COMMONWEALTH OF KENTUCKY
BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

APPLICATION OF BIG RIVERS ELECTRIC	)	
CORPORATION FOR A GENERAL	)	**CASE NO. 2011-00036**
ADJUSTMENT IN RATES	)	

KENTUCKY INDUSTRIAL UTILITY CUSTOMERS RESPONSE TO
BIG RIVERS ELECTRIC CORPORATION
FIRST DATA REQUEST
PSC CASE NO. 2011-00036
June 22, 2011

Request BREC-1

Please provide an electronic copy - with searchable electronic formats and all formulas intact - of all exchanges of information among Dr. Morey, Dr. Coomes, Mr. King, Smelters, any person representing a Smelter, the Smelters' respective Corporate parents, and/or Mr. Strong. This includes, but is not limited to, e-mails, letters, charts, graphs, tables, reports, *etc.*

RESPONSE

KIUC objects to this Request on the grounds that it seeks information which is protected from discovery by the attorney-client privilege, the work product rule and the common interest rule. KIUC further objects to this Request on the grounds that it is vague and ambiguous in that it fails to identify a time period for which discovery is sought.

Witness: Counsel

RECEIVED
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PUBLIC SERVICE
COMMISSION

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CORPORATION FOR A GENERAL	)	**CASE NO. 2011-00036**
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FIRST DATA REQUEST
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Request BREC-2

Please provide electronic copies of Exhibits LK-9 and LK-12 to the direct testimony of Mr. Kollen, with cells and formulas intact, along with all computer models, workpapers and other documents that support these exhibits.

RESPONSE

Please see files on enclosed CD.

Witness: Lane Kollen

KIUC Adjustment to Depreciation Expense

ACCT	BALANCE 10/31/2010	COMPANY'S NEW YEARLY RATE	COMPANY'S NEW DEPRECIATION RATE	COMPANY'S PRO FORMA DEPRECIATION EXPENSE	VARIANCE	KIUC NEW YEARLY RATE	KIUC NEW DEPRECIATION RATE	KIUC PRO FORMA DEPRECIATION EXPENSE	KIUC ADJUSTMENT
3010	419.82	0.00	0.000000	0.00	0.00	0.00	0.000000	0.00	0.00
3020	66,475.65	0.00	0.000000	0.00	0.00	0.00	0.000000	0.00	0.00
3030	0.00	0.00	0.000000	0.00	0.00	0.00	0.000000	0.00	0.00
3101	83,342.47	0.00	0.000000	0.00	0.00	0.00	0.000000	0.00	0.00
3102	1,124,664.82	0.00	0.000000	0.00	0.00	0.00	0.000000	0.00	0.00
3103	1,110,711.72	0.00	0.000000	0.00	0.00	0.00	0.000000	0.00	0.00
3104	2,218,857.54	0.00	0.000000	0.00	0.00	0.00	0.000000	0.00	0.00
3111	3,236,944.36	1.38	0.001150	44,669.83	(10,681.92)	1.17	0.000975	37,872.25	(6,797.58)
3112	18,977,054.83	1.38	0.001150	261,883.36	(62,624.28)	1.17	0.000975	222,031.54	(39,851.82)
3113	26,723,028.18	1.38	0.001150	368,777.79	(88,185.99)	1.17	0.000975	312,659.43	(56,118.36)
3114	73,073,034.47	1.38	0.001150	1,008,407.88	(241,141.01)	1.17	0.000975	854,954.50	(153,453.38)
3115	421,179.00	1.38	0.001150	5,812.27	(1,389.89)	1.17	0.000975	4,927.79	(884.48)
3116	577,533.07	1.38	0.001150	7,969.96	(1,905.86)	1.17	0.000975	6,757.14	(1,212.82)
3117	937,856.03	1.38	0.001150	12,942.41	(3,094.93)	1.17	0.000975	10,972.92	(1,969.49)
3119	693,609.79	1.38	0.001150	9,571.82	(2,288.91)	1.17	0.000975	8,115.23	(1,456.59)
3120	29,686.39	1.88	0.001567	558.10	26.59	1.54	0.001283	457.17	(100.93)
312A	220,240.55	2.28	0.001900	5,021.48	858.93	1.95	0.001625	4,294.69	(726.79)
3121	7,193,006.17	1.88	0.001567	135,228.52	6,444.94	1.54	0.001283	110,772.30	(24,456.22)
312B	5,061,431.08	2.28	0.001900	115,400.63	19,739.58	1.95	0.001625	98,697.91	(16,702.72)
3122	77,143,667.49	1.88	0.001567	1,450,300.95	69,120.73	1.54	0.001283	1,188,012.48	(262,288.47)
312C	121,989,593.12	2.28	0.001900	2,781,362.72	475,759.41	1.95	0.001625	2,378,797.07	(402,565.65)
3123	161,617,029.17	1.88	0.001567	3,038,400.15	144,808.86	1.54	0.001283	2,488,902.25	(549,497.90)
312D	113,968,704.31	2.28	0.001900	2,598,486.46	444,477.95	1.95	0.001625	2,222,389.73	(376,096.73)
3124	402,071,586.26	1.88	0.001567	7,558,945.82	360,256.14	1.54	0.001283	6,191,902.43	(1,367,043.39)
312E	268,650,680.12	2.28	0.001900	6,125,235.51	1,047,737.66	1.95	0.001625	5,238,688.26	(886,547.25)
3125	17,389,606.87	1.88	0.001567	326,924.61	15,581.09	1.54	0.001283	267,799.95	(59,124.66)
312F&312K	71,086,231.78	2.28	0.001900	1,620,766.08	277,236.30	1.95	0.001625	1,386,181.52	(234,584.56)
3126	2,554,464.97	1.88	0.001567	48,023.94	2,288.80	1.54	0.001283	39,338.76	(8,685.18)
312G	1,899,172.74	2.28	0.001900	43,301.14	7,406.78	1.95	0.001625	37,033.87	(6,267.27)
3127	376,268.58	1.88	0.001567	7,073.85	337.14	1.54	0.001283	5,794.54	(1,279.31)
3128	1,186,252.75	1.88	0.001567	22,301.55	1,062.88	1.54	0.001283	18,268.29	(4,033.26)
312J	15,438.27	2.28	0.001900	351.99	60.21	1.95	0.001625	301.05	(50.94)
3140	0.00	1.91	0.001592	0.00	0.00	1.54	0.001283	0.00	0.00
3141	4,310,530.58	1.91	0.001592	82,331.13	10,793.56	1.54	0.001283	66,382.17	(15,948.96)
3142	32,762,390.07	1.91	0.001592	625,761.65	82,037.02	1.54	0.001283	504,540.81	(121,220.84)
3143	57,679,599.22	1.91	0.001592	1,101,680.35	144,429.72	1.54	0.001283	888,265.83	(213,414.52)
3144	127,883,751.07	1.91	0.001592	2,442,579.65	320,220.92	1.54	0.001283	1,969,409.77	(473,169.88)
3145	4,991,571.10	1.91	0.001592	95,339.01	12,498.90	1.54	0.001283	76,870.19	(18,468.82)
3146	262,741.29	1.91	0.001592	5,018.36	657.91	1.54	0.001283	4,046.22	(972.14)
3147	18,495.15	1.91	0.001592	353.26	46.31	1.54	0.001283	284.83	(68.43)
3151	1,494,658.69	1.99	0.001658	29,743.71	5,835.15	1.08	0.000900	16,142.31	(13,601.40)
3152	8,552,676.77	1.99	0.001658	170,198.27	33,389.65	1.08	0.000900	92,368.91	(77,829.36)
3153	16,091,239.72	1.99	0.001658	320,215.67	62,820.20	1.08	0.000900	173,785.39	(146,430.28)
3154	35,070,442.41	1.99	0.001658	697,901.80	136,915.00	1.08	0.000900	378,760.78	(319,141.02)
3155	171,384.26	1.99	0.001658	3,410.55	669.09	1.08	0.000900	1,850.95	(1,559.60)
3159	43,548.07	1.99	0.001658	866.61	170.02	1.08	0.000900	470.32	(396.29)
3160	56,008.08	3.78	0.003150	2,117.11	1,092.16	3.77	0.003142	2,111.50	(5.61)
3161	1,227.09	3.78	0.003150	46.38	23.92	3.77	0.003142	46.26	(0.12)

KIUC Adjustment to Depreciation Expense

ACCT	BALANCE 10/31/2010	COMPANY'S NEW YEARLY RATE	COMPANY'S NEW DEPRECIATION RATE	COMPANY'S PRO FORMA DEPRECIATION EXPENSE	VARIANCE	KIUC NEW YEARLY RATE	KIUC NEW DEPRECIATION RATE	KIUC PRO FORMA DEPRECIATION EXPENSE	KIUC ADJUSTMENT
3162	849,312.17	3.78	0.003150	32,104.00	16,561.59	3.77	0.003142	32,019.07	(84.93)
3163	779,447.85	3.78	0.003150	29,463.13	15,199.23	3.77	0.003142	29,385.18	(77.95)
3164	749,577.26	3.78	0.003150	28,334.02	14,616.76	3.77	0.003142	28,259.06	(74.96)
3165	345,677.46	3.78	0.003150	13,066.61	6,740.71	3.77	0.003142	13,032.04	(34.57)
3166	308,147.79	3.78	0.003150	11,647.99	6,008.89	3.77	0.003142	11,617.17	(30.82)
3167	88,777.93	3.78	0.003150	3,355.81	1,731.17	3.77	0.003142	3,346.93	(8.88)
3169	107,699.80	3.78	0.003150	4,071.05	2,100.14	3.77	0.003142	4,060.28	(10.77)
3401	0.00	0.00	0.000000	0.00	0.00	0.00	0.000000	0.00	0.00
3410	154,232.79	1.17	0.000975	1,804.52	(1,758.26)	1.17	0.000975	1,804.52	0.00
3420	1,436,911.63	9.10	0.007583	130,758.96	97,428.36	9.10	0.007583	130,758.96	0.00
3430	4,915,885.63	3.02	0.002517	148,459.75	27,057.04	3.02	0.002517	148,459.75	0.00
3440	1,102,963.67	0.50	0.000417	5,514.82	(19,076.86)	0.50	0.000417	5,514.82	0.00
3450	383,519.62	2.05	0.001708	7,862.15	(688.80)	2.05	0.001708	7,862.15	0.00
3460	0.00	0.00	0.000000	0.00	0.00	0.00	0.000000	0.00	0.00
3500	13,151,946.52	0.00	0.000000	0.00	0.00	0.00	0.000000	0.00	0.00
3501	704,868.36	0.00	0.000000	0.00	0.00	0.00	0.000000	0.00	0.00
3520	5,817,594.61	1.90	0.001583	110,534.30	8,121.36	1.90	0.001583	110,534.30	0.00
3521	20,369.05	1.90	0.001583	387.01	28.43	1.90	0.001583	387.01	0.00
3522	157,304.64	1.90	0.001583	2,988.79	219.60	1.90	0.001583	2,988.79	0.00
3524	679,442.21	1.90	0.001583	12,909.40	948.50	1.90	0.001583	12,909.40	0.00
3530	78,645,358.50	2.23	0.001858	1,753,791.49	7,864.53	2.23	0.001858	1,753,791.49	0.00
3531	3,031,650.37	2.23	0.001858	67,605.80	303.16	2.23	0.001858	67,605.80	0.00
3532	5,573,659.91	2.23	0.001858	124,292.62	557.37	2.23	0.001858	124,292.62	0.00
3533	5,947,214.37	2.23	0.001858	132,622.88	594.72	2.23	0.001858	132,622.88	0.00
3534	22,364,145.19	2.23	0.001858	498,720.44	2,236.42	2.23	0.001858	498,720.44	0.00
3540	8,134,239.23	1.42	0.001183	115,506.20	(69,954.45)	1.42	0.001183	115,506.20	0.00
3541	146,747.32	1.42	0.001183	2,083.81	(1,262.03)	1.42	0.001183	2,083.81	0.00
3550	42,097,383.75	2.06	0.001717	867,206.11	(496,749.12)	2.06	0.001717	867,206.11	0.00
3551	234,314.24	2.06	0.001717	4,826.87	(2,764.91)	2.06	0.001717	4,826.87	0.00
3560	43,673,282.78	1.69	0.001408	738,078.48	(340,476.91)	1.69	0.001408	738,078.48	0.00
3561	86,900.75	1.69	0.001408	1,468.62	(677.48)	1.69	0.001408	1,468.62	0.00
3890	407,251.23	0.00	0.000000	0.00	0.00	0.00	0.000000	0.00	0.00
3900	3,948,933.89	2.84	0.002367	112,149.72	9,888.13	2.84	0.002367	112,149.72	0.00
3910	589,902.92	17.12	0.014267	100,991.38	94,443.46	17.12	0.014267	100,991.38	0.00
3912	7,163,171.79	10.29	0.008575	737,090.38	657,579.17	10.29	0.008575	737,090.38	0.00
3913	0.00	0.00	0.000000	0.00	0.00	0.00	0.000000	0.00	0.00
3916	1,894.73	17.12	0.014267	324.38	303.35	17.12	0.014267	324.38	0.00
3917	3,059.60	17.12	0.014267	523.80	489.84	17.12	0.014267	523.80	0.00
3922	1,764,679.12	4.39	0.003658	77,469.41	(21,698.50)	4.39	0.003658	77,469.41	0.00
3923	1,257,239.84	6.14	0.005117	77,194.53	6,542.68	6.14	0.005117	77,194.53	0.00
3930	98,765.68	4.40	0.003667	4,345.69	819.76	4.40	0.003667	4,345.69	0.00
3940	722,077.41	4.61	0.003842	33,287.77	12,708.56	4.61	0.003842	33,287.77	0.00
3950	221,278.64	4.41	0.003675	9,758.39	3,430.71	4.41	0.003675	9,758.39	0.00
3960	342,907.40	3.70	0.003083	12,687.57	1.37	3.70	0.003083	12,687.57	0.00
3961	183,073.76	3.70	0.003083	6,773.73	0.73	3.70	0.003083	6,773.73	0.00
3970	1,640,119.50	4.35	0.003625	71,345.20	0.00	4.35	0.003625	71,345.20	0.00
3980	165,070.19	11.80	0.009833	19,478.28	10,499.12	11.80	0.009833	19,478.28	0.00
3986	0.00	11.80	0.009833	0.00	0.00	11.80	0.009833	0.00	0.00

KIUC Adjustment to Depreciation Expense

ACCT	BALANCE 10/31/2010	COMPANY'S NEW YEARLY RATE	COMPANY'S NEW DEPRECIATION RATE	COMPANY'S PRO FORMA DEPRECIATION EXPENSE	VARIANCE	KIUC NEW YEARLY RATE	KIUC NEW DEPRECIATION RATE	KIUC PRO FORMA DEPRECIATION EXPENSE	KIUC ADJUSTMENT
3987	1,625.49	11.80	0.009833	191.81	103.39	11.80	0.009833	191.81	0.00
312 L-P	3,208,938.00	20.22	0.016850	648,847.26	588,198.33	19.31	0.016092	619,645.93	(29,201.33)
312 V-Z	868,755.00	14.39	0.011992	125,013.84	109,459.65	19.31	0.016092	167,756.59	42,742.75
3525	185,107.45	1.90	0.001583	3,517.04	258.41	1.90	0.001583	3,517.04	0.00
3535	6,511,340.66	2.23	0.001858	145,202.90	651.14	2.23	0.001858	145,202.90	0.00
3545	312,557.79	1.42	0.001183	4,438.32	(2,688.00)	1.42	0.001183	4,438.32	0.00
3555	79,206.80	2.06	0.001717	1,631.66	(934.64)	2.06	0.001717	1,631.66	0.00
3565	104,571.36	1.69	0.001408	1,767.26	(815.23)	1.69	0.001408	1,767.26	0.00
Total - No CWIP Included	1,942,558,139.59			40,218,778.28	4,017,641.32			34,367,973.80	-5,850,804.48

KIUC Adjustment to Depreciation Expense

ACCT	BALANCE 10/31/2010	COMPANY'S NEW YEARLY RATE	COMPANY'S NEW DEPRECIATION RATE	COMPANY'S PRO FORMA DEPRECIATION EXPENSE	VARIANCE	KIUC NEW YEARLY RATE	KIUC NEW DEPRECIATION RATE	KIUC PRO FORMA DEPRECIATION EXPENSE	KIUC ADJUSTMENT
3010	419.82	0.00	0.000000	0.00	0.00	0.00	0.000000	0.00	0.00
3020	66,475.65	0.00	0.000000	0.00	0.00	0.00	0.000000	0.00	0.00
3030	0.00	0.00	0.000000	0.00	0.00	0.00	0.000000	0.00	0.00
3101	83,342.47	0.00	0.000000	0.00	0.00	0.00	0.000000	0.00	0.00
3102	1,124,664.82	0.00	0.000000	0.00	0.00	0.00	0.000000	0.00	0.00
3103	1,110,711.72	0.00	0.000000	0.00	0.00	0.00	0.000000	0.00	0.00
3104	2,218,857.54	0.00	0.000000	0.00	0.00	0.00	0.000000	0.00	0.00
3111	3,236,944.36	1.38	0.001150	44,669.83	(10,681.92)	1.17	0.000975	37,872.25	(6,797.58)
3112	18,977,054.83	1.38	0.001150	261,883.36	(62,624.28)	1.17	0.000975	222,031.54	(39,851.82)
3113	26,723,028.18	1.38	0.001150	368,777.79	(88,185.99)	1.17	0.000975	312,659.43	(56,118.36)
3114	73,073,034.47	1.38	0.001150	1,008,407.88	(241,141.01)	1.17	0.000975	854,954.50	(153,453.38)
3115	421,179.00	1.38	0.001150	5,812.27	(1,389.89)	1.17	0.000975	4,927.79	(884.48)
3116	577,533.07	1.38	0.001150	7,969.96	(1,905.86)	1.17	0.000975	6,757.14	(1,212.82)
3117	937,856.03	1.38	0.001150	12,942.41	(3,094.93)	1.17	0.000975	10,972.92	(1,969.49)
3119	693,609.79	1.38	0.001150	9,571.82	(2,288.91)	1.17	0.000975	8,115.23	(1,456.59)
3120	29,686.39	1.88	0.001567	558.10	26.59	1.54	0.001283	457.17	(100.93)
312A	220,240.55	2.28	0.001900	5,021.48	858.93	1.95	0.001625	4,294.69	(726.79)
3121	7,193,006.17	1.88	0.001567	135,228.52	6,444.94	1.54	0.001283	110,772.30	(24,456.22)
312B	5,061,431.08	2.28	0.001900	115,400.63	19,739.58	1.95	0.001625	98,697.91	(16,702.72)
3122	77,143,667.49	1.88	0.001567	1,450,300.95	69,120.73	1.54	0.001283	1,188,012.48	(262,288.47)
312C	121,989,593.12	2.28	0.001900	2,781,362.72	475,759.41	1.95	0.001625	2,378,797.07	(402,565.65)
3123	161,617,029.17	1.88	0.001567	3,038,400.15	144,808.86	1.54	0.001283	2,488,902.25	(549,497.90)
312D	113,968,704.31	2.28	0.001900	2,598,486.46	444,477.95	1.95	0.001625	2,222,389.73	(376,096.73)
3124	402,071,586.26	1.88	0.001567	7,558,945.82	360,256.14	1.54	0.001283	6,191,902.43	(1,367,043.39)
312E	268,650,680.12	2.28	0.001900	6,125,235.51	1,047,737.66	1.95	0.001625	5,238,688.26	(886,547.25)
3125	17,389,606.87	1.88	0.001567	326,924.61	15,581.09	1.54	0.001283	267,799.95	(59,124.66)
312F&312K	71,086,231.78	2.28	0.001900	1,620,766.08	277,236.30	1.95	0.001625	1,386,181.52	(234,584.56)
3126	2,554,464.97	1.88	0.001567	48,023.94	2,288.80	1.54	0.001283	39,338.76	(8,685.18)
312G	1,899,172.74	2.28	0.001900	43,301.14	7,406.78	1.95	0.001625	37,033.87	(6,267.27)
3127	376,268.58	1.88	0.001567	7,073.85	337.14	1.54	0.001283	5,794.54	(1,279.31)
3128	1,186,252.75	1.88	0.001567	22,301.55	1,062.88	1.54	0.001283	18,268.29	(4,033.26)
312J	15,438.27	2.28	0.001900	351.99	60.21	1.95	0.001625	301.05	(50.94)
3140	0.00	1.91	0.001592	0.00	0.00	1.54	0.001283	0.00	0.00
3141	4,310,530.58	1.91	0.001592	82,331.13	10,793.56	1.54	0.001283	66,382.17	(15,948.96)
3142	32,762,390.07	1.91	0.001592	625,761.65	82,037.02	1.54	0.001283	504,540.81	(121,220.84)
3143	57,679,599.22	1.91	0.001592	1,101,680.35	144,429.72	1.54	0.001283	888,265.83	(213,414.52)
3144	127,883,751.07	1.91	0.001592	2,442,579.65	320,220.92	1.54	0.001283	1,969,409.77	(473,169.88)
3145	4,991,571.10	1.91	0.001592	95,339.01	12,498.90	1.54	0.001283	76,870.19	(18,468.82)
3146	262,741.29	1.91	0.001592	5,018.36	657.91	1.54	0.001283	4,046.22	(972.14)
3147	18,495.15	1.91	0.001592	353.26	46.31	1.54	0.001283	284.83	(68.43)
3151	1,494,658.69	1.99	0.001658	29,743.71	5,835.15	1.08	0.000900	16,142.31	(13,601.40)
3152	8,552,676.77	1.99	0.001658	170,198.27	33,389.65	1.08	0.000900	92,368.91	(77,829.36)
3153	16,091,239.72	1.99	0.001658	320,215.67	62,820.20	1.08	0.000900	173,785.39	(146,430.28)
3154	35,070,442.41	1.99	0.001658	697,901.80	136,915.00	1.08	0.000900	378,760.78	(319,141.02)
3155	171,384.26	1.99	0.001658	3,410.55	669.09	1.08	0.000900	1,850.95	(1,559.60)
3159	43,548.07	1.99	0.001658	866.61	170.02	1.08	0.000900	470.32	(396.29)
3160	56,008.08	3.78	0.003150	2,117.11	1,092.16	3.77	0.003142	2,111.50	(5.61)
3161	1,227.09	3.78	0.003150	46.38	23.92	3.77	0.003142	46.26	(0.12)

KIUC Adjustment to Depreciation Expense

ACCT	BALANCE 10/31/2010	COMPANY'S NEW YEARLY RATE	COMPANY'S NEW DEPRECIATION RATE	COMPANY'S PRO FORMA DEPRECIATION EXPENSE	VARIANCE	KIUC NEW YEARLY RATE	KIUC NEW DEPRECIATION RATE	KIUC PRO FORMA DEPRECIATION EXPENSE	KIUC ADJUSTMENT
3162	849,312.17	3.78	0.003150	32,104.00	16,561.59	3.77	0.003142	32,019.07	(84.93)
3163	779,447.85	3.78	0.003150	29,463.13	15,199.23	3.77	0.003142	29,385.18	(77.95)
3164	749,577.26	3.78	0.003150	28,334.02	14,616.76	3.77	0.003142	28,259.06	(74.96)
3165	345,677.46	3.78	0.003150	13,066.61	6,740.71	3.77	0.003142	13,032.04	(34.57)
3166	308,147.79	3.78	0.003150	11,647.99	6,008.89	3.77	0.003142	11,617.17	(30.82)
3167	88,777.93	3.78	0.003150	3,355.81	1,731.17	3.77	0.003142	3,346.93	(8.88)
3169	107,699.80	3.78	0.003150	4,071.05	2,100.14	3.77	0.003142	4,060.28	(10.77)
3401	0.00	0.00	0.000000	0.00	0.00	0.00	0.000000	0.00	0.00
3410	154,232.79	1.17	0.000975	1,804.52	(1,758.26)	1.17	0.000975	1,804.52	0.00
3420	1,436,911.63	9.10	0.007583	130,758.96	97,428.36	9.10	0.007583	130,758.96	0.00
3430	4,915,885.63	3.02	0.002517	148,459.75	27,057.04	3.02	0.002517	148,459.75	0.00
3440	1,102,963.67	0.50	0.000417	5,514.82	(19,076.86)	0.50	0.000417	5,514.82	0.00
3450	383,519.62	2.05	0.001708	7,862.15	(688.80)	2.05	0.001708	7,862.15	0.00
3460	0.00	0.00	0.000000	0.00	0.00	0.00	0.000000	0.00	0.00
3500	13,151,946.52	0.00	0.000000	0.00	0.00	0.00	0.000000	0.00	0.00
3501	704,868.36	0.00	0.000000	0.00	0.00	0.00	0.000000	0.00	0.00
3520	5,817,594.61	1.90	0.001583	110,534.30	8,121.36	1.90	0.001583	110,534.30	0.00
3521	20,369.05	1.90	0.001583	387.01	28.43	1.90	0.001583	387.01	0.00
3522	157,304.64	1.90	0.001583	2,988.79	219.60	1.90	0.001583	2,988.79	0.00
3524	679,442.21	1.90	0.001583	12,909.40	948.50	1.90	0.001583	12,909.40	0.00
3530	78,645,358.50	2.23	0.001858	1,753,791.49	7,864.53	2.23	0.001858	1,753,791.49	0.00
3531	3,031,650.37	2.23	0.001858	67,605.80	303.16	2.23	0.001858	67,605.80	0.00
3532	5,573,659.91	2.23	0.001858	124,292.62	557.37	2.23	0.001858	124,292.62	0.00
3533	5,947,214.37	2.23	0.001858	132,622.88	594.72	2.23	0.001858	132,622.88	0.00
3534	22,364,145.19	2.23	0.001858	498,720.44	2,236.42	2.23	0.001858	498,720.44	0.00
3540	8,134,239.23	1.42	0.001183	115,506.20	(69,954.45)	1.42	0.001183	115,506.20	0.00
3541	146,747.32	1.42	0.001183	2,083.81	(1,262.03)	1.42	0.001183	2,083.81	0.00
3550	42,097,383.75	2.06	0.001717	867,206.11	(496,749.12)	2.06	0.001717	867,206.11	0.00
3551	234,314.24	2.06	0.001717	4,826.87	(2,764.91)	2.06	0.001717	4,826.87	0.00
3560	43,673,282.78	1.69	0.001408	738,078.48	(340,476.91)	1.69	0.001408	738,078.48	0.00
3561	86,900.75	1.69	0.001408	1,468.62	(677.48)	1.69	0.001408	1,468.62	0.00
3890	407,251.23	0.00	0.000000	0.00	0.00	0.00	0.000000	0.00	0.00
3900	3,948,933.89	2.84	0.002367	112,149.72	9,888.13	2.84	0.002367	112,149.72	0.00
3910	589,902.92	17.12	0.014267	100,991.38	94,443.46	17.12	0.014267	100,991.38	0.00
3912	7,163,171.79	10.29	0.008575	737,090.38	657,579.17	10.29	0.008575	737,090.38	0.00
3913	0.00	0.00	0.000000	0.00	0.00	0.00	0.000000	0.00	0.00
3916	1,894.73	17.12	0.014267	324.38	303.35	17.12	0.014267	324.38	0.00
3917	3,059.60	17.12	0.014267	523.80	489.84	17.12	0.014267	523.80	0.00
3922	1,764,679.12	4.39	0.003658	77,469.41	(21,698.50)	4.39	0.003658	77,469.41	0.00
3923	1,257,239.84	6.14	0.005117	77,194.53	6,542.68	6.14	0.005117	77,194.53	0.00
3930	98,765.68	4.40	0.003667	4,345.69	819.76	4.40	0.003667	4,345.69	0.00
3940	722,077.41	4.61	0.003842	33,287.77	12,708.56	4.61	0.003842	33,287.77	0.00
3950	221,278.64	4.41	0.003675	9,758.39	3,430.71	4.41	0.003675	9,758.39	0.00
3960	342,907.40	3.70	0.003083	12,687.57	1.37	3.70	0.003083	12,687.57	0.00
3961	183,073.76	3.70	0.003083	6,773.73	0.73	3.70	0.003083	6,773.73	0.00
3970	1,640,119.50	4.35	0.003625	71,345.20	0.00	4.35	0.003625	71,345.20	0.00
3980	165,070.19	11.80	0.009833	19,478.28	10,499.12	11.80	0.009833	19,478.28	0.00
3986	0.00	11.80	0.009833	0.00	0.00	11.80	0.009833	0.00	0.00

KIUC Adjustment to Depreciation Expense

ACCT	BALANCE 10/31/2010	COMPANY'S NEW YEARLY RATE	COMPANY'S NEW DEPRECIATION RATE	COMPANY'S PRO FORMA DEPRECIATION EXPENSE	VARIANCE	KIUC NEW YEARLY RATE	KIUC NEW DEPRECIATION RATE	KIUC PRO FORMA DEPRECIATION EXPENSE	KIUC ADJUSTMENT
3987	1,625.49	11.80	0.009833	191.81	103.39	11.80	0.009833	191.81	0.00
312 L-P	3,208,938.00	20.22	0.016850	648,847.26	588,198.33	19.31	0.016092	619,645.93	(29,201.33)
312 V-Z	868,755.00	14.39	0.011992	125,013.84	109,459.65	19.31	0.016092	167,756.59	42,742.75
3525	185,107.45	1.90	0.001583	3,517.04	258.41	1.90	0.001583	3,517.04	0.00
3535	6,511,340.66	2.23	0.001858	145,202.90	651.14	2.23	0.001858	145,202.90	0.00
3545	312,557.79	1.42	0.001183	4,438.32	(2,688.00)	1.42	0.001183	4,438.32	0.00
3555	79,206.80	2.06	0.001717	1,631.66	(934.64)	2.06	0.001717	1,631.66	0.00
3565	104,571.36	1.69	0.001408	1,767.26	(815.23)	1.69	0.001408	1,767.26	0.00
CWIP									
312	18,256,534.04	1.88	0.001567	343,222.84	16,357.85	1.54	0.001283	281,150.62	(62,072.22)
312 env	4,191,946.40	2.28	0.001900	95,576.38	16,348.59	1.95	0.001625	81,742.95	(13,833.43)
3530	7,475,859.18	2.23	0.001858	166,711.66	747.59	2.23	0.001858	166,711.66	0.00
3910	2,165,170.04	17.12	0.014267	370,677.11	346,643.72	17.12	0.014267	370,677.11	0.00
3912	11,736,080.31	10.29	0.008575	1,207,642.66	1,077,372.17	10.29	0.008575	1,207,642.66	0.00
3970	2,976,548.00	4.35	0.003625	129,479.84	0.00	4.35	0.003625	129,479.84	0.00
Total Before Retirements	1,989,360,277.56			42,532,088.77	5,475,111.24			36,605,378.64	(5,926,710.13)
Retirements									
312	-8,243,351.13	1.88	0.001567	(154,975.00)		1.54	0.001283	(126,947.61)	28,027.39
312 env	-1,892,784.58	2.28	0.001900	(43,155.49)		1.95	0.001625	(36,909.30)	6,246.19
3530	-3,375,565.81	2.23	0.001858	(75,275.12)		2.23	0.001858	(75,275.12)	0.00
3910	-977,636.66	17.12	0.014267	(167,371.40)		17.12	0.014267	(167,371.40)	0.00
3912	-5,299,178.40	10.29	0.008575	(545,285.46)		10.29	0.008575	(545,285.46)	0.00
3970	-1,343,997.18	4.35	0.003625	(58,463.88)		4.35	0.003625	(58,463.88)	0.00
Total Retirements	-21,132,513.76			(1,044,526.35)				(1,010,252.77)	
Adjustments After Retirements				41,487,562.42	4,430,584.89			35,595,125.87	(5,892,436.55)

COMMONWEALTH OF KENTUCKY
BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

APPLICATION OF BIG RIVERS ELECTRIC	**)**	
CORPORATION FOR A GENERAL	**)**	**CASE NO. 2011-00036**
ADJUSTMENT IN RATES	**)**	

**KENTUCKY INDUSTRIAL UTILITY CUSTOMERS RESPONSE TO
BIG RIVERS ELECTRIC CORPORATION
FIRST DATA REQUEST
PSC CASE NO. 2011-00036
June 22, 2011**

Request BREC-3
Please provide electronic copies of Exhibits SJB-3, SJB-4, SJB-5, and SJB-6 to the direct testimony of Mr. Baron, with cells and formulas intact, along with all computer models, workpapers and other documents that support these exhibits.

RESPONSE:

See attached on enclosed CD.

Witness: Stephen J. Baron

Table 4
Subsidies Remaining at Proposed Rates

		Total System	Rurals	Large Industrials	Smelters
1	Rate Base - 6 CP	1,170,341,502	390,335,625	96,406,419	683,599,459
2	Net Utility Operating Margin	25,806,684	(9,711,995)	2,075,623	33,443,057
3	Return on Rate Base	2.21%	-2.49%	2.15%	4.89%
4	Subsidy at Present Rates	-	(18,319,114)	(50,193)	18,369,307
5	**Adjusted Total Increase Required**	**18,679,000**			
6	Eliminate Rural Subsidy	18,319,114	18,319,114		
7	Spread of Increase Remainder	359,886	98,395	34,009	227,482
	Step 1 Increase - Rurals Subsidy	18,319,114	18,319,114	-	-
8	**Net Increase**	**18,679,000**	**18,417,509**	**34,009**	**227,482**
9	Income at Proposed Rates (line 2 + line 8)	44,485,684	8,705,513	2,109,631	33,670,539
10	ROR - Proposed Rates (line 9/line 1)	3.80%	2.23%	2.19%	4.93%
11	Net Utility Operating Margin at System ROR	44,485,684	14,836,992	3,664,491	25,984,202
12	**Subsidy at Proposed Rates (line 11 - line 9)**	**-**	**6,131,478**	**1,554,859**	**(7,686,338)**

Big Rivers Electric Corporation

Analysis of Rate Increase Scenario

6 CP Cost of Service using Seelye model with TIER Adjustment at $1.95

Line		Total System		Rurals		Large Industrials		Smelters
1	Rate Base - 6 CP	1,170,341,502	$	390,335,625	$	96,406,419	$	683,599,459
2	Net Utility Operating Margin	25,806,684	$	(9,711,995)	$	2,075,623	$	33,443,057
3	Return on Rate Base	2.21%		-2.49%		2.15%		4.89%
4	Subsidy at Present Rates	-		(18,319,114)		(50,193)		18,369,307
5	Adjusted Total Increase Required	18,679,000						

Table 3
KIUC Proposed Rate Increases

Line		Total System	Rurals	Large Industrials	Smelters
4	Subsidy at Present Rates	-	(18,319,114)	(50,193)	18,369,307
5	**KIUC Proposed Revenue Increase**	**18,679,000**			
6	Eliminate Subsidy to Rurals	18,319,114	18,319,114	-	-
16	Spread of Increase Remainder	359,886	98,395	34,009	227,482
17	Step 1 Increase - Rurals Subsidy	18,319,114	18,319,114	-	-
19	Net Increase	18,679,000	18,417,509	34,009	227,482
20	Rural Mitigation from RER Fund	(4,245,506)	(4,245,506)	-	-
21	Net Increase after Mitigation		14,172,003	34,009	227,482
22	Patronage Capital Distribution	(2,708,000)	(621,285)	(235,635)	(1,851,080)
23	Final Effective Base Rate Increase		13,550,718	(201,626)	(1,623,598)
25	Percent Increase		12.26%	-0.51%	-0.57%

10,675,114,974	2,449,147,804	928,887,170	7,297,080,000
1	0.229425895	0.087014254	0.683559851

Big Rivers Electric Corporation

KIUC Proposed Rate Increases

6 CP Cost of Service using Seelye model with TIER Adjustment at test year level of $1.95

Line		Total System	Rurals	Large Industrials	Smelters
1	Rate Base - 6 CP	1,170,341,502	390,335,625	96,406,419	683,599,459
2	Net Utility Operating Margin	25,806,684	(9,711,995)	2,075,623	33,443,057
3	Return on Rate Base	2.21%	-2.49%	2.15%	4.89%
4	*Subsidy at Present Rates*	-	(18,319,114)	(50,193)	18,369,307
5	**KIUC Proposed Revenue Increase**	**18,679,000**			
6	Eliminate Subsidy to Rurals	18,319,114	18,319,114	-	-
7	Remainder of Increase to be Allocated	359,886			
8	Demand/Energy Base Revenue - Current Rates	118,930,921	88,490,963	30,439,958	
9	Weather Normalization Adjustment	(421,610)	(421,610)	-	
10	Base Rate Revenue	322,119,734	88,069,353	30,439,958	203,610,423
11	Revenue Allocator using Smelter/Industrial Ratio	322,119,734	88,069,353	30,439,958	203,610,423
12	**Percent Allocator**	**100.00%**	**27.34%**	**9.45%**	**63.21%**
13	Spread of Increase Remainder	359,886	98,395	34,009	227,482
14	Step 1 Increase - Rurals Subsidy	18,319,114	18,319,114	-	-
15	Net Increase (before Rural Reserve or Capital Credits)	18,679,000	18,417,509	34,009	227,482
16	Rural Mitigation from Rural Economic Reserve Fund	(4,245,506)	(4,245,506)	-	-
17	Net Increase after Mitigation		14,172,003	34,009	227,482
18	Patronage Capital Distribution per kWh	(2,708,000)	(621,285)	(235,635)	(1,851,080)
19	Final Effective Base Rate Increase		13,550,718	(201,626)	(1,623,598)
20	Present Revenue	432,165,302	110,513,089	39,260,372	282,391,841
21	Percent Increase		12.26%	-0.51%	-0.57%
22	Amortization of Non-FAC PPA	(3,236,077)	(2,340,068)	(896,009)	-
23	Revenue Increase with Non-FAC PPA Amortization		11,210,650	(1,097,635)	(1,623,598)
24	Percent Increase		10.14%	-2.80%	-0.57%
25	Impact of Lowering the Non-FAC PPA Base	(2,959,158)	(2,145,453)	(813,705)	-
26	Adjusted Revenue Increase		9,065,197	(1,911,340)	(1,623,598)
27	Percent Increase		8.20%	-4.87%	-0.57%

Big Rivers Electric Corporation
Cost of Service Study
Development of A&E Factor

BR System Peak	1,510,692
BR System Energy	10,491,356,334
Average Demand	1,197,643
Annual Load Factor	79.3%

	RURAL	LARGE INDUSTRIAL	SMELTERS	TOTAL
Energy	2,449,147,804	928,887,170	7,113,321,360	10,491,356,334
Average Demand	279,583	106,037	812,023	1,197,643
Allocation Vector	0.233444	0.088538	0.678017	1.000000
Weighted Vector (LF)	0.185070	0.070191	0.537517	0.792778
Class NCP (60 minute) w/o Cogen	539,955	106,622	850,000	
Cogen	-	25,000	-	
Adjusted Class NCP	539,955	131,622	850,000	1,521,577
Excess Demand	260,372	25,584	37,977	323,933
Allocation Vector	0.803783	0.078980	0.117237	1.000000
Weighted Vector (1 - LF)	0.166561	0.016366	0.024294	0.207222
Total A&E Factor	0.351631	0.086558	0.561811	1.000000

	0			1	3	5	7	9
EBMTRY		EBMTRM	EBMTRD	HR1	HR2	HR3	HR4	HR5
20C	2009	11	1	208,022	205,501	209,381	215,337	224,555
20C	2009	11	2	208,024	209,332	212,315	218,772	234,204
20C	2009	11	3	181,117	180,884	182,793	187,934	202,043
20C	2009	11	4	227,349	223,105	220,989	222,352	232,527
20C	2009	11	5	196,482	198,457	201,310	208,139	224,888
20C	2009	11	6	226,695	227,232	228,083	234,048	248,389
20C	2009	11	7	186,152	180,983	178,889	181,865	189,966
20C	2009	11	8	154,843	151,568	151,523	154,002	159,866
20C	2009	11	9	149,368	146,142	145,872	148,033	158,465
20C	2009	11	10	152,699	152,224	152,053	153,755	165,959
20C	2009	11	11	165,687	163,771	165,636	170,790	184,622
20C	2009	11	12	209,969	210,850	213,453	219,137	234,114
20C	2009	11	13	216,217	218,137	221,785	228,054	242,364
20C	2009	11	14	197,415	195,440	195,556	201,259	211,937
20C	2009	11	15	171,038	166,363	163,453	162,549	165,383
20C	2009	11	16	148,258	144,510	143,170	146,149	157,053
20C	2009	11	17	159,377	155,793	154,775	159,739	171,070
20C	2009	11	18	209,556	206,163	206,388	208,998	221,283
20C	2009	11	19	209,853	207,432	205,960	208,861	220,352
20C	2009	11	20	221,471	220,575	222,465	229,195	242,953
20C	2009	11	21	205,836	203,397	204,713	208,972	218,116
20C	2009	11	22	192,217	189,930	190,914	193,930	201,264
20C	2009	11	23	193,008	191,564	192,090	195,460	206,933
20C	2009	11	24	181,743	176,687	175,506	178,503	187,470
20C	2009	11	25	194,649	193,284	195,712	202,350	215,576
20C	2009	11	26	220,377	218,162	220,137	227,366	238,605
20C	2009	11	27	254,803	255,116	257,712	264,363	273,496
20C	2009	11	28	252,534	248,281	247,425	249,630	254,758
20C	2009	11	29	189,953	186,101	186,032	189,132	194,840
20C	2009	11	30	187,659	187,597	191,091	197,885	212,446
20C	2009	12	1	277,029	274,179	276,219	280,028	291,160
20C	2009	12	2	245,441	242,256	240,077	241,490	249,475
20C	2009	12	3	251,473	247,307	247,450	250,492	261,170
20C	2009	12	4	293,908	295,703	299,509	306,117	318,791
20C	2009	12	5	316,207	315,707	315,381	320,355	329,724
20C	2009	12	6	333,777	332,250	332,688	334,700	338,217
20C	2009	12	7	275,591	270,721	270,831	274,615	286,363
20C	2009	12	8	256,965	254,380	255,645	260,650	270,600
20C	2009	12	9	207,444	204,731	207,926	215,722	232,367
20C	2009	12	10	353,983	351,747	353,388	359,590	372,744
20C	2009	12	11	365,104	362,309	362,640	368,129	380,587
20C	2009	12	12	337,081	332,131	329,868	331,033	336,984

20C	2009	12	13	253,702	243,592	238,594	235,393	235,495
20C	2009	12	14	215,446	210,579	208,964	210,855	221,905
20C	2009	12	15	220,945	222,586	227,973	237,796	257,189
20C	2009	12	16	346,777	347,723	351,187	358,255	373,337
20C	2009	12	17	333,416	332,048	333,248	338,965	353,105
20C	2009	12	18	286,405	281,685	278,963	281,156	291,378
20C	2009	12	19	251,198	246,623	246,855	248,759	255,647
20C	2009	12	20	306,331	299,384	296,004	296,102	300,205
20C	2009	12	21	302,565	299,043	298,737	301,941	312,874
20C	2009	12	22	288,154	284,063	282,546	286,538	296,403
20C	2009	12	23	224,491	218,336	215,063	217,057	226,322
20C	2009	12	24	217,951	210,851	207,805	209,695	215,733
20C	2009	12	25	205,819	196,239	192,825	195,282	201,913
20C	2009	12	26	311,863	307,745	306,807	309,100	316,642
20C	2009	12	27	286,070	281,031	279,937	281,824	289,212
20C	2009	12	28	341,114	338,172	338,315	343,321	355,155
20C	2009	12	29	325,083	322,485	322,523	326,445	336,470
20C	2009	12	30	303,546	299,981	297,536	298,575	305,622
20C	2009	12	31	258,003	250,795	246,675	246,706	251,756
201	2010	1	1	333,463	338,215	342,936	348,279	356,926
201	2010	1	2	388,210	388,859	391,457	394,954	401,665
201	2010	1	3	409,414	408,830	409,673	413,781	420,993
201	2010	1	4	403,750	404,739	408,367	416,566	433,504
201	2010	1	5	413,085	415,555	419,977	428,361	443,249
201	2010	1	6	409,289	409,779	412,548	417,912	431,553
201	2010	1	7	344,198	341,852	342,413	346,715	357,456
201	2010	1	8	436,599	436,874	440,292	445,520	457,556
201	2010	1	9	418,661	417,046	417,318	418,944	423,237
201	2010	1	10	440,923	442,468	445,330	448,784	455,968
201	2010	1	11	397,508	394,226	393,276	393,247	401,982
201	2010	1	12	369,954	370,277	372,520	376,557	386,777
201	2010	1	13	370,493	374,134	378,948	386,081	399,840
201	2010	1	14	325,497	326,367	329,057	335,653	347,432
201	2010	1	15	244,765	240,921	240,502	243,888	254,515
201	2010	1	16	249,911	247,565	249,228	252,219	259,251
201	2010	1	17	227,569	223,816	221,934	224,546	229,122
201	2010	1	18	283,109	286,114	288,973	295,334	306,049
201	2010	1	19	266,041	266,750	267,334	270,984	282,380
201	2010	1	20	210,503	207,910	208,171	212,218	223,862
201	2010	1	21	204,591	202,197	202,050	206,623	217,928
201	2010	1	22	218,574	218,056	219,366	226,450	238,247
201	2010	1	23	237,131	230,859	227,017	227,032	228,853
201	2010	1	24	217,748	210,517	206,356	206,079	207,675
201	2010	1	25	232,754	235,246	240,483	247,802	264,007
201	2010	1	26	296,546	295,444	295,475	298,391	311,053
201	2010	1	27	348,284	347,493	349,623	353,987	364,816
201	2010	1	28	267,791	263,834	265,096	274,240	291,897

201	2010	1	29	350,856	352,681	353,973	360,352	373,203
201	2010	1	30	389,623	385,564	383,872	388,396	393,128
201	2010	1	31	392,332	397,983	404,753	413,330	422,231
201	2010	2	1	360,200	363,853	370,386	377,653	391,350
201	2010	2	2	289,069	287,584	287,813	292,839	305,757
201	2010	2	3	276,551	274,215	273,639	277,822	291,886
201	2010	2	4	301,523	300,182	300,391	304,361	316,889
201	2010	2	5	267,409	265,082	263,941	265,736	276,091
201	2010	2	6	291,747	291,107	293,445	298,553	307,205
201	2010	2	7	330,071	330,493	334,803	340,843	350,821
201	2010	2	8	336,202	337,664	340,502	343,434	352,215
201	2010	2	9	308,375	305,366	304,498	306,115	315,003
201	2010	2	10	398,924	395,622	391,678	388,991	393,305
201	2010	2	11	351,356	352,570	355,293	363,731	378,712
201	2010	2	12	357,585	362,320	368,172	376,732	392,668
201	2010	2	13	312,122	308,704	309,403	312,292	318,844
201	2010	2	14	321,058	318,333	318,208	319,728	323,201
201	2010	2	15	331,320	337,955	345,081	353,913	370,165
201	2010	2	16	359,269	356,533	358,274	361,394	370,367
201	2010	2	17	341,236	342,391	345,813	353,527	368,582
201	2010	2	18	323,830	325,766	330,029	340,042	356,217
201	2010	2	19	325,322	327,652	333,119	341,419	356,826
201	2010	2	20	272,169	265,261	263,512	265,406	271,331
201	2010	2	21	226,089	222,459	222,467	223,599	228,840
201	2010	2	22	192,570	191,407	192,311	196,563	208,156
201	2010	2	23	273,230	269,554	271,838	275,494	288,146
201	2010	2	24	300,943	300,660	300,933	307,663	323,396
201	2010	2	25	339,434	340,542	343,066	349,395	361,902
201	2010	2	26	329,474	329,033	333,676	341,008	355,019
201	2010	2	27	314,051	311,479	313,171	317,422	326,447
201	2010	2	28	277,805	276,494	277,778	280,727	287,596
201	2010	3	1	259,413	260,348	263,277	270,459	282,875
201	2010	3	2	268,618	267,463	266,362	272,550	286,145
201	2010	3	3	300,332	297,158	296,117	298,788	308,759
201	2010	3	4	291,036	288,877	292,835	301,861	318,468
201	2010	3	5	291,979	292,605	297,529	306,385	322,983
201	2010	3	6	282,800	282,221	285,781	292,996	303,280
201	2010	3	7	266,665	269,163	272,610	275,990	280,583
201	2010	3	8	187,143	187,700	191,169	198,001	215,355
201	2010	3	9	206,245	202,560	204,759	210,723	224,129
201	2010	3	10	175,349	166,740	163,672	164,621	175,274
201	2010	3	11	152,103	145,491	144,946	148,288	158,141
201	2010	3	12	166,781	162,172	162,856	167,860	181,727
201	2010	3	13	208,105	201,916	199,767	202,259	207,709
201	2010	3	14	215,319	211,597	-	208,951	210,254
201	2010	3	15	216,777	213,178	212,011	214,992	226,095
201	2010	3	16	216,689	209,910	206,975	208,729	218,749

201	2010	3	17	205,003	198,259	197,358	202,263	213,965
201	2010	3	18	201,437	198,730	202,235	209,566	225,252
201	2010	3	19	184,248	183,542	186,792	195,608	211,405
201	2010	3	20	172,771	167,947	168,867	173,475	183,073
201	2010	3	21	162,521	158,219	156,110	157,095	160,796
201	2010	3	22	192,796	195,004	201,854	209,888	223,481
201	2010	3	23	223,941	222,451	222,886	228,746	240,330
201	2010	3	24	186,484	187,696	188,225	195,137	210,269
201	2010	3	25	161,205	158,911	155,317	156,317	165,762
201	2010	3	26	224,190	226,182	228,161	235,405	247,289
201	2010	3	27	233,085	233,288	235,083	237,272	244,291
201	2010	3	28	164,170	159,488	158,045	158,849	162,766
201	2010	3	29	199,683	201,464	205,972	213,070	227,353
201	2010	3	30	201,435	206,131	205,792	214,036	228,950
201	2010	3	31	168,197	168,685	170,928	177,576	190,760
201	2010	4	1	147,626	142,107	136,028	137,421	145,000
201	2010	4	2	151,585	143,601	135,381	132,654	137,284
201	2010	4	3	151,022	141,685	132,845	129,596	130,703
201	2010	4	4	149,621	142,363	139,379	139,059	145,962
201	2010	4	5	143,260	136,635	132,170	131,726	138,033
201	2010	4	6	165,676	154,173	144,970	141,985	145,496
201	2010	4	7	163,147	154,685	145,700	142,702	147,495
201	2010	4	8	147,239	141,178	136,098	133,501	139,599
201	2010	4	9	178,190	177,668	174,594	177,865	189,750
201	2010	4	10	172,357	171,259	167,930	170,059	177,190
201	2010	4	11	150,586	146,009	145,271	146,811	151,986
201	2010	4	12	141,085	134,882	132,352	135,076	145,109
201	2010	4	13	149,457	142,992	135,883	135,555	142,924
201	2010	4	14	155,063	147,036	137,044	135,058	141,474
201	2010	4	15	158,752	149,022	139,707	137,368	142,303
201	2010	4	16	158,156	149,971	140,720	138,017	143,087
201	2010	4	17	151,733	142,151	134,238	132,454	135,992
201	2010	4	18	157,107	149,382	147,576	149,599	157,262
201	2010	4	19	151,271	149,085	149,884	153,682	165,591
201	2010	4	20	152,633	148,308	143,689	144,457	154,011
201	2010	4	21	150,575	146,285	141,921	145,274	156,210
201	2010	4	22	146,004	143,071	139,059	141,428	149,965
201	2010	4	23	149,473	142,562	135,799	135,733	141,843
201	2010	4	24	161,818	152,938	142,018	138,305	138,858
201	2010	4	25	146,884	137,916	132,929	130,549	131,818
201	2010	4	26	146,908	141,444	139,795	140,986	150,353
201	2010	4	27	160,096	155,411	151,295	153,077	162,566
201	2010	4	28	178,015	176,252	173,856	179,213	190,670
201	2010	4	29	155,027	152,140	148,410	151,751	162,493
201	2010	4	30	153,120	145,401	137,871	135,709	142,656
201	2010	5	1	178,467	163,155	151,039	143,580	142,139
201	2010	5	2	154,004	144,707	139,535	137,080	136,621

201	2010	5	3	152,221	142,735	137,081	134,997	140,880
201	2010	5	4	158,158	148,623	139,228	137,350	142,699
201	2010	5	5	159,915	149,637	141,406	139,715	145,908
201	2010	5	6	179,178	166,890	154,463	148,213	150,411
201	2010	5	7	166,941	156,145	146,750	143,878	149,350
201	2010	5	8	161,380	147,818	137,201	133,464	134,848
201	2010	5	9	158,073	152,633	149,960	150,656	153,867
201	2010	5	10	149,442	146,367	145,415	147,883	158,049
201	2010	5	11	157,978	154,035	148,094	148,111	155,331
201	2010	5	12	161,735	151,807	143,885	143,450	150,138
201	2010	5	13	177,655	165,218	156,862	155,318	161,612
201	2010	5	14	195,144	181,054	169,128	163,989	166,245
201	2010	5	15	165,288	153,213	143,488	140,204	140,200
201	2010	5	16	159,882	147,351	139,994	136,181	135,138
201	2010	5	17	148,243	140,692	136,801	135,969	142,313
201	2010	5	18	152,249	143,389	137,343	135,981	141,816
201	2010	5	19	150,992	144,426	137,962	137,456	144,521
201	2010	5	20	151,528	145,177	138,191	138,178	145,721
201	2010	5	21	151,949	146,114	140,428	139,344	145,051
201	2010	5	22	163,535	150,355	140,482	136,447	137,047
201	2010	5	23	179,446	164,511	155,064	148,836	146,034
201	2010	5	24	219,804	200,582	187,482	180,006	180,675
201	2010	5	25	203,109	186,072	171,962	165,923	169,277
201	2010	5	26	202,235	186,014	171,153	164,882	167,245
201	2010	5	27	205,304	188,373	173,209	166,095	168,034
201	2010	5	28	183,810	167,754	159,286	156,117	159,223
201	2010	5	29	200,906	182,452	167,968	159,974	157,571
201	2010	5	30	212,623	192,369	179,000	170,120	165,210
201	2010	5	31	210,336	191,201	177,684	169,122	166,346
201	2010	6	1	190,367	174,985	164,598	160,282	163,441
201	2010	6	2	231,208	212,220	197,690	190,514	192,701
201	2010	6	3	187,837	176,536	168,970	165,649	169,641
201	2010	6	4	218,389	197,898	182,532	175,388	175,512
201	2010	6	5	246,086	228,828	212,996	202,560	198,310
201	2010	6	6	251,764	231,920	218,857	210,326	207,232
201	2010	6	7	176,467	163,976	155,267	152,446	155,102
201	2010	6	8	191,471	177,435	165,859	161,732	162,838
201	2010	6	9	217,369	204,531	196,435	191,911	194,569
201	2010	6	10	234,870	218,514	202,724	193,630	192,049
201	2010	6	11	253,530	232,343	215,095	208,396	206,999
201	2010	6	12	248,132	230,965	217,582	211,479	210,093
201	2010	6	13	282,127	258,494	240,023	225,502	215,248
201	2010	6	14	279,952	257,900	240,868	232,027	230,106
201	2010	6	15	240,074	220,766	204,302	196,907	197,883
201	2010	6	16	235,082	218,692	204,941	198,145	198,592
201	2010	6	17	238,078	219,356	201,588	193,682	194,485
201	2010	6	18	224,652	208,351	193,085	186,281	186,658

201	2010	6	19	294,477	267,479	247,594	237,039	230,834
201	2010	6	20	240,765	216,110	199,126	187,138	181,433
201	2010	6	21	285,137	261,147	241,978	230,060	225,369
201	2010	6	22	287,478	263,520	242,961	231,432	227,732
201	2010	6	23	298,362	275,221	256,217	245,395	243,090
201	2010	6	24	291,708	271,812	254,971	245,024	244,766
201	2010	6	25	237,133	216,722	199,512	191,607	190,083
201	2010	6	26	251,112	227,415	213,716	201,473	196,700
201	2010	6	27	301,647	276,001	256,381	242,139	234,445
201	2010	6	28	291,343	258,214	236,060	223,892	220,430
201	2010	6	29	226,556	206,961	193,867	186,925	187,012
201	2010	6	30	213,129	197,153	181,921	172,987	171,977
201	2010	7	1	189,465	173,731	161,795	156,791	159,128
201	2010	7	2	187,113	172,379	160,179	154,271	155,708
201	2010	7	3	195,514	177,698	163,359	155,445	153,825
201	2010	7	4	261,807	238,012	221,395	210,555	202,463
201	2010	7	5	248,826	223,633	205,606	194,185	188,817
201	2010	7	6	230,503	210,471	195,594	188,336	188,018
201	2010	7	7	265,955	243,623	223,157	211,694	209,803
201	2010	7	8	283,521	259,085	239,190	228,136	226,798
201	2010	7	9	278,617	257,722	240,558	230,210	228,895
201	2010	7	10	239,693	219,803	201,338	191,177	187,038
201	2010	7	11	229,021	203,554	188,016	177,339	171,826
201	2010	7	12	228,346	209,485	196,887	189,507	191,492
201	2010	7	13	250,725	233,653	220,374	214,768	215,752
201	2010	7	14	249,915	228,189	211,367	202,022	200,785
201	2010	7	15	287,255	262,394	242,291	229,958	227,550
201	2010	7	16	299,145	280,695	260,898	247,862	242,333
201	2010	7	17	286,090	262,570	240,936	227,120	221,185
201	2010	7	18	284,827	259,722	242,706	231,632	226,164
201	2010	7	19	240,024	227,033	219,048	214,373	214,753
201	2010	7	20	237,637	222,373	213,275	207,099	210,018
201	2010	7	21	282,835	267,028	253,214	245,350	245,298
201	2010	7	22	248,878	231,989	221,148	214,635	217,050
201	2010	7	23	307,081	282,310	263,449	250,315	246,790
201	2010	7	24	298,829	274,362	254,519	241,456	230,240
201	2010	7	25	307,836	284,592	268,994	257,013	249,582
201	2010	7	26	280,639	259,337	243,321	233,437	231,830
201	2010	7	27	276,699	259,894	247,239	238,171	236,988
201	2010	7	28	273,689	252,315	235,092	226,152	226,371
201	2010	7	29	270,564	255,799	242,528	236,285	235,740
201	2010	7	30	274,297	249,085	231,103	218,694	215,563
201	2010	7	31	256,192	235,838	221,131	213,511	208,445
201	2010	8	1	284,065	261,682	244,298	230,230	220,722
201	2010	8	2	232,100	213,061	199,810	191,929	192,111
201	2010	8	3	258,611	235,822	221,399	212,701	213,305
201	2010	8	4	336,841	312,611	293,295	279,825	276,469

201	2010	8	5	341,393	317,625	297,595	285,393	282,149
201	2010	8	6	260,946	240,044	228,261	219,346	219,607
201	2010	8	7	233,422	212,694	197,704	188,166	183,715
201	2010	8	8	228,139	207,017	192,284	181,750	176,801
201	2010	8	9	262,747	240,578	225,938	216,651	216,120
201	2010	8	10	312,188	290,390	275,177	263,772	262,354
201	2010	8	11	323,467	300,795	285,225	273,787	271,474
201	2010	8	12	321,393	298,370	281,515	270,516	268,044
201	2010	8	13	251,848	234,397	223,513	220,730	221,062
201	2010	8	14	312,996	288,233	268,823	256,478	248,576
201	2010	8	15	267,542	249,631	236,183	227,681	223,785
201	2010	8	16	280,300	258,039	240,138	226,199	222,423
201	2010	8	17	212,296	196,223	189,286	182,009	184,285
201	2010	8	18	239,200	225,093	214,836	211,536	213,721
201	2010	8	19	241,994	222,225	211,438	203,903	206,922
201	2010	8	20	248,988	228,158	214,087	205,739	204,410
201	2010	8	21	271,192	254,560	245,501	239,732	239,459
201	2010	8	22	255,096	233,816	217,528	207,908	202,746
201	2010	8	23	239,479	219,275	205,514	197,199	197,503
201	2010	8	24	218,551	201,693	191,686	185,432	188,595
201	2010	8	25	222,021	203,921	192,238	185,851	189,807
201	2010	8	26	198,516	179,932	171,563	167,496	170,063
201	2010	8	27	185,595	172,297	164,296	160,813	164,700
201	2010	8	28	192,518	178,296	168,391	162,645	162,664
201	2010	8	29	254,534	234,944	221,121	210,258	203,364
201	2010	8	30	227,766	214,908	205,797	200,989	206,122
201	2010	8	31	224,725	207,923	194,454	187,512	189,653
201	2010	9	1	231,514	213,114	201,780	193,193	197,095
201	2010	9	2	234,451	218,042	205,451	200,462	200,404
201	2010	9	3	230,454	217,772	210,622	207,213	209,167
201	2010	9	4	178,413	165,678	158,086	154,591	155,166
201	2010	9	5	159,055	148,662	143,604	141,394	140,853
201	2010	9	6	167,283	155,316	147,519	144,271	145,057
201	2010	9	7	192,648	179,330	171,593	168,186	173,564
201	2010	9	8	226,622	211,231	199,589	192,429	192,653
201	2010	9	9	182,991	172,600	164,640	163,522	168,623
201	2010	9	10	173,862	166,514	161,228	158,410	163,534
201	2010	9	11	174,210	165,427	162,798	160,165	164,001
201	2010	9	12	180,705	166,649	156,553	150,421	148,010
201	2010	9	13	161,174	151,490	145,986	144,184	151,277
201	2010	9	14	182,095	168,735	162,671	158,416	165,025
201	2010	9	15	185,864	175,677	168,212	165,245	168,879
201	2010	9	16	229,850	218,690	210,759	207,190	208,089
201	2010	9	17	189,018	174,382	167,016	161,520	165,238
201	2010	9	18	175,055	163,147	155,963	151,291	151,731
201	2010	9	19	184,428	169,796	160,165	154,808	152,818
201	2010	9	20	182,888	169,543	161,380	158,142	162,878

201	2010	9	21	216,744	202,445	192,546	185,078	185,965
201	2010	9	22	228,026	210,451	199,078	190,478	190,240
201	2010	9	23	216,702	202,725	189,692	183,095	185,906
201	2010	9	24	234,976	220,434	209,641	202,787	205,381
201	2010	9	25	192,520	175,910	164,296	156,712	155,207
201	2010	9	26	163,363	153,527	146,235	142,287	141,309
201	2010	9	27	142,985	137,602	134,941	135,347	142,476
201	2010	9	28	152,218	146,929	143,960	144,111	151,192
201	2010	9	29	151,715	146,458	144,173	143,801	151,727
201	2010	9	30	148,355	142,419	139,860	139,213	146,708
201	2010	10	1	157,780	150,141	144,590	143,768	149,500
201	2010	10	2	151,489	145,017	143,910	142,778	145,257
201	2010	10	3	153,707	147,706	145,202	144,434	146,394
201	2010	10	4	163,574	161,969	163,316	167,446	177,052
201	2010	10	5	174,705	172,634	172,228	175,077	186,008
201	2010	10	6	167,012	164,951	167,043	171,448	184,065
201	2010	10	7	153,973	149,102	146,424	148,393	155,292
201	2010	10	8	153,938	146,782	142,253	142,080	149,288
201	2010	10	9	154,144	147,402	143,049	141,958	145,614
201	2010	10	10	149,851	140,574	135,335	132,917	134,685
201	2010	10	11	149,487	141,037	136,187	135,273	141,192
201	2010	10	12	162,529	154,701	149,776	148,721	152,609
201	2010	10	13	152,079	143,204	138,986	137,837	143,626
201	2010	10	14	150,047	144,752	140,775	141,811	150,707
201	2010	10	15	157,246	153,003	150,068	151,017	159,490
201	2010	10	16	165,135	162,150	161,537	162,900	168,055
201	2010	10	17	152,300	147,646	144,635	144,606	148,653
201	2010	10	18	140,761	134,524	131,590	132,505	141,046
201	2010	10	19	150,514	144,625	139,804	140,014	148,298
201	2010	10	20	153,780	148,048	148,251	151,759	162,737
201	2010	10	21	150,560	146,230	145,544	148,730	158,467
201	2010	10	22	163,745	162,312	163,314	168,218	180,506
201	2010	10	23	155,059	149,435	146,277	145,700	150,652
201	2010	10	24	145,914	137,834	132,827	130,767	131,575
201	2010	10	25	143,702	137,433	132,699	133,027	139,879
201	2010	10	26	158,065	151,914	151,448	153,761	161,142
201	2010	10	27	153,630	150,093	148,871	150,598	161,397
201	2010	10	28	149,646	143,238	140,550	143,567	151,420
201	2010	10	29	189,926	189,071	190,476	197,239	210,472
201	2010	10	30	214,657	212,481	213,182	217,035	224,793
201	2010	10	31	170,345	166,665	166,400	168,623	173,662

11	13	15	17	19	21	23	25	27
HR6	HR7	HR8	HR9	HR10	HR11	HR12	HR13	HR14
239,078	252,083	260,572	255,349	238,491	220,265	210,762	207,163	203,624
267,885	292,964	276,365	254,080	239,685	229,326	219,557	214,274	210,654
235,097	263,609	255,955	240,459	229,843	222,831	215,703	209,911	206,576
262,748	289,903	274,563	258,949	241,847	227,320	216,715	210,671	205,326
259,942	291,282	271,307	252,199	238,396	227,062	216,593	210,608	206,215
279,440	303,935	279,169	254,261	235,968	223,847	213,839	207,698	203,673
203,141	213,967	219,095	218,599	216,390	212,311	206,477	202,517	199,024
171,419	182,453	199,443	209,238	206,031	197,492	195,342	198,726	198,346
189,146	221,470	218,095	210,583	206,501	207,635	207,095	205,681	204,244
197,049	231,023	224,843	219,869	215,268	212,482	206,772	206,244	205,585
217,481	251,320	240,694	229,111	223,472	217,915	211,619	207,063	204,665
270,461	300,851	279,005	255,006	238,055	227,081	217,730	211,337	207,154
275,527	302,785	287,268	264,429	246,237	230,616	216,667	207,161	203,481
225,352	237,984	240,303	234,391	224,951	215,954	207,782	201,080	197,193
170,439	179,801	194,658	211,101	210,239	200,606	198,059	199,691	197,470
186,119	215,795	214,199	211,774	210,733	209,945	207,779	206,099	204,984
202,042	238,522	233,551	231,571	231,968	232,280	229,700	228,721	230,316
250,573	282,763	271,008	262,875	256,056	254,525	250,294	249,009	249,034
250,391	279,856	269,326	264,361	256,333	245,734	236,251	224,677	218,367
275,157	304,022	287,551	261,516	242,276	227,707	213,922	207,411	203,275
233,467	248,135	254,561	247,669	236,171	224,025	215,124	206,989	201,631
212,670	227,445	244,649	259,563	248,376	227,932	215,858	209,684	204,598
237,115	269,947	262,168	254,080	250,273	246,561	242,289	238,909	236,782
215,949	248,931	243,566	239,618	237,083	232,456	223,042	215,706	213,681
239,933	263,013	268,763	264,357	256,184	248,637	238,439	229,988	226,397
255,190	271,507	287,629	306,134	318,658	321,739	305,109	277,423	261,952
289,607	304,510	305,654	299,670	287,475	270,329	255,854	242,077	232,186
266,025	276,439	280,267	272,813	261,876	247,491	232,030	216,281	205,484
205,558	216,867	228,966	245,525	246,362	235,781	231,429	232,597	231,664
246,279	285,466	284,057	282,901	284,405	279,210	272,112	264,123	252,552
324,291	356,319	337,351	308,514	283,736	264,327	246,377	236,678	227,243
277,425	309,920	300,361	294,774	294,330	292,281	285,468	279,929	276,375
293,790	330,127	323,049	316,815	313,355	310,032	304,057	299,151	295,582
350,850	387,196	372,408	343,918	320,606	301,106	282,652	271,754	268,537
347,951	368,035	374,297	360,565	339,819	318,665	300,228	284,003	271,674
349,654	365,000	376,449	377,390	362,197	336,613	321,890	313,819	307,830
316,440	351,595	341,264	331,995	324,679	314,709	303,671	296,488	292,092
301,173	338,914	327,376	319,777	320,019	319,315	315,735	315,075	313,784
268,242	310,623	309,322	310,203	322,561	332,593	331,949	335,365	336,811
403,537	441,047	428,597	408,615	394,555	380,622	365,374	353,736	343,022
410,879	441,496	425,571	405,559	386,828	352,282	319,422	300,401	288,726
349,398	363,869	367,566	364,853	355,309	343,047	328,936	315,800	310,361

241,308	253,063	268,223	286,668	287,480	276,714	273,004	271,973	266,456
250,666	283,893	274,218	265,814	261,009	250,389	238,121	230,378	228,228
296,197	339,749	336,963	338,552	342,126	341,114	334,498	328,625	329,402
406,550	441,602	422,173	390,747	366,942	342,388	319,144	301,360	289,500
385,016	419,509	401,027	373,586	346,283	323,596	301,912	284,871	273,187
319,180	354,140	341,897	330,552	321,228	305,502	288,872	273,874	261,145
270,925	289,788	307,154	326,433	337,990	340,860	339,294	338,017	337,809
309,094	324,249	342,564	362,824	363,011	349,698	343,532	343,496	342,562
334,484	355,704	357,843	362,313	363,366	358,936	349,523	341,703	335,426
319,048	341,560	349,085	351,263	341,793	316,186	288,080	269,936	257,290
248,650	272,335	282,221	288,178	292,346	288,947	276,423	263,744	256,581
229,239	249,168	265,883	283,646	296,768	296,159	283,417	270,722	265,015
215,847	238,768	263,395	294,564	318,380	334,725	342,156	338,021	332,498
328,633	341,474	345,067	343,597	339,498	337,884	329,172	313,159	300,562
301,770	317,961	331,344	342,964	346,019	340,381	345,992	350,721	346,393
375,056	395,311	399,077	402,831	406,133	407,244	402,944	396,787	387,695
358,977	382,757	387,664	375,144	356,333	340,498	322,425	308,319	301,435
324,545	343,473	347,547	350,154	352,720	348,574	339,319	329,240	322,931
265,365	282,822	291,466	298,979	307,158	311,543	309,461	307,963	306,452
369,556	383,576	387,076	387,774	385,812	380,548	369,301	354,889	341,255
415,579	431,612	442,512	444,798	432,906	414,547	395,809	380,395	366,796
432,694	448,832	459,349	465,547	451,280	420,937	394,842	379,326	368,068
466,129	496,244	491,105	471,737	449,958	429,838	409,889	391,624	379,365
477,034	511,386	499,174	477,049	456,443	434,176	411,282	394,151	377,806
463,042	499,061	486,447	458,123	433,588	411,584	386,289	364,550	342,339
380,151	398,980	401,296	404,526	413,778	421,670	424,380	420,312	420,402
477,489	499,106	502,390	503,463	497,923	490,975	479,020	468,341	463,579
433,310	447,581	458,163	468,477	468,507	454,003	434,473	412,846	397,928
468,206	484,160	495,892	492,192	464,069	426,371	399,015	381,739	365,780
425,642	452,890	448,102	433,202	413,560	387,192	372,664	362,906	362,450
415,793	445,646	432,301	415,876	398,193	376,369	351,637	327,896	316,297
432,533	466,975	451,987	412,679	380,011	353,482	326,028	304,049	289,571
378,870	414,001	397,850	371,141	343,054	316,124	289,979	271,129	258,140
281,968	316,526	308,468	299,020	294,160	286,972	274,724	257,841	243,701
271,359	286,751	298,685	310,182	304,830	292,312	276,215	261,598	253,506
239,689	254,393	273,383	293,616	298,407	288,396	279,496	272,893	261,012
325,224	346,799	352,359	356,544	359,654	357,215	342,058	325,091	309,239
310,020	343,340	329,391	313,394	293,056	273,752	253,189	237,846	228,448
253,676	287,826	284,773	275,641	275,072	273,423	266,776	261,277	257,729
247,389	284,381	282,414	273,389	273,034	274,131	270,535	266,527	263,944
269,996	306,377	301,990	298,200	298,599	299,572	295,466	288,769	283,703
238,000	251,882	262,097	275,344	281,562	277,235	266,314	251,945	241,735
212,806	222,866	235,872	252,347	254,897	247,087	242,866	242,594	239,314
298,554	337,326	331,667	327,801	328,930	331,270	331,199	333,024	335,314
343,004	379,586	374,906	369,244	367,720	369,871	362,876	353,637	350,488
394,578	425,457	409,943	385,838	367,719	346,165	318,130	297,226	293,651
326,510	366,365	362,595	349,858	340,486	331,955	318,690	306,813	302,470

401,572	434,200	434,333	434,653	435,401	431,829	427,217	420,159	414,251
402,256	409,952	413,520	420,591	424,182	419,550	403,026	385,931	374,591
434,291	449,009	456,178	441,957	406,326	368,614	342,017	322,765	305,544
421,548	453,772	446,232	405,340	367,018	340,396	315,773	294,774	281,121
338,512	374,948	364,295	343,169	319,139	298,858	288,864	286,134	284,929
328,781	366,445	359,181	333,443	310,052	293,180	278,413	265,888	257,384
348,098	382,387	370,960	360,728	352,945	342,874	327,425	314,370	304,785
306,934	341,809	334,538	327,047	324,035	320,115	314,172	308,179	303,805
321,217	339,930	357,057	378,013	389,363	390,380	383,770	377,261	372,769
363,835	378,038	391,516	384,232	361,801	336,906	321,013	312,707	305,336
380,180	412,591	402,919	389,443	373,205	360,626	349,640	338,950	334,915
335,932	353,689	353,596	358,969	361,049	365,901	365,763	363,591	364,126
410,057	427,205	424,105	421,903	413,942	401,059	385,331	371,460	359,510
408,868	437,743	428,466	395,904	363,839	341,762	322,194	306,802	295,104
425,934	454,033	447,552	413,769	373,487	341,940	316,539	297,509	286,608
333,472	348,253	361,867	371,489	372,140	361,593	350,717	338,542	328,650
330,989	341,319	354,881	365,400	361,332	349,904	342,131	338,430	332,352
394,239	415,964	424,085	429,897	433,141	426,951	415,762	402,515	394,984
391,802	413,644	411,046	401,307	392,142	380,622	372,142	366,416	363,301
398,165	425,142	416,664	400,499	382,676	362,412	342,107	328,373	321,120
389,817	424,165	400,097	359,582	332,069	311,584	292,976	276,974	266,515
390,958	423,829	400,684	358,151	322,624	295,866	272,365	254,413	240,886
282,828	295,735	304,522	301,920	292,185	275,554	253,509	236,271	224,656
238,455	249,484	264,956	271,416	259,517	240,326	223,107	214,502	208,107
240,747	278,817	276,873	276,480	282,737	290,233	292,547	294,106	297,608
320,970	357,379	352,245	346,607	341,599	339,507	330,092	318,870	312,518
360,151	396,337	389,610	383,942	375,836	365,497	355,388	350,020	347,746
394,557	428,461	415,196	396,611	379,321	360,673	340,780	323,546	310,226
388,936	418,373	395,334	362,463	339,648	321,658	302,862	287,830	276,499
339,643	352,278	360,874	361,945	348,480	330,054	310,757	295,313	286,704
295,872	307,480	323,099	333,840	325,092	302,165	286,304	279,003	268,111
314,032	346,107	337,150	324,718	317,451	309,404	300,482	295,205	292,982
320,846	356,627	349,509	341,804	334,777	324,197	310,531	297,147	288,825
339,169	367,530	357,525	341,863	327,105	314,831	305,653	299,077	294,692
354,802	381,753	355,514	324,001	300,685	283,000	264,376	250,186	239,940
358,236	383,859	354,746	315,774	286,876	265,211	247,542	233,951	223,505
319,997	331,091	324,775	307,280	284,351	263,559	243,051	226,544	214,689
290,138	298,211	309,272	300,897	276,375	249,615	231,000	217,926	206,060
251,970	284,169	274,275	259,645	252,200	243,476	232,937	221,989	209,993
256,805	281,975	268,317	251,302	242,559	235,048	226,465	221,265	217,124
205,721	231,153	222,531	211,658	204,697	200,661	196,413	194,328	192,870
188,917	223,146	221,476	217,620	213,619	209,907	203,940	201,676	197,844
215,116	247,678	248,080	246,588	249,609	250,113	246,078	241,236	234,880
220,096	230,852	248,851	259,284	261,953	260,520	259,272	251,952	248,346
214,082	223,978	238,514	256,757	263,017	261,027	262,845	263,808	260,485
254,624	292,558	286,418	277,100	273,802	269,261	263,104	261,136	256,575
247,181	284,305	276,806	268,260	264,216	257,476	244,004	231,730	223,041

244,806	281,492	275,510	266,339	263,455	260,591	252,904	244,183	235,271
260,332	299,266	288,333	261,471	239,881	224,942	212,587	204,948	197,041
247,708	288,964	278,100	251,370	231,368	217,424	206,330	198,980	193,316
198,411	217,453	232,984	234,122	226,521	216,953	204,768	195,843	190,826
169,102	182,440	199,583	223,324	230,587	223,780	225,309	230,291	231,523
257,770	296,440	295,063	291,333	290,610	287,980	278,200	270,362	262,052
271,848	307,525	298,030	283,751	270,286	253,789	234,143	218,845	208,935
245,159	282,688	270,469	244,371	226,348	212,803	201,930	196,497	194,334
194,241	231,925	228,371	224,971	227,978	229,812	228,370	227,957	226,787
279,580	317,822	308,554	289,223	277,150	263,548	246,251	231,225	219,961
258,875	277,219	286,673	281,782	266,461	248,196	229,393	214,573	203,613
171,342	187,159	205,437	227,452	235,166	227,780	225,312	227,155	227,223
259,612	294,959	285,116	265,012	251,802	242,196	231,268	221,345	212,474
262,311	298,438	286,007	256,234	232,729	216,502	205,382	200,273	194,940
220,080	254,078	243,736	224,119	211,092	204,441	197,375	195,473	193,517
169,553	202,978	200,597	196,524	195,605	196,871	196,740	199,521	202,182
155,883	182,635	189,172	191,837	194,812	198,907	198,386	200,532	203,813
138,404	151,079	168,664	192,163	207,543	211,633	207,468	200,885	195,513
157,964	170,916	194,359	211,502	206,442	191,073	185,269	184,852	180,270
158,317	176,121	183,792	196,880	209,952	220,828	228,912	236,575	242,479
164,713	179,503	187,623	197,826	209,480	220,554	225,568	231,740	238,703
167,815	183,094	188,704	198,227	205,000	209,526	209,158	207,563	206,852
159,528	180,730	188,615	196,665	204,121	207,763	205,425	199,478	195,653
217,668	239,011	235,631	221,076	211,225	208,236	201,028	195,316	190,880
191,033	203,613	212,827	213,118	208,825	202,227	195,413	191,196	188,872
161,970	171,252	186,773	197,531	195,537	187,629	186,978	191,797	195,559
175,570	205,865	203,636	195,879	195,766	201,262	204,791	210,245	215,944
170,835	200,615	199,588	194,881	197,107	203,455	211,060	223,821	234,788
168,556	196,388	195,306	193,937	199,968	210,433	221,918	237,517	251,642
167,997	194,747	195,157	198,027	207,805	221,462	234,579	249,293	259,570
166,963	192,266	195,713	199,460	209,215	221,436	231,899	241,021	250,928
143,433	149,094	167,616	184,140	192,296	194,937	192,884	191,126	189,155
167,663	178,666	198,838	210,586	205,042	192,362	187,058	186,385	184,303
198,416	227,824	222,921	210,726	203,492	200,127	197,637	196,656	196,104
181,888	208,903	205,678	198,615	194,387	195,369	194,592	195,520	198,373
187,085	216,428	212,844	204,080	198,875	198,010	197,139	198,656	200,745
177,846	204,108	203,145	196,594	195,954	198,293	201,358	205,935	210,631
165,931	192,936	194,737	194,864	200,489	208,529	214,201	223,601	233,958
144,549	151,071	167,623	190,888	208,229	218,635	219,620	219,072	215,264
136,188	138,527	162,005	187,132	194,328	191,303	191,358	194,542	193,987
177,857	207,499	210,358	209,537	213,509	217,579	215,899	210,730	208,501
190,703	220,316	221,180	218,111	221,753	223,917	223,503	219,155	213,786
221,722	246,965	235,338	218,340	208,995	203,765	198,321	197,687	196,670
191,406	218,676	211,807	202,858	201,194	200,192	198,512	200,840	201,720
165,583	189,363	195,063	197,670	201,636	207,550	209,781	216,455	223,782
145,931	156,670	169,966	191,957	209,260	219,453	220,984	219,931	215,923
140,557	145,724	161,210	188,852	207,714	213,621	218,603	223,870	226,012

163,442	188,406	197,536	203,487	215,886	229,388	238,197	246,771	255,208
164,427	189,761	194,042	197,809	207,373	219,682	229,517	240,328	251,266
167,630	193,581	200,199	206,907	221,224	238,502	252,065	266,757	280,308
169,005	194,278	201,699	205,874	212,651	222,834	231,230	241,379	252,456
171,410	198,882	211,078	223,457	241,605	259,942	272,578	284,273	298,019
139,449	148,780	169,349	184,996	193,174	194,430	190,353	186,881	184,462
160,692	170,855	190,016	207,355	206,774	192,716	184,044	181,007	175,697
185,423	213,355	212,305	206,224	207,371	209,094	207,133	204,894	201,422
179,187	201,430	200,126	197,943	200,196	204,664	205,340	207,736	209,627
175,676	205,137	212,126	211,795	218,837	226,381	232,540	244,470	255,905
183,874	212,331	229,365	243,860	255,435	268,260	279,853	287,714	297,646
186,162	213,431	221,569	225,612	234,756	244,231	251,520	257,142	265,895
143,410	150,397	171,452	190,529	204,851	217,310	226,753	235,512	243,065
137,962	140,295	160,484	185,975	199,466	199,476	203,341	209,566	211,211
164,902	190,642	198,686	202,912	210,520	218,291	223,169	227,859	231,261
158,609	173,798	185,349	192,319	199,225	206,835	206,851	207,938	209,126
165,418	190,749	194,799	193,572	196,844	201,983	203,487	205,665	208,211
165,756	191,490	195,890	196,746	200,919	204,020	204,139	201,964	201,271
166,024	192,134	199,632	203,504	208,442	213,785	217,625	223,668	229,143
139,265	151,140	176,305	199,599	220,592	239,232	250,306	262,215	275,842
142,988	150,634	183,579	226,244	262,358	290,862	318,990	345,391	363,554
196,646	226,251	247,028	268,636	293,754	320,321	345,630	370,344	384,368
185,464	213,767	231,226	249,564	273,546	301,032	325,249	349,596	367,933
184,212	210,640	231,826	256,378	287,670	318,191	341,501	362,206	378,049
183,787	211,306	232,883	257,533	287,379	320,004	348,688	369,450	371,254
175,561	198,893	216,522	239,028	264,290	293,189	317,556	339,712	357,366
157,119	166,616	197,757	236,896	275,031	306,957	330,638	349,028	364,552
160,747	171,655	209,241	257,437	294,256	317,528	337,322	356,416	370,757
166,739	171,546	197,831	236,787	269,289	293,615	311,784	327,136	338,844
176,486	200,703	225,348	247,020	272,503	306,592	335,355	364,044	384,789
205,471	224,964	244,750	260,122	282,179	314,102	345,545	375,526	387,721
182,388	200,177	221,980	247,517	281,049	313,335	340,379	364,445	383,640
185,174	206,574	233,549	262,605	296,120	324,953	353,146	376,312	394,861
196,911	208,727	243,190	283,932	321,557	350,866	372,357	385,320	397,864
206,667	215,213	242,939	270,308	284,869	295,544	301,220	309,302	319,024
164,398	183,671	207,618	232,872	260,744	290,428	313,549	334,813	351,184
172,491	192,414	216,412	239,624	266,854	297,465	321,113	344,284	362,622
210,454	222,640	242,097	260,674	272,666	284,474	298,020	313,898	331,257
199,989	218,927	244,381	274,704	307,112	337,477	360,258	383,223	401,424
217,209	238,061	261,502	284,235	302,792	320,979	337,542	354,451	373,334
210,147	222,210	254,391	296,876	338,860	375,180	402,376	419,930	433,320
204,213	215,049	256,386	304,289	344,694	374,238	401,520	425,173	441,800
237,431	258,670	300,274	340,122	377,544	413,391	434,823	442,755	441,787
206,557	230,332	268,991	305,050	345,280	386,832	418,615	441,947	458,529
206,059	227,936	259,736	290,547	326,239	356,670	379,801	397,011	411,065
203,773	223,143	243,556	261,555	282,991	310,381	337,931	365,287	364,901
196,153	217,555	251,520	286,697	327,329	368,493	401,404	430,139	452,943

221,797	214,162	226,475	245,947	275,863	316,840	351,109	380,589	403,662
174,700	186,250	225,927	277,996	325,314	362,558	396,297	424,537	442,353
229,615	251,122	289,293	326,941	370,802	411,867	442,896	466,132	483,142
234,282	251,709	285,289	320,965	358,568	395,718	428,908	454,496	471,279
248,980	270,828	306,865	341,565	378,683	412,376	436,387	453,648	467,233
253,076	271,691	304,486	339,882	372,043	397,523	406,155	408,323	417,220
196,662	215,446	247,056	279,522	314,036	347,922	375,462	397,982	419,922
194,756	205,547	241,816	287,160	332,708	374,590	410,809	437,774	458,268
227,544	234,258	266,641	307,336	344,611	368,968	396,744	426,896	445,592
226,715	242,471	268,365	293,396	320,587	350,678	364,353	373,218	390,582
194,037	215,064	248,074	277,772	311,199	342,013	364,459	381,175	394,440
179,901	195,979	219,682	242,051	265,616	288,990	305,940	323,294	334,708
167,117	183,494	207,013	225,167	247,599	269,243	286,581	303,564	319,842
162,633	177,465	200,136	220,262	242,952	264,631	282,590	300,271	318,978
151,677	160,161	185,734	222,216	268,653	314,032	353,952	383,277	404,546
194,898	201,044	240,458	293,701	336,553	366,054	390,438	412,935	427,487
185,790	192,659	225,820	272,807	321,456	364,751	391,414	408,371	420,973
194,796	213,167	248,436	285,102	329,283	372,785	406,223	431,683	451,197
214,448	230,947	264,217	305,372	348,399	392,978	427,147	448,334	464,112
231,998	248,400	284,203	322,778	366,200	408,961	437,800	458,966	473,932
239,221	250,138	267,078	284,344	302,763	325,111	340,491	350,394	357,308
184,921	192,873	227,799	270,861	313,393	351,352	378,320	397,896	410,975
166,187	172,304	207,343	255,762	300,243	334,669	367,148	395,110	412,406
203,192	222,275	247,606	277,416	303,524	322,475	340,236	362,815	381,336
228,145	239,373	251,193	260,348	274,182	292,349	314,992	345,292	370,969
209,191	227,484	262,725	301,373	343,797	384,614	415,868	439,723	458,284
235,206	249,199	282,336	322,409	368,275	414,480	445,494	468,352	485,831
247,689	258,004	283,823	314,945	353,275	391,473	421,351	445,223	462,680
219,953	225,054	252,326	286,671	318,605	350,098	379,586	406,030	429,222
221,529	226,138	261,778	301,916	329,869	351,912	377,742	403,443	403,903
225,024	241,372	270,741	300,530	335,929	373,172	405,065	432,171	451,505
220,405	234,062	251,810	275,981	316,008	350,010	381,255	409,001	419,692
254,183	262,811	283,478	307,771	344,561	382,711	397,823	394,195	386,757
224,634	241,073	275,180	312,996	358,901	404,872	437,612	458,646	475,474
250,660	263,489	297,978	335,729	375,540	415,892	445,437	468,596	484,971
227,167	232,523	269,721	320,401	370,801	413,442	445,198	467,512	484,225
245,830	246,085	275,038	320,836	357,474	381,522	405,510	429,788	449,869
240,526	254,684	280,162	302,639	328,501	359,163	385,279	409,025	418,256
244,350	253,638	279,743	307,280	336,434	361,641	380,397	397,263	412,435
236,942	253,124	281,455	313,533	351,991	392,146	424,043	444,196	447,776
245,329	261,399	290,115	320,936	361,242	407,326	439,328	460,694	475,915
220,126	232,045	256,655	285,062	319,010	350,696	377,056	399,294	418,111
208,894	210,262	236,123	270,957	307,945	344,183	380,682	411,186	435,761
216,241	215,592	238,636	269,934	296,120	315,263	338,018	362,239	384,645
204,507	219,516	245,972	280,673	322,228	366,528	400,158	427,055	448,700
223,577	238,906	269,782	303,507	342,892	391,307	434,231	467,624	493,478
284,688	295,855	325,724	368,870	416,911	461,446	493,520	518,595	532,924

292,976	309,426	327,067	344,507	358,853	374,248	393,025	416,672	439,531
230,221	244,714	264,660	286,327	317,123	347,649	375,578	400,348	420,568
181,278	181,655	206,288	243,470	283,467	321,169	352,776	376,609	397,131
175,243	174,479	206,432	255,241	301,823	340,553	376,652	412,024	438,321
232,945	252,382	271,647	298,608	339,815	391,769	433,382	463,685	481,215
273,850	290,161	310,017	346,171	392,937	438,704	469,316	487,296	499,848
286,361	305,623	321,864	355,587	399,428	441,862	469,098	487,965	504,684
282,045	301,086	320,500	357,134	405,057	452,863	486,199	508,250	519,735
237,828	260,975	279,564	310,305	349,496	393,520	431,148	463,612	487,716
248,952	252,540	283,061	322,653	364,283	403,534	439,460	470,010	485,209
224,643	226,091	248,123	284,821	316,912	351,425	389,463	424,296	451,370
238,440	257,437	267,145	286,289	308,595	329,962	349,553	368,731	387,996
203,079	225,175	236,934	257,339	284,505	315,967	344,353	372,348	397,906
231,596	254,876	264,039	280,700	311,114	345,041	375,140	402,208	425,557
225,948	250,938	257,897	273,830	302,161	342,304	379,712	413,471	436,364
220,606	244,975	258,676	285,935	323,133	364,109	397,877	427,612	450,317
241,945	246,503	253,492	271,876	290,522	308,613	335,127	368,829	396,038
202,601	202,873	236,064	288,769	332,591	363,245	390,663	416,050	435,292
217,014	239,215	252,970	275,342	303,957	337,234	363,616	382,530	400,003
205,529	230,434	242,132	261,274	289,996	320,537	346,345	366,177	379,891
209,186	234,097	238,662	250,915	271,063	298,177	321,645	347,403	371,610
188,498	209,317	213,778	227,583	246,218	268,908	290,888	311,471	330,406
181,846	203,597	209,003	221,053	240,346	264,786	286,341	308,075	332,174
166,312	169,610	190,699	222,381	260,083	304,241	348,816	385,548	415,766
202,015	200,313	230,138	280,077	321,207	350,696	378,319	399,503	408,554
229,009	261,188	263,490	271,877	292,826	319,812	345,408	370,655	389,430
211,499	238,068	241,768	256,601	287,314	325,694	354,433	377,325	399,682
219,293	245,017	255,842	273,902	306,104	339,398	363,571	384,085	402,405
218,124	242,620	256,521	275,899	306,051	342,102	362,303	376,542	391,918
232,466	259,396	262,883	264,298	270,410	284,122	305,201	316,702	327,172
159,610	162,401	178,305	199,126	216,144	225,027	234,140	242,858	253,791
144,540	146,471	163,435	186,194	199,594	206,684	218,866	234,207	250,292
150,638	152,368	167,035	194,891	225,798	256,310	284,209	308,038	330,984
199,204	230,048	240,985	264,122	299,074	342,505	379,755	408,448	429,816
211,005	236,434	232,204	240,459	259,596	279,119	296,060	312,341	327,621
190,102	217,043	215,259	219,712	230,562	241,113	247,415	253,579	260,544
185,424	217,746	213,163	211,853	217,440	221,016	221,013	218,760	220,893
171,900	181,462	199,165	228,984	262,463	290,007	298,280	299,457	300,945
149,872	151,023	170,267	201,960	224,916	240,918	258,896	279,067	294,745
174,495	199,841	201,330	209,497	226,025	248,855	272,362	299,048	325,646
186,096	214,119	214,308	223,034	243,555	271,234	296,079	324,786	343,874
192,178	220,064	219,235	231,957	255,280	289,928	320,496	351,018	374,674
228,589	255,749	249,780	255,592	271,592	288,422	293,832	309,170	335,531
186,183	213,333	212,235	220,207	235,933	253,748	267,319	287,291	307,817
157,576	164,247	179,765	199,013	220,983	246,451	270,732	296,489	324,250
154,693	156,340	173,612	205,086	229,044	251,375	282,301	313,685	335,955
183,926	214,108	215,981	230,368	259,068	293,415	326,665	360,807	388,366

208,287	235,613	236,496	254,184	285,625	324,334	360,405	395,654	425,029
216,124	244,757	243,438	262,779	296,707	335,675	367,452	392,556	411,810
208,975	239,619	238,405	257,707	290,180	331,553	366,373	396,079	418,702
226,047	255,784	258,001	278,390	309,915	344,387	374,406	381,864	375,827
159,565	166,061	176,700	197,469	215,881	234,938	249,676	264,213	280,667
144,559	151,335	163,870	185,786	193,958	192,228	195,050	199,326	200,821
167,445	196,393	192,497	194,622	200,438	206,756	209,945	215,445	221,259
173,717	204,725	198,962	196,779	198,997	202,351	203,723	208,406	214,490
176,718	206,555	199,036	195,894	198,678	203,927	208,410	214,161	223,321
171,699	203,129	195,088	194,488	198,355	207,637	216,203	227,532	241,697
172,028	199,208	194,731	195,699	200,064	205,522	207,023	210,300	217,460
155,858	169,099	179,406	189,558	192,656	195,089	194,187	193,317	190,402
153,726	165,399	181,858	202,283	204,175	196,360	192,439	192,583	190,705
203,983	236,767	235,692	229,176	222,014	215,659	207,785	201,903	200,255
212,698	245,162	240,718	225,974	215,932	207,747	203,453	200,165	199,364
208,722	235,721	230,083	219,681	210,734	205,909	201,120	201,375	202,030
178,079	204,952	203,164	198,326	200,815	205,170	209,979	216,718	225,427
172,447	200,065	199,757	198,788	200,735	207,551	213,686	221,749	233,268
155,542	165,757	175,216	186,959	193,311	200,022	208,295	219,756	233,408
140,032	148,714	160,541	181,070	189,999	196,319	211,650	233,544	253,154
162,214	187,252	188,498	195,562	205,094	218,945	233,969	255,067	273,720
173,702	197,699	195,737	196,876	205,142	218,877	229,482	238,579	242,280
164,693	190,006	188,493	192,111	198,208	204,168	207,066	211,801	214,482
174,589	200,893	199,882	195,693	196,150	196,839	196,226	197,909	199,611
182,918	208,248	204,111	200,464	198,946	198,333	195,906	196,461	197,062
179,807	195,049	206,306	211,253	207,135	200,127	194,054	190,975	190,086
156,353	168,671	181,875	197,323	195,793	188,783	190,035	196,168	202,972
167,281	201,905	197,264	194,753	196,878	204,253	212,281	222,745	233,689
173,218	208,018	199,808	195,343	195,918	196,913	194,593	195,255	195,238
192,344	233,692	224,231	212,326	203,010	199,250	196,819	196,413	197,795
187,132	222,300	213,126	203,022	199,361	198,487	197,458	196,710	196,864
211,348	250,973	241,194	226,770	214,423	205,705	199,078	196,347	195,855
160,579	173,963	182,307	191,891	198,343	198,674	196,669	194,945	195,173
136,532	147,667	158,701	180,574	190,367	191,750	198,521	205,247	209,324
166,000	200,603	200,082	195,401	199,263	204,238	206,830	212,039	213,495
189,684	228,367	228,308	218,518	209,753	206,309	202,049	200,084	198,313
189,004	226,435	218,499	206,593	201,252	200,139	197,820	198,599	201,495
180,820	218,865	213,588	205,878	203,265	202,264	197,551	194,117	192,431
245,401	286,894	278,179	261,398	244,872	234,183	219,003	207,924	200,541
238,634	257,232	269,077	269,174	257,351	240,224	222,788	208,059	199,486
183,546	199,830	215,291	225,288	215,028	198,752	192,416	192,929	191,740

29 31 33 35 37 39 41 43 45

HR15	HR16	HR17	HR18	HR19	HR20	HR21	HR22	HR23
200,014	201,867	217,999	254,124	262,081	257,582	255,332	241,769	224,863
208,094	208,947	220,364	255,716	264,336	259,418	247,177	227,763	203,690
202,704	206,036	223,124	267,988	281,740	286,028	283,342	268,926	248,122
202,991	205,658	222,136	260,115	266,798	264,253	255,851	240,373	216,487
202,824	206,821	224,736	266,077	280,582	282,448	281,625	266,652	246,499
200,899	200,831	213,976	246,480	247,792	244,891	239,807	228,707	212,536
198,398	201,045	209,039	233,857	230,849	221,723	213,192	198,566	182,238
198,092	201,296	213,765	244,857	244,740	235,835	222,365	201,654	177,897
201,892	204,188	222,388	251,977	252,125	244,864	231,267	208,768	182,475
202,004	204,391	216,968	252,139	256,894	251,193	239,854	218,841	192,233
201,849	207,249	226,849	266,942	273,678	270,541	267,083	252,577	233,456
203,074	207,487	228,624	266,429	274,318	277,677	272,955	255,874	235,381
198,649	198,005	215,130	247,672	250,023	248,082	245,678	234,691	219,415
194,663	197,546	213,728	238,754	238,060	231,893	224,606	211,027	195,795
194,544	197,816	214,562	244,773	244,536	237,844	224,961	203,826	179,081
205,262	213,255	235,659	259,576	258,122	252,459	239,923	218,148	189,486
231,597	241,007	266,519	294,599	295,834	293,916	285,942	266,259	238,884
248,561	256,720	283,978	304,631	303,934	299,038	288,006	266,372	239,392
211,419	214,857	238,177	277,650	285,748	288,390	283,449	266,456	243,240
197,513	199,791	217,860	246,575	248,558	247,792	245,316	237,616	225,213
198,595	197,650	210,710	237,105	238,437	238,114	235,085	225,691	212,533
201,299	207,100	230,938	261,155	265,501	264,450	256,940	240,628	218,056
234,395	240,513	261,911	283,596	283,995	277,778	266,085	244,295	215,601
212,180	218,868	245,152	268,146	269,649	265,391	257,821	242,008	222,006
226,054	232,583	254,986	280,575	282,072	279,849	273,648	262,398	244,783
256,941	258,468	269,182	285,128	290,210	292,361	292,851	286,345	273,263
224,509	227,433	255,771	294,008	300,041	302,252	299,582	291,119	276,433
200,434	201,346	218,960	248,505	249,096	247,714	243,427	232,634	216,568
230,815	237,167	261,341	279,376	276,469	270,839	256,077	235,971	212,957
247,573	253,635	288,560	334,629	346,271	351,017	348,223	331,655	305,324
224,173	236,043	274,789	318,013	328,763	332,121	325,380	305,593	278,304
273,410	281,512	307,909	328,629	329,636	331,168	327,990	310,537	284,151
293,649	306,964	338,072	363,564	369,704	372,822	367,918	348,589	323,038
274,562	293,663	332,433	369,229	374,519	377,044	374,857	362,692	345,512
269,626	278,450	319,099	360,354	368,481	373,980	375,831	369,658	356,344
304,824	314,162	344,550	372,201	373,822	372,665	363,472	345,227	314,468
288,969	292,708	320,574	351,282	355,070	354,046	344,870	323,226	292,523
311,448	322,523	343,612	353,227	347,199	333,068	315,639	287,699	251,130
337,784	353,389	388,455	418,108	423,717	426,294	425,399	413,702	388,878
338,726	349,661	394,070	437,554	444,100	445,434	442,894	426,576	397,874
282,044	288,545	333,843	381,142	389,541	394,271	393,085	384,943	367,132
310,154	316,236	338,787	354,857	348,821	340,104	330,570	315,589	293,110

260,434	263,522	289,487	316,777	318,099	317,579	307,615	287,180	256,472
226,698	235,110	267,979	297,604	299,458	298,166	291,005	274,904	247,910
334,533	344,173	376,031	414,331	423,357	424,797	419,807	403,317	375,763
282,042	291,852	339,181	392,625	405,931	413,032	411,616	395,562	366,677
274,999	286,964	320,642	357,954	368,662	372,195	370,366	352,840	324,688
258,087	267,961	298,753	327,972	328,830	325,828	320,413	308,771	287,416
340,901	349,099	371,200	383,733	380,991	377,864	372,279	359,969	339,840
344,209	349,676	370,017	386,029	383,314	382,223	375,564	360,602	334,973
330,877	334,693	356,695	384,880	384,072	381,159	373,078	355,186	327,151
251,925	256,773	284,309	314,488	317,227	314,704	306,022	290,394	265,088
251,966	255,297	279,458	303,655	301,110	296,749	291,126	280,015	257,919
260,718	259,717	271,739	278,906	271,314	266,251	262,064	256,360	241,931
335,586	338,090	351,816	366,801	366,746	366,292	363,089	355,485	341,380
293,906	298,786	326,414	360,562	362,947	360,754	354,153	340,440	320,058
347,133	352,958	375,579	399,031	403,806	405,403	401,849	391,279	370,005
377,522	372,126	389,024	415,896	413,984	406,532	396,680	380,081	357,006
305,271	314,026	343,253	383,426	387,768	387,413	380,752	362,417	337,379
320,071	319,922	336,929	356,146	353,209	345,010	335,364	318,027	293,177
309,159	316,330	338,930	356,783	345,813	337,506	333,186	332,674	330,964
335,336	342,227	377,958	415,827	417,700	417,248	415,874	411,438	401,938
357,531	359,725	389,641	437,512	443,142	446,744	445,598	437,511	423,900
371,453	387,047	420,440	459,355	466,237	468,033	460,773	445,818	423,254
372,691	381,230	420,465	468,841	479,264	479,693	473,127	453,793	431,718
371,226	378,582	414,847	461,175	474,480	477,160	472,357	455,132	431,030
330,475	335,760	374,376	420,849	429,649	430,650	423,084	403,543	376,223
422,076	432,189	462,815	506,873	510,451	505,052	494,324	477,889	456,446
458,296	460,218	476,028	499,996	494,834	485,017	472,498	455,911	438,262
392,267	396,449	422,120	465,733	473,012	474,357	472,502	463,908	452,451
354,726	360,535	392,579	445,483	460,555	466,692	462,858	447,798	424,621
364,329	370,553	390,013	422,224	425,851	425,468	423,012	414,457	392,274
313,340	322,821	353,772	399,008	413,788	418,127	415,968	407,924	387,586
281,379	283,884	312,581	367,254	382,990	387,853	386,924	372,413	348,469
252,736	261,683	289,165	327,000	335,085	332,896	323,315	302,293	276,199
239,346	243,885	261,136	291,654	296,140	293,618	292,007	285,153	272,189
254,425	259,863	272,876	295,623	293,927	288,124	281,928	270,566	255,481
250,611	248,252	262,169	303,081	313,389	315,787	314,953	309,674	297,101
297,269	290,791	305,999	344,281	352,921	348,903	339,143	318,817	291,932
224,794	229,850	250,841	285,205	293,051	290,170	284,229	266,358	239,994
256,000	262,180	280,114	301,819	301,114	292,988	283,645	263,746	237,177
260,951	259,034	267,510	293,009	302,474	301,260	294,459	275,389	250,741
280,573	284,260	296,457	317,084	314,336	306,740	298,579	284,537	266,582
238,031	237,543	247,852	274,867	278,557	274,897	269,266	259,405	244,814
234,871	235,278	247,737	277,373	283,545	285,032	278,680	267,513	250,721
339,700	346,616	362,840	389,504	393,897	388,335	376,016	354,618	326,952
349,164	353,655	363,579	399,037	414,582	413,973	408,369	394,113	372,278
300,797	309,819	331,157	358,152	361,688	359,378	353,861	333,795	303,226
296,829	303,969	341,431	386,666	404,693	409,965	407,374	393,457	372,004

412,269	418,238	431,564	456,179	457,361	450,814	444,315	431,145	412,977
359,366	348,588	360,540	401,634	420,563	419,174	415,307	411,109	398,628
294,193	294,144	316,485	370,082	395,875	401,853	398,821	389,447	372,608
272,663	277,499	303,312	348,302	366,781	366,934	359,304	342,172	315,741
289,661	300,235	322,419	352,083	359,919	356,989	351,424	329,939	304,357
252,610	256,903	283,326	335,634	359,442	366,124	365,901	351,166	326,398
299,662	305,220	319,439	346,502	355,866	355,133	345,306	324,245	297,675
301,180	304,709	314,465	335,998	340,061	337,997	335,286	327,548	312,897
370,575	371,351	377,240	394,899	396,213	388,737	378,616	366,992	350,449
299,911	300,786	317,914	356,037	373,286	382,409	381,444	379,825	358,352
337,439	343,686	357,940	387,030	397,032	394,174	383,360	363,343	336,707
365,920	382,699	412,917	453,080	470,321	466,730	462,821	449,166	426,565
352,894	355,661	367,500	399,252	419,564	416,830	408,378	391,768	368,667
286,340	288,185	309,933	359,072	390,166	398,999	398,708	387,915	370,016
279,904	283,562	305,935	342,938	363,724	365,164	362,831	353,419	338,565
322,913	327,369	336,895	357,036	368,012	365,809	359,729	352,893	341,185
331,726	335,197	344,741	364,518	370,402	370,534	363,658	355,844	343,458
389,724	393,489	410,504	438,885	451,022	444,293	431,827	410,780	385,301
362,528	370,133	384,541	408,820	422,215	416,890	403,991	386,666	363,346
320,180	330,129	350,548	379,727	395,098	393,044	383,202	366,161	339,799
260,211	260,543	272,852	315,579	355,904	369,408	372,171	360,767	342,014
229,988	236,033	247,814	279,853	309,787	317,465	319,072	314,249	299,912
216,471	214,806	219,184	236,660	262,989	266,176	269,870	262,406	250,050
203,125	207,057	221,389	247,440	264,127	265,806	257,965	240,806	218,829
300,137	309,040	323,750	343,855	356,694	355,313	345,271	326,218	298,595
308,365	312,460	330,845	356,479	375,730	374,959	365,934	350,624	322,456
346,640	353,449	370,527	396,642	419,025	417,538	409,416	390,564	362,449
304,467	308,931	324,775	352,109	383,008	388,735	384,711	369,604	346,993
266,701	268,022	278,576	308,614	345,590	353,668	354,001	348,159	334,899
284,789	288,560	299,799	315,086	334,488	333,162	327,238	317,099	300,667
260,673	260,082	270,180	290,488	318,861	323,773	318,575	303,856	282,476
293,956	303,687	316,682	339,658	356,651	353,309	341,807	322,887	295,450
283,761	291,702	307,804	336,830	368,493	370,595	365,250	348,516	322,363
294,631	304,030	320,615	344,402	367,119	364,747	359,344	342,924	316,611
232,589	233,060	242,656	273,476	320,908	337,017	340,296	328,438	309,192
214,148	214,200	218,617	240,493	282,430	295,321	302,218	301,311	292,303
206,195	205,033	210,328	228,101	264,390	276,765	282,016	279,984	274,006
198,953	199,117	210,271	227,747	257,581	262,709	254,897	235,998	211,085
201,411	201,665	204,784	223,859	264,572	271,437	265,866	250,739	227,914
211,565	216,691	224,708	243,638	271,756	270,197	258,983	236,595	209,183
191,452	194,031	198,634	212,646	242,735	246,246	235,263	214,612	185,528
195,383	198,339	203,575	215,745	244,310	248,594	240,969	220,773	195,040
229,330	231,737	240,401	252,386	271,031	270,459	263,796	252,306	234,104
249,897	255,304	261,736	271,966	283,133	277,707	270,146	257,070	240,104
257,655	259,159	261,919	267,864	278,408	299,425	295,472	279,051	252,141
251,009	256,311	266,591	280,051	294,285	308,701	300,086	280,148	252,237
219,104	222,644	229,024	240,712	251,994	276,296	276,826	263,553	238,435

223,527	221,495	225,273	233,579	245,196	268,341	270,436	255,899	228,975
190,699	193,033	196,985	202,033	210,166	242,587	248,216	235,892	209,211
188,544	188,825	190,462	191,762	197,804	220,467	220,703	212,568	196,566
187,867	188,600	191,348	194,277	197,836	220,462	218,218	206,837	193,523
229,452	230,993	242,290	250,097	258,979	274,573	266,935	245,320	220,535
257,073	261,434	277,938	290,251	299,894	313,475	305,111	285,414	257,377
200,916	196,459	201,238	206,491	214,916	245,521	250,512	235,575	211,368
190,412	190,669	197,238	206,080	212,828	236,406	241,073	223,682	195,068
223,638	222,969	228,120	234,768	247,525	272,836	277,110	264,522	247,175
210,643	204,419	205,498	207,158	215,098	247,106	261,749	259,712	250,379
195,942	192,868	196,056	201,748	206,202	223,944	222,616	216,552	195,664
227,102	230,454	241,799	251,170	258,229	273,923	268,536	251,720	228,352
203,480	200,306	203,031	207,475	218,467	249,576	259,357	248,415	223,551
189,397	186,584	192,202	197,564	204,565	233,006	242,594	225,714	198,899
191,468	192,732	199,056	205,222	208,333	229,651	240,377	222,437	190,396
202,041	205,390	213,581	219,710	220,808	239,638	249,045	230,428	198,827
204,614	206,621	210,373	212,759	209,596	224,586	231,106	216,185	193,672
193,265	194,650	196,406	196,995	197,050	211,582	220,944	207,914	187,830
179,024	182,088	187,683	192,222	194,549	213,406	226,283	209,576	182,925
243,872	247,088	253,289	261,846	262,263	275,964	280,069	255,584	219,973
241,751	245,588	251,363	253,918	253,086	264,250	270,364	247,640	213,243
205,349	206,605	213,499	223,300	229,588	238,434	228,656	208,310	182,888
191,278	190,345	197,019	202,437	208,220	230,226	242,101	229,861	207,141
188,617	185,129	186,829	192,849	193,210	211,443	224,549	212,806	195,984
187,906	190,494	195,905	198,578	197,393	210,334	219,754	203,243	183,501
198,505	206,247	216,361	223,295	223,696	236,492	246,937	220,736	186,604
220,694	230,203	241,247	248,812	249,263	257,303	264,107	236,230	195,582
242,084	251,721	266,177	272,574	270,254	273,731	279,996	250,381	207,148
263,003	275,208	289,323	296,342	287,711	285,875	288,644	259,352	214,199
268,660	277,759	285,995	286,900	283,009	283,816	291,118	259,476	215,254
256,819	260,009	256,260	248,665	242,171	246,246	241,605	221,902	195,534
189,485	195,395	199,231	198,911	195,806	206,971	217,647	205,157	187,432
181,062	182,657	188,067	195,038	197,742	216,533	231,382	212,788	184,197
193,545	194,074	200,693	207,642	213,348	233,784	241,236	217,864	187,257
198,258	200,218	207,614	210,342	214,600	229,999	243,609	221,591	187,172
201,999	206,288	215,801	218,170	217,986	229,208	242,254	221,543	187,567
211,872	213,626	220,329	224,354	224,221	240,227	253,663	230,610	195,566
238,907	241,404	248,796	246,752	239,171	242,314	251,640	235,261	210,209
210,965	212,378	218,596	220,193	215,561	213,651	221,707	208,217	187,642
191,180	192,593	200,475	207,822	211,855	222,734	224,929	206,950	182,305
204,164	205,014	211,074	214,115	219,187	235,264	244,248	224,581	194,376
208,012	205,538	208,459	213,519	219,745	231,601	249,452	234,000	206,874
195,496	195,864	201,111	206,678	207,696	220,793	242,088	223,185	191,169
202,120	207,345	215,169	220,583	221,610	230,165	253,035	234,463	200,912
228,207	235,511	243,703	249,453	245,987	249,317	262,580	250,687	227,086
212,301	210,067	210,051	206,412	209,241	214,502	225,246	212,261	193,082
226,913	234,427	243,511	249,067	247,281	249,966	259,135	237,600	204,132

259,578	265,482	275,518	280,454	275,156	268,134	279,926	254,872	213,588
261,796	272,417	284,876	288,975	285,146	275,198	285,240	259,858	216,328
289,261	299,726	315,555	320,687	313,161	302,481	310,236	284,807	239,826
262,425	275,017	288,539	293,074	286,146	275,565	288,594	264,975	224,914
304,583	300,324	294,437	291,634	282,210	278,627	278,628	253,053	217,671
182,662	184,537	187,514	189,625	189,647	194,704	213,270	207,856	190,950
172,360	174,124	177,996	183,278	188,627	201,385	224,536	210,922	184,918
196,857	198,060	208,336	218,430	224,026	233,364	246,072	228,227	196,635
209,763	215,000	226,944	232,867	235,467	241,589	261,612	245,573	211,278
265,844	273,529	290,598	299,382	296,854	294,717	307,087	284,644	240,180
303,783	315,765	329,067	328,763	319,663	313,393	326,239	302,427	259,792
277,886	289,465	298,640	292,222	274,790	255,407	262,089	244,893	216,197
249,906	258,944	263,454	260,982	250,651	240,598	249,749	235,652	207,626
210,384	213,887	223,294	229,520	228,827	232,599	239,553	221,499	192,748
234,369	238,816	248,774	251,489	245,898	237,395	246,997	230,904	199,075
209,001	208,296	215,202	220,146	223,549	224,559	238,932	224,399	193,582
208,792	213,100	220,803	227,636	226,746	228,849	244,567	228,619	196,621
199,510	202,036	210,804	216,582	219,472	224,971	237,345	221,567	194,435
234,265	242,670	255,260	258,508	252,560	244,911	253,278	239,682	213,764
289,048	304,724	318,218	321,766	314,086	296,431	292,967	275,066	240,266
373,354	383,106	393,151	396,968	388,490	375,794	373,999	348,491	298,462
387,856	385,680	388,905	388,304	380,222	364,158	361,022	331,747	281,085
377,153	383,781	390,939	388,796	377,333	357,784	353,825	324,968	277,015
388,520	397,590	405,135	400,804	386,495	365,147	357,670	328,855	279,365
360,981	339,138	326,882	314,419	303,515	295,633	298,993	277,429	240,493
370,790	380,045	383,800	373,289	351,508	328,924	320,263	298,777	264,899
377,355	389,108	395,023	383,948	363,728	339,831	341,384	321,479	283,167
378,123	382,551	384,934	379,880	358,061	336,358	331,377	310,716	275,307
348,490	357,606	361,359	358,021	343,532	330,353	327,675	299,433	255,422
400,577	413,020	425,556	427,705	416,836	395,296	385,261	360,814	310,475
353,188	320,417	308,703	301,177	291,090	281,769	285,875	274,852	243,174
399,210	410,664	417,878	414,598	399,277	377,394	369,310	345,247	295,502
408,820	413,867	422,214	418,647	403,202	378,905	370,900	353,559	315,424
409,252	418,187	414,433	403,163	387,416	369,107	363,627	349,343	316,480
327,194	333,453	340,231	340,303	327,836	308,086	298,056	282,051	242,770
356,374	357,834	349,774	342,230	327,218	312,396	310,981	294,840	256,267
373,799	379,686	379,607	370,373	353,420	336,750	331,571	313,433	275,320
351,616	372,462	391,262	393,712	388,083	369,747	358,874	343,114	301,804
414,299	422,416	430,376	428,119	414,010	393,217	385,413	367,602	324,931
383,185	386,120	389,503	382,534	366,281	352,688	351,608	337,854	304,825
443,333	450,760	457,058	454,460	441,995	418,419	409,359	388,445	350,003
450,217	453,814	461,595	464,241	453,899	438,052	428,449	406,566	360,710
438,135	438,734	434,382	428,196	418,129	402,664	392,993	361,765	313,807
467,558	474,117	477,351	450,447	410,635	380,400	362,112	337,693	293,744
424,108	433,884	443,100	445,222	434,093	408,790	392,012	369,044	319,099
359,451	360,919	375,410	384,747	379,302	365,087	355,970	342,107	300,169
466,710	474,162	481,704	475,558	460,015	439,147	427,924	410,966	371,311

421,134	434,011	442,461	440,432	427,442	404,395	384,601	362,875	321,549
457,140	467,701	476,429	476,800	465,699	448,114	436,513	416,631	369,118
492,698	499,146	502,124	500,198	489,383	468,489	455,771	428,663	375,170
478,820	485,122	493,850	495,794	485,232	464,301	450,685	428,250	382,355
476,981	483,744	495,629	495,402	483,921	459,049	445,688	422,746	373,052
427,636	432,158	439,716	436,212	418,631	395,160	380,374	360,484	315,886
436,164	446,415	456,535	455,399	440,988	415,221	392,827	370,092	329,843
471,497	480,193	484,401	482,311	468,582	445,411	430,980	414,961	376,920
457,253	465,873	473,571	474,546	463,037	443,780	433,601	415,426	375,450
405,956	417,554	427,883	429,997	417,947	392,050	371,516	349,682	303,102
396,540	392,878	388,846	388,081	378,149	354,007	340,635	325,046	283,647
345,692	356,834	368,995	373,053	359,708	333,257	313,909	297,169	257,248
333,500	346,912	360,103	363,313	352,405	328,910	311,690	296,660	257,138
337,779	354,973	369,506	375,751	363,778	339,447	315,476	298,776	263,224
420,571	435,175	443,936	441,825	427,708	402,176	379,893	357,010	330,372
437,236	443,888	447,989	442,708	425,058	396,110	368,481	342,484	319,584
431,133	439,276	446,145	443,734	427,531	407,312	387,535	363,594	313,263
462,842	473,498	483,915	487,075	475,246	452,831	433,084	405,685	354,686
473,948	482,244	489,662	490,130	475,824	455,118	440,158	414,093	363,263
484,690	492,276	496,399	494,104	476,546	455,988	439,726	405,473	353,540
363,789	375,095	388,342	392,220	388,109	367,888	359,197	344,566	310,069
421,934	434,714	439,273	435,237	420,242	392,604	371,086	346,935	306,031
416,806	414,033	412,513	404,344	386,377	373,631	363,923	336,682	297,450
394,731	402,870	417,681	424,562	413,628	396,128	389,431	364,573	320,040
392,816	412,067	429,829	439,473	434,769	414,672	397,281	375,135	330,653
470,392	482,227	492,326	492,845	482,975	459,906	442,743	416,928	370,367
495,918	504,359	505,497	503,534	492,605	472,726	461,010	436,574	387,806
472,445	476,691	473,781	461,259	447,304	429,488	418,460	398,394	360,664
445,701	461,677	465,340	464,006	451,337	430,221	415,680	392,714	353,861
378,916	365,807	372,945	380,247	373,040	359,309	352,552	335,633	299,555
465,340	472,603	472,217	445,396	412,230	385,547	372,413	348,507	305,178
420,078	432,221	443,442	449,802	444,683	427,426	421,962	395,631	353,545
390,177	396,914	397,611	398,923	392,334	376,023	374,079	353,593	313,131
487,873	496,576	502,004	502,328	492,542	468,609	460,175	435,286	389,517
494,670	502,495	505,176	502,698	490,309	463,077	446,038	419,175	377,584
496,602	505,486	508,361	503,730	487,544	462,754	450,468	422,933	380,833
462,782	473,028	479,366	478,704	464,504	441,315	431,242	405,605	359,297
433,468	444,790	454,685	466,030	459,094	438,239	430,022	398,566	351,026
427,509	439,146	451,006	458,606	451,744	430,584	421,304	392,812	347,648
439,725	439,113	440,367	438,993	427,301	411,230	406,696	383,052	341,421
485,709	488,976	491,168	488,822	475,578	451,077	439,715	407,550	357,590
432,175	439,785	437,776	426,189	405,414	382,846	376,089	352,245	317,375
453,284	466,634	469,370	462,461	449,443	428,807	420,096	395,153	354,830
401,360	417,558	429,893	432,766	418,051	392,752	380,984	353,751	308,842
463,576	474,707	477,879	475,201	460,066	440,154	427,622	391,656	340,034
510,987	522,704	531,248	531,253	521,957	503,783	496,142	465,027	416,313
535,155	535,386	539,666	539,955	527,592	512,046	503,873	470,335	419,915

452,274	456,007	460,932	467,391	454,734	434,308	425,419	390,740	338,996
435,199	445,279	449,081	444,362	424,335	393,754	378,062	346,759	304,871
414,720	428,500	437,029	433,080	414,082	383,161	367,926	337,397	297,891
456,018	470,140	479,524	480,839	466,654	442,490	430,218	393,446	341,991
494,002	504,562	512,367	518,831	509,374	492,535	481,583	440,935	387,903
503,682	515,894	525,028	524,857	515,542	499,044	492,238	451,502	400,094
510,831	517,550	528,527	530,977	519,687	502,787	492,442	451,422	399,550
496,675	471,175	457,813	444,249	421,393	409,394	402,671	369,393	321,516
503,559	514,002	517,558	516,308	500,730	475,466	464,773	429,953	388,849
471,412	446,912	426,379	410,202	393,325	381,030	378,826	356,609	324,750
468,408	482,450	492,382	487,724	477,908	464,729	454,435	411,822	358,901
403,710	419,525	432,377	439,029	423,677	396,174	382,649	341,634	288,217
416,591	432,175	438,499	431,473	414,995	398,546	392,709	354,334	305,945
439,578	449,897	458,222	457,856	444,437	420,371	411,334	367,955	316,339
452,157	465,146	472,919	473,420	458,974	436,856	425,882	381,149	326,972
465,692	474,563	480,300	473,112	449,267	423,757	408,107	374,846	336,804
419,456	434,899	433,951	431,568	418,845	401,042	376,510	363,931	323,332
447,677	458,505	465,185	462,392	443,730	423,238	411,217	367,599	315,976
413,291	423,759	431,587	429,531	412,877	392,669	381,532	337,123	287,888
390,110	398,186	401,696	401,339	388,087	378,841	372,966	337,335	290,155
386,724	397,903	404,798	405,569	389,158	366,801	357,742	316,301	266,066
344,975	359,436	370,322	369,578	355,587	334,769	328,193	290,945	246,128
354,018	371,607	383,062	385,446	365,656	335,218	320,119	288,660	252,273
437,245	450,520	456,354	451,223	429,189	409,081	394,309	359,869	320,335
414,847	412,688	405,521	396,458	379,948	374,742	366,553	331,322	288,739
400,913	409,373	417,796	418,941	405,892	394,240	383,343	343,231	295,601
420,366	435,201	443,173	440,700	424,650	409,737	395,528	353,075	303,716
418,652	434,050	446,369	449,042	430,701	411,096	393,853	353,812	302,809
403,345	408,562	406,647	403,929	392,412	386,093	374,503	336,670	291,011
333,317	334,129	333,848	326,460	300,963	284,151	277,243	255,637	227,755
263,646	274,559	282,009	279,065	264,662	254,667	249,730	228,875	201,770
267,071	285,548	300,391	305,167	290,265	276,186	266,900	243,955	215,747
353,710	374,990	388,139	389,915	373,764	361,767	346,537	303,484	256,409
437,201	432,434	421,157	402,751	387,685	391,343	377,238	336,567	292,378
339,851	344,753	351,894	352,100	335,489	328,415	315,132	282,804	239,660
261,649	261,556	265,501	266,633	268,052	280,872	273,240	251,884	219,581
221,521	222,498	229,909	236,325	239,128	249,877	247,876	235,046	216,611
304,968	314,976	321,092	319,772	303,598	300,976	289,405	263,604	233,772
307,257	319,244	328,537	328,024	308,751	303,536	287,995	252,936	214,478
347,198	366,662	380,422	379,932	359,965	351,048	328,095	288,370	243,687
353,893	364,867	369,521	362,112	346,023	346,694	327,902	291,343	245,414
390,431	400,024	404,545	396,363	382,974	378,589	357,252	323,906	284,548
353,745	365,103	374,409	372,976	353,661	356,442	338,742	301,685	253,832
323,271	338,126	346,024	338,782	311,958	299,522	281,605	256,638	226,453
349,264	369,725	380,790	374,661	347,220	331,525	306,445	274,106	239,560
346,025	360,938	370,559	365,133	345,846	346,545	324,309	286,067	243,052
410,444	426,745	437,610	434,127	414,170	405,597	375,258	335,138	285,699

438,095	446,931	446,737	437,505	420,541	411,310	382,502	341,337	292,966
424,189	432,216	438,333	433,098	410,671	401,699	373,413	331,384	280,477
434,975	441,329	441,426	434,253	416,795	412,564	384,955	346,207	302,938
365,901	365,247	364,956	355,170	336,966	331,173	307,142	281,386	251,152
293,519	296,142	287,209	272,963	260,808	265,236	251,236	229,777	205,272
200,940	202,212	206,891	211,016	218,938	237,618	227,499	206,091	178,203
226,268	232,952	240,884	241,802	243,154	260,703	248,251	222,007	191,472
221,360	228,920	236,718	239,351	240,706	255,408	243,380	220,608	187,818
232,001	243,166	253,683	257,673	253,284	262,485	248,420	223,053	189,319
251,477	261,170	267,536	263,832	260,274	274,474	261,436	237,448	204,302
224,568	230,087	234,333	230,684	224,401	231,272	221,253	207,443	188,545
190,061	190,793	191,319	193,070	202,798	218,248	211,889	199,419	182,780
187,210	188,440	193,485	201,369	215,380	234,251	227,770	211,799	189,761
198,217	199,323	203,621	210,386	225,851	244,618	236,329	222,884	200,301
197,607	197,446	200,376	205,344	219,914	238,703	230,237	212,739	189,857
202,081	205,258	211,680	215,132	225,614	238,046	228,958	211,051	184,179
233,558	239,639	246,623	246,911	250,271	258,764	245,462	224,188	194,021
243,225	251,768	258,369	254,046	247,533	245,857	230,424	213,162	192,345
247,049	260,641	268,550	264,145	256,312	253,543	235,224	213,608	189,268
267,924	282,912	292,005	288,140	280,257	278,303	255,268	225,042	194,097
286,000	293,160	295,509	291,383	293,554	291,156	267,600	240,534	209,540
242,968	244,736	246,064	248,243	258,486	257,753	243,175	223,536	192,409
214,492	217,956	220,970	226,398	239,678	240,399	230,907	213,890	187,156
200,189	203,078	206,480	207,329	222,316	234,481	227,622	212,077	189,442
197,703	199,373	202,149	201,616	212,537	220,229	214,743	206,477	189,797
191,214	194,091	198,188	197,057	209,136	215,369	208,287	195,541	179,166
210,807	219,689	229,154	232,307	245,372	250,159	235,001	210,889	181,030
242,713	248,587	252,774	252,376	263,776	266,025	249,649	224,248	189,131
193,393	195,266	201,243	207,503	232,169	239,972	232,138	213,786	185,056
196,892	200,584	207,898	212,191	231,525	237,587	230,556	211,003	183,882
196,852	199,195	203,251	208,315	229,993	239,183	232,007	215,833	192,553
197,434	199,409	203,092	202,461	217,361	219,681	212,548	201,768	187,472
196,077	198,397	202,098	202,094	218,362	219,309	210,261	196,636	178,457
210,547	212,779	220,225	227,083	241,190	242,325	230,339	209,704	182,949
212,101	213,724	219,849	231,200	253,442	254,551	243,014	224,331	196,093
196,779	199,297	204,832	212,923	235,850	241,285	230,679	212,594	184,873
203,144	206,128	210,923	215,750	237,922	240,031	232,754	216,712	186,761
190,307	191,462	197,713	212,382	245,400	256,966	256,109	242,012	217,872
194,464	193,112	196,781	205,491	234,246	242,214	244,430	241,498	231,152
194,722	192,889	190,591	189,456	208,431	214,257	212,811	206,026	192,322
189,310	188,775	189,545	193,614	216,033	222,289	218,805	205,228	184,606

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HR24
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168,776	4,616,995	4,618,761	(1,766)
169,017	4,495,011	4,496,569	(1,558)
165,577	4,331,416	4,332,424	(1,008)
157,968	4,324,755	4,325,377	(622)
187,966	5,023,591	5,025,195	(1,604)
182,268	5,031,482	5,033,179	(1,698)
160,606	4,626,899	4,628,536	(1,636)
187,125	4,521,343	4,523,160	(1,818)
181,307	4,790,860	4,792,502	(1,643)
163,692	4,616,716	4,617,451	(736)
156,479	4,531,040	4,531,708	(667)
164,238	4,805,139	4,806,785	(1,646)
173,698	5,030,720	5,032,233	(1,513)
179,421	5,230,416	5,232,098	(1,682)
180,183	5,287,958	5,289,633	(1,675)
170,470	4,978,533	4,980,069	(1,536)
168,271	4,265,554	4,266,565	(1,011)
161,321	4,422,618	4,423,337	(719)
162,848	4,675,707	4,677,362	(1,656)
161,098	4,590,924	4,592,664	(1,740)
160,385	4,655,327	4,656,938	(1,610)
165,320	4,693,177	4,695,046	(1,869)
183,675	4,872,785	4,874,340	(1,555)
165,083	4,542,883	4,544,136	(1,254)
158,501	4,268,811	4,269,391	(580)
171,673	4,714,649	4,716,175	(1,526)
186,120	4,898,189	4,899,722	(1,533)
167,239	4,877,126	4,878,846	(1,720)
170,196	4,752,621	4,754,212	(1,591)
200,006	4,914,176	4,915,877	(1,701)
170,624			(42,872)
171,956			

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EBMTRY		EBMTRM	EBMTRD	HR1	HR2	HR3	HR4	HR5
20C	2009	11	1	64,815	64,435	64,211	63,204	62,805
20C	2009	11	2	74,246	74,712	75,248	76,721	77,769
20C	2009	11	3	90,594	88,903	88,038	88,322	88,516
20C	2009	11	4	86,552	83,738	83,872	89,821	89,587
20C	2009	11	5	86,471	85,573	86,740	84,772	87,637
20C	2009	11	6	91,675	89,052	89,824	87,655	90,167
20C	2009	11	7	75,508	73,074	72,810	71,864	71,564
20C	2009	11	8	68,510	68,020	67,537	67,021	64,286
20C	2009	11	9	70,486	76,627	78,652	77,006	77,110
20C	2009	11	10	87,242	85,243	83,829	83,097	85,533
20C	2009	11	11	88,710	87,478	89,962	86,402	83,989
20C	2009	11	12	83,913	82,609	81,899	75,931	76,217
20C	2009	11	13	81,077	79,068	78,397	78,128	78,517
20C	2009	11	14	65,918	69,052	66,772	63,380	69,262
20C	2009	11	15	68,513	68,164	68,565	68,786	68,330
20C	2009	11	16	70,759	70,831	71,467	72,819	76,974
20C	2009	11	17	83,901	83,394	83,149	85,323	83,650
20C	2009	11	18	86,947	85,443	83,720	83,124	79,956
20C	2009	11	19	85,037	83,653	78,931	75,811	76,349
20C	2009	11	20	91,727	84,478	83,494	81,567	82,837
20C	2009	11	21	78,431	76,524	76,056	75,705	75,191
20C	2009	11	22	69,761	69,748	69,621	68,932	68,904
20C	2009	11	23	75,149	76,321	77,217	78,961	82,634
20C	2009	11	24	87,478	84,677	82,439	80,918	81,482
20C	2009	11	25	90,610	89,474	83,409	83,268	86,833
20C	2009	11	26	72,327	70,834	70,641	69,610	69,521
20C	2009	11	27	58,681	58,878	58,984	59,323	59,279
20C	2009	11	28	63,828	63,964	64,195	64,641	65,720
20C	2009	11	29	67,230	67,083	66,646	67,420	67,510
20C	2009	11	30	77,659	79,637	81,641	81,275	83,323
20C	2009	12	1	87,608	88,559	88,240	86,789	85,979
20C	2009	12	2	85,509	86,924	85,790	85,719	85,829
20C	2009	12	3	90,596	85,282	86,546	84,900	87,234
20C	2009	12	4	91,749	90,765	88,208	89,432	89,822
20C	2009	12	5	84,511	82,687	82,065	81,606	80,858
20C	2009	12	6	70,813	70,685	70,477	70,237	70,046
20C	2009	12	7	74,399	78,661	81,298	80,023	79,928
20C	2009	12	8	87,708	86,180	85,544	87,710	84,927
20C	2009	12	9	88,253	87,034	81,624	83,063	89,118
20C	2009	12	10	88,517	92,654	93,242	92,186	94,367
20C	2009	12	11	90,070	89,123	88,918	84,295	82,931
20C	2009	12	12	84,281	87,224	87,424	83,927	84,261

20C	2009	12	13	71,600	71,121	71,618	72,895	71,764
20C	2009	12	14	74,248	79,010	79,624	80,473	80,235
20C	2009	12	15	92,374	89,887	86,705	85,520	85,232
20C	2009	12	16	90,990	89,174	87,335	79,086	76,497
20C	2009	12	17	84,360	90,599	88,142	86,237	87,763
20C	2009	12	18	87,349	87,095	85,293	84,797	81,454
20C	2009	12	19	73,232	72,545	72,892	71,752	72,553
20C	2009	12	20	71,536	70,996	70,351	70,367	69,996
20C	2009	12	21	74,981	75,454	76,484	77,484	81,618
20C	2009	12	22	87,173	86,180	85,253	84,047	83,838
20C	2009	12	23	87,852	87,495	85,448	84,279	83,465
20C	2009	12	24	69,927	68,196	68,275	67,516	66,177
20C	2009	12	25	58,076	58,251	58,095	58,062	58,113
20C	2009	12	26	61,168	61,322	60,014	59,522	59,638
20C	2009	12	27	69,073	69,753	70,000	70,156	70,429
20C	2009	12	28	75,192	76,438	76,677	74,198	74,669
20C	2009	12	29	87,366	86,525	86,033	85,073	85,700
20C	2009	12	30	87,842	88,554	88,557	83,919	83,663
20C	2009	12	31	85,620	84,074	77,920	72,504	72,878
201	2010	1	1	78,318	79,385	73,237	74,314	74,849
201	2010	1	2	70,913	70,049	70,235	69,343	69,400
201	2010	1	3	69,788	70,745	70,418	69,874	69,714
201	2010	1	4	75,457	76,841	78,256	81,223	86,534
201	2010	1	5	94,229	92,902	92,451	91,024	90,579
201	2010	1	6	95,076	91,259	89,435	88,839	88,908
201	2010	1	7	93,860	91,774	91,453	88,428	88,067
201	2010	1	8	95,607	89,861	92,600	90,617	89,406
201	2010	1	9	85,273	78,275	73,856	71,802	71,841
201	2010	1	10	74,354	74,361	74,483	73,550	73,656
201	2010	1	11	75,196	75,672	76,558	76,557	78,255
201	2010	1	12	88,693	85,947	82,199	88,939	91,429
201	2010	1	13	96,039	90,899	86,284	80,773	79,147
201	2010	1	14	96,246	89,454	91,078	87,837	90,413
201	2010	1	15	92,007	90,067	92,455	91,771	89,071
201	2010	1	16	84,764	82,195	80,970	79,681	83,758
201	2010	1	17	71,716	71,086	70,878	70,512	70,513
201	2010	1	18	74,604	75,968	76,673	77,460	81,822
201	2010	1	19	92,070	91,349	88,931	82,186	77,030
201	2010	1	20	74,387	72,999	72,248	74,405	78,482
201	2010	1	21	90,656	88,456	87,090	85,627	86,432
201	2010	1	22	93,313	89,004	86,998	88,856	90,699
201	2010	1	23	83,880	81,625	80,923	79,496	81,590
201	2010	1	24	67,031	66,874	66,471	66,506	66,655
201	2010	1	25	66,236	67,538	70,632	73,439	71,296
201	2010	1	26	91,467	89,494	89,858	87,824	88,186
201	2010	1	27	95,848	93,649	91,288	89,489	91,411
201	2010	1	28	93,919	91,772	92,695	93,376	94,883

201	2010	1	29	92,027	90,581	89,476	88,403	88,838
201	2010	1	30	80,259	78,420	76,603	74,615	74,641
201	2010	1	31	69,435	69,615	69,809	69,415	70,445
201	2010	2	1	73,845	74,640	74,153	75,203	76,219
201	2010	2	2	93,253	90,001	88,386	87,880	88,316
201	2010	2	3	92,224	85,724	88,818	87,023	89,764
201	2010	2	4	90,929	91,719	89,519	88,914	91,591
201	2010	2	5	93,620	93,758	92,155	90,094	91,093
201	2010	2	6	88,491	82,715	79,780	81,705	76,998
201	2010	2	7	81,878	81,665	79,490	81,318	80,930
201	2010	2	8	79,164	80,341	81,138	80,572	82,220
201	2010	2	9	89,743	88,682	91,451	86,067	91,363
201	2010	2	10	92,612	90,611	90,552	85,718	86,583
201	2010	2	11	91,176	91,417	90,599	91,791	95,214
201	2010	2	12	93,778	94,664	94,627	93,253	91,761
201	2010	2	13	90,122	88,992	83,416	80,540	84,592
201	2010	2	14	80,795	79,745	79,993	79,075	82,004
201	2010	2	15	84,844	87,133	87,814	88,155	85,390
201	2010	2	16	94,538	92,145	87,112	83,509	85,548
201	2010	2	17	89,581	87,749	87,258	85,287	85,046
201	2010	2	18	87,687	89,117	88,826	88,038	88,946
201	2010	2	19	88,951	90,202	88,555	87,517	87,868
201	2010	2	20	85,934	84,991	83,987	83,978	81,847
201	2010	2	21	77,596	77,548	78,495	74,445	73,989
201	2010	2	22	80,613	79,139	78,085	79,152	76,313
201	2010	2	23	94,908	94,006	89,620	84,867	86,447
201	2010	2	24	88,443	85,212	85,163	83,293	83,977
201	2010	2	25	95,726	94,284	93,243	92,578	93,247
201	2010	2	26	90,482	95,819	92,605	91,740	90,842
201	2010	2	27	85,510	84,878	86,874	84,939	85,837
201	2010	2	28	77,459	77,657	77,108	81,047	80,342
201	2010	3	1	74,971	79,892	82,275	80,560	81,150
201	2010	3	2	90,565	88,438	86,207	85,006	87,300
201	2010	3	3	90,504	87,233	89,633	88,327	88,703
201	2010	3	4	87,361	86,871	90,939	90,734	91,073
201	2010	3	5	87,624	89,454	88,986	87,355	88,934
201	2010	3	6	83,147	80,887	80,169	79,321	79,887
201	2010	3	7	80,632	79,597	80,337	79,997	78,690
201	2010	3	8	79,136	79,106	79,356	81,465	82,433
201	2010	3	9	89,991	86,454	88,506	87,668	85,708
201	2010	3	10	93,687	88,312	89,087	88,122	87,844
201	2010	3	11	85,280	84,333	83,836	80,874	82,648
201	2010	3	12	92,137	85,761	86,755	85,397	85,074
201	2010	3	13	84,414	81,700	81,079	80,078	79,668
201	2010	3	14	79,196	79,963	-	79,428	79,608
201	2010	3	15	79,283	78,633	77,111	76,055	76,671
201	2010	3	16	88,076	85,046	83,837	83,305	84,665

201	2010	3	17	83,502	81,830	81,427	76,403	75,456
201	2010	3	18	88,572	89,774	89,465	88,958	89,148
201	2010	3	19	88,103	89,085	86,304	82,047	88,112
201	2010	3	20	85,889	84,798	83,848	83,041	79,547
201	2010	3	21	72,445	71,605	70,283	69,708	72,599
201	2010	3	22	81,010	81,326	80,831	77,050	80,986
201	2010	3	23	93,948	92,216	88,885	88,672	84,044
201	2010	3	24	93,064	90,386	88,070	85,214	85,806
201	2010	3	25	91,514	90,945	89,924	82,257	81,101
201	2010	3	26	88,904	84,702	87,775	86,318	85,712
201	2010	3	27	87,298	84,957	84,223	81,347	81,709
201	2010	3	28	78,774	78,603	76,769	75,777	76,207
201	2010	3	29	81,543	79,605	79,780	79,548	80,926
201	2010	3	30	91,586	86,537	85,686	88,337	87,820
201	2010	3	31	89,987	87,447	86,156	85,914	89,333
201	2010	4	1	86,954	84,762	84,322	79,171	80,487
201	2010	4	2	85,965	85,437	84,796	83,867	83,529
201	2010	4	3	82,368	82,063	79,989	78,277	76,655
201	2010	4	4	75,028	76,059	76,335	75,451	76,610
201	2010	4	5	78,601	75,911	77,668	77,222	80,654
201	2010	4	6	92,082	86,887	86,236	84,896	86,150
201	2010	4	7	92,381	82,638	86,103	80,614	81,303
201	2010	4	8	89,499	86,821	86,307	85,352	87,009
201	2010	4	9	86,192	82,733	83,856	82,298	84,364
201	2010	4	10	80,559	72,407	73,407	74,351	77,772
201	2010	4	11	75,270	74,815	74,834	74,396	74,317
201	2010	4	12	78,277	78,152	81,976	81,800	79,342
201	2010	4	13	92,729	89,107	86,429	82,125	83,887
201	2010	4	14	94,941	91,855	88,716	82,891	84,958
201	2010	4	15	93,767	87,404	88,324	83,521	88,534
201	2010	4	16	90,849	87,491	90,575	84,872	86,454
201	2010	4	17	81,097	77,581	78,284	79,892	79,216
201	2010	4	18	79,916	74,786	77,991	77,689	78,022
201	2010	4	19	77,928	80,319	81,296	80,184	81,584
201	2010	4	20	91,882	87,317	86,399	86,282	87,137
201	2010	4	21	92,490	86,789	76,607	67,630	68,037
201	2010	4	22	85,877	85,511	87,237	86,850	86,382
201	2010	4	23	88,841	85,936	86,293	84,174	85,054
201	2010	4	24	87,545	87,502	86,899	85,076	84,479
201	2010	4	25	78,549	77,789	76,771	76,986	76,614
201	2010	4	26	80,156	79,334	79,899	81,087	82,372
201	2010	4	27	87,767	84,969	83,804	82,864	84,699
201	2010	4	28	90,114	89,470	86,934	82,160	83,222
201	2010	4	29	88,996	86,055	84,475	85,448	83,746
201	2010	4	30	92,173	91,650	84,955	86,441	87,509
201	2010	5	1	82,203	82,500	83,522	76,469	77,573
201	2010	5	2	76,339	76,065	75,122	74,487	76,750

201	2010	5	3	74,252	70,908	75,014	73,538	74,127
201	2010	5	4	82,100	80,563	78,787	77,910	78,221
201	2010	5	5	83,041	81,443	80,789	78,966	79,023
201	2010	5	6	84,206	80,919	79,424	78,340	78,185
201	2010	5	7	84,449	80,793	80,147	78,338	79,069
201	2010	5	8	86,695	83,948	83,181	81,435	80,443
201	2010	5	9	81,156	79,028	78,401	79,769	77,734
201	2010	5	10	79,233	77,208	77,832	80,734	79,776
201	2010	5	11	89,667	87,755	85,609	88,125	88,959
201	2010	5	12	91,507	88,455	83,632	80,810	82,843
201	2010	5	13	91,519	89,025	87,322	86,836	86,470
201	2010	5	14	90,419	86,164	85,148	84,542	87,337
201	2010	5	15	83,518	80,060	80,095	75,418	76,252
201	2010	5	16	79,022	79,042	80,548	79,048	76,724
201	2010	5	17	81,906	80,948	82,236	82,867	83,649
201	2010	5	18	79,041	75,349	75,362	74,321	74,766
201	2010	5	19	81,338	77,630	71,454	70,265	69,012
201	2010	5	20	80,068	77,451	77,427	77,283	76,412
201	2010	5	21	87,658	85,220	83,811	81,168	84,928
201	2010	5	22	86,156	84,073	84,537	86,090	82,756
201	2010	5	23	81,785	81,681	79,931	80,161	72,989
201	2010	5	24	81,093	80,195	80,376	80,806	82,931
201	2010	5	25	97,247	94,940	93,981	92,146	93,916
201	2010	5	26	92,349	91,451	90,676	90,791	91,053
201	2010	5	27	95,862	91,769	91,016	88,896	89,291
201	2010	5	28	94,375	91,745	89,008	85,533	85,080
201	2010	5	29	85,577	84,703	84,390	82,280	78,404
201	2010	5	30	77,139	77,379	77,564	79,789	80,216
201	2010	5	31	75,132	71,491	74,225	73,696	75,426
201	2010	6	1	78,740	77,103	78,351	80,404	81,109
201	2010	6	2	93,628	90,635	86,579	78,980	77,293
201	2010	6	3	88,476	86,899	86,273	86,948	84,129
201	2010	6	4	88,447	91,477	91,621	88,831	89,730
201	2010	6	5	88,486	86,098	84,901	86,123	85,986
201	2010	6	6	84,178	82,987	81,276	79,915	80,337
201	2010	6	7	81,053	78,899	79,641	87,258	86,518
201	2010	6	8	96,064	87,802	90,932	89,264	89,493
201	2010	6	9	87,018	84,298	82,581	81,429	81,843
201	2010	6	10	88,601	85,898	83,983	81,845	82,429
201	2010	6	11	88,354	85,914	82,837	81,194	82,346
201	2010	6	12	84,462	82,745	86,324	82,078	79,254
201	2010	6	13	78,686	77,297	78,414	75,331	77,037
201	2010	6	14	80,443	79,906	81,742	81,865	81,331
201	2010	6	15	90,239	89,085	87,909	85,049	87,127
201	2010	6	16	96,739	95,362	92,739	92,446	93,069
201	2010	6	17	94,379	92,782	95,448	89,965	89,680
201	2010	6	18	93,290	88,639	86,710	85,326	86,326

201	2010	6	19	89,282	87,695	88,420	85,131	88,280
201	2010	6	20	81,499	79,550	77,711	76,531	80,733
201	2010	6	21	78,637	81,268	81,106	80,870	86,025
201	2010	6	22	90,382	85,980	86,273	89,047	91,136
201	2010	6	23	89,582	89,549	89,494	87,863	86,770
201	2010	6	24	95,175	88,541	89,795	84,590	88,050
201	2010	6	25	91,211	89,131	87,425	85,282	89,402
201	2010	6	26	84,108	83,471	83,099	81,145	83,005
201	2010	6	27	75,390	75,364	75,094	74,344	74,280
201	2010	6	28	77,670	78,580	82,408	81,261	83,022
201	2010	6	29	87,240	87,337	86,644	86,705	85,786
201	2010	6	30	86,518	89,475	87,492	85,226	85,902
201	2010	7	1	89,807	85,075	86,979	83,450	83,154
201	2010	7	2	79,886	78,456	77,139	76,371	76,890
201	2010	7	3	78,155	80,632	80,513	80,534	78,698
201	2010	7	4	81,914	81,723	79,751	78,333	77,761
201	2010	7	5	72,336	73,445	70,115	70,271	70,770
201	2010	7	6	80,444	79,827	84,616	82,832	81,873
201	2010	7	7	88,290	86,438	84,604	82,105	81,880
201	2010	7	8	87,423	85,703	84,639	82,601	81,419
201	2010	7	9	87,909	86,187	86,323	85,081	85,803
201	2010	7	10	74,699	77,088	79,930	76,598	77,996
201	2010	7	11	76,232	75,477	75,774	74,935	74,751
201	2010	7	12	78,038	79,749	79,805	75,234	76,381
201	2010	7	13	92,562	89,081	90,637	88,780	89,318
201	2010	7	14	96,367	94,634	93,546	92,057	91,596
201	2010	7	15	86,951	87,257	86,066	84,915	86,076
201	2010	7	16	90,696	87,598	86,180	83,289	87,951
201	2010	7	17	86,154	82,372	86,052	83,680	83,029
201	2010	7	18	80,001	78,672	78,164	77,538	77,797
201	2010	7	19	75,843	78,132	78,751	78,491	79,580
201	2010	7	20	91,200	88,578	88,881	88,164	91,472
201	2010	7	21	76,513	68,643	67,636	61,579	59,851
201	2010	7	22	63,373	61,246	58,880	56,021	59,827
201	2010	7	23	89,157	82,779	84,578	83,102	85,811
201	2010	7	24	87,801	85,200	87,038	82,301	81,208
201	2010	7	25	80,810	82,806	84,290	78,473	78,515
201	2010	7	26	80,560	81,858	76,355	75,654	81,107
201	2010	7	27	89,982	85,953	82,193	84,368	84,025
201	2010	7	28	94,497	85,433	80,316	78,431	78,900
201	2010	7	29	89,761	85,592	87,233	85,665	85,922
201	2010	7	30	87,629	85,453	82,837	81,096	81,874
201	2010	7	31	85,342	82,678	82,439	82,923	83,522
201	2010	8	1	79,524	81,161	80,653	79,603	76,454
201	2010	8	2	74,743	74,279	77,491	77,360	79,395
201	2010	8	3	93,126	87,969	90,143	92,145	88,824
201	2010	8	4	92,901	86,993	87,382	86,193	84,058

201	2010	8	5	87,352	89,595	89,792	88,160	86,261
201	2010	8	6	94,070	93,882	90,604	88,227	86,469
201	2010	8	7	86,496	83,614	83,374	82,656	81,863
201	2010	8	8	76,859	76,148	74,923	73,270	75,646
201	2010	8	9	74,759	75,496	75,337	75,357	78,247
201	2010	8	10	92,128	91,355	90,993	92,224	92,028
201	2010	8	11	91,463	89,796	90,699	90,747	85,122
201	2010	8	12	93,080	95,464	93,934	92,553	93,471
201	2010	8	13	94,206	92,072	90,461	86,772	88,171
201	2010	8	14	85,534	84,224	84,107	81,755	78,851
201	2010	8	15	82,802	82,057	83,043	81,789	81,185
201	2010	8	16	78,166	78,745	77,929	78,260	78,724
201	2010	8	17	92,534	94,211	94,552	93,545	93,446
201	2010	8	18	98,278	94,690	91,551	89,331	90,542
201	2010	8	19	90,370	87,530	88,670	82,079	82,045
201	2010	8	20	92,579	89,348	89,014	85,710	87,773
201	2010	8	21	86,206	86,854	86,330	82,814	81,145
201	2010	8	22	77,680	78,514	77,167	77,795	80,042
201	2010	8	23	75,753	78,549	81,109	76,768	77,639
201	2010	8	24	92,531	92,464	92,241	89,570	90,299
201	2010	8	25	97,072	94,430	90,360	85,875	86,721
201	2010	8	26	91,282	89,591	88,064	87,596	91,732
201	2010	8	27	92,479	91,502	92,185	91,182	91,783
201	2010	8	28	86,551	85,196	84,603	80,585	79,828
201	2010	8	29	84,794	81,255	79,502	80,397	79,279
201	2010	8	30	79,524	80,132	78,190	75,978	77,870
201	2010	8	31	91,017	86,010	84,650	85,338	92,103
201	2010	9	1	93,079	89,229	91,862	89,219	86,018
201	2010	9	2	95,770	96,007	94,058	89,150	89,376
201	2010	9	3	89,642	90,442	89,829	88,364	86,913
201	2010	9	4	79,369	77,263	75,874	76,621	76,019
201	2010	9	5	79,166	75,493	75,810	74,168	73,594
201	2010	9	6	74,823	73,353	72,534	70,991	70,292
201	2010	9	7	70,885	68,432	72,611	76,054	73,884
201	2010	9	8	88,064	83,469	85,267	81,128	80,007
201	2010	9	9	90,492	90,125	89,161	86,593	88,499
201	2010	9	10	91,189	88,494	87,626	85,484	87,233
201	2010	9	11	90,182	86,364	85,323	86,291	85,556
201	2010	9	12	80,483	80,087	79,554	78,255	80,208
201	2010	9	13	78,626	78,542	77,863	76,887	78,700
201	2010	9	14	94,911	94,351	92,990	90,203	90,515
201	2010	9	15	95,981	88,228	87,027	83,699	85,320
201	2010	9	16	92,033	85,405	87,110	87,072	86,696
201	2010	9	17	97,281	93,509	92,815	91,357	90,781
201	2010	9	18	90,121	84,130	82,378	81,309	81,731
201	2010	9	19	83,612	82,902	82,049	79,787	76,355
201	2010	9	20	80,590	80,279	81,345	80,938	80,979

201	2010	9	21	97,222	88,556	90,955	93,204	94,180
201	2010	9	22	96,212	92,292	90,360	84,714	85,905
201	2010	9	23	92,858	89,801	89,760	85,436	87,673
201	2010	9	24	88,153	86,521	90,434	89,841	90,935
201	2010	9	25	89,942	89,624	91,467	90,212	87,066
201	2010	9	26	81,319	84,141	81,572	80,792	83,736
201	2010	9	27	80,182	85,949	83,743	83,482	84,977
201	2010	9	28	96,223	90,652	93,213	90,854	87,028
201	2010	9	29	96,139	94,126	95,041	87,488	86,539
201	2010	9	30	91,438	88,732	90,185	88,977	88,476
201	2010	10	1	90,199	84,239	86,869	84,324	82,974
201	2010	10	2	84,646	84,025	83,570	80,391	78,943
201	2010	10	3	77,904	76,886	77,627	75,523	73,133
201	2010	10	4	77,780	75,488	77,894	78,319	80,885
201	2010	10	5	87,351	86,468	89,389	85,293	85,495
201	2010	10	6	92,908	89,593	88,149	85,342	86,655
201	2010	10	7	87,019	82,730	82,432	82,301	81,600
201	2010	10	8	89,448	86,355	86,773	84,531	82,092
201	2010	10	9	76,858	75,975	74,966	75,805	74,385
201	2010	10	10	70,080	70,837	71,748	72,746	73,703
201	2010	10	11	75,920	76,079	77,547	76,086	78,558
201	2010	10	12	85,575	85,029	88,369	86,969	87,320
201	2010	10	13	83,750	81,060	79,911	79,821	79,103
201	2010	10	14	82,386	83,479	82,608	81,688	82,562
201	2010	10	15	94,250	91,371	89,747	85,752	86,989
201	2010	10	16	82,224	81,471	82,300	83,083	77,842
201	2010	10	17	73,267	72,524	73,337	72,493	72,201
201	2010	10	18	77,786	79,333	78,542	77,702	80,481
201	2010	10	19	93,284	92,864	90,663	89,406	88,316
201	2010	10	20	93,631	91,780	91,132	86,897	86,564
201	2010	10	21	93,988	89,194	87,882	85,551	82,321
201	2010	10	22	93,428	91,497	91,672	84,755	84,103
201	2010	10	23	86,418	84,238	84,820	82,664	82,368
201	2010	10	24	77,995	79,186	77,958	77,086	77,150
201	2010	10	25	75,871	75,975	75,863	75,489	73,553
201	2010	10	26	83,858	81,806	79,848	79,367	81,315
201	2010	10	27	87,424	85,807	85,167	83,458	82,235
201	2010	10	28	86,611	85,035	82,973	79,062	77,343
201	2010	10	29	80,866	79,502	76,606	75,614	75,325
201	2010	10	30	70,600	70,423	69,641	68,869	67,710
201	2010	10	31	62,350	62,596	62,383	62,121	62,135

11	13	15	17	19	21	23	25	27
HR6	HR7	HR8	HR9	HR10	HR11	HR12	HR13	HR14
62,832	61,766	61,579	62,561	62,249	62,172	61,026	60,788	62,086
79,390	81,287	81,057	82,894	85,013	85,136	85,573	86,705	87,932
90,966	96,259	94,104	98,071	97,189	96,763	96,453	95,446	98,327
87,941	90,395	94,406	88,702	82,710	87,156	86,597	83,604	80,659
92,218	97,214	97,436	98,312	96,261	93,842	96,695	98,882	98,706
92,783	95,329	94,819	96,137	93,853	93,350	89,272	90,819	91,238
71,163	70,591	67,224	67,836	67,637	68,517	67,634	67,486	67,545
59,538	51,633	48,987	48,741	48,617	48,732	46,947	46,204	48,313
80,985	84,048	85,659	87,616	91,535	92,238	90,610	90,686	91,062
84,108	89,948	91,600	94,222	91,979	91,380	90,531	93,292	95,386
88,430	91,869	90,450	92,855	92,522	91,870	91,018	91,430	91,262
78,432	86,571	84,646	85,325	84,929	86,585	86,428	87,426	87,078
80,813	84,048	82,413	82,438	82,582	83,708	82,164	82,380	81,060
68,377	67,801	67,290	67,387	67,267	67,961	69,189	69,207	68,593
68,216	67,256	68,864	68,959	68,880	69,150	68,456	68,032	69,289
80,974	83,615	83,194	85,944	86,561	84,809	85,795	85,260	84,149
86,912	89,676	89,718	91,433	90,550	89,975	88,297	92,769	91,972
81,444	85,686	90,016	90,572	91,048	87,889	86,628	93,147	93,850
85,315	92,998	96,181	95,077	93,963	92,315	90,813	89,949	91,689
85,104	86,822	88,165	89,293	89,583	90,573	84,959	85,116	84,409
74,825	74,229	72,779	74,182	73,965	73,604	72,461	72,941	73,633
68,343	68,008	67,906	68,167	67,510	67,133	66,592	66,744	67,439
86,712	86,388	86,608	85,776	84,610	88,150	91,187	91,677	91,653
82,359	85,361	84,715	90,028	88,363	92,851	89,180	84,822	85,215
87,326	88,791	90,335	92,603	93,565	94,030	93,260	91,364	93,978
67,853	65,537	61,771	61,166	59,764	58,926	58,782	58,869	58,812
59,418	59,140	61,208	61,946	62,246	63,000	62,229	61,572	60,954
67,994	70,793	70,243	74,768	75,108	75,517	75,680	77,087	76,984
67,648	67,576	66,943	67,230	67,367	66,518	65,847	66,756	66,872
84,350	88,248	87,330	88,618	89,648	91,286	90,457	94,943	92,219
88,263	88,886	90,045	90,188	92,874	92,648	92,760	91,169	91,621
84,831	85,961	86,624	89,724	90,623	91,843	85,913	81,999	78,864
90,154	92,178	93,670	93,159	92,370	91,248	95,128	96,235	97,374
91,374	92,754	90,063	89,457	89,092	88,279	89,695	90,507	92,238
75,724	78,024	81,220	77,064	72,151	77,272	73,182	74,296	75,964
69,422	69,249	69,407	69,240	68,334	67,854	67,161	66,504	66,827
79,456	83,043	83,479	88,510	92,770	91,995	90,877	91,694	91,352
83,046	86,670	89,578	95,584	95,319	95,483	97,560	98,385	99,073
90,139	94,127	96,950	98,190	98,880	98,042	94,174	94,844	97,444
95,728	96,393	94,700	96,243	98,280	100,244	100,115	98,797	97,555
87,912	90,200	87,784	91,235	95,696	94,759	89,972	91,163	91,744
83,372	82,525	82,609	82,835	81,904	79,039	80,538	80,002	80,803

71,327	70,750	70,344	70,260	70,041	69,495	68,223	68,374	68,135
80,579	83,437	83,834	85,687	89,698	91,472	91,061	90,505	91,707
89,602	92,777	91,267	93,322	93,722	94,212	93,466	91,664	91,739
82,175	84,734	87,485	89,794	91,131	90,432	90,268	89,569	89,996
88,702	91,717	90,086	91,641	92,587	94,644	92,942	91,624	90,237
82,188	86,470	89,235	88,070	86,735	89,246	88,415	87,648	83,889
70,715	71,671	72,082	72,379	73,697	74,307	73,428	74,132	73,353
67,255	67,362	66,647	67,183	67,110	67,703	68,011	68,793	69,282
86,272	88,337	86,571	87,062	86,329	89,284	90,116	90,874	90,339
88,057	92,323	91,272	93,372	95,273	93,325	91,640	89,999	87,193
83,076	86,368	87,908	88,795	88,864	89,777	89,230	85,338	88,044
66,099	64,374	62,844	62,713	62,942	61,973	58,188	57,523	59,097
58,089	58,337	58,237	59,686	59,822	59,572	59,604	60,023	59,940
60,033	60,543	63,587	64,810	65,007	67,985	67,413	67,557	68,012
69,065	68,637	67,480	67,842	67,588	68,134	67,759	67,376	67,424
74,682	77,484	78,731	78,605	79,100	84,013	82,090	85,532	81,223
85,749	88,064	90,188	91,569	89,230	89,029	87,547	84,855	85,495
84,599	85,103	85,976	88,457	85,659	89,335	85,929	90,394	89,841
77,836	80,410	82,944	81,411	80,271	81,373	80,566	81,133	79,241
74,052	73,795	72,871	75,407	74,201	72,859	70,749	70,298	69,448
69,626	67,556	68,067	70,675	71,807	73,369	72,663	74,358	74,348
68,992	68,462	68,965	69,924	69,545	69,557	68,775	68,861	68,018
89,869	90,199	88,003	91,310	93,362	96,932	95,666	91,266	90,485
92,648	96,303	96,099	94,973	95,128	99,120	94,817	94,820	91,428
93,323	97,172	98,099	96,964	96,808	95,734	93,150	93,991	100,190
91,788	97,993	98,584	97,760	99,170	98,881	100,181	101,853	100,602
95,025	96,908	98,386	99,278	100,058	100,532	96,021	95,020	93,625
70,541	69,648	73,298	74,834	75,472	75,286	75,824	74,968	75,224
73,669	73,314	72,414	71,764	71,531	71,637	71,210	70,766	70,480
81,341	83,537	86,366	87,917	89,097	90,356	88,998	94,978	93,019
93,727	98,186	98,268	89,042	87,736	92,140	96,198	99,720	99,835
83,441	89,259	89,740	91,512	91,526	85,015	86,214	87,460	87,638
91,279	95,875	90,540	93,929	100,339	95,867	97,032	98,568	99,143
91,752	93,491	93,032	95,928	98,214	95,522	94,398	94,164	93,860
87,187	81,724	75,593	78,494	83,961	82,590	81,127	78,469	79,939
69,495	67,934	66,787	66,092	66,139	65,619	65,440	65,822	66,164
84,289	88,199	88,901	92,958	95,342	95,216	95,482	95,991	97,345
73,070	74,802	74,396	78,755	78,185	72,438	72,053	73,298	71,078
89,296	92,209	93,984	97,197	95,740	93,060	94,980	96,198	96,321
91,440	93,724	93,131	86,467	88,278	89,830	90,013	91,807	92,441
93,290	96,478	96,304	94,438	96,358	96,102	95,274	95,084	94,439
81,499	82,683	84,545	83,270	81,602	81,791	83,241	84,021	80,087
67,327	66,607	65,959	64,901	64,353	64,365	63,759	64,035	64,809
72,623	76,655	76,809	79,676	80,122	80,355	80,141	79,744	80,409
91,054	92,678	94,893	97,308	100,077	101,429	100,407	101,324	103,209
94,411	95,883	96,263	93,600	91,992	93,190	97,347	97,652	96,056
96,134	99,647	95,325	98,211	92,028	92,915	92,005	92,508	93,913

92,115	95,483	96,615	98,262	99,348	99,716	97,926	97,567	97,911
73,785	75,613	79,719	80,423	79,866	78,941	78,195	77,478	75,546
71,740	71,199	70,806	70,308	69,681	69,659	69,407	68,274	67,786
77,655	81,758	83,566	84,505	85,941	87,726	88,020	90,470	89,078
91,897	92,777	91,922	92,189	93,409	93,169	93,481	93,872	97,106
91,697	92,834	91,238	89,974	91,241	93,649	92,984	94,385	95,734
95,283	98,252	99,700	100,689	100,654	100,178	100,744	98,057	99,224
92,757	93,992	93,353	96,923	95,956	92,536	93,135	91,468	94,201
76,345	77,121	77,960	79,174	78,913	78,934	77,928	78,224	79,013
78,556	78,744	78,284	78,164	78,013	78,099	78,597	74,910	77,505
84,577	87,697	90,077	92,011	92,749	92,476	92,759	93,082	93,512
88,495	90,602	92,555	90,799	95,125	95,845	95,228	94,783	95,671
88,566	92,323	92,280	94,722	95,672	94,934	94,993	95,121	95,130
98,265	97,482	95,584	90,395	92,826	95,950	96,209	99,951	102,131
92,449	95,814	97,637	96,584	94,508	94,261	95,092	100,195	99,028
84,514	87,267	87,423	89,190	88,673	92,243	85,894	88,054	83,963
83,171	80,689	78,532	78,863	79,854	81,724	82,711	81,318	77,715
87,508	90,972	90,526	87,726	91,471	94,375	93,426	94,614	94,452
88,149	92,445	93,005	95,151	96,518	96,741	95,787	95,927	95,749
88,385	90,204	92,096	94,440	96,724	95,779	94,536	92,913	94,256
92,195	95,908	95,920	97,270	93,582	96,043	95,829	97,371	98,280
87,386	91,219	89,887	93,439	92,471	90,092	89,261	90,511	93,762
79,696	77,866	79,480	79,329	79,489	78,798	78,171	79,205	76,981
75,306	76,222	77,337	73,132	74,931	74,392	70,965	69,470	67,405
80,085	86,749	89,357	92,198	92,283	93,789	93,660	93,460	95,008
88,406	90,577	92,135	94,053	94,208	95,707	95,416	95,675	97,090
86,004	89,443	91,447	91,863	92,163	93,542	95,786	95,531	94,741
95,245	97,039	98,465	99,676	96,532	97,459	97,093	98,340	97,741
90,576	91,813	88,502	90,287	92,815	95,439	94,644	96,504	93,769
85,672	86,105	85,788	86,382	86,732	85,480	84,925	82,898	82,593
80,533	78,843	73,469	71,196	71,826	72,246	72,709	71,373	70,115
81,711	84,469	82,972	81,471	83,228	83,263	83,949	85,298	83,950
89,842	94,169	97,765	97,560	95,746	96,880	92,762	94,212	93,517
87,930	90,258	89,262	90,979	93,538	95,983	96,582	95,487	97,630
93,574	96,293	91,801	93,992	92,645	89,612	97,706	95,626	92,517
89,173	93,221	95,856	98,946	99,493	98,274	98,380	98,480	99,830
80,272	80,766	81,480	82,752	79,031	82,849	82,234	81,659	80,618
77,623	74,586	75,312	74,795	73,304	72,643	72,109	71,380	72,376
81,811	83,807	85,609	89,567	91,501	95,267	96,206	92,752	90,205
86,943	91,132	88,784	91,664	92,991	94,828	98,503	100,617	98,132
84,827	87,897	91,814	94,782	92,039	89,048	89,856	91,291	92,418
82,531	84,984	85,297	87,106	88,578	90,132	91,599	93,967	94,085
86,966	90,328	91,900	85,278	84,076	90,734	95,848	96,108	93,747
77,837	78,108	78,355	82,891	81,153	79,686	80,228	82,556	81,690
79,176	77,860	71,482	73,589	76,428	76,381	75,714	74,532	72,084
81,613	85,550	87,618	89,491	90,444	94,381	90,772	91,594	89,822
85,927	88,596	89,452	92,984	95,197	95,313	94,931	93,522	92,531

78,846	83,681	83,821	84,175	87,713	87,934	89,746	93,979	93,585
89,638	92,934	95,549	96,445	93,362	93,960	93,998	93,015	92,720
88,100	90,969	92,959	92,920	93,279	95,186	96,506	95,087	94,761
76,062	75,288	75,371	74,806	74,648	73,049	73,707	76,433	78,099
71,987	71,888	73,031	72,559	71,870	72,976	72,005	71,770	70,516
85,334	86,419	85,436	88,642	98,074	99,177	99,820	93,392	95,426
85,039	82,418	80,269	82,169	76,635	74,168	72,987	78,936	82,216
88,928	95,292	98,152	98,575	98,276	96,348	96,935	99,532	98,625
83,195	87,434	87,874	88,335	93,607	94,499	93,446	93,363	93,250
85,598	87,403	86,985	90,630	90,433	93,204	91,313	93,243	94,849
80,421	81,161	82,171	85,281	85,709	85,433	83,561	89,200	88,872
76,578	73,236	73,553	74,816	74,835	75,397	72,876	72,398	68,945
84,191	89,103	90,839	92,969	96,446	99,221	95,152	92,907	94,253
89,594	94,075	97,206	99,432	101,184	98,422	99,552	100,359	101,181
92,861	96,538	96,413	95,938	95,358	96,115	95,036	97,052	94,137
83,380	87,532	87,102	88,486	89,729	90,148	89,707	88,421	91,238
84,655	85,867	84,941	84,635	83,550	83,833	81,071	85,867	84,995
74,139	74,508	74,974	76,326	75,903	75,998	73,647	75,067	74,554
75,674	74,731	73,656	72,678	72,916	72,496	74,195	69,857	68,726
83,021	83,222	85,871	90,458	91,857	92,908	93,362	95,614	95,886
91,143	96,093	97,006	96,568	97,578	98,730	95,757	95,357	97,582
84,150	87,981	88,344	89,213	93,235	93,919	93,681	93,310	95,298
88,965	94,999	94,170	95,455	96,038	97,759	97,755	98,407	99,036
90,322	93,665	96,196	96,889	97,827	99,059	98,325	97,119	96,051
76,722	75,699	74,548	76,112	75,158	75,947	74,562	73,623	73,026
74,481	74,482	74,318	74,903	74,362	74,429	71,496	73,462	72,135
81,405	88,072	89,276	88,532	88,849	90,855	93,772	96,091	93,593
91,186	96,374	96,691	98,297	95,739	98,715	99,090	99,314	99,638
87,598	88,668	88,301	89,651	92,054	92,912	93,871	96,165	94,993
90,305	97,540	93,310	93,392	92,609	92,328	95,268	97,471	98,309
89,279	91,673	91,455	90,847	94,213	96,510	97,581	93,387	92,481
80,941	79,721	77,938	78,429	76,765	79,001	79,355	79,204	78,699
77,216	75,859	74,941	71,411	73,132	74,722	72,867	72,575	73,628
83,893	88,441	90,632	94,596	95,620	93,190	92,013	91,310	94,392
90,130	95,212	96,054	94,593	97,193	94,487	92,836	95,524	98,723
69,128	73,678	74,928	74,918	76,667	76,059	72,058	71,001	70,481
86,043	90,501	89,747	90,614	91,984	95,670	98,186	93,542	93,564
82,246	89,547	92,186	91,344	91,139	95,150	94,592	87,657	89,638
82,453	82,935	84,713	85,275	84,519	84,550	86,670	85,416	82,118
75,960	75,247	72,809	73,858	73,334	73,648	73,588	74,084	73,890
86,414	88,514	89,798	93,269	90,073	89,608	91,665	95,409	94,299
89,894	94,716	91,558	92,503	95,590	97,478	97,218	96,885	96,252
85,236	89,767	89,956	90,551	92,351	92,145	91,665	91,974	93,069
87,242	92,530	92,597	89,998	90,645	94,571	95,117	92,372	93,598
87,599	85,326	85,038	87,032	86,941	91,617	91,447	89,836	89,293
77,173	78,076	78,015	75,234	73,547	76,759	81,087	80,280	80,533
76,500	76,655	77,004	76,982	75,730	76,413	74,750	75,400	74,583

77,458	80,868	82,173	84,410	83,169	83,427	83,332	82,383	82,091
81,467	85,888	87,637	88,497	89,700	91,163	90,988	87,686	85,147
83,550	87,222	88,441	90,326	89,934	88,697	87,782	87,902	90,089
79,519	83,352	85,067	87,741	88,353	88,607	88,127	88,611	89,694
79,741	84,877	87,016	87,516	87,829	88,700	89,150	91,252	93,501
81,611	80,215	83,381	84,777	83,186	83,308	84,215	84,213	85,782
76,915	76,997	76,980	77,219	75,972	74,971	73,432	75,326	72,345
80,673	86,416	89,622	91,899	93,451	94,996	94,794	90,215	92,380
92,119	95,682	94,440	94,018	97,464	96,363	95,897	98,693	97,788
82,481	89,318	93,924	95,885	96,514	99,132	100,610	100,870	96,216
89,928	92,704	90,439	92,252	93,095	93,603	91,595	92,345	93,098
89,827	94,435	95,462	95,532	97,435	98,007	95,979	98,335	100,473
78,231	79,523	78,306	79,822	79,273	82,879	85,048	80,572	78,046
78,900	78,352	77,645	77,806	76,461	78,219	77,725	77,891	75,988
84,103	86,406	89,123	89,494	91,367	93,751	94,817	97,488	95,788
74,047	79,893	78,291	79,538	82,974	82,421	83,119	83,431	83,560
73,173	76,706	76,962	77,642	78,556	79,955	79,350	79,821	80,645
79,108	86,052	84,709	85,074	89,362	91,836	88,881	89,612	90,777
90,354	91,304	89,585	91,209	93,446	96,166	99,077	99,301	99,126
85,715	86,225	84,400	82,986	83,478	85,747	84,735	86,976	86,523
73,289	73,947	76,033	79,977	79,781	77,736	73,609	73,736	72,887
80,817	82,302	83,198	89,108	92,105	93,358	94,982	97,362	100,642
96,248	98,808	97,448	95,378	99,195	101,035	102,696	102,356	99,216
93,829	97,051	95,863	97,334	97,500	96,756	97,343	91,253	92,387
92,303	98,360	98,005	99,593	99,216	98,328	98,007	96,652	97,055
87,758	90,626	90,278	92,128	93,846	91,481	90,154	89,250	92,146
81,612	84,109	82,957	81,531	79,560	82,072	83,290	80,974	80,003
75,132	73,773	74,944	74,489	74,153	70,672	71,896	72,603	72,466
70,943	68,285	70,113	71,998	69,554	67,599	68,437	70,820	70,653
83,129	85,130	88,614	90,632	93,666	88,621	87,319	92,070	93,520
74,722	74,110	74,547	72,767	74,847	73,245	75,002	75,061	71,113
88,392	95,230	95,757	96,543	97,108	97,821	97,549	98,097	99,295
92,052	97,125	95,954	96,817	93,180	100,296	98,216	97,470	96,201
85,161	86,863	82,980	83,123	85,786	88,823	88,442	88,317	88,275
78,218	81,311	83,791	80,314	78,529	75,201	74,118	74,214	74,043
87,290	87,538	90,355	92,374	93,608	96,293	96,778	94,110	95,713
90,581	96,035	96,541	97,024	94,541	98,471	97,308	96,646	95,436
86,233	88,757	90,741	90,152	90,061	89,790	90,672	92,384	94,237
86,122	90,540	87,594	88,206	90,486	92,984	94,261	92,639	96,440
87,975	93,943	91,378	95,165	95,754	97,001	94,454	95,570	95,917
79,372	79,724	80,467	80,299	80,204	81,095	77,676	76,173	77,359
76,699	75,583	76,433	76,662	73,972	75,369	74,789	76,100	74,419
79,738	86,805	90,999	92,072	90,005	95,375	95,231	97,506	97,241
88,535	91,657	94,148	92,477	93,645	95,738	95,785	96,701	100,147
97,033	100,240	99,176	96,748	97,623	98,912	97,828	98,168	98,138
93,771	97,304	98,197	101,806	101,445	97,492	98,242	97,586	97,677
90,657	95,771	97,960	99,576	97,833	99,878	97,746	97,671	98,621

91,248	89,880	89,839	92,201	89,434	91,650	91,964	90,398	92,335
78,788	76,228	76,128	73,778	75,575	77,904	77,734	76,749	70,392
88,519	95,257	97,317	97,842	94,986	92,463	99,638	103,012	101,886
90,213	94,592	95,977	98,634	99,657	99,576	101,819	101,916	100,435
87,187	91,571	91,452	93,135	93,074	95,129	96,051	95,874	98,718
91,421	95,256	90,860	89,235	91,171	93,422	94,054	92,510	91,688
93,447	97,185	98,521	101,267	99,294	102,345	100,861	101,441	102,347
83,317	81,800	83,828	79,197	78,864	79,453	81,707	81,577	77,622
73,604	72,405	72,769	71,463	69,792	71,948	75,095	76,023	74,412
85,145	86,490	86,900	88,222	87,901	88,205	85,122	82,711	83,967
85,847	90,885	92,294	91,779	88,606	91,244	90,363	90,795	90,738
90,224	91,788	92,584	95,848	92,924	94,655	93,237	88,406	90,299
82,675	86,270	86,770	85,533	86,171	86,909	86,025	82,688	78,573
77,206	79,950	79,577	81,274	82,688	87,950	87,979	87,093	87,934
78,273	76,733	76,658	76,510	77,558	76,653	73,909	74,908	78,982
75,438	74,311	72,516	71,937	72,743	72,974	71,304	72,737	71,678
71,465	70,036	69,929	70,190	70,638	71,619	71,319	72,245	76,454
83,108	85,413	90,078	87,181	82,981	81,389	84,834	86,099	85,030
84,072	84,490	84,824	87,193	87,830	86,984	87,272	87,181	88,845
85,394	90,317	88,311	88,573	86,794	88,045	89,272	91,553	90,097
87,812	86,749	88,598	92,171	92,052	92,497	91,072	90,690	88,670
80,115	81,523	82,541	80,379	82,385	83,031	80,345	78,949	78,622
73,814	72,764	72,764	72,864	74,571	73,721	72,102	77,156	75,789
79,049	83,828	83,544	83,342	85,175	86,361	84,585	85,298	86,186
92,134	96,091	95,308	96,707	97,175	98,385	98,533	92,403	98,864
93,909	91,407	93,452	92,359	92,234	92,305	91,723	91,763	91,809
88,731	91,006	94,342	94,047	95,351	95,490	95,713	96,017	96,763
92,717	95,320	96,599	96,117	96,310	99,941	100,294	97,657	97,875
79,860	80,067	82,988	84,869	82,597	79,889	78,677	82,360	82,829
77,816	75,170	79,490	78,990	77,126	79,424	78,046	78,678	78,107
87,697	89,616	88,379	94,366	93,808	92,581	95,939	95,796	94,605
92,010	92,312	97,065	100,071	97,554	93,476	93,456	95,529	96,576
58,336	60,000	59,644	62,285	64,097	65,685	64,063	62,511	64,783
65,935	69,914	72,135	74,993	76,275	78,968	81,982	75,536	74,439
89,379	93,691	93,072	91,036	89,965	92,246	92,721	93,727	92,712
83,474	82,968	82,955	81,047	84,979	85,150	81,910	83,225	83,614
78,821	79,205	78,538	74,376	71,086	71,473	72,777	75,122	71,133
86,971	89,044	92,081	92,386	89,727	92,619	95,284	93,584	87,526
87,054	89,662	93,062	95,037	95,051	91,748	91,195	96,912	96,021
82,318	88,391	85,208	84,714	85,166	82,356	84,115	85,926	86,918
86,693	88,116	84,121	87,910	89,431	92,240	92,663	93,215	92,370
84,693	90,684	89,905	88,495	91,544	95,709	96,687	97,934	97,522
80,292	85,429	85,937	88,429	90,357	90,498	91,910	92,415	86,804
76,370	75,787	75,976	75,017	75,766	77,242	75,509	75,645	74,420
86,452	86,903	83,333	87,804	85,440	86,036	89,770	92,046	94,420
91,629	97,767	99,121	97,555	97,888	99,211	99,178	100,184	101,575
87,061	90,739	95,356	98,240	96,991	98,412	96,252	97,995	96,085

87,614	92,490	97,478	97,754	96,987	96,568	96,620	96,065	98,122
89,787	92,533	93,938	91,786	92,225	95,623	98,040	97,192	98,508
78,476	76,746	78,948	78,142	79,206	79,742	78,648	78,433	77,261
77,349	74,726	74,508	74,755	74,140	73,682	73,858	73,067	73,734
84,662	88,688	90,872	90,729	87,732	90,055	90,368	90,139	90,184
93,628	94,846	94,947	92,152	99,376	102,596	96,407	94,477	96,285
86,774	89,294	90,434	89,697	90,178	92,115	93,727	98,039	98,457
96,080	100,827	98,667	96,604	101,471	100,173	100,103	100,189	99,842
89,331	94,286	100,779	103,398	99,048	99,310	103,566	102,740	102,019
70,268	70,983	71,739	73,351	77,287	76,265	71,867	77,419	80,528
79,119	77,357	76,198	77,917	79,857	80,233	79,094	78,231	77,038
79,458	83,564	85,671	86,491	86,950	86,634	86,114	87,979	89,817
96,554	96,242	95,663	98,259	97,763	98,313	95,820	100,700	102,633
93,316	94,241	96,859	96,521	98,502	94,090	94,323	100,562	100,433
89,695	94,194	93,209	96,163	96,818	99,202	100,638	101,178	100,840
91,789	94,803	93,355	92,394	94,761	97,020	99,474	99,496	98,386
82,779	84,182	83,350	82,924	82,385	82,951	83,499	82,339	79,356
82,589	81,416	77,643	78,154	78,368	75,757	69,778	75,219	73,177
81,340	83,945	84,803	84,508	86,712	90,933	93,873	95,838	96,447
91,106	92,667	93,763	92,619	94,236	93,657	98,039	100,328	97,644
88,581	92,406	92,677	93,878	95,731	96,849	95,251	94,670	94,712
93,598	94,413	90,357	91,831	97,528	96,955	96,146	94,951	93,831
94,715	96,419	99,244	100,362	100,245	102,705	100,591	95,788	95,145
84,357	83,477	84,412	86,005	83,636	83,972	82,209	81,853	79,295
79,157	76,987	75,845	75,866	78,181	74,942	71,768	75,426	75,498
83,083	84,194	86,122	89,619	90,782	90,182	90,811	90,499	88,809
95,680	97,743	96,180	97,088	98,599	98,017	98,738	94,948	91,171
88,713	93,136	92,513	91,673	95,230	97,756	97,341	97,141	97,562
91,732	91,334	92,965	94,849	93,284	90,028	94,082	94,765	96,654
85,941	89,888	93,249	93,707	90,387	94,047	91,545	90,565	92,798
76,689	77,115	79,242	79,021	77,648	75,467	79,459	78,877	78,205
69,771	68,404	69,841	72,014	75,276	73,114	72,447	72,747	73,238
71,174	69,385	67,561	65,598	64,286	64,162	67,372	66,967	65,306
79,632	85,462	85,515	82,888	84,933	88,560	89,432	90,110	91,229
78,633	80,554	80,417	78,270	76,370	78,535	79,308	82,077	85,269
89,363	92,619	91,999	90,822	90,273	89,576	83,729	85,764	89,404
90,132	90,725	89,398	92,555	96,799	98,781	99,223	95,196	90,547
85,760	87,782	87,415	89,415	89,536	90,029	88,937	87,866	87,805
81,451	81,298	80,321	80,034	79,059	77,020	74,521	76,745	77,237
82,572	87,180	91,895	94,773	95,077	93,335	95,794	94,955	97,857
92,732	96,263	97,722	100,973	103,509	99,666	98,073	100,306	99,052
88,913	92,812	94,877	95,811	98,065	100,067	98,479	97,244	96,242
89,363	95,995	95,367	91,127	88,089	90,115	87,807	88,669	94,949
95,153	98,406	100,201	98,071	101,208	102,019	102,084	101,906	101,404
85,201	85,209	85,552	83,719	84,448	90,221	92,606	86,624	89,383
75,129	76,574	75,848	77,423	78,212	78,982	77,034	76,478	73,909
85,182	89,276	91,950	93,915	94,391	95,520	100,430	99,949	99,992

98,355	100,726	102,830	104,484	105,066	102,346	103,801	105,233	103,043
89,001	89,560	89,783	95,221	95,888	95,414	93,966	94,036	94,574
90,507	96,511	95,862	98,027	101,141	102,196	99,611	100,971	101,243
92,085	94,325	96,375	98,508	101,352	103,298	98,963	98,909	102,547
86,379	86,302	85,330	86,461	90,174	91,216	90,468	88,888	88,001
81,256	80,957	79,534	78,406	77,804	78,841	77,808	73,650	74,176
87,444	92,761	94,434	96,148	96,012	96,433	96,661	97,560	97,663
90,086	95,569	99,610	102,863	102,655	105,593	102,789	102,370	106,622
89,947	93,906	95,415	97,638	97,535	98,031	96,283	98,897	100,055
88,851	91,963	94,567	98,257	100,360	100,021	99,605	99,030	99,042
84,715	88,108	87,490	90,835	91,156	90,111	96,175	97,940	97,185
82,416	82,116	80,883	79,823	79,422	77,242	74,858	75,682	75,511
73,865	75,186	72,619	70,831	69,871	69,308	70,355	74,376	74,995
80,194	85,586	86,910	87,450	87,174	86,639	84,935	87,580	88,844
86,664	91,757	93,341	97,446	98,355	99,565	99,040	99,950	98,946
88,331	95,416	99,953	98,643	100,082	96,177	96,999	97,966	97,489
83,736	88,021	90,543	93,245	93,532	94,321	91,640	91,015	91,422
79,642	86,584	93,431	96,739	98,221	98,863	98,202	100,328	99,522
74,740	70,595	69,271	70,398	70,264	72,446	74,544	75,337	77,358
73,542	71,949	71,642	71,886	72,040	68,533	68,046	71,179	70,740
79,876	80,722	82,923	85,385	87,318	89,860	89,405	89,350	89,592
88,168	92,167	96,355	96,703	96,749	101,474	98,462	99,493	101,184
82,121	85,221	84,216	82,721	81,650	81,933	80,749	82,820	90,911
86,209	88,854	91,683	93,688	96,388	96,268	96,209	94,228	95,320
89,232	98,494	101,264	101,869	98,242	99,740	103,362	105,233	103,096
81,006	81,157	80,888	79,771	79,677	81,285	77,295	75,648	79,739
70,781	70,388	69,594	70,329	69,171	69,844	68,816	70,571	73,751
81,080	87,171	88,783	94,047	93,310	88,736	85,051	88,642	93,873
93,489	98,958	100,949	97,076	97,121	98,240	98,814	99,994	103,139
87,276	89,446	92,448	94,721	96,791	96,653	96,560	97,274	97,343
83,257	89,244	92,574	92,450	93,424	94,098	97,608	101,956	103,782
87,778	93,730	95,127	99,511	100,072	96,739	94,516	95,215	101,848
80,632	81,603	81,898	82,654	81,896	84,996	84,226	84,046	84,005
79,742	77,445	78,682	78,739	74,392	64,803	64,806	63,926	67,122
72,434	77,788	80,747	83,334	84,158	85,467	85,143	85,778	86,578
83,758	88,686	91,436	94,083	93,338	94,444	90,831	92,618	94,014
84,572	87,875	90,739	93,644	94,440	95,320	92,188	92,253	92,174
82,864	88,024	88,569	91,521	92,485	93,890	92,491	93,763	92,309
78,478	83,549	83,325	83,785	84,872	83,917	81,613	81,575	81,980
66,061	64,659	64,208	62,534	62,206	61,924	62,552	62,733	60,966
62,254	61,641	61,215	61,727	60,783	60,231	56,728	55,220	51,851

29	31	33	35	37	39	41	43	45
HR15	HR16	HR17	HR18	HR19	HR20	HR21	HR22	HR23
65,685	65,066	64,540	65,514	65,203	67,165	68,296	68,796	69,498
87,158	86,486	86,929	88,759	91,259	88,968	92,789	88,538	88,317
99,911	97,302	93,799	97,234	96,367	97,400	97,612	93,872	89,968
81,782	79,373	77,407	80,089	79,865	83,018	88,024	89,422	83,308
98,816	92,776	93,238	97,831	99,351	93,809	91,239	91,731	93,327
88,053	83,831	84,274	88,828	89,911	89,173	88,038	85,410	82,598
67,525	67,463	68,039	68,265	67,760	68,709	70,881	71,049	69,527
48,245	48,363	47,930	49,989	51,388	58,255	61,688	64,542	65,983
91,596	89,363	88,818	90,068	91,152	90,836	90,820	90,401	91,761
94,138	88,817	87,651	87,147	93,675	93,700	94,192	92,776	91,440
89,153	89,132	85,441	86,229	87,563	86,987	86,423	87,247	87,340
87,033	85,397	83,414	82,929	84,585	85,390	84,035	84,030	85,772
78,765	79,161	79,739	82,073	77,560	75,962	75,980	71,874	68,607
69,082	69,741	69,906	70,030	69,923	68,428	68,588	67,680	66,719
68,069	67,838	68,308	66,186	66,971	65,838	67,347	67,211	68,391
83,734	84,694	88,551	89,614	88,413	90,715	90,703	90,757	89,230
90,698	89,614	87,725	87,345	88,060	89,435	90,514	91,507	91,618
91,229	88,697	89,505	93,038	93,508	89,700	89,644	88,966	89,361
93,535	90,066	90,113	95,621	95,318	95,889	95,144	94,312	93,253
85,392	88,737	92,649	91,446	90,265	87,266	87,429	86,130	84,095
73,323	72,524	72,371	72,996	72,534	71,980	72,732	72,933	71,644
67,556	67,303	67,328	68,367	68,924	68,585	69,363	69,762	69,299
91,538	90,478	91,165	86,526	87,709	90,050	90,816	90,305	88,435
88,517	87,811	86,506	88,592	90,592	90,511	91,288	92,103	92,944
90,844	88,888	90,331	93,417	91,197	87,206	88,622	88,314	82,522
58,825	58,912	59,107	59,388	59,554	59,291	59,284	59,275	59,377
59,959	60,084	60,222	60,600	61,023	61,324	61,430	61,929	62,528
74,204	72,493	72,660	74,562	72,852	73,243	75,654	74,868	71,283
63,375	63,538	67,517	68,287	68,712	69,470	69,730	68,893	70,725
88,427	89,958	92,008	92,745	92,695	92,238	95,367	94,904	92,900
92,596	92,520	90,729	90,353	88,801	89,454	94,684	92,052	88,387
78,701	72,634	74,877	78,182	79,663	78,765	84,539	91,347	92,020
93,973	94,128	96,546	95,583	96,572	96,197	97,902	95,979	95,285
91,436	91,529	92,189	91,740	94,533	96,460	95,204	92,462	89,650
76,121	76,389	77,207	79,370	77,212	77,775	73,022	72,936	72,916
67,106	67,067	67,254	67,644	67,478	67,263	67,473	68,788	69,595
87,408	83,589	88,876	91,851	89,949	92,127	93,951	93,269	91,346
96,770	94,367	92,814	91,054	90,404	91,064	92,560	91,426	89,471
95,676	96,007	96,118	96,166	96,571	96,482	95,650	96,955	95,394
98,077	96,904	94,500	92,867	92,115	91,824	93,431	93,067	90,576
89,692	92,288	92,049	90,929	88,573	87,042	86,699	88,248	86,089
77,501	80,465	78,628	77,869	78,674	75,878	74,640	73,392	72,677

67,232	67,309	68,010	69,464	69,371	69,333	69,192	69,171	69,428
91,295	88,077	88,342	83,669	86,614	88,255	92,958	94,832	93,057
90,621	89,108	93,092	93,338	87,129	87,773	92,769	97,401	96,516
87,469	89,471	90,368	86,381	84,788	85,092	86,313	87,668	88,434
91,757	90,404	89,836	91,398	91,294	90,783	91,327	91,656	89,708
82,115	85,653	86,027	86,775	84,191	81,569	81,249	80,226	77,681
74,270	73,450	73,179	73,444	74,382	74,121	74,073	74,065	73,618
68,954	68,998	69,278	69,448	68,865	69,048	70,150	70,153	70,702
89,028	87,930	89,079	90,722	89,626	88,862	90,680	89,498	89,264
86,340	93,311	94,536	93,771	89,229	87,483	88,825	88,604	87,713
89,777	87,309	86,774	87,435	85,543	82,037	85,082	82,384	75,592
59,776	60,168	60,391	60,718	61,067	60,952	60,483	60,061	59,907
60,000	55,476	52,617	55,027	55,867	57,849	58,849	59,886	60,413
68,210	67,865	68,460	69,103	69,190	69,108	68,588	68,340	68,158
66,865	66,730	62,066	60,827	62,049	63,659	65,618	68,199	69,509
80,558	78,339	80,112	84,894	86,927	86,858	85,175	88,294	87,507
85,467	85,149	87,970	89,738	89,210	88,431	89,629	89,585	88,896
86,859	85,096	86,902	86,274	86,578	86,205	85,633	84,386	83,615
78,738	76,545	80,007	81,154	80,730	79,309	76,246	77,848	76,249
67,260	69,498	70,970	70,604	70,321	70,738	70,352	70,457	69,487
74,435	74,672	75,232	74,487	71,175	71,128	69,582	69,545	70,965
67,610	67,342	67,315	68,897	67,669	65,107	66,477	68,393	70,525
94,127	95,443	95,799	95,357	96,431	96,773	96,993	95,556	95,008
93,309	93,910	92,309	96,681	99,820	100,300	97,725	97,612	99,217
98,685	96,800	97,213	95,843	94,948	95,789	95,565	96,098	96,045
101,552	98,570	99,362	97,938	98,631	97,078	96,406	96,679	97,451
95,744	93,818	94,119	92,967	94,607	96,555	99,243	96,704	95,894
74,353	73,561	73,931	74,404	74,040	73,611	74,076	74,287	73,738
70,116	69,698	70,404	72,011	72,026	72,504	72,733	73,524	73,625
94,879	89,643	92,128	93,820	93,133	93,949	92,007	92,001	93,128
98,512	96,987	94,867	96,711	99,627	99,242	99,770	96,552	98,217
87,741	87,961	88,859	89,211	90,235	91,281	92,106	93,742	96,776
98,993	96,144	93,267	97,499	96,003	94,322	95,430	95,485	96,487
92,742	91,046	88,269	87,660	87,537	88,878	89,131	91,009	90,282
82,482	79,589	79,670	81,241	79,150	75,389	76,904	76,121	75,286
65,826	67,165	67,245	68,924	68,168	68,085	68,821	69,848	70,638
96,235	96,128	94,254	94,726	96,837	96,174	93,541	92,208	95,087
73,139	73,924	73,208	76,362	77,873	79,202	80,589	80,761	79,008
98,954	95,395	91,975	92,803	93,887	93,431	95,727	94,569	91,521
93,138	92,282	90,075	91,721	93,946	92,738	92,700	93,533	94,686
92,325	90,818	91,156	91,495	91,355	92,822	91,652	91,158	87,714
76,464	77,388	76,953	77,806	74,863	74,034	70,859	67,897	67,747
65,573	65,785	66,128	67,249	67,081	68,380	69,578	70,007	67,126
77,704	79,323	88,979	93,091	95,437	95,326	94,971	93,479	93,834
99,281	88,881	83,413	91,028	95,483	96,948	98,969	97,974	96,890
98,836	96,171	95,865	96,195	95,533	90,373	89,654	94,767	98,271
97,205	96,155	95,305	96,651	93,431	93,023	94,300	97,689	95,422

97,235	96,224	93,959	92,894	92,019	90,697	89,869	84,398	82,336
75,882	73,247	76,169	76,684	75,767	73,808	73,650	72,360	71,670
69,201	69,618	69,384	69,251	69,186	69,949	69,915	70,705	71,949
90,712	85,924	82,271	87,166	87,032	88,395	88,501	87,895	91,833
94,830	93,587	93,588	93,677	92,563	92,374	96,741	98,358	96,180
95,101	92,242	90,901	93,097	96,498	96,291	96,253	96,752	97,857
101,185	97,318	97,593	97,400	96,091	95,734	96,137	96,211	96,636
97,701	97,166	96,117	95,929	95,089	92,497	91,002	90,628	90,979
78,316	78,548	81,868	85,758	85,050	86,145	85,246	84,533	82,152
75,522	78,383	78,919	79,358	80,306	79,582	76,479	77,184	80,547
95,498	93,737	95,163	96,577	96,165	95,332	95,281	99,790	101,243
99,872	96,159	95,562	98,884	95,543	97,775	98,235	97,116	98,107
96,146	94,594	92,570	93,805	93,496	93,263	94,694	95,174	95,174
101,736	101,060	99,080	96,844	96,964	95,440	97,249	97,359	97,712
98,840	96,571	94,093	93,685	91,720	93,435	93,839	96,125	96,078
83,096	84,917	82,097	84,660	88,883	87,719	88,149	87,569	86,494
77,987	78,308	78,488	79,355	78,619	79,171	78,225	81,406	83,674
92,920	89,738	92,399	93,687	96,050	94,938	97,052	96,562	99,163
96,362	94,195	92,589	91,698	91,851	90,840	92,426	92,913	91,438
94,673	92,590	91,720	92,706	93,040	92,181	92,872	89,352	90,425
96,613	95,893	93,099	94,946	98,160	97,670	91,434	91,429	90,748
94,532	94,337	92,647	91,604	91,477	93,356	95,719	95,969	96,723
77,064	75,900	77,752	81,329	79,859	74,877	76,206	77,741	77,462
69,645	71,515	70,941	70,579	71,551	72,648	73,699	73,422	73,720
93,384	92,855	94,231	95,931	95,562	94,863	95,573	95,860	96,702
96,251	93,113	88,847	85,711	87,425	89,308	90,741	91,842	94,642
96,060	94,016	93,298	93,771	91,646	92,224	92,994	94,218	99,855
97,909	96,059	92,372	93,516	93,075	96,093	92,529	91,691	92,150
96,499	93,842	94,112	91,550	91,491	88,343	89,598	90,809	90,569
85,073	85,982	84,474	83,798	82,096	83,102	83,297	84,259	82,557
71,788	74,431	74,291	74,752	73,926	73,013	69,459	72,069	75,132
84,249	85,461	87,727	84,409	85,214	87,532	91,520	94,335	94,749
96,554	97,860	97,081	95,661	95,110	91,750	89,838	90,181	92,414
99,553	99,358	95,528	95,496	91,306	89,325	91,232	90,139	91,571
89,686	87,617	88,555	88,981	87,664	92,731	94,155	93,293	94,442
99,051	95,686	90,173	91,130	90,221	90,355	90,430	89,389	88,633
82,417	82,174	81,838	82,712	79,533	76,148	78,716	80,013	80,252
74,398	74,070	73,513	74,047	73,430	76,039	76,967	73,774	77,650
90,695	83,309	86,403	88,799	89,561	91,398	88,807	90,920	88,393
101,646	96,994	93,808	94,716	94,583	94,916	95,627	91,754	91,457
91,309	83,200	80,979	85,036	86,695	87,173	86,519	85,303	85,699
94,136	91,886	91,183	89,902	88,601	88,953	89,155	90,117	93,962
94,227	89,501	88,676	88,436	90,079	89,679	87,388	88,894	87,965
81,901	83,065	82,617	82,585	83,223	82,512	83,018	83,339	83,547
70,128	70,229	69,508	73,363	75,424	75,562	76,534	77,556	78,120
89,600	89,647	88,816	89,768	87,748	89,195	90,395	90,470	91,241
90,637	87,878	86,349	85,765	85,455	85,074	87,854	87,282	87,537

88,960	85,863	84,714	85,865	85,418	86,903	86,375	86,272	88,734
96,346	96,189	94,512	92,783	92,503	93,960	89,101	90,176	93,360
95,745	92,991	91,616	93,166	93,994	92,727	90,908	91,227	92,424
80,005	79,533	78,749	77,672	74,191	72,273	75,552	75,553	76,759
73,551	74,045	74,605	73,630	73,001	73,802	77,319	76,067	76,355
95,836	96,202	95,919	95,626	95,825	95,782	97,042	95,747	97,064
82,347	85,099	84,519	83,024	87,408	92,728	93,724	96,283	96,215
96,795	91,840	88,979	93,248	94,309	96,169	95,917	92,749	93,244
93,756	90,060	86,450	88,092	87,909	88,992	90,133	90,888	93,592
92,036	92,078	93,743	92,774	93,393	92,307	92,942	89,273	91,106
89,248	84,337	80,551	80,025	80,051	79,089	78,456	77,409	81,014
70,755	70,619	71,076	70,185	74,280	77,004	75,932	73,308	71,124
93,331	89,690	90,516	93,606	94,638	95,085	96,495	96,709	96,311
101,500	94,972	95,913	99,125	95,824	89,701	92,119	98,642	99,180
92,419	90,654	90,205	90,391	87,511	88,112	91,888	91,732	91,083
89,304	85,756	86,160	86,770	87,019	87,824	88,876	90,190	87,478
85,491	85,713	87,098	87,437	85,085	84,581	85,263	85,250	84,197
77,522	77,138	78,703	79,370	76,892	75,498	79,666	79,286	75,284
71,194	71,682	68,958	71,692	71,944	72,404	73,078	72,358	74,534
96,729	92,298	89,404	89,515	88,593	89,581	91,850	89,367	93,930
98,104	95,529	94,673	94,100	94,901	94,884	93,390	93,963	92,240
95,160	92,675	90,263	89,653	88,087	89,418	89,075	92,082	95,045
96,811	93,062	93,875	91,297	92,011	90,714	89,970	89,764	89,297
97,860	95,447	93,769	88,041	89,866	90,782	90,886	89,088	85,367
73,741	73,222	73,415	74,009	73,736	77,715	76,176	75,291	77,191
74,620	70,152	71,399	70,532	70,971	71,915	75,125	73,003	73,057
93,664	90,519	90,295	93,184	93,367	94,391	98,560	97,843	97,187
99,179	96,281	92,205	94,275	94,939	93,751	95,928	97,679	98,114
95,324	91,658	89,670	89,623	89,855	90,707	90,581	91,275	95,165
95,854	90,759	88,554	89,398	87,622	89,173	91,171	91,411	90,290
94,702	90,868	89,255	91,871	90,585	91,237	91,742	90,824	90,905
76,695	76,205	75,524	76,980	77,516	77,521	77,321	77,932	80,358
73,456	73,604	70,705	69,019	73,001	74,343	74,904	73,603	75,703
94,048	92,306	93,385	93,598	93,830	94,282	96,161	94,771	96,073
98,950	96,613	96,754	95,273	92,834	93,695	95,184	96,128	95,993
70,451	70,707	69,831	73,427	72,334	71,835	73,395	74,681	76,190
96,420	96,192	95,973	96,425	95,466	95,386	95,476	96,844	92,588
91,107	91,499	91,675	87,385	88,806	88,451	88,457	92,668	91,427
77,423	77,198	78,394	76,011	76,166	78,891	80,780	81,752	81,206
71,067	71,527	73,377	72,144	71,875	69,388	68,140	70,589	72,923
91,405	87,234	89,543	92,170	92,913	94,358	97,885	97,842	98,425
96,430	94,291	94,887	96,228	94,521	91,558	90,431	91,588	95,127
93,768	90,416	89,390	88,496	90,766	93,107	94,097	95,422	94,496
95,146	95,663	90,555	90,682	90,938	89,469	92,750	93,318	91,499
90,494	90,122	90,998	88,968	89,558	88,693	93,631	90,364	89,952
80,597	79,315	74,477	74,793	75,124	74,207	73,591	74,847	77,867
75,073	74,453	74,073	74,734	72,988	74,368	75,131	76,539	79,471

82,387	83,375	84,485	85,660	86,398	86,934	87,454	87,569	85,635
85,655	88,569	86,718	86,383	85,777	86,742	87,671	85,841	85,520
91,696	88,816	88,834	89,390	87,795	87,397	88,475	88,341	87,800
88,481	87,703	86,480	85,571	85,732	87,137	86,208	88,212	88,738
95,683	93,856	89,127	91,315	90,615	89,400	91,381	91,310	91,680
86,208	85,519	82,873	86,363	86,739	84,499	85,516	85,071	84,930
72,881	71,723	70,958	68,066	69,780	73,465	75,089	78,160	79,710
94,376	94,075	93,204	95,318	96,091	95,858	95,646	94,847	96,000
96,421	96,329	96,079	93,531	93,466	93,838	93,306	96,206	95,510
98,451	98,313	98,190	97,638	94,550	95,611	95,742	93,537	93,117
94,104	91,851	95,683	97,232	94,309	93,567	92,981	92,031	90,383
101,042	96,130	93,335	97,111	96,101	93,338	92,304	92,073	95,094
76,549	77,588	78,193	83,337	81,452	81,603	82,982	82,528	83,001
76,614	77,645	77,686	75,746	74,752	76,772	77,381	77,096	79,246
97,310	95,403	96,295	95,692	96,163	97,183	98,442	95,017	87,099
84,399	80,706	78,340	79,233	81,857	83,748	85,325	84,626	83,787
81,676	81,099	79,679	80,607	82,814	85,241	83,613	82,874	82,307
89,829	90,426	93,218	97,040	98,436	96,962	90,514	93,743	98,788
103,682	98,498	93,638	95,968	96,561	96,550	97,910	97,637	98,237
86,638	84,691	84,802	84,488	82,702	81,044	83,304	81,433	81,488
72,858	73,851	73,874	74,545	72,312	73,879	74,747	73,755	74,497
101,273	97,830	99,057	96,055	98,390	99,587	99,351	99,798	103,379
98,187	98,216	98,753	99,139	96,809	99,159	101,165	95,432	99,214
96,410	95,436	97,030	96,744	96,131	101,511	102,833	101,183	99,856
96,579	92,401	91,128	93,958	92,911	92,577	93,271	96,425	97,016
94,530	91,393	91,227	93,310	92,108	92,035	91,356	94,430	93,140
80,261	81,248	82,750	77,304	76,560	76,259	80,238	81,297	78,125
72,251	72,027	70,676	70,705	70,355	71,611	71,843	72,765	74,086
70,557	70,945	71,203	70,448	67,703	71,034	73,207	73,709	72,613
92,504	94,793	97,703	96,884	96,551	96,244	95,570	95,028	97,197
72,637	70,206	69,284	73,542	75,214	77,043	81,873	85,175	88,064
100,082	96,963	93,263	94,850	93,786	94,347	95,071	96,294	95,046
98,686	95,952	93,799	94,627	93,715	94,666	96,215	92,813	92,697
88,356	87,872	90,184	89,173	87,206	86,620	86,525	84,273	83,897
73,426	71,814	74,925	75,979	75,213	77,001	76,946	77,043	78,465
100,056	97,787	95,739	97,057	95,170	96,785	97,794	98,808	100,704
95,197	95,181	92,907	95,307	92,112	91,191	91,074	90,842	88,477
94,023	91,253	91,386	93,662	93,013	91,194	91,242	92,350	93,704
94,917	92,879	92,996	93,292	91,896	90,901	91,720	92,997	92,857
95,670	93,932	92,567	91,773	92,950	95,904	96,494	96,955	93,499
80,244	78,605	78,414	76,996	77,475	79,630	80,018	78,770	80,145
72,817	74,156	75,524	77,090	76,506	77,037	77,080	74,362	76,631
95,678	97,207	96,461	97,060	92,560	91,497	96,958	94,629	92,008
103,034	99,071	99,179	94,774	95,807	96,645	100,465	100,971	100,712
99,226	98,957	96,309	101,252	100,692	102,482	101,187	100,662	100,832
99,093	100,278	95,819	96,481	94,274	93,480	91,496	94,580	95,567
98,724	96,184	94,060	94,607	94,387	96,870	97,046	94,206	94,784

94,177	91,413	91,182	89,005	88,233	92,252	94,417	90,507	83,411
68,001	66,085	66,786	68,217	68,665	72,226	71,900	71,931	76,036
101,607	96,625	98,163	98,638	93,267	94,188	93,967	94,239	94,456
100,078	94,378	94,453	92,605	92,047	91,439	90,990	92,705	94,101
98,093	93,091	91,613	94,081	93,612	95,282	95,956	92,395	97,279
93,329	91,010	89,962	91,641	96,389	97,384	97,487	97,834	97,673
100,999	96,893	98,079	94,808	94,318	95,271	94,767	94,785	91,424
76,934	76,010	78,459	78,075	76,330	78,561	77,785	77,214	77,232
76,335	76,741	76,882	75,571	74,659	76,410	77,528	73,993	74,793
83,874	86,652	86,734	87,431	87,766	89,897	90,826	89,847	89,782
91,300	90,841	84,741	86,386	85,848	87,909	88,653	88,929	86,726
93,232	89,444	88,977	89,834	89,016	90,365	89,900	90,074	90,843
78,594	78,727	79,792	81,664	81,078	81,483	81,481	81,677	83,834
85,592	86,114	86,495	88,189	87,600	86,808	87,252	87,593	83,848
77,391	73,048	73,253	73,658	73,044	74,303	79,246	78,395	81,092
71,267	68,262	68,459	72,820	70,474	69,925	69,569	73,150	73,109
75,287	74,756	75,472	75,398	74,836	73,020	76,551	77,557	76,961
84,552	83,076	81,647	83,555	79,776	82,352	85,015	89,123	89,447
87,734	86,973	86,946	86,849	83,955	86,287	87,575	86,955	86,480
90,249	88,058	87,495	84,403	85,085	86,441	87,006	87,251	87,533
87,670	86,567	84,121	85,683	85,129	86,807	87,095	85,878	84,483
79,068	78,705	82,037	81,161	76,145	75,404	77,005	77,741	77,394
72,908	76,502	77,610	76,713	75,336	72,577	72,199	71,464	71,876
88,379	87,089	87,125	90,010	88,667	89,292	92,867	91,841	91,383
98,987	96,054	97,507	95,446	92,152	91,332	91,141	91,301	96,915
92,506	91,818	90,541	90,169	89,124	89,106	91,659	93,947	91,336
94,588	95,962	94,481	93,502	92,191	90,943	93,943	93,417	94,942
97,749	93,944	94,850	94,998	93,131	92,524	93,144	92,646	87,845
85,394	85,240	82,141	81,366	84,106	83,679	86,206	85,803	83,993
74,425	71,864	73,703	74,103	72,258	72,718	74,373	74,641	75,343
97,236	97,217	97,083	95,283	96,263	95,547	97,473	100,182	98,799
98,120	96,287	90,274	89,021	90,677	92,177	93,651	93,871	94,143
66,485	64,991	64,736	64,399	63,031	64,284	66,526	69,180	65,251
80,017	79,345	77,227	76,975	78,341	79,138	84,960	89,847	91,005
90,944	88,778	88,677	90,128	93,817	93,304	92,707	92,825	92,075
82,437	84,404	84,820	83,186	83,757	84,852	85,209	83,362	83,468
71,953	69,216	70,711	74,540	73,156	74,357	75,388	74,435	75,114
85,594	84,367	84,659	87,745	90,529	91,752	93,249	95,324	92,542
98,173	92,399	96,091	96,290	95,295	96,937	94,955	96,940	99,358
86,897	89,677	92,300	90,000	80,623	83,861	87,562	90,930	92,111
91,948	89,545	90,389	93,320	91,055	87,871	92,639	91,867	92,745
97,302	96,142	92,659	95,413	93,882	93,146	92,152	90,298	86,634
88,167	84,036	83,056	89,507	88,582	87,392	88,748	87,251	85,582
75,949	74,365	77,634	76,018	76,188	72,597	72,307	71,829	75,048
96,009	97,057	95,493	95,372	92,880	92,774	96,365	98,082	99,099
101,515	99,350	98,932	98,160	94,503	92,974	97,833	98,573	98,830
92,521	91,252	90,385	91,678	86,343	89,123	90,210	89,134	89,408

99,849	96,973	95,588	95,163	96,096	95,346	99,163	99,023	97,128
98,303	96,149	93,889	92,615	93,003	94,578	96,388	91,176	92,167
76,609	76,562	75,347	75,484	75,636	79,146	78,777	78,842	77,444
71,857	69,219	70,029	69,414	68,344	69,789	73,960	75,403	72,556
85,674	82,830	86,784	89,536	89,611	94,746	94,987	92,027	92,839
95,334	93,181	88,773	88,180	90,021	95,179	94,894	93,448	96,171
96,738	95,279	94,055	95,334	94,321	95,304	97,604	99,498	101,578
103,308	100,871	98,786	98,028	94,906	97,327	99,274	100,201	96,622
99,443	97,319	95,288	93,607	95,172	94,795	94,570	94,004	92,884
85,010	82,128	82,948	82,587	82,423	82,315	79,617	79,450	81,924
77,759	77,944	79,108	78,310	78,587	80,816	79,873	79,300	78,434
90,560	89,284	90,283	90,292	87,865	90,784	93,514	93,030	93,246
102,965	101,282	98,860	97,279	98,477	98,276	100,381	98,857	98,703
101,009	101,389	96,315	98,204	98,429	95,429	95,797	94,543	96,125
101,670	98,071	95,899	95,490	93,858	95,848	96,898	96,058	97,383
99,350	96,509	93,816	91,595	91,125	88,809	91,534	94,324	93,078
79,789	82,672	83,435	80,223	76,984	83,704	83,063	83,107	77,194
72,165	71,395	71,877	75,101	76,934	76,356	73,798	73,042	73,934
95,411	93,687	91,497	90,403	91,089	93,545	96,877	98,076	96,888
101,385	98,252	98,397	97,890	95,367	94,528	94,564	94,591	96,288
97,155	94,502	91,616	91,957	91,303	91,913	95,134	95,913	95,719
95,991	88,494	84,309	86,754	87,374	92,386	94,315	85,056	83,910
95,640	91,488	95,055	95,411	94,764	96,423	99,200	98,304	95,389
76,796	82,016	85,047	85,274	84,815	85,335	85,765	80,851	80,958
75,910	75,487	73,494	73,314	73,767	74,058	77,011	75,450	73,379
89,446	90,922	91,839	93,755	93,664	95,295	95,958	96,068	93,667
94,977	95,621	92,514	93,497	95,190	93,956	96,426	96,572	96,993
96,391	91,205	90,304	92,452	92,387	91,361	92,422	94,182	98,689
94,381	96,959	95,528	97,860	96,273	95,076	94,310	94,751	95,178
95,257	95,105	94,663	91,377	93,375	93,903	94,693	90,406	86,070
78,325	78,860	77,482	73,839	71,768	72,344	72,962	74,188	77,831
71,992	70,945	72,034	72,455	73,484	76,576	75,977	75,400	75,966
64,520	65,651	66,842	63,696	61,519	66,430	71,337	70,854	72,216
95,050	95,544	92,253	91,638	91,515	89,600	90,273	91,344	93,829
86,315	87,148	89,090	90,626	89,162	89,694	92,187	92,507	92,726
90,778	86,982	91,838	95,598	96,915	95,103	95,885	97,014	94,447
92,751	92,775	97,686	98,253	95,975	93,279	96,154	93,514	93,197
87,606	86,341	85,122	85,205	84,310	88,060	87,215	86,473	85,216
74,362	74,440	76,068	71,504	69,019	69,368	67,046	66,571	71,056
99,167	97,462	98,254	96,689	95,898	98,464	96,735	95,801	93,661
100,644	100,644	96,133	96,278	95,227	98,602	101,823	102,626	100,987
95,129	94,006	91,689	92,374	90,422	91,371	93,067	93,918	97,348
98,190	94,893	94,375	98,873	97,084	97,925	100,108	98,727	102,311
101,505	96,902	93,907	98,844	97,474	97,342	99,230	97,955	95,939
88,211	85,499	84,640	86,578	84,899	86,565	85,506	85,661	83,469
77,239	74,773	75,360	74,484	75,273	75,367	75,095	74,680	76,279
100,284	92,339	91,738	95,183	93,591	94,721	96,392	99,127	100,050

105,314	97,596	93,833	97,982	95,777	95,603	95,115	93,264	98,078
99,355	97,193	95,859	95,910	94,905	96,823	97,668	97,128	97,448
103,733	99,863	99,894	96,681	95,836	96,299	99,002	99,607	95,729
106,243	103,235	99,654	98,985	99,589	100,325	99,878	100,199	98,501
90,005	90,756	91,561	89,382	89,247	88,780	89,305	88,992	82,629
80,552	79,005	78,829	75,891	72,569	72,283	73,361	73,782	74,311
98,629	96,714	96,271	96,703	94,771	98,705	100,266	100,505	97,051
103,436	98,806	99,967	101,343	99,546	104,153	104,543	103,702	102,795
98,994	96,176	93,196	93,028	92,809	94,176	94,860	95,067	95,080
99,384	97,004	96,231	95,995	95,036	94,733	96,076	93,831	93,286
97,722	94,294	96,518	96,312	94,646	95,198	94,185	91,296	92,062
74,587	75,478	75,708	74,404	73,930	74,266	78,827	80,490	80,892
72,715	73,076	73,328	73,949	73,800	74,364	74,419	74,677	74,918
91,325	90,404	91,021	92,268	90,489	92,079	92,544	87,396	89,857
95,761	96,754	96,205	95,136	94,429	98,373	98,706	96,315	95,936
98,255	92,673	94,768	96,318	96,201	93,970	92,455	92,234	92,913
92,236	92,336	92,739	91,616	91,710	92,387	92,437	93,574	96,016
98,348	95,124	92,208	92,587	91,638	92,392	92,349	89,195	84,806
77,683	74,807	72,514	72,610	71,418	71,175	75,127	76,542	75,186
71,208	71,657	70,589	69,117	71,247	72,670	72,668	72,670	72,842
91,039	86,401	90,191	91,746	90,285	91,435	93,545	90,059	87,495
102,245	98,628	95,414	97,441	97,252	98,552	100,264	99,748	99,103
92,612	91,591	89,843	89,180	88,390	89,032	90,744	88,293	86,735
96,452	95,889	96,999	97,486	97,271	100,761	102,224	101,256	98,912
101,499	100,892	98,113	98,791	96,195	92,658	89,683	87,947	87,020
82,144	81,013	80,340	80,816	81,410	82,855	76,704	76,773	74,921
75,837	73,523	75,925	74,825	75,152	74,698	73,297	72,984	73,955
93,065	91,027	89,964	88,063	90,025	90,584	90,450	91,982	93,498
102,846	94,949	94,389	95,155	93,943	94,901	101,429	102,597	101,192
96,690	93,163	93,748	97,839	98,253	100,487	99,429	101,611	99,033
100,116	95,724	95,602	95,279	98,931	97,910	95,190	93,357	97,269
101,973	96,712	93,094	89,600	89,005	88,418	88,729	91,765	89,962
83,740	80,470	80,728	84,112	84,264	84,374	83,456	80,987	79,937
69,138	70,445	69,052	69,902	68,897	69,911	69,953	70,701	74,785
85,791	84,513	84,779	84,349	84,811	86,849	88,520	88,111	86,299
93,605	89,535	89,308	90,735	90,756	91,040	90,125	89,079	89,755
91,904	90,276	91,623	91,697	90,880	91,660	92,165	91,579	91,233
91,702	89,617	87,145	85,724	84,298	83,903	84,002	84,437	83,592
81,735	76,020	72,561	75,737	74,539	73,386	75,041	74,271	73,795
62,415	63,050	63,367	63,553	63,027	63,428	64,287	63,439	62,300
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90,069			
84,737	2,085,553	4,618,761	#######
84,853	2,037,975	4,496,569	#######
72,725	1,846,553	4,332,424	#######
77,125	1,759,379	4,325,377	#######
93,455	2,116,976	5,025,195	#######
95,056	2,248,905	5,033,179	#######
94,501	2,158,126	4,628,536	#######
90,777	2,215,149	4,523,160	#######
81,769	2,187,766	4,792,502	#######
74,391	1,802,781	4,617,451	#######
75,853	1,764,327	4,531,708	#######
96,084	2,155,085	4,806,785	#######
97,017	2,268,685	5,032,233	#######
96,355	2,187,784	5,232,098	#######
90,156	2,196,471	5,289,633	#######
88,327	2,187,983	4,980,069	#######
79,224	1,881,398	4,266,565	#######
75,928	1,789,020	4,423,337	#######
96,756	2,170,607	4,677,362	#######
95,462	2,250,656	4,592,664	#######
77,840	1,781,161	4,656,938	#######
91,419	2,213,896	4,695,046	#######
89,069	2,144,340	4,874,340	#######
77,641	1,975,610	4,544,136	#######
76,346	1,770,504	4,269,391	#######
92,571	2,156,244	4,716,175	#######
92,617	2,213,874	4,899,722	#######
92,323	2,170,894	4,878,846	#######
94,414	2,181,824	4,754,212	#######
84,049	2,133,686	4,915,877	#######
78,438			#######
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86,289
91,914
83,838
82,934
81,882
71,187
79,594
88,965
90,189
87,846
79,072
76,930
77,445
91,506
99,146
88,834
94,594
87,379
79,802
73,703
94,491
90,393
64,380
92,349
89,585
81,645
77,925
90,458
100,362
94,933
91,719
85,996
81,466
76,450
96,127
98,860
90,566

97,600
90,694
76,217
73,186
90,741
94,442
97,599
95,705
89,834
81,323
77,519
94,015
99,097
93,589
95,083
86,988
75,785
75,525
95,003
98,896
93,712
92,549
90,504
84,576
75,446
92,599
96,993
98,318
93,665
82,335
74,741
72,047
70,824
92,388
92,337
93,976
92,578
83,036
74,436
96,043
98,786
95,478
99,925
90,630
83,752
78,554
99,364

99,725
96,296
90,094
97,708
81,287
77,228
95,181
101,393
94,728
93,528
86,418
81,443
76,652
90,540
95,033
93,352
94,599
80,955
67,918
73,918
87,113
94,158
85,144
96,281
84,230
73,053
76,944
95,967
99,290
97,091
95,641
86,285
77,984
76,581
85,799
90,230
89,539
84,090
71,428
61,919
61,983

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Description	Name	Functional Vector	Total System	Production Demand	Production Energy	Steam Direct	Transmission Demand
Plant in Service							
Intangible Plant	INTPLT	PT&D	$ 66,895	58,634	-	-	8,261
Production Plant	PPROD	F001	$ 1,686,796,955	1,686,796,955	-	-	-
Transmission Plant	PTRAN	F002	$ 237,659,206	-	-	-	237,659,206
Distribution Plant	PDIST	F003	$ -	-	-	-	-
Total Production & Transmission Plant	PT&D		1,924,456,160	1,686,796,955	-	-	237,659,206
General Plant	PGP	PT&D	$ 18,511,051	16,225,043	-	-	2,286,008
Total Plant in Service	TPIS		$ 1,943,034,107	$ 1,703,080,632	$ -	$ -	$ 239,953,475
Construction Work in Progress (CWIP)							
CWIP Production	CWIP1	PPROD	$ 22,411,274	22,411,274	-	-	-
CWIP Transmission	CWIP2	PTRAN	$ 7,475,859	-	-	-	7,475,859
CWIP Distribution Plant	CWIP3	PDIST	$ -	-	-	-	-
CWIP General Plant	CWIP4	PT&D	$ 16,915,005	14,826,100	-	-	2,088,905
Total Construction Work in Progress	TCWIP		$ 46,802,138	$ 37,237,374	$ -	$ -	$ 9,564,764
Total Utility Plant			$ 1,989,836,245	$ 1,740,318,006	$ -	$ -	$ 249,518,239

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Description	Name	Functional Vector	Total System	Production Demand	Production Energy	Steam Direct	Transmission Demand
Rate Base							
Total Utility Plant	TUP		$ 1,989,836,245	$ 1,740,318,006	$ -	$ -	$ 249,518,239
Less: Acummulated Provision for Depreciation							
Production	ADEPREPA	PPROD	$ 790,847,523	790,847,523	-	-	-
Transmission	ADEPRTP	PTRAN	$ 107,564,747	-	-	-	107,564,747
Distribution	ADEPRD11	PDIST	$ -	-	-	-	-
General & Common Plant	ADEPRD12	PT&D	$ 6,300,770	5,522,661	-	-	778,109
Intangible, Misc, and Other Plant	ADEPRGP	PT&D	$ -	-	-	-	-
Retirement Work In Progress	ADEPRRT	PT&D	$ -	-	-	-	-
Total Accumulated Depreciation	TADEPR		$ 904,713,040	$ 796,370,184	$ -	$ -	$ 108,342,855
Net Utility Plant	NTPLANT		$ 1,085,123,206	$ 943,947,822	$ -	$ -	$ 141,175,384
Working Capital							
Cash Working Capital - Operation and Maintenance Expenses	CWC	OMLPP	$ 28,114,365	13,900,247	11,969,243	-	2,244,875
Materials and Supplies	M&S	TPIS	$ 22,777,820	19,964,891	-	-	2,812,929
Fuel Stock	PREPAY	TPIS	$ 34,326,112	30,087,036	-	-	4,239,076
Total Working Capital	TWC		$ 85,218,297	$ 63,952,174	$ 11,969,243	$ -	$ 9,296,880
Net Rate Base	RB		$ 1,170,341,502	$ 1,007,899,995	$ 11,969,243	$ -	$ 150,472,264

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Description	Name	Functional Vector	Total System	Production Demand	Production Energy	Steam Direct	Transmission Demand
Operation and Maintenance Expenses							
Steam Power Generation Operation Expenses							
500 OPERATION SUPERVISION & ENGINEERING	OM500	PROFIX	$ 4,974,566	4,974,566	-	-	-
501 FUEL	OM501	Energy	$ 200,919,367	-	200,919,367	-	-
502 STEAM EXPENSES	OM502	PROFIX	$ 34,453,882	34,453,882	-	-	-
505 ELECTRIC EXPENSES	OM505	PROFIX	$ 5,730,122	5,730,122	-	-	-
506 MISC. STEAM POWER EXPENSES	OM506	PROFIX	$ 7,451,302	7,451,302	-	-	-
507 RENTS	OM507	PROFIX	$ -	-	-	-	-
509 ALLOWANCES	OM509	Energy	$ 429,682	-	429,682	-	-
Total Steam Power Operation Expenses			$ 253,958,921	$ 52,609,872	$ 201,349,049	$ -	$ -
Steam Power Generation Maintenance Expenses							
510 MAINTENANCE SUPERVISION & ENGINEERING	OM510	Energy	$ 3,631,867	-	3,631,867	-	-
511 MAINTENANCE OF STRUCTURES	OM511	PROFIX	$ 3,346,806	3,346,806	-	-	-
512 MAINTENANCE OF BOILER PLANT	OM512	Energy	$ 30,113,309	-	30,113,309	-	-
513 MAINTENANCE OF ELECTRIC PLANT	OM513	Energy	$ 6,251,804	-	6,251,804	-	-
514 MAINTENANCE OF MISC STEAM PLANT	OM514	PROFIX	$ 877,364	877,364	-	-	-
Total Steam Power Generation Maintenance Expense			$ 44,221,151	$ 4,224,170	$ 39,996,981	$ -	$ -
Total Steam Power Generation Expense			$ 298,180,072	$ 56,834,042	$ 241,346,030	$ -	$ -

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Description	Name	Functional Vector		Total System		Production Demand		Production Energy		Steam Direct		Transmission Demand
Operation and Maintenance Expenses (Continued)												
Other Power Generation Operation Expense												
546 OPERATION SUPERVISION & ENGINEERING	OM546	PROFIX	$	-		-		-		-		-
547 FUEL	OM547	Energy	$	706,789		-		706,789		-		-
548 GENERATION EXPENSE	OM548	PROFIX	$	34,608		34,608		-		-		-
549 MISC OTHER POWER GENERATION	OM549	PROFIX	$	-		-		-		-		-
550 RENTS	OM550	PROFIX	$	-		-		-		-		-
Total Other Power Generation Expenses			$	741,396	$	34,608	$	706,789	$	-	$	-
Other Power Generation Maintenance Expense												
551 MAINTENANCE SUPERVISION & ENGINEERING	OM551	PROFIX	$	-		-		-		-		-
552 MAINTENANCE OF STRUCTURES	OM552	PROFIX	$	-		-		-		-		-
553 MAINTENANCE OF GENERATING & ELEC PLANT	OM553	PROFIX	$	625,088		625,088		-		-		-
554 MAINTENANCE OF MISC OTHER POWER GEN PLT	OM554	PROFIX	$	-		-		-		-		-
Total Other Power Generation Maintenance Expense			$	625,088	$	625,088	$	-	$	-	$	-
Total Other Power Generation Expense			$	1,366,485	$	659,696	$	706,789	$	-	$	-
Total Station Expense			$	299,546,557	$	57,493,738	$	242,052,819	$	-	$	-

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Description	Name	Functional Vector	Total System	Production Demand	Production Energy	Steam Direct	Transmission Demand
Operation and Maintenance Expenses (Continued)							
Other Power Supply Expenses							
555 PURCHASED POWER Energy	OM555	OMPP	$ 19,466,790	-	19,466,790	-	-
555 PURCHASED POWER Demand	OMD555	OMPPD	$ 4,210,045	4,210,045	-	-	-
555 PURCHASED POWER BREC Share of HMP&L Station Two	OMH555	OMPPH	$ 58,293,374	13,175,571	45,117,803	-	-
555 PURCHASED POWER OPTIONS	OMO555	OMPP	$ -	-	-	-	-
555 BROKERAGE FEES	OMB555	OMPP	$ -	-	-	-	-
555 MISO TRANSMISSION EXPENSES	OMM555	OMPP	$ -	-	-	-	-
556 SYSTEM CONTROL AND LOAD DISPATCH	OM556	PROFIX	$ 909,422	909,422	-	-	-
557 OTHER EXPENSES	OM557	PROFIX	$ 20,575,465	20,575,465	-	-	-
558 DUPLICATE CHARGES	OM558	Energy	$ -	-	-	-	-
Total Other Power Supply Expenses	TPP		$ 103,455,096	$ 38,870,503	$ 64,584,593	$ -	$ -
Total Electric Power Generation Expenses			$ 403,001,653	$ 96,364,241	$ 306,637,411	$ -	$ -
Transmission Expenses							
560 OPERATION SUPERVISION AND ENG	OM560	LBTRAN	$ 876,815	-	-	-	876,815
561 LOAD DISPATCHING	OM561	LBTRAN	$ 1,454,938	-	-	-	1,454,938
562 STATION EXPENSES	OM562	PTRAN	$ 1,163,408	-	-	-	1,163,408
563 OVERHEAD LINE EXPENSES	OM563	PTRAN	$ 1,090,014	-	-	-	1,090,014
565 TRANSMISSION OF ELECTRICITY BY OTHERS	OM565	PTRAN	$ 3,065,817	-	-	-	3,065,817
566 MISC. TRANSMISSION EXPENSES	OM566	PTRAN	$ 475,381	-	-	-	475,381
567 RENTS	OM567	PTRAN	$ 24,701	-	-	-	24,701
568 MAINTENACE SUPERVISION AND ENG	OM568	LBTRAN	$ 647,227	-	-	-	647,227
569 STRUCTURES	OM569	PTRAN	$ 26,913	-	-	-	26,913
570 MAINT OF STATION EQUIPMENT	OM570	PTRAN	$ 1,936,760	-	-	-	1,936,760
571 MAINT OF OVERHEAD LINES	OM571	PTRAN	$ 2,876,462	-	-	-	2,876,462
572 UNDERGROUND LINES	OM572	PTRAN	$ -	-	-	-	-
573 MISC PLANT	OM573	PTRAN	$ 97,880	-	-	-	97,880
Total Transmission Expenses			$ 13,736,318	$ -	$ -	$ -	$ 13,736,318
Distribution Operation Expense							
580 OPERATION SUPERVISION AND ENGI	OM580	LBDO	$ -	-	-	-	-
581 LOAD DISPATCHING	OM581	PDIST	$ -	-	-	-	-
582 STATION EXPENSES	OM582	PDIST	$ -	-	-	-	-
583 OVERHEAD LINE EXPENSES	OM583	PDIST	$ -	-	-	-	-
584 UNDERGROUND LINE EXPENSES	OM584	PDIST	$ -	-	-	-	-
585 STREET LIGHTING EXPENSE	OM585	PDIST	$ -	-	-	-	-
586 METER EXPENSES	OM586	PDIST	$ -	-	-	-	-
586 METER EXPENSES - LOAD MANAGEMENT	OM586x	PDIST	$ -	-	-	-	-
587 CUSTOMER INSTALLATIONS EXPENSE	OM587	PDIST	$ -	-	-	-	-
588 MISCELLANEOUS DISTRIBUTION EXP	OM588	PDIST	$ -	-	-	-	-
588 MISC DISTR EXP -- MAPPIN	OM588x	PDIST	$ -	-	-	-	-
589 RENTS	OM589	PDIST	$ -	-			
Total Distribution Operation Expense	OMDO		$ -	$ -	$ -	$ -	$ -

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Description	Name	Functional Vector	Total System	Production Demand	Production Energy	Steam Direct	Transmission Demand
Operation and Maintenance Expenses (Continued)							
Distribution Maintenance Expense							
590 MAINTENANCE SUPERVISION AND EN	OM590	LBDM	$ -	-	-	-	-
591 STRUCTURES	OM591	PDIST	$ -	-	-	-	-
592 MAINTENANCE OF STATION EQUIPME	OM592	PDIST	$ -	-	-	-	-
593 MAINTENANCE OF OVERHEAD LINES	OM593	PDIST	$ -	-	-	-	-
594 MAINTENANCE OF UNDERGROUND LIN	OM594	PDIST	$ -	-	-	-	-
595 MAINTENANCE OF LINE TRANSFORME	OM595	PDIST	$ -	-	-	-	-
596 MAINTENANCE OF ST LIGHTS & SIG SYSTEMS	OM596	PDIST	$ -	-	-	-	-
597 MAINTENANCE OF METERS	OM597	PDIST	$ -	-	-	-	-
598 MISCELLANEOUS DISTRIBUTION EXPENSES	OM598	PDIST	$ -	-	-	-	-
Total Distribution Maintenance Expense	OMDM		$ -	$ -	$ -	$ -	$ -
Total Distribution Operation and Maintenance Expenses			-	-	-	-	-
Transmission and Distribution Expenses			13,736,318	-	-	-	13,736,318
Production, Transmission and Distribution Expenses	OMSUB		$ 416,737,971	$ 96,364,241	$ 306,637,411	$ -	$ 13,736,318
Customer Accounts Expense							
901 SUPERVISION/CUSTOMER ACCTS	OM901	F025	$ -	-	-	-	-
902 METER READING EXPENSES	OM902	F025	$ -	-	-	-	-
903 RECORDS AND COLLECTION	OM903	F025	$ -	-	-	-	-
904 UNCOLLECTIBLE ACCOUNTS	OM904	F025	$ -	-	-	-	-
905 MISC CUST ACCOUNTS	OM903	F025	$ -	-	-	-	-
Total Customer Accounts Expense	OMCA		$ -	$ -	$ -	$ -	$ -
Customer Service Expense							
907 SUPERVISION	OM907	TUP	$ -	-	-	-	-
908 CUSTOMER ASSISTANCE EXPENSES	OM908	TUP	$ 591,192	517,058	-	-	74,133
908 CUSTOMER ASSISTANCE EXP-INCENTIVES	OM908x	TUP	$ -	-	-	-	-
909 INFORMATIONAL AND INSTRUCTIONA	OM909	TUP	$ -	-	-	-	-
909 INFORM AND INSTRUC -LOAD MGMT	OM909x	TUP	$ -	-	-	-	-
910 MISCELLANEOUS CUSTOMER SERVICE	OM910	TUP	$ -	-	-	-	-
911 DEMONSTRATION AND SELLING EXP	OM911	TUP	$ -	-	-	-	-
912 DEMONSTRATION AND SELLING EXP	OM912	TUP	$ -	-	-	-	-
913 ADVERTISING EXPENSES	OM913	TUP	$ 488,103	426,897	-	-	61,206
915 MDSE-JOBBING-CONTRACT	OM915	TUP	$ -	-	-	-	-
916 MISC SALES EXPENSE	OM916	TUP	$ -	-	-	-	-
Total Customer Service Expense	OMCS		$ 1,079,295	$ 943,955	$ -	$ -	$ 135,340
Sub-Total Prod, Trans, Dist, Cust Acct and Cust Service	OMSUB2		417,817,266	97,308,197	306,637,411	-	13,871,658

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Description	Name	Functional Vector	Total System	Production Demand	Production Energy	Steam Direct	Transmission Demand
Operation and Maintenance Expenses (Continued)							
Administrative and General Expense							
920 ADMIN. & GEN. SALARIES-	OM920	LBSUB9	$ 14,315,713	6,663,061	5,595,161	-	2,057,491
921 OFFICE SUPPLIES AND EXPENSES	OM921	LBSUB9	$ 6,915,648	3,218,798	2,702,915	-	993,935
922 ADMINISTRATIVE EXPENSES TRANSFERRED	OM922	LBSUB9	$ -	-	-	-	-
923 OUTSIDE SERVICES EMPLOYED	OM923	LBSUB9	$ 3,954,189	1,840,425	1,545,457	-	568,306
924 PROPERTY INSURANCE	OM924	TUP	$ -	-	-	-	-
925 INJURIES AND DAMAGES - INSURAN	OM925	LBSUB9	$ 179,889	83,727	70,308	-	25,854
926 EMPLOYEE BENEFITS	OM926	LBSUB9	$ 169,663	78,967	66,311	-	24,384
927 FRANCHISE REQUIREMENTS	OM927	TUP	$ -	-	-	-	-
928 REGULATORY COMMISSION FEES	OM928	TUP	$ 1,188,958	1,039,867	-	-	149,091
929 DUPLICATE CHARGES-CR	OM929	LBSUB9	$ -	-	-	-	-
930 MISCELLANEOUS GENERAL EXPENSES	OM930	LBSUB9	$ 1,686,131	784,788	659,008	-	242,335
931 RENTS AND LEASES	OM931	PGP	$ 1,933	1,694	-	-	239
935 MAINTENANCE OF GENERAL PLANT	OM935	PGP	$ 208,156	182,450	-	-	25,706
Total Administrative and General Expense	OMAG		$ 28,620,280	$ 13,893,778	$ 10,639,160	$ -	$ 4,087,342
Total Operation and Maintenance Expenses	TOM		$ 446,437,546	$ 111,201,975	$ 317,276,572	$ -	$ 17,959,000
Operation and Maintenance Expenses Less Purchase Power & Fuel	OMLPP		$ 224,914,919	$ 111,201,975	$ 95,753,945	$ -	$ 17,959,000

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Description	Name	Functional Vector		Total System		Production Demand		Production Energy		Steam Direct		Transmission Demand
Labor Expenses												
Steam Power Generation Operation Expenses												
500 OPERATION SUPERVISION & ENGINEERING	LB500	PROFIX	$	4,967,667		4,967,667		-		-		-
501 FUEL	LB501	Energy	$	3,889,944		-		3,889,944		-		-
502 STEAM EXPENSES	LB502	PROFIX	$	9,023,322		9,023,322		-		-		-
505 ELECTRIC EXPENSES	LB505	PROFIX	$	4,523,897		4,523,897		-		-		-
506 MISC. STEAM POWER EXPENSES	LB506	PROFIX	$	940,518		940,518		-		-		-
507 RENTS	LB507	PROFIX	$	-		-		-		-		-
509 ALLOWANCES	LB509	Energy	$	-		-		-		-		-
Total Steam Power Operation Expenses	LBSUB1		$	23,345,348	$	19,455,404	$	3,889,944	$	-	$	-
Steam Power Generation Maintenance Expenses												
510 MAINTENANCE SUPERVISION & ENGINEERING	LB510	Energy	$	3,623,969		-		3,623,969		-		-
511 MAINTENANCE OF STRUCTURES	LB511	PROFIX	$	986,831		986,831		-		-		-
512 MAINTENANCE OF BOILER PLANT	LB512	Energy	$	8,700,235		-		8,700,235		-		-
513 MAINTENANCE OF ELECTRIC PLANT	LB513	Energy	$	1,595,642		-		1,595,642		-		-
514 MAINTENANCE OF MISC STEAM PLANT	LB514	PROFIX	$	200,886		200,886		-		-		-
Total Steam Power Generation Maintenance Expense	LBSUB2		$	15,107,564	$	1,187,718	$	13,919,846	$	-	$	-
Total Steam Power Generation Expense			$	38,452,913	$	20,643,122	$	17,809,791	$	-	$	-

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Description	Name	Functional Vector		Total System		Production Demand		Production Energy		Steam Direct		Transmission Demand
Labor Expenses (Continued)												
Other Power Generation Operation Expense												
546 OPERATION SUPERVISION & ENGINEERING	LB546	PROFIX	$	-		-		-		-		-
547 FUEL	LB547	Energy	$	-		-		-		-		-
548 GENERATION EXPENSE	LB548	PROFIX	$	-		-		-		-		-
549 MISC OTHER POWER GENERATION	LB549	PROFIX	$	-		-		-		-		-
550 RENTS	LB550	PROFIX	$	-		-		-		-		-
Total Other Power Generation Expenses	LBSUB7		$	-	$	-	$	-	$	-	$	-
Other Power Generation Maintenance Expense												
551 MAINTENANCE SUPERVISION & ENGINEERING	LB551	PROFIX	$	-		-		-		-		-
552 MAINTENANCE OF STRUCTURES	LB552	PROFIX	$	-		-		-		-		-
553 MAINTENANCE OF GENERATING & ELEC PLANT	LB553	PROFIX	$	89,555		89,555		-		-		-
554 MAINTENANCE OF MISC OTHER POWER GEN PLT	LB554	PROFIX	$	-		-		-		-		-
Total Other Power Generation Maintenance Expense	LBSUB8		$	89,555	$	89,555	$	-	$	-	$	-
Total Other Power Generation Expense			$	89,555	$	89,555	$	-	$	-	$	-
Total Production Expense	LPREX		$	38,542,468	$	20,732,677	$	17,809,791	$	-	$	-

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Description	Name	Functional Vector	Total System	Production Demand	Production Energy	Steam Direct	Transmission Demand
Labor Expenses (Continued)							
Purchased Power							
555 PURCHASED POWER Energy	LB555	OMPP	$ -	-	-	-	-
555 PURCHASED POWER Demand	LBD555	OMPPD	$ -	-	-	-	-
555 PURCHASED POWER OPTIONS	LBO555	OMPP	$ -	-	-	-	-
555 BROKERAGE FEES	LBB555	OMPP	$ -	-	-	-	-
555 MISO TRANSMISSION EXPENSES	LBM555	OMPP	$ -	-	-	-	-
556 SYSTEM CONTROL AND LOAD DISPATCH	LB556	PROFIX	$ -	-	-	-	-
557 OTHER EXPENSES	LB557	PROFIX	$ -	-	-	-	-
558 DUPLICATE CHARGES	LB558	Energy	$ -	-	-	-	-
Total Purchased Power Labor	LBPP		$ -	$ -	$ -	$ -	$ -
Transmission Labor Expenses							
560 OPERATION SUPERVISION AND ENG	LB560	PTRAN	$ 835,977	-	-	-	835,977
561 LOAD DISPATCHING	LB561	PTRAN	$ 1,304,969	-	-	-	1,304,969
562 STATION EXPENSES	LB562	PTRAN	$ 598,382	-	-	-	598,382
563 OVERHEAD LINE EXPENSES	LB563	PTRAN	$ 236,393	-	-	-	236,393
565 TRANSMISSION OF ELECTRICITY BY OTHERS	LB565	PTRAN	$ -	-	-	-	-
566 MISC. TRANSMISSION EXPENSES	LB566	PTRAN	$ 312,375	-	-	-	312,375
567 RENTS	LB567	PTRAN	$ -	-	-	-	-
568 MAINTENACE SUPERVISION AND ENG	LB568	PTRAN	$ 644,925	-	-	-	644,925
569 MAINTENACE OF STRUCTURES	LB569	PTRAN	$ 318	-	-	-	318
570 MAINT OF STATION EQUIPMENT	LB570	PTRAN	$ 1,433,304	-	-	-	1,433,304
571 MAINT OF OVERHEAD LINES	LB571	PTRAN	$ 1,067,766	-	-	-	1,067,766
573 MAINT OF MISC. TRANSMISSION PLANT	LB573	PTRAN	$ 46,439	-	-	-	46,439
Total Transmission Labor Expenses	LBTRAN		$ 6,480,848	$ -	$ -	$ -	$ 6,480,848
Distribution Operation Labor Expense							
580 OPERATION SUPERVISION AND ENGI	LB580	F023	$ -	-	-	-	-
581 LOAD DISPATCHING	LB581	PDIST	$ -	-	-	-	-
582 STATION EXPENSES	LB582	PDIST	$ -	-	-	-	-
583 OVERHEAD LINE EXPENSES	LB583	PDIST	$ -	-	-	-	-
584 UNDERGROUND LINE EXPENSES	LB584	PDIST	$ -	-	-	-	-
585 STREET LIGHTING EXPENSE	LB585	PDIST	$ -	-	-	-	-
586 METER EXPENSES	LB586	PDIST	$ -	-	-	-	-
586 METER EXPENSES - LOAD MANAGEMENT	LB586x	PDIST	$ -	-	-	-	-
587 CUSTOMER INSTALLATIONS EXPENSE	LB587	PDIST	$ -	-	-	-	-
588 MISCELLANEOUS DISTRIBUTION EXP	LB588	PDIST	$ -	-	-	-	-
589 RENTS	LB589	PDIST	$ -	-	-	-	-
Total Distribution Operation Labor Expense	LBDO		$ -	$ -	$ -	$ -	$ -

BIG RIVERS ELECTRIC CORPORATION
Cost of Service Study
Functional Assignment and Classification

12 Months Ended
October 2010

Description	Name	Functional Vector	Total System	Production Demand	Production Energy	Steam Direct	Transmission Demand
Labor Expenses (Continued)							
Distribution Maintenance Labor Expense							
590 MAINTENANCE SUPERVISION AND EN	LB590	F024	$ -	-	-	-	-
591 MAINTENANCE OF STRUCTURES	LB591	PDIST	$ -	-	-	-	-
592 MAINTENANCE OF STATION EQUIPME	LB592	PDIST	$ -	-	-	-	-
593 MAINTENANCE OF OVERHEAD LINES	LB593	PDIST	$ -	-	-	-	-
594 MAINTENANCE OF UNDERGROUND LIN	LB594	PDIST	$ -	-	-	-	-
595 MAINTENANCE OF LINE TRANSFORME	LB595	PDIST	$ -	-	-	-	-
596 MAINTENANCE OF ST LIGHTS & SIG SYSTEMS	LB596	PDIST	$ -	-	-	-	-
597 MAINTENANCE OF METERS	LB597	PDIST	$ -	-	-	-	-
598 MAINTENANCE OF MISC DISTR PLANT	LB598	PDIST	$ -	-	-	-	-
Total Distribution Maintenance Labor Expense	LBDM		$ -	$ -	$ -	$ -	$ -
Total Distribution Operation and Maintenance Labor Expenses		PDIST	-	-	-	-	-
Transmission and Distribution Labor Expenses			6,480,848	-	-	-	6,480,848
Production, Transmission and Distribution Labor Expenses	LBSUB		$ 45,023,316	$ 20,732,677	$ 17,809,791	$ -	$ 6,480,848
Customer Accounts Expense							
901 SUPERVISION/CUSTOMER ACCTS	LB901	F025	$ -	-	-	-	-
902 METER READING EXPENSES	LB902	F025	$ -	-	-	-	-
903 RECORDS AND COLLECTION	LB903	F025	$ -	-	-	-	-
904 UNCOLLECTIBLE ACCOUNTS	LB904	F025	$ -	-	-	-	-
905 MISC CUST ACCOUNTS	LB903	F025	$ -	-	-	-	-
Total Customer Accounts Labor Expense	LBCA		$ -	$ -	$ -	$ -	$ -
Customer Service Expense							
907 SUPERVISION	LB907	TUP	$ -	-	-	-	-
908 CUSTOMER ASSISTANCE EXPENSES	LB908	TUP	$ 544,608	476,316	-	-	68,292
908 CUSTOMER ASSISTANCE EXP-LOAD MGMT	LB908x	TUP	$ -	-	-	-	-
909 INFORMATIONAL AND INSTRUCTIONA	LB909	TUP	$ -	-	-	-	-
909 INFORM AND INSTRUC -LOAD MGMT	LB909x	TUP	$ -	-	-	-	-
910 MISCELLANEOUS CUSTOMER SERVICE	LB910	TUP	$ -	-	-	-	-
911 DEMONSTRATION AND SELLING EXP	LB911	TUP	$ -	-	-	-	-
912 DEMONSTRATION AND SELLING EXP	LB912	TUP	$ -	-	-	-	-
913 WATER HEATER - HEAT PUMP PROGRAM	LB913	TUP	$ -	-	-	-	-
915 MDSE-JOBBING-CONTRACT	LB915	TUP	$ -	-	-	-	-
916 MISC SALES EXPENSE	LB916	TUP	$ -	-	-	-	-
Total Customer Service Labor Expense	LBCS		$ 544,608	$ 476,316	$ -	$ -	$ 68,292
Sub-Total Labor Exp	LBSUB9		45,567,924	21,208,994	17,809,791	-	6,549,140

BIG RIVERS ELECTRIC CORPORATION
Cost of Service Study
Functional Assignment and Classification

12 Months Ended
October 2010

Description	Name	Functional Vector	Total System	Production Demand	Production Energy	Steam Direct	Transmission Demand
Labor Expenses (Continued)							
Administrative and General Expense							
920 ADMIN. & GEN. SALARIES-	LB920	LBSUB9	$ 14,315,714	6,663,061	5,595,161	-	2,057,491
921 OFFICE SUPPLIES AND EXPENSES	LB921	LBSUB9	$ -	-	-	-	-
922 ADMIN. EXPENSES TRANSFERRED - CREDIT	LB922	LBSUB9	$ -	-	-	-	-
923 OUTSIDE SERVICES EMPLOYED	LB923	LBSUB9	$ -	-	-	-	-
924 PROPERTY INSURANCE	LB924	TUP	$ -	-	-	-	-
925 INJURIES AND DAMAGES - INSURAN	LB925	LBSUB9	$ 27,509	12,804	10,752	-	3,954
926 EMPLOYEE BENEFITS	LB926	LBSUB9	$ 17,136	7,976	6,698	-	2,463
928 REGULATORY COMMISSION FEES	LB928	TUP	$ -	-	-	-	-
929 DUPLICATE CHARGES-CR	LB929	LBSUB9	$ -	-	-	-	-
930 MISCELLANEOUS GENERAL EXPENSES	LB930	LBSUB9	$ -	-	-	-	-
931 RENTS AND LEASES	LB931	PGP	$ -	-	-	-	-
935 MAINTENANCE OF GENERAL PLANT	LB935	PGP	$ 74,927	65,674	-	-	9,253
Total Administrative and General Expense	LBAG		$ 14,435,286	$ 6,749,515	$ 5,612,610	$ -	$ 2,073,161
Total Operation and Maintenance Expenses	TLB		$ 60,003,210	$ 27,958,509	$ 23,422,401	$ -	$ 8,622,301
Operation and Maintenance Expenses Less Purchase Power	LBLPP		$ 60,003,210	$ 27,958,509	$ 23,422,401	$ -	$ 8,622,301

BIG RIVERS ELECTRIC CORPORATION
Cost of Service Study
Functional Assignment and Classification

12 Months Ended
October 2010

Description	Name	Functional Vector		Total System		Production Demand		Production Energy		Steam Direct		Transmission Demand
Other Expenses												
Depreciation Expenses												
Production	DEPRDP2	PPROD	$	28,815,395		28,815,395		-		-		-
Transmission	DEPRDP3	PTRAN	$	5,182,459		-		-		-		5,182,459
Transmission	DEPRDP4	PTRAN	$	-		-		-		-		-
Distribution	DEPRDP5	PDIST	$	-		-		-		-		-
General & Common Plant	DEPRDP6	PGP	$	238,155		208,744		-		-		29,411
Other Plant	DEPROTH	TPIS	$	-		-		-		-		-
Total Depreciation Expense	TDEPR		$	34,236,009		29,024,140		-		-		5,211,869
Accretion Expense												
Production	ACRTNP	F017	$	-		-		-		-		-
Transmission	ACRTNT	PTRAN	$	-		-		-		-		-
Distribution	ACRTND	PDIST	$	-		-		-		-		-
Total Accretion Expense	TACRTN		$	-	$	-	$	-	$	-	$	-
Property Taxes & Other	PTAX	TUP	$	(94,563)		(82,705)		-		-		(11,858)
Amortization of Investment Tax Credit	OTAX	TUP	$	-		-		-		-		-
Other Expenses	OT	TUP	$	(365,864)		(319,986)		-		-		(45,878)
Interest	INTLTD	TUP	$	47,622,710		41,650,995		-		-		5,971,715
Other Deductions	DEDUCT	TUP	$	109,257		95,557		-		-		13,700
Total Other Expenses	TOE		$	81,507,549	$	70,368,000	$	-	$	-	$	11,139,549
Total Cost of Service (O&M + Other Expenses)			$	527,945,095	$	181,569,975	$	317,276,572	$	-	$	29,098,548

BIG RIVERS ELECTRIC CORPORATION
Cost of Service Study
Functional Assignment and Classification

12 Months Ended
October 2010

Description	Name	Functional Vector	Total System	Production Demand	Production Energy	Steam Direct	Transmission Demand
Functional Vectors							
Production Plant	F001		1.000000	1.000000	0.000000	0.000000	0.000000
Transmission Plant	F002		1.000000	0.000000	0.000000	0.000000	1.000000
Distribution Plant	F003		1.000000	0.000000	0.000000	0.000000	1.000000
Production Plant	F017		1.000000	0.000000	1.000000	0.000000	0.000000
Provar	PROVAR		1.000000	0.000000	1.000000	0.000000	0.000000
PROFIX	PROFIX		1.000000	1.000000	0.000000	0.000000	0.000000
Distribution Operation Labor	F023		-	-	-	-	-
Distribution Maintenance Labor	F024		-	-	-	-	-
Customer Accounts Expense	F025		1.000000	0.000000	0.000000	0.000000	1.000000
Customer Service Expense	F026		1.000000	0.000000	0.000000	0.000000	1.000000
Purchased Power Energy	OMPP		1.000000	0.000000	1.000000	0.000000	0.000000
Purchased Power Demand	OMPPD		1.000000	1.000000	0.000000	0.000000	0.000000
Purchased Power BREC Share of HMP&L Station Two	OMPPH		58,293,374	13,175,571	45,117,803	0.000000	0.000000
Production Energy	Energy		1.000000	0.000000	1.000000	0.000000	0.000000
Internally Generated Functional Vectors							
Total Prod, Trans, and Dist Plant		PT&D	1.000000	0.876506	-	-	0.123494
Total Transmission Plant		PTRAN	1.000000	-	-	-	1.000000
Operation and Maintenance Expenses Less Purchase Power		OMLPP	1.000000	0.494418	0.425734	-	0.079848
Total Plant in Service		TPIS	1.000000	0.876506	-	-	0.123494
Total Operation and Maintenance Expenses (Labor)		TLB	1.000000	0.465950	0.390352	-	0.143697
Sub-Total Prod, Trans, Dist, Cust Acct and Cust Service		OMSUB2	1.000000	0.232897	0.733903	-	0.033200
Total Steam Power Operation Expenses (Labor)		LBSUB1	1.000000	0.833374	0.166626	-	-
Total Steam Power Generation Maintenance Expense (Labor)		LBSUB2	1.000000	0.078617	0.921383	-	-
Total Transmission Labor Expenses		LBTRAN	1.000000	-	-	-	1.0000000
Sub-Total Labor Exp		LBSUB7	1.000000	0.465437	0.390841	-	0.143723
Total General Plant		PGP	1.000000	0.876506	-	-	0.123494
Total Production Plant		PPROD	1.000000	1.000000	-	-	-
Total Intangible Plant		INTPLT	1.000000	0.876506	-	-	0.123494

BIG RIVERS ELECTRIC CORPORATION
Cost of Service Study
Rate Schedule Allocation
12 Months Ended
October 2010
Average Excess Demand - Smelter TIER Adjustment Revenues at $1.95/mWh

Description	Ref	Name	Allocation Vector	Rurals	Large Industrials	Smelters	Total System
Cost of Service Summary -- Unadjusted							
Operating Revenues							
Sales to Members		REVUC	R01	$ 110,934,700	$ 39,110,620	$ 282,406,135	$ 432,451,455
Off System Sales Revenue			OSSALL	$ 12,744,879	$ 4,569,868	$ 59,229,055	$ 76,543,801
Income from Leased Property Net		OTHREV	RBPLT	$ 51,608	$ 12,924	$ 85,141	$ 149,673
Other Operating Revenue & Income		OTHREV	RBPLT	$ 4,750,980	$ 1,189,792	$ 7,837,973	$ 13,778,745
Total Operating Revenues		TOR		$ 128,482,167	$ 44,883,204	$ 349,558,304	$ 522,923,675
Operating Expenses							
Operation and Maintenance Expenses				$ 121,960,887	$ 40,042,146	$ 284,434,513	$ 446,437,546
Depreciation and Amortization Expenses				$ 11,810,735	$ 2,954,142	$ 19,471,132	$ 34,236,009
Property and Other Taxes			NPT	$ (32,733)	$ (8,164)	$ (53,666)	$ (94,563)
Total Operating Expenses		TOE		$ 133,738,889	$ 42,988,124	$ 303,851,979	$ 480,578,992
Utility Operating Margin				$ (5,256,723)	$ 1,895,081	$ 45,706,325	$ 42,344,683
Non-Operating Items							
Interest Income			RBPLT	$ -	$ -	$ -	$ -
Other Non-Operating Income			RBPLT	$ -	$ -	$ -	$ -
Other Credits			RBPLT	$ -	$ -	$ -	$ -
Interest on Long Term Debt				$ -	$ -	$ -	$ -
Other Interest Expense			RBPLT	$ -	$ -	$ -	$ -
Other Deductions			RBPLT	$ -	$ -	$ -	$ -
Total Non-Operating Items				$ -	$ -	$ -	$ -
Net Utility Operating Margin		TOM		$ (5,256,723)	$ 1,895,081	$ 45,706,325	$ 42,344,683
Net Cost Rate Base				$ 403,539,604	$ 101,058,766	$ 665,743,132	$ 1,170,341,502

BIG RIVERS ELECTRIC CORPORATION
Cost of Service Study
Rate Schedule Allocation
12 Months Ended
October 2010
Average Excess Demand - Smelter TIER Adjustment Revenues at $1.95/mWh

Description	Ref	Name	Allocation Vector	Rurals	Large Industrials	Smelters	Total System
Cost of Service Summary – Pro-Forma							
Operating Revenues							
Total Operating Revenue				$ 128,482,167	$ 44,883,204	$ 349,558,304	$ 522,923,675
Pro-Forma Adjustments:							
To annualize revenue for new industrial customer	2.01			$ -	$ 149,752	$ -	$ 149,752
To adjust mismatch in fuel cost recovery	2.02	FACREV		$ (25,166,503)	$ (9,525,471)	$ (73,123,203)	$ (107,815,177)
To eliminate Environmental Surcharge revenues	2.03	ESREV		$ (5,315,462)	$ (2,025,233)	$ (15,493,538)	$ (22,834,232)
To reflect temperature normalized sales volumes	2.04		EnergyR	$ (421,610)	$ -	$ -	$ (421,610)
To eliminate Non-FAC PPA revenues	2.05	NFPR		$ 2,757,108	$ 1,045,800	$ 7,785,109	$ 11,588,017
To eliminate WKEC Lease Expenses	2.19		RBPLT	$ (51,608)	$ (12,924)	$ (85,141)	$ (149,673)
To eliminate RRI Domtar Cogen Backup revenues	2.09			$ -	$ (1,115,159)	$ -	$ (1,115,159)
To adjust for Smelter TIER Adjustment Charge	2.22			$ -	$ -	$ -	$ -
Total Pro-Forma Operating Revenue				$ 100,284,092	$ 33,399,969	$ 268,641,532	$ 402,325,592

BIG RIVERS ELECTRIC CORPORATION
Cost of Service Study
Rate Schedule Allocation
12 Months Ended
October 2010
Average Excess Demand - Smelter TIER Adjustment Revenues at $1.95/mWh

Description	Ref	Name	Allocation Vector	Rurals	Large Industrials	Smelters	Total System
Cost of Service Summary – Pro-Forma							
Operating Expenses							
Operation and Maintenance Expenses				121,960,887	40,042,146	284,434,513	446,437,546
Depreciation and Amortization Expenses				11,810,735	2,954,142	19,471,132	34,236,009
Property and Other Taxes			NPT	(32,733)	(8,164)	(53,666)	(94,563)
Adjustments to Operating Expenses:							
To annualize expenses for new industrial customer	2.01			-	110,607	-	110,607
To adjust mismatch in fuel cost recovery	2.02		FACREV	(25,685,949)	(9,722,081)	(74,632,493)	(110,040,523)
To eliminate Environmental Surcharge expenses	2.03		ESREV	(5,462,944)	(2,081,425)	(15,923,422)	(23,467,791)
To reflect weather normalized sales volumes	2.04		EnergyR	(295,293)	-	-	(295,293)
To eliminate Non-FAC PPA expenses	2.05		NFPR	2,858,740	1,084,350	8,072,083	12,015,173
To reflect annualized depreciation expenses	2.06		PLT	2,164,890	539,845	3,547,916	6,252,651
To reflect increases in labor and labor-related costs	2.07		LBPLT	186,980	54,413	383,501	624,894
To reflect current interest on construction (CWIP)	2.08		PLT	178,577	44,531	292,659	515,767
To eliminate RRI Domtar Cogen Backup expenses	2.09			-	(2,086,416)	-	(2,086,416)
To reflect levelized production expenses	2.10		CP	1,990,470	489,975	3,180,233	5,660,678
To reflect levelized production expenses	2.11		CP	958,885	236,040	1,532,040	2,726,965
To reflect going forward Information Technology support services	2.12		RBPLT	100,750	25,231	166,213	292,194
To reflect amortizaton of rate case expenses	2.13		RBPLT	97,138	24,326	160,254	281,719
To reflect MISO related expenses	2.14		12CPTR	1,667,501	459,102	3,288,398	5,415,000
To annualize interest on long-term debt	2.15		RBPLT	24,277	6,080	40,051	70,408
To reflect leased property income (Soaper Building Rent)	2.16		LBPLT	(38,410)	(11,178)	(78,780)	(128,368)
To adjust for costs related to LEM Dispatch	2.17		CP	(329,413)	(81,089)	(526,313)	(936,815)
To adjust for costs related to APM	2.18		CP	72,116	17,752	115,222	205,090
To reflect going forward level of Outside Services	2.25		EnergyNS	(725,000)	(275,000)	-	(1,000,000)
To eliminate costs for SFPC membership	2.20		RBPLT	(62,332)	(15,610)	(102,833)	(180,775)
To adjust for MISO Case-related expenses	2.21		12CPTR	(237,459)	(65,378)	(468,281)	(771,118)
To reflect commitment to Energy Efficiency Programs	2.26		EnergyNS	725,000	275,000	-	1,000,000
To eliminate promo advertising, lobbying, donation and econ dev	2.23		R01	(130,114)	(45,872)	(331,230)	(507,216)
To reflect going forward level of income taxes	2.24		NTPLT	63,337	15,805	103,942	183,084
Total Expense Adjustments				(21,878,252)	(11,000,991)	(71,180,840)	(104,060,084)
Total Operating Expenses		TOE		111,860,637	31,987,132	232,671,139	376,518,908
Utility Operating Margins – Pro-Forma				(11,576,545)	1,412,836	35,970,393	25,806,684
Non-Operating Items				-	-	-	-
Total Non-Operating Items				-	-	-	-
Net Utility Operating Margin				(11,576,545)	1,412,836	35,970,393	25,806,684
Net Cost Rate Base				403,539,604	101,058,766	665,743,132	1,170,341,502
Return on Rate Base – Utility Operating Margin Divided by Rate Base				-2.87%	1.40%	5.40%	2.21%

BIG RIVERS ELECTRIC CORPORATION
Cost of Service Study
Rate Schedule Allocation
12 Months Ended
October 2010
Average Excess Demand - Smelter TIER Adjustment Revenues at $1.95/mWh

Description	Ref	Name	Allocation Vector	Rurals	Large Industrials	Smelters	Total System
Subsidies Paid and Received at Present Rates							
(subisidies received shown as positive value)							
Rate Base				$ 403,539,604	$ 101,058,766	$ 665,743,132	$ 1,170,341,502
Operating Margins (present rates)				$ (11,576,545)	$ 1,412,836	$ 35,970,393	$ 25,806,684
Operating Margins at Equal Rate of Return	ROR	2.21%		$ 8,898,274	$ 2,228,402	$ 14,680,008	$ 25,806,684
Subsidies Paid and Received				$ 20,474,819	$ 815,566	$ (21,290,385)	$ (0)

Big Rivers Electric Corporation
Summary of Cost of Service Study
For the 12 Months Ended October 2010

Rate of Return Summary

Unadjusted

Rate Schedule		Utility Operating Margins		Net Cost Rate Base	Rate of Return
Total Rural	$	(11,576,545)	$	403,539,604	-2.87%
Total Large Industrial		1,412,836		101,058,766	1.40%
Total Smelter		35,970,393		665,743,132	5.40%
Total	$	25,806,684	$	1,170,341,502	2.21%

Adjusted for Proposed Rate Increase

Rate Schedule		Utility Operating Margins		Net Cost Rate Base	Rate of Return
Total Rural	$	2,595,458	$	403,539,604	0.64%
Total Large Industrial		4,641,403		101,058,766	4.59%
Total Smelter		58,523,789		665,743,132	8.79%
Total	$	65,760,649	$	1,170,341,502	5.62%

Description	Name	Functional Vector	Total System	November 2009	December 2009	January 2010	February 2010	March 2010
Plant in Service								
Intangible Plant	INTPLT	PT&D	$ 66,895					
Production Plant	PPROD	F001	$ 1,686,796,955					
Transmission Plant	PTRAN	F002	$ 237,659,206					
Distribution Plant	PDIST	F003	$ -					
Total Production & Transmission Plant	PT&D		1,924,456,160					
General Plant	PGP	PT&D	$ 18,511,051					
Total Plant in Service	TPIS		$ 1,943,034,107					
Construction Work in Progress (CWIP)								
CWIP Production	CWIP1	PPROD	$ 22,411,274					
CWIP Transmission	CWIP2	PTRAN	$ 7,475,859					
CWIP Distribution Plant	CWIP3	PDIST	$ -					
CWIP General Plant	CWIP4	PT&D	$ 16,915,005					
Total Construction Work in Progress	TCWIP		$ 46,802,138					
Total Utility Plant			$ 1,989,836,245					
Rate Base								
Total Utility Plant	TUP		$ 1,989,836,245					
Less: Acummulated Provision for Depreciation								
Production	ADEPREPA	PPROD	$ 790,847,523					
Transmission	ADEPRTP	PTRAN	$ 107,564,747					
Distribution	ADEPRD11	PDIST	$ -					
General & Common Plant	ADEPRD12	PT&D	$ 6,300,770					
Intangible, Misc, and Other Plant	ADEPRGP	PT&D	$ -					
Retirement Work In Progress	ADEPRRT	PT&D	$ -					
Total Accumulated Depreciation	TADEPR		$ 904,713,040					
Net Utility Plant	NTPLANT		$ 1,085,123,206					
Working Capital								
Cash Working Capital - Operation and Maintenance Expenses	CWC	OMLPP	$ 28,114,365					
Materials and Supplies	M&S	TPIS	$ 22,777,820	20327197.9	85340.04	-68898.4	208485.44	-95121.11
Fuel Stock	PREPAY	TPIS	$ 34,326,112	39158400.85	-1328756.9	-4130766.79	-359777.13	1918732.52
Total Working Capital	TWC		$ 85,218,297					
Net Rate Base	RB		$ 1,170,341,502					

Description	Name	Functional Vector	April 2010	May 2010	June 2010	July 2010	August 2010	September 2010
Plant in Service								
Intangible Plant	INTPLT	PT&D						
Production Plant	PPROD	F001						
Transmission Plant	PTRAN	F002						
Distribution Plant	PDIST	F003						
Total Production & Transmission Plant	PT&D							
General Plant	PGP	PT&D						
Total Plant in Service	TPIS							
Construction Work in Progress (CWIP)								
CWIP Production	CWIP1	PPROD						
CWIP Transmission	CWIP2	PTRAN						
CWIP Distribution Plant	CWIP3	PDIST						
CWIP General Plant	CWIP4	PT&D						
Total Construction Work in Progress	TCWIP							
Total Utility Plant								
Rate Base								
Total Utility Plant	TUP							
Less: Acummulated Provision for Depreciation								
Production	ADEPREPA	PPROD						
Transmission	ADEPRTP	PTRAN						
Distribution	ADEPRD11	PDIST						
General & Common Plant	ADEPRD12	PT&D						
Intangible, Misc, and Other Plant	ADEPRGP	PT&D						
Retirement Work In Progress	ADEPRRT	PT&D						
Total Accumulated Depreciation	TADEPR							
Net Utility Plant	NTPLANT							
Working Capital								
Cash Working Capital - Operation and Maintenance Expenses	CWC	OMLPP						
Materials and Supplies	M&S	TPIS	-220183.19	207004.7	357212.07	240129.05	-144241.07	2889566.56
Fuel Stock	PREPAY	TPIS	2552249.61	867432.81	-287963.1	-3463026.24	-2018344.81	-578882.38
Total Working Capital	TWC							
Net Rate Base	RB							

Description	Name	Functional Vector	October 2010
Plant in Service			
Intangible Plant	INTPLT	PT&D	
Production Plant	PPROD	F001	
Transmission Plant	PTRAN	F002	
Distribution Plant	PDIST	F003	
Total Production & Transmission Plant	PT&D		
General Plant	PGP	PT&D	
Total Plant in Service	TPIS		
Construction Work in Progress (CWIP)			
CWIP Production	CWIP1	PPROD	
CWIP Transmission	CWIP2	PTRAN	
CWIP Distribution Plant	CWIP3	PDIST	
CWIP General Plant	CWIP4	PT&D	
Total Construction Work in Progress	TCWIP		
Total Utility Plant			
Rate Base			
Total Utility Plant	TUP		
Less: Acummulated Provision for Depreciation			
Production	ADEPREPA	PPROD	
Transmission	ADEPRTP	PTRAN	
Distribution	ADEPRD11	PDIST	
General & Common Plant	ADEPRD12	PT&D	
Intangible, Misc, and Other Plant	ADEPRGP	PT&D	
Retirement Work In Progress	ADEPRRT	PT&D	
Total Accumulated Depreciation	TADEPR		
Net Utility Plant	NTPLANT		
Working Capital			
Cash Working Capital - Operation and Maintenance Expenses	CWC	OMLPP	
Materials and Supplies	M&S	TPIS	-1008672.24
Fuel Stock	PREPAY	TPIS	1996813.82
Total Working Capital	TWC		
Net Rate Base	RB		

Description	Name	Functional Vector		Total System	November 2009	December 2009	January 2010	February 2010	March 2010
Operation and Maintenance Expenses									
Steam Power Generation Operation Expenses									
500 OPERATION SUPERVISION & ENGINEERING	OM500	PROFIX	$	4,974,566	342962.62	1034901.09	358703.86	318491.34	384828.47
501 FUEL	OM501	Energy	$	200,919,367	11957675.62	16736745.89	19103323.18	17630280.19	17173097.35
502 STEAM EXPENSES	OM502	PROFIX	$	34,453,882	2424633.22	2490999.61	2647322.04	2676616.85	2911578.89
505 ELECTRIC EXPENSES	OM505	PROFIX	$	5,730,122	399281.19	656713.94	477935.99	489102.92	443771.24
506 MISC. STEAM POWER EXPENSES	OM506	PROFIX	$	7,451,302	837237.41	458663.32	531778.12	516078.68	646116.36
507 RENTS	OM507	PROFIX	$	-		0	0	0	0
509 ALLOWANCES	OM509	Energy	$	429,682		0	0	55382.46	42291.31
Total Steam Power Operation Expenses			$	253,958,921	$ 7,775	$ 146,296	$ 7,154	$ 15,852	$ 21,245
Steam Power Generation Maintenance Expenses									
510 MAINTENANCE SUPERVISION & ENGINEERING	OM510	Energy	$	3,631,867	301562.96	282674.01	282136.07	286174.73	324812.85
511 MAINTENANCE OF STRUCTURES	OM511	PROFIX	$	3,346,806	-2396.3	561809.41	164027.98	219884.17	122851.74
512 MAINTENANCE OF BOILER PLANT	OM512	Energy	$	30,113,309	2665049.9	2707987.08	1617573	1413359.02	2039706.29
513 MAINTENANCE OF ELECTRIC PLANT	OM513	Energy	$	6,251,804	2443905.77	804364.44	-26124.91	190619.56	167015.92
514 MAINTENANCE OF MISC STEAM PLANT	OM514	PROFIX	$	877,364	136355.09	154030.5	71461.85	48046.95	35868.33
Total Steam Power Generation Maintenance Expense			$	44,221,151	$ 3,659	$ 7,366	$ 1,455	$ 6,057	$ 9,772
Total Steam Power Generation Expense			$	298,180,072					

Description	Name	Functional Vector	April 2010	May 2010	June 2010	July 2010	August 2010	September 2010
Operation and Maintenance Expenses								
Steam Power Generation Operation Expenses								
500 OPERATION SUPERVISION & ENGINEERING	OM500	PROFIX	338223.38	414283.22	372420.21	359404.38	369945.71	334708.35
501 FUEL	OM501	Energy	15868543.13	15412621.99	16949864.35	18643264.65	19588180.27	17004762.52
502 STEAM EXPENSES	OM502	PROFIX	2801318.34	3017168.8	3110448.48	3022221.22	3095094.21	3132173.1
505 ELECTRIC EXPENSES	OM505	PROFIX	430459.27	473960.9	440316.02	456264.08	479912.75	476352.39
506 MISC. STEAM POWER EXPENSES	OM506	PROFIX	557984.26	577686.56	640171.09	585642.46	806920.28	725866.29
507 RENTS	OM507	PROFIX	0	0	0	0	0	0
509 ALLOWANCES	OM509	Energy	33437.63	31618.94	46952.89	62169.21	49573.1	28256.05
Total Steam Power Operation Expenses			$ 6,070	$ 8,052	$ 5,213	$ 267,644	$ 167,124	$ 44,089
Steam Power Generation Maintenance Expenses								
510 MAINTENANCE SUPERVISION & ENGINEERING	OM510	Energy	297530.92	289425	297802.77	281476.85	309430.59	294029.27
511 MAINTENANCE OF STRUCTURES	OM511	PROFIX	153063.03	309779.07	306987.02	458108.12	372678.29	488354.6
512 MAINTENANCE OF BOILER PLANT	OM512	Energy	1740181.45	2535024.61	2164789.64	2054585.86	2034329.79	2855272.84
513 MAINTENANCE OF ELECTRIC PLANT	OM513	Energy	313812.24	389518.49	251988.71	302199.64	422000.23	534239.62
514 MAINTENANCE OF MISC STEAM PLANT	OM514	PROFIX	61896.28	58285.06	85932.24	51800.09	89344.85	66090.33
Total Steam Power Generation Maintenance Expense			$ (325)	$ 4,943	$ 216,501	$ 175,754	$ 65,241	$ 96,186
Total Steam Power Generation Expense								

Description	Name	Functional Vector	October 2010
Operation and Maintenance Expenses			
Steam Power Generation Operation Expenses			
500 OPERATION SUPERVISION & ENGINEERING	OM500	PROFIX	345693.85
501 FUEL	OM501	Energy	14851007.4
502 STEAM EXPENSES	OM502	PROFIX	3124307.14
505 ELECTRIC EXPENSES	OM505	PROFIX	506051.44
506 MISC. STEAM POWER EXPENSES	OM506	PROFIX	567156.95
507 RENTS	OM507	PROFIX	0
509 ALLOWANCES	OM509	Energy	80000.79
Total Steam Power Operation Expenses			$ 44,882
Steam Power Generation Maintenance Expenses			
510 MAINTENANCE SUPERVISION & ENGINEERING	OM510	Energy	384811.34
511 MAINTENANCE OF STRUCTURES	OM511	PROFIX	191658.45
512 MAINTENANCE OF BOILER PLANT	OM512	Energy	6285449.98
513 MAINTENANCE OF ELECTRIC PLANT	OM513	Energy	458264.77
514 MAINTENANCE OF MISC STEAM PLANT	OM514	PROFIX	18252.47
Total Steam Power Generation Maintenance Expense			$ 38,478
Total Steam Power Generation Expense			

Description	Name	Functional Vector		Total System		November 2009		December 2009		January 2010		February 2010		March 2010
Operation and Maintenance Expenses (Continued)														
Other Power Generation Operation Expense														
546 OPERATION SUPERVISION & ENGINEERING	OM546	PROFIX	$	-		0		0		0		0		0
547 FUEL	OM547	Energy	$	706,789		7379.85		135814.53		4779.27		13479.11		18872.46
548 GENERATION EXPENSE	OM548	PROFIX	$	34,608		394.54		10481.32		2375		2373		2373
549 MISC OTHER POWER GENERATION	OM549	PROFIX	$	-		0		0		0		0		0
550 RENTS	OM550	PROFIX	$	-		0		0		0		0		0
Total Other Power Generation Expenses			$	741,396	$	(1)	$	(0)	$	0	$	1	$	0
Other Power Generation Maintenance Expense														
551 MAINTENANCE SUPERVISION & ENGINEERING	OM551	PROFIX	$	-		0		0		0		0		0
552 MAINTENANCE OF STRUCTURES	OM552	PROFIX	$	-		0		0		0		0		0
553 MAINTENANCE OF GENERATING & ELEC PLANT	OM553	PROFIX	$	625,088		3658.66		7365.41		1454.85		6056.77		9772.16
554 MAINTENANCE OF MISC OTHER POWER GEN PLT	OM554	PROFIX	$	-		0		0		0		0		0
Total Other Power Generation Maintenance Expense			$	625,088	$	0	$	(0)	$	(0)	$	0	$	0
Total Other Power Generation Expense			$	1,366,485										
Total Station Expense			$	299,546,557										

Description	Name	Functional Vector		April 2010	May 2010	June 2010	July 2010	August 2010	September 2010
Operation and Maintenance Expenses (Continued)									
Other Power Generation Operation Expense									
546 OPERATION SUPERVISION & ENGINEERING	OM546	PROFIX		0	0	0	0	0	0
547 FUEL	OM547	Energy		3696.82	5679.30	2839.60	265271.41	164750.42	41716.70
548 GENERATION EXPENSE	OM548	PROFIX		2373	2373.00	2373.00	2373.00	2373.00	2373.00
549 MISC OTHER POWER GENERATION	OM549	PROFIX		0	0	0	0	0	0
550 RENTS	OM550	PROFIX		0	0	0	0	0	0
Total Other Power Generation Expenses			$	(0) $	1 $	(0) $	0 $	(0) $	0
Other Power Generation Maintenance Expense									
551 MAINTENANCE SUPERVISION & ENGINEERING	OM551	PROFIX		0	0	0	0	0	0
552 MAINTENANCE OF STRUCTURES	OM552	PROFIX		0	0	0	0	0	0
553 MAINTENANCE OF GENERATING & ELEC PLANT	OM553	PROFIX		-322.62	4943.09	216501.24	175754.02	65240.65	96186.42
554 MAINTENANCE OF MISC OTHER POWER GEN PLT	OM554	PROFIX		0	0	0	0	0	0
Total Other Power Generation Maintenance Expense			$	2 $	0 $	1 $	(0) $	(1) $	0
Total Other Power Generation Expense									
Total Station Expense									

Description	Name	Functional Vector		October 2010
Operation and Maintenance Expenses (Continued)				
Other Power Generation Operation Expense				
546 OPERATION SUPERVISION & ENGINEERING	OM546	PROFIX		0
547 FUEL	OM547	Energy		42509.14
548 GENERATION EXPENSE	OM548	PROFIX		2373.00
549 MISC OTHER POWER GENERATION	OM549	PROFIX		0
550 RENTS	OM550	PROFIX		0
Total Other Power Generation Expenses			$	(0)
Other Power Generation Maintenance Expense				
551 MAINTENANCE SUPERVISION & ENGINEERING	OM551	PROFIX		0
552 MAINTENANCE OF STRUCTURES	OM552	PROFIX		0
553 MAINTENANCE OF GENERATING & ELEC PLANT	OM553	PROFIX		38477.63
554 MAINTENANCE OF MISC OTHER POWER GEN PLT	OM554	PROFIX		0
Total Other Power Generation Maintenance Expense			$	(0)
Total Other Power Generation Expense				
Total Station Expense				

Description	Name	Functional Vector		Total System	November 2009	December 2009	January 2010	February 2010	March 2010
Operation and Maintenance Expenses (Continued)									
Other Power Supply Expenses									
555 PURCHASED POWER Energy	OM555	OMPP	$	19,466,790	3,827,952.61	2,536,760.36	1,913,169.62	941,370.11	911,294.71
555 PURCHASED POWER Demand	OMD555	OMPPD	$	4,210,045	350,837.07	350,837.07	350,837.07	350,837.07	350,837.07
555 PURCHASED POWER BREC Share of HMP&L Station Two	OMH555	OMPPH	$	58,293,374	4,582,937.26	5,054,161.64	4,549,698.12	4,432,913.73	4,763,164.98
555 PURCHASED POWER OPTIONS	OMO555	OMPP	$	-	0	0	0	0	0
555 BROKERAGE FEES	OMB555	OMPP	$	-	0	0	0	0	0
555 MISO TRANSMISSION EXPENSES	OMM555	OMPP	$	-	0	0	0	0	0
556 SYSTEM CONTROL AND LOAD DISPATCH	OM556	PROFIX	$	909,422	143177.05	161775.92	84110.82	66492.87	77558.07
557 OTHER EXPENSES	OM557	PROFIX	$	20,575,465	2479520.29	2210820.92	1519858.99	1381956.22	1577347.72
558 DUPLICATE CHARGES	OM558	Energy	$	-	0	0	0	0	0
Total Other Power Supply Expenses	TPP		$	103,455,096	11,384,424.28	10,314,355.91	8,417,674.62	7,173,570.00	7,680,202.55
Total Electric Power Generation Expenses			$	403,001,653					
Transmission Expenses									
560 OPERATION SUPERVISION AND ENG	OM560	LBTRAN	$	876,815	159722.72	99111.49	64131.05	56493.74	71626.61
561 LOAD DISPATCHING	OM561	LBTRAN	$	1,454,938	245368.38	141741.21	113777.21	98967.65	113022.44
562 STATION EXPENSES	OM562	PTRAN	$	1,163,408	138650.41	111166.28	70289.35	78900.11	96317.14
563 OVERHEAD LINE EXPENSES	OM563	PTRAN	$	1,090,014	116902.84	72507.66	91764.75	90248.86	92136.75
565 TRANSMISSION OF ELECTRICITY BY OTHERS	OM565	PTRAN	$	3,065,817	227372.33	270804.44	222495.76	313990.87	298157.74
566 MISC. TRANSMISSION EXPENSES	OM566	PTRAN	$	475,381	82941.08	54676.78	40839.08	35322.18	39484.82
567 RENTS	OM567	PTRAN	$	24,701	2058.43	2058.43	2058.43	2058.43	2058.43
568 MAINTENACE SUPERVISION AND ENG	OM568	LBTRAN	$	647,227	120702.88	66051.02	48367.7	40149.83	53439.26
569 STRUCTURES	OM569	PTRAN	$	26,913	36.88	6259.34	0	1874.02	59.12
570 MAINT OF STATION EQUIPMENT	OM570	PTRAN	$	1,936,760	272171.89	208826.01	135405.37	165513.32	155839.56
571 MAINT OF OVERHEAD LINES	OM571	PTRAN	$	2,876,462	318695.62	624358.63	20316.93	128651.35	134146
572 UNDERGROUND LINES	OM572	PTRAN	$	-	0	0	0	0	0
573 MISC PLANT	OM573	PTRAN	$	97,880	8341.27	4665	3732.37	5821.94	34823.78
Total Transmission Expenses			$	13,736,318	1,692,964.73	1,662,226.29	813,178.00	1,017,992.30	1,091,111.65

Description	Name	Functional Vector	April 2010	May 2010	June 2010	July 2010	August 2010	September 2010
Operation and Maintenance Expenses (Continued)								
Other Power Supply Expenses								
555 PURCHASED POWER Energy	OM555	OMPP	1,360,105.55	2,595,157.16	1,414,751.54	1,276,714.40	516,721.89	613,253.53
555 PURCHASED POWER Demand	OMD555	OMPPD	350,837.07	350,837.07	350,837.07	350,837.07	350,837.07	350,837.07
555 PURCHASED POWER BREC Share of HMP&L Station Two	OMH555	OMPPH	5,098,546.01	4,460,755.81	4,842,232.95	5,325,056.85	5,088,921.31	4,972,622.48
555 PURCHASED POWER OPTIONS	OMO555	OMPP	0	0	0	0	0	0
555 BROKERAGE FEES	OMB555	OMPP	0	0	0	0	0	0
555 MISO TRANSMISSION EXPENSES	OMM555	OMPP	0	0	0	0	0	0
556 SYSTEM CONTROL AND LOAD DISPATCH	OM556	PROFIX	0	92094.61	73384.96	71377.18	39951.63	51309.82
557 OTHER EXPENSES	OM557	PROFIX	1535653.17	1420108.84	1438109.81	1546376.13	1542523.95	2323941.19
558 DUPLICATE CHARGES	OM558	Energy	0	0	0	0	0	0
Total Other Power Supply Expenses	TPP		8,345,141.80	8,918,953.49	8,119,316.33	8,570,361.63	7,538,955.85	8,311,964.09
Total Electric Power Generation Expenses								
Transmission Expenses								
560 OPERATION SUPERVISION AND ENG	OM560	LBTRAN	59387.59	61734.83	72275.43	57830.16	52970.2	70253.05
561 LOAD DISPATCHING	OM561	LBTRAN	89896.48	94173.59	104627.56	94297.49	86936.32	135835
562 STATION EXPENSES	OM562	PTRAN	84122.23	90931.03	103923.43	86043.52	116294.21	83898.29
563 OVERHEAD LINE EXPENSES	OM563	PTRAN	87522.07	87158.79	89203.39	89187.21	86736.29	88209.66
565 TRANSMISSION OF ELECTRICITY BY OTHERS	OM565	PTRAN	229091.63	251486.95	238169.64	253067.81	259149.57	237980.88
566 MISC. TRANSMISSION EXPENSES	OM566	PTRAN	28982.15	30160.95	44581.15	19944.19	35290.89	32930.62
567 RENTS	OM567	PTRAN	2058.43	2058.43	2058.43	2058.43	2058.43	2058.43
568 MAINTENACE SUPERVISION AND ENG	OM568	LBTRAN	44241.45	45590.11	51110.87	42324.47	40557.13	55824.53
569 STRUCTURES	OM569	PTRAN	80.04	577.95	1084.71	2771.42	1003.78	1896.87
570 MAINT OF STATION EQUIPMENT	OM570	PTRAN	124235.3	158259.64	153920.85	137834.03	134856.99	175088.1
571 MAINT OF OVERHEAD LINES	OM571	PTRAN	140543.65	122631.69	245673.12	136904.15	282898.22	547382.49
572 UNDERGROUND LINES	OM572	PTRAN	0	0	0	0	0	0
573 MISC PLANT	OM573	PTRAN	4923.69	6697.42	5370.15	3919.44	6630.08	5359.76
Total Transmission Expenses			895,084.71	951,461.38	1,111,998.73	926,182.32	1,105,382.11	1,436,717.68

Description	Name	Functional Vector	October 2010
Operation and Maintenance Expenses (Continued)			
Other Power Supply Expenses			
555 PURCHASED POWER Energy	OM555	OMPP	1559538.19
555 PURCHASED POWER Demand	OMD555	OMPPD	350837.07
555 PURCHASED POWER BREC Share of HMP&L Station Two	OMH555	OMPPH	5,122,362.96
555 PURCHASED POWER OPTIONS	OMO555	OMPP	0
555 BROKERAGE FEES	OMB555	OMPP	0
555 MISO TRANSMISSION EXPENSES	OMM555	OMPP	0
556 SYSTEM CONTROL AND LOAD DISPATCH	OM556	PROFIX	48189.16
557 OTHER EXPENSES	OM557	PROFIX	1599248
558 DUPLICATE CHARGES	OM558	Energy	0
Total Other Power Supply Expenses	TPP		8,680,175.38
Total Electric Power Generation Expenses			
Transmission Expenses			
560 OPERATION SUPERVISION AND ENG	OM560	LBTRAN	51278.57
561 LOAD DISPATCHING	OM561	LBTRAN	136294.18
562 STATION EXPENSES	OM562	PTRAN	102872.03
563 OVERHEAD LINE EXPENSES	OM563	PTRAN	98436.13
565 TRANSMISSION OF ELECTRICITY BY OTHERS	OM565	PTRAN	264049.42
566 MISC. TRANSMISSION EXPENSES	OM566	PTRAN	30227.33
567 RENTS	OM567	PTRAN	2058.43
568 MAINTENACE SUPERVISION AND ENG	OM568	LBTRAN	38868.14
569 STRUCTURES	OM569	PTRAN	11269.17
570 MAINT OF STATION EQUIPMENT	OM570	PTRAN	114809.26
571 MAINT OF OVERHEAD LINES	OM571	PTRAN	174260.22
572 UNDERGROUND LINES	OM572	PTRAN	0
573 MISC PLANT	OM573	PTRAN	7595.34
Total Transmission Expenses			1,032,018.22

Description	Name	Functional Vector		Total System	November 2009	December 2009	January 2010	February 2010	March 2010
Distribution Operation Expense									
580 OPERATION SUPERVISION AND ENGI	OM580	LBDO	$	-	0	0	0	0	0
581 LOAD DISPATCHING	OM581	PDIST	$	-	0	0	0	0	0
582 STATION EXPENSES	OM582	PDIST	$	-	0	0	0	0	0
583 OVERHEAD LINE EXPENSES	OM583	PDIST	$	-	0	0	0	0	0
584 UNDERGROUND LINE EXPENSES	OM584	PDIST	$	-	0	0	0	0	0
585 STREET LIGHTING EXPENSE	OM585	PDIST	$	-	0	0	0	0	0
586 METER EXPENSES	OM586	PDIST	$	-	0	0	0	0	0
586 METER EXPENSES - LOAD MANAGEMENT	OM586x	PDIST	$	-	0	0	0	0	0
587 CUSTOMER INSTALLATIONS EXPENSE	OM587	PDIST	$	-	0	0	0	0	0
588 MISCELLANEOUS DISTRIBUTION EXP	OM588	PDIST	$	-	0	0	0	0	0
588 MISC DISTR EXP -- MAPPIN	OM588x	PDIST	$	-	0	0	0	0	0
589 RENTS	OM589	PDIST	$	-	0	0	0	0	0
Total Distribution Operation Expense	OMDO		$	-					
Operation and Maintenance Expenses (Continued)									
Distribution Maintenance Expense									
590 MAINTENANCE SUPERVISION AND EN	OM590	LBDM	$	-	0	0	0	0	0
591 STRUCTURES	OM591	PDIST	$	-	0	0	0	0	0
592 MAINTENANCE OF STATION EQUIPME	OM592	PDIST	$	-	0	0	0	0	0
593 MAINTENANCE OF OVERHEAD LINES	OM593	PDIST	$	-	0	0	0	0	0
594 MAINTENANCE OF UNDERGROUND LIN	OM594	PDIST	$	-	0	0	0	0	0
595 MAINTENANCE OF LINE TRANSFORME	OM595	PDIST	$	-	0	0	0	0	0
596 MAINTENANCE OF ST LIGHTS & SIG SYSTEMS	OM596	PDIST	$	-	0	0	0	0	0
597 MAINTENANCE OF METERS	OM597	PDIST	$	-	0	0	0	0	0
598 MISCELLANEOUS DISTRIBUTION EXPENSES	OM598	PDIST	$	-	0	0	0	0	0
Total Distribution Maintenance Expense	OMDM		$	-					
Total Distribution Operation and Maintenance Expenses				-					
Transmission and Distribution Expenses				13,736,318					
Production, Transmission and Distribution Expenses	OMSUB		$	416,737,971					

Description	Name	Functional Vector	April 2010	May 2010	June 2010	July 2010	August 2010	September 2010
Distribution Operation Expense								
580 OPERATION SUPERVISION AND ENGI	OM580	LBDO	0	0	0	0	0	0
581 LOAD DISPATCHING	OM581	PDIST	0	0	0	0	0	0
582 STATION EXPENSES	OM582	PDIST	0	0	0	0	0	0
583 OVERHEAD LINE EXPENSES	OM583	PDIST	0	0	0	0	0	0
584 UNDERGROUND LINE EXPENSES	OM584	PDIST	0	0	0	0	0	0
585 STREET LIGHTING EXPENSE	OM585	PDIST	0	0	0	0	0	0
586 METER EXPENSES	OM586	PDIST	0	0	0	0	0	0
586 METER EXPENSES - LOAD MANAGEMENT	OM586x	PDIST	0	0	0	0	0	0
587 CUSTOMER INSTALLATIONS EXPENSE	OM587	PDIST	0	0	0	0	0	0
588 MISCELLANEOUS DISTRIBUTION EXP	OM588	PDIST	0	0	0	0	0	0
588 MISC DISTR EXP -- MAPPIN	OM588x	PDIST	0	0	0	0	0	0
589 RENTS	OM589	PDIST	0	0	0	0	0	0
Total Distribution Operation Expense	OMDO							
Operation and Maintenance Expenses (Continued)								
Distribution Maintenance Expense								
590 MAINTENANCE SUPERVISION AND EN	OM590	LBDM	0	0	0	0	0	0
591 STRUCTURES	OM591	PDIST	0	0	0	0	0	0
592 MAINTENANCE OF STATION EQUIPME	OM592	PDIST	0	0	0	0	0	0
593 MAINTENANCE OF OVERHEAD LINES	OM593	PDIST	0	0	0	0	0	0
594 MAINTENANCE OF UNDERGROUND LIN	OM594	PDIST	0	0	0	0	0	0
595 MAINTENANCE OF LINE TRANSFORME	OM595	PDIST	0	0	0	0	0	0
596 MAINTENANCE OF ST LIGHTS & SIG SYSTEMS	OM596	PDIST	0	0	0	0	0	0
597 MAINTENANCE OF METERS	OM597	PDIST	0	0	0	0	0	0
598 MISCELLANEOUS DISTRIBUTION EXPENSES	OM598	PDIST	0	0	0	0	0	0
Total Distribution Maintenance Expense	OMDM							
Total Distribution Operation and Maintenance Expenses								
Transmission and Distribution Expenses								
Production, Transmission and Distribution Expenses	OMSUB							

Description	Name	Functional Vector	October 2010
Distribution Operation Expense			
580 OPERATION SUPERVISION AND ENGI	OM580	LBDO	0
581 LOAD DISPATCHING	OM581	PDIST	0
582 STATION EXPENSES	OM582	PDIST	0
583 OVERHEAD LINE EXPENSES	OM583	PDIST	0
584 UNDERGROUND LINE EXPENSES	OM584	PDIST	0
585 STREET LIGHTING EXPENSE	OM585	PDIST	0
586 METER EXPENSES	OM586	PDIST	0
586 METER EXPENSES - LOAD MANAGEMENT	OM586x	PDIST	0
587 CUSTOMER INSTALLATIONS EXPENSE	OM587	PDIST	0
588 MISCELLANEOUS DISTRIBUTION EXP	OM588	PDIST	0
588 MISC DISTR EXP -- MAPPIN	OM588x	PDIST	0
589 RENTS	OM589	PDIST	0
Total Distribution Operation Expense	OMDO		
Operation and Maintenance Expenses (Continued)			
Distribution Maintenance Expense			
590 MAINTENANCE SUPERVISION AND EN	OM590	LBDM	0
591 STRUCTURES	OM591	PDIST	0
592 MAINTENANCE OF STATION EQUIPME	OM592	PDIST	0
593 MAINTENANCE OF OVERHEAD LINES	OM593	PDIST	0
594 MAINTENANCE OF UNDERGROUND LIN	OM594	PDIST	0
595 MAINTENANCE OF LINE TRANSFORME	OM595	PDIST	0
596 MAINTENANCE OF ST LIGHTS & SIG SYSTEMS	OM596	PDIST	0
597 MAINTENANCE OF METERS	OM597	PDIST	0
598 MISCELLANEOUS DISTRIBUTION EXPENSES	OM598	PDIST	0
Total Distribution Maintenance Expense	OMDM		
Total Distribution Operation and Maintenance Expenses			
Transmission and Distribution Expenses			
Production, Transmission and Distribution Expenses	OMSUB		

Description	Name	Functional Vector		Total System	November 2009	December 2009	January 2010	February 2010	March 2010
Customer Accounts Expense									
901 SUPERVISION/CUSTOMER ACCTS	OM901	F025	$	-	0	0	0	0	0
902 METER READING EXPENSES	OM902	F025	$	-	0	0	0	0	0
903 RECORDS AND COLLECTION	OM903	F025	$	-	0	0	0	0	0
904 UNCOLLECTIBLE ACCOUNTS	OM904	F025	$	-	0	0	0	0	0
905 MISC CUST ACCOUNTS	OM903	F025	$	-	0	0	0	0	0
Total Customer Accounts Expense	OMCA		$	-					
Customer Service Expense									
907 SUPERVISION	OM907	TUP	$	-	0	0	0	0	0
908 CUSTOMER ASSISTANCE EXPENSES	OM908	TUP	$	591,192	104389.97	75645.08	40729.07	42316.45	53316.29
908 CUSTOMER ASSISTANCE EXP-INCENTIVES	OM908x	TUP	$	-	0	0	0	0	0
909 INFORMATIONAL AND INSTRUCTIONA	OM909	TUP	$	-	0	0	0	0	0
909 INFORM AND INSTRUC -LOAD MGMT	OM909x	TUP	$	-	0	0	0	0	0
910 MISCELLANEOUS CUSTOMER SERVICE	OM910	TUP	$	-	0	0	0	0	0
911 DEMONSTRATION AND SELLING EXP	OM911	TUP	$	-	0	0	0	0	0
912 DEMONSTRATION AND SELLING EXP	OM912	TUP	$	-	0	0	0	0	0
913 ADVERTISING EXPENSES	OM913	TUP	$	488,103	103663.39	219971.2	7179.7	3679.68	21007.78
915 MDSE-JOBBING-CONTRACT	OM915	TUP	$	-	0	0	0	0	0
916 MISC SALES EXPENSE	OM916	TUP	$	-	0	0	0	0	0
Total Customer Service Expense	OMCS		$	1,079,295	208053.36	295616.28	47908.77	45996.13	74324.07
Sub-Total Prod, Trans, Dist, Cust Acct and Cust Service	OMSUB2			417,817,266					
<u>**Operation and Maintenance Expenses (Continued)**</u>									
Administrative and General Expense									
920 ADMIN. & GEN. SALARIES-	OM920	LBSUB9	$	14,315,713	2092449.03	1522142.97	1300504.05	1313340.25	1495631.43
921 OFFICE SUPPLIES AND EXPENSES	OM921	LBSUB9	$	6,915,648	432853.99	1082881.21	447533.76	790015.22	520665.52
922 ADMINISTRATIVE EXPENSES TRANSFERRED	OM922	LBSUB9	$	-	0	0	0	0	0
923 OUTSIDE SERVICES EMPLOYED	OM923	LBSUB9	$	3,954,189	337609.86	1175322.5	167190.31	217289.45	526048.51
924 PROPERTY INSURANCE	OM924	TUP	$	-	0	0	0	0	0
925 INJURIES AND DAMAGES - INSURAN	OM925	LBSUB9	$	179,889	13413.2	21072.48	15311.2	15178.2	25828.68
926 EMPLOYEE BENEFITS	OM926	LBSUB9	$	169,663	4383.08	-2896.98	25050.87	3276.12	0
927 FRANCHISE REQUIREMENTS	OM927	TUP	$	-	0	0	0	0	0
928 REGULATORY COMMISSION FEES	OM928	TUP	$	1,188,958	2785	925	0	0	1790.1
929 DUPLICATE CHARGES-CR	OM929	LBSUB9	$	-	0	0	0	0	0
930 MISCELLANEOUS GENERAL EXPENSES	OM930	LBSUB9	$	1,686,131	68132.08	249532.88	81732.32	215359.96	139106.95
931 RENTS AND LEASES	OM931	PGP	$	1,933	161.09	161.09	161.09	161.09	161.09
935 MAINTENANCE OF GENERAL PLANT	OM935	PGP	$	208,156	23769.07	24452.06	14946.22	44645.76	14798.82
Total Administrative and General Expense	OMAG		$	28,620,280	2,975,556.40	4,073,593.21	2,052,429.82	2,599,266.05	2,724,031.10
Total Operation and Maintenance Expenses	TOM		$	446,437,546					
Operation and Maintenance Expenses Less Purchase Power & Fuel	OMLPP		$	224,914,919					

Description	Name	Functional Vector	April 2010	May 2010	June 2010	July 2010	August 2010	September 2010
Customer Accounts Expense								
901 SUPERVISION/CUSTOMER ACCTS	OM901	F025	0	0	0	0	0	0
902 METER READING EXPENSES	OM902	F025	0	0	0	0	0	0
903 RECORDS AND COLLECTION	OM903	F025	0	0	0	0	0	0
904 UNCOLLECTIBLE ACCOUNTS	OM904	F025	0	0	0	0	0	0
905 MISC CUST ACCOUNTS	OM903	F025	0	0	0	0	0	0
Total Customer Accounts Expense	OMCA							
Customer Service Expense								
907 SUPERVISION	OM907	TUP	0	0	0	0	0	0
908 CUSTOMER ASSISTANCE EXPENSES	OM908	TUP	42590.29	45548.65	47955.97	41989.91	36242.46	23856.1
908 CUSTOMER ASSISTANCE EXP-INCENTIVES	OM908x	TUP	0	0	0	0	0	0
909 INFORMATIONAL AND INSTRUCTIONA	OM909	TUP	0	0	0	0	0	0
909 INFORM AND INSTRUC -LOAD MGMT	OM909x	TUP	0	0	0	0	0	0
910 MISCELLANEOUS CUSTOMER SERVICE	OM910	TUP	0	0	0	0	0	0
911 DEMONSTRATION AND SELLING EXP	OM911	TUP	0	0	0	0	0	0
912 DEMONSTRATION AND SELLING EXP	OM912	TUP	0	0	0	0	0	0
913 ADVERTISING EXPENSES	OM913	TUP	-36141.33	11695.6	18760.65	13630.34	24487.44	100169
915 MDSE-JOBBING-CONTRACT	OM915	TUP	0	0	0	0	0	0
916 MISC SALES EXPENSE	OM916	TUP	0	0	0	0	0	0
Total Customer Service Expense	OMCS		6448.96	57244.25	66716.62	55620.25	60729.9	124025.1
Sub-Total Prod, Trans, Dist, Cust Acct and Cust Service	OMSUB2							
Operation and Maintenance Expenses (Continued)								
Administrative and General Expense								
920 ADMIN. & GEN. SALARIES-	OM920	LBSUB9	1326991.23	427833.15	1263415.19	446430.74	948956.12	1178332.32
921 OFFICE SUPPLIES AND EXPENSES	OM921	LBSUB9	591943.78	481169.78	617503.76	673906.86	384307.2	494280.5
922 ADMINISTRATIVE EXPENSES TRANSFERRED	OM922	LBSUB9	0	0	0	0	0	0
923 OUTSIDE SERVICES EMPLOYED	OM923	LBSUB9	388800.48	188378.03	280346.99	85723.73	284467.92	205203.9
924 PROPERTY INSURANCE	OM924	TUP	0	0	0	0	0	0
925 INJURIES AND DAMAGES - INSURAN	OM925	LBSUB9	14679.26	12401	12401	12401	12401	12401
926 EMPLOYEE BENEFITS	OM926	LBSUB9	53705.24	8851.25	5962.88	6192.45	33341.38	6109.83
927 FRANCHISE REQUIREMENTS	OM927	TUP	0	0	0	0	0	0
928 REGULATORY COMMISSION FEES	OM928	TUP	1353.14	48087.75	665466.25	48046.08	139142.52	18419
929 DUPLICATE CHARGES-CR	OM929	LBSUB9	0	0	0	0	0	0
930 MISCELLANEOUS GENERAL EXPENSES	OM930	LBSUB9	94167.83	259652.47	119570.46	108391.43	155943.83	63658.14
931 RENTS AND LEASES	OM931	PGP	161.09	161.09	161.09	161.09	161.09	161.09
935 MAINTENANCE OF GENERAL PLANT	OM935	PGP	8698.33	7258.14	13445.04	8125.63	22399.01	9027.98
Total Administrative and General Expense	OMAG		2,480,500.38	1,433,792.66	2,978,272.66	1,389,379.01	1,981,120.07	1,987,593.76
Total Operation and Maintenance Expenses	TOM							
Operation and Maintenance Expenses Less Purchase Power & Fuel	OMLPP							

Description	Name	Functional Vector	October 2010
Customer Accounts Expense			
901 SUPERVISION/CUSTOMER ACCTS	OM901	F025	0
902 METER READING EXPENSES	OM902	F025	0
903 RECORDS AND COLLECTION	OM903	F025	0
904 UNCOLLECTIBLE ACCOUNTS	OM904	F025	0
905 MISC CUST ACCOUNTS	OM903	F025	0
Total Customer Accounts Expense	OMCA		
Customer Service Expense			
907 SUPERVISION	OM907	TUP	0
908 CUSTOMER ASSISTANCE EXPENSES	OM908	TUP	36611.39
908 CUSTOMER ASSISTANCE EXP-INCENTIVES	OM908x	TUP	0
909 INFORMATIONAL AND INSTRUCTIONA	OM909	TUP	0
909 INFORM AND INSTRUC -LOAD MGMT	OM909x	TUP	0
910 MISCELLANEOUS CUSTOMER SERVICE	OM910	TUP	0
911 DEMONSTRATION AND SELLING EXP	OM911	TUP	0
912 DEMONSTRATION AND SELLING EXP	OM912	TUP	0
913 ADVERTISING EXPENSES	OM913	TUP	0
915 MDSE-JOBBING-CONTRACT	OM915	TUP	0
916 MISC SALES EXPENSE	OM916	TUP	0
Total Customer Service Expense	OMCS		36611.39
Sub-Total Prod, Trans, Dist, Cust Acct and Cust Service	OMSUB2		
<u>**Operation and Maintenance Expenses (Continued)**</u>			
Administrative and General Expense			
920 ADMIN. & GEN. SALARIES-	OM920	LBSUB9	999686.96
921 OFFICE SUPPLIES AND EXPENSES	OM921	LBSUB9	398586.21
922 ADMINISTRATIVE EXPENSES TRANSFERRED	OM922	LBSUB9	0
923 OUTSIDE SERVICES EMPLOYED	OM923	LBSUB9	97807.2
924 PROPERTY INSURANCE	OM924	TUP	0
925 INJURIES AND DAMAGES - INSURAN	OM925	LBSUB9	12401
926 EMPLOYEE BENEFITS	OM926	LBSUB9	25686.5
927 FRANCHISE REQUIREMENTS	OM927	TUP	0
928 REGULATORY COMMISSION FEES	OM928	TUP	262942.92
929 DUPLICATE CHARGES-CR	OM929	LBSUB9	0
930 MISCELLANEOUS GENERAL EXPENSES	OM930	LBSUB9	130882.85
931 RENTS AND LEASES	OM931	PGP	161.09
935 MAINTENANCE OF GENERAL PLANT	OM935	PGP	16590.29
Total Administrative and General Expense	OMAG		1,944,745.02
Total Operation and Maintenance Expenses	TOM		
Operation and Maintenance Expenses Less Purchase Power & Fuel	OMLPP		

Description	Name	Functional Vector		Total System	November 2009	December 2009	January 2010	February 2010	March 2010
Labor Expenses									
Steam Power Generation Operation Expenses									
500 OPERATION SUPERVISION & ENGINEERING	LB500	PROFIX	$	4,967,667	342832.39	1034681.8	357452.74	317350.15	384316.78
501 FUEL	LB501	Energy	$	3,889,944	323255.71	364406.07	338654.53	313289.78	326385.9
502 STEAM EXPENSES	LB502	PROFIX	$	9,023,322	657659.63	771924.79	681077.92	630021.61	688026.67
505 ELECTRIC EXPENSES	LB505	PROFIX	$	4,523,897	357040.19	416235	378976.79	348125.67	369036.85
506 MISC. STEAM POWER EXPENSES	LB506	PROFIX	$	940,518	52261.31	80829.64	70706.68	101840.85	81036.08
507 RENTS	LB507	PROFIX	$	-	0	0	0	0	0
509 ALLOWANCES	LB509	Energy	$	-	0	0	0	0	0
Total Steam Power Operation Expenses	LBSUB1		$	23,345,348	1066961.13	1268989.43	1130761.39	1079988.13	1138099.6
Steam Power Generation Maintenance Expenses									
510 MAINTENANCE SUPERVISION & ENGINEERING	LB510	Energy	$	3,623,969	301562.96	282674.01	280925.01	285686.26	324812.85
511 MAINTENANCE OF STRUCTURES	LB511	PROFIX	$	986,831	60839.92	78449.28	79549.6	75632	64969.97
512 MAINTENANCE OF BOILER PLANT	LB512	Energy	$	8,700,235	613650.58	728746.59	804049.52	597501.69	694231.84
513 MAINTENANCE OF ELECTRIC PLANT	LB513	Energy	$	1,595,642	209176.55	143092.64	90379.11	93612.16	119373.66
514 MAINTENANCE OF MISC STEAM PLANT	LB514	PROFIX	$	200,886	16879.23	22485.07	12128	16408.41	14092.69
Total Steam Power Generation Maintenance Expense	LBSUB2		$	15,107,564	1202109.24	1255447.59	1267031.24	1068840.52	1217481.01
Total Steam Power Generation Expense			$	38,452,913	2269070.37	2524437.02	2397792.63	2148828.65	2355580.61
Labor Expenses (Continued)									
Other Power Generation Operation Expense									
546 OPERATION SUPERVISION & ENGINEERING	LB546	PROFIX	$	-	0	0	0	0	0
547 FUEL	LB547	Energy	$	-	0	0	0	0	0
548 GENERATION EXPENSE	LB548	PROFIX	$	-	0	0	0	0	0
549 MISC OTHER POWER GENERATION	LB549	PROFIX	$	-	0	0	0	0	0
550 RENTS	LB550	PROFIX	$	-	0	0	0	0	0
Total Other Power Generation Expenses	LBSUB7		$	-					
Other Power Generation Maintenance Expense									
551 MAINTENANCE SUPERVISION & ENGINEERING	LB551	PROFIX	$	-	0	0	0	0	0
552 MAINTENANCE OF STRUCTURES	LB552	PROFIX	$	-	0	0	0	0	0
553 MAINTENANCE OF GENERATING & ELEC PLANT	LB553	PROFIX	$	89,555	682.21	4299.67	1026.96	2400.3	4848.64
554 MAINTENANCE OF MISC OTHER POWER GEN PLT	LB554	PROFIX	$	-	0	0	0	0	0
Total Other Power Generation Maintenance Expense	LBSUB8		$	89,555					
Total Other Power Generation Expense			$	89,555					
Total Production Expense	LPREX		$	38,542,468					

Description	Name	Functional Vector	April 2010	May 2010	June 2010	July 2010	August 2010	September 2010
Labor Expenses								
Steam Power Generation Operation Expenses								
500 OPERATION SUPERVISION & ENGINEERING	LB500	PROFIX	338156.02	414149.39	371014.23	359005.08	369873.15	334189.99
501 FUEL	LB501	Energy	309863.06	297596.67	304977.88	310355.07	339148.89	336547.05
502 STEAM EXPENSES	LB502	PROFIX	640194.64	1123637.4	744724.17	661984.49	702417.45	982572.63
505 ELECTRIC EXPENSES	LB505	PROFIX	342341.75	393006.64	354302.21	368561.14	384521.42	384533.54
506 MISC. STEAM POWER EXPENSES	LB506	PROFIX	63015.48	66970.66	87852.14	88369.17	86572.5	91267.67
507 RENTS	LB507	PROFIX	0	0	0	0	0	0
509 ALLOWANCES	LB509	Energy	0	0	0	0	0	0
Total Steam Power Operation Expenses	LBSUB1		1045551.87	1583614.7	1186878.52	1118914.8	1173511.37	1458373.84
Steam Power Generation Maintenance Expenses								
510 MAINTENANCE SUPERVISION & ENGINEERING	LB510	Energy	297255.94	289425	296206.84	280281.91	307241.14	294029.27
511 MAINTENANCE OF STRUCTURES	LB511	PROFIX	50081.03	70791.44	106230.99	106856.88	116200.49	96973.59
512 MAINTENANCE OF BOILER PLANT	LB512	Energy	617716.63	961798.07	675983.16	535600.92	651081.61	924014.95
513 MAINTENANCE OF ELECTRIC PLANT	LB513	Energy	96940.39	142971.1	124922.34	132978.24	129288.01	126399.56
514 MAINTENANCE OF MISC STEAM PLANT	LB514	PROFIX	9843.3	16400.27	20426.8	23473.83	26283.4	15419.85
Total Steam Power Generation Maintenance Expense	LBSUB2		1071837.29	1481385.88	1223770.13	1079191.78	1230094.65	1456837.22
Total Steam Power Generation Expense			2117389.16	3065000.58	2410648.65	2198106.58	2403606.02	2915211.06
Labor Expenses (Continued)								
Other Power Generation Operation Expense								
546 OPERATION SUPERVISION & ENGINEERING	LB546	PROFIX	0	0	0	0	0	0
547 FUEL	LB547	Energy	0	0	0	0	0	0
548 GENERATION EXPENSE	LB548	PROFIX	0	0	0	0	0	0
549 MISC OTHER POWER GENERATION	LB549	PROFIX	0	0	0	0	0	0
550 RENTS	LB550	PROFIX	0	0	0	0	0	0
Total Other Power Generation Expenses	LBSUB7							
Other Power Generation Maintenance Expense								
551 MAINTENANCE SUPERVISION & ENGINEERING	LB551	PROFIX	0	0	0	0	0	0
552 MAINTENANCE OF STRUCTURES	LB552	PROFIX	0	0	0	0	0	0
553 MAINTENANCE OF GENERATING & ELEC PLANT	LB553	PROFIX	903.26	760.91	37267.71	11775.09	12921.35	10584.31
554 MAINTENANCE OF MISC OTHER POWER GEN PLT	LB554	PROFIX	0	0	0	0	0	0
Total Other Power Generation Maintenance Expense	LBSUB8							
Total Other Power Generation Expense								
Total Production Expense	LPREX							

Description	Name	Functional Vector	October 2010
Labor Expenses			
Steam Power Generation Operation Expenses			
500 OPERATION SUPERVISION & ENGINEERING	LB500	PROFIX	344645.64
501 FUEL	LB501	Energy	325463.54
502 STEAM EXPENSES	LB502	PROFIX	739080.82
505 ELECTRIC EXPENSES	LB505	PROFIX	427215.91
506 MISC. STEAM POWER EXPENSES	LB506	PROFIX	69795.43
507 RENTS	LB507	PROFIX	0
509 ALLOWANCES	LB509	Energy	0
Total Steam Power Operation Expenses	LBSUB1		1236092.16
Steam Power Generation Maintenance Expenses			
510 MAINTENANCE SUPERVISION & ENGINEERING	LB510	Energy	383868.11
511 MAINTENANCE OF STRUCTURES	LB511	PROFIX	80256.21
512 MAINTENANCE OF BOILER PLANT	LB512	Energy	895859.55
513 MAINTENANCE OF ELECTRIC PLANT	LB513	Energy	186508.29
514 MAINTENANCE OF MISC STEAM PLANT	LB514	PROFIX	7045.58
Total Steam Power Generation Maintenance Expense	LBSUB2		1553537.74
Total Steam Power Generation Expense			2642951.16
Labor Expenses (Continued)			
Other Power Generation Operation Expense			
546 OPERATION SUPERVISION & ENGINEERING	LB546	PROFIX	0
547 FUEL	LB547	Energy	0
548 GENERATION EXPENSE	LB548	PROFIX	0
549 MISC OTHER POWER GENERATION	LB549	PROFIX	0
550 RENTS	LB550	PROFIX	0
Total Other Power Generation Expenses	LBSUB7		
Other Power Generation Maintenance Expense			
551 MAINTENANCE SUPERVISION & ENGINEERING	LB551	PROFIX	
552 MAINTENANCE OF STRUCTURES	LB552	PROFIX	
553 MAINTENANCE OF GENERATING & ELEC PLANT	LB553	PROFIX	2084.81
554 MAINTENANCE OF MISC OTHER POWER GEN PLT	LB554	PROFIX	
Total Other Power Generation Maintenance Expense	LBSUB8		
Total Other Power Generation Expense			
Total Production Expense	LPREX		

Description	Name	Functional Vector		Total System	November 2009	December 2009	January 2010	February 2010	March 2010
Labor Expenses (Continued)									
Purchased Power									
555 PURCHASED POWER	LB555	OMPP	$	-	0	0	0	0	0
555 PURCHASED POWER Demand	LBD555	OMPPD	$	-	0	0	0	0	0
555 PURCHASED POWER OPTIONS	LBO555	OMPP	$	-	0	0	0	0	0
555 BROKERAGE FEES	LBB555	OMPP	$	-	0	0	0	0	0
555 MISO TRANSMISSION EXPENSES	LBM555	OMPP	$	-	0	0	0	0	0
556 SYSTEM CONTROL AND LOAD DISPATCH	LB556	PROFIX	$	-	0	0	0	0	0
557 OTHER EXPENSES	LB557	PROFIX	$	-	0	0	0	0	0
558 DUPLICATE CHARGES	LB558	Energy	$	-	0	0	0	0	0
Total Purchased Power Labor	LBPP		$	-					
Transmission Labor Expenses									
560 OPERATION SUPERVISION AND ENG	LB560	PTRAN	$	835,977	155357.97	88621.66	61719.3	53192.77	69331.26
561 LOAD DISPATCHING	LB561	PTRAN	$	1,304,969	240520.6	133245.05	93819.32	87693.64	104400.26
562 STATION EXPENSES	LB562	PTRAN	$	598,382	102945.93	50883.95	33705.43	39512.69	54112.06
563 OVERHEAD LINE EXPENSES	LB563	PTRAN	$	236,393	52690.64	20206.01	20032.96	18769.45	17519.18
565 TRANSMISSION OF ELECTRICITY BY OTHERS	LB565	PTRAN	$	-	0	0	0	0	0
566 MISC. TRANSMISSION EXPENSES	LB566	PTRAN	$	312,375	55300.19	33112.8	26544.3	26563.55	28599.72
567 RENTS	LB567	PTRAN	$	-	0	0	0	0	0
568 MAINTENACE SUPERVISION AND ENG	LB568	PTRAN	$	644,925	120270.89	65874.61	48314.25	39737.97	53182.86
569 MAINTENACE OF STRUCTURES	LB569	PTRAN	$	318	36.88	59.34	0	0	59.12
570 MAINT OF STATION EQUIPMENT	LB570	PTRAN	$	1,433,304	240458.8	137581.27	112331.02	103977.18	112839.1
571 MAINT OF OVERHEAD LINES	LB571	PTRAN	$	1,067,766	187769.72	120250.23	62124.04	70835.46	82150.36
573 MAINT OF MISC. TRANSMISSION PLANT	LB573	PTRAN	$	46,439	6906.42	2875.43	2872.93	4248.62	4851.27
Total Transmission Labor Expenses	LBTRAN		$	6,480,848	1162258.04	652710.35	461463.55	444531.33	527045.19
Distribution Operation Labor Expense									
580 OPERATION SUPERVISION AND ENGI	LB580	F023	$	-	0	0	0	0	0
581 LOAD DISPATCHING	LB581	PDIST	$	-	0	0	0	0	0
582 STATION EXPENSES	LB582	PDIST	$	-	0	0	0	0	0
583 OVERHEAD LINE EXPENSES	LB583	PDIST	$	-	0	0	0	0	0
584 UNDERGROUND LINE EXPENSES	LB584	PDIST	$	-	0	0	0	0	0
585 STREET LIGHTING EXPENSE	LB585	PDIST	$	-	0	0	0	0	0
586 METER EXPENSES	LB586	PDIST	$	-	0	0	0	0	0
586 METER EXPENSES - LOAD MANAGEMENT	LB586x	PDIST	$	-	0	0	0	0	0
587 CUSTOMER INSTALLATIONS EXPENSE	LB587	PDIST	$	-	0	0	0	0	0
588 MISCELLANEOUS DISTRIBUTION EXP	LB588	PDIST	$	-	0	0	0	0	0
589 RENTS	LB589	PDIST	$	-	0	0	0	0	0
Total Distribution Operation Labor Expense	LBDO		$	-					

Description	Name	Functional Vector	April 2010	May 2010	June 2010	July 2010	August 2010	September 2010
Labor Expenses (Continued)								
Purchased Power								
555 PURCHASED POWER	LB555	OMPP	0	0	0	0	0	0
555 PURCHASED POWER Demand	LBD555	OMPPD	0	0	0	0	0	0
555 PURCHASED POWER OPTIONS	LBO555	OMPP	0	0	0	0	0	0
555 BROKERAGE FEES	LBB555	OMPP	0	0	0	0	0	0
555 MISO TRANSMISSION EXPENSES	LBM555	OMPP	0	0	0	0	0	0
556 SYSTEM CONTROL AND LOAD DISPATCH	LB556	PROFIX	0	0	0	0	0	0
557 OTHER EXPENSES	LB557	PROFIX	0	0	0	0	0	0
558 DUPLICATE CHARGES	LB558	Energy	0	0	0	0	0	0
Total Purchased Power Labor	LBPP							
Transmission Labor Expenses								
560 OPERATION SUPERVISION AND ENG	LB560	PTRAN	57113.62	58908.5	68081.43	56191.8	51380.65	68130.77
561 LOAD DISPATCHING	LB561	PTRAN	79471.75	90840.85	104792.75	86864.08	84835.7	115440.78
562 STATION EXPENSES	LB562	PTRAN	43463.43	48316.48	56470.33	35035.32	46067.52	51613.79
563 OVERHEAD LINE EXPENSES	LB563	PTRAN	14223.62	16460.25	15132.13	14168.98	13692.1	15806.34
565 TRANSMISSION OF ELECTRICITY BY OTHERS	LB565	PTRAN	0	0	0	0	0	0
566 MISC. TRANSMISSION EXPENSES	LB566	PTRAN	21343.51	20102.2	25810.07	11252.29	17357.03	25204.78
567 RENTS	LB567	PTRAN	0	0	0	0	0	0
568 MAINTENACE SUPERVISION AND ENG	LB568	PTRAN	43994.75	45554.09	50783.31	42264.13	40489.73	55734.99
569 MAINTENACE OF STRUCTURES	LB569	PTRAN	26.22	0	24.61	26.14	26.21	0.65
570 MAINT OF STATION EQUIPMENT	LB570	PTRAN	98690.36	92937.1	116008.73	108080.33	93852.16	126204.48
571 MAINT OF OVERHEAD LINES	LB571	PTRAN	66143.16	68592.74	93608.24	76903.52	71073.25	95620.68
573 MAINT OF MISC. TRANSMISSION PLANT	LB573	PTRAN	4378.83	3303.42	3349.41	3196.71	3607.42	3592.3
Total Transmission Labor Expenses	LBTRAN		428849.25	445015.63	534061.01	433983.3	422381.77	557349.56
Distribution Operation Labor Expense								
580 OPERATION SUPERVISION AND ENGI	LB580	F023	0	0	0	0	0	0
581 LOAD DISPATCHING	LB581	PDIST	0	0	0	0	0	0
582 STATION EXPENSES	LB582	PDIST	0	0	0	0	0	0
583 OVERHEAD LINE EXPENSES	LB583	PDIST	0	0	0	0	0	0
584 UNDERGROUND LINE EXPENSES	LB584	PDIST	0	0	0	0	0	0
585 STREET LIGHTING EXPENSE	LB585	PDIST	0	0	0	0	0	0
586 METER EXPENSES	LB586	PDIST	0	0	0	0	0	0
586 METER EXPENSES - LOAD MANAGEMENT	LB586x	PDIST	0	0	0	0	0	0
587 CUSTOMER INSTALLATIONS EXPENSE	LB587	PDIST	0	0	0	0	0	0
588 MISCELLANEOUS DISTRIBUTION EXP	LB588	PDIST	0	0	0	0	0	0
589 RENTS	LB589	PDIST	0	0	0	0	0	0
Total Distribution Operation Labor Expense	LBDO							

Description	Name	Functional Vector	October 2010
Labor Expenses (Continued)			
Purchased Power			
555 PURCHASED POWER	LB555	OMPP	0
555 PURCHASED POWER Demand	LBD555	OMPPD	0
555 PURCHASED POWER OPTIONS	LBO555	OMPP	0
555 BROKERAGE FEES	LBB555	OMPP	0
555 MISO TRANSMISSION EXPENSES	LBM555	OMPP	0
556 SYSTEM CONTROL AND LOAD DISPATCH	LB556	PROFIX	0
557 OTHER EXPENSES	LB557	PROFIX	0
558 DUPLICATE CHARGES	LB558	Energy	0
Total Purchased Power Labor	LBPP		0
Transmission Labor Expenses			
560 OPERATION SUPERVISION AND ENG	LB560	PTRAN	47946.89
561 LOAD DISPATCHING	LB561	PTRAN	83043.95
562 STATION EXPENSES	LB562	PTRAN	36255.02
563 OVERHEAD LINE EXPENSES	LB563	PTRAN	17691.07
565 TRANSMISSION OF ELECTRICITY BY OTHERS	LB565	PTRAN	
566 MISC. TRANSMISSION EXPENSES	LB566	PTRAN	21184.45
567 RENTS	LB567	PTRAN	
568 MAINTENACE SUPERVISION AND ENG	LB568	PTRAN	38723.49
569 MAINTENACE OF STRUCTURES	LB569	PTRAN	59.17
570 MAINT OF STATION EQUIPMENT	LB570	PTRAN	90343.75
571 MAINT OF OVERHEAD LINES	LB571	PTRAN	72694.7
573 MAINT OF MISC. TRANSMISSION PLANT	LB573	PTRAN	3256.6
Total Transmission Labor Expenses	LBTRAN		205077.71
Distribution Operation Labor Expense			
580 OPERATION SUPERVISION AND ENGI	LB580	F023	0
581 LOAD DISPATCHING	LB581	PDIST	0
582 STATION EXPENSES	LB582	PDIST	0
583 OVERHEAD LINE EXPENSES	LB583	PDIST	0
584 UNDERGROUND LINE EXPENSES	LB584	PDIST	0
585 STREET LIGHTING EXPENSE	LB585	PDIST	0
586 METER EXPENSES	LB586	PDIST	0
586 METER EXPENSES - LOAD MANAGEMENT	LB586x	PDIST	0
587 CUSTOMER INSTALLATIONS EXPENSE	LB587	PDIST	0
588 MISCELLANEOUS DISTRIBUTION EXP	LB588	PDIST	0
589 RENTS	LB589	PDIST	0
Total Distribution Operation Labor Expense	LBDO		

Description	Name	Functional Vector		Total System	November 2009	December 2009	January 2010	February 2010	March 2010
Labor Expenses (Continued)									
Distribution Maintenance Labor Expense									
590 MAINTENANCE SUPERVISION AND EN	LB590	F024	$	-	0	0	0	0	0
591 MAINTENANCE OF STRUCTURES	LB591	PDIST	$	-	0	0	0	0	0
592 MAINTENANCE OF STATION EQUIPME	LB592	PDIST	$	-	0	0	0	0	0
593 MAINTENANCE OF OVERHEAD LINES	LB593	PDIST	$	-	0	0	0	0	0
594 MAINTENANCE OF UNDERGROUND LIN	LB594	PDIST	$	-	0	0	0	0	0
595 MAINTENANCE OF LINE TRANSFORME	LB595	PDIST	$	-	0	0	0	0	0
596 MAINTENANCE OF ST LIGHTS & SIG SYSTEMS	LB596	PDIST	$	-	0	0	0	0	0
597 MAINTENANCE OF METERS	LB597	PDIST	$	-	0	0	0	0	0
598 MAINTENANCE OF MISC DISTR PLANT	LB598	PDIST	$	-	0	0	0	0	0
Total Distribution Maintenance Labor Expense	LBDM		$	-					
Total Distribution Operation and Maintenance Labor Expenses		PDIST		-					
Transmission and Distribution Labor Expenses				6,480,848					
Production, Transmission and Distribution Labor Expenses	LBSUB		$	45,023,316					
Customer Accounts Expense									
901 SUPERVISION/CUSTOMER ACCTS	LB901	F025	$	-	0	0	0	0	0
902 METER READING EXPENSES	LB902	F025	$	-	0	0	0	0	0
903 RECORDS AND COLLECTION	LB903	F025	$	-	0	0	0	0	0
904 UNCOLLECTIBLE ACCOUNTS	LB904	F025	$	-	0	0	0	0	0
905 MISC CUST ACCOUNTS	LB903	F025	$	-	0	0	0	0	0
Total Customer Accounts Labor Expense	LBCA		$	-					
Customer Service Expense									
907 SUPERVISION	LB907	TUP	$	-	0	0	0	0	0
908 CUSTOMER ASSISTANCE EXPENSES	LB908	TUP	$	544,608	98543.49	44838.51	39429.59	38666.03	49827.22
908 CUSTOMER ASSISTANCE EXP-LOAD MGMT	LB908x	TUP	$	-	0	0	0	0	0
909 INFORMATIONAL AND INSTRUCTIONA	LB909	TUP	$	-	0	0	0	0	0
909 INFORM AND INSTRUC -LOAD MGMT	LB909x	TUP	$	-	0	0	0	0	0
910 MISCELLANEOUS CUSTOMER SERVICE	LB910	TUP	$	-	0	0	0	0	0
911 DEMONSTRATION AND SELLING EXP	LB911	TUP	$	-	0	0	0	0	0
912 DEMONSTRATION AND SELLING EXP	LB912	TUP	$	-	0	0	0	0	0
913 WATER HEATER - HEAT PUMP PROGRAM	LB913	TUP	$	-	0	0	0	0	0
915 MDSE-JOBBING-CONTRACT	LB915	TUP	$	-	0	0	0	0	0
916 MISC SALES EXPENSE	LB916	TUP	$	-	0	0	0	0	0
Total Customer Service Labor Expense	LBCS		$	544,608	98543.49	44838.51	39429.59	38666.03	49827.22
Sub-Total Labor Exp	LBSUB9			45,567,924					

Description	Name	Functional Vector	April 2010	May 2010	June 2010	July 2010	August 2010	September 2010
Labor Expenses (Continued)								
Distribution Maintenance Labor Expense								
590 MAINTENANCE SUPERVISION AND EN	LB590	F024	0	0	0	0	0	0
591 MAINTENANCE OF STRUCTURES	LB591	PDIST	0	0	0	0	0	0
592 MAINTENANCE OF STATION EQUIPME	LB592	PDIST	0	0	0	0	0	0
593 MAINTENANCE OF OVERHEAD LINES	LB593	PDIST	0	0	0	0	0	0
594 MAINTENANCE OF UNDERGROUND LIN	LB594	PDIST	0	0	0	0	0	0
595 MAINTENANCE OF LINE TRANSFORME	LB595	PDIST	0	0	0	0	0	0
596 MAINTENANCE OF ST LIGHTS & SIG SYSTEMS	LB596	PDIST	0	0	0	0	0	0
597 MAINTENANCE OF METERS	LB597	PDIST	0	0	0	0	0	0
598 MAINTENANCE OF MISC DISTR PLANT	LB598	PDIST	0	0	0	0	0	0
Total Distribution Maintenance Labor Expense	LBDM							
Total Distribution Operation and Maintenance Labor Expenses		PDIST						
Transmission and Distribution Labor Expenses								
Production, Transmission and Distribution Labor Expenses	LBSUB							
Customer Accounts Expense								
901 SUPERVISION/CUSTOMER ACCTS	LB901	F025	0	0	0	0	0	0
902 METER READING EXPENSES	LB902	F025	0	0	0	0	0	0
903 RECORDS AND COLLECTION	LB903	F025	0	0	0	0	0	0
904 UNCOLLECTIBLE ACCOUNTS	LB904	F025	0	0	0	0	0	0
905 MISC CUST ACCOUNTS	LB903	F025	0	0	0	0	0	0
Total Customer Accounts Labor Expense	LBCA							
Customer Service Expense								
907 SUPERVISION	LB907	TUP	0	0	0	0	0	0
908 CUSTOMER ASSISTANCE EXPENSES	LB908	TUP	37915.48	41556.72	44591.58	38345.68	32873.52	44118.04
908 CUSTOMER ASSISTANCE EXP-LOAD MGMT	LB908x	TUP	0	0	0	0	0	0
909 INFORMATIONAL AND INSTRUCTIONA	LB909	TUP	0	0	0	0	0	0
909 INFORM AND INSTRUC -LOAD MGMT	LB909x	TUP	0	0	0	0	0	0
910 MISCELLANEOUS CUSTOMER SERVICE	LB910	TUP	0	0	0	0	0	0
911 DEMONSTRATION AND SELLING EXP	LB911	TUP	0	0	0	0	0	0
912 DEMONSTRATION AND SELLING EXP	LB912	TUP	0	0	0	0	0	0
913 WATER HEATER - HEAT PUMP PROGRAM	LB913	TUP	0	0	0	0	0	0
915 MDSE-JOBBING-CONTRACT	LB915	TUP	0	0	0	0	0	0
916 MISC SALES EXPENSE	LB916	TUP	0	0	0	0	0	0
Total Customer Service Labor Expense	LBCS		37915.48	41556.72	44591.58	38345.68	32873.52	44118.04
Sub-Total Labor Exp	LBSUB9							

Description	Name	Functional Vector	October 2010
Labor Expenses (Continued)			
Distribution Maintenance Labor Expense			
590 MAINTENANCE SUPERVISION AND EN	LB590	F024	
591 MAINTENANCE OF STRUCTURES	LB591	PDIST	
592 MAINTENANCE OF STATION EQUIPME	LB592	PDIST	
593 MAINTENANCE OF OVERHEAD LINES	LB593	PDIST	
594 MAINTENANCE OF UNDERGROUND LIN	LB594	PDIST	
595 MAINTENANCE OF LINE TRANSFORME	LB595	PDIST	
596 MAINTENANCE OF ST LIGHTS & SIG SYSTEMS	LB596	PDIST	
597 MAINTENANCE OF METERS	LB597	PDIST	
598 MAINTENANCE OF MISC DISTR PLANT	LB598	PDIST	
Total Distribution Maintenance Labor Expense	LBDM		
Total Distribution Operation and Maintenance Labor Expenses		PDIST	
Transmission and Distribution Labor Expenses			
Production, Transmission and Distribution Labor Expenses	LBSUB		
Customer Accounts Expense			
901 SUPERVISION/CUSTOMER ACCTS	LB901	F025	
902 METER READING EXPENSES	LB902	F025	
903 RECORDS AND COLLECTION	LB903	F025	
904 UNCOLLECTIBLE ACCOUNTS	LB904	F025	
905 MISC CUST ACCOUNTS	LB903	F025	
Total Customer Accounts Labor Expense	LBCA		
Customer Service Expense			
907 SUPERVISION	LB907	TUP	
908 CUSTOMER ASSISTANCE EXPENSES	LB908	TUP	33902.45
908 CUSTOMER ASSISTANCE EXP-LOAD MGMT	LB908x	TUP	
909 INFORMATIONAL AND INSTRUCTIONA	LB909	TUP	
909 INFORM AND INSTRUC -LOAD MGMT	LB909x	TUP	
910 MISCELLANEOUS CUSTOMER SERVICE	LB910	TUP	
911 DEMONSTRATION AND SELLING EXP	LB911	TUP	
912 DEMONSTRATION AND SELLING EXP	LB912	TUP	
913 WATER HEATER - HEAT PUMP PROGRAM	LB913	TUP	
915 MDSE-JOBBING-CONTRACT	LB915	TUP	
916 MISC SALES EXPENSE	LB916	TUP	
Total Customer Service Labor Expense	LBCS		33902.45
Sub-Total Labor Exp	LBSUB9		

Description	Name	Functional Vector		Total System	November 2009	December 2009	January 2010	February 2010	March 2010
Labor Expenses (Continued)									
Administrative and General Expense									
920 ADMIN. & GEN. SALARIES-	LB920	LBSUB9	$	14,315,714	2092449.04	1522142.8	1300504.05	1313340.25	1495631.43
921 OFFICE SUPPLIES AND EXPENSES	LB921	LBSUB9	$	-	0	0	0	0	0
922 ADMIN. EXPENSES TRANSFERRED - CREDIT	LB922	LBSUB9	$	-	0	0	0	0	0
923 OUTSIDE SERVICES EMPLOYED	LB923	LBSUB9	$	-	0	0	0	0	0
924 PROPERTY INSURANCE	LB924	TUP	$	-	0	0	0	0	0
925 INJURIES AND DAMAGES - INSURAN	LB925	LBSUB9	$	27,509	2777.2	3471.48	2777.2	2777.2	13427.68
926 EMPLOYEE BENEFITS	LB926	LBSUB9	$	17,136	2711	-43974.67	0	0	0
928 REGULATORY COMMISSION FEES	LB928	TUP	$	-	0	0	0	0	0
929 DUPLICATE CHARGES-CR	LB929	LBSUB9	$	-	0	0	0	0	0
930 MISCELLANEOUS GENERAL EXPENSES	LB930	LBSUB9	$	-	0	0	0	0	0
931 RENTS AND LEASES	LB931	PGP	$	-	0	0	0	0	0
935 MAINTENANCE OF GENERAL PLANT	LB935	PGP	$	74,927	14602.3	14130.42	6605.75	5191.93	4971.6
Total Administrative and General Expense	LBAG		$	14,435,286					
Total Operation and Maintenance Expenses	TLB		$	60,003,210					
Operation and Maintenance Expenses Less Purchase Power	LBLPP		$	60,003,210					
Other Expenses									
Depreciation Expenses									
Production	DEPRDP2	PPROD	$	28,815,395	2347440.74	2389099.7	2595994.55	2361961.48	2361968.56
Transmission	DEPRDP3	PTRAN	$	5,182,459	443546.44	533184.66	214261.5	442312.53	442305.66
Transmission	DEPRDP4	PTRAN	$	-					
Distribution	DEPRDP5	PDIST	$	-					
General & Common Plant	DEPRDP6	PGP	$	238,155	17050.71	19802.63	19799.44	19799.44	19766.55
Other Plant	DEPROTH	TPIS	$	-	0	0	0	0	0
Total Depreciation Expense	TDEPR		$	34,236,009	2808037.89	2942086.99	2830055.49	2824073.45	2824040.77
Accretion Expense									
Production	ACRTNP	F017	$	-	0	0	0	0	0
Transmission	ACRTNT	PTRAN	$	-	0	0	0	0	0
Distribution	ACRTND	PDIST	$	-	0	0	0	0	0
Total Accretion Expense	TACRTN		$	-					
Property Taxes & Other	PTAX	TUP	$	(94,563)	$ (379,997)	$ 87,636	$ -	$ -	$ 910
Amortization of Investment Tax Credit	OTAX	TUP	$	-	0	0	0	0	0
Other Expenses	OT	TUP	$	(365,864)	$ (6,691)	$ (14,191)	$ (18,627)	$ (23,851)	$ (16,042)
Interest	INTLTD	TUP	$	47,622,710	4168487.53	4316793.16	4234968.72	3796291.74	4133482.27
Other Deductions	DEDUCT	TUP	$	109,257	7611	15379	4539	6545	5640
Total Other Expenses	TOE		$	81,507,549	$ 3,789,411	$ 4,405,617	$ 4,220,881	$ 3,778,986	$ 4,123,991
Total Cost of Service (O&M + Other Expenses)			$	527,945,095					

Description	Name	Functional Vector	April 2010	May 2010	June 2010	July 2010	August 2010	September 2010
Labor Expenses (Continued)								
Administrative and General Expense								
920 ADMIN. & GEN. SALARIES-	LB920	LBSUB9	1326991.23	427833.15	1263415.19	446430.74	948956.12	1178332.32
921 OFFICE SUPPLIES AND EXPENSES	LB921	LBSUB9	0	0	0	0	0	0
922 ADMIN. EXPENSES TRANSFERRED - CREDIT	LB922	LBSUB9	0	0	0	0	0	0
923 OUTSIDE SERVICES EMPLOYED	LB923	LBSUB9	0	0	0	0	0	0
924 PROPERTY INSURANCE	LB924	TUP	0	0	0	0	0	0
925 INJURIES AND DAMAGES - INSURAN	LB925	LBSUB9	2278.26	0	0	0	0	0
926 EMPLOYEE BENEFITS	LB926	LBSUB9	23360	5840	5840	5840	5840	5840
928 REGULATORY COMMISSION FEES	LB928	TUP	0	0	0	0	0	0
929 DUPLICATE CHARGES-CR	LB929	LBSUB9	0	0	0	0	0	0
930 MISCELLANEOUS GENERAL EXPENSES	LB930	LBSUB9	0	0	0	0	0	0
931 RENTS AND LEASES	LB931	PGP	0	0	0	0	0	0
935 MAINTENANCE OF GENERAL PLANT	LB935	PGP	5560.19	2953.32	3794.54	2464	6700.24	5197.69
Total Administrative and General Expense	LBAG							
Total Operation and Maintenance Expenses	TLB							
Operation and Maintenance Expenses Less Purchase Power	LBLPP							
Other Expenses								
Depreciation Expenses								
Production	DEPRDP2	PPROD	2361962.84	2422279.6	2384018.59	2354733.3	2368037.83	2494767.54
Transmission	DEPRDP3	PTRAN	442357.04	442363.4	442363.15	442486.5	440016.44	450445.41
Transmission	DEPRDP4	PTRAN						
Distribution	DEPRDP5	PDIST						
General & Common Plant	DEPRDP6	PGP	19733.28	21031.35	19852.73	20082.98	19987.32	21286.62
Other Plant	DEPROTH	TPIS	0	0	0	0	0	0
Total Depreciation Expense	TDEPR		2824053.16	2885674.35	2846234.47	2817302.78	2828041.59	2966499.57
Accretion Expense								
Production	ACRTNP	F017	0	0	0	0	0	0
Transmission	ACRTNT	PTRAN	0	0	0	0	0	0
Distribution	ACRTND	PDIST	0	0	0	0	0	0
Total Accretion Expense	TACRTN							
Property Taxes & Other	PTAX	TUP	$ 65,000	$ 2,342	$ 65,000	$ -	$ (429)	$ 65,000
Amortization of Investment Tax Credit	OTAX	TUP	0	0	0	0	0	0
Other Expenses	OT	TUP	$ (27,557)	$ (8,263)	$ (42,136)	$ (42,545)	$ (48,997)	$ (56,550)
Interest	INTLTD	TUP	3848131.38	3699835.35	3741933.32	3942436.65	3958146.18	3830668.47
Other Deductions	DEDUCT	TUP	-2109	4540	14599	10828	16243	12411
Total Other Expenses	TOE		$ 3,883,465	$ 3,698,454	$ 3,779,396	$ 3,910,720	$ 3,924,964	$ 3,851,529
Total Cost of Service (O&M + Other Expenses)								

Description	Name	Functional Vector	October 2010
Labor Expenses (Continued)			
Administrative and General Expense			
920 ADMIN. & GEN. SALARIES-	LB920	LBSUB9	999687.37
921 OFFICE SUPPLIES AND EXPENSES	LB921	LBSUB9	
922 ADMIN. EXPENSES TRANSFERRED - CREDIT	LB922	LBSUB9	
923 OUTSIDE SERVICES EMPLOYED	LB923	LBSUB9	
924 PROPERTY INSURANCE	LB924	TUP	
925 INJURIES AND DAMAGES - INSURAN	LB925	LBSUB9	0
926 EMPLOYEE BENEFITS	LB926	LBSUB9	5840
928 REGULATORY COMMISSION FEES	LB928	TUP	
929 DUPLICATE CHARGES-CR	LB929	LBSUB9	
930 MISCELLANEOUS GENERAL EXPENSES	LB930	LBSUB9	
931 RENTS AND LEASES	LB931	PGP	
935 MAINTENANCE OF GENERAL PLANT	LB935	PGP	2754.81
Total Administrative and General Expense	LBAG		
Total Operation and Maintenance Expenses	TLB		
Operation and Maintenance Expenses Less Purchase Power	LBLPP		
Other Expenses			
Depreciation Expenses			
Production	DEPRDP2	PPROD	2373130.48
Transmission	DEPRDP3	PTRAN	446815.89
Transmission	DEPRDP4	PTRAN	
Distribution	DEPRDP5	PDIST	
General & Common Plant	DEPRDP6	PGP	19962.11
Other Plant	DEPROTH	TPIS	0
Total Depreciation Expense	TDEPR		2839908.48
Accretion Expense			
Production	ACRTNP	F017	0
Transmission	ACRTNT	PTRAN	0
Distribution	ACRTND	PDIST	0
Total Accretion Expense	TACRTN		
Property Taxes & Other	PTAX	TUP	$ (25)
Amortization of Investment Tax Credit	OTAX	TUP	0
Other Expenses	OT	TUP	$ (60,414)
Interest	INTLTD	TUP	3951535
Other Deductions	DEDUCT	TUP	13031
Total Other Expenses	TOE		$ 3,904,127
Total Cost of Service (O&M + Other Expenses)			

Description	Name	Functional Vector	Total System	November 2009	December 2009	January 2010	February 2010	March 2010
Revenues								
Jackson Purchase			$ 31,526,082	2,047,421	2,967,876	3,236,562	2,630,578	2,282,284
Kenergy			$ 56,579,648	3,789,093	5,385,841	5,977,907	4,990,050	4,209,222
Meade			$ 22,828,970	1,551,653	2,374,865	2,690,998	2,281,167	1,830,442
Large Industrial			$ 39,110,620	3,326,073	3,242,060	3,257,550	3,000,170	3,334,841
Century Total			$ 150,725,511	14,123,587	13,900,845	12,327,658	10,978,277	13,026,782
Alcan Total			$ 131,680,624	11,327,935	11,867,881	11,227,291	10,087,671	11,349,236
	Total Rural		$ 110,934,700	$ 7,388,167	$ 10,728,582	$ 11,905,467	$ 9,901,794	$ 8,321,948
	Total Industrial		$ 39,110,620	$ 8,666,818	$ 11,002,766	$ 11,926,456	$ 10,271,387	$ 9,374,506
	Total Smelter		$ 282,406,135	$ 25,451,523	$ 25,768,725	$ 23,554,949	$ 21,065,948	$ 24,376,019
	Total		$ 432,451,455	$ 36,165,762	$ 39,739,368	$ 38,717,967	$ 33,967,912	$ 36,032,808
Century Invoiced			$ 149,837,373	12,898,686	13,350,197	12,412,617	10,978,277	13,026,782
Alcan Invoiced			$ 131,911,075	10,982,583	11,672,836	11,353,440	10,087,671	11,349,236
Century Adjustments			$ 888,139	1,224,902	550,648	(84,959)		
Alcan Adjustments			$ (230,451)	345,352	195,044	(126,150)		
Off System Sales			$ 76,543,801	$ 1,839,442	$ 4,073,308	$ 8,147,840	$ 9,539,433	$ 7,986,498
Income from Leased Property Net			$ 149,673	$ 149,673	$ -	$ -	$ -	$ -
Other Operating Revenue & Income			$ 13,778,745	$ 1,230,861	$ 1,033,968	$ 1,152,998	$ 1,145,023	$ 1,070,097
OSS Variable O&M			$ 46,035,981	$ 1,471,622	$ 2,691,212	$ 4,162,194	$ 5,284,841	$ 5,083,040
Energy								
Jackson Purchase			694,512,540	45,926,970	65,978,630	71,338,200	59,712,514	49,429,743
Kenergy			1,255,008,258	85,135,870	120,014,010	132,891,880	114,367,690	91,992,020
Meade			499,627,006	34,444,920	51,694,410	59,035,140	51,393,370	38,028,116
Large Industrial			928,887,170	78,192,702	74,359,872	75,056,282	70,510,685	78,126,590
Century			3,949,411,321	310,167,027	331,563,740	339,238,984	318,278,276	343,763,177
Alcan			3,163,910,039	257,031,413	268,912,646	270,478,213	245,969,029	270,738,402
Total Rural			2,449,147,804	165,507,760	237,687,050	263,265,220	225,473,574	179,449,879
Total Industrial			928,887,170	78,192,702	74,359,872	75,056,282	70,510,685	78,126,590
Total Smelter			7,113,321,360	567,198,440	600,476,386	609,717,197	564,247,305	614,501,579
Total			10,491,356,334	810,898,902	912,523,308	948,038,699	860,231,564	872,078,048

Description	Name	Functional Vector	April 2010	May 2010	June 2010	July 2010	August 2010	September 2010
Revenues								
Jackson Purchase			1,799,767	2,308,067	3,063,639	3,258,780	3,399,012	2,561,800
Kenergy			3,188,379	4,134,538	5,323,163	5,636,870	5,853,842	4,573,561
Meade			1,214,667	1,532,681	1,963,540	2,110,692	2,169,733	1,693,499
Large Industrial			3,161,352	3,245,699	3,234,324	3,234,990	3,373,185	3,344,243
Century Total			12,044,160	12,679,922	11,679,623	12,055,865	12,367,467	11,801,654
Alcan Total			10,471,146	11,169,007	10,543,631	10,857,129	10,839,072	10,177,927
	Total Rural		$ 6,202,813	$ 7,975,287	$ 10,350,341	$ 11,006,341	$ 11,422,586	$ 8,828,859
	Total Industrial		$ 7,564,398	$ 8,912,918	$ 10,521,026	$ 10,982,552	$ 11,396,759	$ 9,611,302
	Total Smelter		$ 22,515,306	$ 23,848,930	$ 22,223,254	$ 22,912,994	$ 23,206,539	$ 21,979,581
	Total		$ 31,879,471	$ 35,069,915	$ 35,807,919	$ 37,154,326	$ 38,002,310	$ 34,152,683
Century Invoiced			12,044,160	12,679,922	11,679,623	12,055,865	12,367,467	12,580,920
Alcan Invoiced			10,471,146	11,169,007	10,543,631	10,857,129	10,839,072	10,806,724
Century Adjustments								(779,265)
Alcan Adjustments								(628,797)
Off System Sales			$ 5,678,794	$ 6,341,556	$ 7,049,362	$ 7,908,927	$ 8,630,309	$ 5,166,061
Income from Leased Property Net			$ -	$ -	$ -	$ -	$ -	$ -
Other Operating Revenue & Income			$ 1,140,133	$ 1,143,171	$ 1,284,686	$ 1,142,016	$ 1,145,336	$ 1,142,234
OSS Variable O&M			$ 3,852,774	$ 3,932,574	$ 3,863,529	$ 4,155,945	$ 4,803,709	$ 3,568,984
Energy								
Jackson Purchase			40,334,720	49,465,221	67,937,977	74,389,907	74,455,490	53,358,978
Kenergy			72,904,910	88,391,581	119,415,050	128,859,539	129,305,728	95,902,980
Meade			28,079,875	32,805,170	43,966,515	47,969,570	47,509,670	35,325,370
Large Industrial			78,086,611	79,512,076	79,858,265	78,927,327	82,005,334	79,182,043
Century			323,212,786	331,276,534	324,397,171	337,256,977	345,310,998	317,766,683
Alcan			260,668,275	268,579,997	259,859,800	268,729,560	268,160,608	257,328,832
Total Rural			141,319,505	170,661,972	231,319,542	251,219,016	251,270,888	184,587,328
Total Industrial			78,086,611	79,512,076	79,858,265	78,927,327	82,005,334	79,182,043
Total Smelter			583,881,061	599,856,531	584,256,971	605,986,537	613,471,606	575,095,515
Total			803,287,177	850,030,579	895,434,778	936,132,880	946,747,828	838,864,886

Description	Name	Functional Vector	October 2010
Revenues			
Jackson Purchase			1,970,297
Kenergy			3,517,183
Meade			1,415,034
Large Industrial			3,356,132
Century Total			13,739,670
Alcan Total			11,762,698
	Total Rural		$ 6,902,515
	Total Industrial		$ 8,288,350
	Total Smelter		$ 25,502,368
	Total		$ 35,761,015
Century Invoiced			13,762,856
Alcan Invoiced			11,778,599
Century Adjustments			(23,186)
Alcan Adjustments			(15,901)
Off System Sales			4,182,271
Income from Leased Property Net			$ -
Other Operating Revenue & Income			$ 1,148,221
OSS Variable O&M			$ 3,165,556
Energy			
Jackson Purchase			42,184,190
Kenergy			75,827,000
Meade			29,374,880
Large Industrial			75,069,383
Century			327,178,968
Alcan			267,453,264
Total Rural			147,386,070
Total Industrial			75,069,383
Total Smelter			594,632,232
Total			817,087,685

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Description	Name	Functional Vector	Total System	Production Demand	Production Energy	Steam Direct	Transmission Demand
Plant in Service							
Intangible Plant	INTPLT	PT&D	$ 66,895	58,634	-	-	8,261
Production Plant	PPROD	F001	$ 1,686,796,955	1,686,796,955	-	-	-
Transmission Plant	PTRAN	F002	$ 237,659,206	-	-	-	237,659,206
Distribution Plant	PDIST	F003	$ -	-	-	-	-
Total Production & Transmission Plant	PT&D		1,924,456,160	1,686,796,955	-	-	237,659,206
General Plant	PGP	PT&D	$ 18,511,051	16,225,043	-	-	2,286,008
Total Plant in Service	TPIS		$ 1,943,034,107	$ 1,703,080,632	$ -	$ -	$ 239,953,475
Construction Work in Progress (CWIP)							
CWIP Production	CWIP1	PPROD	$ 22,411,274	22,411,274	-	-	-
CWIP Transmission	CWIP2	PTRAN	$ 7,475,859	-	-	-	7,475,859
CWIP Distribution Plant	CWIP3	PDIST	$ -	-	-	-	-
CWIP General Plant	CWIP4	PT&D	$ 16,915,005	14,826,100	-	-	2,088,905
Total Construction Work in Progress	TCWIP		$ 46,802,138	$ 37,237,374	$ -	$ -	$ 9,564,764
Total Utility Plant			$ 1,989,836,245	$ 1,740,318,006	$ -	$ -	$ 249,518,239

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Description	Name	Functional Vector	Total System	Production Demand	Production Energy	Steam Direct	Transmission Demand
Rate Base							
Total Utility Plant	TUP		$ 1,989,836,245	$ 1,740,318,006	$ -	$ -	$ 249,518,239
Less: Acummulated Provision for Depreciation							
Production	ADEPREPA	PPROD	$ 790,847,523	790,847,523	-	-	-
Transmission	ADEPRTP	PTRAN	$ 107,564,747	-	-	-	107,564,747
Distribution	ADEPRD11	PDIST	$ -	-	-	-	-
General & Common Plant	ADEPRD12	PT&D	$ 6,300,770	5,522,661	-	-	778,109
Intangible, Misc, and Other Plant	ADEPRGP	PT&D	$ -	-	-	-	-
Retirement Work In Progress	ADEPRRT	PT&D	$ -	-	-	-	-
Total Accumulated Depreciation	TADEPR		$ 904,713,040	$ 796,370,184	$ -	$ -	$ 108,342,855
Net Utility Plant	NTPLANT		$ 1,085,123,206	$ 943,947,822	$ -	$ -	$ 141,175,384
Working Capital							
Cash Working Capital - Operation and Maintenance Expenses	CWC	OMLPP	$ 28,114,365	13,900,247	11,969,243	-	2,244,875
Materials and Supplies	M&S	TPIS	$ 22,777,820	19,964,891	-	-	2,812,929
Fuel Stock	PREPAY	TPIS	$ 34,326,112	30,087,036	-	-	4,239,076
Total Working Capital	TWC		$ 85,218,297	$ 63,952,174	$ 11,969,243	$ -	$ 9,296,880
Net Rate Base	RB		$ 1,170,341,502	$ 1,007,899,995	$ 11,969,243	$ -	$ 150,472,264

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Description	Name	Functional Vector		Total System		Production Demand		Production Energy		Steam Direct		Transmission Demand
Operation and Maintenance Expenses												
Steam Power Generation Operation Expenses												
500 OPERATION SUPERVISION & ENGINEERING	OM500	PROFIX	$	4,974,566		4,974,566		-		-		-
501 FUEL	OM501	Energy	$	200,919,367		-		200,919,367		-		-
502 STEAM EXPENSES	OM502	PROFIX	$	34,453,882		34,453,882		-		-		-
505 ELECTRIC EXPENSES	OM505	PROFIX	$	5,730,122		5,730,122		-		-		-
506 MISC. STEAM POWER EXPENSES	OM506	PROFIX	$	7,451,302		7,451,302		-		-		-
507 RENTS	OM507	PROFIX	$	-		-		-		-		-
509 ALLOWANCES	OM509	Energy	$	429,682		-		429,682		-		-
Total Steam Power Operation Expenses			$	253,958,921	$	52,609,872	$	201,349,049	$	-	$	-
Steam Power Generation Maintenance Expenses												
510 MAINTENANCE SUPERVISION & ENGINEERING	OM510	Energy	$	3,631,867		-		3,631,867		-		-
511 MAINTENANCE OF STRUCTURES	OM511	PROFIX	$	3,346,806		3,346,806		-		-		-
512 MAINTENANCE OF BOILER PLANT	OM512	Energy	$	30,113,309		-		30,113,309		-		-
513 MAINTENANCE OF ELECTRIC PLANT	OM513	Energy	$	6,251,804		-		6,251,804		-		-
514 MAINTENANCE OF MISC STEAM PLANT	OM514	PROFIX	$	877,364		877,364		-		-		-
Total Steam Power Generation Maintenance Expense			$	44,221,151	$	4,224,170	$	39,996,981	$	-	$	-
Total Steam Power Generation Expense			$	298,180,072	$	56,834,042	$	241,346,030	$	-	$	-

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Description	Name	Functional Vector		Total System		Production Demand		Production Energy		Steam Direct		Transmission Demand
<u>Operation and Maintenance Expenses (Continued)</u>												
Other Power Generation Operation Expense												
546 OPERATION SUPERVISION & ENGINEERING	OM546	PROFIX	$	-		-		-		-		-
547 FUEL	OM547	Energy	$	706,789		-		706,789		-		-
548 GENERATION EXPENSE	OM548	PROFIX	$	34,608		34,608		-		-		-
549 MISC OTHER POWER GENERATION	OM549	PROFIX	$	-		-		-		-		-
550 RENTS	OM550	PROFIX	$	-		-		-		-		-
Total Other Power Generation Expenses			$	741,396	$	34,608	$	706,789	$	-	$	-
Other Power Generation Maintenance Expense												
551 MAINTENANCE SUPERVISION & ENGINEERING	OM551	PROFIX	$	-		-		-		-		-
552 MAINTENANCE OF STRUCTURES	OM552	PROFIX	$	-		-		-		-		-
553 MAINTENANCE OF GENERATING & ELEC PLANT	OM553	PROFIX	$	625,088		625,088		-		-		-
554 MAINTENANCE OF MISC OTHER POWER GEN PLT	OM554	PROFIX	$	-		-		-		-		-
Total Other Power Generation Maintenance Expense			$	625,088	$	625,088	$	-	$	-	$	-
Total Other Power Generation Expense			$	1,366,485	$	659,696	$	706,789	$	-	$	-
Total Station Expense			$	299,546,557	$	57,493,738	$	242,052,819	$	-	$	-

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Description	Name	Functional Vector		Total System		Production Demand		Production Energy		Steam Direct		Transmission Demand
Operation and Maintenance Expenses (Continued)												
Other Power Supply Expenses												
555 PURCHASED POWER Energy	OM555	OMPP	$	19,466,790		-		19,466,790		-		-
555 PURCHASED POWER Demand	OMD555	OMPPD	$	4,210,045		4,210,045		-		-		-
555 PURCHASED POWER BREC Share of HMP&L Station Two	OMH555	OMPPH	$	58,293,374		13,175,571		45,117,803		-		-
555 PURCHASED POWER OPTIONS	OMO555	OMPP	$	-		-		-		-		-
555 BROKERAGE FEES	OMB555	OMPP	$	-		-		-		-		-
555 MISO TRANSMISSION EXPENSES	OMM555	OMPP	$	-		-		-		-		-
556 SYSTEM CONTROL AND LOAD DISPATCH	OM556	PROFIX	$	909,422		909,422		-		-		-
557 OTHER EXPENSES	OM557	PROFIX	$	20,575,465		20,575,465		-		-		-
558 DUPLICATE CHARGES	OM558	Energy	$	-		-		-		-		-
Total Other Power Supply Expenses	TPP		$	103,455,096	$	38,870,503	$	64,584,593	$	-	$	-
Total Electric Power Generation Expenses			$	403,001,653	$	96,364,241	$	306,637,411	$	-	$	-
Transmission Expenses												
560 OPERATION SUPERVISION AND ENG	OM560	LBTRAN	$	876,815		-		-		-		876,815
561 LOAD DISPATCHING	OM561	LBTRAN	$	1,454,938		-		-		-		1,454,938
562 STATION EXPENSES	OM562	PTRAN	$	1,163,408		-		-		-		1,163,408
563 OVERHEAD LINE EXPENSES	OM563	PTRAN	$	1,090,014		-		-		-		1,090,014
565 TRANSMISSION OF ELECTRICITY BY OTHERS	OM565	PTRAN	$	3,065,817		-		-		-		3,065,817
566 MISC. TRANSMISSION EXPENSES	OM566	PTRAN	$	475,381		-		-		-		475,381
567 RENTS	OM567	PTRAN	$	24,701		-		-		-		24,701
568 MAINTENACE SUPERVISION AND ENG	OM568	LBTRAN	$	647,227		-		-		-		647,227
569 STRUCTURES	OM569	PTRAN	$	26,913		-		-		-		26,913
570 MAINT OF STATION EQUIPMENT	OM570	PTRAN	$	1,936,760		-		-		-		1,936,760
571 MAINT OF OVERHEAD LINES	OM571	PTRAN	$	2,876,462		-		-		-		2,876,462
572 UNDERGROUND LINES	OM572	PTRAN	$	-		-		-		-		-
573 MISC PLANT	OM573	PTRAN	$	97,880		-		-		-		97,880
Total Transmission Expenses			$	13,736,318	$	-	$	-	$	-	$	13,736,318
Distribution Operation Expense												
580 OPERATION SUPERVISION AND ENGI	OM580	LBDO	$	-		-		-		-		-
581 LOAD DISPATCHING	OM581	PDIST	$	-		-		-		-		-
582 STATION EXPENSES	OM582	PDIST	$	-		-		-		-		-
583 OVERHEAD LINE EXPENSES	OM583	PDIST	$	-		-		-		-		-
584 UNDERGROUND LINE EXPENSES	OM584	PDIST	$	-		-		-		-		-
585 STREET LIGHTING EXPENSE	OM585	PDIST	$	-		-		-		-		-
586 METER EXPENSES	OM586	PDIST	$	-		-		-		-		-
586 METER EXPENSES - LOAD MANAGEMENT	OM586x	PDIST	$	-		-		-		-		-
587 CUSTOMER INSTALLATIONS EXPENSE	OM587	PDIST	$	-		-		-		-		-
588 MISCELLANEOUS DISTRIBUTION EXP	OM588	PDIST	$	-		-		-		-		-
588 MISC DISTR EXP -- MAPPIN	OM588x	PDIST	$	-		-		-		-		-
589 RENTS	OM589	PDIST	$	-		-		-		-		-
Total Distribution Operation Expense	OMDO		$	-	$	-	$	-	$	-	$	-

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Description	Name	Functional Vector	Total System	Production Demand	Production Energy	Steam Direct	Transmission Demand
Operation and Maintenance Expenses (Continued)							
Distribution Maintenance Expense							
590 MAINTENANCE SUPERVISION AND EN	OM590	LBDM	$ -	-	-	-	-
591 STRUCTURES	OM591	PDIST	$ -	-	-	-	-
592 MAINTENANCE OF STATION EQUIPME	OM592	PDIST	$ -	-	-	-	-
593 MAINTENANCE OF OVERHEAD LINES	OM593	PDIST	$ -	-	-	-	-
594 MAINTENANCE OF UNDERGROUND LIN	OM594	PDIST	$ -	-	-	-	-
595 MAINTENANCE OF LINE TRANSFORME	OM595	PDIST	$ -	-	-	-	-
596 MAINTENANCE OF ST LIGHTS & SIG SYSTEMS	OM596	PDIST	$ -	-	-	-	-
597 MAINTENANCE OF METERS	OM597	PDIST	$ -	-	-	-	-
598 MISCELLANEOUS DISTRIBUTION EXPENSES	OM598	PDIST	$ -	-	-	-	-
Total Distribution Maintenance Expense	OMDM		$ -	$ -	$ -	$ -	$ -
Total Distribution Operation and Maintenance Expenses			-	-	-	-	-
Transmission and Distribution Expenses			13,736,318	-	-	-	13,736,318
Production, Transmission and Distribution Expenses	OMSUB		$ 416,737,971	$ 96,364,241	$ 306,637,411	$ -	$ 13,736,318
Customer Accounts Expense							
901 SUPERVISION/CUSTOMER ACCTS	OM901	F025	$ -	-	-	-	-
902 METER READING EXPENSES	OM902	F025	$ -	-	-	-	-
903 RECORDS AND COLLECTION	OM903	F025	$ -	-	-	-	-
904 UNCOLLECTIBLE ACCOUNTS	OM904	F025	$ -	-	-	-	-
905 MISC CUST ACCOUNTS	OM903	F025	$ -	-	-	-	-
Total Customer Accounts Expense	OMCA		$ -	$ -	$ -	$ -	$ -
Customer Service Expense							
907 SUPERVISION	OM907	TUP	$ -	-	-	-	-
908 CUSTOMER ASSISTANCE EXPENSES	OM908	TUP	$ 591,192	517,058	-	-	74,133
908 CUSTOMER ASSISTANCE EXP-INCENTIVES	OM908x	TUP	$ -	-	-	-	-
909 INFORMATIONAL AND INSTRUCTIONA	OM909	TUP	$ -	-	-	-	-
909 INFORM AND INSTRUC -LOAD MGMT	OM909x	TUP	$ -	-	-	-	-
910 MISCELLANEOUS CUSTOMER SERVICE	OM910	TUP	$ -	-	-	-	-
911 DEMONSTRATION AND SELLING EXP	OM911	TUP	$ -	-	-	-	-
912 DEMONSTRATION AND SELLING EXP	OM912	TUP	$ -	-	-	-	-
913 ADVERTISING EXPENSES	OM913	TUP	$ 488,103	426,897	-	-	61,206
915 MDSE-JOBBING-CONTRACT	OM915	TUP	$ -	-	-	-	-
916 MISC SALES EXPENSE	OM916	TUP	$ -	-	-	-	-
Total Customer Service Expense	OMCS		$ 1,079,295	$ 943,955	$ -	$ -	$ 135,340
Sub-Total Prod, Trans, Dist, Cust Acct and Cust Service	OMSUB2		417,817,266	97,308,197	306,637,411	-	13,871,658

BIG RIVERS ELECTRIC CORPORATION
Cost of Service Study
Functional Assignment and Classification

12 Months Ended
October 2010

Description	Name	Functional Vector		Total System		Production Demand		Production Energy		Steam Direct		Transmission Demand
<u>Operation and Maintenance Expenses (Continued)</u>												
Administrative and General Expense												
920 ADMIN. & GEN. SALARIES-	OM920	LBSUB9	$	14,315,713		6,663,061		5,595,161		-		2,057,491
921 OFFICE SUPPLIES AND EXPENSES	OM921	LBSUB9	$	6,915,648		3,218,798		2,702,915		-		993,935
922 ADMINISTRATIVE EXPENSES TRANSFERRED	OM922	LBSUB9	$	-		-		-		-		-
923 OUTSIDE SERVICES EMPLOYED	OM923	LBSUB9	$	3,954,189		1,840,425		1,545,457		-		568,306
924 PROPERTY INSURANCE	OM924	TUP	$	-		-		-		-		-
925 INJURIES AND DAMAGES - INSURAN	OM925	LBSUB9	$	179,889		83,727		70,308		-		25,854
926 EMPLOYEE BENEFITS	OM926	LBSUB9	$	169,663		78,967		66,311		-		24,384
927 FRANCHISE REQUIREMENTS	OM927	TUP	$	-		-		-		-		-
928 REGULATORY COMMISSION FEES	OM928	TUP	$	1,188,958		1,039,867		-		-		149,091
929 DUPLICATE CHARGES-CR	OM929	LBSUB9	$	-		-		-		-		-
930 MISCELLANEOUS GENERAL EXPENSES	OM930	LBSUB9	$	1,686,131		784,788		659,008		-		242,335
931 RENTS AND LEASES	OM931	PGP	$	1,933		1,694		-		-		239
935 MAINTENANCE OF GENERAL PLANT	OM935	PGP	$	208,156		182,450		-		-		25,706
Total Administrative and General Expense	OMAG		$	28,620,280	$	13,893,778	$	10,639,160	$	-	$	4,087,342
Total Operation and Maintenance Expenses	TOM		$	446,437,546	$	111,201,975	$	317,276,572	$	-	$	17,959,000
Operation and Maintenance Expenses Less Purchase Power & Fuel	OMLPP		$	224,914,919	$	111,201,975	$	95,753,945	$	-	$	17,959,000

BIG RIVERS ELECTRIC CORPORATION
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12 Months Ended
October 2010

Description	Name	Functional Vector		Total System		Production Demand		Production Energy		Steam Direct		Transmission Demand
Labor Expenses												
Steam Power Generation Operation Expenses												
500 OPERATION SUPERVISION & ENGINEERING	LB500	PROFIX	$	4,967,667		4,967,667		-		-		-
501 FUEL	LB501	Energy	$	3,889,944		-		3,889,944		-		-
502 STEAM EXPENSES	LB502	PROFIX	$	9,023,322		9,023,322		-		-		-
505 ELECTRIC EXPENSES	LB505	PROFIX	$	4,523,897		4,523,897		-		-		-
506 MISC. STEAM POWER EXPENSES	LB506	PROFIX	$	940,518		940,518		-		-		-
507 RENTS	LB507	PROFIX	$	-		-		-		-		-
509 ALLOWANCES	LB509	Energy	$	-		-		-		-		-
Total Steam Power Operation Expenses	LBSUB1		$	23,345,348	$	19,455,404	$	3,889,944	$	-	$	-
Steam Power Generation Maintenance Expenses												
510 MAINTENANCE SUPERVISION & ENGINEERING	LB510	Energy	$	3,623,969		-		3,623,969		-		-
511 MAINTENANCE OF STRUCTURES	LB511	PROFIX	$	986,831		986,831		-		-		-
512 MAINTENANCE OF BOILER PLANT	LB512	Energy	$	8,700,235		-		8,700,235		-		-
513 MAINTENANCE OF ELECTRIC PLANT	LB513	Energy	$	1,595,642		-		1,595,642		-		-
514 MAINTENANCE OF MISC STEAM PLANT	LB514	PROFIX	$	200,886		200,886		-		-		-
Total Steam Power Generation Maintenance Expense	LBSUB2		$	15,107,564	$	1,187,718	$	13,919,846	$	-	$	-
Total Steam Power Generation Expense			$	38,452,913	$	20,643,122	$	17,809,791	$	-	$	-

BIG RIVERS ELECTRIC CORPORATION
Cost of Service Study
Functional Assignment and Classification

12 Months Ended
October 2010

Description	Name	Functional Vector		Total System		Production Demand		Production Energy		Steam Direct		Transmission Demand
Labor Expenses (Continued)												
Other Power Generation Operation Expense												
546 OPERATION SUPERVISION & ENGINEERING	LB546	PROFIX	$	-		-		-		-		-
547 FUEL	LB547	Energy	$	-		-		-		-		-
548 GENERATION EXPENSE	LB548	PROFIX	$	-		-		-		-		-
549 MISC OTHER POWER GENERATION	LB549	PROFIX	$	-		-		-		-		-
550 RENTS	LB550	PROFIX	$	-		-		-		-		-
Total Other Power Generation Expenses	LBSUB7		$	-	$	-	$	-	$	-	$	-
Other Power Generation Maintenance Expense												
551 MAINTENANCE SUPERVISION & ENGINEERING	LB551	PROFIX	$	-		-		-		-		-
552 MAINTENANCE OF STRUCTURES	LB552	PROFIX	$	-		-		-		-		-
553 MAINTENANCE OF GENERATING & ELEC PLANT	LB553	PROFIX	$	89,555		89,555		-		-		-
554 MAINTENANCE OF MISC OTHER POWER GEN PLT	LB554	PROFIX	$	-		-		-		-		-
Total Other Power Generation Maintenance Expense	LBSUB8		$	89,555	$	89,555	$	-	$	-	$	-
Total Other Power Generation Expense			$	89,555	$	89,555	$	-	$	-	$	-
Total Production Expense	LPREX		$	38,542,468	$	20,732,677	$	17,809,791	$	-	$	-

BIG RIVERS ELECTRIC CORPORATION
Cost of Service Study
Functional Assignment and Classification

12 Months Ended
October 2010

Description	Name	Functional Vector	Total System	Production Demand	Production Energy	Steam Direct	Transmission Demand
Labor Expenses (Continued)							
Purchased Power							
555 PURCHASED POWER Energy	LB555	OMPP	$ -	-	-	-	-
555 PURCHASED POWER Demand	LBD555	OMPPD	$ -	-	-	-	-
555 PURCHASED POWER OPTIONS	LBO555	OMPP	$ -	-	-	-	-
555 BROKERAGE FEES	LBB555	OMPP	$ -	-	-	-	-
555 MISO TRANSMISSION EXPENSES	LBM555	OMPP	$ -	-	-	-	-
556 SYSTEM CONTROL AND LOAD DISPATCH	LB556	PROFIX	$ -	-	-	-	-
557 OTHER EXPENSES	LB557	PROFIX	$ -	-	-	-	-
558 DUPLICATE CHARGES	LB558	Energy	$ -	-	-	-	-
Total Purchased Power Labor	LBPP		$ -	$ -	$ -	$ -	$ -
Transmission Labor Expenses							
560 OPERATION SUPERVISION AND ENG	LB560	PTRAN	$ 835,977	-	-	-	835,977
561 LOAD DISPATCHING	LB561	PTRAN	$ 1,304,969	-	-	-	1,304,969
562 STATION EXPENSES	LB562	PTRAN	$ 598,382	-	-	-	598,382
563 OVERHEAD LINE EXPENSES	LB563	PTRAN	$ 236,393	-	-	-	236,393
565 TRANSMISSION OF ELECTRICITY BY OTHERS	LB565	PTRAN	$ -	-	-	-	-
566 MISC. TRANSMISSION EXPENSES	LB566	PTRAN	$ 312,375	-	-	-	312,375
567 RENTS	LB567	PTRAN	$ -	-	-	-	-
568 MAINTENACE SUPERVISION AND ENG	LB568	PTRAN	$ 644,925	-	-	-	644,925
569 MAINTENACE OF STRUCTURES	LB569	PTRAN	$ 318	-	-	-	318
570 MAINT OF STATION EQUIPMENT	LB570	PTRAN	$ 1,433,304	-	-	-	1,433,304
571 MAINT OF OVERHEAD LINES	LB571	PTRAN	$ 1,067,766	-	-	-	1,067,766
573 MAINT OF MISC. TRANSMISSION PLANT	LB573	PTRAN	$ 46,439	-	-	-	46,439
Total Transmission Labor Expenses	LBTRAN		$ 6,480,848	$ -	$ -	$ -	$ 6,480,848
Distribution Operation Labor Expense							
580 OPERATION SUPERVISION AND ENGI	LB580	F023	$ -	-	-	-	-
581 LOAD DISPATCHING	LB581	PDIST	$ -	-	-	-	-
582 STATION EXPENSES	LB582	PDIST	$ -	-	-	-	-
583 OVERHEAD LINE EXPENSES	LB583	PDIST	$ -	-	-	-	-
584 UNDERGROUND LINE EXPENSES	LB584	PDIST	$ -	-	-	-	-
585 STREET LIGHTING EXPENSE	LB585	PDIST	$ -	-	-	-	-
586 METER EXPENSES	LB586	PDIST	$ -	-	-	-	-
586 METER EXPENSES - LOAD MANAGEMENT	LB586x	PDIST	$ -	-	-	-	-
587 CUSTOMER INSTALLATIONS EXPENSE	LB587	PDIST	$ -	-	-	-	-
588 MISCELLANEOUS DISTRIBUTION EXP	LB588	PDIST	$ -	-	-	-	-
589 RENTS	LB589	PDIST	$ -	-	-	-	-
Total Distribution Operation Labor Expense	LBDO		$ -	$ -	$ -	$ -	$ -

BIG RIVERS ELECTRIC CORPORATION
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12 Months Ended
October 2010

Description	Name	Functional Vector		Total System		Production Demand		Production Energy		Steam Direct		Transmission Demand
Labor Expenses (Continued)												
Distribution Maintenance Labor Expense												
590 MAINTENANCE SUPERVISION AND EN	LB590	F024	$	-		-		-		-		-
591 MAINTENANCE OF STRUCTURES	LB591	PDIST	$	-		-		-		-		-
592 MAINTENANCE OF STATION EQUIPME	LB592	PDIST	$	-		-		-		-		-
593 MAINTENANCE OF OVERHEAD LINES	LB593	PDIST	$	-		-		-		-		-
594 MAINTENANCE OF UNDERGROUND LIN	LB594	PDIST	$	-		-		-		-		-
595 MAINTENANCE OF LINE TRANSFORME	LB595	PDIST	$	-		-		-		-		-
596 MAINTENANCE OF ST LIGHTS & SIG SYSTEMS	LB596	PDIST	$	-		-		-		-		-
597 MAINTENANCE OF METERS	LB597	PDIST	$	-		-		-		-		-
598 MAINTENANCE OF MISC DISTR PLANT	LB598	PDIST	$	-		-		-		-		-
Total Distribution Maintenance Labor Expense	LBDM		$	-	$	-	$	-	$	-	$	-
Total Distribution Operation and Maintenance Labor Expenses		PDIST		-		-		-		-		-
Transmission and Distribution Labor Expenses				6,480,848		-		-		-		6,480,848
Production, Transmission and Distribution Labor Expenses	LBSUB		$	45,023,316	$	20,732,677	$	17,809,791	$	-	$	6,480,848
Customer Accounts Expense												
901 SUPERVISION/CUSTOMER ACCTS	LB901	F025	$	-		-		-		-		-
902 METER READING EXPENSES	LB902	F025	$	-		-		-		-		-
903 RECORDS AND COLLECTION	LB903	F025	$	-		-		-		-		-
904 UNCOLLECTIBLE ACCOUNTS	LB904	F025	$	-		-		-		-		-
905 MISC CUST ACCOUNTS	LB903	F025	$	-		-		-		-		-
Total Customer Accounts Labor Expense	LBCA		$	-	$	-	$	-	$	-	$	-
Customer Service Expense												
907 SUPERVISION	LB907	TUP	$	-		-		-		-		-
908 CUSTOMER ASSISTANCE EXPENSES	LB908	TUP	$	544,608		476,316		-		-		68,292
908 CUSTOMER ASSISTANCE EXP-LOAD MGMT	LB908x	TUP	$	-		-		-		-		-
909 INFORMATIONAL AND INSTRUCTIONA	LB909	TUP	$	-		-		-		-		-
909 INFORM AND INSTRUC -LOAD MGMT	LB909x	TUP	$	-		-		-		-		-
910 MISCELLANEOUS CUSTOMER SERVICE	LB910	TUP	$	-		-		-		-		-
911 DEMONSTRATION AND SELLING EXP	LB911	TUP	$	-		-		-		-		-
912 DEMONSTRATION AND SELLING EXP	LB912	TUP	$	-		-		-		-		-
913 WATER HEATER - HEAT PUMP PROGRAM	LB913	TUP	$	-		-		-		-		-
915 MDSE-JOBBING-CONTRACT	LB915	TUP	$	-		-		-		-		-
916 MISC SALES EXPENSE	LB916	TUP	$	-		-		-		-		-
Total Customer Service Labor Expense	LBCS		$	544,608	$	476,316	$	-	$	-	$	68,292
Sub-Total Labor Exp	LBSUB9			45,567,924		21,208,994		17,809,791		-		6,549,140

BIG RIVERS ELECTRIC CORPORATION
Cost of Service Study
Functional Assignment and Classification

12 Months Ended
October 2010

Description	Name	Functional Vector		Total System		Production Demand		Production Energy		Steam Direct		Transmission Demand
Labor Expenses (Continued)												
Administrative and General Expense												
920 ADMIN. & GEN. SALARIES-	LB920	LBSUB9	$	14,315,714		6,663,061		5,595,161		-		2,057,491
921 OFFICE SUPPLIES AND EXPENSES	LB921	LBSUB9	$	-		-		-		-		-
922 ADMIN. EXPENSES TRANSFERRED - CREDIT	LB922	LBSUB9	$	-		-		-		-		-
923 OUTSIDE SERVICES EMPLOYED	LB923	LBSUB9	$	-		-		-		-		-
924 PROPERTY INSURANCE	LB924	TUP	$	-		-		-		-		-
925 INJURIES AND DAMAGES - INSURAN	LB925	LBSUB9	$	27,509		12,804		10,752		-		3,954
926 EMPLOYEE BENEFITS	LB926	LBSUB9	$	17,136		7,976		6,698		-		2,463
928 REGULATORY COMMISSION FEES	LB928	TUP	$	-		-		-		-		-
929 DUPLICATE CHARGES-CR	LB929	LBSUB9	$	-		-		-		-		-
930 MISCELLANEOUS GENERAL EXPENSES	LB930	LBSUB9	$	-		-		-		-		-
931 RENTS AND LEASES	LB931	PGP	$	-		-		-		-		-
935 MAINTENANCE OF GENERAL PLANT	LB935	PGP	$	74,927		65,674		-		-		9,253
Total Administrative and General Expense	LBAG		$	14,435,286	$	6,749,515	$	5,612,610	$	-	$	2,073,161
Total Operation and Maintenance Expenses	TLB		$	60,003,210	$	27,958,509	$	23,422,401	$	-	$	8,622,301
Operation and Maintenance Expenses Less Purchase Power	LBLPP		$	60,003,210	$	27,958,509	$	23,422,401	$	-	$	8,622,301

BIG RIVERS ELECTRIC CORPORATION
Cost of Service Study
Functional Assignment and Classification

12 Months Ended
October 2010

Description	Name	Functional Vector	Total System	Production Demand	Production Energy	Steam Direct	Transmission Demand
Other Expenses							
Depreciation Expenses							
Production	DEPRDP2	PPROD	$ 28,815,395	28,815,395	-	-	-
Transmission	DEPRDP3	PTRAN	$ 5,182,459	-	-	-	5,182,459
Transmission	DEPRDP4	PTRAN	$ -	-	-	-	-
Distribution	DEPRDP5	PDIST	$ -	-	-	-	-
General & Common Plant	DEPRDP6	PGP	$ 238,155	208,744	-	-	29,411
Other Plant	DEPROTH	TPIS	$ -	-	-	-	-
Total Depreciation Expense	TDEPR		$ 34,236,009	29,024,140	-	-	5,211,869
Accretion Expense							
Production	ACRTNP	F017	$ -	-	-	-	-
Transmission	ACRTNT	PTRAN	$ -	-	-	-	-
Distribution	ACRTND	PDIST	$ -	-	-	-	-
Total Accretion Expense	TACRTN		$ -	$ -	$ -	$ -	$ -
Property Taxes & Other	PTAX	TUP	$ (94,563)	(82,705)	-	-	(11,858)
Amortization of Investment Tax Credit	OTAX	TUP	$ -	-	-	-	-
Other Expenses	OT	TUP	$ (365,864)	(319,986)	-	-	(45,878)
Interest	INTLTD	TUP	$ 47,622,710	41,650,995	-	-	5,971,715
Other Deductions	DEDUCT	TUP	$ 109,257	95,557	-	-	13,700
Total Other Expenses	TOE		$ 81,507,549	$ 70,368,000	$ -	$ -	$ 11,139,549
Total Cost of Service (O&M + Other Expenses)			$ 527,945,095	$ 181,569,975	$ 317,276,572	$ -	$ 29,098,548

BIG RIVERS ELECTRIC CORPORATION
Cost of Service Study
Functional Assignment and Classification

12 Months Ended
October 2010

Description	Name	Functional Vector	Total System	Production Demand	Production Energy	Steam Direct	Transmission Demand
Functional Vectors							
Production Plant	F001		1.000000	1.000000	0.000000	0.000000	0.000000
Transmission Plant	F002		1.000000	0.000000	0.000000	0.000000	1.000000
Distribution Plant	F003		1.000000	0.000000	0.000000	0.000000	1.000000
Production Plant	F017		1.000000	0.000000	1.000000	0.000000	0.000000
Provar	PROVAR		1.000000	0.000000	1.000000	0.000000	0.000000
PROFIX	PROFIX		1.000000	1.000000	0.000000	0.000000	0.000000
Distribution Operation Labor	F023		-	-	-	-	-
Distribution Maintenance Labor	F024		-	-	-	-	-
Customer Accounts Expense	F025		1.000000	0.000000	0.000000	0.000000	1.000000
Customer Service Expense	F026		1.000000	0.000000	0.000000	0.000000	1.000000
Purchased Power Energy	OMPP		1.000000	0.000000	1.000000	0.000000	0.000000
Purchased Power Demand	OMPPD		1.000000	1.000000	0.000000	0.000000	0.000000
Purchased Power BREC Share of HMP&L Station Two	OMPPH		58,293,374	13,175,571	45,117,803	0.000000	0.000000
Production Energy	Energy		1.000000	0.000000	1.000000	0.000000	0.000000
Internally Generated Functional Vectors							
Total Prod, Trans, and Dist Plant		PT&D	1.000000	0.876506	-	-	0.123494
Total Transmission Plant		PTRAN	1.000000	-	-	-	1.000000
Operation and Maintenance Expenses Less Purchase Power		OMLPP	1.000000	0.494418	0.425734	-	0.079848
Total Plant in Service		TPIS	1.000000	0.876506	-	-	0.123494
Total Operation and Maintenance Expenses (Labor)		TLB	1.000000	0.465950	0.390352	-	0.143697
Sub-Total Prod, Trans, Dist, Cust Acct and Cust Service		OMSUB2	1.000000	0.232897	0.733903	-	0.033200
Total Steam Power Operation Expenses (Labor)		LBSUB1	1.000000	0.833374	0.166626	-	-
Total Steam Power Generation Maintenance Expense (Labor)		LBSUB2	1.000000	0.078617	0.921383	-	-
Total Transmission Labor Expenses		LBTRAN	1.000000	-	-	-	1.0000000
Sub-Total Labor Exp		LBSUB7	1.000000	0.465437	0.390841	-	0.143723
Total General Plant		PGP	1.000000	0.876506	-	-	0.123494
Total Production Plant		PPROD	1.000000	1.000000	-	-	-
Total Intangible Plant		INTPLT	1.000000	0.876506	-	-	0.123494

BIG RIVERS ELECTRIC CORPORATION
Cost of Service Study
Rate Schedule Allocation
12 Months Ended
October 2010
6 CP - Smelter TIER Adjustment - Revenues @ $1.95/mWh

Description	Ref	Name	Allocation Vector	Rurals	Large Industrials	Smelters	Total System
Cost of Service Summary -- Unadjusted							
Operating Revenues							
Sales to Members		REVUC	R01	$ 110,934,700	$ 39,110,620	$ 282,406,135	$ 432,451,455
Off System Sales Revenue			OSSALL	$ 12,751,365	$ 4,563,381	$ 59,229,055	$ 76,543,801
Income from Leased Property Net		OTHREV	RBPLT	$ 49,919	$ 12,329	$ 87,424	$ 149,673
Other Operating Revenue & Income		OTHREV	RBPLT	$ 4,595,526	$ 1,135,019	$ 8,048,200	$ 13,778,745
Total Operating Revenues		TOR		$ 128,331,510	$ 44,821,350	$ 349,770,815	$ 522,923,675
Operating Expenses							
Operation and Maintenance Expenses				$ 120,514,880	$ 39,518,059	$ 286,404,608	$ 446,437,546
Depreciation and Amortization Expenses				$ 11,430,505	$ 2,820,170	$ 19,985,334	$ 34,236,009
Property and Other Taxes			NPT	$ (31,650)	$ (7,782)	$ (55,131)	$ (94,563)
Total Operating Expenses		TOE		$ 131,913,735	$ 42,330,446	$ 306,334,811	$ 480,578,992
Utility Operating Margin				$ (3,582,224)	$ 2,490,903	$ 43,436,004	$ 42,344,683
Non-Operating Items							
Interest Income			RBPLT	$ -	$ -	$ -	$ -
Other Non-Operating Income			RBPLT	$ -	$ -	$ -	$ -
Other Credits			RBPLT	$ -	$ -	$ -	$ -
Interest on Long Term Debt				$ -	$ -	$ -	$ -
Other Interest Expense			RBPLT	$ -	$ -	$ -	$ -
Other Deductions			RBPLT	$ -	$ -	$ -	$ -
Total Non-Operating Items				$ -	$ -	$ -	$ -
Net Utility Operating Margin		TOM		$ (3,582,224)	$ 2,490,903	$ 43,436,004	$ 42,344,683
Net Cost Rate Base				$ 390,335,625	$ 96,406,419	$ 683,599,459	$ 1,170,341,502

BIG RIVERS ELECTRIC CORPORATION
Cost of Service Study
Rate Schedule Allocation
12 Months Ended
October 2010
6 CP - Smelter TIER Adjustment - Revenues @ $1.95/mWh

Description	Ref	Name	Allocation Vector		Rurals		Large Industrials		Smelters		Total System
<u>Cost of Service Summary -- Pro-Forma</u>											
Operating Revenues											
Total Operating Revenue				$	128,331,510	$	44,821,350	$	349,770,815	$	522,923,675
Pro-Forma Adjustments:											
To annualize revenue for new industrial customer	2.01			$	-	$	149,752	$	-	$	149,752
To adjust mismatch in fuel cost recovery	2.02	FACREV		$	(25,166,503)	$	(9,525,471)	$	(73,123,203)	$	(107,815,177)
To eliminate Environmental Surcharge revenues	2.03	ESREV		$	(5,315,462)	$	(2,025,233)	$	(15,493,538)	$	(22,834,232)
To reflect temperature normalized sales volumes	2.04		EnergyR	$	(421,610)	$	-	$	-	$	(421,610)
To eliminate Non-FAC PPA revenues	2.05	NFPR		$	2,757,108	$	1,045,800	$	7,785,109	$	11,588,017
To eliminate WKEC Lease Expenses	2.19		RBPLT	$	(49,919)	$	(12,329)	$	(87,424)	$	(149,673)
To eliminate RRI Domtar Cogen Backup revenues	2.09			$	-	$	(1,115,159)	$	-	$	(1,115,159)
To adjust for Smelter TIER Adjustment Charge	2.22			$	-	$	-	$	-	$	-
Total Pro-Forma Operating Revenue				$	100,135,124	$	33,338,709	$	268,851,759	$	402,325,592

BIG RIVERS ELECTRIC CORPORATION
Cost of Service Study
Rate Schedule Allocation
12 Months Ended
October 2010
6 CP - Smelter TIER Adjustment - Revenues @ $1.95/mWh

Description	Ref	Name	Allocation Vector	Rurals	Large Industrials	Smelters	Total System
Cost of Service Summary -- Pro-Forma							
Operating Expenses							
Operation and Maintenance Expenses				$ 120,514,880	$ 39,518,059	$ 286,404,608	$ 446,437,546
Depreciation and Amortization Expenses				$ 11,430,505	$ 2,820,170	$ 19,985,334	$ 34,236,009
Property and Other Taxes			NPT	$ (31,650)	$ (7,782)	$ (55,131)	$ (94,563)
Adjustments to Operating Expenses:							
To annualize expenses for new industrial customer	2.01			$ -	$ 110,607	$ -	$ 110,607
To adjust mismatch in fuel cost recovery	2.02		FACREV	$ (25,685,949)	$ (9,722,081)	$ (74,632,493)	$ (110,040,523)
To eliminate Environmental Surcharge expenses	2.03		ESREV	$ (5,462,944)	$ (2,081,425)	$ (15,923,422)	$ (23,467,791)
To reflect weather normalized sales volumes	2.04		EnergyR	$ (295,293)	$ -	$ -	$ (295,293)
To eliminate Non-FAC PPA expenses	2.05		NFPR	$ 2,858,740	$ 1,084,350	$ 8,072,083	$ 12,015,173
To reflect annualized depreciation expenses	2.06		PLT	$ 2,093,093	$ 514,548	$ 3,645,010	$ 6,252,651
To reflect increases in labor and labor-related costs	2.07		LBPLT	$ 183,165	$ 53,069	$ 388,660	$ 624,894
To reflect current interest on construction (CWIP)	2.08		PLT	$ 172,654	$ 42,444	$ 300,669	$ 515,767
To eliminate RRI Domtar Cogen Backup expenses	2.09			$ -	$ (2,086,416)	$ -	$ (2,086,416)
To reflect levelized production expenses	2.10		CP	$ 1,916,312	$ 463,846	$ 3,280,520	$ 5,660,678
To reflect levelized production expenses	2.11		CP	$ 923,161	$ 223,452	$ 1,580,352	$ 2,726,965
To reflect going forward Information Technology support services	2.12		RBPLT	$ 97,453	$ 24,069	$ 170,671	$ 292,194
To reflect amortizaton of rate case expenses	2.13		RBPLT	$ 93,960	$ 23,206	$ 164,553	$ 281,719
To reflect MISO related expenses	2.14		12CPTR	$ 1,667,501	$ 459,102	$ 3,288,398	$ 5,415,000
To annualize interest on long-term debt	2.15		RBPLT	$ 23,483	$ 5,800	$ 41,125	$ 70,408
To reflect leased property income (Soaper Building Rent)	2.16		LBPLT	$ (37,626)	$ (10,902)	$ (79,840)	$ (128,368)
To adjust for costs related to LEM Dispatch	2.17		CP	$ (317,140)	$ (76,764)	$ (542,910)	$ (936,815)
To adjust for costs related to APM	2.18		CP	$ 69,429	$ 16,805	$ 118,855	$ 205,090
To reflect going forward level of Outside Services	2.25		EnergyNS	$ (725,000)	$ (275,000)	$ -	$ (1,000,000)
To eliminate costs for SFPC membership	2.20		RBPLT	$ (60,293)	$ (14,891)	$ (105,591)	$ (180,775)
To adjust for MISO Case-related expenses	2.21		12CPTR	$ (237,459)	$ (65,378)	$ (468,281)	$ (771,118)
To reflect commitment to Energy Efficiency Programs	2.26		EnergyNS	$ 725,000	$ 275,000	$ -	$ 1,000,000
To eliminate promo advertising, lobbying, donation and econ dev	2.23		R01	$ (130,114)	$ (45,872)	$ (331,230)	$ (507,216)
To reflect going forward level of income taxes	2.24		NTPLT	$ 61,251	$ 15,070	$ 106,763	$ 183,084
Total Expense Adjustments				$ (22,066,615)	$ (11,067,360)	$ (70,926,109)	$ (104,060,084)
Total Operating Expenses		TOE		$ 109,847,120	$ 31,263,086	$ 235,408,702	$ 376,518,908
Utility Operating Margins -- Pro-Forma				$ (9,711,995)	$ 2,075,623	$ 33,443,057	$ 25,806,684
Non-Operating Items				$ -	$ -	$ -	-
Total Non-Operating Items				$ -	$ -	$ -	-
Net Utility Operating Margin				$ (9,711,995)	$ 2,075,623	$ 33,443,057	$ 25,806,684
Net Cost Rate Base				$ 390,335,625	$ 96,406,419	$ 683,599,459	$ 1,170,341,502
Return on Rate Base -- Utility Operating Margin Divided by Rate Base				-2.49%	2.15%	4.89%	2.21%

BIG RIVERS ELECTRIC CORPORATION
Cost of Service Study
Rate Schedule Allocation
12 Months Ended
October 2010
6 CP - Smelter TIER Adjustment - Revenues @ $1.95/mWh

Description	Ref	Name	Allocation Vector	Rurals	Large Industrials	Smelters	Total System
Subsidies Paid and Received at Present Rates							
(subisidies received shown as positive value)							
Rate Base				$ 390,335,625	$ 96,406,419	$ 683,599,459	$ 1,170,341,502
Operating Margins (present rates)				$ (9,711,995)	$ 2,075,623	$ 33,443,057	$ 25,806,684
Operating Margins at Equal Rate of Return	ROR	2.21%		$ 8,607,119	$ 2,125,815	$ 15,073,750	$ 25,806,684
Subsidies Paid and Received				$ 18,319,114	$ 50,193	$ (18,369,307)	$ 0

Big Rivers Electric Corporation
Summary of Cost of Service Study
For the 12 Months Ended October 2010

<u>Rate of Return Summary</u>

Unadjusted

Rate Schedule		Utility Operating Margins		Net Cost Rate Base	Rate of Return
Total Rural	$	(9,711,995)	$	390,335,625	-2.49%
Total Large Industrial		2,075,623		96,406,419	2.15%
Total Smelter		33,443,057		683,599,459	4.89%
Total	$	25,806,684	$	1,170,341,502	2.21%

Adjusted for Proposed Rate Increase

Rate Schedule		Utility Operating Margins		Net Cost Rate Base	Rate of Return
Total Rural	$	4,460,008	$	390,335,625	1.14%
Total Large Industrial		5,304,189		96,406,419	5.50%
Total Smelter		55,996,452		683,599,459	8.19%
Total	$	65,760,649	$	1,170,341,502	5.62%

Description	Name	Functional Vector		Total System	November 2009	December 2009	January 2010	February 2010	March 2010
Plant in Service									
Intangible Plant	INTPLT	PT&D	$	66,895					
Production Plant	PPROD	F001	$	1,686,796,955					
Transmission Plant	PTRAN	F002	$	237,659,206					
Distribution Plant	PDIST	F003	$	-					
Total Production & Transmission Plant	PT&D			1,924,456,160					
General Plant	PGP	PT&D	$	18,511,051					
Total Plant in Service	TPIS		$	1,943,034,107					
Construction Work in Progress (CWIP)									
CWIP Production	CWIP1	PPROD	$	22,411,274					
CWIP Transmission	CWIP2	PTRAN	$	7,475,859					
CWIP Distribution Plant	CWIP3	PDIST	$	-					
CWIP General Plant	CWIP4	PT&D	$	16,915,005					
Total Construction Work in Progress	TCWIP		$	46,802,138					
Total Utility Plant			$	1,989,836,245					
Rate Base									
Total Utility Plant	TUP		$	1,989,836,245					
Less: Acummulated Provision for Depreciation									
Production	ADEPREPA	PPROD	$	790,847,523					
Transmission	ADEPRTP	PTRAN	$	107,564,747					
Distribution	ADEPRD11	PDIST	$	-					
General & Common Plant	ADEPRD12	PT&D	$	6,300,770					
Intangible, Misc, and Other Plant	ADEPRGP	PT&D	$	-					
Retirement Work In Progress	ADEPRRT	PT&D	$	-					
Total Accumulated Depreciation	TADEPR		$	904,713,040					
Net Utility Plant	NTPLANT		$	1,085,123,206					
Working Capital									
Cash Working Capital - Operation and Maintenance Expenses	CWC	OMLPP	$	28,114,365					
Materials and Supplies	M&S	TPIS	$	22,777,820	20327197.9	85340.04	-68898.4	208485.44	-95121.11
Fuel Stock	PREPAY	TPIS	$	34,326,112	39158400.85	-1328756.9	-4130766.79	-359777.13	1918732.52
Total Working Capital	TWC		$	85,218,297					
Net Rate Base	RB		$	1,170,341,502					

Description	Name	Functional Vector	April 2010	May 2010	June 2010	July 2010	August 2010	September 2010
Plant in Service								
Intangible Plant	INTPLT	PT&D						
Production Plant	PPROD	F001						
Transmission Plant	PTRAN	F002						
Distribution Plant	PDIST	F003						
Total Production & Transmission Plant	PT&D							
General Plant	PGP	PT&D						
Total Plant in Service	TPIS							
Construction Work in Progress (CWIP)								
CWIP Production	CWIP1	PPROD						
CWIP Transmission	CWIP2	PTRAN						
CWIP Distribution Plant	CWIP3	PDIST						
CWIP General Plant	CWIP4	PT&D						
Total Construction Work in Progress	TCWIP							
Total Utility Plant								
Rate Base								
Total Utility Plant	TUP							
Less: Acummulated Provision for Depreciation								
Production	ADEPREPA	PPROD						
Transmission	ADEPRTP	PTRAN						
Distribution	ADEPRD11	PDIST						
General & Common Plant	ADEPRD12	PT&D						
Intangible, Misc, and Other Plant	ADEPRGP	PT&D						
Retirement Work In Progress	ADEPRRT	PT&D						
Total Accumulated Depreciation	TADEPR							
Net Utility Plant	NTPLANT							
Working Capital								
Cash Working Capital - Operation and Maintenance Expenses	CWC	OMLPP						
Materials and Supplies	M&S	TPIS	-220183.19	207004.7	357212.07	240129.05	-144241.07	2889566.56
Fuel Stock	PREPAY	TPIS	2552249.61	867432.81	-287963.1	-3463026.24	-2018344.81	-578882.38
Total Working Capital	TWC							
Net Rate Base	RB							

Description	Name	Functional Vector	October 2010
Plant in Service			
Intangible Plant	INTPLT	PT&D	
Production Plant	PPROD	F001	
Transmission Plant	PTRAN	F002	
Distribution Plant	PDIST	F003	
Total Production & Transmission Plant	PT&D		
General Plant	PGP	PT&D	
Total Plant in Service	TPIS		
Construction Work in Progress (CWIP)			
CWIP Production	CWIP1	PPROD	
CWIP Transmission	CWIP2	PTRAN	
CWIP Distribution Plant	CWIP3	PDIST	
CWIP General Plant	CWIP4	PT&D	
Total Construction Work in Progress	TCWIP		
Total Utility Plant			
Rate Base			
Total Utility Plant	TUP		
Less: Acummulated Provision for Depreciation			
Production	ADEPREPA	PPROD	
Transmission	ADEPRTP	PTRAN	
Distribution	ADEPRD11	PDIST	
General & Common Plant	ADEPRD12	PT&D	
Intangible, Misc, and Other Plant	ADEPRGP	PT&D	
Retirement Work In Progress	ADEPRRT	PT&D	
Total Accumulated Depreciation	TADEPR		
Net Utility Plant	NTPLANT		
Working Capital			
Cash Working Capital - Operation and Maintenance Expenses	CWC	OMLPP	
Materials and Supplies	M&S	TPIS	-1008672.24
Fuel Stock	PREPAY	TPIS	1996813.82
Total Working Capital	TWC		
Net Rate Base	RB		

Description	Name	Functional Vector		Total System	November 2009	December 2009	January 2010	February 2010	March 2010
Operation and Maintenance Expenses									
Steam Power Generation Operation Expenses									
500 OPERATION SUPERVISION & ENGINEERING	OM500	PROFIX	$	4,974,566	342962.62	1034901.09	358703.86	318491.34	384828.47
501 FUEL	OM501	Energy	$	200,919,367	11957675.62	16736745.89	19103323.18	17630280.19	17173097.35
502 STEAM EXPENSES	OM502	PROFIX	$	34,453,882	2424633.22	2490999.61	2647322.04	2676616.85	2911578.89
505 ELECTRIC EXPENSES	OM505	PROFIX	$	5,730,122	399281.19	656713.94	477935.99	489102.92	443771.24
506 MISC. STEAM POWER EXPENSES	OM506	PROFIX	$	7,451,302	837237.41	458663.32	531778.12	516078.68	646116.36
507 RENTS	OM507	PROFIX	$	-		0	0	0	0
509 ALLOWANCES	OM509	Energy	$	429,682		0	0	55382.46	42291.31
Total Steam Power Operation Expenses			$	253,958,921	$ 7,775	$ 146,296	$ 7,154	$ 15,852	$ 21,245
Steam Power Generation Maintenance Expenses									
510 MAINTENANCE SUPERVISION & ENGINEERING	OM510	Energy	$	3,631,867	301562.96	282674.01	282136.07	286174.73	324812.85
511 MAINTENANCE OF STRUCTURES	OM511	PROFIX	$	3,346,806	-2396.3	561809.41	164027.98	219884.17	122851.74
512 MAINTENANCE OF BOILER PLANT	OM512	Energy	$	30,113,309	2665049.9	2707987.08	1617573	1413359.02	2039706.29
513 MAINTENANCE OF ELECTRIC PLANT	OM513	Energy	$	6,251,804	2443905.77	804364.44	-26124.91	190619.56	167015.92
514 MAINTENANCE OF MISC STEAM PLANT	OM514	PROFIX	$	877,364	136355.09	154030.5	71461.85	48046.95	35868.33
Total Steam Power Generation Maintenance Expense			$	44,221,151	$ 3,659	$ 7,366	$ 1,455	$ 6,057	$ 9,772
Total Steam Power Generation Expense			$	298,180,072					

Description	Name	Functional Vector	April 2010	May 2010	June 2010	July 2010	August 2010	September 2010
Operation and Maintenance Expenses								
Steam Power Generation Operation Expenses								
500 OPERATION SUPERVISION & ENGINEERING	OM500	PROFIX	338223.38	414283.22	372420.21	359404.38	369945.71	334708.35
501 FUEL	OM501	Energy	15868543.13	15412621.99	16949864.35	18643264.65	19588180.27	17004762.52
502 STEAM EXPENSES	OM502	PROFIX	2801318.34	3017168.8	3110448.48	3022221.22	3095094.21	3132173.1
505 ELECTRIC EXPENSES	OM505	PROFIX	430459.27	473960.9	440316.02	456264.08	479912.75	476352.39
506 MISC. STEAM POWER EXPENSES	OM506	PROFIX	557984.26	577686.56	640171.09	585642.46	806920.28	725866.29
507 RENTS	OM507	PROFIX	0	0	0	0	0	0
509 ALLOWANCES	OM509	Energy	33437.63	31618.94	46952.89	62169.21	49573.1	28256.05
Total Steam Power Operation Expenses			$ 6,070	$ 8,052	$ 5,213	$ 267,644	$ 167,124	$ 44,089
Steam Power Generation Maintenance Expenses								
510 MAINTENANCE SUPERVISION & ENGINEERING	OM510	Energy	297530.92	289425	297802.77	281476.85	309430.59	294029.27
511 MAINTENANCE OF STRUCTURES	OM511	PROFIX	153063.03	309779.07	306987.02	458108.12	372678.29	488354.6
512 MAINTENANCE OF BOILER PLANT	OM512	Energy	1740181.45	2535024.61	2164789.64	2054585.86	2034329.79	2855272.84
513 MAINTENANCE OF ELECTRIC PLANT	OM513	Energy	313812.24	389518.49	251988.71	302199.64	422000.23	534239.62
514 MAINTENANCE OF MISC STEAM PLANT	OM514	PROFIX	61896.28	58285.06	85932.24	51800.09	89344.85	66090.33
Total Steam Power Generation Maintenance Expense			$ (325)	$ 4,943	$ 216,501	$ 175,754	$ 65,241	$ 96,186
Total Steam Power Generation Expense								

Description	Name	Functional Vector	October 2010
Operation and Maintenance Expenses			
Steam Power Generation Operation Expenses			
500 OPERATION SUPERVISION & ENGINEERING	OM500	PROFIX	345693.85
501 FUEL	OM501	Energy	14851007.4
502 STEAM EXPENSES	OM502	PROFIX	3124307.14
505 ELECTRIC EXPENSES	OM505	PROFIX	506051.44
506 MISC. STEAM POWER EXPENSES	OM506	PROFIX	567156.95
507 RENTS	OM507	PROFIX	0
509 ALLOWANCES	OM509	Energy	80000.79
Total Steam Power Operation Expenses			$ 44,882
Steam Power Generation Maintenance Expenses			
510 MAINTENANCE SUPERVISION & ENGINEERING	OM510	Energy	384811.34
511 MAINTENANCE OF STRUCTURES	OM511	PROFIX	191658.45
512 MAINTENANCE OF BOILER PLANT	OM512	Energy	6285449.98
513 MAINTENANCE OF ELECTRIC PLANT	OM513	Energy	458264.77
514 MAINTENANCE OF MISC STEAM PLANT	OM514	PROFIX	18252.47
Total Steam Power Generation Maintenance Expense			$ 38,478
Total Steam Power Generation Expense			

Description	Name	Functional Vector		Total System	November 2009	December 2009	January 2010	February 2010	March 2010
Operation and Maintenance Expenses (Continued)									
Other Power Generation Operation Expense									
546 OPERATION SUPERVISION & ENGINEERING	OM546	PROFIX	$	-	0	0	0	0	0
547 FUEL	OM547	Energy	$	706,789	7379.85	135814.53	4779.27	13479.11	18872.46
548 GENERATION EXPENSE	OM548	PROFIX	$	34,608	394.54	10481.32	2375	2373	2373
549 MISC OTHER POWER GENERATION	OM549	PROFIX	$	-	0	0	0	0	0
550 RENTS	OM550	PROFIX	$	-	0	0	0	0	0
Total Other Power Generation Expenses			$	741,396	$ (1)	$ (0)	$ 0	$ 1	$ 0
Other Power Generation Maintenance Expense									
551 MAINTENANCE SUPERVISION & ENGINEERING	OM551	PROFIX	$	-	0	0	0	0	0
552 MAINTENANCE OF STRUCTURES	OM552	PROFIX	$	-	0	0	0	0	0
553 MAINTENANCE OF GENERATING & ELEC PLANT	OM553	PROFIX	$	625,088	3658.66	7365.41	1454.85	6056.77	9772.16
554 MAINTENANCE OF MISC OTHER POWER GEN PLT	OM554	PROFIX	$	-	0	0	0	0	0
Total Other Power Generation Maintenance Expense			$	625,088	$ 0	$ (0)	$ (0)	$ 0	$ 0
Total Other Power Generation Expense			$	1,366,485					
Total Station Expense			$	299,546,557					

Description	Name	Functional Vector		April 2010		May 2010		June 2010		July 2010		August 2010		September 2010
Operation and Maintenance Expenses (Continued)														
Other Power Generation Operation Expense				0		0		0		0		0		0
546 OPERATION SUPERVISION & ENGINEERING	OM546	PROFIX		3696.82		5679.30		2839.60		265271.41		164750.42		41716.70
547 FUEL	OM547	Energy		2373		2373.00		2373.00		2373.00		2373.00		2373.00
548 GENERATION EXPENSE	OM548	PROFIX		0		0		0		0		0		0
549 MISC OTHER POWER GENERATION	OM549	PROFIX		0		0		0		0		0		0
550 RENTS	OM550	PROFIX												
Total Other Power Generation Expenses			$	(0)	$	1	$	(0)	$	0	$	(0)	$	0
Other Power Generation Maintenance Expense				0		0		0		0		0		0
551 MAINTENANCE SUPERVISION & ENGINEERING	OM551	PROFIX		0		0		0		0		0		0
552 MAINTENANCE OF STRUCTURES	OM552	PROFIX		-322.62		4943.09		216501.24		175754.02		65240.65		96186.42
553 MAINTENANCE OF GENERATING & ELEC PLANT	OM553	PROFIX		0		0		0		0		0		0
554 MAINTENANCE OF MISC OTHER POWER GEN PLT	OM554	PROFIX												
Total Other Power Generation Maintenance Expense			$	2	$	0	$	1	$	(0)	$	(1)	$	0
Total Other Power Generation Expense														
Total Station Expense														

Description	Name	Functional Vector	October 2010
Operation and Maintenance Expenses (Continued)			
Other Power Generation Operation Expense			
546 OPERATION SUPERVISION & ENGINEERING	OM546	PROFIX	0
547 FUEL	OM547	Energy	42509.14
548 GENERATION EXPENSE	OM548	PROFIX	2373.00
549 MISC OTHER POWER GENERATION	OM549	PROFIX	0
550 RENTS	OM550	PROFIX	0
Total Other Power Generation Expenses			$ (0)
Other Power Generation Maintenance Expense			
551 MAINTENANCE SUPERVISION & ENGINEERING	OM551	PROFIX	0
552 MAINTENANCE OF STRUCTURES	OM552	PROFIX	0
553 MAINTENANCE OF GENERATING & ELEC PLANT	OM553	PROFIX	38477.63
554 MAINTENANCE OF MISC OTHER POWER GEN PLT	OM554	PROFIX	0
Total Other Power Generation Maintenance Expense			$ (0)
Total Other Power Generation Expense			
Total Station Expense			

Description	Name	Functional Vector		Total System	November 2009	December 2009	January 2010	February 2010	March 2010
Operation and Maintenance Expenses (Continued)									
Other Power Supply Expenses									
555 PURCHASED POWER Energy	OM555	OMPP	$	19,466,790	3,827,952.61	2,536,760.36	1,913,169.62	941,370.11	911,294.71
555 PURCHASED POWER Demand	OMD555	OMPPD	$	4,210,045	350,837.07	350,837.07	350,837.07	350,837.07	350,837.07
555 PURCHASED POWER BREC Share of HMP&L Station Two	OMH555	OMPPH	$	58,293,374	4,582,937.26	5,054,161.64	4,549,698.12	4,432,913.73	4,763,164.98
555 PURCHASED POWER OPTIONS	OMO555	OMPP	$	-	0	0	0	0	0
555 BROKERAGE FEES	OMB555	OMPP	$	-	0	0	0	0	0
555 MISO TRANSMISSION EXPENSES	OMM555	OMPP	$	-	0	0	0	0	0
556 SYSTEM CONTROL AND LOAD DISPATCH	OM556	PROFIX	$	909,422	143177.05	161775.92	84110.82	66492.87	77558.07
557 OTHER EXPENSES	OM557	PROFIX	$	20,575,465	2479520.29	2210820.92	1519858.99	1381956.22	1577347.72
558 DUPLICATE CHARGES	OM558	Energy	$	-	0	0	0	0	0
Total Other Power Supply Expenses	TPP		$	103,455,096	11,384,424.28	10,314,355.91	8,417,674.62	7,173,570.00	7,680,202.55
Total Electric Power Generation Expenses			$	403,001,653					
Transmission Expenses									
560 OPERATION SUPERVISION AND ENG	OM560	LBTRAN	$	876,815	159722.72	99111.49	64131.05	56493.74	71626.61
561 LOAD DISPATCHING	OM561	LBTRAN	$	1,454,938	245368.38	141741.21	113777.21	98967.65	113022.44
562 STATION EXPENSES	OM562	PTRAN	$	1,163,408	138650.41	111166.28	70289.35	78900.11	96317.14
563 OVERHEAD LINE EXPENSES	OM563	PTRAN	$	1,090,014	116902.84	72507.66	91764.75	90248.86	92136.75
565 TRANSMISSION OF ELECTRICITY BY OTHERS	OM565	PTRAN	$	3,065,817	227372.33	270804.44	222495.76	313990.87	298157.74
566 MISC. TRANSMISSION EXPENSES	OM566	PTRAN	$	475,381	82941.08	54676.78	40839.08	35322.18	39484.82
567 RENTS	OM567	PTRAN	$	24,701	2058.43	2058.43	2058.43	2058.43	2058.43
568 MAINTENACE SUPERVISION AND ENG	OM568	LBTRAN	$	647,227	120702.88	66051.02	48367.7	40149.83	53439.26
569 STRUCTURES	OM569	PTRAN	$	26,913	36.88	6259.34	0	1874.02	59.12
570 MAINT OF STATION EQUIPMENT	OM570	PTRAN	$	1,936,760	272171.89	208826.01	135405.37	165513.32	155839.56
571 MAINT OF OVERHEAD LINES	OM571	PTRAN	$	2,876,462	318695.62	624358.63	20316.93	128651.35	134146
572 UNDERGROUND LINES	OM572	PTRAN	$	-	0	0	0	0	0
573 MISC PLANT	OM573	PTRAN	$	97,880	8341.27	4665	3732.37	5821.94	34823.78
Total Transmission Expenses			$	13,736,318	1,692,964.73	1,662,226.29	813,178.00	1,017,992.30	1,091,111.65

Description	Name	Functional Vector	April 2010	May 2010	June 2010	July 2010	August 2010	September 2010
Operation and Maintenance Expenses (Continued)								
Other Power Supply Expenses								
555 PURCHASED POWER Energy	OM555	OMPP	1,360,105.55	2,595,157.16	1,414,751.54	1,276,714.40	516,721.89	613,253.53
555 PURCHASED POWER Demand	OMD555	OMPPD	350,837.07	350,837.07	350,837.07	350,837.07	350,837.07	350,837.07
555 PURCHASED POWER BREC Share of HMP&L Station Two	OMH555	OMPPH	5,098,546.01	4,460,755.81	4,842,232.95	5,325,056.85	5,088,921.31	4,972,622.48
555 PURCHASED POWER OPTIONS	OMO555	OMPP	0	0	0	0	0	0
555 BROKERAGE FEES	OMB555	OMPP	0	0	0	0	0	0
555 MISO TRANSMISSION EXPENSES	OMM555	OMPP	0	0	0	0	0	0
556 SYSTEM CONTROL AND LOAD DISPATCH	OM556	PROFIX	0	92094.61	73384.96	71377.18	39951.63	51309.82
557 OTHER EXPENSES	OM557	PROFIX	1535653.17	1420108.84	1438109.81	1546376.13	1542523.95	2323941.19
558 DUPLICATE CHARGES	OM558	Energy	0	0	0	0	0	0
Total Other Power Supply Expenses	TPP		8,345,141.80	8,918,953.49	8,119,316.33	8,570,361.63	7,538,955.85	8,311,964.09
Total Electric Power Generation Expenses								
Transmission Expenses								
560 OPERATION SUPERVISION AND ENG	OM560	LBTRAN	59387.59	61734.83	72275.43	57830.16	52970.2	70253.05
561 LOAD DISPATCHING	OM561	LBTRAN	89896.48	94173.59	104627.56	94297.49	86936.32	135835
562 STATION EXPENSES	OM562	PTRAN	84122.23	90931.03	103923.43	86043.52	116294.21	83898.29
563 OVERHEAD LINE EXPENSES	OM563	PTRAN	87522.07	87158.79	89203.39	89187.21	86736.29	88209.66
565 TRANSMISSION OF ELECTRICITY BY OTHERS	OM565	PTRAN	229091.63	251486.95	238169.64	253067.81	259149.57	237980.88
566 MISC. TRANSMISSION EXPENSES	OM566	PTRAN	28982.15	30160.95	44581.15	19944.19	35290.89	32930.62
567 RENTS	OM567	PTRAN	2058.43	2058.43	2058.43	2058.43	2058.43	2058.43
568 MAINTENACE SUPERVISION AND ENG	OM568	LBTRAN	44241.45	45590.11	51110.87	42324.47	40557.13	55824.53
569 STRUCTURES	OM569	PTRAN	80.04	577.95	1084.71	2771.42	1003.78	1896.87
570 MAINT OF STATION EQUIPMENT	OM570	PTRAN	124235.3	158259.64	153920.85	137834.03	134856.99	175088.1
571 MAINT OF OVERHEAD LINES	OM571	PTRAN	140543.65	122631.69	245673.12	136904.15	282898.22	547382.49
572 UNDERGROUND LINES	OM572	PTRAN	0	0	0	0	0	0
573 MISC PLANT	OM573	PTRAN	4923.69	6697.42	5370.15	3919.44	6630.08	5359.76
Total Transmission Expenses			895,084.71	951,461.38	1,111,998.73	926,182.32	1,105,382.11	1,436,717.68

Description	Name	Functional Vector	October 2010
Operation and Maintenance Expenses (Continued)			
Other Power Supply Expenses			
555 PURCHASED POWER Energy	OM555	OMPP	1559538.19
555 PURCHASED POWER Demand	OMD555	OMPPD	350837.07
555 PURCHASED POWER BREC Share of HMP&L Station Two	OMH555	OMPPH	5,122,362.96
555 PURCHASED POWER OPTIONS	OMO555	OMPP	0
555 BROKERAGE FEES	OMB555	OMPP	0
555 MISO TRANSMISSION EXPENSES	OMM555	OMPP	0
556 SYSTEM CONTROL AND LOAD DISPATCH	OM556	PROFIX	48189.16
557 OTHER EXPENSES	OM557	PROFIX	1599248
558 DUPLICATE CHARGES	OM558	Energy	0
Total Other Power Supply Expenses	TPP		8,680,175.38
Total Electric Power Generation Expenses			
Transmission Expenses			
560 OPERATION SUPERVISION AND ENG	OM560	LBTRAN	51278.57
561 LOAD DISPATCHING	OM561	LBTRAN	136294.18
562 STATION EXPENSES	OM562	PTRAN	102872.03
563 OVERHEAD LINE EXPENSES	OM563	PTRAN	98436.13
565 TRANSMISSION OF ELECTRICITY BY OTHERS	OM565	PTRAN	264049.42
566 MISC. TRANSMISSION EXPENSES	OM566	PTRAN	30227.33
567 RENTS	OM567	PTRAN	2058.43
568 MAINTENACE SUPERVISION AND ENG	OM568	LBTRAN	38868.14
569 STRUCTURES	OM569	PTRAN	11269.17
570 MAINT OF STATION EQUIPMENT	OM570	PTRAN	114809.26
571 MAINT OF OVERHEAD LINES	OM571	PTRAN	174260.22
572 UNDERGROUND LINES	OM572	PTRAN	0
573 MISC PLANT	OM573	PTRAN	7595.34
Total Transmission Expenses			1,032,018.22

Description	Name	Functional Vector		Total System	November 2009	December 2009	January 2010	February 2010	March 2010
Distribution Operation Expense									
580 OPERATION SUPERVISION AND ENGI	OM580	LBDO	$	-	0	0	0	0	0
581 LOAD DISPATCHING	OM581	PDIST	$	-	0	0	0	0	0
582 STATION EXPENSES	OM582	PDIST	$	-	0	0	0	0	0
583 OVERHEAD LINE EXPENSES	OM583	PDIST	$	-	0	0	0	0	0
584 UNDERGROUND LINE EXPENSES	OM584	PDIST	$	-	0	0	0	0	0
585 STREET LIGHTING EXPENSE	OM585	PDIST	$	-	0	0	0	0	0
586 METER EXPENSES	OM586	PDIST	$	-	0	0	0	0	0
586 METER EXPENSES - LOAD MANAGEMENT	OM586x	PDIST	$	-	0	0	0	0	0
587 CUSTOMER INSTALLATIONS EXPENSE	OM587	PDIST	$	-	0	0	0	0	0
588 MISCELLANEOUS DISTRIBUTION EXP	OM588	PDIST	$	-	0	0	0	0	0
588 MISC DISTR EXP – MAPPIN	OM588x	PDIST	$	-	0	0	0	0	0
589 RENTS	OM589	PDIST	$	-	0	0	0	0	0
Total Distribution Operation Expense	OMDO		$	-					
<u>Operation and Maintenance Expenses (Continued)</u>									
Distribution Maintenance Expense									
590 MAINTENANCE SUPERVISION AND EN	OM590	LBDM	$	-	0	0	0	0	0
591 STRUCTURES	OM591	PDIST	$	-	0	0	0	0	0
592 MAINTENANCE OF STATION EQUIPME	OM592	PDIST	$	-	0	0	0	0	0
593 MAINTENANCE OF OVERHEAD LINES	OM593	PDIST	$	-	0	0	0	0	0
594 MAINTENANCE OF UNDERGROUND LIN	OM594	PDIST	$	-	0	0	0	0	0
595 MAINTENANCE OF LINE TRANSFORME	OM595	PDIST	$	-	0	0	0	0	0
596 MAINTENANCE OF ST LIGHTS & SIG SYSTEMS	OM596	PDIST	$	-	0	0	0	0	0
597 MAINTENANCE OF METERS	OM597	PDIST	$	-	0	0	0	0	0
598 MISCELLANEOUS DISTRIBUTION EXPENSES	OM598	PDIST	$	-	0	0	0	0	0
Total Distribution Maintenance Expense	OMDM		$	-					
Total Distribution Operation and Maintenance Expenses				-					
Transmission and Distribution Expenses				13,736,318					
Production, Transmission and Distribution Expenses	OMSUB		$	416,737,971					

Description	Name	Functional Vector	April 2010	May 2010	June 2010	July 2010	August 2010	September 2010
Distribution Operation Expense								
580 OPERATION SUPERVISION AND ENGI	OM580	LBDO	0	0	0	0	0	0
581 LOAD DISPATCHING	OM581	PDIST	0	0	0	0	0	0
582 STATION EXPENSES	OM582	PDIST	0	0	0	0	0	0
583 OVERHEAD LINE EXPENSES	OM583	PDIST	0	0	0	0	0	0
584 UNDERGROUND LINE EXPENSES	OM584	PDIST	0	0	0	0	0	0
585 STREET LIGHTING EXPENSE	OM585	PDIST	0	0	0	0	0	0
586 METER EXPENSES	OM586	PDIST	0	0	0	0	0	0
586 METER EXPENSES - LOAD MANAGEMENT	OM586x	PDIST	0	0	0	0	0	0
587 CUSTOMER INSTALLATIONS EXPENSE	OM587	PDIST	0	0	0	0	0	0
588 MISCELLANEOUS DISTRIBUTION EXP	OM588	PDIST	0	0	0	0	0	0
588 MISC DISTR EXP -- MAPPIN	OM588x	PDIST	0	0	0	0	0	0
589 RENTS	OM589	PDIST	0	0	0	0	0	0
Total Distribution Operation Expense	OMDO							
Operation and Maintenance Expenses (Continued)								
Distribution Maintenance Expense								
590 MAINTENANCE SUPERVISION AND EN	OM590	LBDM	0	0	0	0	0	0
591 STRUCTURES	OM591	PDIST	0	0	0	0	0	0
592 MAINTENANCE OF STATION EQUIPME	OM592	PDIST	0	0	0	0	0	0
593 MAINTENANCE OF OVERHEAD LINES	OM593	PDIST	0	0	0	0	0	0
594 MAINTENANCE OF UNDERGROUND LIN	OM594	PDIST	0	0	0	0	0	0
595 MAINTENANCE OF LINE TRANSFORME	OM595	PDIST	0	0	0	0	0	0
596 MAINTENANCE OF ST LIGHTS & SIG SYSTEMS	OM596	PDIST	0	0	0	0	0	0
597 MAINTENANCE OF METERS	OM597	PDIST	0	0	0	0	0	0
598 MISCELLANEOUS DISTRIBUTION EXPENSES	OM598	PDIST	0	0	0	0	0	0
Total Distribution Maintenance Expense	OMDM							
Total Distribution Operation and Maintenance Expenses								
Transmission and Distribution Expenses								
Production, Transmission and Distribution Expenses	OMSUB							

Description	Name	Functional Vector	October 2010
Distribution Operation Expense			
580 OPERATION SUPERVISION AND ENGI	OM580	LBDO	0
581 LOAD DISPATCHING	OM581	PDIST	0
582 STATION EXPENSES	OM582	PDIST	0
583 OVERHEAD LINE EXPENSES	OM583	PDIST	0
584 UNDERGROUND LINE EXPENSES	OM584	PDIST	0
585 STREET LIGHTING EXPENSE	OM585	PDIST	0
586 METER EXPENSES	OM586	PDIST	0
586 METER EXPENSES - LOAD MANAGEMENT	OM586x	PDIST	0
587 CUSTOMER INSTALLATIONS EXPENSE	OM587	PDIST	0
588 MISCELLANEOUS DISTRIBUTION EXP	OM588	PDIST	0
588 MISC DISTR EXP -- MAPPIN	OM588x	PDIST	0
589 RENTS	OM589	PDIST	0
Total Distribution Operation Expense	OMDO		
Operation and Maintenance Expenses (Continued)			
Distribution Maintenance Expense			
590 MAINTENANCE SUPERVISION AND EN	OM590	LBDM	0
591 STRUCTURES	OM591	PDIST	0
592 MAINTENANCE OF STATION EQUIPME	OM592	PDIST	0
593 MAINTENANCE OF OVERHEAD LINES	OM593	PDIST	0
594 MAINTENANCE OF UNDERGROUND LIN	OM594	PDIST	0
595 MAINTENANCE OF LINE TRANSFORME	OM595	PDIST	0
596 MAINTENANCE OF ST LIGHTS & SIG SYSTEMS	OM596	PDIST	0
597 MAINTENANCE OF METERS	OM597	PDIST	0
598 MISCELLANEOUS DISTRIBUTION EXPENSES	OM598	PDIST	0
Total Distribution Maintenance Expense	OMDM		
Total Distribution Operation and Maintenance Expenses			
Transmission and Distribution Expenses			
Production, Transmission and Distribution Expenses	OMSUB		

Description	Name	Functional Vector		Total System	November 2009	December 2009	January 2010	February 2010	March 2010
Customer Accounts Expense									
901 SUPERVISION/CUSTOMER ACCTS	OM901	F025	$	-	0	0	0	0	0
902 METER READING EXPENSES	OM902	F025	$	-	0	0	0	0	0
903 RECORDS AND COLLECTION	OM903	F025	$	-	0	0	0	0	0
904 UNCOLLECTIBLE ACCOUNTS	OM904	F025	$	-	0	0	0	0	0
905 MISC CUST ACCOUNTS	OM903	F025	$	-	0	0	0	0	0
Total Customer Accounts Expense	OMCA		$	-					
Customer Service Expense									
907 SUPERVISION	OM907	TUP	$	-	0	0	0	0	0
908 CUSTOMER ASSISTANCE EXPENSES	OM908	TUP	$	591,192	104389.97	75645.08	40729.07	42316.45	53316.29
908 CUSTOMER ASSISTANCE EXP-INCENTIVES	OM908x	TUP	$	-	0	0	0	0	0
909 INFORMATIONAL AND INSTRUCTIONA	OM909	TUP	$	-	0	0	0	0	0
909 INFORM AND INSTRUC -LOAD MGMT	OM909x	TUP	$	-	0	0	0	0	0
910 MISCELLANEOUS CUSTOMER SERVICE	OM910	TUP	$	-	0	0	0	0	0
911 DEMONSTRATION AND SELLING EXP	OM911	TUP	$	-	0	0	0	0	0
912 DEMONSTRATION AND SELLING EXP	OM912	TUP	$	-	0	0	0	0	0
913 ADVERTISING EXPENSES	OM913	TUP	$	488,103	103663.39	219971.2	7179.7	3679.68	21007.78
915 MDSE-JOBBING-CONTRACT	OM915	TUP	$	-	0	0	0	0	0
916 MISC SALES EXPENSE	OM916	TUP	$	-	0	0	0	0	0
Total Customer Service Expense	OMCS		$	1,079,295	208053.36	295616.28	47908.77	45996.13	74324.07
Sub-Total Prod, Trans, Dist, Cust Acct and Cust Service	OMSUB2			417,817,266					
<u>Operation and Maintenance Expenses (Continued)</u>									
Administrative and General Expense									
920 ADMIN. & GEN. SALARIES-	OM920	LBSUB9	$	14,315,713	2092449.03	1522142.97	1300504.05	1313340.25	1495631.43
921 OFFICE SUPPLIES AND EXPENSES	OM921	LBSUB9	$	6,915,648	432853.99	1082881.21	447533.76	790015.22	520665.52
922 ADMINISTRATIVE EXPENSES TRANSFERRED	OM922	LBSUB9	$	-	0	0	0	0	0
923 OUTSIDE SERVICES EMPLOYED	OM923	LBSUB9	$	3,954,189	337609.86	1175322.5	167190.31	217289.45	526048.51
924 PROPERTY INSURANCE	OM924	TUP	$	-	0	0	0	0	0
925 INJURIES AND DAMAGES - INSURAN	OM925	LBSUB9	$	179,889	13413.2	21072.48	15311.2	15178.2	25828.68
926 EMPLOYEE BENEFITS	OM926	LBSUB9	$	169,663	4383.08	-2896.98	25050.87	3276.12	0
927 FRANCHISE REQUIREMENTS	OM927	TUP	$	-	0	0	0	0	0
928 REGULATORY COMMISSION FEES	OM928	TUP	$	1,188,958	2785	925	0	0	1790.1
929 DUPLICATE CHARGES-CR	OM929	LBSUB9	$	-	0	0	0	0	0
930 MISCELLANEOUS GENERAL EXPENSES	OM930	LBSUB9	$	1,686,131	68132.08	249532.88	81732.32	215359.96	139106.95
931 RENTS AND LEASES	OM931	PGP	$	1,933	161.09	161.09	161.09	161.09	161.09
935 MAINTENANCE OF GENERAL PLANT	OM935	PGP	$	208,156	23769.07	24452.06	14946.22	44645.76	14798.82
Total Administrative and General Expense	OMAG		$	28,620,280	2,975,556.40	4,073,593.21	2,052,429.82	2,599,266.05	2,724,031.10
Total Operation and Maintenance Expenses	TOM		$	446,437,546					
Operation and Maintenance Expenses Less Purchase Power & Fuel	OMLPP		$	224,914,919					

Description	Name	Functional Vector	April 2010	May 2010	June 2010	July 2010	August 2010	September 2010
Customer Accounts Expense								
901 SUPERVISION/CUSTOMER ACCTS	OM901	F025	0	0	0	0	0	0
902 METER READING EXPENSES	OM902	F025	0	0	0	0	0	0
903 RECORDS AND COLLECTION	OM903	F025	0	0	0	0	0	0
904 UNCOLLECTIBLE ACCOUNTS	OM904	F025	0	0	0	0	0	0
905 MISC CUST ACCOUNTS	OM903	F025	0	0	0	0	0	0
Total Customer Accounts Expense	OMCA							
Customer Service Expense								
907 SUPERVISION	OM907	TUP	0	0	0	0	0	0
908 CUSTOMER ASSISTANCE EXPENSES	OM908	TUP	42590.29	45548.65	47955.97	41989.91	36242.46	23856.1
908 CUSTOMER ASSISTANCE EXP-INCENTIVES	OM908x	TUP	0	0	0	0	0	0
909 INFORMATIONAL AND INSTRUCTIONA	OM909	TUP	0	0	0	0	0	0
909 INFORM AND INSTRUC -LOAD MGMT	OM909x	TUP	0	0	0	0	0	0
910 MISCELLANEOUS CUSTOMER SERVICE	OM910	TUP	0	0	0	0	0	0
911 DEMONSTRATION AND SELLING EXP	OM911	TUP	0	0	0	0	0	0
912 DEMONSTRATION AND SELLING EXP	OM912	TUP	0	0	0	0	0	0
913 ADVERTISING EXPENSES	OM913	TUP	-36141.33	11695.6	18760.65	13630.34	24487.44	100169
915 MDSE-JOBBING-CONTRACT	OM915	TUP	0	0	0	0	0	0
916 MISC SALES EXPENSE	OM916	TUP	0	0	0	0	0	0
Total Customer Service Expense	OMCS		6448.96	57244.25	66716.62	55620.25	60729.9	124025.1
Sub-Total Prod, Trans, Dist, Cust Acct and Cust Service	OMSUB2							
<u>**Operation and Maintenance Expenses (Continued)**</u>								
Administrative and General Expense								
920 ADMIN. & GEN. SALARIES-	OM920	LBSUB9	1326991.23	427833.15	1263415.19	446430.74	948956.12	1178332.32
921 OFFICE SUPPLIES AND EXPENSES	OM921	LBSUB9	591943.78	481169.78	617503.76	673906.86	384307.2	494280.5
922 ADMINISTRATIVE EXPENSES TRANSFERRED	OM922	LBSUB9	0	0	0	0	0	0
923 OUTSIDE SERVICES EMPLOYED	OM923	LBSUB9	388800.48	188378.03	280346.99	85723.73	284467.92	205203.9
924 PROPERTY INSURANCE	OM924	TUP	0	0	0	0	0	0
925 INJURIES AND DAMAGES - INSURAN	OM925	LBSUB9	14679.26	12401	12401	12401	12401	12401
926 EMPLOYEE BENEFITS	OM926	LBSUB9	53705.24	8851.25	5962.88	6192.45	33341.38	6109.83
927 FRANCHISE REQUIREMENTS	OM927	TUP	0	0	0	0	0	0
928 REGULATORY COMMISSION FEES	OM928	TUP	1353.14	48087.75	665466.25	48046.08	139142.52	18419
929 DUPLICATE CHARGES-CR	OM929	LBSUB9	0	0	0	0	0	0
930 MISCELLANEOUS GENERAL EXPENSES	OM930	LBSUB9	94167.83	259652.47	119570.46	108391.43	155943.83	63658.14
931 RENTS AND LEASES	OM931	PGP	161.09	161.09	161.09	161.09	161.09	161.09
935 MAINTENANCE OF GENERAL PLANT	OM935	PGP	8698.33	7258.14	13445.04	8125.63	22399.01	9027.98
Total Administrative and General Expense	OMAG		2,480,500.38	1,433,792.66	2,978,272.66	1,389,379.01	1,981,120.07	1,987,593.76
Total Operation and Maintenance Expenses	TOM							
Operation and Maintenance Expenses Less Purchase Power & Fuel	OMLPP							

Description	Name	Functional Vector	October 2010
Customer Accounts Expense			
901 SUPERVISION/CUSTOMER ACCTS	OM901	F025	0
902 METER READING EXPENSES	OM902	F025	0
903 RECORDS AND COLLECTION	OM903	F025	0
904 UNCOLLECTIBLE ACCOUNTS	OM904	F025	0
905 MISC CUST ACCOUNTS	OM903	F025	0
Total Customer Accounts Expense	OMCA		
Customer Service Expense			
907 SUPERVISION	OM907	TUP	0
908 CUSTOMER ASSISTANCE EXPENSES	OM908	TUP	36611.39
908 CUSTOMER ASSISTANCE EXP-INCENTIVES	OM908x	TUP	0
909 INFORMATIONAL AND INSTRUCTIONA	OM909	TUP	0
909 INFORM AND INSTRUC -LOAD MGMT	OM909x	TUP	0
910 MISCELLANEOUS CUSTOMER SERVICE	OM910	TUP	0
911 DEMONSTRATION AND SELLING EXP	OM911	TUP	0
912 DEMONSTRATION AND SELLING EXP	OM912	TUP	0
913 ADVERTISING EXPENSES	OM913	TUP	0
915 MDSE-JOBBING-CONTRACT	OM915	TUP	0
916 MISC SALES EXPENSE	OM916	TUP	0
Total Customer Service Expense	OMCS		36611.39
Sub-Total Prod, Trans, Dist, Cust Acct and Cust Service	OMSUB2		
Operation and Maintenance Expenses (Continued)			
Administrative and General Expense			
920 ADMIN. & GEN. SALARIES-	OM920	LBSUB9	999686.96
921 OFFICE SUPPLIES AND EXPENSES	OM921	LBSUB9	398586.21
922 ADMINISTRATIVE EXPENSES TRANSFERRED	OM922	LBSUB9	0
923 OUTSIDE SERVICES EMPLOYED	OM923	LBSUB9	97807.2
924 PROPERTY INSURANCE	OM924	TUP	0
925 INJURIES AND DAMAGES - INSURAN	OM925	LBSUB9	12401
926 EMPLOYEE BENEFITS	OM926	LBSUB9	25686.5
927 FRANCHISE REQUIREMENTS	OM927	TUP	0
928 REGULATORY COMMISSION FEES	OM928	TUP	262942.92
929 DUPLICATE CHARGES-CR	OM929	LBSUB9	0
930 MISCELLANEOUS GENERAL EXPENSES	OM930	LBSUB9	130882.85
931 RENTS AND LEASES	OM931	PGP	161.09
935 MAINTENANCE OF GENERAL PLANT	OM935	PGP	16590.29
Total Administrative and General Expense	OMAG		1,944,745.02
Total Operation and Maintenance Expenses	TOM		
Operation and Maintenance Expenses Less Purchase Power & Fuel	OMLPP		

Big Rivers Electric Corporation
Month by Month Accounts

Description	Name	Functional Vector		Total System	November 2009	December 2009	January 2010	February 2010	March 2010
Labor Expenses									
Steam Power Generation Operation Expenses									
500 OPERATION SUPERVISION & ENGINEERING	LB500	PROFIX	$	4,967,667	342832.39	1034681.8	357452.74	317350.15	384316.78
501 FUEL	LB501	Energy	$	3,889,944	323255.71	364406.07	338654.53	313289.78	326385.9
502 STEAM EXPENSES	LB502	PROFIX	$	9,023,322	657659.63	771924.79	681077.92	630021.61	688026.67
505 ELECTRIC EXPENSES	LB505	PROFIX	$	4,523,897	357040.19	416235	378976.79	348125.67	369036.85
506 MISC. STEAM POWER EXPENSES	LB506	PROFIX	$	940,518	52261.31	80829.64	70706.68	101840.85	81036.08
507 RENTS	LB507	PROFIX	$	-	0	0	0	0	0
509 ALLOWANCES	LB509	Energy	$	-	0	0	0	0	0
Total Steam Power Operation Expenses	LBSUB1		$	23,345,348	1066961.13	1268989.43	1130761.39	1079988.13	1138099.6
Steam Power Generation Maintenance Expenses									
510 MAINTENANCE SUPERVISION & ENGINEERING	LB510	Energy	$	3,623,969	301562.96	282674.01	280925.01	285686.26	324812.85
511 MAINTENANCE OF STRUCTURES	LB511	PROFIX	$	986,831	60839.92	78449.28	79549.6	75632	64969.97
512 MAINTENANCE OF BOILER PLANT	LB512	Energy	$	8,700,235	613650.58	728746.59	804049.52	597501.69	694231.84
513 MAINTENANCE OF ELECTRIC PLANT	LB513	Energy	$	1,595,642	209176.55	143092.64	90379.11	93612.16	119373.66
514 MAINTENANCE OF MISC STEAM PLANT	LB514	PROFIX	$	200,886	16879.23	22485.07	12128	16408.41	14092.69
Total Steam Power Generation Maintenance Expense	LBSUB2		$	15,107,564	1202109.24	1255447.59	1267031.24	1068840.52	1217481.01
Total Steam Power Generation Expense			$	38,452,913	2269070.37	2524437.02	2397792.63	2148828.65	2355580.61
Labor Expenses (Continued)									
Other Power Generation Operation Expense									
546 OPERATION SUPERVISION & ENGINEERING	LB546	PROFIX	$	-	0	0	0	0	0
547 FUEL	LB547	Energy	$	-	0	0	0	0	0
548 GENERATION EXPENSE	LB548	PROFIX	$	-	0	0	0	0	0
549 MISC OTHER POWER GENERATION	LB549	PROFIX	$	-	0	0	0	0	0
550 RENTS	LB550	PROFIX	$	-	0	0	0	0	0
Total Other Power Generation Expenses	LBSUB7		$	-					
Other Power Generation Maintenance Expense									
551 MAINTENANCE SUPERVISION & ENGINEERING	LB551	PROFIX	$	-	0	0	0	0	0
552 MAINTENANCE OF STRUCTURES	LB552	PROFIX	$	-	0	0	0	0	0
553 MAINTENANCE OF GENERATING & ELEC PLANT	LB553	PROFIX	$	89,555	682.21	4299.67	1026.96	2400.3	4848.64
554 MAINTENANCE OF MISC OTHER POWER GEN PLT	LB554	PROFIX	$	-	0	0	0	0	0
Total Other Power Generation Maintenance Expense	LBSUB8		$	89,555					
Total Other Power Generation Expense			$	89,555					
Total Production Expense	LPREX		$	38,542,468					

Big Rivers Electric Corporation
Month by Month Accounts

Description	Name	Functional Vector	April 2010	May 2010	June 2010	July 2010	August 2010	September 2010
Labor Expenses								
Steam Power Generation Operation Expenses								
500 OPERATION SUPERVISION & ENGINEERING	LB500	PROFIX	338156.02	414149.39	371014.23	359005.08	369873.15	334189.99
501 FUEL	LB501	Energy	309863.06	297596.67	304977.88	310355.07	339148.89	336547.05
502 STEAM EXPENSES	LB502	PROFIX	640194.64	1123637.4	744724.17	661984.49	702417.45	982572.63
505 ELECTRIC EXPENSES	LB505	PROFIX	342341.75	393006.64	354302.21	368561.14	384521.42	384533.54
506 MISC. STEAM POWER EXPENSES	LB506	PROFIX	63015.48	66970.66	87852.14	88369.17	86572.5	91267.67
507 RENTS	LB507	PROFIX	0	0	0	0	0	0
509 ALLOWANCES	LB509	Energy	0	0	0	0	0	0
Total Steam Power Operation Expenses	LBSUB1		1045551.87	1583614.7	1186878.52	1118914.8	1173511.37	1458373.84
Steam Power Generation Maintenance Expenses								
510 MAINTENANCE SUPERVISION & ENGINEERING	LB510	Energy	297255.94	289425	296206.84	280281.91	307241.14	294029.27
511 MAINTENANCE OF STRUCTURES	LB511	PROFIX	50081.03	70791.44	106230.99	106856.88	116200.49	96973.59
512 MAINTENANCE OF BOILER PLANT	LB512	Energy	617716.63	961798.07	675983.16	535600.92	651081.61	924014.95
513 MAINTENANCE OF ELECTRIC PLANT	LB513	Energy	96940.39	142971.1	124922.34	132978.24	129288.01	126399.56
514 MAINTENANCE OF MISC STEAM PLANT	LB514	PROFIX	9843.3	16400.27	20426.8	23473.83	26283.4	15419.85
Total Steam Power Generation Maintenance Expense	LBSUB2		1071837.29	1481385.88	1223770.13	1079191.78	1230094.65	1456837.22
Total Steam Power Generation Expense			2117389.16	3065000.58	2410648.65	2198106.58	2403606.02	2915211.06
Labor Expenses (Continued)								
Other Power Generation Operation Expense								
546 OPERATION SUPERVISION & ENGINEERING	LB546	PROFIX	0	0	0	0	0	0
547 FUEL	LB547	Energy	0	0	0	0	0	0
548 GENERATION EXPENSE	LB548	PROFIX	0	0	0	0	0	0
549 MISC OTHER POWER GENERATION	LB549	PROFIX	0	0	0	0	0	0
550 RENTS	LB550	PROFIX	0	0	0	0	0	0
Total Other Power Generation Expenses	LBSUB7							
Other Power Generation Maintenance Expense								
551 MAINTENANCE SUPERVISION & ENGINEERING	LB551	PROFIX	0	0	0	0	0	0
552 MAINTENANCE OF STRUCTURES	LB552	PROFIX	0	0	0	0	0	0
553 MAINTENANCE OF GENERATING & ELEC PLANT	LB553	PROFIX	903.26	760.91	37267.71	11775.09	12921.35	10584.31
554 MAINTENANCE OF MISC OTHER POWER GEN PLT	LB554	PROFIX	0	0	0	0	0	0
Total Other Power Generation Maintenance Expense	LBSUB8							
Total Other Power Generation Expense								
Total Production Expense	LPREX							

Description	Name	Functional Vector	October 2010
Labor Expenses			
Steam Power Generation Operation Expenses			
500 OPERATION SUPERVISION & ENGINEERING	LB500	PROFIX	344645.64
501 FUEL	LB501	Energy	325463.54
502 STEAM EXPENSES	LB502	PROFIX	739080.82
505 ELECTRIC EXPENSES	LB505	PROFIX	427215.91
506 MISC. STEAM POWER EXPENSES	LB506	PROFIX	69795.43
507 RENTS	LB507	PROFIX	0
509 ALLOWANCES	LB509	Energy	0
Total Steam Power Operation Expenses	LBSUB1		1236092.16
Steam Power Generation Maintenance Expenses			
510 MAINTENANCE SUPERVISION & ENGINEERING	LB510	Energy	383868.11
511 MAINTENANCE OF STRUCTURES	LB511	PROFIX	80256.21
512 MAINTENANCE OF BOILER PLANT	LB512	Energy	895859.55
513 MAINTENANCE OF ELECTRIC PLANT	LB513	Energy	186508.29
514 MAINTENANCE OF MISC STEAM PLANT	LB514	PROFIX	7045.58
Total Steam Power Generation Maintenance Expense	LBSUB2		1553537.74
Total Steam Power Generation Expense			2642951.16
Labor Expenses (Continued)			
Other Power Generation Operation Expense			
546 OPERATION SUPERVISION & ENGINEERING	LB546	PROFIX	0
547 FUEL	LB547	Energy	0
548 GENERATION EXPENSE	LB548	PROFIX	0
549 MISC OTHER POWER GENERATION	LB549	PROFIX	0
550 RENTS	LB550	PROFIX	0
Total Other Power Generation Expenses	LBSUB7		
Other Power Generation Maintenance Expense			
551 MAINTENANCE SUPERVISION & ENGINEERING	LB551	PROFIX	
552 MAINTENANCE OF STRUCTURES	LB552	PROFIX	
553 MAINTENANCE OF GENERATING & ELEC PLANT	LB553	PROFIX	2084.81
554 MAINTENANCE OF MISC OTHER POWER GEN PLT	LB554	PROFIX	
Total Other Power Generation Maintenance Expense	LBSUB8		
Total Other Power Generation Expense			
Total Production Expense	LPREX		

Description	Name	Functional Vector		Total System	November 2009	December 2009	January 2010	February 2010	March 2010
Labor Expenses (Continued)									
Purchased Power									
555 PURCHASED POWER	LB555	OMPP	$	-	0	0	0	0	0
555 PURCHASED POWER Demand	LBD555	OMPPD	$	-	0	0	0	0	0
555 PURCHASED POWER OPTIONS	LBO555	OMPP	$	-	0	0	0	0	0
555 BROKERAGE FEES	LBB555	OMPP	$	-	0	0	0	0	0
555 MISO TRANSMISSION EXPENSES	LBM555	OMPP	$	-	0	0	0	0	0
556 SYSTEM CONTROL AND LOAD DISPATCH	LB556	PROFIX	$	-	0	0	0	0	0
557 OTHER EXPENSES	LB557	PROFIX	$	-	0	0	0	0	0
558 DUPLICATE CHARGES	LB558	Energy	$	-	0	0	0	0	0
Total Purchased Power Labor	LBPP		$	-					
Transmission Labor Expenses									
560 OPERATION SUPERVISION AND ENG	LB560	PTRAN	$	835,977	155357.97	88621.66	61719.3	53192.77	69331.26
561 LOAD DISPATCHING	LB561	PTRAN	$	1,304,969	240520.6	133245.05	93819.32	87693.64	104400.26
562 STATION EXPENSES	LB562	PTRAN	$	598,382	102945.93	50883.95	33705.43	39512.69	54112.06
563 OVERHEAD LINE EXPENSES	LB563	PTRAN	$	236,393	52690.64	20206.01	20032.96	18769.45	17519.18
565 TRANSMISSION OF ELECTRICITY BY OTHERS	LB565	PTRAN	$	-	0	0	0	0	0
566 MISC. TRANSMISSION EXPENSES	LB566	PTRAN	$	312,375	55300.19	33112.8	26544.3	26563.55	28599.72
567 RENTS	LB567	PTRAN	$	-	0	0	0	0	0
568 MAINTENACE SUPERVISION AND ENG	LB568	PTRAN	$	644,925	120270.89	65874.61	48314.25	39737.97	53182.86
569 MAINTENACE OF STRUCTURES	LB569	PTRAN	$	318	36.88	59.34	0	0	59.12
570 MAINT OF STATION EQUIPMENT	LB570	PTRAN	$	1,433,304	240458.8	137581.27	112331.02	103977.18	112839.1
571 MAINT OF OVERHEAD LINES	LB571	PTRAN	$	1,067,766	187769.72	120250.23	62124.04	70835.46	82150.36
573 MAINT OF MISC. TRANSMISSION PLANT	LB573	PTRAN	$	46,439	6906.42	2875.43	2872.93	4248.62	4851.27
Total Transmission Labor Expenses	LBTRAN		$	6,480,848	1162258.04	652710.35	461463.55	444531.33	527045.19
Distribution Operation Labor Expense									
580 OPERATION SUPERVISION AND ENGI	LB580	F023	$	-	0	0	0	0	0
581 LOAD DISPATCHING	LB581	PDIST	$	-	0	0	0	0	0
582 STATION EXPENSES	LB582	PDIST	$	-	0	0	0	0	0
583 OVERHEAD LINE EXPENSES	LB583	PDIST	$	-	0	0	0	0	0
584 UNDERGROUND LINE EXPENSES	LB584	PDIST	$	-	0	0	0	0	0
585 STREET LIGHTING EXPENSE	LB585	PDIST	$	-	0	0	0	0	0
586 METER EXPENSES	LB586	PDIST	$	-	0	0	0	0	0
586 METER EXPENSES - LOAD MANAGEMENT	LB586x	PDIST	$	-	0	0	0	0	0
587 CUSTOMER INSTALLATIONS EXPENSE	LB587	PDIST	$	-	0	0	0	0	0
588 MISCELLANEOUS DISTRIBUTION EXP	LB588	PDIST	$	-	0	0	0	0	0
589 RENTS	LB589	PDIST	$	-	0	0	0	0	0
Total Distribution Operation Labor Expense	LBDO		$	-					

Description	Name	Functional Vector	April 2010	May 2010	June 2010	July 2010	August 2010	September 2010
Labor Expenses (Continued)								
Purchased Power								
555 PURCHASED POWER	LB555	OMPP	0	0	0	0	0	0
555 PURCHASED POWER Demand	LBD555	OMPPD	0	0	0	0	0	0
555 PURCHASED POWER OPTIONS	LBO555	OMPP	0	0	0	0	0	0
555 BROKERAGE FEES	LBB555	OMPP	0	0	0	0	0	0
555 MISO TRANSMISSION EXPENSES	LBM555	OMPP	0	0	0	0	0	0
556 SYSTEM CONTROL AND LOAD DISPATCH	LB556	PROFIX	0	0	0	0	0	0
557 OTHER EXPENSES	LB557	PROFIX	0	0	0	0	0	0
558 DUPLICATE CHARGES	LB558	Energy	0	0	0	0	0	0
Total Purchased Power Labor	LBPP							
Transmission Labor Expenses								
560 OPERATION SUPERVISION AND ENG	LB560	PTRAN	57113.62	58908.5	68081.43	56191.8	51380.65	68130.77
561 LOAD DISPATCHING	LB561	PTRAN	79471.75	90840.85	104792.75	86864.08	84835.7	115440.78
562 STATION EXPENSES	LB562	PTRAN	43463.43	48316.48	56470.33	35035.32	46067.52	51613.79
563 OVERHEAD LINE EXPENSES	LB563	PTRAN	14223.62	16460.25	15132.13	14168.98	13692.1	15806.34
565 TRANSMISSION OF ELECTRICITY BY OTHERS	LB565	PTRAN	0	0	0	0	0	0
566 MISC. TRANSMISSION EXPENSES	LB566	PTRAN	21343.51	20102.2	25810.07	11252.29	17357.03	25204.78
567 RENTS	LB567	PTRAN	0	0	0	0	0	0
568 MAINTENACE SUPERVISION AND ENG	LB568	PTRAN	43994.75	45554.09	50783.31	42264.13	40489.73	55734.99
569 MAINTENACE OF STRUCTURES	LB569	PTRAN	26.22	0	24.61	26.14	26.21	0.65
570 MAINT OF STATION EQUIPMENT	LB570	PTRAN	98690.36	92937.1	116008.73	108080.33	93852.16	126204.48
571 MAINT OF OVERHEAD LINES	LB571	PTRAN	66143.16	68592.74	93608.24	76903.52	71073.25	95620.68
573 MAINT OF MISC. TRANSMISSION PLANT	LB573	PTRAN	4378.83	3303.42	3349.41	3196.71	3607.42	3592.3
Total Transmission Labor Expenses	LBTRAN		428849.25	445015.63	534061.01	433983.3	422381.77	557349.56
Distribution Operation Labor Expense								
580 OPERATION SUPERVISION AND ENGI	LB580	F023	0	0	0	0	0	0
581 LOAD DISPATCHING	LB581	PDIST	0	0	0	0	0	0
582 STATION EXPENSES	LB582	PDIST	0	0	0	0	0	0
583 OVERHEAD LINE EXPENSES	LB583	PDIST	0	0	0	0	0	0
584 UNDERGROUND LINE EXPENSES	LB584	PDIST	0	0	0	0	0	0
585 STREET LIGHTING EXPENSE	LB585	PDIST	0	0	0	0	0	0
586 METER EXPENSES	LB586	PDIST	0	0	0	0	0	0
586 METER EXPENSES - LOAD MANAGEMENT	LB586x	PDIST	0	0	0	0	0	0
587 CUSTOMER INSTALLATIONS EXPENSE	LB587	PDIST	0	0	0	0	0	0
588 MISCELLANEOUS DISTRIBUTION EXP	LB588	PDIST	0	0	0	0	0	0
589 RENTS	LB589	PDIST	0	0	0	0	0	0
Total Distribution Operation Labor Expense	LBDO							

Description	Name	Functional Vector	October 2010
Labor Expenses (Continued)			
Purchased Power			
555 PURCHASED POWER	LB555	OMPP	0
555 PURCHASED POWER Demand	LBD555	OMPPD	0
555 PURCHASED POWER OPTIONS	LBO555	OMPP	0
555 BROKERAGE FEES	LBB555	OMPP	0
555 MISO TRANSMISSION EXPENSES	LBM555	OMPP	0
556 SYSTEM CONTROL AND LOAD DISPATCH	LB556	PROFIX	0
557 OTHER EXPENSES	LB557	PROFIX	0
558 DUPLICATE CHARGES	LB558	Energy	0
Total Purchased Power Labor	LBPP		0
Transmission Labor Expenses			
560 OPERATION SUPERVISION AND ENG	LB560	PTRAN	47946.89
561 LOAD DISPATCHING	LB561	PTRAN	83043.95
562 STATION EXPENSES	LB562	PTRAN	36255.02
563 OVERHEAD LINE EXPENSES	LB563	PTRAN	17691.07
565 TRANSMISSION OF ELECTRICITY BY OTHERS	LB565	PTRAN	
566 MISC. TRANSMISSION EXPENSES	LB566	PTRAN	21184.45
567 RENTS	LB567	PTRAN	
568 MAINTENACE SUPERVISION AND ENG	LB568	PTRAN	38723.49
569 MAINTENACE OF STRUCTURES	LB569	PTRAN	59.17
570 MAINT OF STATION EQUIPMENT	LB570	PTRAN	90343.75
571 MAINT OF OVERHEAD LINES	LB571	PTRAN	72694.7
573 MAINT OF MISC. TRANSMISSION PLANT	LB573	PTRAN	3256.6
Total Transmission Labor Expenses	LBTRAN		205077.71
Distribution Operation Labor Expense			
580 OPERATION SUPERVISION AND ENGI	LB580	F023	0
581 LOAD DISPATCHING	LB581	PDIST	0
582 STATION EXPENSES	LB582	PDIST	0
583 OVERHEAD LINE EXPENSES	LB583	PDIST	0
584 UNDERGROUND LINE EXPENSES	LB584	PDIST	0
585 STREET LIGHTING EXPENSE	LB585	PDIST	0
586 METER EXPENSES	LB586	PDIST	0
586 METER EXPENSES - LOAD MANAGEMENT	LB586x	PDIST	0
587 CUSTOMER INSTALLATIONS EXPENSE	LB587	PDIST	0
588 MISCELLANEOUS DISTRIBUTION EXP	LB588	PDIST	0
589 RENTS	LB589	PDIST	0
Total Distribution Operation Labor Expense	LBDO		

Description	Name	Functional Vector		Total System	November 2009	December 2009	January 2010	February 2010	March 2010
Labor Expenses (Continued)									
Distribution Maintenance Labor Expense									
590 MAINTENANCE SUPERVISION AND EN	LB590	F024	$	-	0	0	0	0	0
591 MAINTENANCE OF STRUCTURES	LB591	PDIST	$	-	0	0	0	0	0
592 MAINTENANCE OF STATION EQUIPME	LB592	PDIST	$	-	0	0	0	0	0
593 MAINTENANCE OF OVERHEAD LINES	LB593	PDIST	$	-	0	0	0	0	0
594 MAINTENANCE OF UNDERGROUND LIN	LB594	PDIST	$	-	0	0	0	0	0
595 MAINTENANCE OF LINE TRANSFORME	LB595	PDIST	$	-	0	0	0	0	0
596 MAINTENANCE OF ST LIGHTS & SIG SYSTEMS	LB596	PDIST	$	-	0	0	0	0	0
597 MAINTENANCE OF METERS	LB597	PDIST	$	-	0	0	0	0	0
598 MAINTENANCE OF MISC DISTR PLANT	LB598	PDIST	$	-	0	0	0	0	0
Total Distribution Maintenance Labor Expense	LBDM		$	-					
Total Distribution Operation and Maintenance Labor Expenses		PDIST		-					
Transmission and Distribution Labor Expenses				6,480,848					
Production, Transmission and Distribution Labor Expenses	LBSUB		$	45,023,316					
Customer Accounts Expense									
901 SUPERVISION/CUSTOMER ACCTS	LB901	F025	$	-	0	0	0	0	0
902 METER READING EXPENSES	LB902	F025	$	-	0	0	0	0	0
903 RECORDS AND COLLECTION	LB903	F025	$	-	0	0	0	0	0
904 UNCOLLECTIBLE ACCOUNTS	LB904	F025	$	-	0	0	0	0	0
905 MISC CUST ACCOUNTS	LB903	F025	$	-	0	0	0	0	0
Total Customer Accounts Labor Expense	LBCA		$	-					
Customer Service Expense									
907 SUPERVISION	LB907	TUP	$	-	0	0	0	0	0
908 CUSTOMER ASSISTANCE EXPENSES	LB908	TUP	$	544,608	98543.49	44838.51	39429.59	38666.03	49827.22
908 CUSTOMER ASSISTANCE EXP-LOAD MGMT	LB908x	TUP	$	-	0	0	0	0	0
909 INFORMATIONAL AND INSTRUCTIONA	LB909	TUP	$	-	0	0	0	0	0
909 INFORM AND INSTRUC -LOAD MGMT	LB909x	TUP	$	-	0	0	0	0	0
910 MISCELLANEOUS CUSTOMER SERVICE	LB910	TUP	$	-	0	0	0	0	0
911 DEMONSTRATION AND SELLING EXP	LB911	TUP	$	-	0	0	0	0	0
912 DEMONSTRATION AND SELLING EXP	LB912	TUP	$	-	0	0	0	0	0
913 WATER HEATER - HEAT PUMP PROGRAM	LB913	TUP	$	-	0	0	0	0	0
915 MDSE-JOBBING-CONTRACT	LB915	TUP	$	-	0	0	0	0	0
916 MISC SALES EXPENSE	LB916	TUP	$	-	0	0	0	0	0
Total Customer Service Labor Expense	LBCS		$	544,608	98543.49	44838.51	39429.59	38666.03	49827.22
Sub-Total Labor Exp	LBSUB9			45,567,924					

Big Rivers Electric Corporation
Month by Month Accounts

Description	Name	Functional Vector	April 2010	May 2010	June 2010	July 2010	August 2010	September 2010
Labor Expenses (Continued)								
Distribution Maintenance Labor Expense								
590 MAINTENANCE SUPERVISION AND EN	LB590	F024	0	0	0	0	0	0
591 MAINTENANCE OF STRUCTURES	LB591	PDIST	0	0	0	0	0	0
592 MAINTENANCE OF STATION EQUIPME	LB592	PDIST	0	0	0	0	0	0
593 MAINTENANCE OF OVERHEAD LINES	LB593	PDIST	0	0	0	0	0	0
594 MAINTENANCE OF UNDERGROUND LIN	LB594	PDIST	0	0	0	0	0	0
595 MAINTENANCE OF LINE TRANSFORME	LB595	PDIST	0	0	0	0	0	0
596 MAINTENANCE OF ST LIGHTS & SIG SYSTEMS	LB596	PDIST	0	0	0	0	0	0
597 MAINTENANCE OF METERS	LB597	PDIST	0	0	0	0	0	0
598 MAINTENANCE OF MISC DISTR PLANT	LB598	PDIST	0	0	0	0	0	0
Total Distribution Maintenance Labor Expense	LBDM							
Total Distribution Operation and Maintenance Labor Expenses		PDIST						
Transmission and Distribution Labor Expenses								
Production, Transmission and Distribution Labor Expenses	LBSUB							
Customer Accounts Expense								
901 SUPERVISION/CUSTOMER ACCTS	LB901	F025	0	0	0	0	0	0
902 METER READING EXPENSES	LB902	F025	0	0	0	0	0	0
903 RECORDS AND COLLECTION	LB903	F025	0	0	0	0	0	0
904 UNCOLLECTIBLE ACCOUNTS	LB904	F025	0	0	0	0	0	0
905 MISC CUST ACCOUNTS	LB903	F025	0	0	0	0	0	0
Total Customer Accounts Labor Expense	LBCA							
Customer Service Expense								
907 SUPERVISION	LB907	TUP	0	0	0	0	0	0
908 CUSTOMER ASSISTANCE EXPENSES	LB908	TUP	37915.48	41556.72	44591.58	38345.68	32873.52	44118.04
908 CUSTOMER ASSISTANCE EXP-LOAD MGMT	LB908x	TUP	0	0	0	0	0	0
909 INFORMATIONAL AND INSTRUCTIONA	LB909	TUP	0	0	0	0	0	0
909 INFORM AND INSTRUC -LOAD MGMT	LB909x	TUP	0	0	0	0	0	0
910 MISCELLANEOUS CUSTOMER SERVICE	LB910	TUP	0	0	0	0	0	0
911 DEMONSTRATION AND SELLING EXP	LB911	TUP	0	0	0	0	0	0
912 DEMONSTRATION AND SELLING EXP	LB912	TUP	0	0	0	0	0	0
913 WATER HEATER - HEAT PUMP PROGRAM	LB913	TUP	0	0	0	0	0	0
915 MDSE-JOBBING-CONTRACT	LB915	TUP	0	0	0	0	0	0
916 MISC SALES EXPENSE	LB916	TUP	0	0	0	0	0	0
Total Customer Service Labor Expense	LBCS		37915.48	41556.72	44591.58	38345.68	32873.52	44118.04
Sub-Total Labor Exp	LBSUB9							

Description	Name	Functional Vector	October 2010
Labor Expenses (Continued)			
Distribution Maintenance Labor Expense			
590 MAINTENANCE SUPERVISION AND EN	LB590	F024	
591 MAINTENANCE OF STRUCTURES	LB591	PDIST	
592 MAINTENANCE OF STATION EQUIPME	LB592	PDIST	
593 MAINTENANCE OF OVERHEAD LINES	LB593	PDIST	
594 MAINTENANCE OF UNDERGROUND LIN	LB594	PDIST	
595 MAINTENANCE OF LINE TRANSFORME	LB595	PDIST	
596 MAINTENANCE OF ST LIGHTS & SIG SYSTEMS	LB596	PDIST	
597 MAINTENANCE OF METERS	LB597	PDIST	
598 MAINTENANCE OF MISC DISTR PLANT	LB598	PDIST	
Total Distribution Maintenance Labor Expense	LBDM		
Total Distribution Operation and Maintenance Labor Expenses		PDIST	
Transmission and Distribution Labor Expenses			
Production, Transmission and Distribution Labor Expenses	LBSUB		
Customer Accounts Expense			
901 SUPERVISION/CUSTOMER ACCTS	LB901	F025	
902 METER READING EXPENSES	LB902	F025	
903 RECORDS AND COLLECTION	LB903	F025	
904 UNCOLLECTIBLE ACCOUNTS	LB904	F025	
905 MISC CUST ACCOUNTS	LB903	F025	
Total Customer Accounts Labor Expense	LBCA		
Customer Service Expense			
907 SUPERVISION	LB907	TUP	33902.45
908 CUSTOMER ASSISTANCE EXPENSES	LB908	TUP	
908 CUSTOMER ASSISTANCE EXP-LOAD MGMT	LB908x	TUP	
909 INFORMATIONAL AND INSTRUCTIONA	LB909	TUP	
909 INFORM AND INSTRUC -LOAD MGMT	LB909x	TUP	
910 MISCELLANEOUS CUSTOMER SERVICE	LB910	TUP	
911 DEMONSTRATION AND SELLING EXP	LB911	TUP	
912 DEMONSTRATION AND SELLING EXP	LB912	TUP	
913 WATER HEATER - HEAT PUMP PROGRAM	LB913	TUP	
915 MDSE-JOBBING-CONTRACT	LB915	TUP	
916 MISC SALES EXPENSE	LB916	TUP	
Total Customer Service Labor Expense	LBCS		33902.45
Sub-Total Labor Exp	LBSUB9		

Big Rivers Electric Corporation
Month by Month Accounts

Description	Name	Functional Vector	Total System	November 2009	December 2009	January 2010	February 2010	March 2010
Labor Expenses (Continued)								
Administrative and General Expense								
920 ADMIN. & GEN. SALARIES-	LB920	LBSUB9	$ 14,315,714	2092449.04	1522142.8	1300504.05	1313340.25	1495631.43
921 OFFICE SUPPLIES AND EXPENSES	LB921	LBSUB9	$ -	0	0	0	0	0
922 ADMIN. EXPENSES TRANSFERRED - CREDIT	LB922	LBSUB9	$ -	0	0	0	0	0
923 OUTSIDE SERVICES EMPLOYED	LB923	LBSUB9	$ -	0	0	0	0	0
924 PROPERTY INSURANCE	LB924	TUP	$ -	0	0	0	0	0
925 INJURIES AND DAMAGES - INSURAN	LB925	LBSUB9	$ 27,509	2777.2	3471.48	2777.2	2777.2	13427.68
926 EMPLOYEE BENEFITS	LB926	LBSUB9	$ 17,136	2711	-43974.67	0	0	0
928 REGULATORY COMMISSION FEES	LB928	TUP	$ -	0	0	0	0	0
929 DUPLICATE CHARGES-CR	LB929	LBSUB9	$ -	0	0	0	0	0
930 MISCELLANEOUS GENERAL EXPENSES	LB930	LBSUB9	$ -	0	0	0	0	0
931 RENTS AND LEASES	LB931	PGP	$ -	0	0	0	0	0
935 MAINTENANCE OF GENERAL PLANT	LB935	PGP	$ 74,927	14602.3	14130.42	6605.75	5191.93	4971.6
Total Administrative and General Expense	LBAG		$ 14,435,286					
Total Operation and Maintenance Expenses	TLB		$ 60,003,210					
Operation and Maintenance Expenses Less Purchase Power	LBLPP		$ 60,003,210					
Other Expenses								
Depreciation Expenses								
Production	DEPRDP2	PPROD	$ 28,815,395	2347440.74	2389099.7	2595994.55	2361961.48	2361968.56
Transmission	DEPRDP3	PTRAN	$ 5,182,459	443546.44	533184.66	214261.5	442312.53	442305.66
Transmission	DEPRDP4	PTRAN	$ -					
Distribution	DEPRDP5	PDIST	$ -					
General & Common Plant	DEPRDP6	PGP	$ 238,155	17050.71	19802.63	19799.44	19799.44	19766.55
Other Plant	DEPROTH	TPIS	$ -	0	0	0	0	0
Total Depreciation Expense	TDEPR		$ 34,236,009	2808037.89	2942086.99	2830055.49	2824073.45	2824040.77
Accretion Expense								
Production	ACRTNP	F017	$ -	0	0	0	0	0
Transmission	ACRTNT	PTRAN	$ -	0	0	0	0	0
Distribution	ACRTND	PDIST	$ -	0	0	0	0	0
Total Accretion Expense	TACRTN		$ -					
Property Taxes & Other	PTAX	TUP	$ (94,563)	$ (379,997)	$ 87,636	$ -	$ -	$ 910
Amortization of Investment Tax Credit	OTAX	TUP	$ -	0	0	0	0	0
Other Expenses	OT	TUP	$ (365,864)	$ (6,691)	$ (14,191)	$ (18,627)	$ (23,851)	$ (16,042)
Interest	INTLTD	TUP	$ 47,622,710	4168487.53	4316793.16	4234968.72	3796291.74	4133482.27
Other Deductions	DEDUCT	TUP	$ 109,257	7611	15379	4539	6545	5640
Total Other Expenses	TOE		$ 81,507,549	$ 3,789,411	$ 4,405,617	$ 4,220,881	$ 3,778,986	$ 4,123,991
Total Cost of Service (O&M + Other Expenses)			$ 527,945,095					

Description	Name	Functional Vector	April 2010	May 2010	June 2010	July 2010	August 2010	September 2010
Labor Expenses (Continued)								
Administrative and General Expense								
920 ADMIN. & GEN. SALARIES-	LB920	LBSUB9	1326991.23	427833.15	1263415.19	446430.74	948956.12	1178332.32
921 OFFICE SUPPLIES AND EXPENSES	LB921	LBSUB9	0	0	0	0	0	0
922 ADMIN. EXPENSES TRANSFERRED - CREDIT	LB922	LBSUB9	0	0	0	0	0	0
923 OUTSIDE SERVICES EMPLOYED	LB923	LBSUB9	0	0	0	0	0	0
924 PROPERTY INSURANCE	LB924	TUP	0	0	0	0	0	0
925 INJURIES AND DAMAGES - INSURAN	LB925	LBSUB9	2278.26	0	0	0	0	0
926 EMPLOYEE BENEFITS	LB926	LBSUB9	23360	5840	5840	5840	5840	5840
928 REGULATORY COMMISSION FEES	LB928	TUP	0	0	0	0	0	0
929 DUPLICATE CHARGES-CR	LB929	LBSUB9	0	0	0	0	0	0
930 MISCELLANEOUS GENERAL EXPENSES	LB930	LBSUB9	0	0	0	0	0	0
931 RENTS AND LEASES	LB931	PGP	0	0	0	0	0	0
935 MAINTENANCE OF GENERAL PLANT	LB935	PGP	5560.19	2953.32	3794.54	2464	6700.24	5197.69
Total Administrative and General Expense	LBAG							
Total Operation and Maintenance Expenses	TLB							
Operation and Maintenance Expenses Less Purchase Power	LBLPP							
Other Expenses								
Depreciation Expenses								
Production	DEPRDP2	PPROD	2361962.84	2422279.6	2384018.59	2354733.3	2368037.83	2494767.54
Transmission	DEPRDP3	PTRAN	442357.04	442363.4	442363.15	442486.5	440016.44	450445.41
Transmission	DEPRDP4	PTRAN						
Distribution	DEPRDP5	PDIST						
General & Common Plant	DEPRDP6	PGP	19733.28	21031.35	19852.73	20082.98	19987.32	21286.62
Other Plant	DEPROTH	TPIS	0	0	0	0	0	0
Total Depreciation Expense	TDEPR		2824053.16	2885674.35	2846234.47	2817302.78	2828041.59	2966499.57
Accretion Expense								
Production	ACRTNP	F017	0	0	0	0	0	0
Transmission	ACRTNT	PTRAN	0	0	0	0	0	0
Distribution	ACRTND	PDIST	0	0	0	0	0	0
Total Accretion Expense	TACRTN							
Property Taxes & Other	PTAX	TUP	$ 65,000	$ 2,342	$ 65,000	$ -	$ (429)	$ 65,000
Amortization of Investment Tax Credit	OTAX	TUP	0	0	0	0	0	0
Other Expenses	OT	TUP	$ (27,557)	$ (8,263)	$ (42,136)	$ (42,545)	$ (48,997)	$ (56,550)
Interest	INTLTD	TUP	3848131.38	3699835.35	3741933.32	3942436.65	3958146.18	3830668.47
Other Deductions	DEDUCT	TUP	-2109	4540	14599	10828	16243	12411
Total Other Expenses	TOE		$ 3,883,465	$ 3,698,454	$ 3,779,396	$ 3,910,720	$ 3,924,964	$ 3,851,529
Total Cost of Service (O&M + Other Expenses)								

Description	Name	Functional Vector	October 2010
Labor Expenses (Continued)			
Administrative and General Expense			
920 ADMIN. & GEN. SALARIES-	LB920	LBSUB9	999687.37
921 OFFICE SUPPLIES AND EXPENSES	LB921	LBSUB9	
922 ADMIN. EXPENSES TRANSFERRED - CREDIT	LB922	LBSUB9	
923 OUTSIDE SERVICES EMPLOYED	LB923	LBSUB9	
924 PROPERTY INSURANCE	LB924	TUP	
925 INJURIES AND DAMAGES - INSURAN	LB925	LBSUB9	0
926 EMPLOYEE BENEFITS	LB926	LBSUB9	5840
928 REGULATORY COMMISSION FEES	LB928	TUP	
929 DUPLICATE CHARGES-CR	LB929	LBSUB9	
930 MISCELLANEOUS GENERAL EXPENSES	LB930	LBSUB9	
931 RENTS AND LEASES	LB931	PGP	
935 MAINTENANCE OF GENERAL PLANT	LB935	PGP	2754.81
Total Administrative and General Expense	LBAG		
Total Operation and Maintenance Expenses	TLB		
Operation and Maintenance Expenses Less Purchase Power	LBLPP		
Other Expenses			
Depreciation Expenses			
Production	DEPRDP2	PPROD	2373130.48
Transmission	DEPRDP3	PTRAN	446815.89
Transmission	DEPRDP4	PTRAN	
Distribution	DEPRDP5	PDIST	
General & Common Plant	DEPRDP6	PGP	19962.11
Other Plant	DEPROTH	TPIS	0
Total Depreciation Expense	TDEPR		2839908.48
Accretion Expense			
Production	ACRTNP	F017	0
Transmission	ACRTNT	PTRAN	0
Distribution	ACRTND	PDIST	0
Total Accretion Expense	TACRTN		
Property Taxes & Other	PTAX	TUP	$ (25)
Amortization of Investment Tax Credit	OTAX	TUP	0
Other Expenses	OT	TUP	$ (60,414)
Interest	INTLTD	TUP	3951535
Other Deductions	DEDUCT	TUP	13031
Total Other Expenses	TOE		$ 3,904,127
Total Cost of Service (O&M + Other Expenses)			

Big Rivers Electric Corporation
Month by Month Accounts

Description	Name	Functional Vector	Total System	November 2009	December 2009	January 2010	February 2010	March 2010
Revenues								
Jackson Purchase			$ 31,526,082	2,047,421	2,967,876	3,236,562	2,630,578	2,282,284
Kenergy			$ 56,579,648	3,789,093	5,385,841	5,977,907	4,990,050	4,209,222
Meade			$ 22,828,970	1,551,653	2,374,865	2,690,998	2,281,167	1,830,442
Large Industrial			$ 39,110,620	3,326,073	3,242,060	3,257,550	3,000,170	3,334,841
Century Total			$ 150,725,511	14,123,587	13,900,845	12,327,658	10,978,277	13,026,782
Alcan Total			$ 131,680,624	11,327,935	11,867,881	11,227,291	10,087,671	11,349,236
	Total Rural		$ 110,934,700	$ 7,388,167	$ 10,728,582	$ 11,905,467	$ 9,901,794	$ 8,321,948
	Total Industrial		$ 39,110,620	$ 8,666,818	$ 11,002,766	$ 11,926,456	$ 10,271,387	$ 9,374,506
	Total Smelter		$ 282,406,135	$ 25,451,523	$ 25,768,725	$ 23,554,949	$ 21,065,948	$ 24,376,019
	Total		$ 432,451,455	$ 36,165,762	$ 39,739,368	$ 38,717,967	$ 33,967,912	$ 36,032,808
Century Invoiced			$ 149,837,373	12,898,686	13,350,197	12,412,617	10,978,277	13,026,782
Alcan Invoiced			$ 131,911,075	10,982,583	11,672,836	11,353,440	10,087,671	11,349,236
Century Adjustments			$ 888,139	1,224,902	550,648	(84,959)		
Alcan Adjustments			$ (230,451)	345,352	195,044	(126,150)		
Off System Sales			$ 76,543,801	$ 1,839,442	$ 4,073,308	$ 8,147,840	$ 9,539,433	$ 7,986,498
Income from Leased Property Net			$ 149,673	$ 149,673	$ -	$ -	$ -	$ -
Other Operating Revenue & Income			$ 13,778,745	$ 1,230,861	$ 1,033,968	$ 1,152,998	$ 1,145,023	$ 1,070,097
OSS Variable O&M			$ 46,035,981	$ 1,471,622	$ 2,691,212	$ 4,162,194	$ 5,284,841	$ 5,083,040
Energy								
Jackson Purchase			694,512,540	45,926,970	65,978,630	71,338,200	59,712,514	49,429,743
Kenergy			1,255,008,258	85,135,870	120,014,010	132,891,880	114,367,690	91,992,020
Meade			499,627,006	34,444,920	51,694,410	59,035,140	51,393,370	38,028,116
Large Industrial			928,887,170	78,192,702	74,359,872	75,056,282	70,510,685	78,126,590
Century			3,949,411,321	310,167,027	331,563,740	339,238,984	318,278,276	343,763,177
Alcan			3,163,910,039	257,031,413	268,912,646	270,478,213	245,969,029	270,738,402
Total Rural			2,449,147,804	165,507,760	237,687,050	263,265,220	225,473,574	179,449,879
Total Industrial			928,887,170	78,192,702	74,359,872	75,056,282	70,510,685	78,126,590
Total Smelter			7,113,321,360	567,198,440	600,476,386	609,717,197	564,247,305	614,501,579
Total			10,491,356,334	810,898,902	912,523,308	948,038,699	860,231,564	872,078,048

Big Rivers Electric Corporation
Month by Month Accounts

Description	Name	Functional Vector	April 2010	May 2010	June 2010	July 2010	August 2010	September 2010
Revenues								
Jackson Purchase			1,799,767	2,308,067	3,063,639	3,258,780	3,399,012	2,561,800
Kenergy			3,188,379	4,134,538	5,323,163	5,636,870	5,853,842	4,573,561
Meade			1,214,667	1,532,681	1,963,540	2,110,692	2,169,733	1,693,499
Large Industrial			3,161,352	3,245,699	3,234,324	3,234,990	3,373,185	3,344,243
Century Total			12,044,160	12,679,922	11,679,623	12,055,865	12,367,467	11,801,654
Alcan Total			10,471,146	11,169,007	10,543,631	10,857,129	10,839,072	10,177,927
	Total Rural		$ 6,202,813	$ 7,975,287	$ 10,350,341	$ 11,006,341	$ 11,422,586	$ 8,828,859
	Total Industrial		$ 7,564,398	$ 8,912,918	$ 10,521,026	$ 10,982,552	$ 11,396,759	$ 9,611,302
	Total Smelter		$ 22,515,306	$ 23,848,930	$ 22,223,254	$ 22,912,994	$ 23,206,539	$ 21,979,581
	Total		$ 31,879,471	$ 35,069,915	$ 35,807,919	$ 37,154,326	$ 38,002,310	$ 34,152,683
Century Invoiced			12,044,160	12,679,922	11,679,623	12,055,865	12,367,467	12,580,920
Alcan Invoiced			10,471,146	11,169,007	10,543,631	10,857,129	10,839,072	10,806,724
Century Adjustments								(779,265)
Alcan Adjustments								(628,797)
Off System Sales			$ 5,678,794	$ 6,341,556	$ 7,049,362	$ 7,908,927	$ 8,630,309	$ 5,166,061
Income from Leased Property Net			$ -	$ -	$ -	$ -	$ -	$ -
Other Operating Revenue & Income			$ 1,140,133	$ 1,143,171	$ 1,284,686	$ 1,142,016	$ 1,145,336	$ 1,142,234
OSS Variable O&M			$ 3,852,774	$ 3,932,574	$ 3,863,529	$ 4,155,945	$ 4,803,709	$ 3,568,984
Energy								
Jackson Purchase			40,334,720	49,465,221	67,937,977	74,389,907	74,455,490	53,358,978
Kenergy			72,904,910	88,391,581	119,415,050	128,859,539	129,305,728	95,902,980
Meade			28,079,875	32,805,170	43,966,515	47,969,570	47,509,670	35,325,370
Large Industrial			78,086,611	79,512,076	79,858,265	78,927,327	82,005,334	79,182,043
Century			323,212,786	331,276,534	324,397,171	337,256,977	345,310,998	317,766,683
Alcan			260,668,275	268,579,997	259,859,800	268,729,560	268,160,608	257,328,832
Total Rural			141,319,505	170,661,972	231,319,542	251,219,016	251,270,888	184,587,328
Total Industrial			78,086,611	79,512,076	79,858,265	78,927,327	82,005,334	79,182,043
Total Smelter			583,881,061	599,856,531	584,256,971	605,986,537	613,471,606	575,095,515
Total			803,287,177	850,030,579	895,434,778	936,132,880	946,747,828	838,864,886

Description	Name	Functional Vector	October 2010
Revenues			
Jackson Purchase			1,970,297
Kenergy			3,517,183
Meade			1,415,034
Large Industrial			3,356,132
Century Total			13,739,670
Alcan Total			11,762,698
	Total Rural		$ 6,902,515
	Total Industrial		$ 8,288,350
	Total Smelter		$ 25,502,368
	Total		$ 35,761,015
Century Invoiced			13,762,856
Alcan Invoiced			11,778,599
Century Adjustments			(23,186)
Alcan Adjustments			(15,901)
Off System Sales			4,182,271
Income from Leased Property Net			$ -
Other Operating Revenue & Income			$ 1,148,221
OSS Variable O&M			$ 3,165,556
Energy			
Jackson Purchase			42,184,190
Kenergy			75,827,000
Meade			29,374,880
Large Industrial			75,069,383
Century			327,178,968
Alcan			267,453,264
Total Rural			147,386,070
Total Industrial			75,069,383
Total Smelter			594,632,232
Total			817,087,685

BIG RIVERS ELECTRIC CORPORATION
Cost of Service Study
Functional Assignment and Classification

12 Months Ended
October 2010

Description	Name	Functional Vector	Total System	Production Demand	Production Energy	Steam Direct	Transmission Demand
Plant in Service							
Intangible Plant	INTPLT	PT&D	$ 66,895	58,634	-	-	8,261
Production Plant	PPROD	F001	$ 1,686,796,955	1,686,796,955	-	-	-
Transmission Plant	PTRAN	F002	$ 237,659,206	-	-	-	237,659,206
Distribution Plant	PDIST	F003	$ -	-	-	-	-
Total Production & Transmission Plant	PT&D		1,924,456,160	1,686,796,955	-	-	237,659,206
General Plant	PGP	PT&D	$ 18,511,051	16,225,043	-	-	2,286,008
Total Plant in Service	TPIS		$ 1,943,034,107	$ 1,703,080,632	$ -	$ -	$ 239,953,475
Construction Work in Progress (CWIP)							
CWIP Production	CWIP1	PPROD	$ 22,411,274	22,411,274	-	-	-
CWIP Transmission	CWIP2	PTRAN	$ 7,475,859	-	-	-	7,475,859
CWIP Distribution Plant	CWIP3	PDIST	$ -	-	-	-	-
CWIP General Plant	CWIP4	PT&D	$ 16,915,005	14,826,100	-	-	2,088,905
Total Construction Work in Progress	TCWIP		$ 46,802,138	$ 37,237,374	$ -	$ -	$ 9,564,764
Total Utility Plant			$ 1,989,836,245	$ 1,740,318,006	$ -	$ -	$ 249,518,239

BIG RIVERS ELECTRIC CORPORATION
Cost of Service Study
Functional Assignment and Classification

12 Months Ended
October 2010

Description	Name	Functional Vector	Total System	Production Demand	Production Energy	Steam Direct	Transmission Demand
Rate Base							
Total Utility Plant	TUP		$ 1,989,836,245	$ 1,740,318,006	$ -	$ -	$ 249,518,239
Less: Acummulated Provision for Depreciation							
Production	ADEPREPA	PPROD	$ 790,847,523	790,847,523	-	-	-
Transmission	ADEPRTP	PTRAN	$ 107,564,747	-	-	-	107,564,747
Distribution	ADEPRD11	PDIST	$ -	-	-	-	-
General & Common Plant	ADEPRD12	PT&D	$ 6,300,770	5,522,661	-	-	778,109
Intangible, Misc, and Other Plant	ADEPRGP	PT&D	$ -	-	-	-	-
Retirement Work In Progress	ADEPRRT	PT&D	$ -	-	-	-	-
Total Accumulated Depreciation	TADEPR		$ 904,713,040	$ 796,370,184	$ -	$ -	$ 108,342,855
Net Utility Plant	NTPLANT		$ 1,085,123,206	$ 943,947,822	$ -	$ -	$ 141,175,384
Working Capital							
Cash Working Capital - Operation and Maintenance Expenses	CWC	OMLPP	$ 28,114,365	13,900,247	11,969,243	-	2,244,875
Materials and Supplies	M&S	TPIS	$ 22,777,820	19,964,891	-	-	2,812,929
Fuel Stock	PREPAY	TPIS	$ 34,326,112	30,087,036	-	-	4,239,076
Total Working Capital	TWC		$ 85,218,297	$ 63,952,174	$ 11,969,243	$ -	$ 9,296,880
Net Rate Base	RB		$ 1,170,341,502	$ 1,007,899,995	$ 11,969,243	$ -	$ 150,472,264

BIG RIVERS ELECTRIC CORPORATION
Cost of Service Study
Functional Assignment and Classification

12 Months Ended
October 2010

Description	Name	Functional Vector	Total System	Production Demand	Production Energy	Steam Direct	Transmission Demand
Operation and Maintenance Expenses							
Steam Power Generation Operation Expenses							
500 OPERATION SUPERVISION & ENGINEERING	OM500	PROFIX	$ 4,974,566	4,974,566	-	-	-
501 FUEL	OM501	Energy	$ 200,919,367	-	200,919,367	-	-
502 STEAM EXPENSES	OM502	PROFIX	$ 34,453,882	34,453,882	-	-	-
505 ELECTRIC EXPENSES	OM505	PROFIX	$ 5,730,122	5,730,122	-	-	-
506 MISC. STEAM POWER EXPENSES	OM506	PROFIX	$ 7,451,302	7,451,302	-	-	-
507 RENTS	OM507	PROFIX	$ -	-	-	-	-
509 ALLOWANCES	OM509	Energy	$ 429,682	-	429,682	-	-
Total Steam Power Operation Expenses			$ 253,958,921	$ 52,609,872	$ 201,349,049	$ -	$ -
Steam Power Generation Maintenance Expenses							
510 MAINTENANCE SUPERVISION & ENGINEERING	OM510	Energy	$ 3,631,867	-	3,631,867	-	-
511 MAINTENANCE OF STRUCTURES	OM511	PROFIX	$ 3,346,806	3,346,806	-	-	-
512 MAINTENANCE OF BOILER PLANT	OM512	Energy	$ 30,113,309	-	30,113,309	-	-
513 MAINTENANCE OF ELECTRIC PLANT	OM513	Energy	$ 6,251,804	-	6,251,804	-	-
514 MAINTENANCE OF MISC STEAM PLANT	OM514	PROFIX	$ 877,364	877,364	-		
Total Steam Power Generation Maintenance Expense			$ 44,221,151	$ 4,224,170	$ 39,996,981	$ -	$ -
Total Steam Power Generation Expense			$ 298,180,072	$ 56,834,042	$ 241,346,030	$ -	$ -

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Description	Name	Functional Vector	Total System	Production Demand	Production Energy	Steam Direct	Transmission Demand
Operation and Maintenance Expenses (Continued)							
Other Power Generation Operation Expense							
546 OPERATION SUPERVISION & ENGINEERING	OM546	PROFIX	$ -	-	-	-	-
547 FUEL	OM547	Energy	$ 706,789	-	706,789	-	-
548 GENERATION EXPENSE	OM548	PROFIX	$ 34,608	34,608	-	-	-
549 MISC OTHER POWER GENERATION	OM549	PROFIX	$ -	-	-	-	-
550 RENTS	OM550	PROFIX	$ -	-	-	-	-
Total Other Power Generation Expenses			$ 741,396	$ 34,608	$ 706,789	$ -	$ -
Other Power Generation Maintenance Expense							
551 MAINTENANCE SUPERVISION & ENGINEERING	OM551	PROFIX	$ -	-	-	-	-
552 MAINTENANCE OF STRUCTURES	OM552	PROFIX	$ -	-	-	-	-
553 MAINTENANCE OF GENERATING & ELEC PLANT	OM553	PROFIX	$ 625,088	625,088	-	-	-
554 MAINTENANCE OF MISC OTHER POWER GEN PLT	OM554	PROFIX	$ -	-	-	-	-
Total Other Power Generation Maintenance Expense			$ 625,088	$ 625,088	$ -	$ -	$ -
Total Other Power Generation Expense			$ 1,366,485	$ 659,696	$ 706,789	$ -	$ -
Total Station Expense			$ 299,546,557	$ 57,493,738	$ 242,052,819	$ -	$ -

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Description	Name	Functional Vector	Total System	Production Demand	Production Energy	Steam Direct	Transmission Demand
Operation and Maintenance Expenses (Continued)							
Other Power Supply Expenses							
555 PURCHASED POWER Energy	OM555	OMPP	$ 19,466,790	-	19,466,790	-	-
555 PURCHASED POWER Demand	OMD555	OMPPD	$ 4,210,045	4,210,045	-	-	-
555 PURCHASED POWER BREC Share of HMP&L Station Two	OMH555	OMPPH	$ 58,293,374	13,175,571	45,117,803	-	-
555 PURCHASED POWER OPTIONS	OMO555	OMPP	$ -	-	-	-	-
555 BROKERAGE FEES	OMB555	OMPP	$ -	-	-	-	-
555 MISO TRANSMISSION EXPENSES	OMM555	OMPP	$ -	-	-	-	-
556 SYSTEM CONTROL AND LOAD DISPATCH	OM556	PROFIX	$ 909,422	909,422	-	-	-
557 OTHER EXPENSES	OM557	PROFIX	$ 20,575,465	20,575,465	-	-	-
558 DUPLICATE CHARGES	OM558	Energy	$ -	-	-	-	-
Total Other Power Supply Expenses	TPP		$ 103,455,096	$ 38,870,503	$ 64,584,593	$ -	$ -
Total Electric Power Generation Expenses			$ 403,001,653	$ 96,364,241	$ 306,637,411	$ -	$ -
Transmission Expenses							
560 OPERATION SUPERVISION AND ENG	OM560	LBTRAN	$ 876,815	-	-	-	876,815
561 LOAD DISPATCHING	OM561	LBTRAN	$ 1,454,938	-	-	-	1,454,938
562 STATION EXPENSES	OM562	PTRAN	$ 1,163,408	-	-	-	1,163,408
563 OVERHEAD LINE EXPENSES	OM563	PTRAN	$ 1,090,014	-	-	-	1,090,014
565 TRANSMISSION OF ELECTRICITY BY OTHERS	OM565	PTRAN	$ 3,065,817	-	-	-	3,065,817
566 MISC. TRANSMISSION EXPENSES	OM566	PTRAN	$ 475,381	-	-	-	475,381
567 RENTS	OM567	PTRAN	$ 24,701	-	-	-	24,701
568 MAINTENACE SUPERVISION AND ENG	OM568	LBTRAN	$ 647,227	-	-	-	647,227
569 STRUCTURES	OM569	PTRAN	$ 26,913	-	-	-	26,913
570 MAINT OF STATION EQUIPMENT	OM570	PTRAN	$ 1,936,760	-	-	-	1,936,760
571 MAINT OF OVERHEAD LINES	OM571	PTRAN	$ 2,876,462	-	-	-	2,876,462
572 UNDERGROUND LINES	OM572	PTRAN	$ -	-	-	-	-
573 MISC PLANT	OM573	PTRAN	$ 97,880	-	-	-	97,880
Total Transmission Expenses			$ 13,736,318	$ -	$ -	$ -	$ 13,736,318
Distribution Operation Expense							
580 OPERATION SUPERVISION AND ENGI	OM580	LBDO	$ -	-	-	-	-
581 LOAD DISPATCHING	OM581	PDIST	$ -	-	-	-	-
582 STATION EXPENSES	OM582	PDIST	$ -	-	-	-	-
583 OVERHEAD LINE EXPENSES	OM583	PDIST	$ -	-	-	-	-
584 UNDERGROUND LINE EXPENSES	OM584	PDIST	$ -	-	-	-	-
585 STREET LIGHTING EXPENSE	OM585	PDIST	$ -	-	-	-	-
586 METER EXPENSES	OM586	PDIST	$ -	-	-	-	-
586 METER EXPENSES - LOAD MANAGEMENT	OM586x	PDIST	$ -	-	-	-	-
587 CUSTOMER INSTALLATIONS EXPENSE	OM587	PDIST	$ -	-	-	-	-
588 MISCELLANEOUS DISTRIBUTION EXP	OM588	PDIST	$ -	-	-	-	-
588 MISC DISTR EXP -- MAPPIN	OM588x	PDIST	$ -	-	-	-	-
589 RENTS	OM589	PDIST	$ -	-	-	-	-
Total Distribution Operation Expense	OMDO		$ -	$ -	$ -	$ -	$ -

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Operation and Maintenance Expenses (Continued)							
Distribution Maintenance Expense							
590 MAINTENANCE SUPERVISION AND EN	OM590	LBDM	$ -	-	-	-	-
591 STRUCTURES	OM591	PDIST	$ -	-	-	-	-
592 MAINTENANCE OF STATION EQUIPME	OM592	PDIST	$ -	-	-	-	-
593 MAINTENANCE OF OVERHEAD LINES	OM593	PDIST	$ -	-	-	-	-
594 MAINTENANCE OF UNDERGROUND LIN	OM594	PDIST	$ -	-	-	-	-
595 MAINTENANCE OF LINE TRANSFORME	OM595	PDIST	$ -	-	-	-	-
596 MAINTENANCE OF ST LIGHTS & SIG SYSTEMS	OM596	PDIST	$ -	-	-	-	-
597 MAINTENANCE OF METERS	OM597	PDIST	$ -	-	-	-	-
598 MISCELLANEOUS DISTRIBUTION EXPENSES	OM598	PDIST	$ -	-	-	-	-
Total Distribution Maintenance Expense	OMDM		$ -	$ -	$ -	$ -	$ -
Total Distribution Operation and Maintenance Expenses			-	-	-	-	-
Transmission and Distribution Expenses			13,736,318	-	-	-	13,736,318
Production, Transmission and Distribution Expenses	OMSUB		$ 416,737,971	$ 96,364,241	$ 306,637,411	$ -	$ 13,736,318
Customer Accounts Expense							
901 SUPERVISION/CUSTOMER ACCTS	OM901	F025	$ -	-	-	-	-
902 METER READING EXPENSES	OM902	F025	$ -	-	-	-	-
903 RECORDS AND COLLECTION	OM903	F025	$ -	-	-	-	-
904 UNCOLLECTIBLE ACCOUNTS	OM904	F025	$ -	-	-	-	-
905 MISC CUST ACCOUNTS	OM903	F025	$ -	-	-	-	-
Total Customer Accounts Expense	OMCA		$ -	$ -	$ -	$ -	$ -
Customer Service Expense							
907 SUPERVISION	OM907	TUP	$ -	-	-	-	-
908 CUSTOMER ASSISTANCE EXPENSES	OM908	TUP	$ 591,192	517,058	-	-	74,133
908 CUSTOMER ASSISTANCE EXP-INCENTIVES	OM908x	TUP	$ -	-	-	-	-
909 INFORMATIONAL AND INSTRUCTIONA	OM909	TUP	$ -	-	-	-	-
909 INFORM AND INSTRUC -LOAD MGMT	OM909x	TUP	$ -	-	-	-	-
910 MISCELLANEOUS CUSTOMER SERVICE	OM910	TUP	$ -	-	-	-	-
911 DEMONSTRATION AND SELLING EXP	OM911	TUP	$ -	-	-	-	-
912 DEMONSTRATION AND SELLING EXP	OM912	TUP	$ -	-	-	-	-
913 ADVERTISING EXPENSES	OM913	TUP	$ 488,103	426,897	-	-	61,206
915 MDSE-JOBBING-CONTRACT	OM915	TUP	$ -	-	-	-	-
916 MISC SALES EXPENSE	OM916	TUP	$ -	-	-	-	-
Total Customer Service Expense	OMCS		$ 1,079,295	$ 943,955	$ -	$ -	$ 135,340
Sub-Total Prod, Trans, Dist, Cust Acct and Cust Service	OMSUB2		417,817,266	97,308,197	306,637,411	-	13,871,658

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Description	Name	Functional Vector		Total System		Production Demand		Production Energy		Steam Direct		Transmission Demand
Operation and Maintenance Expenses (Continued)												
Administrative and General Expense												
920 ADMIN. & GEN. SALARIES-	OM920	LBSUB9	$	14,315,713		6,663,061		5,595,161		-		2,057,491
921 OFFICE SUPPLIES AND EXPENSES	OM921	LBSUB9	$	6,915,648		3,218,798		2,702,915		-		993,935
922 ADMINISTRATIVE EXPENSES TRANSFERRED	OM922	LBSUB9	$	-		-		-		-		-
923 OUTSIDE SERVICES EMPLOYED	OM923	LBSUB9	$	3,954,189		1,840,425		1,545,457		-		568,306
924 PROPERTY INSURANCE	OM924	TUP	$	-		-		-		-		-
925 INJURIES AND DAMAGES - INSURAN	OM925	LBSUB9	$	179,889		83,727		70,308		-		25,854
926 EMPLOYEE BENEFITS	OM926	LBSUB9	$	169,663		78,967		66,311		-		24,384
927 FRANCHISE REQUIREMENTS	OM927	TUP	$	-		-		-		-		-
928 REGULATORY COMMISSION FEES	OM928	TUP	$	1,188,958		1,039,867		-		-		149,091
929 DUPLICATE CHARGES-CR	OM929	LBSUB9	$	-		-		-		-		-
930 MISCELLANEOUS GENERAL EXPENSES	OM930	LBSUB9	$	1,686,131		784,788		659,008		-		242,335
931 RENTS AND LEASES	OM931	PGP	$	1,933		1,694		-		-		239
935 MAINTENANCE OF GENERAL PLANT	OM935	PGP	$	208,156		182,450		-		-		25,706
Total Administrative and General Expense	OMAG		$	28,620,280	$	13,893,778	$	10,639,160	$	-	$	4,087,342
Total Operation and Maintenance Expenses	TOM		$	446,437,546	$	111,201,975	$	317,276,572	$	-	$	17,959,000
Operation and Maintenance Expenses Less Purchase Power & Fuel	OMLPP		$	224,914,919	$	111,201,975	$	95,753,945	$	-	$	17,959,000

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Description	Name	Functional Vector	Total System	Production Demand	Production Energy	Steam Direct	Transmission Demand
Labor Expenses							
Steam Power Generation Operation Expenses							
500 OPERATION SUPERVISION & ENGINEERING	LB500	PROFIX	$ 4,967,667	4,967,667	-	-	-
501 FUEL	LB501	Energy	$ 3,889,944	-	3,889,944	-	-
502 STEAM EXPENSES	LB502	PROFIX	$ 9,023,322	9,023,322	-	-	-
505 ELECTRIC EXPENSES	LB505	PROFIX	$ 4,523,897	4,523,897	-	-	-
506 MISC. STEAM POWER EXPENSES	LB506	PROFIX	$ 940,518	940,518	-	-	-
507 RENTS	LB507	PROFIX	$ -	-	-	-	-
509 ALLOWANCES	LB509	Energy	$ -	-	-	-	-
Total Steam Power Operation Expenses	LBSUB1		$ 23,345,348	$ 19,455,404	$ 3,889,944	$ -	$ -
Steam Power Generation Maintenance Expenses							
510 MAINTENANCE SUPERVISION & ENGINEERING	LB510	Energy	$ 3,623,969	-	3,623,969	-	-
511 MAINTENANCE OF STRUCTURES	LB511	PROFIX	$ 986,831	986,831	-	-	-
512 MAINTENANCE OF BOILER PLANT	LB512	Energy	$ 8,700,235	-	8,700,235	-	-
513 MAINTENANCE OF ELECTRIC PLANT	LB513	Energy	$ 1,595,642	-	1,595,642	-	-
514 MAINTENANCE OF MISC STEAM PLANT	LB514	PROFIX	$ 200,886	200,886	-	-	-
Total Steam Power Generation Maintenance Expense	LBSUB2		$ 15,107,564	$ 1,187,718	$ 13,919,846	$ -	$ -
Total Steam Power Generation Expense			$ 38,452,913	$ 20,643,122	$ 17,809,791	$ -	$ -

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Description	Name	Functional Vector	Total System	Production Demand	Production Energy	Steam Direct	Transmission Demand
Labor Expenses (Continued)							
Other Power Generation Operation Expense							
546 OPERATION SUPERVISION & ENGINEERING	LB546	PROFIX	$ -	-	-	-	-
547 FUEL	LB547	Energy	$ -	-	-	-	-
548 GENERATION EXPENSE	LB548	PROFIX	$ -	-	-	-	-
549 MISC OTHER POWER GENERATION	LB549	PROFIX	$ -	-	-	-	-
550 RENTS	LB550	PROFIX	$ -	-	-	-	-
Total Other Power Generation Expenses	LBSUB7		$ -	$ -	$ -	$ -	$ -
Other Power Generation Maintenance Expense							
551 MAINTENANCE SUPERVISION & ENGINEERING	LB551	PROFIX	$ -	-	-	-	-
552 MAINTENANCE OF STRUCTURES	LB552	PROFIX	$ -	-	-	-	-
553 MAINTENANCE OF GENERATING & ELEC PLANT	LB553	PROFIX	$ 89,555	89,555	-	-	-
554 MAINTENANCE OF MISC OTHER POWER GEN PLT	LB554	PROFIX	$ -	-	-	-	-
Total Other Power Generation Maintenance Expense	LBSUB8		$ 89,555	$ 89,555	$ -	$ -	$ -
Total Other Power Generation Expense			$ 89,555	$ 89,555	$ -	$ -	$ -
Total Production Expense	LPREX		$ 38,542,468	$ 20,732,677	$ 17,809,791	$ -	$ -

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Description	Name	Functional Vector	Total System	Production Demand	Production Energy	Steam Direct	Transmission Demand
Labor Expenses (Continued)							
Purchased Power							
555 PURCHASED POWER Energy	LB555	OMPP	$ -	-	-	-	-
555 PURCHASED POWER Demand	LBD555	OMPPD	$ -	-	-	-	-
555 PURCHASED POWER OPTIONS	LBO555	OMPP	$ -	-	-	-	-
555 BROKERAGE FEES	LBB555	OMPP	$ -	-	-	-	-
555 MISO TRANSMISSION EXPENSES	LBM555	OMPP	$ -	-	-	-	-
556 SYSTEM CONTROL AND LOAD DISPATCH	LB556	PROFIX	$ -	-	-	-	-
557 OTHER EXPENSES	LB557	PROFIX	$ -	-	-	-	-
558 DUPLICATE CHARGES	LB558	Energy	$ -	-	-	-	-
Total Purchased Power Labor	LBPP		$ -	$ -	$ -	$ -	$ -
Transmission Labor Expenses							
560 OPERATION SUPERVISION AND ENG	LB560	PTRAN	$ 835,977	-	-	-	835,977
561 LOAD DISPATCHING	LB561	PTRAN	$ 1,304,969	-	-	-	1,304,969
562 STATION EXPENSES	LB562	PTRAN	$ 598,382	-	-	-	598,382
563 OVERHEAD LINE EXPENSES	LB563	PTRAN	$ 236,393	-	-	-	236,393
565 TRANSMISSION OF ELECTRICITY BY OTHERS	LB565	PTRAN	$ -	-	-	-	-
566 MISC. TRANSMISSION EXPENSES	LB566	PTRAN	$ 312,375	-	-	-	312,375
567 RENTS	LB567	PTRAN	$ -	-	-	-	-
568 MAINTENACE SUPERVISION AND ENG	LB568	PTRAN	$ 644,925	-	-	-	644,925
569 MAINTENACE OF STRUCTURES	LB569	PTRAN	$ 318	-	-	-	318
570 MAINT OF STATION EQUIPMENT	LB570	PTRAN	$ 1,433,304	-	-	-	1,433,304
571 MAINT OF OVERHEAD LINES	LB571	PTRAN	$ 1,067,766	-	-	-	1,067,766
573 MAINT OF MISC. TRANSMISSION PLANT	LB573	PTRAN	$ 46,439	-	-	-	46,439
Total Transmission Labor Expenses	LBTRAN		$ 6,480,848	$ -	$ -	$ -	$ 6,480,848
Distribution Operation Labor Expense							
580 OPERATION SUPERVISION AND ENGI	LB580	F023	$ -	-	-	-	-
581 LOAD DISPATCHING	LB581	PDIST	$ -	-	-	-	-
582 STATION EXPENSES	LB582	PDIST	$ -	-	-	-	-
583 OVERHEAD LINE EXPENSES	LB583	PDIST	$ -	-	-	-	-
584 UNDERGROUND LINE EXPENSES	LB584	PDIST	$ -	-	-	-	-
585 STREET LIGHTING EXPENSE	LB585	PDIST	$ -	-	-	-	-
586 METER EXPENSES	LB586	PDIST	$ -	-	-	-	-
586 METER EXPENSES - LOAD MANAGEMENT	LB586x	PDIST	$ -	-	-	-	-
587 CUSTOMER INSTALLATIONS EXPENSE	LB587	PDIST	$ -	-	-	-	-
588 MISCELLANEOUS DISTRIBUTION EXP	LB588	PDIST	$ -	-	-	-	-
589 RENTS	LB589	PDIST	$ -	-	-	-	-
Total Distribution Operation Labor Expense	LBDO		$ -	$ -	$ -	$ -	$ -

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Description	Name	Functional Vector	Total System	Production Demand	Production Energy	Steam Direct	Transmission Demand
Labor Expenses (Continued)							
Distribution Maintenance Labor Expense							
590 MAINTENANCE SUPERVISION AND EN	LB590	F024	$ -	-	-	-	-
591 MAINTENANCE OF STRUCTURES	LB591	PDIST	$ -	-	-	-	-
592 MAINTENANCE OF STATION EQUIPME	LB592	PDIST	$ -	-	-	-	-
593 MAINTENANCE OF OVERHEAD LINES	LB593	PDIST	$ -	-	-	-	-
594 MAINTENANCE OF UNDERGROUND LIN	LB594	PDIST	$ -	-	-	-	-
595 MAINTENANCE OF LINE TRANSFORME	LB595	PDIST	$ -	-	-	-	-
596 MAINTENANCE OF ST LIGHTS & SIG SYSTEMS	LB596	PDIST	$ -	-	-	-	-
597 MAINTENANCE OF METERS	LB597	PDIST	$ -	-	-	-	-
598 MAINTENANCE OF MISC DISTR PLANT	LB598	PDIST	$ -	-	-	-	-
Total Distribution Maintenance Labor Expense	LBDM		$ -	$ -	$ -	$ -	$ -
Total Distribution Operation and Maintenance Labor Expenses		PDIST	-	-	-	-	-
Transmission and Distribution Labor Expenses			6,480,848	-	-	-	6,480,848
Production, Transmission and Distribution Labor Expenses	LBSUB		$ 45,023,316	$ 20,732,677	$ 17,809,791	$ -	$ 6,480,848
Customer Accounts Expense							
901 SUPERVISION/CUSTOMER ACCTS	LB901	F025	$ -	-	-	-	-
902 METER READING EXPENSES	LB902	F025	$ -	-	-	-	-
903 RECORDS AND COLLECTION	LB903	F025	$ -	-	-	-	-
904 UNCOLLECTIBLE ACCOUNTS	LB904	F025	$ -	-	-	-	-
905 MISC CUST ACCOUNTS	LB903	F025	$ -	-	-	-	-
Total Customer Accounts Labor Expense	LBCA		$ -	$ -	$ -	$ -	$ -
Customer Service Expense							
907 SUPERVISION	LB907	TUP	$ -	-	-	-	-
908 CUSTOMER ASSISTANCE EXPENSES	LB908	TUP	$ 544,608	476,316	-	-	68,292
908 CUSTOMER ASSISTANCE EXP-LOAD MGMT	LB908x	TUP	$ -	-	-	-	-
909 INFORMATIONAL AND INSTRUCTIONA	LB909	TUP	$ -	-	-	-	-
909 INFORM AND INSTRUC -LOAD MGMT	LB909x	TUP	$ -	-	-	-	-
910 MISCELLANEOUS CUSTOMER SERVICE	LB910	TUP	$ -	-	-	-	-
911 DEMONSTRATION AND SELLING EXP	LB911	TUP	$ -	-	-	-	-
912 DEMONSTRATION AND SELLING EXP	LB912	TUP	$ -	-	-	-	-
913 WATER HEATER - HEAT PUMP PROGRAM	LB913	TUP	$ -	-	-	-	-
915 MDSE-JOBBING-CONTRACT	LB915	TUP	$ -	-	-	-	-
916 MISC SALES EXPENSE	LB916	TUP	$ -	-	-	-	-
Total Customer Service Labor Expense	LBCS		$ 544,608	$ 476,316	$ -	$ -	$ 68,292
Sub-Total Labor Exp	LBSUB9		45,567,924	21,208,994	17,809,791	-	6,549,140

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Description	Name	Functional Vector	Total System	Production Demand	Production Energy	Steam Direct	Transmission Demand
Labor Expenses (Continued)							
Administrative and General Expense							
920 ADMIN. & GEN. SALARIES-	LB920	LBSUB9	$ 14,315,714	6,663,061	5,595,161	-	2,057,491
921 OFFICE SUPPLIES AND EXPENSES	LB921	LBSUB9	$ -	-	-	-	-
922 ADMIN. EXPENSES TRANSFERRED - CREDIT	LB922	LBSUB9	$ -	-	-	-	-
923 OUTSIDE SERVICES EMPLOYED	LB923	LBSUB9	$ -	-	-	-	-
924 PROPERTY INSURANCE	LB924	TUP	$ -	-	-	-	-
925 INJURIES AND DAMAGES - INSURAN	LB925	LBSUB9	$ 27,509	12,804	10,752	-	3,954
926 EMPLOYEE BENEFITS	LB926	LBSUB9	$ 17,136	7,976	6,698	-	2,463
928 REGULATORY COMMISSION FEES	LB928	TUP	$ -	-	-	-	-
929 DUPLICATE CHARGES-CR	LB929	LBSUB9	$ -	-	-	-	-
930 MISCELLANEOUS GENERAL EXPENSES	LB930	LBSUB9	$ -	-	-	-	-
931 RENTS AND LEASES	LB931	PGP	$ -	-	-	-	-
935 MAINTENANCE OF GENERAL PLANT	LB935	PGP	$ 74,927	65,674	-	-	9,253
Total Administrative and General Expense	LBAG		$ 14,435,286	$ 6,749,515	$ 5,612,610	$ -	$ 2,073,161
Total Operation and Maintenance Expenses	TLB		$ 60,003,210	$ 27,958,509	$ 23,422,401	$ -	$ 8,622,301
Operation and Maintenance Expenses Less Purchase Power	LBLPP		$ 60,003,210	$ 27,958,509	$ 23,422,401	$ -	$ 8,622,301

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Description	Name	Functional Vector	Total System	Production Demand	Production Energy	Steam Direct	Transmission Demand
Other Expenses							
Depreciation Expenses							
Production	DEPRDP2	PPROD	$ 28,815,395	28,815,395	-	-	-
Transmission	DEPRDP3	PTRAN	$ 5,182,459	-	-	-	5,182,459
Transmission	DEPRDP4	PTRAN	$ -	-	-	-	-
Distribution	DEPRDP5	PDIST	$ -	-	-	-	-
General & Common Plant	DEPRDP6	PGP	$ 238,155	208,744	-	-	29,411
Other Plant	DEPROTH	TPIS	$ -	-	-	-	-
Total Depreciation Expense	TDEPR		$ 34,236,009	29,024,140	-	-	5,211,869
Accretion Expense							
Production	ACRTNP	F017	$ -	-	-	-	-
Transmission	ACRTNT	PTRAN	$ -	-	-	-	-
Distribution	ACRTND	PDIST	$ -	-	-	-	-
Total Accretion Expense	TACRTN		$ -	$ -	$ -	$ -	$ -
Property Taxes & Other	PTAX	TUP	$ (94,563)	(82,705)	-	-	(11,858)
Amortization of Investment Tax Credit	OTAX	TUP	$ -	-	-	-	-
Other Expenses	OT	TUP	$ (365,864)	(319,986)	-	-	(45,878)
Interest	INTLTD	TUP	$ 47,622,710	41,650,995	-	-	5,971,715
Other Deductions	DEDUCT	TUP	$ 109,257	95,557	-	-	13,700
Total Other Expenses	TOE		$ 81,507,549	$ 70,368,000	$ -	$ -	$ 11,139,549
Total Cost of Service (O&M + Other Expenses)			$ 527,945,095	$ 181,569,975	$ 317,276,572	$ -	$ 29,098,548

BIG RIVERS ELECTRIC CORPORATION
Cost of Service Study
Functional Assignment and Classification

12 Months Ended
October 2010

Description	Name	Functional Vector	Total System	Production Demand	Production Energy	Steam Direct	Transmission Demand
Functional Vectors							
Production Plant	F001		1.000000	1.000000	0.000000	0.000000	0.000000
Transmission Plant	F002		1.000000	0.000000	0.000000	0.000000	1.000000
Distribution Plant	F003		1.000000	0.000000	0.000000	0.000000	1.000000
Production Plant	F017		1.000000	0.000000	1.000000	0.000000	0.000000
Provar	PROVAR		1.000000	0.000000	1.000000	0.000000	0.000000
PROFIX	PROFIX		1.000000	1.000000	0.000000	0.000000	0.000000
Distribution Operation Labor	F023		-	-	-	-	-
Distribution Maintenance Labor	F024		-	-	-	-	-
Customer Accounts Expense	F025		1.000000	0.000000	0.000000	0.000000	1.000000
Customer Service Expense	F026		1.000000	0.000000	0.000000	0.000000	1.000000
Purchased Power Energy	OMPP		1.000000	0.000000	1.000000	0.000000	0.000000
Purchased Power Demand	OMPPD		1.000000	1.000000	0.000000	0.000000	0.000000
Purchased Power BREC Share of HMP&L Station Two	OMPPH		58,293,374	13,175,571	45,117,803	0.000000	0.000000
Production Energy	Energy		1.000000	0.000000	1.000000	0.000000	0.000000
Internally Generated Functional Vectors							
Total Prod, Trans, and Dist Plant		PT&D	1.000000	0.876506	-	-	0.123494
Total Transmission Plant		PTRAN	1.000000	-	-	-	1.000000
Operation and Maintenance Expenses Less Purchase Power		OMLPP	1.000000	0.494418	0.425734	-	0.079848
Total Plant in Service		TPIS	1.000000	0.876506	-	-	0.123494
Total Operation and Maintenance Expenses (Labor)		TLB	1.000000	0.465950	0.390352	-	0.143697
Sub-Total Prod, Trans, Dist, Cust Acct and Cust Service		OMSUB2	1.000000	0.232897	0.733903	-	0.033200
Total Steam Power Operation Expenses (Labor)		LBSUB1	1.000000	0.833374	0.166626	-	-
Total Steam Power Generation Maintenance Expense (Labor)		LBSUB2	1.000000	0.078617	0.921383	-	-
Total Transmission Labor Expenses		LBTRAN	1.000000	-	-	-	1.0000000
Sub-Total Labor Exp		LBSUB7	1.000000	0.465437	0.390841	-	0.143723
Total General Plant		PGP	1.000000	0.876506	-	-	0.123494
Total Production Plant		PPROD	1.000000	1.000000	-	-	-
Total Intangible Plant		INTPLT	1.000000	0.876506	-	-	0.123494

BIG RIVERS ELECTRIC CORPORATION
Cost of Service Study
Rate Schedule Allocation
12 Months Ended
October 2010
12 CP - Smelter TIER Adjustment Revenues @ $1.95/mWh

Description	Ref	Name	Allocation Vector	Rurals	Large Industrials	Smelters	Total System
Cost of Service Summary -- Unadjusted							
Operating Revenues							
Sales to Members		REVUC	R01	$ 110,934,700	$ 39,110,620	$ 282,406,135	$ 432,451,455
Off System Sales Revenue			OSSALL	$ 12,699,401	$ 4,615,345	$ 59,229,055	$ 76,543,801
Income from Leased Property Net		OTHREV	RBPLT	$ 45,976	$ 12,696	$ 91,001	$ 149,673
Other Operating Revenue & Income		OTHREV	RBPLT	$ 4,232,544	$ 1,168,737	$ 8,377,465	$ 13,778,745
Total Operating Revenues		TOR		$ 127,912,621	$ 44,907,398	$ 350,103,656	$ 522,923,675
Operating Expenses							
Operation and Maintenance Expenses				$ 117,027,890	$ 39,919,424	$ 289,490,232	$ 446,437,546
Depreciation and Amortization Expenses				$ 10,542,673	$ 2,902,642	$ 20,790,694	$ 34,236,009
Property and Other Taxes			NPT	$ (29,120)	$ (8,017)	$ (57,426)	$ (94,563)
Total Operating Expenses		TOE		$ 127,541,444	$ 42,814,048	$ 310,223,500	$ 480,578,992
Utility Operating Margin				$ 371,177	$ 2,093,350	$ 39,880,156	$ 42,344,683
Non-Operating Items							
Interest Income			RBPLT	$ -	$ -	$ -	$ -
Other Non-Operating Income			RBPLT	$ -	$ -	$ -	$ -
Other Credits			RBPLT	$ -	$ -	$ -	$ -
Interest on Long Term Debt				$ -	$ -	$ -	$ -
Other Interest Expense			RBPLT	$ -	$ -	$ -	$ -
Other Deductions			RBPLT	$ -	$ -	$ -	$ -
Total Non-Operating Items				$ -	$ -	$ -	$ -
Net Utility Operating Margin		TOM		$ 371,177	$ 2,093,350	$ 39,880,156	$ 42,344,683
Net Cost Rate Base				$ 359,504,551	$ 99,270,357	$ 711,566,594	$ 1,170,341,502

BIG RIVERS ELECTRIC CORPORATION
Cost of Service Study
Rate Schedule Allocation
12 Months Ended
October 2010
12 CP - Smelter TIER Adjustment Revenues @ $1.95/mWh

Description	Ref	Name	Allocation Vector	Rurals	Large Industrials	Smelters	Total System
Cost of Service Summary -- Pro-Forma							
Operating Revenues							
Total Operating Revenue				$ 127,912,621	$ 44,907,398	$ 350,103,656	$ 522,923,675
Pro-Forma Adjustments:							
To annualize revenue for new industrial customer	2.01			$ -	$ 149,752	$ -	$ 149,752
To adjust mismatch in fuel cost recovery	2.02	FACREV		$ (25,166,503)	$ (9,525,471)	$ (73,123,203)	$ (107,815,177)
To eliminate Environmental Surcharge revenues	2.03	ESREV		$ (5,315,462)	$ (2,025,233)	$ (15,493,538)	$ (22,834,232)
To reflect temperature normalized sales volumes	2.04		EnergyR	$ (421,610)	$ -	$ -	$ (421,610)
To eliminate Non-FAC PPA revenues	2.05	NFPR		$ 2,757,108	$ 1,045,800	$ 7,785,109	$ 11,588,017
To eliminate WKEC Lease Expenses	2.19		RBPLT	$ (45,976)	$ (12,696)	$ (91,001)	$ (149,673)
To eliminate RRI Domtar Cogen Backup revenues	2.09			$ -	$ (1,115,159)	$ -	$ (1,115,159)
To adjust for Smelter TIER Adjustment Charge	2.22			$ -	$ -	$ -	$ -
Total Pro-Forma Operating Revenue				$ 99,720,178	$ 33,424,391	$ 269,181,024	$ 402,325,592

BIG RIVERS ELECTRIC CORPORATION
Cost of Service Study
Rate Schedule Allocation
12 Months Ended
October 2010
12 CP - Smelter TIER Adjustment Revenues @ $1.95/mWh

Description	Ref	Name	Allocation Vector	Rurals	Large Industrials	Smelters	Total System
Cost of Service Summary -- Pro-Forma							
Operating Expenses							
Operation and Maintenance Expenses				$ 117,027,890	$ 39,919,424	$ 289,490,232	$ 446,437,546
Depreciation and Amortization Expenses				$ 10,542,673	$ 2,902,642	$ 20,790,694	$ 34,236,009
Property and Other Taxes			NPT	$ (29,120)	$ (8,017)	$ (57,426)	$ (94,563)
Adjustments to Operating Expenses:							
To annualize expenses for new industrial customer	2.01			$ -	$ 110,607	$ -	$ 110,607
To adjust mismatch in fuel cost recovery	2.02		FACREV	$ (25,685,949)	$ (9,722,081)	$ (74,632,493)	$ (110,040,523)
To eliminate Environmental Surcharge expenses	2.03		ESREV	$ (5,462,944)	$ (2,081,425)	$ (15,923,422)	$ (23,467,791)
To reflect weather normalized sales volumes	2.04		EnergyR	$ (295,293)	$ -	$ -	$ (295,293)
To eliminate Non-FAC PPA expenses	2.05		NFPR	$ 2,858,740	$ 1,084,350	$ 8,072,083	$ 12,015,173
To reflect annualized depreciation expenses	2.06		PLT	$ 1,925,448	$ 530,120	$ 3,797,082	$ 6,252,651
To reflect increases in labor and labor-related costs	2.07		LBPLT	$ 174,259	$ 53,897	$ 396,739	$ 624,894
To reflect current interest on construction (CWIP)	2.08		PLT	$ 158,826	$ 43,728	$ 313,213	$ 515,767
To eliminate RRI Domtar Cogen Backup expenses	2.09			$ -	$ (2,086,416)	$ -	$ (2,086,416)
To reflect levelized production expenses	2.10		CP	$ 1,743,155	$ 479,931	$ 3,437,592	$ 5,660,678
To reflect levelized production expenses	2.11		CP	$ 839,745	$ 231,201	$ 1,656,019	$ 2,726,965
To reflect going forward Information Technology support services	2.12		RBPLT	$ 89,756	$ 24,784	$ 177,654	$ 292,194
To reflect amortizaton of rate case expenses	2.13		RBPLT	$ 86,538	$ 23,896	$ 171,285	$ 281,719
To reflect MISO related expenses	2.14		12CPTR	$ 1,667,501	$ 459,102	$ 3,288,398	$ 5,415,000
To annualize interest on long-term debt	2.15		RBPLT	$ 21,628	$ 5,972	$ 42,808	$ 70,408
To reflect leased property income (Soaper Building Rent)	2.16		LBPLT	$ (35,797)	$ (11,072)	$ (81,500)	$ (128,368)
To adjust for costs related to LEM Dispatch	2.17		CP	$ (288,484)	$ (79,426)	$ (568,905)	$ (936,815)
To adjust for costs related to APM	2.18		CP	$ 63,156	$ 17,388	$ 124,546	$ 205,090
To reflect going forward level of Outside Services	2.25		EnergyNS	$ (725,000)	$ (275,000)	$ -	$ (1,000,000)
To eliminate costs for SFPC membership	2.20		RBPLT	$ (55,530)	$ (15,334)	$ (109,911)	$ (180,775)
To adjust for MISO Case-related expenses	2.21		12CPTR	$ (237,459)	$ (65,378)	$ (468,281)	$ (771,118)
To reflect commitment to Energy Efficiency Programs	2.26		EnergyNS	$ 725,000	$ 275,000	$ -	$ 1,000,000
To eliminate promo advertising, lobbying, donation and econ dev	2.23		R01	$ (130,114)	$ (45,872)	$ (331,230)	$ (507,216)
To reflect going forward level of income taxes	2.24		NTPLT	$ 56,379	$ 15,522	$ 111,182	$ 183,084
Total Expense Adjustments				$ (22,506,439)	$ (11,026,504)	$ (70,527,141)	$ (104,060,084)
Total Operating Expenses		TOE		$ 105,035,005	$ 31,787,544	$ 239,696,360	$ 376,518,908
Utility Operating Margins -- Pro-Forma				$ (5,314,827)	$ 1,636,847	$ 29,484,664	$ 25,806,684
Non-Operating Items				$ -	$ -	$ -	-
Total Non-Operating Items				$ -	$ -	$ -	-
Net Utility Operating Margin				$ (5,314,827)	$ 1,636,847	$ 29,484,664	$ 25,806,684
Net Cost Rate Base				$ 359,504,551	$ 99,270,357	$ 711,566,594	$ 1,170,341,502
Return on Rate Base -- Utility Operating Margin Divided by Rate Base				-1.48%	1.65%	4.14%	2.21%

BIG RIVERS ELECTRIC CORPORATION
Cost of Service Study
Rate Schedule Allocation
12 Months Ended
October 2010
12 CP - Smelter TIER Adjustment Revenues @ $1.95/mWh

Description	Ref	Name	Allocation Vector	Rurals	Large Industrials	Smelters	Total System
Subsidies Paid and Received at Present Rates							
(subisidies received shown as positive value)							
Rate Base				$ 359,504,551	$ 99,270,357	$ 711,566,594	$ 1,170,341,502
Operating Margins (present rates)				$ (5,314,827)	$ 1,636,847	$ 29,484,664	$ 25,806,684
Operating Margins at Equal Rate of Return		ROR	2.21%	$ 7,927,276	$ 2,188,967	$ 15,690,441	$ 25,806,684
Subsidies Paid and Received				$ 13,242,103	$ 552,120	$ (13,794,223)	$ 0

Big Rivers Electric Corporation
Summary of Cost of Service Study
For the 12 Months Ended October 2010

Rate of Return Summary

Unadjusted

Rate Schedule		Utility Operating Margins		Net Cost Rate Base	Rate of Return
Total Rural	$	(5,314,827)	$	359,504,551	-1.48%
Total Large Industrial		1,636,847		99,270,357	1.65%
Total Smelter		29,484,664		711,566,594	4.14%
Total	$	25,806,684	$	1,170,341,502	2.21%

Adjusted for Proposed Rate Increase

Rate Schedule		Utility Operating Margins		Net Cost Rate Base	Rate of Return
Total Rural	$	8,857,176	$	359,504,551	2.46%
Total Large Industrial		4,865,413		99,270,357	4.90%
Total Smelter		52,038,060		711,566,594	7.31%
Total	$	65,760,649	$	1,170,341,502	5.62%

Description	Name	Functional Vector	Total System	November 2009	December 2009	January 2010	February 2010	March 2010
Plant in Service								
Intangible Plant	INTPLT	PT&D	$ 66,895					
Production Plant	PPROD	F001	$ 1,686,796,955					
Transmission Plant	PTRAN	F002	$ 237,659,206					
Distribution Plant	PDIST	F003	$ -					
Total Production & Transmission Plant	PT&D		1,924,456,160					
General Plant	PGP	PT&D	$ 18,511,051					
Total Plant in Service	TPIS		$ 1,943,034,107					
Construction Work in Progress (CWIP)								
CWIP Production	CWIP1	PPROD	$ 22,411,274					
CWIP Transmission	CWIP2	PTRAN	$ 7,475,859					
CWIP Distribution Plant	CWIP3	PDIST	$ -					
CWIP General Plant	CWIP4	PT&D	$ 16,915,005					
Total Construction Work in Progress	TCWIP		$ 46,802,138					
Total Utility Plant			$ 1,989,836,245					
Rate Base								
Total Utility Plant	TUP		$ 1,989,836,245					
Less: Acummulated Provision for Depreciation								
Production	ADEPREPA	PPROD	$ 790,847,523					
Transmission	ADEPRTP	PTRAN	$ 107,564,747					
Distribution	ADEPRD11	PDIST	$ -					
General & Common Plant	ADEPRD12	PT&D	$ 6,300,770					
Intangible, Misc, and Other Plant	ADEPRGP	PT&D	$ -					
Retirement Work In Progress	ADEPRRT	PT&D	$ -					
Total Accumulated Depreciation	TADEPR		$ 904,713,040					
Net Utility Plant	NTPLANT		$ 1,085,123,206					
Working Capital								
Cash Working Capital - Operation and Maintenance Expenses	CWC	OMLPP	$ 28,114,365					
Materials and Supplies	M&S	TPIS	$ 22,777,820	20327197.9	85340.04	-68898.4	208485.44	-95121.11
Fuel Stock	PREPAY	TPIS	$ 34,326,112	39158400.85	-1328756.9	-4130766.79	-359777.13	1918732.52
Total Working Capital	TWC		$ 85,218,297					
Net Rate Base	RB		$ 1,170,341,502					

Big Rivers Electric Corporation
Month by Month Accounts

Description	Name	Functional Vector	April 2010	May 2010	June 2010	July 2010	August 2010	September 2010
Plant in Service								
Intangible Plant	INTPLT	PT&D						
Production Plant	PPROD	F001						
Transmission Plant	PTRAN	F002						
Distribution Plant	PDIST	F003						
Total Production & Transmission Plant	PT&D							
General Plant	PGP	PT&D						
Total Plant in Service	TPIS							
Construction Work in Progress (CWIP)								
CWIP Production	CWIP1	PPROD						
CWIP Transmission	CWIP2	PTRAN						
CWIP Distribution Plant	CWIP3	PDIST						
CWIP General Plant	CWIP4	PT&D						
Total Construction Work in Progress	TCWIP							
Total Utility Plant								
Rate Base								
Total Utility Plant	TUP							
Less: Acummulated Provision for Depreciation								
Production	ADEPREPA	PPROD						
Transmission	ADEPRTP	PTRAN						
Distribution	ADEPRD11	PDIST						
General & Common Plant	ADEPRD12	PT&D						
Intangible, Misc, and Other Plant	ADEPRGP	PT&D						
Retirement Work In Progress	ADEPRRT	PT&D						
Total Accumulated Depreciation	TADEPR							
Net Utility Plant	NTPLANT							
Working Capital								
Cash Working Capital - Operation and Maintenance Expenses	CWC	OMLPP						
Materials and Supplies	M&S	TPIS	-220183.19	207004.7	357212.07	240129.05	-144241.07	2889566.56
Fuel Stock	PREPAY	TPIS	2552249.61	867432.81	-287963.1	-3463026.24	-2018344.81	-578882.38
Total Working Capital	TWC							
Net Rate Base	RB							

Description	Name	Functional Vector	October 2010
Plant in Service			
Intangible Plant	INTPLT	PT&D	
Production Plant	PPROD	F001	
Transmission Plant	PTRAN	F002	
Distribution Plant	PDIST	F003	
Total Production & Transmission Plant	PT&D		
General Plant	PGP	PT&D	
Total Plant in Service	TPIS		
Construction Work in Progress (CWIP)			
CWIP Production	CWIP1	PPROD	
CWIP Transmission	CWIP2	PTRAN	
CWIP Distribution Plant	CWIP3	PDIST	
CWIP General Plant	CWIP4	PT&D	
Total Construction Work in Progress	TCWIP		
Total Utility Plant			
Rate Base			
Total Utility Plant	TUP		
Less: Acummulated Provision for Depreciation			
Production	ADEPREPA	PPROD	
Transmission	ADEPRTP	PTRAN	
Distribution	ADEPRD11	PDIST	
General & Common Plant	ADEPRD12	PT&D	
Intangible, Misc, and Other Plant	ADEPRGP	PT&D	
Retirement Work In Progress	ADEPRRT	PT&D	
Total Accumulated Depreciation	TADEPR		
Net Utility Plant	NTPLANT		
Working Capital			
Cash Working Capital - Operation and Maintenance Expenses	CWC	OMLPP	
Materials and Supplies	M&S	TPIS	-1008672.24
Fuel Stock	PREPAY	TPIS	1996813.82
Total Working Capital	TWC		
Net Rate Base	RB		

Description	Name	Functional Vector		Total System		November 2009		December 2009		January 2010		February 2010		March 2010
Operation and Maintenance Expenses														
Steam Power Generation Operation Expenses														
500 OPERATION SUPERVISION & ENGINEERING	OM500	PROFIX	$	4,974,566		342962.62		1034901.09		358703.86		318491.34		384828.47
501 FUEL	OM501	Energy	$	200,919,367		11957675.62		16736745.89		19103323.18		17630280.19		17173097.35
502 STEAM EXPENSES	OM502	PROFIX	$	34,453,882		2424633.22		2490999.61		2647322.04		2676616.85		2911578.89
505 ELECTRIC EXPENSES	OM505	PROFIX	$	5,730,122		399281.19		656713.94		477935.99		489102.92		443771.24
506 MISC. STEAM POWER EXPENSES	OM506	PROFIX	$	7,451,302		837237.41		458663.32		531778.12		516078.68		646116.36
507 RENTS	OM507	PROFIX	$	-				0		0		0		0
509 ALLOWANCES	OM509	Energy	$	429,682				0		0		55382.46		42291.31
Total Steam Power Operation Expenses			$	253,958,921	$	7,775	$	146,296	$	7,154	$	15,852	$	21,245
Steam Power Generation Maintenance Expenses														
510 MAINTENANCE SUPERVISION & ENGINEERING	OM510	Energy	$	3,631,867		301562.96		282674.01		282136.07		286174.73		324812.85
511 MAINTENANCE OF STRUCTURES	OM511	PROFIX	$	3,346,806		-2396.3		561809.41		164027.98		219884.17		122851.74
512 MAINTENANCE OF BOILER PLANT	OM512	Energy	$	30,113,309		2665049.9		2707987.08		1617573		1413359.02		2039706.29
513 MAINTENANCE OF ELECTRIC PLANT	OM513	Energy	$	6,251,804		2443905.77		804364.44		-26124.91		190619.56		167015.92
514 MAINTENANCE OF MISC STEAM PLANT	OM514	PROFIX	$	877,364		136355.09		154030.5		71461.85		48046.95		35868.33
Total Steam Power Generation Maintenance Expense			$	44,221,151	$	3,659	$	7,366	$	1,455	$	6,057	$	9,772
Total Steam Power Generation Expense			$	298,180,072										

Description	Name	Functional Vector	April 2010	May 2010	June 2010	July 2010	August 2010	September 2010
Operation and Maintenance Expenses								
Steam Power Generation Operation Expenses								
500 OPERATION SUPERVISION & ENGINEERING	OM500	PROFIX	338223.38	414283.22	372420.21	359404.38	369945.71	334708.35
501 FUEL	OM501	Energy	15868543.13	15412621.99	16949864.35	18643264.65	19588180.27	17004762.52
502 STEAM EXPENSES	OM502	PROFIX	2801318.34	3017168.8	3110448.48	3022221.22	3095094.21	3132173.1
505 ELECTRIC EXPENSES	OM505	PROFIX	430459.27	473960.9	440316.02	456264.08	479912.75	476352.39
506 MISC. STEAM POWER EXPENSES	OM506	PROFIX	557984.26	577686.56	640171.09	585642.46	806920.28	725866.29
507 RENTS	OM507	PROFIX	0	0	0	0	0	0
509 ALLOWANCES	OM509	Energy	33437.63	31618.94	46952.89	62169.21	49573.1	28256.05
Total Steam Power Operation Expenses			$ 6,070	$ 8,052	$ 5,213	$ 267,644	$ 167,124	$ 44,089
Steam Power Generation Maintenance Expenses								
510 MAINTENANCE SUPERVISION & ENGINEERING	OM510	Energy	297530.92	289425	297802.77	281476.85	309430.59	294029.27
511 MAINTENANCE OF STRUCTURES	OM511	PROFIX	153063.03	309779.07	306987.02	458108.12	372678.29	488354.6
512 MAINTENANCE OF BOILER PLANT	OM512	Energy	1740181.45	2535024.61	2164789.64	2054585.86	2034329.79	2855272.84
513 MAINTENANCE OF ELECTRIC PLANT	OM513	Energy	313812.24	389518.49	251988.71	302199.64	422000.23	534239.62
514 MAINTENANCE OF MISC STEAM PLANT	OM514	PROFIX	61896.28	58285.06	85932.24	51800.09	89344.85	66090.33
Total Steam Power Generation Maintenance Expense			$ (325)	$ 4,943	$ 216,501	$ 175,754	$ 65,241	$ 96,186
Total Steam Power Generation Expense								

Description	Name	Functional Vector	October 2010
Operation and Maintenance Expenses			
Steam Power Generation Operation Expenses			
500 OPERATION SUPERVISION & ENGINEERING	OM500	PROFIX	345693.85
501 FUEL	OM501	Energy	14851007.4
502 STEAM EXPENSES	OM502	PROFIX	3124307.14
505 ELECTRIC EXPENSES	OM505	PROFIX	506051.44
506 MISC. STEAM POWER EXPENSES	OM506	PROFIX	567156.95
507 RENTS	OM507	PROFIX	0
509 ALLOWANCES	OM509	Energy	80000.79
Total Steam Power Operation Expenses			$ 44,882
Steam Power Generation Maintenance Expenses			
510 MAINTENANCE SUPERVISION & ENGINEERING	OM510	Energy	384811.34
511 MAINTENANCE OF STRUCTURES	OM511	PROFIX	191658.45
512 MAINTENANCE OF BOILER PLANT	OM512	Energy	6285449.98
513 MAINTENANCE OF ELECTRIC PLANT	OM513	Energy	458264.77
514 MAINTENANCE OF MISC STEAM PLANT	OM514	PROFIX	18252.47
Total Steam Power Generation Maintenance Expense			$ 38,478
Total Steam Power Generation Expense			

Description	Name	Functional Vector		Total System		November 2009		December 2009		January 2010		February 2010		March 2010
Operation and Maintenance Expenses (Continued)														
Other Power Generation Operation Expense														
546 OPERATION SUPERVISION & ENGINEERING	OM546	PROFIX	$	-		0		0		0		0		0
547 FUEL	OM547	Energy	$	706,789		7379.85		135814.53		4779.27		13479.11		18872.46
548 GENERATION EXPENSE	OM548	PROFIX	$	34,608		394.54		10481.32		2375		2373		2373
549 MISC OTHER POWER GENERATION	OM549	PROFIX	$	-		0		0		0		0		0
550 RENTS	OM550	PROFIX	$	-		0		0		0		0		0
Total Other Power Generation Expenses			$	741,396	$	(1)	$	(0)	$	0	$	1	$	0
Other Power Generation Maintenance Expense														
551 MAINTENANCE SUPERVISION & ENGINEERING	OM551	PROFIX	$	-		0		0		0		0		0
552 MAINTENANCE OF STRUCTURES	OM552	PROFIX	$	-		0		0		0		0		0
553 MAINTENANCE OF GENERATING & ELEC PLANT	OM553	PROFIX	$	625,088		3658.66		7365.41		1454.85		6056.77		9772.16
554 MAINTENANCE OF MISC OTHER POWER GEN PLT	OM554	PROFIX	$	-		0		0		0		0		0
Total Other Power Generation Maintenance Expense			$	625,088	$	0	$	(0)	$	(0)	$	0	$	0
Total Other Power Generation Expense			$	1,366,485										
Total Station Expense			$	299,546,557										

Description	Name	Functional Vector	April 2010	May 2010	June 2010	July 2010	August 2010	September 2010
Operation and Maintenance Expenses (Continued)								
Other Power Generation Operation Expense			0	0	0	0	0	0
546 OPERATION SUPERVISION & ENGINEERING	OM546	PROFIX	3696.82	5679.30	2839.60	265271.41	164750.42	41716.70
547 FUEL	OM547	Energy	2373	2373.00	2373.00	2373.00	2373.00	2373.00
548 GENERATION EXPENSE	OM548	PROFIX	0	0	0	0	0	0
549 MISC OTHER POWER GENERATION	OM549	PROFIX	0	0	0	0	0	0
550 RENTS	OM550	PROFIX						
Total Other Power Generation Expenses			$ (0)	$ 1	$ (0)	$ 0	$ (0)	$ 0
Other Power Generation Maintenance Expense								
551 MAINTENANCE SUPERVISION & ENGINEERING	OM551	PROFIX	0	0	0	0	0	0
552 MAINTENANCE OF STRUCTURES	OM552	PROFIX	0	0	0	0	0	0
553 MAINTENANCE OF GENERATING & ELEC PLANT	OM553	PROFIX	-322.62	4943.09	216501.24	175754.02	65240.65	96186.42
554 MAINTENANCE OF MISC OTHER POWER GEN PLT	OM554	PROFIX	0	0	0	0	0	0
Total Other Power Generation Maintenance Expense			$ 2	$ 0	$ 1	$ (0)	$ (1)	$ 0
Total Other Power Generation Expense								
Total Station Expense								

Description	Name	Functional Vector		October 2010
Operation and Maintenance Expenses (Continued)				
Other Power Generation Operation Expense				
546 OPERATION SUPERVISION & ENGINEERING	OM546	PROFIX		0
547 FUEL	OM547	Energy		42509.14
548 GENERATION EXPENSE	OM548	PROFIX		2373.00
549 MISC OTHER POWER GENERATION	OM549	PROFIX		0
550 RENTS	OM550	PROFIX		0
Total Other Power Generation Expenses			$	(0)
Other Power Generation Maintenance Expense				
551 MAINTENANCE SUPERVISION & ENGINEERING	OM551	PROFIX		0
552 MAINTENANCE OF STRUCTURES	OM552	PROFIX		0
553 MAINTENANCE OF GENERATING & ELEC PLANT	OM553	PROFIX		38477.63
554 MAINTENANCE OF MISC OTHER POWER GEN PLT	OM554	PROFIX		0
Total Other Power Generation Maintenance Expense			$	(0)
Total Other Power Generation Expense				
Total Station Expense				

Description	Name	Functional Vector		Total System	November 2009	December 2009	January 2010	February 2010	March 2010
Operation and Maintenance Expenses (Continued)									
Other Power Supply Expenses									
555 PURCHASED POWER Energy	OM555	OMPP	$	19,466,790	3,827,952.61	2,536,760.36	1,913,169.62	941,370.11	911,294.71
555 PURCHASED POWER Demand	OMD555	OMPPD	$	4,210,045	350,837.07	350,837.07	350,837.07	350,837.07	350,837.07
555 PURCHASED POWER BREC Share of HMP&L Station Two	OMH555	OMPPH	$	58,293,374	4,582,937.26	5,054,161.64	4,549,698.12	4,432,913.73	4,763,164.98
555 PURCHASED POWER OPTIONS	OMO555	OMPP	$	-	0	0	0	0	0
555 BROKERAGE FEES	OMB555	OMPP	$	-	0	0	0	0	0
555 MISO TRANSMISSION EXPENSES	OMM555	OMPP	$	-	0	0	0	0	0
556 SYSTEM CONTROL AND LOAD DISPATCH	OM556	PROFIX	$	909,422	143177.05	161775.92	84110.82	66492.87	77558.07
557 OTHER EXPENSES	OM557	PROFIX	$	20,575,465	2479520.29	2210820.92	1519858.99	1381956.22	1577347.72
558 DUPLICATE CHARGES	OM558	Energy	$	-	0	0	0	0	0
Total Other Power Supply Expenses	TPP		$	103,455,096	11,384,424.28	10,314,355.91	8,417,674.62	7,173,570.00	7,680,202.55
Total Electric Power Generation Expenses			$	403,001,653					
Transmission Expenses									
560 OPERATION SUPERVISION AND ENG	OM560	LBTRAN	$	876,815	159722.72	99111.49	64131.05	56493.74	71626.61
561 LOAD DISPATCHING	OM561	LBTRAN	$	1,454,938	245368.38	141741.21	113777.21	98967.65	113022.44
562 STATION EXPENSES	OM562	PTRAN	$	1,163,408	138650.41	111166.28	70289.35	78900.11	96317.14
563 OVERHEAD LINE EXPENSES	OM563	PTRAN	$	1,090,014	116902.84	72507.66	91764.75	90248.86	92136.75
565 TRANSMISSION OF ELECTRICITY BY OTHERS	OM565	PTRAN	$	3,065,817	227372.33	270804.44	222495.76	313990.87	298157.74
566 MISC. TRANSMISSION EXPENSES	OM566	PTRAN	$	475,381	82941.08	54676.78	40839.08	35322.18	39484.82
567 RENTS	OM567	PTRAN	$	24,701	2058.43	2058.43	2058.43	2058.43	2058.43
568 MAINTENACE SUPERVISION AND ENG	OM568	LBTRAN	$	647,227	120702.88	66051.02	48367.7	40149.83	53439.26
569 STRUCTURES	OM569	PTRAN	$	26,913	36.88	6259.34	0	1874.02	59.12
570 MAINT OF STATION EQUIPMENT	OM570	PTRAN	$	1,936,760	272171.89	208826.01	135405.37	165513.32	155839.56
571 MAINT OF OVERHEAD LINES	OM571	PTRAN	$	2,876,462	318695.62	624358.63	20316.93	128651.35	134146
572 UNDERGROUND LINES	OM572	PTRAN	$	-	0	0	0	0	0
573 MISC PLANT	OM573	PTRAN	$	97,880	8341.27	4665	3732.37	5821.94	34823.78
Total Transmission Expenses			$	13,736,318	1,692,964.73	1,662,226.29	813,178.00	1,017,992.30	1,091,111.65

Description	Name	Functional Vector	April 2010	May 2010	June 2010	July 2010	August 2010	September 2010
Operation and Maintenance Expenses (Continued)								
Other Power Supply Expenses								
555 PURCHASED POWER Energy	OM555	OMPP	1,360,105.55	2,595,157.16	1,414,751.54	1,276,714.40	516,721.89	613,253.53
555 PURCHASED POWER Demand	OMD555	OMPPD	350,837.07	350,837.07	350,837.07	350,837.07	350,837.07	350,837.07
555 PURCHASED POWER BREC Share of HMP&L Station Two	OMH555	OMPPH	5,098,546.01	4,460,755.81	4,842,232.95	5,325,056.85	5,088,921.31	4,972,622.48
555 PURCHASED POWER OPTIONS	OMO555	OMPP	0	0	0	0	0	0
555 BROKERAGE FEES	OMB555	OMPP	0	0	0	0	0	0
555 MISO TRANSMISSION EXPENSES	OMM555	OMPP	0	0	0	0	0	0
556 SYSTEM CONTROL AND LOAD DISPATCH	OM556	PROFIX	0	92094.61	73384.96	71377.18	39951.63	51309.82
557 OTHER EXPENSES	OM557	PROFIX	1535653.17	1420108.84	1438109.81	1546376.13	1542523.95	2323941.19
558 DUPLICATE CHARGES	OM558	Energy	0	0	0	0	0	0
Total Other Power Supply Expenses	TPP		8,345,141.80	8,918,953.49	8,119,316.33	8,570,361.63	7,538,955.85	8,311,964.09
Total Electric Power Generation Expenses								
Transmission Expenses								
560 OPERATION SUPERVISION AND ENG	OM560	LBTRAN	59387.59	61734.83	72275.43	57830.16	52970.2	70253.05
561 LOAD DISPATCHING	OM561	LBTRAN	89896.48	94173.59	104627.56	94297.49	86936.32	135835
562 STATION EXPENSES	OM562	PTRAN	84122.23	90931.03	103923.43	86043.52	116294.21	83898.29
563 OVERHEAD LINE EXPENSES	OM563	PTRAN	87522.07	87158.79	89203.39	89187.21	86736.29	88209.66
565 TRANSMISSION OF ELECTRICITY BY OTHERS	OM565	PTRAN	229091.63	251486.95	238169.64	253067.81	259149.57	237980.88
566 MISC. TRANSMISSION EXPENSES	OM566	PTRAN	28982.15	30160.95	44581.15	19944.19	35290.89	32930.62
567 RENTS	OM567	PTRAN	2058.43	2058.43	2058.43	2058.43	2058.43	2058.43
568 MAINTENACE SUPERVISION AND ENG	OM568	LBTRAN	44241.45	45590.11	51110.87	42324.47	40557.13	55824.53
569 STRUCTURES	OM569	PTRAN	80.04	577.95	1084.71	2771.42	1003.78	1896.87
570 MAINT OF STATION EQUIPMENT	OM570	PTRAN	124235.3	158259.64	153920.85	137834.03	134856.99	175088.1
571 MAINT OF OVERHEAD LINES	OM571	PTRAN	140543.65	122631.69	245673.12	136904.15	282898.22	547382.49
572 UNDERGROUND LINES	OM572	PTRAN	0	0	0	0	0	0
573 MISC PLANT	OM573	PTRAN	4923.69	6697.42	5370.15	3919.44	6630.08	5359.76
Total Transmission Expenses			895,084.71	951,461.38	1,111,998.73	926,182.32	1,105,382.11	1,436,717.68

Description	Name	Functional Vector	October 2010
Operation and Maintenance Expenses (Continued)			
Other Power Supply Expenses			
555 PURCHASED POWER Energy	OM555	OMPP	1559538.19
555 PURCHASED POWER Demand	OMD555	OMPPD	350837.07
555 PURCHASED POWER BREC Share of HMP&L Station Two	OMH555	OMPPH	5,122,362.96
555 PURCHASED POWER OPTIONS	OMO555	OMPP	0
555 BROKERAGE FEES	OMB555	OMPP	0
555 MISO TRANSMISSION EXPENSES	OMM555	OMPP	0
556 SYSTEM CONTROL AND LOAD DISPATCH	OM556	PROFIX	48189.16
557 OTHER EXPENSES	OM557	PROFIX	1599248
558 DUPLICATE CHARGES	OM558	Energy	0
Total Other Power Supply Expenses	TPP		8,680,175.38
Total Electric Power Generation Expenses			
Transmission Expenses			
560 OPERATION SUPERVISION AND ENG	OM560	LBTRAN	51278.57
561 LOAD DISPATCHING	OM561	LBTRAN	136294.18
562 STATION EXPENSES	OM562	PTRAN	102872.03
563 OVERHEAD LINE EXPENSES	OM563	PTRAN	98436.13
565 TRANSMISSION OF ELECTRICITY BY OTHERS	OM565	PTRAN	264049.42
566 MISC. TRANSMISSION EXPENSES	OM566	PTRAN	30227.33
567 RENTS	OM567	PTRAN	2058.43
568 MAINTENACE SUPERVISION AND ENG	OM568	LBTRAN	38868.14
569 STRUCTURES	OM569	PTRAN	11269.17
570 MAINT OF STATION EQUIPMENT	OM570	PTRAN	114809.26
571 MAINT OF OVERHEAD LINES	OM571	PTRAN	174260.22
572 UNDERGROUND LINES	OM572	PTRAN	0
573 MISC PLANT	OM573	PTRAN	7595.34
Total Transmission Expenses			1,032,018.22

Description	Name	Functional Vector		Total System	November 2009	December 2009	January 2010	February 2010	March 2010
Distribution Operation Expense									
580 OPERATION SUPERVISION AND ENGI	OM580	LBDO	$	-	0	0	0	0	0
581 LOAD DISPATCHING	OM581	PDIST	$	-	0	0	0	0	0
582 STATION EXPENSES	OM582	PDIST	$	-	0	0	0	0	0
583 OVERHEAD LINE EXPENSES	OM583	PDIST	$	-	0	0	0	0	0
584 UNDERGROUND LINE EXPENSES	OM584	PDIST	$	-	0	0	0	0	0
585 STREET LIGHTING EXPENSE	OM585	PDIST	$	-	0	0	0	0	0
586 METER EXPENSES	OM586	PDIST	$	-	0	0	0	0	0
586 METER EXPENSES - LOAD MANAGEMENT	OM586x	PDIST	$	-	0	0	0	0	0
587 CUSTOMER INSTALLATIONS EXPENSE	OM587	PDIST	$	-	0	0	0	0	0
588 MISCELLANEOUS DISTRIBUTION EXP	OM588	PDIST	$	-	0	0	0	0	0
588 MISC DISTR EXP -- MAPPIN	OM588x	PDIST	$	-	0	0	0	0	0
589 RENTS	OM589	PDIST	$	-	0	0	0	0	0
Total Distribution Operation Expense	OMDO		$	-					
<u>**Operation and Maintenance Expenses (Continued)**</u>									
Distribution Maintenance Expense									
590 MAINTENANCE SUPERVISION AND EN	OM590	LBDM	$	-	0	0	0	0	0
591 STRUCTURES	OM591	PDIST	$	-	0	0	0	0	0
592 MAINTENANCE OF STATION EQUIPME	OM592	PDIST	$	-	0	0	0	0	0
593 MAINTENANCE OF OVERHEAD LINES	OM593	PDIST	$	-	0	0	0	0	0
594 MAINTENANCE OF UNDERGROUND LIN	OM594	PDIST	$	-	0	0	0	0	0
595 MAINTENANCE OF LINE TRANSFORME	OM595	PDIST	$	-	0	0	0	0	0
596 MAINTENANCE OF ST LIGHTS & SIG SYSTEMS	OM596	PDIST	$	-	0	0	0	0	0
597 MAINTENANCE OF METERS	OM597	PDIST	$	-	0	0	0	0	0
598 MISCELLANEOUS DISTRIBUTION EXPENSES	OM598	PDIST	$	-	0	0	0	0	0
Total Distribution Maintenance Expense	OMDM		$	-					
Total Distribution Operation and Maintenance Expenses				-					
Transmission and Distribution Expenses				13,736,318					
Production, Transmission and Distribution Expenses	OMSUB		$	416,737,971					

Description	Name	Functional Vector	April 2010	May 2010	June 2010	July 2010	August 2010	September 2010
Distribution Operation Expense								
580 OPERATION SUPERVISION AND ENGI	OM580	LBDO	0	0	0	0	0	0
581 LOAD DISPATCHING	OM581	PDIST	0	0	0	0	0	0
582 STATION EXPENSES	OM582	PDIST	0	0	0	0	0	0
583 OVERHEAD LINE EXPENSES	OM583	PDIST	0	0	0	0	0	0
584 UNDERGROUND LINE EXPENSES	OM584	PDIST	0	0	0	0	0	0
585 STREET LIGHTING EXPENSE	OM585	PDIST	0	0	0	0	0	0
586 METER EXPENSES	OM586	PDIST	0	0	0	0	0	0
586 METER EXPENSES - LOAD MANAGEMENT	OM586x	PDIST	0	0	0	0	0	0
587 CUSTOMER INSTALLATIONS EXPENSE	OM587	PDIST	0	0	0	0	0	0
588 MISCELLANEOUS DISTRIBUTION EXP	OM588	PDIST	0	0	0	0	0	0
588 MISC DISTR EXP -- MAPPIN	OM588x	PDIST	0	0	0	0	0	0
589 RENTS	OM589	PDIST	0	0	0	0	0	0
Total Distribution Operation Expense	OMDO							
Operation and Maintenance Expenses (Continued)								
Distribution Maintenance Expense								
590 MAINTENANCE SUPERVISION AND EN	OM590	LBDM	0	0	0	0	0	0
591 STRUCTURES	OM591	PDIST	0	0	0	0	0	0
592 MAINTENANCE OF STATION EQUIPME	OM592	PDIST	0	0	0	0	0	0
593 MAINTENANCE OF OVERHEAD LINES	OM593	PDIST	0	0	0	0	0	0
594 MAINTENANCE OF UNDERGROUND LIN	OM594	PDIST	0	0	0	0	0	0
595 MAINTENANCE OF LINE TRANSFORME	OM595	PDIST	0	0	0	0	0	0
596 MAINTENANCE OF ST LIGHTS & SIG SYSTEMS	OM596	PDIST	0	0	0	0	0	0
597 MAINTENANCE OF METERS	OM597	PDIST	0	0	0	0	0	0
598 MISCELLANEOUS DISTRIBUTION EXPENSES	OM598	PDIST	0	0	0	0	0	0
Total Distribution Maintenance Expense	OMDM							
Total Distribution Operation and Maintenance Expenses								
Transmission and Distribution Expenses								
Production, Transmission and Distribution Expenses	OMSUB							

Description	Name	Functional Vector	October 2010
Distribution Operation Expense			
580 OPERATION SUPERVISION AND ENGI	OM580	LBDO	0
581 LOAD DISPATCHING	OM581	PDIST	0
582 STATION EXPENSES	OM582	PDIST	0
583 OVERHEAD LINE EXPENSES	OM583	PDIST	0
584 UNDERGROUND LINE EXPENSES	OM584	PDIST	0
585 STREET LIGHTING EXPENSE	OM585	PDIST	0
586 METER EXPENSES	OM586	PDIST	0
586 METER EXPENSES - LOAD MANAGEMENT	OM586x	PDIST	0
587 CUSTOMER INSTALLATIONS EXPENSE	OM587	PDIST	0
588 MISCELLANEOUS DISTRIBUTION EXP	OM588	PDIST	0
588 MISC DISTR EXP -- MAPPIN	OM588x	PDIST	0
589 RENTS	OM589	PDIST	0
Total Distribution Operation Expense	OMDO		
Operation and Maintenance Expenses (Continued)			
Distribution Maintenance Expense			
590 MAINTENANCE SUPERVISION AND EN	OM590	LBDM	0
591 STRUCTURES	OM591	PDIST	0
592 MAINTENANCE OF STATION EQUIPME	OM592	PDIST	0
593 MAINTENANCE OF OVERHEAD LINES	OM593	PDIST	0
594 MAINTENANCE OF UNDERGROUND LIN	OM594	PDIST	0
595 MAINTENANCE OF LINE TRANSFORME	OM595	PDIST	0
596 MAINTENANCE OF ST LIGHTS & SIG SYSTEMS	OM596	PDIST	0
597 MAINTENANCE OF METERS	OM597	PDIST	0
598 MISCELLANEOUS DISTRIBUTION EXPENSES	OM598	PDIST	0
Total Distribution Maintenance Expense	OMDM		
Total Distribution Operation and Maintenance Expenses			
Transmission and Distribution Expenses			
Production, Transmission and Distribution Expenses	OMSUB		

Description	Name	Functional Vector		Total System	November 2009	December 2009	January 2010	February 2010	March 2010
Customer Accounts Expense									
901 SUPERVISION/CUSTOMER ACCTS	OM901	F025	$	-	0	0	0	0	0
902 METER READING EXPENSES	OM902	F025	$	-	0	0	0	0	0
903 RECORDS AND COLLECTION	OM903	F025	$	-	0	0	0	0	0
904 UNCOLLECTIBLE ACCOUNTS	OM904	F025	$	-	0	0	0	0	0
905 MISC CUST ACCOUNTS	OM903	F025	$	-	0	0	0	0	0
Total Customer Accounts Expense	OMCA		$	-					
Customer Service Expense									
907 SUPERVISION	OM907	TUP	$	-	0	0	0	0	0
908 CUSTOMER ASSISTANCE EXPENSES	OM908	TUP	$	591,192	104389.97	75645.08	40729.07	42316.45	53316.29
908 CUSTOMER ASSISTANCE EXP-INCENTIVES	OM908x	TUP	$	-	0	0	0	0	0
909 INFORMATIONAL AND INSTRUCTIONA	OM909	TUP	$	-	0	0	0	0	0
909 INFORM AND INSTRUC -LOAD MGMT	OM909x	TUP	$	-	0	0	0	0	0
910 MISCELLANEOUS CUSTOMER SERVICE	OM910	TUP	$	-	0	0	0	0	0
911 DEMONSTRATION AND SELLING EXP	OM911	TUP	$	-	0	0	0	0	0
912 DEMONSTRATION AND SELLING EXP	OM912	TUP	$	-	0	0	0	0	0
913 ADVERTISING EXPENSES	OM913	TUP	$	488,103	103663.39	219971.2	7179.7	3679.68	21007.78
915 MDSE-JOBBING-CONTRACT	OM915	TUP	$	-	0	0	0	0	0
916 MISC SALES EXPENSE	OM916	TUP	$	-	0	0	0	0	0
Total Customer Service Expense	OMCS		$	1,079,295	208053.36	295616.28	47908.77	45996.13	74324.07
Sub-Total Prod, Trans, Dist, Cust Acct and Cust Service	OMSUB2			417,817,266					
Operation and Maintenance Expenses (Continued)									
Administrative and General Expense									
920 ADMIN. & GEN. SALARIES-	OM920	LBSUB9	$	14,315,713	2092449.03	1522142.97	1300504.05	1313340.25	1495631.43
921 OFFICE SUPPLIES AND EXPENSES	OM921	LBSUB9	$	6,915,648	432853.99	1082881.21	447533.76	790015.22	520665.52
922 ADMINISTRATIVE EXPENSES TRANSFERRED	OM922	LBSUB9	$	-	0	0	0	0	0
923 OUTSIDE SERVICES EMPLOYED	OM923	LBSUB9	$	3,954,189	337609.86	1175322.5	167190.31	217289.45	526048.51
924 PROPERTY INSURANCE	OM924	TUP	$	-	0	0	0	0	0
925 INJURIES AND DAMAGES - INSURAN	OM925	LBSUB9	$	179,889	13413.2	21072.48	15311.2	15178.2	25828.68
926 EMPLOYEE BENEFITS	OM926	LBSUB9	$	169,663	4383.08	-2896.98	25050.87	3276.12	0
927 FRANCHISE REQUIREMENTS	OM927	TUP	$	-	0	0	0	0	0
928 REGULATORY COMMISSION FEES	OM928	TUP	$	1,188,958	2785	925	0	0	1790.1
929 DUPLICATE CHARGES-CR	OM929	LBSUB9	$	-	0	0	0	0	0
930 MISCELLANEOUS GENERAL EXPENSES	OM930	LBSUB9	$	1,686,131	68132.08	249532.88	81732.32	215359.96	139106.95
931 RENTS AND LEASES	OM931	PGP	$	1,933	161.09	161.09	161.09	161.09	161.09
935 MAINTENANCE OF GENERAL PLANT	OM935	PGP	$	208,156	23769.07	24452.06	14946.22	44645.76	14798.82
Total Administrative and General Expense	OMAG		$	28,620,280	2,975,556.40	4,073,593.21	2,052,429.82	2,599,266.05	2,724,031.10
Total Operation and Maintenance Expenses	TOM		$	446,437,546					
Operation and Maintenance Expenses Less Purchase Power & Fuel	OMLPP		$	224,914,919					

Description	Name	Functional Vector	April 2010	May 2010	June 2010	July 2010	August 2010	September 2010
Customer Accounts Expense								
901 SUPERVISION/CUSTOMER ACCTS	OM901	F025	0	0	0	0	0	0
902 METER READING EXPENSES	OM902	F025	0	0	0	0	0	0
903 RECORDS AND COLLECTION	OM903	F025	0	0	0	0	0	0
904 UNCOLLECTIBLE ACCOUNTS	OM904	F025	0	0	0	0	0	0
905 MISC CUST ACCOUNTS	OM903	F025	0	0	0	0	0	0
Total Customer Accounts Expense	OMCA							
Customer Service Expense								
907 SUPERVISION	OM907	TUP	0	0	0	0	0	0
908 CUSTOMER ASSISTANCE EXPENSES	OM908	TUP	42590.29	45548.65	47955.97	41989.91	36242.46	23856.1
908 CUSTOMER ASSISTANCE EXP-INCENTIVES	OM908x	TUP	0	0	0	0	0	0
909 INFORMATIONAL AND INSTRUCTIONA	OM909	TUP	0	0	0	0	0	0
909 INFORM AND INSTRUC -LOAD MGMT	OM909x	TUP	0	0	0	0	0	0
910 MISCELLANEOUS CUSTOMER SERVICE	OM910	TUP	0	0	0	0	0	0
911 DEMONSTRATION AND SELLING EXP	OM911	TUP	0	0	0	0	0	0
912 DEMONSTRATION AND SELLING EXP	OM912	TUP	0	0	0	0	0	0
913 ADVERTISING EXPENSES	OM913	TUP	-36141.33	11695.6	18760.65	13630.34	24487.44	100169
915 MDSE-JOBBING-CONTRACT	OM915	TUP	0	0	0	0	0	0
916 MISC SALES EXPENSE	OM916	TUP	0	0	0	0	0	0
Total Customer Service Expense	OMCS		6448.96	57244.25	66716.62	55620.25	60729.9	124025.1
Sub-Total Prod, Trans, Dist, Cust Acct and Cust Service	OMSUB2							
Operation and Maintenance Expenses (Continued)								
Administrative and General Expense								
920 ADMIN. & GEN. SALARIES-	OM920	LBSUB9	1326991.23	427833.15	1263415.19	446430.74	948956.12	1178332.32
921 OFFICE SUPPLIES AND EXPENSES	OM921	LBSUB9	591943.78	481169.78	617503.76	673906.86	384307.2	494280.5
922 ADMINISTRATIVE EXPENSES TRANSFERRED	OM922	LBSUB9	0	0	0	0	0	0
923 OUTSIDE SERVICES EMPLOYED	OM923	LBSUB9	388800.48	188378.03	280346.99	85723.73	284467.92	205203.9
924 PROPERTY INSURANCE	OM924	TUP	0	0	0	0	0	0
925 INJURIES AND DAMAGES - INSURAN	OM925	LBSUB9	14679.26	12401	12401	12401	12401	12401
926 EMPLOYEE BENEFITS	OM926	LBSUB9	53705.24	8851.25	5962.88	6192.45	33341.38	6109.83
927 FRANCHISE REQUIREMENTS	OM927	TUP	0	0	0	0	0	0
928 REGULATORY COMMISSION FEES	OM928	TUP	1353.14	48087.75	665466.25	48046.08	139142.52	18419
929 DUPLICATE CHARGES-CR	OM929	LBSUB9	0	0	0	0	0	0
930 MISCELLANEOUS GENERAL EXPENSES	OM930	LBSUB9	94167.83	259652.47	119570.46	108391.43	155943.83	63658.14
931 RENTS AND LEASES	OM931	PGP	161.09	161.09	161.09	161.09	161.09	161.09
935 MAINTENANCE OF GENERAL PLANT	OM935	PGP	8698.33	7258.14	13445.04	8125.63	22399.01	9027.98
Total Administrative and General Expense	OMAG		2,480,500.38	1,433,792.66	2,978,272.66	1,389,379.01	1,981,120.07	1,987,593.76
Total Operation and Maintenance Expenses	TOM							
Operation and Maintenance Expenses Less Purchase Power & Fuel	OMLPP							

Description	Name	Functional Vector	October 2010
Customer Accounts Expense			
901 SUPERVISION/CUSTOMER ACCTS	OM901	F025	0
902 METER READING EXPENSES	OM902	F025	0
903 RECORDS AND COLLECTION	OM903	F025	0
904 UNCOLLECTIBLE ACCOUNTS	OM904	F025	0
905 MISC CUST ACCOUNTS	OM903	F025	0
Total Customer Accounts Expense	OMCA		
Customer Service Expense			
907 SUPERVISION	OM907	TUP	0
908 CUSTOMER ASSISTANCE EXPENSES	OM908	TUP	36611.39
908 CUSTOMER ASSISTANCE EXP-INCENTIVES	OM908x	TUP	0
909 INFORMATIONAL AND INSTRUCTIONA	OM909	TUP	0
909 INFORM AND INSTRUC -LOAD MGMT	OM909x	TUP	0
910 MISCELLANEOUS CUSTOMER SERVICE	OM910	TUP	0
911 DEMONSTRATION AND SELLING EXP	OM911	TUP	0
912 DEMONSTRATION AND SELLING EXP	OM912	TUP	0
913 ADVERTISING EXPENSES	OM913	TUP	0
915 MDSE-JOBBING-CONTRACT	OM915	TUP	0
916 MISC SALES EXPENSE	OM916	TUP	0
Total Customer Service Expense	OMCS		36611.39
Sub-Total Prod, Trans, Dist, Cust Acct and Cust Service	OMSUB2		
Operation and Maintenance Expenses (Continued)			
Administrative and General Expense			
920 ADMIN. & GEN. SALARIES-	OM920	LBSUB9	999686.96
921 OFFICE SUPPLIES AND EXPENSES	OM921	LBSUB9	398586.21
922 ADMINISTRATIVE EXPENSES TRANSFERRED	OM922	LBSUB9	0
923 OUTSIDE SERVICES EMPLOYED	OM923	LBSUB9	97807.2
924 PROPERTY INSURANCE	OM924	TUP	0
925 INJURIES AND DAMAGES - INSURAN	OM925	LBSUB9	12401
926 EMPLOYEE BENEFITS	OM926	LBSUB9	25686.5
927 FRANCHISE REQUIREMENTS	OM927	TUP	0
928 REGULATORY COMMISSION FEES	OM928	TUP	262942.92
929 DUPLICATE CHARGES-CR	OM929	LBSUB9	0
930 MISCELLANEOUS GENERAL EXPENSES	OM930	LBSUB9	130882.85
931 RENTS AND LEASES	OM931	PGP	161.09
935 MAINTENANCE OF GENERAL PLANT	OM935	PGP	16590.29
Total Administrative and General Expense	OMAG		1,944,745.02
Total Operation and Maintenance Expenses	TOM		
Operation and Maintenance Expenses Less Purchase Power & Fuel	OMLPP		

Description	Name	Functional Vector		Total System	November 2009	December 2009	January 2010	February 2010	March 2010
Labor Expenses									
Steam Power Generation Operation Expenses									
500 OPERATION SUPERVISION & ENGINEERING	LB500	PROFIX	$	4,967,667	342832.39	1034681.8	357452.74	317350.15	384316.78
501 FUEL	LB501	Energy	$	3,889,944	323255.71	364406.07	338654.53	313289.78	326385.9
502 STEAM EXPENSES	LB502	PROFIX	$	9,023,322	657659.63	771924.79	681077.92	630021.61	688026.67
505 ELECTRIC EXPENSES	LB505	PROFIX	$	4,523,897	357040.19	416235	378976.79	348125.67	369036.85
506 MISC. STEAM POWER EXPENSES	LB506	PROFIX	$	940,518	52261.31	80829.64	70706.68	101840.85	81036.08
507 RENTS	LB507	PROFIX	$	-	0	0	0	0	0
509 ALLOWANCES	LB509	Energy	$	-	0	0	0	0	0
Total Steam Power Operation Expenses	LBSUB1		$	23,345,348	1066961.13	1268989.43	1130761.39	1079988.13	1138099.6
Steam Power Generation Maintenance Expenses									
510 MAINTENANCE SUPERVISION & ENGINEERING	LB510	Energy	$	3,623,969	301562.96	282674.01	280925.01	285686.26	324812.85
511 MAINTENANCE OF STRUCTURES	LB511	PROFIX	$	986,831	60839.92	78449.28	79549.6	75632	64969.97
512 MAINTENANCE OF BOILER PLANT	LB512	Energy	$	8,700,235	613650.58	728746.59	804049.52	597501.69	694231.84
513 MAINTENANCE OF ELECTRIC PLANT	LB513	Energy	$	1,595,642	209176.55	143092.64	90379.11	93612.16	119373.66
514 MAINTENANCE OF MISC STEAM PLANT	LB514	PROFIX	$	200,886	16879.23	22485.07	12128	16408.41	14092.69
Total Steam Power Generation Maintenance Expense	LBSUB2		$	15,107,564	1202109.24	1255447.59	1267031.24	1068840.52	1217481.01
Total Steam Power Generation Expense			$	38,452,913	2269070.37	2524437.02	2397792.63	2148828.65	2355580.61
Labor Expenses (Continued)									
Other Power Generation Operation Expense									
546 OPERATION SUPERVISION & ENGINEERING	LB546	PROFIX	$	-	0	0	0	0	0
547 FUEL	LB547	Energy	$	-	0	0	0	0	0
548 GENERATION EXPENSE	LB548	PROFIX	$	-	0	0	0	0	0
549 MISC OTHER POWER GENERATION	LB549	PROFIX	$	-	0	0	0	0	0
550 RENTS	LB550	PROFIX	$	-	0	0	0	0	0
Total Other Power Generation Expenses	LBSUB7		$	-					
Other Power Generation Maintenance Expense									
551 MAINTENANCE SUPERVISION & ENGINEERING	LB551	PROFIX	$	-	0	0	0	0	0
552 MAINTENANCE OF STRUCTURES	LB552	PROFIX	$	-	0	0	0	0	0
553 MAINTENANCE OF GENERATING & ELEC PLANT	LB553	PROFIX	$	89,555	682.21	4299.67	1026.96	2400.3	4848.64
554 MAINTENANCE OF MISC OTHER POWER GEN PLT	LB554	PROFIX	$	-	0	0	0	0	0
Total Other Power Generation Maintenance Expense	LBSUB8		$	89,555					
Total Other Power Generation Expense			$	89,555					
Total Production Expense	LPREX		$	38,542,468					

Description	Name	Functional Vector	April 2010	May 2010	June 2010	July 2010	August 2010	September 2010
Labor Expenses								
Steam Power Generation Operation Expenses								
500 OPERATION SUPERVISION & ENGINEERING	LB500	PROFIX	338156.02	414149.39	371014.23	359005.08	369873.15	334189.99
501 FUEL	LB501	Energy	309863.06	297596.67	304977.88	310355.07	339148.89	336547.05
502 STEAM EXPENSES	LB502	PROFIX	640194.64	1123637.4	744724.17	661984.49	702417.45	982572.63
505 ELECTRIC EXPENSES	LB505	PROFIX	342341.75	393006.64	354302.21	368561.14	384521.42	384533.54
506 MISC. STEAM POWER EXPENSES	LB506	PROFIX	63015.48	66970.66	87852.14	88369.17	86572.5	91267.67
507 RENTS	LB507	PROFIX	0	0	0	0	0	0
509 ALLOWANCES	LB509	Energy	0	0	0	0	0	0
Total Steam Power Operation Expenses	LBSUB1		1045551.87	1583614.7	1186878.52	1118914.8	1173511.37	1458373.84
Steam Power Generation Maintenance Expenses								
510 MAINTENANCE SUPERVISION & ENGINEERING	LB510	Energy	297255.94	289425	296206.84	280281.91	307241.14	294029.27
511 MAINTENANCE OF STRUCTURES	LB511	PROFIX	50081.03	70791.44	106230.99	106856.88	116200.49	96973.59
512 MAINTENANCE OF BOILER PLANT	LB512	Energy	617716.63	961798.07	675983.16	535600.92	651081.61	924014.95
513 MAINTENANCE OF ELECTRIC PLANT	LB513	Energy	96940.39	142971.1	124922.34	132978.24	129288.01	126399.56
514 MAINTENANCE OF MISC STEAM PLANT	LB514	PROFIX	9843.3	16400.27	20426.8	23473.83	26283.4	15419.85
Total Steam Power Generation Maintenance Expense	LBSUB2		1071837.29	1481385.88	1223770.13	1079191.78	1230094.65	1456837.22
Total Steam Power Generation Expense			2117389.16	3065000.58	2410648.65	2198106.58	2403606.02	2915211.06
Labor Expenses (Continued)								
Other Power Generation Operation Expense								
546 OPERATION SUPERVISION & ENGINEERING	LB546	PROFIX	0	0	0	0	0	0
547 FUEL	LB547	Energy	0	0	0	0	0	0
548 GENERATION EXPENSE	LB548	PROFIX	0	0	0	0	0	0
549 MISC OTHER POWER GENERATION	LB549	PROFIX	0	0	0	0	0	0
550 RENTS	LB550	PROFIX	0	0	0	0	0	0
Total Other Power Generation Expenses	LBSUB7							
Other Power Generation Maintenance Expense								
551 MAINTENANCE SUPERVISION & ENGINEERING	LB551	PROFIX	0	0	0	0	0	0
552 MAINTENANCE OF STRUCTURES	LB552	PROFIX	0	0	0	0	0	0
553 MAINTENANCE OF GENERATING & ELEC PLANT	LB553	PROFIX	903.26	760.91	37267.71	11775.09	12921.35	10584.31
554 MAINTENANCE OF MISC OTHER POWER GEN PLT	LB554	PROFIX	0	0	0	0	0	0
Total Other Power Generation Maintenance Expense	LBSUB8							
Total Other Power Generation Expense								
Total Production Expense	LPREX							

Description	Name	Functional Vector	October 2010
Labor Expenses			
Steam Power Generation Operation Expenses			
500 OPERATION SUPERVISION & ENGINEERING	LB500	PROFIX	344645.64
501 FUEL	LB501	Energy	325463.54
502 STEAM EXPENSES	LB502	PROFIX	739080.82
505 ELECTRIC EXPENSES	LB505	PROFIX	427215.91
506 MISC. STEAM POWER EXPENSES	LB506	PROFIX	69795.43
507 RENTS	LB507	PROFIX	0
509 ALLOWANCES	LB509	Energy	0
Total Steam Power Operation Expenses	LBSUB1		1236092.16
Steam Power Generation Maintenance Expenses			
510 MAINTENANCE SUPERVISION & ENGINEERING	LB510	Energy	383868.11
511 MAINTENANCE OF STRUCTURES	LB511	PROFIX	80256.21
512 MAINTENANCE OF BOILER PLANT	LB512	Energy	895859.55
513 MAINTENANCE OF ELECTRIC PLANT	LB513	Energy	186508.29
514 MAINTENANCE OF MISC STEAM PLANT	LB514	PROFIX	7045.58
Total Steam Power Generation Maintenance Expense	LBSUB2		1553537.74
Total Steam Power Generation Expense			2642951.16
Labor Expenses (Continued)			
Other Power Generation Operation Expense			
546 OPERATION SUPERVISION & ENGINEERING	LB546	PROFIX	0
547 FUEL	LB547	Energy	0
548 GENERATION EXPENSE	LB548	PROFIX	0
549 MISC OTHER POWER GENERATION	LB549	PROFIX	0
550 RENTS	LB550	PROFIX	0
Total Other Power Generation Expenses	LBSUB7		
Other Power Generation Maintenance Expense			
551 MAINTENANCE SUPERVISION & ENGINEERING	LB551	PROFIX	
552 MAINTENANCE OF STRUCTURES	LB552	PROFIX	
553 MAINTENANCE OF GENERATING & ELEC PLANT	LB553	PROFIX	2084.81
554 MAINTENANCE OF MISC OTHER POWER GEN PLT	LB554	PROFIX	
Total Other Power Generation Maintenance Expense	LBSUB8		
Total Other Power Generation Expense			
Total Production Expense	LPREX		

Description	Name	Functional Vector		Total System	November 2009	December 2009	January 2010	February 2010	March 2010
Labor Expenses (Continued)									
Purchased Power									
555 PURCHASED POWER	LB555	OMPP	$	-	0	0	0	0	0
555 PURCHASED POWER Demand	LBD555	OMPPD	$	-	0	0	0	0	0
555 PURCHASED POWER OPTIONS	LBO555	OMPP	$	-	0	0	0	0	0
555 BROKERAGE FEES	LBB555	OMPP	$	-	0	0	0	0	0
555 MISO TRANSMISSION EXPENSES	LBM555	OMPP	$	-	0	0	0	0	0
556 SYSTEM CONTROL AND LOAD DISPATCH	LB556	PROFIX	$	-	0	0	0	0	0
557 OTHER EXPENSES	LB557	PROFIX	$	-	0	0	0	0	0
558 DUPLICATE CHARGES	LB558	Energy	$	-	0	0	0	0	0
Total Purchased Power Labor	LBPP		$	-					
Transmission Labor Expenses									
560 OPERATION SUPERVISION AND ENG	LB560	PTRAN	$	835,977	155357.97	88621.66	61719.3	53192.77	69331.26
561 LOAD DISPATCHING	LB561	PTRAN	$	1,304,969	240520.6	133245.05	93819.32	87693.64	104400.26
562 STATION EXPENSES	LB562	PTRAN	$	598,382	102945.93	50883.95	33705.43	39512.69	54112.06
563 OVERHEAD LINE EXPENSES	LB563	PTRAN	$	236,393	52690.64	20206.01	20032.96	18769.45	17519.18
565 TRANSMISSION OF ELECTRICITY BY OTHERS	LB565	PTRAN	$	-	0	0	0	0	0
566 MISC. TRANSMISSION EXPENSES	LB566	PTRAN	$	312,375	55300.19	33112.8	26544.3	26563.55	28599.72
567 RENTS	LB567	PTRAN	$	-	0	0	0	0	0
568 MAINTENACE SUPERVISION AND ENG	LB568	PTRAN	$	644,925	120270.89	65874.61	48314.25	39737.97	53182.86
569 MAINTENACE OF STRUCTURES	LB569	PTRAN	$	318	36.88	59.34	0	0	59.12
570 MAINT OF STATION EQUIPMENT	LB570	PTRAN	$	1,433,304	240458.8	137581.27	112331.02	103977.18	112839.1
571 MAINT OF OVERHEAD LINES	LB571	PTRAN	$	1,067,766	187769.72	120250.23	62124.04	70835.46	82150.36
573 MAINT OF MISC. TRANSMISSION PLANT	LB573	PTRAN	$	46,439	6906.42	2875.43	2872.93	4248.62	4851.27
Total Transmission Labor Expenses	LBTRAN		$	6,480,848	1162258.04	652710.35	461463.55	444531.33	527045.19
Distribution Operation Labor Expense									
580 OPERATION SUPERVISION AND ENGI	LB580	F023	$	-	0	0	0	0	0
581 LOAD DISPATCHING	LB581	PDIST	$	-	0	0	0	0	0
582 STATION EXPENSES	LB582	PDIST	$	-	0	0	0	0	0
583 OVERHEAD LINE EXPENSES	LB583	PDIST	$	-	0	0	0	0	0
584 UNDERGROUND LINE EXPENSES	LB584	PDIST	$	-	0	0	0	0	0
585 STREET LIGHTING EXPENSE	LB585	PDIST	$	-	0	0	0	0	0
586 METER EXPENSES	LB586	PDIST	$	-	0	0	0	0	0
586 METER EXPENSES - LOAD MANAGEMENT	LB586x	PDIST	$	-	0	0	0	0	0
587 CUSTOMER INSTALLATIONS EXPENSE	LB587	PDIST	$	-	0	0	0	0	0
588 MISCELLANEOUS DISTRIBUTION EXP	LB588	PDIST	$	-	0	0	0	0	0
589 RENTS	LB589	PDIST	$	-	0	0	0	0	0
Total Distribution Operation Labor Expense	LBDO		$	-					

Description	Name	Functional Vector	April 2010	May 2010	June 2010	July 2010	August 2010	September 2010
Labor Expenses (Continued)								
Purchased Power								
555 PURCHASED POWER	LB555	OMPP	0	0	0	0	0	0
555 PURCHASED POWER Demand	LBD555	OMPPD	0	0	0	0	0	0
555 PURCHASED POWER OPTIONS	LBO555	OMPP	0	0	0	0	0	0
555 BROKERAGE FEES	LBB555	OMPP	0	0	0	0	0	0
555 MISO TRANSMISSION EXPENSES	LBM555	OMPP	0	0	0	0	0	0
556 SYSTEM CONTROL AND LOAD DISPATCH	LB556	PROFIX	0	0	0	0	0	0
557 OTHER EXPENSES	LB557	PROFIX	0	0	0	0	0	0
558 DUPLICATE CHARGES	LB558	Energy	0	0	0	0	0	0
Total Purchased Power Labor	LBPP							
Transmission Labor Expenses								
560 OPERATION SUPERVISION AND ENG	LB560	PTRAN	57113.62	58908.5	68081.43	56191.8	51380.65	68130.77
561 LOAD DISPATCHING	LB561	PTRAN	79471.75	90840.85	104792.75	86864.08	84835.7	115440.78
562 STATION EXPENSES	LB562	PTRAN	43463.43	48316.48	56470.33	35035.32	46067.52	51613.79
563 OVERHEAD LINE EXPENSES	LB563	PTRAN	14223.62	16460.25	15132.13	14168.98	13692.1	15806.34
565 TRANSMISSION OF ELECTRICITY BY OTHERS	LB565	PTRAN	0	0	0	0	0	0
566 MISC. TRANSMISSION EXPENSES	LB566	PTRAN	21343.51	20102.2	25810.07	11252.29	17357.03	25204.78
567 RENTS	LB567	PTRAN	0	0	0	0	0	0
568 MAINTENACE SUPERVISION AND ENG	LB568	PTRAN	43994.75	45554.09	50783.31	42264.13	40489.73	55734.99
569 MAINTENACE OF STRUCTURES	LB569	PTRAN	26.22	0	24.61	26.14	26.21	0.65
570 MAINT OF STATION EQUIPMENT	LB570	PTRAN	98690.36	92937.1	116008.73	108080.33	93852.16	126204.48
571 MAINT OF OVERHEAD LINES	LB571	PTRAN	66143.16	68592.74	93608.24	76903.52	71073.25	95620.68
573 MAINT OF MISC. TRANSMISSION PLANT	LB573	PTRAN	4378.83	3303.42	3349.41	3196.71	3607.42	3592.3
Total Transmission Labor Expenses	LBTRAN		428849.25	445015.63	534061.01	433983.3	422381.77	557349.56
Distribution Operation Labor Expense								
580 OPERATION SUPERVISION AND ENGI	LB580	F023	0	0	0	0	0	0
581 LOAD DISPATCHING	LB581	PDIST	0	0	0	0	0	0
582 STATION EXPENSES	LB582	PDIST	0	0	0	0	0	0
583 OVERHEAD LINE EXPENSES	LB583	PDIST	0	0	0	0	0	0
584 UNDERGROUND LINE EXPENSES	LB584	PDIST	0	0	0	0	0	0
585 STREET LIGHTING EXPENSE	LB585	PDIST	0	0	0	0	0	0
586 METER EXPENSES	LB586	PDIST	0	0	0	0	0	0
586 METER EXPENSES - LOAD MANAGEMENT	LB586x	PDIST	0	0	0	0	0	0
587 CUSTOMER INSTALLATIONS EXPENSE	LB587	PDIST	0	0	0	0	0	0
588 MISCELLANEOUS DISTRIBUTION EXP	LB588	PDIST	0	0	0	0	0	0
589 RENTS	LB589	PDIST	0	0	0	0	0	0
Total Distribution Operation Labor Expense	LBDO							

Description	Name	Functional Vector	October 2010
Labor Expenses (Continued)			
Purchased Power			
555 PURCHASED POWER	LB555	OMPP	0
555 PURCHASED POWER Demand	LBD555	OMPPD	0
555 PURCHASED POWER OPTIONS	LBO555	OMPP	0
555 BROKERAGE FEES	LBB555	OMPP	0
555 MISO TRANSMISSION EXPENSES	LBM555	OMPP	0
556 SYSTEM CONTROL AND LOAD DISPATCH	LB556	PROFIX	0
557 OTHER EXPENSES	LB557	PROFIX	0
558 DUPLICATE CHARGES	LB558	Energy	0
Total Purchased Power Labor	LBPP		0
Transmission Labor Expenses			
560 OPERATION SUPERVISION AND ENG	LB560	PTRAN	47946.89
561 LOAD DISPATCHING	LB561	PTRAN	83043.95
562 STATION EXPENSES	LB562	PTRAN	36255.02
563 OVERHEAD LINE EXPENSES	LB563	PTRAN	17691.07
565 TRANSMISSION OF ELECTRICITY BY OTHERS	LB565	PTRAN	
566 MISC. TRANSMISSION EXPENSES	LB566	PTRAN	21184.45
567 RENTS	LB567	PTRAN	
568 MAINTENACE SUPERVISION AND ENG	LB568	PTRAN	38723.49
569 MAINTENACE OF STRUCTURES	LB569	PTRAN	59.17
570 MAINT. OF STATION EQUIPMENT	LB570	PTRAN	90343.75
571 MAINT OF OVERHEAD LINES	LB571	PTRAN	72694.7
573 MAINT OF MISC. TRANSMISSION PLANT	LB573	PTRAN	3256.6
Total Transmission Labor Expenses	LBTRAN		205077.71
Distribution Operation Labor Expense			
580 OPERATION SUPERVISION AND ENGI	LB580	F023	0
581 LOAD DISPATCHING	LB581	PDIST	0
582 STATION EXPENSES	LB582	PDIST	0
583 OVERHEAD LINE EXPENSES	LB583	PDIST	0
584 UNDERGROUND LINE EXPENSES	LB584	PDIST	0
585 STREET LIGHTING EXPENSE	LB585	PDIST	0
586 METER EXPENSES	LB586	PDIST	0
586 METER EXPENSES - LOAD MANAGEMENT	LB586x	PDIST	0
587 CUSTOMER INSTALLATIONS EXPENSE	LB587	PDIST	0
588 MISCELLANEOUS DISTRIBUTION EXP	LB588	PDIST	0
589 RENTS	LB589	PDIST	0
Total Distribution Operation Labor Expense	LBDO		

Description	Name	Functional Vector		Total System	November 2009	December 2009	January 2010	February 2010	March 2010
Labor Expenses (Continued)									
Distribution Maintenance Labor Expense									
590 MAINTENANCE SUPERVISION AND EN	LB590	F024	$	-	0	0	0	0	0
591 MAINTENANCE OF STRUCTURES	LB591	PDIST	$	-	0	0	0	0	0
592 MAINTENANCE OF STATION EQUIPME	LB592	PDIST	$	-	0	0	0	0	0
593 MAINTENANCE OF OVERHEAD LINES	LB593	PDIST	$	-	0	0	0	0	0
594 MAINTENANCE OF UNDERGROUND LIN	LB594	PDIST	$	-	0	0	0	0	0
595 MAINTENANCE OF LINE TRANSFORME	LB595	PDIST	$	-	0	0	0	0	0
596 MAINTENANCE OF ST LIGHTS & SIG SYSTEMS	LB596	PDIST	$	-	0	0	0	0	0
597 MAINTENANCE OF METERS	LB597	PDIST	$	-	0	0	0	0	0
598 MAINTENANCE OF MISC DISTR PLANT	LB598	PDIST	$	-	0	0	0	0	0
Total Distribution Maintenance Labor Expense	LBDM		$	-					
Total Distribution Operation and Maintenance Labor Expenses		PDIST		-					
Transmission and Distribution Labor Expenses				6,480,848					
Production, Transmission and Distribution Labor Expenses	LBSUB		$	45,023,316					
Customer Accounts Expense									
901 SUPERVISION/CUSTOMER ACCTS	LB901	F025	$	-	0	0	0	0	0
902 METER READING EXPENSES	LB902	F025	$	-	0	0	0	0	0
903 RECORDS AND COLLECTION	LB903	F025	$	-	0	0	0	0	0
904 UNCOLLECTIBLE ACCOUNTS	LB904	F025	$	-	0	0	0	0	0
905 MISC CUST ACCOUNTS	LB903	F025	$	-	0	0	0	0	0
Total Customer Accounts Labor Expense	LBCA		$	-					
Customer Service Expense									
907 SUPERVISION	LB907	TUP	$	-	0	0	0	0	0
908 CUSTOMER ASSISTANCE EXPENSES	LB908	TUP	$	544,608	98543.49	44838.51	39429.59	38666.03	49827.22
908 CUSTOMER ASSISTANCE EXP-LOAD MGMT	LB908x	TUP	$	-	0	0	0	0	0
909 INFORMATIONAL AND INSTRUCTIONA	LB909	TUP	$	-	0	0	0	0	0
909 INFORM AND INSTRUC -LOAD MGMT	LB909x	TUP	$	-	0	0	0	0	0
910 MISCELLANEOUS CUSTOMER SERVICE	LB910	TUP	$	-	0	0	0	0	0
911 DEMONSTRATION AND SELLING EXP	LB911	TUP	$	-	0	0	0	0	0
912 DEMONSTRATION AND SELLING EXP	LB912	TUP	$	-	0	0	0	0	0
913 WATER HEATER - HEAT PUMP PROGRAM	LB913	TUP	$	-	0	0	0	0	0
915 MDSE-JOBBING-CONTRACT	LB915	TUP	$	-	0	0	0	0	0
916 MISC SALES EXPENSE	LB916	TUP	$	-	0	0	0	0	0
Total Customer Service Labor Expense	LBCS		$	544,608	98543.49	44838.51	39429.59	38666.03	49827.22
Sub-Total Labor Exp	LBSUB9			45,567,924					

Description	Name	Functional Vector	April 2010	May 2010	June 2010	July 2010	August 2010	September 2010
Labor Expenses (Continued)								
Distribution Maintenance Labor Expense								
590 MAINTENANCE SUPERVISION AND EN	LB590	F024	0	0	0	0	0	0
591 MAINTENANCE OF STRUCTURES	LB591	PDIST	0	0	0	0	0	0
592 MAINTENANCE OF STATION EQUIPME	LB592	PDIST	0	0	0	0	0	0
593 MAINTENANCE OF OVERHEAD LINES	LB593	PDIST	0	0	0	0	0	0
594 MAINTENANCE OF UNDERGROUND LIN	LB594	PDIST	0	0	0	0	0	0
595 MAINTENANCE OF LINE TRANSFORME	LB595	PDIST	0	0	0	0	0	0
596 MAINTENANCE OF ST LIGHTS & SIG SYSTEMS	LB596	PDIST	0	0	0	0	0	0
597 MAINTENANCE OF METERS	LB597	PDIST	0	0	0	0	0	0
598 MAINTENANCE OF MISC DISTR PLANT	LB598	PDIST	0	0	0	0	0	0
Total Distribution Maintenance Labor Expense	LBDM							
Total Distribution Operation and Maintenance Labor Expenses		PDIST						
Transmission and Distribution Labor Expenses								
Production, Transmission and Distribution Labor Expenses	LBSUB							
Customer Accounts Expense								
901 SUPERVISION/CUSTOMER ACCTS	LB901	F025	0	0	0	0	0	0
902 METER READING EXPENSES	LB902	F025	0	0	0	0	0	0
903 RECORDS AND COLLECTION	LB903	F025	0	0	0	0	0	0
904 UNCOLLECTIBLE ACCOUNTS	LB904	F025	0	0	0	0	0	0
905 MISC CUST ACCOUNTS	LB903	F025	0	0	0	0	0	0
Total Customer Accounts Labor Expense	LBCA							
Customer Service Expense								
907 SUPERVISION	LB907	TUP	0	0	0	0	0	0
908 CUSTOMER ASSISTANCE EXPENSES	LB908	TUP	37915.48	41556.72	44591.58	38345.68	32873.52	44118.04
908 CUSTOMER ASSISTANCE EXP-LOAD MGMT	LB908x	TUP	0	0	0	0	0	0
909 INFORMATIONAL AND INSTRUCTIONA	LB909	TUP	0	0	0	0	0	0
909 INFORM AND INSTRUC -LOAD MGMT	LB909x	TUP	0	0	0	0	0	0
910 MISCELLANEOUS CUSTOMER SERVICE	LB910	TUP	0	0	0	0	0	0
911 DEMONSTRATION AND SELLING EXP	LB911	TUP	0	0	0	0	0	0
912 DEMONSTRATION AND SELLING EXP	LB912	TUP	0	0	0	0	0	0
913 WATER HEATER - HEAT PUMP PROGRAM	LB913	TUP	0	0	0	0	0	0
915 MDSE-JOBBING-CONTRACT	LB915	TUP	0	0	0	0	0	0
916 MISC SALES EXPENSE	LB916	TUP	0	0	0	0	0	0
Total Customer Service Labor Expense	LBCS		37915.48	41556.72	44591.58	38345.68	32873.52	44118.04
Sub-Total Labor Exp	LBSUB9							

Description	Name	Functional Vector	October 2010
Labor Expenses (Continued)			
Distribution Maintenance Labor Expense			
590 MAINTENANCE SUPERVISION AND EN	LB590	F024	
591 MAINTENANCE OF STRUCTURES	LB591	PDIST	
592 MAINTENANCE OF STATION EQUIPME	LB592	PDIST	
593 MAINTENANCE OF OVERHEAD LINES	LB593	PDIST	
594 MAINTENANCE OF UNDERGROUND LIN	LB594	PDIST	
595 MAINTENANCE OF LINE TRANSFORME	LB595	PDIST	
596 MAINTENANCE OF ST LIGHTS & SIG SYSTEMS	LB596	PDIST	
597 MAINTENANCE OF METERS	LB597	PDIST	
598 MAINTENANCE OF MISC DISTR PLANT	LB598	PDIST	
Total Distribution Maintenance Labor Expense	LBDM		
Total Distribution Operation and Maintenance Labor Expenses		PDIST	
Transmission and Distribution Labor Expenses			
Production, Transmission and Distribution Labor Expenses	LBSUB		
Customer Accounts Expense			
901 SUPERVISION/CUSTOMER ACCTS	LB901	F025	
902 METER READING EXPENSES	LB902	F025	
903 RECORDS AND COLLECTION	LB903	F025	
904 UNCOLLECTIBLE ACCOUNTS	LB904	F025	
905 MISC CUST ACCOUNTS	LB903	F025	
Total Customer Accounts Labor Expense	LBCA		
Customer Service Expense			
907 SUPERVISION	LB907	TUP	
908 CUSTOMER ASSISTANCE EXPENSES	LB908	TUP	33902.45
908 CUSTOMER ASSISTANCE EXP-LOAD MGMT	LB908x	TUP	
909 INFORMATIONAL AND INSTRUCTIONA	LB909	TUP	
909 INFORM AND INSTRUC -LOAD MGMT	LB909x	TUP	
910 MISCELLANEOUS CUSTOMER SERVICE	LB910	TUP	
911 DEMONSTRATION AND SELLING EXP	LB911	TUP	
912 DEMONSTRATION AND SELLING EXP	LB912	TUP	
913 WATER HEATER - HEAT PUMP PROGRAM	LB913	TUP	
915 MDSE-JOBBING-CONTRACT	LB915	TUP	
916 MISC SALES EXPENSE	LB916	TUP	
Total Customer Service Labor Expense	LBCS		33902.45
Sub-Total Labor Exp	LBSUB9		

Description	Name	Functional Vector		Total System	November 2009	December 2009	January 2010	February 2010	March 2010
Labor Expenses (Continued)									
Administrative and General Expense									
920 ADMIN. & GEN. SALARIES-	LB920	LBSUB9	$	14,315,714	2092449.04	1522142.8	1300504.05	1313340.25	1495631.43
921 OFFICE SUPPLIES AND EXPENSES	LB921	LBSUB9	$	-	0	0	0	0	0
922 ADMIN. EXPENSES TRANSFERRED - CREDIT	LB922	LBSUB9	$	-	0	0	0	0	0
923 OUTSIDE SERVICES EMPLOYED	LB923	LBSUB9	$	-	0	0	0	0	0
924 PROPERTY INSURANCE	LB924	TUP	$	-	0	0	0	0	0
925 INJURIES AND DAMAGES - INSURAN	LB925	LBSUB9	$	27,509	2777.2	3471.48	2777.2	2777.2	13427.68
926 EMPLOYEE BENEFITS	LB926	LBSUB9	$	17,136	2711	-43974.67	0	0	0
928 REGULATORY COMMISSION FEES	LB928	TUP	$	-	0	0	0	0	0
929 DUPLICATE CHARGES-CR	LB929	LBSUB9	$	-	0	0	0	0	0
930 MISCELLANEOUS GENERAL EXPENSES	LB930	LBSUB9	$	-	0	0	0	0	0
931 RENTS AND LEASES	LB931	PGP	$	-	0	0	0	0	0
935 MAINTENANCE OF GENERAL PLANT	LB935	PGP	$	74,927	14602.3	14130.42	6605.75	5191.93	4971.6
Total Administrative and General Expense	LBAG		$	14,435,286					
Total Operation and Maintenance Expenses	TLB		$	60,003,210					
Operation and Maintenance Expenses Less Purchase Power	LBLPP		$	60,003,210					
Other Expenses									
Depreciation Expenses									
Production	DEPRDP2	PPROD	$	28,815,395	2347440.74	2389099.7	2595994.55	2361961.48	2361968.56
Transmission	DEPRDP3	PTRAN	$	5,182,459	443546.44	533184.66	214261.5	442312.53	442305.66
Transmission	DEPRDP4	PTRAN	$	-					
Distribution	DEPRDP5	PDIST	$	-					
General & Common Plant	DEPRDP6	PGP	$	238,155	17050.71	19802.63	19799.44	19799.44	19766.55
Other Plant	DEPROTH	TPIS	$	-	0	0	0	0	0
Total Depreciation Expense	TDEPR		$	34,236,009	2808037.89	2942086.99	2830055.49	2824073.45	2824040.77
Accretion Expense									
Production	ACRTNP	F017	$	-	0	0	0	0	0
Transmission	ACRTNT	PTRAN	$	-	0	0	0	0	0
Distribution	ACRTND	PDIST	$	-	0	0	0	0	0
Total Accretion Expense	TACRTN		$	-					
Property Taxes & Other	PTAX	TUP	$	(94,563)	$ (379,997)	$ 87,636	$ -	$ -	$ 910
Amortization of Investment Tax Credit	OTAX	TUP	$	-	0	0	0	0	0
Other Expenses	OT	TUP	$	(365,864)	$ (6,691)	$ (14,191)	$ (18,627)	$ (23,851)	$ (16,042)
Interest	INTLTD	TUP	$	47,622,710	4168487.53	4316793.16	4234968.72	3796291.74	4133482.27
Other Deductions	DEDUCT	TUP	$	109,257	7611	15379	4539	6545	5640
Total Other Expenses	TOE		$	81,507,549	$ 3,789,411	$ 4,405,617	$ 4,220,881	$ 3,778,986	$ 4,123,991
Total Cost of Service (O&M + Other Expenses)			$	527,945,095					

Description	Name	Functional Vector	April 2010	May 2010	June 2010	July 2010	August 2010	September 2010
Labor Expenses (Continued)								
Administrative and General Expense								
920 ADMIN. & GEN. SALARIES-	LB920	LBSUB9	1326991.23	427833.15	1263415.19	446430.74	948956.12	1178332.32
921 OFFICE SUPPLIES AND EXPENSES	LB921	LBSUB9	0	0	0	0	0	0
922 ADMIN. EXPENSES TRANSFERRED - CREDIT	LB922	LBSUB9	0	0	0	0	0	0
923 OUTSIDE SERVICES EMPLOYED	LB923	LBSUB9	0	0	0	0	0	0
924 PROPERTY INSURANCE	LB924	TUP	0	0	0	0	0	0
925 INJURIES AND DAMAGES - INSURAN	LB925	LBSUB9	2278.26	0	0	0	0	0
926 EMPLOYEE BENEFITS	LB926	LBSUB9	23360	5840	5840	5840	5840	5840
928 REGULATORY COMMISSION FEES	LB928	TUP	0	0	0	0	0	0
929 DUPLICATE CHARGES-CR	LB929	LBSUB9	0	0	0	0	0	0
930 MISCELLANEOUS GENERAL EXPENSES	LB930	LBSUB9	0	0	0	0	0	0
931 RENTS AND LEASES	LB931	PGP	0	0	0	0	0	0
935 MAINTENANCE OF GENERAL PLANT	LB935	PGP	5560.19	2953.32	3794.54	2464	6700.24	5197.69
Total Administrative and General Expense	LBAG							
Total Operation and Maintenance Expenses	TLB							
Operation and Maintenance Expenses Less Purchase Power	LBLPP							
Other Expenses								
Depreciation Expenses								
Production	DEPRDP2	PPROD	2361962.84	2422279.6	2384018.59	2354733.3	2368037.83	2494767.54
Transmission	DEPRDP3	PTRAN	442357.04	442363.4	442363.15	442486.5	440016.44	450445.41
Transmission	DEPRDP4	PTRAN						
Distribution	DEPRDP5	PDIST						
General & Common Plant	DEPRDP6	PGP	19733.28	21031.35	19852.73	20082.98	19987.32	21286.62
Other Plant	DEPROTH	TPIS	0	0	0	0	0	0
Total Depreciation Expense	TDEPR		2824053.16	2885674.35	2846234.47	2817302.78	2828041.59	2966499.57
Accretion Expense								
Production	ACRTNP	F017	0	0	0	0	0	0
Transmission	ACRTNT	PTRAN	0	0	0	0	0	0
Distribution	ACRTND	PDIST	0	0	0	0	0	0
Total Accretion Expense	TACRTN							
Property Taxes & Other	PTAX	TUP	$ 65,000	$ 2,342	$ 65,000	$ -	$ (429)	$ 65,000
Amortization of Investment Tax Credit	OTAX	TUP	0	0	0	0	0	0
Other Expenses	OT	TUP	$ (27,557)	$ (8,263)	$ (42,136)	$ (42,545)	$ (48,997)	$ (56,550)
Interest	INTLTD	TUP	3848131.38	3699835.35	3741933.32	3942436.65	3958146.18	3830668.47
Other Deductions	DEDUCT	TUP	-2109	4540	14599	10828	16243	12411
Total Other Expenses	TOE		$ 3,883,465	$ 3,698,454	$ 3,779,396	$ 3,910,720	$ 3,924,964	$ 3,851,529
Total Cost of Service (O&M + Other Expenses)								

Description	Name	Functional Vector	October 2010
Labor Expenses (Continued)			
Administrative and General Expense			
920 ADMIN. & GEN. SALARIES-	LB920	LBSUB9	999687.37
921 OFFICE SUPPLIES AND EXPENSES	LB921	LBSUB9	
922 ADMIN. EXPENSES TRANSFERRED - CREDIT	LB922	LBSUB9	
923 OUTSIDE SERVICES EMPLOYED	LB923	LBSUB9	
924 PROPERTY INSURANCE	LB924	TUP	
925 INJURIES AND DAMAGES - INSURAN	LB925	LBSUB9	0
926 EMPLOYEE BENEFITS	LB926	LBSUB9	5840
928 REGULATORY COMMISSION FEES	LB928	TUP	
929 DUPLICATE CHARGES-CR	LB929	LBSUB9	
930 MISCELLANEOUS GENERAL EXPENSES	LB930	LBSUB9	
931 RENTS AND LEASES	LB931	PGP	
935 MAINTENANCE OF GENERAL PLANT	LB935	PGP	2754.81
Total Administrative and General Expense	LBAG		
Total Operation and Maintenance Expenses	TLB		
Operation and Maintenance Expenses Less Purchase Power	LBLPP		
Other Expenses			
Depreciation Expenses			
Production	DEPRDP2	PPROD	2373130.48
Transmission	DEPRDP3	PTRAN	446815.89
Transmission	DEPRDP4	PTRAN	
Distribution	DEPRDP5	PDIST	
General & Common Plant	DEPRDP6	PGP	19962.11
Other Plant	DEPROTH	TPIS	0
Total Depreciation Expense	TDEPR		2839908.48
Accretion Expense			
Production	ACRTNP	F017	0
Transmission	ACRTNT	PTRAN	0
Distribution	ACRTND	PDIST	0
Total Accretion Expense	TACRTN		
Property Taxes & Other	PTAX	TUP	$ (25)
Amortization of Investment Tax Credit	OTAX	TUP	0
Other Expenses	OT	TUP	$ (60,414)
Interest	INTLTD	TUP	3951535
Other Deductions	DEDUCT	TUP	13031
Total Other Expenses	TOE		$ 3,904,127
Total Cost of Service (O&M + Other Expenses)			

Description	Name	Functional Vector	Total System	November 2009	December 2009	January 2010	February 2010	March 2010
Revenues								
Jackson Purchase			$ 31,526,082	2,047,421	2,967,876	3,236,562	2,630,578	2,282,284
Kenergy			$ 56,579,648	3,789,093	5,385,841	5,977,907	4,990,050	4,209,222
Meade			$ 22,828,970	1,551,653	2,374,865	2,690,998	2,281,167	1,830,442
Large Industrial			$ 39,110,620	3,326,073	3,242,060	3,257,550	3,000,170	3,334,841
Century Total			$ 150,725,511	14,123,587	13,900,845	12,327,658	10,978,277	13,026,782
Alcan Total			$ 131,680,624	11,327,935	11,867,881	11,227,291	10,087,671	11,349,236
	Total Rural		$ 110,934,700	$ 7,388,167	$ 10,728,582	$ 11,905,467	$ 9,901,794	$ 8,321,948
	Total Industrial		$ 39,110,620	$ 8,666,818	$ 11,002,766	$ 11,926,456	$ 10,271,387	$ 9,374,506
	Total Smelter		$ 282,406,135	$ 25,451,523	$ 25,768,725	$ 23,554,949	$ 21,065,948	$ 24,376,019
	Total		$ 432,451,455	$ 36,165,762	$ 39,739,368	$ 38,717,967	$ 33,967,912	$ 36,032,808
Century Invoiced			$ 149,837,373	12,898,686	13,350,197	12,412,617	10,978,277	13,026,782
Alcan Invoiced			$ 131,911,075	10,982,583	11,672,836	11,353,440	10,087,671	11,349,236
Century Adjustments			$ 888,139	1,224,902	550,648	(84,959)		
Alcan Adjustments			$ (230,451)	345,352	195,044	(126,150)		
Off System Sales			$ 76,543,801	$ 1,839,442	$ 4,073,308	$ 8,147,840	$ 9,539,433	$ 7,986,498
Income from Leased Property Net			$ 149,673	$ 149,673	$ -	$ -	$ -	$ -
Other Operating Revenue & Income			$ 13,778,745	$ 1,230,861	$ 1,033,968	$ 1,152,998	$ 1,145,023	$ 1,070,097
OSS Variable O&M			$ 46,035,981	$ 1,471,622	$ 2,691,212	$ 4,162,194	$ 5,284,841	$ 5,083,040
Energy								
Jackson Purchase			694,512,540	45,926,970	65,978,630	71,338,200	59,712,514	49,429,743
Kenergy			1,255,008,258	85,135,870	120,014,010	132,891,880	114,367,690	91,992,020
Meade			499,627,006	34,444,920	51,694,410	59,035,140	51,393,370	38,028,116
Large Industrial			928,887,170	78,192,702	74,359,872	75,056,282	70,510,685	78,126,590
Century			3,949,411,321	310,167,027	331,563,740	339,238,984	318,278,276	343,763,177
Alcan			3,163,910,039	257,031,413	268,912,646	270,478,213	245,969,029	270,738,402
Total Rural			2,449,147,804	165,507,760	237,687,050	263,265,220	225,473,574	179,449,879
Total Industrial			928,887,170	78,192,702	74,359,872	75,056,282	70,510,685	78,126,590
Total Smelter			7,113,321,360	567,198,440	600,476,386	609,717,197	564,247,305	614,501,579
Total			10,491,356,334	810,898,902	912,523,308	948,038,699	860,231,564	872,078,048

Description	Name	Functional Vector	April 2010	May 2010	June 2010	July 2010	August 2010	September 2010
Revenues								
Jackson Purchase			1,799,767	2,308,067	3,063,639	3,258,780	3,399,012	2,561,800
Kenergy			3,188,379	4,134,538	5,323,163	5,636,870	5,853,842	4,573,561
Meade			1,214,667	1,532,681	1,963,540	2,110,692	2,169,733	1,693,499
Large Industrial			3,161,352	3,245,699	3,234,324	3,234,990	3,373,185	3,344,243
Century Total			12,044,160	12,679,922	11,679,623	12,055,865	12,367,467	11,801,654
Alcan Total			10,471,146	11,169,007	10,543,631	10,857,129	10,839,072	10,177,927
	Total Rural		$ 6,202,813	$ 7,975,287	$ 10,350,341	$ 11,006,341	$ 11,422,586	$ 8,828,859
	Total Industrial		$ 7,564,398	$ 8,912,918	$ 10,521,026	$ 10,982,552	$ 11,396,759	$ 9,611,302
	Total Smelter		$ 22,515,306	$ 23,848,930	$ 22,223,254	$ 22,912,994	$ 23,206,539	$ 21,979,581
	Total		$ 31,879,471	$ 35,069,915	$ 35,807,919	$ 37,154,326	$ 38,002,310	$ 34,152,683
Century Invoiced			12,044,160	12,679,922	11,679,623	12,055,865	12,367,467	12,580,920
Alcan Invoiced			10,471,146	11,169,007	10,543,631	10,857,129	10,839,072	10,806,724
Century Adjustments								(779,265)
Alcan Adjustments								(628,797)
Off System Sales			$ 5,678,794	$ 6,341,556	$ 7,049,362	$ 7,908,927	$ 8,630,309	$ 5,166,061
Income from Leased Property Net			$ -	$ -	$ -	$ -	$ -	$ -
Other Operating Revenue & Income			$ 1,140,133	$ 1,143,171	$ 1,284,686	$ 1,142,016	$ 1,145,336	$ 1,142,234
OSS Variable O&M			$ 3,852,774	$ 3,932,574	$ 3,863,529	$ 4,155,945	$ 4,803,709	$ 3,568,984
Energy								
Jackson Purchase			40,334,720	49,465,221	67,937,977	74,389,907	74,455,490	53,358,978
Kenergy			72,904,910	88,391,581	119,415,050	128,859,539	129,305,728	95,902,980
Meade			28,079,875	32,805,170	43,966,515	47,969,570	47,509,670	35,325,370
Large Industrial			78,086,611	79,512,076	79,858,265	78,927,327	82,005,334	79,182,043
Century			323,212,786	331,276,534	324,397,171	337,256,977	345,310,998	317,766,683
Alcan			260,668,275	268,579,997	259,859,800	268,729,560	268,160,608	257,328,832
Total Rural			141,319,505	170,661,972	231,319,542	251,219,016	251,270,888	184,587,328
Total Industrial			78,086,611	79,512,076	79,858,265	78,927,327	82,005,334	79,182,043
Total Smelter			583,881,061	599,856,531	584,256,971	605,986,537	613,471,606	575,095,515
Total			803,287,177	850,030,579	895,434,778	936,132,880	946,747,828	838,864,886

Description	Name	Functional Vector	October 2010
Revenues			
Jackson Purchase			1,970,297
Kenergy			3,517,183
Meade			1,415,034
Large Industrial			3,356,132
Century Total			13,739,670
Alcan Total			11,762,698
	Total Rural		$ 6,902,515
	Total Industrial		$ 8,288,350
	Total Smelter		$ 25,502,368
	Total		$ 35,761,015
Century Invoiced			13,762,856
Alcan Invoiced			11,778,599
Century Adjustments			(23,186)
Alcan Adjustments			(15,901)
Off System Sales			4,182,271
Income from Leased Property Net			$ -
Other Operating Revenue & Income			$ 1,148,221
OSS Variable O&M			$ 3,165,556
Energy			
Jackson Purchase			42,184,190
Kenergy			75,827,000
Meade			29,374,880
Large Industrial			75,069,383
Century			327,178,968
Alcan			267,453,264
Total Rural			147,386,070
Total Industrial			75,069,383
Total Smelter			594,632,232
Total			817,087,685

COMMONWEALTH OF KENTUCKY
BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

APPLICATION OF BIG RIVERS ELECTRIC	)	
CORPORATION FOR A GENERAL	)	**CASE NO. 2011-00036**
ADJUSTMENT IN RATES	)	

KENTUCKY INDUSTRIAL UTILITY CUSTOMERS RESPONSE TO
BIG RIVERS ELECTRIC CORPORATION
FIRST DATA REQUEST
PSC CASE NO. 2011-00036
June 22, 2011

Request BREC-4
Please provide Mr. Baron's testimony for the following cases:

Case	Jurisdiction	Utility
R-00061346	Pennsylvania	Duquesne Light Company
R-00061366	Pennsylvania	Metropolitan Edison/Pennsylvania Electric
R-00072155	Pennsylvania	Pennsylvania Power & Light
E-01933A-05-0650	Arizona	Tuscon Electric Power Company
E-01345A-08-0172	Arizona	Arizona Public Service Company
R-2010-2161575	Pennsylvania	PECO Energy Company

RESPONSE:

See attached on enclosed CD.

Witness: Stephen J. Baron

PPLICA Statement No. 1

BEFORE

THE PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission	)	
	)	
v.	)	Docket No. R-00072155
	)	
PPL Electric Utilities Corporation	)	

DIRECT TESTIMONY

AND EXHIBITS

OF

STEPHEN J. BARON

ON BEHALF OF

PP&L INDUSTRIAL CUSTOMER ALLIANCE ("PPLICA")

J. KENNEDY AND ASSOCIATES, INC.
ROSWELL, GEORGIA

July 2007

BEFORE

THE PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission	)	
	)	
v.	)	**Docket No. R-00072155**
	)	
PPL Electric Utilities Corporation	)	

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BEFORE

THE PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission	)	
	)	
v.	)	**Docket No. R-00072155**
	)	
PPL Electric Utilities Corporation	)	

DIRECT TESTIMONY OF STEPHEN J. BARON

I. QUALIFICATIONS AND SUMMARY

Q. Please state your name and business address.

A. My name is Stephen J. Baron. My business address is J. Kennedy and Associates, Inc. ("Kennedy and Associates"), 570 Colonial Park Drive, Suite 305, Roswell, Georgia 30075.

Q. What is your occupation and by who are you employed?

A. I am the President and a Principal of Kennedy and Associates, a firm of utility rate, planning, and economic consultants in Atlanta, Georgia.

Q. Please describe briefly the nature of the consulting services provided by Kennedy and Associates.

A. Kennedy and Associates provides consulting services in the electric and gas utility industries. Our clients include state agencies and industrial electricity consumers. The firm provides expertise in system planning, load forecasting, financial analysis, cost-of-service, and rate design. Current clients include the Georgia and Louisiana Public Service Commissions, and industrial consumer groups throughout the United States.

Q. Please state your educational background.

A. I graduated from the University of Florida in 1972 with a B.A. degree with high honors in Political Science and significant coursework in Mathematics and Computer Science. In 1974, I received a Master of Arts Degree in Economics, also from the University of Florida. My areas of specialization were econometrics, statistics, and public utility economics. My thesis concerned the development of an econometric model to forecast electricity sales in the State of Florida, for which I received a grant from the Public Utility Research Center of the University of

Florida. In addition, I have advanced study and coursework in time series analysis and dynamic model building.

Q. Please describe your professional experience.

A. I have more than thirty years of experience in the electric utility industry in the areas of cost and rate analysis, forecasting, planning, and economic analysis.

Following the completion of my graduate work in economics, I joined the staff of the Florida Public Service Commission in August of 1974 as a Rate Economist. My responsibilities included the analysis of rate cases for electric, telephone, and gas utilities, as well as the preparation of cross-examination material and the preparation of staff recommendations.

In December 1975, I joined the Utility Rate Consulting Division of Ebasco Services, Inc. as an Associate Consultant. In the seven years I worked for Ebasco, I received successive promotions, ultimately to the position of Vice President of Energy Management Services of Ebasco Business Consulting Company. My responsibilities included the management of a staff of consultants engaged in providing services in the areas of econometric modeling, load and energy forecasting, production cost modeling, planning, cost-of-service analysis, cogeneration, and load management.

I joined the public accounting firm of Coopers & Lybrand in 1982 as a Manager of the Atlanta Office of the Utility Regulatory and Advisory Services Group. In this capacity I was responsible for the operation and management of the Atlanta office. My duties included the technical and administrative supervision of the staff, budgeting, recruiting, and marketing as well as project management on client engagements. At Coopers & Lybrand, I specialized in utility cost analysis, forecasting, load analysis, economic analysis, and planning.

In January 1984, I joined the consulting firm of Kennedy and Associates as a Vice President and Principal. I became President of the firm in January 1991.

During the course of my career, I have provided consulting services to more than thirty utility, industrial, and Public Service Commission clients, including three international utility clients.

I have presented numerous papers and published an article entitled "How to Rate Load Management Programs" in the March 1979 edition of "Electrical World." My article on "Standby Electric Rates" was published in the November 8, 1984 issue of "Public Utilities Fortnightly." In February of 1984, I completed a detailed analysis entitled "Load Data Transfer Techniques" on behalf of the Electric Power Research Institute, which published the study.

I have presented testimony as an expert witness in Arizona, Arkansas, Colorado, Connecticut, Florida, Georgia, Indiana, Kentucky, Louisiana, Maine, Michigan, Minnesota, Maryland, Missouri, New Jersey, New Mexico, New York, North Carolina, Ohio, Pennsylvania, Texas, Virginia, West Virginia, Federal Energy Regulatory Commission and in United States Bankruptcy Court. A list of my specific regulatory appearances can be found in Baron Exhibit ____ (SJB-1).

Q. Have your previously presented testimony in PPL rate proceedings?

A. Yes. I have participated in six PPL rate proceedings before the Pennsylvania PUC since 1984, including PPL's restructuring proceeding in Docket No. R-973954 and PPL's 2004 distribution base rate proceeding at Docket No. R-00049255, together with the Remand proceeding at the same docket.

Q. On whose behalf are you testifying in this proceeding?

A. I am testifying on behalf of the PP&L Industrial Customer Alliance ("PPLICA"), a group of large industrial customers of PPL Electric Utilities Corporation ("PPL") who take service primarily on PPL Rate Schedules LP-4, LP-5, LP-6, IS-P and IS-T. I will refer to customers on these rate schedules generally as Large Commercial and Industrial or "Large C&I" customers.

Q. Would you please briefly describe the members of PPLICA who are participating in this rate proceeding?

A. There are nineteen PPLICA members who are participating in this rate proceeding and on whose behalf I am presenting testimony. These companies consume in excess of 2.2 billion kWhs annually on the PPL system. PPLICA member companies are major employers in the Commonwealth of Pennsylvania and contribute in a substantial manner to the overall economy of the state. This contribution includes not only direct benefits in the form of jobs to Pennsylvanians, but also includes the payment of corporate state income taxes, charitable and community development contributions and other activities which contribute to the overall well being of the citizens of the Commonwealth.

Q. What is the purpose of your testimony?

A. I am responding to the Company's proposals on the appropriate class cost of service methodology, the allocation of the requested revenue increase to rate schedules (revenue apportionment) and some proposed changes to tariff rules that will impact PPLICA members.

Specifically, I will respond to the testimony of PPL witness Joseph Kleha on class cost of service methodology. Mr. Kleha presents the results of the Company's class cost of service study using a minimum system approach to classify a portion of distribution costs as customer related. As in the 2004 PPL distribution rate case, I support the Company's methodology. I will also respond to the testimony of PPL witness Douglas Krall on the issue of the allocation of the approved revenue increase to rate schedule. Though PPL has proposed an approach to move class rates of return toward equality over two rate cases (this case and a subsequent case), the results of the Company's revenue apportionment proposed in its direct testimony continue to leave substantial dollar subsidies embedded in PPL's distribution rates. As I will discuss, PPLICA continues to support a 50% dollar subsidy reduction methodology, which will fully eliminate subsidies over two rate cases, but do so in a manner that reduces the dollar amount of the subsidy paid by PPL's commercial and industrial customers.

Finally, I will respond to PPL witness Oliver Kasper regarding proposed changes to tariff Rule 4A, which defines the character of service provided by PPL. The Company is proposing to dramatically eliminate its obligations to provide interconnections (service lines) to customers taking service at voltages of 69 kV or greater on Rate Schedules LP-5, IS-T, LP-6, ISA and LPEP.

Q. Would you summarize your recommendations in this proceeding?

A. Yes.

- **PPL is proposing to apportion the revenue increase approved in this case so that rate schedule rates of return move "half-way" towards full cost of service. PPLICA strongly agrees that moving PPL's distribution rates to full cost of service in this case and the next rate case is appropriate and is also consistent with the Commonwealth Court's decision in <u>Lloyd.</u>**

  However, a more appropriate methodology to achieve cost of service based rates in this case is to apportion the revenue increase in such a manner that "dollar subsidies" paid and received by each rate schedule are reduced by 50% from the levels in present distribution rates. In the next rate case, all subsidies would be eliminated, as rates are set at cost of service (equal rate of return). The Commission authorized revenue increase should be allocated based on PPLICA's proposed "50% dollar subsidy" methodology. By reducing dollar subsidies paid or received by each rate schedule by 50%, the PPLICA methodology specifically reflects gradualism.

- **PPL is proposing to change tariff Rule 4A by limiting its applicability to distribution customers taking service at voltages below 69 kV, which effectively excludes all customers on Rate Schedules LP-5, IS-T, LP-6, ISA and LPEP, or new or existing customers that require**

transmission voltage service, from this tariff rule. This change has potentially significant economic and service consequences to some customers and, contrary to statements by PPL, is not a clarification to the tariff. Rather it is a major reduction in the obligation of PPL to provide standard service to these customers by removing the Company's obligation to install service lines interconnecting the customer to the Company's transmission system. The proposal is not justified and should be rejected by the Commission.

II. CLASS COST OF SERVICE STUDY AND THE APPORTIONMENT OF THE REVENUE INCREASE TO RATE SCHEDULES

Q. Have you reviewed the Company's cost of service study in this case?

A. Yes. In general, I do not have objections to the Company's original filed cost of service study (Kleha Exhibit JMK-2) and believe that it is a reasonable basis upon which to make a determination of the appropriate allocation of any Commission authorized increase in distribution revenue requirements. The Company's study follows generally accepted methodologies to classify and allocate distribution costs to rate schedules and is consistent with methods discussed in the NARUC Electric Utility Cost Allocation manual. However, I do not necessarily agree with the supplemental cost of service study presented by Mr. Kleha (Exhibit JKK-2A) that reflects the results of the settlement of the remand of Docket No. R-00049255. My preliminary review of this cost of service study indicates that the estimated remand settlement revenue changes are not consistent with my understanding of the rate changes. I anticipate that these issues will be clarified upon further discovery, which has not yet been completed due to the abbreviated time between the Company's supplemental testimony and the submission of my testimony. As I will discuss below, I have developed an independent analysis of the impact of the remand settlement on the class cost of service study in this case and rely on this analysis to develop my recommendations. In addition, the revised, (JMK-2A) Company's cost of service study at proposed revenues assumes the same "dollar" revenue increases that were proposed by PPL in its original filing. This implies a different set of proposed rates for each rate schedule then originally filed in this case (though the Company does not present these rates or any analysis supporting such revised proposed rates). PPL witness Kleha states in his supplemental testimony (Statement 6A) that the Company is not proposing a revision to proposed rates "at this time." As a result, the results of Exhibit JMK-2A under proposed rates are inconsistent with the proposed tariff rates submitted on March 29, 2007, in this case. In the analyses that I prepared and discuss subsequently, I have assumed that the original proposed PPL distribution rates remain applicable. If the Company subsequently revises these rates, I reserve the opportunity to respond to the revised proposal.

Q. Do you agree with the Company's use of a minimum size system methodology to classify distribution costs between customer and demand related costs?

A. Yes. As discussed by PPL witness Kleha, the Company has conducted an analysis of the transformers, lines and other equipment that is installed on the system to interconnect a customer to the Company's system. To the extent that PPL installs certain minimum size components (for example, overhead or underground transformers) regardless of the size of the customer, these costs are reasonably classified as customer related and should be allocated to rate schedules based on the relative number of customers on each schedule. This approach reasonably recognizes the "cost causation" underlying distribution plant investment and should be used to allocate costs.

Q. **What are the results of the Company's test year cost of service study (Exhibit JMK-2), with regard to class rates of return on distribution investment and the subsidies existing between rate classes?**

A. Baron Exhibit ____(SJB-2) shows a summary of the Company's cost of service results for the test year under present rates and at the proposed rates recommended by PPL for distribution cost recovery in this case. It should be noted that I adjusted the cost of service results under "present" rates to reflect the impact of the agreed upon rate schedule revenue adjustments in the settlement of Docket No. R-00049255, "Remand." The proposed revenues for each rate schedule reflect the Company's original filing in this case and have not been adjusted since the settlement. Although the Company provided supplemental testimony reflecting its proposed implementation of the remand settlement on the cost of service results (which, as I stated previously, I do not agree with), PPL did not modify its allocation of the distribution rate increase reflected in this case in that supplemental testimony.

The exhibit shows both the rate of return on distribution investment at present and proposed rates for each rate schedule as well as the dollar subsidy incorporated into present and proposed rates.

A negative value for the "present subsidy" means that this rate schedule is receiving a subsidy. A positive value indicates that the rate schedule is paying a subsidy. Table 1 summarizes the rates of return and the dollar subsidies for each rate schedule at present rates. Even with the original Commission approved revenue increases in Docket No. R-00049255 and the additional increases allocated to the residential class in the settlement of the remand proceeding, residential RS customers continue to receive an annual subsidy of $50 million from other rate schedules. The 4.07% rate of return paid by residential RS customers is substantially less than the average system rate of return paid by PPL's distribution customers.

Table 1
Rates of Return and Dollar Subsidies at Present Rates*

Rate Class	Rate of Return	Present Subsidies
RS, RTD	4.07%	(49,972)
RTS	-3.90%	(7,140)
GS-1, BL	12.35%	20,525
GS-3, IS-1	12.06%	32,542
LP-4 *	12.83%	9,320
ISP *	18.61%	880
LP-5 *	10.61%	253
IST *	31.68%	385
LP-6	3.44%	(15)
LPEP	13.95%	118
ISA *	157.89%	530
GH	7.58%	576
SL/AL	0.56%	(7,993)
L5-S	1.11%	(9)
Total	6.13%	0

* Adjusted to reflect settlement in Doc. No. R-00049255

Q. Based on the information depicted on Table 1, do any rate schedules warrant special consideration to correct disparately high or low rates of return at present rates?

A. Yes. Rate Schedules IS-T and ISA obviously show much higher returns and should be provided with special consideration to address this unduly discriminatory situation. Rate Schedule RTS shows a negative return, which could be addressed through individualized analysis.

Q. How is the Company proposing to address this problem of continuing large subsidies in the majority of its distribution rates?

A. As discussed in the testimony of PPL witness Krall and Kasper, PPL has recognized that the Commonwealth Court Lloyd decision requires that the PPL's distribution rates reasonably reflect cost of service. The Court specifically found that cost of service is the "Polestar" for electric utility rate design and the apportionment of the approved revenue increase to rate schedules. The Company also recognizes that "gradualism" can be considered in this process.

Q. How does the Company propose to move distribution rates to cost of service?

A. PPL is proposing that the revenue increase approved in this case be apportioned to rate schedules so that each rate schedule's rate of return moves half-way (50%) towards the system average rate of return (at proposed rates). PPL then states that in its next distribution rate case, it would propose to move each rate schedule's rate of return fully to the system average rate of return. As previously discussed, the Company has not applied this methodology to calculate proposed rates based on the revised "present" rates that result from the remand settlement. As a result, it is not clear what result the application of the Company's methodology will have in this case.

Q. Do you support the Company's proposal on this issue?

A. I agree with the Company's objectives of moving each rate schedule to full cost of service, while recognizing the principle of gradualism; however, I believe that a more appropriate method is to apportion the revenue increase among rate schedules in such a manner that 50% of the dollar subsidies are reduced in this case, with the remaining subsidies eliminated in the next distribution rate case.

As I discussed in previous PPL rate proceedings, the reduction in dollar subsidies paid or received by each rate schedule accomplishes the same ultimate objective as supported by the Company, but has the important advantage that the impact of the "adjustment" is directly reflected in the rates paid by customers. In many cases, apportioning a revenue increase to move rate schedule relative rates of return toward "1.0", which is the Company's recommended approach, can actually lead to increases in the dollar subsidies paid and received. In the original Commission approved distribution rates in Docket No. R-00049255, the subsidies received by the residential class actually increased by about $20 million, even though the rate of return for the residential class moved closer to the system average rate of return. Apportioning the distribution revenue increase in a manner to specifically reduce dollar subsidies provides a direct impact on the "dollars" of rates paid by each rate schedule.[1]

Q. Does the PPLICA recommended "50% subsidy reduction" method to apportion the approved revenue increase reflect a consideration of the principle of "gradualism?"

A. Yes. By reducing dollar subsidies paid or received by each rate schedule by 50%, the PPLICA methodology specifically reflects gradualism. Under the PPLICA method, there continue to be dollar subsidies remaining in the Company's distribution rates. However, these subsidies should be fully eliminated in the next PPL distribution rate case.

Q. Does the Company's proposed revenue apportionment in this case adequately reduce the dollar subsidies paid and received by each rate schedule, at proposed rates?

---

[1] When rates are set at full cost of service, there are no dollar subsidies and the relative rates of return for each rate schedule are all equal to 1.0. Thus, following the next distribution rate case, rates should be the same under both PPL's method and the "50% subsidy reduction" method that I am recommending.

A. No. Table 2 shows the dollar subsidies at proposed rates that reflect the Company's recommendation in this case.[2] Table 2 also shows the percentage rate increases proposed for each rate schedule by the Company. Baron Exhibit__(SJB-3) shows the development of these rate schedule increases. Though PPL's proposal reduces dollar subsidies received by the residential class by 25% (in contrast to its recommendation in Docket No. R-00049255, in which the Company proposed an increase in the residential class subsidy), I continue to believe that a full 50% subsidy reduction in this case, with the remaining 50% reduction in the next case, is a more reasoned approach to the design of distribution rates.

[2] As noted previously, the present rates reflect the revenue impacts in the Remand case settlement in Docket No. R-00049255.

Table 2
PPL Proposed Revenue Increases and Subsidies*
($000)

Rate Class	PPL Proposed Subsidies	Revenue Increase*	Percent Increase
RS, RTD	(37,369)	67,038	17.4%
RTS	(8,071)	678	17.2%
GS-1, BL	16,355	3,301	4.5%
GS-3, IS-1	26,779	6,498	5.9%
LP-4 *	7,198	1,050	3.6%
ISP *	647	(85)	-4.8%
LP-5 *	561	437	41.7%
IST *	372	16	2.9%
LP-6	45	69	110.0%
LPEP	82	(1)	-0.2%
ISA *	528	(0)	0.0%
GH	878	1,200	18.6%
SL/AL	(8,004)	3,295	18.8%
L5-S	0	13	35.5%
Total w/o PRS	(0)	83,510	13.3%

* Adjusted to reflect settlement in Docket No. R-00049255 Remand

Q. Have you developed an analysis that apportions the revenue increase using a 50% subsidy reduction method?

A. Yes. Baron Exhibit__(SJB-4), schedules 1 and 2 develop the analysis. Schedule 1 of the exhibit shows the revenue apportionment of the Company's requested $83.5 million rate schedule increase that reduces the current subsidies paid and received by 50%. The last column of the exhibit shows the rate of return for each rate schedule, following the increase.

As can be seen from this schedule, even after the reduction of 50% of the dollar subsidies, the rates of return for Rate Schedules IS-T and ISA are substantial. In addition, the revenue increase necessary to reduce the subsidies received by Rate Schedule RTS by 50% would result in a 131% rate increase, which is obviously not consistent with gradualism. As a result, I have made two adjustments to the increases shown in schedule 1. First, I have combined the increases for rate schedules RS, RTD and RTS to produce an equal percentage increase for these rates. Since rate RTS is very small, this has a minimal impact on the residential class results. The second adjustment that I made is to further reduce the distribution rates for Rate Schedules IS-T and ISA such that the final rate of return for these two schedules is equal to the LP-5 rate of return. Again, because of the small amount of distribution revenues paid by these two schedules, the impact of this adjustment on other rate schedules is minimal. Table 3 below shows the PPLICA recommended increases in this case, under the assumption that PPL receives its entire increase request.

Table 3
PPLICA Recommended Revenue Increases
"50% Subsidy Reduction Methodology"
($1000)

Rate Class	PPLICA Proposed Subsidies	Revenue Increase*	Percent Increase
RS, RTD	(20,521)	84,012	21.8%
RTS	(7,878)	861	21.8%
GS-1, BL	10,362	(2,755)	-3.8%
GS-3, IS-1	16,270	(3,950)	-3.6%
LP-4 *	4,724	(1,473)	-5.1%
ISP *	430	(292)	-16.5%
LP-5 *	129	3	0.3%
IST *	34	(317)	-55.8%
LP-6	(10)	17	26.8%
LPEP	61	(23)	-6.9%
ISA *	8	(514)	-97.6%
GH	297	615	9.5%
SL/AL	(3,903)	7,317	41.8%
L5-S	(4)	8	22.8%
Total	0	83,510	13.3%

* Adjusted to reflect settlement in Docket No. R-00049255 Remand

Q. **If, as is likely from past cases, PPL receives less than its requested increase, how should the increases and decreases in Table 3 be adjusted?**

A. First, the reduction should be used to provide targeted relief to those rate schedules that continue to show a disproportionately high return even with the 50% subsidy reduction. Specifically, Rate Schedules IS-T and ISA should be brought to a rate of return commensurate with Rate Schedules LP-5; this targeted relief is included in my proposal and should be included in any alternate allocation adopted by the Commission in this matter.

Second, after the rate schedules with disproportionately high returns are addressed, the most appropriate method to scale back the PPLICA adjusted recommended increases would be to allocate the reduction from the Company's requested $83.5 million increase on the basis of each rate schedule's distribution rate base. Thus for example, if the Commission authorizes a $73.5 million revenue increase, the $10 million "reduction" from the Company's requested increase should be allocated on the basis of each rate schedule's distribution rate base. In this case, the residential class (rates RS, RTD and RTS), which has a distribution rate base of $1,321.699 million (out of a total retail distribution rate base of $2,022.966 million) would receive about 65% of the reduction, or a $6.5 million reduction from the PPLICA revenue increases shown in Table 3. Allocating the "reduction from the PPL requested revenue increase" on rate base preserves the rate of return relationships produced by the "50% subsidy reduction" apportionment methodology.

Q. Do you have any further comments on the allocation of the distribution rate increase?

A. Yes. As previously discussed, the Company has not yet applied its preferred methodology to reduce interclass subsidization to the new rates established in the remand settlement. If the Company continues to advocate for this approach in its rebuttal testimony, I reserve the opportunity to comment further on this topic.

III. TARIFF RULE CHANGES

Q. PPL witness Kasper discusses the Company's proposal to limit the applicability of tariff Rule 4A to distribution customers taking service below 69 kV. Do you have any comments on this proposal?

A. Yes. Tariff Rule 4 of PPL's tariff governs the "Supply of Service" and sets forth the basic obligations of PPL and each customer with regard to the interconnection of the customer to the Company's system. Rule 4A, which PPL proposes to change, addresses the "Characteristics of Service" and obligates the Company to supply service to the customer from the nearest available line at a voltage "not less than" the voltage specified in the rate schedule. Currently, the rule obligates PPL to provide service facilities up to 500 feet to all customers taking service on any of its rate schedules.

Q. What changes is the Company proposing to make to Rule 4A?

A. PPL is proposing to limit the applicability of this rule, which is the basic statement of the Company's interconnection obligation to its retail distribution customers, to only those customers taking service at voltages "less than the nominal 69,000 volts and excluding service extensions and lines energized at voltages of nominal 69,000 volts or higher." This change explicitly excludes all of PPL's distribution customers on Rate Schedules LP-5, IST, LP-6, ISA and LPEP. There is no basis for this proposed change in the tariff.

Distribution customers on these high voltage rates have historically always been considered distribution customers of the Company. A substantial portion of the PPLICA members take service on these rates, and they pay distribution charges. Customers on Rate Schedule LP-5 are currently paying $0.261 per kW for a "Distribution Charge." The Company's proposed rule change is discriminatory on its surface and should be rejected.

Q. Does PPL have an obligation to provide reliable electric service to its customers on Rate Schedules LP-5, IST, LP-6, ISA and LPEP?

A. Yes. The fact that these customers take service at high voltage and do not use secondary and primary distribution facilities does not change the obligation of PPL to provide service to these customers under the regulations of the Commission. PPL still has an obligation to "connect and deliver" electricity for these customers, even after the generation rate cap expires, under Section

2807(e)(2) of the Public Utility Code. Pursuant to Section 2804(10), the Commission continues "to regulate distribution services for new and existing customers in accordance with [Chapter 28] and Chapter 13 (relating to rates and ratemaking)." With the proposed rule change eliminating the obligation of the Company to provide service to these customers, the protection afforded by the tariff and the concomitant regulatory oversight (with regard to the provision of service, as opposed to rates and charges for electricity) would effectively be denied to large customers on these rates. PPL would be given the opportunity to set the service extension charges and conditions, unilaterally, for the provision of service to new customers or expanding existing customers taking service on these rates. Alternatively, PPL's customers purchasing PUC-jurisdictional "distribution" service may be required to resort to the Federal Energy Regulatory Commission ("FERC") to address disputes regarding service extensions, and, perhaps even service reliability complaints.

Q. Based on your experience, why would a new or existing customer request service at 69 kV?

A. Large industrial customers typically conduct analyses to determine if it is economically and/or technically beneficial for the customer to own or lease its own transformer facilities to step-down transmission voltages to the service voltage for their particular manufacturing process. A manufacturing facility may consist of a variety of machinery and equipment that use different service voltages. In these situations, the customer may actively manage its voltage through various transformers, breakers, switches, capacitors and other equipment. Taking service at 69 kV may result in better service reliability in some situations, such as when the customer's equipment is very sensitive to voltage fluctuations.

There also may be cost advantages. Customers that take service at transmission voltages are metered on the "high" side of the distribution transformer. In this case, the customer is billed for the transformation voltage losses (since this occurs on the customer's side of the meter). In exchange for the customer absorbing the transformation losses and the ownership costs of the distribution transformers, the customer is charged a lower cost for distribution service and a lower cost for energy and demand (due to the customer absorbing the losses, not the electric distribution company). Customers taking service at transmission voltage do not impose any distribution costs on the electric distribution company (except for metering). These "avoided" distribution costs include the cost for primary and secondary lines, primary and secondary poles, distribution substations (including transformers and structures) and secondary transformers.

New or existing large customers conduct the economic and, in some cases, technical, evaluation that considers the tradeoff between the ownership costs of distribution facilities (plus the customer absorbed losses due to "high" side metering), any technical advantages and the lower cost of service and corresponding distribution rate that is offered to transmission customers. For large, high load factor customers, there typically is a benefit to taking service at transmission voltage. Almost every utility in the U.S. offers customers the option of taking service at transmission voltage. PPL's Rule 4 modifications may effectively eliminate this option and deprive PPL's customers of these choices that are available to similarly situated customers in Pennsylvania and elsewhere.

Q. Has the Company provided any evidence that their proposed change to Rule 4A is justified?

A. No. PPL has simply requested Commission approval to make the change without any legitimate justification.

Q. On page 17, at line 20 of his testimony, Mr. Kasper states that the proposed rule change to eliminate its applicability to customers on Rate Schedules LP-

5, IST, LP-6, ISA and LPEP is a "clarification." Do you agree that this change represents a "clarification?"

A. No. The existing Rule 4A clearly applies to customers taking service on any of the Company's rate schedules. In fact, the current language of Rule 4A specifically includes the language "Where the rate schedule specifies service at 12,000 volts or higher..." This clearly includes customers on primary voltage rates at 12,470 <u>and</u> customers on Rate Schedules LP-5, IST, LP-6, ISA and LPEP taking service at 69,000 volts or higher. This change has potentially significant economic and service consequences to some customers; it is not a clarification to the tariff.

Q. Does the fact that PPL's current 69 kV facilities are included in its FERC rate base conclusively establish that the PUC does not have jurisdiction over service extensions requested by current or future distribution customers involving 69 kV facilities?

A. No. The Electricity Generation Customer Choice and Competition Act ("Competition Act") requires the Commission to continue to regulate distribution services for new and existing customers in accordance with Chapter 13 of the

Public Utility Code. Prior to enactment of the Competition Act, this obviously included the installation of 69 kV services for distribution customers when appropriate, as evidenced by the Company's long history of doing so and the existence of 144 current customers taking service on 69 kV service extensions. Nothing in the Competition Act appears to diminish the electric distribution companies' obligation to continue providing distribution service at comparable levels in the restructured regulatory environment. Moreover, if the current 69 kV services are not jurisdictional distribution service, then presumably any current customer served at 69 kV is converted to wholesale customer status and would not pay any more distribution charges, and possibly other charges such as the Competitive Transition Charge and Intangible Transition Charge.

Q. Does PPL propose any other changes to Rule 4?

A. Yes. The Company proposes to remove certain language from Rule 4C to "clarify" how PPL treats service extensions to customer facilities.

Q. Describe these "clarifying" changes to Rule 4C.

A. Currently, Rule 4C provides, in relevant part: "The Company furnishes and installs all electric service line facilities extending from its distribution supply lines at or near the customer's property line to the customer's point of delivery using normal construction for load conditions according to the Company's standards" subject to certain exceptions. One of these exceptions currently states, in part, that the "customer provides all mechanical facilities on his property, other than poles and guys, which are required to accommodate the installation of the Company's electric facility." PPL seeks to eliminate the phrases "at or near the customer's property line" and "on his property."

Q. Do PPL's proposed changes raise any concerns for customers seeking service extensions?

A. Yes. The proposed changes appear to eliminate the Company's current obligation to use the distribution supply lines closest to a customer's property line when installing a service extension. The absence of such an obligation may increase the cost of installing a service line extension. Moreover, as modified, Rule 4C shifts to the customer the cost of all mechanical facilities necessary to accommodate the installation of the service extension, regardless of whether the mechanical facilities are on the customer's property.

Q. What are the implications of the Company's proposed changes to Tariff Rule 4C?

A. The Company's proposed changes will increase the costs of installing a service extension for customers and will provide the Company with guaranteed recovery of upgrade costs on an expedited basis, thus avoiding the need to include such costs in rate base. These proposals are not reasonable and should be rejected.

Q. Do you have any additional comments regarding the Company's proposed changes to Tariff Rule 4A?

A. Yes. In paragraph (7) the Company has added language that refers to an "Institutional Complex," but does not offer any definition of such a customer. In response to PPLICA Set II, Question No. 4, the Company provides the following definition: "A premise with more than two electric services to separate buildings under the control of a single customer, and with limited access, is considered to be an institutional complex." Situations can exist where a large customer with a single building desires two points of delivery. It is unclear whether this change would eliminate this option, or whether alternate service can continue to be requested by non-institutional complexes under Rule 4D. At a minimum, the proposed change to Rule 4 should incorporate a definition of the term "institutional complex" so that there is no confusion as to the applicability of Rule 4A(7). In addition, to the extent that this change in any way reduces PPL's obligation to provide distribution service (and thus results in a shifting of costs from the Company to an individual customer), this change may be inconsistent with the provisions of the Competition Act.

Q. Does that complete your Direct Testimony?

A. Yes.

BEFORE

THE PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission	)	
	)	
v.	)	**Docket No. R-00072155**
	)	
PPL Electric Utilities Corporation	)	

EXHIBITS

OF

STEPHEN J. BARON

ON BEHALF OF

PP&L INDUSTRIAL CUSTOMER ALLIANCE ("PPLICA")

J. KENNEDY AND ASSOCIATES, INC.
ROSWELL, GEORGIA

BEFORE

THE PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission	)	
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EXHIBIT__(SJB-1)

OF

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Expert Testimony Appearances
of
Stephen J. Baron
As of June 2007

Date	Case	Jurisdict.	Party	Utility	Subject
4/81	203(B)	KY	Louisville Gas & Electric Co.	Louisville Gas & Electric Co.	Cost-of-service.
4/81	ER-81-42	MO	Kansas City Power & Light Co.	Kansas City Power & Light Co.	Forecasting.
6/81	U-1933	AZ	Arizona Corporation Commission	Tucson Electric Co.	Forecasting planning.
2/84	8924	KY	Airco Carbide	Louisville Gas & Electric Co.	Revenue requirements, cost-of-service, forecasting, weather normalization.
3/84	84-038-U	AR	Arkansas Electric Energy Consumers	Arkansas Power & Light Co.	Excess capacity, cost-of-service, rate design.
5/84	830470-EI	FL	Florida Industrial Power Users' Group	Florida Power Corp.	Allocation of fixed costs, load and capacity balance, and reserve margin. Diversification of utility.
10/84	84-199-U	AR	Arkansas Electric Energy Consumers	Arkansas Power and Light Co.	Cost allocation and rate design.
11/84	R-842651	PA	Lehigh Valley Power Committee	Pennsylvania Power & Light Co.	Interruptible rates, excess capacity, and phase-in.
1/85	85-65	ME	Airco Industrial Gases	Central Maine Power Co.	Interruptible rate design.
2/85	I-840381	PA	Philadelphia Area Industrial Energy Users' Group	Philadelphia Electric Co.	Load and energy forecast.
3/85	9243	KY	Alcan Aluminum Corp., et al.	Louisville Gas & Electric Co.	Economics of completing fossil generating unit.
3/85	3498-U	GA	Attorney General	Georgia Power Co.	Load and energy forecasting, generation planning economics.
3/85	R-842632	PA	West Penn Power Industrial Intervenors	West Penn Power Co.	Generation planning economics, prudence of a pumped storage hydro unit.
5/85	84-249	AR	Arkansas Electric Energy Consumers	Arkansas Power & Light Co.	Cost-of-service, rate design return multipliers.
5/85		City of Santa	Chamber of Commerce	Santa Clara Municipal	Cost-of-service, rate design.

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Date	Case	Jurisdict.	Party	Utility	Subject
6/85	84-768-E-42T	Clara WV	West Virginia Industrial Intervenors	Monongahela Power Co.	Generation planning economics, prudence of a pumped storage hydro unit.
6/85	E-7 Sub 391	NC	Carolina Industrials (CIGFUR III)	Duke Power Co.	Cost-of-service, rate design, interruptible rate design.
7/85	29046	NY	Industrial Energy Users Association	Orange and Rockland Utilities	Cost-of-service, rate design.
10/85	85-043-U	AR	Arkansas Gas Consumers	Arkla, Inc.	Regulatory policy, gas cost-of-service, rate design.
10/85	85-63	ME	Airco Industrial Gases	Central Maine Power Co.	Feasibility of interruptible rates, avoided cost.
2/85	ER-8507698	NJ	Air Products and Chemicals	Jersey Central Power & Light Co.	Rate design.
3/85	R-850220	PA	West Penn Power Industrial Intervenors	West Penn Power Co.	Optimal reserve, prudence, off-system sales guarantee plan.
2/86	R-850220	PA	West Penn Power Industrial Intervenors	West Penn Power Co.	Optimal reserve margins, prudence, off-system sales guarantee plan.
3/86	85-299U	AR	Arkansas Electric Energy Consumers	Arkansas Power & Light Co.	Cost-of-service, rate design, revenue distribution.
3/86	85-726-EL-AIR	OH	Industrial Electric Consumers Group	Ohio Power Co.	Cost-of-service, rate design, interruptible rates.
5/86	86-081-E-GI	WV	West Virginia Energy Users Group	Monongahela Power Co.	Generation planning economics, prudence of a pumped storage hydro unit.
8/86	E-7 Sub 408	NC	Carolina Industrial Energy Consumers	Duke Power Co.	Cost-of-service, rate design, interruptible rates.
10/86	U-17378	LA	Louisiana Public Service Commission Staff	Gulf States Utilities	Excess capacity, economic analysis of purchased power.
12/86	38063	IN	Industrial Energy Consumers	Indiana & Michigan Power Co.	Interruptible rates.

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Date	Case	Jurisdict.	Party	Utility	Subject
3/87	EL-86-53-001 EL-86-57-001	Federal Energy Regulatory Commission (FERC)	Louisiana Public Service Commission Staff	Gulf States Utilities, Southern Co.	Cost/benefit analysis of unit power sales contract.
4/87	U-17282	LA	Louisiana Public Service Commission Staff	Gulf States Utilities	Load forecasting and imprudence damages, River Bend Nuclear unit.
5/87	87-023-E-C	WV	Airco Industrial Gases	Monongahela Power Co.	Interruptible rates.
5/87	87-072-E-G1	WV	West Virginia Energy Users' Group	Monongahela Power Co.	Analyze Mon Power's fuel filing and examine the reasonableness of MP's claims.
5/87	86-524-E-SC	WV	West Virginia Energy Users' Group	Monongahela Power Co.	Economic dispatching of pumped storage hydro unit.
5/87	9781	KY	Kentucky Industrial Energy Consumers	Louisville Gas & Electric Co.	Analysis of impact of 1986 Tax Reform Act.
6/87	3673-U	GA	Georgia Public Service Commission	Georgia Power Co.	Economic prudence, evaluation of Vogtle nuclear unit - load forecasting, planning.
6/87	U-17282	LA	Louisiana Public Service Commission Staff	Gulf States Utilities	Phase-in plan for River Bend Nuclear unit.
7/87	85-10-22	CT	Connecticut Industrial Energy Consumers	Connecticut Light & Power Co.	Methodology for refunding rate moderation fund.
8/87	3673-U	GA	Georgia Public Service Commission	Georgia Power Co.	Test year sales and revenue forecast.
9/87	R-850220	PA	West Penn Power Industrial Intervenors	West Penn Power Co.	Excess capacity, reliability of generating system.
10/87	R-870651	PA	Duquesne Industrial Intervenors	Duquesne Light Co.	Interruptible rate, cost-of-service, revenue allocation, rate design.
10/87	I-860025	PA	Pennsylvania Industrial Intervenors		Proposed rules for cogeneration, avoided cost, rate recovery.

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Date	Case	Jurisdict.	Party	Utility	Subject
10/87	E-015/ GR-87-223	MN	Taconite Intervenors	Minnesota Power & Light Co.	Excess capacity, power and cost-of-service, rate design.
10/87	8702-EI	FL	Occidental Chemical Corp.	Florida Power Corp.	Revenue forecasting, weather normalization.
12/87	87-07-01	CT	Connecticut Industrial Energy Consumers	Connecticut Light Power Co.	Excess capacity, nuclear plant phase-in.
3/88	10064	KY	Kentucky Industrial Energy Consumers	Louisville Gas & Electric Co.	Revenue forecast, weather normalization rate treatment of cancelled plant.
3/88	87-183-TF	AR	Arkansas Electric Consumers	Arkansas Power & Light Co.	Standby/backup electric rates.
5/88	870171C001	PA	GPU Industrial Intervenors	Metropolitan Edison Co.	Cogeneration deferral mechanism, modification of energy cost recovery (ECR).
6/88	870172C005	PA	GPU Industrial Intervenors	Pennsylvania Electric Co.	Cogeneration deferral mechanism, modification of energy cost recovery (ECR).
7/88	88-171-EL-AIR 88-170-EL-AIR Interim Rate Case	OH	Industrial Energy Consumers	Cleveland Electric/ Toledo Edison	Financial analysis/need for interim rate relief.
7/88	Appeal of PSC	19th Judicial Docket U-17282	Louisiana Public Service Commission Circuit Court of Louisiana	Gulf States Utilities	Load forecasting, imprudence damages.
11/88	R-880989	PA	United States Steel	Carnegie Gas	Gas cost-of-service, rate design.
11/88	88-171-EL-AIR 88-170-EL-AIR	OH	Industrial Energy Consumers	Cleveland Electric/ Toledo Edison. General Rate Case.	Weather normalization of peak loads, excess capacity, regulatory policy.
3/89	870216/283 284/286	PA	Armco Advanced Materials Corp., Allegheny Ludlum Corp.	West Penn Power Co.	Calculated avoided capacity, recovery of capacity payments.

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Date	Case	Jurisdict.	Party	Utility	Subject
8/89	8555	TX	Occidental Chemical Corp.	Houston Lighting & Power Co.	Cost-of-service, rate design.
8/89	3840-U	GA	Georgia Public Service Commission	Georgia Power Co.	Revenue forecasting, weather normalization.
9/89	2087	NM	Attorney General of New Mexico	Public Service Co. of New Mexico	Prudence - Palo Verde Nuclear Units 1, 2 and 3, load fore-casting.
10/89	2262	NM	New Mexico Industrial Energy Consumers	Public Service Co. of New Mexico	Fuel adjustment clause, off-system sales, cost-of-service, rate design, marginal cost.
11/89	38728	IN	Industrial Consumers for Fair Utility Rates	Indiana Michigan Power Co.	Excess capacity, capacity equalization, jurisdictional cost allocation, rate design, interruptible rates.
1/90	U-17282	LA	Louisiana Public Service Commission Staff	Gulf States Utilities	Jurisdictional cost allocation, O&M expense analysis.
5/90	890366	PA	GPU Industrial Intervenors	Metropolitan Edison Co.	Non-utility generator cost recovery.
6/90	R-901609	PA	Armco Advanced Materials Corp., Allegheny Ludlum Corp.	West Penn Power Co.	Allocation of QF demand charges in the fuel cost, cost-of-service, rate design.
9/90	8278	MD	Maryland Industrial Group	Baltimore Gas & Electric Co.	Cost-of-service, rate design, revenue allocation.
12/90	U-9346 Rebuttal	MI	Association of Businesses Advocating Tariff Equity	Consumers Power Co.	Demand-side management, environmental externalities.
12/90	U-17282 Phase IV	LA	Louisiana Public Service Commission Staff	Gulf States Utilities	Revenue requirements, jurisdictional allocation.
12/90	90-205	ME	Airco Industrial Gases	Central Maine Power Co.	Investigation into interruptible service and rates.
1/91	90-12-03 Interim	CT	Connecticut Industrial Energy Consumers	Connecticut Light & Power Co.	Interim rate relief, financial analysis, class revenue allocation.

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Date	Case	Jurisdict.	Party	Utility	Subject
5/91	90-12-03 Phase II	CT	Connecticut Industrial Energy Consumers	Connecticut Light & Power Co.	Revenue requirements, cost-of-service, rate design, demand-side management.
8/91	E-7, SUB SUB 487	NC	North Carolina Industrial Energy Consumers	Duke Power Co.	Revenue requirements, cost allocation, rate design, demand-side management.
8/91	8341 Phase I	MD	Westvaco Corp.	Potomac Edison Co.	Cost allocation, rate design, 1990 Clean Air Act Amendments.
8/91	91-372 EL-UNC	OH	Armco Steel Co., L.P.	Cincinnati Gas & Electric Co.	Economic analysis of cogeneration, avoid cost rate.
9/91	P-910511 P-910512	PA	Allegheny Ludlum Corp., Armco Advanced Materials Co., The West Penn Power Industrial Users' Group	West Penn Power Co.	Economic analysis of proposed CWIP Rider for 1990 Clean Air Act Amendments expenditures.
9/91	91-231 -E-NC	WV	West Virginia Energy Users' Group	Monongahela Power Co.	Economic analysis of proposed CWIP Rider for 1990 Clean Air Act Amendments expenditures.
10/91	8341 - Phase II	MD	Westvaco Corp.	Potomac Edison Co.	Economic analysis of proposed CWIP Rider for 1990 Clean Air Act Amendments expenditures.
10/91	U-17282	LA	Louisiana Public Service Commission Staff	Gulf States Utilities	Results of comprehensive management audit.
Note: No testimony was prefiled on this.					
11/91	U-17949 Subdocket A	LA	Louisiana Public Service Commission Staff	South Central Bell Telephone Co. and proposed merger with Southern Bell Telephone Co.	Analysis of South Central Bell's restructuring and
12/91	91-410-EL-AIR	OH	Armco Steel Co., Air Products & Chemicals, Inc.	Cincinnati Gas & Electric Co.	Rate design, interruptible rates.
12/91	P-880286	PA	Armco Advanced Materials Corp., Allegheny Ludlum Corp.	West Penn Power Co.	Evaluation of appropriate avoided capacity costs - QF projects.

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Date	Case	Jurisdict.	Party	Utility	Subject
1/92	C-913424	PA	Duquesne Interruptible Complainants	Duquesne Light Co.	Industrial interruptible rate.
6/92	92-02-19	CT	Connecticut Industrial Energy Consumers	Yankee Gas Co.	Rate design.
8/92	2437	NM	New Mexico Industrial Intervenors	Public Service Co. of New Mexico	Cost-of-service.
8/92	R-00922314	PA	GPU Industrial Intervenors	Metropolitan Edison Co.	Cost-of-service, rate design, energy cost rate.
9/92	39314	ID	Industrial Consumers for Fair Utility Rates	Indiana Michigan Power Co.	Cost-of-service, rate design, energy cost rate, rate treatment.
10/92	M-00920312 C-007	PA	The GPU Industrial Intervenors	Pennsylvania Electric Co.	Cost-of-service, rate design, energy cost rate, rate treatment.
12/92	U-17949	LA	Louisiana Public Service Commission Staff	South Central Bell Co.	Management audit.
12/92	R-00922378	PA	Armco Advanced Materials Co. The WPP Industrial Intervenors	West Penn Power Co.	Cost-of-service, rate design, energy cost rate, SO_2 allowance rate treatment.
1/93	8487	MD	The Maryland Industrial Group	Baltimore Gas & Electric Co.	Electric cost-of-service and rate design, gas rate design (flexible rates).
2/93	E002/GR-92-1185	MN	North Star Steel Co. Praxair, Inc.	Northern States Power Co.	Interruptible rates.
4/93	EC92 21000 ER92-806-000 (Rebuttal)	Federal Energy Regulatory Commission	Louisiana Public Service Commission Staff	Gulf States Utilities/Entergy agreement.	Merger of GSU into Entergy System; impact on system
7/93	93-0114-E-C	WV	Airco Gases	Monongahela Power Co.	Interruptible rates.
8/93	930759-EG	FL	Florida Industrial Power Users' Group	Generic - Electric Utilities	Cost recovery and allocation of DSM costs.
9/93	M-009 30406	PA	Lehigh Valley Power Committee	Pennsylvania Power & Light Co.	Ratemaking treatment of off-system sales revenues.

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Date	Case	Jurisdict.	Party	Utility	Subject
11/93	346	KY	Kentucky Industrial Utility Customers	Generic - Gas Utilities	Allocation of gas pipeline transition costs - FERC Order 636.
12/93	U-17735	LA	Louisiana Public Service Commission Staff	Cajun Electric Power Cooperative	Nuclear plant prudence, forecasting, excess capacity.
4/94	E-015/ GR-94-001	MN	Large Power Intervenors	Minnesota Power Co.	Cost allocation, rate design, rate phase-in plan.
5/94	U-20178	LA	Louisiana Public Service Commission	Louisiana Power & Light Co.	Analysis of least cost integrated resource plan and demand-side management program.
7/94	R-00942986	PA	Armco, Inc.; West Penn Power Industrial Intervenors	West Penn Power Co.	Cost-of-service, allocation of rate increase, rate design, emission allowance sales, and operations and maintenance expense.
7/94	94-0035-E-42T	WV	West Virginia Energy Users Group	Monongahela Power Co.	Cost-of-service, allocation of rate increase, and rate design.
8/94	EC94 13-000	Federal Energy Regulatory Commission	Louisiana Public Service Commission	Gulf States Utilities/Entergy	Analysis of extended reserve shutdown units and violation of system agreement by Entergy.
9/94	R-00943 081 R-00943 081C0001	PA	Lehigh Valley Power Committee	Pennsylvania Public Utility Commission	Analysis of interruptible rate terms and conditions, availability.
9/94	U-17735	LA	Louisiana Public Service Commission	Cajun Electric Power Cooperative	Evaluation of appropriate avoided cost rate.
9/94	U-19904	LA	Louisiana Public Service Commission	Gulf States Utilities	Revenue requirements.
10/94	5258-U	GA	Georgia Public Service Commission	Southern Bell Telephone & Telegraph Co.	Proposals to address competition in telecommunication markets.
11/94	EC94-7-000 ER94-898-000	FERC	Louisiana Public Service Commission	El Paso Electric and Central and Southwest	Merger economics, transmission equalization hold harmless proposals.
2/95	941-430EG	CO	CF&I Steel, L.P.	Public Service Company of Colorado	Interruptible rates, cost-of-service.

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Date	Case	Jurisdict.	Party	Utility	Subject
4/95	R-00943271	PA	PP&L Industrial Customer Alliance	Pennsylvania Power & Light Co.	Cost-of-service, allocation of rate increase, rate design, interruptible rates.
6/95	C-00913424 C-00946104	PA	Duquesne Interruptible Complainants	Duquesne Light Co.	Interruptible rates.
8/95	ER95-112 -000	FERC	Louisiana Public Service Commission	Entergy Services, Inc.	Open Access Transmission Tariffs - Wholesale.
10/95	U-21485	LA	Louisiana Public Service Commission	Gulf States Utilities Company	Nuclear decommissioning, revenue requirements, capital structure.
10/95	ER95-1042 -000	FERC	Louisiana Public Service Commission	System Energy Resources, Inc.	Nuclear decommissioning, revenue requirements.
10/95	U-21485	LA	Louisiana Public Service Commission	Gulf States Utilities Co.	Nuclear decommissioning and cost of debt capital, capital structure.
11/95	I-940032	PA	Industrial Energy Consumers of Pennsylvania	State-wide - all utilities	Retail competition issues.
7/96	U-21496	LA	Louisiana Public Service Commission	Central Louisiana Electric Co.	Revenue requirement analysis.
7/96	8725	MD	Maryland Industrial Group	Baltimore Gas & Elec. Co., Potomac Elec. Power Co., Constellation Energy Co.	Ratemaking issues associated with a Merger.
8/96	U-17735	LA	Louisiana Public Service Commission	Cajun Electric Power Cooperative	Revenue requirements.
9/96	U-22092	LA	Louisiana Public Service Commission	Entergy Gulf States, Inc.	Decommissioning, weather normalization, capital structure.
2/97	R-973877	PA	Philadelphia Area Industrial Energy Users Group	PECO Energy Co.	Competitive restructuring policy issues, stranded cost, transition charges.
6/97	Civil Action No. 94-11474	US Bank-ruptcy Court Middle District of Louisiana	Louisiana Public Service Commission	Cajun Electric Power Cooperative	Confirmation of reorganization plan; analysis of rate paths produced by competing plans.

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Date	Case	Jurisdict.	Party	Utility	Subject
6/97	R-973953	PA	Philadelphia Area Industrial Energy Users Group	PECO Energy Co.	Retail competition issues, rate unbundling, stranded cost analysis.
6/97	8738	MD	Maryland Industrial Group	Generic	Retail competition issues
7/97	R-973954	PA	PP&L Industrial Customer Alliance	Pennsylvania Power & Light Co.	Retail competition issues, rate unbundling, stranded cost analysis.
10/97	97-204	KY	Alcan Aluminum Corp. Southwire Co.	Big River Electric Corp.	Analysis of cost of service issues - Big Rivers Restructuring Plan
10/97	R-974008	PA	Metropolitan Edison Industrial Users	Metropolitan Edison Co.	Retail competition issues, rate unbundling, stranded cost analysis.
10/97	R-974009	PA	Pennsylvania Electric Industrial Customer	Pennsylvania Electric Co.	Retail competition issues, rate unbundling, stranded cost analysis.
11/97	U-22491	LA	Louisiana Public Service Commission	Entergy Gulf States, Inc.	Decommissioning, weather normalization, capital structure.
11/97	P-971265	PA	Philadelphia Area Industrial Energy Users Group	Enron Energy Services Power, Inc./ PECO Energy	Analysis of Retail Restructuring Proposal.
12/97	R-973981	PA	West Penn Power Industrial Intervenors	West Penn Power Co.	Retail competition issues, rate unbundling, stranded cost analysis.
12/97	R-974104	PA	Duquesne Industrial Intervenors	Duquesne Light Co.	Retail competition issues, rate unbundling, stranded cost analysis.
3/98 (Allocated Stranded Cost Issues)	U-22092	LA	Louisiana Public Service Commission	Gulf States Utilities Co.	Retail competition, stranded cost quantification.
3/98	U-22092		Louisiana Public Service Commission	Gulf States Utilities, Inc.	Stranded cost quantification, restructuring issues.
9/98	U-17735		Louisiana Public Service Commission	Cajun Electric Power Cooperative, Inc.	Revenue requirements analysis, weather normalization.
12/98	8794	MD	Maryland Industrial Group and	Baltimore Gas and Electric Co.	Electric utility restructuring, stranded cost recovery, rate

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			Millennium Inorganic Chemicals Inc.		unbundling.
12/98	U-23358	LA	Louisiana Public Service Commission	Entergy Gulf States, Inc.	Nuclear decommissioning, weather normalization, Entergy System Agreement.
5/99 (Cross-Answering Testimony)	EC-98-40-000	FERC	Louisiana Public Service Commission	American Electric Power Co. & Central South West Corp.	Merger issues related to market power mitigation proposals.
5/99 (Response Testimony)	98-426	KY	Kentucky Industrial Utility Customers, Inc.	Louisville Gas & Electric Co.	Performance based regulation, settlement proposal issues, cross-subsidies between electric. gas services.
6/99	98-0452	WV	West Virginia Energy Users Group	Appalachian Power, Monongahela Power, & Potomac Edison Companies	Electric utility restructuring, stranded cost recovery, rate unbundling.
7/99	99-03-35	CT	Connecticut Industrial \Energy Consumers	United Illuminating Company	Electric utility restructuring, stranded cost recovery, rate unbundling.
7/99	Adversary Proceeding No. 98-1065	U.S. Bankruptcy Court	Louisiana Public Service Commission	Cajun Electric Power Cooperative	Motion to dissolve preliminary injunction.
7/99	99-03-06	CT	Connecticut Industrial Energy Consumers	Connecticut Light & Power Co.	Electric utility restructuring, stranded cost recovery, rate unbundling.
10/99	U-24182	LA	Louisiana Public Service Commission	Entergy Gulf States, Inc.	Nuclear decommissioning, weather normalization, Entergy System Agreement.
12/99	U-17735	LA	Louisiana Public Service Commission	Cajun Electric Power Cooperative, Inc.	Ananlysi of Proposed Contract Rates, Market Rates.
03/00	U-17735	LA	Louisiana Public Service Commission	Cajun Electric Power Cooperative, Inc.	Evaluation of Cooperative Power Contract Elections
03/00	99-1658-EL-ETP	OH	AK Steel Corporation	Cincinnati Gas & Electric Co.	Electric utility restructuring, stranded cost recovery, rate Unbundling.

Expert Testimony Appearances
of
Stephen J. Baron
As of June 2007

Date	Case	Jurisdict.	Party	Utility	Subject
08/00	98-0452 E-GI	WVA	West Virginia Energy Users Group	Appalachian Power Co. American Electric Co.	Electric utility restructuring rate unbundling.
08/00	00-1050 E-T 00-1051-E-T	WVA	West Virginia Energy Users Group	Mon Power Co. Potomac Edison Co.	Electric utility restructuring rate unbundling.
10/00	SOAH 473-00-1020 PUC 2234	TX	The Dallas-Fort Worth Hospital Council and The Coalition of Independent Colleges And Universities	TXU, Inc.	Electric utility restructuring rate unbundling.
12/00	U-24993	LA	Louisiana Public Service Commission	Entergy Gulf States, Inc.	Nuclear decommissioning, revenue requirements.
12/00	EL00-66-000 & ER-2854-000 EL95-33-002	LA	Louisiana Public Service Commission	Entergy Services Inc.	Inter-Company System Agreement: Modifications for retail competition, interruptible load.
04/01	U-21453, U-20925, U-22092 (Subdocket B) Addressing Contested Issues	LA	Louisiana Public Service Commission	Entergy Gulf States, Inc.	Jurisdictional Business Separation - Texas Restructuring Plan
10/01	14000-U	GA	Georgia Public Service Commission Adversary Staff	Georgia Power Co.	Test year revenue forecast.
11/01	U-25687	LA	Louisiana Public Service Commission	Entergy Gulf States, Inc.	Nuclear decommissioning requirements transmission revenues.
11/01	U-25965	LA	Louisiana Public Service Commission	Generic	Independent Transmission Company ("Transco"). RTO rate design.
03/02	001148-EI	FL	South Florida Hospital and Healthcare Assoc.	Florida Power & Light Company	Retail cost of service, rate design, resource planning and demand side management.
06/02	U-25965	LA	Louisiana Public Service Commission	Entergy Gulf States Entergy Louisiana	RTO Issues
07/02	U-21453	LA	Louisiana Public Service Commission	SWEPCO, AEP	Jurisdictional Business Sep. - Texas Restructuring Plan.

Expert Testimony Appearances
of
Stephen J. Baron
As of June 2007

Date	Case	Jurisdict.	Party	Utility	Subject
08/02	U-25888	LA	Louisiana Public Service Commission	Entergy Louisiana, Inc. Entergy Gulf States, Inc.	Modifications to the Inter-Company System Agreement, Production Cost Equalization.
08/02	EL01-88-000	FERC	Louisiana Public Service Commission	Entergy Services Inc. and the Entergy Operating Companies	Modifications to the Inter-Company System Agreement, Production Cost Equalization.
11/02	02S-315EG	CO	CF&I Steel & Climax Molybdenum Co.	Public Service Co. of Colorado	Fuel Adjustment Clause
01/03	U-17735	LA	Louisiana Public Service Commission	Louisiana Coops	Contract Issues
02/03	02S-594E	CO	Cripple Creek and Victor Gold Mining Co.	Aquila, Inc.	Revenue requirements, purchased power.
04/03	U-26527	LA	Louisiana Public Service Commission	Entergy Gulf States, Inc.	Weather normalization, power purchase expenses, System Agreement expenses.
11/03	ER03-753-000	FERC	Louisiana Public Service Commission Staff	Entergy Services, Inc. and the Entergy Operating Companies	Proposed modifications to System Agreement Tariff MSS-4.
11/03	ER03-583-000 ER03-583-001 ER03-583-002 ER03-681-000, ER03-681-001 ER03-682-000, ER03-682-001 ER03-682-002	FERC	Louisiana Public Service Commission	Entergy Services, Inc., the Entergy Operating Companies, EWO Market-ing, L.P, and Entergy Power, Inc.	Evaluation of Wholesale Purchased Power Contracts.
12/03	U-27136	LA	Louisiana Public Service Commission	Entergy Louisiana, Inc.	Evaluation of Wholesale Purchased Power Contracts.
01/04	E-01345-03-0437	AZ	Kroger Company	Arizona Public Service Co.	Revenue allocation rate design.
02/04	00032071	PA	Duquesne Industrial Intervenors	Duquesne Light Company	Provider of last resort issues.
03/04	03A-436E	CO	CF&I Steel, LP and Climax Molybedenum	Public Service Company of Colorado	Purchased Power Adjustment Clause.

Expert Testimony Appearances
of
Stephen J. Baron
As of June 2007

Date	Case	Jurisdict.	Party	Utility	Subject
04/04	2003-00433 2003-00434	PA	Kentucky Industrial Utility Customers, Inc.	Louisville Gas & Electric Co. Kentucky Utilities Co.	Cost of Service Rate Design
0-6/04	03S-539E	CO	Cripple Creek, Victor Gold Mining Co., Goodrich Corp., Holcim (U.S.,), Inc., and The Trane Co.	Aquila, Inc.	Cost of Service, Rate Design Interruptible Rates
06/04	R-00049255	PA	PP&L Industrial Customer Alliance PPLICA	PPL Electric Utilities Corp.	Cost of service, rate design, tariff issues and transmission service charge.
10/04	04S-164E	CO	CF&I Steel Company, Climax Mines	Public Service Company of Colorado	Cost of service, rate design, Interruptible Rates.
03/05	Case No. 2004-00426 Case No. 2004-00421	KY	Kentucky Industrial Utility Customers, Inc.	Kentucky Utilities Louisville Gas & Electric Co.	Environmental cost recovery.
06/05	050045-EI	FL	South Florida Hospital and Healthcare Assoc.	Florida Power & Light Company	Retail cost of service, rate design
07/05	U-28155	LA	Louisiana Public Service Commission Staff	Entergy Louisiana, Inc. Entergy Gulf States, Inc.	Independent Coordinator of Transmission – Cost/Benefit
09/05	Case Nos. 05-0402-E-CN 05-0750-E-PC	WVA	West Virginia Energy Users Group	Mon Power Co. Potomac Edison Co.	Environmental cost recovery, Securitization, Financing Order
01/06	2005-00341	KY	Kentucky Industrial Utility Customers, Inc.	Kentucky Power Company	Cost of service, rate design, transmission expenses, Congestion Cost Recovery Mechanism
03/06	U-22092	LA	Louisiana Public Service Commission Staff	Entergy Gulf States, Inc.	Separation of EGSI into Texas and Louisiana Companies.
04/06	U-25116	LA	Louisiana Public Service Commission Staff	Entergy Louisiana, Inc.	Transmission Prudence Investigation
06/06	R-00061346 C0001-0005	PA	Duquesne Industrial Intervenors & IECPA	Duquesne Light Co.	Cost of Service, Rate Design, Transmission Service Charge, Tariff Issues
06/06	R-00061366 R-00061367 P-00062213 P-00062214		Met-Ed Industrial Energy Users Group and Penelec Industrial Customer Alliance	Metropolitan Edison Co. Pennsylvania Electric Co.	Generation Rate Cap, Transmission Service Charge, Cost of Service, Rate Design, Tariff Issues
07/06	U-22092 Sub-J	LA	Louisiana Public Service Commission Staff	Entergy Gulf States, Inc.	Separation of EGSI into Texas and Louisiana Companies.

Expert Testimony Appearances
of
Stephen J. Baron
As of June 2007

Date	Case	Jurisdict.	Party	Utility	Subject
07/06	Case No. 2006-00130 Case No. 2006-00129	KY	Kentucky Industrial Utility Customers, Inc.	Kentucky Utilities Louisville Gas & Electric Co.	Environmental cost recovery.
08/06	Case No. PUE-2006-00065	VA	Old Dominion Committee For Fair Utility Rates	Appalachian Power Co.	Cost Allocation, Allocation of Revenue Incr, Off-System Sales margin rate treatment
11/06	Doc. No. 97-01-15RE02	CT	Connecticut Industrial Energy Consumers	Connecticut Light & Power United Illuminating	Rate unbundling issues.
01/07	Case No. 06-0960-E-42T	WV	West Virginia Energy Users Group	Mon Power Co. Potomac Edison Co.	Retail Cost of Service Revenue apportionment
03/07	U-29764	LA	Louisiana Public Service Commission Staff	Entergy Gulf States, Inc. Entergy Louisiana, LLC	Implementation of FERC Decision Jurisdictional & Rate Class Allocation
05/07	Case No. 07-63-EL-UNC	OH	Ohio Energy Group	Ohio Power, Columbus Southern Power	Environmental Surcharge Rate Design
05/07	R-00049255 Remand	PA	PP&L Industrial Customer Alliance PPLICA	PPL Electric Utilities Corp.	Cost of service, rate design, tariff issues and transmission service charge.

BEFORE

THE PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission	)	
	)	
v.	)	**Docket No. R-00072155**
	)	
PPL Electric Utilities Corporation	)	

EXHIBIT__(SJB-2)

OF

STEPHEN J. BARON

ON BEHALF OF

PP&L INDUSTRIAL CUSTOMER ALLIANCE ("PPLICA")

J. KENNEDY AND ASSOCIATES, INC.
ROSWELL, GEORGIA

PPL Electric Utilities Corporation
Summary of Subsidies - Present and PPL Proposed Rates
(Adjusted for Remand Case Settlement in Docket No. R-00049255)

	Rate Class	(1) Rate Base	(2) Present Return	(3) Present Rate of Return	(4) Present Subsidy	(5) PPL Proposed Return	(6) Proposed Rate of Return	(7) PPL Proposed Subsidy	(8) % Change in Subsidy
1	RS	1,321,699	53,801	4.07%	(49,972)	90,137	6.82%	(37,369)	-25.2%
2	RTS	38,737	(1,512)	-3.90%	(7,140)	(1,155)	-2.98%	(8,071)	13.0%
3	GS-1	179,448	22,169	12.35%	20,525	23,901	13.32%	16,355	-20.3%
4	GS-3	298,479	36,004	12.06%	32,542	39,524	13.24%	26,779	-17.7%
5	LP-4	75,648	9,709	12.83%	9,320	10,241	13.54%	7,198	-22.8%
6	ISP	3,836	714	18.61%	880	673	17.54%	647	-26.4%
7	LP-5	3,072	326	10.61%	253	562	18.29%	561	121.8%
8	IST	820	260	31.68%	385	271	33.05%	372	-3.4%
9	LP-6	294	10	3.44%	(15)	49	16.67%	45	-409.0%
10	LPEP	821	115	13.95%	118	113	13.76%	82	-30.9%
11	ISA	190	300	157.89%	530	303	159.47%	528	-0.4%
12	GH	21,654	1,641	7.58%	576	2,288	10.57%	878	52.3%
13	SL/AL	78,174	440	0.56%	(7,993)	2,178	2.79%	(8,004)	0.1%
14	L5-S	94	1	1.11%	(9)	8	8.51%	0	-103.0%
15	Total	2,022,966	123,977	6.13%	0	169,093	8.36%	(0)	

Gross Revenue Conversion Factor (calculated from Exh Future 1, Sch D-13, p.5 of 6 - 83573/45487) 1.83729

Baron Exhibit__(SJB-2)

BEFORE

THE PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission	)	
	)	
v.	)	**Docket No. R-00072155**
	)	
PPL Electric Utilities Corporation	)	

EXHIBIT__(SJB-3)

OF

STEPHEN J. BARON

ON BEHALF OF

PP&L INDUSTRIAL CUSTOMER ALLIANCE ("PPLICA")

J. KENNEDY AND ASSOCIATES, INC.
ROSWELL, GEORGIA

PPL Electric Utilities Corporation
Summary of Distribution Rate Increases under PPL Proposed Rates*
Excludes Revenue Annualization, Other Revenue Increases, STAS

Rate Class	Distribution Revenues	USR Revenues	EER Revenues	(1) Present Distribution Revenues	Distribution Revenues	USR Revenues	EER Revenues	(2) Proposed Distribution Revenue	(3) Increase	(4) Percent Increase
RS, RTD	365,177	20,475	-	385,651	422,697	27,629	2,363	452,689	67,038	17.4%
RTS	3,756	195	-	3,951	4,339	267	23	4,629	678	17.2%
GS-1	72,974	-	-	72,974	75,804	-	471	76,275	3,301	4.5%
GS-3	109,981	-	-	109,981	116,479	-	-	116,479	6,498	5.9%
LP-4 **	28,861	-	-	28,861	29,911	-	-	29,911	1,050	3.6%
ISP **	1,765	-	-	1,765	1,681	-	-	1,681	(85)	-4.8%
LP-5 **	1,047	-	-	1,047	1,484	-	-	1,484	437	41.7%
IST **	567	-	-	567	583	-	-	583	16	2.9%
LP-6	63	-	-	63	131	-	-	131	69	110.0%
LPEP	331	-	-	331	330	-	-	330	(1)	-0.2%
ISA **	527	-	-	527	527	-	-	527	(0)	0.0%
GH	6,451	-	-	6,451	7,651	-	-	7,651	1,200	18.6%
SL/AL	17,492	-	-	17,492	20,786	-	-	20,786	3,295	18.8%
L5-S	36	-	-	36	49			49	13	35.5%
Total w/o PRS	609,027	20,670	-	629,696	682,453	27,896	2,857	713,206	83,510	13.3%
PRS	421	-	-	421	421			421	-	0.0%
Total w/o PRS	609,448	20,670	-	630,118	682,874	27,896	2,857	713,627	83,510	13.3%

* Adjusted for Settlement in Docket No. R-00049255 Remand.
** Excludes revenues from PRS which are included in COSS revenues

Baron Exhibit__(SJB-3)

BEFORE

THE PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission	)	
	)	
v.	)	**Docket No. R-00072155**
	)	
PPL Electric Utilities Corporation	)	

EXHIBIT__(SJB-4)

OF

STEPHEN J. BARON

ON BEHALF OF

PP&L INDUSTRIAL CUSTOMER ALLIANCE ("PPLICA")

J. KENNEDY AND ASSOCIATES, INC.
ROSWELL, GEORGIA

Baron Exhibit__(SJB-4)
Schedule 1

PPL Electric Utilities Corporation

Summary of Increases required to reduce Present Rate subsidies by 50% at Proposed Rates

Rate Class	Present Distribution Revenues	Present Subsidy	50% of Present Subsidy	Increase @ Equal ROR	Increase with 50% Subsidy	Proposed Distribution Revenue	Percent Increase	Rate of Return
RS, RTD	385,651	(49,972)	(24,986)	104,407	79,421	465,073	20.6%	7.34%
RTS	3,951	(7,140)	(3,570)	8,749	5,179	9,130	131.1%	3.37%
GS-1	72,974	20,525	10,262	(13,054)	(2,791)	70,183	-3.8%	11.51%
GS-3	109,981	32,542	16,271	(20,281)	(4,010)	105,971	-3.6%	11.33%
LP-4 *	28,861	9,320	4,660	(6,148)	(1,488)	27,373	-5.2%	11.76%
ISP *	1,765	880	440	(732)	(292)	1,473	-16.6%	14.46%
LP-5 *	1,047	253	126	(124)	3	1,050	0.2%	10.65%
IST *	567	385	193	(356)	(163)	404	-28.8%	20.85%
LP-6	63	(15)	(7)	24	17	79	26.7%	6.53%
LPEP	331	118	59	(82)	(23)	308	-7.0%	12.42%
ISA *	527	530	265	(528)	(263)	264	-49.9%	82.66%
GH	6,451	576	288	322	610	7,061	9.5%	9.11%
SL/AL	17,492	(7,993)	(3,997)	11,298	7,302	24,793	41.7%	5.65%
L5-S	36	(9)	(4)	13	8	44	22.7%	5.84%
Total w/o PRS	629,696	0	0	83,510	83,510	713,206	13.3%	8.38%
PRS	421	-	-	-	-	421	0.0%	
Total w/o PRS	630,118	-	-	83,510	83,510	713,627	13.3%	

Gross Revenue Conversion Factor (calculated from Exh Future 1, Sch D-13, p.5 of 6 - 83573/45487)
* Excludes revenues from PRS which are included in COSS revenues

Baron Exhibit__(SJB-4)
Schedule 2

PPL Electric Utilities Corporation
Summary of Increases required to reduce Present Rate subsidies by 50% at Proposed Rates
(with IST and ISA Adjustments)

Rate Class	Increase	Return Increase	Present Return	Return after Increase	Rate Base	Rate of Return	Rev Adj to Cap ROR	Adjusted Increase	Adjusted Percent Increase	Adjusted Rate of Return
RS, RTD	79,421	43,227	53,801	97,028	1,321,699	7.34%	265	79,686	20.7%	7.35%
RTS	5,179	2,819	(1,512)	1,307	38,737	3.37%	8	5,187	131.3%	3.39%
RES Total								84,873	21.8%	
Adjusted RESIDENTIAL:										
RS, RTD								84,012	21.8%	7.53%
RTS								861	21.8%	-2.69%
GS-1	(2,791)	(1,519)	22,169	20,649	179,448	11.51%	36	(2,755)	-3.8%	11.52%
GS-3	(4,010)	(2,182)	36,004	33,822	298,479	11.33%	60	(3,950)	-3.6%	11.34%
LP-4 *	(1,488)	(810)	9,709	8,899	75,648	11.76%	15	(1,473)	-5.1%	11.77%
ISP *	(292)	(159)	714	555	3,836	14.46%	1	(292)	-16.5%	14.47%
LP-5 *	3	1	326	327	3,072	10.65%	1	3	0.3%	10.66%
IST *	(163)	(89)	260	171	820	20.85%	(153)	(317)	-55.8%	10.66%
LP-6	17	9	10	19	294	6.53%	0	17	26.8%	6.54%
LPEP	(23)	(13)	115	102	821	12.42%	0	(23)	-6.9%	12.43%
ISA *	(263)	(143)	300	157	190	82.66%	(251)	(514)	-97.6%	10.66%
GH	610	332	1,641	1,973	21,654	9.11%	4	615	9.5%	9.12%
SL/AL	7,302	3,974	440	4,414	78,174	5.65%	16	7,317	41.8%	5.66%
L5-S	8	4	1	5	94	5.84%	0	8	22.8%	5.86%
Total w/o PRS	83,510	45,453	123,977	169,429	2,022,966	8.38%	0	83,510	13.3%	8.38%
PRS	-	-								
Total w/o PRS	83,510	45,453								

Gross Revenue Conversion Factor (calculated from Exh Future 1, Sch D-13, p.5 of 6 - 83573/45487)
* Excludes revenues from PRS which are included in COSS revenues

DII STATEMENT NO. 1

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission	:	
	:	Docket No. R-00061346C0001-0005
v.	:	
	:	
Duquesne Light Company	:	

DIRECT TESTIMONY

AND EXHIBITS

OF

STEPHEN J. BARON

ON BEHALF OF

DUQUESNE INDUSTRIAL INTERVENORS

AND

THE INDUSTRIAL ENERGY CONSUMERS OF PENNSYLVANIA

J. KENNEDY AND ASSOCIATES, INC.
ROSWELL, GEORGIA
JULY 2006

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission	:	
	:	**Docket No. R-00061346C0001-0005**
v.	:	
	:	
Duquesne Light Company	:	

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III. COST OF SERVICE AND ALLOCATION OF PROPOSED REVENUE INCREASE 16

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V. TRANSMISSION SERVICE CHARGE ("TSC") 40

VI. TARIFF ISSUES 43

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission	:	
	:	**Docket No. R-00061346C0001-0005**
v.	:	
	:	
Duquesne Light Company	:	

DIRECT TESTIMONY OF STEPHEN J. BARON

I. INTRODUCTION

Q. Please state your name and business address.

A. My name is Stephen J. Baron. My business address is J. Kennedy and Associates, Inc. ("Kennedy and Associates"), 570 Colonial Park Drive, Suite 305, Roswell, Georgia 30075.

Q. What is your occupation and by whom are you employed?

A. I am the President and a Principal of Kennedy and Associates, a firm of utility rate, planning, and economic consultants in Atlanta, Georgia.

Q. Please describe briefly the nature of the consulting services provided by Kennedy and Associates.

A. Kennedy and Associates provides consulting services in the electric and gas utility industries. Our clients include state agencies and industrial electricity consumers. The firm provides expertise in system planning, load forecasting, financial analysis, cost-of-service, and rate design. Current clients include the Georgia and Louisiana Public Service Commissions, and industrial consumer groups throughout the United States.

Q. Please state your educational background.

A. I graduated from the University of Florida in 1972 with a B.A. degree with high honors in Political Science and significant coursework in Mathematics and Computer Science. In 1974, I received a Master of Arts Degree in Economics, also from the University of Florida. My areas of specialization were econometrics, statistics, and public utility economics. My thesis concerned the development of an econometric model to forecast electricity sales in the State of Florida, for which I received a grant from the Public Utility Research Center of the University of Florida. In addition, I have advanced study and coursework in time series analysis and dynamic model building.

Q. Please describe your professional experience.

A. I have more than thirty years of experience in the electric utility industry in the areas of cost and rate analysis, forecasting, planning, and economic analysis.

Following the completion of my graduate work in economics, I joined the staff of the Florida Public Service Commission in August of 1974 as a Rate Economist. My responsibilities included the analysis of rate cases for electric, telephone, and gas utilities, as well as the preparation of cross-examination material and the preparation of staff recommendations.

In December 1975, I joined the Utility Rate Consulting Division of Ebasco Services, Inc. as an Associate Consultant. In the seven years I worked for Ebasco, I received successive promotions, ultimately to the position of Vice President of Energy Management Services of Ebasco Business Consulting Company. My responsibilities included the management of a staff of consultants engaged in providing services in the areas of econometric modeling, load and energy forecasting, production cost modeling, planning, cost-of-service analysis, cogeneration, and load management.

I joined the public accounting firm of Coopers & Lybrand in 1982 as a Manager of the Atlanta Office of the Utility Regulatory and Advisory Services Group. In this capacity I was responsible for the operation and management of the Atlanta office. My duties included the technical and administrative supervision of the staff, budgeting, recruiting, and marketing as well as project management on client engagements. At Coopers &

Lybrand, I specialized in utility cost analysis, forecasting, load analysis, economic analysis, and planning.

In January 1984, I joined the consulting firm of Kennedy and Associates as a Vice President and Principal. I became President of the firm in January 1991.

During the course of my career, I have provided consulting services to more than thirty utility, industrial, and Public Service Commission clients, including three international utility clients.

I have presented numerous papers and published an article entitled "How to Rate Load Management Programs" in the March 1979 edition of "Electrical World." My article on "Standby Electric Rates" was published in the November 8, 1984 issue of "Public Utilities Fortnightly." In February of 1984, I completed a detailed analysis entitled "Load Data Transfer Techniques" on behalf of the Electric Power Research Institute, which published the study.

I have presented testimony as an expert witness in Arizona, Arkansas, Colorado, Connecticut, Florida, Georgia, Indiana, Kentucky, Louisiana, Maine, Michigan, Minnesota, Maryland, Missouri, New Jersey, New Mexico, New York, North Carolina, Ohio, Pennsylvania, Texas, West Virginia, Federal Energy Regulatory Commission and in United States Bankruptcy Court. A list of my specific regulatory appearances can be found in Baron Exhibit ____ (SJB-1)

Q. Have you previously testified in Duquesne Light Company proceedings in Pennsylvania?

A. Yes. I have previously testified in a number of proceedings involving Duquesne Light Company ("Duquesne or DLC"), including the 1998 restructuring proceeding and the Company's last base rate case in 1987. Specifically, I have testified in the following Duquesne cases: R-870651 (1987), C-913424 (1992), C-00946104 (1995), R-974104 (1997) and P-00032071 (2004).

Q. On whose behalf are you testifying in this proceeding?

A. I am testifying on behalf of the Duquesne Industrial Intervenors ("DII"). DII represents industrial, commercial and institutional customers taking service on the Duquesne system, primarily under Rate Schedules GL, GLH, L and HVPS. The twelve DII members collectively consume over 2 billion kWhs of electricity on these rate schedules. I am also testifying on behalf of the Industrial Energy Consumers of Pennsylvania, which is a statewide organization of Large Commercial and Industrial ("Large C&I") customers.

Q. What is the purpose of your testimony?

A. I will address a number of significant issues raised by the Company in its direct testimony. Among the issue that I will address are: the allocation of the proposed revenue increase to rate schedules; the Company's request to implement a Distribution System Improvement Charge ("DSIC"); and the Transmission Service Charge ("TSC"). I will also address some specific tariff and rule changes proposed by the Company.

With regard to the Company's cost of service study and its use to allocate the distribution related revenue increase, I will discuss the inadequacy of the Company's proposed reduction in inter-class rate subsidies. Though DII recognizes the progress that is being made by the Company to reduce subsidies in this case, the Company's proposed distribution rates continue to incorporate substantial subsidies that should be reduced or eliminated in this rate proceeding.

With regard to the Company's proposal to implement a DSIC, I will discuss why such a proposal is not warranted and should be rejected. In addition, though the Company's proposal should be rejected, if it is adopted by the Commission, it should not apply to customers taking service at transmission voltages, who do not use the Company's distribution system.

I will address the Company's proposal to implement a Transmission Service Charge to recover expenses associated with PJM Open Access Transmission Tariff ("OATT") charges. The Company has proposed a TSC recovery approach that reflects the manner in which Duquesne incurs transmission service expenses from PJM, which is primarily related to the magnitude of the Company's coincident peak demand. The Duquesne TSC reasonably reflects cost to provide transmission service for each of its rate schedules and should be approved by the Commission.

Finally, I will address some proposed rate design and tariff changes being requested by the Company, including it proposal to eliminate language in tariff Rule 4 that permits the Company to negotiate individual contracts with customers. This rule should be contained to provide the Company and its customers with the maximum amount of flexibility in developing rates. In addition, because the PUC recently decided to rebid the fixed price POLR option for Large C&I customers and that auction was successful, the language regarding the fixed price POLR option should be reinserted. Any tariff changes regarding POLR service should be accomplished through a compliance filing or the implementation filing contemplated under the proposed POLR regulations.

Q. Please summarize your findings and recommendations.

A. As discussed in detail in this testimony:

- **The Company's proposal in this case to utilize a "total bill" impact criterion to limit the movement of distribution rates towards cost of service is not appropriate for Duquesne and reflects a continuation of rate "bundling" that no longer exists. Duquesne's distribution rates should be evaluated on a standalone basis, particularly since the Company is no longer subject to rate caps.**

- **The allocation of Duquesne's proposed distribution rate increases to rate schedules are not reasonable and result in excessive and unjustified increases to Rate Schedules GL and L, in particular. Based on the Company's cost of service study, these rate schedules are paying substantial subsidies at present rates. Despite this result, Duquesne has unreasonably proposed increases for these rate schedules at twice the system average distribution percentage increase.**

- **The allocation of the Company's requested distribution revenue increase should be based on distribution cost of service. Rates should be increased in such a manner that the current distribution rate subsidies (based on the Company's cost of service study) be reduced by 50% at proposed rates. Rate HVPS should receive a rate decrease to fully eliminate subsidies paid by these customers, who do not use the Company's primary and secondary distribution system.**

- **Duquesne's proposed Distribution System Improvement Charge ("DSIC") is not justified and should be rejected by the Commission. The Company has not established that there are any changed circumstances that would support such a rider. The DSIC also should be rejected because it would result in a single-issue rate change.**

- **Duquesne's proposed Transmission Service Charge ("TSC") is a reasonable proposal to recover transmission costs, properly reflects cost causation in its rate recovery mechanism and should be approved by the Commission. Because the TSC tracks the rates and billing determinants on which Duquesne purchases service from PJM, the TSC ensure that retail electric customers are provided with transmission service on rates comparable to the Company's use of the system.**

- **The Company's proposal to eliminate Tariff Rule 4, which permits the Company to enter special contracts with its customers, should be rejected. This tariff rule should be continued because it is only applicable in the event**

that the Company, "in its sole discretion" determines that such a contract should be entered. Since there is no obligation to enter a Rule 4 contract, it would appear to be beneficial to maintain the option in the event that the Company, the affected Rule 4 customer and other Duquesne customers could benefit from such a contract. There is no reason to eliminate this tariff rule.

- **Duquesne is proposing several changes in this case to reflect the elimination of the fixed price POLR option for Large C&I customers. Because this fixed price POLR option will be available and continue through May 31, 2007, it is premature to propose changes; the Company's proposal should be rejected at this time. Duquesne can address this issue in a compliance or implementation plan filing at a later date.**

- **Duquesne's proposed untransformed service credit for transmission voltage customers on Rate Schedule L is greatly understated, unjust and unreasonable. The Company must calculate a revised credit based on the actual costs to provide distribution service to these transmission voltage customers.**

II. STANDARD FOR EVALUATING TRANSMISSION AND DISTRIBUITON RATE CHANGES

Q. Have you reviewed the principles used by Duquesne to allocate the transmission and distribution rate increases among customer classes?

A. Yes. Duquesne witness Mr. Pfrommer discusses the Company's principles and criteria in his direct testimony, beginning on page 4. The objectives cited by Mr. Pfrommer are first, to "reflect the cost of service to each rate class" and second, "to mitigate potentially extreme rate impacts. These objectives were applied to both the distribution and transmission increases at issue in this case.

Q. In light of the Company's second objective, mitigating the impact of the rate increases, how did Duquesne allocate its requested revenue increases for distribution and transmission in its proposed rates?

A. Mr. Pfrommer discusses five criteria that the Company used to allocate the increases to rate schedules. These criteria are:

1. The increase should result in no rate class having a Rate of Return ("ROR") on distribution rate base of less than 1% or more that 25%.

2. The overall increase on a "total bill" (distribution, transmission, POLR supply) should not exceed "1.4 times" the system average increase.

3. No rate class should receive a revenue decrease on a "total bill" basis.

4. Each rate class should move closer to system average ROR after increase.

5. Retail transmission rates should be set to exactly recover cost of service.

The key element of the Company's allocation methodology is that rates should be increased in a manner that limits the impact on a "total" bundled bill basis, including POLR supply, while moving rates closer to cost of service.

Q. Do you agree that the allocation of the transmission and distribution rate increases among rate schedules should be driven primarily by the desire to keep the "total bill" impact for all rate schedules below a certain level?

A. No, I am advised by counsel that Pennsylvania's Electric Generation Customer Choice and Competition Act ("Choice Act") requires each rate element to be viewed independently, rather than "rebundling" the unbundled elements in assigning responsibility for the two increases. This also subverts the reason that the rates were unbundled and sends inappropriate price signals to customers regarding their usage of the transmission and distribution system.

Q. Did the PUC use the "total bill" impact analysis in PPL's recent rate case?

A. Yes. However, it is my understanding that this determination is under appeal to the Commonwealth Court.

Q. Are there factors that justify using a different standard in this proceeding?

A. Duquesne and PPL are in different stages of the "transition" process under Pennsylvania's Choice Act. While PPL's ratepayers continue to be under rate caps, Duquesne has completed it stranded cost recovery and is no longer subject to a distribution <u>or generation</u> rate cap. In fact, Duquesne's generation rates have already been adjusted twice (for residential and small commercial customers) and multiple times for large commercial and industrial customers since the generation rate caps expired. During this process, the Commission has distinguished between the generation service options available to various rate schedules, with the fixed price option available to Large C&I customers returning to POLR service changing quarterly, while residential and small commercial customers have pre-established, fixed rate protection through December 31, 2007. Under the current structure, Large C&I customers will have only hourly-priced POLR service available after June 1, 2007. All PPL customers have fixed, predetermined generation rates through December 31, 2009.

Q. Does the difference in the POLR options for Large C&I customers in comparison to other Duquesne customers impact how the PUC should view this case?

A. Yes. In addition to the impact of previously sanctioning differences in the treatment of Duquesne customer classes in the POLR III case, the different POLR plans have practical impacts on the PUC's consideration of this case.

First, because most Large C&I customers' generation rates are determined by competitive negotiations, the Commission cannot definitively determine the "total bill" impact for most of Duquesne's Large C&I customers. As Duquesne recognized, if the customer's generation rate from an EGS is lower than the POLR generation rate, then that customer will experience a higher "total bill" percentage increase, all else being equal. (See DLC Response to DII II-7 (Pfrommer)).

Second, for customers purchasing hourly POLR service, any "total bill" comparison is invalid. As the Company confirmed, for hourly priced customers, the Company simply imputed generation costs based on the fixed POLR rates. (DLC Response to DII II-9 (Pfrommer)). This may not reflect the customer's actual costs. This problem will be exacerbated in the future if no fixed generation rate is available for Large C&I customers.

Third, the difference in the POLR options has already disparately impacted Large C&I customers. Mr. O'Brien testified that all of Duquesne's customers are paying rates that are lower than 1992 levels. (DLC Statement No. 1, p. 12). Duquesne confirmed in discovery that this was not accurate regarding Large C&I customers on Rate Schedules GL, GLH, L and HVPS.

> **4. Reference DLC Statement No. 1, p. 12, lines 10-11 which states: 'As a result, Duquesne Light's rates today are lower than they were in 1992.' Please confirm whether this applies to all rate schedules. If not, please specify the rate schedules to which this statement does not apply and provide a calculation of the rates in 1992 and 2006 for the rate schedule(s).**
>
> **Response:**
>
> **The above statement was made in the general context that for nearly all of Duquesne's 587,227 customers, retail tariff rates today are lower than they were in 1992. Attachment No. 1 provides a comparison of current rates to those rates that were in effect in 1992. The primary exception to the above statement is for customers on general service rates GL, GLH, L and HVPS. Retail tariff rates for these general service rate schedules were lower in 2004 than they were in 1992 as shown in Attachment 2. However, as a result of the POLR III plan that became effective January 1, 2005, the POLR III generation rates for general service rates GL, GLH, L and HVPS were the result of a request for proposal "RFP" or hourly priced service. Since these POLR III rates were based on an RFP, total retail tariff rates (i.e. transmission, distribution and generation combined) are higher than they were in 1992.** (DLC Response to DII II-4 (Pfrommer), attachments omitted).

This analysis does <u>not</u> include the impact of the expiration of various special contracts under Rule 4 of the Company's tariff. (<u>See</u> DLC Response to DII II-5). In summary, Duquesne's Large C&I customers have already been subjected to rate increases in recent years that other Duquesne customers have not experienced.

These reasons are in addition to the legal, policy and economic development reasons that the distribution and transmission rates for Large C&I customers may warrant special consideration in this proceeding. DII's other witnesses and briefs will expand on these arguments.

Q. How should the Commission review the transmission and distribution proposals in this proceeding?

A. Each proposal should be analyzed separately to ensure consistency with the Choice Act and the Public Utility Code.

III. COST OF SERVICE AND ALLOCATION OF PROPOSED REVENUE INCREASE

Q. Have you reviewed the Company's filed distribution class cost of service study in this case?

A. Yes. Although I may not agree with every assumption, the Company's study is a reasonable basis for allocating distribution costs to rate classes. The relative rates of return by class at present rates and the related "dollar subsidies" produced by the Company's study should be used to allocate the Commission approved distribution revenue increase to rate schedules.

Q. Company witness Pfrommer discusses Duquesne's objective to set distribution rates consistent with cost allocation principles over time, subject to a number of constraints to "avoid sudden and disparate increases to different rate classes." Do you agree with the Company's general approach to allocate the revenue increase in this case?

A. In general, I agree with the basic objective stated by Mr. Pfrommer to move distribution rates towards cost of service and reduce subsidies. I also recognize that it may not be feasible to accomplish this objective in a single rate case, and therefore, gradualism must be considered to some extent. As previously discussed, however, I do not agree that the impact of the combined transmission and distribution increases on the "total bill" for a customer class should be considered.

Q. Does Mr. Pfrommer provide any authoritative source for his choice of 1.4 times the system average overall increase as the ceiling on the impact of both rate changes on customer classes or his choice of 25% as the cap on rate schedule distribution return at proposed rates?

A. No.

Q. Does Duquesne's proposed allocation of the distribution rate increase among the rate schedules produce any strange results?

A. First, given that customers on Rate Schedules GL and L are already earning rates of return well in excess of the system average at present rates, it is curious that customers on theses rate schedules face over 100% increases in distribution rates, in comparison to a 51.3% overall increase.

Second, the Company is not consistent in its treatment of rate schedules that currently are below the system average rate of return. For example, Duquesne is proposing the largest percentage increase for customers on Rate Schedule GLH (at 203%) despite the fact that two rate schedules (RH and RA) earn lower relative returns at present rates. Rate Schedule RS faces only a 38.4% increase under Duquesne's proposal, despite the fact that this will allow the rate schedule to earn a return of only 5.3% at proposed rates (based on Duquesne's calculations)[1], while rate schedule GLH would earn a return of 8.6% and the system average return would be 9.08%.

This is not a just, reasonable and nondiscriminatory result.

Q. Do you believe that the Company's proposed allocation of the distribution revenue increase in this case meets the general objectives to move class rates towards cost of service?

A. No. I believe that examining the monetary (dollar) subsidies at present and proposed rates is more indicative than examining the rates of return; however, Table 1 below shows the rate of return at present rates, the relative rate of return (a classes' rate of return compared to the system average rate of return) and the proposed revenue increases for each rate class. As can be seen from this table, the Company is proposing substantial increases on Rate Schedules GL and L, despite the fact that these classes are earning rates of return at present rates significantly in excess of the average retail rate of return.

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[1]As set forth below, Duquesne's calculation of the return at proposed rates is not correct.

Table 1				
Rate Class	Present Rate of Return	Relative Rate of Return	Duquesne Proposed Increase	Percent Increase
RS	-0.54%	(0.20)	56,609	38.4%
RH	11.42%	(4.17)	8,393	161.1%
RA	-9.26%	(3.38)	603	79.2%
GS/GM	12.27%	4.48	23,443	35.6%
GMH	1.49%	0.54	3,014	73.7%
GL	5.21%	1.90	34,788	110.0%
GLH	-3.77%	(1.38)	5,908	203.5%
L	4.94%	1.81	10,922	108.6%
HVPS	47.66%	17.42	(31)	-7.3%
AL	-6.25%	(2.28)	-	0.0%
SE	68.10%	24.89	17	1.1%
SM	18.91%	6.91	15	0.2%
SH	2.32%	0.85	52	73.2%
MTS	45.54%	16.64	-	0.0%
PAL	98.57%	36.02	(62)	-35.8%
TOTAL	2.74%		143,671	51.3%

Q. Have you developed an analysis that shows the dollar subsidies paid and received by each rate schedule at present distribution rates?

A. Yes. Table 2 below summarizes the subsidies for each rate schedule, based on the results of Company witness Gorman's class cost of service study. These results are derived directly from the Company's filed study and I have made no adjustments to their analysis.

Table 2

Rate Class	Present Subsidy ($1000)
RS	(21,971)
RH	(9,333)
RA	(683)
GS/GM	22,578
GMH	(328)
GL	4,492
GLH	(2,293)
L	1,296
HVPS	153
AL	(2)
SE	1,209
SM	4,340
SH	(1)
MTS	401
PAL	142

Q. What do these results (Table 2) show about the Company's current distribution rates?

A. The key conclusion from this analysis is that residential distribution rates are being subsidized by more than $30 million, while Rate Schedules GL, L and HVPS are paying subsidies of almost $5 million and GS/GM is paying subsidies of $23 million. Most other smaller rate schedules are also paying subsidies, while rate GLH is receiving a subsidy. These results strongly suggest that the Company's distribution rates need to be realigned to meet the cost of service objectives advocated by Duquesne and which I generally support.

Q. Mr. Pfrommer, on page 8 of his testimony, states that the Company's proposed allocation of its requested distribution revenue increase has achieved its revenue allocation principles and shows class rate of return results at present and proposed distribution rates (his Table No. 2) to support his conclusion. Is the analysis shown in his Table No. 2 correct?

A. No. The rates of return at proposed rates shown in Mr. Pfrommer's Table No. 2 have not been properly calculated. These rates of return were developed by Mr. Gorman and presented in his (Gorman) Exhibit HSG-7. Rather than move distribution rates towards cost of service, Duquesne's proposed distribution rates move some classes' further away from cost of service and have resulted in an increase in the dollar subsidies paid by rates GL and L. Table 3 below shows the current and proposed subsidies paid by each rate schedule based on the Company's proposed rates.

Rate Class	Subsidy @ Present Rates	Subsidy @ Proposed Rates	Difference	% Increase (Decrease)
RS	(21,971)	(38,879)	(16,908)	77.0%
RH	(9,333)	(8,185)	1,148	-12.3%
RA	(683)	(708)	(25)	3.6%
GS/GM	22,578	20,103	(2,476)	-11.0%
GMH	(328)	(184)	144	-43.9%
GL	4,492	19,407	14,915	332.0%
GLH	(2,293)	(248)	2,045	-89.2%
L	1,296	5,779	4,483	346.0%
HVPS	153	85	(69)	-44.7%
AL	(2)	(4)	(2)	162.1%
SE	1,209	1,028	(181)	-15.0%
SM	4,340	1,435	(2,905)	-66.9%
SH	(1)	6	7	-1041.4%
MTS	401	300	(101)	-25.3%
PAL	142	64	(77)	-54.6%

Table 3

As can be seen, for rates GL and L, the amount of subsidies has increased by $15 million and $4.5 million respectively. This is not an indication that rates are moving towards cost of service; rather, customers on these rate schedules are being forced to pay even greater subsidies at proposed distribution rates than at present rates. Similarly, some rate schedules that show negative subsidies at present rates are being asked to eliminate those subsidies much faster than other rates (<u>i.e.,</u> Rate Schedule GLH v. Rate Schedule RS).

Q. Even if the "relative rate of return" criterion supported by the Company is used to allocate the rate increase (rather than dollar subsidies), is the Duquesne analysis correct?

A. No. Table 4 below is a corrected version of Mr. Pfrommer's "Table No. 2" that was shown on page 8 of his testimony. The rates of return at present rates are the same as presented in Mr. Pfrommer's table. Rates of return at proposed rates, which have been corrected, are based on an analysis contained in Baron Exhibit__(SJB-2).

Table 4

CORRECTED PFROMMER TABLE NO. 2 DISTRIBUTION SYSTEM ROR PROGRESS TOWARD SYSTEM AVERAGE ROR											
	System	RS	RH	RA	GSGM	GMH	GL	GLH	L	HVPS	LIGHTING
At Present Rates											
Class ROR	2.74%	(0.5%)	(11.4%)	(9.3%)	12.3%	1.5%	5.2%	(3.8%)	4.9%	47.7%	22.9%
Class ROR/System Average ROR	1.00 X	(0.20 X)	(4.17 X)	(3.38 X)	4.48 X	0.54 X	1.90 X	(1.38 X)	1.81 X	17.42 X	8.37 X
At Proposed Rates											
Class ROR	9.08%	3.3%	(3.3%)	(3.3%)	17.6%	8.4%	19.8%	8.4%	18.9%	33.8%	18.4%
Class ROR/System Average ROR	1.00 X	0.36 X	(0.37 X)	(0.37 X)	1.94 X	0.92 X	2.18 X	0.92 X	2.08 X	3.72 X	2.03 X

Q. You indicated that the rates of return at proposed rates in Mr. Pfrommer's Table No. 2 are not computed correctly. Would you explain the problem that you have identified?

A. The problem in the Company's computation of rates of return at proposed rates in Mr. Pfrommer's Table No. 2, which were developed in Gorman Exhibit HSG-7, is that there is an inconsistent (and incorrect) calculation of income taxes associated with the revenue increases for each rate class. In Mr. Gorman's class cost of service study, he allocated test year income tax expense on plant (which is effectively the same as an allocation on rate base). This is an appropriate methodology and recognizes that income tax expense is a cost of service for which each class has a responsibility, irrespective of the actual rate of return produced by the rate class. Thus, even if a rate class is earning a negative rate of return, it is still responsible for its share of the system's overall income tax expense. The method used by Mr. Gorman to compute the class rates of return at present rates correctly reflects an allocation of income taxes, while his method for computing income taxes associated with proposed rates is not.

The problem in Mr. Pfrommer's Table No. 2 analysis of rates of return at proposed distribution rates is that the additional income taxes associated with the Company's $143 million distribution revenue increase are not allocated (as is done by Mr. Gorman for test year income taxes). Instead, the incremental income taxes are "computed" for each rate schedule's specific revenue increase. The end result of this inconsistent treatment is that rate schedules that are receiving a smaller increase than is warranted by the cost of service study itself are being assigned a smaller amount of cost responsibility for the income taxes associated with the Company's distribution revenue increase of $143 million. Likewise, for rate schedules like GL and L, which are being allocated excessive rate increases (compared to the amount indicated by the cost of service study), a greater share of income tax expense is being assigned. This is like a restaurant overcharging a customer, and then asking the customer to pay a higher "tip" on the overcharged bill. I have corrected this problem in the results that I presented in Table 4 above.

Q. Does this correction impact Duquesne's compliance with the Company's proposed principles and standards governing the allocation of the rate increases among customer classes?

A. Yes. The rate increases for Rate Schedules RH and RA no longer ensure that all rate schedules show a positive return. In addition, Rate Schedule HVPS shows a class rate of return in excess of 25% at proposed rates.

Q. In Table 3, you presented an analysis that showed the amount of subsidies that will remain in Duquesne's distribution rates, based on the Company's proposals in this case. Have you prepared an analysis that shows how these remaining subsidies "translate" into actual rate impacts?

A. Yes. Baron Exhibit__(SJB-3) shows an analysis for rates GL, GLH, L and HVPS of the impact of the remaining "subsidies" on the distribution demand charges for each of the rates. Table 5 below summarizes these subsidies for each rate schedule. For example, rate GL customers will continue to pay a $3.52 per kW "subsidy" for distribution billing demand, under the Company's proposal in this case to move rates towards cost of service. Large subsidies also remain for rates L and HVPS. These subsidies should not continue at such high levels in proposed rates.

Table 5
Impact of Duquesne Proposed Subsidies on Distribution Rates

	Duquesne Proposed Subsidy ($/kW)
Rate GL	$3.52
Rate GLH	-$0.91
Rate L	$1.95
Rate HVPS	$0.03

Q. Have you developed a recommendation for allocating the approved distribution revenue increase in this case?

A. Yes. Baron Exhibit__(SJB-4) presents an analysis using the results of the Company's cost of service study to achieve a 50% subsidy reduction at proposed rates, for all rate schedules except HVPS. Rate HVPS customers take service at transmission voltages and do not use the Duquesne primary and secondary distribution system. Therefore, it is appropriate that these customers should not continue paying any subsidy in distribution rates. This adjustment in HVPS rates, which fully eliminates the subsidy, increases revenue for all other rates by $76,000, or about 5/100 of 1%.

A 50% subsidy reduction is a reasonable approach that moves distribution rates towards cost of service for all rate classes in a systematic fashion. As discussed previously, the Commission should evaluate the reasonableness of distribution rates on an unbundled basis. As I showed in Table 3, the Company is proposing to continue very large subsidies in its proposed rates, and in fact, is proposing to increase these subsidies for some rate schedules. Table 6 below summarizes my recommended rate schedule increases using this methodology.

Table 6
DII Proposed Revenue Allocation

Rate Class	Proposed Distribution Increase	Percent Increase
RS	84,533	57.3%
RH	11,908	228.6%
RA	970	127.5%
GS/GM	14,647	22.2%
GMH	3,035	74.2%
GL	17,642	55.8%
GLH	5,009	172.5%
L	5,795	57.6%
HVPS	(114)	-26.8%
AL	3	323.8%
SE	(403)	-27.0%
SM	768	8.4%
SH	47	65.8%
MTS	(98)	-16.7%
PAL	(55)	-31.9%
TOTAL	143,686	51.3%

Q. Have you calculated the rate of return for each rate schedule under your proposal?

A. Yes. Table 7 shows the rates of return and relative rates of return at proposed rates, based on my recommend rate schedule increases.

Table 7
Rate of Return @ DII Proposed Revenue Increases

Rate Class	Proposed Rate of Return	Relative Rate of Return
RS	7.44%	0.82
RH	1.99%	0.22
RA	3.10%	0.34
GS/GM	13.85%	1.53
GMH	8.46%	0.93
GL	10.32%	1.14
GLH	5.82%	0.64
L	10.19%	1.12
HVPS	9.42%	1.04
AL	7.92%	0.87
SE	41.90%	4.62
SM	17.23%	1.90
SH	9.30%	1.02
MTS	30.55%	3.37
PAL	56.79%	6.26
TOTAL	9.08%	

Q. Have you develop distribution rates for rate schedules GL, GLH, L and HVPS that reflect your recommended rate schedule increases shown in Table 6?

A. Yes. Baron Exhibit__(SJB-5) shows proposed rates for each of these schedules using the recommended increases shown in Table 6. The rates reflect a scale down of the Company's proposed rates for each of these schedules. Of course, these rates and the increases shown in Table 6 are based on the Company's full $143 million revenue increase.

Q. If the Company receives a distribution revenue increase less than the $143 million requested, how should it be allocated to rate schedules?

A. My recommendation is to proportionately scale back the total proposed revenue for each rate schedule that include the increases in Table 5. For example, present distribution revenues for rate RS, before any increase, are $147,575,381. From Table 5, DII is recommending an increase for rate RS of $84,533,000, assuming that the Company received its entire $143 million request. Total proposed revenues for rate RS, after the increase, would be $232,108,662. If, for example, Duquesne receives authorization from the Commission to increase its distribution rates by $100 million, the total proposed revenues for each rate schedule would be scaled back by 10.3%. Using this example, RS total revenues would be $208,108,662. The increase to rate RS would thus be $60,598,132. These calculations are shown in Baron Exhibit__(SJB-6) for all rate schedules, using the $100 million increase example.

Q. Why is it appropriate to scale back the total revenues, after the assumed $143 million increase, rather than the increases themselves (shown in Table 5)?

A. This "total revenue" scale back approach is necessary because some rate schedules are being allocated decreases in distribution revenues. If the increases and decreases shown in Table 5 are simply scaled back, those rate schedules receiving a decrease would actually pay higher distribution rates under any scenario in which Duquesne was authorized a lower overall distribution revenue increase (for example, $100 million instead of its requested $143 million). This occurs because the proposed decreases for these rate schedules would be scaled back, resulting in higher overall distribution charges. This clearly doesn't make sense. Using a "total revenue" scale back approach reasonably adjusts the proposed revenue increases for all rate schedules, including those that are being assigned rate decreases.

IV. DISTRIBUTION SYSTEM IMPROVEMENT CHARGE

Q. Have you reviewed Duquesne's proposal to implement a Distribution System Improvement Charge ("DSIC") in this proceeding?

A. Yes. The Company's proposed DSIC is described in detail beginning on page 25 of Mr. William V. Pfrommer's Direct Testimony. The proposed DSIC is in essence an automatic adjustment clause that would recover incremental fixed distribution system costs ("depreciation and pre-tax return"). The charge would be updated quarterly and recovered from all kWh sales from all rate schedules.

Q. Should the Company's proposed DSIC be approved by the Commission?

A. No. As I will discuss below, the Company's proposed DSIC is unreasonable and I recommend that the Commission reject it.

Q. The DSIC rider (No. 20) contains a formula that produces a "DSIC" in the form of a percentage factor. Is it your understanding of the Company's proposal that this "percentage factor" would be applied to all distribution revenues as a surcharge?

A. Based on the formula contained in Rider No. 20, Mr. Pfrommer's testimony and his exhibits showing the DSIC factors for 2007 and future years, it appears that the DSIC is in the form of a "revenue percentage factor", as opposed to say, a uniform charge per kWh. However, in two portions of Rider No. 20, there is language that implies that the DSIC is in the form of a kWh charge. Specifically, on page 1 of the rider it states: "This DSIC applies to all kilowatt-hours in each Rate Schedule and applicable Riders under this Tariff and becomes effective for bills rendered on or after April 1, 2007." On page 2 of the rider, it states: "The DSIC, determined to the nearest one-thousandth of one mill per kilowatt-hour, in accordance with the formula set forth below, shall be applied to all kilowatt-hours billed for electric service during the billing month". I assume that these references to "kilowatt-hours" are in error, and that the DSIC is in the form of a percentage revenue factor. Though I am recommending that the Commission reject the proposal, if the rider is approved, it should be corrected to eliminate the references to kilowatt-hours.

Q. What is Mr. Pfrommer's rationale for requesting a DSIC?

A. On page 25, lines 17 through 19, Mr. Pfrommer's stated that the proposed DSIC "will mitigate rate impacts to customers and allow rates to increase more gradually than through the filing of much larger base rate increases."

Q. Did any of the Company witnesses identify any "changed circumstances" that would necessitate a DSIC from a financial standpoint?

A. No. None of the Company's witnesses identified any such circumstances that would justify an automatic adjustment clause for certain distribution-related investments. The Company has always made such investments without any DSIC and recovered its costs, including a fair rate of return, by filing a base rate proceeding. Duquesne has this right and can file a base rate proceeding at any time it chooses in order to collect its costs and earn a return on all of its investments.

Essentially, Duquesne's proposed DSIC would create a mechanism that would insulate the Company from regulatory lag, without providing consumers the opportunity to benefit from potential offsetting cost decreases elsewhere or sales increases that may otherwise obviate the need for an increase despite the additional distribution plant investment. Such an approach is biased in favor of the Company's shareholders and against ratepayers.

Furthermore, the DSIC would also insulate the Company from the kind of regulatory review and auditing scrutiny that are part of the normal rate case process. The Commission, its Staff, and other parties would no longer be able to review the

Company's distribution investment costs for reasonableness and for whether they are used and useful in the provisions of service to ratepayers.

Q. Did the Company provide any commitment to filing less frequent rate cases is the DSIC were approved by the Commission?

A. No. Duquesne provided no commitment to the Commission or the parties to filing less frequent rate cases if the DSIC were approved. To underscore this point, the following is the question and the Company's response to OCA-IV-75:

> **Please state whether Duquesne Light C. anticipates that the proposed DSIC will reduce the frequency of rate cases. If yes, please identify the estimated interval until the next rate case until the next rate case with and without the DSIC. If not, explain why not.**
>
> **Response:**
>
> **If a DSIC were authorized by legislation and approved by the Commission, the DSIC would mitigate attrition to return associated with increasing investment related to replacements and reliability improvements, and to that extent would reduce the frequency of rate filings. However, the decision of when the next rate case will be filed will be affected by numerous other factors, such as changes in operating costs due to inflation and changes in capital costs. *As a result, Duquesne cannot identify when its next rate filing would be made, with or without a DSIC.* (emphasis added)**

The Company's response to this data request indicates that it cannot provide any assurance that the approval and operation of a DSIC would decrease the frequency of rate filings before the Commission.

Q. Has the Company provided any mechanism in its DSIC to provide affected consumers the opportunity to benefit from distribution plant retirements or depreciation that may offset the increases associated with the DSIC?

A. No. The only provisions included in the Company's proposal are those designed to reflect cost increases. There are no provisions to reflect potential cost decreases. For example, there is nothing in the DSIC that would reflect potential productivity increases (e.g., lower maintenance expenses) due to the addition of more modern distribution facilities. Under Duquesne's proposal, customers would be charged the cost of the new investment and the Company's shareholders would receive the benefit (if any) of productivity increases. This is but one example of the potential harm to ratepayers from a single issue rate case, which the DSIC represents.

Q. Are there other concerns that you have with the proposed DSIC?

A. Yes. In addition to the potential for the Company to earn excess returns as a result of the DSIC (by failing to provide ratepayers potential offsetting cost savings or revenue increases due to customer consumption increases), the DSIC will also lengthen the period, all else being equal, between distribution rate cases. Although Duquesne could not provide definitive dates, it follows that if Duquesne is recovering its fixed costs associated with certain of its incremental distribution investments on an automatic basis, while retaining potential offsetting savings, that the Company would file less frequent base rate cases. The problem with this, in addition to the lost opportunity for the Commission to evaluate the overall distribution revenue requirement is that it also precludes the opportunity of the Staff, OCA and other parties to evaluate the reasonableness of the underlying allocation of distribution revenue requirements to rate classes. As set forth in the previous section of my testimony, significant interclass subsidies will continue to exist after this case, even under my proposal.

Q. Do you have any concerns with Duquesne's proposal to apply the DSIC "revenue factor" to sales from each rate schedule and customer?

A. Yes. The proposed DSIC incorporates a recovery factor that essentially allocates the incremental distribution investment to all rate schedules on the basis of relative distribution revenues, rather than the cost of service allocation factors reflecting distribution related facilities. In particular, it would apply to rate HVPS distribution revenues, which primarily consists of metering costs, since these customers are served at transmission voltages and do not use secondary or primary lines and substation facilities. There is no justification for the DSIC to apply to this rate schedule or to any customer served at transmission voltages.

Similarly, because it is based on a percentage of the customer's distribution charges, the DSIC would penalize rate schedules that are earning rates of return in excess of the system average. This is similar to my tipping analogy discussed in the prior section.

Q. **Are you familiar with PPL Electronic Utilities Corporation's ("PPL") request for approval of a DSIC in its most recent base rate proceeding, Docket No. R-00049255?**

A. Yes. I testified in that PPL proceeding and specifically addressed the Company's request for approval of a DSIC. In that proceeding PPL proposed a DSIC that was similar to the one that Duquesne is proposing in this case.

Q. **What was the Commission's final decision regarding PPL's DSIC proposal in that case?**

A. The Commission rejected PPL's proposed DSIC in that docket. Specifically, the Commission found the following:

> **We agree with the ALJ's disposition of this issue and deny the Exceptions of PPL and the OSBA. Although Section 1307 of the Code carves out exceptions to the general prohibition against single issue ratemaking, we must reject PPL's request to implement a DSIC. 66 Pa. C.S. § 1307. The Company has not demonstrated a need for the DSIC or a need to by-pass the normal ratemaking process. Although PPL asserted that a DSIC would "facilitate" making the investment necessary to upgrade or replace its aging infrastructure, the Company did not submit evidence that the repairs would not be made if the DSIC is not available. Nor did PPL demonstrate it was approaching serious reliability problems. (R.D. at 36, 46). Additionally, the Commission notes the current uncertainty associated with its authority to approve automatic adjustment mechanisms beyond our water utilities. *See Pennsylvania Public Utility Commission v. PPL Electric Utilities Corporation,* Docket No. R-00049255, Order entered Dec. 22, 2005, slip op. at 23.**

Q. Do you believe that the Commission's findings regarding PPL's request are equally valid and applicable to Duquesne's proposed DSIC?

A. Yes. Referring to the Commission's finding, which I cited above, the Company failed to provide any evidence that system repairs would not be made in the absence of the DSIC. Duquesne has not presented evidence in this proceeding that it has serious reliability problems that would be remedied by the DSIC.

Q. What is your recommendation to the Commission regarding the proposed DSIC?

A. Based on the reasons that I just discussed, I recommend that the Commission reject the proposed DSIC.

V. TRANSMISSION SERVICE CHARGE ("TSC")

Q. Have you reviewed the Company's proposal to implement a Transmission Service Charge?

A. Yes. As explained in the direct testimony of Duquesne witness Mr. Pfrommer, the Company is proposing a TSC that will recover network transmission service costs incurred pursuant to the PJM OATT on a pass-through basis from customers. The Duquesne TSC is designed to recover these transmission expenses on the basis of each rate schedule's contribution to the Duquesne 1 CP demand, which is the basis on which the Company is charged for POLR transmission service. Rate schedules on which customers are normally billed on a kW demand basis will be charged a TSC using the customer's 1 CP demand as the billing determinant.

Q. Do you agree with the Company's approach to recovering its transmission expenses from POLR customers?

A. Yes. Duquesne recognizes that it is essential to have a competitively neutral transmission rate for each customer, whether the customer takes POLR service or service from an EGS. The only transmission expense recovery methodology that will produce such a competitively neutral result is the approach taken by the Company to allocate and recover costs on a "1 CP" basis. As discussed by Mr. Pfrommer, PJM assigns the cost for network service to either Duquesne (for a POLR customer) or an EGS, based on the customer's contribution to the Duquesne transmission zone 1 CP demand. If Duquesne does not follow this same cost allocation and rate design methodology in its retail POLR transmission cost recovery rate (the proposed TSC), there will be an uneconomic subsidy (either paid or received) provided to POLR customers, relative to what that same customer would be charged if the customer selected an EGS for service.[2] In order to prevent an anti-competitive result, it is necessary and appropriate for the Company to allocate its PJM transmission expenses to rate schedules in the same manner as it is being assigned these costs by PJM. In addition, to the extent that a rate schedule includes kW demand charges, these transmission costs should also be charged on a demand basis, reflecting the customer's 1 CP demand. Duquesne's proposed TSC accomplishes this objective and should be approved by the Commission.

Q. Is the Company's TSC consistent with the Choice Act?

A. Yes. Section 2804(6) of the Choice Act states:

> **Consistent with the provision of section 2806, the Commission shall require that a public utility that owns or operates jurisdictional transmission and distribution facilities shall provide transmission and distribution service**

[2] Though the EGS may not charge the customer its actual transmission costs, the EGS will be charged for transmission service associated with the customer on the basis of the customer's 1 CP demand.

> **to all retail electric customers in their service territory and to electric cooperative corporations and electric generation suppliers, affiliated or non-affiliated, on rates, terms of access and conditions that are comparable to the utility's own use of the system. (66 Pa.C.S. § 2804(6)).**

Duquesne is a public utility that owns jurisdictional transmission and distribution facilities. Because the TSC tracks the rates and billing determinants on which Duquesne purchases service from PJM, the TSC ensures that retail electric customers are provided with transmission service on rates comparable to the Company's use of the system.

Q. Is the Company's TSC generally consistent with traditional ratemaking principles (<u>i.e.</u>, just, reasonable and not unduly discriminatory)?

A. Yes. As I discussed, Duquesne's proposed TSC follows cost causation and cost of service principles. Therefore, it is just, reasonable and not unduly discriminatory.

VI. TARIFF ISSUES

Q. The Company is proposing to modify tariff Rule 4 to eliminate the ability of the Company to enter special contracts with customers whose load exceeds 100 kW. Do you have any concerns regarding this proposal by the Company?

A. Yes. According to the testimony of Company witness Ms. Krajovic, Duquesne is eliminating this provision of Rule 4 of its tariff because transmission and distribution charges constitute a very small portion of a large customer's bill.

Q. Does this current provision of Rule 4 require the Company to enter contracts with its qualified customers?

A. No. Rule 4 simply gives the Company a right (option) to enter such contracts "to address changing business needs or operating conditions." Even if Ms. Krajovic is correct that a Rule 4 contract would only apply to transmission and distribution charges, it is reasonable for the Company to continue to maintain this option. Since there is no obligation to enter a Rule 4 contract, it would appear to be beneficial to maintain the option in the event that the Company, the affected Rule 4 customer and other Duquesne customers could benefit from such a contract.

Q. Did the Company perform any surveys or other studies to support its proposed elimination of the Rule 4 contract option?

A. No. Baron Exhibit__(SJB-7) contains a copy of the Company's response to DII-II-15, in which it is confirmed that no such surveys or studies were performed on this issue.

Q. Do you believe that customers support continuation of this option?

A. Based on the testimony of the DII witnesses, yes.

Q. What is your recommendation regarding the elimination of the special contract provisions of tariff Rule 4?

A. This tariff rule should be continued, since it is only applicable in the event that the Company, "in its sole discretion" determines that such a contract should be entered. There is no reason to eliminate this tariff rule. In addition, any other language in the tariff that is inconsistent with this concept should be modified.

Q. Do you have any other comments regarding Duquesne's proposed tariff changes?

A. Yes. Duquesne proposes several changes to reflect the elimination of the fixed price POLR option for Large C&I customers. Because this option will continue through May 31, 2007, these changes should be rejected at this time. Duquesne can address this issue in a compliance or implementation plan filing at a later date.

Q. Do you have concerns regarding any specific rate schedule issues in this case?

A. Yes. Duquesne Rate L contains a provision to recognize that some customers taking service on this rate do so at transmission voltages exceeding 69,000 volts. Some customers on this rate take service at 138 kV. The proposed Rate L tariff includes an "Untransformed Service Credit" (voltage credit) for customers taking service at transmission voltages of $0.091 per kW. This transmission service credit is decreasing from the $0.0925 per kW in the current tariff.

Q. Has the Company provided any analysis in this case justifying a transmission service voltage credit of $0.091 per kW?

A. No.

Q. Is the magnitude of this voltage credit consistent with other evidence in this case regarding the cost of providing distribution service to transmission voltage customers?

A. No. Under the Company's proposed rates, transmission service customers on Rate L will pay $5.74 per kW for distribution demand, versus $5.83 kW for customers taking primary service.[3] This $5.74 per kW distribution rate for transmission service customers compares to the Company's proposed Rate HVPS distribution rate of $0.30 per kW.[4] Rate HVPS customers take service at 69,000 volts or higher and thus have similar characteristics to Rate L transmission service customers, at least with regard to factors that influence the cost of providing distribution service.

Q. Is the proposed Rate HVPS distribution demand charge consistent with the cost of providing distribution service to a transmission voltage customer on the Duquesne system?

A. Yes. In fact, as I discussed earlier in my testimony, even this rate ($0.30 per kW) exceeds cost of service.

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[3] These demand charges reflect the pricing of demand in excess of 5,000 kW per month. The demand charge for the first 5,000 kW per month is $30,555 under the Company's proposed tariff.
[4] This is based on the cost per kW of the minimum 30,000 kW charge ($9,115 divided by 30,000).

Q. Is there any reason to believe that the cost to provide distribution service to a Rate L transmission customer is "19 times" greater than an HVPS transmission customer?

A. No. There is no reason to believe that the cost per kW to provide service to a Rate L customer taking distribution service at 138,000 volts is materially different than it is for an HVPS customer. Clearly, there is no basis to believe that it is 19 times more expensive to serve a Rate L customer than a similarly configured Rate HVPS customer.

Q. Are there any DII customers adversely impacted by this unreasonable voltage credit?

A. Yes. For example, U.S. Steel has a Rate L facility with a monthly demand of approximately 9,000 kW that takes service at 138,000 volts. The proposed Rate L distribution demand cost (including the $0.091 per kW credit) for this facility would be approximately $70,000 per month, while the cost on Rate HVPS would be $2,800, based on the unit charge per kW from the proposed HVPS minimum rate.[5] This is a difference of $806,400 in distribution charges per year. Even if the 30,000 kW HVPS minimum charge is recognized, the HVPS bill for a 9,000 kW load would

[5] The proposed HVPS distribution rate for excess kW (greater than 30,000 per month) is only $0.016 per kW.

only be $9,115 per month, the monthly minimum charge, which is a difference of $730,620 annually.

Q. Based on this comparison, do believe that the Rate L "Untransformed Service Credit" is reasonable?

A. No. This credit is not just or reasonable and appears to be unduly discriminatory. Duquesne should develop an updated credit and modify its proposed tariff in its rebuttal testimony in this case.

Q. Does that complete your testimony?

A. Yes.

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission	:
	: **Docket No. R-00061346C0001-0005**
v.	:
	:
Duquesne Light Company	:

EXHIBITS

OF

STEPHEN J. BARON

ON BEHALF OF

DUQUESNE INDUSTRIAL INTERVENORS

AND

THE INDUSTRIAL ENERGY CONSUMERS OF PENNSYLVANIA

J. KENNEDY AND ASSOCIATES, INC.
ROSWELL, GEORGIA
JULY 2006

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission	:	
	:	**Docket No. R-00061346C0001-0005**
v.	:	
	:	
Duquesne Light Company	:	

EXHIBIT SJB-1

OF

STEPHEN J. BARON

ON BEHALF OF

DUQUESNE INDUSTRIAL INTERVENORS

AND

THE INDUSTRIAL ENERGY CONSUMERS OF PENNSYLVANIA

Expert Testimony Appearances
of
Stephen J. Baron
As of May 2006

Date	Case	Jurisdict.	Party	Utility	Subject
4/81	203(B)	KY	Louisville Gas & Electric Co.	Louisville Gas & Electric Co.	Cost-of-service.
4/81	ER-81-42	MO	Kansas City Power & Light Co.	Kansas City Power & Light Co.	Forecasting.
6/81	U-1933	AZ	Arizona Corporation Commission	Tucson Electric Co.	Forecasting planning.
2/84	8924	KY	Airco Carbide	Louisville Gas & Electric Co.	Revenue requirements, cost-of-service, forecasting, weather normalization.
3/84	84-038-U	AR	Arkansas Electric Energy Consumers	Arkansas Power & Light Co.	Excess capacity, cost-of-service, rate design.
5/84	830470-EI	FL	Florida Industrial Power Users' Group	Florida Power Corp.	Allocation of fixed costs, load and capacity balance, and reserve margin. Diversification of utility.
10/84	84-199-U	AR	Arkansas Electric Energy Consumers	Arkansas Power and Light Co.	Cost allocation and rate design.
11/84	R-842651	PA	Lehigh Valley Power Committee	Pennsylvania Power & Light Co.	Interruptible rates, excess capacity, and phase-in.
1/85	85-65	ME	Airco Industrial Gases	Central Maine Power Co.	Interruptible rate design.
2/85	I-840381	PA	Philadelphia Area Industrial Energy Users' Group	Philadelphia Electric Co.	Load and energy forecast.
3/85	9243	KY	Alcan Aluminum Corp., et al.	Louisville Gas & Electric Co.	Economics of completing fossil generating unit.
3/85	3498-U	GA	Attorney General	Georgia Power Co.	Load and energy forecasting, generation planning economics.
3/85	R-842632	PA	West Penn Power Industrial Intervenors	West Penn Power Co.	Generation planning economics, prudence of a pumped storage hydro unit.
5/85	84-249	AR	Arkansas Electric Energy Consumers	Arkansas Power & Light Co.	Cost-of-service, rate design return multipliers.
5/85		City of Santa	Chamber of Commerce	Santa Clara Municipal	Cost-of-service, rate design.

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Date	Case	Jurisdict.	Party	Utility	Subject
6/85	84-768-E-42T	Clara WV	West Virginia Industrial Intervenors	Monongahela Power Co.	Generation planning economics, prudence of a pumped storage hydro unit.
6/85	E-7 Sub 391	NC	Carolina Industrials (CIGFUR III)	Duke Power Co.	Cost-of-service, rate design, interruptible rate design.
7/85	29046	NY	Industrial Energy Users Association	Orange and Rockland Utilities	Cost-of-service, rate design.
10/85	85-043-U	AR	Arkansas Gas Consumers	Arkla, Inc.	Regulatory policy, gas cost-of-service, rate design.
10/85	85-63	ME	Airco Industrial Gases	Central Maine Power Co.	Feasibility of interruptible rates, avoided cost.
2/85	ER-8507698	NJ	Air Products and Chemicals	Jersey Central Power & Light Co.	Rate design.
3/85	R-850220	PA	West Penn Power Industrial Intervenors	West Penn Power Co.	Optimal reserve, prudence, off-system sales guarantee plan.
2/86	R-850220	PA	West Penn Power Industrial Intervenors	West Penn Power Co.	Optimal reserve margins, prudence, off-system sales guarantee plan.
3/86	85-299U	AR	Arkansas Electric Energy Consumers	Arkansas Power & Light Co.	Cost-of-service, rate design, revenue distribution.
3/86	85-726-EL-AIR	OH	Industrial Electric Consumers Group	Ohio Power Co.	Cost-of-service, rate design, interruptible rates.
5/86	86-081-E-GI	WV	West Virginia Energy Users Group	Monongahela Power Co.	Generation planning economics, prudence of a pumped storage hydro unit.
8/86	E-7 Sub 408	NC	Carolina Industrial Energy Consumers	Duke Power Co.	Cost-of-service, rate design, interruptible rates.
10/86	U-17378	LA	Louisiana Public Service Commission Staff	Gulf States Utilities	Excess capacity, economic analysis of purchased power.
12/86	38063	IN	Industrial Energy Consumers	Indiana & Michigan Power Co.	Interruptible rates.

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Date	Case	Jurisdict.	Party	Utility	Subject
3/87	EL-86-53-001 EL-86-57-001	Federal Energy Regulatory Commission (FERC)	Louisiana Public Service Commission Staff	Gulf States Utilities, Southern Co.	Cost/benefit analysis of unit power sales contract.
4/87	U-17282	LA	Louisiana Public Service Commission Staff	Gulf States Utilities	Load forecasting and imprudence damages, River Bend Nuclear unit.
5/87	87-023-E-C	WV	Airco Industrial Gases	Monongahela Power Co.	Interruptible rates.
5/87	87-072-E-G1	WV	West Virginia Energy Users' Group	Monongahela Power Co.	Analyze Mon Power's fuel filing and examine the reasonableness of MP's claims.
5/87	86-524-E-SC	WV	West Virginia Energy Users' Group	Monongahela Power Co.	Economic dispatching of pumped storage hydro unit.
5/87	9781	KY	Kentucky Industrial Energy Consumers	Louisville Gas & Electric Co.	Analysis of impact of 1986 Tax Reform Act.
6/87	3673-U	GA	Georgia Public Service Commission	Georgia Power Co.	Economic prudence, evaluation of Vogtle nuclear unit - load forecasting, planning.
6/87	U-17282	LA	Louisiana Public Service Commission Staff	Gulf States Utilities	Phase-in plan for River Bend Nuclear unit.
7/87	85-10-22	CT	Connecticut Industrial Energy Consumers	Connecticut Light & Power Co.	Methodology for refunding rate moderation fund.
8/87	3673-U	GA	Georgia Public Service Commission	Georgia Power Co.	Test year sales and revenue forecast.
9/87	R-850220	PA	West Penn Power Industrial Intervenors	West Penn Power Co.	Excess capacity, reliability of generating system.
10/87	R-870651	PA	Duquesne Industrial Intervenors	Duquesne Light Co.	Interruptible rate, cost-of-service, revenue allocation, rate design.
10/87	I-860025	PA	Pennsylvania Industrial Intervenors		Proposed rules for cogeneration, avoided cost, rate recovery.

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Date	Case	Jurisdict.	Party	Utility	Subject
10/87	E-015/ GR-87-223	MN	Taconite Intervenors	Minnesota Power & Light Co.	Excess capacity, power and cost-of-service, rate design.
10/87	8702-EI	FL	Occidental Chemical Corp.	Florida Power Corp.	Revenue forecasting, weather normalization.
12/87	87-07-01	CT	Connecticut Industrial Energy Consumers	Connecticut Light Power Co.	Excess capacity, nuclear plant phase-in.
3/88	10064	KY	Kentucky Industrial Energy Consumers	Louisville Gas & Electric Co.	Revenue forecast, weather normalization rate treatment of cancelled plant.
3/88	87-183-TF	AR	Arkansas Electric Consumers	Arkansas Power & Light Co.	Standby/backup electric rates.
5/88	870171C001	PA	GPU Industrial Intervenors	Metropolitan Edison Co.	Cogeneration deferral mechanism, modification of energy cost recovery (ECR).
6/88	870172C005	PA	GPU Industrial Intervenors	Pennsylvania Electric Co.	Cogeneration deferral mechanism, modification of energy cost recovery (ECR).
7/88	88-171-EL-AIR 88-170-EL-AIR Interim Rate Case	OH	Industrial Energy Consumers	Cleveland Electric/ Toledo Edison	Financial analysis/need for interim rate relief.
7/88	Appeal of PSC	19th Judicial Docket U-17282	Louisiana Public Service Commission Circuit Court of Louisiana	Gulf States Utilities	Load forecasting, imprudence damages.
11/88	R-880989	PA	United States Steel	Carnegie Gas	Gas cost-of-service, rate design.
11/88	88-171-EL-AIR 88-170-EL-AIR	OH	Industrial Energy Consumers	Cleveland Electric/ Toledo Edison. General Rate Case.	Weather normalization of peak loads, excess capacity, regulatory policy.
3/89	870216/283 284/286	PA	Armco Advanced Materials Corp., Allegheny Ludlum Corp.	West Penn Power Co.	Calculated avoided capacity, recovery of capacity payments.

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Date	Case	Jurisdict.	Party	Utility	Subject
8/89	8555	TX	Occidental Chemical Corp.	Houston Lighting & Power Co.	Cost-of-service, rate design.
8/89	3840-U	GA	Georgia Public Service Commission	Georgia Power Co.	Revenue forecasting, weather normalization.
9/89	2087	NM	Attorney General of New Mexico	Public Service Co. of New Mexico	Prudence - Palo Verde Nuclear Units 1, 2 and 3, load fore-casting.
10/89	2262	NM	New Mexico Industrial Energy Consumers	Public Service Co. of New Mexico	Fuel adjustment clause, off-system sales, cost-of-service, rate design, marginal cost.
11/89	38728	IN	Industrial Consumers for Fair Utility Rates	Indiana Michigan Power Co.	Excess capacity, capacity equalization, jurisdictional cost allocation, rate design, interruptible rates.
1/90	U-17282	LA	Louisiana Public Service Commission Staff	Gulf States Utilities	Jurisdictional cost allocation, O&M expense analysis.
5/90	890366	PA	GPU Industrial Intervenors	Metropolitan Edison Co.	Non-utility generator cost recovery.
6/90	R-901609	PA	Armco Advanced Materials Corp., Allegheny Ludlum Corp.	West Penn Power Co.	Allocation of QF demand charges in the fuel cost, cost-of-service, rate design.
9/90	8278	MD	Maryland Industrial Group	Baltimore Gas & Electric Co.	Cost-of-service, rate design, revenue allocation.
12/90	U-9346 Rebuttal	MI	Association of Businesses Advocating Tariff Equity	Consumers Power Co.	Demand-side management, environmental externalities.
12/90	U-17282 Phase IV	LA	Louisiana Public Service Commission Staff	Gulf States Utilities	Revenue requirements, jurisdictional allocation.
12/90	90-205	ME	Airco Industrial Gases	Central Maine Power Co.	Investigation into interruptible service and rates.
1/91	90-12-03 Interim	CT	Connecticut Industrial Energy Consumers	Connecticut Light & Power Co.	Interim rate relief, financial analysis, class revenue allocation.

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Date	Case	Jurisdict.	Party	Utility	Subject
5/91	90-12-03 Phase II	CT	Connecticut Industrial Energy Consumers	Connecticut Light & Power Co.	Revenue requirements, cost-of-service, rate design, demand-side management.
8/91	E-7, SUB SUB 487	NC	North Carolina Industrial Energy Consumers	Duke Power Co.	Revenue requirements, cost allocation, rate design, demand-side management.
8/91	8341 Phase I	MD	Westvaco Corp.	Potomac Edison Co.	Cost allocation, rate design, 1990 Clean Air Act Amendments.
8/91	91-372 EL-UNC	OH	Armco Steel Co., L.P.	Cincinnati Gas & Electric Co.	Economic analysis of cogeneration, avoid cost rate.
9/91	P-910511 P-910512	PA	Allegheny Ludlum Corp., Armco Advanced Materials Co., The West Penn Power Industrial Users' Group	West Penn Power Co.	Economic analysis of proposed CWIP Rider for 1990 Clean Air Act Amendments expenditures.
9/91	91-231 -E-NC	WV	West Virginia Energy Users' Group	Monongahela Power Co.	Economic analysis of proposed CWIP Rider for 1990 Clean Air Act Amendments expenditures.
10/91	8341 - Phase II	MD	Westvaco Corp.	Potomac Edison Co.	Economic analysis of proposed CWIP Rider for 1990 Clean Air Act Amendments expenditures.
10/91 Note: No testimony was prefiled on this.	U-17282	LA	Louisiana Public Service Commission Staff	Gulf States Utilities	Results of comprehensive management audit.
11/91	U-17949 Subdocket A	LA	Louisiana Public Service Commission Staff	South Central Bell Telephone Co. and proposed merger with Southern Bell Telephone Co.	Analysis of South Central Bell's restructuring and
12/91	91-410-EL-AIR	OH	Armco Steel Co., Air Products & Chemicals, Inc.	Cincinnati Gas & Electric Co.	Rate design, interruptible rates.
12/91	P-880286	PA	Armco Advanced Materials Corp., Allegheny Ludlum Corp.	West Penn Power Co.	Evaluation of appropriate avoided capacity costs - QF projects.

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Date	Case	Jurisdict.	Party	Utility	Subject
1/92	C-913424	PA	Duquesne Interruptible Complainants	Duquesne Light Co.	Industrial interruptible rate.
6/92	92-02-19	CT	Connecticut Industrial Energy Consumers	Yankee Gas Co.	Rate design.
8/92	2437	NM	New Mexico Industrial Intervenors	Public Service Co. of New Mexico	Cost-of-service.
8/92	R-00922314	PA	GPU Industrial Intervenors	Metropolitan Edison Co.	Cost-of-service, rate design, energy cost rate.
9/92	39314	ID	Industrial Consumers for Fair Utility Rates	Indiana Michigan Power Co.	Cost-of-service, rate design, energy cost rate, rate treatment.
10/92	M-00920312 C-007	PA	The GPU Industrial Intervenors	Pennsylvania Electric Co.	Cost-of-service, rate design, energy cost rate, rate treatment.
12/92	U-17949	LA	Louisiana Public Service Commission Staff	South Central Bell Co.	Management audit.
12/92	R-00922378	PA	Armco Advanced Materials Co. The WPP Industrial Intervenors	West Penn Power Co.	Cost-of-service, rate design, energy cost rate, SO_2 allowance rate treatment.
1/93	8487	MD	The Maryland Industrial Group	Baltimore Gas & Electric Co.	Electric cost-of-service and rate design, gas rate design (flexible rates).
2/93	E002/GR-92-1185	MN	North Star Steel Co. Praxair, Inc.	Northern States Power Co.	Interruptible rates.
4/93	EC92 21000 ER92-806-000 (Rebuttal)	Federal Energy Regulatory Commission	Louisiana Public Service Commission Staff	Gulf States Utilities/Entergy agreement.	Merger of GSU into Entergy System; impact on system
7/93	93-0114-E-C	WV	Airco Gases	Monongahela Power Co.	Interruptible rates.
8/93	930759-EG	FL	Florida Industrial Power Users' Group	Generic - Electric Utilities	Cost recovery and allocation of DSM costs.
9/93	M-009 30406	PA	Lehigh Valley Power Committee	Pennsylvania Power & Light Co.	Ratemaking treatment of off-system sales revenues.

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Date	Case	Jurisdict.	Party	Utility	Subject
11/93	346	KY	Kentucky Industrial Utility Customers	Generic - Gas Utilities	Allocation of gas pipeline transition costs - FERC Order 636.
12/93	U-17735	LA	Louisiana Public Service Commission Staff	Cajun Electric Power Cooperative	Nuclear plant prudence, forecasting, excess capacity.
4/94	E-015/ GR-94-001	MN	Large Power Intervenors	Minnesota Power Co.	Cost allocation, rate design, rate phase-in plan.
5/94	U-20178	LA	Louisiana Public Service Commission	Louisiana Power & Light Co.	Analysis of least cost integrated resource plan and demand-side management program.
7/94	R-00942986	PA	Armco, Inc.; West Penn Power Industrial Intervenors	West Penn Power Co.	Cost-of-service, allocation of rate increase, rate design, emission allowance sales, and operations and maintenance expense.
7/94	94-0035-E-42T	WV	West Virginia Energy Users Group	Monongahela Power Co.	Cost-of-service, allocation of rate increase, and rate design.
8/94	EC94 13-000	Federal Energy Regulatory Commission	Louisiana Public Service Commission	Gulf States Utilities/Entergy	Analysis of extended reserve shutdown units and violation of system agreement by Entergy.
9/94	R-00943 081 R-00943 081C0001	PA	Lehigh Valley Power Committee	Pennsylvania Public Utility Commission	Analysis of interruptible rate terms and conditions, availability.
9/94	U-17735	LA	Louisiana Public Service Commission	Cajun Electric Power Cooperative	Evaluation of appropriate avoided cost rate.
9/94	U-19904	LA	Louisiana Public Service Commission	Gulf States Utilities	Revenue requirements.
10/94	5258-U	GA	Georgia Public Service Commission	Southern Bell Telephone & Telegraph Co.	Proposals to address competition in telecommunication markets.
11/94	EC94-7-000 ER94-898-000	FERC	Louisiana Public Service Commission	El Paso Electric and Central and Southwest	Merger economics, transmission equalization hold harmless proposals.
2/95	941-430EG	CO	CF&I Steel, L.P.	Public Service Company of Colorado	Interruptible rates, cost-of-service.

Expert Testimony Appearances
of
Stephen J. Baron
As of May 2006

Date	Case	Jurisdict.	Party	Utility	Subject
4/95	R-00943271	PA	PP&L Industrial Customer Alliance	Pennsylvania Power & Light Co.	Cost-of-service, allocation of rate increase, rate design, interruptible rates.
6/95	C-00913424 C-00946104	PA	Duquesne Interruptible Complainants	Duquesne Light Co.	Interruptible rates.
8/95	ER95-112 -000	FERC	Louisiana Public Service Commission	Entergy Services, Inc.	Open Access Transmission Tariffs - Wholesale.
10/95	U-21485	LA	Louisiana Public Service Commission	Gulf States Utilities Company	Nuclear decommissioning, revenue requirements, capital structure.
10/95	ER95-1042 -000	FERC	Louisiana Public Service Commission	System Energy Resources, Inc.	Nuclear decommissioning, revenue requirements.
10/95	U-21485	LA	Louisiana Public Service Commission	Gulf States Utilities Co.	Nuclear decommissioning and cost of debt capital, capital structure.
11/95	I-940032	PA	Industrial Energy Consumers of Pennsylvania	State-wide - all utilities	Retail competition issues.
7/96	U-21496	LA	Louisiana Public Service Commission	Central Louisiana Electric Co.	Revenue requirement analysis.
7/96	8725	MD	Maryland Industrial Group	Baltimore Gas & Elec. Co., Potomac Elec. Power Co., Constellation Energy Co.	Ratemaking issues associated with a Merger.
8/96	U-17735	LA	Louisiana Public Service Commission	Cajun Electric Power Cooperative	Revenue requirements.
9/96	U-22092	LA	Louisiana Public Service Commission	Entergy Gulf States, Inc.	Decommissioning, weather normalization, capital structure.
2/97	R-973877	PA	Philadelphia Area Industrial Energy Users Group	PECO Energy Co.	Competitive restructuring policy issues, stranded cost, transition charges.
6/97	Civil Action No. 94-11474	US Bank-ruptcy Court Middle District of Louisiana	Louisiana Public Service Commission	Cajun Electric Power Cooperative	Confirmation of reorganization plan; analysis of rate paths produced by competing plans.

Expert Testimony Appearances
of
Stephen J. Baron
As of May 2006

Date	Case	Jurisdict.	Party	Utility	Subject
6/97	R-973953	PA	Philadelphia Area Industrial Energy Users Group	PECO Energy Co.	Retail competition issues, rate unbundling, stranded cost analysis.
6/97	8738	MD	Maryland Industrial Group	Generic	Retail competition issues
7/97	R-973954	PA	PP&L Industrial Customer Alliance	Pennsylvania Power & Light Co.	Retail competition issues, rate unbundling, stranded cost analysis.
10/97	97-204	KY	Alcan Aluminum Corp. Southwire Co.	Big River Electric Corp.	Analysis of cost of service issues - Big Rivers Restructuring Plan
10/97	R-974008	PA	Metropolitan Edison Industrial Users	Metropolitan Edison Co.	Retail competition issues, rate unbundling, stranded cost analysis.
10/97	R-974009	PA	Pennsylvania Electric Industrial Customer	Pennsylvania Electric Co.	Retail competition issues, rate unbundling, stranded cost analysis.
11/97	U-22491	LA	Louisiana Public Service Commission	Entergy Gulf States, Inc.	Decommissioning, weather normalization, capital structure.
11/97	P-971265	PA	Philadelphia Area Industrial Energy Users Group	Enron Energy Services Power, Inc./ PECO Energy	Analysis of Retail Restructuring Proposal.
12/97	R-973981	PA	West Penn Power Industrial Intervenors	West Penn Power Co.	Retail competition issues, rate unbundling, stranded cost analysis.
12/97	R-974104	PA	Duquesne Industrial Intervenors	Duquesne Light Co.	Retail competition issues, rate unbundling, stranded cost analysis.
3/98 (Allocated Stranded Cost Issues)	U-22092	LA	Louisiana Public Service Commission	Gulf States Utilities Co.	Retail competition, stranded cost quantification.
3/98	U-22092		Louisiana Public Service Commission	Gulf States Utilities, Inc.	Stranded cost quantification, restructuring issues.
9/98	U-17735		Louisiana Public Service Commission	Cajun Electric Power Cooperative, Inc.	Revenue requirements analysis, weather normalization.
12/98	8794	MD	Maryland Industrial Group and	Baltimore Gas and Electric Co.	Electric utility restructuring, stranded cost recovery, rate

Expert Testimony Appearances
of
Stephen J. Baron
As of May 2006

Date	Case	Jurisdict.	Party	Utility	Subject
			Millennium Inorganic Chemicals Inc.		unbundling.
12/98	U-23358	LA	Louisiana Public Service Commission	Entergy Gulf States, Inc.	Nuclear decommissioning, weather normalization, Entergy System Agreement.
5/99 (Cross-Answering Testimony)	EC-98-40-000	FERC	Louisiana Public Service Commission	American Electric Power Co. & Central South West Corp.	Merger issues related to market power mitigation proposals.
5/99 (Response Testimony)	98-426	KY	Kentucky Industrial Utility Customers, Inc.	Louisville Gas & Electric Co.	Performance based regulation, settlement proposal issues, cross-subsidies between electric. gas services.
6/99	98-0452	WV	West Virginia Energy Users Group	Appalachian Power, Monongahela Power, & Potomac Edison Companies	Electric utility restructuring, stranded cost recovery, rate unbundling.
7/99	99-03-35	CT	Connecticut Industrial \Energy Consumers	United Illuminating Company	Electric utility restructuring, stranded cost recovery, rate unbundling.
7/99	Adversary Proceeding No. 98-1065	U.S. Bankruptcy Court	Louisiana Public Service Commission	Cajun Electric Power Cooperative	Motion to dissolve preliminary injunction.
7/99	99-03-06	CT	Connecticut Industrial Energy Consumers	Connecticut Light & Power Co.	Electric utility restructuring, stranded cost recovery, rate unbundling.
10/99	U-24182	LA	Louisiana Public Service Commission	Entergy Gulf States, Inc.	Nuclear decommissioning, weather normalization, Entergy System Agreement.
12/99	U-17735	LA	Louisiana Public Service Commission	Cajun Electric Power Cooperative, Inc.	Ananlysi of Proposed Contract Rates, Market Rates.
03/00	U-17735	LA	Louisiana Public Service Commission	Cajun Electric Power Cooperative, Inc.	Evaluation of Cooperative Power Contract Elections
03/00	99-1658-EL-ETP	OH	AK Steel Corporation	Cincinnati Gas & Electric Co.	Electric utility restructuring, stranded cost recovery, rate Unbundling.

Expert Testimony Appearances
of
Stephen J. Baron
As of May 2006

Date	Case	Jurisdict.	Party	Utility	Subject
08/00	98-0452 E-GI	WVA	West Virginia Energy Users Group	Appalachian Power Co. American Electric Co.	Electric utility restructuring rate unbundling.
08/00	00-1050 E-T 00-1051-E-T	WVA	West Virginia Energy Users Group	Mon Power Co. Potomac Edison Co.	Electric utility restructuring rate unbundling.
10/00	SOAH 473-00-1020 PUC 2234	TX	The Dallas-Fort Worth Hospital Council and The Coalition of Independent Colleges And Universities	TXU, Inc.	Electric utility restructuring rate unbundling.
12/00	U-24993	LA	Louisiana Public Service Commission	Entergy Gulf States, Inc.	Nuclear decommissioning, revenue requirements.
12/00	EL00-66-000 & ER-2854-000 EL95-33-002	LA	Louisiana Public Service Commission	Entergy Services Inc.	Inter-Company System Agreement: Modifications for retail competition, interruptible load.
04/01	U-21453, U-20925, U-22092 (Subdocket B) Addressing Contested Issues	LA	Louisiana Public Service Commission	Entergy Gulf States, Inc.	Jurisdictional Business Separation - Texas Restructuring Plan
10/01	14000-U	GA	Georgia Public Service Commission Adversary Staff	Georgia Power Co.	Test year revenue forecast.
11/01	U-25687	LA	Louisiana Public Service Commission	Entergy Gulf States, Inc.	Nuclear decommissioning requirements transmission revenues.
11/01	U-25965	LA	Louisiana Public Service Commission	Generic	Independent Transmission Company ("Transco"). RTO rate design.
03/02	001148-EI	FL	South Florida Hospital and Healthcare Assoc.	Florida Power & Light Company	Retail cost of service, rate design, resource planning and demand side management.
06/02	U-25965	LA	Louisiana Public Service Commission	Entergy Gulf States Entergy Louisiana	RTO Issues
07/02	U-21453	LA	Louisiana Public Service Commission	SWEPCO, AEP	Jurisdictional Business Sep. - Texas Restructuring Plan.

Expert Testimony Appearances
of
Stephen J. Baron
As of May 2006

Date	Case	Jurisdict.	Party	Utility	Subject
08/02	U-25888	LA	Louisiana Public Service Commission	Entergy Louisiana, Inc. Entergy Gulf States, Inc.	Modifications to the Inter-Company System Agreement, Production Cost Equalization.
08/02	EL01-88-000	FERC	Louisiana Public Service Commission	Entergy Services Inc. and the Entergy Operating Companies	Modifications to the Inter-Company System Agreement, Production Cost Equalization.
11/02	02S-315EG	CO	CF&I Steel & Climax Molybdenum Co.	Public Service Co. of Colorado	Fuel Adjustment Clause
01/03	U-17735	LA	Louisiana Public Service Commission	Louisiana Coops	Contract Issues
02/03	02S-594E	CO	Cripple Creek and Victor Gold Mining Co.	Aquila, Inc.	Revenue requirements, purchased power.
04/03	U-26527	LA	Louisiana Public Service Commission	Entergy Gulf States, Inc.	Weather normalization, power purchase expenses, System Agreement expenses.
11/03	ER03-753-000	FERC	Louisiana Public Service Commission Staff	Entergy Services, Inc. and the Entergy Operating Companies	Proposed modifications to System Agreement Tariff MSS-4.
11/03	ER03-583-000 ER03-583-001 ER03-583-002 ER03-681-000, ER03-681-001 ER03-682-000, ER03-682-001 ER03-682-002	FERC	Louisiana Public Service Commission	Entergy Services, Inc., the Entergy Operating Companies, EWO Marketing, L.P, and Entergy Power, Inc.	Evaluation of Wholesale Purchased Power Contracts.
12/03	U-27136	LA	Louisiana Public Service Commission	Entergy Louisiana, Inc.	Evaluation of Wholesale Purchased Power Contracts.
01/04	E-01345-03-0437	AZ	Kroger Company	Arizona Public Service Co.	Revenue allocation rate design.
02/04	00032071	PA	Duquesne Industrial Intervenors	Duquesne Light Company	Provider of last resort issues.
03/04	03A-436E	CO	CF&I Steel, LP and Climax Molybedenum	Public Service Company of Colorado	Purchased Power Adjustment Clause.

Expert Testimony Appearances
of
Stephen J. Baron
As of May 2006

Date	Case	Jurisdict.	Party	Utility	Subject
04/04	2003-00433 2003-00434	PA	Kentucky Industrial Utility Customers, Inc.	Louisville Gas & Electric Co. Kentucky Utilities Co.	Cost of Service Rate Design
0-6/04	03S-539E	CO	Cripple Creek, Victor Gold Mining Co., Goodrich Corp., Holcim (U.S.,), Inc., and The Trane Co.	Aquila, Inc.	Cost of Service, Rate Design Interruptible Rates
06/04	R-00049255	PA	PP&L Industrial Customer Alliance PPLICA	PPL Electric Utilities Corp.	Cost of service, rate design, tariff issues and transmission service charge.
10/04	04S-164E	CO	CF&I Steel Company, Climax Mines	Public Service Company of Colorado	Cost of service, rate design, Interruptible Rates.
03/05	Case No. 2004-00426 Case No. 2004-00421	KY	Kentucky Industrial Utility Customers, Inc.	Kentucky Utilities Louisville Gas & Electric Co.	Environmental cost recovery.
06/05	050045-EI	FL	South Florida Hospital and Healthcare Assoc.	Florida Power & Light Company	Retail cost of service, rate design
07/05	U-28155	LA	Louisiana Public Service Commission Staff	Entergy Louisiana, Inc. Entergy Gulf States, Inc.	Independent Coordinator of Transmission – Cost/Benefit
09/05	Case Nos. 05-0402-E-CN 05-0750-E-PC	WVA	West Virginia Energy Users Group	Mon Power Co. Potomac Edison Co.	Environmental cost recovery, Securitization, Financing Order
01/06	2005-00341	KY	Kentucky Industrial Utility Customers, Inc.	Kentucky Power Company	Cost of service, rate design, transmission expenses, Congestion Cost Recovery Mechanism
03/06	U-22092	LA	Louisiana Public Service Commission Staff	Entergy Gulf States, Inc.	Separation of EGSI into Texas and Louisiana Companies.
04/06	U-25116	LA	Louisiana Public Service Commission Staff	Entergy Louisiana, Inc.	Transmission Prudence Investigation

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission	:	
	:	**Docket No. R-00061346C0001-0005**
v.	:	
	:	
Duquesne Light Company	:	

EXHIBIT SJB-2

OF

STEPHEN J. BARON

ON BEHALF OF

DUQUESNE INDUSTRIAL INTERVENORS

AND

THE INDUSTRIAL ENERGY CONSUMERS OF PENNSYLVANIA

Duquesne Light Company
Correction of Class Rates of Return under Proposed Rates

Rate Class	Distribution Rate Base	Proposed Net Income per DUQ	Income Taxes per DUQ	Allocated Income Taxes	Corrected Net Income	Corrected ROR
RS	630,118	33,388	17,929	30,713	20,604	3.27%
RH	62,030	619	333	3,023	(2,071)	-3.34%
RA	5,369	54	29	262	(179)	-3.33%
GS/GM	222,791	32,528	17,469	10,859	39,138	17.57%
GMH	24,641	2,124	1,141	1,201	2,064	8.38%
GL	170,729	27,377	14,702	8,322	33,757	19.77%
GLH	33,138	2,856	1,534	1,615	2,775	8.37%
L	55,307	8,558	4,596	2,696	10,458	18.91%
HVPS	321	81	43	16	108	33.76%
AL	16	(1)	-	1	(2)	-11.12%
SE	1,740	787	422	85	1,124	64.61%
SM	25,244	3,170	1,702	1,230	3,642	14.43%
SH	388	39	21	19	41	10.59%
MTS	885	264	142	43	363	41.00%
PAL	140	52	28	7	73	52.27%
TOTAL	1,232,857	111,896	60,091	60,091	111,896	9.08%

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission	:	
	:	**Docket No. R-00061346C0001-0005**
v.	:	
	:	
Duquesne Light Company	:	

EXHIBIT SJB-3

OF

STEPHEN J. BARON

ON BEHALF OF

DUQUESNE INDUSTRIAL INTERVENORS

AND

THE INDUSTRIAL ENERGY CONSUMERS OF PENNSYLVANIA

Baron Exhibit__(SJB-3)

IMPACT OF DUQUESNE PROPOSED SUBSIDIES ON DISTRIBUTION RATES

	Units	Rate As Proposed	Rate Without Subsidies	Duquesne Proposed Subsidy
Rate GL				
Distribution				
First 300 kW or less	8,944	$2,120.00	$2,120.00	
Additional kW	5,505,728	$6.45	$2.93	$3.52
All kWh	3,338,997,219	$0.003579	$0.003579	
Subtotal	3,338,997,219			
Revenue		$66,424,024	$47,017,024	$19,407,000
Rate GLH				
Total Bills	1,404	$30.00	$30.00	
Summer first 300 kW or less	474	$2,120.00	$2,120.00	
Summer additional kW	273,644	$6.45	$7.36	-$0.91
All kWh	186,123,390	$0.003579	$0.003579	
Winter first block kWh	136,426,499	$0.032939	$0.032939	
Winter additional kWh	234,318,677	$0.003579	$0.003579	
Subtotal	556,868,565			
Revenue		$8,810,946	$9,058,946	$ (248,000)
Rate L				
First 5,000 KW or less	297	$30,555.00	$20,312.00	$10,243.00
Next 10,000 KW	1,028,067	$5.83	$3.88	$1.95
Next 25,000 KW	300,847	$5.83	$3.88	$1.95
Additional KW	49,444	$5.83	$3.88	$1.95
First Block kWh	1,088,846,871	$0.002982	$0.002982	
Next 150 KWH per KW	163,452,212	$0.002982	$0.002982	
Additional KWH	21,616,836	$0.002982	$0.002982	
Untransformed Service Cr		-$48,174	-$48,174	
Rate L & Rider 16				
L Monthly Minimum	8	$1,405.00	$934.00	$471.00
L Demand Charge kW	20,000	$5.83	$3.88	$1.95
L Energy Charge kWh	3,303,478	$0.00	$0.00	
Revenue		$20,989,773	$15,210,773	$ 5,779,000
Rate HVPS				
First 30,000 KW	36	$9,115.00	$7,148.00	$1,967.00
Additional KW	420,000	$0.16	$0.12	$0.03
On-Peak KWH	400,168,800	$0.000000	$0.000000	
Off-Peak KWH	933,727,200	$0.000000	$0.000000	
Revenue		$393,967	$308,967	$ 85,000

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission	:
	: **Docket No. R-00061346C0001-0005**
v.	:
	:
Duquesne Light Company	:

EXHIBIT SJB-4

OF

STEPHEN J. BARON

ON BEHALF OF

DUQUESNE INDUSTRIAL INTERVENORS

AND

THE INDUSTRIAL ENERGY CONSUMERS OF PENNSYLVANIA

Duquesne Light Company
Calculation of Distribution Rate Increases to Achieve a 50.0% Subsidy Reduction

Rate Class	Present Rate Revenues	Increase to Requested ROR	Subdsidy @ Present Rates	Proposed Subsidy*	Proposed Increase	Percent Increase
RS	147,575	95,474	(21,971)	(10,985)	84,533	57.3%
RH	5,209	16,568	(9,333)	(4,667)	11,908	228.6%
RA	761	1,311	(683)	(342)	970	127.5%
GS/GM	65,831	3,350	22,578	11,289	14,647	22.2%
GMH	4,089	3,197	(328)	(164)	3,035	74.2%
GL	31,636	15,387	4,492	2,246	17,642	55.8%
GLH	2,903	6,153	(2,293)	(1,147)	5,009	172.5%
L	10,068	5,144	1,296	648	5,795	57.6%
HVPS	425	(114)	153	0	(114)	-26.8%
AL	1	4	(2)	(1)	3	323.8%
SE	1,494	(1,007)	1,209	604	(403)	-27.0%
SM	9,129	(1,403)	4,340	2,170	768	8.4%
SH	71	47	(1)	(0)	47	65.8%
MTS	590	(299)	401	201	(98)	-16.7%
PAL	173	(126)	142	71	(55)	-31.9%
TOTAL	279,955	143,686			143,686	51.3%

* HVPS subsidy set to $0

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission	:
	: Docket No. R-00061346C0001-0005
v.	:
	:
Duquesne Light Company	:

EXHIBIT SJB-5

OF

STEPHEN J. BARON

ON BEHALF OF

DUQUESNE INDUSTRIAL INTERVENORS

AND

THE INDUSTRIAL ENERGY CONSUMERS OF PENNSYLVANIA

Baron Exhibit__(SJB-5)

DII PROPOSED DISTRIBUTION RATES
(@ Duquesne's Revenue Requirement Increase)

	Units	Rate As Proposed By Duquesne	Rate @ DII 50% Subsidy Reduction*
Rate GL			
Distribution			
First 300 kW or less	8,944	$2,120.00	$1,570.00
Additional kW	5,505,728	$6.45	$4.79
All kWh	3,338,997,219	$0.003579	$0.002655
Subtotal	3,338,997,219		
Revenue		$66,424,024	49,278,288
Rate GLH			
Total Bills	1,404	$30.00	$30.00
Summer first 300 kW or less	474	$2,120.00	$1,903.00
Summer additional kW	273,644	$6.45	$5.79
All kWh	186,123,390	$0.003579	$0.003212
Winter first block kWh	136,426,499	$0.032939	$0.029562
Winter additional kWh	234,318,677	$0.003579	$0.003212
Subtotal	556,868,565		
Revenue		$8,810,946	$7,912,081
Rate L			
First 5,000 KW or less	297	$30,555.00	$23,101.00
Next 10,000 KW	1,028,067	$5.83	$4.41
Next 25,000 KW	300,847	$5.83	$4.41
Additional KW	49,444	$5.83	$4.41
First Block kWh	1,088,846,871	$0.002982	$0.0022540
Next 150 KWH per KW	163,452,212	$0.002982	$0.0022540
Additional KWH	21,616,836	$0.002982	$0.0022540
Untransformed Service Cr		-$48,174	-$48,174
Rate L & Rider 16			
L Monthly Minimum	8	$1,405.00	$1,062.00
L Demand Charge kW	20,000	$5.83	$4.41
L Energy Charge kWh	3,303,478	$0.00	$0.00
Revenue		$20,989,773	15,863,040
Rate HVPS			
First 30,000 KW	36	$9,115.00	$7,232.00
Additional KW	420,000	$0.16	$0.12
On-Peak KWH	400,168,800	$0.000000	$0.000000
Off-Peak KWH	933,727,200	$0.000000	$0.000000
Revenue		$393,967	$311,000

* HVPS subsidy set to $0

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission	:	
	:	**Docket No. R-00061346C0001-0005**
v.	:	
	:	
Duquesne Light Company	:	

EXHIBIT SJB-6

OF

STEPHEN J. BARON

ON BEHALF OF

DUQUESNE INDUSTRIAL INTERVENORS

AND

THE INDUSTRIAL ENERGY CONSUMERS OF PENNSYLVANIA

Example of Rate Schedule Distribution Revenue Allocation Assuming a $100 Million Total Revenue Increase

Rate Class	Present Distribution Revenues	DII Proposed Increase	DII Total Revenues	Total Revenues @ $100 million Increase	DII Proposed Increase @ $100 million	Percent Increase
RS	$147,575,381	84,533,281	232,108,662	208,173,513	60,598,132	41.1%
RH	$5,208,870	11,907,726	17,116,596	15,351,525	10,142,655	194.7%
RA	$760,625	969,895	1,730,520	1,552,068	791,443	104.1%
GS/GM	$65,831,430	14,646,894	80,478,324	72,179,363	6,347,933	9.6%
GMH	$4,088,687	3,034,781	7,123,468	6,388,893	2,300,206	56.3%
GL	$31,635,576	17,642,288	49,277,864	44,196,309	12,560,732	39.7%
GLH	$2,903,096	5,009,081	7,912,177	7,096,269	4,193,174	144.4%
L	$10,067,782	5,795,040	15,862,821	14,227,040	4,159,258	41.3%
HVPS	$425,418	(114,000)	311,418	279,305	(146,114)	-34.3%
AL	$1,003	3,238	4,241	3,803	2,800	279.2%
SE	$1,493,807	(402,865)	1,090,942	978,444	(515,363)	-34.5%
SM	$9,129,115	767,534	9,896,649	8,876,102	(253,013)	-2.8%
SH	$71,242	46,696	117,938	105,776	34,535	48.5%
MTS	$589,692	(98,318)	491,374	440,703	(148,989)	-25.3%
PAL	$172,793	(55,270)	117,522	105,403	(67,389)	-39.0%
		-	-			
TOTAL	$279,954,517	143,686,000	423,640,517	379,954,517	100,000,000	35.7%

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission	:
	: Docket No. R-00061346C0001-0005
v.	:
	:
Duquesne Light Company	:

EXHIBIT SJB-7

OF

STEPHEN J. BARON

ON BEHALF OF

DUQUESNE INDUSTRIAL INTERVENORS

AND

THE INDUSTRIAL ENERGY CONSUMERS OF PENNSYLVANIA

Duquesne Industrial Intervenors
Interrogatory Set II

15. Reference DLC Statement No. 14, p.4, lines 10-14. Please provide all surveys, reports, analyses or other documents supporting Duquesne Light's conclusion that Rule 4 special contracts are not "an effective offering for our customers."

Response: Duquesne began offering special contract provisions under Rule No. 4 in 1994, when the industry was still fully regulated and the Company owned generating facilities. In that operating environment, the Company had the opportunity under the provisions of Rule No. 4 which required that "rates established under special contracts will be sufficient to recover, at a minimum, all appropriate incremental costs, and an appropriate contribution to fixed costs" to negotiate prices less than stated tariff rates to address incremental customer usage or compete with alternate energy sources. This provided a benefit to the recipient of the negotiated prices, as well as to the customer base as a whole, as increased or retained kWh consumption served to positively impact the efficient use of the Company's assets overall.

No formal studies, reports, etc. exist that can be provided in response to this interrogatory. However, as a result of Company restructuring and unbundling of the rates that existed when Rule No. 4 contracts were offered, each business (transmission, distribution and generation) is now measured and considered on a stand-alone basis. Considering the services that Duquesne now provides as a fully regulated transmission and distribution company, the opportunity to provide a material discount to regulated rates has been greatly reduced. Transmission and distribution charges constitute less than 15% of the monthly average charges. POLR generation rates, most notably for those rates applicable to the majority of customers who could potentially engage in Rule No. 4 contracts, are market based and supplied through contracts between the Company and third party suppliers. As a practical matter, since the Company is not permitted to market POLR service, since nearly all of the potentially eligible Rule No. 4 customers have switched to and electric generation supplier, and since the transmission and distribution rates are a small regulated portion of the customers charges, the Company believes that Rule No. 4 is no longer an effective offering.

MEIUG/PICA STATEMENT NO. 1

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

PENNSYLVANIA PUBLIC UTILITY COMMISSION, ET AL.	:	
	:	DOCKET NOS. R-00061366
	:	R-00061367
v.	:	P-00062213
	:	P-00062214
	:	A-110300F0095
	:	A-110400F0040
METROPOLITAN EDISON COMPANY AND PENNSYLVANIA ELECTRIC COMPANY	:	

DIRECT TESTIMONY

AND EXHIBITS

OF

STEPHEN J. BARON

ON BEHALF OF

MET-ED INDUSTRIAL USERS GROUP
PENELEC INDUSTRIAL CUSTOMER ALLIANCE

J. KENNEDY AND ASSOCIATES, INC.
ROSWELL, GEORGIA

JULY 10, 2006

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

PENNSYLVANIA PUBLIC UTILITY COMMISSION, ET AL.	:	**DOCKET NOS. R-00061366**
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BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

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METROPOLITAN EDISON COMPANY AND PENNSYLVANIA ELECTRIC COMPANY	:	

DIRECT TESTIMONY OF STEPHEN J. BARON

I. INTRODUCTION

Q. Please state your name and business address.

A. My name is Stephen J. Baron. My business address is J. Kennedy and Associates, Inc. ("Kennedy and Associates"), 570 Colonial Park Drive, Suite 305, Roswell, Georgia 30075.

Q. What is your occupation and by whom are you employed?

A. I am the President and a Principal of Kennedy and Associates, a firm of utility rate, planning, and economic consultants in Atlanta, Georgia.

Q. Please describe briefly the nature of the consulting services provided by Kennedy and Associates.

A. Kennedy and Associates provides consulting services in the electric and gas utility industries. Our clients include state agencies and industrial electricity consumers. The firm provides expertise in system planning, load forecasting, financial analysis, cost-of-service, and rate design. Current clients include the Georgia and Louisiana Public Service Commissions, and industrial consumer groups throughout the United States.

Q. Please state your educational background.

A. I graduated from the University of Florida in 1972 with a B.A. degree with high honors in Political Science and significant coursework in Mathematics and Computer Science. In 1974, I received a Master of Arts Degree in Economics, also from the University of Florida. My areas of specialization were econometrics, statistics, and public utility economics. My thesis concerned the development of an econometric model to forecast electricity sales in the State of Florida, for which I received a grant from the Public Utility Research Center of the University of Florida. In addition, I have advanced study and coursework in time series analysis and dynamic model building.

Q. Please describe your professional experience.

A. I have more than thirty years of experience in the electric utility industry in the areas of cost and rate analysis, forecasting, planning, and economic analysis.

Following the completion of my graduate work in economics, I joined the staff of the Florida Public Service Commission in August of 1974 as a Rate Economist. My responsibilities included the analysis of rate cases for electric, telephone, and gas utilities, as well as the preparation of cross-examination material and the preparation of staff recommendations.

In December 1975, I joined the Utility Rate Consulting Division of Ebasco Services, Inc. as an Associate Consultant. In the seven years I worked for Ebasco, I received successive promotions, ultimately to the position of Vice President of Energy Management Services of Ebasco Business Consulting Company. My responsibilities included the management of a staff of consultants engaged in providing services in the areas of econometric modeling, load and energy forecasting, production cost modeling, planning, cost-of-service analysis, cogeneration, and load management.

I joined the public accounting firm of Coopers & Lybrand in 1982 as a Manager of the Atlanta Office of the Utility Regulatory and Advisory Services Group. In this capacity I was responsible for the operation and management of the Atlanta office. My duties included the technical and administrative supervision of the staff, budgeting, recruiting, and marketing as well as project management on client engagements. At Coopers & Lybrand, I specialized in utility cost analysis, forecasting, load analysis, economic analysis, and planning.

In January 1984, I joined the consulting firm of Kennedy and Associates as a Vice President and Principal. I became President of the firm in January 1991.

During the course of my career, I have provided consulting services to more than thirty utility, industrial, and Public Service Commission clients, including three international utility clients.

I have presented numerous papers and published an article entitled "How to Rate Load Management Programs" in the March 1979 edition of "Electrical World." My article on "Standby Electric Rates" was published in the November 8, 1984 issue of "Public Utilities Fortnightly." In February of 1984, I completed a detailed analysis entitled "Load Data Transfer Techniques" on behalf of the Electric Power Research Institute, which published the study.

I have presented testimony as an expert witness in Arizona, Arkansas, Colorado, Connecticut, Florida, Georgia, Indiana, Kentucky, Louisiana, Maine, Michigan, Minnesota, Maryland, Missouri, New Jersey, New Mexico, New York, North Carolina, Ohio, Pennsylvania, Texas, West Virginia, as well as before the Federal Energy Regulatory Commission ("FERC") and the United States Bankruptcy Court. A list of my specific regulatory appearances can be found in Baron Exhibit ____ (SJB-1)

Q. **Have you previously testified in a Metropolitan-Edison Company ("Met-Ed") or Pennsylvania Electric Company ("Penelec") (jointly, "Companies") proceeding in Pennsylvania?**

A. Yes. I have previously testified in a number of proceedings involving both Companies, including the 1998 restructuring proceedings. Specifically, I have testified in the following cases: Met-Ed Docket Nos. 870171C-001 (1988), R-00922314 (1992), and R-974008 (1997); Penelec Docket Nos. 871017C-005 (1988), R-00920312 (1992), and R-974009 (1997).

Q. On whose behalf are you testifying in this proceeding?

A. I am testifying on behalf of the Met-Ed Industrial Users Group ("MEIUG") and the Penelec Industrial Customer Alliance ("PICA"). These groups represent large commercial and industrial customers taking service on the Met-Ed and Penelec systems, primarily under rate schedules TP and GP on the Met-Ed system and LP and GP on the Penelec system.

Q. What is the purpose of your testimony?

A. I am responding to a number of significant issues raised by the Companies in their respective testimony. The issues that I will address include the Companies' request to breach the generation rate cap, prior to 2010, when the Companies complete their recovery of stranded costs. Both Companies agreed to a generation rate cap as part of the settlement of the restructuring plans of each company ("Joint Petition for Full Settlement of the Restructuring Plans of Metropolitan Edison Company and Pennsylvania Electric Company and Related Dockets and Related Court Proceedings," dated September 23, 1998, hereinafter referred to as the "1998 Settlement"). Though the Electricity Generation and Customer Choice and Competition Act ("Competition Act") provides for limited relief from the generation rate cap, the Companies have not shown in their filings that such relief should be granted in this case. My testimony will discuss this important issue and explain why the generation rate cap should continue for both Companies through 2010.

My testimony will also address a number of other issues raised in the Companies' extensive requests in these cases. Of particular concern to MEIUG and PICA members is the

Companies' proposal to implement a Transmission Service Charge that is allocated and recovered from customers on a 100% energy (kWh) basis and the inappropriate inclusion of congestion costs as part of this charge (the proposed "TSC"). I will also address the Companies' proposal to implement a Universal Service Charge (Rider "E"). In particular, I will address the inclusion of uncollectible expenses in this charge and the proposed kWh recovery method requested by the Companies. Uncollectible expenses should be specifically assigned to rate classes and not recovered on a kWh basis. As I will discuss, this proposal unreasonably shifts costs to high load factor customers, such as the members of MEIUG and PICA, and does not follow methodologies previously used by the Companies and approved by this Commission to recover uncollectible expenses from ratepayers.

Finally, I will address a number of tariff rule and rate design changes that the Companies are proposing in this case. For the most part, these changes are not appropriate and should be rejected by the Commission. Many of the rate design changes result in an increase in the generation rate, which is not permissible and should not be accepted.

Q. Please summarize your findings and recommendations.

A.

- **The Companies' argument in this case that the failure of the Competitive Default Service ("CDS") process justifies an increase in the generation rate cap is unreasonable and should be rejected by the Pennsylvania Public Utility Commission ("PUC" or "Commission"). The language in the 1998 Settlement (Section F.9) does not state that the Companies can**

justify an increase in the generation rate cap because of a failure of the CDS process. This language simply states that the Companies can request an increase in the generation rate cap from the Commission. It does not provide for any additional rights to the Companies beyond the general rights provided by the Competition Act in Section 2804(4). Nothing in the 1998 Settlement permits the Companies to increase the rate cap due to the failure to achieve an 80% CDS level.

- **The Companies request for a generation rate cap exception pursuant to Section 2804(4) of the Competition Act should be rejected. The Companies have not met the requirements under this provision of the Competition Act and should therefore not be granted an increase in their respective generation rate caps.**

- **The issue of whether the Companies were "prudent" in their Provider of Last Resort ("POLR") procurement is really an issue between the Companies' management and their stockholders. Met-Ed and Penelec had and continue to have obligations to provide POLR service at the generation rate cap, whether or not they purchased POLR supply in a least cost manner.**

- **The Companies' proposed TSC is unreasonable as filed and should not be accepted by the Commission. Though a properly designed TSC is appropriate, the Companies' proposal improperly seeks to recover congestion charges, which are related to POLR supply costs, subject to the generation rate cap, and not a transmission service expense. These congestion charges should be eliminated from the TSC.**

- **The Companies have also requested to recover deferred 2006 transmission costs in the TSC. The congestion portion of these deferred costs (plus associated carrying charges that the Companies have included in their filings), should not be recovered because they are part of POLR supply costs and subject to the generation rate cap. With regard to the remaining (non-congestion) costs, if the Commission permits these costs to be recovered from ratepayers, they should be recovered through a separate transmission expense amortization charge and not through the TSC. In addition, any such amortization charges (assuming a 10 year amortization) should be classified on a demand and energy basis, following the approach that I am recommending for on-going TSC expenses.**

- **With regard to the remaining transmission expenses for which the Companies are seeking recovery in the TSC, these costs should not be recovered through a uniform kWh charge, as proposed by the Companies. These remaining transmission expenses should be classified within the TSC on a demand and energy basis, reflecting the cost basis on which these expenses are incurred by the Companies from PJM Interconnection LLC ("PJM"). The majority of the Companies' transmission costs are demand related and it is unreasonable to recover these expenses from rate classes on a uniform kWh basis that does not reflect voltage differences among rate classes. The Commission should adopt the MEIUG/PICA proposed TSC that reasonably reflects the underlying costs basis for transmission expenses.**

- **If a Universal Service Charge ("USC") rider is established in this case, it should only apply to residential customers, as is currently the case for universal service costs. A substantial portion of the Companies' claimed USC expenses are for uncollectible expenses, which have historically been recovered from rate classes on a specific assignment basis, assigning the "cost" to the customers causing the cost. The Companies' proposal in this case to recover USC expenses from all rate classes, including uncollectible expenses, on a uniform kWh basis is unreasonable and is particularly so for high load factor commercial and industrial customers. Each additional kWh consumed by these customers in the off peak period or at night creates a liability for additional universal service costs under the Companies' proposal.**

- **If the Commission decides as a matter of public policy to assign the costs to all rate schedules, uncollectible expenses should be removed and specifically assigned to rate schedules in a manner consistent with the past treatment of these expenses by the Companies, and the remainder of the USC expenses should be assigned to rate schedules on the basis of the number of relative customers.**

- **The Companies are proposing a number of tariff rule changes that are not justified and should be rejected by the Commission. As discussed in my testimony, the Commission should reject the Companies' proposals to modify or eliminate the following tariff rules and tariff riders:**

  Rule 12(b)(9)
  Rule 15(d)
  Met-Ed Riders K and L
  Penelec Riders M and N

- **The Companies are proposing increases in the Competitive Transition Charge ("CTC") charges and substantial increases in generation rates. These changes, both with respect to the rate design and the CTC and generation rate increases, are not consistent with the requirement of the Competition Act and result in an increase in the generation rate cap. If the Companies increase the CTC charges for a rate schedule due to a change in amortization rate, then there must be a corresponding decrease in the generation rate in order to maintain the rate cap.**

- **Met-Ed's proposal to eliminate the optional "Eight Hour On-Peak Time-Of-Day Service" provision for rates GS, GST, GP, and TP should be rejected. This issue is an intra-rate schedule rate design issue and does not affect customers on other rate schedules. Given the magnitude of the Company's proposed increases in this case, there is no justifiable policy reason to eliminate this optional rate provision. Customers who currently rely on this option will face larger than average increases as a result of the Company's proposal. At a minimum, customers who currently utilize and rely on this option should be permitted to continue to use this eight hour on-peak rate provision.**

- **Met-Ed's proposal to eliminate its current optional Seasonal Time-Of-Day Service on rate schedules GS, GST, GP, and TP should be rejected. Though there is no mention of this change in Company witness Pleiss' testimony on rate design changes, the Company is proposing to eliminate the optional seasonal summer/non-summer kW demand rates that currently recover generation related costs through the CTC. The Company has provided no justification for this change. In fact, it is inconsistent with the position of the Company regarding the establishment of seasonal generation charges.**

II. REQUEST BY THE COMPANIES TO BREACH THE GENERATION RATE CAP

Q. Would you please briefly describe the Companies' request for relief from the generation rate cap agreed upon in the 1998 Settlement?

A. As discussed in the testimony of the Companies' witnesses Anthony Alexander, David Blank, and others, the Companies are requesting authorization from the Commission to breach the generation rate cap established in the 1998 Settlement and implement a new transition plan that would have the effect of substantially increasing generation rates for the Companies' ratepayers taking POLR service, which is nearly 100% of the customers of both Companies. Met-Ed's POLR generation rate would increase by $130.6 million annually, and Penelec's generation rate would increase by $87.6 million annually if the new transition plan were adopted by the Commission. Future increases would continue to occur for both Companies under the plan, as the First Energy Solutions ("FES") supply contract is reduced over time and replaced by market purchases.

As I understand the Companies' testimony, they argue that the failure of the Competitive Default Service ("CDS") plan envisioned in the 1998 Settlement is sufficient justification to break the cap. Notwithstanding this position, the Companies also argue that the exceptions of the Competition Act permit an increase in the generation rate cap based on the assertions of Companies' witnesses in this case.

While it is not disputable that market prices have increased in recent years and currently exceed the generation rate cap, there is much to dispute regarding the Companies' justification and evidence provided to support a breach of the generation rate cap.

Q. The Companies' testimony seems to rely heavily on the failure of the CDS process as justification for an increase in the generation rate cap. Is this a reasonable basis for the Commission to grant an increase in the cap in this case?

A. No. The 1998 Settlement requires the Companies to cap their respective generation rates while the CTC is being charged to ratepayers, with a one-time 5% increase occurring at one point during the last five years of the rate cap period. Though the provisions of Section 2804(4) of the Competition Act apply to these rate caps, and thus authorize the Commission to grant an increase in the rate cap under certain limited circumstances, the provisions of the 1998 Settlement regarding the CDS process do not automatically provide for a rate cap exception upon the "failure" of the CDS process.

Q. Would you explain why the failure of the CDS process does not justify an increase in the generation rate cap?

A. First, the language in the 1998 Settlement (Section F.9) does not state that the Companies can justify an increase in the generation rate cap because of a failure of the CDS process.

Specifically, Section F.9 states:

> **Any bid for CDS that exceeds the Companies' generation rate caps shall be rejected. If no qualified bids for CDS are received at or below the Companies' generation rate caps, GPUE shall provide PLR service at the rate cap levels unless GPUE files a petition with the Commission, served on the Joint Petitioners, and receives authorization from the Commission to provide PLR service at rates that exceed the rate cap levels.**

This language simply states that the Companies can request an increase in the generation rate cap from the Commission. It does not provide for any additional rights to the Companies beyond the general rights provided by the Competition Act in Section 2804(4). In fact, the most significant portion of Section F.9 of the 1998 Settlement is that the Companies are obligated to continue providing POLR service under the generation rate caps, even if the CDS process fails. Beyond that, the Companies are permitted to <u>seek</u> an increase in the cap from the Commission, but they are not guaranteed an increase.

Q. The Companies argue in this case that the 1998 Settlement envisioned that they would only be responsible for 20% of the POLR load by June 2003. Having not been able to shift this load to competitive default service suppliers, is it reasonable to grant the Companies an increase in the rate cap in this case?

A. No. From the perspective of the time period during which the 1998 Settlement was entered, any reasonable person would have known that the competitive suppliers would not bid or otherwise agree to serve 80% (or any amount, for that matter) of the Companies' POLR load obligation in the event that market prices exceeded the generation rate cap. The Companies' testimony in this case seems to suggest that this was a surprise, leaving the Companies with an unintended 100% of the POLR load to serve at the rate cap. Since this outcome (the failure of the CDS process) would have been almost certain if market prices exceeded the generation rate cap, the Companies argument in this case can be reduced to the following: "because market prices have exceeded the generation rate cap, we need an increase in the generation rate cap."

Of course, this is precisely the reason that a generation rate cap was implemented. It is designed to protect consumers in the event that market prices increase. If market prices were less than the generation rate cap, the generation rate cap would have no effect. In fact, in this case (market prices less than the generation rate cap), most customers would likely leave POLR service and take service from an Electric Generation Supplier ("EGS") at lower rates. To the extent that customers remained under POLR service in this case, the Companies would actually make a margin on selling POLR service at the generation rate cap, while buying the energy at lower market based prices.

From the perspective of the 1998 time period in which the Settlement occurred, the CDS process would have reasonably been expected to fail if market prices exceeded the generation rate cap, in which case the Companies would be obligated to provide POLR generation service at the rate cap and obtain a POLR supply at market prices exceeding the cap. It is simply not credible to argue today that the failure of the CDS program, by itself, is justification for an increase in the generation rate cap. As I explained, this argument is equivalent to stating that increase in the generation rate cap is justified because market prices exceed the generation rate cap. If this was correct, the generation rate cap would only apply when it is not needed (market prices less than the rate cap), but it would not apply when it is needed to protect consumers from the impact of high market prices during a transition period.

Q. Is the generation rate cap contingent on the success of the CDS process in the 1998 Settlement?

A. No. Paragraph F.3 of the 1998 Settlement explicitly makes clear that the Companies are obligated to provide POLR service subject to the generation rate cap, whether or not the CDS process is effective. This paragraph states as follows:

> **Regardless of whether PLR service is provided by GPUE or a competitive PLR supplier, all retail PLR service shall be subject to the applicable generation rate caps.**

Nothing in the 1998 Settlement permits the Companies to increase the rate cap due to the failure to achieve an 80% CDS level. Rather, the Companies are simply permitted to seek approval from the Commission to increase their respective generation rate caps. The consideration of these requests should, absent language in the 1998 Settlement to the contrary (which does not exist), be based on the Competition Act.

Q. Have the Companies requested an alternative basis (beyond the failure of the CDS process) to justify their request for an increase in their generation rate caps?

A. Yes. The Companies, perhaps anticipating the lack of support in the 1998 Settlement for an increase in their generation rate caps due to the CDS process, have also made a request for a generation rate cap exception pursuant to Section 2804(4) of the Competition Act. As I will discuss, the Companies have not in my view met the necessary requirements under this provision of the Competition Act and should therefore not be granted an increase in their respective generation rate caps.

Q. Would you briefly describe the basic provisions of Section 2804(4)(iii) of the Competition Act that must be met in order to justify an increase in a generation rate cap?

A. Part (d) of this Section of the Act permits a distribution utility to "seek" an exception to the generation rate cap if "the electric distribution utility is subject to significant increases in the unit rate of fuel for utility generation or the price of purchased power that are outside of the control of the utility and that would not allow the utility to earn a fair rate of return." This is the provision of the Act that the Companies are relying on in this case to support their alternative request to increase the generation rate cap (in the event that the Commission does not approve their request based on acceptance to the CDS process argument that I previously discussed). I will address each of these provisions and explain why the Companies fail to qualify for a rate cap exception in this case.

Q. Would you please discuss the "rate of return" requirement of Section 2804(4)(iii) and its applicability to the Companies' request in this case for an increase in the generation rate cap?

A. The rate of return standard ("ROR") cannot reasonably be construed to apply in this case. A reasonable interpretation of this criterion is that, due to the high cost of fuel that is being utilized in a distribution Company's generation, the Company is unable to earn a reasonable rate of return on investment if it continues to sell power at the capped generation rate. In the case of Met-Ed and Penelec, neither owns generation (except for some very small investments) and therefore neither has an "investment" on which to even calculate a rate of return. The Act does not require divesture of generation assets, as the Companies have done, nor does it even require a transfer of assets to an unregulated affiliate. As such, the ROR provision in the Act can only be applicable in cases wherein a utility continues to own generation in its regulated utility and such generation is being used to provide power to serve the POLR load obligation.

Q. What about the "purchased power" provisions of this section of the Act?

A. In the event that a utility purchases power, there is no generation related investment on which to "earn" a rate of return. In the context of utility ratemaking, a fair rate of return refers to a return on the capital invested in the utility. In the case of a utility purchase of power, there is no such investment. Purchased power expenses are generally a "pass-through" cost to an electric utility, in this case subject to a generation rate cap. Since there is no investment on which to "earn" a fair rate of return, the rate of return provision does not logically apply. The only interpretation of this rate of return provision applicable to purchased power would be if it were to apply to the entire utility, including affiliates that may own generation. In this case, the Companies have provided no evidence regarding First Energy's rate of return, including the generation investments in its affiliate, FES.

Q. Couldn't the ROR standard apply to the Companies' transmission and distribution investments?

A. No, such an application is illogical. While the Companies do have distribution and transmission investments, the Act cannot reasonably be construed to apply to the earned return on transmission and distribution investment, since a reasonable presumption is that these investments are earning a just and reasonable ROR on a standalone basis. The rate cap applies to the generation component, and the Companies have had the ability to request transmission and distribution rate increases since the end of 2004. In particular, the FERC, not the Commission, sets the rate of return on the Companies' transmission investments. If the ROR provision were interpreted to include the overall return on the Companies' regulated assets (with little or no generation assets), then all that a utility would have to demonstrate to meet this standard is that the market price for power is greater than the shopping credit. The "loss" (the difference between the market price of power and the shopping credit), when added to the otherwise applicable earned rate of return on transmission and distribution investment, would likely produce an unreasonably low combined ROR (assuming that the "loss" due to high market prices was material).

This could not have been the intent of the Act, since it effectively means that any utility could support a breach of the rate cap if the market price exceeds the rate cap. The fact that all Pennsylvania utilities subject to a generation rate cap have not requested relief during periods when the market price exceeds the shopping credit is further evidence that the ROR criteria was not intended to apply to a utility (such as the Companies) that effectively only has transmission and distribution investments. The alternative interpretation, advocated by the Companies, means that every utility could receive a generation rate cap exception as soon as market prices exceed the cap, an interpretation that would make the generation rate cap provision of the Act relatively meaningless.

Q. Have the Companies demonstrated that they meet the rate of return criterion of Section 2404(4)(iii) of the Act?

A. No. As I explained, the ROR criterion cannot reasonably be applied to the Companies' regulated investments in this case, as the Companies have done in their filing. The fact that the Companies may have inadequate rates of return on their overall regulated investments, the vast majority of which are either transmission investments regulated by the FERC or distribution investments that are entitled to an opportunity to earn a just and reasonable rate of return, does not support an increase in the generation rate cap. Under circumstances, such as currently exist, wherein the market price of power exceeds the generation rate cap, it is almost self-evident that the Companies will not earn an adequate rate of return on regulated transmission and distribution investment, if the POLR losses are included.

Q. Is there an interpretation of this Section of the Act (rate of return criterion) that could be applicable to the Companies' situation in this case?

A. The only possible applicability of the rate of return criterion to the evaluation of the Companies' request to increase the generation rate cap is to apply the rate of return standard to the Companies' overall investments and First Energy's generation assets, whether regulated or not.

Q. Is there support for this interpretation of the rate of return criterion in Section 2804(4)(iii)(d) of the Act from the Commonwealth Court?

A. Yes. In its February 21, 2002, decision in the "ARIPPA" case, the Court addressed this issue and found that GPU Energy had not presented evidence in the Commission case on the "overall return earned by GPU Energy in all aspects of its utility business, including revenues from its generation supply, transmission and distribution functions." ARIPPA v. Pa. PUC, et al., 792 A.2d 636, 666 (Pa. Commw. 2002). As in the ARIPPA case, the Companies have not presented any evidence in this case on the overall rate of return on investment, including First Energy's generation assets. As such, the Companies have not demonstrated that relief from the generation rate cap is warranted in this case.

Q. Do the Companies meet the other criterion in Section 2804(4)(iii)(d) regarding whether "the electric distribution utility is subject to significant increases in the unit rate of fuel for utility generation or the price of purchased power that are outside the control of the utility?"

A. No. Though this is the only applicable criterion that the Commission should consider in evaluating the Companies' request in this case for a rate cap exception, the Companies have not presented reasonable evidence as to why they did not take measures to adequately hedge the enormous POLR supply risk that they agreed to absorb upon entering the 1998 Settlement. As I previously discussed, pursuant to the 1998 Settlement, the Companies agreed to provide POLR service at prices not to exceed the generation rate cap, whether or not the CDS process was successful. Any reasonable person could have anticipated that if market prices exceeded the generation rate cap the CDS goals would not be met, the Companies customers would not take service from an EGS at higher market prices, and ultimately the Companies would be required to serve up to 100% of their entire load as POLR load under the generation rate cap. Though it may not have been possible to predict this outcome, it was certainly a possibility, and one for which the Companies would incur substantial losses if they were not adequately hedged with longer term supply contracts.

Q. The Companies have presented evidence in this case regarding their response to their POLR obligations, their hedging strategies, and the losses incurred by FES in supplying POLR load. Do these arguments justify the failure of the Companies to adequately hedge the potential liabilities that they faced to provide Provider of Last Resort Service to all of their customers at a capped generation rate through the year 2010?

A. No. None of this evidence can explain how a corporation such as GPU Energy or First Energy could accept the liability of providing POLR service through 2010 at a capped generation rate without adequately hedging through the use of long term commitments for POLR supply at known prices. The Companies' explanation and justification for its actions regarding its "POLR Situation" are summed up by Companies witness Frank Graves (among others). Mr. Graves' conclusion regarding the Companies POLR procurement approach is that it has been reasonable and prudent.

Q. Does Mr. Graves' conclusion that the Companies' have acted reasonably and prudently with regard to POLR supply really address the issue before the Commission in this case, which is whether the Companies met the requirements of the 1998 Settlement and the Act?

A. No. Mr. Graves and other Companies' witnesses discuss the environment faced by the Companies after 1998 and conclude that their POLR procurement strategy was reasonable, given the market conditions. At various times in his testimony, Mr. Graves states that alternatives (from the strategy undertaken by the Companies) were not "attractive" (at page 24, line 7) or that alternative purchases would have "locked in substantial losses" (at page 25, line 30). Though these conclusions may be correct and may be reasonable from a profit maximization standpoint (which is the standpoint facing an unregulated supplier), it is not the appropriate basis to evaluate the Companies' actions in light of their obligation to serve up to 100% of their customer load at the generation rate cap and pursuant to the 1998 Settlement. The fact that the Companies may have engaged in an optimal, cost minimizing procurement strategy for POLR load, through a combination of long term and short term purchases, misses the point. The Companies had and continue to have an obligation to serve POLR load through 2010 at the generation rate cap. Though it may not be consistent with a typical profit maximizing strategy, the Companies may have had to enter contracts that were likely to produce losses in order to meet their obligations. The fact that such contracts may not have been attractive or might produce losses (relative to the rate cap) is a consequence of the Companies' actions, including the decision to divest generation resources and the decision to enter into the 1998 Settlement.

The Companies clearly understood that they had a substantial liability associated with POLR supply through 2010, yet chose to engage in a strategy that relied on shorter term purchases. At the same time, based on a response to OCA Set II, No. 3, First Energy apparently hedged its POLR obligations in Ohio through the end of the Competitive Transition Period in Ohio. Baron Exhibit__(SJB-2) contains an excerpt from this response, containing page 17 of a 4th quarter 2002 earnings release statement from First Energy. It states:

> **We've hedged virtually al[sic] of our provider of last resort obligation on peak energy supply through 2005 which coincides with the end of the competitive transition period in Ohio. Our hedge position also allowed us to lock in a positive margin at serving our polar [sic] obligation in Pennsylvania.**

In Ohio, First Energy's strategy apparently was to hedge its POLR obligations through the transition period, while in Pennsylvania, the Company highlighted locking in "positive margins" for its POLR supply.

Q. Is Mr. Graves' conclusion that the Companies' POLR procurement process was prudent the appropriate standard in this case, even if it is correct?

A. No. The Commonwealth Court determined in its ARIPPA decision that "prudence" is not sufficient to meet the "outside of the control of the utility" requirement of the Act. Specifically, the Court said:

> **However, the Commission's approval of the non-unanimous Stipulation Settlement raises the question of whether merely because a procurement practice was found to be reasonable and prudent at the time the decision was made, the losses incurred due to that "reasonable and prudent" decision were "outside of the control" of the decision-maker, in this case, GPU Energy. When a "reasonable and prudent" investment does not go the way it was planned, that does not mean the losses incurred as a result were out of the control of the company.**

ARIPPA, 792 A.2d 664.

The Court further concludes the following:

> **We agree with Commissioner Brownell's assessment that the Commission's interpretation is clearly erroneous because the plain meaning of the term "outside of the control" does not means[sic] that ratepayers will act as the surety for companies that act to maximize their return, and not, as other utilities did, to protect their exposure from known and definable obligations.**

Id. at 665-66.

The issue of whether or not the Companies were "prudent" in their POLR procurement is really an issue between the Companies' management and its stockholders. Met-Ed and Penelec had and continue to have obligations to provide POLR service at the generation rate cap. If the Companies met this obligation in a least cost manner, then their stockholders could have expected no better performance. Irrespective of this, the Companies had a continuing obligation to serve POLR load.

Q. Did other Pennsylvania utilities face similar liabilities and yet continue providing POLR service under their respective generation rate caps?

A. Yes. PPL Electric Utilities Corporation ("PPL") issued a Request for Proposal ("RFP") to obtain POLR supplies in the spring of 2001. It was fully anticipated at that time that PPL might have to pay the "winning bidder(s) substantial amount in excess of revenues received by PPL Electric Utilities for POLR service under the current rate caps."[1] In seeking to fulfill its POLR obligation, PPL fully expected to pay in excess of the generation shopping credit for POLR supplies.

Q. What were the results of the RFP and subsequent regulatory requests associated with PPL's new POLR supply contract?

A. The winning bidder was PPL Energy Plus, LLC, an affiliate (similar to First Energy Solutions in that regard). PPL entered a full requirements contract with PPL Energy Plus

[1] In Re: Securities Certificate of PPL Electric Utilities Corporation; Docket No. S-00010853; May 10, 2001, paragraph 11(c).

in which PPL Energy Plus agreed to supply 100% of PPL's POLR load obligation through December 31, 2009, the end of PPL's generation rate cap.

The agreement required PPL to remit its POLR generation revenue to the supplier each month. This revenue reflects the amount that PPL recovers from its POLR customers pursuant to the generation rate cap (the shopping credit portion thereof).

Q. Did PPL have to pay additional amounts to the POLR supplier, over and above the generation shopping credit?

A. Yes. The Generation Supply Agreement ("GSA"), in section 6.4, requires PPL to make an "advance payment" to the supplier of $89.769 million "for performance under this Agreement." This represents the excess amount over the generation rate cap that was required to be paid the POLR supplier. Baron Exhibit__(SJB-3) contains an excerpt from the GSA that discusses the payment requirements.

Q. Did PPL request authorization from the Commission to recover this excess amount, above the generation rate cap, from customers?

A. No. PPL entered a Joint Stipulation in Settlement with the Office of Consumer Advocate ("OCA") and the PP&L Industrial Customer Alliance ("PPLICA") (July 5, 2001) in which the Company agreed to fully absorb all of the excess POLR costs above the rate cap. Paragraph 9(a) of the Joint Stipulation states as follows:

> **PPL will not ask an exception to its generation rate cap or its transmission and distribution rate cap or file a retail transmission and distribution rate case after the expiration of the transmission and distribution rate cap to recover all or any portion of the $89,769,000 paid to PPL EnergyPlus pursuant to the affiliated interest agreement filed at Docket No. G-00010886.**

A copy of the entire stipulation is contained in Baron Exhibit__(SJB-4).

Q. What conclusions do you draw from the PPL transaction?

A. In early 2001, PPL entered a full requirements POLR supply contract for the entire remaining term of its generation rate cap obligation. The supply contract resulted in a POLR expense that exceeded its generation rate cap by $89.8 million, which PPL agreed to absorb so as not to break the generation rate cap. This PPL agreement with a POLR supplier provides 100% of the energy needed to meet PPL's POLR obligation through the end of its generation rate cap. The Companies' (Met-Ed and Penelec) argument in this case, that no such long term contracts could have been secured, is inconsistent with the PPL experience and indicates that such long term contracts could have been obtained during this time frame.

Finally, it should be noted that the Companies provided no testimony or evidence in this proceeding that they, or GPU, attempted to conduct an RFP for POLR supplies, other than through the CDS process. Upon the failure of the CDS process, the Companies should have attempted to secure POLR supplies through an RFP, as PPL successfully did in 2001.

Q. Are there other examples of Pennsylvania electric utilities agreeing to absorb POLR supply or competitive default supplier bids in excess of the generation rate cap shopping credit?

A. Yes. Allegheny Power ("AP") submitted, and the Commission approved, a plan for a CDS program for the year 2001 in which AP agreed to absorb any costs in excess of the generation shopping credit. AP had sole discretion as to whether or not to accept such CDS bids; however, if it did accept such bids, it would absorb any "incremental cost for the generation supply above the shopping credit" and such costs would "not be charged to ratepayers at any time." (Commission Order in AP Docket No. P-00001802, October 25, 2000).

Q. Based on your analysis, what is your recommendation to the Commission regarding the Companies requests for an increase in their generation rate caps?

A. The Companies have failed to meet the criteria set forth in the Act to increase their generation rate cap and therefore their requests should be denied.

III. TRANSMISSION SERVICE CHARGE ("TSC")

Q. Have you reviewed the Companies' proposal to implement a TSC in this case?

A. Yes. As described in the testimony of Companies' witness Richard D'Angelo, the Companies are proposing a TSC to recover transmission service-related costs incurred to meet their POLR obligations. The TSC is in the form of a rider that will collect transmission costs at a uniform rate per kWh from each POLR customer, regardless of size, load factor, or the delivery voltage at which the customer takes service.

Q. Do you support the Companies' request for a TSC in the form that they are proposing in this case?

A. No. Though MEIUG/PICA does not oppose a properly designed TSC for the Companies to recover transmission related costs, the Companies proposal, as filed, is not reasonable for at least two key reasons. First, the largest cost component in the Companies' proposed TSC is related to congestion costs, which are generation related and not a transmission service cost. Congestion costs are properly related to the POLR supply obligation and are subject to the generation rate cap. Second, the remaining, legitimate transmission service costs, including ancillary services, should be allocated, within the TSC, to rate schedules on both a demand and an energy basis, reflecting the manner in which these costs are incurred by the Companies from PJM. For the most part, transmission costs are charged to the Companies based on the summer coincident peak load of its POLR customers. This is the proper basis to recover these costs from customers.

Q. Would you please explain why congestion costs should not be included in the TSC?

A. Yes. Congestion costs in PJM reflect "differences in the cost of generation that cannot be equalized through the capability of the transmission system to deliver the cheapest energy to all parts of the system in every hour" (Section 7 – Congestion, 2005 PJM State of the Market Report). It is computed as the difference between the locational marginal price ("LMP") at the generation source (the area supplying the Companies POLR load) and the LMP at the Companies' load buses. These costs are related to the supply of generation to meet POLR load requirements and are determined based on the particular sources contracted by the Companies to supply POLR load. For example, because the majority of the Companies' POLR load is met by FES, the Companies' transmission charges are based upon the congestion costs in obtaining power from FES at the western end of the system. In other words, congestion costs are directly tied to generation supply because, if the Companies chose to receive their supply elsewhere, these congestion costs may increase or decrease depending upon the supplier. This is in contrast to network transmission service and ancillary service charges imposed by PJM on the Companies as load serving entities. It is only these latter costs that should be included in the TSC. Congestion costs, and the related Financial Transmission Rights ("FTR") revenues and expenses and the Auction Revenue Rights ("ARR") revenues, are appropriately related to the POLR supply obligation that is governed by the generation rate cap.

Q. The direct testimony of Companies' witness Michelle Henry states on page 12 at lines 6 through 8 that the Companies' proposed TSC "is consistent with the treatment of transmission costs previously approved by the Commission in the most recent PPL Electric Utilities Corporation rate case, Docket No. R-00049255." Is this correct?

A. No. I am familiar with PPL's TSC, having addressed this issue in Docket No. R-00049255. PPL does not include any congestion costs in its TSC.

Q. Are you familiar with Duquesne Light Company's recently filed rate case in which it is requesting approval of a TSC?

A. Yes. As I understand it, Duquesne's proposed TSC does not include any congestion costs.

Q. In addition to congestion costs, the Company is also including a provision for "Transmission Risk Management" costs. Should these costs be included in the TSC?

A. No. As explained in the testimony of Michelle Henry, these costs are associated with "managing the risk so that congestion costs will not exceed certain levels" (Henry direct, page 6, line 10). For the reasons discussed above, these risk management costs should not be included in the TSC. Because these costs are associated with congestion, they are generation-related costs and subject to the generation rate cap.

Q. As discussed by witness D'Angelo, the Companies are requesting recovery of a 10 year amortization of deferred 2006 incremental PJM costs in the TSC. Is this a reasonable cost to include in the TSC?

A. No, the Companies should not be permitted to recover these costs in the TSC. Based on the estimates calculated in Mr. D'Angelo's exhibits RAD-61, the deferred 2006 expenses for Med Ed are $174.6 million and $72.8 million for Penelec. Of these amounts, $116.4 million and $14.3 million represent congestion charges and related carrying charges. These 2006 deferred congestion costs should not be permitted for recovery, for the reasons that I discussed previously. Because these congestion costs are related to POLR supply, recovery, even through a 10 year amortization, causes the generation rate cap to be exceeded. With regard to the remaining (non-congestion) costs, if the Commission permits these costs to be recovered from ratepayers, they should be recovered through a separate transmission expense amortization charge, and not through the TSC. In addition, any such amortization charges (assuming a 10 year amortization) should be classified on a demand and energy basis, following the approach that I am recommending for on-going TSC expenses.

Finally, since the congestion costs that are being deferred in the Companies' proposal are generation costs, the deferral is a further violation of the Commonwealth Court's prior order because the Court said that a deferral of such costs during the rate cap period was a rate cap violation. As I discussed earlier, congestion costs are incurred when the LMPs at the generator busses exceed the LMPs at the load busses. Congestion is a part of the

POLR generation supply cost and therefore must be included in the generation rate that is limited by the generation rate cap. Deferring congestion costs thus is equivalent to deferring any other generation costs.

Q. What costs should be recoverable in the TSC?

A. The TSC should recover PJM transmission charges, which are designated as Network Integrated Transmission Services ("NITS") costs and PJM Ancillary Services costs in Mr. D'Angelo's exhibit RAD-62. These costs correspond to the transmission costs that were approved by the Commission for recovery by PPL in its TSC.

Q. The Companies are proposing to recover all TSC charges through a uniform rate per kWh. Is this a reasonable basis to recover all PJM NITS and Ancillary Service charges?

A. No. The majority of these costs are incurred by the Companies based on the coincident kW demand of their respective POLR load. It is unreasonable to charge customers through a uniform kWh charge for these demand related costs. There is no recognition in the TSC mechanism to distinguish the recovery of costs that are incurred by the Companies on a kW demand basis from those incurred on a kWh energy basis. Nor is there any recognition in the TSC to reflect voltage differentials and the corresponding losses associated with serving each of the Companies' rate schedules. Despite the fact that PJM provides bills for transmission service and ancillary services on both a kW demand and a kWh energy basis, the Companies have decided to ignore this cost differential (demand versus energy) in its TSC.

As stated in the Companies' response to MEIUG/PICA Set II, No. 11, "The load used to derive NITS expenses is based on the sum of the customer's loads at the time of the annual peak of the PJM zone (e.g., Met-Ed or Penelec) in which the load is located." NITS expenses are clearly incurred on the basis of annual peak (single CP) kW demand, not kWh energy at the meter (the basis for the assignment of TSC costs being proposed by the Companies in this case). The complete data response is attached as Baron Exhibit__(SJB-5). This is also confirmed in witness Henry's direct testimony on page 8 at lines 1 to 2, which states: "And finally, the transmission costs assessed by PJM and incurred by the Companies are based on annual and peak loads...."

Q. Do you believe that the Companies' design of the TSC is reasonable, in light of the proposal to use a uniform kWh energy charge for all transmission revenue requirements applied to customer sales, regardless of voltage level, load factor, or other customer load characteristic differences among rate schedules?

A. No. The proposed design of the TSC is not reasonable and results in an unjust allocation of transmission revenue requirements among its schedules. In addition, the TSC proposal will result in different transmission charges for its retail customers, depending on whether such a customer is a POLR customer or an EGS customer. As I will discuss, the Companies' proposed TSC recovery mechanism, which recovers both demand and energy related costs through a uniform kWh sales rate, creates an inappropriate disparity in the charges that customers would pay for POLR transmission service versus the allocated costs to an EGS for the same customer, which reflects a kW demand allocation.

This lack of consistency between the POLR transmission rate and the costs assigned to an EGS for the same customer for the same transmission service is inappropriate and could lead to confused and uneconomic decision-making on the part of the Companies' customers. In addition, if a customer is paying a subsidy under the TSC and subsequently moves to an EGS, the Companies would experience a transmission revenue shortfall (all else being equal), since costs would decrease less than revenues upon losing the customer. Irrespective of this consistency problem, the Companies' proposed cost recovery mechanism completely ignores cost-based differences in providing transmission service to retail rate schedules.

A relatively straightforward decomposition of the Companies' transmission revenue requirements (excluding congestions costs and the deferred 2006 costs) into demand and energy components can easily be implemented in a TSC mechanism. Transmission and ancillary service costs should be allocated to the Companies' rate schedules consistent with the methodology that PJM uses to bill for these services. For larger customers, the retail transmission rates should be designed consistent with the PJM charges by including demand and energy components. Such an alternative TSC, which considers the cost basis associated with each of the charges incurred by the Companies from PJM, would produce a just and reasonable recovery mechanism for these costs.

Q. Do you have an alternative design for the TSC that would recognize the cost of service differences among customer classes for transmission service?

A. Yes. The most reasonable approach to recover transmission revenue requirements is to employ both a demand and an energy based cost recovery mechanism for transmission charges following the Companies' basic TSC proposal (excluding congestion and deferral costs). Essentially, the transmission revenue requirement can be classified into demand and energy components (based on the cost classification shown in Exhibit__(SJB-6), pages 1 and 2, which is based on PJM rate schedules and billings to each Company) and developed into separate TSC demand related costs and energy related costs.[2] Transmission costs would be charged to rate schedules on the basis of the applicable demand and energy charges (at transmission voltages) on which these same costs are incurred by the Companies from PJM. Once these charges are established through the revised TSC, individual rate schedule transmission revenue requirements can be easily calculated on both a demand and energy basis and corresponding rate schedule transmission rates can be computed.

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[2] As discussed previously, congestion costs and the amortization of 2006 deferred costs have not been included in this exhibit.

For classes in which large customers are billed on a demand basis, such as Met-Ed Rate Schedules GP and TP and Penelec Rate Schedules GP and LP, customers can be charged directly based on the customer' allocated zonal coincident peak demand responsibility that is determined by allocating a Company's zonal NITS peak on the basis of each customer's contribution to the Company CP demand.[3]

Q. Would you please explain the specific approach that you are recommending for the design of separate demand and energy related TSC charges?

A. The first step in the process is to classify the Company's transmission revenue requirements into those costs that are billed by PJM to the Companies on the basis of demand, and those costs that are billed on the basis of energy. This classification has already been shown in the Exhibit___(SJB-6) for each Company. The next step in the process is to allocate the TSC demand and energy revenue requirements to rate schedules using each classes' CP demand and kWh energy (at power supply voltage). This is shown for each of the Companies in Baron Exhibit__(SJB-7), pages 1 and 2. The results of this allocation are a set of demand and energy charges (in total dollars) for each rate schedule, reflecting a cost based assignment corresponding to the incurrence of these costs by the Companies from PJM. The TSC rate for each rate schedule can then be developed by unitizing the allocated demand and energy revenue requirements by the rate schedule kWh energy (at the meter).

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[3] This is essentially identical to using the customer's individual NITS demand, which would be appropriate if it is available.

For Met-Ed rate schedules GP and TP and Penelec rate schedules GP and LP, separate TSC demand and energy rates have been computed. The demand rates are developed by unitizing the respective rate schedule allocated demand costs by the rate schedule's NITS demand.

Q. Have you prepared a summary of the TSC rates that you are recommending for each Company?

A. Yes. Table 1 shows a summary of the TSC rates for Met-Ed, and Table 2 contains the proposed rates for Penelec. These rates produce the same TSC revenues as the uniform kWh rates proposed by the Companies in this case, except that they do not include the recovery of congestion costs or the deferred 2006 incremental expenses.

Table 1
Metropolitan Edison Company
Summary of TSC Rates by Rate Schedule

	Demand Rate $/kW-mo	Energy Rate $/kWh
RT	-	0.00388
RS	-	0.00546
GS	1.264	0.00200
GST	1.264	0.00191
GP	1.264	0.00170
TP	1.264	0.00173
MS	-	0.00435
AL	-	0.00183
SL	-	0.00183
BRD	-	0.00305
TOTAL		0.00476

Table 2
Pennsylvania Electric Company
Summary of TSC Rates by Rate Schedule

	Demand Rate $/kW-mo	Energy Rate $/kWh
RT	-	0.00285
RS	-	0.00471
GSS/GSM		0.00508
H		0.00319
GSL		0.00434
GP	1.249	0.00184
LP	1.249	0.00166
ST LTG	-	0.00183
OL	-	0.00183
BRD	-	0.00377
WAVERLY	-	0.00477
TOTAL		0.00436

Q. If the Commission accepts the Companies' request to include congestion charges in the TSC, how should these costs be recovered?

A. Though, as I discussed, congestion costs are energy supply costs and not transmission service costs, if the Commission accepts the Companies' proposal to recover them in the TSC, it is appropriate to allocate these congestion expenses to rate classes in a cost based manner. Since congestion costs vary by month and by time of day, it is reasonable to allocate these costs using a weighted allocation factor similar to the method that the Companies are proposing in this case to allocate POLR supply costs.

The Companies have provided a breakdown of 2005 congestion costs by month and by on-peak/off-peak period. Using 2005 hourly loads for each rate schedule, these 2005 congestion costs can be more precisely allocated to rate classes, reflecting the variations in load patterns and congestion costs by time period for each rate class. The result of this allocation of 2005 costs can be summarized in a percentage congestion cost responsibility factor for each rate class, which can then be used to allocate the current period (in this case estimated 2006) congestion costs. Baron Exhibit__(SJB-8), pages 1 and 2 shows the development of the allocation of congestion costs for Met-Ed and Penelec, together with the demand/energy allocation of NITS and ancillary service costs that I previously presented. If the Commission accepts the Companies' requests for the inclusion of congestion costs in the TSC, then the methodology presented in Exhibit___(SJB-8) should be used to develop rates.

Q. **The Companies have proposed a reconciliation factor for net over or under collection of charges associated with transmission service in their TSC. How could this be incorporated into your proposal?**

A. Since the reconciliation factor would not likely be large relative to the overall TSC charges, the easiest approach would be to incorporate the reconciliation factor into the energy related costs for each rate schedule. The reconciliation dollars should be allocated to each rate schedule using the kWh energy at the transmission voltage level and then incorporated into the respective rate schedule TSC energy rate.

IV. UNIVERSAL SERVICE CHARGE ISSUES

Q. Have you reviewed the Companies' proposal to implement a Universal Service Charge rider in these cases?

A. Yes. The Companies are proposing to implement a Universal Service Charge ("USC") that would be applied on a uniform kWh basis to all customers. This represents a substantial policy change in the assignment and recovery of universal service costs, which are now recovered only from residential (rates RS and RT) customers. Baron Exhibit__(SJB-9) is an excerpt from the current Met-Ed Rule 13(b)(14) that clearly states that USC costs are only included in residential rates. A similar provision is in Penelec Rule 13(b)(13).

Q. Are you opposed to the implementation of a USC?

A. No; however, if a USC is established, it should continue to only apply to residential customers. The costs being recovered from the USC are primarily associated with customer assistance programs and uncollectible expenses. Uncollectible expenses have always been specifically assigned to rate classes in the Companies' past rate proceedings based on the actual incurrence of these "costs." Baron Exhibit__(SJB-10), pages 1 through 4, contains copies of the response of each Company to MEIUG/PICA Set I, Nos. 9 and 10, which state that, in the most recent Met-Ed and Penelec rate cases, uncollectible expenses were assigned based on a weighted uncollectible expense per customer for each rate schedule. As can be seen on pages 3 and 4 of the exhibit, more than 85% of the uncollectible expenses were assigned to the residential rates of each Company. None of the uncollectible expenses was assigned to rates TP and LP, while about ½ of 1% of the costs were assigned to rate GP of each Company.

Q. How much of the proposed USC for each Company is comprised of uncollectible expenses?

A. For Met-Ed, 41% of the proposed USC revenue requirement of $19.1 million is comprised of uncollectible expenses, while for Penelec these costs comprise 34% of the total USC revenue requirement.

Q. Should these costs be included in the USC?

A. No. Uncollectible expenses have always been a base rate expense. These expenses should be specifically assigned to each rate schedule based on the incidence of the cost and recovered in the distribution revenue requirement.

Q. Mr. D'Angelo has argued in his direct testimony that the Companies included uncollectible expenses in the USC because the other USC expenditures are perceived to reduce uncollectible expenses. Is this a valid justification?

A. No. Even if it were shown that the expenditures that comprise the USC (other than uncollectible expenses) did reduce these expenses, this is no justification for including these uncollectible expenses in the USC and recovering them on a uniform kWh basis. Uncollectible expenses are a traditional cost of doing business that have historically been recovered from customers on a rate class by rate class basis, not uniformly recovered on a kWh energy basis.

Q. How should the other USC costs be recovered from ratepayers?

A. The USC (excluding uncollectible expenses) should be recovered from residential customers, as is currently done in each Company's rates. Because residential customers are the only class of customers eligible to benefit from these programs, cost causation theory requires residential customers to be allocated the costs of such programs.

Q. Assuming, hypothetically, that the USC costs are allocated to all customers, should this allocation occur on a per kWh basis?

A. No. The recovery of these expenses on a uniform per kWh basis is not reasonable, particularly for high load factor customers who are utilizing energy during the off-peak periods.

Table 3 shows the impact of the Companies' USC proposal (at the rates proposed by each Company) on a 10,000 kW rate TP and LP customer at 70%, 80%, and 90% load factors. As can be seen in the table, high load factor customers would pay a substantial amount for the USC, which is comprised primarily of residential uncollectible expenses and residential customer assistance programs. Because the Companies are proposing a uniform USC charge per kWh, industrial and commercial customers who have larger, relative amounts of off-peak and weekend energy use are penalized the most. Effectively, the Companies' proposed USC amounts to a "tax" on kWh usage, which discourages large commercial and industrial customers from expanding their operations through additional shifts. This is contrary to economic development objectives, and, more importantly, it is contrary to cost causation principles.

Table 3
Annual Impact of USC on a 10 mW Customer

	Load Factor	USC ($0.00146)
TP:		
	70%	$89,527
	80%	$102,317
	90%	$115,106
LP:	Load Factor	USC ($0.00173)
	70%	$106,084
	80%	$121,238
	90%	$136,393

Q. What is your recommendation regarding the Companies' proposed USC?

A. The USC should be assigned to residential rate schedules, as is the case currently. If the Commission decides as a matter of public policy to assign the costs to all rate schedules, uncollectible expenses should be removed and specifically assigned to rate schedules in a manner consistent with the past treatment of these expenses by the Companies. The remainder of the USC expenses should not be assigned to rate schedules on the basis of kWh usage, which is unreasonable and is particularly detrimental to high load factor, energy intensive customers. If these remaining USC costs (without uncollectible expenses) are assigned to all rate schedules, an appropriate allocation factor would be to assign cost on the basis of the number of customers in the rate class. In this manner, these USC costs would be recovered on a uniform basis from each customer, rather than as an "energy adder."

V. COST OF SERVICE ISSUES

Q. Have you reviewed the Companies' filed class cost of services studies in this case?

A. Yes. The Companies have inexplicably filed bundled and unbundled cost of service studies in this case. Since 1999, the Companies costs and rates have been unbundled and therefore a bundled cost of service study is irrelevant in this proceeding; however, it appears that the Companies have relied on the bundled cost of service studies to allocate proposed POLR generation rates in this case, to the detriment of customers taking service on Met-Ed rates GP and TP and Penelec rates GP and LP. These cost of service studies should not be used in this proceeding to allocate any revenue requirements. The only cost of service study of relevance in this proceeding is a "distribution only" study. The Companies are also proposing a 100% pass-through transmission rider that will fully recover transmission expenses from customers. There is no value whatsoever it examining a historical transmission cost of service study in this case.

Likewise, there is no value in the Companies' analysis of historic power supply cost of service in this environment. The Companies are subject to generation rate caps that govern the level of each rate schedules' generation and CTC rates, and there is no useful information provided by the Companies' attempt to evaluate historical rates of return on investment (which, as I will discuss next, is limited to distribution plant). Effectively, the Companies' bundled cost of service studies are attempting to measure overall revenues by rate schedule for distribution, transmission, and generation (governed by the rate cap) against distribution investment by rate schedule. These bundled cost of service studies provide no useful information to the Commission in its determinations in this case.

The bundled studies are particularly biased in evaluating the reasonableness of the rates paid by Met-Ed rate TP and Penelec rate LP customers, the vast majority of which are served at transmission voltage. These rate schedules have very limited amounts of allocated rate base, since transmission voltage customers are properly not assigned distribution investment costs.[4] Though not as significant, the same is also true for Met-Ed and Penelec rate GP, on which customers take service at primary voltage and are not responsible for secondary distribution system costs. The end result is that very small differences in return dollars, when measured against a very limited rate base for these rate schedules, produces very large swings in the rate of return. For all of these reasons, the Companies' bundled studies should be ignored by the Commission.

Q. Did the Companies rely on their own bundled cost of service studies in this case?

A. It does not appear that they did, which raises the question as to why the Companies would even offer the cost of service studies in this proceeding. Considering the bias of the studies, combined with the Companies' decision not to utilize the results, providing these studies as part of the filing does nothing more than confuse the issues.

[4] For the most part, these customers only require metering equipment, except for the limited facilities associated with customers who may take primary service.

Q. **Have you reviewed the Companies' distribution cost of service studies and their proposed allocation of the requested distribution revenue changes?**

A. Yes. The Companies' distribution cost of service studies are reasonable and should be used to allocate the distribution revenue changes approved by the Commission in this case. The Companies have proposed a reasonable allocation of their requested distribution revenue changes and have made reasonable progress towards cost of service in its revenue allocation proposals.

VI. TARIFF RULE CHANGES

Q. Have you reviewed some of the numerous proposed changes in the Companies tariffs that they are requesting in this case?

A. Yes. As discussed in Mr. Pleiss' testimony, the Companies are proposing changes in some of their rules, as well as some specific rate schedule provisions. For the most part, the rule changes and some of the tariff changes are applicable to both Companies, while some of the tariff changes are Company specific. As an organizational matter, I will address rule and tariff changes applicable to both Companies first, then address Company specific changes.

Q. Have you reviewed the Companies' proposal to modify Rule 12(b)(9) of the tariff that permits the Companies to adjust the energy charges of bills by 2.5% to compensate for losses in the event that meters are placed at the high or low side of Company owned transformers at the Companies' option?

A. Yes. As explained by Mr. Pleiss, this rule change is a clarification that the existing adjustment, which previously only applied to demand charges, will also now apply to energy charges. Though I understand the basis for the Companies' proposed change, there does not appear to be any recognition in the Companies' filings of the potential revenue effect from this tariff change. Given the magnitude of the increases being requested by the Companies in this case, there should be recognition given to each additional increase that the Companies are requesting. In addition, the Companies have not provided any evidence supporting the reasonableness of the proposed 2.5% energy charge adjustment. Finally, to the extent that energy charge increases occur as a result of this provision, this proposal violates the rate cap, as the Act says the "total charges" cannot increase (Section 2804(4)(ii)).

Q. The Companies are proposing a significant modification to the rules regarding "exit fees" associated with new on-site generation. Do you have any comments on their proposed changes to these provisions in Rule 15(d)?

A. Yes. The current version of this rule is designed to recover CTC (stranded costs) from customers who install on-site generation that results in a decrease in their usage, relative to a baseline level established in 1996. The underlying rationale for this provision is to insure that existing customers will not avoid their CTC responsibilities for load that they had on-line in the 1996 base period by adding on-site generation. The current exit fee is applied in cases where on-site generation causes the customer's current kWh consumption to drop more than 10% below the customer's 1996 level. In this event, the customer is charged an additional CTC based on the difference between current use (with on-site generation) and the customer's 1996 usage. Another provision of the rule applies to customers who add 4 mW or more of on-site generation and can document that a written economic feasibility study was completed between 1992 and 1996. In this event, the customer will be charged an additional CTC based on 1/3 the difference between current usage and the customer's 1996 base level of usage.

Q. What is you understanding of the rationale for the existing provisions of this rule?

A. The purpose of the rule is to require existing customers to pay their share of stranded costs based on the customers' load and usage in 1996, despite reductions in current billing determinants as a result of new on-site generation. The provision is basically similar to a "take-or-pay" provision on the stranded cost portion of a customer's bill (the CTC) and implies a "liability" incurred by existing large customers established at the time that stranded generation costs were incurred by the Companies. The 1996 base period is a key term of the rule in that it establishes the basis for a customer's potential liability for stranded costs. Since the Companies' stranded costs are based on the generation and NUG contracts in existence prior to restructuring, a customer's CTC liability should only reflect the customer's load and usage associated with generation resources incurred to meet this level of usage. For example, if a current customer had 10 mW of load on the system in 1996 (for which the Companies had obtained generation resources that were subsequently "stranded"), and the customer then added 5 mW to its load in 2002 and then installed 5 mW of on-site generation in 2004, the Companies stranded costs would not be affected at all. In this case, the customer's usage would still be based on the 10 mW of load that existed in 1996. Under the current version of Rule 15(d), the customer would pay a CTC based on current usage, which is also the usage in 1996.

Q. What change are the Companies proposing to make to this rule?

A. The proposed rule, which is now designated as Rule 14(d), eliminates the 1996 base period as the basis for comparison and substitutes "the energy usage based upon the monthly average of the prior four years immediately preceding a customer's request to invoke Rule 14d." This change now results in a customer paying for stranded costs on the difference between new load additions (occurring in the past four years) and new load reductions, due to on-site generation. There is simply no basis or rationale for the Companies' proposed change.

Q. Have the Companies' offered any explanation for the proposed change?

A. Mr. Pleiss provides only a single sentence of justification in his testimony for the change. He states: "As the Company has modified its primary computer system and data bases over the last several years, it no longer has available customers' billing determinants for 1996" (Met-Ed testimony at page 26, line 8; Penelec testimony at page 25, line 11). This is not a justification for the proposed rule change that could potentially impose large additional costs on some of the Companies' ratepayers. The current Rule 14d has been in the Companies' tariffs for many years, and the Companies had an obligation to maintain billing data in order to implement and apply this Rule, should the need arise. In the event that the Companies no longer have historical data, then the appropriate remedy is to estimate the 1996 level of usage, combined with other information that the customers themselves may be able to provide, rather than simply change the entire economic rationale for the Rule (as is being proposed by the Companies in this case). This rule change should be rejected by the Commission in this case.

Q. As discussed in the testimony of Mr. Pleiss, Met-Ed is proposing to eliminate current Business Development Riders K and L, and Penelec is proposing to restrict availability to its Business Development Riders M and N to existing customers, and eliminate these riders at the end of the CTC recovery period. Do you have any comments on these proposed tariff changes?

A. Yes. These riders, which were introduced in early 2000, are designed to promote economic development in the Companies' service areas by foregoing the CTC charge for new, incremental load. According to Mr. Pleiss' testimony, Penelec has a number of customers taking service pursuant to these riders, while Met-Ed has no current customers.

The rationale for these riders stems from the logical conclusion that new load, added to the Companies' systems after 2000, could not possibly be responsible for prior stranded costs associated with generation that was already divested or NUG contracts that were previously entered. Therefore, it makes economic sense to offer new large customers (and expansions of existing customers) an incentive to add new jobs in Pennsylvania by eliminating the CTC charge on these additions. If new jobs can be created through load additions that do not contribute to stranded costs, by definition, it is a "win-win" situation. The Companies' proposal to eliminate any new customers or existing customer expansions from the incentives provided by these riders is counterproductive and is not justified. The same rationale that existed in 2000 for implementing these riders exists today and therefore there is no basis for the Companies to eliminate these riders for new customers and load expansions.

Q. The Companies are also proposing to modify their rules with respect to the limitation on liability for service. Do you have any comments regarding this proposed modification?

A. Yes, as I understand, currently the Companies' tariff limits the Companies' liability unless the actions are caused by the sole negligence or willful misconduct of the Companies. In such an instance, there is no limit on the resulting damages. Under the newly proposed language, the monetary liability of the Companies is limited unless the incident is caused by the willful and/or wanton misconduct of the Companies.

Q. Do you have concerns with this proposal?

A. Yes. Under this proposal, if the Companies' sole negligence is responsible for an interruption in electric service for a large commercial or industrial customer, the Company can only be liable for $2,000, regardless of the actual amount of damages. Because interruption of service can cause significant ramifications for large commercial and industrial customers, limiting liability to $2,000 does not seem appropriate. Moreover, the Companies propose to limit aggregate liability for multiple claims arising from a single alleged negligent act to $200,000. Under this instance, if a single negligent act affected 20 customers, each customer would be eligible for only $10,000, even if their damages significantly exceeded this amount.

Q. Do the Companies provide any basis for this modification?

A. According to Mr. Pless' testimony, the Companies base this amount on an evaluation of claims paid to customers between 2002 and 2005 and determined that the majority of claims paid to large commercial and industrial customers amounted to $2,000 or less. This methodology fails to account for the average size of the claims against the Companies. Similarly, it fails to account for large claims that are beyond the scope of $2,000. If the Company is going to provide a monetary limitation with respect to liability, the Company must set a realistic limit that accounts for the significant damage that can occur when a large commercial or industrial customer has their service interrupted due to a negligent act by the Companies.

VII. RATE DESIGN ISSUES

Q. The Companies are proposing a number of significant rate design issues that will affect customers taking service on Met-Ed rates GP and TP and Penelec rates GP and LP. In addition, the Companies are proposing increases in the CTC charges and substantial increases in generation rates. Are these changes, both the rate design and the CTC and generation rate increases, consistent with the requirements of the Act?

A. No. As I discussed earlier in my testimony, there is no basis to increase the generation rate cap for either Company in this case. Therefore, consistent with the Act, there should be no net increases in the CTC and generation rates for any rate schedule. This means that if the Companies increase the CTC charges for a rate schedule due to a change in amortization rate, then there must be a corresponding decrease in the generation rate, in order to maintain the rate cap. The Companies are proposing to increase the CTC charges by substantial amounts for some rate schedules, such as Met-Ed's rate TP. In order to maintain the overall generation rate cap, it would be necessary to implement a corresponding reduction in the generation rate (shopping credit) for Rate TP.

Q. Would this requirement to maintain the rate cap also apply to specific rate design issues?

A. Yes. The unbundled rates of each Company were carefully designed to preserve the existing rate designs, prevent any cost shifting among rate schedules and among customers within each rate schedule, and insure that the generation rates do "not exceed the generation component charged to the customers that has been approved by the commission for such service, as of the effective date of this chapter" (2804(4)(ii)). The Companies are proposing substantial changes in rate design in this case that will have the effect of shifting costs among customers within some rate schedules and increasing generation charges for customers. I will discuss a number of these changes subsequently in my testimony.

The overall position of MEIUG/PICA in this case, that the generation rate cap be maintained, also requires that the existing CTC and generation rate design be maintained in order to avoid inappropriately increasing generation charges to customers.

Q. If the Commission rejects your recommendation to maintain the existing generation rate cap, should the Companies' proposed rate design changes for rates GP, TP, and LP be accepted as filed?

A. No. As I will discuss subsequently, even if the Commission agrees to allow an increase in the Companies' respective generation rate caps, it is reasonable and appropriate, to the extent possible, to maintain the general structure of the existing CTC and generation rate design. This will preserve the intra-class relationships among customers with regard to these costs and more closely follow the intent of the generation rate cap provisions of the Act.

Q. The Companies are proposing to eliminate the CTC energy rates for Met-Ed rate schedules GP and TP and Penelec rate schedules GP and LP. Is this appropriate?

A. No. Following the principle that I just discussed, it is appropriate for the on and off-peak CTC energy charges to be maintained in proposed rates, even if the CTC recovery rates are increased for these rates. The Companies are proposing to eliminate the energy charges associated with the CTC. While there are no "economic price" signal issues associated with the CTC, since it reflects the recovery of previously incurred stranded costs, it is appropriate to maintain the intra-rate schedule relationships that exist so that customers within a rate schedule do not face disproportionately higher increases in the CTC. By maintaining the existing CTC rate design, some of the provisions of the generation rate cap will be maintained, at least among customers taking service under the same rate schedule.

Q. Met-Ed is proposing to eliminate the optional "Eight Hour On-Peak Time-Of-Day Service" provision for rates GS, GST, GP and TP. Do you agree with the Company's proposal?

A. No. Met-Ed customers on these rates currently have the option to elect an eight hour period for the determination of monthly billing demand. At the option of the customer, the on-peak period can either be set from 9 a.m. to 5 p.m. or 10 a.m. to 6 p.m. A number of Met-Ed customers have made this election, including members of MEIUG. Met-Ed has had this provision in its tariffs for many years, having established it prior to restructuring. Customers taking service under this provision have relied on its availability, and it is unreasonable for the Company to now propose its elimination.

This issue is an intra-rate schedule rate design issue and does not affect customers on other rate schedules. Given the magnitude of the Company's proposed increases in this case, there is no justifiable policy reason to eliminate this optional rate provision. Customers who currently rely on this option will face larger than average increases as a result of the Company's proposal. At a minimum, customers who currently utilize and rely on this option should be permitted to continue to use this eight hour on-peak rate provision.

Q. Under current rates, the generation rates for Met-Ed rate schedules GP and TP are the same in both the on-peak and off-peak periods. In this manner, the choice of an 8 hour or 12 hour on-peak period has no impact on the generation prices paid. Would this continue to be true under proposed rates, if the 8 hour on-peak period is maintained, as you are recommending?

A. Met-Ed is proposing an on-peak generation rate in this case that is substantially greater than the off-peak generation rate. Therefore, if the 8 hour option is maintained, as I recommend, it will be necessary to develop a set of on-peak and off-peak generation rates that are appropriate for customers electing the 8 hour on-peak option. The Company should develop such rates in its compliance filing in this case. These rates should be consistent with the Commission approved 12 hour on-peak generation rates, but adjusted to reflect the shorter on-peak period in the 8 hour option.

Q. Mr. Pleiss, in his testimony on page 36 at lines 22 and 23, states that customers who use this eight hour on-peak option receive lower off-peak energy for a longer period. Is this correct?

A. No. Met-Ed current GS, GST, GP, and TP rates have identical on-peak and off-peak generation energy charges. As explained above, this provision (the eight hour on-peak option) affects the period during which a customer's on-peak billing demand (kW) is established each month. The current rates do reflect different on-peak and off-peak CTC energy charges used to recover stranded costs; however, customers electing the eight hour on-peak option pay higher CTC energy charges on-peak and off-peak than the regular 12 hour CTC energy rates.

Q. Met-Ed's rate schedule GP currently offers customers the option to elect among five different 12 hour on-peak periods, beginning at hours 6 a.m., 7 a.m., 8 a.m., 9 a.m., and 10 a.m. The Company is proposing to eliminate this option and restrict customers to a 12 hour on-peak period beginning at 8 a.m. for rate GP. Do you have any concerns with Met-Ed's proposal on this issue?

A. Yes. This option, which apparently has been incorporated in the Company's rates for many years, has provided its customers with a degree of flexibility that customers have now relied upon in their decision making. Each of these alternative 12 hour periods is within the PJM 16 hour on-peak window and thus should continue to be offered to Met-Ed customers. The result of the Company's proposal is to shift costs among customers within each of these rate schedules and potentially result in much larger increases to some customers within the rate schedules. I have been informed by some members of MEIUG that the proposed change to a 12 hour on-peak period beginning at 8 a.m. will cause detrimental impacts on these customers. Given the fact that the Company has long offered this tariff option, that the Company's customers have long relied on its availability, the potential intra-rate class cost shifts that the change would produce, and that the option 12 hour on-peak blocks are each within the PJM on-peak period, the option should be continued in Met-Ed's rates.

Met-Ed has recently filed an errata notice that indicates that the elimination of this option for rate GP was a mistake. If this proposal to eliminate the optional on-peak period for rate GP is now being withdrawn, the Company should confirm this in its rebuttal testimony.

Q. Have you reviewed Met-Ed's proposal to eliminate its current optional Seasonal Time-Of-Day Service on rate schedules GS, GST, GP, and TP?

A. Yes. Though there is no mention of this change in Company witness Pleiss' testimony on rate design changes, Met-Ed is proposing to eliminate the optional seasonal summer/non-summer kW demand rates that currently recover generation related costs through the CTC. Met-Ed has provided no justification for this change. In fact, it is inconsistent with the position of the Company regarding the establishment of seasonal generation charges.

Moreover, Met-Ed's proposal to eliminate this tariff provision will have detrimental impacts on larger customers, who are already facing substantial increases in their electric charges based on the Companies' filing. The impact of Met-Ed's proposed elimination of this rate option is to increase the CTC for some of its larger customers, including some members of MEIUG, relative to the average increase for each of the affected rate schedules. There is simply no reason why the seasonal demand rate option, which is only associated with the recovery of the CTC, should be eliminated. The Company's proposal is unreasonable and should be rejected by the Commission.

Q. Do you have any concerns with respect to any other provisions of the filing?

A. Yes. In GRP-4, Attachment A, Mr. Pleiss indicates that there will be no revenues for the ½ hour notice provision with respect to obtaining the monthly credit applicable to a customer's CTC for curtailable load. This exhibit suggests that the Companies are proposing to eliminate the ½ hour notice provision; however, the proposed tariff revisions retain the ½ notice provision. If the Companies are proposing such elimination, I would strongly object to this proposal, as many customers utilize this provision, and the Companies have not provided any basis for such elimination. Also, on Penelec exhibit GRP-4, Attachment A, page 8 of 13, the rate for the Company's Rider E Curtailable Credit is being reduced. There is no basis to make such a reduction in this curtailable credit.

In two very late filed data responses in this case (responses to MEIUG/PICA Set IV, Nos. 17, 18 and 19), the Companies indicated that the suggested elimination of the ½ hour notice provision was an error. The Companies should confirm in their rebuttal testimony that they are not proposing to eliminate the ½ notice provision and reduce the Rider E Curtailable Credit.

Q. Does that complete your testimony?

A. MEIUG and PICA still have outstanding interrogatory requests and are awaiting responses from the Companies regarding various issues in this proceeding. Counsel has indicated that we reserve the opportunity to submit supplemental testimony, if necessary, upon receipt and review of these interrogatory responses.

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

PENNSYLVANIA PUBLIC	:	
UTILITY COMMISSION, ET AL.	:	
	:	**DOCKET NOS. R-00061366**
	:	**R-00061367**
v.	:	**P-00062213**
	:	**P-00062214**
	:	**A-110300F0095**
	:	**A-110400F0040**
METROPOLITAN EDISON COMPANY	:	
AND PENNSYLVANIA ELECTRIC	:	
COMPANY	:	

EXHIBITS

OF

STEPHEN J. BARON

ON BEHALF OF

MET-ED INDUSTRIAL USERS GROUP
PENELEC INDUSTRIAL CUSTOMER ALLIANCE

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

PENNSYLVANIA PUBLIC UTILITY COMMISSION, ET AL.	:	
	:	**DOCKET NOS. R-00061366**
	:	**R-00061367**
v.	:	**P-00062213**
	:	**P-00062214**
	:	**A-110300F0095**
	:	**A-110400F0040**
METROPOLITAN EDISON COMPANY AND PENNSYLVANIA ELECTRIC COMPANY	:	

EXHIBIT__(SJB-1)

OF

STEPHEN J. BARON

ON BEHALF OF

MET-ED INDUSTRIAL USERS GROUP
PENELEC INDUSTRIAL CUSTOMER ALLIANCE

Expert Testimony Appearances
of
Stephen J. Baron
As of May 2006

Date	Case	Jurisdict.	Party	Utility	Subject
4/81	203(B)	KY	Louisville Gas & Electric Co.	Louisville Gas & Electric Co.	Cost-of-service.
4/81	ER-81-42	MO	Kansas City Power & Light Co.	Kansas City Power & Light Co.	Forecasting.
6/81	U-1933	AZ	Arizona Corporation Commission	Tucson Electric Co.	Forecasting planning.
2/84	8924	KY	Airco Carbide	Louisville Gas & Electric Co.	Revenue requirements, cost-of-service, forecasting, weather normalization.
3/84	84-038-U	AR	Arkansas Electric Energy Consumers	Arkansas Power & Light Co.	Excess capacity, cost-of-service, rate design.
5/84	830470-EI	FL	Florida Industrial Power Users' Group	Florida Power Corp.	Allocation of fixed costs, load and capacity balance, and reserve margin. Diversification of utility.
10/84	84-199-U	AR	Arkansas Electric Energy Consumers	Arkansas Power and Light Co.	Cost allocation and rate design.
11/84	R-842651	PA	Lehigh Valley Power Committee	Pennsylvania Power & Light Co.	Interruptible rates, excess capacity, and phase-in.
1/85	85-65	ME	Airco Industrial Gases	Central Maine Power Co.	Interruptible rate design.
2/85	I-840381	PA	Philadelphia Area Industrial Energy Users' Group	Philadelphia Electric Co.	Load and energy forecast.
3/85	9243	KY	Alcan Aluminum Corp., et al.	Louisville Gas & Electric Co.	Economics of completing fossil generating unit.
3/85	3498-U	GA	Attorney General	Georgia Power Co.	Load and energy forecasting, generation planning economics.
3/85	R-842632	PA	West Penn Power Industrial Intervenors	West Penn Power Co.	Generation planning economics, prudence of a pumped storage hydro unit.
5/85	84-249	AR	Arkansas Electric Energy Consumers	Arkansas Power & Light Co.	Cost-of-service, rate design return multipliers.
5/85		City of Santa	Chamber of Commerce	Santa Clara Municipal	Cost-of-service, rate design.

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of
Stephen J. Baron
As of May 2006

Date	Case	Jurisdict.	Party	Utility	Subject
6/85	84-768-E-42T	Clara WV	West Virginia Industrial Intervenors	Monongahela Power Co.	Generation planning economics, prudence of a pumped storage hydro unit.
6/85	E-7 Sub 391	NC	Carolina Industrials (CIGFUR III)	Duke Power Co.	Cost-of-service, rate design, interruptible rate design.
7/85	29046	NY	Industrial Energy Users Association	Orange and Rockland Utilities	Cost-of-service, rate design.
10/85	85-043-U	AR	Arkansas Gas Consumers	Arkla, Inc.	Regulatory policy, gas cost-of-service, rate design.
10/85	85-63	ME	Airco Industrial Gases	Central Maine Power Co.	Feasibility of interruptible rates, avoided cost.
2/85	ER-8507698	NJ	Air Products and Chemicals	Jersey Central Power & Light Co.	Rate design.
3/85	R-850220	PA	West Penn Power Industrial Intervenors	West Penn Power Co.	Optimal reserve, prudence, off-system sales guarantee plan.
2/86	R-850220	PA	West Penn Power Industrial Intervenors	West Penn Power Co.	Optimal reserve margins, prudence, off-system sales guarantee plan.
3/86	85-299U	AR	Arkansas Electric Energy Consumers	Arkansas Power & Light Co.	Cost-of-service, rate design, revenue distribution.
3/86	85-726-EL-AIR	OH	Industrial Electric Consumers Group	Ohio Power Co.	Cost-of-service, rate design, interruptible rates.
5/86	86-081-E-GI	WV	West Virginia Energy Users Group	Monongahela Power Co.	Generation planning economics, prudence of a pumped storage hydro unit.
8/86	E-7 Sub 408	NC	Carolina Industrial Energy Consumers	Duke Power Co.	Cost-of-service, rate design, interruptible rates.
10/86	U-17378	LA	Louisiana Public Service Commission Staff	Gulf States Utilities	Excess capacity, economic analysis of purchased power.
12/86	38063	IN	Industrial Energy Consumers	Indiana & Michigan Power Co.	Interruptible rates.

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Date	Case	Jurisdict.	Party	Utility	Subject
3/87	EL-86-53-001 EL-86-57-001	Federal Energy Regulatory Commission (FERC)	Louisiana Public Service Commission Staff	Gulf States Utilities, Southern Co.	Cost/benefit analysis of unit power sales contract.
4/87	U-17282	LA	Louisiana Public Service Commission Staff	Gulf States Utilities	Load forecasting and imprudence damages, River Bend Nuclear unit.
5/87	87-023-E-C	WV	Airco Industrial Gases	Monongahela Power Co.	Interruptible rates.
5/87	87-072-E-G1	WV	West Virginia Energy Users' Group	Monongahela Power Co.	Analyze Mon Power's fuel filing and examine the reasonableness of MP's claims.
5/87	86-524-E-SC	WV	West Virginia Energy Users' Group	Monongahela Power Co.	Economic dispatching of pumped storage hydro unit.
5/87	9781	KY	Kentucky Industrial Energy Consumers	Louisville Gas & Electric Co.	Analysis of impact of 1986 Tax Reform Act.
6/87	3673-U	GA	Georgia Public Service Commission	Georgia Power Co.	Economic prudence, evaluation of Vogtle nuclear unit - load forecasting, planning.
6/87	U-17282	LA	Louisiana Public Service Commission Staff	Gulf States Utilities	Phase-in plan for River Bend Nuclear unit.
7/87	85-10-22	CT	Connecticut Industrial Energy Consumers	Connecticut Light & Power Co.	Methodology for refunding rate moderation fund.
8/87	3673-U	GA	Georgia Public Service Commission	Georgia Power Co.	Test year sales and revenue forecast.
9/87	R-850220	PA	West Penn Power Industrial Intervenors	West Penn Power Co.	Excess capacity, reliability of generating system.
10/87	R-870651	PA	Duquesne Industrial Intervenors	Duquesne Light Co.	Interruptible rate, cost-of-service, revenue allocation, rate design.
10/87	I-860025	PA	Pennsylvania Industrial Intervenors		Proposed rules for cogeneration, avoided cost, rate recovery.

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As of May 2006

Date	Case	Jurisdict.	Party	Utility	Subject
10/87	E-015/ GR-87-223	MN	Taconite Intervenors	Minnesota Power & Light Co.	Excess capacity, power and cost-of-service, rate design.
10/87	8702-EI	FL	Occidental Chemical Corp.	Florida Power Corp.	Revenue forecasting, weather normalization.
12/87	87-07-01	CT	Connecticut Industrial Energy Consumers	Connecticut Light Power Co.	Excess capacity, nuclear plant phase-in.
3/88	10064	KY	Kentucky Industrial Energy Consumers	Louisville Gas & Electric Co.	Revenue forecast, weather normalization rate treatment of cancelled plant.
3/88	87-183-TF	AR	Arkansas Electric Consumers	Arkansas Power & Light Co.	Standby/backup electric rates.
5/88	870171C001	PA	GPU Industrial Intervenors	Metropolitan Edison Co.	Cogeneration deferral mechanism, modification of energy cost recovery (ECR).
6/88	870172C005	PA	GPU Industrial Intervenors	Pennsylvania Electric Co.	Cogeneration deferral mechanism, modification of energy cost recovery (ECR).
7/88	88-171- EL-AIR 88-170- EL-AIR Interim Rate Case	OH	Industrial Energy Consumers	Cleveland Electric/ Toledo Edison	Financial analysis/need for interim rate relief.
7/88	Appeal of PSC	19th Judicial Docket U-17282	Louisiana Public Service Commission Circuit Court of Louisiana	Gulf States Utilities	Load forecasting, imprudence damages.
11/88	R-880989	PA	United States Steel	Carnegie Gas	Gas cost-of-service, rate design.
11/88	88-171- EL-AIR 88-170- EL-AIR	OH	Industrial Energy Consumers	Cleveland Electric/ Toledo Edison. General Rate Case.	Weather normalization of peak loads, excess capacity, regulatory policy.
3/89	870216/283 284/286	PA	Armco Advanced Materials Corp., Allegheny Ludlum Corp.	West Penn Power Co.	Calculated avoided capacity, recovery of capacity payments.

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As of May 2006

Date	Case	Jurisdict.	Party	Utility	Subject
8/89	8555	TX	Occidental Chemical Corp.	Houston Lighting & Power Co.	Cost-of-service, rate design.
8/89	3840-U	GA	Georgia Public Service Commission	Georgia Power Co.	Revenue forecasting, weather normalization.
9/89	2087	NM	Attorney General of New Mexico	Public Service Co. of New Mexico	Prudence - Palo Verde Nuclear Units 1, 2 and 3, load fore-casting.
10/89	2262	NM	New Mexico Industrial Energy Consumers	Public Service Co. of New Mexico	Fuel adjustment clause, off-system sales, cost-of-service, rate design, marginal cost.
11/89	38728	IN	Industrial Consumers for Fair Utility Rates	Indiana Michigan Power Co.	Excess capacity, capacity equalization, jurisdictional cost allocation, rate design, interruptible rates.
1/90	U-17282	LA	Louisiana Public Service Commission Staff	Gulf States Utilities	Jurisdictional cost allocation, O&M expense analysis.
5/90	890366	PA	GPU Industrial Intervenors	Metropolitan Edison Co.	Non-utility generator cost recovery.
6/90	R-901609	PA	Armco Advanced Materials Corp., Allegheny Ludlum Corp.	West Penn Power Co.	Allocation of QF demand charges in the fuel cost, cost-of-service, rate design.
9/90	8278	MD	Maryland Industrial Group	Baltimore Gas & Electric Co.	Cost-of-service, rate design, revenue allocation.
12/90	U-9346 Rebuttal	MI	Association of Businesses Advocating Tariff Equity	Consumers Power Co.	Demand-side management, environmental externalities.
12/90	U-17282 Phase IV	LA	Louisiana Public Service Commission Staff	Gulf States Utilities	Revenue requirements, jurisdictional allocation.
12/90	90-205	ME	Airco Industrial Gases	Central Maine Power Co.	Investigation into interruptible service and rates.
1/91	90-12-03 Interim	CT	Connecticut Industrial Energy Consumers	Connecticut Light & Power Co.	Interim rate relief, financial analysis, class revenue allocation.

Expert Testimony Appearances
of
Stephen J. Baron
As of May 2006

Date	Case	Jurisdict.	Party	Utility	Subject
5/91	90-12-03 Phase II	CT	Connecticut Industrial Energy Consumers	Connecticut Light & Power Co.	Revenue requirements, cost-of-service, rate design, demand-side management.
8/91	E-7, SUB SUB 487	NC	North Carolina Industrial Energy Consumers	Duke Power Co.	Revenue requirements, cost allocation, rate design, demand-side management.
8/91	8341 Phase I	MD	Westvaco Corp.	Potomac Edison Co.	Cost allocation, rate design, 1990 Clean Air Act Amendments.
8/91	91-372 EL-UNC	OH	Armco Steel Co., L.P.	Cincinnati Gas & Electric Co.	Economic analysis of cogeneration, avoid cost rate.
9/91	P-910511 P-910512	PA	Allegheny Ludlum Corp., Armco Advanced Materials Co., The West Penn Power Industrial Users' Group	West Penn Power Co.	Economic analysis of proposed CWIP Rider for 1990 Clean Air Act Amendments expenditures.
9/91	91-231 -E-NC	WV	West Virginia Energy Users' Group	Monongahela Power Co.	Economic analysis of proposed CWIP Rider for 1990 Clean Air Act Amendments expenditures.
10/91	8341 - Phase II	MD	Westvaco Corp.	Potomac Edison Co.	Economic analysis of proposed CWIP Rider for 1990 Clean Air Act Amendments expenditures.
10/91	U-17282	LA	Louisiana Public Service Commission Staff	Gulf States Utilities	Results of comprehensive management audit.
Note: No testimony was prefiled on this.					
11/91	U-17949 Subdocket A	LA	Louisiana Public Service Commission Staff	South Central Bell Telephone Co. and proposed merger with Southern Bell Telephone Co.	Analysis of South Central Bell's restructuring and
12/91	91-410-EL-AIR	OH	Armco Steel Co., Air Products & Chemicals, Inc.	Cincinnati Gas & Electric Co.	Rate design, interruptible rates.
12/91	P-880286	PA	Armco Advanced Materials Corp., Allegheny Ludlum Corp.	West Penn Power Co.	Evaluation of appropriate avoided capacity costs - QF projects.

Expert Testimony Appearances
of
Stephen J. Baron
As of May 2006

Date	Case	Jurisdict.	Party	Utility	Subject
1/92	C-913424	PA	Duquesne Interruptible Complainants	Duquesne Light Co.	Industrial interruptible rate.
6/92	92-02-19	CT	Connecticut Industrial Energy Consumers	Yankee Gas Co.	Rate design.
8/92	2437	NM	New Mexico Industrial Intervenors	Public Service Co. of New Mexico	Cost-of-service.
8/92	R-00922314	PA	GPU Industrial Intervenors	Metropolitan Edison Co.	Cost-of-service, rate design, energy cost rate.
9/92	39314	ID	Industrial Consumers for Fair Utility Rates	Indiana Michigan Power Co.	Cost-of-service, rate design, energy cost rate, rate treatment.
10/92	M-00920312 C-007	PA	The GPU Industrial Intervenors	Pennsylvania Electric Co.	Cost-of-service, rate design, energy cost rate, rate treatment.
12/92	U-17949	LA	Louisiana Public Service Commission Staff	South Central Bell Co.	Management audit.
12/92	R-00922378	PA	Armco Advanced Materials Co. The WPP Industrial Intervenors	West Penn Power Co.	Cost-of-service, rate design, energy cost rate, SO_2 allowance rate treatment.
1/93	8487	MD	The Maryland Industrial Group	Baltimore Gas & Electric Co.	Electric cost-of-service and rate design, gas rate design (flexible rates).
2/93	E002/GR-92-1185	MN	North Star Steel Co. Praxair, Inc.	Northern States Power Co.	Interruptible rates.
4/93	EC92 21000 ER92-806-000 (Rebuttal)	Federal Energy Regulatory Commission	Louisiana Public Service Commission Staff	Gulf States Utilities/Entergy agreement.	Merger of GSU into Entergy System; impact on system
7/93	93-0114-E-C	WV	Airco Gases	Monongahela Power Co.	Interruptible rates.
8/93	930759-EG	FL	Florida Industrial Power Users' Group	Generic - Electric Utilities	Cost recovery and allocation of DSM costs.
9/93	M-009 30406	PA	Lehigh Valley Power Committee	Pennsylvania Power & Light Co.	Ratemaking treatment of off-system sales revenues.

Expert Testimony Appearances
of
Stephen J. Baron
As of May 2006

Date	Case	Jurisdict.	Party	Utility	Subject
11/93	346	KY	Kentucky Industrial Utility Customers	Generic - Gas Utilities	Allocation of gas pipeline transition costs - FERC Order 636.
12/93	U-17735	LA	Louisiana Public Service Commission Staff	Cajun Electric Power Cooperative	Nuclear plant prudence, forecasting, excess capacity.
4/94	E-015/ GR-94-001	MN	Large Power Intervenors	Minnesota Power Co.	Cost allocation, rate design, rate phase-in plan.
5/94	U-20178	LA	Louisiana Public Service Commission	Louisiana Power & Light Co.	Analysis of least cost integrated resource plan and demand-side management program.
7/94	R-00942986	PA	Armco, Inc.; West Penn Power Industrial Intervenors	West Penn Power Co.	Cost-of-service, allocation of rate increase, rate design, emission allowance sales, and operations and maintenance expense.
7/94	94-0035-E-42T	WV	West Virginia Energy Users Group	Monongahela Power Co.	Cost-of-service, allocation of rate increase, and rate design.
8/94	EC94 13-000	Federal Energy Regulatory Commission	Louisiana Public Service Commission	Gulf States Utilities/Entergy	Analysis of extended reserve shutdown units and violation of system agreement by Entergy.
9/94	R-00943 081 R-00943 081C0001	PA	Lehigh Valley Power Committee	Pennsylvania Public Utility Commission	Analysis of interruptible rate terms and conditions, availability.
9/94	U-17735	LA	Louisiana Public Service Commission	Cajun Electric Power Cooperative	Evaluation of appropriate avoided cost rate.
9/94	U-19904	LA	Louisiana Public Service Commission	Gulf States Utilities	Revenue requirements.
10/94	5258-U	GA	Georgia Public Service Commission	Southern Bell Telephone & Telegraph Co.	Proposals to address competition in telecommunication markets.
11/94	EC94-7-000 ER94-898-000	FERC	Louisiana Public Service Commission	El Paso Electric and Central and Southwest	Merger economics, transmission equalization hold harmless proposals.
2/95	941-430EG	CO	CF&I Steel, L.P.	Public Service Company of Colorado	Interruptible rates, cost-of-service.

Expert Testimony Appearances
of
Stephen J. Baron
As of May 2006

Date	Case	Jurisdict.	Party	Utility	Subject
4/95	R-00943271	PA	PP&L Industrial Customer Alliance	Pennsylvania Power & Light Co.	Cost-of-service, allocation of rate increase, rate design, interruptible rates.
6/95	C-00913424 C-00946104	PA	Duquesne Interruptible Complainants	Duquesne Light Co.	Interruptible rates.
8/95	ER95-112 -000	FERC	Louisiana Public Service Commission	Entergy Services, Inc.	Open Access Transmission Tariffs - Wholesale.
10/95	U-21485	LA	Louisiana Public Service Commission	Gulf States Utilities Company	Nuclear decommissioning, revenue requirements, capital structure.
10/95	ER95-1042 -000	FERC	Louisiana Public Service Commission	System Energy Resources, Inc.	Nuclear decommissioning, revenue requirements.
10/95	U-21485	LA	Louisiana Public Service Commission	Gulf States Utilities Co.	Nuclear decommissioning and cost of debt capital, capital structure.
11/95	I-940032	PA	Industrial Energy Consumers of Pennsylvania	State-wide - all utilities	Retail competition issues.
7/96	U-21496	LA	Louisiana Public Service Commission	Central Louisiana Electric Co.	Revenue requirement analysis.
7/96	8725	MD	Maryland Industrial Group	Baltimore Gas & Elec. Co., Potomac Elec. Power Co., Constellation Energy Co.	Ratemaking issues associated with a Merger.
8/96	U-17735	LA	Louisiana Public Service Commission	Cajun Electric Power Cooperative	Revenue requirements.
9/96	U-22092	LA	Louisiana Public Service Commission	Entergy Gulf States, Inc.	Decommissioning, weather normalization, capital structure.
2/97	R-973877	PA	Philadelphia Area Industrial Energy Users Group	PECO Energy Co.	Competitive restructuring policy issues, stranded cost, transition charges.
6/97	Civil Action No. 94-11474	US Bank-ruptcy Court Middle District of Louisiana	Louisiana Public Service Commission	Cajun Electric Power Cooperative	Confirmation of reorganization plan; analysis of rate paths produced by competing plans.

Expert Testimony Appearances
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Stephen J. Baron
As of May 2006

Date	Case	Jurisdict.	Party	Utility	Subject
6/97	R-973953	PA	Philadelphia Area Industrial Energy Users Group	PECO Energy Co.	Retail competition issues, rate unbundling, stranded cost analysis.
6/97	8738	MD	Maryland Industrial Group	Generic	Retail competition issues
7/97	R-973954	PA	PP&L Industrial Customer Alliance	Pennsylvania Power & Light Co.	Retail competition issues, rate unbundling, stranded cost analysis.
10/97	97-204	KY	Alcan Aluminum Corp. Southwire Co.	Big River Electric Corp.	Analysis of cost of service issues - Big Rivers Restructuring Plan
10/97	R-974008	PA	Metropolitan Edison Industrial Users	Metropolitan Edison Co.	Retail competition issues, rate unbundling, stranded cost analysis.
10/97	R-974009	PA	Pennsylvania Electric Industrial Customer	Pennsylvania Electric Co.	Retail competition issues, rate unbundling, stranded cost analysis.
11/97	U-22491	LA	Louisiana Public Service Commission	Entergy Gulf States, Inc.	Decommissioning, weather normalization, capital structure.
11/97	P-971265	PA	Philadelphia Area Industrial Energy Users Group	Enron Energy Services Power, Inc./ PECO Energy	Analysis of Retail Restructuring Proposal.
12/97	R-973981	PA	West Penn Power Industrial Intervenors	West Penn Power Co.	Retail competition issues, rate unbundling, stranded cost analysis.
12/97	R-974104	PA	Duquesne Industrial Intervenors	Duquesne Light Co.	Retail competition issues, rate unbundling, stranded cost analysis.
3/98 (Allocated Stranded Cost Issues)	U-22092	LA	Louisiana Public Service Commission	Gulf States Utilities Co.	Retail competition, stranded cost quantification.
3/98	U-22092		Louisiana Public Service Commission	Gulf States Utilities, Inc.	Stranded cost quantification, restructuring issues.
9/98	U-17735		Louisiana Public Service Commission	Cajun Electric Power Cooperative, Inc.	Revenue requirements analysis, weather normalization.
12/98	8794	MD	Maryland Industrial Group and	Baltimore Gas and Electric Co.	Electric utility restructuring, stranded cost recovery, rate

Expert Testimony Appearances
of
Stephen J. Baron
As of May 2006

Date	Case	Jurisdict.	Party	Utility	Subject
			Millennium Inorganic Chemicals Inc.		unbundling.
12/98	U-23358	LA	Louisiana Public Service Commission	Entergy Gulf States, Inc.	Nuclear decommissioning, weather normalization, Entergy System Agreement.
5/99 (Cross-Answering Testimony)	EC-98-40-000	FERC	Louisiana Public Service Commission	American Electric Power Co. & Central South West Corp.	Merger issues related to market power mitigation proposals.
5/99 (Response Testimony)	98-426	KY	Kentucky Industrial Utility Customers, Inc.	Louisville Gas & Electric Co.	Performance based regulation, settlement proposal issues, cross-subsidies between electric. gas services.
6/99	98-0452	WV	West Virginia Energy Users Group	Appalachian Power, Monongahela Power, & Potomac Edison Companies	Electric utility restructuring, stranded cost recovery, rate unbundling.
7/99	99-03-35	CT	Connecticut Industrial \Energy Consumers	United Illuminating Company	Electric utility restructuring, stranded cost recovery, rate unbundling.
7/99	Adversary Proceeding No. 98-1065	U.S. Bankruptcy Court	Louisiana Public Service Commission	Cajun Electric Power Cooperative	Motion to dissolve preliminary injunction.
7/99	99-03-06	CT	Connecticut Industrial Energy Consumers	Connecticut Light & Power Co.	Electric utility restructuring, stranded cost recovery, rate unbundling.
10/99	U-24182	LA	Louisiana Public Service Commission	Entergy Gulf States, Inc.	Nuclear decommissioning, weather normalization, Entergy System Agreement.
12/99	U-17735	LA	Louisiana Public Service Commission	Cajun Electric Power Cooperative, Inc.	Ananlysi of Proposed Contract Rates, Market Rates.
03/00	U-17735	LA	Louisiana Public Service Commission	Cajun Electric Power Cooperative, Inc.	Evaluation of Cooperative Power Contract Elections
03/00	99-1658-EL-ETP	OH	AK Steel Corporation	Cincinnati Gas & Electric Co.	Electric utility restructuring, stranded cost recovery, rate Unbundling.

Expert Testimony Appearances
of
Stephen J. Baron
As of May 2006

Date	Case	Jurisdict.	Party	Utility	Subject
08/00	98-0452 E-GI	WVA	West Virginia Energy Users Group	Appalachian Power Co. American Electric Co.	Electric utility restructuring rate unbundling.
08/00	00-1050 E-T 00-1051-E-T	WVA	West Virginia Energy Users Group	Mon Power Co. Potomac Edison Co.	Electric utility restructuring rate unbundling.
10/00	SOAH 473-00-1020 PUC 2234	TX	The Dallas-Fort Worth Hospital Council and The Coalition of Independent Colleges And Universities	TXU, Inc.	Electric utility restructuring rate unbundling.
12/00	U-24993	LA	Louisiana Public Service Commission	Entergy Gulf States, Inc.	Nuclear decommissioning, revenue requirements.
12/00	EL00-66-000 & ER-2854-000 EL95-33-002	LA	Louisiana Public Service Commission	Entergy Services Inc.	Inter-Company System Agreement: Modifications for retail competition, interruptible load.
04/01	U-21453, U-20925, U-22092 (Subdocket B) Addressing Contested Issues	LA	Louisiana Public Service Commission	Entergy Gulf States, Inc.	Jurisdictional Business Separation - Texas Restructuring Plan
10/01	14000-U	GA	Georgia Public Service Commission Adversary Staff	Georgia Power Co.	Test year revenue forecast.
11/01	U-25687	LA	Louisiana Public Service Commission	Entergy Gulf States, Inc.	Nuclear decommissioning requirements transmission revenues.
11/01	U-25965	LA	Louisiana Public Service Commission	Generic .	Independent Transmission Company ("Transco"). RTO rate design.
03/02	001148-EI	FL	South Florida Hospital and Healthcare Assoc.	Florida Power & Light Company	Retail cost of service, rate design, resource planning and demand side management.
06/02	U-25965	LA	Louisiana Public Service Commission	Entergy Gulf States Entergy Louisiana	RTO Issues
07/02	U-21453	LA	Louisiana Public Service Commission	SWEPCO, AEP	Jurisdictional Business Sep. - Texas Restructuring Plan.

**Expert Testimony Appearances
of
Stephen J. Baron
As of May 2006**

Date	Case	Jurisdict.	Party	Utility	Subject
08/02	U-25888	LA	Louisiana Public Service Commission	Entergy Louisiana, Inc. Entergy Gulf States, Inc.	Modifications to the Inter-Company System Agreement, Production Cost Equalization.
08/02	EL01-88-000	FERC	Louisiana Public Service Commission	Entergy Services Inc. and the Entergy Operating Companies	Modifications to the Inter-Company System Agreement, Production Cost Equalization.
11/02	02S-315EG	CO	CF&I Steel & Climax Molybdenum Co.	Public Service Co. of Colorado	Fuel Adjustment Clause
01/03	U-17735	LA	Louisiana Public Service Commission	Louisiana Coops	Contract Issues
02/03	02S-594E	CO	Cripple Creek and Victor Gold Mining Co.	Aquila, Inc.	Revenue requirements, purchased power.
04/03	U-26527	LA	Louisiana Public Service Commission	Entergy Gulf States, Inc.	Weather normalization, power purchase expenses, System Agreement expenses.
11/03	ER03-753-000	FERC	Louisiana Public Service Commission Staff	Entergy Services, Inc. and the Entergy Operating Companies	Proposed modifications to System Agreement Tariff MSS-4.
11/03	ER03-583-000 ER03-583-001 ER03-583-002 ER03-681-000, ER03-681-001 ER03-682-000, ER03-682-001 ER03-682-002	FERC	Louisiana Public Service Commission	Entergy Services, Inc., the Entergy Operating Companies, EWO Market-Ing, L.P, and Entergy Power, Inc.	Evaluation of Wholesale Purchased Power Contracts.
12/03	U-27136	LA	Louisiana Public Service Commission	Entergy Louisiana, Inc.	Evaluation of Wholesale Purchased Power Contracts.
01/04	E-01345-03-0437	AZ	Kroger Company	Arizona Public Service Co.	Revenue allocation rate design.
02/04	00032071	PA	Duquesne Industrial Intervenors	Duquesne Light Company	Provider of last resort issues.
03/04	03A-436E	CO	CF&I Steel, LP and Climax Molybedenum	Public Service Company of Colorado	Purchased Power Adjustment Clause.

Expert Testimony Appearances
of
Stephen J. Baron
As of May 2006

Date	Case	Jurisdict.	Party	Utility	Subject
04/04	2003-00433 2003-00434	PA	Kentucky Industrial Utility Customers, Inc.	Louisville Gas & Electric Co. Kentucky Utilities Co.	Cost of Service Rate Design
0-6/04	03S-539E	CO	Cripple Creek, Victor Gold Mining Co., Goodrich Corp., Holcim (U.S.,), Inc., and The Trane Co.	Aquila, Inc.	Cost of Service, Rate Design Interruptible Rates
06/04	R-00049255	PA	PP&L Industrial Customer Alliance PPLICA	PPL Electric Utilities Corp.	Cost of service, rate design, tariff issues and transmission service charge.
10/04	04S-164E	CO	CF&I Steel Company, Climax Mines	Public Service Company of Colorado	Cost of service, rate design, Interruptible Rates.
03/05	Case No. 2004-00426 Case No. 2004-00421	KY	Kentucky Industrial Utility Customers, Inc.	Kentucky Utilities Louisville Gas & Electric Co.	Environmental cost recovery.
06/05	050045-EI	FL	South Florida Hospital and Healthcare Assoc.	Florida Power & Light Company	Retail cost of service, rate design
07/05	U-28155	LA	Louisiana Public Service Commission Staff	Entergy Louisiana, Inc. Entergy Gulf States, Inc.	Independent Coordinator of Transmission – Cost/Benefit
09/05	Case Nos. 05-0402-E-CN 05-0750-E-PC	WVA	West Virginia Energy Users Group	Mon Power Co. Potomac Edison Co.	Environmental cost recovery, Securitization, Financing Order
01/06	2005-00341	KY	Kentucky Industrial Utility Customers, Inc.	Kentucky Power Company	Cost of service, rate design, transmission expenses. Congestion Cost Recovery Mechanism
03/06	U-22092	LA	Louisiana Public Service Commission Staff	Entergy Gulf States, Inc.	Separation of EGSI into Texas and Louisiana Companies.
04/06	U-25116	LA	Louisiana Public Service Commission Staff	Entergy Louisiana, Inc.	Transmission Prudence Investigation

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

PENNSYLVANIA PUBLIC UTILITY COMMISSION, ET AL.	:	DOCKET NOS. R-00061366
	:	R-00061367
v.	:	P-00062213
	:	P-00062214
	:	A-110300F0095
	:	A-110400F0040
METROPOLITAN EDISON COMPANY AND PENNSYLVANIA ELECTRIC COMPANY	:	

EXHIBIT__(SJB-2)

OF

STEPHEN J. BARON

ON BEHALF OF

MET-ED INDUSTRIAL USERS GROUP
PENELEC INDUSTRIAL CUSTOMER ALLIANCE

METROPOLITAN EDISON COMPANY
PENNSYLVANIA ELECTRIC COMPANY
DOCKET NOS. R-00061366, R-00061367, P-00062213, P-00062214

OFFICE OF CONSUMER ADVOCATE Set II, No. 3:

"Please provide a copy of all public statements from the Company (e.g., General Public Utilities statements to shareholders) issued during 2000, 2001 and 2002 that address needs, planning for and/or procurement of a Provider of Last Resort ("POLR") supply."

RESPONSE:

See OCA Interrogatory Set II, No. 3 Attachment A

4Q02 Earnings Release

We met all the customer shopping targets under the Ohio restructuring plan which secures our recovery of transition costs under that plan. We also launched a major effort to increase the capacity factor of our fossil generating plants and achieved record output levels from the fleet even though Davis-Besse was out of service for much of the year.

We exceeded our merger cost saving targets and implemented an additional cost savings initiative focused on reducing our headquarter and back office costs. And when these two programs are fully implemented, we expect to save over $285 million annually in operating costs.

We've hedged virtually al of our provider of last resort obligation on peak energy supply through 2005 which coincides with the end of the competitive transition period in Ohio. Our hedge position also allowed us to lock in a positive margin at serving our polar obligation in Pennsylvania.

And importantly, we also significantly reduced our outstanding debt through the partial sale of Avon and our continued aggressive debt retirement program.

We also refinanced $1.2 billion of debt and taken together these activities improve our credit profile from a (unintelligible) of 25 cents per share annually to future earnings.

While we're proud of our progress during the year, there was certainly no shortage of challenges. And none was larger than the Davis-Besse issue that tested our company in many different ways.

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

PENNSYLVANIA PUBLIC UTILITY COMMISSION, ET AL.	:	
	:	**DOCKET NOS. R-00061366**
	:	**R-00061367**
v.	:	**P-00062213**
	:	**P-00062214**
	:	**A-110300F0095**
	:	**A-110400F0040**
METROPOLITAN EDISON COMPANY AND PENNSYLVANIA ELECTRIC COMPANY	:	

EXHIBIT__(SJB-3)

OF

STEPHEN J. BARON

ON BEHALF OF

MET-ED INDUSTRIAL USERS GROUP
PENELEC INDUSTRIAL CUSTOMER ALLIANCE

GENERATION SUPPLY AGREEMENT

BETWEEN

PPL ELECTRIC UTILITIES CORPORATION

AND

PPL ENERGYPLUS, LLC

this Agreement. As soon as practicable, PPL Electric shall prorate the Monthly Generation Revenue remitted to Supplier during the first two months of this Agreement such that Supplier receives only those revenues associated with service provided on those days that fall within the term of this Agreement. The Parties further recognize that the initial Monthly Generation Revenue distributed by PPL Electric to Supplier for December of 2009 will not include all revenue attributable to service provided during that month. As soon as practicable, PPL Electric shall remit to Supplier the remainder of the Monthly Generation Revenue attributable to service provided in December of 2009 such that Supplier receives all revenues associated with service provided on those days that fall within the term of this Agreement.

6.4 Advance Payment. In addition to the payment of Monthly Generation Revenue, on or before January 1, 2002, PPL Electric shall remit to Supplier for performance under this Agreement, the following amount: $89,769,000.00.

6.5 Distribution of Capacity Deficiency Revenues. If PPL Electric receives a distribution of capacity deficiency revenues from PJM pursuant to Schedule 11 of the RAA or any success thereto, and Supplier has met its obligations under this Agreement pursuant to Sections 3.2 and 3.2.1 to provide Unforced Capacity for the period covered by such capacity deficiency revenues, then PPL Electric shall distribute to Supplier Supplier's Percentage of the capacity deficiency revenues received from PJM. If PPL Electric would have received such a distribution of capacity deficiency revenues but did not receive such revenues because PPL Electric did not fully satisfy its Unforced Capacity obligation under the RAA for the period covered by such capacity deficiency revenues, and Supplier has met its obligations under this Agreement pursuant to Sections 3.2 and 3.2.1 to provide Unforced Capacity for such period, then PPL Electric shall calculate and pay to Supplier the dollar amount equal to Supplier's Percentage of the distribution of capacity deficiency revenues that PPL Electric would have received from PJM had PPL Electric fully satisfied its Unforced Capacity obligation under the RAA for such period.

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

PENNSYLVANIA PUBLIC UTILITY COMMISSION, ET AL.	:	
	:	**DOCKET NOS. R-00061366**
	:	**R-00061367**
v.	:	**P-00062213**
	:	**P-00062214**
	:	**A-110300F0095**
	:	**A-110400F0040**
METROPOLITAN EDISON COMPANY AND PENNSYLVANIA ELECTRIC COMPANY	:	

EXHIBIT__(SJB-4)

OF

STEPHEN J. BARON

ON BEHALF OF

MET-ED INDUSTRIAL USERS GROUP
PENELEC INDUSTRIAL CUSTOMER ALLIANCE

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Securities Certificate of PPL Electric Utilities Corporation	Securities Certificate S-00010853
Agreements Between and Among PPL Electric Utilities and Affiliates	Affiliated Interest Agreements G-00010872
PPL Electric Utilities Corporation Affiliated Interest Agreement	Docket No. G-00010886
PPL Electric Utilities Corporation Affiliated Interest Agreement	Docket No. G-00010887

JOINT STIPULATION IN SETTLEMENT

TO THE PENNSYLVANIA PUBLIC UTILITY COMMISSION:

I. INTRODUCTION

1. PPL Electric Utilities Corporation ("PPL"), the Office of Consumer Advocate ("OCA") and PP&L Industrial Customer Alliance ("PPLICA") (collectively, the "Parties"), hereby join in this Stipulation in Settlement ("Stipulation") and request that the Public Utility Commission ("Commission" or "PUC") approve the above-captioned filings. In support of this Stipulation, the Parties state the following:

II. PROCEDURAL HISTORY

2. On May 10, 2001, PPL filed a Securities Certificate and Related Affiliate Interest Filings at Docket Nos. S-00010853 and G-00010872 ("Securities Certificate Filing"). The Securities Certificate Filing was served on all parties in PPL's Restructuring Proceeding. In the Securities Certificate Filing, PPL requested that the Commission authorize PPL to issue up to $900 million in Senior Secured Bonds ("Bonds"). PPL proposed to use the proceeds of the Bonds to finance the purchase of power at prices in excess of the shopping credit, to fund the

retirement of $200 million in debt, for capital additions to transmission and distribution facilities and/or for general corporate purposes.

3. In the Securities Certificate Filing, PPL explained that it was initiating a competitive bidding process for Electric Generation Suppliers to enter into a Generation Supply Agreement ("GSA") with PPL. PPL undertook the competitive bidding process in order to procure power to fulfill its provider of last resort ("POLR") obligation. As PPL explained in the Securities Certificate Filing, a portion of the Bond proceeds will be used to purchase power under the GSA to meet PPL's POLR obligation.

4. On May 30, 2001, PPL supplemented the Securities Certificate Filing by filing a form of GSA with the Commission. PPL had indicated that it would file the form of GSA as an attachment to the Securities Certificate Filing when it became available. The form of GSA was filed as early as possible in order to expedite Commission approval of the GSA as an affiliate interest agreement in the event PPL EnergyPlus, LLC ("PPL EnergyPlus") was a winning bidder.

5. On June 6, 2001, PPL filed a letter with the Commission voluntarily extending the 30 day statutory consideration period for the Securities Certificate Filing until July 16, 2001.

6. On June 20, 2001, PPL filed an executed GSA between PPL and PPL EnergyPlus with the Commission. The executed GSA is a full requirements contract whereby PPL EnergyPlus agrees to provide the capacity and energy required for PPL to meet its POLR obligations from January 1, 2002, until December 31, 2009. PPL EnergyPlus won the right to this contract by supplying the lowest bids in PPL's competitive bidding process for energy supply.

7. Also on June 20, 2001, PPL filed an executed Trademark Assignment Agreement ("TAA") between PPL and its affiliate, PPL Properties, Inc. According to the terms of the TAA,

and subsequent to Commission approval, PPL will transfer its right, title, and interest in various trademarks and logos to PPL Properties, Inc. As further explained in the Securities Certificate Filing, this transfer will assist in formalizing the structural separation of PPL from its unregulated affiliates.

III. TERMS AND CONDITIONS OF THE STIPULATION

8. After its initial filings, PPL entered into informal discussions with the OCA and PPLICA to attempt to settle any issues that either party might have. The Parties believed that any issues presented by the Securities Certificate Filing and the related affiliated interest filings could be resolved without litigation. As a result, PPL agreed to extend the time period for Commission consideration of its Securities Certificate Filing until July 16, 2001. Thereafter, the Parties met by telephone or in person on several occasions, and PPL provided additional information to assist OCA and PPLICA in their review of PPL's filings.

9. Based on these discussions, the Parties have agreed to the following Stipulation, which resolves all outstanding issues among the Parties:

a. PPL will not seek an exception to its generation rate cap or its transmission and distribution rate cap or file a retail transmission and distribution rate case after the expiration of the transmission and distribution rate cap to recover all or any portion of the $89,769,000 paid to PPL EnergyPlus pursuant to the affiliated interest agreement filed at Docket No. G-00010886.

b. PPL will fully reflect all outstanding debt issued pursuant to the Securities Certificate filed at Docket No. S-00010853 in its proposed capital structure in all future retail transmission and distribution rate cases. PPL will not seek a separate premium or similar adjustment in its cost of capital in future retail transmission and distribution rate proceedings based upon the debt issued pursuant to the Securities Certificate filed at Docket No. S-00010853.

c. PPL will continue to provide safe, adequate and reliable service in accordance with the requirements of the Public Utility Code and applicable Commission regulations. PPL agrees that it will not assert as a reason for any potential decline in the reliability of service the financial impact of the debt issued pursuant to the Securities Certificate filed at Docket No. S-00010853.

d. PPL will not assert that any financial covenants entered into in connection with the above-reference issuance of debt create any additional exception to the rate caps established in the Competition Act, 66 Pa.C.S. Chapter 28, and PPL's Restructuring Settlement, or in any way alter or change the Commission's obligation to establish just and reasonable rates under the Public Utility Code, 66 Pa.C.S. § 101 et seq.

e. Commission approval of the affiliated interest agreement relating to the transfer of various PPL trademarks and logos at Docket No. G-00010887 does not address the proper ratemaking treatment of these transfers, and the Parties can address the proper ratemaking treatment in future PPL retail transmission and distribution rate cases.

f. This Stipulation is fully enforceable among the Parties; provided, however, any failure to comply with any portion of this Stipulation will not be the basis for any argument that the issuance of securities pursuant to the above-referenced Securities Certificate was or is unlawful.

10. With these Stipulations, OCA and PPLICA will not object to or protest this filing and agree that this matter is ripe for disposition by the Commission at its July 13, 2001 public meeting. Further, if the Commission approves this Stipulation as filed, the Parties agree not to seek any further administrative or judicial review of the Commission orders approving the above-referenced PPL filings.

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

PENNSYLVANIA PUBLIC UTILITY COMMISSION, ET AL.	:	DOCKET NOS. R-00061366
	:	R-00061367
v.	:	P-00062213
	:	P-00062214
	:	A-110300F0095
	:	A-110400F0040
METROPOLITAN EDISON COMPANY AND PENNSYLVANIA ELECTRIC COMPANY	:	

EXHIBIT__(SJB-5)

OF

STEPHEN J. BARON

ON BEHALF OF

MET-ED INDUSTRIAL USERS GROUP
PENELEC INDUSTRIAL CUSTOMER ALLIANCE

METROPOLITAN EDISON COMPANY
PENNSYLVANIA ELECTRIC COMPANY
DOCKET NOS. R-00061366, R-00061367, P-00062213, P-00062214, A-110300F0095, A-110400F0040

MET-ED INDUSTRIAL ENERGY USERS GROUP AND PENELEC INDUSTRIAL CUSTOMER ALLIANCE Set II, No. 11:

"Please explain the basis used to allocate the NITS Load for Met-Ed's service area between Electric Generation Supplier and Provider of Last Resort loads. If a customer switches from Provider of Last Resort service to an Electric Generation Supplier, how is the amount of NITS Load responsibility that is shifted determined?"

RESPONSE:

The load used to derive NITS expenses is based on the sum of the customer's loads at the time of the annual peak of the PJM zone (e.g., MetEd or Penelec) in which the load is located. The annual peak is determined from the twelve month period ending October 31 of the calendar year preceding the calendar year in which the billing month occurs. Using the customer's loads at the time of the annual peak, a daily load is derived by dividing the load value by 365 (number of days in a year). The daily load is then applied to a NITS charge that is expressed as $/MW-day to yield the NITS expense. If a customer switches from Provider of Last Resort service to an Electric Generation Supplier (or vice versa) during the current year, the daily peak loads used to derive NITS expenses are adjusted between the Electric Generation Supplier and the Provider of Last Resort using actual meter information at the time of the annual peak used for NITS Load, or using load profile data to derive the customer's load at the time of the annual peak, if actual meter data is not available.

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

PENNSYLVANIA PUBLIC UTILITY COMMISSION, ET AL.	:	DOCKET NOS. R-00061366
	:	R-00061367
v.	:	P-00062213
	:	P-00062214
	:	A-110300F0095
	:	A-110400F0040
METROPOLITAN EDISON COMPANY AND PENNSYLVANIA ELECTRIC COMPANY	:	

EXHIBIT__(SJB-6)

OF

STEPHEN J. BARON

ON BEHALF OF

MET-ED INDUSTRIAL USERS GROUP
PENELEC INDUSTRIAL CUSTOMER ALLIANCE

Metropolitan Edison Company
Transmission Service Charge Rate
Effective January 1, 2007

Line No.	Transmission Costs	2006 as Adjusted	Demand Charges	Energy Charges
	Network Integrated Transmission Service			
1	NITS Contra-Revenues	$ 33,775,288	$ 33,775,288	
2	Seams Elimination Cost Assignment	-	-	
3	Total Network Contra-Revenues	$ 33,775,288	$ 33,775,288	$ -
	PJM Ancillary Services			
4	PJM Management/Administration Services and Regulatory Charges	$ 4,976,328		$ 4,976,328
5	Trans Owner Sched & Dispatch	1,090,204		1,090,204
6	Reactive Supply & Voltage Control	3,993,839	3,993,839	
7	Black Start	329,888	329,888	
8	PJM West Transition Charge	-		-
9	Area Regulation	10,097,991		10,097,991
10	Operating and Spinning Reserves	8,239,953		8,239,953
11	MAAC	-		-
12	PJM Membership Dues	-		-
13	Expansion Cost Recovery	95,872		95,872
14	Total Ancillary Services Expenses	$ 28,824,075	$ 4,323,727	$ 24,500,348
	Congestion and FTRs/ARRs			
15	Congestion Expense	$ -		
16	Congestion Revenues	-		
17	Net Congestion	$ -		
18	FTR's and ARR Expenses	$ -		
19	FTR's and ARR Revenues	-		
20	Net FTR's and ARR's	$ -		
21	Total Congestion, FTRs and ARRs	$ -	$ -	$ -
22	**Total Transmission Costs**	$ 62,599,363	$ 38,099,015	$ 24,500,348
23	Amortization over 10 years (1/10 of RAD-61, col. 2, line 26)	-	-	-
24	Total	$ 62,599,363	$ 38,099,015	$ 24,500,348
25	Gross Receipts Tax Gross-Up Factor [1/(1-T) with T=5.90%]	1.062699	1.062699	1.062699
26	Revenue Requirement (col. 1, line 29 X col. 1, line 30)	$ 66,524,280	$ 40,487,785	$ 26,036,495
27	2006 Normalized MWh	13,961,230		
28	Transmission Service Charge (line 26 / line 27)	4.765 mills per kWh		

Pennsylvania Electric Company
Transmission Service Charge Rate
Effective January 1, 2007

Line No.	Transmission Costs	2006 as Adjusted	Demand Charges	Energy Charges
	Network Integrated Transmission Service			
1	NITS Contra-Revenues	$ 31,327,146	$ 31,327,146	
2	Seams Elimination Cost Assignment	-	-	
3	Total Network Contra-Revenues	$ 31,327,146	$ 31,327,146	$ -
	PJM Ancillary Services			
4	PJM Management/Administration Services and Regulatory Charges	$ 5,064,235		$ 5,064,235
5	Trans Owner Sched & Dispatch	1,116,464		1,116,464
6	Reactive Supply & Voltage Control	2,477,556	2,477,556	
7	Black Start	266,554	266,554	
8	PJM West Transition Charge	-		-
9	Area Regulation	9,806,669		9,806,669
10	Operating and Spinning Reserves	8,400,184		8,400,184
11	MAAC	-		-
12	PJM Membership Dues	-		-
13	Expansion Cost Recovery	98,182		98,182
14	Total Ancillary Services Expenses	$ 27,229,843	$ 2,744,110	$ 24,485,733
	Congestion and FTRs/ARRs			
15	Congestion Expense	$ -		
16	Congestion Revenues	-		
17	Net Congestion	$ -		
18	FTR's and ARR Expenses	$ -		
19	FTR's and ARR Revenues	-		
20	Net FTR's and ARR's	$ -		
21	Total Congestion, FTRs and ARRs	$ -	$ -	$ -
22	**Total Transmission Costs**	$ 58,556,989	$ 34,071,255	$ 24,485,733
23	Amortization over 10 years (1/10 of RAD-61, col. 2, line 26)	-	-	-
24	Total	$ 58,556,989	$ 34,071,255	$ 24,485,733
25	Gross Receipts Tax Gross-Up Factor [1/(1-T) with T=5.90%]	1.062699	1.062699	1.062699
26	Revenue Requirement (col. 1, line 29 X col. 1, line 30)	$ 62,228,453	$ 36,207,489	$ 26,020,964
27	2006 Normalized MWh	14,267,571		
28	Transmission Service Charge (line 26 / line 27)	4.362 mills per kWh		

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

PENNSYLVANIA PUBLIC UTILITY COMMISSION, ET AL.	:	
	:	**DOCKET NOS. R-00061366**
	:	**R-00061367**
v.	:	**P-00062213**
	:	**P-00062214**
	:	**A-110300F0095**
	:	**A-110400F0040**
METROPOLITAN EDISON COMPANY AND PENNSYLVANIA ELECTRIC COMPANY	:	

EXHIBIT__(SJB-7)

OF

STEPHEN J. BARON

ON BEHALF OF

MET-ED INDUSTRIAL USERS GROUP
PENELEC INDUSTRIAL CUSTOMER ALLIANCE

Metropolitan Edison Company
Calculation of TSC by Rate Class

	Coincident Peak Demand	Kwh @ Power Supply	Congestion Hourly Wtd Vector	Allocated 2006 NITS Demand	ME Norm mWh @ Mtr	Demand Charges	Energy Charges	Hourly Wtd Energy Charges	Demand Rate $/kW-mo	Energy Rate $/kWh
RT	126,322	1,051,881,453	0.06488118	123,979	947,616	1,880,154	1,794,699	-	-	0.00388
RS	1,042,200	4,940,547,515	0.32017872	1,022,872	4,384,872	15,511,934	8,429,464	-	-	0.00546
GS	648,594	3,236,386,540	0.21917652	636,566	2,758,251	9,653,571	5,521,859	-	1.264	0.00200
GST	205,884	1,233,956,362	0.08333124	202,066	1,102,976	3,064,341	2,105,352	-	1.264	0.00191
GP	453,769	2,989,844,888	0.19686561	445,353	2,997,972	6,753,817	5,101,214	-	1.264	0.00170
TP	226,573	1,649,633,862	0.10590755	222,371	1,624,222	3,372,272	2,814,573	-	1.264	0.00173
MS	16,798	110,402,890	0.00739176	16,486	100,779	250,018	188,367	-	-	0.00435
AL	-	9,653,703	0.00045990	-	9,007	-	16,471	-	-	0.00183
SL	-	37,034,977	0.00175685	-	34,554	-	63,188	-	-	0.00183
BRD	113	766,507	0.00005067	111	981	1,680	1,308	-	-	0.00305
TOTAL	2,720,252	15,260,108,696	1.00000000	2,669,803	13,961,230	40,487,785	26,036,495	-		

Pennsylvania Electric Company
Calculation of TSC by Rate Class

	Coincident Peak Demand	Kwh @ Power Supply	Congestion Hourly Wtd Vector	Allocated 2006 NITS Demand	PE Norm mWh @ Mtr	Demand Charges	Energy Charges	Hourly Wtd Energy Charges	Demand Rate $/kW-mo	Energy Rate $/kWh
RT	35,584	422,501,937	0.01125576	34,598	430,203	518,452	706,164	-	-	0.00285
RS	763,402	4,441,325,585	0.25777801	742,263	3,933,920	11,122,721	7,423,171	-	-	0.00471
GSS/GSM	830,390	4,340,062,318	0.29698265	807,396	3,809,050	12,098,730	7,253,921	-		0.00508
H	4,561	55,408,397	0.00017755	4,434	49,930	66,450	92,609	-		0.00319
GSL	195,613	1,217,112,488	0.08394017	190,197	1,125,459	2,850,072	2,034,265	-		0.00434
GP	284,765	1,927,571,572	0.12251622	276,880	1,748,319	4,149,015	3,221,717	-	1.249	0.00184
LP	358,964	3,027,696,256	0.21958091	349,024	3,048,775	5,230,086	5,060,450	-	1.249	0.00166
ST LTG	-	42,267,401	0.00225401	-	38,618	-	70,645	-	-	0.00183
OL	-	25,011,514	0.00129594	-	22,852	-	41,804	-	-	0.00183
BRD	44	564,242	(0.00003313)	43	419	637	943	-	-	0.00377
WAVERLY	11,759	68,969,442	0.00425190	11,433	60,026	171,325	115,275	-	-	0.00477
TOTAL	2,485,081	15,568,491,152	1.00000000	2,416,268	14,267,571	36,207,489	26,020,964	-		0.00436

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

PENNSYLVANIA PUBLIC UTILITY COMMISSION, ET AL.	:	DOCKET NOS. R-00061366
	:	R-00061367
v.	:	P-00062213
	:	P-00062214
	:	A-110300F0095
	:	A-110400F0040
METROPOLITAN EDISON COMPANY AND PENNSYLVANIA ELECTRIC COMPANY	:	

EXHIBIT__(SJB-8)

OF

STEPHEN J. BARON

ON BEHALF OF

MET-ED INDUSTRIAL USERS GROUP
PENELEC INDUSTRIAL CUSTOMER ALLIANCE

Metropolitan Edison Company
Calculation of TSC by Rate Class

	Coincident Peak Demand	Kwh @ Power Supply	Congestion Hourly Wtd Vector	Allocated 2006 NITS Demand	ME Norm mWh @ Mtr	Demand Charges	Energy Charges	Hourly Wtd Energy Congestion Charges	Demand Rate $/kW-mo	Energy Rate $/kWh
RT	126,322	1,051,881,453	0.06488118	123,979	947,616	1,880,154	1,794,699	4,522,174	-	0.00865
RS	1,042,200	4,940,547,515	0.32017872	1,022,872	4,384,872	15,511,934	8,429,464	22,316,239	-	0.01055
GS	648,594	3,236,386,540	0.21917652	636,566	2,758,251	9,653,571	5,521,859	15,276,454	1.264	0.00754
GST	205,884	1,233,956,362	0.08333124	202,066	1,102,976	3,064,341	2,105,352	5,808,131	1.264	0.00717
GP	453,769	2,989,844,888	0.19686561	445,353	2,997,972	6,753,817	5,101,214	13,721,399	1.264	0.00628
TP	226,573	1,649,633,862	0.10590755	222,371	1,624,222	3,372,272	2,814,573	7,381,684	1.264	0.00628
MS	16,798	110,402,890	0.00739176	16,486	100,779	250,018	188,367	515,201	-	0.00946
AL	-	9,653,703	0.00045990	-	9,007	-	16,471	32,055	-	0.00539
SL	-	37,034,977	0.00175685	-	34,554	-	63,188	122,451	-	0.00537
BRD	113	766,507	0.00005067	111	981	1,680	1,308	3,532	-	0.00665
TOTAL	2,720,252	15,260,108,696	1.00000000	2,669,803	13,961,230	40,487,785	26,036,495	69,699,320		

Pennsylvania Electric Company
Calculation of TSC by Rate Class

	Coincident Peak Demand	Kwh @ Power Supply	Congestion Hourly Wtd Vector	Allocated 2006 NITS Demand	PE Norm mWh @ Mtr	Demand Charges	Energy Charges	Hourly Wtd Energy Congestion Charges	Demand Rate $/kW-mo	Energy Rate $/kWh
RT	35,584	422,501,937	0.01125576	34,598	430,203	518,452	706,164	58,821	-	0.00298
RS	763,402	4,441,325,585	0.25777801	742,263	3,933,920	11,122,721	7,423,171	1,347,121	-	0.00506
GSS/GSM	830,390	4,340,062,318	0.29698265	807,396	3,809,050	12,098,730	7,253,921	1,552,001		0.00549
H	4,561	55,408,397	0.00017755	4,434	49,930	66,450	92,609	928		0.00320
GSL	195,613	1,217,112,488	0.08394017	190,197	1,125,459	2,850,072	2,034,265	438,663		0.00473
GP	284,765	1,927,571,572	0.12251622	276,880	1,748,319	4,149,015	3,221,717	640,257	1.249	0.00221
LP	358,964	3,027,696,256	0.21958091	349,024	3,048,775	5,230,086	5,060,450	1,147,507	1.249	0.00204
ST LTG	-	42,267,401	0.00225401	-	38,618	-	70,645	11,779	-	0.00213
OL	-	25,011,514	0.00129594	-	22,852	-	41,804	6,772	-	0.00213
BRD	44	564,242	(0.00003313)	43	419	637	943	(173)	-	0.00336
WAVERLY	11,759	68,969,442	0.00425190	11,433	60,026	171,325	115,275	22,220	-	0.00514
TOTAL	2,485,081	15,568,491,152	1.00000000	2,416,268	14,267,571	36,207,489	26,020,964	5,225,897		

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

PENNSYLVANIA PUBLIC UTILITY COMMISSION, ET AL.	:	
	:	**DOCKET NOS. R-00061366**
	:	**R-00061367**
v.	:	**P-00062213**
	:	**P-00062214**
	:	**A-110300F0095**
	:	**A-110400F0040**
METROPOLITAN EDISON COMPANY AND PENNSYLVANIA ELECTRIC COMPANY	:	

EXHIBIT__(SJB-9)

OF

STEPHEN J. BARON

ON BEHALF OF

MET-ED INDUSTRIAL USERS GROUP
PENELEC INDUSTRIAL CUSTOMER ALLIANCE

Supplement No. 38
Electric Pa. P.U.C. No. 48

METROPOLITAN EDISON COMPANY

READING, PENNSYLVANIA

Electric Service Tariff

Effective in

The Territory as Defined on
Page Nos. 11 - 13 of this Tariff

Issued: December 21, 2005 **Effective: January 1, 2006**

By: Anthony J. Alexander, CEO
Reading, Pennsylvania

NOTICE

This Supplement decreases and changes an existing Rider.
See Twenty-third Revised Page 2.

immediately and/or require the Customer to pay all costs correcting any and all unauthorized conditions at the premises. In the event service has been terminated under these circumstances it shall not be restored to the Customer's premises until: (i) the Customer has a certificate of compliance with the provisions of the National Electric Code and the regulations of the National Fire Protection Association has been issued by the municipal inspection bureau or by any Company-accepted inspection agency, (ii) the Customer has complied with all of the Company's requirements and (iii) the Customer pays the Company a reconnection fee and deposit.

In the event there is any evidence that a Customer knowingly and willfully obtained service for themselves or for another by creating or reinforcing a false impression, statement or representation and fails to correct the same, the Company shall immediately correct the account information in question and issue an adjustment for all current or previous amounts. The Customer shall be required to show proof of identity and sign an agreement for payment of all electric service received, plus any and all costs and administrative expenses associated with any investigation(s) (i.e., Legal, Accounts / Billing, etc.) which shall be added to their account. The Customer shall have three (3) business days in which to provide proof of identity. The Company may, in its sole discretion, terminate a Customer's electric service if the Customer fails to provide such proof of identity within the aforementioned time period.

(14) Universal Service Charge

The Company's Universal Service Charge is included in the Distribution Charge of Rate RS and Rate RT.

14. <u>Payment of Bills</u>

Except as otherwise provided in the Tariff, bills for service shall be rendered monthly based upon the Company's read and billing schedule and are due and payable by the Customer to the Company upon presentation by the Company for service furnished during the preceding period.

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

PENNSYLVANIA PUBLIC UTILITY COMMISSION, ET AL.	:	**DOCKET NOS. R-00061366**
	:	**R-00061367**
v.	:	**P-00062213**
	:	**P-00062214**
	:	**A-110300F0095**
	:	**A-110400F0040**
METROPOLITAN EDISON COMPANY AND PENNSYLVANIA ELECTRIC COMPANY	:	

EXHIBIT__(SJB-10)

OF

STEPHEN J. BARON

ON BEHALF OF

MET-ED INDUSTRIAL USERS GROUP
PENELEC INDUSTRIAL CUSTOMER ALLIANCE

METROPOLITAN EDISON COMPANY
PENNSYLVANIA ELECTRIC COMPANY
DOCKET NOS. R-00061366, R-00061367, P-00062213, P-00062214, A-110300F0095, A-110400F0040

MET-ED INDUSTRIAL ENERGY USERS GROUP AND PENELEC INDUSTRIAL CUSTOMER ALLIANCE Set I, No. 9:

"Please provide a narrative description of the methodology used by Met-Ed in its most recent prior base rate case to allocate uncollectible expenses to rate classes/rate schedules. Include an excerpt from the class cost of service study that demonstrates the allocation to rate classes/rate schedules."

RESPONSE:

Uncollectible expenses, charged to FERC Account 904 in the prior rate unbundling case (Docket No. R-00974008), were allocated to rate schedules using the number of customers in each rate schedule weighted by the relative uncollectible expense per customer from a 1992 study. The allocator was named "UNCOLLEC_904".

See MEIUG/PICA Set I, No. 9 Attachment A.

METROPOLITAN EDISON COMPANY
PENNSYLVANIA ELECTRIC COMPANY
DOCKET NOS. R-00061366, R-00061367, P-00062213, P-00062214, A-110300F0095, A-110400F0040

MET-ED INDUSTRIAL ENERGY USERS GROUP AND PENELEC INDUSTRIAL CUSTOMER ALLIANCE Set I, No. 10:

"Please provide a narrative description of the methodology used by Penelec in its most recent prior base rate case to allocate uncollectible expenses to rate classes/rate schedules. Include an excerpt from the class cost of service study that demonstrates the allocation to rate classes/rate schedules."

RESPONSE:

The uncollectible expenses, charged to FERC Account 904 in the prior rate unbundling case (Docket No. R-00974009), were allocated using weighted customers similar to the Me-Ed study referenced in MEIUG/PICA-9. However the Company is unable to locate the study used as a basis for developing the weighting factors that were applied to the number of customers for each rate schedule.

See MEIUG/PICA Set I, No. 10 Attachment A.

METROPOLITAN EDISON COMPANY
COST OF SERVICE STUDY
FOR TEST YEAR ENDING DECEMBER 31, 1996
COST CLASSIFICATION AND ALLOCATION

IV. CUSTOMER ACCOUNTS EXPENSES

ACCT. NAME CLASSIFICA' ACCT NO.	NO.(s)	FUNC. FACTOR	CLASS. FACTOR	ALLOC. FACTOR	TOTAL COMPANY	RT	RS	GS	GSSH	GST	GP	TP/QF	MS	ALTG	SLTG	BRD LINE	FERC
G. Uncollectibles	904		CUS	0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Demand		CUSTOMER SERV.		UNCOLLEC_904	6,576,000	1,695,232	3,999,481	726,286	0	122,200	31,932	0	0	869	0	0	0
Customer		CUSTOMER SERV.		0	0	0	0	0	0	0	0	0	0	0	0	0	0
Energy		CUSTOMER SERV.			$6,576,000	$1,695,232	$3,999,481	$726,286	$0	$122,200	$31,932	$0	$0	$869	$0	$0	$0
				UNCOLLEC_904	574,051	147,985	349,134	63,401	0	10,667	2,787	0	0	76	0	0	0
					1	0.2578	0.6082	0.1104	0.0000	0.0186	0.0049	0.0000	0.0000	0.0001	0.0000	0.0000	0.0000

Source:
Docket No. R-00974008
Met-Ed Statement No.11
Supplement No. 2
Met-Ed Exhibit MRK-2-R(2)
Schedule B-1
Pages 28 & 155

PENNSYLVANIA ELECTRIC COMPANY
COST OF SERVICE STUDY
FOR TEST YEAR ENDING DECEMBER 31, 1996
COST CLASSIFICATION AND ALLOCATION

IV. CUSTOMER ACCOUNTS EXPENSES

ACCT. NAME	CLASSIFICATON	ACCT NO. / NO.(s)	FUNC. FACTOR	CLASS. FACTOR	ALLOC. FACTOR	TOTAL COMPANY	RES. RT	RES. RS	GEN.GS	GEN. GST	GEN. GP	GEN. LP	GEN. OPWH	GEN. H	LIGHTING-OL	LIGHTING-SL	BORDERLINE	ELKLAND	FERC-RESALE	NEW YORK
F. Uncollectible Accounts		904		CUS																
	Demand		CUSTOMER SERV.		0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	Customer		CUSTOMER SERV.		UNCOLL_904	5,961,000	436,522	4,633,378	726,157	43,575	37,097	0	2,104	0	6,929	0	0	8,827	0	68,410
	Energy		CUSTOMER SERV.			0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
						$5,961,000	$436,522	$4,633,378	$726,157	$43,575	$37,097	$0	$2,104	$0	$6,929	$0	$0	$8,827	$0	$68,410
					UNCOLL_904	620,358	45,429	482,193	75,571	4,535	3,861	0	219	0	721	0	0	919	0	8,911
							0.073230	0.777282	0.121818	0.007310	0.006223	0.000000	0.000353	0.000000	0.001162	0.000000	0.000000	0.001481	0.000000	0.011141

Source:
Docket No. R-00974009
Penelec Statement No.11
Supplement No. 1
Penelec Exhibit MRK-2-R
Schedule B-1
Pages 37 & 182

PAIEUG STATEMENT NO. 1

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission	)	
v.	)	**Docket No. R-2010-2161575**
PECO Energy Company – Electric Division	)	

DIRECT TESTIMONY

AND EXHIBITS

OF

STEPHEN J. BARON

ON BEHALF OF

PHILIDELPHIA AREA INDUSTRIAL ENERGY USERS GROUP
"PAIEUG"

J. KENNEDY AND ASSOCIATES, INC.
ROSWELL, GEORGIA

July 7, 2010

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission	)	
v.	)	**Docket No. R-2010-2161575**
PECO Energy Company – Electric Division	)	

TABLE OF CONTENTS

I. INTRODUCTION 1

II. CLASS COST OF SERVICE AND APPORTIONMENT OF REVENUE INCREASE TO RATE SCHEDULES 8

III. RATE DESIGN ISSUES 16

IV. TRANSMISSION SERVICE CHARGE ISSUES 24

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission	)	
v.	)	**Docket No. R-2010-2161575**
PECO Energy Company – Electric Division	)	

DIRECT TESTIMONY OF STEPHEN J. BARON

I. INTRODUCTION

Q. Please state your name and business address.

A. My name is Stephen J. Baron. My business address is J. Kennedy and Associates, Inc. ("Kennedy and Associates"), 570 Colonial Park Drive, Suite 305, Roswell, Georgia 30075.

Q. What is your occupation and by whom are you employed?

A. I am the President and a Principal of Kennedy and Associates, a firm of utility rate, planning, and economic consultants in Atlanta, Georgia.

Q. Please describe briefly the nature of the consulting services provided by Kennedy and Associates.

A. Kennedy and Associates provides consulting services in the electric and natural gas utility industries. Our clients include state agencies and industrial electricity consumers. The firm provides expertise in system planning, load forecasting, financial analysis, cost-of-service, and rate design. Current clients include the Georgia and Louisiana Public Service Commissions, and industrial consumer groups throughout the United States.

Q. Please state your educational background.

A. I graduated from the University of Florida in 1972 with a B.A. degree with high honors in Political Science and significant coursework in Mathematics and Computer Science. In 1974, I received a Master of Arts Degree in Economics, also from the University of Florida. My areas of specialization were econometrics, statistics, and public utility economics. My thesis concerned the development of an econometric model to forecast electricity sales in the State of Florida, for which I received a grant from the Public Utility Research Center of the University of Florida. In addition, I have advanced study and coursework in time series analysis and dynamic model building.

Q. Please describe your professional experience.

A. I have more than thirty years of experience in the electric utility industry in the areas of cost and rate analysis, forecasting, planning, and economic analysis.

Following the completion of my graduate work in economics, I joined the staff of the Florida Public Service Commission in August of 1974 as a Rate Economist. My responsibilities included the analysis of rate cases for electric, telephone, and gas utilities, as well as the preparation of cross-examination material and the preparation of staff recommendations.

In December 1975, I joined the Utility Rate Consulting Division of Ebasco Services, Inc., as an Associate Consultant. In the seven years I worked for Ebasco, I received successive promotions, ultimately to the position of Vice President of Energy Management Services of

Ebasco Business Consulting Company. My responsibilities included the management of a staff of consultants engaged in providing services in the areas of econometric modeling, load and energy forecasting, production cost modeling, planning, cost-of-service analysis, cogeneration, and load management.

I joined the public accounting firm of Coopers & Lybrand in 1982 as a Manager of the Atlanta Office of the Utility Regulatory and Advisory Services Group. In this capacity I was responsible for the operation and management of the Atlanta office. My duties included the technical and administrative supervision of the staff, budgeting, recruiting, and marketing, as well as project management on client engagements. At Coopers & Lybrand, I specialized in utility cost analysis, forecasting, load analysis, economic analysis, and planning.

In January 1984, I joined the consulting firm of Kennedy and Associates as a Vice President and Principal. I became President of the firm in January 1991.

During the course of my career, I have provided consulting services to more than thirty utility, industrial, and Public Service Commission clients, including three international utility clients.

I have presented numerous papers and published an article entitled "How to Rate Load Management Programs" in the March 1979 edition of "Electrical World." My article on "Standby Electric Rates" was published in the November 8, 1984 issue of "Public Utilities

Fortnightly." In February of 1984, I completed a detailed analysis entitled "Load Data Transfer Techniques" on behalf of the Electric Power Research Institute, which published the study.

I have presented testimony as an expert witness in Arizona, Arkansas, Colorado, Connecticut, Florida, Georgia, Indiana, Kentucky, Louisiana, Maine, Michigan, Minnesota, Maryland, Missouri, New Jersey, New Mexico, New York, North Carolina, Ohio, Pennsylvania, Texas, Utah, Virginia, West Virginia, Wisconsin, Wyoming, the Federal Energy Regulatory Commission, and in the United States Bankruptcy Court. A list of my specific regulatory appearances can be found in Exhibit ___ (SJB-1).

Q. Have you previously testified in any PECO Energy Company ("PECO" or "Company") proceedings in Pennsylvania?

A. Yes. I have previously testified in four proceedings involving PECO, including the 1997 Restructuring Proceedings pursuant to the Electricity Generation Customer Choice and Competition Act ("Competition Act"). Specifically, I have testified in the following proceedings: Docket Nos. I-840381 (1985); R-973877 (1997); R-973953 (1997); and P-971265 (1997). Since 1985, I have testified in a total of 39 proceedings involving electric and gas utilities before the Pennsylvania Public Utility Commission.

Q. On whose behalf are you testifying in this proceeding?

A. I am testifying on behalf of the Philadelphia Area Industrial Energy Users Group ("PAIEUG"), a group of large commercial and industrial customers taking electricity service on PECO's system, primarily under Rate Schedules GS, PD, and HT.

Q. What is the purpose of your testimony?

A. I am presenting testimony in response to PECO's proposals on class cost of service ("CCOS"), the apportionment of the overall electric revenue increase to rate classes, and a number of rate design issues raised in the Company's filing. In addition, I will also address the Company's proposal to implement a Transmission Service Charge ("TSC") Rider.

With regard to the Company's class cost of service study, I discuss the proposed methodology relied on by PECO witness Howard Gorman. While I believe that it would be more appropriate to incorporate a minimum distribution system methodology in PECO's analysis, which the Company did not do, I have relied on the results of Mr. Gorman's study to assess the reasonableness of PECO's revenue apportionment (i.e., the revenue increases proposed for each rate class). As I will discuss, the Company's proposed apportionment, which is presented by PECO witness Alan Cohn, does not adequately address the subsidies that currently are being paid by PECO's general service customers on rates PD and HT. I will present an alternative recommendation that more reasonably reduces these subsides at proposed rates.

With regard to rate design issues, I will address some of the changes that PECO is proposing to rate HT. These include the elimination of the rate HT Night Service Rider ("NSR"), which currently provides an incentive for customers to shift load to off-peak periods. While the Company argues that there is no longer a basis to offer this provision, I will present an alternative proposal to provide some continued off-peak incentive provisions in the HT distribution rate. I will also address the issue of the elimination of certain off-peak provisions associated with the NSR, the space heat provisions for rate GS, and proposed revisions to the Auxiliary Service Rider.

The final issue that I address concerns PECO's proposal to implement a TSC Rider to recover PJM Interconnection, L.L.C. ("PJM") transmission expenses. While I generally support PECO's proposal, I will discuss an alternative rate design approach for the large Commercial and Industrial ("C&I") rate classes that incorporates an on-peak demand charge as an alternative to PECO's proposal to use a customer's maximum kW demand to recover transmission costs for these large customers.

Q. Please summarize your primary recommendations for this proceeding.

A. My primary recommendations, which are detailed in later sections of my testimony, are as follows:

- PECO's cost of service study should incorporate a minimum distribution system methodology, which would more reasonably classify and allocate primary and secondary distribution facilities and associated expenses to rate classes. Notwithstanding my preference for a minimum distribution system study, for the purposes of this case, I will rely on the Company's cost of service study.

- The approved revenue increase in this case should be apportioned to rate classes in a manner such that the existing dollar subsidies paid and received by each rate class are reduced by 50% at proposed rates.

- The Commission should reject PECO's proposed elimination of the rate GS, PD, and HT NSRs. The demand charges associated with these NSRs should be increased at the same percentage as the overall percentage increase to each of the rate schedules for purposes of this proceeding, with the Company maintaining the ability to address the rates under the NSRs in future base rate proceedings.

- The percentage increase in distribution charges for HT customers relying on the Large Interruptible Load Rider should be limited to "two times" the average HT distribution increase. The percentage increase in distribution charges for space heating customers on rate GS should be limited to "two times" the average GS distribution increase.

- Similarly, PECO should mitigate the significant distribution rate increase stemming from proposed changes to the Auxiliary Services Rider by limiting the resulting increase to "two times" the average rate HT increase approved in this proceeding.

- To recover demand-based transmission costs from demand metered rate schedules, pursuant to the proposed Transmission Service Charge Rider, PECO should use an on-peak kW billing demand.

II. CLASS COST OF SERVICE AND OF APPORTIONMENT REVENUE INCREASE TO RATE SCHEDULES

Q. Have you reviewed PECO's class cost of service study presented by Mr. Gorman in this case?

A. Yes. While I generally support the methodology used by the Company to allocate distribution and transmission costs to rate classes, the PECO study does not incorporate a minimum distribution system methodology, which would more reasonably classify and allocate primary and secondary distribution facilities and associated expenses to rate classes. Because the PECO analysis did not use a minimum distribution system methodology, the costs allocated to rate schedules GS, PD and, in particular, HT, are overstated. As a result, all else being equal, the rates of return presented in the Company's exhibits (i.e., Mr. Gorman's Exhibit HSG-1) likely understate the rates of return and relative rates of return for these classes.

Q. Why do you believe that a minimum distribution system methodology, which classifies distribution costs (other than services and meters) as demand- and customer-related, is appropriate?

A. As described in the NARUC Electric Utility Cost Allocation Manual ("NARUC Manual"), the underlying argument in support of a customer component is that there is a minimal level of distribution investment necessary to connect a customer to the distribution system (e.g., lines, poles, transformers) that is independent of the level of demand of the customer.[1] To the extent that this component of distribution cost is a function of the requirement to

[1] An excerpt from the NARUC Manual that discusses the classification of distribution costs is contained in Baron Exhibit__(SJB-2).

interconnect the customer, regardless of the customer's size, it is appropriate to assign the cost of these facilities to rate schedules on the basis of the number of customers, rather than on the kW demand of the class. As stated on page 90 of the NARUC Manual:

> When the utility installs distribution plant to provide service to a customer and to meet the individual customer's peak demand requirements, the utility must classify distribution plant data separately into demand- and customer-related costs.

Q. Would you briefly explain the conceptual basis for a minimum distribution cost methodology?

A. There are two approaches that are typically used to develop a customer component of distribution plant and expenses. Each of the two approaches ("zero-intercept" and "minimum size") is designed to measure a "zero load cost" associated with serving customers. Each methodology attempts to measure the customer component of various distribution plant accounts (e.g., poles, primary lines, secondary lines, line transformers, etc.). Each of the two methods (the zero-intercept method, for example) is designed to estimate the component of distribution plant cost that is incurred by a utility to effectively interconnect a customer to the system, as opposed to providing a specific level of power (kW demand) to the customer. Though arithmetically the zero-intercept method does produce the cost of "line transformers" associated with "0" kW demand, the more appropriate interpretation of the zero-intercept is that it represents the portion of cost that does not vary with a change in size or kW demand and thus should not be allocated on class non-coincident peak ("CNCP"). Essentially, the "zero-intercept" represents the cost that would be incurred, irrespective of differences in the kW demand of a distribution customer. It is this load-invariant component that is used in the zero-intercept method to identify the portion of distribution costs that should be allocated to rate classes based on the number of primary and secondary distribution customers taking service in the class.

Conceptually, this analysis is designed to estimate the behavior of costs statistically, as the Company meets growth in both the number of distribution customers and the loads of these customers.

Q. **Do other Pennsylvania electric utilities utilize a minimum distribution study methodology for class cost of service analysis?**

A. Yes. Both Duquesne Light Company ("Duquesne") and PPL Electric Utilities Corporation ("PPL") use such a methodology in their distribution cost of service analyses. To my knowledge, the Commission has accepted these studies in recent Duquesne and PPL rate proceedings, at Docket Nos. R-00061346 and R-00049255, respectively.[2]

Q. **Notwithstanding your preference for a minimum distribution system study, do you believe that the Company's cost of service study should be relied on in this case to apportion the overall revenue increase to rate schedules?**

A. Yes. For the purposes of this case, I will rely on the Company's cost of service study.

[2] I presented testimony in both Duquesne's and PPL's recent distribution rate cases, supporting the use of a minimum distribution system methodology.

Q. What are the results of the Company's class cost of service study for each rate schedule?

A. Table 1 below summarizes the rates of return, relative rates of return, and the dollar subsidies paid and received (negative values) by each rate class.

Table 1
PECO Class Cost of Service Results - Present Rates
Future Test Year 2010

Class	Rate of Return	ROR Index	Subsidies ($000)
Residential	3.42%	0.94	(4,728)
Residential Heating	2.89%	0.79	(3,280)
Off Peak	4.84%	1.33	1,111
General Service	0.71%	0.19	(27,489)
Primary Distribution	17.21%	4.73	4,943
High Tension	8.11%	2.23	25,501
Electric Propulsion	14.21%	3.90	3,993
Lighting	3.57%	0.98	(51)
Total	3.64%	1.00	

As can be seen from the results in Table 1, the HT and PD rate classes are currently paying rates significantly above cost of service. This means that customers on these rate schedules are paying rates that contain significant dollar subsidies that support below cost rates for other rate classes. Dollar subsidies represent the difference in rate revenues for each rate schedule (positive or negative) between full cost of service and the level paid by each rate class. For example, rate HT customers would have paid $1,380 million during the test year if HT rates were at PECO's cost of service, compared to the actual amount of

$1,405 that HT customers paid in test year revenues. The difference represents the subsidy paid by rate HT customers to other rate classes that are below cost.[3]

Q. Is there reason to believe that these subsidies have existed since at least 1998 when PECO's rates were restructured?

A. Yes. While an exact calculation could only be made by performing a cost of service study for each of the past 12 years, it is reasonable to assume that these subsidies have existed for each of the years. For HT customers, this means that they have likely overpaid by perhaps $300 million ($25 million for 12 years) since restructured rates have been implemented.

Q. Is PECO proposing to address this subsidy problem in its rate proposals in this case?

A. Only partially and in an insufficient manner. Table 2 shows the proposed rate schedule increases recommended by PECO witness Cohn, together with the proposed level of dollar subsidies that would remain in the Company's proposed rates.

[3] In this case, "cost of service" is defined as fully allocated revenue requirements at PECO's earned rate of return during the test year.

Table 2
PECO Proposed Rates
($000)

Class	Increase	Proposed Subsidies	% Change in Subsidy
Residential	146,523	(11,933)	152%
Residential Heating	33,369	(2,402)	-27%
Off Peak	3,712	489	-56%
General Service	91,080	(5,340)	-81%
Primary Distribution	700	2,542	-49%
High Tension	40,592	24,701	-3%
Electric Propulsion	711	1,753	-56%
Lighting	(341)	(9,822)	19072%
Total	316,347		

For rate HT, customers would continue paying subsidies to other rate classes of $24.7 million annually. Based on test year rate HT billing kW shown in Mr. Cohn's Exhibit ABC-13, this translates into an additional HT demand charge of $0.93/kW per month that is due to subsidy payments alone.[4]

Q. Do you believe that the Company's proposed rate class increases are reasonable?

A. No. PECO's proposed rates do not adequately move rates towards cost of service. While I support the concept of gradualism in rate design and the apportionment of the approved revenue increase, given the possibility that it may be a number of years until PECO's next distribution rate case, it is appropriate to make a more significant movement towards cost based rates and the mitigation of subsidies in this case.

[4] PECO is proposing an HT demand charge of $3.91/kW. If the entire subsidy were removed from rate HT via a reduction in the demand charge, the resultant rate would be $2.98/kW.

Q. Do you have a specific recommendation on the apportionment of the overall revenue increase in this case that more reasonably mitigates and reduces current subsidies paid and received by each rate class?

A. Yes. I recommend that the approved revenue increase in this case be apportioned to rate classes in a manner such that the existing dollar subsidies paid and received by each rate class (see Table 1) are reduced by 50% at proposed rates. Given the fact that these subsidies have likely existed for many years, this level of mitigation is appropriate. A 50% subsidy reduction does not move each rate class fully to cost of service; however, it recognizes the concept of gradualism, which I believe is appropriate in this case, especially in light of the fact that this is PECO's first distribution rate case since Restructuring in 1998.

Exhibit__(SJB-3) presents my proposed revenue apportionment of the rate increase to rate schedules, reflecting a 50% reduction in current dollar subsidies. The first section of the analysis calculates the dollar subsidy amounts paid and received by each rate class at present rates. The next section of the analysis develops the rates of return and subsidies under PECO's proposed rates. The remaining section of the analysis computes the revenue increases by rate schedule reflecting a 50% subsidy reduction. This calculation begins with the increases necessary to achieve full cost of service for each rate schedule and then adds back a subsidy amount equal to 50% of the current dollar subsidy. For example, if the revenue increase necessary to bring rate class "X" to full cost of service at proposed rates is $1000, and the subsidy received by rate class "X" is $100 at present rate, the adjusted increase to rate class "X" would be [1000 – 50% of 100] or <u>$950</u>. The

$950 increase to rate class "X" would reflect a $50 subsidy receipt, which is half the subsidy received by this class at present rates. The last section summarizes the revenue increases and the remaining subsidies that will continue to be paid and received by each rate class under my proposal.

Table 3
PAIEUG Proposed Rates
($000)

Class	Increase	Proposed Subsidies	% Change in Subsidy
Residential	156,092	(2,364)	-50%
Residential Heating	34,131	(1,640)	-50%
Off Peak	3,779	555	-50%
General Service	82,675	(13,744)	-50%
Primary Distribution	630	2,471	-50%
High Tension	28,642	12,751	-50%
Electric Propulsion	955	1,996	-50%
Lighting	9,455	(26)	-50%
Total	316,359		

Q. In the event that the Commission authorizes an overall revenue increase that is less than requested by the Company, how should your proposed rate class increases be scaled-back?

A. The rate class increases shown in Table 3 should be scaled-back proportionately. This is consistent with PECO's proposed scale-back method. I do not object to PECO's proposal to apply the scaled-back revenue reductions to reduce all rate elements except the fixed distribution charges of each rate. For example, hypothetically, if the proportionate scale-back of the overall PECO requested $316 million increase resulted in a reduction in the HT distribution revenue increase of $5 million (an HT increase of $23.6 million versus the HT increase of $28.6 million shown in Table 3), this $5 million reduction would be applied proportionately to each proposed HT distribution demand and energy charge, but not the proposed HT distribution customer charge, which would remain at the PECO proposed level of $295.30 per month.

III. RATE DESIGN ISSUES

Q. Would you please discuss the concerns that you have identified with PECO's proposed distribution rate design changes in this case?

A. Yes. The focus of my concern is primarily on rates GS, PD, and HT, on which large customers currently take service. The first major issue that I have identified concerns the Company's proposal to eliminate the NSRs related to the aforementioned rate. The NSRs associated with these rates provide for a reduced demand charge for off-peak kW demand that is in excess of on-peak kW billing demand. For example, for rate HT, the billing demand charge is currently $1.68/kW month, based on the customer's maximum monthly kW demand. Under the "Night Service HT Rider," a customer whose off-peak demand is in excess of its on-peak demand would be charged $0.92/kW for the excess off-peak demand. In addition, the on-peak kW demand would be used to determine the energy charge pursuant to the current HT hours-use blocking provisions.

Q. Why is PECO proposing to eliminate the NSR provisions of its tariff?

A. As discussed by PECO witness Alan Cohn, the Company argues that the NSR provisions are a legacy from the previously bundled rates in effect before PECO's restructuring and are not cost justified. Mr. Cohn states on page 16 at lines 4 through 9 of his testimony as follows: "From a distribution perspective, however, the system is designed to meet each class' maximum peak demand whenever it occurs and, accordingly, the costs of distribution facilities are allocated on the basis of each class' non-coincident peak demand. For customers that would use the GS NSR, i.e., those whose overall demands are highest in the Off-Peak hours, their non-coincident peak occurs in the off-peak period." While this portion of his testimony concerns the elimination of the NSR for rate GS, Mr. Cohn supports the NSR elimination for rates PD and HT based on this testimony.

Q. Do you agree with the Company's argument on this NSR elimination?

A. No. As noted in the excerpt from Mr. Cohn's testimony, the cost causation associated with most distribution facilities for rates GS, PD, and HT is class maximum diversified demand (i.e., class peak demand). For rate HT, almost 100% of the distribution cost of service (other than for billing costs) is associated with "Primary HT Demand," which is allocated to customer classes based on class NCP (i.e., class peak).[5] Because these costs are associated with each customer's demand at the time of the class peak (for example, HT class peak), customer demands that occur in the off-peak period do not impact cost responsibility.[6] For example, in 2009, the HT class peak occurred during the month of August 2009 on the 21st of the month at hour 13 (an on-peak hour). For rate GS, the class peak occurred on August 20th at hour 16; also an on-peak hour. As a result, individual

[5] See PECO witness Howard Gorman's Exhibit HSG 1-B, page 1 of 1.

[6] The class peaks for rates HT, PD, and GS occur in the on-peak periods. See PECO's response Attachment OCA-1-1(f) attached as Exhibit__(SJB-4).

customer demands in the off-peak hours in excess of the customer's on-peak demand did not impact cost causation for any cost associated with class NCP.

Q. What do you conclude from this analysis?

A. Based on cost causation, there is a basis for the NSRs.

Q. Is there additional justification to maintain the NSR provisions for PECO's distribution tariffs?

A. Yes. Because the NSR encourages customers to shift demands from the on-peak to the off-peak period, the NSR is consistent with the Commission's policy on Energy Efficiency and Conservation ("EE&C"), pursuant to Act 129.[7] Act 129 requires each distribution utility to reduce system peak demand in the highest 100 hours. The NSR provisions provide an incentive for large customers to shift demand to the off-peak period, consistent with the objectives of Act 129. In PECO's EE&C proceeding at Docket No. M-2009-2093215, the Commission approved programs that are designed to reduce PECO's peak demand and shift load from on-peak to off-peak periods.[8]

Finally, as I will discuss subsequently in my testimony, the rate impacts that will result from the Company's rate design proposals are extreme and very clearly constitute rate shock. Maintaining the current NSRs will assist in mitigating this rate shock.

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[7] See Act 129 of 2008, P.L. 1592 (Oct. 15, 2008) ("Act 129").

[8] See generally Petition of PECO Energy Company for Approval of Its Act 129 Energy Efficiency and Conservation Plan and Expedited Approval of Its Compact Fluorescent Lamp Program, Final Order, Docket No. M-2009-2093215 (Oct. 28, 2009).

Q. Could you provide an example of the rate impact that will result from PECO's proposed elimination of the NSR for rate HT?

A. Yes. Table 4 shows the impact on a hypothetical monthly bill for a customer with off-peak demands that are 35% greater than on-peak demands.[9] Currently, the customer is billed a reduced rate for the excess off-peak demand, while under the Company's proposed rates, this reduction will be eliminated.

Table 4
Rate HT - Night Service Rider
Impact of PECO Proposed Increase

		Present		Proposed			
		Rate	Charges	Rate	Charges	Increase	Percent
Customer Charge	1	291.52	$ 292	295.3	$ 295		
Max kW	5,500			3.91	$ 21,505		
On-Pk kW	4,000	1.68	$ 6,720				
Off-Pk KW	5,500						
Total kWh	3,000,000			0.0027	$ 8,100		
kWh -1st blk	600,000	0.0090	$ 5,400				
kWh -2nd blk	600,000	0.0053	$ 3,180				
kWh - Additional	1,800,000	0.0017	$ 3,060				
Night Service Rider KW	1,500	0.92	$ 1,380				
Night Service Billing	1	11.39	$ 11				
Total			$ 20,043		$ 29,900	$ 9,857	49.2%
Rate HT Average Increase							31.6%

As can be seen from this table, the rate impact of the Company's proposal is a 49% increase in distribution charges, compared to the average HT increase proposed by PECO of 32%. This represents a substantial additional increase that cannot be supported based on the Company's cost of service analysis, which utilizes class NCP demand as the basis for cost causation.

[9] In order to further evaluate this hypothetical, PAIEUG propounded data requests on PECO. Upon receipt and review of PECO's responses, further clarification was deemed necessary. Accordingly, I reserve the right to supplement my testimony based upon receipt and review of any such clarification by PECO.

Q. What is your recommendation on this issue?

A. I recommend that the Commission reject PECO's proposed elimination of the rate GS, PD, and HT NSRs and that the NSR demand charges associated with these riders be increased at the same percentage rates as the overall percentage increase to each of the rate schedules. Table 5 shows the impact of such a proposal, using the same data as assumed in Table 4. For the purposes of this illustration, I have not factored in the impact of lost revenues associated with the NSR on the HT demand charge, though, in the Company's compliance rate filing, this adjustment would be required so that the proposed change I am recommending is revenue neutral within rate HT.[10] While the percentage increase for such a customer would be larger than average for HT as a whole (i.e., 36% vs. 32%), it would be more reasonable than PECO's proposal.

Table 5
Rate HT - Night Service Rider
Impact of PECO Proposed Increase w/continuation of the Night Service Rider

		Present		Proposed			
		Rate	Charges	Rate	Charges	Increase	Percent
Customer Charge	1	291.52	$ 292	295.3	$ 295		
Max kW	5,500						
On-Pk kW	4,000	1.68	$ 6,720	3.91	$ 15,640		
Off-Pk KW	5,500						
Total kWh	3,000,000			0.0027	$ 8,100		
kWh -1st blk	600,000	0.0090	$ 5,400				
kWh -2nd blk	600,000	0.0053	$ 3,180				
kWh - Additional	1,800,000	0.0017	$ 3,060				
Night Service Rider KW	1,500	0.92	$ 1,380	2.14	3,211.79		
Night Service Billing	1	11.39	$ 11				
Total			$ 20,043		$ 27,247	$ 7,204	35.9%
Rate HT Average Increase							31.6%

[10] I have increased the current \$0.92/kW night service rider kW demand charge by the same percentage increase proposed by the Company for the HT demand charge.

Q. Will your recommendation on this rate design issue have an impact on any other rate schedule?

A. No. This recommendation is purely an intra-class rate design matter and does not impact any other rate class or schedule (i.e., the GS NSR only impacts rate GS, while the HT NSR only impacts rate HT).

Q. Would you please address the next concern that you have identified with the Company's rate design proposals?

A. The next concern that I have identified is a broad-based concern with the rate impact of some of the Company's distribution rate design proposals, specifically the Company's elimination of the existing Large Interruptible Load Rider ("LILR") that is currently available to rate HT customers and the "space heating" provisions of rate GS. Unlike the NSR issue that I discussed above, I do object to the general approach that PECO's is taking with these two provisions from a cost of service standpoint. Specifically, the rate impact on certain PECO customers requires some mitigation of the proposals, and PECO has not offered any such mitigation in this case.

Q. Would you give an example of the rate impact of the Company's proposed elimination of LILR on large customers who currently rely on this tariff provision?

A. Yes. Based on an analysis of the impact of this provision, as well as other HT rate design changes, customers currently using LILR will face increases in the range of 125% in distribution charges, assuming that the Company's rates are approved as filed. Table 6 illustrates the impact of the Company's rate design proposal in this case.

Table 6
Rate HT - Large Interruptible Load Rider/Night Service Rider
Impact of PECO Proposed Increase

		Present		Proposed			
		Rate	Charges	Rate	Charges	Increase	Percent
Customer Charge	1	291.52	$ 292	295.3	$ 295		
Max kW	22,090			3.91	$ 86,372		
On-Pk kW	22,090						
Interruptible kW	22,065						
Firm On-Pk kW	25	1.68	$ 42				
Off-Pk KW	17,568						
Total kWh	5,860,613			0.0027	$ 15,824		
kWh -1st blk	3,750	0.0090	$ 34				
kWh -2nd blk	3,750	0.0053	$ 20				
kWh - Additional	5,853,113	0.0017	$ 9,950				
LILR kWh	3,581,933	0.0053	$ 18,984				
Night Service Rider KW	17,543	0.92	$ 16,140				
Night Service Billing	1	11.39	$ 11				
Total			$ 45,473		$ 102,491	$ 57,018	125.4%
Rate HT Average Increase							31.6%

This 125% increase for HT-LILR customers compares to an increase of 32% in distribution charges for rate HT customers on average. By any reasonable measure, this constitutes rate shock. While I do not propose maintaining an interruptible rate provision from PECO distribution rates, I do believe that the impact of this increase should be mitigated through a transition adjustment. The adjustment, which would provide for a maximum percentage increase in the rates for any specific HT customer, should be set at some multiple of the overall approved increase for rate HT in this case.

Q. Do you have a recommendation for the mitigation "cap" for rate HT customers in this case?

A. Yes. I believe that it would be appropriate to limit the percentage increase in distribution charges for HT customers currently relying on LILR to "two times" the average HT distribution increase (in percent). For example, under the Company's filing, rate HT distribution rates would increase by 31.6%. My proposed mitigation would limit the increase to an HT-LILR customer to no more than 63%. In future rate cases, the impact of eliminating LILR would be further mitigated to the extent necessary, while ultimately moving these customers to the full HT rate.

Q. How do you propose to implement the LILR mitigation for rate HT?

A. One approach would be for the Company to calculate the adjustment factor necessary to meet the "two times" percentage increase limit in its compliance rate design in this case. The lost revenues associated with the "adjustment" would be recovered via the rate HT distribution demand and energy charges. In this manner, no other rate class or schedule would be impacted by the mitigation.

Q. Do you have a similar proposal to address the large impacts resulting from the elimination of the rate GS space heating provisions?

A. Yes. I recommend the same approach to provide for mitigation of the impact on GS space heating customers as a result of the Company's proposed tariff revisions.

Q. Do you have any additional concerns regarding PECO's proposed rate design changes?

A. Yes. PECO is proposing to revise its Auxiliary Service Rider by removing a specific distribution rate provision. Under the proposed rider, customers taking supplementary and back-up service would obtain distribution service via the customer's standard rate (for example, rate HT). This proposal has the effect of eliminating the interruptible supplemental or back-up distribution service provisions existing in the current rate. Since

PECO is also proposing to eliminate its LILR rate provisions, which provided interruptible discounts to the standard rate HT, the Company's proposed revisions to its Auxiliary Service Rider will require current customers that rely on interruptible supplemental or back-up service to purchase firm distribution service. As I discussed above (and illustrated in Table 6), such customers will likely face extremely large increases (possibly, in excess of 100%) for distribution service. While, in principle, I do not object to the Company's basic proposal to revise its Auxiliary Service Rider, the Company's proposal will likely result in significant rate shock and should be mitigated to the extent possible.

Q. What is your recommendation to mitigate the rate shock that may arise as a result of the Company's proposed revisions to its Auxiliary Service Rider?

A. The rate increase to customer's taking distribution service under the Auxiliary Service Rider should be limited to two times the average rate HT increase approved in this case. This is the same mitigation proposal that I am recommending for rate HT itself, so effectively, I am recommending that customers taking service pursuant to the Auxiliary Service Rider be subject to the same provisions as other rate HT customers.

IV. TRANSMISSION SERVICE CHARGE ISSUES

Q. Have you reviewed PECO's proposal to implement a Transmission Service Charge ("TSC") Rider in this case?

A. Yes. As described by PECO witness Cohn, the TSC is designed to fully recover costs charged to PECO by PJM, thus removing this cost recovery from base rates. Based on my review, the TSC appears to be a cost-based allocation of these transmission costs. For large customers on rates PD, HT, and EP, these costs will be recovered on a $/kW month basis. While I support the basis TSC proposal, including the allocation of transmission costs to rate classes and the recovery of TSC costs on $/kW month basis for customers on rates PD, HT and EP, I believe that the kW demand charges should be recovered based on a customer's on-peak kW demand, rather than maximum kW demand as proposed by PECO. PECO has allocated these costs on the basis of rate class single coincident peak ("1 CP") demand, which follows the allocation of these transmission costs to PECO by PJM. For large customers on rates PD, HT, and EP, recovering transmission costs on the basis of on-peak billing kW demand instead of a customer's maximum kW demand (which could occur during the off-peak period for some customers) would be a more appropriate basis to recover these costs since it more closely reflects cost causation.

Q. Why do you believe using an on-peak billing kW demand provides a more appropriate basis for recovering such costs from large C&I customers?

A. As I indicated, the basis for PECO incurring transmission costs from PJM is the annual 1 CP demand, which is used by PECO to allocate these costs to rate classes. To the extent feasible and practicable, it is likewise appropriate to recover costs from individual customers on the same basis. I believe that for large, higher load factor customers on rates PD, HT, and EP, the use of monthly on-peak kW billing demand is a more reasonable proxy for annual 1 CP kW demand than a customer's maximum monthly kW demand (<u>i.e.,</u> PECO's proposed billing demand basis).

Q. Does your recommendation to use an on-peak kW demand billing basis to recover TSC costs from large C&I customers have any impact on other rate schedules?

A. No. This is strictly a rate design issue that affects customers on rates PD, HT, and EP. It has no effect on other rate classes. However, because the large C&I TSC demand rate is developed jointly for PD, HT, and EP rate classes, the amount of transmission revenues that will be produced on an individual rate class basis for these three rates will be different from the amounts computed by PECO. This change will affect the residual distribution revenue targets that are applicable for the design of rates PD, HT, and EP distribution charges.

Q. Is there additional justification to use an on-peak kW demand billing basis to recover TSC costs from large C&I customers?

A. Yes. Using an on-peak kW demand billing basis will provide large C&I customers with an incentive to minimize demand during on-peak periods. Promoting such behavior is consistent with Act 129 and directly assists PECO in satisfying its obligations to reduce system peak demand.

Q. Does that complete your testimony?

A. Yes, it does.

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission	)	
v.	)	Docket No. R-2010-2161575
PECO Energy Company – Electric Division	)	

EXHIBITS

OF

STEPHEN J. BARON

ON BEHALF OF

PHILIDELPHIA AREA INDUSTRIAL ENERGY USERS GROUP
"PAIEUG"

J. KENNEDY AND ASSOCIATES, INC.
ROSWELL, GEORGIA

July 7, 2010

Expert Testimony Appearances
of
Stephen J. Baron
As of June 2010

Date	Case	Jurisdict.	Party	Utility	Subject
4/81	203(B)	KY	Louisville Gas & Electric Co.	Louisville Gas & Electric Co.	Cost-of-service.
4/81	ER-81-42	MO	Kansas City Power & Light Co.	Kansas City Power & Light Co.	Forecasting.
6/81	U-1933	AZ	Arizona Corporation Commission	Tucson Electric Co.	Forecasting planning.
2/84	8924	KY	Airco Carbide	Louisville Gas & Electric Co.	Revenue requirements, cost-of-service, forecasting, weather normalization.
3/84	84-038-U	AR	Arkansas Electric Energy Consumers	Arkansas Power & Light Co.	Excess capacity, cost-of-service, rate design.
5/84	830470-EI	FL	Florida Industrial Power Users' Group	Florida Power Corp.	Allocation of fixed costs, load and capacity balance, and reserve margin. Diversification of utility.
10/84	84-199-U	AR	Arkansas Electric Energy Consumers	Arkansas Power and Light Co.	Cost allocation and rate design.
11/84	R-842651	PA	Lehigh Valley Power Committee	Pennsylvania Power & Light Co.	Interruptible rates, excess capacity, and phase-in.
1/85	85-65	ME	Airco Industrial Gases	Central Maine Power Co.	Interruptible rate design.
2/85	I-840381	PA	Philadelphia Area Industrial Energy Users' Group	Philadelphia Electric Co.	Load and energy forecast.
3/85	9243	KY	Alcan Aluminum Corp., et al.	Louisville Gas & Electric Co.	Economics of completing fossil generating unit.
3/85	3498-U	GA	Attorney General	Georgia Power Co.	Load and energy forecasting, generation planning economics.
3/85	R-842632	PA	West Penn Power Industrial Intervenors	West Penn Power Co.	Generation planning economics, prudence of a pumped storage hydro unit.
5/85	84-249	AR	Arkansas Electric Energy Consumers	Arkansas Power & Light Co.	Cost-of-service, rate design return multipliers.
5/85		City of Santa Clara	Chamber of Commerce	Santa Clara Municipal	Cost-of-service, rate design.

Expert Testimony Appearances
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As of June 2010

Date	Case	Jurisdict.	Party	Utility	Subject
6/85	84-768-E-42T	WV	West Virginia Industrial Intervenors	Monongahela Power Co.	Generation planning economics, prudence of a pumped storage hydro unit.
6/85	E-7 Sub 391	NC	Carolina Industrials (CIGFUR III)	Duke Power Co.	Cost-of-service, rate design, interruptible rate design.
7/85	29046	NY	Industrial Energy Users Association	Orange and Rockland Utilities	Cost-of-service, rate design.
10/85	85-043-U	AR	Arkansas Gas Consumers	Arkla, Inc.	Regulatory policy, gas cost-of-service, rate design.
10/85	85-63	ME	Airco Industrial Gases	Central Maine Power Co.	Feasibility of interruptible rates, avoided cost.
2/85	ER-8507698	NJ	Air Products and Chemicals	Jersey Central Power & Light Co.	Rate design.
3/85	R-850220	PA	West Penn Power Industrial Intervenors	West Penn Power Co.	Optimal reserve, prudence, off-system sales guarantee plan.
2/86	R-850220	PA	West Penn Power Industrial Intervenors	West Penn Power Co.	Optimal reserve margins, prudence, off-system sales guarantee plan.
3/86	85-299U	AR	Arkansas Electric Energy Consumers	Arkansas Power & Light Co.	Cost-of-service, rate design, revenue distribution.
3/86	85-726-EL-AIR	OH	Industrial Electric Consumers Group	Ohio Power Co.	Cost-of-service, rate design, interruptible rates.
5/86	86-081-E-GI	WV	West Virginia Energy Users Group	Monongahela Power Co.	Generation planning economics, prudence of a pumped storage hydro unit.
8/86	E-7 Sub 408	NC	Carolina Industrial Energy Consumers	Duke Power Co.	Cost-of-service, rate design, interruptible rates.
10/86	U-17378	LA	Louisiana Public Service Commission Staff	Gulf States Utilities	Excess capacity, economic analysis of purchased power.
12/86	38063	IN	Industrial Energy Consumers	Indiana & Michigan Power Co.	Interruptible rates.

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As of June 2010

Date	Case	Jurisdict.	Party	Utility	Subject
3/87	EL-86-53-001 EL-86-57-001	Federal Energy Regulatory Commission (FERC)	Louisiana Public Service Commission Staff	Gulf States Utilities, Southern Co.	Cost/benefit analysis of unit power sales contract.
4/87	U-17282	LA	Louisiana Public Service Commission Staff	Gulf States Utilities	Load forecasting and imprudence damages, River Bend Nuclear unit.
5/87	87-023-E-C	WV	Airco Industrial Gases	Monongahela Power Co.	Interruptible rates.
5/87	87-072-E-G1	WV	West Virginia Energy Users' Group	Monongahela Power Co.	Analyze Mon Power's fuel filing and examine the reasonableness of MP's claims.
5/87	86-524-E-SC	WV	West Virginia Energy Users' Group	Monongahela Power Co.	Economic dispatching of pumped storage hydro unit.
5/87	9781	KY	Kentucky Industrial Energy Consumers	Louisville Gas & Electric Co.	Analysis of impact of 1986 Tax Reform Act.
6/87	3673-U	GA	Georgia Public Service Commission	Georgia Power Co.	Economic prudence, evaluation of Vogtle nuclear unit - load forecasting, planning.
6/87	U-17282	LA	Louisiana Public Service Commission Staff	Gulf States Utilities	Phase-in plan for River Bend Nuclear unit.
7/87	85-10-22	CT	Connecticut Industrial Energy Consumers	Connecticut Light & Power Co.	Methodology for refunding rate moderation fund.
8/87	3673-U	GA	Georgia Public Service Commission	Georgia Power Co.	Test year sales and revenue forecast.
9/87	R-850220	PA	West Penn Power Industrial Intervenors	West Penn Power Co.	Excess capacity, reliability of generating system.
10/87	R-870651	PA	Duquesne Industrial Intervenors	Duquesne Light Co.	Interruptible rate, cost-of-service, revenue allocation, rate design.
10/87	I-860025	PA	Pennsylvania Industrial Intervenors		Proposed rules for cogeneration, avoided cost, rate recovery.
10/87	E-015/	MN	Taconite	Minnesota Power	Excess capacity, power and

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Date	Case	Jurisdict.	Party	Utility	Subject
	GR-87-223		Intervenors	& Light Co.	cost-of-service, rate design.
10/87	8702-EI	FL.	Occidental Chemical Corp.	Florida Power Corp.	Revenue forecasting, weather normalization.
12/87	87-07-01	CT	Connecticut Industrial Energy Consumers	Connecticut Light Power Co.	Excess capacity, nuclear plant phase-in.
3/88	10064	KY	Kentucky Industrial Energy Consumers	Louisville Gas & Electric Co.	Revenue forecast, weather normalization rate treatment of cancelled plant.
3/88	87-183-TF	AR	Arkansas Electric Consumers	Arkansas Power & Light Co.	Standby/backup electric rates.
5/88	870171C001	PA	GPU Industrial Intervenors	Metropolitan Edison Co.	Cogeneration deferral mechanism, modification of energy cost recovery (ECR).
6/88	870172C005	PA	GPU Industrial Intervenors	Pennsylvania Electric Co.	Cogeneration deferral mechanism, modification of energy cost recovery (ECR).
7/88	88-171-EL-AIR 88-170-EL-AIR *Interim Rate Case*	OH	Industrial Energy Consumers	Cleveland Electric/ Toledo Edison	Financial analysis/need for interim rate relief.
7/88	Appeal of PSC	19th Judicial Docket U-17282	Louisiana Public Service Commission Circuit Court of Louisiana	Gulf States Utilities	Load forecasting, imprudence damages.
11/88	R-880989	PA	United States Steel	Carnegie Gas	Gas cost-of-service, rate design.
11/88	88-171-EL-AIR 88-170-EL-AIR	OH	Industrial Energy Consumers	Cleveland Electric/ Toledo Edison. General Rate Case.	Weather normalization of peak loads, excess capacity, regulatory policy.
3/89	870216/283 284/286	PA	Armco Advanced Materials Corp., Allegheny Ludlum Corp.	West Penn Power Co.	Calculated avoided capacity, recovery of capacity payments.
8/89	8555	TX	Occidental Chemical Corp.	Houston Lighting & Power Co.	Cost-of-service, rate design.

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Date	Case	Jurisdict.	Party	Utility	Subject
8/89	3840-U	GA	Georgia Public Service Commission	Georgia Power Co.	Revenue forecasting, weather normalization.
9/89	2087	NM	Attorney General of New Mexico	Public Service Co. of New Mexico	Prudence - Palo Verde Nuclear Units 1, 2 and 3, load fore-casting.
10/89	2262	NM	New Mexico Industrial Energy Consumers	Public Service Co. of New Mexico	Fuel adjustment clause, off-system sales, cost-of-service, rate design, marginal cost.
11/89	38728	IN	Industrial Consumers for Fair Utility Rates	Indiana Michigan Power Co.	Excess capacity, capacity equalization, jurisdictional cost allocation, rate design, interruptible rates.
1/90	U-17282	LA	Louisiana Public Service Commission Staff	Gulf States Utilities	Jurisdictional cost allocation, O&M expense analysis.
5/90	890366	PA	GPU Industrial Intervenors	Metropolitan Edison Co.	Non-utility generator cost recovery.
6/90	R-901609	PA	Armco Advanced Materials Corp., Allegheny Ludlum Corp.	West Penn Power Co.	Allocation of QF demand charges in the fuel cost, cost-of-service, rate design.
9/90	8278	MD	Maryland Industrial Group	Baltimore Gas & Electric Co.	Cost-of-service, rate design, revenue allocation.
12/90	U-9346 Rebuttal	MI	Association of Businesses Advocating Tariff Equity	Consumers Power Co.	Demand-side management, environmental externalities.
12/90	U-17282 Phase IV	LA	Louisiana Public Service Commission Staff	Gulf States Utilities	Revenue requirements, jurisdictional allocation.
12/90	90-205	ME	Airco Industrial Gases	Central Maine Power Co.	Investigation into interruptible service and rates.
1/91	90-12-03 Interim	CT	Connecticut Industrial Energy Consumers	Connecticut Light & Power Co.	Interim rate relief, financial analysis, class revenue allocation.
5/91	90-12-03 Phase II	CT	Connecticut Industrial Energy Consumers	Connecticut Light & Power Co.	Revenue requirements, cost-of-service, rate design, demand-side management.

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Date	Case	Jurisdict.	Party	Utility	Subject
8/91	E-7, SUB SUB 487	NC	North Carolina Industrial Energy Consumers	Duke Power Co.	Revenue requirements, cost allocation, rate design, demand-side management.
8/91	8341 Phase I	MD	Westvaco Corp.	Potomac Edison Co.	Cost allocation, rate design, 1990 Clean Air Act Amendments.
8/91	91-372 EL-UNC	OH	Armco Steel Co., L.P.	Cincinnati Gas & Electric Co.	Economic analysis of cogeneration, avoid cost rate.
9/91	P-910511 P-910512	PA	Allegheny Ludlum Corp., Armco Advanced Materials Co., The West Penn Power Industrial Users' Group	West Penn Power Co.	Economic analysis of proposed CWIP Rider for 1990 Clean Air Act Amendments expenditures.
9/91	91-231 -E-NC	WV	West Virginia Energy Users' Group	Monongahela Power Co.	Economic analysis of proposed CWIP Rider for 1990 Clean Air Act Amendments expenditures.
10/91	8341 - Phase II	MD	Westvaco Corp.	Potomac Edison Co.	Economic analysis of proposed CWIP Rider for 1990 Clean Air Act Amendments expenditures.
10/91	U-17282	LA	Louisiana Public Service Commission Staff	Gulf States Utilities	Results of comprehensive management audit.
Note: No testimony was prefiled on this.					
11/91	U-17949 Subdocket A	LA	Louisiana Public Service Commission Staff	South Central Bell Telephone Co. and proposed merger with Southern Bell Telephone Co.	Analysis of South Central Bell's restructuring and
12/91	91-410-EL-AIR	OH	Armco Steel Co., Air Products & Chemicals, Inc.	Cincinnati Gas & Electric Co.	Rate design, interruptible rates.
12/91	P-880286	PA	Armco Advanced Materials Corp., Allegheny Ludlum Corp.	West Penn Power Co.	Evaluation of appropriate avoided capacity costs - QF projects.
1/92	C-913424	PA	Duquesne Interruptible Complainants	Duquesne Light Co.	Industrial interruptible rate.
6/92	92-02-19	CT	Connecticut Industrial Energy Consumers	Yankee Gas Co.	Rate design.

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Date	Case	Jurisdict.	Party	Utility	Subject
8/92	2437	NM	New Mexico Industrial Intervenors	Public Service Co. of New Mexico	Cost-of-service.
8/92	R-00922314	PA	GPU Industrial Intervenors	Metropolitan Edison Co.	Cost-of-service, rate design, energy cost rate.
9/92	39314	ID	Industrial Consumers for Fair Utility Rates	Indiana Michigan Power Co.	Cost-of-service, rate design, energy cost rate, rate treatment.
10/92	M-00920312 C-007	PA	The GPU Industrial Intervenors	Pennsylvania Electric Co.	Cost-of-service, rate design, energy cost rate, rate treatment.
12/92	U-17949	LA	Louisiana Public Service Commission Staff	South Central Bell Co.	Management audit.
12/92	R-00922378	PA	Armco Advanced Materials Co. The WPP Industrial Intervenors	West Penn Power Co.	Cost-of-service, rate design, energy cost rate, SO_2 allowance rate treatment.
1/93	8487	MD	The Maryland Industrial Group	Baltimore Gas & Electric Co.	Electric cost-of-service and rate design, gas rate design (flexible rates).
2/93	E002/GR-92-1185	MN	North Star Steel Co. Praxair, Inc.	Northern States Power Co.	Interruptible rates.
4/93	EC92 21000 ER92-806-000 (Rebuttal)	Federal Energy Regulatory Commission	Louisiana Public Service Commission Staff	Gulf States Utilities/Entergy agreement.	Merger of GSU into Entergy System; impact on system
7/93	93-0114-E-C	WV	Airco Gases	Monongahela Power Co.	Interruptible rates.
8/93	930759-EG	FL	Florida Industrial Power Users' Group	Generic - Electric Utilities	Cost recovery and allocation of DSM costs.
9/93	M-009 30406	PA	Lehigh Valley Power Committee	Pennsylvania Power & Light Co.	Ratemaking treatment of off-system sales revenues.
11/93	346	KY	Kentucky Industrial Utility Customers	Generic - Gas Utilities	Allocation of gas pipeline transition costs - FERC Order 636.
12/93	U-17735	LA	Louisiana Public Service Commission Staff	Cajun Electric Power Cooperative	Nuclear plant prudence, forecasting, excess capacity.

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Date	Case	Jurisdict.	Party	Utility	Subject
4/94	E-015/ GR-94-001	MN	Large Power Intervenors	Minnesota Power Co.	Cost allocation, rate design, rate phase-in plan.
5/94	U-20178	LA	Louisiana Public Service Commission	Louisiana Power & Light Co.	Analysis of least cost integrated resource plan and demand-side management program.
7/94	R-00942986	PA	Armco, Inc.; West Penn Power Industrial Intervenors	West Penn Power Co.	Cost-of-service, allocation of rate increase, rate design, emission allowance sales, and operations and maintenance expense.
7/94	94-0035-E-42T	WV	West Virginia Energy Users Group	Monongahela Power Co.	Cost-of-service, allocation of rate increase, and rate design.
8/94	EC94 13-000	Federal Energy Regulatory Commission	Louisiana Public Service Commission	Gulf States Utilities/Entergy	Analysis of extended reserve shutdown units and violation of system agreement by Entergy.
9/94	R-00943 081 R-00943 081C0001	PA	Lehigh Valley Power Committee	Pennsylvania Public Utility Commission	Analysis of interruptible rate terms and conditions, availability.
9/94	U-17735	LA	Louisiana Public Service Commission	Cajun Electric Power Cooperative	Evaluation of appropriate avoided cost rate.
9/94	U-19904	LA	Louisiana Public Service Commission	Gulf States Utilities	Revenue requirements.
10/94	5258-U	GA	Georgia Public Service Commission	Southern Bell Telephone & Telegraph Co.	Proposals to address competition in telecommunication markets.
11/94	EC94-7-000 ER94-898-000	FERC	Louisiana Public Service Commission	El Paso Electric and Central and Southwest	Merger economics, transmission equalization hold harmless proposals.
2/95	941-430EG	CO	CF&I Steel, L.P.	Public Service Company of Colorado	Interruptible rates, cost-of-service.
4/95	R-00943271	PA	PP&L Industrial Customer Alliance	Pennsylvania Power & Light Co.	Cost-of-service, allocation of rate increase, rate design, interruptible rates.
6/95	C-00913424 C-00946104	PA	Duquesne Interruptible Complainants	Duquesne Light Co.	Interruptible rates.

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Date	Case	Jurisdict.	Party	Utility	Subject
8/95	ER95-112 -000	FERC	Louisiana Public Service Commission	Entergy Services, Inc.	Open Access Transmission Tariffs - Wholesale.
10/95	U-21485	LA	Louisiana Public Service Commission	Gulf States Utilities Company	Nuclear decommissioning, revenue requirements, capital structure.
10/95	ER95-1042 -000	FERC	Louisiana Public Service Commission	System Energy Resources, Inc.	Nuclear decommissioning, revenue requirements.
10/95	U-21485	LA	Louisiana Public Service Commission	Gulf States Utilities Co.	Nuclear decommissioning and cost of debt capital, capital structure.
11/95	I-940032	PA	Industrial Energy Consumers of Pennsylvania	State-wide - all utilities	Retail competition issues.
7/96	U-21496	LA	Louisiana Public Service Commission	Central Louisiana Electric Co.	Revenue requirement analysis.
7/96	8725	MD	Maryland Industrial Group	Baltimore Gas & Elec. Co., Potomac Elec. Power Co., Constellation Energy Co.	Ratemaking issues associated with a Merger.
8/96	U-17735	LA	Louisiana Public Service Commission	Cajun Electric Power Cooperative	Revenue requirements.
9/96	U-22092	LA	Louisiana Public Service Commission	Entergy Gulf States, Inc.	Decommissioning, weather normalization, capital structure.
2/97	R-973877	PA	Philadelphia Area Industrial Energy Users Group	PECO Energy Co.	Competitive restructuring policy issues, stranded cost, transition charges.
6/97	Civil Action No. 94-11474	US Bank-ruptcy Court Middle District of Louisiana	Louisiana Public Service Commission	Cajun Electric Power Cooperative	Confirmation of reorganization plan; analysis of rate paths produced by competing plans.
6/97	R-973953	PA	Philadelphia Area Industrial Energy Users Group	PECO Energy Co.	Retail competition issues, rate unbundling, stranded cost analysis.
6/97	8738	MD	Maryland Industrial Group	Generic	Retail competition issues

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Date	Case	Jurisdict.	Party	Utility	Subject
7/97	R-973954	PA	PP&L Industrial Customer Alliance	Pennsylvania Power & Light Co.	Retail competition issues, rate unbundling, stranded cost analysis.
10/97	97-204	KY	Alcan Aluminum Corp. Southwire Co.	Big River Electric Corp.	Analysis of cost of service issues - Big Rivers Restructuring Plan
10/97	R-974008	PA	Metropolitan Edison Industrial Users	Metropolitan Edison Co.	Retail competition issues, rate unbundling, stranded cost analysis.
10/97	R-974009	PA	Pennsylvania Electric Industrial Customer	Pennsylvania Electric Co.	Retail competition issues, rate unbundling, stranded cost analysis.
11/97	U-22491	LA	Louisiana Public Service Commission	Entergy Gulf States, Inc.	Decommissioning, weather normalization, capital structure.
11/97	P-971265	PA	Philadelphia Area Industrial Energy Users Group	Enron Energy Services Power, Inc./ PECO Energy	Analysis of Retail Restructuring Proposal.
12/97	R-973981	PA	West Penn Power Industrial Intervenors	West Penn Power Co.	Retail competition issues, rate unbundling, stranded cost analysis.
12/97	R-974104	PA	Duquesne Industrial Intervenors	Duquesne Light Co.	Retail competition issues, rate unbundling, stranded cost analysis.
3/98 (Allocated Stranded Cost Issues)	U-22092	LA	Louisiana Public Service Commission	Gulf States Utilities Co.	Retail competition, stranded cost quantification.
3/98	U-22092		Louisiana Public Service Commission	Gulf States Utilities, Inc.	Stranded cost quantification, restructuring issues.
9/98	U-17735		Louisiana Public Service Commission	Cajun Electric Power Cooperative, Inc.	Revenue requirements analysis, weather normalization.
12/98	8794	MD	Maryland Industrial Group and Millennium Inorganic Chemicals Inc.	Baltimore Gas and Electric Co.	Electric utility restructuring, stranded cost recovery, rate unbundling.
12/98	U-23358	LA	Louisiana Public Service Commission	Entergy Gulf States, Inc.	Nuclear decommissioning, weather normalization, Entergy System Agreement.
5/99 (Cross-Answering Testimony)	EC-98-40-000	FERC	Louisiana Public Service Commission	American Electric Power Co. & Central South West Corp.	Merger issues related to market power mitigation proposals.

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Date	Case	Jurisdict.	Party	Utility	Subject
5/99 (Response Testimony)	98-426	KY	Kentucky Industrial Utility Customers, Inc.	Louisville Gas & Electric Co.	Performance based regulation, settlement proposal issues, cross-subsidies between electric. gas services.
6/99	98-0452	WV	West Virginia Energy Users Group	Appalachian Power, Monongahela Power, & Potomac Edison Companies	Electric utility restructuring, stranded cost recovery, rate unbundling.
7/99	99-03-35	CT	Connecticut Industrial \Energy Consumers	United Illuminating Company	Electric utility restructuring, stranded cost recovery, rate unbundling.
7/99	Adversary Proceeding No. 98-1065	U.S. Bankruptcy Court	Louisiana Public Service Commission	Cajun Electric Power Cooperative	Motion to dissolve preliminary injunction.
7/99	99-03-06	CT	Connecticut Industrial Energy Consumers	Connecticut Light & Power Co.	Electric utility restructuring, stranded cost recovery, rate unbundling.
10/99	U-24182	LA	Louisiana Public Service Commission	Entergy Gulf States, Inc.	Nuclear decommissioning, weather normalization, Entergy System Agreement.
12/99	U-17735	LA	Louisiana Public Service Commission	Cajun Electric Power Cooperative, Inc.	Ananlysi of Proposed Contract Rates, Market Rates.
03/00	U-17735	LA	Louisiana Public Service Commission	Cajun Electric Power Cooperative, Inc.	Evaluation of Cooperative Power Contract Elections
03/00	99-1658-EL-ETP	OH	AK Steel Corporation	Cincinnati Gas & Electric Co.	Electric utility restructuring, stranded cost recovery, rate Unbundling.

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Date	Case	Jurisdict.	Party	Utility	Subject
08/00	98-0452 E-GI	WV	West Virginia Energy Users Group	Appalachian Power Co. American Electric Co.	Electric utility restructuring rate unbundling.
08/00	00-1050 E-T 00-1051-E-T	WV	West Virginia Energy Users Group	Mon Power Co. Potomac Edison Co.	Electric utility restructuring rate unbundling.
10/00	SOAH 473-00-1020 PUC 2234	TX	The Dallas-Fort Worth Hospital Council and The Coalition of Independent Colleges And Universities	TXU, Inc.	Electric utility restructuring rate unbundling.
12/00	U-24993	LA	Louisiana Public Service Commission	Entergy Gulf States, Inc.	Nuclear decommissioning, revenue requirements.
12/00	EL00-66-000 & ER00-2854 EL95-33-002	LA	Louisiana Public Service Commission	Entergy Services Inc.	Inter-Company System Agreement: Modifications for retail competition, interruptible load.
04/01	U-21453, U-20925, U-22092 (Subdocket B) Addressing Contested Issues	LA	Louisiana Public Service Commission	Entergy Gulf States, Inc.	Jurisdictional Business Separation - Texas *Restructuring* Plan
10/01	14000-U	GA	Georgia Public Service Commission Adversary Staff	Georgia Power Co.	Test year revenue forecast.
11/01	U-25687	LA	Louisiana Public Service Commission	Entergy Gulf States, Inc.	Nuclear decommissioning requirements transmission revenues.
11/01	U-25965	LA	Louisiana Public Service Commission	Generic	Independent Transmission Company ("Transco"). RTO rate design.
03/02	001148-EI	FL	South Florida Hospital and Healthcare Assoc.	Florida Power & Light Company	Retail cost of service, rate design, resource planning and demand side management.
06/02	U-25965	LA	Louisiana Public Service Commission	Entergy Gulf States Entergy Louisiana	RTO Issues
07/02	U-21453	LA	Louisiana Public Service Commission	SWEPCO, AEP	Jurisdictional Business Sep. - Texas Restructuring Plan.

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Date	Case	Jurisdict.	Party	Utility	Subject
08/02	U-25888	LA	Louisiana Public Service Commission	Entergy Louisiana, Inc. Entergy Gulf States, Inc.	Modifications to the Inter-Company System Agreement, Production Cost Equalization.
08/02	EL01-88-000	FERC	Louisiana Public Service Commission	Entergy Services Inc. and the Entergy Operating Companies	Modifications to the Inter-Company System Agreement, Production Cost Equalization.
11/02	02S-315EG	CO	CF&I Steel & Climax Molybdenum Co.	Public Service Co. of Colorado	Fuel Adjustment Clause
01/03	U-17735	LA	Louisiana Public Service Commission	Louisiana Coops	Contract Issues
02/03	02S-594E	CO	Cripple Creek and Victor Gold Mining Co.	Aquila, Inc.	Revenue requirements, purchased power.
04/03	U-26527	LA	Louisiana Public Service Commission	Entergy Gulf States, Inc.	Weather normalization, power purchase expenses, System Agreement expenses.
11/03	ER03-753-000	FERC	Louisiana Public Service Commission Staff	Entergy Services, Inc. and the Entergy Operating Companies	Proposed modifications to System Agreement Tariff MSS-4.
11/03	ER03-583-000 ER03-583-001 ER03-583-002 ER03-681-000, ER03-681-001 ER03-682-000, ER03-682-001 ER03-682-002	FERC	Louisiana Public Service Commission	Entergy Services, Inc., the Entergy Operating Companies, EWO Marketing, L.P, and Entergy Power, Inc.	Evaluation of Wholesale Purchased Power Contracts.
12/03	U-27136	LA	Louisiana Public Service Commission	Entergy Louisiana, Inc.	Evaluation of Wholesale Purchased Power Contracts.
01/04	E-01345-03-0437	AZ	Kroger Company	Arizona Public Service Co.	Revenue allocation rate design.
02/04	00032071	PA	Duquesne Industrial Intervenors	Duquesne Light Company	Provider of last resort issues.
03/04	03A-436E	CO	CF&I Steel, LP and Climax Molybdenum	Public Service Company of Colorado	Purchased Power Adjustment Clause.

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Date	Case	Jurisdict.	Party	Utility	Subject
04/04	2003-00433 2003-00434	KY	Kentucky Industrial Utility Customers, Inc.	Louisville Gas & Electric Co. Kentucky Utilities Co.	Cost of Service Rate Design
0-6/04	03S-539E	CO	Cripple Creek, Victor Gold Mining Co., Goodrich Corp., Holcim (U.S.,), Inc., and The Trane Co.	Aquila, Inc.	Cost of Service, Rate Design Interruptible Rates
06/04	R-00049255	PA	PP&L Industrial Customer Alliance PPLICA	PPL Electric Utilities Corp.	Cost of service, rate design, tariff issues and transmission service charge.
10/04	04S-164E	CO	CF&I Steel Company, Climax Molybdenum	Public Service Company of Colorado	Cost of service, rate design, Interruptible Rates.
03/05	Case No. 2004-00426 Case No. 2004-00421	KY	Kentucky Industrial Utility Customers, Inc.	Kentucky Utilities Louisville Gas & Electric Co.	Environmental cost recovery.
06/05	050045-EI	FL	South Florida Hospital and Healthcare Assoc.	Florida Power & Light Company	Retail cost of service, rate design
07/05	U-28155	LA	Louisiana Public Service Commission Staff	Entergy Louisiana, Inc. Entergy Gulf States, Inc.	Independent Coordinator of Transmission – Cost/Benefit
09/05	Case Nos. 05-0402-E-CN 05-0750-E-PC	WV	West Virginia Energy Users Group	Mon Power Co. Potomac Edison Co.	Environmental cost recovery, *Securitization, Financing Order*
01/06	2005-00341	KY	Kentucky Industrial Utility Customers, Inc.	Kentucky Power Company	Cost of service, rate design, transmission expenses, Congestion Cost Recovery Mechanism
03/06	U-22092	LA	Louisiana Public Service Commission Staff	Entergy Gulf States, Inc.	Separation of EGSI into Texas and Louisiana Companies.
04/06	U-25116	LA	Louisiana Public Service Commission Staff	Entergy Louisiana, Inc.	Transmission Prudence Investigation
06/06	R-00061346 C0001-0005	PA	Duquesne Industrial Intervenors & IECPA	Duquesne Light Co.	Cost of Service, Rate Design, Transmission Service Charge, Tariff Issues
06/06	R-00061366 R-00061367 P-00062213 P-00062214		Met-Ed Industrial Energy Users Group and Penelec Industrial Customer Alliance	Metropolitan Edison Co. Pennsylvania Electric Co.	Generation Rate Cap, Transmission Service Charge, Cost of Service, Rate Design, Tariff Issues
07/06	U-22092 Sub-J	LA	Louisiana Public Service Commission Staff	Entergy Gulf States, Inc.	Separation of EGSI into Texas and Louisiana Companies.

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Date	Case	Jurisdict.	Party	Utility	Subject
07/06	Case No. 2006-00130 Case No. 2006-00129	KY	Kentucky Industrial Utility Customers, Inc.	Kentucky Utilities Louisville Gas & Electric Co.	Environmental cost recovery.
08/06	Case No. PUE-2006-00065	VA	Old Dominion Committee For Fair Utility Rates	Appalachian Power Co.	Cost Allocation, Allocation of Rev Incr, Off-System Sales margin rate treatment
09/06	E-01345A-05-0816	AZ	Kroger Company	Arizona Public Service Co.	Revenue allocation, cost of service, rate design.
11/06	Doc. No. 97-01-15RE02	CT	Connecticut Industrial Energy Consumers	Connecticut Light & Power United Illuminating	Rate unbundling issues.
01/07	Case No. 06-0960-E-42T	WV	West Virginia Energy Users Group	Mon Power Co. Potomac Edison Co.	Retail Cost of Service Revenue apportionment
03/07	U-29764	LA	Louisiana Public Service Commission Staff	Entergy Gulf States, Inc. Entergy Louisiana, LLC	Implementation of FERC Decision Jurisdictional & Rate Class Allocation
05/07	Case No. 07-63-EL-UNC	OH	Ohio Energy Group	Ohio Power, Columbus Southern Power	Environmental Surcharge Rate Design
05/07	R-00049255 Remand	PA	PP&L Industrial Customer Alliance PPLICA	PPL Electric Utilities Corp.	Cost of service, rate design, tariff issues and transmission service charge.
06/07	R-00072155	PA	PP&L Industrial Customer Alliance PPLICA	PPL Electric Utilities Corp.	Cost of service, rate design, tariff issues.
07/07	Doc. No. 07F-037E	CO	Gateway Canyons LLC	Grand Valley Power Coop.	Distribution Line Cost Allocation
09/07	Doc. No. 05-UR-103	WI	Wisconsin Industrial Energy Group, Inc.	Wisconsin Electric Power Co.	Cost of Service, rate design, tariff issues, Interruptible rates.
11/07	ER07-682-000	FERC	Louisiana Public Service Commission Staff	Entergy Services, Inc. and the Entergy Operating Companies	Proposed modifications to System Agreement Schedule MSS-3. Cost functionalization issues.
1/08	Doc. No. 20000-277-ER-07	WY	Cimarex Energy Company	Rocky Mountain Power (PacifiCorp)	Vintage Pricing, Marginal Cost Pricing Projected Test Year
1/08	Case No. 07-551	OH	Ohio Energy Group	Ohio Edison, Toledo Edison Cleveland Electric Illuminating	Class Cost of Service, Rate Restructuring, Apportionment of Revenue Increase to Rate Schedules
2/08	ER07-956	FERC	Louisiana Public Service Commission Staff	Entergy Services, Inc. and the Entergy Operating Companies	Entergy's Compliance Filing System Agreement Bandwidth Calculations.
2/08	Doc No. P-00072342	PA	West Penn Power Industrial Intervenors	West Penn Power Co.	Default Service Plan issues.

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Date	Case	Jurisdict.	Party	Utility	Subject
3/08	Doc No. E-01933A-05-0650	AZ	Kroger Company	Tucson Electric Power Co.	Cost of Service, Rate Design
05/08	08-0278 E-GI	WV	West Virginia Energy Users Group	Appalachian Power Co. American Electric Power Co.	Expanded Net Energy Cost "ENEC" Analysis.
6/08	Case No. 08-124-EL-ATA	OH	Ohio Energy Group	Ohio Edison, Toledo Edison Cleveland Electric Illuminating	Recovery of Deferred Fuel Cost
7/08	Docket No. 07-035-93	UT	Kroger Company	Rocky Mountain Power Co.	Cost of Service, Rate Design
08/08	Doc. No. 6680-UR-116	WI	Wisconsin Industrial Energy Group, Inc.	Wisconsin Power and Light Co.	Cost of Service, rate design, tariff Issues, Interruptible rates.
09/08	Doc. No. 6690-UR-119	WI	Wisconsin Industrial Energy Group, Inc.	Wisconsin Public Service Co.	Cost of Service, rate design, tariff Issues, Interruptible rates.
09/08	Case No. 08-936-EL-SSO	OH	Ohio Energy Group	Ohio Edison, Toledo Edison Cleveland Electric Illuminating	Provider of Last Resort Competitive Solicitation
09/08	Case No. 08-935-EL-SSO	OH	Ohio Energy Group	Ohio Edison, Toledo Edison Cleveland Electric Illuminating	Provider of Last Resort Rate Plan
09/08	Case No. 08-917-EL-SSO 08-918-EL-SSO	OH	Ohio Energy Group	Ohio Power Company Columbus Southern Power Co.	Provider of Last Resort Rate Plan
10/08	2008-00251 2008-00252	KY	Kentucky Industrial Utility Customers, Inc.	Louisville Gas & Electric Co. Kentucky Utilities Co.	Cost of Service, Rate Design
11/08	08-1511 E-GI	WV	West Virginia Energy Users Group	Mon Power Co. Potomac Edison Co.	Expanded Net Energy Cost "ENEC" Analysis.
11/08	M-2008-2036188, M-2008-2036197	PA	Met-Ed Industrial Energy Users Group and Penelec Industrial Customer Alliance	Metropolitan Edison Co. Pennsylvania Electric Co.	Transmission Service Charge
01/09	ER08-1056	FERC	Louisiana Public Service Commission	Entergy Services, Inc. and the Entergy Operating Companies	Entergy's Compliance Filing System Agreement Bandwidth Calculations.
01/09	E-01345A-08-0172	AZ	Kroger Company	Arizona Public Service Co.	Cost of Service, Rate Design
02/09	2008-00409	KY	Kentucky Industrial Utility Customers, Inc.	East Kentucky Power Cooperative, Inc.	Cost of Service, Rate Design

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Date	Case	Jurisdict.	Party	Utility	Subject
5/09	PUE-2009 -00018	VA	VA Committee For Fair Utility Rates	Dominion Virginia Power Company	Transmission Cost Recovery Rider
5/09	09-0177-E-GI	WV	West Virginia Energy Users Group	Appalachian Power Company	Expanded Net Energy Cost "ENEC" Analysis
6/09	PUE-2009 -00016	VA	VA Committee For Fair Utility Rates	Dominion Virginia Power Company	Fuel Cost Recovery Rider
6/09	PUE-2009 -00038	VA	Old Dominion Committee For Fair Utility Rates	Appalachian Power Company	Fuel Cost Recovery Rider
7/09	080677-EI	FL	South Florida Hospital and Healthcare Assoc.	Florida Power & Light Company	Retail cost of service, rate design
8/09	U-20925 (RRF 2004)	LA	Louisiana Public Service Commission Staff	Entergy Louisiana LLC	Interruptible Rate Refund Settlement
9/09	09AL-299E	CO	CF&I Steel Company Climax Molybdenum	Public Service Company of Colorado	Energy Cost Rate Issues
9/09	Doc. No. 05-UR-104	WI	Wisconsin Industrial Energy Group, Inc.	Wisconsin Electric Power Co.	Cost of Service, rate design, tariff Issues, Interruptible rates.
9/09	Doc. No. 6680-UR-117	WI	Wisconsin Industrial Energy Group, Inc.	Wisconsin Power and Light Co.	Cost of Service, rate design, tariff Issues, Interruptible rates.
10/09	Docket No. 09-035-23	UT	Kroger Company	Rocky Mountain Power Co.	Cost of Service, Allocation of Rev Increase
10/09	09AL-299E	CO	CF&I Steel Company Climax Molybdenum	Public Service Company of Colorado	Cost of Service, Rate Design
11/09	PUE-2009 -00019	VA	VA Committee For Fair Utility Rates	Dominion Virginia Power Company	Cost of Service, Rate Design
11/09	09-1485 E-P	WV	West Virginia Energy Users Group	Mon Power Co. Potomac Edison Co.	Expanded Net Energy Cost "ENEC" Analysis.
12/09	Case No. 09-906-EL-SSO	OH	Ohio Energy Group	Ohio Edison, Toledo Edison Cleveland Electric Illuminating	Provider of Last Resort Rate Plan
12/09	ER09-1224	FERC	Louisiana Public Service Commission	Entergy Services, Inc. and the Entergy Operating Companies	Entergy's Compliance Filing System Agreement Bandwidth Calculations.
12/09	Case No. PUE-2009-00030	VA	Old Dominion Committee For Fair Utility Rates	Appalachian Power Co.	Cost Allocation, Allocation of Rev Increase, Rate Design

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As of June 2010

Date	Case	Jurisdict.	Party	Utility	Subject
2/10	Docket No. 09-035-23	UT	Kroger Company	Rocky Mountain Power Co.	Rate Design
3/10	Case No. 09-1352-E-42T	WV	West Virginia Energy Users Group	Mon Power Co. Potomac Edison Co.	Retail Cost of Service Revenue apportionment
3/10	E015/ GR-09-1151	MN	Large Power Intervenors	Minnesota Power Co.	Cost of Service, rate design
4/10	EL09-61	FERC	Louisiana Public Service Service Commission	Entergy Services, Inc. and the Entergy Operating Companies	System Agreement Issues Related to off-system sales
4/10	2009-00459	KY	Kentucky Industrial Utility Customers, Inc.	Kentucky Power Company	Cost of service, rate design, transmission expenses.
4/10	2009-00548 2009-00549	KY	Kentucky Industrial Utility Customers, Inc.	Louisville Gas & Electric Co. Kentucky Utilities Co.	Cost of Service, Rate Design

ELECTRIC UTILITY COST ALLOCATION MANUAL

NATIONAL ASSOCIATION OF REGULATORY UTILITY COMMISSIONERS

January, 1992

PREFACE

This project was jointly assigned to the NARUC Staff Subcommittees on Electricity and Economics in February, 1985. Jack Doran, at the California PUC had led a task force in 1969 that wrote the original Cost Allocation Manual; the famous "Green Book". I was asked to put together a task force to revise it and include a Marginal Cost section.

I knew little about the subject and was not sure what I was getting into so I asked Jack how he had gone about drafting the first book. "Oh" he said, "There wasn't much to it. We each wrote a chapter and then exchanged them and rewrote them." What Jack did not tell me was that like most NARUC projects, the work was done after five o'clock and on weekends because the regular work always takes precedence. It is a good thing we did not realize how big a task we were tackling or we might never have started.

There was great interest in the project so when I asked for volunteers, I got plenty. We split into two working groups; embedded cost and marginal cost. Joe Jenkins from the Florida PSC headed up the Embedded Cost Working Group and Sarah Voll from the New Hampshire PUC took the Marginal Cost Working Group. We followed Jack's suggestions but, right from the beginning, we realized that once the chapters were technically correct, we would need a single editor to cast them all "into one hand" as Joe Jenkins put it. Steven Mintz from the Department of Energy volunteered for this task and has devoted tremendous effort to polishing the book into the final product you hold in your hands. Victoria Jow at the California PUC took Steven's final draft and desktop published the entire document using Ventura Publisher.

We set the following objectives for the manual:

- It should be simple enough to be used as a primer on the subject for new employees yet offer enough substance for experienced witnesses.
- It must be comprehensive yet fit in one volume.
- The writing style should be non-judgmental; not advocating any one particular method but trying to include all currently used methods with pros and cons.

It is with extreme gratitude that I acknowledge the energy and dedication contributed by the following task force members over the last five years.

Steven Mintz, Department of Energy, Editor; Joe Jenkins, Florida PSC, Leader, Embedded Cost Working Group; Sarah Voll, New Hampshire PUC, Leader, Marginal Cost Working Group; Victoria Jow, California PUC; John A. Anderson, ELCON; Jess Galura, Sacramento MUD; Chris Danforth, California PUC; Alfred Escamilla, Southern California Edison; Byron Harris, West Virginia CAD; Steve Houle, Texas Utility Electric Co.; Kevin Kelly, formally NRRI; Larry Klapow California PUC; Jim Ketter P.E., Missouri PSC; Ed Lucero, Price Waterhouse; J. Robert Malko, Utah State University; George McCluskey, New Hampshire PUC; Marge Meeter, Florida PSC; Gordon Murdock, The FERC; Dennis Nightingale, North Carolina UC; John Orecchio, The FERC; Carl Silsbee, Southern California Edison; Ben Turner, North Carolina UC; Dr. George Parkins, Colorado PUC; Warren Wendling, Colorado PUC; Schef Wright, formally Florida PSC; IN MEMORIAL Bob Kennedy Jr., Arkansas PSC.

Julian Ajello
California PUC

CHAPTER 6

CLASSIFICATION AND ALLOCATION OF DISTRIBUTION PLANT

Distribution plant equipment reduces high-voltage energy from the transmission system to lower voltages, delivers it to the customer and monitors the amounts of energy used by the customer.

Distribution facilities provide service at two voltage levels: primary and secondary. Primary voltages exist between the substation power transformer and smaller line transformers at the customer's points of service. These voltages vary from system to system and usually range between 480 volts to 35 KV. In the last few years, advances in equipment and cable technology have permitted the use of higher primary distribution voltages. Primary voltages are reduced to more usable secondary voltages by smaller line transformers installed at customer locations along the primary distribution circuit. However, some large industrial customers may choose to install their own line transformers and take service at primary voltages because of their large electrical requirements.

In some cases, the utility may choose to install a transformer for the exclusive use of a single commercial or industrial customer. On the other hand, in service areas with high customer density, such as housing tracts, a line transformer will be installed to serve many customers. In this case, secondary voltage lines run from pole-to-pole or from handhole-to-handhole, and each customer is served by a drop tapped off the secondary line leading directly to the customer's premise.

I. COST ACCOUNTING FOR DISTRIBUTION PLANT AND EXPENSES

The Federal Energy Regulatory Commission (FERC) Uniform System of Accounts requires separate accounts for distribution investment and expenses. Distribution plant accounts are summarized and classified in Table 6-1. Distribution expense accounts are summarized and classified in Table 6-2. Some utilities may choose to establish subaccounts for more detailed cost reporting.

TABLE 6-1

CLASSIFICATION OF DISTRIBUTION PLANT[1]

FERC Uniform System of Accounts No.	Description	Demand Related	Customer Related
	Distribution Plant [2]		
360	Land & Land Rights	X	X
361	Structures & Improvements	X	X
362	Station Equipment	X	-
363	Storage Battery Equipment	X	-
364	Poles, Towers, & Fixtures	X	X
365	Overhead Conductors & Devices	X	X
366	Underground Conduit	X	X
367	Underground Conductors & Devices	X	X
368	Line Transformers	X	X
369	Services	-	X
370	Meters	-	X
371	Installations on Customer Premises	-	X
372	Leased Property on Customer Premises	-	X
373	Street Lighting & Signal Systems [1]	-	-

[1] Assignment or "exclusive use" costs are assigned directly to the customer class or group which exclusively uses such facilities. The remaining costs are then classified to the respective cost components.

[2] The amounts between classification may vary considerably. A study of the minimum intercept method or other appropriate methods should be made to determine the relationships between the demand and customer components.

TABLE 6-2

CLASSIFICATION OF DISTRIBUTION EXPENSES[1]

FERC Uniform System of Accounts No.	Description	Demand Related	Customer Related
	Operation [2]		
580	Operation Supervision & Engineering	X	X
581	Load Dispatching	X	-
582	Station Expenses	X	-
583	Overhead Line Expenses	X	X
584	Underground Line Expenses	X	X
585	Street Lighting & Signal System Expenses [1]	-	-
586	Meter Expenses	-	X
587	Customer Installation Expenses	-	X
588	Miscellaneous Distribution Expenses	X	X
589	Rents	X	X
	Maintenance [2]		
590	Maintenance Supervision & Engineering	X	X
591	Maintenance of Structures	X	X
592	Maintenance of Station Equipment	X	-
593	Maintenance of Overhead Lines	X	X
594	Maintenance of Underground Lines	X	X
595	Maintenance of Line Transformers	X	X
596	Maint. of Street Lighting & Signal Systems [1]	-	-
597	Maintenance of Meters	-	X
598	Maint. of Miscellaneous Distribution Plants	X	X

[1]Direct assignment or "exclusive use" costs are assigned directly to the customer class or group which exclusively uses such facilities. The remaining costs are then classified to the respective cost components.

[2]The amounts between classifications may vary considerably. A study of the minimum intercept method or other appropriate methods should be made to determine the relationships between the demand and customer components.

To ensure that costs are properly allocated, the analyst must first classify each account as demand-related, customer-related, or a combination of both. The classification depends upon the analyst's evaluation of how the costs in these accounts were incurred. In making this determination, supporting data may be more important than theoretical considerations.

Allocating costs to the appropriate groups in a cost study requires a special analysis of the nature of distribution plant and expenses. This will ensure that costs are assigned to the correct functional groups for classification and allocation. As indicated in Chapter 4, all costs of service can be identified as energy-related, demand-related, or customer-related. Because there is no energy component of distribution-related costs, we need consider only the demand and customer components.

To recognize voltage level and use of facilities in the functionalization of distribution costs, distribution line costs must be separated into overhead and underground, and primary and secondary voltage classifications. A typical functionalization and classification of distribution plant would appear as follows:

Substations:	Demand
Distribution:	Overhead Primary
	Demand
	Customer
	Overhead Secondary
	Demand
	Customer
	Underground Primary
	Demand
	Customer
	Underground Secondary
	Demand
	Customer
	Line Transformers
	Demand
	Customer
Services:	Overhead
	Demand
	Customer
	Underground
	Demand
	Customer
Meters:	Customer
Street Lighting:	Customer
Customer Accounting:	Customer
Sales:	Customer

From this breakdown it can be seen that each distribution account must be analyzed before it can be assigned to the appropriate functional category. Also, these accounts must be classified as demand-related, customer-related, or both. Some utilities assign distribution to customer-related expenses. Variations in the demands of various customer groups are used to develop the weighting factors for allocating costs to the appropriate group.

II. DEMAND AND CUSTOMER CLASSIFICATIONS OF DISTRIBUTION PLANT ACCOUNTS

When the utility installs distribution plant to provide service to a customer and to meet the individual customer's peak demand requirements, the utility must classify distribution plant data separately into demand- and customer-related costs.

Classifying distribution plant as a demand cost assigns investment of that plant to a customer or group of customers based upon its contribution to some total peak load. The reason is that costs are incurred to serve area load, rather than a specific number of customers.

Distribution *substations costs* (which include Accounts 360 -Land and Land Rights, 361 - Structures and Improvements, and 362 -Station Equipment), are normally classified as demand-related. This classification is adopted because substations are normally built to serve a particular load and their size is not affected by the number of customers to be served.

Distribution plant Accounts 364 through 370 involve demand and customer costs. The customer component of distribution facilities is that portion of costs which varies with the number of customers. Thus, the number of poles, conductors, transformers, services, and meters are directly related to the number of customers on the utility's system. As shown in Table 6-1, each primary plant account can be separately classified into a demand and customer component. Two methods are used to determine the demand and customer components of distribution facilities. They are, the minimum-size-of-facilities method, and the minimum-intercept cost (zero-intercept or positive-intercept cost, as applicable) of facilities.

A. The Minimum-Size Method

Classifying distribution plant with the minimum-size method assumes that a minimum size distribution system can be built to serve the minimum loading requirements of the customer. The minimum-size method involves determining the minimum size pole, conductor, cable, transformer, and service that is currently installed by the utility. Normally, the average book cost for each piece of equipment determines the price of all installed units. Once determined for each primary plant account, the minimum size distribution system is classified as customer-related costs. The demand-related costs for each account are the difference between the total investment in the account and customer-related costs. Comparative studies between the minimum-size and other methods show that it generally produces a larger customer component than the zero-intercept method (to be discussed). The following describes the methodologies for determining the minimum size for distribution plant Accounts 364, 365, 366, 367, 368, and 369.

1. Account 364 - Poles, Towers, and Fixtures

   - Determine the average installed book cost of the minimum height pole currently being installed.
   - Multiply the average book cost by the number of poles to find the customer component. Balance of plant account is the demand component.

2. Account 365 - Overhead Conductors and Devices

   - Determine minimum size conductor currently being installed.
   - Multiply average installed book cost per mile of minimum size conductor by the number of circuit miles to determine the customer component. Balance of plant account is demand component. (Note: two conductors in minimum system.)

3. Accounts 366 and 367 - Underground Conduits, Conductors, and Devices

   - Determine minimum size cable currently being installed.
   - Multiply average installed book cost per mile of minimum size cable by the circuit miles to determine the customer component. Balance of plant Account 367 is demand component. (Note: one cable with ground sheath is minimum system.) Account 366 conduit is assigned, basedon ratio of cable account.
   - Multiply average installed book cost of minimum size transformer by number of transformers in plant account to determine the customer component. Balance of plant account is demand component.

4. Account 368 - Line Transformers

   - Determine minimum size transformer currently being installed.

- Multiply average installed book cost of minimum size transformer by number of transformers in plant account to determine the customer component.

5. **Account 369 - Services**

- Determine minimum size and average length of services currently being installed.
- Estimate cost of minimum size service and multiply by number of services to get customer component.
- If overhead and underground services are booked separately, they should be handled separately. Most companies do not book service by size. This requires an engineering estimate of the cost of the minimum size, average length service. The resultant estimate is usually higher than the average book cost. In addition, the estimate should be adjusted for the average age of service, using a trend factor.

B. The Minimum-Intercept Method

The minimum-intercept method seeks to identify that portion of plant related to a hypothetical no-load or zero-intercept situation. This requires considerably more data and calculation than the minimum-size method. In most instances, it is more accurate, although the differences may be relatively small. The technique is to relate installed cost to current carrying capacity or demand rating, create a curve for various sizes of the equipment involved, using regression techniques, and extend the curve to a no-load intercept. The cost related to the zero-intercept is the customer component. The following describes the methodologies for determining the minimum intercept for distribution-plant Accounts 364, 365, 366, 367, and 368.

1. **Account 364 - Poles, Towers, and Fixtures**

- Determine the number, investment, and average installed book cost of distribution poles by height and class of pole. (Exclude stubs for guying.)
- Determine minimum intercept of pole cost by creating a regression equation, relating classes and heights of poles, and using the Class 7 cost intercept for each pole of equal height weighted by the number of poles in each height category.
- Multiply minimum intercept cost by total number of distribution poles to get customer component.

- Balance of pole investment is assigned to demand component.
- Total account dollars are assigned based on ratio of pole investment. (Transformer platforms in Account 364 are all demand-related. They should be removed before determining the account ratio of customer- and demand-related costs, and then they should be added to the demand portion of Account 364.)

2. Account 365 - Overhead Conductors and Devices

- If accounts are divided between primary and secondary voltages, develop a customer component separately for each. The total investment is assigned to primary and secondary; then the customer component is developed for each. Since conductors generally are of many types and sizes, select those sizes and types which represent the bulk of the investment in this account, if appropriate.
- When developing the customer component, consider only the investment in conductors, and not such devices as circuit breakers, insulators, switches, etc. The investment in these devices will be assigned later between the customer and demand component, based on the conductor assignment.
  - Determine the feet, investment, and average installed book cost per foot for distribution conductors by size and type.
  - Determine minimum intercept of conductor cost per foot using cost per foot by size and type of conductor weighted by feet or investment in each category, and developing a cost for the utility's minimum size conductor.
  - Multiply minimum intercept cost by the total number of circuit feet times 2. (Note that circuit feet, not conductor feet, are used to get customer component.)
  - Balance of conductor investment is assigned to demand.
  - Total primary or secondary dollars in the account, including devices, are assigned to customer and demand components based on conductor investment ratio.

3. Accounts 366 and 367 - Underground Conduits, Conductors, and Devices

- The customer demand component ratio is developed for conductors and applied to conduits. Underground conductors are generally booked by type and size of conductor for both one-conductor (l/c) cable and three-conductor (3/c) cables. If conductors are booked by voltage, as between primary and secondary, a customer component is developed for each. If network and URD investments are segregated, a customer component must be developed for each.

- The conductor sizes and types for the customer component derivation are restricted to l/c cable. Since there are generally many types and sizes of l/c cable, select those sizes and types which represent the bulk of the investment, when appropriate.

  - Determine the feet, investment, and average installed book cost per foot for l/c cables by size and type of cable.

  - Determine minimum intercept of cable cost per foot using cost per foot by size and type of cable weighted by feet of investment in each category.

  - Multiply minimum intercept cost by the total number of circuit feet (l/c cable with sheath is considered a circuit) to get customer component.

  - Balance of cable investment is assigned to demand.

  - Total dollars in Accounts 366 and 367 are assigned to customer and demand components based on conductor investment ratio.

4. Account 368 - Line Transformers

- The line transformer account covers all sizes and voltages for single- and three-phase transformers. Only single-phase sizes up to and including 50 KVA should be used in developing the customer components. Where more than one primary distribution voltage is used, it may be appropriate to use the transformer price from one or two predominant, selected voltages.

  - Determine the number, investment, and average installed book cost per transformer by size and type (voltage).

  - Determine zero intercept of transformer cost using cost per transformer by type, weighted by number for each category.

  - Multiply zero intercept cost by total number of line transformers to get customer component.

  - Balance of transformer investment is assigned to demand component.

  - Total dollars in the account are assigned to customer and demand components based on transformer investment ratio from customer and demand components.

C. The Minimum-System vs. Minimum-Intercept Approach

When selecting a method to classify distribution costs into demand and customer costs, the analyst must consider several factors. The minimum-intercept method can sometimes produce statistically unreliable results. The extension of the regression equation beyond the boundaries of the data normally will intercept the Y axis at a positive value. In some cases, because of incorrect accounting data or some other abnormality in the data, the regression equation will intercept the Y axis at a negative value. When this happens, a review of the accounting data must be made, and suspect data deleted.

The results of the minimum-size method can be influenced by several factors. The analyst must determine the minimum size for each piece of equipment: "Should the minimum size be based upon the minimum size equipment currently installed, historically installed, or the minimum size necessary to meet safety requirements?" The manner in which the minimum size equipment is selected will directly affect the percentage of costs that are classified as demand and customer costs.

Cost analysts disagree on how much of the demand costs should be allocated to customers when the minimum-size distribution method is used to classify distribution plant. When using this distribution method, the analyst must be aware that the minimum-size distribution equipment has a certain load-carrying capability, which can be viewed as a demand-related cost.

When allocating distribution costs determined by the minimum-size method, some cost analysts will argue that some customer classes can receive a disproportionate share of demand costs. Their rationale is that customers are allocated a share of distribution costs classified as demand-related. Then those customers receive a second layer of demand costs that have been mislabeled customer costs because the minimum-size method was used to classify those costs.

Advocates of the minimum-intercept method contend that this problem does not exist when using their method. The reason is that the customer cost derived from the minimum-intercept method is based upon the zero-load intercept of the cost curve. Thus, the customer cost of a particular piece of equipment has no demand cost in it whatsoever.

D. Other Accounts

The preceding discussion of the merits of minimum-system versus the zero-intercept classification schemes will affect the major distribution-plant accounts for FERC Accounts 364 through 368. Several other plant accounts remain to be classified. While the classification of the following distribution-plant accounts is an important step, it is not as controversial as the classification of substations, poles, transformers, and conductors.

1. Account 369 - Services

This account is generally classified as customer-related. Classification of services may also include a demand component to reflect the fact that larger customers will require more costly service drops.

2. Account 370 - Meters

Meters are generally classified on a customer basis. However, they may also be classified using a demand component to show that larger-usage customers require more expensive metering equipment.

3. Account 371 - Installations on Customer Premises

This account is generally classified as customer-related and is often directly assigned. The kind of equipment in this account often influences how this account is treated. The equipment in this account is owned by the utility, but is located on the customer's side of the meter. A utility will often include area lighting equipment in this account and assign the investment directly to the lighting customer class.

4. Account 373 - Street Lighting and Signal Systems

This account is generally customer-related and is directly assigned to the street customer class.

III. ALLOCATION OF THE DEMAND AND CUSTOMER COMPONENTS OF DISTRIBUTION PLANT

After completing the classification of distribution plant accounts, the next major step in the cost of service process is to allocate the classified costs. Generally, determining the distribution-demand allocator will require more data and analysis than determining the customer allocators. Following are procedures used to calculate the demand and customer allocation factors.

A. Development of the Distribution Demand Allocators

There are several factors to consider when allocating the demand components of distribution plant. Distribution facilities, from a design and operational perspective, are installed primarily to meet localized area loads. Distribution substations are designed to meet the maximum load from the distribution feeders emanating from the substation.

Similarly, when designing primary and secondary distribution feeders, the distribution engineer ensures that sufficient conductor and transformer capacity is available to meet the customer's loads at the primary- and secondary-distribution service levels. Local area loads are the major factors in sizing distribution equipment. Consequently, customer-class noncoincident demands (NCPs) and individual customer maximum demands are the load characteristics that are normally used to allocate the demand component of distribution facilities. The customer-class load characteristic used to allocate the demand component of distribution plant (whether customer class NCPs or the summation of individual customer maximum demands) depends on the load diversity that is present at the equipment to be allocated. The load diversity at distribution substations and primary feeders is usually high. For this reason, customer-class peaks are normally used for the allocation of these facilities. The facilities nearer the customer, such as secondary feeders and line transformers, have much lower load diversity. They are normally allocated according to the individual customer's maximum demands. Although these are the methods normally used for the allocation of distribution demand costs, some exceptions exist.

The load diversity differences for some utilities at the transmission and distribution substation levels may not be large. Consequently, some large distribution substations may be allocated using the same method as the transmission system. Before the cost analyst selects a method to allocate the different levels of distribution facilities, he must know the design and operational characteristics of the distribution system, as well as the demand losses at each level of the distribution system.

As previously indicated, the distribution system consists of several levels. The first level starts at the distribution substation, and the last level ends at the customer's meters. Power losses occur at each level and should be included in the demand allocators. Power losses are incorporated into the demand allocators by showing different demand loss factors at each predominant voltage level. The demand loss factor used to develop the primary-distribution demand allocator will be slightly larger than the demand loss factor used to develop the secondary demand allocator. When developing the distribution demand allocator, be aware that some customers take service at different voltage levels.

Cost analysts developing the allocator for distribution of substations or primary demand facilities must ensure that only the loads of those customers who benefit from these facilities are included in the allocator. For example, the loads of customers who take service at transmission level should not be reflected in the distribution substation or primary demand allocator. Similarly, when analysts develop the allocator for secondary demand facilities, the loads for customers served by the primary distribution system should not be included.

Utilities can gather load data to develop demand allocators, either through their load research program or their transformer load management program. In most cases, the load research program gathers data from meters on the customers' premises. A more complex procedure is to use the transformer load management program.

This procedure involves simulating load profiles for the various classes of equipment on the distribution system. This provides information on the nature of the load diversity between the customer and the substation, and its effect on equipment cost. Determining demand allocators through simulation provides a first-order load approximation, which represents the peak load for each type of distribution equipment.

The concept of peak load or "equipment peak" for each piece of distribution equipment can be understood by considering line transformers. If a given transformer's loading for each hour of a month can be calculated, a transformer load curve can be developed. By knowing the types of customers connected to each load management transformer, a simulated transformer load profile curve can be developed for the system. This can provide each customer's class demand at the time of the transformer's peak load. Similarly, an equipment peak can be defined for equipment at each level of the distribution system. Although the equipment peak obtained by this method may not be ideal, it will closely approximate the actual peak. Thus, this method should reflect the different load diversities among customers at each level of the distribution system. An illustration of the simulation procedure is provided in Appendix 6-A.

B. Allocation of Customer-Related Costs

When the demand-customer classification has been completed, most of the assumptions will have been made that affect the results of the completed cost of service study.

The allocation of the customer-related portion of the various plant accounts is based on the number of customers by classes of service, with appropriate weightings and adjustments. Weighting factors reflect differences in characteristics of customers within a given class, or between classes. Within a class, for instance, we may want to give more weighting of a certain plant account to rural customers, as compared to urban customers. The metering account is a clear example of an account requiring weighting for differences between classes. A metering arrangement for a single industrial customer may be 20 to 80 times as costly as the metering for one residential customer.

While customer allocation factors should be weighted to offset differences among various types of customers, highly refined weighting factors or detailed and time consuming studies may not seem worthwhile. Such factors applied in this final step of the cost study may affect the final results much less than such basic assumptions as the demand-allocation method or the technique for determining demand-customer classifications.

Expense allocations generally are based on the comparable plant allocator of the various classes. For instance, maintenance of overhead lines is generally assumed to be directly related to plant in overhead conductors and devices. Exceptions to this rule will occur in some accounts. Meter expenses, for example, are often a function of maintenance and testing schedules related more to revenue per customer than to the cost of the meters themselves.

PECO Energy Company (Electric)
Future Test Year 2010
Class Cost of Service Study ($000s)
TOTAL REVENUE REQUIREMENT
SUMMARY OF CLASS SUBSIDIES - PRESENT TRANSMISSION REVENUES PER ABC-13

	Reference	Total Dollars	Residential	Residential Heating	Off Peak	General Service	Primary Distribution	High Tension	Electric Propulsion	Lighting
			Rate R	Rate RH	Rate OP	Rate GS	Rate PD	Rate HT	Rate EP	Rates L
Present Revenues		4,555,655	1,546,993	364,690	44,823	1,009,657	69,034	1,404,955	76,106	39,398
Subsidy at Present Rates	Page 2	(0)	(4,728)	(3,280)	1,111	(27,489)	4,943	25,501	3,993	(51)
PECO Proposed Rate Revenue	ABC-2	4,854,257	1,677,201	393,301	48,181	1,100,351	69,803	1,450,461	76,928	38,031
Add: Other Revenue	HSG-1	17,744	16,315	4,758	354	385	(68)	(4,914)	(111)	1,026
Total Proposed Revenue		4,872,002	1,693,516	398,059	48,535	1,100,737	69,735	1,445,547	76,817	39,057
Proposed Increase		316,347	146,523	33,369	3,712	91,080	700	40,592	711	(341)
Increase Required to Cost of Service		316,359	158,456	35,771	3,223	96,420	(1,842)	15,892	(1,042)	9,480
Subsidy at Proposed Rates		(12)	(11,933)	(2,402)	489	(5,340)	2,542	24,701	1,753	(9,822)
% Change in Subsidy - PECO Proposed			152%	-27%	-56%	-81%	-49%	-3%	-56%	19072%
PAIEUG Proposed Subsidy	50%	(0)	(2,364)	(1,640)	555	(13,744)	2,471	12,751	1,996	(26)
Increase to Full Cost of Service		316,359	158,456	35,771	3,223	96,420	(1,842)	15,892	(1,042)	9,480
PAIEUG Proposed Increase		316,359	156,092	34,131	3,779	82,675	630	28,642	955	9,455
Present Distribution Revenues	HSG-1	915,062	485,048	90,659	15,198	158,969	12,100	121,796	9,705	21,587
PECO Total Proposed Increase		316,347	146,523	33,369	3,712	91,080	700	40,592	711	(341)
Less: Other Revenue Increase		1,313	958	217	24	114	0	0	-	-
Less: PECO Proposed Trans Increase	ABC-13	26,681	19,381	(409)	264	3,525	597	2,151	1,619	(448)
PECO Proposed Dist Increase		288,352	126,184	33,561	3,425	87,440	103	38,441	(908)	107
Proposed % Dist Increase		31.5%	26.0%	37.0%	22.5%	55.0%	0.9%	31.6%	-9.4%	0.5%
PAIEUG Total Proposed Increase		316,359	156,092	34,131	3,779	82,675	630	28,642	955	9,455
Less: Other Revenue Increase		1,313	958	217	24	114	0	0	-	-
Less: PECO Proposed Trans Increase		26,681	19,381	(409)	264	3,525	597	2,151	1,619	(448)
PAIEUG Proposed Dist Increase		288,365	135,753	34,323	3,492	79,036	32	26,491	(665)	9,903
Proposed % Dist Increase		31.5%	28.0%	37.9%	23.0%	49.7%	0.3%	21.8%	-6.8%	45.9%

PECO Energy Company (Electric)
Future Test Year 2010
Class Cost of Service Study ($000s)
TOTAL DISTRIBUTION REVENUE REQUIREMENT - AVERAGE EARNED RATE OF RETURN

Account Description	Total Dollars	Residential	Residential Heating	Off Peak	General Service	Primary Distribution	High Tension	Electric Propulsion	Lighting
REVENUE REQUIREMENTS									
Target Rate of Return	3.641%	3.641%	3.641%	3.641%	3.641%	3.641%	3.641%	3.641%	3.641%
Rate Base	3,236,437	1,519,025	346,573	34,584	737,619	32,528	437,150	30,968	97,991
Operating expenses	3,920,203	1,272,005	304,252	36,192	899,989	57,384	1,257,803	65,083	27,495
Uncollectibles expense	67,793	49,447	11,209	1,219	5,895	1	22	0	0
Depreciation expense	127,752	60,675	13,202	1,930	30,735	1,129	14,350	1,034	4,697
Regulatory Commission Expenses	14,568	4,962	1,177	140	3,317	205	4,411	231	126
General taxes / Other	25,505	12,773	2,718	282	5,538	232	2,969	214	780
Subtotal- Operating Costs to recover	4,155,821	1,399,861	332,558	39,762	945,475	58,950	1,279,555	66,561	33,098
Target Return on Rate Base- After taxes	117,854	55,315	12,620	1,259	26,860	1,185	15,919	1,128	3,568
Income taxes to recover	17,049	8,002	1,826	182	3,886	171	2,303	163	516
Subtotal- Rev Req before GRT	4,290,724	1,463,178	347,004	41,204	976,221	60,306	1,297,777	67,852	37,183
GRT needed	264,931	88,542	20,966	2,508	60,925	3,785	81,677	4,261	2,267
TOTAL REVENUE REQUIREMENT	4,555,655	1,551,721	367,969	43,712	1,037,145	64,092	1,379,453	72,113	39,450
Revenue at Present rates	4,555,655	1,546,993	364,690	44,823	1,009,657	69,034	1,404,955	76,106	39,398
Subsidy at Present Rates	(0)	(4,728)	(3,280)	1,111	(27,489)	4,943	25,501	3,993	(51)

Date	Hour	Class	CP KW	Date	Hour	Class	NCP KW	Month	Class	KWh
1/16/2009	19	EP	173282.72	1/16/2009	8	EP	188622.81	1/1/2009	EP	72497730.21
1/16/2009	19	GS	1471240.8	1/16/2009	10	GS	1763420.9	1/1/2009	GS	814070662.3
1/16/2009	19	HT	1948098.1	1/16/2009	11	HT	2133377.4	1/1/2009	HT	1344541449
1/16/2009	19	OP	50699.86	1/16/2009	21	RH	1174277.9	1/1/2009	OP	35920266.17
1/16/2009	19	PD	86679.54	1/19/2009	7	SLE	20279.77	1/1/2009	PD	59521074.12
1/16/2009	19	POL	3494.1	1/19/2009	7	SLP	21059.24	1/1/2009	POL	1502527.91
1/16/2009	19	R	2031268.3	1/19/2009	7	SLS	2102.43	1/1/2009	R	1068054090
1/16/2009	19	RH	944060.7	1/19/2009	8	TL	4815.36	1/1/2009	RH	490408072.9
1/16/2009	19	SLE	13412.64	1/19/2009	19	R	2238170.1	1/1/2009	SLE	6422208.61
1/16/2009	19	SLP	13928.16	1/28/2009	12	PD	112102.15	1/1/2009	SLP	7482003.21
1/16/2009	19	SLS	1390.5	1/30/2009	6	POL	5092.94	1/1/2009	SLS	662607.31
1/16/2009	19	TL	3143.8	1/30/2009	8	OP	111791.44	1/1/2009	TL	2479429.82
2/5/2009	19	EP	157978.92	2/1/2009	6	POL	5340.32	2/1/2009	EP	60210517.12
2/5/2009	19	GS	1341182.3	2/1/2009	6	SLE	19559.86	2/1/2009	GS	707540468.8
2/5/2009	19	HT	1989094.4	2/1/2009	6	SLP	22343.66	2/1/2009	HT	1200280501
2/5/2009	19	OP	63582.21	2/1/2009	6	SLS	2030.58	2/1/2009	OP	31374116.31
2/5/2009	19	PD	85446	2/1/2009	6	TL	4728.3	2/1/2009	PD	53642499.87
2/5/2009	19	POL	3578.08	2/4/2009	8	EP	184968.27	2/1/2009	POL	1486285.46
2/5/2009	19	R	1941659.4	2/5/2009	8	RH	1136735.2	2/1/2009	R	856131163.8
2/5/2009	19	RH	922207.17	2/5/2009	20	R	1993728.9	2/1/2009	RH	338618070.3
2/5/2009	19	SLE	13480.45	2/6/2009	10	GS	1620714.4	2/1/2009	SLE	6199155.35
2/5/2009	19	SLP	15011.08	2/6/2009	10	HT	2120017.4	2/1/2009	SLP	7614761.25
2/5/2009	19	SLS	1392.69	2/18/2009	13	PD	110443.29	2/1/2009	SLS	639723.27
2/5/2009	19	TL	3187.39	2/27/2009	8	OP	122224.18	2/1/2009	TL	2379186.02
3/2/2009	19	EP	163038.71	3/2/2009	11	GS	1472205.7	3/1/2009	EP	66644576.86
3/2/2009	19	GS	1355828.3	3/2/2009	20	R	2023342.1	3/1/2009	GS	714891542.6
3/2/2009	19	HT	1843689.6	3/3/2009	8	EP	174885.06	3/1/2009	HT	1290657337
3/2/2009	19	OP	40636.1	3/3/2009	8	RH	1147017.8	3/1/2009	OP	32157907.75
3/2/2009	19	PD	80127.86	3/5/2009	8	OP	111042.97	3/1/2009	PD	56704487.56
3/2/2009	19	POL	3543.86	3/5/2009	10	HT	2034904	3/1/2009	POL	1600314.41
3/2/2009	19	R	1985093.8	3/6/2009	6	POL	5166.89	3/1/2009	R	855895601.4
3/2/2009	19	RH	827502.19	3/6/2009	6	SLE	19690.65	3/1/2009	RH	301816519.4
3/2/2009	19	SLE	13481.93	3/6/2009	6	SLP	19856.54	3/1/2009	SLE	6819965.78
3/2/2009	19	SLP	13606.37	3/6/2009	6	SLS	2044.83	3/1/2009	SLP	7603528.45
3/2/2009	19	SLS	1400.62	3/6/2009	6	TL	4389.77	3/1/2009	SLS	706377.41
3/2/2009	19	TL	3050.69	3/6/2009	11	PD	103722.38	3/1/2009	TL	2493874.13
4/27/2009	17	EP	114748.96	4/1/2009	8	RH	580446.32	4/1/2009	EP	62410443.62
4/27/2009	17	GS	1587372.6	4/2/2009	6	SLE	17792.34	4/1/2009	GS	656050886.9
4/27/2009	17	HT	2333972.1	4/2/2009	6	SLS	1853	4/1/2009	HT	1279875630
4/27/2009	17	OP	23089.51	4/2/2009	6	TL	4049.11	4/1/2009	OP	27337190.28
4/27/2009	17	PD	111701.3	4/13/2009	6	POL	4898.25	4/1/2009	PD	53501743.65
4/27/2009	17	POL	0	4/13/2009	6	SLP	19231.46	4/1/2009	POL	1525968.03
4/27/2009	17	R	1972563.3	4/15/2009	8	OP	97069.87	4/1/2009	R	771180455.4
4/27/2009	17	RH	322016.87	4/24/2009	18	EP	160363.9	4/1/2009	RH	201212388
4/27/2009	17	SLE	2765.26	4/27/2009	15	HT	2423190.7	4/1/2009	SLE	6107220.44
4/27/2009	17	SLP	3050.38	4/27/2009	19	R	2141097.9	4/1/2009	SLP	7430259.35
4/27/2009	17	SLS	241.49	4/28/2009	15	PD	125424.77	4/1/2009	SLS	637373.9
4/27/2009	17	TL	3166.26	4/28/2009	16	GS	1780090	4/1/2009	TL	2318950.62
5/22/2009	17	EP	130904.63	5/1/2009	6	POL	4519.9	5/1/2009	EP	62872670.5

Date	Hour	Class	CP KW	Date	Hour	Class	NCP KW	Month	Class	KWh
5/22/2009	17	GS	1383527.8	5/1/2009	6	SLP	17356.58	5/1/2009	GS	672875411.3
5/22/2009	17	HT	2123646.3	5/1/2009	13	HT	2256807.3	5/1/2009	HT	1331539378
5/22/2009	17	OP	19130	5/1/2009	18	EP	160870.74	5/1/2009	OP	25561486.99
5/22/2009	17	PD	97549.46	5/4/2009	6	SLE	16669.47	5/1/2009	PD	56619033.59
5/22/2009	17	POL	0	5/4/2009	6	SLS	1744.18	5/1/2009	POL	1500410.5
5/22/2009	17	R	1426595.3	5/5/2009	8	RH	437270.08	5/1/2009	R	804408421.4
5/22/2009	17	RH	198822.02	5/6/2009	8	OP	87469.04	5/1/2009	RH	158336252
5/22/2009	17	SLE	2842.94	5/22/2009	12	PD	113204.47	5/1/2009	SLE	6236261.08
5/22/2009	17	SLP	2966.98	5/25/2009	11	TL	3819.7	5/1/2009	SLP	7256095.71
5/22/2009	17	SLS	246.62	5/25/2009	18	R	1922486.7	5/1/2009	SLS	647215
5/22/2009	17	TL	3197.71	5/28/2009	14	GS	1445529.6	5/1/2009	TL	2356329.29
6/26/2009	17	EP	125288.73	6/5/2009	8	OP	81770.44	6/1/2009	EP	63590699.73
6/26/2009	17	GS	1620525.7	6/10/2009	8	EP	153820.2	6/1/2009	GS	722093068.6
6/26/2009	17	HT	2313831.6	6/13/2009	14	TL	4115.85	6/1/2009	HT	1360723403
6/26/2009	17	OP	16436.1	6/15/2009	6	POL	4542.41	6/1/2009	OP	23567847.45
6/26/2009	17	PD	107762.67	6/15/2009	6	SLE	17769.43	6/1/2009	PD	58838469.78
6/26/2009	17	POL	0	6/15/2009	6	SLP	18533.84	6/1/2009	POL	1424818.94
6/26/2009	17	R	2181612.2	6/15/2009	6	SLS	1832.86	6/1/2009	R	933015705.7
6/26/2009	17	RH	428529.9	6/25/2009	13	HT	2394184.6	6/1/2009	RH	160917525.3
6/26/2009	17	SLE	3080	6/25/2009	16	GS	1807990.6	6/1/2009	SLE	6169707.25
6/26/2009	17	SLP	3212.39	6/25/2009	21	RH	441058.69	6/1/2009	SLP	7207448.74
6/26/2009	17	SLS	265.2	6/26/2009	16	PD	119460.41	6/1/2009	SLS	634144.47
6/26/2009	17	TL	3399.93	6/26/2009	18	R	2338015.6	6/1/2009	TL	2323427.52
7/28/2009	17	EP	121559.68	7/2/2009	18	EP	154985.99	7/1/2009	EP	66777911.86
7/28/2009	17	GS	1814428.8	7/3/2009	8	TL	3792.97	7/1/2009	GS	788388650.8
7/28/2009	17	HT	2333659.4	7/20/2009	8	OP	68423.38	7/1/2009	HT	1451126608
7/28/2009	17	OP	15736.73	7/28/2009	21	RH	532659.11	7/1/2009	OP	22937549.16
7/28/2009	17	PD	111160.89	7/28/2009	22	R	2715386	7/1/2009	PD	61963005.97
7/28/2009	17	POL	0	7/29/2009	14	HT	2483861.8	7/1/2009	POL	1466320.98
7/28/2009	17	R	2599529.6	7/30/2009	15	GS	1906228.8	7/1/2009	R	1180968720
7/28/2009	17	RH	346917.16	7/30/2009	15	PD	123496.82	7/1/2009	RH	186184085
7/28/2009	17	SLE	2645.31	7/31/2009	18	POL	4700.72	7/1/2009	SLE	5717112.53
7/28/2009	17	SLP	2844.92	7/31/2009	18	SLE	16173.45	7/1/2009	SLP	6638789.04
7/28/2009	17	SLS	232.86	7/31/2009	18	SLP	17446.29	7/1/2009	SLS	600087.34
7/28/2009	17	TL	2974.55	7/31/2009	18	SLS	1708.11	7/1/2009	TL	2176681.91
8/10/2009	17	EP	120221.11	8/6/2009	8	OP	72734.91	8/1/2009	EP	67346622.85
8/10/2009	17	GS	1816195.5	8/10/2009	19	R	3264522.4	8/1/2009	GS	844900715.9
8/10/2009	17	HT	2338628	8/16/2009	16	TL	4259.14	8/1/2009	HT	1498959504
8/10/2009	17	OP	20373.51	8/19/2009	18	EP	161125.34	8/1/2009	OP	23465061.87
8/10/2009	17	PD	110294.34	8/20/2009	16	GS	2056211.8	8/1/2009	PD	65951840.78
8/10/2009	17	POL	0	8/21/2009	13	HT	2529787.9	8/1/2009	POL	1131491.22
8/10/2009	17	R	3050273.5	8/21/2009	14	PD	130465.7	8/1/2009	R	1378044736
8/10/2009	17	RH	534764.05	8/21/2009	15	RH	647008.83	8/1/2009	RH	210178847.6
8/10/2009	17	SLE	2594.6	8/22/2009	20	POL	3525.94	8/1/2009	SLE	6474644.98
8/10/2009	17	SLP	2580.15	8/22/2009	20	SLE	18526.42	8/1/2009	SLP	7271327.59
8/10/2009	17	SLS	224.77	8/22/2009	20	SLP	18428.07	8/1/2009	SLS	669346
8/10/2009	17	TL	2865.42	8/22/2009	20	SLS	1920.52	8/1/2009	TL	2438533.44
9/24/2009	15	EP	94776.55	9/11/2009	8	OP	75438.46	9/1/2009	EP	65165970.52
9/24/2009	15	GS	1654510.2	9/21/2009	6	POL	3388.44	9/1/2009	GS	673059865.3

Date	Hour	Class	CP KW
9/24/2009	15	HT	2418754.1
9/24/2009	15	OP	14187.2
9/24/2009	15	PD	116705.56
9/24/2009	15	POL	0
9/24/2009	15	R	1569767.2
9/24/2009	15	RH	194028.08
9/24/2009	15	SLE	0
9/24/2009	15	SLP	3127.53
9/24/2009	15	SLS	0
9/24/2009	15	TL	3147.37
10/15/2009	20	EP	93648.75
10/15/2009	20	GS	1010846.8
10/15/2009	20	HT	1818914.7
10/15/2009	20	OP	55612.23
10/15/2009	20	PD	75373.61
10/15/2009	20	POL	2737.61
10/15/2009	20	R	1696825.2
10/15/2009	20	RH	463467.99
10/15/2009	20	SLE	13066.41
10/15/2009	20	SLP	14611.98
10/15/2009	20	SLS	1378.72
10/15/2009	20	TL	2923.24
11/30/2009	18	EP	135000.76
11/30/2009	18	GS	1088041.1
11/30/2009	18	HT	1918451.1
11/30/2009	18	OP	21663.17
11/30/2009	18	PD	83291.98
11/30/2009	18	POL	2673.78
11/30/2009	18	R	1755878.7
11/30/2009	18	RH	407716.15
11/30/2009	18	SLE	14951.13
11/30/2009	18	SLP	13938.97
11/30/2009	18	SLS	1508.99
11/30/2009	18	TL	2957.53
12/29/2009	19	EP	139877.42
12/29/2009	19	GS	1400658.1
12/29/2009	19	HT	1832396
12/29/2009	19	OP	57070.52
12/29/2009	19	PD	71988.34
12/29/2009	19	POL	2152.87
12/29/2009	19	R	1930167.4
12/29/2009	19	RH	920488.5
12/29/2009	19	SLE	10703.89
12/29/2009	19	SLP	11362.62
12/29/2009	19	SLS	1119.47
12/29/2009	19	TL	2302.52

Date	Hour	Class	NCP KW
9/21/2009	6	SLE	17124.1
9/21/2009	6	SLP	18030.36
9/21/2009	6	SLS	1781.75
9/21/2009	6	TL	3628.94
9/23/2009	22	R	1943177
9/24/2009	15	HT	2418754.1
9/24/2009	15	PD	116705.56
9/24/2009	16	GS	1700232.7
9/24/2009	18	EP	160473.3
9/28/2009	20	RH	393931.69
10/9/2009	14	HT	2210844.6
10/18/2009	20	R	1784409
10/19/2009	6	POL	3532.9
10/19/2009	6	SLE	16858.6
10/19/2009	6	SLP	18850.26
10/19/2009	6	SLS	1778.9
10/19/2009	6	TL	3771.13
10/20/2009	8	RH	563326.36
10/20/2009	18	EP	170377.54
10/28/2009	11	PD	98189.63
10/28/2009	13	GS	1317555.4
10/30/2009	8	OP	90719.76
11/4/2009	8	RH	560740.65
11/10/2009	14	HT	2046146.9
11/10/2009	18	EP	163267.09
11/13/2009	6	POL	3471.06
11/13/2009	6	SLE	18911.59
11/13/2009	6	SLP	17551.36
11/13/2009	6	SLS	1910.47
11/13/2009	6	TL	3739.96
11/13/2009	8	OP	88208.39
11/13/2009	12	GS	1343804.4
11/13/2009	12	PD	96585.24
11/22/2009	19	R	1865404
12/9/2009	10	PD	95751.29
12/11/2009	11	HT	2070658.4
12/13/2009	3	POL	3193.23
12/13/2009	7	SLE	16758.83
12/13/2009	7	SLP	17787.37
12/13/2009	7	SLS	1751.72
12/13/2009	7	TL	3604.43
12/20/2009	19	R	2305032
12/23/2009	8	EP	177578.71
12/23/2009	8	OP	96719.2
12/30/2009	4	RH	930818.47
12/31/2009	12	GS	1704165.3

Month	Class	KWh
9/1/2009	HT	1331316934
9/1/2009	OP	21646797.93
9/1/2009	PD	55460637.69
9/1/2009	POL	1057293.91
9/1/2009	R	833335245.6
9/1/2009	RH	146599709.3
9/1/2009	SLE	6007277.17
9/1/2009	SLP	7044010.27
9/1/2009	SLS	621157.13
9/1/2009	TL	2152337.51
10/1/2009	EP	66527817.91
10/1/2009	GS	648408105.9
10/1/2009	HT	1323771481
10/1/2009	OP	24728957.4
10/1/2009	PD	52950484.32
10/1/2009	POL	1146530.75
10/1/2009	R	791401759.3
10/1/2009	RH	188269373.9
10/1/2009	SLE	6105170.82
10/1/2009	SLP	7503566.16
10/1/2009	SLS	640617.34
10/1/2009	TL	2235351.31
11/1/2009	EP	60239109.49
11/1/2009	GS	632362304.8
11/1/2009	HT	1237042784
11/1/2009	OP	26372466.64
11/1/2009	PD	50219268.09
11/1/2009	POL	1068506.67
11/1/2009	R	825018138.5
11/1/2009	RH	219908056.8
11/1/2009	SLE	6421018.73
11/1/2009	SLP	6619449.94
11/1/2009	SLS	648622.48
11/1/2009	TL	2078689.22
12/1/2009	EP	70906882
12/1/2009	GS	806922140.5
12/1/2009	HT	1315008373
12/1/2009	OP	31701324.98
12/1/2009	PD	53454041.77
12/1/2009	POL	1029976.99
12/1/2009	R	1008026110
12/1/2009	RH	383847248.7
12/1/2009	SLE	5711166.95
12/1/2009	SLP	6654098.75
12/1/2009	SLS	593967.05
12/1/2009	TL	1986806.27

5050.120

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Via Overnight Mail

January 8, 2009

Arizona Corporation Commission
Attn: Docket Filing Window
1200 Washington Street
Phoenix, AZ 85007

Re: Docket No. E-01345A-08-0172

Dear Sir or Madam:

Please find enclosed the original and thirteen (13) copies of the DIRECT TESTIMONY AND EXHIBITS OF STEPHEN J. BARON on behalf of THE KROGER CO. filed in the above-referenced matter.

All parties of record have been served. Please place this document of file.

Very Truly Yours,

Michael L. Kurtz, Esq.
Kurt J. Boehm, Esq.
BOEHM, KURTZ & LOWRY

John William Moore, Jr.,
Arizona Bar No. 021942

MLKkew
Attachments

G:\WORK\MLK\KROGER\ARIZONA\E-01345A-08-0172 (Arizona Public Service Co.)\Commission ltr.doc

CERTIFICATE OF SERVICE

I hereby certify that true copy of the foregoing was served by regular U.S. mail (unless otherwise noted), this 8TH day of January, 2009 on the parties listed on the attached service list.

Company	Contact	Address
	Nicholas Enoch	349 N. Fourth Ave. Phoenix, Arizona 85003
	Cynthia Zwick	1940 E. Luke Avenue Phoenix, Arizona 85016
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Michael L. Kurtz, Esq.
Kurt J. Boehm, Esq.

BEFORE THE

ARIZONA CORPORATION COMMISSION

Mike Gleason, Chairman
William A. Mundell
Jeff Hatch-Miller
Kristin K. Mayes
Gary Pierce

IN THE MATTER OF THE APPLICATION OF	)
ARIZONA PUBLIC SERVICE COMPANY FOR	)
A HEARING TO DETERMINE THE FAIR VALUE	)
OF THE UTILITY PROPERTY OF THE COMPANY	) Docket No. E-01345A-08-0172
FOR RATEMAKING PURPOSES, TO FIX A JUST	)
AND REASONABLE RATE OF RETURN	)
THEREON, TO APPROVE RATE SCHEDULES	)
DESIGNED TO DEVELOP SUCH RETURN	)

DIRECT TESTIMONY

AND EXHIBITS

OF

STEPHEN J. BARON

ON BEHALF OF THE

KROGER CO.

J. KENNEDY AND ASSOCIATES, INC.
ROSWELL, GEORGIA

January 2009

BEFORE THE

ARIZONA CORPORATION COMMISSION

IN THE MATTER OF THE APPLICATION OF ARIZONA PUBLIC SERVICE COMPANY FOR A HEARING TO DETERMINE THE FAIR VALUE OF THE UTILITY PROPERTY OF THE COMPANY FOR RATEMAKING PURPOSES, TO FIX A JUST AND REASONABLE RATE OF RETURN THEREON, TO APPROVE RATE SCHEDULES DESIGNED TO DEVELOP SUCH RETURN	**))))))))**	**Docket No. E-01345A-08-0172**

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BEFORE THE

ARIZONA CORPORATION COMMISSION

IN THE MATTER OF THE APPLICATION OF ARIZONA PUBLIC SERVICE COMPANY FOR A HEARING TO DETERMINE THE FAIR VALUE OF THE UTILITY PROPERTY OF THE COMPANY FOR RATEMAKING PURPOSES, TO FIX A JUST AND REASONABLE RATE OF RETURN THEREON, TO APPROVE RATE SCHEDULES DESIGNED TO DEVELOP SUCH RETURN	**) Docket No. E-01345A-08-0172**

DIRECT TESTIMONY OF STEPHEN J. BARON

I. INTRODUCTION

Q. Please state your name and business address.

A. My name is Stephen J. Baron. My business address is J. Kennedy and Associates, Inc. ("Kennedy and Associates"), 570 Colonial Park Drive, Suite 305, Roswell, Georgia 30075.

Q. What is your occupation and by who are you employed?

A. I am the President and a Principal of Kennedy and Associates, a firm of utility rate, planning, and economic consultants in Atlanta, Georgia.

Q. Please describe briefly the nature of the consulting services provided by Kennedy and Associates.

A. Kennedy and Associates provides consulting services in the electric and gas utility industries. Our clients include state agencies and industrial electricity consumers. The firm provides expertise in system planning, load forecasting, financial analysis, cost-of-service, and rate design. Current clients include the Georgia and Louisiana Public Service Commissions, and industrial consumer groups throughout the United States.

Q. Please state your educational background.

A. I graduated from the University of Florida in 1972 with a B.A. degree with high honors in Political Science and significant coursework in Mathematics and Computer Science. In 1974, I received a Master of Arts Degree in Economics, also from the University of Florida. My areas of specialization were econometrics, statistics, and public utility economics. My thesis concerned the development of an econometric model to forecast electricity sales in the State of Florida, for which I received a grant from the Public Utility Research Center of the University of Florida.

In addition, I have advanced study and coursework in time series analysis and dynamic model building.

Q. Please describe your professional experience.

A. I have more than thirty years of experience in the electric utility industry in the areas of cost and rate analysis, forecasting, planning, and economic analysis.

Following the completion of my graduate work in economics, I joined the staff of the Florida Public Service Commission in August of 1974 as a Rate Economist. My responsibilities included the analysis of rate cases for electric, telephone, and gas utilities, as well as the preparation of cross-examination material and the preparation of staff recommendations.

In December 1975, I joined the Utility Rate Consulting Division of Ebasco Services, Inc. as an Associate Consultant. In the seven years I worked for Ebasco, I received successive promotions, ultimately to the position of Vice President of Energy Management Services of Ebasco Business Consulting Company. My responsibilities included the management of a staff of consultants engaged in providing services in the areas of econometric modeling, load and energy forecasting, production cost modeling, planning, cost-of-service analysis, cogeneration, and load management.

I joined the public accounting firm of Coopers & Lybrand in 1982 as a Manager of the Atlanta Office of the Utility Regulatory and Advisory Services Group. In this capacity I was responsible for the operation and management of the Atlanta office. My duties included the technical and administrative supervision of the staff, budgeting, recruiting, and marketing as well as project management on client engagements. At Coopers & Lybrand, I specialized in utility cost analysis, forecasting, load analysis, economic analysis, and planning.

In January 1984, I joined the consulting firm of Kennedy and Associates as a Vice President and Principal. I became President of the firm in January 1991.

During the course of my career, I have provided consulting services to more than thirty utility, industrial, and Public Service Commission clients, including three international utility clients.

I have presented numerous papers and published an article entitled "How to Rate Load Management Programs" in the March 1979 edition of "Electrical World." My article on "Standby Electric Rates" was published in the November 8, 1984 issue of "Public Utilities Fortnightly." In February of 1984, I completed a detailed analysis entitled "Load Data Transfer Techniques" on behalf of the Electric Power Research Institute, which published the study.

I have presented testimony as an expert witness in Arizona, Arkansas, Colorado, Connecticut, Florida, Georgia, Indiana, Kentucky, Louisiana, Maine, Michigan, Minnesota, Maryland, Missouri, New Jersey, New Mexico, New York, North Carolina, Ohio, Pennsylvania, Texas, Virginia, West Virginia, Wisconsin; before the Federal Energy Regulatory Commission and in United States Bankruptcy Court. A list of my specific regulatory appearances can be found in Baron Exhibit ____ (SJB-1).

Q. Have you previously presented testimony before the Arizona Corporation Commission?

A. Yes. I presented testimony in two previous Arizona Public Service Company rate cases on behalf of Kroger Co. in 2004 and in 2006 (Docket Nos. E-01345-03-0437 and E-01345A-05-0816). I also presented testimony in two Tucson Electric Power Company proceedings; in 1981 on behalf of the Commission (Docket No. U-1933I) and in 2008 on behalf of Kroger Co. (Docket No. E-01933A-07-0402).

Q. On whose behalf are you testifying in this proceeding?

A. I am testifying on behalf of the Kroger Co. Kroger has approximately 36 stores in the APS service territory operating under the names Fry's, Fred Meyer and Smith's. These stores consume in excess of 100 million kWhs per year on the APS system.

Q. What is the purpose of your testimony?

A. I will be presenting testimony on the Company's class cost of service study, the allocation of the proposed revenue increase to rate schedules and APS's proposal to disaggregate the E-32 General Service rate into 4 separate rates.

In general, though I believe that the 4 Coincident Peak class cost of service methodology used by APS in prior cases is more appropriate for allocating costs to rate classes, I accept the Company's Average and Excess Demand method in this case.[1] However, as I will discuss, the Company's cost study shows that there are substantial differences between the rates paid by some customers and the cost to provide service. In particular, residential customers are currently receiving very substantial dollar subsidies from general service customers. Despite this finding, the Company's proposed increases to its Residential and General Service rate classes do not provide a material level of mitigation to this disparity between cost of service and rates. I will address this issue and recommend that the Commission adopt a

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[1] Kroger is not presenting testimony on the Company's requested revenue increase in this case. For purposes of my testimony, I have utilized the APS requested increase of $448 million. This should not be construed as an endorsement of the Company's requested increase.

specific level of subsidy reduction, based on the class cost of service results, in its determination of the increases to each rate schedule.

With regard to rate design, I will discuss the APS's proposed revisions to rate E-32; specifically the proposal to disaggregate the rate by kW demand levels. As I will discuss, Kroger supports the Company's proposed E-32 rate design and recommends that the Commission adopt it in this case.

Q. Would you please summarize your recommendations?

A. Yes.

- **For the purposes of assessing the reasonableness of the Company's proposed allocation of the revenue increase to rate schedule in this case, APS' proposal to use an Average and Excess Demand ("AED") class cost of service method is reasonable. The AED method is a traditional cost of service method that recognizes the role of both customer kW demand and energy in cost causation. Unlike other weighted demand and energy methodologies, the AED method gives a reasonable weighting to the importance of class demands in the allocation of the system's fixed production costs to rate classes.**

- **Though APS has given some recognition to the cost of service results in its proposed rate schedule increases in this case, it is appropriate to make some additional progress towards eliminating the subsidies contained in present rates in this case. A reasonable and balanced approach would be to reduce class subsidies by 25% as a means of moving towards the objective of setting rates based on cost of service. Eliminating 25% of the subsidy would result in an increase to residential customers of $259.9 million (19.3%), while producing a $180.0 million increase (14.5%) to the general service class if the full increase proposed by APS were adopted.**

- **APS is proposing to disaggregate its Rate E-32 into four separate rates delineated by kW demand levels. The Company's proposal is reasonable and should be adopted by the Commission. Because load characteristics are different for these General Service customers, the Company's proposal provides a more reasonable rate design that reflects cost of service and reduces intra-class subsidies among General Service customers.**

II. REVENUE ALLOCATION AND COST OF SERVICE

Q. Have you reviewed the Company's 12 month ending December 2007 test year cost of service study filed in this proceeding?

A. Yes. The Company is utilizing a traditional Average and Excess Demand ("AED") class cost of service study in this proceeding to allocate production related demand costs. In prior cases, APS has used a 4 CP allocation method because of the pronounced demands on the system during the summer months.[2] In the prior two APS base rate cases, I supported the Company's use of the 4 CP method and continue to do so in this case. The fact that the Company is continuing to rely on the 4 CP methodology to allocate jurisdictional costs indicates that it is an appropriate methodology for APS, given the load characteristics of the system and the significance of summer peak loads on generation costs.

Q. Do you believe that the Company's proposal to use the AED method for retail class cost of service allocation provides a reasonable basis to evaluate the relationship between the rates being charged each rate class and the underlying cost of providing service to these customers?

[2] APS is continuing to use a 4 CP methodology in its jurisdictional cost allocation study in this case.

A. Yes, it is appropriate to use for the purpose of assessing the reasonableness of the Company's proposed allocation of the revenue increase to rate schedule in this case. The AED method is a traditional cost of service method that recognizes the role of both customer kW demand and energy in cost causation. Unlike other weighted demand and energy methodologies, the AED method gives a reasonable weighting to the importance of class demands in the allocation of the system's fixed production costs to rate classes.

Q. How should the results of the Company's class cost of service study be used in this case?

A. The purpose of an embedded, fully allocated class cost of service study is to assess the reasonableness of a utility's rates, in relation to the underlying cost of providing service to the customers on each rate class. As a matter of policy, it is both efficient and equitable to establish rates on the basis of the cost of service and, to the extent feasible, to move rates towards cost of service in a rate case in which a utility is requesting a change in revenues. In other words, a rate case, such as the current APS proceeding, is an opportunity to evaluate the Company's rates and make incremental adjustments so that, over time, each class will pay rates reflecting cost of service. In so doing, rates paid by each customer will provide efficient "price signals" reflecting the resource cost of meeting customer demands. In addition, cost based rates provide an equitable basis to assign the Company's overall revenue requirement to customers. In this manner, customers in one rate class do not pay or receive unjustified monetary subsidies from other rate customers.

Q. How do the Company's current rates compare to the underlying cost of service?

A. A good measure of this rate versus cost relationship is the relative class rates of return at present rates. This measurement, which is the ratio of a class's rate of return relative to the average retail earned rate of return, provides a good summary of the rate versus cost relationship, based on the results of the Company's AED cost of service study.

Q. What are the relative class rate of return results produced by the Company's test year AED cost of service study?

A. The table below summarizes the rates of return and the relative rate of return indices ("ROR Index") for each of the major rate classes using the results of the Company's AED study.

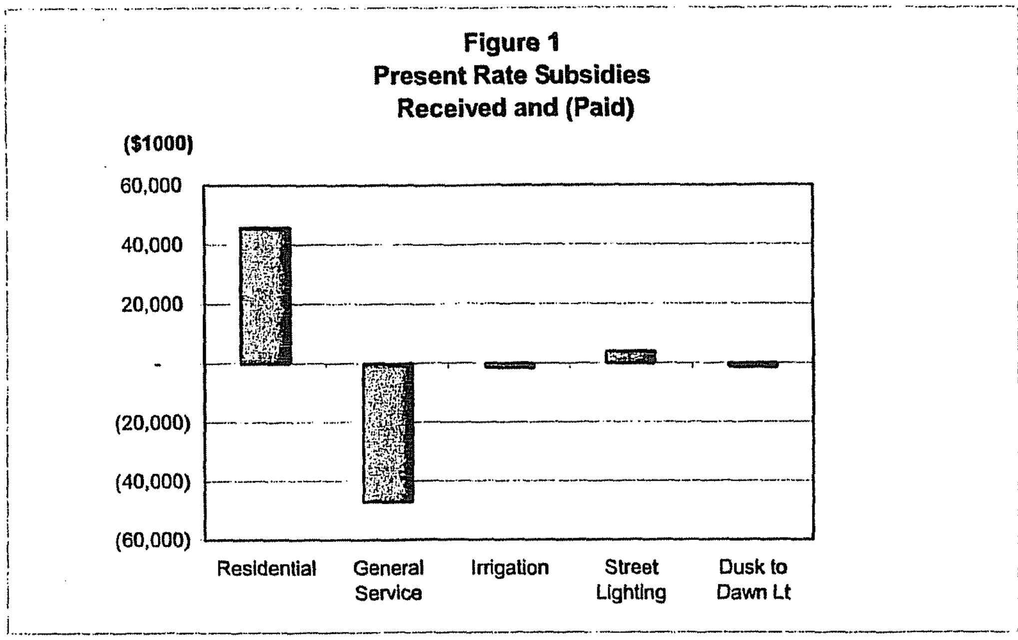
TABLE 1
Comparison of Relative Rates of Return
Average and Excess Demand Cost of Service Study
Present Rates

Class	Rate of Return	ROR Index
Residential	2.85%	0.75
General Svc	5.04%	1.33
E-20 (Church Rate)	-0.82%	(0.22)
E-32 TOU	5.93%	1.56
E-30, E-32 (0-20 kW)	3.53%	0.93
E-32 (21-100 kW)	5.67%	1.50
E-32 (101-400 kW)	5.87%	1.55
E-32 (401+ kW)	6.57%	1.73
E-34	3.48%	0.92
E-35	-0.50%	(0.13)
Irrigation	6.91%	1.82
Street Light	-0.03%	(0.01)
Dusk to Dawn	6.61%	1.74
Total Retail	3.79%	1.00

Based on these results, the residential class is paying only 75% of its allocated cost of service under present rates, while general service customers are paying a relative rate of return that is approximately 130% of the system average. This is a substantial difference and one that should be addressed in this rate proceeding. More significantly, within the General Service rate class, customers on rate schedules E-32 (M) and E-32 (L) are paying significantly higher subsidies than the General Service class as a whole. As can be seen, customers on E-32 M (101 to 400 kW demands) and E-32 L (greater than 400 kW demands) are paying relative rates of return at present rates of 155% and 173% of the system average.

Q. Have you computed the dollar subsidies being paid and received by each rate class at present rates, based on the results of the Company's cost of service study?

A. Yes. Figure 1 below shows the dollar subsidies paid and received at present rates. As can be seen, the residential class is receiving (shown as a positive value) over $45 million in subsidies at present rate from other rate classes. At the same time, general service customers pay annual subsidies of over $46 million. These results are based on the Company's filed AED class cost of service study, without any adjustments. These subsidies have actually grown over time, since the Company's last base rate case.



Q. Has APS made rate spread proposals in this case that adequately address the substantial disparities between present rates and cost of service?

A. Not in my opinion. APS is proposing to increase General Service rates at a ¼ of 1% lower percentage rate than the system average, while increasing the Residential class at a rate ¼ of 1% higher than the system average. This proposal does nothing to address the significant disparities between rates and cost of service. In fact, the Company's proposal makes matters worse. The Company is essentially proposing a uniform percentage increase for the residential and general service classes, which comprise about 98% of base revenues. This is despite the fact that the Company's own cost of service study shows that residential customers are currently paying substantially less than cost of service. Table 2 shows the proposed percentage rate increases recommended by APS in this proceeding and the resulting dollar subsidies that will exist at proposed rates. Despite the substantial variation in relative rate of return and the concomitant subsidies being paid by general service customers, APS is recommending that the subsidies paid by general service customers be increased.

TABLE 2
Proposed Increases and Subsidies
Average and Excess Demand Cost of Service Study

Class	Proposed % Increase	Proposed Subsidy
Residential	17.27%	60,190
General Svc	16.74%	(63,713)
E-20 (Church Rate)	20.20%	1,115
E-32 TOU	16.71%	(1,380)
E-30, E-32 (0-20 kW)	18.67%	5,038
E-32 (21-100 kW)	16.58%	(15,599)
E-32 (101-400 kW)	16.22%	(21,513)
E-32 (401+ kW)	15.74%	(30,120)
E-34	16.50%	(2,836)
E-35	18.69%	1,582
Irrigation	12.30%	(2,150)
Street Light	19.41%	6,064
Dusk to Dawn	19.36%	(391)
Total Retail	16.99%	

Figure 2 below shows the present and proposed dollar subsidies being recommended by APS in this case. APS is proposing to increase the subsidies received by residential customers by close to $15 million, and to increase the subsidies paid by general service customers by an equal amount.

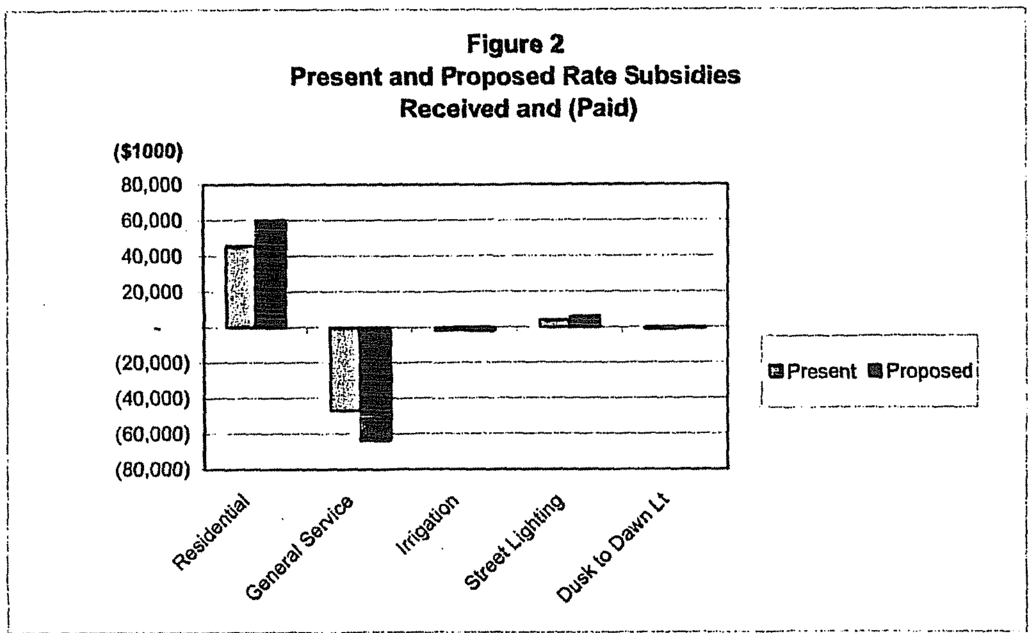


Figure 2
Present and Proposed Rate Subsidies
Received and (Paid)

Q. Are you recommending that proposed rates in this case be set at cost of service to eliminate all subsidies?

A. No. I recognize that this would not be realistic, given the impact on residential customers. It would also be inconsistent with the regulatory concept of gradualism. Though this would be an ideal result and one that should be recognized as a longer-term goal in future rate proceedings, I am not recommending the elimination of all subsidies in this proceeding. However, there is no justification for increasing the disparities, given the existing situation. Some mitigation of the subsidies should be made in this case.

If the cost of service study is used directly to allocate the requested $450 million increase, residential customers would be assigned a $293 million increase (22%), while general service customers would receive a $144 million increase (12%). This is the result that would be obtained if 100% of the current subsidies were eliminated in this proceeding.

At the same time, it is unreasonable to completely ignore the results of the Company's cost of service study (and other cost of service analyses prepared by the Company in response to data requests).

Q. In light of the impact on residential customers of completely eliminating the subsidies in this proceeding, do you have an alternative recommendation that would recognize the results of the Company's cost of service study in allocating the increase?

A. Yes. I believe that it is appropriate to make some progress towards eliminating the subsidies contained in present rates in this case. A reasonable and balanced approach would be to reduce class subsidies by 25% as a means of moving towards the objective of setting rates based on cost of service. The analysis presented in

Exhibit ___(SJB-2) shows the results of a 25% subsidy reduction in the allocation of the requested $448 million increase. As can be seen in the third "box" in Exhibit ___(SJB-2), eliminating 25% of the subsidy would result in an increase to residential customers of $259.9 million (19.3%), while producing a $180.0 million increase (14.5%) to the general service class. A 25% subsidy reduction criterion for allocating the approved revenue requirement increase in this case would still result in proposed rates that contain substantial subsidies, though these subsidies will be reduced going forward. Subsequent rate cases should be used to further reduce subsidies in future periods.

Q. **Are you also proposing that this "25% subsidy reduction" methodology be extended to include each of the General Service Rate schedules?**

A. Yes. Baron Exhibit__(SJB-3) contains the results for the individual General Service rate schedules. The total for the General Service rate schedule increases equals the amount for the General Service class shown in Exhibit__(SJB-2).

Table 3 summarizes the proposed increases for each major rate class and the individual General Service Rate schedules that I am recommending (assuming that the Company received its full rate request). Also shown are the remaining subsidies that will be received and paid, after the 25% reduction at proposed rates.

TABLE 3
Kroger Proposed Increases and Subsidies
25% Subsidy Reduction

Class	Proposed Increase	Proposed % Increase
Residential	259,938	19.30%
General Svc	180,229	14.53%
E-20 (Church Rate)	660	20.21%
E-32 TOU	1,870	12.12%
E-30, E-32 (0-20 kW)	36,443	20.96%
E-32 (21-100 kW)	43,269	15.83%
E-32 (101-400 kW)	39,834	13.62%
E-32 (401+ kW)	35,168	11.46%
E-34	10,918	12.73%
E-35	12,068	13.53%
Irrigation	2,148	8.46%
Street Light	4,428	25.49%
Dusk to Dawn	1,451	19.36%
Total Retail	448,193	16.99%

Q. Does your recommended methodology reflect any adjustments to mitigate the impact on specific rate classes?

A. Yes. The increases recommended in Exhibits__(SJB-3) and (SJB-3), as well as Table 3 reflect a "capping" of the increase to the Street Light at 1.5 times the system average percentage increase and setting the increase for the Dusk to Dawn rate class at the level proposed by the Company, which already reflected a substantial decrease in the subsidies paid by this rate class.[3] Finally, within the General Service rate class, I have adopted the Company's proposed increase for "Rate E-20 Church Rate."

Q. Have you developed any alternative recommendation for the allocation of the revenue increase, in the event that the Commission does not elect to reduce intra-class subsidies by 25%, as you have proposed?

A. Yes. My alternative recommendation is to adopt the Company's proposed intra-class revenue increase allocation (rate spread), and apply a 25% subsidy reduction allocation only within the General Service class. Effectively, under this alternative recommendation, the increases to each major rate class would be the APS proposed increases shown in my Table 2 (e.g., General Service as a whole would receive an increase of 16.74%).

However, within the General Service rate class, the Company's proposed increases to individual rate schedules would be adjusted so that dollar subsidies, relative to the entire General Service class, are reduced by 25%.

[3] Without this adjustment, the Dusk to Dawn lighting class would have received a very large increase, even though it is paying subsidies at present rates. This occurs because of the relationship between revenues and rate base for this class (the ratio of revenues to rate base for this class is very low, compared to the retail average relationship). APS has proposed a substantial elimination of the current subsidy paid by this class.

Baron Exhibit__(SJB-4) shows the results on this analysis, while Table 4 presents the increases to each General Service rate. As can be seen, the overall General Service increase remains at the same level as proposed by APS.[4]

TABLE 4
Kroger Proposed Increases and Subsidies
General Service Class Only - 25% Subsidy Reduction

Class	Proposed Increase	Proposed % Increase
General Svc	207,600	16.74%
E-20 (Church Rate)	660	20.20%
E-32 TOU	2,169	14.06%
E-30, E-32 (0-20 kW)	41,586	23.92%
E-32 (21-100 kW)	50,078	18.32%
E-32 (101-400 kW)	46,172	15.79%
E-32 (401+ kW)	40,986	13.35%
E-34	12,456	14.53%
E-35	13,493	15.12%

Q. What is your recommendation for allocating the revenue increase if the Company is authorized a lower increase than it is requesting in this case?

A. The recommended dollar increases to each rate class shown in exhibit__(SJB-2) should be reduced on an equal percentage basis.

[4] I have also made no change to the Company's proposed increase to rate schedule E-20 (Church Rate).

III. RATE E-32 RATE DESIGN

Q. Have you reviewed APS' proposal to disaggregate Rate E-32 into four separate rates based on kW demand levels?

A. Yes. I have reviewed the Company's proposal and support the proposed separation in four new rates, delineated by kW demand levels. As noted in the testimony of Company witness DeLizio on page 28 of his testimony, the disaggregated rates provide a better matching of cost of service and rate design for General Service customers.

Q. Mr. Delizio states on page 29 of his testimony that the disaggregated E-32 rates were developed to moderate the impact of the redesign. Do you agree with the Company's proposal on this issue?

A. Though I agree that the disaggregated E-32 rate design should consider the impact on the individual new rates, as I discussed in the prior section of my testimony, the mitigation proposed by the Company in its design does not adequately reduce intra-General Service class subsidies. Such subsidies should be reduced by 25% in this case, as I discussed previously.

Q. Does that complete your testimony?

A. Yes.

BEFORE THE

ARIZONA CORPORATION COMMISSION

IN THE MATTER OF THE APPLICATION OF	**)**	
ARIZONA PUBLIC SERVICE COMPANY FOR	**)**	
A HEARING TO DETERMINE THE FAIR VALUE	**)**	
OF THE UTILITY PROPERTY OF THE COMPANY	**)**	**Docket No. E-01345A-08-0172**
FOR RATEMAKING PURPOSES, TO FIX A JUST	**)**	
AND REASONABLE RATE OF RETURN	**)**	
THEREON, TO APPROVE RATE SCHEDULES	**)**	
DESIGNED TO DEVELOP SUCH RETURN	**)**	

EXHIBIT__(SJB-1)

OF

STEPHEN J. BARON

ON BEHALF OF THE

KROGER CO.

Expert Testimony Appearances
of
Stephen J. Baron
As of December 2008

Date	Case	Jurisdict.	Party	Utility	Subject
4/81	203(B)	KY	Louisville Gas & Electric Co.	Louisville Gas & Electric Co.	Cost-of-service.
4/81	ER-81-42	MO	Kansas City Power & Light Co.	Kansas City Power & Light Co.	Forecasting.
6/81	U-1933	AZ	Arizona Corporation Commission	Tucson Electric Co.	Forecasting planning.
2/84	8924	KY	Airco Carbide	Louisville Gas & Electric Co.	Revenue requirements, cost-of-service, forecasting, weather normalization.
3/84	84-038-U	AR	Arkansas Electric Energy Consumers	Arkansas Power & Light Co.	Excess capacity, cost-of-service, rate design.
5/84	830470-EI	FL	Florida Industrial Power Users' Group	Florida Power Corp.	Allocation of fixed costs, load and capacity balance, and reserve margin. Diversification of utility.
10/84	84-199-U	AR	Arkansas Electric Energy Consumers	Arkansas Power and Light Co.	Cost allocation and rate design.
11/84	R-842651	PA	Lehigh Valley Power Committee	Pennsylvania Power & Light Co.	Interruptible rates, excess capacity, and phase-in.
1/85	85-65	ME	Airco Industrial Gases	Central Maine Power Co.	Interruptible rate design.
2/85	I-840381	PA	Philadelphia Area Industrial Energy Users' Group	Philadelphia Electric Co.	Load and energy forecast.
3/85	9243	KY	Alcan Aluminum Corp., et al.	Louisville Gas & Electric Co.	Economics of completing fossil generating unit.
3/85	3498-U	GA	Attorney General	Georgia Power Co.	Load and energy forecasting, generation planning economics.
3/85	R-842632	PA	West Penn Power Industrial Intervenors	West Penn Power Co.	Generation planning economics, prudence of a pumped storage hydro unit.
5/85	84-249	AR	Arkansas Electric Energy Consumers	Arkansas Power & Light Co.	Cost-of-service, rate design return multipliers.
5/85		City of Santa	Chamber of Commerce	Santa Clara Municipal	Cost-of-service, rate design.

Expert Testimony Appearances
of
Stephen J. Baron
As of December 2008

Date	Case	Jurisdict.	Party	Utility	Subject
6/85	84-768-E-42T	Clara WV	West Virginia Industrial Intervenors	Monongahela Power Co.	Generation planning economics, prudence of a pumped storage hydro unit.
6/85	E-7 Sub 391	NC	Carolina Industrials (CIGFUR III)	Duke Power Co.	Cost-of-service, rate design, interruptible rate design.
7/85	29046	NY	Industrial Energy Users Association	Orange and Rockland Utilities	Cost-of-service, rate design.
10/85	85-043-U	AR	Arkansas Gas Consumers	Arkla, Inc.	Regulatory policy, gas cost-of-service, rate design.
10/85	85-63	ME	Airco Industrial Gases	Central Maine Power Co.	Feasibility of interruptible rates, avoided cost.
2/85	ER-8507698	NJ	Air Products and Chemicals	Jersey Central Power & Light Co.	Rate design.
3/85	R-850220	PA	West Penn Power Industrial Intervenors	West Penn Power Co.	Optimal reserve, prudence, off-system sales guarantee plan.
2/86	R-850220	PA	West Penn Power Industrial Intervenors	West Penn Power Co.	Optimal reserve margins, prudence, off-system sales guarantee plan.
3/86	85-299U	AR	Arkansas Electric Energy Consumers	Arkansas Power & Light Co.	Cost-of-service, rate design, revenue distribution.
3/86	85-726-EL-AIR	OH	Industrial Electric Consumers Group	Ohio Power Co.	Cost-of-service, rate design, interruptible rates.
5/86	86-081-E-GI	WV	West Virginia Energy Users Group	Monongahela Power Co.	Generation planning economics, prudence of a pumped storage hydro unit.
8/86	E-7 Sub 408	NC	Carolina Industrial Energy Consumers	Duke Power Co.	Cost-of-service, rate design, interruptible rates.
10/86	U-17378	LA	Louisiana Public Service Commission Staff	Gulf States Utilities	Excess capacity, economic analysis of purchased power.
12/86	38063	IN	Industrial Energy Consumers	Indiana & Michigan Power Co.	Interruptible rates.

Expert Testimony Appearances
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Date	Case	Jurisdict.	Party	Utility	Subject
3/87	EL-86-53-001 EL-86-57-001	Federal Energy Regulatory Commission (FERC)	Louisiana Public Service Commission Staff	Gulf States Utilities, Southern Co.	Cost/benefit analysis of unit power sales contract.
4/87	U-17282	LA	Louisiana Public Service Commission Staff	Gulf States Utilities	Load forecasting and imprudence damages, River Bend Nuclear unit.
5/87	87-023-E-C	WV	Airco Industrial Gases	Monongahela Power Co.	Interruptible rates.
5/87	87-072-E-G1	WV	West Virginia Energy Users' Group	Monongahela Power Co.	Analyze Mon Power's fuel filing and examine the reasonableness of MP's claims.
5/87	86-524-E-SC	WV	West Virginia Energy Users' Group	Monongahela Power Co.	Economic dispatching of pumped storage hydro unit.
5/87	9781	KY	Kentucky Industrial Energy Consumers	Louisville Gas & Electric Co.	Analysis of impact of 1986 Tax Reform Act.
6/87	3673-U	GA	Georgia Public Service Commission	Georgia Power Co.	Economic prudence, evaluation of Vogtle nuclear unit - load forecasting, planning.
6/87	U-17282	LA	Louisiana Public Service Commission Staff	Gulf States Utilities	Phase-in plan for River Bend Nuclear unit.
7/87	85-10-22	CT	Connecticut Industrial Energy Consumers	Connecticut Light & Power Co.	Methodology for refunding rate moderation fund.
8/87	3673-U	GA	Georgia Public Service Commission	Georgia Power Co.	Test year sales and revenue forecast.
9/87	R-850220	PA	West Penn Power Industrial Intervenors	West Penn Power Co.	Excess capacity, reliability of generating system.
10/87	R-870651	PA	Duquesne Industrial Intervenors	Duquesne Light Co.	Interruptible rate, cost-of-service, revenue allocation, rate design.
10/87	I-860025	PA	Pennsylvania Industrial Intervenors		Proposed rules for cogeneration, avoided cost, rate recovery.

Expert Testimony Appearances
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Date	Case	Jurisdict.	Party	Utility	Subject
10/87	E-015/ GR-87-223	MN	Taconite Intervenors	Minnesota Power & Light Co.	Excess capacity, power and cost-of-service, rate design.
10/87	8702-EI	FL	Occidental Chemical Corp.	Florida Power Corp.	Revenue forecasting, weather normalization.
12/87	87-07-01	CT	Connecticut Industrial Energy Consumers	Connecticut Light Power Co.	Excess capacity, nuclear plant phase-in.
3/88	10064	KY	Kentucky Industrial Energy Consumers	Louisville Gas & Electric Co.	Revenue forecast, weather normalization rate treatment of cancelled plant.
3/88	87-183-TF	AR	Arkansas Electric Consumers	Arkansas Power & Light Co.	Standby/backup electric rates.
5/88	870171C001	PA	GPU Industrial Intervenors	Metropolitan Edison Co.	Cogeneration deferral mechanism, modification of energy cost recovery (ECR).
6/88	870172C005	PA	GPU Industrial Intervenors	Pennsylvania Electric Co.	Cogeneration deferral mechanism, modification of energy cost recovery (ECR).
7/88	88-171- EL-AIR 88-170- EL-AIR Interim Rate Case	OH	Industrial Energy Consumers	Cleveland Electric/ Toledo Edison	Financial analysis/need for interim rate relief.
7/88	Appeal of PSC	19th Judicial Docket U-17282	Louisiana Public Service Commission Circuit Court of Louisiana	Gulf States Utilities	Load forecasting, imprudence damages.
11/88	R-880989	PA	United States Steel	Carnegie Gas	Gas cost-of-service, rate design.
11/88	88-171- EL-AIR 88-170- EL-AIR	OH	Industrial Energy Consumers	Cleveland Electric/ Toledo Edison. General Rate Case.	Weather normalization of peak loads, excess capacity, regulatory policy.
3/89	870216/283 284/286	PA	Armco Advanced Materials Corp., Allegheny Ludlum Corp.	West Penn Power Co.	Calculated avoided capacity, recovery of capacity payments.

Expert Testimony Appearances
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Date	Case	Jurisdict.	Party	Utility	Subject
8/89	8555	TX	Occidental Chemical Corp.	Houston Lighting & Power Co.	Cost-of-service, rate design.
8/89	3840-U	GA	Georgia Public Service Commission	Georgia Power Co.	Revenue forecasting, weather normalization.
9/89	2087	NM	Attorney General of New Mexico	Public Service Co. of New Mexico	Prudence - Palo Verde Nuclear Units 1, 2 and 3, load fore-casting.
10/89	2262	NM	New Mexico Industrial Energy Consumers	Public Service Co. of New Mexico	Fuel adjustment clause, off-system sales, cost-of-service, rate design, marginal cost.
11/89	38728	IN	Industrial Consumers for Fair Utility Rates	Indiana Michigan Power Co.	Excess capacity, capacity equalization, jurisdictional cost allocation, rate design, interruptible rates.
1/90	U-17282	LA	Louisiana Public Service Commission Staff	Gulf States Utilities	Jurisdictional cost allocation, O&M expense analysis.
5/90	890366	PA	GPU Industrial Intervenors	Metropolitan Edison Co.	Non-utility generator cost recovery.
6/90	R-901609	PA	Armco Advanced Materials Corp., Allegheny Ludlum Corp.	West Penn Power Co.	Allocation of QF demand charges in the fuel cost, cost-of-service, rate design.
9/90	8278	MD	Maryland Industrial Group	Baltimore Gas & Electric Co.	Cost-of-service, rate design, revenue allocation.
12/90	U-9346 Rebuttal	MI	Association of Businesses Advocating Tariff Equity	Consumers Power Co.	Demand-side management, environmental externalities.
12/90	U-17282 Phase IV	LA	Louisiana Public Service Commission Staff	Gulf States Utilities	Revenue requirements, jurisdictional allocation.
12/90	90-205	ME	Airco Industrial Gases	Central Maine Power Co.	Investigation into interruptible service and rates.
1/91	90-12-03 Interim	CT	Connecticut Industrial Energy Consumers	Connecticut Light & Power Co.	Interim rate relief, financial analysis, class revenue allocation.

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Date	Case	Jurisdict.	Party	Utility	Subject
5/91	90-12-03 Phase II	CT	Connecticut Industrial Energy Consumers	Connecticut Light & Power Co.	Revenue requirements, cost-of-service, rate design, demand-side management.
8/91	E-7, SUB SUB 487	NC	North Carolina Industrial Energy Consumers	Duke Power Co.	Revenue requirements, cost allocation, rate design, demand-side management.
8/91	8341 Phase I	MD	Westvaco Corp.	Potomac Edison Co.	Cost allocation, rate design, 1990 Clean Air Act Amendments.
8/91	91-372	OH	Armco Steel Co., L.P.	Cincinnati Gas &	Economic analysis of
	EL-UNC			Electric Co.	cogeneration, avoid cost rate.
9/91	P-910511 P-910512	PA	Allegheny Ludlum Corp., Armco Advanced Materials Co., The West Penn Power Industrial Users' Group	West Penn Power Co.	Economic analysis of proposed CWIP Rider for 1990 Clean Air Act Amendments expenditures.
9/91	91-231 -E-NC	WV	West Virginia Energy Users' Group	Monongahela Power Co.	Economic analysis of proposed CWIP Rider for 1990 Clean Air Act Amendments expenditures.
10/91	8341 - Phase II	MD	Westvaco Corp.	Potomac Edison Co.	Economic analysis of proposed CWIP Rider for 1990 Clean Air Act Amendments expenditures.
10/91	U-17282	LA	Louisiana Public Service Commission Staff	Gulf States Utilities	Results of comprehensive management audit.
Note: No testimony was prefiled on this.					
11/91	U-17949 Subdocket A	LA	Louisiana Public Service Commission Staff	South Central Bell Telephone Co. and proposed merger with Southern Bell Telephone Co.	Analysis of South Central Bell's restructuring and
12/91	91-410-EL-AIR	OH	Armco Steel Co., Air Products & Chemicals, Inc.	Cincinnati Gas & Electric Co.	Rate design, interruptible rates.
12/91	P-880286	PA	Armco Advanced Materials Corp., Allegheny Ludlum Corp.	West Penn Power Co.	Evaluation of appropriate avoided capacity costs - QF projects.

Expert Testimony Appearances
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Date	Case	Jurisdict.	Party	Utility	Subject
1/92	C-913424	PA	Duquesne Interruptible Complainants	Duquesne Light Co.	Industrial interruptible rate.
6/92	92-02-19	CT	Connecticut Industrial Energy Consumers	Yankee Gas Co.	Rate design.
8/92	2437	NM	New Mexico Industrial Intervenors	Public Service Co. of New Mexico	Cost-of-service.
8/92	R-00922314	PA	GPU Industrial Intervenors	Metropolitan Edison Co.	Cost-of-service, rate design, energy cost rate.
9/92	39314	ID	Industrial Consumers for Fair Utility Rates	Indiana Michigan Power Co.	Cost-of-service, rate design, energy cost rate, rate treatment.
10/92	M-00920312 C-007	PA	The GPU Industrial Intervenors	Pennsylvania Electric Co.	Cost-of-service, rate design, energy cost rate, rate treatment.
12/92	U-17949	LA	Louisiana Public Service Commission Staff	South Central Bell Co.	Management audit.
12/92	R-00922378	PA	Armco Advanced Materials Co. The WPP Industrial Intervenors	West Penn Power Co.	Cost-of-service, rate design, energy cost rate, SO_2 allowance rate treatment.
1/93	8487	MD	The Maryland Industrial Group	Baltimore Gas & Electric Co.	Electric cost-of-service and rate design, gas rate design (flexible rates).
2/93	E002/GR-92-1185	MN	North Star Steel Co. Praxair, Inc.	Northern States Power Co.	Interruptible rates.
4/93	EC92 21000 ER92-806-000 (Rebuttal)	Federal Energy Regulatory Commission	Louisiana Public Service Commission Staff	Gulf States Utilities/Entergy agreement.	Merger of GSU into Entergy System; impact on system
7/93	93-0114-E-C	WV	Airco Gases	Monongahela Power Co.	Interruptible rates.
8/93	930759-EG	FL	Florida Industrial Power Users' Group	Generic - Electric Utilities	Cost recovery and allocation of DSM costs.
9/93	M-009 30406	PA	Lehigh Valley Power Committee	Pennsylvania Power & Light Co.	Ratemaking treatment of off-system sales revenues.

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Date	Case	Jurisdict.	Party	Utility	Subject
11/93	346	KY	Kentucky Industrial Utility Customers	Generic - Gas Utilities	Allocation of gas pipeline transition costs - FERC Order 636.
12/93	U-17735	LA	Louisiana Public Service Commission Staff	Cajun Electric Power Cooperative	Nuclear plant prudence, forecasting, excess capacity.
4/94	E-015/ GR-94-001	MN	Large Power Intervenors	Minnesota Power Co.	Cost allocation, rate design, rate phase-in plan.
5/94	U-20178	LA	Louisiana Public Service Commission	Louisiana Power & Light Co.	Analysis of least cost integrated resource plan and demand-side management program.
7/94	R-00942986	PA	Armco, Inc.; West Penn Power Industrial Intervenors	West Penn Power Co.	Cost-of-service, allocation of rate increase, rate design, emission allowance sales, and operations and maintenance expense.
7/94	94-0035-E-42T	WV	West Virginia Energy Users Group	Monongahela Power Co.	Cost-of-service, allocation of rate increase, and rate design.
8/94	EC94 13-000	Federal Energy Regulatory Commission	Louisiana Public Service Commission	Gulf States Utilities/Entergy	Analysis of extended reserve shutdown units and violation of system agreement by Entergy.
9/94	R-00943 081 R-00943 081C0001	PA	Lehigh Valley Power Committee	Pennsylvania Public Utility Commission	Analysis of interruptible rate terms and conditions, availability.
9/94	U-17735	LA	Louisiana Public Service Commission	Cajun Electric Power Cooperative	Evaluation of appropriate avoided cost rate.
9/94	U-19904	LA	Louisiana Public Service Commission	Gulf States Utilities	Revenue requirements.
10/94	5258-U	GA	Georgia Public Service Commission	Southern Bell Telephone & Telegraph Co.	Proposals to address competition in telecommunication markets.
11/94	EC94-7-000 ER94-898-000	FERC	Louisiana Public Service Commission	El Paso Electric and Central and Southwest	Merger economics, transmission equalization hold harmless proposals.
2/95	941-430EG	CO	CF&I Steel, L.P.	Public Service Company of Colorado	Interruptible rates, cost-of-service.

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Date	Case	Jurisdict.	Party	Utility	Subject
4/95	R-00943271	PA	PP&L Industrial Customer Alliance	Pennsylvania Power & Light Co.	Cost-of-service, allocation of rate increase, rate design, interruptible rates.
6/95	C-00913424 C-00946104	PA	Duquesne Interruptible Complainants	Duquesne Light Co.	Interruptible rates.
8/95	ER95-112 -000	FERC	Louisiana Public Service Commission	Entergy Services, Inc.	Open Access Transmission Tariffs - Wholesale.
10/95	U-21485	LA	Louisiana Public Service Commission	Gulf States Utilities Company	Nuclear decommissioning, revenue requirements, capital structure.
10/95	ER95-1042 -000	FERC	Louisiana Public Service Commission	System Energy Resources, Inc.	Nuclear decommissioning, revenue requirements.
10/95	U-21485	LA	Louisiana Public Service Commission	Gulf States Utilities Co.	Nuclear decommissioning and cost of debt capital, capital structure.
11/95	I-940032	PA	Industrial Energy Consumers of Pennsylvania	State-wide - all utilities	Retail competition issues.
7/96	U-21496	LA	Louisiana Public Service Commission	Central Louisiana Electric Co.	Revenue requirement analysis.
7/96	8725	MD	Maryland Industrial Group	Baltimore Gas & Elec. Co., Potomac Elec. Power Co., Constellation Energy Co.	Ratemaking issues associated with a Merger.
8/96	U-17735	LA	Louisiana Public Service Commission	Cajun Electric Power Cooperative	Revenue requirements.
9/96	U-22092	LA	Louisiana Public Service Commission	Entergy Gulf States, Inc.	Decommissioning, weather normalization, capital structure.
2/97	R-973877	PA	Philadelphia Area Industrial Energy Users Group	PECO Energy Co.	Competitive restructuring policy issues, stranded cost, transition charges.
6/97	Civil Action No. 94-11474	US Bankruptcy Court *Middle District* of Louisiana	Louisiana Public Service Commission	Cajun Electric Power Cooperative	Confirmation of reorganization plan; analysis of rate paths produced by competing plans.

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of
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As of December 2008

Date	Case	Jurisdict.	Party	Utility	Subject
6/97	R-973953	PA	Philadelphia Area Industrial Energy Users Group	PECO Energy Co.	Retail competition issues, rate unbundling, stranded cost analysis.
6/97	8738	MD	Maryland Industrial Group	Generic	Retail competition issues
7/97	R-973954	PA	PP&L Industrial Customer Alliance	Pennsylvania Power & Light Co.	Retail competition issues, rate unbundling, stranded cost analysis.
10/97	97-204	KY	Alcan Aluminum Corp. Southwire Co.	Big River Electric Corp.	Analysis of cost of service issues - Big Rivers Restructuring Plan
10/97	R-974008	PA	Metropolitan Edison Industrial Users	Metropolitan Edison Co.	Retail competition issues, rate unbundling, stranded cost analysis.
10/97	R-974009	PA	Pennsylvania Electric Industrial Customer	Pennsylvania Electric Co.	Retail competition issues, rate unbundling, stranded cost analysis.
11/97	U-22491	LA	Louisiana Public Service Commission	Entergy Gulf States, Inc.	Decommissioning, weather normalization, capital structure.
11/97	P-971265	PA	Philadelphia Area Industrial Energy Users Group	Enron Energy Services Power, Inc./ PECO Energy	Analysis of Retail Restructuring Proposal.
12/97	R-973981	PA	West Penn Power Industrial Intervenors	West Penn Power Co.	Retail competition issues, rate unbundling, stranded cost analysis.
12/97	R-974104	PA	Duquesne Industrial Intervenors	Duquesne Light Co.	Retail competition issues, rate unbundling, stranded cost analysis.
3/98	U-22092 (Allocated Stranded Cost Issues)	LA	Louisiana Public Service Commission	Gulf States Utilities Co.	Retail competition, stranded cost quantification.
3/98	U-22092		Louisiana Public Service Commission	Gulf States Utilities, Inc.	Stranded cost quantification, restructuring issues.
9/98	U-17735		Louisiana Public Service Commission	Cajun Electric Power Cooperative, Inc.	Revenue requirements analysis, weather normalization.
12/98	8794	MD	Maryland Industrial Group and	Baltimore Gas and Electric Co.	Electric utility restructuring, stranded cost recovery, rate

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As of December 2008

Date	Case	Jurisdict.	Party	Utility	Subject
			Millennium Inorganic Chemicals Inc.		unbundling.
12/98	U-23358	LA	Louisiana Public Service Commission	Entergy Gulf States, Inc.	Nuclear decommissioning, weather normalization, Entergy System Agreement.
5/99 (Cross-Answering Testimony)	EC-98-40-000	FERC	Louisiana Public Service Commission	American Electric Power Co. & Central South West Corp.	Merger issues related to market power mitigation proposals.
5/99 (Response Testimony)	98-426	KY	Kentucky Industrial Utility Customers, Inc.	Louisville Gas & Electric Co.	Performance based regulation, settlement proposal issues, cross-subsidies between electric. gas services.
6/99	98-0452	WV	West Virginia Energy Users Group	Appalachian Power, Monongahela Power, & Potomac Edison Companies	Electric utility restructuring, stranded cost recovery, rate unbundling.
7/99	99-03-35	CT	Connecticut Industrial \Energy Consumers	United Illuminating Company	Electric utility restructuring, stranded cost recovery, rate unbundling.
7/99	Adversary Proceeding No. 98-1065	U.S. Bankruptcy Court	Louisiana Public Service Commission	Cajun Electric Power Cooperative	Motion to dissolve preliminary injunction.
7/99	99-03-06	CT	Connecticut Industrial Energy Consumers	Connecticut Light & Power Co.	Electric utility restructuring, stranded cost recovery, rate unbundling.
10/99	U-24182	LA	Louisiana Public Service Commission	Entergy Gulf States, Inc.	Nuclear decommissioning, weather normalization, Entergy System Agreement.
12/99	U-17735	LA	Louisiana Public Service Commission	Cajun Electric Power Cooperative, Inc.	Ananlysi of Proposed Contract Rates, Market Rates.
03/00	U-17735	LA	Louisiana Public Service Commission	Cajun Electric Power Cooperative, Inc.	Evaluation of Cooperative Power Contract Elections
03/00	99-1658-EL-ETP	OH	AK Steel Corporation	Cincinnati Gas & Electric Co.	Electric utility restructuring, stranded cost recovery, rate Unbundling.

Expert Testimony Appearances
of
Stephen J. Baron
As of December 2008

Date	Case	Jurisdict.	Party	Utility	Subject
08/00	98-0452 E-GI	WVA	West Virginia Energy Users Group	Appalachian Power Co. American Electric Co.	Electric utility restructuring rate unbundling.
08/00	00-1050 E-T 00-1051-E-T	WVA	West Virginia Energy Users Group	Mon Power Co. Potomac Edison Co.	Electric utility restructuring rate unbundling.
10/00	SOAH 473-00-1020 PUC 2234	TX	The Dallas-Fort Worth Hospital Council and The Coalition of Independent Colleges And Universities	TXU, Inc.	Electric utility restructuring rate unbundling.
12/00	U-24993	LA	Louisiana Public Service Commission	Entergy Gulf States, Inc.	Nuclear decommissioning, revenue requirements.
12/00	EL00-66-000 & ER00-2854 EL95-33-002	LA	Louisiana Public Service Commission	Entergy Services Inc.	Inter-Company System Agreement: Modifications for retail competition, interruptible load.
04/01	U-21453, U-20925, U-22092 (Subdocket B) Addressing Contested Issues	LA	Louisiana Public Service Commission	Entergy Gulf States, Inc.	Jurisdictional Business Separation - Texas Restructuring Plan
10/01	14000-U	GA	Georgia Public Service Commission Adversary Staff	Georgia Power Co.	Test year revenue forecast.
11/01	U-25687	LA	Louisiana Public Service Commission	Entergy Gulf States, Inc.	Nuclear decommissioning requirements transmission revenues.
11/01	U-25965	LA	Louisiana Public Service Commission	Generic	Independent Transmission Company ("Transco"). RTO rate design.
03/02	001148-EI	FL	South Florida Hospital and Healthcare Assoc.	Florida Power & Light Company	Retail cost of service, rate design, resource planning and demand side management.
06/02	U-25965	LA	Louisiana Public Service Commission	Entergy Gulf States Entergy Louisiana	RTO Issues
07/02	U-21453	LA	Louisiana Public Service Commission	SWEPCO, AEP	Jurisdictional Business Sep. - Texas Restructuring Plan.

Expert Testimony Appearances
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As of December 2008

Date	Case	Jurisdict.	Party	Utility	Subject
08/02	U-25888	LA	Louisiana Public Service Commission	Entergy Louisiana, Inc. Entergy Gulf States, Inc.	Modifications to the Inter-Company System Agreement, Production Cost Equalization.
08/02	EL01-88-000	FERC	Louisiana Public Service Commission	Entergy Services Inc. and the Entergy Operating Companies	Modifications to the Inter-Company System Agreement, Production Cost Equalization.
11/02	02S-315EG	CO	CF&I Steel & Climax Molybdenum Co.	Public Service Co. of Colorado	Fuel Adjustment Clause
01/03	U-17735	LA	Louisiana Public Service Commission	Louisiana Coops	Contract Issues
02/03	02S-594E	CO	Cripple Creek and Victor Gold Mining Co.	Aquila, Inc.	Revenue requirements, purchased power.
04/03	U-26527	LA	Louisiana Public Service Commission	Entergy Gulf States, Inc.	Weather normalization, power purchase expenses, System Agreement expenses.
11/03	ER03-753-000	FERC	Louisiana Public Service Commission Staff	Entergy Services, Inc. and the Entergy Operating Companies	Proposed modifications to System Agreement Tariff MSS-4.
11/03	ER03-583-000 ER03-583-001 ER03-583-002 ER03-681-000, ER03-681-001 ER03-682-000, ER03-682-001 ER03-682-002	FERC	Louisiana Public Service Commission	Entergy Services, Inc., the Entergy Operating Companies, EWO Marketing, L.P, and Entergy Power, Inc.	Evaluation of Wholesale Purchased Power Contracts.
12/03	U-27136	LA	Louisiana Public Service Commission	Entergy Louisiana, Inc.	Evaluation of Wholesale Purchased Power Contracts.
01/04	E-01345-03-0437	AZ	Kroger Company	Arizona Public Service Co.	Revenue allocation rate design.
02/04	00032071	PA	Duquesne Industrial Intervenors	Duquesne Light Company	Provider of last resort issues.
03/04	03A-436E	CO	CF&I Steel, LP and Climax Molybedenum	Public Service Company of Colorado	Purchased Power Adjustment Clause.

Expert Testimony Appearances
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As of December 2008

Date	Case	Jurisdict.	Party	Utility	Subject
04/04	2003-00433 2003-00434	KY	Kentucky Industrial Utility Customers, Inc.	Louisville Gas & Electric Co. Kentucky Utilities Co.	Cost of Service Rate Design
0-6/04	03S-539E	CO	Cripple Creek, Victor Gold Mining Co., Goodrich Corp., Holcim (U.S.,), Inc., and The Trane Co.	Aquila, Inc.	Cost of Service, Rate Design Interruptible Rates
06/04	R-00049255	PA	PP&L Industrial Customer Alliance PPLICA	PPL Electric Utilities Corp.	Cost of service, rate design, tariff issues and transmission service charge.
10/04	04S-164E	CO	CF&I Steel Company, Climax Mines	Public Service Company of Colorado	Cost of service, rate design, Interruptible Rates.
03/05	Case No. 2004-00426 Case No. 2004-00421	KY	Kentucky Industrial Utility Customers, Inc.	Kentucky Utilities Louisville Gas & Electric Co.	Environmental cost recovery.
06/05	050045-EI	FL	South Florida Hospital and Healthcare Assoc.	Florida Power & Light Company	Retail cost of service, rate design
07/05	U-28155	LA	Louisiana Public Service Commission Staff	Entergy Louisiana, Inc. Entergy Gulf States, Inc.	Independent Coordinator of Transmission – Cost/Benefit
09/05	Case Nos. 05-0402-E-CN 05-0750-E-PC	WVA	West Virginia Energy Users Group	Mon Power Co. Potomac Edison Co.	Environmental cost recovery, Securitization, Financing Order
01/06	2005-00341	KY	Kentucky Industrial Utility Customers, Inc.	Kentucky Power Company	Cost of service, rate design, transmission expenses. Congestion Cost Recovery Mechanism
03/06	U-22092	LA	Louisiana Public Service Commission Staff	Entergy Gulf States, Inc.	Separation of EGSI into Texas and Louisiana Companies.
04/06	U-25116	LA	Louisiana Public Service Commission Staff	Entergy Louisiana, Inc.	Transmission Prudence Investigation
06/06	R-00061346 C0001-0005	PA	Duquesne Industrial Intervenors & IECPA	Duquesne Light Co.	Cost of Service, Rate Design, Transmission Service Charge, Tariff Issues
06/06	R-00061366 R-00061367 P-00062213 P-00062214		Met-Ed Industrial Energy Users Group and Penelec Industrial Customer Alliance	Metropolitan Edison Co. Pennsylvania Electric Co.	Generation Rate Cap, Transmission Service Charge, Cost of Service, Rate Design, Tariff Issues
07/06	U-22092 Sub-J	LA	Louisiana Public Service Commission Staff	Entergy Gulf States, Inc.	Separation of EGSI into Texas and Louisiana Companies.

Expert Testimony Appearances
of
Stephen J. Baron
As of December 2008

Date	Case	Jurisdict.	Party	Utility	Subject
07/06	Case No. 2006-00130 Case No. 2006-00129	KY	Kentucky Industrial Utility Customers, Inc.	Kentucky Utilities Louisville Gas & Electric Co.	Environmental cost recovery.
08/06	Case No. PUE-2006-00065	VA	Old Dominion Committee For Fair Utility Rates	Appalachian Power Co.	Cost Allocation, Allocation of Revenue Incr, Off-System Sales margin rate treatment
09/06	E-01345A- 05-0816	AZ	Kroger Company	Arizona Public Service Co.	Revenue allocation, cost of service, rate design.
11/06	Doc. No. 97-01-15RE02	CT	Connecticut Industrial Energy Consumers	Connecticut Light & Power United Illuminating	Rate unbundling issues.
01/07	Case No. 06-0960-E-42T	WV	West Virginia Energy Users Group	Mon Power Co. Potomac Edison Co.	Retail Cost of Service Revenue apportionment
03/07	U-29764	LA	Louisiana Public Service Commission Staff	Entergy Gulf States, Inc. Entergy Louisiana, LLC	Implementation of FERC Decision Jurisdictional & Rate Class Allocation
05/07	Case No. 07-63-EL-UNC	OH	Ohio Energy Group	Ohio Power, Columbus Southern Power	Environmental Surcharge Rate Design
05/07	R-00049255 Remand	PA	PP&L Industrial Customer Alliance PPLICA	PPL Electric Utilities Corp.	Cost of service, rate design, tariff issues and transmission service charge.
06/07	R-00072155	PA	PP&L Industrial Customer Alliance PPLICA	PPL Electric Utilities Corp.	Cost of service, rate design, tariff issues.
07/07	Doc. No. 07F-037E	CO	Gateway Canyons LLC	Grand Valley Power Coop.	Distribution Line Cost Allocation
09/07	Doc. No. 05-UR-103	WI	Wisconsin Industrial Energy Group, Inc.	Wisconsin Electric Power Co.	Cost of Service, rate design, tariff Issues, Interruptible rates.
11/07	ER07-682-000	FERC	Louisiana Public Service Commission Staff	Entergy Services, Inc. and the Entergy Operating Companies	Proposed modifications to System Agreement Schedule MSS-3. Cost functionalization issues.
1/08	Doc. No. 20000-277-ER-07	WY	Cimarex Energy Company	Rocky Mountain Power (PacifiCorp)	Vintage Pricing, Marginal Cost Pricing Projected Test Year
1/08	Case No. 07-551	OH	Ohio Energy Group	Ohio Edison, Toledo Edison Cleveland Electric Illuminating	Class Cost of Service, Rate Restructuring, Apportionment of Revenue Increase to Rate Schedules
2/08	ER07-956	FERC	Louisiana Public Service Commission Staff	Entergy Services, Inc. and the Entergy Operating Companies	Entergy's Compliance Filing System Agreement Bandwidth Calculations.
2/08	Doc No.	PA	West Penn Power	West Penn Power Co.	Default Service Plan Issues.

Expert Testimony Appearances
of
Stephen J. Baron
As of December 2008

Date	Case	Jurisdict.	Party	Utility	Subject
	P-00072342		Industrial Intervenors		
3/08	Doc No. E-01933A-05-0650	AZ	Kroger Company	Tucson Electric Power Co.	Cost of Service, Rate Design
05/08	08-0278 E-GI	WV	West Virginia Energy Users Group	Appalachian Power Co. American Electric Power Co.	Expanded Net Energy Cost "ENEC" Analysis.
6/08	Case No. 08-124-EL-ATA	OH	Ohio Energy Group	Ohio Edison, Toledo Edison Cleveland Electric Illuminating	Recovery of Deferred Fuel Cost
7/08	Docket No. 07-035-93	UT	Kroger Company	Rocky Mountain Power Co.	Cost of Service, Rate Design
08/08	Doc. No. 6680-UR-116	WI	Wisconsin Industrial Energy Group, Inc.	Wisconsin Power and Light Co.	Cost of Service, rate design, tariff Issues, Interruptible rates.
09/08	Doc. No. 6690-UR-119	WI	Wisconsin Industrial Energy Group, Inc.	Wisconsin Public Service Co.	Cost of Service, rate design, tariff Issues, Interruptible rates.
09/08	Case No. 08-936-EL-SSO	OH	Ohio Energy Group	Ohio Edison, Toledo Edison Cleveland Electric Illuminating	Provider of Last Resort Competitive Solicitation
09/08	Case No. 08-935-EL-SSO	OH	Ohio Energy Group	Ohio Edison, Toledo Edison Cleveland Electric Illuminating	Provider of Last Resort Rate Plan
09/08	Case No. 08-917-EL-SSO 08-918-EL-SSO	OH	Ohio Energy Group	Ohio Power Company Columbus Southern Power Co.	Provider of Last Resort Rate Plan
11/08	08-0278 E-GI	WV	West Virginia Energy Users Group	Appalachian Power Co. American Electric Power Co.	Expanded Net Energy Cost "ENEC" Analysis.
11/08	M-2008-2036188, M-2008-2036197	PA	Met-Ed Industrial Energy Users Group and Penelec Industrial Customer Alliance	Metropolitan Edison Co. Pennsylvania Electric Co.	Transmission Service Charge

BEFORE THE

ARIZONA CORPORATION COMMISSION

IN THE MATTER OF THE APPLICATION OF	**)**
ARIZONA PUBLIC SERVICE COMPANY FOR	**)**
A HEARING TO DETERMINE THE FAIR VALUE	**)**
OF THE UTILITY PROPERTY OF THE COMPANY	**) Docket No. E-01345A-08-0172**
FOR RATEMAKING PURPOSES, TO FIX A JUST	**)**
AND REASONABLE RATE OF RETURN	**)**
THEREON, TO APPROVE RATE SCHEDULES	**)**
DESIGNED TO DEVELOP SUCH RETURN	**)**

EXHIBIT__(SJB-2)

OF

STEPHEN J. BARON

ON BEHALF OF THE

KROGER CO.

ARIZONA PUBLIC SERVICE COMPANY
Computation of Rate Increase Necessar y to Reduce Class Subsidies by 25%
Adjusted to Cap Lighting at 1.5x System Average

	Total ACC Jurisdiction	Residential	General Service	Water Pumping	Street Lighting	Dusk to Dawn
COST OF SERVICE AT PRESENT RATES						
Revenues from Base Rates	2,637,447	1,347,035	1,240,168	25,376	17,372	7,496
Revenues from Surcharges	-	-	-	-	-	-
Other Electric Revenues	94,461	47,608	42,643	867	3,063	280
Total Revenue (Existing Rates)	2,731,908	1,394,643	1,282,811	26,243	20,435	7,776
Operating Expenses before Income Taxes	2,500,562	1,310,086	1,140,256	23,495	21,437	5,288
Income Taxes	28,234	368	27,578	666	(981)	603
Net Operating Income	203,112	84,189	114,977	2,082	(21)	1,885
Rate Base	5,359,964	2,954,460	2,282,488	30,142	64,347	28,527
Rate of Return	3.79%	2.85%	5.04%	6.91%	-0.03%	6.61%
Rate of Return Index	1.000	0.752	1.329	1.823	(0.009)	1.744
Subsidy at Present Rate of Return	(0)	45,792	(46,972)	(1,550)	4,056	(1,326)
Percentage Increase		3.28%	-3.66%	-5.91%	19.85%	-17.05%
Increase to Equalized Proposed Rate of Return	448,194	292,840	143,887	971	9,436	1,060
Percentage Increase	16.99%	21.74%	11.60%	3.83%	54.32%	14.13%
APS Proposed Percentage Increases	16.99%	17.27%	16.74%	12.30%	19.41%	19.36%
Proposed Class Rate Increase	448,194	232,650	207,600	3,121	3,372	1,451
Less: Incremental Income Taxes	(176,409)	(91,571)	(81,711)	(1,228)	(1,327)	(571)
Net Income @ proposed rates	474,897	225,268	240,866	3,975	2,024	2,765
Rate of Return @ proposed rates	8.86%	7.62%	10.55%	13.19%	3.15%	9.69%
Rate of Return Index	1.000	0.861	1.191	1.488	0.355	1.094
Subsidy at Company Proposed Rates	0	60,190	(63,713)	(2,150)	6,064	(391)
Kroger Proposed Subsidy (75% of Present)	(0)	34,344	(35,229)	(1,162)	3,042	(994)
Adjustment	-	1,441	1,113	15	(1,966)	(603)
Required Rate Increase	448,194	259,938	180,229	2,148	4,428	1,451
Percentage Increase	16.99%	19.30%	14.53%	8.46%	25.49%	19.36%
Net Income with Kroger Subsidy Reduction	474,897	241,815	224,268	3,384	2,664	2,765
Rate of Return	8.86%	8.18%	9.83%	11.23%	4.14%	9.69%
Rate of Return Index		0.924	1.109	1.267	0.467	1.094
Pro Forma PSA Impact	(169,977)	(79,859)	(87,217)	(1,989)	(758)	(154)
Net Increase	278,217	180,079	93,012	159	3,670	1,297
Net Percentage Increase	10.55%	13.37%	7.50%	0.63%	21.13%	17.30%

BEFORE THE

ARIZONA CORPORATION COMMISSION

IN THE MATTER OF THE APPLICATION OF	)	
ARIZONA PUBLIC SERVICE COMPANY FOR	)	
A HEARING TO DETERMINE THE FAIR VALUE	)	
OF THE UTILITY PROPERTY OF THE COMPANY	)	**Docket No. E-01345A-08-0172**
FOR RATEMAKING PURPOSES, TO FIX A JUST	)	
AND REASONABLE RATE OF RETURN	)	
THEREON, TO APPROVE RATE SCHEDULES	)	
DESIGNED TO DEVELOP SUCH RETURN	)	

EXHIBIT__(SJB-3)

OF

STEPHEN J. BARON

ON BEHALF OF THE

KROGER CO.

ARIZONA PUBLIC SERVICE COMPANY
Computation of Rate Increase Necessary to Reduce Class Subsidies by 25%

	Total ACC Jurisdiction	General Service	E-20 (Church Rate)	E-32 TOU	E-30, E-32 (0 - 20 kW)	E-32 (21 - 100 kW)	E-32 (101 - 400 kW)	E-32 (401+ kW)	E-34	E-35
COST OF SERVICE AT PRESENT RATES										
Revenues from Base Rates	2,637,447	1,240,169	3,267	15,429	173,838	273,358	292,377	306,941	85,742	89,217
Revenues from Surcharges	-	-	-	-	-	-	-	-	-	-
Other Electric Revenues	94,461	42,643	140	570	5,502	8,912	10,049	10,722	3,195	3,553
Total Revenue (Existing Rates)	2,731,908	1,282,812	3,408	15,999	179,339	282,270	302,426	317,663	88,937	92,770
Operating Expenses before Income Taxes	2,500,562	1,140,256	3,718	14,113	162,560	241,372	262,770	276,075	84,073	95,575
Income Taxes	28,234	27,578	(219)	417	1,704	8,855	8,767	9,846	422	(2,214)
Net Operating Income	203,112	114,978	(91)	1,468	15,078	32,042	30,889	31,741	4,443	(591)
Rate Base	5,359,984	2,282,488	11,122	24,772	428,821	565,107	525,980	482,809	127,572	118,308
Rate of Return	3.79%	5.04%	-0.82%	5.93%	3.53%	5.67%	5.87%	6.57%	3.48%	-0.50%
Rate of Return Index	1.000	1.329	(0.215)	1.564	0.932	1.496	1.550	1.735	0.919	(0.132)
Subsidy at Present Rate of Return	-	(46,873)	845	(874)	1,811	(17,526)	(18,069)	(22,173)	646	8,368
Percentage Increase		-3.79%	25.85%	-5.66%	1.04%	-6.41%	-6.18%	-7.22%	0.75%	9.38%
Increase to Equalized Proposed Rate of Return	448,194	143,886	1,775	1,198	37,501	29,727	25,913	16,199	11,313	16,261
Percentage Increase	16.99%	11.60%	54.32%	7.76%	21.57%	10.87%	8.86%	5.93%	13.19%	20.47%
APS Proposed Percentage Increases	16.99%	16.74%	20.20%	16.71%	18.67%	16.58%	16.22%	15.74%	16.50%	18.69%
Proposed Class Rate Increase	448,194	207,600	660	2,678	32,443	45,326	47,428	48,319	14,149	16,679
Less: Incremental Income Taxes	(176,409)	(81,711)	(260)	(1,015)	(12,777)	(17,840)	(18,667)	(19,018)	(5,569)	(6,565)
Net Income @ proposed rates	474,897	240,866	309	3,032	34,761	59,528	59,648	61,042	13,023	9,523
Rate of Return @ proposed rates	8.86%	10.55%	2.78%	12.24%	8.14%	10.53%	11.34%	12.64%	10.21%	8.05%
Rate of Return Index	1.000	1.191	0.314	1.381	0.919	1.189	1.280	1.427	1.152	0.909
Subsidy at Company Proposed Rates	-	(63,714)	1,115	(1,380)	5,038	(15,599)	(21,513)	(30,120)	(2,838)	1,582
Kroger Proposed Subsidy (75% of Present)	-	(35,230)	634	(655)	1,358	(13,145)	(13,552)	(16,630)	484	6,276
Adjustment for E-20		-	481	(5)	(90)	(120)	(111)	(102)	(27)	(25)
Adjustment for "1.5" Times Rate Cap		1,113	-	12	209	277	258	237	63	58
Required Rate Increase	448,194	160,229	660	1,870	36,443	43,269	39,834	35,168	10,918	12,068
Kroger Percentage Increase	16.99%	14.53%	20.21%	12.12%	20.86%	15.83%	13.62%	11.46%	12.73%	13.63%
Net Income with Kroger Subsidy Reduction	474,897	224,268	310	2,603	37,175	58,280	55,044	53,087	11,064	6,727
Rate of Return	8.86%	9.83%	2.78%	10.51%	8.71%	10.31%	10.47%	10.99%	8.67%	5.69%
Rate of Return Index		1.109	0.314	1.186	0.983	1.164	1.181	1.241	0.979	0.642
Pro Forma PSA Impact	(169,977)	(87,217)	(203)	(1,246)	(8,490)	(18,122)	(20,433)	(23,958)	(7,605)	(9,160)
Net Increase	278,217	93,012	457	624	27,953	27,147	19,401	11,210	3,313	2,908
Net Percentage Increase	10.55%	7.50%	13.99%	4.05%	16.08%	9.93%	6.64%	3.65%	3.86%	3.26%

BEFORE THE

ARIZONA CORPORATION COMMISSION

IN THE MATTER OF THE APPLICATION OF	)
ARIZONA PUBLIC SERVICE COMPANY FOR	)
A HEARING TO DETERMINE THE FAIR VALUE	)
OF THE UTILITY PROPERTY OF THE COMPANY	) Docket No. E-01345A-08-0172
FOR RATEMAKING PURPOSES, TO FIX A JUST	)
AND REASONABLE RATE OF RETURN	)
THEREON, TO APPROVE RATE SCHEDULES	)
DESIGNED TO DEVELOP SUCH RETURN	)

EXHIBIT__(SJB-4)

OF

STEPHEN J. BARON

ON BEHALF OF THE

KROGER CO.

ARIZONA PUBLIC SERVICE COMPANY
Computation of Rate Increase Necessary to Reduce General Service Class Only Intra-Class Subsidies by 25%

	Total ACC Jurisdiction	General Service	E-20 (Church Rate)	E-32 TOU	E-30, E-32 (0 - 20 kW)	E-32 (21 - 100 kW)	E-32 (101 - 400 kW)	E-32 (401+ kW)	E-34	E-35
COST OF SERVICE AT PRESENT RATES										
Revenues from Base Rates	2,637,447	1,240,169	3,267	15,429	173,838	273,358	292,377	306,941	85,742	89,217
Revenues from Surcharges	-	-	-	-	-	-	-	-	-	-
Other Electric Revenues	94,461	42,643	140	570	5,502	8,912	10,049	10,722	3,195	3,553
Total Revenue (Existing Rates)	2,731,908	1,282,812	3,408	15,999	179,339	282,270	302,426	317,663	88,937	92,770
Operating Expenses before Income Taxes	2,500,562	1,140,258	3,718	14,113	162,560	241,372	262,770	276,075	84,073	95,575
Income Taxes	28,234	27,578	(219)	417	1,704	8,855	8,767	9,846	422	(2,214)
Net Operating Income	203,112	114,978	(91)	1,468	15,076	32,042	30,889	31,741	4,443	(591)
Rate Base	5,359,964	2,282,468	11,122	24,772	428,821	566,107	525,980	482,809	127,572	118,306
Rate of Return	3.79%	5.04%	-0.82%	5.93%	3.53%	5.67%	5.87%	6.57%	3.48%	-0.50%
Rate of Return Index	1.000	1.329	(0.215)	1.564	0.932	1.496	1.550	1.735	0.919	(0.132)
Subsidy at Present Rate of Return	-	(0)	1,074	(384)	10,595	(5,897)	(7,245)	(12,237)	3,271	10,803
Percentage Increase		0.00%	32.86%	-2.36%	6.09%	-2.16%	-2.48%	-3.99%	3.82%	12.11%
Increase to Equalized Proposed Rate of Return	448,194	143,880	1,775	1,198	37,501	29,727	25,913	18,199	11,313	18,261
Percentage Increase	16.99%	11.60%	54.32%	7.76%	21.57%	10.87%	8.86%	5.93%	13.19%	20.47%
APS Proposed Percentage Increases	16.99%	16.74%	20.20%	16.71%	18.67%	16.58%	16.22%	15.74%	16.50%	18.69%
Proposed Class Rate Increase	448,194	207,600	660	2,578	32,463	45,328	47,426	48,319	14,149	16,679
Less: Incremental Income Taxes	(176,409)	(81,711)	(260)	(1,015)	(12,777)	(17,840)	(18,667)	(19,018)	(5,569)	(6,565)
Net Income @ proposed rates	474,897	240,866	309	3,032	34,761	59,528	59,646	61,042	13,023	9,523
Rate of Return @ proposed rates	8.86%	10.55%	2.78%	12.24%	8.14%	10.53%	11.34%	12.64%	10.21%	8.05%
Rate of Return Index	1.000	1.191	0.314	1.381	0.919	1.189	1.280	1.427	1.152	0.909
Subsidy at Company Proposed Rates	-	0	1,425	(689)	16,953	178	(6,831)	(16,643)	725	4,884
Kroger Proposed Subsidy (75% of Present)	-	(0)	805	(273)	7,946	(4,422)	(5,434)	(9,178)	2,453	8,102
Adjustment for E-20		(0)	(620)	7	116	154	144	132	35	32
Required Rate Increase	448,194	207,600	660	2,169	41,586	50,078	48,172	40,968	12,456	13,493
Kroger Percentage Increase	16.99%	16.74%	20.20%	14.06%	23.92%	18.32%	15.79%	13.35%	14.53%	15.12%
Net Income with Kroger Subsidy Reduction	474,897	240,866	309	2,784	40,294	62,410	58,888	56,595	11,996	7,591
Rate of Return	8.86%	10.55%	2.78%	11.24%	9.44%	11.04%	11.20%	11.72%	9.40%	6.42%
Rate of Return Index		1.191	0.314	1.266	1.065	1.246	1.264	1.323	1.061	0.724
Pro Forma PSA Impact	(169,977)	(87,217)	(203)	(1,246)	(8,490)	(16,122)	(20,433)	(23,958)	(7,605)	(9,160)
Net Increase	278,217	120,383	457	923	33,096	33,956	25,739	17,028	4,851	4,333
Net Percentage Increase	10.55%	9.71%	13.99%	5.98%	19.04%	12.42%	8.80%	5.55%	5.68%	4.88%

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BEFORE THE

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ARIZONA CORPORATION COMMISSION

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AZ CORP COMMISSION
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Mike Gleason, Chairman
William A. Mundell
Jeff Hatch-Miller
Kristin K. Mayes
Gary Pierce

In the Matter of the Filing by Tucson Electric Power Company to Amend Decision No. 62103	**) Docket No. E-01933A-05-0650**
In the Matter of the Application of Tucson Electric Power Company for the Establishment of Just and Reasonable Rates and Charges Designed to Realize A Reasonable Rate of Return on the Fair Value of Its Operations Throughout the State of Arizona	**) Docket No. E-01933A-07-0402**

DIRECT TESTIMONY

AND EXHIBITS

OF

STEPHEN J. BARON

ON BEHALF OF THE

KROGER CO.

Arizona Corporation Commission
DOCKETED
MAR 14 2008
DOCKETED BY nr

J. KENNEDY AND ASSOCIATES, INC.
ROSWELL, GEORGIA

March 2008

BEFORE THE

ARIZONA CORPORATION COMMISSION

In the Matter of the Filing by Tucson Electric Power Company to Amend Decision No. 62103	**) Docket No. E-01933A-05-0650**
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BEFORE THE

ARIZONA CORPORATION COMMISSION

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DIRECT TESTIMONY OF STEPHEN J. BARON

I. INTRODUCTION

Q. Please state your name and business address.

A. My name is Stephen J. Baron. My business address is J. Kennedy and Associates, Inc. ("Kennedy and Associates"), 570 Colonial Park Drive, Suite 305, Roswell, Georgia 30075.

Q. What is your occupation and by who are you employed?

A. I am the President and a Principal of Kennedy and Associates, a firm of utility rate, planning, and economic consultants in Atlanta, Georgia.

Q. Please describe briefly the nature of the consulting services provided by Kennedy and Associates.

A. Kennedy and Associates provides consulting services in the electric and gas utility industries. Our clients include state agencies and industrial electricity consumers. The firm provides expertise in system planning, load forecasting, financial analysis, cost-of-service, and rate design. Current clients include the Georgia and Louisiana Public Service Commissions, and industrial consumer groups throughout the United States.

Q. Please state your educational background.

A. I graduated from the University of Florida in 1972 with a B.A. degree with high honors in Political Science and significant coursework in Mathematics and Computer Science. In 1974, I received a Master of Arts Degree in Economics, also from the University of Florida. My areas of specialization were econometrics, statistics, and public utility economics. My thesis concerned the development of an econometric model to forecast electricity sales in the State of Florida, for which I received a grant from the Public Utility Research Center of the University of Florida. In addition, I have advanced study and coursework in time series analysis and dynamic model building.

Q. Please describe your professional experience.

A. I have more than thirty years of experience in the electric utility industry in the areas of cost and rate analysis, forecasting, planning, and economic analysis.

Following the completion of my graduate work in economics, I joined the staff of the Florida Public Service Commission in August of 1974 as a Rate Economist. My responsibilities included the analysis of rate cases for electric, telephone, and gas utilities, as well as the preparation of cross-examination material and the preparation of staff recommendations.

In December 1975, I joined the Utility Rate Consulting Division of Ebasco Services, Inc. as an Associate Consultant. In the seven years I worked for Ebasco, I received successive promotions, ultimately to the position of Vice President of Energy Management Services of Ebasco Business Consulting Company. My responsibilities included the management of a staff of consultants engaged in providing services in the areas of econometric modeling, load and energy forecasting, production cost modeling, planning, cost-of-service analysis, cogeneration, and load management.

I joined the public accounting firm of Coopers & Lybrand in 1982 as a Manager of the Atlanta Office of the Utility Regulatory and Advisory Services Group. In this capacity I was responsible for the operation and management of the Atlanta office. My duties included the technical and administrative supervision of the staff, budgeting, recruiting, and marketing as well as project management on client engagements. At Coopers & Lybrand, I specialized in utility cost analysis, forecasting, load analysis, economic analysis, and planning.

In January 1984, I joined the consulting firm of Kennedy and Associates as a Vice President and Principal. I became President of the firm in January 1991.

During the course of my career, I have provided consulting services to more than thirty utility, industrial, and Public Service Commission clients, including three international utility clients.

I have presented numerous papers and published an article entitled "How to Rate Load Management Programs" in the March 1979 edition of "Electrical World." My article on "Standby Electric Rates" was published in the November 8, 1984 issue of "Public Utilities Fortnightly." In February of 1984, I completed a detailed analysis entitled "Load Data Transfer Techniques" on behalf of the Electric Power Research Institute, which published the study.

I have presented testimony as an expert witness in Arizona, Arkansas, Colorado, Connecticut, Florida, Georgia, Indiana, Kentucky, Louisiana, Maine, Michigan, Minnesota, Maryland, Missouri, New Jersey, New Mexico, New York, North Carolina, Ohio, Pennsylvania, Texas, Virginia, West Virginia, Wisconsin; before the Federal Energy Regulatory Commission and in United States Bankruptcy Court. A list of my specific regulatory appearances can be found in Baron Exhibit ____ (SJB-1).

Q. Have you previously presented testimony before the Arizona Corporation Commission?

A. Yes. I presented testimony in a Tucson Electric Power Company proceeding in 1981 on behalf of the Commission (Docket No. U-1933I). I also presented testimony in two Arizona Public Service Company rate cases on behalf of Kroger Co. (Docket Nos. E-01345-03-0437 and E-01345A-05-0816).

Q. On whose behalf are you testifying in this proceeding?

A. I am testifying on behalf of the Kroger Co. Kroger has approximately 22 stores and other facilities in the TEP service territory. These stores consume in excess of 48 million kWhs per year on the TEP system.

Q. What is the purpose of your testimony?

A. I will be presenting testimony on a number of cost of service and rate design issues that affect Kroger's service on TEP's General Service rate schedules, primarily rate GS-85.[1] As I will discuss, I do not support the Company's proposed Average and Peaks class cost of service methodology in this case. A 4CP methodology is more appropriate for retail cost allocation and is consistent with the Company's proposed jurisdictional allocation methodology.

With regard to rate design, I will discuss the Company's proposed revisions to its time-of-day rates, specifically focusing on rate GS-85N. TEP is proposing the elimination of a substantial portion of the current rate GS-85 kW demand charges and rolling these amounts into its proposed time-of-day energy charges. As I will discuss, this causes a substantial portion of the GS-85N transmission charge (which is demand related) to be recovered through off-peak energy charges. This is not reasonable and should be corrected. I will also discuss other rate design problems that I have identified with the proposed GS-85N rate related to the recovery of demand cost through the energy charges of the rate.

Q. Would you please summarize your recommendations?

A. Yes.

- **TEP's "average and peaks"class cost of service methodology is not reasonable and should be rejected. The Company uses a 4 CP methodology for jurisdictional allocation of generation and transmission-related costs. For the same reasons cited by TEP witness Erdwurm to support the use of the 4 CP method for jurisdictional cost allocation, the 4 CP method is also appropriate for retail class cost of service allocation.**

---

1 Kroger is not presenting testimony on the Company's requested revenue increase in this case. This should not be construed as an endorsement of the Company's requested increase.

- **Even if the Commission continues to use the average and peaks methodology to allocate generation-related costs to retail rate classes, the Commission should require TEP to revise its class cost of service study to incorporate a 4 CP allocator for transmission costs, since these costs are incurred by TEP on the basis of 4 CP demands.**

- **The Company's proposed rates for Rate schedule GS-85N substantially exceed cost of service (calculated using TEP's average and peaks class cost of service study), under both the "Cost of Service" and "Hybrid" regulatory schemes. The proposed increase to GS-85N should be reduced to address this unreasonable subsidy payment that is produced by the Company's recommendations in this case.**

- **TEP's proposed rate design for rate schedule GS-85N is unreasonable because it understates the kW demand charge of the rate and overstates the time-of-day energy charges. The Company's proposed rate design improperly recovers demand related distribution, transmission and generation costs through energy charges. Rate GS-85N should be revised to recover a greater portion of demand related costs through kW demand charges.**

- **In the event that the Commission approves the recovery of the Company's proposed TCRA regulatory asset, it is inappropriate to recover the cost on a uniform kWh basis. It is reasonable to assume that the revenue deficiency used to compute the regulatory asset was produced by rate schedules in proportion to their individual rate base amounts on which rate of return and income deficiencies are determined, not on kWh energy use. If the recovery of the regulatory asset is approved by the Commission, the TCRA should be allocated to rate schedules on the basis of rate base, not kWh energy use.**

II. REVENUE ALLOCATION AND COST OF SERVICE

Q. Have you reviewed the Company's 12 month ending December 2006 test year cost of service study filed in this proceeding?

A. Yes. The Company is utilizing a 4 coincident peak and average demand ("Average & Peaks") cost of service study in this proceeding to allocate production and transmission demand costs to retail rate classes. For jurisdictional cost allocation, the Company allocates generation and transmission-related demand costs using a 4 CP methodology (not the average and peaks method). According to TEP witness D. Bentley Erdwurm,

> **Coincident peak demand determines the maximum capacity of the system. It is the demand of each jurisdiction at system peak that determines each jurisdiction's use of that capacity".** (direct testimony at page 5, line 7).

I support the use of a 4 CP methodology to allocate generation and transmission-related demand costs to jurisdictions and among retail rate schedules. For the same reasons cited by Mr. Erdwurm to support the use of the 4 CP method for jurisdictional cost allocation, the 4 CP method is also appropriate for retail class cost of service allocation.

Q, How does TEP reconcile the use of a 4 CP allocation method for jurisdictional cost allocation and an "average and peaks" methodology for retail class cost allocation?

A. I don't believe that the Company has adequately reconciled these two very different cost causation theories. Beginning on page 21 if his testimony, Mr. Erdwurm states that the average and peaks method is the methodology previously adopted by the Commission and also argues that the average and peaks method recognizes that base load units produce fuel savings, relative to less efficient gas fired peaking units. This argument, which is commonly referred to as the "capital substitution" theory, relies on the economic tradeoffs in resource planning between base load, intermediate and peaking capacity. However, there is no foundation presented by TEP in this case for the specific use of an allocation factor based on a weighting of average demand and peak demand. The weight, which in the TEP analysis, is based on the system load factor, is not supported by any cost analysis that attempts to measure the economic tradeoffs between the costs of a base load unit, versus a peaking or intermediate unit. The so-called "weight" used by the Company is arbitrary.

Q. What support has the Company provided in its testimony for the allocation of transmission costs using the average and peaks allocation factor?

A. There is no such support, nor is there any legitimate basis to use an average and peaks methodology to allocate transmission costs. Transmission costs are incurred by TEP to serve retail customers based on 4 CP kW demands, not "average and peaks." Even if the Commission continues to use the average and peaks methodology to allocate generation-related costs to retail rate classes, the Commission should require TEP to revise its class cost of service study to incorporate a 4 CP allocator for transmission costs.

Q. Do you believe that the Company's average and peaks cost of service study provides a reasonable basis to evaluate the relationship between the rates being charged each rate class and the underlying cost of providing service to these customers?

A. No. For the same reasons cited by the Company in support of a 4 CP method for jurisdiction cost allocation, I believe that the 4 CP method should be used for retail class cost of service purposes. As I discussed above, at a minimum, transmission costs should be allocated using the 4 CP allocator, since there is obviously no economic justification for use of an average demand allocation factor for transmission expenses incurred by TEP pursuant to its OATT. Though I am not presenting an alternative 4 CP class cost of service study in this case, I believe that the Commission should adopt such a methodology for purposes of assessing the reasonableness of TEP's retail rates, in relation to the underlying cost of providing service to the customers on each rate class.

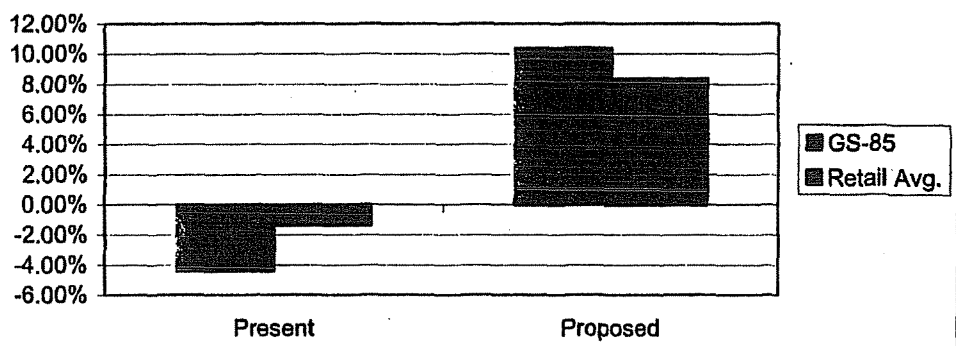
Q. How do the Company's current rates compare to the underlying cost of service?

A. Notwithstanding my previous discussion of the problems with the Company's average and peaks class cost of service study, the results of the Company's filed study show that a number of rate classes are earning rates of return below the system average rate of return.

Q. Has the Company attempted to move rate schedule rates of return toward equality in its proposed rates for each schedule?

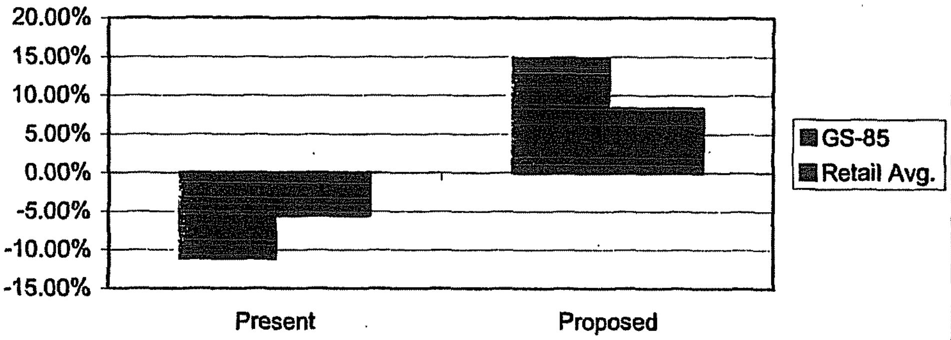
A. Yes. Again, notwithstanding my objection to the Company's class cost of service study methodology, TEP has attempted to move class rates of return. However, in the case of rate schedule GS-85, the Company's proposed rates substantially exceed cost of service, under both the "Cost of Service" and "Hybrid" regulatory schemes. Figures 1 and 2 below show the rates of return for current rate GS-85 at present and proposed rates, compared to the system average rate of return. As can be seen from the charts, the Company has moved rate GS-85 from a position below cost of service to above cost of service in this case. Since GS-85 customers have a relatively high load factor, the use of a 4 CP cost of service methodology would show even greater disparities between rates and cost, at the proposed GS-85N rate for these customers.[2]

Figure 1
Rate of Return at Present and Proposed Rates
GS-85 versus Retail Average ("Cost of Service Methodology")



[2] Under the Company's proposal, current GS-85 and GS-13 customers will migrate to rate GS-85N.

Figure 2
Rate of Return at Present and Proposed Rates
GS-85 versus Retail Average ("Hybrid Methodology")



The conclusion to draw from these graphs is that the GS-85N rate design is not reasonable and over charges the existing GS-85 customers who will now be assigned to this rate. As I will discuss in the next section of my testimony (Rate Design), I am proposing modifications to the Company's proposed GS-85N rate that more reasonably reflect cost of service.

II. RATE DESIGN ISSUES

Q. Have you reviewed TEP's design for proposed rate GS-85N?

A. Yes. This new time-of-day rate will serve current customers on rates GS-13 and GS-85. Rate GS-85 is already a time-of-day rate, while GS-13 is not. The main feature of GS-85N is that it will substantially (and unreasonably) reduce the demand charges in the current GS-85 time-of-day rate, while substantially increasing the energy charges. Table 1 shows a comparison between the present and proposed rates, using the "cost of service" methodology for comparison purposes.

Table 1
Comparison of Present GS-85 to Proposed GS-85N Rate
("Cost of Service Methodology" version)

	GS-85	GS-85N	% Change
Customer Charge	98.01	371.88	279.4%
On-Peak Demand Summer	7.50	3.00	-60.0%
On-Peak Demand Winter	4.96	3.00	-39.5%
Shoulder Demand Summer[1]	4.96	0.00	-100.0%
Off-Peak Demand Summer[1]	3.75	1.00	-73.3%
Off-Peak Demand Winter[1]	2.48	1.00	-59.7%
On-Peak kWh Summer	0.069587	0.129339	85.9%
On-Peak kWh Winter	0.065667	0.113160	72.3%
Shoulder kWh	0.065667	0.077613	18.2%
Off-Peak kWh Summer	0.061746	0.058589	-5.1%
Off-Peak kWh Winter	0.057826	0.042410	-26.7%

[1] For GS-85, this charge only applies to kW in excess of 150% of on-peak kW

Though the two rates have somewhat different structures (e.g., the on-peak summer period begins at 2pm for GS-85N and at 1 pm for the existing rate GS-85), the comparison reveals a substantial reduction in the costs that are being recovered through a kW demand charge, versus the time-of-day energy charges. This change is occurring at the same time that the overall increase in proposed by the Company for GS-85 customers is 32.5% under the "cost of service" rate plan.[3] As I will discuss below, these rate design changes are not supported by the Company's cost of service data and are not just and reasonable.

Q. **Would you please explain why TEP's proposed GS-85N rate design is inconsistent with the cost of providing service?**

A. Yes. First, as I discussed previously (Figures 1 and 2), the Company is proposing to charge GS-85N customers above cost of service at proposed rates, based on TEP's average and peak class cost of service study.[4] Second, setting aside the overall revenue requirement being charge to GS-85N customers, the design of the rate itself is inconsistent with the unbundled costs developed in TEP's class cost of service study.

[3] As I noted earlier, GS-85 customers are paying in excess of cost of service at proposed rates.
[4] The disparities between rates and cost of service are likely worse under a more appropriate 4 CP class cost of service study methodology.

As shown in the proposed tariff, the unbundled transmission rate per kWh for GS-85N is $0.007298 per kWh. Baron Exhibit__(SJB-2) is an excerpt from page 3 of 4 of the "Pricing Plan GS-85N" tariff, based on the "cost of service methodology." The identical transmission charge appears in both the "Hybrid" and "Market" tariffs for GS-85N.

Q. Are transmission charges (other than ancillary services) incurred by TEP based on kWh energy use?

A. No. TEP incurs these OATT transmission charges based on the 4CP demands of its customers. Though the Company's class cost of service study inappropriately allocates these transmission costs to rate schedules on the basis of the average and peaks demand allocator (instead of a 4CP allocator), the Company at least recognizes that these transmission costs are demand related. Nevertheless, the Company is proposing to collect these costs from rate General Service rate schedules on a uniform kWh basis, regardless of when those kWh are actually consumed. This is not consistent with the nature of the transmission costs and is inconsistent with cost based ratemaking. In addition, it provides inaccurate price signals to customers, who are charged additional transmission costs for off-peak kWh usage that does not result in additional transmission expenses to the Company.

Q. You indicated that the Company is proposing a uniform transmission rate among all General Service rate schedules. How does this compare to the cost of providing transmission service to these rates?

A. Table 2 shows a comparison for General Service rate schedules of transmission revenues (based on the uniform $0.007298 per kWh charge) versus the allocated cost providing transmission to these rates from the TEP class cost of service study.

Table 2
Comparison of Transmission Revenues to Cost of Service
(Proposed Commercial Class Rates)

Rate	Adjusted kWh Sales	Transmission Rate	Transmission Revenue	Transmission Cost	Excess Charge
GS-10	1,763,653,754	0.007298	$ 12,871,145	$ 13,714,671	$ (843,526)
GS-76N	136,727,732	0.007298	$ 997,839	$ 806,751	$ 191,088
GS-31	16,196,892	0.007298	$ 118,205	$ -	$ 118,205
GS-11	60,332,539	0.007298	$ 440,307	$ 435,189	$ 5,118
GS-85N	1,337,468,740	0.007298	$ 9,760,847	$ 9,189,116	$ 571,731
Total	3,314,379,657		$ 24,188,343	$ 24,145,727	$ 42,616

As can be seen, rate schedule GS-85N is being charged $571,731 in excess transmission revenues, compared to the cost of transmission service for the customers. There is no justification for this overcharge and it should be corrected in the TEP rate design for GS-85N.

Q. Within the GS-85N rate class, how are transmission charges being collected from customers?

A. Table 3 shows a distribution of transmission revenues by time-of-day period for the proposed GS-85N rate schedules. As can be seen, more than 67% of the transmission revenues are being collected from GS-85N customers during the summer and winter off-peak periods, while only 11.5% of transmission revenues are being collected for summer on-peak usage. This is occurring, despite the fact that TEP pays for transmission service (via the OATT) on the basis of customer usage during the summer on-peak period. Clearly, TEP's proposed uniform kWh transmission rate is widely inconsistent with cost of service and cost causation principals.

Table 3
GS-85N Transmission Cost Rate Recovery by Time-of-Day Period

	Summer On-Peak	Summer Shoulder	Summer Off-Peak	Winter On-Peak	Winter Off-Peak	Total[1]
kWh	153,880,266	147,863,362	464,852,681	131,424,081	434,689,156	1,332,709,547
Transmission Revenue[2]	$ 1,123,018	$ 1,079,107	$ 3,392,495	$ 959,133	$ 3,172,361	9,726,114
Percent in TOD Period	11.5%	11.1%	34.9%	9.9%	32.6%	100.0%

[1] *Does not include PRS-13 sales*
[2]Transmission Rate per kWh: $ 0.007298

Q. What recommendation do you have to address this problem?

A. I have recalculated the GS-85N transmission rate based on the allocated cost of providing transmission service to this rate schedule. In addition, I have developed the transmission rate on a \$/kW billing demand basis, in recognition of the nature of these costs. This calculation is shown in Table 4 below. I recommend that this rate be used to recover transmission costs for GS-85N. To do so, the uniform \$0.007298 charge should be removed from the kWh delivery charges of the proposed rate and the \$2.63/kW charge that I calculated in Table 4 should be added to the rate schedule.

Table 4
Development of Transmission Rate for GS-85N

Rate	Transmission Cost	kW Billing Determinants[1]	kW Rate
GS-13	$ 8,391,904	3,285,983	
GS-85	$ 797,212	213,046	
Total 85N	$ 9,189,116	3,499,029	$ 2.63

[1] Summer and Winter on-peak kW

Q. Have you identified other problems with the design of the GS-85N rate proposed by TEP?

A. Yes. In addition to the transmission rate design problem, the Company has also included an insufficient amount of cost in the proposed $3.00/kW GS-85N on-peak demand rate and simultaneously overstated the delivery energy charges. Based on an analysis of the Company's unit cost data from its cost of service study for the "Cost of Service" methodology, the production and distribution demand component revenue requirements for Rate Schedule GS-85N would support an on-peak demand charge in excess of $15 per kW month.[5] For the Hybrid methodology, the on-peak demand cost is in excess of $14 per kW month. Neither of these unit costs include transmission demand costs; they only reflect production demand and distribution demand cost components.

Q. Are you recommending that the GS-85N on-peak demand charge be set at the $14 to $15 per kW level justified by the Company's unit cost analysis?

A. No. Though such a rate could be justified based on TEP's own cost of service analysis, I am recommending that the GS-85N on-peak demand charge plus my recommended $2.63 per kW month transmission demand charge be limited to a

[5] For the "Cost of Service" methodology, these demand component revenue requirements are shown in TEP's "Schedule G-6 (Unit Costs) Cost of Service," page 14 of 20.

total of $7.88 per kW month for the "Cost of Service" methodology rate and $8.74 per kW for the "Hybrid" methodology rate. For comparison purposes to the Company's proposed on-peak demand charge of $3.00 per kW (not including transmission charges).

Q. What is the basis for your recommended $7.88 and $8.74 per kW on-peak demand charges for GS-85N?

A. Rate Schedule Gs-85N is a new rate that combines customers on existing rates GS-13, GS-85A and GS-85F. These current rates have very different current demand charges. Rate GS-13 has a demand charge of $6.52 per kW, GS-85A has a summer on-peak demand charge of $7.50 and GS-85F has an on-peak summer demand charge of $16.34. As a compromise and to reflect mitigation for GS-13 customers, my recommendation is to set the proposed GS-85n on-peak demand rate at the existing GS-85A on-peak rate, adjusted for the average rate increase to all GS-85N customers. This produces a rate of $7.88 for the "Cost of Service" method and $8.74 per kW for the Hybrid method.

Q. Have you developed a recommended GS=85N rate, reflecting your proposed rate design changes for the "Cost of Service" methodology?

A. Yes, Baron Exhibit__(SJB-3), Schedules 1, 2 and 3 shows this analysis. Schedule 1 shows a proof of revenues for GS-85N using the Company's filed rate design. Schedule 2 shows the adjustment to reflect my proposed $2.63 per kW transmission rate (added to the Company's proposed $3.00 on-peak charge) and the removal of the Company's $0.007298 per kWh transmission charge from the GS-85N energy delivery rates. Finally, Schedule 3 shows the GS-85N rate design and proof of revenues using my proposed $7.88 per kW on-peak demand rate. The energy delivery charges have been adjusted to reflect the removal of a portion of the demand related production and distribution costs that are now being shifted from the time-of-day energy charges to the on-peak demand charge.

Q. Have you developed a similar analysis using the Company's Hybrid methodology?

A. Yes. Baron Exhibit__(SJB-4) shows the development of the GS-85N rate using the Company's unit cost analysis from the Hybrid methodology case.

III. TERMINATION COST REGULATORY ASSET CHARGE

Q. Have you reviewed the cost recovery approach that TEP is recommending for its requested $788 million Termination Cost Regulatory Asset ("TCRA")?

A. Yes. Although I am not addressing the reasonableness of the recovery of the regulatory asset itself, in the event that the Commission approves the recovery of the Company's regulatory asset charge, it is inappropriate to recover the cost on a uniform kWh basis.[6] As discussed in the Company's testimony, these regulatory asset costs are asserted to be based on an imputed revenue deficiency beginning in 2004. If this is true, it is reasonable to assume that this revenue deficiency was produced by rate schedules in proportion to their individual rate base amounts on which rate of return and income deficiencies are determined, not on kWh energy use. Essentially, the Company's argument for the recovery of the revenue deficiency is equivalent to an argument for an insufficient rate of return on rate base. Therefore, if the recovery of the regulatory asset is approved by the Commission, the TCRA should be allocated to rate schedules on the basis of rate base, not kWh energy use. Baron Exhibit__(SJB-5) shows an

[6] This should not be construed to indicate that Kroger Co. is supporting the TCRAC.

allocation of the TCRA to rate schedules on the basis of a rate base allocator and compares this result to the Company's proposal for a uniform kWh TCRA charge.

Q. Does that complete your testimony?

A. Yes.

BEFORE THE

ARIZONA CORPORATION COMMISSION

In the Matter of the **Filing by Tucson Electric Power Company to Amend Decision No. 62103**	) Docket No. E-01933A-05-0650
In the Matter of the Application of Tucson Electric Power Company for the Establishment of Just and Reasonable Rates and Charges Designed to Realize A Reasonable Rate of Return on the Fair Value of Its Operations Throughout the State of Arizona	) Docket No. E-01933A-07-0402

EXHIBITS

OF

STEPHEN J. BARON

ON BEHALF OF THE

KROGER CO.

J. KENNEDY AND ASSOCIATES, INC.
ROSWELL, GEORGIA

BEFORE THE

ARIZONA CORPORATION COMMISSION

In the Matter of the Filing by Tucson Electric	**) Docket No. E-01933A-05-**
0650	
Power Company to Amend Decision No. 62103	**)**
In the Matter of the Application of Tucson Electric	**)**
Power Company for the Establishment of Just and)	
Reasonable Rates and Charges Designed to Realize	**) Docket No. E-01933A-07-**
0402	
A Reasonable Rate of Return on the Fair Value of	**)**
Its Operations Throughout the State of Arizona	**)**

EXHIBIT__(SJB-1)

OF

STEPHEN J. BARON

ON BEHALF OF THE

KROGER CO.

Expert Testimony Appearances
of
Stephen J. Baron
As of March 2008

Date	Case	Jurisdict.	Party	Utility	Subject
4/81	203(B)	KY	Louisville Gas & Electric Co.	Louisville Gas & Electric Co.	Cost-of-service.
4/81	ER-81-42	MO	Kansas City Power & Light Co.	Kansas City Power & Light Co.	Forecasting.
6/81	U-1933	AZ	Arizona Corporation Commission	Tucson Electric Co.	Forecasting planning.
2/84	8924	KY	Airco Carbide	Louisville Gas & Electric Co.	Revenue requirements, cost-of-service, forecasting, weather normalization.
3/84	84-038-U	AR	Arkansas Electric Energy Consumers	Arkansas Power & Light Co.	Excess capacity, cost-of-service, rate design.
5/84	830470-EI	FL	Florida Industrial Power Users' Group	Florida Power Corp.	Allocation of fixed costs, load and capacity balance, and reserve margin. Diversification of utility.
10/84	84-199-U	AR	Arkansas Electric Energy Consumers	Arkansas Power and Light Co.	Cost allocation and rate design.
11/84	R-842651	PA	Lehigh Valley Power Committee	Pennsylvania Power & Light Co.	Interruptible rates, excess capacity, and phase-in.
1/85	85-65	ME	Airco Industrial Gases	Central Maine Power Co.	Interruptible rate design.
2/85	I-840381	PA	Philadelphia Area Industrial Energy Users' Group	Philadelphia Electric Co.	Load and energy forecast.
3/85	9243	KY	Alcan Aluminum Corp., et al.	Louisville Gas & Electric Co.	Economics of completing fossil generating unit.
3/85	3498-U	GA	Attorney General	Georgia Power Co.	Load and energy forecasting, generation planning economics.
3/85	R-842632	PA	West Penn Power Industrial Intervenors	West Penn Power Co.	Generation planning economics, prudence of a pumped storage hydro unit.
5/85	84-249	AR	Arkansas Electric Energy Consumers	Arkansas Power & Light Co.	Cost-of-service, rate design return multipliers.
5/85		City of Santa	Chamber of Commerce	Santa Clara Municipal	Cost-of-service, rate design.

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As of March 2008

Date	Case	Jurisdict.	Party	Utility	Subject
6/85	84-768-E-42T	Clara WV	West Virginia Industrial Intervenors	Monongahela Power Co.	Generation planning economics, prudence of a pumped storage hydro unit.
6/85	E-7 Sub 391	NC	Carolina Industrials (CIGFUR III)	Duke Power Co.	Cost-of-service, rate design, interruptible rate design.
7/85	29046	NY	Industrial Energy Users Association	Orange and Rockland Utilities	Cost-of-service, rate design.
10/85	85-043-U	AR	Arkansas Gas Consumers	Arkla, Inc.	Regulatory policy, gas cost-of-service, rate design.
10/85	85-63	ME	Airco Industrial Gases	Central Maine Power Co.	Feasibility of interruptible rates, avoided cost.
2/85	ER-8507698	NJ	Air Products and Chemicals	Jersey Central Power & Light Co.	Rate design.
3/85	R-850220	PA	West Penn Power Industrial Intervenors	West Penn Power Co.	Optimal reserve, prudence, off-system sales guarantee plan.
2/86	R-850220	PA	West Penn Power Industrial Intervenors	West Penn Power Co.	Optimal reserve margins, prudence, off-system sales guarantee plan.
3/86	85-299U	AR	Arkansas Electric Energy Consumers	Arkansas Power & Light Co.	Cost-of-service, rate design, revenue distribution.
3/86	85-726-EL-AIR	OH	Industrial Electric Consumers Group	Ohio Power Co.	Cost-of-service, rate design, interruptible rates.
5/86	86-081-E-GI	WV	West Virginia Energy Users Group	Monongahela Power Co.	Generation planning economics, prudence of a pumped storage hydro unit.
8/86	E-7 Sub 408	NC	Carolina Industrial Energy Consumers	Duke Power Co.	Cost-of-service, rate design, interruptible rates.
10/86	U-17378	LA	Louisiana Public Service Commission Staff	Gulf States Utilities	Excess capacity, economic analysis of purchased power.
12/86	38063	IN	Industrial Energy Consumers	Indiana & Michigan Power Co.	Interruptible rates.

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Date	Case	Jurisdict.	Party	Utility	Subject
3/87	EL-86-53-001 EL-86-57-001	Federal Energy Regulatory Commission (FERC)	Louisiana Public Service Commission Staff	Gulf States Utilities, Southern Co.	Cost/benefit analysis of unit power sales contract.
4/87	U-17282	LA	Louisiana Public Service Commission Staff	Gulf States Utilities	Load forecasting and imprudence damages, River Bend Nuclear unit.
5/87	87-023-E-C	WV	Airco Industrial Gases	Monongahela Power Co.	Interruptible rates.
5/87	87-072-E-G1	WV	West Virginia Energy Users' Group	Monongahela Power Co.	Analyze Mon Power's fuel filing and examine the reasonableness of MP's claims.
5/87	86-524-E-SC	WV	West Virginia Energy Users' Group	Monongahela Power Co.	Economic dispatching of pumped storage hydro unit.
5/87	9781	KY	Kentucky Industrial Energy Consumers	Louisville Gas & Electric Co.	Analysis of impact of 1986 Tax Reform Act.
6/87	3673-U	GA	Georgia Public Service Commission	Georgia Power Co.	Economic prudence, evaluation of Vogtle nuclear unit - load forecasting, planning.
6/87	U-17282	LA	Louisiana Public Service Commission Staff	Gulf States Utilities	Phase-in plan for River Bend Nuclear unit.
7/87	85-10-22	CT	Connecticut Industrial Energy Consumers	Connecticut Light & Power Co.	Methodology for refunding rate moderation fund.
8/87	3673-U	GA	Georgia Public Service Commission	Georgia Power Co.	Test year sales and revenue forecast.
9/87	R-850220	PA	West Penn Power Industrial Intervenors	West Penn Power Co.	Excess capacity, reliability of generating system.
10/87	R-870651	PA	Duquesne Industrial Intervenors	Duquesne Light Co.	Interruptible rate, cost-of-service, revenue allocation, rate design.
10/87	I-860025	PA	Pennsylvania Industrial Intervenors		Proposed rules for cogeneration, avoided cost, rate recovery.

Expert Testimony Appearances
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Date	Case	Jurisdict.	Party	Utility	Subject
10/87	E-015/ GR-87-223	MN	Taconite Intervenors	Minnesota Power & Light Co.	Excess capacity, power and cost-of-service, rate design.
10/87	8702-EI	FL	Occidental Chemical Corp.	Florida Power Corp.	Revenue forecasting, weather normalization.
12/87	87-07-01	CT	Connecticut Industrial Energy Consumers	Connecticut Light Power Co.	Excess capacity, nuclear plant phase-in.
3/88	10064	KY	Kentucky Industrial Energy Consumers	Louisville Gas & Electric Co.	Revenue forecast, weather normalization rate treatment of cancelled plant.
3/88	87-183-TF	AR	Arkansas Electric Consumers	Arkansas Power & Light Co.	Standby/backup electric rates.
5/88	870171C001	PA	GPU Industrial Intervenors	Metropolitan Edison Co.	Cogeneration deferral mechanism, modification of energy cost recovery (ECR).
6/88	870172C005	PA	GPU Industrial Intervenors	Pennsylvania Electric Co.	Cogeneration deferral mechanism, modification of energy cost recovery (ECR).
7/88	88-171-EL-AIR 88-170-EL-AIR Interim Rate Case	OH	Industrial Energy Consumers	Cleveland Electric/ Toledo Edison	Financial analysis/need for interim rate relief.
7/88	Appeal of PSC	19th Judicial Docket U-17282	Louisiana Public Service Commission Circuit Court of Louisiana	Gulf States Utilities	Load forecasting, imprudence damages.
11/88	R-880989	PA	United States Steel	Carnegie Gas	Gas cost-of-service, rate design.
11/88	88-171-EL-AIR 88-170-EL-AIR	OH	Industrial Energy Consumers	Cleveland Electric/ Toledo Edison. General Rate Case.	Weather normalization of peak loads, excess capacity, regulatory policy.
3/89	870216/283 284/286	PA	Armco Advanced Materials Corp., Allegheny Ludlum Corp.	West Penn Power Co.	Calculated avoided capacity, recovery of capacity payments.

Expert Testimony Appearances
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Date	Case	Jurisdict.	Party	Utility	Subject
8/89	8555	TX	Occidental Chemical Corp.	Houston Lighting & Power Co.	Cost-of-service, rate design.
8/89	3840-U	GA	Georgia Public Service Commission	Georgia Power Co.	Revenue forecasting, weather normalization.
9/89	2087	NM	Attorney General of New Mexico	Public Service Co. of New Mexico	Prudence - Palo Verde Nuclear Units 1, 2 and 3, load forecasting.
10/89	2262	NM	New Mexico Industrial Energy Consumers	Public Service Co. of New Mexico	Fuel adjustment clause, off-system sales, cost-of-service, rate design, marginal cost.
11/89	38728	IN	Industrial Consumers for Fair Utility Rates	Indiana Michigan Power Co.	Excess capacity, capacity equalization, jurisdictional cost allocation, rate design, interruptible rates.
1/90	U-17282	LA	Louisiana Public Service Commission Staff	Gulf States Utilities	Jurisdictional cost allocation, O&M expense analysis.
5/90	890366	PA	GPU Industrial Intervenors	Metropolitan Edison Co.	Non-utility generator cost recovery.
6/90	R-901609	PA	Armco Advanced Materials Corp., Allegheny Ludlum Corp.	West Penn Power Co.	Allocation of QF demand charges in the fuel cost, cost-of-service, rate design.
9/90	8278	MD	Maryland Industrial Group	Baltimore Gas & Electric Co.	Cost-of-service, rate design, revenue allocation.
12/90	U-9346 Rebuttal	MI	Association of Businesses Advocating Tariff Equity	Consumers Power Co.	Demand-side management, environmental externalities.
12/90	U-17282 Phase IV	LA	Louisiana Public Service Commission Staff	Gulf States Utilities	Revenue requirements, jurisdictional allocation.
12/90	90-205	ME	Airco Industrial Gases	Central Maine Power Co.	Investigation into interruptible service and rates.
1/91	90-12-03 Interim	CT	Connecticut Industrial Energy Consumers	Connecticut Light & Power Co.	Interim rate relief, financial analysis, class revenue allocation.

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Date	Case	Jurisdict.	Party	Utility	Subject
5/91	90-12-03 Phase II	CT	Connecticut Industrial Energy Consumers	Connecticut Light & Power Co.	Revenue requirements, cost-of-service, rate design, demand-side management.
8/91	E-7, SUB SUB 487	NC	North Carolina Industrial Energy Consumers	Duke Power Co.	Revenue requirements, cost allocation, rate design, demand-side management.
8/91	8341 Phase I	MD	Westvaco Corp.	Potomac Edison Co.	Cost allocation, rate design, 1990 Clean Air Act Amendments.
8/91	91-372 EL-UNC	OH	Armco Steel Co., L.P.	Cincinnati Gas & Electric Co.	Economic analysis of cogeneration, avoid cost rate.
9/91	P-910511 P-910512	PA	Allegheny Ludlum Corp., Armco Advanced Materials Co., The West Penn Power Industrial Users' Group	West Penn Power Co.	Economic analysis of proposed CWIP Rider for 1990 Clean Air Act Amendments expenditures.
9/91	91-231 -E-NC	WV	West Virginia Energy Users' Group	Monongahela Power Co.	Economic analysis of proposed CWIP Rider for 1990 Clean Air Act Amendments expenditures.
10/91	8341 - Phase II	MD	Westvaco Corp.	Potomac Edison Co.	Economic analysis of proposed CWIP Rider for 1990 Clean Air Act Amendments expenditures.
10/91	U-17282	LA	Louisiana Public Service Commission Staff	Gulf States Utilities	Results of comprehensive management audit.
Note: No testimony was prefiled on this.					
11/91	U-17949 Subdocket A	LA	Louisiana Public Service Commission Staff	South Central Bell Telephone Co. and proposed merger with Southern Bell Telephone Co.	Analysis of South Central Bell's restructuring and
12/91	91-410-EL-AIR	OH	Armco Steel Co., Air Products & Chemicals, Inc.	Cincinnati Gas & Electric Co.	Rate design, interruptible rates.
12/91	P-880286	PA	Armco Advanced Materials Corp., Allegheny Ludlum Corp.	West Penn Power Co.	Evaluation of appropriate avoided capacity costs - QF projects.

Expert Testimony Appearances
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Date	Case	Jurisdict.	Party	Utility	Subject
1/92	C-913424	PA	Duquesne Interruptible Complainants	Duquesne Light Co.	Industrial interruptible rate.
6/92	92-02-19	CT	Connecticut Industrial Energy Consumers	Yankee Gas Co.	Rate design.
8/92	2437	NM	New Mexico Industrial Intervenors	Public Service Co. of New Mexico	Cost-of-service.
8/92	R-00922314	PA	GPU Industrial Intervenors	Metropolitan Edison Co.	Cost-of-service, rate design, energy cost rate.
9/92	39314	ID	Industrial Consumers for Fair Utility Rates	Indiana Michigan Power Co.	Cost-of-service, rate design, energy cost rate, rate treatment.
10/92	M-00920312 C-007	PA	The GPU Industrial Intervenors	Pennsylvania Electric Co.	Cost-of-service, rate design, energy cost rate, rate treatment.
12/92	U-17949	LA	Louisiana Public Service Commission Staff	South Central Bell Co.	Management audit.
12/92	R-00922378	PA	Armco Advanced Materials Co. The WPP Industrial Intervenors	West Penn Power Co.	Cost-of-service, rate design, energy cost rate, SO_2 allowance rate treatment.
1/93	8487	MD	The Maryland Industrial Group	Baltimore Gas & Electric Co.	Electric cost-of-service and rate design, gas rate design (flexible rates).
2/93	E002/GR-92-1185	MN	North Star Steel Co. Praxair, Inc.	Northern States Power Co.	Interruptible rates.
4/93	EC92 21000 ER92-806-000 (Rebuttal)	Federal Energy Regulatory Commission	Louisiana Public Service Commission Staff	Gulf States Utilities/Entergy agreement.	Merger of GSU into Entergy System; impact on system
7/93	93-0114-E-C	WV	Airco Gases	Monongahela Power Co.	Interruptible rates.
8/93	930759-EG	FL	Florida Industrial Power Users' Group	Generic - Electric Utilities	Cost recovery and allocation of DSM costs.
9/93	M-009 30406	PA	Lehigh Valley Power Committee	Pennsylvania Power & Light Co.	Ratemaking treatment of off-system sales revenues.

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Date	Case	Jurisdict.	Party	Utility	Subject
11/93	346	KY	Kentucky Industrial Utility Customers	Generic - Gas Utilities	Allocation of gas pipeline transition costs - FERC Order 636.
12/93	U-17735	LA	Louisiana Public Service Commission Staff	Cajun Electric Power Cooperative	Nuclear plant prudence, forecasting, excess capacity.
4/94	E-015/ GR-94-001	MN	Large Power Intervenors	Minnesota Power Co.	Cost allocation, rate design, rate phase-in plan.
5/94	U-20178	LA	Louisiana Public Service Commission	Louisiana Power & Light Co.	Analysis of least cost integrated resource plan and demand-side management program.
7/94	R-00942986	PA	Armco, Inc.; West Penn Power Industrial Intervenors	West Penn Power Co.	Cost-of-service, allocation of rate increase, rate design, emission allowance sales, and operations and maintenance expense.
7/94	94-0035-E-42T	WV	West Virginia Energy Users Group	Monongahela Power Co.	Cost-of-service, allocation of rate increase, and rate design.
8/94	EC94 13-000	Federal Energy Regulatory Commission	Louisiana Public Service Commission	Gulf States Utilities/Entergy	Analysis of extended reserve shutdown units and violation of system agreement by Entergy.
9/94	R-00943 081 R-00943 081C0001	PA	Lehigh Valley Power Committee	Pennsylvania Public Utility Commission	Analysis of interruptible rate terms and conditions, availability.
9/94	U-17735	LA	Louisiana Public Service Commission	Cajun Electric Power Cooperative	Evaluation of appropriate avoided cost rate.
9/94	U-19904	LA	Louisiana Public Service Commission	Gulf States Utilities	Revenue requirements.
10/94	5258-U	GA	Georgia Public Service Commission	Southern Bell Telephone & Telegraph Co.	Proposals to address competition in telecommunication markets.
11/94	EC94-7-000 ER94-898-000	FERC	Louisiana Public Service Commission	El Paso Electric and Central and Southwest	Merger economics, transmission equalization hold harmless proposals.
2/95	941-430EG	CO	CF&I Steel, L.P.	Public Service Company of Colorado	Interruptible rates, cost-of-service.

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Date	Case	Jurisdict.	Party	Utility	Subject
4/95	R-00943271	PA	PP&L Industrial Customer Alliance	Pennsylvania Power & Light Co.	Cost-of-service, allocation of rate increase, rate design, interruptible rates.
6/95	C-00913424 C-00946104	PA	Duquesne Interruptible Complainants	Duquesne Light Co.	Interruptible rates.
8/95	ER95-112 -000	FERC	Louisiana Public Service Commission	Entergy Services, Inc.	Open Access Transmission Tariffs - Wholesale.
10/95	U-21485	LA	Louisiana Public Service Commission	Gulf States Utilities Company	Nuclear decommissioning, revenue requirements, capital structure.
10/95	ER95-1042 -000	FERC	Louisiana Public Service Commission	System Energy Resources, Inc.	Nuclear decommissioning, revenue requirements.
10/95	U-21485	LA	Louisiana Public Service Commission	Gulf States Utilities Co.	Nuclear decommissioning and cost of debt capital, capital structure.
11/95	I-940032	PA	Industrial Energy Consumers of Pennsylvania	State-wide - all utilities	Retail competition issues.
7/96	U-21496	LA	Louisiana Public Service Commission	Central Louisiana Electric Co.	Revenue requirement analysis.
7/96	8725	MD	Maryland Industrial Group	Baltimore Gas & Elec. Co., Potomac Elec. Power Co., Constellation Energy Co.	Ratemaking issues associated with a Merger.
8/96	U-17735	LA	Louisiana Public Service Commission	Cajun Electric Power Cooperative	Revenue requirements.
9/96	U-22092	LA	Louisiana Public Service Commission	Entergy Gulf States, Inc.	Decommissioning, weather normalization, capital structure.
2/97	R-973877	PA	Philadelphia Area Industrial Energy Users Group	PECO Energy Co.	Competitive restructuring policy issues, stranded cost, transition charges.
6/97	Civil Action No. 94-11474	US Bank-ruptcy Court Middle District of Louisiana	Louisiana Public Service Commission	Cajun Electric Power Cooperative	Confirmation of reorganization plan; analysis of rate paths produced by competing plans.

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Date	Case	Jurisdict.	Party	Utility	Subject
6/97	R-973953	PA	Philadelphia Area Industrial Energy Users Group	PECO Energy Co.	Retail competition issues, rate unbundling, stranded cost analysis.
6/97	8738	MD	Maryland Industrial Group	Generic	Retail competition issues
7/97	R-973954	PA	PP&L Industrial Customer Alliance	Pennsylvania Power & Light Co.	Retail competition issues, rate unbundling, stranded cost analysis.
10/97	97-204	KY	Alcan Aluminum Corp. Southwire Co.	Big River Electric Corp.	Analysis of cost of service issues - Big Rivers Restructuring Plan
10/97	R-974008	PA	Metropolitan Edison Industrial Users	Metropolitan Edison Co.	Retail competition issues, rate unbundling, stranded cost analysis.
10/97	R-974009	PA	Pennsylvania Electric Industrial Customer	Pennsylvania Electric Co.	Retail competition issues, rate unbundling, stranded cost analysis.
11/97	U-22491	LA	Louisiana Public Service Commission	Entergy Gulf States, Inc.	Decommissioning, weather normalization, capital structure.
11/97	P-971265	PA	Philadelphia Area Industrial Energy Users Group	Enron Energy Services Power, Inc./ PECO Energy	Analysis of Retail Restructuring Proposal.
12/97	R-973981	PA	West Penn Power Industrial Intervenors	West Penn Power Co.	Retail competition issues, rate unbundling, stranded cost analysis.
12/97	R-974104	PA	Duquesne Industrial Intervenors	Duquesne Light Co.	Retail competition issues, rate unbundling, stranded cost analysis.
3/98 (Allocated Stranded Cost Issues)	U-22092	LA	Louisiana Public Service Commission	Gulf States Utilities Co.	Retail competition, stranded cost quantification.
3/98	U-22092		Louisiana Public Service Commission	Gulf States Utilities, Inc.	Stranded cost quantification, restructuring issues.
9/98	U-17735		Louisiana Public Service Commission	Cajun Electric Power Cooperative, Inc.	Revenue requirements analysis, weather normalization.
12/98	8794	MD	Maryland Industrial Group and	Baltimore Gas and Electric Co.	Electric utility restructuring, stranded cost recovery, rate

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Date	Case	Jurisdict.	Party	Utility	Subject
			Millennium Inorganic Chemicals Inc.		unbundling.
12/98	U-23358	LA	Louisiana Public Service Commission	Entergy Gulf States, Inc.	Nuclear decommissioning, weather normalization, Entergy System Agreement.
5/99 (Cross-Answering Testimony)	EC-98-40-000	FERC	Louisiana Public Service Commission	American Electric Power Co. & Central South West Corp.	Merger issues related to market power mitigation proposals.
5/99 (Response Testimony)	98-426	KY	Kentucky Industrial Utility Customers, Inc.	Louisville Gas & Electric Co.	Performance based regulation, settlement proposal issues, cross-subsidies between electric. gas services.
6/99	98-0452	WV	West Virginia Energy Users Group	Appalachian Power, Monongahela Power, & Potomac Edison Companies	Electric utility restructuring, stranded cost recovery, rate unbundling.
7/99	99-03-35	CT	Connecticut Industrial \Energy Consumers	United Illuminating Company	Electric utility restructuring, stranded cost recovery, rate unbundling.
7/99	Adversary Proceeding No. 98-1065	U.S. Bankruptcy Court	Louisiana Public Service Commission	Cajun Electric Power Cooperative	Motion to dissolve preliminary injunction.
7/99	99-03-06	CT	Connecticut Industrial Energy Consumers	Connecticut Light & Power Co.	Electric utility restructuring, stranded cost recovery, rate unbundling.
10/99	U-24182	LA	Louisiana Public Service Commission	Entergy Gulf States, Inc.	Nuclear decommissioning, weather normalization, Entergy System Agreement.
12/99	U-17735	LA	Louisiana Public Service Commission	Cajun Electric Power Cooperative, Inc.	Ananlysi of Proposed Contract Rates, Market Rates.
03/00	U-17735	LA	Louisiana Public Service Commission	Cajun Electric Power Cooperative, Inc.	Evaluation of Cooperative Power Contract Elections
03/00	99-1658-EL-ETP	OH	AK Steel Corporation	Cincinnati Gas & Electric Co.	Electric utility restructuring, stranded cost recovery, rate Unbundling.

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Date	Case	Jurisdict.	Party	Utility	Subject
08/00	98-0452 E-GI	WVA	West Virginia Energy Users Group	Appalachian Power Co. American Electric Co.	Electric utility restructuring rate unbundling.
08/00	00-1050 E-T 00-1051-E-T	WVA	West Virginia Energy Users Group	Mon Power Co. Potomac Edison Co.	Electric utility restructuring rate unbundling.
10/00	SOAH 473-00-1020 PUC 2234	TX	The Dallas-Fort Worth Hospital Council and The Coalition of Independent Colleges And Universities	TXU, Inc.	Electric utility restructuring rate unbundling.
12/00	U-24993	LA	Louisiana Public Service Commission	Entergy Gulf States, Inc.	Nuclear decommissioning, revenue requirements.
12/00	EL00-66-000 & ER00-2854 EL95-33-002	LA	Louisiana Public Service Commission	Entergy Services Inc.	Inter-Company System Agreement: Modifications for retail competition, interruptible load.
04/01	U-21453, U-20925, U-22092 (Subdocket B) Addressing Contested Issues	LA	Louisiana Public Service Commission	Entergy Gulf States, Inc.	Jurisdictional Business Separation - Texas Restructuring Plan
10/01	14000-U	GA	Georgia Public Service Commission Adversary Staff	Georgia Power Co.	Test year revenue forecast.
11/01	U-25687	LA	Louisiana Public Service Commission	Entergy Gulf States, Inc.	Nuclear decommissioning requirements transmission revenues.
11/01	U-25965	LA	Louisiana Public Service Commission	Generic	Independent Transmission Company ("Transco"). RTO rate design.
03/02	001148-EI	FL	South Florida Hospital and Healthcare Assoc.	Florida Power & Light Company	Retail cost of service, rate design, resource planning and demand side management.
06/02	U-25965	LA	Louisiana Public Service Commission	Entergy Gulf States Entergy Louisiana	RTO Issues
07/02	U-21453	LA	Louisiana Public Service Commission	SWEPCO, AEP	Jurisdictional Business Sep. - Texas Restructuring Plan.

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Date	Case	Jurisdict.	Party	Utility	Subject
08/02	U-25888	LA	Louisiana Public Service Commission	Entergy Louisiana, Inc. Entergy Gulf States, Inc.	Modifications to the Inter-Company System Agreement, Production Cost Equalization.
08/02	EL01-88-000	FERC	Louisiana Public Service Commission	Entergy Services Inc. and the Entergy Operating Companies	Modifications to the Inter-Company System Agreement, Production Cost Equalization.
11/02	02S-315EG	CO	CF&I Steel & Climax Molybdenum Co.	Public Service Co. of Colorado	Fuel Adjustment Clause
01/03	U-17735	LA	Louisiana Public Service Commission	Louisiana Coops	Contract Issues
02/03	02S-594E	CO	Cripple Creek and Victor Gold Mining Co.	Aquila, Inc.	Revenue requirements, purchased power.
04/03	U-26527	LA	Louisiana Public Service Commission	Entergy Gulf States, Inc.	Weather normalization, power purchase expenses, System Agreement expenses.
11/03	ER03-753-000	FERC	Louisiana Public Service Commission Staff	Entergy Services, Inc. and the Entergy Operating Companies	Proposed modifications to System Agreement Tariff MSS-4.
11/03	ER03-583-000 ER03-583-001 ER03-583-002 ER03-681-000, ER03-681-001 ER03-682-000, ER03-682-001 ER03-682-002	FERC	Louisiana Public Service Commission	Entergy Services, Inc., the Entergy Operating Companies, EWO Marketing, L.P, and Entergy Power, Inc.	Evaluation of Wholesale Purchased Power Contracts.
12/03	U-27136	LA	Louisiana Public Service Commission	Entergy Louisiana, Inc.	Evaluation of Wholesale Purchased Power Contracts.
01/04	E-01345-03-0437	AZ	Kroger Company	Arizona Public Service Co.	Revenue allocation rate design.
02/04	00032071	PA	Duquesne Industrial Intervenors	Duquesne Light Company	Provider of last resort issues.
03/04	03A-436E	CO	CF&I Steel, LP and Climax Molybedenum	Public Service Company of Colorado	Purchased Power Adjustment Clause.

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Date	Case	Jurisdict.	Party	Utility	Subject
04/04	2003-00433 2003-00434	KY	Kentucky Industrial Utility Customers, Inc.	Louisville Gas & Electric Co. Kentucky Utilities Co.	Cost of Service Rate Design
0-6/04	03S-539E	CO	Cripple Creek, Victor Gold Mining Co., Goodrich Corp., Holcim (U.S.,), Inc., and The Trane Co.	Aquila, Inc.	Cost of Service, Rate Design Interruptible Rates
06/04	R-00049255	PA	PP&L Industrial Customer Alliance PPLICA	PPL Electric Utilities Corp.	Cost of service, rate design, tariff issues and transmission service charge.
10/04	04S-164E	CO	CF&I Steel Company, Climax Mines	Public Service Company of Colorado	Cost of service, rate design, Interruptible Rates.
03/05	Case No. 2004-00426 Case No. 2004-00421	KY	Kentucky Industrial Utility Customers, Inc.	Kentucky Utilities Louisville Gas & Electric Co.	Environmental cost recovery.
06/05	050045-EI	FL	South Florida Hospital and Healthcare Assoc.	Florida Power & Light Company	Retail cost of service, rate design
07/05	U-28155	LA	Louisiana Public Service Commission Staff	Entergy Louisiana, Inc. Entergy Gulf States, Inc.	Independent Coordinator of Transmission – Cost/Benefit
09/05	Case Nos. 05-0402-E-CN 05-0750-E-PC	WVA	West Virginia Energy Users Group	Mon Power Co. Potomac Edison Co.	Environmental cost recovery, Securitization, Financing Order
01/06	2005-00341	KY	Kentucky Industrial Utility Customers, Inc.	Kentucky Power Company	Cost of service, rate design, transmission expenses. Congestion Cost Recovery Mechanism
03/06	U-22092	LA	Louisiana Public Service Commission Staff	Entergy Gulf States, Inc.	Separation of EGSI into Texas and Louisiana Companies.
04/06	U-25116	LA	Louisiana Public Service Commission Staff	Entergy Louisiana, Inc.	Transmission Prudence Investigation
06/06	R-00061346 C0001-0005	PA	Duquesne Industrial Intervenors & IECPA	Duquesne Light Co.	Cost of Service, Rate Design, Transmission Service Charge, Tariff Issues
06/06	R-00061366 R-00061367 P-00062213 P-00062214		Met-Ed Industrial Energy Users Group and Penelec Industrial Customer Alliance	Metropolitan Edison Co. Pennsylvania Electric Co.	Generation Rate Cap, Transmission Service Charge, Cost of Service, Rate Design, Tariff Issues
07/06	U-22092 Sub-J	LA	Louisiana Public Service Commission Staff	Entergy Gulf States, Inc.	Separation of EGSI into Texas and Louisiana Companies.

Expert Testimony Appearances
of
Stephen J. Baron
As of March 2008

Date	Case	Jurisdict.	Party	Utility	Subject
07/06	Case No. 2006-00130 Case No. 2006-00129	KY	Kentucky Industrial Utility Customers, Inc.	Kentucky Utilities Louisville Gas & Electric Co.	Environmental cost recovery.
08/06	Case No. PUE-2006-00065	VA	Old Dominion Committee For Fair Utility Rates	Appalachian Power Co.	Cost Allocation, Allocation of Revenue Incr, Off-System Sales margin rate treatment
11/06	Doc. No. 97-01-15RE02	CT	Connecticut Industrial Energy Consumers	Connecticut Light & Power United Illuminating	Rate unbundling issues.
01/07	Case No. 06-0960-E-42T	WV	West Virginia Energy Users Group	Mon Power Co. Potomac Edison Co.	Retail Cost of Service Revenue apportionment
03/07	U-29764	LA	Louisiana Public Service Commission Staff	Entergy Gulf States, Inc. Entergy Louisiana, LLC	Implementation of FERC Decision Jurisdictional & Rate Class Allocation
05/07	Case No. 07-63-EL-UNC	OH	Ohio Energy Group	Ohio Power, Columbus Southern Power	Environmental Surcharge Rate Design
05/07	R-00049255 Remand	PA	PP&L Industrial Customer Alliance PPLICA	PPL Electric Utilities Corp.	Cost of service, rate design, tariff issues and transmission service charge.
06/07	R-00072155	PA	PP&L Industrial Customer Alliance PPLICA	PPL Electric Utilities Corp.	Cost of service, rate design, tariff issues.
07/07	Doc. No. 07F-037E	CO	Gateway Canyons LLC	Grand Valley Power Coop.	Distribution Line Cost Allocation
09/07	Doc. No. 05-UR-103	WI	Wisconsin Industrial Energy Group, Inc.	Wisconsin Electric Power Co.	Cost of Service, rate design, tariff issues, Interruptible rates.
11/07	ER07-682-000	FERC	Louisiana Public Service Commission Staff	Entergy Services, Inc. and the Entergy Operating Companies	Proposed modifications to System Agreement Schedule MSS-3. Cost functionalization issues.
1/08	Doc. No. 20000-277-ER-07	WY	Cimarex Energy Company	Rocky Mountain Power (PacifiCorp)	Vintage Pricing, Marginal Cost Pricing Projected Test Year
1/08	Case No. 07-551	OH	Ohio Energy Group	Ohio Edison, Toledo Edison Cleveland Electric Illuminating	Class Cost of Service, Rate Restructuring, Apportionment of Revenue Increase to Rate Schedules

Expert Testimony Appearances
of
Stephen J. Baron
As of March 2008

Date	Case	Jurisdict.	Party	Utility	Subject
2/08	ER07-956	FERC	Louisiana Public Service Commission Staff	Entergy Services, Inc. and the Entergy Operating Companies	Entergy's Compliance Filing System Agreement Bandwidth Calculations.
2/08	Doc No. P-00072342	PA	West Penn Power Industrial Intervenors	West Penn Power Co.	Default Service Plan issues.

BEFORE THE

ARIZONA CORPORATION COMMISSION

In the Matter of the Filing by Tucson Electric	**) Docket No. E-01933A-05-**
0650	
Power Company to Amend Decision No. 62103	**)**
In the Matter of the Application of Tucson Electric	**)**
Power Company for the Establishment of Just and)	
Reasonable Rates and Charges Designed to Realize	**) Docket No. E-01933A-07-**
0402.	
A Reasonable Rate of Return on the Fair Value of	**)**
Its Operations Throughout the State of Arizona	**)**

EXHIBIT__(SJB-2)

OF

STEPHEN J. BARON

ON BEHALF OF THE

KROGER CO.

Pricing Plan GS-85N
General Service Time-of-Use

	SUMMER (May – October)	WINTER (November – April)
On-peak	$0.043901	$0.039219
Shoulder-peak	$0.027985	N/A
Off-peak	$0.022651	$0.017969

Fixed Must-Run (See Must-Run Generation – Rider No. 2) $0.003293 per kWh

System Benefits $0.000443 per kWh

Transmission $0.007298 per kWh

Transmission Ancillary Services

System Control & Dispatch	$0.000099 per kWh
Reactive Supply and Voltage Control	$0.000390 per kWh
Regulation and Frequency Response	$0.000377 per kWh
Spinning Reserve Service	$0.001024 per kWh
Supplemental Reserve Service	$0.000167 per kWh

Energy Imbalance Service: currently charged pursuant to the Company's OATT.

Generation Charges:

Generation Capacity $0.000171 per kWh

Fuel and Purchased Power:

	SUMMER (May – October)	WINTER (November – April)
On-peak	$0.072176	$0.060679
Shoulder-peak	$0.036366	N/A
Off-peak	$0.022676	$0.011179

DIRECT ACCESS

A customer's Direct Access bill will include all unbundled components except those services provided by a qualified third party. Those services may include Metering (Installation, Maintenance and/or Equipment), Meter Reading, Billing and Collection, Transmission and Generation. If any of these services are not available from a third party supplier and must be obtained from the Company, the rates for Unbundled Components set forth in this tariff will be applied to the customer's bill.

FOR DIRECT ACCESS: ARIZONA INDEPENDENT SCHEDULING ADMINISTRATOR (AISA) CHARGE

A charge per kWh shall, subject to FERC authorization, be applied for costs associated with the implementation of the AISA in Arizona.

BEFORE THE

ARIZONA CORPORATION COMMISSION

In the Matter of the Filing by Tucson Electric 0650 Power Company to Amend Decision No. 62103	) Docket No. E-01933A-05-)
In the Matter of the Application of Tucson Electric Power Company for the Establishment of Just and) Reasonable Rates and Charges Designed to Realize 0402 A Reasonable Rate of Return on the Fair Value of Its Operations Throughout the State of Arizona	)) Docket No. E-01933A-07-))

EXHIBIT__(SJB-3)

OF

STEPHEN J. BARON

ON BEHALF OF THE

KROGER CO.

Exhibit ___(SJB-3)
Schedule 1

TUCSON ELECTRIC POWER
LARGE GENERAL SERVICE TIME OF USE - LGS-85N
Cost of Service Methodology

Line No.			New Billing Determinants	TEP Proposed Rate	Proposed Revenue
1	Customer Charge		7,812	$371.88	$2,905,127
	DELIVERY DEMAND CHARGES				
	Summer Demand				
2	On Peak kW		1,753,711	$3.00	$5,261,134
3	Off Peak kW		1,753,711	$1.00	$1,751,958
	Winter Demand				
4	On Peak kW		1,732,383	$3.00	$5,197,150
5	Off Peak kW		1,732,383	$1.00	$1,730,651
	DELIVERY ENERGY CHARGES				
	Summer				
6	On Peak kWhs		153,880,266	$0.056992	$8,769,912
7	Off Peak kWhs		464,852,681	$0.035742	$16,614,667
8	Shoulder Peak kWhs		147,863,362	$0.041076	$6,073,625
	Winter				
9	On Peak kWhs		199,664,087	$0.052310	$10,444,345
10	Off Peak kWhs		366,449,150	$0.031060	$11,381,757
11	Revenue Delivery Charges				$70,130,325
12	Generation Capacity		1,332,709,547	0.000171	227,813
13	**FUEL & PURCHASED POWER**				
	Summer				
	On Peak kWhs		153,880,266	0.072176	11,106,525
	Off Peak kWhs		464,852,681	0.022676	10,541,190
	Shoulder Peak kWhs		147,863,362	0.036366	5,377,217
	Winter				
	On Peak kWhs		199,664,087	0.060679	12,115,445
	Off Peak kWhs		366,449,150	0.011179	4,096,586
14	TOTAL REVENUE				$113,595,101
15	**TOTAL LGS-85N**	kWh	1,332,709,547		
16		Cust	651		

Exhibit ___(SJB-3)
Schedule 2

TUCSON ELECTRIC POWER
LARGE GENERAL SERVICE TIME OF USE - LGS-85N
Cost of Service Methodology

Line No.			New Billing Determinants	Proposed Rate	Proposed Revenue
1	Customer Charge		7,812	$371.88	$2,905,127
	DELIVERY DEMAND CHARGES				
	Summer Demand				
2	On Peak kW		1,753,711	$5.63	$9,873,395
3	Off Peak kW		1,753,711	$1.00	$1,751,958
	Winter Demand				
4	On Peak kW		1,732,383	$5.63	$9,753,318
5	Off Peak kW		1,732,383	$1.00	$1,730,651
	DELIVERY ENERGY CHARGES				
	Summer				
6	On Peak kWhs		153,880,266	$0.049694	$7,646,894
7	Off Peak kWhs		464,852,681	$0.028444	$13,222,172
8	Shoulder Peak kWhs		147,863,362	$0.033778	$4,994,518
	Winter				
9	On Peak kWhs		199,664,087	$0.045012	$8,987,196
10	Off Peak kWhs		366,449,150	$0.023762	$8,707,411
11	Revenue Delivery Charges				$69,572,639
12	Generation Capacity		1,332,709,547	0.000171	227,813
13	**FUEL & PURCHASED POWER**				
	Summer				
	On Peak kWhs		153,880,266	0.072176	11,106,525
	Off Peak kWhs		464,852,681	0.022676	10,541,190
	Shoulder Peak kWhs		147,863,362	0.036366	5,377,217
	Winter				
	On Peak kWhs		199,664,087	0.060679	12,115,445
	Off Peak kWhs		366,449,150	0.011179	4,096,586
14	TOTAL REVENUE				$113,037,415
15	**TOTAL LGS-85N**	kWh	1,332,709,547		
16		Cust	651		

TUCSON ELECTRIC POWER
LARGE GENERAL SERVICE TIME OF USE - LGS-85N
Cost of Service Methodology

Line No.			New Billing Determinants	Proposed Rate	Proposed Revenue
1	Customer Charge		7,812	$371.88	$2,905,127
	DELIVERY DEMAND CHARGES				
	Summer Demand				
2	On Peak kW		1,753,711	$7.88	$13,819,246
3	Off Peak kW		1,753,711	$1.00	$1,751,958
	Winter Demand				
4	On Peak kW		1,732,383	$7.88	$13,651,180
5	Off Peak kW		1,732,383	$1.00	$1,730,651
	DELIVERY ENERGY CHARGES				
	Summer				
6	On Peak kWhs		153,880,266	$0.043808	$6,741,226
7	Off Peak kWhs		464,852,681	$0.022558	$10,486,264
8	Shoulder Peak kWhs		147,863,362	$0.027892	$4,124,262
	Winter				
9	On Peak kWhs		199,664,087	$0.039126	$7,812,066
10	Off Peak kWhs		366,449,150	$0.017876	$6,550,661
11	Revenue Delivery Charges				$69,572,639
12	Generation Capacity		1,332,709,547	0.000171	227,813
13	**FUEL & PURCHASED POWER**				
	Summer				
	On Peak kWhs		153,880,266	0.072176	11,106,525
	Off Peak kWhs		464,852,681	0.022676	10,541,190
	Shoulder Peak kWhs		147,863,362	0.036366	5,377,217
	Winter				
	On Peak kWhs		199,664,087	0.060679	12,115,445
	Off Peak kWhs		366,449,150	0.011179	4,096,586
14	TOTAL REVENUE				$113,037,415
15	**TOTAL LGS-85N**	kWh	1,332,709,547		
16		Cust	651		

BEFORE THE

ARIZONA CORPORATION COMMISSION

In the Matter of the Filing by Tucson Electric	) Docket No. E-01933A-05-
0650	
Power Company to Amend Decision No. 62103	)
In the Matter of the Application of Tucson Electric	)
Power Company for the Establishment of Just and)	
Reasonable Rates and Charges Designed to Realize	) Docket No. E-01933A-07-
0402	
A Reasonable Rate of Return on the Fair Value of	)
Its Operations Throughout the State of Arizona	)

EXHIBIT__(SJB-4)

OF

STEPHEN J. BARON

ON BEHALF OF THE

KROGER CO.

Exhibit ___(SJB-4)
Schedule 1

TUCSON ELECTRIC POWER
LARGE GENERAL SERVICE TIME OF USE - LGS-85N
Hybrid Methodology

Line No.			New Billing Determinants	TEP Proposed Rate	Proposed Revenue
1	Customer Charge		7,812	$371.88	$2,905,127
	DELIVERY DEMAND CHARGES				
	Summer Demand				
2	On Peak kW		1,753,711	$3.00	$5,261,134
3	Off Peak kW		1,753,711	$1.00	$1,751,958
	Winter Demand				
4	On Peak kW		1,732,383	$3.00	$5,197,150
5	Off Peak kW		1,732,383	$1.00	$1,730,651
	DELIVERY ENERGY CHARGES				
	Summer				
6	On Peak kWhs		153,880,266	$0.056992	$8,769,912
7	Off Peak kWhs		464,852,681	$0.035742	$16,614,667
8	Shoulder Peak kWhs		147,863,362	$0.041076	$6,073,625
	Winter				
9	On Peak kWhs		199,664,087	$0.052310	$10,444,345
10	Off Peak kWhs		366,449,150	$0.031060	$11,381,757
11	Revenue Delivery Charges				$70,130,325
12	Generation Capacity		1,332,709,547	0.000208	277,770
13	**FUEL & PURCHASED POWER**				
	Summer				
	On Peak kWhs		153,880,266	0.081447	12,533,078
	Off Peak kWhs		464,852,681	0.031947	14,850,625
	Shoulder Peak kWhs		147,863,362	0.045637	6,747,990
	Winter				
	On Peak kWhs		199,664,087	0.069950	13,966,439
	Off Peak kWhs		366,449,150	0.020450	7,493,767
14	TOTAL REVENUE				$125,999,994
15	**TOTAL LGS-85N**	kWh	1,332,709,547		
16		Cust	651		

Exhibit ___(SJB-4)
Schedule 2

TUCSON ELECTRIC POWER
LARGE GENERAL SERVICE TIME OF USE - LGS-85N
Hybrid Methodology

Line No.			New Billing Determinants	Proposed Rate	Proposed Revenue
1	Customer Charge		7,812	$371.88	$2,905,127
	DELIVERY DEMAND CHARGES				
	Summer Demand				
2	On Peak kW		1,753,711	$5.63	$9,873,395
3	Off Peak kW		1,753,711	$1.00	$1,751,958
	Winter Demand				
4	On Peak kW		1,732,383	$5.63	$9,753,318
5	Off Peak kW		1,732,383	$1.00	$1,730,651
	DELIVERY ENERGY CHARGES				
	Summer				
6	On Peak kWhs		153,880,266	$0.049694	$7,646,894
7	Off Peak kWhs		464,852,681	$0.028444	$13,222,172
8	Shoulder Peak kWhs		147,863,362	$0.033778	$4,994,518
	Winter				
9	On Peak kWhs		199,664,087	$0.045012	$8,987,196
10	Off Peak kWhs		366,449,150	$0.023762	$8,707,411
11	Revenue Delivery Charges				$69,572,639
12	Generation Capacity		1,332,709,547	0.000208	277,770
13	**FUEL & PURCHASED POWER**				
	Summer				
	On Peak kWhs		153,880,266	0.081447	12,533,078
	Off Peak kWhs		464,852,681	0.031947	14,850,625
	Shoulder Peak kWhs		147,863,362	0.045637	6,747,990
	Winter				
	On Peak kWhs		199,664,087	0.069950	13,966,439
	Off Peak kWhs		366,449,150	0.020450	7,493,767
14	TOTAL REVENUE				$125,442,308
15	**TOTAL LGS-85N**	kWh	1,332,709,547		
16		Cust	651		

Exhibit ___(SJB-4)
Schedule 3

TUCSON ELECTRIC POWER
LARGE GENERAL SERVICE TIME OF USE - LGS-85N
Hybrid Methodology

Line No.			New Billing Determinants	Proposed Rate	Proposed Revenue
1	Customer Charge		7,812	$371.88	$2,905,127
	DELIVERY DEMAND CHARGES				
	Summer Demand				
2	On Peak kW		1,753,711	$8.74	$15,327,437
3	Off Peak kW		1,753,711	$1.00	$1,751,958
	Winter Demand				
4	On Peak kW		1,732,383	$8.74	$15,141,030
5	Off Peak kW		1,732,383	$1.00	$1,730,651
	DELIVERY ENERGY CHARGES				
	Summer				
6	On Peak kWhs		153,880,266	$0.041559	$6,395,059
7	Off Peak kWhs		464,852,681	$0.020309	$9,440,539
8	Shoulder Peak kWhs		147,863,362	$0.025643	$3,791,631
	Winter				
9	On Peak kWhs		199,664,087	$0.036876	$7,362,905
10	Off Peak kWhs		366,449,150	$0.015626	$5,726,303
11	Revenue Delivery Charges				$69,572,639
12	Generation Capacity		1,332,709,547	0.000208	277,770
13	**FUEL & PURCHASED POWER**				
	Summer				
	On Peak kWhs		153,880,266	0.081447	12,533,078
	Off Peak kWhs		464,852,681	0.031947	14,850,625
	Shoulder Peak kWhs		147,863,362	0.045637	6,747,990
	Winter				
	On Peak kWhs		199,664,087	0.069950	13,966,439
	Off Peak kWhs		366,449,150	0.020450	7,493,767
14	TOTAL REVENUE				$125,442,308
15	**TOTAL LGS-85N**	kWh	1,332,709,547		
16		Cust	651		

BEFORE THE

ARIZONA CORPORATION COMMISSION

In the Matter of the Filing by Tucson Electric	) Docket No. E-01933A-05-0650
Power Company to Amend Decision No. 62103	)
In the Matter of the Application of Tucson Electric	)
Power Company for the Establishment of Just and	)
Reasonable Rates and Charges Designed to Realize	) Docket No. E-01933A-07-0402
A Reasonable Rate of Return on the Fair Value of	)
Its Operations Throughout the State of Arizona	)

EXHIBIT__(SJB-5)

OF

STEPHEN J. BARON

ON BEHALF OF THE

KROGER CO.

Tucson Electric Power Company
Revised Calculation of Termination Cost Regulatory Asset Charge ("TCRA")

	2009 kWh Sales	kWh Sales Allocation Factor	Rate Base	Rate Base Allocation Factor	TCRA Revenue Requirement kWh	TCRA Revenue Requirement Rate Base	TCRA Revenue Requirement Difference	TCRA Rate Per kWh kWh	TCRA Rate Per kWh Rate Base
Residential	4,057,909,707	41.06%	507,485,022	51.64%	51,216,174	64,423,235	13,205,061	0.012622	0.015876
General Service	3,536,655,904	35.78%	354,002,346	36.02%	44,639,006	44,939,211	300,204	0.012622	0.012707
Large Light & Power	1,009,916,581	10.22%	50,716,184	5.16%	12,746,977	6,438,221	(6,308,756)	0.012622	0.006375
Mining	993,510,862	10.05%	34,877,502	3.55%	12,539,907	4,427,562	(8,112,345)	0.012622	0.004456
Lighting	44,057,808	0.45%	10,840,637	1.10%	556,089	1,376,176	820,087	0.012622	0.031236
Public Authority	241,969,743	2.45%	24,812,468	2.52%	3,054,097	3,149,846	95,749	0.012622	0.013018
Rate Schedules									
R01	3,832,493,679	38.77%	478,682,748	48.71%	48,373,015	60,766,899	12,393,884	0.012622	0.015856
R02	5,740,124	0.06%	365,592	0.04%	72,451	46,410	(26,040)	0.012622	0.008085
R21	56,407,817	0.57%	7,281,382	0.74%	711,969	924,343	212,374	0.012622	0.016387
R70	66,526,767	0.67%	9,428,747	0.96%	839,688	1,198,942	357,254	0.012622	0.017992
R201	96,741,319	0.98%	11,726,553	1.19%	1,221,051	1,488,640	287,589	0.012622	0.015388
GS10	1,876,733,213	18.99%	209,893,343	21.36%	23,687,774	26,645,138	2,957,363	0.012622	0.014198
GS11	64,688,259	0.65%	6,908,269	0.70%	816,483	876,978	60,495	0.012622	0.013557
GS76	140,498,681	1.42%	12,190,899	1.24%	1,773,348	1,547,587	(225,761)	0.012622	0.011015
GS13	1,298,675,285	13.14%	114,134,487	11.61%	16,391,635	14,488,928	(1,902,710)	0.012622	0.011157
GS85	138,662,019	1.40%	10,217,836	1.04%	1,750,166	1,297,114	(453,052)	0.012622	0.009355
GS31	17,398,448	0.18%	657,512	0.07%	219,600	83,469	(136,131)	0.012622	0.004797
I14	750,777,615	7.60%	38,452,081	3.91%	9,476,174	4,881,341	(4,594,833)	0.012622	0.006502
I90	259,138,946	2.62%	12,264,103	1.25%	3,270,803	1,556,880	(1,713,923)	0.012622	0.006008
Total Mining	993,510,862	10.05%	34,877,502	3.55%	12,539,907	4,427,582	(8,112,345)	0.012622	0.004456
Total Lighting	44,057,808	0.45%	10,840,637	1.10%	556,089	1,376,176	820,087	0.012622	0.031236
Pub Auth P40	108,881,979	1.10%	13,867,159	1.41%	1,374,288	1,760,382	386,094	0.012622	0.016168
Pub Auth P43-44	133,087,764	1.35%	10,945,309	1.11%	1,679,809	1,389,464	(290,345)	0.012622	0.010440
Total	9,884,020,585	100%	982,734,159	100%	124,754,251	124,754,251			

Baron Exhibit__(SJB-5)