Appropriate AFUDC Additions, 1997-2000
(millions $)

Line No.	Date	Construction Work in Progress: Property Additions	Construction Work in Progress: Transfers to Property	Construction Work in Progress: Property Balance	In-service Ratio	Compounding Additions Equity AFUDC	Equity %	Equity Addn's	Equity Transfers	Equity Base	ROE	Incremental Equity AFUDC	Transfers Equity AFUDC
	1	2	3	4	5	6	7	8	9	10	11	12	13
379	Mar-00	$2.198982	$6.272882	$43.022113	12.7%	$0	50.5%	$1.110486	$3.167806	$23.783487	14.75%	$0.292339	$0.506744
380	Apr-00	$1.922147	$0.000000	$44.944260	0.0%	$0	50.5%	$0.970684	$0.000000	$21.726167	14.75%	$0.267051	$0.000000
381	May-00	$4.073904	$0.000000	$49.018164	0.0%	$0	50.5%	$2.057322	$0.000000	$22.696851	14.75%	$0.278982	$0.000000
382	Jun-00	$4.715232	$0.000000	$53.733396	0.0%	$0	50.5%	$2.381192	$0.000000	$24.754173	14.75%	$0.304270	$0.000000
383	Jul-00	$4.715232	$0.000000	$58.448628	0.0%	$0	50.5%	$2.381192	$0.000000	$27.135365	14.75%	$0.333539	$0.000000
384	Aug-00	$4.715232	$0.000000	$63.163860	0.0%	$0	50.5%	$2.381192	$0.000000	$29.516557	14.75%	$0.362808	$0.000000
385	Sep-00	$4.715232	$0.000000	$67.879092	0.0%	$0	50.5%	$2.381192	$0.000000	$31.897749	14.75%	$0.392077	$0.000000
386	Oct-00	$4.715232	$0.000000	$72.594324	0.0%	$0	50.5%	$2.381192	$0.000000	$34.278942	14.75%	$0.421345	$0.000000
387	Nov-00	$4.715232	$0.000000	$77.309556	0.0%	$0	50.5%	$2.381192	$0.000000	$36.660134	14.75%	$0.450614	$0.000000
388	Dec-00	$8.733863	$55.628420	$30.415000	64.7%	$0	50.5%	$4.410601	$28.092352	$39.041326	14.75%	$0.479883	$4.253099

SOURCE:

Column 1	Time in months
Column 2	Exhibit 143-RGV-C, TAPS-RGV WP3, Schedule 3
Column 3	Exhibit 143-RGV-C, TAPS-RGV WP3, Schedule 3
Column 4	Exhibit 143-RGV-C, TAPS-RGV WP3, Schedule 3
Column 5	Exhibit 143-RGV-C, TAPS-RGV WP3, Schedule 3
Column 6	Sum (prior six months Col 12) - sumproduct(prior six months Col 12 * prior six months Col 5) [A]
Column 7	Part VI.A.1
Column 8	Col 2 * Col 7
Column 9	(cum Col 8 - cum prior Col 9 + cum Col 6) * Col 5
Column 10	prior (Col 8 - Col 9 + Col 10) + Col 6
Column 11	Part VI.A.3
Column 12	(Col 10 * Col 11)/12
Column 13	prior Col 14 * Col 5 + [B]
Column 14	prior Col 14 + Col 12 - Col 13
Column 15	Sum (prior six months Col 21) - sumproduct(prior six months Col 21 * prior six months Col 5) [A]
Column 16	1.0 - Col 7
Column 17	Col 2 * Col 16
Column 18	(cum Col 17 - cum prior Col 18 + cum Col 15) * Col 5
Column 19	prior (Col 17 - Col 18 + Col 19) + Col 15
Column 20	Part VI.A.2
Column 21	(Col 19 * Col 20) / 12
Column 22	prior Col 23 * Col 5 +[C]
Column 23	prior Col 23 + Col 21 - Col 22

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Appropriate AFUDC Additions, 1997-2000
(millions $)

Line No.	Date	Equity AFUDC Balance	Compounding Additions Debt AFUDC	Debt %	Debt Addn's	Debt Transfers	Debt Base	COD	Incremental Debt AFUDC	Transfers Debt AFUDC	Debt AFUDC Balance
	1	14	15	16	17	18	19	20	21	22	23
341	Jan-97	$5.930018	$0.000000	49.5%	$1.435055	$0.105254	$36.610885	7.84%	$0.239191	$0.009652	$3.718312
342	Feb-97	$6.339059	$0.000000	49.5%	$1.895488	$0.168774	$37.940685	7.84%	$0.247879	$0.015753	$3.950437
343	Mar-97	$6.782857	$0.000000	49.5%	$2.761071	$0.067783	$39.667399	7.84%	$0.259160	$0.006311	$4.203287
344	Apr-97	$7.252057	$0.000000	49.5%	$2.445856	$0.102680	$42.360686	7.84%	$0.276756	$0.009632	$4.470411
345	May-97	$7.742156	$0.000000	49.5%	$3.522854	$0.142708	$44.703862	7.84%	$0.292065	$0.013228	$4.749248
346	Jun-97	$8.271420	$0.000000	49.5%	$3.554593	$0.139894	$48.084008	7.84%	$0.314149	$0.012866	$5.050530
347	Jul-97	$8.849920	$0.000000	49.5%	$3.857194	$0.072368	$51.498708	7.84%	$0.336458	$0.006603	$5.380386
348	Aug-97	$9.482544	$0.000000	49.5%	$2.027510	$0.000000	$55.283534	7.84%	$0.361186	$0.000000	$5.741572
349	Sep-97	$9.961329	$0.000000	49.5%	$3.235648	$1.130413	$57.311043	7.84%	$0.374432	$0.107196	$6.008808
350	Oct-97	$10.618549	$0.000000	49.5%	$2.130796	$0.140231	$59.416279	7.84%	$0.388186	$0.013691	$6.383304
351	Nov-97	$11.191161	$0.000000	49.5%	$2.434914	$0.782097	$61.406844	7.84%	$0.401191	$0.078199	$6.706296
352	Dec-97	$3.267953	$0.000000	49.5%	$1.403073	$49.795413	$63.059661	7.84%	$0.411990	$5.180400	$1.937885
353	Jan-98	$3.430184	$0.000000	49.5%	$0.580894	$0.000000	$14.667321	7.84%	$0.095826	$0.000000	$2.033712
354	Feb-98	$3.598840	$0.000000	49.5%	$0.534105	$0.000000	$15.248215	7.84%	$0.099622	$0.000000	$2.133333
355	Mar-98	$3.773403	$0.000000	49.5%	$1.003976	$0.000000	$15.782320	7.84%	$0.103111	$0.000000	$2.236445
356	Apr-98	$4.073604	$0.000000	49.5%	$0.217413	($0.516106)	$16.786296	7.84%	$0.109670	($0.067882)	$2.413997
357	May-98	$4.262840	$0.000000	49.5%	$0.160240	$0.019725	$17.519815	7.84%	$0.114463	$0.002693	$2.525766
358	Jun-98	$4.422757	$0.000000	49.5%	$1.417978	$0.158515	$17.660330	7.84%	$0.115381	$0.020986	$2.620162
359	Jul-98	$4.632023	$0.000000	49.5%	$2.155319	$0.000000	$18.919793	7.84%	$0.123609	$0.000000	$2.743771
360	Aug-98	$4.865128	$0.000000	49.5%	$0.558060	$0.000000	$21.075112	7.84%	$0.137691	$0.000000	$2.881462
361	Sep-98	$5.104406	$0.000000	49.5%	$1.778849	$0.000000	$21.633172	7.84%	$0.141337	$0.000000	$3.022798
362	Oct-98	$5.199813	$0.000000	49.5%	$1.341494	$0.793107	$23.412021	7.84%	$0.152959	$0.096851	$3.078906
363	Nov-98	$5.373656	$0.000000	49.5%	$1.342138	$0.443668	$23.960407	7.84%	$0.156541	$0.053987	$3.181460
364	Dec-98	$3.737433	$0.000000	49.5%	$5.024282	$10.628160	$24.858877	7.84%	$0.162411	$1.131509	$2.212362
365	Jan-99	$3.972506	$0.000000	49.5%	$0.400372	$0.000000	$19.254999	7.84%	$0.125799	$0.000000	$2.338162
366	Feb-99	$4.207608	$0.000000	49.5%	$1.058054	$0.025334	$19.655371	7.84%	$0.128415	$0.002860	$2.463717
367	Mar-99	$4.411274	$0.000000	49.5%	$0.997409	$0.252041	$20.688091	7.84%	$0.135162	$0.028635	$2.570244
368	Apr-99	$4.672942	$0.000000	49.5%	$0.662560	$0.000000	$21.433459	7.84%	$0.140032	$0.000000	$2.710276
369	May-99	$4.942700	$0.000000	49.5%	$0.991457	$0.000000	$22.096019	7.84%	$0.144361	$0.000000	$2.854637
370	Jun-99	$5.224561	$0.000000	49.5%	$2.155460	$0.000000	$23.087476	7.84%	$0.150838	$0.000000	$3.005475
371	Jul-99	$5.529946	$0.000000	49.5%	$2.191726	$0.014661	$25.242936	7.84%	$0.164921	$0.001606	$3.168790
372	Aug-99	$5.674026	$0.000000	49.5%	$1.381247	$0.993077	$27.420001	7.84%	$0.179144	$0.109261	$3.238673
373	Sep-99	$5.597208	$0.000000	49.5%	$2.230933	$2.204014	$27.808172	7.84%	$0.181680	$0.237626	$3.182727
374	Oct-99	$5.937031	$0.000000	49.5%	$4.146489	$0.000000	$27.835091	7.84%	$0.181856	$0.000000	$3.364582
375	Nov-99	$5.892316	$0.000000	49.5%	$2.818037	$2.550666	$31.981580	7.84%	$0.208946	$0.246610	$3.326919
376	Dec-99	$3.432753	$0.000000	49.5%	$9.395430	$20.165711	$32.248951	7.84%	$0.210693	$1.611014	$1.926598
377	Jan-00	$3.702095	$0.000000	49.5%	$0.859397	$0.000000	$21.478670	7.84%	$0.140327	$0.000000	$2.066925
378	Feb-00	$3.982214	$0.000000	49.5%	$0.974460	$0.000000	$22.338067	7.84%	$0.145942	$0.000000	$2.212867

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Appropriate AFUDC Additions, 1997-2000
(millions $)

Line No.	Date	Equity AFUDC Balance	Compounding Additions Debt AFUDC	Debt %	Debt Addn's	Debt Transfers	Debt Base	COD	Incremental Debt AFUDC	Transfers Debt AFUDC	Debt AFUDC Balance
	1	14	15	16	17	18	19	20	21	22	23
379	Mar-00	$3.767808	$0.000000	49.5%	$1.088496	$3.105077	$23.312527	7.84%	$0.152309	$0.281592	$2.083584
380	Apr-00	$4.034859	$0.000000	49.5%	$0.951463	$0.000000	$21.295946	7.84%	$0.139134	$0.000000	$2.222718
381	May-00	$4.313841	$0.000000	49.5%	$2.016582	$0.000000	$22.247409	7.84%	$0.145350	$0.000000	$2.368068
382	Jun-00	$4.618111	$0.000000	49.5%	$2.334040	$0.000000	$24.263991	7.84%	$0.158525	$0.000000	$2.526592
383	Jul-00	$4.951650	$0.000000	49.5%	$2.334040	$0.000000	$26.598031	7.84%	$0.173774	$0.000000	$2.700366
384	Aug-00	$5.314458	$0.000000	49.5%	$2.334040	$0.000000	$28.932071	7.84%	$0.189023	$0.000000	$2.889389
385	Sep-00	$5.706534	$0.000000	49.5%	$2.334040	$0.000000	$31.266111	7.84%	$0.204272	$0.000000	$3.093661
386	Oct-00	$6.127879	$0.000000	49.5%	$2.334040	$0.000000	$33.600151	7.84%	$0.219521	$0.000000	$3.313182
387	Nov-00	$6.578494	$0.000000	49.5%	$2.334040	$0.000000	$35.934190	7.84%	$0.234770	$0.000000	$3.547952
388	Dec-00	$2.805277	$0.000000	49.5%	$4.323262	$27.536068	$38.268230	7.84%	$0.250019	$2.293807	$1.504164

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Appropriate Depreciation Charges, 1997-2000
(millions $)

Line No.	Description	Source	1997	1998	1999	2000
1	Net Depreciable Property In Service, BOY 1/	Prior Line 11	$606.511872	$685.123043	$675.332318	$689.627199
2	Grand Total, New Construction Expenditures	Part VI.B.1, Table, Ln. 2	$61.176000	$30.324000	$95.277000	$44.757000
3	Additions to Capitalized Interest	Part VI.B.1, Table, Ln. 9 - Prior Ln. 9	($0.007000)	($0.002000)	($0.004000)	$0.000000
4	Transfers to Depreciable Property from CWIP 2/	Part VI.B.1, Table, Ln. 7 - Prior Ln. 7	$44.290000	($9.278000)	($4.250000)	$12.823000
5	Total Additions to Depreciable Property in Service	Lns. (2 - 3 + 4)	$105.473000	$21.048000	$91.031000	$57.580000
6	Depreciation Basis	Lns. 1 + 5	$711.984872	$706.171043	$766.363318	$747.207199
7	Composit Depreciation Factor	Part VI.B.1	0.033333333	0.034482759	0.035714286	0.037037037
8	Depreciation	Lns. 7 * 6	$23.732829	$24.350726	$27.370118	$27.674341
9	Retirements	Part VI.B.1, Table, Ln. 4	($3.115000)	($6.458000)	($49.053000)	($44.737000)
10	Adjustments	Part VI.B.1, Table, Ln. 5	($0.014000)	($0.030000)	($0.313000)	$0.000000
11	Net Depreciable Property In Service, EOY	Lns. (6 - 8 + 9 + 10)	$685.123043	$675.332318	$689.627199	$674.795859

1/ For 1997, Exhibit 24, Ln 5 - Ln 7
2/ For 1997, Part VI.B.1. Table, Ln 7 - Exhibit 8, Ln. 8

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Appropriate Amortization of AFUDC, 1997-2000
(millions $)

Line No.	Description		Source	1997	1998	1999	2000
1	Amortization Factor		Part VI.B.3.c	3.33%	3.45%	3.57%	3.70%
2	Net Equity AFUDC - BOY	1/	Prior Ln. 5	$71.553625	$77.959339	$77.290303	$78.340764
3	Equity AFUDC Additions		Exhibit 35, Col. 13	$9.093966	$2.091332	$3.951971	$4.759844
4	Current Period Equity AFUDC Amortization		(Ln.2 + Ln.3) * Ln.1	$2.688253	$2.760368	$2.901510	$3.077800
5	Net Equity AFUDC - EOY		Lns.(2+3-4)	$77.959339	$77.290303	$78.340764	$80.022808
6	Accumulated Equity AFUDC Additions	1/	Ln. 3 + Prior Ln. 6	$1,576.896714	$1,578.988046	$1,582.940017	$1,587.699861
7	Accumulated Equity AFUDC Amortization	1/	Ln. 4 + Prior Ln. 7	$1,498.937375	$1,501.697743	$1,504.599253	$1,507.677053
8	Net Debt AFUDC - BOY	1/	Prior Ln. 11	$24.112478	$28.580477	$28.790393	$29.919861
9	Debt AFUDC Additions		Exhibit 35, Col. 22	$5.453532	$1.238144	$2.237612	$2.575398
10	Current Period Debt AFUDC Amortization		(Ln. 8 + Ln. 9) * Ln.1	$0.985534	$1.028228	$1.108143	$1.203528
11	Net Debt AFUDC - EOY		Lns. (8 + 9 - 10)	$28.580477	$28.790393	$29.919861	$31.291731
12	Accumulated Debt AFUDC Additions	1/	Ln. 9 + Prior Ln. 12	$478.571569	$479.809714	$482.047325	$484.622723
13	Accumulated Debt AFUDC Amortization	1/	Ln. 10 + Prior Ln. 13	$449.991093	$451.019321	$452.127464	$453.330992
14	Annual AFUDC Amortization		Ln. 4 + Ln. 10	$3.673787	$3.788596	$4.009653	$4.281328

1/ 1997 BOY balance from corresponding line, Exhibit 25

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Appropriate Retirements from Accumulated Depreciaton, 1997-2000
(millions)

Line No.	Description	Source	1997	1998	1999	2000
1	Property Account - Grand Total - Credits for Retirements	Exhibit 8, Ln. 5	($3.12)	($6.46)	($2.63)	($6.57)
2	Depreciation Account - Grand Total - Retirements	FERC Form 6 - From 143-RGV-C, TAPS-RGV WP3, Sch. 12	(3.08)	(6.38)	(2.58)	(5.36)
3	Depreciation Account - Adjusted Retirements	Year's worksheet	(3.11)	(6.44)	(2.63)	(6.55)

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Appropriate Retirements from Accumulated Depreciaton, 1997-2000
(millions)

Line No.	Description	Source	1977	1978	1979	1980	1981	1982	1983	1984
1	Gross Depreciable Property EOY	Exhibit 8, Lns (9-8-7)	$9,075.01	$9,248.94	$9,328.41	$9,439.73	$9,485.10	$9,521.27	$9,580.77	$9,613.04
2	Capitalized Interest - EOY	Exhibit 8, Ln. 10	$1,215.57	$1,215.57	$1,215.57	$1,215.57	$1,215.11	$1,215.11	$1,215.11	$1,214.31
3	Depreciable Property Net Capitalized Interest	Lns. 1 - 2	$7,859.44	$8,033.37	$8,112.84	$8,224.16	$8,269.99	$8,306.16	$8,365.66	$8,398.73
4	Depreciation Expense (Net Capitalized Interest)	Exhibit 22, Ln. 1	$108	$501	$605	$693	$668	$682	$660	$642
5	Gross Accumulated Depreciation	Cumlative sum, ln. 4	$108	$609	$1,214	$1,907	$2,575	$3,257	$3,918	$4,559
6	Composite Depreciation Rate (Net basis, unadjusted)	To 2000, Ln. 4/(Lns. 3+4-5); 31-BWF-E, Ln. 14 after	1.38%	6.32%	8.06%	9.89%	10.50%	11.90%	12.93%	14.32%
7	TSM Basis Cumulative "Undepreciated Property Factor" to date	Prior Ln. 7 - Lns. (6 * 7)	98.62%	92.39%	84.94%	76.54%	68.50%	60.35%	52.55%	45.03%

Appropriate Retirements from Accumulated Depreciaton, 1997-2000
(millions)

Line No.	Description	Source	1985	1986	1987	1988	1989	1990	1991	1992
1	Gross Depreciable Property EOY	Exhibit 8, Lns (9-8-7)	$9,628.07	$9,645.07	$9,660.89	$9,657.85	$9,689.22	$9,765.45	$9,915.04	$9,968.82
2	Capitalized Interest - EOY	Exhibit 8, Ln. 10	$1,214.06	$1,214.01	$1,213.86	$1,213.81	$1,213.80	$1,213.80	$1,213.55	$1,213.52
3	Depreciable Property Net Capitalized Interest	Lns. 1 - 2	$8,414.01	$8,431.06	$8,447.03	$8,444.04	$8,475.41	$8,551.66	$8,701.49	$8,755.30
4	Depreciation Expense (Net Capitalized Interest)	Exhibit 22, Ln. 1	$543	$515	$504	$459	$395	$336	$296	$286
5	Gross Accumulated Depreciation	Cumlative sum, ln. 4	$5,102	$5,617	$6,120	$6,579	$6,975	$7,310	$7,606	$7,892
6	Composite Depreciation Rate (Net basis, unadjusted)	To 2000, Ln. 4/(Lns. 3+4-5); 31-BWF-E, Ln. 14 after	14.09%	15.46%	17.79%	19.75%	20.85%	21.28%	21.26%	24.87%
7	TSM Basis Cumulative "Undepreciated Property Factor" to date	Prior Ln. 7 - Lns. (6 * 7)	38.68%	32.70%	26.88%	21.57%	17.08%	13.44%	10.58%	7.95%

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Appropriate Retirements from Accumulated Depreciaton, 1997-2000
(millions)

Line No.	Description	Source	1993	1994	1995	1996	1997	1998	1999
1	Gross Depreciable Property EOY	Exhibit 8, Lns (9-8-7)	$10,003.62	$10,036.68	$10,069.13	$10,063.31	$10,165.66	$10,180.24	$10,223.96
2	Capitalized Interest - EOY	Exhibit 8, Ln. 10	$1,213.52	$1,213.51	$1,213.50	$1,204.65	$1,204.64	$1,204.64	$1,204.64
3	Depreciable Property Net Capitalized Interest	Lns. 1 - 2	$8,790.11	$8,823.18	$8,855.63	$8,858.66	$8,961.02	$8,975.60	$9,019.33
4	Depreciation Expense (Net Capitalized Interest)	Exhibit 22, Ln. 1	$237	$196	$165	$127	$82	$50	$49
5	Gross Accumulated Depreciation	Cumlative sum, ln. 4	$8,129	$8,325	$8,490	$8,617	$8,699	$8,748	$8,797
6	Composite Depreciation Rate (Net basis, unadjusted)	To 2000, Ln. 4/(Lns. 3+4-5); 31-BWF-E, Ln. 14 after	26.39%	28.23%	31.15%	34.42%	23.70%	17.87%	17.92%
7	TSM Basis Cumulative "Undepreciated Property Factor" to date	Prior Ln. 7 - Lns. (6 * 7)	5.85%	4.20%	2.89%	1.90%	1.45%	1.19%	0.98%

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Appropriate Retirements from Accumulated Depreciaton, 1997-2000
(millions)

Line No.	Description	Source	2000	2001	2002	2003	2004	2005	2006
1	Gross Depreciable Property EOY	Exhibit 8, Lns (9-8-7)	$10,280.94						
2	Capitalized Interest - EOY	Exhibit 8, Ln. 10	$1,204.64						
3	Depreciable Property Net Capitalized Interest	Lns. 1 - 2	$9,076.31						
4	Depreciation Expense (Net Capitalized Interest)	Exhibit 22, Ln. 1	$56						
5	Gross Accumulated Depreciation	Cumlative sum, ln. 4	$8,853						
6	Composite Depreciation Rate (Net basis, unadjusted)	To 2000, Ln. 4/(Lns. 3+4-5); 31-BWF-E, Ln. 14 after	20.19%	14.7448%	16.1863%	17.0635%	18.8198%	21.4145%	25.2500%
7	TSM Basis Cumulative "Undepreciated Property Factor" to date	Prior Ln. 7 - Lns. (6 * 7)	0.78%	0.66%	0.56%	0.46%	0.37%	0.29%	0.22%

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Appropriate Retirements from Accumulated Depreciaton, 1997-2000
(millions)

Line No.	Description	Source	2007	2008	2009	2010	2011
1	Gross Depreciable Property EOY	Exhibit 8, Lns (9-8-7)					
2	Capitalized Interest - EOY	Exhibit 8, Ln. 10					
3	Depreciable Property Net Capitalized Interest	Lns. 1 - 2					
4	Depreciation Expense (Net Capitalized Interest)	Exhibit 22, Ln. 1					
5	Gross Accumulated Depreciation	Cumlative sum, ln. 4					
6	Composite Depreciation Rate (Net basis, unadjusted)	To 2000, Ln. 4/(Lns. 3+4-5); 31-BWF-E, Ln. 14 after	29.0970%	35.3774%	42.3358%	54.4304%	100.0000%
7	TSM Basis Cumulative "Undepreciated Property Factor" to date	Prior Ln. 7 - Lns. (6 * 7)	0.16%	0.10%	0.06%	0.03%	0.00%

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Appropriate Retirements from Accumulated Depreciaton, 1997-2000
(millions)

	a	b	c	d	e	f
Retirements by Vintage Year	Credits to Property	Charges to Accrued Depreciation	Useful life as proportion of Inferred Expected Life	Year of retirement, assuming normalized 34.5 year life	Adjusted Undepreciated Property As Percentage of Property Retired	Adjusted Chrages to Accrued Depreciation
	FERC Form 6	FERC Form 6	b/a	if a>b, 2011, else c*34 + 1977	lookup ln. 7 from Sch. 2, given d	a*(1-e)
1977	1,684	1,684	100.00%	2011	0.000%	1684.000
1978	50	49	98.00%	2010	0.026%	49.987
1979	9	9	100.00%	2011	0.000%	9.000
1980	259	259	100.00%	2011	0.000%	259.000
1981	4	4	100.00%	2011	0.000%	4.000
1982	64	64	100.00%	2011	0.000%	64.000
1983	54	54	100.00%	2011	0.000%	54.000
1984						
1985	151	151	100.00%	2011	0.000%	151.000
1986	45	45	100.00%	2011	0.000%	45.000
1987	11	11	100.00%	2011	0.000%	11.000
1988	29	29	100.00%	2011	0.000%	29.000
1989	147	138	93.88%	2009	0.058%	146.915
1990	82	80	97.56%	2010	0.026%	81.978
1991	95	90	94.74%	2009	0.058%	94.945
1992	212	208	98.11%	2010	0.026%	211.944
1993	41	41	100.00%	2011	0.000%	41.000
1994	13	13	100.00%	2011	0.000%	13.000
1995	165	152	92.12%	2008	0.101%	164.834
1996						
1997						
1998						
1999						
2000						
Total	3,115	3,081				3,115

Weighted Average Vintage 1982

Appropriate Retirements from Accumulated Depreciaton, 1997-2000
(millions)

	a	b	c	d	e	f
Retirements by Vintage Year	Credits to Property	Charges to Accrued Depreciation	Useful life as proportion of Inferred Expected Life	Year of retirement, assuming normalized 34.5 year life	Adjusted Undepreciated Property As Percentage of Property Retired	Adjusted Chrages to Accrued Depreciation
	FERC Form 6	FERC Form 6	b/a	if a>b, 2011, else c*34 + 1977	lookup ln. 7 from Sch. 2, given d	a*(1-e)
1977						
1978						
1979						
1980						
1981	6	6	100.00%	2011	0.000%	6.000
1982	17	17	100.00%	2011	0.000%	17.000
1983	70	70	100.00%	2011	0.000%	70.000
1984	56	56	100.00%	2011	0.000%	56.000
1985	14	14	100.00%	2011	0.000%	14.000
1986	127	127	100.00%	2011	0.000%	127.000
1987	14	14	100.00%	2011	0.000%	14.000
1988	3	3	100.00%	2011	0.000%	3.000
1989	353	351	99.43%	2011	0.000%	353.000
1990	199	176	88.44%	2007	0.156%	198.690
1991	1,504	1,493	99.27%	2011	0.000%	1504.000
1992	1,518	1,505	99.14%	2011	0.000%	1518.000
1993	1,358	1,358	100.00%	2011	0.000%	1358.000
1994	490	473	96.53%	2010	0.026%	489.870
1995	50	50	100.00%	2011	0.000%	50.000
1996	339	339	100.00%	2011	0.000%	339.000
1997	75	62				62.000
1998	265	265				265.000
1999						
2000						
Total	6,458	6,379				6,445

Weighted Average Vintage 1992

Appropriate Retirements from Accumulated Depreciaton, 1997-2000
(millions)

	a	b	c	d	e	f
Retirements by Vintage Year	Credits to Property	Charges to Accrued Depreciation	Useful life as proportion of Inferred Expected Life	Year of retirement, assuming normalized 34.5 year life	Adjusted Undepreciated Property As Percentage of Property Retired	Adjusted Chrages to Accrued Depreciation
	FERC Form 6	FERC Form 6	b/a	if a>b, 2011, else c*34 + 1977	lookup ln. 7 from Sch. 2, given d	a*(1-e)
1977	875	875	100.00%	2011	0.00%	875.000
1978						
1979						
1980	43	37	86.05%	2006	0.22%	42.905
1981						
1982	74	51	68.92%	2000	0.78%	73.424
1983						
1984	536	537	100.00%	2011	0.00%	537.000
1985	29	28	96.55%	2010	0.03%	28.992
1986						
1987	6	7	100.00%	2011	0.00%	7.000
1988	13	13	100.00%	2011	0.00%	13.000
1989	43	43	100.00%	2011	0.00%	43.000
1990	197	193	97.97%	2010	0.03%	196.948
1991	221	206	93.21%	2009	0.06%	220.872
1992	277	277	100.00%	2011	0.00%	277.000
1993	234	235	100.00%	2011	0.00%	235.000
1994	64	60	93.75%	2009	0.06%	63.963
1995	16	16	100.00%	2011	0.00%	16.000
1996						
1997						
1998						
1999						
2000						
Total	2,628	2,578				2,630

Weighted Average Vintage 1985

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Schedule for 1999
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Appropriate Retirements from Accumulated Depreciaton, 1997-2000
(millions)

	a	b	c	d	e	f
Retirements by Vintage Year	Credits to Property	Charges to Accrued Depreciation	Useful life as proportion of Inferred Expected Life	Year of retirement, assuming normalized 34.5 year life	Adjusted Undepreciated Property As Percentage of Property Retired	Adjusted Chrages to Accrued Depreciation
	FERC Form 6	FERC Form 6	b/a	if a>b, 2011, else c*34 + 1977	lookup ln. 7 from Sch. 2, given d	a*(1-e)
1975						
1976	4.302	3.472	0.807	2004	0.375%	4.286
1977	170.485	151.816	0.890	2007	0.156%	170.219
1978						
1979	205.924	180.924	0.879	2007	0.156%	205.603
1980	51.455	51.289	0.997	2011	0.000%	51.455
1981						
1982	231.780	200.532	0.865	2006	0.220%	231.270
1983	34.809	34.062	0.979	2010	0.026%	34.800
1984	781.323	662.837	0.848	2006	0.220%	779.604
1985	6.910	4.337	0.628	1998	1.189%	6.828
1986						
1987	41.470	37.094	0.894	2007	0.156%	41.405
1988	194.439	165.066	0.849	2006	0.220%	194.011
1989	279.847	237.500	0.849	2006	0.220%	279.231
1990	1983.767	1480.444	0.746	2002	0.556%	1972.730
1991	1258.791	1053.601	0.837	2005	0.294%	1255.086
1992	354.819	269.151	0.759	2003	0.461%	353.182
1993	793.397	661.024	0.833	2005	0.294%	791.062
1994	162.984	160.332	0.984	2010	0.026%	162.941
1995	46.725	46.538	0.996	2011	0.000%	46.725
1996	145.432	116.835	0.803	2004	0.375%	144.887
1997						
1998						
1999						
2000						
Total	6,574	5,362				6,551

Weighted Average Vintage 1989

Appropriate State Tax Depreciation, 1997-2000
(millions $)

State Tax Depreciation[2]				Year	**21** 1997	**22** 1998	**23** 1999	**24** 2000
					------	------	------	------
Depreciation Factors - (1977)					0.00%	0.00%	0.00%	0.00%
Depreciation Factors - (1978)					0.00%	0.00%	0.00%	0.00%
Depreciation Factors - (1979)					0.00%	0.00%	0.00%	0.00%
Depreciation Factors - (1980)					0.00%	0.00%	0.00%	0.00%
Depreciation Factors - (1981)					0.00%	0.00%	0.00%	0.00%
Depreciation Factors - (1982-present)					0.00%	0.00%	0.00%	0.00%
Year		Property Additions (a) Exhibit 8 and Part VI.B.1, col c - cols (a+b)[1]	AFUDC Additions (b) Exhibits 21 and 35, col 22	Tax Basis for Depreciation (c) (a) + (b)				
1977	1	$7,888.922995	$0.649170	$7,889.572165	$0.000000	$0.000000	$0.000000	$0.000000
1978	2	$112.175000	$4.405407	$116.580407	$0.000000	$0.000000	$0.000000	$0.000000
1979	3	$96.610000	$2.175618	$98.785618	$0.000000	$0.000000	$0.000000	$0.000000
1980	4	$123.421000	$4.239075	$127.660075	$0.783961	$0.000000	$0.000000	$0.000000
1981	5	$49.180000	$4.883692	$54.063692	$0.663956	$0.332005	$0.000000	$0.000000
1982	6	$60.335000	$4.805775	$65.140775	$1.199958	$0.799994	$0.399964	$0.000000
1983	7	$84.072000	$3.309559	$87.381559	$2.146266	$1.609656	$1.073133	$0.536523
1984	8	$50.841000	$1.748567	$52.589567	$1.614605	$1.291705	$0.968752	$0.645852
1985	9	$28.867000	$0.315518	$29.182518	$1.075172	$0.895962	$0.716781	$0.537571
1986	10	$20.045000	$0.199332	$20.244332	$0.870162	$0.745862	$0.621541	$0.497241
1987	11	$32.530000	$0.308453	$32.838453	$1.613156	$1.411495	$1.209867	$1.008206
1988	12	$9.947000	$0.112255	$10.059255	$0.555915	$0.494151	$0.432377	$0.370613
1989	13	$36.586000	$0.459883	$37.045883	$2.274802	$2.047304	$1.819842	$1.592343
1990	14	$80.845000	$1.104859	$81.949859	$5.535303	$5.032131	$4.528877	$4.025705
1991	15	$202.510000	$3.584536	$206.094536	$15.186076	$13.920655	$12.655235	$11.389608
1992	16	$69.470000	$2.535052	$72.005052	$5.747875	$5.305692	$4.863581	$4.421470
1993	17	$45.801000	$1.567387	$47.368387	$4.072071	$3.781229	$3.490340	$3.199498
1994	18	$43.384000	$1.392469	$44.776469	$4.124226	$3.849254	$3.574326	$3.299354
1995	19	$35.960000	$1.269024	$37.229024	$3.657640	$3.429054	$3.200430	$2.971844
1996	20	$28.554000	$1.134040	$29.688040	$3.199035	$2.916761	$2.734476	$2.552162
1997	21	$105.466000	$5.453532	$110.919532	$6.338275	$11.952134	$10.897511	$10.216465
1998	22	$21.016000	$1.238144	$22.254144	$0.000000	$1.271669	$2.397995	$2.186403
1999	23	$46.445000	$2.237612	$48.682612	$0.000000	$0.000000	$2.781870	$5.245795
2000	24	$57.580000	$2.575398	$60.155398	$0.000000	$0.000000	$0.000000	$3.437460
Total State Tax Depreciation					$60.658453	$61.086712	$58.366901	$58.134115

1 For 1977, Exhibit 8, col c - cols (a+b+e)
[2] Depreciation factors for earlier years are at Exhibit 26

Appropriate Federal Tax Depreciation
(millions $)

Federal Tax Depreciation[2]					Year	**21**	**22**	**23**	**24**
						1997	1998	1999	2000
						------	------	------	------
Depreciation Factors - (1977-1980)						0.00%	0.00%	0.00%	0.00%
Depreciation Factors - (1981-1986)						0.00%	0.00%	0.00%	0.00%
Depreciation Factors - (1987-Present)						0.00%	0.00%	0.00%	0.00%
Year		Property Addition (a) Exhibit 8 and Part VI.B.1, col c - cols (a+b)[1]	AFUDC Addition (b) Exhibits 21 and 35, col 22	TEFRA Adjustment (c) Exhibit 40	Tax Basis for Depreciation (d) (a) + (b) - (c)				
1977	1	$7,888.922995	$0.649170	$0.000000	$7,889.572165	$0.000000	$0.000000	$0.000000	$0.000000
1978	2	$112.175000	$4.405407	$0.000000	$116.580407	$0.000000	$0.000000	$0.000000	$0.000000
1979	3	$96.610000	$2.175618	$0.000000	$98.785618	$0.000000	$0.000000	$0.000000	$0.000000
1980	4	$123.421000	$4.239075	$0.000000	$127.660075	$0.783961	$0.000000	$0.000000	$0.000000
1981	5	$49.180000	$4.883692	$0.000000	$54.063692	$0.000000	$0.000000	$0.000000	$0.000000
1982	6	$60.335000	$4.805775	$0.000000	$65.140775	$0.000000	$0.000000	$0.000000	$0.000000
1983	7	$84.072000	$3.309559	$4.369078	$83.012481	$0.000000	$0.000000	$0.000000	$0.000000
1984	8	$50.841000	$1.748567	$2.629478	$49.960088	$0.000000	$0.000000	$0.000000	$0.000000
1985	9	$28.867000	$0.315518	$1.459126	$27.723392	$0.000000	$0.000000	$0.000000	$0.000000
1986	10	$20.045000	$0.199332	$0.000000	$20.244332	$0.000000	$0.000000	$0.000000	$0.000000
1987	11	$32.530000	$0.308453	$0.000000	$32.838453	$1.939078	$1.939078	$1.939078	$1.939078
1988	12	$9.947000	$0.112255	$0.000000	$10.059255	$0.593989	$0.593989	$0.593989	$0.593989
1989	13	$36.586000	$0.459883	$0.000000	$37.045883	$2.187522	$2.187522	$2.187522	$2.187522
1990	14	$80.845000	$1.104859	$0.000000	$81.949859	$4.839057	$4.839057	$4.839057	$4.839057
1991	15	$202.510000	$3.584536	$0.000000	$206.094536	$12.169676	$12.169676	$12.169676	$12.169676
1992	16	$69.470000	$2.535052	$0.000000	$72.005052	$4.488039	$4.251826	$4.251826	$4.251826
1993	17	$45.801000	$1.567387	$0.000000	$47.368387	$3.280498	$2.952448	$2.797056	$2.797056
1994	18	$43.384000	$1.392469	$0.000000	$44.776469	$3.445549	$3.100994	$2.790895	$2.644006
1995	19	$35.960000	$1.269024	$0.000000	$37.229024	$3.183082	$2.864773	$2.578296	$2.320466
1996	20	$28.554000	$1.134040	$0.000000	$29.688040	$2.820364	$2.538327	$2.284495	$2.056045
1997	21	$105.466000	$5.453532	$0.000000	$110.919532	$5.545977	$10.537356	$9.483620	$8.535258
1998	22	$21.016000	$1.238144	$0.000000	$22.254144	$0.000000	$1.112707	$2.114144	$1.902729
1999	23	$46.445000	$2.237612	$0.000000	$48.682612	$0.000000	$0.000000	$2.434131	$4.624848
2000	24	$57.580000	$2.575398	$0.000000	$60.155398	$0.000000	$0.000000	$0.000000	$3.007770
Total Federal Tax Depreciation						$45.276791	$49.087755	$50.463785	$53.869327

[1] For 1977, Exhibit 8, col c - cols (a+b+e)
[2] Depreciation factors for earlier years are at Exhibit 26

Appropriate TEFRA Adjustment to Rates, 1997-2000
(millions $)

Line No.	Description	Source	1997	1998	1999	2000
1	Tax Depreciation Basis before TEFRA Adjustment	Exhibit 39, Schedule 1	$110.919532	$22.254144	$48.682612	$60.155398
2	Tax Depreciation Basis Reduction	143-RGV-C, TAPS-RGV WP3, Sch. 9	0.00%	0.00%	0.00%	0.00%
3	TEFRA Adjustment	Ln. 1 * Ln. 2	$0.000000	$0.000000	$0.000000	$0.000000
4	TEFRA Adjustment Balance (BOY) 1/	Ln. 3 + Prior Ln. 7	$0.616108	$0.595572	$0.575035	$0.554498
5	Amortization Factor	Part VI.B.3.b	3.33%	3.45%	3.57%	3.70%
6	Amortization of TEFRA Adjustment	Ln. 4 * Ln. 5	$0.0205369	$0.0205369	$0.020537	$0.020537
7	TEFRA Adjustment Balance (EOY)	Ln. 4 - Ln. 6	$0.595572	$0.575035	$0.554498	$0.533961

1/ For 1997, BOY balance from Ln. 4, Exhibit 27

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Appropriate ADIT Balances, 1997-2000
(millions $)

Line No.	Description		Source	1997	1998	1999	2000
1	Regulatory Depreciation Incl. Amortization of Debt AFUDC		Exh. 36 Ln.8+Exh. 37 Ln.10	$24.718363	$25.378954	$28.478262	$28.877869
2	State Tax Depreciation		Exhibit 39, Schedule 1	$60.658453	$61.086712	$58.366901	$58.134115
3	State Tax Timing Differences		Ln. 2 - Ln. 1	$35.940091	$35.707758	$29.888640	$29.256246
4	State Income Tax Rate		AK Stat.	$0.094000	$0.094000	$0.094000	$0.094000
5	State Tax Effect		Ln. 3 * Ln. 4	$3.378369	$3.356529	$2.809532	$2.750087
6	State ADIT Balance	1/	Ln. 5 + Prior Ln. 6	$19.184881	$22.541410	$25.350942	$28.101029
7	Regulatory Depreciation Incl. Amortization of Debt AFUDC		Ln.1	$24.718363	$25.378954	$28.478262	$28.877869
8	Depreciation of TEFRA Adjustment		Exhibit 40, Ln. 6	$0.020537	$0.020537	$0.020537	$0.020537
9	Regulatory Depreciation after TEFRA Adjustment		Ln. 7 - Ln. 8	$24.697826	$25.358417	$28.457725	$28.857332
10	Federal Tax Depreciation		Exhibit 39, Schedule 2	$45.276791	$49.087755	$50.463785	$53.869327
11	Tax Effect of State Timing Differences		Ln. 5	$3.378369	$3.356529	$2.809532	$2.750087
12	Total Federal Tax Deductions		Ln. 10 - Ln.11	$41.898422	$45.731225	$47.654253	$51.119240
13	Federal Tax Timing Differences		Ln.12 - Ln. 9	$17.200597	$20.372808	$19.196528	$22.261908
14	Federal Income Tax Rate		IRC	35.00%	35.00%	35.00%	35.00%
15	Federal Tax Effect		Ln. 13 * Ln. 14	$6.020209	$7.130483	$6.718785	$7.791668
16	FASB 96/109 Adjustment		Cum. Ln 13 * Change in Ln 14	$0.000000	$0.000000	$0.000000	$0.000000
17	Amortization Basis for FASB 96/109 Adjustment	1/	Lns(Prior 17 + 16 - Prior 18)	$13.424545	$12.977061	$12.529576	$12.082091
18	Amortization of FASB 96/109 Adjustment		Ln. 17 * Depreciation Factors, Part VI.B.3.b	$0.447485	$0.447485	$0.447485	$0.447485
19	Federal ADIT Balance	1/	Prior Ln.19 + Ln.15 - Ln.18	$78.928053	$85.611051	$91.882351	$99.226534
20	Total State And Federal ADIT Balances		Ln. 6 + Ln. 19	$98.112934	$108.152461	$117.233293	$127.327563

[1] For prior to 1997 see corresponding line, Exhibit 28

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Appropriate Rate Base, 1997-2000
(millions $)

Line No.	Description	Source	1997	1998	1999	2000
1	Gross Carrier Property - BOY	Prior Ln. 10	$10,992.972780	$11,065.574278	$11,092.741755	$11,144.846337
2	Gross Carrier Property Additions	Part IV.B.1, Table, Ln. 3	$61.176000	$30.324000	$95.277000	$44.757000
3	Less Additions to Capitalized Interest	Part IV.B.1, Table, [Ln. 10 - Prior Ln. 10]	($0.007000)	($0.002000)	($0.004000)	$0.000000
4	Gross Carrier Property Additions, Net IDC	Ln. 2 - Ln. 3	$61.183000	$30.326000	$95.281000	$44.757000
5	Acquisitions of Carrier Property in Service	Part IV.B.1, Table, Ln. 4	$0.000000	$0.000000	$0.000000	$0.000000
6	Retirements of CPIS	Part IV.B.1, Table, Ln. 5	($3.115000)	($6.458000)	($49.053000)	($44.737000)
7	Adjustments to CPIS	Part IV.B.1, Table, Ln. 6	($0.014000)	($0.030000)	($0.313000)	$0.000000
8	Equity AFUDC Additions	Exhibit 35, col. 13	$9.093966	$2.091332	$3.951971	$4.759844
9	Debt AFUDC Additions	Exhibit 35, col. 22	$5.453532	$1.238144	$2.237612	$2.575398
10	Gross Carrier Property - EOY 1/	Lns (1+4+5+6+7+8+9)	$11,065.574278	$11,092.741755	$11,144.846337	$11,152.201579
11	Depreciation	Exhibit 36, Ln. 8	$23.732829	$24.350726	$27.370118	$27.674341
12	Adjustments to Accumulated Depreciation	FERC Form 6, from 143-RGV-C	$0.224000	($0.311000)	$0.016000	$0.000000
13	RCA-Adjusted Retirements from Accumulated	Exhibit 38, Ln. 3	($3.114602)	($6.444560)	($2.630104)	($6.550819)
14	Accumulated Depreciation 2/	Lns (11 + 12 + 13) + Prior Ln. 14	$8,272.993355	$8,290.588521	$8,315.344536	$8,336.468057
15	Accumulated Equity AFUDC Amortization	Exhibit 37, Ln. 7	$1,498.937375	$1,501.697743	$1,504.599253	$1,507.677053
16	Accumulated Debt AFUDC Amortization	Exhibit 37, Ln. 13	$449.991093	$451.019321	$452.127464	$453.330992
17	CWIP Balance - EOY	Part VI.B.1, Table, Ln. 7	$29.708000	$38.986000	$43.236000	$30.413000
18	Net Carrier Property	Lns (10-14-15-16-17)	$813.944455	$810.450170	$829.539085	$824.312477
19	Working Capital	Part VI.B.1, Table, Ln. 10	$43.959000	$43.062000	$47.445000	$23.800000
20	ADIT	Exhibit 41, Ln. 20	$98.112934	$108.152461	$117.233293	$127.327563
21	Rate Base, EOY	Lns (18+19-20)	$759.790522	$745.359709	$759.750792	$720.784914
22	Average Rate Base	(Ln.21+Prior Ln.21)/2	$714.306826	$752.575116	$752.555251	$740.267853

1/ 1996 EOY Balance from Exhibit 29, Line 10
2/ 1996 Balance is from Exhibit 22, Line 6

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Appropriate Return on Rate Base, 1997-2000
(millions $)

Line No.	Description	Source	1997	1998	1999	2000
1	Weighted Rate of Return	Part VI.A.5	10.68%	10.45%	11.13%	11.33%
2	Average Rate Base	Exhibit 42, Ln. 22	$714.306826	$752.575116	$752.555251	$740.267808
3	Total Return on Rate Base	Ln.1 * Ln.2	$76.287969	$78.644100	$83.759399	$83.872343
4	Debt Capital Structure	Part VI.A.1	49.50%	49.50%	49.50%	49.50%
5	Cost of Debt	Part VI.A.2	7.84%	7.84%	7.84%	7.84%
6	Debt Weighted Rate of Return	Ln.4 * Ln.5	3.88%	3.88%	3.88%	3.88%
7	Interest Expense	Ln.2 * Ln.6	$27.720819	$29.205935	$29.205164	$28.728313
8	Equity Weighted Rate of Return	Ln.1 - Ln.6	6.80%	6.57%	7.25%	7.45%
9	Return on Equity	Ln.2 * Ln.8	$48.567150	$49.438164	$54.554235	$55.144030

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Appropriate Income Tax Allowance, 1997-2000
(millions $)

Line No.	Description	Source	1997	1998	1999	2000
1	Total Return on Rate Base	Exhibit 43 Ln. 3	$76.287969	$78.644100	$83.759399	$83.872343
2	Interest Expense	Exhibit 43 Ln. 7	$27.720819	$29.205935	$29.205164	$28.728313
3	Equity Portion of Return on Rate Base	Ln. 1 - Ln. 2	$48.567150	$49.438164	$54.554235	$55.144030
	Permanent Differences - Federal Income Tax:					
4	Amortization of Equity AFUDC	Exhibit 37 Ln. 4	$2.688253	$2.760368	$2.901510	$3.077800
5	Amortization of TEFRA Adjustment	Exhibit 40 Ln. 6	$0.020537	$0.020537	$0.020537	$0.020537
6	Amortization of Deferred Tax Adjustments	Exhibit 41 Ln. 18	$0.447485	$0.447485	$0.447485	$0.447485
7	Subtotal for Federal Income Tax Allowance	Lns (3 + 4 + 5 - 6)	$50.828455	$51.771585	$57.028797	$57.794882
8	Federal Income Tax Rate	RGV-143-C, TAPS-RGV WP3, Sch.8	35.00%	35.00%	35.00%	35.00%
9	Net-to-Tax Multiplier - Federal Income Tax	Ln. 8 / (1 - Ln. 8)	53.85%	53.85%	53.85%	53.85%
10	Federal Income Tax Allowance	Ln. 7 * Ln. 9 - Ln. 6	$26.921683	$27.429522	$30.260329	$30.672836
	Permanent Differences - State Income Tax:					
11	Amortization of Equity AFUDC	Exhibit 37 Ln. 4	$2.688253	$2.760368	$2.901510	$3.077800
12	Subtotal for State Income Tax Allowance	Lns (3 + 10 + 11)	$78.177086	$79.628055	$87.716074	$88.894666
13	Alaska State Income Tax Rate	RGV-143-C, TAPS-RGV WP3, Sch.8	9.40%	9.40%	9.40%	9.40%
14	Net-to-Tax Multiplier - State Income Tax	Ln 13 / (1 - Ln. 13)	10.38%	10.38%	10.38%	10.38%
15	State Income Tax Allowance	Ln. 12 * Ln. 14	$8.111088	$8.261630	$9.100785	$9.223067
16	Total Income Tax Allowance	Ln. 10 + Ln. 15	$35.032772	$35.691153	$39.361114	$39.895903

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Appropriate TAPS Revenue Requirement, 1997-2000
(millions $)

Line No.	Description	Source	1997	1998	1999	2000
1	Operating Expense Excluding Depreciation and DR&R	Part VI.D	$603.775	$565.598	$567.658	$553.280
2	Depreciation Expense	Exhibit 36 Ln. 8	$23.732829	$24.350726	$27.370118	$27.674341
3	Amortization of AFUDC	Exhibit 37, Ln 14	$3.673787	$3.788596	$4.009653	$4.281328
4	Return on Rate Base	Exhibit 43 Ln 3	$76.287969	$78.644100	$83.759399	$83.872343
5	Income Tax Allowance	Exhibit 44 Ln. 16	$35.032772	$35.691153	$39.361114	$39.895903
6	Total Cost of Service	Sum Lns 1 to 5	$742.502356	$708.072574	$722.158284	$709.003915

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1997-2000 Just and Reasonable Intrastate Rates

Line No.	Description	Source	1997	1998	1999	2000
1	GVEA Deliveries	143-RGV-C, TAPS RGV-WP 3, Schedule 16, Ln. 1	17.53	18.54	21.98	22.73
2	Petro Star Valdez Deliveries	143-RGV-C, TAPS RGV-WP 3, Schedule 16, Ln. 2	3.41	3.58	3.73	3.78
3	Valdez Marine Terminal Intrastate Deliveries	143-RGV-C, TAPS RGV-WP 3, Schedule 16, Ln. 3	16.06	15.68	0.00	0.00
4	Valdez Marine Terminal Interstate Deliveries	143-RGV-C, TAPS RGV-WP 3, Schedule 16, Ln. 4	444.98	402.82	365.10	341.41
5	Total Barrels	Lns (1 + 2 + 3 + 4)	481.97	440.61	390.80	367.92
6	GVEA Distance	Exhibit RGV-14, Schedule 1	469.06	469.06	469.06	469.06
7	Petro Star Valdez Distance	Exhibit RGV-14, Schedule 1	796.00	796.00	796.00	796.00
8	Valdez Marine Terminal Distance	Exhibit RGV-14, Schedule 1	800.32	800.32	800.32	800.32
9	GVEA Barrel Miles	Line (1 * 6)	8,221	8,694	10,309	10,662
10	Petro Star Valdez Barrel Miles	Line (2 * 7)	2,717	2,850	2,967	3,005
11	Valdez Marine Terminal Intrastate Barrel Miles	Line (3 * 8)	12,851	12,547	0	0
12	Valdez Marine Terminal Interstate Barrel Miles	Line (4 * 8)	356,124	322,382	292,194	273,239
13	Total Barrel Miles	Lns (9 + 10 + 11 + 12)	379,912	346,472	305,470	286,905
14	GVEA Connection Costs (millions $)	143-RGV-C, TAPS RGV-WP 3, Schedule 15, Ln. 1	$0.767000	$0.000000	$0.000000	$0.000000
15	GVEA Connection Costs Per GVEA Barrel	Line (14 / 1)	$0.04	$0.00	$0.00	$0.00
16	Non-Distance Related Costs (millions $)	143-RGV-C, TAPS RGV-WP 3, Schedule 15, Ln. 2	$77.493000	$79.641000	$80.288000	$80.13
17	Non-Distance Related Costs Per Barrel	Lns (16 / 5)	$0.16	$0.18	$0.21	$0.22
18	Total DOC Cost of Service (millions $)	Exhibit 45, Ln. 6	$742.502356	$708.072574	$722.158284	$709.003915
19	Remaining Cost of Service (millions $)	Line (18 - 14 - 16)	$664.242356	$628.431574	$641.870284	$628.876915
20	GVEA Portion of Cost of Service (millions $)	Lns (((15 + 17) * 1) + (19 * (9 / 13)))	$17.958115	$19.119489	$26.175934	$28.319938
21	Petro Star Valdez Portion of Cost of Service (millions $)	Lns ((17 * 2) + (19 * (10 / 13)))	$5.298741	$5.815849	$6.999475	$7.409420
22	Valdez Marine Terminal Intrastate Portion of Cost of Service (M $)	Lns ((17 * 3) + (19 * (11 / 13)))	$25.050051	$25.590733	$0.000000	$0.000000
23	Valdez Marine Terminal Interstate Portion of Cost of Service (M $)	Lns ((17 * 4) + (19 * (12 / 13)))	$694.195450	$657.546503	$688.982875	$673.274557
24	GVEA Tariff ($/BBL)	Lns (20 / 1)	$1.02	$1.03	$1.19	$1.25
25	Petro Star Valdez Tariff ($/BBL)	Lns (21 / 2)	$1.55	$1.62	$1.88	$1.96
26	Valdez Marine Terminal Intrastate Tariff ($/BBL)	Lns (22 / 3)	$1.56	$1.63	N/A	N/A

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PUC Docket No. 52195
TIEC's 9th, Q. No. TIEC 9-2
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ORDER NO. 85724

IN THE MATTER OF THE APPLICATION OF POTOMAC ELECTRIC POWER COMPANY FOR AN INCREASE IN ITS RETAIL RATES FOR THE DISTRIBUTION OF ELECTRIC ENERGY	* * *	BEFORE THE PUBLIC SERVICE COMMISSION OF MARYLAND
		CASE NO. 9311

Before: W. Kevin Hughes, Chairman
Harold D. Williams, Commissioner
Lawrence Brenner, Commissioner
Kelly Speakes-Backman, Commissioner

Issued: July 12, 2013

APPEARANCES

Douglas E. Micheel, Matthew K. Segers, Wendy K. Stark, Peter E. Meier and Theodore F. Duver for Potomac Electric Power Company

Paula M. Carmody, Theresa V. Czarski, Anne Johnson, Ronald Herzfeld and Gregory Simmons for the Maryland Office of People's Counsel

Annette B. Garofalo, Lloyd Spivak, and Michael Dean for the Public Service Commission Staff

William Leibovici for AARP Maryland

Frann G. Francis and Nicola Whiteman for the Apartment and Office Building Association of Metropolitan Washington

John P. Markovs and Lisa Brennan for Montgomery County, Maryland

Brent A. Bolea for the Maryland Energy Administration

Heather Cameron for the General Services Administration

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I. Introduction and Executive Summary

In this Order, we consider Potomac Electric Power Company's ("Pepco" or "the Company") second request for an increase in electric distribution rates in the last two years, and third request in the last four years.[1] In each of the last two cases, we granted the Company less than half the amount it requested, and then only to permit the Company to improve its ability to deliver reliable service to its customers. Here, we again reduce the Company's requested rate increase by more than half, and grant only what we find necessary to enable the Company to continue - and even accelerate - the pace of its improvement in reliability and resiliency of its electric distribution system.

Pepco filed its Application in the present case on November 30, 2012 requesting a rate increase of $60.827 million and an increase in the return on equity ("ROE") from 9.31 percent to 10.25 percent.[2] Pepco argued that the large rate increase is necessary "because the Company has made, and continues to make, prudent investments in the reliability of its electric distribution infrastructure which have resulted in a 38% improvement in SAIFI and a 36% improvement in SAIDI."[3] Based on our thorough review of Pepco's Application – the record in this case includes written testimony from 26 witnesses, 10 days of evidentiary hearings, two public evening hearings in College Park, and Rockville, Maryland and extensive post-hearing briefs - we find that a revenue increase of $27.883 million and an ROE of 9.36 percent will be sufficient to permit the Company to continue to improve its reliability and resiliency at just and reasonable rates.

[1] Case No. 9286, decided on July 20, 2012 and Case No. 9217, decided on August 6, 2010.
[2] *Application of Potomac Electric Power Company for Adjustments to its Retail Rates for the Distribution of Electric Energy*, p. 3.
[3] Initial Brief of Potomac Electric Power Company, p. 1. SAIFI is the "System average interruption frequency index." SAIDI is the "System average interruption duration index."

This increase will have an average residential monthly bill impact of $2.41, and represents a 2.19 percent increase in the overall bill.

We have been carefully monitoring Pepco's record of electric reliability for these past four years, and we demanded improvement. In December 2011, we fined Pepco $1 million for its failure to adequately maintain its distribution system over the prior decade.[4] In its last rate case, we disallowed $6.4 million in "catch up" operations and maintenance expenses attributed to the Company's prior neglect, and reduced the Company's ROE from 9.83 percent to 9.31 percent. Recognizing the Company's need to increase reliability spending, we departed from traditional ratemaking principles and allowed end-of-test year reliability plant and three months post-test year reliability spending adjustments in rate base.[5] In May 2012, we adopted comprehensive electric reliability regulations in COMAR 20.50.12.02 (also referred to as Rule Making (RM) 43), providing specific SAIDI and SAIFI standards that will result in required annual reliability improvement for the Company from 2012 through 2015.

In this rate case, we once again allow Pepco to recover costs related to its significant and sustained increase in spending on reliability projects. We allow the Company to include in its rate base $12.5 million for completed reliability projects through the end of the test period (December 31, 2012) and $45 million for projects completed in the first three months of 2013. Additionally, we allow the recovery, as the law requires, of known and measurable expenses Pepco has incurred to comply with the Commission's RM 43 reliability regulations.

[4] *In the Matter of an Investigation into the Reliability and Quality of the Electric Distribution Service of Potomac Electric Power Company,* Case No. 9240, Order No 84564 (2011).
[5] Case No. 9286, Order No. 85028.

In addition to the request for an increase in its base distribution rates, and in response to the Governor's Grid Resiliency Task Force ("GRTF") Report recommendations, Pepco included a $192 million Grid Resiliency Charge (GRC) proposal aimed at increasing the reliability and resiliency of the Company's distribution system in an accelerated time frame from 2014 through 2016. Pepco proposed three specific reliability projects: $17 million for Accelerated Vegetation Management; $151 million for Selective Undergrounding of six feeders; and $24 million for an Accelerated Priority Feeders project to accelerate the hardening of 24 feeders over two years, 12 feeders each in 2014 and 2015.

In order to improve Pepco's reliability and resiliency for outages due to major storm events, we approve the latter of the three projects, the Accelerated Priority Feeders, but only on the condition that Pepco provide: (1) a detailed description of the proposed hardening work; (2) performance objectives for each feeder project; (3) incremental milestones and estimated costs for each project; and (4) estimated total costs.[6] We also require annual filings so that we can closely monitor each of the feeder projects, including a reconciliation of projected costs and recoveries that includes a true-up calculation of over- and under- recoveries of the prior year, following which we will issue an order to establish the Company's new annual GRC adjustment for the following year. Subject to the Company's detailed filings, the GRC for an average residential monthly bill will be approximately $ 0.06 in the first year[7]. With regard to the Selective

[6] Commissioner Harold D. Williams dissented from the approval of the Accelerated Priority Feeders component of the GRC and Commissioner Lawrence Brenner wrote a separate concurrence statement. Both Commissioner Williams' dissent and Commissioner Brenner's concurrence are attached to this Order.
[7] The surcharge, based on the approved scope and rate of return, for a customer using 1000 kWh per month, is estimated to be $0.06 in 2014, $0.19 in 2015, and $0.27 in 2016.

Undergrounding project, we believe that the record is insufficient to justify its approval at this time, and more study is warranted.

We do not grant Pepco a rate increase or the GRC lightly. We are cognizant of the effect these increases will impose on Pepco ratepayers of all classes, and also of the demands we have placed on the Company for improved performance. We have granted a limited rate increase and the partial GRC due to the financial strain of Pepco's increased infrastructure reliability spending, and only while demanding specific and measurable improvements in Pepco's reliability performance exceeding those set forth in our present COMAR standards.

II. Background

On November 30, 2012, Potomac Electric Power Company, a subsidiary of Pepco Holdings, Inc. ("PHI"), filed an Application for Adjustments to its Retail Rates for the Distribution of Electric Energy ("Application") pursuant to §§ 4-203 and 4-204 of the Public Utilities Article of the *Annotated, Code of Maryland* ("PUA"), for authority to increase its rates and charges for electric distribution service in Maryland. On January 4, 2013, the Commission extended the suspension period for the tariff revisions for an additional 30 days beyond the initial 150-day suspension period, or until June 28, 2013.[8] The Company sought an increase of $60,827,000 based on a test year ending December 31, 2012, which included six months of forecasted data.[9] Pepco also requested a return on equity ("ROE") of 10.25%, asserting that its current adjusted ROE is 4.71%.[10] If the

[8] Order No. 85285. On April 16, 2013 Pepco agreed to extend the procedural schedule for two weeks by re-setting the starting date of the suspension period, thereby extending the suspension period until July 12, 2013. Order No. 85508.
[9] The Company filed updated actual data on February 8, 2013, and supplemented this data several times during the proceedings.
[10] Application at 3.

Company's Application were granted in full, the typical residential Standard Offer Service ("SOS") customer using 1,000 kilowatt-hours ("kWh") of electricity per month would have seen an increase in the total monthly bill of $7.13, which would have been a 4.98% increase in the overall bill, or a 19.50% increase in distribution rates.[11]

On May 22, 2013, the Public Service Commission Staff ("Staff"), on behalf of itself, Pepco, the Maryland Office of People's Counsel ("OPC"), the Apartment and Office Building Association of Metropolitan Washington ("AOBA") and Montgomery County, Maryland ("Montgomery County") submitted a comparison chart reconciling the parties' revenue requirement positions (hereafter "Chart"), which is appended to this Order as Appendix II. The Chart reflects Pepco's final purported revenue requirement deficiency of $66,351,000[12] for the base rate portion of their request; Staff's final proposed revenue requirement recommendation of $30,568,000; OPC's final proposed revenue requirement recommendation of <u>minus</u> $5,372,000[13]; AOBA's recommendation of $10,183,000[14]; and Montgomery County's recommendation of $30,272,000.[15]

A number of parties filed written testimony in this proceeding. Pepco sponsored the testimony of Frederick J. Boyle, Senior Vice President and Chief Financial Officer of PHI, who testified on the general basis for the rate increase, the Company's proposed capital structure and rate of return, and the Company's Grid Resiliency Charge ("GRC")

[11] Pepco Exhibit ("Ex.") 25, Direct Testimony of Joseph F. Janocha ("Janocha Direct") at 10 and Schedule ("Sch.") JFJ-1, page ("p.") 2 of 18.
[12] Pepco is limited to its initial revenue request of $60,827,000.
[13] In its Reply Brief at p. 48, OPC states that Pepco's rate reduction should be $6.979 million. AARP states that it supports OPC's proposed ($5.372 million) rate reduction recommendation. AARP Reply Brief at 12.
[14] In its Initial Brief at p. 83, AOBA states that Pepco's revenue deficiency is no more than $9.688 million.
[15] In its Initial Brief at p. 4, Montgomery County states that Pepco's revenue deficiency is no more than $6.519 million. *See also*, Attachment 1.

proposal;[16] Robert B. Hevert, Managing Partner of Sussex Economic Advisors, LLC, who testified about the cost of equity;[17] Linda J. Hook, Manager, Revenue Requirements for Pepco, who testified regarding the Company's revenue requirement and adjustments;[18] Kathleen A. White, Assistant Controller for PHI, who testified about accounting issues and procedures, and Pepco's Cost Allocation Manual ("CAM");[19] William M. Gausman, Senior Vice President, Strategic Initiatives for PHI, who testified about the Company's construction program, its Reliability Enhancement Plan ("REP"), Vegetation Management ("VM") and the GRC;[20] Hallie M. Reese, Vice President Customer Care for PHI, who testified regarding the Energy Advisor and Energy Engineer ("EA&EE") positions;[21] Christopher A. Nagle, Lead Regulatory Analyst, Cost Allocation for Pepco, who testified about Pepco's jurisdictional and customer class cost of service studies ("COSS");[22] Joseph F. Janocha, Manager of Rate Economics for PHI, who testified regarding rate design, calculation of the Bill Stabilization Adjustment ("BSA") and Pepco's proposed GRC and accompanying tariffs;[23] and Dr. Kimbugwe A. Kateregga, Vice President of Foster Associates, Inc., who testified regarding depreciation issues.[24]

[16] Pepco Ex. 2, Direct Testimony of Frederick J. Boyle ("Boyle Direct"); Pepco Ex. 3, Boyle Supplemental Direct; Pepco Ex. 4, Boyle Rebuttal; Pepco Ex. 5, Boyle Supplemental Rebuttal.
[17] Pepco Ex. 30, Direct Testimony of Robert B. Hervert ("Hervert Direct"); Pepco Ex. 31, Hervert Rebuttal.
[18] Pepco Ex. 6, Direct Testimony of Linda J. Hook ("Hook Direct"); Pepco Ex. 7, Hook Supplemental Direct; Pepco Ex. 8, Hook Additional Supplemental Direct; Pepco Ex. 9, Hook Revised Additional Supplemental Direct; Pepco Ex. 10, Hook Rebuttal; Pepco Ex. 11, Hook Supplemental Rebuttal.
[19] Pepco Ex. 18, Direct Testimony of Kathleen A. White ("White Direct"); Pepco Ex. 19, White Supplemental Direct.
[20] Pepco Ex. 12, Direct Testimony of William M. Gausman ("Gausman Direct"); Pepco Ex. 13, Gausman Supplemental Direct; Pepco Ex. 14, Gausman Rebuttal.
[21] Pepco Ex. 17, Rebuttal Testimony of Hallie M. Reese ("Reese Rebuttal").
[22] Pepco Ex. 21, Direct Testimony of Christopher A. Nagle ("Nagle Direct"); Pepco Ex. 22, Nagle Supplemental Direct; Pepco Ex. 23, Nagle Rebuttal.
[23] Pepco Ex. 25, Direct Testimony of Joseph F. Janocha ("Janocha Direct"); Pepco Ex. 26, Janocha Supplemental Direct; Pepco Ex. 27, Janocha Rebuttal.
[24] Pepco Ex. 20, Rebuttal Testimony of Dr. Kimbugwe A. Kateregga ("Kateregga Rebuttal").

OPC filed the testimony of Helmuth W. Schultz, III, Senior Regulatory Analyst at Larkin & Associates, who testified about revenue requirement issues;[25] Dr. David E. Dismukes, a consulting economist with the Acadian Consulting Group, who testified about the Company's cost of service, rate design issues and the proposed GRC;[26] Peter J. Lanzalotta, a principal with Lanzalotta & Associates LLC, who testified about reliability and GRC issues;[27] and Charles W. King, President Emeritus of Snavely King Majoros & Associates, Inc., who testified regarding rate of return and depreciation issues.[28]

Staff presented the testimony of Patricia M. Stinnette, Director of Accounting, who testified regarding revenue requirement issues and the GRC;[29] Jennifer C. Brekke-Miles, Senior Public Utility Auditor, who testified regarding revenue requirement issues;[30] Gregory M. Campbell Jr., a regulatory economist, who addressed rate design and GRC issues;[31] James R. Currier, III, a regulatory economist, who discussed cost of service issues;[32] Dr. Özlen D. Luznar, a regulatory economist, who addressed rate of return issues;[33] Stacy Sherwood, a regulatory economist, who testified about EA&EE

[25] OPC Ex. 37, Direct Testimony of Helmuth W. Schultz III and OPC Ex. 37A, Corrections to Direct Testimony (jointly "Schultz Direct); OPC Ex. 38, Surrebuttal Testimony and OPC Ex. 38A Corrections to Surrebuttal Testimony (jointly "Schultz Surrebuttal"); OPC Ex. 45, Schultz Supplemental Surrebuttal.
[26] OPC Ex. 39, Direct Testimony of Dr. David E. Dismukes and OPC Ex. 39A, Corrections to Direct Testimony (jointly "Dismukes Direct"); OPC Ex. 40, Dismukes Surrebuttal.
[27] OPC Ex. 43, Direct Testimony of Peter J. Lanzalotta ("Lanzalotta Direct"); OPC Ex. 44, Lanzalotta Surrebuttal.
[28] OPC Ex. 41, Direct Testimony of Charles W. King ("King Direct"); OPC Ex. 42, Surrebuttal Testimony and OPC Ex. 42A, Corrections to Surrebuttal (jointly "King Surrebuttal").
[29] Staff Ex. 11, Corrected Direct Testimony of Patricia M. Stinnette ("Stinnette Direct"); Staff Ex. 12, Stinnette Rebuttal; Staff Ex. 13, Stinnette Surrebuttal; Staff Ex. 24, Stinnette Supplemental Surrebuttal.
[30] Staff Ex. 14, Corrected Direct Testimony of Jennifer C. Brekke-Miles ("Brekke-Miles Direct"); Staff Ex. 14A, Brekke-Miles Confidential Direct; Staff Ex. 15, Brekke-Miles Surrebuttal; Staff Ex. 15A, Brekke-Miles Confidential Surrebuttal.
[31] Staff Ex. 1, Corrected Direct Testimony of Gregory M. Campbell, Jr. ("Campbell Direct"); Staff Ex. 2, Campbell Rebuttal; Staff Ex. 3, Campbell Surrebuttal.
[32] Staff Ex. 4, Direct Testimony of James R. Currier, III ("Currier Direct"); Staff Ex. 5, Currier Rebuttal; Staff Ex. 6, Currier Surrebuttal.
[33] Staff Ex. 16, Direct Testimony of Dr. Özlen D. Luznar ("Luznar Direct"); Staff Ex. 17, Luznar Rebuttal; Staff Ex. 18, Luznar Surrebuttal.

positions as well as advanced metering infrastructure ("AMI") issues;[34] Chinyere J. Tucker, an electric distribution engineer, who testified about GRC technical issues;[35] and Phillip E. VanderHeyden, Director of the Electricity Division, who testified about the GRC.[36]

Other parties presenting testimony in this case included: AOBA, Montgomery County, AARP Maryland ("AARP"), the federal General Services Administration ("GSA") and the Maryland Energy Administration ("MEA"). AOBA presented the testimony of Bruce R. Oliver, President of Revilo Hill Associates, Inc., who addressed cost of capital issues, cost of service and rate design issues, select revenue requirement issues and the GRC.[37] Montgomery County presented the testimony of Bion C. Ostrander, President of Ostrander Consulting, who testified on revenue requirement issues and the GRC.[38] AARP presented the testimony of Ralph C. Smith, a senior regulatory utility consultant with Larkin & Associates, PLLC, who addressed GRC issues.[39] MEA presented the testimony of Kevin Lucas, Director of Energy Market Strategies at MEA, who addressed the GRC and related issues.[40] GSA presented the testimony of Dennis W. Goins, who operates Potomac Management Group, who testified about GRC issues.[41] The City of Gaithersburg, Town of Somerset, POWERUPMONTCO

[34] Staff Ex. 19, Direct Testimony of Stacy Sherwood ("Sherwood Direct"); Staff Ex. 20, Sherwood Surrebuttal.
[35] Staff Ex. 22, Direct Testimony of Chinyere J. Tucker ("Tucker Direct"); Staff Ex. 23, Tucker Surrebuttal.
[36] Staff Ex. 7 Direct Testimony of Phillip E. VanderHeyden Direct"); Staff Ex. 8, VanderHeyden Rebuttal.
[37] AOBA Ex. 119, Direct Testimony of Bruce R. Oliver ("Oliver Direct"); AOBA Ex. 120, Oliver Rebuttal; AOBA Ex. 121, Oliver Surrebuttal.
[38] Montgomery County Ex. 1, Direct Testimony of Bion C. Ostrander ("Ostrander Direct"); Montgomery County Ex. 1A, Ostrander Confidential Direct; Montgomery County Ex. 2, Ostrander Surrebuttal.
[39] AARP Ex. 1, Direct Testimony of Ralph C. Smith and AARP Ex. 2 Corrections to Direct (jointly "Smith Direct"); AARP Ex. 3, Smith Surrebuttal.
[40] MEA Ex. 1, Direct Testimony of Kevin Lucas ("Lucas Direct"); MEA Ex. 2, Lucas Surrebuttal.
[41] GSA Ex. 1, Direct Testimony of Dennis W. Goins ("Goins Direct"); GSA Ex. 2, Goins Surrebuttal.

of Montgomery County, Maryland, and the Mayor and Council of Rockville all filed petitions to intervene, which were granted.

Staff, OPC, AOBA, Montgomery County, AARP, MEA, and GSA filed their direct cases on March 8, 2013. Rebuttal testimony was filed by Pepco, Staff, and AOBA on March 25, 2013. Supplemental Rebuttal testimony was filed by Pepco on April 8, 2013. Surrebuttal testimony was filed by Staff, OPC, AARP, AOBA, GSA, Montgomery County and MEA on April 10, 2013. Supplemental Surrebuttal testimony was filed by Staff, OPC and Montgomery County on May 10, 2013. Evidentiary hearings were conducted at the Commission's offices in Baltimore on April 15-19, 22-24 and 26 as well as May 15, 2013. Initial briefs were filed by the parties on June 3, 2013, and reply briefs were filed on June 14, 2013.[42] Evening hearings were held to receive public comment on May 6, 2013, in College Park and May 9, 2013, in Rockville, Maryland. The record in this case closed on June 14, 2013.

All of the evidence presented in this case, including the public's comments, has been thoroughly reviewed and carefully considered by the Commission in reaching the decisions in this Order.

III. Discussion and Findings

A. Rate Base and Operating Income

Rate base represents the investment the Company makes in plant and equipment in order to provide safe and reliable electric service to its customers. Operating income is derived based upon the revenues the Company receives for electric service minus the

[42] On June 10, 2012, Pepco filed a Motion to Strike portions of the Initial Briefs of AOBA and Montgomery, arguing that they introduced new evidence not in the record. After considering the responses of AOBA, Montgomery County, and Staff, on June 14, 2012, the Commission granted in part the Motion to Strike as to AOBA and denied the Motion as to Montgomery County.

prudent costs it incurs in providing service to customers. The parties have proposed various adjustments to the Company's unadjusted rate base and operating income. We have reviewed the record and accept the unadjusted amounts and the uncontested adjustments. The undisputed portion of the rate base, including uncontested adjustments, is $1,152,648,000. The undisputed portion of operating income, including uncontested adjustments, is $67,216,000. The parties dispute certain proposed rate base and operating income adjustments, which we resolve below.[43]

1. Reliability Plant Additions

Safety and reliability are foremost concerns when we consider rate requests by utilities. In recent rate proceedings, the Commission has recognized that under appropriate circumstances, and when properly supported, adjustments to the historically accepted average test year may be warranted to meet objective standards for safety and reliability investments and expenses, when such investments or expenses do not generate additional utility revenues. Non-revenue producing safety and reliability investments, which we discuss in this section, generally serve existing customers rather than support new customers, the latter of which will result in incremental utility revenues.

a. Parties' Positions

The Company has proposed three separate reliability plant ratemaking adjustments ("RMA").[44] The first, RMA1, annualizes the effect of reliability projects completed in the test year.[45] Pepco's second adjustment, RMA2, reflects the effect of reliability plant that was added to Electric Plant in Service ("EPIS") from January

[43] *See* Appendix I for the Commission's calculation of the appropriate rate base, operating income and overall revenue requirement for rate making purposes.
[44] Hook Direct at 7-10.
[45] This adjustment would increase rate base by $12,487,000 and decrease operating income by $748,000. Hook Supp. Rebuttal, Sch. (LJH-SR)-1 at p. 4.

through March 2013,[46] the three months immediately following the test year. Pepco's third proposed adjustment, RMA3, reflects the impact of reliability projects that are projected to be placed in service between April and December of 2013,[47] up to twelve months after the test year. The Company's proposed adjustments also reflect the impact on depreciation expense and accumulated deferred income taxes.[48] Additionally, in Supplemental Rebuttal testimony Ms. Hook modified RMA1, 2 and 3 for the effect of a net operating loss carry-forward ("NOLC"), which we discuss in detail in the following section.[49] Pepco asserts that adoption of its adjustments will reflect "an appropriate matching of benefits that customers receive to the cost associated with providing reliable service."[50] Furthermore, Pepco asserts that RMA3 will provide "a means by which to mitigate regulatory lag through the use of more forward-looking data."[51]

Generally speaking, the other parties addressing the reliability adjustments support Pepco RMA1 and RMA2, except for the modifications to reflect the NOLC.[52] No other party testified in support of RMA3.[53]

Pepco recommends increasing rate base by $12.487 million for RMA1 and $44.993 million for RMA2.[54] Staff recommends that these amounts be reduced by $6.992 million for RMA1, (to a net increase of $5.495 million) and by $5.217 million for

[46] If accepted, the adjustment would increase rate base by $44,993,000 and decrease operating income by $580,000.
[47] The impact of this adjustment would increase rate base by $123,528,000 and decrease operating income by $1,215,000.
[48] Hook Direct at 8-9.
[49] The effect of the Company's proposed RMA1, 2 and 3 on rate base and operating income, without the NOLC impact, is included in Ms. Hook's Rebuttal testimony at Schedules (LJH-R)-1 at pages 4-7; The rate base and operating income effect with the NOLC impact is in Ms. Hook's Supplemental Rebuttal testimony at Schedule (LJH-SR)-1, at pages 4-7.
[50] Hook Direct at 8.
[51] *Id.* at 10.
[52] AOBA did not contest RMA1, but did not accept RMA2. *See* the Chart.
[53] In its Initial Brief, at pages 17-20, MEA supports RMA3.
[54] Hook Supplemental Rebuttal, Schedule (LJH-SR)-1, pages 4-7.

RMA2 (to a net increase of $39.776 million) to remove the impact of the NOLC on these adjustments.[55] Montgomery County did not contest RMA1 and RMA2 - however, it did "strongly oppose the NOLC" amounts included in those Company adjustments.[56] OPC also removed the impact of the NOLC from Company RMA1.[57] As for RMA2, OPC witness Schultz recommended that the Company's "initial request," which increased rate base by $18.995 million, be adopted, although he stated that this "could be viewed as generous."[58] Mr. Schultz questioned why the Company's RMA2 adjustment for plant closings increased from approximately $32.4 million initially to more than $58.5 million in its final reconciliation. Specifically, he questioned whether all of the increase was for reliability projects.[59] Additionally, he raised a concern that the adjustment to remove construction work in progress ("CWIP") only increased by approximately $100,000 when the plant projects increased by millions of dollars. He noted that if the reduction to CWIP is understated, then rate base would be overstated.[60] Finally, Mr. Schultz questioned the Company not reflecting any deferred income tax liability associated with the increases in plant. Mr. Schultz concluded that the Company's proposed accounting is one-sided.[61]

Staff, Montgomery County and OPC all oppose Pepco's RMA3 for April-December 2013 projected reliability plant additions.[62] Staff witness Stinnette stated that Pepco's adjustment is not completely known and measurable and does not adhere to the

[55] Stinnette Supplemental Surrebuttal at 2 and Supp. Surr. Exhibit AID-2.
[56] Ostrander Direct at 30 and Ostrander Supplemental Surrebuttal at 2-4. Montgomery County modified its position in its Initial Brief, at pages 19 and 70, adopting OPC's position on RMA2.
[57] Schultz Supplemental Surrebuttal, Ex. LA-1SR, Sch. B-1.
[58] *Id.* at 9 and Ex. LA-1SR, Sch. B-2. *See also* Hook Supplemental Direct, Sch. (LJH-S)-1 at pages 4, 6.
[59] Schultz Supplemental Surrebuttal at 4-8.
[60] *Id.* at 4 and 8-10.
[61] *Id.* at 4 and 10.
[62] Stinnette Corrected Direct at 5-6; Schultz Direct at 10-12; Ostrander Direct at 32.

matching principle. Furthermore, she asserted that only actual costs should be allowed, noting that the Commission has historically excluded this type of projected adjustment.[63] Montgomery County witness Ostrander concurred, noting that these plant additions are not currently used and useful and are not justified by the "regulatory lag" argument.[64] Additionally, Mr. Ostrander asserted that Pepco's forecast and budget process for projected reliability plant additions is neither accurate nor reliable, pointing out a $25 million or 27% deviation between the Company's original projection and the actual results it filed just two months later for this adjustment.[65] OPC witness Schultz also agreed, arguing that acceptance of RMA3 would "lead the Commission down a slippery slope towards changing the rate making policy of Maryland, and abandoning appropriate reliance on the historic test year."[66]

In Rebuttal, Ms. Hook stated that RMA3 reflects projects included in Pepco's Reliability Enhancement Plan ("REP"). She stated that the Company "seeks to better coordinate recovery of the costs associated with these projects… with their provision of benefits to customers." She asserted that Pepco is simply extending the ratemaking treatment approved for projects placed in service by the hearing date. Pepco concluded that it is an appropriate adjustment to "close the gap between cost/benefit incurrence and cost/recovery."[67]

[63] Stinnette Corrected Direct at 5-6 and Corrected Ex. AID-3 and AID-9. (Hereafter Ms. Stinnette's Corrected Direct testimony is simply referred to as "Direct").
[64] Ostrander Direct at 32.
[65] *Id.* at 36 and 39-41.
[66] Schultz Direct at 12.
[67] Hook Rebuttal at 6.

b. <u>Commission Decision</u>

In Pepco's last rate case we accepted adjustments similar to RMA1 and RMA2 because Pepco had demonstrated a significant and sustained increase in spending for reliability projects, and because the amounts were known and measurable.[68] According to Company witness Gausman, Pepco has increased its planned reliability investment by $54.5 million from 2011 to 2013 and plans to further increase reliability spending through 2017.[69] RMA1 and RMA2 represent additions to plant in service through March 2013, which the Company has updated for actual spending and is thus known and measurable. We believe it is both appropriate and it is our obligation to encourage and demand a commitment to reliable service and we find that, subject to our decision on the NOLC, the RMA1 and RMA2 reliability projects should be reflected in rate base. Therefore, we will increase rate base by $12,487,000 and decrease operating income by $748,000 for RMA1. For RMA2, rate base shall be increased by $44,993,000 and operating income will be reduced by $580,000.

RMA3 raises another issue entirely. Even the Company admits that it simply represents a forecast of anticipated spending. Thus, this is not a known and measurable adjustment. Furthermore, as several parties have pointed out, RMA3 does not represent plant additions that are currently used and useful and is inconsistent with the matching principle. The Commission has historically rejected this type of projected adjustment finding that it is not justified by regulatory lag arguments; and as history has shown and witnesses have testified in this case, the Company has not even typically been able to

[68] Case No. 9286, Order No. 85028 at 17-18.
[69] Gausman Direct at 4-5. *See also* Errata to Gausman Direct.

accurately estimate future costs. For these reasons, and consistent with Commission precedent, we reject RMA3.

2. Net Operating Loss Carry-Forward (NOLC)

On April 8, 2013, four months after the filing of its initial case, and a full month after Montgomery County witness Ostrander first identified a Net Operating Loss Carry-Forward ("NOLC") inconsistency, Pepco witness Hook filed Supplemental Rebuttal Testimony in which she disclosed for the first time an "additional" $23.4 million NOLC adjustment related to the Company's proposed reliability plant RMAs 1, 2 and 3, adding $3 million to the revenue requirement.[70] This disclosure, and the entire NOLC matter, became one of the most contentious issues in the case.

Pepco is currently in a NOLC tax position and did not have to pay federal or state income taxes in 2011 and 2012, and likely will not have a 2013 income tax obligation. Accumulated Deferred Income Taxes ("ADIT") reduce rate base, and thus the cost of service, because the deferral of current tax liabilities is treated as cost-free capital to the utility. However, when a company has a NOLC, the future tax obligation is not simply deferred; the future tax obligation is reduced by the amount of the NOLC. Consequently, a NOLC is considered a deferred tax asset. Thus, a NOLC increases rate base and the current cost of service because it offsets the ADIT balance that would otherwise reduce rate base.

a. Mr. Ostrander's Testimony

Montgomery County witness Ostrander has identified a $66 million NOLC, which is composed of a 13-month average balance at December 31, 2012 of $42.6

[70] Hook Supplemental Rebuttal Testimony at 1-3 and Schedule (LJH-SR)-1.

million and another $23.5 million related to Pepco RMAs1, 2 and 3.[71] Mr. Ostrander recommended that the $66 million NOLC be removed from rate base in order to share the NOLC benefit with customers, which he calculated would reduce Pepco's revenue requirement by approximately $9 million.[72] Additionally, Mr. Ostrander removed $3.7 million of federal income tax expense to partially account for the positive effect of the NOLC on the income statement.[73] Pepco witness Hook countered that removal of any part of the NOLC would create a federal income tax problem as this would violate the IRS depreciation normalization rules. Ms. Hook asserted that if these rules are violated, then Pepco would lose the benefit of accelerated depreciation tax deductions in the future, which would increase the Company's tax expense and ratepayers' cost of service.[74]

Mr. Ostrander argued that Pepco's NOLC balance should be disallowed in this case because: 1) Pepco has not met a reasonable burden of proof as it has failed to support its NOLC calculations and specifically has not reconciled 2011 and 2012 tax return losses with related NOLC amounts; 2) Pepco's $23.5 million NOLC adjustment related to RMA1, 2 and 3 is a forecasted amount, which is not allowable, and is not related to actual federal income tax return losses; 3) Pepco has not shown that its NOLC treatment complies with IRS tax normalization rules; and 4) Pepco has not demonstrated, but should be required to demonstrate, that it provided customers with the benefit of tax loss carrybacks in prior years.[75] Mr. Ostrander stated that the NOLC amount "should be removed from the ADIT deferred liability balance and set up as a separate deferred asset

[71] Ostrander Supplemental Surrebuttal at 7 and Hook Supplemental Rebuttal at 2 and Sch. (LJH-SR)-1, pages 5-7.
[72] Ostrander Supplemental Surrebuttal at 3-7. The $9 million figure is based upon the $66 million NOLC and the rate of return in Pepco's last case of 7.96%. *Id.* at 7.
[73] Ostrander Direct at 54.
[74] Hook Rebuttal at 26 and 33.
[75] Ostrander Surrebuttal at 6-8.

balance so that it can be properly tracked and monitored for changes over time."[76] He concluded that the Commission should require Pepco to obtain an IRS ruling that its treatment of the NOLC is proper.[77]

According to Mr. Ostrander, tax normalization rules require that any NOLC be related to losses reported on the Company's federal income tax return, which he asserts Pepco admits.[78] Mr. Ostrander asserted that Pepco's 2012 and 2013 tax losses are "merely estimated" because the Company has not filed its federal or state tax returns for these years.[79] Mr. Ostrander noted that Pepco's response to certain data requests "refers to Pepco's 2012 tax loss as an 'estimated' amount", which indicates significant issues need to be resolved before the 2012 tax return is filed.[80] Consequently, he concluded that the Company's related NOLC calculations are not known and measurable and thus fail to meet the burden of proof required in this case.[81] Mr. Ostrander also stated that Pepco has provided inconsistent NOLC calculations, only recently introduced the concept of a state NOLC,[82] cannot support other calculations underlying the NOLC, and takes inaccurate and inconsistent NOLC positions.[83] Furthermore, he stated the NOLC calculation has to be limited to the loss specifically related to deferred taxes on accelerated/bonus depreciation and not for any other reasons.[84]

[76] Ostrander Direct at 58.
[77] Ostrander Surebuttal at 8.
[78] *Id.* at18.
[79] Ostrander Supplemental Surrebuttal at 10.
[80] *Id.* at 21.
[81] *Id.* at 10. Mr. Schultz stated that the NOLC for 2012 and 2013 is not known and measurable because it is neither documented nor certain until the respective tax returns are filed. Schultz Supplemental Surrebuttal at 18-19.
[82] The state NOLC is much smaller than the federal NOLC. *See* Ostrander Supplemental Surrebuttal at 9.
[83] Ostrander Supplemental Surrebuttal at 13-15.
[84] Ostrander Surrebuttal at 19.

Since the $23.5 million NOLC adjustment is tied to 2013 plant additions, Mr. Ostrander stated that the NOLC adjustment is "clearly a forecasted amount." Moreover, since this NOLC amount is not tied to any actual losses related to an actual 2013 income tax return, the adjustment should be removed in its entirety. Further, he argued that Ms. Hook's adjustment erroneously assumes that all deferred taxes on accelerated/bonus depreciation will contribute to a loss on the 2013 federal return, but this cannot be known or measured at this time. Moreover, he argued this adjustment raises a concern that Pepco has used other erroneous assumptions that may overstate its existing $42.6 million NOLC.[85] Mr. Ostrander responded that, under Ms. Hook's strict interpretation of tax normalization rules, if a premature flow-through of tax benefits to customers creates a violation, then to be consistent the opposite must be true, that normalization rules are also violated if the utility's tax expense or related rate base are increased beyond the amount of actual deferred taxes or exceed the amount of the deferred NOLC.[86]

Although Pepco has cited the Internal Revenue Code ("IRC") and Treasury Regulations ("Treas. Reg.") to support its NOLC positions, Mr. Ostrander countered that the Company's citations "do not specifically require a NOLC to be included in rate base and do not state that the failure to include NOLC in rate base for regulatory purposes is a tax normalization violation."[87] Mr. Ostrander emphasized that Treas. Reg. 1.167(1)-

[85] Ostrander Surrebuttal at 18-20.
[86] *Id.* at 24. Mr. Ostrander stated that the following types of adjustments could cause a normalization violation: (1) using different federal income tax losses in the calculation of Pepco's $42.6 million NOLC instead of actual income tax losses shown on Pepco's federal income tax return; (2) using a 13-month average for regulatory purposes to calculate the NOLC in this case versus the actual calendar 2012 NOL from Pepco's tax return; (3) use of post-test period adjustments to adjust rate base, which could confer a different level of tax normalization benefits to customers compared to actual related losses on the tax return; and (4) use of projected amounts in this case as these are not included in the 2012 tax return for which the related losses were supposedly used to calculate the $47.6 million NOLC in this case. Ostrander Surrebuttal at 24-25.
[87] Ostrander Supplemental Surrebuttal at 28.

1(h)(6)(ii) relates only to projected amounts related to the traditional ADIT reserves to be excluded from rate base and does not apply to Pepco's NOLC amounts that the Company includes as increases to rate base. Therefore, Mr. Ostrander concluded that Pepco's increases in the (projected) 2013 NOLC are not justified by the Treasury Regulations and should be disallowed.[88]

According to Mr. Ostrander, for "a normal ADIT" you can calculate the deferred income tax based on a projection or a combination of projected and actual results. However, he argued that same standard does not apply to a NOLC because the tax code "does not specifically allow for projections."[89] He stated the "only way" a NOLC can be calculated "is if you know there is going to be a tax loss."[90] However, when challenged that nothing in Treas. Reg. 1.167(1)-1 (h)(6)(ii) prevents projecting a NOLC, Mr. Ostrander responded "I guess you can say that."[91]

Mr. Ostrander argued that the Commission cannot cause Pepco to violate a tax normalization rule for tax returns that do not exist as a final order will be issued in this case before Pepco files a 2012 tax return.[92] Mr. Ostrander also argued that Pepco has not provided one example of where the IRS has substituted its judgment for a state utility regulatory agency and found a tax normalization violation when the state regulator did

[88] Ostrander Supplemental Surrebuttal at 25-26. Mr. Ostrander stated that if the Commission wants to act "conservatively" and avoid the prospect of a tax normalization violation, it could accept the $5.2million 2011 NOLC, while disallowing the 2012 and 2013 NOLC amounts in this case, subject to further review of the 2012 and 2013 amounts when Pepco's tax returns are available for review. Ostrander Supp. Surr. at 26-27.
[89] Transcript ("T") at 2017-2018. Mr. Ostrander has argued that since the tax returns for 2012 and 2013 have not been filed the NOLC associated with those periods is projected.
[90] T at 2019.
[91] T at 2020-2022 and Pepco Ex. 87 at pages 1077-1078. When asked the logic of this "one-way scenario", that it is permissible to deduct projected deferred income taxes from rate base but not permissible to include projected NOLC amounts in rate base, Mr. Ostrander responded that different people interpret the tax code differently and that the answer is not black and white as Pepco claims because the tax code has a lot of gray areas. T at 2034-2035.
[92] Ostrander Supplemental Surrebuttal at 15-16.

not identify a violation.[93] Further, he argued that if the Commission removed the NOLC from rate base, the Commission would not intend to violate or cause a tax normalization violation.[94] Therefore, even if the IRS later determined that removal of the NOLC from rate base did cause a violation, Mr. Ostrander did not think that this would be anything that is not repairable, because there was no intent to violate normalization rules.[95]

According to Mr. Ostrander, the Company has stated that prior to 2011 Pepco's federal income tax losses were normally treated on a carry-back basis and did not result in a NOLC. However, Mr. Ostrander asserted that it is not clear if customers ever received the benefit of these losses, which Pepco should be required to explain. Mr. Ostrander argued that if Pepco did not return the benefit of carry-back tax losses to customers, then Pepco technically violated the normalization rules, which would indicate this is not a concern for Pepco. In such a case he stated that the $42.6 million test year NOLC should be removed from rate base to offset the benefit of tax loss carry-backs that were not passed through to customers by Pepco in prior years.[96]

b. Ms. Hook's Testimony

Ms. Hook stated that Congress created certain tax incentives, including accelerated/bonus depreciation, to encourage investment in depreciable assets. She asserted that if this incentive is reflected in utility rates it would convert the investment incentive into a consumption subsidy for customers. To prevent this conversion, Ms. Hook asserted that Congress devised the depreciation normalization rules, which prohibit

[93] Ostrander Supplemental Surrebuttal at 17. Commenting on Example 1 of Treas. Reg. 1.167(1)-1(h)(6)(iv), Mr. Ostrander admitted that the IRS could find a violation of the normalization rules depending on the facts in a particular rate case and a utility commission's particular ruling. T at 2029-2031.
[94] T at 2009.
[95] T at 2010.
[96] Ostrander Surrebuttal at 26-27.

the benefits of accelerated depreciation from being flowed through as reductions to the tax expense element of the cost of service.[97]

Ms. Hook responded that Mr. Ostrander's proposed adjustments "ignore the requirements of the IRS depreciation normalization rules."[98] While Pepco admits that customers have not been provided the benefit of a substantial amount of bonus depreciation deductions, Ms. Hook argued that Mr. Ostrander's adjustments are inappropriate because "the Company can only provide the tax benefits to customers to the extent the Company actually receives a cash benefit."[99] Since Pepco is in a net operating loss ("NOL") position, Ms. Hook argued that the effect of Mr. Ostrander's adjustments would be to provide customers a tax benefit that Pepco has not yet received.[100] Ms. Hook noted that the NOL will eventually provide a benefit prospectively when the NOL can be used to offset taxable income and that it provided a benefit already in carryback years; however, taxable income in the two carryback years was not adequate to absorb the entire NOL, therefore Pepco has a NOLC.[101] Further, Ms. Hook asserted that under normalization tax accounting the tax expense element of the cost of service is not impacted by bonus depreciation.[102] Ms. Hook concluded that the "bottom line" regarding Mr. Ostrander's proposals is that it would diminish the benefits Pepco receives for accelerated depreciation, which is contrary to depreciation normalization rules.[103]

[97] Hook Rebuttal at 31-32.
[98] *Id.* at 26.
[99] *Id.* at 27.
[100] *Id.* at 27.
[101] *Id.* at 28.
[102] *Id.* at 31.
[103] *Id.* at 32-33.

Ms. Hook also addressed Mr. Ostrander's contention that Pepco has inaccuracies and inconsistencies in its NOL calculations.[104] She stated that the $42.6 million NOL deferred tax asset reflected in unadjusted rate base "is no less known or measurable than the deferred tax credit balances."[105] She noted that the accumulated deferred tax credit is $345.9 million, which means the net credit balance is $303.334 million.[106] Consequently, the NOLC tax asset is embedded and offsetting the deferred tax liabilities that are also in rate base. Therefore, Ms. Hook concluded that Mr. Ostrander's proposal to reflect the ADIT but not the NOLC is one-sided.[107]

c. Mr. Schultz's Testimony

According to OPC witness Schultz "there is merit to both parties' arguments."[108] He stated that Pepco is correct that elimination of the deferred tax debit (NOLC) from rate base would violate the normalization rules. However, Mr. Schultz stated that the violation only applies to the NOL that was created as a result of tax depreciation; if the NOL was due to some other cost, then that debit should not be included as an offset against the deferred income tax credit. As for the income tax expense, Mr. Schultz agreed, in part, with Mr. Ostrander. Because of the NOL, Pepco will not incur any current income tax expense, but he noted that this proceeding reflects a current tax expense; therefore, the NOLC should be reduced by the amount of taxes in the rate effective period by zeroing out income tax expense.[109] Further, Mr. Schultz stated that in accounting, any journal entry must have a debit and a credit "but Ms. Hook's proposed

[104] *See* T at 1943-1946 for a discussion of specific claimed inaccuracies.
[105] T at 1937-1939.
[106] T at 1939-1940. Ms. Hook referenced her Supplemental Rebuttal, Schedule (LJH-SR)-1, page 1.
[107] T at 1942.
[108] Schultz Surrebuttal at 39.
[109] *Id.* at 39-40.

accounting is only a single sided entry and is not proper." Mr. Schultz stated that to properly reflect the accounting proposed by Ms. Hook, income tax expense must be reduced.[110]

Additionally, Mr. Schultz pointed out that in Case No. 9286, Pepco had a NOL (for 2011) but did not offset the deferred tax liability for the NOL as it has in this case. Therefore, he concluded that if Pepco's position is correct, then a normalization violation has already occurred. Consistent with the treatment in Case No. 9286, Mr. Schultz adjusted the deferred income tax liability for reliability plant additions, thereby reducing rate base by $6.992 million for RMA1 and $134,000 for RMA2.[111]

In his Supplemental Surrebuttal testimony Mr. Schultz stated that Pepco has not met its burden of proof that a normalization violation would occur if the NOLC is excluded from rate base; therefore, he reduced rate base by $42.7 million. Further, he argued Pepco has not shown that if the NOLC is allowed in rate base, then the Company is also entitled to recover income taxes that will not be paid during the rate year. Mr. Schultz stated that if the Commission disagrees, then only the NOLC amount specific to accelerated depreciation should be allowed in rate base, which Pepco should be required to demonstrate.[112]

Mr. Schultz stated that his position is based upon a review of the Internal Revenue Code ("IRC") and IRS Regulations. He stated that § 168(i)(9) of the IRC does not address NOLCs. Further, regulation 1.167(1)-1(h)(1)(b)(iii) does not mention a NOL and indicates that the determination of the timing and manner that any impact will be

[110] Schultz Surrebuttal at 40-41.
[111] *Id.* at 41-43 and Ex. LA-1R, Sch. B-1 and B-2.
[112] Schultz Supplemental Surrebuttal at 12-13.

recorded will be made by the IRS district director.[113] Mr. Schultz notes that Pepco has not sought any IRS determination of this issue.[114] Additionally, Mr. Schultz stated that regulation 1.167(1)-(1)(h)(6)(i) also does not address NOLCs. Mr. Schultz stated that it is significant that regulation 1.167(1)-1(a) does state that normalization requirements pertain only to the deferral of federal income tax liability resulting from use of accelerated depreciation. Therefore, even if Pepco's NOLC position has merit, only the NOLC amount related to accelerated depreciation would need to comply with normalization rules. Mr. Schultz noted that the NOLC amount Pepco has included in rate base is, in part, the result of timing differences other than accelerated depreciation.[115] Mr. Schultz also stated that the Private Letter Ruling ("PLR") relied on by Pepco to support its position is inconsistent with the tax scenario in this case.[116]

Mr. Schultz stated that the recording of the NOLC debit to a deferred asset account results in a credit to income tax expense, which effectively zeros out the debit made to expense when the current or deferred tax liability is recorded, meaning there is no income tax expense. However, Pepco's filing includes $25.609 million of income tax expense. Consequently, ratepayers are providing funds for income taxes even though Pepco will not pay any income taxes. Mr. Schultz stated that, pursuant to normalization accounting, neither the Company nor its ratepayers should receive a financial benefit from the deferral of tax payments. Therefore, Mr. Schultz concluded that if rates are established based upon including the NOLC debit in rate base without an appropriate reduction in income tax expense, Pepco will receive a financial benefit to the extent it is

[113] The IRS no longer has district directors. Stinnette Supplemental Surrebuttal at 4.
[114] Schultz Supplemental Surrebuttal at 14-15.
[115] *Id* at 15-16.
[116] *Id.* at 16-17. Pepco cites PLR 8818040.

generated by the accelerated depreciation and other tax timing differences, which will cause a normalization violation.[117]

Mr. Schultz concluded that it is not appropriate to require ratepayers to pay increased rates as a result of the NOLC offsetting the ADIT balance and provide no offset for the fact Pepco will not pay any income taxes. He also stated that Pepco's NOLC adjustment is "one-sided."[118]

d. Mr. Boyle's Testimony

Company witness Boyle stated that consistent with sound rate-making, the normalization rules require that rate base not be reduced for deferred taxes in a NOL situation because you don't have cost-free capital until the company receives the cash benefit, which only occurs when a company is paying taxes. Mr. Boyle emphasized that the tax normalization rules codify this rate-making concept.[119] However, he admitted that Pepco has committed a "foot fault" as it unintentionally failed to follow the normalization rules previously, which he stated the Company does not believe amounts to a violation of the rules. Conversely, Mr. Boyle argued that in this case there is a "considerable record" on this issue and if the normalization rules are not followed pursuant to a Commission decision, it would amount to a normalization violation.[120]

According to Mr. Boyle, the fact that the Company has not yet filed its 2012 tax return does not determine whether the normalization rules apply. He stated that the rules require that where projections or estimates are used, they be done consistently. Mr. Boyle stated that the normalization rules contemplate the use of projections or estimates,

[117] Schultz Supplemental Surrebuttal at 18-19.
[118] *Id.* at 10.
[119] T at 1897-1899.
[120] T at 1913-1914.

but require consistency for tax and rate making purposes. Therefore, if estimates are used for tax expense, depreciation expense, or the reserve for deferred taxes, then all such elements must be estimated consistently. Consequently, he argued that even though a tax return has not yet been filed, the normalization rules do in fact apply.[121] Further, he stated that Pepco's books for 2012, which will be the basis for its 2012 tax return, have been closed. He argued that the timing of the Company's 2012 tax return does not indicate there are any problems. Therefore, he concluded the NOL calculation is known and measurable.[122]

Mr. Boyle noted that OPC witness Schultz stated that if the NOLC is allowed in rate base, then there should be an offsetting credit reflected as a reduction to tax expense. Mr. Boyle responded that the credit is reflected in the NOLC adjustment to rate base.[123] Therefore, Pepco is not proposing one-sided accounting. The Company is reflecting "the way the determination of income taxes and rates work."[124]

Mr. Boyle agreed that a significant amount of the NOLC is composed of amounts other than bonus tax depreciation.[125] Noting that Congress has extended bonus depreciation, Mr. Boyle stated that, coupled with heavy capital spending, "it will be a little while" before Pepco will be paying income taxes and thus able to offset the NOLC.[126] Finally, Mr. Boyle stated that even though they had not done so to date, if the Commission orders Pepco to get a PLR on this issue, the Company would do so.[127]

[121] T at 1910-1913.
[122] T at 1917-1920.
[123] T at 1926.
[124] T at 1922.
[125] T at 1927.
[126] T at 1933-1934.
[127] T at 1930-1931.

e. Ms. Stinnette's Testimony

Staff Witness Stinnette recommended disallowing Pepco's NOLC adjustments for RMA 1 and 2.[128] She noted that these NOLC adjustments decreased the ADIT balance thereby increasing rate base.[129] Ms. Stinnette stated that to comply with the tax normalization rules, four elements of a rate case - tax expense, depreciation expense, deferred taxes and rate base - should all be based upon actual expenses. Ms. Stinnette disagreed that using projections is appropriate.[130] Although Pepco has stated that if the NOLC is not included as a debit to the ADIT balance a normalization violation would occur, Ms. Stinnette asserted that the Company has not definitively established this position to Staff's satisfaction. Because district directors no longer exist within the IRS organizational hierarchy, Ms. Stinnette stated that neither IRS regulation 1.167(1)(h)(1)(b)(iii) nor other sources definitively provide how a NOLC should be accounted for in either an ADIT account or a rate case.[131] Since Pepco's 2012 and 2013 tax returns have not been filed, Ms. Stinnette concluded the NOLs associated with RMA 1 and 2 are not known and measurable. Ms. Stinnette concluded that Pepco has not provided adequate support to permit her to make a final recommendation on the NOLC issue at this time, citing the fact Pepco has not filed a 2012 or 2013 tax return.[132] Therefore, Staff proposed disallowing the Company's NOLC adjustments at this time and recommended that a Phase II proceeding be established for review of Pepco's NOLC.[133]

[128] Stinnette Supplemental Surrebuttal at 2. Staff also recommends the complete disallowance of RMA 3, including the associated NOLC.
[129] Stinnette Supplemental Surrebuttal at 2.
[130] T at 2045.
[131] Stinnette Supplemental Surrebuttal at 2-4.
[132] *Id.* at 3.
[133] *Id.* at 4-5.

To verify the accuracy for the appropriate treatment of the NOLC in this rate case, Staff recommended that Pepco get a PLR from the IRS.[134]

f. Commission Decision

Based upon the record in this case, three points are clear: *one,* that none of the witnesses who testified on this issue are tax "experts;" *two,* that all parties concur that NOLC issues are extremely complex; and *three,* the Company has not sought an IRS Private Letter Ruling. Because no party has provided a definitive analysis of the NOLC and associated tax implications, we will err on the side of caution and accept Pepco's NOLC ratemaking adjustments at this time, subject to our disallowance of RMA3. However, we direct Pepco to immediately seek an IRS Private Letter Ruling that addresses the ratemaking implications of the NOLC raised in *this* proceeding, including the impact on income tax expense, and not to rely on other PLRs, which are not proven to be fully applicable to this case. Specifically, we want to know for our ratemaking purposes, must any or all of the Company's NOLC be included as an offset to the ADIT and reflected in rate base. Further, should Pepco fail to support its position with a PLR within three years from the date of this order, the Commission will make an appropriate adjustment in its subsequent rate case to remove the revenue impact of the NOLC, including carrying costs at the authorized rate of return, in this proceeding. Additionally, we direct the Company to separately account for the NOLC so that it can be more readily tracked and monitored for changes prospectively.

[134] T at 2050.

3. Depreciation

a. Depreciation Rates

1. Parties' Positions

Company RMA4 annualizes the impact of the new (lower) depreciation rates that the Commission approved in Pepco's last base rate case. Ms. Hook stated that the adjustment is necessary to reflect the full annual impact of the depreciation rate change since the order in Case No. 9286 became effective midway through the 2012 test year used in this case.[135]

Mr. Ostrander stated that the Company's depreciation rate adjustment does not reduce depreciation expenses enough to properly reflect the new depreciation rates adopted by the Commission in Case No. 9286,[136] and needs to be corrected. He asserted that Pepco's adjustment is "based largely on 'estimates' for both the 'existing' and 'new' depreciation rates as the starting point for the adjustment, thus rendering the adjustment somewhat inaccurate."[137] Mr. Ostrander stated that he used a "simplified" but more accurate approach. He took the actual depreciation expense for the last five months of 2012, when the new depreciation rates were in effect, and annualized this amount. He concluded that his adjustment "would calculate a conservatively high depreciation expense," because as plant investment trends upward during the year, so does the depreciation expense.[138]

Ms. Hook responded that Mr. Ostrander's calculation "is contrary to the manner in which the impact of Maryland depreciation rate changes has historically been

[135] Hook Direct at 10.
[136] Ostrander Direct at 59.
[137] *Id.* at 60.
[138] *Id.* at 60-61.

computed."[139] Citing the computations of Pepco Witness Kateregga in this case and OPC witness King in Case No. 9286, Ms. Hook asserted that the Company's computations are consistent with practices in Maryland. She stated that Pepco's adjustment applies the rate differential by FERC[140] plant account to the plant balance in that account at December 31, 2012, prorated over the number of months the new rate was not in effect in the test period.[141]

OPC witness King stated that when Order No. 85028 was issued in Case No. 9286, Pepco had not developed depreciation rates reflecting the rebalancing of depreciation reserves authorized in that Order, so Pepco implemented the "un-rebalanced" rates recommended by Mr. King and approved by the Commission. Mr. King stated that Pepco "has now filed new depreciation rates that reflect the life and salvage parameters underlying the depreciation rates that the Commission adopted in Case No. 9286 but with the reserves rebalanced."[142] Mr. King stated that the Company's revised depreciation rates should be used to calculate depreciation expense for the distribution plant accounts, but not for the general plant accounts. Mr. King contended that Pepco has "incorrectly allocated reserves from the three depreciable [general plant] accounts to the eight accounts that are subject to amortization." Mr. King concluded that the effect of this "inappropriate" allocation "is to increase the depreciation rates for the depreciable accounts with no offsetting adjustment in the amortization rates for the other

[139] Hook Rebuttal at 11-12.
[140] FERC is the Federal Energy Regulatory Commission.
[141] Hook Rebuttal at 12.
[142] King Direct at 40.

general plant accounts."[143] For these reasons, Mr. King proposed a reduction in test year depreciation expense of $2,077,049.[144]

Company witness Kateregga responded that Mr. King's recommended depreciation changes are based upon materials provided to OPC to support Pepco's Commission-approved redistribution of depreciation reserves.[145] Dr. Kateregga stated that the depreciation rates the Company used to develop depreciation expense in this case for the depreciable plant accounts[146] are based upon the rates Mr. King proposed and the Commission adopted in Case No. 9286. Since the Commission also approved amortization accounting for some of the general plant accounts and approved depreciation account reserve rebalancing as Pepco had requested in Case No. 9286, then for those accounts subject to amortization accounting "Company witness Hook has used [in this case] the rates that were described in the [Company's] 2011 Depreciation Study as the appropriate rates to use after retiring all plant that has reached an age equal to the amortization period for each account."[147] Dr. Kateregga noted that it is particularly important to rebalance reserves where, as here, amortization is implemented (for certain general plant accounts) for the first time in order to prevent reserve imbalances created in perpetuity.[148] However, Dr. Kateregga emphasized that no party to Case No. 9286 advocated that Pepco be required to implement new depreciation rates upon completing the rebalancing of the reserves, and he argued that the Commission should not in this case revise the depreciation rates adopted in Pepco's last case.[149]

[143] King Direct at 40.
[144] *Id.*, Exhibit CWK-4.
[145] Kateregga Direct at 3.
[146] This includes all distribution plant accounts and some general plant accounts.
[147] Kateregga Direct at 4.
[148] *Id.* at 7.
[149] *Id.* at 3 and 5.

2. Commission Decision

As we have noted in the past, depreciation rates should be adjusted pursuant to a depreciation study, where all aspects of depreciation can be examined together and piecemeal changes are avoided.[150] In Case No. 9286 we examined the Company's depreciation rates in detail, based upon a full depreciation study. However, when new depreciation rates were implemented pursuant to Order No. 83516, the process of rebalancing reserves, which we authorized, had not yet been completed. OPC witness King's depreciation adjustment incorporates the rebalancing of reserves based upon information provided by Pepco. Consequently, we find that OPC's adjustment appropriately reflects this aspect of our decision – the rebalancing of reserves - and is based upon the depreciation study, which was deferred until this proceeding. Therefore, we accept OPC's depreciation adjustment. Rate base will be increased accordingly, by $4,361,000, and operating income will be increased by $8,723,000. Finally, on this record and because we accept OPC's adjustment, we reject Montgomery County's "simplified" depreciation rate adjustment.

b. OPC's Accumulated Depreciation Adjustment

1. Parties' Positions

OPC witness Schultz asserted that Pepco failed to properly reflect accumulated depreciation for the period January 1, 2013, through June 30, 2014, because approximately $83 million in depreciation expense will be incurred during this period but is not reflected in the Company's filing. He claimed that not reflecting this adjustment "would constitute a failure to properly match known and measurable changes of

[150] *Re* Potomac Electric Power Company, Case No. 9217, Order No. 83516, 101 MD PSC 290, 312, (2010).

revenue/expenses with known and measurable changes to the rate base."[151] Mr. Schultz argued that this adjustment is not one-sided because the "historical plant in the test year and the depreciation on that plant is known and measurable," whereas future plant additions "are not known and measurable because the construction has not occurred and the plant is not in service." Furthermore, he stated that this depreciation expense will be collected in the rates during the year new rates will be in effect.[152] Mr. Schultz cited proceedings in Vermont as support for his proposition.[153] Mr. Shultz concluded that Pepco's rate base should be reduced by $50.359 million.[154]

Ms. Hook responded that Mr. Schultz's adjustment "is flawed because it represents a selective use of a fully forecasted test year."[155] Ms. Hook stated that Mr. Schultz is only recognizing changes that reduce rate base (depreciation) and ignores post-test year plant additions that will increase rate base, which creates a mismatch. Ms. Hook argued that recognizing only one element of rate base on a fully forecasted basis without recognizing other elements is "contrary to accepted practice in Maryland." Moreover, she pointed out that Mr. Schultz's adjustment assumes Pepco will experience zero plant retirements related to the 2012 plant balance, which is "highly unlikely."[156]

2. <u>Commission Decision</u>

Only OPC asserts that the Company's rate base should be reduced to reflect accumulated depreciation expense for the post-test year period January 1, 2013 – June 30, 2014. We have accepted post-test year reliability plant additions in the past, and we have

[151] Schultz Direct at 22-23.
[152] *Id.* at 24.
[153] *Id.* at 26-28.
[154] Schultz Surrebuttal at 20-21.
[155] Hook Rebuttal at 7.
[156] *Id.* at 8.

required that accumulated depreciation and deferred taxes also be reflected. In this case, we concur with the Company that OPC's proposed accumulated depreciation adjustment is not symmetrical as it ignores post–test year additions to plant. As OPC has not made a compelling argument to depart from this principle, we reject their adjustment.

4. Amortization of 2012 Major Storms

a. Parties' Positions

The Company has proposed two RMAs for two major storms that occurred in 2012. RMA6 reflects amortization of the incremental operations and maintenance ("O&M") costs associated with the June 29, 2012, Derecho storm. Pepco proposed to amortize the costs over five years and include the unamortized balance in rate base, which it asserts is consistent with the Commission's treatment of 2011 major storms in Case No. 9286. RMA7 reflects O&M costs associated with Hurricane Sandy, which the Company also proposed to amortize over five years.[157]

OPC witness Schultz raised a number of issues with RMA 6. He asserted that some of the Derecho O&M costs are estimated and therefore are not known and measurable. He stated that the cost summary was not sufficiently detailed to permit verification and characterized the Company's response as only permitting "an impractical review." He also claimed that "the Company has no support for the method of allocating storm costs between Maryland and Washington DC." Mr. Schultz questioned whether Pepco properly capitalized storm costs. Additionally, he raised a concern that the restoration cost was excessive "because the Company failed to properly perform vegetation maintenance prior to 2010."[158]

[157] Hook Direct at 11.
[158] Schultz Direct at 12-13.

Mr. Schultz argued that the Company's method of basing jurisdictional cost allocation on the number of customer outages is "too restrictive," as there are "many factors" that impact costs. He took issue with the fact that Pepco has not performed a study to determine if direct cost assignment would be more accurate. Further, he stated that some storm costs should be capitalized because deferral mechanisms allow for recovery over a shorter time frame. Mr. Schultz stated that it is unclear how much of the cost of the two storms was capitalized.[159]

Mr. Schultz argued that, based on the Commission's decision in Case No. 9240 (a review of Pepco's service reliability and quality) and his review of Pepco's tree trimming practices, "it is evident the Company did not sufficiently focus on its vegetation management over the years 2000-2009."[160] He also argued that Pepco "still had a significant amount of catch-up to perform in 2012." Therefore, he concluded that Pepco should share in the Derecho restoration costs and argued that the deferral should be reduced "by at least 17.5%."[161] Noting that in Case No. 9217 (a Pepco base rate case), storm costs were deferred over ten years, Mr. Schultz recommended a seven year amortization period as it would permit "a timely repayment to the Company while mitigating the rate increase to customers."[162]

Mr. Schultz stated similar concerns with the Company's Hurricane Sandy costs. He emphasized that an even larger percentage of these costs are not known and

[159] Schultz Direct at 16.
[160] *Id.* at 17.
[161] *Id.* at 18-19. *See* pages 20-21 for Mr. Schultz's derivation of the 17.5% figure.
[162] Schultz Direct at 19.

measurable. As in RMA6, he recommended that 17.5% of RMA7 costs be disallowed, and that the amortization period be extended to seven years.[163]

Montgomery County witness Ostrander stated that all estimated and accrued storm expenses should be removed from the Company's storm adjustments. He asserted that actual amounts should be available by now.[164]

Responding to OPC and Montgomery County, Ms. Hook stated that the Company updated RMA6 and RMA7 for actual invoiced storm costs as of the date of her Rebuttal testimony, thereby eliminating the concern about estimated costs.[165] Ms. Hook emphasized that the "Company provided numerous contractor invoices and supporting expense schedules … during the discovery process" and, because the invoices are voluminous, "exceeding hundreds of transactions," offered all parties an opportunity for a more extensive review at Pepco's premises.[166] She also stated that the Company provided a breakdown of overtime expenses.[167] Addressing jurisdictional allocations, Ms. Hook stated that the Company's method is consistent with the method approved in its last two rate cases, and that it would be impractical to directly assign major storm costs. Therefore, she argued that allocating costs based on the number of restorations is reasonable.[168] Ms. Hook stated that approximately 46% of Derecho and 32% of Hurricane Sandy costs were capitalized based upon PHI's Capitalization Policy, which is consistent with FERC rules and Generally Accepted Accounting Principles ("GAPP").[169] Ms. Hook argued that Pepco lessened the extent of storm damage due to aggressive

[163] Schultz Direct at 21-22.
[164] Ostrander Direct at 76-79.
[165] Hook Rebuttal at 50. Ms. Hook filed her Rebuttal testimony on March 25, 2013.
[166] *Id.* at 51.
[167] *Id.* at 52.
[168] *Id.* at 52.
[169] *Id.* at 53.

vegetation management in recent years, and that Mr. Schultz's allegations to the contrary are "unsupported."[170] Finally, Ms. Hook stated that OPC's proposal to extend the storm amortization period to seven years is unsupported and inconsistent with recent Commission practice. She noted that while such a proposal may reduce current customer rates marginally, some customers will be burdened in the future with the costs of storms that occurred before they were even customers.[171] For these reasons, she recommended rejection of OPC and Montgomery County's storm adjustments.[172]

In his Surrebuttal testimony, Mr. Schultz emphasized the need for an audit of the 2012 major storms.[173] He stated that there "has been no determination that [storm] costs are accurate and/or were prudently incurred," and that a rate case provides a limited opportunity for such an analysis.[174] He asserted that an "audit is the most practical manner to verify that the costs are reasonable" and is the best means to identify and eliminate "inappropriate charges."[175]

Mr. Ostrander responded that Ms. Hook "appears to be claiming that all estimated and accrued amounts have been trued-up to actual invoiced amounts...." However, he stated that he could not find any supporting documents to support her claim. Therefore, Mr. Ostrander declined to change his original adjustment for estimated and accrued expenses.[176]

[170] Hook Rebuttal at 54.
[171] *Id.* at 54-55.
[172] *Id.* at 51-55.
[173] Schultz Surrebuttal at 8-14.
[174] *Id.* at 9.
[175] *Id.* at 10-11.
[176] Ostrander Surrebuttal at 40-41.

b. Commission Decision

According to the Company, Maryland incremental Derecho costs were $19,174,000 and Hurricane Sandy costs were $4,472,885.[177] These costs were explained by the Company and examined in detail by other parties, particularly OPC and Montgomery County. Because we find the Company's testimony credible but unverified, and the criticisms general and lacking in detail, we authorize recovery in this case for RMA6 and RMA7, subject to further audit. Additionally, we concur that major storm costs should be amortized over five years, consistent with past findings. We find merit to OPC's recommendation to audit these costs, which will also address Montgomery County's concerns about any remaining estimated costs. Therefore, we direct Pepco to conduct an audit of both the Derecho and Hurricane Sandy costs and provide that audit to the Commission within six months from the date of this order, or at the time of the Company's next base rate case, whichever is sooner.[178] We reserve our right to make any necessary adjustment in Pepco's next base rate case based upon the audit and our review. Consequently, rate base shall be increased by $10,292,000 and operating income reduced by $2,287,000 for RMA6, the Derecho rate base shall be increased by $2,401,000 and operating income reduced by $534,000 for RMA7, Hurricane Sandy.

5. Vegetation Management (VM)[179]

a. Parties' Positions

Company witness Gausman noted that Pepco spent approximately $5.7 million in 2012 performing accelerated vegetation management ("VM") activities for reliability

[177] Hook Rebuttal, Exhibits LJH-R-1, pages 10-11. Ms. Hook revised page 11 for RMA7 during the hearing. T at 305.
[178] Pepco shall provide copies of the audit to Staff, OPC, Montgomery County and any party to this case that requests a copy.
[179] This issue is separate from Grid Resiliency Charge vegetation management issues.

purposes. The Company's RMA21 reflects a reduction in the rate-effective period, compared to test year O&M expenses associated with these accelerated VM activities.[180] Pepco proposed to offset this reduction by approximately $1.3 million to annualize the cost of compliance with the Service Quality and Reliability standards, plus an anticipated contractor escalation rate of 2%.[181] Mr. Gausman noted that the annual cost for the VM program is $20.3 million.[182]

Mr. Schultz asserted that Pepco's $20.3 million VM figure is too high, arguing that Pepco's VM costs for 2011 and 2012 "reflects years of catch up costs and is significantly inflated because of the Company's attempt to make up for years of under-spending." He stated that Pepco has done tree trimming equivalent to 1.4 times the total mileage on its system over the past three years. He also noted the Commission's findings regarding Pepco's inadequate historical VM practices in Case No. 9240. Mr. Schultz concluded that the Company's recent VM costs are not representative of its post-test year VM costs.[183]

Specifically, Mr. Schultz took issue with: (1) the Company's projected average cost per mile; (2) the assumption that 2013 costs will be the same as 2012; (3) the amount of incremental RM 43 compliance costs; and (4) Pepco's 2% escalation factor.[184] He opined that the level of costs per mile from 2007-2010 were too low (because VM was inadequate) and in 2011-2012 too high (because of catch-up spending).[185] However, Mr. Schultz concluded that "the best cost per mile" should be developed by dividing the total

[180] Gausman Direct at 17 and Supplemental Direct at 1-3. In Case No 9286 the Commission disallowed certain VM costs finding they were "catch-up" reliability costs. *See* Order No. 85028 at 38-39. *See* also Case No. 9240.
[181] Gausman Direct at 17. *See* also Hook Direct Schedule (LJH)-1 at page 25.
[182] Gausman Direct at 17 and Schedule (WMG)-1 page 1.
[183] Schultz Direct at 51-52.
[184] *Id.* at 52-53.
[185] *Id.* at 53-54.

miles trimmed in 2012 by total 2012 costs.[186] Further, he noted that the projected miles to be trimmed in 2013 are less than half of the 2012 miles.[187] He asserted that Rulemaking ("RM") 43 costs are overstated because employee costs are overstated. Finally, Mr. Schultz stated that the escalation factor is inappropriate because the 2013 contractor escalation is deferred until 2014. Mr. Schultz recommended $12.124 million for tree trimming costs, a reduction of $8.180 million.[188]

AOBA witness Oliver stated that he has concerns with Pepco's renegotiated VM contract, which permits the deferral of costs for future recovery. He asserted that this complicates the task of segregating and verifying costs for associated activities. He stated that Pepco should be required to document all deferred costs and demonstrate their reasonableness. He concluded that the Commission will not be able to verify the reasonableness of VM costs recovered through a GRC, if approval of these costs cannot be directly tied to their specific services.[189]

Staff proposed to eliminate $237,000 from RMA 21 for the 2% contractor escalation factor because the adjustment is beyond the test year. Staff also asserted that the 2% factor fails to meet the known and measurable standard because it is only an estimate.[190]

Mr. Gausman stated that the 2% escalation factor included in RMA21 reflects contract terms that call for VM rates to increase 3% in 2013 and 2.5% in 2014. Although the 2013 escalation is now deferred to 2014, he argued that because the first year of new

[186] Schultz Direct at 55.
[187] *Id.* at 55-56.
[188] *Id.* at 56-57. Montgomery County adopted OPC's position. Montgomery County Initial Brief at 69.
[189] Oliver Direct at 59-61.
[190] Stinnette Direct at 10. AOBA supports Staff's position. AOBA Initial Brief at 50-51.

rates in this case will include a 5.5% VM increase beginning January 2014 that the 2% escalation factor is reasonable.[191]

Mr. Gausman emphasized that Pepco is only requesting cost recovery for VM work that will actually be performed in 2013, noting that "catch-up" costs have been removed. Addressing unit costs per mile, he stated that the average cost per mile was developed based upon contract costs associated with feeders completed between January and July 2012. He asserted that it is not correct to take the total dollars spent and miles completed (in a given year) and average the cost as Mr. Schultz did because "the work must be matched with the payments to achieve the true cost per mile."[192] Mr. Gausman emphasized that the timing of payments and work completed must be factored into the calculation to derive the average cost. Furthermore, he argued that the mileage rate was developed prior to the implementation of RM 43 and therefore costs should be adjusted for RM 43 costs expected to be incurred in 2013.[193] Mr. Gausman noted that VM plans are designed to conform to the regulations and that work is not segregated between "regular" trimming and "enhanced" trimming.[194]

b. <u>Commission Decision</u>

With one exception, we find the Company's reduction to VM costs for the rate-effective period appropriate. The Company has eliminated $5.7 million of VM test year costs associated with "accelerated" or "catch-up" VM activities. Further, the Company has agreed to forego $2.8 million for accelerated VM work that was not accomplished in

[191] Gausman Rebuttal at 7.
[192] *Id.* at 8. Payments can occur in various years to complete a feeder project. *Id.* at 8-9.
[193] *Id.* at 8-9.
[194] *Id.* at 10.

2012 and is to be completed in 2013, for a total of $8.5 million.[195] We find that the record in this case supports these adjustments. However, we agree with Staff that, because there will not be an escalation in contractor costs in 2013, the 2% escalation factor should be removed. Consequently, we accept Staff's adjustment for VM activities in the rate effective period, which increases operating income by $2,825,000.

6. Cash Working Capital (CWC)

a. Parties' Positions

Ms. Hook stated that the Company's cash working capital ("CWC") adjustment was developed consistent with the Commission's Order in Case No. 7662 (a Pepco rate case filed in 1982).[196] She noted that the revenue and expense lags used in determining Pepco's CWC allowance were developed in the Company's 2005 lead-lag study ("2005 Study"), which was approved in Case No. 9092 and subsequently used in Case Nos. 9217 and 9286. Ms. Hook "updated" the 2005 Study to reflect a change from quarterly to monthly remittances for the Montgomery County Fuel and Energy Tax ("MCFET").[197]

Mr. Schultz stated that Pepco's 2005 Study is outdated. He noted that business processes have changed since then, which have reduced the revenue lag. Specifically, he asserted that advanced meters have reduced the billing lag, eliminating the need to manually record much data, and that electronic payments have shortened the collection lag. Further, he criticized Pepco for not considering pensions and OPEB payments in the expense lag as the Company has made major pension contributions in recent years. Mr. Schultz also took issue with the payroll, federal income tax and Maryland income tax lag

[195] Only the $5.7 million is a reduction to test year expenses as the additional $2.8 million is outside of the test year.
[196] Hook Direct at 16.
[197] *Id.* at 18.

calculations. He emphasized that Pepco's net lag has increased from 6.89 days in its last case to 19.20 days in just one year, which he argued indicates the calculations are flawed. He concluded that Pepco's 2005 Study "is of no value," and therefore the Commission should consider eliminating the Company's CWC request.[198]

AOBA witness Oliver argued that Pepco's 2005 Study "does not provide a reasonable or appropriate portrayal of its actual revenue lags" in light of the subsequent implementation of a Bill Stabilization Adjustment ("BSA") mechanism. Although Pepco has adjusted for the MCFET, the Company has not adjusted for the effect of the BSA mechanism even though it now has "sufficient historical experience" to do so. Mr. Oliver questioned the fairness of this lack of balance in the 2005 Study. Furthermore, he recommended that the Commission order Pepco to "prepare a special study" for its next case that assesses the influence of the BSA on the Company's billing and revenue collection lags.[199]

Staff also argued that the 2005 Study is "outdated," noting that today more customers pay bills online, which reduces the revenue lag. Ms. Stinnette stated that lead-lag studies should generally be performed every five years. Furthermore, she stated that by only adjusting for the MCFET, "the Company appears to be 'cherry-picking.'" Although she admitted that CWC is a legitimate part of the cost of service, Ms. Stinnette recommended the elimination of Pepco's entire CWC allowance because more current data should have been used to develop the CWC allowance.[200]

[198] Schultz Direct at 33-35. Montgomery County supports OPC's CWC adjustment. Montgomery County Initial Brief at 73-74.
[199] Oliver Direct at 61-63.
[200] Stinnette Direct at 6-8. Staff witness Brekke-Miles proposed a CWC adjustment using the net lag days from Case No. 9286 for changes in O&M expenses. Brekke-Miles Direct at 3.

Ms. Hook responded that AMI implementation will not change Pepco's billing cycle, and that OPC has offered no evidence that electronic payments will shorten the net revenue lag.[201] Ms. Hook emphasized that the 2005 Study was accepted just four and one-half months prior to filing this case, no party requested a new study, and the Commission did not direct that a new one be filed in its last case. She said Pepco will file an updated lead-lag study in its next case.[202] As for pensions, she noted that such payments are not part of day-to-day operations. Further, she stated there is no "disconnect" in the Company's payroll calculation in the CWC computation as it is the same as the amount in its (uncontested) adjustment RMA11 to annualize wage increases.[203] Ms. Hook asserted that the only reason for the change in net lag days from Case No. 9286 is due to the MCFET, which she emphasized constitutes 40% of the total expenses included in the net lag day computation.[204] Ms. Hook argued that Staff has provided "no quantification of specific operational changes and their impact on the Company's cash working capital requirement."[205] Ms. Hook stated that AOBA has mischaracterized the BSA and that it has "no impact on either the billing process or collection activities."[206] Ms. Hook concluded that the CWC requirement "does not change substantially over time, absent a significant change in lag days to a significant item," like the MCFET. Therefore, she asserted Pepco's CWC adjustment should be accepted.[207]

[201] Hook Rebuttal at 14-15.
[202] *Id.* at 16.
[203] *Id.* at 16-18.
[204] *Id.* at 19.
[205] *Id.* at 20.
[206] *Id.* at 21.
[207] *Id.* at 22.

b. Commission Decision

We agree with Staff, OPC and AOBA that the 2005 Study, which forms the basis for the Company's CWC adjustment, is outdated. We concur with Staff and others that such studies should, in the future, be conducted approximately every five years. Further, we find the Company's "update" to the 2005 Study for the MCFET is one-sided, as it would increase CWC requirements without even considering any updates that might reduce CWC requirements. However, we find the recommendations to eliminate Pepco's entire CWC allowance to be unsupported and without merit, as no party presented a compelling case that the Company does not have a continuing CWC requirement. On balance, we find that the appropriate solution is to modify the Company's unadjusted 2005 lead-lag study to remove the Company's one-sided "update" for the change in lag days associated with the MCFET to reflect the lag days used in Case No. 9286.[208] Based upon the Commission's decisions herein, we find that rate base should be reduced by $21,129,000 for CWC purposes. Further, we direct the Company to file a new lead-lag study in its next base rate proceeding, and further direct Pepco to consult with the parties regarding the new study, including but not limited to the influence (if any) of the BSA on CWC requirements.[209]

7. Annual Incentive Plan (AIP)

a. Parties' Positions

Pepco's RMA13 reflects non-executive Annual Incentive Plan ("AIP") management employee costs at a three-year average level. Ms. Hook stated that this

[208] We urge Pepco to work with Montgomery County officials to reinstate the quarterly remittances for the MCFET. The loss of CWC from the change from quarterly to monthly remittances will, according to Company witness Hook, result in increased costs to ratepayers of about $14 million when included in a rate case Transcript at 420.
[209] As Pepco will be responsible for the study, we do not mandate any particular adjustments.

adjustment is consistent with previous adjustments approved in Pepco's last two rate cases.[210]

OPC argued that the AIP is not sufficiently customer focused because it ensures payouts to employees rather than requiring improved performance. Consequently, Mr. Schultz recommended disallowance of 90% of the AIP adjustment, noting that "there is 5% benefit coming from each of the questionable customer and employee goals."[211] Mr. Schultz emphasized that the financial goals in the AIP are "shareholder oriented." Further, he asserted Pepco lowered customer goals in 2011 in order to achieve the goals, which means there was "no incentive for improvement because the Company's goal was simply to maintain the status quo."[212] He noted that the employee goals were the same in 2011 as 2010. Despite the criticism, Mr. Schultz stated that the Company should not eliminate its incentive plans because properly focused plans "can have value." He concluded that "a 50/50 sharing of the cost between shareholders and customers would be justified if the goals actually did require better than average performance and better than average customer service and reliability."[213]

Company witness Boyle stated that the 2012 AIP has not significantly changed from the previously approved 2011 AIP. He argued that attention must be paid to shareholders and the Company must demonstrate an appropriate level of accountability in order to raise the capital necessary to provide utility services to customers. Furthermore, he stated that the Commission has determined that an AIP may appropriately include both financial and operational goals. Mr. Boyle stated that continually increasing goals could

[210] Hook Direct at 13-14.
[211] Schultz Direct at 41.
[212] *Id.* at 45.
[213] *Id.* at 47-48.

render the goals unattainable and therefore useless as incentive tools. He emphasized that the goals are "based on a thoughtful and balanced approach" to incent a high level of performance, which is demonstrated in his view by the fact that Pepco has met or exceeded the new Service Quality and Reliability Standards.[214] Ms. Hook responded that the AIP is an important part of total employee compensation and promotes operational excellence. She stated that OPC's proposal should be disregarded noting that no other party disputed the computation of this adjustment.[215]

Mr. Schultz stated that the fact the AIP has not changed significantly is a problem, because Pepco achieves a goal and doesn't change (raise) it. Further, if goals are not met, exceptions are made so incentives can be paid, which means customers are paying the cost for lower customer satisfaction requirements. He argued that financial performance should be tied to increased earnings or cost savings and then shareholders and ratepayers can both share in improved performance. For these reasons, Mr. Schultz continues to recommend disallowance of 90% of AIP costs.[216]

b. Commission Decision

We find in this case, as we did in Pepco's last rate case, that the non-executive AIP is an appropriate method to encourage employees to achieve operational efficiency and promotes quality customer service, which benefits ratepayers.[217] Even OPC agrees that appropriately focused incentive plans can have value. We also note that RMA13 is based upon a three-year average level of expense, which reduces the cost of service for

[214] Boyle Rebuttal at 11-13.
[215] Hook Rebuttal at 47- 48.
[216] Schultz Surrebuttal at 29-32.
[217] *See also* Case No. 9286, Order No. 85028 at 66.

ratepayers compared to 2012 expenses. Therefore, we will increase operating income by $443,000.

8. Energy Advisors and Energy Engineers (EA&EE)

a. Parties' Positions

In response to Commission Order No. 85319,[218] Ms. Hook added a ratemaking adjustment to reflect the 2013 cost for energy advisors and energy engineers ("EA&EE").[219] Staffs, OPC and AOBA take issue with the adjustment.

Mr. Schultz argued that customer service representatives have provided energy assistance and advice for years. He noted that only a small number (476) of customers were assisted by the EA&EEs, at a ratepayer cost of $1.7 million, which equates to $3,488 per customer. He also noted a concern with a possible duplication of costs. Therefore, OPC recommended that this adjustment be disallowed.[220]

AOBA witness Mr. Oliver stated that Pepco has not demonstrated either the need or cost-effectiveness of the EA&EE program, noting the Company's failure to tie costs to energy efficiency gains or cost savings for its system. Moreover, Mr. Oliver asserted that the services EA&EEs provide are not substantially different from services available in the competitive market. He argued that it is unfair for customers who use outside vendors to be required to pay for a limited number of customers to get such services for free. He argued that the program "constitutes little more than a public relations program for

[218] Order 85319 was issued January 17, 2013, in Pepco's EmPOWER proceeding, Case No. 9155. Order No. 85319 authorized recovery of 2011 and 2012 EA&EE costs in the EmPOWER surcharge but directed that future costs be reviewed in a base rate proceeding.
[219] Hook Supplemental Direct at 2-3. MEA supports Pepco's EA&EE adjustment. MEA Reply Brief at 6-8.
[220] Schultz Direct at 61-62.

Pepco." He concluded that, if the program is to be continued, then costs should be billed to customers who use the services.[221]

Staff witness Sherwood asserted that Pepco has failed to provide evidence why these post- test year costs should be recovered and also has failed to demonstrate that the EA&EE costs are not duplicative.[222] Ms. Sherwood asserted that Pepco has not demonstrated a need for the EA&EE positions or proven that the positions are cost effective.[223] She noted that the Commission has disallowed cost recovery for these positions in two previous Pepco base rate cases.[224] Ms. Sherwood argued that the Company is trying to socialize costs that benefit an "extremely small" number of customers. She emphasized that the services EA&EEs provide can and should be provided by customer service representatives ("CSRs"), the crises call center, and EmPOWER Maryland call centers. As for a home analysis or other guidance, Ms. Sherwood recommended that Pepco direct customers to contact an electrician or outside expert.[225] Ms. Sherwood stated that if the Company believes these positions support the EmPOWER or AMI programs, then it should seek recovery through those programs.[226] Ms. Stinnette also noted that the adjustment does not adhere to the matching principle.[227] For these reasons Staff recommended rejection of the Company's adjustment.[228]

Pepco witness Reese responded that the EA&EEs "provide valuable service to customers on a wide range of topics," and that the roles have not changed since the

[221] Oliver Direct at 57-59.
[222] Sherwood Direct at 1-3.
[223] Sherwood Surrebuttal at 10 and 14.
[224] *Id.* at 2.
[225] *Id.* at 1, 5-7, 10 and 14.
[226] *Id.* at 10-11.
[227] Stinnette Direct at 10.
[228] Sherwood Direct at 1. Mr. Schultz stated that the Company offered no reasons to change his recommendation to eliminate this expense. Schultz Surrebuttal at 35. Montgomery County supports Staff's position. Montgomery County Initial Brief at 72.

Commission found them "prudent" in Case No. 9155.[229] Ms. Reese stated that the purpose of the initiative is to provide customers necessary information to make informed energy choices, noting that the volume of services continues to rise. Ms. Reese emphasized that EA&EEs have special skills and requirements and do not perform the same functions as customer service employees. She also argued that EA&EEs are available to all of Pepco's customers and the costs should not be directly assigned.[230] Ms. Hook stated that costs for these positions are not duplicative.[231]

b. Commission Decision

In Order No. 85319 issued in Pepco's EmPOWER proceeding,[232] we authorized the Company to recover its 2011 and 2012 costs for its EA&EE positions in the EmPOWER surcharge. However, we directed that any future requests for cost recovery be made in a rate case.[233] We noted our finding that EA&EEs "are utilized to handle a wide range of topics with the Utilities' customers, from EmPOWER matters to AMI, and from reliability issues to customer call assistance in the case of mass call events."[234] Therefore, contrary to Staff's position we do not believe that EA&EE costs should be parceled out for recovery in either Pepco's EmPOWER or AMI proceedings but are more appropriately considered in a base rate case. Upon review of the record in this case, we find that Pepco has supported the recovery of EA&EE costs for 2013[235] as these personnel support a diverse range of customer assistance initiatives. Therefore, operating income will be reduced $989,000.

[229] Reese Rebuttal at 3.
[230] *Id.* at 3-5.
[231] Hook Rebuttal at 50.
[232] Case No. 9155.
[233] Order No. 85319 at 1.
[234] *Id.* at 4.
[235] See particularly Reese Rebuttal and Transcript at 667-721.

9. AMI Meters

a. Parties' Positions

Mr. Schultz for OPC noted that Pepco has included an average cost of $32 million in unadjusted rate base for AMI meters, but argues that this is not appropriate because the Commission has not yet authorized recovery for these meters.[236] He stated that AMI costs should be deferred pending a determination about AMI's cost-effectiveness. Mr. Schultz also noted a concern because the undepreciated costs of legacy (old) meters are to be considered in a depreciation proceeding, yet it appears Pepco is continuing to collect a return on plant that is no longer used and useful. He recommended disallowing most of the AMI cost ($29.76 million) noting that the Commission allowed recovery ($2.966 million) in Case No. 9286 of AMI meters actually installed in that test year.[237]

Ms. Stinnette stated that AMI meter costs should not be recovered until Pepco has delivered a cost-effective AMI system. Until then, costs should be deferred into the regulatory asset as directed by Order No. 83571.[238] She noted that the entire AMI system is forecasted to cost $141 million, and opined that, if the system proves not to be cost-effective, then "the Commission will be unable to disallow the recovery of the meters since they would not be part of the regulatory asset."[239]

Ms. Hook responded that the Company is only requesting recovery of costs associated with meters that are used and useful and serving customers. She noted that

[236] Schultz Direct at 30.
[237] *Id.* at 31-32.
[238] Order No. 83571 was issued in Pepco's AMI proceeding, Case No. 9207.
[239] Stinnette Direct at 8-9. *See also* Sherwood Surrebuttal at 11-14. Staff modified its original proposal and now only proposes to exclude AMI costs in excess of costs approved in Case No. 9286. Stinnette Surrebuttal at 2. AOBA supports Staff. AOBA Initial Brief at 51. Montgomery County also supports Staff's position. Montgomery County Initial Brief at 70-72.

400,000 AMI meters cannot be deployed instantaneously. Ms. Hook emphasized that Pepco is not requesting recovery of AMI infrastructure deferred costs.[240]

Montgomery County addressed another aspect of AMI. Mr. Ostrander proposed an adjustment to remove AMI "expenses" that he argued should not be included in the test period. He stated that expenses should be included in the AMI deferred costs. Although Mr. Ostrander identified some AMI expenses, he was not able to identify all of them as yet. Moreover, he noted Pepco claimed a problem with identifying vendor payments on a Maryland specific basis, so Mr. Ostrander allocated approximately 50% of the total estimated Pepco AMI expenses to Maryland.[241]

Responding to Mr. Ostrander, Ms. Hook stated that the AMI costs he has identified "were either appropriately deferred in a regulatory asset or not related to AMI."[242] In his Surrebuttal testimony Mr. Ostrander revised his proposed adjustment downward in response to clarifications in Ms. Hook's Rebuttal testimony. However, because of inconsistencies between some of Ms. Hook's statements and Company responses to data requests, Mr. Ostrander continues to claim that some AMI expenses are included in the cost of service.[243]

b. Commission Decision

In Order No. 83532, issued in Pepco's AMI proceeding, Case No. 9207, we stated that we would require the Company to demonstrate that its AMI system is cost-effective for its customers as a condition of recovery of prudently incurred costs.[244] We affirmed

[240] Hook Rebuttal at 12-14. MEA supports Pepco's recovery of AMI meter costs. MEA Reply Brief at 8-11.
[241] Ostrander Direct at 63-64.
[242] Hook Rebuttal at 35. Ms. Hook provides additional details at pages 36.37.
[243] Ostrander Surrebuttal at 30-34. According to the Chart, Montgomery County proposes reducing expenses by $590,000 for claimed AMI expenses in the cost of service.
[244] Order No. 83532 at 2.

this position in Order No. 83571 when we authorized Pepco to establish a regulatory asset for the incremental costs associated with AMI deployment, stating that when Pepco could demonstrate that it has delivered a cost-effective AMI system, then the Company could seek cost recovery in a base rate proceeding.[245] Pepco does not contest that new AMI meters, regardless of whether they have been installed, represent incremental AMI costs. Additionally, it is undisputed that Pepco has not yet demonstrated that its AMI system is cost-effective. We are aware that in Order No. 85028 in Case No. 9286, we allowed recovery in rates of the AMI meters actually installed in the test year, for the reason that they were in service and used and useful. However, upon further consideration, we realize that this would lead to a result where the cost of the vast majority of AMI meters would be installed and included in rates before Pepco demonstrates the installation was cost-effective. Allowance of such costs outside the boundaries of the Company's test year would not satisfy the prudently incurred requirement established in Order No. 83532. Therefore, we reaffirm the prudently incurred costs pre-condition adopted in Order No. 83532, which included the requirement that Pepco demonstrate that its AMI system is also cost-effective for its customers.[246] Thus, we decline to follow Order No. 85028 in this case. Instead, we adopt Staff's recommendation to remove the cost of the Company's AMI meters in this case, which will reduce rate base by $23,402,000 and increase operating income by $542,000. However, we reject Montgomery County's proposed expense adjustment as unsupported.

[245] Order No. 83571 at 57.
[246] *See Order No. 83532 at 2.*

10. Average Overtime Expense

a. Parties' Positions

Ms. Hook noted that in Case No. 9286 the Commission approved a downward adjustment for overtime expense (net of storms) that reflected the six-year (2006-2011) expense average because Pepco failed to meet its burden of proof regarding a substantial increase in test year overtime expenses. In 2012, Pepco's overtime costs, net of major storm costs, was $11 million, compared to $13.6 million in 2011 and the 2007-2010 average of $7.7 million. Ms. Hook stated that the increase in the last two years "is due to increased substation equipment and overhead line maintenance costs associated with ongoing reliability efforts which will continue into the foreseeable future."[247] Because of these and other costs, Ms. Hook concluded that 2012 overtime expenses are more reflective of future costs than a historical average.[248]

Mr. Schultz stated Pepco's explanation for the recent increase in overtime costs is "not satisfactory" because it is "too general and does not provide any comparative detail that would explain the increase and variance from the years 2006-2010."[249] Mr. Schultz stated that "beyond the storm events, the Company has provided no support for a claim that the variance is reliability related."[250] He also noted that Pepco has not conducted any audit of its overtime expenses.[251] Because 2011 and 2012 variances remain unexplained, which means the costs are not known and measurable, he recommended calculating the

[247] Hook Direct at 19. *See* also Schedule (LJH)-3.
[248] *Id.* at 19-20.
[249] Schultz Direct at 37.
[250] *Id.* at 39.
[251] Schultz Surrebuttal at 28.

variance by comparing 2012 costs to costs for 2006-2009. He stated that his adjustment reduces Pepco's Maryland overtime expense by $2.3 million.[252]

Mr. Ostrander, using the six-year average method adopted in Case No. 9286, removed $2.2 million of 2012 "unexplained" overtime expenses.[253] Furthermore, he stated that Pepco has not explained why these costs were treated differently than other storm-related overtime costs, which were removed and amortized over five years by Pepco.[254] Mr. Ostrander characterized Ms. Hook's explanations as "vague," arguing that they are "not supported by any calculations or documentation.[255] Furthermore, he argued that there is no documentation demonstrating that the remaining overtime costs are recurring and will be incurred in 2013 and beyond.[256] Therefore, he concluded a six-year (2007-2012) average of costs should be used or the remaining costs should be amortized over five years.[257]

Ms. Hook responded that the increased level of non-storm overtime expense beginning in 2011 "is the result of the combined impact of the Company's Reliability Enhancement Plan, use of overtime to support increased emergency preparedness, and increased maintenance requirements associated with higher reliability standards and expectations," which will "remain the norm going forward."[258] Although Mr. Ostrander's adjustment comports with the Commission's averaging method in Case No. 9286, Ms. Hook noted that Mr. Schultz's adjustment does not. She stated that Mr.

[252] Schultz Direct at 40.
[253] Ostrander Direct at 46 and Exhibit BCO-2, Schedule A-5 (Ad; BCO-4). The six year averaged overtime costs, excluding 2007-2012 overtime storm costs removed by Pepco, is $9.3 million. Net storm costs for 2012 are $11.5 million.
[254] Ostrander Direct at 46-47.
[255] *Id.* at 48.
[256] *Id.* at 51.
[257] *Id.* at 52.
[258] Hook Rebuttal at 44.

Schultz ignored 2011 and 2012 overtime experience and noted that the Commission used the most recent six-year average in Case No. 9286. However, she stated that the Company has reflected a more appropriate level of expected costs rather than a reduced level that reflects a cost pattern that no longer exists.[259]

b. Commission Decision

In Case No 9286, we denied Pepco's request to include test-year overtime expense because the Company had not performed an appropriate analysis to examine the significant increase in these costs. Consequently, we used the most recent six-year average of net-of-storm overtime costs. Although Pepco has provided a general explanation for the increase in recent (2011 and 2012) years in this case, it has failed to conduct an audit to examine this matter in detail. Consequently, we accept Montgomery County's adjustment, which will increase operating income by $1,338,000. Further, we direct Pepco in its next rate case to provide a more thorough analysis of overtime (net of storm) expenses, which shall include an audit of expenses from 2007, forward.

11. Rate Case Expense

a. Parties' Positions

Pepco stated that the total rate case costs are $238,000 and that the incremental costs should be included in rates. Pepco noted that figure is much less than in recent cases and, because the frequency of filings has increased, this is an "appropriate level of expense upon which to establish rates going forward."[260]

OPC challenged the $93,000 cost of the return on equity ("ROE") witness and recommended removal of half of the cost because the amount is "excessive," particularly

[259] Hook Rebuttal at 44-45.
[260] Hook Direct at 15 and Schedule (LJH-S)-1, page 4.

since the witness provided similar testimony in past cases. OPC also recommended removal of the entire $100,000 for outside counsel costs because Pepco has five in-house attorneys working on the case and has not even retained outside counsel.[261]

Mr. Ostrander opposed Pepco's proposal to expense current rate case costs. He recommended that they be amortized over three years consistent with the decision in Case No. 9286.[262]

Staff stated that Pepco should recover only known and measurable rate case expenses that are incurred through the end of the hearing. However, Staff stated that of Pepco's five in-house attorneys working on the case, three have worked on Pepco's last three cases and one has worked on the last five. Staff concluded that, with this experience, Pepco should not be able to recover any outside counsel costs for this case.[263]

Ms. Hook responded that total rate case expenses in Case No. 9286 were $681,000, of which $107,845 was for expert ROE testimony. She argued that costs have been substantially reduced, and that Mr. Schultz offered nothing more than personal opinion to support his proposed reduction. As for house counsel, she noted that they are not devoted full-time to this case.[264]

b. Commission Decision

Pepco requests recovery of $238,000 in rate case expense, which is a substantial reduction from its last base rate proceeding.[265] Based upon this record, we do not find that Staff or OPC has presented a persuasive case to reduce this amount further. However, rather than expense this cost as Pepco proposed, we concur with Montgomery

[261] Schultz Direct at 63-65.
[262] Ostrander Direct at 80-82.
[263] Brekke-Miles Direct at 5.
[264] Hook Rebuttal at 39-41.
[265] Case No. 9286, Order No. 85028 at 58-60 and Hook Rebuttal at 39.

County that current rate case expense should be amortized over three years, consistent with Commission precedent. Therefore, operating income will be reduced by $37,000.

12. Uncollectibles

a. Parties' Positions

Company RMA10 reflects uncollectible expense based upon the write-off percent experienced through September 2012 applied to test period revenues. Ms. Hook stated that the percentage of write-offs is trending slightly upward. Therefore, she stated the most recent experience can be expected to occur in the rate effective period.[266] Mr. Schultz recommended using a five-year average for uncollectible expense, asserting that 2012 write-offs actually trended downward. He stated that averaging provides a representative expense level for a normal year.[267] Ms. Hook responded that uncollectibles averaged .6546% of revenue from 2006-2009 but averaged 1.0123% from 2009-2012. Although the percentage of write-offs dropped slightly in 2012 from 2010/2011 levels, she stated that RMA10 "appropriately reflects that."[268]

b. Commission Decision

Based upon this record, we find the Company's proposed adjustment appropriately reflects a reasonable level of uncollectible expense. Therefore, operating income is reduced by $1,031,000.[269]

[266] Hook Direct at 11-12.
[267] Schultz Direct at 60-61 and Ex. LA-1, Sch. C-9.
[268] Hook Rebuttal at 47.
[269] We note that OPC's adjustment would have reduced operating income by $1,065,000.

13. Employee Activity Costs

a. Parties' Positions

Staff stated that employee activity costs are "costs incurred by the Company in support of non-business activities of employees."[270] While such activities promote, "to a degree," employee productivity and operational improvements, Ms. Brekke-Miles noted that the activities also benefit shareholders. Consequently, she recommended dividing the costs equally between the Company and its customers.[271] The Company responded that the "modest amount of employee activity costs" it seeks to recover do not reflect the total amount it spends on employee morale and team building, and therefore "should be allowed without further reduction."[272] Ms. Brekke-Miles noted that Staff's position is consistent with Commission precedent.[273]

b. Commission Decision

Consistent with Commission precedent, we concur with Staff that employee activity expenses benefit both shareholders and ratepayers. Therefore, it is appropriate to divide the costs equally. Consequently, we accept Staff's adjustment, which will increase operating income by $89,000.

14. Supplemental Executive Retirement Plan (SERP) Expense

a. Parties' Positions

Mr. Schultz stated that the supplemental executive retirement plan ("SERP") is an additional benefit for select high-level employees that is not available to others. Only 93 current and former employees participate. He stated that this retirement plan is

[270] Brekke-Miles Direct at 5.
[271] *Id.* at 5-6. OPC concurs with Staff. OPC Reply Brief at 24. Montgomery County also supports Staff's position. Montgomery County Initial Brief at 73.
[272] Hook Rebuttal at 48.
[273] Brekke-Miles Surrebuttal at 3.

considered a "discriminatory plan", which is referred to as a "non-qualified plan for IRS purposes."[274] He noted that these employees are also covered by three other Company retirement plans. Mr. Schultz concluded that "it is not reasonable to require ratepayers to pay this excessive amount of benefits limited to a select group and therefore recommended disallowing this expense.[275]

Ms. Hook responded that SERP expense has been uncontested in Pepco's last three rate cases and was approved in another utility rate case. She noted that Pepco is including the SERP liability in rate base. She concluded "there is no justification to look backward, and retroactively remove expense related to prior periods." Therefore, she stated that OPC's proposal to remove the SERP expense should be rejected.[276]

b. Commission Decision

The SERP rewards only 93 select senior officials who, as OPC points out, receive three other pension benefits from Pepco. While it is for the Company to determine the appropriate compensation for employees, the Company has the burden to prove that such costs are appropriate to pass on to ratepayers. Not only is the SERP highly selective, it is uncontested that it is also a "nonqualified plan" for IRS purposes. On this record, we do not find that the Company has justified passing on 100% of these select pension costs to ratepayers. Rather, as with employee activity expenses, we find that it is more reasonable to divide these costs equally between the Company and ratepayers. Therefore, we accept one-half of OPC's adjustment, which will increase operating income by $909,000.

[274] Schultz Direct at 48-49
[275] *Id.* at 49. Mr. Schultz also recommended that rate base be reduced for the average Maryland SERP liability as of December 2012. The Company and other parties concur with this and it is now reflected as an uncontested adjustment. *See* the Chart and Hook Rebuttal at 34.
[276] Hook Rebuttal at 34-35.

Additionally, we will revisit this issue in Pepco's next base rate case to determine what, if any, of these costs provide any benefit to ratepayers.

15. Directors and Officers Liability Insurance

a. Parties' Positions

Mr. Schultz recommended that 50% of the Company's directors' and officers' liability insurance ("D&O insurance") cost be excluded. He stated that shareholders are a "primary beneficiary" of this expense, as directors are elected by shareholders to represent their interests, not those of ratepayers. He concluded that, because shareholders receive most of the benefit of this expense, it is not appropriate for ratepayers to pay 100% of the cost. He also stated that other jurisdictions have recognized that cost-sharing is appropriate.[277]

Ms. Hook responded that D&O insurance permits the Company to attract qualified directors because "[n]o one with reasonable judgment or knowledge would expose themselves to personal liability for such duties."[278] Further, she asserted that the directors are responsible for hiring senior management, who are responsible for maintaining operational integrity and system reliability, which is a direct benefit to ratepayers. She noted that in Pepco's last case, the Commission declined to remove any D&O costs from the cost of service.[279]

b. Commission Decision

As we have stated previously, we find that D&O insurance is a legitimate business expense. OPC has not offered a sufficient basis to exclude part of these costs in this case; therefore, we reject OPC's proposed adjustment.

[277] Schultz Direct at 65-69.
[278] Hook Rebuttal at 45.
[279] *Id.* at 45-46.

16. Materials and Supplies

a. Parties' Positions

Mr. Ostrander proposed to reduce the materials and supplies ("M&S") balance reflected in rate base by $3.4 million because Pepco allegedly failed to explain the reason for the significant 34% increase from 2011 to 2012. He stated that the M&S balance should instead reflect only a 20% increase for 2012, which coincides with the increase that occurred from 2010 to 2011. He also argued that "[a]n 'aged' inventory listing might have shown that old, obsolete, or seldom-used materials are included in M&S and should be written off or at least adjusted for regulatory purposes."[280]

Ms. Hook responded that the end-of-test-year balance "reflects the level which is expected to be maintained in the rate effective period and beyond."[281] She noted that Pepco is in a capital-intensive period of reliability spending and that the 2013-2017 planned spending is 63% greater than that planned for 2012-2016. She stated that Pepco reviews its M&S inventory for obsolescence and wrote off approximately $6.2 million of M&S from 2008-2012.[282] Ms. Hook provided a chart listing categories of M&S that increased for 2012, noting that the amounts relate to reliability construction projects and complying with new performance standards.[283]

Mr. Ostrander countered that Pepco has not demonstrated that a 34% annual increase in M&S will be normal in the future. He also questioned the meaningfulness of Pepco's documentation and assumptions, noting that a 63% increase in reliability spending over five years is only a 12.6% annual increase. Mr. Ostrander further

[280] Ostrander Direct at 83-84. OPC concurs with Montgomery County's position. OPC Brief at 24.
[281] Hook Rebuttal at 23.
[282] *Id.* at 23-24.
[283] *Id.* at 25.

questioned the relationship between M&S levels and reliability spending and the accuracy of Pepco's budgeting process.[284]

b. Commission Decision

The issue before us is what the representative level of M&S inventory should be for the rate effective period. Historical fluctuations are less meaningful where the test year balance is not expected to decrease. In recent years, the Company has increased reliability spending; materials and supplies are necessary to carry out that process. We find that Pepco has met its burden of proof, and that the terminal test-year M&S balance is reasonable for ratemaking. Therefore, we reject Montgomery County's proposed adjustment.

17. Excess Outside Legal Expense

a. Parties' Positions

Mr. Ostrander stated that $483,263 in 2012 outside legal expenses should be removed because they are excessive, noting that Pepco's 2012 outside legal expense of $7.9 million is almost the same as the 2011 expense, (after removal of Case No. 9240 outside legal costs), which the Commission found excessive in Case No. 9286. Mr. Ostrander stated that Pepco has not explained why 2012 costs remain at excessive levels. He stated that his adjustment brings 2012 outside legal expenses in line with 2010 expenses, which were apparently deemed reasonable by the Commission.[285]

Ms. Hook responded that the Company provided Mr. Ostrander with "extensive documentation" of its outside legal expenses, noting that costs have increased particularly

[284] Ostrander Surrebuttal at 42- 44.
[285] Ostrander Direct at 72-76 and Ex. BCO-2. Mr. Ostrander states that his adjustment is "conservative" compared to the last case because he did not remove the increase in costs for the categories "Md. 9240", "Regulatory Matters MD" and "Workman's Comp." *Id.* at 75-76.

in the areas of litigation support, general corporate and environmental.[286] She noted that the Company must defend its interests and "must weigh the hiring of a larger in-house staff of attorneys versus the use of outside counsel with expertise in specific areas."[287] She asserted that Mr. Ostrander has not provided any evidence as to why 2010 represents an appropriate level of expense and fails to acknowledge that inflationary pressures have raised costs. She concluded that Montgomery County's proposed adjustment should be rejected.[288]

b. Commission Decision

In Pepco's last rate case, we found that the Company had "failed to provide documentation explaining the significant increase in the Maryland portion of legal costs from 2010 to 2011" and consequently disallowed the increase in those outside legal costs.[289] We find Pepco's explanation of why 2012 costs remain much higher than 2010 costs still lacking sufficient detail. Because Pepco has the burden of proof, which it has not met, we accept Montgomery County's proposed adjustment. Therefore, operating income will increase by $288,000.

18. Accenture Expenses

a. Parties' Positions

Mr. Ostrander originally proposed a $1 million reduction to expenses as a placeholder to reflect savings from a contract between Pepco and a vendor, Accenture, for services performed in 2012.[290] Ms. Hook responded that the Accenture contract was for a sourcing and procurement project, which was designed to reduce O&M expenses by

[286] Hook Rebuttal at 41-42.
[287] *Id.* at 42.
[288] *Id.* at 42.
[289] Case No. 9286, Order No. 85028 at 68.
[290] Ostrander Direct at 66-71.

$6 million on a PHI-wide basis in 2013. She noted that the Pepco/Maryland costs in 2012 were $401,000.[291] Ms. Hook argued that this is a prudent and necessary business cost that should be reflected in the cost of service, although she admitted that potential savings "have not yet been realized."[292] Mr. Ostrander subsequently recommended that, because the costs were incurred in 2012 but the savings are expected in 2013, expenses should be reduced in this case by $401,000 and the Accenture expense should be moved to a deferred asset account (and thus reflected in rate base), subject to review and potential recovery in Pepco's next rate case.[293]

b. Commission Decision

Based upon the record we concur with Montgomery County. While the expenses were incurred in 2012, it is undisputed that savings are not expected until 2013. Given the scope of the Accenture contract, we find that it is more appropriate to match the benefits with the expenses for what appears to be a significant non-recurring expense. Therefore, operating income is increased by $239,000 and rate base will be increased by $401,000.

19. Case No. 9214 Expense

a. Parties' Positions

Mr. Ostrander proposed that Pepco's Case No. 9214[294] expenses incurred in 2012 be amortized over a "reasonable" three-year period. He noted that this is similar to the treatment of rate case expenses.[295] Ms. Hook responded that regardless of whether these

[291] Hook Rebuttal at 38. The PHI-wide costs in 2012 were $1,456,000. *Id.*
[292] *Id.* at 38-39.
[293] Ostrander Surrebuttal at 34-36. OPC concurs with Montgomery County's position. OPC Reply Brief at 24.
[294] Case No. 9214 involves an investigation into whether new generating facilities are needed. Pepco has appealed the Commission's decision to court.
[295] Ostrander Direct at 79-80. OPC concurs with Montgomery County's position. OPC Reply Brief at 24.

costs are already incurred by Pepco, the Company will always have a variety of non-base-rate matters before the Commission. Therefore, she argued Montgomery County's proposed adjustment is inappropriate.[296]

b. Commission Decision

We agree with Pepco that the Company routinely has non-base-rate matters before the Commission. However, the Company did not quantify what those annual expenses are normally. Consequently, we accept Montgomery County's adjustment and will increase operating income by $121,000.

20. "Excess" Long-Term Debt Costs[297]

a. Parties' Positions

AOBA witness Oliver concluded that the long-term debt rate proposed by Pepco was high compared to the long-term debt rates of other Maryland utilities. Specifically, Mr. Oliver claimed that Pepco's long-term debt rate was higher than the average cost of debt for such utilities as Delmarva Power & Light Company ("Delmarva"), for which the Commission recently approved a rate for long-term debt of 5.30%, and Baltimore Gas and Electric Company ("BGE"), for which the Commission approved a long-term debt rate of 5.46%. Pepco's higher rate, according to Mr. Oliver, added $5 to $6 million to its test year cost of service.[298]

Contributing to Pepco's cost of debt, Mr. Oliver argued, was the Company's issuance in 2008 of 30-year bonds with an effective cost of 8.06%" and a make-whole provision, thereby locking in the burden of that considerably higher than average cost

[296] Hook Rebuttal at 43-44.
[297] *See also* the Commission's Ruling on Motion issued June 14, 2013, which also addresses this issue. The Ruling is Docket Entry No. 156.
[298] Oliver Direct. at 49-59,

issuance through 2038."[299] Mr. Oliver noted that in 2008 Delmarva issued bonds with five-year maturities at 6.63%, and 30-year bonds at an interest rate of 4.00%. He also pointed out that in 2008, Pepco issued 10-year bonds at the considerably lower rate of 3.31%.[300]

As he concluded that Pepco's cost of long-term debt was unjustifiable, Mr. Oliver recommended "that the Commission deduct at least half the annual value of those added costs from any revenue requirement approved in this proceeding."[301] Mr. Oliver concluded by noting that PHI had treated financing for Pepco and Delmarva differently, to Pepco's disadvantage, a difference that justifies some disallowance of Pepco's costs. He noted that Pepco could seek elimination of any current disallowance in the present case in a future base rate case.[302]

On cross-examination, Mr. Oliver explained that by including a make-whole provision in its 2008 bonds, Pepco required itself and its ratepayers to either pay 8.06% to holders of Pepco's 2008 bond issuance until 2038, or to redeem the bonds earlier, at a similarly high cost. Mr. Oliver did not challenge the 2008 bond issuance in itself, but considered imprudent the make-whole provision that limited Pepco's ability to retire the bonds economically.[303]

On brief, AOBA set out other ways in which it claimed Pepco has not prudently managed the costs of its long-term debt portfolio. It failed to justify the costs of that portfolio, according to AOBA, as Mr. Boyle could not explain why Pepco's March 2013 issuance of $250 million in 30 year bonds was 68% more expensive than a similar

[299] Oliver Direct. at 50.
[300] *Id.* at 52.
[301] *Id.* at 52.
[302] *Id.* at 52-53.
[303] T at 1401-1402.

Delmarva bond issuance. Further, AOBA asserted that Pepco did not stagger its bond issuances properly, and "withheld information from the Commission ... in Case 9286 regarding a new debt issuance that would have lowered [Pepco's] weighted average cost of debt …."[304]

In its response on brief, Pepco points to the many ways in which companies decide to issue bonds, suggesting that comparisons among companies can lead to inaccurate and inappropriate conclusions.[305] As to Pepco's 2008 bond issuance, Pepco notes that it was approved by the Commission, which stated that Pepco acted prudently at the time. Its 2012 10-year bond issuance, according to Pepco, was at the lowest or next lowest coupon rate of any PHI debt, and lowered Pepco's cost of debt below the rate that issuance of 30-year bonds would have achieved. Finally, Pepco states that its current weighted cost of debt is 63 basis points lower than its cost of debt in Case 9286.[306] Pepco therefore concludes that AOBA's arguments concerning Pepco's management of its long-term debt portfolio should be rejected.

b. Commission Decision

We will allow Pepco to recover the returns on 30-year bonds it issued in 2008. We will not, in this instance, use hindsight to penalize the Company for a decision approved by us and made under financial circumstances not seen since the Great Depression. The record does not explain why financing for Delmarva has been available at a lower cost than for Pepco. We will therefore require Pepco, in future financing applications, to supply the Commission with information supporting the length of maturity of the debt (10-year, 30-year, etc.), the rationale for any make-whole provision,

[304] AOBA Initial Brief at 39.
[305] Pepco Initial Brief at 3.
[306] *Id.* at 4.

and all other data requested by Staff to provide a more complete picture of proposed debt issuances than current filings provide.

21. Allowance for Funds Used During Construction (AFUDC)

AFUDC is computed by multiplying the rate of return authorized by the Commission in this case by the average balance of test period Construction Work in Progress ("CWIP") accruing AFUDC. Accordingly, we will reduce operating income by $2,477,000.

22. Interest Synchronization

Interest synchronization is a procedure used to adjust the Company's interest deduction for State and federal income taxes, which results from various ratemaking decisions. The interest deduction is calculated by multiplying the rate base by the weighted cost of debt. The resulting interest is then multiplied by the State and federal income tax rates to arrive at the operating income adjustment. Based upon the ratemaking decisions in this Order, the appropriate interest synchronization results in a decrease in net operating income of $55,000.

B. Cost of Capital

1. Parties' Positions

A utility's cost of capital consists of the return it must pay to investors in its common stock (equity) and bonds (debt) in order to attract and retain those investors in a competitive market. The utility recovers its return on equity ("ROE") and return on debt through charges paid by ratepayers. The cost of debt can be directly observed, as bonds are issued subject to specific interest rates. Return on equity, however, requires more analysis, as it is typically based on the returns of a group of comparable companies and on different analytical approaches. Once the returns on debt and equity are determined, they are weighted according to their book values, that is, the percentage of debt and equity in the utility's capital structures. The sum of the weighted return on equity and return on debt is the utility's overall rate of return ("ROR").

The rates of return determined in this case must conform to the principles of the Supreme Court's rulings in the *Bluefield* and *Hope* cases.[307] The Commission has stated that "*Bluefield* and *Hope* require that returns be sufficient to attract capital on reasonable terms, maintain the utility's financial integrity, and provide investors with the opportunity to earn a return comparable to investments carrying similar risks."[308]

Although Pepco is a subsidiary of PHI and its stock is not publicly traded, the Commission must still examine Pepco's level of risk and its financial capital structure to determine its cost of capital. In doing so, we look to the analyses of the parties comparing Pepco to companies deemed comparable.

a. <u>Pepco</u>

Pepco witness Robert B. Hevert proposed a return on equity ("ROE") for Pepco of 10.50%, even higher than that ultimately requested by Pepco, and accepted Pepco's capital structure.[309] Mr. Hevert determined that Pepco's request for a 10.25% ROE was at the lower end of the acceptable range.

Mr. Hevert performed several standard financial analyses to develop his recommended rate of return. As a first step, Mr. Hevert selected two groups of companies he deemed comparable to Pepco: a Transmission and Distribution ("T&D")

[307] *Bluefield Waterworks and Improvement Co. v. Public Service Comm'n of West Virginia*, 262 U.S. 679 (1923). *Federal Power Comm'n v. Hope Natural Gas Co.*, 320 U.S. 591, 603 (1944).
[308] *In the Matter of the Application of Potomac Electric Power Company for Authority to Increase Its Rates and Charges for Electric Distribution Services,* Case 9286, at 83 (2012).
[309] Hevert Direct at 2, 3, 49.

group and an Electric Utility group. He noted, however, that Pepco is solely a T&D utility, and that "there are no 'pure play' state jurisdictional electric T&D companies that may be used as a proxy for [Pepco's] Maryland electric distribution operations."[310] Mr. Hevert therefore relied on electric and gas distribution facilities for the contents of his T&D proxy group. He qualified, however, that by relying only on a group of combined natural gas and electric utilities, Pepco's cost of equity "would be biased downward," as gas distribution is considered less risky – therefore normally requiring a lower return on investment – than electric distribution.[311]

In selecting his T&D group, Mr. Hevert performed five screening tests, relating variously to cash dividends, analysts' ratings, presence or absence of generating assets, and percentage of income from regulated sources. Those tests were meant to identify utilities most similar to Pepco and resulted in his choosing Center Point Energy, Inc.; Consolidated Edison, Inc.; Northeast Utilities; and UIL Holdings Corporation as his comparable T&D companies.[312]

As his second proxy group, Mr. Hevert selected companies he referred to as his Electric Utility Proxy Group. In contrast to his T&D proxy group, and Pepco itself, Mr. Hevert's Electric Utility Proxy Group included some electric companies with regulated generating assets. He included companies with as much as 90% of operating income derived from electric operations, and excluded companies involved in a merger or that obtained more than 50% of their operating income from regulated natural gas. At the end of his analysis, Mr. Hevert selected the following companies for his Electric Utility Proxy Group: American Electric Power Company, Inc.; Cleco Corporation; Empire

[310] Hevert Direct at 7.
[311] *Id.* at 7.
[312] *Id.*, RBH-1 at 1.

District Electric Company; Great Plains Energy, Inc.; IDACORP, Inc.; Otter Tail Corporation; PNM Resources, Inc.; Portland General Electric Company; Southern Company; and Westar Energy, Inc.[313]

Mr. Hevert first performed a constant growth discounted cash flow ("DCF") analysis on his T&D and Electric Utility Proxy Group companies. The DCF methodology assumes that investors purchase a stock based on the future price appreciation and dividend growth they anticipate will result from that investment. The constant growth DCF formula assumes that a company's dividends, earnings, book value, and stock price all grow at the same constant rate.[314]

To obtain price terms for his constant growth DCF calculations, Mr. Hevert used the average daily closing prices for the 30-, 90-, and 180-day stock trading periods ended October 12, 2012. For the dividend term he used the annualized dividend per share. Mr. Hevert employed earnings growth estimates from Zacks, First Call, and Value Line for the growth term required by the constant growth DCF formula.

Using those metrics, Mr. Hevert calculated 30-, 90-, and 180-day averages of the high, mean, and low growth rates for the T&D and Electric Utility Proxy Groups, summarized in the following table. The first two sets of results include DCF results for Mr. Hevert's T&D and Electric Utility groups, respectively. The third set combines Staff witness Luznar's proxy companies with Mr. Hevert's Electric Utility group. The fourth set combines Mr. Hevert's T&D group with both his and Dr. Luznar's other proxy companies:

[313] Hevert Direct, RBH-1 at 5.
[314] *Id.* at 14.