201-2

MISSOURI PUBLIC SERVICE COMMISSION

STAFF REPORT

COST OF SERVICE

APPENDIX 2
Support for Staff Cost
of
Capital Recommendations

UNION ELECTRIC COMPANY
d/b/a Ameren Missouri

FILE NO. ER-2011-0028

Jefferson City, Missouri
February 2011

Staff Exhibit No. 201-2
Date 4/26/11 Reporter SmB
File No. ER-2011-0028

AN ANALYSIS OF THE COST OF CAPITAL

FOR

Union Electric Company d/b/a Ameren Missouri

FILE NO. ER-2011-0028

SCHEDULES

BY

DAVID MURRAY

UTILITY SERVICES DIVISION

MISSOURI PUBLIC SERVICE COMMISSION

FEBRUARY 2011

Union Electric Company d/b/a Ameren Missouri
FILE NO. ER-2011-0028

List of Schedules

Union Electric Company d/b/a Ameren Missouri
FILE NO. ER-2011-0028

Federal Reserve Discount Rate Changes and Federal Reserve Funds Rate Changes

Date	Federal Reserve Discount Rate	Federal Reserve Funds Rate
01/01/83	8.50%	
12/31/83	8.50%	
04/09/84	9.00%	
11/21/84	8.50%	
12/24/84	8.00%	
05/20/85	7.50%	
03/07/86	7.00%	
04/21/86	6.50%	
07/11/86	6.00%	
08/21/86	5.50%	
09/04/87	6.00%	
08/09/88	6.50%	
02/24/89	7.00%	
07/13/90		8.00% *
10/29/90		7.75%
11/13/90		7.50%
12/07/90		7.25%
12/18/90		7.00%
12/19/90	6.50%	
01/09/91		6.75%
02/01/91	6.00%	6.25%
03/08/91		6.00%
04/30/91	5.50%	5.75%
08/06/91		5.50%
09/13/91	5.00%	5.25%
10/31/91		5.00%
11/06/91	4.50%	4.75%
12/06/91		4.50%
12/20/91	3.50%	4.00%
04/09/92		3.75%
07/02/92	3.00%	3.25%
09/04/92		3.00%
01/01/93		
12/31/93	No Changes	No Changes
02/04/94		3.25%
03/22/94		3.50%
04/18/94		3.75%
05/17/94	3.50%	4.25%
08/16/94	4.00%	4.75%
11/15/94	4.75%	5.50%
02/01/95	5.25%	6.00%
07/06/95		5.75%
12/19/95		5.50%
01/31/96	5.00%	5.25%
03/25/97		5.50%
12/12/97	5.00%	
01/09/98	5.00%	
03/06/98	5.00%	
09/29/98		5.25%
10/15/98	4.75%	5.00%
11/17/98	4.50%	4.75%

Date	Federal Reserve Discount Rate	Federal Reserve Funds Rate
06/30/99	4.50%	5.00%
08/24/99	4.75%	5.25%
11/16/99	5.00%	5.50%
02/02/00	5.25%	5.75%
03/21/00	5.50%	6.00%
05/19/00	6.00%	6.50%
01/03/01	5.75%	6.00%
01/04/01	5.50%	6.00%
01/31/01	5.00%	5.50%
03/20/01	4.50%	5.00%
04/18/01	4.00%	4.50%
05/15/01	3.50%	4.00%
06/27/01	3.25%	3.75%
08/21/01	3.00%	3.50%
09/17/01	2.50%	3.00%
10/02/01	2.00%	2.50%
11/06/01	1.50%	2.00%
12/11/01	1.25%	1.75%
11/06/02	0.75%	1.25%
01/09/03	2.25%**	1.25%
06/25/03	2.00%	1.00%
06/30/04	2.25%	1.25%
08/10/04	2.50%	1.50%
09/21/04	2.75%	1.75%
11/10/04	3.00%	2.00%
12/14/04	3.25%	2.25%
02/02/05	3.50%	2.50%
03/22/05	3.75%	2.75%
05/03/05	4.00%	3.00%
06/30/05	4.25%	3.25%
08/09/05	4.50%	3.50%
09/20/05	4.75%	3.75%
11/01/05	5.00%	4.00%
12/13/05	5.25%	4.25%
01/31/06	5.50%	4.50%
03/28/06	5.75%	4.75%
05/10/06	6.00%	5.00%
06/29/06	6.25%	5.25%
08/17/07	5.75%	5.25%
09/18/07	5.25%	4.75%
10/31/07	5.00%	4.50%
12/11/07	4.75%	4.25%
01/22/08	4.00%	3.50%
01/30/08	3.50%	3.00%
03/16/08	3.25%	
03/18/08	2.50%	2.25%
04/30/08	2.25%	2.00%
10/08/08	1.75%	1.50%
10/28/08	1.25%	1.00%
12/30/08	0.50%	0% - 0.25%
02/19/10	0.75%	

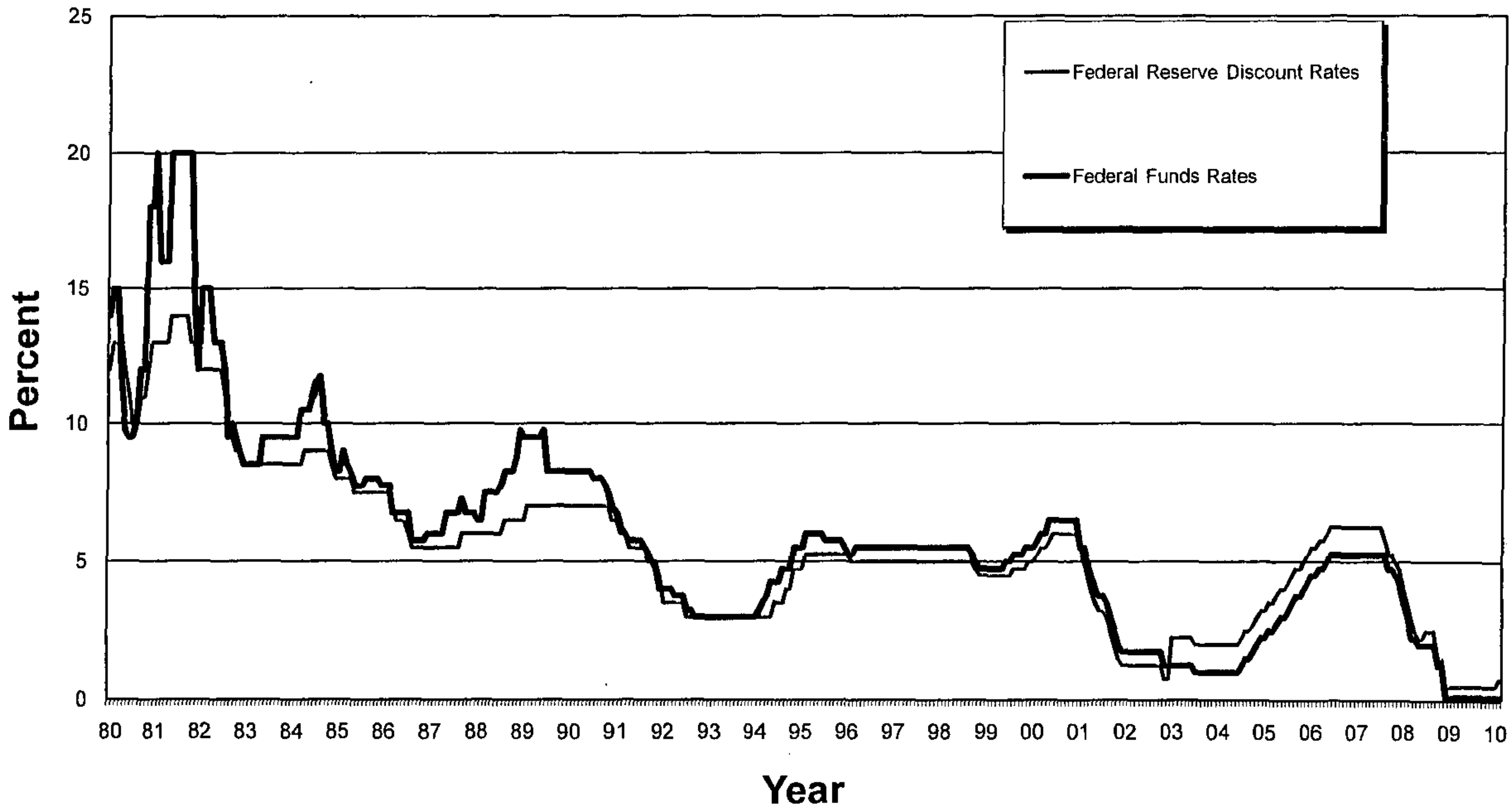
* Staff began tracking the Federal Funds Rate.
**Revised discount window program begins. Reflects rate on primary credit. This revised discount window policy results in incomparability of the discount rates after January 9, 2003 to discount rates before January 9, 2003.

Source:
Federal Reserve Discount rate http://www.newyorkfed.org/markets/statistics/dlyrates/fedrate.html
Federal Reserve Funds rate http://www.newyorkfed.org/markets/statistics/dlyrates/fedrate.html

Note: Interest rates as of December 31 for each year are underlined.

Union Electric Company d/b/a Ameren Missouri
File No. ER-2011-0028

Federal Reserve Discount Rates and Federal Funds Rates
1980 - 2010



SCHEDULE 2 - 2

SCHEDULE 2-2

Union Electric Company d/b/a Ameren Missouri
File No. ER-2011-0028

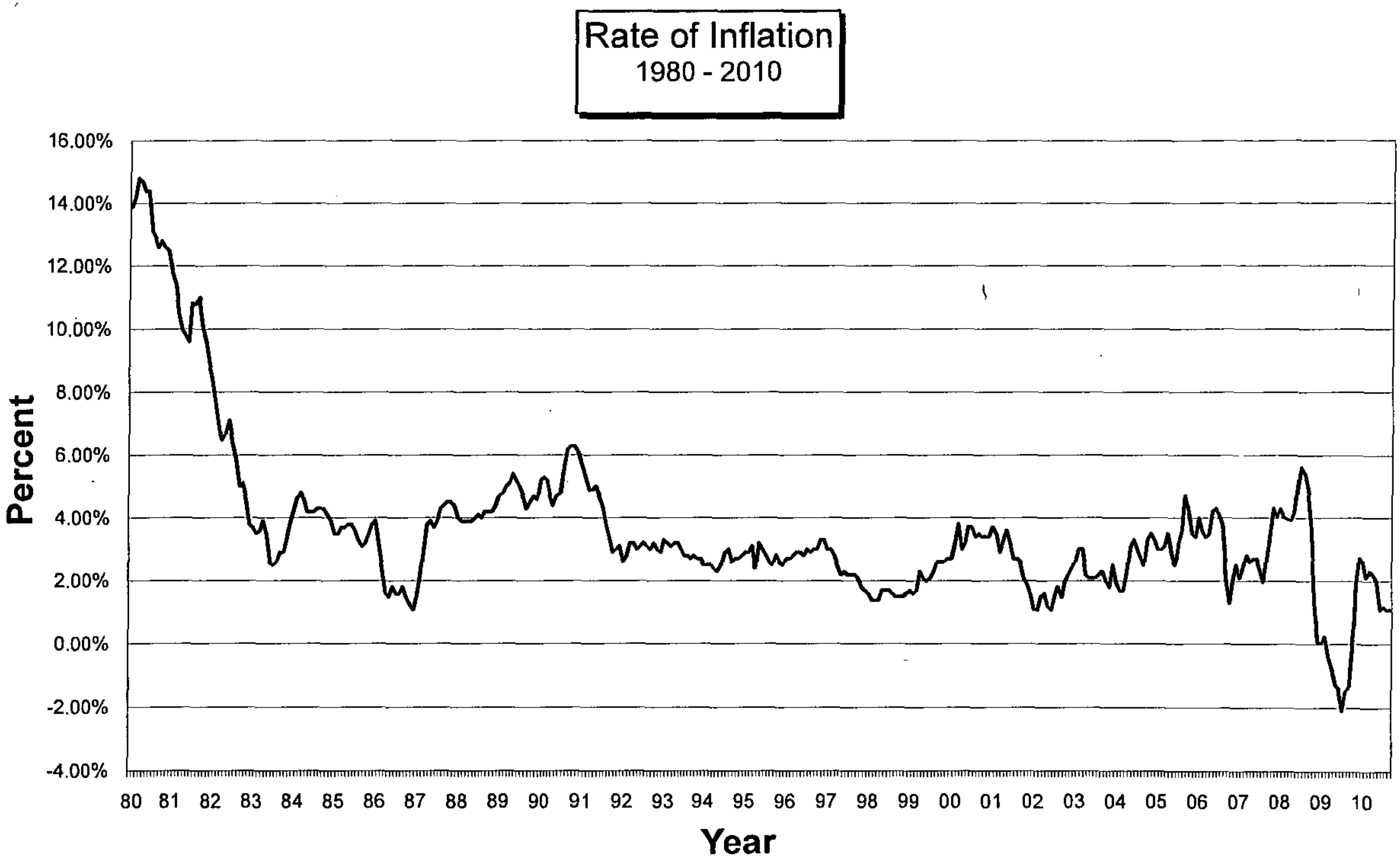
Rate of Inflation

Mo/Year	Rate (%)	Mo/Year	Rate (%)	Mo/Year	Rate (%)	Mo/Year	Rate (%)	Mo/Year	Rate (%)	Mo/Year	Rate (%)	Mo/Year	Rate (%)	Mo/Year	Rate (%)
Jan 1980	13.90	Jan 1984	4.20	Jan 1988	4.00	Jan 1992	2.60	Jan 1996	2.70	Jan 2000	2.70	Jan 2004	1.90	Jan 2008	4.30
Feb	14.20	Feb	4.60	Feb	3.90	Feb	2.80	Feb	2.70	Feb	3.20	Feb	1.70	Feb	4.00
Mar	14.80	Mar	4.80	Mar	3.90	Mar	3.20	Mar	2.80	Mar	3.70	Mar	1.70	Mar	4.00
Apr	14.70	Apr	4.60	Apr	3.90	Apr	3.20	Apr	2.90	Apr	3.00	Apr	2.30	Apr	3.90
May	14.40	May	4.20	May	3.90	May	3.00	May	2.90	May	3.20	May	3.10	May	4.20
Jun	14.40	Jun	4.20	Jun	4.00	Jun	3.10	Jun	2.80	Jun	3.70	Jun	3.30	Jun	5.00
Jul	13.10	Jul	4.20	Jul	4.10	Jul	3.20	Jul	3.00	Jul	3.70	Jul	3.00	Jul	5.60
Aug	12.90	Aug	4.30	Aug	4.00	Aug	3.10	Aug	2.90	Aug	3.40	Aug	2.70	Aug	5.40
Sep	12.60	Sep	4.30	Sep	4.20	Sep	3.00	Sep	3.00	Sep	3.50	Sep	2.50	Sep	4.90
Oct	12.80	Oct	4.30	Oct	4.20	Oct	3.20	Oct	3.00	Oct	3.40	Oct	3.30	Oct	3.70
Nov	12.60	Nov	4.10	Nov	4.20	Nov	3.00	Nov	3.30	Nov	3.40	Nov	3.50	Nov	1.10
Dec	12.50	Dec	3.90	Dec	4.40	Dec	2.90	Dec	3.30	Dec	3.40	Dec	3.30	Dec	0.10
Jan 1981	11.80	Jan 1985	3.50	Jan 1989	4.70	Jan 1993	3.30	Jan 1997	3.00	Jan 2001	3.70	Jan 2005	3.00	Jan 2009	0.00
Feb	11.40	Feb	3.50	Feb	4.80	Feb	3.20	Feb	3.00	Feb	3.50	Feb	3.00	Feb	0.20
Mar	10.50	Mar	3.70	Mar	5.00	Mar	3.10	Mar	2.80	Mar	2.90	Mar	3.10	Mar	-0.40
Apr	10.00	Apr	3.70	Apr	5.10	Apr	3.20	Apr	2.50	Apr	3.30	Apr	3.50	Apr	-0.70
May	9.80	May	3.80	May	5.40	May	3.20	May	2.20	May	3.60	May	2.80	May	-1.28
Jun	9.60	Jun	3.80	Jun	5.20	Jun	3.00	Jun	2.30	Jun	3.20	Jun	2.50	Jun	-1.40
Jul	10.80	Jul	3.60	Jul	5.00	Jul	2.80	Jul	2.20	Jul	2.70	Jul	3.20	Jul	-2.10
Aug	10.80	Aug	3.30	Aug	4.70	Aug	2.80	Aug	2.20	Aug	2.70	Aug	3.60	Aug	-1.50
Sep	11.00	Sep	3.10	Sep	4.30	Sep	2.70	Sep	2.20	Sep	2.60	Sep	4.70	Sep	-1.30
Oct	10.10	Oct	3.20	Oct	4.50	Oct	2.80	Oct	2.10	Oct	2.10	Oct	4.30	Oct	-0.20
Nov	9.60	Nov	3.50	Nov	4.70	Nov	2.70	Nov	1.80	Nov	1.90	Nov	3.50	Nov	1.80
Dec	8.90	Dec	3.80	Dec	4.60	Dec	2.70	Dec	1.70	Dec	1.60	Dec	3.40	Dec	2.70
Jan 1982	8.40	Jan 1986	3.90	Jan 1990	5.20	Jan 1994	2.50	Jan 1998	1.60	Jan 2002	1.10	Jan 2006	4.00	Jan 2010	2.60
Feb	7.60	Feb	3.10	Feb	5.30	Feb	2.50	Feb	1.40	Feb	1.10	Feb	3.60	Feb	2.10
Mar	6.80	Mar	2.30	Mar	5.20	Mar	2.50	Mar	1.40	Mar	1.50	Mar	3.40	Mar	2.30
Apr	6.50	Apr	1.60	Apr	4.70	Apr	2.40	Apr	1.40	Apr	1.60	Apr	3.50	April	2.20
May	6.70	May	1.50	May	4.40	May	2.30	May	1.70	May	1.20	May	4.20	May	2.00
Jun	7.10	Jun	1.80	Jun	4.70	Jun	2.50	Jun	1.70	Jun	1.10	June	4.30	June	1.10
Jul	6.40	Jul	1.60	Jul	4.80	Jul	2.90	Jul	1.70	Jul	1.50	July	4.10	July	1.20
Aug	5.90	Aug	1.60	Aug	5.60	Aug	3.00	Aug	1.60	Aug	1.80	Aug	3.80	August	1.10
Sep	5.00	Sep	1.80	Sep	6.20	Sep	2.60	Sep	1.50	Sep	1.50	Sep	2.10	September	1.10
Oct	5.10	Oct	1.50	Oct	6.30	Oct	2.70	Oct	1.50	Oct	2.00	Oct	1.30	Oct	1.20
Nov	4.60	Nov	1.30	Nov	6.30	Nov	2.70	Nov	1.50	Nov	2.20	Nov	2.00	Nov	1.10
Dec	3.80	Dec	1.10	Dec	6.10	Dec	2.80	Dec	1.60	Dec	2.40	Dec	2.50	Dec	1.50
Jan 1983	3.70	Jan 1987	1.50	Jan 1991	5.70	Jan 1995	2.90	Jan 1999	1.70	Jan 2003	2.60	Jan 2007	2.10		
Feb	3.50	Feb	2.10	Feb	5.30	Feb	2.90	Feb	1.60	Feb	3.00	Feb	2.40		
Mar	3.60	Mar	3.00	Mar	4.90	Mar	3.10	Mar	1.70	Mar	3.00	Mar	2.80		
Apr	3.90	Apr	3.80	Apr	4.90	Apr	2.40	Apr	2.30	Apr	2.20	Apr	2.60		
May	3.50	May	3.90	May	5.00	May	3.20	May	2.10	May	2.10	May	2.70		
Jun	2.60	Jun	3.70	Jun	4.70	Jun	3.00	Jun	2.00	Jun	2.10	Jun	2.70		
Jul	2.50	Jul	3.90	Jul	4.40	Jul	2.80	Jul	2.10	Jul	2.10	Jul	2.40		
Aug	2.60	Aug	4.30	Aug	3.80	Aug	2.60	Aug	2.30	Aug	2.20	Aug	2.00		
Sep	2.90	Sep	4.40	Sep	3.40	Sep	2.50	Sep	2.60	Sep	2.30	Sep	2.80		
Oct	2.90	Oct	4.50	Oct	2.90	Oct	2.80	Oct	2.60	Oct	2.00	Oct	3.50		
Nov	3.30	Nov	4.50	Nov	3.00	Nov	2.60	Nov	2.60	Nov	1.80	Nov	4.30		
Dec	3.80	Dec	4.40	Dec	3.10	Dec	2.50	Dec	2.70	Dec	1.90	Dec	4.10		

Source: U.S. Dept of Labor, Bureau of Labor Statistics, Consumer Price Index - All Urban Consumers,
Change for 12-Month Period, Bureau of Labor Statistics,
http://www.bls.gov/schedule/archives/cpi_nr.htm

SCHEDULE 3-1

Union Electric Company d/b/a Ameren Missouri
File No. ER-2011-0028



SCHEDULE 3 - 2

Union Electric Company d/b/a Ameren Missouri
File No. ER-2011-0028

Average Yields on Public Utility Bonds

Mo/Year	Rate (%)	Mo/Year	Rate (%)	Mo/Year	Rate (%)	Mo/Year	Rate (%)	Mo/Year	Rate (%)	Mo/Year	Rate (%)	Mo/Year	Rate (%)	Mo/Year	Rate (%)
Jan 1980	12.12	Jan 1984	13.40	Jan 1988	10.75	Jan 1992	8.67	Jan 1996	7.20	Jan 2000	8.22	Jan 2004	6.23	Jan 2008	6.08
Feb	13.48	Feb	13.50	Feb	10.11	Feb	8.77	Feb	7.37	Feb	8.10	Feb	6.17	Feb	6.28
Mar	14.33	Mar	14.03	Mar	10.11	Mar	8.84	Mar	7.72	Mar	8.14	Mar	6.01	Mar	6.29
Apr	13.50	Apr	14.30	Apr	10.53	Apr	8.79	Apr	7.88	Apr	8.14	Apr	6.38	Apr	6.36
May	12.17	May	14.95	May	10.75	May	8.72	May	7.99	May	8.55	May	6.68	May	6.38
Jun	11.87	Jun	15.16	Jun	10.71	Jun	8.64	Jun	8.07	Jun	8.22	Jun	6.53	Jun	6.50
Jul	12.12	Jul	14.92	Jul	10.96	Jul	8.46	Jul	8.02	Jul	8.17	Jul	6.34	Jul	6.50
Aug	12.82	Aug	14.29	Aug	11.09	Aug	8.34	Aug	7.84	Aug	8.05	Aug	6.18	Aug	6.48
Sep	13.29	Sep	14.04	Sep	10.56	Sep	8.32	Sep	8.01	Sep	8.16	Sep	6.01	Sep	6.59
Oct	13.53	Oct	13.68	Oct	9.92	Oct	8.44	Oct	7.76	Oct	8.08	Oct	5.95	Oct	7.70
Nov	14.07	Nov	13.15	Nov	9.89	Nov	8.53	Nov	7.48	Nov	8.03	Nov	5.97	Nov	7.80
Dec	14.48	Dec	12.96	Dec	10.02	Dec	8.36	Dec	7.58	Dec	7.79	Dec	5.93	Dec	6.87
Jan 1981	14.22	Jan 1985	12.88	Jan 1989	10.02	Jan 1993	8.23	Jan 1997	7.79	Jan 2001	7.76	Jan 2005	5.80	Jan 2009	6.77
Feb	14.84	Feb	13.00	Feb	10.02	Feb	8.00	Feb	7.68	Feb	7.69	Feb	5.64	Feb	6.72
Mar	14.86	Mar	13.66	Mar	10.16	Mar	7.85	Mar	7.92	Mar	7.59	Mar	5.86	Mar	6.85
Apr	15.32	Apr	13.42	Apr	10.14	Apr	7.76	Apr	8.08	Apr	7.81	Apr	5.72	Apr	6.90
May	15.84	May	12.89	May	9.92	May	7.78	May	7.94	May	7.88	May	5.60	May	6.83
Jun	15.27	Jun	11.91	Jun	9.49	Jun	7.68	Jun	7.77	Jun	7.75	Jun	5.39	June	6.54
Jul	15.87	Jul	11.88	Jul	9.34	Jul	7.53	Jul	7.52	Jul	7.71	Jul	5.50	July	6.15
Aug	16.33	Aug	11.93	Aug	9.37	Aug	7.21	Aug	7.57	Aug	7.57	Aug	5.51	Aug	5.80
Sep	16.89	Sep	11.95	Sep	9.43	Sep	7.01	Sep	7.50	Sep	7.73	Sep	5.54	Sep	5.60
Oct	16.76	Oct	11.84	Oct	9.37	Oct	6.99	Oct	7.37	Oct	7.64	Oct	5.79	Oct	5.64
Nov	15.50	Nov	11.33	Nov	9.33	Nov	7.30	Nov	7.24	Nov	7.61	Nov	5.88	Nov	5.71
Dec	15.77	Dec	10.82	Dec	9.31	Dec	7.33	Dec	7.16	Dec	7.86	Dec	5.83	Dec	5.86
Jan 1982	16.73	Jan 1986	10.66	Jan 1990	9.44	Jan 1994	7.31	Jan 1998	7.03	Jan 2002	7.69	Jan 2006	5.77	Jan 2010	5.83
Feb	16.72	Feb	10.16	Feb	9.66	Feb	7.44	Feb	7.09	Feb	7.62	Feb	5.83	Feb	5.94
Mar	16.07	Mar	9.33	Mar	9.75	Mar	7.83	Mar	7.13	Mar	7.83	Mar	5.98	Mar	5.90
Apr	15.82	Apr	9.02	Apr	9.87	Apr	8.20	Apr	7.12	Apr	7.74	Apr	6.28	Apr	5.87
May	15.60	May	9.52	May	9.89	May	8.32	May	7.11	May	7.76	May	6.39	May	5.59
Jun	16.18	Jun	9.51	Jun	9.69	Jun	8.31	Jun	6.99	June	7.67	June	6.39	June	5.55
Jul	16.04	Jul	9.19	Jul	9.66	Jul	8.47	Jul	6.99	July	7.54	July	6.37	July	5.39
Aug	15.22	Aug	9.15	Aug	9.84	Aug	8.41	Aug	6.96	Aug	7.34	Aug	6.20	Aug	5.10
Sep	14.56	Sep	9.42	Sep	10.01	Sep	8.65	Sep	6.88	Sep	7.23	Sep	6.03	Sep	5.10
Oct	13.88	Oct	9.39	Oct	9.94	Oct	8.88	Oct	6.88	Oct	7.43	Oct	6.01	Oct	5.20
Nov	13.58	Nov	9.15	Nov	9.76	Nov	9.00	Nov	6.96	Nov	7.31	Nov	5.82	Nov	5.45
Dec	13.55	Dec	8.96	Dec	9.57	Dec	8.79	Dec	6.84	Dec	7.20	Dec	5.83	Dec	5.61
Jan 1983	13.46	Jan 1987	8.77	Jan 1991	9.56	Jan 1995	8.77	Jan 1999	6.87	Jan 2003	7.13	Jan 2007	5.96		
Feb	13.60	Feb	8.81	Feb	9.31	Feb	8.56	Feb	7.00	Feb	6.92	Feb	5.91		
Mar	13.28	Mar	8.75	Mar	9.39	Mar	8.41	Mar	7.18	Mar	6.80	Mar	5.87		
Apr	13.03	Apr	9.30	Apr	9.30	Apr	8.30	Apr	7.16	Apr	6.68	Apr	6.01		
May	13.00	May	9.82	May	9.29	May	7.93	May	7.42	May	6.35	May	6.03		
Jun	13.17	Jun	9.87	Jun	9.44	Jun	7.62	Jun	7.70	Jun	6.21	June	6.34		
Jul	13.28	Jul	10.01	Jul	9.40	Jul	7.73	Jul	7.66	Jul	6.54	July	6.28		
Aug	13.50	Aug	10.33	Aug	9.16	Aug	7.86	Aug	7.86	Aug	6.78	Aug	6.28		
Sep	13.35	Sep	11.00	Sep	9.03	Sep	7.62	Sep	7.87	Sep	6.58	Sep	6.24		
Oct	13.19	Oct	11.32	Oct	8.99	Oct	7.46	Oct	8.02	Oct	6.50	Oct	6.17		
Nov	13.33	Nov	10.82	Nov	8.93	Nov	7.40	Nov	7.86	Nov	6.44	Nov	6.04		
Dec	13.48	Dec	10.99	Dec	8.76	Dec	7.21	Dec	8.04	Dec	6.36	Dec	6.23		

Sources:
Mergent Bond Record (January 1980 through November 2010); BondsOnline (December 2010)

SCHEDULE 4 - 1

Union Electric Company d/b/a Ameren Missouri
File No. ER-2011-0028

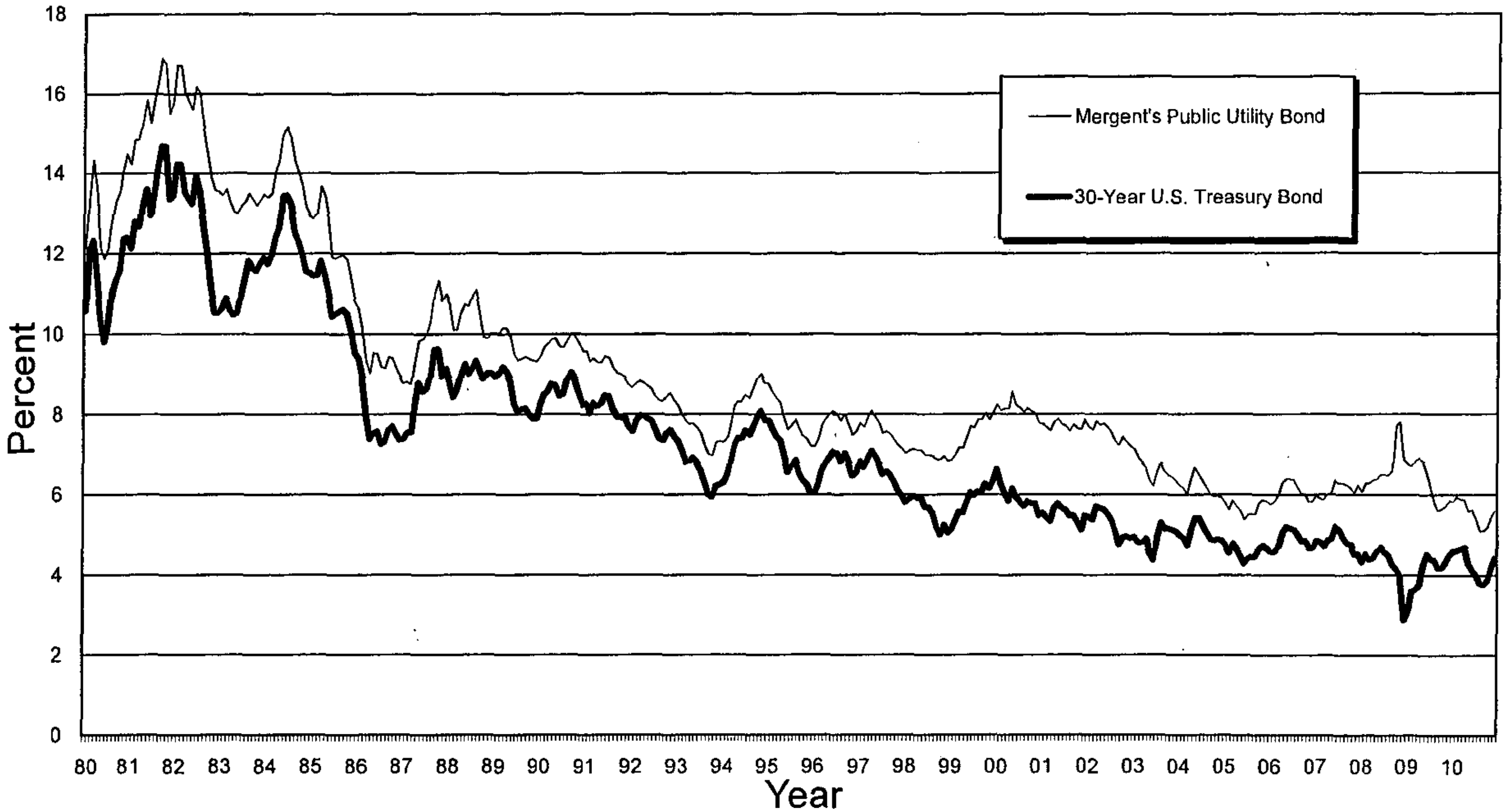
Average Yields on Thirty-Year U.S. Treasury Bonds

Mo/Year	Rate (%)	Mo/Year	Rate (%)	Mo/Year	Rate (%)	Mo/Year	Rate (%)	Mo/Year	Rate (%)	Mo/Year	Rate (%)	Mo/Year	Rate (%)	Mo/Year	Rate (%)
Jan 1980	10.60	Jan 1984	11.75	Jan 1988	8.83	Jan 1992	7.58	Jan 1996	6.05	Jan 2000	6.63	Jan 2004	4.99	Jan 2008	4.33
Feb	12.13	Feb	11.95	Feb	8.43	Feb	7.85	Feb	6.24	Feb	6.23	Feb	4.93	Feb	4.52
Mar	12.34	Mar	12.38	Mar	8.63	Mar	7.97	Mar	6.60	Mar	6.05	Mar	4.74	Mar	4.39
Apr	11.40	Apr	12.65	Apr	8.95	Apr	7.96	Apr	6.79	Apr	5.85	Apr	5.14	Apr	4.44
May	10.36	May	13.43	May	9.23	May	7.89	May	6.93	May	6.15	May	5.42	May	4.60
Jun	9.81	Jun	13.44	Jun	9.00	Jun	7.84	Jun	7.06	Jun	5.93	Jun	5.41	Jun	4.69
Jul	10.24	Jul	13.21	Jul	9.14	Jul	7.60	Jul	7.03	Jul	5.85	Jul	5.22	Jul	4.57
Aug	11.00	Aug	12.54	Aug	9.32	Aug	7.39	Aug	6.84	Aug	5.72	Aug	5.06	Aug	4.50
Sep	11.34	Sep	12.29	Sep	9.06	Sep	7.34	Sep	7.03	Sep	5.83	Sep	4.90	Sep	4.27
Oct	11.59	Oct	11.98	Oct	8.89	Oct	7.53	Oct	6.81	Oct	5.80	Oct	4.86	Oct	4.17
Nov	12.37	Nov	11.56	Nov	9.02	Nov	7.61	Nov	6.48	Nov	5.78	Nov	4.89	Nov	4.00
Dec	12.40	Dec	11.52	Dec	9.01	Dec	7.44	Dec	6.55	Dec	5.49	Dec	4.86	Dec	2.87
Jan 1981	12.14	Jan 1985	11.45	Jan 1989	8.93	Jan 1993	7.34	Jan 1997	6.83	Jan 2001	5.54	Jan 2005	4.73	Jan 2009	3.13
Feb	12.80	Feb	11.47	Feb	9.01	Feb	7.09	Feb	6.69	Feb	5.45	Feb	4.55	Feb	3.59
Mar	12.69	Mar	11.81	Mar	9.17	Mar	6.82	Mar	6.93	Mar	5.34	Mar	4.78	Mar	3.64
Apr	13.20	Apr	11.47	Apr	9.03	Apr	6.85	Apr	7.09	Apr	5.65	Apr	4.65	Apr	3.76
May	13.60	May	11.05	May	8.83	May	6.92	May	6.94	May	5.78	May	4.49	May	4.23
Jun	12.96	Jun	10.44	Jun	8.27	Jun	6.81	Jun	6.77	Jun	5.67	Jun	4.29	Jun	4.52
Jul	13.59	Jul	10.50	Jul	8.08	Jul	6.63	Jul	6.51	Jul	5.61	Jul	4.41	July	4.41
Aug	14.17	Aug	10.56	Aug	8.12	Aug	6.32	Aug	6.58	Aug	5.48	Aug	4.46	Aug	4.37
Sep	14.67	Sep	10.61	Sep	8.15	Sep	6.00	Sep	6.50	Sep	5.48	Sep	4.47	Sep	4.19
Oct	14.68	Oct	10.50	Oct	8.00	Oct	5.94	Oct	6.33	Oct	5.32	Oct	4.67	Oct	4.19
Nov	13.35	Nov	10.06	Nov	7.90	Nov	6.21	Nov	6.11	Nov	5.12	Nov	4.73	Nov	4.31
Dec	13.45	Dec	9.54	Dec	7.90	Dec	6.25	Dec	5.99	Dec	5.48	Dec	4.66	Dec	4.49
Jan 1982	14.22	Jan 1986	9.40	Jan 1990	8.26	Jan 1994	6.29	Jan 1998	5.81	Jan 2002	5.44	Jan 2006	4.59	Jan 2010	4.60
Feb	14.22	Feb	8.93	Feb	8.50	Feb	6.49	Feb	5.89	Feb	5.39	Feb	4.58	Feb	4.62
Mar	13.53	Mar	7.96	Mar	8.56	Mar	6.91	Mar	5.95	Mar	5.71	Mar	4.73	Mar	4.64
Apr	13.37	Apr	7.39	Apr	8.76	Apr	7.27	Apr	5.92	Apr	5.67	Apr	5.06	Apr	4.69
May	13.24	May	7.52	May	8.73	May	7.41	May	5.93	May	5.64	May	5.20	May	4.29
Jun	13.92	Jun	7.57	Jun	8.46	Jun	7.40	Jun	5.70	Jun	5.52	Jun	5.16	Jun	4.13
Jul	13.55	Jul	7.27	Jul	8.50	Jul	7.58	Jul	5.68	Jul	5.38	July	5.13	July	3.99
Aug	12.77	Aug	7.33	Aug	8.86	Aug	7.49	Aug	5.54	Aug	5.08	Aug	5.00	Aug	3.80
Sep	12.07	Sep	7.62	Sep	9.03	Sep	7.71	Sep	5.20	Sep	4.76	Sep	4.85	Sep	3.77
Oct	11.17	Oct	7.70	Oct	8.86	Oct	7.94	Oct	5.01	Oct	4.93	Oct	4.85	Oct	3.87
Nov	10.54	Nov	7.52	Nov	8.54	Nov	8.08	Nov	5.25	Nov	4.95	Nov	4.69	Nov	4.19
Dec	10.54	Dec	7.37	Dec	8.24	Dec	7.87	Dec	5.06	Dec	4.92	Dec	4.68	Dec	4.42
Jan 1983	10.63	Jan 1987	7.39	Jan 1991	8.27	Jan 1995	7.85	Jan 1999	5.16	Jan 2003	4.94	Jan 2007	4.85		
Feb	10.88	Feb	7.54	Feb	8.03	Feb	7.61	Feb	5.37	Feb	4.81	Feb	4.82		
Mar	10.63	Mar	7.55	Mar	8.29	Mar	7.45	Mar	5.58	Mar	4.80	Mar	4.72		
Apr	10.48	Apr	8.25	Apr	8.21	Apr	7.36	Apr	5.55	Apr	4.90	Apr	4.86		
May	10.53	May	8.78	May	8.27	May	6.95	May	5.81	May	4.53	May	4.90		
Jun	10.93	Jun	8.57	Jun	8.47	Jun	6.57	Jun	6.04	Jun	4.37	Jun	5.20		
Jul	11.40	Jul	8.64	Jul	8.45	Jul	6.72	Jul	5.98	Jul	4.93	July	5.11		
Aug	11.82	Aug	8.97	Aug	8.14	Aug	6.86	Aug	6.07	Aug	5.30	Aug	4.93		
Sep	11.63	Sep	9.59	Sep	7.95	Sep	6.55	Sep	6.07	Sep	5.14	Sep	4.79		
Oct	11.58	Oct	9.61	Oct	7.93	Oct	6.37	Oct	6.26	Oct	5.16	Oct	4.77		
Nov	11.75	Nov	8.95	Nov	7.92	Nov	6.26	Nov	6.15	Nov	5.13	Nov	4.52		
Dec	11.88	Dec	9.12	Dec	7.70	Dec	6.06	Dec	6.35	Dec	5.08	Dec	4.53		

Sources:
http://finance.yahoo.com/q/hp?s=^TYX
http://research.stlouisfed.org/fred2/data/GS30.txt

Union Electric Company d/b/a Ameren Missouri
File No. ER-2011-0028

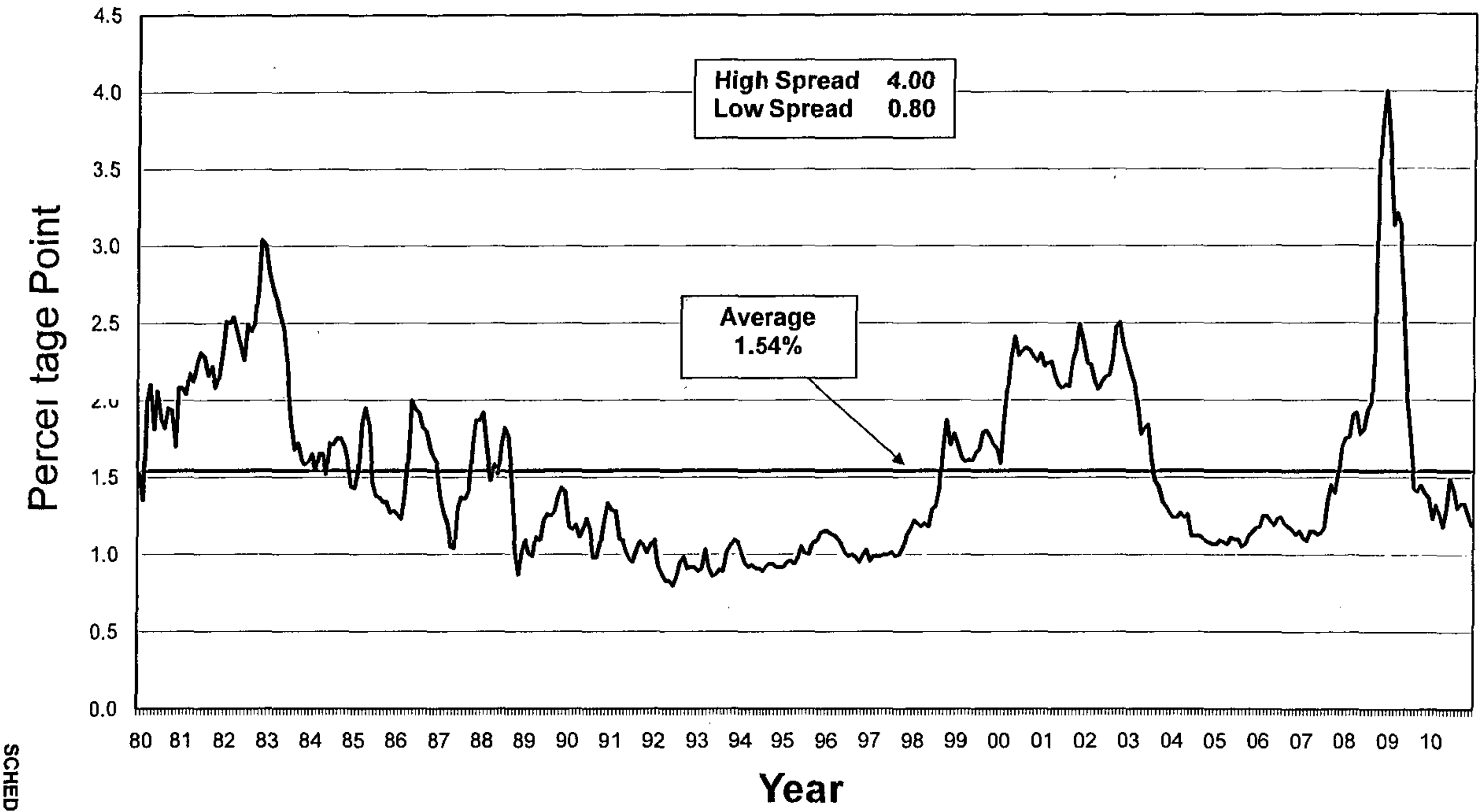
Average Yields on Public Utility Bonds and Thirty-Year U.S. Treasury Bonds (1980 - 2010)



SCHEDULE 4-3

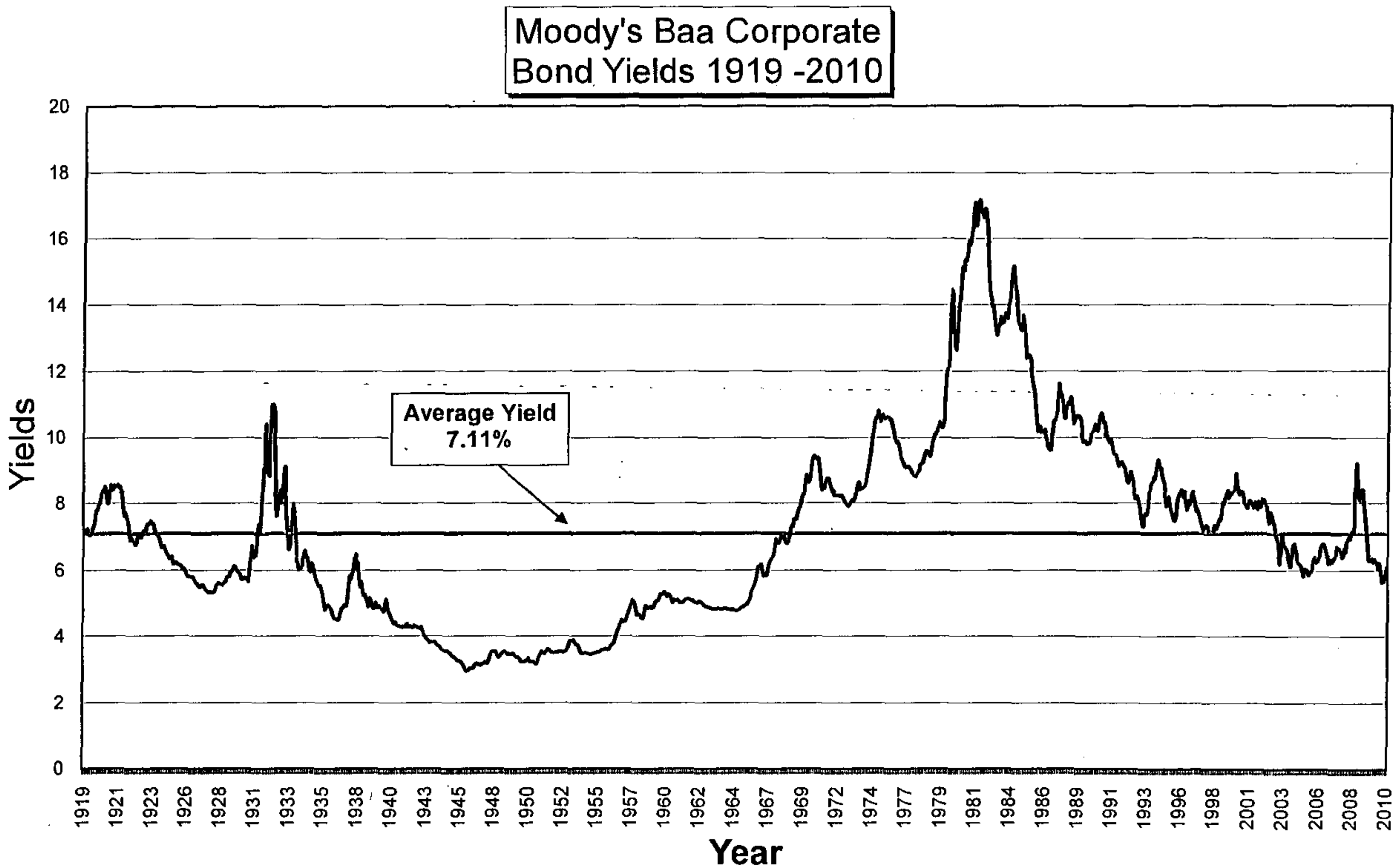
Union Electric Company d/b/a Ameren Missouri
File No. ER-2011-0028

Monthly Spreads Between Yields on Public Utility Bonds and Thirty-Year U.S. Treasury Bonds (1980 - 2010)



SCHEDULE 4 - 4

Union Electric Company d/b/a Ameren Missouri
File No. ER-2011-0028



Source: St. Louis Federal Reserve Website: http://stlouisfed.org

SCHEDULE 4 - 5

Union Electric Company d/b/a Ameren Missouri
File No. ER-2011-0028

Historical Consolidated Capital Structures for Union Electric Company

(Millions of Dollars)

Capital Components	2005	2006	2007	2008	2009
Common Equity	$2,903.0	$3,040.0	$3,488.0	$3,449.0	$3,944
Preferred Stock	113.0	113.0	113.0	113.0	$113
Long-Term Debt	2,702.0 *	2,939.0 *	3,360.0 *	3,677.0 *	$4,022
Short-Term Debt	80.0	311.0	82.0	343.0	$0
Total	$5,798.0	$6,403.0	$7,043.0	$7,582.0	$8,079.0

Historical Consolidated Capital Structures for Ameren

(Millions of Dollars)

Capital Components	2005	2006	2007	2008	2009
Common Equity	$6,381.0	$6,599.0	$6,774.0	$6,984.0	$7,865.0
Preferred Stock	214.0	213.0	211.0	195.0	195.0
Long-Term Debt	5,450.0 *	5,741.0 *	5,912.0 *	6,934.0 *	7,317.0
Short-Term Debt	193.0	612.0	1,472.0	1,174.0	20.0
Total	$12,238.0	$13,165.0	$14,369.0	$15,287.0	$15,397.0

Source: Ameren's Annual SEC 10-K Filings.

Note: *Includes current maturities of long-term debt.

SCHEDULE 5 - 1

Union Electric Company d/b/a Ameren Missouri
File No. ER-2011-0028

Historical Consolidated Capital Structures for Union Electric Company

(in Percentages)

Capital Components	2005	2006	2007	2008	2009	5-Year Average
Common Equity	50.07%	47.48%	49.52%	45.49%	48.82%	48.28%
Preferred Stock	1.95%	1.76%	1.60%	1.49%	1.40%	1.64%
Long-Term Debt	46.60% *	45.90% *	47.71% *	48.50% *	49.78% *	47.70%
Short-Term Debt	1.38%	4.86%	1.16%	4.52%	0.00%	2.39%
Total	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%

Historical Consolidated Capital Structures for Ameren

(in Percentages)

Capital Components	2005	2006	2007	2008	2009	5-Year Average
Common Equity	52.14%	50.13%	47.14%	45.69%	51.08%	49.24%
Preferred Stock	1.75%	1.62%	1.47%	1.28%	1.27%	1.48%
Long-Term Debt	44.53%	43.61%	41.14%	45.36%	47.52%	44.43%
Short-Term Debt	1.58%	4.65%	10.24%	7.68%	0.13%	4.86%
Total	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%

Sources: Ameren's 10-K Filings.

SCHEDULE 5 - 2

Union Electric Company d/b/a Ameren Missouri
File No. ER-2011-0028

Capital Structure as of March 31, 2010
Union Electric Company

Capital Component	Dollar Amount	Percentage of Capital
Common Stock Equity	$ 3,913,191,356	50.92%
Preferred Stock	$ 114,502,040	1.49%
Long-Term Debt	$ 3,657,492,156	47.59%
Short-Term Debt	$ -	0.00%
Total Capitalization	**$ 7,685,185,552**	**100.00%**

Source: Company Witness Michael O'Bryan's Schedule MGO-E1 attached to his Direct Testimony.

Union Electric Company d/b/a Ameren Missouri
File No. ER-2011-0028

Criteria for Selecting Comparable Electric Utility Companies

(1) ValueLine Electric Utility Companies	(2) Ticker	(3) Stock Publicly Traded	(4) Regulated Electric Utility (EEI)	(5) % Electric Revenues ≥ 70%	(6) 10-Year Value Line Historical Growth Available	(7) No Reduced Dividend since 2007	(8) Projected Growth Available from Value Line and Reuters	(9) At Least Investment Grade S&P Corporate Credit Rating	(10) Generation Assets	(11) No Announced Merger or Acquistion	(12) **Comparable Company Met All Criteria**
Allegheny Energy	AYE	Yes	No								
ALLETE	ALE	Yes	Yes	Yes	No						
Alliant Energy	**LNT**	**Yes**	**Yes**	**Yes**	**Yes**	**Yes**	**Yes**	**Yes**	**Yes**	**Yes**	**Yes**
Amer. Elec. Power	**AEP**	**Yes**	**Yes**	**Yes**	**Yes**	**Yes**	**Yes**	**Yes**	**Yes**	**Yes**	**Yes**
Ameren Corp	AEE	Yes	Yes	Yes	Yes	No					
Avista Corp.	AVA	Yes	Yes	No							
Black Hills	BKH	Yes	No								
Cen. Vermont Pub. Serv.	CV	Yes	Yes	Yes	Yes	Yes	No				
CenterPoint Energy	CNP	Yes	No								
CH Energy Group	CHG	Yes	Yes	No							
Cleco Corp.	**CNL**	**Yes**	**Yes**	**Yes**	**Yes**	**Yes**	**Yes**	**Yes**	**Yes**	**Yes**	**Yes**
CMS Energy Corp.	CMS	Yes	Yes	No							
Consol. Edison	ED	Yes	Yes	No							
Constellation Energy	CEG	Yes	No								
Dominion Resources	D	Yes	No								
DPL Inc.	**DPL**	**Yes**	**Yes**	**Yes**	**Yes**	**Yes**	**Yes**	**Yes**	**Yes**		**Yes**
DTE Energy	DTE	Yes	Yes	No							
Duke Energy	DUK	Yes	No								
Edison Int'l	EIX	Yes	No								
El Paso Electric	EE	Yes	Yes	Yes	Yes	No[1]					
Empire Dist. Elec.	EDE	Yes	Yes	Yes	Yes	Yes	No				
Entergy Corp.	ETR	Yes	No								
Evergreen Energy Inc	EEE	Yes	NA								
Exelon Corp.	EXC	Yes	No								
FirstEnergy Corp.	FE	Yes	No								
G't Plains Energy	GXP	Yes	Yes	Yes	Yes	No					
Hawaiian Elec.	HE	Yes	No								
IDACORP, Inc.	**IDA**	**Yes**	**Yes**	**Yes**	**Yes**	**Yes**	**Yes**	**Yes**	**Yes**	**Yes**	**Yes**
Integrys Energy	TEG	Yes	No								
ITC Holdings	ITC	Yes	NA								
Maine & Maritimes Corp	MAM	Yes	Yes	Yes	Yes	No					
MGE Energy	MGEE	Yes	No								
NextEra Energy	FPL	Yes	No								
Northeast Utilities	NU	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	No	
NorthWestern Corp	NWE	Yes	Yes	Yes	No						
NSTAR	NST	Yes	Yes	Yes	Yes	Yes	Yes	Yes	No		
NV Energy Inc.	NVE	Yes	Yes	Yes	Yes	Yes	Yes	No			
OGE Energy	OGE	Yes	No								
Otter Tail Corp.	OTTR	Yes	No								
Pepco Holdings	POM	Yes	No								
PG&E Corp.	**PCG**	**Yes**	**Yes**	**Yes**	**Yes**	**Yes**	**Yes**	**Yes**	**Yes**	**Yes**	**Yes**
Pinnacle West Capital	**PNW**	**Yes**	**Yes**	**Yes**	**Yes**	**Yes**	**Yes**	**Yes**	**Yes**	**Yes**	**Yes**
PNM Resources	PNM	Yes	Yes	Yes	Yes	No					
Portland General	POR	Yes	Yes	Yes	No						
PPL Corp.	PPL	Yes	No								
Progress Energy	PGN	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	No	
Public Serv. Enterprise	PEG	Yes	No								
SCANA Corp.	SCG	Yes	No								
Sempra Energy	SRE	Yes	No								
Southern Co.	**SO**	**Yes**	**Yes**	**Yes**	**Yes**	**Yes**	**Yes**	**Yes**	**Yes**	**Yes**	**Yes**
TECO Energy	TE	Yes	Yes	No							
UIL Holdings	UIL	Yes	Yes	Yes	Yes	Yes	Yes	Yes	No		
UniSource Energy	UNS	Yes	Yes	Yes	Yes	Yes	Yes	No			
UNITIL Corp.	UTL	Yes	Yes	No							
Vectren Corp.	VVC	Yes	Yes	No							
Westar Energy	**WR**	**Yes**	**Yes**	**Yes**	**Yes**	**Yes**	**Yes**	**Yes**	**Yes**	**Yes**	**Yes**
Wisconsin Energy	WEC	Yes	Yes	No							
Xcel Energy Inc.	**XEL**	**Yes**	**Yes**	**Yes**	**Yes**	**Yes**	**Yes**	**Yes**	**Yes**	**Yes**	**Yes**

Sources: Columns 1, 2, 3, 6, 7, 8 and 10 = The Value Line Investment Survey: Ratings & Reports
Column 4 = Edison Electric Institute 2009 Financial Review
Column 5 = January 2011 AUS Utility Reports and Companies' 10Ks and 10Qs
Columnn 8 = Reuters com on January 27, 2011
Column 9 = S&P RatingsDirect

Notes:
1 No dividends per share

Union Electric Company d/b/a Ameren Missouri
File No. ER-2011-0028

Comparable Electrical Utility Companies
for Union Electric Company d/b/a Ameren Missouri

Number	Ticker Symbol	Company Name		S&P Corporate Credit Rating
1	LNT	Alliant Energy		BBB+
2	AEP	American Electric Power		BBB
3	CNL	Cleco Corp.		BBB
4	DPL	DPL Inc.		A-
5	IDA	IDACORP, Inc.		BBB
6	PCG	PG&E Corp.		BBB+
7	PNW	Pinnacle West Capital		BBB-
8	SO	Southern Company		A
9	WR	Westar Energy, Inc.		BBB
10	XEL	Xcel Energy		A-
			Average	BBB+
		Ameren and Union Electric		BBB-

SCHEDULE 8

Union Electric Company d/b/a Ameren Missouri
File No. ER-2011-0028

Ten-Year Dividends Per Share, Earnings Per Share & Book Value Per Share Growth Rates for the Comparable Electric Utility Companies

	---------- 10-Year Annual Compound Growth Rates ----------			
Company Name	DPS	EPS	BVPS	Average of 10 Year Annual Compound Growth Rates
Alliant Energy	-3.50%	3.00%	1.00%	0.17%
American Electric Power	-4.00%	0.00%	0.50%	-1.17%
Cleco Corp.	1.00%	3.50%	7.00%	3.83%
DPL Inc.	1.50%	4.50%	0.00%	2.00%
IDACORP, Inc.	-4.50%	-0.50%	3.50%	-0.50%
PG&E Corp.	2.50%	4.50%	2.50%	3.17%
Pinnacle West Capital	5.50%	-2.00%	3.00%	2.17%
Southern Company	2.50%	3.00%	2.00%	2.50%
Westar Energy, Inc.	-6.50%	1.50%	-4.00%	-3.00%
Xcel Energy	-4.00%	-1.00%	-0.50%	-1.83%
Average	**-0.95%**	**1.65%**	**1.50%**	**0.73%**

Source: The Value Line Investment Survey: Ratings & Reports, November 5 and 26, and December 24, 2010.

SCHEDULE 9 - 1

Union Electric Company d/b/a Ameren Missouri
File No. ER-2011-0028

Five-Year Dividends Per Share, Earnings Per Share & Book Value Per Share Growth Rates for the Comparable Electric Utility Companies

Company Name	DPS	EPS	BVPS	Average of 5 Year Annual Compound Growth Rates
	------------ 5-Year Annual Compound Growth Rates		------------	
Alliant Energy	0.50%	9.00%	3.50%	4.33%
American Electric Power	-2.50%	2.00%	5.00%	1.50%
Cleco Corp.	0.00%	3.00%	10.00%	4.33%
DPL Inc.	3.00%	10.50%	3.00%	5.50%
IDACORP, Inc.	-5.50%	8.50%	4.00%	2.33%
PG&E Corp.	0.00%	NMF	14.00%	7.00%
Pinnacle West Capital	4.00%	-1.00%	2.00%	1.67%
Southern Company	3.50%	3.00%	5.50%	4.00%
Westar Energy, Inc.	-0.50%	21.50%	1.00%	7.33%
Xcel Energy	1.00%	8.00%	4.00%	4.33%
Average	**0.35%**	**6.45%**	**5.20%**	**4.23%**

Source: The Value Line Investment Survey: Ratings & Reports, November 5 and 26, and December 24, 2010

SCHEDULE 9 - 2

Union Electric Company d/b/a Ameren Missouri
File No. ER-2011-0028

Five-Year Projected Dividends Per Share, Earnings Per Share & Book Value Per Share Growth Rates for the Comparable Electric Utility Companies

	------------ 5-Year Projected Compound Growth Rates	------------		
Company Name	DPS	EPS	BVPS	Average of 5 Year Annual Compound Growth Rates
Alliant Energy	5.50%	7.00%	3.50%	5.33%
American Electric Power	3.50%	3.00%	4.50%	3.67%
Cleco Corp.	8.50%	9.50%	6.50%	8.17%
DPL Inc.	5.50%	7.00%	6.50%	6.33%
IDACORP, Inc.	2.50%	5.50%	5.00%	4.33%
PG&E Corp.	6.00%	6.00%	6.00%	6.00%
Pinnacle West Capital	1.50%	6.00%	2.00%	3.17%
Southern Company	4.00%	4.50%	5.50%	4.67%
Westar Energy, Inc.	3.50%	8.50%	3.00%	5.00%
Xcel Energy	3.50%	5.50%	4.50%	4.50%
Average	**4.40%**	**6.25%**	**4.70%**	**5.12%**

Source: The Value Line Investment Survey: Ratings & Reports, November 5 and 26, and December 24, 2010.

Union Electric Company d/b/a Ameren Missouri
File No. ER-2011-0028

Historical and Projected Growth Rates for the Comparable Electric Utility Companies

Company Name	(1) Historical 10-Year Compound Growth Rates (DPS, EPS and BVPS)	(2) Historical 5-Year Compound Growth Rates (DPS, EPS and BVPS)	(3) Projected 5-Year Compound Growth Rates (DPS, EPS and BVPS)	(4) Projected 5-Year EPS Growth Reuters (Mean)	(5) Projected 3-5 Year EPS Growth Value Line	(6) Average Projected EPS Growth
Alliant Energy	0.17%	4.33%	5.33%	6.67%	7.00%	6.84%
American Electric Power	-1.17%	1.50%	3.67%	4.25%	3.00%	3.63%
Cleco Corp.	3.83%	4.33%	8.17%	3.00%	9.50%	6.25%
DPL Inc.	2.00%	5.50%	6.33%	8.00%	7.00%	7.50%
IDACORP, Inc.	-0.50%	2.33%	4.33%	4.67%	5.50%	5.09%
PG&E Corp.	3.17%	7.00%	6.00%	6.30%	6.00%	6.15%
Pinnacle West Capital	2.17%	1.67%	3.17%	6.65%	6.00%	6.33%
Southern Company	2.50%	4.00%	4.67%	5.06%	4.50%	4.78%
Westar Energy, Inc.	-3.00%	7.33%	5.00%	7.62%	8.50%	8.06%
Xcel Energy	-1.83%	4.33%	4.50%	6.03%	5.50%	5.77%
Average	**0.73%**	**4.23%**	**5.12%**	**5.83%**	**6.25%**	**6.04%**

Proposed Range of Growth for Comparables: **4.00%-5.00%**

Column 5 = [(Column 3 + Column 4) / 2]

Sources: Column 1 = Schedule 9-1.

Column 2 = Schedule 9-2

Column 3 = Schedule 9-3.

Column 4 = Reuters.com on January 27, 2011

Union Electric Company d/b/a Ameren Missouri
File No. ER-2011-0028

Average High / Low Stock Price for October 2010 through December 2010
for the Comparable Electric Utility Companies

	(1)	(2)	(3)	(4)	(5)	(6)	(7)
	-- October 2010 --		-- November 2010 --		-- December 2010 --		**Average High/Low Stock Price (10/10 - 12/10)**
Company Name	High Stock Price	Low Stock Price	High Stock Price	Low Stock Price	High Stock Price	Low Stock Price	
Alliant Energy	37.00	35.66	37.65	35.69	37.32	36.28	**36.60**
American Electric Power	37.55	35.68	37.94	35.36	36.47	34.92	**36.32**
Cleco Corp.	31.47	29.59	31.76	30.10	31.22	30.05	**30.70**
DPL Inc.	27.80	26.03	27.10	25.03	26.45	25.32	**26.29**
IDACORP, Inc.	37.20	35.88	37.34	35.46	37.76	36.57	**36.70**
PG&E Corp.	48.11	45.38	48.63	46.16	48.63	46.61	**47.25**
Pinnacle West Capital	42.68	40.93	42.44	39.97	41.99	40.15	**41.36**
Southern Company	38.62	37.10	38.48	37.32	38.49	37.43	**37.91**
Westar Energy, Inc.	25.79	24.21	25.90	24.64	25.52	24.50	**25.09**
Xcel Energy	24.08	23.02	24.36	23.17	23.89	23.20	**23.62**

Notes:

Column 7 = [(Column 1 + Column 2 + Column 3 + Column 4 + Column 5 + Column 6) / 6].

Source: http://finance.yahoo.com

SCHEDULE 10

Union Electric Company d/b/a Ameren Missouri
File No. ER-20011-0028

Constant-Growth Discounted Cash Flow (DCF) Estimated Costs of Common Equity for the Comparable Electric Utility Companies

	(1)	(2)	(3)
Company Name	Expected Annual Dividend	Average High/Low Stock Price	Projected Dividend Yield
Alliant Energy	$1.65	$36.600	4.51%
American Electric Power	$1.84	$36.320	5.07%
Cleco Corp.	$1.08	$30.698	3.52%
DPL Inc.	$1.28	$26.288	4.87%
IDACORP, Inc.	$1.20	$36.702	3.27%
PG&E Corp.	$1.92	$47.253	4.06%
Pinnacle West Capital	$2.10	$41.360	5.08%
Southern Company	$1.88	$37.907	4.96%
Westar Energy, Inc.	$1.28	$25.280	5.06%
Xcel Energy	$1.03	$23.620	4.36%
Average			**4.48%**

Proposed Dividend Yield:	**4.50%**
Proposed Range of Growth:	**4.00% - 5.00%**
Estimated Proxy Cost of Common Equity:	**8.50 - 9.50%**

Notes: Column 1 = Estimated Dividend Declared per share represents Value Line projected dividends for 2011.

Column 3 = (Column 1 / Column 2).

Sources: Column 1 = The Value Line Investment Survey: Ratings and Reports, November 5 and 26, and December 24, 2010.

Column 2 = Schedule 10.

Union Electric Company d/b/a Ameren Missouri
File No. ER-2011-0028

Multiple-Stage Discounted Cash Flow (DCF) Estimated Costs of Common Equity for the Comparable Electric Utility Companies

	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
Company Name	Annualized Quarterly Dividend	Growth Years 1-5	6	7	Growth Years 8	9	10	Growth in Perpetuity	Cost of Equity
Alliant Energy	$1.58	6.84%	6.20%	5.56%	4.92%	4.28%	3.64%	3.00%	8.62%
American Electric Power	$1.84	3.63%	3.52%	3.42%	3.31%	3.21%	3.10%	3.00%	8.42%
Cleco Corp.	$1.00	6.25%	5.71%	5.17%	4.63%	4.08%	3.54%	3.00%	7.12%
DPL Inc.	$1.21	7.50%	6.75%	6.00%	5.25%	4.50%	3.75%	3.00%	9.22%
IDACORP, Inc.	$1.20	5.09%	4.74%	4.39%	4.04%	3.70%	3.35%	3.00%	6.85%
PG&E Corp.	$1.82	6.15%	5.63%	5.10%	4.58%	4.05%	3.53%	3.00%	7.83%
Pinnacle West Capital	$2.10	6.33%	5.77%	5.22%	4.66%	4.11%	3.55%	3.00%	9.38%
Southern Company	$1.82	4.78%	4.48%	4.19%	3.89%	3.59%	3.30%	3.00%	8.51%
Westar Energy, Inc.	$1.24	8.06%	7.22%	6.37%	5.53%	4.69%	3.84%	3.00%	9.81%
Xcel Energy	$1.01	5.77%	5.30%	4.84%	4.38%	3.92%	3.46%	3.00%	8.22%
									8.40%

Sources: Column 1 = The Value Line Investment Survey: Ratings and Reports, November 5 and 26, and December 24, 2010.
Column 2 = Reuters.com on January 27, 2011.
Column 8 = See range of averages from Schedules 13-1 through Schedules 13-4 and Schedule 14.

Union Electric Company d/b/a Ameren Missouri
File No. ER-2011-0028

Multiple-Stage Discounted Cash Flow (DCF) Estimated Costs of Common Equity for the Comparable Electric Utility Companies

	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
Company Name	Annualized Quarterly Dividend	Growth Years 1-5	6	7	Growth Years 8	9	10	Growth in Perpetuity	Cost of Equity
Alliant Energy	$1.58	6.84%	6.28%	5.72%	5.17%	4.61%	4.06%	3.50%	8.97%
American Electric Power	$1.84	3.63%	3.60%	3.58%	3.56%	3.54%	3.52%	3.50%	8.78%
Cleco Corp.	$1.00	6.25%	5.79%	5.33%	4.88%	4.42%	3.96%	3.50%	7.51%
DPL Inc.	$1.21	7.50%	6.83%	6.17%	5.50%	4.83%	4.17%	3.50%	9.56%
IDACORP, Inc.	$1.20	5.09%	4.82%	4.56%	4.29%	4.03%	3.76%	3.50%	7.24%
PG&E Corp.	$1.82	6.15%	5.71%	5.27%	4.83%	4.38%	3.94%	3.50%	8.20%
Pinnacle West Capital	$2.10	6.33%	5.85%	5.38%	4.91%	4.44%	3.97%	3.50%	9.72%
Southern Company	$1.82	4.78%	4.57%	4.35%	4.14%	3.93%	3.71%	3.50%	8.87%
Westar Energy, Inc.	$1.24	8.06%	7.30%	6.54%	5.78%	5.02%	4.26%	3.50%	10.14%
Xcel Energy	$1.01	5.77%	5.39%	5.01%	4.63%	4.26%	3.88%	3.50%	8.59%
									8.76%

Sources: Column 1 = The Value Line Investment Survey: Ratings and Reports, November 5 and 26, and December 24, 2010.
Column 2 = Reuters.com on January 27, 2011.
Column 8 = See range of averages from Schedules 13-1 through Schedules 13-4 and Schedule 14.

Union Electric Company d/b/a Ameren Missouri
File No. ER-2011-0028

Multiple-Stage Discounted Cash Flow (DCF) Estimated Costs of Common Equity for the Comparable Electric Utility Companies

	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
Company Name	Annualized Quarterly Dividend	Growth Years 1-5	6	7	Growth Years 8	9	10	Growth in Perpetuity	Cost of Equity
Alliant Energy	$1.58	6.84%	6.36%	5.89%	5.42%	4.95%	4.47%	4.00%	9.34%
American Electric Power	$1.84	3.63%	3.69%	3.75%	3.81%	3.88%	3.94%	4.00%	9.15%
Cleco Corp.	$1.00	6.25%	5.88%	5.50%	5.13%	4.75%	4.38%	4.00%	7.91%
DPL Inc.	$1.21	7.50%	6.92%	6.33%	5.75%	5.17%	4.58%	4.00%	9.91%
IDACORP, Inc.	$1.20	5.09%	4.90%	4.72%	4.54%	4.36%	4.18%	4.00%	7.64%
PG&E Corp.	$1.82	6.15%	5.79%	5.43%	5.08%	4.72%	4.36%	4.00%	8.58%
Pinnacle West Capital	$2.10	6.33%	5.94%	5.55%	5.16%	4.78%	4.39%	4.00%	10.07%
Southern Company	$1.82	4.78%	4.65%	4.52%	4.39%	4.26%	4.13%	4.00%	9.24%
Westar Energy, Inc.	$1.24	8.06%	7.38%	6.71%	6.03%	5.35%	4.68%	4.00%	10.48%
Xcel Energy	$1.01	5.77%	5.47%	5.18%	4.88%	4.59%	4.29%	4.00%	8.96%
									9.13%

Sources: Column 1 = The Value Line Investment Survey: Ratings and Reports, November 5 and 26, and December 24, 2010.
Column 2 = Reuters.com on January 27, 2011.
Column 8 = See range of averages from Schedules 13-1 through Schedules 13-4 and Schedule 14.

Union Electric d/b/a Ameren Missouri
File No. ER-2011-0028

Central Region Electric Utility Proxy Group
EPS
10-Year Compound Growth Rate Averages (1968-1999)

Years	Dayton P & L/ DPL	Detroit Edison/ DTE	Empire	IPALCO	Kansas City P & L	Northern States Power	Okla. Gas & Electric/ OGE Energy Corp.	SJL&P	WPS Resources/ Wisconsin Public Serv.	WI Energy/ WI Electric Power	Average
1968-70 to 1978-80	-1.74%	-0.57%	0.24%	4.13%	1.77%	4.13%	1.16%	1.40%	6.23%	6.32%	**2.31%**
1969-71 to 1979-81	-0.21%	0.05%	-0.64%	4.30%	2.62%	4.02%	0.48%	1.66%	6.60%	6.79%	**2.57%**
1970-72 to 1980-82	0.98%	-0.46%	0.41%	3.14%	3.24%	4.48%	1.88%	2.66%	6.41%	7.24%	**3.00%**
1971-73 to 1981-83	2.72%	0.53%	2.64%	2.87%	4.83%	6.11%	2.90%	4.03%	6.92%	7.77%	**4.13%**
1972-74 to 1982-84	3.71%	1.48%	5.33%	4.69%	6.44%	7.64%	3.02%	5.65%	7.78%	8.25%	**5.40%**
1973-75 to 1983-85	4.19%	3.60%	6.21%	5.91%	7.60%	8.08%	2.58%	6.94%	8.54%	9.39%	**6.30%**
1974-76 to 1984-86	4.19%	4.41%	6.50%	5.86%	5.75%	8.03%	2.81%	7.89%	7.98%	9.60%	**6.30%**
1975-77 to 1985-87	5.10%	4.69%	5.70%	4.19%	4.26%	7.59%	2.90%	8.10%	6.81%	9.18%	**5.85%**
1976-78 to 1986-88	5.84%	4.29%	5.68%	5.40%	3.02%	7.24%	3.92%	7.95%	5.98%	8.86%	**5.82%**
1977-79 to 1987-89	6.16%	3.93%	5.49%	5.09%	4.12%	6.73%	5.22%	8.49%	5.08%	8.96%	**5.93%**
1978-80 to 1988-90	5.61%	4.41%	5.52%	5.11%	3.09%	6.07%	6.65%	8.20%	4.35%	9.08%	**5.81%**
1979-81 to 1989-91	3.75%	5.35%	6.06%	4.67%	1.90%	5.45%	6.56%	7.68%	3.70%	8.07%	**5.32%**
1980-82 to 1990-92	2.46%	6.83%	4.65%	4.43%	0.31%	3.15%	3.63%	5.76%	3.91%	6.16%	**4.13%**
1981-83 to 1991-93	1.00%	6.06%	2.56%	3.11%	-1.01%	1.58%	1.58%	3.37%	3.45%	4.33%	**2.60%**
1982-84 to 1992-94	1.31%	4.75%	-0.16%	1.44%	-2.03%	0.83%	0.71%	2.88%	2.19%	2.64%	**1.46%**
1983-85 to 1993-95	1.36%	2.97%	-1.18%	1.78%	-2.21%	1.85%	1.81%	2.46%	1.03%	2.58%	**1.24%**
1984-86 to 1994-96	1.71%	1.79%	-1.39%	3.31%	-1.08%	2.26%	2.15%	2.56%	0.20%	2.27%	**1.38%**
1985-87 to 1995-97	1.65%	0.64%	-1.47%	4.22%	0.35%	1.90%	2.19%	1.90%	0.12%	-0.46%	**1.10%**
1986-88 to 1996-98	2.28%	0.57%	-0.92%	4.59%	1.57%	1.50%	2.11%	1.34%	-0.86%	-2.24%	**0.99%**
1987-89 to 1997-99	2.62%	1.08%	-0.46%	5.06%	0.15%	0.40%	2.36%	0.49%	-0.38%	-3.07%	**0.83%**
Average	**2.73%**	**2.82%**	**2.54%**	**4.17%**	**2.23%**	**4.45%**	**2.83%**	**4.57%**	**4.30%**	**5.59%**	**3.62%**

SCHEDULE 13 - 1

Union Electric d/b/a Ameren Missouri
File No. ER-2011-0028

Central Region Electric Utility Proxy Group
DPS
10-Year Compound Growth Rate Averages (1968-1999)

Years	Dayton P & L/ DPL	Detroit Edison/ DTE	Empire	IPALCO	Kansas City P & L	Northern States Power	Okla. Gas & Electric/ OGE Energy Corp.	SJL&P	WPS Resources/ Wisconsin Public Serv.	WI Energy/ WI Electric Power	Average
1968-70 to 1978-80	0.90%	1.17%	2.45%	3.52%	3.34%	3.37%	3.79%	1.89%	4.36%	5.46%	**3.03%**
1969-71 to 1979-81	0.87%	1.43%	2.17%	4.15%	3.03%	3.76%	3.52%	1.89%	4.69%	5.70%	**3.12%**
1970-72 to 1980-82	1.04%	1.59%	1.90%	4.69%	3.17%	4.02%	3.32%	2.01%	5.13%	5.98%	**3.28%**
1971-73 to 1981-83	1.41%	1.64%	1.98%	4.92%	3.56%	4.39%	3.35%	2.28%	5.64%	6.23%	**3.54%**
1972-74 to 1982-84	1.70%	1.60%	2.32%	4.95%	4.13%	4.88%	3.49%	2.82%	6.18%	6.37%	**3.84%**
1973-75 to 1983-85	1.89%	1.48%	2.86%	5.03%	4.45%	5.60%	3.62%	3.50%	6.72%	6.52%	**4.17%**
1974-76 to 1984-86	1.89%	1.48%	3.31%	5.19%	4.12%	6.31%	3.75%	4.32%	7.18%	6.78%	**4.43%**
1975-77 to 1985-87	2.01%	1.44%	3.77%	5.73%	3.40%	6.78%	3.91%	4.97%	7.38%	7.08%	**4.65%**
1976-78 to 1986-88	2.26%	1.28%	4.14%	5.65%	2.96%	6.95%	4.04%	5.36%	7.30%	7.34%	**4.73%**
1977-79 to 1987-89	2.56%	0.94%	4.50%	5.49%	3.16%	6.96%	4.14%	5.72%	7.00%	7.51%	**4.80%**
1978-80 to 1988-90	2.83%	0.86%	4.81%	4.96%	3.58%	6.86%	4.27%	6.10%	6.66%	7.65%	**4.86%**
1979-81 to 1989-91	2.92%	0.99%	5.08%	4.80%	3.77%	6.72%	4.33%	6.53%	6.26%	7.68%	**4.91%**
1980-82 to 1990-92	2.83%	1.38%	5.27%	4.53%	3.78%	6.54%	4.30%	6.63%	5.83%	7.59%	**4.87%**
1981-83 to 1991-93	2.59%	1.70%	5.18%	4.24%	3.47%	6.22%	4.02%	6.49%	5.30%	7.29%	**4.65%**
1982-84 to 1992-94	2.59%	1.93%	4.80%	3.96%	3.02%	5.75%	3.64%	6.03%	4.65%	6.89%	**4.33%**
1983-85 to 1993-95	2.89%	2.06%	4.22%	3.75%	2.72%	5.14%	3.21%	5.50%	3.88%	6.44%	**3.98%**
1984-86 to 1994-96	3.41%	2.06%	3.58%	3.69%	3.14%	4.49%	2.77%	4.90%	3.15%	6.00%	**3.72%**
1985-87 to 1995-97	3.79%	2.06%	2.92%	1.92%	3.74%	3.91%	2.33%	4.42%	2.63%	5.54%	**3.33%**
1986-88 to 1996-98	3.95%	2.06%	2.30%	0.76%	3.99%	3.46%	1.87%	3.92%	2.39%	5.00%	**2.97%**
1987-89 to 1997-99	3.81%	2.06%	1.74%	-0.41%	3.52%	3.11%	1.42%	3.37%	2.31%	4.36%	**2.53%**
Average	**2.41%**	**1.56%**	**3.46%**	**4.08%**	**3.50%**	**5.26%**	**3.46%**	**4.43%**	**5.23%**	**6.47%**	**3.99%**

SCHEDULE 13 - 2

Union Electric d/b/a Ameren Missouri
File No. ER-2011-0028

Central Region Electric Utility Proxy Group
BVPS
10-Year Compound Growth Rate Averages (1968-1999)

Years	Dayton P & L/ DPL	Detroit Edison/ DTE	Empire	IPALCO	Kansas City P & L	Northern States Power	Okla. Gas & Electric/ OGE Energy Corp.	SJL&P	WPS Resources/ Wisconsin Public Serv.	WI Energy/ WI Electric Power	Average
1968-70 to 1978-80	1.40%	0.04%	2.37%	5.21%	1.88%	4.34%	5.76%	1.28%	4.13%	4.03%	**3.05%**
1969-71 to 1979-81	0.84%	-0.35%	1.93%	4.93%	1.51%	4.19%	4.58%	1.15%	4.37%	3.71%	**2.69%**
1970-72 to 1980-82	0.28%	-0.88%	1.63%	4.43%	1.19%	4.15%	3.83%	1.13%	4.50%	3.84%	**2.41%**
1971-73 to 1981-83	0.16%	-1.30%	1.58%	3.84%	1.20%	4.31%	3.00%	1.31%	4.57%	4.09%	**2.27%**
1972-74 to 1982-84	0.27%	-1.51%	1.89%	3.77%	1.35%	4.72%	2.66%	1.65%	4.89%	4.49%	**2.42%**
1973-75 to 1983-85	0.25%	-1.27%	2.32%	3.99%	1.88%	5.18%	2.33%	2.36%	5.27%	5.02%	**2.73%**
1974-76 to 1984-86	0.30%	-0.77%	2.82%	4.47%	2.26%	5.56%	2.43%	3.27%	5.56%	5.52%	**3.14%**
1975-77 to 1985-87	0.27%	-0.18%	3.17%	4.63%	2.54%	5.73%	2.33%	4.20%	5.57%	5.86%	**3.41%**
1976-78 to 1986-88	0.66%	-0.61%	3.51%	4.82%	2.32%	5.80%	2.33%	4.89%	5.42%	6.11%	**3.53%**
1977-79 to 1987-89	1.13%	-1.05%	3.79%	4.77%	2.28%	5.80%	2.30%	5.41%	5.16%	6.38%	**3.60%**
1978-80 to 1988-90	1.80%	-1.34%	4.17%	4.79%	2.28%	5.74%	2.57%	5.69%	4.77%	6.69%	**3.72%**
1979-81 to 1989-91	2.31%	-0.30%	4.59%	4.84%	2.44%	5.65%	2.92%	5.82%	4.27%	6.91%	**3.95%**
1980-82 to 1990-92	2.29%	0.97%	4.88%	4.92%	2.41%	5.43%	2.96%	5.72%	3.96%	6.94%	**4.05%**
1981-83 to 1991-93	1.97%	2.03%	4.82%	4.84%	2.10%	5.14%	2.75%	5.41%	3.75%	6.74%	**3.95%**
1982-84 to 1992-94	1.84%	2.72%	4.36%	4.50%	1.71%	4.77%	2.37%	5.01%	3.57%	6.33%	**3.72%**
1983-85 to 1993-95	2.33%	2.95%	3.83%	4.15%	1.17%	4.46%	2.16%	4.60%	3.29%	5.91%	**3.48%**
1984-86 to 1994-96	2.78%	2.82%	3.34%	3.73%	0.78%	4.21%	1.91%	4.27%	2.99%	5.48%	**3.23%**
1985-87 to 1995-97	3.14%	2.52%	2.92%	2.52%	0.41%	4.01%	1.85%	3.99%	2.77%	4.81%	**2.89%**
1986-88 to 1996-98	3.26%	3.25%	2.56%	1.45%	0.50%	3.81%	1.86%	3.75%	2.43%	3.99%	**2.69%**
1987-89 to 1997-99	3.42%	4.16%	2.20%	1.19%	0.42%	3.56%	2.04%	3.47%	2.20%	3.17%	**2.58%**
Average	**1.54%**	**0.60%**	**3.13%**	**4.09%**	**1.63%**	**4.83%**	**2.75%**	**3.72%**	**4.17%**	**5.30%**	**3.18%**

SCHEDULE 13 - 3

Union Electric d/b/a Ameren Missouri
File No. ER-2011-0028

Central Region Electric Utility Proxy Group
DPS, EPS, BVPS & GDP
10-Year Compound Growth Rate Averages (1968-1999)

DPS		*EPS*		*BVPS*		GDP	
Years	10 yr compound growth rate avgs	Years	10 yr compound growth rate avgs	Years	10 yr compound growth rate avgs	Years	10 yr compound growth rate avgs
1968-70 to 1978-80	3.03%	1968-70 to 1978-80	2.31%	1968-70 to 1978-80	3.05%	1968-70 to 1978-80	10.05%
1969-71 to 1979-81	3.12%	1969-71 to 1979-81	2.57%	1969-71 to 1979-81	2.69%	1969-71 to 1979-81	10.41%
1970-72 to 1980-82	3.28%	1970-72 to 1980-82	3.00%	1970-72 to 1980-82	2.41%	1970-72 to 1980-82	10.42%
1971-73 to 1981-83	3.54%	1971-73 to 1981-83	4.13%	1971-73 to 1981-83	2.27%	1971-73 to 1981-83	10.22%
1972-74 to 1982-84	3.84%	1972-74 to 1982-84	5.40%	1972-74 to 1982-84	2.42%	1972-74 to 1982-84	10.03%
1973-75 to 1983-85	4.17%	1973-75 to 1983-85	6.30%	1973-75 to 1983-85	2.73%	1973-75 to 1983-85	9.96%
1974-76 to 1984-86	4.43%	1974-76 to 1984-86	6.30%	1974-76 to 1984-86	3.14%	1974-76 to 1984-86	9.77%
1975-77 to 1985-87	4.65%	1975-77 to 1985-87	5.85%	1975-77 to 1985-87	3.41%	1975-77 to 1985-87	9.34%
1976-78 to 1986-88	4.73%	1976-78 to 1986-88	5.82%	1976-78 to 1986-88	3.53%	1976-78 to 1986-88	8.80%
1977-79 to 1987-89	4.80%	1977-79 to 1987-89	5.93%	1977-79 to 1987-89	3.60%	1977-79 to 1987-89	8.32%
1978-80 to 1988-90	4.86%	1978-80 to 1988-90	5.81%	1978-80 to 1988-90	3.72%	1978-80 to 1988-90	7.92%
1979-81 to 1989-91	4.91%	1979-81 to 1989-91	5.32%	1979-81 to 1989-91	3.95%	1979-81 to 1989-91	7.38%
1980-82 to 1990-92	4.87%	1980-82 to 1990-92	4.13%	1980-82 to 1990-92	4.05%	1980-82 to 1990-92	7.06%
1981-83 to 1991-93	4.65%	1981-83 to 1991-93	2.60%	1981-83 to 1991-93	3.95%	1981-83 to 1991-93	6.72%
1982-84 to 1992-94	4.33%	1982-84 to 1992-94	1.46%	1982-84 to 1992-94	3.72%	1982-84 to 1992-94	6.49%
1983-85 to 1993-95	3.98%	1983-85 to 1993-95	1.24%	1983-85 to 1993-95	3.48%	1983-85 to 1993-95	6.12%
1984-86 to 1994-96	3.72%	1984-86 to 1994-96	1.38%	1984-86 to 1994-96	3.23%	1984-86 to 1994-96	5.89%
1985-87 to 1995-97	3.33%	1985-87 to 1995-97	1.10%	1985-87 to 1995-97	2.89%	1985-87 to 1995-97	5.81%
1986-88 to 1996-98	2.97%	1986-88 to 1996-98	0.99%	1986-88 to 1996-98	2.69%	1986-88 to 1996-98	5.73%
1987-89 to 1997-99	2.53%	1987-89 to 1997-99	0.83%	1987-89 to 1997-99	2.58%	1987-89 to 1997-99	5.63%
Average	**3.99%**	**Average**	**3.62%**	**Average**	**3.18%**	**Average**	**8.10%**

Average of 10-year Rolling Averages EPS, DPS and BVPS **3.59%**

Source: Value Line Investment Survey

Average EPS, DPS and BVPS as a percentage of average GDP: 44.36%

SCHEDULE 13-4

Union Electric Company d/b/a Ameren Missouri
File No. ER-2011-0028

Electric Utility
DPS, EPS, BVPS & GDP
10-Year Compound Growth Rate Averages (1947-1999)

DPS Years	10 yr compound growth rate avgs	*EPS* Years	10 yr compound growth rate avgs	*BVPS* Years	10 yr compound growth rate avgs	GDP Years	10 yr compound growth rate avgs
1947-49 to 1957-59	4.58%	1947-49 to 1957-59	4.92%	1947-49 to 1957-59	3.10%	1947-49 to 1957-59	6.28%
1948-50 to 1958-60	4.49%	1948-50 to 1958-60	4.91%	1948-50 to 1958-60	3.30%	1948-50 to 1958-60	6.10%
1949-51 to 1959-60	4.33%	1949-51 to 1959-60	5.00%	1949-51 to 1959-60	3.39%	1949-51 to 1959-60	5.77%
1950-52 to 1960-62	4.31%	1950-52 to 1960-62	5.35%	1950-52 to 1960-62	3.48%	1950-52 to 1960-62	5.27%
1951-53 to 1961-63	4.48%	1951-53 to 1961-63	5.76%	1951-53 to 1961-63	3.79%	1951-53 to 1961-63	4.96%
1952-54 to 1962-64	4.74%	1952-54 to 1962-64	5.99%	1952-54 to 1962-64	4.22%	1952-54 to 1962-64	5.26%
1953-55 to 1963-65	5.16%	1953-55 to 1963-65	6.09%	1953-55 to 1963-65	4.53%	1953-55 to 1963-65	5.47%
1954-56 to 1964-66	5.52%	1954-56 to 1964-66	6.26%	1954-56 to 1964-66	4.65%	1954-56 to 1964-66	5.82%
1955-57 to 1965-67	5.87%	1955-57 to 1965-67	6.50%	1955-57 to 1965-67	4.65%	1955-57 to 1965-67	5.94%
1956-58 to 1966-68	5.97%	1956-58 to 1966-68	6.57%	1956-58 to 1966-68	4.69%	1956-58 to 1966-68	6.36%
1957-59 to 1967-69	5.96%	1957-59 to 1967-69	6.50%	1957-59 to 1967-69	4.73%	1957-59 to 1967-69	6.63%
1958-60 to 1968-70	5.89%	1958-60 to 1968-70	6.06%	1958-60 to 1968-70	4.88%	1958-60 to 1968-70	6.93%
1959-61 to 1969-71	5.68%	1959-61 to 1969-71	5.60%	1959-61 to 1969-71	4.97%	1959-61 to 1969-71	7.16%
1960-62 to 1970-72	5.42%	1960-62 to 1970-72	5.27%	1960-62 to 1970-72	5.14%	1960-62 to 1970-72	7.46%
1961-63 to 1971-73	5.00%	1961-63 to 1971-73	4.95%	1961-63 to 1971-73	5.05%	1961-63 to 1971-73	7.92%
1962-64 to 1972-74	4.35%	1962-64 to 1972-74	4.41%	1962-64 to 1972-74	4.92%	1962-64 to 1972-74	8.24%
1963-65 to 1973-75	3.50%	1963-65 to 1973-75	3.71%	1963-65 to 1973-75	4.83%	1963-65 to 1973-75	8.49%
1964-66 to 1974-76	2.77%	1964-66 to 1974-76	3.02%	1964-66 to 1974-76	4.92%	1964-66 to 1974-76	8.62%
1965-67 to 1975-77	2.46%	1965-67 to 1975-77	2.90%	1965-67 to 1975-77	5.00%	1965-67 to 1975-77	8.91%
1966-68 to 1976-78	2.47%	1966-68 to 1976-78	2.63%	1966-68 to 1976-78	4.83%	1966-68 to 1976-78	9.29%
1967-69 to 1977-79	2.71%	1967-69 to 1977-79	2.71%	1967-69 to 1977-79	4.63%	1967-69 to 1977-79	9.71%
1968-70 to 1978-80	3.03%	1968-70 to 1978-80	2.49%	1968-70 to 1978-80	4.40%	1968-70 to 1978-80	10.05%
1969-71 to 1979-81	3.46%	1969-71 to 1979-81	2.88%	1969-71 to 1979-81	4.16%	1969-71 to 1979-81	10.41%
1970-72 to 1980-82	3.89%	1970-72 to 1980-82	3.19%	1970-72 to 1980-82	3.78%	1970-72 to 1980-82	10.42%
1971-73 to 1981-83	4.29%	1971-73 to 1981-83	3.69%	1971-73 to 1981-83	3.49%	1971-73 to 1981-83	10.22%
1972-74 to 1982-84	4.82%	1972-74 to 1982-84	4.36%	1972-74 to 1982-84	3.37%	1972-74 to 1982-84	10.03%
1973-75 to 1983-85	5.27%	1973-75 to 1983-85	4.80%	1973-75 to 1983-85	3.17%	1973-75 to 1983-85	9.96%
1974-76 to 1984-86	5.57%	1974-76 to 1984-86	5.15%	1974-76 to 1984-86	3.01%	1974-76 to 1984-86	9.77%
1975-77 to 1985-87	5.43%	1975-77 to 1985-87	4.45%	1975-77 to 1985-87	2.81%	1975-77 to 1985-87	9.34%
1976-78 to 1986-88	4.98%	1976-78 to 1986-88	3.44%	1976-78 to 1986-88	2.71%	1976-78 to 1986-88	8.80%
1977-79 to 1987-89	4.32%	1977-79 to 1987-89	1.78%	1977-79 to 1987-89	2.36%	1977-79 to 1987-89	8.32%
1978-80 to 1988-90	3.59%	1978-80 to 1988-90	0.82%	1978-80 to 1988-90	1.88%	1978-80 to 1988-90	7.92%
1979-81 to 1989-91	2.99%	1979-81 to 1989-91	0.34%	1979-81 to 1989-91	1.82%	1979-81 to 1989-91	7.38%
1980-82 to 1990-92	2.46%	1980-82 to 1990-92	0.16%	1980-82 to 1990-92	1.93%	1980-82 to 1990-92	7.06%
1981-83 to 1991-93	1.93%	1981-83 to 1991-93	-0.50%	1981-83 to 1991-93	2.43%	1981-83 to 1991-93	6.72%
1982-84 to 1992-94	1.37%	1982-84 to 1992-94	-1.81%	1982-84 to 1992-94	2.90%	1982-84 to 1992-94	6.49%
1983-85 to 1993-95	0.87%	1983-85 to 1993-95	-1.71%	1983-85 to 1993-95	2.62%	1983-85 to 1993-95	6.12%
1984-86 to 1994-96	0.49%	1984-86 to 1994-96	-1.51%	1984-86 to 1994-96	2.25%	1984-86 to 1994-96	5.89%
1985-87 to 1995-97	0.19%	1985-87 to 1995-97	-1.51%	1985-87 to 1995-97	1.78%	1985-87 to 1995-97	5.81%
1986-88 to 1996-98	-0.35%	1986-88 to 1996-98	-2.94%	1986-88 to 1996-98	1.59%	1986-88 to 1996-98	5.73%
1987-89 to 1997-99	-0.70%	1987-89 to 1997-99	-2.50%	1987-89 to 1997-99	2.51%	1987-89 to 1997-99	5.63%
Average	3.74%	Average	3.18%	Average	3.63%	Average	7.53%

Average of 10-year Rolling Averages EPS, DPS and BVPS 3.52%

Source: 2003 *Mergent Public Utility and Transportation Manual*

Union Electric Company d/b/a Ameren Missouri
File No. ER-2011-0028

Capital Asset Pricing Model (CAPM) Costs of Common Equity Estimates
Based on Historical Return Differences Between Common Stocks and Long-Term U.S. Treasuries
for the Comparable Electric Utility Companies

	(1)	(2)	(3)	(4)	(5)	(6)
Company Name	Risk Free Rate	Company's Value Line Beta	Arithmetic Average Market Risk Premium (1926-2009)	Geometric Average Market Risk Premium (1926-2009)	Arithmetic CAPM Cost of Common Equity (1926-2009)	Geometric CAPM Cost of Common Equity (1926-2009)
Alliant Energy	4.16%	0.70	6.00%	4.40%	8.36%	7.24%
American Electric Power	4.16%	0.70	6.00%	4.40%	8.36%	7.24%
Cleco Corp.	4.16%	0.65	6.00%	4.40%	8.06%	7.02%
DPL Inc.	4.16%	0.60	6.00%	4.40%	7.76%	6.80%
IDACORP, Inc.	4.16%	0.70	6.00%	4.40%	8.36%	7.24%
PG&E Corp.	4.16%	0.55	6.00%	4.40%	7.46%	6.58%
Pinnacle West Capital	4.16%	0.70	6.00%	4.40%	8.36%	7.24%
Southern Company	4.16%	0.55	6.00%	4.40%	7.46%	6.58%
Westar Energy, Inc.	4.16%	0.75	6.00%	4.40%	8.66%	7.46%
Xcel Energy	4.16%	0.65	6.00%	4.40%	8.06%	7.02%
Average		**0.66**			**8.09%**	**7.04%**

Column 1 = The appropriate yield is equal to the average 30-year U.S. Treasury Bond yield for October, November and December 2010 which was obtained from the St. Louis Federal Reserve website at http://research.stlouisfed.org/fred2/series/GS30/22.

Column 2 = Beta is a measure of the movement and relative risk of an individual stock to the market as a whole as reported by the Value Line Investment Survey: Ratings & Reports, November 5 and 26, and December 24, 2010.

Column 3 = The Market Risk Premium represents the expected return from holding the entire market portfolio less the expected return from holding a risk free investment. The appropriate Market Risk Premium for the period 1926 - 2009 was determined to be 6.00% based on an arithmetic average as calculated in Ibbotson Associates, Inc.'s Stocks, Bonds, Bills, and Inflation: 2010 Yearbook.

Column 4 = The Market Risk Premium represents the expected return from holding the entire market portfolio less the expected return from holding a risk free investment. The appropriate Market Risk Premium for the period 1926 - 2009 was determined to be 4.4% based on a geometric average as calculated in Ibbotson Associates, Inc.'s Stocks, Bonds, Bills, and Inflation: 2010 Yearbook.

Column 5 = (Column 1 + (Column 2 * Column 3)).

Column 6 = (Column 1 + (Column 2 * Column 4)).

Union Electric Company d/b/a Ameren Missouri
File No. ER-2011-0028

Weighted Cost of Capital as of March 31, 2010
for Union Electric Company

Capital Component	Percentage of Capital	Embedded Cost	Weighted Cost of Capital Using Common Equity Return of: Ameren Missouri 8.25%	8.75%	9.25%
Common Stock Equity	50.92%	-----	4.20%	4.46%	4.71%
Preferred Stock	1.49%	5.189%	0.08%	0.08%	0.08%
Long-Term Debt	47.59%	5.944%	2.83%	2.83%	2.83%
Total	**100.00%**		**7.11%**	**7.36%**	**7.62%**

Notes:

See Schedule 5 for the Capital Structure Ratios.

Embedded Cost of Long-Term Debt and Embedded Cost of Preferred Stock Provided in Schedule MGO-E1 of Michael G. O'Bryan's Direct Testimony.

Unanimous Fed Keeps Buying Bonds

WSJ FAJ 1/27/2011

By Sudeep Reddy

The Federal Reserve, acknowledging a slow recovery and stubbornly high unemployment, decided Wednesday to proceed with its plans to buy as much as $600 billion in long-term Treasury bonds as it awaits a stronger pickup in growth.

The decision was unanimous, marking the first meeting of the policy-making Federal Open Market Committee without a dissenting vote since December 2009.

Despite increasingly optimistic assessments of the economy from private-sector forecasters, the Fed offered a lukewarm outlook. In a statement after its two-day meeting, the committee said "the economic recovery is continuing, though at a rate that has been insufficient to bring about a significant improvement in labor market conditions."

Fed officials acknowledged the recent rise in commodity prices, which have spurred increasing inflation worries from central bankers around the world, but largely shrugged them off. While commodity prices "have risen," they said, "longer-term inflation expectations have remained stable" and underlying inflation—excluding volatile food and energy prices—has been "trending downward."

Barring a surprise shift in the economy—an unanticipated burst of inflation or a significant speed-up or slowdown in economic growth—the Fed is likely to stay the course with the bond purchases through June. So far, it has purchased about a third of the $600 billion target. In the spring, the committee will have to decide what to do next.

The Fed has been holding short-term interest rates near zero since December 2008, and reiterated Wednesday that it expects to keep them there for "an extended period." The central bank embarked on a new round of bond-buying in November, as inflation sat well below its informal 2% target—the Fed's definition of "price stability"—and unemployment stood above any definition of "maximum employment," the other half of its mandate. The Fed's aim was to push interest rates on longer-term Treasurys lower than they would otherwise be and prod investors to put money in other assets, such as stocks.

> While commodity prices have risen, said Federal Reserve policy makers, 'longer-term inflation expectations have remained stable.'

Some Fed officials want to continue the bond purchases beyond June if underlying inflation remains extremely low. A slowdown in growth later this year, below the 3% rate that marks longer-run expansion in the economy, also could reignite deflation fears and spur officials to extend the bond purchases.

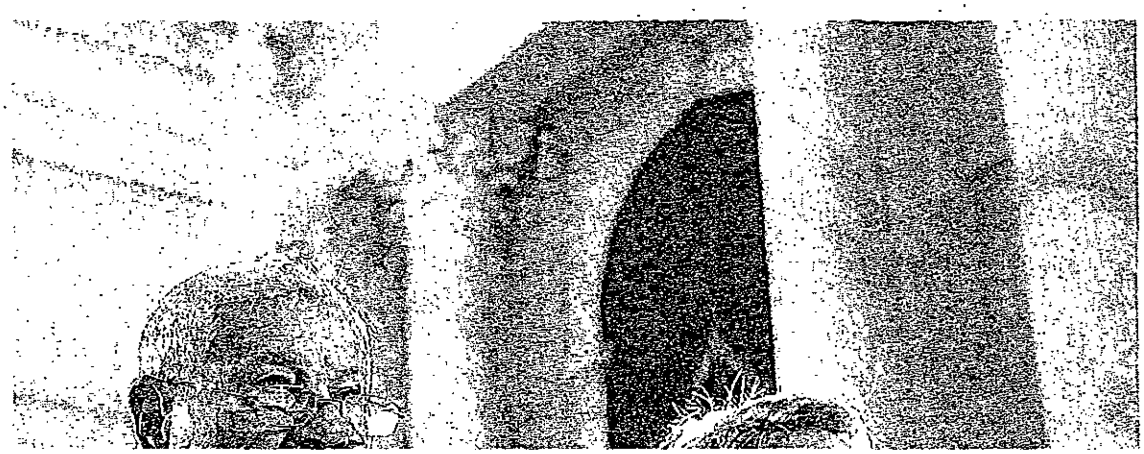
Still, other Fed officials expect growth and job creation to accelerate in coming months. A tax-cut deal by the White House and Congress in December, which reduces payroll taxes for all workers this year, is expected to boost growth by putting more money in consumers' pockets. Economic forecasters generally expect the economy to expand at a pace of around 3.5% to 4% this year. A pickup in growth heading into June could spur pressure from the more-optimistic Fed officials to move toward ending the ultra-loose monetary policy of the past two years.

The most likely course, said Michael Feroli, chief U.S. economist at J.P. Morgan Chase, is that "they'll stop once they finish the $600 billion. I don't think a lot happens after that. Then gradually you're going to start talking about exit and baby steps toward the exit."

Investors believe the Fed will start raising rates in early 2012, according to futures markets, earlier than some Fed officials say they expect to do so. Most central-bank policy makers expect the jobless rate, at 9.4% in December, to stay above 9% into late this year and put downward pressure on prices across the U.S.

Top Fed officials credit the bond-buying program with reducing deflation risks and easing worries U.S. growth may slow again in coming months. The move helped push investors out of safe Treasury securities and into riskier assets such as stocks and corporate bonds. The Dow Jones Industrial Average crossed the 12000 mark Wednesday for the first time since July 2008, putting it up about 20% since the end of August—when Chairman Ben Bernanke first hinted at new Fed action—and 7% since the Fed's announcement in early November.

In Wednesday's vote, all four regional Fed bank presidents who rotated onto the voting membership of the FOMC sided with Mr. Bernanke, including two who last year expressed doubts about the bond purchases, Richard Fisher of Dallas and Charles Plosser of Philadelphia. Last year, Kansas City Fed President Thomas Hoenig, who is no longer a voter and plans to retire this year, dissented at all eight meetings, preferring that the Fed stop loosening policy and start the process of normalizing interest rates.



ATTACHMENT A

EEI

Stock Performance

Q4 2010
FINANCIAL UPDATE

QUARTERLY REPORT
OF THE U.S. SHAREHOLDER-OWNED
ELECTRIC UTILITY INDUSTRY

EDISON ELECTRIC INSTITUTE

About EEI

The Edison Electric Institute is the association of U.S. shareholder-owned electric companies. Our members serve 95% of the ultimate customers in the shareholder-owned segment of the industry, and represent approximately 70% of the U.S. electric power industry. We also have 79 international electric companies as Affiliate members and more than 190 industry suppliers and related organizations as Associate members.

About EEI's Quarterly Financial Updates

EEI's quarterly financial updates present industry trend analyses and financial data covering 62 U.S. shareholder-owned electric utility companies. These 62 companies include 57 electric utility holding companies whose stocks are traded on major U.S. stock exchanges and eleven electric utilities who are subsidiaries of non-utility or foreign companies. Financial updates are published for the following topics:

Dividends	Rate Case Summary
Stock Performance	SEC Financial Statements (Holding Companies)
Credit Ratings	FERC Financial Statements (Regulated Utilities)
Construction	Fuel

For EEI Member Companies

The EEI Finance and Accounting Division is developing current year and historical data sets that cover a wide range of industry financial and operating metrics. We look forward to serving as a resource for member companies who wish to produce customized industry financial data and trend analyses for use in:

- Investor relations studies and presentations
- Internal company presentations
- Performance benchmarking
- Peer group analyses
- Annual and quarterly reports to shareholders

We Welcome Your Feedback

EEI is interested in ensuring that our financial publications and industry data sets best address the needs of member companies and the financial community. We welcome your comments, suggestions and inquiries.

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Future EEI Finance Meetings

EEI International Utility Conference
March 13-15, 2011
London Hilton on Park Lane
London, United Kingdom

For more information about EEI Finance Meetings, please contact Debra Henry, (202) 508-5496, dhenry@eei.org

Edison Electric Institute
701 Pennsylvania Avenue, N.W.
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The 62 U.S. Shareholder-Owned Electric Utilities

The companies listed below all serve a regulated distribution territory. Other utilities, such as transmission provider ITC Holdings, are not shown below because they do not serve a regulated distribution territory. However, their financial information is included in relevant EEI data sets, such as transmission-related construction spending.

Allegheny Energy, Inc. (AYE)
ALLETE, Inc. (ALE)
Alliant Energy Corporation (LNT)
Ameren Corporation (AEE)
American Electric Power Company, Inc. (AEP)
Avista Corporation (AVA)
Black Hills Corporation (BKH)
CenterPoint Energy, Inc. (CNP)
Central Vermont Public Service Corporation (CV)
CH Energy Group, Inc. (CHG)
Cleco Corporation (CNL)
CMS Energy Corporation (CMS)
Consolidated Edison, Inc. (ED)
Constellation Energy Group, Inc. (CEG)
Dominion Resources, Inc. (D)
DPL, Inc. (DPL)
DTE Energy Company (DTE)
Duke Energy Corporation (DUK)
Edison International (EIX)
El Paso Electric Company (EE)
Empire District Electric Company (EDE)
Energy East Corporation
Energy Future Holdings Corp. (formerly TXU Corp.)
Entergy Corporation (ETR)
Exelon Corporation (EXC)
FirstEnergy Corp. (FE)
Great Plains Energy Incorporated (GXP)
Hawaiian Electric Industries, Inc. (HE)
IDACORP, Inc. (IDA)
Integrys Energy Group, Inc. (TEG)
IPALCO Enterprises, Inc.
MDU Resources Group, Inc. (MDU)
MGE Energy, Inc. (MGEE)
MidAmerican Energy Holdings Company
NextEra Energy, Inc. (NEE)
NiSource Inc. (NI)
Northeast Utilities (NU)
NorthWestern Corporation (NWE)
NSTAR (NST)
NV Energy, Inc. (NVE)
OGE Energy Corp. (OGE)
Otter Tail Corporation (OTTR)
Pepco Holdings, Inc. (POM)
PG&E Corporation (PCG)
Pinnacle West Capital Corporation (PNW)
PNM Resources, Inc. (PNM)
Portland General Electric Company (POR)
PPL Corporation (PPL)
Progress Energy (PGN)
Public Service Enterprise Group Inc. (PEG)
Puget Energy, Inc.
SCANA Corporation (SCG)
Sempra Energy (SRE)
Southern Company (SO)
TECO Energy, Inc. (TE)
UIL Holdings Corporation (UIL)
UniSource Energy Corporation (UNS)
Unitil Corporation (UTL)
Vectren Corporation (VVC)
Westar Energy, Inc. (WR)
Wisconsin Energy Corporation (WEC)
Xcel Energy, Inc. (XEL)

Companies Listed by Category
(as of 12/31/09)

Please refer to the Quarterly Financial Updates webpage for previous years' lists.

Given the diversity of utility holding company corporate strategies, no single company categorization approach will be useful for all EEI members and utility industry analysts. Never-the-less, we believe the following classification provides an informative framework for tracking financial trends and the capital markets' response to business strategies as companies depart from the traditional regulated utility model.

Regulated	80%+ of total assets are regulated
Mostly Regulated	50% to 80% of total assets are regulated
Diversified	Less than 50% of total assets are regulated

Categorization of the 58 publicly traded utility holding companies is based on year-end business segmentation data presented in 10Ks, supplemented by discussions with company IR departments. Categorization of the five non-publicly traded companies (*shown in italics*) is based on estimates derived from FERC Form 1 data and information provided by parent company IR departments.

The EEI Finance and Accounting Division continues to evaluate our approach to company categorization and business segmentation. In addition, we can produce customized categorization and peer group analyses in response to member company requests. We welcome comments, suggestions and feedback from EEI member companies and the financial community.

Regulated (38 of 63)

ALLETE, Inc.
Alliant Energy Corporation
Ameren Corporation
American Electric Power Company, Inc.
Avista Corporation
Central Vermont Public Service Corporation
CH Energy Group, Inc.
Cleco Corporation
CMS Energy Corporation
Consolidated Edison, Inc.
DPL, Inc.
DTE Energy Company
El Paso Electric Company
Empire District Electric Company
Energy East Corporation
Great Plains Energy Incorporated
IDACORP, Inc.
IPALCO Enterprises, Inc.
Maine & Maritimes Corporation
Northeast Utilities
NorthWestern Energy
NSTAR
NV Energy, Inc.
PG&E Corporation
Pinnacle West Capital Corporation
PNM Resources, Inc.
Portland General Electric Company
Progress Energy
Puget Energy, Inc.
Southern Company
TECO Energy, Inc.
UIL Holdings Corporation
UniSource Energy Corporation
Unitil Corporation
Vectren Corporation
Westar Energy, Inc.
Wisconsin Energy Corporation
Xcel Energy, Inc.

Mostly Regulated (20 of 63)

Allegheny Energy, Inc.
Black Hills Corporation
CenterPoint Energy, Inc.
Dominion Resources, Inc.
Duke Energy Corporation
Edison International
Entergy Corporation
Exelon Corporation
First Energy Corp.
Integrys Energy Group
MGE Energy, Inc.
MidAmerican Energy Holdings
NextEra Energy, Inc.
NiSource Inc.
OGE Energy Corp.
Otter Tail Corporation
Pepco Holdings, Inc.
Public Service Enterprise Group, Inc.
SCANA Corporation
Sempra Energy

Diversified (5 of 63)

Constellation Energy Group, Inc.
Energy Future Holdings
Hawaiian Electric Industries, Inc.
MDU Resources Group, Inc.
PPL Corporation

Note: Based on assets at 12/31/09

Q4 2010

Stock Performance

HIGHLIGHTS

- The EEI Index returned 1.3% during Q4, trailing the Dow Jones Industrials' 8.0% return, the S&P 500's 10.7% return and the Nasdaq Composite's 12.0% gain, and reversing the outperformance seen in Q2 and Q3.
- Supported by generally low interest rates and steady dividends, the Regulated group of companies produced an unweighted average total return of 15.8% in 2010 — surpassing both the Dow Jones Industrial's 14.1% return and the S&P 500's 15.1% return.
- The cap-weighted EEI Index returned 7.0% in 2010, held back by weakness in companies with competitive power operations whose earnings outlook has eroded with falling natural gas prices. The Mostly Regulated group returned 8.5% and the Diversified group, whose number has dwindled in recent years, returned –5.2%.
- Many regulated utilities are engaged in capital spending programs that should help drive solid mid- to high-single -digit earnings growth over the next several years, which will augment the group's strong dividend yield.

COMMENTARY

The EEI Index produced a 1.3% return in the fourth quarter of 2010, significantly trailing the Dow Jones Industrials' 8.0% return, the S&P 500's 10.7% return and the Nasdaq Composite's 12.0% gain. During the quarter, the broad market sustained the rally that began in July on signs that the U.S. economy would avoid a dip back into recession and that Europe's political leaders would find a way to defuse the sovereign debt crisis affecting its weaker economies, avoiding a traumatic impact on the stability of European banks. Fears of slowing U.S growth and the eruption of Europe's

I. Index Comparison (% Return)

Index	2004	2005	2006	2007	2008	2009	2010
EEI Index	22.8	16.0	20.8	16.6	-25.9	10.7	7.0
Dow Jones Inds.	5.3	1.7	19.1	8.9	-31.9	22.7	14.1
S&P 500	10.9	4.9	15.8	5.5	-37.0	26.5	15.1
Nasdaq Comp.^	8.6	1.4	9.5	9.8	-40.5	43.9	16.9

Calendar year returns shown for all periods.
^Price gain/loss only. Other indices show total return.
Full year, except where noted.
Source: EEI Finance Department

II. Category Comparison (% Return)

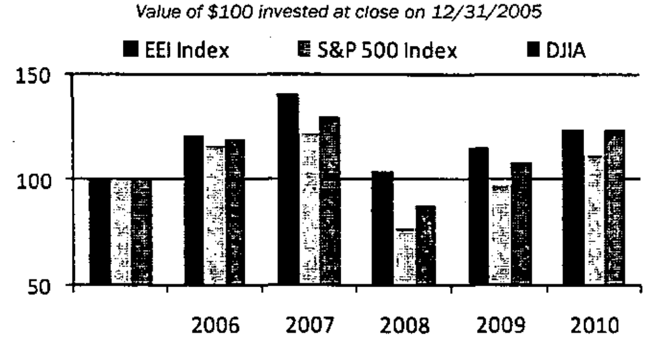
U.S. Shareholder-Owned Electric Utilities

Index	2004	2005	2006	2007	2008	2009	2010
All Companies	18.9	9.9	22.5	9.8	-20.9	14.1	11.9
Regulated	14.4	2.7	22.6	7.8	-15.6	14.2	15.8
Mostly Regulated	16.4	12.9	22.4	9.9	-27.0	15.6	8.5
Diversified	36.7	24.7	22.2	18.5	-33.9	8.1	-5.2

Calendar year returns shown for all periods.
Returns shown here are unweighted averages of constituent company returns. The EEI Index return shown in Table I above is cap-weighted.
Source: EEI Finance Department, SNL Financial and company annual reports.

III. Total Return Comparison

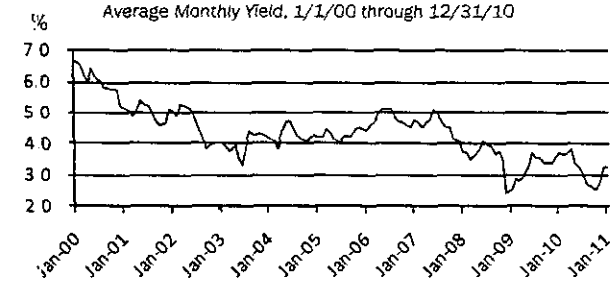
Value of $100 invested at close on 12/31/2005



Note: Full year, except where noted.
Source: EEI Finance Department

IV. 10-Year Treasury Yield — Monthly

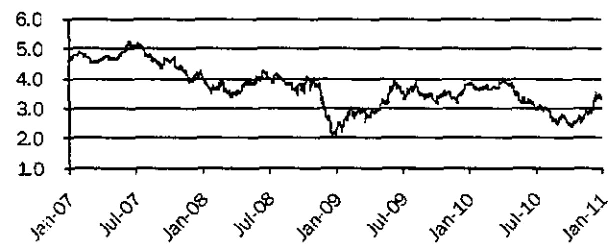
Average Monthly Yield, 1/1/00 through 12/31/10



Source: U.S. Federal Reserve

V. 10-Year Treasury Yield — Daily

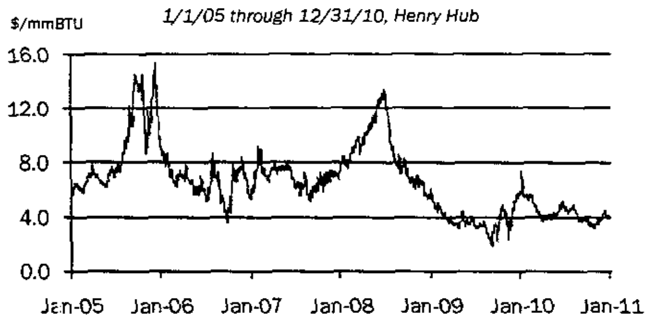
Daily Yield, 1/1/07 through 12/31/10



Source: U.S. Federal Reserve

VI. Natural Gas Spot Prices

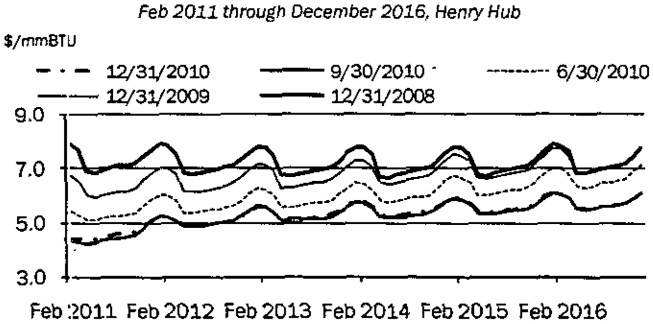
1/1/05 through 12/31/10, Henry Hub



Source: SNL Financial

VII. NYMEX Natural Gas Futures

Feb 2011 through December 2016, Henry Hub



Source: SNL Financial

VIII. Returns by Quarter

Index	2008 Q1	2008 Q2	2008 Q3	2008 Q4	2009 Q1	2009 Q2	2009 Q3	2009 Q4	2010 Q1	2010 Q2	2010 Q3	2010 Q4
EEI Index	-10.4	7.1	-14.3	-9.9	-11.0	9.1	5.5	8.0	-2.5	-3.7	12.6	1.3
Dow Jones Ind.	-7.0	-6.9	-3.7	-18.4	-12.5	12.0	15.8	8.1	4.8	-9.4	11.1	8.0
S&P 500	-9.5	-2.7	-8.4	-21.9	-11.0	15.9	15.6	6.0	5.4	-11.4	11.3	10.7
Nasdaq Comp.^	-14.1	0.6	-9.2	-24.3	-3.1	20.0	15.7	6.9	5.7	-12.0	12.3	12.0

^Price gain/loss only. Other indices show total return.
Source: EEI Finance Department

Category*	2008 Q1	2008 Q2	2008 Q3	2008 Q4	2009 Q1	2009 Q2	2009 Q3	2009 Q4	2010 Q1	2010 Q2	2010 Q3	2010 Q4
All Companies	-12.4	6.1	-6.2	-9.3	-12.6	9.8	9.0	9.0	0.3	-3.7	12.1	3.3
Regulated	-13.6	4.9	-0.3	-5.9	-11.5	7.5	9.6	9.6	1.3	-2.7	12.0	4.8
Mostly Regulated	-10.1	8.7	-13.9	-14.0	-11.9	11.3	8.9	8.3	-0.8	-5.2	13.7	1.5
Diversified	-11.6	6.7	-15.5	-17.0	-22.8	22.8	5.6	8.0	-2.6	-7.1	5.1	-0.2

* Returns shown here are unweighted averages of constituent company returns. The EEI Index return shown above is cap-weighted.
Source: EEI Finance Department, SNL Financial and company annual reports.

IX. Sector Comparison, Trailing 12 mo. Total Return

For the twelve-month period ending 12/31/10

Sector	Total Return
Basic Materials	31.7%
Industrials	26.0%
Consumer Services	23.7%
Oil & Gas	19.7%
Consumer Goods	19.5%
Telecommunications	17.7%
Aggregate Index	16.6%
Financials	12.7%
Technology	12.6%
Utilities	7.8%
EEI Index	**7.0%**
Healthcare	4.5%

Note: Sector Comparison page based on the Dow Jones U.S. Indexes, which are market-capitalization-weighted indices. Find more information at http://www.djindexes.com/mdsidx/downloads/fact_info/Dow_Jones_US_Indexes_Industry_Indexes_Fact_Sheet.pdf

X. Sector Comparison, Q4 2010 Total Return

For the three-month period ending 12/31/10

Sector	Total Return
Oil & Gas	21.1%
Basic Materials	20.5%
Industrials	13.7%
Aggregate Index	11.4%
Technology	11.4%
Consumer Services	11.2%
Financials	11.0%
Consumer Goods	9.9%
Telecommunications	7.3%
Healthcare	3.9%
Utilities	2.3%
EEI Index	**1.3%**

Note: Sector Comparison page based on the Dow Jones U.S. Indexes, which are market-capitalization-weighted indices. Find more information at http://www.djindexes.com/mdsidx/downloads/fact_info/

XI. Market Capitalization at December 31, 2010 (in $ Mil.)

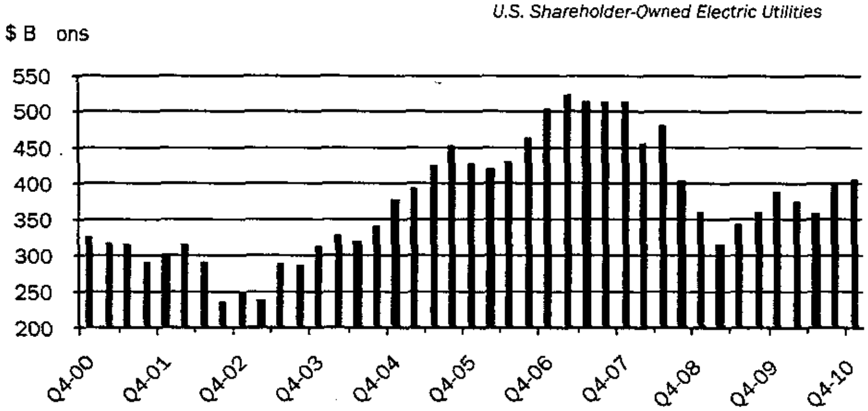
U.S. Shareholder-Owned Electric Utilities

Company	Stock Symbo	$ Ma ket Cap	% Tota	Company	Stock Symbo	$ Ma ket Cap	% Tota
Southe n Company	SO	31 958 5	7 85%	Al ant Ene gy Co p	LNT	4 061 9	1 00%
Exe on Co po at on	EXC	27 572 3	6 77%	MDU Resou ces G oup	MDU	3 814 2	0 94%
Dom n on Resou ces nc	D	24 991 2	6 14%	TECO Ene gy nc	TE	3 792 1	0 93%
Duke Ene gy Co po at on	DUK	23 509 2	5 77%	nteg ys Ene gy G oup	TEG	3 769 2	0 93%
NextEra Ene gy nc	NEE	21 362 7	5 25%	NV Ene gy nc	NVE	3 303 4	0 81%
PG&E Co po at on	PCG	18 657 6	4 58%	DPL nc	DPL	2 977 2	0 73%
Ame E ec Powe	AEP	17 255 2	4 24%	Westa Ene gy nc	WR	2 810 5	0 69%
Pub c Svc Ent G oup	PEG	16 104 2	3 95%	G eat P a ns Ene gy nc	GXP	2 621 5	0 64%
Conso dated Ed son	ED	14 028 3	3 44%	Hawa an Elect c nd	HE	2 135 4	0 52%
Ente gy Co po ation	ETR	13 171 7	3 23%	Vect en Co po ation	VVC	2 060 9	0 51%
Semp a Ene gy	SRE	12 945 1	3 18%	C eco Co po at on	CNL	1 860 1	0 46%
P og ess Ene gy nc	PGN	12 783 1	3 14%	DACORP nc	DA	1 778 2	0 44%
PPL Co po at on	PPL	12 700 8	3 12%	Po t and Gen E ect c	POR	1 635 4	0 40%
Ed son nte nat ona	EIX	12 583 6	3 09%	Un Sou ce Ene gy	UNS	1 309 3	0 32%
F stEne gy Co p	FE	11 254 1	2 76%	ALLETE nc	ALE	1 281 7	0 31%
Xce Ene gy nc	XEL	10 848 7	2 66%	Av sta Co po ation	AVA	1 253 0	0 31%
DTE Ene gy Company	DTE	7 659 1	1 88%	PNM Resou ces nc	PNM	1 192 1	0 29%
W scons n Ene gy Co p	WEC	6 880 7	1 69%	E Paso E ect c Company	EE	1 181 6	0 29%
Ame en Co po ation	AEE	6 745 9	1 66%	B ack H s Co po ation	BKH	1 168 0	0 29%
Cente Po nt Ene gy nc	CNP	6 636 6	1 63%	No thWeste n Co p	NWE	1 043 5	0 26%
Conste at on Ene gy	CEG	6 159 7	1 51%	MGE Ene gy nc	MGEE	988 4	0 24%
No theast Uti t es	NU	5 634 9	1 38%	U L Ho d ngs Co po at on	U L	964 0	0 24%
SCANA Co po at on	SCG	5 140 0	1 26%	Emp e D st ct Elect c	EDE	919 2	0 23%
N Sou ce nc	N	4 899 9	1 20%	Otte Ta Co po at on	OTTR	807 1	0 20%
P nnac e West Cap ta	PNW	4 502 8	1 11%	CH Ene gy G oup nc	CHG	772 0	0 19%
OGE Ene gy Co p	OGE	4 435 6	1 09%	Cen Ve mont Pub c Svc	CV	273 6	0 07%
NSTAR	NST	4 370 3	1 07%	Un ti Co po at on	UTL	246 3	0 06%
CMS Ene gy Co po at on	CMS	4 259 4	1 05%				
A egheny Ene gy nc	AYE	4 115 3	1 01%	**Tota ndustry**		**407,274 5**	**100 00%**
Pepco Ho d ngs nc	POM	4 088 0	1 00%				

Source: EEI Finance Department and Wall Street Journal

XII. EEI Index Market Capitalization (at Period End)

U.S. Shareholder-Owned Electric Utilities



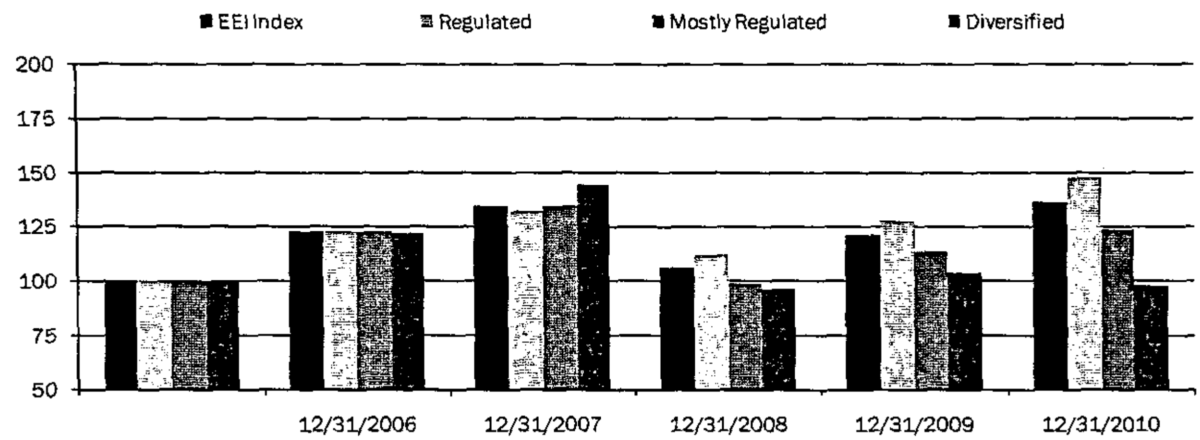
Note: Change in EEI Index market capitalization reflects the impact of buyout and spin-off activity in addition to stock market performance.
Source: EEI Finance Department and Wall Street Journal

EEI Index Market Cap (in $Billions)

Q1-01	319,484	Q1-06	422,899
Q2-01	317,546	Q2-06	432,848
Q3-01	291,035	Q3-06	464,281
Q4-01	300,200	Q4-06	503,858
Q1-02	317,668	Q1-07	525,088
Q2-02	292,238	Q2-07	515,565
Q3-02	238,331	Q3-07	514,946
Q4-02	249,553	Q4-07	514,486
Q1-03	240,598	Q1-08	456,711
Q2-03	289,454	Q2-08	482,024
Q3-03	288,073	Q3-08	404,472
Q4-03	314,324	Q4-08	361,921
Q1-04	329,601	Q1-09	316,070
Q2-04	323,193	Q2-09	343,844
Q3-04	342,460	Q3-09	363,185
Q4-04	380,305	Q4-09	389,672
Q1-05	395,663	Q1-10	377,281
Q2-05	425,989	Q2-10	360,044
Q3-05	454,727	Q3-10	402,014
Q4-05	428,825	Q4-10	407,275

XIII. Comparative Category Total Annual Returns

U.S. Shareholder-Owned Electric Utilities, Value of $100 invested at close on 12/31/2005



	2005	2006	2007	2008	2009	2010
EEI Index Annual Return (%)		22.47	9.83	(20.93)	14.13	11.87
EEI Index Cumulative Return ($)	100	134.57	147.81	116.87	133.38	135.78
Regulated EEI Index Annual Return		22.65	7.81	(15.59)	14.25	15.75
Regulated EEI Index Cumulative Return	100	126.00	135.84	114.66	131.00	147.60
Mostly Regulated EEI Index Annual Return		22.37	9.93	(27.00)	15.58	8.51
Mostly Regulated EEI Index Cumulative Return	100	138.11	151.83	110.84	128.11	123.16
Diversified EEI Index Annual Return		22.16	18.46	(33.90)	8.07	(5.16)
Diversified EEI Index Cumulative Return	100	152.37	180.49	119.30	128.93	98.03

Calendar year returns shown, except where noted.
Returns are unweighted averages of constituent company returns.

sovereign debt worries had driven the broad market down during May and June, while regulated utilities stocks outperformed. In a strong quarter for the market, one might expect utilities to underperform, and indeed they did during Q4. But the broad EEI Index, which is capitalization-weighted and influenced by large companies with competitive generation, suffered from ongoing weakness in natural gas prices and the resultant impact on competitive electricity prices.

Regulated Group's Strength Continues

The Regulated group of companies continued to outperform competitive power generators during the quarter, extending for the sixth consecutive quarter a trend that began in Q3 2009. As shown in Table VIII, EEI's Regulated group (80% of assets are regulated) returned 4.8% during Q4 while the Diversified group (less than 50% of assets are regulated) returned –0.2%. The Mostly Regulated group (50% to 80% of assets are regulated), a mix of companies that balance regulated and competitive operations to varying degrees, returned 1.5%. However, due to the migration of company strategies toward traditional regulated operations in recent years, the

XIV. EEI Index Top Ten Performers

For the 12-month period ending 12/31/10

Company	Category	% Return
El Paso Electric Company	R	35.7
Northeast Utilities	R	28.1
OGE Energy Corp.	MR	28.0
Alliant Energy Corporation	R	27.2
Empire District Electric Company	R	26.4
MGE Energy, Inc.	MR	24.4
CMS Energy Corporation	R	23.9
Integrys Energy Group, Inc.	MR	22.3
Westar Energy, Inc.	R	22.1
Wisconsin Energy Corporation	R	21.7

Note: Return figures include capital gains and dividends.
R = Regulated, MR = Mostly Regulated, D = Diversified
Source: EEI Finance Department

Diversified group is down to only four publicly traded companies from ten in 2004, while the Mostly Regulated group has decreased from 26 companies to 20.

For full-year 2010, the Regulated group's dominance is clear in the data. Supported by generally low interest rates and steady dividends, the group produced an unweighted average total return of 15.8% — surpassing both the Dow Jones Industrial's 14.1% and the S&P 500's 15.1% returns. The cap-weighted EEI Index returned 7.0%. And as shown in Table XIV, seven out of the EEI Index's top ten gainers for 2010 are members of the Regulated group, while the other three are in the Mostly Regulated group.

Natural Gas Prices Remain Depressed

The most significant trend in terms of overall macroeconomic fundamentals impacting the industry during 2010 was the ongoing softness in natural gas spot and futures prices. Natural gas-fired generators are typically the marginal price setters in many competitive power markets across the country and natural gas prices, therefore, exert a strong influence on competitive power prices.

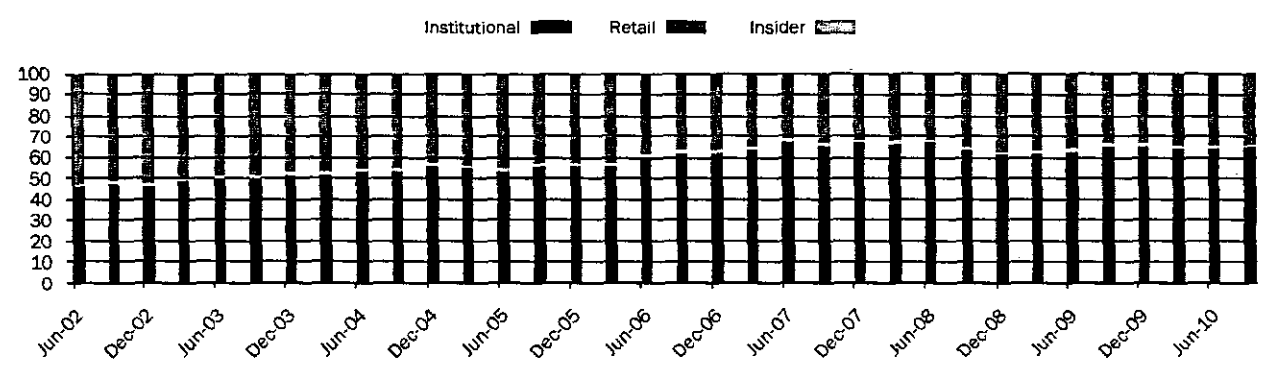
As shown in Chart VI, after an early-year winter rally, spot gas prices languished around $4/mm BTU for most of the year. Chart VII shows the marked decline in futures prices during the second half of 2010 and over the past two years. Domestic natural gas supply has been boosted by production from low-cost shale reserves, while the economic recession and tepid recovery has reduced demand, creating a supply glut. As a result, analysts became increasingly bearish as 2010 progressed about the prospects for natural gas prices and long-term competitive power prices, even in a sustainable economic rebound. These developments weighed heavily on the share prices of many companies with significant competitive generation assets.

Power Demand Boosted by Hot Summer

After declining nearly 4% on an annual basis in recession-wracked 2009, nationwide electricity output rose 3.7% during the economically stronger 2010. Helped by a generally hot summer across the country (cooling degree days, a measure of air conditioning usage, were 22% higher than the historical average), power demand jumped 6.9% in Q3 2010 and hit record levels in some cities, which likely contributed to the industry's share price strength during the summer. Nevertheless, the long-term outlook for power demand remains uncertain, dependent not only on the strength of economic growth but on the impact that energy efficiency, smart grid and demand response technologies, along with general conservation measures, will have on power usage.

XV. Share Ownership by Investor Category (% of total)

U.S. Shareholder-Owned Electric Utilities



	Dec-02	Mar-03	Jun-03	Sep-03	Dec-03	Mar-04	Jun-04	Sep-04	Dec-04	Mar-05	Jun-05	Sep-05	Dec-05	Mar-06	Jun-06	Sep-06
Institutional	46.6	48.6	49.6	50	51.5	51.4	53.1	53.5	55.6	54.9	53.3	56.1	55.9	55.6	60.2	61.8
Insider	1.5	1.6	1.6	1.6	1.6	1.7	1.7	1.7	1.7	1.8	1.8	1.8	1.8	1.8	1.8	1.8
Retail	51.9	49.7	48.8	48.4	46.9	47.1	45.4	45.1	43.0	43.3	44.9	42.2	42.3	42.7	38.0	36.4
Total	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0

	Dec-06	Mar-07	Jun-07	Sep-07	Dec-07	Mar-08	Jun-08	Sep-08	Dec-09	Mar-09	Jun-09	Sep-09	Dec-09	Mar-10	Jun-10	Sep-10
Institutional	61.7	63.4	66.9	65.7	66.7	66.4	66.7	64.0	61.8	61.9	63.0	65.4	65.7	64.7	64.8	65.4
Insider	1.8	1.8	1.7	1.7	1.5	1.5	1.5	1.5	1.4	1.4	1.4	1.4	1.3	1.2	1.2	1.2
Retail	36.5	34.8	31.4	32.6	31.8	32.1	31.8	34.5	36.9	36.7	35.6	33.2	33.0	34.0	34.0	33.4
Total	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0

Source: SNL Financial and EEI Finance Department. Note: Institutional figures represent end-of-quarter, unweighted average of the 58 publicly traded EEI Index companies.

Utility Dividends Offer Relief from Low Interest Rates

Interest rates continue to be a wildcard for the industry and its investors, most directly impacting regulated utility shares, which often appeal to income-oriented investors as a bond substitute with dividend growth potential. Widespread predictions by economists in recent years that interest rates will rise have continually been confounded by declining rates.

As shown in Table V, the 10-year Treasury yield fell from 3.8% at the start of the year to under 2.5% in October. But after the Federal Reserve's early November announcement that it would implement a second round of quantitative easing to support the economy, the 10-year Treasury yield posted it's sharpest climb since early 2009, and finished the year at 3.3% (a level, nevertheless, still quite low by historical standards).

With bond yields low, the strong dividends and slow but steady earnings growth offered by many utilities have been an important source of support for the industry's stocks. At December 31, the average dividend yield for the EEI Index's 63 publicly traded utilities stood at 4.5%, well above the S&P 500's 1.8%. However, many Wall Street analysts have commented that regulated utilities tend to underperform the broad markets during periods of rising rates. Should interest rates rise significantly during 2011 and beyond, the group would likely face a struggle to sustain the strong performance of recent years. The Regulated group has benefitted as interest rates have declined, earnings growth prospects have stayed healthy and as investors have sought stability during periods of market uncertainty. The Regulated Group has outperformed the S&P 500 in five of the last seven calendar years (through 2010).

Industry Prospects Appear to Be Sound

Many regulated utilities are engaged in capital spending programs that should help drive solid mid- to high-single-digit earnings growth over the next several years, which analysts point to as an ongoing source of attraction for investors in addition to the sector's dividends. Moreover, recent EPA moves to limit coal plant emissions through the Clean Air Transport Rule (CATR) — which will target SOx and NOx emission — and a Maximum Achievable Control Technology (MACT) rule for mercury will conceivably force the retirement of 50 to 60 gigawatts of older, inefficient coal plants within the next five to ten years, according to many Wall Street analysts who follow the industry. This represents a sizeable slice of a total coal fleet that totals approximately 340 gigawatts.

Replacing this capacity and upgrading other coal plants with emissions control technology offers the potential for extended strong rate base growth at regulated utilities. However, as is always the case in this most political of industries, maintaining healthy regulatory relationships will be a key to achieving reasonable returns for investors.

The sharp decline in natural gas prices in recent years has helped to moderate the rise in end-user rates required to finance the industry's elevated capital spending. While most analysts now predict that natural gas prices will remain low over the next few years, any significant uptrend has the potential to boost the fuel cost component of rates and renew the more confrontational regulatory politics seen in some jurisdictions several years ago, when power prices were forced upward by surging natural gas prices.

Political Strengths

However, utilities have important political strengths as well. Their capital investment programs are a source of high-quality jobs and they are often among the largest employers in a given state. In an economy burdened by chronically high unemployment and considerable nervousness about job stability — even among those who are employed — regulators, utility managements, company employees and local communities all agree that financially healthy utilities and the good jobs they offer serve everyone's best interest. Nevertheless, the judicious management of regulatory relationships will likely be among the most important factors in achieving success for shareholders and all stakeholders in the years ahead.

No Longer Undervalued

By late in the year, most industry analysts were commenting that utility price earnings multiples had climbed above their historical average levels and that the undervaluation evident earlier in the year had largely disappeared. However, with interest rates as low as they are and the risk of a return to broad economic weakness still very much in play, there was a general sense of confidence that the sector's capital investment growth potential and strong dividend yields offer a floor of support for its stock prices, especially if the economy should suffer renewed weakness.

The situation for competitive power providers was less certain. While few analysts were willing to call the bottom for competitive power — and indeed earnings for many will likely decline over the next several years as higher-priced hedges roll off — some suggested that the grinding bear market may bottom in 2011. The year will bring additional clarity from the EPA about new regulations for a wide range of emissions, which in turn will offer insights about the magnitude of needed coal plant retirements and the industry's strategy for replacing this capacity — likely emphasizing natural gas generation. PJM's May 2001 capacity auction for the 2014/2015 year was widely cited as a key indicator of any potential power market turnaround. But a solid earnings recovery likely remains several years in the future.■

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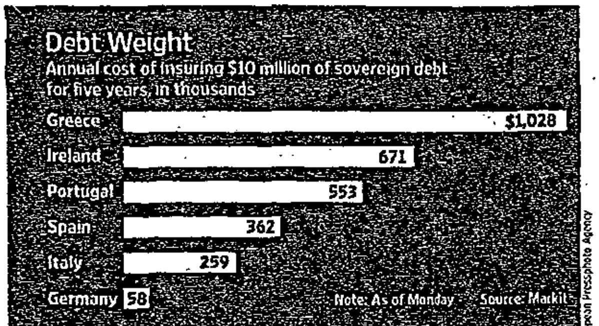


Prime Minister Jose Socrates

't of Call in Crisis

Growth in 2011 will be restrained by tightening measures totaling 4% of GDP; even the Portuguese government's 0.2% growth forecast looks ambitious. Meanwhile, Portugal's current-account deficit is only slowly edging down. Ultimately, Portugal may simply run out of time to convince investors, with unsustainable financing costs forcing it to seek aid.

Europe missed a trick by not bailing out Portugal when it helped Ireland, although it would have required the government to ask for aid. The same mistake shouldn't be repeated. Ideally, any Portuguese bailout would be accompanied by measures to stop the crisis spreading to Spain. These could include increased bond purchases by the European Central Bank; a credible plan for recapitalizing European banks; and an increase in euro-zone lending facilities to cope with any possible request for help. Citigroup recommends a €2 trillion ($2.6 trillion) bailout fund, with a vastly increased role for the ECB.

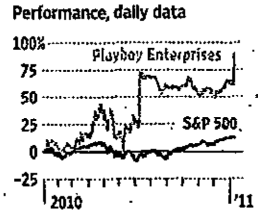
Portugal's next challenge is Wednesday, with a €1.25 billion bond auction. Poor auction results will raise the odds of a bailout. But Europe should be working on an answer that goes beyond Portugal.

—Richard Barley

er Will Work on Playboy in Private

Rabbit, Run

Performance, daily data



Source: WSJ Market Data Group

summer, this is no lowball bid. It implies a roughly $300 million enterprise value, nearly 20 times RBC Capital Markets' estimated 2010 earnings before interest, taxes, depreciation and amortization but after programming expenses.

Playboy's magazine and TV businesses have been in free fall, undercut by competition from the Internet. Revenues for the first three quarters of 2010 were 37% lower than in the same period in 2007. Only licensing has been stable.

Rizvi and its investors, which along with Mr. Hefner are putting up equity of more than half the deal's value, will have a majority stake. Earning a decent return depends on continued expansion of Playboy's brand licensing efforts.

RBC analyst David Bank projects licensing revenue nearly doubles by 2013, which could translate to total Ebitda of $42.6 million. As Mr. Bank notes, applying the eight-times forward multiple at which Iconix Brand Group is trading would then imply an enterprise value of $341 million—surely not enough for Rizvi. That suggests this is at least a five-year turnaround. By then, even Mr. Hefner may be running out of energy.

— Martin Peers

OVERHEARD

It isn't just investors being taught a lesson by the slump in education stocks. After **Strayer Education** reported a 20% fall in winter-term new-student enrollment, one analyst lamented it isn't just the sector with an overcapacity problem. With declining deal flow and trading revenue, the sector looks over-covered by Wall Street. Some 22 analysts cover industry bellwether **Apollo Group**. Yet FactSet data show the leading firm in the similarly sized health-care-supplies sector, **Dentsply International**, is covered by just 10.

* * *

Going public is no picnic. Just four U.S. retail companies had initial public offerings in 2010, accounting for 2% of the $35.7 billion in total volume, says Dealogic. So it's little surprise **Crumbs Holdings** is trying the backdoor. The fast-growing cupcake retailer said Monday it plans to sell itself to a special-purpose acquisition company that will rename itself Crumbs Bake Shop and trade on Nasdaq. After **Krispy Kreme's** spectacular rise and fall, investors should beware gorging on cupcakes.

The Latest Energy Deal Lacks Spark

Hearing utility executives talk about merger synergies is a bit like watching paint dry—except that paint sticks.

Concerns that any savings from the merger of Duke Energy and Progress Energy will be clawed back by state regulators largely explains why Monday's deal hit both stocks.

Based on the midpoint of guidance, nonfuel deal synergies are worth about $2 billion after tax, assuming some up-front costs. If regulators hand half those gains to bill payers, Duke's shareholders should still accrue almost 50 cents a share in value. Yet Duke stock fell 20 cents. As this is an all-stock deal, Progress also fell.

Discounting all potential synergies, and more, is harsh. With overlap in the Carolinas, there is scope to cut costs. And extra savings on fuel, which can be passed on to customers, could earn grace with regulators. A larger, more-diversified utility also should enjoy a lower risk premium.

Such benefits, though, are hazy. Moreover, Duke's claim that the combined group will increase earnings per share by 4% to 6% annually in the long term looks ambitious. And the company has yet to issue guidance even for 2011. "This merger, if successful, will defend their growth aspirations, not enhance them," is how Greg Gordon, chief utilities analyst at Morgan Stanley, put it.

The stocks face another, paradoxical headwind: hope. Regulated utilities, with high, stable dividends, often are treated as bond proxies, a big reason for outperforming other utilities since early 2009. As broader optimism rises, however, so should debt yields, making regulated utility stocks relatively less attractive. Making them sexy again won't be easy when even a $13.7 billion merger doesn't set pulses racing.

—Liam Denning

ATTACHMENT C

BARCLAYS CAPITAL

Utilities

POWER & UTILITIES
Utilities

SECTOR VIEW

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Capital Management

The capital cycle that began in 2007 continues for regulated utilities, as aging infrastructure and government policies dictate material upgrades and investment in the system. In this report, we review the scale and scope of spending over the next 5 years. We also analyze patterns from past capital and business cycles in an attempt to provide some tools to identify investment themes.

- We estimate that regulated utilities will spend more than $300 billion of Cap-ex between 2009 and 2013. This represents approximately 2x depreciation and amortization, and is down only 2% from last year's survey in spite of the current recession.
- This investment should continue to cause an elevated number of rate case filings. We expect 60 rate case filings in the next 18 months. We also estimate over $100B of external capital needs, including $20B of equity over the next 5 years.
- In the short term, investors have been attracted to regulated utilities as confidence in the economy has been tested. At this point in the business cycle, the highest quality regulated stocks look fully valued, and we would therefore recommend smaller-cap utilities that carry a little more risk, but represent better relative value. CMS, DPL, and NVE are our favorites.
- In the intermediate term, rate cases and equity issuance schedules should present some of the best catalysts for utility investment. We like AEP over this time period due to its completed equity issuance and resolution of its most significant rate case matter in Ohio.
- In the long term, we like companies that can best manage the execution, rate recovery, and financing risks associated with large investment programs. We like WEC most among this group.

July 16, 2009

PLEASE SEE ANALYST(S) CERTIFICATION(S) ON PAGE 96 AND IMPORTANT DISCLOSURES BEGINNING ON PAGE 97

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ATTACHMENT D - 3

Capital Management in the Capital Cycle

We are in the third year of the infrastructure build cycle for regulated utilities that began in 2007. Based on our 2009 capex survey, we now anticipate that the industry will proceed with a pre-dividend free cash flow deficit through at least 2013, but likely significantly longer. We estimate over the next five years, the industry will spend on average 2.0x its annual depreciation and amortization expense growing industry rate base at an average annual pace of 6.3%.

We expect that the risks of this build cycle will offset much of the growth opportunity in share performance through the construction period. This is consistent with the investor experience in the last major infrastructure cycle which extended from 1973–1984. The headwinds we forecast will likely come from the dilutive effect of heightened external capital funding requirements, regulatory risk in a rising rate environment and execution risk associated with a significant construction program. The best performing stocks over the cycle will likely be those spending on infrastructure with the highest public policy support, with the highest quality balance sheets, doing business in the best regulatory jurisdictions.

This report updates: 1) our recommendations and investment strategy, which we believe will maximize shareholder returns over the short, intermediate, and long term; 2) our latest estimates of the drivers and size of the investment ahead; 3) our examination of the business consequences and cost of capital implications for the build cycle from the 1970s and the parallels to today; 4) our analysis of utility regulatory jurisdictions; and 5) our review of the pending rate matters for our coverage universe.

Recommendations and Investment Strategies

We break our views on the group into three time periods: the long term (i.e., the duration of the capital cycle), intermediate term (i.e., one to two years), and short term (i.e., the next six to 12 months.)

In the long term, structural headwinds should persist for regulated utilities, owing to risks associated with capital acquisition, construction execution, and regulatory recovery in a rising rate-base environment. The bulk of this report is focused on these long run trends. As a result of these trends, we would be owners of the most constructive regulatory jurisdictions, the strongest balance sheets, and most capable managements. We acknowledge, however, that many of the names that fit this description are pricey at the moment, following a year of investor defensiveness and caution. One from the group that we believe does screen attractively is Wisconsin Energy (WEC). We like WEC due to solid management, consistent Wisconsin regulation, and the earnings and rate base growth it should derive from its Oak Creek plant that is in the final stages of construction. Additionally, WEC is one of three regulated utilities we expect to be pre-dividend free cash flow positive over the next several years.

In the intermediate term, we are looking for potential catalysts around rate case filings and equity issuance schedules. Given that AEP has essentially concluded its Electric Security Plan in Ohio, set its guidance based on trough dark spread margins for off-system sales, and has cleared its equity issuance needs for the foreseeable future with a $1.7B offering in April, we like its positioning relative to the regulated group.

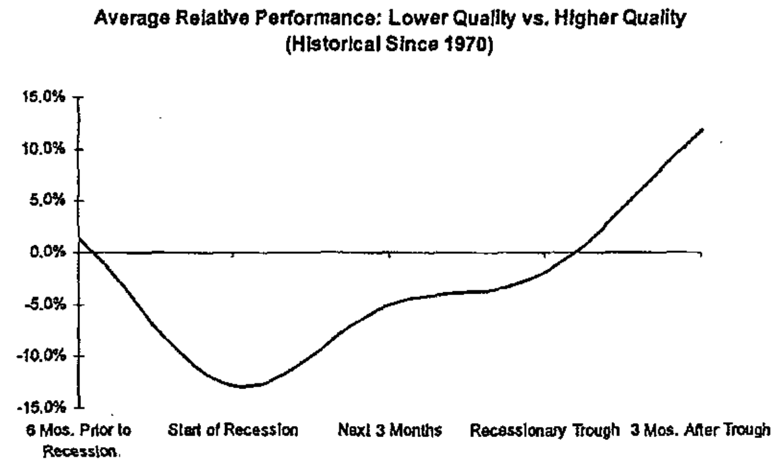
In the short term, we believe the investment winners will be driven by macro fund flows in support of fundamentals. Based on the precedent of previous recessions, higher quality utility names with good liquidity attract investors during the earlier stages, and as the recession matures, investors move out the risk curve to smaller- and mid-cap names that are less liquid. The reasons for this are two-fold: investors add risk as the economy recovers to better participate in the upswing, and the early-stage bid that goes to the highest quality names also creates a relative pricing disparity that allows the smaller less liquid utilities to represent better value. We recommend CMS, DPL, and NVE among this smaller-cap group.

The Short Term: Recessions Drive a Quality Trade

As we have seen, when the economy enters a recession, investor funds tend to migrate toward regulated utilities. Further, in the early throes of recession, the funds flow into higher quality regulated utilities versus lower tier regulated utilities. Higher quality names would be characterized by defensive qualities identified as superior credit access (higher credit ratings), secure and growing dividends, located in supportive regulatory districts, and exhibiting superior trading liquidity for ease of entry and exit. The utilities we classify as higher quality would be DUK, ED, NST, PCG, PGN, SO, WEC, and XEL. As a group, these high quality stocks outperformed the lower tier universe by 21% from 6 months prior to the recession's beginning to the March trough.

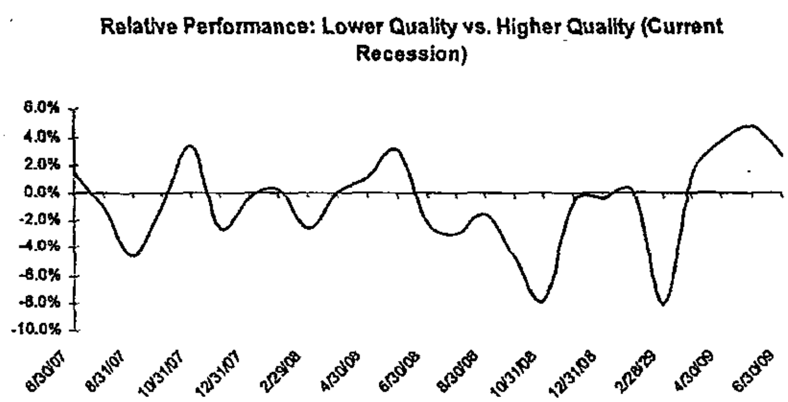
On a broader look at past recessions, this pattern also holds. The higher quality / lower tier pairing has produced on average 18% returns beginning 6 months prior to the recession through the recession's trough. This performance is the average of the recessions since 1970. Conversely, as the market perceives an economic recovery, lower tier names begin to outperform higher quality names. In the recessions since 1970, lower tier utilities outperformed higher quality by 22% from trough to 6 months post-recession, while outperformance of the lower tier in the current recession is about 12% through June 2009 from March.

Figure 1: High Quality Outperforms Heading Into Recessions; Trails Heading Out



Source: FactSet, Barclays Capital estimates.

Figure 2: Lower Quality Names Recently Starting to Outperform



Source: FactSet, Barclays Capital estimates.

At this point, and in spite of lower tier performance since March, a significant valuation gap persists, favoring smaller, less liquid names.

Figure 3:Relative Valuations Higher Quality vs. Lower Quality

Group	2010 P/E	Current P/BV	Dividend Yield	Payout Ratio
Higher Quality	11.6x	1.5x	5.3%	65.3%
Lower Quality	10.7x	1.2x	5.6%	64.0%

Source: FactSet, Barclays Capital estimates.

The Intermediate Term: Rate Case Timing and Equity Needs Provide Catalysts

Continued FCF Deficits Will Require Equity / Rate Cases

Based on the capex survey we have performed associated with this report, we continue to see net free cash flow deficits for the group well into next decade (see Figure 4). In fact, the biggest surprise in this year's survey was the fact that spending only came down 2% versus our 2008 work for overlapping years. As a result, the significant capital raising appetite shown by the group in 2009 year-to-date appears to be just the tip of the iceberg. In order to maintain current debt/cap ratios, we anticipate that the regulated utility group will need to raise at least $100 billion in debt and equity to complement retained earnings over the next five years.

Figure 4: Capex Forecast Changes, y/y

($ in millions)

	2008E	2009E	2010E	2011E	2012E	Total
2006 Estimates	$39,129	$37,588	$37,053	n/a	n/a	n/a
2007 Estimates	$52,714	$51,745	$51,881	n/a	n/a	n/a
2008 Estimates	$61,338	$60,472	$61,102	$63,350	$62,301	$308,562
2009 Estimates	$63,335	$58,144	$59,819	$62,057	$63,282	$306,637
% Increase ('09 v. '06)	61.9%	54.7%	61.4%	n/a	n/a	n/a
% Increase ('09 v. '08)	3.3%	-3.8%	-2.1%	-2.0%	1.6%	-0.6%

Source: Barclays Capital estimates, company filings.

Figure 5: Forecasted Cash Flow and Capital Needs

Capital and Cash Flow Projections
Shareholder Owned Regulated Utilities
($ in millions)

	2008P	2009E	2010E	2011E	2012E	2013E
Debt	$320,507	$337,471	$356,002	$374,239	$389,850	$402,079
Equity	$252,380	$267,282	$281,748	$296,722	$311,595	$326,117
Total Capital	$572,887	$604,753	$637,750	$670,961	$701,446	$728,195
Equity %	44%	44%	44%	44%	44%	45%
Cash from Operations	$45,550	$46,730	$48,197	$51,148	$56,013	$59,853
CapEx	($63,335)	($58,144)	($59,819)	($62,057)	($63,282)	($62,527)
Dividends	($10,879)	($11,205)	($11,541)	($11,888)	($12,244)	($12,611)
Free Cash, Post Div.	($28,664)	($22,619)	($23,164)	($22,797)	($19,514)	($15,285)
Debt Issued (Retired)	$22,931	$16,964	$18,531	$18,237	$15,611	$12,228
Equity Issued (Retired)	$5,733	$5,655	$4,633	$4,559	$3,903	$3,057
Assumptions / Drivers						
Retained Earnings Growth	9.5%	7.1%	6.3%	5.9%	5.3%	4.5%
Cash from Operations Change		2.6%	3.1%	6.1%	9.5%	6.9%
CapEx Change	14.4%	-8.2%	2.9%	3.7%	2.0%	-1.2%
Dividend Growth	3.0%	3.0%	3.0%	3.0%	3.0%	3.0%
Proportion Returned to (Drawn from) Debt	80%	75%	80%	80%	80%	80%
Proportion Returned to (Drawn from) Equity	20%	25%	20%	20%	20%	20%

Note: Figures reflect Barclays Capital utility coverage scaled up by a factor of 1.08x to reflect companies not in Barclays coverage universe.

Source: Company filings, Barclays Capital estimates.

The following table takes a company by company look at our estimate of equity needs.

Figure 6: Projected Equity Issuance Schedule

		Amount & Year of Issuance ($ in millions)				
Company	**Ticker**	**2008**	**2009E**	**2010E**	**2011E**	**2012E**
Alliant Energy	LNT	1		0	350 (1)	
Ameren Corp.	AEE	154	100	100	100	500 (1)
American Electric Power	AEP	159	691 (1)	150	150	150
CMS Energy Corp	CMS	9	173 (1)			
Consolidated Edison	ED	51	400 (1)	550 (1)	550 (1)	400 (1)
Dominion Resources Inc	D	240	600	400	250	250
Duke Energy Corp	DUK		360	150	300	300
FPL Group Inc	FPL	41	403 (1)	200	500 (1)	500 (1)
Great Plains Energy	GXP	15	432 (1)			
Hawaiian Electric Indust.	HE	136	0	45	45	45
NiSource Inc	NI	1	60			
Northeast Utilities	NU	6	370 (1)		350 (1)	
NV Energy	NVE	6		150 (1)		
PG&E Corp	PCG	225	225	400	150	150
Pinnacle West Capital	PNW		25	300 (1)	25	25
Pepco Holdings	POM	316	29	300 (1)	350 (1)	100
Portland General	POR		175 (1)			
Progress Energy	PGN	132	469 (1)	300	300	300
Public Service Entrp Group	PEG	0				
Sempra Energy	SRE	18	23	23	23	23
Southern Co	SO	474	500	600	600	600
TECO Energy Inc	TE	22	25	25	25	25
Westar Energy	WR	294			60	
Xcel Energy	XEL	353	75	75	75	75
Total		**$3,265**	**$6,494**	**$3,768**	**$4,203**	**$3,443**

(1) Represents actual or estimated marketed offerings, as opposed to DRIP or dribble programs.

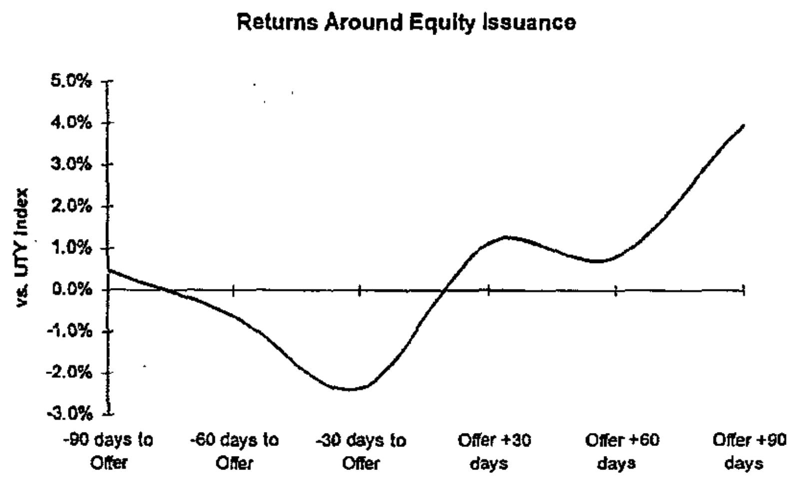
Note: Gray cells indicate actual amounts issued

Source: Company filings, Barclays Capital estimates.

ATTACHMENT D - 9

As an investment tool, these issuance events provide meaningful catalysts to performance. When the market anticipates an equity need, the stock will tend to underperform the group. In contrast, once the equity issuance has occurred and the new shares have been digested by investors, the median stock will outperform the group. Financing needs having been met, and balance sheets shored up provide more than ample reason to justify this behavior. Figure 7 shows the value of this catalyst in light of the issuance-heightened environment for the last 12 months.

Figure 7: Stocks Perform Well Once Equity Has Been Cleared

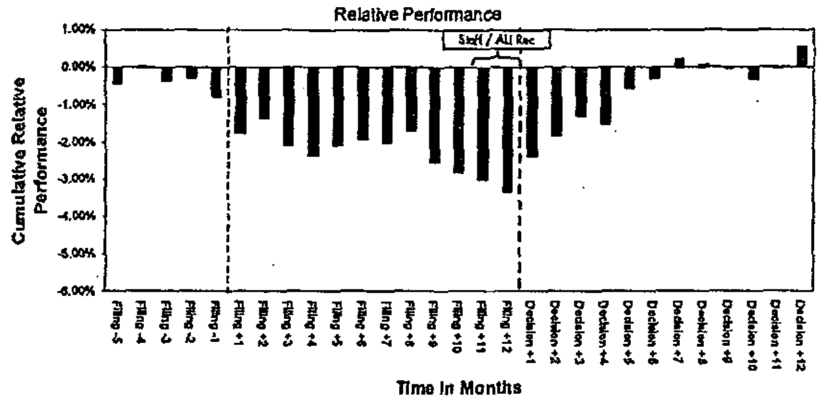


Source: FactSet.

Rate Cases Provide Trading Opportunities

Also during a capital cycle, tactical opportunities will develop around rate case timing, since rate case filings tend to cause uncertainty around future earnings. As a result a risk premium is attached to utility stocks whose subsidiaries are anticipated to file a rate case or are in the rate case process. As the rate case process moves forward, more and more clarity begins to develop around the parameters of a potential order. Once the staff recommendation is released the likely worst case scenario can be understood and once the ALJ recommendation is made, the final parameters of an order can be closely estimated. From this point forward the higher risk premium created as a result of rate case uncertainty abates. This tradable phenomenon is shown in Figure 8.

Figure 8: Relative Performance and Rate Case Timing

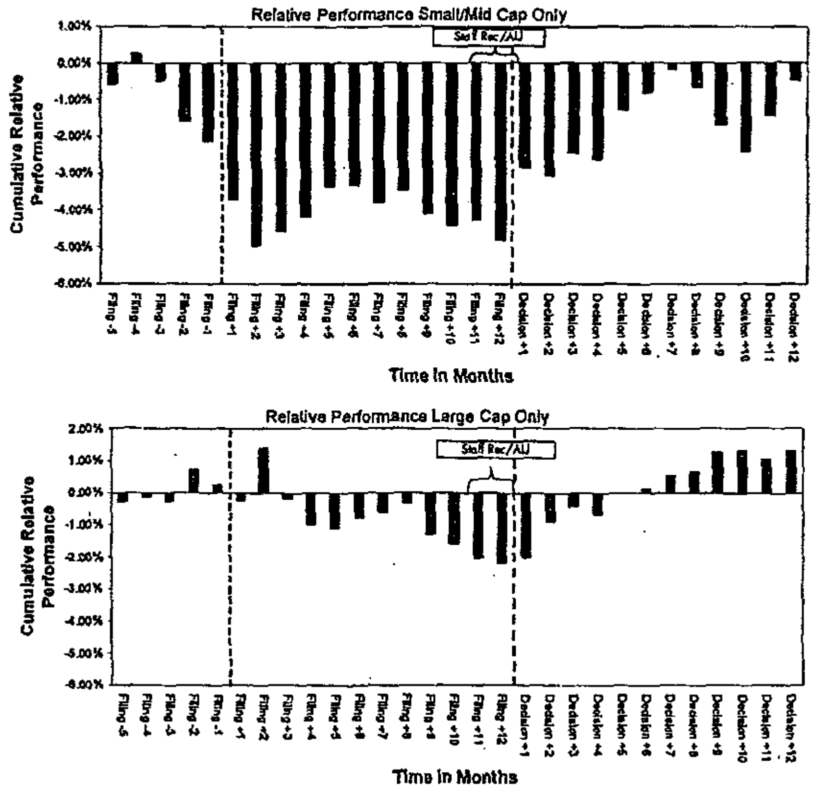


Source: SNL Financial, Bloomberg, Barclays Capital estimates.

All else equal, if an investor shorts a stock four months prior to a rate case filing through the time of the ruling he/she should outperform the regulated group by 334 basis points (bp), on average. If in turn that same investor then buys the utility 12 months after the rate case filing through 12 months after the decision he/she should earn, on average, an additional 388 bp relative to the regulated group. It is important to note that this analysis last year showed relative returns of 398 bp and 644 bp, respectively. The returns from the trade were dampened as a result of 2008 being a very volatile year in which broader systemic risks drove the market more than any company specific risk such as rate cases. As the market moves toward a more "normal" environment across the intermediate term, and away from trading around broader systemic risks and fund flow dynamics in the short run, we would expect this trade's effectiveness to improve.

Given that most small-cap regulated utilities are only single or dual jurisdictional and most large-cap regulated utilities are multi-jurisdictional the risk premium during a rate case should be larger for smaller-cap utilities.

Figure 9: Rate Cases and Relative Performance by Cap Size



Source: SNL Financial, Bloomberg, Barclays Capital estimates.

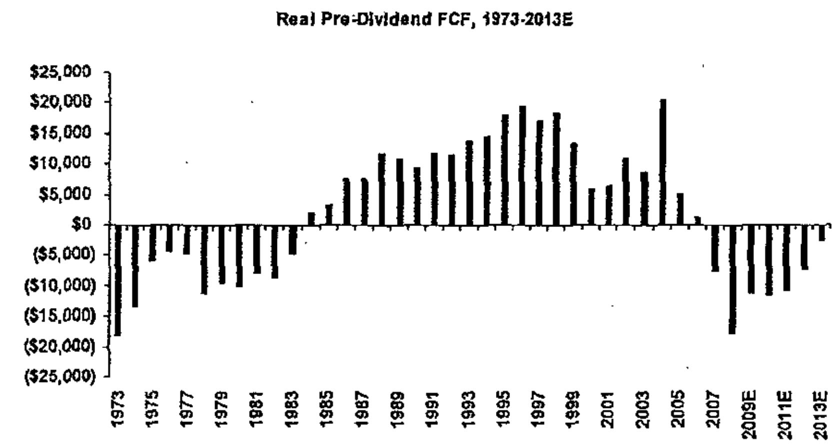
This is in fact the case, as shown in Figure 9. The trading returns from the same general "short-then-long" strategy as described above is 480 bp and 433 bp for small cap utilities and 221 bp and 353 bp for large cap utilities. Before the systemic-risk-driven market of 2008, for the same strategies, our study showed excess returns of 916/828 bp and 266/532 bp for small- and large-cap utilities, respectively.

The Long Term: Secular Headwinds Still In Place

In our estimation, the regulated utility group entered a capital cycle beginning in 2007 characterized by pre-dividend FCF deficits. These negative cash flows exacerbate risks related to execution, financing, and regulation, leading to our more negative view of the group in the longer term.

As we've noted, aggregate pre-dividend free cash flow for the regulated utilities space turned negative in 2007. Figure 10 highlights the changes in FCF dating back to 1973, in 2008 dollars and includes our estimate of the deficits we anticipate through 2013.

Figure 10: Pre-Dividend FCF throughout Capital Cycles, in 2008 $

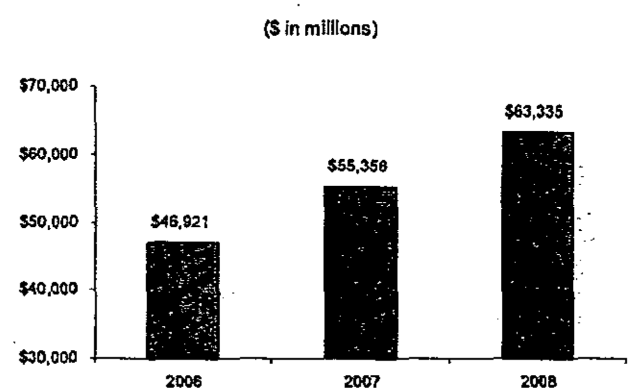


Source: FactSet, Barclays Capital estimates.

The current cycle is marked by four drivers: 1) an aging post-war infrastructure, 2) environmental policy forcing upgrades to old plant and equipment, 3) the implementation of new technologies (e.g., solar, wind, and smart grid), and 4) the addition of new transmission to account for renewable energy hook-ups and improved system redundancy. Due to the very extensive public policy drivers to this build, we estimate it could ultimately last as long as or even exceed the '73 to '84 experience.

As shown in Figure 11, we estimate that capex rose 14% for regulated utilities in 2008. That marked the second year of exceptional growth in spending.

Figure 11: Three Year Historical CapEx



Source: Company filings, Barclays Capital estimates.

We expect this trend to flatten in 2009, as recessionary pressures coupled with prohibitively expensive – or inaccessible – external capital, has led some utilities to cancel or defer spending on growth-oriented projects. At the Edison Electric Institute conference in Arizona last November, several companies announced a first round of cuts that averaged between 10%-15% versus previous levels. In the final tally, however, spending projections for 2009 are estimated to be about 8% lower than our 2008 figures. More surprisingly, the comparison of capital spending plans for overlapping years of our 2009 vs 2008 survey were only down 2%. We can only conclude that relatively little of the group's spending is discretionary (see Figure 12).

Figure 12: CapEx Forecast by Type of Spending

Capital Expenditure Projections
Shareholder Owned Regulated Utilities
($ in millions)

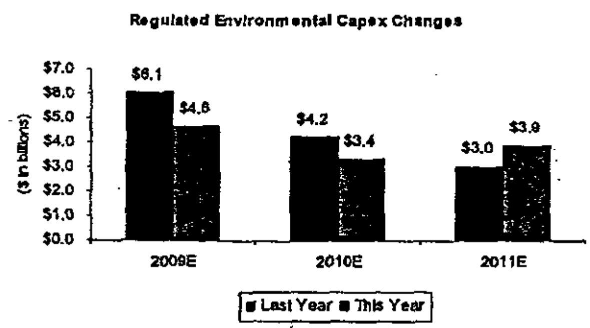
	2006	2007	2008	2009E	2010E	2011E	2012E	2013E	Total
Maintenance / Distribution				$28,950	$31,654	$32,601	$35,390	$36,760	$165,354
Generation				15,855	13,620	13,062	12,518	12,190	$67,246
Enviromental				4,644	3,359	3,886	2,218	2,278	$16,384
Transmission				8,685	11,187	12,508	13,167	11,299	$56,845
Total	$48,921	$56,356	$63,335	$58,144	$59,819	$62,057	$63,282	$62,527	$305,829
Y/Y Increase		18.0%	14.4%	-8.2%	2.9%	3.7%	2.0%	-1.2%	

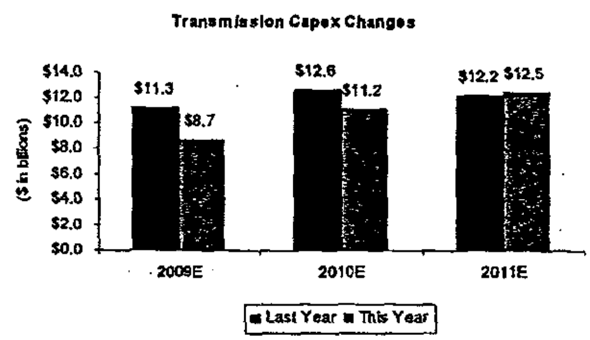
Note: Figures reflect Barclays Capital utility coverage scaled up by a factor of 1.08x to reflect companies not in Barclays coverage universe.

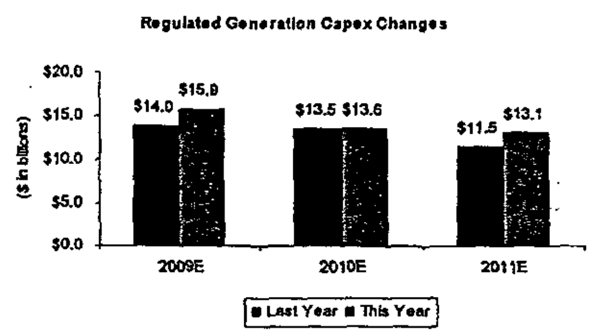
Source: Company filings, Barclays Capital estimates.

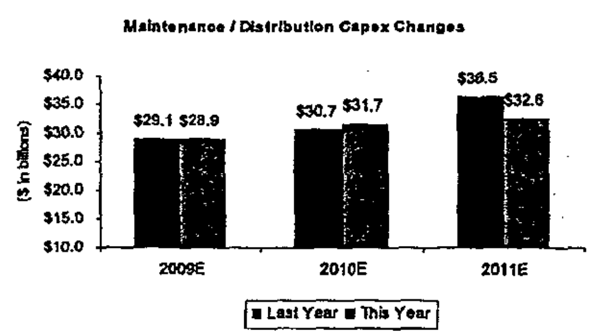
A breakdown in the categories of spending is contained in Figure 13. On a year over year survey comparison, the largest declines appear in regulated environmental spending, and in transmission. The regulated environmental spending reduction is a result of improvements in the effectiveness of coal pollution control programs as the spending nears its conclusion. The decline in transmission is largely the result of permitting delays, with the spending likely deferred, not eliminated. Strength in generation and distribution are largely related to renewable resources and automatic metering infrastructure.

Figure 13: Year-over-Year CapEx Forecast Changes









Source: Company filings, Barclays Capital estimates.

Despite the near-term drop in capex, the rate of spending still exceeds even the inflated spending that began in 2007. As a result of this level of spending, we are still seeing meaningful growth in rate base across the sector.

Figure 14: Rate Base Growth Projections

Shareholder Owned Regulated Utilities
($ in millions)

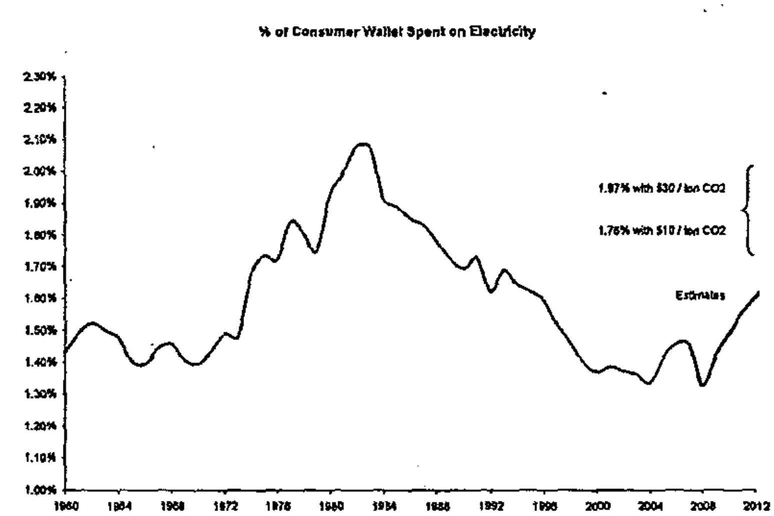
	2008	2009E	2010E	2011E	2012E	2013E
Rate Base	$452,887	$492,335	$524,266	$555,480	$586,449	$616,113
Capital Expenditures	$63,335	$58,144	$59,819	$62,057	$63,282	$62,527
D&A	$23,887	$26,213	$28,605	$31,088	$33,619	$36,120
Rate Base Additions	$39,448	$31,931	$31,214	$30,970	$29,663	$26,407
Rate Base Growth %	9.6%	7.1%	6.3%	5.9%	5.3%	4.5%

Source: Company filings, Edison Electric Institute, Barclays Capital estimates.

What Happens to Consumer Costs?

An interesting side effect of the current recession is the relief it poses to what we've previously seen as an inexorable rise in prices to consumers. The good news is that the decline in fuel rates has created a soft spot where overall prices are unlikely to rise in 2009 or 2010 in spite of rate base growth. The bad news is that higher forward fuel prices, continued additions to rate base, and the potential for significant new costs from government environmental mandates (CO2) will likely force significant inflation next decade. Figures 15 and 16 track our forecasts for prices, Figure 15 as compared to consumer spending over the long run and Figure 16 showing the driving forces over the next 5 years.

Figure 15: Historical and Projected Price to Consumers



Source: EIA, Bureau of Economic Analysis, Barclays Capital estimates.

Figure 16: Projected Revenue Requirements

Actual and Projected Industry Revenues & Costs
($ in millions)

	2006	2007	2008	2009E	2010E	2011E	2012E	2013E
Industry Revenues	$328,506	$343,703	$365,355	$365,355	$365,741	$351,431	$382,382	$408,022
Plus: Incremental Fuel				($14,372)	($25,882)	$18,103	$13,267	$11,308
Plus: Incremental Environmental				$1,164	$841	$794	$428	$399
Plus: Incremental Transmission				$2,180	$2,138	$2,558	$2,537	$1,979
Plus: Incremental Generation				$3,975	$2,601	$2,669	$2,414	$2,135
Plus: Maintenance & Distribution				$7,439	$6,195	$6,828	$6,995	$6,600
Incremental Revenue Addition				$386	($14,309)	$30,951	$25,640	$22,420
New Projected Revenue Base	$328,506	$343,703	$365,355	$365,741	$351,431	$382,382	$408,022	$430,443
% Revenue Increase	9.6%	5.3%	6.3%	0.1%	-3.9%	8.8%	6.7%	5.5%
Total GWh Base	3,660,969	3,669,919	3,764,561	3,721,562	3,609,915	3,653,234	3,707,634	3,762,845
Barclays Demand Forecast	0.2%	2.6%	-1.1%	-3.0%	1.2%	1.5%	1.5%	1.5%
Total GWh Used	3,669,919	3,764,561	3,721,582	3,609,915	3,653,234	3,707,634	3,762,845	3,818,877
Nominal $ / MWh Price	$88.97	$91.30	$98.17	$101.32	$96.20	$103.13	$108.43	$112.71
% Nominal Increase	13.8%	2.6%	7.5%	3.2%	-5.1%	7.2%	5.1%	3.9%

Source: EIA, Edison Electric Institute, Barclays Capital estimates.

Regulatory Implications of a Capital Cycle

The current capital cycle is resulting in these negative long-term regulatory trends mimicking the 70's capital cycle:

1) An increase in the frequency of rate cases as companies attempt to recover the capital they are spending on a timelier basis;

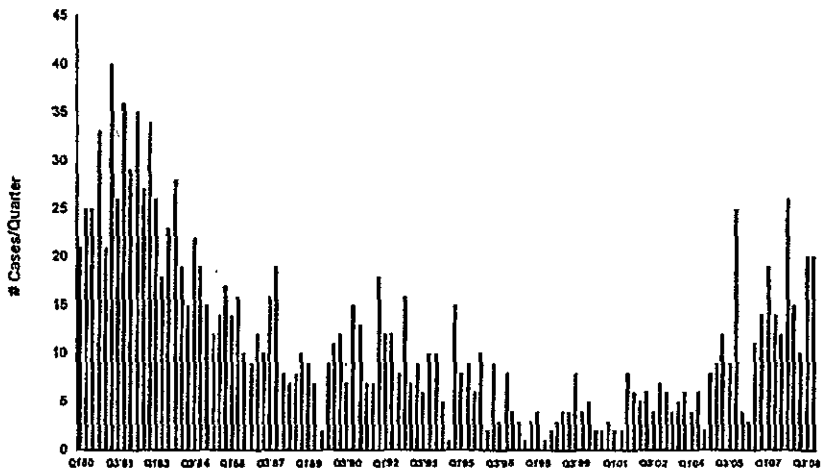
2) A squeezing of spreads–as in the face of large and frequent rate increase requests, regulators tend to scrutinize allowed ROEs for excess returns; and

3) An expansion in Regulatory lag, the gap between authorized returns and earned returns.

Frequency of Rate Cases on the Rise

Due to the cap-ex outlined above, we expect the industry to continue a busy schedule of rate cases in the near term. In fact, rate cases may increase if managements recognize the window of opportunity to raise base rates while potentially lowering customer's bills as a result of a reduction in fuel and purchased power pass through costs. We forecast 60 rate cases over the next 18 months, which includes 24 to be decided by year-end 2009 and 36 to be decided thereafter.

Figure 17: Historical Quarterly Number of Rate Cases



Source: SNL Financial, Federal Reserve, Barclays Capital estimates.

A historical summary of the last 17 years of rate case outcomes is shown in Figure 18.

Figure 18: Rate Case Statistics

Date	Electric: Allowed Return on Equity (%)	# of Electric Rate Cases	Gas: Allowed Return on Equity (%)	# of Gas Rate Cases
2009 1Q	10.53	10	10.24	4
2008	10.33	33	10.39	32
2007	10.31	37	10.23	34
2006	10.45	26	10.40	13
2005	10.54	29	10.36	21
2004	10.88	19	10.63	22
2003	10.98	18	10.95	23
2002	11.22	11	11.09	17
2001	11.12	10	10.96	5
2000	11.58	9	11.35	11
1999	10.65	5	10.74	6
1998	11.91	9	11.51	10
1997	11.33	10	11.31	10
1996	11.40	18	11.12	17
1995	11.59	26	11.44	13
1994	11.21	27	11.24	24
1993	11.48	26	11.37	37
1992	12.06	38	11.99	26

Source: SNL Financial

Return Spreads Tightening

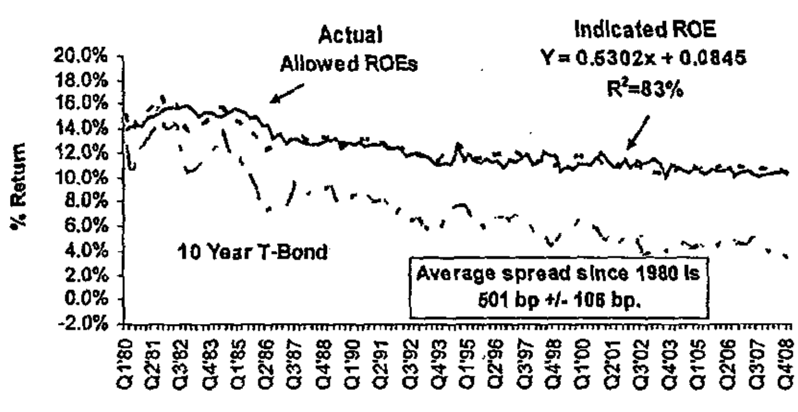
Figure 19: Average Rate Case Outcomes & Relationships, 2005-2009

Year	Allowed ROE	Yield on 10-Year Treasury	Spread (bps)	Yield on Moodys Baa	Spread (bps)
2005	10.54%	4.32%	622	6.08%	446
2006	10.45%	4.77%	567	6.47%	398
2007	10.23%	4.65%	557	6.52%	371
2008	10.35%	3.60%	675	7.40%	295
1Q09	10.22%	2.72%	750	8.23%	199

Source: RRA, SNL Financial.

As shown in Figure 19 the spreads of allowed ROEs to treasury yields tightened from 2005 to 2007 before widening again in 2008 and 2009. We believe this has more to do with the decline in treasury yields as a result of monetary policy versus any increase in allowed ROEs awarded by commissions. In fact, allowed ROEs, while rising slightly in 2008 have fallen back in 1Q09 to near 2007 levels. Moreover, when compared versus corporate bond rates, spreads to allowed ROEs have continued to tighten since 2005 and as the capital cycle began in 2007. Spreads of allowed ROEs to corporate yields have tightened from 446 bp in 2005 to 199 bp in 1Q09, a narrowing of 247 bp (55%). Overall, allowed ROEs are more correlated with corporate bond yields over time than with treasury yields.

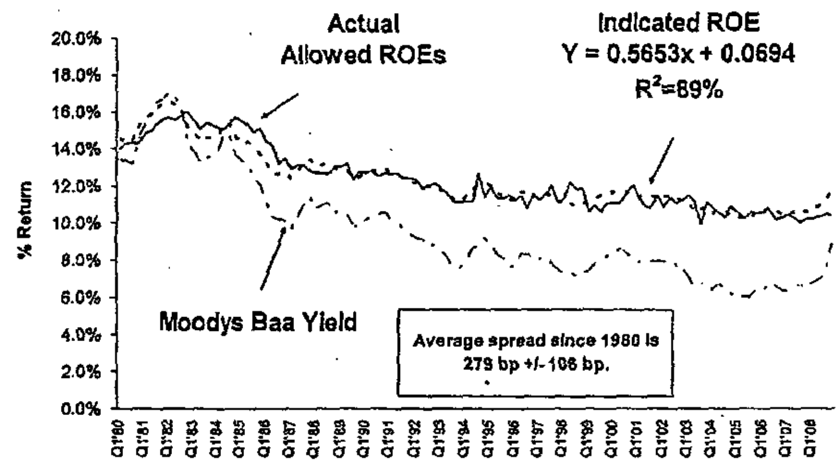
Figure 20: Allowed ROEs vs. 10 Year Bond Yields



Source: SNL Financial, Federal Reserve, Barclays Capital estimates.

In 1,359 cases since 1980 the average outcome has been 501 bp greater than the 10 year treasury yield with a standard deviation of 106 bp. Our regression analysis shows that applying a 0.5302 multiplier to the 10 year yield and adding 845 bp results in an R^2 of 83%. This would have implied a 10.39% allowed ROE in 2008 versus the actual allowed ROE of 10.35%.

Figure 21: Allowed ROEs vs. Corporate Bond Yields



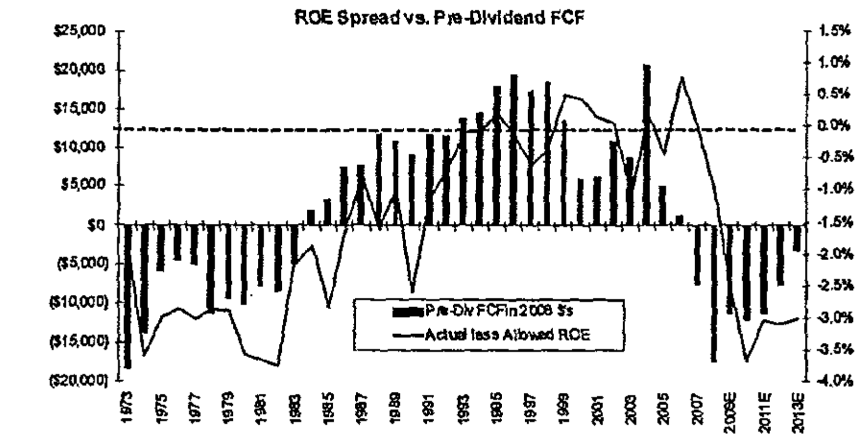
Source: SNL Financial, Federal Reserve, Barclays Capital estimates.

In the same period since 1980 the average outcome for allowed ROEs has been 279 bp higher than the Moody's Baa Corporate Yield with a standard deviation of 106 bp. Our regression analysis shows that applying a factor of 0.5653 to the corporate bond yield and adding 694 bp results in an R^2 of 89%. This would have implied an allowed ROE of 11.94% in 2008 versus the actual ROE of 10.35%.

Regulatory Lag on the Rise

During periods of rising capital expenditures and rate base as well as rising costs, utilities with historic test years cannot fully recover those rising costs over time. That is, during periods of free cash flow deficits, revenues meant to offset depreciation, capital, and operating costs, for utilities with historic test years are often delayed versus the actual incurrence of these costs due to the review process. Figure 22 shows the historical relationship between regulatory lag and pre-dividend free cash flow. We have adjusted pre-dividend free cash flow to be presented consistently in 2008 dollars using the GDP deflator.

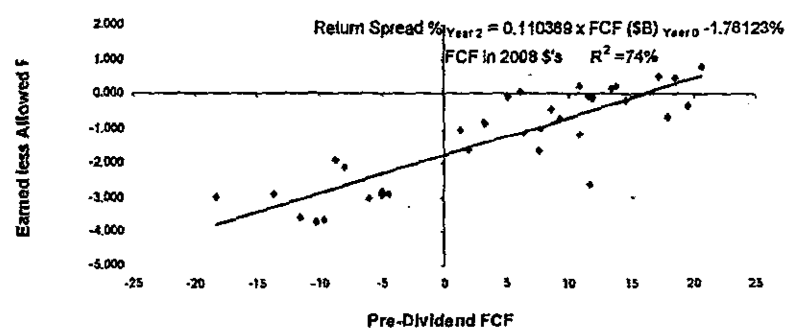
Figure 22: Regulatory Lag Throughout Capital Cycles, Historical & Projected



Source: FactSet, Edison Electric Institute, SNL Financial, Federal Reserve, Barclays Capital estimates.

The relationship, with a two year lag between the pre-dividend FCF and the ROE gap, has been well correlated with an R^2 of 74%. Our regression analysis is shown in Figure 23.

Figure 23: Pre-Dividend FCF vs. ROE Spread



Source: FactSet, Edison Electric Institute, SNL Financial, Federal Reserve, Barclays Capital estimates.

This relationship indicates that utilities earn 176 bp below their allowed returns two years hence from a breakeven FCF. Each $1 billion in FCF variance alters this regulatory lag by approximately 11 bp. We project negative but improving FCF deficits versus 2008 in 2009 through 2011, and another improvement in 2012 and 2013. This would lead to projected earned ROEs between 7.5% and 8.0% through 2013. Correcting for the average discrepancy between our projections and actual ROEs since 2005 of 73 bp would lead to projected earned ROEs of between 8.2% and 8.75%.

Figure 24: Historical and Projected ROEs

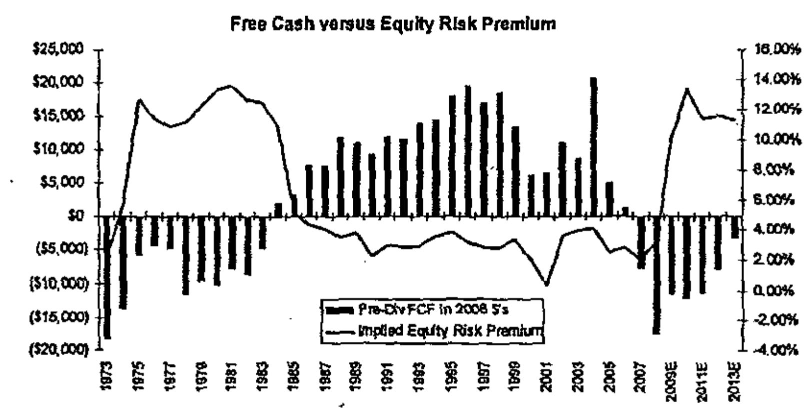
	2005A	2006A	2007A	2008A	2009E	2010E	2011E	2012E	2013E
Pre-Dividend FCF	$4,731	$1,250	($7,128)	($17,605)	($11,953)	($12,206)	($11,394)	($7,753)	($3,361)
Projected Allowed ROE	10.50%	10.38%	10.23%	10.35%	10.56%	11.18%	10.97%	10.79%	10.60%
Projected Over- (Under) Earn	-0.63%	0.07%	-1.24%	-1.62%	-2.55%	-3.70%	-3.04%	-3.11%	-3.02%
Projected Earned ROE	9.83%	10.45%	8.99%	8.73%	8.01%	7.48%	7.94%	7.68%	7.58%
Actual ROE	10.05%	11.16%	10.17%	9.34%	8.74%	8.19%	8.07%	8.41%	8.31%
Discrepancy	-0.41%	-0.71%	-1.18%	-0.62%	-0.73%	-0.73%	-0.73%	-0.73%	-0.73%

Source: FactSet, Edison Electric Institute, SNL Financial, Federal Reserve, Barclays Capital estimates.

The Capital Cycle Could Cause Risk Premiums to Rise

As FCF deficits have increased, this has in turn increased balance sheet strain, regulatory scrutiny, and execution risk. Investors may, as a result, demand a higher risk premium. We calculated the historical implied equity risk premium for the utilities sector as follows: Equity risk premium = earnings yield – 10-year bond yield (risk free rate). Figure 25 shows the historical FCF deficits or premiums adjusted into 2008 dollars using the GDP deflator and the equity risk premium.

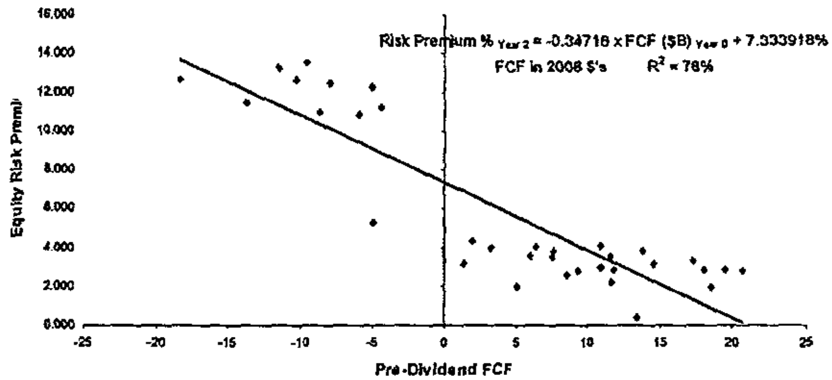
Figure 25: Risk Premiums Throughout Capital Cycles, Historical & Projected



Source: FactSet, Edison Electric Institute, SNL Financial, Federal Reserve, Barclays Capital estimates.

Regressing the equity risk premium versus pre-dividend FCF deficits, with a two year lag displayed a strong relationship with an R^2 of 78%, as shown in Figure 26.

Figure 26: Pre-Dividend FCF vs. Risk Premiums



Source: FactSet, Edison Electric Institute, SNL Financial, Federal Reserve, Barclays Capital estimates.

Based upon this regression relationship we would expect to see risk premiums spike to the area of 13.5% by 2010 versus the 3.17% seen in 2008, before moderating in the 11%–12% area from 2011 to 2013. Returns should move lower with the increase in equity risk premiums.

Know Thy Regulator

The increasing importance of regulatory lag and allowed returns throughout the capital investment cycle increases the value of a utility's governing regulatory district(s). Continuing the trend that we have seen historically, the more favorable regulatory districts (corresponding to lower costs of capital) are clustered in the Southeast and upper Midwest, while the more difficult jurisdictions (and higher costs of capital) are typically located in the desert Southwest and Northeast. We point to six key metrics that we believe best bound the risks inherent in particular jurisdictions, and correspond closely to the differences we see in the relative cost of capital from region to region. A more detailed differentiation of these metrics can be found below.

- Elected versus Appointed: Elected commissions have a greater incentive to be focused on end user prices above cost of capital. Appointed commissions have a buffer to the electorate and can act in a more judicial manner.

- Rules Mechanism: Having certain rules in place allows for more consistent, timely, and transparent regulation over time. Features we assess in this category are: Test Year Period, Fuel Clauses, Non-Fuel Spending Trackers, Statutory Decision Limits, Formal IRP Processes, CWIP vs AFUDC, and Decoupling mechanisms.

- Allowed ROEs: A ranking based on the last five rate case outcomes relative to 10-year Treasury levels. Included decisions go back as far as 15–20 years.

- Settle versus Litigate: Settlement often works out in a better outcome for all parties and consequently earns the state a better rating.

- Rate Levels: The higher the rate, on a relative basis, the greater the difficulty to raise it: lower absolute rates get a better ranking, as they are less prone to attract customer pushback.

- Subjective Investor Friendliness Rating: Based upon three main factors: a track record for reaching decisions that are well defended and within the bounds of testimony; staff reputation, professionalism, and influence; and ability to recognize and address emerging trends.

These six criteria are equal-weighted and receive a value of 1 to 2, with the smaller number representing a better ranking. In the Appendix we have provided our rating details, state commissioner and staff contact information.

While the broad geographical trends of constructive regulation and perceived investor friendliness continue to hold, we have seen some important positive developments in specific states that we think are worth noting. In each state there is a specific regulatory convention (or several) that can be pointed to as driving the significant change in the last year – such as Ohio (incorporation of fuel clause into regulatory scheme), California (bond index-based ROE tracker mechanism), Florida (constructive rate case outcomes in last six months, despite difficult economic conditions), New Mexico (passed a forward test year rule), and Michigan (forward test year, file and implement rules and pre-determination for large investments).

A Recap of State Rankings

We rank the FERC as "above tier 1" given its regulatory return allowance history, appointed nature, investor friendliness, and policy directive. In our 2009 ranking, the top six jurisdictions are Kentucky, Wyoming, Iowa, Idaho, North Carolina, and Florida. The bottom tier consists of New Mexico, Montana, Arizona, Connecticut, Rhode Island, New York, and Maryland. The jurisdictions that dropped one tier from 2008 were Colorado (from tier 1 to tier 2); Arkansas, Indiana, South Carolina, and Wisconsin (from tier 2 to tier 3); Mississippi, Pennsylvania, and Vermont (from tier 3 to tier 4); and Connecticut, Maryland, and Rhode Island (from tier 4 to tier 5). Missouri dropped two tiers from last year (from tier 2 to tier 4). Jurisdictions that moved up two tiers from last year were Florida (from tier 3 to tier 1) and Michigan (from tier 4 to tier 2). The jurisdictions that moved up one tier were North Carolina (from tier 2 to tier 1); California, Minnesota, Ohio, and Texas (from tier 3 to tier 2); Illinois and West Virginia (from tier 4 to tier 3); and New Hampshire (from tier 5 to tier 4).

Figure 27: Tiered State Regulatory Rankings

Tier 1	Tier 2	Tier 3	Tier 4	Tier 5
Lowest Cost Of Capital				Highest Cost of Capital
		Arkansas		
FERC		Delaware		
		District of Columbia		
		Hawaii		
		Illinois		
	Alabama	Indiana	Louisiana	
	California	Kansas	Maine	
	Colorado	Massachusetts	Mississippi	
	Georgia	Oregon	Missouri	Arizona
Florida	Michigan	South Carolina	Nevada	Connecticut
Idaho	Minnesota	Utah	New Hampshire	Maryland
Iowa	North Dakota	Virginia	New Jersey	Montana
Kentucky	Ohio	Washington	Pennsylvania	New Mexico
North Carolina	Oklahoma	West Virginia	South Dakota	New York
Wyoming	Texas	Wisconsin	Vermont	Rhode Island

Source: SNL Financial, Barclays Capital estimates.

Figure 28: Relative Price-to-Book Valuation of Electric Utilities by Region

(1986-Current, weekly)

Region	Price/Book Ratio	Relative P/B Value
Southeast	1.67x	12.0%
Mid-Atlantic	1.68x	11.6%
Midwest	1.67x	11.4%
Plains	1.52x	3.1%
West	1.50x	1.3%
New England	1.33x	-10.6%
Southwest	1.07x	-28.8%

Source: FactSet, Barclays Capital.

We have anecdotally believed, and been told by Southern Company for some time, that customer and shareholder interests are aligned through regulation. This is the result of a feedback loop by which utilities that keep prices relatively low, and service and reliability relatively high, receive constructive regulatory outcomes. In turn, that company enjoys a lower cost of capital, and can afford the investment necessary to keep prices low and reliability high. In an attempt to assess this theory, we review the intersection between our regulatory rankings, cost of capital tendencies by region – as measured by relative price to book, and customer satisfaction according to JD Power & Associates. Figures 28 & 29 fully support our view that positive and constructive regulation reinforces good utility performance and perception.

Figure 29: Customer Satisfaction, by Quintile

State Ranking Quintiles	Avg. JD Power Ranking *(out of 1,000)*
1st Quintile	704
2nd Quintile	684
3rd Quintile	666
4th Quintile	661
5th Quintile	655

Source: JD Power & Associates, Barclays Capital estimates.

Pending or Likely Regulatory Proceedings

Allegheny Energy (AYE)

West Virginia. We expect AYE's returns in West Virginia to improve by $55 million in pre-tax margin by 2011 for a 9% ROE which would add $0.20 per share. The company could file a base rate case in 3Q09 or 4Q09. As a reminder the last full rate case decision was in May 2007 when the company received a 10.5% allowed ROE on a 46.1% equity ratio.

On 7/10 the company filed for an interim fuel adjustment rider in West Virginia of $82M. The company estimated first half 2009 under-recovery of $82M versus $137M estimated in last Fall's decision for the full year 2009. AYE requested a decision on interim recovery by October 1, 2009. AYE expects to file the annual fuel case by September 1, 2009 for rates effective January 1, 2010. We expect full or close to full recovery for AYE.

Pennsylvania. In Pennsylvania, West Power continues to procure power supply for the 2011-2013 period with the next auction results likely October 16 (a few days following the bidding). As planned this auction covers 1.8 MMwhrs. The average procurement price in the two auctions to date for residential customers is $72.24/MWhr and for small and medium non-residential it is $75.40/MWhr. So far 25% of a required 30.2MMwhrs has been procured. Overall, we have assumed AYE gets $69.50/mwhr on 75% of its Allegheny Energy Supply output and $44/Mwhr for the balance. Every $1/MWhr overall at Allegheny Energy Supply is $0.125/share.

Under a July 2008 order West Penn Power customers can phase-in a rate increase over 25% for three years. We do not expect rate-cap extension legislation to be enacted although there have been bills proposed which range from being repetitive of the rate mitigations plans in place to rate cap extension bills similar to those from 2008. Please see our passage on PPL Corporation for additional details.

PATH. The company has already received FERC approval which includes a 14.2% allowed ROE on the $1.2 billion joint project with American Electric Power. Filings for approval have been made in Maryland, Virginia and West Virginia. In Virginia the PATH hearings are set for August 3-6 and the evidentiary hearing is January 9. We expect an outcome to this process by mid-2010.

Alliant Energy (LNT)

Iowa Power and Light Electric General Rate Case

Iowa Power and Light (IPL) filed its retail electric general rate case in Iowa on March 17, 2009 based on a 2008 historical test period. The key drivers for the filing include recovery of investments in reliability and emissions controls, anticipated increases in electric transmission service expenses, and retirement plan costs, known changes in retail electric demand, and expenditures associated with the 2007 winter storms and severe flooding in 2008. Rate changes are implemented in two phases with interim rates effective 10 days after the filing (March 27) and final rates effective approximately nine months later (if the case is fully litigated). IPL is requesting an 11.4% ROE although interim rates will reflect the current allowed ROE of 10.7% on 49% equity on a rate base valued at $1.875 billion. Also, $84 million of the total $171 million revenue increase request has been reflected in base rates effective March 27, 2009, subject to refund. The Consumer Advocate Division of the Department of Justice and any intervenors are scheduled to file testimony on or before July 17, 2009, with rebuttal testimony due on August 21. Assuming the case the case is fully litigated, a hearing is scheduled on October 5, with a decision and new rates implemented 1Q10. Settlement discussion will occur during the rate proceeding. Prospects of the settlement are unknown at this time, although Iowa has a demonstrated history of settlement in rate proceedings. The company plans to file another electric GRC early in 2010 with the same implementation timeframe, in order to recover $425 million in wind and $195 million in environmental controls. Should LNT not receive a transmission rider in the currently-pending GRC, this would also be a driver in next year's case.

Wisconsin Power and Light Electric and Gas General Rate Case

Wisconsin Power and Light (WPL) filed its retail electric/gas general rate case with the Public Service Commission of Wisconsin on May 8, 2009. WPL's filing is based on a 2010 forward-looking test year with a requested ROE of 10.6% on a 53.5% common equity component on an average rate base of $1.362 billion (electric) plus $0.212 (gas). WPL is seeking a total of $91 million rate increase, comprised of an $85 million retail electric increase and a $6 million increase for gas service. WPL projects lower combined revenue deficiency in 2010 of $133 million (11%) in present revenues. Drivers of WPL's rate request include $36 million due to lower retail electric and gas sales, net of fuel, with the unrecovered portion if its revenue deficiency to come from continued cost reduction efforts and deferrals; $30 million for return on CWIP related to Bent Tree Wind project; working capital of $21 million and other of $4 million. WPL expects new rates to be in place 1/1/2010.

Ameren (AEE)

Ameren filed their Illinois rate case on June 5 and we expect a filing in Missouri later this year both mainly to reduce regulatory lag. The combined IL electric request is $181 million with a range of 11.75%-12.25% using a $2.4 billion rate base for the test year ended 12/31/08. The combined IL gas request is $45 million with a range of 11.25%-11.60% using a $1.0 billion rate base. The filed capital structure calls for an equity content of 44%-49%.

AEE positioned the filing against a drop in the commodity side of the bill which has declined significantly since the last adjustment. Under the proposed electric increase the average IL residential electric customer will pay $59-$97 more per year (assuming 10,000 kwhrs) depending on the subsidiary and the average gas customer $38-$60 per year (assuming 785 therms). The savings from the latest electric supply adjustment is a $100 savings per year for the average residential electric customer.

The IL filing is mainly to reduce regulatory lag and AEE comments that more than 77% ($173 million) of the rate increase request relates to construction, operation and maintenance of the delivery system. The company's estimated 2009 IL ROE is 6% and every 1% is $25 million pre-tax. Our EPS estimates are $2.83 for 2009 and $2.70 for 2010 with the IL utilities contributing $0.53 in 2009 and $0.60 in 2010. Guidance for the IL utilities is $0.40–$0.50 for 2009.

We also look for a filing from AEE in Missouri later this year to reduce regulatory lag and seeking a return on environmental investment. The company expects to underearn in Missouri in 2009 with a 7% ROE. As a rule of thumb a 1% change in ROE is worth approximately $50 million of revenues in Missouri. We estimate that the company earns $1.25 in Missouri relative to the company's range of $1.15–$1.25 for Missouri for 2009. The Missouri case filing will include a filing for the environmental rider which includes a recovery on investment that includes non-fuel operations and maintenance spending.

American Electric Power (AEP)

AEP East

Appalachian Power Company (APCo) has made its fourth environmental and reliability (E&R) filing in Virginia on May 15, covering the expenditures made in 2008. This filing asked for $41.6 million, with recovery expected to begin in January 2010. Intervenor testimony is due on August 27, APCo testimony is due on September 10, rebuttal testimony on September 21, and hearings begin on October 1.

In West Virginia, APCo continues in its expanded net energy cost (ENEC) filing, which requested a $156 million recovery in February 2008 before the West Virginia Public Service Commission (WVPSC.) The ENEC filing is essentially a beefed-up fuel filing that incorporates fuel, purchased power, off-system sales credits, etc., and should typically result in no change to earnings given that the filings simply seek to true-up the regulatory recoveries with actual incurred costs. An order is expected in this matter by September 30, 2009.

AEP continues to seek approval to build a 629 MW IGCC plant at its Mountaineer site in Mason County, West Virginia, although the current economic and credit market environment make this project a luxury not likely to be pursued even if approved. It currently stands in limbo in West Virginia, after being denied in Virginia. However, the carbon capture and sequestration (CCS) investment continues to move along at the current Mountaineer site, with AEP expecting operation by September 2009 on a 20-30 MW portion of the plant. If successful, the project would sequester 100,000–300,000 tons of CO_2 per year.

AEP's most important filing in Virginia was made on July 15 as APCo's rate case request was for a $169 million revenue increase, based on 44% equity and a 13.35% ROE. The filing is preliminary, in our estimation, because APCo will likely have to adjust the rate case test year and equity structure periods to reflect the ruling just handed down by the SCC related to Dominion's DVP subsidiary. We expect a modified filing by the end of the summer. Interim rates would be effective by December 12, 2010. With APCo's currently approved 10.2% ROE, actual earned ROE below 8% in 2008, and likely to be below 6% in 2009, there exists a good possibility of rate relief through this process. We expect the rate case will be effective for substantially all of 2010.

AEP West

AEP's Southwestern Electric Power (SWEPCo) unit filed a general base rate case before the Arkansas Public Service Commission (APSC) on February 19. The case (docket # 09-008-U) requested a $53.9 million revenue increase premised upon $608.9 million of rate base, a 35.68% equity structure, and an 11.5% ROE. The $54 million increase includes $28.7 million associated with a generation recovery rider. Rebuttal testimony is due on July 24th, staff and intervenor surrebuttal testimony is due on August 18, and sur-surrebuttal testimony is due on August 25. Hearings are slated to begin on October 20, with a final decision expected in December. Through 1Q, LTM earnings at SWEPCo produced about an 8.7% ROE.

SWEPCo is currently in construction on the J. Lamar Stall plant – a 508 MW combined cycle gas plant at its Arsenal Hill site. The site received its final regulatory approval from Arkansas in June. AEP estimates the plant will cost $348 million, and be operational in mid-2010. SWEPCo also has been building the John W. Turk plant – a 600 MW coal plant in Arkansas. Construction began in late 2008, with a revised cost of $1.6 billion ($1.2 billion expected for AEP, which will own about 73% of the plant), and the plant was expected on-line in 2013. As with all coal-plant proposals, AEP has encountered continual resistance from several parties opposed to the plant. Most recently, and after losing a challenge in the Federal court system before the 8th Circuit, the Hempstead County Hunting Club is suing the APSC in an attempt to reverse the commission's approval of the plant. That challenge before the Arkansas Court of Appeals was successful, with the court revoking the permit granted by the APSC, citing poor procedures followed by both the APSC and SWEPCo. SWEPCo has announced it will appeal the ruling to the Arkansas Supreme Court. Dates around a final order are uncertain. It is continuing construction of the plant while the appeal proceeds.

An appeal of the air permit is also pending before the Arkansas Pollution Control and Ecology Commission, with hearings concluded in mid-June. Parties have until August 21 to file post-hearing briefs, with rebuttal briefs due by September 11. Following that – under an uncertain timeline that could take weeks or months – an Administrative Hearing Officer will make a recommendation to the Ecology Commission, which will then hear oral arguments and rule accordingly at one of its meetings. From that point, the ruling could then be appealed through the sate court system in Arkansas. Final US Army Corps of Engineers approval is pending as well.

We expect the Stall plant will be built, but are less sanguine about the prospects for the Turk plant from here. Given AEP's multiple options for capital allocation, we don't see a meaningful impact on their ability to grow earnings by the 2%–4% they've guided to as a result of the Turk ruling.

AEP Ohio

In March, the Public Utilities Commission of Ohio (PUCO) ruled to approve an electric security plan (ESP) for AEP's Columbus Southern Power (CSP) and Ohio Power (OPCo) subsidiaries. The ruling allowed for average revenue increases of 7.5%, 6.5%, and 7% in 2009, 2010, and 2011, respectively. The ruling also allowed for clause recovery of fuel expenses, and explicitly included carbon-related costs within the fuel clause. Fuel balances in addition to the allowed rate increases outlined above will be deferred, with the balance (plus carrying costs) to be recovered from 2012–2018. The PUCO denied distribution rate increases outside of the gridSMART advanced metering program, anticipating that AEP Ohio will file a separate distribution rate case to address these other items.

On the matter of evaluating whether AEP and its peer utilities would pass or fail a significantly excessive earnings test (SEET) as laid out – but for which no specifics have been established – by legislation, the PUCO will convene workshops in the coming months. A decision on the matter is expected in mid-2010.

The ESP process is currently under appeal from both AEP Ohio and some intervenors. A ruling on the appeals is expected imminently, although we do not expect a material difference to the March order that would distort earnings expectations in a meaningful way.

AEP Transmission

AEP is involved in several active transmission projects, as outlined in Figure 30.

Figure 30: Summary of AEP Transmission Projects

Name	Length	Technology	Partner	Estimated Cost (in millions)	Expected In Service
Electric Transmission Texas (ETT)	N/A	345 kV	MidAmerican (50%)	$400	2013
Prairie Wind	230 miles	765 kV	WR (50%) & MidAmerican (25%)	$800	2013-2014
Tallgrass	170 miles	765 kV	OGE (50%) & MidAmerican (25%)	$500	2013-2014
PATH-WV	275 miles	765 kV	AYE (50%)	$1,200	2014
Pioneer	240 miles	765 kV	DUK (50%)	$1,000	2015

Source: AEP Company Presentations

The ETT projects involved several short lengths of line, as well as substation upgrades, and so quantifying a distance is challenging. That said, of the projects that can be quantified in such a way, AEP is involved in over 900 miles of new construction, at a total cost of about $3.7 billion. AEP's share of that cost should be about $1.6 billion, suggesting a potential incremental $0.15–$0.20 of EPS between now and 2015. Looking further ahead, AEP is considering an additional 4,000–6,000 miles of transmission spending, by our estimates. If these projects were all to come to realization, it would represent an additional $0.80–$1.00 of EPS. Understandably, the market has not been inclined to pay for this longer-term optionality, but we think it's clear that the market is also not currently pricing in even the currently active transmission projects in AEP's stock price.

CMS Energy (CMS)

CMS, under its Consumer's Energy subsidiary operates a regulated electric and a regulated gas utility within most of the state of Michigan excluding the "thumb" portion surrounding metro Detroit. All CMS's transmission assets were legally separated and then sold off. They now are owned by ITC Holdings, Inc. under that company's METC subsidiary.

Michigan Legislation

On September 18, 2008 the Michigan Legislature passed legislation that moved the state's regulatory structure away from a hybrid to a more fully regulated model. The legislation was subsequently signed by the Governor. The legislation instituted a renewable energy standard in the state of 10% by 2015 and institutes energy efficiency goals where program costs are fully recovered and incentives are awarded for beating targets. The cash collection from customers for these programs is collected at a level rate over 10 years while the revenues are booked as the costs are incurred allowing the company to over collect on a cash basis in the earlier years and under collect in the later years. Further, this mitigates rate shock and the need for continual rate increases by allowing the programs to go into place with a one time charge to customer bills.

Further legislation included a forward test year and a file and implement rule which allows for the self-implementation of rates 180 days after filing if no commission decision has been made. The self-implementation will then be modified and trued up or down with interest if it is not in line with what the Michigan PSC eventually approves within the 12 month statutory time limit. All of these measures will work to significantly mitigate regulatory lag, allowing the company to earn closer to its allowed ROE. The legislation also caps customer choice at 10% of load meaning infrastructure investments of significant size can be made with confidence that the customer base will be there in future years. Further, the legislation also created a Certificate of Need (CON) process where projects costing more that $500 million are preapproved for recovery by the commission. Interest costs of the projects would be recovered during construction and the remaining costs would be recovered upon project completion.

Electric Rate Case

On November 14, 2008 the company filed an electric general rate case in Michigan under the laws passed in September referenced above. The requested increase was for $214.5 million premised upon a regulatory accounting equity ratio of 40.88% applied to a 12 month average rate base for the period ending 12/31/09 of approximately $6.3 billion. The requested allowed ROE was 11%. On April 27, 2009 the Michigan PSC staff recommended a revenue increase of about $74.7 million premised upon a 12 month average rate base for the period ending 12/31/2009 of about $6.0 billion, an equity ratio of 40.51% and an allowed ROE of 11%.

While the headline metrics of the staff recommendation are generally in line with the company's request the operating expenses were where there were major differences. The staff, according to the company's statements on their first quarter earnings conference call, used some partial year data for 2008 capital expenditures and interpreted it as full year data. Furthermore, the staff had used historical expenditures and applied a CPI factor to them to project forward year expenses. This is in fact not representative of the amounts the company intends to spend on either an O&M or a cap-ex basis. Since the Michigan legislation calls for the use of a forward test year, and the final commission decision is not due or expected until November, three-quarters of actual data for the 2009 year will be available to determine how close actual numbers are in line with CMS's forecast versus the staff's recommendation.

Under the law in Michigan, consumer's can self-implement rates six months after a filing if no commission decision has yet been made. The Association of Businesses Advocating Tariff Equity (ABATE) of Michigan filed a motion with the commission which asked to have the self-implementation by the company stayed. The commission heard the motion and decided, according to the law that the self-implementation could go forward. After this ruling consumers self-implemented a $179 million revenue increase versus the roughly $215 million request, effective as of May 14, 2009.

Gas Rate Case

On May 22, the company filed a new gas general rate case in Michigan under the current law the company will be allowed to self-implement rates in six months, on or after October 22, 2009. This is important from a seasonal timing perspective as it will allow for new rates to go into effect prior to the next winter heating season. The rate increase request is required under the law to be adjudicated by the commission within 12 months, or by the end of May 2010. The request encompasses a $114 million revenue increase, driven mostly by rate base growth and a declining sales forecast. Further, the return component of the revenue increase request is premised upon a 12 month average rate base for the period ending 9/30/2010 of approximately $2.9 billion. Applied to this rate base were a regulatory accounting based equity ratio of 41.07% and a requested allowed return on that equity portion of 11%. Further, as part of the general rate case the company requested a sales decoupling mechanism, and automatic tracker mechanisms for both uncollectable and pension expenses. A prehearing was held before the Michigan Public Service Commission on June 24 2009 to set the schedule. The current schedule in the case calls for staff and intervenor testimony on October 22, 2009, rebuttal testimony on November 16, 2009, and hearings schedule for the weeks of December 14, 2009 and January 4, 2010. The current targeted date for a final decision is May 22, 2010.

Constellation Energy (CEG)

In Maryland Constellation Energy lost its appeal on July 2 of the Public Service Commission's decision to initiate a public interest review of the proposed nuclear joint venture with Electricite de France as it was found to be premature. We expect an outcome later in the schedule of the public interest proceeding where the PSC has agreed to take action on the case by September 17 which would be consistent with the company's closing timeline. To close the transaction approval is also required from the Nuclear Regulatory Commission. Hearings begin August 19 and end August 25.

Figure 31: Schedule for Public Interest Review of Proposed CEG/EDF Nuclear JV

Date	Action
August 5	Reply Testimony due from parties other than CEG, BG&E, and EDF
August 13	Rebuttal testimony filed by EDF, CEG, and BG&E and served on other parties
August 14	Discovery requestes due on rebuttal testimony
August 17	Responses to post-rebuttal testimony due
August 19-25	Hearings
September 2	All parties file briefs

Source: Maryland Public Service Commission

According to the June 22, 2009 *Baltimore Sun* article "Deal Merits Scrutiny," the State sent CEG a settlement proposal on June 2 seeking "short and long-term rate relief, a commitment to green technologies, ring-fencing to protect BGE from Constellation's speculative financial dealings, and elimination of an $87 million compensation package for Constellation's CEO". We expect a reasonable outcome to be reached as we expect that the State along with the Commission support the transaction.

In the event the transaction does not go through we expect Baltimore Gas & Electric to file a rate case. We do not assume a rate case in our forecast currently which is an 8% ROE in 2010 ($1.83 billion in equity) on an estimated $3.7 billion in electric and gas distribution rate base at year-end 2010. If the 2010 earned ROE was a more reasonable 10%, we calculate it would be $0.19 per share accretive to our $3.54 EPS 2011 EPS estimate.

Consolidated Edison (ED)

ConEd NY Electric

On May 8, ED filed for a three-year electric rate plan proposing level annual rate increases of $695 million effective April 1, 2010, 2011, and 2012, respectively. The filing reflects an 11.6% ROE and equity ratio of 48.2% on a rate base valued at $15.6 billion (as of March 2011), $16.9 billion (March 2012), and $18 billion (March 2013). The filing also includes an alternative proposal for a one-year $854 million increase, reflecting a 10.9% ROE, including property taxes of $127 million, additional operating costs of $153 million, carrying charges on additional infrastructure $237 million, increased pension/benefit costs of $114 million and an increased ROE of $127 million. The company is requesting continuation of decoupling and current recovery provisions for pension/benefits, property taxes, long-term debt and environmental remediation. ED is seeking regulatory deferral if certain expenses exceed 4% annual inflation rate if the actual

ROE is less than authorized. This filing also reflects $30 million of "austerity" measures (see discussion below pertaining to the NYPSC's prior year GRC decision for ConEd NY electric), continuing through March 31, 2011. We expect NYPSC Staff response to the GRC on August 28, 2009.

On May 26, 2009 ED filed for rehearing of the New York Public Service Commission's (PSC's) April 24 electric rate case decision for ConEd NY. In that order, the PSC authorized ED a $523.4 million or 7.2% rate increase, premised on a 10% ROE and 48% equity component of capital on a $14.097 billion rate base effective retroactively to April 1, 2009. The Commission also authorized the company to collect an additional $1998 million beginning May 1, related to a recent change to Public Service Law that raises an existing 0.2% revenue tax by an incremental 1.8% on a temporary basis. The approved base rate revenue requirement reflects a $60 million imputed adjustment for "austerity" measures imposed. If the full $60 million of cost savings are not achieved, ED will be able to petition the PSC to defer that portion of the austerity revenue adjustment, up to $30 million, for recovery at a later date, following the first year of new rates. In addition, the Commission adopted a 2% productivity factor adjustment to the company-proposed test year labor expense level, versus ED's proposed 1% factor. This determination reduced the revenue requirement by an additional $11 million. ED's request for rehearing focuses largely on the arbitrary and unprecedented nature of the aforementioned austerity imputation, arguing that it is..." without basis in the record, at odds with policies adopted by other agencies and governments...and inconsistent with the long-term interests of New York State."

In conjunction with the rehearing request, ED submitted a plan outlining the steps it proposes to take to meet the austerity requirements of the PSC's order. However, the company has indicated this filing should not be construed to indicate agreement or acceptance of the Commission order. The measures to be implemented include reductions in: labor costs ($6.5 million); corporate expenses such as travel, attendance at professional conferences, communications costs, industry association membership fees ($7.4 million); capital projects, and operations and maintenance costs ($33 million); and, other unidentified cost reductions ($13.1 million). There is no established timing or process for this rehearing request at this time.

On May 14, 2009, the NYPSC issued a separate generic order requiring the state's major electric and gas distribution utilities to submit for PSC consideration austerity plans within 30 days. These plans are to address current and future company actions that can reduce or postpone discretionary expenses. Should the PSC rule on rehearing to revoke the austerity provisions of the order, or if this provision is ultimately overturned in the courts, the Commission could required ED to file a plan under the generic ruling, thereby effectively imposing similar requirements.

We also expect ConEd NY to file a gas GRC this year, with new rates effective October 2010.

Orange and Rockland Utilities, Inc.

ED subsidiary Orange and Rockland filed a $17.8 million gas delivery rate increase on November 26, 2008, effective November 1, 2009. The increase is based upon an 11.6% ROE and 48% equity on a rate base valued at $261.8 million. On March 27, 2009 the NYPSC Staff recommended that the Commission authorize a $10.1 million rate increase based upon a 10% ROE and 48% equity component of capital on a $275.8 million rate base. O&R's most recent gas rate decision came in October 2006 when the PSC adopted a three-year rate settlement providing rate increases of $12 million, $0.7 million, and $1.1 million on November 1, 2006, 2007, and 2008, respectively. These increases ultimately were levelized with the use of deferred accounting, whereby increases of $6.5 million were authorized in each of the first two years, with an additional increase of $1.8 million authorized in year three.

On June 30, 2009, Orange and Rockland, Staff of the Department of Public Service, the Consumer Protection Board, USG Corporation, and the Small Customer Marketer Coalition filed a Joint Proposal with the Commission in Orange and Rockland's gas base rate case. The Joint Proposal sets forth a settlement of all outstanding issues in this case. The only active party in the case not joining in the Joint Proposal is the Town of Ramapo. The Joint Proposal, which is subject to the review and approval of the Commission sets forth a three-year gas rate plan (November 1, 2009 through October 31, 2012) for the company. The Joint Proposal provides for gas rate increases of $12.8 million, $5.2 million and $4.5 million effective November 1, 2009, 2010 and 2011, respectively. Alternatively, the Joint Proposal gives the Commission the opportunity to phase in the base rate increase as follows: $8.964 million effective November 1, 2009, $8.964 million effective November 1, 2010, and $4.626 million (in addition to a one time collection of $4.338 million through the Monthly Gas Adjustment) effective November 1, 2011.

The Joint Proposal also contains the following major items:

- An assumed annual return on common equity of 10.4%;
- Reconciliation of actual pension and other post-retirement benefit expenses, environmental remediation expenses, property taxes, long-term debt costs and certain other expenses to amounts reflected in rates;
- Deferral of carrying charges for distribution infrastructure investments to the extent actual expenditures are less than amounts reflected in rates;
- Company may defer carrying charges on up to $2 million of annual incremental Interference related spending;
- Deferral of increases in certain expenses above a 4% annual inflation rate, but only if the actual annual return on common equity is less than 10.4%;

- Implementation of a revenue decoupling mechanism using "revenue per customer" methodology under which actual energy delivery revenues would be compared, on a periodic basis, with the authorized delivery revenues with the difference accrued, for refund to, or recovery from, customers, as applicable; In the first rate year (November 1, 2009–October 31, 2010), as an austerity measure, the company will implement a 2% productivity adjustment (i.e., 1% above the normal 1% productivity adjustment). Statements in support of/in opposition to the Joint Proposal were submitted July 13, 2009. A hearing to consider the Joint Proposal has been scheduled for July 28, 2009. The Commission is expected to consider the Joint Proposal in October 2009.

Dominion Resources (D)

Dominion Virginia Power (DVP) has made five filings before the Virginia State Corporation Commission (SCC) seeking a net increase of $316 million in revenues, to be effective between July 1, 2009 and January 1, 2010. The filings and effective dates are listed below:

Figure 32: Dominion Regulatory Filings

Request	Amount (in millions)	Effective Date
Fuel	($236)	1-Jul
Base Rates	$298	1-Sep
Transmission	$78	1-Sep
Bear Garden	$77	1-Jan
Virginia City Hyrbid Energy Center	$99	1-Jan
Total	$316	

Source: Company and regulatory filings.

The base rate case filing sought a 13.5% ROE on 52.8% equity at the March filing, but the capital structure DVP sought was as of the end of 2010. In a subsequent ruling, the SCC decided that DVP's capital structure would be set as of year-end 2008. This should effectively limit DVP to a 47-48% equity ratio. On about $8.5-9.0 billion of rate base, this equates to about $0.09 to $0.10 of lower possible increase. In addition, the rest of the rate case filing will be amended based on a Sept. 2010 test year, as opposed to the 27-month forward period DVP had planned to utilize. We would expect this to impact the rate base request. The amended filing is due before the SCC by August 3. The ROE mechanism established by Virginia law obliges the state to have a floor set by the majority of DVP's peer utilities in the Southeastern US using a three-year rolling average. The base rates would become effective before the final order is due, subject to refunds. The procedural schedule for that filing doesn't have hearings until January 2010 (see below). A positive note subsequent to the recent SCC rulings noted above on rate case test periods is the clarification that DVP may file a rate case at any time in the future if it feels an economic incentive to do so. Previously, the understanding was that DVP would be unable to file a rate case for another two years. This mitigates some of the impact of the earlier test periods we described above.

The Virginia City Hybrid Energy Center, a 585 MW fluidized bed coal plant under construction in Wise County, Virginia, is designed to be carbon capture compatible. The plant is scheduled to cost $1.8 billion, excluding financing costs, and should be completed in 2012. Consistent with the overall requests in the rate case described above, DVP is seeking a 14.5% ROE for the plant, comprised of the 13.5% ROE request in the rate case, plus a 100 bp adder that is allowable through a separate rider under the re-regulation bill that applies to new coal plants.

The Bear Garden facility is a 580 MW combined cycle plant to be located in Buckingham County, Virginia, that was approved by the SCC in March 2009. Similar to the Virginia City plant above, DVP requested a 13.5% ROE with a 100 bp adder for combined cycle plants, raising the all-in request to a 14.5% ROE. This plant is expected to cost $619 million, and should be completed in 2011.

The $78 million transmission increase is the result of requesting a transmission rider (Rider T) to encompass current and future transmission adjustments, and is net of a $227.3 million revenue requirement, offset by a $149.4 million reduction in base rates as the transmission component is removed. This increase was approved by the VA SCC and will be effective September 1.

Timing for the above open matters is outlined in Figure 33.

Figure 33: Dominion Open Regulatory Matters

Case	Subject	Dates
PUE-2009-00016	Revision to fuel factor	July 9 - comments due July 16 - hearings scheduled
PUE-2009-00017	Establish Rider R for Bear Garden Generating Station	August 4 - comments due August 11 - hearings scheduled
PUE-2009-00011	Adjustment to Rider S for Virginia City Hybrid Energy Center	August 11 - comments due August 18 - hearings scheduled
PUE-2009-00019	Revision to base rates	January 13, 2010 - comments due January 20, 2010 - hearings scheduled

Source: Company Regulatory Filings

In November 2007, Dominion filed a combined operating and construction license (COL) with the NRC for a third unit at its North Anna nuclear site. The COL was based on using GE's Economic Simplified Boiling Water Reactor (ESBWR) design. D has since re-opened its selection process for a technology at the site, and the search is ongoing. It is our belief that D will be in the first wave of new regulated nuclear construction, and to that end, we expect a decision on a design partner to be reached by year end.

DPL, Inc. (DPL)

Ohio Retail Rate Matters

On February 24, 2009 DP&L filed a Stipulation Agreement with the Public Utility Commission of Ohio (PUCO) on its Electric Security Plan (ESP), filed October 10, 2008, as required by SB221. The Stipulation was signed by the PUCO staff, the office of the Ohio Consumers Counsel, and other intervening parties and among other things, extends DP&L's existing rate plan through 2012, adjusts its fuel recovery mechanism beginning in 2010, and provides for the recovery of certain SB221 compliance costs. On June 24, the PUCO unanimously approved DPL's pending ESP Settlement. The approved plan establishes rates through 2012 and implements a fuel recovery mechanism beginning next year. In addition, DPL will be able to continue to retain 75% of the benefits derived from its coal optimization strategy in 2010 and beyond. The plan further stipulates that an excessive earnings test will not be applied until 2013.

As a member of PJM, DP&L incurs costs and receives revenues from the RTO related to its transmission and generation assets, as well as its load obligations for retail customers. SB221 included a provision that would allow Ohio electric utilities to seek and obtain a reconcilable rider to recover RTO-related costs and credits. On February 19, 2009, the PUCO approved DP&L's request to defer costs associated with its transmission, capacity, ancillary service and other PJM-related charges incurred as a member of PJM. On March 28, 2009 DP&L filed for recovery of these RTO-related costs. Through this filing, DP&L proposes to eliminate seven retail riders related to transmission and ancillary services and replace them with a single retail rider that would incorporate all charges and credits from the RTO as well as the amounts approved for deferral. This new rate was approved on May 27, 2009 and went into effect June 1, 2009.

DTE Energy (DTE)

Detroit Edison

On January 26, 2009 DTE's electric utility subsidiary Detroit Edison filed a rate case, their first under Michigan's new regulatory legislation. The new legislation introduced a number of constructive regulatory concepts including a fully forward test year, file-and-implement rate-making, pre-determination on large scale projects, limits on customer switching, and a more clearly articulated plan for renewable construction and spending. All of these constructs, when combined, help Edison to substantially mitigate the affects of regulatory lag, placing the utility in a surprising secure situation with the promise of supportive regulation always in the background.

The power of a forward test year is demonstrated impressively in Edison's case as they are able to recover sales declines in their service territory prospectively. As the electricity supplier to Detroit's "Big 3" automakers, one can imagine that Edison's forecast of an approximate 8% decline in sales (sales expectation is 49,165 GWhs for the July 2009–June 2010 period, down from the 53,600 GWhs currently embedded in rates and corresponding to $164 million in lost revenues) is a definite possibility. While sales declines thus far in 2009 are trending close to in-line with company guidance (down 6%

for the 2009 calendar year at last update) we are watching closely to see how much of the $164 million ask is actually implemented when Edison begins their interim rates on July 26, 2009. In addition to the sales declines (which, in our view, will be very difficult for the commission to argue with), we believe that Edison will likely recover all of the costs associated with increased pension, employee benefit, and bad debt expenses, while the company will likely get more pushback on its request for recovery of inflation and rate base changes, and in all likelihood will be disallowed the revenues associated with the increased ROE request and O&M tied to incentive compensation.

The procedural schedule for Edison's rate case started becoming more active in July, with Staff and intervenor testimony taking place on July 9, 2009, and with rebuttal testimony planned for July 30 (shortly after Edison's likely date of implementation on July 26, 2009), while a final order from the commission will come by January 26, 2010 at the absolute latest (Michigan's legislation mandates that commissions must rule on rate cases within one year of the original filing, or rates automatically become effective). On June 26 Edison took the first step in beginning their implementation when they filed with the MPSC their intention to implement $280 million in interim rates. While details around what specific components make up this amount continue to be vague, we feel that it represents a reasonable jumping off point for the company and a good place to begin discussions with the commission. The staff recommendation that came out on July 9 2009 was well below expectations, with the staff recommending a rate reduction of ~$4M, with an allowed ROE range of 10.5% - 11.0% (Edison is currently allowed on 11.0% ROE). While the recommendation was surprisingly low, we believe that many of the staff's assumptions, in particular their sales forecast, will be found by the commission to be substantially off point.

After rates are finalized by the commission (most likely in January 2010), we expect Edison to continue filing rate cases back to back until sales declines begin to taper off, which, in our view, is unlikely to happen until after the 2011 rate case cycle in a best case scenario. As a result, Edison will be in perpetual rate case cycle for the foreseeable future, with the payoff of this typically negative scenario being that Edison's exposure to weakness in the Michigan economy will be limited to the six months immediately following a filing (until they are allowed to implement interim rates).

MichCon

While MichCon has been absent from the regulatory front since mid-2005 (due to rate moratoriums among other things), the DTE gas utility filed a case on June 9, their first under Michigan's new legislation. MichCon's total ask was $193 million, with rate base additions accounting for the bulk ($83 million) of the increase, while increases in company use and lost gas ($36 million), a new uncollectible tracker ($33 million), lower sales ($15 million), O&M ($16 million), and a higher ROE (11.25% versus the 11.0% authorized being $10 million of the request) making up the balance of the request. We will also be watching closely the discussions around the decoupling mechanism that MichCon included in the filing.

Consistent with the electric regulation in Michigan, we expect that rates will be implemented on an interim basis in January 2010, with a final order expected by June 2010.

Renewables, Efficiency, and Conservation Programs

DTE has the benefit of a customer surcharge that will begin to flow in September 2009. This $3–$4 per month per customer charge allows DTE's utility subsidiaries to have access to the necessary capital in order to meet many of their efficiency and environmental mandates, and without the cost that would come from traditional debt issuances. We view this as very constructive for DTE.

In addition to the regulatory mechanisms that were introduced with the recent legislation, it has long been believed that Michigan is very consciously moving in the direction of full decoupling on the gas and electric distribution front. While fellow Michigan regulated utility CMS Energy is expected to handle decoupling in a separate regulatory filing, it is our expectation that DTE will address the decoupling issue in their next set of rate cases (MichCon included a decoupling mechanism in their June 2009 filing and Detroit Edison's expected January 2010 filing will again address the issue).

Duke Energy (DUK)

Duke Energy Carolinas

Duke Energy Carolinas (DEC) filed a rate case on June 2, 2009 with the North Carolina Utilities Commission (NCUC), and expects rates to be effective January 2010. The filing seeks a $496 million increase in revenues, premised upon 53% equity and an 11.5% ROE. DUK is actually seeking a 12.3% ROE through the case, but has established its revenue request off of the 11.5% level. These amounts are based off a $9.854 billion rate base request.

DUK's Save-A-Watt program was approved via a rider mechanism, subject to refund, in North Carolina. The full issue, including amount of recoveries and the future mechanisms, will be handled through the recently filed rate case.

DEC also expects to file a rate case in South Carolina sometime this summer, with rates expected to be in effect by January 2010.

DEC filed a combined operating and construction license (COL) with the NRC in December 2007 for two new AP 1000 nuclear reactors at the William States Lee site in Cherokee County, South Carolina. Before construction (not expected to begin in earnest until at least 2012), DUK is seeking both a legislative outcome in North Carolina that would allow for better security around the recovery process, as well as a partner in construction to ease the financial and risk burden of the project. These are the early stages of the process, and we do not expect DUK will have a new plant built until closer to 2020.

Duke Energy Ohio

In Ohio, Duke Energy has largely resolved the electric security plan (ESP) process that replaced the previous rate-setting system in Ohio when the Public Utilities Commission of Ohio (PUCO) issued its finding in December 2008. Pending final appeals to the Ohio Supreme Court by the Ohio Consumers' Counsel – which we do not expect will be successful – the order allows a generation rate increase of 1.9%, 2%, and 1.2% in 2009, 2010, and 2011, respectively, and allows for recovery of environmental spending and fuel costs, as well as provides DUK the opportunity to formulate its Save-A-Watt demand response system for further study.

DUK also filed a distribution rate increase in July 2008, which resulted in a settlement between DUK and some parties to the matter that was filed on March 31, 2009 that would result in a $55.3 million rate increase (versus an $86 million original request.) The stipulation also allows DUK to begin a small weatherization and energy efficiency program in Ohio. The settlement was approved by the PUCO on July 8, and includes the $55.3 million increase referenced above, based on a 10.63% ROE.

In Indiana, DUK is awaiting a ruling from the Indiana Utility Regulatory Commission (IURC) on its energy efficiency process. Settlements have been reached with all intervenors except the Citizens Action Coalition of Indiana. A ruling from the IURC is expected in summer 2009.

DUK also continues progress toward building its Edwardsport Generating Station – a 630 MW IGCC in Indiana. The latest cost estimate of $2.35 billion was approved by the IURC in January 2009, along with approval for DUK to begin work on a carbon capture study. Construction work on the IGCC has begun, and the plant is expected to be completed in 2012.

Edison International (EIX)

Southern California Edison (SCE) operates under a long-term cost of capital decision put in place by the California Public Utilities Commission (CPUC), and the current decision stands until January 2011. A new cost of capital case would be expected to be filed in April 2010. The current metrics allow for a 48% equity structure, and an 11.5% ROE. In addition, the California utilities are able to adjust their costs based on moves in the relevant Moody's bond index (the Baa index for SCE). As has been noted several times since the ruling was made last year, utilities are able to adjust their ROE by 50% of the move in the benchmark if the benchmark moves by more than 100 bp. For SCE, the next adjustment period occurs in September.

SCE's last rate case was decided in March 2009, with a new case not expected until fall of 2010 for implementation in January 2012. Based on the results of both the cost of capital and rate case proceedings, SCE's projections for rate base and capex are below.

Figure 34: SoCal Edison Regulatory Projections

SCE Rate Base
($ in millions)

	2009E	2010E	2011E	2012E	2013E
Base Case	$14,500	$16,200	$18,100	$20,800	$23,000
Low Case	$14,200	$15,800	$17,200	$18,800	$20,500

Source: Company presentations.

SCE Capex
($ in millions)

	2009E	2010E	2011E	2012E	2013E
Base Case	$3,400	$3,900	$4,200	$4,400	$4,300
Low Case	$2,800	$3,200	$3,500	$3,700	$3,600

Source: Company presentations.

California has fairly progressive energy efficiency and conservation guidelines in place, and has authorized an incentive structure for the three-year periods from 2006–2008 and 2009–2011. This structure allows for a 9% incentive earning on the value of energy efficiency savings if SCE meets 85% of its goal, and 12% if it meets 100% of its goal. There are progress payments along the way, and the total awards or penalties for meeting or falling short of the goals is capped at $200 million. SCE's goal for the 2006–2008 period was a $1.2 billion savings to customers, which could result in a maximum $146 million pre-tax payment to the utility. The first progress payment, for the 2006–2007 period, was made in December 2008 in the amount of $25 million. SCE expects to receive a $14 million–$26 million second progress payment through rates in 2010 (with the decision expected in 4Q09.) While the rulemaking in this regulation is still fairly fluid, SCE does expect it will receive the full amount of any incentive earnings for the 2006–2008 period by the end of 2010, with the CPUC making a decision in December 2009.

SCE has been approved to deploy about 5.3 million smart meters between 2008 and 2012 through its SmartConnect advanced metering program. The latest total project costs are estimated at $1.7 billion, with $1.25 billion of that amount going into rate base. Consistent with the strengthening trend that we're seeing with demand response and conservation efforts, SCE estimates that this program may shave 1,000 MW of peak demand from its system once fully implemented. Coupled with the 1,000 MW of load that SCE currently shaves through its existing programs, SCE aims to reduce up to about 10% of its peak load through these demand response programs.

California law compels utilities to procure 20% of their electricity via renewable resources by December 2010. SCE does not expect to be able to meet this standard, despite being able to take advantage of built-in flexibility in the methodology that includes rolling over of any past surpluses and the presumption of current renewable energy deliveries that it may roll forward into the current period. There is a maximum $25 million penalty that the CPUC may assess in the course of reviewing the annual compliance filings that SCE and its peer utilities are required to make. It is unclear at this point how this situation will develop, but SCE doesn't believe it will be made to pay a penalty for its 2008 procurement.

In mid-May, SCE stated that it would not seek to build the Arizona portion of the Devers-Palo Verde 2 (DPV2) line that has been proposed for the last few years. The matter would have required a re-filing of the application with the Arizona commission, and in our view success seemed unlikely. SCE will continue to build the California portion of the line that runs from Palm Springs to Blythe, CA. The Arizona portion of the line was expected to cost $304 million, with the California portion estimated at $723 million. The California piece should be completed by 2013.

Entergy Corporation (ETR)

ETR is in the midst of a proposed spin-off of its nuclear business, which has been named Enexus Energy. They obtained NRC approval last summer, and that approval expires on July 28, 2009. Enexus will likely seek an extension of the approval at that point, and we do not anticipate any problems. The spin was also approved by the FERC in June 2008, and that approval remains in effect for a reasonable amount of time. The spin has been hampered by pending regulatory approvals from Vermont and New York states, as well as a tight credit market that would weaken part of the investment case for the spin.

In Vermont, there are two items pending: approval for a re-licensing of the Vermont Yankee (VY) nuclear plant, as well as approval for the license transfer that would authorize the spin. The VY license expires in March 2012, and the Vermont Public Service Board (PSB) and the Vermont legislature have roles to play in any relicensing decision. The legislature will have to grant authorization to the PSB to consider the extension, and then the PSB may decide the situation on its merits. At this point, the legislature has not granted the PSB that authority. The legislature has been unfavorable toward VY in the recent past, seeking to require ETR to fully fund its future decommission liabilities at the present time – only to have that bill vetoed by the governor.. Further, there is a material anti-nuclear atmosphere in Vermont that creates an air of uncertainty. Ultimately, we believe the plant will be relicensed, provided ETR is willing to replace the current power purchase agreement (PPA) that expires at the end of the current license period, with a new one that runs along with the extended life of the plant. The license transfer step that is required for Enexus to take ownership of the plant is awaiting a final determination, with all necessary steps having been completed for months. Again, we believe if an agreement can be reached regarding a future PPA, the rest of the process will unfold favorably.

In New York, the parties involved in the spin-off matter have been in various stages of settlement discussions since December 2008, with no resolution having been reached yet. The state Public Service Commission (NYPSC) process had its last milestone in October 2008, when the ALJs hearing the matter ruled that an adequate record to reach a decision had been reached. If there is no settlement, the ALJs will submit a recommendation to the NYPSC, which could then rule at its discretion.

Entergy Arkansas (EAI)

The 2008 storm cost recovery efforts were begun in January 2009, while early 2009 storms led to further costs incurred at EAI estimated at $120 million–$140 million. The

Arkansas Public Service Commission (APSC) has allowed EAI to defer 2008 storm costs and to seek recovery via the storm damage rider. Given the unfavorable results of the 2006–2007 rate case in Arkansas, where EAI requested a $106.5 million increase, and was instead granted a $5.1 million rate reduction, the storm recovery process that is currently ongoing should serve as a decent barometer of the relationship between the APSC and EAI.

EAI has also sought APSC approval to spend $631 million on environmental upgrades at its White Bluff coal plant. In order to comply with state and federal regulations by 2013, EAI is hoping to begin construction by 4Q09. EAI is asking for an APSC ruling by September 25, 2009.

Entergy Texas (ETI)

The Public Utilities Commission of Texas (PUCT) recently approved a unanimous settlement on March 11 that would increase base rates by $46.7 million, and which stipulated a 10% ROE as reasonable (the settlement was black box, and thus made no specific mention of an allowed ROE.) The rates were effective as of January 28, 2009. Separately, ETI had been seeking permission to either remain in the SERC region, or join ERCOT, as part of its transition to competition plan. The Texas legislature, before adjourning on June 1, passed SB 1492, which pertained to ETI's membership in qualified power regions, and its transition to competition. This effectively forecloses a transition to competition for the next four years, and authorizes ETI to withdraw its current filings before the PUCT to that effect.

Also, ETI filed for $577.5 million of storm costs, and made its filing before the PUCT on April 21. Consistent with state law, the PUCT has 150 days to rule on the amount of recovery and on securitization. Recent staff recommendations would allow all but $3 million of this amount. A settlement conference is slated for July 27, with a hearing to be held on August 3.

Entergy Gulf States Louisiana (EGSL)

EGSL is estimating that it incurred between $240 million–$255 million in storm costs associated with Hurricanes Ike and Gustav. Current legislation in Louisiana allows for securitization of storm costs, and EGSL should be making a filing soon. In addition, the commission staff's review is ongoing for EGSL's formula rate plan (FRP) filing totaling $26.8 million for revenue increases and capacity costs.

Entergy Louisiana (ELL)

ELL had been in the process of repowering its Little Gypsy plant under a dual-fuel (pet coke and coal) process using a circulating fluidized bed technology, until the recent drop in natural gas price, coupled with economic downturn, called into question the near-term economics of the $1.76 billion project. Following an earlier ruling from the Louisiana Public Service Commission (LPSC), ELL recommended a long-term suspension of longer than three years for the project. In late April, the LPSC agreed, while awaiting the next filing from ELL/EGSL which is due by June 20, regarding future claims and next steps regarding recovery. We think the process bears watching because ELL should, in our view, be able to recover investments already made in the project, despite the recent long-term postponement. In fact, this case serves as something of a test case for state commissions' willingness to repay utilities for approved investments that have been subsequently cancelled or delayed.

ELL is also in the middle of a storm cost recovery proceeding, following damage incurred by Hurricanes Ike and Gustav. The company estimates storm damages of about $390million–$405 million, and expects to begin a recovery filing shortly. As noted above with respect to EGSL, existing law in Louisiana already permits securitization of storm costs.

Finally, test year 2006 and 2007 FRP filings are still under review by the LPSC, with a final ruling in the 2006 test year issues expected later this summer.

Current allowed ROEs for each of ETR's regulated subsidiaries are below:

Figure 35: Entergy Allowed ROEs by Subsidiary

Company	Authorized ROE	2008 Actual ROE
EAI	9.90%	3.4%
EGSL	9.9% - 11.4%	10.9%
ELL	9.45% - 11.05%	9.8%
EMI	9.46% - 12.24%	8.9%
ENO	11.1% (electric) 10.75% (gas)	16.5%
ETI	10.00%	6.4%

Source: Company filings, Barclays Capital estimates.

Exelon Corporation (EXC)

PECO

The rate cap transition period ends for EXC's PECO and ExGen subsidiaries on December 31, 2010. PECO filed a default service program and rate mitigation plan (DSP) in September 2008, and the Pennsylvania legislature passed Act 129 in October 2008. Act 129 prescribes a 15 year transition to smart meters, as well as requiring an energy efficiency and conservation (EE) plan be filed by July 1, 2009. The EE plan requires a 1% reduction in the expected June 2009 – May 2010 load by May 2011, and 3% reduction by May 2013. The Act specifies that costs associated with the EE plan not exceed 2% of 2006 revenues (which were about $5.2 billion for PECO). A plan for implementing smart meter rollout must be filed with the PA Public Utility Commission (PAPUC) by August 14, 2009.

Mindful of requirements found in Act 129, the PAPUC approved a settlement with PECO on April 16, 2009, that allowed for a 29-month term beginning January 1, 2011, and ending May 31, 2013. Under the agreement, PECO will participate in nine procurement processes between June 2009 and May 2013, with a variety of short- and long-term contracts. The settlement also allows for certain customers to phase in rates. Finally, the settlement allows for residential and small consumer classes of customers to pre-pay their expected rate increases through 2010, accruing interest at 6%, and then having them applied to their bills in 2011 and 2012. The first RFP process has been held already, with a result for the 17- and 29-month products of $100-$102/MWh, which we believe equates to about $88/MWh to the winning generation bidders when subtracting items such as line losses and PA gross receipts taxes. The remaining auction schedule, along with products up for bid at each auction, is shown in Figure 36.

Figure 36: Exelon PECO Procurement Schedule

Event	Product(s)	Bids Due	PAPUC Decision
Fall 2009	Full Requirements & Block Energy	9/21/2009	9/23/2009
Spring 2010	Full Requirements & Block Energy	5/24/2010	5/26/2010
Fall 2010	Full Requirements & Block Energy	9/20/2010	9/22/2010
Spring 2011	Block Energy Only	5/23/2011	5/25/2011
Fall 2011	Full Requirements & Block Energy	9/19/2011	9/21/2011
Spring 2012	Block Energy Only	4/16/2012	4/18/2012
Winter 2012	Full Requirements Only	1/18/2012	1/20/2012
Fall 2012	Block Energy Only	9/17/2012	9/19/2012

Source: NERA Economic Consulting, www.pecoprocurement.com.

PECO operates under an electric rate freeze until 2011, and we don't anticipate a distribution rate filing there until the post-2010 issues have been clarified.

ComEd

ComEd has a formula rate filing before the FERC to true up its transmission costs; in that filing they requested a $16 million reduction in rates.

Regarding an electric distribution case, which ComEd would typically be on schedule to file later this year, the company plans to defer that filing while it observes what kind of financial position it is in following the announced O&M and capex cuts it made earlier this year. A filing is possible in early 2010, but nothing is planned at this point. ComEd earned a 3.3% ROE, according to company filings and our estimates, in 2008. The company was allowed a 10.3% ROE in its last rate case in Illinois, which was awarded in September 2008.

FirstEnergy (FE)

We look for FE to file a market rate option (MRO) in Ohio in 4Q09. This would cover the June 2011–May 2013 power procurement for the utilities. We look for the company to propose two to three auctions this time to layer-in pricing as opposed to the single auction for June 2009-May 2011. The process can last 275 days and would conclude in 4Q10.

FPL Group Inc. (FPL)

Florida Power & Light (FP&L)

FP&L filed a rate case in mid March, seeking $1.25 billion over 2010 and 2011. The case requests a $1 billion increase in rates for 2010, with an additional $250 million in 2011. These amounts are premised upon a 2010 test year, and a 55.8% equity structure and 12.5% ROE. It is worth noting that FP&L also requested a reduction in its fuel costs for 2010 that would result in a drop of about $2 billion in expense to ratepayers – more than offsetting $1 billion of increase that's been requested for 2010. The rate case should have rounds of testimony and rebuttal testimony in through August, with hearings scheduled for August 24–28 and September 2–4. A staff recommendation is expected in late October, and a commission vote is expected in November, with rates to be effective for January 2010.

FP&L is also asking for a $150 million storm reserve accrual, which it hopes to build to a $650 million level over time. The company is seeking a continuation of its generation base rate adjustment (GBRA) mechanism to reflect the expected addition of the West County #3 unit in mid-2011.

NextEra Energy Resources

There are a couple of regulatory or legislative developments that are relevant for the NextEra piece of the business. In Texas, NextEra has been approved to build a 250 mile 345 kV transmission line as part of the CREZ transmission build-out in the state. The project is expected to cost $600 million, and represents FPL's first regulated transmission build outside of Florida (through a new unit called Lone Star, LLC, which is a subsidiary of FPL Group Capital). Lone Star needs to file for its Certificate of Convenience and Necessity in Texas; hearings are expected in 1Q10, with a final ruling likely later that year. Construction is slated for 2011.

As has been noted numerous times lately, FPL and its peers in renewable energy development look to be beneficiaries of the renewable titles in the American Recovery and Reinvestment Act of 2009 (aka the stimulus bill). The bill would allow wind generation access to the investment tax credit (ITC) that's helped solar energy shave 30% off the capital costs of a project, provided a company has the tax capacity to enjoy it (otherwise the benefit is deferred until it can be used). It would also create an ITC-like grant that would offer a check from the government for 30% of capital costs, payable about 60 days after the unit goes into service, regardless of tax appetite. The rules for parceling out these benefits are expected to be codified by July, and bear watching for anyone interested in renewable energy development.

Great Plains Energy (GXP)

On September 5, 2008, GXP filed rate cases for each of its subsidiaries in all jurisdictions (Kansas City Power and Light in both Missouri and Kansas, and Greater Missouri Operations in Missouri). The cases have not been carried out without surprises. On the positive side, the Kansas staff came out with a ROE well ahead of expectations for KCP&L,

but the lower equity to total cap ratio that was suggested more than outweighs the increase in allowed ROE. In Missouri, the staff recommendations were, as expected, very negative, but the settlements that were announced were definitely positive surprises, in terms of how close to the agreed upon amount was to the original ask and the fact that settlements were agreed upon in the first place. The fact that is worth noting, is GXP's increased revenue requests in September 2008 were premised upon an off-system sales margin based on a gas deck and power prices that are 20%–30% below current levels. Due to regulatory rules that forbid an increase in a company's ask beyond the original request, it is likely that GXP will be subjected to material regulatory lag until the next set of rate cases are filed and the company is trued up to a power environment that more accurately reflects the current situation.

While the settlements were definitely steps in the right direction, they are partially offset by delays associated with bringing Iatan 1 back in-service, causing GXP to ask for one month extensions of their true-up deadlines in both Missouri and Kansas, and effectively knocking back the expected dates for their final orders and delaying the associated rate relief benefits. In conjunction with the revised procedural schedules, GXP issued releases to the financial community with the expected earnings impacts. Management stated that Kansas would be a $0.07 EPS hit in 2009 (but they expected this entire amount would be offset by additional cost cuts) and Missouri's delay would be a $0.10 EPS hit.

Figure 37: GXP Rate Case Summary

	Company Request ($ in Millions)			Staff Recommendations ($ in Millions)			Settlement Details ($ in Millions)
Rate Case	Total	ROE	Equity Ratio	Total	ROE	Equity Ratio	Total
GMO - MPS	$66.0	10.75%	53.82%	$46.0	9.75%	51.03%	$48.0
GMO - L&P	$17.1	10.75%	53.82%	$22.8	9.75%	51.03%	$15.0
GMO - Steam	$1.3	10.75%	53.82%	$1.0	9.75%	51.03%	($1.0)
KCPL - MO	$101.5	10.75%	53.82%	$52.9	9.75%	50.65%	$95.0
KCPL - KS	$71.6	10.75%	55.39%	$53.9	11.40%	50.76%	$59.0

Notes: Amounts and ROE range for MO based utilities is based upon mid-point of Staff's Recommendation

Source: Company filings and presentations.

The settlements that were announced in Missouri defied what has been the status quo for GXP and the Missouri regulators. The terms were a modest concession on GXP's part (relative to the original ask) in both cases. For KCP&L, the company's initial ask was for $101.5 million, and the settlement was for $95 million ($10 million of which will be treated as additional amortization), while GMO originally asked for $83.1 million and got $63 million in the settlement. While the settlements are still waiting approval, it is our view that the commission is likely to accept the agreements. The fact that GXP was able to settle at all in MO is a step in the right direction and bodes well for the upcoming round of cases to be filed in 2010.

While the three main cases in Missouri (KCP&L-MO and MPS/L&P's (GMO)), announced settlements in April and May, respectively, KCP&L KS announced their settlement on June

18 2009. As has already been articulated, a settlement is almost always considered to be a more desirable outcome when looked at relative to the fully litigated alternative, making GXP's handling of their regulatory situations in Missouri and Kansas that much more important and impressive. However, these regulatory successes are partially offset by lapses on the execution side, as was shown by the delays in getting Iatan 1 to meet the commission's standard to be included in rate base. As a result, the rate case process for the outstanding cases was delayed about a month. Rates from the settlement are expected to be effective on September 1, 2009 in Missouri and on August 1 2009 in Kansas.

Shortly after implementation in these cases, we expect KCP&L Kansas to file their final rate case (that was set out by the Comprehensive Energy Plan) during 4Q09, with filings expected for the Missouri subsidiaries during the early portion of 2010. This next set of rate cases is of particular importance due to Iatan 2 flowing into rate base (assuming that construction remains on schedule and the plant is placed in-service during the summer of 2010 as expected). In addition, this next round of cases promises to be filled with some tough issues around cost over-runs associated with Iatan 2, and improper spending around Iatan 1's environmental retrofits (a component of the recently filed settlements stated that during the next round of rate cases, up to $30 million of KCP&L-MO's rate base $15 million of GMO's can be challenged and disallowed if deemed imprudent by the commission). Final orders and effective rates for the next round of rate cases are expected, in our view, during 3Q/4Q for Kansas and in the beginning of 2011 in Missouri. We expect staff testimony for the more important Missouri rate cases (about 70% of the company's rate base) sometime during the summer to early-fall time period. A staff decision typically signals the trough valuation for a regulated utility, and it is at this time (pending valuation) that we would be most compelled to look at becoming more aggressive on GXP.

Hawaiian Electric Industries (HE)

HE subsidiary, Hawaiian Electric Company (HECO), filed a general rate case on July 3, 2008, requesting a $97 million or 5.2% electric rate increase based on an 11.25% return on equity (54.3% of capital) on a rate base valued at $1.4 billion for a 2009 calendar test year. (This requested increase was in addition to an interim increase that was authorized by the Hawaii Public Utilities Commission on October 22, 2007 in the company's 2007 test-year electric rate case proceeding awaiting a final PUC decision for which there is not statutory deadline. The interim increase in the 2007-test-year case was revised on May 1, 2008, to $77.9 million from an initially authorized $70 million.)

In the 2009 test-year proceeding, HECO requested that $73.1 million of the increase be implemented on an interim basis "as soon as "practicable" and the remaining $23.9 million be implemented upon the commercial operation of the company's Campbell Industrial Park (CIP) generating facility (for which the expected in-service date was August 2009 at the time of filing). In addition to the costs of the CIP facility, HECO indicated that the proposed rate increase reflected capital investment needed to maintain and improve system reliability, and higher operation and maintenance and depreciation expenses.

In April 2009, the consumer Advocate filed testimony, recommending a $62.7 million or 3.4% permanent increase, based on a 9.5% to 10.5% ROE on a rate base valued at $1.259 billion that included the CIP facility.

On May 15, 2009 HECO, the Consumer Advocate, and the Department of Defense (but excluding Commission Staff) filed a settlement in the pending 2009 test year electric rate case, calling for HECO to be authorized a $79.8 million (6.2%) interim rate increase, premised on a 10.5% ROE on an average rate base valued at $1.253 billion. The settlement agreement represented a negotiated compromise of the parties' respective positions and was approximately 18% lower than HECO's original request of a $97 million increase in revenues. Under the terms of the settlement, HECO would have been permitted to establish a revenue balancing account (decoupling mechanism) that would have allowed the company to adjust revenues for the differences between actual and authorized revenues. The settlement also reflected inclusion of the company's CIP facility in rates, for which HECO had originally proposed to reflect in a second-step increase. The remaining issues among the parties impacting the amount of the increase for the proceeding related to the appropriate test year expense amount for informational advertising, and the appropriate return on common equity for the test year. This settlement also excluded the requested revenue adjustment mechanism or tracker for operations and maintenance expense and capital expenditures, that was also proposed by HECO, to minimize regulatory recovery lag. This request is now part of a separate docket, which will be considered at a later date.

On July 2, 2009 The Hawaii Public Utilities Commission issued an order partially approving and partially rejecting the aforementioned settlement agreement on interim rates. As a result of the PUC's modification to the settlement, HECO expects that the interim increase ultimately authorized will be $61.1M. The PUC's order requires HECO to exclude from rate base any costs associated with the Campbell Industrial Park facility. The settlement had reflected inclusion of the CIP facility in rates, whereas the company had originally proposed to reflect the facility in rates in a send-step increase. The order also excluded the costs associated with the stipulated employee incentive wage increases, and requires the update of certain transmission and distribution and maintenance costs to reflect current commodity prices. The order further excludes certain stipulated cost items associated with the Hawaii Clean Energy Initiative from base rates, because these initiatives are still the subject of pending PUC proceedings and have not yet been approved.

In addition, the PUC rejected the terms of the agreement calling for HECO to implement a decoupling mechanism which would have allowed the company to adjust revenues for the differences between actual and authorized revenues through the establishment of a revenue balancing account. In its decision to deny the implementation of such a mechanism, the PUC stated that it was considering the issue of decoupling in the context of a separate proceeding, and that "it has not yet determined that a sales decoupling mechanism and the establishment of HECO's proposed revenue balancing account are just and reasonable". The PUC opined that the "parties disregarded the Commission's directive" as it had explicitly advised the Parties to not include any mechanisms or expenses related to programs or applications that have not been approved by the commission, such as decoupling, the renewable energy initiatives program and advanced meter reading. The Commission added that such programs are in the early states of the regulatory approval process, and that the PUC "cannot reasonably determine that the programs will be implemented during the test year."

The Consumer Advocate and the Department of Defense had the opportunity to file comments on HECO's calculated interim increase amount within five days. The interim decision will be implemented after the PUC issues a decision on HECO's calculations. If the amounts collected pursuant to an interim decision exceed the amount of the increase ultimately approved in the final D&O, then the excess would have to be refunded to HECO's customers, with interest.

The procedural schedule for the remainder of the case includes testimony responding to HECO's revised filings as a result of the PUC's ruling are to be filed by July 20, and hearings on the unresolved issues scheduled to begin on August 10. There is no statutory time limit within which the PUC must issue a decision regarding permanent rates.

Maui Electric Company, Inc. (MECO)

On March 20, 2009, MECO filed a Notice of Intent to file an application for a general rate increase on or after May 29, 2009 (but before June 30, 2009) and a motion requesting PUC approval to use a 2009 calendar year test period for the upcoming rate case. The filing of this general rate increase application in accordance with the Energy Agreement, under which the parties agreed that MECO would file a 2009 test year rate case to implement a decoupling mechanism. On April 27, 2009, the PUC issued an order denying MECO's motion and stating that MECO may elect to file its rate case application with either a split 2009/2010 test period or a 2010 calendar test period, pursuant to the PUC's rules. Under the rules, MECO (and HELCO, discussed below) would be allowed to file rate cases with 2010 test years on or after July 1, 2009.

Hawaiian Electric Light Company, Inc. (HELCO)

In order to implement the decoupling mechanism committed to by the parties in the Energy Agreement, the parties agreed that HELCO would file a 2009 test year rate case. In light of recent PUC action denying MECO's motion for approval to use a 2009 test year (see MECO discussion above), HELCO is evaluating the timing of its rate case filing.

Decoupling Proceeding

In the Energy Agreement (described below), the parties agreed to seek approval from the PUC to implement, beginning with the 2009 HECO rate case interim decision, a decoupling mechanism, similar to that in place for several California utilities, which decouples revenue of the utilities from kWh sales, and provides revenue adjustments (increases/decreases) for the differences (shortages/overages) between the amount determined in the last rate case and(a) the current cost of operating the utility as deemed reasonable and approved by the PUC, (b) the return on and return of ongoing capital investment (excluding projects included in a proposed new Clean Energy Infrastructure Surcharge), and (c) changes in tax expense due to changes in State or Federal tax rates. The decoupling mechanism would be subject to review at any time by the PUC or upon request of the utility or Consumer Advocate. On October 24, 2008, the PUC opened an investigative proceeding to examine implementing a decoupling mechanism for the utilities. In addition to the utilities and the Consumer Advocate, there are five other parties in the proceeding. On March 30, 2009, the utilities and the Consumer Advocate filed their joint proposal and initial statement of position and the other parties filed their initial statements of position. The utilities' and Consumer Advocate's joint proposal is for a decoupling mechanism with two components: 1) a sales decoupling component via a revenue balancing account and a revenue escalation component via a revenue adjustment mechanism and 2) an earnings sharing mechanism. Final position statements of the parties were submitted in May 2009. The Commission noted in its July 2, 2009 order that the sales decoupling mechanism and establishment of the proposed RBA are in the early stages of the regulatory approval process, and that it cannot reasonably determine that the program will be implemented during the test year.

Hawaii Clean Energy Initiative

In January 2008, the State of Hawaii and the U.S. Department of Energy (DOE) signed a memorandum of understanding establishing the Hawaii Clean Energy Initiative (HCEI). The stated purpose of the HCEI is to establish a long-term partnership between the State and the DOE that will result in a fundamental and sustained transformation in the way in which energy resources are planned and used in the State. HECO has been working with the State, the DOE and other stakeholders to align the utility's energy plans with the State's plans. On October 20, 2008, the Governor of the State of Hawaii, The State of Hawaii Department of Business, Economic Development and Tourism, the Division of Consumer Advocacy of the State of Hawaii Department of Commerce and Consumer Affairs, and HECO, (on behalf of itself and its subsidiaries, HELCO and MECO) signed an Energy Agreement setting forth goals and objectives under with HCEI and the related commitments of the parties. The Energy Agreement provides that the parties pursue a wide range of actions with the purpose of decreasing Hawaii's dependence on imported fossil fuels through substantial increases in the use of renewable energy and implementation of new programs intended to secure greater energy efficiency and conservation. Many of the actions and programs included in the Energy Agreement will require approval of the PUC in proceedings that will need to be initiated by the PUC or the utilities.

On June 25, Gov. Linda Lingle signed into law House Bill 1464, which, among other initiatives, increases the renewable portfolio standard targets for utilities operating in the state. Renewables now must comprise 25% of each utility's resource portfolio by December 31, 2020, and 40% by December 31, 2030. Previously, the law had required that renewables comprise 10% of each utility's resource portfolio by December 31, 2010, 15% by December 31, 2015, and 20% by December 31, 2020. H.B. 1464 requires that up to 50% of the RPS targets may be met by renewable energy displacement technologies such as solar water heating, or energy efficiency and conservation programs. Under the new law, renewable displacement technologies and energy efficiency and conservation programs would count towards meeting the RPS through December 31, 2014; however, beginning January 1, 2015, the law establishes that these means would no longer count toward meeting the RPS targets. Importantly, the law allows the Hawaii Public Utilities Commission the authority to revise the RPS. H.B. 1464 also establishes energy efficiency portfolio standards, mandating that utilities achieve 4,300 GWH of electricity usage reductions by 2030, with additional interim goals to be established by the PUC. The law states that, beginning in 2015, energy usage reductions brought about by renewable energy displacement technologies will count towards meeting the efficiency standards. The bill requires that the commission establish incentives and penalties for meeting such standards and grants the PUC the authority to adjust the standards.

NiSource(NI)

Gas Distribution Cases

NI, due to its conglomerate status, is consistently involved in the rate case process in at least one of their jurisdictions. While some of these (in particular, Bay State Gas in Massachusetts) have some importance from an earnings standpoint (if full ask of $34.6 million is received, 2010 EPS could have as much as $0.04-$0.05 of upside), many (Columbia Gas of Kentucky) are not of particular significance due to the minimal potential positive upside (entire increase that NI is asking for is about $11.6 million). Final orders are expected in Bay State's and Columbia Gas of Kentucky in November 2009 and March 2010, respectively. In addition to these two outstanding cases, NI's Columbia Gas of Pennsylvania subsidiary could file during 4Q09 or 1Q10.

NIPSCO

NI's regulatory story is dominated by the NIPSCO electric subsidiary and their outstanding rate case that was initiated August 29, 2008. The case takes on particular significance due to NIPSCO's absence from the regulatory process for over 20 years. Furthermore, NIPSCO historically has over-earned their allowed ROE, and this, when coupled with a service territory that has substantial industrial (and steel in particular) exposure, makes for a controversial proceeding. Asking for a rate increase during a profoundly deep recession always makes a rate case more challenging.

NIPSCO is asking for a one-time increase of $85.7 million (revised down from a $105 million total increase that was to be carried out in two steps) premised upon a 49.9% equity to total capital structure and a 12.0% ROE. Not surprisingly, the testimony and recommendations made thus far by the intervenors has been very negative, with the Indiana Office of the Utility Consumer Counselor recommending a revenue reduction of $135 million, predicated upon a 10% ROE and a 39.2% equity to total cap structure. We don't believe that a result of this magnitude is likely, however the prudent approach, in our view and what we have currently reflected in our estimates, is a flat result for the rate case.

Hearings and additional testimony picked back up recently, with the company's rebuttal testimony on June 26 while additional hearings are planned for July 27, 2009. A final decision and effective rates are expected during late 2009, but more likely early 2010.

Northeast Utilities (NU)

Northeast Utilities is composed of four main subsidiaries, three of which are divided across business lines for transmission and distribution/generation. These are Western Massachusetts Electric Company (WMECO), Public Service Company of New Hampshire (PSNH), and Connecticut Light & Power (CL&P). The fourth subsidiary is a gas utility company in CT, Yankee Gas (Yankee). Each electric subsidiary is regulated at the state level for its distribution or generation (NH only) and at the federal level by the Federal Energy Regulatory Commission (FERC) for its transmission assets. Transmission is filed on a project by project incentive basis at the FERC. We do not expect any regulatory rate filings at Yankee Gas provided the strong growth from the expansion plans at that subsidiary continues.

Transmission

Under the FERC NU's transmission assets at the three relevant subsidiaries are allowed a 12.89% return on equity on the New England East West South Projects (NEEWS) and a 13.10% return on equity on other transmission which qualifies for the incentives under the FERC rate structure. The 13.10% ROE is composed of a 10.40% base ROE, to which is added the following:.

- A 74 bp increment which began on 10/31/06 for higher bond yields;
- A 50 bp incentive for regional transmission organization (RTO) membership;
- A 46 bp technology adder if approved for underground portions, etc.; and
- A 100 bp adder for projects entering service post 2004 but prior to 1/1/09.

The 46 bp adder is determined on a project by project basis, and the 100 bp adder post 1/1/09 will also be reviewed by the FERC on a project specific level. We believe the vast majority of NU's transmission projects will qualify for the 100 bp adder while the 46 bp technology adder will be more project dependent.

The FERC has outlined what it sees as criteria, some of which a project must meet for consideration of incentives. The project must be: non-routine, reduce congestion or ensure reliability, large in size, require significant financing, be multi-state, be multi-pool, be multi-company, and/or be technologically advanced.

Non-Transmission

A breakdown of current regulation and expected rate filings by subsidiary is provided in Figure 38.