989
120
IEU

EXHIBIT
122
FES
PENGAD 800-631-6989

FES Exhibit

SCENARIO 1 - Expanded to 2012

Estimate of Ohio Power's Earnings

	Ohio Power Company					
	2012			2013		
	$ millions	$ millions	ROE	$ millions	$ millions	ROE
Projected Earnings (Two Tiered Capacity Pricing)		471	10.4%		331	7.3%
Estimate of February 23, 2012 Ruling:						
Additional Switching net of OSS Margins and Capacity Revenues	(194)			(341)		
Income Taxes	68			119		
Total Adjustment (after-Tax)		(126)			(222)	
Projected Earnings (all capacity at RPM)		344	7.6%		109	2.4%
Remove RPM Capacity Revenue	(33)			(70)		
Add Capacity Revenue @ 356/MW-day	362			753		
Income Taxes	(115)			(239)		
Total adjustment (after-Tax)		214			444	
Projected Earnings (all capacity $356/MW-day)		558	12.3%		553	12.2%

	Jun-12	Jul-12	Aug-12	Sep-12	Oct-12	Nov-12	Dec-12	Jan-13	Feb-13	Mar-13	Apr-13	May-13
SSO Load												
Residential	772.1985	927.821219	838.78327	539.1603	402.8905	422.5136	519.9165	609.6103563	471.8794	453.2185	322.8148	316.7792
Commercial	538.939394	510.362723	462.306141	354.4214	342.2867	275.7136	249.6512	246.2517149	215.4163	242.9087	223.3882	249.0182
Industrial	952.108234	858.044057	812.221178	690.4179	673.5716	582.0137	486.3531	458.2230077	465.2248	485.6865	479.7053	498.4513
	2263.24613	2296.228	2113.31059	1584	1418.749	1280.241	1255.921	1314.085079	1152.521	1181.814	1025.908	1064.249
OAD Load												
Residential	338.878478	526.444014	604.905663	489.7716	459.83	608.0074	952.9348	1132.133519	876.3475	841.6916	599.5133	588.3042
Commercial	749.871954	822.188604	865.530356	776.3928	882.0125	850.7903	941.3533	941.918984	826.4688	931.6826	856.1431	961.7507
Industrial	664.032246	723.892987	824.71672	845.8604	1001.805	1055.432	1080.758	1079.240934	1092.514	1149.389	1129.557	1172.551
	1752.78268	2072.52561	2295.15274	2112.025	2343.648	2514.229	2975.046	3153.293437	2795.33	2922.763	2585.214	2722.606
Total Load	4016.02881	4368.7536	4408.46333	3696.024	3762.397	3794.47	4230.967	4467.378515	3947.85	4104.577	3611.122	3786.855
SSO Rates												
Residential	23.82	23.82	23.82	23.82	23.82	23.82	23.82	23.82	23.82	23.82	23.82	23.82
Commercial	28.10	28.10	28.10	28.10	28.10	28.10	28.10	28.10	28.10	28.10	28.10	28.10
Industrial	18.25	18.25	18.25	18.25	18.25	18.25	18.25	18.25	18.25	18.25	18.25	18.25
Capacity Rates @ 356/MW-day												
Residential	30.01	30.01	30.01	30.01	30.01	30.01	30.01	30.01	30.01	30.01	30.01	30.01
Commercial	23.01	23.01	23.01	23.01	23.01	23.01	23.01	23.01	23.01	23.01	23.01	23.01
Industrial	17.29	17.29	17.29	17.29	17.29	17.29	17.29	17.29	17.29	17.29	17.29	17.29
SSO Revenues												
Residential	$ 26,466	$ 34,641	$ 34,389	$ 24,509	$ 20,550	$ 24,547	$ 35,083	$ 41,488	$ 32,115	$ 30,845	$ 21,970	$ 21,559
Commercial	$ 36,216	$ 37,445	$ 37,312	$ 31,776	$ 34,403	$ 31,655	$ 33,467	$ 33,388	$ 29,277	$ 33,006	$ 30,335	$ 34,023
Industrial	$ 29,495	$ 28,870	$ 29,874	$ 28,037	$ 30,576	$ 29,883	$ 28,600	$ 28,059	$ 28,429	$ 29,840	$ 29,369	$ 30,496
Total	$ 92,176	$ 100,956	$ 101,575	$ 84,322	$ 85,528	$ 86,085	$ 97,150	$ 102,935	$ 89,820	$ 93,691	$ 81,674	$ 86,077
Capacity Revenues												
Residential	$ 33,343	$ 43,642	$ 43,325	$ 30,878	$ 25,890	$ 30,926	$ 44,200	$ 52,270	$ 40,460	$ 38,860	$ 27,679	$ 27,162
Commercial	$ 29,656	$ 30,662	$ 30,554	$ 26,020	$ 28,171	$ 25,921	$ 27,405	$ 27,340	$ 23,974	$ 27,027	$ 24,840	$ 27,860
Industrial	$ 27,943	$ 27,352	$ 28,303	$ 26,562	$ 28,967	$ 28,311	$ 27,095	$ 26,583	$ 26,933	$ 28,270	$ 27,824	$ 28,892
Total	$ 90,942	$ 101,656	$ 102,181	$ 83,461	$ 83,029	$ 85,158	$ 98,701	$ 106,192	$ 91,367	$ 94,158	$ 80,343	$ 83,913

	PY12/13
SSO Revenues	$ 1,101,990
Capacity Revenues	$ 1,101,101

Summary of Long-Term Commodity Price Forecast Scenarios

(Source: AEP Fundamental Analysis)
Annual Average (Nominal Dollars)

NATURAL GAS (Henry Hub) ($/MMBtu)

	'BASE' Fleet Transition: CSAPR (Carbon in 2022)	Alternative Scenarios: FT-CSAPR: HIGHER Band (Carbon in 2022)	FT-CSAPR: LOWER Band (Carbon in 2022)	FT-CSAPR: Early Carbon (Carbon in 2017)	FT-CSAPR: No Carbon
2012	4.48	4.48	3.94	4.48	4.48
2013	4.94	5.43	4.35	4.94	4.94
2014	5.38	6.02	4.73	5.38	5.38
2015	5.52	6.29	4.86	5.52	5.52
2016	5.99	6.94	5.27	5.99	5.99
2017	6.13	7.23	5.39	6.42	6.13
2018	6.32	7.46	5.56	6.60	6.32
2019	6.46	7.62	5.68	6.73	6.46
2020	6.52	7.69	5.73	6.78	6.52
2021	6.75	7.97	5.94	7.06	6.60
2022	7.07	8.34	6.22	7.22	6.68
2023	7.26	8.57	6.39	7.35	6.86
2024	7.51	8.86	6.61	7.51	7.10
2025	7.75	9.14	6.82	7.75	7.32
2026	7.85	9.26	6.91	7.85	7.42
2027	8.04	9.49	7.08	8.04	7.60
2028	8.22	9.78	7.23	8.22	7.77
2029	8.41	10.08	7.40	8.41	7.94
2030	8.52	10.48	7.50	8.52	8.05

CO2 ($/Metric Tonne)

	'BASE' Fleet Transition: CSAPR (Carbon in 2022)	Alternative Scenarios: FT-CSAPR: HIGHER Band (Carbon in 2022)	FT-CSAPR: LOWER Band (Carbon in 2022)	FT-CSAPR: Early Carbon (Carbon in 2017)	FT-CSAPR: No Carbon
2012	0.00	0.00	0.00	0.00	0.00
2013	0.00	0.00	0.00	0.00	0.00
2014	0.00	0.00	0.00	0.00	0.00
2015	0.00	0.00	0.00	0.00	0.00
2016	0.00	0.00	0.00	0.00	0.00
2017	0.00	0.00	0.00	15.08	0.00
2018	0.00	0.00	0.00	15.28	0.00
2019	0.00	0.00	0.00	15.47	0.00
2020	0.00	0.00	0.00	15.68	0.00
2021	0.00	0.00	0.00	15.88	0.00
2022	15.08	15.48	15.48	16.08	0.00
2023	15.28	15.67	15.67	16.29	0.00
2024	15.48	15.88	15.88	16.50	0.00
2025	15.67	16.08	16.08	16.72	0.00
2026	15.88	16.29	16.29	16.94	0.00
2027	16.08	16.50	16.50	17.16	0.00
2028	16.29	16.72	16.72	17.38	0.00
2029	16.50	16.94	16.94	17.60	0.00
2030	16.72	17.12	17.16	17.84	0.00

NAPP (6.0#) ($/Ton-FOB Mine)

	'BASE' Fleet Transition: CSAPR (Carbon in 2022)	Alternative Scenarios: FT-CSAPR: HIGHER Band (Carbon in 2022)	FT-CSAPR: LOWER Band (Carbon in 2022)	FT-CSAPR: Early Carbon (Carbon in 2017)	FT-CSAPR: No Carbon
2012	56.75	64.13	53.91	56.75	56.75
2013	58.00	66.70	53.36	58.00	58.00
2014	60.00	69.00	53.40	60.00	60.00
2015	62.36	72.34	55.50	62.36	62.36
2016	64.72	75.08	57.60	64.72	64.72
2017	65.92	76.47	58.67	64.00	65.92
2018	67.18	77.93	59.79	65.22	67.18
2019	68.45	79.40	60.92	66.46	68.45
2020	69.71	80.87	62.05	67.68	69.71
2021	71.18	82.57	63.35	69.10	71.18
2022	70.90	82.24	63.10	70.55	72.67
2023	72.37	83.95	64.41	72.02	74.18
2024	73.87	85.69	65.74	73.51	75.71
2025	75.38	87.44	67.09	75.01	77.26
2026	76.91	89.22	68.45	76.54	78.84
2027	78.46	91.02	69.83	78.08	80.43
2028	80.04	92.85	71.24	79.65	82.04
2029	81.65	94.71	72.66	81.25	83.69
2030	83.27	96.60	74.11	82.87	85.36

CAPP (1.6#) ($/Ton-FOB Mine)

	'BASE' Fleet Transition: CSAPR (Carbon in 2022)	Alternative Scenarios: FT-CSAPR: HIGHER Band (Carbon in 2022)	FT-CSAPR: LOWER Band (Carbon in 2022)	FT-CSAPR: Early Carbon (Carbon in 2017)	FT-CSAPR: No Carbon
2012	79.97	91.46	75.97	79.97	79.97
2013	83.46	97.95	75.11	83.46	83.46
2014	84.83	101.44	74.65	84.83	84.83
2015	85.21	102.25	74.98	85.21	85.21
2016	85.52	102.62	75.26	85.52	85.52
2017	85.31	102.37	75.07	82.83	85.31
2018	86.94	104.33	76.51	84.41	86.94
2019	88.58	106.30	77.95	86.00	88.58
2020	90.22	108.76	79.39	87.59	90.22
2021	92.07	110.48	81.02	89.38	92.07
2022	91.66	109.99	80.66	91.21	93.95
2023	93.52	112.22	82.30	93.07	95.86
2024	95.41	114.49	83.96	94.94	97.79
2025	97.31	116.77	85.63	96.84	99.74
2026	99.24	119.09	87.33	98.76	101.72
2027	101.19	121.43	89.05	100.70	103.72
2028	103.18	123.81	90.80	102.68	105.76
2029	105.19	126.23	92.57	104.68	107.82
2030	107.24	128.69	94.37	106.72	109.92

ON-Peak Energy (PJM-AEP Gen Hub) ($/Mwh)

	'BASE' Fleet Transition: CSAPR (Carbon in 2022)	Alternative Scenarios: FT-CSAPR: HIGHER Band (Carbon in 2022)	FT-CSAPR: LOWER Band (Carbon in 2022)	FT-CSAPR: Early Carbon (Carbon in 2017)	FT-CSAPR: No Carbon
2012	50.57	55.16	47.59	49.73	50.30
2013	50.14	55.48	44.98	48.59	47.85
2014	54.24	62.03	49.26	54.28	54.45
2015	56.71	65.49	53.60	56.42	56.79
2016	63.56	71.80	58.75	62.42	63.74
2017	63.48	71.72	59.20	71.84	64.41
2018	64.18	73.15	60.06	72.73	65.25
2019	65.44	74.08	60.90	73.21	66.31
2020	66.33	75.16	60.86	73.82	66.55
2021	67.64	77.00	62.38	75.75	67.28
2022	76.79	85.88	72.64	77.34	68.31
2023	78.33	87.97	74.25	78.43	70.32
2024	80.34	89.78	74.99	79.55	71.04
2025	82.18	92.27	76.25	81.48	73.07
2026	83.23	93.67	77.71	82.70	73.94
2027	84.57	95.54	79.22	84.24	75.28
2028	86.25	98.14	80.55	86.25	76.51
2029	87.64	100.30	81.53	87.32	77.70
2030	89.34	103.70	82.78	88.75	78.95

OFF-Peak Energy (PJM-AEP Gen Hub) ($/Mwh)

	'BASE' Fleet Transition: CSAPR (Carbon in 2022)	Alternative Scenarios: FT-CSAPR: HIGHER Band (Carbon in 2022)	FT-CSAPR: LOWER Band (Carbon in 2022)	FT-CSAPR: Early Carbon (Carbon in 2017)	FT-CSAPR: No Carbon
2012	30.92	33.66	29.07	30.33	30.27
2013	30.55	35.01	28.55	30.15	29.97
2014	33.26	38.84	31.15	32.95	33.34
2015	33.89	40.47	32.16	33.73	34.34
2016	39.57	45.94	36.16	38.65	40.12
2017	41.57	48.09	38.59	51.00	41.67
2018	42.57	49.48	39.25	52.03	42.70
2019	43.60	50.18	40.01	52.82	43.47
2020	44.18	51.40	40.52	53.54	44.35
2021	45.76	53.01	41.76	55.14	45.22
2022	55.93	63.44	52.41	56.56	46.22
2023	56.84	65.25	53.42	57.35	47.67
2024	58.85	66.65	54.17	58.69	48.94
2025	60.37	68.79	55.93	60.38	50.72
2026	61.06	70.11	56.67	61.28	51.59
2027	62.64	72.07	58.15	62.85	53.19
2028	64.05	74.08	59.05	64.56	54.40
2029	65.66	76.20	60.20	65.80	55.78
2030	67.49	78.87	61.12	66.82	56.65

Capacity Value (PJM-RTO RPM) ($/MW-Day)

	'BASE' Fleet Transition: CSAPR (Carbon in 2022)	Alternative Scenarios: FT-CSAPR: HIGHER Band (Carbon in 2022)	FT-CSAPR: LOWER Band (Carbon in 2022)	FT-CSAPR: Early Carbon (Carbon in 2017)	FT-CSAPR: No Carbon
2012	16.46	16.46	16.46	16.46	16.46 *
2013	27.73	27.73	27.73	27.73	27.73 *
2014	126.00	126.00	126.00	126.00	126.00 *
2015	215.25	215.25	215.25	215.25	215.25
2016	281.92	281.92	281.92	281.92	281.92
2017	235.98	199.63	230.85	210.98	240.98
2018	200.39	166.43	179.76	180.39	205.39
2019	224.57	211.40	186.64	214.57	230.57
2020	253.47	253.86	212.57	243.47	261.47
2021	280.05	293.65	238.70	265.05	295.05
2022	304.18	330.64	264.71	289.18	322.18
2023	325.73	364.68	288.14	310.73	345.73
2024	344.58	391.96	308.40	329.58	364.58
2025	360.58	405.21	325.58	345.58	380.58
2026	373.61	411.28	340.04	358.61	394.61
2027	383.50	417.45	350.60	363.50	405.50
2028	390.13	423.72	358.23	370.13	413.13
2029	392.94	430.07	362.96	372.94	416.94
2030	392.16	436.27	361.29	372.16	418.16

* Represents PJM-RTO (i.e. "western" or "rest-of-market" PJM) Base Residual Auction UCAP clearing prices for those respective XXXX/(XXXX+1) forward PJM Planning Years

Estimate of Ohio Power's Earnings

	Ohio Power Company					
	2012			2013		
	$ millions	$ millions	ROE	$ millions	$ millions	ROE
Projected Earnings Before February Order		513	11.3%		494	10.9%
Estimate of February 23, 2012 ESP Ruling (excl Capacity):						
Reduction in G Rate	(53)			(63)		
Shopping @ 36% in 2013 - Retail	-			(120)		
Shopping @ 36% in 2013 - Capacity	-			(16)	28.55172	
Shopping @ 36% in 2013 - OSS	-			11		
MTR (loss of market transition rider)	(20)			-		
DIR (loss of distribution investment rider)	(72)			(104)		
EICCR (environmental rider)	19			13		
Reinstate Carrying Cost on Deferred Fuel	25			27		
Reversal of Ohio Growth Fund	35			-		
sub-total	(65)			(252)		
Income Taxes	23			88		
Total adjustment (after-Tax)		(42)			(163)	
Projected Earnings Excluding Capacity		471	10.4%		331	7.3%
Projected Earnings (Two Tiered Capacity Pricing)		471	10.4%		331	7.3%
Estimate of February 23, 2012 Ruling:						
Additional Switching net of OSS Margins and Capacity Revenues	(194)			(341)		
Income Taxes	68			119		
Total adjustment (after-Tax)		(126)			(222)	
Projected Earnings (all capacity at RPM)		344	7.6%		109	2.4%

EXHIBIT
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106
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SNL Forward Power numbers for 12/29/11 and one week later 1/5/12.

Forward Power Prices - On Peak

Region: PJM

	As of: 12/29/2011	*As of: 1/5/2012*	
Term	***AEP-DAYTON HUB***	***AEP-DAYTON HUB***	***Change***
Dec-11	36.07		
Jan-12	40.33	36.73	-9%
Feb-12	40.33	38.05	-6%
Mar-12	37.73	35.63	-6%
Apr-12	37.73	35.63	-6%
May-12	37.65	36.50	-3%
Jun-12	40.98	38.56	-6%
Jul-12	47.47	44.14	-7%
Aug-12	47.47	44.14	-7%
Sep-12	38.85	37.45	-4%
Oct-12	38.09	36.50	-4%
Nov-12	38.09	36.50	-4%
Dec-12	38.09	36.50	-4%
Jan-13	43.18	40.80	-6%
Feb-13	43.18	40.80	-6%
Mar-13	43.18	40.80	-6%
Apr-13	43.18	40.80	-6%
May-13	43.18	40.80	-6%
Jun-13	43.18	40.80	-6%
Jul-13	43.18	40.80	-6%
Aug-13	43.18	40.80	-6%
Sep-13	43.18	40.80	-6%
Oct-13	43.18	40.80	-6%
Nov-13	43.18	40.80	-6%
Dec-13	43.18	40.80	-6%
Jan-14	46.13	43.63	-5%
Feb-14	46.13	43.63	-5%
Mar-14	46.13	43.63	-5%
Apr-14	46.13	43.63	-5%
May-14	46.13	43.63	-5%
Jun-14	46.13	43.63	-5%
Jul-14	46.13	43.63	-5%
Aug-14	46.13	43.63	-5%
Sep-14	46.13	43.63	-5%
Oct-14	46.13	43.63	-5%
Nov-14	46.13	43.63	-5%
Dec-14	46.13	43.63	-5%

EXHIBIT

107

Staff

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December 5, 2011

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PUBLIC SERVICE COMMISSION

Jeff R. Derouen
Executive Director
Public Service Commission
211 Sower Boulevard
P.O. Box 615
Frankfort, KY 40602-0615

RE: Case No. 2011-00401

Dear Mr. Derouen:

Enclosed please find and accept for filing the original and ten copies of Kentucky Power Company's Application in this matter. Also enclosed for filing are the original and ten copies of the Company's motion for an informal conference.

Copies of the Application and motion also are being served today on counsel for Kentucky Industrial Utility Customers, Inc. and the Attorney General along with a copy of this letter.

Please do not hesitate to contact me if you have any questions.

Very truly yours,

STITES & HARBISON, PLLC

Mark R. Overstreet

MRO

cc: Michael L. Kurtz
Jennifer Black Hans
Dennis G. Howard II
Lawrence W. Cook

COMMONWEALTH OF KENTUCKY

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DEC 05 2011

PUBLIC SERVICE COMMISSION

BEFORE THE PUBLIC SERVICE COMMISSION

In The Matter Of:

APPLICATION OF KENTUCKY POWER COMPANY FOR APPROVAL OF ITS 2011 ENVIRONMENTAL COMPLIANCE PLAN, FOR APPROVAL OF ITS AMENDED ENVIRONMENTAL COST RECOVERY SURCHARGE TARIFF, AND FOR THE GRANT OF A CERTIFICATE OF PUBLIC CONVENIENCE AND NECESSITY FOR THE CONSTRUCTION AND ACQUISITION OF RELATED FACILITIES	)	CASE NO. 2011-00401

APPLICATION

Kentucky Power Company ("Kentucky Power," "Company," or "KPCo") applies to the Public Service Commission of Kentucky ("Commission") pursuant to KRS 278.020(1), KRS 278.183, and 807 KAR 5:001, Sections 8, 9, and 11, and all other applicable provisions for an order: (a) approving its 2011 Environmental Compliance Plan; (b) approving its amended Environmental Surcharge Tariff (Tariff E.S.); and (c) granting it a Certificate of Public Convenience and Necessity for construction and acquisition of certain facilities associated with the 2011 Environmental Compliance Plan. Approval of the 2011 Environmental Compliance Plan, amended Tariff E.S., and the related Certificate of Public Convenience and Necessity will enable Kentucky Power to comply with environmental requirements for coal-fired electric generating facilities imposed by "the Clean Air Act, as amended, and those federal, state, or local environmental requirements which apply to coal combustion wastes and by-products from facilities utilized for production of energy from coal...." KRS 278.183(1) ("Environmental Requirements.")

Supplemental Information to Support the KPCo Planning Process and Issues Represented in this CPCN Application

I. BACKGROUND AND GOVERNANCE

A. Overview of the interrelationship between KPCo and AEP for purposes of capacity resource planning

The total AEP System includes eleven utility operating companies, operating in eleven states, with generation and transmission assets in, primarily, two different Regional Transmission Organization (RTO) planning and operational regions. Those RTOs are the PJM Interconnection, L.L.C. ("PJM"), in AEP's eastern zone, and the Southwest Power Pool (SPP) in its western zone. KPCo is a wholly-owned subsidiary of AEP—serving retail customers in eastern Kentucky—and is located in its eastern or PJM zone. In addition to KPCo, the AEP Operating Companies comprising this eastern zone (collectively, "AEP-East") consist of:

- Appalachian Power Company (APCo), serving large portion of West Virginia, and western Virginia;
- Columbus Southern Power Company (CSP), serving portions of central and southern Ohio;
- Indiana Michigan Power Company (I&M), serving portions of northern and eastern Indiana and southwestern Michigan; and
- Ohio Power Company (OPCo), serving portions of Ohio.[1]

In addition, two additional Operating Companies residing in this eastern zone, Kingsport Power Company (KgP) and Wheeling Power Company (WPCo) represent non-generating affiliates.

AEP-East collectively serves about 3.6 million customers in an approximate 90,000 square-mile area of Virginia, West Virginia, Ohio, Indiana, Michigan, Kentucky and Tennessee.

B. AEP Pool: planning responsibilities and obligations

The projected capacity resource needs for KPCo are currently established in concert with that of AEP-East under the auspices of the previously mentioned AEP Interconnection Agreement ("AEP Pool"), which was established "(f)or the purposes of obtaining the most

[1] CSP and OPCo have filed with the Public Utility Commission of Ohio to seek to legally merge the two companies effective January 1, 2012. A decision on that proposed merger has yet to be rendered.

Supplemental Information to Support the KPCo Planning Process and Issues Represented in this CPCN Application

efficient coordinated expansion and operation of their electric power supply facilities…"[2]. This includes the coordinated and integrated determination of load and (peak) demand obligations for KPCo and each of the other Member Companies defined in that agreement (APCo, CSP, I&M, and OPCo). Further, under Article 5.7.1 of the AEP Pool, KPCo and the other Member Companies are obligated to "…rectify or alleviate" any relative (Member Primary) capacity deficits of an extended nature so as to maintain an "equalization" over time.

As such, the going-forward capacity obligations of KPCo have been to, minimally, maintain its resource contribution to meet both the needs of its own native customers, as well as its share of the AEP-East requirements.

1. **Historical fulfillment of KPCo's capacity obligation within the AEP Pool**

   As summarized above, under the AEP Pool the collective resources of each of the AEP Member Companies have historically been considered when determining such capacity positions. As a contributor to that process, KPCo has typically operated in a deficit capacity position vis-à-vis the other AEP Member Companies. Therefore, it has incurred "capacity settlement" payments to those Member Companies that are surplus. As also indicated, this "backstop" arrangement has been utilized over the decades to attempt to ensure reasonable economies for the collective resource needs of the AEP System.

2. **Discussion of potential change to this AEP Pool**

   KPCo and its affiliate AEP Pool Member Companies served notice to each other and the Pool's Agent, AEPSC, on December 17, 2010, of the collective intent to terminate the AEP Pool effective January 1, 2014. This is a revocable notice of termination and that resolution discussions among stakeholders will be forthcoming. At this time, however, the ultimate outcome of that process is not known. Of course not knowing that ultimate outcome, from a planning perspective it further emphasizes the criticality of any future decisions surrounding the make-up of KPCo's "native" resource profile.

[2] Article 4.1 of the AEP Interconnection Agreement.

Supplemental Information to Support the KPCo Planning Process and Issues Represented in this CPCN Application

II. RESOURCE NEED

A. Description of KPCo's customer base

KPCo's customer base consists of both retail and sales-for-resale customers located in eastern Kentucky. Approximately 173,000 residential, commercial, industrial and other retail, end-use customers are served by the Company. These KPCo retail customers represent nearly 99 percent of I&M's energy sales in 2010, with the balance coming from sales to the Cities of Vanceburg and Olive Hill, for which KPCo provides wholesale service for ultimate distribution and resale to their end-use customers.

B. Overview of KPCo's peak demand requirements

To ensure the continuation of reliable service, the peak demand of its customer base represents one of the primary underpinnings of any capacity resource plan. The peak load requirement of all KPCo retail and sales for resale wholesale customers is seasonal in nature, with distinctive peaks occurring in both the summer and the winter seasons. Historically, KPCo's peak demand has been recorded in the winter season, with the all-time winter peak being 1,808 MW, which occurred on February 6, 2007. Contrastingly, the highest recorded summer peak was 1,388 MW, which occurred on August 2, 2006.

The following **Table 1-1** offers the latest AEP Economic Forecasting projection of KPCo and AEP-East (summer) peak demand and internal load. Over the next 10 year period (through 2020) KPCo's summer demand is anticipated to increase by a compound annual growth rate of 0.59 percent, or by a total of 66 MW; relative results which are slightly lower than those of AEP-East for the same period.

Supplemental Information to Support the KPCo Planning Process and Issues Represented in this CPCN Application

Table 1-1

Projected (Summer) Peak Demand and Internal Load
KPCo and AEP-East
(Sep-2011 Fcst)

Year	Peak Demand (MW) KPCo	Peak Demand (MW) AEP-East*	Year	Internal Load (GWh) KPCo	Internal Load (GWh) AEP-East*
2011	**1,221**	20,698	2011	**7,667**	125,470
2012	**1,238**	21,075	2012	**7,729**	127,318
2013	**1,239**	21,351	2013	**7,727**	128,689
2014	**1,243**	21,515	2014	**7,752**	129,445
2015	**1,247**	21,644	2015	**7,772**	129,976
2016	**1,252**	21,711	2016	**7,806**	130,552
2017	**1,256**	21,853	2017	**7,842**	131,173
2018	**1,271**	22,006	2018	**7,883**	131,944
2019	**1,281**	22,163	2019	**7,926**	132,798
2020	**1,287**	22,273	2020	**7,967**	133,593
2021	**1,299**	22,500	2021	**8,013**	134,489
2022	**1,309**	22,672	2022	**8,062**	135,372
2023	**1,313**	22,815	2023	**8,113**	136,258
2024	**1,320**	22,944	2024	**8,168**	137,223
2025	**1,333**	23,186	2025	**8,216**	138,146
2026	**1,344**	23,374	2026	**8,267**	139,105
2027	**1,354**	23,569	2027	**8,319**	140,108
2028	**1,362**	23,721	2028	**8,373**	141,157
2029	**1,369**	23,933	2029	**8,419**	142,128
2030	**1,379**	24,135	2030	**8,470**	143,160

10-Year (2011-2020):	KPCo	AEP-East*	10-Year (2011-2020):	KPCo	AEP-East*
Total Growth	**66**	1,575	Total Growth	**301**	8,123
Compound Annual Growth Rate	**0.59%**	0.82%	Compound Annual Growth Rate	**0.43%**	0.70%

20-Year (2011-2030):	KPCo	AEP-East*	2011-2030:	KPCo	AEP-East*
Total Growth	**157**	3,437	Total Growth	**803**	17,690
Compound Annual Growth Rate	**0.64%**	0.81%	Compound Annual Growth Rate	**0.53%**	0.70%

* AEP-East includes Ohio-Wires customers

C. PJM Reserve Margin Criteria

It is assumed that the underlying minimum reserve margin criteria to be utilized in the determination of AEP-East and, ultimately, KPCo capacity needs assessment is the current PJM board-approved Installed Reserve Margin (IRM) level of 15.3 percent.[3]

[3] As established by PJM for the 2014/15 Reliability Pricing Model (RPM) Base Residual Auction as well as for "non-auction" Fixed Resource Requirement (FRR) entities such as AEP. For purpose of the modeling exercise to be discussed throughout this testimony, it is assumed this 15.3% IRM level would remain constant going-forward.

Supplemental Information to Support the KPCo Planning Process and Issues Represented in this CPCN Application

D. KPCo and AEP obligation to provide reserve margin in PJM

On October 1, 2004, AEP transferred functional control of its transmission facilities as well as its generation dispatch, including the transmission and generation facilities owned by its operating companies, including KPCo, to PJM. With that, the PJM Reliability Assurance Agreement (RAA) defines the requirements surrounding various reliability criteria, including measuring and ensuring capacity adequacy. In that regard, each Load Serving Entity (LSE) in PJM is required to provide an amount of capacity resources determined by PJM based on several factors, including PJM's IRM requirement. This requirement is itself based on the amount of resources needed to maintain, among other things, a loss-of-load expectation of one day in ten years. Additionally, load diversity among the LSEs and PJM, and generating asset-assumed equivalent forced outage rates (EFOR) represent other factors impacting such required minimum reserve levels.

Further, beginning in 2007—for the initial 2010/11 "Planning Year"—through today—for the most recent 2014/15 Planning Year—AEPSC, as agent for its AEP-East LSEs, including KPCo, has given annual notice of its intent to elect to opt-out of the PJM Reliability Pricing Model (RPM) three-year forward capacity auction and, instead, meet its capacity resource obligation through participation in the optional, FERC-authorized Fixed Resource Requirement (FRR) construct. FRR requires AEP and KPCo to set forth its future capacity resource profile and position under, essentially, a "self-planning" format that is predicated upon ensuring the stand-alone achievement of its future customer peak demand *plus* IRM requirements.

It continues to be AEP's position that the interests of its LSEs and, ultimately, those operating company customers are better preserved under that FRR framework. While AEPSC reserves the future option of electing to participate in the RPM forward auction process, it believes that the AEP LSE's customers, including KPCo's, are economically advantaged in that they are subject to lesser levels of (capacity) pricing uncertainty by its participation within the FRR to fulfill its capacity reserve obligations.

Supplemental Information to Support the KPCo Planning Process and Issues Represented in this CPCN Application

E. KPCo's current available capacity resources

To meet the most recent projected peak demand and annual energy requirements of its customers, as part of its FRR obligations in PJM for the current, 2010/2011 Planning Year, KPCo is relying on 1,470 MW of owned—or for which it currently has a long-term purchase entitlement—generating capability. The make-up of KPCo's PJM-recognized installed capability (ICAP) includes a portfolio of coal facilities identified in the following table:

COAL:

- ✓ Big Sandy Unit 1 (278-MW) located in Louisa, KY. In-service 1963
- ✓ Big Sandy Unit 2 (800-MW) located in Louisa, KY. In-service 1969
- ✓ Rockport Unit 1 (197-MW) located in Spencer County, IN[4] In-service 1984
- ✓ Rockport Unit 2 (195-MW) located in Spencer County, IN[5] In-service 1989

TOTAL (2011/2012 PJM Planning Year) **1,470** MW

F. KPCo's current available "demand" resource (DSM)

Demand-Side Management (DSM) in the form of both "active" and "passive" Demand Response (DR) initiatives have been incorporated into the Company's resource planning. Active DSM, in the form of peak-modifying DR activity have been projected as well as passive DSM in the form of Energy Efficiency (EE) programs, which KPCo and this Commission has supported for some time. The following **Table 1-2** identifies the level of KPCo (total) demand reduction initially anticipated over the forecasted time horizon based, in part, on the requirements for DSM as set forth in Case No. 2010-00095, approved in August, 2010. While not at all trivial, it is evident, however, that such DR resource contributions from such estimated DSM activity by or around the mid-part of this decade of approximately 30-40 MW are clearly well below the

[4] This reflects KPCo's 30% purchase entitlement from the (50%), AEP Generating Company (AEG) ownership share of the (total) 1315-MW unit.
[5] This reflects KPCo's 30% purchase entitlement from the (50%), AEG share of the 1300-MW unit that is currently under lease to non-affiliate Lessors.

Supplemental Information to Support the KPCo Planning Process and Issues Represented in this CPCN Application

significant capacity needs that would be at issue when considering the disposition of units on the scale of Big Sandy Unit 2.

Table 1-2

AEP-Projected Demand Response (DR) and Energy Efficiency (EE)
KPCo and AEP-East

	(CURRENT) PJM-APPROVED INTERRUPTIBLE DEMAND RESPONSE Peak Reduction (MW)		+ (PROJECTED) "ACTIVE" DEMAND RESPONSE Peak Reduction (MW)		+ (PROJECTED) "PASSIVE" DEMAND RESPONSE Peak Reduction (MW)		= TOTAL DEMAND RESPONSE Peak Reduction (MW)	
Year	KPCo	AEP-East	KPCo	AEP-East	KPCo	AEP-East	KPCo	AEP-East
2011	0	445	2	47	2	76	4	568
2012	0	445	4	50	4	149	8	644
2013	0	445	4	50	7	252	10	747
2014	0	445	11	180	9	390	19	1,015
2015	0	445	18	300	10	523	28	1,268
2016	0	445	26	450	15	650	41	1,545
2017	0	445	35	600	18	765	53	1,811
2018	0	445	36	612	20	866	56	1,923
2019	0	445	36	624	21	993	58	2,063
2020	0	445	37	637	23	1,128	60	2,210
2021	0	445	38	649	23	1,221	61	2,315
2022	0	445	39	662	24	1,293	62	2,401
2023	0	445	39	676	23	1,350	63	2,471
2024	0	445	40	689	23	1,391	64	2,525
2025	0	445	41	703	23	1,427	64	2,575
2026	0	445	41	703	23	1,439	64	2,587
2027	0	445	41	703	23	1,439	64	2,587
2028	0	445	41	703	24	1,437	65	2,585
2029	0	445	41	703	23	1,439	64	2,587
2030	0	445	41	703	23	1,439	64	2,587

	(PROJECTED) CUMULATIVE ENERGY EFFICIENCY (GWh)	
Year	KPCo	AEP-East
2011	13	611
2012	31	988
2013	47	1,467
2014	60	2,232
2015	70	2,968
2016	95	3,699
2017	113	4,351
2018	122	4,927
2019	130	5,651
2020	136	6,419
2021	137	6,920
2022	138	7,325
2023	138	7,651
2024	137	7,904
2025	136	8,095
2026	135	8,162
2027	135	8,162
2028	136	8,162
2029	135	8,162
2030	135	8,162

Supplemental Information to Support the KPCo Planning Process and Issues Represented in this CPCN Application

G. SUMMARY: KPCo's current PJM "capacity position"

Assuming that the KPCo LSE were viewed individually as part of a PJM-planning perspective, the following **Table 1-3** offers an overview of such a KPCo "stand-alone" capacity position within PJM. This view effectively assumes that the Company would continue to elect to participate in the PJM RPM as an FRR (*i.e.*, self-planning) entity as opposed to participating in PJM's capacity auction construct. Further it assumes, as a "going-in" or base assumption that Big Sandy Unit 2 would continue to contribute ICAP into PJM; whereas Big Sandy Unit 1 would continue to contribute ICAP up to, minimally, the 2014/15 PJM Planning Year and then be retired.

As reflected in the column identified as "Net Position w/ New Capacity" (col. 20), KPCo would ultimately become "short" capacity by 279 MW beginning with that 2014/15 Planning Year timeframe. This demonstrates and confirms that while KPCo may initially be able to maintain a *manageable* capacity position in PJM assuming Big Sandy Unit 1 was retired while Big Sandy Unit 2 was environmentally-retrofitted and continued operation, the Company would clearly become <u>significantly</u> capacity-deficient—with an attendant market pricing exposure—if the 800-MW Big Sandy Unit 2 were *also* to be retired with no contemporaneous replacement of its capacity and energy.

Supplemental Information to Support the KPCo Planning Process and Issues Represented in this CPCN Application

Table 1-3

KENTUCKY POWER COMPANY

Projected Resource Capacity, Load/Peak Demands, and PJM UCAP Reserve Margins ("CLR")--PJM FRR Planning Perspective

Based on September 2011 Load Forecast

(2011/2012 - 2030/2031 PJM Planning Years)

"Going-In" Capacity Position (No New Thermal Resource Additions or Purchases)

(Assuming U.S. EPA [Proposed] EGU MACT Rulemaking "ACCELERATED" Unit Retirements re: BS1)

Planning Year		(1) Internal Demand (a)	(2) DSM (b)	(3) =(1)+(3) Projected DSM Impact (c)	(4) =(1)+(3) Net Internal Demand	(5) Interruptible Demand Response (d)	(6) Demand Response Factor	(7) Forecast Pool Req't (e)	(8) =((4)-((5)*(6)))*(7) UCAP Obligation	(9) Net UCAP Market Obligation (f)	(10) =(8)+(9) Total UCAP Obligation
		Obligation to PJM									
2011 /12	(k)	1,218	(2)	(1)	1,217	2	0.955	1.083	1,317	0	1,317
2012 /13	(k)	1,253	(4)	(1)	1,252	4	0.950	1.080	1,348	0	1,348
2013 /14	(k)	1,283	(7)	(1)	1,282	4	0.957	1.080	1,382	0	1,382
2014 /15	(k)	1,300	(9)	(2)	1,298	11	0.956	1.081	1,392	0	1,392
2015 /16		1,247	(10)	(4)	1,243	18	0.956	1.081	1,326	0	1,326
2016 /17		1,252	(15)	(7)	1,246	26	0.956	1.081	1,319	0	1,319
2017 /18		1,256	(18)	(9)	1,247	35	0.956	1.081	1,312	0	1,312
2018 /19		1,271	(20)	(10)	1,260	36	0.956	1.081	1,325	0	1,325
2019 /20		1,281	(21)	(15)	1,266	36	0.956	1.081	1,331	0	1,331
2020 /21		1,287	(23)	(18)	1,269	37	0.956	1.081	1,333	0	1,333
2021 /22		1,299	(23)	(20)	1,279	38	0.956	1.081	1,344	0	1,344
2022 /23		1,309	(24)	(21)	1,287	39	0.956	1.081	1,352	0	1,352
2023 /24		1,313	(23)	(23)	1,290	39	0.956	1.081	1,354	0	1,354
2024 /25		1,320	(23)	(23)	1,296	40	0.956	1.081	1,360	0	1,360
2025 /26		1,333	(23)	(24)	1,310	41	0.956	1.081	1,373	0	1,373
2026 /27		1,344	(23)	(23)	1,320	41	0.956	1.081	1,385	0	1,385
2027 /28		1,354	(23)	(23)	1,331	41	0.956	1.081	1,397	0	1,397
2028 /29		1,362	(24)	(23)	1,338	41	0.956	1.081	1,404	0	1,404
2029 /30		1,369	(23)	(23)	1,346	41	0.956	1.081	1,412	0	1,412
2030 /31		1,379	(23)	(23)	1,356	41	0.956	1.081	1,423	0	1,423

Planning Year	(11) Existing Capacity & Planned Changes (g)	(12) Net Capacity Sales (h)	(13) Planned Capacity Additions Units	(14) Planned Capacity Additions MW (i)	(15) Annual Purchases	(16) =(11)-(12)+Sum(14)+(15) Net ICAP	(17) AEP EFORd (j)	(18) =(16)*(1-(17)) Available UCAP	(19) =((11)-(12)+(15))*(1-(17))-(10) Net Position w/o New Capacity	(20) =(18)-(10) Net Position w/ New Capacity	(21) =((10)+((5)*(6)*(7)))/(1+(22)) Total UCAP Obligation Less IDR and IRM	(22) Installed Reserve Margin (IRM)	(23) =(20)/(21) I&M Reserve Margin Above PJM IRM	(24) =(22)+(23) Total I&M Reserve Margin	
	Resources								I&M Position (MW)		PJM Reserve Margin				
2011 /12	1,470	104				1,356	6.26%	1,280	(37)	(37)	1,142	15.50%	-3.24%	12.26%	
2012 /13	1,470	56				1,412	7.15%	1,311	(37)	(37)	1,171	15.40%	-3.16%	12.24%	
2013 /14	1,470	(6)				1,476	7.38%	1,367	(15)	(15)	1,202	15.30%	-1.25%	14.05%	
2014 /15	1,192	(6)				1,198	7.09%	1,113	(279)	(279)	1,217	15.30%	-22.93%	-7.63%	(l)
2015 /16	1,180	(5)				1,185	7.09%	1,101	(225)	(225)	1,166	15.30%	-19.30%	-4.00%	
2016 /17	1,187	(7)				1,194	7.09%	1,109	(210)	(210)	1,167	15.30%	-17.99%	-2.69%	
2017 /18	1,187	(8)				1,195	7.09%	1,110	(202)	(202)	1,169	15.30%	-17.28%	-1.98%	
2018 /19	1,187	(8)				1,195	7.09%	1,110	(215)	(215)	1,181	15.30%	-18.20%	-2.90%	
2019 /20	1,193	(5)				1,198	7.08%	1,113	(218)	(218)	1,187	15.30%	-18.37%	-3.07%	
2020 /21	1,198	(4)				1,202	7.08%	1,117	(216)	(216)	1,189	15.30%	-18.16%	-2.86%	
2021 /22	1,198	(3)				1,201	7.08%	1,116	(228)	(228)	1,200	15.30%	-19.01%	-3.71%	
2022 /23	1,198	(2)				1,200	7.08%	1,115	(237)	(237)	1,207	15.30%	-19.63%	-4.33%	
2023 /24	1,198	(1)				1,199	7.08%	1,114	(240)	(240)	1,210	15.30%	-19.84%	-4.54%	
2024 /25	1,198	0				1,198	7.08%	1,113	(247)	(247)	1,218	15.30%	-20.32%	-5.02%	
2025 /26	1,198	0				1,198	7.08%	1,113	(260)	(260)	1,228	15.30%	-21.18%	-5.88%	
2026 /27	1,198	0				1,198	7.08%	1,113	(272)	(272)	1,238	15.30%	-21.97%	-6.67%	
2027 /28	1,198	0				1,198	7.08%	1,113	(284)	(284)	1,248	15.30%	-22.75%	-7.45%	
2028 /29	1,198	0				1,198	7.08%	1,113	(291)	(291)	1,254	15.30%	-23.20%	-7.90%	
2029 /30	1,198	0				1,198	7.08%	1,113	(299)	(299)	1,261	15.30%	-23.70%	-8.40%	
2030 /31	1,198	0				1,198	7.08%	1,113	(310)	(310)	1,271	15.30%	-24.39%	-9.09%	

Notes: (a) Based on (September 2011) Load Forecast (with implied PJM diversity factor)

(b) Existing plus approved and projected "Passive" EE, and VV
(note: these values & timing are for reference only and are not reflected in position determination)

(c) For PJM planning purposes, the impact of new DSM is 'delayed' three years to represent the ultimate recognition of these amounts through the PJM-originated load forecast process

(d) Demand Response approved by PJM in the prior planning year plus forecasted "Active" DR

(e) Installed Reserve Margin (IRM) = 15.5%(2011), 15.4%(2012), 15.3%(2013-2030)
Forecast Pool Requirement (FPR) = (1 + IRM) * (1 - PJM EFORd)

(f) Includes company MLR share of:
FRR view of obligations only

(g) EFFICIENCY IMPROVEMENTS:
2015/16: Rockport 1: 36 MW (turbine upgrade) (offset to DFGD derate)
2019/20: Rockport 2: 36 MW (turbine upgrade)
2020/21: Rockport 2: 35 MW (valve upgrade)

(g) continued
DFGD DERATES:
1/2016: Rockport 1: 35 MW
1/2016: Big Sandy 2: 12 MW
RETIREMENTS (Under "BASE [EGU MACT-ACCELERATED]" view):
1/2015: Big Sandy 1

(h) Includes (MLR Share, pre-2014) of:
<Purchase> (from Constellation) of 315 MW in 2011/12
Commitment (for FRR purposes) of 22 MW from Tanners Ck 4 in 2011/12 and 30 MW in 2012/13
Ceredo/Darby/Glen Lyn Sale to AMPO,ATSI, and IMEA 2011/12-2012/13 (387 MW; 160 MW)
RPM Auction Sales 2011/12 - 2013/14 (1414, 696, 761) (MW ICAP)
3.6 MW capacity <credit> from SEPA's Philpot Dam via Blue Ridge contract
Plus:
Estimated I&M nominations for PJM EE ('passive' DR program) levels --reflected as a UCAP '<resource>'-- as part of PJM's emerging auction products (eff. 2014/15)

(i) Any new wind and solar capacity value is assumed to be 13% and 38% of nameplate

(j) Beginning 2008/09, based on 12-month avg. AEP EFORd in eCapacity
as of twelve months ended 9/30 of the previous year... Forecast represents latest Generation estimates

(k) PJM latest forecast of AEP Zonal coincident peak demand (allocated to Operating Co. LSEs, incl. I&M) which are ultimately utilized to established capacity position

(l) Through the PJM 2014/15 Planning Year, I&M capacity position has been established from an overall AEP (Eastern Zone) perspective, under the Fixed Resource Requirement (FRR) planning options... Subsequent years are to-be-determined.

Supplemental Information to Support the KPCo Planning Process and Issues Represented *in this CPCN Application*

III. ADDITIONAL RISK ANALYSIS

Once the discretely-modeled Strategist® resource alternative plan portfolios identified in Exhibits SCW-4 as well as Exhibits SCW- 4A though 4E were established, they were subjected to risk "stress-testing" to ensure that none of the plans had outcomes that were economically-exposed—versus the other plans—under an array of input variables.

A. The Aurora^{XMP} Model

The proprietary Aurora$^{XMP®}$ model was developed by EPIS, Inc. in the mid 1990's and has been licensed for use by AEP since 2002. Aurora^{XMP} is primarily a production costing model using a fundamentals-based, multi-area, transmission-constrained dispatch logic in order to simulate real market conditions. At AEP it is used by the AEP Fundamental Analysis group primarily as a long-term optimization tool to forecast mid- and long-term power prices and other industry commodity pricing for all regions within the Eastern Interconnect and ERCOT.

One of the features of the Aurora$^{XMP®}$ model is its endogenous risk analysis capabilities for stochastic or random-variable ("Monte Carlo") simulations. For the purposes of this study, a commonly accepted sampling method (the Latin-Hypercube) is employed by the tool in order to generate a plausible distribution of risk factors with a relatively small number of samples or risk iterations.

This study focused solely on the KPCo portfolio of generating units. One hundred (100) risk iteration runs were simulated with six risk factors being sampled. The results take the form of a distribution of possible "G(eneration)" cost-of-service/revenue requirement outcomes for each plan portfolio. The input variables, or "key risk factors" considered by Aurora$^{XMP®}$ within this analysis were:

- Coal prices (\$/MMBtu);
- natural gas prices (\$/MMBtu);
- power prices (on-peak & off-peak) (\$/Mwh);
- CO_2 emission (allowance) price/tax (\$/tonne);
- full requirements KPCo load (Gwh); and
- construction costs (annual carrying costs) (\$/kW-year)

Supplemental Information to Support the KPCo Planning Process and Issues Represented in this CPCN Application

Where appropriate, these key variables were correlated based largely on historical data as represented below in **Table 1-4**:

Table 1-4: ***Assumed Variable Correlations***

Monthly Correlation Targets	Natural Gas Prices	Coal Prices	CO_2 Emission Price/Tax	Power Prices	Load
Natural Gas Prices	1	0.09	-0.22	0.87	*seasonal*
Coal Prices		1	0.69	0.19	0.74
CO_2 Emission Price/Tax			1	-0.14	0.05
Power Prices (All Hrs)				1	0.75
Demand					1

European Futures
European Futures / US Data validated
US Data
Hypothesized

Source: AEP Fundamental Analysis

B. Modeling Process and Results

For each portfolio, the modeled *difference* between the calculated "G"-cost CPW 50^{th} (median) and 95th percentile outcome across the 100 simulations was identified as "Revenue Requirement at Risk" (RRaR). The 95^{th} percentile represents a level of required revenue sufficiently high that it will be exceeded, assuming that the given plan were adopted, with an estimated probability of only 5.0 percent. The RRaR represents a measure of customer risk or uncertainty inherent in each portfolio. The *larger* the RRaR, the *greater* the level of risk that KPCo's customers could be subjected to a higher generation cost-of-service/revenue requirement.

The following **Table 1-5** illustrates for the Option #1 (Big Sandy Unit 2 Retrofit) plan portfolio, the average levels of these key risk factors—both overall (*i.e.*, all outcomes), and in the simulated outcomes in which CPW of G-revenue requirement exceeds the 95^{th} percentile; or the upper-bound of Revenue Requirement at Risk (*i.e.*, the cumulative distribution "tail"). While this figure is specific to the "Retrofit" plan, the numbers would be similar under the other plans.

Supplemental Information to Support the KPCo Planning Process and Issues Represented in this CPCN Application

Table 1-5: ***Key Risk Factors – Means***

Simulated Outcomes -- Big Sandy 2 Retrofit (Option #1)					
Key Risk Factor	**All Outcomes**	**RRaR-Exceeding Outcomes (>95%)**			**Year**
	Mean	**Mean**	**Difference**	**%Diff**	
Coal prices (nominal $/MMBtu)	2.59	3.03	0.43	16.7%	2020
Natural Gas Prices (nominal $/MMBtu)	8.62	10.22	1.59	18.5%	2025
Power Prices (nominal $/Mwh - All Hrs)	54.06	67.38	13.32	24.6%	2020
CO2 Emission Price/Tax ($/Tonne)	13.97	17.23	3.26	23.3%	2022
Load (Gwh)	9,208	11,284	2,076	22.5%	2020
FOM, Constr Costs / MW	4.99	5.44	0.45	9.0%	2025

Source: AEP Fundamental Analysis

The price of Power (energy) and CO_2 Emission Price/Tax are greater among the RRaR-Exceeding Outcomes, suggesting that they are critical sources of risk to revenue requirements. The relative difference between the average "tail" and overall average outcomes for those respective variables is 24.6% and 23.3%, which is marginally greater than the relative difference of other key risk factors.

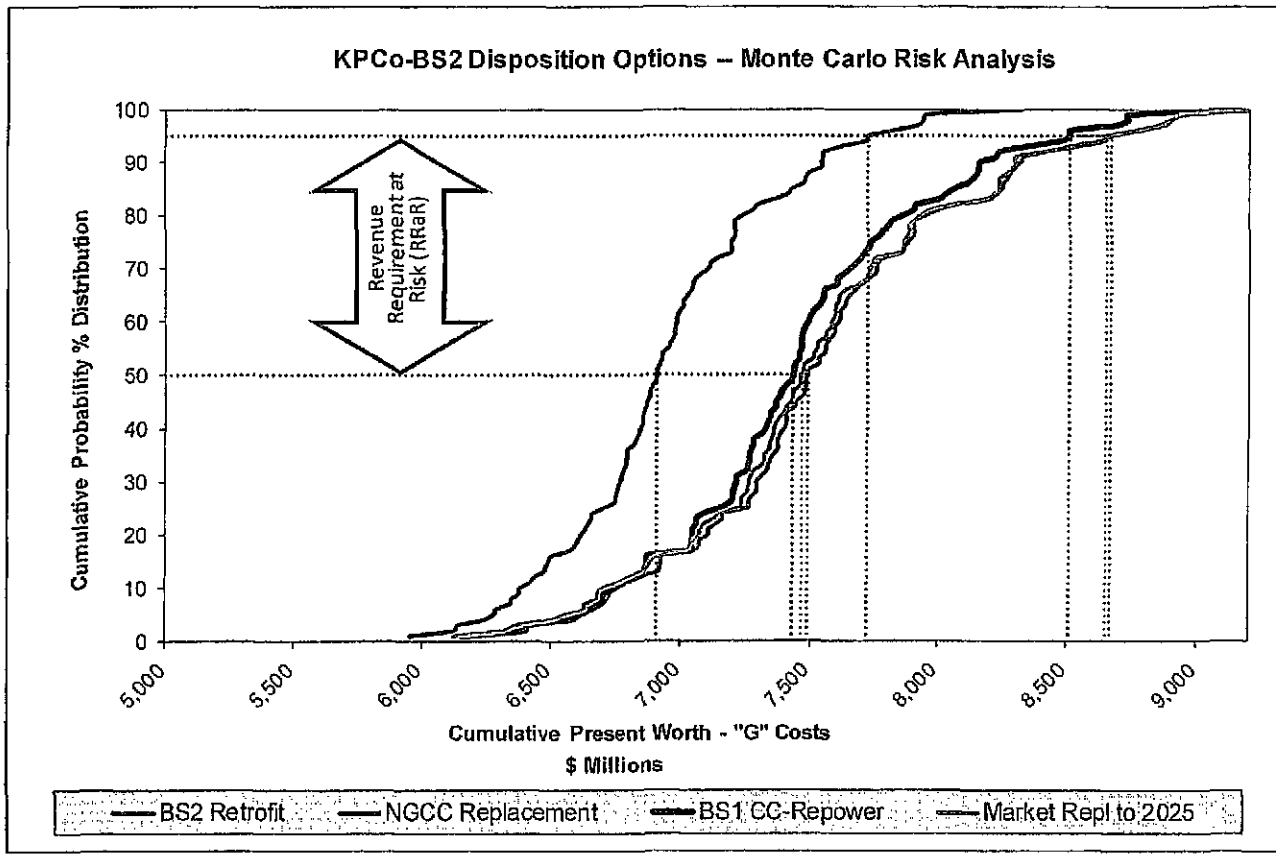
It might be assumed that the very worst possible futures for the Big Sandy Retrofit (Option #1) would be characterized by high fuel and (CO_2) emission prices, but low power prices. But according to the analysis of the historical values of risk factors that underlies this study, such futures have essentially no chance of occurring. Any possible future with higher fuel prices would essentially always have higher power prices. Additionally, the risk factor analysis also implies a slightly inverse correlation between CO_2 emission price/tax and some of the other risk factors that determine the tail cases, including power prices. So, in these tail cases, the average CO_2 allowance price could actually be *less* than the average across all possible futures when power prices are randomly selected to be high.

Figure 1-1 below shows the distribution of outcomes for each of the four plans that were evaluated (Option #1, #2, #3 and #4B). Note that these CPW results are largely consistent with the CPW values calculated using the Strategist® tool, with the Option #1 (Big Sandy 2 DFGD Retrofit) case being the lowest cost plan. The importance of this evaluation, though, is not in matching the discrete Strategist® results, but in examining the relative risk among the portfolios. As Figure 1-1—including the supporting table—indicates, the RRaR (difference between the 50th and

Supplemental Information to Support the KPCo Planning Process and Issues Represented in this CPCN Application

95th probability percentile simulated result) is also far superior (lower) for Option #1. This reinforces the conclusions from the Strategist® optimization analysis that, again, Option #1 is the optimal alternative based on the relative reduced price/cost risk exposure to KPCo's customers over the long-term study period.

Figure 1-1: KPCo-BS2 Disposition – Simulation Risk Distribution



		Option #1	Option #2	Option #3	Option #4B			
CPW ($000)	*Cumul. Distribution Percentile*	BS2 Retrofit	NGCC Replacement	BS1 CC-Repower	Market Repl to 2025	*Delta* Retrofit - NGCC	*Delta* Retrofit - Repower	*Delta* Retrofit - Mkt to 2025
	50	6,907,015	7,492,590	7,433,656	7,469,125	(585,575) *-8.5%*	(526,641) *-7.6%*	(562,110) *-8.1%*
	95	7,722,158	8,666,036	8,508,691	8,647,851	(943,877) *-12.2%*	(786,532) *-10.2%*	(925,693) *-12.0%*
Relative Rank: *CPW*		1	4	2	3			
RRaR ($000)								
	95th vs. 50th	815,143	1,173,446	1,075,034	1,178,726	(358,303) *-44.0%*	(259,891) *-31.9%*	(363,583) *-44.6%*
Relative Rank: *RRaR*		1	3	2	4			

Supplemental Information to Support the KPCo Planning Process and Issues Represented in this CPCN Application

Finally, ***Figure 1-2*** offers a histogram—"bell curve" plotting—of these same Monte Carlo-simulated results. This view of the Aurora$^{XMP®}$ modeled results indicates that the 100 simulated CPW outcomes for Option #1 are more "symmetrical". This means there is approximately an equal probability that any randomly-simulated outcome would be above or below the highest occurring range of outcomes. However the simulated outcomes for Options #2, #3 and #4B are slightly less symmetrical, with those portfolio profiles indicating a greater percentage of outcomes above the highest-occurring range of results (i.e., approaching that "tail" outcome). This would offer another optic highlighting the greater RRaR associated with those options. Likewise, it would point to Option #4B as perhaps having the greatest level of cost uncertainty/risk.

Figure 1-2: KPC-BS2 Disposition-Simulation Histogram

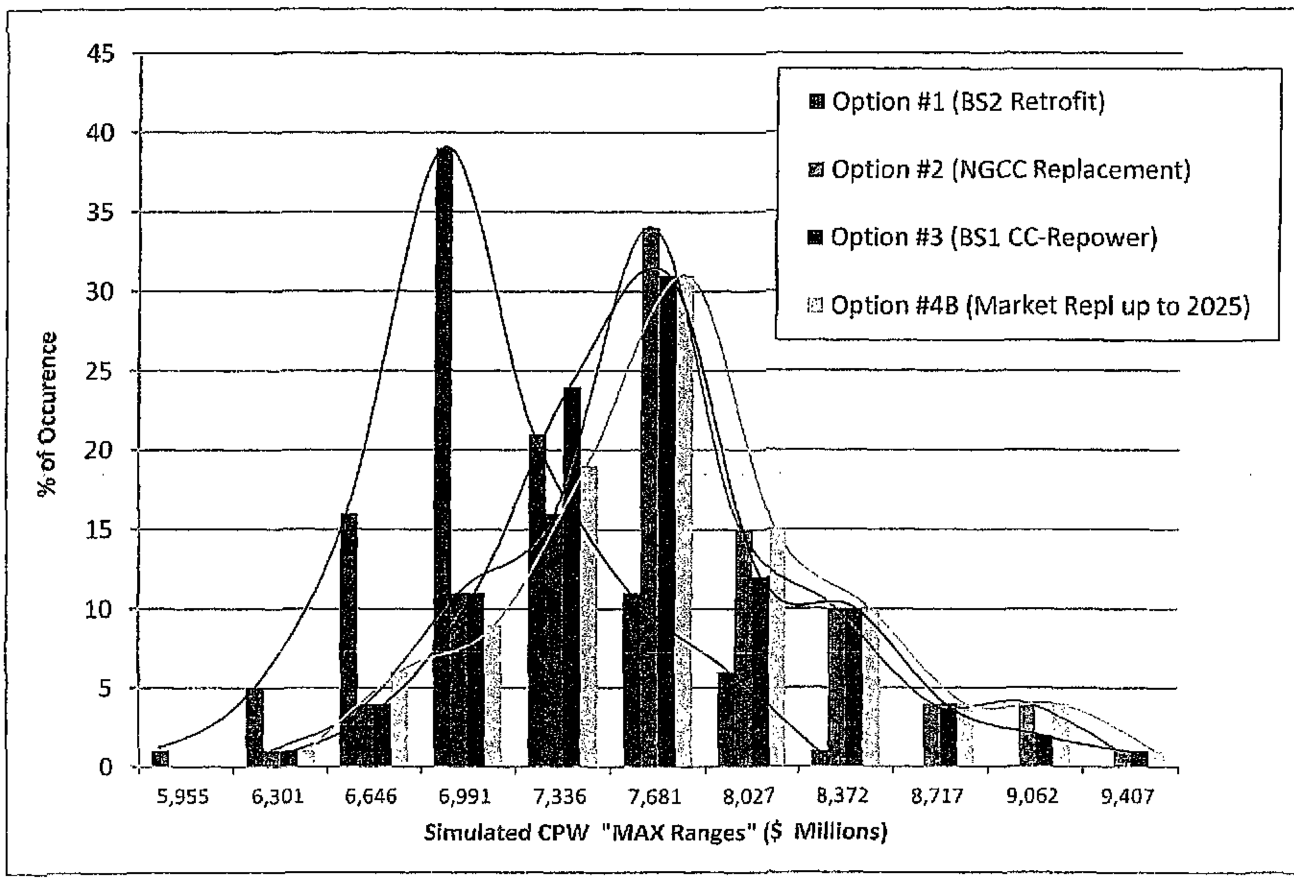


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EXHIBIT
PENGAD 800-631-6989
108
Staff

Short-Term Energy Outlook

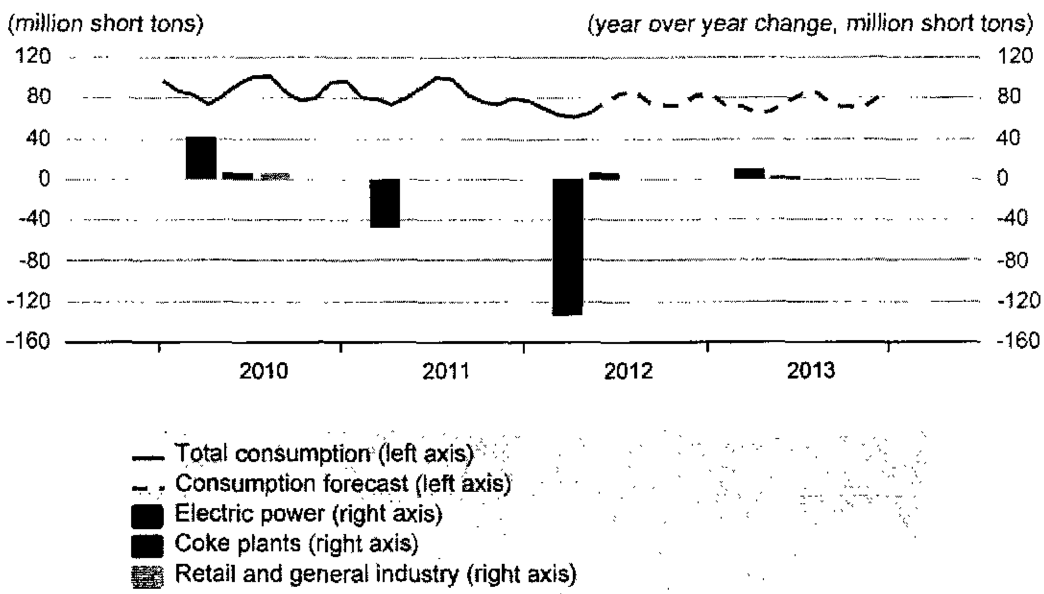
Release Date: May 8, 2012 | **Next Release Date:** June 12, 2012

Coal

U.S. Coal Consumption.

EIA forecasts that electric power sector coal consumption will be about 800 million short tons (MMst) in both 2012 and 2013. Prices for natural gas delivered to the electric power industry fell by 7.5 percent in 2011, which contributed to a significant increase in the share of natural-gas-fired generation. EIA expects this trend to continue in 2012, with electric power sector coal consumption falling by 14 percent (U.S. Coal Consumption Chart). EIA expects that electric power sector coal consumption will increase by 1.2 percent in 2013, as projected power industry coal prices fall (4 percent) and natural gas prices increase.

U.S. Coal Consumption

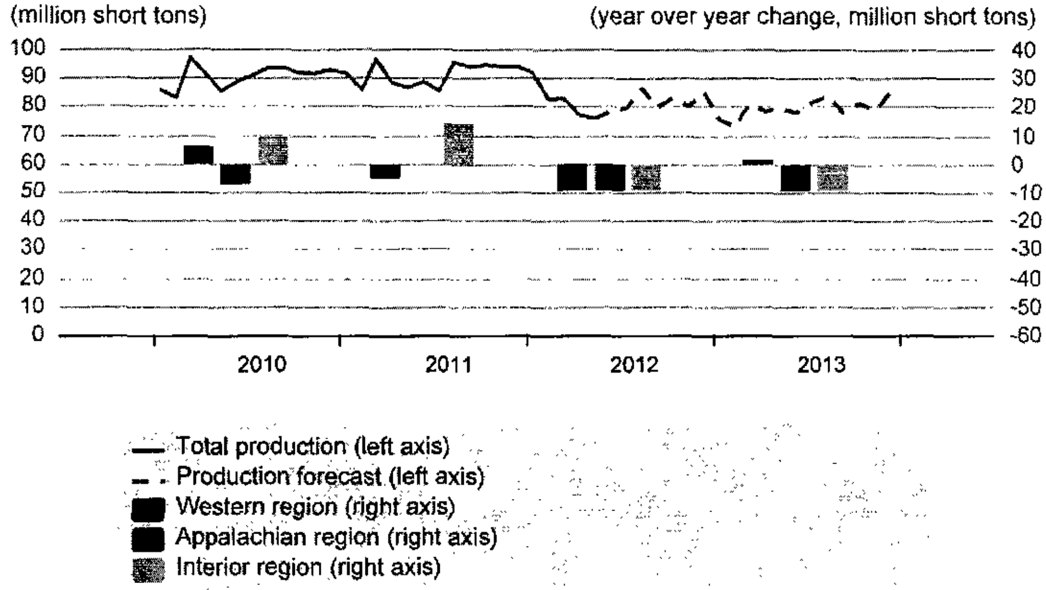


eia Source: Short-Term Energy Outlook, May 2012

U.S. Coal Supply

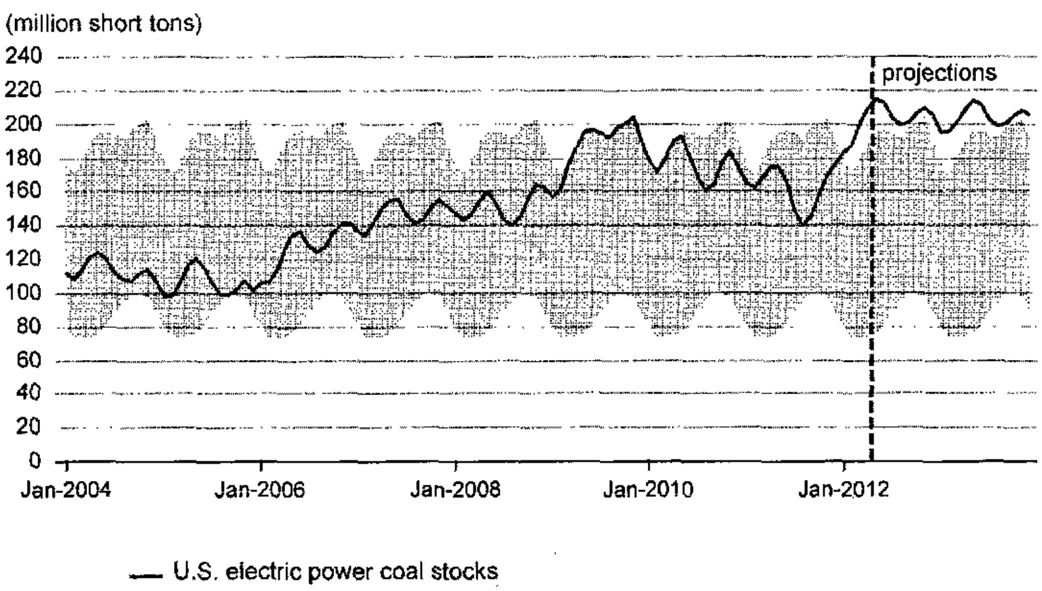
EIA forecasts that coal production will decline by 10.2 percent in 2012 as domestic consumption and exports fall (U.S. Coal Production Chart). Production for the first three months of 2012 was 22 MMst below last year's value for the same period. Annual production declines greater than 25 MMst are expected in each of the three coal-producing regions (Appalachia, Interior and Western). Despite declines in production, EIA projects that secondary inventories will increase in 2012, with electric power sector stocks exceeding 200 MMst, and inventories will remain at elevated levels in 2013 (U.S. Electric Power Sector Coal Stocks Chart).

U.S. Annual Coal Production



eia Source: Short-Term Energy Outlook, May 2012

U.S. Electric Power Sector Coal Stocks



eia Source: Short-Term Energy Outlook, May 2012

Note: Colored band around storage levels represents the range between the minimum and maximum from Jan. 2007 - Dec. 2011.

U.S. Coal Trade

EIA expects U.S. coal exports to remain strong but fall below the 107 MMst exported in 2011. Forecast U.S. coal exports are 100 MMst in 2012 and 97 MMst in 2013. U.S. coal exports averaged 56 MMst in the decade preceding 2011.

U.S. Coal Prices

Delivered coal prices to the electric power industry had increased steadily over the last 10 years and this trend continued in 2011, with an average delivered coal price of $2.40 per MMBtu (a 5.8 percent increase from 2010). However, EIA expects the decline in demand for coal to generate electricity will put downward pressure on coal prices and contribute to the shut-in of higher-cost production. Several companies have recently announced the curtailment of operations, particularly in Appalachia, where production costs at some older mines are high. EIA forecasts the average delivered coal price in 2012 will be 2.8 percent lower than the 2011 average price. EIA predicts the 2013 average delivered coal price to be $2.24 per MMBtu, or 3.8 percent lower than the previous year's price.

EXHIBIT 109 Staff

2011 WL 6119143 (Va.S.C.C.)

PUR Slip Copy

Re Appalachian Power Company
Case No. PUE-2011-00037

Virginia State Corporation Commission
November 30, 2011

Before Christie (dissenting), commissioner.

BY THE COMMISSION:

FINAL ORDER

***1** On March 31, 2011, Appalachian Power Company ('APCo' or 'Company') filed an Application[FN1] with the State Corporation Commission ('Commission') for a biennial review of the Company's rates, terms and conditions for the provision of generation, distribution and transmission services pursuant to §56-585.1 A of the Code of Virginia ('Code') and the Commission's Rules Governing Utility Rate Applications and Annual Informational Filings, 20 VAC 5-201-10 *et seq.* Pursuant to §56-585.1 A 8 of the Code, '[t]he Commission's final order regarding such biennial review shall be entered not more than eight months after the date of filing, and any revisions in rates or credits so ordered shall take effect not more than 60 days after the date of the order.'

The Application requested a $126,364,310 increase in base rates based on the Company's operations for the test year ended December 31, 2010. The Company stated that $51 million of this amount is attributable to the inclusion of new depreciation rates on January 1, 2012. APCo requested to postpone the implementation of the new depreciation rates and to address the issue in its next biennial proceeding - which would reduce its requested rate increase to approximately $75 million.[FN2] The Company subsequently revised its requested rate increase to approximately (i) $117 million, or (ii) $68.5 million if the Commission postpones implementation of new depreciation rates.[FN3]

The Application includes additional proposals, such as: (1) a Capacity Cost Tracker for the Company's capacity equalization costs; (2) a new residential rate design methodology; and (3) a commitment that, if the Company's jurisdictional earnings exceed the base return on common equity ('ROE ') approved by the Commission, APCo will use the net funds available that were not otherwise credited to customers pursuant to §56-585.1 A 8 to offset future rate increases or invest in improved reliability.[FN4] The Application is based on a return on rate base of 8.14%, an ROE of 11.65%, and the Company's proposed capital structure as of December 31, 2010. The Company's proposed 11.65% ROE includes a 0.50% Performance Incentive for meeting the first goal of the Renewable Energy Portfolio Standard ('RPS') Program, as provided in § 56-585.2 C of the Code.[FN5]

On April 12, 2011, the Commission issued an Order for Notice and Hearing that, among other things, established a procedural schedule for this case and directed APCo to provide public notice of this matter.

The following parties filed notices of participation: Office of the Attorney General's Division of Consumer Counsel ('Consumer Counsel'); Steel Dynamics, Inc. ('SDI'); The Kroger Co. ('Kroger');

VML/VACo APCo Steering Committee ('VML/VACO'); Wal-Mart Stores East, LP, and Sam's East, Inc. (collectively, 'Wal-Mart'); Roanoke Gas Company ('Roanoke Gas'); Chesapeake Climate Action Network, Appalachian Voices, and the Virginia Chapter of the Sierra Club (collectively, 'Environmental Respondents'); Michel A. King; and the Old Dominion Committee for Fair Utility Rates ('Committee').

***2** The Commission held public hearings and received testimony from public witnesses in Abingdon (May 25, 2011) and Rocky Mount (May 26, 2011), and also received written and electronic comments from the public in this case. The Commission held the public evidentiary hearing in Richmond on September 13, 14, 15, and 16, 2011, where additional public witness testimony was received. The Commission also heard testimony from witnesses on behalf of the participants in this case and admitted more than 90 exhibits into the record.

On or before October 14, 2011, the following participants filed post-hearing briefs: APCo; VML/VACO; Wal-Mart; SDI; Kroger; Roanoke Gas; Environmental Respondents; Committee; Consumer Counsel; and Staff.

NOW THE COMMISSION, upon consideration of this matter, including all applicable legal requirements, is of the opinion and finds as follows.

'EARNED' RETURN

Section 56-585.1 A 8 of the Code provides in part as follows:

8. If the Commission determines as a result of such biennial review that: (i) The utility has, during the test period or periods under review, considered as a whole, earned more than 50 basis points below a fair combined rate of return on both its generation and distribution services, as determined in subdivision 2, without regard to any return on common equity or other matters determined with respect to facilities described in subdivision 6, the Commission shall order increases to the utility's rates necessary to provide the opportunity to fully recover the costs of providing the utility's services and to earn not less than such fair combined rate of return, using the most recently ended 12-month test period as the basis for determining the amount of the rate increase necessary. However, the Commission may not order such rate increase unless it finds that the resulting rates will provide the utility with the opportunity to fully recover its costs of providing its services and to earn not less than a fair combined rate of return on both its generation and distribution services, as determined in subdivision 2, without regard to any return on common equity or other matters determined with respect to facilities described in subdivision 6, using the most recently ended 12-month test period as the basis for determining the permissibility of any rate increase under the standards of this sentence, and the amount thereof; ... .

The Company's existing fair rate of return on common equity during the test periods under review is 10.53%.[FN6] We find, as concluded by APCo and Staff, that the Company earned more than 50 basis points below such fair combined rate of return during the test periods under review herein.[FN7] Thus, as directed by the above statute, 'the Commission shall order increases to the utility's rates necessary to provide the opportunity to fully recover the costs of providing the utility's services and to earn not less than such fair combined rate of return.'[FN8]

COST OF CAPITAL

Capital Structure and Cost of Debt

***3** Section 56-585.1 A 10 of the Code requires the Commission to 'utiliz [e] the actual end-of-test period capital structure' in this proceeding. Section 56-585.1 A 10 of the Code also requires the Commission to 'utiliz[e] the actual end-of-test period ...cost of capital' in this proceeding, which includes (i) long-term debt, and (ii) short-term debt. We find that Staff's testimony reflects the actual end-of-test period capital structure[FN9] and cost of debt.[FN10]

Return on Equity

In determining ROE under the statute, we utilize the following process. First, we determine the market cost of equity under §56-585.1 A of the Code. We then apply the statutory peer group ROE floor pursuant to §56-585.1 A of the Code. Next, we increase ROE by any statutory Performance Incentive under §§56-585.1 A 2 c or 56-585.2 C of the Code. The result is a statutorily-required ROE, which we will combine with the Company's cost of debt to produce the overall cost of capital and rate of return on rate base.

Market Cost of Equity

Section 56-585.1 A 2 of the Code states that the Commission shall determine fair rates of return on common equity and 'may use any methodology to determine such return it finds consistent with the public interest ... .'[FN11] We find that a market cost of equity within a range of 9.4% to 10.4% represents the actual cost of equity in capital markets for companies comparable in risk to APCo seeking to attract equity capital and results in a fair and reasonable return on common equity. Furthermore, we find, under the circumstances of this case, that using the top of the range - 10.4% - is fair and reasonable for these purposes. This return is supported by the evidence in the record.[FN12] Conversely, we further find that APCo's proposed cost of equity of 11.15% neither represents the market cost of equity nor a reasonable return on common equity for the Company.[FN13]

We find that Staff's results, supported by the Committee, utilize reasonable proxy groups, growth rates, discounted cash flow methods, and risk premium analyses.[FN14] We conclude that the methodologies employed by these witnesses are consistent with the public interest and that the results herein satisfy constitutional standards as stated by Mr. Oliver: 'maintenance of financial integrity, the ability to attract capital on reasonable terms, and earnings commensurate with returns on investments of comparable risk.'[FN15]

Statutory Peer Group Floor

Virginia law next requires that the Commission calculate a statutory floor below which the authorized ROE cannot be set. Section 56-585.1 A 2 a of the Code states as follows:

[S]uch return shall not be set lower than the average of the returns on common equity reported to the Securities and Exchange Commission for the three most recent annual periods for which such data are available by not less than a majority, selected by the Commission as specified in subdivision 2 b, of other investor-owned electric utilities in the peer group of the utility subject to such biennial review, nor shall the Commission set such return more than 300 basis points higher than such average.

***4** In selecting the majority of the peer group utilities to calculate the statutory ROE floor, §56-585.1 A 2 b of the Code directs as follows:

In selecting such majority of peer group investor-owned electric utilities, the Commission shall first remove from such group the two utilities within such group that have the lowest reported returns of the group, as well as the two utilities within such group that have the highest reported returns of the group, and the Commission shall then select a majority of the utilities remaining in such peer group.

No party contested the composition of the statutory peer group - which in this case is comprised of seven utilities after removing the companies with the two highest, and the two lowest, reported returns as required by the above statute.[FN16] The participants, however, differ on which utilities should comprise the 'majority' to be selected by the Commission to determine the statutory floor. We select a majority consisting of four statutory peer group utilities that, on average, had a return on average equity of 10.33%.[FN17]

In this regard, the above statute clearly leaves the selection of this 'majority' to the Commission's discretion. There is no ambiguity in the statute; thus, we do not reach questions of legislative construction or intent.[FN18] If the General Assembly wanted the Commission to apply a particular approach or evaluation methodology in selecting a majority, it could have directed as such; it did not.[FN19] We find that it is reasonable in this proceeding to select a majority that has an earned return that is close to the market cost of equity capital found fair and consistent with the public interest herein. The plain language of the statute giving the Commission the discretion to select a majority in no manner precludes such finding. Moreover, we do not, and need not, find that this is the only majority that is reasonable. We conclude that the specific majority chosen herein has a rational basis and does not violate any constitutional or statutory provision.

Based on the evidence in this case and the statutory directive to determine fair rates of return on common equity using 'any methodology to determine such return it finds consistent with the public interest,'[FN20] we have determined that a fair market cost of equity is within a range of 9.4% to 10.4%, and that 10.4% shall be used for these purposes.[FN21]

Performance Incentive - Renewable Energy Portfolio Standard (RPS)

Section 56-585.2 C of the Code provides in part:

[T]he Commission, in addition to providing recovery of incremental RPS program costs pursuant to subsection E, shall increase the fair combined rate of return on common equity for each utility participating in such program by a single Performance Incentive, as defined in subdivision A 2 of §56-585.1, of 50 basis points whenever the utility attains an RPS Goal established in subsection D. Such Performance Incentive shall first be used in the calculation of a fair combined rate of return for the purposes of the immediately succeeding biennial review conducted pursuant to §56-585.1 after any such RPS Goal is attained, and shall remain in effect if the utility continues to meet the RPS Goals established in this section through and including the third succeeding biennial review conducted thereafter. Any such Performance Incentive, if implemented, shall be in lieu of any other Performance Incentive reducing or increasing such utility's fair combined rate of return on common equity for the same time periods. However, if the utility receives any other Performance Incentive increasing its fair combined rate of return on common equity by more than 50 basis points, the utility shall be entitled to such other Performance Incentive in lieu of this Performance Incentive during the term of such other Performance Incentive.

***5** APCo has met RPS Goals such that it is entitled to the RPS Performance Incentive under the above statute, which requires the Commission to increase the Company's fair rate of return on common equity by an additional 50 basis points.[FN22] The statutorily-required addition of 50 basis points for meeting RPS Goals increases the Company's rates by an additional amount of approximately $7.75 million annually.

Overall Cost of Capital and Rate of Return on Rate Base

In sum, for this base rate proceeding we approve a rate of return on common equity for APCo of 10.9% (*i.e.*, 10.4% plus the 50 basis points for the RPS Performance Incentive), which results in an overall rate of return on rate base and cost of capital of approximately 7.823%. We find that the ROE and overall rate of return on rate base approved herein are fair and reasonable to the Company within the meaning of the statute, permit the attraction of capital on reasonable terms, fairly compensate investors for the risks assumed, and enable the Company to maintain its financial integrity. This finding reduces the Company's requested rate increase, which is based upon an overall cost of capital of 8.14%, including an ROE of 11.65%, by approximately $11.77 million.

EXPENSES

Depreciation Expense

The Company's rates reflect its net investment in plant necessary to serve customers. This investment is included in rate base and incorporates an appropriate depreciation reserve related thereto. Thus, depreciation rates are periodically revised to reflect new plant, to update service lives, and to true-up reserve balances. Prior to the instant case, APCo's most recent depreciation study was based on plant as of December 31, 2005. We continue to find, as we have in prior proceedings, that it is important to implement new depreciation rates on a timely basis in order to correct imbalances in existing rates and to minimize future imbalances.[FN23]

Implementation of the new depreciation rates increases the Company's expenses and reduces its rate base. Until new depreciation rates are implemented and expenses are recovered, these amounts remain in APCo's rate base and, as a result, customers must pay carrying costs (*i.e.*, the Commission-approved overall cost of capital) on this investment. Thus, in the current circumstances, the longer new depreciation rates are delayed, the greater the total amount that customers may be required to pay over time.

Based on the particular circumstances presented in this proceeding, we find that the following is reasonable: (1) new depreciation rates should be based on the Company's depreciation study utilizing depreciable plant balances as of December 31, 2010 ('2010 Study') (not on the 2011 Technical Update as requested by APCo); and (2) new depreciation rates should be implemented as of the effective date of the rates approved herein (not on January 1, 2011 as requested by Staff). This finding increases rates by approximately $39.5 million.[FN24]

Capacity Equalization Charges

***6** The Company is a member of the AEP East Power Pool, which is governed by an Interconnection Agreement approved by the Federal Energy Regulatory Commission ('FERC'). Under the Interconnection Agreement, a generating capacity obligation is calculated for each American Electric Power Company ('AEP') East company, and those companies that do not own enough capacity to satisfy their calculated obligation must make payments to those with surplus capacity. As explained by Consumer Counsel, 'members pay their member load ratio ('MLR ') share of the total AEP East system capacity,' and '[t]his means that a member that has a capacity deficit position, compared to the overall pool, purchases capacity from the capacity surplus members.'[FN25] Moreover, '[f]or the last 30 years APCo has been, and continues to be, the most capacity deficit member of the AEP East Pool.'[FN26]

We reject APCo's proposed estimated rate year capacity equalization charges, which are based on the Company's forecasts of its own capacity during the rate year, forecasts of the total AEP East capacity during the rate year, forecasts of the Capacity Equalization Rate paid by deficit members during the rate year, and APCo's projected MLR during the rate year.[FN27] Based on the uncertain and/or volatile nature of these items, we do not find that the Company's projections thereof 'reasonably can be predicted to occur during the rate year. '[FN28] Rather, we find that it is reasonable - as the Commission has found in prior APCo proceedings - to utilize actual cost data and a five-year average MLR for these purposes.[FN29] This finding increases the Company's rate request by approximately $1.81 million.[FN30]

Dresden Generating Facility

The Commission previously approved APCo's acquisition of the Dresden Generating Facility, a 580 MW natural gas-fired combined cycle generating plant located near Dresden, Ohio.[FN31] The acquisition of the Dresden Generating Facility will reduce the Company's capacity equalization charges once the facility is placed in service. Based on specific facts presented in this case, we find that the commercial operation of the Dresden Generating Facility reasonably can be predicted to occur on or before March 2012. For example: (1) APCo has received all necessary approvals for the facility; (2) the facility has been transferred to APCo and is reflected on the Company's books; (3) the Company is ahead of schedule to commence commercial operation by February 29, 2012; (4) pre-commercial operations testing is scheduled for October 2011; and (5) the facility is not deploying new, risky, or unusual technology but, rather, is a conventional natural gas-fired plant.[FN32] This finding reduces the Company's rate request by approximately $27.53 million.[FN33]

Sporn Unit 5

Ohio Power has requested authority from the Public Utility Commission of Ohio ('PUCO') for approval to retire Sporn Unit 5, a 450 MW unit in New Haven, West Virginia.[FN34] The retirement of Sporn Unit 5 will decrease APCo's capacity equalization charges. Based on specific information presented in this case, we find that the removal of Sporn Unit 5 from APCo's capacity equalization charges reasonably can be predicted to occur during the rate year, which begins in 2012. For example: (1) AEP has slated the unit for retirement in 2011; (2) PJM Interconnection LLC ('PJM') has already approved such retirement; (3) this retirement is included in APCo's 2009 Integrated Resource Plan; (4) no party has opposed this retirement in the proceeding before the PUCO; and (5) the Company asserts that it has taken positive, effective steps that will necessarily remove the gross investment cost of this unit from the calculation of APCo's capacity equalization charges as of December 31, 2011.[FN35] This finding reduces the Company's rate request by approximately $6.33 million.[FN36]

Ohio Merger

***7** Ohio Power and Columbus Southern requested merger approval from the FERC and PUCO. The completed merger of these two companies will likely decrease APCo's capacity equalization charges. We do not find, however, that the proposed merger of these affiliates of APCo is sufficiently progressed to where such merger reasonably can be predicted to occur during the rate year.

Interconnection Agreement

Consumer Counsel asserts that APCo has acted imprudently and unreasonably under the Interconnection Agreement by, among other things, not making non-affiliate capacity purchases - and, thus, Consumer Counsel requests that the Commission disallow certain costs incurred under the Interconnection Agreement.[FN37] In APCo's prior rate case, the Commission explained that it was 'concerned that the decision making over recent years regarding capacity changes has had a significant adverse effect on APCo and its ratepayers. '[FN38] We also noted that the 'Commission, however, is limited in its jurisdiction regarding APCo's capacity equalization expense under the Interconnection Agreement, which is a wholesale power pooling agreement that has been approved by FERC ... .'[FN39] In this instance, the overall facts, as well as the legal authority supporting the action requested by Consumer Counsel, have not been sufficiently established on this record.

Capacity Cost Tracker

We deny the Company's request for a Capacity Cost Tracker ('CCT'). We find that a CCT is not necessary in order for APCo to have an opportunity to recover the capacity equalization charges found reasonable herein.

Off-System Sales

Section 56-249.6 D 1 of the Code provides in part as follows:

Energy revenues associated with off-system sales of power shall be credited against fuel factor expenses in an amount equal to the total incremental fuel factor costs incurred in the production and delivery of such sales. In addition, 75 percent of the total annual margins from off-system sales shall be credited against fuel factor expenses; however, the Commission, upon application and after notice and opportunity for hearing, may require that a smaller percentage of such margins be so credited if it finds by clear and convincing evidence that such requirement is in the public interest. The remaining margins from off-system sales shall not be considered in the biennial reviews of electric utilities conducted pursuant to §56-585.1. In the event such margins result in a net loss to the electric utility, (i) no charges shall be applied to fuel factor expenses and (ii) any such net losses shall not be considered in the biennial reviews of electric utilities conducted pursuant to §56-585.1. For purposes of this subsection, 'margins from off-system sales' shall mean the total revenues received from off-system sales transactions less the total incremental costs incurred; ... .

We reject Consumer Counsel's and Staff's request to reduce base rates by 100% of revenues from off-system sales of capacity.[FN40] Neither participant established that the Commission has the legal authority to take such action. To the contrary, the above statute (i) does not distinguish between off-system 'energy' sales and off-system 'capacity' sales, and (ii) directs that a maximum of 75% of 'total revenues' received from off-system sales transactions may be credited against expenses for the benefit of customers.

Cook Accidental Outage Insurance Proceeds

***8** The Cook Nuclear Power Station ('Cook') is located in Bridgman, Michigan, and is owned by Indiana and Michigan Power Company ('I&M'). Cook Unit 1 experienced an accident on September 20, 2008, and remained out of service until December 18, 2009.[FN41] I&M maintains property damage and accidental outage insurance on Cook and, thus, has received proceeds under both its property damage and accidental outage insurance policies.[FN42] Staff proposes to allocate to APCo a share of I&M's accidental outage insurance policy proceeds. We find that it is reasonable not to deem these specific insurance proceeds received by I&M to be allocable for rate setting purposes in Virginia, and we do not have jurisdiction to direct I&M to share insurance proceeds with its affiliates. We note, however, that this issue presents another example of how APCo's customers have not been appropriately protected by decisions at the holding company level; while APCo's affiliate receives insurance proceeds pursuant to its insurance contract, the Company must pay for replacement power while it also continues to pay a share of Cook's fixed capacity costs.

2010 Employee Severance Program

In 2010, AEP implemented cost reduction initiatives associated primarily with workforce reductions.[FN43] The final cost of the workforce reduction was $299 million at a total AEP level. The Company's 'share of those costs was approximately $26.7 million, of which $16.7 million of such costs was directly related to [APCo's] workforce reductions and approximately $10 million of such costs was for the Company's share of [American Electric Power Service Corporation's ('AEPSC')] workforce reductions.'[FN44] We reject the Company's request to defer and amortize the costs of the workforce reduction program over four years beginning with the effective date of the rates approved in this case, which would 'cause customers to pay the full amount of the workforce reduction costs over that period of time.'[FN45]

We find that it is reasonable - for regulatory accounting purposes in this case - to match the specific costs of this severance program with the specific savings related thereto. We deny the Company's proposal to evaluate earnings to determine whether these 2010 costs should be deferred, amortized, and collected in full from ratepayers in the future. Rather, we conclude that it is appropriate for the amortization of the costs of this program to commence with - and to track - the realization of the savings related thereto in a manner that effectuates the matching of costs and savings. Moreover, this finding provides the Company with a reasonable opportunity to recover its severance costs.

In this regard, based on the evidence presented, we find that the savings realized from this cost reduction initiative exceed the costs thereof prior to the start of the rate year in this case.[FN46] As a result, these severance costs will be completely amortized before the beginning of the rate year, and, thus, no such costs shall be included in rates prospectively. This finding reduces the Company's rate request by *approximately $6.03 million*.[FN47]

Employee Incentive Compensation Plans

***9** AEP has an Annual Incentive Plan ('AIP') and a Long-Term Incentive Plan (collectively, 'Incentive Plans'). Award calculations for the Incentive Plans are based on AEP's earnings and shareholder returns, and AEP's earnings performance ultimately determines the AIP payouts in any given year.[FN48] In APCo's prior rate case, we found that the Company had not yet shown that 100% of the Incentive Plan expenses should be approved; rather, we approved only 50% of such costs.[FN49] In this proceeding, however, APCo has established that 100% of these Incentive Plan costs should be approved. The Company has established that its total compensation costs - which include Incentive Plan costs - are reasonable for purposes of this proceeding. That is, the Company's total compensation package, including Incentive Plan compensation, 'results in compensation that is not higher than and is comparable to the market competitive level of compensation.'[FN50] Indeed, as stated by APCo, the 'reasonableness of the Company's total compensation to employees is uncontroverted in this record.'[FN51] We approve APCo's Incentive Plan expenses as normalized by the *Company*.[FN52]

Environmental Consumable Expenses

We reject APCo's use of forecasts and projections for environmental consumable expenses. As explained by Staff:

[APCo] incurs expenses to operate its environmental control equipment. These expenses include the handling and disposal of gypsum, a by-product of the [flue gas desulfurization] process, and the consumption of urea, limestone, trona, polymer, and lime hydrate. The Company also incurs additional expenses to consume emission allowances, which are used to offset emissions of regulated pollutants.[FN53]

The Company's proposed adjustments for its environmental consumables are based on its forecasts of these costs, which 'depend on numerous inputs and variables, including the generation output of the Company's fossil-fuel units with and without environmental controls and the market prices of the consumables.'[FN54] Moreover, the 'market prices of consumables, in turn, depend on their supply and the utility and other industries' demand for the environmental consumables,' and the 'demand for environmental consumables, in turn, depends on the installation of environmental controls by other utilities and national economic conditions.'[FN55]

We do not find that the Company's overall projections of future expenses in this regard, given all of the unknown variables and inputs that may affect the Company's use and cost of environmental consumables, 'reasonably can be predicted to occur during the rate year.'[FN56] Rather, we find that, based on the unique circumstances here, these environmental expenses should reflect an analysis of actual data audited by Staff and then increased to an annualized amount. We conclude that it is reasonable to annualize these expenses using the March 2011 actual data audited by Staff, and that utilizing this level of environmental expenses provides the Company with a reasonable opportunity to recover its costs. This finding reduces APCo's rate request by approximately $1.44 million, but increases the level of consumables over Staff's recommendation by approximately $2.9 million.[FN57]

***10** *PJM Ancillary Fees and Emission Allowance Gains*

We reject APCo's use of forecasts and projections for PJM ancillary fees and emission allowance gains. As stated by Staff:

PJM ancillary fees, for example, depend on the amount of hours that AEP's generating plants run and the market prices of electricity. The number of hours AEP generating plants will run during the rate year and the rate year market prices for electricity are also notoriously difficult to reasonably predict ... . Factors influencing [emission allowance] gains include the total amount of allowances available to APCo, the amount of allowances used to offset emissions (influenced in turn by customer usage and corresponding generation output, as well as output for [off system sales] which depends in large part on market prices for electricity, APCo's generation source mix which can depend on unpredictable variables such as fuel prices and unplanned outages, and the Company's installation of environmental controls) and the market prices for allowances (influenced in turn by national economic conditions, total U.S. emissions, the generation output and installation of environmental controls by all other U.S. utilities, and the generation source mix of all other U.S. utilities).[FN58]

We do not find that the Company's projections of PJM ancillary fees and emission allowance gains 'reasonably can be predicted to occur during the rate year.'[FN59]

Rather, we continue to find, as we did in APCo's prior rate case, that PJM ancillary fees and emission allowance gains should reflect an analysis of actual data provided in the record. In this regard, we conclude that it is reasonable to use the actual 12-month period ending March 31, 2011, and that such level of fees provides the Company with a reasonable opportunity to recover its costs. This finding, which increases rates by approximately $2.86 million, plus a $4 million increase due to a technical correction identified by Staff, increases APCo's rate request by approximately $6.86 million.[FN60]

Office of the Chairman

We approve APCo's proportional share of the costs associated with AEPSC's Office of the Chairman department.

Amortization Period for 2009 Deferred Storm Damage Costs

In APCo's prior rate case, the Commission allowed the Company to defer on its books the costs of major storms that occurred in December 2009. We find that it is reasonable to amortize and recover these storm costs over a six-year period, beginning with the effective date of the rates approved in this case. This treatment, as recommended by Staff, permits full recovery of these costs and coincides with the Company's biennial review schedule.[FN61] This finding reduces the Company's rate request by approximately $813,740.[FN62]

Software Licensing Expense

We adopt the Company's alternative proposal on how to address the multi-year nature of its software licensing costs, which are incurred on a three-year cycle. Specifically, we find that it is reasonable to defer and amortize these costs over the three-year term of the software license agreement, which results in an annual amortization level of $307,837.[FN63] This finding reduces the Company's rate request by approximately $615,674.[FN64]

Asset Retirement Obligations

***11** We find that it is reasonable - as recommended by APCo and Staff and as previously approved by the Commission - to permit recovery of asset retirement obligation plant assets through depreciation expense.[FN65]

Obsolete Inventory

We find that it is reasonable - as recommended by APCo and Staff - to adjust obsolete inventory expense to reflect a five-year average.[FN66]

Charitable Contributions

We reject the Company's proposed level of charitable contribution expense, which is higher than APCo's proposed budgeted amount for 2011. Rather, as recommended by Consumer Counsel, we find that such expense should be limited to APCo's budget for this item - the expenditure of which is within the Company's control. This in no manner limits additional contributions to charity by APCo but, rather, establishes the level that will be shared by ratepayers in this case. Thus, we conclude that such expense should (i) exclude AEP Foundation contributions (as proposed by the Company), and (ii) include only 50% (consistent with Commission precedent) of APCo's budget for charitable contributions. This finding reduces the Company's rate request by approximately $106,000.[FN67]

Lobbying Expenses

Lobbying expenses are not included in cost of service and are not recovered from ratepayers. Six employees of AEPSC work in the Washington, D.C. office. We find that it is reasonable to allocate 90% of the Virginia portion of the expenses of this office to lobbying activities (not in cost of service) and 10% to non-lobbying activities (included in cost of service).[FN68] This reduces the Company's rate request by approximately $57,872.

Central Machine Shop

We find that APCo's share of salary expenses for employees of AEPSC's Central Machine Shop are approved.[FN69]

Medicare Part D - Tax Law Change

Changes in federal law that became effective in 2010 'repealed the rule permitting deduction of the portion of prescription drug coverage expense that is offset by the Medicare Part D subsidy. With the change in the law, [APCo's] expected tax deductions after 2012 will be reduced by drug coverage expenses allocable to the Medicare Part D subsidy.'[FN70] As further explained by Staff: 'The increase in deferred income tax expense that occurs with the reduction in deferred tax assets relates to *prior* years during which Medicare Part D subsidies were netted against accrued [Other Post Retirement Employment Benefits] costs.'[FN71] We agree with Staff that '[t]hese deferred income taxes are appropriately recognized in 2010 with the change in the law, and should not be deferred to future periods.'[FN72]

Thus, we reject the Company's deferral and creation of a 'regulatory asset that offsets the otherwise unfavorable effect on income resulting from the tax change.'[FN73] This results in two changes to APCo's proposed rate treatment: (1) it eliminates the Company's amortization of the proposed regulatory asset; and (2) it increases the Company's rates in the instant case by approximately $1.42

million.[FN74]

***12** *Staff's Miscellaneous Accounting Adjustments*

Staff states that it 'proposed several miscellaneous accounting adjustments in its direct case that were not addressed in the Company's rebuttal testimony or during the hearing,' and that, 'since the Company failed to produce any evidence whatsoever showing its proposed adjustments were just and reasonable, the Staff's miscellaneous adjustments, shown below, should also be approved. '[FN75] We find that Staff's miscellaneous adjustments, as listed below, are reasonable and shall be approved. Some of the adjustments increase rates, while most of the adjustments serve to decrease rates. The largest adjustment, which reduces rates by over $15 million, corrects a jurisdictional allocation error. In sum, our approval of Staff's proposed miscellaneous adjustments decreases rates by approximately $18.5 million.[FN76]

Description	Revenue Requirement
Fuel Growth and Annualization	$9,856
Jurisdictional Allocation of Other Revenues	(15,011,191)
Non-Deferred Storm Damage Expense	570,327
Postage Expense	(25,551)
OPEB Expense	(586,496)
Pension Expense	(861,043)
Group Insurance Expense	(243,348)
AEPSC Aviation, Umbrella Trust, and Severance Deferral	(16,931)
AEPSC Payroll Expense	(489,108)
AEPSC Pension Expense	(584,499)
AEPSC OPEB Expense	(282,889)
AEPSC Group Insurance Expense	(99,363)
AEPSC June 2011 Update	(1,191,555)
Base Payroll Expense as of 3/31/11	(57,131)
Base Payroll Expense in Rate Year	125,015
Overtime Payroll Expense	866,947
Employee Savings Plan Expense	(55,404)
Depreciation Expense - 12/10 Plant and 2005 Study Rates	(1,032,039)
Taxes Other - Payroll Taxes	(105,411)
Taxes Other - Property Taxes	(572,339)
Taxes Other - OH Commercial Activities Tax	10,288
Cash Working Capital	550,697
Accumulated Depreciation - Virginia-Approved Rates	577,874
Accumulated Depreciation - Expense Contra	(226,986)
Accumulated Depreciation - Remove ARO	240,486
Total	($18,489,794)

Income Tax Expense

Staff accepted, and we find reasonable, APCo's correction to Staff's State Income Tax ('SIT') expense to adjust for bonus-related tax depreciation that is not flowed through for Virginia.[FN77] This increases Staff's SIT expense by $1.51 million and decreases Staff's Federal Income Tax expense by approximately $529,000. Thus, we approve the Company's proposed income tax expense for this purpose.

Property Taxes

We find that Staff's and Consumer Counsel's property tax adjustments based on actual plant information through March 31, 2011, are reasonable, and, as noted by APCo, 'there is only a slight numerical difference between using [Staff's and Consumer Counsel's] adjustments rather than the Company's property tax adjustments.'FN78

RATE BASE

We reject the Company's forecasted rate year projections used to develop adjustments to rate base, which include projected future costs for items such as plant in service, construction work in progress, accumulated depreciation, and accumulated deferred income taxes ('ADIT'). We do not find that the Company's overall forecasted projections of these 'future costs ...reasonably can be predicted to occur during the rate year.'FN79 Although APCo testified that its forecasting models are widely used in the utility industry, the Company has not established that the results of these general forecasting models are necessarily reasonable for ratemaking purposes herein and, as required by Virginia statute, that the results of these models reasonably can be predicted to occur during the rate year.FN80 Rather, we conclude - as we did in APCo's prior rate case - that more item-specific information should be used to establish the Company's rate base projections.

***13** Specifically, we find that it is reasonable to utilize Staff's proposed rate base, which is based on actual, audited amounts through March 31, 2011. As opposed to general forecasting models, Staff uses actual, audited data, along with specific normalized or annualized adjustments. The approved rate base, including any adjustments discussed below, reflects known costs and future costs that we conclude reasonably can be predicted to occur during the rate year.FN81 We find that this approach satisfies statutory requirements and provides the Company with a reasonable opportunity to recover its costs.

Pre-Paid Pension Asset

We reject the Company's request to include in rate base its pre-paid pension asset of approximately $56.9 million. Although the Commission has previously approved rate base treatment of this asset, we find that Consumer Counsel has established - based on the record in this proceeding - that rate base treatment places unreasonable and unnecessary costs on ratepayers. As explained by Consumer Counsel, (1) AEP's executive management can, and does, make discretionary decisions to pre-fund pension obligations at debt rates, and (2) the 'record shows that the AEP management/board made the last large pension prefunding contribution in September 2010 on the basis that would produce net cost savings because it was being funded with low cost commercial paper. 'FN82 Including this asset in rate base, however, requires customers to pay a much higher rate (*i.e.*, the Company's full cost of capital) on this asset. Thus, as concluded by Consumer Counsel, 'the entire economics of the AEP board's decision to prefund pensions is turned upside down, and it becomes an additional cost to ratepayers.'FN83

As a result, as opposed to full cost of capital recovery on this asset, we find that it is reasonable for ratepayers to pay - and the Company to earn - a debt-based return on pre-paid pension assets. Specifically, we adopt Consumer Counsel's option that: (i) removes the pre-paid pension asset from rate base (net of ADIT); and (ii) increases operating expenses by reflecting interest on this asset at a short-term commercial paper debt rate.FN84 This finding, which reduces rate base by $33.61 million and adds $161,000 to operating expense, decreases the Company's requested rates by approximately $3.67 million.

Coal Inventory

We find that, consistent with Commission precedent and as recommended by Staff and Consumer

Counsel, it is reasonable for coal inventory included in rate base to reflect average burn rates - as opposed to maximum burn rates - and a thirty-five-day supply of coal.[FN85] We further conclude, as recommended by Consumer Counsel, that it is reasonable to adjust average coal consumption upward in this instance 'to remove the unusually low monthly burns that occurred in September, October and November of 2010.'[FN86] We find that it is reasonable for this purpose to utilize (i) Consumer Counsel's thirty-five-day average coal consumption over the thirteen-month test period, as adjusted, of 1,025,955 tons, and (ii) an average cost of consumed coal (updated through March 2011) of $67,357 per ton, which results in a total rate base coal inventory value of $69,105,251.[FN87] APCo has not established that such treatment has previously, or will in the future, expose the Company or its customers to risks of plant curtailments or shut downs due to a lack of coal, and we expect that the Company shall continue to meet its public service obligations in this regard.[FN88] This finding decreases the Company's rate request by approximately $516,000.

Accounts Receivable Factoring

***14** The Company sells its accounts receivable - at face value less a discount rate - to AEP Credit. The discount rate consists of a carrying charge, an estimate for bad debts, an agency fee, and bank fees. AEP Credit then uses these receivables for securitized financing from banks. As explained by Staff: (1) the 'percentage of [APCo's] receivables that AEP Credit is able to use for securitized financing has declined recently as the credit quality of [APCo's] receivables has weakened;' and (2) as 'a result of the decline in the credit quality of [APCo's] receivables, AEP Credit incurs greater than normal costs to finance the un-securitized receivables itself.'[FN89] In order to compensate AEP Credit for the additional costs it incurs under the factoring program, APCo proposed to increase the working capital component of rate base by $45.7 million, but revised this amount to $12.6 million at the hearing.

We reject this proposed rate base adjustment. The Commission previously granted authority for the Company's accounts receivable factoring program, and such authority specifically approved a discount rate of 95% debt and 5% equity for this program.[FN90] The Company's proposal, however, would apply a different capital structure with a higher overall cost of capital to a portion of those accounts receivable in contrast to that prior approval. This finding reduces the Company's original rate request by approximately $4.64 million, or its revised request by approximately $1.4 million.[FN91]

Vegetation Management

We deny the Company's request to increase rate base by $11.8 million for additional capital expenditures for reliability improvements, including vegetation management. While we support efforts to increase reliability in a cost-effective manner, APCo did not include this proposal as part of its Application. Rather, this proposal was presented as part of the Company's rebuttal testimony - and was based on significant cost projections as opposed to actually incurred costs.[FN92] We find that the Company has not established the reasonableness of this request at this time.

Next, we direct APCo to develop - in consultation with and as recommended by Staff - a four-year cycle-based vegetation management pilot program to determine the cost effectiveness of implementing such a program on a system-wide basis.[FN93]

Finally, during the hearing, the Company's discussion of its vegetation management practices may suggest that APCo cut back on reliability measures based on its earnings.[FN94] In this regard, we remind the Company that we expect it to, and that it shall, fulfill its public service obligation to take all necessary actions, including right-of-way clearing and vegetation management activities, to provide reliable service to its customers at the just and reasonable rates set forth herein.

FEED Study

In APCo's prior rate case, the Commission disallowed recovery of the costs associated with the Company's pilot project for carbon capture and sequestration ('CCS') at its Mountaineer Generating Facility.[FN95] Accordingly, APCo does not seek to recover any costs associated with the pilot project in its rate year cost of service in this proceeding. The Company, however, seeks to include costs in rate base for its Front-End Engineering and Design ('FEED') study for the commercial-scale phase of CCS at its Mountaineer plant.

***15** We find that APCo has not shown that it is reasonable to recover FEED study costs from Virginia ratepayers at this time. For example: (i) APCo has not shown how its ratepayers have or will benefit from this study; (ii) there are no existing laws or regulations requiring CCS at this time; (iii) as stated by Consumer Counsel, APCo has acknowledged that AEP is no longer 'moving forward with the development of the commercial scale carbon capture project; ' and (iv) the outcome of potential future carbon legislation, the success of any commercial scale project at Mountaineer, and the value of collecting and sequestering CO_2 are all unknown at the present time.[FN96] This finding decreases the Company's rate request by approximately $76,699.[FN97]

2009 Deferred Storm Damage Costs

As explained above, the Commission previously allowed the Company to defer on its books the costs of major storms that occurred in December 2009 - *i.e.*, to create a regulatory asset for these costs. In the instant proceeding, we have permitted APCo to commence recovery of these costs over a six-year period beginning with the effective date of the rates approved herein. In addition, based on the facts in this case, we find that the Company shall be permitted to maintain this regulatory asset and reflect the unamortized balance of these costs in rate base.

REVENUE ALLOCATION AND RATE DESIGN

Cost of Service Studies

We find that APCo's proposed jurisdictional and class cost of service studies are just and reasonable.[FN98] We further find that it is reasonable for the Company to continue to use the six (6) coincident peak method for allocating production costs in the class cost of service studies.[FN99]

Revenue Allocation

We herein approve an annual revenue requirement increase for APCo of $55,071,025. We find that APCo's proposed revenue apportionment, which is consistent with Commission precedent and 'continues to gradually move the customer classes toward parity,' is just and reasonable.[FN100] In addition, since the Commission 'approves a revenue requirement [herein] that is less than the rate increase proposed by the Company, ...the individual class increases [shall] be adjusted proportionally, in accordance with the Company's proposed revenue apportionment and rate design methodologies' also approved herein.[FN101]

Residential and Sanctuary Worship Service Rate Design

We deny the Company's request to implement a new, seasonal rate design for residential and sanctuary worship service ('SWS') customers. The Company asserts that the goal of its proposed rate design is to help these customers mitigate the effects of rate increases by managing their bills and levelizing their payments throughout the year.[FN102]

We agree that it is reasonable and desirable to give customers the ability to levelize their monthly payments and to avoid large swings in monthly bills. Indeed, we have previously approved, and APCo currently offers, two voluntary rate options that do just that: (i) an Average Monthly Payment ('AMP') Plan, which adjusts each month to levelize the 'peaks and valleys' of residential customers' electric consumption; and (ii) a Budget Billing Plan, which charges customers a set amount each month and uses a true-up mechanism at the end of the 12-month period to reconcile the amount paid with the amount owed.[FN103] We find that the current residential and SWS rate design, and the voluntary AMP and Budget Billing Plans, remain just and reasonable.[FN104]

***16** In addition, APCo has not established that its newly proposed rate design, which would be mandatory for residential and SWS customers, is reasonable. For example, questions were raised as to whether this new rate design would, among other things, unreasonably (a) shift costs to non-electric heating customers, (b) increase winter consumption and, thus, increase capacity costs borne by customers, (c) lead to customer confusion as a result of rate changes every quarter (in addition to other rate changes throughout the year resulting from APCo's rate cases), and (d) lead to undesirable price-responsive customer behavior.[FN105]

LGS Rale Design

The Company's proposed Large General Service ('LGS') rate design recovers '70% of the demand-related costs of both the generation and distribution function through demand charges; the remaining demand-related costs are recovered in generation and distribution energy charges.'[FN106] This rate design was approved in APCo's prior rate case and is embedded in the Company's current rates.[FN107] *We find that this rate design remains just and reasonable.*

We reject at this time rate design changes proposed by Wal-Mart and Kroger in this case. Among other things, questions were raised regarding the following issues: (a) such changes could have a disproportionate, negative impact on almost 90% of LGS customers; (b) such changes could have a disproportionate, negative impact on low load factor LGS customers; (c) such changes could be impacted by the fact that there is no direct link between how an individual LGS customer is billed for demand and how demand costs are allocated to the class; and (d) such changes may fail to recognize that the timing of a customer's load, and not simply load factor, is an important element in considering relative rate of return of the LGS class.[FN108]

Differentiated Fuel Charges

We deny SDI's request to 'order APCo to incorporate, in the Company's retail tariffs, differentiated fuel charges according to service level, which include secondary, primary, sub-transmission, and transmission.'[FN109] We find that retaining the currently approved non-differentiated fuel charges remains just and reasonable.

Factoring Costs Recovery Mechanism

As discussed above, the Company sells its accounts receivable - at face value less a discount rate - to AEP Credit. We find that all of APCo's factoring costs should be included as part of base rates and, accordingly, that factoring costs related to specific revenue streams should not be included in the associated rate adjustment clauses ('RAC'). This result comports with Virginia statutes and provides the Company with a reasonable opportunity to recover all of its factoring costs.[FN110] This finding increases the Company's rate request by approximately $2.05 million.[FN111]

Section 56-585.1 A 3 of the Code

Section 56-585.1 A 3 of the Code requires in part as follows:

If the Commission determines that rates should be revised or credits be applied to customers' bills pursuant to subdivision 8 or 9, any rate adjustment clauses previously implemented pursuant to subdivision 4 or 5 or those related to facilities utilizing simple-cycle combustion turbines described in subdivision 6, shall be combined with the utility's costs, revenues and investments until the amounts that are the subject of such rate adjustment clauses are fully recovered. The Commission shall combine such clauses with the utility's costs, revenues and investments only after it makes its initial determination with regard to necessary rate revisions or credits to customers' bills, and the amounts thereof, but after such clauses are combined as herein specified, they shall thereafter be considered part of the utility's costs, revenues, and investments for the purposes of future biennial review proceedings.

***17** The Commission has determined that rates should be revised in this proceeding. APCo has one previously implemented RAC that falls within the above statute - *i.e.*, APCo's Transmission Rider (designated 'T-RAC' by the Company), which was approved under §56-585.1 A 4 of the Code (referenced as 'subdivision 4' in the above statute).[FN112]

Thus, the above statute: (1) requires the Commission to 'combine' such RAC with the utility's costs, revenues, and investments 'until the amounts that are the subject of such [RAC] are fully recovered;' and (2) directs that after such RAC is combined, it 'shall thereafter be considered part of the utility's costs, revenues, and investments for the purposes of future biennial review proceedings.' Accordingly, when APCo files revised tariffs as directed below, that filing shall also reflect such combining of the T-RAC as required by the above statute.'[FN113] In addition, we will initiate a subsequent proceeding to address further implementation of this statute.

Accordingly, IT IS ORDERED THAT:

(1) The Company's Application is granted in part and denied in part as set forth in this Final Order.

(2) The Company shall forthwith file revised tariffs and terms and conditions of service, and workpapers supporting the total revenue requirement and rates, with the Clerk of the Commission and with the Commission's Divisions of Energy Regulation and Utility Accounting and Finance, in accordance with this Final Order, effective for service rendered on and after sixty (60) days from the date of this Final Order. The Clerk of the Commission shall retain such filing for public inspection in person and on the Commission's website: http:// www.scc.virRinia.gov/case.

(3) This case is dismissed.

CHRISTIE, Commissioner, dissenting:

I respectfully dissent from the Final Order's provision allowing the Company to recover 50% of its charitable contributions from its customers. The majority's decision is in accordance with past precedents of this Commission in which recovery of charitable contributions was allowed. I do not believe, however, that ratepayers should be charged for any of the Company's charitable contributions.

Expenses for charitable contributions have nothing to do with the reason APCo received from the state an exclusive service territory. The Company holds its monopoly franchise in order to provide the public with electricity service - a necessity of modern life - that is reliable and is at prices that are in accordance with law. APCo's monopoly does not include a mission of collecting money from captive customers and spending it on charitable causes of the Company's choosing. Many of the charities to which APCo gives are no doubt highly meritorious, do valuable work for the people they serve, and are worthy of continued support. The Company is free to continue its support of those charities with stockholders' funds if it wishes. APCo's customers, however, can choose their own charitable causes to which to donate and should not have to pay for the Company's choices as part of their monthly bills for electricity service.

***18** AN ATTESTED COPY hereof shall be sent by the Clerk of the Commission to all persons on the official Service Lists in these matters. The Service Lists are available from the Clerk of the State Corporation Commission, c/o Document Control Center, 1300 East Main Street, First Floor, Tyler Building, Richmond, Virginia 23219. A copy shall also be sent to the Commission's Office of General Counsel and Divisions of Energy Regulation and Utility Accounting and Finance.

FOOTNOTES

FN1 Subsequent to March 31, 2011, the Company submitted to the Commission errata filings to address errors and omissions from the March 31, 2011 filing. References herein to the 'Application' are inclusive of those errata filings.

FN2 Application at 3. The Company also estimated, in response to a Commission Staff ('Staff') interrogatory, that approximately 49% or more of this $75 million requested rate increase is attributable to environmental compliance costs. *See* Ex. 38 (Carr direct) at 9.

FN3 *See, e.g.*, Ex. 11; APCo's October 14, 2011 Post-Hearing Brief at 1.

FN4 Application at 4-5.

FN5 *Id.* at 3.

FN6 *Application of Appalachian Power Company, For a statutory review of the rates, terms and conditions for the provision of generation, distribution and transmission services pursuant to §56-585.1 A of the Code of Virginia*, Case No. PUE-2009-00030, 2010 S.C.C. Ann. Rept. 308, Final Order (July 15, 2010) (' *APCo 2009 Rate Case*').

FN7 *See, e.g.*, Staff's October 14, 2011 Post-Hearing Brief at 4-5.

FN8 Va. Code §56-585.1 A 8 (i).

FN9 The test period for this case ended on December 31, 2010. The Company's actual end-of-test period capital structure is as follows:

Short-term debt	3.764%
Long-term debt	53.248%
Preferred stock	0.266%
Common equity	42.693%
Investment tax credits	0.029%
Total Capitalization	100%

See Ex. 35 (Maddox direct) at Schedule 1; Staff's October 14, 2011 Post-Hearing Brief at 73-74.

FN10 We approve the actual end-of-test period cost of (i) long-term debt (5.903%), and (ii) short-term debt (0.327%). *See, e.g.*, Ex. 35 (Maddox direct) at Schedule 1.

FN11 Va. Code §56-585.1 A 2 a.

FN12 *See, e.g.*, Staff's October 14, 2011 Post-Hearing Brief at 74-84; Committee's October 14, 2011 Post-Hearing Brief at 7-23; APCo's October 14, 2011 Post-Hearing Brief at 72-80. We also included in our analysis a broad range of economic factors addressed in the evidence.

FN13 *See, e.g.*, Staff's October 14, 2011 Post-Hearing Brief at 75-83; Committee's October 14, 2011 Post-Hearing Brief at 19-23. In addition, we find that APCo has not established that a flotation cost adjustment has actually been incurred, or that such is either reasonable or required in this proceeding. *See, e.g.*, Staff's October 14, 2011 Post-Hearing Brief at 83; Committee's October 14, 2011 Post-Hearing Brief at 22-23.

FN14 Moreover, we note that the risk free rate (*i.e.*, 30-year Treasury bond yield) used in analyzing market cost of equity has decreased during the pendency of this proceeding - further supporting our findings herein. For example, Mr. Oliver uses a three-month average 30-year Treasury rate of 4.34%. *See, e.g.*, Ex. 68 (Oliver direct) at 14-16. During the hearing, however, it was shown that such rate had decreased to 3.52% for the week ending September 2, 2011. *See, e.g.*, Ex.59.

FN15 Ex. 68 (Oliver direct) at 5.

FN16 *See, e.g.*, Tr. at 837 (Avera); Committee's October 14, 2011 Post-Hearing Brief at 24; Staff's October 14, 2011 Post-Hearing Brief at 84.

FN17 For a list of utilities comprising such peer group, *see, e.g.*, Ex. 68 (Oliver direct) at Schedule 17. We find that, based on the facts before us in this case, it is reasonable to utilize returns on average equity for this purpose.

FN18 *See, e.g.*, Brown v. Lukhard, 229 Va. 316, 321, 330 S.E.2d 84, 87 (1985) ('If language is clear and unambiguous, there is no need for construction by the court; the plain meaning and intent of the enactment will be given it ... . Therefore, when the language of an enactment is free from ambiguity, resort to legislative history and extrinsic facts is not permitted because we take the words as written to determine their meaning.' (citations omitted)); *School Bd. of Chesterfield County v. School Bd. of the City of Richmond*, 219 Va. 244, 250, 247 S.E.2d 380, 384 (1978) ('Where a statute is plain and unambiguous there is no room for construction by the court and the plain meaning and intent of the statute will be given to it' (citation omitted).); *Almond v. Gilmer*, 188 Va. 1, 14, 49 S.E.2d 431, 439 (1948) ('The province of construction lies wholly within the domain of ambiguity^ (citation omitted)).

FN19 Moreover, the lack of a particular evaluation methodology for selecting a 'majority' directly contrasts with the very specific criteria prescribed by the General Assembly in other parts of §56-585.1 A 2 of the Code.

FN20 Section 56-585.1 A 2 a of the Code.

FN21 As required by statute, in setting ROE we have also considered and applied the requirements of §56-585.1 A 2 e of the Code:

In addition to other considerations, in setting the return on equity within the range allowed by this section, the Commission shall strive to maintain costs of retail electric energy that are cost competitive with costs of retail electric energy provided by the other peer group investor-owned electric utilities.

See, e.g., Staff's October 14, 2011 Post-Hearing Brief at 87-88. In addition, Staff witness Walker presented comparisons of APCo's rates to statutory peer group utilities. *See, e.g.*, Ex. 40 (Walker direct) at 16-22 and Attachments.

FN22 *See, e.g.*, APCo's October 14, 2011 Post-Hearing Brief at 72; Staff's October 14, 2011 Post-Hearing Brief at 87; Committee's October 14, 2011 Post-Hearing Brief at 30.

In addition, Environmental Respondents note that the Commission has the authority to decrease APCo's return by up to 100 basis points for poor performance under §56-585.1 A 2 c of the Code. No participant herein recommended such a performance penalty. Environmental Respondents, however, raised issues that it believes are relevant to such an evaluation (and which may be considered by the Commission in subsequent performance evaluations under that statute), including generation diversity, environmental compliance planning, and development of cost-effective demand-side management resources. Environmental Respondents' October 14, 2011 Post-Hearing Brief at 14-17.

FN23 *See, e.g.*, Staff's October 14, 2011 Post-Hearing Brief at 14-16; Environmental Respondents' October 14, 2011 Post-Hearing Brief at 9-14.

FN24 *See, e.g.*, Staff's October 14, 2011 Post-Hearing Brief at 12; Ex. 38 (Carr direct) at 75. This amount represents an impact of (I) $38.6 million from using the 2010 Study, and (2) $848,752 from implementing on the effective date of the rates approved herein.

FN25 Consumer Counsel's October 14, 2011 Post-Hearing Brief at 4.

FN26 *Id.*

FN27 *See, e.g.*, Staff's October 14, 2011 Post-Hearing Brief at 23. Staff further explains that the Capacity Equalization Rate is the price charged for APCo's capacity deficiency and consists of (i) the Capacity Investment Rate, which is based on the gross installed cost of the surplus members' generating units and a FERC-approved annual carrying charge of 16.49%, and (ii) the Fixed Operating Rate, which is based on the operating costs and one-half of the maintenance costs of the surplus members' units. *Id.* at n.58. In addition, the Company's MLR is the relationship between its peak demand and the total non-coincident peak demand of the AEP East system, all measured over the preceding twelve months, and each member's capacity obligation is determined on a monthly basis by multiplying the total AEP East capacity by its MLR. *See, e.g.*, APCo 2009 Rate Case at 313, n.46.

FN28 Section 56-235.2 A of the Code permits 'annualized adjustments for future costs as the Commission finds reasonably can be predicted to occur during the rate year.' *See, e.g.*, Staff's October 14, 2011 Post-Hearing Brief at 22-26.

FN29 *See, e.g.*, Staff's October 14, 2011 Post-Hearing Brief at 22-26. We likewise find that it is reasonable (a) to adjust for the loss of Century Aluminum's load in West Virginia, (b) to adjust for the additional load served by competitive retail electric service providers in Ohio that contribute to the MLR peaks of Columbus Southern Power Company ('Columbus Southern') and Ohio Power Company ('Ohio Power'), and (c) not to remove any wind capacity when calculating rate year capacity equalization charges. *See, e.g.*, id. at 24-26. We further conclude that the Interconnection Agreement requires the use of non-coincident peaks, as opposed to SDI's recommendation of coincident peaks, for this purpose. *See, e.g.*, APCo's October 14, 2011 Post-Hearing Brief at 24.

FN30 *See* Staff's October 14, 2011 Post-Hearing Brief at Attachment A.

FN31 *Application of Appalachian Power Company, AEP Generating Company, and American Electric Power Company, Inc., For authority to enter into affiliate transactions under Title 56, Chapter 4 of the Code of Virginia*, Case No. PUE-2011-00023, Doc. Con. Cen. No. 110720091, Order Granting Authority (July 20, 2011).

FN32 *See, e.g.*, Consumer Counsel's October 14, 2011 Post-Hearing Brief at 17-18; Committee's October 14, 2011 Post-Hearing Brief at 32-35; Staff's October 14, 2011

Post-Hearing Brief at 26-28.

FN33 *See, e.g.*, Staff's October 14, 2011 Post-Hearing Brief at 28.

FN34 *In the Matter of the Application of Ohio Power Company for Approval of the Shutdown of Unit 5 of the Philip Sporn Generating Station and to Establish a Plant Shutdown Rider*, PUCO Case No. 10-1454-EL-RDR. *See also* Staff's October 14, 2011 Post-Hearing Brief at 28-29; Consumer Counsel's October 14, 2011 Post-Hearing Brief at 19-20.

FN35 *See, e.g.*, Consumer Counsel's October 14, 2011 Post-Hearing Brief at 19-20; APCo's October 14, 2011 Post-Hearing Brief at 28.

FN36 *See, e.g.*, Staff's October 14, 2011 Post-Hearing Brief at 29.

FN37 *See, e.g.*, Consumer Counsel's October 14, 2011 Post-Hearing Brief at 4-16.

FN38 *APCo 2009 Rate Case* at 313.

FN39 *Id*.

FN40 *See, e.g.*, Staff's October 14, 2011 Post-Hearing Brief at 71; Consumer Counsel's October 14, 2011 Post-Hearing Brief at 16.

FN41 *See, e.g.*, APCo's October 14, 2011 Post-Hearing Brief at 32.

FN42 *See id*.

FN43 *See, e.g.*, APCo's October 14, 2011 Post-Hearing Brief at 61; Staff's October 14, 2011 Post-Hearing Brief at 36.

FN44 Staff's October 14, 2011 Post-Hearing Brief at 36.

FN45 *Id*. at 36-37.

FN46 *See, e.g.*, id. at 36-39.

FN47 *Id*. at 39.

FN48 *See, e.g.*, Staff's October 14, 2011 Post-Hearing Brief at 33-36.

FN49 *See APCo 2009 Rate Case* at 315-316.

FN50 APCo's October 14, 2011 Post-Hearing Brief at 58.

FN51 *Id*. at 57.

FN52 *Id*. at 57-60. In addition, we find that ratepayers should not bear Incentive Plan expenses that exceed a payout ratio of 100%, the benefits of which accrue to shareholders. *See, e.g.*, Ex. 38 (Carr direct) at 50-51. We note, however, that APCo's normalized Incentive Plan expenses approximate such result and, thus, are approved herein. *See id*.

FN53 Staff's October 14, 2011 Post-Hearing Brief at 44.

FN54 *Id.*

FN55 *Id.*

FN56 Va. Code §56-235.2 A.

FN57 In addition, we note that these environmental consumables are not the only environmental-related costs included in the Company's base rate request herein. For example, Staff witness Carr estimated that 'environmental compliance costs included in [Staff's] recommended revenue requirement have increased by at least $35.6 million from the level included in base rates approved in Case No. PUE-2009-00030 to an approximate annual amount of $225.2 million.' Ex. 38 (Carr direct) at 9.

FN58 Staff's October 14, 2011 Post-Hearing Brief at 48 (citations and internal quotes omitted). Moreover, Staff notes that 'the year-to-year variation in the emission allowance gains is further evidence of their unpredictability, with [APCo's] gains, on a Virginia-jurisdictional basis, ranging from as low as $2.8 million in 2003 to as high as $17 million in 2010.' *Id.* at 49.

FN59 Va. Code §56-235.2 A.

FN60 *See, e.g.*, Staff's October 14, 2011 Post-Hearing Brief at 50. This represents an increase for PJM ancillary fees of approximately $4.29 million, and an increase for emission allowance gains of approximately $2.57 million (which includes the $4 million correction).

FN61 *See, e.g.*, Staff's October 14, 2011 Post-Hearing Brief at 52-53.

FN62 *Id.* at 53.

FN63 *See, e.g.*, APCo's October 14, 2011 Post-Hearing Brief at 64. Such deferral does not create a rate base asset, and the Company shall not earn a return on such deferral.

FN64 *Id.*

FN65 *Id.* at 64-66.

FN66 *Id.* at 67.

FN67 *See, e.g.*, Consumer Counsel's October 14, 2011 Post-Hearing Brief at 40-41.

FN68 *See, e.g.*, Staff's October 14, 2011 Post-Hearing Brief at 68-70.

FN69 *See, e.g.*, APCo's October 14, 2011 Post-Hearing Brief at 69.

FN70 Staff's October 14, 2011 Post-Hearing Brief at 56.

FN71 *Id.* at 57 (emphasis in original).

FN72 *Id.*

FN73 *Id.* at 56.

FN74 *Id.* at 57-58.

FN75 *Id.* at 72.

FN76 *Id.* at 72-73.

FN77 APCo's October 14, 2011 Post-Hearing Brief at 71.

FN78 *Id.*

FN79 Va. Code §56-235.2 A.

FN80 *See. e.g.*, Staff's October 14, 2011 Post-Hearing Brief at 18-22; VML/VACO's October 14, 2011 Post-Hearing Brief at 2-5; Consumer Counsel's October 14, 2011 Post-Hearing Brief at 21-23; Committee's October 14, 2011 Post-Hearing Brief at 31-32. Staff further notes that the economic uncertainty which complicates the Company's forecasts and increases the likelihood of both significant errors in the forecasts, along with the exercise of management's discretion to alter its spending plans, also caused 'a delay in the approval of [APCo's] 2012 budget - a budget that was still not approved and finalized before the hearing on the Company's application was adjourned.' Staff's October 14, 2011 Post-Hearing Brief at 21.

FN81 We likewise reject APCo's proposed forecast of its deferred fuel balance. In this regard, Staff states that the 'deferred fuel balance depends on fuel costs and fuel consumption, two notoriously unpredictable cost of service items. Indeed, if fuel costs were reasonably predictable, there would be no need for a fuel factor.' Staff's October 14, 2011 Post-Hearing Brief at 21. Consistent with our adoption of actual, audited rate base as of March 31, 2011, we adopt Staff's proposed revenue growth adjustment. In addition, unless adopted in this Final Order, any other rate base or expense adjustments to the Company's Application proposed by participants herein are denied.

FN82 Consumer Counsel's October 14, 2011 Post-Hearing Brief at 31-32.

FN83 *Id.* at 32.

FN84 *See, e.g.*, id. at 31-36.

FN85 *See, e.g.*, Consumer Counsel's October 14, 2011 Post-Hearing Brief at 28-30; Staff's October 14, 2011 Post-Hearing Brief at 64-66.

FN86 Consumer Counsel's October 14, 2011 Post-Hearing Brief at 28.

FN87 *See, e.g.*, Staff's October 14, 2011 Post-Hearing Brief at 64-66; APCo's October 14, 2011 Post-Hearing Brief at 48-49.

FN88 *See, e.g.*, Staff's October 14, 2011 Post-Hearing Brief at 64-66; Consumer Counsel's October 14, 2011 Post-Hearing Brief at 28-30.

FN89 Staff's October 14, 2011 Post-Hearing Brief at 58.

FN90 *See, e.g.*, id. at 59-60; Consumer Counsel's October 14, 2011 Post-Hearing Brief at 30-31.

FN91 *See, e.g.*, Staff's October 14, 2011 Post-Hearing Brief at 60.

FN92 *See, e.g.*, id. at 66-67.

FN93 *See, e.g.*, Staff's October 14, 2011 Post-Hearing Brief at 67. The Company is not precluded from seeking cost recovery on this matter in the future.

FN94 *See. e.g.*, Tr. at 374.

FN95 *APCo 2009 Rale Case* at 315.

FN96 *See, e.g.*, Staff's October 14, 2011 Post-Hearing Brief at 62-63; Consumer Counsel's October 14, 2011 Post-Hearing Brief at 51.

FN97 *See, e.g.*, Staff's October 14, 2011 Post-Hearing Brief at 63. We also adopt Staff's recommendations that: (a) the Company record the FEED study costs in Account 183, Preliminary Survey and Investigation Charges, until the project is either abandoned or its development re-started; and (b) it is not necessary for the Company to write-off the FEED study costs at this time. *Id.*

FN98 *See, e.g.*, APCo's October 14, 2011 Post-Hearing Brief at 80-83; Staff's October 14, 2011 Post-Hearing Brief at 90-91.

FN99 *Id.*

FN100 Staff's October 14, 2011 Post-Hearing Brief at 92 (citation and internal quotes omitted); see also APCo's October 14, 2011 Post-Hearing Brief at 83-84.

FN101 Staff's October 14, 2011 Post-Hearing Brief at 92. This results in a specific revenue increase for each customer class as follows:

Customer Class	Revenue Increase
Residential	$32,093,098
Small General Service (SGS)	$1,975,754
Medium General Service (MGS)	$2,924,587
Large General Service (LGS)	$7,818,348
Large Power Service (LPS)	$9,711,815
Sanctuary Worship Service (SWS)	$547,423
Outdoor Lighting (OL)	$--
Total	$55,071,025

FN102 *See, e.g.*, APCo's October 14, 2011 Post-Hearing Brief at 84-85.

FN103 *See, e.g.*, Roanoke Gas' October 14, 2011 Post-Hearing Brief at 6-7; Staff's October 14, 2011 Post-Hearing Brief at 93.

FN104 In addition, consistent with Staff's recommendation, we find that for the rate increase approved in this Final Order, the portion allocated to the residential and SWS rate schedules shall be recovered through each schedule's usage charge. *See* Ex. 40 (Walker direct) at 12-13.

FN105 *See, e.g.*, Roanoke Gas' October 14, 2011 Post-Hearing Brief at 2-5; Environmental Respondent's October 14, 2011 Post-Hearing Brief at 3-7; Staff's October 14, 2011 Post-Hearing Brief at 92-95.

FN106 *See, e.g.*, APCo's October 14, 2011 Post-Hearing Brief at 85-86; Staff's October

14, 2011 Post-Hearing Brief at 95.

FN107 *See, e.g.*, id.

FN108 *See, e.g.*, APCo's October 14, 2011 Post-Hearing Brief at 85-87; Staff's October 14, 2011 Post-Hearing Brief at 95-97.

FN109 SDI's October 14, 2011 Post-Hearing Brief at 14.

FN110 *See, e.g.*, Staff's October 14, 2011 Post-Hearing Brief at 60-62. In addition, we note that such treatment of factoring costs under this statute is consistent with the Commission's historical treatment of APCo's factoring costs associated with its fuel adjustment clause; that is, factoring costs associated with fuel recovery are not included in the fuel adjustment clause but, rather, are recovered through base rates. *See, e.g.*, id. at 62.

FN111 *See, e.g.*, id. at Attachment A.

FN112 *See, e.g.*, Staff's August 26, 2011 Legal Memorandum at 9-11; *Petition of Appalachian Power Company, For approval of rate adjustment clause pursuant to §56-585.1 A 4 of the Code of Virginia*, Case No. PUE-2009-00031, 2009 S.C.C. Ann. Rept. 450, Final Order (Oct. 6, 2009).

FN113 Finally, in issuing this Final Order, to the extent relevant, we have taken into consideration the goal of economic development in the Commonwealth as directed in §56-596 A: 'In all relevant proceedings pursuant to this Act, the Commission shall take into consideration, among other things, the goal of economic development in the Commonwealth.'

Va.S.C.C. 2011
Re Appalachian Power Company
2011 WL 6119143 (Va.S.C.C.)

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EXHIBIT
103
RESA

PENGAD 800-631-6989

AMERICAN ELECTRIC POWER CO INC (AEP)

10-K

Annual report pursuant to section 13 and 15(d)
Filed on 2/28/2012
Filed Period 12/31/2011

The following table illustrates certain regulatory information with respect to the states in which the public utility subsidiaries of AEP operate:

Jurisdiction	Percentage of AEP System Retail Revenues (a)	Percentage of OSS Profits Shared with Ratepayers	AEP Utility Subsidiaries Operating in that Jurisdiction	Authorized Return on Equity (b)
Ohio	32%	No sharing included in the ESP	OPCo	(c)
Texas	12%	Not Applicable in ERCOT	TCC	9.96%
		Not Applicable in ERCOT	TNC	9.96%
		90% in SPP	SWEPCo	10.33%
Oklahoma	11%	75%	PSO	10.15%
West Virginia	11%	100%	APCo	10.00%
		100%	WPCo	10.00%
Virginia	10%	75%	APCo	10.90%
Indiana	9%	50% after certain level (d)	I&M	10.50%
Kentucky	5%	60% below and above certain level (e)	KPCo	10.50%
Louisiana	5%	50% to 100% after certain levels (f)	SWEPCo	10.57%
Arkansas	2%	50% to 100% after certain levels (g)	SWEPCo	10.25%
Michigan	2%	80%	I&M	10.20%
Tennessee	1%	Not Applicable	KGPCo	12.00%

(a) Represents the percentage of revenues from sales to retail customers from AEP utility companies operating in each state to the total AEP System revenues from sales to retail customers for the year ended December 31, 2011.

(b) Identifies the predominant authorized return on equity and may not include other, less significant, permitted recovery. Actual return on equity varies from authorized return on equity.

(c) OPCo's generation revenues are governed by its Electric Security Plan (ESP) as approved by the PUCO in March 2009. Under the ESP, authorized rate increases during the ESP period were subject to caps that limit the annual rate increases in 2009 through 2011. Some rate components and increases are exempt from the cap limitations. The ESP also provided for a fuel adjustment clause.

(d) There is an annual $37.5 million credit established for off–system sales in base rates. If the off–system sales profits exceed the amount built into base rates, I&M reimburses ratepayers 50% of the excess.

(e) There is an annual $15.3 million credit established for off–system sales in base rates. If the monthly off–system sales profits do not meet the monthly level built into base rates, ratepayers reimburse KPCo 60% of the shortfall. If the monthly off–system sales profits exceed the monthly level built into base rates, KPCo reimburses ratepayers 60% of the excess.

(f) Below $874,000, 100% is given to customers.
From $874,001 to $1,314,000, 85% is given to customers.
Above $1,314,000, 50% is given to customers.

(g) Below $758,600, 100% is given to customers.
From $758,601 to $1,167,078, 85% is given to customers.
Above $1,167,078, 50% is given to customers.

In December 2011, the PUCT approved an unopposed stipulation allowing TCC to recover $800 million, including carrying charges, and retain contested tax balances in full satisfaction of its true–up proceeding. TCC recorded the reversal of regulatory credits of $65 million ($42 million, net of tax) and the reversal of $89 million of accumulated deferred investment tax credits ($58 million, net of tax) in Extraordinary Items, Net of Tax on the statement of income in the fourth quarter of 2011. Also, in the fourth quarter of 2011, TCC recorded $52 million in pretax Carrying Costs Income on the statement of income. See the "Texas Restructuring Appeals" and "TCC Deferred Investment Tax Credits and Excess Deferred Federal Income Taxes" sections of Note 3.

Regulatory Activity

The table below summarizes our significant 2011 regulatory activities:

	Requested		Approved		
Jurisdiction	Annual Requested Base Rate Change	Requested Return on Common Equity	Annual Approved Base Rate Change	Approved Return on Common Equity	Approved Effective Date
	(in millions)		(in millions)		
Indiana	$ 149	11.15%	$ (a)	(a)	(a)
Michigan	25	11.15%	15	10.2%	April 2012
Ohio	94	11.15%	– (b)	10.2%	January 2012
Virginia	126	11.65%	55	10.9%	February 2012
West Virginia	156	11.75%	51	10.0%	April 2011

(a) The Indiana base rate case is presently under review at the IURC.
(b) Although the distribution base rate did not change, approximately $47 million was being recovered through the Distribution Investment Rider (DIR). Due to the February 2012 PUCO ESP entry on rehearing, which rejected the modified stipulation for a new ESP, collection of the DIR terminated. OPCo has the right to withdraw from the stipulation in its distribution base rate case. Management is currently evaluating all of its options.

2009 – 2011 Ohio ESP

In 2011, the PUCO issued an order in the 2009 – 2011 ESP remand proceeding requiring OPCo to cease POLR billings and apply POLR collections since June 2011 first to the FAC deferral with any remaining balance to be credited to OPCo's customers in November and December 2011. As a result, in comparison to 2010, we lost approximately $71 million of pretax income related to POLR. In February 2012, the Ohio Consumers' Counsel (OCC) and the Industrial Energy Users–Ohio filed appeals with the Supreme Court of Ohio challenging various issues, including the PUCO's refusal to order retrospective relief concerning the POLR charges collected during 2009 – 2011 and various aspects of the approved environmental carrying charge, which if ordered could total up to $698 million, excluding carrying costs.

OPCo filed its 2010 Significantly Excessive Earnings Test (SEET) with the PUCO based upon the approach in the PUCO's 2009 order. Subsequent testimony and legal briefs from intervenors recommended a refund of up to $62 million of 2010 earnings, which included off–system sales in the SEET calculation. In December 2011, the PUCO staff filed testimony that recommended a $23 million refund of 2010 earnings. In the fourth quarter of 2011, OPCo provided a reserve based upon management's estimate of the probable amount for a PUCO ordered SEET refund. OPCo is required to file its 2011 SEET filing with the PUCO in 2012. Management does not currently believe that there are significantly excessive earnings in 2011. See "Ohio Electric Security Plan Filing" section of Note 3.