Division 4-11

Request:

Schedule RBH-8 provides a listing of the authorized return on equity, 30-year Treasury yield and risk premium through July 31, 2017 for electric and gas utilities. Please update this listing for authorized returns extending through December 31, 2017 for both electric and gas utilities.

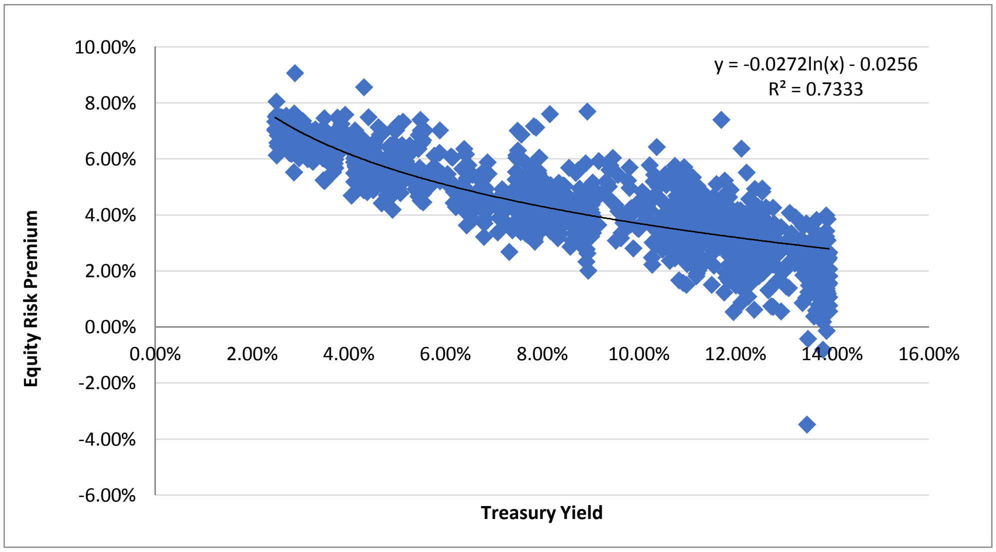
Response:

Please see Attachment DIV 4-11-1 and Attachment DIV 4-11-2.

Prepared by or under the supervision of: Robert B. Hevert

Bond Yield Plus Risk Premium

	[1] Constant	[2] Slope	[3] 30-Year Treasury Yield	[4] Risk Premium	[5] Return on Equity
	-2.56%	-2.72%			
Current 30-Year Treasury			2.77%	7.18%	9.95%
Near-Term Projected 30-Year Treasury			3.30%	6.71%	10.01%
Long-Term Projected 30-Year Treasury			4.20%	6.05%	10.25%



Notes:
[1] Constant of regression equation
[2] Slope of regression equation
[3] Source: Current = Bloomberg Professional,
Near Term Projected = Blue Chip Financial Forecasts, Vol. 36, No. 12, December 1, 2017, at 2,
Long Term Projected = Blue Chip Financial Forecasts, Vol. 36, No. 12, December 1, 2017, at 14.
[4] Equals [1] + ln([3]) x [2]
[5] Equals [3] + [4]
[6] Source: SNL Financial
[7] Source: SNL Financial
[8] Source: Bloomberg Professional, equals 200-trading day average (i.e. lag period)
[9] Equals [7] - [8]

Bond Yield Plus Risk Premium

[6] Date of Electric Rate Case	[7] Return on Equity	[8] 30-Year Treasury Yield	[9] Risk Premium
1/1/1980	14.50%	9.36%	5.14%
1/7/1980	14.39%	9.38%	5.01%
1/9/1980	15.00%	9.40%	5.60%
1/14/1980	15.17%	9.42%	5.75%
1/17/1980	13.93%	9.44%	4.49%
1/23/1980	15.50%	9.47%	6.03%
1/30/1980	13.86%	9.52%	4.34%
1/31/1980	12.61%	9.53%	3.08%
2/6/1980	13.71%	9.58%	4.13%
2/13/1980	12.80%	9.63%	3.17%
2/14/1980	13.00%	9.65%	3.35%
2/19/1980	13.50%	9.68%	3.82%
2/27/1980	13.75%	9.78%	3.97%
2/29/1980	13.75%	9.81%	3.94%
2/29/1980	14.00%	9.81%	4.19%
2/29/1980	14.77%	9.81%	4.96%
3/7/1980	12.70%	9.89%	2.81%
3/14/1980	13.50%	9.97%	3.53%
3/26/1980	14.16%	10.10%	4.06%
3/27/1980	14.24%	10.12%	4.12%
3/28/1980	14.50%	10.13%	4.37%
4/11/1980	12.75%	10.27%	2.48%
4/14/1980	13.85%	10.29%	3.56%
4/16/1980	15.50%	10.31%	5.19%
4/22/1980	13.25%	10.35%	2.90%
4/22/1980	13.90%	10.35%	3.55%
4/24/1980	16.80%	10.38%	6.43%
4/29/1980	15.50%	10.41%	5.09%
5/6/1980	13.70%	10.45%	3.25%
5/7/1980	15.00%	10.45%	4.55%
5/8/1980	13.75%	10.46%	3.29%
5/9/1980	14.35%	10.47%	3.88%
5/13/1980	13.60%	10.48%	3.12%
5/15/1980	13.25%	10.49%	2.76%
5/19/1980	13.75%	10.51%	3.24%
5/27/1980	13.62%	10.54%	3.08%
5/27/1980	14.60%	10.54%	4.06%
5/29/1980	16.00%	10.56%	5.44%
5/30/1980	13.80%	10.56%	3.24%
6/2/1980	15.63%	10.57%	5.06%
6/9/1980	15.90%	10.60%	5.30%
6/10/1980	13.78%	10.60%	3.18%
6/12/1980	14.25%	10.61%	3.64%
6/19/1980	13.40%	10.62%	2.78%
6/30/1980	13.00%	10.65%	2.35%
6/30/1980	13.40%	10.65%	2.75%
7/9/1980	14.75%	10.67%	4.08%
7/10/1980	15.00%	10.68%	4.32%
7/15/1980	15.80%	10.70%	5.10%
7/18/1980	13.80%	10.71%	3.09%
7/22/1980	14.10%	10.72%	3.38%
7/24/1980	15.00%	10.73%	4.27%

Date of Electric Rate Case	Return on Equity	30-Year Treasury Yield	Risk Premium
7/25/1980	13.48%	10.73%	2.75%
7/31/1980	14.58%	10.75%	3.83%
8/8/1980	13.50%	10.78%	2.72%
8/8/1980	14.00%	10.78%	3.22%
8/8/1980	15.45%	10.78%	4.67%
8/11/1980	14.85%	10.78%	4.07%
8/14/1980	14.00%	10.79%	3.21%
8/14/1980	16.25%	10.79%	5.46%
8/25/1980	13.75%	10.82%	2.93%
8/27/1980	13.80%	10.83%	2.97%
8/29/1980	12.50%	10.84%	1.66%
9/15/1980	13.50%	10.88%	2.62%
9/15/1980	13.93%	10.88%	3.05%
9/15/1980	15.80%	10.88%	4.92%
9/24/1980	12.50%	10.93%	1.57%
9/24/1980	15.00%	10.93%	4.07%
9/26/1980	13.75%	10.94%	2.81%
9/30/1980	14.10%	10.96%	3.14%
9/30/1980	14.20%	10.96%	3.24%
10/1/1980	13.90%	10.97%	2.93%
10/3/1980	15.50%	10.98%	4.52%
10/7/1980	12.50%	10.99%	1.51%
10/9/1980	13.25%	11.00%	2.25%
10/9/1980	14.50%	11.00%	3.50%
10/9/1980	14.50%	11.00%	3.50%
10/16/1980	16.10%	11.02%	5.08%
10/17/1980	14.50%	11.03%	3.47%
10/31/1980	13.75%	11.11%	2.64%
10/31/1980	14.25%	11.11%	3.14%
11/4/1980	15.00%	11.12%	3.88%
11/5/1980	13.75%	11.12%	2.63%
11/5/1980	14.00%	11.12%	2.88%
11/8/1980	13.75%	11.14%	2.61%
11/10/1980	14.85%	11.15%	3.70%
11/17/1980	14.00%	11.18%	2.82%
11/18/1980	14.00%	11.19%	2.81%
11/19/1980	13.00%	11.19%	1.81%
11/24/1980	14.00%	11.21%	2.79%
11/26/1980	14.00%	11.21%	2.79%
12/8/1980	14.15%	11.22%	2.93%
12/8/1980	15.10%	11.22%	3.88%
12/9/1980	15.35%	11.22%	4.13%
12/12/1980	15.45%	11.23%	4.22%
12/17/1980	13.25%	11.23%	2.02%
12/18/1980	15.80%	11.23%	4.57%
12/19/1980	14.50%	11.23%	3.27%
12/19/1980	14.64%	11.23%	3.41%
12/22/1980	13.45%	11.23%	2.22%
12/22/1980	15.00%	11.23%	3.77%
12/30/1980	14.50%	11.22%	3.28%
12/30/1980	14.95%	11.22%	3.73%
12/31/1980	13.39%	11.22%	2.17%
1/2/1981	15.25%	11.22%	4.03%
1/7/1981	14.30%	11.21%	3.09%

Date of Electric Rate Case	Return on Equity	30-Year Treasury Yield	Risk Premium
1/19/1981	15.25%	11.20%	4.05%
1/23/1981	13.10%	11.20%	1.90%
1/23/1981	14.40%	11.20%	3.20%
1/26/1981	15.25%	11.20%	4.05%
1/27/1981	15.00%	11.21%	3.79%
1/31/1981	13.47%	11.22%	2.25%
2/3/1981	15.25%	11.23%	4.02%
2/5/1981	15.75%	11.25%	4.50%
2/11/1981	15.60%	11.28%	4.32%
2/20/1981	15.25%	11.33%	3.92%
3/11/1981	15.40%	11.49%	3.91%
3/12/1981	14.51%	11.50%	3.01%
3/12/1981	16.00%	11.50%	4.50%
3/13/1981	13.02%	11.52%	1.50%
3/18/1981	16.19%	11.55%	4.64%
3/19/1981	13.75%	11.56%	2.19%
3/23/1981	14.30%	11.58%	2.72%
3/25/1981	15.30%	11.60%	3.70%
4/1/1981	14.53%	11.68%	2.85%
4/3/1981	19.10%	11.71%	7.39%
4/9/1981	15.00%	11.78%	3.22%
4/9/1981	15.30%	11.78%	3.52%
4/9/1981	16.50%	11.78%	4.72%
4/9/1981	17.00%	11.78%	5.22%
4/10/1981	13.75%	11.80%	1.95%
4/13/1981	13.57%	11.82%	1.75%
4/15/1981	15.30%	11.85%	3.45%
4/16/1981	13.50%	11.87%	1.63%
4/17/1981	14.10%	11.87%	2.23%
4/21/1981	14.00%	11.90%	2.10%
4/21/1981	16.80%	11.90%	4.90%
4/24/1981	16.00%	11.95%	4.05%
4/27/1981	12.50%	11.97%	0.53%
4/27/1981	13.61%	11.97%	1.64%
4/29/1981	13.65%	12.00%	1.65%
4/30/1981	13.50%	12.02%	1.48%
5/4/1981	16.22%	12.05%	4.17%
5/5/1981	14.40%	12.07%	2.33%
5/7/1981	16.25%	12.11%	4.14%
5/7/1981	16.27%	12.11%	4.16%
5/8/1981	13.00%	12.13%	0.87%
5/8/1981	16.00%	12.13%	3.87%
5/12/1981	13.50%	12.16%	1.34%
5/15/1981	15.75%	12.22%	3.53%
5/18/1981	14.88%	12.23%	2.65%
5/20/1981	16.00%	12.26%	3.74%
5/21/1981	14.00%	12.27%	1.73%
5/26/1981	14.90%	12.30%	2.60%
5/27/1981	15.00%	12.31%	2.69%
5/29/1981	15.50%	12.34%	3.16%
6/1/1981	16.50%	12.35%	4.15%
6/3/1981	14.67%	12.37%	2.30%
6/5/1981	13.00%	12.39%	0.61%
6/10/1981	16.75%	12.42%	4.33%

Date of Electric Rate Case	Return on Equity	30-Year Treasury Yield	Risk Premium
6/17/1981	14.40%	12.46%	1.94%
6/18/1981	16.33%	12.47%	3.86%
6/25/1981	14.75%	12.51%	2.24%
6/26/1981	16.00%	12.52%	3.48%
6/30/1981	15.25%	12.54%	2.71%
7/1/1981	15.50%	12.56%	2.94%
7/1/1981	17.50%	12.56%	4.94%
7/10/1981	16.00%	12.62%	3.38%
7/14/1981	16.90%	12.64%	4.26%
7/15/1981	16.00%	12.65%	3.35%
7/17/1981	15.00%	12.67%	2.33%
7/20/1981	15.00%	12.68%	2.32%
7/21/1981	14.00%	12.69%	1.31%
7/28/1981	13.48%	12.74%	0.74%
7/31/1981	13.50%	12.78%	0.72%
7/31/1981	15.00%	12.78%	2.22%
7/31/1981	16.00%	12.78%	3.22%
8/5/1981	15.71%	12.83%	2.88%
8/10/1981	14.50%	12.87%	1.63%
8/11/1981	15.00%	12.88%	2.12%
8/20/1981	13.50%	12.95%	0.55%
8/20/1981	16.50%	12.95%	3.55%
8/24/1981	15.00%	12.97%	2.03%
8/28/1981	15.00%	13.01%	1.99%
9/3/1981	14.50%	13.05%	1.45%
9/10/1981	14.50%	13.11%	1.39%
9/11/1981	16.00%	13.12%	2.88%
9/16/1981	16.00%	13.15%	2.85%
9/17/1981	16.50%	13.16%	3.34%
9/23/1981	15.85%	13.20%	2.65%
9/28/1981	15.50%	13.23%	2.27%
10/9/1981	15.75%	13.33%	2.42%
10/15/1981	16.25%	13.37%	2.88%
10/16/1981	15.50%	13.38%	2.12%
10/16/1981	16.50%	13.38%	3.12%
10/19/1981	14.25%	13.39%	0.86%
10/20/1981	15.25%	13.41%	1.84%
10/20/1981	17.00%	13.41%	3.59%
10/23/1981	16.00%	13.45%	2.55%
10/27/1981	10.00%	13.48%	-3.48%
10/29/1981	14.75%	13.51%	1.24%
10/29/1981	16.50%	13.51%	2.99%
11/3/1981	15.17%	13.53%	1.64%
11/5/1981	16.60%	13.55%	3.05%
11/6/1981	15.17%	13.56%	1.61%
11/24/1981	15.50%	13.61%	1.89%
11/25/1981	15.25%	13.61%	1.64%
11/25/1981	15.35%	13.61%	1.74%
11/25/1981	16.10%	13.61%	2.49%
11/25/1981	16.10%	13.61%	2.49%
12/1/1981	15.70%	13.61%	2.09%
12/1/1981	16.00%	13.61%	2.39%
12/1/1981	16.49%	13.61%	2.88%
12/1/1981	16.50%	13.61%	2.89%

Date of Electric Rate Case	Return on Equity	30-Year Treasury Yield	Risk Premium
12/4/1981	16.00%	13.61%	2.39%
12/11/1981	16.25%	13.63%	2.62%
12/14/1981	14.00%	13.63%	0.37%
12/15/1981	15.81%	13.63%	2.18%
12/15/1981	16.00%	13.63%	2.37%
12/16/1981	15.25%	13.63%	1.62%
12/17/1981	16.50%	13.63%	2.87%
12/18/1981	15.45%	13.63%	1.82%
12/30/1981	14.25%	13.67%	0.58%
12/30/1981	16.00%	13.67%	2.33%
12/30/1981	16.25%	13.67%	2.58%
12/31/1981	16.15%	13.67%	2.48%
1/4/1982	15.50%	13.67%	1.83%
1/11/1982	14.50%	13.72%	0.78%
1/11/1982	17.00%	13.72%	3.28%
1/13/1982	14.75%	13.74%	1.01%
1/14/1982	15.75%	13.75%	2.00%
1/15/1982	15.00%	13.76%	1.24%
1/15/1982	16.50%	13.76%	2.74%
1/22/1982	16.25%	13.79%	2.46%
1/27/1982	16.84%	13.81%	3.03%
1/28/1982	13.00%	13.81%	-0.81%
1/29/1982	15.50%	13.82%	1.68%
2/1/1982	15.85%	13.82%	2.03%
2/3/1982	16.44%	13.84%	2.60%
2/8/1982	15.50%	13.86%	1.64%
2/11/1982	16.00%	13.88%	2.12%
2/11/1982	16.20%	13.88%	2.32%
2/17/1982	15.00%	13.89%	1.11%
2/19/1982	15.17%	13.89%	1.28%
2/26/1982	15.25%	13.89%	1.36%
3/1/1982	15.03%	13.89%	1.14%
3/1/1982	16.00%	13.89%	2.11%
3/3/1982	15.00%	13.88%	1.12%
3/8/1982	17.10%	13.88%	3.22%
3/12/1982	16.25%	13.88%	2.37%
3/17/1982	17.30%	13.88%	3.42%
3/22/1982	15.10%	13.89%	1.21%
3/27/1982	15.40%	13.89%	1.51%
3/30/1982	15.50%	13.90%	1.60%
3/31/1982	17.00%	13.91%	3.09%
4/1/1982	14.70%	13.91%	0.79%
4/1/1982	16.50%	13.91%	2.59%
4/2/1982	15.50%	13.91%	1.59%
4/5/1982	15.50%	13.92%	1.58%
4/8/1982	16.40%	13.93%	2.47%
4/13/1982	14.50%	13.94%	0.56%
4/23/1982	15.75%	13.94%	1.81%
4/27/1982	15.00%	13.94%	1.06%
4/28/1982	15.75%	13.94%	1.81%
4/30/1982	14.70%	13.94%	0.76%
4/30/1982	15.50%	13.94%	1.56%
5/3/1982	16.60%	13.94%	2.66%
5/4/1982	16.00%	13.94%	2.06%

Date of Electric Rate Case	Return on Equity	30-Year Treasury Yield	Risk Premium
5/14/1982	15.50%	13.92%	1.58%
5/18/1982	15.42%	13.92%	1.50%
5/19/1982	14.69%	13.92%	0.77%
5/20/1982	15.00%	13.91%	1.09%
5/20/1982	15.10%	13.91%	1.19%
5/20/1982	15.50%	13.91%	1.59%
5/20/1982	16.30%	13.91%	2.39%
5/21/1982	17.75%	13.91%	3.84%
5/27/1982	15.00%	13.89%	1.11%
5/28/1982	15.50%	13.89%	1.61%
5/28/1982	17.00%	13.89%	3.11%
6/1/1982	13.75%	13.89%	-0.14%
6/1/1982	16.60%	13.89%	2.71%
6/9/1982	17.86%	13.88%	3.98%
6/14/1982	15.75%	13.88%	1.87%
6/15/1982	14.85%	13.88%	0.97%
6/18/1982	15.50%	13.87%	1.63%
6/21/1982	14.90%	13.87%	1.03%
6/23/1982	16.00%	13.86%	2.14%
6/23/1982	16.17%	13.86%	2.31%
6/24/1982	14.85%	13.86%	0.99%
6/25/1982	14.70%	13.86%	0.84%
7/1/1982	16.00%	13.84%	2.16%
7/2/1982	15.62%	13.84%	1.78%
7/2/1982	17.00%	13.84%	3.16%
7/13/1982	14.00%	13.82%	0.18%
7/13/1982	16.80%	13.82%	2.98%
7/14/1982	15.76%	13.82%	1.94%
7/14/1982	16.02%	13.82%	2.20%
7/19/1982	16.50%	13.80%	2.70%
7/22/1982	14.50%	13.77%	0.73%
7/22/1982	17.00%	13.77%	3.23%
7/27/1982	16.75%	13.75%	3.00%
7/29/1982	16.50%	13.74%	2.76%
8/11/1982	17.50%	13.68%	3.82%
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8/20/1982	15.73%	13.60%	2.13%
8/25/1982	16.00%	13.57%	2.43%
8/26/1982	15.50%	13.56%	1.94%
8/30/1982	15.00%	13.55%	1.45%
9/3/1982	16.20%	13.53%	2.67%
9/8/1982	15.00%	13.52%	1.48%
9/15/1982	13.08%	13.50%	-0.42%
9/15/1982	16.25%	13.50%	2.75%
9/16/1982	16.00%	13.50%	2.50%
9/17/1982	15.25%	13.50%	1.75%
9/23/1982	17.17%	13.47%	3.70%
9/24/1982	14.50%	13.46%	1.04%
9/27/1982	15.25%	13.46%	1.79%
10/1/1982	15.50%	13.42%	2.08%
10/15/1982	15.90%	13.32%	2.58%
10/22/1982	15.75%	13.24%	2.51%
10/22/1982	17.15%	13.24%	3.91%
10/29/1982	15.54%	13.16%	2.38%

Date of Electric Rate Case	Return on Equity	30-Year Treasury Yield	Risk Premium
11/1/1982	15.50%	13.15%	2.35%
11/3/1982	17.20%	13.13%	4.07%
11/4/1982	16.25%	13.11%	3.14%
11/5/1982	16.20%	13.09%	3.11%
11/9/1982	16.00%	13.05%	2.95%
11/23/1982	15.50%	12.89%	2.61%
11/23/1982	15.85%	12.89%	2.96%
11/30/1982	16.50%	12.81%	3.69%
12/1/1982	17.04%	12.79%	4.25%
12/6/1982	15.00%	12.73%	2.27%
12/6/1982	16.35%	12.73%	3.62%
12/10/1982	15.50%	12.66%	2.84%
12/13/1982	16.00%	12.65%	3.35%
12/14/1982	15.30%	12.63%	2.67%
12/14/1982	16.40%	12.63%	3.77%
12/20/1982	16.00%	12.57%	3.43%
12/21/1982	14.75%	12.56%	2.19%
12/21/1982	15.85%	12.56%	3.29%
12/22/1982	16.25%	12.54%	3.71%
12/22/1982	16.58%	12.54%	4.04%
12/22/1982	16.75%	12.54%	4.21%
12/29/1982	14.90%	12.48%	2.42%
12/29/1982	16.25%	12.48%	3.77%
12/30/1982	16.00%	12.47%	3.53%
12/30/1982	16.35%	12.47%	3.88%
12/30/1982	16.77%	12.47%	4.30%
1/5/1983	17.33%	12.40%	4.93%
1/11/1983	15.90%	12.34%	3.56%
1/12/1983	14.63%	12.33%	2.30%
1/12/1983	15.50%	12.33%	3.17%
1/20/1983	17.75%	12.24%	5.51%
1/21/1983	15.00%	12.22%	2.78%
1/24/1983	14.50%	12.21%	2.29%
1/24/1983	15.50%	12.21%	3.29%
1/25/1983	15.85%	12.19%	3.66%
1/27/1983	16.14%	12.17%	3.97%
2/1/1983	18.50%	12.13%	6.37%
2/4/1983	14.00%	12.10%	1.90%
2/10/1983	15.00%	12.06%	2.94%
2/21/1983	15.50%	11.98%	3.52%
2/22/1983	15.50%	11.97%	3.53%
2/23/1983	15.10%	11.96%	3.14%
2/23/1983	16.00%	11.96%	4.04%
3/2/1983	15.25%	11.89%	3.36%
3/9/1983	15.20%	11.82%	3.38%
3/15/1983	13.00%	11.77%	1.23%
3/18/1983	15.25%	11.73%	3.52%
3/23/1983	15.40%	11.69%	3.71%
3/24/1983	15.00%	11.67%	3.33%
3/29/1983	15.50%	11.63%	3.87%
3/30/1983	16.71%	11.61%	5.10%
3/31/1983	15.00%	11.59%	3.41%
4/4/1983	15.20%	11.58%	3.62%
4/8/1983	15.50%	11.51%	3.99%

Date of Electric Rate Case	Return on Equity	30-Year Treasury Yield	Risk Premium
4/11/1983	14.81%	11.49%	3.32%
4/19/1983	14.50%	11.38%	3.12%
4/20/1983	16.00%	11.36%	4.64%
4/29/1983	16.00%	11.24%	4.76%
5/1/1983	14.50%	11.24%	3.26%
5/9/1983	15.50%	11.15%	4.35%
5/11/1983	16.46%	11.12%	5.34%
5/12/1983	14.14%	11.11%	3.03%
5/18/1983	15.00%	11.05%	3.95%
5/23/1983	14.90%	11.01%	3.89%
5/23/1983	15.50%	11.01%	4.49%
5/25/1983	15.50%	10.98%	4.52%
5/27/1983	15.00%	10.96%	4.04%
5/31/1983	14.00%	10.95%	3.05%
5/31/1983	15.50%	10.95%	4.55%
6/2/1983	14.50%	10.93%	3.57%
6/17/1983	15.03%	10.84%	4.19%
7/1/1983	14.80%	10.78%	4.02%
7/1/1983	14.90%	10.78%	4.12%
7/8/1983	16.25%	10.76%	5.49%
7/13/1983	13.20%	10.75%	2.45%
7/19/1983	15.00%	10.74%	4.26%
7/19/1983	15.10%	10.74%	4.36%
7/25/1983	16.25%	10.73%	5.52%
7/28/1983	15.90%	10.74%	5.16%
8/3/1983	16.34%	10.75%	5.59%
8/3/1983	16.50%	10.75%	5.75%
8/19/1983	15.00%	10.80%	4.20%
8/22/1983	15.50%	10.80%	4.70%
8/22/1983	16.40%	10.80%	5.60%
8/31/1983	14.75%	10.84%	3.91%
9/7/1983	15.00%	10.86%	4.14%
9/14/1983	15.78%	10.89%	4.89%
9/16/1983	15.00%	10.90%	4.10%
9/19/1983	14.50%	10.91%	3.59%
9/20/1983	16.50%	10.91%	5.59%
9/28/1983	14.50%	10.94%	3.56%
9/29/1983	15.50%	10.95%	4.55%
9/30/1983	15.25%	10.95%	4.30%
9/30/1983	16.15%	10.95%	5.20%
10/4/1983	14.80%	10.96%	3.84%
10/7/1983	16.00%	10.97%	5.03%
10/13/1983	15.52%	10.99%	4.53%
10/17/1983	15.50%	11.00%	4.50%
10/18/1983	14.50%	11.00%	3.50%
10/19/1983	16.25%	11.01%	5.24%
10/19/1983	16.50%	11.01%	5.49%
10/26/1983	15.00%	11.04%	3.96%
10/27/1983	15.20%	11.04%	4.16%
11/1/1983	16.00%	11.06%	4.94%
11/9/1983	14.90%	11.09%	3.81%
11/10/1983	14.35%	11.10%	3.25%
11/23/1983	16.00%	11.13%	4.87%
11/23/1983	16.15%	11.13%	5.02%

Date of Electric Rate Case	Return on Equity	30-Year Treasury Yield	Risk Premium
11/30/1983	15.00%	11.14%	3.86%
12/5/1983	15.25%	11.15%	4.10%
12/6/1983	15.07%	11.15%	3.92%
12/8/1983	15.90%	11.16%	4.74%
12/9/1983	14.75%	11.17%	3.58%
12/12/1983	14.50%	11.17%	3.33%
12/15/1983	15.56%	11.19%	4.37%
12/19/1983	14.80%	11.21%	3.59%
12/20/1983	14.69%	11.22%	3.47%
12/20/1983	16.00%	11.22%	4.78%
12/20/1983	16.25%	11.22%	5.03%
12/22/1983	14.75%	11.23%	3.52%
12/22/1983	15.75%	11.23%	4.52%
1/3/1984	14.75%	11.27%	3.48%
1/10/1984	15.90%	11.30%	4.60%
1/12/1984	15.60%	11.31%	4.29%
1/18/1984	13.75%	11.33%	2.42%
1/19/1984	15.90%	11.33%	4.57%
1/30/1984	16.10%	11.37%	4.73%
1/31/1984	15.25%	11.37%	3.88%
2/1/1984	14.80%	11.38%	3.42%
2/6/1984	13.75%	11.40%	2.35%
2/6/1984	14.75%	11.40%	3.35%
2/9/1984	15.25%	11.42%	3.83%
2/15/1984	15.70%	11.44%	4.26%
2/20/1984	15.00%	11.46%	3.54%
2/20/1984	15.00%	11.46%	3.54%
2/22/1984	14.75%	11.47%	3.28%
2/28/1984	14.50%	11.51%	2.99%
3/2/1984	14.25%	11.54%	2.71%
3/20/1984	16.00%	11.64%	4.36%
3/23/1984	15.50%	11.67%	3.83%
3/26/1984	14.71%	11.68%	3.03%
4/2/1984	15.50%	11.71%	3.79%
4/6/1984	14.74%	11.75%	2.99%
4/11/1984	15.72%	11.78%	3.94%
4/17/1984	15.00%	11.81%	3.19%
4/18/1984	16.20%	11.82%	4.38%
4/25/1984	14.64%	11.85%	2.79%
4/30/1984	14.40%	11.87%	2.53%
5/16/1984	14.69%	11.98%	2.71%
5/16/1984	15.00%	11.98%	3.02%
5/22/1984	14.40%	12.02%	2.38%
5/29/1984	15.10%	12.06%	3.04%
6/13/1984	15.25%	12.15%	3.10%
6/15/1984	15.60%	12.17%	3.43%
6/22/1984	16.25%	12.21%	4.04%
6/29/1984	15.25%	12.26%	2.99%
7/2/1984	13.35%	12.27%	1.08%
7/10/1984	16.00%	12.31%	3.69%
7/12/1984	16.50%	12.32%	4.18%
7/13/1984	16.25%	12.33%	3.92%
7/17/1984	14.14%	12.35%	1.79%
7/18/1984	15.30%	12.36%	2.94%

Date of Electric Rate Case	Return on Equity	30-Year Treasury Yield	Risk Premium
7/18/1984	15.50%	12.36%	3.14%
7/19/1984	14.30%	12.37%	1.93%
7/24/1984	16.79%	12.39%	4.40%
7/31/1984	16.00%	12.43%	3.57%
8/3/1984	14.25%	12.44%	1.81%
8/17/1984	14.30%	12.49%	1.81%
8/20/1984	15.00%	12.49%	2.51%
8/27/1984	16.30%	12.51%	3.79%
8/31/1984	15.55%	12.52%	3.03%
9/6/1984	16.00%	12.53%	3.47%
9/10/1984	14.75%	12.54%	2.21%
9/13/1984	15.00%	12.55%	2.45%
9/17/1984	17.38%	12.56%	4.82%
9/26/1984	14.50%	12.57%	1.93%
9/28/1984	15.00%	12.57%	2.43%
9/28/1984	16.25%	12.57%	3.68%
10/9/1984	14.75%	12.58%	2.17%
10/12/1984	15.60%	12.59%	3.01%
10/22/1984	15.00%	12.59%	2.41%
10/26/1984	16.40%	12.58%	3.82%
10/31/1984	16.25%	12.58%	3.67%
11/7/1984	15.60%	12.58%	3.02%
11/9/1984	16.00%	12.58%	3.42%
11/14/1984	15.75%	12.58%	3.17%
11/20/1984	15.25%	12.58%	2.67%
11/20/1984	15.92%	12.58%	3.34%
11/23/1984	15.00%	12.58%	2.42%
11/28/1984	16.15%	12.57%	3.58%
12/3/1984	15.80%	12.56%	3.24%
12/4/1984	16.50%	12.56%	3.94%
12/18/1984	16.40%	12.53%	3.87%
12/19/1984	14.75%	12.53%	2.22%
12/19/1984	15.00%	12.53%	2.47%
12/20/1984	16.00%	12.53%	3.47%
12/28/1984	16.00%	12.50%	3.50%
1/3/1985	14.75%	12.49%	2.26%
1/10/1985	15.75%	12.47%	3.28%
1/11/1985	16.30%	12.46%	3.84%
1/23/1985	15.80%	12.43%	3.37%
1/24/1985	15.82%	12.43%	3.39%
1/25/1985	16.75%	12.42%	4.33%
1/30/1985	14.90%	12.40%	2.50%
1/31/1985	14.75%	12.39%	2.36%
2/8/1985	14.47%	12.35%	2.12%
3/1/1985	13.84%	12.31%	1.53%
3/8/1985	16.85%	12.28%	4.57%
3/14/1985	15.50%	12.25%	3.25%
3/15/1985	15.62%	12.25%	3.37%
3/29/1985	15.62%	12.17%	3.45%
4/3/1985	14.60%	12.14%	2.46%
4/9/1985	15.50%	12.11%	3.39%
4/16/1985	15.70%	12.06%	3.64%
4/22/1985	14.00%	12.02%	1.98%
4/26/1985	15.50%	11.98%	3.52%

Date of Electric Rate Case	Return on Equity	30-Year Treasury Yield	Risk Premium
4/29/1985	15.00%	11.97%	3.03%
5/2/1985	14.68%	11.94%	2.74%
5/8/1985	15.62%	11.89%	3.73%
5/10/1985	16.50%	11.87%	4.63%
5/29/1985	14.61%	11.73%	2.88%
5/31/1985	16.00%	11.71%	4.29%
6/14/1985	15.50%	11.61%	3.89%
7/9/1985	15.00%	11.45%	3.55%
7/16/1985	14.50%	11.39%	3.11%
7/26/1985	14.50%	11.33%	3.17%
8/2/1985	14.80%	11.29%	3.51%
8/7/1985	15.00%	11.27%	3.73%
8/28/1985	14.25%	11.15%	3.10%
8/28/1985	15.50%	11.15%	4.35%
8/29/1985	14.50%	11.15%	3.35%
9/9/1985	14.60%	11.11%	3.49%
9/9/1985	14.90%	11.11%	3.79%
9/17/1985	14.90%	11.08%	3.82%
9/23/1985	15.00%	11.06%	3.94%
9/27/1985	15.50%	11.05%	4.45%
9/27/1985	15.80%	11.05%	4.75%
10/2/1985	14.00%	11.03%	2.97%
10/2/1985	14.75%	11.03%	3.72%
10/3/1985	15.25%	11.03%	4.22%
10/24/1985	15.40%	10.96%	4.44%
10/24/1985	15.82%	10.96%	4.86%
10/24/1985	15.85%	10.96%	4.89%
10/28/1985	16.00%	10.95%	5.05%
10/29/1985	16.65%	10.94%	5.71%
10/31/1985	15.06%	10.93%	4.13%
11/4/1985	14.50%	10.92%	3.58%
11/7/1985	15.50%	10.90%	4.60%
11/8/1985	14.30%	10.89%	3.41%
12/12/1985	14.75%	10.73%	4.02%
12/18/1985	15.00%	10.69%	4.31%
12/20/1985	14.50%	10.67%	3.83%
12/20/1985	14.50%	10.67%	3.83%
12/20/1985	15.00%	10.67%	4.33%
1/24/1986	15.40%	10.41%	4.99%
1/31/1986	15.00%	10.35%	4.65%
2/5/1986	15.00%	10.32%	4.68%
2/5/1986	15.75%	10.32%	5.43%
2/10/1986	13.30%	10.29%	3.01%
2/11/1986	12.50%	10.28%	2.22%
2/14/1986	14.40%	10.24%	4.16%
2/18/1986	16.00%	10.23%	5.77%
2/24/1986	14.50%	10.18%	4.32%
2/26/1986	14.00%	10.15%	3.85%
3/5/1986	14.90%	10.08%	4.82%
3/11/1986	14.50%	10.02%	4.48%
3/12/1986	13.50%	10.00%	3.50%
3/27/1986	14.10%	9.86%	4.24%
3/31/1986	13.50%	9.84%	3.66%
4/1/1986	14.00%	9.83%	4.17%

Date of Electric Rate Case	Return on Equity	30-Year Treasury Yield	Risk Premium
4/2/1986	15.50%	9.81%	5.69%
4/4/1986	15.00%	9.78%	5.22%
4/14/1986	13.40%	9.69%	3.71%
4/23/1986	15.00%	9.57%	5.43%
5/16/1986	14.50%	9.32%	5.18%
5/16/1986	14.50%	9.32%	5.18%
5/29/1986	13.90%	9.19%	4.71%
5/30/1986	15.10%	9.18%	5.92%
6/2/1986	12.81%	9.17%	3.64%
6/11/1986	14.00%	9.07%	4.93%
6/24/1986	16.63%	8.94%	7.69%
6/26/1986	12.00%	8.91%	3.09%
6/26/1986	14.75%	8.91%	5.84%
6/30/1986	13.00%	8.87%	4.13%
7/10/1986	14.34%	8.75%	5.59%
7/11/1986	12.75%	8.73%	4.02%
7/14/1986	12.60%	8.71%	3.89%
7/17/1986	12.40%	8.66%	3.74%
7/25/1986	14.25%	8.57%	5.68%
8/6/1986	13.50%	8.44%	5.06%
8/14/1986	13.50%	8.35%	5.15%
9/16/1986	12.75%	8.06%	4.69%
9/19/1986	13.25%	8.03%	5.22%
10/1/1986	14.00%	7.95%	6.05%
10/3/1986	13.40%	7.93%	5.47%
10/31/1986	13.50%	7.77%	5.73%
11/5/1986	13.00%	7.75%	5.25%
12/3/1986	12.90%	7.58%	5.32%
12/4/1986	14.44%	7.58%	6.86%
12/16/1986	13.60%	7.52%	6.08%
12/22/1986	13.80%	7.51%	6.29%
12/30/1986	13.00%	7.49%	5.51%
1/2/1987	13.00%	7.49%	5.51%
1/12/1987	12.40%	7.47%	4.93%
1/27/1987	12.71%	7.46%	5.25%
3/2/1987	12.47%	7.47%	5.00%
3/3/1987	13.60%	7.47%	6.13%
3/4/1987	12.38%	7.47%	4.91%
3/10/1987	13.50%	7.47%	6.03%
3/13/1987	13.00%	7.47%	5.53%
3/31/1987	13.00%	7.46%	5.54%
4/6/1987	13.00%	7.47%	5.53%
4/14/1987	12.50%	7.49%	5.01%
4/16/1987	14.50%	7.50%	7.00%
4/27/1987	12.00%	7.54%	4.46%
5/5/1987	12.85%	7.58%	5.27%
5/12/1987	12.65%	7.62%	5.03%
5/28/1987	13.50%	7.70%	5.80%
6/15/1987	13.20%	7.78%	5.42%
6/29/1987	15.00%	7.83%	7.17%
6/30/1987	12.50%	7.84%	4.66%
7/8/1987	12.00%	7.86%	4.14%
7/10/1987	12.90%	7.86%	5.04%
7/15/1987	13.50%	7.88%	5.62%

Date of Electric Rate Case	Return on Equity	30-Year Treasury Yield	Risk Premium
7/16/1987	13.50%	7.88%	5.62%
7/16/1987	15.00%	7.88%	7.12%
7/27/1987	13.00%	7.92%	5.08%
7/27/1987	13.40%	7.92%	5.48%
7/27/1987	13.50%	7.92%	5.58%
7/31/1987	12.98%	7.95%	5.03%
8/26/1987	12.63%	8.06%	4.57%
8/26/1987	12.75%	8.06%	4.69%
8/27/1987	13.25%	8.06%	5.19%
9/9/1987	13.00%	8.14%	4.86%
9/30/1987	12.75%	8.31%	4.44%
9/30/1987	13.00%	8.31%	4.69%
10/2/1987	11.50%	8.33%	3.17%
10/15/1987	13.00%	8.43%	4.57%
11/2/1987	13.00%	8.55%	4.45%
11/19/1987	13.00%	8.64%	4.36%
11/30/1987	12.00%	8.68%	3.32%
12/3/1987	14.20%	8.70%	5.50%
12/15/1987	13.25%	8.77%	4.48%
12/16/1987	13.50%	8.78%	4.72%
12/16/1987	13.72%	8.78%	4.94%
12/17/1987	11.75%	8.79%	2.96%
12/18/1987	13.50%	8.80%	4.70%
12/21/1987	12.01%	8.81%	3.20%
12/22/1987	12.00%	8.81%	3.19%
12/22/1987	12.00%	8.81%	3.19%
12/22/1987	12.75%	8.81%	3.94%
12/22/1987	13.00%	8.81%	4.19%
1/20/1988	13.80%	8.94%	4.86%
1/26/1988	13.90%	8.95%	4.95%
1/29/1988	13.20%	8.96%	4.24%
2/4/1988	12.60%	8.96%	3.64%
3/1/1988	11.56%	8.94%	2.62%
3/23/1988	12.87%	8.92%	3.95%
3/24/1988	11.24%	8.92%	2.32%
3/30/1988	12.72%	8.92%	3.80%
4/1/1988	12.50%	8.92%	3.58%
4/7/1988	13.25%	8.93%	4.32%
4/25/1988	10.96%	8.96%	2.00%
5/3/1988	12.91%	8.97%	3.94%
5/11/1988	13.50%	8.99%	4.51%
5/16/1988	13.00%	8.99%	4.01%
6/30/1988	12.75%	9.00%	3.75%
7/1/1988	12.75%	8.99%	3.76%
7/20/1988	13.40%	8.96%	4.44%
8/5/1988	12.75%	8.92%	3.83%
8/23/1988	11.70%	8.93%	2.77%
8/29/1988	12.75%	8.94%	3.81%
8/30/1988	13.50%	8.94%	4.56%
9/8/1988	12.60%	8.95%	3.65%
10/13/1988	13.10%	8.93%	4.17%
12/19/1988	13.00%	9.02%	3.98%
12/20/1988	12.25%	9.02%	3.23%
12/20/1988	13.00%	9.02%	3.98%

Date of Electric Rate Case	Return on Equity	30-Year Treasury Yield	Risk Premium
12/21/1988	12.90%	9.02%	3.88%
12/27/1988	13.00%	9.03%	3.97%
12/28/1988	13.10%	9.03%	4.07%
12/30/1988	13.40%	9.04%	4.36%
1/27/1989	13.00%	9.05%	3.95%
1/31/1989	13.00%	9.05%	3.95%
2/17/1989	13.00%	9.05%	3.95%
2/20/1989	12.40%	9.05%	3.35%
3/1/1989	12.76%	9.05%	3.71%
3/8/1989	13.00%	9.05%	3.95%
3/30/1989	14.00%	9.05%	4.95%
4/5/1989	14.20%	9.05%	5.15%
4/18/1989	13.00%	9.05%	3.95%
5/5/1989	12.40%	9.05%	3.35%
6/2/1989	13.20%	9.00%	4.20%
6/8/1989	13.50%	8.98%	4.52%
6/27/1989	13.25%	8.91%	4.34%
6/30/1989	13.00%	8.90%	4.10%
8/14/1989	12.50%	8.77%	3.73%
9/28/1989	12.25%	8.63%	3.62%
10/24/1989	12.50%	8.54%	3.96%
11/9/1989	13.00%	8.49%	4.51%
12/15/1989	13.00%	8.34%	4.66%
12/20/1989	12.90%	8.32%	4.58%
12/21/1989	12.90%	8.31%	4.59%
12/27/1989	12.50%	8.29%	4.21%
12/27/1989	13.00%	8.29%	4.71%
1/10/1990	12.80%	8.24%	4.56%
1/11/1990	12.90%	8.24%	4.66%
1/17/1990	12.80%	8.22%	4.58%
1/26/1990	12.00%	8.20%	3.80%
2/9/1990	12.10%	8.17%	3.93%
2/24/1990	12.86%	8.15%	4.71%
3/30/1990	12.90%	8.16%	4.74%
4/4/1990	15.76%	8.17%	7.59%
4/12/1990	12.52%	8.18%	4.34%
4/19/1990	12.75%	8.20%	4.55%
5/21/1990	12.10%	8.28%	3.82%
5/29/1990	12.40%	8.30%	4.10%
5/31/1990	12.00%	8.30%	3.70%
6/4/1990	12.90%	8.30%	4.60%
6/6/1990	12.25%	8.31%	3.94%
6/15/1990	13.20%	8.32%	4.88%
6/20/1990	12.92%	8.32%	4.60%
6/27/1990	12.90%	8.33%	4.57%
6/29/1990	12.50%	8.33%	4.17%
7/6/1990	12.10%	8.34%	3.76%
7/6/1990	12.35%	8.34%	4.01%
8/10/1990	12.55%	8.41%	4.14%
8/16/1990	13.21%	8.43%	4.78%
8/22/1990	13.10%	8.45%	4.65%
8/24/1990	13.00%	8.46%	4.54%
9/26/1990	11.45%	8.59%	2.86%
10/2/1990	13.00%	8.61%	4.39%

Date of Electric Rate Case	Return on Equity	30-Year Treasury Yield	Risk Premium
10/5/1990	12.84%	8.62%	4.22%
10/19/1990	13.00%	8.67%	4.33%
10/25/1990	12.30%	8.68%	3.62%
11/21/1990	12.70%	8.69%	4.01%
12/13/1990	12.30%	8.67%	3.63%
12/17/1990	12.87%	8.67%	4.20%
12/18/1990	13.10%	8.67%	4.43%
12/19/1990	12.00%	8.66%	3.34%
12/20/1990	12.75%	8.66%	4.09%
12/21/1990	12.50%	8.66%	3.84%
12/27/1990	12.79%	8.66%	4.13%
1/2/1991	13.10%	8.65%	4.45%
1/4/1991	12.50%	8.65%	3.85%
1/15/1991	12.75%	8.64%	4.11%
1/25/1991	11.70%	8.63%	3.07%
2/4/1991	12.50%	8.60%	3.90%
2/7/1991	12.50%	8.59%	3.91%
2/12/1991	13.00%	8.58%	4.43%
2/14/1991	12.72%	8.57%	4.15%
2/22/1991	12.80%	8.55%	4.25%
3/6/1991	13.10%	8.53%	4.57%
3/8/1991	12.30%	8.52%	3.78%
3/8/1991	13.00%	8.52%	4.48%
4/22/1991	13.00%	8.49%	4.51%
5/7/1991	13.50%	8.47%	5.03%
5/13/1991	13.25%	8.47%	4.78%
5/30/1991	12.75%	8.44%	4.31%
6/12/1991	12.00%	8.41%	3.59%
6/25/1991	11.70%	8.39%	3.31%
6/28/1991	12.50%	8.38%	4.12%
7/1/1991	12.00%	8.38%	3.62%
7/3/1991	12.50%	8.37%	4.13%
7/19/1991	12.10%	8.34%	3.76%
8/1/1991	12.90%	8.32%	4.58%
8/16/1991	13.20%	8.29%	4.91%
9/27/1991	12.50%	8.23%	4.27%
9/30/1991	12.25%	8.23%	4.02%
10/17/1991	13.00%	8.20%	4.80%
10/23/1991	12.50%	8.20%	4.30%
10/23/1991	12.55%	8.20%	4.35%
10/31/1991	11.80%	8.19%	3.61%
11/1/1991	12.00%	8.19%	3.81%
11/5/1991	12.25%	8.19%	4.06%
11/12/1991	12.50%	8.18%	4.32%
11/12/1991	13.25%	8.18%	5.07%
11/25/1991	12.40%	8.18%	4.22%
11/26/1991	11.60%	8.18%	3.42%
11/26/1991	12.50%	8.18%	4.32%
11/27/1991	12.10%	8.18%	3.92%
12/18/1991	12.25%	8.15%	4.10%
12/19/1991	12.60%	8.15%	4.45%
12/19/1991	12.80%	8.15%	4.65%
12/20/1991	12.65%	8.14%	4.51%
1/9/1992	12.80%	8.09%	4.71%

Date of Electric Rate Case	Return on Equity	30-Year Treasury Yield	Risk Premium
1/16/1992	12.75%	8.07%	4.68%
1/21/1992	12.00%	8.06%	3.94%
1/22/1992	13.00%	8.06%	4.94%
1/27/1992	12.65%	8.05%	4.60%
1/31/1992	12.00%	8.04%	3.96%
2/11/1992	12.40%	8.03%	4.37%
2/25/1992	12.50%	8.01%	4.49%
3/16/1992	11.43%	7.98%	3.45%
3/18/1992	12.28%	7.98%	4.30%
4/2/1992	12.10%	7.95%	4.15%
4/9/1992	11.45%	7.94%	3.51%
4/10/1992	11.50%	7.93%	3.57%
4/14/1992	11.50%	7.93%	3.57%
5/5/1992	11.50%	7.89%	3.61%
5/12/1992	11.87%	7.88%	3.99%
5/12/1992	12.46%	7.88%	4.58%
6/1/1992	12.30%	7.87%	4.43%
6/12/1992	10.90%	7.86%	3.04%
6/26/1992	12.35%	7.85%	4.50%
6/29/1992	11.00%	7.85%	3.15%
6/30/1992	13.00%	7.85%	5.15%
7/13/1992	11.90%	7.84%	4.06%
7/13/1992	13.50%	7.84%	5.66%
7/22/1992	11.20%	7.83%	3.37%
8/3/1992	12.00%	7.81%	4.19%
8/6/1992	12.50%	7.80%	4.70%
9/22/1992	12.00%	7.71%	4.29%
9/28/1992	11.40%	7.71%	3.69%
9/30/1992	11.75%	7.70%	4.05%
10/2/1992	13.00%	7.70%	5.30%
10/12/1992	12.20%	7.70%	4.50%
10/16/1992	13.16%	7.70%	5.46%
10/30/1992	11.75%	7.71%	4.04%
11/3/1992	12.00%	7.71%	4.29%
12/3/1992	11.85%	7.68%	4.17%
12/15/1992	11.00%	7.66%	3.34%
12/16/1992	11.90%	7.66%	4.24%
12/16/1992	12.40%	7.66%	4.74%
12/17/1992	12.00%	7.66%	4.34%
12/22/1992	12.30%	7.65%	4.65%
12/22/1992	12.40%	7.65%	4.75%
12/29/1992	12.25%	7.63%	4.62%
12/30/1992	12.00%	7.63%	4.37%
12/31/1992	11.90%	7.63%	4.27%
1/12/1993	12.00%	7.61%	4.39%
1/21/1993	11.25%	7.59%	3.66%
2/2/1993	11.40%	7.56%	3.84%
2/15/1993	12.30%	7.52%	4.78%
2/24/1993	11.90%	7.49%	4.41%
2/26/1993	11.80%	7.48%	4.32%
2/26/1993	12.20%	7.48%	4.72%
4/23/1993	11.75%	7.29%	4.46%
5/11/1993	11.75%	7.25%	4.50%
5/14/1993	11.50%	7.24%	4.26%

Date of Electric Rate Case	Return on Equity	30-Year Treasury Yield	Risk Premium
5/25/1993	11.50%	7.23%	4.27%
5/28/1993	11.00%	7.22%	3.78%
6/3/1993	12.00%	7.21%	4.79%
6/16/1993	11.50%	7.19%	4.31%
6/18/1993	12.10%	7.18%	4.92%
6/25/1993	11.67%	7.17%	4.50%
7/21/1993	11.38%	7.10%	4.28%
7/23/1993	10.46%	7.09%	3.37%
8/24/1993	11.50%	6.96%	4.54%
9/21/1993	10.50%	6.81%	3.69%
9/29/1993	11.47%	6.77%	4.70%
9/30/1993	11.60%	6.76%	4.84%
11/2/1993	10.80%	6.60%	4.20%
11/12/1993	12.00%	6.57%	5.43%
11/26/1993	11.00%	6.52%	4.48%
12/14/1993	10.55%	6.48%	4.07%
12/16/1993	10.60%	6.48%	4.12%
12/21/1993	11.30%	6.47%	4.83%
1/4/1994	10.07%	6.44%	3.63%
1/13/1994	11.00%	6.42%	4.58%
1/21/1994	11.00%	6.40%	4.60%
1/28/1994	11.35%	6.39%	4.96%
2/3/1994	11.40%	6.38%	5.02%
2/17/1994	10.60%	6.36%	4.24%
2/25/1994	11.25%	6.35%	4.90%
2/25/1994	12.00%	6.35%	5.65%
3/1/1994	11.00%	6.35%	4.65%
3/4/1994	11.00%	6.35%	4.65%
4/25/1994	11.00%	6.41%	4.59%
5/10/1994	11.75%	6.45%	5.30%
5/13/1994	10.50%	6.46%	4.04%
6/3/1994	11.00%	6.54%	4.46%
6/27/1994	11.40%	6.65%	4.75%
8/5/1994	12.75%	6.88%	5.87%
10/31/1994	10.00%	7.33%	2.67%
11/9/1994	10.85%	7.39%	3.46%
11/9/1994	10.85%	7.39%	3.46%
11/18/1994	11.20%	7.45%	3.75%
11/22/1994	11.60%	7.47%	4.13%
11/28/1994	11.06%	7.49%	3.57%
12/8/1994	11.50%	7.54%	3.96%
12/8/1994	11.70%	7.54%	4.16%
12/14/1994	10.95%	7.56%	3.39%
12/15/1994	11.50%	7.57%	3.93%
12/19/1994	11.50%	7.58%	3.92%
12/28/1994	12.15%	7.61%	4.54%
1/9/1995	12.28%	7.64%	4.64%
1/31/1995	11.00%	7.69%	3.31%
2/10/1995	12.60%	7.70%	4.90%
2/17/1995	11.90%	7.70%	4.20%
3/9/1995	11.50%	7.71%	3.79%
3/20/1995	12.00%	7.72%	4.28%
3/23/1995	12.81%	7.72%	5.09%
3/29/1995	11.60%	7.72%	3.88%

Date of Electric Rate Case	Return on Equity	30-Year Treasury Yield	Risk Premium
4/6/1995	11.10%	7.71%	3.39%
4/7/1995	11.00%	7.71%	3.29%
4/19/1995	11.00%	7.70%	3.30%
5/12/1995	11.63%	7.68%	3.95%
5/25/1995	11.20%	7.65%	3.55%
6/9/1995	11.25%	7.60%	3.65%
6/21/1995	12.25%	7.56%	4.69%
6/30/1995	11.10%	7.52%	3.58%
9/11/1995	11.30%	7.20%	4.10%
9/27/1995	11.30%	7.12%	4.18%
9/27/1995	11.50%	7.12%	4.38%
9/27/1995	11.75%	7.12%	4.63%
9/29/1995	11.00%	7.11%	3.89%
11/9/1995	11.38%	6.90%	4.48%
11/9/1995	12.36%	6.90%	5.46%
11/17/1995	11.00%	6.86%	4.14%
12/4/1995	11.35%	6.78%	4.57%
12/11/1995	11.40%	6.74%	4.66%
12/20/1995	11.60%	6.70%	4.90%
12/27/1995	12.00%	6.66%	5.34%
2/5/1996	12.25%	6.48%	5.77%
3/29/1996	10.67%	6.42%	4.25%
4/8/1996	11.00%	6.42%	4.58%
4/11/1996	12.59%	6.43%	6.16%
4/11/1996	12.59%	6.43%	6.16%
4/24/1996	11.25%	6.43%	4.82%
4/30/1996	11.00%	6.43%	4.57%
5/13/1996	11.00%	6.44%	4.56%
5/23/1996	11.25%	6.43%	4.82%
6/25/1996	11.25%	6.48%	4.77%
6/27/1996	11.20%	6.48%	4.72%
8/12/1996	10.40%	6.57%	3.83%
9/27/1996	11.00%	6.71%	4.29%
10/16/1996	12.25%	6.76%	5.49%
11/5/1996	11.00%	6.81%	4.19%
11/26/1996	11.30%	6.83%	4.47%
12/18/1996	11.75%	6.83%	4.92%
12/31/1996	11.50%	6.83%	4.67%
1/3/1997	10.70%	6.83%	3.87%
2/13/1997	11.80%	6.82%	4.98%
2/20/1997	11.80%	6.82%	4.98%
3/31/1997	10.02%	6.80%	3.22%
4/2/1997	11.65%	6.80%	4.85%
4/28/1997	11.50%	6.81%	4.69%
4/29/1997	11.70%	6.81%	4.89%
7/17/1997	12.00%	6.77%	5.23%
12/12/1997	11.00%	6.60%	4.40%
12/23/1997	11.12%	6.57%	4.55%
2/2/1998	12.75%	6.39%	6.36%
3/2/1998	11.25%	6.29%	4.96%
3/6/1998	10.75%	6.27%	4.48%
3/20/1998	10.50%	6.22%	4.28%
4/30/1998	12.20%	6.12%	6.08%
7/10/1998	11.40%	5.94%	5.46%

Date of Electric Rate Case	Return on Equity	30-Year Treasury Yield	Risk Premium
9/15/1998	11.90%	5.78%	6.12%
11/30/1998	12.60%	5.58%	7.02%
12/10/1998	12.20%	5.54%	6.66%
12/17/1998	12.10%	5.52%	6.58%
2/5/1999	10.30%	5.38%	4.92%
3/4/1999	10.50%	5.34%	5.16%
4/6/1999	10.94%	5.32%	5.62%
7/29/1999	10.75%	5.52%	5.23%
9/23/1999	10.75%	5.70%	5.05%
11/17/1999	11.10%	5.90%	5.20%
1/7/2000	11.50%	6.05%	5.45%
1/7/2000	11.50%	6.05%	5.45%
2/17/2000	10.60%	6.17%	4.43%
3/28/2000	11.25%	6.20%	5.05%
5/24/2000	11.00%	6.18%	4.82%
7/18/2000	12.20%	6.16%	6.04%
9/29/2000	11.16%	6.03%	5.13%
11/28/2000	12.90%	5.89%	7.01%
11/30/2000	12.10%	5.88%	6.22%
1/23/2001	11.25%	5.79%	5.46%
2/8/2001	11.50%	5.77%	5.73%
5/8/2001	10.75%	5.62%	5.13%
6/26/2001	11.00%	5.62%	5.38%
7/25/2001	11.02%	5.60%	5.42%
7/25/2001	11.02%	5.60%	5.42%
7/31/2001	11.00%	5.59%	5.41%
8/31/2001	10.50%	5.56%	4.94%
9/7/2001	10.75%	5.55%	5.20%
9/10/2001	11.00%	5.55%	5.45%
9/20/2001	10.00%	5.55%	4.45%
10/24/2001	10.30%	5.54%	4.76%
11/28/2001	10.60%	5.49%	5.11%
12/3/2001	12.88%	5.49%	7.39%
12/20/2001	12.50%	5.50%	7.00%
1/22/2002	10.00%	5.50%	4.50%
3/27/2002	10.10%	5.45%	4.65%
4/22/2002	11.80%	5.45%	6.35%
5/28/2002	10.17%	5.46%	4.71%
6/10/2002	12.00%	5.47%	6.53%
6/18/2002	11.16%	5.48%	5.68%
6/20/2002	11.00%	5.48%	5.52%
6/20/2002	12.30%	5.48%	6.82%
7/15/2002	11.00%	5.48%	5.52%
9/12/2002	12.30%	5.45%	6.85%
9/26/2002	10.45%	5.41%	5.04%
12/4/2002	11.55%	5.29%	6.26%
12/13/2002	11.75%	5.27%	6.48%
12/20/2002	11.40%	5.25%	6.15%
1/8/2003	11.10%	5.19%	5.91%
1/31/2003	12.45%	5.13%	7.32%
2/28/2003	12.30%	5.05%	7.25%
3/6/2003	10.75%	5.03%	5.72%
3/7/2003	9.96%	5.02%	4.94%
3/20/2003	12.00%	4.98%	7.02%

Date of Electric Rate Case	Return on Equity	30-Year Treasury Yield	Risk Premium
4/3/2003	12.00%	4.96%	7.04%
4/15/2003	11.15%	4.94%	6.21%
6/25/2003	10.75%	4.79%	5.96%
6/26/2003	10.75%	4.79%	5.96%
7/9/2003	9.75%	4.79%	4.96%
7/16/2003	9.75%	4.79%	4.96%
7/25/2003	9.50%	4.80%	4.70%
8/26/2003	10.50%	4.83%	5.67%
12/17/2003	9.85%	4.94%	4.91%
12/17/2003	10.70%	4.94%	5.76%
12/18/2003	11.50%	4.94%	6.56%
12/19/2003	12.00%	4.94%	7.06%
12/19/2003	12.00%	4.94%	7.06%
12/23/2003	10.50%	4.94%	5.56%
1/13/2004	12.00%	4.95%	7.05%
3/2/2004	10.75%	4.99%	5.76%
3/26/2004	10.25%	5.02%	5.23%
4/5/2004	11.25%	5.03%	6.22%
5/18/2004	10.50%	5.07%	5.43%
5/25/2004	10.25%	5.08%	5.17%
5/27/2004	10.25%	5.08%	5.17%
6/2/2004	11.22%	5.08%	6.14%
6/30/2004	10.50%	5.10%	5.40%
6/30/2004	10.50%	5.10%	5.40%
7/16/2004	11.60%	5.11%	6.49%
8/25/2004	10.25%	5.10%	5.15%
9/9/2004	10.40%	5.10%	5.30%
11/9/2004	10.50%	5.07%	5.43%
11/23/2004	11.00%	5.06%	5.94%
12/14/2004	10.97%	5.07%	5.90%
12/21/2004	11.25%	5.07%	6.18%
12/21/2004	11.50%	5.07%	6.43%
12/22/2004	10.70%	5.07%	5.63%
12/22/2004	11.50%	5.07%	6.43%
12/29/2004	9.85%	5.07%	4.78%
1/6/2005	10.70%	5.08%	5.62%
2/18/2005	10.30%	4.98%	5.32%
2/25/2005	10.50%	4.96%	5.54%
3/10/2005	11.00%	4.93%	6.07%
3/24/2005	10.30%	4.90%	5.40%
4/4/2005	10.00%	4.88%	5.12%
4/7/2005	10.25%	4.87%	5.38%
5/18/2005	10.25%	4.78%	5.47%
5/25/2005	10.75%	4.76%	5.99%
5/26/2005	9.75%	4.76%	4.99%
6/1/2005	9.75%	4.75%	5.00%
7/19/2005	11.50%	4.64%	6.86%
8/5/2005	11.75%	4.62%	7.13%
8/15/2005	10.13%	4.61%	5.52%
9/28/2005	10.00%	4.54%	5.46%
10/4/2005	10.75%	4.54%	6.21%
12/12/2005	11.00%	4.55%	6.45%
12/13/2005	10.75%	4.55%	6.20%
12/21/2005	10.29%	4.54%	5.75%

Date of Electric Rate Case	Return on Equity	30-Year Treasury Yield	Risk Premium
12/21/2005	10.40%	4.54%	5.86%
12/22/2005	11.00%	4.54%	6.46%
12/22/2005	11.15%	4.54%	6.61%
12/28/2005	10.00%	4.54%	5.46%
12/28/2005	10.00%	4.54%	5.46%
1/5/2006	11.00%	4.53%	6.47%
1/27/2006	9.75%	4.52%	5.23%
3/3/2006	10.39%	4.53%	5.86%
4/17/2006	10.20%	4.61%	5.59%
4/26/2006	10.60%	4.64%	5.96%
5/17/2006	11.60%	4.69%	6.91%
6/6/2006	10.00%	4.74%	5.26%
6/27/2006	10.75%	4.80%	5.95%
7/6/2006	10.20%	4.83%	5.37%
7/24/2006	9.60%	4.86%	4.74%
7/26/2006	10.50%	4.86%	5.64%
7/28/2006	10.05%	4.86%	5.19%
8/23/2006	9.55%	4.89%	4.66%
9/1/2006	10.54%	4.90%	5.64%
9/14/2006	10.00%	4.91%	5.09%
10/6/2006	9.67%	4.92%	4.75%
11/21/2006	10.08%	4.95%	5.13%
11/21/2006	10.08%	4.95%	5.13%
11/21/2006	10.12%	4.95%	5.17%
12/1/2006	10.25%	4.95%	5.30%
12/1/2006	10.50%	4.95%	5.55%
12/7/2006	10.75%	4.95%	5.80%
12/21/2006	10.90%	4.95%	5.95%
12/21/2006	11.25%	4.95%	6.30%
12/22/2006	10.25%	4.95%	5.30%
1/5/2007	10.00%	4.95%	5.05%
1/11/2007	10.10%	4.95%	5.15%
1/11/2007	10.10%	4.95%	5.15%
1/11/2007	10.90%	4.95%	5.95%
1/12/2007	10.10%	4.95%	5.15%
1/13/2007	10.40%	4.95%	5.45%
1/19/2007	10.80%	4.94%	5.86%
3/21/2007	11.35%	4.87%	6.48%
3/22/2007	9.75%	4.86%	4.89%
5/15/2007	10.00%	4.81%	5.19%
5/17/2007	10.25%	4.81%	5.44%
5/17/2007	10.25%	4.81%	5.44%
5/22/2007	10.20%	4.80%	5.40%
5/22/2007	10.50%	4.80%	5.70%
5/23/2007	10.70%	4.80%	5.90%
5/25/2007	9.67%	4.80%	4.87%
6/15/2007	9.90%	4.82%	5.08%
6/21/2007	10.20%	4.83%	5.37%
6/22/2007	10.50%	4.83%	5.67%
6/28/2007	10.75%	4.84%	5.91%
7/12/2007	9.67%	4.86%	4.81%
7/19/2007	10.00%	4.87%	5.13%
7/19/2007	10.00%	4.87%	5.13%
8/15/2007	10.40%	4.88%	5.52%

Date of Electric Rate Case	Return on Equity	30-Year Treasury Yield	Risk Premium
10/9/2007	10.00%	4.91%	5.09%
10/17/2007	9.10%	4.91%	4.19%
10/31/2007	9.96%	4.90%	5.06%
11/29/2007	10.90%	4.87%	6.03%
12/6/2007	10.75%	4.86%	5.89%
12/13/2007	9.96%	4.86%	5.10%
12/14/2007	10.70%	4.86%	5.84%
12/14/2007	10.80%	4.86%	5.94%
12/19/2007	10.20%	4.86%	5.34%
12/20/2007	10.20%	4.85%	5.35%
12/20/2007	11.00%	4.85%	6.15%
12/28/2007	10.25%	4.85%	5.40%
12/31/2007	11.25%	4.85%	6.40%
1/8/2008	10.75%	4.83%	5.92%
1/17/2008	10.75%	4.81%	5.94%
1/28/2008	9.40%	4.80%	4.60%
1/30/2008	10.00%	4.79%	5.21%
1/31/2008	10.71%	4.79%	5.92%
2/29/2008	10.25%	4.75%	5.50%
3/12/2008	10.25%	4.73%	5.52%
3/25/2008	9.10%	4.68%	4.42%
4/22/2008	10.25%	4.60%	5.65%
4/24/2008	10.10%	4.60%	5.50%
5/1/2008	10.70%	4.59%	6.11%
5/19/2008	11.00%	4.56%	6.44%
5/27/2008	10.00%	4.55%	5.45%
6/10/2008	10.70%	4.54%	6.16%
6/27/2008	10.50%	4.54%	5.96%
6/27/2008	11.04%	4.54%	6.50%
7/10/2008	10.43%	4.52%	5.91%
7/16/2008	9.40%	4.52%	4.88%
7/30/2008	10.80%	4.51%	6.29%
7/31/2008	10.70%	4.51%	6.19%
8/11/2008	10.25%	4.51%	5.74%
8/26/2008	10.18%	4.50%	5.68%
9/10/2008	10.30%	4.50%	5.80%
9/24/2008	10.65%	4.48%	6.17%
9/24/2008	10.65%	4.48%	6.17%
9/24/2008	10.65%	4.48%	6.17%
9/30/2008	10.20%	4.48%	5.72%
10/8/2008	10.15%	4.46%	5.69%
11/13/2008	10.55%	4.45%	6.10%
11/17/2008	10.20%	4.44%	5.76%
12/1/2008	10.25%	4.40%	5.85%
12/23/2008	11.00%	4.27%	6.73%
12/29/2008	10.00%	4.24%	5.76%
12/29/2008	10.20%	4.24%	5.96%
12/31/2008	10.75%	4.22%	6.53%
1/14/2009	10.50%	4.15%	6.35%
1/21/2009	10.50%	4.12%	6.38%
1/21/2009	10.50%	4.12%	6.38%
1/21/2009	10.50%	4.12%	6.38%
1/27/2009	10.76%	4.09%	6.67%
1/30/2009	10.50%	4.08%	6.42%

Date of Electric Rate Case	Return on Equity	30-Year Treasury Yield	Risk Premium
2/4/2009	8.75%	4.06%	4.69%
3/4/2009	10.50%	3.96%	6.54%
3/12/2009	11.50%	3.93%	7.57%
4/2/2009	11.10%	3.85%	7.25%
4/21/2009	10.61%	3.80%	6.81%
4/24/2009	10.00%	3.79%	6.21%
4/30/2009	11.25%	3.78%	7.47%
5/4/2009	10.74%	3.77%	6.97%
5/20/2009	10.25%	3.74%	6.51%
5/28/2009	10.50%	3.74%	6.76%
6/22/2009	10.00%	3.76%	6.24%
6/24/2009	10.80%	3.77%	7.03%
7/8/2009	10.63%	3.77%	6.86%
7/17/2009	10.50%	3.78%	6.72%
8/31/2009	10.25%	3.82%	6.43%
10/14/2009	10.70%	4.01%	6.69%
10/23/2009	10.88%	4.06%	6.82%
11/2/2009	10.70%	4.09%	6.61%
11/3/2009	10.70%	4.10%	6.60%
11/24/2009	10.25%	4.15%	6.10%
11/25/2009	10.75%	4.16%	6.59%
11/30/2009	10.35%	4.17%	6.18%
12/3/2009	10.50%	4.18%	6.32%
12/7/2009	10.70%	4.18%	6.52%
12/16/2009	10.90%	4.21%	6.69%
12/16/2009	11.00%	4.21%	6.79%
12/18/2009	10.40%	4.22%	6.18%
12/18/2009	10.40%	4.22%	6.18%
12/22/2009	10.20%	4.23%	5.97%
12/22/2009	10.40%	4.23%	6.17%
12/22/2009	10.40%	4.23%	6.17%
12/30/2009	10.00%	4.26%	5.74%
1/4/2010	10.80%	4.28%	6.52%
1/11/2010	11.00%	4.30%	6.70%
1/26/2010	10.13%	4.35%	5.78%
1/27/2010	10.40%	4.35%	6.05%
1/27/2010	10.40%	4.35%	6.05%
1/27/2010	10.70%	4.35%	6.35%
2/9/2010	9.80%	4.38%	5.42%
2/18/2010	10.60%	4.40%	6.20%
2/24/2010	10.18%	4.41%	5.77%
3/2/2010	9.63%	4.41%	5.22%
3/4/2010	10.50%	4.41%	6.09%
3/5/2010	10.50%	4.41%	6.09%
3/11/2010	11.90%	4.42%	7.48%
3/17/2010	10.00%	4.41%	5.59%
3/25/2010	10.15%	4.42%	5.73%
4/2/2010	10.10%	4.43%	5.67%
4/27/2010	10.00%	4.46%	5.54%
4/29/2010	9.90%	4.46%	5.44%
4/29/2010	10.06%	4.46%	5.60%
4/29/2010	10.26%	4.46%	5.80%
5/12/2010	10.30%	4.45%	5.85%
5/12/2010	10.30%	4.45%	5.85%

Date of Electric Rate Case	Return on Equity	30-Year Treasury Yield	Risk Premium
5/28/2010	10.10%	4.44%	5.66%
5/28/2010	10.20%	4.44%	5.76%
6/7/2010	10.30%	4.44%	5.86%
6/16/2010	10.00%	4.44%	5.56%
6/28/2010	9.67%	4.43%	5.24%
6/28/2010	10.50%	4.43%	6.07%
6/30/2010	9.40%	4.43%	4.97%
7/1/2010	10.25%	4.43%	5.82%
7/15/2010	10.53%	4.43%	6.10%
7/15/2010	10.70%	4.43%	6.27%
7/30/2010	10.70%	4.41%	6.29%
8/4/2010	10.50%	4.41%	6.09%
8/6/2010	9.83%	4.41%	5.42%
8/25/2010	9.90%	4.37%	5.53%
9/3/2010	10.60%	4.35%	6.25%
9/14/2010	10.70%	4.33%	6.37%
9/16/2010	10.00%	4.33%	5.67%
9/16/2010	10.00%	4.33%	5.67%
9/30/2010	9.75%	4.29%	5.46%
10/14/2010	10.35%	4.24%	6.11%
10/28/2010	10.70%	4.21%	6.49%
11/2/2010	10.38%	4.20%	6.18%
11/4/2010	10.70%	4.20%	6.50%
11/19/2010	10.20%	4.18%	6.02%
11/22/2010	10.00%	4.18%	5.82%
12/1/2010	10.13%	4.16%	5.97%
12/6/2010	9.86%	4.15%	5.71%
12/9/2010	10.25%	4.15%	6.10%
12/13/2010	10.70%	4.15%	6.55%
12/14/2010	10.13%	4.15%	5.98%
12/15/2010	10.44%	4.15%	6.29%
12/17/2010	10.00%	4.15%	5.85%
12/20/2010	10.60%	4.15%	6.45%
12/21/2010	10.30%	4.14%	6.16%
12/27/2010	9.90%	4.14%	5.76%
12/29/2010	11.15%	4.14%	7.01%
1/5/2011	10.15%	4.13%	6.02%
1/12/2011	10.30%	4.12%	6.18%
1/13/2011	10.30%	4.12%	6.18%
1/18/2011	10.00%	4.12%	5.88%
1/20/2011	9.30%	4.12%	5.18%
1/20/2011	10.13%	4.12%	6.01%
1/31/2011	9.60%	4.12%	5.48%
2/3/2011	10.00%	4.12%	5.88%
2/25/2011	10.00%	4.14%	5.86%
3/25/2011	9.80%	4.18%	5.62%
3/30/2011	10.00%	4.18%	5.82%
4/12/2011	10.00%	4.21%	5.79%
4/25/2011	10.74%	4.23%	6.51%
4/26/2011	9.67%	4.23%	5.44%
4/27/2011	10.40%	4.24%	6.16%
5/4/2011	10.00%	4.24%	5.76%
5/4/2011	10.00%	4.24%	5.76%
5/24/2011	10.50%	4.27%	6.23%

Date of Electric Rate Case	Return on Equity	30-Year Treasury Yield	Risk Premium
6/8/2011	10.75%	4.30%	6.45%
6/16/2011	9.20%	4.32%	4.88%
6/17/2011	9.95%	4.32%	5.63%
7/13/2011	10.20%	4.36%	5.84%
8/1/2011	9.20%	4.39%	4.81%
8/8/2011	10.00%	4.38%	5.62%
8/11/2011	10.00%	4.38%	5.62%
8/12/2011	10.35%	4.37%	5.98%
8/19/2011	10.25%	4.36%	5.89%
9/2/2011	12.88%	4.32%	8.56%
9/22/2011	10.00%	4.24%	5.76%
10/12/2011	10.30%	4.14%	6.16%
10/20/2011	10.50%	4.10%	6.40%
11/30/2011	10.90%	3.87%	7.03%
11/30/2011	10.90%	3.87%	7.03%
12/14/2011	10.00%	3.80%	6.20%
12/14/2011	10.30%	3.80%	6.50%
12/20/2011	10.20%	3.76%	6.44%
12/21/2011	10.20%	3.76%	6.44%
12/22/2011	9.90%	3.75%	6.15%
12/22/2011	10.40%	3.75%	6.65%
12/23/2011	10.19%	3.74%	6.45%
1/25/2012	10.50%	3.57%	6.93%
1/27/2012	10.50%	3.56%	6.94%
2/15/2012	10.20%	3.47%	6.73%
2/23/2012	9.90%	3.44%	6.46%
2/27/2012	10.25%	3.43%	6.82%
2/29/2012	10.40%	3.41%	6.99%
3/29/2012	10.37%	3.32%	7.05%
4/4/2012	10.00%	3.30%	6.70%
4/26/2012	10.00%	3.21%	6.79%
5/2/2012	10.00%	3.18%	6.82%
5/7/2012	9.80%	3.17%	6.63%
5/15/2012	10.00%	3.14%	6.86%
5/29/2012	10.05%	3.11%	6.94%
6/7/2012	10.30%	3.08%	7.22%
6/14/2012	9.40%	3.06%	6.34%
6/15/2012	10.40%	3.06%	7.34%
6/18/2012	9.60%	3.06%	6.54%
6/19/2012	9.25%	3.05%	6.20%
6/26/2012	10.10%	3.04%	7.06%
6/29/2012	10.00%	3.04%	6.96%
7/9/2012	10.20%	3.03%	7.17%
7/16/2012	9.80%	3.02%	6.78%
7/20/2012	9.31%	3.01%	6.30%
7/20/2012	9.81%	3.01%	6.80%
9/13/2012	9.80%	2.94%	6.86%
9/19/2012	9.80%	2.94%	6.86%
9/19/2012	10.05%	2.94%	7.11%
9/26/2012	9.50%	2.94%	6.56%
10/12/2012	9.60%	2.93%	6.67%
10/23/2012	9.75%	2.93%	6.82%
10/24/2012	10.30%	2.93%	7.37%
11/9/2012	10.30%	2.92%	7.38%

Date of Electric Rate Case	Return on Equity	30-Year Treasury Yield	Risk Premium
11/28/2012	10.40%	2.90%	7.50%
11/29/2012	9.75%	2.89%	6.86%
11/29/2012	9.88%	2.89%	6.99%
12/5/2012	9.71%	2.89%	6.82%
12/5/2012	10.40%	2.89%	7.51%
12/12/2012	9.80%	2.88%	6.92%
12/13/2012	9.50%	2.88%	6.62%
12/13/2012	10.50%	2.88%	7.62%
12/14/2012	10.40%	2.88%	7.52%
12/19/2012	9.71%	2.87%	6.84%
12/19/2012	10.25%	2.87%	7.38%
12/20/2012	9.50%	2.87%	6.63%
12/20/2012	9.80%	2.87%	6.93%
12/20/2012	10.25%	2.87%	7.38%
12/20/2012	10.25%	2.87%	7.38%
12/20/2012	10.30%	2.87%	7.43%
12/20/2012	10.40%	2.87%	7.53%
12/20/2012	10.45%	2.87%	7.58%
12/21/2012	10.20%	2.87%	7.33%
12/26/2012	9.80%	2.86%	6.94%
1/9/2013	9.70%	2.85%	6.85%
1/9/2013	9.70%	2.85%	6.85%
1/9/2013	9.70%	2.85%	6.85%
1/16/2013	9.60%	2.84%	6.76%
1/16/2013	9.60%	2.84%	6.76%
2/13/2013	10.20%	2.84%	7.36%
2/22/2013	9.75%	2.85%	6.90%
2/27/2013	10.00%	2.86%	7.14%
3/14/2013	9.30%	2.88%	6.42%
3/27/2013	9.80%	2.90%	6.90%
5/1/2013	9.84%	2.94%	6.90%
5/15/2013	10.30%	2.96%	7.34%
5/30/2013	10.20%	2.98%	7.22%
5/31/2013	9.00%	2.98%	6.02%
6/11/2013	10.00%	3.00%	7.00%
6/21/2013	9.75%	3.02%	6.73%
6/25/2013	9.80%	3.03%	6.77%
7/12/2013	9.36%	3.07%	6.29%
8/8/2013	9.83%	3.14%	6.69%
8/14/2013	9.15%	3.16%	5.99%
9/11/2013	10.20%	3.26%	6.94%
9/11/2013	10.25%	3.26%	6.99%
9/24/2013	10.20%	3.31%	6.89%
10/3/2013	9.65%	3.33%	6.32%
11/6/2013	10.20%	3.41%	6.79%
11/21/2013	10.00%	3.44%	6.56%
11/26/2013	10.00%	3.45%	6.55%
12/3/2013	10.25%	3.47%	6.78%
12/4/2013	9.50%	3.47%	6.03%
12/5/2013	10.20%	3.48%	6.72%
12/9/2013	8.72%	3.48%	5.24%
12/9/2013	9.75%	3.48%	6.27%
12/13/2013	9.75%	3.50%	6.25%
12/16/2013	9.95%	3.50%	6.45%

Date of Electric Rate Case	Return on Equity	30-Year Treasury Yield	Risk Premium
12/16/2013	9.95%	3.50%	6.45%
12/16/2013	10.12%	3.50%	6.62%
12/17/2013	9.50%	3.51%	5.99%
12/17/2013	10.95%	3.51%	7.44%
12/18/2013	8.72%	3.51%	5.21%
12/18/2013	9.80%	3.51%	6.29%
12/19/2013	10.15%	3.51%	6.64%
12/30/2013	9.50%	3.54%	5.96%
2/20/2014	9.20%	3.68%	5.52%
2/26/2014	9.75%	3.69%	6.06%
3/17/2014	9.55%	3.72%	5.83%
3/26/2014	9.40%	3.73%	5.67%
3/26/2014	9.96%	3.73%	6.23%
4/2/2014	9.70%	3.73%	5.97%
5/16/2014	9.80%	3.70%	6.10%
5/30/2014	9.70%	3.68%	6.02%
6/6/2014	10.40%	3.67%	6.73%
6/30/2014	9.55%	3.64%	5.91%
7/2/2014	9.62%	3.64%	5.98%
7/10/2014	9.95%	3.63%	6.32%
7/23/2014	9.75%	3.61%	6.14%
7/29/2014	9.45%	3.60%	5.85%
7/31/2014	9.90%	3.60%	6.30%
8/20/2014	9.75%	3.57%	6.18%
8/25/2014	9.60%	3.56%	6.04%
8/29/2014	9.80%	3.54%	6.26%
9/11/2014	9.60%	3.51%	6.09%
9/15/2014	10.25%	3.51%	6.74%
10/9/2014	9.80%	3.45%	6.35%
11/6/2014	9.56%	3.37%	6.19%
11/6/2014	10.20%	3.37%	6.83%
11/14/2014	10.20%	3.35%	6.85%
11/26/2014	9.70%	3.33%	6.37%
11/26/2014	10.20%	3.33%	6.87%
12/4/2014	9.68%	3.31%	6.37%
12/10/2014	9.25%	3.29%	5.96%
12/10/2014	9.25%	3.29%	5.96%
12/11/2014	10.07%	3.29%	6.78%
12/12/2014	10.20%	3.28%	6.92%
12/17/2014	9.17%	3.27%	5.90%
12/18/2014	9.83%	3.26%	6.57%
1/23/2015	9.50%	3.14%	6.36%
2/24/2015	9.83%	3.04%	6.79%
3/18/2015	9.75%	2.98%	6.77%
3/25/2015	9.50%	2.96%	6.54%
3/26/2015	9.72%	2.95%	6.77%
4/23/2015	10.20%	2.87%	7.33%
4/29/2015	9.53%	2.86%	6.67%
5/1/2015	9.60%	2.85%	6.75%
5/26/2015	9.75%	2.83%	6.92%
6/17/2015	9.00%	2.82%	6.18%
6/17/2015	9.00%	2.82%	6.18%
9/2/2015	9.50%	2.79%	6.71%
9/10/2015	9.30%	2.79%	6.51%

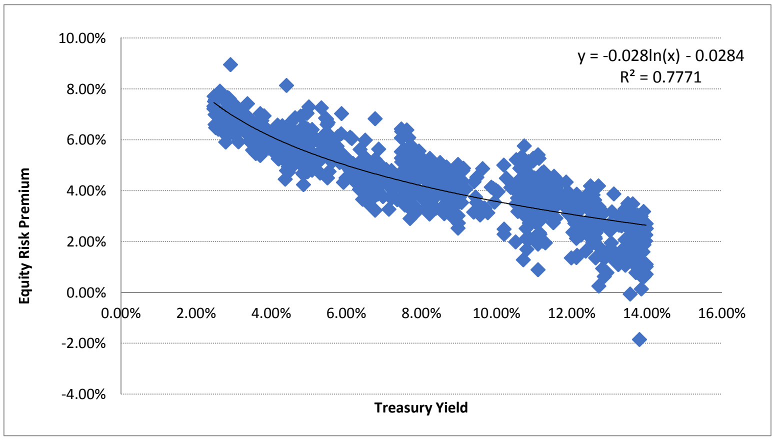
Date of Electric Rate Case	Return on Equity	30-Year Treasury Yield	Risk Premium
10/15/2015	9.00%	2.81%	6.19%
11/19/2015	10.00%	2.88%	7.12%
11/19/2015	10.30%	2.88%	7.42%
12/3/2015	10.00%	2.90%	7.10%
12/9/2015	9.14%	2.90%	6.24%
12/9/2015	9.14%	2.90%	6.24%
12/11/2015	10.30%	2.90%	7.40%
12/15/2015	9.60%	2.91%	6.69%
12/17/2015	9.70%	2.91%	6.79%
12/18/2015	9.50%	2.91%	6.59%
12/30/2015	9.50%	2.93%	6.57%
1/6/2016	9.50%	2.94%	6.56%
2/23/2016	9.75%	2.94%	6.81%
3/16/2016	9.85%	2.91%	6.94%
4/29/2016	9.80%	2.83%	6.97%
6/3/2016	9.75%	2.80%	6.95%
6/8/2016	9.48%	2.80%	6.68%
6/15/2016	9.00%	2.78%	6.22%
6/15/2016	9.00%	2.78%	6.22%
7/18/2016	9.98%	2.71%	7.27%
8/9/2016	9.85%	2.66%	7.19%
8/18/2016	9.50%	2.63%	6.87%
8/24/2016	9.75%	2.62%	7.13%
9/1/2016	9.50%	2.59%	6.91%
9/8/2016	10.00%	2.58%	7.42%
9/28/2016	9.58%	2.54%	7.04%
9/30/2016	9.90%	2.53%	7.37%
11/9/2016	9.80%	2.48%	7.32%
11/10/2016	9.50%	2.48%	7.02%
11/15/2016	9.55%	2.49%	7.06%
11/18/2016	10.00%	2.50%	7.50%
11/29/2016	10.55%	2.51%	8.04%
12/1/2016	10.00%	2.51%	7.49%
12/6/2016	8.64%	2.52%	6.12%
12/6/2016	8.64%	2.52%	6.12%
12/7/2016	10.10%	2.52%	7.58%
12/12/2016	9.60%	2.53%	7.07%
12/14/2016	9.10%	2.53%	6.57%
12/19/2016	9.00%	2.54%	6.46%
12/19/2016	9.37%	2.54%	6.83%
12/22/2016	9.60%	2.55%	7.05%
12/22/2016	9.90%	2.55%	7.35%
12/28/2016	9.50%	2.55%	6.95%
1/18/2017	9.45%	2.58%	6.87%
1/24/2017	9.00%	2.59%	6.41%
1/31/2017	10.10%	2.60%	7.50%
2/15/2017	9.60%	2.62%	6.98%

Date of Electric Rate Case	Return on Equity	30-Year Treasury Yield	Risk Premium
2/22/2017	9.60%	2.64%	6.96%
2/24/2017	9.75%	2.64%	7.11%
2/28/2017	10.10%	2.64%	7.46%
3/2/2017	9.41%	2.65%	6.76%
3/20/2017	9.50%	2.68%	6.82%
4/4/2017	10.25%	2.71%	7.54%
4/12/2017	9.40%	2.74%	6.66%
4/20/2017	9.50%	2.76%	6.74%
5/3/2017	9.50%	2.79%	6.71%
5/11/2017	9.20%	2.81%	6.39%
5/18/2017	9.50%	2.83%	6.67%
5/23/2017	9.70%	2.84%	6.86%
6/16/2017	9.65%	2.89%	6.76%
6/22/2017	9.70%	2.90%	6.80%
6/22/2017	9.70%	2.90%	6.80%
7/24/2017	9.50%	2.95%	6.55%
8/15/2017	10.00%	2.97%	7.03%
9/22/2017	9.60%	2.93%	6.67%
9/28/2017	9.80%	2.92%	6.88%
10/20/2017	9.50%	2.91%	6.59%
10/26/2017	10.20%	2.91%	7.29%
10/26/2017	10.25%	2.91%	7.34%
10/26/2017	10.30%	2.91%	7.39%
11/6/2017	10.25%	2.90%	7.35%
11/15/2017	11.95%	2.89%	9.06%
11/30/2017	10.00%	2.88%	7.12%
11/30/2017	10.00%	2.88%	7.12%
12/5/2017	9.50%	2.88%	6.62%
12/6/2017	8.40%	2.87%	5.53%
12/6/2017	8.40%	2.87%	5.53%
12/7/2017	9.80%	2.87%	6.93%
12/14/2017	9.60%	2.86%	6.74%
12/14/2017	9.65%	2.86%	6.79%
12/18/2017	9.50%	2.86%	6.64%
12/20/2017	9.58%	2.86%	6.72%
12/21/2017	9.10%	2.85%	6.25%
12/28/2017	9.50%	2.85%	6.65%
12/29/2017	9.40%	2.85%	6.55%

# of Cases:	1,541
Average:	4.61%

Bond Yield Plus Risk Premium

	[1] Constant	[2] Slope	[3] 30-Year Treasury Yield	[4] Risk Premium	[5] Return on Equity
	-2.84%	-2.78%			
Current 30-Year Treasury			2.77%	7.15%	9.92%
Near-Term Projected 30-Year Treasury			3.30%	6.66%	9.96%
Long-Term Projected 30-Year Treasury			4.20%	5.99%	10.19%



Notes:
[1] Constant of regression equation
[2] Slope of regression equation
[3] Source: Current = Bloomberg Professional,
Near Term Projected = Blue Chip Financial Forecasts, Vol. 36, No. 12, December 1, 2017, at 2,
Long Term Projected = Blue Chip Financial Forecasts, Vol. 36, No. 12, December 1, 2017, at 14.
[4] Equals [1] + ln([3]) x [2]
[5] Equals [3] + [4]
[6] Source: SNL Financial
[7] Source: SNL Financial
[8] Source: Bloomberg Professional, equals 187-trading day average (i.e. lag period)
[9] Equals [7] - [8]

Bond Yield Plus Risk Premium

[6] Date of Natural Gas Rate Case	[7] Return on Equity	[8] 30-Year Treasury Yield	[9] Risk Premium
1/3/1980	12.55%	9.39%	3.16%
1/4/1980	13.75%	9.40%	4.35%
1/14/1980	13.20%	9.44%	3.76%
1/18/1980	14.00%	9.47%	4.53%
1/31/1980	12.61%	9.56%	3.05%
2/8/1980	14.50%	9.63%	4.87%
2/14/1980	13.00%	9.67%	3.33%
2/15/1980	13.00%	9.69%	3.31%
2/29/1980	14.00%	9.86%	4.14%
3/5/1980	14.00%	9.91%	4.09%
3/7/1980	13.50%	9.95%	3.55%
3/14/1980	14.00%	10.04%	3.96%
3/27/1980	12.69%	10.20%	2.49%
4/1/1980	14.75%	10.26%	4.49%
4/29/1980	12.50%	10.51%	1.99%
5/7/1980	14.27%	10.56%	3.71%
5/8/1980	13.75%	10.56%	3.19%
5/19/1980	15.50%	10.62%	4.88%
5/27/1980	14.60%	10.65%	3.95%
5/29/1980	16.00%	10.67%	5.33%
6/10/1980	13.78%	10.71%	3.07%
6/25/1980	14.25%	10.74%	3.51%
7/9/1980	14.51%	10.77%	3.74%
7/17/1980	12.90%	10.79%	2.11%
7/18/1980	13.80%	10.79%	3.01%
7/22/1980	14.10%	10.79%	3.31%
7/23/1980	14.19%	10.79%	3.40%
8/1/1980	12.50%	10.80%	1.70%
8/11/1980	14.85%	10.81%	4.04%
8/21/1980	13.03%	10.84%	2.19%
8/28/1980	14.00%	10.87%	3.13%
8/28/1980	13.61%	10.87%	2.74%
9/4/1980	14.00%	10.90%	3.10%
9/24/1980	15.00%	10.98%	4.02%
10/9/1980	14.50%	11.05%	3.45%
10/9/1980	14.50%	11.05%	3.45%
10/24/1980	14.00%	11.09%	2.91%
10/27/1980	15.20%	11.10%	4.10%
10/27/1980	15.20%	11.10%	4.10%
10/28/1980	13.00%	11.10%	1.90%
10/28/1980	12.00%	11.10%	0.90%
10/31/1980	14.50%	11.12%	3.38%
11/4/1980	15.00%	11.12%	3.88%
11/6/1980	14.35%	11.13%	3.22%
11/10/1980	13.25%	11.14%	2.11%
11/17/1980	15.50%	11.15%	4.35%
11/19/1980	13.50%	11.14%	2.36%
12/5/1980	14.60%	11.13%	3.47%
12/8/1980	16.40%	11.13%	5.27%
12/12/1980	15.45%	11.15%	4.30%
12/17/1980	14.20%	11.16%	3.04%
12/17/1980	14.40%	11.16%	3.24%
12/18/1980	14.00%	11.16%	2.84%
12/22/1980	13.45%	11.16%	2.29%
12/26/1980	14.00%	11.15%	2.85%
12/30/1980	14.50%	11.14%	3.36%
12/31/1980	14.56%	11.14%	3.42%
1/7/1981	14.30%	11.13%	3.17%
1/12/1981	14.95%	11.14%	3.81%
1/26/1981	15.25%	11.20%	4.05%
1/30/1981	13.25%	11.23%	2.02%
2/11/1981	14.50%	11.33%	3.17%
2/20/1981	14.50%	11.40%	3.10%
3/12/1981	15.65%	11.60%	4.05%
3/25/1981	15.30%	11.74%	3.56%
4/1/1981	15.30%	11.82%	3.48%
4/9/1981	15.00%	11.91%	3.09%
4/29/1981	13.50%	12.12%	1.38%

4/29/1981	14.25%	12.12%	2.13%
4/30/1981	15.00%	12.14%	2.86%
4/30/1981	13.60%	12.14%	1.46%
5/21/1981	14.00%	12.37%	1.63%
6/3/1981	14.67%	12.46%	2.21%
6/22/1981	16.00%	12.57%	3.43%
6/25/1981	14.75%	12.60%	2.15%
7/2/1981	14.00%	12.64%	1.36%
7/10/1981	16.00%	12.69%	3.31%
7/14/1981	16.90%	12.71%	4.19%
7/21/1981	15.78%	12.78%	3.00%
7/27/1981	15.50%	12.82%	2.68%
7/27/1981	13.77%	12.82%	0.95%
7/31/1981	13.50%	12.86%	0.64%
7/31/1981	14.20%	12.86%	1.34%
8/12/1981	13.72%	12.93%	0.79%
8/12/1981	13.72%	12.93%	0.79%
8/12/1981	14.41%	12.93%	1.48%
8/25/1981	15.45%	13.02%	2.43%
8/27/1981	14.43%	13.04%	1.39%
8/28/1981	15.00%	13.05%	1.95%
9/23/1981	14.34%	13.24%	1.10%
9/24/1981	16.25%	13.26%	2.99%
9/29/1981	14.50%	13.31%	1.19%
9/30/1981	15.94%	13.32%	2.62%
10/2/1981	14.80%	13.36%	1.44%
10/12/1981	16.25%	13.43%	2.82%
10/20/1981	16.50%	13.50%	3.00%
10/20/1981	17.00%	13.50%	3.50%
10/20/1981	15.25%	13.50%	1.75%
10/23/1981	15.50%	13.54%	1.96%
10/26/1981	13.50%	13.56%	-0.06%
10/29/1981	16.50%	13.60%	2.90%
11/4/1981	15.33%	13.62%	1.71%
11/6/1981	15.17%	13.64%	1.53%
11/12/1981	15.00%	13.65%	1.35%
11/25/1981	15.25%	13.66%	1.59%
11/25/1981	16.10%	13.66%	2.44%
11/25/1981	16.10%	13.66%	2.44%
11/30/1981	16.75%	13.66%	3.09%
12/1/1981	16.00%	13.66%	2.34%
12/1/1981	15.70%	13.66%	2.04%
12/15/1981	15.81%	13.69%	2.12%
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12/22/1981	15.70%	13.72%	1.98%
12/22/1981	16.00%	13.72%	2.28%
12/30/1981	16.25%	13.74%	2.51%
12/30/1981	16.00%	13.74%	2.26%
1/4/1982	15.50%	13.75%	1.75%
1/14/1982	11.95%	13.80%	-1.85%
1/25/1982	16.25%	13.84%	2.41%
1/27/1982	16.84%	13.85%	2.99%
1/31/1982	14.00%	13.86%	0.14%
2/2/1982	16.24%	13.86%	2.38%
2/8/1982	15.50%	13.87%	1.63%
2/9/1982	14.95%	13.88%	1.07%
2/9/1982	15.75%	13.88%	1.87%
2/11/1982	16.00%	13.89%	2.11%
3/1/1982	15.96%	13.91%	2.05%
3/3/1982	15.00%	13.91%	1.09%
3/8/1982	17.10%	13.92%	3.18%
3/26/1982	16.00%	13.97%	2.03%
3/31/1982	16.25%	13.98%	2.27%
4/1/1982	16.50%	13.98%	2.52%
4/6/1982	15.00%	13.99%	1.01%
4/9/1982	16.50%	13.99%	2.51%
4/12/1982	15.10%	13.99%	1.11%
4/12/1982	16.70%	13.99%	2.71%
4/18/1982	14.70%	13.99%	0.71%
4/27/1982	15.00%	13.97%	1.03%
5/10/1982	14.57%	13.94%	0.63%
5/14/1982	15.80%	13.92%	1.88%
5/20/1982	15.82%	13.91%	1.91%

5/21/1982	15.50%	13.90%	1.60%
5/25/1982	16.25%	13.90%	2.35%
6/2/1982	14.50%	13.87%	0.63%
6/7/1982	16.00%	13.85%	2.15%
6/23/1982	15.50%	13.81%	1.69%
6/25/1982	16.50%	13.81%	2.69%
7/1/1982	16.00%	13.79%	2.21%
7/1/1982	15.55%	13.79%	1.76%
7/2/1982	15.10%	13.79%	1.31%
7/13/1982	16.80%	13.75%	3.05%
7/22/1982	14.50%	13.71%	0.79%
7/28/1982	16.10%	13.68%	2.42%
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12/13/1982	16.00%	12.58%	3.42%
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12/28/1982	15.25%	12.42%	2.83%
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3/23/1983	16.10%	11.53%	4.57%
3/24/1983	15.00%	11.51%	3.49%
4/12/1983	13.25%	11.30%	1.95%

4/29/1983	15.05%	11.09%	3.96%
5/3/1983	15.40%	11.06%	4.34%
5/9/1983	15.50%	11.00%	4.50%
5/19/1983	14.85%	10.90%	3.95%
5/31/1983	14.00%	10.84%	3.16%
6/2/1983	14.50%	10.82%	3.68%
6/7/1983	14.50%	10.80%	3.70%
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6/20/1983	16.50%	10.74%	5.76%
6/27/1983	14.50%	10.71%	3.79%
6/30/1983	14.80%	10.70%	4.10%
6/30/1983	15.90%	10.70%	5.20%
7/1/1983	14.80%	10.70%	4.10%
7/5/1983	15.00%	10.69%	4.31%
7/8/1983	15.50%	10.69%	4.81%
7/19/1983	15.00%	10.70%	4.30%
7/19/1983	15.10%	10.70%	4.40%
8/18/1983	15.30%	10.81%	4.49%
8/19/1983	15.79%	10.82%	4.97%
8/29/1983	16.00%	10.85%	5.15%
8/31/1983	14.75%	10.87%	3.88%
8/31/1983	15.25%	10.87%	4.38%
9/8/1983	14.75%	10.89%	3.86%
9/16/1983	15.51%	10.93%	4.58%
9/26/1983	14.50%	10.96%	3.54%
9/28/1983	14.25%	10.97%	3.28%
9/30/1983	16.15%	10.98%	5.17%
9/30/1983	16.25%	10.98%	5.27%
10/1/1983	16.25%	10.98%	5.27%
10/13/1983	15.52%	11.02%	4.50%
10/19/1983	15.20%	11.04%	4.16%
10/26/1983	14.75%	11.06%	3.69%
10/27/1983	14.88%	11.07%	3.81%
10/27/1983	15.33%	11.07%	4.26%
11/9/1983	14.82%	11.10%	3.72%
11/9/1983	16.51%	11.10%	5.41%
11/9/1983	16.51%	11.10%	5.41%
12/1/1983	14.50%	11.17%	3.33%
12/8/1983	15.90%	11.20%	4.70%
12/9/1983	15.30%	11.21%	4.09%
12/12/1983	14.50%	11.22%	3.28%
12/12/1983	15.50%	11.22%	4.28%
12/20/1983	16.00%	11.26%	4.74%
12/20/1983	15.40%	11.26%	4.14%
12/22/1983	15.75%	11.27%	4.48%
12/29/1983	15.00%	11.30%	3.70%
12/30/1983	15.00%	11.30%	3.70%
1/10/1984	15.90%	11.34%	4.56%
1/13/1984	15.50%	11.36%	4.14%
1/18/1984	15.53%	11.38%	4.15%
1/26/1984	15.90%	11.42%	4.48%
2/14/1984	14.25%	11.51%	2.74%
2/28/1984	14.50%	11.58%	2.92%
3/20/1984	16.00%	11.70%	4.30%
3/23/1984	15.50%	11.72%	3.78%
4/9/1984	15.20%	11.81%	3.39%
4/18/1984	16.20%	11.86%	4.34%
4/27/1984	15.85%	11.90%	3.95%
5/15/1984	13.35%	11.99%	1.36%
5/16/1984	15.00%	12.00%	3.00%
5/22/1984	14.40%	12.04%	2.36%
6/13/1984	15.50%	12.18%	3.32%
7/10/1984	16.00%	12.37%	3.63%
8/7/1984	16.69%	12.51%	4.18%
8/9/1984	15.33%	12.51%	2.82%
8/17/1984	14.82%	12.54%	2.28%
8/21/1984	14.64%	12.54%	2.10%
8/27/1984	14.52%	12.56%	1.96%
8/28/1984	14.75%	12.57%	2.18%
8/30/1984	15.60%	12.58%	3.02%
9/12/1984	15.60%	12.60%	3.00%
9/12/1984	15.90%	12.60%	3.30%

9/25/1984	16.25%	12.61%	3.64%
10/2/1984	14.80%	12.62%	2.18%
10/9/1984	14.75%	12.63%	2.12%
10/10/1984	15.50%	12.63%	2.87%
10/18/1984	15.00%	12.65%	2.35%
10/24/1984	15.50%	12.65%	2.85%
11/7/1984	15.00%	12.64%	2.36%
11/20/1984	15.92%	12.63%	3.29%
11/30/1984	15.50%	12.60%	2.90%
12/18/1984	15.00%	12.55%	2.45%
12/20/1984	15.00%	12.54%	2.46%
12/28/1984	15.75%	12.51%	3.24%
12/28/1984	16.25%	12.51%	3.74%
1/2/1985	16.00%	12.50%	3.50%
1/31/1985	14.75%	12.37%	2.38%
2/7/1985	14.85%	12.33%	2.52%
2/15/1985	15.00%	12.27%	2.73%
2/20/1985	14.50%	12.25%	2.25%
2/22/1985	14.86%	12.25%	2.61%
3/14/1985	15.50%	12.16%	3.34%
3/28/1985	14.80%	12.08%	2.72%
4/9/1985	15.50%	12.02%	3.48%
4/16/1985	15.70%	11.96%	3.74%
6/10/1985	15.75%	11.58%	4.17%
6/26/1985	14.82%	11.46%	3.36%
7/9/1985	15.00%	11.38%	3.62%
7/26/1985	14.50%	11.26%	3.24%
8/29/1985	14.50%	11.11%	3.39%
8/30/1985	14.38%	11.11%	3.27%
9/12/1985	15.25%	11.07%	4.18%
9/23/1985	15.30%	11.03%	4.27%
9/25/1985	14.50%	11.02%	3.48%
9/26/1985	13.80%	11.02%	2.78%
9/26/1985	14.50%	11.02%	3.48%
10/25/1985	15.25%	10.91%	4.34%
11/8/1985	12.94%	10.85%	2.09%
11/20/1985	14.90%	10.81%	4.09%
11/25/1985	13.30%	10.79%	2.51%
12/6/1985	12.00%	10.71%	1.29%
12/11/1985	14.90%	10.68%	4.22%
12/20/1985	15.00%	10.59%	4.41%
12/20/1985	14.88%	10.59%	4.29%
12/20/1985	15.00%	10.59%	4.41%
12/30/1985	15.75%	10.53%	5.22%
12/31/1985	14.00%	10.51%	3.49%
12/31/1985	14.50%	10.51%	3.99%
1/17/1986	14.50%	10.38%	4.12%
2/11/1986	12.50%	10.20%	2.30%
2/12/1986	15.20%	10.19%	5.01%
3/11/1986	14.00%	9.98%	4.02%
4/2/1986	12.90%	9.76%	3.14%
4/28/1986	13.01%	9.47%	3.54%
5/21/1986	13.25%	9.18%	4.07%
5/28/1986	14.00%	9.12%	4.88%
5/29/1986	13.90%	9.10%	4.80%
6/2/1986	13.00%	9.08%	3.92%
6/11/1986	14.00%	8.97%	5.03%
6/13/1986	13.55%	8.94%	4.61%
6/27/1986	11.88%	8.77%	3.11%
7/14/1986	12.60%	8.59%	4.01%
7/30/1986	13.30%	8.38%	4.92%
8/14/1986	13.50%	8.22%	5.28%
9/5/1986	13.30%	8.02%	5.28%
9/23/1986	12.75%	7.91%	4.84%
10/30/1986	13.00%	7.67%	5.33%
10/31/1986	13.75%	7.66%	6.09%
11/10/1986	14.00%	7.61%	6.39%
11/19/1986	13.75%	7.56%	6.19%
11/25/1986	13.15%	7.54%	5.61%
12/22/1986	13.80%	7.47%	6.33%
12/30/1986	13.90%	7.47%	6.43%
1/20/1987	12.75%	7.47%	5.28%
1/23/1987	13.55%	7.47%	6.08%

1/27/1987	12.16%	7.47%	4.69%
2/13/1987	12.60%	7.47%	5.13%
2/24/1987	12.00%	7.47%	4.53%
3/30/1987	12.20%	7.46%	4.74%
3/31/1987	13.00%	7.47%	5.53%
5/5/1987	12.85%	7.60%	5.25%
5/28/1987	13.50%	7.73%	5.77%
6/15/1987	13.20%	7.80%	5.40%
6/30/1987	12.60%	7.85%	4.75%
7/10/1987	12.90%	7.88%	5.02%
7/27/1987	13.50%	7.93%	5.57%
8/25/1987	11.40%	8.09%	3.31%
9/18/1987	13.00%	8.27%	4.73%
10/20/1987	12.98%	8.55%	4.43%
10/20/1987	12.60%	8.55%	4.05%
11/12/1987	12.75%	8.68%	4.07%
11/13/1987	12.75%	8.68%	4.07%
11/24/1987	12.50%	8.73%	3.77%
12/8/1987	12.50%	8.81%	3.69%
12/22/1987	12.00%	8.90%	3.10%
12/31/1987	13.25%	8.94%	4.31%
12/31/1987	12.85%	8.94%	3.91%
1/15/1988	13.15%	8.99%	4.16%
1/20/1988	12.75%	8.99%	3.76%
1/29/1988	13.20%	8.99%	4.21%
2/4/1988	12.60%	8.99%	3.61%
3/23/1988	13.00%	8.95%	4.05%
5/27/1988	13.18%	9.02%	4.16%
6/14/1988	13.50%	9.00%	4.50%
6/17/1988	11.72%	8.99%	2.73%
6/24/1988	11.50%	8.97%	2.53%
7/1/1988	12.75%	8.95%	3.80%
7/8/1988	12.00%	8.93%	3.07%
7/18/1988	12.00%	8.91%	3.09%
7/20/1988	13.40%	8.90%	4.50%
8/8/1988	12.74%	8.90%	3.84%
9/20/1988	12.90%	8.93%	3.97%
9/26/1988	12.40%	8.93%	3.47%
9/27/1988	13.65%	8.93%	4.72%
9/30/1988	13.25%	8.94%	4.31%
10/13/1988	13.10%	8.93%	4.17%
10/21/1988	12.80%	8.94%	3.86%
10/25/1988	13.25%	8.94%	4.31%
10/26/1988	13.50%	8.94%	4.56%
10/27/1988	12.95%	8.94%	4.01%
10/28/1988	13.00%	8.95%	4.05%
11/15/1988	12.00%	8.98%	3.02%
11/29/1988	12.75%	9.01%	3.74%
12/19/1988	13.00%	9.05%	3.95%
12/21/1988	12.90%	9.05%	3.85%
12/22/1988	13.50%	9.05%	4.45%
1/26/1989	12.60%	9.06%	3.54%
1/27/1989	13.00%	9.06%	3.94%
2/8/1989	13.37%	9.05%	4.32%
3/8/1989	13.00%	9.04%	3.96%
5/4/1989	13.00%	9.04%	3.96%
6/8/1989	13.50%	8.96%	4.54%
7/19/1989	11.80%	8.84%	2.96%
7/25/1989	12.80%	8.82%	3.98%
7/31/1989	13.00%	8.81%	4.19%
8/14/1989	12.50%	8.76%	3.74%
8/22/1989	12.80%	8.73%	4.07%
8/23/1989	12.90%	8.72%	4.18%
9/21/1989	12.10%	8.62%	3.48%
10/6/1989	13.00%	8.58%	4.42%
10/17/1989	12.41%	8.54%	3.87%
10/18/1989	13.25%	8.54%	4.71%
10/20/1989	12.90%	8.53%	4.37%
10/31/1989	13.60%	8.50%	5.10%
11/3/1989	12.93%	8.48%	4.45%
11/5/1989	13.20%	8.48%	4.72%
11/9/1989	13.00%	8.45%	4.55%
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11/28/1989	12.75%	8.37%	4.38%
12/7/1989	13.25%	8.32%	4.93%
12/15/1989	13.00%	8.28%	4.72%
12/20/1989	12.90%	8.26%	4.64%
12/21/1989	12.90%	8.25%	4.65%
12/21/1989	12.80%	8.25%	4.55%
12/27/1989	12.50%	8.23%	4.27%
1/9/1990	13.00%	8.19%	4.81%
1/18/1990	12.50%	8.16%	4.34%
1/26/1990	12.10%	8.14%	3.96%
3/21/1990	12.80%	8.15%	4.65%
3/28/1990	13.00%	8.16%	4.84%
4/5/1990	12.20%	8.17%	4.03%
4/12/1990	13.25%	8.19%	5.06%
4/30/1990	12.45%	8.24%	4.21%
5/31/1990	12.40%	8.31%	4.09%
6/15/1990	13.20%	8.33%	4.87%
6/27/1990	12.90%	8.34%	4.56%
6/29/1990	13.25%	8.35%	4.90%
7/6/1990	12.10%	8.36%	3.74%
7/19/1990	11.70%	8.38%	3.32%
8/31/1990	12.50%	8.53%	3.97%
8/31/1990	12.50%	8.53%	3.97%
9/13/1990	12.50%	8.58%	3.92%
9/18/1990	12.75%	8.60%	4.15%
9/20/1990	12.50%	8.61%	3.89%
10/2/1990	13.00%	8.65%	4.35%
10/17/1990	11.90%	8.68%	3.22%
10/31/1990	12.95%	8.70%	4.25%
11/9/1990	13.25%	8.70%	4.55%
11/19/1990	13.00%	8.70%	4.30%
11/21/1990	12.50%	8.70%	3.80%
11/21/1990	12.10%	8.70%	3.40%
11/28/1990	12.75%	8.70%	4.05%
11/29/1990	12.75%	8.70%	4.05%
12/18/1990	13.10%	8.68%	4.42%
12/20/1990	12.50%	8.67%	3.83%
12/21/1990	13.00%	8.67%	4.33%
12/21/1990	13.60%	8.67%	4.93%
12/21/1990	12.50%	8.67%	3.83%
1/3/1991	13.02%	8.66%	4.36%
1/16/1991	13.25%	8.63%	4.62%
1/25/1991	11.70%	8.61%	3.09%
2/15/1991	12.80%	8.56%	4.24%
2/15/1991	12.70%	8.56%	4.14%
4/3/1991	13.00%	8.51%	4.49%
4/30/1991	12.45%	8.48%	3.97%
4/30/1991	13.00%	8.48%	4.52%
6/25/1991	11.70%	8.34%	3.36%
6/28/1991	12.50%	8.34%	4.16%
7/1/1991	11.70%	8.34%	3.36%
7/19/1991	12.10%	8.31%	3.79%
7/19/1991	12.30%	8.31%	3.99%
7/22/1991	12.90%	8.30%	4.60%
8/15/1991	12.25%	8.28%	3.97%
8/29/1991	13.30%	8.26%	5.04%
9/27/1991	12.50%	8.23%	4.27%
9/30/1991	12.40%	8.23%	4.17%
10/3/1991	11.30%	8.22%	3.08%
10/9/1991	11.70%	8.21%	3.49%
10/15/1991	13.40%	8.20%	5.20%
11/1/1991	12.90%	8.20%	4.70%
11/8/1991	12.75%	8.20%	4.55%
11/26/1991	11.60%	8.18%	3.42%
11/26/1991	12.00%	8.18%	3.82%
11/27/1991	12.70%	8.18%	4.52%
12/6/1991	12.70%	8.16%	4.54%
12/10/1991	11.75%	8.15%	3.60%
12/19/1991	12.80%	8.14%	4.66%
12/19/1991	12.60%	8.14%	4.46%
12/30/1991	12.10%	8.11%	3.99%
1/22/1992	12.84%	8.05%	4.79%
1/31/1992	12.00%	8.03%	3.97%

2/20/1992	13.00%	8.00%	5.00%
2/27/1992	11.75%	7.98%	3.77%
3/18/1992	12.50%	7.94%	4.56%
5/15/1992	12.75%	7.86%	4.89%
6/24/1992	12.20%	7.85%	4.35%
6/29/1992	11.00%	7.85%	3.15%
7/14/1992	12.00%	7.83%	4.17%
7/22/1992	11.20%	7.82%	3.38%
8/10/1992	12.10%	7.79%	4.31%
8/26/1992	12.43%	7.75%	4.68%
9/30/1992	11.60%	7.72%	3.88%
10/6/1992	12.25%	7.72%	4.53%
10/13/1992	12.75%	7.71%	5.04%
10/23/1992	11.65%	7.71%	3.94%
10/28/1992	12.25%	7.71%	4.54%
10/29/1992	12.75%	7.70%	5.05%
10/30/1992	11.40%	7.70%	3.70%
11/9/1992	10.60%	7.70%	2.90%
11/25/1992	11.00%	7.68%	3.32%
11/25/1992	12.00%	7.68%	4.32%
12/3/1992	11.85%	7.66%	4.19%
12/16/1992	11.90%	7.64%	4.26%
12/22/1992	12.40%	7.62%	4.78%
12/22/1992	12.30%	7.62%	4.68%
12/30/1992	12.00%	7.61%	4.39%
12/31/1992	12.00%	7.61%	4.39%
1/12/1993	12.00%	7.59%	4.41%
1/12/1993	12.00%	7.59%	4.41%
2/2/1993	11.40%	7.53%	3.87%
2/22/1993	11.60%	7.48%	4.12%
4/23/1993	11.75%	7.27%	4.48%
5/3/1993	11.50%	7.25%	4.25%
5/3/1993	11.75%	7.25%	4.50%
6/3/1993	12.00%	7.20%	4.80%
6/7/1993	11.50%	7.20%	4.30%
6/22/1993	11.75%	7.16%	4.59%
7/21/1993	11.78%	7.06%	4.72%
7/21/1993	11.90%	7.06%	4.84%
7/23/1993	11.50%	7.05%	4.45%
7/29/1993	11.50%	7.03%	4.47%
8/12/1993	10.75%	6.97%	3.78%
8/24/1993	11.50%	6.92%	4.58%
8/31/1993	11.90%	6.88%	5.02%
9/1/1993	11.47%	6.87%	4.60%
9/1/1993	11.25%	6.87%	4.38%
9/27/1993	10.50%	6.74%	3.76%
9/29/1993	11.00%	6.72%	4.28%
9/30/1993	11.60%	6.72%	4.88%
10/8/1993	11.50%	6.67%	4.83%
10/14/1993	11.20%	6.65%	4.55%
10/15/1993	11.75%	6.64%	5.11%
10/25/1993	11.55%	6.60%	4.95%
10/28/1993	11.50%	6.58%	4.92%
10/29/1993	10.10%	6.57%	3.53%
10/29/1993	10.20%	6.57%	3.63%
10/29/1993	11.25%	6.57%	4.68%
11/2/1993	10.80%	6.56%	4.24%
11/12/1993	11.80%	6.53%	5.27%
11/23/1993	12.50%	6.51%	5.99%
11/26/1993	11.00%	6.50%	4.50%
12/1/1993	11.45%	6.49%	4.96%
12/16/1993	10.60%	6.45%	4.15%
12/16/1993	11.20%	6.45%	4.75%
12/21/1993	11.30%	6.44%	4.86%
12/22/1993	11.00%	6.44%	4.56%
12/23/1993	10.10%	6.44%	3.66%
1/5/1994	11.50%	6.41%	5.09%
1/10/1994	11.00%	6.40%	4.60%
1/25/1994	12.00%	6.37%	5.63%
2/2/1994	10.40%	6.35%	4.05%
2/9/1994	10.70%	6.34%	4.36%
4/6/1994	11.24%	6.35%	4.89%
4/25/1994	11.00%	6.39%	4.61%

6/16/1994	10.50%	6.63%	3.87%
6/23/1994	10.60%	6.67%	3.93%
7/19/1994	10.70%	6.83%	3.87%
9/29/1994	11.00%	7.20%	3.80%
9/29/1994	10.90%	7.20%	3.70%
10/7/1994	11.87%	7.26%	4.61%
10/18/1994	11.50%	7.32%	4.18%
10/18/1994	11.50%	7.32%	4.18%
10/24/1994	11.00%	7.35%	3.65%
11/22/1994	12.12%	7.52%	4.60%
11/29/1994	11.30%	7.55%	3.75%
12/1/1994	11.00%	7.56%	3.44%
12/8/1994	11.50%	7.59%	3.91%
12/8/1994	11.70%	7.59%	4.11%
12/12/1994	11.82%	7.60%	4.22%
12/14/1994	11.50%	7.61%	3.89%
12/19/1994	11.50%	7.62%	3.88%
4/19/1995	11.00%	7.72%	3.28%
9/11/1995	11.30%	7.16%	4.14%
9/15/1995	10.40%	7.13%	3.27%
9/29/1995	11.50%	7.06%	4.44%
10/13/1995	10.76%	6.98%	3.78%
11/7/1995	12.50%	6.86%	5.64%
11/8/1995	11.10%	6.85%	4.25%
11/8/1995	11.30%	6.85%	4.45%
11/17/1995	10.90%	6.81%	4.09%
11/20/1995	11.40%	6.80%	4.60%
11/27/1995	13.60%	6.77%	6.83%
12/14/1995	11.30%	6.68%	4.62%
12/20/1995	11.60%	6.65%	4.95%
1/31/1996	11.30%	6.45%	4.85%
3/11/1996	11.60%	6.40%	5.20%
4/3/1996	11.13%	6.41%	4.72%
4/15/1996	10.50%	6.41%	4.09%
4/17/1996	10.77%	6.40%	4.37%
4/26/1996	10.60%	6.40%	4.20%
5/10/1996	11.00%	6.40%	4.60%
5/13/1996	11.25%	6.41%	4.84%
7/3/1996	11.25%	6.49%	4.76%
7/22/1996	11.25%	6.54%	4.71%
10/3/1996	10.00%	6.77%	3.23%
10/29/1996	11.30%	6.84%	4.46%
11/26/1996	11.30%	6.86%	4.44%
11/27/1996	11.30%	6.86%	4.44%
11/29/1996	11.00%	6.86%	4.14%
12/12/1996	11.96%	6.85%	5.11%
12/17/1996	11.50%	6.85%	4.65%
1/22/1997	11.30%	6.83%	4.47%
1/27/1997	11.25%	6.83%	4.42%
1/31/1997	11.25%	6.83%	4.42%
2/13/1997	11.00%	6.82%	4.18%
2/13/1997	11.80%	6.82%	4.98%
2/20/1997	11.80%	6.81%	4.99%
3/27/1997	10.75%	6.79%	3.96%
4/29/1997	11.70%	6.81%	4.89%
7/17/1997	12.00%	6.77%	5.23%
10/29/1997	10.75%	6.70%	4.05%
10/31/1997	11.25%	6.70%	4.55%
12/24/1997	10.75%	6.53%	4.22%
4/28/1998	10.90%	6.11%	4.79%
4/30/1998	12.20%	6.10%	6.10%
6/30/1998	11.00%	5.94%	5.06%
8/26/1998	10.93%	5.82%	5.11%
9/3/1998	11.40%	5.80%	5.60%
9/15/1998	11.90%	5.77%	6.13%
10/7/1998	11.06%	5.70%	5.36%
10/30/1998	11.40%	5.63%	5.77%
12/10/1998	12.20%	5.52%	6.68%
12/17/1998	12.10%	5.49%	6.61%
2/19/1999	11.15%	5.32%	5.83%
3/1/1999	10.65%	5.31%	5.34%
3/1/1999	10.65%	5.31%	5.34%
6/8/1999	11.25%	5.35%	5.90%

11/12/1999	10.25%	5.92%	4.33%
12/14/1999	10.50%	5.99%	4.51%
1/28/2000	10.71%	6.16%	4.55%
2/17/2000	10.60%	6.20%	4.40%
5/25/2000	10.80%	6.19%	4.61%
6/19/2000	11.05%	6.18%	4.87%
6/22/2000	11.25%	6.18%	5.07%
7/17/2000	11.06%	6.15%	4.91%
7/20/2000	12.20%	6.14%	6.06%
8/11/2000	11.00%	6.11%	4.89%
9/27/2000	11.25%	6.00%	5.25%
9/29/2000	11.16%	6.00%	5.16%
10/5/2000	11.30%	5.98%	5.32%
11/28/2000	12.90%	5.87%	7.03%
11/30/2000	12.10%	5.86%	6.24%
2/5/2001	11.50%	5.75%	5.75%
3/15/2001	11.25%	5.66%	5.59%
5/8/2001	10.75%	5.61%	5.14%
10/24/2001	11.00%	5.54%	5.46%
10/24/2001	10.30%	5.54%	4.76%
1/9/2002	10.00%	5.50%	4.50%
1/30/2002	11.00%	5.47%	5.53%
1/31/2002	11.00%	5.47%	5.53%
4/17/2002	11.50%	5.44%	6.06%
4/29/2002	11.00%	5.45%	5.55%
6/11/2002	11.77%	5.48%	6.29%
6/20/2002	12.30%	5.48%	6.82%
8/28/2002	11.00%	5.49%	5.51%
9/11/2002	11.20%	5.45%	5.75%
9/12/2002	12.30%	5.45%	6.85%
10/28/2002	11.30%	5.35%	5.95%
10/30/2002	10.60%	5.34%	5.26%
11/1/2002	12.60%	5.34%	7.26%
11/7/2002	11.40%	5.33%	6.07%
11/8/2002	10.75%	5.33%	5.42%
11/20/2002	10.50%	5.30%	5.20%
11/20/2002	10.00%	5.30%	4.70%
12/4/2002	10.75%	5.27%	5.48%
12/30/2002	11.20%	5.19%	6.01%
1/6/2003	11.25%	5.16%	6.09%
2/28/2003	12.30%	5.01%	7.29%
3/7/2003	9.96%	4.99%	4.97%
3/12/2003	11.40%	4.97%	6.43%
3/20/2003	12.00%	4.95%	7.05%
4/3/2003	12.00%	4.92%	7.08%
5/2/2003	11.40%	4.88%	6.52%
5/15/2003	11.05%	4.87%	6.18%
6/26/2003	11.00%	4.80%	6.20%
7/1/2003	11.00%	4.80%	6.20%
7/29/2003	11.71%	4.78%	6.93%
8/22/2003	10.20%	4.81%	5.39%
9/17/2003	9.90%	4.85%	5.05%
9/25/2003	10.25%	4.85%	5.40%
10/17/2003	10.54%	4.87%	5.67%
10/22/2003	10.46%	4.87%	5.59%
10/22/2003	10.71%	4.87%	5.84%
10/30/2003	11.00%	4.88%	6.12%
10/31/2003	10.75%	4.88%	5.87%
10/31/2003	10.20%	4.88%	5.32%
11/10/2003	10.60%	4.89%	5.71%
12/9/2003	10.50%	4.93%	5.57%
12/18/2003	10.50%	4.94%	5.56%
12/19/2003	12.00%	4.94%	7.06%
12/19/2003	12.00%	4.94%	7.06%
1/13/2004	10.25%	4.95%	5.30%
1/13/2004	12.00%	4.95%	7.05%
2/9/2004	11.25%	4.98%	6.27%
3/16/2004	10.90%	5.05%	5.85%
3/16/2004	10.90%	5.05%	5.85%
5/25/2004	10.00%	5.06%	4.94%
6/2/2004	11.22%	5.07%	6.15%
6/30/2004	10.50%	5.10%	5.40%
7/8/2004	10.00%	5.10%	4.90%

7/22/2004	10.25%	5.10%	5.15%
8/26/2004	10.50%	5.10%	5.40%
8/26/2004	10.50%	5.10%	5.40%
9/9/2004	10.40%	5.10%	5.30%
9/21/2004	10.50%	5.09%	5.41%
9/27/2004	10.30%	5.09%	5.21%
9/27/2004	10.50%	5.09%	5.41%
10/20/2004	10.20%	5.08%	5.12%
11/30/2004	10.60%	5.08%	5.52%
12/8/2004	9.90%	5.09%	4.81%
12/21/2004	11.50%	5.09%	6.41%
12/22/2004	11.50%	5.09%	6.41%
12/28/2004	10.25%	5.09%	5.16%
2/18/2005	10.30%	4.95%	5.35%
3/29/2005	11.00%	4.86%	6.14%
4/13/2005	10.60%	4.84%	5.76%
4/28/2005	11.00%	4.80%	6.20%
5/17/2005	10.00%	4.77%	5.23%
6/8/2005	10.18%	4.71%	5.47%
6/10/2005	10.90%	4.71%	6.19%
7/6/2005	10.50%	4.65%	5.85%
7/19/2005	11.50%	4.63%	6.87%
8/11/2005	10.40%	4.60%	5.80%
9/19/2005	9.45%	4.53%	4.92%
9/30/2005	10.51%	4.52%	5.99%
10/4/2005	9.90%	4.52%	5.38%
10/4/2005	10.75%	4.52%	6.23%
10/14/2005	10.40%	4.52%	5.88%
10/31/2005	10.25%	4.53%	5.72%
11/2/2005	9.70%	4.53%	5.17%
11/30/2005	10.00%	4.53%	5.47%
12/9/2005	9.70%	4.53%	5.17%
12/12/2005	11.00%	4.53%	6.47%
12/20/2005	10.13%	4.53%	5.60%
12/21/2005	10.40%	4.52%	5.88%
12/21/2005	11.00%	4.52%	6.48%
12/22/2005	10.20%	4.52%	5.68%
12/22/2005	11.00%	4.52%	6.48%
12/28/2005	10.00%	4.52%	5.48%
1/5/2006	11.00%	4.52%	6.48%
1/25/2006	11.20%	4.52%	6.68%
1/25/2006	11.20%	4.52%	6.68%
2/3/2006	10.50%	4.52%	5.98%
2/15/2006	9.50%	4.53%	4.97%
4/26/2006	10.60%	4.65%	5.95%
7/24/2006	10.00%	4.87%	5.13%
7/24/2006	9.60%	4.87%	4.73%
9/20/2006	11.00%	4.93%	6.07%
9/26/2006	10.75%	4.93%	5.82%
10/20/2006	9.80%	4.96%	4.84%
11/2/2006	9.71%	4.97%	4.74%
11/9/2006	10.00%	4.97%	5.03%
11/21/2006	11.00%	4.98%	6.02%
12/5/2006	10.20%	4.97%	5.23%
1/5/2007	10.40%	4.95%	5.45%
1/9/2007	11.00%	4.94%	6.06%
1/11/2007	10.90%	4.94%	5.96%
1/19/2007	10.80%	4.93%	5.87%
1/26/2007	10.00%	4.92%	5.08%
2/8/2007	10.40%	4.91%	5.49%
3/14/2007	10.10%	4.86%	5.24%
3/20/2007	10.25%	4.84%	5.41%
3/21/2007	11.35%	4.84%	6.51%
3/22/2007	10.50%	4.84%	5.66%
3/29/2007	10.00%	4.83%	5.17%
6/13/2007	10.75%	4.81%	5.94%
6/29/2007	9.53%	4.84%	4.69%
6/29/2007	10.10%	4.84%	5.26%
7/3/2007	10.25%	4.85%	5.40%
7/13/2007	9.50%	4.86%	4.64%
7/24/2007	10.40%	4.87%	5.53%
8/1/2007	10.15%	4.88%	5.27%
8/29/2007	10.50%	4.91%	5.59%

9/10/2007	9.71%	4.91%	4.80%
9/19/2007	10.00%	4.91%	5.09%
9/25/2007	9.70%	4.92%	4.78%
10/8/2007	10.48%	4.92%	5.56%
10/19/2007	10.50%	4.91%	5.59%
10/25/2007	9.65%	4.91%	4.74%
11/15/2007	10.00%	4.89%	5.11%
11/20/2007	9.90%	4.89%	5.01%
11/27/2007	10.00%	4.88%	5.12%
11/29/2007	10.90%	4.88%	6.02%
12/14/2007	10.80%	4.87%	5.93%
12/18/2007	10.40%	4.86%	5.54%
12/19/2007	9.80%	4.86%	4.94%
12/19/2007	9.80%	4.86%	4.94%
12/19/2007	10.20%	4.86%	5.34%
12/21/2007	9.10%	4.86%	4.24%
1/8/2008	10.75%	4.83%	5.92%
1/17/2008	10.75%	4.81%	5.94%
1/17/2008	10.75%	4.81%	5.94%
2/5/2008	9.99%	4.78%	5.21%
2/5/2008	10.19%	4.78%	5.41%
2/13/2008	10.20%	4.76%	5.44%
3/31/2008	10.00%	4.63%	5.37%
5/28/2008	10.50%	4.53%	5.97%
6/24/2008	10.00%	4.52%	5.48%
6/27/2008	10.00%	4.52%	5.48%
7/31/2008	10.70%	4.50%	6.20%
7/31/2008	10.82%	4.50%	6.32%
8/27/2008	10.25%	4.50%	5.75%
9/2/2008	10.25%	4.50%	5.75%
9/19/2008	10.70%	4.48%	6.22%
9/24/2008	10.68%	4.48%	6.20%
9/24/2008	10.68%	4.48%	6.20%
9/24/2008	10.68%	4.48%	6.20%
9/30/2008	10.20%	4.48%	5.72%
10/3/2008	10.30%	4.48%	5.82%
10/8/2008	10.15%	4.47%	5.68%
10/20/2008	10.06%	4.47%	5.59%
10/24/2008	10.60%	4.46%	6.14%
10/24/2008	10.60%	4.46%	6.14%
11/21/2008	10.50%	4.42%	6.08%
11/21/2008	10.50%	4.42%	6.08%
11/21/2008	10.50%	4.42%	6.08%
11/24/2008	10.50%	4.41%	6.09%
12/3/2008	10.39%	4.37%	6.02%
12/24/2008	10.00%	4.26%	5.74%
12/26/2008	10.10%	4.24%	5.86%
12/29/2008	10.20%	4.23%	5.97%
1/13/2009	10.45%	4.14%	6.31%
2/2/2009	10.05%	4.04%	6.01%
3/9/2009	10.30%	3.89%	6.41%
3/25/2009	10.17%	3.84%	6.34%
4/2/2009	10.75%	3.81%	6.94%
5/5/2009	10.75%	3.71%	7.04%
5/15/2009	10.20%	3.70%	6.50%
5/29/2009	9.54%	3.70%	5.84%
6/3/2009	10.10%	3.71%	6.39%
6/22/2009	10.00%	3.73%	6.27%
6/29/2009	10.21%	3.74%	6.47%
6/30/2009	9.31%	3.74%	5.57%
7/17/2009	9.26%	3.75%	5.51%
7/17/2009	10.50%	3.75%	6.75%
10/16/2009	10.40%	4.09%	6.31%
10/26/2009	10.10%	4.11%	5.99%
10/28/2009	10.15%	4.12%	6.03%
10/28/2009	10.15%	4.12%	6.03%
10/30/2009	9.95%	4.12%	5.83%
11/20/2009	9.45%	4.18%	5.27%
12/14/2009	10.50%	4.24%	6.26%
12/16/2009	10.75%	4.25%	6.50%
12/17/2009	10.30%	4.26%	6.04%
12/18/2009	10.40%	4.26%	6.14%
12/18/2009	10.50%	4.26%	6.24%

12/18/2009	10.40%	4.26%	6.14%
12/22/2009	10.20%	4.27%	5.93%
12/22/2009	10.40%	4.27%	6.13%
12/28/2009	10.85%	4.29%	6.56%
12/29/2009	10.38%	4.30%	6.08%
1/11/2010	10.24%	4.34%	5.90%
1/21/2010	10.23%	4.37%	5.86%
1/21/2010	10.33%	4.37%	5.96%
1/26/2010	10.40%	4.37%	6.03%
2/10/2010	10.00%	4.39%	5.61%
2/23/2010	10.50%	4.40%	6.10%
3/9/2010	9.60%	4.40%	5.20%
3/24/2010	10.13%	4.42%	5.71%
3/31/2010	10.70%	4.43%	6.27%
4/1/2010	9.50%	4.43%	5.07%
4/2/2010	10.10%	4.44%	5.66%
4/8/2010	10.35%	4.44%	5.91%
4/29/2010	9.19%	4.46%	4.73%
4/29/2010	9.40%	4.46%	4.94%
4/29/2010	9.40%	4.46%	4.94%
5/17/2010	10.55%	4.46%	6.09%
5/24/2010	10.05%	4.46%	5.59%
6/3/2010	11.00%	4.46%	6.54%
6/16/2010	10.00%	4.46%	5.54%
6/18/2010	10.30%	4.46%	5.84%
8/9/2010	12.55%	4.41%	8.14%
8/17/2010	10.10%	4.40%	5.70%
9/16/2010	10.00%	4.31%	5.69%
9/16/2010	10.00%	4.31%	5.69%
9/16/2010	9.60%	4.31%	5.29%
9/16/2010	10.30%	4.31%	5.99%
10/21/2010	10.40%	4.20%	6.20%
11/2/2010	9.75%	4.17%	5.58%
11/2/2010	9.75%	4.17%	5.58%
11/3/2010	10.75%	4.17%	6.58%
11/19/2010	10.20%	4.15%	6.05%
12/1/2010	10.00%	4.13%	5.87%
12/6/2010	10.09%	4.12%	5.97%
12/6/2010	9.56%	4.12%	5.44%
12/9/2010	10.25%	4.12%	6.13%
12/14/2010	10.33%	4.11%	6.22%
12/17/2010	10.10%	4.11%	5.99%
12/20/2010	10.10%	4.11%	5.99%
12/23/2010	9.92%	4.10%	5.82%
1/6/2011	10.35%	4.09%	6.26%
1/12/2011	10.30%	4.09%	6.21%
1/13/2011	10.30%	4.09%	6.21%
3/10/2011	10.10%	4.16%	5.94%
3/31/2011	9.45%	4.20%	5.25%
4/18/2011	10.05%	4.23%	5.82%
5/26/2011	10.50%	4.32%	6.18%
6/21/2011	10.00%	4.36%	5.64%
6/29/2011	8.83%	4.38%	4.45%
8/1/2011	9.20%	4.41%	4.79%
9/1/2011	10.10%	4.33%	5.77%
11/14/2011	9.60%	3.93%	5.67%
12/13/2011	9.50%	3.76%	5.74%
12/20/2011	10.00%	3.72%	6.28%
12/22/2011	10.40%	3.70%	6.70%
1/10/2012	9.45%	3.59%	5.86%
1/10/2012	9.45%	3.59%	5.86%
1/10/2012	9.06%	3.59%	5.47%
1/23/2012	10.20%	3.53%	6.67%
1/31/2012	10.00%	3.49%	6.51%
4/24/2012	9.75%	3.16%	6.59%
4/24/2012	9.50%	3.16%	6.34%
5/7/2012	9.80%	3.13%	6.67%
5/22/2012	9.60%	3.10%	6.50%
5/24/2012	9.70%	3.09%	6.61%
6/7/2012	10.30%	3.06%	7.24%
6/15/2012	10.40%	3.05%	7.35%
6/18/2012	9.60%	3.05%	6.55%
7/2/2012	9.75%	3.04%	6.71%

10/24/2012	10.30%	2.92%	7.38%
10/26/2012	9.50%	2.92%	6.58%
10/31/2012	9.90%	2.92%	6.98%
10/31/2012	9.30%	2.92%	6.38%
10/31/2012	10.00%	2.92%	7.08%
11/1/2012	9.45%	2.91%	6.54%
11/8/2012	10.10%	2.91%	7.19%
11/9/2012	10.30%	2.90%	7.40%
11/26/2012	10.00%	2.89%	7.11%
11/28/2012	10.40%	2.88%	7.52%
11/28/2012	10.50%	2.88%	7.62%
12/4/2012	10.50%	2.87%	7.63%
12/4/2012	10.00%	2.87%	7.13%
12/20/2012	10.10%	2.84%	7.26%
12/20/2012	10.30%	2.84%	7.46%
12/20/2012	10.40%	2.84%	7.56%
12/20/2012	10.50%	2.84%	7.66%
12/20/2012	9.50%	2.84%	6.66%
12/20/2012	10.25%	2.84%	7.41%
12/26/2012	9.80%	2.83%	6.97%
2/22/2013	9.60%	2.86%	6.74%
3/14/2013	9.30%	2.89%	6.41%
3/27/2013	9.80%	2.92%	6.88%
4/23/2013	9.80%	2.96%	6.84%
5/10/2013	9.25%	2.96%	6.29%
6/13/2013	9.40%	3.01%	6.39%
6/18/2013	9.28%	3.02%	6.26%
6/18/2013	9.28%	3.02%	6.26%
6/25/2013	9.80%	3.04%	6.76%
9/23/2013	9.60%	3.33%	6.27%
11/6/2013	10.20%	3.42%	6.78%
11/13/2013	9.84%	3.44%	6.40%
11/14/2013	10.25%	3.44%	6.81%
11/22/2013	9.50%	3.47%	6.03%
12/5/2013	10.20%	3.50%	6.70%
12/13/2013	9.60%	3.52%	6.08%
12/16/2013	9.73%	3.53%	6.20%
12/17/2013	10.00%	3.53%	6.47%
12/18/2013	9.08%	3.53%	5.55%
12/23/2013	9.72%	3.55%	6.17%
12/30/2013	10.00%	3.57%	6.43%
1/21/2014	9.65%	3.66%	5.99%
1/22/2014	9.18%	3.66%	5.52%
2/20/2014	9.30%	3.71%	5.59%
2/21/2014	9.85%	3.72%	6.13%
2/28/2014	9.55%	3.73%	5.83%
3/16/2014	9.72%	3.74%	5.98%
4/21/2014	9.50%	3.73%	5.77%
4/22/2014	9.80%	3.73%	6.07%
5/8/2014	9.10%	3.71%	5.39%
5/8/2014	9.59%	3.71%	5.88%
6/6/2014	10.40%	3.66%	6.74%
6/12/2014	10.10%	3.66%	6.44%
6/12/2014	10.10%	3.66%	6.44%
6/12/2014	10.10%	3.66%	6.44%
7/7/2014	9.30%	3.63%	5.67%
7/25/2014	9.30%	3.60%	5.70%
7/31/2014	9.90%	3.59%	6.31%
9/4/2014	9.10%	3.50%	5.60%
9/24/2014	9.35%	3.46%	5.89%
9/30/2014	9.75%	3.44%	6.31%
10/29/2014	10.80%	3.37%	7.43%
11/6/2014	10.20%	3.35%	6.85%
11/14/2014	10.20%	3.33%	6.87%
11/14/2014	10.30%	3.33%	6.97%
11/26/2014	10.20%	3.30%	6.90%
12/3/2014	10.00%	3.29%	6.71%
1/13/2015	10.30%	3.16%	7.14%
1/21/2015	9.05%	3.13%	5.92%
1/21/2015	9.05%	3.13%	5.92%
4/9/2015	9.50%	2.88%	6.62%
5/11/2015	9.80%	2.82%	6.98%
6/17/2015	9.00%	2.79%	6.21%

8/21/2015	9.75%	2.78%	6.97%
10/7/2015	9.55%	2.82%	6.73%
10/13/2015	9.75%	2.83%	6.92%
10/15/2015	9.00%	2.84%	6.16%
10/30/2015	9.80%	2.87%	6.93%
11/19/2015	10.00%	2.89%	7.11%
12/3/2015	10.00%	2.91%	7.09%
12/9/2015	9.60%	2.92%	6.68%
12/11/2015	9.90%	2.92%	6.98%
12/18/2015	9.50%	2.94%	6.56%
1/6/2016	9.50%	2.97%	6.53%
1/6/2016	9.50%	2.97%	6.53%
1/28/2016	9.40%	2.97%	6.43%
2/10/2016	9.60%	2.95%	6.65%
2/16/2016	9.50%	2.94%	6.56%
2/29/2016	9.40%	2.92%	6.48%
4/29/2016	9.80%	2.83%	6.97%
5/5/2016	9.49%	2.82%	6.67%
6/1/2016	9.55%	2.80%	6.75%
6/3/2016	9.65%	2.79%	6.86%
6/15/2016	9.00%	2.77%	6.23%
6/15/2016	9.00%	2.77%	6.23%
9/2/2016	9.50%	2.56%	6.94%
9/23/2016	9.75%	2.52%	7.23%
9/27/2016	9.50%	2.51%	6.99%
9/29/2016	9.11%	2.50%	6.61%
10/13/2016	10.20%	2.48%	7.72%
10/28/2016	9.70%	2.47%	7.23%
11/9/2016	9.80%	2.47%	7.33%
11/18/2016	10.00%	2.49%	7.51%
12/9/2016	10.10%	2.51%	7.59%
12/15/2016	9.00%	2.53%	6.47%
12/15/2016	9.00%	2.53%	6.47%
12/20/2016	9.75%	2.53%	7.22%
12/22/2016	9.50%	2.54%	6.96%
1/24/2017	9.00%	2.59%	6.41%
2/21/2017	10.55%	2.63%	7.92%
3/1/2017	9.25%	2.65%	6.60%
4/11/2017	9.50%	2.77%	6.73%
4/20/2017	8.70%	2.79%	5.91%
4/28/2017	9.50%	2.81%	6.69%
5/23/2017	9.60%	2.88%	6.72%
6/6/2017	9.70%	2.91%	6.79%
6/22/2017	9.70%	2.93%	6.77%
6/30/2017	9.60%	2.94%	6.66%
7/20/2017	9.55%	2.97%	6.58%
7/31/2017	10.10%	2.98%	7.12%
9/13/2017	9.40%	2.93%	6.47%
9/19/2017	9.70%	2.92%	6.78%
9/22/2017	11.88%	2.92%	8.96%
9/27/2017	10.20%	2.92%	7.28%
10/20/2017	9.60%	2.90%	6.70%
10/26/2017	10.20%	2.90%	7.30%
10/30/2017	10.05%	2.90%	7.15%
11/21/2017	9.50%	2.88%	6.62%
12/5/2017	9.50%	2.86%	6.64%
12/7/2017	9.80%	2.86%	6.94%
12/13/2017	9.25%	2.85%	6.40%
12/28/2017	9.50%	2.84%	6.66%

# of Cases:	1076
Average:	4.62%

Division 4-12

Request:

Please provide the current state-authorized capital structure percentages and return on equity for each Narragansett U.S. gas and electric utility affiliate. Please indicate the date (month/year) when each return on equity was authorized.

Response:

The current state-authorized capital structure percentages and return on equity for each of the Company's US gas and electric utility affiliates are as follows:

On November 2, 2010, the Massachusetts Department of Public Utilities (Docket No. D.P.U. 10-55) authorized a hypothetical capital structure consisting of 50.00 percent long-term debt and 50.00 percent common equity and a return on equity of 9.75 percent for both Boston Gas Company and Colonial Gas Company. Boston Gas Company and Colonial Gas Company have an ongoing proceeding presently before the Massachusetts Department of Public Utilities (Docket No. D.P.U. 17-170) in which the companies are seeking to update their authorized capital structure and return on equity.

On March 14, 2013, the New York State Public Service Commission (Cases 12-E-0201 and 12-G-0202) authorized a comprehensive, multi-year, settlement agreement that included a capital structure consisting of 49.71 percent long-term debt, 1.01 percent short-term debt, 0.72 percent customer deposits, 0.56 percent preferred stock, and 48.00 percent common equity with a return on equity of 9.30 percent for Niagara Mohawk Power Corporation's electric and gas operations for the first year (coincident with the forecasted test year) of its three-year rate agreement. For the second year of the agreement, in addition to base revenue increases, the company was authorized a capital structure consisting of 49.95 percent long-term debt, 0.83 percent short-term debt, 0.69 percent customer deposits, 0.53 percent preferred stock, and 48.00 percent common equity with a return on equity of 9.30. For the third year of the agreement, in addition to base revenue increases, the company was authorized a capital structure consisting of 48.71 percent long-term debt, 2.16 percent short-term debt, 0.64 percent customer deposits, 0.49 percent preferred stock, and 48.00 percent common equity with a return on equity of 9.30. For all years of the rate agreement, and in conjunction with performance incentives, incremental earnings are shared between shareholders and customers based on a graduated sharing provision for returns in excess of 9.30 percent. On May 19, 2016, the company was permitted to extend its rate agreement an additional two years, incorporating incremental adjustments to the company's revenue requirement. Niagara Mohawk Power Corporation has an ongoing proceeding presently before the New York State Public Service Commission (Cases 17-E-0238 and 17-G-0239) seeking to update its authorized capital structure and return on equity.

Prepared by or under the supervision of: Joshua Nowak

On September 30, 2016, the Massachusetts Department of Public Utilities (Docket No. D.P.U. 15-155) authorized a consolidated capital structure consisting of 49.22 percent long-term debt, 0.09 percent preferred stock, and 50.70 percent common equity (numbers do not add to 100.00 percent due to rounding) and a return on equity of 9.90 percent for Massachusetts Electric Company and Nantucket Electric Company.

On December 15, 2016, the New York State Public Service Commission (Cases 16-G-0058 and 16-G-0059) authorized a comprehensive, multi-year, settlement agreement that included a capital structure consisting of 51.18 percent long-term debt, 0.82 percent customer deposits, and 48.00 percent common equity and a return on equity of 9.00 percent for The Brooklyn Union Gas Company (KEDNY) for the first year (coincident with the forecasted test year) of its three-year rate agreement. For the second year of the agreement, in addition to base revenue increases, KEDNY was authorized a capital structure consisting of 51.28 percent long-term debt, 0.72 percent customer deposits, and 48.00 percent common equity with a return on equity of 9.00. For the third year of the agreement, in addition to base revenue increases, KEDNY was authorized a capital structure consisting of 51.34 percent long-term debt, 0.66 percent customer deposits, and 48.00 percent common equity with a return on equity of 9.00. For all years of the rate agreement, and in conjunction with performance incentives, incremental earnings up to 9.50 percent are permitted to be retained by shareholders, with a graduated sharing provision for returns in excess of 9.50 percent.

In the same proceeding, and KeySpan Gas East Corporation (KEDLI) was authorized a capital structure consisting of 51.33 percent long-term debt, 0.67 percent customer deposits, and 48.00 percent common equity and a return on equity of 9.00 percent for the first year (coincident with the forecasted test year) of its three-year rate agreement. For the second year of the agreement, in addition to base revenue increases, KEDLI was authorized a capital structure consisting of 51.35 percent long-term debt, 0.65 percent customer deposits, and 48.00 percent common equity with a return on equity of 9.00. For the third year of the agreement, in addition to base revenue increases, KEDLI was authorized a capital structure consisting of 51.40 percent long-term debt, 0.60 percent customer deposits, and 48.00 percent common equity with a return on equity of 9.00. For all years of the rate agreement, and in conjunction with performance incentives, incremental earnings up to 9.50 percent are permitted to be retained by shareholders, with a graduated sharing provision for returns in excess of 9.50 percent.

Prepared by or under the supervision of: Joshua Nowak

Division 4-13

Request:

Please state the total number of retail utility customers served by National Grid USA.

Response:

As of January 3, 2018, the total number of active customer accounts as retrieved from National Grid's production billing systems was 6,605,440 for the gas and electric distribution operating companies of National Grid USA[1].

[1] These companies are The Narragansett Electric Company, Massachusetts Electric Company, Nantucket Electric Company, Boston Gas Company, Colonial Gas Company, Niagara Mohawk Power Corporation, The Brooklyn Union Gas Company, and KeySpan Gas East Corporation.

Prepared by or under the supervision of: Jody Allison

Division 4-14

Request:

Please state the current (or most recently available) net book value for National Grid USA.

Response:

Per the most recent GAAP financial statements for National Grid USA, and its subsidiaries (see Page 6 of Attachment DIV 4-14) as of September 30, 2017,the net book value is $30,320,000,000, calculated as the sum of the following:

	(in millions)
Total shareholders' equity	$15,754
Long-term debt	$9,804
Advance from affiliate	$4,384
Commercial paper	$143
Current portion of long-term debt	$123
Customer deposits	$112

Prepared by or under the supervision of: Joshua Nowak

National Grid USA and Subsidiaries

Condensed Consolidated Financial Statements

For the six months ended September 30, 2017 and 2016

(Unaudited)

NATIONAL GRID USA AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF INCOME
(in millions of dollars)

	Six Months Ended September 30, 2017	Six Months Ended September 30, 2016
Operating revenues:		
Electric services	**$ 3,248**	$ 3,097
Gas distribution	**1,629**	1,464
Other	**12**	11
Total operating revenues	**4,889**	4,572
Operating expenses:		
Purchased electricity	**778**	755
Purchased gas	**424**	313
Operations and maintenance	**2,181**	2,051
Depreciation	**530**	522
Other taxes	**573**	536
Total operating expenses	**4,486**	4,177
Operating income	**403**	395
Other income and (deductions):		
Interest on long-term debt	**(209)**	(202)
Other interest, including affiliate interest	**(37)**	(32)
Income from equity investments	**16**	15
Unrealized losses on investment in Dominion Midstream Partners, LP	**-**	(40)
Other income, net	**41**	33
Total other deductions, net	**(189)**	(226)
Income before income taxes	**214**	169
Income tax expense	**52**	47
Income from continuing operations	**162**	122
Income (loss) from discontinued operations, net of taxes	**1**	(1)
Net income	**163**	121
Net income attributable to non-controlling interest	**(1)**	(1)
Dividends paid on preferred stock	**(549)**	(592)
Net loss attributable to common shares	**$ (387)**	$ (472)

NATIONAL GRID USA AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME
(in millions of dollars)

	Six Months Ended September 30, 2017	Six Months Ended September 30, 2016
Net income	**$ 163**	$ 121
Other comprehensive income, net of taxes:		
Unrealized gains on securities	**5**	7
Change in pension and other postretirement obligations	**42**	50
Total other comprehensive income	**47**	57
Comprehensive income	**$ 210**	$ 178
Less: comprehensive income attributable to non-controlling interest	**(1)**	(1)
Comprehensive income attributable to common and preferred stock	**$ 209**	$ 177
Related tax (expense) benefit:		
Unrealized gains on securities	**$ (3)**	$ (3)
Change in pension and other postretirement obligations	**(31)**	(36)
Total tax expense	**$ (34)**	$ (39)

NATIONAL GRID USA AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF CASH FLOWS
(in millions of dollars)

	Six Months Ended September 30, 2017	2016
Operating activities:		
Net income	$ 163	$ 121
Adjustments to reconcile net income to net cash provided by operating activities:		
Depreciation	530	522
Regulatory amortizations	22	50
Provision for (benefit from) deferred income taxes	46	(6)
Bad debt expense	57	72
Loss (income) from equity and financial investments, net of dividends received	(16)	(18)
Unrealized losses on investment in Dominion Midstream Partners, LP	-	40
Allowance for equity funds used during construction	(12)	(19)
Amortization of debt discount and issuance costs	6	8
Net postretirement benefits expense (contributions)	40	(254)
Environmental remediation payments	(43)	(57)
Share based compensation	17	15
Changes in operating assets and liabilities:		
Accounts receivable, net, and unbilled revenues	629	402
Accounts receivable from/payable to affiliates, net	(12)	6
Inventory	(157)	(70)
Regulatory assets and liabilities, net	(43)	85
Derivative instruments	18	(5)
Prepaid and accrued taxes	(22)	13
Accounts payable and other liabilities	(284)	(134)
Renewable energy certificate obligations, net	29	(9)
Other, net	(23)	(27)
Net cash provided by operating activities	945	735
Investing activities:		
Capital expenditures	(1,370)	(1,335)
Proceeds from restricted cash and special deposits	55	82
Payments on restricted cash and special deposits	(53)	(51)
Cost of removal	(117)	(96)
Contributions in equity and financial investments	(68)	(35)
Other	8	(4)
Net cash used in investing activities	(1,545)	(1,439)
Financing activities:		
Preferred stock dividends	(549)	(592)
Payments on long-term debt	(26)	(439)
Proceeds from long-term debt	500	1,200
Payment of debt issuance costs	(2)	(13)
Commercial paper (paid) issued	(839)	644
Advance from affiliate	1,293	(513)
Payments on sale/leaseback arrangement	(2)	(3)
Net cash provided by financing activities	375	284
Net decrease in cash and cash equivalents	(225)	(420)
Net cashflow from discontinued operations - operating	1	8
Cash and cash equivalents, beginning of period	354	884
Cash and cash equivalents, end of period	$ 130	$ 472

NATIONAL GRID USA AND SUBSIDIARIES
CONSOLIDATED BALANCE SHEETS
(in millions of dollars)

	September 30, 2017	March 31, 2017
ASSETS		
Current assets:		
Cash and cash equivalents	$ 130	$ 354
Restricted cash and special deposits	72	74
Accounts receivable	1,761	2,250
Allowance for doubtful accounts	(397)	(416)
Accounts receivable from affiliates	1	2
Unbilled revenues	292	508
Inventory	501	399
Regulatory assets	658	530
Derivative instruments	9	32
Prepaid taxes	140	159
Other	98	83
Total current assets	3,265	3,975
Equity investments	268	210
Property, plant and equipment, net	30,412	29,418
Other non-current assets:		
Regulatory assets	4,764	4,833
Goodwill	7,129	7,129
Derivative instruments	3	2
Postretirement benefits asset	293	293
Financial investments	783	757
Other	156	157
Total other non-current assets	13,128	13,171
Total assets	$ 47,073	$ 46,774

NATIONAL GRID USA AND SUBSIDIARIES
CONSOLIDATED BALANCE SHEETS
(in millions of dollars)

	September 30, 2017	March 31, 2017
LIABILITIES AND CAPITALIZATION		
Current liabilities:		
Accounts payable	$ 1,190	$ 1,391
Accounts payable to affiliates	19	32
Advance from affiliate	4,384	3,091
Commercial paper	143	982
Current portion of long-term debt	123	106
Taxes accrued	33	74
Customer deposits	112	115
Interest accrued	148	145
Regulatory liabilities	878	833
Derivative instruments	61	54
Renewable energy certificate obligations	108	140
Other	386	458
Total current liabilities	7,585	7,421
Other non-current liabilities:		
Regulatory liabilities	3,134	3,049
Asset retirement obligations	98	96
Deferred income tax liabilities, net	5,637	5,548
Postretirement benefits	2,204	2,358
Environmental remediation costs	1,990	2,002
Derivative instruments	33	44
Other	834	833
Total other non-current liabilities	13,930	13,930
Capitalization:		
Common and preferred stock	14,281	14,264
Retained earnings	1,956	2,343
Accumulated other comprehensive loss	(505)	(552)
Common and preferred equity	15,732	16,055
Non-controlling interest	22	21
Total shareholders' equity	15,754	16,076
Long-term debt	9,804	9,347
Total capitalization	25,558	25,423
Total liabilities and capitalization	$ 47,073	$ 46,774

NATIONAL GRID USA AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF CHANGES IN SHAREHOLDERS' EQUITY
(in millions of dollars)

				Accumulated Other Comprehensive Income (Loss)						
	Common Stock	Cumulative Preferred Stock	Additional Paid-in Capital	Unrealized Gain (Loss) on Available-For-Sale Securities	Pension and Other Postretirement Benefits	Hedging Activity	Total Accumulated Other Comprehensive Income (Loss)	Retained Earnings	Non-controlling Interest	Total
Balance as of March 31, 2016	$ -	$ 35	$ 14,180	$ 4	$ (848)	$ (2)	$ (846)	$ 2,322	$ 9	$ 15,700
Net income	-	-	-	-			-	120	1	121
Other comprehensive income (loss):										
Unrealized gains on securities, net of $3 tax expense	-	-	-	7	-	-	7	-	-	7
Change in pension and other postretirement obligations, net of $36 tax expense	-	-	-	-	50	-	50	-	-	50
Total comprehensive income										178
Share based compensation	-	-	15	-	-	-	-	-	-	15
Preferred stock dividends	-	-	-	-	-	-	-	(592)	-	(592)
Balance as of September 30, 2016	$ -	$ 35	$ 14,195	$ 11	$ (798)	$ (2)	$ (789)	$ 1,850	$ 10	$ 15,301
Balance as of March 31, 2017	$ -	$ 35	$ 14,229	$ 12	$ (562)	$ (2)	$ (552)	$ 2,343	$ 21	$ 16,076
Net income	-	-	-	-			-	162	1	163
Other comprehensive income:										
Unrealized gains on securities, net of $3 tax expense	-	-	-	5	-	-	5	-	-	5
Change in pension and other postretirement obligations, net of $31 tax expense	-	-	-	-	42	-	42	-	-	42
Total comprehensive income										210
Share based compensation	-	-	17	-	-	-	-	-	-	17
Preferred stock dividends	-	-	-	-	-	-	-	(549)	-	(549)
Balance as of September 30, 2017	$ -	$ 35	$ 14,246	$ 17	$ (520)	$ (2)	$ (505)	$ 1,956	$ 22	$ 15,754

The Company had 641 shares of common stock authorized, issued and outstanding, with a par value of $0.10 per share, 915 shares of preferred stock authorized, issued and outstanding, with a par value of $0.10 per share and 372,641 shares of cumulative preferred stock authorized, issued and outstanding, with par values of $100 and $50 per share at September 30, 2017 and 2016.

Division 4-15

Request:

Please provide witness Hevert's opinion concerning the business risk profile of pure delivery service electric and gas utilities as compared to vertically-integrated electric utilities that own and operate generation facilities.

Response:

As noted in the Company's response to PUC 3-6, the business risk of a regulated electric utility, whether distribution-only or vertically integrated, is dependent on a number of factors. Holding all else equal, an electric utility that owns generation may have more business risk than a distribution-only electric utility. The nature of any such risk differential, however, varies on a case-by-case basis. Among other factors, the risk of an individual company will be largely dependent on its operating environment and the supportiveness of the jurisdiction's regulation.

Prepared by or under the supervision of: Robert Hevert

Division 4-16

Request:

Please state Narragansett's capital structure target (i.e., percentages for debt and equity) and the basis for selecting those targets.

Response:

The Company's current authorized regulatory capital structure consists of 49.14 percent common equity, 0.15 percent preferred stock, and 50.71 percent debt, but the Company targets a capital structure consisting of approximately 51 percent equity and 49 percent debt (excluding goodwill and accumulated other comprehensive income). These targets are determined in line with the Company's credit and risk profile and sound utility and rate-setting practices.

Prepared by or under the supervision of: Joshua Nowak

Division 4-17

Request:

Please provide copies of the Brattle Group reports (or the relevant portions relied upon by Mr. Hevert) referenced at footnotes 75 and 76 of Mr. Hevert's testimony.

Response:

Please see Attachment DIV 4-17-1 and Attachment DIV 4-17-2.

Prepared by or under the supervision of: Robert Hevert

The Impact of Revenue Decoupling on the Cost of Capital for Electric Utilities: An Empirical Investigation

PREPARED FOR

The Energy Foundation

PREPARED BY

Michael J. Vilbert
Joseph B. Wharton
Charles Gibbons
Melanie Rosenberg
Yang Wei Neo

March 20, 2014

THE Brattle GROUP

This report was prepared for The Energy Foundation. All results and any errors are the responsibility of the authors and do not represent the opinion of The Brattle Group, Inc. or its clients.

Acknowledgement: We acknowledge the valuable contributions of many individuals to this report and to the underlying analysis, including members of a peer review group that included Sheryl Carter, Ralph Cavanagh, Marty Kushler and Devra Wang.

Table of Contents

I. OVERVIEW AND SUMMARY

Research into the costs and benefits of energy efficiency (EE) technologies has shown that the expected value of long-run savings frequently exceeds the costs, and EE programs have the additional benefit of producing no harmful emissions. From 2007 to the present, several more states have adopted long-term goals for EE and have designated utilities, and in a few cases third party entities, as the program administrators. Despite the programs being beneficial and cost-effective to society and to utility systems, traditional regulation creates a substantial disincentive for utilities to pursue EE programs.

Traditional cost-of-service ratemaking collects a utility's total costs, fixed and variable, largely through volumetric rates. A large portion of an electric, gas, or water utility's costs is fixed in the short run and does not vary with the quantity of the service provided (kWh, Therms, or Cubic feet). A successful EE program will reduce the volume of sales, which will simultaneously reduce the recovery of fixed costs. If sales are lower than expected when rates are set, a utility will not fully recover its authorized fixed-cost revenue requirement; and if sales are higher than expected, a utility will over-collect its revenue requirement. As a result, utilities have what is often called a "throughput incentive" that conflicts with the objectives of EE programs.

Decoupling is a form of regulated ratemaking that disconnects fixed cost recovery from changes in the utility's sales volume.[1] It originated as a policy response in the 1980s when utilities were first encouraged to develop EE programs that significantly reduced the consumption of regulated commodities, such as electricity, gas, or water.[2] Decoupling solves the throughput incentive. The Brattle Group's (Brattle) recent survey of new, alternative ratemaking policies listed 22 states that allowed gas industry decoupling, 12 states that had electric industry decoupling, and 5 states had water conservation adjustments.[3] This report builds on several public surveys of alternative

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1 "Decoupling," as used in this report, means decoupling through symmetric revenue true-up mechanisms. An overall base revenue target is established for a future period. A periodic adjustment of volumetric rates is instituted to true up actual revenues to target revenues, whether actual revenues are above or below the target. Two other alternative ratemaking policies have some similarities but are not included in this study. One is the lost revenue adjustment mechanism (LRAM) for recovering only base revenues lost from validated EE volumetric savings. A second policy is the straight fixed-variable rate design that collects all or most fixed costs in non-volumetric charges.

2 This report focuses on the electric utility industry. There are many similarities and common lessons for decoupling policy development in the electric, natural gas, and private water service industries. Prior research by The Brattle Group addressed the natural gas delivery industry, see footnote 5 below.

3 Joe Wharton, Bente Villadsen, and Heidi Bishop, *Alternative Regulation and Ratemaking Approaches for Water Companies - Supporting Capital Investment Needs of the 21st Century*, The Brattle Group, Prepared for the National Association of Water Companies, September 30, 2013. The number of

Continued on next page

ratemaking policies that include decoupling.[4] In the last half dozen years, decoupling has grown rapidly in the electric industry coincident with the upsurge in expenditures for conservation programs, efficiency standards, and the general flattening of electricity sales growth.

Because of the potential effect on the cost of equity (COE), the adoption of EE programs accompanied by a decoupling policy is sometimes resisted by both regulated companies and interveners for opposite reasons. Some interveners and commission staffs have argued that the allowed return on equity (ROE) should be reduced because decoupling, by design, reduces the variability of revenues, which they believe translates directly into reduced business risk. If the allowed ROE is not reduced, those interveners may not support decoupling. Utilities fear that adoption of decoupling will result in a reduction in the allowed ROE even if there is no proof that decoupling actually reduces the cost of capital. Determining the actual, empirical effect of decoupling on the utility's cost of capital is critical to answering the question of whether the regulated company's allowed cost of capital should be reduced at the time of adoption.

The Brattle authors have considerable experience with the issues of decoupling rate policy and the frequently asked question as to whether it has a measurable impact on the cost of capital (COC) of regulated companies, as assessed in financial markets. In 2010 and again in 2013, the authors empirically tested the hypothesis in the natural gas delivery industry and found that there was no statistically measurable effect on the COC with decoupling.[5] In this report, we test

Continued from previous page

companies and states with decoupling changes relatively frequently. For example, Washington State returned to decoupling in mid-2013, a change that was not in the Brattle survey, *Op. Cit*.

4 Sources of information on decoupling and other alternative regulatory policies beyond the Brattle survey *Op. Cit*. include Pamela Morgan, *A Decade of Decoupling for U.S. Energy Industries: Rate Impacts, Designs, and Observations*, Dec. 2012; Edison Electric Institute (EEI), *Alternative Regulation for Evolving Utility Challenges: An Updated Survey*, Pacific Economics Group Research LLC, Jan. 2013; Institute of Electric Efficiency (IEE), *State Electric Efficiency Regulatory Frameworks*, July 2013; and American Gas Association (AGA), *Natural Gas Innovative Rates, Non-Volumetric Rates, and Tracking Mechanisms Current List*, Cynthia J. Marple, power point presentation, Sept. 2012. For this study, Brattle reviewed many of the sources and updated the periods that decoupling policies have been in place for different states.

5 In the previous research, the authors analyzed a sample of 12 natural gas delivery holding companies (HCs) and their 31 regulated gas subsidiaries over the period 2005 to 2012. The number of gas subsidiary companies operating under decoupling grew from 8 to 22 over the period. This analysis made accurate measurements of the cost of capital and developed consistent measurements of the degree of decoupling of each HC for a decoupling "metric". The findings were that decoupling shows no statistically significant impact on the COC either up or down. See J. Wharton, M. Vilbert, C. Gibbons, and S. Lagos, *An Empirical Study of Impact of Decoupling on Cost of Capital*, Power Point presentation to the Western Conference of the Rutgers University Center for Research in Regulated Industries (CRRI), June 21, 2013.

the same hypothesis for a different set of utilities which are predominantly in the electric utility business.

Theoretical arguments for reducing the cost of capital are frequently offered by interveners in decoupling regulatory proceedings for electric and natural gas companies and have been accepted in a small number of commission decisions.[6] In some proceedings, different interveners have suggested that the effect of decoupling on ROE is anywhere from 25 basis points (bps) to 300 bps.[7] In the past, the Brattle authors have testified that in these regulated, high fixed cost industries, the determinants of the cost of capital are complicated,[8] and there should be no presumption that decoupling automatically lowers the cost of capital. Adoption of decoupling policies could be coincident with other influences that may be increasing non-diversifiable risk.[9] Any reduction in the allowed return on equity should be based upon evidence that decoupling reduces the cost of capital.

The results of our empirical analysis of decoupling in the electric industry do <u>not</u> support the hypothesis that utilities with decoupling have a lower cost of capital than utilities without decoupling. Our study finds that decoupling is not associated with a statistically significant decrease in the estimated cost of capital. This result is consistent with our previous findings for the natural gas distribution industry.

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6 Pamela Morgan reports that the return on equity (ROE) was not reduced in 78% of the Commission decisions adopting decoupling. The remaining decisions reduced the allowed ROE by 10 and 50 basis points. In settlements, 85% had no ROE reductions and the remaining 15% were between 10 and 25 basis points. See "A Decade of Decoupling for U.S. Energy Industries: Rate Impacts, Designs, and Observations", Dec. 2012, p. 14.

7 For example, see pp. 19-20 of "Phase 1B Testimony of Terry L. Murray on behalf of the Division of Ratepayer Advocates on Return on Equity Adjustments" before the California Public Utilities Commission, filed October 19, 2007 in Docket No. I. 07-01-022. Also see a recent discussion on p. 44 of Washington Utilities and Transportation Commission, *Puget Sound Energy, Final Order Granting Petition*, Docket UE-121697, Section D.2.b "Decoupling – Cost of Capital," June 25, 2013.

8 *See* Chapters 7-9, Brealey, Myers and Allen, *Principles of Corporate Finance*, 11th edition, McGraw Hill Irwin, 2014 for a discussion of the cost of capital.

9 Diversifiable risks, such as weather, do not affect the cost of capital because diversifiable risks can be eliminated by investing in a portfolio of unrelated assets.

II. DEVELOPMENTS IN THE POLICY OF REVENUE DECOUPLING

Adoption of a revenue decoupling policy[10] severs the link between recoveries of base or fixed revenues[11], from volumetric sales of kWh, which would normally be the case under traditional cost-of-service regulation. Cost recovery is not based upon actual kWh sales, but instead on a revenue target. Revenues are adjusted to achieve the target. For example, the percent growth in revenues relative to the base period could be set at actual net percentage growth in the numbers of customers over the base period. Over a pre-established period, such as a year, there is an adjustment of rates that will true-up the actual revenues to the target, whether actual sales are higher or lower than expected.

Current decoupling policies frequently evolve from the same policy basis as the earliest version, which was instituted in California in 1980 for natural gas utilities and in 1982-83 for electric utilities.[12] California policy makers determined that decoupling would be "in the public interest" in part because it provided relief for differences in actual revenues compared to forecast revenues when utilities carried out policy directives to pursue aggressive energy efficiency goals. Customers are protected if sales are greater than forecast, and utilities recover their fixed costs if EE programs are more effective than expected.[13]

Figure 1 illustrates the substantial increase in EE expenditures by electric utilities since 2007 as well as two projections of expenditures in 2025.[14] The growth of EE programs, the consequent installation of efficiency measures (equipment and structures), and the concurrent decline in

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10 The treatment of decoupling in this study is straight forward: at a given time for a given state-regulated electric company, a decoupling policy is in place, or it is not. Beyond what is discussed in footnote 1, we recognize but do not attempt to differentiate the several different kinds of decoupling mechanisms. Decoupling policies can vary in several dimensions: the companion revenue adjustment mechanism, the coverage and independence of rate classes; the inclusiveness of causes of demand fluctuation (weather fluctuations may be excluded); the adjustment over time using revenue target adjustment mechanism (numbers of customers and certain cost categories can be used to adjust targets over time).

11 Lost revenues for the recovery of variable costs, such as fuel and purchased power, are not included in decoupling true-ups because variable costs are avoided with the reduction in kWh consumption. Fixed costs only change in the long-term when depreciation and conservation leads to less system investment.

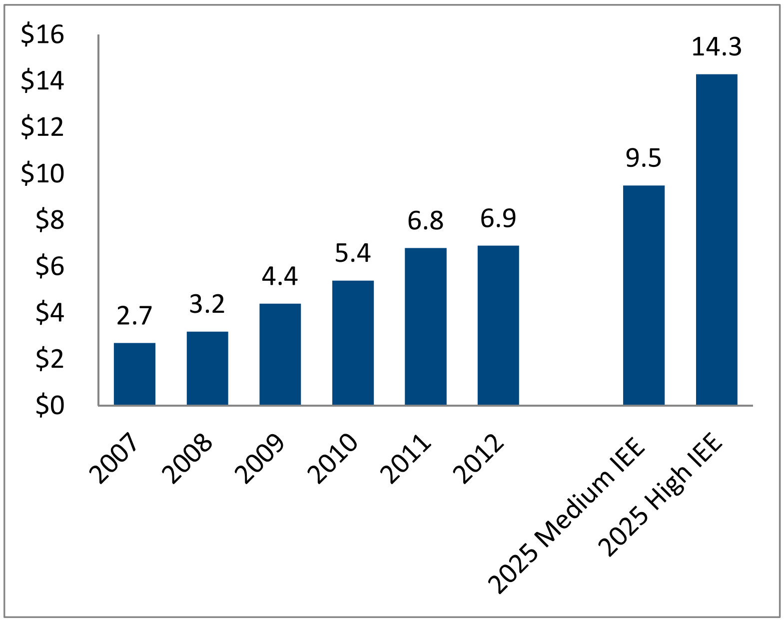
12 Dr. John L. Jurewitz, *Decoupling and Energy Efficiency Incentives: The California Experience*, EEI 2007 Spring Legal Conference, Charleston, SC, April 16, 2007.

13 In addition, disputes over sales forecasts may be reduced because the earnings of the regulated company are not affected by differences in forecasts.

14 Institute of Electric Efficiency (IEE); *State Electric Efficiency Regulatory Frameworks*, July 2013, p. 2. The values are spending and budgets for customer-funded electric efficiency programs.

kWh sales growth, especially for small customers on volumetric rates, highlights the importance of addressing the throughput incentive of regulated utilities.

Figure 1: U.S. Energy Efficiency Expenditures (Customer Funded, in $ Billions)



Source: Institute for Electric Efficiency, 2013

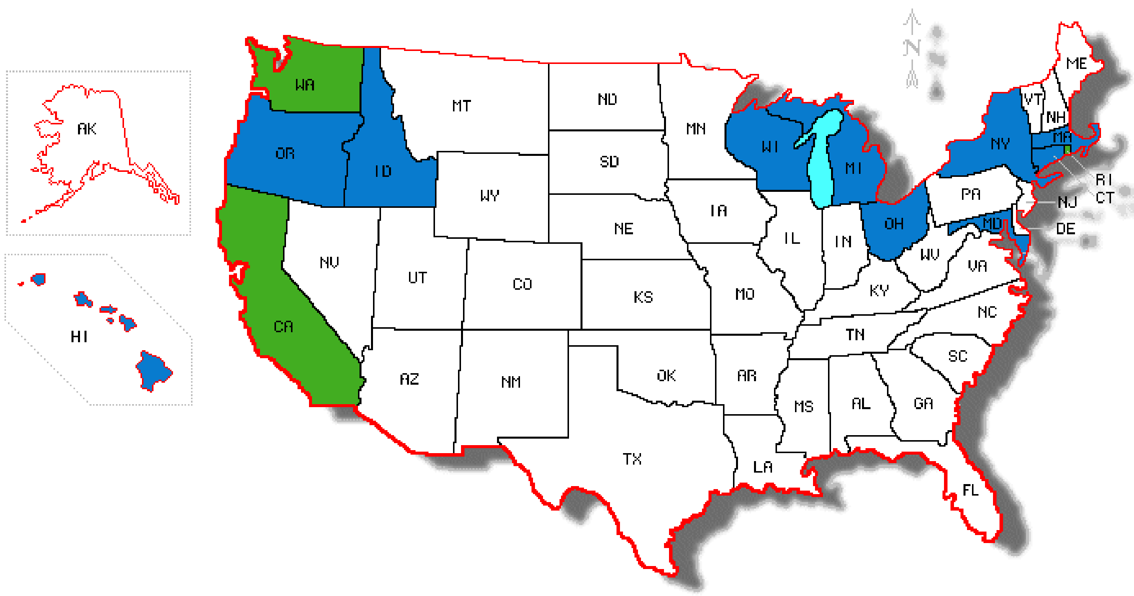
Figure 2 displays a map of the states that at present or in the recent past have had a policy of decoupling.[15] This is the starting point of the analysis. Utilities in California, Washington, and Rhode Island (shown in green) were not used in our sample. National Grid is the holding company for Narragansett Electric in Rhode Island. Observations were removed in the financial data screening because National Grid is a company based in the United Kingdom, so capital market information may not be compatible.[16] The major California utilities had the policy of decoupling or its equivalent across the entire study period 2005 – 2012, and saw no change in policy, so there was no way to compare the cost of capital before and after adoption of

15 In principle and practice, decoupling can be ended. Our sample includes utilities in Michigan where decoupling for electric utilities was instituted by the commission for several electric companies and later determined to be illegal under state law.

16 National Grid is traded as an American Depository Receipt (ADR) and so is excluded from the analysis.

decoupling. Washington state regulators approved decoupling for Puget Sound Energy in June 2013, after the study period ended.[17]

Figure 2: States with a Policy of Decoupling for Electric Utilities at Some Point in Time from 2005 to the Present



Source: The Brattle Group, *Alternative Regulation and Ratemaking Approaches for Water Companies*, Sep. 30, 2013. All states were in the study sample, except Washington, California, and Rhode Island, shown in green.

Decoupling policies often focus on the residential and commercial classes, where volumetric charges collect a considerable portion of the base revenue requirement that recovers capital investment and fixed operations and maintenance (O&M) costs of distribution. Figure 3 shows the downward trend in residential and commercial electric consumption growth in recent decades, indicating that it is likely to be lower than population or GDP growth in the future. Decoupling can be used to address the situation where fixed and unavoidable costs continue to increase, but where sales volume growth is slow or decreasing for any reasons, including the utility's EE programs, building codes, appliance efficiency standards, and the installation of distributed generation systems on customers' premises.

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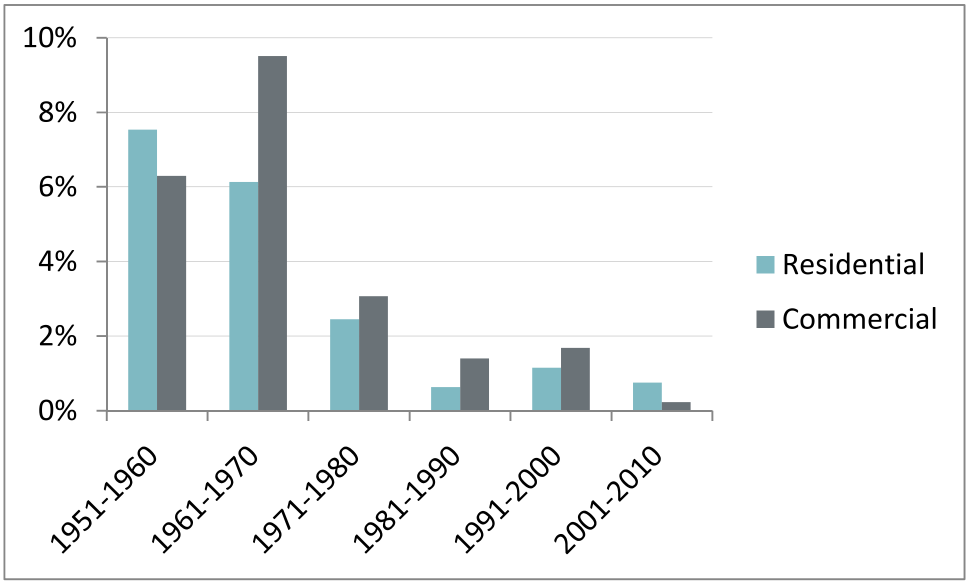
17 See Washington Utilities and Transportation Commission, Puget Sound Energy, *Op. Cit.*, footnote 7. Puget Sound Power & Light, predecessor to Puget Sound Energy, had a decoupling mechanism in place from 1991 to 1995, at which time it was discontinued. This is before the Study Period.

Figure 3: Trends in Electric Consumption Growth by Decade: 1951 - 2010



III. COST OF CAPITAL THEORY AND THE IMPACTS OF DECOUPLING

A regulated utility's operating earnings (i.e., earnings before income taxes) are the difference between base revenues (non-fuel) and the sum of all prudent costs, including O&M, administrative and general (A&G), depreciation, and interest. There are several sources of variability in the base revenue stream that can be eliminated by the decoupling mechanism analyzed here. EE programs normally decrease revenues because they decrease sales. Other increases and/or decreases in base revenues are driven by changes in weather, business activity over the business cycle, the number of net new customers, local, state and federal building and appliance codes and standards, and the number of delinquent bills. By design, decoupling ratemaking eliminates or significantly weakens the linkage between revenues and the volume sold, independently from the sources of variability.

Decoupling should stabilize revenues, but net income can still vary. Although depreciation and interest expense are relatively stable, other costs can change materially between rate cases. At times of rapid capital investment, for example, when utilities face significant environmental retrofits and replacements, depreciation and interest may also increase rapidly and put pressure on earnings unless there are more frequent rate cases to adjust base revenues.

If decoupling stabilizes the revenue side of the earnings equation, does it stabilize operating earnings as well? This leads directly to the question: does decoupling reduce non-diversifiable risk since this is the risk that determines the cost of capital in financial markets? We shall see that the answer is not a simple "yes."

Not all risks or sources of variance in earnings affect the cost of capital equally, because investors can avoid certain risks. Diversification through portfolio formation can remove diversifiable risks; therefore, diversifiable risks do not affect the cost of capital. For example, extreme weather will cause variance in a single utility's revenues and are a risk factor for that utility's earnings. However, investors can assemble a portfolio of utility stocks from across the climate zones in the United States, thus mitigating the effects of weather on individual stocks. For a portfolio of utility stocks, the effect of weather variations should largely cancel out, removing weather as a source of investment risk, and negating its effect on the cost of capital. Non-diversifiable risks (also known as "business risks") are the risks that remain after diversification. Because investors must bear them, these risks affect a company's cost of capital. The distinction between diversifiable risk and non-diversifiable business risk is important to recognize when evaluating the effect of decoupling, or other regulatory policies, on a company's cost of capital. Simply reducing total risk, i.e., the sum of diversifiable and non-diversifiable risk, does not imply that the cost of capital has been reduced. The risk reduced must be part of a company's business risk, i.e., its non-diversifiable risk, to affect its cost of capital.

Decoupling is often praised by credit rating agencies because it clearly reduces total risk, which is the risk important to bond holders. Adoption of decoupling could reduce the overall cost of capital for a company through a reduction in the cost of debt, but that would not justify a reduction in the allowed ROE. Only reductions in business risk justify a reduction in a regulated company's allowed ROE.

The effect of decoupling on the cost of capital in the current electric environment of low growth and high investment cannot be determined solely on theoretical reasoning. Empirical analysis is needed, looking at the record compiled by utilities across the nation, both before and after adoption of decoupling mechanisms.

IV. CREATING A DECOUPLING SAMPLE OF REGULATED ELECTRIC UTILITIES

We start with a large sample of regulated electric company subsidiaries and their holding companies, then compile data on which have a decoupling policy and when it was officially adopted. We immediately note an important dichotomy. Holding companies, not their subsidiaries, have publicly traded stock that provides the financial information necessary to estimate the cost of capital. On the other hand, individual, state-regulated subsidiaries, not the holding companies themselves, apply for, and are granted, the policy of decoupling. Our methodology addresses this dichotomy. We measure the degree of decoupling of each holding company by examining the decoupling policies of its subsidiaries after differentiating each state in which a subsidiary operates. We use the subsidiary's share of the holding company's asset to establish the weights of the different subsidiaries.[18]

Another feature of the study design is to analyze only a sample of regulated utilities that have experienced a change in decoupling policy within the study period, 2005 to 2012.[19] As mentioned above, adoption of decoupling has been increasing along with the surge in spending on EE programs. There are several recent public surveys of alternative ratemaking policies that include decoupling.[20] In the fall of 2013, Brattle, and specifically one of this report's authors, completed a major study comparing the alternative ratemaking schemes of electric utilities on behalf of the National Association of Water Companies.[21] The report used and supplemented the public survey data on regulated electric utilities that had adopted decoupling as of the summer of 2013. This report supplements the earlier sources with additional information on the Specific Date on which the regulatory policy of decoupling was adopted for each state subsidiary.[22]

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[18] In this report, we use the term "subsidiary" to refer to the segment of a utility that is regulated at the state level. A particular holding company might own two utilities that are separate corporations. Assume the first is located in a single state, while the second has a service territory extending over three states. In our analysis, this holding company would have four "subsidiaries" for purposes of calculating its degree of decoupling. There are also situations, such as Con Edison in NY, where a holding company owns more than one subsidiary within a single state, and the individual subsidiaries get decoupling at different times. Our weighted average decoupling metric captures this.

[19] The choice of the study period was deliberate. The study started with the first quarter of 2005 when no holding companies in our sample had an electric subsidiary under decoupling. That continued for seven quarters until first quarter of 2007, when Idaho Power was decoupled. Thus, the study period has eight quarters of data for observing cost of capital without decoupling. There followed steady growth in decoupling across the sample states for the next six years, as shown in Figure 4. Our project and the data collection were initiated in the middle of 2013, so the last quarter of 2012 was used as an end point.

[20] Sources of information on decoupling and other alternative regulatory policies are cited in footnotes 3 and 4. Where there are disagreements, Brattle investigated and decided which policies to include for a state.

[21] The Brattle Group, *Alternative Regulation and Ratemaking Approaches for Water Companies*, *Op. Cit*. Footnote 3. See Appendix A, "Tabulation of the Alternative Regulatory and Rate Approaches in the Three Infrastructure Industries."

[22] We assume that for a particular state subsidiary, this Specific Date of approval is the likely date when any uncertainty in capital markets about adoption of decoupling is fully resolved, resulting in the possible change in cost of capital from a reassessment of the future risk for the holding company that owned the state regulated electric utility at issue. Capital markets are forward looking, and investors are aware of regulatory proceedings that potentially affect future risk. We report in the final section some results that test whether the capital markets anticipate the adoption of decoupling by one, two or three quarters prior to the Specific Date.

Each Specific Date was initially defined as the month and year of adoption. This was then converted to a quarter and year, so as to match the financial data. Decoupling for a state-regulated electric subsidiary is a binary variable, 0 or 1. On its Specific Date, each state subsidiary goes from 0, not decoupled, to 1, decoupled, or in the reverse direction. In general, a holding company may have several subsidiaries, and the Decoupling Index for the holding company is a weighted average of its subsidiaries. The decoupling index changes on each Specific Date, with the weights being the relative book value of assets in the subsidiaries with decoupling compared to the total book value of total assets of the holding company. Thus, for each sample holding company, we calculate a percentage of total assets that are decoupled as of each quarter in the study period. For example, a company with two subsidiaries, one decoupled representing 40 percent of the total assets and the other not decoupled, would have a decoupling index of 0.40 in the quarter.

The calculation of the decoupling index is sometimes complicated by the fact that some regulated subsidiaries cover more than one state and could have decoupling in one state and not the other. In that circumstance, we estimate the percentage of assets that are decoupled for that subsidiary by reference to the percentage of MWh of electricity consumed in the separate jurisdictions compared to the total MWh for the entire subsidiary. This is necessary because the distribution of assets of a multistate subsidiary is not generally reported.

The decoupling sample development started with the Brattle *Alternative Rates* Report of September 2013, supplemented by additional information. The initial list included 98 state regulated electric companies in 42 states. The final sample contains a subset of the following size:

- 14 electric holding companies;
- 21 state-regulated electric subsidiaries of the holding companies. The subsidiaries operate in 11 states and during some quarters in the study period had decoupling;
- 32 quarters from 2005 through 2012, when growth in the policy of decoupling was rapid; and
- 291 observations, each pertaining to a holding company and consisting of the cost of capital in that quarter, the decoupling index value in that quarter, and a set of explanatory or dummy variables, as discussed below in Section V. Holding company data financial data are screened for potential bias, using a set of standard financial and other criteria that Brattle uses continuously when estimating the cost of capital. The criteria are discussed in Section V.

Figure 4 shows the increase in the total state subsidiaries in our sample with decoupling over the study period.

Figure 4: Count of State Regulated Subsidiaries
In Sample with Decoupling over the Study Period 2005 – 2012

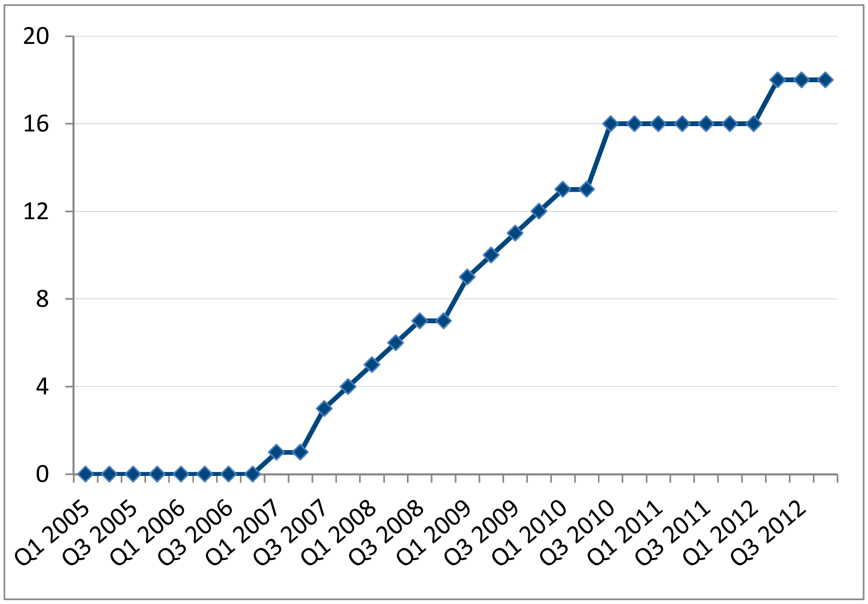
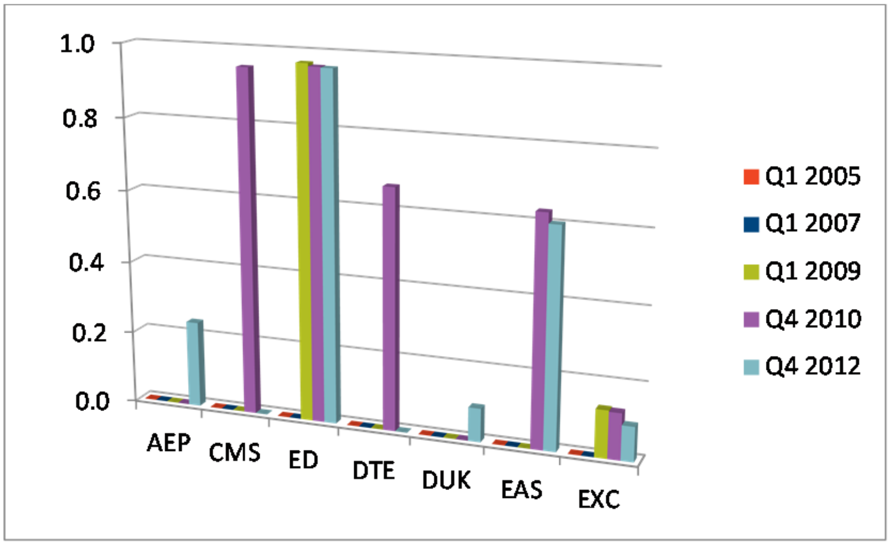
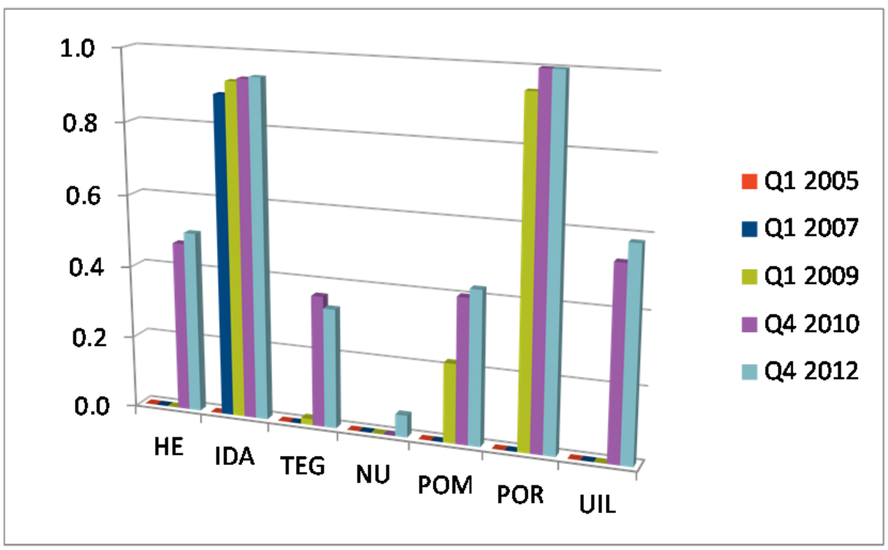


Figure 5 displays the decoupling index values for the 14 individual holding companies at selected times over the study period. These holding companies had no decoupling at the beginning in 2005 – 2006, but this changed substantially over the next six years.

Figure 5: The Level of Electric Decoupling Index for 14 Holding Companies in 5 Selected Quarters in Study Period





The holding companies are American Electric Power Co. Inc. (AEP), CMS Energy Corp. (CMS), Consolidated Edison, Inc. (ED), DTE Energy Co. (DTE), Duke Energy Corp. (DUK), Energy East (EAS), Exelon Corp. (EXC), Hawaiian Electric Industries Inc. (HE), IDACORP Inc. (IDA), Integrys Energy Group Inc. (TEG), Northeast Utilities (NU), Pepco Holdings Inc. (POM), Portland General Electric Co. (POR), UIL Holdings Corp. (UIL).

V. ESTIMATION OF THE COST OF CAPITAL FOR THE ELECTRIC INDUSTRY

This section explains the estimation of the cost of capital for the sample holding companies. First, the universe of holding companies is screened to remove companies whose estimated cost of capital could be biased by other factors. To be in the sample, the holding companies must meet all of the following conditions:

- no recent, substantial merger and acquisition (M&A) activity;
- investment grade credit rating, i.e., BBB- or better;
- has not cut its dividend in the last two quarters; and
- is a U.S. company.

Substantial M&A activity is defined to be a merger or acquisition/divestiture comprising 25 percent or more of the pre-merger book value of assets of the company. The stock prices of companies involved in mergers or acquisitions react more to the latest news on the progress of the M&A than to developments in the capital markets, but this is contrary to the assumptions underlying the cost of capital estimation models. A holding company with substantial M&A activity is dropped from the sample for the period one quarter before the quarter of the merger announcement through two quarters after the quarter in which the merger was consummated or abandoned.

Companies with non-investment grade credit ratings are generally considered to be in financial distress so that their cost of capital estimates could be affected by the market's perception of their likely survival in their current form. Similarly, companies resist cutting dividends unless absolutely necessary to conserve cash. Cutting the dividend is viewed by the market as a signal of some level of financial distress, so we require that there be no dividend cuts in the previous two quarters. Finally, only U.S. companies are considered because the cost of capital may differ for companies whose home capital market is in another country. In all these situations, the cost-of-capital estimates are likely to be biased.

<u>Estimating the Overall After-Tax Weighted-Average Cost of Capital</u>

We estimate the cost of capital quarterly for the period quarter 1, 2005 to quarter 4, 2012. The following describes the steps we used to calculate the overall cost of capital for each of the 14 holding companies listed in Figure 5 above. First, we calculate the <u>cost of equity</u>, COE, using the constant growth version of the discounted cash flow model (DCF).

$$\begin{aligned} r &= \frac{D_1}{P} + g \\ &= \frac{D_0 \times (1+g)}{P} + g \end{aligned} \qquad (1)$$

where "D1" is the dividend expected at the end of the first period, "g" is the perpetual growth rate, and "P" and "r" are the market price and the cost of equity, respectively.

The COE is the information of interest to regulators when they set the allowed ROE for a utility, so our focus is ultimately on whether there is a measurable reduction in the COE from the policy of decoupling.[23] In general, the COE increases not only with increased business risk but also with increased financial risk.[24] Therefore, in testing for an impact on the cost of capital from decoupling, we systematically account for differences in the COE in different holding companies in the samples that arise from different levels of financial risk, which has nothing to do with decoupling.

This analysis relies on the DCF model instead of the Capital Asset Pricing Model (CAPM) because the DCF model is the more forward looking model. The beta parameter in the CAPM is normally estimated using three to five years of historical data, but historical data would not capture the effect of a change in risk from the adoption of decoupling. In contrast, the DCF model relies upon the current stock price and a forecast of the future growth of earnings and dividends. We use an average over 15 trading days for the current stock price and security analyst earnings five-year forecasts from Thomson-Reuters.

Second, we calculate the company's after-tax weighted-average cost of capital (ATWACC) which measures the overall cost of capital for the firm. To control for the effect of differences in capital structure (i.e., differences in financial risk) among the sample companies, we converted estimates of the COE into corresponding estimates of the overall ATWACC.[25] The ATWACC measures the cost of capital for the business itself, while the COE estimate represents the cost of equity capital taking into account the equity-holders' additional financial risk from the company's level of debt financing. In other words, the ATWACC measures business risk, while the COE is also affected by financial risk. We use the ATWACC in our statistical analysis below to control for differences in financial risk. Of course, the effect of decoupling on the cost of capital would primarily be reflected in the COE, but it could also affect the cost of debt, albeit with a lag.

The ATWACC is a better measure of the relevant cost of capital for our investigation because it takes differences in capital structure among the sample firms into consideration. Firms with

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23 In general, the regulator sets the allowed return on equity equal to the estimated cost of equity in order to provide the regulated company a fair opportunity to earn its cost of capital. In some circumstances the regulator may set the allowed ROE above or below the COE to compensate for differences in risk between the regulated company and the sample companies.

24 Financial risk, as distinct from business risk, is related to the degree to which the company's assets are debt financed. The greater the share of debt in the capital structure, the greater the interest that must be paid out of operating revenues before any shareholder earnings are available.

25 To be specific, the ATWACC is the measure we use; it is a weighted average of both the cost of equity and cost of debt after taking into account the tax deductibility of interest payments. The weights used in the calculation are the market values of debt and equity in the capital structure. See Chapter 20 of Brealey, Myers and Allen, Op Cit.

similar assets will have different cost of equity if they have different capital structures even though their overall cost of capital may be identical. The ATWACC is calculated as follows:

$$ATWACC = r_D \times (1 - T_C) \times \%\ D + r_E \times \%\ E \qquad \textbf{(2)}$$

where r_D = market cost of debt,
r_E = market cost of equity,
T_C = corporate income tax rate,
% D = percent debt in the capital structure, and
% E = percent equity in the capital structure.

- The cost of debt, r_D, is based upon the yield on utility debt from Bloomberg's utility bond index for companies of comparable S&P credit ratings.
- For T_C, we use a 40 percent combined federal and state corporate tax rate for all companies.[26]
- For those companies with preferred equity in their capital structures, we estimate the return on preferred equity as equal to the before tax return on the company's debt and weigh it by its share in the capital structure.[27]
- The market value of equity, E, is calculated as the product of P, the price of the stock, and the number of shares outstanding at the time.
- The market value of debt, D, is approximated by the book value of debt because the market value of debt and the book value were not substantially different.
- The market value of preferred, Pf, is also approximated by the book value of preferred equity if there is any in the capital structure.
- The total market value of the firm is the sum of the E, D and Pf.

The result of this process is an estimate of the ATWACC for each sample company for each quarter of the sample period.

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26 Although state tax rates vary, a combined 40 percent rate is used for all to avoid any distortions in the results from attempting to model different tax rates.

27 This is an approximation because we do not know of an index for the cost of preferred equity. The approximation is not likely to have a large effect because the percentage of preferred equity in the companies' capital structures is relatively small.

VI. AN EMPIRICAL TEST OF THE EFFECT OF DECOUPLING ON THE COST OF CAPITAL

Finally, we test the effect of decoupling on the overall cost of capital by regression analysis on the time series of our estimated ATWACCs for the sample of holding companies. The dependent variable is the overall cost of capital, i.e., the ATWACC, and the prime explanatory variable is the decoupling index. We use dummy variables to capture the fixed effects for the different holding companies and for different time periods. These are discussed in more detail below in the section on the Regression Model.

Regression Model

We estimate the following regression model:

$$ATWACC_{i,t} = \beta_0 + \beta_1 * Decoupling\ Index_{i,t} + \beta_2 * QTR_t + \beta_3 * Company_i + \varepsilon_{it} \qquad (3)$$

For the ROE estimate in the ATWACC, we use the single-stage version of the DCF model based upon security analysts' 5-year forecasts of company-specific earnings growth. QTR_t is a dummy variable for the quarter (period t) of the estimate, and $Company_i$ is a dummy variable for the specific company (company i).

In assembling the data set, we recognize that detecting the effect on decoupling will be affected by a number of factors. The *Company* dummy variable captures the difference in the average ATWACC by company, which can be due to such factors as the average amount of unregulated assets compared to regulated assets in the holding company or due to differences in regulation in the various states. There are 14 companies in the sample, so there are 13 Company variables. Unlike our previous study of gas LDCs, the 14 company electric sample is not nearly as close to a "pure-play" sample. That is, the electric utility holding companies are larger and more diverse than the gas LDC sample. There may be changes in the risk of unregulated assets that we are not fully capturing.

The *QTR* dummy variable captures the variation in average ATWACC across companies in a quarter due to differences in interest rates or other economic conditions. Our period covers eight years or 32 quarters so there are 31 *QTR* variables. The *QTR* dummy variables are intended to control for macro-economic effects on the average cost of capital for the sample, which is important given that our study covers a very unusual period for the U.S. economy. The U.S. suffered the worst recession since the Great Depression. Interest rates generally declined.

Decoupling could be signaling the company is entering a period of higher risk. Decoupling reduces both the upside and the downside for a regulated company. If a company believes that policies or economic conditions impose additional risk, the company may request decoupling to mitigate rising risk. On the other hand, state policy makers and commissions may seek to impose decoupling to ensure success of EE programs. Perhaps decoupling reduces risk but not enough to offset the increase in risk due to other associated policies or circumstances.

Finally, we know that financial markets are forward looking. Information is available to the market when a company files for decoupling and the ongoing status of the hearings, and when decisions are expected. To test whether these expectations led the markets to adjust the cost of capital before the decision was released, we consider three alternative periods for when financial markets react to the possibility that decoupling may be implemented. The periods are one, two or three quarters *before* the quarter that the decision was announced, i.e., the Specific Date.[28] We use these alternative anticipation dates in separate models to serve as robustness checks for our primary, contemporaneous specification.

The coefficient of interest for testing our hypothesis is β_1, the coefficient on the Decoupling Index. We consider a null hypothesis that decoupling does not lower the cost of capital, i.e., the ATWACC. This framework allows us to determine whether there is statistically significant evidence in favor of the contention that decoupling does lower the ATWACC.

Statistical Results

The results of our test for each of the four models with varying financial market anticipation are all in general agreement and fail to reject the claim that decoupling does not lower the cost of capital. Although the coefficient on the decoupling index is negative, the null hypothesis that the coefficient is zero or positive (i.e., not negative) cannot be rejected at the 5% level. Hence, there is no statistical support for the claim that decoupling leads to a decrease in the cost of capital. The primary point estimate from the contemporaneous model is -41 bps, with point estimates ranging from -46 to -49 bps for the models with anticipation by the capital markets. The estimated impacts and associated one-sided *p*-values are shown in Table 1 for all four models. The *p*-values are all above the conventional 0.05 level and are generally above the 0.10 level as well, therefore justifying our conclusion that decoupling does not lead to a statistically significant decrease in the cost of capital.[29]

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28 We also recalculate the holding company Decoupling Index for each of the earlier periods in which the effect of decoupling could be reflected in the capital markets.

29 In testing for statistical significance, the *p*-value is the probability of obtaining a test statistic at least as extreme as the one observed, assuming the neutral or null hypothesis is true, which in this case is that decoupling does not reduce the cost of capital. "In most scientific work, the level of statistical significance required to reject the null hypothesis (i.e., to obtain a statistically significant result) is set conventionally at .05, or 5%. The significance level [or *p*-value] measures the probability that the null hypothesis will be rejected incorrectly, assuming that the null hypothesis is true." See Rubinfeld, Daniel, "Reference Guide on Multiple Regression" in National Research Council, *Reference Manual on Scientific Evidence*, 3rd ed. Washington, DC: The National Academies Press. 2011.

In our models, we account for differences in the estimated cost of capital due to economy-wide impacts by quarter and due to company-specific variation through the use of time period-specific and company-specific indicator variables respectively. We also use clustered standard errors to account for correlation in each company's performance across time.

Table 1: Impact of Electric Decoupling in Basis Points and Test Results: Primary Model and Three Alternative Models of Financial Market Anticipation

	Primary model	1 Qtr. anticipation	2 Qtr. anticipation	3 Qtr. anticipation
Estimate	-40.88	-46.5	-48.7	-45.9
***p*-value**	0.14	0.12	0.08	0.11

VII. CONCLUSION

Our statistical tests do <u>not</u> support the claim that the cost of capital is reduced by the adoption of decoupling. The results of our models of the effect of decoupling on the cost of capital are consistent and collectively demonstrate that there is no statistically significant evidence of a decrease in the cost of capital following adoption of decoupling. If decoupling policy decreases the cost of capital, these tests strongly suggest that the effect must be relatively small because we are not able to detect it statistically.

As decoupling continues to grow in importance, cases will frequently come up where interveners and commission staff may explore the extent to which decoupling reduces business risk and the utility's cost of capital. To date, in a small minority of cases in which decoupling was approved, the utility explicitly had their allowed ROE reduced. Our research leads us to conclude that these reductions were implemented without reliable empirical analysis to support the ROE reduction. The results of our analysis show that if such empirical analysis had been done, it is unlikely that it would have supported even the moderate reductions in allowed ROE that were imposed on the utilities.

Although the point estimate of the coefficient on decoupling is negative, this result is not statistically significant (for this sample over this period). Further, there is another reason for the regulator not to simply deduct some amount from the allowed rate of return: the cost of capital comparison samples used in regulatory proceedings are not generally restricted to holding companies without any subsidiaries with decoupling. Whatever effect adoption of decoupling may have on the cost of capital, it will be reflected in the sample results. Reducing the allowed ROE relative to the sample average cost of capital estimate would risk "double counting" the effect of decoupling, because that effect is already captured by the sample estimates.

Even if decoupling does not reduce a company's cost of capital, it is still a beneficial policy if it is effective in removing the utility's disincentive to pursue conservation programs. Where decoupling is associated with implementing enhanced EE programs (as is frequently the case), adopting a reduction in allowed ROE in essence punishes a utility for pursuing EE programs. If a utility's management fears an unjustified reduction in the allowed ROE as a result of decoupling, the original disincentive to pursue EE programs is recreated in a new form, and the purpose of decoupling to align the interests of customers, shareholders, and society as a whole may be frustrated.

Appendix A
Regression Statistics

Variable	Actual	1Q Forward	2Q Forward	3Q Forward
DecoupIndex	-0.00408	-0.00465	-0.00487	-0.00459
	(0.00362)	(0.00376)	(0.00330)	(0.00353)
Constant	0.0504***	0.0503***	0.0502***	0.0502***
	(0.00518)	(0.00509)	(0.00489)	(0.00478)
Observations	291	291	291	291
R-squared	0.678	0.679	0.680	0.679

Clustered standard errors in parentheses

*** p<0.01, ** p<0.05, * p<0.1

ELECTRIC UTILITY
AUTOMATIC ADJUSTMENT CLAUSES:

Benefits and Design Considerations

Prepared for:

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INTRODUCTION AND OVERVIEW

Most states with traditional retail electric markets (*i.e.*, states in which retail service is provided by a regulated electric utility with an exclusive franchise service area), regulate the price of electric utility services using mechanisms that separate the review, approval, and recovery of certain frequently changing costs, such as fuel and purchased power costs, from the corresponding scrutiny of the more fixed and predictable capital and operating costs associated with financing and maintaining the assets of the utility. The more variable, unpredictable costs are recovered in rate components that are allowed to change periodically—at least every year and in many cases more frequently—without the need for a full rate case that reviews all of a utility's cost of service. Instead, these rate components are allowed to change roughly contemporaneously with changes in the utility's underlying related costs. (The remaining fixed or more predictable costs are recovered in "base rates" that are typically modified only every few years in formal rate cases.) These cost recovery mechanisms go by different names, but here we discuss them under the general appellation of "Automatic Adjustment Clauses" or AACs.

The typical motivations for AACs are three-fold:

1) *The underlying costs are often large and quite volatile*. As such, it is difficult to predict their expected level as to price or quantity accurately over long horizons and, at times, even over relatively short horizons. Inevitable prediction errors could result in significant cash and earnings shortfalls for the utility if those costs are not recovered in a timely manner (or unduly high cash burdens for customers when such costs happen to be lower than projected).

2) *The underlying costs are largely beyond the utility's control*, since they reflect, for example, market conditions in the wholesale fuel and power markets that individual utilities do not choose or influence. Accordingly, they often do not require the same depth or type of scrutiny as critical resource decisions with long-term cost implications, such as asset (ratebase) expansion and long-term power purchases, which are specific business choices customized to each utility. Furthermore, utilities earn no margin or return component on these expenses. Utilities should be primarily at risk for costs and performance factors they can control, and regulatory review should be focused proportionately on the same.

3) *To facilitate recovery of "pre-approved" items*, such as the costs of long-term power purchases in accordance with a commission-approved resource plan or the costs incurred in implementing approved environmental compliance plans.

Notwithstanding the general validity of these principles, there are some states that currently do not have or do not utilize AACs. Two states, Vermont and Wisconsin[1], explicitly prohibit the use of AACs. Vermont's prohibition of AACs arises from legislative strictures against "single issue ratemaking" -- evidently out of concern that this could result in ratemaking that places undue focus on one cost factor while failing to capture contemporaneous, offsetting reductions in other costs during the resetting of utility rates.[2] In addition, there can be concerns that adjustment clauses will reduce a utility's incentive to keep expenses down. But even in states that currently employ AACs, full recovery of the incurred costs is not assured simply because an AAC is in place. This is because AAC mechanisms may be designed to allow cost recovery only within certain limits, and most states also conduct periodic audits that can trigger AAC prudence reviews. For instance, Louisiana performs a comprehensive audit of fuel costs every 2-3 years, while Florida conducts a hearing every November to review the accuracy of filings made pursuant to its adjustment clause. Other states, such as Colorado, have AACs that are subject to various "deadbands" within which the variation in costs does not trigger a dollar-for-dollar adjustment, and they may then hold any costs outside of these bands in deferral accounts for subsequent review and amortization, if and when such costs are found reasonable. Thus, the degree of rapidity, administrative burden and assurance of cost recovery varies across a wide range of specific practices.

The purpose of this report is to clarify why AACs and their predictable administration have become very important for the financial stability of utilities and for the avoidance of indirect costs that will ultimately fall on consumers if such cost recovery is ineffective or inadequate. Indeed, we suggest expanding the scope of costs that should be eligible for recovery in AACs, recognizing that there now generally is more reliance than in the past by utilities on wholesale markets for short-term purchases and sales of diverse services such as short-term energy and capacity, ancillary services, and congestion relief. In addition, we discuss how the administration of AACs can be made both more predictable and compatible with other important regulatory objectives, such as rate stability, hedging, and incentives to control costs.

HISTORY AND CONTEXT

The Federal Power Act (Title 16 U. S. C. §824d(f)(4) of the U.S. Code) provides a working definition of an automatic adjustment clause as: "a provision of a rate schedule which provides for increases or decreases (or both), without prior hearing, in rates reflecting increases or decreases (or both) in costs incurred by an electric utility. Such term does not include any rate which takes effect subject to refund and subject to a later determination of the appropriate amount of such rate." In fact, this language is a bit stronger than many AACs in practice, but the basic principle of allowing timely and relatively unchallenged recovery of certain recurring costs is a common feature. For this discussion, we will define an AAC as a cost recovery mechanism which meets the following criteria:

- Generally applies to volatile, financially material commodity costs that arise in wholesale markets, such as fuel and purchase power costs, with other, mostly fixed and long-term capital costs recovered under distinct, separate ratemaking procedures. However, certain capital costs associated with mandatory investments, such as the capital cost of environmental compliance investments, sometimes are recovered through an AAC as well, because such investments are beyond the utility's discretion.
- Recognition in allowable rates of incurred AAC costs does not require *a priori* review and approval, except to the extent of confirming the appropriateness of the type, procurement process, and accounting for such costs.
- Recovery of AAC costs is timely and assured enough that the risk of non-recovery is very low; in particular, such risk is low enough that it does not compromise the debt ratings and creditworthiness of the utility.

This definition leaves room for deadbands, provided their limits are reasonable, and deferred accounts, so long as eventual cost recovery is deemed highly likely by the financial community. It can also accommodate innovative arrangements, such as inclusion of hedging costs or basing allowed AAC costs on forecasted or forward prices for fuel, subject to the proviso that the total revenues eventually collected from customers are trued-up for any deviations (possibly outside of deadbands) between actual costs and initially estimated rates.

AACs for fuel costs arose in the US initially in response to escalating coal prices during World War I. They became prominent again in the 1970s, when the oil price shocks spurred by OPEC became large and economically critical. Such events dramatized the utilities' financial exposure to costs they could not control, and on which they earned no profits. (At that time, oil comprised a much larger portion of the electric generation fuel mix than it does today.) Traditional rate proceedings, in which months of preparatory analyses are required, followed by 6-12 months typically elapsing before a Commission acts upon a utility's rate filing, were deemed too slow to deal with volatile and rapidly rising fuel expenses. Indeed, in a world of constantly changing fuel costs, a utility may find itself filing for a fuel-related rate change before its Commission has acted upon a prior rate filing.

Since the 1970s, most states and most utilities have some degree of contemporaneous "flow through" of at least a portion of fuel costs, as well as fuel transportation costs, short term purchased power, and emission allowance costs. All but three of the thirty traditionally-regulated states (Missouri, Vermont, and Utah) have AACs to recover fuel and the energy portion of purchased power costs and the Missouri Commission is in the process of implementing a fuel adjustment clause after Missouri passed enabling legislation in 2005 allowing the Commission to do so.[3] Moreover, a recent survey performed by *The Brattle Group* found that, of the 27 traditionally-regulated states that currently have AACs, all allow the pass-through of the energy portion of purchase power costs, and at least 12 allow the pass-through of the capacity or demand-portion of purchase power costs as well. Eleven states allow rate adjustments for environmental capital costs and for the cost of emissions allowances and thirteen allow the pass-through of hedging costs. (Some utilities have separate rate riders to recover (and amortize) certain environmental compliance capital and operating costs on technologies that are mandatory, including environmental equipment bond financing costs.) A few states have, or are considering, similar recovery mechanisms for Regional Transmission Organization (RTO) participation costs that are variable and uncertain, such as ancillary service costs and congestion-related costs.

Utilities in some restructured states have AACs, usually to recover the cost of power purchased on behalf of retail customers that continue to purchase bundled generation service from the local utility. Some utilities in restructured states also have the ability to recover environmental compliance costs in an AAC-type mechanism (*e.g.*, certain Ohio utilities). However, some utilities in restructured states provide their generation services under rate caps or complicated settlements that provide them no or limited opportunity to adjust rates for rising fuel and other commodity costs. Other utilities in restructured states (*e.g.*, the Michigan utilities) regained their AACs upon the expiration of their rate caps.[4] Thus, it is hard to generalize about the situation of utilities in restructured states other than to point out that utilities that purchase all or most of their generation requirements face very substantial financial risks if those costs are not reliably recovered. Increasingly, utilities with divested generation procure their supplies through Commission-approved auctions or procurements and are then permitted to flow through the winning bidders' price(s) for those purchases in an AAC-like mechanism, particularly when they are no longer subject to a transitional rate cap. However, where a utility is subject to a rate cap, a portion of its power procurement cost may be deferred for later recovery or even written off, which can cause the company severe financial distress.

AACs can be used reliably in conjunction with other rate and regulatory policy mechanisms. In particular, they are very compatible with incentive regulation that involves risk-sharing between utility shareholders and ratepayers, once general agreements have been struck with regulators regarding how utilities can incorporate risk management (hedging) contracts into their AAC cost structures. This is likely to be an increasingly important aspect of AAC design and performance evaluation, because wholesale fuel and power spot price volatility has been increasing in the last few years.

Accordingly, unrestricted flow-through of all or most wholesale power costs at spot prices may result in rates that are too unstable for some customers.

The alternative to having an AAC is to attempt to recover these costs in base rates set every few years through full-fledged rate cases. This approach requires utilities to determine fuel and other volatile costs for an adjusted (historical or future) test year, include an estimate for these costs in base rates, and then the utility must hope that actual costs are not higher than the estimate (*i.e.*, both volumes and prices per unit of fuel or purchased power were fairly well estimated). Correspondingly, customers must hope that incurred costs are not much lower than the forecast, or else they will be overpaying. The utility will re-file for an overall review and resetting of its rates from time to time if and when these rates no longer cover actual costs. This recurring forecasting and refiling puts a substantial administrative burden both on the utility and its regulators (as well as interveners), and it may result in significant variance in rates billed relative to actual costs and/or financial distress for the utility. Administrative burden has a direct cost, of course, but also may have an "opportunity cost" as both regulatory and utility resources are diverted from the forward-looking analyses and planning necessary to develop creative new policies and to maintain economical and reliable service in the long-term.

THE CURRENT NEED FOR AACS

There are three main drivers of utilities' current, heightened need for AACs:

1) High volatility of many critical wholesale costs, causing increased financial risk if costs do not match revenues;

2) Increased vertical unbundling of supply functions, such that integrated rate cases reviewing all functions and costs are becoming inefficient or even dysfunctional; and

3) Down-graded credit ratings and reduced total capitalization of many utilities, especially those which divested their generation and now have substantially smaller base revenues with as large or larger variable costs than in the past

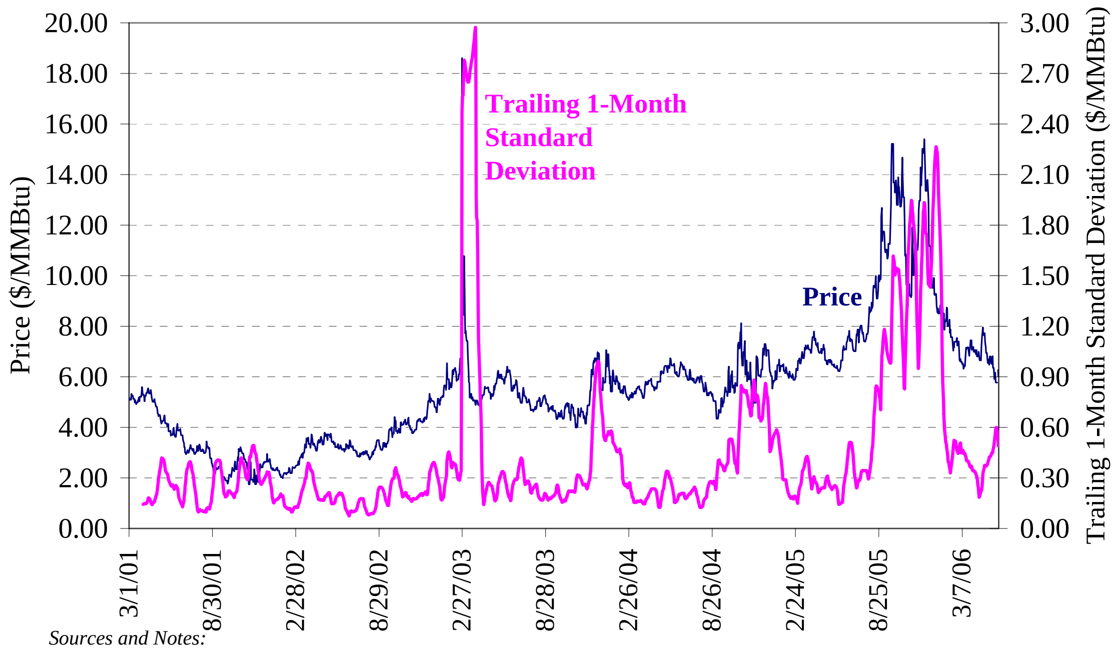
Some of the empirical evidence for these factors is discussed below.

INPUT COST VOLATILITY

The overwhelming majority of an electric utility's operating expenses is concentrated in two categories—fuel and purchased power. A review of FERC Form 1 data for all investor-owned utilities shows that, as of 2005, fuel and purchase power expenses accounted for 71 percent of total utility O&M expenses. To the extent that changes in the price of these items are not reflected in rates, a utility can be exposed to significant cash flow volatility. This point has been brought home by the highly volatile natural gas and wholesale power markets of 2005.

Fuel price levels and price volatility are seemingly at an all time high. Today, almost 70 percent of America's electric power is supplied by coal and natural gas. After being at $3/mmbtu for much of the 1990s, the spot price of natural gas in 2006 has been about $7-$8/mmbtu. (The spot price was even higher in late 2005—about $13/mmbtu—largely because of the production disruptions caused by Hurricane Katrina.) This generally is due to the end of the "gas bubble" of excess supply that was induced by well-head price deregulation under the NGPA of 1976, and which extended through approximately 1997. Since then, the US has had declining reserve-to-production ratios, and many newly developed wells have been smaller and shorter-lived than in the past.[5] In short, gas supplies are getting tighter, which has been aggravated by geopolitical concerns about the Middle East. Supply tightness causes both higher prices and more volatile prices than prevail in times of plenty.

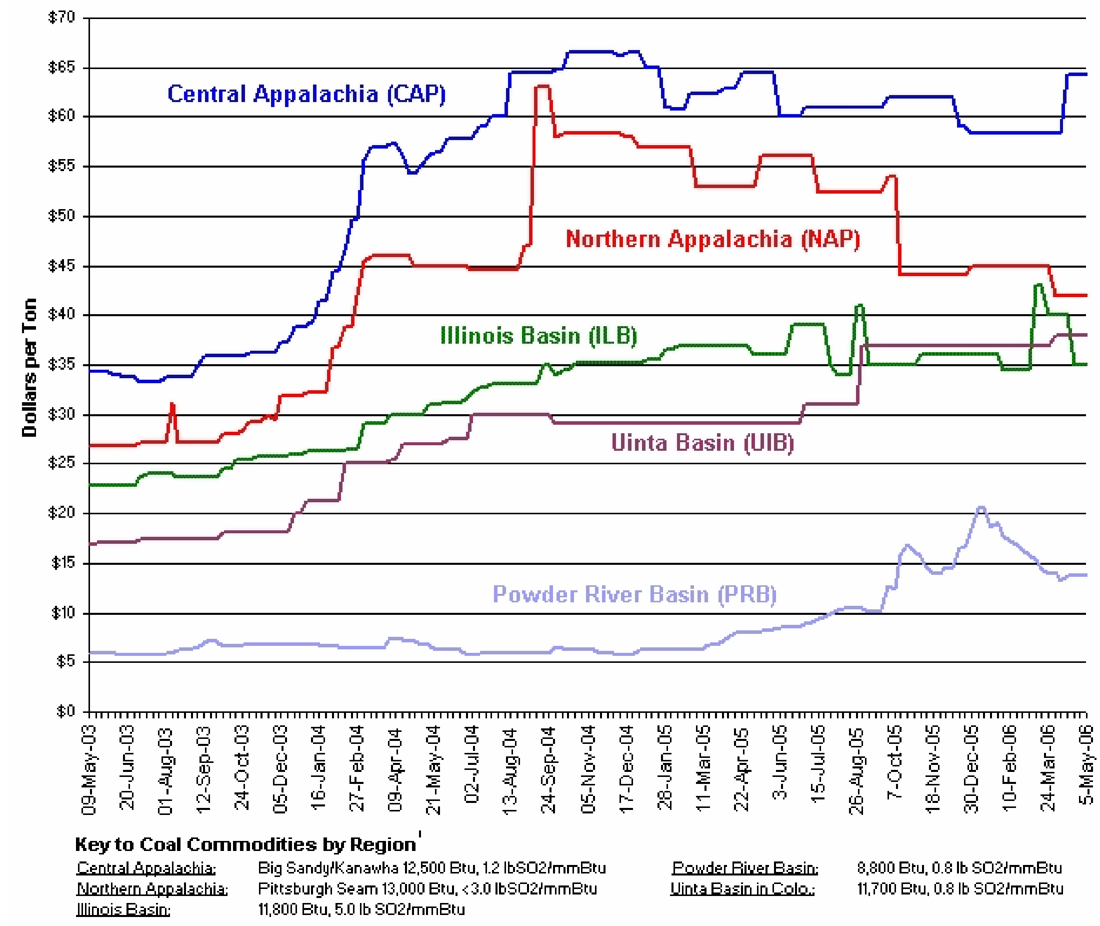
Figure 1
Henry Hub Spot Prices by Flow Date and Standard Deviation



Sources and Notes:
Platts Gas Daily.
Excludes 8/30/05, 9/27/05-10/7/05 when Henry Hub operations were disrupted due to damage caused by Hurricanes Katrina and Rita. Standard deviation calculated over current and previous thirty days.

Delivered coal prices to utilities, which reflect contracts that bind the majority of coal deliveries, declined in nominal terms starting in 1985 for approximately 15 years. However, between 2003 and 2005, delivered coal prices to electric generators increased over 20 percent. More dramatic increases occurred in the spot price of coal over this same period. For example, prices at the Powder River Basin have risen from $6/short ton in March 2003 to about $15/short ton in March 2006, an increase of well over 100 percent. Figure 2 below shows this recent trend in spot prices. As more long-term contracts begin to expire, the effect of this dramatic increase in spot coal prices will be borne by utilities and their customers.

Figure 2
Coal Spot Prices (March 2003 – May 2006)

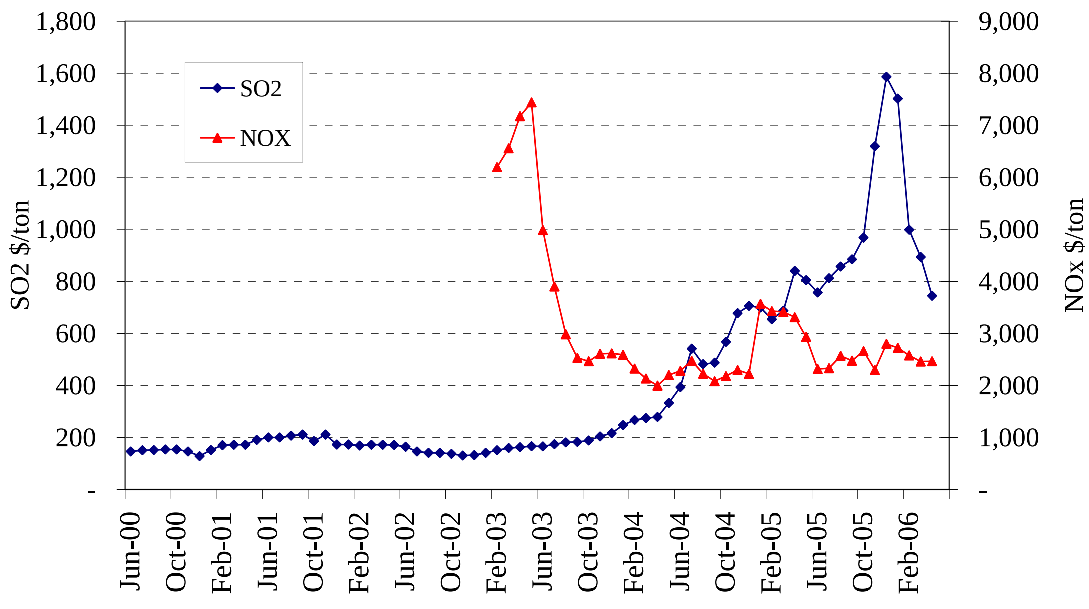


Source: EIA - http://www.eia.doe.gov/cneaf/coal/page/coalnews/coalmar.html#spot.

In addition to the rising costs of fuel for coal plants, the associated environmental allowance prices for SO_2 and NO_X have become quite high and volatile, in part due to impending new controls on coal-fired generation and much higher natural gas prices, which have encouraged higher levels of coal-fired generation. For example, the spot price of SO_2 allowances, which had been steady at about $200/ton during the early years of this decade, suddenly spiked to levels of nearly $1,600/ton in late 2005. While a $1000/ton increase in SO_2 prices raises operating costs for a modern, scrubbed pulverized coal plant with a 10,000 Btu/kWh heat rate by only about $1/MWh, the increase in operating costs for an un-scrubbed plant would be about $5-$15/MWh, depending on the sulfur content of the coal burned.

Figure 3

SO_2 and NO_X Emissions Allowance Prices



Source: Argus Air Daily Monthly Average Prices.

While not yet a factor in US fuel markets, there is a non-trivial possibility of CO_2 taxes or allowance costs also becoming part of the variable costs of burning fossil fuels, which provides over 70 percent of the total electric energy in the US. Since a $1/ton of CO_2 corresponds to roughly $1/MWh of increased operating costs for a baseload coal unit and about $0.40/MWh for an efficient gas combined cycle gas turbine (CCGT), a material carbon reduction target could add another very large and volatile element to utility costs in the next few years.

VOLATILITY OF PURCHASE POWER COSTS

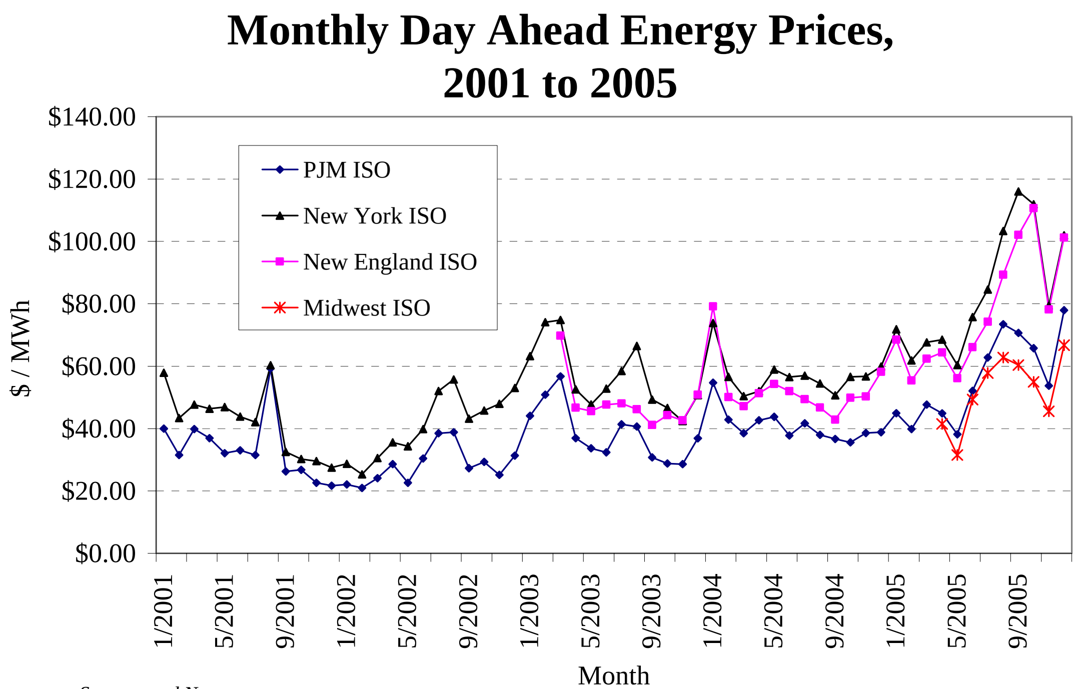
Today's wholesale power markets are much more volatile than those that existed throughout most of the 1970s to mid-90s.[6] Prior to the early 1990s, most of the power transacted in wholesale markets was sold at cost-based rates. Around 1990, the FERC began to permit wholesale power providers, including vertically-integrated utilities, to sell at market-based rates as long as the seller showed that it did not have market power or, if it did, that it had sufficiently mitigated such market power.[7] For example, in 1990 FERC approved a proposal by PSI Energy to sell up to 450 MW of long-term, firm power at market-based rates in exchange for a commitment by PSI to open its transmission grid.[8] The Energy Policy Act of 1992 encouraged the trend toward market-based pricing by creating a class of generators known as Exempt Wholesale Generators (EWGs), who were permitted to sell in wholesale markets at unregulated rates.

As the 1990s progressed, sales at market-based rates became common in wholesale power markets. The market-based price of power is generally at or above the operating cost of the most expensive unit needed in a given hour to serve load. It will tend to be equal to the marginal cost of the last plant dispatched (or willing to trade) if there are many sellers; it may be above this level if capacity is tight enough for sellers to be able to obtain a premium for their output. In any event, in wholesale power markets hourly prices are set by the interplay of demand and supply rather than by any particular seller's average cost of service. Whereas cost-based rates tend to be fairly stable because a seller's average costs do not change significantly, particularly in the near-term, market prices can fluctuate dramatically from hour to hour based on sudden changes in fuel costs for the marginal plants, demand, generation unit availability, and transmission constraints, among other factors. If a utility should need to make a large quantity of purchases on a day when market prices are high, its monthly costs can rise significantly.

Today, there are five centralized energy markets in the U.S. – the markets operated by the California ISO (CAISO), the Midwest ISO, PJM, the New York ISO (NYISO), and ISO New England (ISO-NE).[9] The Southwest Power Pool (SPP) is implementing a real-time energy market that will have some of the attributes of the centralized markets cited above. Texas, via its statewide reliability council (ERCOT), has initiated the development of a centralized nodal market scheduled for the beginning of 2009.[10] RTO charges add, sometimes substantially, to a utility's cost of purchased power. These additional elements include congestion premiums for dispatching around transmission constraints affecting certain areas (especially “load pockets” that are often urban areas), ancillary service charges for grid management (such as operating reserves, voltage support, and the like), and capacity obligations levied against load-serving entities. Some RTOs offer short term markets (daily, weekly, monthly, seasonal) in which these capacity obligations can be satisfied, and the observed prices tend to be quite volatile. In less centralized markets, the value of these grid support and reliability services can be embedded in the spot price for firm energy, making that power both more expensive and often more volatile than the underlying fuel costs.

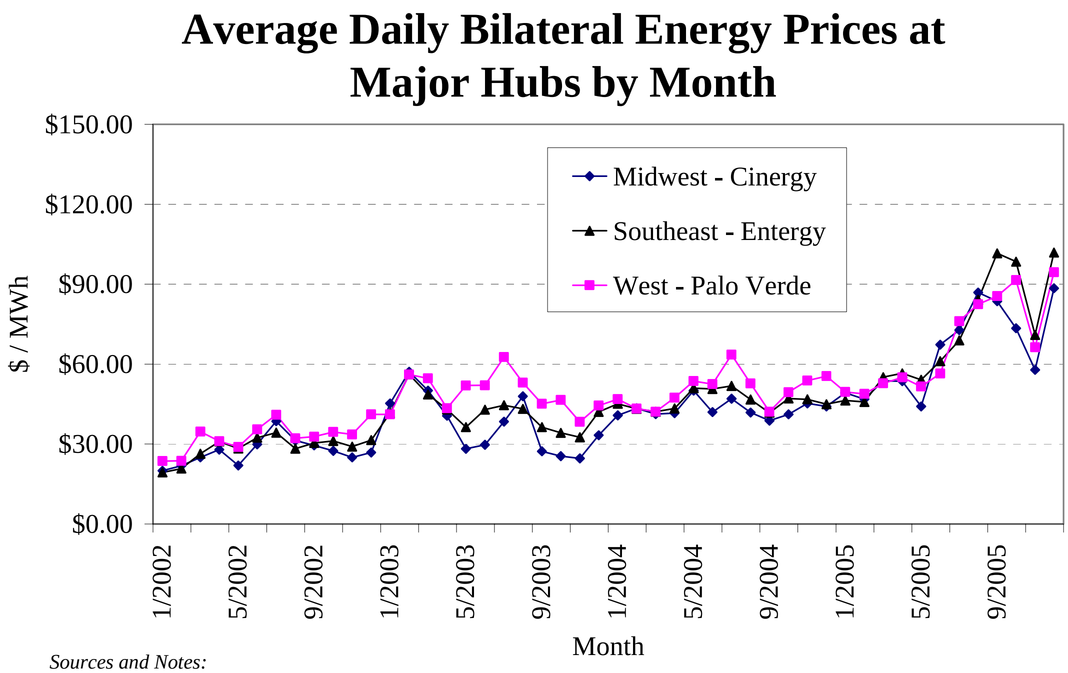
Figure 4 demonstrates the recent growth in levels and volatility in market energy prices for various locations around the US. Shown are average monthly energy prices in PJM-West; Cinergy, Entergy, and Palo Verde 5-year period 2001-2005. Average monthly prices have varied from about $21/MWh to over $116/MWh in the Eastern power markets. If a utility were buying 1000 MW for all 730 hours of a typical month, this could entail a cost variation of roughly $15 million to $85 million, depending on the month. While certain seasonal patterns are predictable, the price levels themselves have varied significantly from year to year. Ranges and volatility are comparable for the Midwest, Southeast, and West (though the latter had much more dramatic price levels in 2000 and early 2001).

Figure 4



Sources and Notes:
Global Insights' Energy Velocity database. Prices represent mean LMP prices within each market.
Midwest ISO begins in April 2005. New England ISO begins in March 2003.

Figure 5



Sources and Notes:
Global Energy Decisions.
The Midwest region was organized into the Midwest ISO in April of 2005, and for this reason the datasource for Cinergy changed between March and April of '05.

As a rule, wholesale prices did not fluctuate to this extent prior to market-based pricing. This is not to say that price volatility is either bad or unexpected. Price volatility is normal in commodity markets and is a facet of market efficiency -- providing market participants with useful signals regarding constantly changing market fundamentals. Electricity markets, however, are particularly volatile, often exhibiting a higher degree of volatility than many other commodities, such as agricultural products and metals. Electricity prices are highly volatile primarily because, unlike most other commodities, electricity cannot be stored, and its short run demand is highly price inelastic. Electricity production is also very capital-intensive, with a few years of lead-time required to significantly expand capacity. This makes electricity prices particularly sensitive to changes in market conditions, such as changes in the price of the marginal plant's fuel, the loss of a large generating plant or large transmission line, or the occurrence of a long, seasonal drought. Some of the hourly or daily manifestations of this volatility can be hedged away via purchasing of monthly or longer term forward contracts, but even those positions will reflect average (and shifting) expectations for future supply scarcity (or surplus), recurring patterns of congestion, and seasonal fuel price variability. Further, it is not possible to completely hedge retail electric requirements. Electricity demand itself varies enough to require some degree of supplementing forward purchases and sales with spot market transactions that are fully exposed to the above risks. With very volatile prices, even a few extreme hours of the month can cause a significant average cost increase.

UTILITY FINANCIAL EXPOSURE

At the same time that fuel and purchase power costs are becoming more volatile and, thus, more risky, many utilities have less capability to bear significant price risks. There are several reasons for this. Many utilities in states with restructured markets divested most if not all of their generating assets, which exposes them to significant risks associated with Provider of Last Resort (POLR) service in the context of having reduced overall capitalization.[11] Initially, the expectation for retail restructuring was that many customers, including residential customers, would leave the local utility and purchase service from an alternative supplier. For the most part, this has not happened. Most small customers in retail access states continue to purchase bundled service from the local utility. Competition has failed to develop for small customers, in no small part because most electric distribution companies in retail access states have been subject to rate caps during a "transition period" beginning with the implementation of retail choice.[12] These frozen rates have, in many cases, turned out to be below the going market price for generation service. The absence of a competitive market means that utilities will, for the foreseeable future, be responsible for procuring generation to serve such customers.[13] Since many of these utilities no longer own generation, they have to buy generation supply in the wholesale market at market-based prices. Generation procurement costs will be by far the largest operational expense incurred by such companies. The absence of full and timely recovery of generation procurement costs could be financially damaging to such companies.[14] Such firms no longer have the larger earnings base that generation asset ownership had provided, so the magnitude of their net power cost variability can be large relative to their relatively smaller earnings base. An AAC that includes recovery of all purchase power costs will reduce the electric distributor's exposure to cash flow volatility significantly.

This power procurement, risk problem does not apply solely to utilities in retail access states. Some utilities in traditionally-regulated states also rely on purchased power to meet a material portion of their supply requirements, and they remain exposed to the aforementioned volatile fuel and RTO costs for the generation they own and the power they purchase from the market. An inability to reflect changes in the price of fuel and purchase power costs in its rates—whether caused by a rate freeze or the absence of an AAC—can expose a utility to significant cash flow volatility.[15]

The financial risk created by volatile commodity costs is often felt first in the cost of debt. Bondholders receive fixed payments, so they do not participate in the financial upside performance of a utility if or when it has a highly profitable year. As a result, they are primarily concerned about avoiding the possibility of an unprofitable year, or period within a year, during which revenues do not significantly exceed operating costs. They rely on those operating margins to adequately cover debt service payments. Bond ratings agencies closely scrutinize the depth and stability of each utility's ability to sustain significant debt service coverage. A rate freeze, coupled with volatile operating costs, is a particularly unwelcome combination. An AAC that roughly synchronizes revenues with costs greatly improves the situation, reducing risk and reducing the cost of debt.

A poor debt rating has more consequences than simply adding a few basis points to interest rates imposed on the utility. It can significantly constrain operations and expansion, thereby raising costs and risks to customers. For instance, utilities are able to buy fuel and power under long-term, fixed prices that would eliminate much of the volatility problem only if they are deemed creditworthy by the sellers. Typically this requires a good bond rating, or the ability to post lots of cash as collateral for the long term purchase whenever forward prices move to new levels that are below the contractual price. The inability to do so may result in no sellers being willing to enter long-dated contracts – forcing the buyer into mostly short-term, volatile purchases that continue the utility's exposure to significant risk! Central Vermont Power Corp. faced this predicament when its credit rating was decreased by both S&P and Fitch Ratings in June of 2005.[16] Similar downgrades were also issued to Ameren Corp. and Commonwealth Edison due to regulatory uncertainty about post-2006 cost recovery[17] and most recently Empire District Company.[18] The financial strain of operating in this "catch-22" environment may also cause that utility to forego or defer cost-saving or risk-mitigating investments. Thus ratepayers may incur direct costs (interest rates) and indirect costs (constrained operations) if their utility is not authorized to operate with an AAC.

The importance of AACs is highlighted by the fact that the industry's financial condition, while generally sound, has declined somewhat over the last several years, as evidenced by declining credit ratings. The fraction of utilities rated BBB+ or above by Standard and Poor's, which was 75 percent prior to the 1990s, is now only about 40 percent. As of 2005 nearly 20 percent of all utilities were below investment grade. These companies cannot weather greater financial impairment. In addition, the operating cash flows of utilities in 2005 were insufficient to cover their capital expenditures and higher operating costs. Utility cash flows were about $10 billion less than the sum of operating and capital costs in 2005, and this gap could widen significantly during the next several years as regulated utilities undertake expenditures for infrastructure development and environmental improvements.[19] Utilities without AACs will have trouble maintaining stable cash flows in an environment of rising and volatile fuel and purchase power costs.

BENEFITS OF AACS

AACs provide several important benefits to utilities, customers, regulators and other stakeholders. For one, AACs ensure that costs are assigned to those customers that benefit from the incurrence of the costs and thus are consistent with the principles of "cost causality" and "inter-generational equity." The lag between rate cases can be significant, and fuel market conditions can change significantly over such periods. AACs enable a better alignment of cost recovery with the customer demands that cause the costs to be incurred. If variable costs are only estimated and placed in base rates, or if significant imbalances in the recovery of variable costs are deferred for long periods and amortized only infrequently and slowly, they may well be assigned to some customers who did not consume much or any of the power that caused those costs to arise. This is both inefficient and inequitable. Conversely, a timely flow-through shows customers the prevailing social, avoidable cost of their consumption decisions, thereby encouraging conservation and energy improvements (or allowing more enjoyment of energy-intensive services, when prices are low).

Second, AACs streamline the regulatory process by eliminating the need for formal, adjudicatory proceedings to review rate adjustments for changes in fuel costs and other variable costs that are largely outside the utility's control. This reduces the regulatory costs imposed on all parties. Moreover, "base rate" proceedings can become more infrequent as a result of the AAC. This will give utilities stronger incentives to control costs that are not included in the AAC. That is, "regulatory lag" will provide utilities an incentive to manage effectively those costs that are largely within their control. By allowing the pass-through of costs beyond the company's control, an AAC enables utility management to focus on those costs and factors over which it has substantial control.[20]

Third, AACs reduce the volatility of a utility's operating margins by shortening the lag between costs incurred and receipts earned to pay such costs. This allows the utility to pay its bills in a timely manner and, just as importantly, reduces the financial markets' perceived risk of the utility having inadequate cash flow. Lowering the perceived risk of inadequate cash flow and, at the extreme, bankruptcy, in turn, will prevent the utility's cost of debt from rising, or may even lower it. This will be an objective benefit, publicly observable in its debt rating and embedded interest rates. (Note that the cost of equity will likely not be altered by an AAC, because it reflects a different kind of risk. This is discussed further in the next section.) In addition, having a more assured cash flow will prevent the utility from having to raise its working capital allowances to compensate for the volatility of unpredictable and largely uncontrollable expenses. As previously described, this financial health also assures the utility's ability to make ongoing investments to maintain and improve the quality of service. Such investments are likely to be increasingly important in the near-future, as there is a growing consensus that utility infrastructure needs expansion and improvement.[21]

Finally, having an AAC in place will avoid exposure to occasional large rate shocks that can arise if rising commodity costs are deferred and accumulated over long periods of time. This may not seem to be an advantage, but it is akin to the benefit of paying credit card bills when they arise rather than running up a large debt of unpaid balances. Customers can make spending and consumption adjustments over time if they have a steady signal of timely information about costs; they cannot do this for sudden, large increases.

These benefits accrue both to utilities and their customers. Lower debt costs and lower working capital requirements enable lower rates—a direct benefit for customers. In addition, a financially healthy utility is better able to make investments in new infrastructure that will reduce expenses and rates in the long-term and better enable the utility to meet the service requirements of a modern economy (*e.g.*, digital-quality power). Indeed, quasi-AACs for immediate rate-basing of mid-sized, one-off capital expenditures such as may be needed for environmental controls might allow the use of more debt financing for such assets. AACs also provide a convenient mechanism to credit profits from off-system power sales to customers, thereby ensuring that customers enjoy the benefits of high wholesale market prices (to the extent their utility makes such sales) as well as incur their costs. While AACs do shift some price risk to customers, this will benefit customers during periods of declining fuel and power costs. Moreover, the dollar-for-dollar recovery provided by an AAC ensures that customers never pay more than the actual costs incurred by the utility.

POSSIBLE CONCERNS ABOUT AACS

While there is a very sound economic basis for endorsing AACs, they are opposed by some who are skeptical of their need or usefulness. A number of issues against the use of automatic adjustment clauses have been raised in various forums; these are described and discussed below. Generally, it is our view that the typical criticisms are either out of date, reflect an incomplete view of the consequences of not having an AAC, or assume an unduly limited model of AAC design. Below, we discuss five common concerns:

1) *Preference for bundled, all-cost ratemaking; possibility of missing offsetting costs in other line items if single issues are analyzed and allowed separately.*

   This concern may have had merit in the past, when utilities were fully integrated and focused fairly narrowly on their local franchise, but this model no longer applies. The modern separation of functions between generation and retail service is strong and growing, even where no retail restructuring has occurred, due to the FERC's policies of fostering transparent, liquid wholesale power markets and insisting that affiliated supply transactions be comparable to available wholesale market alternatives. In addition, bundled, all-in ratemaking may entail less effective oversight of utility costs, since it will involve many more cost items. Indeed, the methods of scrutiny for just and reasonable AAC items are different than for base rate items: AAC items are reasonable to the extent the quantity and type of items purchased correspond to needs (e.g., no speculative positions), and to the extent competitive procurement without affiliate favoritism has been used. They are often easily benchmarked or validated against posted market prices. On the other hand, base rate items involve investment prudence, sizing and timing, and long run (unhedgeable) risk exposure choices, with few standard benchmarks against which they can be compared. They must be evaluated for cost-effectiveness using sophisticated long-term operational and financial planning models.

2) *Loss of incentives by the utility to control fuel costs if they are automatically recoverable*

   While it is true that complete insulation from all volumetric revenue and cost risk could make a utility largely indifferent to the level of such costs, retaining some appropriate risk does not require that a utility be prevented from timely recovery of its AAC-type costs. This would be overkill, for two reasons. First, such cost variations can be very large compared to the allowed equity returns on invested capital. All that is needed to keep utilities intent on cost management is for a modest fraction of the equity return to be volumetrically sensitive. In general, this is already the case for most utilities, even if they have a very efficient AAC, because some portion of fixed costs is typically recovered in variable charges. Accordingly, volume matters to utilities, and this creates a desire to avoid any adverse influences on volume, such as price spikes from the fuel component of rates. Second, the fuel component is largely uncontrollable, so putting it strongly at risk cannot induce meaningful defensive, pro-customer practices. It simply makes the utility's other jobs more difficult, financially.

The main opportunity utilities have to "control" AAC-type costs is to hedge them. This does not reduce their expected costs, but it does reduce their potential variability. Incentive mechanisms for this kind of control can easily be built into an AAC. The utility can then use forward purchases, options, or other hedges to try to stay within the bands.

A less plausible variation on this theme is the fear that an AAC that permits full recovery of fuel costs will incline utilities towards generation technologies that are less efficient, *i.e.*, less expensive in terms of capital costs and more costly in terms of fuel (because those costs are ostensibly easier to recover). The risk of exposure to this kind of distorted decision making is very small, because the utility would still have to obtain regulatory approval for its generation technology choices, (*e.g.*, at resource plan hearings, planning reviews, siting reviews, and financing approvals,) typically well before the plans would be irreversible. The utility would face disallowance penalties or rejection of plans for alternatives that simply shift risk to favor the utility's preferences, rather than satisfying a least cost standard. In other words, regulation has other effective tools that address this directly.

3) *Wholesale purchased power costs are often significantly controllable, via appropriate timing and type of purchases*

This is only partially true: Volatility can be reduced by forward purchasing of power, though not eliminated, but any secular[22] trends in the value of power (such as a general increase due to fuel costs, persistent congestion, or lack of capacity reserves) cannot be hedged away. In general, expected future costs cannot be avoided by any kind of clever contracting, because hedging contracts traded in the market reflect expectations about future supply conditions, which in turn reflect beliefs about underlying market fundamentals that will be manifest in the spot market. Forward trading does not alter these expectations, it just prices them. Even if a utility is using significant hedging to limit volatility, the costs of hedges themselves are the uncontrollable market prices of traded derivatives, which should be recoverable through the AAC. The relevant criteria for determining that such hedges were appropriate are much like those for approving the commodity costs in an AAC: affirming that the right type, procurement process, and accounting for those instruments were used. These are not the least-cost planning criteria that should be applied to base rate items.

In addition, some risk is pretty much unhedgeable, especially volume uncertainty -- which tends to aggravate price risk, since unexpectedly high demand invokes unexpectedly high prices.[23]

4) *Capacity prices are typically recovered in base rates, often under statutory rules, and such components of purchased power costs should be eliminated from AACs*

This concept, somewhat like bundled ratemaking, arose when “capacity costs” were quite consistently associated with demand charges in long term contracts that offered firm service backed by either specific units, or by curtailment priority equal to the native load of the supplier. Load requirements themselves were quite stable in that pre-restructuring era as well. Today, however, capacity has become a highly fungible aspect of wholesale electric power, traded over short intervals to satisfy the shifting needs of a shifting mix of buyers and sellers whose daily obligations can be quite inconstant. A highly desirable, efficient outcome in such a market is for capacity to be traded, either explicitly or implicitly in a firmness premium for delivered power. It is neither useful nor appropriate to attempt to separate out such costs from other fuel and purchased power costs, for three reasons:

a) These costs are every bit as volatile and uncontrollable as the corresponding fuel and "energy" components of purchased power, such that omitting them could cause a significant financial hardship of exactly the same character as we prevent with fuel in AACs

b) Attempting to infer precisely how much of what purchased power price ought to be deemed "capacity" is fraught with imprecision, potential bias, and extreme difficulty. It is not the case that the embedded capacity price is simply the total price less the energy cost of some hypothetical marginal source of capacity, such as a peaker. Such a unit may not even be on the margin for much or any of the contract delivery period. The transaction in which a "capacity premium" appears to be included may have been contracted at an earlier time, such that spot prices at the time of delivery do not describe its terms or expected performance conditions. It may also have complex contingencies and degrees of firmness or performance restrictions that do not make the service equivalent to owning and operating a peaker (*e.g.*, dispatch scheduling restrictions, or features that actual peaking technology would not enjoy, such as a hedged energy price. Accordingly, the "capacity premium" may be a payment for several kinds of complex features.)

c) The incentives created by attempting to exclude imputed capacity in AACs are potentially perverse and undesirable for ratepayers. In particular, they would lead a utility to over-invest in physical capacity, to the point where all energy could be bought on a non-firm basis. This would be very expensive and uneconomic, akin to trying to build the transmission grid to the point where it experienced no congestion. It is far more efficient to purchase a bit of capacity on the spot market when it is unexpectedly needed than to always carry reserves, much like it is often more convenient (and lower cost) to take a cab than to rent a car or drive your own car.

5) *The risk of variable cost recovery is already compensated in the allowed cost of equity*

This is a common misperception, which in its general form holds that virtually any kind of risk of regulatory disapproval is already part of the set of possibilities that shareholders should expect could happen, therefore they must be being compensated for this exposure in the risk premium they demand in the price of the stock. Despite the rhetorical appeal of this view, it misconstrues the nature of a stock's risk premium and is not correct.

The cost of equity capital includes a risk premium that compensates investors for the tendency of the stock price to move up <u>and</u> down in tandem with the stock market and the macro-economy as a whole. To the extent that a stock price moves with the broad market, the returns on the stock have a non-diversifiable character and so require compensation above the risk-free (government bond) rate. To the extent the stock moves up or down independently, that risk is diversifiable across a portfolio of many stocks and so does not require a risk premium. In stock markets, the price of the stock will adjust until it is centered on a level that involves a balance of potential up and down future movements; if it were expected to move in only one way, it would not be priced properly.

The normal valuation in fuel costs over time could be symmetric (up and down) around some fixed rate. But a problem arises if fuel costs move systematically up and become controversial to recover. The risk of regulatory disallowance of a large deferred balance of fuel or purchased power costs (absent an AAC) does not involve both up and downside prospective returns for investors. Rather, it only involves a downside possibility, the effect of which is to drive down the stock price until it offers a fair return to new investors, despite the likelihood of partial cost disallowance. This fair return will be the same as it would be for a similar company that was not exposed to a disallowance, because both stocks have the same prospective tendency to gain or lose value in synchrony with the stock market as a whole. Thus, measurements of the required rate of return consistent with those depressed stock prices will not show a premium. Rather, the stock will have been discounted to where no premium is required.

However, that does not mean it is appropriate to simply disallow such costs. Utilities need an unbiased opportunity to earn a fair return on all of their prudently invested capital as measured at book value, in order to keep attracting capital. If a portion of operating expenses is disallowed, with no offsetting opportunity for earning a superior return being created somewhere else, then the utility can no longer expect to earn its cost of capital. This is simply uncompensated value expropriation. The first result of that will be to block the utility from reinvesting in its own infrastructure; the second will be to force it to find ways of becoming capital-intensive. Fiduciary responsibilities to its investors demand that the utility managers not "throw good money after bad."

The best way to prevent this is to assure a fair opportunity to recover all reasonably incurred operating expenses, not to add some kind of *ad hoc* premium to other return allowances. A viable AAC is one of the best ways of achieving this. Importantly, the above also implies that it is not appropriate to reduce the cost of equity if/when an AAC is created or made more "automatic." Generally, that will not affect the required rate of return on equity – though it may improve (reduce) the cost of debt. If say that reduced cost of debt will be objectively evident when it occurs, as seen in enhanced credit ratings and lower interest rates on future debt issues or refinancings. Again, on immediate rate adjustment to reflect this possibility is needed or appropriate, until it is a realized outcome.

Many of the above doubts about AACs can be addressed through alternative designs. For example, AACs with risk-sharing and incentive clauses can be easily created, by agreeing in advance with regulators about how much risk to try to protect ratepayers from, and on how the associated hedging costs will be recovered. The result can be rates that are fairly stable for customers and cash flow that is not unduly volatile for the financial managers. The key to such an arrangement is to understand that hedged costs will not necessarily turn out to be lower than spot, but they will be less volatile. The hedge costs themselves will arise from wholesale market transactions; like the commodity costs they are written against, these will be uncontrollable. Accordingly, they should be given a timely pass-through in the AAC itself.

Similarly, rate riders for mandated environmental expenditures can be implemented that do not undermine either utilities' incentives to be efficient or regulator's opportunity (and obligation) to review and approve costs. Simply allowing a targeted, timely rate increase for audited expenditures that are imposed via other regulations will increase utilities' readiness to perform such system improvements that otherwise have no direct or indirect cost recovery mechanism (absent a full base rate review, which may not be otherwise necessary).

CONCLUSIONS

- The circumstances justifying AACs as beneficial to utilities and their customers are more pronounced today than ever: more volatile fuel and wholesale power prices, more vertical unbundling and consequent out-sourcing of supply needs, reduced credit ratings of many utilities, and an increasing number of new or emerging cost items which utilities cannot control and from which they do not profit.
- While it is understandably tempting to try to protect customers from material increases and volatility in utility operating costs, doing so one-sidedly is self-defeating and therefore is not in the interest of consumers. Placing uncontrollable costs at risk of long deferral and potential disallowance will inevitably raise costs, either directly through higher costs of debt, or indirectly through impaired maintenance and reduced investment in improving the utility's infrastructure and support services.

- It is unnecessary to place a utility strongly at risk for fuel and similar AAC-type costs in order to be confident the utility will attend to cost management opportunities. A vast literature on incentives shows that imposing too much risk is generally counterproductive.
- The cost of debt may fall with an effective AAC, while the cost of equity is unlikely to be affected. Other customer benefits of AACs arise from having steady, timely price signals for managing their personal finances, and from the utility having steady cash flow from operations to maintain the appropriate quality of service.
- It is possible to have both financial security for the utility and tolerable rate stability for customers, with AACs that include explicit agreement on how a utility can hedge and can recover the costs associated with those risk management positions through the AAC itself.

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1 Wisconsin State Statute 196.20(4)(b) states that: "An electric public utility may not recover in rates any increase in costs, including fuel, by means of the operation of an automatic adjustment clause."

2 This prohibition may be circumvented, indirectly, if cost indexing in rates is pursued in conjunction with alternative ratemaking practices, such as incentive ratemaking. *Central Vermont Public Service Corporation*, Vermont Supreme Court, 473 A.2d 1155, January 13, 1984.

3 Vermont is the only state that does not permit AACs. Utah has a settlement under which utilities refrain from using an AAC.

4 See *U.S. Electric Utilities: Credit Implications of Commodity Cost Recovery*, Fitch Ratings, February 13, 2006, p. 7.

5 Annual Energy Review 2005, published by the Energy Information Administration (EIA). In particular, see Table 6.2 (Natural Gas Production, 1949-2004) and Table 6.6 (Natural Gas in Underground Storage, 1954-2004). In Table 6.6, we define reserves as Base Gas underground storage only.

6 There were occasional excursions of high price volatility in the 1970s and early '80s due to the Mid-East oil crises.

7 See, for example, Boston Edison Company Re : Edgar Electric Energy Company, 55 FERC ¶ 61,382 (1991), and Heartland Energy Services Inc ., 68 FERC ¶ 61,223 (1994).

8 *Electricity Transmission Access*, National Energy Strategy Technical Annex 3, U.S. Department of Energy, 1991/1992, p. 9.

9 The CAISO only has a real-time energy market, whereas the other centralized markets have both a real-time and day-ahead energy market.

10 http://www.ercot.com/news/press_releases/2006/ERCOT_at_a_Glance_News_Update_-_February_9%2C_2006.html#Fee%20Case%20Hearing

11 POLR is bundled generation service provided by the local utility to retail customers unable or uninterested in finding an alternative retail supplier.

12 See, for example, Frank C. Graves and Joseph B. Wharton, "Provider of Last Resort Service Hindering Retail Market Development", *Natural Gas*, Volume 18, Number 3, October 2001.

13 See, for example, Johannes P. Pfeifenberger, Joseph B. Wharton and Adam C. Schumacher, "Keeping Up with Retail Access? Developments in U.S. Restructuring and Resource Procurement for Regulated Retail Service," *The Electricity Journal*, December 2004, pp. 50-64.

14 To mitigate rate shock, purchase power costs could be deferred for a period. Rate deferrals are covered in a monograph

15 See, for example, *Fuel and Purchased Power Cost Recovery in the Wake of Volatile Gas and Power Markets – U.S. Electric Utilities to Watch, Standard and Poor's*, March 22, 2006.

16 See Dow Jones and Reuters, "S&P Downgrades CVPS Corporate Credit Rating", 14 June 2005. Also see, Dow Jones and Reuters, "CVPS Hit with Second Downgrade", 21 June 2005.

17 See St. Louis Business Journal, "S&P cuts long-term credit rating on Ameren", 3 October 2005. Also, see Dow Jones and Reuters, "Wary About Cost Recovery, Moody's Cuts Debt Ratings of Ameren, ComEd", 19 December 2005.

18 See Standard & Poor's, "Research Update: Empire District Electric Downgraded To 'BBB-' on Expected Tight Financials", 17 May 2006.

19 *Why Are Electricity Prices Increasing?: An Industry-Wide Perspective*, The Brattle Group, Prepared for the Edison Foundation, June 2006, p. 4.

20 David E.M. Sappington, Johannes P. Pfeifenberger, Philip Hanser, and Gregory N. Basheda, "The State of Performance-Based Regulation in the U.S. Electric Utility Industry", *The Electricity Journal*, October 2001, Vol. 14, No. 8, pp. 71-79.

21 See, for example, *The Emerging Smart Grid: Investment and Entrepreneurial Potential in the Electric Power Grid of the Future*, Center for Smart Energy, October 2005.

22 See, Meyer, Peter B. (Ed.) 2001. *Glossary of Research Economics* [online]. Available: http://econterms.com.

23 Finally, if a utility is going to be asked (or forced) to find a hedging strategy that allows it to operate without an AAC, then the local Commission must also make the utility's complete recovery of complex hedging costs very reliable. Few utilities have reached this degree of regulatory accord with their Commissions.

Division 4-18

Request:

Mr. Hevert employs a 5.36 percent long-term growth rate of nominal U.S. GDP in his multi-stage DCF studies. Please provide the DCF results if his studies had instead employed a nominal U.S.GDP growth rate of 4.36 percent. That is, please revise Mr. Hevert's Table 7 based on substituting the 4.36 percent growth rate for the 5.36 percent growth rate.

Response:

As discussed at Pages 42-43 (Bates Pages 45-46 of Book 2) of Company Witness Robert B. Hevert's pre-filed direct testimony, Mr. Hevert has derived results from the Multi-Stage DCF model using a long-term growth rate based on the expected rate of U.S. Gross Domestic Product growth, in perpetuity, beginning in the tenth year of the analysis. This is the proper indicator of long-term growth because it represents the forward-looking view of growth beginning ten years in the future. Mr. Hevert also explains the basis for his long-term growth rate calculation and the fundamental relationships among expected long-term growth and other model inputs and assumptions.

The question asks for a recalculation of Mr. Hevert's Multi-Stage DCF model results but does not identify the source of the 4.36 percent growth rate. Therefore, it appears that the 4.36 percent growth rate is simply an assumed 100 basis-point reduction in the expected rate of U.S. Gross Domestic Product growth. There is no analytical basis for a reduction of the expected rate of U.S. Gross Domestic Product growth, nor any source for the requested 4.36 percent growth rate. Without an analytical basis for the requested change, the recalculation would not have any analytical meaning or value. For that reason, Mr. Hevert has not undertaken the requested calculation.

Prepared by or under the supervision of: Robert B. Hevert

Division 4-19

Request:

Please provide Narragansett's projection of capital spending for each of the next three years, 2018 - 2020.

Response:

The Company's projected capital expenditures are provided in the table below.

Please note that estimates for capital expenditures associated with Electric Distribution and Gas Distribution are also provided in the Company's recent Infrastructure, Safety, and Reliability (ISR) Plan filings, as follows: RIPUC Docket No. 4783 (FY2019 Electric ISR Plan); Docket No. 4781 (FY2019 Gas ISR Plan); Docket No. 4678 (FY2018 Gas ISR Plan); and Docket 4682 (FY2018 Electric ISR Plan).

Gas Distribution Growth-related investments are not included in the ISR Plan, and are, therefore, provided separately (as shown in Schedule MAL-11-GAS Page 5, Line 3 (Bates Page 116 of Book 9). The Electric Transmission investments include FERC-jurisdictional assets and are not included in ISR filings.

Projected Capital Expenditures *($ thousands)*	**Fiscal Year 2018**	**Fiscal Year 2019**	**Fiscal Year 2020**
Electric Distribution	$100,620	$108,767	$108,500
Gas Distribution	$101,185	$107,079	$117,889
Gas Growth	$ 19,474	$ 27,432	$ 20,403
Electric Transmission	$ 29,000	$ 53,000	$ 61,000

Prepared by or under the supervision of: Joshua Nowak and Melissa Little

Division 4-20

Request:

Please provide a description of Narragansett's dividend payment policy and the basis for that policy.

Response:

The Company reviews its capital structure on a periodic basis and manages its dividend payments to align its actual capital structure with its target capital structure. These targets are determined in line with the Company's credit and risk profile and sound utility and rate setting practices.

Prepared by or under the supervision of: Joshua Nowak