S T A T E O F M I C H I G A N

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

In the matter of the application of	)	
CONSUMERS ENERGY COMPANY	)	
for authority to increase its rates for	)	Case No. U-20963
the generation and distribution of	)	
electricity and for other relief.	)	
	)	

EXHIBITS

OF

BRIAN J. VANBLARCUM

ON BEHALF OF

CONSUMERS ENERGY COMPANY

March 2021

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Development of the Property Tax Rate for the Test Year

Case No.: U-20963
Exhibit No.: A-115 (BJV-1)

Witness: BJVanBlarcum
Date: March 2021

Line No.	(a) Description	(b) Amount (millions)	(c) Amount (millions)	(d) Amount (millions)	(e) Source
1	Electric Property Taxes Paid - 2021 Estimate			$ 198.7	WP BJV-5, L-5
2	Electric Property Taxes on 2021 Plant Investment			20.1	Ex. A-115 (BJV-1), p.2, L-9
3	2022 Coal Plant Valuation Tax Reduction			(0.7)	WP BJV-8, L-4
4	Electric Property Taxes on Real Property Taxable Value Increases			1.1	Ex. A-115 (BJV-1), p.3, L-4
5	Electric Property Taxes to be Paid - 2022			$ 219.2	
6	2021 Fiscal Year Property Taxes expensed in 2022			98.6	(Line 1 * 49.6%) [1]
7	2022 Property Taxes expensed in 2023			(108.7)	(Line 5 * 49.6%) [1]
8	Electric Property Tax Expense - 2022			$ 209.1	
9	2021 Estimated Year-End Plant-in-Service		$ 17,445.0 [2]		
10	2021 Estimated Construction Work-in-Progress	$ 532.0 [3]			
11	@ 50%	50.00%			
12	2021 Estimated Construction Work-in-Progress		$ 266.0		
13	Estimated Taxable Plant			$17,711.0	(L-9 + L-12)
14	Property Tax Rate			0.011806222	(L-8/L-13)

Footnotes
[1] The 49.6% factor is from the 2020 CE Property Tax Fiscal Year Study
[2] Plant in Service Balance as of 12-31-2021; Plant Model U-20963; PIS (WP-JRC-33); Line 17
[3] Construction Work in Progress Balance as of 12-31-2021; Plant Model U-20963; CWIP (WP-JRC-34); Line 17

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Development of the 2022 Property Taxes
on 2021 Plant Investment

Case No.: U-20963
Exhibit No.: A-115 (BJV-1)
Page: 2 of 3
Witness: BJVanBlarcum
Date: March 2021

Line No.	(a) Description	(b) Amount (millions)		(c) Source
1	**Assessed Value of Personal Property (millions)**			
2	Year-end 2021 Estimated Taxable Closings less Retirements	$ 839.9	[1]	
3	First Year STC Multiplier	96.0%	[2]	
4	**True Cash Value of Personal Property (millions)**	$ 806.3		
5	Statutory Factor for Assessed Value	50%	[3]	
6	New Plant - Assessed Value	$ 403.2		
7	**Estimated Property Tax (millions)**			
8	Estimated Composite Millage Rate	49.8651	[4]	
9	Estimated 2022 Property Taxes Paid	$ 20.1		

Footnotes
[1] 2022 Electric Rate Case Property Tax Model
[2] Michigan Dept of Treasury Form 3589 - 1st year multiplier for Electric Distribution and Equipment
[3] Article IX, Section 3 of Constitution of Michigan of 1963
[4] CE Composite Millage Rate.xls

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Development of the 2022 Estimated Electric Portion of
Real Property Taxable Value Increase

Case No.: U-20963
Exhibit No.: A-115 (BJV-1)

Witness: BJVanBlarcum
Date: March 2021

Line No.	(a) Description	(b) Amount (millions)		(c) Source
1	**2022 Estimated Electric Portion of Real Property Tax Increase (millions)**			
2	2022 Real Property Taxable Value - Estimated Electric Portion	$ 21.1	[1]	
3	2022 Estimated Composite Millage Rate	49.8651	[2]	
4	2022 Estimated Electric Portion of Real Property Taxable Value increase	$ 1.1		

Footnotes
[1] 2022 Electric Rate Case Property Tax Model
[2] CE Composite Millage Rate.xls

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Amortization of Excess Deferred Federal
Income Taxes for the Test Year

Case No.: U-20963
Exhibit No.: A-116 (BJV-2)

Witness: BJVanBlarcum
Date: March 2021

	(a)	(b)	(c)
Line No.	Description	Projected Regulatory Liability Amortization [1]	Projected Annual Excess Deferred Tax [2]
1	Protected Plant Balance - Subject to ARAM		
2	2022	(31,436,000)	(23,441,000)
3			
4	**TCJA Amortization - ARAM**		
5			
6			
7			
8	Non-Protected Plant Balance - 27 years		
9	2022	3,145,000	2,345,000
10			
11			
12	Non-Protected Other Balance - 10 years		
13	2022	(8,708,000)	(6,493,000)
14			
15	**TCJA Amortization - Non ARAM**		(4,148,000)
16			
17			
18			
19	**Total Test Year Excess Deferred Taxes**		(27,589,000)
20			
21	[1] Based on the Company's regulatory liability amortization schedule approved in Case No. U-20309.		
22	[2] Adjustment to pre-tax based on 1.341056 gross-up factor used in Case No. U-20309.		

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company

Case No.: U-20963
Exhibit No.: A-116 (BVJ-2)
Page: 2 of 2
Witness: BJVanBlarcum
Date: March 2021

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
CE Electric
Projected Tax Reform Regulatory Liability & Amortization
($000)

Case No.: U-20309
Exhibit No.: A-5 (SBM-3)
Page: 1 of 1
Witness: SBMcIntosh
Date: April 2019

	(a)	(b)	(c)	(d)	(e)
Line No.	**Description**	**Plant Diff ***	**Oth Plant Diff**	**All Other**	**Total Electric**
1	Amortization Period	ARAM	27	10	
2					
3	**Tax Reform Regulatory Asset (Liability) After Gross Up**	**$ (1,172,029)**	**$ 84,923**	**$ (87,076)**	**$ (1,174,181)**
4					
5	**Amortization Schedule**				
6	**2019	(8,953)	1,048	(2,903)	(10,807)
7	**2020	(28,209)	3,145	(8,708)	(33,771)
8	2021	(30,187)	3,145	(8,708)	(35,749)
9	2022	(31,436)	3,145	(8,708)	(36,998)
10	2023	(35,546)	3,145	(8,708)	(41,108)
11	2024	(36,898)	3,145	(8,708)	(42,460)
12	2025	(37,086)	3,145	(8,708)	(42,648)
13	2026	(37,134)	3,145	(8,708)	(42,697)
14	2027	(39,904)	3,145	(8,708)	(45,467)
15	2028	(42,747)	3,145	(8,708)	(48,309)
16	2029	(44,426)	3,145	(5,805)	(47,085)
17	2030	(45,859)	3,145	-	(42,713)
18	2031	(46,326)	3,145	-	(43,181)
19	2032	(47,316)	3,145	-	(44,170)
20	2033	(49,093)	3,145	-	(45,948)
21	2034	(51,089)	3,145	-	(47,944)
22	2035	(44,865)	3,145	-	(41,719)
23	2036	(42,334)	3,145	-	(39,189)
24	2037	(29,201)	3,145	-	(26,055)
25	2038	(26,019)	3,145	-	(22,874)
26	2039	(25,183)	3,145	-	(22,037)
27	2040	(24,370)	3,145	-	(21,225)
28	2041	(24,256)	3,145	-	(21,110)
29	2042	(24,259)	3,145	-	(21,114)
30	2043	(24,313)	3,145	-	(21,168)
31	2044	(24,345)	3,145	-	(21,199)
32	2045	(24,242)	3,145	-	(21,097)
33	2046	(24,063)	2,097	-	(21,966)
34	2047	(23,974)	-	-	(23,974)
35	2048 - 2056	(198,398)	-	-	(198,398)
36		**$ (1,172,029)**	**$ 84,923**	**$ (87,076)**	**$ (1,174,181)**

** Subject to the normalization provisions of the Internal Revenue Code.*
*** Assumes Calculation C Interim Credit beginning September 2019 through December 2020.*

S T A T E O F M I C H I G A N

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

In the matter of the application of **CONSUMERS ENERGY COMPANY** for authority to increase its rates for the generation and distribution of electricity and for other relief.	))))))	Case No. U-20963

EXHIBITS

OF

LINCOLN D. WARRINER

ON BEHALF OF

CONSUMERS ENERGY COMPANY

March 2021

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Summary of Business Case Costs and Benefits
2007 - 2032
(000)

Case No.: U-20963
Exhibit No.: A-117 (LDW-1)
Page: 1 of 8
Witness: LDWarriner
Date: March 2021

Smart Grid Program - Annual Capital Expenditures

Line No.	(a) Utility	(b) Description	(c) 2007	(d) 2008	(e) 2009	(f) 2010	(g) 2011	(h) 2012	(i) 2013	(j) 2014	(k) 2015	(l) 2016	(m) 2017	(n) 2018	(o) 2019	(p) 2020
1	Electric	Meters	$ -	$ 1,424	$ 1,231	$ 930	$ 128	$ 9,602	$ 21,432	$ 29,976	$ 62,152	$ 109,569	$ 53,679	$ -	$ -	$ -
2		Field Equipment/Facilities	$ -	$ 113	$ 1,305	$ 1,510	$ 341	$ 259	$ 171	$ 154	$ 270	$ 1,200	$ 5,965	$ 6,331	$ 8,440	$ 8,580
3		Software/Systems Development	$ 7,889	$ 8,214	$ 12,259	$ 15,909	$ 19,654	$ 20,770	$ 32,100	$ 31,990	$ 45,038	$ 24,918	$ (1,734)	$ 1,162	$ 16,390	$ 952
4		SG Infrastructure	$ -	$ -	$ -	$ 2,789	$ 7,834	$ 5,912	$ 1,109	$ 976	$ 1,463	$ 3,391	$ 750	$ 1,943	$ 2,827	$ 3,375
5		Pilot Prep & Project Management	$ -	$ 7,883	$ 8,932	$ 13,283	$ 9,558	$ 7,919	$ 6,194	$ 6,063	$ 6,657	$ 4,790	$ 2,493	$ -	$ -	$ -
6		Total Capital Costs before Avoidance - Electric	$ 7,889	$ 17,634	$ 23,726	$ 34,421	$ 37,515	$ 44,463	$ 61,005	$ 69,159	$ 115,581	$ 143,868	$ 61,153	$ 9,436	$ 27,657	$ 12,907
7		Avoided Capital Costs - Electric	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ (306)	$ (240)	$ 410	$ 352	$ 263	$ 274
8		Total Capital Costs Net - Electric	$ 7,889	$ 17,634	$ 23,726	$ 34,421	$ 37,515	$ 44,463	$ 61,005	$ 69,159	$ 115,274	$ 143,628	$ 61,563	$ 9,787	$ 27,920	$ 13,181
9																
10	Gas	Modules	$ -	$ -	$ -	$ 5	$ -	$ -	$ -	$ -	$ 6,663	$ 25,404	$ 15,845	$ -	$ -	$ -
11		Field Equipment/Facilities	$ -	$ 15	$ 162	$ 95	$ 41	$ 37	$ 23	$ 21	$ -	$ -	$ -	$ -	$ -	$ -
12		Software/Systems Development	$ 1,076	$ 1,120	$ 1,524	$ 2,143	$ 2,664	$ 2,832	$ 4,377	$ 4,362	$ 5,995	$ 3,359	$ (54)	$ 158	$ 165	$ 130
13		SG Infrastructure	$ -	$ -	$ -	$ 380	$ 1,068	$ 806	$ 151	$ 133	$ 200	$ 470	$ 102	$ 265	$ 385	$ 460
14		Pilot Prep & Project Management	$ -	$ 1,573	$ 2,348	$ 3,016	$ 1,737	$ 1,183	$ 827	$ 727	$ 872	$ 667	$ 354	$ -	$ -	$ -
15		Total Capital Costs before Avoidance - Gas	$ 1,076	$ 2,709	$ 4,034	$ 5,639	$ 5,510	$ 4,858	$ 5,379	$ 5,243	$ 13,730	$ 29,900	$ 16,248	$ 423	$ 550	$ 590
16		Avoided Capital Costs - Gas	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ (10)	$ (20)	$ (34)	$ (42)	$ (43)	$ (43)
17		Total Capital Costs Net - Gas	$ 1,076	$ 2,709	$ 4,034	$ 5,639	$ 5,510	$ 4,858	$ 5,379	$ 5,243	$ 13,720	$ 29,881	$ 16,213	$ 381	$ 507	$ 547
18																
19	Total	Meter/Module Purchases, including Set & Test	$ -	$ 1,424	$ 1,231	$ 935	$ 128	$ 9,602	$ 21,432	$ 29,976	$ 68,816	$ 134,973	$ 69,524	$ -	$ -	$ -
20		Field Equipment/Facilities	$ -	$ 128	$ 1,466	$ 1,605	$ 382	$ 296	$ 194	$ 174	$ 270	$ 1,200	$ 5,965	$ 6,331	$ 8,440	$ 8,580
21		Software/Systems Development	$ 8,965	$ 9,334	$ 13,782	$ 18,052	$ 22,318	$ 23,602	$ 36,477	$ 36,353	$ 51,033	$ 28,277	$ (1,788)	$ 1,320	$ 16,555	$ 1,082
22		SG Infrastructure	$ -	$ -	$ -	$ 3,170	$ 8,903	$ 6,719	$ 1,260	$ 1,109	$ 1,663	$ 3,861	$ 853	$ 2,208	$ 3,212	$ 3,835
23		Pilot Prep & Project Management	$ -	$ 9,456	$ 11,280	$ 16,299	$ 11,294	$ 9,102	$ 7,021	$ 6,790	$ 7,529	$ 5,457	$ 2,848	$ -	$ -	$ -
24		Total Capital Costs before Avoidance	$ 8,965	$ 20,342	$ 27,760	$ 40,060	$ 43,025	$ 49,320	$ 66,384	$ 74,402	$ 129,311	$ 173,768	$ 77,401	$ 9,859	$ 28,207	$ 13,498
25		Avoided Capital Costs	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ (316)	$ (260)	$ 375	$ 309	$ 220	$ 231
26		Total Capital Costs Net	$ 8,965	$ 20,342	$ 27,760	$ 40,060	$ 43,025	$ 49,320	$ 66,384	$ 74,402	$ 128,994	$ 173,508	$ 77,776	$ 10,168	$ 28,428	$ 13,729
27																
28																
29		Note:														
30		Cost of Removal	$ -	$ -	$ -	$ -	$ -	$ 129	$ 120	$ 1	$ -	$ 59	$ 23	$ -	$ -	$ -
31		Total Capital Costs Incl COR before Avoidance	$ 8,965	$ 20,342	$ 27,760	$ 40,060	$ 43,025	$ 49,450	$ 66,504	$ 74,403	$ 129,311	$ 173,827	$ 77,424	$ 9,859	$ 28,207	$ 13,498
32		Cml Total Capital Costs Incl COR before Avoidance	$ 8,965	$ 29,307	$ 57,067	$ 97,127	$ 140,152	$ 189,602	$ 256,106	$ 330,509	$ 459,820	$ 633,647	$ 711,071	$ 720,930	$ 749,137	$ 762,634

Total NPV Benefit of -$57.5 million based on nominal values 2007 - 2012 and present values 2013 - 2032.

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Summary of Business Case Costs and Benefits
2007 - 2032
(000)

Case No.: U-20963
Exhibit No.: A-117 (LDW-1)
Page: 2 of 8
Witness: LDWarriner
Date: March 2021

Smart Grid Program - Annual Capital Expenditures

	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)	(o)
Line No.	Utility	Description	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	Total 2007-2032
1	Electric	Meters	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 290,123
2		Field Equipment/Facilities	$ 7,651	$ 7,349	$ 1,169	$ 977	$ 1,007	$ 1,037	$ 1,070	$ 1,104	$ 1,140	$ 1,179	$ 1,219	$ 1,262	$ 60,802
3		Software/Systems Development	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 235,511
4		SG Infrastructure	$ 2,916	$ 2,342	$ 2,569	$ 3,064	$ 2,985	$ 2,617	$ 2,577	$ 2,850	$ 2,943	$ 2,756	$ 2,648	$ 2,760	$ 65,395
5		Pilot Prep & Project Management	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 73,771
6		Total Capital Costs before Avoidance - Electric	$ 10,566	$ 9,691	$ 3,739	$ 4,041	$ 3,992	$ 3,654	$ 3,647	$ 3,954	$ 4,083	$ 3,935	$ 3,867	$ 4,021	$ 725,602
7		Avoided Capital Costs - Electric	$ (882)	$ 355	$ 375	$ 386	$ 345	$ 323	$ 323	$ 344	$ 544	$ 544	$ 544	$ 544	$ 4,498
8		Total Capital Costs Net - Electric	$ 9,685	$ 10,046	$ 4,114	$ 4,427	$ 4,337	$ 3,977	$ 3,970	$ 4,299	$ 4,627	$ 4,479	$ 4,410	$ 4,565	$ 730,100
9															
10	Gas	Modules	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 47,918
11		Field Equipment/Facilities	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 394
12		Software/Systems Development	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 29,851
13		SG Infrastructure	$ 398	$ 319	$ 350	$ 418	$ 407	$ 357	$ 351	$ 389	$ 401	$ 376	$ 361	$ 376	$ 8,925
14		Pilot Prep & Project Management	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 13,305
15		Total Capital Costs before Avoidance - Gas	$ 398	$ 319	$ 350	$ 418	$ 407	$ 357	$ 351	$ 389	$ 401	$ 376	$ 361	$ 376	$ 100,392
16		Avoided Capital Costs - Gas	$ (43)	$ (43)	$ (43)	$ (43)	$ (43)	$ (43)	$ (43)	$ (43)	$ (43)	$ (43)	$ (43)	$ (43)	$ (707)
17		Total Capital Costs Net - Gas	$ 355	$ 276	$ 307	$ 375	$ 364	$ 314	$ 309	$ 346	$ 358	$ 333	$ 318	$ 333	$ 99,685
18															
19	Total	Meter/Module Purchases, including Set & Test	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 338,040
20		Field Equipment/Facilities	$ 7,651	$ 7,349	$ 1,169	$ 977	$ 1,007	$ 1,037	$ 1,070	$ 1,104	$ 1,140	$ 1,179	$ 1,219	$ 1,262	$ 61,196
21		Software/Systems Development	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 265,362
22		SG Infrastructure	$ 3,313	$ 2,661	$ 2,920	$ 3,482	$ 3,392	$ 2,974	$ 2,929	$ 3,239	$ 3,344	$ 3,132	$ 3,009	$ 3,136	$ 74,320
23		Pilot Prep & Project Management	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 87,076
24		Total Capital Costs before Avoidance	$ 10,964	$ 10,010	$ 4,089	$ 4,459	$ 4,399	$ 4,011	$ 3,998	$ 4,343	$ 4,484	$ 4,311	$ 4,228	$ 4,398	$ 825,994
25		Avoided Capital Costs	$ (925)	$ 312	$ 332	$ 344	$ 302	$ 280	$ 281	$ 301	$ 501	$ 501	$ 501	$ 501	$ 3,791
26		Total Capital Costs Net	$ 10,039	$ 10,322	$ 4,421	$ 4,802	$ 4,701	$ 4,291	$ 4,279	$ 4,644	$ 4,985	$ 4,812	$ 4,728	$ 4,898	$ 829,785
27															
28															
29		Note:													
30		Cost of Removal	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 332
31		Total Capital Costs Incl COR before Avoidance	$ 10,964	$ 10,010	$ 4,089	$ 4,459	$ 4,399	$ 4,011	$ 3,998	$ 4,343	$ 4,484	$ 4,311	$ 4,228	$ 4,398	$ 826,327
32		Cml Total Capital Costs Incl COR before Avoidance	$ 773,598	$ 783,608	$ 787,697	$ 792,156	$ 796,554	$ 800,565	$ 804,564	$ 808,907	$ 813,391	$ 817,702	$ 821,929	$ 826,327	

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Summary of Business Case Costs and Benefits
2007 - 2032
(000)

Case No.: U-20963
Exhibit No.: A-117 (LDW-1)
Page: 3 of 8
Witness: LDWarriner
Date: March 2021

Smart Grid Program - Benefits and O&M costs

	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)	(o)	(p)
Line No.	Utility	Description	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
33	Electric	Meter Reading	$ -	$ -	$ -	$ -	$ -	$ -	$ (116)	$ (1,878)	$ (5,151)	$ (9,767)	$ (16,577)	$ (19,196)	$ (19,926)	$ (20,325)
34		Uncollectible Expense	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ (128)	$ (3,685)	$ (6,227)	$ (8,181)	$ (8,344)	$ (8,511)
35		Other O&M	$ -	$ -	$ -	$ -	$ -	$ -	$ (1,271)	$ (1,115)	$ (2,917)	$ (4,690)	$ (7,375)	$ (7,942)	$ (8,183)	$ (8,508)
36		AC Load Control Avoided Generation, Transmission	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ (135)	$ (960)	$ (3,502)	$ (4,674)
37		Demand Response Avoided Generation, Transmission	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ (0)	$ (47)	$ (490)	$ (954)	$ (1,809)
38		Theft Reduction	$ -	$ -	$ -	$ -	$ -	$ (93)	$ (919)	$ (1,837)	$ (4,787)	$ (6,943)	$ (8,342)	$ (9,810)	$ (15,126)	$ (22,561)
39		AMI Induced Conservation & Efficiency Energy	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ (2,906)	$ (5,571)	$ (7,991)	$ (10,912)	$ (8,513)
40		Load Management Conserved Energy	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
41		Demand Response Conserved Energy	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ (1,417)
42		Property Tax (Savings) - Legacy Meters	$ -	$ -	$ -	$ -	$ -	$ (33)	$ (97)	$ (235)	$ (500)	$ (835)	$ (1,067)	$ (1,067)	$ (1,067)	$ (1,067)
43		Terminal Value	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
44		Total Non Capital Benefits before Costs - Electric	$ -	$ -	$ -	$ -	$ -	$ (126)	$ (2,403)	$ (5,064)	$ (13,482)	$ (28,827)	$ (45,340)	$ (55,636)	$ (68,014)	$ (77,384)
45		Common	$ 382	$ 67	$ 545	$ 1,165	$ 1,094	$ 2,586	$ 5,977	$ 4,853	$ 6,466	$ 6,821	$ 8,606	$ 9,360	$ 9,502	$ 9,724
46		Meters, Modules & Communications	$ -	$ -	$ -	$ -	$ -	$ 97	$ 963	$ 1,310	$ 1,671	$ 3,226	$ 4,898	$ 5,227	$ 5,228	$ 5,228
47		Customer Engagement	$ -	$ -	$ -	$ -	$ -	$ 1,538	$ 2,444	$ 1,956	$ 1,833	$ 4,179	$ 5,275	$ 7,938	$ 21,493	$ 9,299
48		Load Control Program	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 195	$ 665	$ 2,567	$ 3,017	$ 2,726	$ 2,625
49		Demand Response Program	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 16	$ 194	$ 2,219	$ 986	$ 606	$ 618
50		Property Taxes - AMI	$ -	$ 24	$ 44	$ 70	$ 52	$ 335	$ 862	$ 1,572	$ 2,977	$ 5,402	$ 6,644	$ 6,515	$ 6,407	$ 6,270
51		Total Non Capital Benefits Net - Electric	$ 382	$ 91	$ 589	$ 1,235	$ 1,146	$ 4,430	$ 7,843	$ 4,627	$ (325)	$ (8,340)	$ (15,131)	$ (22,594)	$ (22,052)	$ (43,620)
52																
53	Gas	Meter Reading	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 0	$ (591)	$ (1,965)	$ (2,507)	$ (2,602)	$ (2,654)
54		Uncollectible Expense	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ (168)	$ (1,335)	$ (2,144)	$ (2,187)	$ (2,231)
55		Other O&M	$ -	$ -	$ -	$ -	$ -	$ -	$ (68)	$ 10	$ (1)	$ (214)	$ (411)	$ (444)	$ (454)	$ (468)
56		Theft Reduction	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ (235)	$ (462)	$ (531)	$ (667)	$ (890)	$ (3,460)
57		AMI Induced Conservation & Efficiency Energy	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ (199)	$ (1,433)	$ (2,247)	$ (2,585)	$ (2,705)
58		LAUF Gas Reduction Enabled	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ (22)	$ (173)	$ (181)	$ (190)
59		Terminal Value	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
60		Total Non Capital Benefits before Costs - Gas	$ -	$ -	$ -	$ -	$ -	$ -	$ (68)	$ 10	$ (236)	$ (1,634)	$ (5,697)	$ (8,182)	$ (8,900)	$ (11,709)
61		Common	$ 367	$ 64	$ 87	$ 143	$ 73	$ 127	$ 36	$ 11	$ 216	$ 746	$ 1,173	$ 1,276	$ 1,296	$ 1,326
62		Meters, Modules & Communications	$ -	$ -	$ -	$ -	$ -	$ 5	$ 6	$ -	$ 42	$ 466	$ 1,237	$ 1,371	$ 1,371	$ 1,371
63		Property Taxes - AMI	$ -	$ -	$ -	$ 5	$ 5	$ 8	$ 12	$ 11	$ 141	$ 692	$ 891	$ 831	$ 778	$ 728
64		Total Non Capital Benefits Net - Gas	$ 367	$ 64	$ 87	$ 148	$ 78	$ 140	$ (14)	$ 32	$ 164	$ 271	$ (2,396)	$ (4,704)	$ (5,455)	$ (8,283)
65																
66	Total	Meter Reading	$ -	$ -	$ -	$ -	$ -	$ -	$ (116)	$ (1,878)	$ (5,151)	$ (10,358)	$ (18,542)	$ (21,704)	$ (22,529)	$ (22,979)
67		Uncollectible Expense	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ (128)	$ (3,853)	$ (7,562)	$ (10,325)	$ (10,531)	$ (10,742)
68		Other O&M	$ -	$ -	$ -	$ -	$ -	$ -	$ (1,339)	$ (1,105)	$ (2,917)	$ (4,905)	$ (7,786)	$ (8,386)	$ (8,637)	$ (8,976)
69		AC Load Control Avoided Generation, Transmission	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ (135)	$ (960)	$ (3,502)	$ (4,674)
70		Demand Response Avoided Generation, Transmission	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ (0)	$ (47)	$ (490)	$ (954)	$ (1,809)
71		Theft Reduction	$ -	$ -	$ -	$ -	$ -	$ (93)	$ (919)	$ (1,837)	$ (5,023)	$ (7,405)	$ (8,873)	$ (10,477)	$ (16,016)	$ (26,021)
72		AMI Induced Conservation & Efficiency Energy	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ (3,105)	$ (7,004)	$ (10,238)	$ (13,497)	$ (11,218)
73		Load Management Conserved Energy	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
74		Demand Response Conserved Energy	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ (1,417)
75		Property Tax (Savings) - Legacy Meters	$ -	$ -	$ -	$ -	$ -	$ (33)	$ (97)	$ (235)	$ (500)	$ (835)	$ (1,067)	$ (1,067)	$ (1,067)	$ (1,067)
76		LAUF Gas Reduction Enabled	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ (22)	$ (173)	$ (181)	$ (190)
77		Terminal Value	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
78		Total Non Capital Benefits before Costs	$ -	$ -	$ -	$ -	$ -	$ (126)	$ (2,471)	$ (5,055)	$ (13,718)	$ (30,461)	$ (51,037)	$ (63,819)	$ (76,914)	$ (89,093)
79		Common	$ 749	$ 131	$ 632	$ 1,308	$ 1,167	$ 2,713	$ 6,013	$ 4,864	$ 6,682	$ 7,567	$ 9,779	$ 10,636	$ 10,798	$ 11,050
80		Meters, Modules & Communications	$ -	$ -	$ -	$ -	$ -	$ 102	$ 969	$ 1,310	$ 1,713	$ 3,692	$ 6,135	$ 6,598	$ 6,599	$ 6,599
81		Other O&M	$ -	$ -	$ -	$ -	$ -	$ 1,538	$ 2,444	$ 1,956	$ 1,833	$ 4,179	$ 5,275	$ 7,938	$ 21,493	$ 9,299
82		Load Control Program	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 195	$ 665	$ 2,567	$ 3,017	$ 2,726	$ 2,625
83		Demand Response Program	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 16	$ 194	$ 2,219	$ 986	$ 606	$ 618
84		Property Taxes - AMI	$ -	$ 24	$ 44	$ 75	$ 57	$ 343	$ 874	$ 1,583	$ 3,118	$ 6,094	$ 7,535	$ 7,346	$ 7,185	$ 6,999
85		Total Non Capital Benefits Net	$ 749	$ 155	$ 676	$ 1,383	$ 1,224	$ 4,569	$ 7,829	$ 4,659	$ (161)	$ (8,069)	$ (17,526)	$ (27,298)	$ (27,507)	$ (51,903)

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Summary of Business Case Costs and Benefits
2007 - 2032
(000)

Case No.: U-20963
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Date: March 2021

Smart Grid Program - Benefits and O&M Costs

Line No.	(a) Utility	(b) Description	(c) 2021	(d) 2022	(e) 2023	(f) 2024	(g) 2025	(h) 2026	(i) 2027	(j) 2028	(k) 2029	(l) 2030	(m) 2031	(n) 2032	(o) Total 2007-2032
33	Electric	Meter Reading	$ (20,935)	$ (21,563)	$ (22,210)	$ (22,876)	$ (23,562)	$ (24,269)	$ (24,997)	$ (25,747)	$ (26,519)	$ (27,315)	$ (28,134)	$ (28,978)	$ (390,041)
34		Uncollectible Expense	$ (8,681)	$ (8,855)	$ (9,032)	$ (9,213)	$ (9,397)	$ (9,585)	$ (9,776)	$ (9,972)	$ (10,171)	$ (10,375)	$ (10,582)	$ (10,794)	$ (151,509)
35		Other O&M	$ (8,826)	$ (9,104)	$ (9,363)	$ (9,613)	$ (9,865)	$ (10,124)	$ (10,392)	$ (10,669)	$ (10,953)	$ (11,247)	$ (11,550)	$ (11,863)	$ (165,570)
36		AC Load Control Avoided Generation, Transmission	$ (6,080)	$ (7,375)	$ (8,248)	$ (8,493)	$ (8,658)	$ (8,834)	$ (9,010)	$ (9,190)	$ (9,374)	$ (9,561)	$ (9,753)	$ (9,948)	$ (113,795)
37		Demand Response Avoided Generation, Transmission	$ (10,982)	$ (11,437)	$ (12,226)	$ (13,614)	$ (15,469)	$ (17,562)	$ (19,732)	$ (21,806)	$ (22,243)	$ (22,687)	$ (23,141)	$ (23,604)	$ (217,804)
38		Theft Reduction	$ (27,997)	$ (35,010)	$ (39,052)	$ (39,833)	$ (40,629)	$ (41,442)	$ (42,271)	$ (43,116)	$ (43,978)	$ (44,858)	$ (45,755)	$ (46,670)	$ (561,029)
39		AMI Induced Conservation & Efficiency Energy	$ (8,683)	$ (8,857)	$ (9,034)	$ (9,215)	$ (9,399)	$ (9,587)	$ (9,779)	$ (9,974)	$ (10,174)	$ (10,377)	$ (10,585)	$ (10,797)	$ (152,354)
40		Load Management Conserved Energy	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
41		Demand Response Conserved Energy	$ (1,577)	$ (1,681)	$ (1,744)	$ (1,810)	$ (1,865)	$ (1,920)	$ (1,978)	$ (2,037)	$ (2,097)	$ (2,156)	$ (2,215)	$ (2,270)	$ (24,767)
42		Property Tax (Savings) - Legacy Meters	$ (1,067)	$ (1,067)	$ (1,067)	$ (1,067)	$ (1,067)	$ (1,067)	$ (1,067)	$ (1,067)	$ (1,067)	$ (1,067)	$ (1,067)	$ (1,067)	$ (18,767)
43		Terminal Value	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ (252,923)	$ (252,923)
44		Total Non Capital Benefits before Costs - Electric	$ (94,829)	$ (104,948)	$ (111,975)	$ (115,733)	$ (119,911)	$ (124,390)	$ (129,002)	$ (133,578)	$ (136,577)	$ (139,644)	$ (142,782)	$ (398,914)	$ (2,048,559)
45		Common	$ 11,294	$ 11,525	$ 10,781	$ 11,012	$ 11,258	$ 11,510	$ 11,774	$ 12,032	$ 12,297	$ 12,579	$ 12,868	$ 13,171	$ 209,249
46		Meters, Modules & Communications	$ 5,228	$ 5,228	$ 5,228	$ 5,228	$ 5,228	$ 5,228	$ 5,228	$ 5,228	$ 5,228	$ 5,228	$ 5,228	$ 5,228	$ 90,579
47		Customer Engagement	$ 3,598	$ 3,614	$ 3,631	$ 3,647	$ 3,664	$ 3,682	$ 3,700	$ 3,718	$ 3,736	$ 3,755	$ 3,775	$ 3,794	$ 100,270
48		Load Control Program	$ 2,530	$ 2,425	$ 631	$ 582	$ 599	$ 617	$ 636	$ 656	$ 677	$ 698	$ 721	$ 745	$ 23,311
49		Demand Response Program	$ 874	$ 879	$ 1,226	$ 669	$ 683	$ 696	$ 710	$ 724	$ 739	$ 754	$ 769	$ 784	$ 14,147
50		Property Taxes - AMI	$ 6,138	$ 5,996	$ 5,815	$ 5,583	$ 5,357	$ 5,135	$ 4,925	$ 4,736	$ 4,579	$ 4,480	$ 4,449	$ 4,450	$ 98,816
51		Total Non Capital Benefits Net - Electric	$ (65,167)	$ (75,280)	$ (84,663)	$ (89,012)	$ (93,122)	$ (97,523)	$ (102,029)	$ (106,485)	$ (109,321)	$ (112,151)	$ (114,973)	$ (370,742)	$ (1,512,188)
52															
53	Gas	Meter Reading	$ (2,734)	$ (2,816)	$ (2,901)	$ (2,988)	$ (3,077)	$ (3,170)	$ (3,265)	$ (3,363)	$ (3,464)	$ (3,567)	$ (3,674)	$ (3,785)	$ (49,122)
54		Uncollectible Expense	$ (2,276)	$ (2,321)	$ (2,367)	$ (2,415)	$ (2,463)	$ (2,512)	$ (2,563)	$ (2,614)	$ (2,666)	$ (2,719)	$ (2,774)	$ (2,829)	$ (38,585)
55		Other O&M	$ (484)	$ (501)	$ (519)	$ (537)	$ (556)	$ (575)	$ (595)	$ (615)	$ (636)	$ (658)	$ (680)	$ (703)	$ (9,111)
56		Theft Reduction	$ (4,501)	$ (5,570)	$ (7,363)	$ (7,601)	$ (7,753)	$ (7,908)	$ (8,066)	$ (8,227)	$ (8,392)	$ (8,560)	$ (8,731)	$ (8,906)	$ (97,824)
57		AMI Induced Conservation & Efficiency Energy	$ (2,846)	$ (3,002)	$ (3,174)	$ (3,352)	$ (3,419)	$ (3,487)	$ (3,557)	$ (3,628)	$ (3,701)	$ (3,775)	$ (3,850)	$ (3,927)	$ (50,888)
58		LAUF Gas Reduction Enabled	$ (201)	$ (213)	$ (225)	$ (238)	$ (243)	$ (248)	$ (252)	$ (256)	$ (260)	$ (263)	$ (267)	$ (270)	$ (3,502)
59		Terminal Value	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ (34,490)	$ (34,490)
60		Total Non Capital Benefits before Costs - Gas	$ (13,042)	$ (14,424)	$ (16,550)	$ (17,131)	$ (17,511)	$ (17,900)	$ (18,297)	$ (18,703)	$ (19,119)	$ (19,543)	$ (19,977)	$ (54,910)	$ (283,522)
61		Common	$ 1,540	$ 1,572	$ 1,470	$ 1,502	$ 1,535	$ 1,570	$ 1,606	$ 1,641	$ 1,677	$ 1,715	$ 1,755	$ 1,796	$ 26,319
62		Meters, Modules & Communications	$ 1,371	$ 1,371	$ 1,371	$ 1,371	$ 1,371	$ 1,371	$ 1,371	$ 1,371	$ 1,371	$ 1,371	$ 1,371	$ 1,371	$ 22,324
63		Property Taxes - AMI	$ 685	$ 644	$ 603	$ 563	$ 522	$ 482	$ 441	$ 401	$ 362	$ 334	$ 326	$ 326	$ 9,792
64		Total Non Capital Benefits Net - Gas	$ (9,446)	$ (10,837)	$ (13,105)	$ (13,695)	$ (14,083)	$ (14,477)	$ (14,879)	$ (15,290)	$ (15,708)	$ (16,123)	$ (16,525)	$ (51,416)	$ (225,087)
65															
66	Total	Meter Reading	$ (23,669)	$ (24,379)	$ (25,110)	$ (25,864)	$ (26,639)	$ (27,439)	$ (28,262)	$ (29,110)	$ (29,983)	$ (30,882)	$ (31,809)	$ (32,763)	$ (439,164)
67		Uncollectible Expense	$ (10,957)	$ (11,176)	$ (11,399)	$ (11,627)	$ (11,860)	$ (12,097)	$ (12,339)	$ (12,586)	$ (12,838)	$ (13,094)	$ (13,356)	$ (13,623)	$ (190,094)
68		Other O&M	$ (9,310)	$ (9,605)	$ (9,882)	$ (10,150)	$ (10,420)	$ (10,699)	$ (10,987)	$ (11,284)	$ (11,590)	$ (11,905)	$ (12,231)	$ (12,566)	$ (174,681)
69		AC Load Control Avoided Generation, Transmission	$ (6,080)	$ (7,375)	$ (8,248)	$ (8,493)	$ (8,658)	$ (8,834)	$ (9,010)	$ (9,190)	$ (9,374)	$ (9,561)	$ (9,753)	$ (9,948)	$ (113,795)
70		Demand Response Avoided Generation, Transmission	$ (10,982)	$ (11,437)	$ (12,226)	$ (13,614)	$ (15,469)	$ (17,562)	$ (19,732)	$ (21,806)	$ (22,243)	$ (22,687)	$ (23,141)	$ (23,604)	$ (217,804)
71		Theft Reduction	$ (32,498)	$ (40,580)	$ (46,415)	$ (47,434)	$ (48,382)	$ (49,350)	$ (50,337)	$ (51,344)	$ (52,370)	$ (53,418)	$ (54,486)	$ (55,576)	$ (658,852)
72		AMI Induced Conservation & Efficiency Energy	$ (11,529)	$ (11,860)	$ (12,209)	$ (12,567)	$ (12,818)	$ (13,074)	$ (13,336)	$ (13,602)	$ (13,875)	$ (14,152)	$ (14,435)	$ (14,724)	$ (203,243)
73		Load Management Conserved Energy	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
74		Demand Response Conserved Energy	$ (1,577)	$ (1,681)	$ (1,744)	$ (1,810)	$ (1,865)	$ (1,920)	$ (1,978)	$ (2,037)	$ (2,097)	$ (2,156)	$ (2,215)	$ (2,270)	$ (24,767)
75		Property Tax (Savings) - Legacy Meters	$ (1,067)	$ (1,067)	$ (1,067)	$ (1,067)	$ (1,067)	$ (1,067)	$ (1,067)	$ (1,067)	$ (1,067)	$ (1,067)	$ (1,067)	$ (1,067)	$ (18,767)
76		LAUF Gas Reduction Enabled	$ (201)	$ (213)	$ (225)	$ (238)	$ (243)	$ (248)	$ (252)	$ (256)	$ (260)	$ (263)	$ (267)	$ (270)	$ (3,502)
77		Terminal Value	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ (287,413)	$ (287,413)
78		Total Non Capital Benefits before Costs	$ (107,871)	$ (119,372)	$ (128,525)	$ (132,864)	$ (137,422)	$ (142,290)	$ (147,299)	$ (152,281)	$ (155,695)	$ (159,187)	$ (162,759)	$ (453,823)	$ (2,332,082)
79		Common	$ 12,835	$ 13,097	$ 12,251	$ 12,513	$ 12,793	$ 13,080	$ 13,380	$ 13,672	$ 13,974	$ 14,294	$ 14,623	$ 14,967	$ 235,568
80		Meters, Modules & Communications	$ 6,599	$ 6,599	$ 6,599	$ 6,599	$ 6,599	$ 6,599	$ 6,599	$ 6,599	$ 6,599	$ 6,599	$ 6,599	$ 6,599	$ 112,903
81		Other O&M	$ 3,598	$ 3,614	$ 3,631	$ 3,647	$ 3,664	$ 3,682	$ 3,700	$ 3,718	$ 3,736	$ 3,755	$ 3,775	$ 3,794	$ 100,270
82		Load Control Program	$ 2,530	$ 2,425	$ 631	$ 582	$ 599	$ 617	$ 636	$ 656	$ 677	$ 698	$ 721	$ 745	$ 23,311
83		Demand Response Program	$ 874	$ 879	$ 1,226	$ 669	$ 683	$ 696	$ 710	$ 724	$ 739	$ 754	$ 769	$ 784	$ 14,147
84		Property Taxes - AMI	$ 6,823	$ 6,641	$ 6,419	$ 6,146	$ 5,879	$ 5,616	$ 5,366	$ 5,137	$ 4,941	$ 4,813	$ 4,775	$ 4,776	$ 108,608
85		Total Non Capital Benefits Net	$ (74,613)	$ (86,117)	$ (97,768)	$ (102,707)	$ (107,205)	$ (112,000)	$ (116,908)	$ (121,775)	$ (125,029)	$ (128,273)	$ (131,498)	$ (422,159)	$ (1,737,275)

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Summary of Business Case Costs and Benefits
2007 - 2032
(000)

Case No.: U-20963
Exhibit No.: A-117 (LDW-1)
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Date: March 2021

Smart Grid Program - Annual Calculation of Pretax Return on AMI Investment

	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)	(o)	(p)
Line No.	Utility	Description	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
86	Electric	Beginning Plant in Service Value	$ -	$ 7,889	$ 25,487	$ 49,111	$ 83,376	$116,739	$151,423	$199,494	$251,849	$345,377	$ 460,025	$ 486,608	$ 459,004	$ 457,704
87		Ending Plant in Service Value	$ 7,889	$ 25,487	$ 49,111	$ 83,376	$116,739	$151,423	$199,494	$251,849	$345,377	$460,025	$ 486,608	$ 459,004	$ 457,704	$ 429,447
88																
89		Average Plant in Service Value [(Line 86 + Line 87)/2]	$ 3,945	$ 16,688	$ 37,299	$ 66,244	$100,058	$134,081	$175,459	$225,672	$298,613	$402,701	$ 473,317	$ 472,806	$ 458,354	$ 443,575
90		Pre-tax Cost of Capital (Actual approved amounts through 2021,			9.76%	9.76%	9.82%	9.13%	9.13%	9.13%	8.90%	8.90%	8.58%	7.32%	7.40%	7.40%
91		then most recently approved after 2021)														
92																
93		Pretax Return on AMI Investment	$ -	$ -	$ 3,640	$ 6,465	$ 9,826	$ 12,242	$ 16,019	$ 20,604	$ 26,577	$ 35,840	$ 40,611	$ 34,609	$ 33,918	$ 32,825
94																
95	Gas	Beginning Plant in Service Value	$ -	$ 1,076	$ 3,769	$ 7,641	$ 13,186	$ 18,032	$ 21,449	$ 25,061	$ 28,177	$ 39,235	$ 65,277	$ 76,472	$ 71,418	$ 66,459
96		Ending Plant in Service Value	$ 1,076	$ 3,769	$ 7,641	$ 13,186	$ 18,032	$ 21,449	$ 25,061	$ 28,177	$ 39,235	$ 65,277	$ 76,472	$ 71,418	$ 66,459	$ 61,502
97																
98		Average Plant in Service Value	$ 538	$ 2,422	$ 5,705	$ 10,413	$ 15,609	$ 19,741	$ 23,255	$ 26,619	$ 33,706	$ 52,256	$ 70,874	$ 73,945	$ 68,939	$ 63,981
99		Pre-tax Cost of Capital (Actual approved amounts through 2021,			9.76%	9.76%	9.82%	9.13%	9.13%	9.13%	8.90%	8.90%	8.58%	7.32%	7.40%	7.40%
100		then most recently approved after 2021)														
101																
102		Pretax Return on AMI Investment	$ -	$ -	$ 557	$ 1,016	$ 1,533	$ 1,802	$ 2,123	$ 2,430	$ 3,000	$ 4,651	$ 6,081	$ 5,413	$ 5,101	$ 4,735
103																
104	Total	Beginning Plant in Service Value	$ -	$ 8,965	$ 29,256	$ 56,752	$ 96,562	$134,771	$172,872	$224,556	$280,026	$384,613	$ 525,303	$ 563,080	$ 530,423	$ 524,163
105		Ending Plant in Service Value	$ 8,965	$ 29,256	$ 56,752	$ 96,562	$134,771	$172,872	$224,556	$280,026	$384,613	$525,303	$ 563,080	$ 530,423	$ 524,163	$ 490,949
106																
107		Average Plant in Service Value	$ 4,483	$ 19,111	$ 43,004	$ 76,657	$115,666	$153,821	$198,714	$252,291	$332,319	$454,958	$ 544,191	$ 546,751	$ 527,293	$ 507,556
108		Pre-tax Cost of Capital (Actual approved amounts through 2021,			9.76%	9.76%	9.82%	9.13%	9.13%	9.13%	8.90%	8.90%	8.58%	7.32%	7.40%	7.40%
109		then most recently approved after 2021)														
110																
111		Pretax Return on AMI Investment	$ -	$ -	$ 4,197	$ 7,482	$ 11,358	$ 14,044	$ 18,143	$ 23,034	$ 29,576	$ 40,491	$ 46,692	$ 40,022	$ 39,020	$ 37,559

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Summary of Business Case Costs and Benefits
2007 - 2032
(000)

Case No.: U-20963
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Date: March 2021

Smart Grid Program - Annual Calculation of Pretax Return on AMI Investment

	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)
Line No.	Utility	Description	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
86	Electric	Beginning Plant in Service Value	$429,447	$397,959	$364,833	$325,166	$285,506	$245,510	$208,772	$177,087	$148,554	$123,767	$ 103,009	$ 85,744
87		Ending Plant in Service Value	$397,959	$364,833	$325,166	$285,506	$245,510	$208,772	$177,087	$148,554	$123,767	$103,009	$ 85,744	$ 70,781
88														
89		Average Plant in Service Value [(Line 86 + Line 87)/2]	$413,703	$381,396	$345,000	$305,336	$265,508	$227,141	$192,929	$162,820	$136,161	$113,388	$ 94,377	$ 78,263
90		Pre-tax Cost of Capital (Actual approved amounts through 2021,	7.07%	7.07%	7.07%	7.07%	7.07%	7.07%	7.07%	7.07%	7.07%	7.07%	7.07%	7.07%
91		then most recently approved after 2021)												
92														
93		Pretax Return on AMI Investment	$ 29,249	$ 26,965	$ 24,391	$ 21,587	$ 18,771	$ 16,059	$ 13,640	$ 11,511	$ 9,627	$ 8,017	$ 6,672	$ 5,533
94														
95	Gas	Beginning Plant in Service Value	$ 61,502	$ 56,319	$ 51,035	$ 45,758	$ 40,524	$ 35,252	$ 30,525	$ 26,552	$ 22,930	$ 19,648	$ 16,723	$ 14,156
96		Ending Plant in Service Value	$ 56,319	$ 51,035	$ 45,758	$ 40,524	$ 35,252	$ 30,525	$ 26,552	$ 22,930	$ 19,648	$ 16,723	$ 14,156	$ 11,768
97														
98		Average Plant in Service Value	$ 58,911	$ 53,677	$ 48,397	$ 43,141	$ 37,888	$ 32,888	$ 28,538	$ 24,741	$ 21,289	$ 18,185	$ 15,439	$ 12,962
99		Pre-tax Cost of Capital (Actual approved amounts through 2021,	7.07%	7.07%	7.07%	7.07%	7.07%	7.07%	7.07%	7.07%	7.07%	7.07%	7.07%	7.07%
100		then most recently approved after 2021)												
101														
102		Pretax Return on AMI Investment	$ 4,165	$ 3,795	$ 3,422	$ 3,050	$ 2,679	$ 2,325	$ 2,018	$ 1,749	$ 1,505	$ 1,286	$ 1,092	$ 916
103														
104	Total	Beginning Plant in Service Value	$490,949	$454,278	$415,868	$370,925	$326,031	$280,762	$239,297	$203,639	$171,484	$143,415	$ 119,732	$ 99,900
105		Ending Plant in Service Value	$454,278	$415,868	$370,925	$326,031	$280,762	$239,297	$203,639	$171,484	$143,415	$119,732	$ 99,900	$ 82,549
106														
107		Average Plant in Service Value	$472,614	$435,073	$393,396	$348,478	$303,396	$260,029	$221,468	$187,561	$157,450	$131,573	$ 109,816	$ 91,225
108		Pre-tax Cost of Capital (Actual approved amounts through 2021,	7.07%	7.07%	7.07%	7.07%	7.07%	7.07%	7.07%	7.07%	7.07%	7.07%	7.07%	7.07%
109		then most recently approved after 2021)												
110														
111		Pretax Return on AMI Investment	$ 33,414	$ 30,760	$ 27,813	$ 24,637	$ 21,450	$ 18,384	$ 15,658	$ 13,261	$ 11,132	$ 9,302	$ 7,764	$ 6,450

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Summary of Business Case Costs and Benefits
2007 - 2032
(000,000)

Case No.: U-20963
Exhibit No.: A-117 (LDW-1)
Page: 7 of 8
Witness: LDWarriner
Date: March 2021

Smart Grid Program - Calculation of Net Present Value of Net Revenue Requirements - Total

	(a)	(b)	(c)		(d)		(e)		(f)		(g)		(h)		(i)
Line No.	Year	Description	Pretax Return on AMI Investment		AMI Depreciation		Revenue Requirements - Avoided Capital Costs		Total Non-Capital Benefits Net		Net Revenue Requirements		NPV Factor		NPV of Net Revenue Requirements
139	2009		$4.2	+	$0.1	+	$0.0	+	$0.7	=	$5.0	x	1.000000	=	$5.0
140	2010		$7.5	+	0.2	+	0.0	+	1.4	=	9.0	x	1.000000	=	9.0
141	2011		$11.4	+	4.8	+	0.0	+	1.2	=	17.4	x	1.000000	=	17.4
142	2012	First Year of Electric AMI Meter Installations	$14.0	+	10.9	+	0.0	+	4.6	=	29.5	x	1.000000	=	29.5
143	2013		$18.1	+	14.5	+	(0.1)	+	7.8	=	40.4	x	0.916338	=	37.0
144	2014		$23.0	+	18.8	+	(0.3)	+	4.7	=	46.2	x	0.839676	=	38.8
145	2015	First Year of Gas Module Installations	$29.6	+	24.7	+	(0.4)	+	(0.2)	=	53.8	x	0.774313	=	41.6
146	2016		$40.5	+	33.2	+	(0.4)	+	(8.1)	=	65.2	x	0.711031	=	46.3
147	2017	Electric AMI Meter and Gas Module Installations complete	$46.7	+	40.0	+	(0.4)	+	(17.5)	=	68.7	x	0.662599	=	45.5
148	2018		$40.0	+	42.5	+	(4.4)	+	(27.3)	=	50.9	x	0.654510	=	33.3
149	2019		$39.0	+	44.5	+	(4.2)	+	(27.5)	=	51.9	x	0.606694	=	31.5
150	2020		$37.6	+	46.7	+	(4.0)	+	(51.9)	=	28.4	x	0.564892	=	16.0
151	2021		$33.4	+	47.6	+	(3.8)	+	(74.6)	=	2.6	x	0.540742	=	1.4
152	2022		$30.8	+	48.4	+	(3.6)	+	(86.1)	=	(10.6)	x	0.505036	=	(5.3)
153	2023		$27.8	+	49.0	+	(3.4)	+	(97.8)	=	(24.3)	x	0.471687	=	(11.5)
154	2024		$24.6	+	49.4	+	(3.2)	+	(102.7)	=	(31.9)	x	0.440541	=	(14.0)
155	2025		$21.5	+	49.7	+	(2.9)	+	(107.2)	=	(39.0)	x	0.411451	=	(16.1)
156	2026		$18.4	+	45.5	+	(2.7)	+	(112.0)	=	(50.8)	x	0.384283	=	(19.5)
157	2027		$15.7	+	39.7	+	(2.5)	+	(116.9)	=	(64.1)	x	0.358908	=	(23.0)
158	2028		$13.3	+	36.5	+	(2.2)	+	(121.8)	=	(74.2)	x	0.335209	=	(24.9)
159	2029		$11.1	+	32.6	+	(2.0)	+	(125.0)	=	(83.3)	x	0.313074	=	(26.1)
160	2030		$9.3	+	28.0	+	(1.7)	+	(128.3)	=	(92.7)	x	0.292401	=	(27.1)
161	2031		$7.8	+	24.1	+	(1.5)	+	(131.5)	=	(101.2)	x	0.273094	=	(27.6)
162	2032		$6.4	+	21.7	+	(1.2)	+	(134.7)	=	(107.8)	x	0.255061	=	(27.5)
163	2032	Model Terminal Value							(283.4)	=	(283.4)	x	0.255061	=	(72.3)
164															
165		Total 2009-2032	$531.6		$752.9		($44.8)		($1,734.1)		($494.4)				$57.5

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Summary of Business Case Costs and Benefits
2007 - 2032
(000,000)

Case No.: U-20963
Exhibit No.: A-117 (LDW-1)

Witness: LDWarriner
Date: March 2021

Smart Grid Program - Calculation of Net Present Value of Net Revenue Requirements - Electric Portion

Line No.	(a) Year	(b) Description	(c) Pretax Return on AMI Investment		(d) AMI Depreciation		(e) Revenue Requirements - Avoided Capital Costs		(f) Total Non-Capital Benefits Net		(g) Net Revenue Requirements		(h) NPV Factor		(i) NPV of Net Revenue Requirements
166	2009		$3.640	+	$0.1	+	$0.0	+	$0.6	=	$4.3	x	1.000000	=	$4.3
167	2010		$6.465	+	0.2	+	0.0	+	1.2	=	7.9	x	1.000000	=	7.9
168	2011		$9.826	+	4.2	+	0.0	+	1.1	=	15.1	x	1.000000	=	15.1
169	2012	First Year of Electric AMI Meter Installations	$12.242	+	9.5	+	0.0	+	4.4	=	26.2	x	1.000000	=	26.2
170	2013		$16.019	+	12.8	+	(0.1)	+	7.8	=	36.5	x	0.916338	=	33.5
171	2014		$20.604	+	16.7	+	(0.3)	+	4.6	=	41.6	x	0.839676	=	34.9
172	2015	First Year of Gas Module Installations	$26.577	+	22.1	+	(0.4)	+	(0.3)	=	47.9	x	0.774313	=	37.1
173	2016		$35.840	+	29.3	+	(0.4)	+	(8.3)	=	56.4	x	0.711031	=	40.1
174	2017	Electric AMI Meter and Gas Module Installations complete	$40.611	+	34.9	+	(0.4)	+	(15.1)	=	60.0	x	0.662599	=	39.8
175	2018		$34.609	+	37.0	+	(4.4)	+	(22.6)	=	44.7	x	0.654510	=	29.2
176	2019		$33.918	+	39.0	+	(4.2)	+	(22.1)	=	46.7	x	0.606694	=	28.3
177	2020		$32.825	+	41.2	+	(4.0)	+	(43.6)	=	26.4	x	0.564892	=	14.9
178	2021		$29.249	+	42.1	+	(3.8)	+	(65.2)	=	2.3	x	0.540742	=	1.3
179	2022		$26.965	+	42.8	+	(3.6)	+	(75.3)	=	(9.1)	x	0.505036	=	(4.6)
180	2023		$24.391	+	43.4	+	(3.4)	+	(84.7)	=	(20.3)	x	0.471687	=	(9.6)
181	2024		$21.587	+	43.7	+	(3.2)	+	(89.0)	=	(26.9)	x	0.440541	=	(11.8)
182	2025		$18.771	+	44.0	+	(2.9)	+	(93.1)	=	(33.3)	x	0.411451	=	(13.7)
183	2026		$16.059	+	40.4	+	(2.7)	+	(97.5)	=	(43.8)	x	0.384283	=	(16.8)
184	2027		$13.640	+	35.3	+	(2.5)	+	(102.0)	=	(55.5)	x	0.358908	=	(19.9)
185	2028		$11.511	+	32.5	+	(2.2)	+	(106.5)	=	(64.7)	x	0.335209	=	(21.7)
186	2029		$9.627	+	28.9	+	(2.0)	+	(109.3)	=	(72.8)	x	0.313074	=	(22.8)
187	2030		$8.017	+	24.7	+	(1.7)	+	(112.2)	=	(81.2)	x	0.292401	=	(23.7)
188	2031		$6.672	+	21.1	+	(1.5)	+	(115.0)	=	(88.7)	x	0.273094	=	(24.2)
189	2032		$5.533	+	19.0	+	(1.2)	+	(117.8)	=	(94.5)	x	0.255061	=	(24.1)
190	2032	Model Terminal Value							(249.4)	=	(249.4)	x	0.255061	=	(63.6)
191															
192		Total 2009-2032	$465.2		$664.7		($44.8)		($1,509.1)		($424.0)				$56.0

S T A T E O F M I C H I G A N

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

In the matter of the application of **CONSUMERS ENERGY COMPANY** for authority to increase its rates for the generation and distribution of electricity and for other relief.	))))))	Case No. U-20963

EXHIBITS

OF

TODD A. WEHNER

ON BEHALF OF

CONSUMERS ENERGY COMPANY

March 2021

Schedule D-5

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Cost of Common Shareholders' Equity
For the Projected 12 Month Period Ending December 31, 2022

Case No.: U-20963
Exhibit No.: A-14 (TAW-1)
Schedule: D-5
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Witness: TAWehner
Date: March 2021

Proxy Companies

(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)
Line	Company	Relevant Ticker	Regulated Generation Capacity (MW)	Net PP&E ($)	LTM Payout Ratio >= 55%	S&P IG Rated Bond?	Moody's IG Rated Bond?
1	Alliant Energy Corporation	LNT	8,183	13,543,100	57	✓	✓
2	Ameren Corporation	AEE	11,453	24,412,000	57	✓	✓
3	DTE Energy Company	DTE	12,503	25,100,000	57	✓	✓
4	Edison International	EIX	3,297	44,978,000	59	✓	✓
5	Evergy, Inc.	EVRG	12,782	19,450,900	64	✓	✓
6	NiSource Inc.	NI	3,380	16,976,400	59	✓	✓
7	Pinnacle West Capital Corporation	PNW	7,300	14,377,787	56	✓	✓
8	Portland General Electric Company	POR	3,885	6,820,000	85	✓	✓
9	WEC Energy Group, Inc.	WEC	8,329	23,675,200	65	✓	✓
10	Xcel Energy Inc.	XEL	22,587	41,155,000	61	✓	✓
11	Average		9,370	23,048,839	62	✓	✓
12	Consumers Energy	CMS	6,617	18,545,000	57	✓	✓

Proxy Group Selection Criteria:

Regulated generation capacity must be greater than 2,000 MW.
Net Property Plant and Equipment ("PP&E") must be greater than $5 billion but less than $60 billion.
Last Twelve Months ("LTM") dividend payout ratio must be greater than or equal to 55%.
Company must not be selling its business as a part of a corporate acquisition or be a restructuring entity.
Company must have investment grade ("IG") rated bonds.

Sources:

Columns (d), (e): S&P Global Market Intelligence as of December 31, 2020.
Columns (f), (g): CapitalQ data as of December 31, 2020.
Columns (h): I/B/E/S data as of December 31, 2020.

Schedule D-5

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Cost of Common Shareholders' Equity
For the Projected 12 Month Period Ending December 31, 2022

Case No.: U-20963
Exhibit No.: A-14 (TAW-1)
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Empirical Capital Asset Pricing Model Application

Equation: $K_e = R_f + \alpha + F + B \times (R_p - \alpha)$

Where:

		Report	Date	Test Year Average		2022
K_e =	The annual required return on equity					
R_f =	The risk free rate	IHS Markit	December 2020	2.12%	→	2.12%
α =	The alpha of the risk-return line					
F =	The flotation cost adjustment, not included in the calculation					2022
B =	The beta, or covariance of the stock price to market	Blue Chip	December 2020	2.10%	→	2.10%
R_p =	The expected equity risk premium					

(a) Line	(b) Company	(c) Ticker	(d) Current Beta (B)	(e) Alpha (α)	(f) Test Year Risk-Free Rate (R_f)	(g) Projected Risk Premium (R_P)	(h) **Projected Risk Premium ECAPM ROE**
1	Alliant Energy Corporation	LNT	0.85	1.50%	2.11%	11.25%	**11.90%**
2	Ameren Corporation	AEE	0.85	1.50%	2.11%	11.25%	**11.90%**
3	DTE Energy Company	DTE	0.95	1.50%	2.11%	11.25%	**12.87%**
4	Edison International	EIX	0.95	1.50%	2.11%	11.25%	**12.87%**
5	Evergy, Inc.	EVRG	1.00	1.50%	2.11%	11.25%	**13.36%**
6	NiSource Inc.	NI	0.85	1.50%	2.11%	11.25%	**11.90%**
7	Pinnacle West Capital Corporation	PNW	0.90	1.50%	2.11%	11.25%	**12.39%**
8	Portland General Electric Company	POR	0.85	1.50%	2.11%	11.25%	**11.90%**
9	WEC Energy Group, Inc.	WEC	0.80	1.50%	2.11%	11.25%	**11.41%**
10	Xcel Energy Inc.	XEL	0.80	1.50%	2.11%	11.25%	**11.41%**
11	**Average**		0.88				**12.19%**
12	**Minimum**		0.80				**11.41%**
13	**Maximum**		1.00				**13.36%**

Sources: Column (d), (e) & (f): Value Line Investment Survey (EIX, PNW, POR and XEL as of January 22, 2020; PPL as of November 13, 2020; NI as of November 27, 2020; LNT, AEE, ETR, DTE, EVRG, & WEC as of December 11, 2020).
Column (e): Alpha, mid-point of reasonable range of 1% to 2% cited by Roger A. Morin, "New Regulatory Finance" (2006).
Column (f): Average of IHS Markit U.S. Economic Outlook (December 2020) & Blue Chip Financial Forecasts (December, 2020).
Column (g): Exhibit A-14 (TAW-1), Schedule D-5, page 11.
Column (h) = Column (f) + Column (g).

Schedule D-5

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Cost of Common Shareholders' Equity
For the Projected 12 Month Period Ending December 31, 2022

Case No.: U-20963
Exhibit No.: A-14 (TAW-1)
Schedule: D-5
Page: 3 of 12
Witness: TAWehner
Date: March 2021

Total Beta Capital Asset Pricing Model Applicatior

Equation: $K_e = R_f + F + B_T \times (R_p)$ $\quad B_T = \quad B_T = \quad B_T = \dfrac{\text{Standard Deviation}_{\text{Proxy Group}}}{\text{Standard Deviation}_{\text{Market}}}$

Where:
K_e = The annual required return on equity
R_f = The risk free rate
F = The flotation cost adjustment, not included in the calculation
B_T = The total beta
R_p = The expected equity risk premium

(a) Line	(b) Company	(c) Proxy Group Standard Deviation	(d) Market Standard Deviation	(e) Total Beta (B_T)	(f) Test Year Risk-Free Rate (R_f)	(g) Projected Risk Premium (R_P)	(h) **Total Beta CAPM ROE**
1	Proxy Group	21.83%	19.23%	1.14	2.11%	11.25%	**14.88%**

Sources: Column (b): See exhibit A-14 (TAW-1), Schedule D-5, page 1.
Column (c): Bloomberg data, 5-yr estimate, rebalanced daily.
Column (d): Bloomberg 5-yr estimate.
Column (e) = Column (c) / Column (d).
Column (f): Exhibit A-14 (TAW-1), Schedule D-5, page 2, Column (f).
Column (f): Exhibit A-14 (TAW-1), Schedule D-5, page 2, Column (g).
Column (h) = Column (f) + Column (g) x Column (e).

Schedule D-5

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Cost of Common Shareholders' Equity
For the Projected 12 Month Period Ending December 31, 2022

Case No.: U-20963
Exhibit No.: A-14 (TAW-1)
Schedule: D-5
Page: 4 of 12
Witness: TAWehner
Date: March 2021

Projected Risk Premium Analysis Over Utility Bonds

(a)	(b)	(c)	(d)	(e)	(f)
		S&P Bond Rating			
Line	Description	A	A-	BBB+	BBB
	Projected Risk Premium Analysis (Appropriate Use of Spread and Projected Long-Term Bond Rates)				
1	Projected Long-Term Government Bond Return	2.11%	2.11%	2.11%	2.11%
2	Corporate Spread	1.18%	1.32%	1.37%	2.10%
3	Current Estimated Bond Yield (Line 2 + Line 3)	3.29%	3.43%	3.48%	4.21%
4	Current Spread of Electric Utility Common Stock Over Utility Bonds	11.30%	11.30%	11.30%	11.30%
5	Cost of Equity (Line 1 + Line 4)	14.59%	14.73%	14.78%	15.51%
6	**Average**				**14.90%**
7	**Minimum**				**14.59%**
8	**Maximum**				**15.51%**

Sources: Line 1, 13: Exhibit A-14 (TAW-1), Schedule D-5, page 2, column (f).
Line 2: Exhibit A-31 (MRB-9), page 6, lines 89-92.
Line 3: Exhibit A-14 (TAW-1), Schedule D-5, page 9, line 92.

Schedule D-5

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Cost of Common Shareholders' Equity
For the Projected 12 Month Period Ending December 31, 2022

Case No.: U-20963
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Discounted Cash Flow ("DCF") Model Application

Equation: $K_e = D_1 / P_0 + g + F$

Where:
K_e = Annual required rate of return on equity
D_1 = Expected annual dividend per share at the end of first year.
P_0 = Current price of stock
g = Growth rate
F = The flotation cost adjustment, not included in the calculation

(a) Line	(b) Company	(c) Ticker	(d) Avg of 30-day Closing ($)	(e) Last Qtrly Dividend Payment	(f) Current Annual Div (D_0)	(g) Current Dividend Yield	(h) Number of Analyst Estimates	(i) Consensus Analyst Growth (%)	(j) Expected Dividend Yield	(k) **Analyst Consensus DCF ROE**	(l) Flotation Cost Adjust. (F)
1	Alliant Energy Corporation	LNT	51.67	0.380	1.52	2.94%	3	6.5%	3.13%	**9.63%**	0.15%
2	Ameren Corporation	AEE	77.54	0.495	1.98	2.55%	9	5.0%	2.68%	**7.68%**	0.13%
3	DTE Energy Company	DTE	122.90	1.013	4.05	3.30%	10	6.3%	3.50%	**9.80%**	0.16%
4	Edison International	EIX	62.27	0.638	2.55	4.09%	9	3.5%	4.24%	**7.74%**	0.20%
5	Evergy, Inc.	EVRG	54.43	0.505	2.02	3.71%	2	5.9%	3.93%	**NMF**	0.19%
6	NiSource Inc.	NI	22.93	0.210	0.84	3.66%	7	5.0%	3.85%	**8.85%**	0.18%
7	Pinnacle West Capital Corporation	PNW	79.91	0.783	3.13	3.92%	8	4.7%	4.10%	**8.80%**	0.20%
8	Portland General Electric Company	POR	41.82	0.408	1.63	3.90%	6	4.3%	4.07%	**8.37%**	0.19%
9	WEC Energy Group, Inc.	WEC	92.02	0.633	2.53	2.75%	7	6.7%	2.93%	**9.63%**	0.14%
10	Xcel Energy Inc.	XEL	65.93	0.430	1.72	2.61%	9	5.5%	2.75%	**8.25%**	0.13%
11	**Average**								**3.52%**	**8.75%**	**0.17%**
12	**Minimum**								**2.68%**	**7.68%**	**0.13%**
13	**Maximum**								**4.24%**	**9.80%**	**0.20%**

Sources:
Column (d): CapitalIQ data from November 18, 2020 through December 31, 2020.
Column (e): CapitalIQ as of December 31, 2020.
Column (f) = 4 x Column (e).
Column (g) = Column (f) / Column (d).
Column (h): Number of I/B/E/S 3-year consensus analyst dividend per share ("DPS") growth estimate as of December 31, 2020.
Column (i): I/B/E/S 3-year consensus analyst dividend per share ("DPS") growth estimate as of December 31, 2020.
Column (j) = Column (g) x (1 + Column (i)).
Column (k) = Column (i) + Column (j).
Column (l): Flotation cost adjustment of 5% of current dividend yield, as described by Roger A. Morin, "New Regulatory Finance" (2006).
While flotation cost adjustment are estimated and demonstrated in this analysis, the adjustment is not included in any of the calculations comprising the analysis.

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Comparable Earnings Analysis

(a)	(b)	(c)	(d)	(e)	(f)	(g)
				2023-2025		
Line	Company	Ticker	Current Beta (B)	Earnings Per Share	Book Value Per Share	**Implied ROE**
1	Alliant Energy Corporation	LNT	0.85	3.00	28.45	**10.54%**
2	Ameren Corporation	AEE	0.85	4.50	44.50	**10.11%**
3	DTE Energy Company	DTE	0.95	8.50	79.00	**10.76%**
4	Edison International	EIX	0.95	4.75	44.00	**10.80%**
5	Evergy, Inc.	EVRG	1.00	4.00	43.00	**9.30%**
6	NiSource Inc.	NI	0.85	2.05	16.20	**12.65%**
7	Pinnacle West Capital Corporation	PNW	0.90	6.00	58.00	**10.34%**
8	Portland General Electric Company	POR	0.85	3.00	33.00	**9.09%**
9	WEC Energy Group, Inc.	WEC	0.80	4.75	38.00	**12.50%**
10	Xcel Energy Inc.	XEL	0.80	3.50	33.25	**10.53%**
11	**Average**					**10.66%**
12	**Minimum**					**9.09%**
13	**Maximum**					**12.65%**

Sources: Column (d), (e) & (f): Value Line Investment Survey (EIX, PNW, POR and XEL as of January 22, 2020; PPL as of November 13, 2020; NI as of November 27, 2020; LNT, AEE, ETR, DTE, EVRG, & WEC as of December 11, 2020).
Column (g) = Column (e) / Column (f).

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Cumulative Annual Interest Savings

(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)	(o)	(p)	(q)	(r)	(s)
Line			2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	Total
1	S&P Senior Secured Debt Credit Rating		BBB-	BBB	BBB	BBB	BBB+	BBB+	BBB+	A-	A	A	A	A	A	A	A	
2	Debt Issued - First Mortgage Bonds ($ millions)	A		$ -	$ 600	$ 500	$ 600	$ -	$ 725	$ 750	$ 500	$ 250	$ 450	$ 535	$1,900	$1,001	$1,661	$ 9,471
3	Interest Spread Differential vs. BBB-	B		1.31%	1.31%	1.31%	0.93%	0.99%	1.24%	0.82%	0.82%	0.53%	0.72%	0.61%	1.71%	0.85%	0.74%	
4	Annual Interest Savings ($ millions)	A x B		$ -	$ 8	$ 7	$ 6	$ -	$ 9	$ 6	$ 4	$ 1	$ 3	$ 3	$ 32	$ 8	$ 12	
5	Cumulative Annual Interest Savings ($ millions)			$ -	$ 8	$ 14	$ 20	$ 20	$ 29	$ 35	$ 39	$ 41	$ 44	$ 47	$ 80	$ 88	$ 100	**$ 100**

Annual savings repeats throughout entire life of the debt.

6	BBB- Rating Issuance Spread	C	NA	NA	NMF	4.40%	2.17%	2.55%	2.47%	1.71%	1.69%	1.63%	1.83%	1.47%	2.64%	1.97%	2.01%
7	Current Rating Issuance Spread	D	NA	NA	NMF	3.09%	1.24%	1.56%	1.23%	0.90%	0.87%	1.11%	1.11%	0.86%	0.93%	1.12%	1.27%
8	Issuance Spread Differential vs. BBB-	C - D	-	-	-	1.31%	0.93%	0.99%	1.24%	0.82%	0.82%	0.53%	0.72%	0.61%	1.71%	0.85%	0.74%

Source: All issuance spreads per the Barclays Bank Utility Deal listing. Initial data began during calendar year 2008.
Line 3: Annual average fixed rate issuance spread versus BBB-, calculated in line 8.
Line 6: Annual average fixed rate BBB- issuance spread.
Line 7: Annual average fixed rate issuance spread for current ratings shown in Line 1.
Line 8 = Line 6 - Line 7.

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Equity Risk Premium Analysis

(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)
Line	Period	Large Company Total Returns	Long Term Gov Bonds Income Returns	Difference	Period	Large Company Total Returns	Long Term Gov Bonds Income Returns	Difference
1	1926	11.62%	3.73%	7.89%	1976	23.93%	7.89%	16.04%
2	1927	37.49%	3.41%	34.08%	1977	-7.16%	7.14%	-14.30%
3	1928	43.61%	3.22%	40.39%	1978	6.57%	7.90%	-1.33%
4	1929	-8.42%	3.47%	-11.89%	1979	18.61%	8.86%	9.75%
5	1930	-24.90%	3.32%	-28.22%	1980	32.50%	9.97%	22.53%
6	1931	-43.34%	3.33%	-46.67%	1981	-4.92%	11.55%	-16.47%
7	1932	-8.19%	3.69%	-11.88%	1982	21.55%	13.50%	8.05%
8	1933	53.99%	3.12%	50.87%	1983	22.56%	10.38%	12.18%
9	1934	-1.44%	3.18%	-4.62%	1984	6.27%	11.74%	-5.47%
10	1935	47.67%	2.81%	44.86%	1985	31.73%	11.25%	20.48%
11	1936	33.92%	2.77%	31.15%	1986	18.67%	8.98%	9.69%
12	1937	-35.03%	2.66%	-37.69%	1987	5.25%	7.92%	-2.67%
13	1938	31.12%	2.64%	28.48%	1988	16.61%	8.97%	7.64%
14	1939	-0.41%	2.40%	-2.81%	1989	31.69%	8.81%	22.88%
15	1940	-9.78%	2.23%	-12.01%	1990	-3.10%	8.19%	-11.29%
16	1941	-11.59%	1.94%	-13.53%	1991	30.47%	8.22%	22.25%
17	1942	20.34%	2.46%	17.88%	1992	7.62%	7.26%	0.36%
18	1943	25.90%	2.44%	23.46%	1993	10.08%	7.17%	2.91%
19	1944	19.75%	2.46%	17.29%	1994	1.32%	6.59%	-5.27%
20	1945	36.44%	2.34%	34.10%	1995	37.58%	7.60%	29.98%
21	1946	-8.07%	2.04%	-10.11%	1996	22.96%	6.18%	16.78%
22	1947	5.71%	2.13%	3.58%	1997	33.36%	6.64%	26.72%
23	1948	5.50%	2.40%	3.10%	1998	28.58%	5.83%	22.75%
24	1949	18.79%	2.25%	16.54%	1999	21.04%	5.57%	15.47%
25	1950	31.71%	2.12%	29.59%	2000	-9.10%	6.50%	-15.60%
26	1951	24.02%	2.38%	21.64%	2001	-11.89%	5.53%	-17.42%
27	1952	18.37%	2.66%	15.71%	2002	-22.10%	5.59%	-27.69%
28	1953	-0.99%	2.84%	-3.83%	2003	28.68%	4.80%	23.88%
29	1954	52.62%	2.79%	49.83%	2004	10.88%	5.02%	5.86%
30	1955	31.56%	2.75%	28.81%	2005	4.91%	4.69%	0.22%
31	1956	6.56%	2.99%	3.57%	2006	15.79%	4.68%	11.11%
32	1957	-10.78%	3.44%	-14.22%	2007	5.49%	4.86%	0.63%
33	1958	43.36%	3.27%	40.09%	2008	-37.00%	4.45%	-41.45%
34	1959	11.96%	4.01%	7.95%	2009	26.46%	3.47%	22.99%
35	1960	0.47%	4.26%	-3.79%	2010	15.06%	4.25%	10.81%
36	1961	26.89%	3.83%	23.06%	2011	2.11%	3.82%	-1.71%
37	1962	-8.73%	4.00%	-12.73%	2012	16.00%	2.46%	13.54%
38	1963	22.80%	3.89%	18.91%	2013	32.39%	2.88%	29.51%
39	1964	16.48%	4.15%	12.33%	2014	13.69%	3.41%	10.28%
40	1965	12.45%	4.19%	8.26%	2015	1.38%	2.47%	-1.09%
41	1966	-10.06%	4.49%	-14.55%	2016	11.96%	2.30%	9.66%
42	1967	23.98%	4.59%	19.39%	2017	21.83%	2.67%	19.16%
43	1968	11.06%	5.50%	5.56%	2018	-4.38%	2.82%	-7.20%
44	1969	-8.50%	5.95%	-14.45%	2019	0.31%	2.55%	-2.24%
45	1970	3.86%	6.74%	-2.88%				
46	1971	14.30%	6.32%	7.98%				
47	1972	18.99%	5.87%	13.12%				
48	1973	-14.69%	6.51%	-21.20%				
49	1974	-26.47%	7.27%	-33.74%				
50	1975	37.23%	7.99%	29.24%				
51					**1926-2019 Average:**	**11.76%**	**4.94%**	**6.82%**
52						**Equity Risk Premium:**		**6.82%**
53					**1942-1951 Average**	**18.01%**	**2.30%**	**15.71%**
54						**Equity Risk Premium:**		**15.71%**
55					**2011-2019 Average:**	**10.59%**	**2.82%**	**7.77%**
56						**Equity Risk Premium:**		**7.77%**
57		**Low Interest Period, 1942-1951 & 2011-2019 Average:**				**14.49%**	**2.55%**	**11.95%**
58						**Equity Risk Premium:**		**11.95%**

Source: Columns (b), (c), (d), (f), (g) & (h): 2020 Stocks, Bonds, Bills, and Inflation (SBBI) Yearbook, Roger Ibbotson, et al.
Column (e) = Column (c) - Column (d).
Column (i) = Column (g) - Column (h).

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Case No.: U-20963
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Schedule: D-5

Witness: TAWehner
Date: March 2021

	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)
		Moody's Electric Utility Common Stocks					Yields on "A" Rated Utility Bonds	Stock Spread Over "A" Rated Bond Yields
Line	Year	Year End Avg Pr/Sh	Average Div/Share	% Gain	Dividend Yield	Total Return	(Year End)	
1	1931	43.23	3.47					
2	1932	39.42	2.63	-8.81%	6.08%	-2.73%	5.85%	-8.58%
3	1933	28.73	1.95	-27.12%	4.95%	-22.17%	7.22%	-29.39%
4	1934	21.06	1.60	-26.70%	5.57%	-21.13%	5.36%	-26.49%
5	1935	36.06	1.32	71.23%	6.27%	77.49%	4.29%	73.20%
6	1936	41.60	1.48	15.36%	4.10%	19.47%	3.83%	15.64%
7	1937	24.24	1.74	-41.73%	4.18%	-37.55%	4.03%	-41.58%
8	1938	27.55	1.50	13.66%	6.19%	19.84%	3.74%	16.10%
9	1939	28.85	1.48	4.72%	5.37%	10.09%	3.38%	6.71%
10	1940	22.22	1.54	-22.98%	5.34%	-17.64%	3.10%	-20.74%
11	1941	13.45	1.44	-39.47%	6.48%	-32.99%	3.06%	-36.05%
12	1942	14.29	1.26	6.25%	9.37%	15.61%	3.06%	12.55%
13	1943	21.01	1.28	47.03%	8.96%	55.98%	2.99%	52.99%
14	1944	21.09	1.31	0.38%	6.24%	6.62%	2.97%	3.65%
15	1945	31.14	1.30	47.65%	6.16%	53.82%	2.75%	51.07%
16	1946	32.71	1.43	5.04%	4.59%	9.63%	2.76%	6.87%
17	1947	25.60	1.56	-21.74%	4.77%	-16.97%	3.05%	-20.02%
18	1948	26.20	1.60	2.34%	6.25%	8.59%	3.06%	5.53%
19	1949	30.57	1.66	16.68%	6.34%	23.02%	2.78%	20.24%
20	1950	30.81	1.76	0.79%	5.76%	6.54%	2.86%	3.68%
21	1951	33.85	1.88	9.87%	6.10%	15.97%	3.29%	12.68%
22	1952	37.85	1.91	11.82%	5.64%	17.46%	3.22%	14.24%
23	1953	39.61	2.01	4.65%	5.31%	9.96%	3.38%	6.58%
24	1954	47.56	2.13	20.07%	5.38%	25.45%	3.11%	22.34%
25	1955	49.35	2.21	3.76%	4.65%	8.41%	3.35%	5.06%
26	1956	48.96	2.32	-0.79%	4.70%	3.91%	3.91%	0.00%
27	1957	50.30	2.43	2.74%	4.96%	7.70%	4.36%	3.34%
28	1958	66.37	2.50	31.95%	4.97%	36.92%	4.49%	32.43%
29	1959	65.77	2.61	-0.90%	3.93%	3.03%	4.96%	-1.93%
30	1960	76.82	2.68	16.80%	4.07%	20.88%	4.65%	16.23%
31	1961	99.32	2.81	29.29%	3.66%	32.95%	4.65%	28.30%
32	1962	96.49	2.97	-2.85%	2.99%	0.14%	4.44%	-4.30%
33	1963	102.31	3.21	6.03%	3.33%	9.36%	4.46%	4.90%
34	1964	115.54	3.43	12.93%	3.35%	16.28%	4.54%	11.74%
35	1965	114.86	3.86	-0.59%	3.34%	2.75%	4.83%	-2.08%
36	1966	105.99	4.11	-7.72%	3.58%	-4.14%	5.67%	-9.81%
37	1967	98.19	4.34	-7.36%	4.09%	-3.26%	6.67%	-9.93%
38	1968	104.04	4.50	5.96%	4.58%	10.54%	6.87%	3.67%
39	1969	84.62	4.61	-18.67%	4.43%	-14.23%	8.59%	-22.82%
40	1970	88.59	4.70	4.69%	5.55%	10.25%	8.48%	1.77%
41	1971	85.56	4.77	-3.42%	5.38%	1.96%	7.90%	-5.94%
42	1972	83.61	4.87	-2.28%	5.69%	3.41%	7.48%	-4.07%
43	1973	60.87	5.01	-27.20%	5.99%	-21.21%	8.24%	-29.45%
44	1974	41.17	4.83	-32.36%	7.93%	-24.43%	10.27%	-34.70%
45	1975	55.66	4.97	35.20%	12.07%	47.27%	10.11%	37.16%
46	1976	66.29	5.18	19.10%	9.31%	28.40%	8.62%	19.78%
47	1977	68.19	5.54	2.87%	8.36%	11.22%	8.64%	2.58%
48	1978	59.75	5.81	-12.38%	8.52%	-3.86%	9.70%	-13.56%
49	1979	56.41	6.22	-5.59%	10.41%	4.82%	11.79%	-6.97%
50	1980	54.42	6.58	-3.53%	11.66%	8.14%	14.63%	-6.49%
51	1981	57.20	6.99	5.11%	12.84%	17.95%	16.29%	1.66%
52	1982	70.26	7.43	22.83%	12.99%	35.82%	14.43%	21.39%
53	1983	72.03	7.87	2.52%	11.20%	13.72%	13.52%	0.20%
54	1984	80.16	8.26	11.29%	11.47%	22.75%	13.11%	9.64%
55	1985	94.98	8.61	18.49%	10.74%	29.23%	10.97%	18.26%
56	1986	113.66	8.89	19.67%	9.36%	29.03%	9.12%	19.91%
57	1987	94.24	9.12	-17.09%	8.02%	-9.06%	10.98%	-20.04%
58	1988	100.94	8.87	7.11%	9.41%	16.52%	10.06%	6.46%
59	1989	122.52	8.82	21.38%	8.74%	30.12%	9.44%	20.68%
60	1990	117.77	8.79	-3.88%	7.17%	3.30%	9.73%	-6.43%
61	1991	144.02	8.95	22.29%	7.60%	29.89%	8.88%	21.01%
62	1992	141.06	9.05	-2.06%	6.28%	4.23%	8.43%	-4.20%
63	1993	146.70	8.99	4.00%	6.37%	10.37%	7.34%	3.03%
64	1994	115.50	8.96	-21.27%	6.11%	-15.16%	8.76%	-23.92%
65	1995	142.90	9.02	23.72%	7.81%	31.53%	7.23%	24.30%
66	1996	136.00	9.06	-4.83%	6.34%	1.51%	7.59%	-6.08%
67	1997	155.73	9.06	14.51%	6.66%	21.17%	7.16%	14.01%
68	1998	181.84	7.83	16.77%	5.03%	21.79%	6.91%	14.88%
69	1999	137.30	8.10	-24.49%	4.45%	-20.04%	8.14%	-28.18%
70	2000	227.09	8.27	65.40%	6.02%	71.42%	7.84%	63.58%
71	2001	200.50	8.69	-11.71%	3.83%	-7.88%	7.83%	-15.71%
72	2002	169.50	9.13	-15.46%	4.55%	-10.91%	6.93%	-17.84%
73	2003					25.74%	5.78%	19.95%
74	2004					26.34%	5.46%	20.88%
75	2005					19.62%	5.56%	14.06%
76	2006					19.83%	5.83%	14.00%
77	2007					20.59%	6.06%	14.53%
78	2008					-27.06%	5.99%	-33.04%
79	2009					8.73%	5.88%	2.85%
80	2010					4.83%	5.64%	-0.81%
81	2011					19.67%	4.09%	15.58%
82	2012					0.80%	3.95%	-3.16%
83	2013					11.20%	4.75%	6.45%
84	2014					29.67%	3.94%	25.73%
85	2015					-4.48%	4.39%	-8.87%
86	2016					16.54%	4.22%	12.32%
87	2017					11.98%	3.75%	8.23%
88	2018					3.30%	4.35%	-1.05%
89	2019					26.49%	3.48%	23.01%
90	2020					1.20%	2.71%	-1.51%
89					**1932-2020 Average:**	**10.83%**	**6.31%**	**4.52%**
90					**1942-1951 Average:**	**17.88%**	**2.96%**	**14.92%**
91					**2011-2020 Average:**	**11.64%**	**3.96%**	**7.67%**
92					**Low Interest Period, 1942-1951 & 2011-2020 Average:**	**14.76%**	**3.46%**	**11.30%**

Sources: Columns (b) & (c): Mergent Public Utility Manual. Per Moody's & Mergent, Moody's Electric Utility Index is no longer maintained.
Column (d) = (current year Column (b) - prior year Column (b)) / prior year Column (b).
Column (e) = current year Column (c) / prior year Column (b).
Column (f) = Column (d) + Column (e). For 2003 - 2020, the total return is the average of the total returns from Bloomberg for the S&P 500 Utilities & Electric Utilities Index and the Dow Jones Utilities Index (See Exhibit A-14 (TAW-1), Schedule D5, page 10).
Column (g): 1932 - 2002 Mergent Public Utility Manual; 2003 - 2020 Bloomberg.
Column (h) = Column (f) - Column (g).

Schedule D-5

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Cost of Common Shareholders' Equity
For the Projected 12 Month Period Ending December 31, 2022

Case No.: U-20963
Exhibit No.: A-14 (TAW-1)
Schedule: D-5

Witness: TAWehner
Date: March 2021

Utility Index Total Returns

(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)
		S&P 500 Electric Utilities Index			S&P 500 Utilities Index			Dow Jones Utilities Index			Average
		Dec 31,		Total	Dec 31,		Total	Dec 31,		Total	Total
Line	Year	Price	Dividends	Return	Price	Dividends	Return	Price	Dividends	Return	Return
	2000	179.91			216.03			412.16			
1	2001	144.69	5.620	-16.45%	145.88	5.376	-29.98%	293.94	11.698	-25.84%	-24.09%
2	2002	117.42	5.843	-14.81%	97.76	5.036	-29.53%	215.18	11.411	-22.91%	-22.42%
3	2003	139.72	5.093	23.33%	118.39	4.254	25.45%	266.90	9.446	28.43%	25.74%
4	2004	170.17	5.721	25.89%	141.60	4.789	23.65%	334.95	10.668	29.49%	26.34%
5	2005	193.16	6.655	17.42%	159.66	5.511	16.65%	405.11	12.886	24.79%	19.62%
6	2006	229.94	6.991	22.66%	186.60	5.841	20.53%	456.77	14.331	16.29%	19.83%
7	2007	274.48	7.853	22.79%	216.11	6.175	19.12%	532.53	14.972	19.86%	20.59%
8	2008	196.27	8.570	-25.37%	147.93	6.632	-28.48%	370.76	16.281	-27.32%	-27.06%
9	2009	193.33	8.799	2.99%	157.99	6.652	11.30%	398.01	16.883	11.90%	8.73%
10	2010	190.39	9.067	3.17%	159.34	6.845	5.19%	404.99	17.402	6.13%	4.83%
11	2011	219.63	9.547	20.37%	182.98	7.301	19.42%	464.68	18.134	19.22%	19.67%
12	2012	208.67	9.774	-0.54%	177.66	7.655	1.28%	453.09	19.256	1.65%	0.80%
13	2013	215.55	9.515	7.86%	193.21	7.782	13.13%	490.57	19.675	12.61%	11.20%
14	2014	271.96	9.429	30.54%	240.14	7.976	28.42%	618.08	19.965	30.06%	29.67%
15	2015	247.30	9.802	-5.46%	220.00	8.418	-4.88%	577.82	21.085	-3.10%	-4.48%
16	2016	274.98	10.324	15.37%	246.83	8.782	16.19%	659.61	22.668	18.08%	16.54%
17	2017	293.61	10.575	10.62%	267.37	9.209	12.05%	723.37	23.767	13.27%	11.98%
18	2018	295.01	10.549	4.07%	268.61	9.345	3.96%	712.93	24.080	1.89%	3.30%
19	2019	363.25	11.439	27.01%	328.36	10.012	25.97%	876.08	25.601	26.48%	26.49%
20	2020	360.96	12.993	2.95%	319.07	10.577	0.39%	850.39	27.915	0.25%	1.20%

Sources: Columns (c), (d), (f), (g), (i) & (j): Bloomberg.
Column (e) = (Column (c(t)) - Column (c(t-1)) + Column (d(t))) / Column (c(t-1)).
Column (h) = (Column (f(t)) - Column (f(t-1)) + Column (g(t))) / Column (f(t-1)).
Column (k) = (Column (i(t)) - Column (i(t-1)) + Column (j(t))) / Column (i(t-1)).
Column (l) = Average of Columns (e), (h) & (k).

Schedule D-5

Projected Equity Risk Premium S&P 500

Equation: K_e = Dividend Yield + g

Where:

K_e = Annual required rate of return on equity

Dividend Yield = Expected dividend yield of Market

g = Growth rate

(a)	(b)		(c)
Line			
1	S&P 500 Index Expected Dividend Yield		1.58%
2	S&P 500 Index Expected Long-Term EPS Growth Rate	+	11.78%
3	Market Expected ROE (Lines 1+2)		13.36%
4	Less Risk Free Rate	(-)	2.11%
5	**Estimated Market Risk Premium (Line 3 - Line 4)**		**11.25%**

Sources:

Rows 1 and 2: Bloomberg data as of December 31, 2020.

Row 4: Exhibit A-14 (TAW-1). Schedule D-5, page 2, column (f).

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Cost of Common Shareholders' Equity
For the Projected 12 Month Period Ending December 31, 2022

Case No.: U-20963
Exhibit No.: A-14 (TAW-1)
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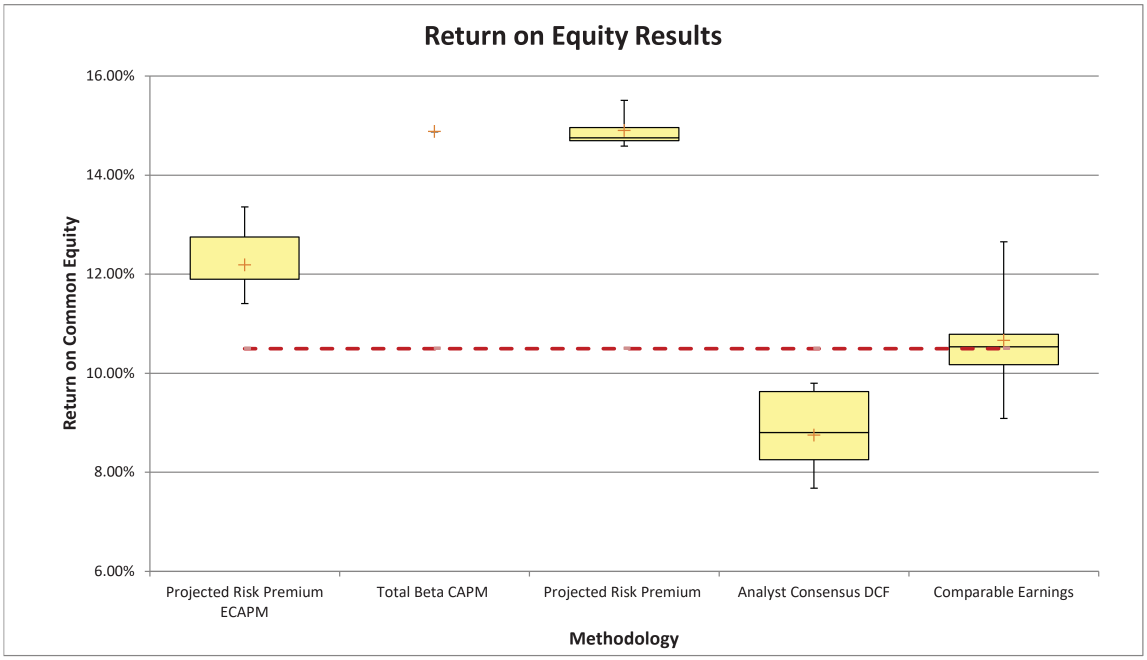
Witness: TAWehner
Date: March 2021

Summary of Return on Equity Results

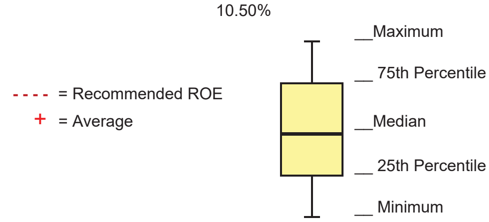


Numerical Summary of ROE Results

		Min	25th%	Median	75th%	Max	Avg		
1	Projected Risk Premium ECAPM	11.41%	11.90%	11.90%	12.75%	13.36%	12.19%	Exhibit A-14 (TAW-1)	Page 2 of 12
2	Total Beta CAPM	14.88%	14.88%	14.88%	14.88%	14.88%	14.88%	Exhibit A-14 (TAW-1)	Page 3 of 12
3	Projected Risk Premium	14.59%	14.69%	14.75%	14.96%	15.51%	14.90%	Exhibit A-14 (TAW-1)	Page 4 of 12
4	Analyst Consensus DCF	7.68%	8.25%	8.80%	9.63%	9.80%	8.75%	Exhibit A-14 (TAW-1)	Page 5 of 12
5	Comparable Earnings	9.09%	10.17%	10.54%	10.79%	12.65%	10.66%	Exhibit A-14 (TAW-1)	Page 6 of 12

6 Recommended Cost of Equity Range for Consumers Energy: 10.0% - 11.0%

7 Recommended Ratemaking Cost of Equity for Consumers Energy: 10.50%



How Customer Satisfaction Drives Return On Equity for Regulated Utilities

J.D. POWER
McGRAW HILL FINANCIAL

SNL Energy

A McGraw Hill Financial White Paper

October 2015

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TABLE OF CONTENTS

Introduction

The purpose of this white paper is to share the key findings from in-depth analyses completed by J.D. Power and SNL Energy regarding the recent results of rate cases for regulated U.S. utilities. The white paper focuses on the approved return on equity (ROE) for recent rate cases, demonstrating how customer satisfaction influences the authorized ROE for regulated electric utilities.

The research presented herein updates the previous analysis conducted by J.D. Power, which found that customer satisfaction is a leading indicator of the approved return on equity for regulated electric utilities. The original J.D. Power white paper on this topic was published in May 2012:

> *"How Customer Satisfaction Drives Return On Equity for Regulated Electric Utilities"*
> Andrew Heath and Dan Seldin, Ph.D.

Both the 2015 and 2012 white papers are published at www.jdpower.com and www.snlenergy.com.

Executive Summary

During the past decade, J.D. Power, SNL Energy affiliate Regulatory Research Associates, and Standard and Poor's Rating Services* have examined the relationship between customer satisfaction and key financial metrics in the electric utility industry, such as profitability and credit ratings. During the same period, the number of electric rate cases has steadily increased, prompting McGraw Hill Financial to take a closer look at the relationship between satisfaction and return on equity (ROE) in the industry. Similar to profitability and credit ratings, customer satisfaction has a noteworthy impact on ROE for regulated electric utilities. This white paper summarizes and provides an update to the findings previously published in 2012.

When the customer satisfaction results of regulated electric utilities are categorized into quartiles, results show that higher levels of satisfaction one year prior to a rate case are associated with higher levels of ROE. On average, a 10-point increase in satisfaction (based on J.D. Power's proprietary 1,000-point index scale) is associated with a .04% increase in ROE. More importantly, there is an increase in ROE among utilities in the top quartile of customer satisfaction one year prior to their rate case; on average, top quartile utilities earned 10.7% ROE whereas bottom quartile utilities earned 10.1% ROE. Applying this 0.6% increase to an equity base of $1 billion translates into a $6 million annualized increase in earnings available to shareholders. Moreover, utilities in the top quartile also receive rate increases closer to their request than do utilities in the bottom quartile.

The primary implication of these findings is this: investing in the customer experience can yield rewards as significant as those when investing in tangible assets, such as power plants, transmission lines, and distribution infrastructure.

* J.D. Power, SNL Energy, and Standard and Poor's Rating Services are business units of McGraw Hill Financial

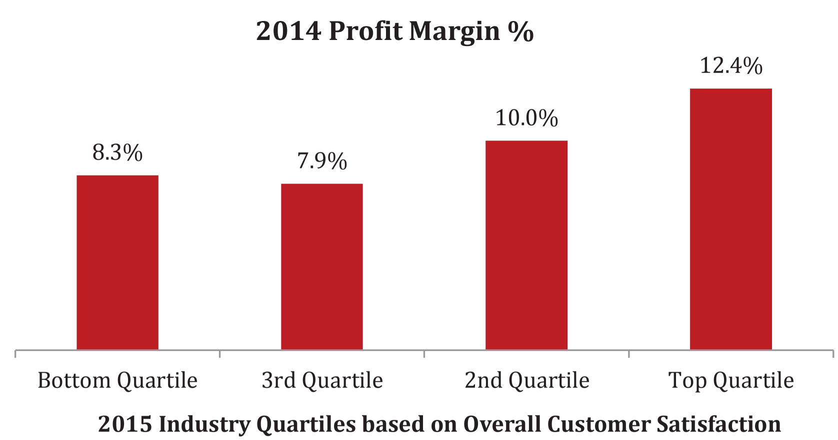
Impact of Customer Satisfaction on Profit and Credit Ratings

Impact of Customer Satisfaction on Credit Ratings and Profit

- In a 2005 report, S&P Rating Services provided insights regarding how it uses customer satisfaction data when determining utility credit ratings.[1] The report included findings from an internal study conducted by S&P that compared the opinions of credit analysts about the regulatory environment of particular utility companies with a utility's customer satisfaction index score, as measured by J.D. Power. S&P's analysis identified a correlation between the credit analyst's view of regulatory risk and customer satisfaction. Furthermore, based on those findings, S&P clarified its methodology would include customer satisfaction as one of the many variables they use to assess risk and, ultimately, their credit ratings.

[1] "Customer Satisfaction Levels Can Affect U.S. Utility Credit Quality," Todd Shipman. Standard & Poor's Ratings Direct Service. August 2005.

- One of the primary drivers and key performance indicators for all companies is profit. Ongoing research conducted by J.D. Power examines the relationship between electric utilities' customer satisfaction performance and their most recently published profit margin, as reported by utilities to the Federal Energy Regulatory Commission (FERC). Results show a positive relationship between the level of satisfaction and profit margin. Electric utilities in the top quartile of customer satisfaction typically report profits 3%-4% higher than utilities in the three lower quartiles.



Sources: *J.D. Power 2015 Electric Utility Residential Customer Satisfaction Study*[SM] and Federal Energy Regulatory Commission (FERC) Data, 2014

Capital Expenditure Overview

Drivers of Capital Expenditure/Rate Case Activity

There are many drivers that have led to the need for the electric industry to increase capital investments and address changes in net operating income. In turn, these drivers have led to an increased need to secure rate case increases for the majority of regulated U.S. electric utilities. The main drivers in each category are as follows:

Rate Base Additions/Capital Expenditures

- Remediating aging infrastructure
- Storm restoration costs
- Reliability-system hardening
- Environmental compliance
- Need for new generation
- Renewable resource requirements
- Transmission expansion

Net Operating Income Impacts

- Rising employee costs—pension and healthcare
- Demand Side Management program costs/lost revenues
- Weakness in (or lack of) sales growth
- Inflation

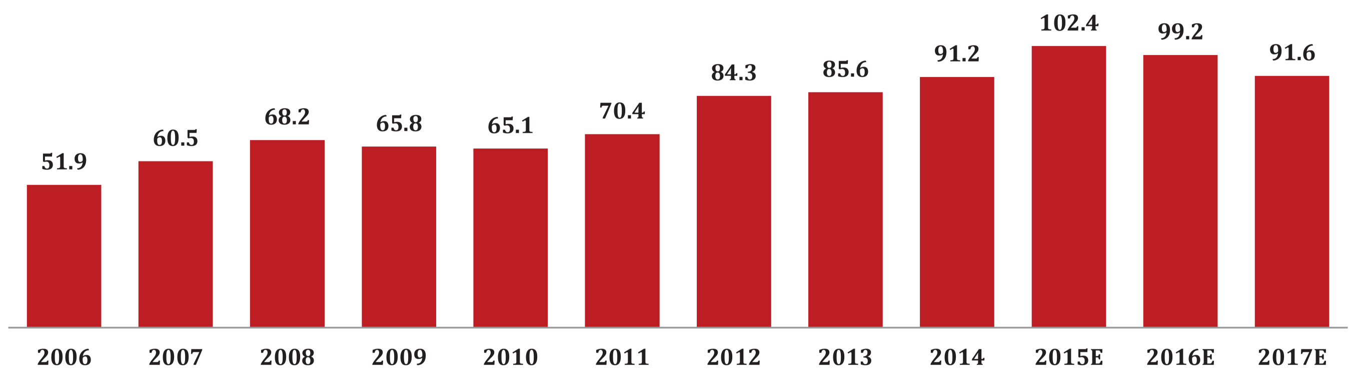
Capital Expenditure Trends

- One of the overarching themes in regulation during the next several years will be the need to address increased utility capital spending plans. While capital expenditures in the utility industry are expected to be somewhat lower in 2016 and 2017 than are forecasted for 2015, the projected level of spending in the 2015-2017 time frame is nearly double the level spent in the 2006-2008 time frame.

- As illustrated in the graph below, the 45 companies included in the RRA Index are projecting that capital expenditures will aggregate to $102 billion in 2015 vs. only $52 billion in 2006. These companies include the largest (by customer count) investor-owned electric and gas utility holding companies in the United States.

- While 2016 and 2017 forecasts are somewhat lower than 2015 at $99 million and $92 million, respectively, these levels are higher than previously forecasted for 2016 and 2017. The increased level of capital expenditure is expected to continue.

Total Capital Expenditures for 45 Utilities
Historical and Forecast ($ billions)

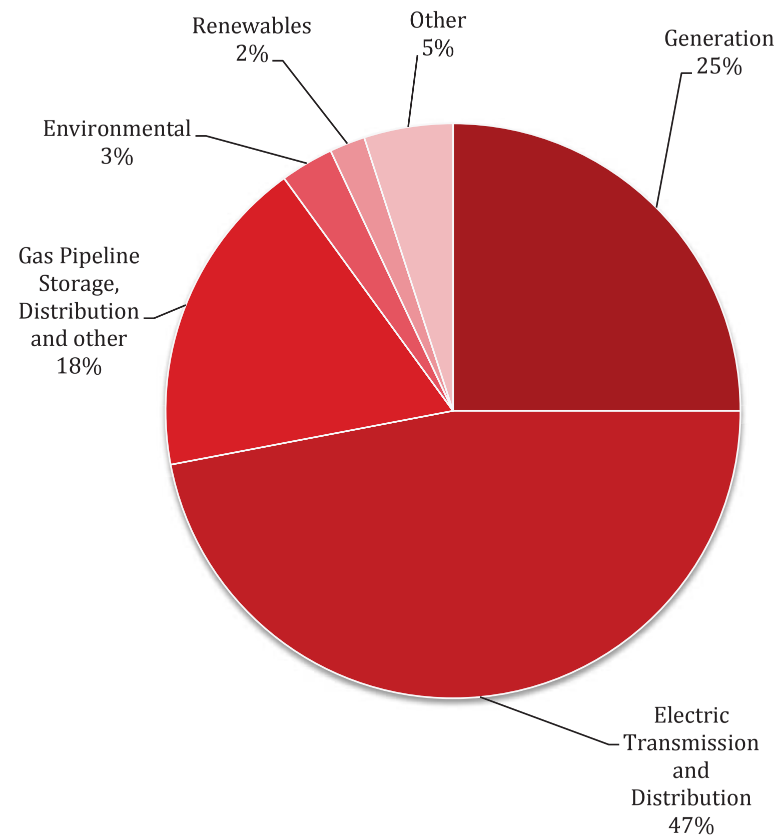


Source: Regulatory Research Associates, a division of SNL Energy

Capital Expenditure by Category—Electric and Gas Utilities (2016 and 2017)

With respect to the components that comprise capital expenditure plans:

- The majority of planned spending will be devoted to regulated operations—whether regulated at the state level or the federal level.
- Nearly half (47%) of planned spending is dedicated to the electric transmission and distribution system alone, with gas pipeline investment accounting for another 18% of planned spending.
- Assuming that a portion of the other categories of spend are a mix of regulated and deregulated assets, if it is conservatively assumed that only half of this is regulated, then three quarters of aggregate planned investment will be subject to review and approval by state or federal regulatory agencies.
- Achieving timely and constructive rate treatment of this investment will be key to the long-term financial performance of regulated electric and gas utilities.



Source: Regulatory Research Associates, a division of SNL Energy

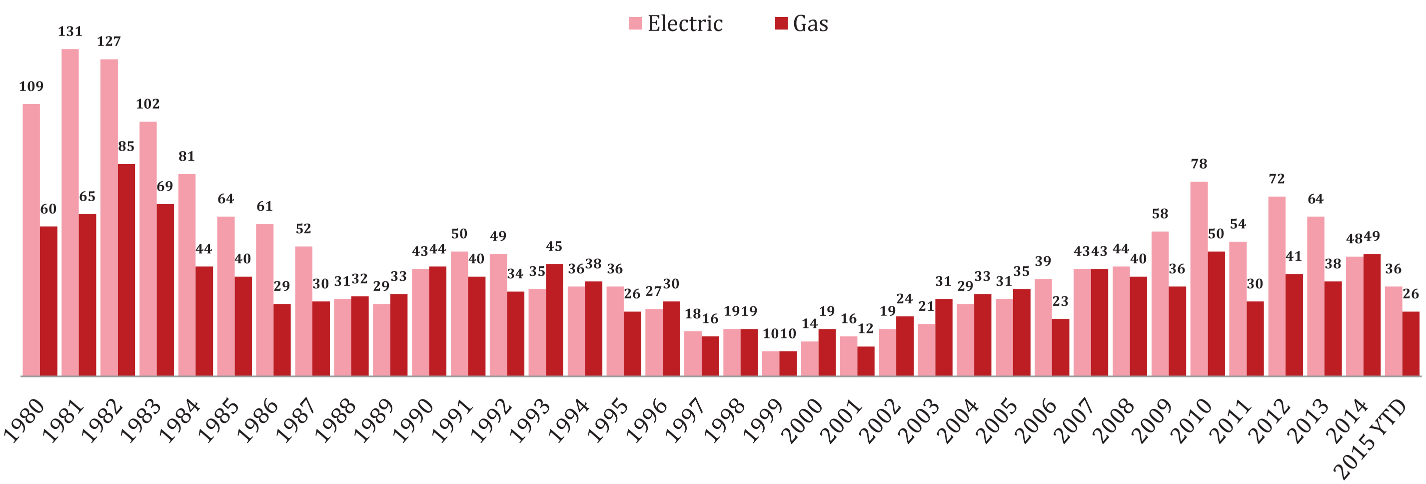
Rate Case Trends

Major Rate Case Decisions: 1980 - 2015

- Rate case activity has been brisk during the past few years—as illustrated below—with 100 or more electric and gas rate cases being decided across the United States each year since 2010. While these numbers are as large as the numbers of cases adjudicated during the generation construction boom of the 1980s, the statistics are significant, fewer companies are in the industry than there were during the 1980s due to mergers.

- By the third quarter of 2015, there were 62 cases decided, with roughly 80 cases pending nationwide. Regulatory Research Associates predicts that the final 2015 rate case tally will be approximately 75-80 cases by the end of the year.

Major Rate Case Decisions—1980 to 2015 YTD



Source: Regulatory Research Associates, a division of SNL Energy

Return on Equity Trends

Drivers of Authorized Return on Equity

- Interest rates—near historical lows
- Impact and timing of quantitative easing
- Economic hardship for customers
- Risk-reducing mechanisms

Approved return on equity has recently been driven by interest rates that are at or near historical lows; regulators' concerns about the economic hardship for customers associated with increasing rates as well as their tolerance for the same in light of the sheer amount of capital spending that must be recognized; and the presence of such risk-reducing features as decoupling mechanisms.

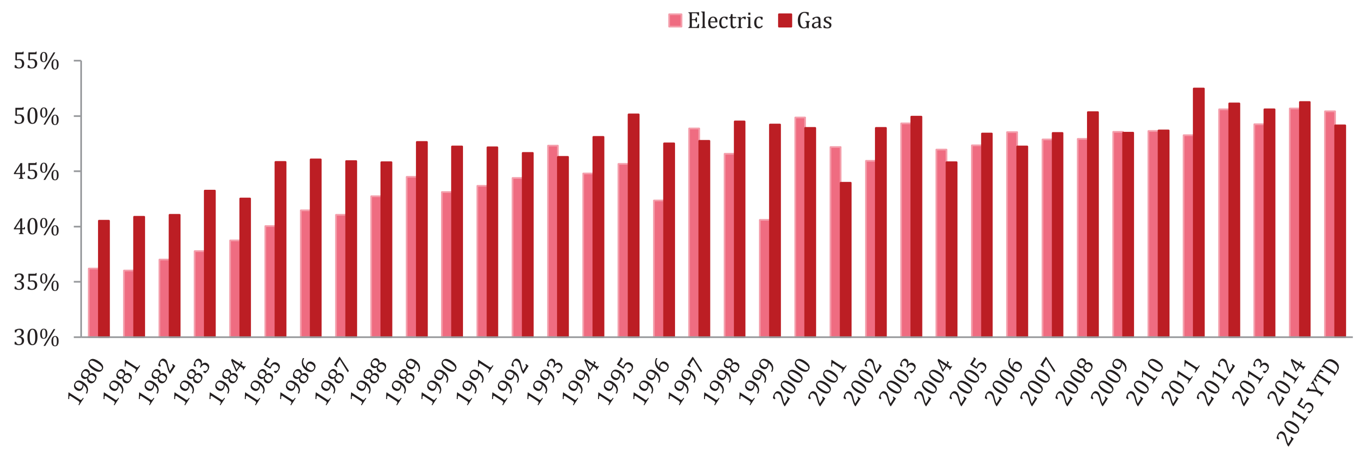
In contrast to the negative forces has been a heightened sensitivity among regulators to liquidity and credit quality issues that developed following the 2008 economic crisis; the need to maintain access to capital to fund capital expenditure programs; incentive ROE premiums that have been awarded for certain asset classes; and a recognition by commissions that uncertainty in the broader economic markets means uncertainty for utilities.

- Consideration of utility liquidity/financial health
- Need to maintain access to capital
- Incentive ROE premiums
- Economic uncertainty for utilities

Authorized Capital in Rate Cases Represents Half the Equity Value for Regulated Electric and Gas Utilities

- Unlike the return on equity, the authorized common equity percentages have risen during the past 30 years, while during the same time the common equity percentages for electric utilities have converged with gas utilities.
- The average equity component of capital used to establish rates in 2014 was 50.67% for electric utilities and 51.25% for gas utilities, which are notably higher than the percentages of 36% and 41%, respectively, in 1980. More recently, in the first nine months of 2015, the average equity ratio for electric companies was 50.41% and 49.2% for gas distribution companies.

Average Common Equity to Total Capital (%) 1980 - 2015 YTD



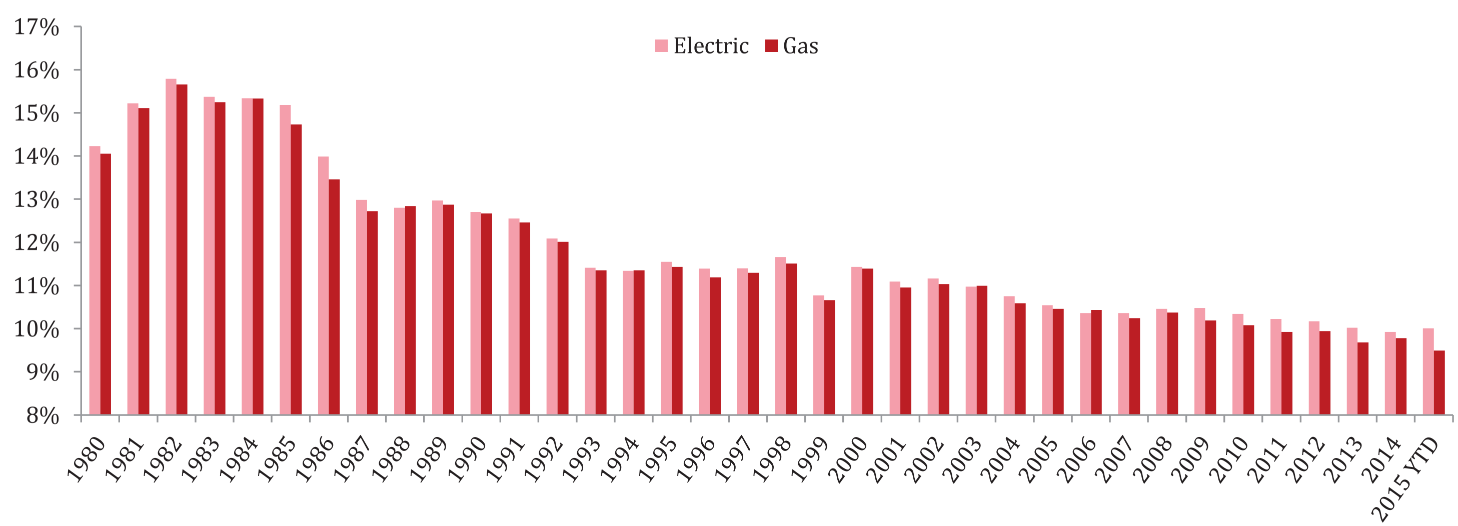
Source: Regulatory Research Associates, a division of SNL Energy

Authorized ROE Trends: 1980-2015 YTD

- Average authorized returns on equity for electric and gas utilities included in the RRA Index have been trending downward since they peaked at close to 16% in 1982. In general, electric and gas ROEs have moved together, while authorized ROEs for the gas industry have remained modestly below those for the electric industry.

- In 2014, the average ROE authorized for electric utilities nationwide was 9.91%, and the average ROE for gas utilities was 9.78%. For the first nine months of 2015, the average ROE was 10.0% for electric utilities and 9.49% for gas utilities. This difference is largely attributable to incentive ROE premiums offered in certain jurisdictions for select types of electric generation investment.

Average Return on Equity (%)
1980 - 2015 YTD



Source: Regulatory Research Associates, a division of SNL Energy

Relationship between Customer Satisfaction and Return on Equity

Methodology

- To assess the relationship between satisfaction and rate case outcomes, the approved ROE from each rate case and the customer satisfaction results of the *J.D. Power Electric Utility Residential Customer Satisfaction Study,*[SM] *2001-2015* were examined. The study surveys customers of large and midsize utilities regarding their experiences with their utility in six key factors: Power Quality & Reliability; Price; Billing & Payment; Communications; Corporate Citizenship; and Customer Service. The relative importance of each factor in relation to overall customer satisfaction with a utility's performance is derived using J.D. Power's proprietary index methodology. These derived importance weights are then applied to customer ratings, and utility company customer satisfaction performance is then based on aggregating the weighted ratings into an overall satisfaction index score that ranges from 100 to 1,000 points.

- National rate case information for 2002 to 2014 was gathered from SNL Energy's Regulatory Research Associates' database of regulator requests and outcomes. The majority of the rate cases included in the final analysis occurred between 2006 and 2015. The rate case database included the submission and close dates for each rate case; the initial requested amount; the return on equity; the authorized amount; the RRA commission utility score; the first counteroffer amount; and the second counteroffer amount.

- To assess the relationship between satisfaction and rate case outcomes, brand-level customer satisfaction data by year were merged with rate case data, yielding 436 data points. Customer satisfaction one year prior to the rate case submission was used to predict the various rate case outcomes. Pearson product moment correlations and simple linear regression models were used to determine the degree to which customer satisfaction impacts rate case outcomes.

Since 2001, Electric Utilities with Above-Average Satisfaction Have Above-Average Return on Equity

- In general, utility brands with above-average customer satisfaction scores realize higher approved rates of return on equity than below-average brands. Furthermore, every year since 2001 the utilities with above-average satisfaction have realized the highest average approved return on equity.
- The approved ROE for bottom-quartile utilities is relatively flat over time and, while ROE rates are still higher among top-two quartile brands vs. bottom-two quartile brands today, that gap between the top and bottom brands has narrowed. In 2013 and 2014, there is some evidence that this premium is increasing again.

Approved ROE by Customer Satisfaction Quartile - Electric

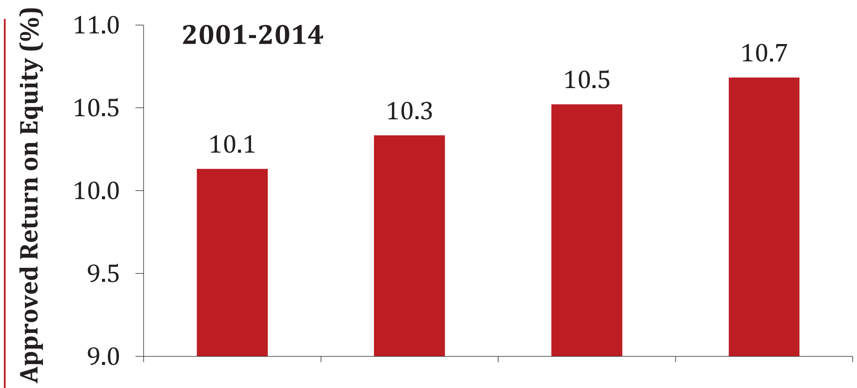
Sources: *J.D. Power Electric Utility Residential Customer Satisfaction Study,*[SM] *2001-2014* and Regulatory Research Associates, a division of SNL Energy

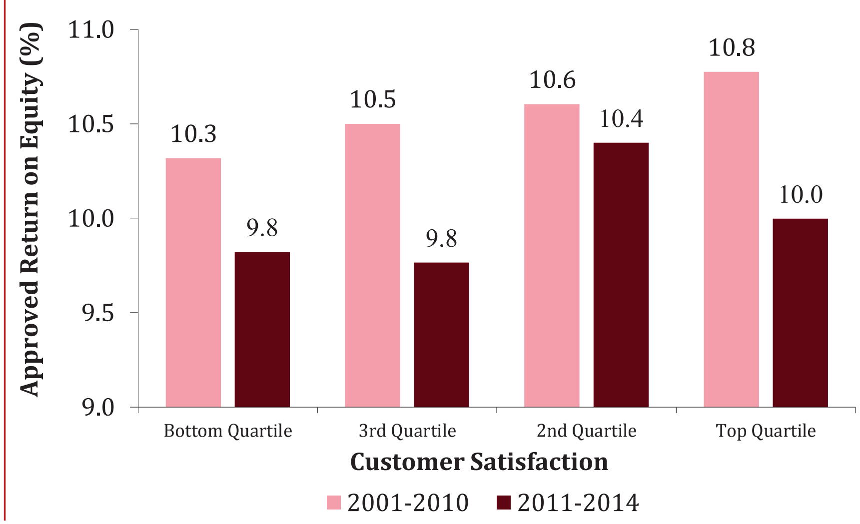
Return on Equity by Customer Satisfaction Quartile—Electric Utilities (2001-2014)

- When regulated electric utilities are categorized into quartiles of satisfaction, higher levels of customer satisfaction one year prior to a rate case are associated with higher ROE.

- A significant positive relationship was found between customer satisfaction and subsequent ROE one year later, such that a 10-point improvement in the overall satisfaction index score yielded a .04% increase in ROE ($R^2 = .35$). In dollar amounts, if a utility were requesting a rate change on an equity base of $1 billion, it would translate into an increase of $400,000 for every 10-point increase in the overall satisfaction index score. Moreover, when utilities in the top quartile were compared with those in the bottom quartile, an ROE difference of .6% was found. Again, that translates into $6 million more per rate case for the top-quartile vs. bottom-quartile utilities (assuming an equity base of $1 billion).

- For the period 2011 to 2014, the average approved ROE was below 10%, and, on average, only those utilities in the top or second quartile realized approved ROE rates at or above 10%.





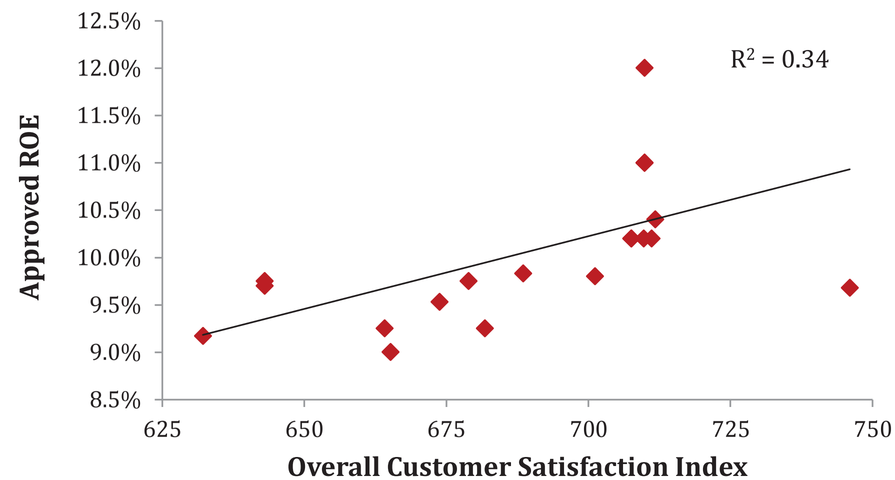
Sources: *J.D. Power Electric Utility Residential Customer Satisfaction Study,*[SM] *2001-2014* and Regulatory Research Associates, a division of SNL Energy

2014 Correlation between Customer Satisfaction and ROE

- There are 21 electric brands measured by J.D. Power that submitted rate cases in 2014 that were approved on completion of the analysis in this white paper.
- In 2014, customer satisfaction explains 34% of the variability in the outcome of the levels of ROE approved by electric utility regulators.
- With one exception, the analysis of rate cases from each year from 2003 to 2013 also shows a positive relationship between satisfaction scores the year prior to submitting a rate case and the approved ROE.
- The 2014 data* shows the strongest relationship since 2003. Each year between 2003 and 2014, ROE explains an average of 10% of the variations in ROE.

* Sources: *J.D. Power 2013 Electric Utility Residential Customer Satisfaction Study*SM and Regulatory Research Associates, a division of SNL Energy

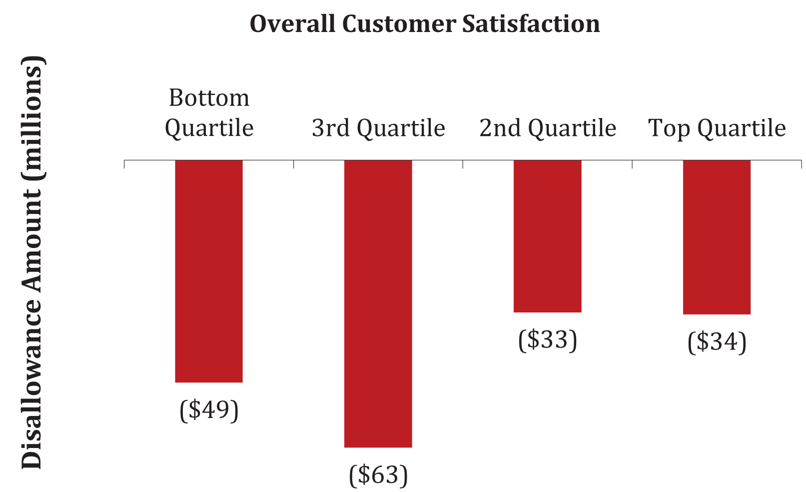
Approved ROE by Customer Satisfaction: 2014 Rate Cases



Sources: *J.D. Power 2013 Electric Utility Residential Customer Satisfaction Study*SM and Regulatory Research Associates, a division of SNL Energy

Disallowance by Satisfaction—Electric Utilities (2011-2015)

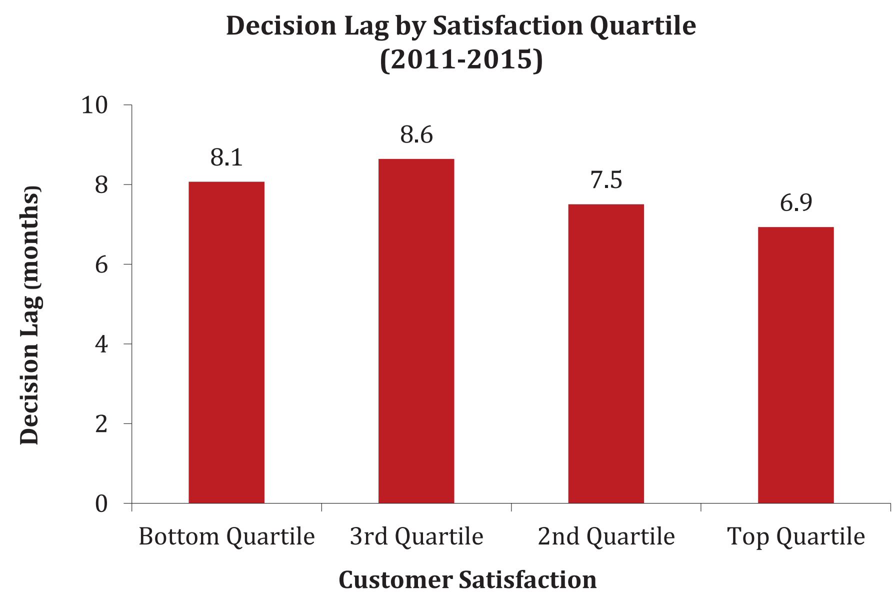
- Consistent with findings from the 2012 white paper that examined the impact of customer satisfaction on ROE, the 2011 to 2015 findings also show that utilities with the highest proportions of highly satisfied customers (i.e., top quartile) received rate increases closer to their requests than did utilities in the bottom quartile.
- When measured in absolute terms, utilities in the bottom quartile received an approved rate increase that was an average of $49 million below their original request, whereas top-quartile utilities received an approved rate increase that was an average of $34 million less than initially requested.



Sources: *J.D. Power Electric Utility Residential Customer Satisfaction Study,*[SM] *2001-2015* and Regulatory Research Associates, a division of SNL Energy

Top-Quartile Utilities Secure Rate Case Approvals Sooner Than Bottom-Quartile Utilities

- Over the past five years, the average time taken to approve rate cases is more than seven months.
- On average, electric utilities with top-quartile satisfaction scores receive regulatory approval in less than seven months, compared with more than eight months for bottom-quartile utilities.



Sources: *J.D. Power Electric Utility Residential Customer Satisfaction Study,*[SM] *2011-2015* and Regulatory Research Associates, a division of SNL Energy

Conclusions

Implications of Customer Satisfaction and Its Influence on Key Financial Metrics

- This research replicates previous work that found customer satisfaction is a leading indicator of the approved return on equity for regulated electric utilities.
- Providing customers a better experience yields improved rate case outcomes via faster approval turnaround, higher percentage of requested amounts granted, and an elevated allowed rate of return.
- That customer satisfaction can be a leading indicator of ROE remains an important discovery of the analysis conducted by J.D. Power and SNL Energy. This finding clearly suggests that utility companies can benefit directly from investing in programs aimed specifically at improving customer satisfaction. Data submitted to FERC indicate that when electric utilities invest in their customers, there is a corresponding improvement in satisfaction, suggesting that efforts can be aligned to achieve benefits for both customers and utilities.
- For regulated electric utilities, higher customer satisfaction is associated with higher rates of ROE and allowed returns that are closer to the requested returns. Other factors, especially prevailing interest rates, also drive ROE. Indeed, it is unlikely that customer satisfaction is the main driver of ROE. However, even a relatively small influence on ROE is noteworthy, given the major impact that approved ROE has on a regulated utility's financial performance.
- For utilities with higher levels of customer satisfaction, it is encouraging that, on average, regulators tend to look more favorably on the requested ROE when reviewing their rate case. This positive regulatory environment, in turn, provides the utilities with additional support for further investments in their operations that continue to promote customer satisfaction. Unfortunately, the same dynamic may also explain why many utilities with dissatisfied customers fail to improve—they lack the regulatory support necessary to secure approval for the investments required to convert their dissatisfied customers into satisfied customers.

A Virtuous (or Vicious) Cycle

- For regulated electric utilities looking to maximize ROE during a rate case, it is important to know that customer satisfaction makes a difference. Therefore, regulated utilities need to understand their levels of satisfaction and what drives satisfaction. Furthermore, knowing how to improve customer satisfaction is important and can play a critical role in realizing higher ROE rates.

- Positive customer satisfaction creates positive regulatory outcomes that, in turn, support further investments to promote customer satisfaction. Conversely, customer dissatisfaction can constrain a utility's ability to secure the funding needed to resolve the causes of dissatisfaction.

McGRAW HILL FINANCIAL

Essential Intelligence

Funds from operations ("FFO") is a vital credit metric referenced by the credit rating agencies.

In the long-term, FFO is simply the net income of a Company plus depreciation.

$$\boldsymbol{FFO = Net\ Income + Depreciation} \qquad \textit{(1)}$$

This equation can be further developed by using the follow relationships

$$\boldsymbol{Net\ Income = ROE\ x\ Equity}, \text{ and } \boldsymbol{Depreciation = \frac{Assets}{Life\ of\ Assets}}$$

Substituting these equations into (1) results in the following relationship

$$\boldsymbol{FFO = ROE\ x\ Equity + \frac{Assets}{Life\ of\ Assets}} \qquad \textit{(2)}$$

Furthermore, $\boldsymbol{Assets = Debt + Equity}$, and $\boldsymbol{\frac{1}{Life\ of\ Assets} = Depreciation\ Rate}$

Using these relationships and equation (2) results in the following

$$\boldsymbol{FFO = ROE\ x\ Equity + Depreciation\ Rate\ x\ (Debt + Equity)}$$

The equation for the FFO to Debt metric can therefore be derived as follows

$$\boldsymbol{\frac{FFO}{Debt} = \frac{ROE\ x\ Equity + \mathbf{Depreciation\ Rate}\ \mathrm{x}\ (Debt+Equity)}{Debt}} \qquad \textit{(3)}$$

Simple mathematic distribution arrives at the following

$$\boldsymbol{\frac{FFO}{Debt} = \frac{ROE\ x\ Equity}{Debt} + \frac{Depreciation\ Rate\ x\ (Debt+Equity)}{Debt}} \qquad \textit{(4)}$$

Further mathematical manipulation results in the following

$$\boldsymbol{\frac{FFO}{Debt} = \frac{ROE\ x\ Equity}{Debt} + Depreciation\ Rate\ x\left(1 + \frac{Equity}{Debt}\right)} \qquad \textit{(5)}$$

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

Belmont Municipal Light Department; Braintree Electric Light Department; Concord Municipal Light Plant; Georgetown Municipal Light Department; Groveland Electric Light Department; Hingham Municipal Lighting Plant; Littleton Electric Light & Water Department; Middleborough Gas & Electric Department; Middleton Electric Light Department; Reading Municipal Light Department; Rowley Municipal Lighting Plant; Taunton Municipal Lighting Plant; Wellesley Municipal Light Plant,	)	
Complainants,	)	
v.	)	Docket No. EL16-64-002
Central Maine Power Company; Emera Maine (formerly known as Bangor Hydro-Electric Company); Eversource Energy Service Company and its operating company affiliates: The Connecticut Light and Power Company, Western Massachusetts Electric Company, Public Service Company of New Hampshire, and NSTAR Electric Company; New England Power Company d/b/a National Grid; New Hampshire Transmission LLC d/b/a NextEra; The United Illuminating Company; Fitchburg Gas and Electric Light Company; and Vermont Transco, LLC,	)	
Respondents.	)	

ANSWERING TESTIMONY AND EXHIBITS OF

JOHN D. QUACKENBUSH, CFA

ON BEHALF OF
THE NEW ENGLAND TRANSMISSION OWNERS

MARCH 23, 2017

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EXHIBITS TO ANSWERING TESTIMONY

Exhibit No.	**Description**
NET-02301	Qualifications of John D. Quackenbush
NET-02302	Federal Funds Effective Rate
NET-02303	Yields on U.S. Treasury Securities
NET-02304	Yields on Ten-Year U.S. Treasury Securities
NET-02305	Moody's Baa Utility Bond Yields
NET-02306	Yields on Global Government Securities
NET-02307	Securities Held Outright by the Federal Reserve Bank
NET-02308	RRA State-Authorized ROEs

I. INTRODUCTION

Q1. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A1. My name is John D. Quackenbush and my business address is 46320 Station Road, New Buffalo, Michigan 49117. I am the President of JQ Resources, LLC.

Q2. HAVE YOU PREVIOUSLY APPEARED AS A WITNESS IN ANY CASES BEFORE THIS COMMISSION?

A2. No, but I have testified as a witness before state regulatory commissions including the Florida Public Service Commission, the Kansas Corporation Commission, the Illinois Commerce Commission, the Missouri Public Service Commission, the Nevada Public Service Commission, the New Jersey Board of Public Utilities, the North Carolina Utilities Commission, the Oregon Public Utility Commission, the South Carolina Public Service Commission, the Tennessee Public Service Commission, and the Public Utility Commission of Texas. Additionally, I have served as the Chairman of the Michigan Public Service Commission and the Chief Financial Analyst of the Illinois Commerce Commission.

A listing of my qualifications is presented as Exhibit No. NET-02301.

Q3. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A3. I am appearing on behalf of the Respondents in this proceeding, a group of New England Transmission Owners (NETOs), to respond to the direct testimony of Dr. Lesser and Dr. Peters filed on behalf of Eastern Massachusetts Consumer-Owned Systems (EMCOS). In particular, my testimony will rebut the erroneous assertions of Dr. Lesser that the existence of DCF model risk is incompatible with the Commission's finding that the Efficient Market Hypothesis is valid. I will demonstrate that the anomalous capital market conditions that prevailed in the time period relevant to this proceeding have not changed from those that the Commission found to be anomalous in Opinion No. 531 and Opinion No. 551.[1] I will also rebut Dr. Peter's assertion that the New England region is in danger of building too much transmission infrastructure and Dr. Peters' recommendation that Dr. Lesser's recommended base ROE of 8.59% should be adjusted downward by 39 basis points to 8.20% due to capital structure issues. I will also explain my view that Dr. Lesser and Dr. Peters misjudge the relative risk of transmission and distribution investments and that vertically integrated electric utility state-authorized ROEs, rather than distribution-only state-authorized ROEs, are the most relevant state-regulated authorized ROEs on which the Commission should focus in this proceeding. In conclusion, I explain why the base returns on equity (ROEs) recommended by Dr. Lesser and Dr. Peters would not provide an adequate return relative to the risks of building electric transmission infrastructure and do not satisfy the requirements of the U.S. Supreme Court's guidance in the *Hope*[2] and *Bluefield*[3] decisions.

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[1] *Coakley v. Bangor Hydro-Elec. Co.*, Opinion No. 531, 147 FERC ¶ 61,234, *order on paper hearing*, Opinion No. 531-A, 149 FERC ¶ 61,032 (2014), *order on reh'g*, Opinion No. 531-B, 150 FERC ¶ 61,165 (2015), *appeals docketed*, *Emera Me. v. FERC*, No. 15-1118 (D.C. Cir. Apr. 30, 2015), *Braintree Elec. Light Dep't v. FERC*, No. 15-1119 (D.C. Cir. May 1, 2015), *Mass. v. FERC*, No. 15-1121 (D.C. Cir. May 1, 2015). *Ass'n of Businesses Advocating Tariff Equity v. Midcontinent Indep. Sys. Operator, Inc.*, Opinion No. 551, 156 FERC ¶ 61,234 (2016), *reh'g pending*.
[2] *FPC v. Hope Natural Gas Co*., 320 U.S. 591 (1944) ("*Hope*").
[3] *Bluefield Water Works & Improvement Co. v. Pub. Serv. Comm'n of W. Va.*, 262 U.S. 679 (1923) ("*Bluefield*").

Q4. WHAT IS THE BASIS FOR YOUR TESTIMONY?

A4. My testimony is based on my 35 years of experience working in the field of utility regulation. My career includes more than four years supporting state utility regulators as a finance staff member of the Illinois Commerce Commission; 14 years performing regulatory and treasury functions in the telecommunications industry for Sprint Corporation partially during the application of utility cost of service regulation to incumbent local exchange carriers and partially during the transition from cost of service regulation to price cap regulation; 11 years in the investment community covering approximately 80 North American companies including regulated utilities, building U.S. and Canadian domestic portfolios, and leading the global utilities team in building global utility portfolios for UBS Global Asset Management (UBS); more than four years regulating utilities as a state utility regulatory commissioner at the Michigan Public Service Commission; and most recently providing consulting services for the last year to participants in regulated utility industries.

In preparing my testimony, I relied on my own knowledge of both U.S. and global financial markets and areas of investment with which the NETOs compete in the capital markets for investor funds. Also, I regularly meet and interact with institutional investors and sell-side security analysts that focus on the utility sector and I continue to monitor how investors currently perceive and evaluate utility investment opportunities and risks.

Q5. WHAT DO YOU MEAN WHEN YOU SAY YOU COVERED 80 NORTH AMERICAN COMPANIES INCLUDING REGULATED UTILITIES AT UBS?

A5. My duties at UBS during 2001 through 2011 included building a five-year forecasted income statement, balance sheet, and cash flow statement for each covered company. The exact number of covered companies varied over time with mergers, acquisitions, and divestitures, but I generally covered approximately 40 regulated electric utilities at any time. I also met regularly with the senior management, customers, suppliers, and regulators of each covered company. During my time at UBS, I directed the investment of significant amounts of client funds in several owners of NETOs, including Northeast Utilities (a predecessor of Eversource Energy and parent of The Connecticut Light and Power Company, Western Massachusetts Electric Company, and Public Service Company of New Hampshire) in the U.S. portfolio, Emera (parent of Emera Maine) in the Canadian portfolio, NextEra Energy and its predecessor FPL Group (owner of New Hampshire Transmission LLC) in the U.S. portfolio, and National Grid (parent of New England Power Company) in the global portfolio.

Q6. WHILE WORKING IN THE TELECOMMUNICATIONS INDUSTRY, WHAT TREASURY DUTIES DID YOU PERFORM THAT ARE RELEVANT TO THE ISSUES IN THIS PROCEEDING?

A6. At Sprint Corporation, during the period from 1995 through 2000, I prepared risk-adjusted cost of capital estimates on a quarterly basis that were used for capital investment, valuation, mergers and acquisitions, Economic Value Added (EVA), and product / service costing analysis across divisions. These risk-adjusted cost of capital estimates varied by division and were utilized as hurdle rates for capital budgeting decisions across the Local, Long Distance, and Wireless Divisions.

Additionally, during 1995 through 2000, I was responsible for managing Sprint's relationships with four rating agencies. In providing the quantitative and qualitative information required by the rating agencies to rate the parent and several separately-rated subsidiaries, I became familiar with how the rating agencies differentiated risk among different companies and subsidiaries of the same company.

II. SUMMARY OF CONCLUSIONS

Q7. PLEASE SUMMARIZE YOUR CONCLUSIONS.

A7. I conclude that the anomalous capital market conditions that the Commission previously found to exist in Opinion No. 531 and Opinion No. 551 still persist. I disagree with the conclusion of Dr. Peters that there has been too much transmission investment in New England. To the contrary, transmission investment in New England occurs under the direction of ISO-NE and only after a rigorous needs and solutions assessment. I also disagree with both Dr. Lesser and Dr. Peters on the relative risk of transmission and distribution investment and concur with the Commission's previous conclusion that transmission investment is more risky than distribution investment. Furthermore, Dr. Peters' proposal to reduce Dr. Lesser's already inadequate recommended base ROE by 39 basis points is inappropriate. Finally, I demonstrate that both Dr. Lesser's and Dr. Peters' base ROE recommendations are grossly inadequate for the NETOs to meet the *Hope* and *Bluefield* standards.

III. ANOMALOUS CAPITAL MARKET CONDITIONS PERSIST

Q8. IN OPINION NO. 531 AND OPINION NO. 551, DID THE COMMISSION REACH ANY FINDINGS THAT ARE RELEVANT TO YOUR TESTIMONY IN THIS PROCEEDING?

A8. Yes. These two opinions contain a number of findings that are relevant to my testimony. With respect to capital market conditions, the Commission stated in Paragraph 142 of Opinion No. 531:

> [W]e conclude that a mechanical application of the DCF methodology with the use of the midpoint here would result in an ROE that does not satisfy the requirements of *Hope* and *Bluefield*. Therefore, based on the record in this case, including the unusual capital market conditions present, we conclude that the just and reasonable base ROE for the NETOs should be set halfway between the midpoint of the zone of reasonableness and the top of the zone of reasonableness.

The Commission continued in paragraph 145 of Opinion No. 531:

> We are concerned that capital market conditions in the record are anomalous, thereby making it difficult to determine the return necessary for public utilities to attract capital. In these circumstances, we have less confidence that the midpoint of the zone of reasonableness established in this proceeding accurately reflects the equity returns necessary to meet the *Hope* and *Bluefield* capital attraction standards. We find it necessary and reasonable to consider additional record evidence, including evidence of alternative benchmark methodologies and state commission-approved ROEs, to gain insight into the potential impacts of these unusual capital market conditions on the appropriateness of using the resulting midpoint.

Turning to Opinion No. 551, the Commission found in paragraph 122:

> Because the evidence in this proceeding indicates that capital market conditions continue to reflect the type of unusual conditions that the Commission identified in Opinion No.

> 531, we remain concerned that a mechanical application of the DCF methodology would result in a return inconsistent with *Hope* and *Bluefield*.

Furthermore, the Commission concluded in paragraph 137 of Opinion No. 551:

> [D]ue to the presence of unusual capital market conditions, we find it appropriate to look to other record evidence to inform the just and reasonable placement of the ROE within the zone of reasonableness produced by the DCF methodology.

Q9. BASED ON YOUR STATE REGULATORY EXPERIENCE, IS WHAT THE COMMISSION DID BY CONSIDERING MULTIPLE ROE METHODOLOGIES AND SETTING THE BASE ROE ABOVE THE MIDPOINT OF A ZONE AT ALL UNUSUAL?

A9. No, it is not. In making ROE decisions, it is typical for regulatory commissions to be confronted with a record consisting of multiple methodologies from multiple witnesses. Amid the plethora of evidence before it, the regulatory commission is charged with considering and weighing all the evidence and determining a specific authorized base ROE. The "weighing" part is challenging and can be different in each commissioner's reasoning, but the task at hand for commissioners is to agree on an authorized base ROE that is within the zone defined by the evidence. There are circumstances that may lead a commission to conclude that the midpoint of the zone is appropriate, but at other times, the weight of the evidence dictates that there is reason to select a different point in the zone. It is not surprising that under certain circumstances, commissions may choose to emphasize a particular methodology while downplaying that same methodology in different circumstances. Similarly, it is not surprising that under certain circumstances, a commission may find that it is appropriate to give more weight to the upper part or even the very top of the zone. Given this perpetual challenge that faces regulatory commissions in general, it is not surprising that the Commission decided to rely on multiple methods and set the base ROE above the midpoint of a zone of reasonableness.

Q10. IN ANOMALOUS MARKET CONDITIONS, SHOULD THE COMMISSION BE CONCERNED ABOUT MODEL RISK?

A10. Yes, it should. Model risk is the risk that a model used to evaluate real-world situations will fail to predict or represent the real phenomenon that is being modeled. For example, the DCF model is often used to estimate the cost of equity. The implementation of the DCF model requires inputs including the dividend yield and the expected growth rate. If a financial analyst implements the DCF model but relies on unusual or anomalous dividend yields or growth rates, the model outputs are unlikely to represent an accurate estimate of the cost of equity.

An ROE recommendation by a witness or an ROE decision by a regulator requires both the application of financial models and the use of informed judgment. An ROE based solely on judgment would be inappropriate, as would be an ROE that relied solely on the mechanical application of theoretical financial models. In my opinion, it is common for regulatory commissions to acknowledge that any theoretical model, no matter how conceptually appealing and well-supported, needs to be supplemented with informed judgment. Commissions are on a constant quest to balance the theoretical with the practical.

Q11. HOW DO INVESTORS VIEW MODEL RISK?

A11. Investors use many valuation approaches, and the traditional DCF methodology is among the most important. However, investors do not have homogeneous expectations. Not all investors use the same tools or inputs. Differing expectations are what result in different investors placing different valuations on the same investment, thus creating a marketplace. I will focus my comments on large institutional investors that are the primary price-determining force in the marketplace, as these large institutional investors tend to engage in more complex, independent analysis than retail investors do. I want to point out, though, that even sophisticated investors do not have homogeneous expectations.

While at UBS, our primary valuation approach incorporated DCF and CAPM methodologies. To enhance investment comparisons across industries, all analysts covering different industries used a specific type of multi-stage DCF model, but I know of other large institutional investors that used different and simpler single-stage or two-stage DCF models. At UBS, analysts initially developed individual cash flow projections for each company generally for the next five years and industry "normal" growth, which by default began in year ten. Years six through ten were modeled as a transition from the company-specific growth rate toward the industry growth rate in year ten. The analysts had discretion to deviate from the default five year initial period and year ten start of the "normal" period in the DCF model if justified by specific circumstances. At UBS, our DCF inputs of expected dividends and expected growth rates were driven largely by the financial modeling we did to forecast income statements, balance sheets, and cash flow statements. I know that my DCF growth rate estimates differed from other investors and often did not match consensus. I also know analysts and investors that give more weight to non-DCF valuation tools. But regardless of model differences and different inputs to the model, investors apply judgment to the results in making investment decisions. Thoughtful investors do not rely exclusively on mechanical application of a single theoretical model. As with regulators, investors are constantly balancing theory and the real world.

Q12. DR. LESSER CRITICIZES COMMISSION FINDINGS ON MODEL RISK FOUND IN OPINION NO. 531 AND OPINION NO. 551. PLEASE COMMENT.

A12. Dr. Lesser quotes from Footnote 286 of Opinion No. 531, which states:

> As the NETOs' witness Lapson testified, "There is 'model risk' associated with excessive reliance or mechanical application of a model when the surrounding conditions are outside the normal range. 'Model risk' is the risk that a theoretical model that is used to value real-world transactions fails to predict or represent the real phenomenon that is being modeled."

Dr. Lesser also quotes from Finding 125 of Opinion No. 551, which states:

> Consistent with Opinion No. 531, we find that the DCF methodology is subject to model risk of providing unreliable outputs in the presence of unusual capital market conditions.

Dr. Lesser takes issue with the Commission's finding that model risk exists. Dr. Lesser attempts to prepare a theoretical critique of model risk and concludes model risk theoretically cannot exist. However, Dr. Lesser completely misses the point that the Commission does not need more theory, but rather, it is concerned, as are investors, with balancing the theoretical and the practical.

Q13. WHAT ARE YOUR VIEWS ON DR. LESSER'S DISCUSSION OF THE EFFICIENT MARKET HYPOTHESIS?

A13. Dr. Lesser postulates a false argument when he asserts that the efficient market hypothesis is repudiated by the FERC's past findings of the existence of model risk and anomalous capital markets conditions. Mechanical application of any model can entail model risk depending on the inputs and the model's ability to reflect reality. Dr. Lesser assumes that theoretical models do not have practical limitations and thus his comments on model risk are ill-informed, as judgment must always be applied to assess how well the mechanical application of a theoretical model reflects the real world.

Model risk exists in the real world, is a practical consideration for both investors and commissions, and does not attack or invalidate the efficient market hypothesis. Mechanically plugging data into a model, no matter how theoretically robust, can result in outputs that do not reflect the real world. Model risk and the lack of a perfect cost of capital model is further evidenced by the continual quest of academics and practitioners to discover new models.

Furthermore, Dr. Lesser's extensive exercise related to the lambda factor fundamentally misses the point that a theoretical model, by definition, is never a true reflection of all the parameters that investors consider when making investment decisions. Any model abstracts from reality and makes simplifying assumptions to get to a practicable result.

Dr. Lesser essentially treats a simplified model as the ultimate truth. Dr. Lesser's lambda exercise ignores the crux of the issue - the Commission intuitively found that outputs of alternative models were deemed more representative of reality than the two-stage DCF model results given prevailing anomalous market conditions.

Q14. DO YOU AGREE WITH THE COMMISSION'S PREVIOUS FINDING ON THE EFFICIENT MARKET HYPOTHESIS?

A14. Yes. The Commission found in paragraph 132 of Opinion No. 551 that:

> The finding that mechanical application of the DCF methodology may produce results inconsistent with *Hope* and *Bluefield* in certain circumstances is not inconsistent with the efficient market theory underlying the typical application of the DCF methodology in normal circumstances.

I agree with the Commission that a finding of anomalous capital market conditions is not inconsistent with the Efficient Market Hypothesis, and I disagree with Dr. Lesser's assertion on this point.

Q15. WHAT LEADS YOU TO CONCLUDE THAT THE ANOMALOUS CAPITAL MARKET CONDITIONS RECOGNIZED BY THE COMMISSION IN OPINION NO. 531 AND OPINION NO. 551 ARE STILL IN EFFECT?

A15. In response to the global financial crisis of 2008, the U.S. Federal Reserve Bank and other global central banks began a massive monetary stimulus program in late 2008 / early 2009 that created and have perpetuated anomalous capital market conditions. According to the Federal Reserve Bank of New York Staff Report No. 441 entitled "Large Scale Asset Purchases by the Federal Reserve: Did They Work?" dated March 2010, the Federal Reserve Bank's traditional policy instrument, the target federal funds rate, had effectively been driven to its lower bound of zero. In order to further ease the stance of monetary policy as the economic outlook deteriorated, the Federal Reserve Bank purchased massive quantities of assets with medium and long maturities. These purchased securities are reported on the Federal Reserve Bank balance sheet as "Securities Held Outright." These purchases led to significant and long-lasting reductions in longer-term interest rates on a range of securities, including securities that were not included in the purchase programs. Many other countries faced the same policy dilemma, making the impact global.

Janet Yellen, Chair of the Board of Governors of the Federal Reserve System, confirmed in a speech on March 3, 2017:

> [O]nce the Committee had cut the federal funds rate to near zero in late 2008, it became necessary to deploy new tools to supply the considerable monetary accommodation required by the extremely weak state of the job market and persistently low inflation. Those tools—especially our large-scale securities purchases and increasingly forward guidance pertaining to the likely future path of the federal funds rate—enabled the Federal Reserve to provide necessary additional support to the U.S. economy by pushing down longer-term interest rates and easing financial conditions more generally.[4]

Chair Yellen continued by mentioning that the Federal Reserve Bank completed its latest round of large-scale asset purchases, sometimes referred to as quantitative easing, or QE, in 2014. The Federal Open Market Committee (FOMC) then issued a set of "normalization principles" that indicated its intention "to maintain the overall size of the Federal

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[4] Janet L. Yellen, Chair, Bd. of Governors of Fed. Reserve Sys., From Adding Accommodation to Scaling It Back (Mar. 3, 2017), https://www.federalreserve.gov/newsevents/speech/yellen20170303a.htm.

Reserve's balance sheet at an elevated level until sometime after the FOMC had begun to raise its target for the federal funds rate." Chair Yellen's March 3, 2017 speech contained footnote 9 that explained:

> Large Federal Reserve holdings of longer-term securities reduce the total amount of such securities available for purchase by the public, exerting upward pressure on their prices and, thus, depressing their yields and contributing to lower borrowing costs for American families and businesses.

U.S. and global financial markets continue demonstrably to exhibit the effects during the relevant Complaint IV period of a massive exercise of monetary policy which has produced anomalous capital market conditions. This anomaly impacts monetary aggregates, interest rates, and the valuation of financial assets due to the significant and unprecedented amount of monetary stimulus that has been applied by the U.S. Federal Reserve Bank and other global central banks including the European Central Bank, the Bank of Japan, the Bank of England, the Swiss National Bank, and the Bank of Canada.

U.S. and global interest rates and financial markets remain subject to powerful and unprecedented monetary policy actions by the Federal Reserve Bank and other global central banks that continue to affect capital market conditions during the refund period of this proceeding beginning on April 29, 2016 and during the time periods utilized by Dr. Lesser and NETOs' Witness McKenzie for their DCF analyses in this proceeding. The abnormal capital market conditions include very low U.S. and global long-term and short-term interest rates and monetary supply significantly in excess of its normal use. The anomaly is evident in unusually low U.S. Treasury bond yields and utility bond yields.

Besides very low interest rates, a hugely significant component of the monetary stimulus has been quantitative easing, or the ramp up and maintenance of an unprecedented $4.2 trillion level of U.S. Treasuries and mortgage-backed securities purchased and held outright by the Federal Reserve Bank. Dr. Lesser focuses his comments solely on low interest rates and downplays the impact of the massive amount of Treasury and mortgage-backed securities held outright by the Federal Reserve Bank.

Q16. WHAT ARE THE IMPORTANT TIME PERIODS OF THIS PROCEEDING?

A16. The FERC has set a refund effective date of April 29, 2016 for this complaint. The refund period is therefore from approximately May 2016 through July 2017. In addition, Dr. Lesser has used a DCF analysis period of July 1, 2016 to December 31, 2016. NETOs' Witness McKenzie has utilized a DCF analysis period of September 2016 to February 2017. Both witnesses are using DCF study periods during the refund period. Prospective rates from this proceeding will be effective upon the Commission's decision in this proceeding, likely in mid-2018. Anomalous market conditions have existed during the refund period to date and continue. I cannot predict with certainty the market conditions that will exist in mid-2018 and beyond, but there have been no indications at this time that the Federal Reserve plans to sell the $4.2 trillion of securities it currently holds, even if there may be several more increases in the federal funds rate by mid-2018.

Q17. PLEASE DESCRIBE CURRENT U.S. INTEREST RATE LEVELS.

A17. Despite recent increases from record lows, interest rates are still extraordinarily low. I draw this conclusion after comparing short-term and long-term U.S. and global interest rates.

The federal funds rate is an important benchmark in financial markets and is the primary policy tool of the Federal Reserve Bank. The federal funds effective rate is the interest rate at which depository institutions lend to each other overnight. The Federal Open Market Committee (FOMC) establishes the federal funds target rate and then the Federal Reserve Bank uses open market operations to influence the U.S. money supply to ensure that the federal funds effective rate follows the federal funds target rate. A time series of the federal funds effective rate since 1954 is shown on Exhibit No. NET-02302. The current federal funds effective rate is low at 0.66% as of February 28, 2017. By comparison, the federal funds effective rate ranged from 4.24% to 5.26% during the pre-crisis base period of 2006 to 2007; 0.14% to 0.16% during the Opinion No. 531 study period of October 1, 2012 to March 31, 2013; 0.07% to 0.12% during the Opinion No. 551 study period of November 12, 2013 to February 11, 2015; and 0.37% to 0.66% during the refund period to date of this proceeding, April 29, 2016 to February 28, 2017. When observers say that the FOMC is expected to raise interest rates three times during 2017, three times during 2018, and three times during 2019, it is the target federal funds rate to which they refer. On March 15, 2017, the FOMC decided to raise the target federal funds rate 25 basis points to a range of 0.75% to 1.00%. The Committee disclosed in a press release that "the federal funds rate is likely to remain, for some time, significantly below levels that are expected to prevail in the longer run." Changes in the federal funds rate have a direct influence on short-term market interest rates and a limited influence on long-term market interest rates.

A frequently cited short-term market interest rate is the yield on one-month U.S. Treasury securities. One-month U.S. Treasury yields are low at 0.40% as of February 28, 2017. A time series of one-month U.S. Treasury yields since July 2001 is shown on Exhibit No. NET-02303, along with ten-year U.S. Treasury yields. By comparison, one-month U.S. Treasury yields ranged from 2.42% to 5.27% during the pre-crisis base period of 2006 to 2007; 0.00% to 0.17% during the Opinion No. 531 study period of October 1, 2012 to March 31, 2013; 0.00% to 0.13% during the Opinion No. 551 study period of November 12, 2013 to February 11, 2015; and 0.09% to 0.53% during the portion of the refund period to date of this proceeding from April 29, 2016 through the end of February 2017.

A frequently cited long-term market interest rate is the yield on ten-year U.S. Treasury securities. Ten-year U.S. Treasury yields are low at 2.36% as of February 28, 2017. A time series of ten-year U.S. Treasury yields since January 1962 is shown on Exhibit No. NET-02304, as well as since July 2001 on Exhibit No. NET-02303. By comparison, ten-year U.S. Treasury yields ranged from 3.83% to 5.26% during the pre-crisis base period of 2006 to 2007; 1.58% to 2.07% during the Opinion No. 531 study period of October 1, 2012 to March 31, 2013; 1.68% to 3.04% during the Opinion No. 551 study period of November 12, 2013 to February 11, 2015; and 1.37% to 2.60% during the refund period to date of this proceeding, April 29, 2016 to February 28, 2017.

Moody's Baa-rated utility bond yields are low at 4.58% as of February 2017. A time series of Moody's Baa-rated utility bond yields since January 1968 is shown on Exhibit No. NET-02305. By comparison, Moody's Baa-rated utility bond yields ranged from 6.04% to 6.61% during the pre-crisis base period of 2006 to 2007; 4.51% to 4.74% during the Opinion No. 531 study period of October 1, 2012 to March 31, 2013; 4.39% to 5.25% during the Opinion No. 551 study period of November 12, 2013 to February 11, 2015; and 4.16% to 5.28% during the refund period to date of this proceeding, April 29, 2016 to February 28, 2017.

Q18. PLEASE DESCRIBE GLOBAL INTEREST RATE LEVELS AND HOW THEY RELATE TO U.S. INTEREST RATES.

A18. Many countries have short-term and long-term interest rates significantly lower than the U.S., due to intervention by global central banks that have, in many ways, paralleled that of the U.S. Federal Reserve Bank. A time series of global interest rates for five key countries is shown on Exhibit No. NET-02306. As of February 2017, the short-term yield on government securities was 0.88% in Canada, negative 0.33% in Germany, 0.34% in the United Kingdom, 0.06% in Japan, and negative 0.73% in Switzerland. The yields all fell precipitously in 2008 except for Japan, which experienced anomalous capital market conditions earlier than the other countries, as shown on page 1 of Exhibit No. NET-02306. Short-term central bank interest rates hovering near zero include 0.00% at the Bank of Japan and 0.00% at the European Central Bank. Negative interest rates are unsustainable and indicate that investors are paying for the privilege of holding government debt. In the U.S., as can be seen from Exhibit NET-02303, the one-month U.S. Treasury yield scraped down to 0.00% for several days at several times between December 2008 and October 2015, but never fell negative.

Likewise, as of February 2017, the ten-year yield on government securities was 1.71% in Canada, 0.26% in Germany, 1.31% in the United Kingdom, 0.08% in Japan, and negative 0.21% in Switzerland, as shown on page 2 of Exhibit No. NET-02306. The negative ten-year government yield in Switzerland is especially notable. Negative interest rates on ten-year government securities are even more anomalous and unsustainable than negative interest rates on short-term government securities.

Global interest rates even lower that U.S. interest rates motivate foreign investors to invest in U.S. securities. The capital marketplace is globally competitive. These extraordinarily low global interest rates help explain why global investors are attracted to U.S. debt and dividend-paying equities and further show the persistence of anomalous capital market conditions in the U.S. and globally.

Q19. PLEASE SUMMARIZE THE INTEREST RATES THAT YOU HAVE DISCUSSED.

A19. The following table summarizes some relevant interest rate comparisons. For comparison purposes, I began with a pre-crisis base period of 2006 to 2007. I also show the interest rate that prevailed during the Opinion No. 531 and Opinion No. 551 study periods. Finally, I show interest rates that have existed during the relevant refund period of this proceeding to date along with the most recent rates available at the time I prepared my testimony.

INTEREST RATE TABLE

(% per annum)

Interest Rates	Pre-Crisis 2006 to 2007	531 Study Period 10-1-12 to 3-31-13	551 Study Period 11-12-13 to 2-11-15	Refund Period To Date 4-29-16 to 2-28-17	Recent 2/28/2017
U.S. Interest Rates					
Federal Funds Effective Rate	4.24 to 5.26	0.14 to 0.16	0.07 to 0.12	0.37 to 0.66	0.66
One-Month US Treasury Yield	2.42 to 5.27	0.00 to 0.17	0.00 to 0.13	0.09 to 0.53	0.40
Ten-Year US Treasury Yield	3.83 to 5.26	1.58 to 2.07	1.68 to 3.04	1.37 to 2.60	2.36
Moody's Baa Utility Yield	6.04 to 6.61	4.51 to 4.74	4.39 to 5.25	4.16 to 5.28	4.58
Global Short-Term Governments Yields					
Germany	2.51 to 4.85	0.19 to 0.22	0.05 to 0.33	-0.33 to -0.25	-0.33
Japan	0.10 to 0.87	0.25 to 0.33	0.17 to 0.22	0.06 to 0.06	0.06
Canada	3.62 to 5.12	1.16 to 1.16	0.89 to 1.19	0.81 to 0.88	0.88
United Kingdom	4.52 to 6.58	0.49 to 0.54	0.50 to 0.55	0.34 to 0.57	0.34
Switzerland	1.02 to 2.90	0.01 to 0.03	-0.85 to 0.02	-0.78 to -0.73	-0.73
Global Ten-Year Governments Yields					
Germany	3.32 to 4.56	1.30 to 1.54	0.30 to 1.80	-0.15 to 0.26	0.26
Japan	1.50 to 1.96	0.49 to 0.78	0.28 to 0.69	-0.24 to 0.08	0.08
Canada	3.98 to 4.61	1.74 to 1.97	1.38 to 2.67	1.04 to 1.73	1.71
United Kingdom	4.08 to 5.43	1.77 to 2.18	1.59 to 2.95	0.74 to 1.57	1.31
Switzerland	2.15 to 3.19	0.53 to 0.79	-0.07 to 1.25	-0.54 to -0.07	-0.21

This table demonstrates that U.S. and global interest rates to date continue to be extremely, unusually, and anomalously low. Refund period interest rates are similar to or lower than interest rates during the Opinion No. 531 and Opinion No. 551 study periods and are significantly lower than interest rates observed during the pre-crisis base period of 2006 to 2007.

Q20. PLEASE DESCRIBE THE OTHER SIGNIFICANT COMPONENT OF THE U.S. FEDERAL RESERVE BANK'S EXTREME MONETARY POLICY: THE SECURITIES PURCHASED AND

HELD OFF OF THE OPEN MARKET BY THE FEDERAL RESERVE BANK.

A20. The balance of Federal Reserve Bank securities held outright is still massive at $4.2 trillion. A time series of securities held outright since 2002 is shown on Exhibit No. NET-02307. The massive Federal Reserve Bank purchases of securities during 2009 to 2014 is often referred to as quantitative easing (QE) and consists primarily of longer-term U.S. Treasury and mortgage-backed securities. The massive balance of securities held outright is a huge overhang on the Federal Reserve Bank balance sheet. The $4.2 trillion balance has been maintained since 2014 by the reinvestment of interest and principal payments. The March 15, 2017 Federal Reserve press release stated: "The Committee is maintaining its existing policy of reinvesting principal payments from its holdings of agency debt and agency mortgage-backed securities in agency and mortgage-backed securities and of rolling over maturing Treasury securities at auction, and it anticipates doing so until normalization of the level of the federal funds rate is well under way. This policy, by keeping the Committee's holdings of longer-term securities at sizable levels, should help maintain accommodative financial conditions."

This policy of maintaining massive amounts of securities held outright on the Federal Reserve Bank balance sheet indicates that anomalous capital market conditions will persist even after several increases in the federal funds target rate.

Q21. DO YOU HAVE ANY INDICATION OF HOW LOW U.S. INTEREST RATES MIGHT HAVE GONE IF THE FEDERAL RESERVE BANK

DID NOT PURCHASE THE MASSIVE AMOUNTS OF SECURITIES HELD OUTRIGHT?

A21. On February 9, 2017, Dr. Charles Evans, President of the Federal Reserve Bank of Chicago and member of the Federal Open Market Committee made a presentation to the CFA Society of Chicago entitled "Risk Management in a Low Interest Rate Environment." During the presentation, Dr. Evans indicated that the U.S. Federal Reserve Bank desired to avoid negative interest rates in the U.S. like those that were being experienced due to central bank monetary intervention in other global markets. The Federal Reserve Bank's massive purchases of long-term securities were an attempt to continue flooding the economy with liquidity instead of permitting interest rates to go negative, while more directly influencing long-term interest rates. Dr. Evans also indicated that, in his view, the level of negative interest rates needed to provide the Federal Reserve Bank's desired level of economic stimulus was negative 4.0%. In other words, the Federal Reserve's desired monetary stimulus was equivalent to negative interest rates at the level of negative 4.0%, but the Federal Reserve Bank found negative interest rates unpalatable to the U.S. economy. Instead, the Federal Reserve Bank achieved its desired level of economic stimulus by maintaining slightly positive interest rates and pursuing the unprecedented massive security purchases that grew the Federal Reserve Bank's securities balance from $0.5 trillion in 2008 to the $4.2 trillion it is today. This is evidence of the extraordinary lengths gone to by the Federal Reserve and why anomalous capital market conditions resulted. This is also evidence that anomalous market conditions are unlikely to disappear immediately just because short-term interest rates such as the federal funds rate and the one-month Treasury yield, are observed to be increasing. It will also be necessary to see evidence that the massive balance sheet overhang is eliminated. On February 9, 2017, Dr. Evans also mentioned that equilibrium interest rates are likely to be lower than they have been in the past. He cites a recent study that indicates that the effective real federal funds rate today is 325 basis points lower than the average in the 1970s, 1980s, and 1990s. He continues by observing that current forecasts of the equilibrium federal funds rate, including those of the FOMC, would imply a 250 basis point increase to get to equilibrium.

Q22. WHEN THE TIME COMES, HOW WILL THE FEDERAL RESERVE BANK LIKELY BEGIN REDUCING THE $4.2 TRILLION BALANCE OF SECURITIES HELD OUTRIGHT?

A22. The Federal Reserve Bank currently maintains the high balance of securities holdings by reinvesting interest payments and maturities into the purchase of new long-term securities. The Fed will likely begin to gradually reduce the $4.2 trillion balance by stopping the reinvestment of interest payments and maturities into new securities. When this reinvestment ceases, the massive balance sheet overhang will begin a gradual reduction.

Q23. HAS THE FEDERAL RESERVE BANK YET BEGUN TO CEASE THE REINVESTMENT OF INTEREST PAYMENTS AND MATURITIES?

A23. No.

Q24. WHEN MIGHT THE REINVESTMENT CEASE?

A24. On February 9, 2017, Dr. Evans indicated that, in his opinion, the Federal Reserve Bank may hike the federal funds rate three times per year for the next three years, and that the Federal Reserve Bank would be unlikely to entertain the notion of ceasing reinvestment until at least two or three more interest rate hikes occur.

Q25. WHAT OTHER EVIDENCE OF ANOMALOUS CAPITAL MARKET CONDITIONS EXIST?

A25. Dr. Lesser's Exhibit No. EMC-7 provides ample evidence that anomalous capital market conditions persist. Exhibit No. EMC-7 is a Client Alert from Duff & Phelps entitled "Duff & Phelps Increases U.S. Equity Risk Premium Recommendation to 5.5%, Effective January 31, 2016." I am not making a market risk premium recommendation in this proceeding and, as such, I do not endorse the Duff & Phelps market risk premium recommendation, but its client alert is instructive in acknowledging the prevalence of anomalous capital market conditions. This Duff & Phelps client alert recommends that a normalized risk-free rate of 4.0% be used in a CAPM analysis rather than a spot risk-free rate of 2.4%. The difference of 160 basis points is Duff & Phelps' estimated impact of anomalous capital market conditions. Duff & Phelps provides an extensive explanation of anomalous capital market conditions on page 9 through 33 of Exhibit No. EMC-7. The key point is summarized on page 31 of the Client Alert:

> As stated earlier, in most circumstances we would prefer to use the "spot" yield on U.S. government bonds available in the market as a proxy for the U.S. risk-free rate. However, during times of flight to quality and/or high levels of central bank intervention, those lower observed yields imply a lower cost of capital (all other factors held the same) – just the opposite of what one would expect in times of relative

> economic distress – so a "normalization" adjustment may be considered appropriate. By "normalization" we mean estimating a rate that more likely reflects the sustainable average return of long-term risk-free rates. *If spot yield-to-maturity were used at these times, without any other adjustments, one would arrive at an overall discount rate that is likely inappropriately low vis-à-vis the risks currently facing investors.*

Duff & Phelps concludes that mechanistic ROE calculations determined in the manner that Dr. Lesser advocates are likely to be inappropriately low vis-à-vis the risk currently facing investors. Duff & Phelps' recommended normalization is remarkably conceptually similar to this Commission's findings of anomalous capital market conditions and the decision to deviate from the DCF midpoint in Opinion No. 531 and Opinion No. 551.

Q26. PLEASE SUMMARIZE YOUR VIEW OF ANOMALOUS CAPITAL MARKET CONDITIONS.

A26. The Commission found that the conditions I describe above produced anomalous capital market conditions in Opinion No. 531 and Opinion No. 551. For all the reasons discussed above, the Commission's conclusions in those Opinions have applied since the beginning of the refund period in this Complaint IV and still apply today.

Q27. WHEN DO YOU ANTICIPATE THAT ANOMALOUS CAPITAL MARKET CONDITIONS CAUSED BY EXTREME MONETARY POLICY WILL BE OVER?

A27. I expect that there will come a day when the anomalous market conditions caused by extreme monetary policy will unwind and the extreme monetary policy will no longer have the distorting impact on capital market pricing that it does today. In my opinion, the evidence of this happening will consist of all of the following: (1) short-term interest rates rise significantly to a more normal level; (2) long-term interest rates rise significantly to a more normal level; (3) the Federal Reserve Bank discontinues rolling over interest payments on and maturities of its securities held outright; and (4) the Federal Reserve Bank sells on the open market most, if not all, of its $4.2 trillion securities held outright. None of these four events has happened yet, and there is no evidence that they will happen in the near future.

Q28. WHEN THE ANOMALOUS CONDITIONS CURRENTLY PRESENT IN THE CAPITAL MARKETS ARE RESOLVED, DO YOU BELIEVE IT WOULD BE APPROPRIATE FOR THE COMMISSION TO RELY SOLELY ON THE RESULTS OF A SINGLE DCF METHOD TO EVALUATE A FAIR ROE?

A28. No. As I noted earlier, no single methodological approach can be considered a wholly reliable indicator of investors' required return. In my experience, it is common practice for regulators to consider the results of alternative methods, along with their assessment of the merits of each approach, in arriving at a just and reasonable ROE that meets the requirements of regulatory standards.

IV. THE NETOS' EXPANSION OF THE NEW ENGLAND TRANSMISSION GRID IS CONSISTENT WITH PUBLIC POLICY AND SUBJECT TO THOROUGH REVIEW

Q29. DO YOU AGREE WITH DR. PETERS' CONCERN THAT THE NEW ENGLAND REGION IS IN DANGER OF BUILDING TOO MUCH TRANSMISSION?

A29. No, not at all. Transmission projects in New England are a result of a rigorous ISO New England (ISO-NE) planning process designed to ensure that system upgrades necessary to meet appropriate reliability standards are constructed. These reliability standards include those of North American Electric Reliability Corporation (NERC) and the Northeast Power Coordinating Council (NPCC). The ISO-NE-led planning process may be thought of in two distinct phases with the first being the "needs" phase and the second being the "solutions" phase. The initial needs assessment evaluates the transmission system's performance against mandatory national and regional standards (NERC and NPCC) and if performance deficiencies are found, then a solution study is initiated. The solution study includes development and evaluation of a comprehensive list of mitigating alternatives, of which one ultimately is recommended as "preferred" to ISO-NE stakeholders.

It is important to note that throughout the entire process, New England stakeholders are given multiple opportunities to provide input and feedback both to the transmission owner and to ISO-NE staff. In addition, at any time throughout the needs or solutions phase, ISO-NE can, and has, declared the need to re-assess the study needs or solutions as a result of material forecasted system changes; for example, generation additions and retirements, and load forecast updates. This continual re-assessment of needs and solutions throughout the study process ensures that only justified transmission upgrades are constructed. Since May 2015, ISO-NE's Open Access Transmission Tariff provides for competitive solicitations to determine solutions. Nevertheless, the ISO-NE process remains rigorous and focused on adherence to mandatory national and regional standards.

While serving as Chairman of the Michigan Public Service Commission, I was familiar with the MISO and PJM transmission planning processes, as different Michigan regions participate in MISO or PJM. I observe that the ISO-NE transmission planning process shares many positive attributes of the rigorous MISO and PJM planning processes.

Most industry observers, including regulators and investors, are rightly concerned about the implications of too little energy infrastructure, including electric transmission in New England. As New England pursues additional renewable and low carbon energy sources, sufficient new transmission infrastructure must be built to allow access to those new resources.

Q30. HAVE CONGRESS AND THIS COMMISSION ENCOURAGED THE DEVELOPMENT OF TRANSMISSION?

A30. Yes, they have. Congress passed the Energy Policy Act of 2005 that set forth several statutory requirements intended to support transmission investment. The Commission, through a 2012 Policy Statement, reaffirmed its pricing reform encouraging transmission investment through incentive rate treatments to assist in mitigating the risks associated with developing, constructing, operating, and maintaining transmission infrastructure. The Commission also enabled regional and interregional coordination processes and supporting cost recovery processes through Order 1000.

Dr. Peters offers no compelling reason for Congress and the Commission to abandon their support for enhancement and expansion of transmission infrastructure. Transmission remains the smallest percentage of electricity costs when compared to distribution and generation costs. Only 11% of the average U.S. price of electricity results from the costs of transmission services.[5] Recently, the American Society of Civil Engineers (ASCE) released its 2017 Infrastructure Report Card. Using the simple "A to F" school report card format, the ACSE assigns a "D+" to energy infrastructure. Specific to transmission infrastructure, ASCE states:

> Much of the U.S. energy system predates the turn of the 20th century. Most electric transmission and distribution lines were constructed in the 1950s and 1960s with a 50-year life expectancy, and the more than 640,000 miles of high-voltage transmission lines in the lower 48 states' power grids are at full capacity. Energy infrastructure is undergoing increased investment to ensure long-term capacity and sustainability; in 2015, 40% of additional power generation came from natural gas and renewable systems. Without greater attention to aging equipment, capacity bottlenecks, and increased demand, as well as increasing storm and climate impacts, Americans will likely experience longer and more frequent power interruptions.[6]

Specific to New England, the New England States Committee on Electricity (NESCOE) recently studied the impact of the clean energy policy goals of the New England states on transmission needs. The NESCOE-sponsored report concluded that, if new transmission build is limited only to reliability-related upgrades that are currently in progress, "the region is forecast to be under-supplied with Renewable Energy

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[5] *Annual Energy Outlook 2017*, U.S. Energy Information Administration, January 2017, Table 8.

[6] *2017 Infrastructure Report Card, Energy Overview*, American Society of Civil Engineers, http://www.infrastructurereportcard.org/wp-content/uploads/2017/01/Energy-Final.pdf.

Certificates (REC) relative to Renewable Portfolio Standard (RPS) targets" by 10.5% in 2025 and by 17.0% in 2030.[7] It is clear that more transmission is needed to achieve the New England states' RPS and other clean energy requirements.

V. SHORTCOMINGS OF DR. LESSER'S AND DR. PETERS' ANALYSIS

A. Dr. Lesser and Dr. Peters Misjudge the NETOs' Risks, Particularly in Comparison to Distribution Investment

Q31. DO YOU AGREE WITH DR. PETERS' CONCLUSION THAT TRANSMISSION INVESTMENT IS LESS RISKY THAN DISTRIBUTION INVESTMENT?

A31. No, Dr. Peter's views are contrary to investors' views and directly challenge the findings of the Commission in Opinion No. 531 and Opinion No. 551.

On page 16 of Exhibit EMC-12, Dr. Peters lists 13 sources of risk and makes the blanket conclusion that the magnitude of each risk does not differ between transmission and distribution. However, at least four of his enumerated risks differ markedly between transmission and distribution, including permitting risk, cost overrun risk, schedule delays, and local opposition to construction. Transmission projects are larger and have a longer lead time to construction than distribution projects. Permitting requirements for transmission projects are more significant and provide more opportunities for local opposition to construction than distribution projects. The larger size and longer lead time of transmission projects contribute to higher risk of cost overruns and schedule delays.

[7] *Renewable and Clean Energy Scenarios and Mechanisms 2.0 Study Base Case Results*, New England States Committee on Electricity, November 17, 2016.

Q32. DR. PETERS OPINES THAT THERE IS A "GUARANTEE" THAT THE NETOS WILL EARN THEIR AUTHORIZED ROE. DO YOU AGREE?

A32. No, I do not. There is no guarantee that the NETOs will earn their authorized ROE on transmission investment. Under the Commission's abandoned plant precedent, there is a risk that the NETOs may spend considerable sums developing projects that are never placed in service, yet not fully recover their costs. This Commission's Order 1000 contemplates that the NETOs could propose transmission projects in competitive solicitations and if not selected, the NETOs would not recover the associated development costs.

Q33. DR. LESSER APPEARS TO CONCLUDE THAT DISTRIBUTION INVESTMENTS ARE MORE RISKY THAN TRANSMISSION INVESTMENTS BECAUSE THE INTRODUCTION OF DISTRIBUTED ENERGY RESOURCES MAKES THE DISTRIBUTION GRID OBSOLETE AND THUS MORE RISKY. DO YOU AGREE?

A33. No, I do not. The distribution grid is ripe with investment opportunities due to the growth of distributed energy resources. As a result, the distribution grid needs to become even more robust and vibrant with investments in smart meters and sensors to enable the growth of distributed energy resources. Distributed energy resource owners are reliant on the distribution grid for the two-way flow of electricity. Also, the distribution grid relies upon the transmission grid for its own reliability and to ensure a reliable supply of energy. The growth of distributed energy resources does not place the distribution grid or the transmission grid in danger of becoming irrelevant.

Q34. WHAT HAS THE COMMISSION PREVIOUSLY CONCLUDED ABOUT THE RELATIVE RISK OF TRANSMISSION AND DISTRIBUTION INVESTMENT?

A34. The Commission, in Opinion No. 531, properly recognized that transmission investment is riskier than distribution investment. In fact, the Commission found in paragraph 149 of Opinion No. 531 that state-regulated electric distribution has lower business risks than electric transmission investment.

Some of the risks that the Commission noted for electric transmission are:

> For example, investors providing capital for electric transmission infrastructure face risk including the following: long delays in transmission siting, greater project complexity, environmental impact proceedings, requiring approval from multiple jurisdictions overseeing permits and rights of way, liquidity risk from financing projects that are large relative to the size of the balance sheet, and shorter investment history. We find that these factors increase the NETOs' risk relative to the state-regulated distribution companies.

Several of these transmission risks identified by the Commission have clear parallels to electric generation risks but not distribution risks, including the potential for long delays, greater project complexity, the burdensome impact of environmental regulations, multiple jurisdictions overseeing siting, environmental compliance decisions, and financing projects that are large relative to the size of the corporate balance sheet.

Nothing has changed to reverse the Commission's previous conclusion that transmission investment is riskier than distribution investment.

Q35. HOW DO INVESTORS PERCEIVE THE THREAT OF PANCAKED ROE COMPLAINTS TO IMPACT THE RELATIVE RISK OF TRANSMISSION?

A35. Investors perceive that the prospect of never-ending pancaked ROE complaints heightens both the risk of transmission investment and transmission's relative risk to distribution. For example, Value Line provides an example of the filing of an ROE complaint that caused an immediate 6% stock price drop for a transmission provider.[8] NETOs' Witness McKenzie cites a Wolfe Research report that observes that "pancaking of ROE challenges against the same transmission owners" represented one of the "real risks" to investors in transmission.[9] Moreover, a recent research note from UBS, in discussing the Commission's Final Order in the first MISO ROE complaint (EL14-12-002), stated "it's notable a third subsequent pancaked case has not been filed, a positive in our view."[10] It is clear that pancaked ROE complaints increase the risk associated with transmission investment.

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[8] The Value Line Investment Survey, ITC Holdings Corp., December 20, 2013.
[9] Wolfe Research, *Don't you FERCedabout ROE, Don't Don't Don't Don't!*, Utilities & Power (Apr. 6, 2015).
[10] *FERC Affirms the MISO Win*, UBS Global Research, September 29, 2016, at 1.

B. Capital Structure Differences Should Not Be Used to Reduce the Understated Base ROE Recommendation of Dr. Lesser

Q36. DO YOU AGREE WITH DR. PETERS' PROPOSAL TO REDUCE THE BASE ROE BY 39 BASIS POINTS TO ACCOUNT FOR CAPITAL STRUCTURE DIFFERENCES BETWEEN THE NETOS AND THE PROXY GROUP?

A36. No, I do not. To begin with, Dr. Peters' vague academic references about optimal capital structure do not offer any empirical evidence to pinpoint one. In the real world of practical corporate finance, academic theoretical references are interesting and may provide a helpful guide but do not provide a useful tool to fine tune a company's capital structure. Dr. Peters ignores real-world practical corporate financial realities.

A utility must be permitted latitude in managing capital structure ratios. Since there is no practical methodology to pinpoint theoretically optimal capital structure ratios, targeted ratios can only be broadly conceptualized. Appropriate ratios may shift over time as capital market conditions or business risk characteristics change. Additionally, the timing of upcoming issuances and maturities may influence the capital structure ratios because both the size and frequency of issuances are affected by the relative cost-effectiveness of various issuance increments. Treasury professionals need an adequate degree of flexibility to perform their duties. Given these practical considerations, capital structure ratios cannot be deemed to be inappropriate unless the ratios significantly diverge from sound industry practice and cause a lack of financial flexibility that may lead to higher overall costs. As Dr. Peters shows on his Figure 4 entitled "Least Cost Capital Structure" on page 22 of Exhibit No. EMC-12, the

Weighted Average Cost of Capital curve is shaped like a very shallow dish such that large variances in capital structure ratios lead to minimal change in overall costs.

Moreover, the Commission's proxy group selection criteria are meant to determine companies of comparable risk. The Commission has chosen to exclude capital structure as an explicit factor when determining the comparable risk proxy group. The Commission does include credit ratings in its criteria, and the credit rating agencies evaluate capital structure among other risk factors when determining credit ratings. As a result, the impact of capital structure is already included in the Commission's proxy group selection criteria. Dr. Peter's proposed adjustment would be redundant and is clearly inappropriate.

In Opinion No. 551, the Commission affirmed that it has never encouraged utilities to feature more debt in their capital structure and found that it would be inappropriate to encourage additional debt leveraging of utilities, many of which are undertaking large investments or do not have high credit ratings. The Commission points out in paragraph 286:

> [Complainants] seek a risk adjustment based upon a single factor, an alleged equity-rich capital structure, without consideration of any other risk factor. This is contrary to Commission policy.

Further, the Commission realized the redundant nature of this capital structure adjustment in paragraph 288:

> In any event, Complainants' position fails to take into account the fact that our criteria for selecting members of the proxy group are intended to produce a proxy group make up of companies of similar risk. Those criteria include screens to ensure that the proxy group contains only utilities with similar credit ratings to the utility at issue. . . . Consequently,

> additional reductions to the ROEs that are proposed by Complainants essentially reduce the ROE twice for featuring equity-rich capital structures.

Finally, the Commission concluded in paragraph 289:

> Furthermore, as a policy matter, the Commission does not directly incentivize utilities to adjust their preferred capital structures. The Commission has not previously directly encouraged utilities to feature more debt in their capital structure. We find that it would be inappropriate to encourage additional debt leveraging of utilities, many of which are undertaking large investments or do not have high credit ratings.

Dr. Peters' recommendation that the Commission depart from its well-conceived policy stance on capital structure is ill-advised and should be rejected.

C. Dr. Lesser's and Dr. Peters' Base ROE Recommendations Are Inadequate

Q37. WILL THE BASE ROES RECOMMENDED BY DRS. LESSER AND PETERS PROVIDE INVESTORS WITH A RETURN COMMENSURATE WITH THE ASSOCIATED RISK AND ATTRACT NEW CAPITAL TO TRANSMISSION INVESTMENT?

A37. No, the base ROEs of 8.59% recommended by Dr. Lesser and 8.20% recommended by Dr. Peters are way too low to attract investors to provide capital for electric transmission investments. Coming so soon after Opinion No. 531 in which the Commission established a base ROE of 10.57% and potential decisions in the second and third complaints, investors would react with surprise and alarm if the Commission determined a base ROE in this proceeding consistent with either Dr. Lesser's or Dr. Peters' recommendations. Measured against the Opinion

No. 531 authorized base ROE of 10.57%, their proposed decreases are in the range of 198 to 237 basis points and are even larger than the 175 basis point differential between the then-current authorized base ROE and the midpoint of the mechanically-applied DCF methodology that troubled the Commission in paragraph 150 of Opinion No. 531. An ROE consistent with either Dr. Lesser's or Dr. Peters' recommendations would discourage investment in transmission projects, and would have a chilling effect on all FERC-jurisdictional transmission providers, discouraging new capital investments in transmission assets.

Q38. HOW WOULD THE BASE ROES PROPOSED BY DRS. LESSER AND PETERS IMPACT THE NETOS' ABILITY TO COMPETE FOR CAPITAL IN THE GLOBAL INVESTMENT MARKETS?

A38. U.S. electric transmission investments compete in the financial market with other sectors and other geographies, including utilities and non-utility businesses. The most directly comparable sector is the state-regulated electric utility investments, and more specifically, the state-regulated vertically integrated electric utilities. The recommended base ROEs of Dr. Lesser and Dr. Peters are significantly below the lowest of the base ROE determinations over the last two years for vertically integrated electric utilities in state jurisdictions. Such a low base ROE determination would put transmission infrastructure at a competitive disadvantage in the capital market in comparison to investments in vertically integrated electric utilities.

Q39. DID YOU PERFORM AN ANALYSIS OF STATE JURISDICTIONAL BASE ROE DETERMINATIONS FOR ELECTRIC UTILITIES?

A39. Yes, I performed an analysis using jurisdictional allowed ROEs published by S&P Global Market Intelligence's Regulatory Research Associates (RRA). RRA is a respected source that is relied on for accurate jurisdictional authorized ROE information by both investors and expert witnesses in utility regulatory matters. RRA characterizes vertically integrated electric utilities as those that provide distribution, transmission, and regulated generation services.

Q40. TO YOUR KNOWLEDGE, DOES FERC RELY ON THE RESULTS OF STATE ROE DETERMINATIONS AS A BASIS FOR ITS OWN ROE DETERMINATIONS?

A40. The Commission has repeatedly affirmed the use of the DCF methodology as its primary model for determining the base ROE and the range or zone of reasonable ROEs. In Opinion No. 531, the Commission stated that the substantial difference between state ROE determinations and the midpoint of the modeled DCF range calls into question the sole reliance on the DCF midpoint without adjustment during a period of anomalous capital market conditions. The Commission stated in paragraph 148:

> Although we are not using state commission approved ROEs to establish the NETOs' ROE in this proceeding, the discrepancy between state ROEs and the 9.39 percent midpoint serves as an indicator that an upward adjustment to the midpoint here is necessary to satisfy *Hope* and *Bluefield*.

In other words, a significant difference between state-authorized ROEs and the results of the mechanical application of the DCF model is in itself further evidence that capital market conditions are anomalous. Furthermore, as the Commission explained in Opinion No. 531, its ROE determinations are guided by the Supreme Court's decisions in the *Hope* and *Bluefield* cases to allow returns on invested capital that are comparable to returns available to investors in businesses of similar risk. Therefore, evidence of state-authorized ROEs for companies in a related industry group is an important source of information to which the Commission should give weight when determining where the ROE should be placed within a range or zone of reasonableness. Furthermore, investors are clearly aware of the state-authorized ROEs, and transmission owners must compete for capital in the marketplace generally, as well as among divisions within a specific utility (some of which are global companies), against other types of utility investments, as well as against the entire range of investment opportunities in the capital markets. Thus, the information provided by ROEs recently authorized by a wide sample of state utility regulators is relevant to the Commission's decision in this proceeding.

Q41. HOW DID YOU PREPARE YOUR ANALYSIS OF THE STATE-AUTHORIZED ROES?

A41. To perform this analysis, I began with all cases reported by RRA in all jurisdictions. Because some cases are decided by the jurisdiction without an ROE finding, I captured only those cases in which RRA identified an ROE finding. Next, I reviewed orders to determine if any explicit incentives or penalties were identified in the applicable order. If applicable, I separated the authorized ROE into a base ROE and incentive adders or penalties. I then focused only on state-authorized base ROEs during the most recent 24 month period.

Q42. PLEASE EXPLAIN HOW YOU TREAT THE INCENTIVE ADDERS OR PENALTIES.

A42. In Exhibit No. NET-02308, I separate each authorized ROE reported by RRA into two components: the base ROE and any explicit ROE incentives or penalties. This separation allows me to focus on the base ROE for comparison purposes to the Commission base ROE. It is important to capture the base ROE information in the analysis and is conceptually similar to separating out the base ROE from electric transmission ROEs that contain incentive adders.

Q43. PLEASE DESCRIBE THE ADJUSTMENTS TO THE STATE ROE ANALYSIS ON PAGE 2 OF EXHIBIT NO. NET-02308.

A43. In several instances during the 24 month period, the Virginia Corporation Commission (VCC) issued multiple orders within a short period of time containing similar ROE determinations that relate to individual projects, not for the entire utility. These orders contain valuable information, but to include each and every order separately would over-represent the VCC's decisions. Therefore, as shown on page 2 of Exhibit No. NET-02308, I compress the VCC ROE determinations of individual projects that contained the same base ROE in close proximity into one observation. In other words, I replaced five ROE determinations of 10.00% for Virginia Electric and Power Company during the first half of 2015 with a single observation of 10.00%. Likewise, I replaced five ROE determinations of 9.60% for Virginia Electric and Power during the first quarter of 2016 with a single observation of 9.60%, as well as replacing two ROE determinations of 9.60% during the second quarter of 2016 with a single observation of 9.60%. Besides the Virginia orders, I identified one ROE determination for Indianapolis Power & Light that required adjustment as shown on page 2 of Exhibit No. NET-02308. With these adjustments, the number of observations is slightly reduced and the range is unchanged, but the results are more representative.

Q44. ARE YOUR ADJUSTMENTS TO THE STATE ROES CONSISTENT WITH ADJUSTMENTS MADE BY THE NETOS IN DOCKET NOS. EL13-33 AND EL14-86?

A44. Yes, they are.

Q45. WHY DO YOU CHOOSE A 24-MONTH PERIOD FOR YOUR STATE-AUTHORIZED ROE ANALYSIS?

A45. In each quarter of a year, there are typically only a limited number of decisions in a small number of state jurisdictions for RRA to report. For example, RRA reported electric utility ROE decisions per quarter between 2 and 12 during 2015 and between 7 and 18 during 2016. In most quarters, only a few jurisdictions are represented. The sample group from quarter to quarter over 24 months is comprised of a greater variety of companies in a greater variety of jurisdictions. Some utilities are involved in frequent rate cases, while other utilities have multiple-year rate orders or have other means to avoid regular rate cases, and are rarely reported on the list of ROE determinations. Thus, the reported ROE determinations from quarter to quarter, or even year to year, do not represent a constant population of states or companies. Extending the data to eight quarters makes the sample more representative. In my opinion, using 24 months of data provides an appropriate balance between choosing a representative sample and ensuring the sample is meaningfully recent. A 24 month period also is consistent with the Commission's finding in paragraph 148 of Opinion No. 531.

Q46. WHY DO YOU CONSIDER THE VERTICALLY INTEGRATED ELECTRIC UTILITIES TO BE THE MOST APPROPRIATE GROUP FOR THE COMPARISON OF STATE-AUTHORIZED ROES?

A46. RRA reports ROE decisions at several different levels of aggregation, including separately for electric utilities and natural gas utilities, and further splitting the electric utility cases into vertically integrated cases and delivery only cases. Vertically integrated electric utilities are electric utilities that own transmission, distribution, and regulated generation assets. As I discuss in Section V.A. "Dr. Lesser and Dr. Peters Misjudge the NETOs' Risks, Particularly in Comparison to Distribution Investment," nothing has changed to alter the Commission's previous conclusion that transmission investment is more risky than distribution investment. The natural gas and electric delivery-only utilities are generally regarded by investors and state regulators as having lower business risk than vertically integrated electric utilities. Thus, the vertically integrated electric utilities group is the most representative sample group for this analysis because it is the group most similar in risk to the NETOs. For that reason, these are the utilities that I include in Exhibit No. NET-02308.

Q47. IS THE STATE-AUTHORIZED ROE METHODOLOGY THAT YOU APPLIED FOR VERTICALLY INTEGRATED UTILITIES THE SAME AS THAT USED BY NETO WITNESS LAPSON IN DOCKET NOS. EL11-66 AND EL13-33/EL14-86?

A47. Yes, it is.

Q48. WHAT DO THE STATE ROE CASES IN EXHIBIT NO. NET-02308 SHOW ABOUT DR. LESSER'S AND DR. PETERS' ROE PROPOSALS IN THIS CASE?

A48. The sample group of 44 state ROE cases is shown on page 1 of Exhibit No. NET-02308. Dr. Lesser's recommended ROE of 8.59% is a dramatic 64 basis points below the lowest of the 44 observations. Dr. Peters' recommended ROE of 8.20% is an astounding 103 basis points below the lowest of the 44 observations. If either of their proposals were adopted, it would send a strong signal that the Commission does not want capital invested in transmission.

Q49. DO YOU HAVE ANY COMMENTS ABOUT DR. PETERS' CONCLUSION ON STATE-AUTHORIZED ROES?

A49. On page 37 of Exhibit No. EMC-12, Dr. Peters concludes that the state-authorized ROE "most similar" to those approved by state commissions generally is 9.00%. To begin with, his conclusion about state-authorized ROEs is significantly flawed by his sole reliance on lower-risk electric distribution ROEs. But his conclusion of 9.00% is especially puzzling when considering how his own data fails to support his conclusion. Dr. Peters' Table 5 shows an average state-authorized ROE of 9.31% and his Table 6 shows a state-authorized ROE range of 9.17% to 9.90%. I am uncertain how Dr. Peters can conclude that the ROE "most similar" to this data is 9.00%.

Q50. PLEASE SUMMARIZE YOUR CONCLUSIONS REGARDING THE VERTICALLY INTEGRATED UTILITIES' STATE-AUTHORIZED ROES.

A50. The state-authorized ROEs demonstrate that the ROE recommendations of Dr. Lesser and Dr. Peters are much too low to attract investment to transmission infrastructure. If limited to the ROE recommendations of Drs. Lesser and Peters, the NETOs would be unable to achieve returns on transmission investment that meet the *Hope* and *Bluefield* standards and would not be able to raise capital for transmission investment.

VI. SUMMARY AND CONCLUSION

Q51. PLEASE SUMMARIZE YOUR CONCLUSIONS.

A51. I conclude that the anomalous capital market conditions that the Commission previously found to exist still persist. I disagree with the conclusion of Dr. Peters that there has been too much transmission investment in New England. To the contrary, transmission investment in New England occurs under the direction of ISO-NE and only after a rigorous needs and solutions assessment. I also disagree with both Dr. Lesser and Dr. Peters on the relative risk of transmission and distribution investment and concur with the Commission's previous conclusion that transmission investment is more risky than distribution investment. Furthermore, Dr. Peters' proposal to reduce Dr. Lesser's already inadequate recommended base ROE by 39 basis points for capital structure considerations is inappropriate. Finally, I demonstrate that both Dr. Lesser's and Dr. Peters' base ROE recommendations are grossly inadequate for the NETOs to meet the *Hope* and *Bluefield* standards.

Q52. DOES THIS CONCLUDE YOUR TESTIMONY?

A52. Yes, it does.

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

Belmont Municipal Light Department, *et al.*	)	
	)	
v.	)	**Docket No. EL16-64-002**
	)	
Central Maine Power Company, *et al.*	)	

AFFIDAVIT OF JOHN D. QUACKENBUSH

John D. Quackenbush, being first duly sworn, deposes and says that he is the John D. Quackenbush referred to in the foregoing testimony, that he has read such testimony and is familiar with the contents thereof and that the answers therein are true and correct to the best of his knowledge, information, and belief.

John D. Quackenbush

Subscribed and sworn to before me this 23RD day of March, 2017, by John D. Quackenbush, proved to me on the basis of satisfactory evidence to be the person who appeared before me.

Carol C Shubert
Notary Public

Commission Expires on: CAROL C SHUBERT
Notary Public, State of Michigan
County of Berrien
My Commission Expires 12-23-2019
Acting in the County of Berrien

PENNSYLVANIA
PUBLIC UTILITY COMMISSION
Harrisburg, PA 17105-3265

Public Meeting Held December 5, 2012

Commissioners Present:

Robert F. Powelson, Chairman
John F. Coleman, Jr., Vice Chairman
Wayne E. Gardner, Dissenting in Part & Concurring in Result Only Statements
James H. Cawley, Dissenting in Part Statement
Pamela A. Witmer

Pennsylvania Public Utility Commission	R-2012-2290597
Office of Consumer Advocate	C-2012-2300266
Office of Small Business Advocate	C-2012-2301063
PP&L Industrial Customer Alliance	C-2012-2306728
William Andrews	C-2012-2300402
Tracey Andrews	C-2012-2328596
Eric Joseph Epstein	C-2012-2313283
Dave A. Kenney	C-2012-2299539
Roberta A. Kurrell	C-2012-2304870
Donald Leventry	C-2012-2304903
John G. Lucas	C-2012-2298593
Helen Schwika	C-2012-2299335

v.

PPL Electric Utilities Corporation

Table of Contents

OPINION AND ORDER

BY THE COMMISSION:

I. Matter Before the Commission

Before the Pennsylvania Public Utility Commission (Commission) for consideration and disposition is the Recommended Decision of Administrative Law Judge (ALJ) Susan D. Colwell, issued on October 19, 2012, relative to the above-captioned general rate increase proceeding. Also before the Commission are the Exceptions and Replies to Exceptions filed with respect thereto.

Exceptions to the Recommended Decision were filed on November 8, 2012, by the following Parties: PPL Electric Utilities Corporation (PPL or Company), the Commission's Bureau of Investigation and Enforcement (I&E), the Office of Consumer Advocate (OCA), the Office of Small Business Advocate (OSBA), the Commission on Economic Opportunity (CEO), Direct Energy Services LLC (Direct Energy), Dominion Retail, Inc. d/b/a Dominion Energy Solutions (DR), and the PP&L Industrial Customer Alliance (PPLICA). Replies to Exceptions were filed on November 19, 2012, by the following Parties: PPL, the OCA, the OSBA, DR, and PPLICA. I&E filed Replies to Exceptions on November 29, 2012.

II. History of the Proceeding[1]

On March 30, 2012, PPL filed Supplement No. 118 to Tariff – Electric Pa. P.U.C. No. 201, to become effective June 1, 2012, containing proposed changes in rates, rules, and regulations calculated to produce approximately $104.6 million in additional annual revenues. This proposed rate change represents an average increase in the Company's distribution rates of approximately 13%, which equates to an average increase in total rates (distribution, transmission, and generation charges) of approximately 2.9%. The filing was suspended by Commission Order entered on May 24, 2012.

Formal Complaints against this proposed tariff were filed by the following: the OCA, on April 23, 2012; the OSBA, on April 25, 2012; PPLICA, on May 25, 2012; John G. Lucas, on April 9, 2012; Helen Schwika, on April 11, 2012; Dave A. Kenney, on April 16, 2012; William Andrews, on April 19, 2012; Tracey Andrews, on May 1, 2012; Roberta Kurrell, on May 3, 2012; Donald Leventry, on May 15, 2012;[2] and Eric Joseph Epstein, on July 5, 2012. Petitions to intervene were filed by the following: DR, on April 9, 2012; the CEO, on April 30, 2012; the International Brotherhood of Electrical Workers Local 1600, on May 1, 2012; the Sustainable Energy Fund (SEF), on May 3, 2012; Direct Energy, on May 24, 2012; and Granger Energy of Honey Brook LLC and Granger Energy of Morgantown LLC (collectively, Granger), on May 24, 2012. I&E filed a Notice of Appearance on April 10, 2012.

[1] For a full and complete history, as well as information regarding the testimony provided during the Public Input hearings, please refer to the Recommended Decision at 2-10.

[2] By letter received on June 19, 2012, Mr. Leventry indicated that he did not want to be involved in the litigation and asked that he be removed from the service list.

A Prehearing Conference was held on May 31, 2012. On June 1, 2012, ALJ Colwell issued a Scheduling Order which adopted the schedule agreed to by the Parties at the Prehearing Conference.

On June 11, 2012, the Company filed a Motion for a Protective Order. No Party filed a responsive pleading, and the Protective Order was granted on July 3, 2012.

On June 18, 20, and 21, Public Input Hearings were held in Scranton, Wilkes-Barre, Bethlehem, Allentown, and Harrisburg.

On July 13, 2012, Richards Energy Group, Inc. (REG) submitted a late-filed Petition to Intervene. The ALJ granted the intervention by Order issued July 26, 2012.

The evidentiary hearings were held on August 6, 7, 9, and 10, 2012. A hearing was also held on October 11, 2012, to hear the testimony of Tracey Andrews, whose Formal Complaint was filed on May 1, 2012, but was not properly associated with this rate case until October 10, 2012. The record consists of a transcript of 613 pages and numerous statements and exhibits presented by various Parties, as detailed in Appendix A of the Recommended Decision.

On August 29, 2012, the Parties filed Main Briefs and the record was thereupon closed. In addition, PPL filed a Petition to Reopen the Record in order to provide updated information regarding the long-term debt issued on August 24, 2012. As no objections were received, by Order issued September 10, 2012, the ALJ reopened the record for the purpose of accepting the updated information.

On September 14, 2012, the Parties filed Reply Briefs. The record closed upon the receipt of the Reply Briefs.

By way of Recommended Decision, issued on October 19, 2012, ALJ Colwell recommended, *inter alia*, that the company be permitted to file tariffs or tariff supplements containing rates designed to produce a $63,830,000 increase to the Company's present revenues. I.D. at 141. As previously noted, PPL, I&E, the OCA, the OSBA, the CEO, Direct Energy, DR, and PPLICA filed Exceptions. PPL, the OCA, the OSBA, DR, and PPLICA filed Replies to Exceptions. I&E filed Replies to Exceptions on November 29, 2012, as well as a letter requesting that the Commission accept its Replies to Exceptions as timely filed.[3]

[3] In its letter, I&E stated that on November 19, 2012, it electronically served its Replies to Exceptions on all Parties and the Office of Administrative Law Judge and served hard copies upon all internal Commission offices. I&E averred that it did not discover until November 29, 2012, that due to an administrative error, its Replies to Exceptions were inadvertently uploaded for e-filing on November 19, 2012, rather than submitted for e-filing. Under these circumstances, we find it appropriate to consider I&E's Replies to Exceptions in the interest of securing a just, speedy and inexpensive determination in this proceeding. *See*, 52 Pa. Code § 1.2(a). We do not believe that any of the Parties to this proceeding will be prejudiced by our consideration of I&E's Replies to Exceptions, as the Parties and this Commission were timely served with them.

III. Discussion

A. Description of the Company

PPL is a jurisdictional electrical distribution company (EDC) providing electric distribution service to approximately 1.4 million customers in all or portions of twenty-nine counties in eastern and central Pennsylvania. Under its present corporate structure, it is a wholly owned subsidiary of PPL Corporation (PPL Corp.). Another subsidiary of PPL Corporation is PPL Services Corporation, which provides various administrative and general services to the utility, including legal services, human resources, auditing, and community affairs.

B. Legal Standards

In deciding this or any other general rate increase case brought under Section 1308(d) of the Public Utility Code (Code), 66 Pa. C.S. § 1308(d), certain general principles always apply. A public utility is entitled to an opportunity to earn a fair rate of return on the value of the property dedicated to public service. *Pa. PUC v. Pennsylvania Gas and Water Co.* 341 A.2d 239, 251 (Pa. Cmwlth. 1975). In determining a fair rate of return, the Commission is guided by the criteria provided by the United States Supreme Court in the landmark cases of *Bluefield Water Works and Improvement Co. v. Public Service Comm'n of West Virginia*, 262 U.S. 679 (1923) and *Federal Power Comm'n v. Hope Natural Gas Co.*, 320 U.S. 591 (1944). In *Bluefield*, the Court stated:

> A public utility is entitled to such rates as will permit it to earn a return on the value of the property which it employs for the convenience of the public equal to that generally being made at the same time and in the same general part of the country on investments in other business undertakings which are attended by corresponding risks and uncertainties; but it has no constitutional right to profits such as are realized or

> anticipated in highly profitable enterprises or speculative ventures. The return should be reasonably sufficient to assure confidence in the financial soundness of the utility and should be adequate, under efficient and economical management, to maintain and support its credit and enable it to raise the money necessary for the proper discharge of its public duties. A rate of return may be too high or too low by changes affecting opportunities for investment, the money market and business conditions generally.

Bluefield, 262 U.S. at 692-693.

The burden of proof to establish the justness and reasonableness of every element of a public utility's rate increase request rests solely upon the public utility in all proceedings filed under Section 1308(d) of the Code. The standard to be met by the public utility is set forth in Section 315(a) of the Code, 66 Pa. C.S. § 315(a), as follows:

> **Reasonableness of rates.** – In any proceeding upon the motion of the commission, involving any proposed or existing rate of any public utility, or in any proceedings upon complaint involving any proposed increase in rates, the burden of proof to show that the rate involved is just and reasonable shall be upon the public utility.

In reviewing Section 315(a) of the Code, the Pennsylvania Commonwealth Court interpreted a public utility's burden of proof in a rate proceeding as follows:

> Section 315(a) of the Public Utility Code, 66 Pa. C.S. § 315(a), places the burden of proving the justness and reasonableness of a proposed rate hike squarely on the public utility. *It is well-established that the evidence adduced by a utility to meet this burden must be substantial*.

Lower Frederick Twp. Water Co. v. Pa. PUC, 409 A.2d 505, 507 (Pa. Cmwlth. 1980) (emphasis added). *See also*, *Brockway Glass Co. v. Pa. PUC*, 437 A.2d 1067 (Pa. Cmwlth. 1981).

In general rate increase proceedings, it is well established that the burden of proof does not shift to parties challenging a requested rate increase. Rather, the utility's burden of establishing the justness and reasonableness of every component of its rate request is an affirmative one, and that burden remains with the public utility throughout the course of the rate proceeding. There is no similar burden placed on parties to justify a proposed adjustment to the Company's filing. The Pennsylvania Supreme Court has held:

> [T]he appellants did not have the burden of proving that the plant additions were improper, unnecessary or too costly; on the contrary, that burden is, by statute, on the utility to demonstrate the reasonable necessity and cost of the installations, and that is the burden which the utility patently failed to carry.

Berner v. Pa. PUC, 382 Pa. 622, 631, 116 A.2d 738, 744 (1955).

This does not mean, however, that in proving that its proposed rates are just and reasonable, a public utility must affirmatively defend every claim it has made in its filing, even those which no other party has questioned. As the Pennsylvania Commonwealth Court has held:

> While it is axiomatic that a utility has the burden of proving the justness and reasonableness of its proposed rates, it cannot be called upon to account for every action absent prior notice that such action is to be challenged.

Allegheny Center Assocs. v. Pa. PUC, 570 A.2d 149, 153 (Pa. Cmwlth. 1990) (citation omitted). *See also, Pa. PUC v. Equitable Gas Co.*, 73 Pa. P.U.C. 310, 359-360 (1990).

Additionally, Section 315(a) of the Code, 66 Pa. C.S. § 315(a), cannot reasonably be read to place the burden of proof on the utility with respect to an issue the utility did not include in its general rate case filing and which, frequently, the utility would oppose. Inasmuch as the Legislature is not presumed to intend an absurd result in interpretation of its enactments,[4] the burden of proof must be on the party who proposes a rate increase beyond that sought by the utility. The mere rejection of evidence contrary to that adduced by the public utility is not an impermissible shifting of the evidentiary burden. *United States Steel Corp. v. Pa. PUC*, 456 A.2d 686 (Pa. Cmwlth. 1983).

In analyzing a proposed general rate increase, the Commission determines a rate of return to be applied to a rate base measured by the aggregate value of all the utility's property used and useful in the public service. The Commission determines a proper rate of return by calculating the utility's capital structure and the cost of the different types of capital during the period in issue. The Commission is granted wide discretion, because of its administrative expertise, in determining the cost of capital. *Equitable Gas Co. v. Pa. PUC*, 405 A.2d 1055, 1059 (Pa. Cmwlth. 1979) (determination of cost of capital is basically a matter of judgment which should be left to the regulatory agency and not disturbed absent an abuse of discretion).

As we proceed in our review of the various positions of the Parties in this proceeding, we are reminded that any issue or Exception that we do not specifically address shall be deemed to have been duly considered and denied without further discussion. The Commission is not required to consider expressly or at length each contention or argument raised by the parties. *Consolidated Rail Corp. v. Pa. PUC*, 625 A.2d 741 (Pa. Cmwlth. 1993); *also see, generally, University of Pennsylvania v. Pa. PUC*, 485 A.2d 1217 (Pa. Cmwlth. 1984).

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[4] 1 Pa. C.S. § 1922(1), *PA Financial Responsibility Assigned Claims Plan v. English*, 541 Pa. 424, 430-431, 64 A.2d 84, 87 (1995).

C. Rate Base

1. Depreciation Reserve

a. Positions of the Parties

In its filing, PPL claimed $1.813 billion in its Accumulated Reserve for Depreciation based on plant in service and amortization of net salvage for the test year ending December 31, 2012. PPL Future 1-Revised, Sch. C-1. PPL reflected depreciation accruals of $155.248 million and proposed that the Commission recognize annual depreciation expenses of $168.92 million. PPL Exh. Future 1-Revised, Sch.D-10.

PPL explained that rate base items are not annualized but are the balances projected to be in effect at the end of the test year. PPL also explained that annualization applies only to revenue and expense items, and not to rate base items. PPL M.B. at 22. PPL averred that the OCA's approach of using a non-annualized level of plant in service with an annualized level of depreciation reserve would create a mismatch between plant in service and the accumulated reserve for depreciation, which would result in an overstatement of the accumulated depreciation reserve and an understatement of rate base. PPL further asserted that the OCA's approach is inconsistent with the fundamentals of test year ratemaking, because by including annualized depreciation expense in the calculation of the accumulated depreciation reserve, the OCA's adjustment would add depreciation expense to the reserve that has not and will not be accrued at the end of the future test year (FTY). *Id*. at 23.

The OCA recommended that the Company's proposed level of Accumulated Reserve for Depreciation be increased by $10.417 million to better match the claimed depreciation expense, resulting in a corresponding reduction to PPL's rate base of $10.417 million. OCA M.B. at 12; OCA St. 1-REV. at 11-12; Exh. KC-1-REV. Sched. 2 at 3. The OCA averred that, since ratepayers are being asked to pay for the full level of depreciation expense, it is appropriate for ratepayers to have the full amount of that expense applied to accumulated depreciation. OCA M.B. at 13; OCA St. 1-SR at 4.

b. ALJ's Recommendation

The ALJ recommended adoption of PPL's position to use the accrued depreciation amount of $155.248 million for calculating the depreciation reserve, rather than the claimed $168.92 million in depreciation expense. R.D. at 17. The ALJ agreed with the Company's reasoning that rate base items are not annualized but are the balances which are projected to be in effect at the end of the year. *Id*. at 16, 17. The ALJ found the Company's following argument persuasive:

> The reserve for depreciation is built up by recording depreciation expense, but the expense recorded is the expense per books for a particular period of time, here calendar year 2012. OCA's proposal to ignore the projected per books depreciation expense and use instead the theoretical, annualized level of expense is not correct. The annualized depreciation expense as of December 31, 2012 will not be recorded on PPL Electric's books during calendar year 2012. Therefore, it is not part of the "build-up" of the depreciation reserve by recording depreciation expense related to plant in service.

Id. at 17-18 (citing PPL R.B. at 9-10). Accordingly, the ALJ recommended that the OCA's proposed $10.417 million adjustment be rejected. *Id*. at 18.

c. Exceptions

In its Exceptions, the OCA avers that the ALJ erred by rejecting the OCA's accumulated reserve for depreciation adjustment. The OCA states that it recommended an adjustment to PPL's accumulated reserve for depreciation to match PPL's claimed depreciation expense. OCA Exc. at 2; OCA St. 1-REV. at 11-12; Exh. KC-1-REV.

Sched. 2 at 3. The OCA explains its position that the depreciation expense included in the cost of service and the additions to the depreciation reserve, which are deducted from rate base, should be based on the level of plant the Company claims will be in service at the end of the FTY and the depreciation expense claimed for the FTY that is related to that plant. OCA Exc. at 2-3. The OCA asserts that ratepayers should receive the full benefit of the depreciation expense for which they are being charged by receiving the corresponding full benefit of accumulated depreciation reserve. *Id*. at 3.

In its Replies to Exceptions, PPL states that the ALJ properly rejected the OCA's proposal. PPL R.Exc. at 11. PPL submits that the accumulated reserve for depreciation, plant in service, and retirements as of December 31, 2012, are determined by bringing forward the book balances as of December 31, 2011, by reflecting the projected plant additions, annual depreciation expense per books, projected retirements per books, and projected net salvage per books. *Id*. at 11; PPL Exh. JJS-2 at III-6-III-7; PPL Exh. 1, Part V-A-3 at 1-3. PPL also submits that the OCA is proposing to change only one of these elements in determining net plant in service – the projected depreciation expense per books for 2012. PPL avers that the OCA's proposed adjustment is flawed, because the use of the annualized depreciation expense would be a mismatch with every other component of net plant in service, as those components are based on projected transactions per books. PPL asserts that there is not an annualized level of plant in service as of December 31, nor are there annualized retirements or annualized net salvage. PPL R.Exc. at 11. PPL further avers that its method of determining the accumulated reserve for depreciation was approved in its prior rate proceeding and has been accepted by the Commission for all major electric, gas, and water public utilities. *Id*.; PPL St. 13-R at 4.

d. Disposition

Based on our review of the record, the Parties' positions, and the Recommended Decision, we find that the ALJ properly adopted PPL's claim and rejected the OCA's proposal to use an annualized level of depreciation. PPL has met its burden of proof by showing that its method of determining the accumulated reserve for depreciation is reasonable, is consistent with the fundamentals of test year ratemaking, and is consistent with the methods used by other major public utilities. We agree with PPL that rate base items are not annualized but are balances to be in effect at the end of the test year. PPL is correct that the OCA's proposed adjustment to use a non-annualized level of plant in service with an annualized level of depreciation reserve would create a mismatch between plant in service and the accumulated reserve for depreciation, which would result in an overstatement of the accumulated depreciation reserve and an understatement of rate base. For these reasons, we shall deny the OCA's Exceptions and adopt the ALJ's decision on this issue.

2. Cash Working Capital – Lag Days for Payments to Affiliates

a. Positions of the Parties

PPL explained that its expense lag days for payments to its affiliate for support services is thirty-five days, consisting of the sum of fifteen days, which is the midpoint of the monthly service period, and twenty days, which is a standard accounting transaction for the preceding month. PPL M.B. at 24. PPL stated that it treats its payments to affiliates in the same manner that it treats its payments to non-affiliated vendors, and that it should not discriminate in favor of, or against, its affiliates. PPL also stated that a payment lag of thirty days is commercially reasonable and typical of the terms required by PPL's vendors. PPL asserted that it has consistently incorporated a thirty-five day payment lag for its affiliates in previous rate cases, and the Commission and the other parties to those proceedings have accepted the thirty-five day payment lag for affiliated services in calculating cash working capital (CWC) requirements. *Id*. at 25; PPL St. 7-R at 3.

I&E recommended a reduction in the CWC operation and maintenance (O&M) claims based on its position that PPL unnecessarily pays its affiliate substantially in advance of the required due date under the Company's service agreement with its affiliate. I&E submitted that, under the service agreement, PPL is billed monthly and has sixty days to pay its affiliate. Therefore, I&E argued that PPL has an allowable payment lag of seventy-five days pursuant to contract. I&E M.B. at 12. I&E proposed changing the payment date to the affiliate which, when weighted with the other expense groups, would result in an overall average expense lag payment of approximately forty-eight days, compared to PPL's claimed average expense payment lag of approximately thirty-five days. *Id*.; I&E St. 2 at 56. Application of I&E's recommendation would result in a $13,021,000 reduction to the Company's CWC claim to rate base. I&E M.B. at 11; I&E St. 2 at 56. I&E further argued that PPL did not provide any evidence that it has consistently incorporated a thirty-five day affiliate payment lag in its prior rates cases. I&E R.B. at 10. According to I&E, no prior litigated case addressed CWC generally or this O&M expense lag specifically, and there are no prior applicable Commission Orders providing the Company with Commission approval for this expense lag. *Id*. at 10-11.

b. ALJ's Recommendation

The ALJ adopted I&E's recommendation for a $13.021 million reduction to O&M in the CWC component of the Company's claimed rate base. The ALJ found persuasive I&E's argument that PPL did not have to pay its affiliate for services within the time period that the Company claimed but had the discretion to take advantage of a longer payment period of up to sixty days under the terms of the contract with its affiliate. The ALJ did not believe that PPL met its burden of proving its claim was reasonable, because the Company was causing the ratepayers a substantial amount of money due to a practice it could not otherwise justify except by saying that it has always been done that way. R.D. at 20.

c. Exceptions

In its Exceptions, PPL avers that the Recommended Decision's proposed adjustment to its lag days for payments to its affiliate should be rejected. PPL Exc. at 35. PPL submits that it uses a computerized system to pay all of its invoices from PPL Services and non-affiliated vendors. The Company notes that it pays its affiliates on the twentieth day of the month after services are received, which results in a thirty-five day payment lag for services it receives from its affiliates. PPL asserts that the ALJ's reliance on the payment terms in the agreement with its affiliate is not an adequate basis for the adjustment, because the agreement does not require a sixty-day payment period and clearly authorizes a twenty-day payment period. The Company explains that the agreement was entered into seventeen years ago when computers were not used to the extent they are currently and a longer time period for invoice payment was more common. *Id*. at 36.

I&E rejoins that the ALJ properly rejected PPL's calculation of its expense lag days based on the evidence presented by I&E, which demonstrated that the Company paid its affiliate well in advance of the due date, thereby resulting in a significantly shorter expense payment lag and an unnecessary annual ratepayer CWC contribution of $1.1 million. I&E R.Exc. at 3; I&E St. 2-SR at 62. I&E believes that PPL should be required to save its ratepayers $1.1 million annually by paying its affiliate as permitted under the agreement. I&E asserts that the manner in which PPL pays its affiliate disadvantages ratepayers and benefits its affiliate. I&E submits that, as a regulated monopoly with captive ratepayers, PPL should be held to a strict standard regarding the manner in which it handles payments to affiliates. I&E R.Exc. at 4.

d. Disposition

We agree with the ALJ's decision to adopt I&E's recommended $13.021 million O&M reduction to the CWC component of the Company's claimed rate base. PPL did not meet its burden of proving that its expense lag days for payments to its affiliate are reasonable. Since PPL has up to sixty days to pay its affiliate under the agreement, it would have been reasonable for PPL to take advantage of the longer payment period and, by doing so, to minimize the rate impact on its customers. PPL has control over when it pays its affiliate and can alter its computerized system to change the date on which it pays its affiliate. The evidence presented by I&E demonstrated that PPL's choice to pay its affiliate forty days early resulted in an annual ratepayer CWC contribution of $1.1 million. I&E St. 2-SR at 62. PPL's customers should not be burdened with this expense when it can be avoided. For these reasons, we shall deny PPL's Exception and adopt the ALJ's decision on this matter.

3. Cash Working Capital – Prepayment of Postage Expense

a. Positions of the Parties

PPL averred that it is proper for postage expense to be reflected in both the operation and maintenance expense component of working capital and prepayments, because each component addresses the expense during separate and distinct time periods. PPL M.B. at 26. PPL explained that the first time period related to postage expense is the prepayment, which begins when it makes prepayments to the United States Postal Service for postage to be used by the postage meter and ends when the postage meter adds postage to an envelope. According to PPL, the second time period is the payment lag, which begins when the postage is used. During the second time period, the expense appears in the working capital requirement as an O&M expense to reflect the period between when the postage meter adds postage to an envelope and when customers pay PPL. PPL's position was that there is no double recovery, because the inclusion of postage expense as a prepayment is separate from its treatment as an O&M expense in the working capital calculation. *Id*. at 27; PPL St. 7-R at 6-7. In its Reply Brief, PPL stated that its position that there is no double recovery was consistent with controlling Commission precedent, particularly the Commission's decision in the Company's 2004 rate case. PPL R.B. at 14 (citing *Pa. PUC v. PPL Electric Utilities Corp*., Docket No. R-00049255, at 11-12 (Order entered December 22, 2004)).

I&E did not recommend a specific adjustment to the Company's treatment of postage expense, but stated that the Company should be ordered to discontinue this practice in future proceedings because it is an improper CWC calculation that overstates the Company's CWC needs. I&E M.B. at 18. I&E averred that PPL includes a full twelve-month expense dollar amount claim for postage in its total CWC O&M expense, and also includes a twelve-month average prepayment dollar amount for postage in the Prepayment CWC component. *Id*. at 17. I&E's position was that this practice overstates the actual CWC requirement for postage, because the inclusion of two different CWC components results in a funding claim that is greater than what is incurred on an annual basis. *Id*. at 17-18.

b. ALJ's Recommendation

ALJ Colwell agreed with I&E's position. The ALJ found that PPL should discontinue its practice of including the same CWC need for postage in both the O&M expense and prepayment components of the CWC calculation, because this practice improperly inflates the CWC calculation. R.D. at 22. The ALJ distinguished this case from PPL's 2004 rate case. The ALJ stated that, in the 2004 case, the Commission accepted ALJ Turner's finding that the evidence did not support a conclusion that the Company prepaid its postage, which ALJ Turner admitted would have changed her recommendation. In this case, ALJ Colwell noted that PPL admitted to prepaying for postage and using the prepaid postage in its postage meter. R.D. at 21.

c. Exceptions

In its Exceptions, PPL avers that it should be permitted to continue to calculate the postage expense component of working capital as it has been calculating it. PPL states that it has fully explained its treatment of postage expense in rate base in its briefs. PPL also states that the Commission previously approved its treatment of postage expense and that nothing has changed since the Commission's previous approval. PPL Exc. at 37 (citing *Pa. PUC v. PPL Electric Utilities Corp*., Docket No. R-00049255, at 11-12 (Order entered December 22, 2004)).

In its Replies to Exceptions, I&E states that the ALJ correctly found that the Company overstated postage and that the Company should correctly calculate its postage expense in future proceedings. I&E avers that PPL improperly included postage expense as both an O&M expense and a prepayment, which resulted in a funding claim greater than the Company incurred. I&E believes that PPL's 2004 rate case is distinguishable from this case because, in that case, the OCA did not provide evidence that the Company included a prepayment and an expense for the same item, whereas, the Company admitted that it did in this case. I&E submits that PPL's CWC claim for postage is overstated, because, whether loaded into a meter or directly expensed, postage is paid only once. I&E R.Exc. at 5.

d. Disposition

Based on our review of the record, the Parties' positions, and the ALJ's decision, we find that PPL improperly included the same postage expense in two CWC components by listing it as both an O&M expense and a prepayment, resulting in an overstatement of that expenditure. We do not find merit in PPL's reliance on our Order in the Company's 2004 rate case. We agree with the ALJ and I&E that this case is distinguishable from the 2004 rate case. In the 2004 case, PPL included a claim for the net lag in recovery of operating expenses based upon a lead/lag study and a separate claim for average prepayments. In that case, PPL stated that the time period captured in its lead/lag study was from the date the bills were mailed to the date payment was received from customers, thus, excluding the time period from when the postage was paid to when it was expensed. *Pa. PUC v. PPL Electric Utilities Corp*., Docket No. R-00049255, at 11 (Order entered December 22, 2004). In the 2004 case, we concluded that the Company's position refuted the OCA's argument of double counting, because the time period from when the postage was paid to when it was expensed was excluded. *Id*. at 12. In the present case, PPL is expressly claiming that it properly included a prepayment and an expense for the same postage item. Accordingly, we shall adopt the ALJ's recommendation that PPL discontinue its practice of including the same CWC need for postage in both the O&M expense and prepayment components of the CWC calculation and deny PPL's Exception.

4. Cash Working Capital – Prepayment of Regulatory Assessments

a. Positions of the Parties

PPL stated that, consistent with Commission precedent, it included the Commission assessment in the prepayment component of its working capital requirement. PPL M.B. at 28 (citing *Pa. PUC v. National Fuel Gas Distribution Corp*., 1994 Pa. PUC Lexis 134). PPL stated that, while the Commission's assessment is calculated based on a utility's jurisdictional revenue for the prior calendar year, the assessment applies for the forthcoming fiscal year as provided in the Commission's June 21, 2012 invoice. PPL quoted the language in the Commission's invoice as follows:

> The Commission is submitting a request for **pre-payment** of PPL Electric's estimated Public Utility Commission assessment for the fiscal year 2012-2013. The requested pre-payment amount is an estimate based on the revenues shown

> on your Company's GAO-11 submission and the Commission's **fiscal year 2012-2013 budget** request. When the assessment invoices are issued in August for the **fiscal year 2012-2013** your invoice will be adjusted to reflect the payment made in response to this letter.

PPL M.B. at 29; PPL Exh. BLJ-1 (emphasis added).

PPL averred that its position that the assessment is for the fiscal year beginning on the following July 1 is also supported by the language in Section 510 of the Code, 66 Pa.C.S. § 510. PPL explained that, under Section 510, the Commission budget is proposed to the Governor and the General Assembly the preceding November 1, and the General Assembly is expected to approve a Commission budget for the upcoming fiscal year by the preceding March 30. PPL stated that, based on the approved budget, the Commission allocates the assessment among public utilities according to each utility's jurisdictional revenues for the preceding calendar year. PPL stated that, once the Commission makes the calculations, it prepares payment requests that the utilities receive in June prior to the fiscal year for which the assessment is made. PPL M.B. at 29.

I&E recommended removing the Company's claimed Commission assessments from the prepayments component of its CWC claim, which would result in an allowable working capital prepayment of $394,000, a reduction of $2.78 million to the Company's working capital prepayment claim. I&E averred that the Commission assessment is not a prepayment. I&E explained that the assessment is calculated as a proportion of Commission, OCA, and OSBA services that have been provided to PPL's utility type in the prior year, and it is billed as a percentage assessed on PPL's prior calendar year jurisdictional revenue and payable to the Commission, the OCA, and the OSBA in the subsequent calendar year. I&E M.B. at 15. I&E opined that the assessment is akin to a tax and, thus, should be treated as an expense with an associated lag. I&E argued that the assessment should be matched against the revenue generation time period on which the expense was based, namely, the prior year's jurisdictional revenue. *Id*. at 16.

b. ALJ's Recommendation

The ALJ recommended that I&E's proposal to remove PPL's Commission assessment expense as a prepayment under its CWC calculation be denied. The ALJ stated that several large utilities, including PPL, pay their assessments, or a portion of them, early in order to assure continued funding of the Commission's activities for the first quarter of the fiscal year. The ALJ found that it was clear that the assessment is based on a prior year's revenues, but the application period is the following fiscal year. R.D. at 23.

c. Exceptions

In its Exceptions, I&E avers that the ALJ erred by recommending rejection of I&E's adjustment to remove PPL's claimed regulatory assessments from the prepayments component of its CWC claim. I&E Exc. at 4. I&E states that the ALJ's finding that the regulatory assessment is a prepayment due to the time period in which the actual funds are spent is erroneous. I&E Exc. at 5. I&E contends that, under Section 510(b) of the Code, 66 Pa. C.S. § 510(b), although the assessment is paid in the subsequent fiscal year, the assessment covers the regulatory expenses incurred in the prior year. As such, I&E asserts that the assessment is not a prepayment for the next year's expenses, and it should be treated as an expense with an associated lag. *Id*. at 6.

I&E also distinguishes assessments from prepayments because prepayments are paid in advance of a service and may be refunded if the service is terminated before the end of the service period, whereas a utility's assessments are representative of the proportion of agency services rendered to the utility in the prior year and are not subject to a refund if the utility ceases operations the following year. *Id.* I&E believes that for ratemaking purposes, the assessment, which is a billed expense, must be matched against the revenue generation time period on which the expense was based, which is the prior year's jurisdictional revenue. I&E avers that this practice is consistent with the manner in which the assessment is made and with the accrual accounting concept of matching expenses with the revenue earning period that manifested the expenses, or matching revenues with the expenses that result from the production of those revenues. *Id*. at 7; I&E St. 2-SR at 63.

I&E further submits that the Commission's June assessment letter does not support the ALJ's recommendation. I&E describes the assessment process and states that the assessment is based upon the utilities' prior calendar year revenues, which must be reported by March of the following calendar year. I&E Exc. at 7. While assessments are made in August of a fiscal year, the Commission issues letters in June, such as the one issued to PPL, asking certain larger utilities to submit an early payment of the fiscal year's assessment based on a preliminary early assessment provided by the Commission. *Id*. at 7-8; PPL Exh. BLJ-1. Thus, I&E avers that the Commission's use of the word "prepayment" in the June assessment letter is merely a request for an early payment to assure the continuous funding of regulatory agencies, and is not determinative of the status of the assessment payment for purposes of the proper calculation of PPL's CWC requirements. *Id*. at 8.

In its Replies to Exceptions, PPL avers that the ALJ properly included regulatory assessments as a prepayment in the working capital calculation. PPL states that I&E's proposed adjustment is inconsistent with the Commission's invoice for assessments, the relevant law, and the manner in which the Commission operates. According to PPL, the language in the Commission's invoice supports its position that regulatory assessments are a prepayment. PPL R.Exc. at 14. PPL states that Section

511(b) of the Code, 66 Pa. C.S. § 511(b), also supports its position. *Id*. at 14-15.[5] PPL asserts that I&E's position suggests that regulatory assessments are paid after the fact and, if this were true, the Commission would have to borrow money to fund operations while collections of assessments were pending. PPL believes that I&E's position ignores reality and the way the Commission operates. *Id*. at 15.

d. Disposition

We find that PPL properly included the Commission assessment in the prepayment component of its working capital requirement. PPL presented evidence to show that, based on the language in the Commission's June 21, 2012 invoice, the assessment applies for the forthcoming fiscal year, July 1 through June 30. *See,* PPL St. 7-R at 3-4; PPL Exh. BLJ-1. PPL also presented evidence demonstrating that, pursuant to the assessment process set forth in Section 510 of the Code, 66 Pa. C.S. § 510, the assessment payment qualifies as a prepayment. PPL St. 7-R at 4. While it is clear under Section 510 that the assessment is calculated based on operating revenues for the preceding calendar year, the assessment that a utility pays is for the upcoming fiscal year. Moreover, PPL paid its assessment early, as requested in the Commission's invoice, and based its prepayment calculation on the manner in which it handles its assessment payments. *Id*. PPL's inclusion of the assessment as a prepayment is consistent with our prior decisions. *See, Pa. PUC v. National Fuel Gas Distribution Corp*., 1994 Pa. PUC Lexis 134, *29-30 (permitting the public utility to include in rate base a prepayment

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[5] PPL quotes Section 511(b) of the Code, which provides the following:

> All such assessments and fees, having been **advanced** by public utilities for the purpose of defraying the cost of administering this part, shall be held in trust solely for that purpose, and shall be earmarked for the use of, and annually appropriated to, the commission for disbursement solely for that purpose.

PPL R.Exc. at 15 (quoting 66 Pa. C.S. § 511(b) (emphasis added)).

balance that included the Commission's assessment). For these reasons, we shall deny I&E's Exceptions and adopt the ALJ's decision on this issue.

D. Expenses

1. Incentive Compensation

a. Positions of the Parties

PPL provides three types of compensation to its employees: base pay, benefits, and eligibility for incentive compensation. PPL makes incentive compensation payments to its own employees and reimburses PPL Services for its share of PPL Services' incentive compensation, which enables PPL Services to make incentive payments to its eligible employees. PPL St. 3-R at 15-26; PPL M.B. at 33.

The OCA recommended disallowing half of the incentive compensation expense, thereby requiring the shareholders to share equally in the cost of the compensation plans. The OCA recommendation is to adjust the expenses of $4.468 million for the Company's incentive compensation plan and $4.902 million related to the PPL Services' incentive compensation plan downward. OCA Exh. KC-1-SR, Sch. 4 at 4; Sch. 1 at 2.

I&E recommended an equal sharing of the claimed incentive compensation expenses between shareholders and ratepayers, resulting in a jurisdictional allowance of $4.459 million and a reduction of the same amount from PPL's claim. I&E asserted that PPL has provided no evidence that the incurrence of this cost is necessary for the provision of safe and reliable service at just and reasonable rates. I&E M.B. at 28-29.

PPL argued that the incentive compensation payments are a part of the total compensation package that was developed and is maintained based, at least in part, on a comparison with those of other employers for comparable positions. PPL stated that, if the incentive compensation payments to employees were eliminated, the fixed compensation would have to be raised in order to remain competitive with other employers, and "[t]here would be no savings to ratepayers." PPL St. 3-R at 16-17; PPL M.B. at 34.

Further, PPL stated that the Commission has approved incentive compensation programs in numerous prior rate cases. PPL M.B. at 36-37 (citing *Pa. PUC v. Aqua Pennsylvania, Inc.*, Docket No. R-00072711, at 20-21 (Order entered July 31, 2008); *Pa. PUC v. PPL Gas Utilities Corporation*, Docket No. R-00061398, at 40 (Order entered February 8, 2007)).

b. ALJ's Recommendation

The ALJ stated that, because the Parties have not challenged the reasonableness of the total compensation expense, the overall amount was not at issue; rather, only the method of recovery was at issue. While the two public advocates rely on the inherent fairness of having shareholders fund half of the incentive program, since they too receive a benefit, the ALJ found that the law does not support that concept. Rather, the ALJ found that a utility is entitled to recover in rates all expenses reasonably necessary to provide service to its customers and to earn a fair return on its investment in plant used and useful in providing service. The ALJ stated that to require a sharing of expense is to deny that portion in a rate case, which is simply not permitted under case law. R.D. at 28 (citing *Butler Township Water Co. v. Pa. PUC,* 473 A.2d 219, 221, 222 (Pa. Cmwlth. 1984); *T.W. Phillips Gas and Oil Co. v. Pa. PUC*, 474 A.2d 355 (Pa. Cmwlth. 1984)). Based upon the above rationale, the ALJ recommended that PPL be permitted full recovery of its incentive compensation plan. R.D. at 27-28.

c. Exceptions

The OCA and I&E excepted to the ALJ's recommended full recovery of PPL's incentive compensation plan. As presented in its Main and Reply Briefs and in its Exceptions, the OCA asserted that there is ample case law to support the OCA's position that shareholders should fund a portion of the incentive compensation plan. OCA Exc. at 3 (citing *Pa. PUC v. Philadelphia Gas Works*, 2007 Pa. PUC Lexis 45; *Pa. PUC v. UGI Utilities, Inc. - Electric Division*, 82 Pa. P.U.C. 488, 508 (1994); *Pa. PUC v. Roaring Creek Water Co*., 1994 Pa. PUC Lexis 41 (1994)). The OCA believes that the ALJ erred in failing to recommend a sharing of PPL's incentive compensation plans. *Id.*

In its Exceptions, I&E contends that neither the evidence nor the case relied upon by the ALJ supports the recommendation that PPL be permitted to recover the entire incentive compensation program expense from ratepayers. I&E Exc. at 9. I&E argues that while PPL is entitled to recover all reasonably incurred expenses, necessary for the provision of safe, reliable and adequate utility service, it must first satisfy its burden of proof. *Id.* I&E contends that PPL did not meet this burden. I&E opines that, absent sufficient data to determine the relative ratepayer and shareholder values, its proposed equal sharing of the expense is fair because the Company's earnings per share performance and other financial measures directly impact shareholder value, I&E's. *Id.* at 10. I&E also contends that the ALJ erroneously concluded that *Butler Township Water Co. v. Pa. PUC*, 473 A.2d 219 (Pa. Cmwlth. 1984), prohibited, as a matter of law adoption of I&E's proposal to disallow half of PPL's incentive compensation program. *Id.* at 11.

In its Replies to Exceptions, PPL averred that this adjustment would ignore the fact that almost everything PPL does will provide a benefit to both shareholders and ratepayers. PPL R.Exc. at 12. Further, PPL argues that this adjustment is unlawful because a public utility is entitled to recover expenses reasonably necessary to provide service to customers and to earn a fair rate of return. *Id.* A public utility is also entitled to recover operating expenses that are prudently incurred to provide service to customers. *Id.* In *PGW*, *UGI*, and *Roaring Creek*, as cited by the OCA and I&E, incentive compensation was disallowed in total because the utilities could not demonstrate that the program would provide a benefit to ratepayers. *Id.*at 13. In further support of its incentive compensation plan, PPL notes the plan's three overarching objectives: to achieve operational excellence; to optimize workforce readiness and engagement and to increase shareholder value. *Id.*

d. Disposition

We agree with the ALJ's interpretation of *Butler.* We find that, because PPL's incentive compensation plan is reasonable, prudently incurred, and is not excessive in amount, PPL is permitted full recovery of this expense. *See*, *Butler*, 473 A.2d at 221. PPL correctly notes that many of the cases the OCA and I&E rely on are distinguishable from this case because, in those cases there was not adequate evidence that the incentive compensation expense was reasonable or that there was a benefit to ratepayers. *See, Pa. PUC v. Philadelphia Gas Works*, 2007 Pa. PUC Lexis at *73-75; *Pa. PUC v. Roaring Creek Water Co.*, 1994 Pa. PUC Lexis at *37-38. Our decision to allow this incentive compensation expense is consistent with our prior decisions approving incentive compensation programs that are focused on improving operational effectiveness. *See, e.g., Pa. PUC v. Aqua Pennsylvania, Inc.*, 2008 Pa. PUC Lexis 50 at *24; *Pa. PUC v. Duquesne Light Co.*, 1987 Pa. PUC Lexis 342 at *99-100. Accordingly, the exceptions of the OCA and I&E on this issue are denied.

2. PPL Services

a. Environmental Management

i. Positions of the Parties

PPL's FTY claim of $467,000 is based upon the adoption of new federal, state and local environmental regulations that require PPL to undertake greater levels of environmental management activities. More specifically, federal and state environmental rules mandate that routine inspection of storm water and erosion, and sedimentation control measures continue beyond project completion. PPL further asserted that its budgeted increase in construction carries with it an increased need for environmental management services. For these reasons, PPL asserted that the past years' variability of this expense does not support the use of an historic average because, in this instance, the past is not representative of the future. PPL St. 3-R at 2-5; PPL M.B. at 41, 42.

I&E recommended a four-year average of actual annual jurisdictional direct support fees from 2009 through 2011, and the 2012 budget amount, resulting in a ratemaking allowance of $364,000, or a reduction of $103,000 from PPL's FTY claim. It is I&E's position that PPL's claimed level of expense is unsubstantiated. I&E's analysis includes PPL's FTY claim, which I&E believes recognizes an increase over PPL's historic level by giving consideration to the equivalent of 1.5 new full time employees. I&E is also of the opinion that PPL failed to substantiate how new environmental regulations may impact the expenses of operating PPL's distribution system. I&E M.B. at 25-26. I&E further contended that PPL ignored the fact that costs for the implementation of a new software system will not recur, and should not be included within the FTY claim. I&E M.B. at 34.

PPL asserted that I&E's rationale for its proposed disallowance, which relies upon the variability of the expense, the nonrecurring nature of the cost of the new computer system and that PPL does not expect its FTY level of expense to be sustained in subsequent years, was either incorrect or irrelevant, or both. PPL explained that while its expenses for the new software will not extend beyond the FTY, PPL will require additional licenses for employees using the software and additional environmental management support as more employees become authorized to use the software. PPL M.B. at 42. Further, as indicated in the data provided to I&E in response to discovery, PPL's business plan anticipates an increase in environmental management expense as follows: $485,000 for 2013; $494,000 for 2014; $508,000 for 2015; and $549,000 for 2016 and 2017. *Id.* at 43.

ii. ALJ's Recommendation

The ALJ concluded that PPL did not provide citations to the new regulations, nor any specific cost estimates for specific requirements to support its claim that there will be additional costs for environmental compliance. Further, the ALJ found that PPL did not sustain its burden of proving entitlement to the level of support fees sought. In the absence of record evidence to support its claim, the ALJ recommended adoption of I&E's proposal to reduce PPL's FTY claim by $103,000. R.D. at 29-30.

iii. Exceptions

In its Exception, PPL argues that the ALJ's recommendation is in error. PPL claims that, due to the adoption of new regulations, it will be required to undertake greater levels of environmental management activities due to the increase in construction activity throughout its system. This increase in construction activity elevates PPL's expenses related to environmental permitting and the need for additional employees. PPL Exc. at 32.

I&E rejoins that the ALJ correctly rejected PPL's claim for payment to its affiliate for environmental management services and recommended adoption of I&E's $103,000 reduction. I&E argues that PPL's claim contained costs that were irregular, erratic, and unsupported in the FTY. I&E R.Exc. at 9. I&E submits that despite PPL's claims that environmental compliance costs will increase substantially, PPL Corp. contended otherwise in its reports to investors, stating there will be no environmental downside for its distribution system, noting no significant exposure to currently proposed environmental regulations. *Id.* at 10.

iv. Disposition

We agree with I&E and the ALJ on this issue and shall grant the $103,000 expense reduction proposed by I&E. We find that PPL failed to carry its burden of proof that adoption of new regulations will require PPL to undertake greater levels of environmental management activities due to the increase in construction throughout its system. PPL did not refer to any newly adopted environmental regulations to which it is, or will become subject to, in the FTY. Absent this type of support we find the position of I&E to be reasonable. Accordingly, we shall deny PPL's Exception on this issue.

b. External Affairs

i. Positions of the Parties

PPL's budget for 2012 includes $2.602 million for direct services from the External Affairs[6] Department of PPL Services, which is an increase of $1.17 million, or 81% above the $1.432 million 2011 expense. PPL St. 3-R at 6; PPL M.B. at 43. The indirect expenses from this department totaled $1.252 million for the Historical Test Year

[6] External Affairs provides, in part, for the coordination of government relations activities, corporate communications, such as media and public relations services, as well as community and economic development activities. PPL St. 2 at 21-22.

(HTY) and are budgeted at $1.368 million for the FTY. I&E St. 2-SR at 17. The total charges to PPL represent 25% of the annual corporate budget for the HTY and 36% for the FTY. *Id.*

PPL explained that the reason for the increase from 25% to 36% of the annual corporate budget is two-fold. First, a review of the day-to-day activities of the regional community relations directors, who are part of the External Affairs Department, revealed that their activities center around reliability, connections and disconnections, billing and payment, street lighting and requests related to economic development. All of these activities directly benefit PPL, not other members of the PPL corporate system. Therefore, these expenses now are being directly charged to PPL instead of being allocated as indirect charges among all members of the PPL corporate system. Second, PPL stated that increases in line siting and upgrading work, tree trimming and enhanced storm damage communication protocols have also added to the responsibilities of this department. PPL St. 3-R at 6-7; PPL R.B. at 36-37.

I&E contended that the proposed percentage increase would shift an inordinate portion to the rate-regulated entity, PPL, without express consideration of the broader nature of the function of the External Affairs Department. I&E RB at 27. I&E stated that while External Affairs may become involved in billing and connection issues on occasion, PPL has other divisions specifically designed to address these functions on a daily basis. *Id.* at 27-28. In further support of its position, I&E explained that there is very little nexus, if any, between community development activities and the safe and reliable provision of utility service. *Id.* at 28. At a minimum, I&E contended that PPL's efforts with respect to community development enhance the corporate brand at least as much as they affect the provision of electric distribution service. *Id.*

I&E's original recommendation was to allow only the HTY level of directly assigned costs, or $1.432 million representing an expense adjustment of $1.170

million. However, upon review of PPL's explanation of the increase in this cost element from the HTY to the FTY, I&E revised its original expense adjustment. I&E R.B. at 27. I&E's revised expense allowance is based upon an average of the HTY percentage of 25% and the FTY proposed percentage of 36%, for an average of 30.5%. This average percentage, as developed in the table above, was then applied to the total FTY External Affairs Division budget of $10.982 million, providing a recommended allowance of $3.350 million. I&E's revised adjustment, therefore, is $3.970 million - $3.350 million, or $620,000. I&E St. 2-SR at 18.

ii. ALJ's Recommendation

The ALJ found that PPL did not adequately support the proposed increase in its allocated share of the External Affairs Division's FTY budget. The ALJ also found that PPL's only reference was to a schedule attached to its rebuttal testimony. The ALJ recommended that I&E's revised adjustment of $620,000, be adopted based upon I&E's rationale to support its calculated disallowance. R.D. at 31.

iii. Exceptions

In its Exceptions, PPL argues that the Commission should reverse the ALJ and allow the total claim of $2.6 million. PPL Exc. at 33. PPL explains that the increased costs for external affairs is driven primarily by refinements to the process of identifying the affiliates who benefit from the services provided, rather than a dollar increase in the overall costs of those services, which was only 0.8% from 2011 to 2012. *Id*. PPL explains that starting with the FTY, more of the costs for external affairs are directly assigned rather than being allocated as an indirect cost. *Id.* at 34.

In reply, I&E states that PPL provided no evidence to connect monies spent on community and economic development ($865,000 for 2011 and $1.7 million for 2012) and government relations ($463,000 for 2011 and $727,000 for 2012) to the provision of safe and reliable utility service. I&E R.Exc. at 10; I&E Exh. No. 2, Schedule 13, at 2. I&E also states that while logic dictated that as the allocation of direct costs rose, the allocation of indirect costs should have decreased, because overall expenses of PPL Services for this account increased by only 0.8% I&E R.Exc. at 11.

iv. Disposition

Based upon our review of the record evidence, we shall reverse the ALJ's recommendation on this issue. I&E's position is based upon its opinion that this expense lacks any nexus to PPL's provision of safe and reliable utility service and that the proposed percentage increase would shift an inordinate portion to the rate-regulated entity, PPL, without express consideration of the broader nature of the function of the External Affairs Department. I&E has also taken the position that since there was a very small increase in the total expense, the significant rise in direct expenses should have caused the indirect expense allocation to shrink. As shown in the table above, the allocated indirect costs increased from 2011 to the FTY by 9.2%, or $116,000, while the total indirect and other expenses to be allocated increased by 75.0%, or $21.951 million.

PPL Exhibit DAC-1, Schedule 4, page 2, indicates that the indirect and other costs to be allocated increased from $29.241 million to $51.192 million from 2011 to the FTY. The $29.241 includes a Storm Insurance recovery of $15.501 million. Without this significant insurance recovery, the increase in this account would be only 14% or $6.45 million. I&E did not present any issue regarding the amount of indirect and other costs to be allocated until after it adopted PPL's explanation for the increase in direct assignment of costs relative to this account.

I&E's final position is to 'split the baby' by taking an average percentage of the jurisdictional expense level for 2011 and the FTY, as they are compared with the total amount of expense as shown in the table above. We believe that this mathematical adjustment is not supported by I&E's contentions of an insufficient nexus or that the percentage increase in the direct assignment portion represents an excessive shift of expense to PPL, the regulated entity. Accordingly, we shall grant PPL's Exception and reverse the ALJ's recommendation on this issue.

c. Office of General Counsel

i. Positions of the Parties

Legal services to PPL Electric are provided by PPL Corporation's Office of General Counsel (OGC), and PPL's jurisdictional FTY claim for OGC is $6.083 million. I&E Exh. 2, Sch. 17 p. 2. According to I&E, PPL's claim is based on its HTY expense increased by $1.2 million in estimated costs for outside counsel fees related to this proceeding. Because of this, I&E recommended a ratemaking allowance of $4.833 million for OGC expense, which is a $1.2 million reduction to PPL's claim. The basis for I&E's adjustment is to eliminate the additional expense associated with outside counsel for this proceeding since the Company also includes a claim for rate case expense in its pro forma adjustments. I&E M.B. at 38.

PPL agreed with the adjustment but argued that it was more appropriate to eliminate the duplication from O&M expenses because the expense in question will be incurred by the OGC and then charged directly to PPL. PPL St. 8-R, at 41-42. PPL M.B. at 47.

I&E acknowledged PPL's acceptance of the expense reduction, but contended that it is appropriate to reflect the reduction as a part of the affiliate support allocation, and not as a rate case expense reduction. I&E M.B. at 39. I&E explained that keeping the expense as a part of PPL's affiliate support allocation will overstate the level of OGC affiliate support dedicated to the provision of electric distribution service in years when there is no rate case. *Id.* In other words, ratepayers will be allocated an inflated portion of OGC expenses based upon rate proceeding expenses that are not provided annually or regularly by OGC. *Id.* Further, the overstated level of OGC affiliate support allocated to PPL in this proceeding will then be used in future proceedings to support similarly overstated OGC allocations. *Id.*

ii. ALJ's Recommendation

The ALJ found merit in I&E's rationale and recommended that in order to prevent the overstatement of legal expenses in non-rate case years, this reduction should be to the Affiliate Support (Direct) – Office of General Counsel expense claim. R.D. at 32.

iii. Exceptions

Exceptions were not filed by the Parties on this issue.

iv. Disposition

Finding it otherwise reasonable, we will adopt the recommendation of the ALJ. However**,** some accounting clarification is in order.

In PPL's Exhibit Future 1-Revised, Sch. D-6, an adjustment was made to O&M expenses to reflect its revision to rate case expense. In rebuttal testimony, PPL explained its adjustment. The original rate case expense claim of $2.025 million was normalized over a two-year period, providing for an annual expense of $1.013 million. Based upon opposing testimony, PPL revised this claim by removing the remaining $674,000, representing its 2010 rate case expense, and by $1.2 million, representing a duplicate entry. The $1.2 million was budgeted by the OGC for this proceeding. PPL St. 8-R at 42. With these two adjustments, PPL's original O&M expense claim of $1.687 million was revised to be a reduction to FTY O&M of $0.861 million. Based upon these two adjustments, which include rate case expense and a direct assignment of cost from the OGC, PPL's reduction to its collective O&M expenses for the FTY would appear to be properly reflected in Exhibit Future 1-Revised.[7]

The adjustment proposed by I&E and recommended by the ALJ to reduce the OGC allocated expense and to leave the $1.2 million in rate case expense will not change the outcome of the revenue allowance in this proceeding. This proposed change would effectively reverse the decrease in rate case expense already included by PPL in its Future 1-Revised by $1.2 million and reduce the OGC expense by that same amount. The impact would be an increase in rate case expense of $1.2 million and a decrease in OGC expense of $1.2 million.

Accordingly, we shall adopt the recommendation of the ALJ on this issue.

3. Storm Damage Expense Recovery

i. Positions of the Parties

PPL revised its total storm damage expense recovery claim due to the unavailability of insurance beyond the FTY. PPL Exc. at 20-26. PPL stated that without storm damage insurance, PPL's initial FTY expense claim as it related to insurance is moot. PPL's revised FTY storm damage expense of $23.199 million includes the following: $17.875 million for annual storm damage expenses and a proposal to amortize over five years the extraordinary storm expenses in excess of insurance recoveries of $26.620 million incurred during major storms in August 2011, Hurricane Irene, and October 2011 at $5.324 million per year for five years. PPL Exc. at 24-25; PPL Exh. GLB-9.

[7] *See*, Exhibit Future 1-Revised, Schedule D-6.

PPL stated that among the details to be agreed upon before a rider may become effective are (1) provisions for interest on under and over collections; (2) timing of reconciliation; (3) reporting of storm damage expenses and revenue for their recovery; (4) methods for adjusting the annual level of the expense in rates; and (5) exact categories of storm damage expense that would be subject to the reconciliation. PPL M.B. at 71.

I&E recommended a simple five year average of total storm damage expenses, which would account for yearly fluctuations to determine an appropriate level of expense for ratemaking purposes. I&E's calculated five-year average of PPL's storm expenses from 2009 to 2011 inclusive is $23.785 million. I&E St. 2 at 35. I&E also recommended that PPL establish either a reserve account or a rider to recover storm damage expenses. I&E St. 2-SSR at 4-5.

ii. ALJ's Recommendation

The ALJ recommended that PPL be directed to establish a storm damage reserve account, as proposed by I&E, to be submitted to the Commission for approval. R.D. at 39. If approved by the Commission, the ALJ found that the reserve account should be implemented when the insurance coverage provided by PPL's present provider expires. The ALJ also recommended that the statutory advocates be included in the development of this storm damage reserve account. R.D. at 39. The ALJ also approved PPL's original storm damage expense claim of $26.699 million, which includes $12.625 million for annual storm damage expenses not covered by insurance, $8.75 million for insurance premiums and a five-year $5.324 million amortization of PPL's 2011 extraordinary storm damage expense claim.

iii. Exceptions

In its Exceptions, PPL supports the ALJ's recommendation to establish a reserve/tracker mechanism with reconciliation for over and under collections. PPL states that it intends to propose such a mechanism in a filing to be made as soon after the Commission decision in this proceeding as practicable. PPL will request that the proposal be given expedited consideration so that it can become effective at the earliest possible date. PPL Exc. at 23. PPL also revised its expense claim because it will be unable to purchase insurance beyond 2012. PPL Exc. at 24-26. PPL's revised claim is comprised of $12.625 million for expected storm damage not covered by current insurance; $5.25 million for the normal ongoing level of storm damage previously covered by insurance beyond 2012; and a five-year amortization of $5.324 million for the extraordinary loss incurred in 2011, for a total revised expense claim of $23.199 million.

In reply, I&E encourages the Commission to require PPL to meet with the statutory advocates to develop a rider within ninety days of Order entry. I&E R.Exc. at 13.

iv. Disposition

Based upon our review of the record and the Parties' Exceptions and Replies to this issue, we agree with the ALJ's recommendation to adopt I&E's proposal for PPL to propose a Storm Damage Expense Rider for Commission review. R.D. at 39. The issues to be discussed between PPL and the public advocates shall include, but not be limited to, the following: (1) provisions for interest on under and over collections; (2) timing of reconciliation; (3) reporting of storm damage expenses and revenue for their recovery; (4) methods for adjusting the annual level of the expense in rates; and (5) exact categories of storm damage expense that would be subject to the reconciliation. Additionally, we approve I&E's recommendation, and so direct, that PPL file a rider for storm damage expense recovery within ninety days of the date of entry of this Opinion and Order. PPL has stated its intention to file as soon as practicable after the Commission's entry of a final decision in this proceeding.

Recovery of PPL's revised FTY storm damage expenses of $23.199 million shall be through base rates. Any recovery through a Storm Damage Rider shall be permitted only to the extent that such expense exceeds the amount included within base rates.

4. Payroll - Employee Complement

i. Positions of the Parties

PPL has proposed a budget for payroll based upon an employee complement of 2,002, which it states is necessary for the management and maintenance of the Company's transmission and distribution systems in order to meet the needs of customers. PPL St. 2-R at 8-9; PPL M.B. at 71.

The OCA has proposed reducing the payroll budget to allow for an employee complement of 1,943, which is PPL's average number of employees over the sixteen-month period prior to March 2012. OCA M.B at 18. The OCA's proposal would reduce PPL's FTY wages, payroll taxes and benefits by $3.740 million. OCA St. 1-REV at 17. In response, PPL asserted that it is in the process of filling 106 positions. PPL St. 2-R at 8; PPL M.B. at 72.

The OCA argued that the budgeted staff levels should be reasonably based on historic data. *See e.g., Pa. PUC v. PPL Gas Utilities Corporation,* 255 P.U.R. 4th 209, 242 (Pa. PUC 2007) (utility's complement claim was reasonable and supported by the record where at times the actual number of employees was greater than budgeted, because the number was supported by historic data). OCA M.B. at 18. The OCA also noted that PPL's employee complement had declined from 1,974 in December 2010, to 1,943 in June 2012. OCA M.B. at 19. Thus, it is the OCA's opinion that since PPL had neither claimed nor proven that the lower complement had resulted in inadequate service, there is no evidence of record to support a need for the higher number of employees. OCA M.B. at 19.

ii. ALJ's Recommendation

The ALJ took notice that PPL's actual employee complement for the first three months of the FTY was, on average, seventy-one employees less than budgeted and that, as of June 2012, the Company's complement was 1,942, which was still one person lower than the OCA recommendation. OCA R.B. at 6. However, the ALJ found that PPL is most familiar with its own needs in terms of staffing, and that PPL's historical payroll supports a finding that the Company's claim is reasonable. R.D. at 41. Accordingly, the ALJ rejected the OCA's adjustment and recommended adoption of PPL's employee complement. *Id.*

iii. Exceptions

In its Exceptions, the OCA states that the ALJ erred in granting PPL's employee complement of 2,002 because, according to the OCA, it is not supported by the record. OCA Exc. at 9. The OCA further asserts that it is unlikely that PPL's complement will increase by three percent to achieve the budgeted 2,002 employee level by December 31, 2012. *Id.*at 11.

PPL replies that the OCA failed to recognize the appropriate level of staffing needed to maintain and manage PPL's system and instead relied upon a sixteen-month average complement ending March 2012 as the basis for its adjustment. PPL R.Exc. at 15.

iv. Disposition

We agree with the ALJ that PPL is most familiar with its needs in terms of staffing, and that PPL's historical payroll supports a finding that the Company's claim is reasonable. Further, we believe that the basis for the OCA's adjustment, while mathematically accurate, does not envision an appropriate level of staff needed to maintain and manage PPL's system. Accordingly, we shall deny the OCA's Exception on this issue.

5. Uncollectible Expenses

i. Positions of the Parties

PPL's total FTY uncollectible accounts percentage is 2.23%, representing an expense of $42.099 million. This amount includes expected write-offs plus any change in the reserve for doubtful accounts due to increased accounts receivable, which are subject to write-off. PPL M.B. at 72.

I&E's position is that PPL's proposed reserve allowance for uncollectible accounts expense should be rejected because that methodology is subject to manipulation and does not reflect PPL's actual expense or historic percentage write-off factor. I&E St. 2 at 5-6. Further, I&E stated that the Commission has no authority to permit recovery of hypothetical expenses not actually incurred by PPL, pursuant to *Barasch v. Pa. PUC,* 493 A.2d 653, 655 (Pa. 1985):

> Although the Commission is vested with broad discretion in determining what expenses incurred by a utility may be charged to the ratepayers, the Commission has no authority to permit, in the rate-making process, the inclusion of hypothetical expenses not actually incurred. When it does so,

as it did in this case, it is an error of law subject to reversal on appeal.

I&E's analysis presents PPL's actual net write-off uncollectible percentages from 2007 to 2011, which is based upon the following data supplied by PPL in response to interrogatory I&E-RE-10:

Actual Net Write-Off Uncollectible Percent				
2007	↑ 2008	↓ 2009	↓ 2010	↑ 2011
1.57%	1.72%	1.63%	1.49%	1.97%

I&E Exh. No. 2, Sch. 1 and 2; I&E MB at 22. Additionally, I&E stated that its analysis clearly showed that PPL's proposed 2.23% write-off factor is unsupported by record evidence. I&E notes that in determining the Purchase of Receivables program administrative factor percentage in PPL's 2010 base rate case, the ALJ found that use of a five-year average, as proposed by I&E here, is appropriate. *Id.* at 23 (citing *Pa. PUC v. PPL Electric Utilities Corporation,* Docket No. R-2010-2161694 (Order entered December 16, 2010)).

ii. ALJ's Recommendation

The ALJ concluded that PPL's use of a FTY permits forecasting in terms of using real data to forecast the final uncollectibles for 2012, which is sufficient to ensure that the Company's uncollectibles will be covered. Doubtful accounts, however, present an unmeasurable, and unsupported, factor which the ALJ disallowed. R.D. at 42.

I&E used five years of data in its calculation, which includes four years of recession and two years post-rate cap. The final I&E recommendation is based on the 2009-2011 three-year average, which is confirmed by I&E's five-year average, each yielding a 1.70% uncollectible rate. The ALJ stated that it is evident that the highest historic percentage of uncollectible accounts between 2007 and 2011 is below PPL's requested 2.23% recovery rate. Further, the ALJ found that PPL's proposed increase in the uncollectible rate is unjustified. Accordingly, the ALJ found that the methodology and result proposed by I&E is reasonable and should be adopted by the Commission.

iii. Exceptions

In its Exceptions, PPL states that an historic three-year average, as proposed by I&E and recommended for approval by the ALJ, is not appropriate because it is inconsistent with the ongoing increase in write-offs over the last three years and because the three-year average is inconsistent with actual, current data. PPL Exc. at 30. PPL explains that the goal in this proceeding should be to set rates which reasonably reflect future conditions. The three-year average relied upon by the ALJ included 2009, when PPL's generation supply rates were capped. Since then, PPL's electric supply rates for provider-of-last-resort service have increased significantly, when compared to prior periods where the generation supply rate cap was in effect. Not surprisingly, PPL experienced increases in the number and dollar amounts of uncollectible accounts since the generation rate cap has ended. *Id.* In addition, PPL and its customers continue to experience the effects of the recession. *Id.* PPL, therefore, asserts that the unfavorable economic conditions adversely affect uncollectible accounts expense and the use of a three-year average where uncollectible accounts expenses are increasing will, by definition, understate current costs. Accordingly, PPL believes that there is no basis for using a three-year history to calculate PPL's FTY uncollectible accounts allowance. *Id.* Lastly, PPL excepts to the ALJ's disallowance of its proposed increase in bad debt reserve. PPL states that elimination of this adjustment would be improper because the reserve includes charges for the increase in accounts receivable that are subject to eventual write-off. *Id.* at 31.

In reply, I&E contends that PPL ignores the facts, cited by the ALJ, that the five-year average, commencing in 2007 and extending through 2011, includes not only two years of data following removal of the generation rate cap (2010 and 2011), but also four years of data from the continuing recession (2008, 2009, 2010, and 2011). I&E R.Exc. at 6-7. I&E believes that while citing an increase in the number of accounts and uncollectible dollars from 2009 through 2011, PPL has misconstrued those facts to claim there is an ongoing increase over the last three years. I&E R.Exc. at 7.

I&E also contends that the facts do not support PPL's claimed 2.23% uncollectible accounts expense rate unless the Commission looks at only a snapshot of six months of experience in the first part of the FTY and then extrapolates that to an assumed level. I&E R.Exc. at 7. However, I&E notes that this Commission has never calculated an allowed uncollectibles expense rate on this basis. *Id.* Further, I&E claims that its calculation comports with the Commission's Regulations, the Company's own calculation of other claims, and PPL's calculation of its uncollectibles expense in both its 1985 and 2010 rate cases. *Id.* I&E submits that PPL's claims that the ALJ's allowance understates PPL's experience and that a three-year average fails to reflect ongoing increases is inaccurate. *Id.*

iv. Disposition

Based upon our review of the record evidence, the ALJ's recommendation and the Exceptions and Replies filed thereto, we shall adopt PPL's position on this issue as it reflects the level of uncollectible accounts on a going forward basis. In this proceeding, a FTY is the basis for ongoing utility expenses. We believe that I&E's historic analysis, although used by the Commission in prior decisions, is not warranted in this instance as it will not reasonably reflect future conditions. Accordingly, we shall deny I&E's Exception on this issue.

6. Revised Rate Case Expense and Normalization Period

i. Positions of the Parties

PPL's original rate case expense of $1.687 million for the FTY was comprised of $2.025 million for the instant proceeding and $674,000 as an amortization recovery of its 2010 base rate case expense. PPL proposed to recover the $2.025 million over a two-year period, or $1.013 million per year. This two-year normalized amount of $1.013 million plus the amortization portion of $674,000, totaled $1.687 million. Subsequently, PPL revised its rate case expense claim to remove its proposed amortization expense of $674,000 and $1.2 million, which PPL inadvertently included in both rate case expense and PPL Services-Office of General Counsel. These two adjustments have been reflected in PPL Exhibit Future 1-Revised, Schedule D-6, and result in a reduction to O&M expense of $861,000.

PPL proposed a two-year normalization period to recover the rate case expense associated with the instant proceeding and argued that a two-year recovery period was appropriate given the pressure that its capital spending program will place on earnings. PPL's planned rate base capital expenditures of approximately $1.7 billion over the next two calendar years represent an increase in PPL's total net measure of value as of December 31, 2012, exceeding fifty percent. PPL MB at 76. PPL asserted that with such a significant capital investment over the next two years, it seems more likely than not that its next base rate case could be filed during or before 2014. Further, PPL stated that even though it may request a distribution system improvement charge (DSIC), that mechanism is capped at five percent of revenue, which would do little to offset the incremental revenue requirement associated with the significant investment in rate base projected over the next two years. For these reasons, PPL believes that a two-year normalization of rate case expense is appropriate. *Id.*

The OCA advocates using a three-year period because PPL's last three rate cases filed in 2004, 2007, and 2010, were held exactly three years apart. The OCA's position is that it is the historical filings, not the actual intentions of the utility, which will guide the determination of the normalization period. OCA M.B. at 26. (citing *Pa. PUC v. City of Lancaster,* Docket No. R-2010-2179103 (Order entered July 14, 2011); *Pa. PUC v. Metropolitan Edison Company,* Docket No. R-00061366 (Order entered January 4, 2007)).

I&E agreed that the normalization period should be determined by the historical filings and, accordingly, recommended a thirty-two month normalization period based upon PPL's last four base rate filings.

Thus, I&E's recommended allowance for expenses associated with the instant rate proceeding is $759,375. This is calculated by dividing PPL's $2.025 million rate case expense claim by thirty-two months and then multiplying the result by twelve months to arrive at a normalized level of expense. [$2,025,000 / 32 months = $63,281.25; $63,281.25 x 12 months = $759,375] This reduces PPL's FTY claim by $253,625. ($1,013,000 - $759,375 = $253,625).

ii. ALJ's Recommendation

PPL has agreed to two adjustments regarding its claimed rate case expense. First, PPL has removed the prior base rate expense claim of $647,000 from its FTY total. Second, PPL has removed from total FTY expenses the $1.2 million double count of rate case expense as described above.

As discussed above,[8] the ALJ recommended the double count of $1.2 million of legal fees included by PPL in both its rate case expense claim and its PPL Services-OGC, be removed from the PPL Services expense and not the rate case expense as requested by PPL.

Regarding the normalized recovery period for allowable rate case expense, the ALJ found that the OCA and I&E used the appropriate historic analysis methodology. The ALJ found I&E's analysis to be more accurate because it used the filing date of each of the last four base rate cases to develop a normalized period reflective of PPL's actual base rate filing frequency. Therefore, the ALJ recommended adoption of I&E's thirty-two month recovery period.

iii. Exceptions

In its Exceptions, PPL notes that in late 2008, it conducted a comprehensive study to assess the age, condition and performance of plant in order to develop a strategy for capital replacements in order to avoid the cost and reliability of service effects of aging infrastructure. Based on this study, PPL embarked on a ten-year capital plan to replace, maintain and improve plant and anticipates adding $1.6 billion in plant from 2012 through 2016. Rate case history prior to 2010 does not reflect this construction program. PPL believes that plant expenditures of this magnitude will necessitate a base rate case within two years, if not sooner. Based upon PPL's capital improvement plan, PPL also believes it is unreasonable to rely on an historic pattern of rate cases that extends back eight years to 2004 to determine the appropriate period for normalization of rate case expenses. PPL Exc. at 35.

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[8] See discussion in the Office of General Counsel section above.

In reply, I&E states that citing no error by the ALJ, PPL repeats the same argument rejected by the ALJ, namely, that because of infrastructure plans, rate case history prior to 2010 is not an accurate reflection of the Company's future rate case plans. I&E R.Exc. at 8.

I&E explains that the law is well-settled that, absent exceptional circumstances, rate case expense is normalized based upon a party's filing history and not its presently stated intentions, no matter how unequivocally declared. *Id.* (citing *Popowsky v. Pa. PUC*, 674 A.2d 1149, 1154 (Pa. Cmwlth. 1996); *Pa. P.U.C. v. Borough of Media Water Works*, 72 Pa. P.U.C. 144 (1990)). I&E believes that there are no exceptional circumstances here. Conversely, I&E asserts that there are mitigating circumstances in the form of the effect of the DSIC. *Id.*

I&E contends that PPL has been finely attuned to its infrastructure needs since 2004 when it began regularly filing rate cases and, contrary to PPL's characterization, the current infrastructure improvement plan is not a sudden development that renders its recent rate case history irrelevant. *Id.* I&E notes that, recently, the Commission rejected a similar argument in which the Borough of Quakertown disputed a seven-year normalization based on filing history because anticipated intensive capital construction was under contract and had broken ground with an estimated 2013 completion date. *Id.* In affirming the ALJ, the Commission found that if the Borough filed sooner it "may be appropriate to consider a shorter normalization period going forward." *Id.* (citing *Pa. PUC v. Borough of Quakertown*, Docket No. R-2011-2251181 (Order entered September 13, 2012)).

iv. Disposition

Based upon our review of the record established in this proceeding, the ALJ's recommendation, the Exceptions and the Replies filed thereto, we shall reverse the

ALJ and grant the Exception of PPL on this issue. As previously discussed, this proceeding is premised upon a FTY and, based upon that criterion, certain expenses may now be based upon future expectations. We believe that the normalization period for rate case expense is one of those expenses. We fully support PPL's capital expenditure program and expect that it will proceed into the future as explained by PPL. Further, we can reasonably expect that PPL will file its next base rate case much closer to a twenty-four month interval than to a thirty-two month interval as proposed by I&E and the OCA. Accordingly, we shall grant the exceptions of PPL on this issue.

7. CEO's Proposed Increase in LIURP Funding

i. Positions of the Parties

PPL has proposed no changes in its universal service programs (USPs) nor to the funding for them, as these are subject to separate proceedings. *PPL Electric Utilities Corporation Universal Service and Energy Conservation Plan for 2011-2013,* Docket No. M-2010-2179796 (Order entered May 5, 2011). This was a litigated proceeding, with the participation of interested parties.

PPL's USPs include OnTrack (PPL's customer assistance program), WRAP (PPL's free weatherization program or Low Income Usage Reduction Program), Operation Help (PPL's hardship fund for customers with incomes at or below 200 percent of the federal poverty level, and CARES (PPL's Customer Assistance and Referral Evaluation Services, which connects customers with local community based organizations offering short-term help to customers at or below 200 percent of the federal poverty level). PPL St. 9 at 3-4.

PPL's currently effective USPs were approved by Commission Order entered May 5, 2011, at Docket No. M-2010-2179796, and run through December 2013. In June 2013, PPL will submit to the Commission for review and approval its USP plan for years 2014 through 2016, and will include therein proposals for any necessary or appropriate changes to the current programs and services available to low-income customers. PPL M.B. at 77.

CEO argued that PPL's last increase of $250,000 in the 2011-2013 USP case was inadequate to serve the needs of the low-income customer base and suggests that funding increase from $8.0 million to $9.5 million for PPL's WRAP Program. CEO disagreed with PPL's position that a base rate case is not the proper place for this argument, citing former rate cases that have evaluated the low-income plan budgets.

CEO pointed out that the funding for WRAP increased only 3% in the USP case, which translates into an additional 106 customers per year at the average cost of $2,349, an increase not consistent with the increased number of low income customers in PPL Electric's territory, which CEO argues is 44% based on the 2008 census. CEO M.B. at 5; CEO St. 1 at 7. CEO continues that the usefulness of a well-funded LIURP program has long been recognized by the Commission as a tool for lowering heating bills, thus creating a heating bill that the customer is more likely to pay. CEO M.B. at 5-6. In addition, CEO states that the higher prices resulting from this proceeding will be effective January 1, 2013, a full year prior to the end of the effective period from the current USP case. CEO R.B. at 2. It is CEO's opinion that refraining from addressing this issue now will deprive low-income customers of timely relief from a rate increase. CEO R.B. at 3.

PPL countered that the increase in low-income customers in its service territory should not be viewed in isolation. Rather, consideration needs to be given to the cost impact on other residential customers, the ability of the community based organizations (CBOs), which administer the programs, to deliver additional services, and the availability of funding from other sources. PPL advocated for the consideration of all of these issues within the triennial filings for approval of the plans themselves, where all entities involved may participate. PPL St. 9-R at 6; PPL M.B. at 79.

I&E opposed CEO's proposal because it fails to consider the total increase in the funding of universal service benefits in recent years. Since 2004, over three base rate cases, the funding for the OnTrack program increased from $9.5 million to $41.2 million, and from 2000 to 2008, weatherization funding grew from $5.7 million to $8 million. I&E M.B. at 66-67. I&E stated the following:

> Through 2012 PPL ratepayers will be compelled to contribute $75.35 million annually to the funding of PPL's USP benefits. That mandatory ratepayer funding is projected to increase to $78 million by 2014. The trajectory of mandatory ratepayer funding of PPL's universal service benefits has skyrocketed upward, increasing 122% from 2008 to 2011 and projected to increase by 145% through 2014. I&E submits that PPL's ratepayers are contributing sufficiently towards relief for their low-income neighbors. PPL's LIURP funding should remain at its current $8 million.

I&E M.B. at 68.

ii. ALJ's Recommendation

The ALJ found that base rate cases are the traditional forum for budgets of low-income plans, but in recent years, the Commission has required companies to file separate cases to address the USP budgets. R.D. at 44-45. PPL has a Commission-approved plan in place, including a budget. R.D. at 45.

The ALJ continued by observing that the USPs for EDCs, including PPL, are filed every three years and concentrate on the programs included in the customer assistance portfolio. After noting that, in a base rate case, any part of the Company's tariff may be brought into question, the ALJ stated that as an issue raised by another party, the burden of proving that the universal service issues deserve additional funding belongs to the party raising it – here, CEO. *Id.*

The ALJ concluded that the Commission's institution of separate proceedings for these plans is indicative of a preference to address the issues within those proceedings. Therefore, the ALJ recommended that CEO's proposed increase in funding be denied. However, the ALJ encouraged CEO to participate in the triennial plan reviews. *Id.* at 46.

iii. Exceptions

In its Exceptions, CEO submits that the Commission has a statutory duty to ensure that a company's USPs are appropriately funded and available. Further, CEO contends that a proceeding that results in a rate increase to low-income customers would require the Commission to determine the effect of the rate increase on whether those USPSs are, or remain, appropriately funded and available. CEO Exc. at 6. CEO alleges that to postpone consideration of universal service funding to a time after a rate increase takes effect, and to a non-adversarial proceeding, is contrary to the Commission's past practice and its statutory duty. *Id.*

PPL responds that the ALJ properly rejected CEO's proposal because the USP costs are no longer recovered through base rates. PPL R.Exc. at 22-23. I&E also supports the ALJ's recommendation on this issue. I&E R.Exc. at 14-15.

iv. Disposition

We agree with the ALJ, PPL and I&E on this issue. Recent Commission practice is to address all aspects of USPs through the triennial filing process and to collect all revenues through a rider to base rates. We believe this process has provided, and will continue to provide, the customers who rely upon USPs with appropriate funding levels on a timely basis. Accordingly, we deny the Exceptions of CEO on this issue.

8. Consumer Education Expenses

i. Positions of the Parties

PPL's consumer education program was mandated and authorized by the Commission's Final Order in *PPL Electric Utilities Corporation Consumer Education Plan for 2008-2012,* Docket No. M-2008-2032279 (Order entered July 18, 2008), which was designed to communicate Energy Education Standards to customers. The goal was to educate consumers in each EDC's service territory regarding (1) the expiration of rate caps; (2) ways to reduce energy consumption and, thereby, lower bills; and (3) the availability of retail competition.

PPL's FTY consumer education expense claim of $7.976 million is comprised of $5.482 million associated with the final year of PPL's Commission-approved Consumer Education Plan (CEP), plus $2.494 million for three Retail Markets Investigation (RMI) mailings and customer protections regarding the Eligible Customer List (ECL), which PPL proposed to collect through a CER. PPL St. 5-R at 28-29.

I&E and the OCA opposed portions of PPL's proposal. I&E pointed out that PPL's proposed CER is designed to recover costs of the RMI initiatives, and that any costs related to education regarding those initiatives should be recovered through that rider and not included in base rates. While I&E does not object to recovery of the Commission mandated RMI costs and costs related to the ECL mailings, it notes that these should be recovered under the CER, if it is approved, and removed from base rates. I&E points out that the Commission and its EDCs are moving into the next phase of retail competition and that shopping and energy efficiency are more effectively addressed by the Act 129 Energy Efficiency and Conservation (EE&C) Plan and the RMI mandates. These are funded through the Act 129 Rider and the proposed CER. I&E St. 2 at 44; I&E M.B. at 62-63.

The OCA recommends that the Company's consumer education funding be set at $5,400,000, annually, based on the budget amount approved in the 2008-2012 Consumer Education Plan. OCA MB at 29.

ii. ALJ's Recommendation

The ALJ found that the Commission's mandates must be funded, and the issue here is the best method of funding. While PPL must be reimbursed fully for its prudent expense, there must be a limit to the amount that should be spent. The ALJ concluded that the I&E proposal to recover the costs through a CER is the best choice, as it fully funds the Commission's mandates but does not waste ratepayer money on duplication.

Accordingly, the ALJ recommended that funding for PPL's CEP lapse at the end of the FTY and that the education costs of $2.494 million incurred in carrying out the RMI mandates be recovered using the CER and, thus, removed from the allowed increase in base rates associated with this proceeding. R.D. at 49.

iii. Exceptions

In its Exception, PPL explains that the ALJ would disallow complete recovery of costs associated with PPL's Commission-approved Consumer Education Plan, which promotes and encourages the competitive retail market for electric generation in PPL's service territory and encourages conservation, beyond 2012. PPL Exc. at 26. The issue presented here, as viewed by PPL, is whether the Commission recognizes the need for the Energy Education Standards established in the Commission's Final Order on *Policies to Mitigate Potential Electricity Price Increases*, at Docket No. M-00061957, and wants the Consumer Education Plan to continue. According to PPL, if the Plan is to continue, the Commission should approve PPL's claim of $5.482 million for that Plan, in addition to other consumer education expenses. If not, PPL states that the ALJ's recommendation should be adopted on this issue, and PPL will discontinue the program. *Id.*

I&E rejoins that despite PPL's assertion otherwise, the Act 129 Plan provides both financial incentives as well as education about energy efficiency, rendering the CEP duplicative. *See* I&E St. 2-SR at 47-48, citing PPL's *Final Report for Year 2 of PPL Electric Utilities Corporation's Act 129 Plan,* at Docket No. M-2009-2093216. I&E R.Exc. at 14. In addition, I&E states that while the specific activities and programs may differ, the goals under all of these programs are the same: (1) to educate customers about shopping and efficiency; and (2) to provide financial incentives to modify behavior. Accordingly, I&E continues to urge that PPL's five-year plan and its $5.4 million annual cost should be allowed to lapse naturally at the end of year 2012. *Id.*

iv. Disposition

As discussed above, we agree that Commission mandates must be funded. With regard to the recovery of Act 129 costs, we believe that it is proper to recover these costs through a rider to base rates. It is unknown whether the Act 129 expenses discussed in this section will be in place for many years or for only a few years, which supports recovery through a rider to base rates. Accordingly, we shall approve the education costs incurred in carrying out RMI mandates as expenses to be recovered through the CER Rider.

Regarding continued recovery of PPL's CEP costs of $5.482 million, we find that the record supports allowing these pre-Act 129 expenses to lapse at the end of the FTY. Accordingly, we shall deny the Exceptions of PPL on this issue and reduce PPL's O&M expenses by $5.482 million.

9. CAP (Customer Assistance Program) Outreach

i. Positions of the Parties

In its Exceptions, the OCA states that the ALJ did not address its recommendations regarding CAP outreach initiatives. OCA Exc. at 12-13. The OCA proposed three specific outreach initiatives: (1) that PPL engage in a direct-contact outreach program aimed at a population of customers that are both confirmed low-income and 120 days or more in arrears; (2) that all shut-off notices to confirmed low-income customers be modified so that they also contain a notice of CAP availability and the means of accessing CAP; and (3) that PPL engage in a direct-contact outreach program focused on customers 120 days or more in arrears whether or not those customers are confirmed low-income customers. OCA St. 4 at 33-34; OCB M.B. at 115.

PPL noted that it is not opposed to modifying its termination notice to include information about CAP so long as it does not add another page to the termination notice because that would increase the cost. PPL St. 9-R at 22. Further, PPL would not consider a requirement to have two separate termination notices, one for confirmed low-income customers and one all other residential customers. *Id.* at 23. PPL further stated that it is willing to propose the content and format of the new information on the termination notice and review it with Commission staff and interested Parties. *Id.*

Regarding the OCA's first and third recommendations, PPL states that these should not be adopted. PPL asserts that its current outreach programs are sufficient and that the OCA has not provided evidence that more outreach is needed to contact confirmed low-income customers who are 120 days or more in arrears. PPL St. 9-R at 22. Further, most residential customers with overdue balances or terminated accounts call PPL to address their concerns. *Id.* at 23. Depending on a customers' status in the collection process, PPL has concerns about sending them a mixed messages regarding the requirements stated in the collection notices versus the content of the targeted outreach. *Id.* at 23-24.

ii. ALJ's Recommendation

As noted by the OCA, the ALJ's Recommended Decision did not address this issue.

iii. Disposition

Based upon the testimony of the Parties, we shall grant the OCA's Exception, in part, with regard to its second recommendation that shut off notices to confirmed low income customers include information about CAP. However, we expressly acknowledge and accept PPL's willingness to propose the content and format of the new information on the termination notice and review it with Commission Staff and interested Parties. We encourage PPL to proceed in a timely manner, in this regard. Further, PPL should submit its proposed content and format of the new notice to the OCA and the Commission's Bureau of Consumer Services for review. Lastly, we agree with PPL that their current outreach programs, as discussed in testimony, are well designed and that the OCA has not provided sufficient evidence to support its first and third recommendations. Accordingly, we shall grant the OCA's exception in part, as discussed above.

E. Rate of Return

1. Introduction

The overall rate of return position of the Parties in this proceeding is summarized in the following tables:

PPL

Capital Type	Percent of Total %	Cost Rate %	Weighted Cost %
Debt	48.98	5.58	2.73
Common Equity	51.02	11.25	5.74
Total	100		8.47

PPL St. 11, Exh. PRM-1, Sch. 1.

PPL modified its overall return to reflect the actual issuance of $250 million of long-term debt on August 24, 2012, at an interest rate of 2.61%. This update resulted in the following revised rate of return position of PPL:

PPL Revised

Capital Type	Percent of Total %	Cost Rate %	Weighted Cost %
Debt	49.22	5.50	2.71
Common Equity	50.78	11.25	5.71
Total	100		8.42

PPL M.B. at 91.

OCA

Capital Type	Percent of Total %	Cost Rate %	Weighted Cost %
Debt	52.84	5.58	2.95
Common Equity	47.16	9.00	4.24
Total	100		7.19

OCA St. 2, Exh. SGH-1, Sch. 11 at 1.

I&E

Capital Type	Percent of Total %	Cost Rate %	Weighted Cost %
Debt	54.89	5.58	3.07
Common Equity	45.11	8.38	3.77
Total	100		6.84

I&E St. 1 at 12.

The Company argued that the public advocates' recommendations relied on historically low interest rates instituted during the recent recession in an attempt to justify returns on common equity that are far below any allowed by this Commission in decades. Even in these difficult financial times, allowed ROEs have ranged between 9.75% and 10.99%. PPL M.B. at 87-88; PPL St. 12-R at 3-5. The Company averred that if either of these is adopted, Pennsylvania utilities will be placed at a disadvantage compared to other utilities in the country in terms of raising capital during what it terms to be a critical infrastructure replacement phase, PPL St. 12-R at 3-5, as well as at risk for another downgrade in its credit rating.[9] Of course, accompanying this would be higher debt costs and potential limits to access to capital in difficult markets. PPL M.B. at 87-88.

2. Capital Structure

Capital structure involves a determination of the appropriate proportions of debt and equity used to finance the rate base. This is crucial to developing the weighted cost of capital, which, in turn, determines the overall rate of return in the revenue requirement equation.

[9] Note that in presenting its 2004 rate case, PPL had an A minus rating, which it sought to retain at that time. *See*, Docket No. R-00049255, Recommended Decision of Administrative Law Judge Allison K. Turner, at 94.

a. Positions of the Parties

The Capital Structure recommendations of the Parties in this proceeding are summarized in the following table:

Capital Type	PPL (1)	I&E (2)	OCA (3)
	(%)	(%)	(%)
Debt	49.22	54.89	52.84
Common Equity	50.78	45.11	47.16
Total	100.00	100.00	100.00

(1) PPL M.B. at 91 fn. 16
(2) I&E St. 1 at 12
(3) OCA St. 2 at 25

As noted above, PPL proposed the use of its actual capital structure of 49.22% long-term debt and 50.78% common equity. According to the Company, the legal standard in Pennsylvania for deciding whether to use a hypothetical capital structure in setting rates is that if a utility's actual capital structure is within the range of a similarly situated barometer group of companies, rates are set based on the utility's actual capital structure. PPL stated that only if the capital structure is atypical, outside of the range of the barometer group, should a hypothetical capital structure be used to set rates for a utility. PPL R.B. at 41 (citing *Pa. PUC v. City of Lancaster – Water,* 1999 Pa. PUC Lexis 37 at *17; *Pa. PUC v. City of Bethlehem,* 84 Pa. P.U.C. 275, 304 (1995); *Carnegie Natural Gas Co. v. Pa. PUC,* 433 A.2d 938, 940 (Pa. Cmwlth. 1981) (where a utility's actual capital structure is too heavily weighted on either the debt or equity side, the Commission must make adjustments)).

Both I&E and the OCA sought to utilize a hypothetical capital structure in this proceeding. I&E stated that a capital structure should be representative of the industry norm and be an efficient use of capital. According to I&E, the use of a capital structure that is significantly outside the range of the industry's capital structure may result in an overstated overall rate of return. I&E advocated for the use of a hypothetical capital structure based upon an industry average for ratemaking purposes if the use of the utility's actual capital structure has the potential to overstate the overall cost of capital. I&E M.B. at 82.

The OCA submitted that the Commission should adopt a hypothetical capital structure for PPL as the Company's proposed capital structure is unnecessary to attract capital and would create an unreasonable cost burden for ratepayers. The OCA averred that its proposed capital structure of 47.16% equity and 52.84% debt is reasonable, consistent with how PPL has been capitalized over the last few years prior to this current rate filing, and similar to the manner in which the electric industry is capitalized. The OCA noted that of particular concern in this case is the percentage of common equity in the capital structure, since common equity commands a higher return than debt financing. OCA M.B. at 32-42

The I&E and the OCA recommendations to utilize a hypothetical capital structure are based upon use of a barometer group of companies with characteristics similar to PPL. The three Parties' barometer groups all contain comparison companies which are higher and lower than PPL's capital structure in this case.Error! Bookmark not defined. A barometer (or proxy) group is a group of companies that act as a benchmark for determining the utility's rate of return. I&E M.B. at 79. I&E noted that a barometer group is necessary because PPL is a private wholly owned subsidiary of PPL Corp. and is not publicly traded. According to I&E, using data from a group of companies is more reliable than data from a single company in that it smooths short-term anomalies and the use of a barometer group satisfies the long-established principle of utility regulation that seeks to provide the utility the opportunity to earn a return equal to that of similar companies with corresponding risks. I&E M.B. at 79 – 80.

PPL selected two barometer groups, an Electric Distribution Group (EDG) and an Integrated Electric Group (IEG). PPL's EDG group was based upon the following criteria:

1. Their stock is traded on the New York Stock Exchange;

2. They are listed in the Electric Utility (East) section of *The Value Line Investment Survey*;

3. They are not currently the target of a publicly-announced merger or acquisition; and

4. They do not have a significant amount of electric generation.

PPL's criteria for its IEG are identical except for criterion four, which requires that at least 75% of the companies' identifiable assets are subject to public regulation. PPL St. 11 at 4-5.

I&E used a barometer group comprised of Consolidated Edison, Dominion Resources, Nextera Energy, TECO Energy, PEPCO Holdings, and UIL Holdings. I&E St. 1 at 9-11. These were chosen by I&E based on the following criteria:

1. 50% or more of the company's revenue were generated from the electric distribution industry;

2. The company's stock was publicly traded;

3. Investment information for the company was available from more than one source;

4. The company was not currently involved/targeted in an announced merger or acquisition; and

5. The company had six consecutive years of historic earnings data.

I&E M.B. at 80.

The equity ratios for I&E's barometer group for 2011 range from 39.34% equity to 52.47% equity. I&E Exh. 1, Sch. 1 at 2. I&E then averaged the companies in its barometer group and developed a hypothetical capital structure based upon the average of 54.89% long-term debt and 45.11% equity for the FTY, or 55% debt/45% equity. I&E M.B. at 82.

The OCA used sixteen companies that had at least 70% of revenues from electric operations, did not have a pending merger, did not have a recent dividend cut, had stable book values and a senior bond rating between "A" and "BBB-". The OCA used "wires" companies as well as those with generation, and all were listed in *Value Line*. OCA St. 2 at 29-30. OCA M.B. at 52.

I&E argued that PPL's selected EDG and IEG barometer groups are flawed. According to I&E, Northeast Utilities must be excluded from PPL's EDG and Duke must be excluded from its IEG because their inclusion violates the Company's own presumably objective criteria number three in that Northeast is the subject of an announced merger with NSTAR and Duke is the subject of an announced merger with Progress Energy. I&E M.B. at 81. Also, I&E maintained that TECO Energy and Dominion Resources should be excluded from the Company's IEG and, instead, included in its EDG, because they derive more than 50% of their revenues from their regulated electric distribution sector. I&E further contended that the Company's IEG group should be disregarded in its entirety, because the group is too dissimilar in terms of business lines to be comparable to PPL in this proceeding. Specifically, I&E stated that PPL does not have regulated generation or gas distribution, properties common to SCANA Corp.

and Southern Co. included in the IEG, and neither company's revenues are derived more than 50% from electric distribution only. I&E St. 1 at 11-12. I&E M.B. at 80-82.

I&E asserted that PPL's claimed capital structure, if left unadjusted, overstated its capital needs by $15 million. I&E M.B. at 83. According to the OCA, the Company's equity-rich common equity ratio would cost its ratepayers an additional $10.6 million annually compared to the more economically efficient capital structure it has employed in recent years. OCA M.B. at 41.

b. ALJ's Recommendation

The ALJ concluded that the appropriate capital structure is the Company's actual capital structure of 49.22% long-term debt and 50.78% common equity. R.D. at 60.

c. Exceptions

In its Exceptions, the OCA states that PPL's proposed capital structure is unnecessarily burdensome to ratepayers, contains more common equity capital than the electric industry on average and is inconsistent with how PPL has been capitalized over the last several years prior to this rate case being filed. The OCA avers that its proposed capital structure of 47.16% equity/52.4% debt is reasonable, consistent with how PPL has been capitalized over the last few years and similar to the manner in which the electric utility industry is capitalized. The OCA notes that PPL's proposed capital structure is not really an "actual" capital structure, but rather a projection based on 2012 year-end data. OCA Exc. at 12-13.

Next, the OCA avers that the ALJ erred by finding that PPL's capital structure is not atypical, as the Company's proposed capital structure contains significantly more equity than comparable utilities. According to the OCA, the average common equity ratio for publicly-traded electric and combination gas and electric utilities is 45.9% as reported by AUS Utility Reports in its May 2012 publication. Also, the OCA submits that the average common equity ratio of PPL's IEG sample group, and the S&P Public Utilities was 44.4% and 45% in 2010, respectively. The OCA opines that these ratios are far below the 50.78% common equity ratio requested by PPL. According to the OCA, the Company's own barometer group shows that a 45% common equity ratio is common in the industry for publicly traded companies. OCA Exc. at 13-14.

The OCA submits that Pennsylvania courts have upheld the use of a hypothetical capital structure where the utility's management adopts an actual capital structure that imposes an unfair cost burden on ratepayers. The OCA refers to *T.W. Phillips Gas and Oil Co. v. Pa. PUC,* 474 A.2d 355, 362 (Pa. Cmwlth.1984) and *Carnegie Natural Gas Co. v. Pa. PUC*, 433 A.2d 938 (Pa. Cmwlth. 1981) as support for its assertion. OCA Exc. at 14.

Next, the OCA reiterates that PPL's average common equity ratio from 2006 through 2010 was 43.7% of permanent capital per PPL's Exhibit PRM 1, Schedule 2. According to the OCA, PPL's requested ratemaking capital structure contains considerably more common equity than that with which it has been successfully capitalized historically. The OCA states that PPL plans to reduce its reliance on preferred stock and increase its reliance on more expensive common equity by means of a $150 million capital contribution to PPL by its parent company, which is a management decision at PPL Corporation that changes the regulated capital structure of PPL. The OCA avers that this new test year capitalization will cost the Company's ratepayers approximately $10.6 million more every year than the capital structure the Company has relied on for many years. The OCA submits that ratepayers should not bear this unnecessary and unfair burden and that the ALJ's recommendation should be rejected. OCA Exc. at 14-15.

I&E also excepts to the ALJ's recommendation on capital structure, stating that the ALJ erred in not applying a more cost-efficient capital structure for PPL, using I&E's calculated industry average, particularly because PPL's more expensive equity ratio is assigned by its affiliate. I&E avers that a hypothetical capital structure based upon an industry average should be used for ratemaking purposes if use of the utility's actual capital structure has the potential to overstate the overall cost of capital. I&E recommends a hypothetical capital structure based upon its industry average of 54.89% long-term debt and 45.11% equity for the FTY. According to I&E, PPL's proposed capital structure is neither representative of the industry norm nor an efficient use of capital. I&E Exc. at 15-16.

I&E submits that while the differences between PPL's and I&E's proposed capital structures are nuanced, PPL's actual capital structure includes sufficiently more expensive equity than less expensive debt, such that I&E's proposed adjustment is appropriate. According to I&E, imposing the industry average capital structure upon PPL saves ratepayers an annual $15 million while still providing the Company competitive and effective means to finance its capital needs. This is particularly true, alleges I&E, given today's economic environment where debt rates have been and remain at all-time lows, and where PPL's capitalization is controlled by its affiliate, which is financially accountable to PPL's corporate parent and not PPL's ratepayers. I&E offers that if the corporate family is unwilling to take advantage of historically low interest rates to benefit its affiliated rate-regulated entity's ratepayers, then it is incumbent upon this Commission to do so. I&E Exc. at 17.

Next, I&E avers that contrary to PPL's characterization, the legal standard for employment of a hypothetical capital structure is not that the actual capital structure is "atypical." Rather, I&E maintains that use of a capital structure that is representative of the industry average presents a better option for PPL's efficient capitalization than the capital structure assigned to PPL by its corporate family. According to I&E, use of a barometer group average is more reliable than comparing data from individual companies as individual company data may be subject to short-term anomalies that distort its return on equity. I&E notes that its industry average, as well as the common equity ratio averages from PPL's own barometer groups (44.8% for EDG, 45.1% for IEG and 45.3% for the S&P Public Utilities) more closely support I&E's recommended capital structure of 45% equity and 55% debt. I&E Exc. at 18.

In conclusion, I&E submits that while it agrees that PPL's actual capital structure does not deviate substantially from the industry range, the applicable legal standard is not that the capital structure must be "atypical" before a hypothetical structure should be considered. I&E notes that Commission decisions have specifically avoided setting numeric standards to define efficient capital structures, instead using standards such as "in proper proportions," "on balance," and not "too heavily weighted" one way or another. I&E opines that a $15 million ratepayer expense based solely upon a capital structure chosen by the same PPL affiliates that benefit from the profitability of the rate regulated entity is unfair and unreasonable to ratepayers because it can be moderated without financial harm to PPL through a minor adjustment to the rate-regulated entity's capital structure. Therefore, I&E requests that its capital structure be adopted to impartially achieve a fair balance of ratepayer and shareholder interests. I&E Exc. at 21-22.

In reply, PPL states that the ALJ's recommendation should be accepted as its actual capital structure is not atypical and, pursuant to precedent, provides no basis to employ a hypothetical capital structure. Also, PPL states that it requires an equity ratio near the high end of the historic range employed by the barometer group companies to support its expanded infrastructure replacement program and its credit rating. According to PPL, the OCA and I&E misstate the circumstances that authorize the use of a hypothetical capital structure. PPL avers that both Parties rely on statements in cases where the utility's equity ratio was outside the range of the equity ratios of barometer group companies to contend that a hypothetical capital structure should be employed in this proceeding where the actual equity ratio is clearly within the historic range of equity ratios employed by barometer group companies. PPL opines that while the cases cited identify the Commission's power to employ a hypothetical capital structure where the actual capital structure is extreme and atypical, they do not address how to determine when the actual capital structure is atypical. PPL R. Exc. at 3-4.

Next, PPL avers that its equity ratio is not atypical and provides no basis for use of a hypothetical capital structure and that its equity ratio is necessary to support its ability to attract capital and maintain its credit rating. PPL maintains that these are important considerations as it continues to ramp up its infrastructure replacement program. PPL avers that the OCA and I&E are ignoring the fact that PPL's unsecured bond was downgraded from Baa1 to Baa2 by Moody's Investors Service in April of 2010 due to Moody's opinion that PPL's cash flow metrics will decline from their recent levels due, in part, to the increased expenditures for capital investments needed to maintain PPL's aging delivery systems. According to PPL, the modest increase in the equity ratio was designed to avoid any further downgrade of PPL's rating to Baa3 and is consistent with projections of increasing equity ratios for other electric utilities as they expand their infrastructure replacement programs. PPL R. Exc. at 4-5.

Finally, PPL avers that the OCA's and I&E's claimed savings calculations are illusory because they incorrectly assume that PPL can undertake a dramatically expanded infrastructure program without strengthening its equity ratio. PPL states that it should not be placed at a disadvantage in raising capital and be placed at risk of a further downgrade by adopting a hypothetical equity ratio. Also, PPL avers that the OCA's and I&E's calculations are erroneous because they ignore the fact that a substantial part of the increase in PPL's equity ratio results from refinancing preference stock, which does not receive a tax deduction on dividends, with 50% equity and 50% tax deductible debt at a small net savings to ratepayers. As a result, PPL explains that the Parties alleged savings from a lower equity ratio are significantly overstated because they incorrectly assume that the increased equity to refinance preference stock increases costs to ratepayers. PPL R. Exc. at 6.

d. Disposition

Upon our consideration of the evidence of record, the Recommended Decision and the Exceptions and Reply Exceptions filed by the Parties, we are persuaded by the position of PPL to adopt the Company's actual capital structure and affirm the recommendation of the ALJ. It is important to note that the actual capital structure represents the Company's decision, in which it has full discretion, on how to capitalize its rate base. This actual capitalization forms the basis upon which PPL attracts capital. PPL's debt cost rate of 5.50%, which all Parties have accepted for ratemaking purposes, fully reflects the capitalization determined by the Company to be appropriate. Absent a finding by the Commission that a utility's actual capital structure is atypical or too heavily weighted on either the debt or equity side, we would not normally exercise our discretion with regard to implementing a hypothetical capital structure. *See, Pa. PUC v. City of Lancaster –Water*, 1999 Pa. PUC Lexis 37 at *17; *Carnegie Natural Gas Co. v. Pa. PUC,* 433 A.2d 938, 940 (Pa. Cmwlth. 1981). With regard to these factors, we are persuaded by the arguments of PPL that its actual capital structure is not atypical, is within a range of reasonableness, and, pursuant to precedent, provides no basis to employ a hypothetical capital structure. Also, we are further swayed by PPL's assertion that it requires an equity ratio near the high end of the historic range employed by the barometer group companies to support its expanded infrastructure replacement program and its credit rating.

Accordingly, based upon the foregoing discussion, we shall deny the Exceptions of I&E and the OCA, and adopt the recommendation of the ALJ to utilize PPL's actual capital structure of 49.22% long-term debt and 50.78% common equity.

3. Cost of Debt

PPL proposed to use its expected cost of long-term debt and amortization of loss on reacquired debt for the FTY of 5.50%. PPL M.B. at 91. Both I&E and the OCA agree with PPL that 5.50% is the appropriate cost of long-term debt for purposes of this proceeding.[10] I&E M.B. at 83; OCA M.B. at 46. This cost of debt was unopposed by any Party. R.D. at 60. No Exceptions were filed on this issue. Finding the PPL proposed cost of debt to be reasonable and appropriate, we adopt it without further comment.

4. Cost of Equity

a. Overview

Although there are various models used to estimate the cost of equity, the Discounted Cash Flow (DCF) method applied to a barometer group of similar utilities, has historically been the primary determinant utilized by the Commission. *Pa. PUC v. City of Lancaster – Bureau of Water*, Docket No. R-2010-2179103, at 56 (Order entered July 14, 2011); *Pa. PUC v. PPL Electric Utilities Corp.*, Docket No. R-00049255, at 59 (Order entered December 22, 2004). The DCF model assumes that the market price of a stock is the present value of the future benefits of holding that stock. These benefits are the future cash flows of holding the stock, *i.e.*, the dividends paid and the proceeds from the ultimate sale of the stock. Because dollars received in the future are worth less than

[10] As noted above, PPL adjusted its long-term debt cost to reflect the results of the Company's actual issuance of $250 million of long–term debt, which reduced its weighted average long-term debt cost to 5.50%. PPL M.B. at 91.

dollars received today, the cash flow must be "discounted" back to the present value at the investor's rate of return.

b. Summary

In the instant proceeding, only PPL, I&E and the OCA presented a position on a reasonable rate of return on equity (ROE). The Parties' positions were generally developed through comparison groups' market data, costing models, reflection or rejection of risk and leverage adjustments and a management performance adjustment, as will be further addressed, *infra*. The following table summarizes the cost of common equity claims made and the methodologies used by the Parties in this proceeding:

	DCF (%)	RP (%)	CAPM (%)	CE (%)	Risk (%)	Leverage (%)	MEA (%)	ROE (%)
PPL-EDG	9.67	10.75	10.58	11.60	1.20	0.7	0.12	11.13
PPL-IEG	9.69	10.75	11.28	11.60	1.20	1.18	0.12	11.43
OCA	8.97	7.3	-----	-----	0	0	0	9.00
I&E	8.38	-----	8.68	-----	0	0	0	8.38
ALJ	9.68	-----			0	0	0.06	9.74

PPL proposed a common equity cost rate of 11.25% based on the results of the DCF, Risk Premium (RP), Capital Asset Pricing Model (CAPM) and Comparable Earnings (CE) methodologies. PPL included a risk adjustment of 120 basis points, a leverage adjustment of 70 basis points, and a management performance adjustment of 12 basis points to arrive at its total request. PPL stated that the use of more than one method provides a superior foundation to arrive at the cost of equity. According to PPL, at any point in time, reliance on a single method can provide an incomplete measure of the cost of equity. PPL St. 11 at 5-6.

Both the OCA and I&E argued that an 11.25% return on equity is excessive. The OCA stated that it would result in a shareholder windfall at the expense of ratepayers and would result in rates that are unjust and unreasonable. The OCA stated that "the current and near-term future economic outlook is one that includes a low cost of capital." OCA St. 2 at 11-19. The OCA proposed a common equity cost rate of 9.00%, based primarily on the results of the DCF analysis without consideration of any of the additional adjustments proposed by the Company. The OCA utilized a CAPM, a Modified Earnings-Price Ratio (MEPR) and a Market-to-Book Ratio analyses as a check on the reasonableness of the DCF results. The OCA also cited numerous other jurisdictions which have awarded less than 10% returns on equity. OCA M.B. at 47-52 (citing *e.g.*, *In re PEPCO*, Order No. 85028 (MD PSC, July 20, 2012) (authorizing a 9.31% ROE)).

I&E recommended a cost of common equity of 8.38% based on the DCF methodology, with consideration of CAPM as a check, with no additional adjustments. I&E's analysis used a spot dividend yield and a 52-week dividend yield, and a combination of earnings growth forecasts and a log-linear regression analysis growth rate. Using the standard DCF model formula,[11] I&E recommended a dividend yield of 4.89% and a recommended growth rate of 3.49%. I&E M.B. at 84-86.

[11] I&E St. 1 at 24.

c. Cost Rate Models

i. Positions of the Parties

PPL performed a RP analysis to determine the cost of equity, based upon the basic financial tenet that an equity investor in a company has greater risk than a bond holder in a company. PPL explained this is because all interest on bonds is paid before any return is received by the equity investor, and, upon bankruptcy or dissolving a company, the bond holder receives his capital before any capital is provided to the equity investors. PPL M.B. at 109-110; PPL St. 11 at 44; Appendix G at G-2.

PPL claimed that the RP method has common sense appeal to investors, who would expect to earn equity returns in excess of bond returns, as has been the case for any extended period in the capital markets. Accordingly, the Company explained the RP method as determining the cost of equity by summing the expected public utility bond yield and the return of equities over bond returns (the "equity premium") over a historic period, as adjusted to reflect lower risk of utilities compared to the common equity of all corporations. PPL St. 11 at 49-50; PPL M.B. at 110.

The Company determined the RP cost of equity to be 10.75% as follows:

Interest Rate		Risk Premium		Cost Rate
5.25%	+	5.50%	=	10.75%

Id.

PPL also performed a CAPM analysis to estimate the cost of equity for the EDG and IEG and determined the risk free rate to be 3.75% based on current and near term project yields on long term treasury bonds. PPL St. 11 at 53-54. According to PPL, the CAPM analysis determines a "risk-free" interest rate based on U.S. Treasury obligations and an equity risk premium that is proportional to the systematic (*i.e.,* beta) risk of a stock, which are combined to produce cost rate of equity. PPL St. 11 at 50-52.

PPL determined the market or equity premium to be 8.76% based upon an average of historic and projected market premiums. PPL St. 11 at 54; Appendix H at H-4 - H-6. PPL stated that betas are applied to the market premiums to adjust for electric company risks relative to the total market, and the betas are adjusted for the same reasons as the leverage adjustment to the DCF. PPL St. 11 at 52-53. Finally, the Company added a size adjustment to reflect greater risk for smaller firms relative to the market. PPL St. 11 at 54-55. The result of the PPL CAPM analysis was 11.78% for the EDG and 12.48% for the IEG. According to PPL, the results of the CAPM analysis indicate the upper range of the cost of equity analysis using the theoretical models typically employed in utility rate cases. PPL M.B. at 113.

PPL further performed a CE analysis. PPL noted that because regulation is a substitute for competitively determined prices, returns realized by non-regulated firms with similar risks can be used as a guide to determine a fair rate of return. PPL St. 11 at 56. Based on the PPL analysis, the comparable earnings group yielded an historical return of 10.9% and a forecasted return of 12.3%, which resulted in an average return of 11.6%. PPL M.B. at 113-114.

I&E stated that while it was not opposed to using the CAPM results as a comparison to the results of the DCF calculation, it is inappropriate to give the CAPM, RP and CE models comparable weight. I&E St. 1 at 38. I&E recommended against using the RP method and averred that it cannot be used because it relies on historic risk premiums achieved over bond yields which may not be applicable to the future. I&E St. 1 at 19.

Both the OCA and I&E used a CAPM as a check of reasonableness for their DCF calculations. However, both also believe there are shortcomings to this model, express concerns regarding its use and note their preference for using the DCF model to determine the cost of equity capital. I&E M.B. at 85; OCA St. 2 at 39.

I&E also performed an analysis of a return on equity using the CAPM methodology but gave no specific weight to its CAPM results because of its concerns that unlike the DCF, which measures the cost of equity directly by measuring the discounted present value of future cash flows, the CAPM measures the cost of equity indirectly and can be manipulated by the time period used. However, having presented two analyses – historic and forecasted – both of which are comprehensive in the time periods covered, I&E submitted that for purposes of providing another point of comparison, the 8.68% simple average of those two analyses confirmed the reasonableness of the I&E 8.38% return under its DCF calculation. I&E St. 1 at 31-36; I&E M.B. at 88-89.

In its CAPM analysis, OCA chose a risk free rate based on the long-term trend for Treasury Bonds, which it determined to be 4% for a forward looking CAPM analysis. Based on historical Morningstar data which shows an 11.8% return on stocks and a 5.8% return on long-term Treasury bonds since 1926, the OCA determined a risk premium of 6%; yielding an overall expected stock market return of 10% (4% + 6%). The OCA determined a beta of 0.69 based on *Value Line* beta coefficients for its electric group. Based on this analysis, the OCA's CAPM analysis yielded a cost of equity of 8.14% (4 %+(0.69*6%)). OCA St. 2 at 41-44.

I&E did not perform a CE analysis. I&E stated that the CE methodology is subjective in terms of the selection of comparable companies, has generally been rejected by the Commission and, in PPL's particular analysis, compares projected returns of companies of dissimilar business and financial risks.[12] I&E M.B. at 92.

ii. ALJ's Recommendation

Based on the I&E position, the ALJ recommended that reliance on the RP method be denied. The ALJ concluded that the Commission's preferred method of determining a utility's ROE is the DCF model. The ALJ recommended utilization of the I&E DCF analysis. R.D. at 78, 93.

d. Dividend yields

i. Positions of the Parties

PPL derived the dividend yield by calculating the six month average dividend yields for each group and adjusting those yields for expected growth in the following year to produce the 4.67% for the Electric Delivery Group and 4.69% for the Integrated Electric Group. PPL St. 11 at 26; PPL M.B. at 104.

I&E stated that a representative yield must be calculated over a time frame sufficient to avoid short-term anomalies and stale data. The I&E's dividend yield calculation placed equal emphasis on the most recent spot (4.78%) and 52-week average (5%) dividend yields resulting in an average dividend yield of 4.89%. I&E St. 1 at 40-41; I&E M.B. at 86.

The OCA employed a 4.44% DCF adjusted yield, based upon the average dividend yield of its proxy group of similar companies. OCA St. 2 at 38; OCA M.B. at 55.

[12] I&E St. 1 at 19-23, 38-39.

ii. ALJ's Recommendation

For the reasons set forth by I&E, the ALJ recommended the adoption of the I&E proxy group and methodology for determining a 4.89% dividend yield. R.D. at 66.

e. Growth Rates

i. Positions of the Parties

PPL reviewed various methods of calculating investor expected growth rates and concluded that analysts' projections of growth rates are the best indicator of expected growth. PPL St. 11 at 34. PPL arrived at a range of growth rates from 4.50% to 5.08% for the EDG and from 4.59% to 6.00% for the IEG. PPL chose a growth rate of 5.00% based upon an average EDG growth rate of 4.87% and an average IEG growth rate of 5.14%. PPL M.B. at 105.

I&E used both earnings growth forecasts and a log-linear regression analysis data to calculate its expected growth rate. The I&E earnings forecasts were developed from projected growth rates using five-year estimates from established forecasting entities for the selected barometer group of companies, yielding an average five-year growth forecast of 4.79%. I&E St. 1 at 25-26.

I&E averred that investor forecasts may be biased and/or distorted by misestimates and, therefore, used a log-linear regression analysis to determine a more appropriate long term growth rate. I&E's log-linear regression analysis used historic earnings per share (EPS) from *Value Line* for the years 2006-2011, and the financial analysts forecasted growth rate to project EPS values for the FTY (2012) through 2016. The result of this log-linear regression analysis provided an average growth rate of 3.49%. I&E St. 1 at 25-30; I&E M.B. at 85-86.

ii. ALJ's Recommendation

The ALJ recommended using the 4.79% growth rate of I&E without the log-linear analysis. R.D. at 68.

Based upon the ALJ's recommendation with regard to her dividend yield recommendation of 4.89% and her 4.79% recommendation for PPL's growth rate, the ALJ recommended utilization of a DCF based 9.68% cost of equity, prior to the adoption of any of PPL's proposed adjustments.

iii. Exceptions

PPL excepts to the ALJ's conclusion with regard to its cost rate for common equity, stating that the ALJ's recommendation is far too low and should be increased to at least 10.5%. PPL avers that the principal error in the ALJ's analysis contained in the Recommended Decision is its sole reliance on an unadjusted DCF cost rate without any check on its validity. PPL submits that the ALJ simply rejects the results of other cost rate models based on alleged flaws in the models without recognition of the flaws of the DCF model. PPL Exc. at 6-7.

With regard to the ALJ's rejection of the RP method, PPL states that the RP method has particular applicability in this case because it reflects the prospective A-rated public utility bond yield under current market conditions. Therefore, PPL alleges, it reflects interest rates to be experienced by public utilities during the period rates will be in effect. According to PPL, using an A-rated bond yield produces an equity cost rate below PPL's cost rate because PPL is rated Baa2, indicating a higher cost of debt and equity. PPL notes that the OCA witness admitted that risk premiums tend to increase during periods of lower interest rates. PPL Exc. at 8; Tr. at 329-330. Accordingly, PPL submits that it is likely that the lower interest rates currently being experienced indicate that the average historic premium understates the premium expected by investors for the future. This, PPL asserts, makes the RP analysis in this case conservatively low under current market conditions. PPL opines that the 10.75% RP provides a clear demonstration of the inadequacy of the unadjusted DCF analysis. PPL Exc. at 7-8.

With regard to the ALJ's rejection of the CAPM analysis as a check on the ROE recommendation, PPL submits that the ALJ simply accepted the OCA's and I&E's contention that there are "shortcomings" in the model. PPL avers that its CAPM analysis resulted in a cost rate of 10.58%, after removal of the 120 basis point size adjustment which the ALJ's rejects. PPL maintains that the ALJ did not provide any basis for rejecting the revised CAPM analysis excluding the size adjustment. PPL notes that the ALJ herself noted that the Commission has concluded that it is necessary to use other methods as a check on the results of the DCF, citing the Commission decision in PPL's 2004 rate case. PPL proffers that based on that decision, the ALJ's sole reliance on a DCF analysis with no leverage adjustment should not be adopted. According to PPL, the ALJ failed to follow the Commission precedent by either adding the leverage adjustment to the unadjusted DCF result or relying on other methods, such as the RP. PPL Exc. at 9-10.

PPL further excepts to the ALJ's apparent reliance on the Maryland *In re PEPCO* decision, *supra*, to justify an ROE less than 10%. PPL avers that neither the ALJ nor the OCA cites a further quote from the *In re PEPCO* decision provided in the Company's Reply Brief, which explained that the ROE that was approved for PEPCO reflected poor service quality and the effects of a revenue decoupling mechanism employed by PEPCO. PPL maintains that neither of those circumstances apply to PPL and, as such, the 9.31% ROE does not demonstrate the reasonableness of the ALJ's recommended allowance for PPL in this proceeding. PPL notes that the ROE should reflect prospective conditions, as relying too much on the past can risk under-estimating the cost of equity capital that PPL will face as it seeks to raise capital to fund its expanded infrastructure improvement program during the period that rates set in this proceeding will be in effect. PPL Exc. at 16-19.

In reply, the OCA avers that the ALJ was correct in primarily relying on the DCF results to arrive at a reasonable ROE for PPL. The OCA states that the ALJ spent considerable effort in her Recommended Decision reviewing and discussing the results of the Parties' various ROE estimating studies, other than the DCF, and that PPL's criticism of the ALJ for relying on an unadjusted DCF result without any check on its validity is unwarranted. According to the OCA, the ALJ correctly concluded that the Commission primarily relies on the DCF method to establish a reasonable ROE. The OCA points out that the ALJ provided an extensive discussion and review of the results of the RP analysis, the CAPM analysis, and PPL's CE study, which led the ALJ to conclude that they should not be relied upon in this proceeding. The OCA submits that the ALJ's conclusion to rely primarily on the DCF method to arrive at an ROE recommendation is consistent with well-established Commission precedent and should be accepted. OCA R.Exc. at 4-8.

In response to PPL's Exception with regard to the *PEPCO* decision referenced by the ALJ, the OCA states that PPL's attempt to differentiate the *PEPCO* decision from its situation is without merit. The OCA submits that the quoted portions of the *PEPCO* Order only serve to reinforce the fact that the ALJ's recommendation of a 9.68% ROE is adequate and reasonable. According to the OCA, PPL is similar to PEPCO as it owns no generation, has no competition for distribution service and serves a heavily residential customer base, so PPL's attempts to distance itself from PEPCO is without merit and should be rejected. OCA R.Exc. at 10-14.

In its Reply Exceptions, I&E asserts that the ALJ's 9.68% calculated ROE is supported by the record and should be adopted. I&E asserts that as this Commission recently confirmed, although it may review other results as a check, the Commission relies primarily on the DCF methodology. I&E R.Exc. at 18 (citing *Pa. PUC v. City of Lancaster – Bureau of Water*, Docket No. R-2010-2179103, at 56 (Order entered July 14, 2011)). Therefore, I&E avers that PPL's assertions are erroneous as the DCF has always been the primary standard. Notwithstanding this position, I&E posits that the reasonableness of the ALJ's recommendation was confirmed by I&E's two CAPM analyses, the historic and forecasted. According to I&E, its 8.68% simple average of its two CAPM studies, employing the same simple averaging PPL undertook of its four methodologies, confirmed the reasonableness of I&E's DCF return of 8.38%. I&E points out that since the ALJ rejected its log linear regression analysis, the ALJ's recommended 9.68% recommended ROE is substantially higher than the 8.68% check provided by its CAPM analysis. I&E R.Exc. at 17-19.

iv. Disposition

Upon our consideration of the record evidence, we agree with the finding of the ALJ that the Company's cost of equity in this proceeding should primarily be based upon the use of the DCF methodology. We also are persuaded by the arguments of PPL that it is important to temper the results of the unadjusted DCF results in comparison to the results from the other cost of equity methodologies as presented by the Parties in the context of this proceeding. Sole reliance on one methodology without checking the validity of the results of that methodology with other cost of equity analyses does not always lend itself to responsible ratemaking. We conclude that methodologies other than the DCF can be used as a check upon the reasonableness of the DCF derived equity return calculation. *See*, *Pa. PUC v. PPL Electric Utilities Corp*., Docket No. R-00049255, at 67 (Order entered December 22, 2004). It is important to recognize that each of the Parties presenting a cost of equity position in this proceeding have done so. We also note that we historically have primarily relied upon the DCF methodology in arriving at previous determinations of the proper cost of equity and utilized the results of methods, such as the CAPM and RP methods, as a check upon the reasonableness of the DCF derived equity return amount, tempered by informed judgment. As such, where evidence based on the CAPM and RP methods suggests that the DCF-only results may understate the utility's current cost of equity capital, we will give consideration to those other methods, to some degree, in determining the appropriate range of reasonableness for our equity return determination. Therefore, we are not in agreement with the ALJ that the proper ROE in this proceeding should be determined based strictly on the reliance of the unadjusted DCF calculations presented by the Parties.

In *Lower Paxton Township v. Pa. PUC,* 317 A.2d 917, 920-921 (Pa. Cmwlth. 1974), the Commonwealth Court recognized that the Commission may consider its judgment as well as other factors which affect the cost of capital, including the utility's financial structure, credit standing, dividends, risks, regulatory lag and any peculiar features of the utility involved. The Court stated that "the cost of capital is basically a matter of judgment governed by the evidence presented and the regulatory agency's expertise." *Id*. at 921. Here, we are guided by the legal analysis in *Lower Paxton.* In this case, we will rely upon the DCF methodology and informed judgment in arriving at our determination of the proper cost of common equity. In particular, we note that the evidence presented in this case based on the CAPM and RP methods produced a range of results that was consistently higher than the results produced by a DCF-only approach. This suggests that, while properly computed in the abstract, the DCF-only results understate the current cost of equity for PPL and that consideration should be given to the CAPM and RP evidence in determining the appropriate range of reasonableness. Furthermore, we note that the setting of the proper return on equity is even more critical in this proceeding as our Pennsylvania jurisdictional utilities implement plans to accelerate the greatly needed replacement of aging infrastructure. Attracting capital to Pennsylvania at reasonable rates to accomplish this infrastructure replacement has never been more important to PPL, its customers and the Commonwealth of Pennsylvania.

Based upon our analysis and review of the record evidence, we find that a range of reasonableness for the cost of equity in this proceeding is from 9.0% to 11.25%. We conclude that within that range, considering PPL's need to fund $1.6 billion of planned distribution improvements between 2012 and 2016, a cost of common equity of 10.28% is reasonable and appropriate to incorporate into our return determinations under the circumstances of this proceeding. We note that this return on equity is exclusive of any of the PPL-requested adjustments to be discussed, *infra.* We note, further, that (1) the DCF-derived cost of equity ranged from 8.38% (I&E) to 9.69% (PPL); (2) the range determined from the RP methodology was 7.3% (OCA) to 10.75% (PPL); and (3) the range of the CAPM calculations was 8.14% (OCA) to 11.28% (PPL). Based upon our consideration and analysis of this evidence, as explained herein, we are of the opinion that an equity return of 10.28% is reasonable and appropriate for PPL.

Accordingly, the Exceptions of PPL are granted, in part, to the extent consistent with the foregoing discussion.

f. Leverage Adjustment

i. Positions of the Parties

PPL promoted a leverage adjustment in this proceeding, which it explained was designed to adjust the DCF cost rate for the different percentage level of debt in the capital structure when capital structure is calculated at the market prices of equity and debt securities as opposed to book value. PPL M.B. at 105.

PPL proposed a 70 basis point leverage adjustment to its EDG and a 118 basis point leverage adjustment to its IEG. PPL theorized that if regulators use the results of the DCF to compute the weighted average cost of capital based on a book value capital structure used for ratemaking purposes, the utility will not, by definition, recover its risk-adjusted capital cost. PPL believed this is because market valuations of equity are based on market value capital structures, which in general have more equity, less debt and, therefore, less risk than the capitalization measured at its book value. PPL St. 11 at 35.

The Company pointed out that the Commission has accepted the leverage adjustment in a number of cases, including PPL's last fully litigated rate case in 2004. PPL M.B. at 107 (citing *Pa. PUC v. Pa. American Water Co.*, Docket No. R-0001639 (Order entered January 10, 2012) (60 basis point adjustment); *Pa. PUC v. Philadelphia Suburban Water Company,* Docket No. R-00016750 (Order entered August 1, 2002) (80 basis points); *Pa. PUC v. Pa. American Water Co.*, Docket No. R-00038304 (Order entered November 8, 2004) (60 basis points affirmed); *Popowsky v. Pa. PUC*, 868 A.2d 606 (Pa. Cmwlth. 2004); *Pa. PUC v. Aqua Pa. Inc.*, Docket No. R-00038805 (Order entered August 5, 2004) (60 basis point adjustment); *Pa. PUC v. PPL Electric Utilities Corp.,* Docket No. R-00049255 (Order entered December 22, 2004) (45 basis point adjustment); *Pa. PUC v. PPL Gas Utilities Corp.,* Docket No. R-00061398 (Order entered February 8, 2007) (70 basis points)).

According to PPL, use of the DCF alone, and without consideration of the leverage adjustment, significantly understates the cost of equity. PPL opined that when investors' expectations of future earnings are pessimistic due to factors including future regulatory allowances, there is the potential for the DCF to be circular and not market based. PPL St. 11 at 24; PPL M.B. at 108.

I&E argued that rating agencies assess financial risk based upon the Company's booked debt obligations and the ability of its cash flow to cover the interest payments on those obligations by using financial statements, particularly income statements, for their analyses, not market capitalization.

I&E pointed out that, while the Commission has granted this adjustment on occasion, it has also rejected it:

> In a Blue Mountain Water Company case on remand from Commonwealth Court to clarify findings concerning fair rate of return, the Commission identified seven principles that were applied to analyze the company's required and lawful rate of return. The Commission's third identified principle stated that "[m]arket price-book value ratios are not a goal of regulation but a result of regulation, general economic factors and individual company's characteristics of management, operations and perceived future. *In general, we view a market-book ratio in the area of one-to-one as appropriate for regulated industry*."[13]
>
> In a 2008 case involving Aqua Pennsylvania, Inc., the Commission rejected the ALJ's recommendation for a leverage adjustment stating, "the fact that we have granted leverage adjustments in the past does not mean that such adjustments are indicated in all cases."[14] In a 2007 Metropolitan Edison Company case, the Commission rejected the Company's financial risk increment related to the leverage difference between market capital structures and book value capital structures.[15] Most recently in a City of Lancaster case, the Commission agreed with Ms. Sears' recommendation to reject the leverage adjustment, stating "any adjustment to the results of the market based DCF as we have previously adopted are unnecessary and will harm ratepayers. Consistent with our determination in *Aqua 2008* there is no need to add a leverage adjustment."[16]

I&E M.B. at 73-74.

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[13] *Pa. PUC v. Blue Mountain Consolidated Water Co.*, 1982 WL 213115, at 1 (emphasis added).

[14] *Pa. PUC v. Aqua Pennsylvania, Inc.*, Docket No. R-00072711, at 38 (Order entered July 31, 2008).

[15] *Pa. PUC v. Metropolitan Edison Co.*, Docket No. R-00061366, at 34 (Order entered January 11, 2007).

[16] *Pa. PUC v. City of Lancaster – Bureau of Water*, Docket No. R-2010-2179103, at 79 (Order entered July 14, 2011).

I&E determined that there are six cases in which the Commission accepted the leverage adjustment, most recently in 2007. According to I&E, the adjustment has been proposed in sixty-eight cases over a twenty-three year period, yielding six successful results. Finally, I&E charged that PPL's formulae for the adjustment are flawed as it used formulae which do not appear in the research cited to support it. I&E M.B. at 100.

The OCA recommended against the Company's leverage adjustment because there was no evidence to support a risk difference between a market-based capital structure and a book value capital structure. Rather, according to the OCA, the claim that the DCF results should be increased by 70-118 basis points due to PPL's leverage adjustment is "not sound ratemaking." OCA M.B. at 60. The OCA submitted that no ROE-enhancing adder is needed or appropriate for PPL based on the facts of this matter. As the OCA witness testified:

> While there are certainly many aspects of rate of return analysis that are subject to judgment and, thus, debate regarding the proper application of a particular technique, Mr. Moul's use of an imaginary risk difference between a market-based capital structure and a book value capital structure is not one of them. There is no evidence available in the literature of financial economics to support any risk difference between market-value and book-value capital structures. Miller and Modigliani (supposedly the source of Mr. Moul's "leverage" adjustment) do *not* compare market-value and book value capital structures.

OCA St. 2-SR at 4. (emphasis in original).

According to the OCA, PPL testified that when utility market prices exceed book values, a risk difference exists between market-value capital structures and book-value capital structures, and market-based cost of equity estimates should, therefore, be adjusted upwards to account for that risk difference. The OCA noted that this is the basis for PPL's "leverage adjustment." OCA St. 2 at 55-56. The OCA witness testified as to the flawed nature of this theory, in relevant part:

> There simply is no difference in financial risk when the market-value capital structure of a firm is different from the book-value capital structure. Financial risk is a function of the interest payments on the debt issued by the firm. That is, a firm's debt payments create financial risk and when the amount of debt used to finance plant investment increases relative to common equity the financial risk increases. Whether the capital structure is measured with market values or book values, the debt interest payments do not change and, therefore, financial risk does not change. As a result, market-value capital structures are useful as indicators of financial risk only when they are compared with other market-value capital structures (as Miller and Modigliani do in their treatise), and Mr. Moul's mixed-metaphor comparison of market-value and book-value capital structures has no economic meaning.

OCA St. 2 at 56.

> The Company is making an improper comparison between market value capital structures and book value capital structures in order to claim that a financial risk difference exists. When utility common equity market prices are above book value, the capital structure measured with market values will have a higher equity percentage and lower debt percentages than the capital structure measured with book value. That does not mean, as the Company claims, that those different capital structure measures signify any difference whatsoever in financial risk.

OCA St. 2 at 61.

The OCA acknowledged that, in some cases, the Commission made an adjustment to a DCF based cost of equity such as that proposed by PPL.

However, the OCA claimed that, more recently, the Commission has not adopted PPL's leverage adjustment, as Mr. Hill testified:

> [I]t is important to note that this Commission has rejected "financial risk adders" in Docket No. R-00061366 (Metropolitan Edison (Met Ed), Pennsylvania Electric, Opinion and Order, January 11, 2007, p. 136). The "financial risk adders" in the Met Ed case were based on the leverage/risk difference between market-value capital structures and book value capital structures, just as Mr. Moul's are. In addition, in Docket No. R-00072711, Aqua Pennsylvania, Inc., July 17, 2008, at pages 35 through 39, this Commission specifically rejected Mr. Moul's leverage/risk analysis—the same leverage/financial risk adjustment Mr. Moul uses in his testimony in this proceeding.

OCA St. 2 at 57. The OCA argued that other state commissions have uniformly recognized this type of adjustment as unwarranted in their decisions. OCA M.B. at 62 (citing *West Virginia Public Service Comm'n v. West Virginia-American Water Works*, 2004 W. Va. PUC Lexis 6 at *18 (2004)). In addition to the West Virginia Public Service Commission, other Commissions have rejected similar market-to-book adjustments to the DCF model. The District of Columbia Public Service Commission rejected a company's arguments that an adjustment to the DCF was appropriate to meet investors' requirements. OCA M.B. at 62 (citing *In the Matter of the Application of Washington Gas Light Company, District of Columbia Division, for Authority to Increase Existing Rates and Charges for Gas Service,* 2003 D.C. PUC Lexis 220 at *72 (2003)).

In its surrebuttal testimony in this proceeding, the OCA summarized the reasons this Commission should reject PPL's "fictional leverage" adjustment:

> - The comparison of market value capital structures and book value capital structure to measure financial risk differences, is not supported in the literature of finance;

- There is no financial risk difference between market value and book value capital structures because interest expense (the actual source of financial risk) doesn’t change, regardless of the capital structure measurement perspective;

- One company cannot have two levels of financial risk (i.e., one based on book value and one based on market value);

- The DCF model does not “mis-specify” the cost of equity when market prices are different from book value, and utilities are able to attract capital on reasonable terms absent any so-called “leverage” adjustment;

- Moul’s “leverage” adjustment is, fundamentally, a market-to-book ratio adjustment, and this Commission has rejected market-to-book ratio adjustments in the past;

- The “leverage” adjustment is based on the “fair value” of the capital employed in financing the utility operation, as such it is a surrogate for “fair value” rate base, which results in a revenue requirement higher than that required by law in a regulatory jurisdiction in which rates are to be based on original cost (depreciated book value);

- A utility market price significantly above book value indicates that investors expect that firm to earn a return above its cost of equity, but according to Mr. Moul’s “leverage” adjustment the higher the market price, the greater the upward adjustment necessary, which would exacerbate the over-recovery;

- The “leverage” adjustment recommended by Mr. Moul has been presented in dozens of regulatory jurisdictions. It has been rejected by all of those jurisdictions (including, recently, Pennsylvania).

OCA St. 2-SR at 11. The OCA submitted that for the reasons just discussed, and taking the record as a whole, such an adjustment should not be considered in this matter. OCA M.B. at 60-64.

ii. ALJ's Recommendation

For the reasons developed by the OCA and I&E, the ALJ recommended that the Company's leverage adjustment be denied. R.D. at 76.

iii. Exceptions

PPL excepts to the ALJ's rejection of its proposed leverage adjustment, noting that the Commission has accepted a leverage adjustment in a number of cases, including PPL's last fully litigated rate case in 2004, where the Commission adopted a forty-five basis point adjustment. PPL avers that the ALJ appears to conclude that the OCA's and I&E's criticisms of the leverage adjustment are a basis to reject the leverage adjustment, despite the fact that it has been accepted on numerous occasions in the past and each of these criticisms have been offered in the past. PPL points out that the principal criticism offered by the OCA and I&E is that there is no risk difference between a capital structure where equity is valued at market as compared to book prices, because the amount of interest that must be paid on debt remains the same. PPL opines that the error of this argument is that the interest amounts are greater as a percentage of book equity capitalization than they are as a percentage of market equity capitalization. Therefore, asserts PPL, the risk of debt payments is less as a percentage of market equity capitalization than it is at book equity capitalization. PPL states that because the DCF sets the equity cost rate at market capitalization, it understates the investor cost rate when applied to the rate base. According to PPL, the ALJ erred in declining to include a leverage adjustment when relying solely on the DCF analysis to arrive at the recommended cost of equity. PPL Exc. at 11-16.

In reply, the OCA states that the ALJ was correct to reject the leverage adjustment, as she accepted the fact that artificially increasing the ROE based on a technique that finds no support in the financial literature, does not represent sound ratemaking. Additionally, the OCA avers that PPL's leverage adjustment has been thoroughly reviewed and rejected in virtually every regulatory jurisdiction where it has been proposed, noting that since 2007, PPL's witness has testified in twenty-four regulatory jurisdictions, and none has specifically accepted and utilized the "leverage/risk" adjustment. According to the OCA, there is no need for a leverage adjustment within the confines of standard regulatory practice or a need for such a mechanism in Pennsylvania. OCA R. Exc. at 8-10.

In its Reply Exceptions, I&E asserts that the leverage adjustment is wholly discretionary and, in this case, fundamentally unnecessary, not only for the reasons directly noted by the ALJ, but also because PPL's inputs into its 9.68% DCF calculation are already overstated. Further, I&E opines that today's investment market does not support PPL's ROE. According to I&E, both PPL's calculated growth and dividend rates within its DCF analysis already provide the equity boost that PPL seeks through its leverage adjustment. I&E explains that the PPL 5% growth rate was based on its average barometer group growth rates, which were flawed in I&E's opinion because they did not satisfy even its own criteria. I&E submits that though accepting its unadjusted growth rate of 4.79%, the ALJ nonetheless arrived at a calculated return on equity of 9.6%, the same DCF return calculated by PPL using inflated growth rates. I&E avers that because PPL's DCF calculation already has inflated inputs, a further upward boost from the leverage adjustment is unnecessary. I&E R. Exc. at 19-20.

iv. Disposition

Based upon our analysis of the evidence of record, we are persuaded by the arguments of the OCA and I&E that PPL's requested leverage adjustment is not reasonable and should be denied. The fact that we have granted leverage adjustments in a few select cases in the past as noted by PPL does not mean that such adjustments are warranted in all cases. The award of such an adjustment is not precedential but discretionary with the Commission. In fact, the Commission has rejected leverage/financial risk adjustments that are similar to the one proposed by PPL in this proceeding. *See, e.g., Pa. PUC v. Aqua Pennsylvania, Inc.*, Docket No. R-00072711, at 38-39 (Order entered July 31, 2008). Moreover, in the context of our determination, *supra*, of a reasonable return on equity for PPL of 10.28%, we conclude that there is no need to have an artificial upwards adjustment to compensate for any perceived risk related to PPL's market-to-book ratio. Accordingly, we shall deny the Exceptions of PPL and adopt the ALJ's recommendation to reject PPL's requested leverage adjustment.

g. Risk Adjustment

i. Positions of the Parties

PPL proposed a 120 basis point upward adjustment because the Company believes that as the size of a firm decreases, its risk and, hence, its required return, increases. Further, PPL used the SBBI Yearbook to argue that the returns for stocks in lower deciles had returns in excess of those shown by the simple CAPM. PPL St. 11 at 54-55.

Alternatively, I&E charged that PPL's rate of return recommendations are also grossly overstated by its assignment of several faulty assumptions of risk to PPL. I&E noted:

> While some technical market literature supports adjustments relating to a company's size, in a critical point of distinction, this literature is *not* specific to the utility industry. On the other hand, utility-specific academic literature specifically argues against a size adjustment for utilities. A specific study of utility stocks and the size effect concluded as follows:
>
> The objective of this study is to examine if the size effect exists in the utility industry. After controlling for equity values, there is some weak evidence that firm size is a missing factor from the CAPM for the industrial but not for utility stocks. This implies that although the size phenomenon has been strongly documented for the industrials, the findings suggest that *there is no need to adjust for the firm size in utility rate regulation.*[17]

As to unpredictability, I&E stated that "one cannot expect risky companies to always outperform less risky companies; otherwise they would not be risky." I&E M.B. at 101-103.

ii. ALJ's Recommendation

The ALJ recommended that PPL's proposed size adjustment be denied. R.D. at 82.

iii. Exceptions

No Party filed Exceptions on this issue with regard to the ALJ's recommendation. Finding the ALJ's recommendation to be reasonable, we adopt it without further comment. Accordingly, PPL's proposed size adjustment is denied.

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[17] I&E M.B. n. 220; I&E St. 1 at 55, citing Dr. Annie Wong, "Utility Stocks and the Size Effect: An Empirical Analysis," *Journal of Midwest Finance Association*, 1993, at 95-101 (emphasis added), reproduced in I&E Exh. I, Sch. 15.

h. Management Effectiveness Adjustment

i. Positions of the Parties

PPL included a twelve basis points management effectiveness adjustment to its return on equity claim. Both I&E and the OCA oppose any allowance for management effectiveness.

The Company summarized its evidence in support of this adjustment as follows:

> PPL Electric's management is effectively controlling costs, while at the same time, providing customers with high quality service and expanded service options. As detailed in the Statement of Reasons, the Company has taken substantial efforts to improve productivity and manage costs, including, but not limited to: (1) new technology to improve productivity and including advanced meters; (2) a smart grid distribution automation system, which will provide direct reliability benefits to over 60,000 customers in the project area and lead to increased reliability benefits to all customers by providing system operators advanced and timely situational awareness and control capabilities through a wider deployment throughout PPL Electric's service territory; (3) a work and asset management system, which is a new large scale software solution that will improve associated work management business processes in order to more effectively and efficiently manage the portfolio of work; (4) several initiatives to improve storm processes including call handling time and volume; (5) increased investment to address aging infrastructure, which will have a positive, long-term benefit in controlling reactive operating costs; and (6) capital investment in information systems to support customer choice and to provide expanded self-service options for customers, which improves service to customers while controlling operating costs. In addition, the Company is testing and evaluating a variety of applications and features that will expand the capabilities of the current system and equipment over the next five years.

PPL M.B. at 116-117.

I&E argued that the twelve basis points sought by PPL translates into an additional $3 million in rate revenues. Tr. at 335; I&E M.B. at 116. I&E argued further that there is considerable room for improvement in several areas, including preventable major outages, customer service calls answered within thirty seconds, the number and percentage of bills not rendered to residential customers and small businesses, and the number of disputes with no response within thirty days. I&E M.B. at 119-120. As I&E saw it, PPL's requested twelve basis point upward adjustment to the cost of equity is neither warranted nor supported. I&E opined that it should be rejected. I&E M.B. at 123.

The OCA agreed with I&E. The OCA referred to the $832,000 that PPL has either agreed to pay or was ordered to pay in fines and penalties. OCA M.B. at 65.

ii. ALJ's Recommendation

The ALJ stated that PPL presented substantial evidence of management effectiveness in a number of areas, including advanced metering infrastructure, operating initiatives, customer contact center, customer education, energy efficiency programs, and customer assistance programs. According to the ALJ, the provision of safe, reliable, adequate and reasonable service is the minimum required by the Code, and simply meeting that standard does not warrant excessive rewards. However, the ALJ concluded that the actions taken by PPL in its response to Commission initiatives, and in providing excellent, albeit imperfect, service, in meeting the needs of its ratepayers and customers, merited a management effectiveness increase of six basis points. R.D. at 89

iii. Exceptions

In its Exceptions, PPL notes that the ALJ correctly summarized PPL's evidence presented to support its management performance adjustment. However, PPL criticizes the ALJ for recommending a six basis point adjustment in lieu of its twelve basis point request, as she relied on certain criticisms of PPL where the Company agreed to negotiate payments to resolve certain alleged violations of the Code or Commission Regulations. PPL avers that these limited circumstances do not provide a basis for denying PPL's requested twelve basis point adjustment to the cost of equity. PPL Exc. at 19.

The OCA excepted to the ALJ's recommendation, stating that the ALJ erred by awarding any management performance bonus as the evidence of record does not support such a conclusion. The OCA maintains that all regulated utilities in Pennsylvania are required to provide safe, adequate, reasonable and efficient service as a matter of law. 66 Pa. C.S. § 1501. The OCA avers that a utility must be doing more than providing efficient and reasonable service in order to receive more than the indicated rate of return. The OCA references its Cross Exhibit 1, which listed five separate dockets where the Commission's Prosecutory Staff had investigated PPL for potential violations of the Code and avers that such actions do not support the award recommended by the ALJ. OCA Exc. at 15-18.

I&E also excepted to the ALJ's recommendation, alleging that it is not supported by the evidence. I&E avers that PPL selectively presented evidence of "high quality" service and alleges that PPL essentially sought an investor reward for implementing statutorily-mandated programs that were purely ratepayer funded through Commission-mandated rates that guaranteed PPL recovery with interest through separate surcharges and riders. I&E opines that while the Commission has the discretion to reward management, because such action essentially sanctions approval of a ratepayer premium, the Commission should exercise that discretion circumspectly. According to I&E, circumstances warranting investor rewards should be the exception not the norm.

I&E opines that PPL's service is not exceptional, finding instead that it was at times above average, at other times below average, and sometimes just average. According to I&E, PPL presented no clear evidence of any particular shareholder commitment that justifies gratuitous ratepayer funding. I&E Exc. at 23-26.

In reply, PPL states that clearly a public utility has a statutory duty to provide adequate, efficient, safe and reasonable service at just and reasonable rates. However, PPL posits that it is the efforts and manner in which the utility meets the statutory requirements that the Commission considers when determining if a management performance adder is appropriate. For example, PPL provides that the Commission awarded a twenty-five basis point adder to compensate a utility where it "promoted and accomplished cost efficiencies in several operational aspects". PPL R.Exc. at 9 (citing *Pa. PUC v. West Penn Power Co*., 1994 Pa. PUC Lexis 144 at *147). Similarly, PPL notes that the Commission awarded a twenty-two basis point adder where a utility's "managerial performance related to its water quality, customer service and low income program continues to be laudable." PPL R.Exc. at 8-9 (citing *Pa. PUC v. Aqua Pennsylvania, Inc.,* Docket No. R-00072711, at 50 (Order entered July 31, 2008)).

PPL avers that in this proceeding, I&E and the OCA ignore the record evidence of the exceptional manner in which PPL has exceeded its statutory obligation to provide adequate, efficient, safe and reasonable service and facilities at just and reasonable rates. According to PPL, the record evidence demonstrates that PPL's management is effectively controlling costs, while at the same time, providing customers with high quality service and expanded service options. In response to the Parties' allegations with regard to the five instances over the last four years where PPL paid a civil penalty, PPL responds that these parties overlook that PPL has 1.4 million customers and has millions of interactions with these customers annually. PPL points out that in only four instances has any penalty been applied, and in three of those cases the Company settled the matter without any finding of any violation. PPL submits that in only one instance in the past four years has it been found to have violated the Code, and on that occasion, it was assessed a civil penalty of $100. Given the Company's efforts, PPL opines that the requested twelve basis point adder clearly is modest and within the range previously awarded by the Commission. PPL R.Exc. at 9-10.

In its Replies to Exceptions, the OCA notes its continuing opposition to the management performance bonus in its entirety and requests that the Commission modify the ALJ's recommendation and remove the six basis point ROE adder. OCA R.Exc. at 14.

In its Replies to Exceptions, I&E similarly notes that PPL's evidence does not support any management bonus. I&E R.Exc. at 17.

iv. Disposition

Pursuant to the Code, the Commission may reward utilities through rates for their performance. In pertinent part, Section 523 of the Code, 66 Pa. C.S. § 523 provides:

> **§ 523. Performance factor consideration.**
>
> (a) **Considerations.** – The Commission shall consider, in addition to all other relevant evidence of record, the efficiency, effectiveness and adequacy of service of each utility when determining just and reasonable rates under this title. On the basis of the commission's consideration of such evidence, it shall give effect to this section by making such adjustments to specific components of the utility's claimed cost of service as it may determine to be proper and appropriate. Any adjustment made under this section shall be made on the basis of specific findings upon evidence of record, which findings shall be set forth explicitly, together with their underlying rationale, in the final order of the commission.

> (b) **Fixed utilities.** – As part of its duties pursuant to subsection (a), the commission shall set forth criteria by which it will evaluate future fixed utility performance and in assessing the performance of a fixed utility pursuant to subsection (a), the commission shall consider specifically the following:
>
> (1) Management effectiveness and operating efficiency as measured by an audit pursuant to Section 516 (relating to audits of certain utilities) to the extent that the audit or portions of the audit have been properly introduced by a party into the record of the proceeding in accordance with applicable rules of evidence and procedure.
>
> * * *
>
> (4) Action or failure to act to encourage development of cost-effective energy supply alternatives such as conservation or load management, cogeneration or small power production for electric and gas utilities.
>
> * * *
>
> (7) Any other relevant and material evidence of efficiency, effectiveness and adequacy of service.

Based upon our analysis of the evidence of record, we are persuaded by the arguments of the Company that its management performance related to its advanced metering infrastructure, operating initiatives, customer contact center, electric competition, customer education, energy efficiency programs, and customer assistance programs is laudable and warrants consideration as a factor in our final cost of equity allowance. Accordingly, we shall grant PPL's Exception and adopt its twelve basis point management effectiveness adjustment to our prior return on equity recommendation in recognition of its exemplary managerial performance. In the context of the evidentiary record developed in this proceeding, we conclude that this adjustment is reasonable, appropriate and conservative based on Section 523 of the Code and the similar allowances in the prior Commission decisions cited by the Company. The ALJ's recommendation of a six basis point allowance shall be modified, consistent with the foregoing and the Exceptions of I&E and the OCA are denied.

i. Summary on Common Equity

i. Positions of the Parties

As noted above, there are four methods of determining the cost of equity: DCF, RP, CAPM, and CE. PPL relied on each of these methodologies in presenting its recommended return on equity of 11.25%.

I&E argued that equal weight should not be given to the four different methodologies as PPL did in its evaluation.

Both the OCA and I&E took issue with the Company's analysis in arriving at the proposed cost of equity and capital structure. The OCA pointed out that the Commission has indicated a preference for using the DCF method to establish reasonable common equity costs.

While calculating average returns on equity for its respective groups of 11.13% and 11.43%, PPL's indicated cost of common equity reflects an upward adjustment of seventy basis points for its EDG and 118 basis points for its IEG to account for the leverage claim. It further reflects an upward adjustment of 120 basis points for both EDG and IEG to reflect its claim that PPL has higher business risk due to its small size relative to its proxy group. Finally, the indicated cost of common equity reflects PPL's upward adjustment of another twelve basis points to reflect PPL's requested award for claimed management efficiency.

I&E opposed PPL's calculated return on equity for several reasons. First, I&E averred that PPL's selected barometer group was flawed in that several of its selections failed to meet PPL's own purportedly objective selection criteria. Second, I&E maintained that PPL gave undue weight to the RP and CE methods. Third, I&E claimed that PPL employed an inflated DCF growth rate and a dividend yield adjustment that was unnecessary. Fourth, according to I&E, PPL employed inflated CAPM betas. Finally, I&E rejected PPL's extra-method adjustments for leverage, size (business risk), and management efficiency as they are unsupported and inappropriate.

ii. ALJ's Recommendation

The ALJ concluded that the Commission's preferred method of determining a utility's ROE is the DCF model. Consequently, the ALJ recommended adoption of I&E's DCF analysis, consisting of a dividend yield of 4.89% and a growth rate, prior to I&E's log-linear adjustment, of 4.79%. Additionally, the ALJ recommended adoption of a six basis point adjustment to PPL's ROE for management effectiveness. The result of the ALJ's recommendations equates to an overall ROE of 9.74%. R.D. at 93.

iii. Disposition

The ALJ recommended that the Company's position of an actual capital structure consisting of 49.22% long-term debt and 50.78% common equity along with a long-term debt cost rate of 5.50% be adopted. Additionally, the ALJ recommended adoption of the I&E position on PPL's cost of equity capital of 9.74%. According to the ALJ, the evidence overwhelmingly demonstrated that PPL's claim for a return on equity of 11.25% and an overall rate of return of 8.47% overstated what reasonable investors should expect from a regulated public utility and is not necessary for PPL to safely and reliably provide electric distribution service to its captive ratepayers. Based on these recommendations, the resulting overall rate of return per the ALJ is 7.65%.

Capital Type	Ratio (%)	Cost Rate (%)	Weighted Cost (%)
Debt	49.22	5.50	2.71
Equity	50.78	9.74	4.95
Total	100.00		7.65

R.D. at 93-94.

Based upon the foregoing, we conclude that PPL's capital structure should be based upon the Company's actual capital structure of 49.22% debt and 50.78% equity. PPL's cost of equity capital is properly determined by the DCF analysis performed by the Parties, with other methods utilized as a check on the reasonableness of the DCF results. Accordingly, we adopt a cost of equity rate of 10.4%. In addition, the 10.4% approved ROE is inclusive of the twelve basis point management efficiency adjustment as requested by the Company. Each of the remaining PPL requested ROE adjustments are rejected as unreasonable.

The following table summarizes our final determinations concerning PPL's capital structure, cost of debt and cost of common equity, as well as the resulting weighted costs and overall rate of return of 7.99%:

Capital Type	Ratio (%)	Cost Rate (%)	Weighted Cost (%)
Debt	49.22	5.50	2.71
Equity	50.78	10.4	5.28
Total	100.00		7.99

F. Taxes – Gross Receipts Tax

1. Positions of the Parties

PPL's total FTY gross receipts tax (GRT) expense claim is $50.102 million, which consists of two components. The first component is a pro forma calculation of gross receipts tax for the FTY at present rates of $43.930 million. PPL Exh. Future 1, Sch. D-11 at 3. The second component is $6.172 million, resulting from the proposed rate increase. PPL M.B. at 133; PPL Exh. Future 1, Sch. D-12 at 6.

I&E recommended a total GRT allowance of $49.168 million, which is a $934,000 reduction to the Company's total claim. The recommendation consists of a pro forma allowance of $43.1 million and a rate increase allowance of $6.068 million, assuming a full rate increase. The recommended GRT adjustments are reductions of $830,000 to the pro forma claim and $104,000 to the rate increase claim. I&E's recommendation is based on the fact that PPL's tax liability for the GRT is limited to the actual revenues PPL receives. As such, I&E recommended that the GRT tax allowance in rates should be calculated using the net revenues collected by PPL. I&E M.B. at 69; I&E St. 2 at 46-48.

2. ALJ's Recommendation

The ALJ found that I&E's recommendation to calculate the GRT allowance using net revenues was reasonable and should be approved, because it is a better match of the claimed actual receipts of revenue that will produce the Company's actual GRT tax liability. R.D. at 95, 96; I&E St. 2 at 46-48. The ALJ stated that the Pennsylvania Department of Revenue (DOR) Corporation Tax Bulletin 2011-02, issued July 20, 2011 (Bulletin), confirmed that the Company's net uncollected revenues would not reduce its GRT tax liability. The ALJ also stated that the Company did not provide any evidence to support that the cost of documentation would exceed the overvaluation of GRT, and the

Company's witness confirmed that the Company maintains records of customers' bad debts. R.D. at 97.

3. Exceptions

In its Exceptions, PPL avers that its GRT should be recovered in full. PPL Exc. at 37. PPL states that the ALJ's recommendation should be rejected because it disregards changes in the calculations of GRT imposed by the DOR in the Bulletin. *Id*. at 37-38. PPL opines that the Bulletin makes use of the deduction from gross receipts for uncollectible accounts almost impossible. PPL explains that, under the Bulletin, its liability for GRT is no longer limited to actual revenues received, but, instead, PPL must file GRT using the accrual method of accounting. As such, a reduction against taxable gross income for an uncollectible account requires PPL to match each write-off to the tax period when the receipts are reported as taxable to Pennsylvania. PPL indicates that it does not have the capability to perform this tracking for the write-offs of amounts for its 1.4 million customers. *Id*. at 38; PPL St. 8-RJ, Part 1, at 36-37. PPL submits, while it is correct that it does maintain records of its customers' bad debts, this does not enable PPL to meet the onerous reporting and accounting requirements that the Bulletin requires. PPL Exc. at 38.

In its Replies to Exceptions, I&E argues that the ALJ correctly determined that the Bulletin confirmed I&E's adjustment to PPL's GRT claim on the basis that PPL's tax liability is the net of uncollectibles. I&E notes that, using the accrual methodology, PPL will deduct from its accrued billed revenues accounts that are written off. I&E asserts that PPL did not present any evidence to prove there are obstacles to it following the requirements in the Bulletin and distinguishing between billed and collected revenues. I&E R.Exc. at 24. I&E avers that, absent evidence that PPL pays taxes on uncollected revenues and that the cost of avoidance exceeds the benefit, the ALJ's decision should be adopted. *Id*. at 25.

4. Disposition

We agree with the ALJ's determination that I&E's recommendation to calculate the GRT allowance using net revenues is reasonable and should be adopted, as it is a better match of the claimed actual receipts of revenue that will produce the Company's actual GRT tax liability. The Bulletin supports I&E's adjustment on the basis that PPL's tax liability is billed revenues net of write-offs and recoveries. PPL will use the accrual method of accounting to deduct from its accrued billed revenues accounts that are written off. The Bulletin states the following, in pertinent part:

> If a taxpayer uses the accrual method of accounting to report its gross receipts, then the taxable gross receipts shall be calculated as follows:
>
> Billed revenues on an accrual basis (no reserves for bad debts)
> Less: Accounts actually written off for previously taxed Pennsylvania bad debts
> Plus: Collections of previously written off <u>Pennsylvania taxable bad debts</u>
>
> <u>Taxable Gross Receipts</u>

I&E Exh. 2-SR, Schedule 1, at 1.

Additionally, as PPL has explained, the Bulletin requires taxpayers claiming a deduction for bad debts to provide the DOR, upon request, with the following documentation: (1) the type and amount of receipts being written off; (2) the customer's location; and (3) the tax period during which the receipts were reported as taxable to Pennsylvania. *Id*. at 2. PPL submits that the DOR's reporting requirements are onerous and would require significant and costly changes to its billing and payment system. PPL M.B. at 134. Nevertheless, as I&E asserts, PPL has not presented any concrete evidence to show that it could not comply with the DOR's reporting requirements, such as cost analyses, evidence of system testing, or evidence of actual complexities. *See*, I&E Exc.

at 24; I&E M.B. at 70-71. PPL has also indicated that it does maintain records of customers' bad debts. Based on the evidence, we find that I&E's adjustment is reasonable. Accordingly, we shall deny PPL's Exception and adopt the ALJ's recommendation on this issue.

G. Rate Structure and Rate Design

This section of the Opinion and Order addresses cost of service, rate design and rate structure allocation issues. When a utility files for a rate increase, it must file a cost-of-service study (COSS) assigning to each customer class a rate based upon operating costs that it incurred in providing that service. 52 Pa. Code § 53.53; *Lloyd v. Pa. PUC,* 904 A.2d 1010, 1015 (Pa. Cmwlth. 2006). Public utility rates should enable the utility to recover its cost of service and should allocate this cost among its customers. These rates are required by statute to be just, reasonable and non-discriminatory. 66 Pa. C.S. §§ 1301, 2804(10).

1. Cost of Service Methodology

a. Positions of the Parties

PPL stated that the fundamental purpose of a cost allocation study is to aid in revenue allocation and the design of rates to be charged by identifying all of the capital and operating costs incurred by a utility to provide service to all of its customers, and then assigning or allocating those costs to individual rate classes on the basis of how those rate classes cause the cost to be incurred. PPL maintained that as a result of the *Lloyd* decision, *supra,* cost of service studies have assumed a greater degree of importance in utility ratemaking, but it still should be recognized that cost allocation is not an exact science, that there is no single correct cost allocation methodology and that the Court did not hold that all other considerations are to be disregarded. PPL M.B. at 136-137.

PPL presented a fully-allocated COSS, showing the allocation of its distribution costs among the various rate classes at both present and proposed rates for the historic (PPL Exh. JMK-1) and future (PPL Exh. JMK-12) test years. According to PPL, the filed COSS in this proceeding is virtually identical to the methodology adopted by the Commission in its 2010 base rate proceeding using the class maximum non-coincident peak (NCP) demand method, which is based on the highest demand imposed by each rate class on its distribution system, to allocate its demand-related distribution costs. PPL St. 8 at 19.

As in 2010, PPL's COSS utilized a "heightened" level of data analysis, using allocators to classify primary voltage level distribution facilities into their demand-related and minimum or no-load customer-related cost components. PPL stated that this method more accurately reflects cost causation than the method used in preceding rate cases, which allocated primary voltage level distribution facilities solely on the basis of demand. PPL St. 8-R at 9. PPL stated that prior to its 2010 case, the Company's cost allocation studies were criticized because not all of the primary voltage level distribution facilities used in its minimum size system studies had been classified into their applicable customer related and demand related components. PPL claimed that this modification is consistent with the National Association of Regulatory Commissioners (NARUC) Electric Utility Cost Allocation Manual (Manual) recommendations "that primary voltage level overhead and underground conductors be classified into their demand-related and customer-related cost components." *Id.;* PPL M.B. at 137-138.

Only the OCA opposed the Company's COSS, and on substantially the same grounds as it opposed the Company's COSS in the last base rate case. The OCA argued that primary plant should be classified on a 100% demand basis, with only secondary plant allocated to both demand and customer components. OCA St. 3 at 18. The OCA presented density studies which it claimed do not support allocation of distribution plant based on customer count. As a "compromise" position, OCA recommended that the Commission allocate 100% of primary plant on a demand basis and apply the OCA's minimum size study to allocate secondary plant on a customer and demand basis. OCA M.B. at 77-82.

The OCA further argued that the Parties have misinterpreted the Commission's 2010 Order that NARUC has updated its cost of service principles since issuing the 1992 NARUC Manual, and argued that its recommendation reflects a compromise. OCA R.B. at 33-38.

The OSBA, PPLICA and REG supported PPL's position on COSS allocation and believe that it is consistent with the NARUC Manual and reflects a more realistic operation of PPL's system than the OCA counterproposal.

The OSBA stated that its primary focus in this case has been to determine whether the COSS presented by the Company conformed to the COSS approved by the Commission in the 2010 base rate case. The OSBA concluded that it did, and therefore, there was no need to re-litigate it in this proceeding. OSBA M.B. at 7.

REG agreed with the Company's classification of distribution plant as partially customer-related and partially demand-related, and the Company's allocation of the plant. This, REG argued, is consistent with the Commission's disposition of the Company's last rate case as well. REG M.B. at 4-5.

PPLICA argued in favor of the Company's COSS, which it believed properly allocates primary distribution facilities costs in both a customer and demand component and is consistent with NARUC policies. PPLICA characterized the OCA approach as "a results-driven density analysis with no meaningful relation to the cost of service principles historically applied by the Commission and supported by NARUC."

PPLICA M.B. at 7. PPLICA averred that PPL's COSS provides a reasonable basis for assessing distribution-related rates of return for each rate schedule, consistent with Commission precedent and NARUC recommendations. *Id.* at 8.

According to PPLICA, there are two recognized methodologies to estimate the customer component of distribution costs: (1) the minimum intercept method; and (2) the minimum size method, which is the method used by PPL. Each is designed to estimate the component of distribution plant cost incurred by a utility to connect a customer to the system. The minimum size method is designed to reflect costs associated with changes in both the number of distribution customers and the loads of these customers. It reflects a classification of the distribution facilities that would be required to simply interconnect a customer to the system, regardless of the kW load of that customer. PPLICA St. 1-R at 4-5; PPLICA M.B. at 9.

b. ALJ's Recommendation

The ALJ concluded that the other Parties rejected the OCA's arguments most persuasively. For the reasons set forth above by the Parties, the ALJ recommended that the Company's COSS be approved, and the OCA alternative be denied. R.D. at 108.

c. Exceptions

In its Exceptions, the OCA opines that the ALJ erred in recommending the use of PPL's COSS to allocate the revenue increase. The OCA avers that the PPL COSS is flawed because it does not accurately reflect cost causation, is inconsistent with the 1992 NARUC Manual and the updated NARUC Report, and is inconsistent with the historical method that PPL used prior to 2010. The OCA submits that, prior to 2010, PPL classified primary distribution plant as 100% demand related and further classified secondary distribution plant as partially demand and partially customer related.

According to the OCA, this method was approved by the Commission in the 2004 and 2007 PPL rate cases, and is the same COSS method that the OCA has proposed in the present case. The major change, starting with the 2010 case, is that PPL now classified primary distribution plant as 63% customer related and 37% demand related. This change, avers the OCA, has caused over one billion dollars of such costs to be shifted from a demand basis to a customer count basis. OCA Exc. at 18-19.

Next, the OCA notes that the ALJ relied on the arguments of the Company and the other Parties in adopting PPL's COSS, whereby the central point made was that the Commission had already ruled against the OCA in PPL's 2010 rate case and should do the same here. The OCA avers that PPL's COSS method does not follow the 1992 NARUC Manual in many respects, and is inconsistent with the more recent 2000 NARUC Report. The OCA states that in the 2010 rate case, PPL's recommended allocation of the entire increase to the residential class was adopted by the Commission, partially because the Commission found the OCA's approach did not accurately reflect the costs incurred to serve the residential class. *Id*. at 20 (citing *Pa. PUC v. PPL Electric Utilities Corporation*, Docket No. R-2010-2161694, at 46 (Order entered December 21, 2010) (*PPL 2010*)). However, the OCA avers that in the 2010 case its approach was identical to PPL's own COSS method used in 2004 and 2007. According to the OCA, PPL's proposed COSS in the instant proceeding contains bias to the residential class that negates any possibility of that class reaching "cost of service" anytime in the foreseeable future. OCA Exc. at 19-20.

Additionally, the OCA maintains that both primary and secondary distribution plant should be classified as 100% demand related, consistent with how regulatory bodies in over thirty states classify such plant. The OCA avers that it has recommended a reasonable and appropriate compromise COSS that maintains a customer/demand split for the secondary distribution plant but allocates primary plant on demand only, which is exactly what PPL did prior to 2010. Further, the OCA then classified secondary distribution plant as partially demand and partially customer related, just like PPL's current and prior COSSs, but with a more appropriate customer component than PPL based on its revisions to PPL's minimum size study and consistent with how such a study is to be performed as per the 1992 NARUC Manual. OCA Exc. at 20-21.

The OCA submits that the ALJ's and other Parties' reliance on *PPL 2010* is misplaced as the Commission has substantial evidence in this record that it did not have in 2010, specifically: (1) PPL's proposed COSS is an outlier in its classification of primary distribution plant as having a customer component; (2) to the extent that a customer component should be a part of distribution plant cost assignment, PPL's minimum size study fails to follow the 1992 NARUC Manual's specific instructions for performing such a study; and (3) the fact that adhering to PPL's proposed COSS will always result in the residential class being allocated a substantial portion of future rate increases with little to no hope of ever achieving cost of service. OCA Exc. at 21.

The OCA maintains that using the method that has been accepted in over thirty states, a 100% demand allocation, the indexed rate of return for the RS class, at present rates, would be 124%. Using the method that PPL proposed in this proceeding, the indexed rate of return for the RS class would be only 63%, per the OCA. The OCA avers that its compromise position, 100% demand allocation only for primary plant, shows the Residence Service (RS) class at an indexed rate of return of 112% at present rates. Therefore, according to the OCA, at current rates under an accurate and reasonable COSS, the RS class is paying more than its cost to serve. As a result, the OCA avers that the Commission's holding in *PPL 2010* should not be controlling here. OCA Exc. at 23-24.

In reply, PPL states that its COSS is virtually identical to the methodology adopted by the Commission in the 2010 base rate proceeding, which was fully litigated on this issue. PPL avers that the Commission fully considered and rejected the OCA's proposal in the 2010 base rate proceeding and that the OCA has offered no change in law or fact that would warrant a departure from that decision. PPL maintains that the ALJ properly approved its COSS. PPL R.Exc. at 16.

In its Replies to Exceptions, the OSBA first notes that, contrary to the OCA's argument, PPL has actually proposed to reduce the customer component of distribution plant costs in the instant proceeding relative to the method that was explicitly approved by the Commission in the Company's 2010 case, to the benefit of residential customers. The OSBA avers that for the OCA to prevail on the issue of cost allocation, it must demonstrate both that the Commission erred in its decision in the 2010 case to allow for the classification of primary system distribution plant costs into both demand and customer components and that the Commission has consistently erred over the past decades in approving PPL's cost classification methodology for secondary distribution system costs. The OSBA notes that the Commission considered virtually all of the evidence presented by the OCA in this proceeding in the 2010 case and rejected the OCA's conclusion. Moreover, the OSBA notes that, in objecting to PPL's method for classifying secondary system plant costs, the OCA is challenging an approach PPL has used for years if not decades. According to the OSBA, in the OCA's view, Commission precedent prior to 2010 is relevant only if it favors residential customers, which is both wrong and inconsistent. OSBA R.Exc. at 4-6.

In response to the OCA's assertion that regulatory bodies in thirty states do not include any customer component in classifying either primary system or secondary system distribution costs, the OSBA states that cost allocation is often hotly debated among the parties to a regulatory proceeding. The OSBA explains that the economic issue of the classification of distribution plant costs is essentially an issue involving residential and small to medium business customers, as large industrial customers are generally served at transmission voltage and have no stake in this issue. According to the

OSBA, the smaller business customers are generally unrepresented in utility regulatory proceedings, so it is unclear whether the regulatory pattern alleged by the OCA results from hard cost analysis, or simply a lack of representation. The OSBA maintains that in either event, the thirty jurisdictions are ignoring the basic principle that this Commission has accepted. As this principle has long been followed in Pennsylvania, the OSBA submits that the alleged practices of other jurisdictions are irrelevant. OSBA R.Exc. at 6-7.

Next, the OSBA submits that the OCA characterization of the "updated NARUC report" as an update to the 1992 NARUC Cost Allocation Manual is deceptive at best. The OSBA explains that the 1992 NARUC Manual was published as a NARUC Report. The report to which the OCA refers to as an update is nothing of the kind, but, in fact, a report prepared by the Regulatory Assistance Project entitled "Charging for Distribution Utility Services: Issues in Rate Design." The OSBA avers that this document contains little in the way of specifics for distribution cost classification and allocation and does not necessarily reflect the positions of NARUC. As a result, the OSBA recommends that the Commission give no weight to this consultant's report. OSBA R.Exc. at 7-8.

In its Replies to Exceptions, PPLICA states that PPL's proposed COSS is firmly supported by NARUC principles, designed to achieve cost of service rates and should be approved. PPLICA points out that while the OCA refers to the updated report as a "NARUC" report, the document is not an official NARUC publication. Also, PPLICA states that the OCA's claim that this document establishes PPL's minimum size system COSS as an outlier is specious. According to PPLICA, this report's statement that allocating primary distribution plant on a 100% demand basis "is used in more than thirty states" dates back to 2000, almost thirteen years ago. PPLICA avers just as PPL classified primary distribution plant on a 100% demand basis before updating its classification methods in 2010, many of the states referenced in the report may have modified their methodologies. Therefore, PPLICA asserts that the Commission should not accord significant weight to stale data. PPLICA R.Exc. at 4-5.

PPLICA further replies that PPL's minimum size study is completely consistent with the NARUC Manual, and that it is worth noting that the same study employed by PPL in this proceeding was fully litigated in the Company's 2010 case and adopted by the Commission. Additionally, PPLICA notes that PPL's minimum size study reflects the Company's actual installations rather than the theoretical adjustments applied by the OCA. Lastly, PPLICA argues that PPL's proposed COSS contains no inherent bias towards any rate class as alleged by the OCA. PPLICA R.Exc. at 5-7.

d. Disposition

Based upon our review of the record evidence, we are in agreement with the ALJ that PPL's proposed COSS should be approved. It is important to note that the PPL COSS methodology is supported by all the Parties which offered a position on this issue, with the exception of the OCA. We have reviewed the OCA's position and Exceptions on this issue and are not persuaded by the arguments it presented in support of its recommended COSS methodology. The position presented by the OCA was considered and rejected by the Commission in the litigation of PPL's 2010 base rate proceeding. *Pa. PUC v. PPL Electric Utilities Corp.*, Docket No. R-2010-2161694, at 46 (Order entered December 21, 2010). We conclude that the OCA has not presented convincing arguments in this proceeding that would cause us to re-evaluate our determination in PPL's prior proceeding. PPL's proposed COSS in the instant proceeding is virtually identical to the COSS approved in 2010, is consistent with the NARUC Manual and more accurately reflects cost-causation principles than the COSS methodology the Company utilized prior to the 2010 base rate case. We conclude that PPL has carried its burden of proof on this issue, and we shall adopt the ALJ's recommendation. Accordingly, we shall deny the Exceptions of the OCA.

2. Revenue Allocation

a. Positions of the Parties

PPL explained that its proposed allocation of revenue requirement among the various rate classes in this proceeding is driven largely by the Commonwealth Court's decision in *Lloyd, supra.* PPL stated that this case is the fourth in a series that have purportedly attempted to move PPL's distribution rates to true cost of service. PPL St. 5 at 8. The Company sought to establish cost of service, and then to apply those costs to the appropriate rate schedules. Because that approach produced a distribution rate increase to customers served under Rate Schedule Residential Thermal Storage (RTS) of about 165 percent, which PPL considered to be unjust and unreasonable, it developed an alternative allocation, which limited the increase to Rate RTS from 165% to approximately 78%. According to PPL, the goal was to bring all rate classes closer to the system average rate of return, while still considering the principle of gradualism. *Id.* at 10; PPL M.B. at 152-153.

The Company's proposal is as follows:

	Relative Rate of Return	
Rate Classes	**Present Rates**	**Proposed Rates**
RS	63.03%	83.81%
RTS	-65.31%	23.05%
GS-1	133.55%	99.05%
GS-3	285.18%	196.34%
LP-4	163.36%	118.44%
LP-5	-90.72%	98.94%
LPEP	353.09%	256.26%

GH-2	86.64%	103.55%
SL/AL	100.49%	99.65%
Total	100%	100%

PPL Exh. JMK-2 at 8-11; PPL M.B. at 154.

The OCA stated that for the second time in two years, PPL has proposed to allocate nearly the entire revenue increase to the RS and RTS rate classes. The OCA noted that of PPL's $104.6 million increase requested, PPL proposed to allocate over $99 million to the residential class with over $3.5 million of that amount allocated to RTS customers. The OCA averred that these increases amount to an annual increase to distribution rates of 20.9% and 77.6%, respectively. OCA M.B. at 66.

The OCA recommended an alternative revenue allocation that it claims reflects the results of a properly conducted, reasonable and equitable cost of service study. The OCA submitted that while cost of service should guide the Commission when setting rates in this proceeding, other ratemaking principles such as gradualism, avoidance of rate shock and basic fairness must not be abandoned. As such, the OCA recommended that no rate class receive a revenue decrease and that no class sustain an increase greater than 150% of the system-wide percentage increase, or no more than 21.45%. *Id.* at 95.

The OCA's proposal results in the following indexed rate of returns by class:

Relative Rate of Return

Rate Classes	Present Rates	Proposed Rates
RS	112%	111%

RTS	-93%	-53%
GS-1	180%	131%
GS-3	104%	109%
LP-4	-13%	11%
LP-5	-88%	-4%
LPEP	399%	289%
GH-2	30%	50%
SL/AL	90%	111%
Total	100%	100%

OCA St. 3 at 37, 41; OCA M.B. at 96-97. According to the OCA, this proposed revenue allocation results in a reasonable movement of all classes to cost of service at PPL's proposed revenue increase, while also recognizing the need for gradualism. OCA M.B. at 97.

REG and PPLICA supported PPL's proposed revenue allocation as consistent with the COSS. According to these Parties, the Company's proposed revenue allocation moves all rate classes closer to cost of service in accordance with the Company's COSS and consistent with *Lloyd*. REG M.B. at 5; PPLICA M.B. at 13-17.

PPLICA pointed out that Rate Schedule LP-5 customers will experience a 59.1% increase, and although Rate Schedule LP-4 customers do not experience an increase, their current rates remain above cost of service. PPLICA recognized that the movement towards actual cost of service rates as set forth is reasonable, and did not oppose this allocation. PPLICA M.B. at 16.

PPLICA argued that the Commission should not give any credence to OCA's COSS, and as the OCA's proposed allocation is based on its flawed COSS, neither should the Commission give any credence to the OCA's recommendation. PPLICA St. 1-R at 8; PPLICA M.B. at 15.

b. ALJ's Recommendation

The ALJ concluded that as the OCA alternative was based on its COSS, and not on the Company's, which she recommended be adopted, the OCA alternative should be denied. The ALJ recommended adoption of the Company's revenue allocation, with the actual numbers to be based on the proportionate adoption of the actual revenue requirement approved. R.D. at 110.

c. Exceptions

In its Exceptions, the OCA submits that its COSS should be adopted as a guide to set rates in this proceeding and for purposes of establishing a fair and reasonable allocation of the revenue increase. The OCA avers that PPL's COSS is unduly discriminatory against residential customers and PPL's proposed revenue allocation is based on that study. The OCA maintains that its proposed allocation is based upon a more reasonable COSS and recognizes gradualism and fairness and caps increases to any one rate class at no greater than 150% of the system-wide percentage increase, or 21.45%. The OCA opines that its revenue allocation method results in a reasonable movement of all classes to cost of service at PPL's proposed revenue increase, while also recognizing the need for gradualism. OCA Exc. at 31-34.

In reply, PPL states that its proposed revenue allocation follows the Company's COSS and substantially moves all rate schedules toward the system average rate of return. PPL avers that since the OCA's revenue allocation is premised on its flawed COSS, its resulting revenue allocation was properly rejected by the ALJ. PPL R. Exc. at 16-17.

In its Replies to Exceptions, the OSBA points out that, as the OCA readily admits, the adoption of the OCA's revenue allocation proposal requires the Commission to agree to the OCA's version of the COSS. According to the OSBA, because the ALJ correctly rejected the OCA cost allocation methodology, the OCA's revenue allocation methodology should similarly be rejected. OSBA R.Exc. at 13-14.

In its reply, PPLICA states that the OCA's proposed COSS is contrary to Commission precedent and unsupported by the NARUC Manual and, as such, any revenue allocation based on the OCA's proposed COSS must be summarily rejected. In response to the OCA's argument about gradualism, PPLICA acknowledges that gradualism is a legitimate ratemaking construct designed to mitigate unreasonable rate increases. However, according to PPLICA, because PPL's COSS shows that residential customers are paying rates significantly below cost-of-service, PPL's revenue allocation limits gradualism adjustments to ensure that customers paying above-cost rates move reasonably closer to cost-of-service. PPLICA posits that as the ALJ's recommendation to approve PPL's revenue allocation incorporates gradualism, it should be approved by the Commission without modification. PPLICA R.Exc. at 9-10.

d. Disposition

Based upon our prior determination and discussion, *supra,* with respect to the rejection of the OCA COSS, we are in agreement with the ALJ that PPL's proposed revenue allocation should be approved. As the OCA's revenue allocation recommendation is based upon its COSS, which we have rejected, we conclude that its allocation proposal should similarly be denied. Additionally, we find that PPL's revenue allocation proposal is consistent with *Lloyd,* moves all rate classes closer to cost of service in a reasonable manner and considers the principle of gradualism. Accordingly, we shall adopt the recommendation of the ALJ and deny the OCA Exceptions on this issue.

3. Revenue Scaleback

a. Positions of the Parties

As the Commission is approving a lesser revenue requirement than sought by PPL, an important consideration is the determination of how the proposed revenue allocation will be affected by the scaleback in rates.

In this proceeding, PPL and the OCA support a proportional scaleback, with no decrease in revenues for classes that do not receive a rate increase. PPL St. 5-R at 4; OCA St. 3 at 42.

I&E proposed applying the first $1,784,000 to lower the revenue requirement for Rate Schedule RTS customers, with any further reductions applied to Rate Schedules RS, GH-2, SL/AL, and on a conditional basis, LP-5. I&E St. 3 at 16-17.

The OSBA recommended a revenue-based scaleback which would allocate any overall rate increase approved by the Commission to each rate class in proportion to the Company's proposed revenues from each class. OSBA St. 1 at 13.

PPLICA supported the scaleback recommendation proposed by the OSBA in the event that the Commission approves an overall revenue increase lower than the Company's requested $104.6 million increase. PPLICA argued that application of a proportional scaleback in this proceeding would hinder progress to cost of service rates by reducing rate increases for customers paying below cost of service rates pursuant to PPL's COSS, but not allowing correlating adjustments for customers whose present rates are above cost of service. PPLICA M.B. at 19, PPLICA R.B. at 9.

PPLICA further asked that should the Commission not adopt the OSBA recommendation, then the scaleback should be applied to all rate classes receiving an increase as proposed by the Company and the OCA, with no further exclusions, as would apply under I&E's proposal. PPLICA opposed the restrictions on the scaleback for Rate Schedule LP-5 that I&E recommended, since that rate schedule is already targeted for a substantial increase. PPLICA M.B. at 18-19.

b. ALJ's Recommendation

The ALJ stated that in the *Lloyd* decision, the Commonwealth Court disapproved the setting of rates according to a flat across-the-board percentage, because there was no dispute that the cost of serving each rate class varied and that rates for certain classes were subsidizing rates for others in the interest of keeping the increase in the total bills of each class to 10% or less. Accordingly, the ALJ found that any scaleback should be utilized to bring the rates of each rate schedule closer to the cost of service. R.D. at 111.

However, the ALJ concluded that this concept, applied blindly, would result in reductions to customers who were not expecting an increase, or greater reductions to some customers than were originally proposed, to the detriment of those whose rates will rise more than necessary. Therefore, the ALJ recommended that PPL's proposal to apply any scaleback on a proportional basis to only those rate schedules that receive increases should be adopted by the Commission. R.D. at 112.

c. Exceptions

In its Exceptions, I&E states that it agrees with the ALJ, but believes the Commission should moderate the increases proposed for the Rate RTS usage rate and the LP-5 customer charge before the proportionate scale-back is applied. I&E Exc. at 29-30.

In its Exceptions, the OCA stated that, as a general principle, it has no disagreement with PPL's proportional scaleback approach. However, the OCA disagrees with using PPL's revenue allocation as a starting point for the proportional scaleback. The OCA submits that its revenue allocation be used as a starting point for a proportional scaleback in this proceeding. OCA Exc. at 34.

The OSBA also excepted to the ALJ's recommendation, stating that the ALJ erred in recommending a proportional scaleback of the rate increase for only those customer classes that were assigned rate increases by PPL. The OSBA avers that Rate Schedule GS-3 is significantly overpaying its cost of service at current rates, and only received mild relief under PPL's original proposed revenue allocation.[18] The OSBA avers that the problem with the proportional scaleback is the progress toward cost-based rates that was part of the original intent of the Company's revenue allocation will not be retained. Under the method adopted by the ALJ, certain customer classes will not benefit from the reduction in PPL's proposed rate increase. The OSBA alleges that the I&E scaleback proposal results in the same unacceptable result. The OSBA recommends that any reduction in the overall increase be shared among the rate classes in proportion to the Company's originally proposed revenues. According to the OSBA, its recommended

[18] The OSBA included Tables showing that the GS-3 class rate of return at present rates is 11.4 percentage points above system average, and, even with the proposed rate decrease, remains 8.2 percentage points above system average at PPL's proposed rates. OSBA Exc. at 8.

scaleback methodology maintains the progress towards cost-based rates that was present in PPL's original revenue allocation proposal. OSBA Exc. at 5-12.

Exceptions to the ALJ's recommendation were also filed by PPLICA, wherein it states that the ALJ erred in rejecting the OSBA recommendation of a revenue-based scaleback. PPLICA observes that PPL has now filed four base rate cases since *Lloyd*, without achieving cost-based rates for certain rate schedules. PPLICA avers that it is imperative that any scaleback applied to the lower revenue requirement also reflect continued progress towards cost-based rates. PPLICA opines that despite the ALJ explicitly acknowledging the directives and principles from *Lloyd*, the ALJ inexplicably declined to adopt the revenue-based scaleback proposed by the OSBA. PPLICA echoes the comments of the OSBA that approval of a proportional scaleback would reverse progress towards cost-based rates by reducing rates for customers receiving an increase, but still paying below cost rates. At the same time, rate schedules currently paying above-cost rates, but not receiving an increase, would be excluded from a scaleback, explains PPLICA. According to PPLICA, no reasonable basis exists for approving a scaleback that reverses progress towards cost-based rates. PPLICA Exc. at 3-6.

In reply to the arguments of the OSBA and PPLICA, PPL states that the scaleback method recommended by the ALJ is fair and should be approved. PPL maintains that the ALJ's recommended scaleback is the same method the Company proposed in its 2010 case, which was litigated and adopted by the Commission. PPL avers that both the scaleback recommended by the ALJ and the method proposed by the OSBA would move rate classes towards the system average return. However, PPL opines that as a matter of fairness, any scaleback of revenues should be applied to those customer classes that would have received a rate increase under the Company's original proposal. PPL R.Exc. at 17.

In its Replies to Exceptions, the OCA states that the ALJ was correct in recommending the use of a proportional scaleback. The OCA notes that the OSBA recommendation was directly addressed in PPL's 2010 case and rejected by the ALJ and the Commission, which stated that asking one class to pay more of an increase than the final total increase in revenue would be unreasonable. According to the OCA, the OSBA's proposed scaleback methodology would impose additional costs on certain rate classes, over and above the total revenue increase authorized, in order to provide additional rate decreases to other rate classes. The OCA avers that neither the OSBA nor PPLICA provide evidence to support the idea of what constituted unreasonable rates in 2010 is now acceptable. OCA R.Exc. at 15-17.

In its Replies to Exceptions, PPLICA first states that since the OCA's proposed revenue allocation is *per se* unreasonable, any scaleback based upon it should be disregarded by the Commission. Additionally, PPLICA avers that an increase-based scaleback will significantly hinder progress towards cost-based rates. PPLICA requests that the Commission deny any proposal to apply a proportional increase-based scaleback and adopt the revenue-based scaleback proposed by the OSBA. PPLICA R.Exc. at 10-11.

d. Disposition

Based upon our review of the record evidence, we are in agreement with the recommendation of the ALJ that PPL's proposed proportional scaleback only to those classes that were proposed to receive rate increases, of the requested revenue increase, are fair, reasonable and should be approved. We find that the OCA's Exceptions with regard to the proper starting point are without merit, as we have herein previously rejected the OCA recommended allocation proposals. We further conclude that the I&E's Exceptions with regard to first providing relief to certain designated rate classes before the proportional scaleback is applied are also without merit.

The OSBA, as well as PPLICA, filed Exceptions opposed to the adoption of a proportional scaleback. These Parties are of the opinion that a revenue based scaleback should be adopted and applied to all customer classes, whether they were to originally receive no increase or a rate decrease. On this point, we are persuaded by the comments of PPL that the ALJ's recommended scaleback is the same method the Company proposed in its 2010 case, which was litigated and adopted by the Commission. Neither the OSBA nor PPLICA have presented sufficient evidence to warrant our reconsideration of this issue in this proceeding. We find that, as a matter of fairness, those customer classes that have not been allotted any rate increase via the Company's original revenue allocation should not receive rate decreases as argued by the OSBA and PPLICA. We conclude that PPL's proposed scaleback methodology maintains the gradual movement to cost based rates and is appropriate under the unique circumstances in this proceeding. Accordingly, the Exceptions of I&E, the OCA, the OSBA and PPLICA are denied, and the ALJ's recommendation is adopted.

4. Residential Customer Charge

a. Positions of the Parties

PPL's current residential distribution schedules are RS, RTS, and Residential Time-of-Day (RTD). In PPL's presently effective residential Rate Schedule RS, a large portion of the distribution revenue is being collected through usage or kWh charges. PPL's minimum size system study indicated that residential customers should be paying a much greater monthly customer charge than the current monthly charge of \$8.75. In this proceeding, PPL has proposed raising the Rate Schedule RS customer charge from its present \$8.75 per month to \$16.00 per month and decreasing the kWh charges from \$0.03364 to \$0.03340. PPL St. 5 at 11-14. The Company pointed out that its COSS supports a charge of \$36.70, and this increase moves the rate schedule closer to the cost of serving it. PPL M.B. at 162-163.

The OCA, the CEO and I&E opposed PPL's proposal to increase the Rate Schedule RS customer charge.

The OCA opposed the increase to residential customers because it is based on the Company's COSS, which it also opposed. The OCA objected further that the Company's proposal will disproportionally impact low-income, low-usage customers and would result in a "significant disincentive" for customers to conserve. OCA M.B. at 106.

The CEO opposed the increase in the fixed monthly customer charge because it takes away a customer's motive and ability to conserve. The CEO stated that one of the only defenses that a family has against sharp increases in energy costs is conservation, CEO St. 1 at 5, and this proposal eliminates the ability to reduce that cost through conservation efforts. CEO M.B. at 7.

The Company pointed out that there is an energy charge component that is being reduced by 0.7%, and that the distribution charge is small in the context of the energy portion of the bill, which comprises 86% of the charges on the average customer's bill. According to PPL, this still provides an adequate opportunity for savings due to conservation. PPL St. 5-R at 6; Exh. DAK4; PPL M.B. at 164.

I&E developed its own offering based upon a direct customer analysis. In preparing its direct customer cost analysis, I&E stated that it was guided by long-standing Commission precedent that identifies the appropriate items to be included in a customer charge. According to I&E, those items that change with the addition or loss of a customer are the direct customer costs that were identified in the Company's cost of service study and are as follows: meter expenses, expenses for services and customer installations, expenses for meter reading and customer records & collection, other customer accounting expenses, depreciation expense and net salvage amortized for meters and services, and the rate base related return and income taxes on customer-based rate base. I&E maintained that the Commission has long held these costs to be those most appropriately included in a customer cost study. I&E M.B. at 131 (citing *Pa. PUC v. West Penn Power Company*, 59 Pa. P.U.C. 552 (1985)). I&E noted that recently the Commission accepted a direct customer cost analysis identical to the analysis it presented in this proceeding[19] in the Columbia Gas of Pennsylvania base rate case at Docket No. R-2010-2251623 (Order entered October 14, 2011). I&E recommended that the RS customer charge remain unchanged at $8.75 per month. I&E M.B. at 130-133.

The Company countered that the OCA and I&E alternative customer cost analyses include only meters and services and exclude all other customer costs, which should be included in a customer charge. PPL M.B. at 170. Further, PPL pointed out that “conservation cannot and does not trump cost of service.” PPL M.B. at 164.

However, in response to the positions of the other Parties, PPL proposed an alternative plan that includes a residential customer charge of $14.09 per month, consistent with the recent Commission decision in *Pa. PUC v. Aqua Pennsylvania, Inc.*, Docket No. R-00038805 (Order entered August 5, 2004) (*Aqua*). PPL stated that the costs included in its alternative Rate Schedule RS customer charge of $14.09 per month properly reflect meters and services net plant and related O&M expenses; meter reading and billing and collection expenses, and the Company’s Meter Data Management System; as well as related employee benefits, administrative and general expenses and other O&M expenses related to the above items. These revenue requirement cost components represent the same type of direct and indirect cost components as those approved in *Aqua*. PPL M.B. at 172. The only difference is that PPL also included $12,678,000 for customer call center-related expense. PPL averred that this expense was not specifically addressed in *Aqua*, but it is consistent with the expenses included in the

19 Tr. at 541-42.

customer charge in *Aqua,* because it is a directly assignable customer service-related expense, and it varies with the number of customer calls and the number of customers. *Id*. at 173; PPL St. 8-RJ (Part 2) at 8.

While PPL opined that the customer component of each rate schedule should include all customer-related costs determined by the cost of service study, if the Commission wished to consider an alternative compromise customer charge, PPL posits that its alternative proposal of $14.09 would be acceptable as it would recover the same type of direct and indirect cost components as those approved in *Aqua*, and would provide some improvement in the level of fixed cost recovery in the customer charge. PPL St. 5-R at 15; PPL M.B. at 172-173.

I&E responded that it is improper to offer a compromise outside the context of a settlement, and that without an actual settlement the Company's position still needs to rely on substantial evidence to support it, which it did not provide. I&E R.B. at 107.

b. ALJ's Recommendation

The ALJ stated that while it would be improper to propose a compromise position for the first time in a brief or exception, it is not improper to propose an alternative during the litigation, when the supporting data already appears in the record, as PPL did in this proceeding. The ALJ recommended approval of the PPL alternative as it is based on an approved cost of service study, which clearly illustrates that customer-related costs for the residential class include elements that I&E ignored in its own analysis and determination of a proper residential customer charge. The ALJ found that it is reasonable to include some of these additional elements in calculating the residential customer charge, as the Commission allowed in the *Aqua* case. R.D. at 120.

According to the ALJ, the Company will be ensured recovery of more of its fixed costs, which are clearly more customer-related than usage-related, while still allowing some revenue to be recovered through usage-based charges. Thus, customers will be provided with more accurate price signals, while still being afforded some opportunity to control their monthly distribution bills through conservation. For these reasons, the ALJ concluded it is appropriate and reasonable to accept PPL's compromise position regarding the residential customer charge. R.D. at 120.

c. Exceptions

In its Exceptions, I&E states that the ALJ's recommendation to adopt the Company's compromise lacks legal support. I&E avers that as originally proposed, PPL's entire residential increase was to be recovered from an 82% increase to its RS customer charge without providing any direct customer cost analysis. I&E notes that PPL provided only a COSS, which is an entirely different cost analysis. According to I&E, PPL found very few, if any, distribution system-related costs that were a function of usage and proposed to recover essentially all fixed costs in the customer charge. I&E states that PPL included all fixed costs that it classified as customer related, as opposed to demand related, in the customer charge and made no distinction between direct and indirect costs. I&E avers that fixed costs and customer costs are not synonymous and opines that fixed costs assigned to the customer charge should be limited to those fixed costs for which there is a direct impact from an individual customer, such as metering and billing. I&E Exc. at 30-31.

Next, I&E notes that although PPL moderated its Rate RS proposal in rebuttal, it still failed to conduct an appropriate customer cost analysis. Rather, I&E asserts that PPL presented a "study" that included both direct and indirect costs that it claimed authorized a $36.70 RS customer charge, but under which PPL only claimed a "compromise" RS customer charge of $14.09.[20] I&E avers that the ALJ's reliance on one aberrant Commission order from 2004, *Aqua,* to support her recommendation to adopt the PPL compromise position lacks adequate legal support. I&E opines that the *Aqua* case is not controlling as the holding of that case, with respect to the inclusion of indirect costs in the calculation of a customer charge, has not been reaffirmed or reapplied since 2004. I&E maintains that since 1985 and most recently in 2011, with the one exception being *Aqua*, the Commission affirmed the basic customer cost analysis it originally articulated in 1985. I&E Exc. at 31-33.

Lastly, I&E states that as *Aqua* formed the sole basis presented by the ALJ for adoption of the Rate RS customer charge, the ALJ's recommendation should be rejected. I&E maintains that PPL's "compromise" RS customer charge fails to meet the parameters of a properly constructed customer cost analysis. Additionally, I&E asserts that the ALJ's recommendation is not supported by the overwhelming Commission precedent and, unless prepared to enunciate a new standard, the Commission should reject it. Further, I&E notes that customers will lose control over a substantial part of their bill, very likely deterring conservation efforts despite the millions of dollars customers have invested in energy conservation efforts. I&E Exc. at 35-36.

The OCA also excepts to the ALJ's recommendation, arguing that PPL's proposed customer charge is based on its flawed COSS results, does not represent the results of a direct customer cost analysis, would disproportionately impact low-income, low-usage customers and would result in a significant disincentive for customers to engage in conservation activities. The OCA recommends that the Rate RS customer charge continue to be set at its correct level of $8.75. The OCA avers that the ALJ erred by accepting PPL's alternative RS customer charge without a direct cost study as support

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[20] I&E asserted that PPL produced no such "study" and made no such "compromise" offer with respect to its originally proposed non-residential customer charges. I&E Exc. at 32.

for such a charge. According to the OCA, the Commission has repeatedly expressed its preference for a direct cost study, which includes only direct costs and not indirect costs, as PPL has done in its alternative proposal as a basis to set customer charges. The OCA notes that, in contrast to the decades of Commission precedent on this issue, PPL supports its alternative customer charge with the lone case of *Aqua*. The OCA submits that the *Aqua* decision was fact specific and provides no support for PPL's current proposal. OCA Exc. at 34-36.

Next, the OCA explains that it performed a direct customer cost analysis, consistent with Commission precedent, and found that the direct residential customer costs ranged from $7.70 per month to $8.24 per month. Therefore, the OCA is of the opinion that the current RS customer charge of $8.75 is reasonable and should not be increased. The OCA avers that PPL's proposed customer charge will disproportionately impose adverse impacts on the customers least able to afford those bill increases and should not be accepted. OCA Exc. at 36-37.

In its Replies to Exceptions, PPL states that unlike the case relied upon by I&E, nothing in *Aqua* limits the Commission's holding only to that case. PPL avers that the Commission clearly stated that requests to include allocated indirect costs, such as employee benefits, local and payroll taxes, and other general and administrative costs, should be reviewed on a case-by-case basis, citing *Aqua,* at 70-72. PPL further submits that there is no order from either the Commission or the appellate courts overturning or otherwise limiting the Commission's conclusion in *Aqua*. PPL maintains that it followed the Commission's conclusion in *Aqua* and proposed the inclusion of the same type of direct and indirect cost components approved by the Commission in *Aqua*. PPL continues that I&E and the OCA failed to offer any criticisms or reasons to exclude from the customer cost study and customer charge the indirect costs that PPL allocated for employee benefits, local and payroll taxes, and other general and administrative costs.

For these reasons, PPL opines that the ALJ properly rejected the positions of I&E and the OCA. PPL R.Exc. at 17-18.

With regard to the Parties' comments on the impact on low income/low usage customers, PPL agrees that increasing the monthly charge while essentially maintaining the usage charge at its current level will result in a greater than average percentage increase to low use customers, regardless of their income level. However, PPL avers that as a utility with an obligation to serve, it must provide infrastructure to serve the needs of those customers. PPL states that utility rates should be designed based upon cost of service, not customers' income levels. According to PPL, ability to pay issues should be addressed through USPs, not by setting rates that disregard the cost of service. PPL R.Exc. at 19.

d. Disposition

Upon our consideration of the evidence of record herein, we shall adopt the ALJ's Recommendation on this issue that PPL's compromise proposal is reasonable and should be approved. In this regard, we conclude that PPL's original proposal is excessive, disregards the principle of gradualism and is not reasonable. Additionally, we conclude that the recommendations of I&E and the OCA that the residential customer charge not be increased at all in this proceeding are equally unreasonable as they are not based on a proper cost analysis. We further conclude that the ALJ correctly recommended that, consistent with *Aqua,* other customer-related costs are properly includable in a customer charge cost analysis. We find that the I&E proposed limitation of costs to only services and meters excludes all other customer costs that should be included in a customer charge and is unreasonably narrow.

With regard to the concerns expressed by the opposing Parties that PPL's compromise proposal discourages conservation, we note our agreement with the

Company's observation that the distribution charge is relatively small in the context of the energy portion of a customer's bill, which comprises approximately 86% of the charges on the average customer's bill. Therefore, we find that this will provide a more than adequate opportunity for customer savings due to energy conservation.

Therefore, we find that PPL has met its statutory burden of establishing the reasonableness of its compromise proposal. Accordingly, we adopt the recommendation of the ALJ and deny the Exceptions of I&E and the OCA on this issue.

5. Non-Residential Customer Charges

a. Positions of the Parties

PPL proposed increases to the customer charges in the Small General Service -- Rate Schedule GS-1 (GS-1), Large General Service – Rate Schedule GS-3 (GS-3), Large Power Firm Service at 12 kV – Rate Schedule LP-4 (LP-4), and Large Power Service at 69 kV – Rate Schedules LP-5, LP-6, and IS-T (LP-5,LP-6 and IS-T).

PPL proposed to increase the customer charge for Rate GS-1from $14.00 to $16.00 per month and decrease the demand charge from $4.530 to $4.258 per kW. PPL stated it has installed demand meters on all GS-1 customer premises, except for small unmetered constant load accounts. PPL St. 5 at 15; PPL Exhs. DAK 1, DAK 2; PPL Exh. 1, Exhibits Regs.

PPL proposed to increase the customer charge for Rate GS-3 from $30.00 to $40.00 per month and decrease the demand charge from $4.510 to $4.192 per kW. PPL St. 5 at 15; PPL Exhs. DAK 1, DAK 2; PPL Exh. 1, Exhibits Regs.

PPL proposed to increase the customer charge for Rate LP-4 from $160.19 to $170.00 per month and decrease the demand charge from $2.136 to $2.127 per kW. PPL St. 5 at 16; PPL Exhs. DAK 1, DAK 2; PPL Ex. 1, Exhibits Regs.

PPL proposed to increase the customer charge for Rate Schedule LP-5 from $709.00 to $1,125.00 per month. PPL stated that presently, there are only two customers on Rate Schedule LP-6. As there is no difference between Rate Schedules LP-6 and LP-5, PPL proposed to eliminate LP-6 and move the two remaining customers to Rate Schedule LP-5. Finally, PPL proposed to eliminate Rate Schedule IS-T because there are no customers on this interruptible service program. According to PPL, all of its interruptible service programs have been superseded by PJM Interconnection LLC's (PJM) programs. PPL St. 5 at 17; PPL Exhs. DAK 1, DAK 2; PPL Exh. 1, Exhibits Regs. PPL M.B. at 157-162.

According to PPL, its proposals to increase the customer charges and reduce the demand charge for these rate schedules are consistent with *Lloyd*, which held that rate structures should be adjusted to reflect the cost of service to each rate class and to eliminate cross-subsidization. *Id.*

I&E argued that the customer charges for these rate schedules should not be increased. I&E used its own direct customer cost analysis which, the Company argued, excludes certain items that the Company evaluation includes. I&E St. 3 at 12-14.

The Company averred that its minimum size system study is the appropriate basis for determining the fixed customer costs that are incurred to serve customers, and that those fixed costs should be recovered through a fixed customer charge. PPL argued that I&E's approach to setting the fixed monthly customer charges ignores the customer costs of the fixed and permanent infrastructure that the electric

distribution company is obligated to provide and which exists between a customer's service and the transmission substation from which the customer's load is served.
PPL M.B. at 174.

b. ALJ's Recommendation

The ALJ stated that as she accepted the Company's cost of service-based evaluation for residential customers, it was consistent to accept it for the commercial and industrial customers as well. Therefore, the ALJ recommended that PPL's proposals be approved. R.D. at 121.

c. Exceptions

In its Exceptions, I&E states that the ALJ's recommendation to adopt the Company's non-residential customer charges to be consistent with the recommendation regarding the residential customer charge lacks factual support. I&E avers that its customer cost analysis did not distinguish between residential and non-residential classes, but was guided solely by the results of the properly constructed direct customer cost analysis. I&E points out that, while PPL proposed an alternative customer charge for the residential class, the Company produced no study or compromise offer with respect to its originally proposed non-residential customer charges. I&E asserts that the ALJ's recommendation to adopt PPL's non-residential customer charges to be consistent with the residential class is actually inconsistent since PPL did not present a compromise analysis applicable to the non-residential customer charges. Therefore, I&E opines that on the basis of that error, the ALJ's non-residential recommendation should not be adopted. I&E Exc. at 30-36.

In reply, PPL acknowledges that it has the burden of proof to establish that its proposed non-residential customer charges are just and reasonable; however, it is not required to develop and present alternatives that it does not support. PPL avers that the evidence demonstrated that I&E's non-residential customer charges are based on its own direct customer cost analysis, which is based on a flawed process. PPL R.Exc. at 19-20.

d. Disposition

Upon our consideration of the record evidence, we conclude that PPL's proposed non-residential customer charges are reasonable and should be approved.

While the ALJ's comment concerning consistency may not be entirely accurate[21], we find that her recommendation to approve PPL's non-residential customer charges is correct. It is important to note that none of the other Parties directly affected by these increased customer charges were opposed to the increase. Only I&E filed Exceptions to the ALJ's recommendation based on its own customer charge cost analysis that we have previously rejected. Accordingly, finding the ALJ's recommendation to be otherwise reasonable and duly supported by the evidence of record herein, it is adopted. The Exceptions of I&E on this issue are denied.

6. Net Metering for Renewable Customer-Generators Rider

a. Positions of the Parties

PPL proposed two changes to its Net Metering tariff provisions for Renewable Customer-Generators. First, PPL proposed to establish a limitation on the size of generator relative to the associated customer usage that would be eligible for net metering. Second, PPL proposed to clarify that, for eligible customer-generators served under PPL's Time of Use default service rate option, a weighted average of the on-peak

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[21] The ALJ stated that as she accepted the Company's cost of service-based evaluation for residential customers, it was consistent to accept it for the commercial and industrial customers as well. However, we note that PPL did not present a compromise analysis for the non-residential customer charge as it did for the residential customer charge.

and off-peak hour prices would be used to derive the Price to Compare for the purpose of compensating customer-generators for excess generation. PPL St. 5 at 25; PPL Exh. DAK 2; PPL M.B. at 180-181.

Both SEF and Granger opposed PPL's proposal to limit the eligibility for net metering based on the size of the generator relative to the associated customer usage. Granger opposed the as-filed proposal, as the Company proposed to limit the generation in all new net-metering applications to 110% of the customer-generator's connected load. SEF pointed out that the Company had provided no evidence to support an allegation that net metering customers cause PPL to incur costs that support an increase in the customer charge and asked that this allegation be rejected. Granger M.B. at 9, SEF R.B. at 1-2.

In response to this opposition, PPL withdrew this proposal and instead proposed a tariff revision to comply with the wording from the policy adopted by the Commission in the Commission's Final Order entered March 29, 2012, at Docket No. M-2011-2249441.[22] This revision limits the 110% restriction to the business model where a third-party developer builds, owns, operates and maintains an alternative energy generation system on or near a customer's property and sells power and/or alternative energy credits to that customer. PPL St. 5-R.

Granger stated that the Company's revised proposal incorporated language from that Commission Order, and, consequently, it did not oppose the proposal. Granger M.B. at 9.

No party opposed PPL's second proposal, which was to revise the tariff to use the weighted average of the on-peak and off-peak hour TOU prices to derive the

[22] *Net Metering – Use of Third Party Operators*, Docket No. M-2011-2249441 (Order entered March 29, 2012).

Price to Compare for customers served under PPL's Time of Use default service rate option. PPL explained that the stated purpose of this proposal was to ensure that compensation for excess generation by TOU customer-generators more closely reflects their actual on-peak and off-peak usage and generation. PPL M.B. at 180-182.

b. ALJ's Recommendation

The ALJ recommended that the revised net metering proposals be approved. R.D. at 126.

c. Disposition

No Party filed exceptions to the ALJ's recommendation. Finding it to be reasonable, we adopt it without further comment.

7. Competitive Enhancement Rider (CER)

a. Positions of the Parties

The Company proposed a new rider, the CER, to recover the costs of all customer education programs. PPL will estimate the total costs it expects to incur, on a calendar-year basis, to provide consumer education programs and competitive retail electricity market enhancement initiatives for all customers who receive distribution service from PPL. According to PPL, the CER will be a Section 1307(e), 66 Pa. C.S. § 1307(e), cost recovery mechanism developed to recover the Company's education and retail market enhancement (RME) related costs. PPL St. 8 at 30-32; PPL Exh. DAK 2; PPL M.B. at 180.

PPL argued that the Commission and the appellate courts have held that an automatic adjustment clause is appropriate when the expenses to be recovered are substantial, subject to variation and beyond the control of the utility. PPL M.B. at 206 (citing *Popowsky v. Pa. PUC,* 869 A.2d 1144, 1159 (Pa. Cmwlth. 2005); *Pennsylvania Industrial Energy Coalition v. Pa. PUC,* 653 A.2d 1336 (Pa. Cmwlth. 1995); *Pa. PUC v. Newtown Artesian Water Co.,* Docket No. R-2009-2117550 (Order entered April 15, 2010); *Pa. PUC v. Philadelphia Thermal Energy Corp.,* 1991 Pa. PUC Lexis 80). According to PPL, its competitive enhancement expenses meet each of these standards. PPL M.B. at 206.

The Company estimated that the costs of the mandates in the RMI and other proceedings will be more than $6 million annually, at least at the beginning, but will depend on the Commission's direction and are not within the control of the Company. PPL M.B. at 206.

The OCA, the OSBA, and Direct Energy have raised various issues and concerns regarding the proposed CER.

The OCA cautioned that care must be taken to prevent double recovery of these costs. In addition, the OCA noted that the Commission had recently held that the competitive enhancement costs should not be collected from ratepayers but from the EGSs. OCA M.B. at 125 (citing *Petition of FirstEnergy,* Docket No. P-2011-2273650, at 136 (Order entered August 16, 2012). The OCA recommended three safeguards: (1) that the allowed costs must conform to the standards in the Commission's May 10, 2007 Order at Docket No M-000061957; (2) that competitive enhancements costs incurred by PPL, consistent with the Commission's directive, be collected from EGSs; and (3) that there be quantifiable assurances in place to prevent double recovery of these costs, such as through the CER and within the approved revenue requirement in this case. *Id.* at 125-126.

The OCA also recommended that the costs be allocated on a per kWh basis instead of per customer, reasoning that those with higher usage will benefit more from the information. According to the OCA, costs are incurred on a per customer basis and should be allocated accordingly. OCA M.B. at 126.

REG avers that Rate CER should be applied only to those customers and customer classes that benefit from the programs, activities, and enhancements funded by Rate CER. As customers already shopping know that they can shop and that Rate CER provides an incentive to customers to shop to the extent that it is imposed on them, Rate CER is best imposed on non-shopping customers to provide them with an incentive to shop and should not be imposed upon customers who have already selected alternative suppliers. REG M.B. at 6; REG R.B. at 1.

PPLICA limited its argument to cautioning the Commission to ensure that the Company's costs are not duplicated in multiple education programs. PPLICA M.B. at 21. PPLICA noted further that the Company's proposal to recover costs of RME programs from the EGSs that benefit from them is consistent with the Commission's Final Order in *Investigation of Pennsylvania's Retail Electricity Market: Intermediate Work Plan,* Docket No. I-2011-2237952 (Order entered March 2, 2012) and, therefore, PPLICA supported this proposal. PPLICA M.B. at 21.

Regarding recovery of costs, PPLICA opined that the costs allocated to a customer class should be recovered per customer, not per kWh, as proposed by the OCA as this is contrary to cost causation principles. PPLICA did not oppose approval of the proposal to recover CER costs through a fixed monthly customer charge. PPLICA M.B. at 23.

PPL asserted that to the extent it recovers these costs from EGSs, they would not be recovered through the CER. PPL M.B. at 209.

b. ALJ's Recommendation

The ALJ recommended that the CER be approved, and that the costs incurred by the Company in implementing the RME programs, including consumer education costs not recoverable from the EGSs, be recovered using the CER. The ALJ further recommended that as all customers benefit from the robust competitive market, then all customers should bear the costs involved in its development, on a per customer basis. R.D. at 128.

c. Exceptions

In its Exceptions, the OCA states that it opposes the ALJ's recommendation regarding retail market enhancement programs, and submits that this type of cost recovery for RME programs is inconsistent with the Commission's directives in this area. The OCA cites to the Commission's recent decision wherein the Commission held that EGSs should pay for RME costs. *Petition of FirstEnergy*, Docket No. P-2011-2273650, at 136 (Order entered August 16, 2012). The OCA avers that *FirstEnergy* is consistent with the Commission's decision to require EGSs to pay for the costs of opt-in auction programs in *Investigation of Pennsylvania's Retail Electricity Market: Intermediate Work Plan, supra,* at 79. OCA Exc. at 37-38.

The OCA also states that consumers that use more energy clearly have greater potential to benefit from these customer education programs than consumers who use very little electricity. Therefore, the OCA opines that a per kWh based rider better equates the costs and benefits of these programs. The OCA submits that whatever consumer education costs are ultimately recovered from ratepayers should be done on a kWh basis. OCA Exc. at 38-39.

The OSBA also excepted to the ALJ's recommendation, stating that there is no need at this time for yet another PPL reconcilable charge. The OSBA avers that implementing another rider will simply lead to the need for enhanced regulatory oversight to ensure that the costs claimed under the new rider include only those costs that were specifically identified as being associated with that rider. The OSBA notes that it agrees with PPL that it should be allowed to fully recover these costs, that many of these costs should be recovered from EGSs and that other Pennsylvania EDCs have similar riders. However, the OSBA does not believe that these costs should be recovered in the context of the instant distribution rate proceeding. The OSBA opines that a rate rider designed to recover RME costs would be better addressed in the Company's pending default service proceeding at Docket No. P-2012-2302074. According to the OSBA, it is established Commission policy that RME costs should be borne by EGSs and that this issue should be resolved in default service proceedings. OSBA Exc. at 15 (citing *FirstEnergy, supra,* at 136). OSBA Exc. at 13-15.

Next, the OSBA maintains that if the Commission does decide that the CER is necessary, then PPL's rate design for recovering the costs of the CER program should be changed. Instead of recovering these costs equally across all of the Company's customers as recommended by the ALJ, the OSBA submits that these costs should be directly assigned to PPL's rate classes for which costs can clearly be attributed. Furthermore, the OSBA avers that costs not specifically associated with a rate class should be allocated using some reasonable cost-based allocation factor. Then the Company should develop a separate CER charge for each rate class or rate class group, based on the allocated costs. OSBA Exc. at 16-17.

Finally, the OSBA submits that it is much more reasonable to directly assign costs, where possible, so that the cost-causing customer class pays. The OSBA asserts that in light of the high level of shopping that already exists among PPL's non-residential customers, it is not clear that there is any benefit to be gained by developing

RME programs for these customers. Additionally, if RME programs apply only to the residential class, PPL's proposal to effectively allocate those costs among all customers is clearly at odds with both cost causation and fairness considerations. OSBA Exc. 17.

In reply, PPL states that its proposed CER is appropriate for three principal reasons. First, PPL avers that such automatic adjustment clauses are appropriate for expenses that are substantial, vary and are beyond the utility's control. According to PPL, initially the CER annual expenses will total more than $6.0 million and, thus, are substantial. PPL opines that they are subject to variation because they will change depending on Commission mandates in the RMI and other proceedings, and they are beyond PPL's control as they are incurred under Commission directives. Second, PPL avers that a CER permits a more flexible approach because it can be adjusted annually should the need for spending levels change in the future. PPL notes that such flexibility is not available if these costs are recovered through base rates. Third, PPL avers that other EDCs are employing Commission approved rider mechanisms to recover expenses incurred in response to the RMI. PPL R.Exc. at 23.

In response to the concerns expressed regarding the double recovery of costs, PPL maintains that the use of a specific reconcilable rider for all customer education expenses would assure that all costs are recovered only once. PPL opines that the possibility of double recovery would be eliminated as these expenses would all be reviewed annually in one reconciliation proceeding, and these expenses and revenues would be trued-up annually to make sure that only actual expenses are recovered. PPL R. Exc. at 23-24.

In response to the rate design issue expressed by the Parties, PPL avers that customer education costs should be recovered as it proposes on a per customer basis. PPL submits that this is consistent with cost causation because it costs the same to send a notice to an industrial customer as to a residential customer. PPL R.Exc. at 24.

Finally, PPL notes that the OSBA's proposal that the CER be addressed in PPL's default service proceeding is impractical, as it is too late for such matters to be considered in that proceeding since the record is closed. Also, PPL submits that it is important for PPL's proposed CER to be considered in this base rate case because, if it is adopted, it will have a direct impact on the level of base rates charged to customers. If it is not adopted, PPL claims that these costs would have to be recovered through base rates. PPL R.Exc. at 24.

In its Replies to Exceptions, PPLICA states that the ALJ correctly approved recovery of the costs included within the CER on a per customer basis. PPLICA avers that the costs potentially recoverable through the CER are generally customer costs and therefore rightfully recovered on a per customer basis. According to PPLICA, potential CER costs comprise broad marketing and education programs, which are readily distinguishable from the more consumption or demand-oriented energy efficiency and conservation plans administered under Act 129 of 2008. PPLICA R.Exc. at 11.

d. Disposition

We are in agreement with the ALJ that PPL's proposed CER is appropriate and should be approved. The CER is meant to recover the costs incurred by PPL to implement the RME Programs, including consumer education costs, not recoverable from EGSs, and should be designed on a per customer basis as proposed by PPL. We are persuaded by the arguments in favor of the CER presented by the Company. We agree that the costs proposed to be recovered through the CER qualify for recovery under an automatic adjustment clause, consistent with the Commonwealth Court's reasoning in *Pennsylvania Industrial Energy Coalition v. Pa. PUC,* 653 A.2d at 1349. We also concur that the CER provides a more flexible methodology for the Company to recover these Commission mandated expenses, and the CER is consistent with Commission approved recovery mechanisms we have adopted in other EDC proceedings. Furthermore, we agree with PPL that these costs are properly recoverable on a per customer basis, consistent with cost-causation principles. Accordingly, we shall adopt the recommendation of the ALJ and deny the Exceptions of the OCA and the OSBA on this issue.

8. Purchase of Receivables

a. Positions of the Parties

PPL purchases, at a discount, the accounts receivable of EGS customers who participate in the Purchase of Receivables (POR) program. This discount is composed of an uncollectible accounts percentage factor and a development, implementation, and administrative factor. Uncollectible expenses are those costs that result from customers not paying for service, and the amount of the non-payment is written off. Uncollectible accounts expense associated with generation supply and transmission service for default service customers is separated from the Company's distribution rates and recovered through the Merchant Function Charge (MFC) and included in its Price to Compare. The cost of uncollectible expense is recovered from default customers through the MFC and from shopping customers through the discounted rate at which PPL purchases the accounts receivable within the POR program. PPL M.B. at 184-185.

The MFC percentages for the residential and small C&I customer classes have been calculated on the Company's expected 2012 uncollectible accounts expense for those customer classes. Based thereon, PPL proposed to change the MFC for the residential class from 1.80% to 2.23% and for small C&I customers from 0.10% to 0.23%. PPL St. 8 at 29-30; PPL St. 8-R at 43-44; PPL Exh. JMK 4.

PPL stated that in the ordinary course of business, the entity rendering the service is responsible for the costs and actions associated with billing and collection of payments, and also bears the risk of non-payment or late payments. Under a POR program, the EGS sells its accounts receivable to PPL and receives immediate payment for the amount due minus a discount meant to reflect collection risk and the time value of money. A POR program, therefore, allows the seller of the receivables to receive payment sooner and avoid the costs and risks associated with collecting any delinquent amounts owed by the customer. PPL M.B. at 184.

PPL explained that the existing POR program was authorized by the Commission's Order in *Petition of PPL Utilities Corporation Requesting Approval of a Voluntary Purchase of Accounts Receivables Program and Merchant Function Charge*, Docket No. P-2009-2129502 (Order entered November 19, 2009). In that Order, the Commission approved a settlement of the following factors: (1) the discount rate for residential service was 1.37%, consisting of an uncollectible accounts expense percentage factor of 1.32% and a POR administrative factor of .05%; (2) in order to participate, an EGS would sell all of its residential customer accounts receivables to the Company; (3) participating EGSs agreed to not reject new customers based on credit-related issues and would not require a deposit; (4) budget billing would be available to customers of participating EGSs; and (5) for small commercial and industrial shopping customers, the discount rate was 0.17%, reflecting an uncollectible accounts expense percentage factor of 0.12% and a POR administrative factor of 0.05%. PPL stated that the percentages were increased in the 2010 base rate case, *Pa. PUC v. PPL Electric Utilities Corporation,* Docket No. R-2010-2161694 (Order entered December 21, 2010). *Id.* at 185.

The Company noted that, in this proceeding, it based its proposed numbers on its actual write-offs from 2011, which were approximately $40 million. PPL M.B. at 187; PPL St. 8-R at 43. To calculate the amount sought, PPL used its proposed 2012 budget amount, which is the sum of projected write-offs and the projected change in the reserve for doubtful accounts for 2012. PPL M.B. at 187; PPL St. 8-R at 44.

Direct Energy and DR opposed PPL's expected 2012 uncollectible accounts expense. Direct Energy recommended, instead, that PPL be permitted to recover 100% of its uncollectible accounts expense by implementing a non-bypassable/non-reconcilable charge applicable to all customers. In the alternative, Direct Energy recommended modifying the Company's proposal in the following manner: (1) by reducing the discount rate to reflect the amount of late payment charges that the Company collects and which offset its net uncollectible accounts expense; and (2) by reducing the discount factor by an administrative cost credit to return to the EGSs the amounts that have been collected through the administrative cost adder but which the Company did not track. Direct Energy St. 1 at 9-11; Direct Energy M.B. at 9.

Direct Energy averred that the Company's proposal must be rejected because there is no record basis to support allocation of the proposed uncollectible accounts expense percentage to generation service customers. Direct Energy claimed that while PPL has proposed that shopping and default customers pay at the same percentage level, it has not provided evidence to support a finding that this is just and reasonable. In fact, the Company admitted that it did not track write-offs by the shopping/default categories. Direct Energy M.B. at 12; Tr. at 404. While Direct Energy pointed out that it is possible that one category may be more reliable in paying bills than the other, and that the shoppers may be unfairly charged here, it is just as likely that the default customers are effectively subsidizing shopping customers. Direct Energy M.B. at 1.

Direct Energy also stated that the Company's proposal will stall development of a fully robust competitive retail market. Direct Energy noted that "[t]he level of competition in PPL's service territory is good, but it could be much better. The current levels of shopping need not only be sustained but increased in order to meet the

Commonwealth's goal of a fully competitive retail electric market. PPL's service territory presents the best opportunity to do that, but only if the Commission continues to remain vigilant about properly allocating costs to EGSs." *Id.* at 14 (footnotes omitted).

According to Direct Energy, the levels of uncollectible discount that PPL is proposing to charge through the POR program will have a significant negative effect on the development of competition because EGSs cannot administer their own programs efficiently and inexpensively and have no real choice but to rely on the Company. *Id.* at 15.

PPL denied that this increase will have a negative effect on the competitive market. While Direct Energy and DR argued that the EGSs would have to bear the difference in cost until the expiration of existing fixed-price contracts, PPL pointed out that there should have been no reasonable expectation that the discount rate would remain static indefinitely. According to PPL, such risk was willingly undertaken by the EGSs, is a business risk, and cannot be used to shift the risk of doing business as an EGS to PPL and its customers. PPL R.B. at 105-106.

Direct Energy stated that the Company's failure to properly support its own proposal opens the door for the Commission to consider the Direct Energy alternative, which is to collect total projected uncollectible accounts expense through a non-bypassable charge for all distribution customers. According to Direct Energy, this eliminates the need for determining the actual uncollectible expense. Direct Energy opined that this approach is superior to the Company's because it is consistent across shopping lines and does not contain the possibility of shoppers subsidizing default customers. Direct Energy M.B. at 18.

PPL argued that the dual MFC/POR method appropriately unbundles the uncollectibles charge and properly assigns risk of nonpayment and that Direct Energy's proposal to refund all amounts that PPL has received under the administrative component of the POR should be rejected as impermissible retroactive ratemaking. PPL M.B. at 189-193. PPL also argued that the Commission has no authority to direct a change in its POR program due to its voluntary nature. *Id.* at 185.

Direct Energy responded that the POR is a tariffed program, which results in the requirement that it be just and reasonable. Direct Energy R.B. at 6-7. Direct Energy and DR further claimed that PPL should be required to use late payment charges to reduce the POR and MFC percentages. Direct Energy R.B. at 2, DR R.B. at 3.

PPL responded that late payment charges are paid, and are, therefore, not uncollectible but are revenue, as reflected in its accounting for decades and repeatedly approved by the Commission. PPL M.B. at 188; PPL St. 8-RJ at 8. In addition, PPL pointed out that late payment charges are used to reduce the overall distribution of revenue requirement for customer rate classes that bear the working capital requirement associated with overdue accounts receivable. PPL averred that granting this request would result in double counting. PPL M.B. at 188. Therefore, according to PPL, should the request be granted, the late payment fees would need to be split between the POR and MFC customers, accompanied by an adjustment in base rate revenues, which would increase rates for all distribution customers. PPL St. 8-RJ; PPL M.B. at 189.

b. ALJ's Recommendation

The ALJ recommended that the Company be required to track uncollectibles by default customers and shopping customers separately, and the correct percentage can be discerned from there. The ALJ noted that the proposed percentage is supported by the past uncollectibles in total, but there is no calculation of which uncollectibles are from default customers and which are from shopping customers.

According to the ALJ, this is not consistent with the terms of the settlement from which the POR program was conceived:

> 25. The Company will monitor individual EGS uncollectible percentages for small C&I customers pursuant to Section12.9.2.6 of the tariff supplement provided in Appendix A and will adjust the discount rate for an individual EGS based upon the provisions contained therein.

R.D. at 131 (quoting *Petition of PPL Electric Utilities Corporation Requesting Approval of a Voluntary Purchase of Accounts Receivables Program and Merchant Function Charge,* Docket No. P-2009-2129502 (Order entered November 19, 2009)).

The ALJ expressed concern that PPL's procedure does not require the Company to determine the actual amount of its uncollectible expenses in order to recover them. The ALJ concluded that the actual amount of the uncollectible expenses is required in order to fairly charge customers the correct amount. Therefore, the ALJ found that PPL should be directed to take the next step and determine that amount for shoppers and to determine that amount for default customers, and to collect it accordingly. The ALJ recommended that PPL's proposed increase in the POR discount rate should be delayed for ninety days until the Company provides data indicating the proportions of uncollectibles attributable to default customers and to shopping customers, to support the proper discount rate. R.D. at 133, 142, O.P. # 10.

The ALJ further recommended that if PPL does not comply with this directive then the percentage discount rates currently in effect in its POR Program should remain in effect. R.D. at 142, Ordering Paragraph No. 11.

The ALJ also stated that Direct Energy and DR had not sustained their burden of proving that their alternatives were appropriate choices for the Commission to adopt in this case. R.D. at 133.

Additionally, the ALJ concluded that late payment fees are presently added to revenues, and that is where they should remain. *Id.* at 134.

c. Exceptions

In its Exceptions, Direct Energy avers that although the ALJ correctly concluded that PPL has failed to prove its increase for the POR discount rate, the ALJ erred in directing PPL to continue the current POR/MFC discount mechanism. Instead of continuing PPL's problematic mechanism, Direct Energy recommended that PPL be required to recover the currently unbundled uncollectible accounts expense in a non-bypassable charge applicable to all customers. Direct Energy avers that PPL's POR program, which reflects total uncollectible expense in the POR discount rate, has resulted in continuing and significant increases to the POR discount rate. Direct Energy compared the January 1, 2010, POR rate of 1.32% to the proposed rate in this proceeding of 2.23%. Direct Energy further notes that if the PPL proposal is adopted, then PPL's POR program would have the highest discount rate of all the Pennsylvania EDCs. Direct Energy Exc. at 3-5.

Direct Energy avers that its proposed non-bypassable mechanism would eliminate the need to determine the specific uncollectible accounts expense for shopping customers, while allocating the uncollectible accounts expense across all customers consistent with traditional rate-making principles. According to Direct Energy, while the ALJ criticizes its proposal because it does not require a calculation of actual uncollectible accounts expense for shopping customers, the fact here is that PPL cannot make that calculation. Direct Energy opines that even the ALJ acknowledged that when the actual uncollectible accounts expense cannot be calculated, Direct Energy's approach is better than the one used by PPL, as she stated that it is "less unfair in its inherent unfairness." Direct Energy Exc. at 8 (quoting R.D. at 133).

Next, Direct Energy states that even if the ALJ's recommendation to continue PPL's current POR discount is adopted, the ALJ erred in failing to recommend adjustments to the calculation of the POR discount rate. According to Direct Energy, the Commission must direct that the initial starting point for the uncollectible accounts expense portion of the POR discount must be the same level of uncollectible accounts expense used to determine PPL's revenue requirement. From there, Direct Energy posits that the Commission should further adjust the POR discount rate to: (1) offset the uncollectible accounts expense percentage factor by the unbundled portion of the revenue PPL receives from late payment charges related to generation rates; and (2) create an administrative credit of 0.05% to the POR discount rate to return to EGSs the money PPL has collected during the POR program through the administrative component based on PPL's admitted failure to track actual incremental administrative costs and to quantify them. Direct Energy Exc. at 10-11.

In its Exceptions, DR first asserts that the ALJ should have set the POR discount at the 1.7% uncollectibles rate she adopted for ratemaking purposes. DR states that there is no real dispute in this case that the POR discount is the same as the uncollectibles rate and that PPL currently does not track uncollectibles separately as between shopping and non-shopping customers. Tr. at 404-405. Therefore, DR posits that PPL does not possess the historical data that would allow the immediate development of an appropriate uncollectible expense level, based on actual experience, for residential or commercial customers and differentiate between shopping and non-shopping customers. DR opines that any PPL proposed differentiation would be speculative, which is not permitted. According to DR, the more certain path would be to require PPL to implement a POR discount based upon an uncollectible expense rate of 1.7%, which the ALJ accepted as reasonable. DR Exc. at 3-4.

Next, DR excepts to the ALJ's decision not to require PPL to use late payment fee revenue to reduce the POR discount. DR asserts that PPL cannot, and does not, reasonably dispute the fact that applying late payment fee revenue from shopping customers to offset the CWC expense for default service results in a subsidy to default service. DR submits that it proposed a reasonable means of eliminating this subsidization by using the late payment fee revenue from shopping customers to offset the uncollectibles expense of shopping customers. According to DR, under the methodology used today, shopping customers subsidize non-shopping or default service customers with every dollar of late payment fee revenue. DR asserts that this revenue should instead be used in a manner that provides at least some benefit to shopping customers, not an exclusive benefit to default service customers as it does today. DR Exc. at 5-6.

In reply, PPL states that it fully explained why Direct Energy's non-bypassable proposal should be rejected, including the fact that the Commission recently considered and rejected the very same proposal in PPL's 2010 base rate case. Also, PPL states that if the ALJ recommendation is approved by the Commission, the Company can and fully intends to promptly comply with the recommendation to track and separately determine the uncollectible accounts expense for shopping customers. In response to the Parties' proposal that the POR discount rate be set at the 1.7% three-year average of uncollectible accounts expense accepted by the ALJ, PPL opines that the 1.7% rate understates PPL's projected uncollectible accounts expense. PPL R. Exc. at 20-21.

PPL next notes that Direct Energy and DR continue to argue that late payment charges from shopping customers offset or reduce uncollectible accounts expense. PPL asserts that is not the case as these charges represent an addition to a utility's revenues and offset accounts receivable. PPL explains that late payment charges are actually paid by customers and the revenues received from late payments are, by definition, not uncollectible. According to PPL, the proposal advanced by Direct Energy and DR would result in double counting of late payment revenues by crediting these revenues to customers twice. PPL R. Exc. at 21.

Lastly, in response to Direct Energy's proposal in regard to the administrative component of the POR discount rate, PPL claims that Direct Energy ignores the record evidence that the Company has incurred incremental expenses with its POR program. PPL asserts that the POR is a Section 1308 rate and cannot be retroactively changed. PPL R. Exc. at 21.

In its Reply Exceptions, PPLICA states that the ALJ correctly rejected the proposal that PPL implement a non-bypassable charge for recovery of uncollectibles expense currently recovered through the POR discount. PPLICA asserts that the ALJ's rejection of a non-bypassable charge reflects the many flaws inherent in this proposal, including the potential for double charging customers not eligible for PPL's POR program and the rebundling of generation, transmission and distribution charges. PPLICA requests that the Commission adopt the ALJ's recommendation. Further, PPLICA avers that the ALJ's rejection of this proposal is fully consistent with Commission precedent and the Code. PPLICA explains that the Commission addressed a similar proposal from the Retail Energy Supply Association in PPL's 2010 rate case and held that "EGSs should bear the collection risk for their own customers, either by including it in the charges to those customers or by selling their receivables to PPL at a discount." PPLICA R. Exc. at 13 (quoting *Pa. PUC v. PPL Electric Utilities Corp.*, Docket No. R-2010-2161694, at 153 (Order entered December 21, 2010)). PPLICA further asserts that adoption of Direct Energy's proposal would violate Section 2804(3) of the Competition Act, 66 Pa. C.S. § 2804(3), which requires EDCs to unbundle generation, transmission and distribution rates. PPLICA R. Exc. at 12-13.

In its Replies to Exceptions on this issue, the OSBA states that although the Direct Energy language it quotes in its Exceptions does not say so, Direct Energy is addressing the residential class uncollectibles rate. The OSBA explains that for the majority of Direct Energy's Exceptions, the 1.7% is referred to as "the uncollectibles rate" when it is, in fact, just the rate for the residential customers. While the OSBA agrees with Direct Energy that the uncollectibles rate determined for the residential class should be used to develop both the residential MFC and the residential POR discount, the OSBA cautions that the 1.7% factor is not appropriate for the non-residential classes. According to the OSBA, the Small C&I and Large C&I MFC and POR discount rates should reflect the uncollectibles rates applicable to those classes. OSBA R. Exc. at 14-15.

d. Disposition

First, with regard to Direct Energy's recommendation for the use of a non-bypassable distribution charge applicable to all customers to collect uncollectible expenses, we find that PPL correctly explained that the use of a non-bypassable charge is improper and has previously been rejected in PPL's prior 2010 base rate proceeding. In that Order we held that the collection risk for shopping customers should remain with the EGSs. *Pa. PUC v. PPL Electric Utilities Corp.*, Docket No. R-2010-2161694, at 95. We affirm that position in the instant proceeding. Therefore, the Exceptions of Direct Energy are denied on this issue.

Next, we agree with the ALJ's recommendation to delay the implementation of the Company's proposed increase in the POR discount percentage for ninety days. We concur with the ALJ's directive that the currently effective rates remain in effect until PPL provides the required breakdown on these expenses between shopping and non-shopping customers. Once this information is developed, the Commission will have thirty additional days to finalize an appropriate course of action. We note that the

Company stated in its Replies to Exceptions that it can and fully intends to promptly comply with the ALJ's recommendation to track and separately determine the uncollectible accounts expense for shopping customers. We also agree with the ALJ that if PPL fails to provide this information, then the currently effective discount rates shall remain unchanged. Therefore, the Exceptions of Direct Energy and DR are denied on this issue.

In response to the Direct Energy and DR recommendation to offset uncollectible accounts expense with late payment fees, we are persuaded by the arguments of PPL that late payment fees do not reduce uncollectibles. We agree with PPL that late payment charges are actually paid by customers and are used to reduce the overall distribution of revenue requirement for customer rate classes that bear the working capital requirement associated with overdue accounts receivable. Accordingly, we adopt the recommendation of the ALJ on this issue and deny the Exceptions of Direct Energy and DR.

In conclusion, we address the recommendation of Direct Energy that since PPL did not track the incremental expenses under the 0.05% administrative cost component of the POR discount rate, then PPL should be directed to refund all amounts collected to date under this component until the amount PPL has collected is returned. We find it disappointing that PPL did not track these costs. The administrative component of the POR rate was designed with cost recovery of incremental costs in mind. However, the tariff did not provide for these refunds. In order to avoid a repetition of this failure, the Parties should address the issue in future proceedings so as to provide a more equitable outcome.

Going forward, we direct PPL to track and make an appropriate filing with the Commission describing all revenues and incremental costs incurred to develop, implement, and administer the POR service, including costs since inception, associated with implementation of its POR service if it desires to seek any further administrative cost recovery in the future. If, at that time, it is determined that PPL over-recovered historical administrative costs, future cost recovery will only be allowed once the historical over-recovery is netted out. Accordingly, we shall adopt the ALJ's recommendation, as modified by this Opinion and Order, and deny the Exceptions of Direct Energy.

In summary, we hold that PPL's proposed POR program discount rates remain as currently in effect for ninety days and that PPL is directed to provide the breakdown of uncollectible expenses between shopping and non-shopping customers within ninety days. If PPL does not comply with this directive, then the percentage rates currently in effect in its POR program shall remain in effect. Furthermore, the recommendations of the intervening Parties with regard to the implementation of a non-bypassable charge, the offset of late payment fees and the refund of the administrative cost component are denied, consistent with the discussion herein.

IV. CONCLUSION

We have reviewed the record as developed in this proceeding, including the ALJ's Recommended Decision and the Exceptions and Replies to Exceptions filed thereto. Based upon our review, evaluation and analysis of the record evidence, the Exceptions filed by the various Parties hereto are granted or denied, and the ALJ's Recommended Decision is modified, consistent with the discussion in this Opinion and Order; **THEREFORE,**

V. ORDERING PARAGRAPHS

IT IS ORDERED:

1. That the Exceptions of the Office of Small Business Advocate, Direct Energy Services, PP&L Industrial Customer Alliance, the Commission on Economic Opportunity and Dominion Resources, filed on November 8, 2012, are denied, consistent with this Opinion and Order.

2. That the Exceptions of PPL Electric Utilities Corporation, the Office of Consumer Advocate, the Bureau of Investigation and Enforcement, filed on November 8, 2012, are granted in part, consistent with this Opinion and Order.

3. That the Recommended Decision of Administrative Law Judge Susan D. Colwell, issued on October 19, 2012, is adopted as modified by this Opinion and Order.

4. That PPL Electric Utilities Corporation shall not place into effect the rates, rules and regulations contained in Supplement No. 118 to Tariff – Electric Pa. P.U.C. No. 201, as filed.

5. That PPL Electric Utilities Corporation is authorized to file tariffs, tariff supplements and/or tariff revisions, on less than statutory notice, and pursuant to the provisions of 52 Pa. Code §§ 53.1, *et seq.*, and 53.101, designed to produce an annual distribution rate revenue increase of approximately $71.065 million, to become effective for service rendered on and after January 1, 2013.

6. That PPL Electric Utilities Corporation shall file detailed calculations with its tariff filing, which shall demonstrate to the Commission's satisfaction that the filed tariff adjustments comply with the provisions of this final Opinion and Order.

7. That PPL Electric Utilities Corporation shall allocate the authorized increase in operating distribution revenue to each customer class, and rate schedule within each customer class, in the manner prescribed in this Opinion and Order.

8. That PPL Electric Utilities Corporation shall comply with all directives, conclusions, and recommendations contained in the body of this Opinion and Order, which are not the subject of an individual directive in these ordering paragraphs, as fully as if they were the subject of a specific ordering paragraph.

9. That the Formal Complaints filed by the Office of Consumer Advocate, the Office of Small Business Advocate and PP&L Industrial Customer Alliance are sustained in part, consistent with this Order.

10. That the Formal Complaints filed by William Andrews; Tracey Andrews; Eric Joseph Epstein; Dave A. Kenney; Roberta Kurrell; Donald Leventry; John G. Lucas and Helen Schwika, and any other Formal Complaint not specifically noted but filed prior to issuance of this Opinion and Order, are hereby dismissed.

11. That, upon Commission approval of the tariff, tariff supplements and/or tariff revisions, submitted in compliance with this Opinion and Order, the investigation at Docket Number R-2012-2290597 shall be marked closed.

BY THE COMMISSION,

Rosemary Chiavetta
Secretary

(SEAL)

ORDER ADOPTED: December 5, 2012

ORDER ENTERED: December 28, 2012

Pennsylvania Public Utility Commission

v.

PPL Electric Utilities Corporation
Docket No. R-2012-2290597

Commission Tables Calculating Allowed Revenue Increase

TABLE I
PPL Electric Utilities Corporation
INCOME SUMMARY
R-2012-2290597
($000s)

Commission Final Allowance

		Pro Forma Present Rates (Revised) [1] (1)	Commission Adjustments [2] (2)	Commission Pro Forma Present Rates (3) = (1) + (2)	Commission Revenue Increase (4)	Total Allowable Revenues (5) = (3) + (4)
1.	Operating Revenue	780,425	0	780,425	71,030	851,455
2.	Expenses:					
3.	O & M Expense	417,869	(11,966)	405,903	1,759	407,662
4.	Depreciation	139,719	0	139,719	0	139,719
5.	Taxes, Other	53,516	(734)	52,782	4,149	56,931
6.	Income Taxes:					
7.	State	1,571	1,346	2,917	6,506	9,423
8.	Federal	(7,321)	4,245	(3,076)	20,516	17,440
9.	Deferred Inc.	28,861	0	28,861	0	28,861
10.	ITC	(915)	0	(915)	0	(915)
11.	Total Expenses	633,300	(7,109)	626,191	32,930	659,120
12.	Income Available for Return	147,125	7,109	154,234	38,100	192,334
13.	Rate Base	2,420,963	(13,237)	2,407,726		2,407,726
14.	Rate of Return	6.08%		6.41%	38,100 (0)	7.98822%

[1] PPL Exh. Future-1 Revised 7-16-12; Schedule D-1, Column 6.
[2] From Table IV - Adjustments

TABLE II
PPL Electric Utilities Corporation
RATE OF RETURN
R-2012-2290597

Commission Final Allowance

		Structure	Cost	After-Tax Weighted Cost	Effective Tax Rate Complement	Pre-Tax Weighted Cost Rate
		(1)	(2)	[(3)=(1)x(2)]	(4)	[(5)=(3)x(4)]
1.	Total Cost of Debt			2.70710%		2.70710%
2.	Long-term Debt	49.22%	5.50%	2.70710%		2.71%
3.	Short-term Debt	0.00%	0.00%	0.00000%		0.00%
4.	Preferred Stock	0.00%	0.00%	0.00000%	0.585065	0.00%
5.	Common Equity	50.78%	10.40%	5.28112%	0.585065	9.03%
6.	Totals	100.00%		7.98822%		11.74%
7.	Pre-Tax Interest Coverage (11.74% / 2.70710%)	4.336%				
8.	After-Tax Interest Coverage (7.872% / 2.70710%)	2.951%				
9.	Tax Rate Complement (1-(35%+(9.99% X (1-35%))	58.50650%				

TABLE III
PPL Electric Utilities Corporation
REVENUE FACTOR
R-2012-2290597

Commission Final Allowance

1.	100%	100.0000%
2.	Uncollectible Accounts Factor	-2.23000%
3.	(Line 1-Line 2)	97.7700%
4.	PUC, OCA, OSBA Assessment Factors	0.2460%
5.	Gross Receipts Tax (GRT) (Modified per Commission Order)	5.7684%
6.	Other Tax Factors (PA CST)	0.0746%
7.	(Sum of Lines 4, 5 and 6)	6.0890%
8.	Effective Assmt/GRT/CST (Line 7)	6.0890%
9.	Factor after Assmt, GRT and CST (Line 3 - Line 8)	91.681%
10.	State Corporate Net Income Tax Rate	9.990%
11.	Effective State Income Tax Rate (Line 9 x Line 10)	9.1589%
12.	Factor After Local and State Taxes (Line 9 - Line 11)	82.5220%
13.	Federal Corporate Income Tax Rate	35.00%
14.	Effective Federal Income Tax Rate (Line 13 x Line 12)	28.883%
15.	Revenue Factor (100% - Effective Tax Rates); (Line 1 - (Lines 2, 3, 8, 11 and 14))	53.6393%

TABLE IV
PPL Electric Utilities Corporation
SUMMARY OF COMMISSION ADJUSTMENTS
R-2012-2290597
($000)

Commission Final Adjustments

	Adjustments	Rate Base	Revenues	Expenses	Depreciation	Taxes-Other	State Income Tax	Federal Income Tax
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
1.	RATE BASE:							
2.	CWC:							
3.	Int. & Div. (Table VI)	(63)						
4.	Taxes (Table V)	174						
5.	O & M (Table VI)	(13,348)						
6.	TAXES OTHER:							
7.	Gross Receipts Tax (Table XI)					(259)	26	82
8.	Capital Stock Tax (Table X)					(475)	47	150
9.	REVENUES:							
			0				0	0
10.	EXPENSES:							
11.	Rate Case Normalization - PPL Revision			1,200			(120)	(378)
12.	Environmental Management			(103)			10	33
13.	Storm Damage Claim - PPL Revision			(3,500)			350	1,103
14.	Office of General Counsel			(1,200)			120	378
15.	Office of the Chairman			(387)			39	122
16.	Consumer Education: Act 129 Move to CER Rider			(2,494)			249	786
17.	Consumer Education: Pre Act 129			(5,482)			548	1,727
18.	DEPRECIATION:							0
					0		0	0
					0		0	0
19.	TAXES:							
20.	Interest Synchronization (Table V)						77	242
21.	TOTALS	(13,237)	0	(11,966)	0	(734)	1,346	4,245

Notes:

Rate Case Expense and Office of General Counsel: PPL Exhibit Future 1-Revised presents PPL's revised rate case expense which removes $1.2 million representing the double counting of OGC expense. See PPL Future Future 1-Revised Schedule D-6. This $1.2 needs to be added back to Rate Case Expense to reflect adoption of the ALJ's recommended treatment of this expense.

Storm Damage Claim: PPL reduced its claim due to the unavalibility of this type of insurance.

Office of General Counsel: This duplicated expense was removed from the Rate Case Expense claim in PPL Future 1-Revised Schedule D-6. The ALJ's R.D. reflected this as a reduction to the OGC expenses.

Consumer Educatio Pre Act 129: The ALJ's R.D. allowed this expense only to the end of the FTY but the adjustment was inadvertantly excluded from the Tables attached to the R.D.

TABLE V
PPL Electric Utilities Corporation
INTEREST SYNCHRONIZATION
R-2012-2290597

Commission Final Adjustments

		Amount (000)
1.	Company Rate Base Claim (PPL Exh. Furure 1-Revised Sch. C-1)	$2,420,963
2.	Commission Rate Base Adjustments (From Table IV)	($13,237)
3.	Commission Rate Bas (Line 1 - Line 2)	$2,407,726
4.	Weighted Cost of Debt (From Table II)	2.7071%
5.	Commission Interest Expense (Line 4 x Line 3)	$65,180
6.	Company Claim (PPL Exh. JMK 2 p. 28, Line 1)	$65,947
7.	Commission Adjustment (Line 6 - Line 5)	$767
8.	Company Adjustment	$0
8.	Net Commission Interest Adjustment (Line 7 - Line 8)	$767
10.	State Corporate Net Income Tax Rate	9.99%
11.	State Corporate Net Income Tax Adjustment (Line 10 x Line 9) (Flow to Table IV)	**$77**
12.	Net Commission Adjustment for Federal Taxable Income (Line 9 - Line 11)	$690
13.	Federal Income Tax Rate	35.00%
14.	Federal Income Tax Adjustment (Line 13 x Line 12) (Flow to Table IV)	**$242**

TABLE VI
PPL Electric Utilities Corporation
CASH WORKING CAPITAL: O & M COMPONENT
R-2012-2290597

Commission Allowance

			(000)
1.	Total O&M Expense per PPL (PPL Exh Future 1-Revised Sch. C-4, p. 2)		$465,055
2.	Jurisdictional Factor (See Line 15 Below)		85.973%
3.	Jurisdictional O&M Expense (Line 1 X Line 2)		$399,823
4.	Commission O&M Adjustments (From Table IV)		($11,966)
5.	Net O&M Expense (Line 3 - Line 4)		$387,857
6.	O&M Expense per Day (Line 5 / 365 days)		$1,063
7.	Average Lag Days (ALJ R.D. at 19-20; Order at Section II C.)		9.60
8.	Commission Allowed O&M CWC Requirement (Line 6 X Line 7)		$10,201
9.	Company Claim (PPL Furure 1-Revised Sch. C-4, p. 2)		$27,391
10.	Jurisdictional Portion of Company Claim (Line 2 X Line 15)		$23,549
11.	Commission Adjustment to Rate Base (Line 8 - Line 10); (Flow to Table IV)		**($13,348)**
12.	O&M Expense Per Company Filing:		
13.	Total O&M (PPL Future 1-Revised Sch. D-1, Col. 5)	$486,045	
14.	Jurisdictional O&M (PPL Future 1-Revised. D-1, Col. 6)	$417,869	
15.	Jurisdictional Factor (To Line 2 above)	85.973%	

TABLE VII
PPL Electric Utilities Corporation
CASH WORKING CAPITAL: ACCRUED TAXES
R-2012-2290597

Commission Allowance

		Pro Forma Taxes (000) (1)	Twelve-Month Accrued Factor per Company (2)	Accrued Taxes (000) (3) = (1) X (2)
1.	Federal Income Tax	($1,312)	(5.95000%)	$78
2.	PA Corporate Net Income Tax	$11,864	(3.86000%)	($458)
3.	PA Gross Receipts Tax (See Below)	$47,861	33.64000%	$16,100
4.	PA Capital Stock Tax	$2,017	(3.86000%)	($78)
5.	PA PURTA Tax	$2,832	21.14000%	$599
6.	Total Accrued Taxes (Sum of Lines 1 - 5)			$16,241
7.	Accrued Taxes per ppl (PPL Exh. Future 1-Revised, Sch. C-4, p. 4, Line 6)			$16,068
8.	Adjustment to Accrued Taxes (Line 6 - Line 7) (Flow to Table IX)			**$173**

PA Gross Receipts Tax

9.	Per Company (Future Revised Schedule D-11 p 13)	$43,670
10.	Adjustment Due To Allowed Revenue Increase (Allowed Increase X 0.059)	$4,191
		$47,861

PA Capital Stock Tax

11.	Per Company (Future Revised Schedule D-11 p. 2)	$1,954
12.	Adjustment Due To Allowed Revenue Increase (Allowed Increase X 0.0089)	$63
		$2,017

TABLE VIII
PPL Electric Utilities Corporation
CASH WORKING CAPITAL: INTEREST PAYMENTS
R-2012-2290597

Commission Allowance

		(000)
1.	Rate Base (Table I)	$2,407,726
2.	Weighted Average Cost of Debt (Table II)	2.70710%
3.	Interest Expense (Line 1 x Line 2)	$65,180
4.	Daily Amount of Interest Expense (Line 3 / 365)	$178.57
5.	Interest Payment Lag Days	32.90
6.	Commission CWC Interest (Line 4 x Line 5)	$5,875
7.	Company Claimed CWC Interest	$5,938
8.	Commission Adjustment (Flow to Table IX)	($63)

TABLE IX
PPL Electric Utilities Corporation
CASH WORKING CAPITAL
R-2012-2290597

		(000)
1.	O&M Expense (PPL Future 1-Revised, Sch. C-4 p. 2, Line 4)	$27,391
2.	Average Prepayments (PPL Future 1-Revised Sch. C-4, p. 3, Line 15)	$3,174
3.	Accrued Taxes (PPL Future 1-Revised, Sch C-4 p. 4, Line 6)	$16,068
4.	Interest Payments (PPL Future 1-Revised Sch. C-4, p. 5, Line 9)	($8,061)
5.	Total CWC per Company (Sum of Lines 1 through 4)	$38,572
6.	Jurisdictional CWC	$31,593
Commission Adjustments		
7.	Calc O&M Difference (From Table VI Row 11)	($13,348)
8.	Calc Accrued Tax Difference (From Table VII)	$173
9.	Calc Interest Payment Difference (From Table VIII)	($63)
10.	Commission CWC Adjustments (Lines 7 + 8 + 9)	($13,237)
11.	Total CWC (Line 6 + Line 10)	$18,356

TABLE X
PPL Electric Utilities Corporation
CAPITAL STOCK TAX (CST)
R-2012-2290597

		(000) Present Rate Adjustment		(000) Proposed Rate Adjustment	
	Net Income				
1.	2008	$87,403		$87,403	
2.	2009	$103,885		$103,885	
3.	2010	$80,572		$80,572	
4.	2011	$129,591		$129,591	
5.	2012	$97,491		$140,630	
6.		$498,942		$542,081	
7.	Average (Line 6 / 5)	$99,788		$108,416	
8.	Net Worth at December 31, 2012 (Note 2)	$1,790,672		$1,833,811	
9.	Pa Capital Stock value (Per Statutory Formula)		$1,196,704		$1,258,269
10.	Statutory Exemption		($160)		($160)
11.	Value of Capital Stock less Statutory Exemption		$1,196,544		$1,258,109
12.	Apportionment Percentage		95.4053%		95.4053%
13.	Pa CST Value (Line 11 x Line 12)		$1,141,566		$1,200,302
14.	PA CST at 0.89 mills (Line 13 x 0.89 mills)		$1,016		$1,068
15.	Less: PA Education tax credit		($217)		($217)
16.	PA CST at Proposed Rates (Line 14 + Line 15)		$799		$851
17.	Less: PA CST at Present Rates (PPL Sch D-11 p. 2)		$1,941		$799
18.	Jurisdictional Allocation (Note 3 Below)		41.6070%		41.6070%
19.	Adjustment to PA CST (Forward to Table IV)		($475)		$52
	Note 1				
20.	Net Income at Present Rates	$97,491			
21.	Net Income from Proposed Rate Increase (Table XI Line 9)	$ 38,100			
22.	Total 2012 Net Income (Line 19 + Line 20)	$135,591			
	Note 2				
23.	Net Worth at Present Rates	$1,790,672			
24.	Net Worth from Proposed Rate Increase (Table XI Line 9)	$ 38,100			
25.	Total 2012 Net Worth (Line 22 + 23)	$1,828,772			
	Note 3				
26.	Total PPL Electric (PPL Exhibit JMK-2 p. 22)	$1,954			
27.	PA Jurisdictional (PPL Exhibit JMK-2 p. 22)	$813			
28.	Allocation for PA Jurisdictional (Line 26 / Line 25)	41.6070%			

TABLE XI
PPL Electric Utilities Corporation
GROSS RECEIPTS TAX (GRT)
R-2012-2290597

	Commission Allowance	($000)
1.	Base for GRT (PPl Exh JMK2 p. 26)	$744,568
2.	Less Uncollectible Accounts Expense (PPL Exh JMK 2 p. 51)	($14,055)
3.	Net Gross Receipts (Line 1 - Line 2)	$730,513
4.	GTR Rate	5.90%
5.	GRT on Net Gross Receipts (Line 4 X Line 5)	$43,100
6.	PA Jurisdictional Base for GRT (Line 1 X (1 - 0.0059))	$740,175
7.	Less Uncollectible Accounts Expense (PPL Exh JMK 2 p. 51)	($14,055)
8.		$726,120
9.	GTR Rate	5.90%
10.	GRT on Jurisdictional Net Gross Receipts (Line 9 X Line 8)	$42,841
11.	Reduction to GRT by Excluding Uncollectible Accounts Expense (Line 5 - Line 10) (Flow to Sch. IV)	($259)

Table XII
PPL Electric Utilities Corporation
R-2012-2290597
RECONCILIATION OF
Operating Revenue and Applicable Tax
Commission Allowed Rate Increase
(000)

Commission Allowance

Line No.	Description	Amount
1.	Commission Allowed Increase (Table I)	$71,030
	Provision for Uncollectibles (Line 1 x 2.23%)	$1,584
2.	PUC, OCA, OSBA Assessment	$175
	PA Gross Receipts Tax ((Line 1 - Line 3) * 59 mils)	$4,097
3.	PA Capital Stock Tax (Table X Line 16)	$52
4.	Sub Total	$5,908
5.	Taxable Income for PA CNI Tax (Line 1 - Line 4)	$65,122
6.	PA CNI Tax (Line 5 * 9.99%)	$6,506
7.	Federal Taxable Income (Line 5 - Line 6)	$58,616
8.	Federal Income Tax (Line 7 * 35%)	$20,516
9.	Operating Income (Line 7 - Line 8) (See Table I, Col. 4, Line 12)	$38,100

UBS

Global Research

29 November 2018

North America Power & Utilities
Roll On (Erratum)

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Moving to 2021 for Valuation and Updating our Outlook

We are rolling forward our methodology to 2021 price to earnings as a basis for valuation. We refreshed our EPS forecasts and updated the UBS Regulatory Rankings for 2018 data. Regulated Utilities stand within a standard deviation of fair value on key relative yield and P/E metrics. Therefore we expect investors to capture a total return of approximately 9%. This consists of an average dividend yield of 3.5% and a return for growth of 5.3% (the average of 5.4% 5 year EPS CAGR and 5.2% dividend growth CAGR). *This version updates Figure 1 to show the current price target for EXC as $51 and for H as $18.*

Raising D and EMA to Buy from Neutral; Lowering AEE to Neutral

We believe D has taken the appropriate actions to overcome the surprise MLP tax ruling by FERC earlier this year and the likelihood of closing the merger with SCG has increased. Our sum of the parts price target goes to $84 from $75. Other ratings changes driven by valuation include AEE to Neutral from Buy while maintaining our $71 price target and CUP to Neutral from Sell with a $1 increase in the price target to $13. We are also upgrading EMA to Buy from Neutral and increasing our PT to C$51 from C$42 as we believe the asset sale process that started with the New England Generation sale on Monday will address the balance sheet and valuation overhang.

Recommendations and Focus Stocks

Our recommendations fall into 4 categories: higher quality total return compounders; higher growth multi-utilities; special situations; and integrated power. Our top choices in each category are ETR, D, FE, and PEG.

Sell Recommendations: POR, PNM, HE and H

We lowered our price target on POR by $1 to $44. POR is a 4th quartile growing utility with -5% total return to our target. We remain cautious on HE at the current valuation while the commission establishes the framework for Performance-Based Ratemaking. The process will be ongoing through 2019. HE and PNM operate in states that fall in the lowest tier of our Regulatory Rankings. We are lowering our H target by C$1 to C$18 and believe that the AVA merger will close by 1Q'19 despite being dilutive. Even post potential AVA merger close, H will predominately operate in Ontario which we rank at the bottom of Tier 4 as a regulatory jurisdiction.

Figure 1: Regulated Utility Price Target Changes

			Price Target Old			Price Target New									
Rating	Ticker	Company	UBS 2020E EPS	2020 P/E Ratio	Old UBS Price Target	UBS 2021E EPS	2021 P/E Ratio	% Discount	New UBS Price Target	Current Dividend Yield	Total Return inc. Div. Yld	5 Yr EPS Growth	5 Yr DPS Growth	Regulatory Quartile	Old Regulatory Quartile
Buy	ACO	ATCO Ltd. (C$)	$3.38	11.7x	$47	$3.34	11.8x	(28%)	$49	3.8%	28%	3.6%	5.2%	4th	4th
Buy	EMA	Emera Inc (C$)	$3.05	14.2x	$42	$3.26	13.3x	(19%)	$51	5.4%	23%	6.2%	5.9%	2nd	2nd
Buy	NEE	NextEra Energy	$9.08	19.6x	$195	$9.84	18.1x	10%	$209	2.5%	20%	9.5%	12.0%	1st	1st
Buy	PEG	Public Service Ent Group	$3.66	14.8x	$60	$3.77	14.4x	(12%)	$63	3.3%	19%	6.6%	4.9%	2nd	2nd
Buy	FE	FirstEnergy Corp	$2.46	15.4x	$43	$2.60	14.6x	(11%)	$43	4.0%	19%	3.0%	3.5%	2nd	2nd
Buy	FTS	Fortis Inc (C$)	$2.84	16.2x	$49	$3.01	15.3x	(7%)	$53	3.9%	19%	4.8%	6.4%	3rd	2nd
Buy	ETR	Entergy Corp	$5.40	16.0x	$94	$5.73	15.1x	(8%)	$99	4.2%	18%	5.5%	2.0%	2nd	3rd
Buy	D	Dominion Energy	$4.35	17.0x	$75	$4.71	15.7x	(4%)	$84	4.5%	18%	6.7%	6.0%	1st	1st
Buy	SRE	Sempra Energy	$6.99	16.1x	$130	$7.55	14.9x	(9%)	$129	3.2%	18%	8.0%	9.0%	3rd	3rd
Buy	DUK	Duke Energy	$5.29	16.6x	$92	$5.59	15.7x	(4%)	$99	4.2%	17%	5.2%	4.0%	1st	1st
Buy	PPL	PPL Corporation	$2.56	12.1x	$34	$2.59	12.0x	(27%)	$34	5.3%	15%	3.3%	3.3%	1st	2nd
Buy	EXC	Exelon	$3.16	14.4x	$50	$3.25	14.0x	(14%)	$51	3.0%	15%	5.9%	5.3%	3rd	2nd
Buy	AEP	American Electric Power	$4.46	17.2x	$83	$4.77	16.0x	(2%)	$85	3.5%	15%	6.0%	6.6%	2nd	2nd
Buy	ES	Eversource Energy	$3.72	18.2x	$69	$3.95	17.1x	4%	$75	3.0%	14%	6.1%	6.0%	3rd	3rd
Neutral	CUP	Caribbean Utilities Corp Ltd	$0.83	14.8x	$12	$0.89	13.9x	(15%)	$13	5.7%	13%	6.6%	5.7%	2nd	2nd
Neutral	CU	Canadian Utilities Ltd (C$)	$2.35	13.2x	$33	$2.31	13.5x	(18%)	$33	5.1%	12%	1.6%	5.9%	4th	4th
Neutral	ED	Consolidated Edison	$4.60	17.2x	$80	$4.93	16.0x	(2%)	$85	3.6%	11%	4.6%	3.0%	4th	4th
Neutral	SO	Southern Company	$3.17	14.5x	$49	$3.30	13.9x	(15%)	$49	5.2%	11%	3.2%	3.5%	1st	1st
Neutral	CMS	CMS Energy	$2.73	18.7x	$54	$2.92	17.5x	7%	$55	2.8%	10%	7.7%	7.0%	1st	1st
Neutral	LNT	Alliant Energy	$2.45	18.3x	$46	$2.54	17.6x	8%	$48	3.0%	10%	7.1%	6.1%	1st	2nd
Neutral	SCG	SCANA Corp	$2.90	16.2x	$41	$2.66	17.7x	8%	$50	1.1%	7%	-8.0%	6.5%	3rd	1st
Neutral	DTE	DTE Energy	$6.62	17.8x	$118	$7.01	16.8x	2%	$121	3.0%	6%	6.1%	6.6%	1st	1st
Neutral	PNW	Pinnacle West Capital Corp	$5.28	17.0x	$90	$5.52	16.3x	(1%)	$92	3.3%	6%	5.6%	6.0%	4th	3rd
Neutral	WEC	WEC Energy Group	$3.74	19.0x	$70	$3.97	17.9x	9%	$73	3.1%	6%	6.0%	6.3%	1st	1st
Neutral	AEE	Ameren Corp	$3.50	19.6x	$71	$3.85	17.8x	9%	$71	2.8%	6%	7.4%	6.0%	2nd	2nd
Neutral	AES	AES Corp.	$1.45	10.5x	$16	$1.61	9.5x	(42%)	$16	3.4%	5%	9.4%	6.5%	2nd	2nd
Neutral	OGE	OGE Energy Corp	$2.30	17.1x	$37	$2.39	16.5x	0%	$40	3.7%	5%	4.9%	8.9%	4th	4th
Neutral	XEL	Xcel Energy	$2.77	18.7x	$50	$2.95	17.5x	7%	$53	2.9%	5%	6.1%	6.0%	2nd	2nd
Neutral	EVRG	Evergy	$3.38	17.7x	$58	$3.44	17.4x	6%	$61	3.1%	5%	8.3%	7.8%	3rd	3rd
Neutral (CBE)	EIX	Edison International	$4.87	11.4x	$55	$5.19	10.7x	(35%)	$55	4.4%	4%	4.4%	0.0%	3rd	3rd
Sell	H	Hydro One Ltd (C$)	$1.34	14.5x	$19	$1.41	13.8x	(16%)	$18	4.7%	(3%)	4.8%	7.1%	4th	4th
Neutral (CBE)	PCG	PG&E Corp	$4.24	6.4x	$26	$4.41	6.1x	(63%)	$26	0.0%	(4%)	4.4%	0.0%	3rd	3rd
Sell	POR	Portland General	$2.64	18.2x	$45	$2.65	18.1x	11%	$44	3.0%	(5%)	3.6%	6.4%	2nd	3rd
Sell	PNM	PNM Resources	$2.19	19.5x	$37	$2.29	18.6x	14%	$39	2.5%	(7%)	4.3%	6.0%	4th	4th
Sell	HE	Hawaiian Electric Industries	$2.20	17.3x	$33	$2.19	17.3x	6%	$33	3.3%	(9%)	6.7%	0.0%	4th	4th
Overall Average (unnormalized, inc. Gas Midstream)				16.5x			15.6x								
Electric Utility Normalized (including Gas Midstream) (a)				17.4x			16.4x								

(a) Normalized multiple excludes AES, EIX, EXC, PCG, PEG, PPL, SCG and SO.

Source: Company reports, UBS estimates, FactSet

Rolling On to 2021 for Valuation

We updated our price targets and the underlying drivers for valuation incorporating 2021 as a basis for P/E. To determine the valuation multiple we assign to stocks we consider: the sector valuation, EPS growth, weighted average regulatory ranking, and unregulated business contributions. For sector valuation we consider relative yield to the Baa corporate bond in a series back to 1981 and for relative P/E we look at valuation back to 2008. Currently, the group is within a standard deviation of fair value using both measures. Using relative yield Regulated Utilities are +6% beyond the mean within a 7% standard deviation and +7% using relative P/E within a 10% standard deviation. Therefore, we expect one year total return for the group to approximate 9% including a 3.5% dividend yield and a 5.3% growth return (the average of a 5.4% 5 year EPS CAGR and a 5.2% 5 year dividend growth CAGR). However, our forecast for earnings leaves the group offering 5% return over the year.

With regard to EPS growth and quality of regulation we rank the companies in quartiles. Based on historical stock performance we assign +5% for top quartile, +2% for second quartile, -2% for third quartile and -5% for fourth quartile which are summarized below. For companies with significant unregulated businesses we value them on a sum of the parts basis. We also allow for special situation company specific adjustments.

Figure 2: Regulated Valuation Methodology Matrix

Investment Opinion	Ticker	Overall Reg Group Premium Discount	Regulatory Quartile Premium Discount	Regulated EPS Growth Premium Discount	ESG Premium	Specific Adjustments	Net Prem Disc. Reg. Valuation	Business Value
Neutral	**AES**	5%	2%	5%	0%	(5%)	7%	$9
Buy	**ACO**	10%	(5%)	(5%)	0%	(5%)	(5%)	$5
Neutral	**LNT**	5%	5%	5%	0%	0%	15%	$0
Neutral	**AEE**	5%	2%	5%	0%	0%	12%	$0
Buy	**AEP**	5%	2%	2%	0%	0%	9%	$0
Neutral	**CU**	10%	(5%)	(5%)	0%	(10%)	(10%)	$0
Neutral	**CUP**	0%	2%	2%	0%	(10%)	(6%)	$0
Neutral	**CMS**	5%	5%	5%	0%	0%	15%	$0
Neutral	**ED**	5%	(5%)	(2%)	8%	0%	6%	$0
Buy	**D**	5%	5%	2%	0%	0%	12%	$40
Neutral	**DTE**	5%	5%	2%	0%	0%	12%	$30
Buy	**DUK**	5%	5%	(2%)	0%	0%	8%	$0
Neutral (CBE)	**EIX**	5%	(2%)	(2%)	0%	(30%)	(29%)	$0
Buy	**EMA**	10%	2%	(2%)	0%	(5%)	5%	$1
Buy	**ETR**	5%	2%	(2%)	0%	0%	5%	$0
Buy	**ES**	5%	(2%)	2%	10%	0%	15%	$0
Neutral	**EVRG**	5%	(2%)	5%	0%	0%	8%	$0
Buy	**EXC**	5%	(2%)	5%	0%	0%	8%	$11
Buy	**FE**	5%	2%	(5%)	0%	0%	2%	$0
Buy	**FTS**	10%	(2%)	2%	0%	0%	10%	$0
Sell	**HE**	5%	(5%)	2%	0%	0%	2%	$8
Sell	**H**	10%	(5%)	(5%)	0%	(15%)	(15%)	$0
Buy	**NEE**	5%	5%	5%	0%	0%	15%	$95
Neutral	**OGE**	5%	(5%)	(2%)	0%	0%	(2%)	$10
Neutral (CBE)	**PCG**	5%	(2%)	(2%)	0%	(63%)	(62%)	$0
Neutral	**PNW**	5%	(5%)	2%	0%	0%	2%	$0
Sell	**PNM**	5%	(5%)	(5%)	0%	8%	3%	$0
Sell	**POR**	5%	2%	(5%)	0%	0%	2%	$0
Buy	**PPL**	5%	5%	(5%)	0%	0%	5%	$13
Buy	**PEG**	5%	2%	5%	0%	0%	12%	$11
Neutral	**SCG**	5%	(2%)	(5%)	0%	0%	(2%)	$0
Buy	**SRE**	5%	(2%)	(2%)	0%	0%	1%	$38
Neutral	**SO**	5%	5%	(5%)	0%	(15%)	(10%)	$0
Neutral	**WEC**	5%	5%	2%	0%	0%	12%	$0
Neutral	**XEL**	5%	2%	2%	0%	0%	9%	$0

Note: CUP is domiciled in Grand Cayman and should not move with US or CDN interest rates

Source: FactSet, UBS Equity Research

Our Recommendations

Our focus on stock selection as we head toward the end of 2018 and into the new year is for Regulated Utilities at a value as the top quality has outperformed in 2018. As shown below, companies that delivered top quartile earnings growth outperformed the rest of the group year-to-date, offering 14% upside. Overall quality which is a ranking we are basing on the average of EPS growth and our UBS weighted average regulatory ranking also performed this year. Special events like California wildfires, major project construction and international drove the bottom quality.

Our recommendations by style are listed below. Our focus stocks by category are ETR for higher quality, total return compounders; D for higher growth multi utilities; FE for special situations; and PEG for integrated power.

Figure 3: Recommended Stocks

Rating	Ticker	Current Price	UBS Price Target	Total Return inc. Div. Yld	UBS 2018E EPS	UBS 2019E EPS	UBS 2020E EPS	UBS 2021E EPS	2020 P/E Ratio	2020 Prem/ Disc	Current Dividend Yield	5 Yr EPS Growth	5 Yr DPS Growth
Higher Quality Total Return Compounders													
Buy	EMA	$43.41	$51	23%	$2.85	$2.80	$3.10	$3.26	14.0x	(17%)	5.4%	6.2%	5.9%
Buy	FTS	$46.04	$53	19%	$2.52	$2.64	$2.83	$3.01	16.2x	(4%)	3.9%	4.8%	6.4%
Buy	ETR	$86.29	$99	18%	$4.70	$5.09	$5.40	$5.73	16.0x	(8%)	4.2%	5.5%	2.0%
Buy	DUK	$87.83	$99	17%	$4.74	$5.03	$5.33	$5.59	16.5x	(5%)	4.2%	5.2%	4.0%
Buy	AEP	$76.58	$85	15%	$3.93	$4.18	$4.46	$4.77	17.2x	(2%)	3.5%	6.0%	6.6%
Buy	ES	$67.45	$75	14%	$3.28	$3.48	$3.72	$3.95	18.2x	4%	3.0%	6.1%	6.0%
Buy	AWK	$92.11	$101	12%	$3.31	$3.57	$3.85	$4.17	23.9x	(3%)	2.0%	8.3%	10.0%
Higher Growth Mutli-Utilities													
Buy	NEE	$178.00	$209	20%	$7.77	$8.43	$9.08	$9.84	19.6x	13%	2.5%	9.5%	12.0%
Buy	D	$74.11	$84	18%	$4.10	$4.25	$4.46	$4.71	16.6x	(5%)	4.5%	6.7%	6.0%
Buy	SRE	$112.69	$129	18%	$5.46	$5.89	$6.99	$7.55	16.1x	(7%)	3.2%	8.0%	9.0%
Special Situation													
Buy	ACO	$39.53	$49	28%	$2.95	$3.13	$3.20	$3.34	12.4x	(27%)	3.8%	3.6%	5.2%
Buy	FE	$37.89	$43	19%	$2.55	$2.57	$2.46	$2.60	15.4x	(12%)	4.0%	3.0%	3.5%
Buy	PPL	$31.12	$34	15%	$2.34	$2.40	$2.56	$2.59	12.2x	(30%)	5.3%	3.3%	3.3%
Integrated Power													
Buy	PEG	$54.29	$63	19%	$3.08	$3.35	$3.69	$3.77	14.7x	(16%)	3.3%	6.6%	4.9%
Buy	EXC	$45.53	$51	15%	$3.14	$3.18	$3.14	$3.25	14.5x	(17%)	3.0%	5.9%	5.3%
Sells													
Sell	AWR	$67.82	$48	(28%)	$1.75	$1.93	$2.04	$2.15	33.2x	37%	1.6%	5.3%	6.0%
Sell	CWT	$46.30	$39	(14%)	$1.27	$1.45	$1.65	$1.76	28.0x	15%	1.6%	5.8%	5.0%
Sell	HE	$37.92	$33	(9%)	$1.86	$1.99	$2.12	$2.19	17.9x	3%	3.3%	6.7%	0.0%
Sell	PNM	$42.60	$39	(7%)	$1.97	$2.14	$2.19	$2.29	19.5x	12%	2.5%	4.3%	6.0%
Sell	POR	$47.99	$44	(5%)	$2.37	$2.48	$2.57	$2.65	18.7x	7%	3.0%	3.6%	6.4%
Sell	CTWS	$69.75	$66	(4%)	$2.17	$2.27	$2.48	$2.69	28.1x	16%	1.8%	5.8%	5.0%
Sell	H	$19.47	$18	(3%)	$1.27	$1.27	$1.35	$1.41	14.4x	(17%)	4.7%	4.8%	7.1%

Source: FactSet, UBS Estimates, Prices as of 11/27/18

Figure 4: 2018 Stock Performance by Measure

EPS Growth	3 Month	6 Month	YTD
1st	4.8%	11.8%	14.2%
2nd	4.5%	10.3%	-0.2%
3rd	-3.7%	1.1%	-4.2%
4th	4.7%	10.4%	2.0%
Regulation	**3 Month**	**6 Month**	**YTD**
1st	4.4%	11.6%	3.0%
2nd	4.1%	10.5%	8.5%
3rd	-2.8%	3.8%	-0.4%
4th	3.7%	6.4%	-2.3%
Quality	**3 Month**	**6 Month**	**YTD**
1st	3.3%	10.6%	7.1%
2nd	6.7%	12.6%	6.0%
3rd	3.0%	9.9%	5.2%
4th	-2.4%	1.3%	-6.4%

Source: FactSet, S&P Global Market Intelligence, UBS Equity Research

Earnings Growth

We updated our EPS estimates with the roll-forward in methodology and summarize our changes by company below. Our utility valuation methodology utilizes 5 year utility, parent and other EPS growth as an input. Top quartile growth begins at 7.1% while median growth is 5.8%. Investors are currently awarding a double digit premium for stocks that offer the highest growth.

Figure 5: Earnings Growth Quality Quartiles

Quality Quartile	Low Growth	High Growth	Current Growth	Current P/E Ratio	Current Prem/Disc
1st	7.10%		8.2%	18.2x	11.4%
2nd	5.80%	6.60%	6.3%	18.2x	10.9%
3rd	4.40%	5.60%	5.0%	15.8x	-3.5%
4th	0.00%	4.30%	1.5%	16.2x	-1.0%

Source: FactSet, S&P Global Market Intelligence, UBS Equity Research

Figure 6: Regulated Utility EPS Estimate Changes

Rating	Ticker	Company	UBS 2018E EPS	UBS 2019E EPS	UBS 2020E EPS	UBS 2021E EPS	UBS 2018E EPS Old	UBS 2019E EPS Old	UBS 2020E EPS Old	UBS 2021E EPS Old
Buy	ACO	ATCO Ltd. (C$)	$2.95	$3.13	$3.20	$3.34	$2.96	$3.29	$3.38	$3.54
Neutral	AEE	Ameren Corp	$3.40	$3.18	$3.48	$3.85	$3.40	$3.18	$3.50	$3.87
Neutral	CMS	CMS Energy	$2.33	$2.50	$2.70	$2.92	$2.33	$2.53	$2.73	$2.95
Neutral	CU	Canadian Utilities Ltd (C$)	$2.06	$2.15	$2.21	$2.31	$2.07	$2.27	$2.35	$2.46
Neutral	CUP	Caribbean Utilities Corp Ltd	$0.71	$0.77	$0.80	$0.89	$0.71	$0.78	$0.83	$0.94
Buy	D	Dominion Energy	$4.10	$4.25	$4.46	$4.71	$4.10	$4.16	$4.35	$4.58
Buy	DUK	Duke Energy	$4.74	$5.03	$5.33	$5.59	$4.74	$5.03	$5.29	$5.56
Buy	EMA	Emera Inc (C$)	$2.85	$2.80	$3.10	$3.26	$2.68	$2.91	$3.05	$3.21
Buy	ES	Eversource Energy	$3.28	$3.48	$3.72	$3.95	$3.28	$3.48	$3.72	$3.95
Buy	EXC	Exelon	$3.14	$3.18	$3.14	$3.25	$3.14	$3.19	$3.16	$3.29
Buy	FTS	Fortis Inc (C$)	$2.52	$2.64	$2.83	$3.01	$2.52	$2.65	$2.84	$3.01
Sell	HE	Hawaiian Electric Industries	$1.86	$1.99	$2.12	$2.19	$1.89	$2.05	$2.20	$2.29
Sell	H	Hydro One Ltd (C$)	$1.27	$1.27	$1.35	$1.41	$1.23	$1.32	$1.34	$1.51
Buy	NEE	NextEra Energy	$7.77	$8.43	$9.08	$9.84	$7.88	$8.41	$9.06	$9.74
Neutral	OGE	OGE Energy Corp	$2.07	$2.12	$2.31	$2.39	$2.08	$2.14	$2.30	$2.38
Sell	POR	Portland General	$2.37	$2.48	$2.57	$2.65	$2.37	$2.53	$2.64	$2.78
Buy	PPL	PPL Corporation	$2.34	$2.40	$2.56	$2.59	$2.33	$2.42	$2.56	$2.59
Buy	PEG	Public Service Ent Group	$3.08	$3.35	$3.69	$3.77	$3.08	$3.47	$3.66	$3.76
Neutral	SCG	SCANA Corp	$2.67	$2.30	$2.44	$2.66	$3.13	$2.76	$2.90	$3.12
Neutral	SO	Southern Company	$3.06	$3.04	$3.17	$3.30	$3.06	$3.04	$3.17	$3.30
Buy	SRE	Sempra Energy	$5.46	$5.89	$6.99	$7.55	$5.31	$5.89	$6.99	$7.55

Source: Company reports, UBS estimates, FactSet

Regulatory Ranking Refresh

We did a refresh of the UBS regulatory rankings to include 2018 rate cases, data updates on the average customer bill and rates, and to note other changes in regulation this year. The states with material moves (beyond 6 slots plus or minus) in the United States were Louisiana, Kansas, Massachusetts, and Oregon on the plus side and Nebraska, New Hampshire, New York, and South Carolina on the negative side. As a reminder our regulatory rankings consider 6 factors in a simple average: 1) Appointed or elected commissions; 2) Allowed return spread history, 3) Mechanisms that reduce regulatory lag; 4) Rates and customer levels compared to region; 5) Tendency to settle versus litigate rate cases; and 6) A subjective investor friendliness factor.

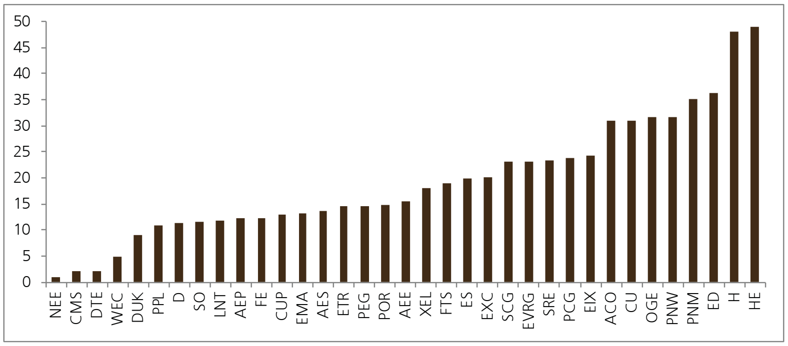
Figure 7: UBS Regulatory Rankings

TIER 1	TIER 2	TIER 3	TIER 4	TIER 5
		Nova Scotia		
		North Dakota		
FERC		Iowa		
		Kentucky		
		Washington		
		Tennessee		
		Texas		
		Missouri		
		Massachusetts		
		South Carolina		
	Pennsylvania	Wyoming	Prince Edward Island	
	Illinois	Kansas	Nevada	
	Arkansas	Rhode Island	New Hampshire	
	Ohio	California	New York	
Florida	Louisiana	Alberta	Oklahoma	New Mexico
Michigan	Georgia	Newfoundland & Labrador	Alaska	Maine
Utah	Idaho	Delaware	West Virginia	Maryland
Wisconsin	British Columbia	Minnesota	South Dakota	Montana
Alabama	Indiana	Connecticut	Nebraska	Hawaii
Colorado	Virginia	New Jersey	Mississippi	Vermont
North Carolina	Oregon	Arizona	Ontario	District of Columbia
JD Power Average Customer Service Scores				
727	722	707	624	695

Source: Canadian Provincial Regulatory Websites, S&P Global Market Intelligence, FactSet, JD Power, UBS Equity Research

Below we provide a weighted average regulatory ranking by company. We believe that constructive regulation is good for the customer and the shareholder. Our ranking of states is positively correlated to JD Power customer service scores.

Figure 8: Weighted Average Regulatory Ranking by Company



Source: FactSet, S&P Global Market Intelligence, UBS Equity Research

Companies with better weighted average regulatory rankings also have higher investment in the system and experience less regulatory lag which contributes to a premium valuation. Companies that had a positive move of 6 slots or more were PPL, AEE and ETR. SCG had a notably negative move.

Figure 9: Regulated Utility Quartiles

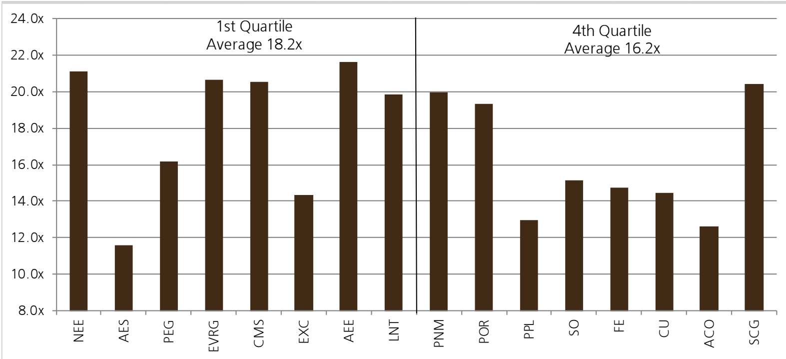
Metric	1st Quartile	2nd Quartile	3rd Quartile	4th Quartile
Ratebase Growth '17-'22	7.6%	6.4%	4.8%	2.7%
Price/Book	2.45x	2.40x	1.56x	1.72x
Earned ROE	11.5%	10.0%	9.8%	9.6%

Source: FactSet, S&P Global Market Intelligence, UBS Equity Research

Back Testing the Methodology

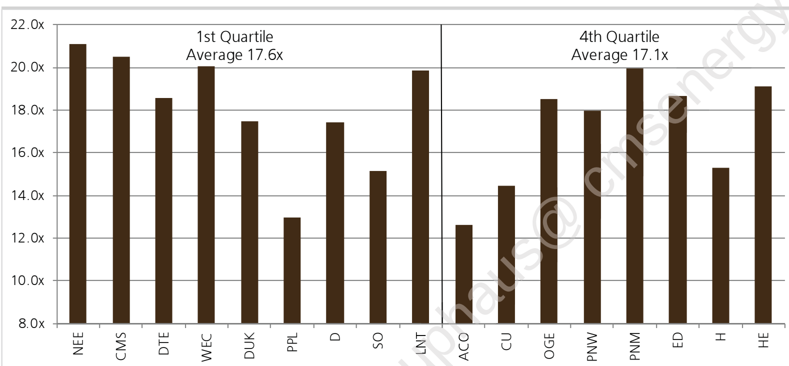
Below we show the top and bottom quartile names by earnings growth, regulatory jurisdiction and overall quality. The spread on forward year P/E premium from top to bottom quartile is 16% which is higher than the spread for growth (+12%) or regulation alone (+3%).

Figure 10: Utility, Parent and Other EPS Growth 1st/4th Quartiles



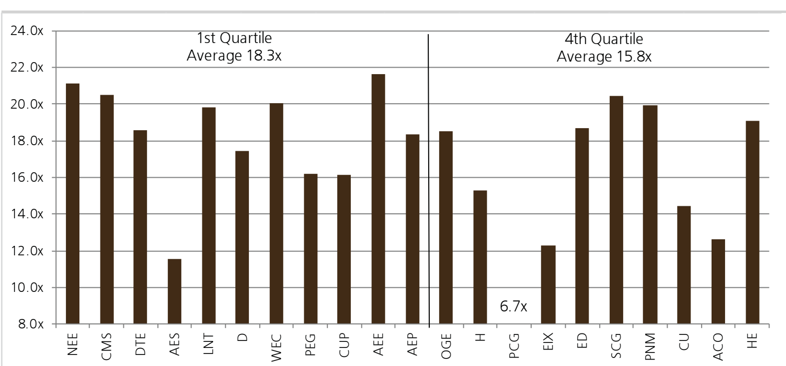
Source: FactSet, S&P Global Market Intelligence, UBS Equity Research

Figure 11: Regulatory Ranking 1st/4th Quartiles



Source: FactSet, S&P Global Market Intelligence, UBS Equity Research

Figure 12: Overall Quality Ranking 1st/4th Quartiles



Source: FactSet, S&P Global Market Intelligence, UBS Equity Research

Company Price Target and EPS Estimate Changes

AES Corp.

We are updating our AES $16 price target methodology. AES expects to achieve investment grade metrics in 2019 and 8-10% free cash flow growth to 2020 or $800M. We forecast 5 year EPS growth of 9% of which ½ comes from contracted renewable investments at double digit returns and could include some asset sales to achieve the growth. The company is de-risking AES Gener in Chile with the 270 MW Candelaria solar and wind project which reduces by 40% Gener's expiring hedged position in 2022.

Our current target of $16 is a sum of parts which reflects $13 for North America utilities, $4 each for South America, MCAC, and EurAsia regions less $8 for debt and 660M shares. This includes a 7% P/E premium of the 2021 Regulated Utility average or 17.7x $0.34 for the U.S. utilities, publicly traded market values for Gener in Chile and Tiete in Brazil, 7.6x 2021 EBITDA for EurAsia and 6.5x for the Mexico/Central America/Caribbean segment. The 7% premium reflects 5% for group undervaluation, 5% for top quartile growth, 2% for regulation, and -5% for sum of the parts discount.

Figure 13: AES Sum of the Parts - Current - Dollars in Millions

2021 Forecasts	EBITDA	Adjusted PTC	EPS	Ownership Debt	UBS Comps (f)	Multiple (g)	Value
U.S. Utilities	$609	$197	$0.34	$3,225	U.S. Regulated	17.5x	$6.04
U.S. Generation	$593	$389		$199	U.S. Multi Utility	7.2x	$6.19
El Salvador	$76	$52		$237	Regulated Utility	6.2x	$0.36
United States & Utilities	$1,279	$594		$3,660			$12.59
South America	$959	$574		$3,487			$4.22
Gener (b)	$665	$378		$2,883	Market Value	6.6x	$2.27
Argentina	$216	$165		$302	Lat Am	6.0x	$1.48
Tiete	$41	$17		$119	Market Value		$0.36
Other	$38	$14		$184		6.6x	$0.10
MCAC	$596	$349		$1,504		6.5x	$3.59
EurAsia	$394	$217		$822	60% Europe/40% Asia	7.6x	$3.26
Corporate	-$27	-$287		$3,664		6.0x	-$8.14
Total	$3,201	$1,447		$11,883		6.9x	$15.52
Shares							660
Unlisted Subs	$1,886			$6,911		6.1x	$6.85
Listed/DPL&IPL	$1,315			$4,973		8.1x	$8.67

(b) Publicly traded market values 11/27/18
(d) Price paid.
(f) Reflects 11/20 values from UBS Global Electric Utility Valuation
(g) Multiples are 2021 EV/EBITDA except U.S. Utilities which is P/E.

Source: Company reports, UBS equity research estimates, Factset

Figure 14: AES Sum of the Parts – Prior – Dollars in Millions

2020 Forecasts	EBITDA	Adjusted PTC	EPS	Ownership Debt	UBS Comps (f)	Multiple	Value
U.S. Utilities	$601	$197	$0.31	$3,347	U.S. Regulated	17.8x	$5.47
U.S. Generation	$566	$345		$277	U.S. Multi Utility	7.2x	$5.75
El Salvador	$76	$52		$237	Regulated Utility	6.2x	$0.36
United States & Utilities	$1,243	$594		$3,861			$11.58
South America	$929	$574		$3,393			$4.50
Gener (b)	$632	$378		$2,749	Market Value	6.9x	$2.46
Argentina	$216	$165		$310	Lat Am	6.2x	$1.56
Tiete	$43	$17		$151	Market Value		$0.40
Other	$38	$14		$184		6.2x	$0.08
MCAC	$596	$349		$1,503		6.5x	$3.59
EurAsia	$407	$217		$822	60% Europe/40% Asia	8.7x	$4.12
Corporate	-$40	-$287		$3,664		6.2x	-$8.24
Total	$3,136	$1,447		$11,883		7.1x	$15.55
Shares							660
Unlisted Subs	$1,860			$6,997		6.3x	$7.21
Listed/DPL&IPL	$1,276			$4,887		8.1x	$8.34

(b) Publicly traded market value 11/6/18
(d) Price paid.
(f) Reflects 10/31 values from UBS Global Electric Utility Valuation

Source: Company reports, UBS equity research estimates, Factset

Our prior $16 target reflected $12 for North America utilities, $4 each for South America, MCAC, and EurAsia regions less $8 for debt and 660M shares. This includes a 12% P/E premium of the 2020 Regulated Utility 15.9x average for the U.S. utilities, publicly traded market values for Gener in Chile and Tiete in Brazil, 8.7x 2020 EBITDA for EurAsia and 6.5x for the Mexico/Central America/Caribbean segment. The 12% premium included 10% for group undervaluation.

Alliant Energy

We are increasing our price target on LNT to $48 from $46. Our EPS estimates remain unchanged at $2.15 in 2018, $2.26 in 2019, $2.45 in 2020 and $2.54 in 2021. LNT is earning its allowed return in Wisconsin and under-earning slightly (20 bp) in Iowa for management compensation non-recovery which is consistent with our forecast. LNT expects to file 2 rate cases in Iowa in 2019 including one with a forward test year. LNT will likely request an increase in the equity ratio potentially to 51% from 49%.

Our current $48 price target is premised upon a 15% premium to the 2021E Regulated Utility P/E multiple or 18.9x 2021E EPS of $2.54. The premium includes 5% for the group undervaluation, 5% for EPS growth and 5% for regulation.

Previously our $46 target reflected a 17% premium and was 18.7x $2.45 in 2020. The prior multiple reflected a premium of 10% for group undervaluation, 5% for EPS growth and 2% for regulation.

Ameren Corp.

We are lowering our rating on Ameren to Neutral from Buy following good performance this year on the passage of Missouri legislation and delivering on guidance. See our separate note (LINK). Since passage of SB 564 in Missouri the stock is up 21% (+10% versus the XLU and +22% versus the S&P 500). We are fine-tuning our EPS estimates to $3.48 in 2020 and $3.85 in 2021 versus $3.50 and $3.87 previously due to the timing of the Missouri investments. The reduction in earnings relates to the timing lag for the deferral of return on wind investment under SB 564 versus the renewable tracker.

Our $71 price target is a 12% premium to the Regulated Utility average or 18.4x 2021E EPS of $3.85. It includes top quartile growth (+5%), above average regulation (+2%) and the impact of the Regulated Utility group discount (+5%).

The prior methodology for our $71 price target reflected a 17% premium applied to the average Regulated Utility P/E or 18.3x 2021E EPS of $3.87.

American Electric Power

We are increasing our price target on AEP to $85 from $83. Up next for AEP are integrated resource plan filings at PSO by 12/21/18 and SWEPCO (Arkansas) by 12/1/18. We also believe there is the opportunity to increase transmission spending at PSO and SWEPCO and in batteries in Texas. We maintain our EPS estimates of $3.93 for 2018, $4.18 for 2020, $4.46 in 2021 and $4.77 in 2022.

Our current price target of $85 is at a 9% premium to the Regulated Utility group and is 17.9x our $4.77 2021 EPS estimate. The valuation includes a 5% premium for the group's undervaluation, 2% for second quartile regulation and 2% for second quartile growth.

Our prior price target of $83 was 18.6x our $4.46 2020 EPS estimate based on a 14% group premium multiple. The premium previously included 10% for the group's undervaluation.

ATCO Ltd.

We reiterate our Buy rating. Upcoming catalysts include potential for Structures & Logistics to be sanctioned work for LNG Canada, sale of the unregulated power plants in Alberta, and potential for a PBR reopener at the Alberta Utilities Commission. We continue to believe that the Canadian Utilities business remains solid and see upside to shares from the unregulated Structures & Logistics and Naltume ports segments as well as any further infrastructure investments from capital proceeds from asset sales and incremental leverage at the ATCO Ltd. level.

We are updating our eps estimates to C$2.95/C$3.13/C$3.20/C$3.34 from C$2.96/C$3.29/C$3.38/C$3.54 for '18-'21E respectively. We are increasing our price target to C$49 from C$47 premised upon multiple expansion and a roll to the 2021 valuation year.

Our prior price target of C$47 was premised upon a SOTP analysis on our UPO eps in 2020E of C$2.96, the group multiple of 15.2x at a 5% discount. A comparable group multiple of 16.8x our Structures & Logistics eps estimate of C$0.32 in 2020. And finally a 7.5x ports 2020E EV/EBITDA multiple times our Naltume Ports 2020E EBITDA of C$56mln on allocated debt of C$340mln.

Our current price target of C$49 is premised upon a 5% discount to the 15.9x 2021E normalized non-gas midstream multiple and our UPO (utility & parent only) 2021E eps of C$2.91 which yields C$44/share. To this we add 15.1x our 2020E S&L eps of C$0.30 which yields C$4.60/share and 7.6x our Naltume Ports EBITDA of C$56mln with C$340mln of allocated debt which yields C$0.70/share.

Figure 15: ATCO Sum of the Parts

UPO EPS	$ 2.91		S&L EPS	$ 0.30
Multiple	15.9x		Multiple	15.1x
Cdn Value vs. Bonds	10%		S&L Value	$ 4.60
Regulatory Ranking	-5%			
Growth	-5%		Neltume '20E EBITDA	56
Company Specific	-5%		EV/EBITDA	7.6x
Total Net Prem/Disc	-5%		Allocated Debt	$ 340
Utility Value	$ 43.95		Neltume Value	$ 0.70
SOTP Value	**$ 49**			

Source: Company reports, UBS equity research

Canadian Utilities Ltd.

We reiterate our Neutral rating. While we see potential upside from continued investment in Alberta Power Line and continued growth in Alberta we see risks to the potential for a PBR reopener in Alberta and the less constructive Alberta regulatory environment.

We are updating our eps estimates to C$2.06/C$2.15/C$2.21/C$2.31 from C$2.07/C$2.27/C$2.35/C$2.46 for '18-'21E respectively. We are maintaining our price target at C$33 premised upon multiple expansion and a roll to the 2021 valuation year, offset by an increased discount for reopener regulatory risk in Alberta.

Our prior target of C$33 was premised upon a 5% discount to the 15.2x group multiple on 2020 estimated earnings per share of C$2.35.

Our current target of C$33 is premised upon a 10% net discount to the 15.9x 2021E normalized non-gas midstream multiple and our 2021E eps of C$2.31.

Caribbean Utilities

We are upgrading Caribbean Utilities to Neutral from Sell on valuation. See our separate note (LINK). We are updating our eps estimates to $0.71/$0.77/$0.80/$0.89 from $0.71/$0.78/$0.83/$0.94 for '18-'21E respectively. We are increasing our price target to $13 from $12 due to multiple expansion and a roll to the 2021 valuation year.

Our prior target of $12 was premised upon a group multiple of 15x our 2020E eps of $0.83.

Our current target of $13 is premised upon a 6% net discount to the 15.9x 2021E normalized non-gas midstream multiple and our 2021E eps of $0.89.

CMS Energy

We are raising our price target to $55 from $54 and fine-tuning our EPS estimates. Our new estimates reflect 8% EPS growth off the high-end of the 2019 $2.46-$2.50 EPS guidance range. Our revised EPS estimates are $2.50 for 2019, $2.70 for 2020 and $2.92 for 2021 versus $2.53/$2.73/$2.95 previously.

CMS expects to receive a proposal for decision in the electric rate case in December and an order in March 2019 and an order in the integrated resource plan proceeding in April 2019 although the company has a track record for achieving partial settlements. We also look for more use of renewable development with the green tariffs in Michigan.

Our $55 price target for CMS is a 15% premium to the Regulated Utility group and is 18.9x our $2.92 2021 EPS estimate. The premium includes a 5% premium for the group's undervaluation, 5% for first quartile Michigan regulation and 5% for first quartile growth.

Our prior $54 target was 19.6x 2020E EPS of $2.73 and included 10% for group undervaluation, 5% for first quartile Michigan regulation and 5% for first quartile growth.

Consolidated Edison

We are increasing our price target on ED to $85 from $80. We expect ED to close the Sempra Solar transaction this year and to file the Consolidated Edison of New York general rate case in early 2019. Despite the fourth quartile ranking for regulation the company has done 8-10 Reforming the Energy Vision projects which have been treated with reasonable regulation. This includes a regulatory mechanism where the company retains 30% of the savings achieved on investments. REV projects also have a 10 year amortization.

Our current price target is at a 5.5% premium to the Regulated Utility average multiple or 17.2x our 2021 EPS estimate of $4.93. The premium includes 5% for the group's undervaluation, -5% for fourth quartile New York regulation, -2% for third quartile growth and a 7.5% ESG (Environmental, Social and Governance) premium for not owning generation.

Our prior $80 price target was 17.5x our 2020 EPS estimate of $4.60. The methodology included 10% for group undervaluation, 7.5% for ESG, -5% for regulation and -2% for growth.

Dominion Energy

We are upgrading our rating on D to Buy from Neutral on valuation and resolution of the financing uncertainty experienced during 2018. See our separate note (LINK). Our estimates exclude SCG; however, the probability of deal close seems increasingly likely with the BLRA lawsuit settlement, providing upside to our estimates. Our price target increases to $84 from $75, based on a sum of the parts methodology that includes $44 for VEPCO, $37 for Gas Infrastructure (including Cove Point) and $4 for Merchant Generation. The outcome of the CT Zero Carbon RFP could impact our estimates. We assume Millstone sells all production at an average energy price of ~$47/MWh in 2021 versus the forward energy price of $43/MWh. Every $1/MWh change in energy price is approximately $0.01 to EPS.

Our estimates are revised up to $4.10 in 2018, $4.25 in 2019, $4.46 in 2020 and $4.71 in 2021, from $4.10, $4.16, $4.35 and $4.58, respectively.

Our current price target of $84 is premised upon VEPCO valued at a 12% net premium to the 16.4x 2021e Regulated Utility multiple, Gas Infrastructure (including Cove Point) valued at the average Gas Midstream 2021e P/E of 16.5x, and Merchant Generation is assigned a 7.2x mid-cycle EV/EBITDA multiple.

Our prior price target of $75 was premised upon VEPCO valued at a 17% net premium to the 15.9x 2020e Regulated Utility multiple, Gas Infrastructure (including Cove Point) valued at a 10% discount to the average Gas Midstream

2020e P/E of 15.9x, and Merchant Generation is assigned a 7.2x mid-cycle EV/EBITDA multiple.

DTE Energy

We are increasing our price target on DTE to $121 from $118. We believe DTE is in a good position having replaced expiring Power and Industrial tax credits in 2020 and 2022. At the margin we look for DTE to continue working to add contracts and to fill the NEXUS pipeline; to continue working on renewable investments through green tariffs and to add investments in tax advantaged renewable natural gas which is animal gas and biodegradable vegetation.

Our current $121 price target is a sum of the parts valuation which includes $91 for utility, parent and other at a 12% premium 2021E P/E multiple of 18.4x $4.98, plus $24 for unregulated EPS of $1.45 at a 16.5x gas conglomerate multiple, $4 for co-gen and renewables and $2 for the NPV of renewable energy fuel tax credits.

Our prior price target of $118 assumed $87 for the utility, parent and other which included a 10% benefit for the group's undervaluation. The UP&O was a 17% P/E premium 19.2x applied to 2020E EPS of $4.53, $27 for unregulated EPS of $1.44 at a 19x gas conglomerate multiple, $3 for co-gen and renewables and $1.50 for the NPV of REF tax credits.

Figure 16: DTE Sum of the Parts

DTE	EPS 2021E	Premium/ Multiple	Value
UP&O	$4.98	12.0%	$91
Unregulated	$1.45	16.5x	$24
Co-Gen	$0.27	16.4x	$4
Renewable Energy Fuel Tax Credits			$2
Total			$121

Source: Company reports, UBS equity research

Duke Energy

We are increasing our price target on DUK to $99 from $92. Our new price target is premised upon a 17.7x multiple to our 2021e EPS of $5.59, or a net 8% premium to the Regulated Utility P/E multiple. Previously our $92 price target reflected a 13% P/E premium to the Regulated Utility P/E multiple on 2020e EPS of $5.29.

Our estimates are revised up to $4.74 in 2018, $5.03 in 2019, $5.33 in 2020 and $5.59 in 2021, from $4.74, $5.03, $5.29 and $5.56, respectively. The revisions reflect increased confidence in DUK's ability to meet capital investment and growth targets.

Emera Inc.

We are upgrading Emera Inc. to Buy from Neutral on valuation and the likelihood of accretive asset sales filling in the C$1.4Bln block equity need through 2021. See our separate note (LINK). We are updating our eps estimates to C$2.68/C$2.80/C$3.10/C$3.26 from C$2.68/C$2.91/C$3.05/C$3.21 for '18-'21E respectively. We are increasing our price target to C$51 from C$42 on multiple expansion, a roll to the 2021 valuation year, and including generation asset sale proceeds in lieu of block equity.

Our prior price target of C$42 was premised upon SOTP valuation which is a 10% premium to the group multiple of 14.5x on utility and parent only (UPO) EPS of $2.55 in 2020E yielding $40 to which we added $2/share for the Energy segment at 7.2x 2020E EBITDA.

Our current price target of C$51 is premised upon a net 5% premium to the 15.9x 2021E normalized non-gas midstream multiple and our '21E UPO eps of C$3.01 which yields C$50/share. To this we add 6.7x our '21E Energy EBITDA of C$51mln with no allocated net debt which yields C$1/share.

Figure 17: EMA Sum of Parts

UPO EPS	$	3.01		Energy EBITDA	51
Multiple		15.9x		Multiple	6.7x
Overall Reg. Group		10%		Enterprise Value	336
Regulatory Prem/Disc		2%		Net Debt	-
Earnings Growth Prem/Disc		-2%		Equity Value	336
Net Premium		5%		Shares Out	277.1
Utility Valuation	$	50		Energy Valuation	$ 1
Consoliatdated Valuation	**$**	**51**			

Source: Company reports, UBS equity research

Entergy Corp

We are increasing our price target on ETR to $99 from $94. Our new price target is premised upon a 17.2x multiple to our 2021e EPS of $5.73, or a net 5% premium to the Regulated Utility P/E multiple.

Our previous $94 price target reflected a 10% premium to the Regulated Utility P/E multiple on 2020e EPS of $5.40. Our EPS estimates remain unchanged at $4.70 in 2018, $5.09 in 2019, $5.40 in 2020 and $5.73 in 2021.

Evergy

We are increasing our price target on EVRG to $61 from $58. EVRG is in the process of executing on the 60M (22% of shares) stock buyback and we expect an update on the implications of Missouri's SB 564 on the fourth quarter conference call. We also expect a cap-ex update including with regard to grid modernization in Missouri.

Our current $61 price target is at an 8% premium to the Regulated Utility average or 17.7x 2021E EPS of $3.44 plus $0.42/share for the NPV of corporate owned life insurance. The 8% premium includes +5% for the group's undervaluation, +5% for top quartile EPS growth of 8% and -2% for below average regulation.

Our prior $58 price target reflected a +10% for valuation and was 17.8x $3.25 in 2020E plus $0.42/share for COLI.

Eversource Energy

We are increasing our price target on ES to $75 from $69. Our new price target is premised upon an 18.9x multiple to our 2021e EPS of $3.95, or a net 15%

premium to the Regulated Utility P/E multiple. Previously our $69 price target reflected an 18% P/E premium to the Regulated Utility P/E multiple on 2020e EPS of $3.72. Our EPS estimates remain unchanged at $3.28 in 2018, $3.48 in 2019, $3.72 in 2020 and $3.95 in 2021.

Exelon Corp.

We reiterate our Buy rating. We continue to believe that Exelon has solid utility growth driven by capital spending and closing the gap between earned and allowed ROEs particularly at the Pepco Holdings utility subsidiaries. We are updating our eps forecast to $3.14/$3.18/$3.14/$3.25 from $3.14/$3.19/$3.16/$3.29 for '18-21E respectively. We are increasing our price target to $51 from $50 premised upon multiple expansion and a roll to the 2021 valuation year for the utility and the 2020 valuation year for ExGen.

Our prior price target of $50 was premised upon a net 17% premium to the group multiple of 16.1x our 2020E UPO eps of $2.05, and 6.7x '19E open EBITDA of $2,585mln for ExGen.

Our current price target of $51 is premised upon a net 8% premium to the 16.4x normalized multiple and our 2021E UPO eps of $2.21 which yields $40/share. To this we add 7.2x our 2020E ExGen open EBITDA of $2,257mln, NPV of hedges of $196mln, net debt of $6,126mln, and 949mln shares outstanding which yields $11/share.

Figure 18: EXC Sum of Parts – Dollars in Millions

SOTP Valuation Methodology		ExGen Valuation	
UPO Valuation		EXGEN EBITDA	2,383
20 UPO EPS	$ 2.21	GM Value of Hedges	126
Regulated Utlity Group Multiple	16.4x	EXGEN Open EBITDA	2,257
Overall Regulated Group	5%	Net Multiple for ExGen	7.2x
Regulatory Ranking	-2%	Total Enterprise Value	16,250
Earnings Growth	5%	NPV of Hedges	196
Net Premium/Discount	8%	Net Debt at ExGen	6,126
UPO Value per Share	**$ 40**	Equity Value	10,320
		Shares	949
Total Value per Share	**$ 51**	**ExGen Value per Share**	**$ 11**

Source: Company reports, UBS equity research

FirstEnergy Corp.

Our price target on FE remains unchanged at $43. Management has stated they plan to provide additional cap-ex guidance on the fourth quarter conference call which could include an additional year (2022). Before increasing cap-ex FE wants to see outcomes on the New Jersey $0.4B infrastructure plan proposal (potentially in Q1'19) and the Ohio SEET (significantly excessive earnings test).

Our price target is updated to reflect a 2% premium to the Regulated Utility P/E multiple or 16.7x 2021E EPS of $2.60. The 2% premium includes 5% for the group's undervaluation, 2% for regulation and -5% for fourth quartile EPS growth.

Previously our $43 reflected a 7% P/E premium to the Regulated Utility group or 17.2x $2.46 in 2020E plus $0.28 for Ohio rider NPV. The premium included 10% for the group's undervaluation.

Fortis Inc.

We are reiterating our Buy rating and continue to believe that Fortis Inc remains undervalued to achievable 6% long term dividend per share growth with lower relative risk resulting from no need block equity, and no significantly large scale capital projects. Further, regulatory matters are limited over the next 12 month with FERC transmission ROEs now settled for the ITC subsidiary.

We are updating our eps estimates to C$2.52/C$2.64/C$2.83/C$3.01 from C$2.52/C$2.65/C$2.84/C$3.01 for '18-'21E respectively. We are updating our price target to C$53 from C$49 on multiple expansion and a roll to the 2021 valuation year.

Our prior price target of C$49 was premised upon a net 14% premium to the group multiple of 15.1x our 2020E eps of C$2.84.

Our current price target of C$53 is premised upon a net 10% premium to the 15.7x 2021E normalized non-gas midstream multiple and our 2021E eps of C$3.01.

Hawaiian Electric Industries

Our price target for HE remains unchanged at $33. Our price target is updated to reflect a 16.7x multiple to our 2021e EPS of $2.19, or a net 2% premium to the Regulated Utility P/E multiple. Previously our $33 target reflected no premium to the Regulated Utility P/E multiple on 2020e EPS of $2.29.

Our EPS estimates are revised up to $1.86 in 2018, $1.99 in 2019, $2.12 in 2020 and $2.19 in 2021, from $1.89, $2.05, $2.20 and $2.29 respectively. The revisions reflect increased confidence in HE's ability to meet capital investment and growth targets.

Hydro One Ltd.

We reiterate our Sell rating. We now believe that, despite being dilutive that the merger with Avista Inc. will close after likely regulatory approvals are received on December 14. As a result we have incorporated the AVA merger dilution into our valuation methodology.

Our eps forecast remains Hydro One Ltd. on a stand-alone basis as we are updating it to C$1.27/C$1.27/C$1.35/C$1.41 from C$1.23/C$1.32/C$1.34/C$1.51 for '18-'21E respectively. We are updating our price target to C$18 from C$19 as a result of the inclusion of the AVA merger dilution in our valuation and lower stand-alone Hydro One eps estimates more than offsetting multiple expansion and the roll to the 2021 valuation year.

Our prior price target of C$19 was premised upon a 14.8x multiple on our 2020E eps of C$1.34.

Our current price target of C$18 is premised upon a net 15% discount to the 15.9x 2021E normalized non-gas midstream multiple and our 2021E eps of C$1.37 inclusive of ($0.04)/share of dilution from the AVA merger.

NextEra Energy

We are increasing our price target on NEE to $209 from $195. Our new price target is premised upon an 18.9x multiple to our 2021e EPS of $9.84, or a net 15% premium to the Regulated Utility P/E multiple. Previously our $195 price target reflected a 20% P/E premium to the Regulated Utility P/E multiple on 2020e EPS of $9.06.

Our EPS estimates are revised up to $7.77 in 2018, $8.43 in 2019, $9.08 in 2020 and $9.84 in 2021, from $7.88, $8.41, $9.06 and $9.74, respectively. The revisions incorporate the Gulf Power acquisition which is expected to close 1Q19, offset somewhat by a more conservative growth trajectory than we had previously modelled at NEER.

OGE Energy

We are raising our price target to $40 from $37. OGE expects to have 1 or more rate cases in 2019 to address investments in the Sooner scrubbers and potentially in grid modernization. We fine-tuned our EPS estimates for cap-ex guidance to $2.07 for 2018, $2.12 for 2019, $2.31 for 2020 and $2.39 in 2021 versus $2.08/$2.14/$2.30/$2.38.

Our current $40 price target is a sum of the parts which includes $30 for the utility, parent and other at a 2% discount to the Regulated Utility average or 16.1x $1.86 in 2021 plus $10 for the company's 25.6% ownership in ENBL. The ENBL valuation reflects UBS MLP and Gas Pipeline analyst Shneur Gershuni's $18 price target. "'19 Guidance Flexes Op Leverage & SCOOP Crude" (11/7/18). The 2% discount multiple includes 5% for the group undervaluation, -2% for third quartile utility, parent and other EPS growth and -4% for fourth quartile regulation.

Our prior $37 price target reflected $30 for UP&O which at a 3% premium to the average Regulated Utility 2020 P/E or 16.7x $1.75 at UP&O and $7/share for ENBL using a mark-to-market for the stock.

Figure 19: OGE Sum of the Parts

OGE	EPS 2021E	Premium/ Multiple	Value
UP&O	$1.86	-2.0%	$30
	$/Share		
ENBL	$18.00		$10
Total			$40

Source: Company reports, UBS equity research

Pinnacle West Capital

We are increasing our price target on PNW to $92 from $90. Our current $92 target is a 2% premium to the Regulated Utility group of 16.7x our 2021 EPS estimate of $5.52. The premium is 5% for the group's undervaluation, 2% for second quartile EPS growth, and -5% for fourth quartile regulation.

Our prior $90 price target was a 5% premium to the Regulated Utility group average P/E of 17.0x $5.28 in 2020E. The valuation multiple had included a -2% discount for third quartile regulation.

PNM Resources

We are increasing our price target on PNM to $39 from $37. Our new price target is premised upon a 16.9x multiple to our 2021e EPS of $2.29, or a net 3% premium to the Regulated Utility P/E multiple.

Previously our $37 price target reflected an 8% premium to the Regulated Utility P/E multiple on 2020e EPS of $2.19. Our EPS estimates remain unchanged at $1.97 in 2018, $2.14 in 2019, $2.19 in 2020 and $2.29 in 2021.

Portland General

We are lowering our price target on POR to $44 from $45. Consistent with guidance we are revising our EPS estimates to reflect 80 bp of regulatory lag versus 50 bp previously (8.7% ROE versus 9.0% earned ROE). Our revised EPS estimates are $2.48 for 2019, $2.57 for 2020, $2.65 for 2021 and $2.73 for 2022 versus $2.53 for 2019, $2.64 for 2020, $2.78 for 2021 and $2.87 for 2022.

Our $44 price target is a 2% premium to the Regulated Utility average or 16.7x $2.65 in 2021E. The valuation includes 5% for the group's undervaluation, 2% for second quartile Oregon regulation, and -5% for 4th quartile EPS growth.

Our prior $45 price target reflected a 6% Regulated Utility premium or 17.1x $2.64 in 2020E and included a 10% benefit the group's undervaluation and 2% discounts for 3rd quartile growth and regulation.

PPL Corporation

We maintain our Buy rating and our $34 price target. We are fine-tuning our EPS estimates for exposure to the British pound and for the gradual expiration of pension revenues in the U.K. at WPD. Our new EPS estimates are $2.34 for 2018, $2.40 for 2019, and $2.56 for 2020 versus $2.33/$2.42/$2.56. Our estimates include 7% 5 year growth (2017-2022) in Pennsylvania, 4% in Kentucky and 1% at WPD in the U.K.

F/X. Our EPS forecast assumes a 1.30x US$/British pound exchange in 2020 and 1.37x for 2021-2022 which is the UBS Global Macro Strategy year-end 2020 forecast "2019 Markets Outlook: Something wicked this way comes?"(pp. 34-35, 11/12/18). This is a -$0.04/share to -$0.06/share impact from 2020 to 2023 versus our prior forecast.

Pension. PPL receives $0.20/share in revenue to fund the pension deficit, but the plan has been outperforming. Pending a review at regulator OFGEM we expect the pension revenue will begin a 4 year calendar year expiration in April 2021. This is a -$0.05 to -$0.07/share annual impact.

EPS growth-U.K. and Pennsylvania. We continue to forecast 5 year 1% EPS growth in the U.K. as we believe we have been understating the impact of 6% rate base growth and incentive opportunities. We also believe PPL's PPL Electric in Pennsylvania can grow EPS 6-7% versus 5-6% previously due to transmission investments.

Our current $34 price target reflects the sum of $21 for a 5% premium to the U.S. utility average or 17.2x $1.23 in 2021E, $15 for a European average utility multiple of 12.5x $1.22, less $4 for the NPV of a -$0.24 exposure in the 2023 RIIO 2 case at a $13.6x P/E. The 5% U.S. premium includes 5% for the group's undervaluation, 2% for second quartile regulation, and -2% for third quartile EPS growth.

Figure 21: PPL Sum of the Parts

PPL	EPS 2021E	Premium/ Multiple	Value
U.S. Utilities	$1.23	5.0%	$21
WPD	$1.36	12.5x	$17
NPV of RIIO 2 Rate Exposure			($4)
Total			$34

Source: Company reports, UBS equity research

Public Service Enterprise Group

We are raising our price target on PEG to $63 from $60. We are fine-tuning our EPS estimates for changes in the forward power and gas curves. Forward around the clock power prices rose in PJM East $5/MWhr around-the-clock in 2019 and $1/Mwhr in 2020 from early October to mid-November according to S&P Global Market Intelligence quotes. Gas prices spiked at Henry hub and Leidy hub 40 cents. These impacts tapered off in 2021 and 2022.

We are lowering our EPS estimates to reflect lower profitability on combined cycle gas plants and an offsetting benefit for higher power prices. Our revised estimates are $3.35 in 2019, $3.69 in 2020, $3.77 in 2021 and $4.02 in 2022 versus $3.47/$3.66/$3.76/$4.04. PEG's baseload generation is 100% hedged through 2019 and 75-80% in 2020 and the intermediate, combined cycle and peaking output is 35-40% hedged in 2019.

Our current $63 sum of the parts based price target includes: $51 for UP&O or 18.4x our 2021 EPS estimate of $2.79 plus $11 for PSEG Power at 6.8x 2021 EBITDA of $1.05B. The premium includes: first quartile EPS growth for utility net of parent 12% (+5%), above-average New Jersey regulation (+2%) and a premium for the Regulated Utility group's undervaluation (+5%).

Previously our $60 price target included $47 for PSE&G using a 12% Regulated Utility premium 2020E P/E multiple of 16.1x applied to $2.59 of UP&O EPS and $13 for PSEG Power at 7.2x $1.1B less $1.7B of debt and 508M shares.

Figure 22: PEG Sum of the Parts – Dollars in Millions

PEG	EPS 2021E	Premium/ Multiple	Value
UP&O	$2.79	12.0%	$51
	$/Share		
PSEG Power	$1,046	6.8x	$11
Total			$63

Source: Company reports, UBS equity research

SCANA Corp.

We are updating our price target to $49 from $41. Given the pending Dominion merger we are not rolling our valuation to the 2021 year rather we are reflecting the value of the Dominion merger which is Dominion's closing price of

$74.11/share at the 0.669 exchange ratio. See our separate note (LINK). Our 2020E SCANA Corp. stand-alone valuation is $41 premised upon 2020E eps under the ORS securitization scenario of $2.35 in 2020 and our updated normalized utility comp group multiple of 17.3x.

We are reiterating our Neutral rating. We are updating our eps estimates to be reflective of the earnings power from the latest Dominion Energy rate proposal before the South Carolina Public Service commission commensurate with no up-front refund but an approximate 15% on-going rate cut as a result of the abandoned V.C. Summer Unit 2 and Unit 3 new nuclear construction project. Our eps forecast is updated to $2.67/$2.30/$2.44/$2.66 from $3.13/$2.76/$2.90/3.12 for '18-'21E respectively.

Our prior price target of $41 was premised upon a 50/50 view of acquisition break/close which results in our $41 price target premised upon the $46/share full value takeout price and our $35/share value on break and the ORS terms with securitization.

Sempra Energy

Our current price target of $129 is premised upon a sum of the parts. We value SDG&E, SoCalGas, Oncor and Parent at a 1% net premium to the 16.4x 2021e Regulated Utility multiple ($75), Cameron at the average Gas Midstream 2021e P/E of 16.5x ($22), other LNG & Midstream at a 5% discount to the average Gas Midstream P/E (-$2), and approximate the mark-to-market for SRE Mexico ($11) and SA Utilities ($6). This derives a value of $112 for the shares. We calculate an upside value of ~$146 under execution of an Elliott-inspired strategy. Our price target is based on an average of these outcomes.

Our prior target of $130 was derived with the same methodology, using 2020 estimates in the base case to arrive at values of $68 for the Utilities and Parent, $24 for Cameron, ($4) for other LNG & Midstream, $15 for SRE Mexico, and $8 for SA Utilities, for total base case value of $111. Our Elliott Plan upside value was $149. Our price target reflected the average of those two outcomes.

Our 2018 EPS estimate is revised up to $5.46 from $5.31. Our other estimates remain unchanged at $5.89 in 2019, $6.99 in 2020 and $7.55 in 2021.

Southern Company

We are reiterating our Neutral rating. Our eps estimates remain unchanged at $33.06/$3.04/$3.17/$3.30 for '18-'21E respectively. We are reiterating our price target of $49 as inclusion of an additional 5% discount for the Georgia triennial rate case year in 2019 balances the impact of multiple expansion and a roll to the 2021 valuation year.

Our prior price target of $49 was premised upon a net 5% discount to the group multiple of 15.7x our 2020E eps of $3.17.

Our current price target of $49 is premised upon a net 10% discount to the 16.4x normalized multiple and our 2021E eps of $3.30.

WEC Energy Group

We are increasing our price target on WEC to $73 from $70. Our new price target is premised upon an 18.4x multiple to our 2021e EPS of $3.97, or a net 12% premium to the Regulated Utility P/E multiple. Previously our $70 price target reflected a 17% premium to the Regulated Utility P/E multiple on 2020e EPS of $3.74. Our EPS estimates remain unchanged at $3.34 in 2018, $3.54 in 2019, $3.74 in 2020 and $3.97 in 2021.

Xcel Energy

We are increasing our price target on XEL to $53 from $50. Our new price target is premised upon a 17.9x multiple to our 2021e EPS of $2.95, or a net 9% premium to the Regulated Utility P/E multiple. Previously our $50 price target reflected a 14% premium to the Regulated Utility P/E multiple on 2020e EPS of $2.77. Our EPS estimates remain unchanged at $2.47 in 2018, $2.60 in 2019, $2.77 in 2020 and $2.95 in 2021.

Valuation Method and Risk Statement

Our valuation methodology for the group is price to earnings based. The adjustments applied fall into 5 categories. These are as follows: 1) Group Valuation Bias: Flowing from our valuation work comparing Baa corporate yields to group dividend yields and RU price to earnings ratios to those for the S&P 500, we incorporate a positive or negative adjustment to our group multiple representing the gap we calculate to the nearest 5%; 2) Growth Adjustment: We adjust our valuations based on the growth quartile each utility occupies. First quartile receives a 5% premium, second quartile a 2% premium, third quartile a 2% discount and fourth quartile a 5% discount; 3) Regulatory Adjustment: Our valuation adjustments for regulation are based on our proprietary Regulatory Rankings. First quartile jurisdictions receive 5%, second quartile 2%, third quartile -2% and fourth quartile -5%; 4) Multi Utility Diversified Valuation: For multi utilities (those with more than 15% diversified or foreign earnings), we perform a sum-of-parts analysis applying business/region appropriate valuations to those diversified businesses; 5) One-off Adjustments: In special situations, we value risk on an issue specific basis. Common areas where we apply such an adjustment include: ESG advantage, large project construction risk, legal risk, and announced M&A completion risk.

Required Disclosures

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12-Month Rating	Definition	Coverage[1]	IB Services[2]
Buy	FSR is > 6% above the MRA.	48%	24%
Neutral	FSR is between -6% and 6% of the MRA.	37%	21%
Sell	FSR is > 6% below the MRA.	15%	12%
Short-Term Rating	**Definition**	**Coverage[3]**	**IB Services[4]**
Buy	Stock price expected to rise within three months from the time the rating was assigned because of a specific catalyst or event.	<1%	<1%
Sell	Stock price expected to fall within three months from the time the rating was assigned because of a specific catalyst or event.	<1%	<1%

Source: UBS. Rating allocations are as of 30 September 2018.
1:Percentage of companies under coverage globally within the 12-month rating category.
2:Percentage of companies within the 12-month rating category for which investment banking (IB) services were provided within the past 12 months.
3:Percentage of companies under coverage globally within the Short-Term rating category.
4:Percentage of companies within the Short-Term rating category for which investment banking (IB) services were provided within the past 12 months.

KEY DEFINITIONS:Forecast Stock Return (FSR) is defined as expected percentage price appreciation plus gross dividend yield over the next 12 months. In some cases, this yield may be based on accrued dividends. **Market Return Assumption (MRA)** is defined as the one-year local market interest rate plus 5% (a proxy for, and not a forecast of, the equity risk premium). **Under Review (UR)** Stocks may be flagged as UR by the analyst, indicating that the stock's price target and/or rating are subject to possible change in the near term, usually in response to an event that may affect the investment case or valuation. **Short-Term Ratings** reflect the expected near-term (up to three months) performance of the stock and do not reflect any change in the fundamental view or investment case. **Equity Price Targets** have an investment horizon of 12 months.

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UBS Securities LLC: Daniel Ford, CFA; Ross Fowler, CFA; Gregg Orrill; Rose-Lynn Armstrong.

Company Disclosures

Company Name	Reuters	12-month rating	Short-term rating	Price	Price date
AES Corp[16]	AES.N	Neutral	N/A	US$15.51	28 Nov 2018
Alliant Energy Corp[16]	LNT.N	Neutral	N/A	US$44.77	28 Nov 2018
Ameren Corp[16]	AEE.N	Neutral	N/A	US$68.11	28 Nov 2018
American Electric Power Inc[2, 4, 6a, 7, 16]	AEP.N	Buy	N/A	US$76.22	28 Nov 2018
ATCO Ltd	ACOx.TO	Buy	N/A	C$40.11	28 Nov 2018
Canadian Utilities Ltd	CU.TO	Neutral	N/A	C$31.28	28 Nov 2018
Caribbean Utilities Corp	CUPu.TO	Neutral	N/A	US$12.50	28 Nov 2018
CMS Energy Corp[16]	CMS.N	Neutral	N/A	US$51.23	28 Nov 2018
Consolidated Edison Inc[16]	ED.N	Neutral	N/A	US$78.84	28 Nov 2018
Dominion Energy Inc[4, 6a, 6c, 7, 16]	D.N	Buy	N/A	US$73.32	28 Nov 2018
DTE Energy Co[4, 6a, 7, 16]	DTE.N	Neutral	N/A	US$117.40	28 Nov 2018
Duke Energy Corp[2, 4, 6a, 7, 16]	DUK.N	Buy	N/A	US$87.60	28 Nov 2018
Emera Inc	EMA.TO	Buy	N/A	C$44.11	28 Nov 2018
Enable Midstream Partners LP[16]	ENBL.N	Buy	N/A	US$13.44	28 Nov 2018
Entergy Corp[7, 16]	ETR.N	Buy	N/A	US$86.08	28 Nov 2018
Evergy, Inc[16]	EVRG.N	Neutral	N/A	US$59.13	28 Nov 2018
Eversource Energy[7, 16]	ES.N	Buy	N/A	US$67.43	28 Nov 2018
Exelon Corp[7, 16]	EXC.N	Buy	N/A	US$45.82	28 Nov 2018
FirstEnergy Corp[16]	FE.N	Buy	N/A	US$37.60	28 Nov 2018
Fortis Inc[7, 16]	FTS.TO	Buy	N/A	C$45.70	28 Nov 2018
Hawaiian Electric Industries Inc[16]	HE.N	Sell	N/A	US$37.94	28 Nov 2018
Hydro One	H.TO	Sell	N/A	C$19.53	28 Nov 2018
NextEra Energy Inc[4, 6a, 7, 16, 26]	NEE.N	Buy	N/A	US$178.05	28 Nov 2018
OGE Energy Corp[16]	OGE.N	Neutral	N/A	US$39.11	28 Nov 2018
PNM Resources Inc[7, 16]	PNM.N	Sell	N/A	US$42.76	28 Nov 2018
Portland General Electric Co[16]	POR.N	Sell	N/A	US$47.96	28 Nov 2018
PPL Corp[2, 4, 6a, 6b, 6c, 7, 16]	PPL.N	Buy	N/A	US$30.86	28 Nov 2018
Public Service Enterprise Group[7, 16]	PEG.N	Buy	N/A	US$54.71	28 Nov 2018

Source: UBS. All prices as of local market close.
Ratings in this table are the most current published ratings prior to this report. They may be more recent than the stock pricing date

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The Cross-Section of Expected Stock Returns

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ABSTRACT

Two easily measured variables, size and book-to-market equity, combine to capture the cross-sectional variation in average stock returns associated with market β, size, leverage, book-to-market equity, and earnings-price ratios. Moreover, when the tests allow for variation in β that is unrelated to size, the relation between market β and average return is flat, even when β is the only explanatory variable.

THE ASSET-PRICING MODEL OF Sharpe (1964), Lintner (1965), and Black (1972) has long shaped the way academics and practitioners think about average returns and risk. The central prediction of the model is that the market portfolio of invested wealth is mean-variance efficient in the sense of Markowitz (1959). The efficiency of the market portfolio implies that (a) expected returns on securities are a positive linear function of their market βs (the slope in the regression of a security's return on the market's return), and (b) market βs suffice to describe the cross-section of expected returns.

There are several empirical contradictions of the Sharpe-Lintner-Black (SLB) model. The most prominent is the size effect of Banz (1981). He finds that market equity, ME (a stock's price times shares outstanding), adds to the explanation of the cross-section of average returns provided by market βs. Average returns on small (low ME) stocks are too high given their β estimates, and average returns on large stocks are too low.

Another contradiction of the SLB model is the positive relation between leverage and average return documented by Bhandari (1988). It is plausible that leverage is associated with risk and expected return, but in the SLB model, leverage risk should be captured by market β. Bhandari finds, however, that leverage helps explain the cross-section of average stock returns in tests that include size (ME) as well as β.

Stattman (1980) and Rosenberg, Reid, and Lanstein (1985) find that average returns on U.S. stocks are positively related to the ratio of a firm's book value of common equity, BE, to its market value, ME. Chan, Hamao, and Lakonishok (1991) find that book-to-market equity, BE/ME, also has a strong role in explaining the cross-section of average returns on Japanese stocks.

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Finally, Basu (1983) shows that earnings-price ratios (E/P) help explain the cross-section of average returns on U.S. stocks in tests that also include size and market β. Ball (1978) argues that E/P is a catch-all proxy for unnamed factors in expected returns; E/P is likely to be higher (prices are lower relative to earnings) for stocks with higher risks and expected returns, whatever the unnamed sources of risk.

Ball's proxy argument for E/P might also apply to size (ME), leverage, and book-to-market equity. All these variables can be regarded as different ways to scale stock prices, to extract the information in prices about risk and expected returns (Keim (1988)). Moreover, since E/P, ME, leverage, and BE/ME are all scaled versions of price, it is reasonable to expect that some of them are redundant for describing average returns. Our goal is to evaluate the joint roles of market β, size, E/P, leverage, and book-to-market equity in the cross-section of average returns on NYSE, AMEX, and NASDAQ stocks.

Black, Jensen, and Scholes (1972) and Fama and MacBeth (1973) find that, as predicted by the SLB model, there is a positive simple relation between average stock returns and β during the pre-1969 period. Like Reinganum (1981) and Lakonishok and Shapiro (1986), we find that the relation between β and average return disappears during the more recent 1963–1990 period, even when β is used alone to explain average returns. The appendix shows that the simple relation between β and average return is also weak in the 50-year 1941–1990 period. In short, our tests do not support the most basic prediction of the SLB model, that average stock returns are positively related to market βs.

Unlike the simple relation between β and average return, the univariate relations between average return and size, leverage, E/P, and book-to-market equity are strong. In multivariate tests, the negative relation between size and average return is robust to the inclusion of other variables. The positive relation between book-to-market equity and average return also persists in competition with other variables. Moreover, although the size effect has attracted more attention, book-to-market equity has a consistently stronger role in average returns. Our bottom-line results are: (a) β does not seem to help explain the cross-section of average stock returns, and (b) the combination of size and book-to-market equity seems to absorb the roles of leverage and E/P in average stock returns, at least during our 1963–1990 sample period.

If assets are priced rationally, our results suggest that stock risks are multidimensional. One dimension of risk is proxied by size, ME. Another dimension of risk is proxied by BE/ME, the ratio of the book value of common equity to its market value.

It is possible that the risk captured by BE/ME is the relative distress factor of Chan and Chen (1991). They postulate that the earning prospects of firms are associated with a risk factor in returns. Firms that the market judges to have poor prospects, signaled here by low stock prices and high ratios of book-to-market equity, have higher expected stock returns (they are penalized with higher costs of capital) than firms with strong prospects. It is also possible, however, that BE/ME just captures the unraveling (regression toward the mean) of irrational market whims about the prospects of firms.

Whatever the underlying economic causes, our main result is straightforward. Two easily measured variables, size (ME) and book-to-market equity (BE/ME), provide a simple and powerful characterization of the cross-section of average stock returns for the 1963–1990 period.

In the next section we discuss the data and our approach to estimating β. Section II examines the relations between average return and β and between average return and size. Section III examines the roles of E/P, leverage, and book-to-market equity in average returns. In sections IV and V, we summarize, interpret, and discuss applications of the results.

I. Preliminaries

A. Data

We use all nonfinancial firms in the intersection of (a) the NYSE, AMEX, and NASDAQ return files from the Center for Research in Security Prices (CRSP) and (b) the merged COMPUSTAT annual industrial files of income-statement and balance-sheet data, also maintained by CRSP. We exclude financial firms because the high leverage that is normal for these firms probably does not have the same meaning as for nonfinancial firms, where high leverage more likely indicates distress. The CRSP returns cover NYSE and AMEX stocks until 1973 when NASDAQ returns also come on line. The COMPUSTAT data are for 1962–1989. The 1962 start date reflects the fact that book value of common equity (COMPUSTAT item 60), is not generally available prior to 1962. More important, COMPUSTAT data for earlier years have a serious selection bias; the pre-1962 data are tilted toward big historically successful firms.

To ensure that the accounting variables are known before the returns they are used to explain, we match the accounting data for all fiscal yearends in calendar year $t - 1$ (1962–1989) with the returns for July of year t to June of $t + 1$. The 6-month (minimum) gap between fiscal yearend and the return tests is conservative. Earlier work (e.g., Basu (1983)) often assumes that accounting data are available within three months of fiscal yearends. Firms are indeed required to file their 10-K reports with the SEC within 90 days of their fiscal yearends, but on average 19.8% do not comply. In addition, more than 40% of the December fiscal yearend firms that do comply with the 90-day rule file on March 31, and their reports are not made public until April. (See Alford, Jones, and Zmijewski (1992).)

We use a firm's market equity at the end of December of year $t - 1$ to compute its book-to-market, leverage, and earnings-price ratios for $t - 1$, and we use its market equity for June of year t to measure its size. Thus, to be included in the return tests for July of year t, a firm must have a CRSP stock price for December of year $t - 1$ and June of year t. It must also have monthly returns for at least 24 of the 60 months preceding July of year t (for "pre-ranking" β estimates, discussed below). And the firm must have COMPUSTAT data on total book assets (A), book equity (BE), and earnings (E), for its fiscal year ending in (any month of) calendar year $t-1$.

Our use of December market equity in the E/P, BE/ME, and leverage ratios is objectionable for firms that do not have December fiscal yearends because the accounting variable in the numerator of a ratio is not aligned with the market value in the denominator. Using ME at fiscal yearends is also problematic; then part of the cross-sectional variation of a ratio for a given year is due to market-wide variation in the ratio during the year. For example, if there is a general fall in stock prices during the year, ratios measured early in the year will tend to be lower than ratios measured later. We can report, however, that the use of fiscal-yearend MEs, rather than December MEs, in the accounting ratios has little impact on our return tests.

Finally, the tests mix firms with different fiscal yearends. Since we match accounting data for all fiscal yearends in calendar year $t-1$ with returns for July of t to June of $t+1$, the gap between the accounting data and the matching returns varies across firms. We have done the tests using the smaller sample of firms with December fiscal yearends with similar results.

B. Estimating Market βs

Our asset-pricing tests use the cross-sectional regression approach of Fama and MacBeth (1973). Each month the cross-section of returns on stocks is regressed on variables hypothesized to explain expected returns. The time-series means of the monthly regression slopes then provide standard tests of whether different explanatory variables are on average priced.

Since size, E/P, leverage, and BE/ME are measured precisely for individual stocks, there is no reason to smear the information in these variables by using portfolios in the Fama-MacBeth (FM) regressions. Most previous tests use portfolios because estimates of market βs are more precise for portfolios. Our approach is to estimate βs for portfolios and then assign a portfolio's β to each stock in the portfolio. This allows us to use individual stocks in the FM asset-pricing tests.

B.1. β Estimation: Details

In June of each year, all NYSE stocks on CRSP are sorted by size (ME) to determine the NYSE decile breakpoints for ME. NYSE, AMEX, and NASDAQ stocks that have the required CRSP-COMPUSTAT data are then allocated to 10 size portfolios based on the NYSE breakpoints. (If we used stocks from all three exchanges to determine the ME breakpoints, most portfolios would include only small stocks after 1973, when NASDAQ stocks are added to the sample.)

We form portfolios on size because of the evidence of Chan and Chen (1988) and others that size produces a wide spread of average returns and βs. Chan and Chen use only size portfolios. The problem this creates is that size and the βs of size portfolios are highly correlated (-0.988 in their data), so asset-pricing tests lack power to separate size from β effects in average returns.

To allow for variation in β that is unrelated to size, we subdivide each size decile into 10 portfolios on the basis of pre-ranking βs for individual stocks. The pre-ranking βs are estimated on 24 to 60 monthly returns (as available) in the 5 years before July of year t. We set the β breakpoints for each size decile using only NYSE stocks that satisfy our COMPUSTAT-CRSP data requirements for year $t - 1$. Using NYSE stocks ensures that the β breakpoints are not dominated after 1973 by the many small stocks on NASDAQ. Setting β breakpoints with stocks that satisfy our COMPUSTAT-CRSP data requirements guarantees that there are firms in each of the 100 size-β portfolios.

After assigning firms to the size-β portfolios in June, we calculate the equal-weighted monthly returns on the portfolios for the next 12 months, from July to June. In the end, we have post-ranking monthly returns for July 1963 to December 1990 on 100 portfolios formed on size and pre-ranking βs. We then estimate βs using the full sample (330 months) of post-ranking returns on each of the 100 portfolios, with the CRSP value-weighted portfolio of NYSE, AMEX, and (after 1972) NASDAQ stocks used as the proxy for the market. We have also estimated βs using the value-weighted or the equal-weighted portfolio of NYSE stocks as the proxy for the market. These βs produce inferences on the role of β in average returns like those reported below.

We estimate β as the sum of the slopes in the regression of the return on a portfolio on the current and prior month's market return. (An additional lead and lag of the market have little effect on these sum βs.) The sum βs are meant to adjust for nonsynchronous trading (Dimson (1979)). Fowler and Rorke (1983) show that sum βs are biased when the market return is autocorrelated. The 1st- and 2nd-order autocorrelations of the monthly market returns for July 1963 to December 1990 are 0.06 and -0.05, both about 1 standard error from 0. If the Fowler-Rorke corrections are used, they lead to trivial changes in the βs. We stick with the simpler sum βs. Appendix Table AI shows that using sum βs produces large increases in the βs of the smallest ME portfolios and small declines in the βs of the largest ME portfolios.

Chan and Chen (1988) show that full-period β estimates for portfolios can work well in tests of the SLB model, even if the true βs of the portfolios vary through time, if the variation in the βs is proportional,

$$\beta_{jt} - \beta_j = k_t(\beta_j - \beta), \tag{1}$$

where β_{jt} is the true β for portfolio j at time t, β_j is the mean of β_{jt} across t, and β is the mean of the β_j. The Appendix argues that (1) is a good approximation for the variation through time in the true βs of portfolios (j) formed on size and β. For diehard β fans, sure to be skeptical of our results on the weak role of β in average stock returns, we can also report that the results stand up to robustness checks that use 5-year pre-ranking βs, or 5-year post-ranking βs, instead of the full-period post-ranking βs.

We allocate the full-period post-ranking β of a size-β portfolio to each stock in the portfolio. These are the βs that will be used in the Fama-MacBeth cross-sectional regressions for individual stocks. We judge that the precision of the full-period post-ranking portfolio βs, relative to the imprecise β estimates that would be obtained for individual stocks, more than makes up for the fact that true βs are not the same for all stocks in a portfolio. And note that assigning full-period portfolio βs to stocks does not mean that a stock's β is constant. A stock can move across portfolios with year-to-year changes in the stock's size (ME) and in the estimates of its β for the preceding 5 years.

B.2. β Estimates

Table I shows that forming portfolios on size and pre-ranking βs, rather than on size alone, magnifies the range of full-period post-ranking βs. Sorted on size alone, the post-ranking βs range from 1.44 for the smallest ME portfolio to 0.92 for the largest. This spread of βs across the 10 size deciles is smaller than the spread of post-ranking βs produced by the β sort of *any* size decile. For example, the post-ranking βs for the 10 portfolios in the smallest size decile range from 1.05 to 1.79. Across all 100 size-β portfolios, the post-ranking βs range from 0.53 to 1.79, a spread 2.4 times the spread, 0.52, obtained with size portfolios alone.

Two other facts about the βs are important. First, in each size decile the post-ranking βs closely reproduce the ordering of the pre-ranking βs. We take this to be evidence that the pre-ranking β sort captures the ordering of true post-ranking βs. (The appendix gives more evidence on this important issue.) Second, the β sort is not a refined size sort. In any size decile, the average values of ln(ME) are similar across the β-sorted portfolios. Thus the pre-ranking β sort achieves its goal. It produces strong variation in post-ranking βs that is unrelated to size. This is important in allowing our tests to distinguish between β and size effects in average returns.

II. β and Size

The Sharpe-Lintner-Black (SLB) model plays an important role in the way academics and practitioners think about risk and the relation between risk and expected return. We show next that when common stock portfolios are formed on size alone, there seems to be evidence for the model's central prediction: average return is positively related to β. The βs of size portfolios are, however, almost perfectly correlated with size, so tests on size portfolios are unable to disentangle β and size effects in average returns. Allowing for variation in β that is unrelated to size breaks the logjam, but at the expense of β. Thus, when we subdivide size portfolios on the basis of pre-ranking βs, we find a strong relation between average return and size, but no relation between average return and β.

A. *Informal Tests*

Table II shows post-ranking average returns for July 1963 to December 1990 for portfolios formed from one-dimensional sorts of stocks on size or β. The portfolios are formed at the end of June each year and their equal-weighted returns are calculated for the next 12 months. We use returns for July to June to match the returns in later tests that use the accounting data. When we sort on just size or 5-year pre-ranking βs, we form 12 portfolios. The middle 8 cover deciles of size or β. The 4 extreme portfolios (1A, 1B, 10A, and 10B) split the bottom and top deciles in half.

Table II shows that when portfolios are formed on size alone, we observe the familiar strong negative relation between size and average return (Banz (1981)), and a strong positive relation between average return and β. Average returns fall from 1.64% per month for the smallest ME portfolio to 0.90% for the largest. Post-ranking βs also decline across the 12 size portfolios, from 1.44 for portfolio 1A to 0.90 for portfolio 10B. Thus, a simple size sort seems to support the SLB prediction of a positive relation between β and average return. But the evidence is muddied by the tight relation between size and the βs of size portfolios.

The portfolios formed on the basis of the ranked market βs of stocks in Table II produce a wider range of βs (from 0.81 for portfolio 1A to 1.73 for 10B) than the portfolios formed on size. Unlike the size portfolios, the β-sorted portfolios do not support the SLB model. There is little spread in average returns across the β portfolios, and there is no obvious relation between β and average returns. For example, although the two extreme portfolios, 1A and 10B, have much different βs, they have nearly identical average returns (1.20% and 1.18% per month). These results for 1963–1990 confirm Reinganum's (1981) evidence that for β-sorted portfolios, there is no relation between average return and β during the 1964–1979 period.

The 100 portfolios formed on size and then pre-ranking β in Table I clarify the contradictory evidence on the relation between β and average return produced by portfolios formed on size or β alone. Specifically, the two-pass sort gives a clearer picture of the separate roles of size and β in average returns. Contrary to the central prediction of the SLB model, the second-pass β sort produces little variation in average returns. Although the post-ranking βs in Table I increase strongly in each size decile, average returns are flat or show a slight tendency to decline. In contrast, within the columns of the average return and β matrices of Table I, average returns and βs decrease with increasing size.

The two-pass sort on size and β in Table I says that variation in β that is tied to size is positively related to average return, but variation in β unrelated to size is not compensated in the average returns of 1963–1990. The proper inference seems to be that there is a relation between size and average return, but controlling for size, there is no relation between β and average return. The regressions that follow confirm this conclusion, and they produce another that is stronger. The regressions show that when one allows

Table I

Average Returns, Post-Ranking βs and Average Size For Portfolios Formed on Size and then β: Stocks Sorted on ME (Down) then Pre-Ranking β (Across): July 1963 to December 1990

Portfolios are formed yearly. The breakpoints for the size (ME, price times shares outstanding) deciles are determined in June of year t (t = 1963–1990) using all NYSE stocks on CRSP. All NYSE, AMEX, and NASDAQ stocks that meet the CRSP-COMPUSTAT data requirements are allocated to the 10 size portfolios using the NYSE breakpoints. Each size decile is subdivided into 10 β portfolios using pre-ranking βs of individual stocks, estimated with 2 to 5 years of monthly returns (as available) ending in June of year t. We use only NYSE stocks that meet the CRSP-COMPUSTAT data requirements to establish the β breakpoints. The equal-weighted monthly returns on the resulting 100 portfolios are then calculated for July of year t to June of year $t+1$.

The post-ranking βs use the full (July 1963 to December 1990) sample of post-ranking returns for each portfolio. The pre- and post-ranking βs (here and in all other tables) are the sum of the slopes from a regression of monthly returns on the current and prior month's returns on the value-weighted portfolio of NYSE, AMEX, and (after 1972) NASDAQ stocks. The average return is the time-series average of the monthly equal-weighted portfolio returns, in percent. The average size of a portfolio is the time-series average of monthly averages of ln(ME) for stocks in the portfolio at the end of June of each year, with ME denominated in millions of dollars

The average number of stocks per month for the size-β portfolios in the smallest size decile varies from 70 to 177. The average number of stocks for the size-β portfolios in size deciles 2 and 3 is between 15 and 41, and the average number for the largest 7 size deciles is between 11 and 22.

The All column shows statistics for equal-weighted size-decile (ME) portfolios. The All row shows statistics for equal-weighted portfolios of the stocks in each β group.

	All	Low-β	β-2	β-3	β-4	β-5	β-6	β-7	β-8	β-9	High-β
Panel A: Average Monthly Returns (in Percent)											
All	1.25	1.34	1.29	1.36	1.31	1.33	1.28	1.24	1.21	1.25	1.14
Small-ME	1.52	1.71	1.57	1.79	1.61	1 50	1.50	1.37	1.63	1.50	1.42
ME-2	1.29	1.25	1.42	1.36	1.39	1.65	1.61	1.37	1 31	1.34	1.11
ME-3	1.24	1.12	1.31	1.17	1.70	1.29	1.10	1.31	1.36	1.26	0.76
ME-4	1.25	1.27	1.13	1.54	1.06	1.34	1.06	1.41	1.17	1.35	0.98
ME-5	1.29	1.34	1.42	1.39	1.48	1.42	1.18	1.13	1.27	1.18	1.08
ME-6	1.17	1.08	1.53	1.27	1.15	1.20	1.21	1.18	1.04	1.07	1.02
ME-7	1.07	0.95	1.21	1.26	1.09	1.18	1.11	1.24	0.62	1.32	0.76
ME-8	1.10	1.09	1.05	1.37	1.20	1.27	0.98	1.18	1.02	1.01	0.94
ME-9	0.95	0.98	0.88	1.02	1.14	1.07	1.23	0.94	0.82	0.88	0.59
Large-ME	0.89	1.01	0.93	1.10	0.94	0.93	0.89	1.03	0.71	0.74	0.56

Table I – *Continued*

	All	Low-β	β-2	β-3	β-4	β-5	β-6	β-7	β-8	β-9	High-β
					Panel B: Post-Ranking βs						
All		0.87	0.99	1.09	1.16	1.26	1.29	1 35	1.45	1.52	1.72
Small-ME	1.44	1.05	1.18	1.28	1.32	1.40	1.40	1.49	1.61	1.64	1 79
ME-2	1.39	0.91	1.15	1.17	1.24	1.36	1.41	1.43	1.50	1.66	1.76
ME-3	1.35	0 97	1 13	1.13	1.21	1.26	1.28	1.39	1.50	1.51	1.75
ME-4	1.34	0 78	1.03	1.17	1.16	1.29	1.37	1.46	1.51	1 64	1.71
ME-5	1 25	0 66	0.85	1.12	1.15	1.16	1.26	1.30	1.43	1.59	1.68
ME-6	1.23	0.61	0.78	1.05	1.16	1.22	1.28	1.36	1.46	1.49	1.70
ME-7	1.17	0.57	0.92	1.01	1.11	1.14	1.26	1.24	1.39	1.34	1.60
ME-8	1.09	0.53	0.74	0.94	1.02	1.13	1.12	1.18	1.26	1.35	1.52
ME-9	1 03	0 58	0.74	0.80	0.95	1.06	1.15	1.14	1.21	1.22	1.42
Large-ME	0.92	0.57	0.71	0.78	0.89	0.95	0.92	1.02	1.01	1.11	1.32
					Panel C: Average Size (ln(ME))						
All	4.11	3.86	4.26	4 33	4.41	4.27	4.32	4.26	4.19	4 03	3.77
Small-ME	2.24	2.12	2.27	2.30	2.30	2.28	2.29	2.30	2.32	2.25	2.15
ME-2	3.63	3.65	3.68	3.70	3.72	3.69	3 70	3.69	3.69	3.70	3.68
ME-3	4.10	4.14	4.18	4.12	4.15	4.16	4.16	4.18	4 14	4.15	4.15
ME-4	4.50	4.53	4.53	4.57	4.54	4.56	4.55	4.52	4.58	4.52	4.56
ME-5	4.89	4.91	4.91	4.93	4.95	4.93	4.92	4 93	4.92	4.92	4.95
ME-6	5.30	5.30	5 33	5 34	5.34	5.33	5.33	5.33	5.33	5.34	5.36
ME-7	5.73	5.73	5.75	5.77	5.76	5.73	5.77	5.77	5 76	5.72	5.76
ME-8	6.24	6.26	6.27	6.26	6.24	6.24	6.27	6.24	6.24	6.24	6 26
ME-9	6.82	6.82	6.84	6.82	6.82	6.81	6.81	6.81	6.81	6.80	6.83
Large-ME	7.93	7.94	8.04	8.10	8.04	8 02	8.02	7.94	7.80	7.75	7.62

Table II

Properties of Portfolios Formed on Size or Pre-Ranking β: July 1963 to December 1990

At the end of June of each year t, 12 portfolios are formed on the basis of ranked values of size (ME) or pre-ranking β. The pre-ranking βs use 2 to 5 years (as available) of monthly returns ending in June of t. Portfolios 2–9 cover deciles of the ranking variables. The bottom and top 2 portfolios (1A, 1B, 10A, and 10B) split the bottom and top deciles in half. The breakpoints for the ME portfolios are based on ranked values of ME for all NYSE stocks on CRSP. NYSE breakpoints for pre-ranking βs are also used to form the β portfolios. NYSE, AMEX, and NASDAQ stocks are then allocated to the size or β portfolios using the NYSE breakpoints. We calculate each portfolio's monthly equal-weighted return for July of year t to June of year $t + 1$, and then reform the portfolios in June of $t + 1$.

BE is the book value of common equity plus balance-sheet deferred taxes, A is total book assets, and E is earnings (income before extraordinary items, plus income-statement deferred taxes, minus preferred dividends). BE, A, and E are for each firm's latest fiscal year ending in calendar year $t - 1$. The accounting ratios are measured using market equity ME in December of year $t - 1$. Firm size ln(ME) is measured in June of year t, with ME denominated in millions of dollars.

The average return is the time-series average of the monthly equal-weighted portfolio returns, in percent. ln(ME), ln(BE/ME), ln(A/ME), ln(A/BE), E/P, and E/P dummy are the time-series averages of the monthly average values of these variables in each portfolio. Since the E/P dummy is 0 when earnings are positive, and 1 when earnings are negative, E/P dummy gives the average proportion of stocks with negative earnings in each portfolio.

β is the time-series average of the monthly portfolio βs. Stocks are assigned the post-ranking β of the size-β portfolio they are in at the end of June of year t (Table I). These individual-firm βs are averaged to compute the monthly βs for each portfolio for July of year t to June of year $t + 1$.

Firms is the average number of stocks in the portfolio each month.

	1A	1B	2	3	4	5	6	7	8	9	10A	10B
Panel A: Portfolios Formed on Size												
Return	1.64	1.16	1.29	1.24	1.25	1.29	1.17	1.07	1.10	0.95	0.88	0.90
β	1.44	1.44	1.39	1.34	1.33	1.24	1.22	1.16	1.08	1.02	0.95	0.90
ln(ME)	1.98	3.18	3.63	4.10	4.50	4.89	5.30	5.73	6.24	6.82	7.39	8.44
ln(BE/ME)	−0.01	−0.21	−0.23	−0.26	−0.32	−0.36	−0.36	−0.44	−0.40	−0.42	−0.51	−0.65
ln(A/ME)	0.73	0.50	0.46	0.43	0.37	0.32	0.32	0.24	0.29	0.27	0.17	−0.03
ln(A/BE)	0.75	0.71	0.69	0.69	0.68	0.67	0.68	0.67	0.69	0.70	0.68	0.62
E/P dummy	0.26	0.14	0.11	0.09	0.06	0.04	0.04	0.03	0.03	0.02	0.02	0.01
E(+)/P	0.09	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.09	0.09
Firms	772	189	236	170	144	140	128	125	119	114	60	64

Table II—*Continued*

	1A	1B	2	3	4	5	6	7	8	9	10A	10B
					Panel B: Portfolios Formed on Pre-Ranking β							
Return	1.20	1 20	1.32	1.26	1.31	1.30	1.30	1.23	1.23	1.33	1.34	1.18
β	0.81	0.79	0.92	1.04	1.13	1.19	1.26	1.32	1.41	1.52	1 63	1.73
ln(ME)	4.21	4.86	4.75	4.68	4.59	4.48	4.36	4.25	3.97	3.78	3.52	3.15
ln(BE/ME)	−0.18	−0.13	−0.22	−0.21	−0.23	−0.22	−0.22	−0.25	−0.23	−0.27	−0.31	−0.50
ln(A/ME)	0.60	0.66	0.49	0.45	0.42	0.42	0.45	0.42	0.47	0 46	0.46	0.31
ln(A/BE)	0.78	0.79	0.71	0.66	0.64	0.65	0.67	0.67	0.70	0.73	0.77	0 81
E/P dummy	0.12	0.06	0.09	0.09	0.08	0.09	0.10	0.12	0.12	0.14	0.17	0.23
E(+)/P	0.11	0.12	0.10	0.10	0.10	0.10	0.10	0.09	0.10	0.09	0 09	0.08
Firms	116	80	185	181	179	182	185	205	227	267	165	291

for variation in β that is unrelated to size, the relation between β and average return is flat, even when β is the only explanatory variable.

B. Fama-MacBeth Regressions

Table III shows time-series averages of the slopes from the month-by-month Fama-MacBeth (FM) regressions of the cross-section of stock returns on size, β, and the other variables (leverage, E/P, and book-to-market equity) used to explain average returns. The average slopes provide standard FM tests for determining which explanatory variables on average have non-zero expected premiums during the July 1963 to December 1990 period.

Like the average returns in Tables I and II, the regressions in Table III say that size, ln(ME), helps explain the cross-section of average stock returns. The average slope from the monthly regressions of returns on size alone is -0.15%, with a t-statistic of -2.58. This reliable negative relation persists no matter which other explanatory variables are in the regressions; the average slopes on ln(ME) are always close to or more than 2 standard errors from 0. The size effect (smaller stocks have higher average returns) is thus robust in the 1963–1990 returns on NYSE, AMEX, and NASDAQ stocks.

In contrast to the consistent explanatory power of size, the FM regressions show that market β does not help explain average stock returns for 1963–1990. In a shot straight at the heart of the SLB model, the average slope from the regressions of returns on β alone in Table III is 0.15% per month and only 0.46 standard errors from 0. In the regressions of returns on size and β, size has explanatory power (an average slope -3.41 standard errors from 0), but the average slope for β is negative and only 1.21 standard errors from 0. Lakonishok and Shapiro (1986) get similar results for NYSE stocks for 1962–1981. We can also report that β shows no power to explain average returns (the average slopes are typically less than 1 standard error from 0) in FM regressions that use various combinations of β with size, book-to-market equity, leverage, and E/P.

C. Can β Be Saved?

What explains the poor results for β? One possibility is that other explanatory variables are correlated with true βs, and this obscures the relation between average returns and measured βs. But this line of attack cannot explain why β has no power when used alone to explain average returns. Moreover, leverage, book-to-market equity, and E/P do not seem to be good proxies for β. The averages of the monthly cross-sectional correlations between β and the values of these variables for individual stocks are all within 0.15 of 0.

Another hypothesis is that, as predicted by the SLB model, there is a positive relation between β and average return, but the relation is obscured by noise in the β estimates. However, our full-period post-ranking βs do not seem to be imprecise. Most of the standard errors of the βs (not shown) are

Table III

Average Slopes (t-Statistics) from Month-by-Month Regressions of Stock Returns on β, Size, Book-to-Market Equity, Leverage, and E/P: July 1963 to December 1990

Stocks are assigned the post-ranking β of the size-β portfolio they are in at the end of June of year t (Table I). BE is the book value of common equity plus balance-sheet deferred taxes, A is total book assets, and E is earnings (income before extraordinary items, plus income-statement deferred taxes, minus preferred dividends) BE, A, and E are for each firm's latest fiscal year ending in calendar year $t-1$. The accounting ratios are measured using market equity ME in December of year $t-1$. Firm size ln(ME) is measured in June of year t. In the regressions, these values of the explanatory variables for individual stocks are matched with CRSP returns for the months from July of year t to June of year $t+1$. The gap between the accounting data and the returns ensures that the accounting data are available prior to the returns. If earnings are positive, E(+)/P is the ratio of total earnings to market equity and E/P dummy is 0. If earnings are negative, E(+)/P is 0 and E/P dummy is 1.

The average slope is the time-series average of the monthly regression slopes for July 1963 to December 1990, and the t-statistic is the average slope divided by its time-series standard error.

On average, there are 2267 stocks in the monthly regressions. To avoid giving extreme observations heavy weight in the regressions, the smallest and largest 0.5% of the observations on E(+)/P, BE/ME, A/ME, and A/BE are set equal to the next largest or smallest values of the ratios (the 0.005 and 0.995 fractiles). This has no effect on inferences.

β	ln(ME)	ln(BE/ME)	ln(A/ME)	ln(A/BE)	E/P Dummy	E(+)/P
0.15 (0.46)						
	−0.15 (−2 58)					
−0.37 (−1.21)	−0.17 (−3.41)					
		0.50 (5.71)				
			0.50 (5 69)	−0.57 (−5.34)		
					0.57 (2.28)	4.72 (4.57)
	−0.11 (−1.99)	0.35 (4.44)				
	−0 11 (−2 06)		0.35 (4.32)	−0 50 (−4.56)		
	−0.16 (−3.06)				0.06 (0 38)	2.99 (3.04)
	−0.13 (−2.47)	0.33 (4.46)			−0.14 (−0.90)	0.87 (1.23)
	−0.13 (−2.47)		0.32 (4.28)	−0.46 (−4.45)	−0.08 (−0.56)	1.15 (1.57)

0.05 or less, only 1 is greater than 0.1, and the standard errors are small relative to the range of the βs (0.53 to 1.79).

The β-sorted portfolios in Tables I and II also provide strong evidence against the β-measurement-error story. When portfolios are formed on pre-ranking βs alone (Table II), the post-ranking βs for the portfolios almost perfectly reproduce the ordering of the pre-ranking βs. Only the β for portfolio 1B is out of line, and only by 0.02. Similarly, when portfolios are formed on size and then pre-ranking βs (Table I), the post-ranking βs in each size decile closely reproduce the ordering of the pre-ranking βs.

The correspondence between the ordering of the pre-ranking and post-ranking βs for the β-sorted portfolios in Tables I and II is evidence that the post-ranking βs are informative about the ordering of the true βs. The problem for the SLB model is that there is no similar ordering in the average returns on the β-sorted portfolios. Whether one looks at portfolios sorted on β alone (Table II) or on size and then β (Table I), average returns are flat (Table II) or decline slightly (Table I) as the post-ranking βs increase.

Our evidence on the robustness of the size effect and the absence of a relation between β and average return is so contrary to the SLB model that it behooves us to examine whether the results are special to 1963–1990. The appendix shows that NYSE returns for 1941–1990 behave like the NYSE, AMEX, and NASDAQ returns for 1963–1990; there is a reliable size effect over the full 50-year period, but little relation between β and average return. Interestingly, there is a reliable simple relation between β and average return during the 1941–1965 period. These 25 years are a major part of the samples in the early studies of the SLB model of Black, Jensen, and Scholes (1972) and Fama and MacBeth (1973). Even for the 1941–1965 period, however, the relation between β and average return disappears when we control for size.

III. Book-to-Market Equity, E/P, and Leverage

Tables I to III say that there is a strong relation between the average returns on stocks and size, but there is no reliable relation between average returns and β. In this section we show that there is also a strong cross-sectional relation between average returns and book-to-market equity. If anything, this book-to-market effect is more powerful than the size effect. We also find that the combination of size and book-to-market equity absorbs the apparent roles of leverage and E/P in average stock returns.

A. Average Returns

Table IV shows average returns for July 1963 to December 1990 for portfolios formed on ranked values of book-to-market equity (BE/ME) or earnings-price ratio (E/P). The BE/ME and E/P portfolios in Table IV are formed in the same general way (one-dimensional yearly sorts) as the size and β portfolios in Table II. (See the tables for details.)

The relation between average return and E/P has a familiar U-shape (e.g., Jaffe, Keim, and Westerfield (1989) for U.S. data, and Chan, Hamao, and Lakonishok (1991) for Japan). Average returns decline from 1.46% per month for the negative E/P portfolio to 0.93% for the firms in portfolio 1B that have low but positive E/P. Average returns then increase monotonically, reaching 1.72% per month for the highest E/P portfolio.

The more striking evidence in Table IV is the strong positive relation between average return and book-to-market equity. Average returns rise from 0.30% for the lowest BE/ME portfolio to 1.83% for the highest, a difference of 1.53% per month. This spread is twice as large as the difference of 0.74% between the average monthly returns on the smallest and largest size portfolios in Table II. Note also that the strong relation between book-to-market equity and average return is unlikely to be a β effect in disguise; Table IV shows that post-ranking market βs vary little across portfolios formed on ranked values of BE/ME.

On average, only about 50 (out of 2317) firms per year have negative book equity, BE. The negative BE firms are mostly concentrated in the last 14 years of the sample, 1976–1989, and we do not include them in the tests. We can report, however, that average returns for negative BE firms are high, like the average returns of high BE/ME firms. Negative BE (which results from persistently negative earnings) and high BE/ME (which typically means that stock prices have fallen) are both signals of poor earning prospects. The similar average returns of negative and high BE/ME firms are thus consistent with the hypothesis that book-to-market equity captures cross-sectional variation in average returns that is related to relative distress.

B. Fama-MacBeth Regressions

B.1. BE/ME

The FM regressions in Table III confirm the importance of book-to-market equity in explaining the cross-section of average stock returns. The average slope from the monthly regressions of returns on ln(BE/ME) alone is 0.50%, with a *t*-statistic of 5.71. This book-to-market relation is stronger than the size effect, which produces a *t*-statistic of -2.58 in the regressions of returns on ln(ME) alone. But book-to-market equity does not replace size in explaining average returns. When both ln(ME) and ln(BE/ME) are included in the regressions, the average size slope is still -1.99 standard errors from 0; the book-to-market slope is an impressive 4.44 standard errors from 0.

B.2. Leverage

The FM regressions that explain returns with leverage variables provide interesting insight into the relation between book-to-market equity and average return. We use two leverage variables, the ratio of book assets to market equity, A/ME, and the ratio of book assets to book equity, A/BE. We interpret A/ME as a measure of market leverage, while A/BE is a measure

Table IV

Properties of Portfolios Formed on Book-to-Market Equity (BE/ME) and Earnings-Price Ratio (E/P): July 1963 to December 1990

At the end of each year $t-1$, 12 portfolios are formed on the basis of ranked values of BE/ME or E/P. Portfolios 2–9 cover deciles of the ranking variables. The bottom and top 2 portfolios (1A, 1B, 10A, and 10B) split the bottom and top deciles in half. For E/P, there are 13 portfolios; portfolio 0 is stocks with negative E/P. Since BE/ME and E/P are not strongly related to exchange listing, their portfolio breakpoints are determined on the basis of the ranked values of the variables for all stocks that satisfy the CRSP-COMPUSTAT data requirements. BE is the book value of common equity plus balance-sheet deferred taxes, A is total book assets, and E is earnings (income before extraordinary items, plus income-statement deferred taxes, minus preferred dividends). BE, A, and E are for each firm's latest fiscal year ending in calendar year $t-1$. The accounting ratios are measured using market equity ME in December of year $t-1$. Firm size ln(ME) is measured in June of year t, with ME denominated in millions of dollars. We calculate each portfolio's monthly equal-weighted return for July of year t to June of year $t+1$, and then reform the portfolios at the end of year t.

Return is the time-series average of the monthly equal-weighted portfolio returns (in percent). ln(ME), ln(BE/ME), ln(A/ME), ln(A/BE), E(+)/P, and E/P dummy are the time-series averages of the monthly average values of these variables in each portfolio. Since the E/P dummy is 0 when earnings are positive, and 1 when earnings are negative, E/P dummy gives the average proportion of stocks with negative earnings in each portfolio.

β is the time-series average of the monthly portfolio βs. Stocks are assigned the post-ranking β of the size-β portfolio they are in at the end of June of year t (Table I). These individual-firm βs are averaged to compute the monthly βs for each portfolio for July of year t to June of year $t+1$.

Firms is the average number of stocks in the portfolio each month.

Portfolio	0	1A	1B	2	3	4	5	6	7	8	9	10A	10B
				Panel A: Stocks Sorted on Book-to-Market Equity (BE/ME)									
Return		0.30	0.67	0.87	0.97	1.04	1.17	1.30	1.44	1.50	1.59	1.92	1.83
β		1.36	1.34	1.32	1.30	1.28	1.27	1.27	1.27	1.27	1.29	1.33	1.35
ln(ME)		4.53	4.67	4.69	4.56	4.47	4.38	4.23	4.06	3.85	3.51	3.06	2.65
ln(BE/ME)		−2.22	−1.51	−1.09	−0.75	−0.51	−0.32	−0.14	0.03	0.21	0.42	0.66	1.02
ln(A/ME)		−1.24	−0.79	−0.40	−0.05	0.20	0.40	0.56	0.71	0.91	1.12	1.35	1.75
ln(A/BE)		0.94	0.71	0.68	0.70	0.71	0.71	0.70	0.68	0.70	0.70	0.70	0.73
E/P dummy		0.29	0.15	0.10	0.08	0.08	0.08	0.09	0.09	0.11	0.15	0.22	0.36
E(+)/P		0.03	0.04	0.06	0.08	0.09	0.10	0.11	0.11	0.12	0.12	0.11	0.10
Firms		89	98	209	222	226	230	235	237	239	239	120	117

Table IV—*Continued*

Portfolio	0	1A	1B	2	3	4	5	6	7	8	9	10A	10B
Panel B: Stocks Sorted on Earnings-Price Ratio (E/P)													
Return	1.46	1.04	0.93	0.94	1.03	1.18	1.22	1.33	1.42	1.46	1.57	1.74	1.72
β	1.47	1.40	1.35	1.31	1.28	1.26	1.25	1.26	1.24	1.23	1.24	1.28	1.31
ln(ME)	2.48	3.64	4.33	4.61	4.64	4.63	4.58	4.49	4.37	4.28	4.07	3.82	3.52
ln(BE/ME)	−0.10	−0.76	−0.91	−0.79	−0.61	−0.47	−0.33	−0.21	−0.08	0.02	0.15	0.26	0.40
ln(A/ME)	0.90	−0.05	−0.27	−0.16	0.03	0.18	0.31	0.44	0.58	0.70	0.85	1.01	1.25
ln(A/BE)	0.99	0.70	0.63	0.63	0.64	0.65	0.64	0.65	0.66	0.68	0.71	0.75	0.86
E/P dummy	1.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
E(+)/P	0.00	0.01	0.03	0.05	0.06	0.08	0.09	0.11	0.12	0.14	0.16	0.20	0.28
Firms	355	88	90	182	190	193	196	194	197	195	195	95	91

of book leverage. The regressions use the natural logs of the leverage ratios, ln(A/ME) and ln(A/BE), because preliminary tests indicated that logs are a good functional form for capturing leverage effects in average returns. Using logs also leads to a simple interpretation of the relation between the roles of leverage and book-to-market equity in average returns.

The FM regressions of returns on the leverage variables (Table III) pose a bit of a puzzle. The two leverage variables are related to average returns, but with opposite signs. As in Bhandari (1988), higher market leverage is associated with higher average returns; the average slopes for ln(A/ME) are always positive and more than 4 standard errors from 0. But higher book leverage is associated with lower average returns; the average slopes for ln(A/BE) are always negative and more than 4 standard errors from 0.

The puzzle of the opposite slopes on ln(A/ME) and ln(A/BE) has a simple solution. The average slopes for the two leverage variables are opposite in sign but close in absolute value, e.g., 0.50 and -0.57. Thus it is the difference between market and book leverage that helps explain average returns. But the difference between market and book leverage is book-to-market equity, $\ln(BE/ME) = \ln(A/ME) - \ln(A/BE)$. Table III shows that the average book-to-market slopes in the FM regressions are indeed close in absolute value to the slopes for the two leverage variables.

The close links between the leverage and book-to-market results suggest that there are two equivalent ways to interpret the book-to-market effect in average returns. A high ratio of book equity to market equity (a low stock price relative to book value) says that the market judges the prospects of a firm to be poor relative to firms with low BE/ME. Thus BE/ME may capture the relative-distress effect postulated by Chan and Chen (1991). A high book-to-market ratio also says that a firm's market leverage is high relative to its book leverage; the firm has a large amount of market-imposed leverage because the market judges that its prospects are poor and discounts its stock price relative to book value. In short, our tests suggest that the relative-distress effect, captured by BE/ME, can also be interpreted as an involuntary leverage effect, which is captured by the difference between A/ME and A/BE.

B.3. E/P

Ball (1978) posits that the earnings-price ratio is a catch-all for omitted risk factors in expected returns. If current earnings proxy for expected future earnings, high-risk stocks with high expected returns will have low prices relative to their earnings. Thus, E/P should be related to expected returns, whatever the omitted sources of risk. This argument only makes sense, however, for firms with positive earnings. When current earnings are negative, they are not a proxy for the earnings forecasts embedded in the stock price, and E/P is not a proxy for expected returns. Thus, the slope for E/P in the FM regressions is based on positive values; we use a dummy variable for E/P when earnings are negative.

The U-shaped relation between average return and E/P observed in Table IV is also apparent when the E/P variables are used alone in the FM regressions in Table III. The average slope on the E/P dummy variable (0.57% per month, 2.28 standard errors from 0) confirms that firms with negative earnings have higher average returns. The average slope for stocks with positive E/P (4.72% per month, 4.57 standard errors from 0) shows that average returns increase with E/P when it is positive.

Adding size to the regressions kills the explanatory power of the E/P dummy. Thus the high average returns of negative E/P stocks are better captured by their size, which Table IV says is on average small. Adding both size and book-to-market equity to the E/P regressions kills the E/P dummy and lowers the average slope on E/P from 4.72 to 0.87 ($t = 1.23$). In contrast, the average slopes for ln(ME) and ln(BE/ME) in the regressions that include E/P are similar to those in the regressions that explain average returns with only size and book-to-market equity. The results suggest that most of the relation between (positive) E/P and average return is due to the positive correlation between E/P and ln(BE/ME), illustrated in Table IV; firms with high E/P tend to have high book-to-market equity ratios.

IV. A Parsimonious Model for Average Returns

The results to here are easily summarized:

(1) When we allow for variation in β that is unrelated to size, there is no reliable relation between β and average return.
(2) The opposite roles of market leverage and book leverage in average returns are captured well by book-to-market equity.
(3) The relation between E/P and average return seems to be absorbed by the combination of size and book-to-market equity.

In a nutshell, market β seems to have no role in explaining the average returns on NYSE, AMEX, and NASDAQ stocks for 1963–1990, while size and book-to-market equity capture the cross-sectional variation in average stock returns that is related to leverage and E/P.

A. Average Returns, Size and Book-to-Market Equity

The average return matrix in Table V gives a simple picture of the two-dimensional variation in average returns that results when the 10 size deciles are each subdivided into 10 portfolios based on ranked values of BE/ME for individual stocks. Within a size decile (across a row of the average return matrix), returns typically increase strongly with BE/ME: on average, the returns on the lowest and highest BE/ME portfolios in a size decile differ by 0.99% (1.63% − 0.64%) per month. Similarly, looking down the columns of the average return matrix shows that there is a negative relation between average return and size: on average, the spread of returns across the size portfolios in a BE/ME group is 0.58% per month. The average return matrix gives life to the conclusion from the regressions that,

Table V

Average Monthly Returns on Portfolios Formed on Size and Book-to-Market Equity; Stocks Sorted by ME (Down) and then BE/ME (Across): July 1963 to December 1990

In June of each year t, the NYSE, AMEX, and NASDAQ stocks that meet the CRSP-COMPUSTAT data requirements are allocated to 10 size portfolios using the NYSE size (ME) breakpoints. The NYSE, AMEX, and NASDAQ stocks in each size decile are then sorted into 10 BE/ME portfolios using the book-to-market ratios for year $t-1$. BE/ME is the book value of common equity plus balance-sheet deferred taxes for fiscal year $t-1$, over market equity for December of year $t-1$. The equal-weighted monthly portfolio returns are then calculated for July of year t to June of year $t+1$.

Average monthly return is the time-series average of the monthly equal-weighted portfolio returns (in percent).

The All column shows average returns for equal-weighted size decile portfolios. The All row shows average returns for equal-weighted portfolios of the stocks in each BE/ME group.

	Book-to-Market Portfolios										
	All	Low	2	3	4	5	6	7	8	9	High
All	1.23	0.64	0.98	1.06	1.17	1.24	1.26	1.39	1.40	1.50	1.63
Small-ME	1.47	0.70	1.14	1.20	1.43	1.56	1.51	1.70	1.71	1.82	1.92
ME-2	1.22	0.43	1.05	0.96	1.19	1.33	1.19	1.58	1.28	1.43	1.79
ME-3	1.22	0.56	0.88	1.23	0.95	1.36	1.30	1.30	1.40	1.54	1.60
ME-4	1.19	0.39	0.72	1.06	1.36	1.13	1.21	1.34	1.59	1.51	1.47
ME-5	1.24	0.88	0.65	1.08	1.47	1.13	1.43	1.44	1.26	1.52	1.49
ME-6	1.15	0.70	0.98	1.14	1.23	0.94	1.27	1.19	1.19	1.24	1.50
ME-7	1.07	0.95	1.00	0.99	0.83	0.99	1.13	0.99	1.16	1.10	1.47
ME-8	1.08	0.66	1.13	0.91	0.95	0.99	1.01	1.15	1.05	1.29	1.55
ME-9	0.95	0.44	0.89	0.92	1.00	1.05	0.93	0.82	1.11	1.04	1.22
Large-ME	0.89	0.93	0.88	0.84	0.71	0.79	0.83	0.81	0.96	0.97	1.18

controlling for size, book-to-market equity captures strong variation in average returns, and controlling for book-to-market equity leaves a size effect in average returns.

B. The Interaction between Size and Book-to-Market Equity

The average of the monthly correlations between the cross-sections of ln(ME) and ln(BE/ME) for individual stocks is -0.26. The negative correlation is also apparent in the average values of ln(ME) and ln(BE/ME) for the portfolios sorted on ME or BE/ME in Tables II and IV. Thus, firms with low market equity are more likely to have poor prospects, resulting in low stock prices and high book-to-market equity. Conversely, large stocks are more likely to be firms with stronger prospects, higher stock prices, lower book-to-market equity, and lower average stock returns.

The correlation between size and book-to-market equity affects the regressions in Table III. Including ln(BE/ME) moves the average slope on ln(ME) from -0.15 ($t = -2.58$) in the univariate regressions to -0.11 ($t = -1.99$) in the bivariate regressions. Similarly, including ln(ME) in the regressions lowers the average slope on ln(BE/ME) from 0.50 to 0.35 (still a healthy 4.44 standard errors from 0). Thus, part of the size effect in the simple regressions is due to the fact that small ME stocks are more likely to have high book-to-market ratios, and part of the simple book-to-market effect is due to the fact that high BE/ME stocks tend to be small (they have low ME).

We should not, however, exaggerate the links between size and book-to-market equity. The correlation (−0.26) between ln(ME) and ln(BE/ME) is not extreme, and the average slopes in the bivariate regressions in Table III show that ln(ME) and ln(BE/ME) are both needed to explain the cross-section of average returns. Finally, the 10×10 average return matrix in Table V provides concrete evidence that, (a) controlling for size, book-to-market equity captures substantial variation in the cross-section of average returns, and (b) within BE/ME groups average returns are related to size.

C. Subperiod Averages of the FM Slopes

The message from the average FM slopes for 1963–1990 (Table III) is that size on average has a negative premium in the cross-section of stock returns, book-to-market equity has a positive premium, and the average premium for market β is essentially 0. Table VI shows the average FM slopes for two roughly equal subperiods (July 1963–December 1976 and January 1977–December 1990) from two regressions: (a) the cross-section of stock returns on size, ln(ME), and book-to-market equity, ln(BE/ME), and (b) returns on β, ln(ME), and ln(BE/ME). For perspective, average returns on the value-weighted and equal-weighted (VW and EW) portfolios of NYSE stocks are also shown.

In FM regressions, the intercept is the return on a standard portfolio (the weights on stocks sum to 1) in which the weighted averages of the explanatory variables are 0 (Fama (1976), chapter 9). In our tests, the intercept is weighted toward small stocks (ME is in millions of dollars so ln(ME) = 0 implies ME = \$1 million) and toward stocks with relatively high book-to-market ratios (Table IV says that ln(BE/ME) is negative for the typical firm, so ln(BE/ME) = 0 is toward the high end of the sample ratios). Thus it is not surprising that the average intercepts are always large relative to their standard errors and relative to the returns on the NYSE VW and EW portfolios.

Like the overall period, the subperiods do not offer much hope that the average premium for β is economically important. The average FM slope for β is only slightly positive for 1963–1976 (0.10% per month, $t = 0.25$), and it is negative for 1977–1990 (−0.44% per month, $t = -1.17$). There is a hint that the size effect is weaker in the 1977–1990 period, but inferences about the average size slopes for the subperiods lack power.

Unlike the size effect, the relation between book-to-market equity and average return is so strong that it shows up reliably in both the 1963–1976 and the 1977–1990 subperiods. The average slopes for ln(BE/ME) are all more than 2.95 standard errors from 0, and the average slopes for the

Table VI

Subperiod Average Monthly Returns on the NYSE Equal-Weighted and Value-Weighted Portfolios and Subperiod Means of the Intercepts and Slopes from the Monthly FM Cross-Sectional Regressions of Returns on (a) Size (ln(ME)) and Book-to-Market Equity (ln(BE/ME)), and (b) β, ln(ME), and ln(BE/ME)

Mean is the time-series mean of a monthly return, Std is its time-series standard deviation, and t(Mn) is Mean divided by its time-series standard error.

	7/63–12/90 (330 Mos.)			7/63–12/76 (162 Mos.)			1/77–12/90 (168 Mos.)		
Variable	Mean	Std	t(Mn)	Mean	Std	t(Mn)	Mean	Std	t(Mn)
	NYSE Value-Weighted (VW) and Equal-Weighted (EW) Portfolio Returns								
VW	0.81	4.47	3.27	0.56	4.26	1.67	1.04	4.66	2.89
EW	0.97	5.49	3.19	0.77	5.70	1.72	1.15	5.28	2.82
	$R_{it} = a + b_{2t}\ln(ME_{it}) + b_{3t}\ln(BE/ME_{it}) + e_{it}$								
a	1.77	8.51	3.77	1.86	10.10	2.33	1.69	6.67	3.27
b_2	−0.11	1.02	−1.99	−0.16	1.25	−1.62	−0.07	0.73	−1.16
b_3	0.35	1.45	4.43	0.36	1.53	2.96	0.35	1.37	3.30
	$R_{it} = a + b_{1t}\beta_{it} + b_{2t}\ln(ME_{it}) + b_{3t}\ln(BE/ME_{it}) + e_{it}$								
a	2.07	5.75	6.55	1.73	6.22	3.54	2.40	5.25	5.92
b_1	−0.17	5.12	−0.62	0.10	5.33	0.25	−0.44	4.91	−1.17
b_2	−0.12	0.89	−2.52	−0.15	1.03	−1.91	−0.09	0.74	−1.64
b_3	0.33	1.24	4.80	0.34	1.36	3.17	0.31	1.10	3.67

subperiods (0.36 and 0.35) are close to the average slope (0.35) for the overall period. The subperiod results thus support the conclusion that, among the variables considered here, book-to-market equity is consistently the most powerful for explaining the cross-section of average stock returns.

Finally, Roll (1983) and Keim (1983) show that the size effect is stronger in January. We have examined the monthly slopes from the FM regressions in Table VI for evidence of a January seasonal in the relation between book-to-market equity and average return. The average January slopes for ln(BE/ME) are about twice those for February to December. Unlike the size effect, however, the strong relation between book-to-market equity and average return is not special to January. The average monthly February-to-December slopes for ln(BE/ME) are about 4 standard errors from 0, and they are close to (within 0.05 of) the average slopes for the whole year. Thus, there is a January seasonal in the book-to-market equity effect, but the positive relation between BE/ME and average return is strong throughout the year.

D. β and the Market Factor: Caveats

Some caveats about the negative evidence on the role of β in average returns are in order. The average premiums for β, size, and book-to-market equity depend on the definitions of the variables used in the regressions. For example, suppose we replace book-to-market equity (ln(BE/ME)) with book equity (ln(BE)). As long as size (ln(ME)) is also in the regression, this change will not affect the intercept, the fitted values or the R^2. But the change, in variables increases the average slope (and the t-statistic) on ln(ME). In other words, it increases the risk premium associated with size. Other redefinitions of the β, size, and book-to-market variables will produce different regression slopes and perhaps different inferences about average premiums, including possible resuscitation of a role for β. And, of course, at the moment, we have no theoretical basis for choosing among different versions of the variables.

Moreover, the tests here are restricted to stocks. It is possible that including other assets will change the inferences about the average premiums for β, size, and book-to-market equity. For example, the large average intercepts for the FM regressions in Table VI suggest that the regressions will not do a good job on Treasury bills, which have low average returns and are likely to have small loadings on the underlying market, size, and book-to-market factors in returns. Extending the tests to bills and other bonds may well change our inferences about average risk premiums, including the revival of a role for market β.

We emphasize, however, that different approaches to the tests are not likely to revive the Sharpe-Lintner-Black model. Resuscitation of the SLB model requires that a better proxy for the market portfolio (a) overturns our evidence that the simple relation between β and average stock returns is flat and (b) leaves β as the only variable relevant for explaining average returns. Such results seem unlikely, given Stambaugh's (1982) evidence that tests of the SLB model do not seem to be sensitive to the choice of a market proxy. Thus, if there is a role for β in average returns, it is likely to be found in a multi-factor model that transforms the flat simple relation between average return and β into a positively sloped conditional relation.

V. Conclusions and Implications

The Sharpe-Lintner-Black model has long shaped the way academics and practitioners think about average return and risk. Black, Jensen, and Scholes (1972) and Fama and MacBeth (1973) find that, as predicted by the model, there is a positive simple relation between average return and market β during the early years (1926–1968) of the CRSP NYSE returns file. Like Reinganum (1981) and Lakonishok and Shapiro (1986), we find that this simple relation between β and average return disappears during the more recent 1963–1990 period. The appendix that follows shows that the relation between β and average return is also weak in the last half century (1941–1990) of returns on NYSE stocks. In short, our tests do not support the central prediction of the SLB model, that average stock returns are positively related to market β.

Banz (1981) documents a strong negative relation between average return and firm size. Bhandari (1988) finds that average return is positively related to leverage, and Basu (1983) finds a positive relation between average return and E/P. Stattman (1980) and Rosenberg, Reid, and Lanstein (1985) document a positive relation between average return and book-to-market equity for U.S. stocks, and Chan, Hamao, and Lakonishok (1992) find that BE/ME is also a powerful variable for explaining average returns on Japanese stocks.

Variables like size, E/P, leverage, and book-to-market equity are all scaled versions of a firm's stock price. They can be regarded as different ways of extracting information from stock prices about the cross-section of expected stock returns (Ball (1978), Keim (1988)). Since all these variables are scaled versions of price, it is reasonable to expect that some of them are redundant for explaining average returns. Our main result is that for the 1963–1990 period, size and book-to-market equity capture the cross-sectional variation in average stock returns associated with size, E/P, book-to-market equity, and leverage.

A. Rational Asset-Pricing Stories

Are our results consistent with asset-pricing theory? Since the FM intercept is constrained to be the same for all stocks, FM regressions always impose a linear factor structure on returns and expected returns that is consistent with the multifactor asset-pricing models of Merton (1973) and Ross (1976). Thus our tests impose a rational asset-pricing framework on the relation between average return and size and book-to-market equity.

Even if our results are consistent with asset-pricing theory, they are not economically satisfying. What is the economic explanation for the roles of size and book-to-market equity in average returns? We suggest several paths of inquiry.

(a) The intercepts and slopes in the monthly FM regressions of returns on ln(ME) and ln(BE/ME) are returns on portfolios that mimic the underlying common risk factors in returns proxied by size and book-to-market equity (Fama (1976), chapter 9). Examining the relations between the returns on these portfolios and economic variables that measure variation in business conditions might help expose the nature of the economic risks captured by size and book-to-market equity.

(b) Chan, Chen, and Hsieh (1985) argue that the relation between size and average return proxies for a more fundamental relation between expected returns and economic risk factors. Their most powerful factor in explaining the size effect is the difference between the monthly returns on low- and high-grade corporate bonds, which in principle captures a kind of default risk in returns that is priced. It would be interesting to test whether loadings on this or other economic factors, such as those of Chen, Roll, and Ross (1986), can explain the roles of size and book-to-market equity in our tests.

(c) In a similar vein, Chan and Chen (1991) argue that the relation between size and average return is a relative-prospects effect. The earning prospects of distressed firms are more sensitive to economic conditions. This results in a distress factor in returns that is priced in expected returns. Chan and Chen construct two mimicking portfolios for the distress factor, based on dividend changes and leverage. It would be interesting to check whether loadings on their distress factors absorb the size and book-to-market equity effects in average returns that are documented here.

(d) In fact, if stock prices are rational, BE/ME, the ratio of the book value of a stock to the market's assessment of its value, should be a direct indicator of the relative prospects of firms. For example, we expect that high BE/ME firms have low earnings on assets relative to low BE/ME firms. Our work (in progress) suggests that there is indeed a clean separation between high and low BE/ME firms on various measures of economic fundamentals. Low BE/ME firms are persistently strong performers, while the economic performance of high BE/ME firms is persistently weak.

B. *Irrational Asset-Pricing Stories*

The discussion above assumes that the asset-pricing effects captured by size and book-to-market equity are rational. For BE/ME, our most powerful expected-return variable, there is an obvious alternative. The cross-section of book-to-market ratios might result from market overreaction to the relative prospects of firms. If overreaction tends to be corrected, BE/ME will predict the cross-section of stock returns.

Simple tests do not confirm that the size and book-to-market effects in average returns are due to market overreaction, at least of the type posited by DeBondt and Thaler (1985). One overreaction measure used by DeBondt and Thaler is a stock's most recent 3-year return. Their overreaction story predicts that 3-year losers have strong post-ranking returns relative to 3-year winners. In FM regressions (not shown) for individual stocks, the 3-year lagged return shows no power even when used alone to explain average returns. The univariate average slope for the lagged return is negative, -6 basis points per month, but less than 0.5 standard errors from 0.

C. *Applications*

Our main result is that two easily measured variables, size and book-to-market equity, seem to describe the cross-section of average stock returns. Prescriptions for using this evidence depend on (a) whether it will persist, and (b) whether it results from rational or irrational asset-pricing.

It is possible that, by chance, size and book-to-market equity happen to describe the cross-section of average returns in our sample, but they were and are unrelated to expected returns. We put little weight on this possibility, especially for book-to-market equity. First, although BE/ME has long been touted as a measure of the return prospects of stocks, there is no evidence that its explanatory power deteriorates through time. The 1963–1990 relation between BE/ME and average return is strong, and remarkably similar for the 1963–1976 and 1977–1990 subperiods. Second, our preliminary work on economic fundamentals suggests that high-BE/ME firms tend to be persistently poor earners relative to low-BE/ME firms. Similarly, small firms have a long period of poor earnings during the 1980s not shared with big firms. The systematic patterns in fundamentals give us some hope that size and book-to-market equity proxy for risk factors in returns, related to relative earning prospects, that are rationally priced in expected returns.

If our results are more than chance, they have practical implications for portfolio formation and performance evaluation by investors whose primary concern is long-term average returns. If asset-pricing is rational, size and BE/ME must proxy for risk. Our results then imply that the performance of managed portfolios (e.g., pension funds and mutual funds) can be evaluated by comparing their average returns with the average returns of benchmark portfolios with similar size and BE/ME characteristics. Likewise, the expected returns for different portfolio strategies can be estimated from the historical average returns of portfolios with matching size and BE/ME properties.

If asset-pricing is irrational and size and BE/ME do not proxy for risk, our results might still be used to evaluate portfolio performance and measure the expected returns from alternative investment strategies. If stock prices are irrational, however, the likely persistence of the results is more suspect.

Appendix
Size Versus β: 1941–1990

Our results on the absence of a relation between β and average stock returns for 1963–1990 are so contrary to the tests of the Sharpe-Lintner-Black model by Black, Jensen, and Scholes (1972), Fama and MacBeth (1973), and (more recently) Chan and Chen (1988), that further tests are appropriate. We examine the roles of size and β in the average returns on NYSE stocks for the half-century 1941–1990, the longest available period that avoids the high volatility of returns in the Great Depression. We do not include the accounting variables in the tests because of the strong selection bias (toward successful firms) in the COMPUSTAT data prior to 1962.

We first replicate the results of Chan and Chen (1988). Like them, we find that when portfolios are formed on size alone, there are strong relations between average return and either size or β; average return increases with β and decreases with size. For size portfolios, however, size (ln(ME)) and β are almost perfectly correlated (-0.98), so it is difficult to distinguish between the roles of size and β in average returns.

One way to generate strong variation in β that is unrelated to size is to form portfolios on size and then on β. As in Tables I to III, we find that the resulting independent variation in β just about washes out the positive simple relation between average return and β observed when portfolios are formed on size alone. The results for NYSE stocks for 1941–1990 are thus much like those for NYSE, AMEX, and NASDAQ stocks for 1963–1990.

This appendix also has methodological goals. For example, the FM regressions in Table III use returns on individual stocks as the dependent variable. Since we allocate portfolio βs to individual stocks but use firm-specific values of other variables like size, β may be at a disadvantage in the regressions for individual stocks. This appendix shows, however, that regressions for portfolios, which put β and size on equal footing, produce results comparable to those for individual stocks.

A. *Size Portfolios*

Table AI shows average monthly returns and market βs for 12 portfolios of NYSE stocks formed on the basis of size (ME) at the end of each year from 1940 to 1989. For these size portfolios, there is a strong positive relation between average return and β. Average returns fall from 1.96% per month for the smallest ME portfolio (1A) to 0.93% for the largest (10B) and β falls from 1.60 to 0.95. (Note also that, as claimed earlier, estimating β as the sum of the slopes in the regression of a portfolio's return on the current and prior month's NYSE value-weighted return produces much larger βs for the smallest ME portfolios and slightly smaller βs for the largest ME portfolios.)

The FM regressions in Table AI confirm the positive simple relation between average return and β for size portfolios. In the regressions of the size-portfolio returns on β alone, the average premium for a unit of β is 1.45% per month. In the regressions of individual stock returns on β (where stocks are assigned the β of their size portfolio), the premium for a unit of β is 1.39%. Both estimates are about 3 standard errors from 0. Moreover, the βs of size portfolios do not leave a residual size effect; the average residuals from the simple regressions of returns on β in Table AI show no relation to size. These positive SLB results for 1941–1990 are like those obtained by Chan and Chen (1988) in tests on size portfolios for 1954–1983.

There is, however, evidence in Table AI that all is not well with the βs of the size portfolios. They do a fine job on the relation between size and average return, but they do a lousy job on their main task, the relation between β and average return. When the residuals from the regressions of returns on β are grouped using the pre-ranking βs of individual stocks, the average residuals are strongly positive for low-β stocks (0.51% per month for group 1A) and negative for high-β stocks (−1.05% for 10B). Thus the market lines estimated with size-portfolio βs exaggerate the tradeoff of average return for β; they underestimate average returns on low-β stocks and overestimate average returns on high-β stocks. This pattern in the β-sorted average residuals for individual stocks suggests that (a) there is variation in β across stocks that is lost in the size portfolios, and (b) this variation in β is not rewarded as well as the variation in β that is related to size.

B. *Two-Pass Size-β Portfolios*

Like Table I, Table AII shows that subdividing size deciles using the (pre-ranking) βs of individual stocks results in strong variation in β that is

Table AI

Average Returns, Post-Ranking βs and Fama-MacBeth Regression Slopes for Size Portfolios of NYSE Stocks: 1941-1990

At the end of each year $t-1$, stocks are assigned to 12 portfolios using ranked values of ME. Included are all NYSE stocks that have a CRSP price and shares for December of year $t-1$ and returns for at least 24 of the 60 months ending in December of year $t-1$ (for pre-ranking β estimates). The middle 8 portfolios cover size deciles 2 to 9. The 4 extreme portfolios (1A, 1B, 10A, and 10B) split the smallest and largest deciles in half. We compute equal-weighted returns on the portfolios for the 12 months of year t using all surviving stocks. Average Return is the time-series average of the monthly portfolio returns for 1941-1990, in percent. Average firms is the average number of stocks in the portfolios each month. The simple βs are estimated by regressing the 1941-1990 sample of post-ranking monthly returns for a size portfolio on the current month's value-weighted NYSE portfolio return. The sum βs are the sum of the slopes from a regression of the post-ranking monthly returns on the current and prior month's VW NYSE returns.

The independent variables in the Fama-MacBeth regressions are defined for each firm at the end of December of each year $t-1$. Stocks are assigned the post-ranking (sum) β of the size portfolio they are in at the end of year $t-1$. ME is price times shares outstanding at the end of year $t-1$. In the individual-stock regressions, these values of the explanatory variables are matched with CRSP returns for each of the 12 months of year t. The portfolio regressions match the equal-weighted portfolio returns with the equal-weighted averages of β and ln(ME) for the surviving stocks in each month of year t. Slope is the average of the (600) monthly FM regression slopes and SE is the standard error of the average slope. The residuals from the monthly regressions for year t are grouped into 12 portfolios on the basis of size (ME) or pre-ranking β (estimated with 24 to 60 months of data, as available) at the end of year $t-1$. The average residuals are the time-series averages of the monthly equal-weighted portfolio residuals, in percent. The average residuals for regressions (1) and (2) (not shown) are quite similar to those for regressions (4) and (5) (shown).

	Portfolios Formed on Size											
	1A	1B	2	3	4	5	6	7	8	9	10A	10B
Ave. return	1.96	1.59	1.44	1.36	1.28	1.24	1.23	1.17	1.15	1.13	0.97	0.93
Ave. firms	57	56	110	107	107	108	111	113	115	118	59	59
Simple β	1.29	1.24	1.21	1.19	1.16	1.13	1.13	1.12	1.09	1.05	1.00	0.98
Standard error	0.07	0.05	0.04	0.03	0.02	0.02	0.02	0.02	0.01	0.01	0.01	0.01
Sum β	1.60	1.44	1.37	1.32	1.26	1.23	1.19	1.17	1.12	1.06	0.99	0.95
Standard error	0.10	0.06	0.05	0.04	0.03	0.03	0.03	0.02	0.02	0.01	0.01	0.01

Table AI—*Continued*

	Portfolio Regressions				Individual Stock Regressions			
	(1) β	(2) ln(ME)	(3) β and ln(ME)		(4) β	(5) ln(ME)	(6) β and ln(ME)	
Slope	1.45	−0.137	3.05	0.149	1.39	−0.133	0.71	−0.060
SE	0.47	0.044	1.51	0.115	0.46	0.043	0.81	0.062

Average Residuals for Stocks Grouped on Size

	1A	1B	2	3	4	5	6	7	8	9	10A	10B
Regression (4)	0.17	0.00	−0.04	−0.06	−0.05	−0.04	0.00	−0.03	0.03	0.08	0.01	0.04
Standard error	0.11	0.06	0.04	0.04	0.04	0.04	0.03	0.03	0.03	0.03	0.05	0.06
Regression (5)	0.30	0.02	−0.05	−0.06	−0.08	−0.07	−0.03	−0.04	0.02	0.08	0.01	0.13
Standard error	0.14	0.07	0.04	0.04	0.04	0.04	0.04	0.03	0.03	0.03	0.04	0.07
Regression (6)	0.20	0.02	−0.05	−0.07	−0.08	−0.06	−0.01	−0.02	0.04	0.09	0.00	0.06
Standard error	0.10	0.06	0.04	0.04	0.04	0.04	0.03	0.03	0.03	0.03	0.05	0.05

Average Residuals for Stocks Grouped on Pre-Ranking β

	1A	1B	2	3	4	5	6	7	8	9	10A	10B
Regression (4)	0.51	0.61	0.38	0.32	0.16	0.12	0.03	−0.10	−0.27	−0.31	−0.66	−1.05
Standard error	0.21	0.19	0.13	0.08	0.04	0.03	0.04	0.05	0.09	0.11	0.18	0.23
Regression (5)	−0.10	0.00	0.02	0.09	0.05	0.07	0.05	0.00	−0.03	−0.01	−0.11	−0.33
Standard error	0.11	0.10	0.07	0.05	0.04	0.03	0.03	0.04	0.05	0.07	0.10	0.13
Regression (6)	0.09	0.25	0.13	0.19	0.11	0.14	0.09	0.01	−0.11	−0.12	−0.38	−0.70
Standard error	0.41	0.37	0.24	0.14	0.07	0.04	0.04	0.09	0.16	0.21	0.34	0.43

Table AII

Properties of Portfolios Formed on Size and Pre-Ranking β: NYSE Stocks Sorted by ME (Down) then Pre-Ranking β (Across): 1941–1990

At the end of year $t-1$, the NYSE stocks on CRSP are assigned to 10 size (ME) portfolios Each size decile is subdivided into 10 β portfolios using pre-ranking βs of individual stocks, estimated with 24 to 60 monthly returns (as available) ending in December of year $t-1$. The equal-weighted monthly returns on the resulting 100 portfolios are then calculated for year t. The average returns are the time-series averages of the monthly returns, in percent. The post-ranking βs use the full 1941-1990 sample of post-ranking returns for each portfolio. The pre- and post-ranking βs are the sum of the slopes from a regression of monthly returns on the current and prior month's NYSE value-weighted market return. The average size for a portfolio is the time-series average of each month's average value of ln(ME) for stocks in the portfolio. ME is denominated in millions of dollars. There are, on average, about 10 stocks in each size-β portfolio each month. The All column shows parameter values for equal-weighted size-decile (ME) portfolios. The All rows show parameter values for equal-weighted portfolios of the stocks in each β group.

	All	Low-β	β-2	β-3	β-4	β-5	β-6	β-7	β-8	β-9	High-β
Panel A: Average Monthly Return (in Percent)											
All		1.22	1.30	1.32	1.35	1.36	1.34	1.29	1.34	1.14	1.10
Small-ME	1.78	1.74	1.76	2.08	1.91	1.92	1.72	1.77	1.91	1.56	1.46
ME-2	1.44	1.41	1.35	1.33	1.61	1.72	1.59	1.40	1.62	1.24	1.11
ME-3	1.36	1.21	1.40	1.22	1.47	1.34	1.51	1.33	1.57	1.33	1.21
ME-4	1.28	1.26	1.29	1.19	1.27	1.51	1.30	1.19	1.56	1.18	1.00
ME-5	1.24	1.22	1.30	1.28	1.33	1.21	1.37	1.41	1.31	0.92	1.06
ME-6	1.23	1.21	1.32	1.37	1.09	1.34	1.10	1.40	1.21	1.22	1.08
ME-7	1.17	1.08	1.23	1.37	1.27	1.19	1.34	1.10	1.11	0.87	1.17
ME-8	1.15	1.06	1.18	1.26	1.25	1.26	1.17	1.16	1.05	1.08	1.04
ME-9	1.13	0.99	1.13	1.00	1.24	1.28	1.31	1.15	1.11	1.09	1.05
Large-ME	0.95	0.99	1.01	1.12	1.01	0.89	0.95	0.95	1.00	0.90	0.68

Table AII—*Continued*

	All	Low-β	β-2	β-3	β-4	β-5	β-6	β-7	β-8	β-9	High-β
Panel B: Post-Ranking β											
All		0.76	0.95	1.05	1.14	1.22	1.26	1.34	1.38	1.49	1.69
Small-ME	1.52	1.17	1.40	1.31	1.50	1.46	1.50	1.69	1.60	1.75	1.92
ME-2	1.37	0.86	1.09	1.12	1.24	1.39	1.42	1.48	1.60	1.69	1.91
ME-3	1.32	0.88	0.96	1.18	1.19	1.33	1.40	1.43	1.56	1.64	1.74
ME-4	1.26	0.69	0.95	1.06	1.15	1.24	1.29	1.46	1.43	1.64	1.83
ME-5	1.23	0.70	0.95	1.04	1.10	1.22	1.32	1.34	1.41	1.56	1.72
ME-6	1.19	0.68	0.86	1.04	1.13	1.20	1.20	1.35	1.36	1.48	1.70
ME-7	1.17	0.67	0.88	0.95	1.14	1.18	1.26	1.27	1.32	1.44	1.68
ME-8	1.12	0.64	0.83	0.99	1.06	1.14	1.14	1.21	1.26	1.39	1.58
ME-9	1.06	0.68	0.81	0.94	0.96	1.06	1.11	1.18	1.22	1.25	1.46
Large-ME	0.97	0.65	0.73	0.90	0.91	0.97	1.01	1.01	1.07	1.12	1.38
Panel C: Average Size (ln(ME))											
All		4.39	4.39	4.40	4.40	4.39	4.40	4.38	4.37	4.37	4.34
Small-ME	1.93	2.04	1.99	2.00	1.96	1.92	1.92	1.91	1.90	1.87	1.80
ME-2	2.80	2.81	2.79	2.81	2.83	2.80	2.79	2.80	2.80	2.79	2.79
ME-3	3.27	3.28	3.27	3.28	3.27	3.27	3.28	3.29	3.27	3.27	3.26
ME-4	3.67	3.67	3.67	3.67	3.68	3.68	3.67	3.68	3.66	3.67	3.67
ME-5	4.06	4.07	4.06	4.05	4.06	4.07	4.06	4.05	4.05	4.06	4.06
ME-6	4.45	4.45	4.44	4.46	4.45	4.45	4.45	4.45	4.44	4.45	4.45
ME-7	4.87	4.86	4.87	4.86	4.87	4.87	4.88	4.87	4.87	4.85	4.87
ME-8	5.36	5.38	5.38	5.38	5.35	5.36	5.37	5.37	5.36	5.35	5.34
ME-9	5.98	5.96	5.98	5.99	6.00	5.98	5.98	5.97	5.95	5.96	5.96
Large-ME	7.12	7.10	7.12	7.16	7.17	7.20	7.29	7.14	7.09	7.04	6.83

independent of size. The β sort of a size decile always produces portfolios with similar average ln(ME) but much different (post-ranking) βs. Table AII also shows, however, that investors are not compensated for the variation in β that is independent of size. Despite the wide range of βs in each size decile, average returns show no tendency to increase with β. AII

The FM regressions in Table AIII formalize the roles of size and β in NYSE average returns for 1941–1990. The regressions of returns on β alone show that using the βs of the portfolios formed on size and β, rather than size alone, causes the average slope on β to fall from about 1.4% per month (Table AI) to about 0.23% (about 1 standard error from 0). Thus, allowing for variation in β that is unrelated to size flattens the relation between average return and β, to the point where it is indistinguishable from no relation at all.

The flatter market lines in Table AIII succeed, however, in erasing the negative relation between β and average residuals observed in the regressions of returns on β alone in Table AI. Thus, forming portfolios on size and β (Table AIII) produces a better description of the simple relation between average return and β than forming portfolios on size alone (Table AI). This improved description of the relation between average return and β is evidence that the β estimates for the two-pass size-β portfolios capture variation in true βs that is missed when portfolios are formed on size alone.

Unfortunately, the flatter market lines in Table AIII have a cost, the emergence of a residual size effect. Grouped on the basis of ME for individual stocks, the average residuals from the univariate regressions of returns on the βs of the 100 size-β portfolios are strongly positive for small stocks and negative for large stocks (0.60% per month for the smallest ME group, 1A, and -0.27% for the largest, 10B). Thus, when we allow for variation in β that is independent of size, the resulting βs leave a large size effect in average returns. This residual size effect is much like that observed by Banz (1981) with the βs of portfolios formed on size and β.

The correlation between size and β is -0.98 for portfolios formed on size alone. The independent variation in β obtained with the second-pass sort on β lowers the correlation to -0.50. The lower correlation means that bivariate regressions of returns on β and ln(ME) are more likely to distinguish true size effects from true β effects in average returns.

The bivariate regressions (Table AIII) that use the βs of the size-β portfolios are more bad news for β. The average slopes for ln(ME) are close to the values in the univariate size regressions, and almost 4 standard errors from 0, but the average slopes for β are negative and less than 1 standard error from 0. The message from the bivariate regressions is that there is a strong relation between size and average return. But like the regressions in Table AIII that explain average returns with β alone, the bivariate regressions say that there is no reliable relation between β and average returns when the tests use βs that are not close substitutes for size. These uncomfortable SLB results for NYSE stocks for 1941–1990 are much like those for NYSE, AMEX, and NASDAQ stocks for 1963–1990 in Table III.

C. Subperiod Diagnostics

Our results for 1941–1990 seem to contradict the evidence in Black, Jensen, and Scholes (BJS) (1972) and Fama and MacBeth (FM) (1973) that there is a reliable positive relation between average return and β. The βs in BJS and FM are from portfolios formed on β alone, and the market proxy is the NYSE equal-weighted portfolio. We use the βs of portfolios formed on size and β, and our market is the value-weighted NYSE portfolio. We can report, however, that our inference that there isn't much relation between β and average return is unchanged when (a) the market proxy is the NYSE EW portfolio, (b) portfolios are formed on just (pre-ranking) βs, or (c) the order of forming the size-β portfolios is changed from size then β to β then size.

A more important difference between our results and the earlier studies is the sample periods. The tests in BJS and FM end in the 1960s. Table AIV shows that when we split the 50-year 1941–1990 period in half, the univariate FM regressions of returns on β produce an average slope for 1941–1965 (0.50% per month, $t = 1.82$) more like that of the earlier studies. In contrast, the average slope on β for 1966–1990 is close to 0 (-0.02, $t = 0.06$).

But Table AIV also shows that drawing a distinction between the results for 1941–1965 and 1966–1990 is misleading. The stronger tradeoff of average return for β in the simple regressions for 1941–1965 is due to the first 10 years, 1941–1950. This is the only period in Table AIV that produces an average premium for β (1.26% per month) that is both positive and more than 2 standard errors from 0. Conversely, the weak relation between β and average return for 1966–1990 is largely due to 1981–1990. The strong negative average slope in the univariate regressions of returns on β for 1981–1990 (-1.01, $t = -2.10$) offsets a positive slope for 1971–1980 (0.82, $t = 1.27$).

The subperiod variation in the average slopes from the FM regressions of returns on β alone seems moot, however, given the evidence in Table AIV that adding size always kills any positive tradeoff of average return for β in the subperiods. Adding size to the regressions for 1941–1965 causes the average slope for β to drop from 0.50 ($t = 1.82$) to 0.07 ($t = 0.28$). In contrast, the average slope on size in the bivariate regressions (-0.16, $t = -2.97$) is close to its value (-0.17, $t = -2.88$) in the regressions of returns on ln(ME) alone. Similar comments hold for 1941–1950. In short, any evidence of a positive average premium for β in the subperiods seems to be a size effect in disguise.

D. Can the SLB Model Be Saved?

Before concluding that β has no explanatory power, it is appropriate to consider other explanations for our results. One possibility is that the variation in β produced by the β sorts of size deciles in just sampling error. If so, it is not surprising that the variation in β within a size decile is unrelated to average return, or that size dominates β in bivariate tests. The standard errors of the βs suggest, however, that this explanation cannot save the SLB

Table AIII

Average Slopes, Their Standard Errors (SE), and Average Residuals from Monthly FM Regressions for Individual NYSE Stocks and for Portfolios Formed on Size and Pre-Ranking β: 1941–1990

Stocks are assigned the post-ranking β of the size-β portfolio they are in at the end of year $t-1$ (Table AII). ln(ME) is the natural log of price times shares outstanding at the end of year $t-1$. In the individual-stock regressions, these values of the explanatory variables are matched with CRSP returns for each of the 12 months in year t. The portfolio regressions match the equal-weighted portfolio returns for the size-β portfolios (Table AII) with the equal-weighted averages of β and ln(ME) for the surviving stocks in each month of year t. Slope is the time-series average of the monthly regression slopes from 1941–1990 (600 months); SE is the time-series standard error of the average slope.

The residuals from the monthly regressions in year t are grouped into 12 portfolios on the basis of size or pre-ranking β (estimated with 24 to 60 months of returns, as available) as of the end of year $t-1$. The average residuals are the time-series averages of the monthly equal-weighted averages of the residuals in percent. The average residuals (not shown) from the FM regressions (1) to (3) that use the returns on the 100 size-β portfolios as the dependent variable are always within 0.01 of those from the regressions for individual stock returns. This is not surprising given that the correlation between the time-series of 1941–1990 monthly FM slopes on β or ln(ME) for the comparable portfolio and individual stock regressions is always greater than 0.99.

	Portfolio Regressions				Individual Stock Regressions			
	(1) β	(2) ln(ME)	(3) β and ln(ME)		(4) β	(5) ln(ME)	(6) β and ln(ME)	
Slope	0.22	−0.128	−0.13	−0.143	0.24	−0.133	−0.14	−0.147
SE	0.24	0.043	0.21	0.039	0.23	0.043	0.21	0.039

Average Residuals for Stocks Grouped on Size

	1A	1B	2	3	4	5	6	7	8	9	10A	10B
Regression (4)	0.60	0.26	0.13	0.06	−0.01	−0.03	−0.03	−0.09	−0.10	−0.11	−0.25	−0.27
Standard error	0.21	0.10	0.06	0.04	0.04	0.04	0.04	0.04	0.04	0.05	0.06	0.08
Regression (5)	0.30	0.02	−0.05	−0.06	−0.08	−0.07	−0.03	−0.04	0.02	0.08	0.01	0.13
Standard error	0.14	0.07	0.04	0.04	0.04	0.04	0.04	0.03	0.03	0.03	0.04	0.07
Regression (6)	0.31	0.02	−0.05	−0.06	−0.09	−0.07	−0.03	−0.04	0.02	0.08	0.01	0.13
Standard error	0.14	0.07	0.04	0.04	0.04	0.04	0.04	0.03	0.03	0.03	0.04	0.07

Table AIII—*Continued*

	Portfolio Regressions						Individual Stock Regressions					
	(1) β		(2) ln(ME)		(3) β and ln(ME)		(4) β		(5) ln(ME)		(6) β and ln(ME)	
	Average Residuals for Stocks Grouped on Pre-Ranking β											
	1A	1B	2	3	4	5	6	7	8	9	10A	10B
Regression (4)	−0.08	0.03	−0.01	0.08	0.04	0.08	0.04	0.02	−0.03	0.02	−0.11	−0.32
Standard error	0.07	0.05	0.03	0.03	0.03	0.03	0.04	0.04	0.04	0.04	0.06	0.07
Regression (5)	−0.10	0.00	0.02	0.09	0.05	0.07	0.05	0.00	−0.03	−0.01	−0.11	−0.33
Standard error	0.11	0.10	0.07	0.05	0.04	0.03	0.03	0.04	0.05	0.07	0.10	0.13
Regression (6)	−0.17	−0.07	−0.02	0.07	0.04	0.06	0.05	0.03	0.00	0.04	−0.04	−0.23
Standard error	0.05	0.04	0.03	0.03	0.03	0.03	0.03	0.03	0.04	0.04	0.06	0.07

Table AIV

Subperiod Average Returns on the NYSE Value-Weighted and Equal-Weighted Portfolios and Average Values of the Intercepts and Slopes for the FM Cross-Sectional Regressions of Individual Stock Returns on β and Size (ln(ME))

Mean is the average VW or EW return or an average slope from the monthly cross-sectional regressions of individual stock returns on β and/or ln(ME). Std is the standard deviation of the time-series of returns or slopes, and t(Mn) is Mean over its time-series standard error. The average slopes (not shown) from the FM regressions that use the returns on the 100 size-β portfolios of Table AII as the dependent variable are quite close to those for individual stock returns. (The correlation between the 1941–1990 month-by-month slopes on β or ln(ME) for the comparable portfolio and individual stock regressions is always greater than 0.99.)

Panel A

Variable	1941–1990 (600 Mos.) Mean	Std	t(Mn)	1941–1965 (300 Mos.) Mean	Std	t(Mn)	1966–1990 (300 Mos.) Mean	Std	t(Mn)
	NYSE Value-Weighted (VW) and Equal-Weighted (EW) Portfolio Returns								
VW	0.93	4.15	5.49	1.10	3.58	5.30	0.76	4.64	2.85
EW	1.12	5.10	5.37	1.33	4.42	5.18	0.91	5.70	2.77
	$R_{it} = a + b_{1t}\beta_{it} + e_{it}$								
a	0.98	3.93	6.11	0.84	3.18	4.56	1.13	4.57	4.26
b_1	0.24	5.52	1.07	0.50	4.75	1.82	−0.02	6.19	−0.06
	$R_{it} = a + b_{2t}\ln(ME_{it}) + e_{it}$								
a	1.70	8.24	5.04	1.88	6.43	5.06	1.51	9.72	2.69
b_2	−0.13	1.06	−3.07	−0.17	1.01	−2.88	−0.10	1.11	−1.54
	$R_{it} = a + b_{1t}\beta_{it} + b_{2t}\ln(ME_{it}) + e_{it}$								
a	1.97	6.16	7.84	1.80	4.77	6.52	2.14	7.29	5.09
b_1	−0.14	5.05	−0.66	0.07	4.15	0.28	−0.34	5.80	−1.01
b_2	−0.15	0.96	−3.75	−0.16	0.94	−2.97	−0.13	0.99	−2.34

Table AIV—*Continued*

Panel B:

Return	1941–1950 Mean	1941–1950 t(Mn)	1951–1960 Mean	1951–1960 t(Mn)	1961–1970 Mean	1961–1970 t(Mn)	1971–1980 Mean	1971–1980 t(Mn)	1981–1990 Mean	1981–1990 t(Mn)
	NYSE Value-Weighted (VW) and Equal-Weighted (EW) Portfolio Returns									
VW	1.05	2.88	1.18	3.95	0.66	1.84	0.72	1.67	1.04	2.40
EW	1.59	3.16	1.13	3.76	0.88	1.96	1.04	1.82	0.95	2.01
	$R_{it} = a + b_{1t}\beta_{it} + e_{it}$									
a	0.24	0.66	1.41	6.36	0.64	1.94	0.27	0.62	2.35	5.99
b_1	1.26	2.20	−0.19	−0.63	0.32	0.72	0.82	1.27	−1.01	−2.10
	$R_{it} = a + b_{2t}\ln(ME_{it}) + e_{it}$									
a	2.63	3.47	1.08	2.73	1.78	2.50	2.18	2.03	0.82	1.20
b_2	−0.37	−2.90	0.03	0.53	−0.17	−2.19	−0.20	−1.57	0.04	0.57
	$R_{it} = a + b_{1t}\beta_{it} + b_{2t}\ln(ME_{it}) + e_{it}$									
a	2.14	3.93	1.38	4.03	2.01	4.16	1.50	2.12	2.84	4.25
b_1	0.34	0.75	−0.17	−0.53	−0.11	−0.27	0.41	0.75	−1.14	−2.16
b_2	−0.34	−2.92	0.01	0.20	−0.18	−2.89	−0.16	−1.50	−0.07	−0.84

model. The standard errors for portfolios formed on size and β are only slightly larger (0.02 to 0.11) than those for portfolios formed on size alone (0.01 to 0.10, Table AI). And the range of the post-ranking βs within a size decile is always large relative to the standard errors of the βs.

Another possibility is that the proportionality condition (1) for the variation through time in true βs, that justifies the use of full-period post-ranking βs in the FM tests, does not work well for portfolios formed on size and β. If this is a problem, post-ranking βs for the size-β portfolios should not be highly correlated across subperiods. The correlation between the half-period (1941–1965 and 1966–1990) βs of the size-β portfolios is 0.91, which we take to be good evidence that the full-period β estimates for these portfolios are informative about true βs. We can also report that using 5-year βs (pre- or post-ranking) in the FM regressions does not change our negative conclusions about the role of β in average returns, as long as portfolios are formed on β as well as size, or on β alone.

Any attempt to salvage the simple positive relation between β and average return predicted by the SLB model runs into three damaging facts, clear in Table AII. (a) Forming portfolios on size and pre-ranking βs produces a wide range of post-ranking βs in every size decile. (b) The post-ranking βs closely reproduce (in deciles 2 to 10 they exactly reproduce) the ordering of the pre-ranking βs used to form the β-sorted portfolios. It seems safe to conclude that the increasing pattern of the post-ranking βs in every size decile captures the ordering of the true βs. (c) Contrary to the SLB model, the β sorts do not produce a similar ordering of average returns. Within the rows (size deciles) of the average return matrix in Table AII, the high-β portfolios have average returns that are close to or less than the low-β portfolios.

But the most damaging evidence against the SLB model comes from the univariate regressions of returns on β in Table AIII. They say that when the tests allow for variation in β that is unrelated to size, the relation between β and average return for 1941–1990 is weak, perhaps nonexistent, even when β is the only explanatory variable. We are forced to conclude that the SLB model does not describe the last 50 years of average stock returns.

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The CAPM is Wanted, Dead or Alive

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ABSTRACT

Kothari, Shanken, and Sloan (1995) claim that βs from annual returns produce a stronger positive relation between β and average return than βs from monthly returns. They also contend that the relation between average return and book-to-market equity (BE/ME) is seriously exaggerated by survivor bias. We argue that survivor bias does not explain the relation between BE/ME and average return. We also show that annual and monthly βs produce the same inferences about the β premium. Our main point on the β premium is, however, more basic. It cannot save the Capital asset pricing model (CAPM), given the evidence that β alone cannot explain expected return.

Fama and French (FF 1992) produce two negative conclusions about the empirical adequacy of the capital asset pricing model (CAPM) of Sharpe (1964) and Lintner (1965): (i) when one allows for variation in CAPM market βs that is unrelated to size, the univariate relation between β and average return for 1941–1990 is weak; (ii) β does not suffice to explain average return. Size (market capitalization) captures differences in average stock returns for 1941–1990 that are missed by β. For the post-1962 period where we have book equity data, BE/ME (the ratio of book to market equity) and other variables also help explain average return.

Kothari, Shanken, and Sloan (KSS 1995) have two main quarrels with these conclusions. First, they claim that using βs estimated from annual rather than monthly returns produces a stronger positive relation between average return and β. Second, KSS contend that the relation between average return and BE/ME observed by FF and others is seriously exaggerated by survivor bias in the COMPUSTAT sample.

We argue (Section II) that survivor bias does not explain the relation between BE/ME and average return. We also show (Section III) that annual and monthly βs produce the same inferences about the presence of a β premium in expected returns. But our main point on the β premium (Section I) is more basic: It cannot save the CAPM, given the evidence that β alone cannot explain expected return.

I. The Logic of Tests of the CAPM

As emphasized by Fama (1976), Roll (1977), and others, the main implication of the CAPM is that in a market equilibrium, the value-weight market port-

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folio, M, is mean-variance-efficient. The mean-variance-efficiency of M in turn says that:

(i) β, the slope in the regression of a security's return on the market return, is the only risk needed to explain expected return;
(ii) There is positive expected premium for β risk.

Our main point is that evidence of (ii), a positive relation between β and expected return, is support for the CAPM only if (i) also holds, that is, only if β suffices to explain expected return. Confirming Banz (1981), however, and like FF (1992), KSS find that size adds to the explanation of average return provided by β. Moreover, size is no longer the prime embarrassment of the CAPM. Variables that (unlike size) do not seem to be correlated with β (such as earnings/price, cashflow/price, BE/ME, and past sales growth) add even more significantly to the explanation of average return provided by β (Basu (1983), Chan, Hamao, and Lakonishok (1991), FF (1992, 1993, 1996), and Lakonishok, Shleifer, and Vishny (1994)).

The average-return anomalies of the CAPM suggest that, if asset pricing is rational, a multifactor version of Merton's (1973) intertemporal CAPM (ICAPM) or Ross' (1976) arbitrage pricing theory (APT) can provide a better description of average returns. The excess market return of the CAPM is a relevant risk in many multifactor alternatives, like the ICAPM and Connor's (1984) equilibrium version of the APT. Thus, evidence of a positive relation between β and expected return does not favor the CAPM over these alternatives.

The three-factor model in Fama and French (1993, 1994, 1995, 1996) illustrates our point. The model provides a better description of average returns than the CAPM, and it captures most of the average-return anomalies missed by the CAPM. Because of its strong theoretical standing, the excess market return is one of the three risk-factors in the model, and our tests confirm that it is important. It captures strong common times-series variation in returns, and the market premium is needed to explain the large differences between the average returns on stocks and bills. Moreover, as in the CAPM, the market premium in our multifactor model is just the average return on M in excess of the risk-free rate. Tests on long sample periods say that this premium is reliably positive. In short, our tests of the CAPM against a multifactor alternative illustrate that a positive β premium does not in itself resuscitate the CAPM, or justify using it in applications.

KSS are not misled on this basic point. But their focus on the univariate β premium may confuse some of their readers. Indeed, because the CAPM is such a simple and attractive tool, we think that many of our colleagues *want* to be confused on this point. Otherwise, we can't explain the strong interest in the KSS β tests, given that, like many others (including Amihud, Christensen, and Mendelson (1992) and Jagannathan and Wang (1996)), KSS consistently find that β does not suffice to explain expected return.

II. Survivor Bias and BE/ME

KSS argue that survivor bias in COMPUSTAT data is important in the strong positive relation between average return and book-to-market-equity (BE/ME) observed by FF (1992) and others. COMPUSTAT is more likely to add distressed (high-BE/ME) firms that ultimately survive and to miss distressed firms that die. The survivors are likely to have unexpectedly high returns in the turnaround years immediately preceding their inclusion on COMPUSTAT. Since COMPUSTAT typically includes some historical data when it adds firms, there can be positive survivor bias in the returns of high-BE/ME firms on COMPUSTAT.

There are counter arguments. In the most detailed study of the issue, Chan, Jegadeesh, and Lakonishok (1995) conclude that survivor bias cannot explain the strong relations between average return and BE/ME observed by Lakonishok, Shleifer, and Vishny (1994) and FF (1992) in tests on the post-1968 and post-1976 periods. After 1968, and certainly after 1976, almost all the traded securities on Center for Research in Security Prices (CRSP) that are not on COMPUSTAT are missing for reasons that have nothing to do with survivor bias. Many of the missing firms are closed-end investment companies, REITs, ADRs, primes, and scores that produce no accounting information or produce information that is not comparable to that of other firms. Many financial companies are also missing because, judging that their accounting data are different from that of other firms, COMPUSTAT limited its coverage of financials for many years. These omissions, which are the result of COMPUSTAT's ex ante policy decisions, are not a source of survivor bias. Finally, some of the securities that seem to be on CRSP but not COMPUSTAT in fact appear on both, but with different identifiers.

There is other evidence that survivor bias cannot explain the relation between average return and BE/ME. Lakonishok, Shleifer, and Vishny (1994) find a strong positive relation between average return and BE/ME for the largest 20 percent of NYSE-AMEX stocks on COMPUSTAT, where survivor bias is not an issue. FF (1993) find that the relation between BE/ME and average return is strong for value-weight portfolios of COMPUSTAT stocks formed on BE/ME. Since value-weight portfolios give most weight to larger stocks, any survivor bias in these portfolios is probably trivial. In three different sets of comparisons (Table VII), KSS themselves find that the relation between average return and BE/ME is strong and strikingly similar for value-weight and equal-weight portfolios of COMPUSTAT stocks formed on BE/ME. KSS concede that survivor bias cannot explain the results for value-weight portfolios.

To support their survivor-bias story, KSS make much of the fact that stocks on CRSP but not COMPUSTAT have lower average returns than stocks on COMPUSTAT. When they risk-adjust returns using a three-factor model like that in FF (1993), however, only the smallest two size deciles of the NYSE-AMEX stocks missing from COMPUSTAT have strong negative abnormal returns (Table IV). This suggests that survivor bias is limited to tiny stocks; the average market cap of the stocks in the second decile is \$13 million, while the average for the first decile is between \$3 million and \$7 million. The remaining 80 percent of the stocks missing on COMPUSTAT, which account for almost all the combined value of the missing stocks, have three-factor abnormal returns that are close to zero and random in sign. In other words, these missing stocks behave like stocks that are on COMPUSTAT. Similarly, Chan, Jegadeesh, and Lakonishok (1995) fill in missing COMPUSTAT book equity (BE) data for the largest 20 percent of the NYSE-AMEX firms on CRSP. The survivor-bias story says that the relation between BE/ME and average return should be weak for the firms missing on COMPUSTAT. They find that it is as strong for the missing firms as for the included firms.

KSS also speculate that the positive relation between book-to-market-equity and average return is the result of data dredging and so is special to the post-1962 COMPUSTAT period. Using a hand-collected sample of large firms that is not subject to survivor bias, however, Davis (1994) finds a strong relation between BE/ME and average return in the 1941–1962 period.

In the end, the KSS survivor-bias story rests on their evidence that there is little relation between average return and BE/ME for the rather limited industry portfolios in the *S&P Analyst's Handbook*. Their results for the S&P industries are strange since FF (1994) document a strong positive relation between average return and BE/ME for value-weight industry portfolios that include *all* NYSE, AMEX, and Nasdaq stocks on CRSP. (We use COMPUSTAT firms only to estimate industry BE/ME.)

KSS do not say that the relation between average return and BE/ME is entirely the result of survivor bias. They push so hard on the survivor-bias story, however, that serious readers are led to strong conclusions. For example, in the lead article to volume 38 of the *Journal of Financial Economics*, MacKinlay (1995, p. 5) concludes,

> *"Their analysis suggests that deviations from the CAPM such as those documented by Fama and French (1993) can be explained by sample selection biases."*

III. Minor Points

KSS claim that using βs estimated from annual rather than monthly returns explains why they measure somewhat stronger relations between β and average return than FF (1992). They also claim that although the explanatory power of size is statistically reliable, for practical purposes, size adds little to the explanation of average return provided by β. The tests that follow explore these issues.

A. Portfolios Formed on β

Table I summarizes returns for 1928–1993 on β deciles of NYSE stocks. Like KSS, we weight the stocks equally. We form the portfolios in June of each year,

Table I

Summary Statistics and Cross-Section Regressions for Postformation Equal-Weight Returns on NYSE β Deciles: 1928–1993

Starting in 1927, ten portfolios of NYSE stocks on CRSP are formed in June of each year based on VW-S βs, the sum of the slopes from regressions of monthly returns on the current and one lag of the value-weight NYSE market return. The formation period βs use 24 to 60 months of past returns (as available), except for 1927, where 18 months are used. Equal-weight monthly postformation returns on the β deciles are calculated from July to June of the following year, yielding time-series of postformation returns for July 1927 to December 1993. The equal-weight monthly decile returns are compounded to get annual returns. The βs shown in Panel A are estimated using all postformation monthly (VW, VW-S, EW, EW-S) or annual (VWA, EWA) returns for 1928–1993 and the value-weight (VW, VW-S, VWA) or equal-weight (EW, EW-S, EWA) NYSE market portfolio. VW-S and EW-S βs are the sums of the slopes from the regressions of the monthly postformation decile returns on the current and one lag of the market return. VW, VWA, EW, and EWA βs use only the contemporaneous market returns. Average Ln (Size) is the average across postformation months of the average monthly value of the natural log of size (price times shares) of the stocks in a β decile. Panel B shows the average slopes (Means) and the t-statistics for the average slopes from univariate cross-section regressions of postformation monthly or annual returns on the ten β portfolio on each of the six different estimates of their postformation βs.

Panel A: Summary Statistics

	Low β	2	3	4	5	6	7	8	9	High β
				Monthly Postformation Returns: 792 Months						
Mean	1.10	1.16	1.23	1.34	1.39	1.32	1.33	1.44	1.45	1.39
Std	5.12	5.76	6.30	6.99	7.66	7.98	8.31	9.50	9.84	11.10
				Annual Postformation Returns: 66 Years						
Mean	14.91	15.53	16.43	17.73	17.98	17.03	17.19	18.44	18.44	17.40
Std	25.69	26.39	28.25	29.85	29.52	30.76	32.04	35.96	36.03	40.55
				Postformation β Estimates						
VW	0.80	0.95	1.05	1.16	1.27	1.32	1.35	1.52	1.57	1.73
VW-S	0.91	1.03	1.14	1.24	1.36	1.41	1.44	1.63	1.70	1.87
VWA	1.06	1.13	1.23	1.33	1.33	1.37	1.43	1.56	1.60	1.71
EW	0.61	0.72	0.80	0.90	0.99	1.03	1.07	1.23	1.26	1.41
EW-S	0.65	0.73	0.81	0.89	0.98	1.02	1.06	1.21	1.26	1.41
EWA	0.78	0.82	0.89	0.96	0.95	0.99	1.02	1.16	1.14	1.27
				Average Ln (Size)						
Mean	12.70	12.76	12.74	12.50	12.36	12.16	12.03	11.73	11.36	11.00

Panel B: Cross-Section Regressions, $R = a + b\beta + e$

	Monthly Dependent Returns, R						Annual Dependent Returns, R					
	VW	VW-S	VWA	EW	EW-S	EWA	VW	VW-S	VWA	EW	EW-S	EWA
	Means						Means					
a	0.86	0.85	0.63	0.90	0.90	0.67	12.94	12.89	10.85	13.37	13.32	11.24
b	0.36	0.34	0.50	0.41	0.42	0.65	3.28	3.07	4.56	3.72	3.78	5.88
	t-Statistics for Means						t-Statistics for Means					
a	4.78	4.53	1.94	5.57	5.28	2.14	3.81	3.72	2.27	4.13	4.04	2.45
b	1.31	1.29	1.29	1.29	1.27	1.25	1.03	1.00	1.01	1.01	0.98	0.98

using βs on the NYSE value-weight market portfolio estimated with two to five years of past monthly returns (as available). Panel A of the table shows that average monthly and annual postformation returns initially increase with post-formation βs, but the relation between average return and β is rather flat from the fourth to the tenth β decile. This pattern in average returns on β portfolios is similar to KSS' Table I. The spread in average returns for their β portfolios is larger than ours, but including AMEX stocks also makes their β sort more like a sort on size than ours.

Panel A of Table I confirms KSS' evidence that βs estimated from monthly and annual returns are different. For the purposes of inferences about the average slopes from cross-section Fama-MacBeth (FM 1973) regressions of return on β, however, the important fact is that postformation βs estimated on annual or monthly returns, and using either an equal-weight or value-weight NYSE market, are near perfect linear transforms of one another. Rounded to two decimals, the correlations between the different βs range from 0.98 to 1.00.

Panel B of Table I shows that in univariate FM regressions of return on β, different βs produce different average slopes. In particular, the average slopes for the regressions that use annual βs to explain returns are about 50 percent larger than the averages for the regressions that use monthly βs. Why? The spread in the monthly βs is about 50 percent larger than the spread in the annual βs. Since the regressions are asked to explain the same dependent returns, and since the different βs are almost perfectly correlated, the smaller spreads in the annual βs lead to larger average slopes. However, although the average slopes in the annual-β regressions are larger, the near-perfect correlation among the βs leads to t-statistics for the average slopes that are nearly identical. (Jegadeesh (1992) reports similar results. See also Chopra, Lakonishok, and Ritter (1992), and Chan and Lakonishok (1993)).

In their cross-section regressions, KSS explain monthly returns with βs from regressions of annual returns on an equal-weight market return. One can argue that this combination is far from the spirit of the CAPM. In light of the recent articles of Roll and Ross (1994) and Kandel and Stambaugh (1995), however, we doubt that there is much future in debates about which approach produces bigger β premiums in cross-section regressions. Kandel and Stambaugh (1995) show that if the market proxy is not exactly mean-variance-efficient *with respect to parameters computed from the sample data*, it is possible to form portfolios that produce essentially any univariate β premium in ordinary-least-squares cross-section regressions. This conclusion about β premiums also applies to cross-section regressions that use β and other variables to explain average return. Moreover, generalized-least-squares (GLS) regressions, like those in Amihud, Christensen, and Mendelson (1992), are no cure. Roll and Ross (1994) note that a positive β premium in univariate GLS cross-section regressions simply says that the market proxy has a higher expected return than the global-minimum-variance portfolio.

B. Portfolios Formed on Size and β

Kandel and Stambaugh (1995) and Roll and Ross (1994) teach us to be wary of inferences about β premiums from FM cross-section regressions. Cross-section regressions can, however, be useful in judging whether β suffices to explain expected return. Like KSS, we address this issue by testing whether size adds to the explanation of average return provided by β. Summary statistics and FM cross-section regressions for 100 portfolios formed yearly first on size (deciles) and then on β are in Tables II and III.

The KSS cross-section regressions (their Table II) consistently show that, on a statistical basis, size improves on β's explanation of average return. This evidence is inconsistent with the CAPM, but KSS argue that the errors of β's predictions of average return are not large. The message from our Tables II and III, however, is that size does make a large incremental contribution to the explanation of average return.

Table II shows that the size sort produces a strong spread in both post-formation β and average return. The average return for 1928–1993 on the smallest decile of NYSE stocks exceeds that for the largest decile by 1.31 percent per month; the spread in βs is a healthy 0.93. Table II also shows that the second pass sort on preformation βs produces large spreads in postformation βs that are independent of size. As in FF (1992), however, the β sorts do not produce much spread in average return.

It seems safe to predict that a single average premium for β cannot capture both the strong positive relation between β and average return produced by the size sort in Table II and the weak relation between β and average return in the β sorts. Table III confirms this prediction. Like KSS, our univariate regressions of return on β produce positive average premiums that are more than 2.0 standard errors from 0.0. But the univariate β regressions leave an unexplained size effect. The spread in the average residuals from the smallest to the largest size decile is 0.66 percent in the regressions for monthly returns and 7.02 percent in annual returns. There is an even more systematic pattern in the average residuals for the β sorts, which are large and positive for low-β portfolios and strongly negative for high-β portfolios. The spread in the average residuals from the lowest to the highest β deciles of NYSE stocks is 0.56 percent in the regressions for monthly returns and 7.25 percent in annual returns.

In short, for portfolios formed on size and β, the average β premiums from univariate regressions of return on β underestimate the positive relation between β and average return produced by the size sort and overestimate the relation between β and average return produced by the β sort. For the extreme size and β deciles, these CAPM pricing errors are large. These results suggest that β alone cannot explain average return. As in KSS, the bivariate regressions of return on β and size in Table III confirm that size always adds substantially to β's description of average stock returns.

Table II

Summary Statistics for 100 Equal-Weight NYSE Portfolios Formed on Size and Then β: 1928–1993, N = 792

Starting in 1927, ten portfolios of the NYSE stocks on CRSP are formed in June of each year based on size (market capitalization, price times shares outstanding). Each size decile is then subdivided into β deciles using βs for individual stocks that are the sum of the slopes from regressions of monthly returns on the current and one lag of the value-weight NYSE market return. The formation period βs use 24 to 60 months of past returns (as available), except for 1927, where 18 months of returns are used. Equal-weight monthly returns on the 100 portfolios are calculated from July to June of the following year, yielding time-series of returns for July 1927 to December 1993. The VW-S βs shown are the sums of the slopes from regressions of monthly postformation returns for the February 1928 to December 1993 period on the current and one lag of the value-weight NYSE market return. Average Ln (Size) is the average across postformation months of the average monthly value of the natural log of size for the stocks in each portfolio. The Ave column of each block is the average across β deciles of the parameter values for a size decile. The Ave row of each block is the average across size deciles of the parameter values for a β decile.

	Low β	2	3	4	5	6	7	8	9	High β	Ave
					Panel A: Average Monthly Postformation Returns						
Small	2.15	2.30	2.20	2.66	2.16	1.89	2.27	2.12	2.23	1.82	2.18
2	1.43	1.65	1.55	1.54	1.65	1.91	1.64	1.63	1.41	1.31	1.57
3	1.42	1.53	1.30	1.56	1.56	1.39	1.51	1.48	1.53	1.26	1.45
4	1.15	1.23	1.40	1.31	1.46	1.41	1.10	1.42	1.26	1.24	1.30
5	1.14	1.37	1.35	1.45	1.22	1.46	1.33	1.39	1.13	1.21	1.31
6	1.24	1.20	1.05	1.15	1.34	1.31	1.29	1.10	1.32	1.27	1.23
7	0.93	1.20	1.06	1.14	1.38	1.08	1.08	1.01	1.28	1.15	1.13
8	1.11	1.12	1.08	1.15	1.11	1.21	1.21	0.79	1.25	1.16	1.12
9	0.84	0.94	1.07	1.12	1.17	1.22	1.01	1.14	1.05	0.95	1.05
Big	0.80	0.82	0.85	0.85	0.91	0.97	0.92	0.84	0.86	0.84	0.87
Ave	1.22	1.34	1.29	1.39	1.40	1.38	1.33	1.29	1.33	1.22	
					Panel B: Postformation VW-S βs						
Small	1.47	1.90	1.56	2.03	2.06	1.69	1.97	1.99	2.21	2.15	1.90
2	1.45	1.43	1.71	1.59	1.52	1.74	1.89	1.84	1.76	1.89	1.68
3	1.29	1.33	1.21	1.49	1.58	1.52	1.68	1.70	1.81	1.91	1.55
4	1.16	1.20	1.16	1.32	1.49	1.41	1.49	1.51	1.76	1.92	1.44
5	0.97	1.13	1.22	1.34	1.36	1.50	1.38	1.70	1.47	1.75	1.38
6	0.74	1.01	1.09	1.30	1.22	1.36	1.37	1.60	1.59	1.77	1.31
7	0.72	0.93	1.03	1.08	1.32	1.25	1.31	1.39	1.47	1.83	1.23
8	0.64	0.76	0.93	1.10	1.17	1.25	1.24	1.26	1.52	1.58	1.15
9	0.63	0.78	0.92	1.11	1.10	1.08	1.14	1.29	1.30	1.53	1.09
Big	0.61	0.81	0.76	0.88	0.93	0.98	1.05	1.11	1.15	1.42	0.97
Ave	0.97	1.13	1.16	1.32	1.38	1.38	1.45	1.54	1.60	1.78	
					Panel C: Average Ln (Size)						
Small	8.59	8.61	8.62	8.59	8.57	8.55	8.54	8.54	8.55	8.42	8.56
2	9.40	9.42	9.41	9.42	9.40	9.41	9.39	9.40	9.38	9.36	9.40
3	9.94	9.93	9.93	9.92	9.90	9.91	9.92	9.91	9.89	9.88	9.91
4	10.33	10.34	10.34	10.34	10.34	10.35	10.33	10.34	10.31	10.32	10.34
5	10.73	10.75	10.75	10.76	10.74	10.75	10.74	10.73	10.72	10.73	10.74
6	11.16	11.14	11.13	11.14	11.14	11.15	11.14	11.12	11.13	11.12	11.14
7	11.57	11.57	11.57	11.58	11.58	11.56	11.55	11.54	11.56	11.55	11.56
8	12.09	12.09	12.08	12.08	12.08	12.08	12.09	12.05	12.05	12.06	12.08
9	12.71	12.73	12.73	12.71	12.74	12.72	12.71	12.71	12.70	12.69	12.71
Big	14.17	14.18	14.15	14.14	14.31	14.27	14.24	14.10	14.07	13.76	14.14
Ave	11.07	11.08	11.07	11.07	11.08	11.08	11.07	11.04	11.04	10.99	

V. Conclusions

Confirming Banz (1981), sorts on size and β like those in KSS or our Tables II and III consistently reject the central CAPM hypothesis that β suffices to explain expected return. Moreover, in recent years the size effect has been displaced as the prime embarrassment of the CAPM. There is much evidence

Table III

Cross-Section Regressions for 100 Equal-Weight Size-β Portfolios: 1928–1993, $R = a + b\beta + s\text{Ln (Size)} + e$

In June of each year beginning in 1927, NYSE stocks on CRSP are sorted into size deciles, which are then subdivided into β deciles (see Table II). Equal-weight monthly returns on the 100 portfolios are calculated from July to June of the following year. Annual returns are obtained by compounding the equal-weight monthly returns. Panel A shows the average slopes (Means) and their t-statistics from univariate cross-section regressions of monthly and annual postformation simple returns on the 100 size-β portfolios on six estimates of their 1928–1993 postformation βs, and bivariate regressions of the 100 size-β portfolio returns on their βs and Ln (Size), the natural log of the average size of the stocks in each of the 100 portfolios at the end of the previous month or year. The βs are estimated using all postformation monthly (VW, VW-S, EW, EW-S) or annual (VWA, EWA) returns for 1928–1993 and the value-weight (VW, VW-S, VWA) or equal-weight (EW, EW-S, EWA) NYSE market portfolio. VW-S and EW-S βs are the sums of the slopes from the regressions of the monthly postformation size-β portfolio returns on the current and one lag of the market return. VW, VWA, EW, and EWA βs use only the contemporaneous market returns. The average slopes in the cross-section regressions of returns on Ln (Size) alone (not shown) are −0.19 (t = −3.60) for monthly returns and −2.67 (t = −3.23) for annual returns. Panel B shows the average residuals from the univariate regressions of monthly (annual) returns on the VW-S (VWA) βs. The Ave column of each block in part B is the average across β deciles of the average residuals for a size decile. The Ave row of each block is the average across size deciles of the average residuals for a β decile.

Panel A: Regression Coefficients

	Monthly Dependent Returns: 792 Months						Annual Dependent Returns: 66 Years					
	VW	VW-S	VWA	EW	EW-S	VWA	VW	VW-S	VWA	EW	EW-S	EWA
	Means						Means					
a	0.50	0.36	0.17	0.43	0.43	0.38	7.26	4.68	0.58	5.61	5.33	3.47
b	0.65	0.70	0.84	0.89	0.88	0.94	7.83	9.13	12.08	11.56	11.84	13.73
	t-Statistics for Means						t-Statistics for Means					
a	2.55	1.72	0.68	2.26	2.28	1.84	2.69	1.71	0.16	2.23	2.16	1.24
b	2.18	2.64	2.98	2.67	2.86	3.27	2.13	2.58	2.76	2.62	2.77	2.89
	Means						Means					
a	3.01	2.86	2.76	2.83	2.68	2.30	45.50	43.46	37.27	43.41	40.97	29.30
b	0.10	0.15	0.18	0.20	0.26	0.37	−0.75	0.29	2.71	0.37	1.48	6.29
s	−0.18	−0.17	−0.16	−0.17	−0.15	−0.13	−2.75	−2.65	−2.28	−2.64	−2.48	−1.69
	t-Statistics for Means						t-Statistics for Means					
a	5.92	5.73	5.33	5.66	5.40	4.98	4.61	4.58	4.82	4.50	4.43	4.33
b	0.40	0.62	0.72	0.65	0.83	1.46	−0.27	0.11	0.79	0.11	0.43	1.43
s	−4.16	−4.12	−3.99	−4.02	−3.78	−3.47	−3.63	−3.67	−3.88	−3.61	−3.56	−3.63

Table III

Continued

Panel B: Average Residuals from Univariate β Regressions

	Low β	2	3	4	5	6	7	8	9	High β	Ave
					Monthly Returns: VW-S βs						
Small	0.76	0.61	0.75	0.87	0.36	0.34	0.52	0.37	0.31	−0.05	0.49
2	0.06	0.29	−0.01	0.06	0.22	0.33	−0.04	−0.03	−0.18	−0.38	0.03
3	0.15	0.24	0.09	0.16	0.10	−0.04	−0.03	−0.07	−0.09	−0.44	0.00
4	−0.02	0.03	0.23	0.03	0.05	0.05	−0.31	−0.00	−0.33	−0.47	−0.07
5	0.10	0.22	0.14	0.16	−0.09	0.06	0.00	−0.16	−0.27	−0.38	−0.02
6	0.36	0.13	−0.08	−0.12	0.12	−0.00	−0.03	−0.37	−0.16	−0.32	−0.05
7	0.07	0.19	−0.01	0.03	0.09	−0.16	−0.20	−0.32	−0.11	−0.49	−0.09
8	0.30	0.23	0.07	0.02	−0.08	−0.03	−0.02	−0.45	−0.18	−0.31	−0.04
9	0.04	0.04	0.06	−0.02	0.04	0.10	−0.15	−0.12	−0.22	−0.48	−0.07
Big	0.01	−0.11	−0.03	−0.13	−0.10	−0.08	−0.18	−0.30	−0.31	−0.51	−0.17
Ave	0.18	0.19	0.12	0.11	0.07	0.06	−0.04	−0.14	−0.15	−0.38	
					Annual Returns: VWA βs						
Small	5.88	7.95	9.85	11.66	6.12	2.37	7.68	4.97	4.21	−2.90	5.78
2	1.51	1.74	−0.31	−0.00	2.33	3.56	−1.53	−3.07	−6.10	−5.37	−0.72
3	2.24	2.42	2.25	2.28	0.60	−1.21	−1.00	−1.20	−1.97	−5.93	−0.15
4	0.20	−0.38	3.56	−0.31	0.52	0.40	−3.33	−0.58	−5.47	−5.75	−1.11
5	0.37	3.16	1.47	2.48	0.44	0.79	−0.28	−1.20	−3.66	−4.55	−0.10
6	4.91	1.94	−0.72	−1.06	0.58	0.00	−0.89	−5.07	−1.80	−3.97	−0.61
7	1.40	4.06	0.41	−0.34	0.28	−1.66	−3.16	−3.83	−1.33	−5.68	−0.99
8	4.97	2.77	1.19	0.45	−0.93	0.29	−0.20	−5.92	−3.10	−3.00	−0.35
9	1.31	1.07	0.75	0.65	1.08	1.59	−1.80	−1.31	−2.59	−5.85	−0.51
Big	0.96	−0.33	0.87	−0.61	−0.38	−0.73	−0.67	−2.62	−3.11	−5.77	−1.24
Ave	2.37	2.44	1.93	1.52	1.06	0.54	−0.52	−1.98	−2.49	−4.88	

that other variables (like earnings/price, cashflow/price, BE/ME, and past sales growth), add even more significantly to the explanation of average return (Basu (1983), Chan, Hamao, and Lakonishok (1991), FF (1992, 1993, 1996), and Lakonishok, Shleifer, and Vishny (1994)). Unlike size, these other variables (especially BE/ME) show little relation to estimates of market βs (FF (1992, 1993, 1994), Lakonishok, Shleifer, and Vishny (1994)), so a CAPM β-proxy story for their role in average returns is unlikely.

It is, of course, possible that the apparent empirical failures of the CAPM are due to bad proxies for the market portfolio. In other words, the true market is mean-variance-efficient, but the proxies used in empirical tests are not. In this view, revival of the CAPM awaits the coming of M. The true market portfolio will cast aside the average return anomalies of existing tests and reveal that β suffices to explain expected return.

This bad-market-proxy argument, however, does not justify the way the CAPM is currently applied, for example, to estimate the cost of capital or to evaluate portfolio managers. The bad market proxies used in tests of the CAPM are similar to those used in applications of the model. If the common market proxies are inefficient, then applications that use them rely on the same flawed estimates of expected return that undermine empirical tests of the CAPM. Like the redemptive empirical tests, valid applications of the CAPM await the coming of M.

In our view, the evidence that β does not suffice to explain expected return is compelling. And the average-return anomalies of the CAPM are serious enough to infer that the model is not a useful approximation. Our bet, made concrete in FF (1993, 1994, 1995, 1996), is that the payoffs in empirical asset pricing are in showing that the failures of the CAPM can be explained by multifactor ICAPM or APT alternatives—or that they are consistent with specific irrational-asset-pricing stories.

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Personal Finance

Tony Tassell: The time has come for the CAPM to RIP

FEBRUARY 9 2007

Few theories are more influential or important in driving financial markets as the inelegantly-named capital asset pricing model. Too bad it does not appear to work very well.

The CAPM, as it is widely known, is a cornerstone of modern financial market analysis, studied like a rosary by analysts and executives at business school. Most financial directors use it to assess everything from the viability of a new project to their cost of capital. Most stock market analysts consider it an essential tool.

But it has faced increasing criticism in recent years as unworkable in the real world, even from luminary market academics such as Harry Markowitz who laid the groundwork for the CAPM with research in 1950s on efficient portfolios.

CAPM is basically a model for valuing stocks or securities by relating risk and expected return. Developed separately by William Sharpe, John Lintner and Jack Treynor, it is based on the idea that investors demand additional expected return to take on additional risk.

It then assumes markets are efficiently priced to reflect greater returns for greater risk. The risk is assessed on a stock or security's so-called beta, a measure of a company's volatility and correlation with the market as a whole. A company with a share price that tends to rise and fall more than the market will have a high beta and vice versa.

It is a seductively simple, catch-all theory to quantify risk and forecast returns. It has spurred the development of quantitative investing.

But there is a problem. James Montier, analyst at Dresdner Kleinwort, says CAPM has become the financial theory equivalent of Monty Python's famous dead parrot sketch. He says the model is empirically bogus – it does not work in any way, shape or form. But like the shopkeeper who insists to a customer with a dead parrot in the sketch that the bird is merely resting, financial markets are in denial.

"The CAPM is, in actual fact, Completely Redundant Asset Pricing (CRAP)," he says.

Some of the most damning evidence came from an exhaustive 2004 study by Eugene Fama and Kenneth French, the academics who helped develop the efficient markets theory in the early 1970s, that argued stocks are always correctly priced as everything that is publicly known about the stock is reflected in its market price.

The study looked at all stocks on the New York Stock Exchange, the American Stock Exchange and Nasdaq from 1923 to 2003. As Montier states, the study shows CAPM woefully underpredicts the returns to low beta stocks and massively overstates the returns to high beta stocks. “Over the long run there has been essentially no relationship between beta and return,” he says.

Fama and French themselves concluded that while CAPM was a theoretical tour de force, its empirical track record was so poor that its use in “applications” was probably invalid. In others words, CAPM is a fine theory but useless in the real world.

A similar study of the 600 largest US stocks by Jeremy Grantham, the value investor, last year yielded similar results. It showed from 1969 to the end of 2005, the lowest decile of beta stocks – notionally the lowest risk – outperformed by an average 1.5 per cent a year. The highest beta stocks, or the riskiest, actually underperformed by 2.7 per cent a year.

The problems in the CAPM lie in its assumptions, particularly those used to derive the efficient portfolio that is used as a benchmark for the model in theory. The most commonly-cited criticism is an implicit assumption that that all investors can borrow or lend funds on equal terms.

Other assumptions that have been criticised include: that there are no transaction costs, that all investors have a “homogeneity” of expectations and risk appetites and that investors can take any market exposure without affecting prices. It also assumes no taxes so investors are indifferent between dividends and capital gains.

Markowitz himself noted that the CAPM is like studying “the motions of objects on Earth under the assumption that the Earth has no air”.

“The calculations and results are much simpler if this assumption is made. But at some point, the obvious fact that on Earth, cannonballs and feathers do not fall at the same rate should be noted,” he says.

Current market conditions might be exacerbating problems. Vineer Bhansali, head of portfolio management analytics at Pimco, adds that the increasing availability of leverage for some investors may actually drive all risky security prices higher.

Grantham says the flaws in the CAPM are probably inconvenient enough for the academic financial establishment to want to ignore it. But there ought to be more debate, particularly in using beta as a risk benchmark.

The concept of pursuing absolute returns rather than relative performance is now widely debated. There needs to be a similar evolution in market thinking on how risk is defined, measured and dealt with.

Montier cites a quote from legendary investor Ben Graham: “What bothers me is that authorities now equate the beta with the concept of risk. Price variability, yes; risk, no. Real investment risk is measured not by the per cent a stock may decline in price in relation to the general market in a given period but by the danger of a loss of quality and earning power through economic changes or deterioration in management.”

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THE CASE AGAINST THE USE OF THE CAPITAL ASSET PRICING MODEL IN PUBLIC UTILITY RATEMAKING

Joe Chartoff, George W. Mayo, Jr.†*
and Walter A. Smith, Jr.‡

INTRODUCTION

In the mid-1960's, the academic community introduced a mathematical formula called the Capital Asset Pricing Model ("CAPM") which, it was contended, could be reliably employed to estimate any given asset's expected rate of return. In the succeeding years, the formula has received substantial attention and been lent considerable credence, not only in academia, but in the business and investment worlds as well. In addition, and most importantly for purpose of this comment, CAPM has been used extensively by regulatory commissions to establish rates of return for utilities.

The most recent evidence, however, strongly suggests that there are serious shortcomings associated with CAPM, and that, in the utility ratemaking context at least, it can produce totally unreliable results. And yet, at the very time when the case against CAPM has become so formidable, the ratemaking bodies' reliance on it appears to have reached its zenith. The purpose of this comment, therefore, is to marshal the evidence concerning the inappropriateness of CAPM's use as an estimator of a utility's required rate of return, and to question the ratemakers' continued reliance upon it.

The comment is organized as follows. First, a description is offered of the CAPM formula, its theoretical underpinnings, and its key components. This is followed by a survey of CAPM's use by the regulatory commissions in establishing utility rates of return. Finally, the case against that use is made.

Before beginning, one other point should be made. The analysis offered below is based not so much upon our own independent expertise, as upon the work of financial economists, investment analysts, statisticians, and utility managers who are expert in, and have a thorough command of, the complexities of the CAPM theory. The case made here against CAPM, however, is a lawyer's case. It is intended to summarize, in laymen's terms, the evidence which is available to a regulatory body considering the use of CAPM. In our opinion, the evidence shows that CAPM is a highly suspect ratemaking tool, and that until its reliability is more clearly established, it should either be rejected, or at the very least modified, in future rate proceedings.

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I. *The CAPM Theory*

Developed and refined over the past two decades,[1] the theory of CAPM, generally stated, is that the expected rate of return on any given asset is a function of the risk which investors perceive to be associated with that particular asset, as compared with the risk of all other assets in which they might invest; that the only risk for which investors expect to be compensated is that risk which cannot be "diversified away" (cancelled out) by holding the asset as part of a "well-diversified portfolio"; that this "nondiversifiable risk" is composed solely of "market risk," *i.e.*, risk which affects the market as a whole, and which therefore affects every asset in the market; that all risk except this nondiversifiable market risk is in fact diversified away when an asset is held as part of a well-diversified portfolio; that investors therefore regard as irrelevant any risks peculiar to a particular asset or to the business or industry of which that asset is a part, and expect compensation only for the way in which the particular asset is affected by market risk.

It is further said, according to the CAPM theory, that the expected compensation on the particular asset has two components — first, the current return due on a riskless investment (such as a U.S. treasury bill) and, second, a "risk premium" above the riskless rate; that this "risk premium" component (or "excess return" component) of a given asset's expected return should be measured in terms of how volatile these excess returns have been on the particular asset as compared with the volatility of the excess returns on the average - risk asset in the market; that this volatility-comparison measurement may be taken by correlating the past excess returns on the given asset with the past excess returns on the average asset, the latter being represented by some broad market index of equity securities such as the Standard & Poor's 500; that this correlation of past excess returns results in a coefficient called "beta," which quantifies the volatility (and therefore the riskiness) of the asset in question relative to the volatility of the average asset; that every asset's risk premium is directly proportional to how much more or less volatile than the market's excess returns have been the asset's excess returns; that beta reflects this proportionality and fully captures the asset's risk premium; and therefore, that once an asset's beta has been determined, nothing more about the asset need be known in order to reliably estimate its expected rate of return.

Based on the foregoing CAPM assumptions, the expected rate of return (or cost of equity) for a given asset is computed according to the following formula:

expected rate of return = risk-free rate + beta ×
(market rate - risk-free rate) + alpha

The *risk-free rate* in the formula is usually determined by examining the current yields offered on treasury bills, which constitute essentially risk-free investments.

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[1]The original development of CAPM is usually attributed to W.F. Sharpe ("Capital Asset Prices: A Theory of Market Equilibrium Under Conditions of Risk," 19 *Journal of Finance* 425 (Sept. 1964)) and J. Lintner ("The Valuation of Risk Assets and the Selection of Risky Investments in Stock Portfolios and Capital Budgets," 47 *Review of Economics and Statistics* 13 (Feb. 1965)).

The quantity *market rate — risk-free rate* (the excess return) represents the risk premium on the average asset. It is normally assumed to be equal to the average long-term return on the market index in excess of the average long-term risk-free rate.

Beta, as described above, purports to assess the riskiness of the given asset in relation to the riskiness of the average asset, and thereby indicates the amount of the asset's risk premium. A beta of 1.0 is said to indicate that the asset is equally risky as the market index because its excess returns fluctuate in line with and by the same percentage amount as the market's excess return; hence, the asset will have the same risk premium as the market itself. By the same token, a beta of 1.5 indicates that the asset is 50% riskier than the market index (because its excess returns increase (or decrease) at 1.5 times the magnitude of increases (or decreases) in the market's excess return) and therefore has an expected risk premium 50% higher than that of the market. It follows that an asset with a beta of zero has no market risk, and is therefore expected to return the riskless rate.

Finally, *alpha* represents that part of a security's expected return which cannot be attributed to, or explained by, the security's response to fluctuations in the market index. CAPM assumes that alpha is zero.

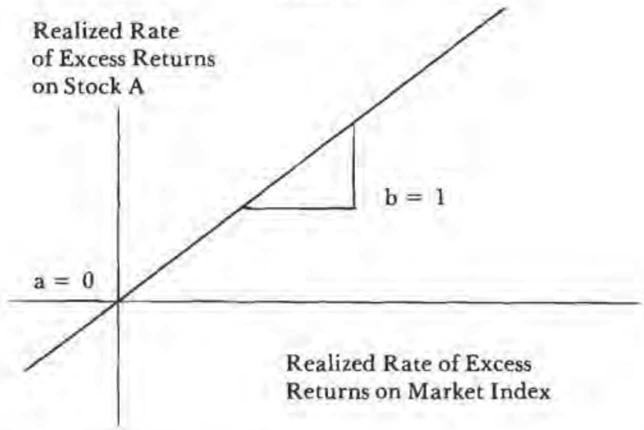
In other words, all that need be done to determine a particular asset's expected return, says CAPM, is, first, determine the asset's beta, then look up the current risk-free return, determine the current market (average asset) return, compute the resulting market "risk premium" by subtracting the risk-free return from the market return, next determine the given asset's risk premium by multiplying the market risk premium by the asset's beta, and, finally, add the current riskless return to the asset's risk premium. The sum, according to the theory, equals the asset's expected rate of return (or, in the case of a utility, its cost of equity).

Plainly, CAPM's centerpiece, and the key to its reliability, is beta. It is important, therefore, to understand how beta is computed, and how, in practice, it is used to estimate an expected rate of return or cost of equity for a particular asset.

Both the beta and the alpha of a particular asset are calculated through the use of a bivariate regression model. Such a model can be used to measure the relationship between any pair of variables. In connection with CAPM, the model is typically used to plot the relationship between the excess returns (*i.e.*, returns in excess of the riskless rate) on the asset in question and the contemporaneous excess returns on a general market index. Beta is determined by a line drawn which best "fits" the pattern of the plotted returns, and is the *slope coefficient* of the regression model; alpha, on the other hand, is determined by the point at which the "beta line" crosses the asset's excess rate-of-return line, and is the *intercept coefficient* of the regression model. Thus, every computation of beta also produces a computation of alpha.

Table 1 illustrates an asset (Stock A) that has a beta of 1.0 and an alpha of 0.

Table 1



Based on its beta of 1.0, Stock A is assumed to have the same nondiversifiable risk (sometimes referred to as "systematic" risk) as the market index, and, according to CAPM, any rise or fall in the market's excess return should lead to a like rise or fall in the excess return on the stock. Therefore, the stock is expected to have a risk premium identical to that for the market. Furthermore, because its alpha is 0, it will be assumed that Stock A's beta captures all of the return (above the riskless rate) which is expected by investors.

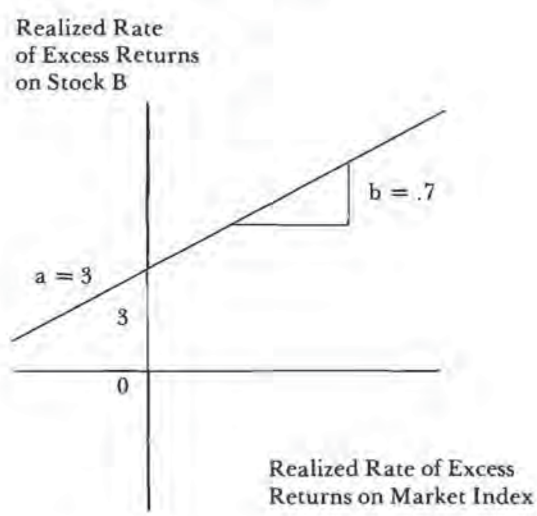
Using the previously-stated CAPM formula, and assuming that the appropriate risk-free rate and market premium can be determined, the cost of equity of Stock A can be easily computed. That equity cost (or required rate of return) is equal to the risk-free rate, plus beta times the risk premium (the return in excess of the risk-free rate) achieved by the market index, plus alpha. Assuming a risk-free rate of 10 percent and a market premium (excess return) of 5 percent, the formula produces the following result:

return (equity cost) = 10% +
1 (beta) × 5% + 0 (alpha) = 15%

Hence the return required on Stock A, and the issuing company's cost of equity, is 15 percent.

Table 2 depicts an asset (Stock B) with a different degree of risk, and one that, as discussed below, is reflective of many utility stocks.

Table 2



Stock B is considered to have less systematic risk than the market index since its excess returns increase or decrease only 70 percent of the extent to which excess returns on the market index increase or decrease. Hence, using CAPM, Stock B will be expected to return a risk premium of only 70 percent of the market risk premium. However, Stock B has an alpha of + 3, indicating that it has earned a 3 percent return premium which is not captured, or measured, by beta. As will be discussed in Part III, experts have advanced several possible explanations for this positive alpha: for example, it could be a measurement of the extent to which beta misestimates the total nondiversifiable risk of the stock, owing to the fact that the particular market index contains less than all the available capital assets in which one might invest; it could demonstrate that the "true" market portfolio of all capital assets is not an "efficient" portfolio; it could indicate that although an asset's premium for nondiversifiable market risk is related to the asset's relative volatility, the premium is not necessarily directly proportional to that volatility; it could capture certain firm-specific (unsystematic) risks of the stock for which investors expect to be compensated; or, stated another way, it could represent the degree to which the well-diversified portfolio which investors could (or do) hold fails to "diversify away" all firm-specific risks; or it could reflect the fact that one of CAPM's necessary assumptions — that investors can freely borrow and lend at the risk-free rate — is not true. Whatever alpha's explanation as to a given asset, if it is not zero it means that beta does not tell the whole story of the asset's risk premium.

Using the previously-stated formula, and assuming the same 10 percent risk-free return and 5 percent excess return as assumed in the Stock-A example, the return required on Stock B (and the cost of equity to the issuer) is computed as follows:

expected return (cost of equity) = 10%
+ (.70 × 5%) + 3% = 16.5%

But CAPM ignores alpha, declaring that beta captures all nondiversifiable risk, and that such risk is the only thing for which investors expect to be compensated (above the riskless rate). Hence, CAPM assumes that alpha is (or in the long run will be) zero, and therefore dictates that Stock B's expected return is not 16.5%, but 13.5%. Clearly, the decision to rely on beta, but to disregard alpha, can be critical in the case of industries which have member-companies with persistent, positive alphas in their past returns. This is the case for the utility industry.

An examination of the data reported by Merrill Lynch in its January 1981 Quantitative Analysis indicates that utilities as a group, on average, had a beta of .6 and an alpha of .2 percent based on market prices as of December 31, 1980. Merrill Lynch Pierce Fenner & Smith Inc., *Quantitative Analysis* 22 (Jan. 1981). More specifically, communication utilities showed, on average, a beta of .5 and an alpha of 1 percent; electric utilities a beta of .6 and an alpha of .4 percent; gas distribution utilities a beta of .8 and an alpha of -1.2 percent; and gas pipeline utilities a beta of 1 and an alpha of -3.3 percent. *Id.* at 7. While these data are of course not definitive — before conclusions could be drawn with respect to the representative beta and alpha of a utility group or an individual utility, a long-term analysis of past betas and alphas would have to be made — nonetheless, the beta and alpha information provided in the Merrill Lynch report is indicative of the importance of alpha's treatment in conjunction with a CAPM analysis.

This importance is highlighted where the alphas of particular securities are examined. Table 3 provides a sample of utilities with high reported alphas.

Table 3

Issuer	Alpha (%)	Beta
Communications		
American Tel. & Tel.	1.1	.5
Cincinnati Bell	2.3	.5
Gen'l Tel. & Elec.	1.5	.7
Western Union	3.7	1.1
Electric		
Carolina Pwr. & Lt.	1.1	.7
Central Ill. Lgt.	2.5	.6
Commonwealth Ed.	3.5	.6
Consumers Power	2.3	.6
Fitchburg G&E	2.0	.7

Maine Pub. Svc.	2.5	.6
Middle South Utl.	1.1	.5
Pennsylvania P&L	2.9	.6
Rochester G&E	3.0	.6
Savannah Elec.	3.1	.6
United Illuminat	2.3	.6
Gas Distribution		
Atlanta Gas Lt.	2.0	.8
Brooklyn Union	1.6	.5
Gas Pipeline		
Pacific Lighting	1.1	.6

Source: Merrill Lynch Pierce Fenner & Smith Inc., *Quantitative Analysis* (Jan. 1981).*

*It should be noted that the alphas and betas reported by Merrill Lynch are estimated alphas and betas, and are therefore subject to estimation errors.

If the positive alphas in Table 3 were representative of the long-term alphas of the indicated companies, and were CAPM employed as a method for establishing those companies' costs of equity, then plainly any decision to ignore the companies' alphas would have a significant downward impact on their resulting rates of return. As will be next discussed (Part II), that, in fact, describes the kind of decisions utility ratemakers have been rendering: in none of the rate cases where CAPM has been advanced or actually employed as a method for establishing a utility's cost of equity has alpha been taken into account. Indeed, in only one case was alpha even mentioned, and there it was ignored. Equally important, the decided rate cases failed to examine the mounting evidence (often because the evidence was not yet available) that the CAPM formula — with or without alpha — can yield highly arbitrary, suspect results.

II. *CAPM's Application in Rate Proceedings*

In the early 1970s, when the issue of CAPM's use in ratemaking was first debated, one of its proponents reported that the CAPM formula "ha[d] not yet been used in a regulatory proceeding."[2] However, over the past decade, CAPM has received increasing attention in rate proceedings before state and

[2] Stewart C. Myers, "The Application of Finance Theory to Public Utility Rate Cases," 3 *The Bell Journal of Economics and Management Science* 58, 69 (Spring 1972). Dr. Myers is Professor of Finance at the Sloan School of Management, Massachusetts Institute of Technology.

federal regulatory agencies. Moreover, it has often been relied upon by those agencies as a justification for lower equity costs than other methodological approaches would have indicated.

For example, as early as 1972, the FCC relied heavily on a CAPM analysis advanced by a trial staff witness in establishing AT&T's cost of equity. *American Telephone & Telegraph Co.*, 38 F.C.C. 2d 213 (1972). In that proceeding, CAPM indicated that AT&T (with a beta of approximately .7) was less risky than the average equity security in the marketplace, and hence that the cost of equity assigned AT&T should be lower than the returns provided on such a security. *Id.* at 237-38. The CAPM analysis endorsed by the Commission supported an equity cost finding substantially lower than that sought by AT&T.[3]

In recent years, state utility commissions have also begun to credit CAPM evidence in assigning equity costs to public utilities. For example, in *Portland General Electric Co.*, 23 PUR 4th 209 (Ore. Pub. Util. Comm'r 1977), Portland General Electric ("PGE") argued for a cost of equity in the range of 13.5 to 16 percent, whereas a witness for the Commissioner's staff, using CAPM, advocated a cost of equity of 11.1 to 12.25 percent. *Id.* at 219-21. After discussing the CAPM approach in detail and the staff's finding that the beta on the utility's stock was between .695 and .781, the Commissioner embraced the staff's CAPM evidence and premised his equity cost finding of 12.5 percent thereon.

The Commissioner's comments reveal how compelling he found the CAPM approach to be:

> Unlike the several common equity returns estimators employed and criticized by company witnesses, the CAP model [*i.e.*, CAPM] has been subjected to the most intensive examination and testing in this proceeding and has been shown to be a reliable and useful measure of the only relevant risk component — systematic (nondiversifiable) risk.
>
> * * * * * *
>
> The commissioner finds the CAP method and associated concepts advanced by staff to have general application to utilities whose common equity shares are traded and reported publicly. [*Id.* at 222.][4]

[3]Interestingly, three years later when CAPM was advanced by Comsat witness Stewart Myers (the same witness who had offered CAPM testimony for the Commission's trial staff in the AT&T proceeding) to support the proposition that Comsat was significantly more risky than the average equity investment, the FCC was totally unreceptive and assigned Comsat a cost of equity substantially lower than that supported by the CAPM analysis. Communications Satellite Corp., 56 F.C.C. 2d 1101 (1975), *remanded on other grounds sub nom.* Communications Satellite Corp. v. FCC, 611 F.2d 883 (D.C. Cir. 1977). The Commission ruled that the CAPM analysis was unreliable on a number of grounds, including the fact that the beta calculated for Comsat varied materially depending upon the data used in the calculation and the Commission's doubt that the basic premise of CAPM that risk should be assessed in the context of a diversified portfolio of investments was relevant to the Commission's task of determining Comsat's cost of equity. 56 F.C.C. 2d at 1169-70.

[4]In two earlier proceedings, the Commissioner had cautiously premised his cost-of-equity findings upon CAPM analyses advanced by the staff, but in each instance had called upon the staff to provide a more detailed evidentiary development of the CAPM approach in the future, a development ultimately provided in the *PGE* proceeding discussed above. *See* California-Pacific Utils. Co., 20 PUR 4th 479, 487-90 (Ore. Pub. Util. Comm'r 1977); Cascade Natural Gas Corp., 19 PUR 4th 170, 182-85 (Ore. Pub. Util. Comm'r 1977).

Similarly, in *Arkansas Western Gas Co.*, 16 PUR 4th 103 (Ark. Pub. Serv. Comm'n 1976), the Commission explicitly adopted the CAPM evidence sponsored by a witness for the Commission staff to establish the cost of equity for the utility in question. Noting that the "capital asset pricing model is a widely accepted model identifying the relationship between risk and return," the Commission found it "to be the appropriate method for establishing the cost of equity."[5] *Id.* at 108-09.

In *Southern Bell Telephone & Telegraph Co.*, 18 PUR 4th 623 (S.C. Pub. Serv. Comm'n 1977), CAPM received further regulatory endorsement. Southern Bell had petitioned for an increase in its rates and offered evidence that it was entitled to a return on equity ranging from 14 to 15.2 percent. *Id.* at 628. Examining various indicators of AT&T and Southern Bell financial performance, the Commission concluded that a reasonable return on Southern Bell's common equity was less than that sought. The Commission explained that its conclusion was "confirmed" by the CAPM testimony offered by the staff's witness, which indicated that 10.45 percent was the upper limit to Southern Bell's appropriate equity cost (the range being 8.04 - 10.45 percent). *Id.* at 630, 634. The Commission was unimpressed by Southern Bell's claim that CAPM "is an academician's theory, rather than a 'decision maker's' tool" (*id.* at 630), noting that "[w]hile it may be that CAPM requires further development before it is completely accepted in rate making, we believe the theory underlying it is sound and the results produced more in touch with reality than those furnished to us by Southern Bell witnesses." *Id.* at 631. Because CAPM indicated that Southern Bell had already been authorized rate increases which would permit it to earn a return in excess of the CAPM-derived estimate of its cost of equity, the Commission denied outright Southern Bell's petition for a rate increase.[6] *Id.* at 634.

In a substantial number of other rate proceedings, commission staffs have advanced, and regulatory commissions have relied, at least in part, upon CAPM evidence to support a lower cost of equity than that being sought by the regulated utilities. For example, cost of equity findings were importantly influenced by staff-submitted CAPM analyses in *New York State Electric & Gas Corp.*, 38 PUR 4th 220, 245-47 (N.Y. Pub. Serv. Comm'n 1980); *New York Telephone Co.*, 32 PUR 4th 353, 360-62 (N.Y. Pub. Serv. Comm'n 1979); *National Fuel Gas Distribution Corp.*, 28 PUR 4th 42, 62-63 (N.Y. Pub. Serv. Comm'n 1978); *Otter Tail Power Co.*, 30 PUR 4th 26, 47-51 (S.D. Pub. Utils. Comm'n 1979); *Northwestern Bell Telephone Co.*, 20 PUR 4th 462, 464-70

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[5]*But cf.* Southwestern Bell Tel. Co., 22 PUR 4th 209, 217-18 (Ark. Pub. Serv. Comm'n 1977), where the Commission rejected the CAPM evidence sponsored by a witness for Southwestern Bell on grounds that the beta he had calculated had arbitrarily been skewed upward to produce a higher risk assessment.

[6]CAPM has been advanced by the Commission staff in three other proceedings before the South Carolina Public Service Commission, and in each case the Commission has relied significantly, although not exclusively, upon the CAPM evidence in establishing the cost of equity of the utility under consideration. *See* Southern Bell Tel. & Tel. Co., 35 PUR 4th 1, 23-31 (S.C. Pub. Serv. Comm'n 1980); South Carolina Elec. & Gas Co., 34 PUR 4th 458, 477-85 (S.C. Pub. Serv. Comm'n 1979); Southern Bell Tel. & Tel. Co., 30 PUR 4th 263, 277-85 (S.C. Pub. Serv. Comm'n 1979).

(Iowa Commerce Comm'n 1977);[7] and *Intermountain Gas Co.*, 18 PUR 4th 79, 87-89 (Idaho Pub. Utils. Comm'n 1976).[8]

In none of the proceedings identified above was any mention made of the alpha of the utilities whose equity costs were analyzed in those proceedings. Indeed, only one case was found where the use of alpha was even addressed by a ratemaking body.

In the recent decision of *New York Telephone Company — Telephone Rates,* Case Nos. 27651 and 27710 (N.Y. Pub. Serv. Comm'n., Jan. 19, 1981), New York Telephone ("NYT") based its equity cost case in part upon a CAPM analysis that took into account a positive alpha calculation.[9] NYT's evidence showed that beta alone supported a 15.1% equity cost, and that where an alpha of .9% was taken into account, that equity cost became 16%. Administrative Law Judges' Recommended Decision, Case Nos. 27651 and 27710 (Oct. 31, 1980) at 65. The alpha adjustment argued for by NYT was not strictly a reflection of NYT's (or AT&T's) own specific alpha, but rather was an adjustment based on the premium above the riskless rate which has consistently been earned (over the 1926-1978 period) by stocks with a beta of zero. NYT argued that the persistence of this alpha premium was clear evidence that stocks with a zero beta provide a return higher than the riskless rate, thereby demonstrating that beta alone does not adequately reflect the required return on investment. *Id.* at 64-65.

In their recommended decision, the Administrative Law Judges (the "Judges") evaluated the described NYT evidence and a CAPM analysis submitted in rebuttal by the Commission staff and then noted, first, that "[i]f anything is clear from the mass of material presented to us with respect to the CAPM method, it is that in its present stage of development we are far from

[7]Although basically adopting the staff's recommended cost of equity, the Iowa Commerce Commission was somewhat cautious in endorsing the CAPM methodology:

> Although we find the theory to be consistent with cost of capital and fair rate of return determinations, much of it is still theoretical and subject to great debate.
>
> * * * * * *
>
> [T]here is the question of the validity of beta as a measure of the cost of capital for an individual stock, not a part of a portfolio. While on each of these points we would have to agree that the record tends to support the staff position, we cannot accept the exact figure generated through this methodology as being the one and only correct cost of equity supported by the record. [20 PUR 4th at 469.]

[8]Commission staffs also submitted CAPM evidence in the following proceedings, although the role that that evidence played in the cost-of-equity determination ultimately made by the utility commission is not entirely clear: Pennsylvania Pub. Util. Comm'n v. Philadelphia Elec. Co., 33 PUR 4th 319, 339-44 (Pa. Pub. Util. Comm'n 1980); Southwestern Bell Tel. Co., 34 PUR 4th 224, 237-262 (Tex. Pub. Util. Comm'n 1979); Granite State Elec. Co., 28 PUR 4th 240, 244 (N.H. Pub. Util. Comm'n 1978); Idaho Power Co., 23 PUR 4th 299, 310-13 (Idaho Pub. Utils. Comm'n 1977); Southern Bell Tel. & Tel. Co., 21 PUR 4th 451, 480-85 (Fla. Pub. Serv. Comm'n 1977).

In a survey as of February 1979, one commentator found that CAPM had been used in rate cases in 13 different states (Georgia, Iowa, Montana, New Hampshire, New Jersey, New Mexico, Nebraska, Ohio, Oregon, Rhode Island, South Carolina, Texas, and Washington). Harrington, "The Changing Use of the Capital Asset Pricing Model in Utility Regulation," 105 *Public Utilities Fortnightly* 28, 29 (Feb. 14, 1980). That survey revealed that in Oregon use of the CAPM model was required, that in South Carolina the commission staff would use CAPM in all future cases, and that only in Texas was there any predisposition against use of the model. *Id.* The survey further indicated that, in total, "38 states were considering or had seen the CAPM used." *Id.*

[9]AT&T offered less than a whole-hearted endorsement of the CAPM method, stating in its opening brief that " '[w]hether CAPM can be used accurately in rate cases is still debatable. . . ' " and taking the position that, if CAPM is to be used at all, it must take into account alpha. Administrative Law Judges' Recommended Decision, Case Nos. 27651 and 27710 (Oct. 31, 1980) at 64.

any consensus as to its proper use for regulatory purposes." *Id.* at 68. With this preface, the Judges endorsed the theoretical validity of the alpha adjustment argued for by NYT, but rejected the precise computation of alpha on evidentiary grounds. *Id.* at 64-65, 69. Nevertheless, in order to take account of their view that to ignore alpha would cause the "CAPM-indicated cost of equity" to be understated "in some undetermined amount" (*id.* at 69), in assigning NYT a cost of equity the Judges based their decision on a weighted composite of the cost indicated by the DCF method[10] and that indicated by the CAPM method (without the alpha adjustment), giving two-thirds weight to the former and only one-third weight to the latter. *Id.* at 73.

On appeal to the New York State Public Service Commission, NYT challenged the Judges' failure to take specifically into account the alpha adjustment supported by its evidence when the Judges had conceded the theoretical validity of the adjustment. On grounds that NYT had failed to prove the validity of the specific alpha adjustment for which it contended, the Commission affirmed the Judges' decision without addressing the correctness of that adjustment as a matter of theory. Slip Op. No. 81-3 (Jan. 19, 1981) at 31.[11] The Public Service Commission repeated this view on NYT's Petition for Rehearing, stating that "[t]he possible need for such an adjustment [based on alpha] was a factor that we considered, but the record did not support a particular adjustment." Order Responding to Petitions for Rehearing (May 14, 1981) at 5.

Thus, a review of the regulatory decisions reveals that the CAPM has achieved widespread acceptance among ratemaking bodies and is now routinely used by those bodies to establish rates of return for utilities. For the reasons that follow, we submit that that acceptance and use should be reconsidered.

III. *The Case Against CAPM*

In our estimation, those contending that regulatory commissions should establish utility rates of return based on CAPM should be asked first to show at least the following:

(A) that the CAPM theory is sound, *i.e.*, that its underlying assumptions have been tested and are valid;
(B) that the theory can be appropriately applied in the utility ratemaking context; and
(C) that, in practice, the theory produces reliable, objective estimates of a utility's cost of equity.

We make this suggestion on the assumption that in any given rate proceeding the proponents of a particular rate-producing methodology can fairly be required to establish that methodology's credentials. The required showing

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[10]The DCF (discounted cash flow) method, simply stated, assumes that the cost of equity for a particular stock is equal to its dividend yield (current dividend divided by current price) plus the annual expected growth rate in dividends.

[11]However, using updated return data, the Commission assigned NYT a higher cost of equity than that recommended by the Judges, and, although basing its finding upon both the DCF and CAPM methods, did not adopt the weighting approach employed by the Judges.

would of course vary with the proven reliability of the method at issue — we do not suggest that every rate proceeding should be burdened by the reinvention of the wheel as to every methodology employed in the proceeding. But our experience with and review of the regulatory case law is that the CAPM wheel appears never to have been invented at all. Rather, CAPM's basic credentials as a reliable ratemaking tool have simply been assumed.

This, we submit, is a mistake. Some minimal showing — such as the three elements suggested above — should be fairly well established before rates are built on a CAPM foundation.[12] Our review convinces us that the minimal showing has not been made; that, in fact, the weight of the available evidence is heavily against CAPM as to all three elements of that showing. That is the evidence we summarize below.

A. *The Validity of the CAPM Theory*

When we assert that the validity of CAPM's underlying assumptions has not been shown, we intend nothing sweeping. Rather, for purposes of the limited (but, we think, important) point we are attempting to make here, we do not presume to challenge the important principle that CAPM borrows from modern portfolio theory — that, generally speaking, the expected return on a particular asset may properly be assessed as if that asset were part of a portfolio, and that by holding the asset in a portfolio an investor can "diversify away" certain of that asset's risk. Neither do we question what we understand to be the basic proposition of CAPM itself — that investors, being risk-averse, tend to price assets so that the riskier ones have higher expected rates of return. Finally, we do not dispute the basic idea of beta — that assets' returns can generally be expected to move up and down in a pattern related to the movements of "the market" as a whole, and that the way in which a particular asset "responds" to market movements is an important indicator of that asset's risk.

But regulatory bodies should require some degree of *proof* before ascribing to these admittedly sound *general* principles a mathematical precision they have never been shown to have. One can accept that portfolios tend, through diversification, to cancel risks, that assets are generally priced to reflect nondiversifiable risks, that one such risk is market risk, and that beta is designed to capture how market risk affects a particular asset, without having to agree that once one has estimated an asset's beta, all that remains to be done to reliably *quantify* that asset's entire expected return is (in effect) to multiply the asset's beta times the market's expected return.

Rather than catalogue all the material assumptions that underlie the proposition that beta is sufficient to produce such a quantification, we discuss here only two that appear to us to be obvious and particularly important: the first necessary assumption is that there not only be a *relationship* between the market's excess return and every asset's excess return, but that every asset's

[12]The absence of any such showing has persuaded some utility commissions to reject CAPM. *See, e.g.*, Connecticut Nat. Gas Corp., 37 PUR 4th 287, 328-29 (Conn. Div. Pub. Util. Control 1980) (characterizing CAPM as an elegant "black box" that "has not survived extensive regulatory scrutiny").

expected excess return is *directly and exactly proportional* to the market's expected excess return, *i.e.*, that the trade off between market risk and return is a straight line; and the second necessary assumption is that once this measurement of expected return owing to market risk has been made (via beta), all expected return has been captured, *i.e.*, there is, by definition, no other risk but beta-risk for which investors expect to be compensated.

It seems to us plain that these two assumptions would have to be well-founded before the regulatory bodies' reliance on beta can be thought sound; and yet, we can find no specific evidence validating either assumption. Indeed, what evidence there is indicates that both assumptions are invalid.

1. *Beta Does Not Capture an Asset's Market-Risk*

Among the most recent and telling criticisms directed at beta have been those articulated by Richard W. Roll, a Professor of Finance at the UCLA Graduate School of Management and a leading advocate for the large (and growing) cadre of professionals who believe that CAPM provides an unreliable measure of asset risks and returns.[13] Through Professor Roll's work, it has been demonstrated[14] that CAPM depends upon a critical assumption which may or may not be true and which, unfortunately, cannot be (or, at least, to date has not been) tested.

The underlying premise of CAPM's reliance on beta is that every stock's expected excess return is directly proportional to the market's expected excess return, and that the degree of proportionality is exactly measured by beta. But, as a matter of mathematics, beta can be relied upon as a measurement of this assumed direct proportionality if, and only if, the market portfolio itself is what is called "mean-variance efficient." This means that, for beta to be sound, the market portfolio of all available assets must in fact provide the highest possible average (mean) return, given the variability (volatility) associated with that portfolio's return. And therein lies the problem.

As noted above, the market index conventionally employed in connection with a CAPM analysis is a broad index of stocks like the Standard & Poor's 500. However, use of such an index would be correct only if (i) it were a valid proxy (in the sense that it would be expected to yield the same beta) for a portfolio of all invested assets, including such difficult-to-measure assets as human capital and other non-traded assets, and (ii) if that portfolio of all invested assets were "mean-variance efficient."

Thus, there are really two problems, and neither one of them has been solved: first, it must be known whether the particular index being used is

[13] *See generally* Wallace, "Is Beta Dead?," *Institutional Investor* 23 (July 1980); Blustein, "Money Managers Bedrock Theory of Investing Comes Under Attack," Wall St. J., Sept. 8, 1980, at 13; Baron, "Assault on Beta Theory Jolting Money Managers," L.A. Times, Oct. 6, 1980, § B, at 1; and 7 *The Journal of Portfolio Management* (Winter 1981), an issue devoted to the "Is Beta Dead?" controversy.

[14] *See* Roll, "Performance Evaluation and Benchmark Errors (I)," 6 *The Journal of Portfolio Management* 5 (Summer 1980); Roll, "Performance Evaluation and Benchmark Error (II)," 7 *The Journal of Portfolio Management* 17 (Winter 1981); Roll, "Testing a Portfolio for Ex Ante Mean/Variance Efficiency," in E. Elton and M. Graber, eds., 11 *TIMS Studies in the Management Sciences* 135 (1979); Roll, "A Reply to Mayers and Rice," 7 *Journal of Financial Economics* 391 (1979); Roll, "Ambiguity When Performance Is Measured by the Securities Market Line," 33 *The Journal of Finance* 1051 (Sept. 1978); Roll, "A Critique of the Asset Pricing Theory's Tests," 4 *Journal of Financial Economics* 129 (Mar. 1977).

indeed a valid (or the best available) proxy for the true market portfolio; and second, it must be known that that true market portfolio is in fact efficient. The reason neither problem has been solved is that a portfolio of all assets (or an acceptable proxy therefor) has never been reliably formed and tested.

On the other hand, it *can* be tested whether the particular index being relied upon to estimate an asset's beta is itself efficient. Professor Roll has demonstrated, for example, that the S&P 500 — ordinarily relied upon in rate proceedings — is not efficient and therefore cannot produce sound betas. Moreover, each inefficient index (such as the S&P 500) will produce a different beta, and a different expected return — none of them reliable.

Since no valid, efficient proxies for the market as a whole have been developed, the beta of a stock as measured against a broad market index is not a reliable indicator and is, in one sense, wholly arbitrary in that it is solely a function of the index chosen. "For every asset, an index can be found to produce a beta of any desired magnitude, however large or small." Roll, "Ambiguity When Performance Is Measured by the Securities Market Line," 33 *The Journal of Finance* 1051, 1056 (Sept. 1978). Thus, since the beta of a stock varies depending upon the market index employed, since there is no dependable index which is truly reflective of the market as a whole, and since there is no way of knowing that that "market as a whole" is efficient, the most recent evidence strongly indicates that no reliable conclusions regarding the risk of an asset or the return required on it can be derived through the beta produced by any given market index. Hence, we submit, conclusions previously reached by the ratemakers through their application of CAPM (relying solely on beta) may have been totally arbitrary.

Moreover, the lack of an efficient, measurable market portfolio is not the only problem with the regulatory reliance on beta. There is considerable evidence that beta in any event does not necessarily capture all of an asset's expected return.

2. *Beta Does Not Fully Capture an Asset's Expected Return*

CAPM "says that [beta] is a complete and sufficient risk measure, that the expected risk premium demanded by investors is zero when beta is zero. . . ."[15] But recent evidence shows that this critical CAPM assumption is simply not correct. In fact, the author of the quoted statement, who has offered evidence in several rate proceedings based on beta measurements, and who has generally been a proponent of such a use of beta,[16] recently testified that CAPM "is probably not a complete description of equilibrium trade-off between risks and returns that actually prevails in capital markets."[17]

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[15] Myers "On the Use of Modern Portfolio Theory in Public Utility Rate Cases: Comment," *Financial Management* 66, 67 (Autumn 1978).

[16] *See id.*, Myers, "On the Use of Beta in Regulatory Proceedings: A Comment," 3 *The Bell Journal of Economics and Management Science* 622 (Winter 1972).

[17] Testimony of Stewart C. Myers In the Matter of the Valuation Proceedings Under §§ 303(c) and 306 of the Regional Rail Reorganization Act, Tr. at 609 (June 6, 1979).

Some of the recent evidence shows that if an asset's beta is to be relied on to estimate its expected return, the asset's alpha also must be taken into account; other evidence shows that some assets consistently earn higher returns than that predicted by beta, and that those higher returns can be predicted by non-CAPM methods. Both kinds of evidence are wholly contrary to the assumption that beta is a complete measurement of an asset's expected return, that an asset with a zero beta has a zero risk premium, and that an asset with a beta of one has a risk premium identical to the market risk premium.

We will first describe the alpha-related evidence, and thereafter explain the evidence concerning beta's inability to predict returns.

The use of a market index to compute a given stock's beta and alpha requires, by definition, that the weighted (by market value) average beta of all the stocks in the index will be exactly 1.0, and the weighted average alpha will be zero. But just as a given stock's beta need not be exactly 1.0, neither need its alpha be exactly zero. Those who take into account a stock's estimated beta in estimating its expected return, but ignore its estimated alpha, do so on the theory that over the long term the particular stock's alpha will average to zero and that, therefore, it should not be treated as statistically significant. It is this theory which has been shown to be highly questionable, if not completely unsound.

In the current litigation designed to value the railroad properties taken by the United States for Conrail, Dr. Richard Meyer, Professor of Managerial Economics at the Harvard University Graduate School of Business Administration, presented a comprehensive survey demonstrating the relative predictive powers of beta and alpha in estimating assets' future returns. Beginning with the five-year period 1960-1965 and going up through the five-year period 1968-1973, Professor Meyer calculated the alpha and beta for every United States company for which dividend-adjusted stock return data were available. This ranged from a low of 666 firms for the 1960-1965 period to a high of 909 firms for the 1968-1973 period. He then compared the actual returns on the stocks for various multi-year periods following each of the five-year estimation periods in order to assess the predictive power of alpha and beta. *See* Testimony of Richard F. Meyer, pp. 58-61 (January 30, 1980). *In the Matter of the Valuation Proceedings under Sections 303(c) and 306 of the Regional Rail Reorganization Act of 1973*, Special Court Misc. No. 76-1 ("The Railroad Valuation Proceedings").

Using standard statistical measurements, the comparison showed that in some periods beta was more significant, and that in others alpha was more significant, but "that alpha and beta have approximately equal significance considered overall." *Id.* at 60. Crucial to these results is that "there is no evidence that alpha is systematically insignificant," even though CAPM assumes that it is. *Id.* Moreover, the study showed that "alpha tends to gain significance with the length of the forecasting period," *id.*, a fact of considerable importance in utility ratemaking where future costs of equity are often estimated for several years or more. Hence, Dr. Meyer concluded, notwithstanding CAPM's assumption that beta fully captures expected returns, "alpha may not arbitrarily be ignored. . . ." *Id.*

There are several theories for why particular assets evidence persistent alphas. One view, stated in Dr. Meyer's testimony, is that beta fails to capture all market-related risk associated with a particular asset since the market index used to compute beta does not contain all available assets. Alpha may measure the effect of these "missing" assets on investors' risk perceptions.[18]

A second explanation, presented by Dr. Robert H. Litzenberger in *New York Telephone Company — Telephone Rates, supra,*[19] is that alphas consistently appear for two reasons.[20] First, according to Dr. Litzenberger, CAPM assumes incorrectly that investors are able to borrow and lend in unrestricted amounts at the risk-free rate, and the fact that they are not means that the relationship between risk and return is not directly proportional to the betas of individual securities. Second, the value-weighted portfolio of all New York Stock Exchange stocks often used to calculate the beta of individual stocks is not a representative surrogate for the market as a whole, but instead is relatively more risky than that market on average.[21] As a consequence, contrary to the CAPM theory, stocks with betas of zero have, over the past 50 years, consistently earned a risk premium above the riskless rate. This additional risk premium is captured by alpha.[22]

A third explanation for the appearance of alphas, as described by Dr. Richard Roll, is that alpha is simply a measurement of the inefficiency of the market index being used to compute beta; that is to say, if the market index were, as earlier discussed, mean-variance efficient, beta would be a reliable measurement of expected return and there would be no alphas. But since the index is not efficient, alpha will not necessarily be zero, and will capture that part of an asset's expected return not captured by beta.[23]

Yet another view of alpha, expressed by a strong proponent of CAPM — Dr. Barr Rosenberg[24] — is that beta *is* a reliable measurement of market risk, and that such risk is an important factor affecting expected return; however,

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[18]Testimony of Richard F. Meyer in The Railroad Valuation Proceedings, Tr. at 636 (Aug. 25, 1980).

[19]Dr. Litzenberger is the C.O.G. Miller Distinguished Professor of Finance at the Graduate School of Business, Stanford University.

[20]*See* Testimony of Robert H. Litzenberger, New York Telephone Co. — Telephone Rates, Case Nos. 27651 and 27710 (N.Y. Pub. Serv. Comm'n), Tr. at 2122-28 (May 15, 1980). *See also* Litzenberger, Ramaswamy, & Sosin, "On the CAPM Approach to the Estimation of a Public Utility's Cost of Equity Capital," 35 *The Journal of Finance* 369 (May 1980).

[21]As previously mentioned, beta is usually measured against a broad index of stocks, but theoretically should be assessed in light of all potential investments.

[22]The actual alpha adjustment developed by Dr. Litzenberger to account for this additional risk premium called for a .9% upward adjustment in the 15.1% NYT equity cost indicated by beta alone (or a total equity cost of 16.0%). The Public Service Commission's analysis of Dr. Litzenberger's evidence suggests that had he demonstrated the value of NYT's particular alpha, rather than simply demonstrating the general inability of beta to capture an asset's total expected return, it might have adopted Dr. Litzenberger's cost of equity figure. *See* Order Responding to Petitions for Rehearing (May 14, 1981) at 5 ("The possible need for such an [alpha] adjustment was a factor that we considered, but the record did not support a particular adjustment.").

Recently, Dr. Litzenberger filed testimony in support of New York Telephone's pending application for a rate increase. His testimony included evidence showing that the alpha adjustment necessary for zero-beta stocks may be appropriately applied to stocks with betas in the more common ranges (from .5 to 1.5). *See* Testimony of Robert H. Litzenberger, New York Telephone Co. General Rate Case, Case No. 27795 (N.Y. Pub. Serv. Com'n), Vol. V at 33-36 and Exhibit at Section 11 (May 1981). A decision by the Public Service Commission is not expected in that case until May 1982.

[23]Roll, "Performance Evaluation and Benchmark Errors (II)," *supra*, at pp. 19-20; Testimony of Richard Roll in The Railroad Valuation Proceedings, pp. 72-73 (January 30, 1980), Tr. 102 (July 21, 1980), Tr. 240-44 (July 22, 1980), and Tr. 1277-78, 1290, 1376 (August 19, 1980).

[24]Dr. Rosenberg is Professor and Director of the Berkeley Program in Finance at the Berkeley Business School, University of California.

since it may be that factors *other* than market risk affect investors' perceptions regarding expected returns, by definition there may be an expected return in excess of that measured by beta. It is this excess which, according to Dr. Rosenberg, alpha captures: "There is nothing mysterious about this alpha; it is simply an expression of judgment on the security's expected return." Rosenberg, "The Capital Asset Pricing Model and the Market Model," 7 *Journal of Portfolio Management* 5, 10 (Winter 1981).

Thus, there is substantial evidence indicating that alpha captures expected return missed by beta. There is, in addition, substantial evidence that CAPM simply misestimates expected return, whether or not the misestimation stems from the failure to consider alpha.

For example, in the previously mentioned railroad valuation proceedings, Dr. Richard Roll presented a study in which numerous portfolios of railroad stocks were specifically constructed so that they had betas exactly equal to 1.0. In all, 40 portfolios were observed over two successive five-year periods, and their returns measured relative to the market index (S&P 500) returns. Contrary to CAPM's assumption, all 40 portfolios consistently outperformed the market index, by an average of 5-8 percentage points[25] — meaning that if CAPM had been relied on (*i.e.,* the beta of 1.0 had been used to compute expected returns), the railroads' cost of equity would have been understated by those 5-8 points. Moreover, through the use of certain non-CAPM methods for estimating the railroads' cost of equity, Dr. Roll confirmed that that cost was in fact 5-8 points higher than the figure indicated by CAPM.[26]

Furthermore, in those same railroad valuation proceedings, Dr. Stewart Myers, who *did* rely on beta in estimating the railroads' cost of equity, and who also rejected the need to take alpha into account, nevertheless testified on cross-examination that "the research suggests that the capital asset pricing model formula misses a measure of risk, and that measure of risk may be the standard deviation."[27] "Standard deviation" is a measurement of *total* volatility of the particular asset's returns, as contrasted with beta which is a measurement only of the asset's volatility *relative* to the market's volatility. Thus, to say that standard deviation may capture expected return not captured by beta is to agree that not *all* asset-specific risk is necessarily cancelled out (diversified away) by holding assets in portfolios. This necessarily means that beta-risk (nondiversifiable market risk) is not the only risk affecting investors' expectations — an idea plainly at odds with a key underpinning of the CAPM theory.

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[25] Testimony of Richard W. Roll in The Railroad Valuation Proceedings, pp. 74-80 (Jan. 30, 1980).

[26] The two non-CAPM methods relied upon by Dr. Roll for estimating costs of equity were, first, measurements over two five-year periods of the actual differences in return between the market index and specially constructed railroad portfolios ("minimum variance portfolios"), and, second, measurement of the actual difference in returns between the market index and general railroad portfolios over the past 50 years. *Id.* at pp. 42-67. Significantly, by relying on both beta and alpha Dr. Richard F. Meyer estimated virtually the same railroad cost of equity as did Dr. Roll. Testimony of Richard F. Meyer, *supra,* at p. 101. It should be noted that the Court in the Railroad Valuation Proceedings ultimately gave no weight to either Dr. Roll's or Dr. Meyer's testimony. The Court offered *no* explanation as to why it was unpersuaded by Dr. Meyer's testimony and, as to Dr. Roll's testimony, stated without analysis that his findings were not "statistically significant." Special Court for Regional Rail Reorganization, Opinion with respect to Valuation for Rail Use at 61-62. (Nov. 24, 1981).

[27] Testimony of Stewart C. Myers in The Railroad Valuation Proceedings, Tr. at 565 (July 5, 1979).

In addition, there is recent evidence to suggest that market risk is not the only kind of systematic risk that affects assets' expected returns. Rather, as Professors Roll and Stephen Ross[28] have shown, through application of what they call the arbitrage pricing theory, that there are at least three, and possibly four, systematic factors — not just beta — which should be taken into account in estimating expected returns.[29] *See* Roll and Ross, "An Empirical Investigation of the Arbitrage Pricing Theory," 35 *The Journal of Finance* 1073 (Dec. 1980); Ross, "The Arbitrage Theory of Capital Asset Pricing," 13 *Journal of Economic Theory* 341 (Dec. 1976). As will be discussed below, one such additional systematic factor — interest-rate risk — has been clearly demonstrated to have a risk impact on expected utility returns which is not captured by beta.

Finally, the most recent empirical research demonstrates that portfolios of stocks with higher price/earnings ratios consistently earn higher returns than portfolios of stocks with low price/earnings ratios, even though all the portfolios have identical betas. And, similarly, portfolios of stocks in small firms consistently earn higher returns than portfolios of stocks in larger firms, again notwithstanding that both kinds of portfolios had identical betas. *See* Reinganum, "Misspecification of Capital Asset Pricing: Empirical Anomalies Based on Earnings Yields and Market Values," 9 *Journal of Financial Economics* 19 (Mar. 1981) 19-46; Banz, "The Relationship Between Return and Market Value of Common Stocks," 9 *Journal of Financial Economics* 3 (Mar. 1981).

This research does not necessarily demonstrate that a high P/E or small size is equated by investors with greater risk — it may be that the higher returns are equated with some other factor that happens fortuitously to be associated with high P/E and/or smaller firms. But what *is* necessarily demonstrated by this research is that some factor other than beta-measured risk affects investors' expected returns. *Id.* at 16-17; Reinganum, *supra,* at 44-45. That is enough to make reliance on CAPM questionable.

B. *CAPM's Applicability in the Ratemaking Context*

In addition to the foregoing general problems with the CAPM theory, there are additional problems with the theory when it is specifically considered in the ratemaking context. To date, these problems have not been resolved, nor even addressed by the ratemakers. We raise three of them here.

The first is that while CAPM assumes that an asset's "response" to market movements is all that need be assessed in estimating the asset's expected rate of return, in the case of utilities there is in fact another important risk to consider — the actions of the ratemakers themselves. The second problem is that utilities are peculiarly affected by a nondiversifiable risk other than market risk — interest-rate risk. Finally, the third problem is that CAPM's assump-

[28]Stephen A. Ross is Professor of Finance at the School of Organization and Management, Yale University.

[29]Moreover, the arbitrage pricing theory (APT) has two distinct advantages over CAPM. First, unlike CAPM, APT does not require that the universe of all available assets be included in the measured market portfolio; rather, APT yields statements of relative pricing based on "subsets" of all available assets. Second, unlike CAPM, APT does not require that the market portfolio be mean variance efficient in order that accurate systematic-factor estimates be made.

tion that everything but market (beta) risk will be cancelled out in a well-diversified portfolio depends on the further assumption that the potential up-side and down-side risk of the various assets in the portfolio is largely symmetrical — an assumption that may not be true of utilities, whose up-side potential is subject to regulatory ceilings.

1. *"Regulatory Risk" Is Not Captured by CAPM*

CAPM asserts that the way in which an asset's returns previously moved up or down in relation to the market's movements — a relationship captured by beta — is a fair estimate of the future volatility of the asset's returns. This future volatility, in turn, is said to be a fair indication of the asset's risk, and therefore of its expected return (relative to the market's risk and expected return). Whatever may be the accuracy of these propositions in the case of an unregulated company, there is serious doubt that they can be correct in the case of regulated utilities.

There are at least two reasons for this special doubt in the case of regulated assets. The first is that, as Messrs. Breen and Lerner[30] have pointed out, "[i]t is reasonable to believe . . . that regulatory decisions themselves directly affect the value of beta, for they influence the corporation's growth rate, stability, size, and payout."[31] If this is so, the regulatory body must determine how its own decision may *change* the way in which the company's returns will in the future respond to the market, *i.e.*, how beta may change as a result of the rate-of-return decision.

Though Dr. Stewart Myers criticized some of the Breen and Lerner description of beta's use in regulatory proceedings, he expressly agreed that: "Breen and Lerner are correct in pointing out that regulatory decisions can affect utilities' risks. Further work is needed to identify situations in which the effect is empirically significant and to devise ways of taking the effect into account in such situations."[32] Yet, to date the regulatory bodies have taken no account of the effect of regulatory risk on utility betas, and no study has been done showing how great might be the distortion in the utility betas which the regulatory bodies have relied on.

Second, the distortion in those utility betas may be severe if, as Professor Carleton[33] has argued, "regulation itself has been the main source of [utility] investor risk in recent years."[34] This investor risk stems from, among other things, uncertainty regarding what decision the regulators will make, when it

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[30]Dr. William J. Breen and Dr. Eugene M. Lerner are both Professors of Finance at the Graduate School of Management, Northwestern University.

[31]Breen and Lerner, "On the Use of Beta in Regulatory Proceedings," 3 *The Bell Journal of Economics and Management Science* 612, 621 (Winter 1972).

[32]Myers, "On the Use of Beta in Regulatory Proceedings: A Comment," 3 *The Bell Journal of Economics and Management Science* 622, 626 (Winter 1972).

[33]Dr. William T. Carleton is William R. Kenan, Jr., Professor of Business Administration at the University of North Carolina.

[34]Carleton, "A Highly Personal Comment on the Use of the CAPM in Public Utility Rate Cases," *Financial Management* 57, 59 (Autumn 1978).

will be made, and the built-in lag between investor-expected and company-realized rates of return. This implies both a changing ability of utilities to react to market-wide risks, a changing character in those reactions, and, certainly, "non-constant expected rates of return to the firm and to investors over future periods."[35]

All of this is at odds with CAPM's assumption that a given asset's returns react in a relatively constant manner to market-wide risks. In large part, in the case of a regulated utility, clearly this is not so; rather, the "regulatory risk" skews the reaction to market-wide risks. And there is no reason to suppose, nor evidence to demonstrate, that past betas capture the impact of that regulatory risk.

2. *Market Risk Is Not the Only Systematic Risk Affecting Utilities*

As suggested by the previously-mentioned work of Professors Ross and Roll, there may be several systematic (nondiversifiable) factors which affect a given asset's expected return. While market risk is plainly one such factor, it need not be the only one. For example, some assets may be more sensitive to interest-rate risks than is the market (or market index) as a whole, and, therefore, this greater sensitivity would not necessarily be captured by such assets' market (beta) risk. Recent empirical evidence has shown, as would be expected, that utilities are among those assets that are in fact more interest-rate sensitive than is the market as a whole. Chance, "Progress in Modeling Utility Stock Holding Period Returns," 107 *Public Utilities Fortnightly* 34 (May 7, 1981).

In the cited article, Professor Chance[36] shows that, if CAPM is to be used, an additional systematic-risk factor should be added to the CAPM formula in order to capture the interest-rate risk that beta misses. The value of this factor is determined through use of a bond index and represents the given utility's "response" to movements in that index, in much the same way that beta represents the utility's "response" to movements in a stock market index.[37] This additional nonstock market factor is generally referred to as "extra-market covariance."

What other "extra-market" factors would have to be added to the CAPM formula (in addition to the interest-rate factor) for it to be a full and fair measure of expected utility returns is not yet clear. What does seem clear, however, is that the CAPM formula which has been relied on in the past is not such a measure.

3. *Non-Market Utility Risk Is Not "Diversified Away"*

The third major problem peculiar to CAPM's application to regulated companies turns on a pivotal CAPM assumption — that all risk other than

[35] *Id.* at 59; *see* Christy & Christy, "Who Says Utilities Are Less Risky?" 105 *Public Utilities Fortnightly* 11, 17-18 (May 8, 1980).

[36] Don M. Chance is Assistant Professor of Finance at Virginia Polytechnic Institute and State University.

[37] Addition of the interest-rate factor is based on the work of Professor Bernell Stone in "Systematic Interest Rate Risk in a Two-Index Model of Returns," 9 *Journal of Financial and Quantitative Analysis* 709-21 (November 1974).

market-related (beta) risk is cancelled out when the particular asset is held in a portfolio. The underpinning of this assumption, as Messrs. Brigham and Crum[38] have explained, is the further assumption that all assets' returns

> are randomly distributed, and that the distribution of returns for each security is reasonably symmetrical. Symmetry means that the random losses on one security can be offset by random gains on another. This makes it possible for investors to diversify away unsystematic, or non-market, risk, leaving systematic risk, which is measured by beta, as the only relevant risk. However, if the distribution of returns on a group of securities is skewed to the left (some probability of large losses but no probability of large gains), then the CAPM breaks down. Diversification can no longer eliminate all unsystematic risk, so market risk as measured by beta is not a complete risk measure.[39]

But as Brigham and Crum further explain, this necessary assumption is simply not true in the case of utility returns. Owing primarily to the fact that utilities' returns are regulated and therefore have a fixed ceiling — but no fixed floor — "investors have reason to view utilities as having more downside risk than upside potential, which translates into a probability distribution of future returns skewed toward negative returns."[40] The result is that utilities — unlike unregulated companies — cannot be assumed to have all their "down-side" non-market risk cancelled out, and, therefore, their "CAPM cost of capital estimates will be downward biased."[41]

Based on the foregoing, there are substantial reasons to conclude that the CAPM theory, both as a general proposition and when specifically considered as a tool for ratemakers, is unsound. Moreover, when actually applied, the theory is no more persuasive, since it has been shown to produce arbitrary, unreliable results.

C. *The CAPM In Practice*

To this point we have tried to show that there currently exists such considerable evidence questioning the validity of the CAPM theory, both generally and in the utility ratemaking context particularly, that regulatory bodies should seriously consider whether to accord it further use. We now wish to make a different point — that even if one were convinced that the CAPM, as theory, had been shown sound enough to warrant regulatory use, there are such significant problems associated with the theory's practical application that the results it produces do not merit regulatory reliance.

Two types of problems will be mentioned here. The first is that the CAPM formula, elegant and simple on its face, is really not simple at all; rather, it requires that choices be made about such matters as holding periods, measurement intervals, the proper risk-free rate, the proper market rate, the proper market index, etc. — all debatable, and some bordering on arbitrary — the resolution of which can produce dramatically differing re-

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[38] Dr. Eugene F. Brigham is Professor of Finance and Director of the Public Utility Research Center at the University of Florida. Dr. Roy C. Crum is Assistant Professor of Finance at the University of Florida.

[39] Brigham and Crum, "Reply to Comments on 'Use of the CAPM in Public Utility Rate Cases,' " 7 *Financial Management* 72, 73-74 (Autumn 1978).

[40] *Id.* at 75.

[41] *Id.*

sults. The second problem that must be confronted — perhaps the most important of all — is that significant evidence exists showing that CAPM produces utility costs of equity out of keeping with common sense.

1. *Application of CAPM Is Prone to Arbitrariness*

Since CAPM states that an asset's expected return is equal to the risk-free rate plus beta times the difference between the market rate and the risk-free rate, one must know only three numbers in order to compute a given asset's expected rate of return: the expected risk-free rate; the expected market rate; and the asset's expected beta. But what each of those numbers should be for any given asset is anything but clear.

Taking the easiest of the three first — the risk-free rate — it is not difficult to determine the expected rate of return on risk-free instruments for any given date. For this purpose, *The Wall Street Journal* may be consulted. But therein lies a two-fold problem for utility regulation: the expected rates of return vary considerably from instrument to instrument, and, at least in the current volatile market, a given instrument's return can vary considerably from day to day (or, in any event, from week to week).

Assuming a current Treasury bill or note is to be relied on, what maturity should be used? In the case of utility ratemaking, it is arguable that, since a cost of equity is being established for a long period — say, five years — the riskless rate on a five-year instrument should be used.[42] On the other hand, CAPM theory provides that whatever measurement interval was used to record periodic returns on the market index and the asset in question must also be used as the maturity period of the riskless asset.[43] This would dictate use of no greater than a 30-day or 90-day bill since measurement intervals less than monthly or quarterly are rarely used for CAPM.

But if only a 30-day or 90-day bill rate is employed, then arguably only a 30-day or 90-day utility cost of equity is being computed.[44] Since regulatory bodies are obviously not going to recompute allowable rates of return every few months, perhaps, alternatively, they should study the differences among prevailing riskless rates of varying maturities, and estimate a different riskless rate (and a different total cost of equity) for each of several successive periods.[45]

However the regulators elect to resolve this risk-free-rate dilemma — particularly if interest rates remain volatile and the spreads among varying maturities remain large — it will potentially have a significant impact on the cost of equity. For example, the rates on all riskless instruments are currently several points higher than they were a few short months ago, and the spread among current riskless instruments of varying maturities is also several points.

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[42]*See, e.g.*, Hyman & Egan, "The Utility Stock Market: Regulation, Risk, and Beta," 105 *Public Utilities Fortnightly* 21, 25 (Feb. 14, 1980).

[43]*See* Brigham and Crum, *supra*, at 75; Carleton, *supra*, at 57-58.

[44]*Id.* at 58.

[45]Messrs. Litzenberger, Ramaswamy, and Sosin have suggested that the risk-free rate should be computed "as a simple average of monthly forward Treasury Bill rates for the period the pending rate order is expected to be in effect." "On the CAPM Approach to the Estimation of a Public Utility's Cost of Equity Capital," 35 *The Journal of Finance* 369, 377 (May 1980).

Hence, using CAPM, the particular risk-free instrument selected and date as of which it is selected can make a substantial difference. And, unfortunately, the end result may produce a cost of equity that bears no resemblance to the utility's *actual* equity costs during the lengthy period for which the rate of return has been set.

The judgmental problems associated with determination of the expected market rate of return are even more formidable. A case can be made that one should determine the expected market return on the basis of long-term historical returns on a broad market index. But, if so, what index, and what historical period should be used? Unfortunately, arguments can be made for various periods and various indices, all resulting in radically different past market returns.[46] And yet, primarily because they *are* past returns, all these numbers now bear little or no resemblance to current returns. Indeed, Ibbotson and Sinquefield, one of the most widely-used sources of determining average market returns, estimate only a 12.5 percent average annual return on the market for the period 1977-2000.[47] If that figure were currently used in the CAPM formula — taking into account that current *risk-free* rates are higher than that 12.5 figure — expected utility rates of return would be computed at *below* Treasury bill rates. Plainly, this is not a sound result.

For several reasons, we do not dwell further here on the problems associated with the expected risk-free rate and the expected market rate: first, because these problems have already been explored in the authorities previously cited in the margin; second, because some of the problems with those two rates are not altogether peculiar to CAPM, but would also affect other methodologies used in ratemaking; and third, because those problems are dwarfed by the difficulties associated with estimating the number that is peculiar to CAPM — beta.

As has already been stated, if one elects to compute a cost of equity based on beta, one can get any number that seems desirable simply by selecting a different market index. But the arbitrariness and ambiguity that surround beta are even more acute than that. Recent evidence demonstrates, unequivocally, that betas — particularly betas for an individual asset (such as, for example, a utility stock) — can change dramatically depending on: the length of the holding period over which the asset's beta is measured; the particular beginning date of the holding period; the ending date of the holding period; and the periodic interval (daily, weekly, monthly, quarterly) at which the asset's and the market's returns are assessed.[48] Because there is no clear-cut reason for necessarily preferring one particular index, holding period, or

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[46] *See, e.g.*, Testimonies of Stewart C. Myers, pp. 28-45 (Dec. 1, 1978), and Richard W. Roll, p. 81 (Jan. 30, 1980) in The Railroad Valuation Proceedings; Hyman and Egan, *supra*, at 25; Glassman, "Discounted Cash Flow Versus the Capital Asset Pricing Model (Is g better than b?)," 102 *Public Utilities Fortnightly* 30, 33-34 (Sept. 14, 1978); Vandell & Malernee, "The Capital Asset Pricing Model and Utility Equity Returns," 102 *Public Utilities Fortnightly* 22, 28 (July 6, 1978).

[47] R. Ibbotson and R. Sinquefield, *Stocks, Bonds, Bills, and Inflation: The Past (1926-1976) and the Future (1977-2000)* 58 (1977).

[48] *See, e.g.*, H. Levy, "The CAPM and the Investment Horizon," 7 *The Journal of Portfolio Management* 32 (1981); B. Fielitz and M. Greene, "Shortcomings in Performance Evaluation via MPT [Modern Portfolio Theory]," 6 *The Journal of Portfolio Management* 13 (Summer 1980); Testimony of Richard F. Meyer, p. 51 (Jan. 30, 1980) in The Railroad Valuation Proceedings (showing that the average beta for the railroad industry for the five-year period July 1969 - June 1974 rose by 40% (from .907 to 1.253) solely by changing from daily to monthly observation of returns).

measurement interval over another, and because the selection among these variables produces altogether different betas, which in turn produce altogether different costs of equity, the process takes on an air of arbitrariness.

Moreover, even if one thought that CAPM and its reliance on beta were sound, and thought further that a reliable beta concerning a particular utility could be estimated from past data (notwithstanding the differing betas produced by different indices, holding periods, and measurement intervals),[49] there would still be no assurance that the *past* utility beta was a reasonable estimate of the *future* utility beta. In other words, no evidence has been adduced showing that utility betas are stable over time.

On the other hand, there has been evidence showing that these betas are *not* stable. For example, a recent empirical study demonstrates that, over any given five-year period, only a beta estimate for a portfolio of at least 100 assets or more can be expected to stay within 90% of the beta estimate at the beginning of the period. Thus, in the case of a single utility equity, or even in the case of a group (under 100) of reasonably comparable utility equities, there can be no confidence at all that an historical beta is a reliable guide to the utility's expected return for the next five years. *See* Tole,[50] "How to Maximize Stationarity of Beta," 7 *The Journal of Portfolio Management* 45 (Winter 1981).

Vivid illustration of the instability of utility betas appears in an analysis performed by Messrs. Hyman and Egan.[51] They computed betas for utilities over the period 1958-1978 by observing returns for three utility indices (Moody's electric utilities, Moody's natural gas industry, and S&P's telephones). By using such portfolios, greater stability in betas can be obtained than is possible through observation of returns on individual utilities. Even so, the result was that, over the 20-year period, wide annual variations in beta appeared in all three groups, ranging from .139 in 1959 to 1.190 in 1965, with a 20-year average of .582, .596, and .664 for the electric, telephone, and natural gas groups, respectively.[52] Whether the 20-year average, the immediately previous 5-year average, an average of the 20-year high and low, the previous year alone, or any other of the 20 single-year betas would constitute a reasonable estimate of the future betas — all of which were different, sometimes very different, numbers[53] — would thus be no more than a guess.[54]

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[49]The problem of reliability is further compounded by the fact that the betas produced through this process are typically very uncertain as a statistical matter, *i.e.*, their standard errors (an indication of how "far off" the estimate could be) are high, and their R^2's (an expression of how much of the asset's movements are in fact "explained" by the market's movements) are low. *See* Hyman and Egan, *supra*, at 24-27; Vandell and Malernee, *supra*, at 27; Myers, "On the Use of Modern Portfolio Theory in Public Utility Rate Cases: Comment," *supra*, at 68.

[50]Dr. Tole is an Associate Professor at Auburn University and an experienced management development specialist and stock broker.

[51]Leonard Hyman is Vice President and head of the Utility Research Group at Merrill Lynch. Joseph Egan is a senior utility analyst at Merrill Lynch.

[52]Hyman and Egan, *supra*, at 24.

[53]For example, the electric utilities' annual betas ranged from .139 to .952 in the 20-year period; their previous 5-year average was .655, and its 20-year average was .582. Telephone betas ranged from .251 to 1.190, with a previous 5-year average of .528 and a 20-year average of .596. Similarly, the natural gas betas were .419 at the low end, .927 at the high end, with a previous 5-year average of .571 and a 20-year average of .664. *Id.* at 24.

[54]The testimony of Stewart Myers in The Railroad Valuation Proceedings shows similar instability in the betas for the railroad industry. Thus, for purposes of determining an expected cost of equity for that industry as of 1974, Professor Myers had to reckon with betas for the S&P Railroad Index as follows: 1969, 1.02; 1970, .98; 1971, 1.37; 1972, .65; and 1973, .82. Myers Testimony, *supra*, at p. 51.

And that, we submit, is no basis upon which to determine utility rates of return.

2. *The CAPM Produces Results Unsound on Their Face*

As the foregoing indicates, there is substantial evidence that CAPM is both theoretically and empirically unsound. In light of this evidence, we submit that regulators should give serious thought to abandoning the model's use in utility ratemaking unless and until its credibility is affirmatively rehabilitated. There is one final argument that supports this view — CAPM is not only unreliable in theory, and unreliable in practice, but, regardless of one's views about the merits or demerits of CAPM itself, the results it produces are too often simply implausible. Several recent studies have elaborated upon this issue, addressing both the general beta-based proposition that utilities are less risky than the market itself (the average asset), as well as the specific indications of risk changes implied by particular utility beta measurements.

First, if the betas of utilities are to be believed, and if CAPM's assumption that beta-risk is the only risk that matters to investors is to be accepted, then, since utility betas are, by and large, consistently less than 1.0, it must follow that utilities are a less risky proposition than, say, unregulated companies on average or the Dow Jones Industrials in particular. To our knowledge, no rate proceeding has included evidence confirming (independent of CAPM) the reliability of this proposition. However, two recent analyses of this proposition declare that it simply is not so.

In "Who Says Utilities Are Less Risky?"[55] and "Competition for the Funds of Investors and the Cost of Capital for Utilities,"[56] the Messrs. Christy[57] and Dr. Lerner, respectively, studied the question whether, notwithstanding what beta may suggest, utilities are more risky than the average company. For several reasons, the authors concluded that utilities are more risky.

First, the Christys showed that utilities are riskier in light of two obvious objective measurements of comparative risk — the consistently greater volatility in price changes displayed by utilities when compared to the Dow Jones and the consistently greater rates of return to investors afforded by utilities as compared to the Dow Jones.[58] Second, in comparing utilities with unregulated companies generally, the authors again found utilities by and large to be riskier, on two broad subjective grounds: first, their higher capital intensity and their corresponding greater sensitivity to inflation and interest-rate uncertainties; and second, the greater risk presented by regulation itself, which not only prevents utilities from reacting to market changes on a daily

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[55] 105 *Public Utilities Fortnightly* 11 (May 8, 1980).

[56] 105 *Public Utilities Fortnightly* 15 (Feb. 28, 1980).

[57] Dr. George A. Christy is Professor of Finance at North Texas State University and served for nine years in telephone company commercial and public relations departments. J. Gordon Christy is Assistant Professor of Law at the University of Oklahoma.

[58] For purposes of analyzing volatility, percent price movements were studied over the 1965-1979 period, and for purposes of analyzing returns received, quarterly earnings/price ratios were studied over the 1975-1979 period. 105 *Public Utilities Fortnightly* at 12-13 (May 8, 1980).

basis, but also raises uncertainties concerning whether, and, if so, when, their increased costs can be recovered.[59]

Dr. Lerner, in a separate study, confirmed these views. First, he showed that if past stability (degree of volatility) is to be taken as an indicator of risk — which CAPM assumes it to be — then regardless "whether stability is measured by the deviations from trend of earnings, sales, dividends, or equity, industrials have been either more stable or comparable to utilities over the past five years."[60] Similarly, he showed that the percentage price changes of utilities have been greater than those of the S&P Industrial Index.[61] Hence, he concluded, "[t]he argument that an industrial commands a higher return than a utility because it has more risk is simply not true."[62]

Finally, in their article "The Utility Stock Market: Regulation, Risk and Beta" (previously referred to), Messrs. Hyman and Egan studied the implications of the various beta changes of utilities (electric, telephone, and natural gas) over the 1958-1978 period. Their judgment was that these implications were simply not credible. Two examples are worth mentioning.

The telephone company betas showed those companies to have "greater risk in the middle 1960's than at present." As to this, said the authors, "[c]onsidering that the financial situation of the industry has not improved and that competition has become a threat to the telephone monopoly, we reject that interpretation altogether."[63] Regarding electric utility betas, at least if CAPM is to be credited, those utilities "involved more risk in the mid-1960's than they do today." Yet, as the authors point out, "[c]onsidering that industry conditions deteriorated substantially between the 1960's and the present time, we reject that interpretation and consider it absurd."[64]

Thus, even putting to one side the considerable theoretical problems associated with CAPM — problems that are intensified in the ratemaking context — and even overlooking that betas tend to be unstable, statistically suspect, and given to arbitrary measurement, it would still be true that the results it produces are too often inconsistent with real-world perceptions about utility risk.

CONCLUSION

For the foregoing reasons, we submit that unless and until those who favor the continued use of CAPM in the utility-ratemaking setting affirmatively establish the model's reliability in that setting, the results produced by the model should not be used further as a basis for determining fair rates of return. In our view, the case which can be made against CAPM's continued

[59] *Id.* at 14-18.
[60] 105 *Public Utilities Fortnightly* at 15-16 (Feb. 28, 1980).
[61] *Id.* at 16-18.
[62] *Id.* at 16.
[63] Hyman & Egan, *supra*, at 24.
[64] *Id.*

use for such ratemaking is now of such proportions that the proponents' burden cannot be met.

This is not to say that we propose abandonment of CAPM altogether. Rather, the case we have tried to make here is that CAPM in its present form — that is, a formula which relies on beta as the only important systematic factor and which assumes that alpha is zero — is so fraught with error, and has led to such improbable results, that it does not merit further credence. However, it may well be that a modified CAPM — one that recognizes the value of alpha and/or takes into account other systematic factors (such as interest-rate risk) known to affect utilities — can be shown to be a valid ratemaking tool. Such a showing, it seems to us, should be of high priority in future proceedings.

Cost of Equity for Energy Utilities: Beyond the CAPM

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Cost of Equity for Energy Utilities: Beyond the CAPM☆

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Abstract

The Capital Asset Pricing Model (CAPM) is applied in regulatory cases to estimate the required rate of return, or cost of equity, for low-beta, value-style energy utilities, despite the model's well documented mispricing of investments with similar characteristics. This paper examines CAPM-based estimates for a sample of American and Canadian energy utilities to assess the risk premium error. We find that the CAPM significantly underestimates the risk premium for energy utilities compared to its historical value by an annualized average of more than 4%. Two CAPM extensions, the Fama-French model and an adjusted CAPM, provide econometric estimates of the risk premium that do not present a significant misevaluation.

JEL Classifications: G12, L51, L95, Q49

Keywords: Cost of Capital, Rate of Returns, Energy Utilities

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Cost of Equity for Energy Utilities: Beyond the CAPM

Abstract

The Capital Asset Pricing Model (CAPM) is applied in regulatory cases to estimate the required rate of return, or cost of equity, for low-beta, value-style energy utilities, despite the model's well documented mispricing of investments with similar characteristics. This paper examines CAPM-based estimates for a sample of American and Canadian energy utilities to assess the risk premium error. We find that the CAPM significantly underestimates the risk premium for energy utilities compared to its historical value by an annualized average of more than 4%. Two CAPM extensions, the Fama-French model and an adjusted CAPM, provide econometric estimates of the risk premium that do not present a significant misevaluation.

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1. Introduction

An important aspect of the regulatory process for energy utilities is the determination of their equity rate of return. This return, also known as the cost of equity capital, represents the expected remuneration of the shareholders of the utilities. It is a crucial component of their total cost of capital, which is central to their investment policy and serves as a basis for setting up the rates to their customers. The purpose of this paper is to highlight the problems of the most commonly used model to determine the equity rate of return for energy utilities and to propose two alternative models that empirically improve on the estimation. By providing new direct and focused evidence for energy utilities, our analysis contributes to the knowledge of energy, regulatory and financial economists, as well as regulators, who are concerned with rate determination.

Regulatory bodies, like the National Energy Board in Canada or the Federal Energy Regulatory Commission in the United States, have the mandate to set the equity rate of return so that it is fair and reasonable. Specifically, according to Bonbright, Danielsen and Kamerschen (1988, Chap. 10), the return should provide the ability to attract and retain capital (the capital-attraction criterion), encourage efficient managerial practice (the management-efficiency criterion), promote consumer rationing (the consumer-rationing criterion), give a reasonably stable and predictable rate level to ratepayers (the rate-level stability and predictability criterion) and ensure fairness to investors (the fairness to investors criterion). While the first four criteria are designed primarily in the interest of the consuming public, the last criterion acts as an equally-important protection for private owners against confiscatory regulation. Its requirement involves determining the return available from the application of the capital to other enterprises of like risk, which demands an understanding of the risk-return relationship in the equity market.

Traditionally, the regulated return has been set through hearings, where arguments on the issue of fairness could be debated. But since the 1990s, numerous boards have adopted an annual mechanism known as a “rate of return formula” or a “rate adjustment formula”. This mechanism determines automatically the allowed rate of return through a calculation that explicitly accounts for the risk-return relationship in the equity market. The use of rate adjustment formulas is particularly prevalent in Canada since the landmark March 1995 decision by the National Energy Board (Decision RH-2-94), which sets the stage for the widespread adoption of closely related formulas by provincial regulators.

Most rate adjustment formulas use a method known as the Equity Risk Premium method.[1] This method can be summarized as calculating a utility's equity rate of return as the risk-free rate of return plus a premium that reflects its risk. The risk-free rate is usually related to the yield on a long-term government bond. The risk premium is obtained from the Capital Asset Pricing Model (CAPM) of Sharpe (1964) and Lintner (1965), a classic model of capital market equilibrium. It is equal to the utility's beta, a measure of its systematic risk, multiplied by the market portfolio risk premium. The Equity Risk Premium method has a number of advantages. First, it is supported by a solid theoretical foundation in the academic literature, thus providing a sound basis for understanding the risk-return relationship. Second, it can be estimated based on stock returns, thereby making it more objective than other methods, and relating it to current market conditions. Third, it is relatively simple to apply and requires data that can be obtained easily.

The Equity Risk Premium method is not, however, without shortcomings. Arguably its most criticized feature is the use of the CAPM as the basis to determine the risk premium. While the CAPM is one of the most important developments in finance, research over the last forty years has produced a large body of work critical of the model. On the theoretical side, Cochrane (1999) summarizes the current most prevalent academic view: "In retrospect, it is surprising that the CAPM worked so well for so long. The assumptions on which it is built are very stylized and simplified."[2] For example, at least since Merton (1973), it is recognized that factors, state variables or sources of priced risk beyond the movements in the market portfolio (the only risk factor in the CAPM) might be needed to explain why some risk premiums are higher than others. On the

[1] There exist other methods for estimating the rate of return, most notably the Comparable Earnings method and the Discounted Cash Flows method. See Morin (2006) for a description. These methods are generally not directly incorporated in the rate adjustment formulas.
[2] Cochrane (1999), p. 39.

empirical side, the finance literature abounds with CAPM deficiencies (so-called “anomalies”). Fama and French (2004) review this literature to highlight that the CAPM is problematic in the estimation of the risk premium of low-beta firms, small-capitalisation firms and value (or low-growth) firms. While these problems have been well documented in the finance literature, their effects have not yet been fully explored for energy utilities, which may be part of the reasons why the CAPM is still widely used in rate adjustment formulas. In particular, as the CAPM does not empirically provide a valid risk-return relationship for the equity market, it might fall short of the requirement associated with the fairness to investors criterion.

Considering the importance of the CAPM in determining the regulated equity rate of return, the objectives of this paper are two-folds. First, we re-examine the use of the model in the context of energy utilities to determine if it is problematic. As utilities are typically low-beta, value-oriented investments, the finance literature suggests that the model will have difficulties in estimating their risk premiums. We analyze the issue empirically by estimating the model and its resulting risk premiums for a sample of Canadian and American energy utilities mostly related to the gas distribution sector, and by testing for the presence of significant differences between the model’s risk premium estimates and the historical ones.

Second, we implement two alternative models that are designed to circumvent some of the empirical problems of the CAPM. The first alternative is a three-factor model proposed by Fama and French (1993) (the Fama-French model hereafter). This model has been used to estimate the cost of equity by Fama and French (1997) for general industrial sectors and by Schink and Bower (1994) for the utilities sector in particular. The second alternative is a modified CAPM that includes the adjustments proposed by Blume (1975) and Litzenberger, Ramaswamy and Sosin (1980) (the Adjusted CAPM hereafter). The Fama-French model and the Adjusted CAPM provide useful comparisons with the CAPM on the estimation of the risk premiums of energy utilities.

Our empirical results can be summarized as follows. First, the CAPM significantly underestimates the risk premiums of energy utilities compared to their historical values. The underestimations are economically important, with annualized averages of respectively 4.5% and 6.2% for the Canadian and American gas utilities we consider, and are consistent with the finance literature on the mispricing of low-beta, value-oriented stocks. Second, the Fama-French model and the Adjusted CAPM are both able to provide costs of equity that are not significantly different from the historical ones. Our results show that the value premium, in the case of the Fama-French model, and a bias correction, in the case of the Adjusted CAPM, are important in eliminating the CAPM underestimations. Both models suggest average risk premiums between 4% and 8% for gas utilities portfolios, and are relevant at the individual utility level as well as at the utilities sector level.

Overall, we conclude that the CAPM is problematic in estimating econometrically the cost of equity of energy utilities. The Fama-French model and the Adjusted CAPM are well specified for this purpose as they reduce considerably the estimation errors. These models could thus be considered as alternatives to the CAPM in the Equity Risk Premium method employed by regulatory bodies to obtain the risk-return relationship for the fairness to investors criterion.

The CAPM dates back to the mid-1960s. While the model is tremendously important, there has been a lot of progress over the last 45 years in the understanding of the cross-section of equity returns. It should be clear that the goals of this paper are not to implement full tests of asset pricing models or examine comprehensively the numerous models in the equity literature. Focusing on energy utilities, this paper is an application of the CAPM and two reasonable and relevant alternatives to the problem of cost of equity estimation, using a standard methodology. Our findings show that it is potentially important to go beyond the CAPM for energy utilities. They represent an invitation to further use the advances in the literature on the cross-section of returns to better understand their equity rate of return.

The rest of the paper is divided as follows. The next section presents our sample of energy utilities and reference portfolios. The third, fourth and fifth sections examine the risk premium estimates with the CAPM, the Fama-French model and the Adjusted CAPM, respectively. Each section provides an overview of the model, presents its empirical estimation and results, and discusses the implications of our findings. The last section concludes.

2. Sample Selection and Descriptive Statistics

This section examines the sample of firms and portfolios for our estimation of the cost of equity of energy utilities. We focus on the gas distribution sector to present complete sector-level and firm-level results, but we also consider utilities indexes to ensure the robustness to other utilities. We provide Canadian and American results for comparison, as both energy markets are relatively integrated and investors might expect similar returns. We first discuss sample selection issues and then present descriptive statistics.

2.1. Sample Selection

Two important choices guide our sample selection process. First, we use monthly historical data in order to have sufficient data for estimating the parameters and test statistics, while avoiding the microstructure problems of the stock markets (low liquidity for numerous securities, non-synchronization of transactions, etc.) in higher frequency data.[3] We then annualized our results for convenience. Second, we emphasize reference portfolios (such as sector indexes) over individual firms. Reference portfolios reduce the potentially large noise (or diversifiable risk) in the stock market returns of individual firms. They allow for an increased statistical accuracy of the estimates, an advantage recognized since (at least) Fama and MacBeth (1973), and alleviate the problem that we do not observe the returns on utilities directly and must rely on utility holding companies.

To represent the gas distribution sector in Canada and the U.S., we use a published index and a constructed portfolio for each market. The independently-calculated published indexes are widely available and consider the entire history of firms having belonged to the gas distribution sector. The constructed portfolios use the most relevant firms at present in the gas distribution or

[3] See Fowler, Rorke and Jog (1979, 1980) for an analysis of these problems in the Canadian stock markets.

energy utility sector. The data collection also allows an examination of the robustness of our results at the firm level. The resulting four gas distribution reference portfolios are described below.

- *DJ_GasDi*: A Canadian gas distribution index published by Dow Jones, i.e. the "Dow Jones Canada Gas Distribution Index." The firms in the index are weighted by their market value. Monthly returns (180) are available from January 1992 to December 2006;
- *CAindex*: An equally-weighted constructed portfolio formed of 13 Canadian energy utilities, most with activities that are related to the gas distribution sector, i.e. ATCO Ltd., Algonquin Power Income Fund, Canadian Utilities Limited, EPCOR Power, Emera Incorporated, Enbridge Inc., Fort Chicago Energy Partners, Fortis Inc., Gaz Métro Limited Partnership, Northland Power Income Fund, Pacific Northern Gas, TransAlta Corporation and TransCanada Pipelines.[4] Monthly returns (263) are available from February 1985 to December 2006;
- *DJ_GasUS*: A U.S. gas distribution index published by Dow Jones, i.e. the "Dow Jones US Gas Distribution Index." The firms in the index are weighted by their market value. Monthly returns (180) are available from January 1992 to December 2006;
- *USindex*: An equally-weighted constructed portfolio formed of nine U.S. firms whose activities are heavily concentrated in local gas distribution, i.e. AGL Resources Inc., Atmos Energy Corp., Laclede Group, New Jersey Resources Corp., Northwest Natural Gas Co., Piedmont Natural Gas Co., South Jersey Industries, Southwest Gas Corp. and WGL Holdings Inc. Monthly returns (407) are available from February 1973 to December 2006.

To confirm the validity of our analysis to other energy utilities, we also consider four utilities reference portfolios, which consist of the utilities sector indexes described below.

- *DJ_Util*: A Canadian utilities index published by Dow Jones, i.e. the "Dow Jones Canada Utilities Index." The firms in the index are weighted by their market value. Monthly returns (180) are available from January 1992 to December 2006;
- *TSX_Util*: A Canadian utilities index published by S&P/TSX, i.e. the "S&P/TSX Utilities Index." The firms in the index are weighted by their market value. Monthly returns (228) are available from January 1988 to December 2006;
- *DJ_UtiUS*: A U.S. utilities index published by Dow Jones, i.e. the "Dow Jones US Utilities Index." The firms in the index are weighted by their market value. Monthly returns (180) are available from January 1992 to December 2006;
- *FF_Util*: A U.S. utilities index formed by Profs. Fama and French, or the University of Chicago and Dartmouth College, respectively. The firms in the index are weighted by their market value. Monthly returns (407) are available from February 1973 to December 2006.

Depending on their availability, the reference portfolio series have different starting dates. In our econometric estimation, we keep the maximum number of observations for each series. Fama

[4] We also considered AltaGas Utility Group, Enbridge Income Fund, Westcoast Energy, Nova Scotia Power and Energy Savings Income Fund. We did not retain the first four because they had a returns history of less than 60 months. We eliminated the last one because it is a gas broker and its average monthly return of more than 3% was a statistical outlier. Our results are robust to variations in the formation of the CAindex portfolio, like the inclusion of these five firms or the exclusion of income funds and limited partnerships.

and French (1997) find that such a choice results in costs of equity more precisely estimated and with more predictive ability than costs of equity obtained from rolling five-year estimation windows, a common choice in practice. The data are collected from the Canadian Financial Markets Research Center (CFMRC), Datastream and the web sites of Prof. French[5] and Dow Jones Indexes[6].

2.2. Descriptive Statistics

Descriptive statistics for the monthly returns are presented in Table 1. Panel A shows the results for the 13 Canadian energy utilities and their equally-weighted portfolio (CAindex). Panel B shows the results for nine U.S. gas distribution utilities and their equally-weighted portfolio (USindex). Panel C shows the statistics for Canadian and U.S. indexes for the utilities sector (DJ_Util, DJ_UtilUS, TSX_Util and FF_Util) and the gas distribution sub-sector (DJ_GasDi and DJ_GasUS).[7]

< INSERT TABLE 1 HERE >

For the Canadian energy utilities, the monthly average return of all 13 firms is 1.0% with a standard deviation of 3.1%. The Dow Jones Canada Gas Distribution Index, the Dow Jones Canada Utilities Index and the S&P/TSX Utilities Index have mean returns of 1.2%, 0.7% and 1.0%, respectively. The monthly average return of the nine U.S. gas distribution utilities is 1.2% with a standard deviation of 4.1%. The Dow Jones US Gas Distribution Index, the Dow Jones US Utilities Index and the Fama-French U.S. Utilities Index show mean returns of 1.2%, 0.9% and 1.0%, respectively. Correlations between the four gas distribution reference portfolios (not tabulated) are between 0.29 and 0.80. These correlations indicate that the portfolios show some commonality, but are not perfect substitutes. We next start our analysis of the equity risk premium models.

[5] http://mba.tuck.dartmouth.edu/pages/faculty/ken.french/data_library.html.
[6] http://www.djindexes.com/mdsidx/index.cfm?event=showtotalMarketIndexData&perf=Historical%20Values.
[7] The returns from August to November 2001 of the Dow Jones U.S. indexes are strongly influenced by the Enron debacle, which started with the resignation of its CEO, Jeffrey Skilling, on August 14, 2001 and ended with the bankruptcy of the company on December 2, 2001. During those four months, the DJ_GasUS and DJ_UtiUS indices lost 68.9% and 16.2% of their value, respectively. By comparison, the equally-weighted portfolio of U.S. gas distributors (USindex) gained 1.2% and the Fama-French utilities index (FF_Util) lost 6.2 %. In order to soften the impact of that statistical aberration (caused by an unprecedented fraud) on the estimation of the risk premium, the returns from August to November 2001 of DJ_GasUS and DJ_UtilUS are replaced by those of USindex and FF_Util, respectively.

3. Equity Risk Premium with the CAPM

This section examines the use of the Capital Asset Pricing Model (CAPM) for estimating the rate of return for energy utilities. The CAPM is the model the most often associated with the Equity Risk Premium method that is the basis of the rate adjustment formulas of regulatory bodies. We first present the model and its relevant literature. Then we estimate the model for our sample of energy utilities. Finally, we discuss the implications of our findings.

3.1. Model and Literature

The CAPM is a model proposed by Sharpe (1964) and Lintner (1965) in which the expected equity return or cost of equity for a gas utility is given by

$$E(R_{GAS}) = R_f + \beta \times \lambda_m ,$$

where R_f is the risk-free rate, β is the firm's beta or sensitivity to the market returns and λ_m is the market risk premium. In this model, a higher beta results in a higher risk premium.

The CAPM is the best known model of expected return. In spite of its undeniable importance in the field of finance, it has long been rejected by numerous empirical tests in the academic literature. The empirical rejections start with the first tests (Black, Jensen and Scholes, 1972, Fama and MacBeth, 1973, and Blume and Friend, 1973) that find that the relation between beta and average return is flatter than predicted by the model. They continue with the discovery of numerous "anomalies" (like the price-to-earnings effect of Basu, 1977, the size effect of Banz, 1981, etc.). Finally, in the 1990s, based on high-impact articles, including Fama and French (1992, 1993, 1996a and 1996b), Jegadeesh and Titman (1993) and Jagannathan and Wang (1996), the academic profession reaches a relative consensus that the CAPM is not valid empirically. In Canada, like elsewhere in the world, the literature reaches similar conclusions (see Morin, 1980, Bartholdy, 1993, Bourgeois and Lussier, 1994, Elfakhani, Lockwood and Zaher, 1998, L'Her, Masmoudi and Suret, 2002, 2004.).

A complete review of the literature on the problems of the CAPM is beyond the scope of this paper. It is nevertheless important to point out the two characteristics of energy utilities that suggest the CAPM might be problematic in estimating their equity return. First, energy utilities have typically low betas, significantly below one. Second, they are known as value investments, in the sense that they have high earnings-to-price, book-to-market, cash flows-to-price or dividend-to-price ratios. In a summary article requested for a symposium on the 40th anniversary of the CAPM, Fama and French (2004) highlight the result of using the model to estimate the cost of equity capital for firms with these two characteristics:

> "As a result, CAPM estimates of the cost of equity for high beta stocks are too high (relative to historical average returns) and estimates for low beta stocks are too low (Friend and Blume, 1970). Similarly, if the high average returns on value stocks (with high book-to-market ratios) imply high expected returns, CAPM cost of equity estimates for such stocks are too low."[8]

As Fama and French (2004) indicate, the low-beta and value characteristics of energy utilities will probably lead the CAPM to estimate a rate of return that is too low. We next examine whether this undervaluation in fact exists in our sample of reference portfolios and utilities.

3.2. Risk Premium Estimates

This section empirically estimates the risk premium with the CAPM using the previously described Canadian and U.S. monthly data.[9] More specifically, we estimate the model using the time-series regression approach pioneered by Black, Jensen and Scholes (1972) with the following equation:

$$R_{GAS,t} - R_{f,t} = \alpha_{GAS} + \beta \times \lambda_{m,t} + \varepsilon_{GAS,t},$$

where $\lambda_{m,t} = R_{m,t} - R_{f,t}$ is the return on the market portfolio in excess of the risk-free return and $\varepsilon_{GAS,t}$ is the mean-zero regression error, at time *t*. In this equation, the CAPM predicts that the alpha (or intercept) is zero ($\alpha_{GAS} = 0$) and the risk premium is $E(R_{GAS,t} - R_{f,t}) = \beta \times E(\lambda_{m,t})$.

[8] Fama and French (2004), p. 43-44.
[9] Our focus is on the estimation of the equity risk premium for energy utilities. To obtain their full cost of equity, we would need to add an appropriate risk-free rate, which could depend on the circumstances. For example, one common choice advocates adding to their equity risk premium the yield on a long-term government bond. But other choices for an appropriate risk-free rate are possible.

An alpha different from zero can be interpreted as the risk premium error of the CAPM (see Pastor and Stambaugh, 1999). A positive alpha indicates the CAPM does not prescribe a large enough risk premium compared to its historical value (an underestimation), whereas a negative alpha indicates the CAPM prescribes a risk premium that is too large (an overestimation). It is therefore possible to determine the CAPM risk premium error for energy utilities based on the estimates of the alpha.[10]

We use Hansen's (1982) Generalized Method of Moments technique in order to estimate jointly the parameters α_{GAS} and β of the model and the market risk premium $E(\lambda_{m,t})$. As Cochrane (2001, Section 12.1) shows, this method has the necessary flexibility to correct the results for possible econometric problems in the data.[11] We take the monthly returns on portfolios of all listed securities weighted by their market value for the market portfolio returns and on the Treasury bills for the risk-free returns.[12] The annualized mean market risk premiums are 5.2% for Canada from February 1985 to December 2006 and 6.0% for the U.S. from February 1973 to December 2006.

Table 2 shows the results of the regressions using each of the four gas distribution reference portfolios. The estimates of the annualized risk premium error (or annualized α_{GAS}), the beta β and the risk premium $\beta \times E(\lambda_{m,t})$ are presented in Panels A, B and C, respectively. For each estimate, the table also shows its standard error, t-statistic and associated p-value.

< INSERT TABLE 2 HERE >

The estimates in Panel A of Table 2 indicate that the risk premium errors are positive. Hence, the CAPM underestimates the risk premium for the gas distribution reference portfolios. The underestimation is not small – a minimum of 4.52% (for CAindex) and a maximum of 8.43%

[10] The time series regression approach is commonly used when the model factors are returns. Cochrane (2001, Chapter 12) emphasizes that the approach implicitly imposes the restriction that the factors (chosen to fully represent the cross section of returns in the modeling) should be priced correctly in the estimation. While there are other ways to estimate a model like the CAPM, one advantage of the times series regression approach is that it can be easily applied to a restricted set of assets (like energy utilities) as the cross-sectional variations in asset returns are already captured by the correct pricing of the traded factors. Cochrane (2001, Chapter 12) also shows that the approach is identical to a Generalized Least Square cross-sectional regression approach.

[11] All standard errors and statistical tests have been estimated using the Newey and West (1987) method, which takes account of the potential heteroscedasticity and autocorrelation in the errors of the statistical models.

[12] The data sources are CFMRC (until 2004) and Datastream (thereafter) for the Canadian returns and the web site of Prof. French for U.S. returns.

(for DJ_GasDi) – and is statistically greater than zero for all portfolios. Also, as expected, the underestimation comes with low beta estimates, with values between 0.21 and 0.46 in Panel B. For example, for CAindex, the beta is 0.34 and the annualized risk premium predicted by the CAPM is 1.76%, an underestimation of the historical risk premium $\alpha_{GAS} = 4.52\%$.

To verify the underestimation is not an artifact of the utilization of the reference portfolios and is robust to other energy utilities, Figure 1 shows the risk premium errors for the utilities that make up the CAindex portfolio (Figure 1a), the gas distributors in the USindex portfolios (Figure 1b) and the four utilities reference portfolios (Figure 1c). Once again, the alphas are always positive, with values between 2.1% and 8.9% for the Canadian utilities, between 3.5% and 8.4% for the U.S. gas distributors, and between 2.1% and 5.0% for the utilities reference portfolios. The constantly positive and often significant errors support the notion that the CAPM might not be appropriate for determining the risk premium in the utilities sector.

< INSERT FIGURE 1 HERE >

3.3. Discussion

Our results show that the CAPM underestimates the risk premium for the gas distribution sub-sector in particular and for the utilities sector in general. This finding is consistent with the empirical literature that finds that the CAPM tends to underestimate the risk premium of securities or sectors associated with low-beta, value and small-cap investments. In the terminology of asset pricing, the returns on energy utilities are "anomalous" with respect to the CAPM. As the application of the model would not be sensible in evaluating the performance of value-type mutual funds, given the related anomaly, it could be unwarranted in evaluating the cost of equity for energy utilities.

While the magnitude of the underestimation for the utilities is large, it is not unexpected. Fama and French (2004) review the evidence on the large CAPM literature for the *full cross-section* of equity returns. Their figures 2 and 3, in particular, illustrate well the findings for portfolios of stocks formed on their beta and their book-to-market ratio value indicator, respectively. In the cross-section of all stock returns, their figure 2 show visually that the CAPM underestimation is about 3% for the lowest beta portfolio (a beta of about 0.6), while its overestimation is about 3% for the highest beta portfolio (a beta of about 1.8). Their figure 3 indicates that the CAPM underestimation is about 5% for the highest book-to-market ratio portfolio, while its overestimation is about 2% for the lowest book-to-market ratio portfolio. As energy utilities are low-beta and value-oriented stocks, our estimates of the CAPM underestimation for this segment are consistent with the evidence from the full cross-section of equity returns.

Our results are related to numerous studies documenting that the CAPM alphas are different from zero. As a consequence of these rejections, finance researchers have considered various models that generalized the CAPM as well as various empirical improvements to the estimates of the CAPM. Based on this literature, we explore two alternative ways of estimating the risk premium of energy utilities in the next two sections.

4. Equity Risk Premium with the Fama-French model

The CAPM claims that a single factor, the market portfolio return, can explain expected returns. The most natural extension is to take multiple factors into account. Clearly, if factors other than the market return have positive risk premiums that contribute to explaining expected returns, then the inclusion of those factors should provide a better estimate of the risk premium and potentially eliminate the CAPM errors (see Merton, 1973, and Ross, 1976, for formal theoretical justifications). This section considers one of the most common generalization of the CAPM, a multifactor model by Fama and French (1993). We first describe the model and then use it to estimate the risk premium of energy utilities. We finally discuss the interpretation of our findings.

4.1. Model and Literature

The Fama-French model is a three-factor model developed to capture the anomalous returns associated with small-cap, value and growth portfolios by including risk premiums for size and value. For a gas utility, the expected equity return is given by

$$E(R_{GAS}) = R_f + \beta \times \lambda_m + \beta_{SIZE} \times \lambda_{SIZE} + \beta_{VALUE} \times \lambda_{VALUE},$$

where R_f is the risk-free rate, β, β_{SIZE} and β_{VALUE} are respectively the firm's market, size and value betas, and λ_m, λ_{SIZE} and λ_{VALUE} are respectively the market, size and value risk premiums. The three betas represent sensitivities to the three sources of risk, and the higher are their values, the higher is a firm's risk premium. In cases when the size and value risk factors are not relevant, then the Fama-French model reduces to the CAPM. Theoretical justifications for the size and value premiums are provided by Berk, Green and Naik (1999), Gomez, Kogan and Zhang (2003), and Carlson, Fisher and Giammarino (2004). Fama and French (1993, 1996a) are the two of the most influential empirical tests of the model.

Like the CAPM, the Fama-French model has been used in applications ranging from performance measurement to abnormal return estimation and asset valuation. For the calculation of the cost of equity capital, the model is studied by, among others, Schink and Bower (1994), Fama and French (1997), and Pastor and Stambaugh (1999). It has also proven to be relevant for explaining stock market returns in most countries where it has been examined. For example, in Canada, the model is validated by Elfakhani, Lockwood and Zaher (1998) and L'Her, Masmoudi and Suret (2002). Given that energy utilities are associated with value investments, the Fama-French model has the potential to improve the estimation of their rates of returns. We next assess this possibility for our sample of reference portfolios and utilities.

4.2. Risk Premium Estimates

The risk premium with the Fama-French model is estimated with a methodology that is similar to the one followed for the CAPM using the following equation:

$$R_{GAS,t} - R_{f,t} = \alpha_{GAS}^{FF} + \beta \times \lambda_{m,t} + \beta_{SIZE} \times \lambda_{SIZE,t} + \beta_{VALUE} \times \lambda_{VALUE,t} + \upsilon_{GAS,t},$$

where $\lambda_{m,t} = R_{m,t} - R_{f,t}$ is the return on the market portfolio in excess of the risk-free return, $\lambda_{SIZE,t} = R_{SMALL,t} - R_{LARGE,t}$ is the return on a small-cap portfolio in excess of the return on a large-cap portfolio, $\lambda_{VALUE,t} = R_{VALUE,t} - R_{GROWTH,t}$ is the return on a value portfolio in excess of the return on a growth portfolio and $\upsilon_{GAS,t}$ is the mean-zero regression error, at time *t*. The alpha α_{GAS}^{FF} is still interpreted as the risk premium error. The three beta parameters give the sensitivities to the market, size and value factors. Finally, $\beta \times E(\lambda_{m,t}) + \beta_{SIZE} \times E(\lambda_{SIZE,t}) + \beta_{VALUE} \times E(\lambda_{VALUE,t})$ represents the risk premium from the Fama-French model.

The data for the market portfolio returns and the risk-free returns are the same used in the CAPM estimation. For the Canadian regressions, the small-cap portfolio returns are from a portfolio of all listed securities weighted equally whereas the large-cap portfolio returns are from a portfolio of all listed securities weighted by their market value.[13] The value and growth portfolios are determined from the earnings-to-price ratio. Specifically, the value (growth) portfolio contains firms having an earnings/price ratio in the highest (lowest) 30%.[14] For U.S. regressions, the size and value premiums are the Fama and French (1993, 1996a) SMB and HML variables, which are computed from market capitalization (size) and book-to-market ratio (value).[15] The annualized mean size and value risk premiums are respectively 8.9% and 6.4% for Canada from February 1985 to December 2006 and 2.7% and 6.0% for the U.S. from February 1973 to December 2006.

Table 3 presents the results of the estimates of the coefficients and the risk premium with the Fama-French model for the four gas distribution reference portfolios previously described. Panel A shows that the annualized risk premium errors are still positive for the four portfolios, ranging from 0.31% (for USindex) to 4.45% (for DJ_GasDi), but the underestimation is now

[13] These indexes are taken from CFMRC for returns up to 2004 and then completed by the returns of the S&P/TSX Composite Index and the MSCI Barra Smallcap Index, respectively.
[14] Data come from the web site of Prof. French, who also provides specific instructions on the composition of the portfolios. The site gives returns for value and growth portfolios based on four indicators – earnings-to-price, book-to-market, cash flows-to-price and dividend-to-price. Fama and French (1996a) show that these indicators contain the same information about expected returns. Fama and French (1998) confirm the relevance of these indicators in explaining the returns in 12 major international financial markets and emerging financial markets. We chose the earnings-to-price indicator because it is more effective in capturing the premium of value securities compared to growth securities in Canada (see Bartholdy, 1993, and Bourgeois and Lussier, 1994). The indicator book-to-market is less effective in Canada because the value effect is mainly concentrated in more extreme portfolios (highest and lowest 10%) than in those available on the site (see L'Her, Masmoudi and Suret, 2002).
[15] Data again come from the web site of Prof. French. Detailed instructions on the composition of the SMB and HML variables are also provided.

statistically negligible. Panel D confirms that the inclusion of the value risk premium is instrumental in the reduction of the errors. The value betas are highly significant, with values between 0.30 and 0.71. The size betas (Panel C) are low and often not statistically different from zero, whereas the market betas (Panel B) are 0.54 on average. The estimated risk premiums vary between 4.23% and 8.83%.

< INSERT TABLE 3 HERE >

Figure 2 compares the Fama-French and CAPM results. Figure 2a illustrates the risk premium errors of the two models, while Figure 2b shows their explanatory power given by the adjusted R^2. The errors have substantially fallen with the Fama-French model for all reference portfolios. Furthermore, the Fama-French model explains a much larger proportion of the variation in the reference portfolio returns.

< INSERT FIGURE 2 HERE >

Figures 3 and 4 present the risk premium errors and the value betas, respectively, for the utilities that make up the CAindex portfolios (Figures 3a and 4a), the gas distributors in the USindex portfolios (Figures 3b and 4b) and the four utilities reference portfolios (Figures 3c and 4c). A comparison of Figure 3 with Figure 1 shows that the risk premium errors have decreased in all cases. None of the errors are now significantly different from zero. Figure 4 confirms that the reductions in the risk premium errors are caused by the inclusion of the value risk premium. All value betas are greater than 0.23 and statistically significant. For example, the TSX_Util portfolio has a value beta of 0.41 that contributes to reduce its risk premium error from 5.0% with the CAPM to 0.7% with the Fama-French model.

< INSERT FIGURE 3 HERE >

< INSERT FIGURE 4 HERE >

4.3. Discussion

Our results support the notion that the Fama-French model is well suited to estimate the risk premium for energy utilities, consistent with the findings of Schink and Bower (1994). We obtain lower risk premium errors with the Fama-French model than with the CAPM and significant value betas, similar to the results reported by Schink and Bower (1994), Fama and French (1997) and Pastor and Stambaugh (1999).

While the model is being increasingly considered in practice, an often mentioned limitation is that the economic interpretation of the size and value premiums is still under debate. On one side, starting with Fama and French (1993), the size and value factors are presented as part of a rational asset pricing model, where they reflect either state variables that predict investment opportunities following the theory of Merton (1973), or statistically useful variables to explain the returns following the theory of Ross (1976). On the other side, as first advocated by Lakonishok, Shleifer and Vishny (1994), the size and value factors are thought to be related to investors' irrationality in the sense that large-cap and growth stocks tend to be glamorized whereas small-cap and value stocks tend to be neglected. There is a vast literature on both sides of this debate.[16]

While the debate is important to improve our understanding of capital markets, Stein (1996) demonstrates that the theoretical interpretation of the model is not relevant to its application to determine the cost of capital. On one side, if the Fama-French model is rational, then the size and value factors capture true risks and should be accounted for in the risk premiums of energy utilities. On the other side, if the size and value factors are irrational, then the significant value betas of energy utilities indicate that they are neglected or undervalued firms. In this case, Stein (1996) shows that rational firms should not undertake a project that provides an expected return lower than the return estimated by the potentially irrational Fama-French model. They are better off in rejecting the project and simply buying back their own shares for which they expect an inflated future return because of the undervaluation. Thus, the potentially irrational Fama-French estimates serve as the appropriate hurdle rate for project investments. Hence, for both interpretations, the equity cost of

[16] A third interpretation, following Lo and MacKinlay (1990) and Kothari, Shanken and Sloan (1995), is that the results of the Fama-French model are spurious, due to biases like data snooping or survivorship. However, the fact that similar size and value premiums have been found in countries outside the U.S. has rendered this explanation less appealing.

capital of energy utilities generated by the Fama-French model is a useful guideline of a fair rate of return for regulators.

Arguably, the Fama-French model is one of the most widely used models of expected returns in the academic finance literature (Davis, 2006). Nevertheless, the literature on the cross-section of equity returns has identified numerous other factors that could be relevant in the multifactor approach. For examples, other influential factors include the labor income factor of Jagannathan and Wang (1996), the momentum factor of Jegadeesh and Titman (1993) and Carhart (1997), the liquidity factor of Pastor and Stambaugh (2003) and the idiosyncratic volatility factor of Ang *et al.* (2006, 2009). These advances in the literature on the cross-section of returns could eventually lead to a better understanding of the equity risk premium for energy utilities.[17] The next section looks at a second approach that goes beyond the CAPM to estimate the equity risk premium.

5. Equity Risk Premium with the Adjusted CAPM

This section considers two empirical adjustments to the CAPM estimates proposed in the academic literature to account for their deficiencies. We call the CAPM with the addition of the two modifications the "Adjusted CAPM". Unlike the CAPM and the Fama-French model, the Adjusted CAPM is not an equilibrium model of expected returns. It contains adjustments to the CAPM that are empirically justified in a context where the known difficulties of a theoretical model need to be lessened for improved estimation. We first introduce the Adjusted CAPM. Then we implement it to estimate the risk premium of energy utilities. We finally offer a brief discussion of our findings.

5.1. Model and Literature

The Adjusted CAPM is based on the CAPM but provides more realistic estimates of the rate of return by considering the empirical problems of the CAPM. More specifically, the Adjusted CAPM is a model in which the expected equity return of a gas utility is arrived at by

[17] Some of the documented effects, like momentum, are short-lived. Hence, their related factor might be irrelevant for estimates of the cost of equity capital.

$$E(R_{GAS}) = R_f + \alpha_{GAS} \times (1 - \beta^{Adj}) + \beta^{Adj} \times \lambda_m .$$

Compared to the CAPM, this equation incorporates a modification to take into account that estimated betas can be adjusted for better predictive power and a modification to take account of the fact the alpha (risk premium error) is high for low-beta value-oriented firms in the CAPM.

The first modification originates from the works of Blume (1971, 1975). Blume (1971) examines historical portfolio betas over two consecutive periods and finds that the historical betas, from one period to another, regress towards one, the average of the market. He also shows that the historical betas adjusted towards one predict future betas better than unadjusted betas. Blume (1975) builds a historical beta adjustment model to capture the tendency to regress towards one. He discovers that the best adjustment is to use a beta equal to $0.343 + 0.677 \times \beta^{His}$, a finding that led to the concept of "adjusted beta". Merrill Lynch, which popularized the use of adjusted betas based on Blume (1975)'s results, advocates the adjustment $\beta^{Adj} = 0.333 + 0.667 \times \beta^{His}$. Merrill Lynch's adjusted beta, now widely used in practice, represents a weighted-average between the beta of the market and the historical beta, with a two-thirds weighting on the historical beta.

The second adjustment is initially proposed by Litzenberger, Ramaswamy and Sosin (1980), who consider solutions to the problem that the CAPM gives a cost of equity capital with a downward bias for low beta firms, as discussed in section 3.1. They note that one way of remedying the problem is to add a bias correction to the CAPM risk premium. To be effective, the correction must take account of the importance of the risk premium error and the level of the firm's beta because these two elements influence the magnitude of the problem. To do this for low beta securities, Litzenberger, Ramaswamy and Sosin (1980) propose the bias correction $\alpha_{GAS} \times (1 - \beta)$. As desired, the correction increases with the risk premium error of the CAPM, and decreases with the beta. The correction is nil for a firm for which the CAPM already works well (when $\alpha_{GAS} = 0$) or for a firm having a beta of one, two cases where the CAPM produces a fair rate of return on average. Morin (2006, Section 6.3) presents an application of this adjustment in regulatory finance through a model he calls the empirical CAPM.

In summary, the two modifications incorporated in the Adjusted CAPM involve first using the adjusted beta instead of the historical beta and second including the bias correction in the risk premium calculation. Considering the documented usefulness of the two adjustments, the Adjusted CAPM has the potential to estimate a reasonable risk premium for the energy utilities.

5.2. Risk Premium Estimates

To compute the Adjusted CAPM estimates for our utilities, the starting point is the estimates of the CAPM of Section 3.2, given in Table 2. The beta estimates are now understood as the unadjusted historical betas β^{His}. The gas utility risk premium with the Adjusted CAPM can then be expressed as $\alpha_{GAS} \times (1-\beta^{Adj}) + \beta^{Adj} \times E(\lambda_{m,t})$, where $\beta^{Adj} = 0.333 + 0.667 \times \beta^{His}$. The Adjusted CAPM risk premium error is arrived at by $\alpha_{GAS}^{Adj} = E(R_{GAS,t} - R_{f,t}) - [\alpha_{GAS} \times (1-\beta^{Adj}) + \beta^{Adj} \times E(\lambda_{m,t})]$.

Table 4 shows the Adjusted CAPM estimates using the four gas distribution reference portfolios. The estimates of the risk premium error α_{GAS}^{Adj}, the adjusted beta β^{Adj}, the bias correction $\alpha_{GAS} \times (1-\beta^{Adj})$ and the risk premium are shown in Panels A, B, C and D, respectively. The risk premium errors are still positive for the four portfolios, with values ranging from 1.39% (for CAindex) to 2.89% (for USindex), but the underestimation is only significant for USindex. The reduction in errors comes from the use of adjusted betas, which are 0.56 on average, and the bias corrections, which are 2.96% on average. Lastly, the risk premiums vary between 4.88% and 8.27%, findings comparable to the estimates obtained with the Fama-French model.

< INSERT TABLE 4 HERE >

Figure 5 shows the risk premium errors for the utilities that make up the CAindex portfolios (Figure 5a), the gas distributors in the USindex portfolios (Figure 5b) and the four utilities reference portfolios (Figure 5c). The errors are generally insignificant and a comparison with Figure 1 indicates that they have decreased considerably for all portfolios. For example, for the TSX_Util portfolio, the error is down from 5.0% with the CAPM to 0.9% with the Adjusted CAPM.

< INSERT FIGURE 5 HERE >

5.3. Discussion

Our results support the validity of the Adjusted CAPM for determining the rate of return on energy utilities. While its risk premium estimates are in the same range as the Fama-French estimates, it arrives at its results from a different perspective. The Fama-French model advocates the use of additional risk factors to reduce the CAPM risk premium errors. The Adjusted CAPM, through its bias correction, effectively estimates the risk premium as a weighted-average of the CAPM risk premium and the realized historical risk premium, with a weighting of beta on the former.

The Adjusted CAPM thus recognizes that the CAPM is an imperfect model that can be improved with the information contained in the historical returns. Pastor and Stambaugh (1999) propose a similar strategy by demonstrating how to estimate the cost of equity by using Bayesian econometrics to incorporate the CAPM risk premium error (or alpha) in an optimal manner based on the priors of the evaluator. Consistent with our results, they also show evidence of higher costs of equity for energy utilities using their technique than using the CAPM alone.[18] As the Adjusted CAPM does not require additional risk factors like size and value, the model might be easier to interpret for regulators already familiar with the standard CAPM in their decisions.

6. Conclusion

It is difficult to overstate the importance of the evaluation of the expected rate of return in finance. For a firm's management group, the expected rate of return on equity (or the equity cost of capital) is central to its overall cost of capital, i.e. the rate used to determine which projects will be undertaken. For portfolio managers, the expected rate of return on equity is an essential ingredient

[18] Pastor and Stambaugh (1999) obtain risk premiums that vary between the CAPM estimates, when they assume that there is zero prior uncertainty on the CAPM, and the historical estimates, when they assume that there is infinite prior uncertainty on the CAPM. Our bias correction corresponds approximately to a prior uncertainty on the CAPM between 3% and 6% in their setup.

in portfolio decisions. For regulatory bodies, the expected return on equity is the basis for determining the fair and reasonable rate of return of a regulated enterprise. This paper is interested in evaluating the rate of return in the context of regulated energy utilities.

The academic literature contains numerous theories for determining the expected rate of return on equity. As those theories are based on simplified assumptions of the complex world in which we live, they cannot be perfect. Even if the theoretical merit of the different models can be debated, the determination of the most valid approach to explain the financial markets really becomes an empirical question – it is necessary to answer the question “which theory best explains the information about actual returns?” This paper empirically examines the validity of the model the most often used in the rate adjustment formula of regulatory bodies, the CAPM, one of the most prominent academic alternatives, the Fama-French model, and a version of the CAPM modified to account for some of its empirical deficiencies, the Adjusted CAPM.

Our empirical results show that the risk premiums for energy utilities estimated with the CAPM are rejected as too low compared to the historical risk premiums. The rejections are related to the well-documented CAPM underestimation of the average returns of low-beta firms and value firms. The Fama-French model and the Adjusted CAPM appear statistically better specified, as we cannot reject the hypothesis that their risk premium errors are equal to zero. They suggest equity risk premiums for gas distribution utilities between 4% and 8%. Overall, our findings demonstrate that models that go beyond the CAPM have the potential to improve the estimation of the cost of equity capital of energy utilities. They are thus interesting avenues for regulators looking to set fair and reasonable equity rates of return.

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TABLE 1
Descriptive Statistics of Monthly Returns

Variable	N	Mean	St Dev	Min	Max	Brief Description
Panel A: Canadian Energy Utilities						
ATCO	263	0.013	0.067	-0.301	0.279	ATCO Ltd.
Algonqui	108	0.009	0.054	-0.163	0.166	Algonquin Power Income Fund
CanUtili	263	0.012	0.043	-0.107	0.159	Canadian Utilities Limited
EPCOR	114	0.008	0.046	-0.201	0.108	EPCOR Power
Emera	143	0.009	0.043	-0.137	0.115	Emera Incorporated
Enbridge	263	0.011	0.054	-0.365	0.205	Enbridge Inc.
FortChic	107	0.009	0.054	-0.119	0.210	Fort Chicago Energy Partners
Fortis	228	0.013	0.041	-0.134	0.146	Fortis Inc.
GazMetro	166	0.010	0.037	-0.134	0.084	Gaz Métro Limited Partnerships
NorthPow	104	0.011	0.063	-0.202	0.205	Northland Power Income Fund
PacNorth	263	0.010	0.070	-0.400	0.507	Pacific Northern Gas
TransAlt	263	0.009	0.048	-0.217	0.188	TransAlta Corporation
TransCan	258	0.008	0.054	-0.214	0.254	TransCanada Pipelines
CAindex	263	0.010	0.031	-0.130	0.087	Equally-weighted portfolio
Panel B: U.S. Gas Distribution Utilities						
AGL_Res	407	0.013	0.052	-0.138	0.253	AGL Resources Inc.
Atmos	277	0.013	0.063	-0.302	0.269	Atmos Energy Corp.
Laclede	407	0.012	0.056	-0.148	0.374	Laclede Group
NJ_Res	407	0.013	0.063	-0.171	0.577	New Jersey Resources Corp.
Northwes	407	0.012	0.060	-0.236	0.274	Northwest Natural Gas Co.
Piedmont	407	0.013	0.059	-0.188	0.315	Piedmont Natural Gas Co.
SouthJer	407	0.012	0.058	-0.194	0.486	South Jersey Industries
Southwes	407	0.011	0.070	-0.304	0.234	Southwest Gas Corp.
WGL_Hold	407	0.012	0.071	-0.232	0.807	WGL Holdings Inc.
USindex	407	0.012	0.041	-0.121	0.338	Equally-weighted portfolio
Panel C: Sector Indexes						
TSX_Util	228	0.010	0.037	-0.101	0.114	S&P/TSX Utilities Index
DJ_GasDi	180	0.012	0.043	-0.139	0.137	Dow Jones Canada Gas Distribution Index
DJ_Util	180	0.007	0.036	-0.139	0.101	Dow Jones Canada Utilities Index
DJ_GasUS	180	0.012	0.039	-0.120	0.143	Dow Jones US Gas Distribution Index
DJ_UtiUS	180	0.009	0.042	-0.127	0.136	Dow Jones US Utilities Index
FF_Util	407	0.010	0.041	-0.123	0.188	Fama-French US Utilities Index

NOTES: This table presents descriptive statistics on the monthly returns of 13 Canadian utilities and their equally-weighted portfolio (CAindex) in Panel A, of nine U.S. gas distribution utilities and their equally-weighted portfolio (USindex) in Panel B, and on selected utilities sector indexes in Panel C. The columns labelled N, Mean, St Dev, Min and Max correspond respectively to the number of observations, the mean, the standard deviation, the minimum value and the maximum value. The column labelled Brief Description gives the full name of the utility holding companies or the utilities sector indexes.

TABLE 2
CAPM Risk Premium Estimates for the Gas Distribution Reference Portfolios

Portfolio	Estimate	SE	t-stat	Prob > |t|
Panel A: Risk Premium Error (Alpha)				
DJ_GasDi	8.43	3.79	2.22	0.028
CAindex	4.52	2.33	1.94	0.053
DJ_GasUS	7.39	3.34	2.21	0.028
USindex	6.23	1.95	3.19	0.002
Panel B: Beta				
DJ_GasDi	0.21	0.11	1.95	0.053
CAindex	0.34	0.07	4.60	<.0001
DJ_GasUS	0.37	0.09	4.16	<.0001
USindex	0.46	0.06	7.37	<.0001
Panel C: Risk Premium				
DJ_GasDi	1.66	1.28	1.30	0.195
CAindex	1.76	1.11	1.58	0.116
DJ_GasUS	2.74	1.46	1.87	0.063
USindex	2.72	1.33	2.04	0.042

NOTES: This table reports the results of the estimation of the CAPM for the gas distribution reference portfolios. Panels A to C look at the annualized risk premium error or alpha (in percent), the market beta and the annualized risk premium (in percent), respectively. The columns labelled Estimate, SE, t-stat and Prob > |t| give respectively the estimates, their standard errors, their t-statistics and their p-values. The four gas distribution reference portfolios and their sample are described in section 2 and table 1. The annualized mean market risk premiums for their corresponding sample period are 8.1% for DJ_GasDi, 5.2% for CAindex, 7.5% for DJ_GasUS and 6.0% for USindex.

TABLE 3
Fama-French Risk Premium Estimates for the Gas Distribution Reference Portfolios

Portfolio	Estimate	SE	t-stat	Prob > |t|
Panel A: Risk Premium Error (Alpha)				
DJ_GasDi	4.45	3.11	1.43	0.155
CAindex	2.04	1.85	1.11	0.270
DJ_GasUS	1.31	3.01	0.43	0.665
USindex	0.31	1.80	0.17	0.863
Panel B: Beta				
DJ_GasDi	0.41	0.08	5.06	<.0001
CAindex	0.48	0.05	10.38	<.0001
DJ_GasUS	0.63	0.07	9.64	<.0001
USindex	0.64	0.06	11.18	<.0001
Panel C: Size Beta				
DJ_GasDi	-0.01	0.08	-0.11	0.912
CAindex	-0.02	0.05	-0.51	0.613
DJ_GasUS	0.00	0.09	0.04	0.971
USindex	0.20	0.07	2.9	0.004
Panel D: Value Beta				
DJ_GasDi	0.33	0.06	5.12	<.0001
CAindex	0.30	0.04	7.64	<.0001
DJ_GasUS	0.59	0.13	4.41	<.0001
USindex	0.71	0.10	7.21	<.0001
Panel E: Risk Premium				
DJ_GasDi	5.64	1.78	3.17	0.002
CAindex	4.23	1.52	2.78	0.006
DJ_GasUS	8.83	2.32	3.81	0.000
USindex	8.64	2.16	4	<.0001

NOTES: This table reports the results of the estimation of the Fama-French model for the gas distribution reference portfolios. Panels A to E look at the annualized risk premium error or alpha (in percent), the market beta, the size beta, the value beta and the annualized risk premium (in percent), respectively. The columns labelled Estimate, SE, t-stat and Prob > |t| give respectively the estimates, their standard errors, their t-statistics and their p-values. The four gas distribution reference portfolios and their sample are described in section 2 and table 1. The annualized mean market risk premiums for their corresponding sample period are 8.1% for DJ_GasDi, 5.2% for CAindex, 7.5% for DJ_GasUS and 6.0% for USindex. The annualized mean size risk premiums for their corresponding sample period are 12.4% for DJ_GasDi, 8.9% for CAindex, 2.7% for DJ_GasUS and 2.7% for USindex. The annualized mean value risk premiums for their corresponding sample period are 7.4% for DJ_GasDi, 6.4% for CAindex, 6.9% for DJ_GasUS and 6.0% for USindex.

TABLE 4
Adjusted CAPM Risk Premium Estimates for the Gas Distribution Reference Portfolios

Portfolio	Estimate	SE	t-stat	Prob > |t|
Panel A: Risk Premium Error (Alpha)				
DJ_GasDi	1.82	2.00	0.91	0.365
CAindex	1.39	1.54	0.9	0.366
DJ_GasUS	2.68	1.97	1.36	0.176
USindex	2.89	1.37	2.11	0.035
Panel B: Adjusted Beta				
DJ_GasDi	0.47	0.07	6.69	<.0001
CAindex	0.56	0.05	11.38	<.0001
DJ_GasUS	0.58	0.06	9.84	<.0001
USindex	0.64	0.04	15.44	<.0001
Panel C: Bias Correction				
DJ_GasDi	4.46	2.28	1.96	0.052
CAindex	1.99	1.10	1.81	0.071
DJ_GasUS	3.12	1.61	1.94	0.054
USindex	2.26	0.77	2.94	0.004
Panel D: Risk Premium				
DJ_GasDi	8.27	2.71	3.05	0.003
CAindex	4.88	2.11	2.31	0.021
DJ_GasUS	7.45	2.52	2.96	0.004
USindex	6.05	1.89	3.21	0.002

NOTES: This table reports the results of the estimation of the Adjusted CAPM for the gas distribution reference portfolios. Panels A to D look at the annualized risk premium error or alpha (in percent), the adjusted market beta, the bias correction and the annualized risk premium (in percent), respectively. The columns labelled Estimate, SE, t-stat and Prob > |t| give respectively the estimates, their standard errors, their t-statistics and their p-values. The four gas distribution reference portfolios and their sample are described in section 2 and table 1. The annualized mean market risk premiums for their corresponding sample period are 8.1% for DJ_GasDi, 5.2% for CAindex, 7.5% for DJ_GasUS and 6.0% for USindex.

FIGURE 1
Risk Premium Errors with the CAPM for Various Utilities

Figure 1a: Firms in the CAindex Portfolio

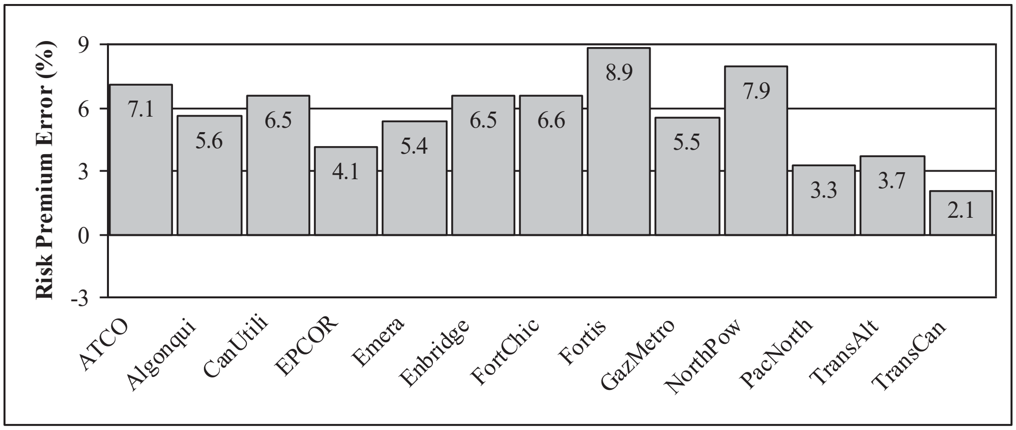


Figure 1b: Firms in the USindex Portfolio

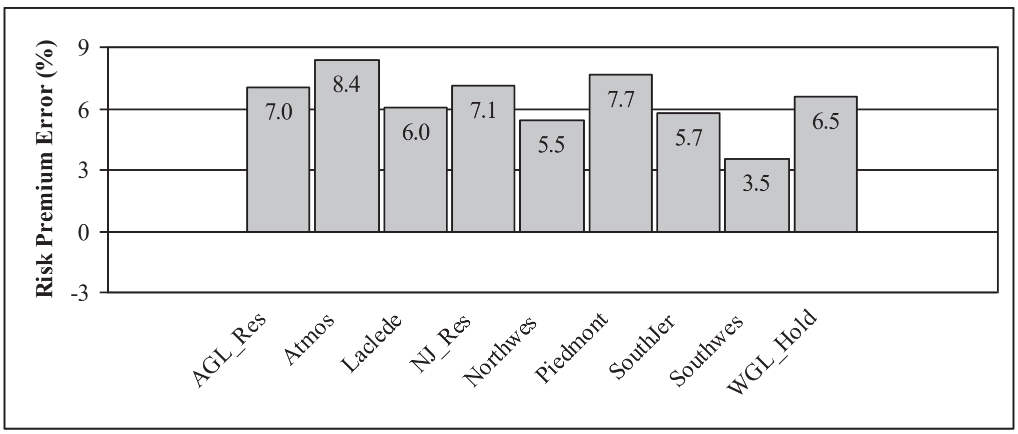
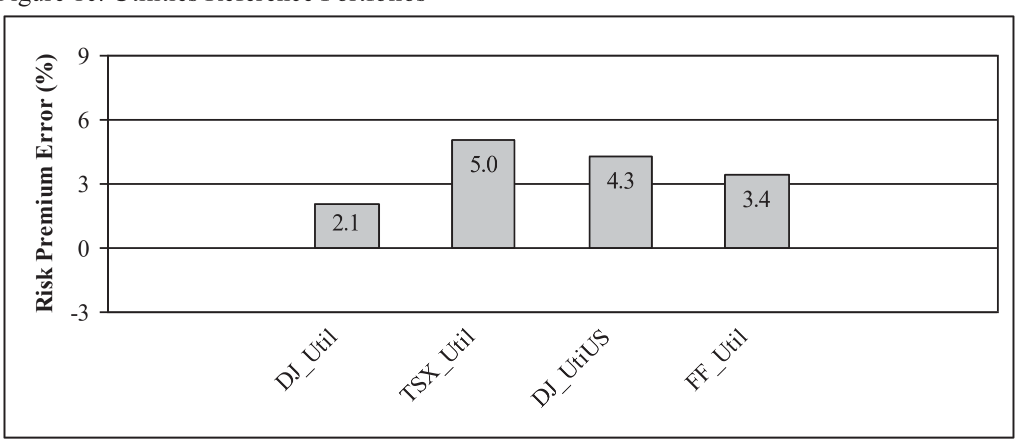


Figure 1c: Utilities Reference Portfolios



NOTES: This figure shows the annualized risk premium errors (or alphas) with the CAPM for the Canadian utilities in the CAindex portfolio (Figure 1a), the U.S. gas distributors in the USindex portfolio (Figure 1b) and the utilities reference portfolios (Figure 1c).

FIGURE 2
Comparison of the Fama-French and CAPM Results

Figure 2a: Risk Premium Errors

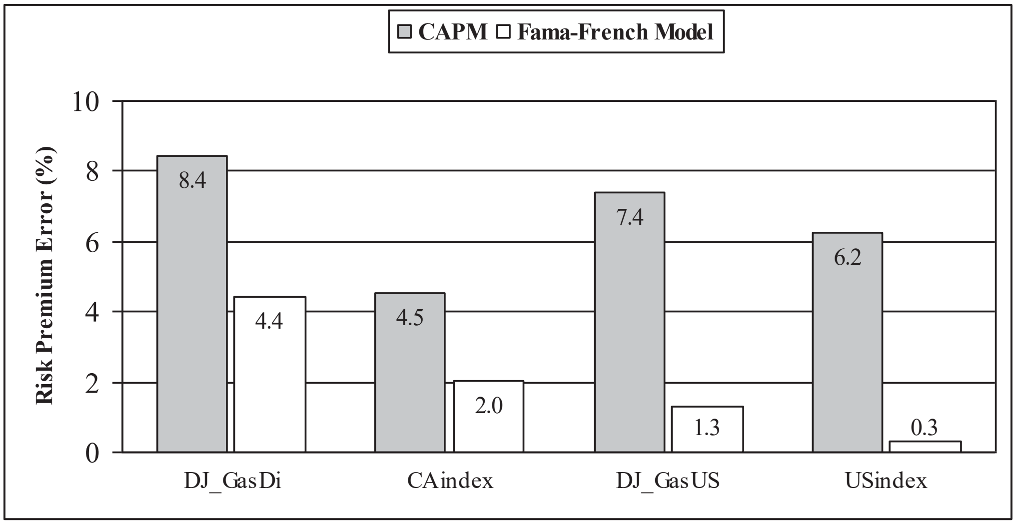
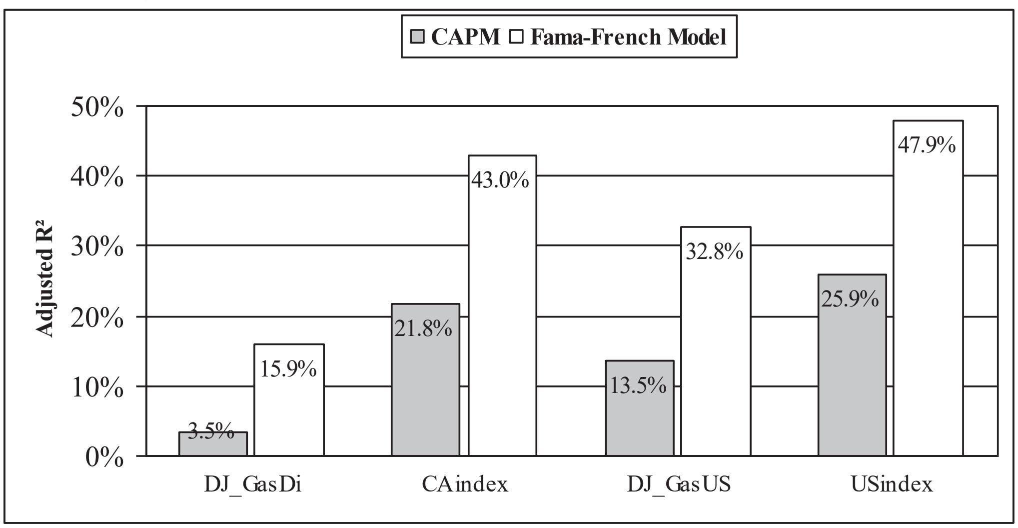


Figure 2b: Adjusted R²s



NOTES: This figure compares the results of the CAPM (gray bars) and the Fama-French model (white bars) in terms of annualized risk premium errors (or alphas) (Figure 2a) and adjusted R^2 (Figure 2b) for the gas distribution reference portfolios.

FIGURE 3
Risk Premium Errors with the Fama-French Model for Various Utilities

Figure 3a: Firms in the CAindex Portfolio

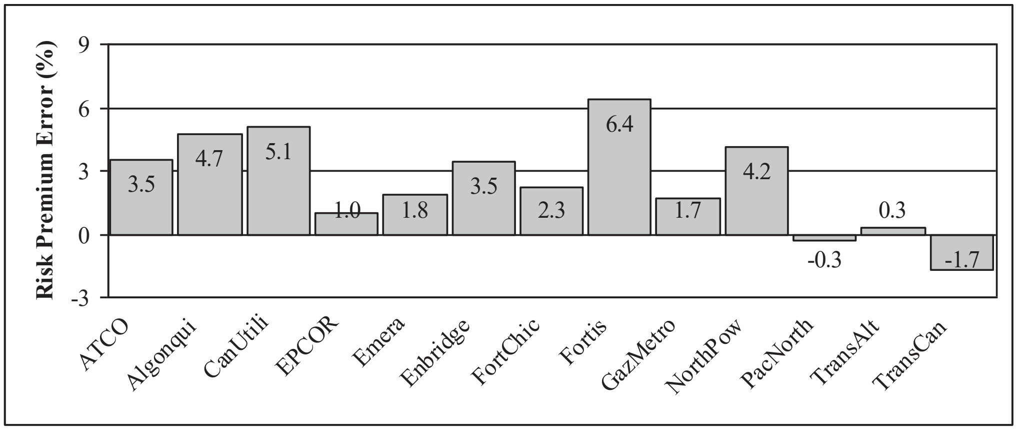


Figure 3b: Firms in the USindex Portfolio

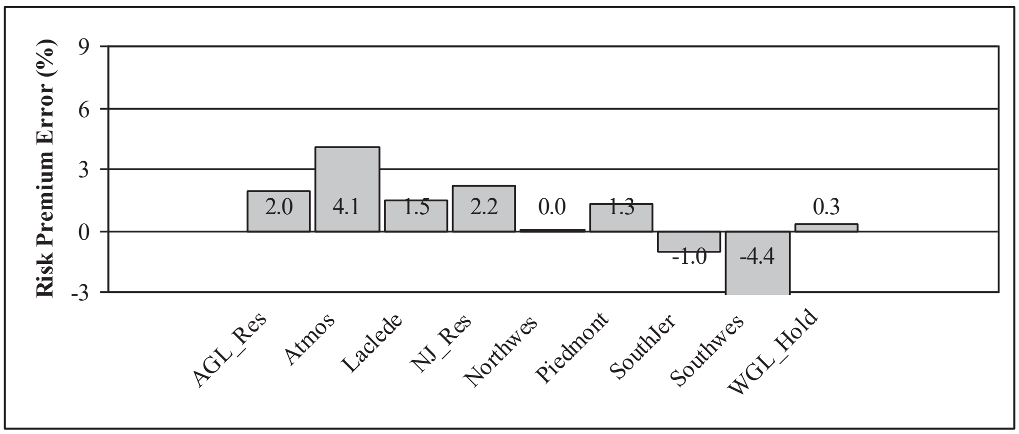
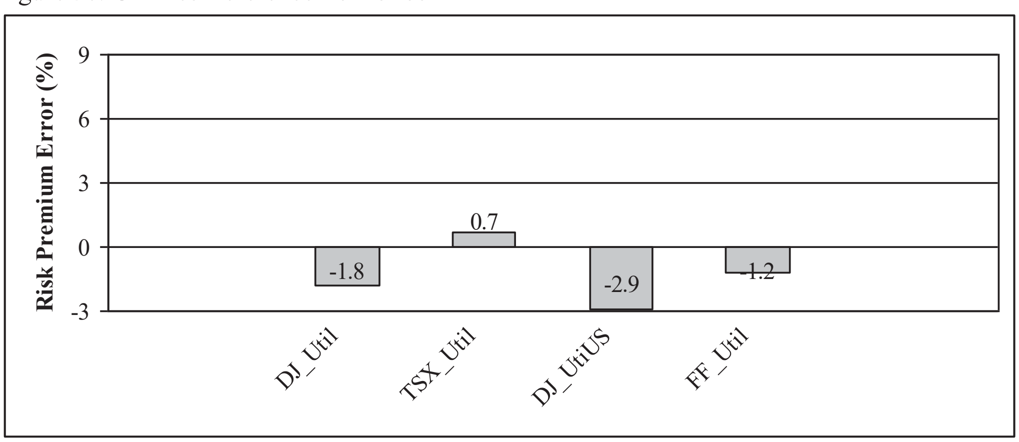


Figure 3c: Utilities Reference Portfolios



NOTES: This figure shows the annualized risk premium errors (or alphas) with the Fama-French model for the Canadian utilities in the CAindex portfolio (Figure 3a), the U.S. gas distributors in the USindex portfolio (Figure 3b) and the utilities reference portfolios (Figure 3c).

FIGURE 4
Value Betas for Various Utilities

Figure 4a: Firms in the CAindex Portfolio

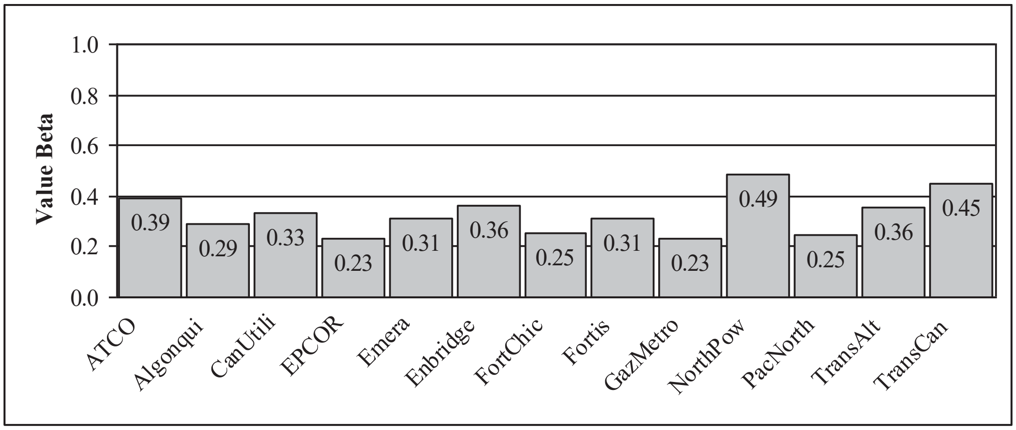


Figure 4b: Firms in the USindex Portfolio

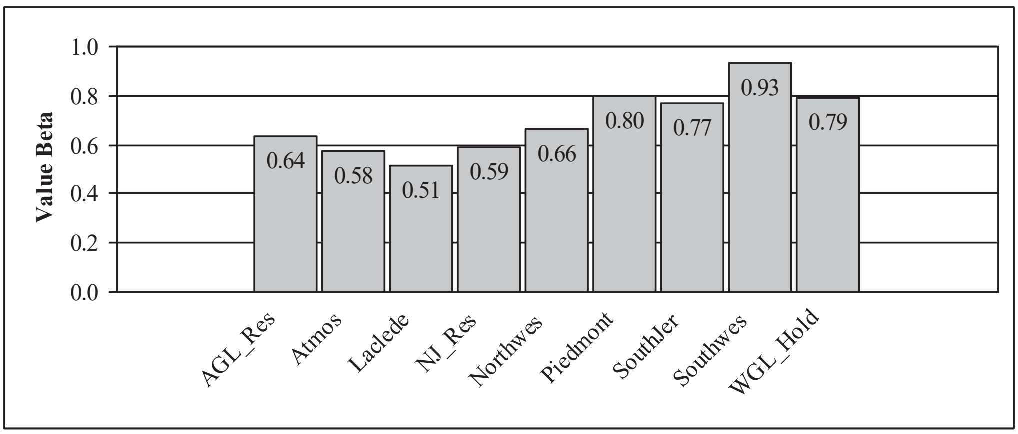
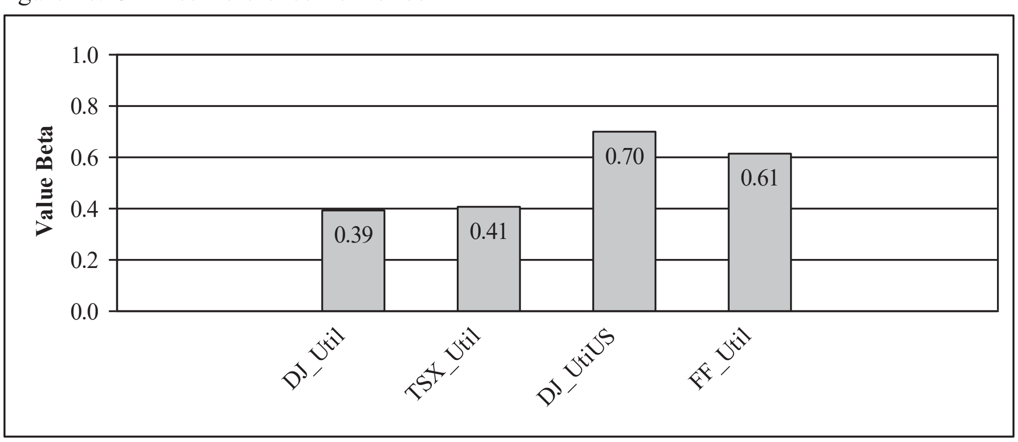


Figure 4c: Utilities Reference Portfolios



NOTES: This figure shows the value betas in the Fama-French model for the Canadian utilities in the CAindex portfolio (Figure 4a), the U.S. gas distributors in the USindex portfolio (Figure 4b) and the utilities reference portfolios (Figure 4c).

FIGURE 5
Risk Premium Errors with the Adjusted CAPM for Various Utilities

Figure 5a: Firms in the CAindex Portfolio

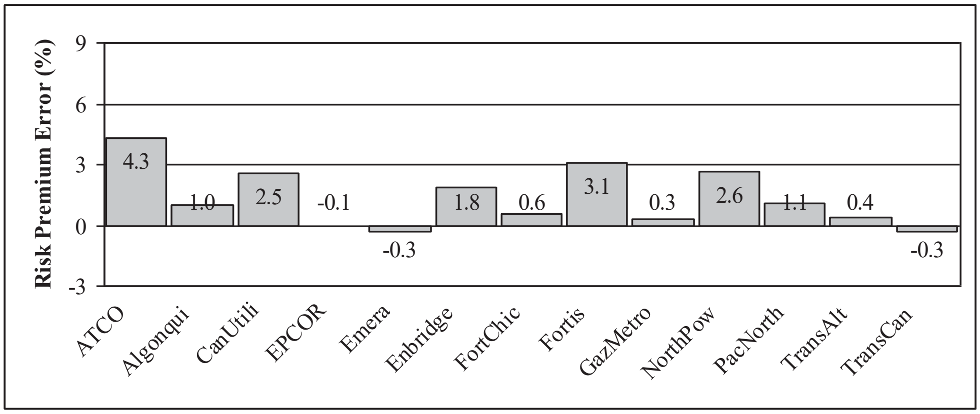


Figure 5b: Firms in the USindex Portfolio

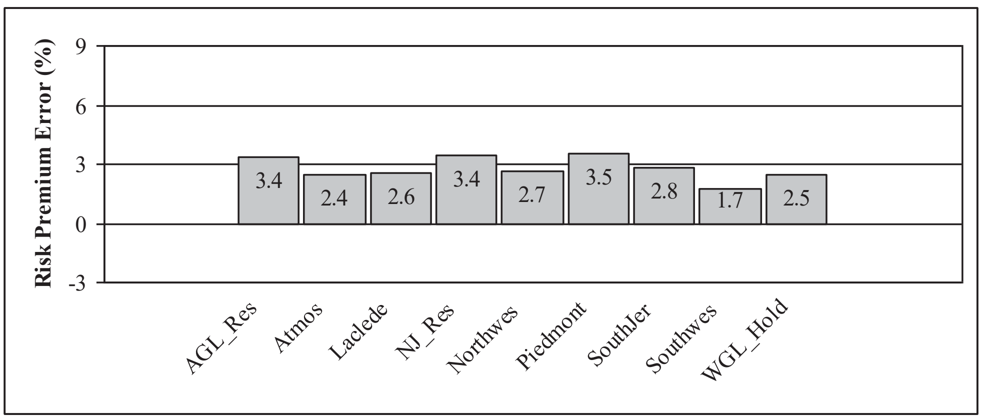
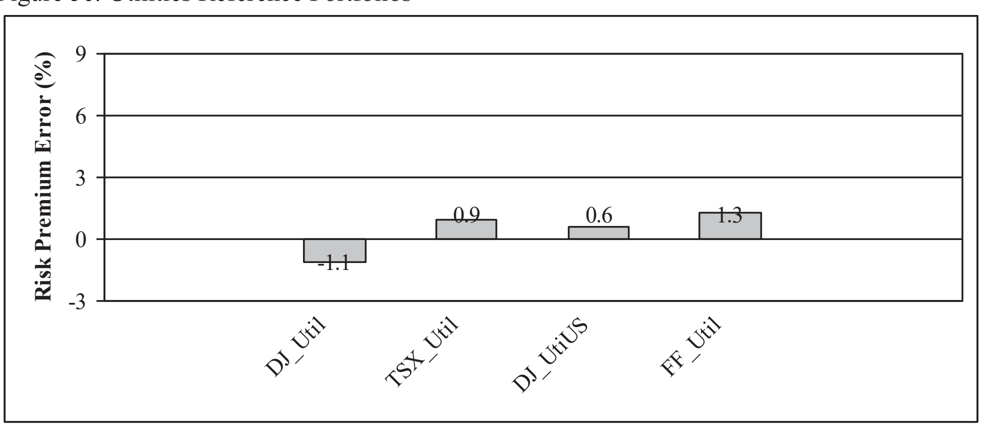


Figure 5c: Utilities Reference Portfolios



NOTES: This figure shows the annualized risk premium errors (or alphas) with the Adjusted CAPM for the Canadian utilities in the CAindex portfolio (Figure 5a), the U.S. gas distributors in the USindex portfolio (Figure 5b) and the utilities reference portfolios (Figure 5c).

150 FERC ¶ 61,165
UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

Before Commissioners: Cheryl A. LaFleur, Chairman;
Philip D. Moeller, Tony Clark,
Norman C. Bay, and Colette D. Honorable.

Martha Coakley, Massachusetts Attorney General; Connecticut Public Utilities Regulatory Authority; Massachusetts Department of Public Utilities; New Hampshire Public Utilities Commission; Connecticut Office of Consumer Counsel; Maine Office of the Public Advocate; George Jepsen, Connecticut Attorney General; New Hampshire Office of Consumer Advocate; Rhode Island Division of Public Utilities and Carriers; Vermont Department of Public Service; Massachusetts Municipal Wholesale Electric Company; Associated Industries of Massachusetts; The Energy Consortium; Power Options, Inc.; and the Industrial Energy Consumer Group v. Bangor Hydro-Electric Co.; Central Maine Power Co.; New England Power Co.; New Hampshire Transmission LLC; NSTAR Electric and Gas Corp.; Northeast Utilities Service Co.; The United Illuminating Co.; Unitil Energy Systems, Inc. and Fitchburg Gas and Electric Light Co.; Vermont Transco, LLC	Docket Nos. EL11-66-002
Martha Coakley, Massachusetts Attorney General; Connecticut Public Utilities Regulatory Authority; Massachusetts Department of Public Utilities; New Hampshire Public Utilities Commission; Connecticut Office of Consumer Counsel; Maine Office of the Public Advocate; George Jepsen, Connecticut Attorney General; New Hampshire Office of Consumer Advocate; Rhode Island Division of Public Utilities and Carriers; Vermont Department of Public Service; Massachusetts Municipal Wholesale Electric Company; Associated Industries of Massachusetts; The Energy Consortium;	EL11-66-003

Power Options, Inc.; and the Industrial Energy
Consumer Group

v.

Bangor Hydro-Electric Co.; Central Maine Power Co.;
New England Power Co.; New Hampshire Transmission
LLC; NSTAR Electric and Gas Corp.; Northeast
Utilities Service Co.; The United Illuminating Co.;
Unitil Energy Systems, Inc. and Fitchburg Gas and
Electric Light Co.; Vermont Transco, LLC

OPINION NO. 531-B

ORDER ON REHEARING

(Issued March 3, 2015)

Table of Contents

1. On July 21, 2014, the New England Transmission Owners (NETOs),[1] a group of complainants (Complainants) and intervenors (collectively, Petitioners),[2] and the Eastern

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[1] The NETOs include Bangor Hydro-Elec. Co.; Central Maine Power Co.; New England Power Co.; New Hampshire Transmission LLC; NSTAR Electric & Gas Corp.; Northeast Utilities Service Co.; United Illuminating Co.; Unitil Energy Systems, Inc. and Fitchburg Gas & Electric Light Co.; and Vermont Transco, LLC.

[2] Complainants include Martha Coakley, Massachusetts Attorney General; Connecticut Public Utilities Regulatory Authority; Massachusetts Department of Public Utilities; New Hampshire Public Utilities Commission; Connecticut Office of Consumer Counsel; Maine Office of the Public Advocate; George Jepsen, Connecticut Attorney General; New Hampshire Office of Consumer Advocate; Rhode Island Division of Public Utilities and Carriers; Vermont Department of Public Service; Massachusetts Municipal Wholesale Electric Co.; Associated Industries of Massachusetts; the Energy Consortium; Power Options, Inc.; and the Industrial Energy Consumer Group. Intervenors

(continued…)

Massachusetts Consumer-Owned Systems (EMCOS), filed requests for rehearing of the Commission's June 19, 2014 order on initial decision[3] concerning a complaint, filed pursuant to section 206 of the Federal Power Act (FPA),[4] challenging the NETOs' base return on equity (ROE) reflected in ISO New England Inc.'s (ISO-NE) open access transmission tariff (OATT).[5] In this order, we deny rehearing.

I. **Background**

2. The NETOs recover their transmission revenue requirements through formula rates included in ISO-NE's OATT. The revenue requirements for Regional Network Service[6] and Local Network Service[7] that the NETOs provide are calculated using the same single base ROE. On October 31, 2006, the Commission, in Opinion No. 489, established the base ROE at 11.14 percent, which consisted of an initial base ROE of 10.4 percent plus an upward adjustment of 74 basis points to account for changes in capital market conditions that took place between the issuance of the Administrative Law Judge's initial decision in that proceeding and the issuance of Opinion No. 489,[8] as reflected in changes in U.S. Treasury bond yields during that time period.

New Hampshire Electric Cooperative, Inc. and Maine Public Utilities Commission requested rehearing jointly with the Complainants.

[3] *Martha Coakley, Mass. Attorney Gen. v. Bangor Hydro-Elec. Co.*, Opinion No. 531, 147 FERC ¶ 61,234 (2014) (Opinion No. 531), *order on paper hearing*, Opinion No. 531-A, 149 FERC ¶ 61,032 (2014) (Opinion No. 531-A).

[4] 16 U.S.C. § 824e (2012).

[5] ISO-NE's OATT is section II of ISO-NE's Transmission, Markets, and Services Tariff (Tariff). *See* ISO-NE, Tariff, § II.

[6] Regional Network Service is the transmission service over the pool transmission facilities described in Part II.B of the OATT. ISO-NE, Tariff, § I.2 (50.0.0); *see also* ISO-NE, Tariff, § II.B Regional Network Service (0.0.0), *et seq.*

[7] Local Network Service is the network service provided under Schedule 21 and the Local Service Schedules of ISO-NE's OATT. ISO-NE, Tariff, § I.2 (50.0.0); *see also* ISO-NE, Tariff, Schedule 21 Local Service (1.0.0), *et seq.*

[8] *Bangor Hydro-Elec. Co.*, Opinion No. 489, 117 FERC ¶ 61,129 (2006) (Opinion No. 489), *order on reh'g*, 122 FERC ¶ 61,265 (2008), *order granting clarification*, 124 FERC ¶ 61,136 (2008), *aff'd sub nom. Conn. Dep't of Pub. Util. Control v. FERC*, 593 F.3d 30 (2010).

3. On September 30, 2011, the Complainants filed a complaint alleging that the NETOs' 11.14 percent base ROE was unjust and unreasonable because capital market conditions had significantly changed since that base ROE was established in 2006. The Complainants argued that the bubble in the U.S. housing market, the subsequent financial crisis and economic recession, and the fiscal and monetary policies of the U.S. government had caused a "flight to quality"[9] in the capital markets. The Complainants contended that these market conditions had lowered bond yields and, as a result, capital costs for utilities.[10] The Complainants argued that, as a result, the NETOs' 11.14 percent base ROE now exceeded the level necessary to satisfy the Supreme Court's standards in *Bluefield*[11] and *Hope*.[12] The Complainants asserted that, based on a discounted cash flow (DCF) analysis conducted by their expert witness, the just and reasonable base ROE for the NETOs should not exceed 9.2 percent.

4. On May 3, 2012, the Commission issued an order on the complaint, establishing hearing and settlement judge procedures.[13] The Hearing Order also set a refund effective date of October 1, 2011. The hearing commenced on May 6, 2012 and was completed on May 10, 2013.[14] In accordance with the hearing's procedural schedule, the participants each first submitted an ROE analysis,[15] based on data from a 6-month study period in

[9] The "flight to quality" refers to investors seeking low-risk investment vehicles.

[10] Complaint, Ex. C-1 at 5-12.

[11] *Bluefield Water Works & Improvement Co. v. Pub. Serv. Comm'n*, 262 U.S. 679 (1923) (*Bluefield*).

[12] *FPC v. Hope Natural Gas Co.*, 320 U.S. 591 (1944) (*Hope*).

[13] *Martha Coakley, Mass. Attorney Gen.. v. Bangor Hydro-Elec. Co.*, 139 FERC ¶ 61,090 (2012) (Hearing Order).

[14] The parties conducted settlement negotiations but reached an impasse, leading to termination of the settlement procedures in August 2012. *Martha Coakley, Mass. Attorney Gen. v. Bangor Hydro-Elec. Co.*, 144 FERC ¶ 63,012, at P 28 (2013) (Initial Decision).

[15] The following expert witnesses submitted ROE analyses: Dr. William E. Avera, for the NETOs; Ms. Sabina U. Joe, for Trial Staff; Dr. John Wilson, for the EMCOS; and Dr. Randall Woolridge, for the Complainants.

2012,[16] and then filed an updated ROE analysis, using the same DCF methodology that each participant used in its initial analysis but with data based on the 6-month study period from October 2012 through March 2013.

5. On August 6, 2013, the Presiding Judge issued the initial decision, finding the NETOs' current 11.14 percent base ROE to be unjust and unreasonable.[17] The Presiding Judge adopted the DCF methodology used by the NETOs and found that it is appropriate to establish two different base ROEs in this proceeding—one for the 15-month refund period from October 1, 2011 (i.e., the refund effective date) to December 31, 2012, and one for the prospective period commencing when the Commission issues its order setting the going-forward base ROE. Thus, the Presiding Judge considered two separate DCF analyses relying on overlapping data from each period, the first using data from May 2012 through October 2012 and the second using data from October 2012 through March 2013. The Presiding Judge found the just and reasonable base ROE for the refund period to be 10.6 percent and the just and reasonable base ROE for the prospective period to be 9.7 percent.[18]

6. On June 19, 2014, the Commission issued Opinion No. 531, affirming in part and reversing in part the initial decision.[19] In Opinion No. 531, the Commission changed its approach on the DCF methodology to be applied in public utility rate cases, by adopting the two-step DCF methodology in place of the one-step DCF methodology the Commission had historically used. The Commission explained that the two-step DCF formula is k=D/P (1+.5g)+g, where "D/P," the dividend yield, is calculated using a single, average dividend yield based on the indicated dividend and the average monthly high and low stock prices over a six-month period; and "g," the constant dividend growth rate, is calculated by averaging short-term and long-term growth estimates, with the short-term estimate receiving two-thirds weight and the long-term estimate receiving one-third weight.[20]

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[16] Due to the different due dates for the parties' initial briefs, which ranged from October 2012 to January 2013, each party's initial ROE analysis was based on a different 6-month period in 2012.

[17] Initial Decision, 144 FERC ¶ 63,012 at P 544.

[18] *Id.*

[19] *See generally* Opinion No. 531, 147 FERC ¶ 61,234.

[20] *Id.* PP 15, 17, 39.

7. The Commission, after finding that there should be only one base ROE applicable to both the refund period and the prospective period in this proceeding, then applied the two-step DCF methodology to the facts of this proceeding, using a national proxy group of companies the Commission found were of comparable risk to the NETOs, to determine the NETOs' base ROE; however, because the parties had not litigated one input to the two-step DCF methodology—i.e., the appropriate long-term growth projection—the Commission instituted a paper hearing on that narrow issue. The Commission also found that, due to the anomalous capital market conditions reflected in the record, mechanically applying the DCF methodology and placing the NETOs' base ROE at the midpoint of the zone of reasonableness produced by that methodology would not satisfy the requirements of *Hope* and *Bluefield*.[21] Therefore, the Commission found it appropriate, based on the record evidence in the proceeding, to place the NETOs' base ROE halfway between the midpoint of the zone of reasonableness and the top of that zone.[22] However, the Commission explained that its finding on the specific numerical just and reasonable ROE for the NETOs was subject to the outcome of the paper hearing on the appropriate long-term growth projection to be used in the two-step DCF methodology.[23] The Commission also explained that, according to Commission precedent, "when a public utility's ROE is changed, either under section 205 or section 206 of the FPA, that utility's total ROE, inclusive of transmission incentive ROE adders, should not exceed the top of the zone of reasonableness produced by the two-step DCF methodology."[24]

8. On October 16, 2014, the Commission issued Opinion No. 531-A, the order on the paper hearing instituted by Opinion No. 531, finding that long-term projected growth in gross domestic product (GDP) is the appropriate long-term growth projection to use in the two-step DCF methodology.[25] Accordingly, the Commission found that a just and reasonable ROE for the NETOs is 10.57 percent, and that the NETOs' total or maximum ROE, including transmission incentive ROE adders, cannot exceed 11.74 percent, i.e., the top of the zone of reasonableness in this proceeding.[26] The Commission also ordered the

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[21] *Id.* P 142.

[22] *Id.*

[23] *Id.*

[24] *Id.* P 165.

[25] Opinion No. 531-A, 149 FERC ¶ 61,032 at P 10.

[26] *Id.* PP 10-11.

NETOs to issue refunds for the 15-month refund period from October 1, 2011 through December 31, 2012.[27]

II. Discussion

A. Procedural Matters

9. On July 21, 2014, the NETOs, Petitioners, and EMCOS filed requests for rehearing of Opinion No. 531. On November 17, 2014, the NETOs requested rehearing of Opinion No. 531-A, in Docket No. EL11-66-003, by submitting the same pleading that they filed on July 21, 2014 as a request for rehearing of Opinion No. 531.[28] Because the NETOs submitted the same pleading as a request for rehearing of both Opinion Nos. 531 and 531-A and, therefore, presented identical arguments in those two proceedings, our merits determinations in the instant order apply to the NETOs' requests for rehearing in both Docket Nos. EL11-66-002 and EL11-66-003. Thus, we also deny the NETOs' request for rehearing of Opinion No. 531-A.

1. Answers to Rehearing Requests, and Related Answers to Answers

10. On August 5, 2014, the Petitioners filed an answer to the NETOs' request for rehearing (Petitioners' August 5 Answer), and the NETOs filed an answer to the Petitioners' request for rehearing (NETOs' August 5 Answer). On August 20, 2014, the NETOs filed an answer to the Petitioners' August 5 Answer (NETOs' August 20 Answer).[29] On August 22, 2014, the Petitioners filed an answer to the NETOs' answer to the Petitioners' request for rehearing (Petitioners' August 22 Answer). On September 4, 2014, the Petitioners filed an answer to the NETOs' August 20 Answer (Petitioners' September 4 Answer).

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[27] *Id.* PP 12, Ordering Paragraph (C).

[28] *See* NETOs, Request for Rehearing, Docket No. EL11-66-003, at 3 (filed Nov. 7, 2014) ("the NETOs seek rehearing of Opinion No. 531-A with respect to the same issues and on the same grounds upon which they sought rehearing of Opinion No. 531. These issues and grounds are set forth in the NETOs' 'Request for Rehearing and Motion for Clarification of the New England Transmission Owners,' which the NETOs filed with the Commission on July 21, 2014, and which is attached hereto and incorporated herein (*see* Attachment A)").

[29] While the NETOs' August 20 Answer was styled as a motion to clarify the record, the filing was, in substance, an answer to the Complainants' August 5 Answer.

11. Rule 713(d) of the Commission's Rules of Practice and Procedure, 18 C.F.R. § 385.713(d) (2014), prohibits answers to a request for rehearing. Therefore, we reject the Petitioners' August 5 Answer and the NETOs' August 5 Answer. Accordingly, we also reject the answers to those answers—specifically, the NETOs' August 20 Answer, the Petitioners' August 22 Answer, and the Petitioners' September 4 Answer.

2. Motion to Strike

12. On August 5, 2014, the NETOs filed a motion to strike certain extra-record evidence from the Petitioners' request for rehearing. On August 20, 2014, the Petitioners filed an answer opposing the NETOs' motion to strike. We grant in part and deny in part the NETOs' motion to strike. The Commission has consistently held that the submission of additional factual information in a request for rehearing is inappropriate.[30] Therefore, we grant the NETOs' motion with respect to the extra-record evidence in Petitioners' request for rehearing. However, we deny the NETOs' motion with respect to the evidence that was already in the record and that Petitioners have merely reframed through graphical representation or basic arithmetic.[31]

3. Motions to Intervene Out-of-Time

13. On July 21, 2014, American Municipal Power, Inc. (AMP) filed a motion to intervene out-of-time and a request for rehearing,[32] and the American Public Power Association (APPA) and the National Rural Electric Cooperative Association (NRECA) jointly filed a motion to intervene out-of-time. APPA and NRECA also joined in the Petitioners' request for rehearing. On August 5, 2014, the NETOs filed an answer

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[30] *E.g.*, *Transcontinental Gas Pipe Line Corp.*, 94 FERC ¶ 61,066, at 61,278 (2001).

[31] Specifically, we deny the NETOs' motion with respect to (1) the altered version of the NETOs' risk premium analysis, at page 38 and Attachment A of Petitioners' request for rehearing; (2) the altered version of Opinion No. 531's Appendix showing an alternate source of growth rate projections, at pages 43 and 51, and at Attachment B, of Petitioners' request for rehearing; (3) the altered version of Opinion No. 531's Appendix reflecting an alternate low-end outlier adjustment, at pages 14, 62, and 63, and at Attachment C, of Petitioners' request for rehearing; (4) the altered version of Exhibit SC-524, at pages 26 and 27 of Petitioners' request for rehearing; (5) the histogram at pages 2-3 of Petitioners' request for rehearing; and (6) the histogram on pages 24-25 of Petitioners' request for rehearing.

[32] While AMP styled its filing as a motion for clarification, it is in substance a request for rehearing.

opposing AMP's, APPA's, and NRECA's motions to intervene out-of-time, and AMP's request for rehearing. On August 12, 2014, APPA and NRECA filed an answer to the NETOs' answer to the motions to intervene out of time and AMP's request for rehearing. On December 5, 2014, the Maine Public Advocate Office filed a motion to intervene out-of-time.

14. In ruling on a late-filed motion to intervene, the Commission applies the criteria set forth in Rule 214(d) of the Commission's Rules of Practice and Procedure, 18 C.F.R. § 385.214(d) (2014), and considers, among other things, whether the movant had good cause for failing to file the motion within the time prescribed, whether any disruption to the proceeding might result from permitting the intervention, and whether any prejudice to or additional burdens upon the existing parties might result from permitting the intervention. A petitioner for late intervention bears a higher burden to show good cause for late intervention after the Commission has issued a final order in a proceeding, and it is the Commission's policy to deny late intervention at the rehearing stage, even when the movant claims that the decision establishes a broad policy of general application.[33]

15. We find that AMP, APPA, NRECA, and the Maine Public Advocate Office have not met their burden of justifying late intervention. The Complainants filed the complaint in this proceeding on September 30, 2011, alleging that the capital market conditions following the collapse of the housing bubble and the resulting economic recession were such that the NETOs' existing ROE was no longer just and reasonable; the Commission then set the complaint for hearing on May 30, 2012 and issued a dispositive order on June 19, 2014, nearly three years after the complaint was filed. Thus, AMP, APPA, NRECA, and the Maine Public Advocate Office had ample notice that this proceeding involved the Commission's approach to determining public utilities' ROE, that the effect of recent capital market conditions on that approach was an issue central to the complaint, and that a Commission order in this proceeding would have precedential effect on similar proceedings before the Commission. AMP, APPA, NRECA, and the Maine Public Advocate Office have not shown good cause for failing to file their motions to intervene during the statutory comment period, or subsequent to that period but prior to the Commission's issuance of Opinion No. 531. AMP's, APPA's, and NRECA's statements that they did not anticipate the specific outcome in this proceeding, without more, do not suffice to make that showing.[34] We therefore deny their late-filed motions to intervene.

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[33] *See, e.g.*, *Williston Basin Interstate Pipeline Co.*, 112 FERC ¶ 61,038, at P 12 (2005).

[34] APPA and NRECA cite *Duke Energy Carolinas, LLC, et al.*, 147 FERC ¶ 61,241 (2014) (*Duke*), as an example of an instance where the Commission has allowed a national organization's late intervention due to an order's far-reaching impacts. However, we find *Duke* to be distinguishable from the instant case. In *Duke*, the National (continued…)

Correspondingly, we also deny AMP's, APPA's, and NRECA's requests for rehearing, because under Rule 713(b) the Commission's Rules of Practice and Procedure only a party to a proceeding may seek rehearing. [35]

B. Substantive Matters

16. The arguments raised on rehearing involve issues concerning the burden of proof, placement of the NETOs' base ROE within the zone of reasonableness, the impact of the change in DCF methodology on the NETOs' existing transmission incentive ROE adders, and the timing of the Commission's establishment of the just and reasonable rate in this proceeding. As discussed below, we deny rehearing on these issues.

1. Burden of Proof

a. Opinion No. 531

17. The Commission in Opinion No. 531 affirmed the Presiding Judge's determination on the burden of proof,[36] explaining that under FPA section 206 the burden to show that a rate is unjust and unreasonable "shall be on the Commission or the complainant,"[37] and, in the context of an ROE proceeding, the burden entails finding that the existing ROE is not "commensurate with returns on investments in other enterprises having corresponding risks . . . [and] sufficient to assure confidence in the financial integrity of the enterprise, so as to maintain its credit and to attract capital."[38] The Commission explained that, to estimate the return necessary to attract equity investors, the Commission uses the DCF

Association of Regulatory Utility Commissioners (NARUC) failed to intervene in an Order No. 1000 proceeding. NARUC explained that it had intervened in multiple Order No. 1000 proceedings, but that its failure to intervene in *Duke* could only have been avoided if NARUC had intervened in every Order No. 1000 proceeding. Unlike *Duke*, the instant proceeding was the first case of its kind to challenge utilities' base ROEs during the economic recession of 2007-2009, and AMP, APPA, and NRECA should have known that the proceeding could have precedential effect on other proceedings.

[35] 16 U.S.C. § 825(l) (2012); 18 C.F.R. § 385.713(b) (2014); *see, e.g.*, *Southern Company Servs., Inc.*, 92 FERC ¶ 61,167 (2000).

[36] Opinion No. 531, 147 FERC ¶ 61,234 at P 49.

[37] *Id.* P 50 (quoting 16 U.S.C. § 824e (2012)).

[38] *Id.* P 50 (quoting *Hope*, 320 U.S. at 603).

model, which identifies a zone of reasonable returns.[39] The Commission rejected the NETOs' argument that the Commission "does not have the authority under FPA section 206 to change the existing base ROE unless the evidence shows that it is entirely outside the zone of reasonableness."[40] The Commission explained that not every ROE within the zone of reasonableness is just and reasonable, and that the zone of reasonableness identified by the DCF model "is simply the first step in the determination of a just and reasonable ROE for a utility or group of utilities."[41]

b. Request for Rehearing

18. The NETOs argue that, because the NETOs' existing ROE of 11.14 percent falls within the zone of reasonableness, the Commission erred in finding that the Complainants and Trial Staff have carried their burden of establishing that the existing ROE is unjust and unreasonable.[42] According to the NETOs, court and Commission precedent support a finding that an ROE within the zone of reasonableness remains just and reasonable.[43] The NETOs state that the Commission misunderstood their contention with respect to FPA sections 205 and 206. They assert that FPA section 206 carries a two-prong burden, the first of which is to show that the existing rate is unjust and unreasonable. The NETOs assert that interpreting FPA section 206 otherwise would eliminate the difference between the burdens of proof under FPA sections 205 and 206 by requiring a complainant to show only that its proposed rate is more just and reasonable than the existing rate. The NETOs concede that not all rates within the zone of reasonableness are equally just and reasonable, but also argue that it is not enough to show that there is a more just and reasonable rate than the existing rate; rather the complainant must demonstrate through substantial evidence that the existing rate does not fall within the zone of just and reasonable rates.[44] The NETOs contend that no party satisfied the first prong of FPA section 206.

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[39] *Id.*

[40] *Id.* P 51.

[41] *Id.*

[42] NETOs Request for Rehearing at 26-27.

[43] *Id.* at 27-30 (citing *Me. Pub. Utils. Comm'n v. FERC*, 520 F.3d 464, 470-71 (D.C. Cir. 2008) (*Maine PUC*), *rev'd in part on other grounds sub nom. NRG Power Mktg., LLC v. Me. Pub. Utils. Comm'n*, 558 U.S. 165 (2010); *Calpine Corp. v. Cal. Indep. Sys. Operator Corp.*, 128 FERC ¶ 61,271, at P 41 (2009)).

[44] *Id.* at 36.

19. The NETOs assert that, in accordance with Commission and federal court precedent, any ROE within the zone of reasonableness cannot be found to be unjust and unreasonable. The NETOs further assert that the Commission erred in finding that the DCF zone of reasonableness is different from the zone of reasonableness under FPA section 206, and that the Commission has never before drawn a distinction between the DCF zone of reasonableness and the zone of reasonableness referred to when applying FPA section 206. The NETOs argue that determining the zone of reasonableness is not merely an intermediate step in a Commission-created DCF analysis whose final step is identification of a "pinpoint" just and reasonable ROE that the Commission believes is optimal in the context of that specific proceeding, but rather is identical to the zone of reasonableness used in FPA section 206 analyses. The NETOs state that in *Northeast Utilities Service Co.*, 124 FERC ¶ 61,044 (2008) (*Northeast Utilities*), *Central Maine Power Co.*, 125 FERC ¶ 61,079 (2008) (*Central Maine*), and *Desert Southwest Power, LLC*, 135 FERC ¶ 61,143 (2011) (*Desert Southwest*) the Commission explicitly identified the DCF zone of reasonableness with the more general zone of reasonableness used in the FPA section 206 context and treated the two as one and the same.[45]

20. The NETOs further argue that the Commission's reliance on *Bangor Hydro* to distinguish the DCF zone of reasonableness from the range of reasonableness under FPA section 206 is inappropriate because *Bangor Hydro* involved application of the last clean rate doctrine after the rate under consideration had been found to be unjust and unreasonable.[46] The NETOs argue that, if *Bangor Hydro* does mean that the DCF zone of reasonableness is not really a zone of reasonableness, then that case was wrongly decided because it would contradict Commission and court precedent, particularly the D.C. Circuit's decision in *City of Winnfield*.[47] The NETOs argue that, although Opinion No. 531 refers to the guidance on this issue in *City of Winnfield* as dicta, the Commission has relied on that guidance in previous decisions.[48] The NETOs argue that FPA section 206 carries a stricter burden of proof than FPA section 205, that the dual burden of proof

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[45] *Id.* at 39.

[46] *Id.* at 41-42 (citing *Bangor Hydro-Electric Co.*, 122 FERC ¶ 61,038 (2008) (*Bangor Hydro*)).

[47] *Id.* at 42-43 (citing *City of Winnfield v. FERC*, 744 F.2d 871, 875-76 (D.C. Cir. 1984) (*City of Winnfield*)).

[48] *Id.* at 42 (citing *Texas Eastern Transmission Corp.*, 32 FERC ¶ 61,056, at 61,150 (1985); *Promoting Transmission Investment through Pricing Reform*, Order No. 679-A, FERC Stats. & Regs. ¶ 31,236, at P 98 (2006) (cross-referenced at 117 FERC ¶ 61,345, at P 98 (2006)) (Order No. 679-A); *New Dominion Energy Coop.*, 118 FERC ¶ 63,024, at n.154 (2007)).

under section 206 provides statutory protection to utility companies, and therefore that Congress intended to create asymmetry between FPA sections 205 and 206.[49] Lastly, the NETOs argue that Opinion No. 531 reduces the clarity and predictability of the zone of reasonableness determination by instituting a method that is no longer limited by an objective formula. The NETOs argue that the resultant lack of predictability increases the perceived risk which is counter to *Hope* and *Bluefield*.[50]

c. Commission Determination

21. We deny rehearing on the issue of the burden of proof. The NETOs once again assert that an existing base ROE cannot be found unjust and unreasonable as long as it is within the zone of reasonableness produced by a DCF analysis, and that the Commission's rejection of this argument in Opinion No. 531 is contrary to court and Commission precedent. We disagree.

22. The NETOs cite precedent setting forth a general ratemaking principle that "there is not a single 'just and reasonable rate' but rather a zone of rates that are just and reasonable; a just and reasonable rate is one that falls within that zone."[51] The NETOs equate references to a "zone of rates that are just and reasonable" or a "zone of reasonableness" in those cases to the "zone of reasonableness" produced by the DCF analysis we use to determine the ROE to include in a public utility's cost of service. On that basis, the NETOs contend that the Commission must show that the NETOs' existing ROE is outside the DCF zone of reasonableness in order to satisfy its FPA section 206 burden to show that their ROE is unjust and unreasonable.

23. In *City of Winnfield* and *Maine PUC*, which did not involve the determination of ROE, the term "zone of reasonableness" was used to express the general principle that under the FPA there can be more than one just and reasonable rate for a service. For example, in the portion of *City of Winnfield* cited by the NETOs, the court addressed the issue of whether the rate for a power sale should be based on an incremental fuel cost or a system average fuel cost, and the court explained that if either methodology was just and

[49] *Id.* at 44 (citing *City of Winnfield*, 744 F.2d at 875).

[50] *Id.* at 45-46.

[51] *See, e.g., Maine PUC*, 520 F.3d at 470-71 (upholding Commission determination that transition payments agreed to in a settlement redesigning New England's capacity market fell within a reasonable range of capacity prices); *City of Winnfield*, 744 F.2d at 875-76.

reasonable, the Commission could not force the utility to shift from one to the other in a section 206 proceeding.[52]

24. In determining the ROE component of a public utility's cost of service pursuant to a DCF analysis, however, the term "zone of reasonableness" has a particular, more technical meaning that differs from its meaning when used in general descriptions of what constitutes a just and reasonable rate charged by a public utility for jurisdictional service, such as in *City of Winnfield* and *Maine PUC*. The Commission uses a three-step process to determine the just and reasonable ROE component of the cost of service of a public utility or a group of public utilities. First, the Commission establishes a proxy group of companies of comparable risk. Second, the Commission performs a DCF analysis of each member of the proxy group in order to determine a "zone of reasonableness," within which to set a just and reasonable ROE. That DCF zone of reasonableness is the range from the lowest proxy member ROE to the highest proxy member ROE. Finally, the Commission establishes a just and reasonable ROE at a single point within the DCF zone of reasonableness.

25. Thus, in the context of determining an ROE, the establishment of the DCF zone of reasonableness is simply one step in the process of determining a just and reasonable ROE for inclusion in the cost of service of the subject public utility or utilities. Typically, the DCF zone of reasonableness is relatively broad. For example, in *Bangor Hydro*[53] setting the NETOs' existing ROE, the DCF zone of reasonableness was from 7.3 percent to 13.1 percent, or almost 600 basis points. In this case, the zone of reasonableness is from 7.03 percent to 11.74 percent, or nearly 500 basis points. Not every ROE within that relatively broad DCF "zone of reasonableness" is a just and reasonable ROE for the particular public utility or utilities at issue. As the Commission held in *Bangor Hydro*, "[c]ertain rates, though within the zone, may not be just and reasonable given the circumstances of the case."[54]

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[52] *See City of Winnfield*, 744 F.2d at 875 ("in that circumstance the agency is effectively using § 205, which is intended for the benefit of the utility—i.e., as a means of enabling it to increase its rates within what has been called the 'zone of reasonableness'—for the quite different purpose of *depriving the utility* of the statutory protection contained in § 206, that its existing rates be found to be entirely outside the zone of reasonableness before the agency can dictate their level or form.") (emphasis in original) (citation omitted).

[53] 122 FERC ¶ 61,038 at PP 10-15.

[54] *Id.* P 11 (quoting *Montana-Dakota Utils. Co. v. Nw. Pub. Serv. Co.*, 341 U.S. 246, 251 (1951) (*Montana-Dakota*)).

26. The decision of the United States Court of Appeals for the District of Columbia Circuit in *S. Cal. Edison Co. v. FERC*,[55] recognized that, in the context of determining ROE, not every ROE within the DCF zone of reasonableness is just and reasonable. In that case, the utility filed to modify its rates under FPA section 205. The court stated that section 205 required the Commission to approve the utility's rate proposal "as long as the new rates are just and reasonable."[56] Nevertheless, the court also held that the Commission had authority to require the utility's ROE to be set at the median of the zone of reasonableness, even though the midpoint of the zone, proposed by the utility, was also within the DCF zone of reasonableness. In short, the court recognized that the Commission need not treat every ROE within the zone of reasonableness as a just and reasonable ROE. If the Commission were required to find any and every ROE within the zone of reasonableness to be just and reasonable, the requirement that the Commission approve any section 205 rate proposal "as long as the new rates are just and reasonable"[57] would require the Commission to accept any ROE proposed by a utility in a section 205 rate case, as long as that ROE did not exceed the top of the range of reasonableness. However, the FPA has never been understood to require such a result, which would be contrary to the consumer protection purpose of the FPA.[58]

27. In Opinion No. 531, the Commission stated that the NETOs were erroneously seeking to apply a different just and reasonable standard in FPA section 206 cases than in section 205 cases. The Commission stated, "Despite the fact FPA section 205 does not require that every ROE within the zone of reasonableness be considered just and reasonable for purposes of a utility rate filing under FPA section 205, the NETOs would

[55] *S. Cal. Edison Co. v. FERC*, 717 F.3d 177, 181-82 (D.C. Cir. 2013) (finding that the Commission had authority to set a utility's ROE at the median of the zone of reasonableness even though the utility proposed using the midpoint, which was also within the zone of reasonableness); *accord Montana-Dakota*, 341 U.S. at 251 (explaining that while statutory reasonableness is an abstract concept represented by an area rather than a pinpoint the Commission must translate that concept into a concrete rate, and it is the rate—not the abstract concept—that governs the rights of the buyer and seller).

[56] *S. Cal. Edison Co. v. FERC*, 717 F.3d at 181.

[57] *Wis. Pub. Power, Inc. v. FERC*, 493 F.3d 239, 254 (D.C. Cir. 2007).

[58] Given that the FPA was intended to be a consumer-protection statute, *see, e.g., Pub. Sys. v. FERC*, 606 F.2d 973, 979 n.27 (D.C. Cir. 1979), it is hard to find persuasive an argument that would allow, under FPA section 205, a utility to propose an increase in its ROE to anywhere in the zone, but would effectively bar, under FPA section 206, a customer from seeking to decrease the ROE being challenged merely because the ROE falls somewhere within the zone.

require us to treat every existing ROE within the zone of reasonableness as just and reasonable in a section 206 case. Nothing in the FPA, however, supports such a different understanding of the phrase "just and reasonable" as between those two sections of the FPA when establishing a utility's ROE."

28. On rehearing, the NETOs do not challenge Opinion No. 531's interpretation of FPA section 205 as not requiring the Commission to treat any ROE proposed by the utility within the DCF zone of reasonableness as a just and reasonable ROE which the Commission must accept. However, the NETOs contend that Opinion No. 531 fails to recognize that the Commission's burden of proof under FPA section 206 contains two prongs: first, the burden to show that an existing rate is unjust and unreasonable; second, the burden to show that the replacement rate is just and reasonable. The NETOs agree that the showing the Commission must make under the second prong of section 206 in order to establish a replacement ROE "is identical to the required section 205 showing, as Opinion No. 531 states."[59] However, they assert that the showing of unjustness and unreasonableness which the Commission must make under the first prong of its section 206 burden "is very different from and more difficult to satisfy" than the showing of justness and reasonableness that must be made under either the second prong of section 206 or under section 205. As a result they assert that any ROE within the zone of reasonableness cannot be found unjust and unreasonable.

29. In making these arguments, the NETOs are confusing differences in who bears the burden of persuasion as between FPA sections 205 and 206 with the substantive "just and reasonable" standard contained in both those sections. The two sections of course differ as to who bears the burden of persuasion, because under FPA section 206 the Commission or complainant must show that the utility's existing rate is unjust and unreasonable and the Commission must show that its replacement rate is just and reasonable, whereas under FPA section 205 the utility need only show that its proposed rate is just and reasonable. However, as the Supreme Court has stated, sections 205 and 206 are "parts of a single statutory scheme under which . . . all rates are subject to being modified by the Commission upon a finding that they are unlawful."[60] While the party bearing the burden of persuasion is different under FPA section 205 and FPA

[59] NETOs Request for Rehearing at 35.

[60] *United Gas Pipe Line Co. v. Mobile Gas Serv. Co.*, 350 U.S. 332, 341 (1956). While this case involved the Natural Gas Act, the Supreme Court held in a companion case that the provisions of the FPA relevant to this question are substantially identical to the equivalent sections under the Natural Gas Act. *FPC v. Sierra Pacific Power Co.*, 350 U.S. 348, 353 (1956).

section 206, "the scope and purpose of the Commission's review remains the same – to determine whether the rate fixed by the [utility] is lawful."[61]

30. Because sections 205 and 206 are part of a single statutory scheme, it follows that a rate that is lawful under one section must also be lawful under the other and a rate that is unlawful under one section must also be unlawful under the other. For this to be true, the substantive standard to determine lawfulness under each section – the just and reasonable standard – must be applied in the same manner under each section. Therefore, if every ROE within the DCF zone of reasonableness must be treated as a lawful just and reasonable ROE which cannot be modified under the first prong of the Commission's FPA section 206 burden, as the NETOs contend, then every ROE within that zone must also be treated as a lawful just and reasonable ROE for all other purposes under the FPA, including a section 205 filing. This would require the Commission to find just and reasonable any ROE proposed by a utility in a section 205 proceeding that was within the DCF zone of reasonableness. However, as already discussed, the D.C. Circuit rejected that proposition in *SoCal Edison*.

31. The NETOs next contend that failing to treat all ROEs within the DCF zone of reasonableness as just and reasonable for purposes of the first prong of the Commission's 206 burden would erase the difference between the burden of proof under FPA sections 205 and 206, because the ROE determination in a section 206 proceeding would be the same as in a section 205 proceeding. We disagree. We recognize that in situations where the Commission has found that more than one methodology may be used to design a just and reasonable rate for a service, such as the incremental rate situation in *City of Winnfield* discussed above, the utility may choose one of the just and reasonable ratemaking methodologies in a section 205 proceeding, and the Commission then cannot require the utility to shift to a different just and reasonable methodology in a subsequent

[61] *United Gas Pipe Line Co. v. Mobile Gas Serv. Co.*, 350 U.S. at 341. The effect of the NETOs' argument, if that argument were to be accepted, would turn the statute on its head. Section 206 would no longer be a tool to challenge an ROE that was no longer reasonable, but rather would serve to insulate that ROE from challenge as long as it fell somewhere—anywhere—within the zone of reasonableness produced by a DCF analysis. A statute that was intended to protect ratepayers from exploitation, *see, e.g.*, *Pub. Sys. v. FERC*, 606 F.2d at 979 n.27, would protect and preserve just such exploitation. But, as the Commission has recognized, as recently as last year the D.C. Circuit has already rejected just such an approach. *See* Opinion No. 531, 147 FERC ¶ 61,234 at P 52 (citing *S. Cal. Edison Co. v. FERC*, 717 F.3d 177).

section 206 proceeding.[62] However, the statute does not require that we approve multiple just and reasonable methodologies to resolve every ratemaking issue. In fact, the D.C. Circuit held in *S. Cal. Edison Co.* that the Commission may require the use of a particular methodology to determine the just and reasonable ROE to be included in a utility's cost of service, despite the existence of other possible methodologies for determining ROE.[63]

32. The Commission has long required the use of a DCF methodology (here the two-step DCF methodology adopted in Opinion No. 531) to determine a zone of reasonableness, with the lawful just and reasonable ROE set at a single numerical point within that range based on the circumstances and record of that case.[64] Therefore, when the Commission finds a utility's base ROE to be just and reasonable in a particular case, it finds *only* that single point to be just and reasonable given the facts and circumstances of that case.[65] It does *not* find any other base ROE within the DCF zone of reasonableness, either above or below the approved ROE, to be a just and reasonable base ROE for that utility or group of utilities. Thus, the DCF zone of reasonableness does not establish a continuum of just and reasonable base ROEs, any one of which the utility would equally be free to charge to ratepayers; rather, only the single point approved by the Commission within the DCF zone of reasonableness is the just and reasonable base

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[62] *See Consolidated Edison of New York, Inc. v. FERC*, 165 F.3d 992, 216-17 (D.C. Cir. 1999). ("While incremental treatment may be required at one end of the rate-setting continuum, and rolled-in pricing required at the other, in between the two extremes lie a series of intermediate points in which both cost-recovery methods would satisfy section 4's just and reasonable test. At each of these places along the continuum, the pricing mechanism will essentially lie in the hands of the initiating pipeline. It is only when the proposed rate crosses the boundary separating the just from the unjust that FERC can act under its section 5 authority to order a rate of its own formulation.")

[63] *S. Cal. Edison Co. v. FERC*, 717 F.3d at 182 ("In order to discharge its statutory duty of ensuring that '[a]ll rates . . . [are] just and reasonable' the Commission may require the use of a particular ratemaking methodology so long as its embrace of that methodology is not arbitrary and capricious.").

[64] *See, e.g.*, *Williston Basin Interstate Pipeline Co. v. FERC*, 165 F.3d 54, 57 (D.C. Cir. 1999).

[65] *Cf. Montana-Dakota*, 341 U.S. at 251 (explaining that while statutory reasonableness is an abstract concept represented by an area rather than a pinpoint the Commission must translate that concept into a concrete rate, and it is the rate—not the abstract concept—that governs the rights of the buyer and seller).

ROE.[66] It follows that showing the existing base ROE established in the prior case is unjust and unreasonable merely requires showing that the Commission's ROE methodology now produces a numerical value below the existing numerical value. Contrary to the NETOs' assertion, the fact that both of the burdens of proof under FPA section 206 can be satisfied using a single ROE analysis—one that generates an ROE that both is below the existing ROE (thus demonstrating that the existing ROE is excessive) and that also is a just and reasonable ROE (thus demonstrating what the new ROE should be)—does not alter those two burdens.[67]

33. In short, the statute does not require that we treat all ROEs within the DCF zone of reasonableness as just and reasonable. Rather, the statute requires that, under section 206, before we may change an ROE we must find it unjust and unreasonable. And, in Opinion No. 531, that we did. Our ROE analysis showing that the NETOs' base ROE is 10.57 percent demonstrates both that their existing 11.14 percent ROE is unjust and unreasonable and that 10.57 percent is the NETOs' just and reasonable replacement base ROE.[68] Thus, we met both burdens under section 206.

34. The NETOs cite precedent that, while correctly stating the general principle of the FPA section 206 burden, is distinguishable from the facts of this case because that precedent did not discuss the FPA section 206 burden in the context of determining a utility's base ROE.[69] Whether a particular rate is just and reasonable, and what the range

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[66] As discussed below in P 35, the addition of an incentive adder for a project can justify a higher overall just and reasonable ROE (i.e., the base ROE plus the incentive adder) for that project.

[67] Further, we reject the NETOs' contention that the Commission's determination on the burden of proof in this proceeding broadens the Commission's discretion and will lead to increased uncertainty and litigation. *See* NETOs Request for Rehearing at 45-46. We are following our long-standing practice with regard to the zone of reasonableness identified by a DCF analysis.

[68] A utility's ROE is simply one component of the cost-of-service reflected in its overall rates for the services it provides. Typically, each component of the cost of service is a single number, based on the utility's actual costs during the relevant test period. For example, if a utility's existing cost of service includes a cost of labor of $10 million, a showing that its actual test period cost of labor is $9 million satisfies both the burden to show that the existing $10 million labor cost is unjustly and unreasonably high and the new just and reasonable labor cost is $9 million. Our treatment of ROE is no different.

[69] *See, e.g.*, *Maine PUC*, 520 F.3d 464, *rev'd in part on other grounds sub nom. NRG Power Mktg., LLC v. Me. Pub. Utils. Comm'n*, 558 U.S. 165 (2010) (upholding Commission determination that transition payments agreed to in a settlement redesigning

(continued…)

of reasonableness is for that rate, largely depends on the nature of the rate at issue. While a utility's base ROE is a single, specific numerical value that is determined by using a well-known methodology, a tariff provision setting forth an energy market rule might produce a numerical result only in conjunction with many other associated market rules. A determination of what is an appropriate range of reasonableness, and what is just and reasonable, in these two disparate contexts requires different analyses and the balancing of different interests. As a result, the Commission uses different approaches to determining the just and reasonable resolution in different circumstances. In determining a utility's base ROE, the Commission has long used a methodology that produces a single, specific numerical value, not a range of reasonable values, and the Commission has therefore interpreted FPA section 206 to protect that specific numerical value, rather than a zone around that value.

35. The NETOs are correct that, in the context of incentive ROE adders authorized for projects, the Commission has capped the overall ROE for a particular project (i.e., the sum of the utility's base ROE and the incentive ROE adder for that project) at the top of the DCF zone of reasonableness.[70] However, it does not follow from this fact that all ROEs within the DCF zone of reasonableness must be treated as just and reasonable for purposes of the first prong of FPA section 206. The Commission awards an incentive adder based on a separate, independent showing that a particular project is of a type that qualifies for such an adder, and—as directed by Congress—the Commission allows the adder to be added to the base ROE and charged to ratepayers so long as the sum of the

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New England's capacity market fell within a reasonable range of capacity prices); *Calpine Corp. v. Cal. Indep. Sys. Operator Corp.*, 128 FERC ¶ 61,271 (finding tariff provisions setting forth a method of socializing the costs of a market participant's financial default to be unjust and unreasonable); *Cal. Mun. Utils. Ass'n v. Cal. Indep. Sys. Operator Corp.*, 126 FERC ¶ 61,315 (2009) (finding that complainants failed to show tariff unjust and unreasonable due to a lack of sufficient safeguards to protect against the risk of anomalous settlements); *Cal. Indep. Sys. Operator Corp.*, 140 FERC ¶ 61,168 (2012) (finding tariff provisions concerning the repayment of an interconnection customers' network upgrade costs to be just and reasonable under FPA section 205).

[70] *See, e.g.*, *Northeast Utils. Serv. Co.*, 124 FERC ¶ 61,044, at P 71 (2008); *Central Maine Power Co.*, 125 FERC ¶ 61,079, at P 74 (2008); *Desert Southwest Power, LLC*, 135 FERC ¶ 61,143, at P 96 (2011). The Commission uses the DCF zone of reasonableness in the same manner to ensure that the sum of a utility's base ROE plus an incentive adder for joining an RTO is just and reasonable.

adder and base ROE for that project is just and reasonable under FPA section 205.[71] The Commission makes that determination by looking at whether the utility's base ROE plus the incentive ROE adder for that project remain within the zone of reasonableness. That is, the Commission looks to whether the sum of the base ROE and the adder for that project falls within the DCF-determined zone of reasonableness, or does that sum instead fall outside the zone of reasonableness, for that project. Absent both a showing that the particular project qualifies for such an adder, and a Commission finding that the resulting overall ROE satisfies the just and reasonable standard laid out in the FPA, the increased overall ROE for the project produced by summing the adder and the base ROE would not be just and reasonable.[72] This use of the DCF-determined zone of reasonableness to place an outer limit on the overall ROE that a utility may earn on a particular project does not in any way suggest that any base ROE up to the top of the DCF-determined zone of reasonableness must be treated as just and reasonable for purposes of FPA section 206. To the contrary, it is only the separate, independent finding that the project qualifies for an incentive adder that justifies increasing the overall ROE for that project to a point within the DCF-determined zone of reasonableness above the point at which the utility's base ROE is set.

2. <u>Placement of the Base ROE within the Zone of Reasonableness</u>

a. <u>Placement of the Base ROE above the Midpoint</u>

i. <u>Opinion No. 531</u>

36. The Commission in Opinion No. 531 found that, although it typically sets the base ROE for a group of utilities at the midpoint of the zone of reasonableness identified by the DCF methodology, "a mechanical application of the DCF methodology with the use of the midpoint here would result in an ROE that does not satisfy the requirements of *Hope* and *Bluefield*."[73] Therefore, the Commission explained that, "based on the record in this case, including the unusual capital market conditions present, . . . the just and reasonable base ROE for the NETOs should be set halfway between the midpoint of the zone of reasonableness and the top of the zone of reasonableness," i.e., 10.57 percent.[74]

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[71] *See* 16 U.S.C. § 824s(d) (2012) ("All rates approved under the rules adopted pursuant to [FPA section 219] . . . are subject to the requirements of sections [205 and 206] of this title that all rates . . . be just and reasonable.").

[72] *See generally, e.g.*, *NSTAR Elec. Co.*, 125 FERC ¶ 61,313 (2008); *Northeast Utils. Serv. Co.*, 124 FERC ¶ 61,044 (2008).

[73] Opinion No. 531, 147 FERC ¶ 61,234 at P 142.

[74] *Id.*

The Commission explained that, as "[p]arties on both sides of the instant ROE issue argue that the unique capital market conditions have impacted the level of equity return the NETOs' require to meet the capital attraction standards of *Hope* and *Bluefield*," the Commission was "concerned that capital market conditions in the record are anomalous, thereby making it more difficult to determine the return necessary for public utilities to attract capital."[75] The Commission explained that "[i]n these circumstances, we have less confidence that the midpoint of the zone of reasonableness established in this proceeding accurately reflects the equity returns necessary to meet the *Hope* and *Bluefield* capital attraction standards."[76]

37. As a result of the anomalous capital market conditions reflected in the record, and their potential impact on the DCF model, the Commission found it "necessary and reasonable to consider additional record evidence, including evidence of alternative benchmark methodologies and state commission-approved ROEs, to gain insight into the potential impacts of these unusual capital market conditions on the appropriateness of using the [midpoint of the zone of reasonableness identified by the DCF methodology]."[77] The Commission found the additional record evidence—specifically the NETOs' risk premium analysis, Capital Asset Pricing Model (CAPM) analysis, expected earnings analysis, and evidence of state commission-authorized ROEs—supported a finding that an upward adjustment from the midpoint was warranted.[78]

38. After determining that the just and reasonable base ROE for the NETOs was above the midpoint, the Commission found that, because it "has traditionally looked to the central tendency to identify the appropriate return within the zone of reasonableness," it is appropriate to "look to the central tendency for the top half of the zone of reasonableness."[79] The Commission explained that "[w]hen placing a base ROE above the central tendency of the zone of reasonableness, the Commission has in the past placed the base ROE at the midpoint of the upper half of the zone."[80] The Commission therefore

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[75] *Id.* P 145.

[76] *Id.*

[77] *Id.*

[78] *Id.* PP 146-150.

[79] *Id.* P 151.

[80] *Id.* P 152 (citing *S. Cal. Edison Co.*, Opinion No. 445, 92 FERC ¶ 61,070, at 61,266 (2000); *Consumers Energy Co.*, Opinion No. 429, 85 FERC ¶ 61,100, at 61,363-64 (1998)).

found that "a base ROE halfway between the midpoint of the zone of reasonableness and the top of that zone represents a just and reasonable ROE for the NETOs."[81]

ii. Requests for Rehearing

39. Petitioners and EMCOS argue that the Commission's placement of the NETOs' base ROE three-quarters of the way up the zone of reasonableness is contrary to record evidence and Commission precedent, and is therefore arbitrary and capricious. Petitioners assert that the only basis for establishing a base ROE above the central tendency of the zone of reasonableness is that the utility or utilities whose base ROE is at issue are riskier than the proxy group. Petitioners argue that the Commission's 38-member national proxy group is far more risky than the NETOs because the average corporate credit rating of the proxy group was between BBB and BBB+, whereas 80 percent of the NETOs are rated between BBB and A.[82] Petitioners further state that, using the appropriate weighting to reflect the relative size of each of the NETOs, the fair average of the NETOs' credit ratings is "A-/BBB+." Petitioners therefore argue that the Commission should place the NETOs' base ROE in the lower half of the zone of reasonableness.[83]

40. EMCOS assert that the Commission has previously and consistently concluded that the midpoint of the zone of reasonableness produces a just and reasonable ROE for a diverse group of utilities because it fairly and accurately evaluates risk. EMCOS further state that Opinion No. 531 acknowledges that the midpoint of the zone of reasonableness yields an appropriate ROE for a diverse group of utilities, but then rejects the use of the 9.39 percent midpoint in favor of the higher 10.57 percent figure.[84] EMCOS state that Opinion No. 531 cites only two cases in which the Commission adopted an ROE at the midpoint of the upper half of the zone of reasonableness, and in each of those cases the utility at issue had a higher risk profile than the proxy group.[85] Petitioners and EMCOS

[81] *Id.*

[82] Petitioners Request for Rehearing 16-18.

[83] *Id.* at 19 (citing Ex. SC-207). Petitioners also cite several other sources claiming that the NETOs have a high level of rate certainty.

[84] EMCOS Request for Rehearing at 10 (citing Opinion No. 531, 147 FERC ¶ 61,234 at P 142).

[85] *Id.* at 13-14 (citing *Consumers Energy Co.*, 85 FERC ¶ 61,100; *S. Cal. Edison Co.*, 88 FERC ¶ 61,254 (1999)).

argue that those two cases resulted in upward adjustments of 18 and 58 basis points, compared to the 118 basis point increase in this proceeding.[86]

41. EMCOS state that Opinion No. 531 rejects the use of the midpoint of the zone of reasonableness asserting that capital market conditions here are "unique" and "anomalous." EMCOS state that the ROE awarded must reflect the capital market conditions under which the NETOs operate and that Commission precedent recognizes the importance of basing an ROE on current market data.[87] Petitioners and EMCOS state that Opinion No. 531 asserts it must adopt an ROE higher than the midpoint because *Hope* and *Bluefield* require the Commission to identify an ROE that will attract sufficient capital; however, this position fails to recognize that market conditions must be reflected in an ROE in order for it to be just and reasonable. EMCOS explain that they made this argument in their Initial Brief, and that Opinion No. 531 acknowledged it, but did not provide any explanation of why it does not apply here.[88] EMCOS argue that this case covers "the Great Recession" which had an effect on all companies and consumers, but Opinion No. 531's decision to upwardly adjust the base ROE in this proceeding uniquely shields the NETOs from the economic realities of that time period at the expense of New England consumers.[89]

42. Petitioners state that Opinion No. 531's reliance on a single issuance from UBS Financial Services (UBS) included in the testimony of the NETOs' witness, Ms. Lapson, is neither well-founded nor consistent with the record. Petitioners also state that the reports in Ms. Lapson's testimony were not selected by her, but were hand-picked by the NETOs' counsel and that the testimony includes almost nothing addressing the views of specific investment analysts as to the potential impact of an ROE reduction in this proceeding on future transmission investment. Petitioners further argue that, a few months after the UBS report, UBS changed its mind and stated that the outcome of this proceeding "impacts only the generic New England rates." Petitioners explain that there were many different views taken by other analysts which were unrebutted, which they state explains why there is no well-founded basis for a concern that a base ROE reduction

[86] *Id.* at 14-15.

[87] *Id.* at 16-17 (citing *Portland Natural Gas Transmission Sys*., Opinion No. 510-A, 142 FERC ¶ 61,198, at P 233 (2013); *Consumer Advocate Div. of the Pub. Serv. Comm'n of West Virginia v. Allegheny Generating Co*., 68 FERC ¶ 61,207, at 61,998 (1994) (*West Virginia Consumer Advocate*)).

[88] *Id.* at 17-18 (citing *Bluefield*, 262 U.S. at 692; *Hope*, 320 U.S. at 614).

[89] *Id.* at 19.

to the central result of the national proxy group could undermine the NETOs' ability to attract capital.[90]

43. Petitioners and EMCOS also assert that the Commission erred in relying on certain record evidence—i.e., the evidence of state commission-authorized ROEs and the NETOs' alternative methodologies for estimating the cost of equity—to corroborate the placement of the base ROE within the zone of reasonableness. Petitioners and EMCOS argue that, in relying on these alternative methodologies, Opinion No. 531 departed from Commission precedent without providing an explanation for doing so. Petitioners contend that the Commission has repeatedly found that non-DCF approaches to determining transmission ROEs are "unlikely to produce a just and reasonable result."[91] For example, Petitioners contend that, in the case that recently concluded with the D.C. Circuit affirming the Commission's sole reliance on the electric utility DCF median, Southern California Edison Company had sought to bolster its case for a high ROE by relying on the CAPM analysis.[92] Petitioners note that the Commission refrained from according the non-DCF analyses even the little weight sought by Southern California Edison Company. Petitioners argue that the use of the NETOs' alternative methodologies should have been subject to the well-established test for an above-center ROE: no upward movement should be undertaken unless those methodologies make "a very persuasive case" that the central result of a conventional DCF study fails to identify the subject utility's true equity cost.[93] Petitioners contend that the Commission failed to state a reasoned basis for not applying the "very persuasive case" standard.

44. Petitioners and EMCOS further argue that the Commission's reliance on the NETOs' alternative benchmark methodologies without scrutinizing their flaws is inconsistent with reasoned decision-making and constitutes judicially-reversible error.[94] Petitioners and EMCOS also argue that the Commission's DCF analysis contains certain

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[90] Petitioners Request for Rehearing 53-57.

[91] *Id.* at 30 (citing *Xcel Energy Servs., Inc.*, 122 FERC ¶ 61,098 at P 73, *clarified,* 125 FERC ¶ 61,092 (2008) (*Xcel*)).

[92] *Id.* at 30-31 (citing *S. Cal. Edison Co.*, 131 FERC ¶ 61,020, at P 114 (2010) (*SoCal Edison*), *reh'g denied*, 137 FERC ¶ 61,016 (2011), *petition for review granted in part and denied in part, S. Cal. Edison Co. v. FERC,* 717 F.3d 177).

[93] *Id.* at 32.

[94] *Id.*; EMCOS Request for Rehearing at 20 (citing *Ill. Pub. Telecomm. Ass'n v. FCC,* 117 F.3d 555, 564 (D.C. Cir. 1997)).

flaws that undermine the Commission's decision to place the base ROE above the midpoint of the zone of reasonableness.

45. Petitioners' and EMCOS's arguments as to the specific, alleged flaws in both the Commission's DCF analysis and the record evidence on which the Commission relied to corroborate the placement of the base ROE above the midpoint are described below.

iii. Commission Determination

46. We deny rehearing on the issue of where to place the NETOs' base ROE within the zone of reasonableness produced by the Commission's DCF analysis.

47. As an initial matter, we disagree with Petitioners' and EMCOS's arguments concerning the circumstances under which the Commission may set a base ROE at a point other than the central tendency of the zone of reasonableness.[95] Petitioners assert that the Commission may only do so by comparing the NETOs' risks to the risks of the proxy group produced by the DCF methodology—i.e., by conducting a comparison that the Commission has historically referred to as the "relative risk analysis." We disagree. In this case, the Commission found the proxy group to be comparable in risk to the NETOs,[96] but determined that it was necessary to adjust the NETOs' base ROE above the midpoint based on considerations other than the relative risk analysis.[97] While the Commission has indeed adjusted a company's base ROE above or below the central

[95] We also disagree with Petitioners' argument that the two precedents the Commission cited in support of using the midpoint of the upper half of the DCF-produced zone of reasonableness are distinguishable from the instant case because the upward adjustments in those two cases—*S. Cal. Edison Co.*, Opinion No. 445, 92 FERC ¶ 61,070, and *Consumers Energy Co.*, Opinion No. 429, 85 FERC ¶ 61,100—were of 58 and 18 basis points, respectively, compared to the 118 basis adjustment in Opinion No. 531. Nothing in those cases indicates that the Commission made those adjustments because they were for 58 or 18 basis points. Instead, the Commission in Opinion Nos. 445 and 429 placed the ROE at the midpoint of the upper half of the zone after finding that an upward adjustment was warranted, which is what the Commission did in Opinion No. 531.

[96] *See* Opinion No. 531, 147 FERC ¶ 61,234 at P 96.

[97] *Id.* PP 144-145.

tendency of the zone or reasonableness based on the relative risk analysis,[98] the Commission is not limited to making adjustments based only on the relative risk analysis. Petitioners' argument to the contrary is inconsistent with both court and Commission precedent showing that the Commission has the discretion to make,[99] and has in fact made, adjustments to a rate based on the particular circumstances of a case, including whether unique circumstances render the results of the Commission's DCF analysis less reliable than usual.[100]

48. We disagree with Petitioners' argument that the NETOs' are less risky than the proxy group. While Petitioners assert that 80 percent of the NETOs' have credit ratings between BBB to A, whereas the average credit rating of the proxy group company is between BBB and BBB+, this alone does not show that the NETOs are less risky than the proxy group. As explained in Opinion No. 531, the Commission uses the credit rating band because it "include[s] in the proxy group only those companies whose credit ratings *approximate* those of the utilities whose rates are at issue."[101] We thus reiterate that Commission's finding that the credit rating band of the proxy group is comparable to the NETOs' credit ratings.[102] Further, Petitioners' argument is based on a flawed comparison of the two groups' credit ratings. Assuming *arguendo* that it is helpful to compare the distribution of the NETOs' credit ratings to the average credit rating of proxy group companies, that analysis should be accompanied by a comparison of how the distribution of the proxy group companies' credit ratings compare to the average credit rating of the proxy group. In other words, the distribution of the NETOs' credit ratings should be compared to the distribution of the proxy companies' credit ratings. Petitioners' comparison is misleading because it fails to do this. In this case 34 of the 38

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[98] *See, e.g.*, *Williston Basin Interstate Pipeline Co. v. FERC*, 165 F.3d at 57 ("Once the Commission has defined a zone of reasonableness [using the DCF model], it then assigns the pipeline a rate within that range to reflect specific investment risks associated with that pipeline as compared to the proxy group companies.").

[99] *See, e.g., Fed. Power Comm'n v. Natural Gas Pipeline Co.*, 315 U.S. 575, 586 (1942) ("The Constitution does not bind rate-making bodies to the service of any single formula or combination of formulas. Agencies to whom this legislative power has been delegated are free, within the ambit of their statutory authority, to make the pragmatic adjustments which may be called for by particular circumstances.")

[100] *See, e.g.*, *Town of Norwood, Mass. v. FERC*, 80 F.3d 526, 534-535 (D.C. Cir. 1996).

[101] Opinion No. 531, 147 FERC ¶ 61,234 at P 106 (emphasis added).

[102] *See id.* P 108.

companies in the proxy group—i.e., 89 percent of the proxy companies—have credit ratings between BBB and A, compared to the 80 percent of the NETOs within that band.[103] This indicates that the credit ratings of the proxy group companies and the NETOs are similarly distributed, and supports a finding that the two groups have comparable risk profiles.

49. Petitioners and EMCOS argue that the Commission erred in basing its decision to set the NETOs' base ROE above the central tendency of the zone of reasonableness produced by the DCF analysis on the presence of anomalous capital market conditions. Petitioners specifically argue that the slow economic growth reflected in the record is not anomalous, but is instead a "new normal" and should, therefore, not justify adjusting the base ROE above the midpoint. We are not persuaded by Petitioners' argument. In Opinion No. 531, the Commission acknowledged that parties on both sides of the issue had cited to unique capital market conditions.[104] The Commission also referenced U.S. Treasury bond yields, not economic growth, as an indicator of current capital market conditions. Given the undisputed presence of such anomalous capital market conditions, the Commission stated that it had "less confidence that the midpoint of the zone of reasonableness established in this proceeding accurately reflects the equity returns necessary to meet the *Hope* and *Bluefield* capital attraction standards."[105] However, we did not stop there in our analysis of whether it was appropriate to establish a base ROE above the midpoint. Rather, the record evidence of unusual capital market conditions served as an impetus for the Commission's consideration of additional record evidence. This consideration was necessary to evaluate, in this proceeding, whether setting the NETOs' ROE at the midpoint of the zone of reasonableness satisfied the requirements of *Hope* and *Bluefield*. Therefore, the Commission conducted a further analysis by analyzing the additional record evidence, including evidence of alternative benchmark methodologies and state commission-approved ROEs, to gain insight into the potential impacts of the unusual capital market conditions on the appropriateness of using the resulting midpoint. We then used this additional record evidence to corroborate our determination that placement at a point above the midpoint was warranted.[106]

50. We also reject EMCOS's argument that, even if the capital market conditions reflected in the record are anomalous, adjusting the NETOs' ROE based on an economic anomaly ignores the *Hope* and *Bluefield* requirement that a utility's ROE must reflect

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[103] *See* Ex. NET-701.

[104] Opinion No. 531, 147 FERC ¶ 61,234 at P 145.

[105] *Id.*

[106] *Id.* PP 146-149.

current market conditions. EMCOS specifically argue that whether capital market conditions in the record are anomalous from a historical perspective is irrelevant to the determination of a just and reasonable base ROE, because the base ROE must reflect the capital market conditions under which the NETOs operate, even if those conditions are historically anomalous. We disagree. The EMCOS's argument assumes that DCF analyses are immune to ever being skewed by economic anomalies. This assumption is unrealistic, as all methods of estimating the cost of equity are susceptible to error when the assumptions underlying them are anomalous.[107] The Commission, in fact, acknowledged this limitation in Opinion No. 531,[108] and was concerned that a mechanical application of the two-step DCF methodology with the use of the midpoint in such circumstances would produce a return that would not satisfy the requirements of *Hope* and *Bluefield*.[109] Therefore, based on the presence of anomalous capital market conditions, the Commission considered additional record evidence that supported an upward adjustment. Contrary to EMCOS's assertions, the Commission is not constrained to a mechanical application of the DCF methodology where the Commission determines that such an approach will not produce a just and reasonable result.[110] We further reject

[107] Roger A. Morin, New Regulatory Finance 28 (Public Utilities Reports, Inc. 2006) ("For instance, by relying solely on the DCF model at a time when the fundamental assumptions underlying the DCF model are tenuous, a regulatory body greatly limits its flexibility and increases the risk of authorizing unreasonable rates of return. The same is true for any one specific model."). We note that participants on both sides of the instant ROE issue in this proceeding have relied upon Dr. Morin's New Regulatory Finance. *See*, *e.g.*, Ex. S-1 at 59-60 (Trial Staff exhibit quoting New Regulatory Finance); Ex. NET-300 at 67 (NETOs exhibit quoting New Regulatory Finance); Tr. 580-581 (Complainants' cross-examination relying on New Regulatory Finance).

[108] Opinion No. 531, 147 FERC ¶ 61,234 at PP 41, 145.

[109] *Id.* PP 150-152.

[110] *See Fed. Power Comm'n v. Natural Gas Pipeline Co.*, 315 U.S. at 586 ("The Constitution does not bind rate-making bodies to the service of any single formula or combination of formulas. Agencies to whom this legislative power has been delegated are free, within the ambit of their statutory authority, to make the pragmatic adjustments which may be called for by particular circumstances.").

We note that neither of the Commission precedents to which Complainants cite in support of their argument—*Portland Nat. Gas Transmission Sys.*, Opinion No. 510-A, 142 FERC ¶ 61,198 (2013) (Opinion No. 510-A) and *West Virginia Consumer Advocate*, 68 FERC ¶ 61,207—constrain the Commission to mechanically apply a particular ratemaking approach without regard to economic anomalies. *West Virginia Consumer*

(continued…)

EMCOS's argument that this analysis should be affected by the fact that the NETOs can subsequently request a rate increase under FPA section 205. The NETOs' ability to subsequently request a rate increase if economic conditions change does not excuse the Commission from establishing an ROE under FPA section 206 that meets the requirements of *Hope* and *Bluefield*.

51. Petitioners argue that the Commission erred in finding that a base ROE of 9.39 percent could undermine the NETOs' ability to attract capital for new investment, because the finding was based on only one analyst's report, from UBS, which is contradicted by record evidence of other analysts' reports. We disagree. Petitioners specifically cite analysts' reports from Credit Suisse; Goldman Sachs; Brean Murray, Carret & Co. (Brean Murray); Deutsche Bank; and a subsequent report from UBS. But none of the reports Petitioners cite contradicts the finding that a base ROE of 9.39 percent—i.e., a reduction of 175 basis points from the existing base ROE—could undermine the NETOs' ability to attract capital.[111]

52. The Deutsche Bank report and the subsequent report from UBS provide no analysis of how a reduced base ROE would impact the NETOs and, therefore, do not contradict the UBS report the Commission relied upon in Opinion No. 531. The Deutsche Bank report merely states the possibility that the Commission could reduce the

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Advocate did not involve any unusual capital market conditions. *See generally West Virginia Consumer Advocate*, 68 FERC ¶ 61,207. While Opinion No. 510-A did involve allegations of economic anomalies, the Commission in that case, in fact, weighed the evidence of anomalous conditions in determining whether to apply its policy of using the most recent record data or to use an alternative data set. *See* Opinion No. 510-A, 142 FERC ¶ 61,198 at P 233. Thus, Opinion No. 510-A demonstrates that the Commission may indeed consider, as it has here in Opinion No. 531, whether to apply or adjust an established policy based on anomalous economic conditions.

[111] We also reject Petitioners' argument that the NETOs' expert witness was not qualified to present testimony on this issue. The NETOs' expert witness has 43 years of experience as a financial professional, including 38 years focused on financial analysis and securities evaluation within the utilities sector, and was formerly the Managing Director of the utilities, power, and gas analytical team at Fitch Ratings, where she "supervised and wrote the credit rating criteria applied in the electric, gas, and water sector." Ex. NET-400 at 1-3.

The Presiding Judge, furthermore, admitted this witness's testimony into the record and found it "to have moderate probative value." S*ee* Initial Decision, 144 FERC ¶ 63,012 at P 576; *Entergy Servs., Inc.*, 109 FERC ¶ 61,108, at P 7 (2004) (citing 18 C.F.R. § 385.209 (2004)).

NETOs' base ROE as a result of the low interest rate environment, while the later UBS report describes the scope of the proceeding and predicts a general trend of lower ROEs for regulated utilities, without discussing the magnitude of the potential ROE reductions or their impact on utilities' ability to attract capital.

53. The reports from Credit Suisse, Goldman Sachs, and Brean Murray provide limited analysis of two holding companies that are parent companies to certain NETOs, and none of that analysis undermines the UBS report the Commission cited in Opinion No. 531. The Credit Suisse report states that a 50 to 100 basis point reduction in Northeast Utilities' ROE in this proceeding would be a "positive" for the company.[112] This statement, which we interpret to mean simply that a reduction of 50 to 100 basis points would be better for Northeast Utilities than would an even greater reduction, is silent on the impacts that a reduced ROE would have on Northeast Utilities' ability to attract capital. The Goldman Sachs report, which also only addresses Northeast Utilities, states that a 100 basis point reduction to Northeast Utilities' ROE would have a minimal impact on Northeast Utilities' earnings per share and that the impact could be overcome by adding $200-$300 million in transmission projects to Northeast Utilities' rate base. This evidence is solely focused on the impact that an ROE reduction would have on Northeast Utilities' earnings per share and, therefore, provides insufficient evidence to determine how such a reduction would impact Northeast Utilities' ability to attract capital.[113] Because the Credit Suisse and the Goldman Sachs reports only address the impact of ROE reductions of up to 100 basis points, neither is probative on the issue of how a significantly greater 175 basis point ROE reduction to 9.39 percent would affect the NETOs' ability to attract capital.

54. The Brean Murray report, which states that "[a] negative impact to [UIL Holdings] from an adverse decision would be minimal, in our view," is the least probative of these three reports. What would constitute an "adverse decision," for example, is unclear. Whether and to what magnitude an adverse ruling in this proceeding would impact the NETOs' ability to attract capital, moreover, cannot be determined with any certainty based on the magnitude of the impact the ruling might have on the much larger and more diversified parent company of one of the NETOs.

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[112] Petitioners Request for Rehearing at 57; Ex. SC-518 at 5. We further note that the 10.57 percent base ROE established in this proceeding reduced the NETOs' base ROE by 57 basis points, which is within the 50 to 100 basis point range that Credit Suisse reported would be a positive outcome for Northeast Utilities.

[113] While a company's earnings are undeniably relevant to its ability to attract capital, it is merely one of multiple factors investors rely on in determining whether to invest in the company. For example, looking at earnings in isolation provides no information about the company's dividend yield.

55. We are also unpersuaded by Petitioners' arguments that, if the Commission concludes that the NETOs' base ROE should be set above the midpoint of the zone of reasonableness, the base ROE should be placed at the true 75th percentile of the zone of reasonableness, i.e., 9.84 percent, rather than at the 10.57 percent midpoint of the upper half of the zone. As the Commission explained in Opinion No. 531, the Commission has traditionally used measures of central tendency to determine an appropriate return in ROE cases and, in cases involving the placement of the base ROE above the central tendency of the zone of reasonableness, the Commission has used the central tendency of the top half of the zone. Our decision to utilize the midpoint of the upper half of the zone is based on the record evidence in this proceeding and is consistent with the Commission's established policy of using the midpoint of the ROEs in a proxy group when establishing a central tendency for a region-wide group of utilities.[114] Further, we reject Petitioners' assertion that *Northwest Pipeline Corp.*, 99 FERC ¶ 61,305 (2002), requires the Commission to consider the distribution of results within the proxy group when determining where in the upper half of the zone to place the NETOs' base ROE. *Northwest Pipeline Corp.* does not bear on the Commission's decision in this proceeding to place the NETOs' base ROE above the midpoint of the zone of reasonableness, as that case involved the issue of which particular measure of central tendency should be used in setting a single pipeline's ROE *at the middle* of the zone of reasonableness.[115]

56. Lastly, we disagree with Petitioners that the Commission erred in relying on the NETOs' alternative methodologies to support its decision that an upward adjustment from the midpoint was warranted in this case. While Petitioners cite *Xcel*, 122 FERC ¶ 61,098, *Pacific Gas & Electric Company*, 141 FERC ¶ 61,168 (2012) (*PG&E*), *SoCal Edison*, 131 FERC ¶ 61,020, and *ITC Holdings Corp.*, 121 FERC ¶ 61,229 (2007)

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[114] *SoCal Edison*, 131 FERC ¶ 61,020 at P 92, *aff'd in relevant part, S. Cal. Edison Co. v. FERC*, 717 F.3d at 185-87.

[115] *Northwest Pipeline Corp.*, 99 FERC ¶ 61,305 at 62,276. The Commission typically looks to the central tendency as the "most just and reasonable" and "most appropriate" return that best considers that range, and typically uses the median as the measure of central tendency in cases involving a single utility's ROE and uses the midpoint as the measure of central tendency in cases involving the ROE for a group of utilities. *See Midwest Indep. Transmission Sys. Operator, Inc.*, 106 FERC ¶ 61,302, at PP 9-10 (2004), *aff'd in relevant part sub nom. Pub. Serv. Comm'n of Ky. v. FERC*, 397 F.3d 1004, 1010-11 (D.C. Cir. 2005) (*PSC of Kentucky*); *SoCal Edison*, 131 FERC ¶ 61,020 at P 92, *aff'd in relevant part*, *S. Cal. Edison Co. v. FERC*, 717 F.3d at 185-87. *Northwest Pipeline Corp.*, in contrast, merely explains the rationale for selecting the median as the appropriate measure of central tendency in a case involving a single utility's ROE.

(*ITC Holdings*), as precedent in which the Commission has declined to rely on alternative methodologies, we find the precedent to be distinguishable from the instant case because in none of those four cases did the record contain evidence of unique capital market conditions that called into question the rote application of the midpoint of the zone of reasonableness resulting from the Commission's DCF methodology. Additionally, in *PG&E*, the Commission set the ROE issue for hearing without any reference to the reliability of the alternative methodologies the utility submitted in support of its filing.[116] Further, Petitioners are mistaken that the Commission in *SoCal Edison* did not give weight to the alternative methodologies. As the Commission in that case explained, the three alternative methodologies submitted in that case "were not used by the Commission in setting a base ROE for SoCal Edison," but "were used to corroborate the results of its DCF analysis."[117] With regard to *ITC Holdings*, as discussed below, the CAPM analysis presented in that case contained methodological shortcomings that distinguish it from the NETOs' CAPM analysis in this case.[118]

57. Petitioners and EMCOS also allege that the Commission's DCF analysis and the evidence the Commission relied upon to corroborate it contain various flaws. Those arguments are addressed in turn below.

b. Discounted Cash Flow Analysis

i. Opinion No. 531

58. In Opinion No. 531, the Commission conducted a DCF analysis using a national proxy group of companies listed as Electric Utilities by *Value Line* and that had credit ratings within one notch above or below the NETOs' credit ratings (referred to as the "credit rating screen"), had paid 6-months of dividend yields without making or announcing a dividend cut, were not involved in merger and acquisition activity significant enough to distort the DCF results, and were not low-end or high-end outliers.

59. In using the national proxy group, rather than a regional proxy group, the Commission explained that "widening the geographic range of the proxy group allows for the application of more stringent screening criteria, to refine the proxy group to a level of risk more comparable, while maintaining a group of proxy companies that is sufficiently

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[116] *PG&E*, 141 FERC ¶ 61,168 at P 23.

[117] *SoCal Edison*, 131 FERC ¶ 61,020 at P 116. And here they were similarly used to "gain insight" and "inform" our thinking on whether an upward adjustment was reasonable. Opinion No. 531, 147 FERC ¶ 61,234 at PP 145-149.

[118] *See infra* P 115.

large and diverse to reliably capture the range of reasonable returns."[119] In applying the credit rating screen, the Commission explained that "the purpose of the credit rating band screen is to include in the proxy group only those companies whose credit ratings approximate those of the utilities whose rates are at issue."[120] The Commission found that, because investors rely on credit ratings from both Standard & Poor's (S&P) and Moody's, "basing the credit rating screen on data only from S&P does not necessarily provide an accurate estimate of the NETOs' risk."[121] Therefore, the Commission found that "in applying the credit rating proxy group screen to exclude companies more than one notch above or below the NETOs' credit ratings, it is appropriate to use both the S&P corporate credit ratings and the Moody's issuer ratings *when both are available*."[122] Because the NETOs' S&P credit ratings ranged from A- to BBB and Moody's credit ratings ranged from A2 to Baa2, the Commission excluded companies from the proxy group that were more than one notch above or below either of those credit rating bands.[123]

60. In screening the proxy groups for outliers, the Commission affirmed the Presiding Judge's application of the Commission's low-end outlier test in this proceeding, explaining that the "purpose of the low-end outlier test is to exclude from the proxy group those companies whose ROE estimates are below the average bond yield or are above the average bond yield but are sufficiently low that an investor would consider the stock to yield essentially the same return as debt."[124] The Commission explained that "[i]n public utility ROE cases, the Commission has used 100 basis points above the cost of debt as an approximation of this threshold, but has also considered the distribution of the proxy group companies to inform its decision on which companies are outliers."[125] The Commission explained that the cost of debt for the relevant study period was 4.61 percent and, therefore, the Commission eliminated three companies whose DCF results failed the low-end outlier test—Edison International (3.11 percent), Ameren Corp.

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[119] Opinion No. 531, 147 FERC ¶ 61,234 at P 96.

[120] *Id.* P 106.

[121] *Id.* P 107.

[122] *Id.*

[123] *Id.* P 108.

[124] *Id.* P 121.

[125] *Id.*

(5.26 percent), and Public Service Enterprise Group Inc. (PSEG) (5.62 percent).[126] The Commission explained that PSEG's DCF result was only one basis point above the 100 basis point threshold, and that the Commission's decision to eliminate PSEG was informed by the fact that there was a 141 basis point break between PSEG's DCF result and that of the next lowest proxy group company.[127]

61. With regard to the high-end outlier test, the Commission found that "the high-end outlier issue in this proceeding is moot,"[128] explaining that "[u]nder the two-step DCF methodology, it is unnecessary to screen the proxy group for unsustainable growth rates because the methodology assumes the long-term growth rate for each company is equal to GDP." The Commission explained that, as a result, "no company in the proxy group we are adopting here has a composite growth rate under the two-step DCF methodology in excess of the 7.66 percent growth rate of PNM Resources, Inc., or an ROE in excess of the 11.74 percent ROE of UIL Holdings," which are "well within any high-end outlier test we have previously applied in utility rate cases."[129]

ii. <u>Requests for Rehearing</u>

62. Petitioners assert that the Commission's DCF analysis in Opinion No. 531 contained flaws that undermine the Commission's decision to place the base ROE above the midpoint of the zone of reasonableness.

63. Petitioners argue that the Commission erred in relying on a short-term growth estimate for UIL Holdings, Inc. (UIL Holdings) of 8.07 percent, which Petitioners allege was based on only one analyst estimate.[130] According to Petitioners, Commission precedent indicates that, when calculating the dividend growth rate, the Commission's analysis should be based upon as much independently calculated data as possible, and that IBES growth estimates are reliable only insofar as they represent the consensus of

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[126] *Id.* P 123.

[127] *Id.*

[128] *Id.* P 118.

[129] *Id.*

[130] Petitioners Request for Rehearing at 48 (citing Exs. SC-313 and SC-314 (showing that 8.07 percent long-term growth projection for UIL Holdings represents the forecast of one analyst)).

multiple analysts.[131] In addition, Petitioners state that the Commission has made clear that its approval of the Yahoo! reported growth estimates that represent a consensus is not exclusive of other credible sources[132] and that comparable growth projections from other sources could be considered along with Value Line projections and what was then IBES.[133]

64. Petitioners state that it is critical in this case, and in future cases, that the Commission follow its precedent by requiring that the short-term growth rate for each proxy company be based on multiple projections. Petitioners argue that UIL Holdings's New England transmission business is smaller than its natural gas distribution business,[134] and it is therefore a less-than-ideal proxy for setting an electric transmission ROE.[135] Petitioners also assert that, during the relevant period, the Moody's credit rating for UIL Holdings was Baa3, lower than the Baa2 rating of its transmission subsidiary, United Illuminating Company, and the lowest rank among all retained proxy

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[131] *Id.* at 45 (citing *Yankee Atomic Elec. Co.*, Opinion No. 285, 40 FERC ¶ 61,372, at 62,210 (1987) (*Yankee Atomic*), *reh'g denied*, Opinion No. 285- A, 43 FERC ¶ 61,232 (1988) (rejecting sole reliance on Zacks' predictions of earnings growth in favor of multiple data sources for projecting earnings); *Northwest Pipeline Corp.*, 87 FERC ¶ 61,266, at 62,059 (1999) (*Northwest Pipeline*) ("[t]he IBES data is a compilation of projected growth rates from various knowledgeable financial advisors with the industry.")).

[132] *Id.* at 46 (citing *Composition of Proxy Groups for Determining Gas and Oil Pipeline Return on Equity*, 123 FERC ¶ 61,048, at PP 83-84 (2008), *reh'g dismissed*, 123 FERC ¶ 61,259 (2008) (conditionally allowing, but not requiring, reference to growth forecasts published by Yahoo!)).

[133] *Id.* (citing *ISO New England, Inc.*, 109 FERC ¶ 61,147, at P 205 (2004), *petition for review denied sub nom. Me. Pub. Utils. Comm'n v. FERC*, 454 F.3d 278 (D.C. Cir. 2006); *ISO New England, Inc.*, 110 FERC ¶ 61,111, at P 23, *reh'g denied*, 111 FERC ¶ 61,344 (2005)).

[134] *Id.* at 49.

[135] *Id.* (citing *Consumers Energy Co.*, Opinion No. 456, 98 FERC ¶ 61,333 (2002)).

companies.[136] Petitioners assert that these considerations provide reasons to avoid undue reliance on the forecasts of one analyst.[137]

65. Petitioners state that because the IBES projection for UIL Holdings was the opinion of a single analyst, Opinion No. 531 erred in failing to apply any of the other growth estimates available in the record to check whether the IBES projection for UIL Holdings produced reasonable results. Petitioners contend that neither Opinion No. 531 nor any participant identified a prior case in which the Commission placed the base ROE three-quarters of the way up the zone of reasonableness based on a high-end proxy result that was driven by the forecast of just one analyst. Petitioners state that using Value Line or Reuters data for UIL Holdings's short-term growth rate in the two-step DCF methodology provides a more appropriate benchmark than the NETOs' alternative cost of equity studies, and shows that a base ROE of 9.39 percent is sufficient for the NETOs.[138]

66. Petitioners also argue that UIL Holdings's DCF result reflects a "circularity problem" that counsels against placing the base ROE at the upper quarter of the zone of reasonableness, and instead supports placing the base ROE no higher than the true 75th percentile of the proxy group companies' DCF results. Petitioners state that the "circularity problem" is that much of UIL Holdings's dividends, earnings, and earnings growth are a result of ROE incentive adders, and UIL Holdings's DCF result reflects investors' expected revenues from those ROE incentive adders. Petitioners assert that the NETOs' base ROE should be determined exclusive of the transmission incentive revenues of the proxy group companies.

67. Petitioners also state that this circularity problem should have been mitigated by placing the base ROE closer to the true "75th percentile" of the proxy group DCF results, i.e., based on 75 percent of the 38 proxy company results (interpolated between the 28th-highest and 29th-highest results), rather than at the upper quarter of the zone of reasonableness. Petitioners state that the key difference between the actual 75th percentile and the top-quarter approach that Opinion No. 531 labels as the "75th percentile" is that the actual percentile reflects the distribution of proxy group results, whereas the Commission's top-quarter approach discards all of that information and relies on the 3:1 weighted average of the two most extreme results. Petitioners assert that discarding information on the distribution of proxy results and considering only their

[136] *Id.* (citing Ex. NET-600 at 9).

[137] *Id.*

[138] *Id.* at 45.

extremes is statistically indefensible and inconsistent with precedent applying Opinion No. 531's two-step DCF methodology.[139]

68. Lastly, Petitioners argue that the Commission erred in eliminating PSEG's DCF result of 5.61 percent as a low-end outlier, thereby raising the bottom of the zone of reasonableness produced by the Commission's DCF analysis. Petitioners state that this error reinforces the arguments against raising the base ROE within the zone of reasonableness. Petitioners state that Opinion No. 531 discarded PSEG's DCF result on the grounds that, although it was above the average bond yield by more than 100 basis points, it fell below a "natural break" in the proxy group's DCF results. Petitioners argue that, while Opinion No. 531 states that this rationale "buttressed" the decision to exclude PSEG, the natural break was actually the sole basis for the Commission's decision.[140]

69. Petitioners argue that the "natural break" standard must be applied evenhandedly to low-end and high-end outliers alike, but in Opinion No. 531 the Commission ignored the fact that there was a comparable "natural break" at the high end of the range of DCF results. Specifically, Petitioners assert that the 5.62 percent result for PSEG should not have been discarded unless the 11.74 percent result for UIL Holdings was also discarded.[141]

iii. Commission Determination

70. We deny rehearing on the various issues that Petitioners and EMCOS raise concerning the Commission's DCF analysis and their related objections to setting the base ROE above the midpoint of the zone of reasonableness.

71. Petitioners argue that the Commission erred in using UIL Holdings's DCF result to set the top of the zone of reasonableness in the Commission's DCF analysis, because UIL Holdings's DCF result was based on an IBES short-term growth projection that reflected only one analyst's growth rate projection. We reject this argument as it is contrary to years of established Commission precedent approving the use of IBES short-term growth projections in the two-step DCF methodology. For example, in *Transcontinental Gas Pipe Line Corp.*[142] the Commission rejected contentions that IBES

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[139] *Id.* at 58-59 (citing *Northwest Pipeline Corp.*, 99 FERC ¶ 61,305).

[140] *Id.* at 60.

[141] *Id.* at 61.

[142] *Transcontinental Gas Pipe Line Corp.*, Opinion No. 414-B, 85 FERC ¶ 61,323, at 62,268-9 (1998) (Opinion No. 414-B).

growth projections should not be used in the two-step DCF methodology, because the analysts making those projections allegedly are overly optimistic in their projections. The Commission pointed to substantial evidence in the record of that case that investors rely on IBES growth projections in making investment decisions. The Commission also noted that the appropriate dividend growth rate to include in a DCF analysis is the growth rate expected by the market. While the market may be wrong in its expectations as reflected in the IBES growth projections, the cost of common equity to a regulated enterprise depends upon what the market expects, not upon precisely what is actually going to happen.

72. We recognize that the Commission has supported its use of IBES growth projections based on the fact that the IBES data is a compilation of projected growth rates from various knowledgeable financial advisors.[143] However, the Commission has not required that the IBES growth projection for each member of the proxy group reflect a minimum number of analyst growth estimates.[144] IBES, which the Commission has long relied on as the source of the growth rate projections to be used in the Commission's DCF analyses, does not publish the number of analyst estimates on which a company's growth rate estimate is based.[145] As a result, there seems little reason to conclude that investors' reliance on IBES growth projections necessarily varies depending upon the exact number of analysts contributing to any particular IBES growth projection. On balance, we find it preferable to use a consistent source of dividend growth projections for all members of the proxy group as provided by IBES, rather than to use different sources of growth projections depending upon the number of analysts contributing to each IBES growth projection, which, as discussed below, could produce skewed results. Accordingly, if a proxy company has a growth rate estimate from IBES, as does UIL Holdings, that growth rate is acceptable for purposes of the Commission's DCF analysis, regardless of the number of analysts on which it was based.

73. Contrary to Petitioners' assertion, *Yankee Atomic* and *Northwest Pipeline* do not require a different result. *Yankee Atomic* involved a much different analysis than in the instant case, because the Commission found that the small proxy group in *Yankee Atomic* was "not a valid indicator of the Yankee companies' cost of capital because the five companies are different from the Yankees in too many significant respects."[146] Because

[143] *Northwest Pipeline*, 87 FERC ¶ 61,266 at 62,059.

[144] *E.g.*, *SoCal Edison*, 131 FERC ¶ 61,020 at P 36.

[145] We also note that the Value Line data—which the Commission has similarly long relied upon as the source of earnings estimates in ROE proceedings—for any company consists of an earnings estimate from only one analyst.

[146] *Yankee Atomic*, 40 FERC ¶ 61,372 at 62,211.

the record did not contain a valid proxy group, the Commission had to project the Yankee Companies' dividend growth based solely on projections of those companies' own dividend growth. Therefore, the Commission determined that it should base the Yankee Companies' dividend growth projection on as many independent growth projections as possible. In contrast, this case involves a robust proxy group of companies that are comparable to the NETOs, for which dividend growth projections are available to enable the Commission to conduct a full DCF analysis. This provides the Commission a significant amount of information concerning the NETOs' cost of equity. As to *Northwest Pipeline*, in that case the Commission actually rejected the very argument on which Petitioners rely, as the Commission found that it would be inappropriate to use multiple sources of growth rate data, rather than IBES alone, in determining the short-term growth projection in the two-step DCF methodology.[147]

74. Petitioners argue that the Commission erred in placing the base ROE halfway between the midpoint of the zone of reasonableness and the top of the zone because UIL Holdings's high-end result is affected by a "circularity problem," i.e., that UIL Holdings's dividends, earnings, and earnings growth are impacted by its incentive ROE adders. The Commission has rejected this argument in the past, and we do so here for the same reasons. In Order No. 679-A, the Commission rejected the argument "that incentive ROEs will 'destabilize' the DCF methodology," explaining that

> First, . . . all ROEs approved pursuant to section 219 will be within the range of reasonableness, as determined consistent with our precedents. Second, any incentive ROEs granted under section 219 should have minimal effect, if any, on the overall range of reasonableness derived from the appropriate proxy group. The DCF methodology uses proxy groups of entire companies, not individual transmission projects. In other words, the "cash flows" being measured in the DCF method are the cash flows of entire companies. These cash flows should not be significantly affected by an incentive return for any particular transmission project for one company within the proxy group. Moreover, to the extent there is any small effect on the overall range of reasonableness, it will appropriately reflect the substantial risks associated with constructing new transmission[.][148]

75. Further, even assuming *arguendo* that this circularity problem exists, it exists for any proxy group company that receives incentive adders and Petitioners have presented no methodology for determining whether or how much a company's incentive adders

[147] *See Northwest Pipeline*, 87 FERC ¶ 61,266 at 62,058-59.

[148] Order No. 679-A, FERC Stats. & Regs. ¶ 31,236 at P 62 (cross-referenced at 117 FERC ¶ 61,345 at P 62).

might impact investors' expectations for a particular company, particularly where the proxy company at issue is involved in diverse business activities, as is UIL Holdings. Thus, absent more evidence, we are not persuaded that this potential "circularity problem" warrants an adjustment to the NETOs' base ROE. Further, even if Petitioners had shown this alleged circularity to be a legitimate problem warranting an adjustment to the base ROE, Petitioners have not shown that placing the base ROE at their proposed true 75th percentile of the proxy group results would be an appropriate solution.

76. We also reject Petitioners' argument that the Commission should have compared UIL Holdings's IBES growth rate against the Reuters data Trial Staff provided and the "br+sv"[149] data in the record. We relied only on IBES data for the DCF analysis in this proceeding, because that is the only short-term growth data available in the record for all the proxy companies. As the Commission explained in Opinion No. 531, "[u]sing different sources of growth rate data for different companies in a proxy group could produce skewed results, because those sources may take different approaches to calculating growth rates."[150] A comparison between UIL Holdings's IBES data and other non-IBES data in the record would be susceptible to this same skewing effect, and therefore would not provide a reliable comparison. Further, as the Commission explained in Opinion No. 531, while "the purpose of the 'br+sv' growth estimate is to act as a check on the reasonableness of the IBES forecasts," in practice the two sources often produce "widely divergent growth rates that do not engender much confidence in the reliability of the estimates."[151] We are, therefore, not persuaded that it is necessary to compare the IBES growth rate data to the "br+sv" data. In addition, we disagree with Petitioners that declining to mix growth rate sources is inconsistent with Opinion No. 531's allowance of credit ratings from both Moody's and S&P. The purpose of using data from both Moody's and S&P is to identify a group of comparable risk companies. In contrast, the purpose of not using multiple sources of growth rate data is to ensure that the cost of equity for each company in the proxy group is estimated using the same protocols.

77. We also reject Petitioners' argument that the Commission should have used the "br+sv" growth rate as the short-term growth rate in the two-step DCF methodology.

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[149] The term "br+sv" represents the sustainable growth formula, in the one-step DCF methodology that the Commission used for public utilities prior to Opinion No. 531, where "b" is the percentage of earnings expected to be retained (after the payment of dividends), "r" is the expected rate of return on book equity, "s" is the percent of common equity expected to be issued annually as new common stock, and "v" is the equity accretion rate.

[150] Opinion No. 531, 147 FERC ¶ 61,234 at P 90.

[151] *Id.* P 37.

While the "br+sv" growth formula relies on short-term Value Line projections of five years or less for the various inputs to the formula, it seeks to estimate a company's "sustainable growth rate." For that reason, although the Commission has stated that the formula "only produces a projection of short-term growth, similar to the IBES projections,"[152] the Commission finds the formula unreasonable for use as the short-term growth projection in the two-step DCF methodology. By seeking to estimate a "sustainable growth rate," the "br+sv" growth formula also contains some elements of a long-term growth projection, in addition to a short-term growth projection, and thus is inappropriate for use as a purely short-term growth projection in a two-step DCF methodology. The Commission adopted the two-step DCF methodology because, among other reasons, its incorporation of a long-term growth projection in the cost of equity calculation would have the effect of ascribing sustainable long-term growth to all members of a proxy group.[153] Thus, the Commission's adoption of the two-step DCF methodology accomplishes what the use of the "br+sv" formula was intended to accomplish.[154]

78. We reject Petitioners' arguments that the Commission erred in its application of the low-end and high-end outlier tests. We reiterate that it is appropriate—and consistent with Commission precedent—to eliminate PSEG as a low-end outlier in this case because PSEG's DCF result is a mere 101 basis points above the applicable bond yield and there is a 141 basis point break between PSEG's DCF result and the next lowest result. Further, we reject as inconsistent with Commission precedent Petitioners' argument that the Commission should have adopted the NETOs' proposed adjustment to the low-end outlier test instead of placing the base ROE above the midpoint of zone of reasonableness. Petitioners have identified no precedent in which the Commission has adopted such an adjustment to the low-end outlier test, and we are not persuaded to do so in this case.

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[152] *Id.* P 34.

[153] *Id.* PP 38, 40.

[154] We also note that the Commission's rationale for adopting the two-step DCF methodology in Opinion No. 531 was, in part, to use a methodology that is more consistent with the methodology the Commission has applied in natural gas and oil pipeline cases. *See id.* P 36. However, using "br+sv" in place of IBES growth rates, as Complainants request, would produce a DCF methodology that is less closely aligned with the methodology the Commission uses in natural gas and oil pipeline cases, where the Commission has rejected the use of the "br+sv" formula. *Composition of Proxy Groups for Determining Gas and Oil Pipeline Return on Equity*, 123 FERC ¶ 61,048 at P 100.

79. Petitioners next argue that, if the Commission eliminates PSEG as a low-end outlier, it must also eliminate UIL Holdings as a high-end outlier because UIL Holdings's DCF result is 112 basis points above the next highest DCF result, and the Commission must apply the same "natural break" analysis in both the low-end and high-end outlier tests. We disagree. The low-end outlier test and the high-end outlier test serve very different purposes: the low-end outlier test is intended to screen out companies whose ROE estimates are low enough that an investor would consider the stock to yield essentially the same return as debt,[155] whereas the high-end outlier test is intended to screen out companies whose growth rates are unsustainably high and therefore fail a threshold test of economic logic.[156] As the Commission explained in Opinion No. 531, the high-end outlier issue in this proceeding is moot because the two-step DCF methodology assumes that the long-term growth rate of all proxy companies is equal to GDP, and is therefore sustainable.

c. State Commission-Authorized ROEs

i. Opinion No. 531

80. The Commission in Opinion No. 531 found that the record evidence of state commission-approved ROEs supported the Commission's determination that a base ROE at the midpoint of the zone of reasonableness would not satisfy *Hope* and *Bluefield*. The Commission explained that, while it has "repeatedly held that it does not establish utilities' ROE based on state commission ROEs for state-regulated electric distribution assets,"[157] this proceeding presents "circumstances under which the midpoint of the zone of reasonableness established in this proceeding has fallen below state commission-approved ROEs, even though transmission entails unique risks that state-regulated electric distribution does not."[158] More specifically, the Commission explained that "while the midpoint in this case is 9.39 percent, the record indicates that, over the 24-month period from October 1, 2010 through September 30, 2012, approximately 85 percent to 91 percent of state commission authorized ROEs were between 9.8 percent and 10.74 percent."[159] Accordingly, the Commission found that "[a]lthough we are not using the state commission-approved ROEs to establish the NETOs' ROE in this

[155] *See S. Cal. Edison Co.*, 92 FERC ¶ 61,070 at 61,266.

[156] *See, e.g.*, *ISO New England, Inc.*, 109 FERC ¶ 61,147 at P 205.

[157] Opinion No. 531, 147 FERC ¶ 61,234 at P 148.

[158] *Id.*

[159] *Id.*

proceeding, the discrepancy between state ROEs and the 9.39 percent midpoint serves as an indicator that an upward adjustment to the midpoint here is warranted to satisfy *Hope* and *Bluefield*."[160]

ii. Requests for Rehearing

81. Petitioners and EMCOS argue that the Commission erred in relying on state commission-authorized ROEs in Opinion No. 531, because comparisons to state-authorized ROEs are not relevant to this proceeding and do not support raising the NETOs' base ROE from the 9.39 percent midpoint to the 10.57 percent upper quartile figure.[161] Petitioners argue that Opinion No. 531 erroneously relies on the spin that the NETOs placed on Ex. NET-403's data, repeating their argument that "approximately 85 percent to 91 percent of state commission authorized ROEs were between 9.8 percent and 10.74 percent."[162] EMCOS argue that the fact that some state commission-approved ROEs are higher than the midpoint in this proceeding is insufficient evidence to support Opinion No. 531's decision to ignore the Commission's strong preference for the use of the midpoint.[163] Petitioners contend that reference points presented in the exhibit show that 89 percent of the past-period state commission ROE outcomes collected by the NETOs fall below 10.57 percent.[164] Petitioners further contend that the central tendency values of the state commission-authorized ROEs presented by the NETOs are a mode of 10 percent, median of 10.13 percent, a mean of 10.14 percent, and a midpoint of 10.25 percent. Petitioners argue that Opinion No. 531 does not explain how these data justify a 10.57 percent base ROE.[165]

82. Petitioners and EMCOS contend that the state commission-authorized ROEs upon which the Commission relied were tainted by substantial lag, and that relying on them is therefore inconsistent with Opinion No. 531's emphasis on using the most recent

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[160] *Id.*

[161] Petitioners Request for Rehearing at 23; EMCOS Request for Rehearing at 25-26.

[162] Petitioners Request for Rehearing at 23.

[163] EMCOS Request for Rehearing at 11, 25-26 (citing *Fla. Gas Transmission Co. v. FERC*, 604 F.3d 636, 639 (D.C. Cir. 2010)).

[164] Petitioners Request for Rehearing at 23.

[165] *Id.* at 25.

information available in the record.[166] Petitioners argue that the record shows that more recent state-authorized base ROEs have averaged below 10 percent. For example, Petitioners state that the Regulatory Research Associates data for the first quarter of 2013 show that the average authorized state electric ROE "approximated 9.75 [percent], 25 [basis points] below the analogous adjusted average ROE for calendar-2012 (which approximated 10 percent)."[167] Petitioners state that Exhibit SC-423 shows that, on March 15, 2013, the New York State Public Service Commission approved an ROE of 9.3 percent for Niagara Mohawk Power Corporation, finding the rate to be "consistent with investor expectations while being slightly below other recently authorized rate plans."[168] In addition, Petitioners state that Exhibit SC-505 shows that, at around the same time, Northeast Utilities' retail ROE was set at 9.38 percent.[169]

83. Petitioners contend that the Commission should have made its own independent finding of the current cost of equity, based on financial market data, rather than being constrained by stale decisions reached elsewhere. Petitioners note that the Commission has previously rejected efforts to use state commission-authorized ROEs as a benchmark for setting regional transmission ROEs.[170] Petitioners argue that if state commission-authorized ROEs are irrelevant when they are lower than the result of the Commission's DCF analysis, then they are also irrelevant when they are higher than the result of the Commission's DCF study. Petitioners argue that the Commission's failure to recognize this symmetry in Opinion No. 531 or to offer any justification for ignoring it renders the decision arbitrary and capricious.[171] Similarly, EMCOS contend that Opinion No. 531 is inconsistent with *Missouri Public Service Commission v. FERC,* 337 F.3d 1066, 1077 (D.C. Cir. 2003) (*Missouri*), which explained that "[w]hen FERC relies upon a state agency's prior approval to support the conclusion that rates are in the public interest, the Commission must at least say something about the prior regulator's rationale for approving those rates."

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[166] *Id.* at 25-26 (citing Opinion No. 531, 147 FERC ¶ 61,234 at PP 55, 88); EMCOS Request for Rehearing at 11, 26 (citing *NorAm Gas Transmission Co. v. FERC*, 148 F.3d 1158, 1165 (1998)).

[167] Petitioners Request for Rehearing at 26.

[168] *Id.* at 28 (citing Ex. SC-423 at 18).

[169] *Id.*

[170] *Id.* at 29.

[171] *Id.* at 29-30.

iii. Commission Determination

84. We disagree with Petitioners' and EMCOS's arguments that the record evidence concerning state commission-authorized ROEs does not support placing the NETOs' base ROE above the midpoint of the zone of reasonableness. The Commission did not use the evidence of state commission-authorized ROEs to determine the level at which the NETOs' base ROE should be set. As explained below, the Commission merely relied on the state commission-authorized ROEs—in conjunction with evidence that interstate transmission is riskier than state-level distribution—as evidence that the 9.39 percent midpoint of the DCF-produced zone of reasonableness was insufficient to satisfy the requirements of *Hope* and *Bluefield* and, therefore, that an adjustment above 9.39 percent was warranted.[172]

85. Contrary to Petitioners' and EMCOS's arguments, applying other measures of central tendency to the NETOs' data on state commission-authorized ROEs does not undermine the Commission's conclusion that an upward adjustment was warranted. Petitioners point to various measures of central tendency for the state commission-authorized ROEs: mode of 10 percent, median of 10.13 percent, a mean of 10.14 percent, and a midpoint of 10.25 percent. But all of these figures are above the 9.39 percent midpoint of the zone of reasonableness; in light of the record evidence showing that interstate transmission is riskier than state-level distribution,[173] all of these figures support adjusting the NETOs' base ROE above that level. Further, while Petitioners focus on the fact that 89 percent of the state commission-authorized ROEs in the NETOs' study are below 10.57 percent, that fact is irrelevant to how the midpoint of the DCF-produced zone of reasonableness compares to the state commission-authorized ROEs. The more relevant fact is that almost 93 percent of the state commission-authorized ROEs are above the 9.39 percent midpoint produced by the Commission's two-step DCF methodology in this case.[174]

86. We reject Petitioners' and EMCOS's arguments that the Commission's reliance on the state ROE figures despite their time-lag is inconsistent with the Commission's preference for the most recent data in the record. The evidence of state commission-

[172] *See* Opinion No. 531, 147 FERC ¶ 61,234 at PP 148-149.

[173] *See id.* P 149. We note that Petitioners have not refuted the record evidence that interstate transmission is riskier than state-level distribution. Petitioners' request for rehearing discusses the Commission's finding on the relative risks of transmission and distribution only in the context of whether the NETOs are more or less risky than the companies in the DCF proxy group. *See* Petitioners Request for Rehearing at 19-22.

[174] *See* Ex. NET-403.

authorized ROEs that the Commission relied upon is, in fact, the most recent complete study in the record. While the record does contain some more recent evidence of state commission-authorized ROEs, that evidence does not represent a data set comparable to the NETOs' 24-month study,[175] but is rather data for only one quarter in 2013 from Regulatory Research Associates concerning the recent trend in average authorized ROEs. According to Petitioners, the report from Regulatory Research Associates indicates that the average state commission-authorized ROE in the first quarter of 2013 "approximated 9.75 [percent], 25 [basis points] below the analogous adjusted average ROE for calendar-2012 (which approximated 10 percent)."[176] This evidence does not undermine, but supports, the Commission's conclusion that the 9.39 percent midpoint, determined by using the DCF methodology, is below most of the state ROEs.

87. We also reject Petitioners' argument that, in using state commission-authorized ROEs to corroborate the outcome of the DCF analysis, the Commission failed to make its own finding on the cost of equity. To the contrary, the Commission conducted its own DCF analysis and did make its own finding, based on the financial market data in the record. That the Commission looked to the state commission-authorized ROEs and alternative methodologies to corroborate the accuracy of its finding, does not undermine the Commission's finding on the cost of equity. Rather, the Commission's analysis of not only the DCF results but also additional record evidence demonstrates that the Commission fully reviewed the record to ensure a just and reasonable ROE sufficient to meet the capital attraction standards required by *Hope* and *Bluefield.*

88. We disagree that the Commission's use of state commission-authorized ROEs in Opinion No. 531 is inconsistent with Commission precedent. As the Commission explained in Opinion No. 531, while the Commission has rejected the use of state ROEs

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[175] The NETOs' study of state commission-allowed ROEs covered the time period from October 1, 2010 through September 30, 2012. *See* Ex. NET-400; Ex. NET-403.

[176] Petitioners Request for Rehearing at 26 (citing Ex. SC-524). We note that the Regulatory Research Associates' report states that the average state commission-allowed ROE for the first quarter of 2013 is 10.24 percent. The 9.75 percent figure to which Petitioners refer was calculated by excluding from the ROE decisions issued in that quarter those from one particular state commission and, as noted, would be 10.24 percent without that exclusion. Further, we note that the record evidence also shows that the average state commission-allowed ROE for the fourth quarter of 2012, i.e., the quarter immediately following the time period of the NETOs' state ROE study, was 10.10 percent. Thus, the data concerning state commission allowed-ROEs for the fourth quarter of 2012 (10.10 percent) and the first quarter of 2013 (10.24 percent) are consistent with the data in the NETOs' study of state commission-allowed ROEs, and do not indicate a downturn in state ROEs as Petitioners allege.

in the past, it has done so on the grounds that the state ROEs alone provide an insufficient basis for determining Commission-jurisdictional rates. Those cases are distinguishable from the instant proceeding, where the Commission instead compared the evidence provided by a significant number of state commission-authorized ROEs to the midpoint produced by the application of the Commission's traditional methodology and concluded that their levels, relative to each other, were illogical in light of the record evidence concerning the comparative risks of state-level electric distribution and interstate electric transmission. We also reject Petitioners' argument that, if state commission-approved ROEs are irrelevant when they are below Commission ROEs, then they are also irrelevant when they are above Commission ROEs. The Commission has not found state commission-approved ROEs to be irrelevant when they are lower than Commission-approved ROEs. As the Commission explained in Opinion No. 531, the relevance of the state commission-approved ROEs was determined in conjunction with the record evidence on the elevated risks of interstate transmission, compared to state-regulated distribution.

89. Lastly, we disagree with EMCOS's assertion that the Commission ignored *Missouri*, 337 F.3d 1066. *Missouri* is inapposite to the facts of this case as it involved the Commission's *adoption* of a specific rate, for a gas pipeline's sales under the Commission's jurisdiction, that had been "approved by [a state commission] under the regulatory regime that governed the pipeline prior to FERC's assertion of jurisdiction."[177] By comparison, in Opinion No. 531, the Commission did not adopt any rate approved by a state commission.

d. Risk Premium Analysis

i. Opinion No. 531

90. In Opinion No. 531, the Commission explained that the risk premium methodology is "based on the simple idea that since investors in stocks take greater risk than investors in bonds, the former expect to earn a return on a stock investment that reflects a 'premium' over and above the return they expect to earn on a bond investment."[178] The Commission further explained that "investors' required risk premiums expand with low interest rates and shrink at higher interest rates," and found that this link "provides a helpful indicator of how investors' required returns on equity

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[177] *Missouri*, 337 F.3d at 1076.

[178] Opinion No. 531, 147 FERC ¶ 61,234 at P 147 (quoting Roger A. Morin, New Regulatory Finance 108 (Public Utilities Reports, Inc. 2006)) (internal quotations omitted).

have been impacted by the interest rate environment."[179] The Commission explained that it has in the past rejected the use of risk premium analyses to estimate investor-required returns on equity, but "those cases are distinguishable from the instant proceeding because they involved proposals to establish a constant risk premium based on the average difference between state commission ROEs and bond rates over multi-year periods."[180]

91. The Commission found the NETOs' risk premium analysis "informative,"[181] as it indicated that the NETOs' cost of equity "is between 10.7 percent and 10.8 percent, which is higher than the 9.39 percent midpoint produced by our DCF analysis."[182] The Commission explained that, in relying on the NETOs' risk premium analysis, "we do not depart from our use of the DCF methodology; rather, we use the record evidence to inform the just and reasonable placement of the ROE within the zone of reasonableness established in the record by the DCF methodology."[183]

ii. <u>Requests for Rehearing</u>

92. EMCOS argue that Opinion No. 531 erred by adopting the NETOs' risk premium analysis despite the fact that the Commission has repeatedly rejected the use of risk premium analysis for determining a just and reasonable ROE for a public utility.[184] EMCOS assert that the Commission in Opinion No. 531 attempted to distinguish those precedents from this proceeding on the basis that the risk premium analyses in those cases relied on "the average state commission ROEs and bond rates over multi-year periods."[185] However, EMCOS contend that the Commission's rationale is flawed because the Commission's rejection of risk premium analyses in the past was not due to the involvement of state commission ROEs, but rather was due to concerns regarding the

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[179] *Id.*

[180] *Id.* n.290.

[181] *Id.* P 146.

[182] *Id.* P 147.

[183] *Id.* P 146.

[184] EMCOS Request for Rehearing at 20-21 (citing *Consumers Energy Co.,* 64 FERC ¶ 63,029 (1993), *aff'd,* 85 FERC ¶ 61,100 at 61,361 (1998); *New England Power Co.,* 31 FERC ¶ 61,378, at 61,841 (1985)).

[185] *Id.* at 21 (citing Opinion No. 531, 147 FERC ¶ 61,234 at P 147 n.290).

reliability of the methodology to produce reliable results in fluctuating market conditions.[186] Additionally, EMCOS argue that Opinion No. 531 fails to respond to criticism that parties presented about the NETOs' risk premium analysis. EMCOS argue that Opinion No. 531's failure to respond to—or even acknowledge—the substantive arguments against the NETOs' specific risk premium analysis renders the decision arbitrary and capricious.[187]

93. Petitioners argue that the NETOs' version of a risk premium analysis contains multiple flaws. Petitioners argue that the NETOs' risk premium analysis detaches the ROEs from the regulatory contexts in which they were approved, and this disconnect should have rendered the NETOs' risk premium study irrelevant as a matter of law.[188] In addition, Petitioners assert that, even if it were acceptable to detach the allowed ROEs from their regulatory contexts, the NETOs' risk premium study's attempt to discern regulatory outcomes and assign dates to those outcomes contains numerous errors. Specifically, Petitioners contend that the risk premium study was performed by a person who did not appear at trial, lacked professional expertise in reading Commission decisions, and used examples supplied by the NETOs' counsel rather than a random or representative sample. Petitioners also argue that the NETOs' risk premium study is flawed because it assumes that the outcomes of Commission proceedings represent equity costs on the day the Commission issued its order approving the ROE, thereby ignoring both regulatory lag and the reality that many Commission decisions that identify an ROE do not involve finding a new, currently cost-based ROE.[189]

94. Additionally, Petitioners argue that the NETOs' risk premium study is flawed because the study makes no attempt to screen its inputs for comparable risk.[190] As an

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[186] *Id.* (citing *Consumers Energy Co.*, 64 FERC ¶ 63,029, *aff'd*, 85 FERC ¶ 61,100 at 61,361; *New England Power Co.,* 31 FERC ¶ 61,378 at 61,841).

[187] *Id.* at 22 (citing *Ill. Pub. Telecomm. Ass'n v. FCC*, 117 F.3d at 564).

[188] *Id.* at 33-34 (citing *Pepco Holdings, Inc.*, 124 FERC ¶ 61,176, at P 127 (2008), *reh'g denied,* 139 FERC ¶ 61,144 (2012)).

[189] Similarly, EMCOS note that Trial Staff and the Complainants argued that the NETOs' risk premium analysis is based on Commission-allowed returns, which are not the same as the market indicated ROEs that this methodology claims to address. Moreover, EMCOS explain that the NETOs' analysis includes ROEs that are the result of settlements, which further skew the results. In addition, EMCOS explain that the NETOs' analysis is rife with errors regarding the applicable dates of the Commission approved ROEs upon which they rely.

[190] Petitioners Request for Rehearing at 35.

example illustrating this flaw, Petitioners state that the NETOs' risk premium study treated as representative of June 2012 risk premiums—without making any finding as to the current equity cost—a Commission order that merely extended to a new MISO participant the 12.38 percent ROE that was established for the MISO region more than a decade earlier.[191] Petitioners further state that the Commission, in Opinion No. 489, rejected the NETOs' reliance on MISO's 12.38 percent ROE as a benchmark for New England.[192] Petitioners also argue that the NETOs' risk premium study treats orders and data from 2008-2009 as comparable to the NETOs' ROE, which was established in 2006 based on data from 2004. The Petitioners further assert that the NETOs' study failed to include orders after June 2012, and that these omissions skewed the NETOs' results by missing the trend towards lower ROEs.

95. Petitioners argue that, although the NETOs' failed to present an informative risk premium study, they did provide a basis to construct a more useful one that accords with Opinion No. 531's discussion of the theory underlying the risk premium methodology. Specifically, Petitioners note Opinion No. 531's explanation that "investors' required risk premiums expand with low interest rates and shrink at high interest rates,"[193] and assert that the NETOs' risk premium study used an incorrect ratio in determining the rate at which risk premiums change in response to changes in interest rates. Petitioners argue that the NETOs' risk premium study relied on an inferred rate at which risk premiums expand when interest rates drop is about 93:100—i.e., a 100 basis points decline in interest rates is deemed to be offset by a risk premium increase of about 93 basis points—which leaves a net decline in the cost of equity of only 7 basis points for every 100 basis point change interest rates. However, Petitioners contend that the NETOs' witness disavowed that ratio at trial, by clarifying that "generally, one half of the move in equity returns [is] related to the move in bond returns," so "if bond returns go up 100 basis points, your best guess of equity costs is 50 or 60 basis points."[194] Therefore, Petitioners state that it is more appropriate to use 45:100[195] as the rate at which risk premiums expand when interest rates drop—i.e., a 100 basis points decline in interest rates is deemed to be offset by a risk premium increase of about 45 basis points—which leaves a net decline in the cost of equity of 55 basis points for every 100 basis point change in

[191] *Id.*

[192] *Id.* at 36.

[193] *Id.* at 37 (citing Opinion No. 531, 147 FERC ¶ 61,234 at P 147).

[194] *Id.* at 38.

[195] Petitioners calculate this ratio by taking the average of the 50-60 basis point range indicated by the NETOs' witness at trial.

interest rates. Petitioners argue that substituting that relationship in Ex. NET-704 for the implausible 93:100 ratio, indicates an ROE of 9.67 percent to 9.91 percent.[196]

96. Petitioners contend that Opinion No. 531's reliance on a stale and poorly designed study of past Commission orders was inconsistent with its finding that ROEs should reflect the most recent information available at the time of trial.

iii. Commission Determination

97. We deny rehearing on the issue of whether the NETOs' risk premium analysis is flawed. As the Commission explained in Opinion No. 531, the theory behind the risk premium methodology is that "since investors in stocks take greater risk than investors in bonds, the former expect to earn a return on a stock investment that reflects a 'premium' over and above the return they expect to earn on a bond investment."[197] There are multiple approaches that have been advanced to determine this equity risk premium for a utility.[198] For example, a risk premium can be developed directly, by conducting a risk premium analysis for the company at issue, or indirectly by conducting a risk premium analysis for the market as a whole and then adjusting that result to reflect the risk of the company at issue.[199] Another approach that investors might choose to look to in the utility context is to "examin[e] the risk premiums implied in the returns on equity allowed by regulatory commissions for utilities over some past period relative to the contemporaneous level of the long-term Treasury bond yield."[200] In the instant case, the NETOs followed the latter approach, developing their risk premium study by analyzing the ROEs allowed by this Commission since April 2006,[201] relative to the

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[196] Petitioners Request for Rehearing at 38.

[197] Roger A. Morin, New Regulatory Finance 108 (Public Utilities Reports, Inc. 2006).

[198] *See generally id.* at 107-130.

[199] *Id.* at 110.

[200] *Id.* at 123.

[201] *See* Ex. NET-704 at 3-4. We note that, although Petitioners assert that the NETOs failed to include any Commission orders issued after June 2012, Petitioners have not cited any final Commission orders establishing a utility's ROE between June 2012 and the date the Presiding Judge set as the deadline for the parties to update their exhibits prior to the hearing. While Petitioners correctly note that the Commission issued such an ROE order on May 6, 2013, that decision was issued after the final updating of exhibits.

contemporaneous level of the long-term Treasury bond yield,[202] to determine the risk premium implied by those regulatory decisions.[203]

98. Petitioners allege that the NETOs' risk premium analysis is flawed because it assigned arbitrary dates to the regulatory decisions on which it was based, ignored the fact that some of the decisions involved rates agreed to by settlement, ignored regulatory lag, and ignored the reality that some of the decisions did not involve the calculation of a current cost of equity. Given the varying duration of regulatory proceedings, it is difficult, if not impossible, to ensure precise contemporaneity between long-term Treasury bond yields and the cost of equity allowed by a regulator. Assigning approximate dates to the cost of equity determinations made in those regulatory proceedings, as the NETOs have done, is often unavoidable, and this fact alone does not undermine the relevance of risk premium analyses.[204] Similarly, whether the regulatory decision involved a settlement agreement or the application of a cost of equity that was calculated in the past, e.g., the 12.38 percent ROE established for the MISO region, does not affect the reliability of a risk premium analysis.[205] Risk premiums allowed by

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[202] NETOs also analyzed the ROEs allowed by regulatory decisions relative to long-term utility bond yields.

[203] *See* Ex. NET-704 at 1-2.

[204] We disagree with Petitioners that the Commission's reliance on the NETOs' risk premium analysis, despite the regulatory lag reflected therein, is inconsistent with Opinion No. 531's finding that "ROEs should reflect the most recent information available at the time of trial." Petitioners Request for Rehearing at 37. The NETOs' risk premium study upon which the Commission relied is indeed the most recent such study in the record.

[205] Further, contrary to Petitioners' assertion, the fact that the Commission, in Opinion No. 489, declined to use the 12.38 percent ROE from the MISO region as a benchmark in establishing the NETOs base ROE has no bearing on this proceeding. Using the ROE from the MISO region as a benchmark in establishing the just and reasonable ROE for the NETOs' is much different than using the ROE from the MISO region as one data point, among many, in a risk premium analysis that is then used to corroborate the results of the Commission's analysis. Additionally, assuming *arguendo* that (1) the 12.38 percent ROE for the MISO region was "stale" in June 2012, *see* Petitioners' Request for Rehearing at 35, (2) the 11.14 percent base ROE for the NETOs' was "stale" in August, November, and December of 2008, *see id.* at 36, and (3) it is therefore appropriate to exclude those data points from the NETOs' risk premium study, Petitioners have not shown that excluding those data points would materially affect the results of the NETOs' risk premium study or undermine its usefulness in

(continued…)

regulators "are presumably based on the results of market-based methodologies presented to regulators in rate hearings and on the actions of objective unbiased investors in a competitive marketplace."[206] This is no less true in the case of settlement agreements, as settling parties rely upon the same market-based methodologies in determining the rates they are willing to accept. In short, while the approach the NETOs used in their risk premium analysis, like any methodology for estimating the cost of equity, is not without inherent weaknesses, it is nonetheless an approach that investors routinely rely upon.[207] We similarly find the NETOs' risk premium analysis sufficiently reliable—not to set the ROE itself—but rather to corroborate our decision to place the NETOs' base ROE above the midpoint of the zone of reasonableness produced by the DCF analysis.

99. We also reject Petitioners' argument that the NETOs' risk premium study does not support placing the NETOs' base ROE above the midpoint of the zone of reasonableness because the NETOs' assumption regarding the inferred rate at which risk premiums expand when interest rates drop—i.e., the assumption that risk premiums expand by 93 basis points for every 100 basis point drop in interest rates—is unsupported. Petitioners assert that, if the NETOs' study is adjusted to reflect a more appropriate ratio than 93:100, the NETOs' risk premium study produces a result between 9.67 and 9.91 percent. While the rate at which risk premiums change as interest rates change is indeed important in a risk premium analysis, we find the alleged flaw to be immaterial in this context in

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corroborating the results of the Commission's DCF analysis. The NETOs' risk premium analysis compared the ROEs established in 66 cases from April 2006 through June 2012 to the contemporaneous 10-year U.S. Treasury bond yields to determine 66 risk premiums, which averaged 7.33 percent. Excluding the alleged stale ROEs would eliminate five of the 66 risk premiums from the NETO's analysis. The remaining 61 risk premiums average 7.28 percent, only marginally less than the average of the 66 risk premiums used in the NETOs' analysis. This indicates that exclusion of the allegedly stale ROEs would not materially reduce the 10.7 percent to 10.8 percent cost of equity produced by the NETOs' risk premium analysis.

[206] Roger A. Morin, New Regulatory Finance 125 (Public Utilities Reports, Inc. 2006).

[207] *Id.* at 123-125. We reject Petitioners' assertion that the NETOs' risk premium study was conducted by an unqualified analyst who did not appear at trial. The analyst to whom Petitioners refer did not conduct the NETOs' risk premium analysis, but rather assisted the NETOs' expert witness in conducting the analysis. *See* Tr. 647:9-648:10. Further, the analyst at issue is a chartered financial analyst, with a Masters Degree in Business Administration, who has assisted the NETOs' expert witness in preparing testimony in over 100 Commission proceedings. *See id.* at 648:14-22.

this case. As an initial matter, the alternative inferred rate—a ratio of 45:100—that Complainants put forth based on the NETOs' witness's testimony at hearing was based on state commission-allowed ROEs, not interstate transmission ROEs allowed by this Commission.[208] In light of the record evidence on the risk differential between state-regulated distribution and Commission-regulated interstate transmission, we are not persuaded that it is appropriate to apply to the NETOs, for the time period at issue in this proceeding, the inferred rate relationship between risk premiums and interest rates that was observed in state commission-allowed ROEs over a time period dating back a quarter century, to 1987. Further, the NETOs' determined the inferred rate relationship between risk premiums and interest rates in their risk premium study by conducting empirical observations and regression analysis of bond yields and Commission-allowed ROEs.[209] In sum, we are not persuaded that the NETOs' empirical results are invalid simply because they differ from the inferred rate relationship reflected in historical state commission-approved ROEs, particularly where anomalous capital market conditions exist that may impact the inferred relationship between risk premiums and interest rates.

100. EMCOS argue that the Commission erred in relying on the NETOs' risk premium analysis because doing so is inconsistent with precedent in which the Commission has rejected the use of risk premium analyses.[210] EMCOS assert that the Commission in Opinion No. 531 attempted to distinguish those precedents on the grounds that the risk premium analyses therein involved state commission-allowed ROEs. EMCOS contend that the Commission's interpretation of those precedents is incorrect, because the Commission in fact rejected the use of risk premium analyses in those past cases due to concerns that risk premium analyses are unreliable under fluctuating market conditions.

101. In Opinion No. 531, the Commission explained that the Commission's rejection of the risk premium analysis in a number of past cases, including *New England Power Co.*, is distinguishable from the instant case because those cases involved "*proposals to establish a constant risk premium* based on the average difference between state commission ROEs and bond rates *over multi-year periods*."[211] EMCOS mischaracterize the Commission's interpretation of *New England Power Co.* and other similar precedents

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[208] *See* Tr. 606:5-7 ("this is based on state returns, and state returns have marched to a slightly different drummer than FERC returns over the years.").

[209] *See generally* Ex. NET-704.

[210] EMCOS Request for Rehearing at 20-21 (citing *Consumers Energy Co.*, 64 FERC ¶ 63,029, *aff'd*, 85 FERC ¶ 61,100 at 61,361; *New England Power Co.*, 31 FERC ¶ 61,378 at 61,841).

[211] Opinion No. 531, 147 FERC ¶ 61,234 at n.290 (emphasis added).

by focusing on Opinion No. 531's reference to the fact that the risk premium analyses in the past cases relied upon state commission ROEs. As the italicized language in the above quote makes clear, however, the Commission's rationale for rejecting the proposal in *New England Power Co.* was not merely reliance on state commission-set ROEs, but was, as EMCOS correctly acknowledge, based on the Commission's finding that "[t]here is no direct relationship between historical risk premiums and a current cost of equity under constantly changing financial conditions."[212] In *New England Power Co.*, the utility proposed to calculate a risk premium based on the difference between the most recent 20-year average yield for certain money market indicators and the most recent 20-year average annual yield for Moody's Electric Utility common stocks plus the 10-year growth in dividends for those stocks. Thus, the utility assumed a constant risk premium for a 20-year period. In the instant case, the NETOs' risk premium analysis does not assume a constant risk premium over any length of time. Rather, the NETOs calculated a varying risk premium based on variations in the difference between allowed ROEs and bond yields during the time period from April 2006 through June 2012. Those cases in which the Commission rejected risk premium analyses in the past are thus distinguishable from the instant case, because unlike the proposals in those cases the NETOs have not proposed their risk premium analysis to establish a constant risk premium.[213]

e. CAPM Analysis

i. Opinion No. 531

102. In Opinion No. 531, the Commission explained that "[s]imilar to the risk premium analysis, the NETOs' CAPM uses interest rates as the input for the risk-free rate, which makes it useful in determining how the interest rate environment has impacted investors' required returns on equity."[214] The Commission also explained that "CAPM is utilized by investors as a measure of the cost of equity relative to its risk."[215] The Commission

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[212] *New England Power Co.*, 31 FERC at 61,841.

[213] Moreover, unlike other cases, the Commission here is *not* setting investor-required ROEs based on this risk premium, but is instead looking to it merely as "a helpful indicator" of the impact of the "interest rate environment" on "investors' required returns on equity." And from this analysis (and others discussed elsewhere in Opinion No. 531 and here) the Commission concludes only that the ROE should indeed be set above the midpoint. *See* Opinion No. 531, 147 FERC ¶ 61,234 at P 147 & n.290.

[214] Opinion No. 531, 147 FERC ¶ 61,234 at P 147.

[215] *Id.*

explained that it has in the past rejected the use of CAPM analyses, but "those cases are distinguishable from the instant proceeding because they involved CAPM analyses that were based on historic market risk premiums," whereas the NETOs' CAPM analysis "is based on forward-looking investor expectations for the market risk premium."[216]

103. The Commission found the NETOs' CAPM analysis "informative,"[217] as it produced a midpoint of 10.4 percent and a median of 10.9 percent, both of which are above the 9.39 percent midpoint produced by the Commission's DCF analysis.[218] The Commission explained that, in relying on the NETOs' CAPM analysis, "we do not depart from our use of the DCF methodology; rather, we use the record evidence to inform the just and reasonable placement of the ROE within the zone of reasonableness established in the record by the DCF methodology."[219]

ii. Requests for Rehearing

104. Petitioners assert that the NETOs' CAPM study is flawed because its assumption that the market as a whole (i.e., most of the S&P 500 companies) will grow at an annual rate of 10.3 percent is overly optimistic, unsustainable, double the historical norms and projections, and inconsistent with the GDP estimate the Commission relied upon in Opinion No. 531 for other purposes.[220] Petitioners argue that the NETOs calculated the unsustainable 10.3 percent growth rate by screening out almost a quarter of the market and placing excessive weight on the projections of non-utility companies' medium-term earnings per share growth while ignoring the fact that those estimates reflect unsustainable short-term stock repurchase programs and are not long-term projections.

105. Petitioners contend that the NETOs' CAPM study is also flawed because it relies on stock betas, which Petitioners assert are unreliable and do not meaningfully measure the risk differential between the proxy group and the dividend paying portion of the S&P 500 companies.[221] Petitioners state that the Commission in *ITC Holdings* found betas to

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[216] *Id.* n.292.

[217] *Id.* P 146.

[218] *Id.* P 147.

[219] *Id.* P 146.

[220] Petitioners Request for Rehearing at 39.

[221] *Id.* at 40 (citing *ITC Holdings Corp.*¸121 FERC ¶ 61,229, at P 43 (2007)); EMCOS Request for Rehearing at 23.

be an unreliable predictor of risk and, as a result, found the CAPM methodology to be inappropriate for determining a company's ROE.[222] Petitioners assert that, while the Commission in Opinion No. 531 attempted to distinguish *ITC Holdings* on the basis that it involved historical risk premiums, Opinion No. 531 did not attempt to address *ITC Holdings*'s finding that betas are unreliable. Similarly, EMCOS assert that, because the NETOs' CAPM analysis relied on betas, that analysis failed to incorporate forward-looking expectations, which undermines the Commission's claim that the NETOs' CAPM analysis is based on "forward-looking investor expectations" and is, therefore, distinguishable from CAPM analyses the Commission has rejected in the past.[223] Petitioners assert that their witness and Trial Staff's witness both presented more credible, forward-looking CAPM studies indicating a cost of equity of 7.5 percent and 8.2 percent, respectively, but that the Commission ignored both of these CAPM studies in Opinion No. 531.

106. In addition, Petitioners contend that the NETOs' CAPM study is flawed because it includes a "size adjustment" based on the theory that smaller companies are riskier and should, therefore, have higher growth and higher returns than the average company in the sample set. Petitioners argue that the NETOs' rationale is undermined by the Petitioners' calculation showing that the smaller firms in the NETOs' sample set have lower-than-average growth—an unweighted average of 9.8 percent, compared to the NETOs' weighted average of 10.3 percent.[224] Petitioners also argue that academic studies have shown that it is improper to apply this type of "size adjustment" to utilities.[225] Petitioners state that, without the size adjustment, the median and midpoint of the NETOs' CAPM analysis is 9.7 percent.[226]

107. EMCOS argue that the NETOs' CAPM analysis is flawed because it used a risky 30-year bond interest rate for the risk-free component of the calculation and inappropriately used a DCF result for the risk premium element of the analysis.

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[222] Petitioners Request for Rehearing at 31 (citing *ITC Holdings*¸121 FERC ¶ 61,229 at P 43; *Orange & Rockland Utils., Inc.*, Opinion No. 314, 44 FERC ¶ 61,253 (*Orange & Rockland*), *order on reh'g*, Opinion No. 314-A, 45 FERC ¶ 61,252 (1988), *reh'g denied,* 46 FERC ¶ 61,036 (1989)).

[223] EMCOS Request for Rehearing at 23 (citing Opinion No. 531, 147 FERC ¶ 61,234 at P 147 n.292).

[224] Petitioners Request for Rehearing at 41 (citing Ex. SC-514).

[225] *Id.* at 42 (citing SC-200 at 35-36).

[226] *Id.*

iii. Commission Determination

108. We deny rehearing on the issue of whether the NETOs' CAPM analysis is flawed. The CAPM methodology has three inputs: the risk-free rate, betas, and the market risk premium.[227] The risk-free rate and betas used in a CAPM study are generally not controversial. The risk-free rate is represented by a proxy, typically the yield on 30-year Treasury bonds.[228] Betas, which measure a stock's risk relative to the market, are published by several commercial sources. The market risk premium, which is where most CAPM studies diverge, can be estimated either using a backward-looking approach, a forward-looking approach, or a survey of academics and investment professionals.[229] A CAPM analysis is backward-looking if its market risk premium component is determined based on historical, realized returns.[230] A CAPM analysis is forward-looking if its market risk premium component is based on a DCF study of a large segment of the market.[231] In a forward-looking CAPM analysis, the market risk premium is calculated by subtracting the risk-free rate from the result produced by the DCF study.[232]

109. In this proceeding, the NETOs submitted a forward-looking CAPM study, using 30-year Treasury bonds for the risk-free rate, betas published by Value Line, and a market risk premium based on a DCF study of all S&P 500 companies that were paying dividends. The NETOs' CAPM approach is a generally accepted methodology routinely relied upon by investors and, therefore, one appropriately used to corroborate our own analysis. As discussed below, we reject the arguments that the NETOs' CAPM analysis contains flaws that undermine its usefulness as corroborative evidence, in determining whether the midpoint of the zone of reasonableness produced by the Commission's DCF analysis provides the NETOs a return that satisfies the requirements of *Hope* and *Bluefield*.

110. As an initial matter, we reject EMCOS's argument that the NETOs' CAPM analysis is flawed because it used a DCF study to determine the market risk premium. As

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[227] Roger A. Morin, New Regulatory Finance 150 (Public Utilities Reports, Inc. 2006).

[228] *Id.* at 151.

[229] *Id.* at 155-162.

[230] *Id.* at 155-156.

[231] *Id.* at 159-160.

[232] *See id.* at 150, 155.

explained above, using a DCF study is the standard method of calculating the market risk premium in a forward-looking CAPM analysis.[233] We are, therefore, unpersuaded that the use of a DCF study renders the NETOs' CAPM analysis deficient. We also disagree with Petitioners' argument that the NETOs' CAPM analysis relied on an overly optimistic growth rate input in determining the market risk premium. The growth rate in the NETOs' CAPM analysis is based on IBES data, which the Commission has long relied upon as a reliable source of growth rate data.[234]

111. While Petitioners' assert that the growth rate input is inflated because the NETOs calculated it based on only those S&P 500 companies that were paying dividends, we are not persuaded that the exclusion of those companies not paying dividends skewed the growth rate input. As the NETOs' witness correctly explained during the hearing, a DCF analysis can only be conducted for companies that pay dividends.[235] Accordingly, the proxy group in our DCF analysis consists of companies that pay dividends. Basing a CAPM study on only dividend-paying companies is therefore appropriate in this context, where the Commission is looking to the CAPM study to corroborate the results of a DCF analysis, because doing so produces a growth rate input that is more representative of the DCF proxy group than a CAPM study based on non-dividend-paying companies would be. Further, we are not persuaded by Petitioners' argument that non-dividend-paying companies have lower growth rate estimates than dividend-paying companies, because in many situations the opposite is true due to non-dividend-paying companies decision to retain and reinvest more of their earnings, rather than pay dividends.

112. We are also unpersuaded that the growth rate projection in the NETOs' CAPM study was skewed by the NETOs' reliance on analysts' projections of non-utility companies' medium-term earnings growth, or that the study failed to consider that those analysts' estimates reflect unsustainable short-term stock repurchase programs and are not long-term projections. As explained above, the NETOs based their growth rate input on data from IBES, which the Commission has found to be a reliable source of such data. Thus, the time periods used for the growth rate projections in the NETOs' CAPM study are the time periods over which IBES forecasts earnings growth. Petitioners' arguments against the time period on which the NETOs' CAPM analysis is based are, in effect, arguments that IBES data are insufficient in a CAPM study. We disagree. We acknowledge that CAPM analyses may be based on different time periods; however, without more evidence, i.e., a CAPM analysis based on a longer time period, we are not persuaded that the time period on which the NETOs' based their CAPM analysis

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[233] *See supra* P 108.

[234] *See supra* PP 71-72.

[235] *See* Tr. 740: 3-4.

undermines the relevance of that analysis in corroborating the results of the Commission's DCF analysis.

113. Further, the fact that the Commission's two-step DCF methodology incorporates a long-term growth rate does not necessitate the incorporation of a long-term growth rate in the DCF study the NETOs used to develop the market risk premium for their CAPM analysis. The Commission's rationale for incorporating a long-term growth rate estimate in DCF analyses for public utilities was that it is often unrealistic and unsustainable for high short-term growth rates to continue in perpetuity.[236] Under the CAPM model, the market risk premium is based on the difference between the "required return on the overall market" and the risk-free rate.[237] The required return on the overall market is determined by conducting a DCF study of "a representative market index, such as the Standard & Poor's 500 Index."[238] As noted above, the NETOs developed the market risk premium in their CAPM analysis in exactly this way, by conducting a DCF analysis of the dividend-paying companies in the S&P 500 to determine the required return on the overall market. The rationale for incorporating a long-term growth rate estimate in conducting a two-step DCF analysis of a specific group of utilities does not necessarily apply when conducting a DCF study of the companies in the S&P 500. That is because the S&P 500 is regularly updated to include only companies with high market capitalization. While an individual company cannot be expected to sustain high short-term growth rates in perpetuity, the same cannot be said for a stock index like the S&P 500 that is regularly updated to contain only companies with high market capitalization, and the record in this proceeding does not indicate that the growth rate of the S&P 500 stock index is unsustainable.

114. We also reject EMCOS's argument that the NETOs' CAPM analysis was flawed because it relied on a "risky 30-year bond interest" to calculate the risk-free rate. As noted above, 30-year U.S. Treasury bond yields are a generally accepted proxy for the risk-free rate in a CAPM analysis, and are also considered superior to short- and intermediate-term bonds for this purpose.[239] Therefore, absent record evidence to the

[236] Opinion No. 531, 147 FERC ¶ 61,234 at P 36 n.63 (citing Roger A. Morin, New Regulatory Finance 308 (Public Utilities Reports, Inc. 2006)).

[237] Roger A. Morin, New Regulatory Finance 146 (Public Utilities Reports, Inc. 2006).

[238] *Id.* at 159.

[239] *See* Roger A. Morin, New Regulatory Finance 151-152 (Public Utilities Reports, Inc. 2006) ("the yield on very long-term government bonds, namely, the yield on 30-year Treasury bonds, is the best measure of the risk-free rate for use in the CAPM and Risk Premium methods.").

contrary, we find 30-year Treasury bond yields to be an appropriate basis for the risk-free rate in the NETOs' CAPM analysis.

115. We also disagree with Petitioners' argument that the NETOs' CAPM study does not support placing the NETOs' base ROE above the midpoint because the study relies on betas. Petitioners' assertion is based on a misinterpretation of Commission precedent. While Petitioners correctly state that the Commission in *ITC Holdings* and *Consumers Energy Co.* found that "betas, *in isolation*, [are] unreliable predictors of risk,"[240] Petitioners ignore the qualifier "in isolation," which highlights an important distinction between the CAPM analyses at issue in those cases and the NETOs' CAPM analysis. In both *ITC Holdings* and *Consumers Energy Co.*, the parties submitted CAPM studies that analyzed only the utility whose rates were at issue. As the Commission explained in *Consumers Energy Co.*, "CAPM is more appropriately used for determining the composition of a portfolio of stocks."[241] In the instant proceeding, the NETOs' CAPM study analyzed, as a portfolio, a proxy group of electric utilities. Thus, the NETOs' CAPM study and associated use of betas do not raise the same concerns as did the studies in *ITC Holdings* and *Consumers Energy Co.*

116. We further disagree with EMCOS's argument that the NETOs' CAPM analysis is not forward-looking because it relies on betas. As explained above, whether a CAPM analysis is forward-looking or backward-looking depends on how the market risk premium—not the betas—are calculated.[242] Although it is true that betas are based on historical data, reliance on betas does not render a CAPM analysis backward-looking, as that term is commonly used in the CAPM context. As explained above, a CAPM study is backward-looking if its market risk premium component is determined based on historical, realized returns,[243] and a CAPM study is forward-looking if its market risk premium component is based on a DCF study of a large segment of the market.[244] Unlike the market risk premium component of the CAPM methodology, betas are necessarily

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[240] *ITC Holdings Corp.*, 121 FERC ¶ 61,229 at P 43 (emphasis added); *Consumers Energy Co.*, 85 FERC ¶ 61,100 at 61,362 (emphasis added).

[241] *Consumers Energy Co.*, 85 FERC ¶ 61,100 at 61,362 n.26 (noting Trial Staff's testimony that, according to Value Line, beta should not be used to determine the ROE for a single company).

[242] *See supra* P 108.

[243] Roger A. Morin, New Regulatory Finance 155-156 (Public Utilities Reports, Inc. 2006).

[244] *Id.* at 159-160.

based on historical data, because "[t]he true beta of a security can never be observed."[245] Therefore, we disagree with EMCOS's assertion that the use of betas renders a CAPM analysis backward-looking. We reiterate that a CAPM study is forward-looking, notwithstanding its use of betas, if its market risk premium component is based on an appropriate DCF study.

117. We disagree with Petitioners' argument that the NETOs' CAPM analysis is flawed due to the fact that the NETOs applied a size adjustment to account for the difference in size between the NETOs and the dividend-paying companies in the S&P 500. This type of size adjustment is a generally accepted approach to CAPM analyses,[246] and we are not persuaded that it was inappropriate to use a size adjustment in this case. The purpose of the NETOs' size adjustment is to render the CAPM analysis useful in estimating the cost of equity for companies that are smaller than the companies that were used to determine the market risk premium in the CAPM analysis. While Petitioners assert that the record shows that smaller firms have lower growth,[247] Petitioners' assertion rests on a comparison of companies *within* the S&P 500—all of which have large market capitalization—rather than a comparison of the S&P 500 companies to companies smaller than the S&P 500 companies. While it may be true that larger dividend-paying members of the S&P 500 are growing faster than the smaller dividend-paying members of the S&P 500, this does not indicate how the growth rates of the dividend-paying members of the S&P 500 compare to the NETOs or to other groups of companies with smaller market capitalization (e.g., the companies in either the S&P 400, which consists of companies with mid-capitalization, or the S&P 600, which consists of companies with small capitalization). Further, Petitioners' assertion is contradicted by other record evidence indicating, and supporting the generally accepted principle,[248] that smaller firms are riskier than larger firms, and therefore experience faster growth.[249]

118. Petitioners also argue that the Commission erred in ignoring Complainants' CAPM study, which indicated a 7.5 percent cost of equity, and Trial Staff's CAPM study, which indicated an 8.2 percent cost of equity. However, we find both Complainants' and

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[245] *Id.* at 79.

[246] *Id.* at 187.

[247] Petitioners Request for Rehearing at 41 (citing Ex. SC-514).

[248] Roger A. Morin, New Regulatory Finance 187 (Public Utilities Reports, Inc. 2006).

[249] *See* Ex. NET-300 at 68 (citing *Morningstar*, "Ibbotson SBBI 2012 Valuation Yearbook," at 85).

Trial Staff's CAPM studies to be flawed. Complainants did not determine the market risk premium by using a DCF study to determine the required return on the overall market and then subtracting the risk-free rate from the DCF result, but instead estimated the market risk premium directly, using market risk premium studies. This approach is acceptable, in theory, as it is a valid method of determining market risk premium; however, it is not clear that Complainants executed the approach as a forward-looking analysis. While Complainants' approach is purportedly forward-looking, it is not clear from the record that their estimated market risk premium is, in fact, based on prospective data. Complainants used a market risk premium of 5.00 percent,[250] which appears to be determined using market risk premium data based on a mix of historical, prospective, and survey approaches.[251] While the record is not clear about how Complainants used these three categories of market risk premium studies to determine the market risk premium, if Complainants' market risk premium is based on a compilation of the three categories we do not consider the resulting market risk premium to be forward-looking. Further, even assuming *arguendo* that Complainants relied only on the prospective market risk premium studies, we are not persuaded that their CAPM study is sufficiently representative of the capital market conditions during this proceeding, as—importantly—all but one of the prospective studies listed in Complainants' exhibit pre-date the Great Recession.[252]

119. We find Trial Staff's CAPM analysis also to be flawed. Similar to Complainants' CAPM analysis, Trial Staff did not calculate the market risk premium by conducting a DCF analysis and subtracting the risk-free rate from the result, but by estimating the market risk premium directly. However, Trial Staff did not provide a study to support its estimated market risk premium,[253] and Trial Staff based its CAPM analysis on only 20 companies. Further, those 20 companies are members of the NETOs' proxy group. Because the purpose of the CAPM methodology is to calculate the cost of equity using a risk-return relationship based entirely on market risk,[254] the index of companies used in determining the market risk premium must be large enough to capture the market risk.[255]

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[250] Ex. SC-112 at 1.

[251] *Id.* at 4-6.

[252] *Id.* at 5-6.

[253] *See* Ex. S-1 at 98.

[254] Roger A. Morin, New Regulatory Finance 145-146 (Public Utilities Reports, Inc. 2006).

[255] *Id.* at 159-160.

We do not consider a group of 20 companies, all of comparable risk, sufficiently large or diverse to accurately reflect the risks of the market as a whole, and we are therefore not persuaded that such a group accurately reflects the market risk premium to be used in a CAPM study. In addition, we note that, unlike the NETOs, neither Complainants nor Trial Staff updated their CAPM studies during the hearing; as a result, the CAPM evidence provided by the NETOs represents the most recent CAPM evidence in the record. In sum, for the above reasons, we find Complainants' and Trial Staff's CAPM analyses to be unreliable as corroborative evidence in this proceeding.

f. Expected Earnings Analysis

i. Opinion No. 531

120. In Opinion No. 531, the Commission explained that the NETOs' expected earnings analysis "can be useful in validating" the ROE determination," given the expected earnings analysis's "close relationship to the comparable earnings standard that originated in *Hope*, and the fact that it is used by investors to estimate the ROE that a utility will earn in the future."[256] The Commission found the NETOs' expected earnings analysis "informative,"[257] as it produced a midpoint of 12.1 percent and a median of 10.2 percent, both of which are above the 9.39 percent midpoint produced by the Commission's DCF analysis.[258] The Commission explained that, in relying on the NETOs' expected earnings analysis, "we do not depart from our use of the DCF methodology; rather, we use the record evidence to inform the just and reasonable placement of the ROE within the zone of reasonableness established in the record by the DCF methodology."[259]

ii. Requests for Rehearing

121. Petitioners argue that the NETOs' version of an expected earnings analysis is flawed because it "attempts to forecast returns on *book* equity, rather than investor-required returns on equity purchased at above-book study-period stock prices."[260] Petitioners state that the NETOs' analysis forecasts returns on book equity because the

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[256] Opinion No. 531, 147 FERC ¶ 61,234 at P 147.

[257] *Id.* P 146.

[258] *Id.* P 147.

[259] *Id.* P 146.

[260] Petitioners Request for Rehearing at 43.

analysis turns on the "expected earnings/book equity ratio ("r") in Value Line's five-year forecast."[261] Petitioners contend that the Commission has long rejected setting ROEs "at the rate of return investors expect [the subject utility] to earn on [book] common equity (r), rather than the market cost of common equity (k)."[262] Petitioners assert that the Commission in Opinion No. 531 failed to address this inconsistency between the NETOs' expected earnings analysis and Commission precedent.

122. Petitioners further assert that the Commission's reliance on the NETOs' expected earnings analysis was especially unreasonable in this case because, in adopting the two-step DCF methodology, the Commission discarded the "br+sv" element of the one-step DCF methodology, which placed the "r" input in proper context by factoring it with other components of utility firm growth. Petitioners contend that, although the record contained the necessary data for the NETOs to place their "r" input in the appropriate context, the NETOs' expected earnings analysis ignored that data and instead emphasized "more speculative and optimistic" inputs.[263] Petitioners argue that the Commission in *Kern River Gas Transmission Co.*, Opinion No. 486, 117 FERC ¶ 61,077 (2006) (Opinion No. 486) held that dividends and payout ratios "should be considered in order to account for going-concern utilities' need to reinvest earnings instead of paying them all to shareholders;" however, Petitioners assert that the NETOs' have failed to do so.

123. Petitioners argue that, by relying on forecasted returns on book equity, rather than forecasted returns on the market cost of equity, the NETOs' expected earnings analysis ignores the market/book ratios of the proxy companies, which range from about 1.0 to 2.3.[264] Petitioners assert that, as a result, the NETOs' approach "simply reflects the perpetuation of a high market/book ratio, as was rejected in *Orange & Rockland*."[265] Petitioners also contend that the midpoint of the NETOs' expected earnings analysis is particularly unreliable because it was skewed upwards by Dominion's "unusually high earnings/book equity projection . . . which in turn reflected Dominion's exceptionally high market/book ratio."[266] Petitioners argue that the Commission's precedent on the use of midpoints in a cost of equity study is confined to DCF studies, and should not be used

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[261] *Id.* at 42-43.

[262] *Id.* at 43 (citing *Orange & Rockland*, 44 FERC ¶ 61,253 at 61,952).

[263] *Id.* at 44.

[264] *Id.*

[265] *Id.*

[266] *Id.* at 44-45.

in the context of the NETOs' expected earnings analysis because relying on a midpoint value that is distorted by a high market-to-book ratio would not help reveal the market cost of equity.[267] Petitioners contend that, if the Commission does give weight to the NETOs' expected earnings analysis, the NETOs' analysis "points no higher than its median result, which was 10.2 percent."[268]

124. EMCOS argue that the NETOs' expected earnings analysis fails to recognize the critical link that "when actual or forecasted earnings are considered as a guide to an appropriate ROE allowance, they must be evaluated in conjunction with actual or forecasted stock prices."[269] EMCOS further argue that Opinion No. 531 adopted and relied upon the NETOs' expected earnings analysis without addressing any of the concerns raised by Trial Staff or Complainants. For example, EMCOS note that Trial Staff argued that the NETOs' analysis "inappropriately relies on accounting return results, which are not reflective of the market's required return as indicated by actual equity stock investors."[270] In addition, EMCOS note that the Complainants raised concerns that the NETOs' analysis included several flaws that rendered it unreliable and "overly optimistic."[271] EMCOS argue that failure to address these arguments is the definition of arbitrary and capricious decision-making.[272]

iii. <u>Commission Determination</u>

125. A comparable earnings analysis is a method of calculating the earnings an investor expects to receive on the book value of a particular stock. A comparable earnings analysis can be based either on the stock's historical earnings on book value, as reflected on the company's accounting statements, or on forward-looking estimates of earnings on book value, as reflected in analysts' earnings forecasts for the company. The latter approach is often referred to as an "expected earnings analysis" and is the approach the NETOs used in conducting their comparable earnings analysis in this proceeding. Petitioners' and EMCOS's argue that the NETOs' expected earnings analysis is flawed and does not support the Commission's decision to place the NETOs' base ROE above

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[267] *Id.* at 45.

[268] *Id.* at 42.

[269] EMCOS Request for Rehearing at 24 (citing Ex. No. EMC-3 at 8:15-18).

[270] *Id.* at 24-25 (citing Trial Staff Initial Brief at 60).

[271] *Id.* (citing Complainants Initial Brief at 62).

[272] *Id.* at 25 (citing *Ill. Pub. Telecomm. Ass'n v. FCC*, 117 F.3d at 564).

the midpoint of the zone of reasonableness produced by the Commission's DCF analysis. We disagree.

126. The NETOs conducted their expected earnings analysis by using the return on book equity that *Value Line* forecasted for the national group of companies that *Value Line* lists as Electric Utilities. The NETOs then multiplied each of those forecasted returns by an adjustment factor to determine each utility's average return, rather than its year-end return, explaining that using the year-end return would understate actual returns because of growth in common equity over the year.[273] We consider the NETOs' expected earnings analysis to be sound, as it is forward-looking, based on a reliable source of earnings data, and appropriately converts the proxy companies' earnings to reflect average returns.[274]

127. While Petitioners correctly state that the Commission in *Orange & Rockland* rejected a proposal that "would, in effect, set the allowed rate of return on common equity at the rate of return investors expect [the utility] to earn on common equity (r), rather than the market cost of common equity (k)," that precedent is inapposite to this case for two reasons. First, *Orange & Rockland* did not involve a comparable earnings analysis; it involved a proposal to alter the DCF model by adjusting the dividend yield to reflect the expected earnings of the company whose rates were at issue, i.e., Orange & Rockland. Specifically, Orange & Rockland proposed to calculate the dividend yield in its DCF study by dividing dividend payments by book value, instead of by a current stock price. By comparison, the NETOs have not proposed to alter the DCF model to reflect expected earnings, but rather submitted an expected earnings study based on a national proxy group of utilities whose risk profiles are comparable to the NETOs.

128. Second, *Orange & Rockland* is inapposite because the Commission in that case rejected a proposal that would have had the effect of *setting* Orange & Rockland's base ROE at Orange & Rockland's own expected return on book equity. In the instant case, the Commission did not *set* the NETOs' base ROE at their own expected return on book equity or endorse an ROE analysis that would have that effect. Rather, the Commission in Opinion No. 531 used the DCF methodology to determine the NETOs' market cost of equity, and found that the NETOs' expected earnings analysis of a national proxy group was used to determine—and only relevant to—whether the midpoint of the DCF-determined zone of reasonableness provided a market cost of equity sufficient to meet the

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[273] *See* Ex. NET-300 at 73, 32.

[274] *See, e.g.*, *S. Cal. Edison Co.*, 92 FERC ¶ 61,070 at 61,263 (finding it necessary to adjust Value Line's forecasted returns on book equity to reflect average returns rather than year-end returns); *see also* Roger A. Morin, New Regulatory Finance 305-306 (Public Utilities Reports, Inc. 2006).

requirements of *Hope* and *Bluefield*. The returns on book equity that investors expect to receive from a group of companies with risks comparable to those of a particular utility are relevant to determining that utility's market cost of equity, because those returns on book equity help investors determine the opportunity cost of investing in that particular utility instead of other companies of comparable risk. Such a calculation is consistent with the requirement in *Hope* that "the return to the equity owner should be commensurate with returns on investments in other enterprises having corresponding risks."[275] As the NETOs' expert witness explained at trial, investors compare each investment alternative with the next best opportunity. If the utility is unable to offer a return similar to that available from other opportunities of comparable risk, investors will become unwilling to supply the capital on reasonable terms.[276]

129. Investors rely on both the market cost of equity and the book return on equity in determining whether to invest in a utility, because investors are concerned with both the return the regulator will allow the utility to earn *and* the company's ability to actually earn that return.[277] If, all else being equal, the regulator sets a utility's ROE so that the utility does not have the opportunity to earn a return on its book value comparable to the amount that investors expect that other utilities of comparable risk will earn on their book equity, the utility will not be able to provide investors the return they require to invest in that utility.[278] Thus, all else being equal, an investor is more likely to invest in a utility that it expects will have the opportunity to earn a comparable amount on its book equity as other enterprises of comparable risk are expected to earn. Because investors rely on expected earnings analyses to help estimate the opportunity cost of investing in a particular utility, we find this type of analysis useful in corroborating whether the results produced by the DCF model may have been skewed by the anomalous capital market conditions reflected in the record.

130. We also reject Petitioners' argument that it was unreasonable for the Commission to rely on the NETOs' expected earnings analysis without also considering the "br+sv" formula in the Commission's DCF analysis. Whether "r" is directly used in the Commission's calculation of the short-term growth rate in the DCF methodology does not bear on the validity of the NETOs' expected earnings analysis or on its relevance in

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[275] *Hope*, 320 U.S. at 603; *see also Petal Gas Storage, L.L.C.*, 496 F.3d 695 (D.C. Cir. 2007).

[276] Ex. No. NET-300 at 71.

[277] *See* Tr. 637:6-12.

[278] As the NETOs' witness testified, returns on book value are analogous to the allowed return on a utility's rate base. *Id.*

corroborating the results of the Commission's DCF analysis.[279] As explained below, the expected earnings analysis and DCF analysis are used to estimate two different types of returns, each valid in its own right, that investors rely upon in determining whether to invest in a particular company.[280]

131. As to the argument that the midpoint of the NETOs' expected earnings analysis is skewed upwards by the results of one company, i.e., Dominion, Petitioners conclusory statements that Dominion's expected earnings are "unusually high" and that Dominion's market-to-book ratio is "exceptionally high" are insufficient to show that Dominion's results skewed the NETOs' analysis. Petitioners state that Dominion has a market-to-book ratio of 2.255, that this value skewed the result of the NETOs' expected earnings analysis, and that there is no evidence that the NETOs have market-to-book ratios comparable to Dominion's.[281] However, Petitioners have provided no evidence demonstrating that Dominion's 2.255 market-to-book ratio is "exceptionally high," and there is no evidence that the NETOs' market-to-book ratios are not comparable to those of the proxy group companies. Lastly, even assuming *arguendo* that it would be more appropriate to eliminate Dominion or to use the median, rather than the midpoint, of the NETOs' expected earnings analysis, the result would be 11.2 percent or 10.2 percent, respectively. Both of these results are above the 9.39 percent midpoint of the DCF-produced zone of reasonableness and, therefore, corroborate the Commission's decision to place the NETOs' base ROE above the 9.39 percent midpoint.

132. While Petitioners and EMCOS[282] assert that the NETOs' expected earnings study ignores the proxy companies' market-to-book ratios, considering market-to-book ratios in an expected earnings study is inconsistent with the purpose of the comparable earnings model. The comparable earnings model is intended to estimate the return on book equity

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[279] We also reject Petitioners' assertion that Opinion No. 486 is relevant to the validity of the NETOs' expected earnings analysis. The language from Opinion No. 486 to which Complainants cite does not involve an expected earnings analysis; rather it concerns whether it is appropriate to base the dividend yield in a DCF analysis of a master limited partnership on its earnings, rather than on dividend payments in excess of earnings. *See* Opinion No. 486, 117 FERC ¶ 61,077 at P 153.

[280] *See infra* P 132.

[281] Petitioners Request for Rehearing at 44-45.

[282] EMCOS argue that the NETOs' expected earnings analysis is flawed because it does not evaluate forecasted earnings in conjunction with forecasted stock prices. This is merely another way of saying that the NETOs' expected earnings analysis failed to consider market-to-book ratios.

that investors expect the *utility* will earn; the market cost of equity, by comparison, is the estimated return to *investors* that an investor requires to invest in the utility. Petitioners and EMCOS seek to adjust the estimated return on book equity produced by the NETOs' expected earnings analysis into the market cost of equity, by applying a market-to-book adjustment. However, as noted above, the return on book equity is relied upon by investors to determine the opportunity cost of investing in a particular company, and investors rely upon expected earnings analysis for this purpose without attempting to convert that opportunity cost into the market cost of equity. We, therefore, find the NETOs' expected earnings analysis reliable as corroborative evidence in this proceeding, notwithstanding the lack of a market-to-book adjustment in that analysis. Further, even assuming *arguendo* that a market-to-book adjustment was appropriate, we are not persuaded that Petitioners' approach of simply dividing a utility's book return on equity by its market-to-book ratio would accurately estimate the utility's market cost of equity. We also disagree with EMCOS's argument that the NETOs' expected earnings analysis relies on accounting return results, and is therefore not corroborative of the market cost of equity. As noted above, the NETOs' expected earnings analysis is based on forecasted earnings, not historical returns reflected on accounting statements.

3. Impact of the DCF Methodology Change on Existing ROE Transmission Incentive Adders

a. Opinion No. 531

133. Opinion No. 531 explained that, "[b]ased on the Commission's policy that the total ROE including any incentive ROE is limited to the zone of reasonableness, the Commission has found in the past that an incentive ROE may not be implemented in full by the utility if the total ROE exceeds the zone of reasonableness."[283] The Commission found that "[n]othing in [Opinion No. 531] changes this Commission policy,"[284] and, therefore, "when a public utility's ROE is changed, either under section 205 or section 206 of the FPA, that utility's total ROE, inclusive of transmission incentive ROE adders, should not exceed the top of the zone of reasonableness produced by the two-step DCF methodology."[285]

[283] Opinion No. 531, 147 FERC ¶ 61,234 at P 164.

[284] *Id.*

[285] *Id.* P 165.

b. Request for Rehearing

134. The NETOs request that the Commission clarify that adjustments to the NETOs' ROE incentive adders are outside the scope of this proceeding.[286] The NETOs state that the base ROE was the sole matter set for hearing, no party submitted evidence relating to incentive adders, and the issue was not discussed in the Initial Decision.[287] The NETOs assert that Opinion No. 531 does not state with specificity that the NETOs' total ROE must not exceed the top of the zone of reasonableness, and the NETOs interpret the Commission's language concerning capping the total ROE as a statement of a general ratemaking principle.[288]

135. If the Commission did intend to require the NETOs to reduce the total ROE to the top of the zone of reasonableness, the NETOs request rehearing of that decision. The NETOs state that the "ROE incentive adders were approved based upon a detailed record of the benefits and risks of the relevant projects and the nexus between the incentive adders and the projects, which included consideration of the ability of the incentive to facilitate construction of the project."[289] The NETOs state that, when the adders were approved, they were below the top end of the then-current zone of reasonableness. The NETOs argue that the Commission placed no conditions on the adders' continued effectiveness, and that the adders do not automatically change when the Commission determines a new zone of reasonableness.[290]

136. The NETOs state that the base ROE was the only matter at issue in this case, and that incentive adders were explicitly excluded by the complaint.[291] The NETOs argue that modifying the incentive adders in this proceeding would violate the Constitution's Due Process Clause and the Administrative Procedure Act.[292] The NETOs state that, in a similar case, the Commission granted an ROE adder without notice to the parties that the issue would be decided during the hearing and the D.C. Circuit found that the

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[286] NETOs Request for Rehearing at 6-7.

[287] *Id.* at 7-8.

[288] *Id.* at 8-9.

[289] *Id.* at 11-12.

[290] *Id.* at 13.

[291] *Id.* at 14-15.

[292] *Id.* at 15-16.

Commission had violated the parties' due process rights.[293] The NETOs state that, in each of the cases that the Commission cited in Opinion No. 531, the ROE incentive adders were implicated prior to the hearing, thus providing the parties with notice and the opportunity to submit evidence on the incentive adders. The NETOs assert that, assuming the Hearing Order had addressed incentive adders, the Commission erred in ruling that the adders must be reduced without accepting evidence on the issue.[294]

137. The NETOs request that the Commission clarify that the term "total ROE" refers to the total transmission assets of a utility rather than project-specific ROEs.[295] The NETOs argue that as long as the ultimate rate charged to consumers is just and reasonable, FPA section 219 is satisfied and the Commission has no basis to look at project-specific ROEs to determine whether they are below the top of the zone of reasonableness.[296]

138. The NETOs argue that, if the term "total ROE" includes incentive ROEs, Opinion No. 531 should be reversed as inconsistent with statutory requirements and Commission precedent. The NETOs state that in Order No. 679 the Commission stated that the test for reviewing a rate is whether the end result is reasonable.[297] The NETOs argue that such an evaluation necessarily involves review of the overall rate inclusive of all components, not merely a review of one component such as an individual project's incentive ROE.[298]

c. Commission Determination

139. We deny rehearing on this issue. As an initial matter, it is worth noting that Opinion No. 531 does not change the incentive ROE adders that the Commission previously granted to the NETOs. Rather, Opinion No. 531 follows Commission policy that a utility's ROE, even if it includes an incentive ROE adder, would be capped at the

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[293] *Id.* at 17-18 (citing *PSC of Kentucky*, 397 F.3d at 1011-12).

[294] *Id.* at 18-20.

[295] *Id.* at 20-22.

[296] *Id.* at 22-23.

[297] *Id.* at 23-24.

[298] *Id.* at 24-26 (citing *Northeast Utils. Serv. Co.*, 52 FERC ¶ 61,097 (1990), *reh'g denied*, 52 FERC ¶ 61,336; *Florida Power & Light Co.*, 24 FERC ¶ 61,171, at 61,408 (1983); *Florida Power & Light Co.*, 32 FERC ¶ 61,059 at 61,162 (1985)).

upper end of the transmission owner's DCF-determined zone of reasonableness. For example, in Order No. 679, the Commission made clear that the total ROE including any incentive ROE adder sought by an applicant must be within the utility's DCF-determined zone of reasonableness.[299] In the orders in which the Commission granted the NETOs' incentive ROE adders, the Commission also made clear that the total ROE including such adders would be capped at the high end of the NETOs' zone of reasonableness.[300] The fact that a transmission owner may not be able to implement in full its awarded incentive ROE adder because the resulting total ROE would exceed the high end of the transmission owner's zone of reasonableness is nothing new.[301] In addition, the

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[299] *Promoting Transmission Investment through Pricing Reform*, Order No. 679, FERC Stats. & Regs. ¶ 31,222, at PP 2, 93 (2006), *order on reh'g*, Order No. 679-A, FERC Stats. & Regs. ¶ 31,236, *order on reh'g*, 119 FERC ¶ 61,062 (2007); *Pac. Gas & Elec. Co.*, 141 FERC ¶ 61,168, at P 26 (2012); *see also Town of Norwood, Mass. v. FERC*, 80 F.3d at 534-535 (supporting the principle that ROE should be cabined within the bounds of the zone of reasonableness, by reversing a Commission decision to set ROE at the bottom of the zone of reasonableness that was established in the utility's prior rate case and explaining that the Commission cannot rely on a zone of reasonableness established in a prior rate case if the utility's circumstances have since changed); 16 U.S.C. § 824s(d) (2012) ("All rates approved under the rules adopted pursuant to [FPA section 219] . . . are subject to the requirements of sections [205 and 206] of this title that all rates . . . be just and reasonable."); Order No. 679-A, FERC Stats. & Regs. ¶ 61,236 at P 15 (cross-referenced at 117 FERC ¶ 61,345 at P 15) (indicating that the Commission will keep any incentive ROE adder within the zone of reasonableness as a means to ensure the Commission comply with its regulatory responsibilities under the FPA). The courts have also recognized that utilities cannot charge rates that exceed the DCF-determined zone of reasonableness. *See, e.g.*, *Union Elec. Co. v. FERC*, 890 F.2d 1193, 1204 (D.C. Cir. 1989).

[300] *See, e.g.*, *Ne. Utils. Serv. Co.*, 124 FERC ¶ 61,044 at P 83.

[301] *See, e.g.*, *NSTAR Elec. Co.*, 125 FERC ¶ 61,313 at PP 81-87 (granting a New England transmission owner an incentive ROE adder, to be bound by the upper end of the zone of reasonableness previously established for the New England transmission owners; and determining, based on an updated DCF analysis, that the overall ROE including the incentive ROE adders remained within the zone of reasonableness); *accord Me. Pub. Utils. Comm'n v. FERC*, 454 F.3d at 288-89 (affirming the Commission's decision to grant transmission owners that join ISO New England a 50 basis point incentive ROE adder for RTO participation, and the Commission's decision to cap the overall ROE at the top of the zone of reasonableness); *Proposed Pricing Policy for Efficient Operation and Expansion of Transmission Grid*, 102 FERC ¶ 61,032, at P 37 (2003) (noting that, in implementing ROE-based incentives, including the RTO

(continued…)

Commission has summarily applied this policy in rate cases initiated after an ROE adder was approved. For example, in establishing a hearing on a section 205 rate filing by Pacific Gas and Electric Co. (PG&E), the Commission held that a 200 basis point adder originally granted to PG&E ten years earlier[302] and a 50 basis point ROE adder for RTO participation granted two years earlier[303] would be limited to within the new zone of reasonableness determined at the hearing.[304] Thus, whether the merits of a utility's incentive ROE adders are implicated by a proceeding is a much different issue than whether the utility can fully implement its incentive ROE adders due to changes in the zone of reasonableness for that utility. This proceeding involves only the latter of these two issues; it does not involve the merits of the NETOs' existing incentive ROE adders.

140. Contrary to the NETOs' assertion, the Commission's ruling in Opinion No. 531 on this issue was not merely a general statement of ratemaking principle, it was a continuation of a Commission policy that the NETOs' total ROE cannot exceed the zone of reasonableness calculated in this proceeding.[305]

141. The NETOs argue that the precedent cited by Opinion No. 531 concerning ROE incentive adders, such as *PG&E*, is distinguishable from the instant proceeding because in the incentives cases the incentives were implicated before the hearing, and the parties therefore had notice and opportunity to submit evidence on the issue. We disagree. In the cases cited by Opinion No. 531, the Commission did not set for hearing the issue of whether an existing incentive adder should be reduced to no higher than the top of the

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participation adder, those incentives would be subject to a cap on the overall ROE equal to the top of the range of reasonable ROEs for a proxy group).

[302] *See Western Area Power Admin.*, 100 FERC ¶ 61,331, at PP 12-13 (2002).

[303] *Pac. Gas & Elec. Co.*, 132 FERC ¶ 61,272, at P 23 (2010).

[304] *PG&E*, 141 FERC ¶ 61,168 at P 26 (continuing to grant a 200 basis point ROE adder for the PATH 15 upgrade project, granted prior to Order No. 679, and a 50 basis point adder for RTO participation, granted subsequent to Order No. 679, and in doing so "remind[ing] PG&E that any ROE adder is limited to within the range of reasonableness of the ROE.").

[305] This is reaffirmed by the Commission's determination in Opinion No. 531-A, the order on the paper hearing that the Commission established in Opinion No. 531, in which the Commission found that the zone of reasonableness produced by the DCF methodology in this proceeding is 7.03 percent to 11.74 percent and, therefore, that "the NETOs' total or maximum ROE, including transmission incentive ROE adders, cannot exceed 11.74 percent." Opinion No. 531-A, 149 FERC ¶ 61,032 at P 11.

new zone of reasonableness. Rather, the Commission summarily ruled on that issue before the hearing. Because the Commission has an established policy that incentive adders must be within the zone of reasonableness in order to comply with section 219(a) of the FPA, the issue of whether to reduce an incentive adder that would otherwise exceed the top of the zone of reasonableness does not present any issue of material fact that would be appropriate for consideration in a hearing.

142. In any event, the NETOs' did in fact have notice and opportunity to present argument on the issue of their total ROE. Because it is well established both that a proceeding to determine a utility's base ROE involves a determination of the utility's zone of reasonableness under the DCF methodology, and that a transmission owner's awarded incentive ROE adder could not exceed the high end of the zone of reasonableness, the NETOs had notice to present evidence regarding the zone and thus the ultimate just and reasonable total ROE.

143. We disagree with the NETOs' argument that *PSC of Kentucky*, 397 F.3d 1004, is relevant to this issue. That case involved the Commission's post-hearing decision to grant an incentive ROE that the Commission, in setting the case for hearing, explicitly declined to grant and stated would not be at issue in the proceeding. Those facts are distinguishable from the facts here.

144. In *PSC of Kentucky*, the court found that the Commission violated the parties' due process rights because the Commission, having initially determined that it would not grant an incentive ROE adder, at the end of the proceeding granted the incentive ROE adder, and thus failed to place the parties on notice at the outset that, post-hearing, its order might grant the incentive ROE adder.[306] The court explained that, while the Commission considered the petitioners' arguments regarding the incentive ROE adder on rehearing, the Commission did not allow them to present evidence at hearing on the relevant factual issue, i.e., the need for, or appropriate size of, the incentive ROE adder.[307] In contrast, here the parties had both opportunities to make their case. The NETOs had notice of the Commission's already-well-established policy that a utility's total ROE must remain within the zone of reasonableness identified by the DCF analysis, and the NETOs had the opportunity to submit—and did, in fact, submit—evidence at hearing on the relevant factual issue, i.e., the zone of reasonableness identified by the

[306] *PSC of Kentucky*, 397 F.3d at 1012.

[307] *Id.*

DCF analysis. Further, they also have had the opportunity to raise their arguments concerning this issue on rehearing.[308]

145. The NETOs assert that the Commission's use of the term "total ROE" in Opinion No. 531 may be read to refer only to "the overall ROE of the utility (inclusive of all transmission assets), rather than project-specific ROEs," because the Commission did not "address the meaning of 'total ROE' in the context of a multiple-asset utility."[309] Contrary to the NETOs' assertion, Opinion No. 531 did address the meaning of the term "total ROE" both in the context of ROEs that apply to specific projects[310] and in the context of ROEs that apply to multiple utility assets.[311] To be clear, the term "total ROE" applies to, and has identical meaning in, both contexts. Requests for incentive ROE adders are typically presented to the Commission in one of three ways: (1) a request for incentive ROE adders that apply to all of a utility's transmission assets;[312] (2) a request for incentive ROE adders that apply only to specific transmission projects;[313] or (3) a request for a combination of incentive ROE adders, some of which apply to all of the utility's transmission assets and some of which apply only to specific transmission projects.[314] In each type of incentive ROE case, the Commission has explained that the total ROE, i.e., the base ROE plus any incentive adders, for the transmission assets to which the adder applies is capped at the top of the zone of reasonableness.[315] In other

[308] *See, e.g.*, *State of Cal. ex rel. Lockyer v. FERC*, 329 F.3d 700, 711 (2003) ("the Commission provided all the procedural protections required by the Fifth Amendment and FPA when it carefully considered all the evidence and arguments that the petitioners offered in their petitions for rehearing and motions to intervene."); *see also ANR Pipeline Co. and TC Offshore LLC*, 143 FERC ¶ 61,225, at PP 57, 60 (2013).

[309] NETOs Request for Rehearing at 20-21.

[310] Opinion No. 531, 147 FERC ¶ 61,234 at P 164 (citing *Trans Bay Cable LLC*, 145 FERC ¶ 61,151 (2013), and *Atlantic Path 15, LLC*, 135 FERC ¶ 61,037 (2011)).

[311] *Id.* (citing *PG&E*, 141 FERC ¶ 61,168).

[312] *See, e.g.*, *Oklahoma Gas & Elec. Co.*, 122 FERC ¶ 61,071 (2008).

[313] *See, e.g.*, *NSTAR Elec. Co.*, 125 FERC ¶ 61,313; *see also RITELine Illinois, LLC & RITELine Indiana, LLC*, 137 FERC ¶ 61,039 (2011).

[314] *See, e.g.*, *PG&E*, 141 FERC ¶ 61,168.

[315] *See, e.g.*, *Oklahoma Gas & Elec. Co.*, 122 FERC ¶ 61,071 at P 36 n.26; *NSTAR Elec. Co.*, 125 FERC ¶ 61,313 at P 81; *PG&E*, 141 FERC ¶ 61,168 at P 26.

words, incentive ROE adders are capped by the top of the DCF-determined zone of reasonableness, regardless of the particular incentive ROE adder authorized or the transmission assets to which it applies. This is appropriate because all incentives ultimately must be evaluated according to the same methodology, i.e., they must be evaluated against a zone of reasonableness above which the record does not support the total ROE including any incentive ROE adders as just and reasonable.

146. We also reject the NETOs' argument that FPA section 219 is satisfied, and the Commission has no basis to change a project-specific ROE, as long as the utility's ultimate rate is just and reasonable. This argument is inconsistent with the Commission's precedent on project-specific ROE incentives, in which the Commission has held that the utility's total ROE for the project cannot exceed the zone of reasonableness.[316] In addition, the practical effect of the NETOs' argument—"even if an incentive ROE for a particular project exceeds a utility's zone of reasonableness, so long as the entire utility's ROE (inclusive of all transmission assets) falls within the utility's zone of reasonableness, no change would be needed to the project-specific incentive ROE"—appears to result in incentive ROE adders applying to facilities to which the Commission has not granted the adders. An incentive ROE adder may not serve to increase the ROE for a transmission asset that has not been granted an incentive. Lastly, we disagree with the NETOs that *Northeast Utilities Service Co.*, 52 FERC ¶ 61,097 (1990), *Florida Power & Light Co.*, 24 FERC ¶ 61,171 (1983), and *Florida Power & Light Co.*, 32 FERC ¶ 61,059 (1985), support allowing project-specific ROEs above the zone of reasonableness. Those cases did not involve an analysis of the utilities' ROE relative to the zone of reasonableness produced by a DCF methodology; rather, those cases involved analyses of the equity returns at issue relative to either the utilities' costs[317] or to other rate designs that the utility could have used.[318]

4. Establishment of a Just and Reasonable Rate

a. Opinion No. 531

147. The Commission in Opinion No. 531 did not establish the NETOs' just and reasonable ROE. As the Commission explained, the "finding concerning the specific numerical just and reasonable ROE for the NETOs is subject to the outcome of the paper

[316] *See, e.g.*, *Pepco Holdings, Inc.*, 125 FERC ¶ 61,130, at PP 75-79, 91-94 (2008).

[317] *See Florida Power & Light*, 24 FERC ¶ 61,171 at 61,408; *Florida Power & Light Co.*, 32 FERC ¶ 61,059 at 61,162.

[318] *See Northeast Utils. Serv. Co.*, 52 FERC ¶ 61,097 at 61,485-486.

hearing on the appropriate long-term growth projection to be used in the two-step DCF methodology."[319]

b. Requests for Rehearing

148. EMCOS requests that the Commission clarify that it intended for Opinion No. 531 to establish 10.57 percent as the prospective base ROE in effect from the date of issuance of Opinion No. 531, pending the outcome of the paper hearing on the long-term growth rate for use in the two-step DCF methodology. Similarly, Petitioners argue that the Commission erred by not directing the NETOs to prospectively reduce their rates as of June 19, 2014, based on the tentative findings in Opinion No. 531.[320] Petitioners also argue that it was arbitrary and inconsistent with the section 206 "bond of protection" for the Commission to rely on the 4.39 percent long-term growth rate for purposes of excluding PSEG, while not relying on a 4.39 percent second-step growth rate for purposes of setting an interim or final ROE to be observed.[321]

149. Petitioners assert that the paper hearing is unlikely to materially alter the conclusions reached in Opinion No. 531 and that any refinement of the NETOs' ROE could be implemented as a refund or surcharge against the 10.57 percent base ROE. Petitioners argue that FPA section 206 requires the Commission to fix the rate to be observed as of the date of Opinion No. 531.[322] Petitioners further argue that courts have found that the Commission has "fixed" a rate when parties are in a position to supply their own inputs to a formula and thereby know the numerical rates. Petitioners contend that Opinion No. 531 provides such a formula by supplying a 10.57 percent base ROE and an 11.74 percent maximum ROE.[323]

150. Petitioners argue that implementing interim rates is required by the Commission's obligation to "act as speedily as possible" on FPA section 206 complaints.[324] Petitioners

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[319] Opinion No. 531, 147 FERC ¶ 61,234 at P 152.

[320] Petitioners Request for Rehearing at 66 (citing *New England Power Generators Association v. ISO New England Inc.*, 146 FERC ¶ 61,038, at P 26 (2014); *Georgia Power Co.*, 57 FERC ¶ 61,353 (1991)).

[321] *Id.* at 61-62.

[322] *Id.* at 69-70.

[323] *Id.* at 70-71.

[324] *Id.* at 71 (quoting 16 U.S.C. § 824e(b)).

state that, as an alternative to making the NETOs' new ROE prospectively effective as of June 19, 2014, the Commission could direct the NETOs to use the final ROE in its true-up calculation for the 2014 rate year.[325] Petitioners note that if the Commission uses this alternative method, the Commission must issue its order on the paper hearing before July 31, 2015 to ensure that the true-up filing is implemented with the correct ROE.[326]

c. **Commission Determination**

151. We deny Petitioners' and EMCOS's requests to prospectively establish the NETOs' replacement rate as of June 19, 2014.[327] FPA section 206 requires that "[w]henever the Commission, after a hearing held upon its own motion or upon complaint, shall find that any rate . . . is unjust, unreasonable, unduly discriminatory or preferential, the Commission shall determine the just and reasonable rate . . . to be thereafter observed and in force, and shall fix the same by order."[328] As the Commission explained in Opinion No. 531, however, its findings regarding the justness and reasonableness of the NETOs' rates were "tentative because [they were] subject to the submission of the record evidence at the paper hearing . . . as to the appropriate long-term growth rate."[329] While the appropriate long-term growth rate itself was a narrow issue, that input had the potential to materially affect the NETOs' ROE by altering the DCF results of the companies in the proxy group.[330] As a result, the Commission could not satisfy the requirement of FPA section 206 that it "fix" the just and reasonable rate to be in effect prospectively until after the paper hearing established by Opinion No. 531. Only

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[325] *Id.* at 72 (citing *South Carolina Elec. & Gas Co.*, 132 FERC ¶ 61,043 (2010)).

[326] *Id.* at 74.

[327] The Commission established the just and reasonable ROE for the NETOs on October 16, 2014, in Opinion No. 531-A. *See* Opinion No. 531-A, 149 FERC ¶ 61,032 at PP 10-12.

[328] 16 U.S.C. § 824e (2012).

[329] Opinion No. 531, 147 FERC ¶ 61,234 at P 142.

[330] We reject Petitioners' assertion that it was inconsistent for the Commission to rely on the 4.39 percent GDP growth rate in eliminating PSEG from the proxy group as a low-end outlier and not rely on that GDP growth rate to establish a just and reasonable rate in Opinion No. 531. If the paper hearing had modified the 4.39 percent GDP growth rate, the Commission could have been required to reconsider its low-end outlier ruling based on the revised DCF results. However, the paper hearing did not change the 4.39 percent GDP growth rate and, therefore, no such reconsideration was required.

with the issuance of Opinion No. 531-A, on October 16, 2014, did the Commission establish the prospective just and reasonable rate.[331]

152. We similarly disagree with Petitioners that the Commission fixed the just and reasonable rate in Opinion No. 531 by providing a formula by which the parties could supply their own inputs and know the numerical rate. The Commission in Opinion No. 531 provided no such formula. Further, even assuming *arguendo* that the Commission's analysis could be characterized as a formula, a key input—the long-term growth rate—was unsettled pending the outcome of the paper hearing. Lastly, we reject Petitioners' request that we direct the NETOs to include the ROE established in this proceeding in their true-up calculation for the 2014 rate year. When the NETOs make the annual Regional Network Service true-up filing in 2015 to update the formula rates to reflect calendar year 2014 actual data, consistent with the requirements of the Regional Network Service formula, the filing should reflect the relevant ROEs in effect for any month within the 2014 time period. As mentioned above, the prospective effective date for the ROE determined in this proceeding is October 16, 2014, the issuance date of Opinion No. 531-A. Accordingly, Petitioners' alternative request to direct the NETOs to include the ROE determined in this proceeding for the entire 2014 calendar year is inconsistent with the effective date established in Opinion 531-A. We note that there are other complaints involving the NETOs' ROEs pending before the Commission in Docket Nos. EL13-33 and EL14-86 that may affect the ROE ultimately charged under the Regional Network Service formula for other months in 2014; however, any changes to the formula as a result of those complaints will not be effective until the Commission issues final orders in those proceedings.

<u>The Commission orders</u>:

(A) Petitioners', EMCOS's, and the NETOs' requests for rehearing of Opinion No. 531 are hereby denied, as discussed in the body of this order.

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[331] *See* Opinion No. 531-A, 149 FERC ¶ 61,032. The Commission in Opinion No. 531-A also directed the NETOs to issue refunds for the 15-month refund period in this proceeding, i.e., from October 1, 2011 through December 31, 2012.

(B) The NETOs' request for rehearing of Opinion No. 531-A is hereby denied, as discussed in the body of this order.

By the Commission. Commissioner Honorable is concurring with a separate statement attached.

(S E A L)

Kimberly D. Bose,
Secretary.

UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

Martha Coakley, Massachusetts Attorney General; Connecticut Public Utilities Regulatory Authority; Massachusetts Department of Public Utilities; New Hampshire Public Utilities Commission; Connecticut Office of Consumer Counsel; Maine Office of the Public Advocate; George Jepsen, Connecticut Attorney General; New Hampshire Office of Consumer Advocate; Rhode Island Division of Public Utilities and Carriers; Vermont Department of Public Service; Massachusetts Municipal Wholesale Electric Company; Associated Industries of Massachusetts; The Energy Consortium; Power Options, Inc.; and the Industrial Energy Consumer Group

Docket Nos. EL11-66-002
EL11-66-003

v.

Bangor Hydro-Electric Company; Central Maine Power Company; New England Power Company d/b/a National Grid; New Hampshire Transmission LLC d/b/a NextEra; NSTAR Electric and Gas Corporation; Northeast Utilities Service Company; The United Illuminating Company; Unitil Energy Systems, Inc. and Fitchburg Gas and Electric Light Company; Vermont Transco, LLC

(Issued March 3, 2015)

HONORABLE, Commissioner, *concurring*:

In denying the requests for rehearing, the Commission sets forth a cogent defense of Opinion No. 531 and duly considers and adequately addresses the arguments of the petitioners in the numerous requests for rehearing. Additionally, it is within the Commission's discretion to alter the DCF methodology for determining the just and reasonable rates of return for the NETOs.

I write separately to emphasize two important points to ensure that they are not lost in the shift in the DCF methodology and the placement of the base ROE above the central tendency of the zone of reasonableness. These points relate to: (1) the determination of the just and reasonable rate; and (2) the anomalous market conditions that prompted the consideration of alternative methodologies which ultimately led to the placement of the base ROE halfway between the midpoint and the top of the zone of reasonableness.

The just and reasonable rate of return for a public utility necessarily must consider *both* the protection of the consumer and the capital attraction standards set forth in *Hope* and *Bluefield*. The Commission appropriately relies upon the landmark *Hope* and *Bluefield* decisions to make the point that the allowed return should be adequate to enable it to secure the funding necessary for the proper discharge of its public duties. The duty to ensure the NETOs' ability to attract capital prompted consideration of additional record evidence and led to the use of alternative methodologies as benchmarks against which the DCF results were measured. However, while the Commission in Opinion No. 531 tacitly recognizes that a just and reasonable rate protects consumers, it does not emphasize consumer protection as forcefully as it could have. The primary purpose of the authority granted to the Commission to ensure a just and reasonable rate is to protect the consumer.[1] Indeed, the *Hope* decision, relied upon by this Commission to articulate the just and reasonable standard, explicitly provides that the Commission must balance both "investor and consumer interests."[2] In finding that balance, the Commission dedicates significant effort to ensuring that the NETOs are able to attract sufficient capital. While capital attraction is essential, Opinion No. 531 should not be interpreted as tipping the scale in favor of investor interests. As intended by Congress and confirmed by the Courts, consumer protection is in the DNA of FERC's ratemaking authority. Opinion No. 531 does not, and cannot, change that fact.

Keeping in mind the delicate balance that the Commission must strike when weighing investor and consumer interests, it is important to note that the finding of "anomalous market conditions" in Opinion No. 531 did not create a bright line test nor did it create a presumption that market conditions will be found to be anomalous going forward. The anomalous, or unusual, market conditions that were found in the original order to justify the placement of the base ROE above the central tendency of the zone of

[1] *See, e.g., Morgan Stanley Capital Grp. Inc. v. Pub. Util. Dist. No. 1 of Snohomish Cnty., Wash.*, 554 U.S. 527, 564 (2008) ("Congress enacted the FPA precisely because it concluded that regulation was necessary to protect consumers from deficient markets.").

[2] *FPC v. Hope Natural Gas Co.*, 320 U.S. 591, 603 (1944).

reasonableness were, by definition, atypical. Any public utility that seeks to rely upon anomalous market conditions to justify placement of its base ROE in the upper end of the zone of reasonableness will be tasked with demonstrating, in each case, that market conditions are indeed anomalous and that the adequacy of a base ROE set at the midpoint of the zone of reasonableness should be scrutinized. The utility should expect a rigorous analysis of the record when it attempts to make such a demonstration.

The decision in Opinion No. 531 is within the Commission's broad discretion to determine the just and reasonable rate. I concur with this denial of the requests for rehearing to emphasize the points discussed above.

Colette D. Honorable
Commissioner

Federal Reserve Bank of New York
Staff Reports

The Equity Risk Premium: A Review of Models

Fernando Duarte
Carlo Rosa

Staff Report No. 714
February 2015

The Equity Risk Premium: A Review of Models

Fernando Duarte and Carlo Rosa

Federal Reserve Bank of New York Staff Reports, no. 714
February 2015
JEL classification: C58, G00, G12, G17

Abstract

We estimate the equity risk premium (ERP) by combining information from twenty models. The ERP in 2012 and 2013 reached heightened levels—of around 12 percent—not seen since the 1970s. We conclude that the high ERP was caused by unusually low Treasury yields.

Key words: equity premium, stock returns

Duarte, Rosa: Federal Reserve Bank of New York (e-mail: fernando.duarte@ny.frb.org, carlo.rosa@ny.frb.org). The authors thank Tobias Adrian and James Egelhof for helpful comments on earlier drafts. This article is an update of, and a more comprehensive and rigorous treatment than, our blog post in Liberty Street Economics (http://libertystreeteconomics.newyorkfed.org/2013/05/are-stocks-cheap-a-review-of-the-evidence.html).

1. Introduction

The equity risk premium —the expected return on stocks in excess of the risk-free rate— is a fundamental quantity in all of asset pricing, both for theoretical and practical reasons. It is a key measure of aggregate risk-aversion and an important determinant of the cost of capital for corporations, savings decisions of individuals and budgeting plans for governments. Recently, the equity risk premium (ERP) has also returned to the forefront as a leading indicator of the evolution of the economy, a potential explanation for jobless recoveries and a gauge of financial stability[3].

In this article, we estimate the ERP by combining information from twenty prominent models used by practitioners and featured in the academic literature. Our main finding is that the ERP has reached heightened levels. The first principal component of all models –a linear combination that explains as much of the variance of the underlying data as possible– places the one-year-ahead ERP in June 2012 at 12.2 percent, above the 10.5 percent that was reached during the financial crisis in 2009 and at levels similar to those in the mid and late 1970s. Since June 2012 and until the end of our sample in June 2013, the ERP has remained little changed, despite substantial positive realized returns. It is worth keeping in mind, however, that there is considerable uncertainty around these estimates. In fact, the issue of whether stock returns are predictable is still an active area of research.[4] Nevertheless, we find that the dispersion in estimates across models, while quite large, has been shrinking, potentially signaling increased agreement

[3] As an indicator of future activity, a high ERP at short horizons tends to be followed by higher GDP growth, higher inflation and lower unemployment. See, for example, Piazzesi and Schneider (2007), Stock and Watson (2003), and Damodaran (2012). Bloom (2009) and Duarte, Kogan and Livdan (2013) study connections between the ERP and real aggregate investment. As a potential explanation of the jobless recovery, Hall (2014) and Kuehn, Petrosky-Nadeau and Zhang (2012) propose that increased risk-aversion has prevented firms from hiring as much as would be expected in the post-crisis macroeconomic environment. Among many others, Adrian, Covitz and Liang (2013) analyze the role of equity and other asset prices in monitoring financial stability.

[4] A few important references among a vast literature are Ang and Bekaert (2007), Goyal and Welch (2008), Campbell and Thompson (2008), Kelly and Pruitt (2013), Chen, Da and Zhao (2013), Neely, Rapach, Tu and Zhou (2014).

even when the models are substantially different from each other and use more than one hundred different economic variables.

In addition to estimating the level of the ERP, we investigate the reasons behind its recent behavior. Because the ERP is the difference between expected stock returns and the risk-free rate, a high estimate can be due to expected stock returns being high or risk-free rates being low. We conclude the ERP is high because Treasury yields are unusually low. Current and expected future dividend and earnings growth play a smaller role. In fact, expected stock returns are close to their long-run mean. One implication of a bond-yield-driven ERP is that traditional indicators of the ERP like the price-dividend or price-earnings ratios, which do not use data from the term structure of risk-free rates, may not be as good a guide to future excess returns as they have been in the past.

As a second contribution, we present a concise and coherent taxonomy of ERP models. We categorize the twenty models into five groups: predictors that use historical mean returns only, dividend-discount models, cross-sectional regressions, time-series regressions and surveys. We explain the methodological and practical differences among these classes of models, including the assumptions and data sources that each require.

2. The Equity Risk Premium: Definition

Conceptually, the ERP is the compensation investors require to make them indifferent at the margin between holding the risky market portfolio and a risk-free bond. Because this compensation depends on the future performance of stocks, the ERP incorporates expectations of future stock market returns, which are not directly observable. At the end of the day, any model of the ERP is a model of investor expectations. One challenge in estimating the ERP is that it is not clear what truly constitutes the market return and the risk-free rate in the real world. In practice, the most common measures of total market returns are based on broad stock market indices, such as the S&P 500 or the Dow Jones Industrial

Average, but those indices do not include the whole universe of traded stocks and miss several other components of wealth such as housing, private equity and non-tradable human capital. Even if we restricted ourselves to all traded stocks, we still have several choices to make, such as whether to use value or equal-weighted indices, and whether to exclude penny or infrequently traded stocks. A similar problem arises with the risk-free rate. While we almost always use Treasury yields as measures of risk-free rates, they are not completely riskless since nominal Treasuries are exposed to inflation[5] and liquidity risks even if we were to assume there is no prospect of outright default. In this paper, we want to focus on how expectations are estimated in different models, and not on measurement issues regarding market returns and the risk-free rate. Thus, we follow common practice and always use the S&P 500 as a measure of stock market prices and either nominal or real Treasury yields as risk-free rates so that our models are comparable with each other and with most of the literature.

While implementing the concept of the ERP in practice has its challenges, we can precisely define the ERP mathematically. First, we decompose stock returns[6] into an expected component and a random component:

$$R_{t+k} = E_t[R_{t+k}] + error_{t+k}. \tag{1}$$

In equation (1), R_{t+k} are *realized* returns between t and $t+k$, and $E_t[R_{t+k}]$ are the returns that were expected from t to $t + k$ using information available at time t. The variable $error_{t+k}$ is a random variable that is unknown at time t and realized at $t + k$. Under rational expectations, $error_{t+k}$ has a mean of zero and is orthogonal to $E_t[R_{t+k}]$. We keep the discussion as general as possible and do not assume rational

[5] Note that inflation risk in an otherwise risk-free nominal asset does not invalidate its usefulness to compute the ERP. If stock returns and the risk-free rate are expressed in nominal terms, their difference has little or no inflation risk. This follows from the following formula, which holds exactly in continuous time and to a first order approximation in discrete time: real stock returns – real risk-free rate = (nominal stock returns – expected inflation) – (nominal risk-free rate – expected inflation) = nominal stock returns– nominal risk-free rate. Hence, there is no distinction between a nominal and a real ERP.
[6] Throughout this article, all returns are *net* returns. For example, a five percent return corresponds to a net return of 0.05 as opposed to a *gross* return of 1.05.

expectations at this stage, although it will be a feature of many of the models we consider. The ERP at time t for horizon k is defined as

$$ERP_t(k) = E_t[R_{t+k}] - R^f_{t+k}, \tag{2}$$

where R^f_{t+k} is the risk-free rate for investing from t to $t+k$ (which, being risk-free, is known at time t).

This definition shows three important aspects of the ERP. First, future expected returns and the future ERP are stochastic, since expectations depend on the arrival of new information that has a random component not known in advance[7]. Second, the ERP has an investment horizon k embedded in it, since we can consider expected excess returns over, say, one month, one year or five years from today. If we fix t, and let k vary, we trace the *term structure* of the equity risk premium. Third, if expectations are rational, because the unexpected component $error_{t+k}$ is stochastic and orthogonal to expected returns, the ERP is always less volatile than realized excess returns. In this case, we expect ERP estimates to be smoother than realized excess returns.

3. Models of the Equity Risk Premium

We describe twenty models of the equity risk premium, comparing their advantages, disadvantages and ease of implementation. Of course, there are many more models of the ERP than the ones we consider. We selected the models in our study based on the recent academic literature, their widespread use by practitioners and data availability. Table I describes the data we use and their sources, all of which are either readily available or standard in the literature[8]. With a few exceptions, all data is monthly from January 1960 to June 2013. Appendix A provides more details.

[Insert Table I here]

[7] More precisely, $E_t[R_{t+k}]$ and $ERP_t(k)$ are known at time t but random from the perspective of all earlier periods.
[8] In fact, except for data from I/B/E/S and Compustat, all sources are public.

We classify the twenty models into five categories based on their underlying assumptions; models in the same category tend to give similar estimates for the ERP. The five categories are: models based on the historical mean of realized returns, dividend discount models, cross-sectional regressions, time-series regressions and surveys.

All but one of the estimates of the ERP are constructed in real time, so that an investor who lived through the sample would have been able to construct the measures at each point in time using available information only[9]. This helps minimize look-ahead bias and makes any out-of-sample evaluation of the models more meaningful. Clearly, most of the models themselves were designed only recently and were not available to investors in real time, potentially introducing another source of forward-looking and selection biases that are much more difficult to quantify and eliminate.

3.1 Historical mean of realized returns

The easiest approach to estimating the ERP is to use the historical mean of realized market returns in excess of the contemporaneous risk-free rate. This model is very simple and, as shown in Goyal and Welch (2008), quite difficult to improve upon when considering out-of-sample predictability performance measures. The main drawbacks are that it is purely backward looking and assumes that the future will behave like the past, i.e. it assumes the mean of excess returns is either constant or very slow moving over time, giving very little time-variation in the ERP. The main choice is how far back into the past we should go when computing the historical mean. Table II shows the two versions of historical mean models that we use.

[Insert Table II here]

[9] The one exception is Adrian, Crump and Moench's (2014) cross-sectional model, which is constructed using full-sample regression estimates.

3.2 Dividend discount models (DDM)

All DDM start with the basic intuition that the value of a stock is determined by no more and no less than the cash flows it produces for its shareholders, as in Gordon (1962). Today's stock price should then be the sum of all expected future cash flows, discounted at an appropriate rate to take into account their riskiness and the time value of money. The formula that reflects this intuition is

$$P_t = \frac{D_t}{\rho_t} + \frac{E_t[D_{t+1}]}{\rho_{t+1}} + \frac{E_t[D_{t+2}]}{\rho_{t+2}} + \frac{E_t[D_{t+3}]}{\rho_{t+3}} + \cdots, \tag{3}$$

where P_t is the current price of the stock, D_t are current cash flows, $E_t[D_{t+k}]$ are the cash flows k periods from now expected as of time t, and ρ_{t+k} is the discount rate for time $t+k$ from the perspective of time t. Cash flows to stockholders certainly include dividends, but can also arise from spin-offs, buy-outs, mergers, buy-backs, etc. In general, the literature focuses on dividend distributions because they are readily available data-wise and account for the vast majority of cash flows. The discount rate can be decomposed into

$$\rho_{t+k} = 1 + R^f_{t+k} + ERP_t(k). \tag{4}$$

In this framework, the risk-free rate captures the discounting associated with the time value of money and the ERP captures the discounting associated with the riskiness of dividends. When using a DDM, we refer to $ERP_t(k)$ as the *implied* ERP. The reason is that we plug in prices, risk-free rates and estimated expected future dividends into equation (3), and then derive what value of $ERP_t(k)$ makes the right-hand side equal to the left-hand side in the equation, i.e. what ERP value is *implied* by equation (3).

DDM are forward looking and are consistent with no arbitrage. In fact, equation (3) must hold in any economy with no arbitrage[10]. Another advantage of DDM is that they are easy to implement. A drawback of DDM is that the results are sensitive to how we compute expectations of future dividends. Table III displays the DDM we consider and a brief description of their different assumptions.

[Insert Table III here]

3.3 Cross-sectional regressions

This method exploits the variation in returns and exposures to the S&P 500 of different assets to infer the ERP[11]. Intuitively, cross-sectional regressions find the ERP by answering the following question: what is the level of the ERP that makes expected returns on a variety of stocks consistent with their exposure to the S&P 500? Because we need to explain the relationship between returns and exposures for multiple stocks with a single value for the ERP (and perhaps a small number of other variables), this model imposes tight restrictions on estimates of the ERP.

The first step is to find the exposures of assets to the S&P 500 by estimating an equation of the following form:

$$R^i_{t+k} - R^f_{t+k} = \alpha^i \times state\ variables_{t+k} + \beta^i \times risk\ factors_{t+k} + idiosyncratic\ risk^i_{t+k}. \quad (5)$$

In equation (5), R^i_{t+k} is the realized return on a stock or portfolio i from time t to $t+k$. $State\ variables_{t+k}$ are any economic indicators that help identify the state of the economy and its likely future path. $Risk\ factors_{t+k}$ are any measures of systematic contemporaneous co-variation in returns across all stocks or portfolios. Of course, some economic indicators can be both state variables and risk

[10] Note that when performing the infinite summation in equation (3) we have not assumed the n^{th} term goes to zero as n tends to infinity, which allows for rational bubbles. In this sense, DDM do allow for a specific kind of bubble.
[11] See Polk, Thompson and Vuolteenaho (2006) and Adrian, Crump and Moench (2014) for a detailed description of this method.

factors at the same time. Finally, $idiosyncratic\ risk^i_{t+k}$ is the component of returns that is particular to each individual stock or portfolio that is not explained by $state\ variables_{t+k}$ or $risk\ factors_{t+k}$ (both of which, importantly, are common to all stocks and hence not indexed by i). Examples of state variables are inflation, unemployment, the yield spread between Aaa and Baa bonds, the yield spread between short and long term Treasuries, and the S&P 500's dividend-to-price ratio. The most important risk factor is the excess return on the S&P 500, which we must include if we want to infer the ERP consistent with the cross-section of stock returns. Other risk-factors usually used are the Fama-French (1992) factors and the momentum factor of Carhart (1997). The values in the vector α^i give the strength of asset-specific return predictability and the values in the vector β^i give the asset-specific exposures to risk factors[12]. For the cross-section of assets indexed by i, we can use the whole universe of traded stocks, a subset of them, or portfolios of stocks grouped, for example, by industry, size, book-to-market, or recent performance. It is important to point out that equation (5) is not a predictive regression; the left and right-hand side variables are both associated with time $t + k$.

The second step is to find the ERP associated with the S&P 500 by estimating the cross-sectional equations

$$R^i_{t+k} - R^f_{t+k} = \lambda_t(k) \times \hat{\beta}^i \,, \tag{6}$$

where $\hat{\beta}^i$ are the values found when estimating equation (5). Equation (6) attempts to find, at each point in time, the vector of numbers $\lambda_t(k)$ that makes exposures β^i as consistent as possible with realized excess returns of all stocks or portfolios considered. The element in the vector $\hat{\lambda}_t(k)$ that is multiplied by

[12] The vectors α^i and β^i could also be time-varying, reflecting a more dynamic relation between returns and their explanatory variables. In this case, the estimation of equation (5) is more complicated and requires making further assumptions. The model by Adrian, Crump and Moench (2014) is the only cross-sectional model we examine that uses time-varying α^i and β^i .

the element in the $\hat{\beta}^i$ vector corresponding to the S&P 500 is $ERP_t(k)$, the equity risk premium we are seeking.

One advantage of cross-sectional regressions is that they use information from more asset prices than other models. Cross-sectional regressions also have sound theoretical foundations, since they provide one way to implement Merton's (1973) Intertemporal Capital Asset Pricing Model. Finally, this method nests many of the other models considered. The two main drawbacks of this method are that results are dependent on what portfolios, state variables and risk factors are used (Harvey, Liu and Zhu (2014)), and that it is not as easy to implement as most of the other options. Table IV displays the cross-sectional models in our study, together with the state variables and risk factors they use.

[Insert Table IV here]

3.4 Time-series regressions

Time-series regressions use the relationship between economic variables and stock returns to estimate the ERP. The idea is to run a predictive linear regression of realized excess returns on lagged "fundamentals":

$$R_{t+k} - R^f_{t+k} = a + b \times Fundamental_t + error_t. \tag{7}$$

Once estimates $\hat{a}$ and $\hat{b}$ for a and b are obtained, the ERP is obtained by ignoring the error term:

$$ERP_t(k) = \hat{a} + \hat{b} \times Fundamental_t. \tag{8}$$

In other words, we estimate only the forecastable or expected component of excess returns. This method attempts to implement equations (1) and (2) as directly as possible in equations (7) and (8), with the assumption that "fundamentals" are the right sources of information to look at when computing expected returns, and that a linear equation is the correct functional specification.

The use of time-series regressions requires minimal assumptions; there is no concept of equilibrium and no absence of arbitrage necessary for the method to be valid[13]. In addition, implementation is quite simple, since it only involves running ordinary least-square regressions. The challenge is to select what variables to include on the right-hand side of equation (7), since results can change substantially depending on what variables are used to take the role of "fundamentals". In addition, including more than one predictor gives poor out-of-sample predictions even if economic theory may suggest a role for many variables to be used simultaneously (Goyal and Welch (2008)). Finally, time-series regressions ignore information in the cross-section of stock returns. Table V shows the time-series regression models that we study.

[Insert Table V here]

3.5 Surveys

The survey approach consists of asking economic agents about the current level of the ERP. Surveys incorporate the views of many people, some of which are very sophisticated and/or make real investment decisions based on the level of the ERP. Surveys should also be good predictors of excess returns because in principle stock prices are determined by supply and demand of investors such as the ones taking the surveys. On the other hand, Greenwood and Shleifer (2014) document that investor expectations of future stock market returns are positively correlated with past stock returns and with the current level of the stock market, but strongly *negatively* correlated with model-based expected returns and future realized stock market returns. Other studies such as Easton and Sommers (2007) also argue that survey measures of the ERP can be systematically biased. In this paper, we use the survey of CFOs by Graham and Harvey (2012), which to our knowledge is the only large-scale ERP survey that has more than just a few years of data (see Table VI).

[Insert Table VI here]

[13] However, the Arbitrage Pricing Theory of Ross (1976) provides a strong theoretical underpinning for time-series regressions by using no-arbitrage conditions.

4. Estimation of the Equity Risk Premium

We now study the behavior of the twenty models we consider by conducting principal component analysis. Since forecast accuracy can be substantially improved through the combination of multiple forecasts[14], the optimal strategy to forecast excess stock returns may consist of combining together all these models. The first principal component of the twenty models that we use is the linear combination of ERP estimates that captures as much of the variation in the data as possible. The second, third, and successive principal components are the linear combinations of the twenty models that explain as much of the variation of the data as possible and are also uncorrelated to all the preceding principal components. If the first few principal components —say one or two— account for most of the variation of the data, then we can use them as a good summary for the variation in all the measures over time, reducing the dimensionality from twenty to one or two. In addition, in the presence of classical measurement error, the first few principal components can achieve a higher signal-to-noise ratio than other summary measures like the cross-sectional mean of all models (Geiger and Kubin (2013)).

To compute the first principal component, we proceed in three steps. We first de-mean all ERP estimates and find their variance-covariance matrix. In the second step, we find the linear combination that explains as much of the variance of the de-meaned models as possible. The weights in the linear combination are the elements of the eigenvector associated with the largest eigenvalue of the variance-covariance matrix found in the first step. In the third step, we add to the linear combination just obtained, which has mean zero, the average of ERP estimates across all models and all time periods. Under the assumption that each of the models is an unbiased and consistent estimator of the ERP, the average across all models and all time periods is an unbiased and consistent estimator of the unconditional mean of the ERP. The time

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[14] See, *inter alia*, Clemen (1989), Diebold and Lopez (1996) and Timmermann (2006).

variation in the first principal component then provides an estimate of the conditional ERP[15]. The share of the variance of the underlying models explained by this principal component is 76 percent, suggesting that there is not too much to gain from examining principal components beyond the first[16].

We now focus on the one-year-ahead ERP estimates and study other horizons in the next section.

The first two columns in Table VII show the mean and standard deviation of each model's estimates. The unconditional mean of the ERP across all models is 5.7 percent, with an average standard deviation of 3.2 percent. DDM give the lowest mean ERP estimates and have moderate standard deviations. In contrast, cross-sectional models tend to have mean ERP estimates on the high end of the distribution and very smooth time-series. Mean ERP estimates for time-series regressions are mixed, with high and low values depending on the predictors used, but uniformly large variances. The survey of CFOs has a mean and standard deviation that are both about half as large as in the overall population of models. The picture that emerges from Table VII is that there is considerable heterogeneity across model types, and even sometimes within model types, thereby underscoring the difficulty inherent in finding precise estimates of the ERP.

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[15] As is customary in the literature, we perform the analysis using ERP estimates in levels, even though they are quite persistent. Results in first-differences do not give economically reasonable estimates since they feature a pro-cyclical ERP and unreasonable magnitudes.

One challenge that arises in computing the principal component is when we have missing observations, either because some models can only be obtained at frequencies lower than monthly or because the necessary data is not available for all time periods (Appendix A contains a detailed description of when this happens). To overcome this challenge, we use an iterative linear projection method, which conceptually preserves the idea behind principal components. Let X be the matrix that has observations for different models in its columns and for different time periods in its rows. On the first iteration, we make a guess for the principal component and regress the non-missing elements of each row of X on the guess and a constant. We then find the first principal component of the variance-covariance matrix of the fitted values of these regressions, and use it as the guess for the next iteration. The process ends when the norm of the difference between consecutive estimates is small enough. We thank Richard Crump for suggesting this method and providing the code for its implementation.

[16] The second and third principal components account for 13 and 8 percent of the variance, respectively.

[Insert Table VII here]

Figure 1 shows the time-series for all one-year-ahead ERP model estimates, with each class of models in a different panel. The green lines are the ERP estimates from the twenty underlying models. The black line, reproduced in each of the panels, is the principal component of all twenty models. The shaded areas are NBER recessions. The figure gives a sense of how the time-series move together, and how much they co-vary with the first principal component. Table VIII shows the correlations among models. Figure 1 and Table VIII give the same message: despite some outliers, there is a fairly strong correlation within each of the five classes of models. Across classes, however, correlations are small and even negative. Interestingly, the correlation between some DDM and cross-sectional models is as low as -91 percent. This negative correlation, however, disappears if we look at lower frequencies. When aggregated to quarterly frequency, the smallest correlation between DDM and cross-sectional models is -22 percent, while at the annual frequency it is 12 percent.

[Insert Figure 1 here]

[Insert Table VIII here]

Figure 1 also shows that the first principal component co-varies negatively with historical mean models, but positively with DDM and cross-sectional regression models. Time-series regression models are also positively correlated with the first principal component, although this is not so clearly seen in Panel 4 of Figure 1 because of the high volatility of time-series ERP estimates. The last panel shows that the survey of CFOs does track the first principal component quite well at low frequencies (e.g. annual), although any conclusions about survey estimates should be interpreted with caution given the short length of the sample.

As explained earlier, the first principal component is a linear combination of the twenty underlying ERP models:

$$PC_t^{(1)} = \sum_{m=1}^{20} w^{(m)} ERP_t^{(m)}. \tag{9}$$

In the above equation, m indexes the different models, $PC_t^{(1)}$ is the first principal component, $ERP_t^{(m)}$ is the estimate from model m and $w^{(m)}$ is the weight that the principal component places on model m. The third column in Table VII, labeled "PC coefficients", shows the weights $w^{(m)}$ normalized to sum up to one to facilitate comparison, i.e. the table reports the weights $\widehat{w}^{(m)}$ where

$$\widehat{w}^{(m)} = \frac{w^{(m)}}{\sum_{m=1}^{20} w^{(m)}}. \tag{10}$$

The first principal component puts positive weight on models based on the historical mean, cross-sectional regressions and the survey of CFOs. It weights DDM and time-series regressions mostly negatively. The absolute values of the weights are very similar for many of the models, and there is no single model or class of models that dominates. This means that the first principal component uses information from many of the models.

The last column in Table VII, labeled "Exposure to PC", shows the extent to which models *load* on the first principal component. By construction, each of the twenty ERP models can be written as a linear combination of twenty principal components:

$$ERP_t^{(m)} = \sum_{i=1}^{20} load_i^{(m)} PC_t^{(i)}, \tag{11}$$

where m indexes the model and i indexes the principal components. The values in the last column of Table VII are the loadings on the first principal component ($i = 1$) for each model ($m = 1, 2, \dots, 20$), again normalized to one for ease of comparability:

$$\widehat{load}_1^{(m)} = \frac{load_1^{(m)}}{\sum_{m=1}^{20} load_i^{(m)}}. \qquad (12)$$

Most models have a positive loading on the first principal component; whenever the loading is negative, it tends to be relatively small. This means the first principal component, as expected, is a good explanatory variable for most models. Looking at the third and fourth columns of Table VII together, we can obtain additional information. For example, a model with a very high loading (fourth column) accompanied by a very small PC coefficient (third column) is likely to mean that the model is almost redundant, in the sense that it is close to being a linear combination of all other models and does not provide much independent information to the principal component. On the other hand, if the PC coefficient and loading are both high, the corresponding model is likely providing information not contained in other measures.

Figure 2 shows the first principal component of all twenty models in black, with recessions indicated by shaded bars (the black line is the same principal component shown in black in each of the panels of Figure 1). As expected, the principal component tends to peak during financial turmoil, recessions and periods of low real GDP growth or high inflation. It tends to bottom out after periods of sustained bullish stock markets and high real GDP growth. Evaluated by the first principal component, the one-year-ahead ERP reaches a local peak in June of 2012 at 12.2 percent. The surrounding months have ERP estimates of similar magnitude, with the most recent estimate in June 2013 at 11.2 percent. This behavior is not so clearly seen by simply looking at the collection of individual models in Figure 1, highlighting the usefulness of principal components analysis. Similarly high levels were seen in the mid and late 1970s, during a period of stagflation, while the recent financial crisis had slightly lower ERP estimates closer to 10 percent.

[Insert Figure 2 here]

Figure 2 also displays the 10^{th}, 25^{th}, 75^{th} and 90^{th} percentiles of the cross-sectional distribution of models. These bands can be interpreted as confidence intervals, since they give the range of the distribution of ERP estimates at each point in time. However, they do not incorporate other relevant sources of uncertainty, such as the errors that occur during the estimation of each individual model, the degree of doubt in the correctness of each model, and the correlation structure between these and all other kinds of errors. Standard error bands that capture all sources of uncertainty are therefore likely to be wider.

The difference in high and low percentiles can also be interpreted as measures of agreement across models. The interquartile range –the difference between the 25^{th} and 75^{th} percentiles— has compressed, mostly because the models in the bottom of the distribution have had higher ERP estimates since 2010. It is also interesting to note that the 75^{th} percentile has remained fairly constant over the last 10 years at a level somewhat below its long-run mean. The cross-sectional standard deviation in ERP estimates (not shown in the graph) also decreased from 10.2% in January of 2000 to 4.3% in June of 2013, confirming that the disagreement among models has decreased.

Another *a priori* reasonable summary statistic for the ERP is the cross-sectional mean of estimates across models. In Figure 3, we can see that by this measure the ERP has also been increasing since the crisis. However, unlike the principal component, it has not reached elevated levels compared to past values. The cross-sectional mean can be useful, but it has a few undesirable features as an overall measure of the ERP compared to the first principal component. First, it is procyclical, which contradicts the economic intuition that expected returns are highest in recessions, when risk aversion is high and future prospects look brighter than current ones. Second, it overloads on DDM simply because there is a higher number of DDM models in our sample. Lastly, it has a smaller correlation with the realized returns it is supposed to predict.

[Insert Figure 3 here]

5. The Term Structure of Equity Risk Premia

In Section 2, we described the term structure of the ERP – what expected excess returns are over different investment horizons. In practical terms, we estimate the ERP at different horizons by using the inputs for all the models at the corresponding horizons[17]. For example, if we want to take the historical mean of returns as our estimate, we can take the mean of returns over one month, six months, or a one-year period. In cross-sectional and time-series regressions, we can predict monthly, quarterly or annual returns using monthly, quarterly or annual right-hand side variables. DDM, on the other hand, have little variation across horizons. In fact, all the DDM we consider have a constant term structure of expected stock returns, and the only term structure variation in ERP estimates comes from risk-free rates[18].

Figure 4 plots the first principal components of the ERP as a function of investment horizon for some selected dates. We picked the dates because they are typical dates for when the ERP was unusually high or unusually low at the one-month horizon. As was the case for one-year-ahead ERP estimates, we can capture the majority of the variance of the underlying models at all horizons by a single principal component. The shares of the variance explained by the first principal components at horizons of one month to three years range between 68 and 94 percent. The grey line in Figure 4 shows the average of the term structure across all periods. It is slightly upward sloping, with a short-term ERP at just over 6 percent and a three-year ERP at almost 7 percent.

[Insert Figure 4 here]

[17] For other ways to estimate the term structure of the ERP using equilibrium models or derivatives, see Ait-Sahalia, Karaman and Mancini (2014), Ang and Ulrich (2012), van Binsbergen, Hueskes, Koijen and Vrugt (2014), Boguth, Carlson, Fisher and Simutin (2012), Durham (2013), Croce, Lettau and Ludvigson (2014), Lemke and Werner (2009), Lettau and Wachter (2011), Muir (2013), among others.

[18] In equation (3), ρ_{t+k} is assumed to be the same for all k, while risk-free rates are allowed to vary over the investment horizon k in equation (4). Of course, with additional assumptions, it is possible to have DDM with a non-constant term structure of expected excess returns.

The first observation is that the term structure of the ERP has significant time variation and can be flat, upward or downward sloping. Figure 4 also shows some examples that hint at lower future expected excess returns when the one-month-ahead ERP is elevated and the term structure is downward sloping, and higher future expected excess returns when the one-month-ahead ERP is low and the term structure is upward sloping. In fact, this is generally true: There is a strong negative correlation between the level and the slope of the ERP term structure of -71 percent. Figure 5 plots monthly observations of the one-month-ahead ERP against the slope of the ERP term structure (the three-year-ahead minus the one-month-ahead ERP) together with the corresponding ordinary least squares regression line in black. Of course, this is only a statistical pattern and should not be interpreted as a causal relation.

[Insert Figure 5 here]

6. Why is the Equity Risk Premium High?

There are two reasons why the ERP can be high: low discount rates and high current or expected future cash flows.

Figure 6 shows that earnings are unlikely to be the reason why the ERP is high. The green line shows the year-on-year change in the mean expectation of one-year-ahead earnings per share for the S&P 500. These expectations are obtained from surveys conducted by the Institutional Brokers' Estimate System (I/B/E/S) and available from Thomson Reuters. Expected earnings per share have been declining from 2010 to 2013, making earnings growth an unlikely reason for why the ERP was high in the corresponding period. The black line shows the realized monthly growth rates of real earnings for the S&P 500 expressed in annualized percentage points. Since 2010, earnings growth has been declining, hovering around zero for the last few months of the sample. It currently stands at 2.5 percent, which is near its long-run average.

[Insert Figure 6 here]

Another way to examine whether a high ERP is due to discount rates or cash flows is shown in Figure 7. The black line is the same one-year-ahead ERP estimate shown in Figure 2. The green line simply adds the realized one-year Treasury yield to obtain expected stock returns. The figure shows expected stock returns have increased since 2000, similarly to the ERP. However, unlike the ERP, expected stock returns are close to their long-run mean, and nowhere near their highest levels, achieved in 1980. The discrepancies between the two lines are due to exceptionally low bond yields since the end of the financial crisis.

[Insert Figure 7 here]

Figure 8 displays the term structure of the ERP under a simple counterfactual scenario, in addition to the mean and current term structures already displayed in Figure 4. In this scenario, we leave expected stock returns unmodified but change the risk-free rates in June 2012 from their actual values to the average nominal bond yields over 1960-2013. In other words, we replace R_{t+k}^{f} in equation (2) by the mean of R_{t+k}^{f} over t. The result of this counterfactual is shown in Figure 8 in green. Using average levels of bond yields brings the whole term structure of the ERP much closer to its mean level (the grey line), especially at intermediate horizons. This shows that a "normalization" of bond yields, everything else being equal, would bring the ERP close to its historical norm. This exercise shows that the current environment of low bond yields is capable, quantitatively speaking, of significantly contributing to an ERP as high as was observed in 2012-2013.

[Insert Figure 8 here]

7. Conclusion

We have analyzed twenty different models of the ERP by considering the assumptions and data required to implement them, and how they relate to each other. When it comes to the ERP, we find that there is substantial heterogeneity in estimation methodology and final estimates. We then extract the first principal component of the twenty models, which signals that the ERP in 2012 and 2013 is at heightened levels compared to previous periods. Our analysis provides evidence that the current level of the ERP is consistent with a bond-driven ERP: expected excess stock returns are elevated not because stocks are expected to have high returns, but because bond yields are exceptionally low. The models we consider suggest that expected stock returns, on their own, are close to average levels.

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Appendix A: Data Variables

Fama and French (1992)	http://mba.tuck.dartmouth.edu/pages/faculty/ken.french/data_library.html Monthly frequency; 1/1/1960 to 6/30/2013. We use 25 portfolios sorted on size and book to market, 10 portfolios sorted on momentum, realized excess market returns, HML, SMB, and the momentum factor.
Shiller (2005)	http://www.econ.yale.edu/~shiller/data.htm Monthly frequency; 1/1/1960 to 6/30/2013. We use the nominal and real price, nominal and real dividends and nominal and real earnings for the S&P 500, CPI, and 10 year nominal treasury yield.
Baker and Wurgler (2007)	http://people.stern.nyu.edu/jwurgler/data/Investor_Sentiment_Data_v23_POST.xlsx Monthly frequency; 7/1/1965 to 12/1/2010. We use the "sentiment measure".
Graham and Harvey (2012)	http://www.cfosurvey.org/index.htm Quarterly frequency; 6/6/2000 to 6/5/2013. We use the answer to the question "Over the next 10 years, I expect the average annual S&P 500 return will be: Expected return:" and the analogous one that asks about the next year.
Damodaran (2012)	http://www.stern.nyu.edu/~adamodar/pc/datasets/histimpl.xls Annual frequency; 1/1/1960 to 12/1/2012. We use the ERP estimates from his dividend discount models (one uses free-cash flow, the other one doesn't).
Gurkaynak, Sack and Wright (2007)	http://www.federalreserve.gov/pubs/feds/2006/200628/200628abs.html Daily frequency; starting on 6/14/61 for one- to seven-year yields; 8/16/71 for nine- and ten-year yields; 11/15/71 for eleven- to fifteen-year yields; 7/2/81 for sixteen- to twenty-year yields; 11/25/85 for twenty-one- to thirty-year yields. We use all series until 6/30/2013.
Gurkaynak, Refet, Sack and Wright (2010)	http://www.federalreserve.gov/econresdata/researchdata.htm Monthly frequency; 1/1/2003 to 7/1/2013. We use yields on TIPS of all maturities available.
Compustat	Variable BKVLPS Annual frequency; 12/31/1977 to 12/31/2012.
Thomson Reuters I/B/E/S	Variables EPS 1 2 3 4 5 Monthly frequency; 1/14/1982 to 4/18/2013 for current and next year forecasts; 9/20/84 to 4/18/2013 for two-year-ahead forecasts; 9/19/85 to 3/15/2012 for three-year-ahead forecasts; 2/18/88 to 3/15/07 for four-year-ahead forecasts.
FRED (St. Louis Federal Reserve)	http://research.stlouisfed.org/fred2/graph/?g=D9J and http://research.stlouisfed.org/fred2/graph/?g=KKk Monthly frequency. 1/1/1960 to 7/1/2013 for Baa minus Aaa bond yield spread and recession indicator.

Tables and Figures

Table I: Data sources	
Fama and French (1992)	Fama-French factors, momentum factor, twenty-five portfolios sorted on size and book-to-market
Shiller (2005)	Inflation and ten-year nominal treasury yield. Nominal price, real price, earnings, dividends and cyclically adjusted price-earnings ratio for the S&P 500
Baker and Wurgler (2007)	Debt issuance, equity issuance, sentiment measure
Graham and Harvey (2012)	ERP estimates from the Duke CFO survey
Damodaran (2012)	ERP estimates
Gurkaynak, Sack and Wright (2007)	Zero coupon nominal bond yields for all maturities[19]
Gurkaynak, Refet, Sack and Wright (2010)	Zero coupon TIPS yields for all maturities
Compustat	Book value per share for the S&P 500
Thomson Reuters I/B/E/S	Mean analyst forecast of expected earnings per share
FRED (St. Louis Federal Reserve)	Corporate bond Baa-Aaa spread and the NBER recession indicator

Note: All variables start in January 1960 (or later, if unavailable for early periods) and end in June 2013 (or until no longer available). CFO surveys are quarterly; book value per share and ERP estimates by Damodaran (2012) are annual; all other variables are monthly. Appendix A provides more details.

[19] Except for the 10-year yield, which is from Shiller (2005). We use the 10-year yield from Shiller (2005) for ease of comparability with the existing literature. Results are virtually unchanged if we use all yields, including the 10-year yield, from Gurkaynak, Sack and Wright (2007).

Table II: Models based on the historical mean of realized returns	
Long-run mean	Average of realized S&P 500 returns minus the risk-free rate using all available historical data
Mean of the previous five years	Average of realized S&P 500 returns minus the risk-free rate using only data for the previous five years

Table III: Dividend Discount Models	
Gordon (1962) with nominal yields	S&P 500 dividend-to-price ratio minus the ten-year nominal Treasury yield
Shiller (2005)	Cyclically adjusted price-earnings ratio (CAPE) minus the ten-year nominal Treasury yield
Gordon (1962) with real yields	S&P 500 dividend-to-price ratio minus the ten year real Treasury yield (computed as the ten-year nominal Treasury rate minus the ten year breakeven inflation implied by TIPS)
Gordon (1962) with earnings forecasts	S&P 500 expected earnings-to-price ratio minus the ten-year nominal Treasury yield
Gordon (1962) with real yields and earnings forecasts	S&P 500 expected earnings-to-price ratio minus the ten-year real Treasury yield (computed as the ten-year nominal Treasury rate minus the ten-year breakeven inflation implied by TIPS)
Panigirtzoglou and Loeys (2005)	Two-stage DMM. The growth rate of earnings over the first five years is estimated by using the fitted values in a regression of average realized earnings growth over the last five years on its lag and lagged earnings-price ratio. The growth rate of earnings from years six and onwards is 2.2 percent
Damodaran (2012)	A six-stage DDM. Dividend growth the first five stages are estimated from analyst's earnings forecasts. Dividend growth in the sixth stage is the ten-year nominal Treasury yield
Damodaran (2012) free cash flow	Same as Damodaran (2012), but uses free-cash-flow-to-equity as a proxy for dividends plus stock buybacks

Table IV: Models with cross-sectional regressions	
Fama and French (1992)	Uses the excess returns on the market portfolio, a size portfolio and a book-to-market portfolio as risk factors
Carhart (1997)	Identical to Fama and French (1992) but adds the momentum measure of Carhart (1997) as an additional risk factor
Duarte (2013)	Identical to Carhart (1997) but adds an inflation risk factor
Adrian, Crump and Moench (2014)	Uses the excess returns on the market portfolio as the single risk factor. The state variables are the dividend yield, the default spread, and the risk free rate

Table V: Models with time-series regressions	
Fama and French (1988)	Only predictor is the dividend-price ratio of the S&P 500
Goyal and Welch (2008)	Uses, at each point in time, the best out-of-sample predictor out of twelve predictive variables proposed by Goyal and Welch (2008)
Campbell and Thompson (2008)	Same as Goyal and Welch (2008), but imposes two restrictions on the estimation. First, the coefficient *b* in equation (9) is replaced by zero if it has the "wrong" theoretical sign. Second, we replace the estimate of the ERP by zero if the estimation otherwise finds a negative ERP
Fama and French (2002)	Uses, at each point in time, the best out-of-sample predictor out of three variables: the price-dividend ratio adjusted by the growth rate of earnings, dividends or stock prices
Baker and Wurgler (2007)	The predictor is Baker and Wurgler's (2007) sentiment measure. The measure is constructed by finding the most predictive linear combination of five variables: the closed-end fund discount, NYSE share turnover, the number and average first-day returns on IPOs, the equity share in new issues, and the dividend premium

Table VI: Surveys	
Graham and Harvey (2012)	Chief financial officers (CFOs) are asked since 1996 about the one and ten-year-ahead ERP. We take the mean of all responses

Table VII: ERP models

		Mean	Std. dev.	PC coefficients $\widehat{w}^{(m)}$	Exposure to PC $\widehat{load}_1^{(m)}$
Based on historical mean	Long-run mean	9.3	1.3	0.78	-0.065
	Mean of previous five years	5.7	5.8	0.42	-0.160
DDM	Gordon (1926): E/P minus nominal 10yr yield	-0.1	2.1	-0.01	0.001
	Shiller (2005): 1/CAPE minus nominal 10yr yield	-0.4	1.8	-0.10	0.011
	Gordon (1962): E/P minus real 10yr yield	3.5	2.1	0.69	-0.077
	Gordon (1962): Expected E/P minus real 10yr yield	5.3	1.7	-0.78	0.208
	Gordon (1962): Expected E/P minus nominal 10yr yield	0.4	2.3	-0.79	0.077
	Panigirtzoglou and Loeys (2005): Two-stage DDM	-1.0	2.3	0.07	-0.011
	Damodaran (2012): Six-stage DDM	3.4	1.3	-0.26	0.032
	Damodaran (2012): Six-stage free cash flow DDM	4.0	1.1	-0.62	0.053
Cross-sectional regressions	Fama and French (1992)	12.6	0.7	0.80	-0.040
	Carhart (1997): Fama-French and momentum	13.1	0.8	0.81	-0.042
	Duarte (2013): Fama-French, momentum and inflation	13.1	0.8	0.82	-0.044
	Adrian, Crump and Moench (2014)	6.5	6.9	-0.05	0.114
Time-series regressions	Fama and French (1988): D/P	2.4	4.0	-0.27	0.069
	Best predictor in Goyal and Welch (2008)	14.5	5.2	-0.07	0.023
	Best predictor in Campbell and Thompson (2008)	3.1	9.8	-0.12	0.081
	Best predictor in Fama French (2002)	11.9	6.8	-0.72	0.321
	Baker and Wurgler (2007) sentiment measure	3.0	4.7	-0.32	0.184
Surveys	Graham and Harvey (2012) survey of CFOs	3.6	1.8	0.72	0.264
	All models	5.7	3.2	0.78	-0.065

For each of the twenty models of the equity risk premium, we show four statistics. The first two are the time-series means and standard deviations for monthly observations from January 1960 to June 2013 (except for surveys, which are quarterly). The units are annualized percentage points. The third statistic, "PC coefficients $\widehat{w}^{(m)}$", is the weight that the first principal component places on each model (normalized to sum to one). The fourth is the "Exposure to PC $\widehat{load}_1^{(m)}$", the weight on the first principal component when each model is written as a weighted sum of all principal components (also normalized to sum to one).

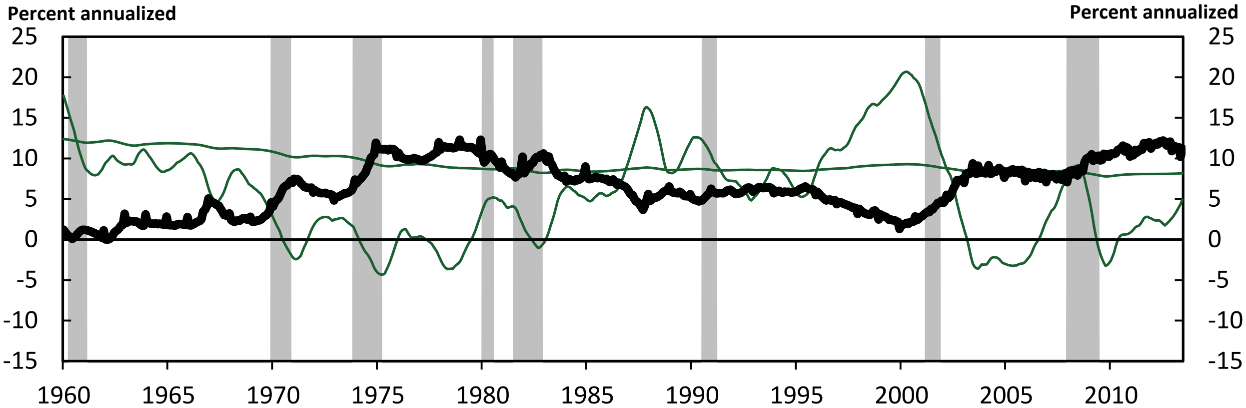
Table VIII: Correlation of ERP models

	LR mean	Mean past 5yr	E/P - 10yr	1/CAPE-10yr	E/P-real 10yr	Exp E/P-real 10yr	Exp E/P- 10yr	Two-stage DDM	Six-stage DDM	Free cash flow	FF	Carhart	Duarte	ACM	D/P	G and W	C and T	FF	Sentiment	CFO Survey
LR mean	100																			
Mean past 5yr	32	100																		
E/P - 10yr	8	15	100																	
1/CAPE-10yr	-9	0	78	100																
E/P-real 10yr	-11	25	98	23	100															
Exp E/P-real 10yr	-58	42	70	84	60	100														
Exp E/P- 10yr	-83	-61	84	95	46	98	100													
Two-stage DDM	17	27	88	54	89	66	79	100												
Six-stage DDM	3	-38	26	39	-30	32	52	-31	100											
Free cash flow	-43	-55	59	70	35	80	94	27	62	100										
FF	69	29	-8	-36	-21	-69	-91	9	-29	-77	100									
Carhart	71	30	-5	-31	-24	-71	-91	10	-25	-75	99	100								
Duarte	71	30	-3	-29	-22	-70	-91	11	-28	-74	99	100	100							
ACM	-1	-52	36	62	6	54	63	27	23	33	-28	-28	-25	100						
D/P	49	12	27	12	27	42	54	24	74	42	44	54	55	21	100					
G and W	25	12	25	21	-7	-36	-60	20	29	-9	7	13	14	-24	61	100				
C and T	27	31	14	-7	81	49	-60	28	-51	-40	60	57	58	-33	54	50	100			
FF	1	-30	-24	-29	37	-27	-37	-18	22	38	36	38	37	-9	40	23	43	100		
Sentiment	-10	33	-4	-20	68	-23	-29	27	-38	-20	18	17	18	-12	-38	-8	21	6	100	
CFO survey	-43	-33	12	30	1	1	13	16	5	-3	-36	-37	-39	60	14	-21	-32	-3	-36	100

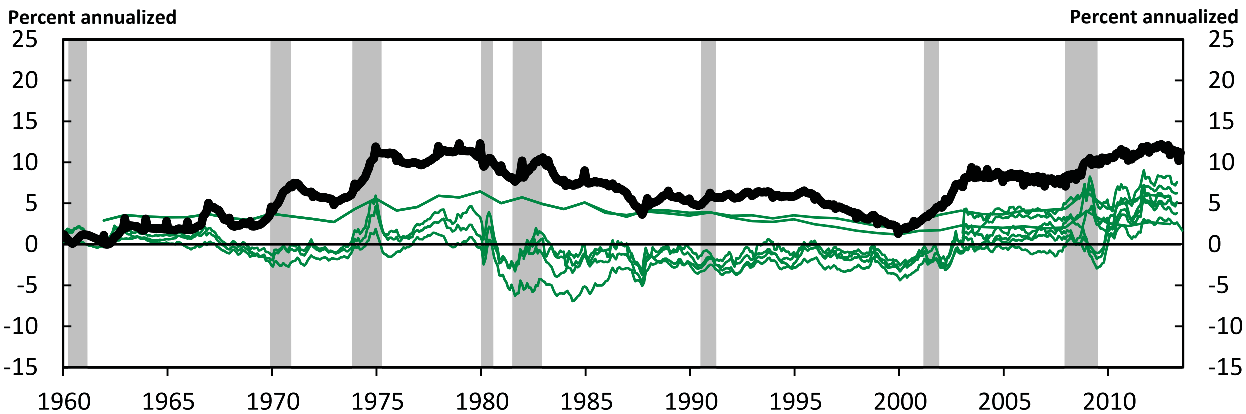
This table shows the correlation matrix of the twenty equity risk premium models we consider. Numbers are rounded to the nearest integer. Thick lines group models by their type (see Tables II to VI). Except for the CFO survey, the observations used to compute correlations are monthly for January 1960 to June 2013. For the CFO survey, correlations are computed by taking the last observation in the quarter for monthly series and then computing quarterly correlations.

Figure 1: ERP estimates for all models

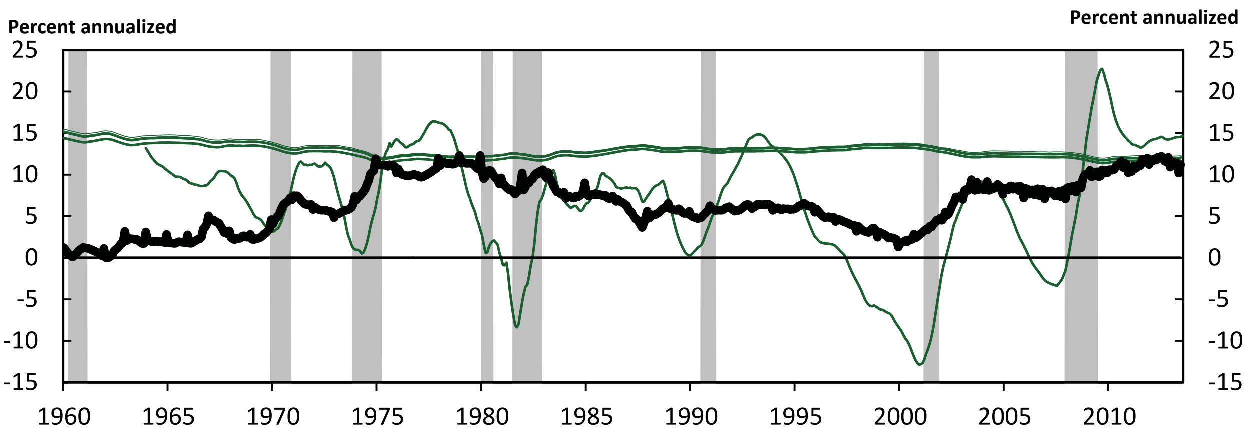
Panel 1: ERP models based on the historical mean of excess returns

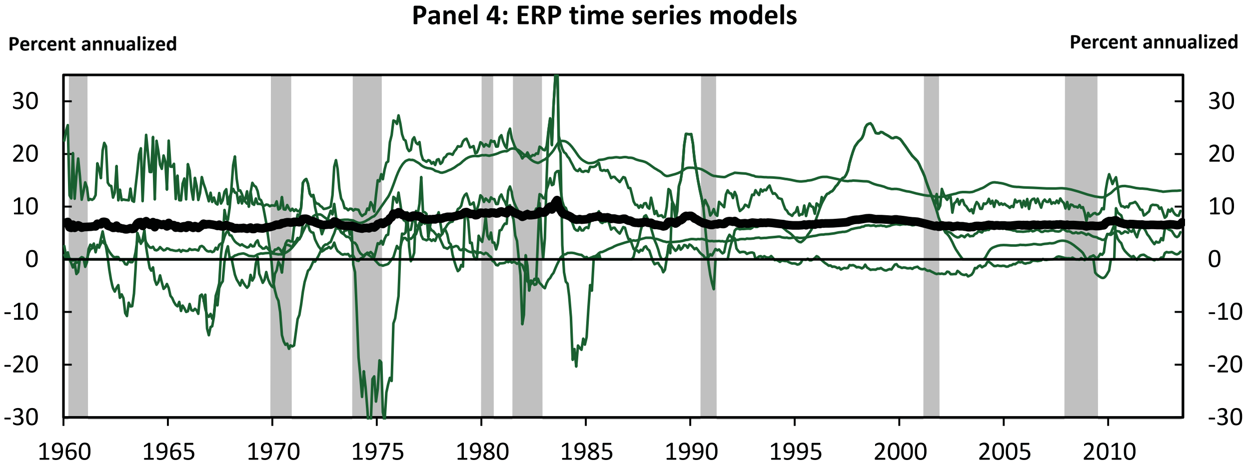


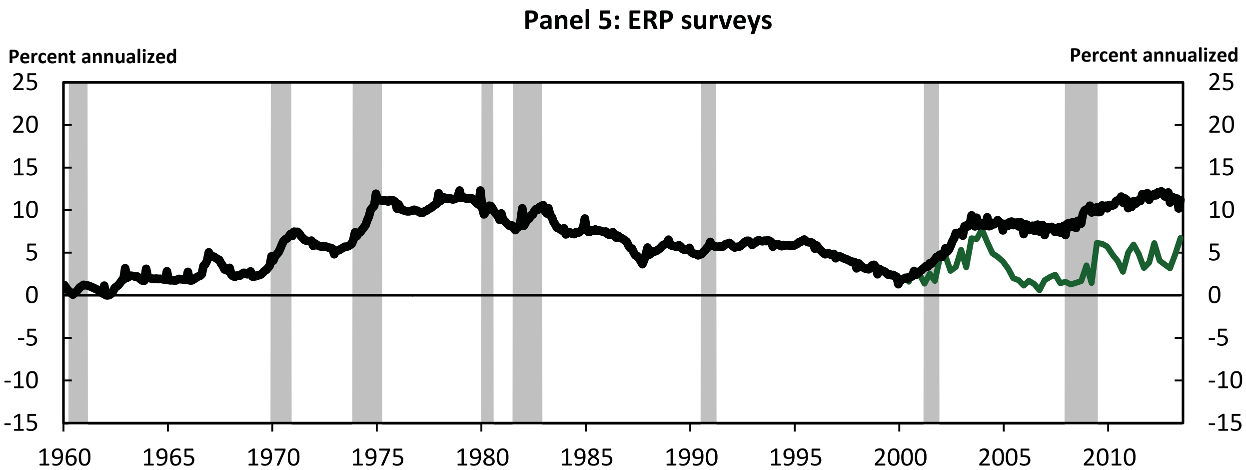
Panel 2: ERP dividend discount models (DDM)



Panel 3: ERP cross sectional models





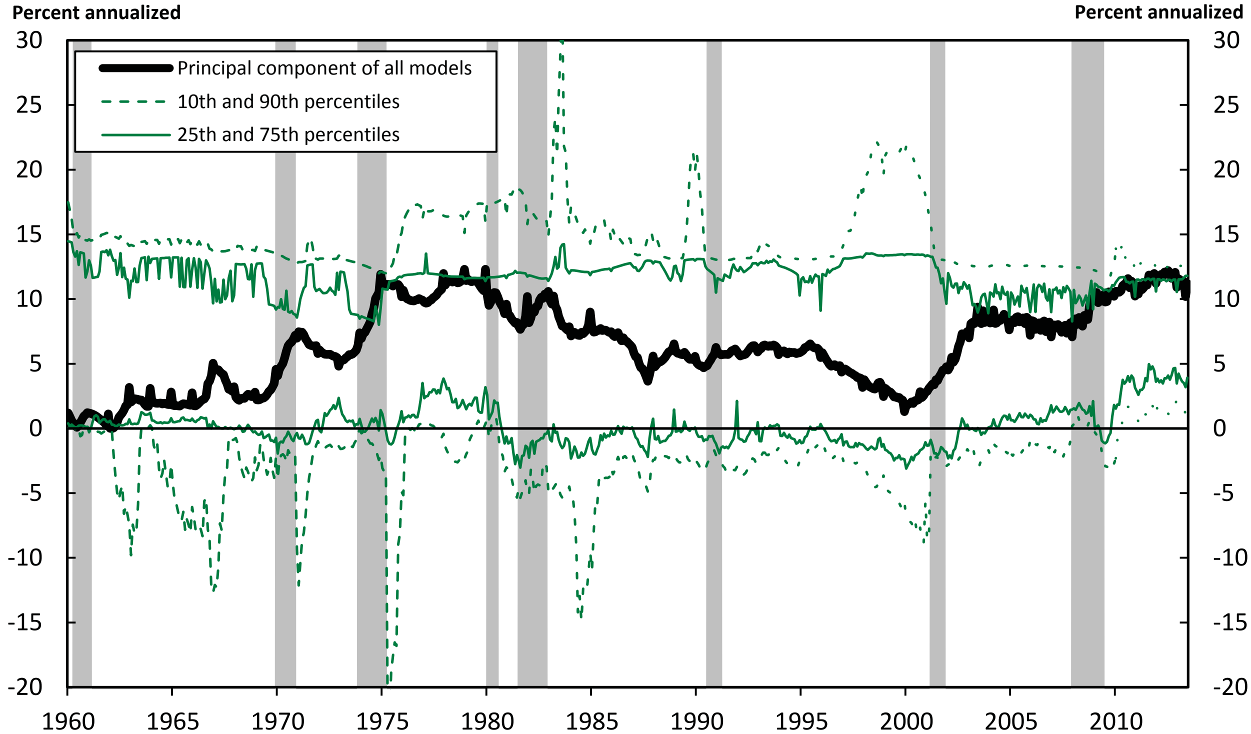


Each green line gives the one-year-ahead equity risk premium from each of the models listed in Tables II to VI. All numbers are in annualized percentage points.

Panel 1 shows the estimates for models based on the historical mean of excess returns, which are listed in Table II. Panel 2 shows estimates computed by the dividend discount models in Table III. Panel 3 uses the cross-sectional regression models from Table IV. Panel 4 shows the equity risk premium computed by the time-series regression models in Table V. Panel 5 gives the estimate obtained from the survey cited in Table VI.

In all panels, the black line is the first principal component of all twenty models (it can look different across panels due to different scales in the y-axis).

Figure 2: One-year-ahead ERP

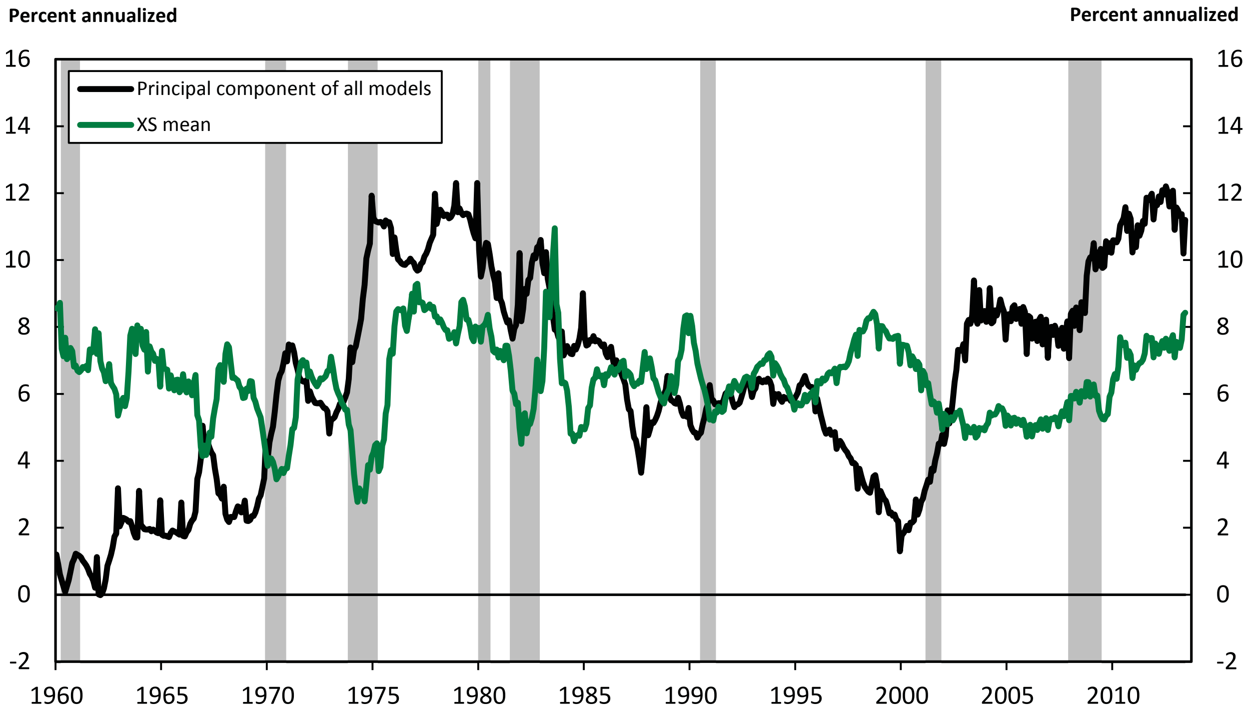


The black line is the first principal component of twenty models of the one-year-ahead equity risk premium (this is the same principal component shown in black in all panels of Figure 1). The models are listed in Tables II to VI.

The 25th and 75th percentiles (solid green lines) give the corresponding quartile of the 20 estimates for each time period, and similarly for the 10th and 90th percentiles (dashed green line).

Shaded bars indicate NBER recessions.

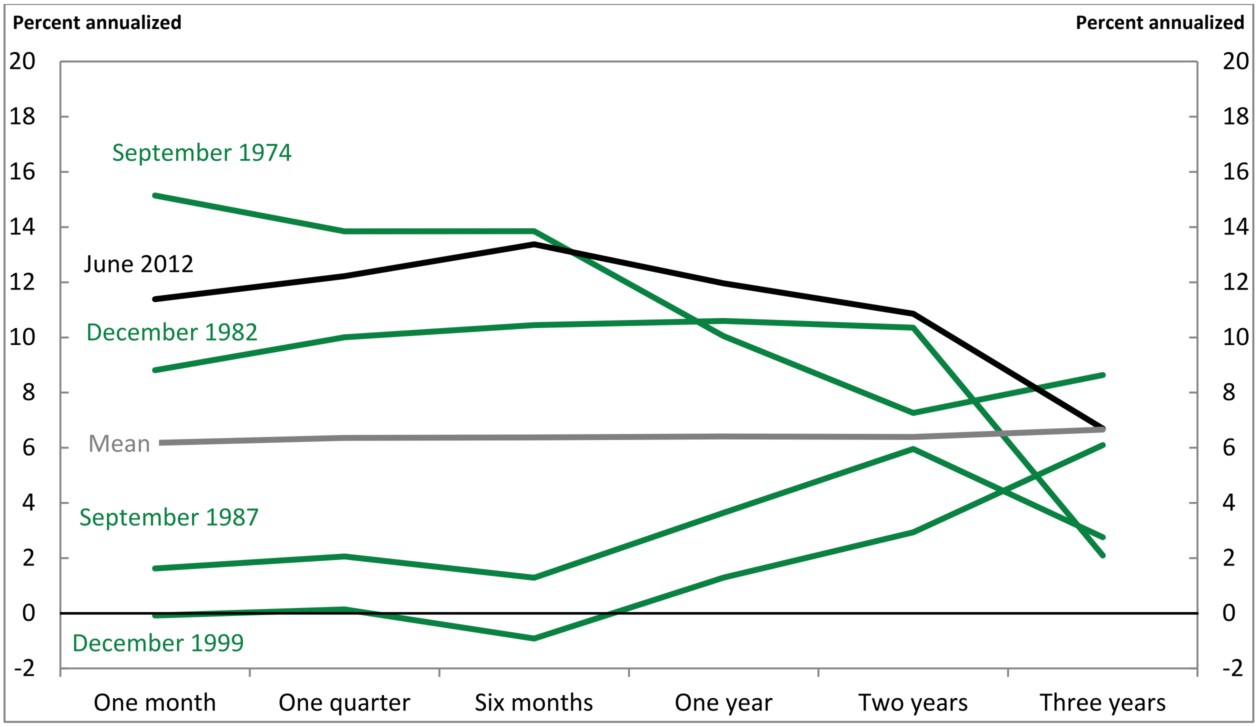
Figure 3: One-year-ahead ERP and cross-sectional mean of models



The black line is the first principal component of twenty models of the one-year-ahead equity risk premium (also shown in Figures 1 and 2). The green line is the cross-sectional average of models for each time period.

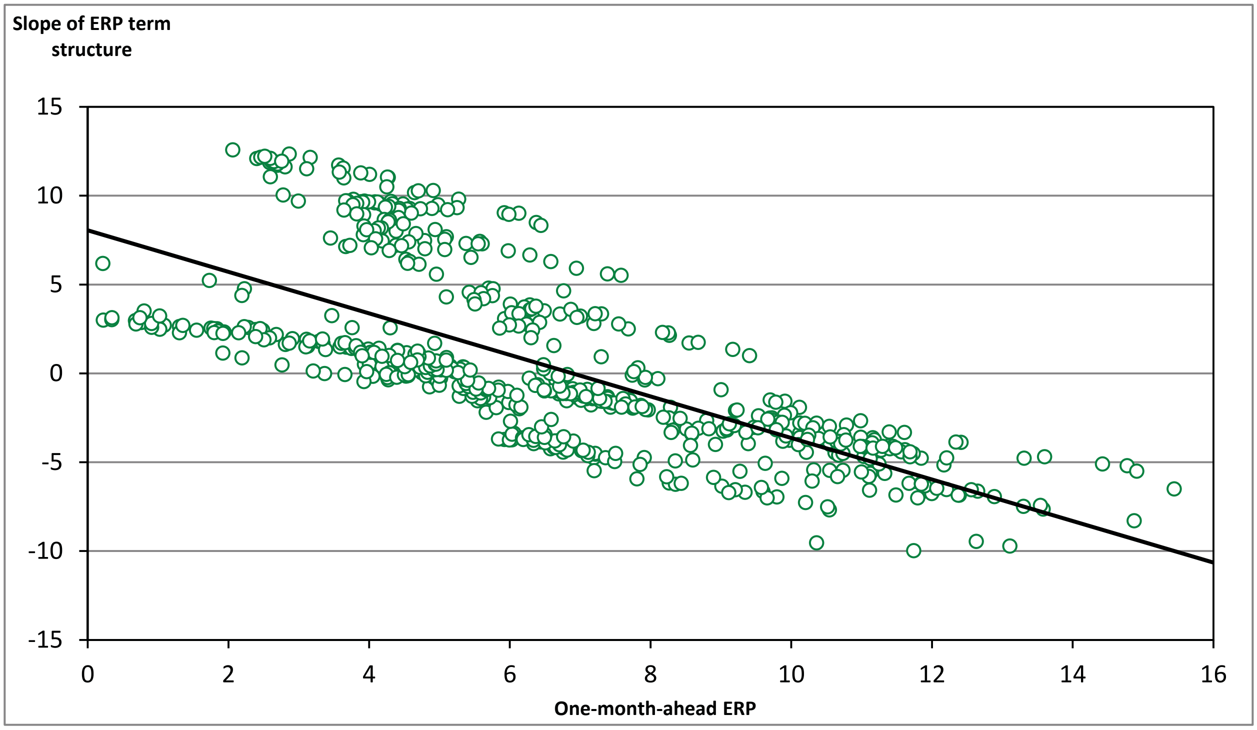
Shaded bars are NBER recessions.

Figure 4: Term structure of the ERP



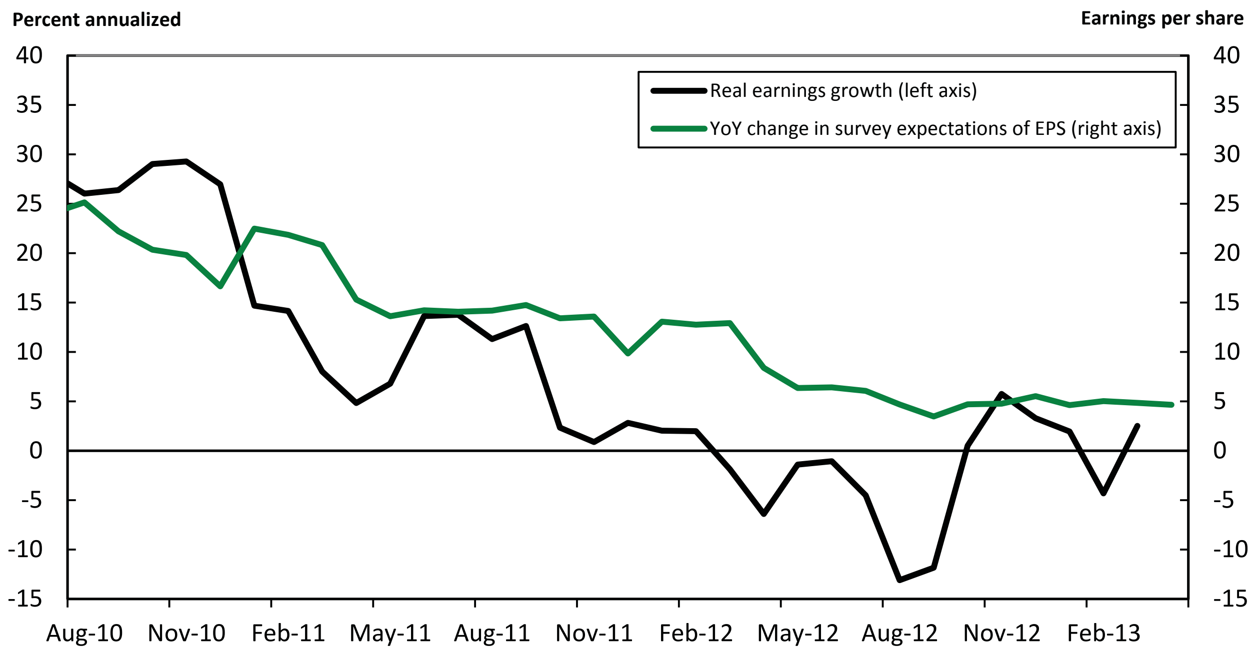
Each line, except for the grey one, shows equity risk premia as a function of investment horizon for some specific months in our sample. We consider horizons of one month, one quarter, six months, one year, two years and three years. The grey line (labeled "Mean") shows the average risk premium at different horizons over the whole sample January 1960 to June 2013. September 1987 and December 1999 were low points in one-month-ahead equity premia. In contrast, September 1974, December 1982 and June 2012 were peaks in the one-month-ahead equity premium.

Figure 5: Regression of the slope of the ERP term structure on one-month-ahead ERP



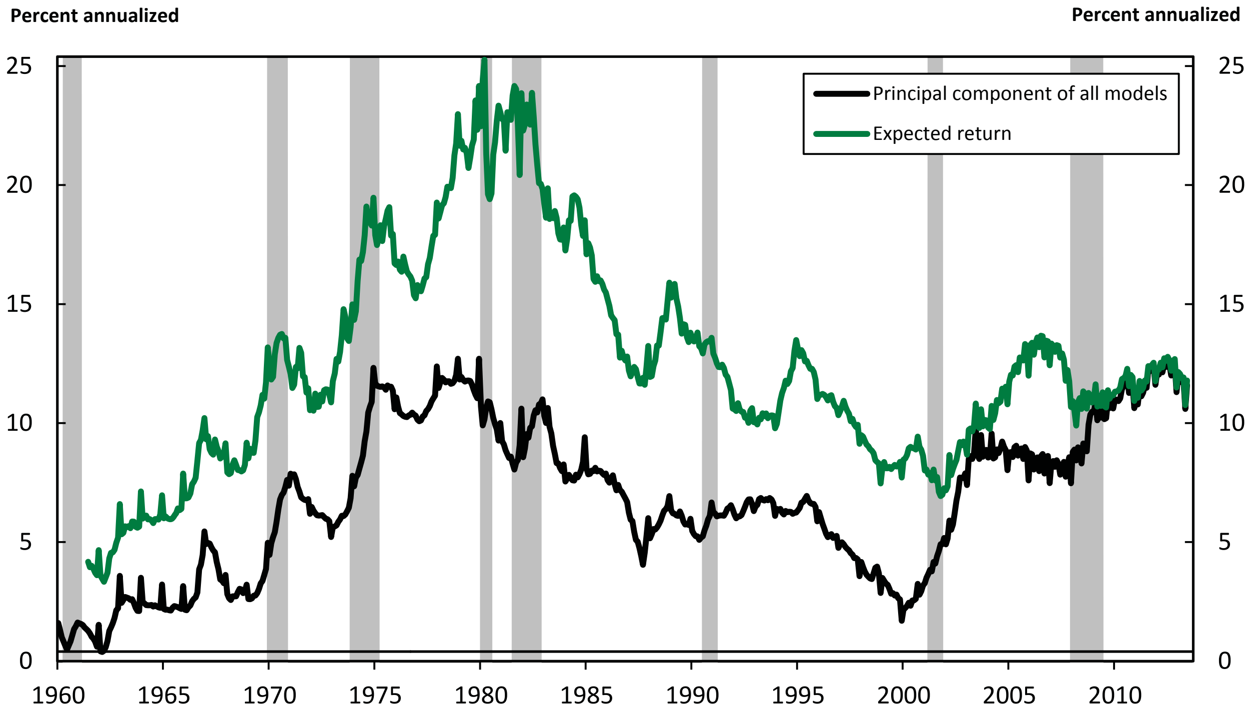
The figure shows monthly observations and the corresponding OLS regression for of the one-month-ahead ERP plotted against the slope of the ERP term structure for the period January 1960 to June 2013. The slope of the ERP term structure is the difference between the three-year-ahead ERP and the one-month-ahead ERP. All units are in annualized percentage points. The one-month-ahead and three-year-ahead ERP estimates used are the first principal components of twenty one-month-ahead or three-year-ahead ERP estimates from models described in Tables II-VI. The OLS regression slope is -1.17 (significant at the 99 percent level) and the R^2 is 50.1 percent.

Figure 6: Earnings behavior



The black line shows the monthly growth rate of real S&P 500 earnings, annualized and in percentage points. The green line shows the year-on-year change in the mean expectation of one-year-ahead earnings per share for the S&P 500 from a survey of analysts provided by Thomson Reuters I/B/E/S.

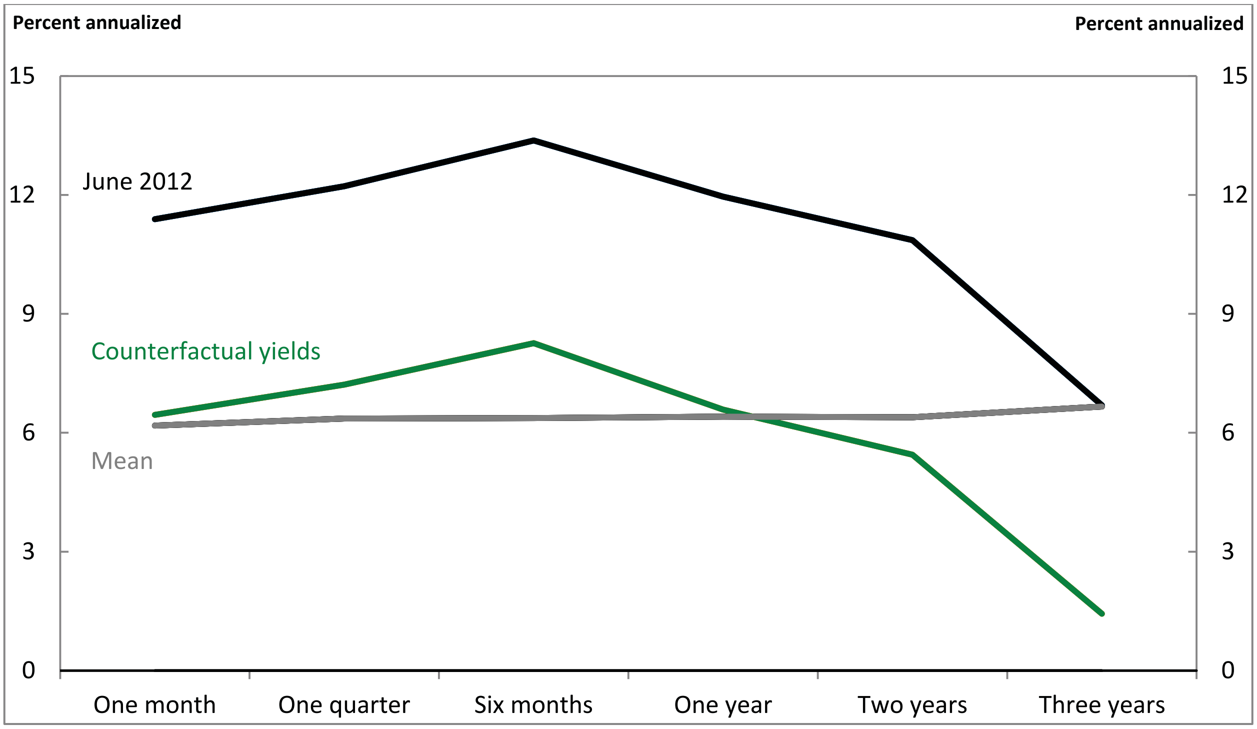
Figure 7: One-year-ahead ERP and expected returns



The black line is the first principal component of twenty models of the one-year-ahead equity risk premium (also shown in Figures 1, 2 and 3). The green line is the one-year-ahead expected return on the S&P 500, obtained by adding the realized one-year maturity Treasury yield from the principal component (the black line).

Shaded bars are NBER recessions.

Figure 8: Term structure of ERP using counterfactual bond yields



The grey line, labeled "Mean", shows the mean term structure of the equity risk premium over the sample January 1960 to June 2013. The black line, labeled "June 2012", shows the term structure for the most recent peak in the one-month-ahead ERP. These two lines are the same as in Figure 4. The green line, labeled "Counterfactual yields", shows what the term structure of equity risk premia would be in June 2012 if instead of subtracting June 2012's yield curve from expected returns we subtracted the average yield curve for January 1960 to June 2013.

The Brattle Group

Estimating the Cost of Equity for Regulated Companies

Date : 17 February 2013

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Australian Pipeline Industry Association

TABLE OF CONTENTS

EXECUTIVE SUMMARY

In this report, we discuss the models available for estimating the cost of equity for the purpose of the Natural Gas Rules in Australia. Given that the new Rule 87 requires relevant estimation methods, financial models and market data to be considered, as well as the "prevailing conditions in the market for equity funds", this report focuses on the characteristics of the various models, how they perform under various market conditions, and therefore how to assign weight to a method, model or other data based on prevailing market or industry conditions. Further, the report finds that practitioners, regulators, and textbooks commonly look to several models or data sources before reaching a conclusion on the cost of equity.

All models have relative strengths and weaknesses, with the result that there is no one model that is the most suitable for estimating the cost of equity at any given time or for any given company. As our colleague and MIT professor Stewart Myers has put it eloquently "Use more than one model when you can. Because estimating the opportunity cost of capital is difficult, only a fool throws away useful information." This report provides a set of guidelines that can be used in deciding which models should have more weight than others under different market, industry, or company-specific circumstances.

The focus of the report is on the key characteristics of the various cost of equity estimation methods available for a decision maker and circumstances under which each method may be more or less suitable. It is imperative that the choice of model(s) and their implementation take into account the prevailing economic conditions, industry specifics as well as characteristics of the firm for which the cost of equity is being determined, because, according to the circumstances, each model can show bias. We therefore emphasize that there is no single or formulaic approach to estimating the cost of equity. Evidence from academics, practitioners and regulators alike agree that a mechanistic reliance on a single model, without regard to changing market or industry conditions, may deliver spurious results.

The different models should be applied to a set of comparable firms, rather than the single firm for which the cost of equity is to be determined, because all methods for estimating the cost of equity introduce significant noise or uncertainty. Applying the models to a set of comparator firms generates a range of cost of equity estimates for each model. Consideration of prevailing economic conditions, industry specifics, and characteristics of the firm for which the cost of equity is to be determined should go to the weight that is put on each model in deriving an overall reasonable range for the cost of equity.

For example, a dividend growth model might have more weight and the Sharpe–Lintner CAPM less weight when (as currently) interest rates on government bonds are unusually low. Conversely, a dividend growth model might have less weight, and the CAPM more weight, in a sector where growth forecasts are considered to be less reliable. In addition, empirical results from the Sharpe–Lintner CAPM suggest that results may be biased for firms with beta significantly different from one. In addition to the traditional Sharpe-Lintner CAPM and dividend growth models, the report also discusses other models such as the Black CAPM, the Fama-French model, the Consumption CAPM, and the Arbitrage Pricing Theory. We also touch upon new developments in implementing the dividend discount model and on other data and evidence that is sometimes used in combination with the models mentioned above.

Once a reasonable range for the cost of equity has been identified, selecting a point within that range is a matter of judgment, but that judgment can be guided by considering the riskiness of the firm at hand relative to the riskiness of the comparable firms used to generate the cost of equity estimates. Only non-diversifiable risks should be included—for example, variation in demand, which might be more highly correlated with general economic growth for a utility with significant industrial load than for a utility serving mostly residential customers.

I. INTRODUCTION

The Australian Energy Market Commission recently changed the rules that guide the regulation of pipelines (and other regulated entities) in Australia. The Australian Pipeline Industry Association (APIA) has therefore asked *The Brattle Group* (*Brattle*) to review the methods that are currently used or could be used to estimate the cost of equity capital for the purposes of the National Gas Rules in Australia. As part of this exercise, the APIA has asked us to review how academics, practitioners and regulators worldwide think models should be used, and how they have been used in determining the cost of equity for regulated entities. Thus, in this report, we discuss examples of regulatory approaches in the U.S., Canada and the U.K. where regulators have considered a number of methods for estimating the cost of equity capital, and have determined the optimal use of these multiple evidence sources in order to provide greater confidence in their results. The report also includes a discussion of the recommendations of academics and practitioners with regards to the use of several cost of equity estimation models.

The report focuses on the new Rule 87 and the new *allowed rate of return objective,* which, in order to be achieved, requires that "regard must be had to relevant estimation methods, financial models, market data and other evidence"[1] in determining the overall rate of return, and that "regard must be had to the prevailing conditions in the market for equity funds"[2] in determining the cost of equity component of the overall rate of return. We therefore focus on introducing a broad set of methods for cost of equity estimation, the risk positioning of a company relative to the industry or other companies, and methods relied upon by regulators and practitioners around the globe.

Section II provides some background for cost of equity estimation. *Section III* focuses on the evolution, theoretical underpinnings, and characteristics of various cost of equity estimation methods including (a) the Sharpe-Lintner Capital Asset Pricing Model (CAPM), (b) variations of the CAPM such as the Empirical CAPM (ECAPM) and the Consumption-Based CAPM, (c) the Fama-French Three-Factor Model, (d) the Arbitrage Pricing Theory, (e) Dividend Discount

1 Rule 87, s.5a.

2 Rule 87, s.7.

Models including both Single-Stage and Multi-Stage models, and (f) Other Models including the so-called Risk Premium method, Residual Income Valuation model, Ibbotson's Build-up method, the Comparable Earnings model, Market-to-Book and Earnings Multiples approaches. We note that the above is not intended to be an exhaustive list of models that regulators or practitioners could feasibly rely upon in determining the cost of equity. We also note that as finance evolves, new estimation methods, financial models, market data and other evidence may become available that could be informative for the purpose of estimating the cost of equity. *Section IV* discusses implementation issues, summarizes the characteristics of the various cost of equity estimation methods, and discusses how to use the models under different market conditions. Additionally, this section includes a description of how to position the target entity relative to a sample based on its relative risk.

II. METHODS, FINANCIAL MODELS, MARKET DATA AND OTHER EVIDENCE USED TO ESTIMATE THE COST OF EQUITY CAPITAL

A. INTRODUCTION

To determine the cost of capital, one must evaluate the cost of equity, the cost of debt (possibly both long-term and short-term) and the capital structure of the company subject to regulation. This report focuses on the estimation of the cost of equity component of a regulated entity's cost of capital.

To determine the cost of equity for a specific utility, decision makers typically look at a range of evidence presented to them. In the case of regulators, they commonly review expert evidence, models and other information presented by experts, the utility and other stakeholders, and also evidence that the regulator itself generates. Ultimately, a degree of judgment is used to arrive at a final determination having considered this evidence. The evidence considered might include different financial models which are used to extract estimates of the cost of equity for similar utilities from market data (stock prices). It might also include estimates from models that take equity analyst forecasts as inputs. For example, three regulators, the Alberta Utilities Commission (AUC), the Ontario Energy Board (OEB), and the U.S. Surface Transportation Board (STB), recently reviewed their cost of equity estimation approach. These three regulators noted that each methodology has its own strengths and weaknesses and subsequently decided to rely on more than one model or approach to determine the cost of equity.[3] We further note here that in discussing the characteristics of each model or practice, we are pointing to advantages or disadvantages of the models assuming they will inform the ultimate decision, but we do not expect any one model to be the only piece of evidence considered and used by either regulators or practitioners in determining the cost of equity.

This report describes a number of models that can be used to inform the regulator's judgment in determining the cost of equity. It also discusses the views of academics and practitioners with regards to the determination of the cost of equity from multiple estimation models.

Below, we describe methodologies that regulators and practitioners use in Australia, Canada, Europe, the U.K., and the U.S., as well as some more recent methods that have been proposed, albeit it is not clear from the record the extent to which regulators have used these methods. It is important to realize that in many jurisdictions the regulator does not look to a single model, but considers all the evidence in front of it and then makes a decision. In North America, where the consideration of more than one model and possibly other evidence is common, the ultimate decision is often not explicit about the weight assigned to each model or other pieces of evidence.[4]

B. The Use of Models for Cost of Capital Estimation

1. Context

The National Gas Rules set the framework for how the AER (and the ERAWA) determine access arrangements for covered gas pipelines, including the rate of return on capital which is a component of the charges paid by pipeline customers. We understand that the regulators are

3 Alberta Utilities Commission, Decision 2011-474, p. 27-28, Ontario Energy Board, EB-2009-084, p. 38, Surface Transportation Board, Ex Parte 664 (Sub-No. 1), pp. 3-5.

4 There are exceptions to this rule such as the Federal Energy Regulatory Commission and the Surface Transportation Board in the U.S., and the Canadian Transportation Agency. However, most U.S. state and Canadian federal and provincial regulators do not have a specified cost of equity estimation method. Instead, they commonly hear evidence from a number of different parties on cost of equity (often including regulatory staff). Based on this information the regulator then makes its decision.

currently developing guidelines as to how the rate of return provisions of the NGR will be applied in future determinations.

The NGR state that "… the rate of return for a service provider is to be commensurate with the efficient financing costs of a benchmark efficient entity with a similar degree of risk… ".[5] In addition, the NGR require that "[I]n determining the allowed rate of return, regard must be had to: (a) relevant estimation methods, financial models, market data and other evidence;…"[6] and that "[i]n estimating the return on equity under subrule (6), regard must be had to the prevailing conditions in the market for equity funds."[7]

In this report, we describe the estimation methods, financial models, market data and other evidence that may be relevant for setting the cost of equity in future access arrangement determinations in Australia.

a) The cost of capital

The cost of capital is a key parameter in regulatory settings, because it contributes to determining the return to the company's investors. Defined as *the expected rate of return in capital markets on alternative investments of equivalent risk*, it is the expected rate of return investors require based on the risk-return alternatives available in competitive capital markets. Stated differently, the cost of capital is a type of opportunity cost: it represents the rate of return that investors could expect to earn elsewhere without bearing more risk.[8, 9]

While the details of energy network regulation are different in different jurisdictions, regulators are in many jurisdictions required to set a cost of capital which provides investors in rate-regulated entities a reasonable opportunity to earn a return on their investment equal to the opportunity cost of capital.

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5 Rule 87(3).

6 Rule 87(5).

7 Rule 87(7).

8 "Expected" is used in the statistical sense: the mean of the distribution of possible outcomes. The terms "expect" and "expected" in this Report, as in the definition of the cost of capital itself, refer to the probability-weighted average over all possible outcomes.

9 The cost of capital is a characteristic of the investment itself, not the investor.

In the U.K., the Gas Act 1986 requires the regulator to have regard to "the need to secure that licence holders are able to finance the[ir] activities.…"[10] Ofgem has also said:

> In setting price controls, we are required to have regard to the ability of efficient network companies to secure financing in a timely way and at a reasonable cost in order to facilitate the delivery of their regulatory obligations.[11]

In Canada, the National Energy Board has explained the "fair return standard" as follows:

> The Board is of the view that the fair return standard can be articulated by having reference to three particular requirements. Specifically, a fair or reasonable return on capital should:
>
> - be comparable to the return available from the application of the invested capital to other enterprises of like risk (the comparable investment standard);
> - enable the financial integrity of the regulated enterprise to be maintained (the financial integrity standard); and
> - permit incremental capital to be attracted to the enterprise on reasonable terms and conditions (the capital attraction standard).[12]

Finally, in the U.S., the starting point for the Federal Energy Regulatory Commission's approach to determining the cost of equity is Supreme Court precedent, which states that:

> the return to the equity owner should be commensurate with the return on investments in other enterprises having corresponding risks. That return, moreover, should be sufficient to assure confidence in the financial integrity of the enterprise, so as to maintain its credit and to attract capital.[13]

While these legal standards are differently worded, a common thread is that regulated entities are allowed to earn a return that is comparable to that of other enterprises of similar risks and which enables the regulated entity to finance its operations. The legal standards in North America and Europe are not specific about how to accomplish the goal(s).

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[10] Gas Act 1986, s. 4AA(2)(b).

[11] *RIIO-T1: Final Proposals for National Grid Electricity Transmission and National Grid Gas*, Ofgem (December 2012), paragraph 4.6.

[12] RH-2-2004, p. 17. See also the Supreme Court of Canada's decision in Northwestern Utilities Limited v. City of Edmonton [1929] S.C.R. 186.

[13] *FPC v. Hope Natural Gas Co.*, 320 U.S. 591 (1944). *Bluefield Water Works & Improvement Co. v. Public Service Comm'n*, 262 U.S. 679 (1923), cited in FERC policy statement on the *Composition of Proxy Groups for Determining Gas and Oil Pipeline Return on Equity*, April 17 2008, p. 2.

b) What should we expect from models?

It is useful to recognize explicitly at the outset that models are imperfect. All are simplifications of reality, and this is especially true of financial models. Simplification, however, is also what makes them useful. By filtering out various complexities, a model can illuminate the underlying relationships and structures that are otherwise obscured. After all, while a perfect scale model representation of the city might be highly accurate, it would make a poor road map. It is therefore imperative that regulators and other users of the models use sound judgment when implementing and using the models — there is no one model or set of models that are perfect.

The gap between financial models and reality can sometimes be quite significant (as was painfully demonstrated by the recent financial crisis). There is no single, widely accepted, best pricing model to estimate the cost of capital — just as there is still no consensus on some fundamental issues, such as the degree to which markets are efficient. Analysts have a host of potential models at their disposal, and it must be acknowledged that cost of capital estimation continues to require the exercise of judgment. Practitioners, regulators, as well as textbooks therefore often recommend that the "best practice" for ensuring robustness is to look at a totality of information.[14] These practitioners, regulators and texts therefore use or present a variety of methodologies that may be applicable for the determination of the cost of equity in a specific circumstance.

While no model is perfect, there are certain features that make models more useful from a regulatory perspective. For example, it is desirable to have models and methods that i) are consistent with the goal being pursued, ii) are transparent, iii) produce consistent results, iv) are robust to small deviations or sampling error, v) are as simple as possible (while maintaining reliability), vi) can be replicated by others (*e.g.,* data is widely available), and vii) recognize the regulatory context and legislative requirements in which the regulatory body operates. Clearly different models will satisfy these criteria to differing degrees, and different models may be better suited to different regulatory jurisdictions.

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[14] See, for example, the Ontario Energy Board's EB-2009-084 decision, December 2009, the U.S. Surface Transportation Board's Ex. Parte 664 (Sub-No. 1) decision, January 2009, Morningstar *Ibbotson Cost of Capital 2012 Yearbook*, and Roger A. Morin, *New Regulatory Finance*, Public Utilities Reports Inc., 2006, Chapter 15.

For example, the CAPM and the Dividend Discount Model (DDM) both are transparent and developed from economic theory. Their results can be replicated easily, since the data required are widely available from many public sources. However, the implementation of the CAPM and DDM requires a number of subjective decisions – decisions which can be hotly contested and can lead to significantly different results. The CAPM, for instance, relies on a risk-free rate that is currently driven unusually low by the recent flight to quality and the easing of monetary policy. The model also requires an estimate of the market risk premium, which may pose difficulties in times of high market volatility.

The single-stage DDM is especially sensitive to the growth rate estimates used, which can vary widely among analysts and over time, contradicting the underlying assumption of growth stability inherent in this model. The variability in growth rates and stock prices may increase when industries are in transition, making the reliability of the DDM more questionable in such periods. In addition, it has become more common to distribute cash to shareholders in a form other than dividends. For example, regulated entities in both the U.S. and the U.K. have had share buyback programs that substantially affected the number of shares, and these are not captured in the standard DDM.[15] Some of the growth rate problems in the DDM are alleviated by the reliance on a multi-stage version of the model as done by, for example, *The Brattle Group*, Morningstar *Ibbotson Cost of Capital Yearbook*, and the U.S. Surface Transportation Board (STB).[16]

Similar problems arise in other models that inherently rely on data for a sample of companies and data for economic phenomena that may be changing quickly; the latter is especially true for models such as the Fama-French, where the reliance on three risk factors can lead to highly variable results across time. As a result, no single model is ideal and the implementation of any model necessarily requires choices that involve subjective judgments. Therefore, it is important to look to the totality of relevant information available from methods, models, market data and

15 See, for example, National Grid Share Buyback Programme and Spectra Energy Corp's 2008 form 10-K.

16 *The Brattle Group* is a consulting firm, Morningstar is a commercial provider of data and the STB is a U.S. federal regulator.

other evidence. The relative strengths and weaknesses of the various cost of equity estimation models are outlined in further detail in *Section III* of this report.

c) Model stability and robustness

For an estimation model used to determine the cost of equity, stability and robustness over time are desirable unless economic conditions have truly changed. Stability means that cost of capital estimates done in similar economic environments should be similar, not only period-to-period but also company-to-company within a comparable sample. Robustness is meant here as the ability of a model to estimate the cost of capital across different economic conditions.

In general, all of the models discussed here have characteristics that make them more or less suited to one economic environment versus another. As such, all individual models can be, and often are, subject to some instability over time. For example, the currently very low government bond yields lead to very low cost of equity estimates using the CAPM — sometimes less than the costs of debt of investment-grade companies! During the early 2000s, the DDM was subject to substantial criticism due to allegations of analysts' optimism bias. Similarly, the risk premium model[17] has produced very different results in times of high and low inflation that did not necessarily reflect the true cost of capital. Thus, estimates at any given point of time may seem too high or too low, and it is important to understand whether the estimated figures are driven by actual changes in the systematic risk of the regulated entities, or by something else (*e.g.,* data irregularities). It is for these reasons that regulators in the U.S. and Canada often rely on and analysts recommend relying on the results from at least two estimation models.[18]

A notable example of a regulator that has acknowledged the difficulty in relying on only one model or method is the U.S. Surface Transportation Board. The STB in 1982 started to rely on a single-stage DDM to determine the cost of equity for U.S. railroads. However, in 2006, the shippers on the railroads complained that the estimated cost of equity was out of line with reality,

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17 The risk premium used in the risk premium model is different from the market risk premium used in the CAPM. The model is frequently used in U.S. regulatory proceedings.

18 See, for example, U.S. Surface Transportation Board, Ex Parte 664 (Sub-No. 1), served January 28, 2009; Mississippi Power, Performance Evaluation Plan, Rate Schedule 'PEP-5', November 9, 2009 (http://www.mississippipower.com/pricing/pdf/pep-5.pdf); Ontario Energy Board, EB-2009-0084, Report of the Board on the Cost of Capital for Ontario's Regulated Utilities, Issued December 11, 2009.

because forecasted growth rates for railroad companies were substantially higher than the economy-wide forecasted growth. The shippers argued successfully that such high growth rates could not be sustained forever as assumed by the single-stage DDM, and the STB thus initiated a rulemaking proceeding to review and eventually determine how to set the allowed cost of equity going forward. Following several years of expert submissions and proceedings, the STB decided to rely on an equally-weighted average of the Sharpe-Lintner Capital Asset Pricing Model and a specific version of the multi-stage DDM. In doing so, the STB concluded:

> if our exploration of this issue has revealed nothing else, it has shown that there is no single simple or correct way to estimate the cost of equity for the railroad industry, and countless reasonable options are available. Both the CAPM and the multi-stage DCF [DDM] models we propose to use have their own strengths and weaknesses, and both take different paths to estimate the same illusory figure. By using an average of the results produced by both models, we harness the strengths of both models while minimizing their respective weaknesses. The result should be a stable yet precise estimate of the cost of equity that we can use in future regulatory proceedings and to gauge the financial health of the railroad industry.[19]

2. Risk-Return Tradeoff

At its most basic level, an asset (security) is a claim to a stream of future (risky) cash flows and sometimes with potential rights to exert some control over those flows. Financial markets allow investors to exchange these claims, and therefore risks. Through trade, investors are able to create different packages of risks and returns than could be achieved by holding individual securities (or fixed packages of securities), and investors can change their risk exposure over time. Because investors are assumed to be risk-averse, they evaluate the universe of risky investments on the basis of a risk-return trade-off. Investors can only be induced to hold a riskier investment if they expect to earn a higher rate of return on that investment. The essential tradeoff between risk and the cost of capital is depicted in Figure 1 below.

[19] *U.S. Surface Transportation Board, Ex Parte 664 (Sub-No. 1)*, served January 28, 2009, p. 15.

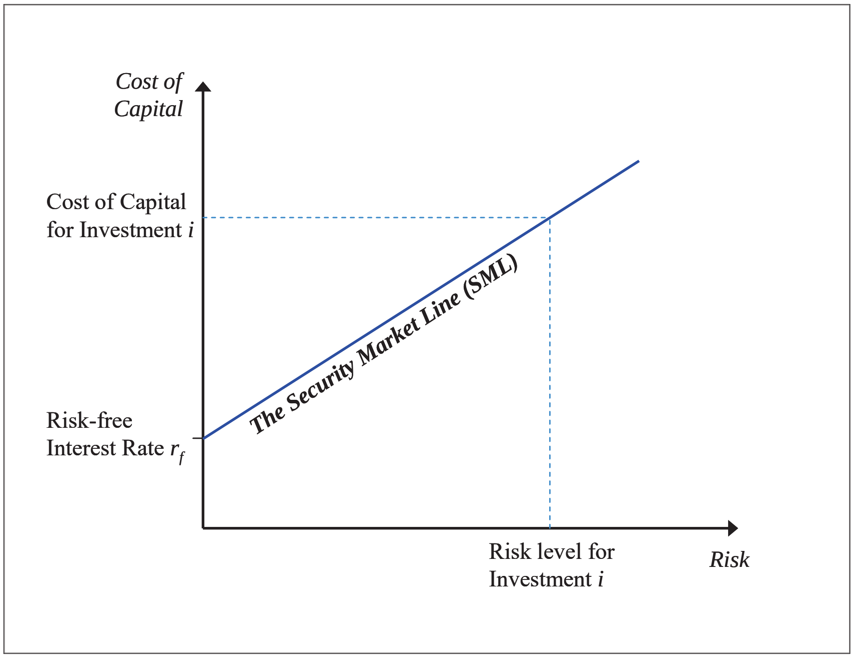

Figure 1: Security Market Line

III. COST OF EQUITY ESTIMATION MODELS

A. Sharpe-Lintner Capital Asset Pricing Model

One of the most common pricing models used in business valuation and regulatory jurisdictions is the Sharpe-Lintner CAPM, which in its simplest form is depicted in Figure 2 below.

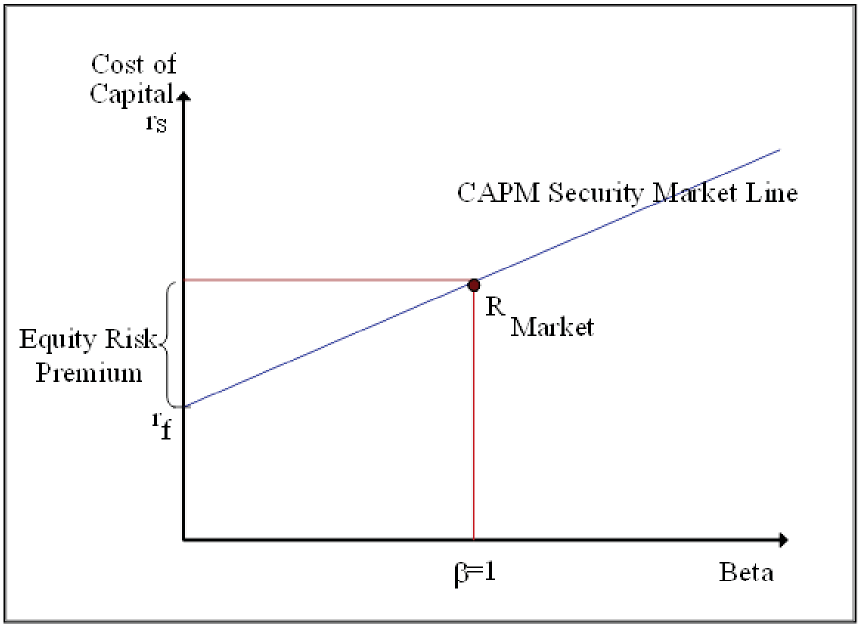

Figure 2: Capital Asset Pricing Model

Thus, in the world in which the CAPM holds, the expected cost of (equity) capital for an investment is a function of the risk-free rate, a measure of systematic risk (beta), and an expected market risk premium (MRP):[20]

$$E(r_S - r_f) = \beta_S \times E(r_M - r_f) \qquad \textbf{(1)}$$

where r_S is the cost of capital for investment *S*; r_M is the return on the market portfolio, r_f is the risk-free rate, and β_S is the measure of systematic risk for the investment *S*. The $(r_M - r_f)$ term is known as the market risk premium (MRP),[21] and β_S measures the response of the stock S to systematic risk. Re-arranging this equation produces the CAPM's formula for the cost of (equity) capital of a traded asset:

$$r_S - r_f = \beta_S \times MRP \qquad (2)$$

20 While the CAPM model frequently is applied to equity capital, it applies to all assets.

21 We note that some European regulators use the term Equity Risk Premium (ERP) instead of MRP.

To implement the CAPM, it is necessary to determine the risk-free rate, r_f, and to estimate the MRP and beta, β_S.

1. Evolution of the CAPM

The CAPM was developed as a theoretical equilibrium model and fits with the intuition of a risk-return tradeoff. The development of the CAPM signaled the first time that economists were able to quantify risk and the reward for bearing it. Under the CAPM, the expected return of an asset must be linearly related to the covariance of its return with the return of the market portfolio.[22]

Markowitz (1959)[23] first laid the groundwork for the CAPM. In his seminal research, he expressed the investor's portfolio selection problem in terms of expected return and variance of return. He argued that investors would optimally hold a mean-variance efficient portfolio, that is, a portfolio with the highest expected return for a given level of variance. Sharpe (1964)[24] and Lintner (1965)[25] built on Markowitz's work to develop economy-wide implications. They showed that if investors have homogeneous expectations and optimally hold mean-variance efficient portfolios, then, in the absence of market frictions, the portfolio of all invested wealth, or the market portfolio, will itself be a mean-variance efficient portfolio. This is the heart of the Sharpe-Lintner CAPM. The standard CAPM equation (as expressed in Equation (2)) is a direct implication of this statement.

The Sharpe-Lintner CAPM assumes unrestricted lending and borrowing at a risk-free rate of interest. In the absence of a risk-free asset, Black (1972)[26] derived a more general version of the CAPM which did not rely on this potentially problematic assumption. In this version, known as the Black CAPM, the expected return of an asset in excess of the "zero-beta" return is linearly

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[22] For a basic introduction to risk-return models, see R.A. Brealey, S.C. Myers, and F. Allen, Principles of Corporate Finance, 10ed, 2011 (Brealey, Myers & Allen (2011), pp. 192-203.

[23] H. Markowitz, "Portfolio Selection: Efficient Diversification of Investments," 1959, John Wiley, New York.

[24] W. Sharpe, "Capital Asset Prices: A Theory of Market Equilibrium under Conditions of Risk," *Journal of Finance* 19, 1964, pp. 425-442.

[25] J. Lintner, "The Valuation of Risky Assets and the Selection of Risky Investments in Stock Portfolios and Capital Budgets," Review of Economics and Statistics 47, 1965, pp. 13-37.

[26] F. Black, "Capital Market Equilibrium with Restricted Borrowing," *Journal of Business* 45, 1972, pp. 444-455.

related to its market beta. In essence, the return on the risk-free asset in Equation (2) above is substituted with a return on a zero-beta portfolio associated with the market portfolio. This zero-beta portfolio is defined to be the portfolio that has the minimum variance of all portfolios uncorrelated with the market portfolio. The empirical implementation of the Black CAPM is often referred to as the Empirical CAPM or ECAPM.

Empirical tests of the Sharpe-Lintner CAPM have focused on three implications of equation (2): (i) The intercept is zero; (ii) The market beta completely captures the cross-sectional variation of expected excess returns; and (iii) The market risk premium is positive.

There is substantial literature on empirical tests of the CAPM since its development in the 1960s, with mixed results. Black, Jensen and Scholes (1972)[27], Fama and Macbeth (1973),[28] and Blume and Friend (1973)[29] found empirical evidence to be consistent with the mean-variance efficiency of the market portfolio. However, Black, Jensen and Scholes (1972) and Fama and MacBeth (1973) identified a fundamental challenge to the CAPM; namely that low-beta stocks have higher average returns than predicted by the CAPM, and high-beta stocks lower average returns. In other words, the empirical estimates are consistent with pivoting the Security Market Line (SML) around beta = 1 compared to the Sharpe-Lintner CAPM. This suggests that the cost of capital for regulated companies, which often have a beta less than one, will be underestimated by the traditional CAPM.[30]

Several subsequent studies confirmed the robustness of this result and proposed explanations revolving around market frictions, such as different borrowing and lending rates, and the role of

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27 F. Black, M.C. Jensen, and M. Scholes, "The Capital Asset Pricing Model: Some Empirical Tests," *Studies in the Theory of Capital Markets*, Praeger Publishers, 1972, pp. 79-121.

28 E. Fama and J. Macbeth, "Risk, Return, and Equilibrium: Empirical Tests," *Journal of Political Economy* 81, 1973, pp. 607-636.

29 M. Blume and I. Friend, "A New Look at the Capital Asset Pricing Model," *Journal of Finance* 28, 1973, pp. 19-33.

30 Implementing a long-run version of the CAPM which uses (annualized) long-horizon returns (*e.g.*, with long bond rates as risk-free rate) generally produces a flatter SML than obtained by using short-rates, due to the general presence of an upward sloping yield curve. While this partially compensates for the empirically observed flattening, it is not sufficient to explain all of the observed flattening of the SML. That is, even implementations that utilize a long-run risk-free interest rate require a further, albeit smaller, adjustment to match the empirical SML.

taxes. Nevertheless, the empirical evidence suggested significant movement in the SML, often flattening, to the point that Fama and French (1992) found a zero slope in the empirical SML.[31] Fama and French (1992, 1993[32]) in turn suggested that factors other than the risk relative to the market, such as size and book-to-market value ratios (among others) were significant in explaining the observed SML. Fama and French found that firms with high book-to-market ratios and small size have higher average returns than is predicted by the standard CAPM, and vice versa. Their work culminated in the model now known as the Fama-French three-factor model.

The Fama-French papers cited above continued in the vein of the so-called "anomalies" literature that had arisen in the late 1970s. These anomalies can be thought of as firm characteristics that provide incremental explanatory power for the sample's mean returns beyond the market. Earlier anomalies included the price-earnings ratio effect (first reported by Basu (1977)[33]) and the detection of the size effect (Banz (1981)[34]). For example, Basu found that firms with low price-earnings ratios have higher sample returns than those predicted by the standard CAPM. The price-earnings ratio and size anomalies are at least partially related, as low price-earnings-ratio firms tend to be small.

The Empirical CAPM (ECAPM), described further in the section below on variations of the standard CAPM, is an alternative method of correcting for the empirical flattening of the SML. The ECAPM can be viewed from the positive school of thought as a practical adjustment that can be made to measure the cost of capital. It can be applied without knowing the "cause" of the increased intercept and decreased slope of the SML relative to the Sharpe-Lintner CAPM.

To sum up, there has been a wealth of statistical evidence contradicting the Sharpe-Lintner CAPM over the past 40 years or so and controversy remains about how the evidence should be

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31 E.F. Fama and K.R. French, "The Cross-Section of Stock Expected Returns," *Journal of Finance* 47, 1992, pp. 427-465.

32 E.F. Fama and K.R. French, "Common risk factors in the returns on stocks and bonds," *Journal of Financial Economics* 33, 1993, pp. 3-56.

33 S. Basu, "The Investment Performance of Common Stocks in Relation to Their Price to Earnings Ratios: A Test of the Efficient Market Hypothesis," *Journal of Finance* 32, 1977, pp. 663-682.

34 R. Banz, "The Relationship Between Return and Market Value of Common Stocks," *Journal of Financial Economics* 9, 1981, pp. 3-18.

interpreted. Some argue that the standard CAPM should be replaced by multifactor models with several sources of risk, such as the Fama-French model. Others argue that evidence against the CAPM is overstated due to potential mis-measurement of the market portfolio, data mining or sample selection biases. One further key deficiency in the CAPM is that it is a static model which ignores consumption decisions, and treats asset prices as being determined by the portfolio choices of investors who have preferences defined over wealth one period in the future. Implicitly, these models assume that investors consume all their wealth after one period or at least that wealth uniquely determines consumption. This assumption does not match with reality. Therefore, to make the model more realistic, intertemporal equilibrium asset pricing models have been developed that model consumption and portfolio choices simultaneously. An example of such a model is the consumption-based CAPM, which is described further in *Section III.B.2* below.

2. CAPM Implementation Issues

Fundamentally, an analyst using the CAPM must determine three parameters to implement the model: the risk-free rate (r_f), the MRP, and the asset's beta (β_S) as shown in Equation (2) above. Through the determination (or estimation) of the parameters on the right-hand side of Equation (2), the analyst obtains an estimate of the cost of equity, r_S.

It is common to choose (i) a forecasted yield on government bonds (as is often done in Canada), (ii) a current measure of local government bond yields (a common practice in the U.S.), or (iii) a regional or global measure of the current yield on government bonds (*e.g.*, the Netherlands).

Like the risk-free rate, the choice of market proxy is local, regional, or global. The choice of risk-free rate and market index should be consistent, so the cost of equity is estimated as either a local, regional, or global figure.

For many years it was common to estimate the MRP from an arithmetic average of historical realized MRPs, measured as the long-term excess of market returns over the risk-free rate in the country or region of interest. European decision makers have in recent years often looked to the study of Dimson, Marsh, and Staunton to determine the MRP, while many in the U.S. commonly look to evidence from Morningstar (formerly Ibbotson).[35] Some decision makers and analysts also look to either forecasted MRPs or survey results.[36] The estimation of the MRP remains controversial and the resulting cost of equity estimates generated by the standard CAPM are sensitive to the choice of MRP.

3. Characteristics of the CAPM

While the strengths and weaknesses of the CAPM inherently depend on its exact implementation, the following are some generic strengths:

- The model is transparent, well-documented and relies on economic theory.
- Data needed for the model are readily available if applied to companies with a reasonable trading history in well-developed markets. It is therefore also auditable.
- The model is sensitive to economic conditions through risk-free rates and market performance, as well as to changes in companies' systematic risk.

Among the weaknesses of the CAPM are the following:

- The model is very sensitive to developments in the risk-free rate that may reflect monetary policy rather than economic conditions.
- The model is sensitive to different estimation procedures for the MRP.
- Because beta estimates rely on historical data, there may be a delay in incorporating changes in systematic risk. MRP estimates based on historical data are also backward-looking.
- The model may downward bias cost of equity estimates for low-beta stocks and vice versa (see section on ECAPM below).

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35 Texts such as Morningstar, *Ibbotson SBBI 2012 Yearbook*, p. 55-56 recommends to use the income return rather than total return or yield as the risk-free rate. The income return consists of the coupon payment divided by the bond price rather than the total return as this is the true risk-free component of the bond return. Capital gains or losses carry risk.

36 For examples, see Bank of England, "Financial Stability Report," June 2012, Chart 1.11 and P. Fernandez, J. Aguirreamolla and L. Corres (2013), "Market Risk Premium used in 82 countries in 2012: a survey with 7,192 answers," IESE Business School, University of Navarra, SSRN 2084213.

- The model incorporates only one source of risk (the market), and therefore does not reflect the effects of, for e.g., consumption or economic growth, technological or regulatory risks.
- The CAPM is a static model and therefore ignores the dynamics of investment behavior and hedging.
- The model is based on the assumption that all investors optimally hold well-diversified portfolios and therefore only care about systematic risks. This assumption does not necessarily hold, however, when investor expectations about returns and investment opportunities are heterogeneous.

Because the model was developed as a generic approach to determining the cost of capital for companies, it does not specifically take industry factors or the context in which it is being used into account. However, the CAPM is a well-founded and commonly used model that relies primarily on readily available information. It may be less stable than ideal because changes in interest rates affect the risk-free rate and market volatility affects the beta estimates. Furthermore, determination of which sample companies to rely upon and the MRP remains controversial.

The CAPM has been widely used for a long period of time for a variety of reasons. The primary reason for the model's widespread use is its solid economic foundation, making it taught in every introductory finance class. The model is also relatively simple to implement. Most market-based models that have been developed since the CAPM take the CAPM as their point of departure to generalize the model. Also, academic researchers have not found any one alternative to the model that is easily applied in practice.

B. VARIATIONS ON THE CAPM

1. The Empirical CAPM

As described above, the ECAPM is one way of correcting for the empirical flattening of the Security Market Line (SML). Specifically, the ECAPM directly adjusts the CAPM SML by a parameter, alpha, that can be controlled for sensitivities, *etc.* Formally, the ECAPM relation is given by Equation (3) below:

$$r_S = r_f + \alpha + \beta_S \times (MRP - \alpha) \quad (3)$$

where α is the "alpha" adjustment of the risk-return line, a constant, and the other symbols are as defined above. The alpha adjustment has the effect of increasing the intercept but reducing the slope of the SML, which results in a security market line that more closely matches the results of empirical tests.

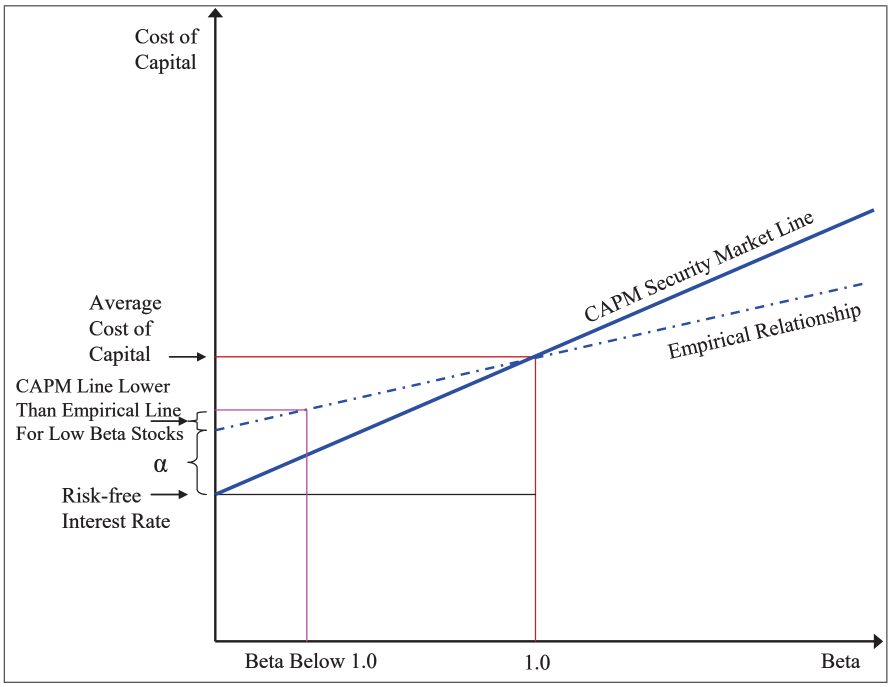

Figure 3: The Empirical Security Market Line

The academic literature has estimated a fairly wide range of alpha parameters, using primarily U.S. data, of approximately 1 to 7 percent.[37] While this is a rather large range, much of the variation between studies arises from differences in methodology and time periods so that the alpha estimates are not strictly comparable. The ECAPM is included among the models relied upon by some decision makers and experts including U.S. state and Canadian provincial regulators.[38]

37 See Appendix A for details.

38 The Mississippi Public Service Commission in the U.S. and the Alberta Utilities Commission in Canada have included the ECAPM as one of the models used to determine the cost of equity.

2. The Consumption-Based CAPM

The Consumption CAPM is an example of an intertemporal equilibrium model. This model aggregates investors into a single representative agent and considers a changing investment opportunity set over time, unlike the static standard CAPM. The representative agent is assumed to derive utility from the aggregate consumption of the economy. In this model, the stochastic discount factor, (defined such that the expected product of any asset return with the stochastic discount factor is equal to one), is equal to the intertemporal marginal rate of substitution for the representative agent.[39] Through mathematical equations, (the so-called Euler equations), asset returns and consumption can be linked. Using this setup, the model explains the risk premia on assets using the covariance between their returns and the intertemporal aggregate consumption marginal rate of substitution. As a result, the consumption-based pricing model can help explain the observed phenomenon of predictable variations in asset risk premia over time, and expands the risk-return relation to allow for a time-varying relationship between a stock's risk and return.

An important feature of the consumption model is that the expected conditional risk premium on an asset is related to its predicted conditional volatility. In particular, the relationship between a stock's risk premium and its conditional volatility could be positive or negative, depending on the extent to which the stock is an intertemporal hedge against shocks to the marginal utility of consumption. Furthermore, hedging assets have volatility patterns that could lead to expected rates of return lower than the risk-free rate. Note that this would generally not be the case for public utility stocks, since they are not viewed as defensive stocks.

Several versions of the consumption-based CAPM have been developed. In one of the more applicable versions, the addition of assumptions about the preferences of investors allows the model to explain the risk premia on assets through their covariance with consumption growth, so that the model, to a degree, can explain variations in the excess returns of risky assets over time. Other versions of the model allow time-varying investor risk aversion to explain predictable movements in risk premia.

[39] This is equal to the discounted ratio of marginal utilities for the representative agent in two successive periods.

In a regulatory setting, the consumption CAPM can be used to either project the expected risk premium over the risk-free rate or verify the relied-upon market risk premium. The model has not commonly been used in a regulatory setting, but a recent implementation of Ahern, *et al.* (2012)[40] was developed explicitly to estimate the cost of equity for regulated entities. The description below therefore focuses on this version of the model.

The Ahern model is estimated using a so-called GARCH-in-mean (GARCH-M) model, which unlike the Sharpe-Lintner CAPM allows for the stock returns to depend on a volatility (variance) measure. In particular, the GARCH-M specification is such that the expected risk premium on a stock is a linear function of its conditional volatility. In this model, the parameter of interest, α, which represents the linear relationship between the risk premium on the stock and the conditional volatility in the GARCH-M model, can be translated into the following implication of the theoretical asset pricing model described above:

$$\alpha = -\frac{vol_t[M_{t+1}]}{E_t[M_{t+1}]} corr_t[M_{t+1}, R_{t+1}] \qquad (4)$$

where R_{t+1} is the expected total return on the public utility stock index or individual utility stock, and M_{t+1} is the stochastic discount factor (SDF), *i.e.*, the (aggregate) consumption intertemporal marginal rate of substitution. The equation above implies that the coefficient on volatility will be positive (*i.e.*, returns and conditional volatility will be positively correlated) if the conditional correlation between the SDF and the asset return is negative, *i.e.*, if the stock is not a hedging asset.

Ahern, *et al.* (2012) estimate the conditional risk-return model using monthly total returns from January 1928 to December 2007 on the S&P Public Utilities stock index, and the monthly Moody's public utility Aa, A, and Baa yields for the cost of debt. The authors then compare the model's performance with the performance of, for example, the Sharpe-Lintner CAPM. The estimates of the cost of common equity from the model are similar to the CAPM values and

[40] P.A. Ahern, F.J. Hanley, R.A. Michelfelder, "New Approach to Estimating the Cost of Common Equity Capital for Public Utilities," *Journal of Regulatory Economics*, 2012 (Ahern, *et al.* 2012)

appear to be stable and consistent over time. Thus, the empirical implementation of the theoretical model resulted in cost of equity estimates that appeared to be within a range of reasonableness. The model has been presented in some U.S. regulatory jurisdictions but regulatory decisions based on the model are either still pending or it is not clear how the regulator used the information. Ahern, *et al.* conclude that the consumption-based asset pricing model "should be used in combination with other cost of common equity pricing models as additional information in the development of a cost of common equity capital recommendation".[41]

3. Characteristics of CAPM Variations

As for the CAPM, the strengths and weaknesses of the variations discussed above depend on the implementation of the models. However, some strengths of the models are:

- Both the ECAPM and the Consumption CAPM allow for empirically observed phenomena to be modeled:
    - The ECAPM recognizes the flatter-than-predicted-by-CAPM Security Market Line.
    - The Consumption-CAPM allows for the expected risk premium to vary with asset and investor characteristics, such as conditional volatility and risk aversion.
- Data needed for the models are usually available if applied to companies with a reasonable trading history in well-developed markets. The models are therefore also auditable.
- The models are sensitive to economic conditions. The Consumption-CAPM considers more factors than does the CAPM.

Among the weaknesses of the models are the following:

[41] Ahern, *et al.* (2012), p. 17.

- The ECAPM has not been tested extensively outside the U.S. or in recent market conditions.
- The Consumption CAPM relies on the use of more data than does the CAPM and requires a refined estimation process, which makes it less accessible to a broader audience.

C. The Fama-French Three-Factor Model

The Fama-French model holds that the expected return of a security is described by an augmented CAPM relationship:

$$E(r_S - r_f) = \beta_S \cdot E(r_M - r_f) + s_S \cdot E(SMB) + h_S \cdot E(HML) \qquad (5)$$

where $E(r_M - r_f)$ is the market risk premium (MRP) as used in the CAPM, SMB is the difference in returns between small companies and big companies ("*Small Minus Big*"), and HML is the difference in returns between securities of firms with a high book-to-market equity ratio and a low one (*"High Minus Low"*). The factor loadings s_S and h_S represent security *S*'s "holding" of each of these risk factors, which is to say they are the regression coefficients of r_S on each of the factors.

Evolution of the Fama-French Three-Factor Model

Fama and French (1992) was the last influential paper in a series of academic research into the placement of the empirical SML relative to the theoretical CAPM. Controlling for firm size, the authors found no relationship between the market and expected return (zero beta). Stated differently, any explanatory power that the market beta in the CAPM might have is absorbed by using size to explain the cross-sectional variation in returns. Fama and French interpreted this to mean that market beta (and by extension the CAPM) had zero explanatory power for expected returns. Moreover, they found that all of the variation in returns that were (in other research) associated with size, earnings/price ratios, book-to-market equity ratios, and leverage, could be captured by size and the book-to-market equity ratio alone. Fama and French (1993) ultimately settled on a three-factor model that brought the market return back into the model (size, book-to-market ratio, and market return). Their 1993 paper found that this model explained 90 percent of the variations in the cross-section of returns, and it has since become known as the Fama-French three-factor model.

From an empirical perspective, the Fama-French model is an alternative to the ECAPM – one should not employ a Fama-French model with an alpha adjustment (Equation (3)). However, the interpretation of the findings of Fama and French has been critiqued by many academics as the size and book-to-market factors may proxy for other phenomena.[42]

Standard Implementation:

The SMB factor and HML factor are typically created following Fama & French's (1993) approach. Specifically, at each point in time one allocates each firm into the small or big category, according to whether its market cap is in the top or bottom half of all firms considered. The firms in each half are then value-weighted to form two portfolios: small firms and big firms. The difference in realized returns between each of these portfolios is then taken as the SMB realization in that period. Creation of the HML series is similar, but firms are allocated to the "high" category if their book-to-market ratio is in the top 30th percentile and to the "low" category if their book-to-market ratio is in the bottom 30th percentile. These two time series can then be used to estimate the average SMB and HML, as well as the factor loadings for a given security; *i.e.*, the factors in the regression version of Equation (5), β_S, s_S, and h_S are estimated.

As a practical matter, the SMB and HML factors can be obtained free of charge from Professor Kenneth French's website,[43] where he maintains a database of the factors for regional areas such as Asia-Pacific, Europe, and North America.

42 For a discussion of this critique, see, for example, Black, F., "Beta and return," *Journal of Portfolio Management* 20, 1993, pp. 8-18; A.C. MacKinlay, "Multifactor Models Do Not Explain Deviations from the CAPM," *Journal of Financial Economics* 38, 1995, pp. 3-28; A. Lo and A.C. MacKinlay, "Data-Snooping Biases in Tests of Financial Asset Pricing Models," *Review of Financial Studies* 3, 1990, pp. 431-467; Fama, E. and K.R. French, "Size and Book-to-Market Factors in Earnings and Returns," *Journal of Finance* 50, 1995, pp. 131-155; and Fama, E., and K.R. French, "Industry costs of equity," *Journal of Financial Economics* 43(2), 1997, pp. 153-193.

43 The website is located at http://mba.tuck.dartmouth.edu/pages/faculty/ken.french/data_library.html.

Regulatory Use

The Fama-French model has been submitted in Australia, North America, and the U.K.[44] While U.S. decisions are only rarely explicit about how evidence was weighted, we are not aware of a U.S. decision that primarily relied on the Fama-French model. However, the U.K. Competition Commission used the model to determine whether a small company premium should be included in the cost of capital.[45] The Régie de l'énergie in Québec considered the Fama-French approach and found that the model had not been sufficiently examined to date to be used as a basis for setting the rate of return for a gas distributor.[46]

Characteristics of the Fama-French Three-Factor Model

Many of the Fama-French model characteristics are similar to those of the CAPM. It relies on a risk-free rate and an estimate of the market risk premium, so like the CAPM it is sensitive to developments in risk-free rates. Like the ECAPM, the Fama-French model captures the empirical observation that the Security Market Line predicted by the CAPM is too steep. The Fama-French model has two additional factors, which vary over time and therefore add to the variations in the cost of equity estimates over time.

D. ARBITRAGE PRICING THEORY

The Arbitrage Pricing Theory (APT) was developed by Ross (1976a, 1976b)[47] as a multifactor alternative to the CAPM. The model is a theoretical approach to explaining the cross-section of returns with additional factors beyond the standard market portfolio in the Sharpe-Lintner CAPM. It is a one-period model in which all investors believe the stochastic properties of capital assets' returns are consistent with a factor structure. Assuming equilibrium prices offer no arbitrage opportunities, the expected returns on these capital assets are approximately linearly

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44 See, for example, Jemena Gas Networks (NSW) Ltd - Initial response to the draft decision - Appendix 5.2 - NERA: Cost of Equity – Fama-French Model; California Public Utilities Commission, "Decision 07-12-049," December 20, 2007; and U.K. Competition Commission, "Market Investigation into Supply of Bulk Liquefied Petroleum Gas for Domestic Use: Provisional Findings Report," August 2005, Appendix K.

45 See, for example, U.K. Competition Commission, "Market Investigation into Supply of Bulk Liquefied Petroleum Gas for Domestic Use: Provisional Findings Report," August 2005, Appendix K.

46 Régie de l'énergie, Décision D-2007-116, Gaz Métropolitain, pp. 23-24.

47 S.A. Ross, "Options and Efficiency," *Quarterly Journal of Economics* 90, 1976, pp. 75-89 and S.A. Ross, "The Arbitrage Theory of Capital Asset Pricing," *Journal of Economic Theory* 13, 1976, pp. 341-360.

related to the factor loadings. The factor loadings are proportional to the returns' covariances with the factors - much like in the CAPM.[48]

The empirical specification of the model is

$$E(r_S) = \beta_1 \cdot E(Factor1) + \beta_2 \cdot E(Factor2) + ... + \beta_N \cdot E(FactorN) \tag{6}$$

The APT is a generalization of the standard CAPM in that it allows for multiple risk factors and does not require the identification of the market portfolio. However, the theoretical APT only provides an approximate relation between expected asset returns and a combination of factors. Therefore, testability of the model depends on imposing several additional assumptions on the conditional distribution of returns. For example, exact factor pricing holds in an equilibrium intertemporal asset pricing framework. In this general model specification, the market portfolio is one pricing factor as in the standard CAPM, and additional factors arise from investors' need to hedge uncertainty about future investment opportunities. These factors can be specified as traded portfolios of assets, or macroeconomic variables that reflect the systematic risks of the economy, such as industrial production growth, changes in bond yield spreads or unanticipated inflation.

The key difference between factor specification in the APT versus the Fama-French model described above, is that the factors in the APT are theoretically motivated as hedging variables that capture economy-wide non-diversifiable risks, whereas the factors in the Fama-French model are empirically motivated, and are instead selected based on observing the firm characteristics that best explain the cross-section of returns over a specific sample period.

E. DIVIDEND DISCOUNT MODEL

Although there are several versions of the Dividend Discount Model (DDM), all versions determine today's stock price as a sum of discounted cash flows that are expected to accrue to shareholders. Assuming that dividends are the only type of cash payment to shareholders, the pricing formula becomes:

48 For a brief introduction, see Gur Huberman, "Arbitrage Pricing Theory," in *The New Palgrave: Finance*, eds. J. Eatwell, M. Milgate, and P. Newman, 1989, pp. 72-80.

$$P_t = \frac{E_t(D_1)}{(1+r_S)} + \frac{E_t(D_2)}{(1+r_S)^2} + \frac{E_t(D_3)}{(1+r_S)^3} + \cdots \qquad (7)$$

where "P_t" is the market price of the stock; "D_i" is the dividend cash flow at the end of period i; "r_S" is the cost of capital of asset/security S (as before); and the sum is into the infinite future.[49] The formula above says that the current stock price is equal to the sum of the expected future dividends (or cash flows), each discounted for the time and risk between now and the time the dividend is expected to be received – with the cost of capital r_S as the appropriate discount rate. The notion that the current stock "price equals the present value of expected future dividends" was first developed in 1938 by Williams and was then rediscovered by Gordon and Shapiro in 1956.[50]

1. Single-Stage DDM

If the dividend growth rate is constant, then we obtain the standard Gordon Growth model,[51] which can be shown to determine the cost of capital on security S as:

$$r_S = \frac{D_O \times (1+g)}{P} + g \qquad \textbf{(8)}$$

where g is the constant, periodical growth rate.

This equation says that the cost of capital equals the expected dividend yield (dividend divided by price) plus the (perpetual) expected future growth rate of dividends. As is readily seen from Equation (8) above, an implementation of the constant growth DDM requires a determination of the current stock price, current dividends, and the applicable growth rate.

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49 With the convention that D_i is zero for periods beyond the expected life of the asset.

50 See Brealey, Myers, and Allen (2011), p. 82.

51 Named after Myron J. Gordon, who published an early version of the model in "Dividends, Earnings and Stock Prices," *Review of Economics and Statistics*, Vol. 41, 1959, pp. 99-105.

2. Multi-Stage DDM

If the assumption of constant growth is not considered reasonable for several years before settling down to a constant rate, variations of the general present value formula can be used instead. For example, if there is reason to believe that investors do *not* expect a steady growth rate forever, but rather have different growth rate forecasts in the near term (*e.g.,* over the next five or ten years) converging to a constant terminal growth, these forecasts can be used to specify the early dividends in Equation (7). Once the near-term dividends are specified, Equation (8) can be used to specify the share price value at the end of the near term (*e.g.,* at the end of five or ten years), and the resulting cost of capital can be determined using a numerical solver. A standard "multi-stage" DDM approach solves the following equation for r_S:

$$P = \frac{D_1}{(1+r_s)} + \frac{D_2}{(1+r_S)^2} + \ldots + \frac{D_T + P_{TERM}}{(1+r_S)^T} \tag{9}$$

The terminal price, P_{TERM}, is just the discounted value of all of the future dividends after constant growth is reached and T is the last of the periods in which a near-term dividend forecast is made. The implementation of the multi-stage growth model requires, in addition to a current price and current dividend, the selection of growth rates for each stage of the model and a determination of the length of each period.

More recent DDM implementations have focused on variations of the multi-stage model described above. For example, the U.S. Surface Transportation Board relies on a version of the multi-stage DDM that uses cash flow rather than dividends and specifies three growth rates – a near-term company-specific growth rate, an intermediate industry-specific growth rate and a long-term economy-wide growth rate.[52] The STB version is identical to the model developed by Morningstar / Ibbotson, Ibbotson's "three-stage" DDM, which is one of five models calculated for all U.S. SIC codes annually. In Ibbotson's version, dividends are replaced by cash flow (excluding extraordinary items) and the figure is normalized over a three-year period. The model then uses company-specific growth rates from analysts over the first five years, industry growth rates over the next five year and the GDP growth rate after year 10.

[52] See Surface Transportation Board, STB Ex Parte No. 664 (Sub-No. 1), "Use of a Multi-Stage Discounted Cash Flow Model in Determining the Railroad Industry's Cost of Capital," January 28, 2009. The Alberta Utilities Commission, Decision 2009-216 (¶271) also specifies a preference for the multi-stage model.

Another example of more recent multi-stage DDMs used is the version frequently estimated by *Brattle*, where company-specific growth rates are used for the first five years while the long-term GDP growth rate is used from year 10 onwards. In the in-between years (6-10), the model assumes that the growth rates converge linearly from the company-specific rates to the GDP growth rate. Similarly, Professor Myers' report suggests that in many industries it is important to look at the total cash flow that accrues to shareholders rather than on a per share basis, because stock buyback programs make the per share figures less reliable. In this model, the fundamental variable being determined is the market value (total price) of a company rather than the price per share, and instead of looking to dividends per share the model uses total cash flow to shareholders.[53]

3. DDM Implementation Issues

To implement the DDM it is necessary to specify one or more growth rates and to determine whether (i) dividends accurately reflect cash flow to shareholders, (ii) the horizon over which to apply each growth rate if using a multi-stage model, and (iii) the exact determination of the initial stock price. In most applications, the choice of growth rate is the most controversial part of the DDM implementation and the determination of the stock price is the least controversial.

4. Characteristics of the DDM

As for the other models, many of the strengths and weaknesses of the DDM depend on its implementation. However, assuming a reliable implementation, some strengths of the DDM are:

- Both the single-stage and the multi-stage DDM rely on forward-looking information and hence estimate a forward-looking cost of equity.
- The models are usually easily replicated and are therefore easy to audit.

Among the weaknesses of the DDM are the following:

- The DDM relies on growth forecasts, which frequently are available only for 2-5 years.

[53] This revised method is explained in R. A. Brealey, S. C. Myers and F. Allen (2013), *Principles of Corporate Finance*, 11th Ed., McGraw-Hill Irwin, Ch. 16 (forthcoming).

- Because stock prices (and to a degree forecasted growth rates) change frequently, the model results often vary substantially over time.

Among the other issues to consider is the prevalence of stock buybacks, which means that dividends do not reflect all cash payments to shareholders. As mentioned above, some regulated entities have share buyback programs. In the pipeline industry, Spectra Energy, a U.S. based pipeline company, recently authorized share buybacks of $600 million for a little over 6% of its equity capital.[54]

Therefore, it is necessary to modify the model to take into account these cash transfers. In addition, for many companies, growth rates are only available on an infrequent basis, making the cost of equity estimates less forward-looking than ideal.

Both the single-stage and multi-stage DDM are frequently used in U.S. rate regulation to estimate the cost of equity. However, it is important to recognize that few U.S. regulators have a pre-specified methodology, but instead hear and review evidence from a variety of parties prior to issuing a decision on the cost of equity. Therefore, estimates from DDMs are only one of several pieces of evidence considered by most U.S. regulators. In addition, U.S. regulation was in place prior to the development of more market-based models such as the CAPM, and there is therefore a tradition to rely on the DDM.

5. Residual Income Model

One model that can be viewed as an extension of the multi-stage DDM is the residual income model, which relies on earnings or abnormal earnings instead of dividends. Broadly speaking, the model defines price as the sum of the book value of equity and the discounted present value of “abnormal” or “residual” earnings.[55] The model is a forward-looking methodology in that it generally uses analysts’ forecasts to determine growth rates, although it uses historical earnings information to derive the current “residual income.” The model is based on the so-called Ohlson-Juettner method, which like the multi-stage DDM allows growth rates to vary over time.

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[54] See Spectra Energy, Form 10-K, 2008 p. 31.

[55] For an early exposition, see J. Ohlson, “Earnings, book values, and dividends in equity valuation,” *Contemporary Accounting Research* 11, pp. 661-687.

Abnormal earnings are typically forecast using earnings estimates for one or two years ahead. Assuming that abnormal earnings in the long run grow at the assumed long-run rate, the model allows for a high short-term earnings growth rate that gradually declines to the long-term level. Technically, the model is appealing because it provides a closed form solution to the cost of equity based on few inputs, so that it is simple to implement.[56]

The Residual Income Valuation (RIV) method has been debated substantially in the accounting literature in recent years. Variations on this model have been cited in recent Australian cases – for example, the "residual income model" proposed by the DBNGP in its most recent access arrangement.[57] The model was also proposed to the STB, albeit the STB instead adopted Ibbotson's three-stage DDM model based on cash flows rather than dividends.

In a recent paper by Nekrasov & Shroff (2009)[58] the authors propose a valuation methodology that applies risk measures based on economic fundamentals directly into the valuation model, aiming to assess the differences in valuation derived from the use of fundamentals-based risk adjustments instead of the commonly used asset pricing models (estimated using historical returns). Note that this paper does not specifically address valuation and cost of equity for the regulated entities.[59]

The authors use the RIV model to derive an accounting-based risk adjustment, which is equal to the covariance between a firm's ROE and economic factors. Accounting risk factors are identified and used to construct a measure of risk adjustment, then applied to calculate firm value. Two components of value are estimated separately: the risk-free present value (RFPV) and

56 The model was also submitted for consideration to the U.S. STB; P.S. Mohanram, *Determining an Appropriate Cost of Capital for Railroads*, submission to the Surface Transportation Board, September 2007.

57 See *Draft Decision on Proposed Revisions to the Access Arrangement for the Dampier to Bunbury Natural Gas Pipeline*, paragraphs 458-467. Tristan Fitzgerald, Stephen Gray, Jason Hall and Ravi Jeyaraj, 2010 "Unconstrained estimates of the equity risk premium," Working paper, The University of Queensland, http://ssrn.com/abstract=1551748 ("Fitzgerald et al.").

58 A. Nekrasov & P. Shroff, "Fundamentals-Based Risk Measurement in Valuation," *The Accounting Review* 84, 2009, pp. 1983-2011.

59 See example or models submitted in regulatory settings; see Fitzgerald et al. and Partha Mohanram, "*Determining an Appropriate Cost of Capital for Railroads*," Submission to the U.S. Surface Transportation Board, September 2007.

the covariance risk adjustment. The RFPV is calculated using a forecast of earnings, book value of equity and the risk-free rate as inputs to the model, while the covariance risk adjustment is estimated by calculating betas on the different risk factors and corresponding factor risk premia.

The authors acknowledge that this methodology "may be more complex to implement than the returns-based cost of equity."[60] However, the authors conclude that the strong empirical performance of the one-factor accounting–beta model, combined with the need of few additional inputs for the estimation, justify its use in valuation applications.

6. Characteristics of the Residual Income Model

The pros and cons of the Residual Income Model are generally similar to those of the DDM model, but we note that the model considers earnings instead of dividends, so that if earnings and cash flows are reasonably consistent, this model better captures the totality of cash flow that accrues to shareholders.

F. OTHER MODELS, METHODS, MARKET DATA AND EVIDENCE

1. Risk Premium Approaches

Some regulators in North America use a simplified version of the CAPM, the so-called risk-premium approach, which collapses the beta and risk premium to one figure and adds this figure to an interest rate. The debt instrument is either government bonds or utility bonds. The risk premium approach calculates the cost of equity, r_S, as:

$$r_S = r_D + \text{estimated risk premium} \tag{10}$$

where r_D is the return on a selected debt instrument. There are many versions of this model depending on the choice of the debt instrument, r_D, and the estimation of the risk premium. It is important to note here that the risk premium approach, while a generalized form of the CAPM, does not have the same level of theoretical support as the standard CAPM. This is because the return on the selected debt instrument used is not necessarily equal to the risk-free rate, and the

[60] *Ibid*. p. 1986.

estimated risk premium used is not explicitly based upon the product of the market beta and the MRP.

Equation (10) is frequently implemented using either a historical estimate of the risk premium, or a forward-looking or expected risk premium. The historical risk premium is commonly determined as the historical spread between equity and debt returns, so the primary choices for the analyst become which equity returns and debt instrument to use, as well as the period over which the spread (*i.e.*, the risk premium) is to be measured. It is not uncommon to see this model implemented using long-term government bonds or utility/corporate bonds to measure the cost of debt, while the equity investments used are typically either (a) realized accounting returns of regulated entities in the same industry, (b) realized stock returns of companies in the same industry, or (c) allowed returns on equity for the industry. In choosing a debt instrument to determine r_D, it is important that it be consistent with the debt instrument used to determine the risk premium. In other words, if a 10-year government bond is used to determine the historical risk premium, then r_D must also be measured using a 10-year government bond. The realized risk premium is highly dependent on the time period over which it is estimated, so that choice is also important.

The forward-looking model requires that the analyst determine a proper measure of the expected cost of debt and estimates the expected risk premium going forward, rather than relying on historical data. Determining the expected equity return is more difficult and requires reliance on an estimation technique. It is common to rely on DDM models to determine the risk premium in the forward-looking version of the model. One result originating from these analyses of historical or forward-looking risk-premium approaches is that empirically there is a negative relationship between the risk premium and the yield-to-maturity. Historically, a 1% increase in the yield-to-maturity of government bonds results in less than a 1% increase in the estimated (or realized) return on common equity.[61] The relationship between the return on equity and

[61] For example, Roger A. Morin, "*New Regulatory Finance*," Public Utilities Reports, Inc., 2006 pp. 128-129 summarizes several studies and found that the realized ROE changes approximately 50 basis points when government bond rates change 100 basis points. Regulatory agencies such as the Ontario Energy Board relied on this empirical finding as well as data submitted by experts in its recent hearing to update its annual change in the estimated cost of equity for Ontario utilities by less than the change in government bond rates.

(government or utility) bond yields is depicted in Figure 4 below. The figure is for illustrative purposes only and does not reflect an actual analysis of the relationship.

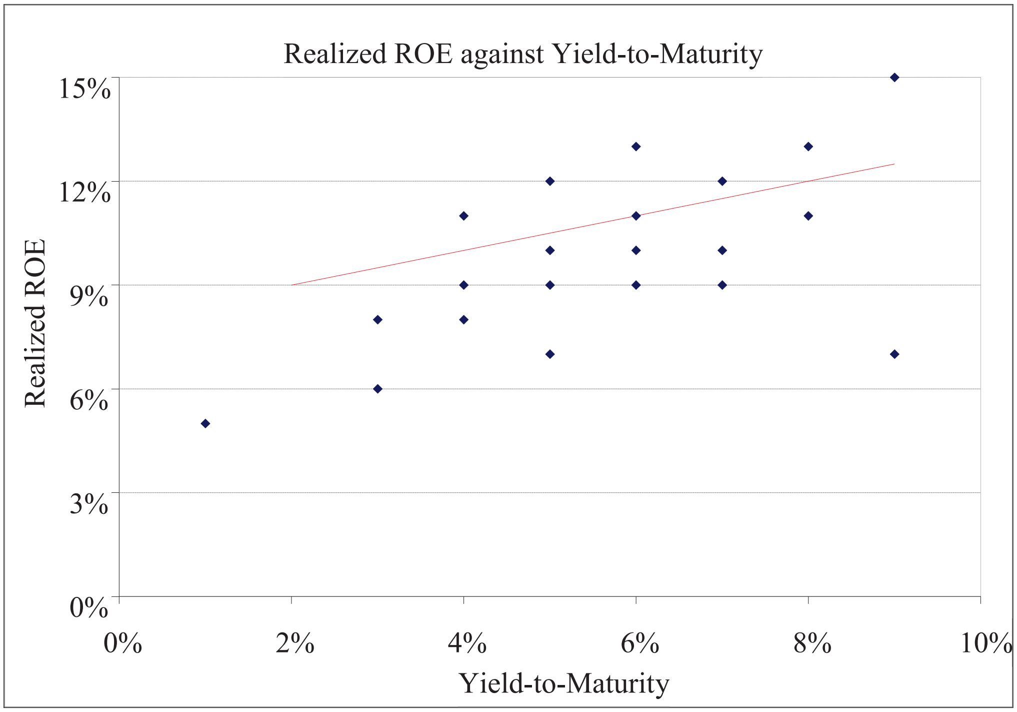

Figure 4

This is a reason why, for example, the Ontario Energy Board (OEB) took evidence from the risk premium approach into consideration when determining its baseline cost of equity in 2009.

2. Build-up Method

The build-up method estimates the return on an asset as the sum of a risk-free rate and one or more risk premia that represent the rewards an investor receives for taking on a specific risk:[62]

Cost of Equity = Risk-Free Rate + Market Risk Premium
+ Firm Size Premium + Industry Premium
+ potentially other factors

[62] *Morningstar Ibbotson SBBI Valuation Edition 2012 Yearbook*, p. 27.

Each of the components of the build-up method is discussed in detail below:

- The Risk-Free Rate is calculated using either Treasury bills ('T-bills") or long-term government bonds.

- The Market Risk Premium reflects the compensation above the return on a risk-free asset that investors require for the additional market risk they bear by investing in a well-diversified market portfolio of risky assets. Ibbotson calculates this as the difference between the total expected return on the market portfolio and the risk-free rate.

- The Firm Size Premium may be included to account for the additional risk inherent in small company stocks. A firm size premium can either be adjusted or unadjusted for the effect that a small company stock's higher beta has on its excess return. To illustrate the magnitude of the size premium, Table 1 below shows the empirically observed size premium for U.S. companies as reported by Ibbotson Associates.

	Beta-Adjusted Size Premia (%)	Non-Beta-Adjusted Small Stock Premia (%)
Mid-Cap	1.1	1.9
Low-Cap	1.9	3.4
Micro-Cap	3.9	6.3
Small Company Stocks	3.1	4.7

Table 1: Ibbotson Associates' Size Premia on a Beta-Adjusted versus Non-Beta-Adjusted Basis, 1926-2011[63]

- An Industry Premium can be determined based on the characteristics of the regulated entity's industry. Research has produced no consensus on this figure and Ibbotson notes that it is important to avoid double-counting industry risk by using other beta-adjusted (hence industry dependent) risk premia (positive or negative) and at the same time adding an industry premium.

63 *Morningstar Ibbotson SBBI Valuation Edition 2012 Yearbook*, p. 27.

In addition to the factors discussed above, some argue for the inclusion of minority discount premia, control premia, key person discount, *etc.* However, these additional premia (positive or negative) are very difficult to measure and we know of no regulator that has included such additional factors. The New Mexico Public Regulation Commission in the U.S. has in the past used the build-up method as one of its methods to estimate the cost of equity.

3. Comparable Earnings

The comparable earnings method requires the analyst to go through three steps. First, a group of *unregulated* companies is required because the realized accounting rate of return of a regulated company depends on its allowed return. Using regulated companies to estimate the comparable earnings cost of capital would be circular, *i.e.*, the allowed rate of return is used to determine the allowed rate of return. However, the use of unregulated companies requires careful consideration of the risk characteristics of the companies and the comparability to those of the target utility.

Second, a time period over which to estimate the return on equity must be selected. Because a company's achieved earnings fluctuate from year to year and depend substantially on both company-specific and economy-wide factors, it is necessary to include companies from several industries, averaged over several periods.

Third, because the comparable companies are unregulated entities, it is necessary to adjust for any risk differences between the sample companies and the target company. There are many ways to adjust for risk differences, so the following is a simplified description of some common approaches rather than an exhaustive review. Analysts often collect information on the comparable companies' and the target company's bond ratings, asset betas, DDM estimates of the cost of equity, and other measurable risk factors. In many instances, this information is also collected for a sample of regulated companies in the same industry as the target company. If the sample companies are found to be consistently more (less) risky than the target company and its industry peers, then an adjustment is made to the required return on equity. This can sometimes be done formally. For example, if the sample companies' DDM estimates of cost of equity are consistently 25 basis points higher (lower) than the DDM estimates for the target company (or industry peers), then a downward (upward) adjustment of 25 basis points is made. For other measures, it is more difficult to determine the exact adjustment, so it is usually made based on the analyst's experience. For example, does a two notch difference in bond rating require a specific upward or downward adjustment? Thus, while the differences are relatively easy to measure, the adjustment for such differences requires subjective judgment.

A major issue is whether realized book returns are a good proxy for the returns that investors expect going forward. From a statistical perspective, the realized accounting return on book equity for any given period is the realization of a single outcome of a distribution, whereas the expected return represents the probability-weighted average of all possible outcomes of the distribution. These two figures can differ substantially. In addition, there are practical problems with the implementation of this model because financial reporting occurs with a lag, which during times of change can mean that the results are out of date.

4. Market-to-Book and Earnings Multiples

In some regulatory decisions on the cost of capital, regulators have sought to "cross check" a proposed cost of capital estimate by examining the market value of the firms they regulate relative to the value of the regulatory asset base (RAB). The theory behind this approach would be that the only capital on which the regulated firm is earning a return (at the regulator-determined cost of capital) is the RAB. Therefore, if the market value of the firm's returns is greater than the RAB, the belief is that it is a signal that investors are discounting future returns at a lower discount rate than the regulator's cost of capital determination — or, in other words, the regulator's cost of capital is "too high".

This kind of cross check approach was cited by the Australian Energy Regulator in its June 2011 determination on Envestra.[64] In that decision, the AER considered two kinds of evidence: premiums paid in takeover transactions relative to the value of the RAB, and market values (based on share prices) relative to RAB.

[64] *Final Decision - Envestra Ltd Access arrangement proposal for the Qld gas network*, AER (June 2011), p. 35-37.

a) Takeover premiums

The AER reviewed premiums paid in takeover transactions, where the premium was assessed as the sale price relative to the value of the underlying RAB. Premiums were in the range of 20% to 120%. The AER considered that these premiums were too large to be explained by factors such as expected synergies, and instead considered this as evidence that the cost of capital determined by regulators has been at least as high and likely higher, than the actual cost of capital faced by the businesses.

However, there are conceptual problems with this approach so that it has no value as a cross check on a regulator's cost of capital determination. First, the reliance on the approach implicitly assumes that (i) the company to which it is applied consists entirely of regulated businesses and (ii) that the regulator's cost of capital determination is the only factor impacting the market value of the company. In reality the cost of equity is only one component of a broader determination on what the firm's regulated rates should be. Thus, even if it were possible to estimate the impact of the regulator's decision on the market value of the firm, this impact would be associated with the overall decision, not with any one specific component (like the cost of capital). The market value of a regulated firm can be thought of as the expected future cash flows (from providing services at regulated rates), discounted at the firm's actual cost of capital. However, the regulator's cost of capital determination is only one of many factors which determine expected future cash flows, particularly where price determinations are forward-looking (as in Australia):

- If investors expect the firm to "beat" regulator assumptions on any of operating costs, capital costs, or revenue growth, expected future cash flows would be larger than the RAB in net present value terms, even if the discount rate is equal to the regulator-determined cost of capital.
- Investor expectations, which are implicit within the firm's market value, encompass expected cash flows beyond the end of the current price control period.
- Expected future cash flows are also affected by firm-specific factors such as idiosyncratic volatility, which would not be captured in the discount rate.

In addition, there are likely to be other more practical difficulties: for example, many regulated firms have at least some unregulated activities. These activities are valued by investors but are not part of the RAB or the regulator's cost of capital decision.

b) Trading premiums

The AER also considered premiums measured on the basis of market value of listed firms (from share prices) relative to RAB. The AER estimated market-to-RAB trading multiples for four firms (including Envestra).[65] The trading multiples were in the range of 1.21 to 1.81.

The AER stated that these premiums were too high to be the result of factors such as expected synergies, and instead considered this as evidence that the cost of capital determined by regulators has been at least as high and likely higher, than the actual cost of capital faced by the businesses. However, the same difficulties described above for takeover premiums also apply to the consideration of trading premiums. In addition to the takeover premiums difficulties, the use of trading premiums suffers from bias in circumstances where the market is very volatile, where day-to-day changes reflect investor reactions to news such as the collapse of Lehman Brothers in September 2008, the ongoing European debt crisis, or industry factors such as cap and trade initiatives, etc. Therefore, trading premiums also have no value as a cross check on the regulator's cost of capital determination.

5. Other Evidence

Other evidence is a very broad category that does not readily lend itself to a short introduction by method. However, expert evidence can be highly valuable if of high quality, so it will be necessary to use judgment and consider how the expert arrived at his or her recommendations. Similarly, academic research may provide insights into the cost of equity, but bear in mind that most academic research focuses on finding or explaining "interesting facts" and often considers all companies and industries for which data are available. Because a result pertains to the market

[65] The four firms were SP Ausnet, Spark, Duet and Envestra (*Ibid.*, Table 5.5).

as a whole, it does not necessarily pertain to a specific industry, which may have unique characteristics.

Other types of evidence that are sometimes considered are equity analysts' reports on a specific company, an industry, or a market. When such evidence is reviewed, it is important to consider the purpose for which the evidence was produced. For example, equity analysts often produce research documents aimed at stock-buying investors and only rarely are concerned with the cost of equity over, for example, a regulatory period. Instead, equity analysts attempt to determine the current (or future) stock price as the discounted sum of future cash flows with the discount rate being the weighted average sum of the cost of debt and equity; *i.e.*, the focus is not on what the best estimate of the cost of equity is – it is merely one of many inputs to determining the stock price. In addition, because a lower cost of equity increases the estimated stock price, equity analysts have an incentive to, if anything, bias the cost of equity estimates downward.

6. Characteristics of Other Methods, Models, Market Data and Evidence

The methods, models, market data and other evidence in this section differ, so the advantages and disadvantages listed below are method-specific:

- The risk premium model is simple and data for its implementation are readily available.
- If the benchmark interest rate is a utility or corporate bond index, then the risk premium model tends to provide relatively stable results over time and is less impacted by monetary policy or country-specific risks than the CAPM.
- The build-up method recognizes size effects and potentially other risks.
- The comparable earnings method's strength is that it incorporates information from non-regulated entities.

Among the weaknesses of the methods we note the following:

- None of the methods are founded in economic or finance theory.
- The risk premium approach does not consider systematic risk specifically and does not allow for company-specific information to be considered.

- The build-up method generally does not consider systematic risks and treats size effects the same across industries.
- The comparable earnings model relies on historic accounting information, which may not be consistent with investor expectations. Also, the historic accounting information may reflect accounting choices rather than economic fundamentals and may be subject to significant variability over time.

As for other evidence such as expert reports and investment reports, the merits of the derived estimates are highly dependent upon the quality of the reports and the purpose for which the estimates were derived. We caution against placing weights on estimates where the purpose for their derivation is not known, and against placing substantial weight on estimates that were derived for purposes other than to provide an independent assessment of the cost of equity. For example, estimates derived for accounting purposes, stock recommendations, *etc.* may not be suitable for other uses.

This section has summarized the major models, methods and evidence that are currently used and considered by regulators and practitioners. The models described above are not intended to comprise an exhaustive list of all possible methods and evidence that could be relied upon in determining the cost of equity capital. Indeed, as the practice of finance continues to evolve, further relevant evidence may still be found, and certain models may become outdated or less relevant.

IV. USING THE METHODS

In this section, we first discuss implementation issues for estimating the cost of capital and summarize the key characteristics of the models described above in *Section III*. We then address the issue of how and when to use the models to determine an appropriate regulatory return on equity, or range for the regulatory return on equity for the industry or benchmark, based on the views of academic, practitioners and regulators. Finally, we discuss how to position a target entity relative to a sample of companies.

A. Implementation Issues

Regardless of the cost of equity estimation method that is used to estimate the cost of capital, there are some key elements of the cost of capital estimation process that must be addressed. This section discusses some of the important issues.

Most analysts rely on a "comparable sample" to determine the cost of equity for the target entity, so it becomes important to determine what is meant by comparable.[66] Although the selection of comparable companies is method and context-specific, it is generally viewed as ideal to have sample companies with business risk similar to that of the target company. Similar business risk generally implies selecting companies in the same line of business. Most researchers and practitioners rely on additional criteria to exclude sample companies that have the potential to bias the cost of capital estimation methodologies. For screening, it is preferable to rely on objective information from publicly available data sources; however, the determination of exactly which criteria to use is subject to the constraint that the sample be "large enough." This, in turn, requires a determination of which criteria are the most important from the many possible criteria that could be considered. Among the criteria typically employed are combinations of the following:

- Include companies with similar business risks (*e.g.,* companies in the same or similar industries);
- Exclude companies that face financial distress;
- Exclude companies that are or have recently been involved in substantial merger and acquisition activity;
- Exclude companies with unique circumstances that may bias the cost of capital estimation (*e.g.,* restatements of financial statements); and
- Exclude companies with insufficient data.

[66] A comparable sample can be used to assess the cost of capital for the target entity by (i) estimating the individual companies' cost of capital and placing the target company's cost of capital in relation to the sample using the average, median, range, or other measure to assess the cost of capital or (ii) using a portfolio approach, where the cost of capital for the portfolio of companies (rather than individual companies) is estimated to assess the cost of capital for the target entity.

There is, however, controversy about how to implement the criteria above. Each element of the sample selection criteria requires some judgment. For example, what size sample is "large enough"? Should the sample include both Australian and foreign companies?[67] How is financial distress measured? How is "substantial merger and acquisition" activity to be defined? The selection criteria are interrelated, because selection of the sample based upon one criterion may immediately reduce the potential sample to a small number of companies. The sample selection process is, therefore, a balancing act between selecting a sample that is "more comparable" and one that is "too small."

Second, decision makers must decide how the components of the cost of capital will be determined. For example, it is possible to estimate (a) the cost of debt, the cost of equity and the capital structure, each separately or (b) an overall cost of capital or (c) a combination of these. Another component of the cost of capital is the allowance for income taxes, which we ignore in this report. Finally, because the dollar amount that accrues to investors in a regulated entity ultimately depends on not only the allowed cost of equity and the size of the rate base but also on the relative share of equity and debt in the capital structure, it is important to consider the overall impact of these capital structure decisions on the individual components. Specifically, it is important to note that cost of equity estimation models provide estimates that reflect both the underlying business risk of the assets but also the financial risk inherent in how those assets have been financed.

B. SUMMARY CHARACTERISTICS OF THE MODELS

Before we discuss how to use the various models and other information that may be available to a decision maker, we summarize in Table 2 below the key characteristics of the discussed models in the form of their economic underpinnings, any potential empirical bias, sensitivity to economic or industry factors, and whether the models are forward or backward-looking.

[67] For example, several Canadian regulators have used beta estimates from U.S. companies. See, for example, the National Energy Board's RH-1-2008 decision p. 67 and Ontario Energy Board's EB-2009-0084 decision, pp. 22-23.

Table 2: Characteristics of Cost of Equity Methods

	Evaluation Criteria			
Cost of Capital Methods	**Economic Underpinnings**	**Bias**	**Impact of Market Conditions**	**Forward or Backward-Looking**
Sharpe-Lintner CAPM	An equilibrium model: Under no arbitrage and in a mean-variance-optimizing world, the expected cost of equity is a function of the risk-free rate, systematic risk (beta) and the expected MRP. Transparent and sensitive to market performance and risk-free rates. Empirical support for explaining cross-sectional returns of average-beta stocks, but failure for low-beta/high-beta/small/high book-to-market firms.	Empirical evidence that CAPM under-estimates the expected return for low-beta stocks. A Portfolio approach to estimate betas provides more consistent results. MRP estimation controversial with some historical measures potentially biased.	Sensitive to monetary policy. Market uncertainty and economic turmoil likely to affect the expected MRP.	Beta estimates are backward-looking. Historical MRP is backward-looking, but forecast MRP (e.g., DDM) are forward-looking.
ECAPM	Same as above, but captures the empirical observation that the SML predicted by CAPM is too steep. Tested in the U.S., but not extensively outside the U.S. or in recent market conditions.	Corrects for the empirical bias induced by the flatter-than-predicted-by-CAPM Security Market Line.	Same as above.	Same as above.

(Table 2 ctd.) Characteristics of Cost of Equity Methods

	Evaluation Criteria			
Cost of Capital Methods	**Economic Underpinnings**	**Bias**	**Impact of Market Conditions**	**Forward or Backward-Looking**
Consumption-Based CAPM	Generalization of the Sharpe-Lintner CAPM that relates the risk premium on the investment to the covariance between the asset return and the intertemporal marginal rate of substitution of the decision maker. The expected conditional risk premium on an asset is related to its predicted conditional volatility. Requires more data and more refined estimation techniques than the Sharpe-Lintner CAPM. Lack of empirical support for most commonly used version (where covariance factor is aggregate consumption growth), but more support for versions with market frictions/time-varying risk aversion.	Allows for expected risk premium to vary with asset and investor characteristics, including conditional volatility and covariance with consumption growth; (considers more factors than the Sharpe-Lintner CAPM). Potentially mitigates empirical biases.	Empirical results appear stable and consistent over time (i.e. more robust to market conditions than standard CAPM).	Models forward-looking equity risk premia based on predicted conditional volatility. More forward-looking than Sharpe-Lintner CAPM.

(Table 2 ctd.) Characteristics of Cost of Equity Methods

	Evaluation Criteria			
Cost of Capital Methods	**Economic Underpinnings**	**Bias**	**Impact of Market Conditions**	**Forward or Backward-Looking**
Fama-French Model	Corrects for empirical biases of Sharpe-Lintner CAPM by adding 2 explanatory risk factors (size and book-to-market). Empirical support for explaining cross-sectional returns of size- and book-to-market-sorted portfolios. Weak empirical support for explaining returns of other portfolios and for out-of-sample predictive power. Fama-French factors (SMB and HML) are empirically motivated.[1]	Captures empirical observation that SML predicted by CAPM is too steep. Adds cross-sectional explanatory power to the standard CAPM.	Sensitive to monetary policy. Estimates of the 3 factor risk premia vary substantially over time and more so when the 3 factors interact.	Betas and factor risk premia estimates are backward-looking.
APT Model	Equilibrium multifactor model which holds under competitive markets, factor structure for asset returns, and absence of arbitrage in large economies. Corrects for empirical biases of Sharpe-Lintner CAPM by adding explanatory risk factors. APT factors are theoretically motivated. Model implemented empirically as intertemporal CAPM (see above for empirical issues).	Same as above.	Sensitive to market uncertainty and economic turmoil via market-related factor. Estimates of factor risk premia can vary substantially over time.	Forward-looking model in theory, but betas and factor risk premia are backward-looking if estimated using historical data.

1) See Fama and French (1993), Kothari, Shanken, and Sloan (1995), Black (1993), MacKinlay (1995), and Lakonishok, Shleifer, and Vishny (1994) for additional detail.

(Table 2 ctd.) Characteristics of Cost of Equity Methods

	Evaluation Criteria			
Cost of Capital Methods	**Economic Underpinnings**	**Bias**	**Impact of Market Conditions**	**Forward or Backward-Looking**
Risk Premium Model	Simplified version of the CAPM, which collapses the beta and market risk premium to one figure and adds this figure to an interest rate. Based on empirical estimation. Does not capture systematic risk or company-specific information.	The relied upon interest rate may be biased due to, *e.g.*, monetary policy. Does not account for changes in the risk premium.	Using a utility or corporate bond index as the benchmark, the risk premium model tends to provide relatively stable results. Reliance on government interest rates makes the model more sensitive to monetary policy. Inflation leads to bias in the risk premium model, because the historical data underlying the estimate of the risk premium may not be consistent with the current level of inflation.	Mostly backward-looking due to reliance on a historic spread of realized equity returns over debt returns to measure the risk premium, and thus does not capture expected changes in the economy.
Single-Stage DDM	Determines today's stock price as the sum of the discounted cash flows that are expected to accrue to shareholders going forward. Assumes that dividends (or cash flows) grow at a constant rate forever. Lack of empirical support for constant dividends/earnings growth rates in perpetuity.	Sensitive to bias in analyst forecasts of earnings growth rates which at best reflect 5 years. Less of an issue for utilities than most other industries. Sensitive to the exact implementation as dividends may not reflect all cash flow if the company engages in share repurchases or borrows to fund dividends. Does not take real options into account and will underestimate the cost of equity for companies with substantial real options.	Model requires the constant-growth assumption. Estimates are sensitive to changes in stock prices and forecasted growth rates, which is especially an issue if the industry is in transition. Stock prices are influenced by the information available to investors. Information about financial distress or merger and acquisition activities may overwhelm fundamental information about growth.	Relies on forecasted (i.e. forward-looking) growth rates and current stock prices. Hence estimates are forward-looking.

(Table 2 ctd.) Characteristics of Cost of Equity Methods

	Evaluation Criteria			
Cost of Capital Methods	**Economic Underpinnings**	**Bias**	**Impact of Market Conditions**	**Forward or Backward-Looking**
Multi-Stage DDM	Extension of single-stage DDM which allows for different growth forecasts over time. Stronger empirical support than constant growth version.	Same as above, but less sensitive to any bias in analyst forecasts than the single-stage DDM, as growth rates usually converge to the GDP growth rate over time.	Requires a series of growth rates; commonly near-term, interim, and for the very long- term. Sensitivity to growth rates is moderated. Similarly to single-stage DDM, less applicable to companies in financial distress or engaged in merger or acquisition activities.	Same as above.
Residual Income Method	Version of the multi-stage DDM that values abnormal or unforeseen earnings instead of dividends. Abnormal earnings are forecast using earnings estimates for one or two years ahead. Allows growth rates to vary over time. Abnormal earnings are based on empirical estimates.	Considers earnings instead of dividends or cash, so if earnings reflect expectations better than dividends or cash, it reduces bias.	Same as above. Performance relative to multi-stage DDM depends on implementation of each.	Same as above.

(Table 2 ctd.) Characteristics of Cost of Equity Methods

	Evaluation Criteria			
Cost of Capital Methods	**Economic Underpinnings**	**Bias**	**Impact of Market Conditions**	**Forward or Backward-Looking**
Build-up Method	Estimates the return on an asset as the sum of a risk-free rate and several risk premia that measure risks associated with size, industry, etc. Based on empirical estimation.	Recognizes size effects and other industry or company-specific risks. Exposed to same potential biases as standard CAPM and Fama-French models.	Exposed to same market uncertainties as standard CAPM and Fama-French models.	If risk factors and factor loadings are estimated from historical data, then the model is backward-looking.
Comparable Earnings	The model calculates the realized accounting rate of return on book equity of comparable (usually non-regulated) companies. Based on empirical estimation. Uses accounting returns rather than market data.	Selecting a sample of non-regulated comparable companies may lead to bias. Accounting changes can produce changes in model estimates without any change in the underlying cost of capital. The choice of estimation period may bias the accounting return on equity as accounting returns vary with economy, industry and company-specific factors.	Realized accounting returns are sensitive to economic, industry and company-specific events as well as to changes in accounting rules.	Uses backward-looking realized accounting rates of return, hence backward-looking. Can be difficult to find a time period that accurately reflects the expected horizon of the regulated entity.

C. HOW TO USE THE MODELS AND OTHER INFORMATION

In this section we discuss how academics, practitioners and regulators think models should be used and how they have been used. The section also discusses the impact of economic conditions, industry factors and company-specific issues on the choice of models. The weight assigned to each model naturally depends on the key characteristics of the cost of equity estimation models described above. Finally, the section discusses how certain regulators have decided to use the models in specific economic environments.

1. Views of Academics, Practitioners and Regulators

Academics, practitioners and regulators have all acknowledged that there is no one way to determine the cost of equity. In the academic literature, several prominent researchers have commented that the use of more than one method is important. For example, Professor Myers of the Massachusetts Institute of Technology commented:

> Use more than one model when you can. Because estimating the opportunity cost of capital is difficult, only a fool throws away useful information. That means you should not use any one model or measure mechanically or exclusively. Beta is helpful as one tool in a kit, to be used in parallel with DCF models or other techniques for interpreting capital market data.[68]

Professors Berk and DeMarzo of Stanford University in their corporate finance textbook comment on the use of the CAPM, DDM, and other models by practitioners, and state:

> In short, there is no clear answer to the question of which technique is used to measure risk in practice — it very much depends on the organization and the sector. It is not difficult to see why there is so little consensus in practice about which technique to use. All the techniques we covered are imprecise. Financial economics has not yet reached the point where we can provide a theory of expected returns that gives a precise estimate of the cost of capital. Consider, too, that all techniques are not equally simple to implement. Because the tradeoff between simplicity and precision varies across sectors, practitioners apply the technique that best suit their particular circumstances.[69]

[68] Stewart C. Myers, "On the Use of Modern Portfolio Theory in Public Utility Rate Cases: Comment," *Financial Management*, Autumn 1978.

[69] Jonathan Berk and Peter DeMarzo, *Corporate Finance: The Core*, 2009, (Berk & DeMarzo 2009) p. 420.

Looking to practitioners' views, the widely used text, *Ibbotson Cost of Capital Yearbook*,[70] reports results on the cost of equity (and associated weighted average cost of capital) by SIC code in the U.S. and other countries. In doing so, the yearbook reports the estimated cost of equity using five estimation methods: Sharpe-Lintner CAPM, CAPM plus/minus a size premium, Fama-French 3-Factor model, Single-Stage DDM, and 3-Stage DDM. The data source does not provide specifics on how to use the data but states that:

> [r]eaders can select cost of equity from five different models explored in this book. Given the size of the database being analyzed, there will clearly be instances where certain cost of equity models will fail to produce useable numbers. When NMF is displayed in a cost of equity column, it indicates that the model is producing unreasonable numbers, and greater emphasis should be placed on other models.[71]

Similarly, Roger A. Morin, in the context of U.S. regulation, mentions the use of the CAPM, DDM, risk premium models, and the comparable earnings method, concluding:

> No one individual method provides the necessary level of precision for determining a fair return, but each method provides useful evidence to facilitate the exercise of an informed judgment. Reliance on any single method or preset formula is inappropriate when dealing with investor expectations because of possible measurement difficulties and vagaries in individual companies' market data.[72]

Looking to regulators, the U.S. Surface Transportation Board (STB) undertook a review of its cost of equity estimation methodology in 2007-09 in two rounds, focused on the CAPM and DDM respectively. The STB's review resulted in two decisions with detailed instructions on how to estimate the cost of capital for the railway industry.[73]

In connection with this review, the STB noted:

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[70] The most recent version is Morningstar, *Ibbotson Cost of Capital 2012 Yearbook* (Ibbotson 2012).

[71] Ibbotson 2012, p. 6. The text views cost of equity estimates below the risk-free rate and above 50 percent as being not meaningful.

[72] Roger A. Morin, *New Regulatory Finance*, Public Utilities Reports, Inc., 2006, (Morin 2006) p. 428.

[73] Surface Transportation Board, STB Ex Parte No. 664, "Methodology to be Employed in Determining the Railroad Industry's Cost of Capital," January 17, 2008 (STB 2008) and STB Ex Parte No. 664 (Sub-No. 1), "Use of a Multi-Stage Discounted Cash Flow Model in Determining the Railroad Industry's Cost of Capital," January 28, 2009 (STB 2009).

> While CAPM is a widely accepted tool for estimating the cost of equity, it has certain strengths and weaknesses, and it may be complemented by a DCF model. In theory, both approaches seek to estimate the true cost of equity for a firm, and if applied correctly should produce the same expected result. The two approaches simply take different paths towards the same objective. **Therefore, by taking an average of the results from the two approaches, we might be able to obtain a more reliable, less volatile, and ultimately superior estimate than by relying on either model standing alone** [emphasis added].[74]

In arriving at this conclusion, the STB took notice of comments from the Federal Reserve that "multiple models will improve estimation techniques when each model provides new information,"[75] and also stated that there is "robust economic literature confirming that, in many cases, combining forecasts from different models is more accurate than relying on a single model."[76]

Similarly, the Ontario Energy Board (OEB) reviewed its cost of capital estimation methodology in 2009 following a year-long process. For context, the OEB does not focus on the cost of equity, but instead determines the premium over the risk-free rate that rate-regulated utilities are allowed. Regarding the methods used to determine the so-called Equity Risk Premium (ERP), the OEB concluded:

> **the use of multiple tests to directly and indirectly estimate the ERP is a superior approach to informing its judgment than reliance on a single methodology**.[77]

Additional examples of regulators who have relied upon multiple cost of equity estimation models and/or judgment based on a range of evidence are discussed in the section below.

To sum up, as clearly illustrated above, many academics, practitioners and regulators find that it is preferable to use more than one estimation method to determine the cost of equity. We agree that it is important to use more than one estimation method and stress that in determining how to

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74 STB 2008, p. 2.

75 STB 2009, p. 15.

76 STB 2009, p. 15.

77 Ontario Energy Board, "EB-2009-0084, Report of the Board on the Cost of Capital for Ontario's Regulated Utilities," Issued December 11, 2009, p. 36 (emphasis in the original).

weigh the estimation results, it is important to consider the degree to which the information from the methods overlaps versus providing additional information, the economic and financial environment that gave rise to the estimates, and the context in which they are being used.

2. Regulatory Practice in using Multiple Models

a) The U.S.

In the U.S., rates for rate-regulated entities are determined by several federal entities as well as regulators in each of the fifty states and the District of Columbia. Federal regulators tend to have well-specified methods to determine the cost of equity although they review all the information put to them. However, state regulators typically do not specify one single method and commonly have evidence from several estimation methods and parties in front of them before issuing a decision on the allowed cost of equity. In most cases the state regulator does not specify which weight was assigned to each method or other evidence. An exception is the determination of the cost of equity in Mississippi Power's Performance Evaluation Plan (PEP), where the Mississippi Public Service Commission annually updated the cost of equity for the company using a combination of the CAPM, ECAPM, risk positioning, and the DDM. In this specific circumstance, the weights assigned to each method are predetermined.[78] Some other examples of U.S. regulators' thought processes are provided below.

Surface Transportation Board

The STB used the constant growth model to track the cost of equity for U.S. railroads for a number of years. However, by 2005 the largest railroads were expanding rapidly and profitability was increasing. Security analysts were forecasting "long-run" earnings growth for some railroads at 15% per year. Such growth could not be sustained, so the constant growth model overstated the true cost of equity by a wide margin. The STB therefore initiated a cost of capital proceeding to consider how to change the determination of the cost of equity. After hearing evidence from academics and practitioners, the STB found that:

[78] http://www.psc.state.ms.us/.

> if our exploration of this issue has revealed nothing else, it has shown that there is no single simple or correct way to estimate the cost of equity for the railroad industry, and countless reasonable options are available.[79]

As a result of its deliberations the STB eventually settled on a blend of the CAPM and a multi-stage DDM.[80]

Georgia

The following example pertaining to Georgia Power, an integrated electric utility, illustrates a common approach in U.S. state regulation.

Georgia Power is regulated by the Georgia Public Service Commission (Georgia PSC), which has no pre-set method to determine the cost of equity. In Georgia Power's 2010 rate case, an expert for Georgia Power as well as for the Georgia PSC submitted evidence on the cost of equity for the company. The company's expert estimated the cost of equity using the Sharpe-Lintner CAPM, a single-stage DDM, and a risk premium approach, and recommended a return on equity of 11.0 to 11.2%. The PSC staff expert estimated the cost of equity using the Sharpe-Lintner CAPM, a sustainable growth DDM and also a comparable earnings model for a recommendation of 9.50 to 10.75%. The Georgia PSC approved a settlement including a cost of equity of 11.15%, but did not specify how it was arrived at.[81]

b) Canada

Until the early 1990s, Canadian regulators, much like U.S. state regulators, heard evidence on a multitude of methods and from various experts before arriving at a decision on the allowed cost of equity. However, starting in British Columbia in 1994, the British Columbia Utilities Commission in the first generic cost of capital proceeding in Canada established a benchmark ROE and a formulaic approach to updating the allowed ROE annually.[82] Shortly thereafter, other Canadian regulators followed suit and similarly established a benchmark ROE and an

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[79] *U.S.* Surface *Transportation Board, Ex Parte 664 (Sub-No. 1)*, issued January 28, 2009, p. 15.

[80] *Ibid.*

[81] Direct Testimony of J.H. Vande Weide in Docket No. 31958; Direct Testimony of D. Parcell in Docket No. 31958, and Settlement Agreement in Docket No. 31958.

[82] BCUC Decision in the Matter of Return on Common Equity BC Gas Utility Ltd., Pacific Northern Gas Ltd., West Kootenay Power Ltd., June 10, 1994 (BCUC 1994 Decision), pp. 39-40.

annual updating formula. These formulae were linked to the change or forecasted change in government bond yields.

While the formula used to update the allowed ROE annually was mechanical, the methods used to estimate the benchmark ROE varied across jurisdictions, and in many jurisdictions, the regulator looked to more than one estimation method.[83]

As the yield on government bonds declined, so did the allowed cost of equity, and as the financial crisis of 2008 impacted financial markets, regulators in Canada abandoned or modified the formula or the relied-upon benchmark. As was the case for the originally developed benchmark, the regulators heard evidence on multiple methods from several experts and implicitly or explicitly weighted these methods to arrive at a new or modified cost of equity methodology.[84] Some examples of this regulatory approach in Canada are provided below.

British Columbia

British Columbia Utilities Commission's (BCUC) views on how to determine the appropriate cost of equity capital have evolved over time. In the BCUC 1994 Decision,[85] the BCUC "placed primary reliance on the various risk premium tests presented" whereas the "comparable earnings and DCF test results have been used primarily as a check upon reasonableness."[86] However, in the BCUC 2006 Decision, the BCUC assigned weight to the DCF model and found the comparable earnings methodology useful.[87] The BCUC 2006 Decision did not state how much weight it assigned to each model it considered. The BCUC's views evolved as the various

[83] For example, the BCUC 1994 Decision at p. 17 indicated that while primary reliance should be placed on risk premium tests, comparable earnings and the DDM should be used as checks.

[84] For example, the National Energy Board abandoned the formulaic approach, the Alberta Utilities Board modified the benchmark, and the Ontario Energy Board modified both the benchmark and the formula. Both the Alberta Utilities Board and the Ontario Energy Board used several cost of equity estimation methods to arrive at their revised benchmark. The British Columbia Utilities Commission is in the midst of a generic cost of capital proceeding that will determine the approach going forward.

[85] BCUC Decision in the Matter of Return on Common Equity BC Gas Utility Ltd., Pacific Northern Gas Ltd., West Kootenay Power Ltd., June 10, 1994 (BCUC 1994 Decision).

[86] BCUC 1994 Decision, p. 17.

[87] BCUC In the Matter of Terasen Gas Inc. *et al.* Return on Equity and Capital Structure Decision, December 16, 2009 (BCUC 2009 Decision), pp. 44-45.

models arrived at more or less plausible results. For example, in its 2009 decision, the BCUC found:

> The Commission Panel agrees that a single variable is unlikely to capture the many causes of changes in ROE and that in particular the recent flight to quality has driven down the yield on long-term Canada bonds, while the cost of risk has been priced upwards.[88]

Having acknowledged the influence of the current economic environment, the BCUC in 2009 gave the most weight to the DDM, less weight to the Equity Risk Premium method and CAPM, and a low weight to the comparable earnings model. While the BCUC acknowledged giving weight to the DDM, ERP, CAPM and comparable earnings method, it did not specify the exact weights used.[89] The BCUC is currently undertaking a review of its cost of capital estimation methodology.

Ontario Energy Board

The Ontario Energy Board ("OEB") regulates electric and gas utilities in Ontario and sets rates for electric and natural gas distribution and transmission. The OEB also regulates other aspects of the electric and natural gas sector, but it does not regulate competitive electric or gas supply. In addition to determining the allowed cost of capital, the OEB also determines a deemed (allowed) capital structure for the utilities it regulates, and the allowed cost of equity is applied to the deemed equity portion of the allowed rate base, which is based on historical cost.

The OEB reviewed its approach to determining the cost of capital for Ontario utilities and in December 2009 issued a report on its estimation procedures going forward.[90] Prior to the review, the OEB relied on a formula-based approach using a version of the risk premium approach, or Equity Risk Premium (ERP) method to determine the return on common equity. Although a number of concerns were raised with this approach, the OEB decided to continue

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88 BCUC 2009 Decision, p. 73.

89 BCUC 2009 Decision, p. 45.

90 Ontario Energy Board, "EB-2009-0084, Report of the Board on the Cost of Capital for Ontario's Regulated Utilities," Issued December 11, 2009 (OEB Report 2009).

relying on a formula-based methodology and the ERP method, but the review led to a resetting of the risk premium and an adjustment to the formula used to update the ROE.

The OEB's current approach to cost-of-capital estimation requires that the Board determine a baseline ROE and subsequently update the estimate annually using the determined formula. The baseline ROE was most recently determined in 2009 during the generic proceeding. To arrive at its initial estimate of the ERP for determining the baseline ROE, the OEB reviewed the recommendations of the submissions as part of the 2009 proceeding, and determined each submission's Low, Medium, and High ERP.[91] In determining the initial ERP, the OEB found that:

> **the use of multiple tests to directly and indirectly estimate the ERP is a superior approach to informing its judgment than reliance on a single methodology.**[92]

As a result, the OEB considered all submissions, which included estimates based on the CAPM, DDM, risk premium model, econometric ERP analyses, realized ERP analyses, the difference between awarded ROEs and realized government bond yields, and various forecasts. The OEB averaged the experts' calculations of the risk premium over the long-term government bond and used judgment to determine that an appropriate premium over long-term government bonds was in the low-end of the range determined by the averages of the experts' ranges.

c) The U.K.

The U.K. regulator Ofgem has for many years made its cost of equity decisions within a CAPM framework, and, at least in a formal sense, has published CAPM parameters which correspond to its cost of equity determinations. However, it is also clear that Ofgem does not treat the CAPM estimates mechanistically, and, in any case, Ofgem uses a degree of judgment in determining the equity beta parameter, since there is little direct market evidence that can be relied on. While some of Ofgem's analysis and discussion of utility submissions is framed in terms of the CAPM parameters, it is clear that Ofgem focuses much more on the final cost of equity figure than on

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[91] OEB 2009, p. 38.

[92] OEB 2009, p. 36 (emphasis in the original).

the mechanistic derivation of that figure, whether in a CAPM framework or otherwise. For example, Ofgem has said: "Overall, our Final Proposals retain the cost of equity assumptions in our Initial Proposals of 7.0 percent for NGET and 6.8 percent for NGGT. Table 3.5 shows our Final Proposals for the cost of equity in terms of the CAPM components. We note, however, that **it is the overall allowed return that matters**. [emphasis added]"[93]

3. Impact of Economic, Industry or Company Factors

It makes sense that multiple cost of equity estimation methods have been developed and remain in use for a variety of reasons as articulated by Professors Berk and DeMarzo: "[a]ll the techniques … are imprecise" and "practitioners apply the technique that best suit their particular circumstances."[94] Because economic, industry, and firm-specific factors vary, it is important to assess the circumstances under which the models discussed in *Section III* are and should be used.

a) Economic Factors

As a pertinent example, due to the flight to quality following the financial crisis and subsequent monetary policy initiatives in many countries, the risk-free rate has been suppressed and is unusually low. Thus, in a standard implementation of the CAPM, the current risk-free rate results in a low cost of equity estimate. At the same time, investors have in recent years faced unusually high market volatility as measured by, for example, the S&P / ASX volatility index or the S&P 500 volatility index.[95] Academic literature finds that investors expect a higher risk premium during more volatile periods. For example, French, Schwert, and Stambaugh (1987) find a positive relationship between the expected market risk premium and volatility:

> We find evidence that the expected market risk premium (the expected return on a stock portfolio minus the Treasury bill yield) is positively related to the predictable volatility of stock returns. There is also evidence that unexpected stock returns are negatively related to the unexpected change in the volatility of

[93] *RIIO-T1: Final Proposals for National Grid Electricity Transmission and National Grid Gas*, Ofgem, 17 December 2012, paragraph 3.45.

[94] Berk & DeMarzo 2009, p. 420.

[95] The S&P/ASX Volatility Index and the S&P 500 Volatility Index reflect the markets' expected volatility in the benchmark Australian and American equity indices, respectively.

> stock returns. This negative relation provides indirect evidence of a positive relation between expected risk premiums and volatility.[96]

And Kim, Morley and Nelson (2004) find:

> When the effects of volatility feedback are fully taken into account, the empirical evidence supports a significant positive relationship between stock market volatility and the equity premium.[97]

Other academic papers have found a relationship between general economic conditions and the MRP. Constantinides (2008) studies a classical utility model where consumers are risk-averse and also summarizes some of the empirical literature. Empirical evidence shows that consumers become more risk-averse in times of economic recession or downturn, and equity investments accentuate this risk.[98] Increased risk aversion leads to a higher expected return for investors before they will invest. Specifically, equities are pro-cyclical and their performance is positively correlated with the economy's performance. Thus, unlike government bonds, equities fail to hedge against income shocks that are more likely to occur during recessions.[99] As a result, investors require an added risk premium to hold equities during economic downturns.

The very low current risk-free rates make the cost of equity estimates from a standard implementation of the Sharpe-Lintner CAPM also very low at a time when volatility measures indicate that the MRP has increased as well. Therefore, these market circumstances call for a serious consideration of economic factors or other models rather than a mechanical implementation of the Sharpe-Lintner CAPM.

Conditional models such as the Consumption CAPM attempt to incorporate the relationship between market volatility and the MRP in determining the cost of equity. As the model

96 K. French, W. Schwert and R. Stambaugh (1987), "Expected Stock Returns and Volatility," *Journal of Financial Economics*, Vol. 19, pp. 3.

97 C-J. Kim, J.C. Morley and C.R. Nelson (2004), "Is There a Positive Relationship Between Stock Market Volatility and the Equity Premium?," *Journal of Money, Credit and Banking*, Vol. 36, p. 357.

98 Constantinides, G.M. (2008), "Understanding the equity risk premium puzzle," In R. Mehra, ed., *Handbook of the Equity Risk Premium*, Elsevier, Amsterdam.

99 Constantinides, G.M., and D. Duffie (1996), "Asset Pricing with Heterogeneous Consumers," *Journal of Political Economy*, pp. 219-240. See also E.S. Mayfield (2004), "Estimating the market risk premium," *Journal of Financial Economics*, vol. 73, pp. 465-496.

estimates a relationship between the risk premium of a stock and its conditional volatility, the model allows for a time-varying relationship between risk and return; *i.e.*, the implied cost of equity varies with the degree to which (i) the underlying stock can serve as a hedge against the market and (ii) market volatility. As rate-regulated entities commonly move with the market, the cost of equity estimate usually moves in the same direction as the volatility of the market. Thus, the consumption-based model addresses the finding that volatility impacts the required risk premium. As such, it may be particularly useful to implement this model when market volatility is unusually high or low.[100]

Given the currently very low risk-free rates and the recent market volatility, the DDM may additionally provide useful insights into the cost of equity. This is especially true for versions of the model that take into account (i) all cash that flows to shareholders through not only dividends but also share buybacks and (ii) changes in the forecasted growth rates in the near term and the longer term (*i.e.* multi-stage versions of the DDM).

Table 3 below displays the impact of two key economic factors discussed above, market volatility and risk-free rates, on the choice of cost of equity estimation model. While there is no specific formula that can be proposed to select a particular model under given market circumstances, or a method that can be used to combine the various models mechanistically, there are certain market scenarios under which it is more appropriate to use one model rather than another. For example, in times of either extremely high or low market volatility, (or extreme values of other macroeconomic indicators such as inflation), the consumption-based CAPM becomes more relevant. The DDM model and especially the multi-stage DDM is also less sensitive to variations in the risk-free rate than the standard CAPM, but it can be sensitive to market volatility. This is because in times of economic turmoil, the growth estimates for companies, including rate-regulated entities, are less likely to be stable going forward. Because the multi-stage DDM has more realistic characteristics and is less sensitive to analysts' short-term forecasts, the tables in this section use the term DDM to reflect the multi-stage DDM.

[100] See Ahern, *et al.* (2012) for a discussion of its use in a regulatory setting.

The effect of the risk-free rate and market volatility on model choice is reflected in Table 3 below, which should be viewed as an illustration on the directional choice rather than a prescription.

Table 3: Relationship Between Key Economic Conditions and Weights to be Given to Models

		Prevailing Risk-free Rate in Economy		
Market Volatility		High	Average	Low
	High	Consumption CAPM		
	Average	Consumption CAPM / DDM	CAPM / ECAPM	Consumption CAPM / DDM
	Low	Consumption CAPM / DDM		

b) Industry Factors

As discussed above, empirical research has consistently found that the Security Market Line determined by the Sharpe-Lintner CAPM (as depicted in Figure 2) is too steep.[101] This result is also consistent with the findings of Fama & French (1992), which estimated a zero slope in the empirical SML.[102] Thus, the ECAPM as well as the Fama-French model attempt to find a model that is a better fit with empirical data from tests of the Shape-Lintner CAPM, showing that the latter tends to under estimate the cost of equity for companies with beta estimates below one, and over estimate the cost of equity for companies with beta estimates above one. A better-fitting model flattens the Security Market Line as depicted in Figure 3. Because most rate-regulated entities have beta estimates below one, reliance on the Sharpe-Lintner CAPM tends to bias the

[101] See, for example, F. Black, M.C. Jensen, and M. Scholes, "The Capital Asset Pricing Model: Some Empirical Tests," *Studies in the Theory of Capital Markets*, Praeger Publishers, 1972, pp. 79-121 and E.F. Fama and J.D. MacBeth, "Risk, Returns and Equilibrium: Empirical Tests," *Journal of Political Economy* 81 (3), 1972, pp. 607-636.

[102] E.F. Fama and K.R. French, "The Cross-Section of Expected Returns," *Journal of Finance* 47, 1992, pp. 427-465.

cost of equity estimates for these companies downwards. Therefore, for entities whose beta estimates are farther from one, it becomes important to look to the ECAPM to accurately reflect the cost of equity for the entity.[103] In many countries or regions, including Australia, Canada, Europe and the U.S, estimated betas for rate-regulated entities declined and become statistically insignificant in the early 2000s as the dot.com bubble burst. In such circumstances, the downward bias in the cost of equity estimates from the Sharpe-Lintner CAPM becomes more pronounced and models such as the ECAPM can improve the estimation.

For some industries the future may look like the past, but for others this is not the case. As an example, the outlook for the U.S shale gas industry today is different than it was in 2008. Similarly, the outlook for the nuclear industry in Japan changed dramatically after the 2011 tsunami. In such circumstances, forward-looking estimates of the industry's cost of capital as obtained through, for example, versions of the DDM, may be especially useful. As noted above, the DDM implementation should carefully consider not only the current economic environment but also industry and firm-specific factors, such as the sustainability of the current growth forecasts and whether dividends truly reflect all cash distribution to shareholders. For example, the multi-stage models discussed in *Section III* rely on several growth rates and therefore enable the analyst to consider near-term, intermediate, and long-term growth prospects for the individual company, industry, and economy. Therefore, a multi-stage DDM model, unlike the Sharpe-Lintner CAPM, can capture both near-term and longer-term changes in an industry. This becomes especially important when an industry's expected risk characteristics differ from its past characteristics.

Rate-Regulated Entities vs. Other Industries

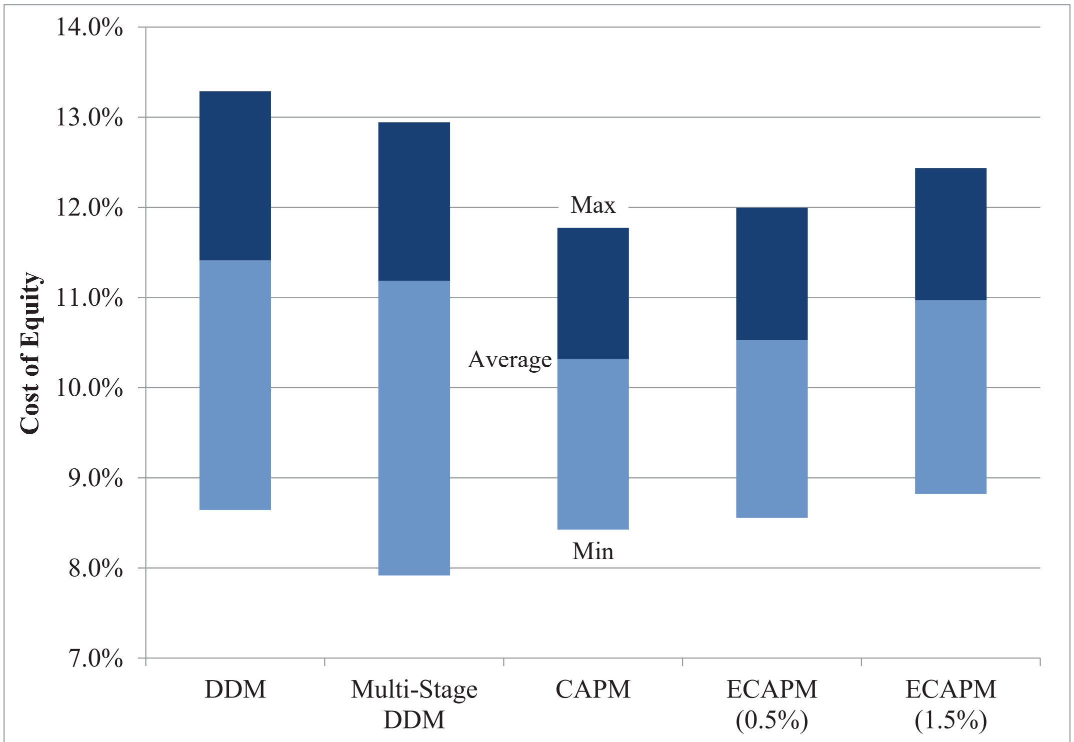
According to empirical studies, the Sharpe-Lintner CAPM remains the most commonly used model across the full spectrum of companies.[104] However, the utility industry and rate-regulated entities have some unique characteristics that make it plausible that the methods that serve other

[103] See Table A-1 in the Appendix for details. Much of the academic literature estimating alpha dates back to the 1980s. Academic research has since turned to the Fama-French multifactor model, which attempts to explicitly capture the empirical pivot of the SML as a function of additional pricing factors.

[104] J.R. Graham and C.R. Harvey, "The Theory and Practice of Corporate Finance: Evidence from the Field," *Journal of Financial Economics* 60, 2001, pp. 187-243.

industries well do not serve this industry nearly as well. For example, the utility industry tends to be relatively stable, so that the DDM (and especially the multi-stage DDM) is much more likely to provide usable results for this industry than for more volatile industries. As the residual income valuation model is a variation of the multi-stage DDM, the same comments pertain to this model.

Prior to the financial crisis, models such as the single-stage DDM, *Brattle*'s multi-stage DDM, the CAPM, and versions of the ECAPM resulted in fairly similar results. Figure 5 below illustrates this for the gas distribution industry in the U.S. towards the end of 2006. Specifically, the figure is based on implementing the constant growth DDM, a 3-stage DDM, the Sharpe-Lintner CAPM, the ECAPM with an alpha of 0.5% and an ECAPM with an alpha of 1.5% for seven gas distribution companies. Figure 5 then shows the range of the cost of equity estimates assuming a 50-50 gearing for the target company. The figure also indicates the average cost of equity obtained from the sample, which is at the split of each bar.



Source: Calculated by The Brattle Group.

Figure 5

It is clear from Figure 5 above that there is substantial overlap in the estimates. We attribute this effect to the fact that the economy was relatively stable in 2006 and so was the gas distribution industry. At the time, these models largely confirmed the range of the cost of equity estimates.

As discussed above, rate-regulated companies also tend to be low-beta entities, so the empirical finding that the SML predicted by the Sharpe-Lintner CAPM is too steep is a serious concern for this industry; *i.e.*, it becomes important to use the ECAPM or other models to ensure that this empirical observation is accurately reflected in the cost of equity estimates.

Analogously to Table 3, Table 4, Panels A and B below summarize the directional weighing of the models depending on various industry characteristics. The two industry factors considered in Table 4, Panel A below are the stability of growth rate forecasts and the average market beta of the industry. For example, as mentioned above, rate-regulated entities tend to have relatively more stable growth forecasts over time and low betas (*i.e.*, beta estimates below one). Therefore, for this industry, the use of the ECAPM or variations of the multi-stage DDM might become valuable in determining the cost of equity capital. The effect of the stability of growth forecasts and the beta value on model choice is reflected in Table 4, Panel A below, which should be viewed as an illustration on the directional choice rather than a prescription.

Table 4: Relationship Between Key Industry Factors and Weights to be given to Models– Panel A

		Stability of Industry Growth Forecasts Over Time		
		High	Average	Low
Market Beta of Industry	High	ECAPM / DDM		ECAPM / Other
	Average	CAPM / DDM		CAPM / Other
	Low	ECAPM / DDM		ECAPM / Other

Another characteristic of the industry that should be considered is whether companies in the industry are exposed to financial distress and/or significant merger and acquisition activity, and the prevalence of share buybacks. As discussed above, market-based estimation models are relatively more affected when a given company faces financial distress, or unique circumstances that may lead to its stock price decoupling from fundamentals. Therefore, if many companies in an industry are subject to such effects, the whole industry may be affected. Further, companies that engage in a substantial amount of share buybacks will end up distributing cash to shareholders in a form other than dividends, which makes a DDM based on a per share dividend ratio less appropriate. Panel B below illustrates these effects.

Table 4: Relationship Between Key Industry Factors and Weights to be given to Models– Panel B

		Industry Exposure to Financial Distress and/or M&A	
Prevalence of Share Buybacks		**High**	**Low**
	High	Other Models: Risk Premium, comparable earnings, maybe use other industries	CAPM, ECAPM, DDM that includes all cash that accrues to shareholders
	Low		CAPM, ECAPM, DDM

c) Company Factors

In many instances company-specific issues are better dealt with via sample selection or through risk positioning than through the determination of how to estimate the cost of equity. A company that is a potential member of the benchmark sample is often dropped if it faces unique circumstances that may bias the cost of capital estimation process. This is the case if, for example, a company is undergoing significant merger or acquisition activity, which inherently affects the information available in the market and therefore drives the stock price (and thus the results from all market-based models, including the CAPM, ECAPM, Fama-French and DDM).

After a range of cost of equity estimates has been obtained, it is necessary to consider where, from within this range, the final determination on the cost of equity will be. Provided that the range has been developed in an appropriate way that takes account of the market and industry factors described in this section, the final step is to consider the relative risk of the target company compared to the sample of companies from which the cost of equity range has been developed. The cost of equity is adjusted upward or downward depending on the target entity's risk characteristics relative to those of the sample. This issue is the topic of the next section.

D. Risk Positioning of the Target Entity

The discussion in the preceding sections covered various models that produce cost of equity estimates. Typically the cost of equity will be estimated for a sample of firms, or all firms in a particular sector, because it usually is not possible to estimate the cost of equity for a single firm with a useful degree of accuracy. To determine a single value for the cost of equity for a specific firm from a range of values for a set of comparator firms, it makes sense to consider the riskiness of the specific firm relative to the riskiness of the sample, since the cost of equity itself is compensating investors for risk.

In the regulatory context, in some cases this process is implicit in the regulator's decision, while in others it is an explicit step in the cost of equity determination process. This step can conveniently be termed "risk positioning", because the regulator considers the risk characteristics of the specific utility relative to the benchmark.

1. Why risk positioning is necessary

While the precise details and wording of the regulator's objective in setting the cost of equity vary from one jurisdiction to another, the underlying idea is that investors will expect a return equivalent to the return that they would expect from other investments of like risk. Utilities generally have low risk relative to the market as a whole, but within the utilities sector, different firms are likely to have somewhat different risk characteristics. "Risk positioning" acknowledges the possibility that different utilities can have somewhat different risks. In this context, "risk" is defined as the characteristic of an investment which determines expected returns which would usually include "systematic" exposure to the wider economy, but not "idiosyncratic" risks associated with specific projects that can be diversified away in an investment portfolio. While the cost of equity solely captures investors' compensation for bearing systematic risk, the cost of debt reflects total risk, including idiosyncratic risks. Therefore, there are instances of regulatory mechanisms, such as decoupling, which reduce the variability of total revenues and therefore also total risk, (affecting the cost of debt), but which may not impact the cost of equity for a given utility.

One way in which a utility is exposed to systematic risk is through variations in demand. End-user demand tends to be at least somewhat correlated with wider economic activity, and is thus a source of exposure to systematic risk. One utility might have more exposure than other, for example if it has a greater proportion of price-sensitive industrial load.

In some jurisdictions, leverage is considered a source of "financial risk", which affects the risk positioning analysis. This could be so, for example, where the rate of return is generally determined on the basis of actual capital structure. A utility with more debt than the benchmark will require a higher return on equity than the benchmark, even if it otherwise has similar business risk exposure as the benchmark (just as two utilities with the same asset beta would have different equity betas if one has higher gearing than the other). Where this approach is taken, the term "business risk" is used to refer to the other sources of relevant risk differences that are taken into account in the risk positioning analysis.

Once a benchmark rate of return has been defined (whether a point estimate or a range), the risk positioning approach requires an analysis of the particular utility's risk relative to that benchmark. To the extent that the utility is found to have more (or less) risk than the benchmark, the rate of return would be set higher (or lower) than the benchmark rate of return.

2. What risk characteristics are relevant?

The characteristics relevant to risk positioning are those which expose the utility to systematic risk and which therefore have an impact on the rate of return required by investors. Some important sources of uncertainty in revenues and returns to investors may not have an impact on the required return to the extent that investors are able to diversify away exposure to those risks. For example, the weather may be an important source of variability in revenues and returns, but may not be an important source of risk to investors because it is diversifiable.

A good way to think about risk positioning is to consider the extent to which different utilities are protected from risks. A distribution utility can in principle be protected from risks to the extent that it is able to pass on risk to its customers (which depends on the detail of the regulatory framework being applied). Demand risk (which is at least partly non-diversifiable), for example, can be borne by the utility if the regulatory regime sets prices and does not "true up" revenues to account for the difference between forecast and actual demand. Alternatively, demand risk can be passed on to customers through a true-up or balancing account process, which would allow the utility to recover in one year any "missing" revenue from the prior year caused by demand forecasting errors. Protection from demand risk in this way depends on both a regulatory framework that allows for such true-ups and on the existence of franchise customers that will bear the risks passed on to them. Therefore, other things equal, a utility with true-ups for demand risk would be considered less risky than one without.

Distribution utilities typically have franchise customers that rely on the utility and have no alternative supply of energy. However, this is typically not the case for gas pipelines: in many jurisdictions, gas pipelines do not have "franchise" customers: customers may be free to switch to competing pipelines. Even if there is no prospect of competition from other pipelines, it may still be difficult for pipelines to pass on demand risk to their customers, since large end-users may be price sensitive (i.e., if the pipeline increases price in response to a fall in demand, the price increase itself could further cut demand).

Pipeline regulators in both the US and Canada apply a risk-positioning approach in determining the cost of equity.

3. FERC Approach

The Federal Energy Regulatory Commission (FERC) has a standard approach to determining the cost of equity for gas pipelines, set out in a "policy statement",[105] which, together with precedent from prior decisions, guides all decisions on the cost of equity for gas pipelines. The FERC's approach is to use a form of the dividend growth model (typically termed the "DCF" model in

[105] *Composition of Proxy Groups for Determining Gas and Oil Pipeline Return on Equity*, FERC (April 2008).

the US) to estimate the cost of equity for a benchmark group of publicly-traded pipeline companies. The results of the model are a cost of equity estimate for each of the companies in the benchmark (or "proxy") group.

FERC starts by assuming that the median company in the proxy group is the appropriate cost of equity, unless either the pipeline or an intervener in the case demonstrates that the instant pipeline has risk factors which mean that the cost of equity should be set above or below the median:

> *after defining the zone of reasonableness through development of the appropriate proxy group for the pipeline, the Commission assigns the pipeline a rate within that range or zone, to reflect specific risks of that pipeline as compared to the proxy group companies.* [f/n omitted] *The Commission has historically presumed that existing pipelines fall within a broad range of average risk. A pipeline or other litigating party has to show highly unusual circumstances that indicate anomalously high or low risk as compared to other pipelines to overcome the presumption.*[106]

And

> unless *a party makes a very persuasive case in support of the need for an adjustment and the level of the adjustment proposed, the Commission will set the pipeline's [ROE] at the median of the range of reasonable returns.*[107]

In line with this approach, most FERC decisions result in the pipeline receiving a cost of equity equal to the median of the proxy group. A recent decision for El Paso Natural Gas (EPNG),[108] however, illustrates how FERC assesses relative risk and may, on occasion, move away from the median. In this case, the FERC ALJ[109] characterized EPNG's business risk on two related dimensions: competitive risk and regulatory risk. US natural gas pipelines typically secure long-term contractual commitments from shippers to use the pipeline capacity (with relatively high fixed charges, equivalent to a take-or-pay commitment). EPNG had long-term contracts for a smaller proportion of its capacity than did the pipelines in the proxy group, and its contracts were typically shorter. Furthermore, EPNG's throughput had been declining. This is symptomatic of higher business risk, because in the absence of contractual commitments and in the absence of

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[106] *Ibid*., p. 4.

[107] *El Paso Natural Gas Company*, Initial Decision, docket no. RP10-1398 (June 18, 2012), paragraph 40, quoting prior FERC decisions.

[108] *El Paso Natural Gas Company, Initial Decision*, docket no. RP10-1398 (June 18, 2012).

[109] A FERC rate case typically results in an "initial decision" issued by an Administrative Law Judge (ALJ). The ALJ's decision is subsequently reviewed by the FERC commissioners, and may be affirmed or varied.

franchise customers, the pipeline is no longer able to pass on risks to its customers. In the limit, the pipeline may be unable to charge rates high enough to recover its authorized revenue requirement (as increasing rates drives throughput lower still).

The ALJ found that EPNG was exposed to competition in its major downstream markets from new pipeline projects, and that this competition was to an extent the result of regulatory policies that favor new pipeline projects to foster competition (possibly harming existing pipelines).

Based on this analysis (and also a finding that EPNG had above-average financial risk, as evidenced by a credit rating of BBB-, lower than all but one of the proxy group companies), the ALJ determined that EPNG's cost of equity should be set "well above the median ROE [of the proxy group]".[110]

4. NEB approach

In Canada, the approach taken by energy regulators (both provincial and national) historically was to set the cost of equity on a formula basis and to us the same cost of equity for all pipelines. Risk positioning was then used to vary the authorized proportion of equity in the capital structure, thereby increasing the overall return on capital for those utilities judged to be riskier. However, in the most recent decision by Canada's National Energy Board (NEB), the NEB moved to an approach which focuses on the overall after-tax return directly, rather than separately determining the cost of equity, the cost of debt, and the proportion of each in the capital structure.[111] The NEB takes a systematic approach to assessing business risk under the headings "supply risk", "market [downstream] risk", "regulatory risk", "competitive risk" and "operating risk", although the NEB said "The various forms of risk are in some cases inextricably linked, and the boundaries between them are subjective".[112] In the RH-1-2008 case,[113] the NEB was concerned with whether the business risk of the pipeline had increased

110 *Ibid.*, p. 45. The ALJ did not specify an ROE. The final decision on ROE rests with the FERC commissioners.

111 See RH-1-2008, discussed further below.

112 *Reasons for Decision, Trans Quebec and Maritimes Pipelines Inc., RH-1-2008*, NEB (March 2009), p. 30.

113 Concerning the Trans Quebec and Maritimes Pipelines, which predominantly move supplies sourced from the Western Canadian Sedimentary Basin (WCSB) via the TransCanada Mainline, into Quebec and on into New Hampshire.

since the last time that a decision on the cost of capital for the pipeline had been taken. The NEB identified a number of factors as contributing to an increased overall business risk.

- **Supply risk**: the pipeline was mainly supplied from a region with declining conventional production and rising costs. While it was possible that new sources of unconventional supply (shale gas) would be developed, the result was increased uncertainty over the availability of competitively-priced supplies, and hence concerns over the possibility for reduced throughput.
- **Market and competitive risk**: because a large and increased proportion of the pipeline's throughput went to large industrial and electric power generation load, which is more variable than domestic and commercial load. In addition, competition with cheap hydro-power in the Quebec also contributed to increased market risk. Market risk was also increased as a result of the potential for competition with LNG imports in the US market.

Overall, the NEB concluded that business risk had increased as a result of these factors relative to the previous cost of capital decision for the pipeline. Whereas the FERC in the US uses a risk positioning approach to determine the cost of equity relative to a benchmark, the NEB estimated the after-tax weighted average cost of capital directly, principally on the basis of market-based estimates of the cost of capital of various comparator companies. The business risk analysis described above was part of the NEB's determination of where the pipeline's cost of capital should be relative to the sample data.[114]

5. Implementation

In the FERC and NEB examples given above, risk positioning of the target utility within the range of comparator or proxy companies is not analytically precise: the regulator considers evidence (which could be quantitative, such as the proportion of price-sensitive industrial load, or more qualitative) as to exposure to various relevant risk factors. Weighing the risk factors, and determining how the analysis of risk should be reflected in the final cost of equity determination is necessarily imprecise, and relies on judgment. For example, a regulator might determine that a

[114] The NEB's analysis is summarized on p.79 of the decision.

particular utility, having an unusually high proportion of industrial load, was of above average risk, and that as a result the cost of equity should be 50 basis points above the mid-point of a range determined for a sample of utilities. The direction of the adjustment (upwards) is clear, but the magnitude is more a matter of judgment than something that can be derived quantitatively.

APPENDIX: ADDITIONAL TABLES AND FIGURES

Table A-1: Empirical Evidence On The Alpha Factor in ECAPM

AUTHOR	RANGE OF ALPHA	PERIOD RELIED UPON
Black (1993)[1]	1% for betas 0 to 0.80	1931-1991
Black, Jensen and Scholes (1972)[2]	4.31%	1931-1965
Fama and MacBeth (1972)	5.76%	1935-1968
Fama and French (1992)[3]	7.32%	1941-1990
Fama and French (2004)[4]	N/A	
Litzenberger and Ramaswamy (1979)[5]	5.32%	1936-1977
Litzenberger, Ramaswamy and Sosin (1980)	1.63% to 3.91%	1926-1978
Pettengill, Sundaram and Mathur (1995)[6]	4.6%	1936-1990

[*] The figures reported in this table are for the longest estimation period available and, when applicable, use the authors' recommended estimation technique. Many of the articles cited also estimate alpha for sub-periods and those alphas may vary.

[1] Black estimates alpha in a one-step procedure rather than in an un-biased two-step procedure.

[2] Estimate a negative alpha for the sub period 1931-39 which contain the depression years 1931-33 and 1937-39.

[3] Calculated using Ibbotson's data for the 30-day treasury yield.

[4] The article does not provide a specific estimate of alpha; however, it supports the general finding that the CAPM underestimates returns for low-beta stocks and overestimates returns for high-beta stocks.

[5] Relies on Litzenberger and Ramaswamy's before-tax estimation results. Comparable after-tax alpha estimate is 4.4%.

[6] Pettengill, Sundaram and Mathur rely on total returns for the period 1936 through 1990 and use 90-day treasuries. The 4.6% figure is calculated using auction averages 90-day treasuries back to 1941 as no other series were found this far back.

Sources:

Black, Fischer. 1993. Beta and Return. *The Journal of Portfolio Management* 20 (Fall): 8-18.

Black, F., Michael C. Jensen, and Myron Scholes. 1972. The Capital Asset Pricing Model: Some Empirical Tests, from Studies in the theory of Capital Markets. In *Studies in the Theory of Capital Markets*, edited by Michael C. Jensen, 79-121. New York: Praeger.

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Litzenberger, Robert H. and Krishna Ramaswamy and Howard Sosin. 1980. On the CAPM Approach to Estimation of a Public Utility's Cost of Equity Capital. *The Journal of Finance* 35 (2): 369-387.

Pettengill, Glenn N., Sridhar Sundaram and Ike Mathur. 1995. The Conditional Relation between Beta and Returns. *Journal of Financial and Quantitative Analysis* 30 (1): 101-116.

MISSISSIPPI POWER
A SOUTHERN COMPANY

PERFORMANCE EVALUATION PLAN
RATE SCHEDULE "PEP-5A"

Mississippi Public Service Commission Schedule No. 28.1		
PAGE 24 of 31	EFFECTIVE DATE **January 1, 2015**	DATE OF VERSION SUPERSEDED **January 9, 2009**

APPENDIX C

Where:

R_f = The Risk Free Rate is the normalized Bond Yield on 30 Year U.S. Treasury bonds as used in the Equity Risk Premium calculation.

Beta = The Beta is the average of the betas as stated in Value Line for the same group of comparable utilities in the DCF test above. Those companies eliminated by the DCF truncation are also eliminated from this calculation

R_m = Two historical Market Risk Premiums shall be used. The first is the total return market equity risk premium for the most current year listed and the second is the income equity risk premium for the same time period. Both are found in Ibbotson Associated Yearbook.

Two projected market risk premiums shall be used. The first is the Value Line Indicated Total Return less the normalized Yield on 30 Year U.S. Treasury bonds. The second is the S&P 500 Indicated Total Return less the normalized Yield on 30 Year U.S. Treasury bonds.

2. R_m Four calculations are performed for the Standard CAPM using each of the four market risk premiums.

Empirical CAPM

3. The following version of the Empirical CAPM model shall be used

$K = R_f + 0.25\ (R_m\text{-}R_f) + 0.75\ \text{Beta}\ (R_m\text{-}R_f)$

Where:

R_f = The Risk Free Rate is the normalized Yield on 30 Year U.S. Treasury bonds as used in the Equity Risk Premium calculation.

Beta = The Beta is the average of the betas as stated in Value Line for the same group of comparable utilities used in the DCF test above. Those companies eliminated by the DCF truncation are also eliminated from this calculation.

193. In applying his version of the ECAPM l, Mr. Hevert used an X factor of 0.25, based on published work of Dr. Morin.[242] The resulting estimates were an average ROE of 8.91 per cent and 10.54 per cent for his Canadian and U.S. proxy groups, respectively, which were approximately 80 bps larger than his estimates using CAPM.[243] Mr. Hevert's resulting estimates do not include any amounts for flotation costs.[244]

194. Dr. Villadsen used an alpha factor of 1.5 per cent, which was based on an average adjustment factor from academic literature.[245] This factor was adjusted downwards to account for differences in government bond maturities and to be conservative.[246] Dr. Villadsen's resulting ROE estimates for her Canadian and U.S. utility proxy groups are presented in Table 5 below. Consistent with her CAPM estimates, Dr. Villadsen included flotation costs and generated results under two scenarios of risk free rates and MERP.

Table 5. Dr. Villadsen's ECAPM estimates

	ROE	
	Scenario 1	Scenario 2
	(%)	
Canadian utility sample	9.0 - 9.5	10.2 - 10.9
U.S. gas utility sample	8.4	9.2
U.S. electric utility sample	8.2 - 8.3	9.0 - 9.1

Source: Exhibit 20622-X0104, evidence of Dr. Villadsen, PDF pages 54-55.

195. Dr. Booth did not use ECAPM to generate ROE estimates, but he did discuss alternatives to CAPM. Dr. Booth observed that there are a wide variety of multi-factor models, which essentially extend the one factor CAPM to include additional factors. The current 'standard' multifactor model, known as the Fama-French three factor model, includes a size premium to address the return difference between small firms and large firms and a value premium to address the return difference between value and growth stocks.[247] Dr. Booth did not use this model or advocate for its use, as he stated this model is unlikely to generate any significant value over the use of the CAPM. He noted that he included this information in his evidence to demonstrate academic support for other risk premium based models.

Commission findings

196. The use of ECAPM is an approach recognized in the academic literature and is used to address a perceived issue with the CAPM, when the CAPM-based SML is steeper than empirical evidence suggests it should be. The ECAPM adjusts the SML by introducing an empirical adjustment factor to flatten the SML.

242 Exhibit 20622-X0215, response to AML/EDTI-AUC-2016FEB18-007, PDF pages 79-80. Transcript, Volume 1, pages 139-140.
243 Exhibit 20622-X0082, evidence of Mr. Hevert, PDF page 76.
244 Exhibit 20622-X0082, evidence of Mr. Hevert, PDF page 124.
245 The academic literature references are listed in Exhibit 20622-X0105, evidence of Dr. Villadsen, Appendices, PDF page 27.
246 Transcript, Volume 5, PDF pages 647-648.
247 Exhibit 20622-X0242, evidence of Dr. Booth, PDF pages 42-43.

197. In exchanges with Commission counsel, both Mr. Hevert[248] and Dr. Villadsen[249] agreed that the empirical adjustment factor used in their respective ECAPMs is a function of the sample used and the time period over which the returns were examined. During the oral hearing, Commission counsel asked Mr. Hevert if there are any kinds of standards or best practices that are employed by professionals in determining what the dataset should be when estimating the empirical adjustment factor. In response, Mr. Hevert described that there have been different studies that produce a range of estimates for the empirical adjustment factor and in his view, the selection of the empirical adjustment factor will inevitably be a matter of judgement.[250]

198. Mr. Hevert's view is supported by the evidence in this proceeding with respect to the empirical adjustment factors selected by the experts who employed an ECAPM. Mr. Hevert relied on an adjustment factor based on Dr. Morin's 1989 empirical study that used data from 1926 to 1984 and Dr. Villadsen used an empirical adjustment factor based on average estimated adjustment factors from academic studies that she then adjusted downwards in order to be conservative. The studies relied upon by Dr. Villadsen used different timeframes, with none of the studies including years beyond 1991.[251]

199. In the Commission's view, the ECAPM appears to be a model that could contribute to the Commission's determination of a fair allowed ROE. Generally speaking, the Commission is supportive of models and methods that attempt to improve upon CAPM results. The Commission agrees with Mr. Hevert that the selection of an empirical adjustment factor is a matter of judgement. Based on the evidence in this proceeding, however, the Commission has been unable to assess adequately the empirical adjustment factors employed by the experts in exercising their judgement. Consequently, the Commission will not rely heavily on the ECAPM results in this proceeding. In order for the Commission to adequately assess the judgement exercised by the experts, the Commission would require a full explanation justifying the sample and time periods adopted.

200. The Commission also notes that the empirical adjustment factors to CAPM used in the ECAPMs in this proceeding does not resolve the issues discussed in Section 6.1.4 regarding the reasonable degree of confidence in the estimated ranges for beta.

6.3 Bond yield plus risk premium model and the predictive risk premium model

201. In addition to relying on their CAPM results in estimating a fair allowed ROE, Mr. Hevert, Dr. Villadsen and Dr. Cleary presented results generated by risk premium models. All of the risk premium models presented in this proceeding are based on the fundamental assumption of modern corporate finance that risk averse investors require higher returns for bearing higher risk. In their general form, risk premium models add a premium to account for equity risk to a measure of interest rates.[252]

202. Mr. Hevert gave primary weight to the results of his CAPM and risk premium models in arriving at his recommended ROE range, and less weight to the results of his DCF model.[253]

248 Transcript, Volume 1, page 138, lines 10-20.
249 Transcript, Volume 5, page 646, lines 7-24.
250 Transcript, Volume 1, page 139.
251 Exhibit 20622-X0457, rebuttal evidence of Dr. Villadsen, PDF page 27.
252 Exhibit 20622-X0082, evidence of Mr. Hevert, PDF page 76. Exhibit 20622-X0164, response to AML/EDTI-UCA-2016FEB18-010, PDF page 29.
253 Exhibit 20622-X0082, evidence of Mr. Hevert, PDF page 159.

Educational Articles

STOCKS

Using Beta

Andrew J. Cueter | October 02, 2012

In finance, the Beta of a security (or portfolio) is used as an indicator of its historical volatility in regards to a benchmark, generally the New York Stock Exchange (NYSE) Composite Index or the S&P 500 Index. At Value Line, we derive the Beta coefficient from a regression analysis of the relationship between weekly percentage changes in the price of a stock and weekly percentage changes in the NYSE Composite Index over a period of five years. In the case of shorter price histories, a shorter time period is used, but two years is the minimum. Value Line then adjusts these Betas to account for their long-term tendency to converge toward 1.00. (Though the scope of this convergence is beyond our purposes here, readers can refer to M. Blume, "On the Assessment of Risk," Journal of Finance, March 1971 for further details.)

Now that we have our Beta number, what does it mean? If an equity mirrors the benchmark, then it carries a Beta of 1.00. If Stock X has a Beta of 2.00, it is expected to rise (or fall) twice as much as the movement of the benchmark. For example, if the NYSE Composite Index rises (falls) 10%, Stock X will likely rise (fall) 20%. (For a more detailed overview, see **Understanding Beta**). Beta can also be negative (infrequent but possible), which would mean that the equity's return tends to move in the opposite direction from the market's move. Moreover, there is no upper or lower bound to Beta, although it typically does not stray too far from 1.00. Finally, a Beta of zero does not mean the asset is risk-free, just that the correlation of that asset's return to the market's return is zero.

Now that we know what Beta is and its implications, how can we use it? If we were able to predict the movements of the overall market, we would simply buy high Beta stocks while the market rises, and low Beta stocks while the market is falling. However, no one is capable of timing the market over the long term. So, what should we do?

If we define a high risk asset in terms of the movement of its price, we can look towards Beta as one indicator of this riskiness. Though Beta by itself does not give a perfect indication of volatility, it does imply the direction and magnitude of movements. Using Beta as a measure of risk, we can relate this to a basic tenet of finance theory, which states that investors demand a return in exchange for assuming risk. Therefore, high-risk (or high-Beta) investments should provide a higher payout, and conversely, low-risk (or low-Beta) investments should provide a lower payout. This proposition seems reasonable and intuitive, but it may not always hold.

In a paper entitled "Re-Thinking Risk: What the Beta Puzzle Tells Us about Investing," written by David Cowan and Sam Wilderman of GMO LLC, they show just the opposite. For the paper, Beta was measured using 250-day returns of a universe of 1,000 stocks, regressed against 250-day returns of that universe. Low- and high-Beta Portfolios were then formed monthly and weighted by market capitalization, with the universe used as the benchmark. Their results present data starting in December, 1969 and show that high-Beta stocks have significantly underperformed the market (average annualized return of 7.2% vs. 10.6% for low-Beta and 9.8% for the universe), and done so with substantially higher annualized volatility (24.5% vs. 12.5% and 16.0%, respectively) and larger drawdown (-84.4% vs. -39.5% and -50.3%, respectively).

Though low-Beta may trump high-Beta over longer periods, there are some problems with solely relying on the Beta coefficient. It is a backward looking metric, and therefore may not be an accurate predictor of the future. The markets change all the time and just because a relationship held in the past does not mean it is certain to continue into the future. Also, since it is solely a statistical measure, it fails to consider underlying business fundamentals or economic developments. Consider **Altria Group** (**MO**). This stock has a Beta of 0.55 and the company primarily sells cigarettes. Due to the low Beta, we may say this is a low-risk stock. However, if for some reason cigarettes were deemed illegal to sell, this company would probably not stick around very long and any investment in the stock will likely become worthless. Solely looking at a stock's Beta will not uncover this risk.

So, back to our question posed earlier; what should we do? We propose Beta should be used as one factor in the equity analysis framework. Investors should also look at our Safety rank and Price Stability score when making investment decisions. Considered in conjunction with Value Line's fundamental research and valuation ratios, we believe investors can create a portfolio that may provide superior risk-adjusted returns over the long haul.

At the time of this article's writing, the author did not have positions in any of the companies mentioned.

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CAPITAL EQUIPMENT ANALYSIS: THE REQUIRED RATE OF PROFIT

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The interest in capital equipment analysis that has been evident in the business literature of the past five years is the product of numerous social, economic, and business developments of the postwar period. No conclusive listing of these developments can be attempted here. However, four should be mentioned which are of particular importance in this search for a more systematic method for discovering, evaluating, and selecting investment opportunities. These are: (1) the high level of capital outlays (in absolute terms); (2) the growth in the size of business firms; (3) the delegation of responsibility for initiating recommendations from top management to the profit center, which has been part of the general movement toward decentralization; and (4) the growing use of "scientific management" in the operations of the business firm.

These developments have motivated the current attempt to develop objective criteria whereby the executive committee in a decentralized firm can arrive at a capital budget. Since each of its profit centers submits capital proposals, the executive committee must screen these and establish an allocation and a level of capital outlays that is consistent with top management's criteria for rationing the firm's funds. Capital budgeting affords the promise that this screening process can be made amenable to some established criteria that are understandable to all the component parts of the firm. Consequently, capital budgeting appeals to top management, for, in the first place, each plant manager can see his proposal in the light of all competing proposals for the funds of the enterprise. This may not completely eliminate irritation among the various parts of the firm, but a rational capital budgeting program can go a long way toward maintaining initiative on the part of a plant manager, even though the executive committee may veto one or all of his proposals. In the second place, the use of a capital budgeting program serves to satisfy top management that each accepted proposal meets adequate predetermined standards and that the budget as a whole is part of a sound, long-run plan for the firm.

What specifically does a capital budgeting program entail? The focal points of capital budgeting are: (1) ascertaining the profit abilities of the array of capital outlay alternatives, and (2) determining the least profitability required to make an investment, i.e., a cut-off point. Capital budgeting also involves administrative procedures and organization designed to discover investment opportunities, process information, and carry out the budget; however, these latter aspects of the subject have been discussed in detail by means of case studies that have appeared in publications of the American Management Association and the

National Industrial Conference Board and in periodicals such as the *N.A.C.A. Bulletin*.[1] Hence, we will not concern ourselves with them here.

There are at least four methods for establishing an order-preference array of the capital expenditure suggestions. They are: (1) the still popular "payoff period"; (2) the average investment formula; (3) the present value formula with the rate of interest given; and (4) the present value formula used to find the rate of profit. It is not our intention in this paper to discuss these various methods specifically, since critical analyses of these alternatives are to be found in papers by Dean, by Lorie and Savage, and by Gordon in a recent issue of the *Journal of Business*,[2] which is devoted exclusively to the subject of capital budgeting.

However, it is of interest to note that in each of these methods the future revenue streams generated by the proposed outlays must be amenable to measurement if the method is to be operational. However, improvements in quality, more pleasant working conditions, strategic advantages of integration, and other types of benefits from a capital outlay are still recognized only in qualitative terms, and there is a considerable hiatus in the literature of capital budgeting with respect to the solution of this problem. Hence, in the absence of satisfactory methods for quantifying these types of benefits, the evaluation of alternative proposals is still characterized by intuitive judgments on the part of management, and a general quantitative solution to the capital budgeting problem is not now feasible. It appears to us that this problem affords one of the most promising opportunities for the application of the methods of management science. In fact, we anticipate that techniques for the quantification of the more important factors now treated qualitatively will soon be found.

Given the rate of profit on each capital outlay proposal, the size of the budget and its allocation are automatically determined with the establishment of the rate of profit required for the inclusion of a proposal in the budget. In the balance of this paper, a method for determining this quantity is proposed and its use in capital budgeting is analyzed.

II

We state that the objective of a firm is the maximization of the value of the stockholders' equity. While there may be legitimate differences of opinion as to whether this is the sole motivation of management, we certainly feel that there can be no quarrel with the statement that it is a dominant variable in manage-

[1] American Management Association, *Tested Approaches to Capital Equipment Replacement*, Special Report No. 1, 1954; American Management Association, *Capital Equipment Replacement*; *AMA Special Conference*, May 3–4, 1954 (New York, 1954, American Management Association, 105 pp.); J. H. Watson, III, National Industrial Conference Board, *Controlling Capital Expenditures*, Studies in Business Policy, No. 62, April, 1953; C. I. Fellers, "Problems of Capital Expenditure Budgeting", *N.A.C.A. Bulletin*, 26 (May, 1955), 918–24; E. N. Martin, "Equipment Replacement Policy and Application", *N.A.C.A. Bulletin*, 35 (February, 1954), 715–30.

[2] *Journal of Business*, Vol. XXVIII, No. 3 (October, 1955).

ment's decisions. It has been shown by Lutz and Lutz in their *Theory of the Investment of the Firm*[3] and by others[4] that this objective is realized in capital budgeting when the budget is set so as to equate the marginal return on investment with the rate of return at which the corporation's stock is selling in the market. The logic and operation of this criterion will be discussed later. Now, we only wish to note the role assigned in capital budgeting to the rate of profit that is required by the market.

At the present time, the dividend yield (the current dividend divided by the price) and the earnings yield (the current income per share divided by the price) are used to measure the rate of profit at which a share is selling. However, both these yields fail to recognize that a share's payments can be expected to grow, and the earnings yield fails to recognize that the corporation's earnings per share are not the payments made to the stockholder.

The practical significance of these failures is evidenced by the qualifications with which these two rate-of-profit measures are used by investment analysts. In the comparative analysis of common stocks for the purpose of arriving at buy or sell recommendations, the conclusions indicated by the dividend and/or the earnings yield are invariably qualified by the presence or absence of the prospect of growth. If it is necessary to qualify a share's yield as a measure of the rate of profit one might expect to earn by buying the share, then it must follow that current yield, whether income or dividend, is inadequate for the purposes of capital budgeting, which is also concerned with the future. In short, it appears to us that the prospective growth in a share's revenue stream should be reflected in a measure of the rate of profit at which the share is selling. Otherwise, its usefulness as the required rate of profit in capital budgeting is questionable.

In his *Theory of Investment Value*[5], a classic on the subject, J. B. Williams tackled this problem of growth. However, the models he developed were arbitrary and complicated so that the problem of growth remained among the phenomena dealt with qualitatively. It is our belief that the following proposal for a definition of the rate of profit that takes cognizance of prospective growth has merit.

The accepted definition of the rate of profit on an asset is the rate of discount that equates the asset's expected future payments with its price. Let $P_0 =$ a share's price at $t = 0$, let $D_t =$ the dividend expected at time t, and let $k =$ the rate of profit. Then, the rate of profit on a share of stock is the value of k that satisfies

$$P_0 = \sum_{t=1}^{\infty} \frac{D_t}{(1 + k)^t}. \tag{1}$$

[3] Friedrich and Vera Lutz, *The Theory of Investment of the Firm* (Princeton, N. J., 1951, Princeton University Press, 253 pp.), 41–43.

[4] Joel Dean, *Capital Budgeting: Top Management Policy on Plant, Equipment, and Product Development* (New York, 1951, Columbia University Press, 174 pp.); Roland P. Soule, "Trends in the Cost of Capital", *Harvard Business Review*, 31 (March, April, 1953), 33–47.

[5] J. B. Williams, *The Theory of Investment Value*, (Cambridge, Massachusetts, 1938, Harvard University Press), 87–96.

It is mathematically convenient to assume that the dividend is paid and discounted continuously at the annual rates D_t and k, in which case

$$P_0 = \int_0^\infty D_t e^{-kt}\, dt. \tag{2}$$

Since P_0 is known, estimating the rate of profit at which a share of stock is selling requires the determination of D_t, $t = 1, 2, \cdots, \infty$.

At the outset it should be made clear that our objective is not to find the rate of profit that *will actually be earned* by buying a share of stock. This requires knowledge of the dividends that will be paid in the future, the price at which the share will be sold, and when it will be sold. Unfortunately, such information is not available to us. The rate of profit of interest here is a relation between the present known price and the *expected future dividends*. The latter will vary among individuals with the information they have on a host of variables and with their personality. Therefore, by expected future dividends we mean an estimate that (1) is derivable from known data in an objective manner, (2) is derived by methods that appear reasonable, i.e., not in conflict with common sense knowledge of corporation financial behavior, and (3) can be used to arrive at a manageable measure of the rate of profit implicit in the expectation.

We arrive at D_t by means of two assumptions. One, a corporation is expected to retain a fraction b of its income after taxes; and two, a corporation is expected to earn a return of r on the book value of its common equity. Let Y_t equal a corporation's income per share of common after taxes at time t. Then the expected dividend at time t is

$$D_t = (1 - b)Y_t \tag{3}$$

The income per share at time t is the income at $(t - 1)$ plus r percent of the income at $(t - 1)$ retained, or

$$Y_t = Y_{t-1} + rbY_{t-1} \tag{4}$$

Equation (4) is simply a compound interest expression so that, if Y_t grows continuously at the rate $g = br$,

$$Y_t = Y_0 e^{gt}. \tag{5}$$

From Equations (3) and (5)

$$D_t = D_0 e^{gt}. \tag{6}$$

Substituting this expression for D_t in Equation (2) and integrating, yields

$$\begin{aligned} P_0 &= \int_0^\infty D_0 e^{gt} e^{-kt}\, dt \\ &= D_0 \int_0^\infty e^{-t(k-g)}\, dt \\ &= \frac{D_0}{k - g}. \end{aligned} \tag{7}$$

The condition for a solution is $k > g$, a condition that is easily satisfied, for otherwise, P_0 would be infinite or negative.

Solving Equation (7) for k we find that

$$\boxed{k = \frac{D_0}{P_0} + g.} \tag{8}$$

Translated, this means that the rate of profit at which a share of common stock is selling is equal to the current dividend, divided by the current price (the dividend yield), plus the rate at which the dividend is expected to grow. Since there are other possible empirical definitions of the market rate of profit on a share of stock, we will refer to k as the growth rate of profit.

III

Let us now review and evaluate the rationale of the model we have just established. Estimating the rate of profit on a share of stock involves estimating the future dividend stream that it provides, and the fundamental difference between this model and the dividend yield is the assumption of growth. The latter, as can be seen, assumes that the dividend will remain constant. Since growth is generally recognized as a factor in the value of a share and since it is used to explain differences in dividend yield among shares, its explicit recognition appears desirable. Future dividends are uncertain, but the problem cannot be avoided by ignoring it. To assume a constant rate of growth and estimate it to be equal to the current rate appears to be a better alternative.

Under this model the dividend will grow at the rate br, which is the product of the fraction of income retained and the rate of return earned on net worth. It is mathematically true that the dividend will grow at this rate if the corporation retains b and earns r. While we can be most certain that the dividend will not grow uniformly and continuously at some rate, unless we believe that an alternative method for estimating the future dividend stream is superior, the restriction of the model to the assumption that it will grow uniformly at some rate is no handicap. Furthermore, the future is discounted; hence, an error in the estimated dividend for a year in the distant future results in a considerably smaller error in k than an error in estimating the dividend in a near year.

It should be noted that this measure of the rate of profit is suspect, when *both* income and dividend are zero, and it may also be questioned when either falls to very low (or negative) values. In such cases, the model yields a lower rate of profit than one might believe that the market requires on a corporation in such difficulties. It is evident that the dividend and the income yields are even more suspect under these conditions and, hence, are subject to the same limitations.

There are other approaches to the estimation of future dividends than the extrapolation of the current dividend on the basis of the growth rate implicit in b and r. In particular, one can arrive at g directly by taking some average of the past rate of growth in a corporation's dividend. Whether or not this or some other measure of the expected future dividends is superior to the one presented earlier will depend on their relative usefulness in such purposes as the analysis of variation in prices among shares and the preferences of those who want an objective measure of a share's rate of profit.

So far, we have compared the growth rate of profit with the income and dividend yields on theoretical grounds. Let us now consider how they differ in practice, using the same measurement rules for the variables in each case. The numerical difference between the growth rate of profit and the dividend yield is simply the growth rate. However, the income yield, which is the measure of the rate of profit commonly recommended for capital budgeting, differs from the growth rate of profit in a more complex manner, and to establish this difference we first note that

$$b = \frac{Y - D}{Y} \text{ and } r = \frac{Y}{B} \tag{9}$$

where $B =$ the net worth or book value per share. The growth rate of profit, therefore, may be written as

$$k = \frac{D}{P} + br = \frac{D}{P} + \frac{Y - D}{B}. \tag{10}$$

Next, the income yield can be decomposed as follows:

$$y = \frac{Y}{P} = \frac{D}{P} + \frac{Y - D}{P}. \tag{11}$$

We see then that y and k will be equal when book and market values are equal. It can be argued that the income yield overstates a share's payment stream by assuming that each payment is equal to the income per share and understates the payment stream by assuming that it will not grow. Hence, in this special case where book and market values are equal, the two errors exactly compensate each other.

Commonly market and book values differ, and y will be above k when market is below book, and it will be below k when market is above book. Hence, a share of IBM, for example, that is priced far above book had had an earnings yield of two to three percent in 1955. We know that the market requires a higher rate of profit on a common stock, even on IBM, and its growth rate of profit, k, is more in accord with the value suggested by common sense. Conversely, when U. S. Steel was selling at one-half of book value in 1950, the high income yield grossly overstated the rate of profit that the market was, in fact, requiring on the stock.

Furthermore, the growth rate of profit will fluctuate in a narrower range than the earnings yield. For instance, during the last few years, income, dividends, and book value have gone up more or less together, but market price has gone up at a considerably higher rate. Consequently, the growth rate of profit, dependent in part on book value, has fallen less than the earnings yield. Conversely, in a declining market k would rise less rapidly than y.

There is a widespread feeling that many accounting figures, particularly book value per share, are insensitive to the realities of the world, and some may feel that the comparative stability of k is merely a consequence of the limitations of accounting data. This is not true! The behavior of k is not a consequence of the supposed lack of realism in accounting data. Rather, book value appears in the model because it, and not market value, is used to measure the rate of return the corporation earns on investment, which, we have seen, is the rate of return that enters into the determination of the rate at which the dividend will grow. The comparative stability of k follows from the simple fact that, when a revenue stream is expected to grow, a change in the required rate of profit will give rise to a more than proportional change in the asset's price. Conversely, a change in the price reflects a less than proportional change in the rate of profit.

IV

Given the rate of profit expected on each item in the schedule of available investment opportunities and given the rate of profit at which the corporation's stock is selling, what should the capital budget be? As stated earlier, the accepted theory is that the budget should be set so as to equate the marginal return on investment with the rate of profit at which the stock is selling. The reasoning is, if the market requires, let us say, a 10 percent return on investment in the corporation's stock, and if the corporation can earn 15 percent on additional investment, obtaining the funds and making the investment will increase the earnings per share. As the earnings and the dividend per share increase or as the market becomes persuaded that they will increase, the price of the stock will rise. The objective, it will be recalled, is the maximization of the value of the stockholder's equity.

The conclusion drawn implicitly assumes that the corporation can sell additional shares at or above the prevailing market, or if a new issue depresses the market, the fall will be slight, and the price will soon rise above the previous level. However, some other consideration may argue against a new stock issue; for example, the management may be concerned with dilution of control, or the costs of floating a new issue may be very high, or a new issue may be expected to depress the price severely and indefinitely for reasons not recognized in the theory. Hence, it does not automatically follow that a new issue should be floated when a firm's demand for funds exceeds, according to the above criterion, those that are internally available.

In determining whether the required rate of profit is above or below r', the marginal return on investment, one can use y, the earnings yield, or k, the growth rate of profit as the required rate of profit. If y and k differ and if the reasoning in support of k presented earlier is valid, using y to estimate the direction in which a new issue will change the price of the stock may result in a wrong conclusion.

In arriving at the optimum size of a stock issue, the objective is to equate r' and y or k, depending on which is used. Internal data may be used to estimate the marginal efficiency of capital schedule. If the required rate of profit is considered a constant, its definition, $y = Y/P$ or $k = D/P + br$, provides its value. However, the required rate of profit may vary with the size of the stock issue or with the variables that may change as a consequence of the issue. In this event,

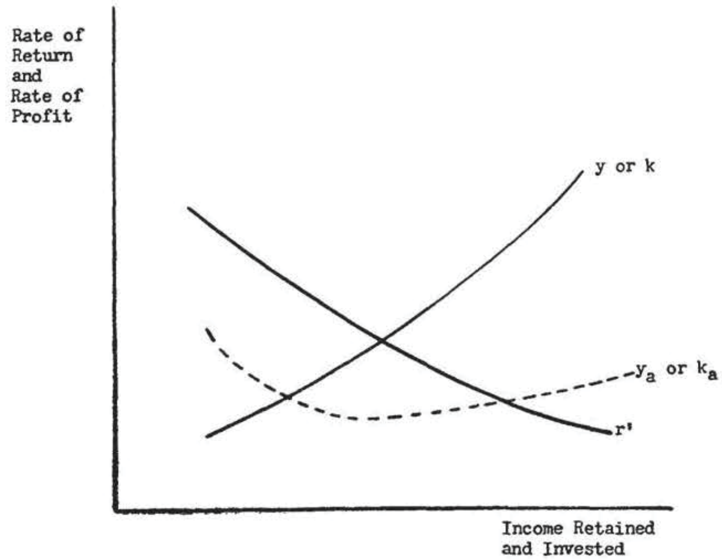

FIG. 1

finding the optimum size of a stock issue requires a model that predicts the variation in the required rate of profit with the relevant variables.

Borrowing is an alternative source of funds for investment. However, an analysis of this alternative requires the measurement of both (1) the variation in risk with debt, and (2) the difference between the rate of profit and the rate of interest needed to cover a given increase in risk. This has not been done as yet, which may explain the widespread practice of arbitrarily establishing a "satisfactory" financial structure and only borrowing to the extent allowed by it.

It has been stated by Dean[6] and Terborgh[7] that the long-term ceiling on a firm's capital outlays is the amount of its internally available funds. However, the share of its income a corporation retains is not beyond the control of its management; and, among the things we want from a capital budgeting model is guidance on whether the share of a corporation's income that is retained for investment should be raised or lowered.

Proceeding along traditional lines, the problem may be posed as follows. A firm estimates its earnings and depreciation allowances for the coming year and deducts the planned dividend to arrive at a preliminary figure for the capital budget. The marginal rate of return on investment in excess of this amount may be above or below the required rate of profit. We infer from theory that the two rates should be equated by (1) raising the budget and reducing the dividend

[6] Dean, *op. cit.*, 53–55.

[7] George Willard Terborgh, *Dynamic Equipment Policy* (New York, 1949, McGraw-Hill, 290 pp.), 228–29.

when the marginal return on investment is above the required rate of return, and (2) raising the dividend and reducing the budget when the reverse holds. The conditions under which this process yields an equilibrium are illustrated in Figure 1. The marginal return on investment, r', should fall as the budget is increased, and the required rate of profit, y or k, should increase or it should fall at a lower rate than r'. The latter case is illustrated by the line y_a or k_a.

Changing the dividend so as to equate r' and say y should maximize the price of the stock. For instance, if r' is above y, the company can earn a higher return on investment than stockholders require, and a dollar used this way is worth more to the stockholders than the dollar distributed in dividends. In other words, the price should go up by more than the income retained.

There are, of course, a number of problems connected with the use of this model for arriving at the optimum dividend rate. First, there is the question whether y or k should be used to measure the required rate of profit. Second, there is no question that the required rate of profit varies with the dividend rate. Hence, the current rate of profit given by the definition does not tell what profit rate will be required with a different dividend rate. This requires a model which predicts the variation in y or k with the dividend rate and other variables. Third, there is a very nasty problem of the short and the long run. It is widely believed, though the evidence has limitations, that the price of a share of stock varies with the dividend rate, in which case a corporation should distribute all of its income. However, it is quite possible that a change in the dividend gives rise to the expectation that earnings and future dividends are changing in the same direction. Further, in the short run, the market is not likely to be informed on a firm's marginal efficiency of capital schedule. For these and other reasons, it is likely that the dividend rate should not be made to vary with short-run changes in the marginal efficiency of capital, and more sophisticated methods than those now in use are needed to establish the variation in price or required rate of profit with the dividend rate.

V

The major points developed in this paper may be summarized as follows. We presented a definition of the rate of profit required by the market on a share of common stock, and we noted some of its advantages. It is theoretically superior to the income and dividend yields because it recognizes that the revenue stream provided by a share can be expected to grow. Furthermore, its empirical characteristics are also superior to those of the income and dividend yields since its value is generally in closer agreement with common sense notions concerning the prevailing rate of profit on a share of stock and since its value fluctuates in a narrower range over time. We next examined some of the problems involved in using this definition of the rate of profit and the earnings yield in capital budgeting models. Finally, we saw that, before capital budgeting theory can be made a reliable guide to action, we must improve our techniques for estimating the future revenue on a capital outlay proposal, and we must learn a good deal more about how the rate of profit the market requires on a share of stock varies with the dividend, the growth rate, and other variables that may influence it.

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Regulated Electric and Gas Utilities – US

Continued decline in ROEs to heighten pressure on financial metrics

» **Lower 30-year Treasury yield to increase pressure on utilities' authorized return on equity.** The decline in the yield on 30-year US Treasury bonds will heighten pressure on the return on equity (ROE) that utilities are authorized to collect in customer rates. The 30-year yield averaged 2.89% in 2019 and finished the year at 2.39%, which is well below the 3.11% average in 2018. If the yield were to remain close to year end levels and the average, roughly 670 basis point spread with utility ROEs over the past 10 years were to be maintained, this would result in an average approved utility ROE of about 9% in 2020, down from 9.65% during 2019.

» **Coronavirus-related drop in 30-year T-bill likely to stay the hand of regulators for now.** Regulators will be hesitant to reduce authorized returns given the current market uncertainty and while rate cases are being delayed. This may lead to the widest spread between the authorized ROE and the 30-year T-bill in at least the past two decades.

» **Modest increases in equity capital support credit strength.** Increasing equity in the capital structure results in higher net income and lower debt in the capital structure, both of which benefit credit quality. In addition, the equity component of the capital structure generally experiences less variability when measured as a percentage change compared to ROE. Thus, the increase in average equity thickness to 50.6% in 2019 from about 49.3% during the previous two years is credit positive for utilities.

» **Credit metrics are more sensitive to changes in ROE and equity capital after US tax reform.** Changes in ROE and equity capital affect financial metrics because utilities generate a significant portion of their cash flow from net income. While US tax reform has not had a direct impact on utility net income, it has reduced the overall level of cash flow by reducing deferred taxes and increasing net income and depreciation as percentages of utility cash flow. As a result, utility credit metrics are more sensitive to changes in authorized ROE and the level of equity capital than they were before tax reform.

» **Outcomes will continue to vary among regulatory jurisdictions.** A variety of factors can influence the outcome of discussions among utilities, regulators and intervenors about authorized returns and equity capital. Utilities use many arguments to bolster their case for increasing shareholder returns that may offset the pressure created by declining Treasury yields. Common issues that are typically raised include the impact of tax reform, large capital programs, access to capital, fair return standards, pressure on utility bills and increasing sector risks.

Declining 30-year Treasury yield to increase pressure on authorized returns on equity

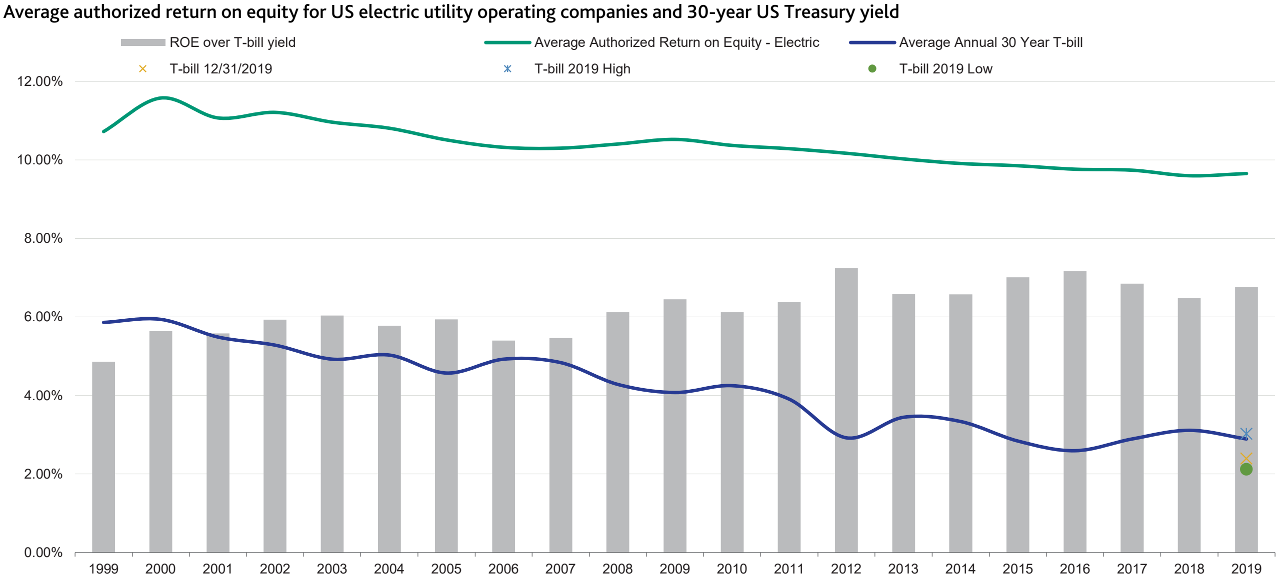
The renewed decline in the 30-year US Treasury yield during 2019 suggests that there will be heightened pressure on the ROE that utilities are authorized to collect in customer rates. During the past two decades, the average authorized ROE of US regulated utilities has fallen in the wake of the long-term decline in the 30-year T-bill. Utility ROEs have been "sticky" – that is, they have declined more slowly than the 30-year T-bill. As a result, the spread between the two has gradually expanded during this period.

The 30-year yield averaged 2.89% in 2019, down from 3.11% in 2018. However, as of 31 December 2019, the yield was 2.39% and the low for the year was 2.12%. If the yield were to remain close to year-end levels and the average 670 basis point spread with ROEs over the past 10 years were to be maintained, this would result in an average approved ROE of about 9% in 2020, down from the 9.65% in 2019. However, the stickiness of utility ROEs illustrated by higher average spreads historically suggests that the average ROE may not fall to 9% so quickly even if T-bills were to remain at year-end levels.

Exhibit

Spread between US utility ROEs and 30-year Treasury yield has widened over time

Average authorized return on equity for US electric utility operating companies and 30-year US Treasury yield



Sources: Moody's Analytics and S&P Global Market Intelligence

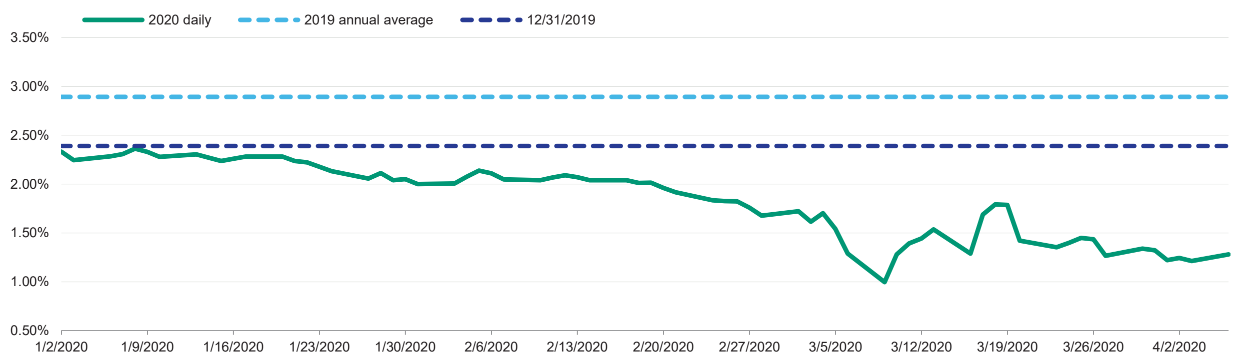
Over time, ROE declines are likely to continue to be more modest than declines in the 30-year Treasury yield. The equity component of the capital structure has increased modestly over the past 15 years, which may offset some of the pressure created by a lower ROE. These movements are important to credit quality because both ROE and the level of equity capital are key factors in utility net income, which makes up slightly less than half of utility cash flow.

Changes to ROE's can take some time to occur. In November, the Federal Energy Regulatory Commission (FERC) lowered the base ROE for Midcontinent Independent System Operator (MISO) transmission owners, which include vertically integrated utilities such as ALLETE Inc. (Baa1 stable), Ameren Corporation (Baa1 stable), Cleco Power LLC (A3 stable), MidAmerican Energy Company (A1 stable) and Otter Tail Power Company (A3 stable). The decision to lower the base ROE to 9.88% with a cap of 12.24%, including ROE incentive adders, was the culmination of a series of inquiries and rulings emanating from a complaint filed in 2013. In that complaint, a group of transmission customers alleged that MISO transmission owners were earning a base ROE that was unjust and unreasonable under section 206 of the Federal Power Act (see "Regulated electric utilities – US: FERC order reducing MISO base ROE is credit negative for transmission owners"). After many parties filed requests for rehearing, FERC published an order on 21 January 2020 granting these requests.

Coronavirus-related drop in 30-year T-bill likely to stay the hand of regulators for now

As a result of the economic fallout from the coronavirus outbreak, the rate on the 30-year T-bill has declined significantly, as shown in Exhibit 2. Assuming utilities continue to earn the average 670 bps spread over the 30-year T-bill, this would suggest that there will be a great deal of pressure on authorized returns. However, we think regulators will be hesitant to significantly reduce allowed returns given the uncertain market environment and the likely delays in adjudicating rate cases because of social distancing mandates and other issues associated with the coronavirus (see "Regulated Electric, Gas and Water Utilities – US: Coronavirus outbreak delays rate cases, but regulatory support remains intact"). This may lead to the widest spread between the authorized ROE and the 30-year T-bill in at least the past two decades. Utilities with a formula driven approach to setting ROEs may be hurt far more quickly as their ROE's are adjusted automatically. We expect some of these utilities to appeal to regulators to either suspend or alter this formula based approach, at least temporarily.

Exhibit 2
The 30-year T-bill has declined sharply amid coronavirus-related recessionary pressures
Yield on 30-year US Treasury bonds since the beginning of 2020



Source: Moody's Analytics

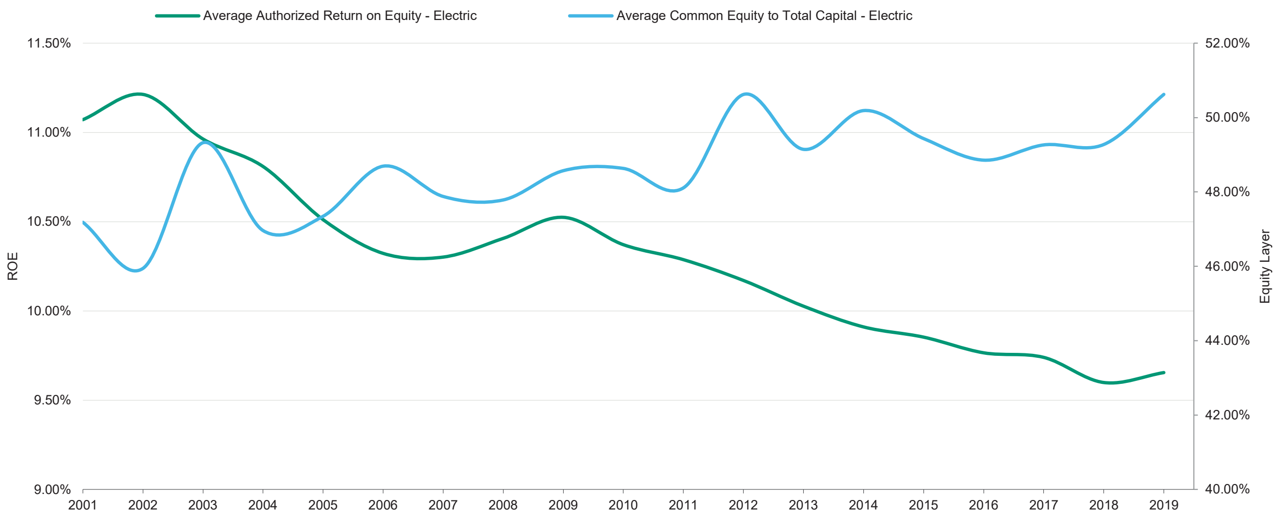
In contrast to the gradual, long-term decline in the 30-year T-bill illustrated in Exhibit 1, the year-to-date decline in the yield has been more abrupt, influenced by the plunge in economic activity at the end of the first quarter. We expect US GDP to undergo a sharp 4.5% contraction in the first half of the year, before finishing full-year 2020 down 2.0% and recovering in 2021 with 2.3% growth (see "Global Macro Outlook 2020-21 [March 25, 2020 Update]: The coronavirus will cause unprecedented shock to the global economy"). Given the continued uncertainty over efforts to contain the coronavirus outbreak, there is significant downside risk to our macroeconomic forecast. But if there were to be a material snapback in growth, we would expect interest rates to follow suit.

Modest increases in equity capital support credit strength

Increasing equity results in higher net income and lower debt in the capital structure, both of which benefit credit quality. In addition, the equity component of the capital structure generally experiences less variability from year to year when measured as a percentage change compared to ROE. Thus, the increase in the average equity thickness to 50.6% in 2019 from about 49.3% during the previous two years is credit positive for utilities.

However, some jurisdictions are moving in a different direction. On 14 November, the Public Utility Commission of Texas (PUCT) issued a preliminary decision in CenterPoint Energy Houston Electric LLC's (CEHE, Baa1 stable) rate case, setting the utility's ROE at 9.25% and its equity ratio at 40%. Both were lower than the 9.42% ROE and 45% equity ratio recommended in September by administrative law judges at the Texas State Office of Administrative Hearings. Following the PUCT's preliminary decision, which also increases regulatory uncertainty for other regulated utilities in the state, we placed CEHE's ratings on review for downgrade and revised our outlook on AEP Texas Inc. (Baa1 negative) to negative from stable. On 21 January 2020 a CEHE filing indicated that a settlement had been reached that would set the ROE at 9.4% and the equity capital layer at 42.5%. The PUCT issued an order on 7 March 2020 based on the stipulation of settlement and incorporating the 9.4% ROE and 42.5% equity layer. CEHE's rating was lowered to Baa1 from A3, partly as are result of the lower ROE incorporated in the stipulation.

Exhibit 3
Equity capital is increasing as ROEs decline
US electric utilities' average authorized return on equity versus average common equity to total capital ratio



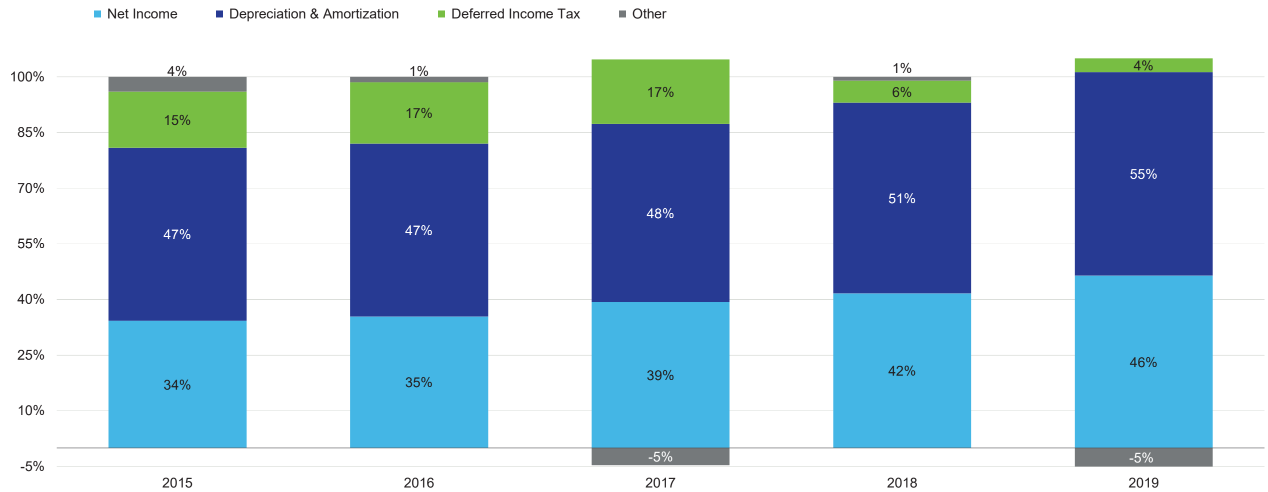
Source: S&P Global Market Intelligence

Credit metrics are more sensitive to changes in ROE and equity capital after US tax reform

Changes in ROE and equity capital will affect financial metrics because utilities generate a significant portion of their cash flow from net income. As a simple proxy, net income is often a function of rate base times the level of equity capital multiplied by the authorized ROE. Rate base, which is the level of historical investment that utilities have made but have not yet recovered in rates, is roughly equal to net property plant and equipment with some adjustments. Investments included in rate base must be approved by the utility regulator.

While US tax reform has not had a direct impact on utility net income, it has reduced the overall level of cash flow by reducing deferred taxes. This has increased net income and depreciation as percentages of utility cash flow, as shown in Exhibit 4. As a result, utility credit metrics are now more sensitive to changes in authorized ROE and the level of equity capital than they were before tax reform.

Exhibit 4
US tax reform has changed the composition of utility cash flow
Components of utility cash flow for 109 rated vertically integrated and T&D operating companies



All numbers include Moody's standard adjustments.
Source: Moody's Investors Service

Key credit metrics are more sensitive to changes in the capital structure than they are to the authorized ROE. While ROE affects net income, changes in the capital structure affect both net income and the level of debt that cash flow has to service so, from a credit perspective, changes to the capital structure are more important to credit quality than ROE. This is clearly illustrated in Exhibit 5, which shows a simple model for estimating the impact of changes in these variables on the ratio of cash flow from operations (CFO) to debt, a key financial metric we use in analyzing a utility's financial strength. The exhibit assumes that all revenue and costs are pass-through items and assumes no impact from other potential variables, such as volume risk or taxes.

Under our base case of 50% equity capital, a 10% authorized ROE and a 4% depreciation rate, CFO/debt would be 18%. Under the alternative scenarios shown below, CFO/debt would decline to 17% if we were to assume a 9% ROE, all else being equal, and the ratio would fall to 15.5% if we were to assume 45% equity capital, all else being equal to our base case. The exhibit also shows that a one percentage point decline in ROE (to 9% from 10%) and a 1.9 percentage point reduction in equity capital (to 48.1% from 50%), all else being equal to our base case, would both result in CFO/debt of 17%.

Exhibit 5
Changes in ROE and equity capital both affect key financial metrics
Four scenarios illustrating how authorized return on equity and equity thickness affect CFO/debt ratio

	Base case (unchanged)	ROE reduced to 9%	Equity reduced to 45%	Equity reduced to 48.1%
Rate base	$100	$100	$100	$100
Allowed ROE	10.0%	**9.0%**	10.0%	10.0%
Equity thickness	50.0%	50.0%	**45.0%**	**48.1%**
Depreciation (years)	25	25	25	25
Depreciation rate (%)	4.0%	4.0%	4.0%	4.0%
Net income	$5.0	$4.5	$4.5	$4.8
Depreciation	$4.0	$4.0	$4.0	$4.0
CFO	$9.0	$8.5	$8.5	$8.8
CFO/debt	18.0%	17.0%	15.5%	17.0%

Source: Moody's Investors Service

Outcomes will continue to vary among regulatory jurisdictions

A variety of factors can influence the outcome of discussions among utilities, regulators and intervenors about authorized returns and equity capital. Outcomes may vary considerably among jurisdictions, with the credit implications for utilities ranging from modest to significant.

Utilities use many arguments to bolster their case for increasing shareholder returns. Common issues that are typically raised include the impact of tax reform, large capital programs, access to capital, fair return standards, higher returns at other utilities within the same corporate group, pressure on utility bills and increasing sector risks.

If capital programs have strong support for regulatory recovery, they may not ultimately pressure utility balance sheets and financial metrics, but they do still increase external capital needs. While we do not believe that utilities will experience difficulties in raising capital as required, as this is a fundamental strength of the sector, the cost of capital may vary considerably as recent market volatility has demonstrated.

Fair return standards that reference capital attraction, comparable returns and access to capital do not ensure that companies will have higher allowed returns because they are not prescriptive in terms of required return levels. Some Canadian jurisdictions, which often have similar fair return concepts, may have significantly different outcomes when it comes to shareholder returns.

It is easier to increase net income (i.e., shareholder returns) if utility bills are low or otherwise declining. It may be significantly more difficult to increase ROE or equity capital in an environment where rates are politically sensitive or are otherwise under significant upward pressure.

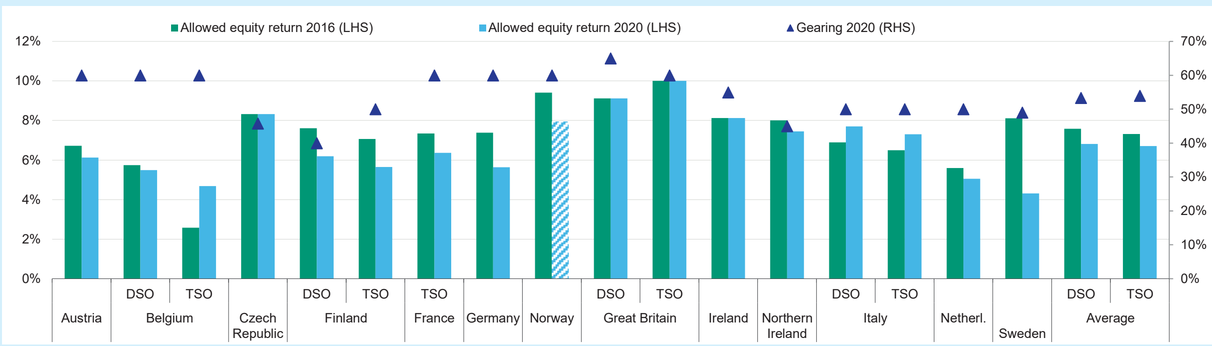
ROE and equity capital are lower in Europe

Allowed returns and equity thickness are generally lower for European electricity distribution and transmission networks. The average gearing or debt to rate base is about 54%, while the average ROE is about 6.8%. As shown in Exhibit 6, allowed equity returns have been relatively stable over the 2016-2020 period, with some notable downward exceptions. But the downward trend is more pronounced when we look at European electricity transmission operators over the period 2016-2023, as shown in Exhibit 7. For more information, see "Regulated electric and gas networks — EMEA: 2020 outlook stable, underpinned by transparent and predictable regulation."

Exhibit 6

Allowed equity returns relatively stable for electricity network operators in recent years; only Finnish, German, Norwegian and Swedish operators have seen material cuts since 2016

All figures nominal post-tax

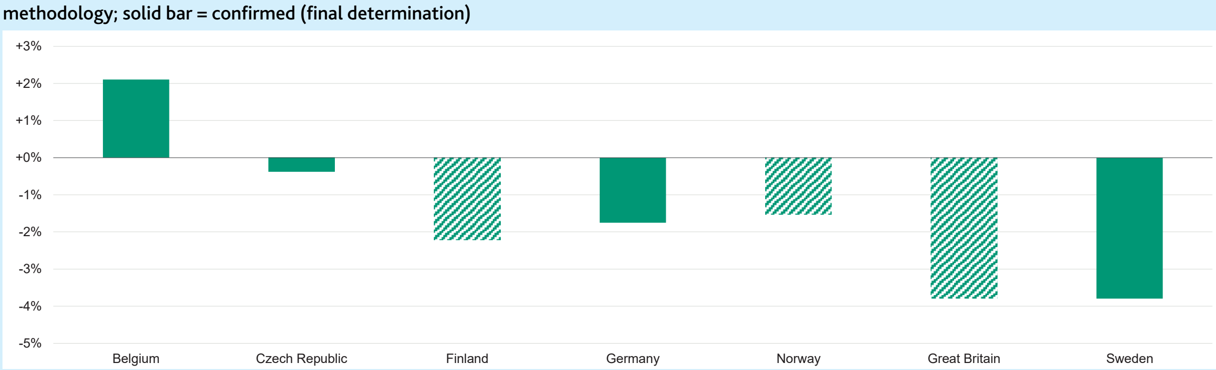


(1) Excludes measures that increase overall allowed return, for example: the 80 basis points higher equity return for new investments in Austria in the current regulatory period; 'aiming up' in Ireland; and 'F factor' in Italy; (2) Belgium Distribution System Operators (DSOs) refers to those in the Flanders region; (3) Where allowed equity returns have been set in real terms, these values have been converted to nominal terms using long-run inflation targets (that is 3% GB, NI; 2% Ireland and Italy) if not been specified by the regulator (Netherlands and Sweden specified); (4) Great Britain TSO figures for National Grid Electricity Transmission plc (A3 stable).
Source: Moody's Investors Service on regulatory data

Exhibit 7

Allowed equity returns for most electricity transmission operators will be materially lower in 2023 than they were in 2016

Change in allowed equity returns between 2016 and 2023, in nominal, post-tax terms. Shaded bar = projection based on draft determination/published methodology; solid bar = confirmed (final determination)



(1) Where allowed equity returns have been set in real terms, these values have been converted to nominal terms using a long-run inflation target (3% for RPI and 2% for CPIH in Great Britain, applicable for 2016 and 2023 respectively) if not specified by the regulator (Sweden specifies).
(2) Prevailing methodology applies to Finland, Great Britain and Norway.
Source: Moody's Investors Service on regulatory data

Moody's related publications

Sector Comments

» Regulated Electric and Gas Utilities – US: Coronavirus recession will impact utility pension underfunding to varying degrees, April 2020

» Infrastructure & Project Finance – Asia-Pacific: Heat map: Exposure to coronavirus disruption is low for 68% of issuers, April 2020

» Regulated Electric, Gas and Water Utilities – US: Coronavirus outbreak delays rate cases, but regulatory support remains intact, April 2020

» Regulated Electric and Gas Utilities – US: Dividends a major source of cash if coronavirus downturn is prolonged, April 2020

» Regulated Electric and Gas Utilities – US: Utilities strengthen liquidity amid capital markets volatility, April 2020

» Regulated Electric and Gas Utilities – US: FAQ on credit implications of the coronavirus outbreak, March 2020

» Regulated Electric, Gas and Water Utilities - US: Utilities demonstrate credit resilience in the face of coronavirus disruptions, March 2020

» Credit Conditions – Global: Coronavirus and oil price shocks: managing ratings in turbulent times, March 2020

Sector In-Depth

» Regulated electric and gas utilities – US: Grid hardening, regulatory support key to credit quality as climate hazards worsen, March 2020

» Regulated electric utilities – US: Intensifying climate hazards to heighten focus on infrastructure investments, January 2020

» Regulated electric and gas utilities – US: Recent regulatory, legislative developments have been largely credit positive, September 2019

» Regulated electric and gas utilities - North America: Free cash flow and capital allocation: external capital needs to decline in 2019, August 2019

» Regulated Electric & Gas Utilities - US: Capital expenditures will remain high, thanks to regulatory recovery mechanisms that provide timely recovery, December 2018

» Regulated Electric and Gas Utilities - US: Renewable generation transition unlikely to create significant stranded asset risk, November 2018

» US Regulated Utilities: Lower Authorized Equity Returns Will Not Hurt Near-Term Credit Profiles, March 2015

Industry Outlook

» Global Macro Outlook 2020-21 (March 25, 2020 Update): The coronavirus will cause unprecedented shock to the global economy, March 2020

» Regulated electric and gas utilities – US: 2020 outlook moves to stable on supportive regulation, weaker but steady credit metrics, November 2019

REPORT NUMBER 1199356

MOODY'S
INVESTORS SERVICE

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Cost of Common Shareholders' Equity
For the Projected 12 Month Period Ending December 31, 2022

Case No.: U-20963
Exhibit No.: A-136 (TAW-20)
Page: 1 of 2
Witness: TAWehner
Date: March 2021

Capital Asset Pricing Model Application - This analysis was not relied upon in forming my recommended ROE

Equation: $K_e = R_f + F + B \times (R_p)$

Where:
K_e = The annual required return on equity
R_f = The risk free rate
F = The flotation cost adjustment, not included in the calculation
B = The beta, or covariance of the stock price to market
R_p = The expected equity risk premium

(a)	(b)	(c)	(d)	(e)	(f)	(g)
				Test Year	Projected	**Projected**
			Current	Risk-Free	Risk Premium	**CAPM**
Line	Company	Ticker	Beta (B)	Rate (R_f)	(R_P)	**ROE**
1	Alliant Energy Corporation	LNT	0.85	2.11%	11.25%	**11.67%**
2	Ameren Corporation	AEE	0.85	2.11%	11.25%	**11.67%**
3	DTE Energy Company	DTE	0.95	2.11%	11.25%	**12.80%**
4	Edison International	EIX	0.95	2.11%	11.25%	**12.80%**
5	Evergy, Inc.	EVRG	1.00	2.11%	11.25%	**13.36%**
6	NiSource Inc.	NI	0.85	2.11%	11.25%	**11.67%**
7	Pinnacle West Capital Corporation	PNW	0.90	2.11%	11.25%	**12.24%**
8	Portland General Electric Company	POR	0.85	2.11%	11.25%	**11.67%**
9	WEC Energy Group, Inc.	WEC	0.80	2.11%	11.25%	**11.11%**
10	Xcel Energy Inc.	XEL	0.80	2.11%	11.25%	**11.11%**
11	**Average**		0.88			**12.01%**
12	**Minimum**		0.80			**11.11%**
13	**Maximum**		1.00			**13.36%**

Sources: Column (d): Exhibit A-14 (TAW-1), Schedule D-5, page 2, Column (d).
Column (e): Exhibit A-14 (TAW-1), Schedule D-5, page 2, Column (f).
Column (f): Exhibit A-14 (TAW-1), Schedule D-5, page 2, Column (g).
Column (g) = Column (e) + Column (d) x Column (f).

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Cost of Common Shareholders' Equity
For the Projected 12 Month Period Ending December 31, 2022

Case No.: U-20963
Exhibit No.: A-136 (TAW-20)

Witness: TAWehner
Date: March 2021

Discounted Cash Flow ("DCF") Model Application - This analysis was not relied upon in forming my recommended ROE

Equation: $K_e = D_1 / P_0 + g + F$

Where:
K_e = Annual required rate of return on equity
D_1 = Expected annual dividend per share at the end of first year.
P_0 = Current price of stock
g = Growth rate
F = The flotation cost adjustment, not included in the calculation

(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)
Line	Company	Ticker	Avg of 30-day Closing $	Last Qtrly Dividend Payment	Current Annual Div (D_0)	Current Dividend Yield	Consensus Analyst EPS Growth	Expected Dividend Yield	Consensus Earnings Growth DCF ROE	Payout Ratio (%)	Analyst EPS Yield	**Earnings Based DCF ROE**	Flotation Cost Adjust. (F)
1	Alliant Energy Corporation	LNT	51.67	0.380	1.52	2.94%	5.3%	3.10%	8.40%	56.7%	5.5%	**10.76%**	0.15%
2	Ameren Corporation	AEE	77.54	0.495	1.98	2.55%	6.2%	2.71%	8.91%	57.5%	4.7%	**10.92%**	0.13%
3	DTE Energy Company	DTE	122.90	1.013	4.05	3.30%	4.7%	3.45%	8.15%	56.6%	6.1%	**10.79%**	0.16%
4	Edison International	EIX	62.27	0.638	2.55	4.09%	0.0%	4.09%	4.09%	59.4%	6.9%	**6.89%**	0.20%
5	Evergy, Inc.	EVRG	54.43	0.505	2.02	3.71%	5.6%	3.92%	9.52%	64.3%	6.1%	**11.69%**	0.19%
6	NiSource Inc.	NI	22.93	0.210	0.84	3.66%	2.7%	3.76%	6.46%	58.7%	6.4%	**9.10%**	0.18%
7	Pinnacle West Capital Corporation	PNW	79.91	0.783	3.13	3.92%	3.3%	4.05%	7.35%	55.7%	7.3%	**10.57%**	0.20%
8	Portland General Electric Company	POR	41.82	0.408	1.63	3.90%	4.6%	4.08%	8.68%	84.9%	4.8%	**9.40%**	0.19%
9	WEC Energy Group, Inc.	WEC	92.02	0.633	2.53	2.75%	6.1%	2.92%	9.02%	65.5%	4.5%	**10.56%**	0.14%
10	Xcel Energy Inc.	XEL	65.93	0.430	1.72	2.61%	6.3%	2.77%	9.07%	60.5%	4.6%	**10.88%**	0.13%
11	**Average**								7.96%			**10.16%**	**0.17%**
12	**Minimum**								4.09%			**6.89%**	**0.13%**
13	**Maximum**								9.52%			**11.69%**	**0.20%**

Sources:
Column (d): CapitalIQ data from November 18, 2020 through December 31, 2020.
Column (e): CapitalIQ as of December 31, 2020.
Column (f) = 4 x Column (e).
Column (g) = Column (f) / Column (d).
Column (h): Number of I/B/E/S 3-year consensus analyst dividend per share ("DPS") growth estimate as of December 31, 2020.
Column (i): I/B/E/S 3-year consensus analyst dividend per share ("DPS") growth estimate as of December 31, 2020.
Column (j) = Column (g) x (1 + Column (i)).
Column (k): CapitalQ data as of December 31, 2020.
Column (l): Column (i) / Column (k).
Column (m): Column (h) + Column (l).
Column (n): Flotation cost adjustment of 5% of current dividend yield, as described by Roger A. Morin, "New Regulatory Finance" (2006).
While flotation cost adjustment are estimated and demonstrated in this analysis, the adjustment is not included in any of the calculations comprising the analysis.