NATURAL GAS UTILITIES
DCF ANALYSIS: VALUE LINE GROWTH FORECASTS

	Company	% Current Divid Yield (1)	Value Line Proj Growth (2)	Expected Divid Yield (3)	Cost of Equity (4)	ROE (5)
1	AGL Resources	4.1	6.5	4.4	10.9	11.1
2	Atmos Energy	3.0	7.0	3.2	10.2	10.4
3	Chesapeake	2.3	8.5	2.5	11.0	11.1
4	Laclede Group	3.5	10.0	3.9	13.9	14.1
5	NiSource	2.2	9.0	2.4	11.4	11.5
6	Northwest Nat. Gas	4.2	7.0	4.5	11.5	11.7
7	Piedmont Natural Gas	3.6	3.0	3.7	6.7	6.9
8	South Jersey Inds.	4.0	8.5	4.3	12.8	13.1
9	Southwest Gas	3.1	6.0	3.3	9.3	9.5
10	WGL Holdings	3.3	4.5	3.4	7.9	8.1
	AVERAGE	**3.3**	**7.0**	**3.6**	**10.6**	**10.7**

Notes:
Column 1, 2: Value Line 2015
Column 3 = Column 1 times (1 + Column 2/100)
Column 4 = Column 2 + Column 3
Column 5 = (Column 3 /0.95) + Column 2

NATURAL GAS UTILITIES
DCF ANALYSIS: ANALYSTS' GROWTH FORECASTS

Ticker		Company	% Current Divid Yield (1)	Analysts' Growth Forecast (2)	% Expected Divid Yield (3)	Cost of Equity (4)	ROE (5)
GAS	1	AGL Resources	4.1	6.9	4.4	11.3	11.5
ATO	2	Atmos Energy	3.0	7.0	3.2	10.2	10.4
CPK	3	Chesapeake	2.3	3.0	2.4	5.4	5.5
LG	4	Laclede Group	3.5	4.4	3.7	8.1	8.2
NI	5	NiSource	2.2	6.9	2.4	9.2	9.3
NWN	6	Northwest Nat. Gas	4.2	4.0	4.4	8.4	8.6
PNY	7	Piedmont Natural Gas	3.6	5.0	3.8	8.8	9.0
SJI	8	South Jersey Inds.	4.0	6.0	4.2	10.2	10.5
SWX	9	Southwest Gas	3.1	4.0	3.2	7.2	7.4
WGL	10	WGL Holdings	3.3	6.5	3.5	10.0	10.2
		AVERAGE	**3.3**	**5.4**	**3.5**	**8.9**	**9.1**

Notes:
Column 1: Value Line 2015
Column 2: Yahoo Finance l/t earnings growth forecast, 6/2015
Column 3 = Column 1 times (1 + Column 2/100)
Column 4 = Column 2 + Column 3
Column 5 = (Column 3 /0.95) + Column 2

AGL and NiSource: no growth estimates available.
took l/t industry analyst growth forecast

Exhibit RAM-4 Page 1 of 2
Combination Elec & Gas Utilities
DCF Analysis Value Line Growth Rates

Line No.		(1) Company Name	(2) Current Dividend Yield	(3) Projected EPS Growth
1	LNT	Alliant Energy	3.80	6.0
2	AEE	Ameren Corp.	4.40	6.0
3	AVA	Avista Corp.	4.00	7.0
4	BKH	Black Hills	3.20	4.5
5	CNP	CenterPoint Energy	5.20	1.0
6	CMS	CMS Energy Corp.	3.80	5.5
7	ED	Consol. Edison	4.30	3.0
8	D	Dominion Resources	3.80	8.0
9	DTE	DTE Energy	3.90	5.0
10	DUK	Duke Energy	4.20	5.0
11	EDE	Empire Dist. Elec.	4.80	3.0
12	ETR	Entergy Corp.	4.70	0.5
13	ES	Eversource Energy	3.50	8.5
14	MGE	MGE Energy	3.10	7.0
15	NEW	NorthWestern Corp.	3.70	6.5
16	POM	Pepco Holdings	4.30	8.0
17	PCG	PG&E Corp.	3.50	8.5
18	PEG	Public Serv. Enterprise	3.80	3.5
19	SCG	SCANA Corp.	4.20	4.5
20	SRE	Sempra Energy	2.60	8.5
21	TE	TECO Energy	5.00	8.0
22	UIL	UIL Holdings	3.50	5.0
23	VVC	Vectren Corp.	3.90	9.5
24	WEC	Wisconsin Energy	3.90	6.0
25	XEL	Xcel Energy Inc.	3.80	4.5

Notes:
- Column 2, 3: Value Line 2015
- Exelon, MDU eliminated <50% reg elec rev
- Eversource Energy added, not in AUS
- Unitil not covered in Value Line
- Chesapeake Util and NiSource already in natural gas group
- Integrys part of Exelon

Exhibit RAM-4 Page 2 of 2
Combination Elec & Gas Utilities
DCF Analysis Value Line Growth Rates

Line No.	(1) Company Name	(2) Current Dividend Yield	(3) Projected EPS Growth	(4) % Expected Divid Yield	(5) Cost of Equity	(6) ROE
1	Alliant Energy	3.80	6.0	4.03	10.03	10.24
2	Ameren Corp.	4.40	6.0	4.66	10.66	10.91
3	Avista Corp.	4.00	7.0	4.28	11.28	11.51
4	Black Hills	3.20	4.5	3.34	7.84	8.02
5	CenterPoint Energy	5.20	1.0	5.25	6.25	6.53
6	CMS Energy Corp.	3.80	5.5	4.01	9.51	9.72
7	Consol. Edison	4.30	3.0	4.43	7.43	7.66
8	Dominion Resources	3.80	8.0	4.10	12.10	12.32
9	DTE Energy	3.90	5.0	4.10	9.10	9.31
10	Duke Energy	4.20	5.0	4.41	9.41	9.64
11	Empire Dist. Elec.	4.80	3.0	4.94	7.94	8.20
12	Entergy Corp.	4.70	0.5	4.72	5.22	5.47
13	Eversource Energy	3.50	8.5	3.80	12.30	12.50
14	MGE Energy	3.10	7.0	3.32	10.32	10.49
15	NorthWestern Corp.	3.70	6.5	3.94	10.44	10.65
16	Pepco Holdings	4.30	8.0	4.64	12.64	12.89
17	PG&E Corp.	3.50	8.5	3.80	12.30	12.50
18	Public Serv. Enterprise	3.80	3.5	3.93	7.43	7.64
19	SCANA Corp.	4.20	4.5	4.39	8.89	9.12
20	Sempra Energy	2.60	8.5	2.82	11.32	11.47
21	TECO Energy	5.00	8.0	5.40	13.40	13.68
22	UIL Holdings	3.50	5.0	3.68	8.68	8.87
23	Vectren Corp.	3.90	9.5	4.27	13.77	14.00
24	Wisconsin Energy	3.90	6.0	4.13	10.13	10.35
25	Xcel Energy Inc.	3.80	4.5	3.97	8.47	8.68
27	**AVERAGE**	3.96	5.70	4.17	9.87	**10.09**

29 Notes:

30 Column 1, 2, 3: Value Line 2015

31 Column 4 = Column 2 times (1 + Column 3/100)

32 Column 5 = Column 4 + Column 3

33 Column 6 = (Column 4 /0.95) + Column 3

Exhibit RAM-5 Page 1 of 2
Combination Elec & Gas Utilities
DCF Analysis Analysts' Growth Forecasts

Line No.		(1) Company Name	(2) Current Dividend Yield	(3) Analysts' Growth Forecast
1	LNT	Alliant Energy	3.80	5.45
2	AEE	Ameren Corp.	4.40	5.85
3	AVA	Avista Corp.	4.00	5.00
4	BKH	Black Hills	3.20	6.19
5	CNP	CenterPoint Energy	5.20	1.91
6	CMS	CMS Energy Corp.	3.80	6.88
7	ED	Consol. Edison	4.30	2.38
8	D	Dominion Resources	3.80	6.07
9	DTE	DTE Energy	3.90	5.01
10	DUK	Duke Energy	4.20	4.65
11	EDE	Empire Dist. Elec.	4.80	5.00
12	ETR	Entergy Corp.	4.70	-0.29
13	ES	Eversource Energy	3.50	6.35
14	MGEE	MGE Energy	3.10	4.00
15	NEW	NorthWestern Corp.	3.70	4.79
16	POM	Pepco Holdings	4.30	7.80
17	PCG	PG&E Corp.	3.50	4.63
18	PEG	Public Serv. Enterprise	3.80	2.95
19	SCG	SCANA Corp.	4.20	4.30
20	SRE	Sempra Energy	2.60	7.93
21	TE	TECO Energy	5.00	7.68
22	UIL	UIL Holdings	3.50	7.79
23	VVC	Vectren Corp.	3.90	5.50
24	WEC	Wisconsin Energy	3.90	7.56
25	XEL	Xcel Energy Inc.	3.80	4.69

27 Notes:
28 Columns 1 and 2: Value Line 2015
Column 3: Yahoo Finance web site 2015
Entergy eliminated: negative growth rate

Exhibit RAM-5 Page 2 of 2
Combination Elec & Gas Utilities
DCF Analysis Analysts' Growth Forecasts

Line No.	(1) Company Name	(2) Current Dividend Yield	(3) Analysts' Growth Forecast	(4) % Expected Divid Yield	(5) Cost of Equity	(6) ROE
1	Alliant Energy	3.80	5.45	4.01	9.46	9.67
2	Ameren Corp.	4.40	5.85	4.66	10.51	10.75
3	Avista Corp.	4.00	5.00	4.20	9.20	9.42
4	Black Hills	3.20	6.19	3.40	9.59	9.77
5	CenterPoint Energy	5.20	1.91	5.30	7.21	7.49
6	CMS Energy Corp.	3.80	6.88	4.06	10.94	11.16
7	Consol. Edison	4.30	2.38	4.40	6.78	7.01
8	Dominion Resources	3.80	6.07	4.03	10.10	10.31
9	DTE Energy	3.90	5.01	4.10	9.11	9.32
10	Duke Energy	4.20	4.65	4.40	9.05	9.28
11	Empire Dist. Elec.	4.80	5.00	5.04	10.04	10.31
12	Eversource Energy	3.50	6.35	3.72	10.07	10.27
13	MGE Energy	3.10	4.00	3.22	7.22	7.39
14	NorthWestern Corp.	3.70	4.79	3.88	8.67	8.87
15	Pepco Holdings	4.30	7.80	4.64	12.44	12.68
16	PG&E Corp.	3.50	4.63	3.66	8.29	8.48
17	Public Serv. Enterprise	3.80	2.95	3.91	6.86	7.07
18	SCANA Corp.	4.20	4.30	4.38	8.68	8.91
19	Sempra Energy	2.60	7.93	2.81	10.74	10.88
20	TECO Energy	5.00	7.68	5.38	13.06	13.35
21	UIL Holdings	3.50	7.79	3.77	11.56	11.76
22	Vectren Corp.	3.90	5.50	4.11	9.61	9.83
23	Wisconsin Energy	3.90	7.56	4.19	11.75	11.98
24	Xcel Energy Inc.	3.80	4.69	3.98	8.67	8.88
26	**AVERAGE**	3.93	5.43	4.14	9.57	**9.78**

Notes:

29 Column 1, 2: Value Line 2015
30 Column 3: Yahoo Finance Analyst long-term earnings growth forecast 2015
31 Column 4 = Column 2 times (1 + Column 3/100)
32 Column 5 = Column 4 + Column 3
33 Column 6 = (Column 4 /0.95) + Column 3

Exhibit RAM-6

Natural Gas Utilities Beta Estimates

	(1)	(2)
Line No	Company Name	Beta
1	AGL Resources	0.80
2	Atmos Energy	0.85
3	Chesapeake	0.65
4	Laclede Group	0.70
5	NiSource	0.85
6	Northwest Nat. Gas	0.70
7	Piedmont Natural Gas	0.80
8	South Jersey Inds.	0.85
9	Southwest Gas	0.85
10	WGL Holdings	0.80
12	**AVERAGE**	**0.79**
14	Source: Value Line 2015	

Exhibit RAM-6

Combination Elec & Gas Utilities Beta Estimates

Line No	(1) Company Name	(2) Beta
1	Alliant Energy	0.80
2	Ameren Corp.	0.75
3	Avista Corp.	0.80
4	Black Hills	0.95
5	CenterPoint Energy	0.80
6	CMS Energy Corp.	0.75
7	Consol. Edison	0.60
8	Dominion Resources	0.70
9	DTE Energy	0.75
10	Duke Energy	0.60
11	Empire Dist. Elec.	0.70
12	Entergy Corp.	0.70
13	Eversource Energy	0.75
14	MGE Energy	0.75
15	NorthWestern Corp.	0.70
16	Pepco Holdings	0.65
17	PG&E Corp.	0.65
18	Public Serv. Enterprise	0.75
19	SCANA Corp.	0.75
20	Sempra Energy	0.80
21	TECO Energy	0.85
22	UIL Holdings	0.80
23	Vectren Corp.	0.80
24	Wisconsin Energy	0.70
25	Xcel Energy Inc.	0.65
28	**AVERAGE**	**0.74**
30	Source: Value Line 2015	

Exhibit RAM-7
MRP Calculations

	(1)	(2)
Dividend Yield (spot times (1+g)	D/P	1.2
Forecast Earnings Growth	g	10.5
DCF Return Value Line Index	K	11.7
Projected Risk-Free Rate	R_f	4.4
DCF Market Risk Premium	DCF MRP	7.3
Morningstar Historical Mkt Risk Premium	HIST MRP	7.0
Average Mkt Risk Premium	**AVG MRP**	**7.2**

Source: Value Line Investment Analyzer 2015

EXHIBIT RAM-8
2015 Utility Industry Historical Risk Premium

		(1)	(2)	(3)	(4)	(5)	(6)	(7)
Line No.	Year	Long-Term Government Bond Yield	20 year Maturity Bond Value	Gain/Loss	Interest	Bond Total Return	S&P Utility Index Return	Utility Equity Risk Premium Over Bond Returns
1	1931	4.07%	1,000.00					
2	1932	3.15%	1,135.75	135.75	40.70	17.64%	-0.54%	-18.18%
3	1933	3.36%	969.60	-30.40	31.50	0.11%	-21.87%	-21.98%
4	1934	2.93%	1,064.73	64.73	33.60	9.83%	-20.41%	-30.24%
5	1935	2.76%	1,025.99	25.99	29.30	5.53%	76.63%	71.10%
6	1936	2.55%	1,032.74	32.74	27.60	6.03%	20.69%	14.66%
7	1937	2.73%	972.40	-27.60	25.50	-0.21%	-37.04%	-36.83%
8	1938	2.52%	1,032.83	32.83	27.30	6.01%	22.45%	16.44%
9	1939	2.26%	1,041.65	41.65	25.20	6.68%	11.26%	4.58%
10	1940	1.94%	1,052.84	52.84	22.60	7.54%	-17.15%	-24.69%
11	1941	2.04%	983.64	-16.36	19.40	0.30%	-31.57%	-31.87%
12	1942	2.46%	933.97	-66.03	20.40	-4.56%	15.39%	19.95%
13	1943	2.48%	996.86	-3.14	24.60	2.15%	46.07%	43.92%
14	1944	2.46%	1,003.14	3.14	24.80	2.79%	18.03%	15.24%
15	1945	1.99%	1,077.23	77.23	24.60	10.18%	53.33%	43.15%
16	1946	2.12%	978.90	-21.10	19.90	-0.12%	1.26%	1.38%
17	1947	2.43%	951.13	-48.87	21.20	-2.77%	-13.16%	-10.39%
18	1948	2.37%	1,009.51	9.51	24.30	3.38%	4.01%	0.63%
19	1949	2.09%	1,045.58	45.58	23.70	6.93%	31.39%	24.46%
20	1950	2.24%	975.93	-24.07	20.90	-0.32%	3.25%	3.57%
21	1951	2.69%	930.75	-69.25	22.40	-4.69%	18.63%	23.32%
22	1952	2.79%	984.75	-15.25	26.90	1.17%	19.25%	18.08%
23	1953	2.74%	1,007.66	7.66	27.90	3.56%	7.85%	4.29%
24	1954	2.72%	1,003.07	3.07	27.40	3.05%	24.72%	21.67%
25	1955	2.95%	965.44	-34.56	27.20	-0.74%	11.26%	12.00%
26	1956	3.45%	928.19	-71.81	29.50	-4.23%	5.06%	9.29%
27	1957	3.23%	1,032.23	32.23	34.50	6.67%	6.36%	-0.31%
28	1958	3.82%	918.01	-81.99	32.30	-4.97%	40.70%	45.67%
29	1959	4.47%	914.65	-85.35	38.20	-4.71%	7.49%	12.20%
30	1960	3.80%	1,093.27	93.27	44.70	13.80%	20.26%	6.46%
31	1961	4.15%	952.75	-47.25	38.00	-0.92%	29.33%	30.25%
32	1962	3.95%	1,027.48	27.48	41.50	6.90%	-2.44%	-9.34%
33	1963	4.17%	970.35	-29.65	39.50	0.99%	12.36%	11.37%
34	1964	4.23%	991.96	-8.04	41.70	3.37%	15.91%	12.54%
35	1965	4.50%	964.64	-35.36	42.30	0.69%	4.67%	3.98%
36	1966	4.55%	993.48	-6.52	45.00	3.85%	-4.48%	-8.33%
37	1967	5.56%	879.01	-120.99	45.50	-7.55%	-0.63%	6.92%
38	1968	5.98%	951.38	-48.62	55.60	0.70%	10.32%	9.62%
39	1969	6.87%	904.00	-96.00	59.80	-3.62%	-15.42%	-11.80%
40	1970	6.48%	1,043.38	43.38	68.70	11.21%	16.56%	5.35%
41	1971	5.97%	1,059.09	59.09	64.80	12.39%	2.41%	-9.98%
42	1972	5.99%	997.69	-2.31	59.70	5.74%	8.15%	2.41%

43	1973	7.26%	867.09	-132.91	59.90	-7.30%	-18.07%	-10.77%
44	1974	7.60%	965.33	-34.67	72.60	3.79%	-21.55%	-25.34%
45	1975	8.05%	955.63	-44.37	76.00	3.16%	44.49%	41.33%
46	1976	7.21%	1,088.25	88.25	80.50	16.87%	31.81%	14.94%
47	1977	8.03%	919.03	-80.97	72.10	-0.89%	8.64%	9.53%
48	1978	8.98%	912.47	-87.53	80.30	-0.72%	-3.71%	-2.99%
49	1979	10.12%	902.99	-97.01	89.80	-0.72%	13.58%	14.30%
50	1980	11.99%	859.23	-140.77	101.20	-3.96%	15.08%	19.04%
51	1981	13.34%	906.45	-93.55	119.90	2.63%	11.74%	9.11%
52	1982	10.95%	1,192.38	192.38	133.40	32.58%	26.52%	-6.06%
53	1983	11.97%	923.12	-76.88	109.50	3.26%	20.01%	16.75%
54	1984	11.70%	1,020.70	20.70	119.70	14.04%	26.04%	12.00%
55	1985	9.56%	1,189.27	189.27	117.00	30.63%	33.05%	2.42%
56	1986	7.89%	1,166.63	166.63	95.60	26.22%	28.53%	2.31%
57	1987	9.20%	881.17	-118.83	78.90	-3.99%	-2.92%	1.07%
58	1988	9.18%	1,001.82	1.82	92.00	9.38%	18.27%	8.89%
59	1989	8.16%	1,099.75	99.75	91.80	19.16%	47.80%	28.64%
60	1990	8.44%	973.17	-26.83	81.60	5.48%	-2.57%	-8.05%
61	1991	7.30%	1,118.94	118.94	84.40	20.33%	14.61%	-5.72%
62	1992	7.26%	1,004.19	4.19	73.00	7.72%	8.10%	0.38%
63	1993	6.54%	1,079.70	79.70	72.60	15.23%	14.41%	-0.82%
64	1994	7.99%	856.40	-143.60	65.40	-7.82%	-7.94%	-0.12%
65	1995	6.03%	1,225.98	225.98	79.90	30.59%	42.15%	11.56%
66	1996	6.73%	923.67	-76.33	60.30	-1.60%	3.14%	4.74%
67	1997	6.02%	1,081.92	81.92	67.30	14.92%	24.69%	9.77%
68	1998	5.42%	1,072.71	72.71	60.20	13.29%	14.82%	1.53%
69	1999	6.82%	848.41	-151.59	54.20	-9.74%	-8.85%	0.89%
70	2000	5.58%	1,148.30	148.30	68.20	21.65%	59.70%	38.05%
71	2001	5.75%	979.95	-20.05	55.80	3.57%	-30.41%	-33.98%
72	2002	4.84%	1,115.77	115.77	57.50	17.33%	-30.04%	-47.37%
73	2003	5.11%	966.42	-33.58	48.40	1.48%	26.11%	24.63%
74	2004	4.84%	1,034.35	34.35	51.10	8.54%	24.22%	15.68%
75	2005	4.61%	1,029.84	29.84	48.40	7.82%	16.79%	8.97%
76	2006	4.91%	962.06	-37.94	46.10	0.82%	20.95%	20.13%
77	2007	4.50%	1,053.70	53.70	49.10	10.28%	19.36%	9.08%
78	2008	3.03%	1,219.28	219.28	45.00	26.43%	-28.99%	-55.42%
79	2009	4.58%	798.39	-201.61	30.30	-17.13%	11.94%	29.07%
80	2010	4.14%	1,059.45	59.45	45.80	10.52%	5.49%	-5.03%
81	2011	2.48%	1,260.50	260.50	41.40	30.19%	19.88%	-10.31%
82	2012	2.41%	1,011.06	11.06	24.80	3.59%	1.99%	-1.60%
83	2013	3.67%	822.57	-177.43	24.10	-15.33%	13.26%	28.59%
84	2014	2.40%	1,200.79	200.79	36.70	23.75%	28.61%	4.86%
86	**Mean**							**5.5%**

88 Source: Bloomberg Web site: Standard & Poors Utility Stock Index % Annual Change, Jan. to Dec.

89 Bond yields from Ibbotson SBBI 2015 Classic Yearbook (Morningstar) Table A-9 Long-Term Government Bonds Yields

EXHIBIT RAM-9

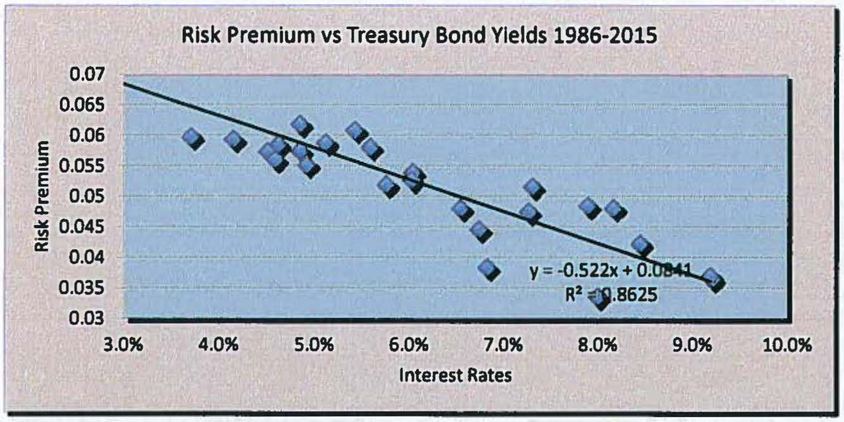
Allowed Equity Risk Premium - Treasury Bon

Line	No. of Decisions	Date	Treasury Bond Yield[1] (1)	Authorized Nat Gas Returns[2] (2)	Indicated Risk Premium (3)
1		1986	7.89%	12.74%	4.9%
2	29	1987	9.20%	12.85%	3.7%
3	31	1988	9.18%	12.88%	3.7%
4	31	1989	8.16%	12.97%	4.8%
5	31	1990	8.44%	12.67%	4.2%
6	35	1991	7.30%	12.46%	5.2%
7	29	1992	7.26%	12.01%	4.8%
8	45	1993	6.54%	11.35%	4.8%
9	28	1994	7.99%	11.35%	3.4%
10	16	1995	6.03%	11.43%	5.4%
11	20	1996	6.73%	11.19%	4.5%
12	13	1997	6.02%	11.29%	5.3%
13	10	1998	5.42%	11.51%	6.1%
14	9	1999	6.82%	10.66%	3.8%
15	12	2000	5.58%	11.39%	5.8%
16	7	2001	5.75%	10.95%	5.2%
17	21	2002	4.84%	11.03%	6.2%
18	25	2003	5.11%	10.99%	5.9%
19	20	2004	4.84%	10.59%	5.8%
20	26	2005	4.61%	10.46%	5.9%
21	16	2006	4.91%	10.43%	5.5%
22	37	2007	4.50%	10.24%	5.7%
23	30	2008	3.03%	10.37%	7.3%
24	29	2009	4.58%	10.19%	5.6%
25	37	2010	4.14%	10.08%	5.9%
26	16	2011	2.48%	9.92%	7.4%
27	35	2012	2.41%	9.94%	7.5%
28	21	2013	3.70%	9.68%	6.0%
29	26	2014	2.40%	9.78%	7.4%
30	6	2015	2.72%	9.45%	6.7%
32	691	**Average**	**5.62%**	**11.10%**	**5.5%**

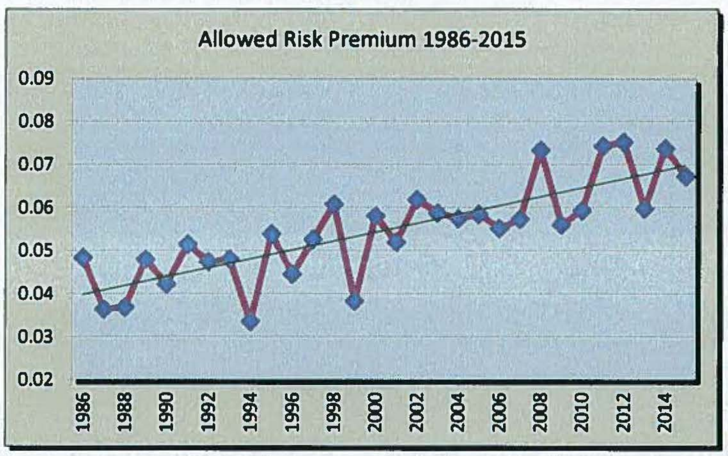
Sources:

[1] Morninstar 2015 Classic Yearbook Table A-9

[2] SNL (Regulatory Research Associates)
Major Rate Case Decisions Jan-June 2015



IFYIELD =	4.50%
THEN RP =	6.06%
Ke =	10.56%



Regulatory Mechanisms Across U.S. States

State	Forward Test Years	Decoupling		Fuel/Purchase Power Balancing Account	Other Balancing Accounts	Capex Cost Tracker	CWIP in Rate Base	DSM Performance Incentives
		Full	Partial					
[1]*	[2]	[3]	[4]	[5]	[6]	[7]	[8]	[9]
Alabama	Yes			Yes	Yes			
Alaska				Yes				
Arizona			E		Yes			Yes
Arkansas	Hybrid		E	Yes	Yes	G&E		Yes
California**	Yes	G&E		Yes	Yes	G&E		Yes
Colorado**	Pending	G	E	Yes	Yes	E	Yes	Yes
Connecticut**	Yes	E	G		Yes			Yes
Delaware	Hybrid				Yes			
D.C.	Hybrid	E			Yes			
Florida**	Yes		G	Yes	Yes	E	Yes	Pending
Georgia	Yes		G	Yes	Yes	G&E	Yes	Yes
Hawaii	Yes	E		Yes	Yes	E		Yes
Idaho		E		Yes	Yes			Pending
Illinois**	Yes	G	G		Yes	G		
Indiana**		G	E	Yes	Yes	G&E	Yes	Yes
Iowa**				Yes	Yes	E		
Kansas			E	Yes	Yes	G&E	Pending	Pending
Kentucky**	Yes		G&E	Yes	Yes	G&E		Yes
Louisiana				Yes	Yes	E	Yes	
Maine	Yes				Yes	E		
Maryland		G&E			Yes		Yes	
Massachusetts**		G&E	G&E		Yes	G&E		Yes
Michigan**	Yes	G&E			Yes		Pending	Yes
Minnesota**	Yes	G, E-Pending		Yes	Yes	E	Yes	Yes
Mississippi	Yes		E	Yes	Yes	E	Yes	
Missouri			G, E-Pending	Yes	Yes	G		Pending
Montana			G					Pending
Nebraska				Yes	Yes		Yes	
Nevada		G	E		Yes			
New Hampshire		G, E-Pending			Yes			Yes
New Jersey**	Hybrid	G			Yes	G&E		
New Mexico	Pending	E-Pending		Yes	Yes		Pending	Yes
New York	Yes	G&E			Yes	G&E		Yes
North Carolina**		G	E	Yes	Yes		Yes	Yes
North Dakota	Yes		G	Yes	Yes		Pending	
Ohio**	Hybrid	E-Pending	E		Yes	G&E		Yes
Oklahoma			G&E	Yes	Yes	E	Pending	Yes
Oregon	Yes	G&E	G		Yes	G&E		
Pennsylvania**	Hybrid				Yes	E		
Rhode Island	Yes	G&E			Yes			Yes
South Carolina**			E	Yes	Yes		Yes	Yes
South Dakota			E	Yes	Yes		Pending	
Tennessee	Yes	G		Yes	Yes			
Texas						E	Yes	Yes
Utah	Yes	G, E-Pending	E-Pending	Yes	Yes	G		Pending
Vermont		G&E			Yes	E		Yes
Virginia**		G	E-Pending		Yes	E	Yes	
Washington		G		Yes	Yes			
West Virginia				Yes	Yes		Yes	
Wisconsin**	Yes	G&E		Yes	Yes		Yes	Yes
Wyoming	E Only	G	E	Yes	Yes			

* See next page for sources, notes, and definitions

** States where PG&E's and TURN's PG&E comparator utilities operate

Sources:

[2] – [4], [7] -[8]: From "Innovative Regulation: A Survey of Remedies of Regulatory Lag", Edison Electric Institute, April 2011, Table 1 and Table 9.
http://www.eei.org/whatwedo/PublicPolicyAdvocacy/StateRegulation/Documents/innovative_regulation_survey.pdf

[5], [9]: From "IEE State Electric Efficiency Regulatory Frameworks Report," July 2012.
http://www1.eere.energy.gov/buildings/betterbuildings/neighborhoods/pdfs/iee_state_reg_frame.pdf

[6]: Adjustment Clauses and Rate Riders ~ A State-By-State Overview ~, Regulatory Research Associates, March 21, 2012.

Notes:

[5], [8], [9]: Data is for electric utilities only.

[6]: Information on other balancing accounts is listed in the following state-by-state table.

Definitions:

[2]: A forward test year is a twelve month period that begins after the rate case is filed.

[3] - [4]: Full decoupling or partial decoupling (lost revenue adjustment mechanisms and/or fixed customer charge) assists the utility in recovering authorized revenue requirements associated with fixed operating costs, despite increases or decreases in sales.

[5]: Fuel/Purchase Power Balancing Accounts include 1) fuel riders that allows fuel costs to adjust intra-year if recoveries or deferrals differ from budget by more than specified amount and 2) Energy Cost Recovery (ECR) mechanisms established on the basis of estimates of electric sales, fuel-related costs, and purchased power costs, and reflects accumulated over- or under-recovered amounts

[7]: Trackers for the annual cost of plant additions are sometimes called capital expenditure ("capex") trackers.

[8]: Many commissions address the delay in receiving a return on investment by including costs of construction work in progress ("CWIP") in the rate base, so that a return on investment can start sooner.

[9]: Performance Incentives are mechanisms that reward utilities for reaching certain energy efficiency program goals, and, in some cases, impose a penalty for performance below the agreed-upon goals.

Other Balancing Accounts by States

Alabama

The Certificated New Plant (Rate CNP) adjustment clause for Alabama Power provides for: the recovery of costs related to the commercial operation of certified generating facilities; the recovery of the costs (excluding fuel) associated with certified purchased power agreements; and, recovery of costs associated with environmental mandates. The tariffs of the major energy utilities include adjustment provisions to allow for recovery of changes in income taxes, and certain general and local taxes.

Alaska

Power cost adjustment mechanisms only.

Arizona

Adjustment mechanisms used by APS are: a system benefits charge for recovery of prudent costs incurred by the utility to comply with the ACC's electric competition rules or costs associated with certain public purpose programs (conservation, wind power development, etc.) authorized by the ACC; a transmission cost adjustor to flow through changes in Federal Energy Regulatory Commission-approved transmission rates; a renewable energy surcharge (RES); a demand-side management adjustment charge; and, an environmental improvement surcharge.

Arkansas

The electric and gas utilities have in place rate riders that provide for the recovery of the costs associated with PSC-approved energy efficiency (EE) programs. Entergy Arkansas utilizes a production cost allocation (PCA) rider, which provides for timely recovery of the costs associated with "rough equalization" of electric generation production costs among the Entergy operating companies, as required by the Federal Energy Regulatory Commission. EA also utilizes a storm recovery charge rider to collect from ratepayers the amounts required to service its related securitization bonds. Oklahoma Gas & Electric (OG&E) uses a storm damage rider to recover incremental storm restoration costs incurred in 2008. OG&E also uses a transmission cost recovery rider and a "Smart Grid" rider.

Other Balancing Accounts by States

California

The CPUC conducts a Biennial or Triennial Cost Allocation Proceeding to allocate non-fuel gas costs between core and non-core customer classes. The BCAP/TCAP provide for the amortization of balances in specified balancing and tracking accounts. The costs tracked through the balancing account mechanisms are subject to annual reasonableness reviews, and a true-up is implemented in the years between the proceedings. In 2010, the CPUC adopted an electric distribution reliability improvement program for PG&E, the costs of which are to be recovered through a dedicated account outside of general rate cases. Rates are to be based on adopted cost forecasts with a balancing account to accumulate any difference in revenue requirement based on recorded costs compared to the adopted forecast.

Colorado

Legislation enacted in 2010, allows a utility that is earning below its authorized equity return and operating under an emissions reduction plan designed to achieve a conversion or closure of coal-based generating capacity by Jan. 1, 2015, to, under certain circumstances, be accorded a special ratemaking mechanism designed to recover the costs of the approved plan. Effective Jan. 1, 2011, the Colorado PUC authorized PSCO to recover, subject to certain adjustments, operations and maintenance and capital costs associated with the company's investment in the gas-fired 652-MW Rocky Mountain Energy Center and the 310-MW Blue Spruce Energy Center via the purchased capacity cost adjustment clause until PSCO's next electric rate case. PSCO is permitted to recover, through a transmission cost adjustment (TCA) clause implemented in 2008, prudent costs incurred in planning, developing, and completing construction or expansion of transmission facilities.

Connecticut

Tracking mechanisms are in place for CL&P and UI that provide for semi-annual adjustments to reflect Federal Energy Regulatory Commission-approved transmission costs. As part of a 2009 rate decision for UI, the Connecticut Public Utilities Regulatory Authority adopted pension and cost-of-debt tracking mechanisms, both of which were discontinued in 2011.

Delaware

DP&L is permitted to submit annual filings to update prices to reflect changes in Federal Energy Regulatory Commission-approved transmission charges.

Other Balancing Accounts by States

Florida

Electric utilities may recover all prudently incurred site selection and preconstruction costs, including carrying charges, for nuclear and integrated gasification combined-cycle (IGCC) power plants through the capacity cost recovery clause (CCRC). Certain fees and taxes, such as franchise fees and gross receipts taxes, are recovered through a line item on customer bills, with the charge adjusted based on customer usage.

Georgia

Atlanta Gas Light (ATGL) has been authorized to recover clean-up costs related to former manufactured gas plant sites through an environmental response cost recovery rider (ERCRR). Costs that are recoverable under the ERCRR include investigation, testing, remediation, and/or litigation costs or other liabilities. In 2009, the PSC approved for ATGL the STRIDE program that authorizes the company to invest about $400 million in infrastructure improvements over the next ten years. Every three years, ATGL is required to file its proposed program for the next three years for PSC review and approval.

Hawaii

HECO, HELCO, and MECO utilize tracking mechanisms for pension and other-than-pension employee benefit (OPEB) costs. As part of an alternative regulation framework (ARF) approved in February 2011, Hawaiian Electric Company (HECO) implemented a cost-of-service recovery mechanism, which recognizes rate base additions and increases in operation and maintenance expenses, and certain depreciation and amortization expenses between rate cases and includes a decoupling mechanism. On Feb. 8, 2012, the PUC issued a preliminary order in HELCO's 2010-test year rate case indicating that the company will be permitted to operate under an ARF similar to HECO's. The PUC has approved recovery of certain demand-side management program costs (to the extent that they are not recovered through base rates) through an annual integrated resource planning (IRP) cost-recovery surcharge, subject to review. In 2009, the PUC authorized HECO, HELCO, and MECO to implement a surcharge mechanism to facilitate the recovery of renewable energy infrastructure investments.

Idaho

The PUC has allowed Idaho Power to increase rates outside a base rate case to recover the cash contribution to its defined benefit pension plan. In February 2011, the Commission adopted Idaho Power's regulatory account and cost recovery plan associated with the early-shut down of the Boardman coal-fired plant that, as a result of changing environmental regulations, is to cease operations 20 years earlier than expected. The PUC approved the establishment of a balancing account, whereby the incremental revenue requirement associated with the early-shut down of the plant is to be tracked for recovery.

Other Balancing Accounts by States

Illinois

Illinois Commerce Commission (ICC) approved a settlement that permits Ameren Illinois to utilize a hazardous materials adjustment clause rider, largely to address asbestos-related litigation and remediation costs. As permitted by state statutes, Ameren Illinois, ComEd, Northern Illinois Gas, Peoples Gas Light & Coke and North Shore Gas utilize riders to facilitate recovery of variations in bad-debt costs. Ameren Illinois utilizes a transmission service rider.

Indiana

The Indiana URC has approved requests to recover from ratepayers the net costs associated with the prospective sale/purchase of emissions allowances. Gas utilities track incremental changes in unaccounted-for gas costs and the gas-cost component of bad debts through gas cost adjustment filings. Legislation permits the electric utilities to recover, through a rate adjustment mechanism, 80% of the costs associated with certain federally-mandated emissions-control projects. The remaining 20% of such costs are to be deferred for future recovery. In 2007, the URC authorized the company to earn a cash return on construction work in progress associated with the Edwardsport plant and to recover the facility's operating costs once complete, through an adjustment mechanism

Iowa

In a 2010 rate decision for IP&L, the Iowa Utilities Board permitted the company to implement a transmission cost recovery mechanism for a three-year term. Revenues and costs associated with IP&L's sales or purchases of emission allowances may be reflected in the energy adjustment clause. MidAmerican Energy uses a rider to recover certain feasibility study costs related to its analysis of the merits of building a new nuclear plant.

Kansas

State statutes permit the local gas distribution companies to request KCC approval of a gas system reliability surcharge (GSRS) mechanism to recover the costs associated with gas distribution system replacement projects between base rate proceedings, subject to annual true-up. Westar and KG&E utilize Transmission Delivery Charge riders that provide for the unbundling and recovery of Federal Energy Regulatory Commission-regulated transmission charges.

Kentucky

Electric utilities utilize mechanisms to recover environmental compliance costs (including a cash return on environmental CWIP) between rate proceedings, and several gas utilities use mechanisms that provide for recovery, between rate cases, of costs associated with their main replacement programs. PSC has allowed certain companies to increase their fixed monthly customer charges to recover a greater proportion of their fixed costs through this charge.

Other Balancing Accounts by States

Louisiana

In 2009, the Louisiana Public Service Commission authorized the state's electric utilities to use an environmental adjustment clause (EAC) to recover from ratepayers the costs associated with the acquisition of emissions credits to comply with federal, state, and local environmental standards. In addition, the utilities are to credit ratepayers through the EAC any revenues associated with the sale or transfer of emission allowances.

Maine

Northern Utilities recovers manufactured gas site remediation expenses through an environmental remediation rate adjustment that is set on a semi-annual basis.

Maryland

Baltimore Gas & Electric has electric and gas riders in place, with surcharge rate changes implemented on an annual basis, to reflect recovery of electric and gas energy efficiency and demand-side program costs that are not included in base rates.

Massachusetts

Pension and post-retirement benefits other than pensions (PBOP) are in place for ME, NE, WMECO, NSTAR Electric, NSTAR Gas, Fitchburg Gas and Electric Light, New England Gas, Boston Gas/Essex Gas, Colonial Gas, and Columbia Gas of Massachusetts. The utilities file annually for recovery of pension and PBOP costs not currently reflected in rates. Such costs are to be recovered through the LDAC reconciliation mechanism for gas utilities and a separate rate component for electric utilities. The electric utilities are permitted to utilize transmission cost recovery mechanisms. A solar cost adjustment charge was approved by the DPU in conjunction with the Department's 2009 approval of Western ME's proposal to install 6 MWs of solar energy generation. In 2010, the DPU approved a solar cost adjustment charge for ME and Nantucket Electric (NE) for the utilities' installation of 5 MWs of solar generation

Michigan

CE, Detroit Edison, and UPP recover transmission costs through the power supply cost-recovery mechanism. Uncollectible expense true-up mechanisms are in place for MCG and Michigan Gas Utilities.

Minnesota

The major electric utilities use rate riders that provide for annual recovery of transmission, conservation, renewable energy, and emission reduction costs.

Other Balancing Accounts by States

Mississippi

An energy efficiency (EE) rider is in place for Entergy Mississippi (EM) through which the company recovers costs associated with its EE program. EM and Mississippi Power (MP) may recover emissions allowance expenses through their adjustment clauses. Since 1992, MP has utilized an Environmental Compliance Overview plan that establishes procedures to facilitate the PSC's review of the company's environmental compliance strategy and provides for base-rate recovery of costs (including the cost of capital) associated with PSC-approved environmental projects, on an annual basis, outside of a base rate case. Since 2005, EM has been recovering the costs of its 480-MW, gas-fired Attala power plant through a temporary rate rider. The rider is to remain in place until the company files for a general rate case.

Missouri

PSC rules allow that a portion of the utility's environmental costs may be recovered through an Environmental Cost Recovery Mechanism and a portion may be recovered through base rates. Atmos Energy, Laclede Gas, Missouri Gas Energy, and Union Electric utilize an infrastructure system replacement surcharge to recover costs associated with certain gas distribution system replacement projects.

Montana

Supply cost recovery mechanism only.

Nebraska

2009 legislation allows gas utilities to apply for Nebraska Public Service Commission (PSC) approval to implement an infrastructure system replacement cost recovery (ISRCR) rider to provide for timely recovery of certain capital investments outside of a general rate case.

Nevada

In 2009, the PUC adopted a natural gas-related bad-debt tracking mechanism for Southwest Gas designed to allow the company to recover from, or refund to, ratepayers the difference between actual bad debt expenses and the level reflected in base rates.

Other Balancing Accounts by States

New Hampshire

A transmission cost adjustment mechanism (TCAM) is in place for PSNH. The TCAM, which is designed to provide recovery of all transmission-related costs, is adjusted annually each July 1. Reliability enhancement and vegetation management programs are in effect for Granite State, PSNH, and Unitil Energy Systems. The programs provide for recovery of both the capital investment and increases to operation and maintenance expense necessary for ongoing system reliability and vegetation management efforts. Major storm reserve accounts are in effect for the state's electric utilities.

New Jersey

PUH is permitted to recover costs associated with manufactured gas site cleanup through a remediation adjustment mechanism. Such expenses are deferred and recovered over a seven-year period, including carrying costs on the balance. During 2009, 2010 and 2011, the New Jersey Board of Public Utilities approved economic stimulus programs proposed by the electric and gas utilities at the BPU's request. The programs called for the acceleration of various infrastructure development projects. The companies are permitted to recover the costs associated with these accelerated capital investment plans through surcharge mechanisms.

New Mexico

In 2009, the New Mexico Public Regulation Commission adopted a rate case settlement for Public Service Co. of New Mexico that contained an SO2 rider through which customers are credited with their share of revenues from allowance sales.

New York

Rate case plans have generally incorporated rate bases that increase over the term of the plan and deferral accounting for increases in such items as net plant, pension expense, and labor costs. Earnings in excess of an established return on equity (ROE) cap to be shared by stockholders and ratepayers.

North Carolina

The NCUC may pre-determine the prudence of a utility's decision to build a baseload generating plant and the facility's projected costs and in the following general rate case, the utility would be permitted to recover previously approved costs following completion of the project. The costs of certain materials used in reducing or treating emissions may be recovered through the fuel adjustment clause. Incremental operation and maintenance costs and annual research and development (R&D) expenses up to $1 million are also recoverable through the renewable energy portfolio standard rider.

Other Balancing Accounts by States

North Dakota

Electric utilities are permitted to file with the Commission for pre-determination of the prudence of planned construction projects. In June 2010, the PSC approved a settlement permitting MDU to recover, through its fuel and purchased power adjustment clause, roughly $9.6 million of costs associated with the cancelled Big Stone II coal plant over three-years beginning Aug. 1, 2010.

Ohio

For CEI, OE, and TED, renewable energy resource requirements for the period June 1, 2011 through May 31, 2014, are to be met through the purchase of renewable energy credits (RECs) and costs are to be recovered through a reconcilable rider. The current electric security plans for CEI, OE, and TED include the implementation of a delivery capital recovery rider that reflects a return of and on distribution, sub-transmission, and general plant-in-service not included in the companies' 2009 rate decisions. In a 2008 rate decision for Columbia Gas of Ohio, the PUC adopted a stipulation that included riders for infrastructure replacement costs and demand-side management program expenses. In a 2009 base rate decision for Vectren Energy Delivery of Ohio (Vectren), the PUC adopted a settlement that included the establishment of distribution rate rider through which the company recovers the costs associated with an accelerated main and service line replacement program.

Oklahoma

In 2009, the OCC adopted a settlement that permits OG&E to recover the costs associated with the 101-MW "OU Spirit" wind facility and Crossroads Wind Farm through a cost recovery rider. The costs associated with the project are to be reflected in the company's base rates in its next rate case decision. OG&E is permitted to recover costs (both capital- and expense-related) associated with the company's "system hardening" and "vegetation management" programs, through a rider. In 2008, the OCC authorized OG&E to implement a storm cost recovery rider. The rider is adjusted annually to reflect any differences between the level of storm costs reflected in base rates and the level of such costs actually incurred in that year.

Oregon

The renewable adjustment clause allows for recovery of renewable resources and associated transmission that are expected to be placed into service in the current year without filing a general rate. In 2009, the PUC authorized NWNG to implement a new System Integrity Program (SIP) designed to recover costs related to base steel, pipeline integrity, and other pipeline safety programs. Costs are to be tracked annually, with recovery to be sought through the purchased gas adjustment after the first $3.3 million of capital costs are incurred by the company.

Other Balancing Accounts by States

Pennsylvania

On Feb. 14, 2012, legislation was enacted to allow the Pennsylvania Public Utility Commission to approve automatic adjustment clauses to recognize between general rate cases utility investments in certain infrastructure projects. PPL Electric Utilities, Duquesne Light, Metropolitan Edison, and Pennsylvania Electric have mechanisms in place to allow changes in Federal Energy Regulatory Commission-approved PJM Interconnection transmission charges to be automatically reflected in rates, subject to annual true-up. PPL-E also has a surcharge in place to recover universal service program costs.

Rhode Island

An alternative regulation plan is in effect for the gas operations of Narragansett Electric that provides for graduated earnings sharing above the benchmark returns. NE is to flow through to ratepayers all non-firm gas margins earned in excess of $2.8 million. The company recovers any shortfall of non-firm margins below $2.8 million through a distribution adjustment clause

South Carolina

Gas utilities are subject to potential annual rate adjustments if their earned equity return is outside a band of +50 basis points around the last authorized return.

South Dakota

While operating under a rate plan, utilities are required to submit annual cost-of-service filings, and the Commission may adjust a utility's rates at any time up to one year following the conclusion of a rate plan. Plans are in place that provide for sharing of certain margins. State law permits electric utilities to seek a cash return on construction work in progress and cost recovery associated with environmental compliance and transmission investments through separate riders. The PUC is statutorily authorized to approve automatic adjustment mechanisms to facilitate the recovery of the capital and operating costs associated with investment in transmission facilities.

Tennessee

PNG recovers margin losses associated with customers who are served under negotiated contracts and are able to bypass the utility's distribution system via its purchased gas adjustment rider. In May 2010, the TRA authorized CG to implement a full revenue decoupling mechanism for its residential and small commercial customers on a three-year pilot basis. Under the gas procurement incentive mechanism, Atmos is permitted to retain 50% of savings associated with gas costs that are less than 97.7% of a predetermined benchmark (lower band), and is required to absorb 50% of gas costs that are more than 102% of the benchmark (upper band).

Other Balancing Accounts by States

Texas

There are no alternative regulation mechanisms currently in place for the electric utilities in Texas.

Utah

A 2009 law permits utilities to seek recovery of costs associated with major plant additions via limited-issue rate proceedings. A pilot infrastructure replacement adjustment (IRA) mechanism was established by the PSC for Questar Gas in an April 2010 rate decision permitting the company to track and recover between rate cases, the costs associated with the replacement of high-pressure natural gas feeder lines. The mechanism is to be adjusted at least annually

Vermont

Under state law, the PSB is permitted to adopt alternative regulation plans (ARPs) for energy utilities. Green Mountain Power's ARP contains an earnings sharing mechanism (ESM) that provides for a 150-basis-point deadband around the authorized ROE. Incremental earnings above the upper end of the range are to be returned to customers, with GMP to recover 50% of any earnings shortfalls between 75 and 125 basis points below the authorized ROE, and all earnings shortfalls in excess of 125 basis points below the authorized ROE.

Virginia

Earnings within a 100-basis-point deadband around the established ROE will be considered reasonable and no rate adjustment will be required. If the SCC determines that the company's earnings for the test periods were more than 50 basis points below the fair ROE, the Commission would be required to approve a rate increase designed to accord the company an opportunity to earn the fair ROE. If the SCC were to determine that the company's earnings for the relevant test periods were more than 50 basis points above the authorized ROE, then 60% of the incremental earnings would be refunded to ratepayers over a subsequent six-to-12-month period. SCC rules also provide for "expedited" rate proceedings, which are essentially make-whole proceedings, and are allowed to be filed by gas utilities and smaller electric utilities (e.g., PPL Corp. subsidiary Kentucky Utilities) once per year. The expedited procedure allows the utility to implement an interim rate change, subject to refund, after 30 days, and subject to applicable provisions of the law.

Washington

In November 2010, the WUTC issued a policy statement on decoupling. The WUTC indicated that it would consider adoption of a full decoupling mechanism ("designed to minimize the risk to both the utilities and to ratepayers of volatility in average use per customer by class regardless of cause, including the effects of weather"), for electric and gas utilities.

Other Balancing Accounts by States

West Virginia

State statutes allow the energy utilities to use adjustment mechanisms that reflect, on a timely basis, changes in electric fuel costs, purchased power expenses, gas costs, investments related to environmental compliance costs, new transmission facilities, and new generation facilities that burn West Virginia coal.

Wisconsin

As permitted by statute, the PSC may authorize equity returns that are applicable only to specific generation projects. Before constructing a generating facility, a utility must obtain a determination of need from the PSC, which includes an estimate of the facility's costs. Cost overruns are considered on a case-by-case basis. A utility that proposes to purchase or construct an electric generating facility may apply to the PSC for an order specifying, in advance, the rate treatment, including the authorized return on equity, that will apply to the plant over its economic life

Wyoming

On Sept. 22, 2011, the PSC approved a settlement authorizing PacifiCorp to implement an adjustment mechanism designed to recover from or refund to ratepayers 100% of the difference between actual renewable energy and SO2 credit revenue levels and the levels reflected in base rates.

Source: ADJUSTMENT CLAUSES AND RATE RIDERS ~ A State-By-State Overview ~, Regulatory Research Associates (RRA), March 21, 2012.

Individual state descriptions from RRA state reports

APPENDIX A

CAPM, EMPIRICAL CAPM

The Capital Asset Pricing Model (CAPM) is a fundamental paradigm of finance. Simply put, the fundamental idea underlying the CAPM is that risk-averse investors demand higher returns for assuming additional risk, and higher-risk securities are priced to yield higher expected returns than lower-risk securities. The CAPM quantifies the additional return, or risk premium, required for bearing incremental risk. It provides a formal risk-return relationship anchored on the basic idea that only market risk matters, as measured by beta. According to the CAPM, securities are priced such that their:

EXPECTED RETURN = RISK-FREE RATE + RISK PREMIUM

Denoting the risk-free rate by R_F and the return on the market as a whole by R_M, the CAPM is:

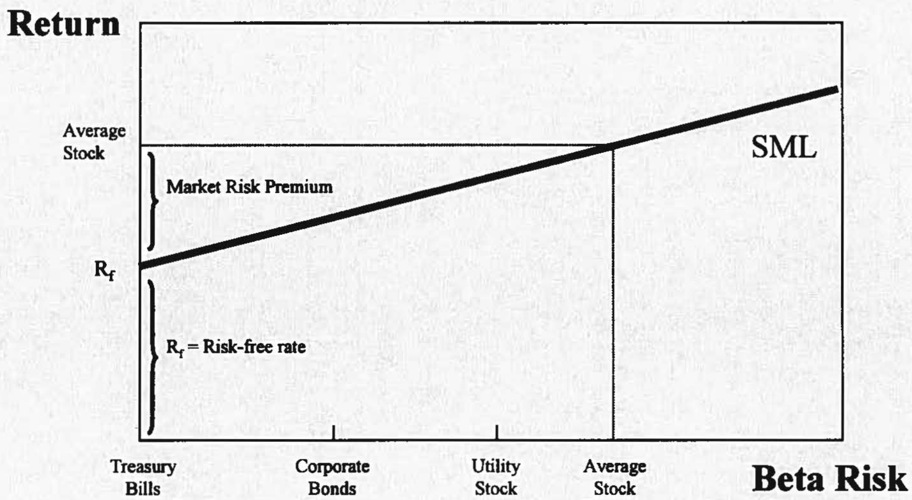
$$K = R_F + \beta(R_M - R_F) \tag{1}$$

Equation 1 is the CAPM expression which asserts that an investor expects to earn a return, K, that could be gained on a risk-free investment, R_F, plus a risk premium for assuming risk, proportional to the security's market risk, also known as beta, β, and the market risk premium, $(R_M - R_F)$, where R_M is the market return . The market risk premium $(R_M - R_F)$ can be abbreviated MRP so that the CAPM becomes:

$$K = R_F + \beta \times MRP \tag{2}$$

The CAPM risk-return relationship is depicted in the figure below and is typically labeled as the Security Market Line (SML) by the investment community.

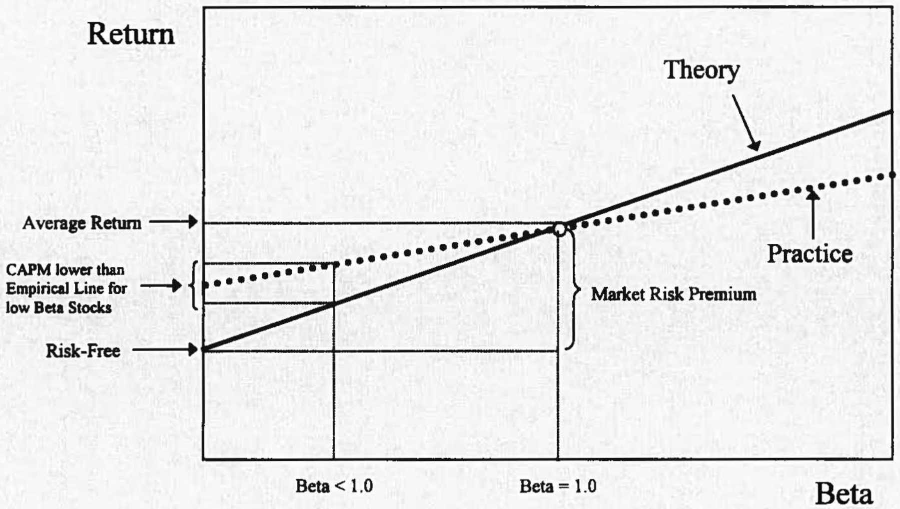
CAPM and Risk - Return in Capital Markets



A myriad empirical tests of the CAPM have shown that the risk-return tradeoff is not as steeply sloped as that predicted by the CAPM, however. That is, low-beta securities earn returns somewhat higher than the CAPM would predict, and high-beta securities earn less than predicted. In other words, the CAPM tends to overstate the actual sensitivity of the cost of capital to beta: low-beta stocks tend to have higher returns and high-beta stocks tend to have lower risk returns than predicted by the CAPM. The difference between the CAPM and the type of relationship observed in the empirical studies is depicted in the figure below. This is one of the most widely known empirical findings of the finance literature. This extensive literature is summarized in Chapter 13 of Dr. Morin's book [Regulatory Finance, Public Utilities Report Inc., Arlington, VA, 1994].

Risk vs Return

Theory vs. Practice



A number of refinements and expanded versions of the original CAPM theory have been proposed to explain the empirical findings. These revised CAPMs typically produce a risk-return relationship that is flatter than the standard CAPM prediction. The following equation makes use of these empirical findings by flattening the slope of the risk-return relationship and increasing the intercept:

$$K = R_F + \alpha + \beta \, (MRP - \alpha) \qquad (3)$$

where α is the "alpha" of the risk-return line, a constant determined empirically, and the other symbols are defined as before. Alternatively, Equation 3 can be written as follows:

$$K = R_F + a\,MRP + (1\text{-}a)\,\beta\,MRP \qquad (4)$$

where a is a fraction to be determined empirically. Comparing Equations 3 and 4, it is easy to see that alpha equals 'a' times MRP, that is, $\alpha = a \times MRP$

Theoretical Underpinnings

The obvious question becomes what would produce a risk return relationship which is flatter than the CAPM prediction, or in other words, how do you explain the presence of "alpha" in the above equation. The exclusion of variables aside from beta would produce this result. Three such variables are noteworthy: dividend yield, skewness, and hedging potential.

The dividend yield effects stem from the differential taxation on corporate dividends and capital gains. The standard CAPM does not consider the regularity of dividends received by investors. Utilities generally maintain high dividend payout ratios relative to the market, and by ignoring dividend yield, the CAPM provides biased cost of capital estimates. To the extent that dividend income is taxed at a higher rate than capital gains, investors will require higher pre-tax returns in order to equalize the after-tax returns provided by high-yielding stocks (e.g. utility stocks) with those of low-yielding stocks. In other words, high-yielding stocks must offer investors higher pre-tax returns. Even if dividends and capital gains are undifferentiated for tax purposes, there is still a tax bias in favor of earnings retention (lower dividend payout), as capital gains taxes are paid only when gains are realized.

Empirical studies by Litzenberger and Ramaswamy (1979) and Litzenberger et al. (1980) find that security returns are positively related to dividend yield as well as to beta. These results are consistent with after-tax extensions of the CAPM developed by Breenan (1973) and Litzenberger and Ramaswamy (1979) and suggest that the relationship between return, beta, and dividend yield should be estimated and employed to calculate the cost of equity capital.

As far as skewness is concerned, investors are more concerned with losing money than with total variability of return. If risk is defined as the probability of loss, it appears more logical to measure risk as the probability of achieving a return which is below the expected return. The traditional CAPM provides downward-biased estimates of cost of capital to the extent that these skewness effects are significant. As shown by Kraus and Litzenberger (1976), expected return depends on both on a stock's systematic risk (beta) and the systematic skewness. Empirical studies by Kraus and Litzenberger (1976), Friend, Westerfield, and Granito (1978), and Morin (1981) found that, in addition to beta, skewness of returns has a significant negative relationship with security returns. This result is consistent with the skewness version of the CAPM developed by Rubinstein (1973) and Kraus and Litzenberger (1976).

This is particularly relevant for public utilities whose future profitability is constrained by the regulatory process on the upside and relatively unconstrained on the downside in the face of socio-political realities of public utility regulation. The process of regulation, by restricting the upward potential for returns and responding sluggishly on the downward side, may impart some asymmetry to the distribution of returns, and is more likely to result in utilities earning less, rather than more, than their cost of capital. The traditional CAPM provides downward-biased estimates of cost of capital to the extent that these skewness effects are significant.

As far as hedging potential is concerned, investors are exposed to another kind of risk, namely, the risk of unfavorable shifts in the investment opportunity set. Merton (1973) shows that investors will hold portfolios consisting of three funds: the risk-free asset, the market portfolio, and a portfolio whose returns are perfectly negatively correlated with the riskless asset so as to hedge against unforeseen changes in the future risk-free rate. The higher the degree of protection offered by an asset against unforeseen changes in interest rates, the lower the required return, and conversely. Merton argues that low beta assets, like utility stocks, offer little protection against changes in interest rates, and require higher returns than suggested by the standard CAPM.

Another explanation for the CAPM's inability to fully explain the process determining security returns involves the use of an inadequate or incomplete market index. Empirical studies to validate the CAPM invariably rely on some stock market index as a proxy for the true market portfolio. The exclusion of several asset categories from the definition of market index mis-specifies the CAPM and biases the results found using only stock market data. Kolbe and Read (1983) illustrate the biases in beta estimates which result from applying the CAPM to public utilities. Unfortunately, no comprehensive and easily accessible data exist for several classes of assets, such as mortgages and business investments, so that the exact relation between return and stock betas predicted by the CAPM does not exist. This suggests that the empirical relationship between returns and stock betas is best estimated empirically (ECAPM) rather than by relying on theoretical and elegant CAPM models expanded to include missing assets effects. In any event, stock betas may be highly correlated with the true beta measured with the true market index.

Yet another explanation for the CAPM's inability to fully explain the observed risk-return tradeoff involves the possibility of constraints on investor borrowing that run counter to the assumptions of the CAPM. In response to this inadequacy, several versions of the CAPM have been developed by researchers. One of these versions is the so-called zero-beta, or two-factor, CAPM which provides for a risk-free return in a market where borrowing and lending rates are divergent. If borrowing rates and lending rates differ, or there is no risk-free borrowing or lending, or there is risk-free lending but no risk-free borrowing, then the CAPM has the following form:

$$K = R_Z + \beta(R_m - R_F)$$

The model, christened the zero-beta model, is analogous to the standard CAPM, but with the return on a minimum risk portfolio which is unrelated to market returns, R_Z, replacing the risk-free rate, R_F. The model has been empirically tested by Black, Jensen, and Scholes (1972), who found a flatter than predicted CAPM, consistent with the model and other researchers' findings.

The zero-beta CAPM cannot be literally employed in cost of capital projections, since the zero-beta portfolio is a statistical construct difficult to replicate.

Empirical Evidence

A summary of the empirical evidence on the magnitude of alpha is provided in the table below.

Empirical Evidence on the Alpha Factor		
Author	**Range of alpha**	**Period relied**
Black (1993)	-3.6% to 3.6%	1931-1991
Black, Jensen and Scholes (1972)	-9.61% to 12.24%	1931-1965
Fama and McBeth (1972)	4.08% to 9.36%	1935-1968
Fama and French (1992)	10.08% to 13.56%	1941-1990
Litzenberger and Ramaswamy (1979)	5.32% to 8.17%	
Litzenberger, Ramaswamy and Sosin (1980)	1.63% to 5.04%	1926-1978
Pettengill, Sundaram and Mathur (1995)	4.6%	
Morin (1994)	2.0%	1926-1984
Harris, Marston, Mishra, and O'Brien (2003)	2.0%	1983-1998

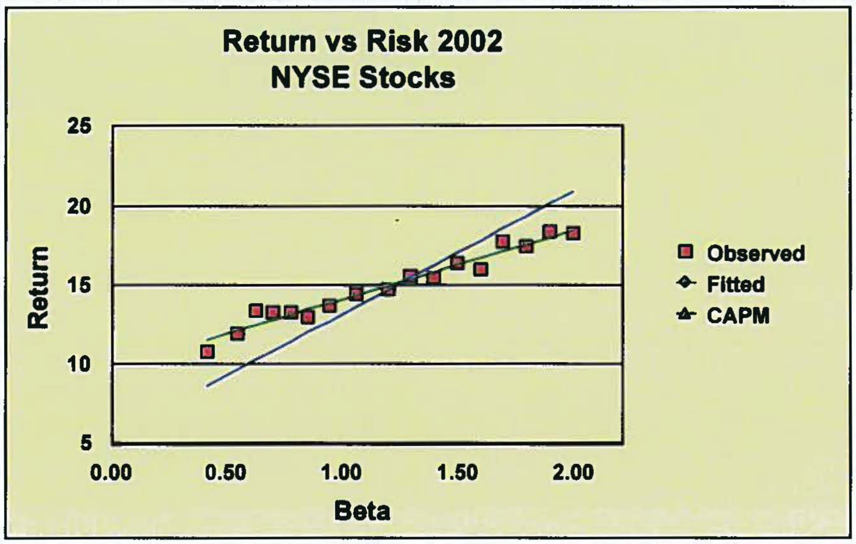
Given the observed magnitude of alpha, the empirical evidence indicates that the risk-return relationship is flatter than that predicted by the CAPM. Typical of the empirical evidence is the findings cited in Morin (1989) over the period 1926-1984 indicating that the observed expected return on a security is related to its risk by the following equation:

$$K = .0829 + .0520\,\beta$$

Given that the risk-free rate over the estimation period was approximately 6 percent, this relationship implies that the intercept of the risk-return relationship is higher than the 6 percent risk-free rate, contrary to the CAPM's prediction. Given that the average return on an average risk stock exceeded the risk-free rate by about 8.0 percent in that period, that is, the market risk premium (R_M - R_F) = 8 percent, the intercept of the observed relationship between return and beta exceeds the risk-free rate by about 2 percent, suggesting an alpha factor of 2 percent.

Most of the empirical studies cited in the above table utilize raw betas rather than Value Line adjusted betas because the latter were not available over most of the time periods covered in these studies. A study of the relationship between return and adjusted beta is reported on Table 6-7 in Ibbotson Associates Valuation Yearbook 2001. If we exclude the portfolio of very small cap stocks from the relationship due to significant size effects, the relationship between the arithmetic mean return and beta for the remaining portfolios is flatter than predicted and the intercept slightly higher than predicted by the CAPM, as shown on the graph below. It is noteworthy that the Ibbotson study relies on adjusted betas as stated on page 95 of the aforementioned study.

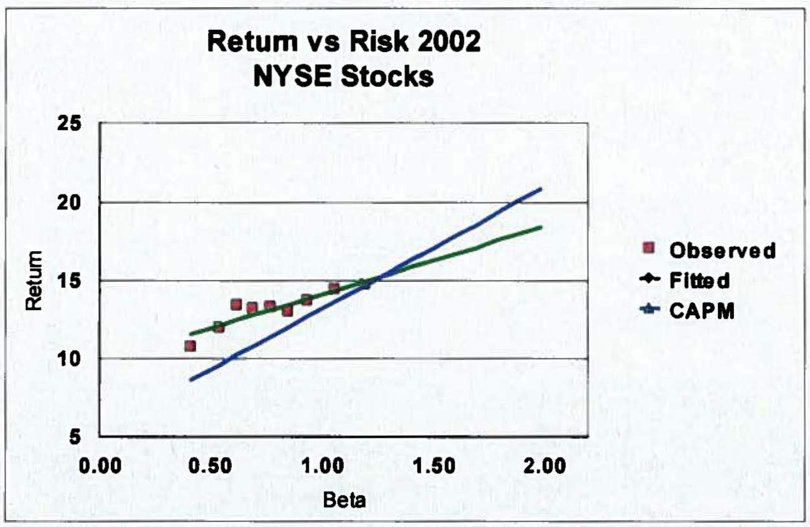
CAPM vs ECAPM



Another study by Morin in May 2002 provides empirical support for the ECAPM. All the stocks covered in the Value Line Investment Survey for Windows for which betas and returns data were available were retained for analysis. There were nearly 2000 such stocks. The expected return was measured as the total shareholder return ("TSR") reported by Value Line over the past ten years. The Value Line adjusted beta was also retrieved from the same data base. The nearly 2000 companies for which all data were available were ranked in ascending order of beta, from lowest to highest. In order to palliate measurement error, the nearly 2000 securities were grouped into ten portfolios of approximately 180 securities for each portfolio. The average returns and betas for each portfolio were as follows:

Portfolio #	Beta	Return
portfolio 1	0.41	10.87
portfolio 2	0.54	12.02
portfolio 3	0.62	13.50
portfolio 4	0.69	13.30
portfolio 5	0.77	13.39
portfolio 6	0.85	13.07
portfolio 7	0.94	13.75
portfolio 8	1.06	14.53
portfolio 9	1.19	14.78
portfolio 10	1.48	20.78

It is clear from the graph below that the observed relationship between DCF returns and Value Line adjusted betas is flatter than that predicted by the plain vanilla CAPM. The observed intercept is higher than the prevailing risk-free rate of 5.7 percent while the slope is less than equal to the market risk premium of 7.7 percent predicted by the plain vanilla CAPM for that period.



In an article published in Financial Management, Harris, Marston, Mishra, and O'Brien ("HMMO") estimate ex ante expected returns for S&P 500 companies over the period 1983-1998[1]. HMMO measure the expected rate of return (cost of equity) of each dividend-paying stock in the S&P 500 for each month from January 1983 to August 1998 by using the constant growth DCF model. They then investigate the relation between the risk premium (expected return over the 20-year U.S. Treasury Bond yield) estimates for each month to equity betas as of that same month (5-year raw betas).

The table below, drawn from HMMO Table 4, displays the average estimate prospective risk premium (Column 2) by industry and the corresponding beta estimate for that industry, both in raw form (Column 3) and adjusted form (Column 4). The latter were calculated with the traditional Value Line – Merrill Lynch – Bloomberg adjustment methodology by giving 1/3 weight of to a beta estimate of 1.00 and 2/3 weight to the raw beta estimate.

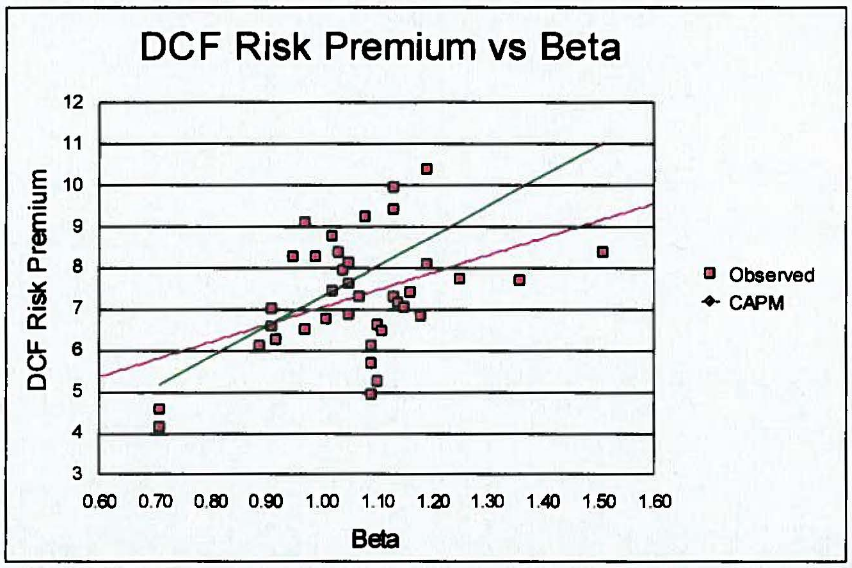
Table A-1 Risk Premium and Beta Estimates by Industry

	Industry (1)	DCF Risk Premium (2)	Raw Industry Beta (3)	Adjusted Industry Beta (4)
1	Aero	6.63	1.15	1.10
2	Autos	5.29	1.15	1.10
3	Banks	7.16	1.21	1.14
4	Beer	6.60	0.87	0.91
5	BldMat	6.84	1.27	1.18
6	Books	7.64	1.07	1.05
7	Boxes	8.39	1.04	1.03
8	BusSv	8.15	1.07	1.05
9	Chems	6.49	1.16	1.11
10	Chips	8.11	1.28	1.19
11	Clths	7.74	1.37	1.25
12	Cnstr	7.70	1.54	1.36
13	Comps	9.42	1.19	1.13
14	Drugs	8.29	0.99	0.99
15	ElcEq	6.89	1.08	1.05
16	Energy	6.29	0.88	0.92
17	Fin	8.38	1.76	1.51
18	Food	7.02	0.86	0.91
19	Fun	9.98	1.19	1.13
20	Gold	4.59	0.57	0.71
21	Hlth	10.40	1.29	1.19
22	Hsld	6.77	1.02	1.01
23	Insur	7.46	1.03	1.02
24	LabEq	7.31	1.10	1.07
25	Mach	7.32	1.20	1.13
26	Meals	7.98	1.06	1.04
27	MedEq	8.80	1.03	1.02
28	Pap	6.14	1.13	1.09
29	PerSv	9.12	0.95	0.97
30	Retail	9.27	1.12	1.08
31	Rubber	7.06	1.22	1.15

[1] Harris, R. S., Marston, F. C., Mishra, D. R., and O'Brien, T. J., "*Ex Ante* Cost of Equity Estimates of S&P 500 Firms: The Choice Between Global and Domestic CAPM," Financial Management, Autumn 2003, pp. 51-66.

32	Ships	1.95	0.95	0.97
33	Stee	4.96	1.13	1.09
34	Telc	6.12	0.83	0.89
35	Toys	7.42	1.24	1.16
36	Trans	5.70	1.14	1.09
37	Txtls	6.52	0.95	0.97
38	Util	4.15	0.57	0.71
39	Whlsl	8.29	0.92	0.95
	MEAN	**7.19**		

The observed statistical relationship between expected return and **adjusted beta** is shown in the graph below along with the CAPM prediction:



If the plain vanilla version of the CAPM is correct, then the intercept of the graph should be zero, recalling that the vertical axis represents returns in excess of the risk-free rate. Instead, the observed intercept is approximately 2 percent, that is approximately equal to 25 percent of the expected market risk premium of 7.2 percent shown at the bottom of Column 2 over the 1983-1998 period, as predicted by the ECAPM. The same is true for the slope of the graph. If the plain vanilla version of the CAPM is correct, then the slope of the relationship should equal the market risk premium of 7.2 percent. Instead, the observed slope of close to 5 percent is approximately equal to 75 percent of the expected market risk premium of 7.2 percent, as predicted by the ECAPM.

In short, the HMMO empirical findings are quite consistent with the predictions of the ECAPM.

Practical Implementation of the ECAPM

The empirical evidence reviewed above suggests that the expected return on a security is related to its risk by the following relationship:

$$K = R_F + \alpha + \beta\ (MRP - \alpha) \tag{5}$$

or, alternatively by the following equivalent relationship:

$$K = R_F + a\,MRP + (1\text{-}a)\,\beta\,MRP \tag{6}$$

The empirical findings support values of α from approximately 2 percent to 7 percent. If one is using the short-term U.S. Treasury Bills yield as a proxy for the risk-free rate, and given that utility stocks have lower than average betas, an alpha in the lower range of the empirical findings, 2 percent - 3 percent is reasonable, albeit conservative.

Using the long-term U.S. Treasury yield as a proxy for the risk-free rate, a lower alpha adjustment is indicated. This is because the use of the long-term U.S. Treasury yield as a proxy for the risk-free rate partially incorporates the desired effect of using the ECAPM[2]. An alpha in the range of 1 percent - 2 percent is therefore reasonable.

To illustrate, consider a utility with a beta of 0.80. The risk-free rate is 5 percent, the MRP is 7 percent, and the alpha factor is 2 percent. The cost of capital is determined as follows:

$$\begin{aligned} K &= R_F + \alpha + \beta\ (MRP - \alpha) \\ K &= 5\% + 2\% + 0.80(7\% - 2\%) \\ &= 11\% \end{aligned}$$

[2] The Security Market Line (SML) using the long-term risk-free rate has a higher intercept and a flatter slope than the SML using the short-term risk-free rate

A practical alternative is to rely on the second variation of the ECAPM:

$$K = R_F + a\,MRP + (1\text{-}a)\,\beta\,MRP$$

With an alpha of 2 percent, a MRP in the 6 percent - 8 percent range, the ‘a” coefficient is 0.25, and the ECAPM becomes[3]:

$$K = R_F + 0.25\ MRP + 0.75\ \beta\ MRP$$

Returning to the numerical example, the utility’s cost of capital is:

$$K = 5\% + 0.25 \times 7\% + 0.75 \times 0.80 \times 7\%$$
$$= 11\%$$

For reasonable values of beta and the MRP, both renditions of the ECAPM produce results that are virtually identical[4].

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[3] Recall that alpha equals ‘a’ times MRP, that is, alpha = a MRP, and therefore a = alpha/MRP. If alpha is 2 percent, then a = 0.25

[4] In the Morin (1994) study, the value of “a” was actually derived by systematically varying the constant "a" in equation 6 from 0 to 1 in steps of 0.05 and choosing that value of 'a' that minimized the mean square error between the observed relationship between return and beta:

$$K = 0.0829 + .0520\ \beta$$

The value of a that best explained the observed relationship was 0.25.

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APPENDIX B

FLOTATION COST ALLOWANCE

To obtain the final cost of equity financing from the investors' expected rate of return, it is necessary to make allowance for underpricing, which is the sum of market pressure, costs of flotation, and underwriting fees associated with new issues. Allowance for market pressure should be made because large blocks of new stock may cause significant pressure on market prices even in stable markets. Allowance must also be made for company costs of flotation (including such items as printing, legal and accounting expenses) and for underwriting fees.

1. MAGNITUDE OF FLOTATION COSTS

According to empirical studies, underwriting costs and expenses average at least 4% of gross proceeds for utility stock offerings in the U.S. (See Logue & Jarrow: "Negotiations vs. Competitive Bidding in the Sale of Securities by Public Utilities", Financial Management, Fall 1978.) A study of 641 common stock issues by 95 electric utilities identified a flotation cost allowance of 5.0%. (See Borum & Malley: "Total Flotation Cost for Electric Company Equity Issues", Public Utilities Fortnightly, Feb. 20, 1986.)

Empirical studies suggest an allowance of 1% for market pressure in U.S. studies. Logue and Jarrow found that the absolute magnitude of the relative price decline due to market pressure was less than 1.5%. Bowyer and Yawitz examined 278 public utility stock issues and found an average market pressure of 0.72%. (See Bowyer & Yawitz, "The Effect of New Equity Issues on Utility Stock Prices", Public Utilities Fortnightly, May 22, 1980.)

Eckbo & Masulis ("Rights vs. Underwritten Stock Offerings: An Empirical Analysis", University of British Columbia, Working Paper No. 1208, Sept., 1987) found an average flotation cost of 4.175% for utility common stock offerings. Moreover, flotation costs increased progressively for smaller size issues. They also found that the relative price decline due to market pressure in the days surrounding the announcement amounted to slightly more than 1.5%. In a classic and monumental study published in the prestigious Journal of Financial Economics by a prominent scholar, a market pressure effect of 3.14% for industrial stock issues and 0.75% for utility common stock issues was found (see Smith, C.W., "Investment Banking and the Capital Acquisition Process," Journal of Financial Economics 15, 1986). Other studies of market pressure are reported in Logue ("On the Pricing of Unseasoned Equity Offerings, Journal of Financial and Quantitative Analysis, Jan. 1973), Pettway ("The Effects of New Equity Sales Upon Utility Share Prices," Public Utilities Fortnightly, May 10 1984), and Reilly and Hatfield ("Investor Experience with New Stock Issues," Financial Analysts' Journal, Sept.-Oct. 1969). In the Pettway study, the market pressure effect for a sample of 368 public utility equity sales was in the range of 2% to 3%. Adding the direct and indirect effects of utility common stock issues, the indicated total flotation cost allowance is above 5.0%, corroborating the results of earlier studies.

As shown in the table below, a comprehensive empirical study by Lee, Lochhead, Ritter, and Zhao, "The Costs of Raising Capital," Journal of Financial Research, Vol. XIX, NO. 1, Spring 1996, shows average direct flotation costs for equity offerings of 3.5% - 5% for stock issues between \$60 and \$500 million. Allowing for market pressure costs raises the flotation cost allowance to well above 5%.

FLOTATION COSTS: RAISING EXTERNAL CAPITAL
(Percent of Total Capital Raised)

Amount Raised in $ Millions	Average Flotation Cost: Common Stock	Average Flotation Cost: New Debt
$ 2 - 9. 99	13.28%	4.39%
10 - 19. 99	8.72	2.76
20 - 39. 99	6.93	2.42
40 - 59. 99	5.87	1.32
60 - 79. 99	5.18	2.34
80 - 99. 99	4.73	2.16
100 - 199. 99	4.22	2.31
200 - 499. 99	3.47	2.19
500 and Up	3.15	1.64

Note: Flotation costs for IPOs are about 17 percent of the value of common stock issued if the amount raised is less than $10 million and about 6 percent if more than $500 million is raised. Flotation costs are somewhat lower for utilities than others.

Source: Lee, Inmoo, Scott Lochhead, Jay Ritter, and Quanshui Zhao, "The Costs of Raising Capital," *The Journal of Financial Research,* Spring 1996.

Therefore, based on empirical studies, total flotation costs including market pressure amount to approximately 5% of gross proceeds. I have therefore assumed a 5% gross total flotation cost allowance in my cost of capital analyses.

2. APPLICATION OF THE FLOTATION COST ADJUSTMENT

The section below shows: 1) why it is necessary to apply an allowance of 5% to the dividend yield component of equity cost by dividing that yield by 0.95 (100% - 5%) to obtain the fair return on equity capital, and 2) why the flotation adjustment is permanently required to avoid confiscation even if no further stock issues are contemplated. Flotation costs are only recovered if the rate of return is applied to total equity, including retained earnings, in all future years.

Flotation costs are just as real as costs incurred to build utility plant. Fair regulatory treatment absolutely must permit the recovery of these costs. An analogy with bond issues is useful to understand the treatment of flotation costs in the case of common stocks.

In the case of a bond issue, flotation costs are not expensed but are rather amortized over the life of the bond, and the annual amortization charge is embedded in the cost of service. This is analogous to the process of depreciation, which allows the recovery of funds invested in utility plant. The recovery of bond flotation expense continues year after year, irrespective of whether the company issues new debt capital in the future, until recovery is complete. In the case of common stock that has no finite life, flotation costs are not amortized. Therefore, the recovery of flotation cost requires an upward adjustment to the allowed return on equity. Roger A. Morin, Regulatory Finance, Public Utilities Reports Inc., Arlington, Va., 1994, provides numerical illustrations that show that even if a utility does not contemplate any additional common stock issues, a flotation cost adjustment is still permanently required. Examples there also demonstrate that the allowance applies to retained earnings as well as to the original capital.

From the standard DCF model, the investor's required return on equity capital is expressed as:

$$K = D_1/P_o + g$$

If P_o is regarded as the proceeds per share actually received by the company from which dividends and earnings will be generated, that is, P_o equals B_o, the book value per share, then the company's required return is:

$$r = D_1/B_o + g$$

Denoting the percentage flotation costs 'f', proceeds per share B_o are related to market price P_o as follows:

$$P - fP = B_o$$

$$P(1 - f) = B_o$$

Substituting the latter equation into the above expression for return on equity, we obtain:

$$r = D_1/P(1\text{-}f) + g$$

that is, the utility's required return adjusted for underpricing. For flotation costs of 5%, dividing the expected dividend yield by 0.95 will produce the adjusted cost of equity capital. For a dividend yield of 6% for example, the magnitude of the adjustment is 32 basis points: .06/.95 = .0632.

In deriving DCF estimates of fair return on equity, it is therefore necessary to apply a conservative after-tax allowance of 5% to the dividend yield component of equity cost.

Even if no further stock issues are contemplated, the flotation adjustment is still permanently required to keep shareholders whole. Flotation costs are only recovered if the rate of return is applied to total equity, including retained earnings, in all future years, even if no future financing is contemplated. This is demonstrated by the numerical example contained in pages 7-9 of this Appendix. Moreover, even if the stock price, hence the DCF estimate of equity return, fully reflected the lack of permanent allowance, the company always nets less than the market price. Only the net proceeds from an equity issue are used to add to the rate base on which the investor earns. A permanent allowance for flotation costs must be authorized in order to insure that in each year the investor earns the required return on the total amount of capital actually supplied.

The example shown on pages 7-9 shows the flotation cost adjustment process using illustrative, yet realistic, market data. The assumptions used in the computation are shown on page 7. The stock is selling in the market for \$25, investors expect the firm to pay a dividend of \$2.25 that will grow at a rate of 5% thereafter. The traditional DCF cost of equity is thus k = D/P + g = 2.25/25 + .05 = 14%. The firm sells one share stock, incurring a flotation cost of 5%. The traditional DCF cost of equity adjusted for flotation cost is thus ROE = D/P(1-f) + g = .09/.95 + .05 = 14.47%.

The initial book value (rate base) is the net proceeds from the stock issue, which are \$23.75, that is, the market price less the 5% flotation costs. The example demonstrates that only if the company is allowed to earn 14.47% on rate base will investors earn their cost of equity of 14%. On page 8, Column 1 shows the initial common stock account, Column 2 the cumulative retained earnings balance, starting at zero, and steadily increasing from the retention of earnings. Total equity in Column 3 is the sum of common stock capital and retained earnings. The stock price in Column 4 is obtained from the seminal DCF formula: $D_1/(k - g)$. Earnings per share in Column 6 are simply the allowed return of 14.47% times the total common equity base. Dividends start at $2.25 and grow at 5% thereafter, which they must do if investors are to earn a 14% return. The dividend payout ratio remains constant, as per the assumption of the DCF model. All quantities, stock price, book value, earnings, and dividends grow at a 5% rate, as shown at the bottom of the relevant columns. Only if the company is allowed to earn 14.47% on equity do investors earn 14%. For example, if the company is allowed only 14%, the stock price drops from $26.25 to $26.13 in the second year, inflicting a loss on shareholders. This is shown on page 9. The growth rate drops from 5% to 4.53%. Thus, investors only earn 9% + 4.53% = 13.53% on their investment. It is noteworthy that the adjustment is always required each and every year, whether or not new stock issues are sold in the future, and that the allowed return on equity must be earned on total equity, including retained earnings, for investors to earn the cost of equity.

ASSUMPTIONS:

ISSUE PRICE =	$25.00
FLOTATION COST =	5.00%
DIVIDEND YIELD =	9.00%
GROWTH =	5.00%
EQUITY RETURN =	**14.00%**
(D/P + g)	
ALLOWED RETURN ON EQUITY =	**14.47%**
(D/P(1-f) + g)	

Yr	COMMON STOCK (1)	RETAINED EARNINGS (2)	TOTAL EQUITY (3)	STOCK PRICE (4)	MARKET / BOOK RATIO (5)	EPS (6)	DPS (7)	PAYOUT (8)
--------	--------	--------	--------	--------	--------	--------	--------	--------
1	$23.75	$0.000	$23.750	$25.000	1.0526	$3.438	$2.250	65.45%
2	$23.75	$1.188	$24.938	$26.250	1.0526	$3.609	$2.363	65.45%
3	$23.75	$2.434	$26.184	$27.563	1.0526	$3.790	$2.481	65.45%
4	$23.75	$3.744	$27.494	$28.941	1.0526	$3.979	$2.605	65.45%
5	$23.75	$5.118	$28.868	$30.388	1.0526	$4.178	$2.735	65.45%
6	$23.75	$6.562	$30.312	$31.907	1.0526	$4.387	$2.872	65.45%
7	$23.75	$8.077	$31.827	$33.502	1.0526	$4.607	$3.015	65.45%
8	$23.75	$9.669	$33.419	$35.178	1.0526	$4.837	$3.166	65.45%
9	$23.75	$11.340	$35.090	$36.936	1.0526	$5.079	$3.324	65.45%
10	$23.75	$13.094	$36.844	$38.783	1.0526	$5.333	$3.490	65.45%
			5.00%	**5.00%**		**5.00%**	**5.00%**	

Yr	COMMON STOCK (1)	RETAINED EARNINGS (2)	TOTAL EQUITY (3)	STOCK PRICE (4)	MARKET/ BOOK RATIO (5)	EPS (6)	DPS (7)	PAYOUT (8)
------	--------	--------	--------	--------	--------	--------	--------	--------
1	$23.75	$0.000	$23.750	$25.000	1.0526	$3.325	$2.250	67.67%
2	$23.75	$1.075	$24.825	$26.132	1.0526	$3.476	$2.352	67.67%
3	$23.75	$2.199	$25.949	$27.314	1.0526	$3.633	$2.458	67.67%
4	$23.75	$3.373	$27.123	$28.551	1.0526	$3.797	$2.570	67.67%
5	$23.75	$4.601	$28.351	$29.843	1.0526	$3.969	$2.686	67.67%
6	$23.75	$5.884	$29.634	$31.194	1.0526	$4.149	$2.807	67.67%
7	$23.75	$7.225	$30.975	$32.606	1.0526	$4.337	$2.935	67.67%
8	$23.75	$8.627	$32.377	$34.082	1.0526	$4.533	$3.067	67.67%
9	$23.75	$10.093	$33.843	$35.624	1.0526	$4.738	$3.206	67.67%
10	$23.75	$11.625	$35.375	$37.237	1.0526	$4.952	$3.351	67.67%
			4.53%	**4.53%**		**4.53%**	**4.53%**	