MISSOURI PUBLIC SERVICE COMMISSION

STAFF REPORT

COST OF SERVICE

APPENDIX 2
Support for Staff Cost
of
Capital Recommendations

THE EMPIRE DISTRICT ELECTRIC COMPANY

FILE NO. ER-2011-0004

Jefferson City, Missouri
February 2011

AN ANALYSIS OF THE COST OF CAPITAL

FOR

THE EMPIRE DISTRICT ELECTRIC COMPANY

FILE NO. ER-2011-0004

SCHEDULES

BY

SHANA ATKINSON

UTILITY SERVICES DIVISION

MISSOURI PUBLIC SERVICE COMMISSION

FEBRUARY 2011

The Empire District Electric Company
Case No. ER-2011-0004

List of Schedules

The Empire District Electric Company
File No. ER-2011-0004

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%

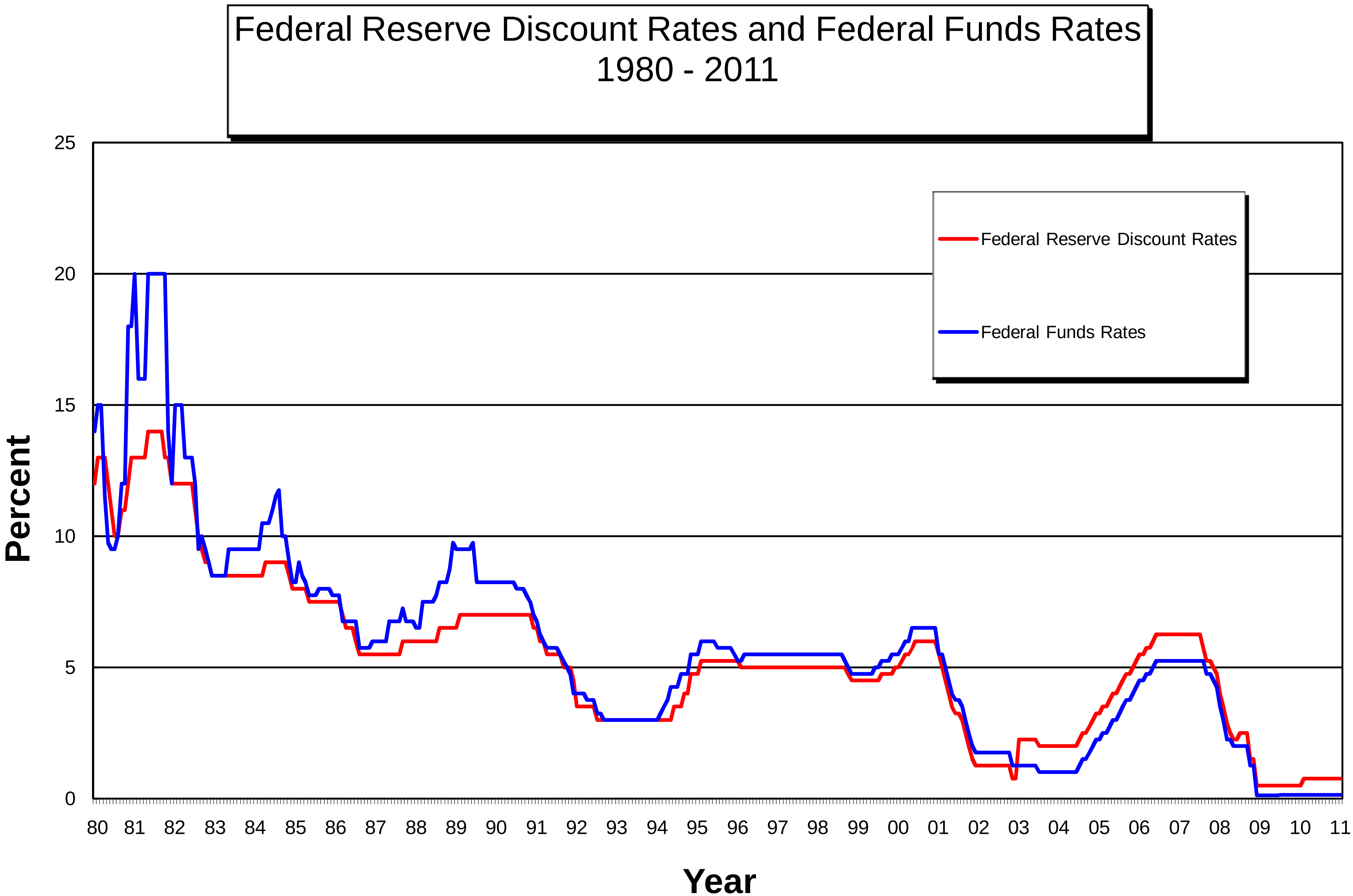
Date	Federal Reserve Discount Rate	Federal Reserve Funds Rate
06/30/99	4.50%	5.00%
08/24/99	4.75%	5.25%
11/16/99	5.00%	5.50%
02/02/00	5.25%	5.75%
03/21/00	5.50%	6.00%
05/19/00	6.00%	6.50%
01/03/01	5.75%	6.00%
01/04/01	5.50%	6.00%
01/31/01	5.00%	5.50%
03/20/01	4.50%	5.00%
04/18/01	4.00%	4.50%
05/15/01	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% - .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.htm

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

The Empire District Electric Company
File No. ER-2011-0004



SCHEDULE 2-2

SCHEDULE 2-2

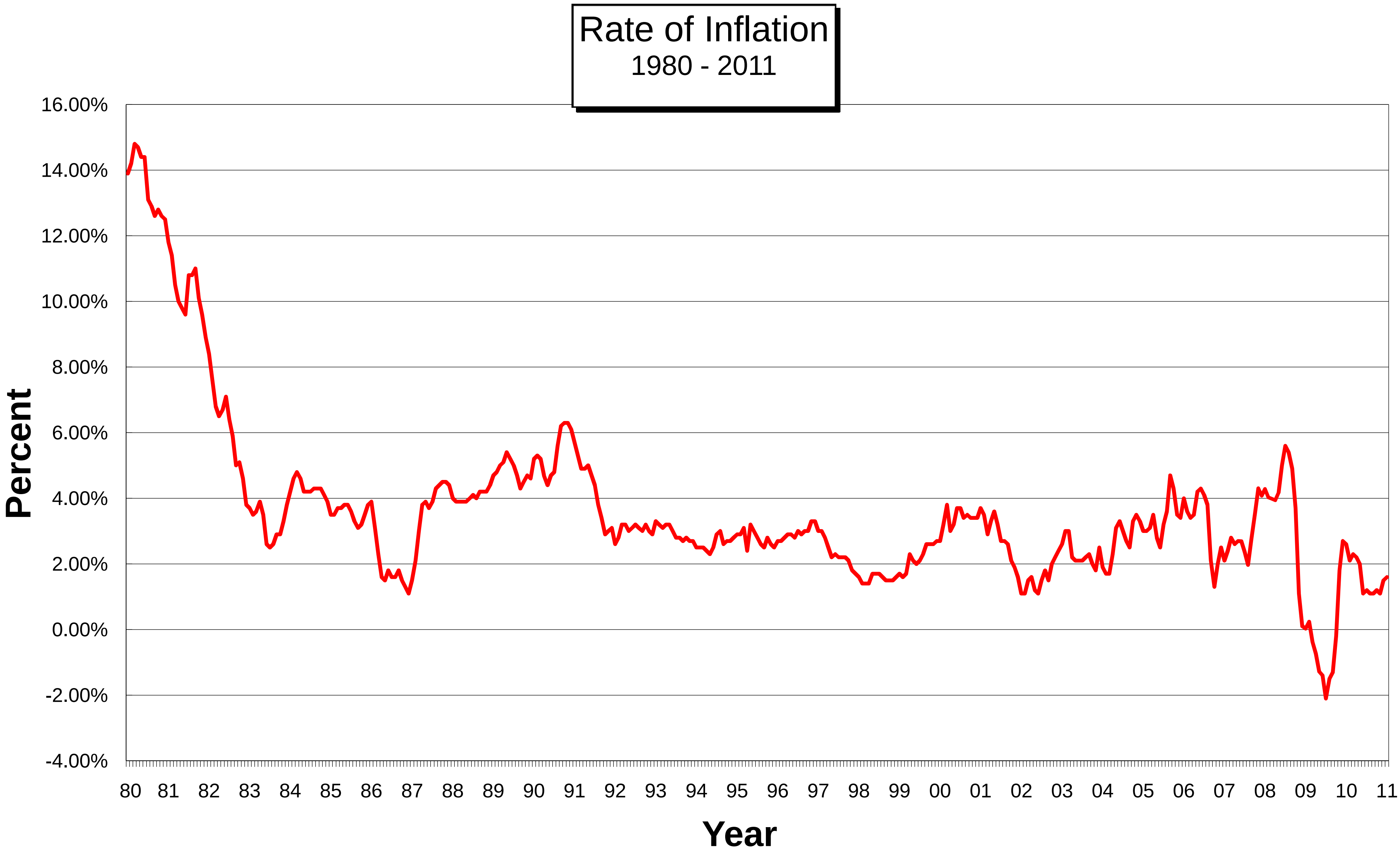
The Empire District Electric Company
File No. ER-2011-0004
Rate of Inflation

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	Aug	1.10
Sep	5.00	Sep	1.80	Sep	6.20	Sep	2.60	Sep	1.50	Sep	1.50	Sep	2.10	Sep	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	Jan 2011	1.60
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

The Empire District Electric Company
File No. ER-2011-0004



SCHEDULE 3-2

The Empire District Electric Company
File No. ER-2011-0004

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	Jun	7.67	June	6.39	June	5.55
Jul	16.04	Jul	9.19	Jul	9.66	Jul	8.47	Jul	6.99	Jul	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	Jan 2011	5.69
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 to January 2011

SCHEDULE 4-1

The Empire District Electric Company
File No. ER-2011-0004

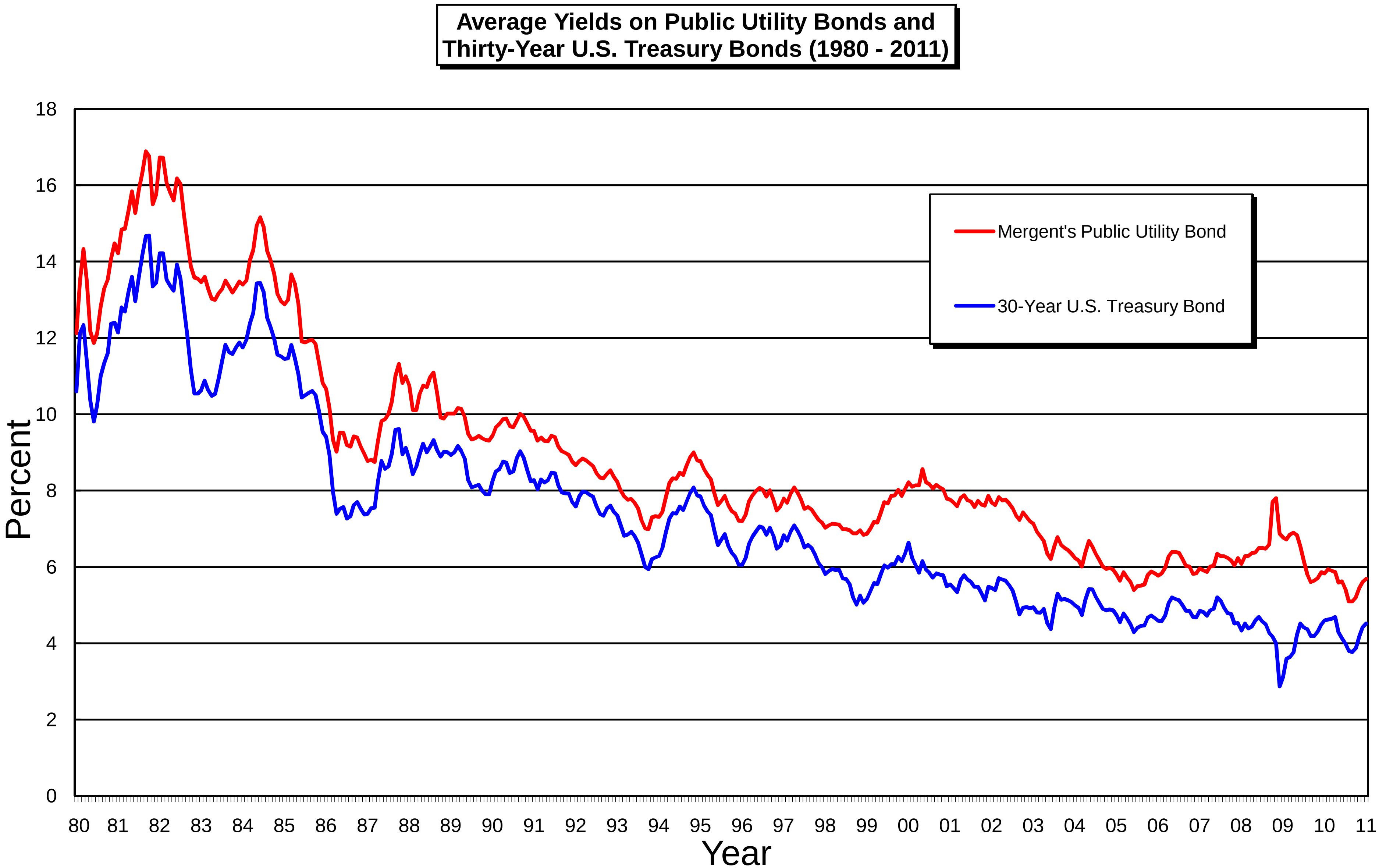
Average Yields on Thirty-Year U.S. Treasury Bonds

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	Jan 2011	4.52
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

SCHEDULE 4-2

The Empire District Electric Company
File No. ER-2011-0004

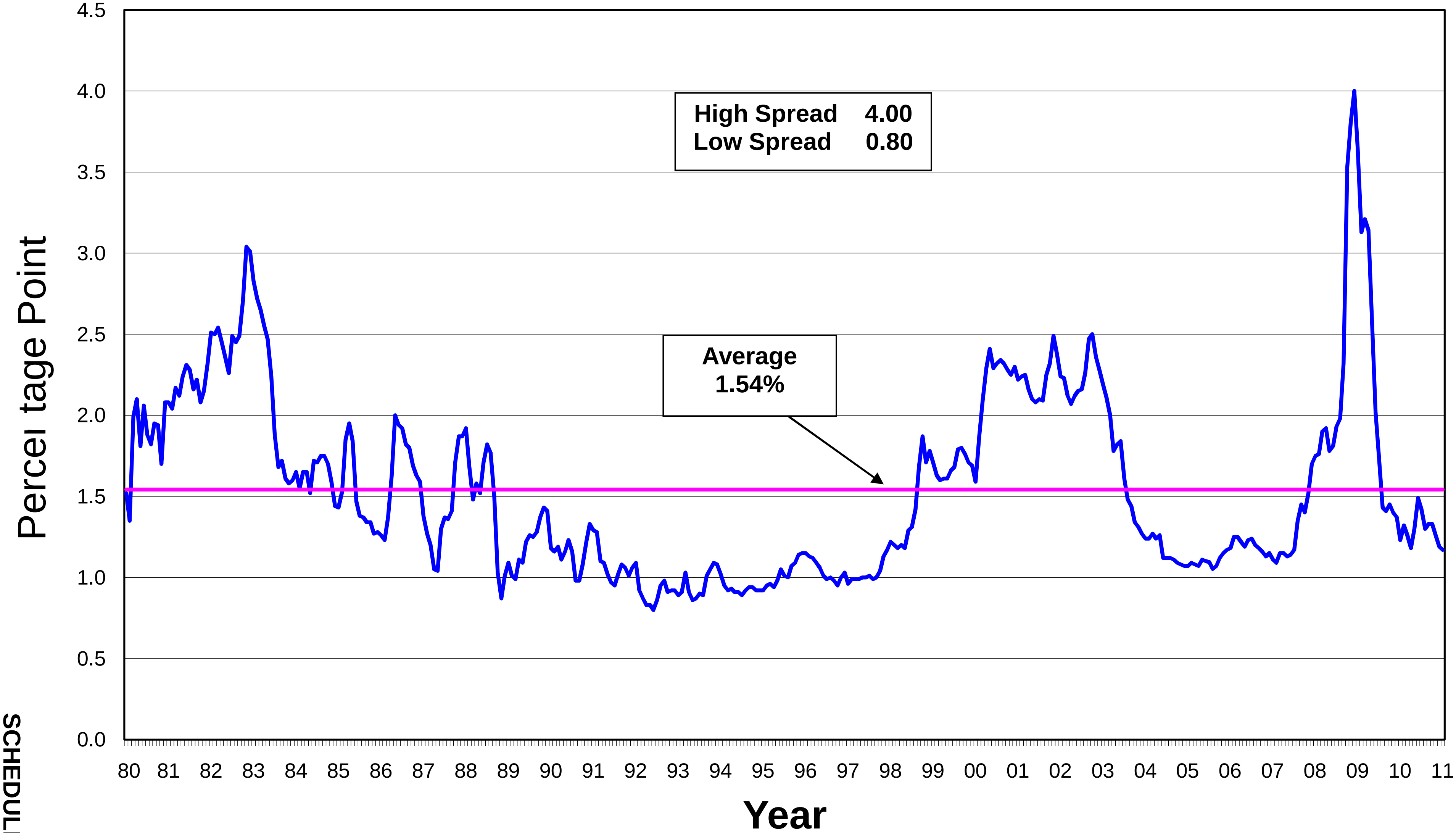


SCHEDULE 4-3

SCHEDULE 4-3

The Empire District Electric Company
File No. ER-2011-0004

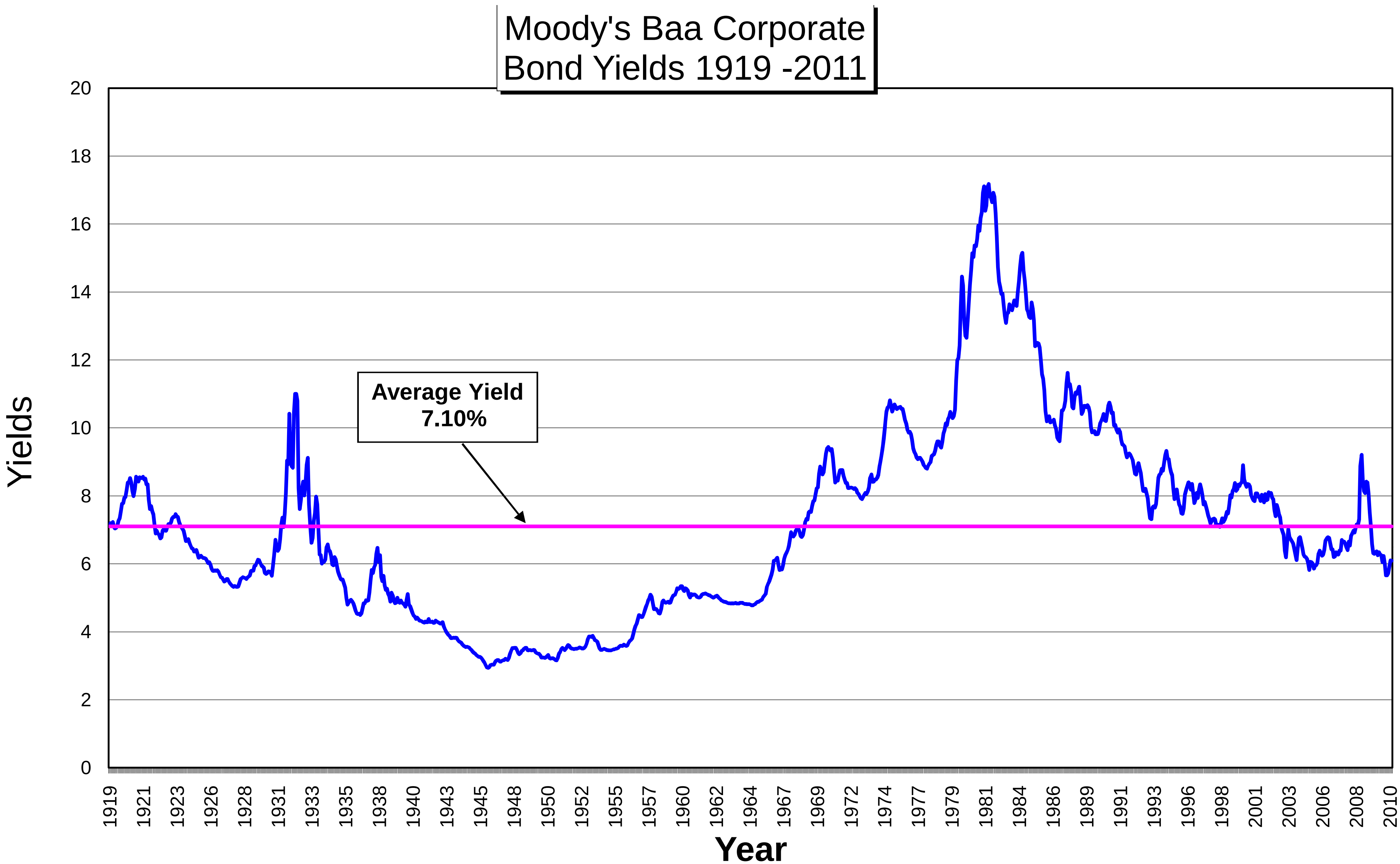
Monthly Spreads Between Yields on Public Utility Bonds and Thirty-Year U.S. Treasury Bonds (1980 - 2011)



SCHEDULE 4-4

SCHEDULE 4-4

The Empire District Electric Company
File No. ER-2011-0004



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

The Empire District Electric Company
File No. ER-2011-0004

Historical Consolidated Capital Structures for The Empire District Electric Company

Capital Components	2005	2006	2007	2008	2009	5-Year Average
Common Equity	$393,411,000.0	$468,609,000.0	$539,176,000.0	$528,872,000.0	$600,150,000.0	$506,043,600.0
Preferred Stock	0.0	0.0	0.0	0.0	0.0	$0.0
Long-Term Debt	408,173,000.0 *	462,539,000.0 *	541,880,000.0 *	611,567,000.0 *	640,156,000.0 *	$532,863,000.0
Short-Term Debt	30,952,000.0	77,050,000.0	33,040,000.0	102,000,000.0	50,500,000.0	$58,708,400.0
Total	$832,536,000.0	$1,008,198,000.0	$1,114,096,000.0	$1,242,439,000.0	$1,290,806,000.0	$1,097,615,000.0

Capital Components	2005	2006	2007	2008	2009	5-Year Average
Common Equity	47.25%	46.48%	48.40%	42.57%	46.49%	46.24%
Preferred Stock	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
Long-Term Debt	49.03%	45.88%	48.64%	49.22%	49.59%	48.47%
Short-Term Debt	3.72%	7.64%	2.97%	8.21%	3.91%	5.29%
Total	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%

Source: Empire District Electric Company's 2005, 2006, 2007, 2008 and 2009 Annual Reports.

Note: * The amount of long-term debt includes current maturities and capital leases.

SCHEDULE 5

The Empire District Electric Company
File No. ER-2011-0004

Embedded Cost of Long-Term Debt
as of November 30, 2010

	Amount Outstanding	Annual Cost
Bonds and Unsecured Notes Series:		
7.2% Series, Due 2016	$25,000,000	$1,800,000
5.2% Pollution Control Series, Due 2013	$5,200,000	$270,400
5.3% Pollution Control Series, Due 2013	$8,000,000	$424,000
5.2% Series, due in 2040	$50,000,000	$2,600,000
6.7% Sr. Notes, Series, Due 2033	$62,000,000	$4,154,000
5.8% Sr. Notes, Series, Due 7/1/2035	$40,000,000	$2,320,000
4.65% Series, Due 6/1/2020	$100,000,000	$4,650,000
4.5% Sr. Notes, Series, Due 2013	$98,000,000	$4,410,000
5.875%, Due 2037	$80,000,000	$4,700,000
6.82% Series, Due 6/1/2036-EDG	$55,000,000	$3,751,000
FMB 6.375% Series, Due 6/1/2018	$90,000,000	$5,737,500
7.0% Series, Due 2/28/2024	$74,854,000	$5,239,780
Premium, Discount and Expense	-$20,406,677 [1]	$2,385,014 [1]
Total	**$667,647,323**	**$42,441,694**

Embedded Cost of Long-term Debt	**6.36%**

Source: Response to DR No. 0099.1 and 101.1.

[1] Adjustment made for disallowance associated with Empire's debt expenses incurred to amend its mortgage bond indenture in order to allow it to maintain its current divident per share.

The Empire District Electric Company
File No. ER-2011-0004

Capital Structure as of November 30, 2010
The Empire District Electric Company

Capital Component	Dollar Amount (000's)	Percentage of Capital
Common Stock Equity	$ 650,734,674	49.36%
Preferred Stock	$ -	0.00%
Long-Term Debt	$ 667,647,323	50.64%
Short-Term Debt	$ -	0.00%
Total Capitalization	**$ 1,318,381,997**	**100.00%**

Source: Responses to Staff DR No. 0099.1.

The Empire District Electric Company
File No. ER-2011-0004
Criteria for Selecting Comparable Electric Utility Companies

(1) Value Line 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) 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

The Empire District Electric Company
Filee No. ER-2011-0004

Comparable Electrical Utility Companies
for The Empire District Electric Company

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+
		The Empire District Electric Company		BBB-

The Empire District Electric Company
File No. ER-2011-0004

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 26, December 24, 2010 and February 4, 2011.

SCHEDULE 10-1

The Empire District Electric Company
File No. ER-2011-0004

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

	------ 5-Year Annual Compound Growth Rates -------			
Company Name	DPS	EPS	BVPS	Average of 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%**	**7.17%**	**5.20%**	**4.23%**

Source: The Value Line Investment Survey: Ratings & Reports, November 26, December 24, 2010 and February 4, 2011.

SCHEDULE 10-2

The Empire District Electric Company
File No. ER-2011-0004

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%	5.50%	5.83%
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%**	**4.65%**	**5.10%**

Source: The Value Line Investment Survey: Ratings & Reports, November 26, December 24, 2010 and February 4, 2011.

SCHEDULE 10-3

The Empire District Electric Company
File No. ER-2011-0004

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 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%	5.83%	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%	4.99%	4.50%	4.75%
Westar Energy, Inc.	-3.00%	7.33%	5.00%	7.62%	8.50%	8.06%
Xcel Energy	-1.83%	4.33%	4.50%	6.07%	5.50%	5.79%
Average	**0.73%**	**4.23%**	**5.10%**	**5.82%**	**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 February 7, 2011.

Column 5 = The Value Line Investment Survey: Ratings & Reports, November 26, December 24, 2010 and February 4, 2011.

SCHEDULE 10-4

The Empire District Electric Company
File No. ER-2011-0004

Average High / Low Stock Price for November 2010 through January 2011
for the Comparable Electric Utility Companies

	(1)	(2)	(3)	(4)	(5)	(6)	(7)
	-- November 2010 --		-- December 2010 --		--January 2011 --		**Average High/Low Stock Price (11/10 - 1/11)**
Company Name	High Stock Price	Low Stock Price	High Stock Price	Low Stock Price	High Stock Price	Low Stock Price	
Alliant Energy	37.65	35.69	37.32	36.28	37.76	36.78	**36.91**
American Electric Power	37.94	35.36	36.47	34.92	36.92	35.19	**36.13**
Cleco Corp.	31.76	30.10	31.22	30.05	31.83	30.56	**30.92**
DPL Inc.	27.10	25.03	26.45	25.32	23.73	25.44	**25.51**
IDACORP, Inc.	37.34	35.46	37.76	36.57	38.72	36.53	**37.06**
PG&E Corp.	48.63	46.16	48.63	46.61	47.99	45.91	**47.32**
Pinnacle West Capital	42.44	39.97	41.99	40.15	42.26	40.71	**41.25**
Southern Company	38.48	37.32	38.49	37.43	38.79	37.55	**38.01**
Westar Energy, Inc.	25.90	24.64	25.52	24.50	26.07	25.05	**25.28**
Xcel Energy	24.36	23.17	23.89	23.20	24.14	23.26	**23.67**

Notes:

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

Source: http://finance.yahoo.com

SCHEDULE 11

The Empire District Electric Company
File No. ER-2011-0004

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

Company Name	(1) Expected Annual Dividend	(2) Average High/Low Stock Price	(3) Projected Dividend Yield
Alliant Energy	$1.65	$36.913	4.47%
American Electric Power	$1.84	$36.133	5.09%
Cleco Corp.	$1.08	$30.920	3.49%
DPL Inc.	$1.28	$25.512	5.02%
IDACORP, Inc.	$1.20	$37.063	3.24%
PG&E Corp.	$1.92	$47.322	4.06%
Pinnacle West Capital	$2.10	$41.253	5.09%
Southern Company	$1.88	$38.010	4.95%
Westar Energy, Inc.	$1.28	$25.280	5.06%
Xcel Energy	$1.03	$23.670	4.35%
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 & Reports, November 26, December 24, 2010 and February 4, 2011.

Column 2 = Schedule 11.

The Empire District Electric Company
File No. ER-2011-0004

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%	8.57%
American Electric Power	$1.84	3.63%	3.52%	3.42%	3.31%	3.21%	3.10%	3.00%	8.45%
Cleco Corp.	$1.00	6.25%	5.71%	5.17%	4.63%	4.08%	3.54%	3.00%	7.09%
DPL Inc.	$1.21	7.50%	6.75%	6.00%	5.25%	4.50%	3.75%	3.00%	9.40%
IDACORP, Inc.	$1.20	5.09%	4.74%	4.39%	4.04%	3.70%	3.35%	3.00%	6.81%
PG&E Corp.	$1.82	6.15%	5.63%	5.10%	4.58%	4.05%	3.53%	3.00%	7.82%
Pinnacle West Capital	$2.10	6.33%	5.77%	5.22%	4.66%	4.11%	3.55%	3.00%	9.39%
Southern Company	$1.82	4.75%	4.45%	4.16%	3.87%	3.58%	3.29%	3.00%	8.49%
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	5.79%	5.32%	4.86%	4.39%	3.93%	3.46%	3.00%	8.22%
									8.40%

Sources: Column 1 = The Value Line Investment Survey: Ratings & Reports, November 26, December 24, 2010 and February 4, 2011.
Column 2 = Reuters.com on February 7, 2011.
Column 8 = See range of averages from Schedule 14-1 through 14-4 and Schedule 15.

The Empire District Electric Company
File No. ER-2011-0004

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%	8.93%
American Electric Power	$1.84	3.63%	3.60%	3.58%	3.56%	3.54%	3.52%	3.50%	8.81%
Cleco Corp.	$1.00	6.25%	5.79%	5.33%	4.88%	4.42%	3.96%	3.50%	7.48%
DPL Inc.	$1.21	7.50%	6.83%	6.17%	5.50%	4.83%	4.17%	3.50%	9.74%
IDACORP, Inc.	$1.20	5.09%	4.82%	4.56%	4.29%	4.03%	3.76%	3.50%	7.21%
PG&E Corp.	$1.82	6.15%	5.71%	5.27%	4.83%	4.38%	3.94%	3.50%	8.19%
Pinnacle West Capital	$2.10	6.33%	5.85%	5.38%	4.91%	4.44%	3.97%	3.50%	9.74%
Southern Company	$1.82	4.75%	4.54%	4.33%	4.12%	3.92%	3.71%	3.50%	8.85%
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	5.79%	5.40%	5.02%	4.64%	4.26%	3.88%	3.50%	8.58%
									8.77%

Sources: Column 1 = The Value Line Investment Survey: Ratings & Reports, November 26, December 24, 2010 and February 4, 2011.
Column 2 = Reuters.com on February 7, 2011.
Column 8 = See range of averages from Schedule 14-1 through 14-4 and Schedule 15.

The Empire District Electric Company
File No. ER-2010-0355

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%	9.29%
American Electric Power	$1.84	3.63%	3.69%	3.75%	3.81%	3.88%	3.94%	4.00%	9.17%
Cleco Corp.	$1.00	6.25%	5.88%	5.50%	5.13%	4.75%	4.38%	4.00%	7.88%
DPL Inc.	$1.21	7.50%	6.92%	6.33%	5.75%	5.17%	4.58%	4.00%	10.09%
IDACORP, Inc.	$1.20	5.09%	4.90%	4.72%	4.54%	4.36%	4.18%	4.00%	7.61%
PG&E Corp.	$1.82	6.15%	5.79%	5.43%	5.08%	4.72%	4.36%	4.00%	8.57%
Pinnacle West Capital	$2.10	6.33%	5.94%	5.55%	5.16%	4.78%	4.39%	4.00%	10.08%
Southern Company	$1.82	4.75%	4.62%	4.50%	4.37%	4.25%	4.12%	4.00%	9.21%
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	5.79%	5.49%	5.19%	4.89%	4.60%	4.30%	4.00%	8.95%
									9.13%

Sources: Column 1 = The Value Line Investment Survey: Ratings & Reports, November 26, December 24, 2010 and February 4, 2011.
Column 2 = Reuters.com on February 7, 2011.
Column 8 = See range of averages from Schedule 14-1 through 14-4 and Schedule 15.

The Empire District Electric Company
File No. ER-2011-0004

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%**

The Empire District Electric Company
File No. ER-2011-0004

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	& Electric/ OGE Energy	SJL&P	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 14-2

The Empire District Electric Company
File No. ER-2011-0004

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	& Electric/ OGE Energy	SJL&P	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 14-3

The Empire District Electric Company
File No. ER-2011-0004

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

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
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 14-4

The Empire District Electric Company
File No. ER-2011-0004

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*

The Empire District Electric Company
File No. ER-2011-0004

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	4.38%	0.70	6.00%	4.40%	8.58%	7.46%
American Electric Power	4.38%	0.70	6.00%	4.40%	8.58%	7.46%
Cleco Corp.	4.38%	0.65	6.00%	4.40%	8.28%	7.24%
DPL Inc.	4.38%	0.60	6.00%	4.40%	7.98%	7.02%
IDACORP, Inc.	4.38%	0.70	6.00%	4.40%	8.58%	7.46%
PG&E Corp.	4.38%	0.55	6.00%	4.40%	7.68%	6.80%
Pinnacle West Capital	4.38%	0.70	6.00%	4.40%	8.58%	7.46%
Southern Company	4.38%	0.55	6.00%	4.40%	7.68%	6.80%
Westar Energy, Inc.	4.38%	0.75	6.00%	4.40%	8.88%	7.68%
Xcel Energy	4.38%	0.65	6.00%	4.40%	8.28%	7.24%
Average		**0.66**			**8.31%**	**7.26%**

Column 1 = The appropriate yield is equal to the average 30-year U.S. Treasury Bond yield for November and December 2010 and January 2011, 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 26, December 24, 2010 and February 4, 2011.

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)).

SCHEDULE 16

The Empire District Electric Company
File No. ER-2011-0004

Weighted Cost of Capital as of November 30, 2010
for The Empire District Electric Company

			Weighted Cost of Capital Using Common Equity Return of:		
Capital Component	Percentage of Capital	Embedded Cost	**8.60%**	**9.10%**	**9.60%**
Common Stock Equity	49.36%	-----	4.24%	4.49%	4.74%
Preferred Stock	0.00%	0.00%	0.00%	0.00%	0.00%
Long-Term Debt	50.64%	6.36%	3.22%	3.22%	3.22%
Short-Term Debt	0.00%	0.00%	0.00%	0.00%	0.00%
Total	**100.00%**		**7.46%**	**7.71%**	**7.96%**

Notes:
See Schedule 7 for the Capital Structure Ratios.

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

EDISON ELECTRIC INSTITUTE

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Stock Performance

Q4 2010
FINANCIAL UPDATE

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

EEI 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

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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)

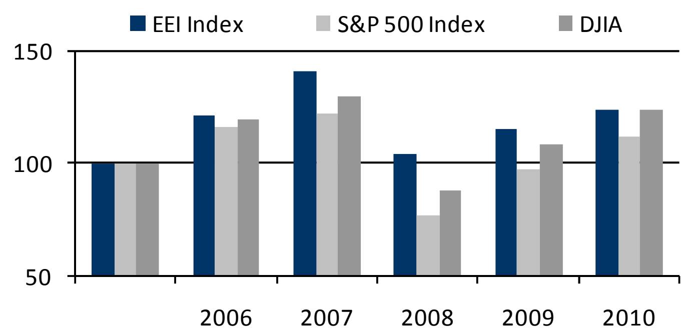
U.S. Shareholder-Owned Electric Utilities

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

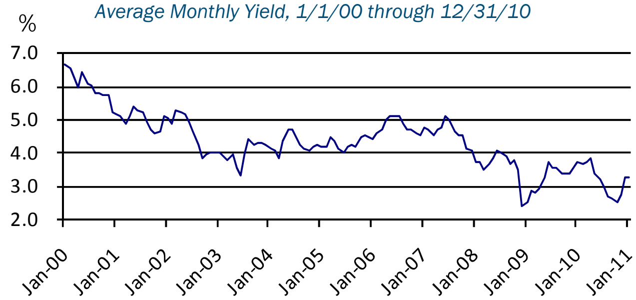
Value of $100 invested at close on 12/31/2005



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

IV. 10-Year Treasury Yield — Monthly

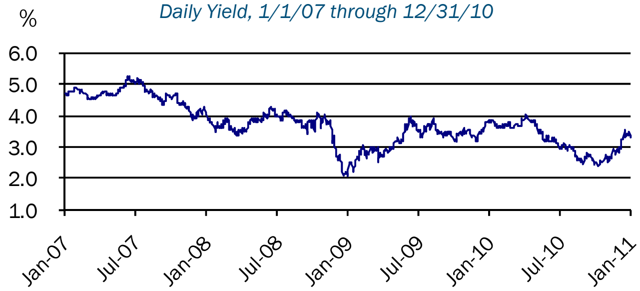
Average Monthly Yield, 1/1/00 through 12/31/10



Source: U.S. Federal Reserve

V. 10-Year Treasury Yield — Daily

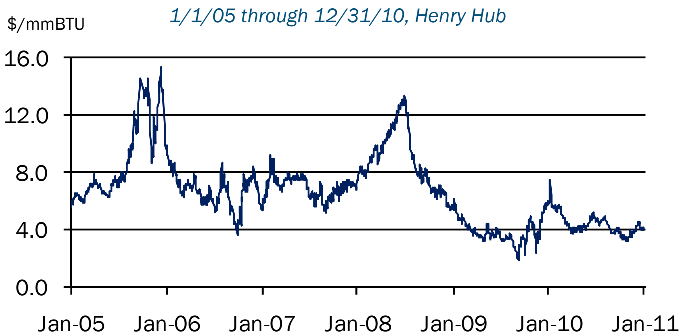
Daily Yield, 1/1/07 through 12/31/10



Source: U.S. Federal Reserve

VI. Natural Gas Spot Prices

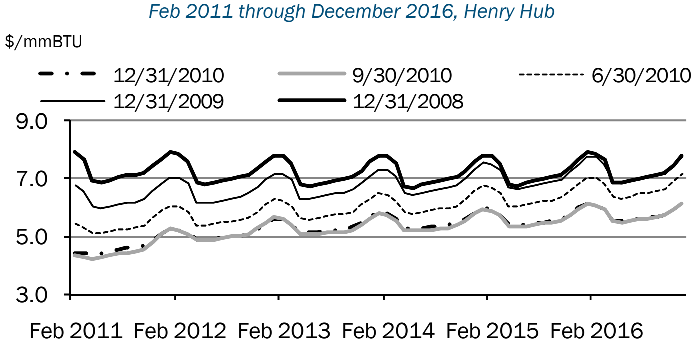
1/1/05 through 12/31/10, Henry Hub



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

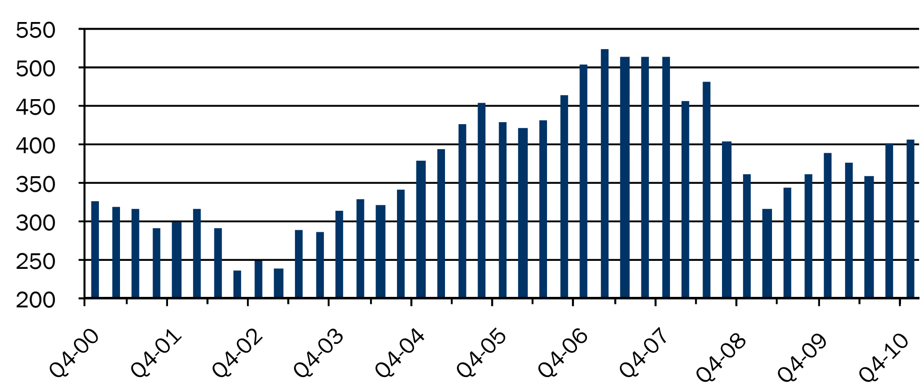
Company	Stock Symbo	$ Ma ket Cap	% Tota	Company	Stock Symbo	$ Ma ket Cap	% Tota
Southe n Company	SO	31 958 5	7 85%	Al ant Ene gy Co p	LNT	4 061 9	1 00%
Exe on Co po at on	EXC	27 572 3	6 77%	MDU Resou ces G oup	MDU	3 814 2	0 94%
Dom n on Resou ces nc	D	24 991 2	6 14%	TECO Ene gy nc	TE	3 792 1	0 93%
Duke 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

$ B ons



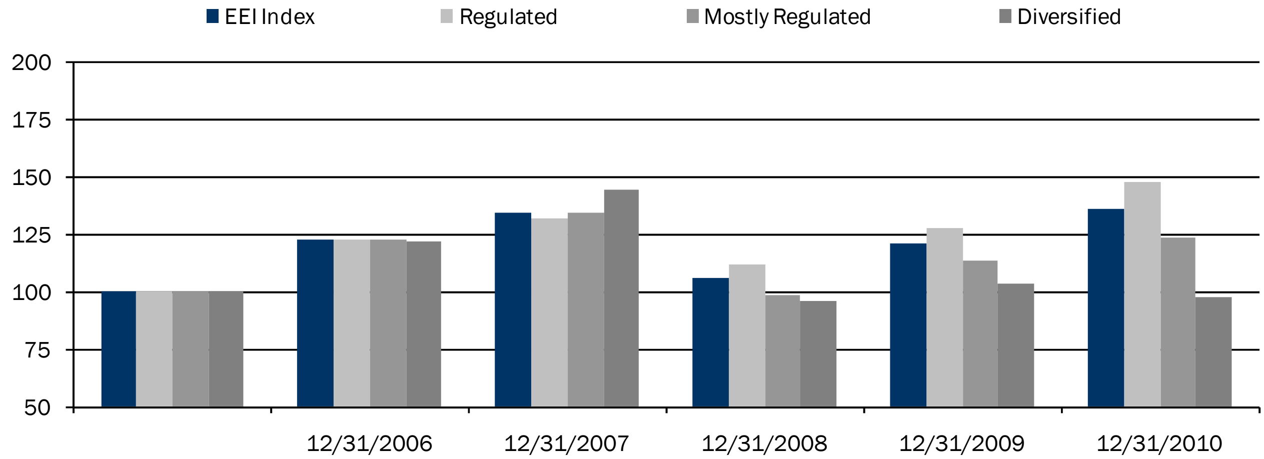
Note: Change in EEI Index market capitalization reflects the impact of buyout and spin-off activity in addition to stock market performance.
Source: EEI Finance Department and Wall Street Journal

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.

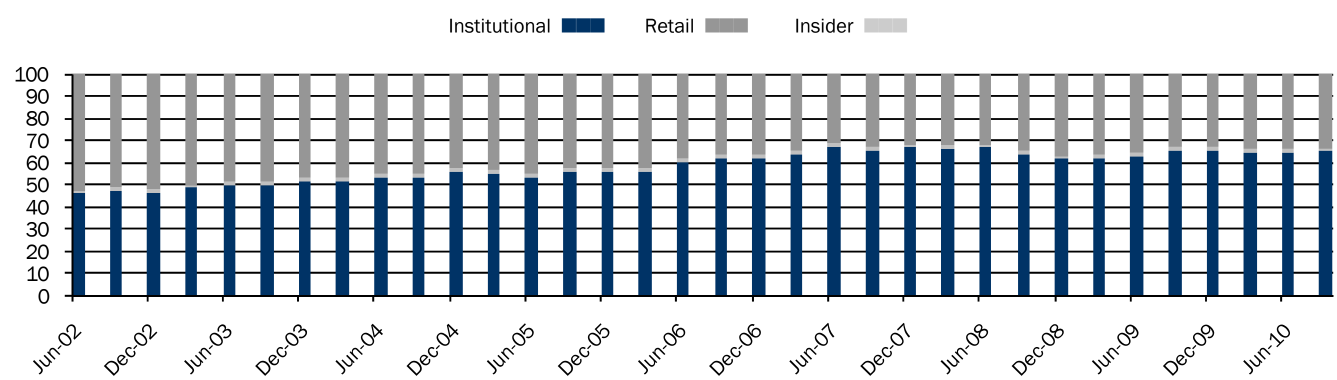
As shown in Chart VI, after an early-year winter rally, spot gas prices languished around $4/mm BTU for most of the year. Chart VII shows the marked decline in futures prices during the second half of 2010 and over the past two years. Domestic natural gas supply has been boosted by production from low-cost 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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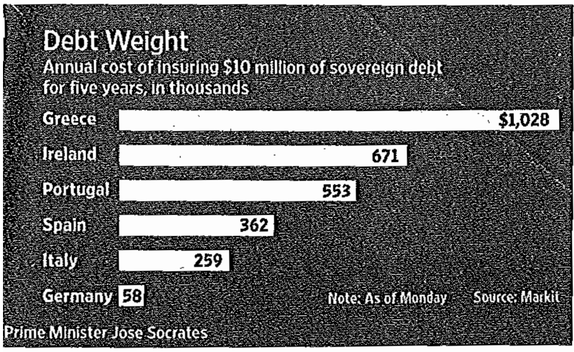
Debt Weight

Annual cost of insuring $10 million of sovereign debt for five years, in thousands



Prime Minister Jose Socrates

European Pressphoto Agency

'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

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.

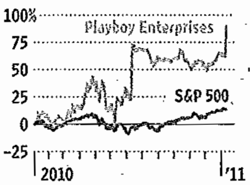
* * *

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 back-door. 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.

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

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

Utilities

POWER & UTILITIES
Utilities

SECTOR VIEW

Rating: 2 - NEUTRAL

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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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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.

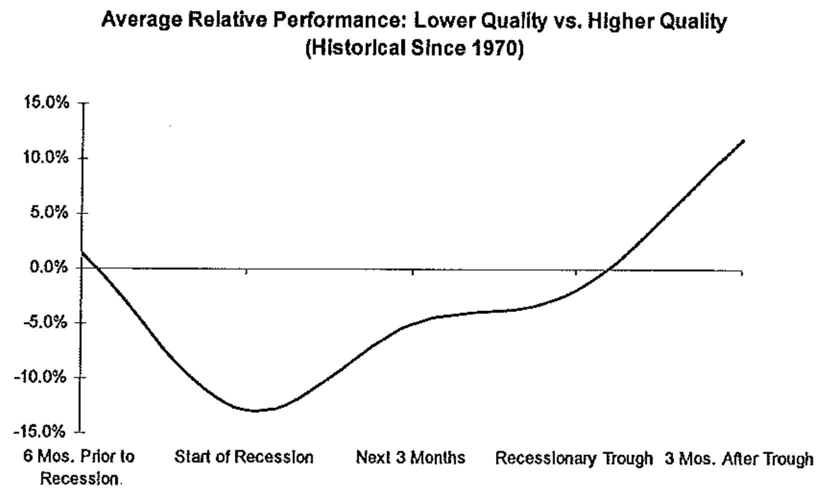
In the short term, we believe the investment winners will be driven by macro fund flows in support of fundamentals. Based on the precedent of previous recessions, higher quality utility names with good liquidity attract investors during the earlier stages, and as the recession matures, investors move 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.

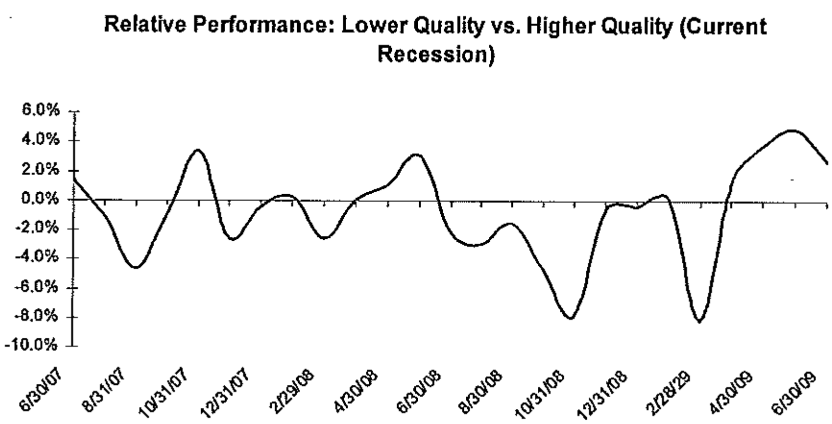
On a broader look at past recessions, this pattern also holds. The higher quality / lower tier pairing has produced on average 18% returns beginning 6 months prior to the recession through the recession's trough. This performance is the average of the recessions since 1970. Conversely, as the market 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	$311,596	$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	$48,730	$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 1.06x 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	1,691 (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	500	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**

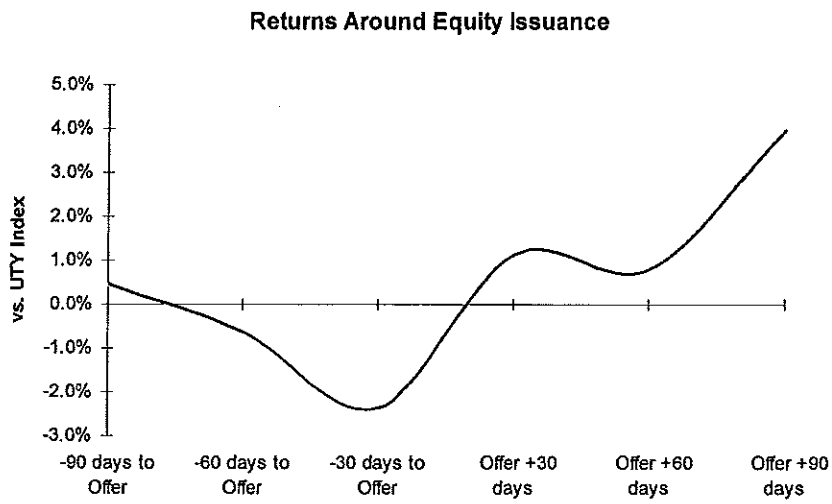
(1) Represents actual or estimated marketed offerings, as opposed to DRIP or dribble programs.

Note: Gray cells indicate actual amounts issued

Source: Company filings, Barclays Capital estimates.

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

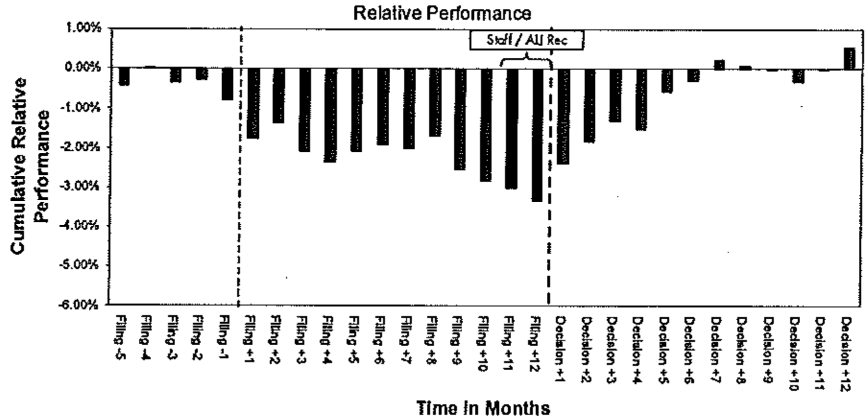


Source: FactSet.

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

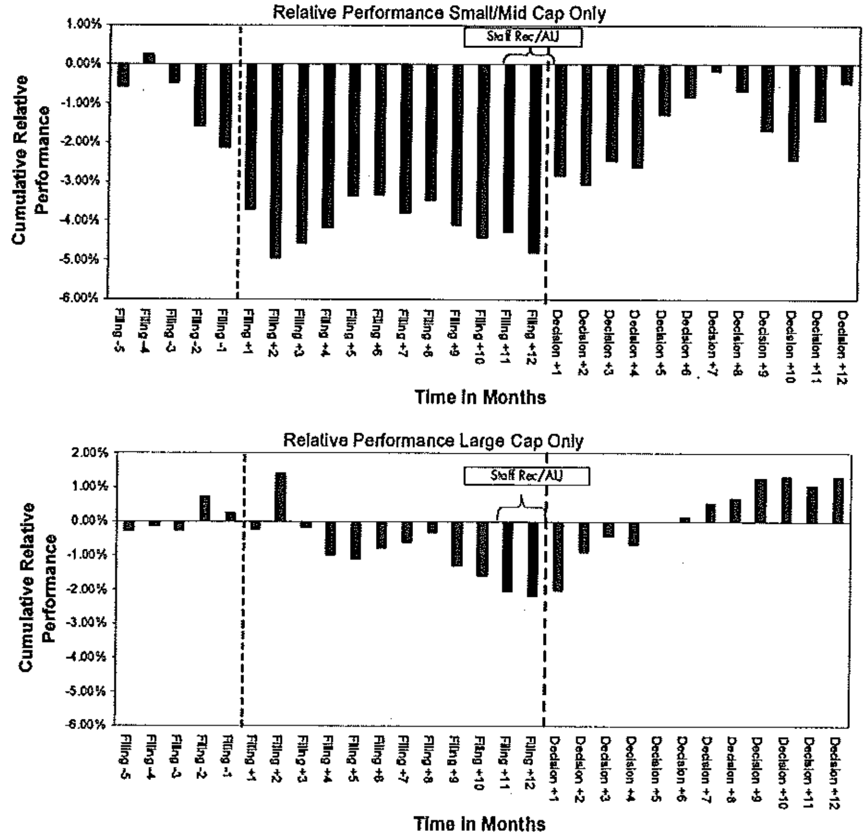


Source: SNL Financial, Bloomberg, Barclays Capital estimates.

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.

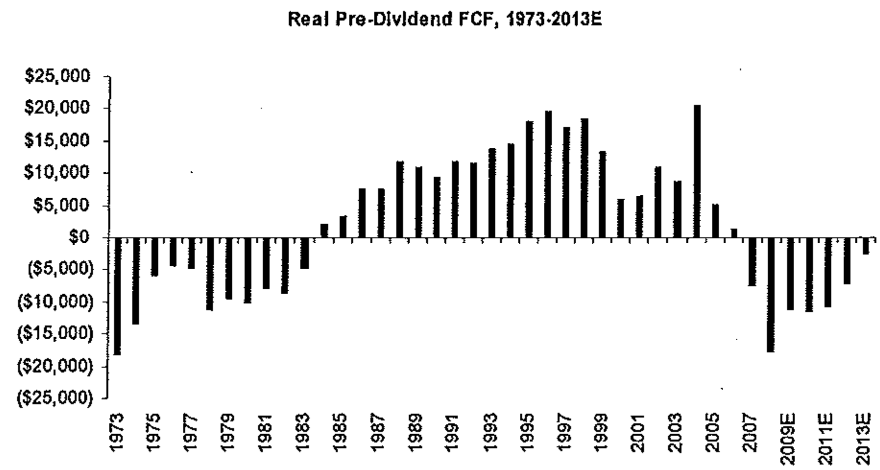
This is in fact the case, as shown in Figure 9. The trading returns from the same general "short-then-long" strategy as described above is 480 bp and 433 bp for small cap utilities and 221 bp and 353 bp for large cap utilities. Before the systemic-risk-driven market of 2008, for the same strategies,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

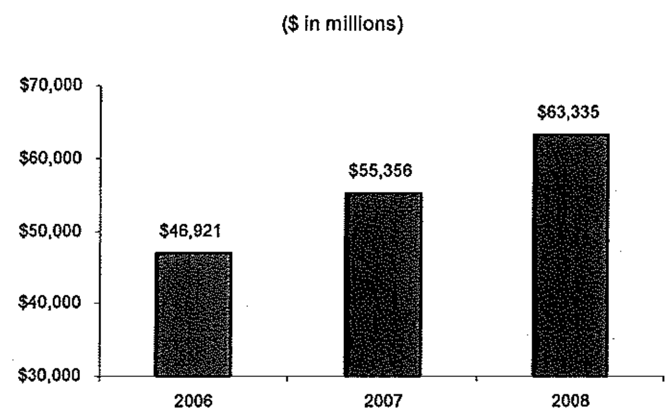


Source: FactSet, Barclays Capital estimates.

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)

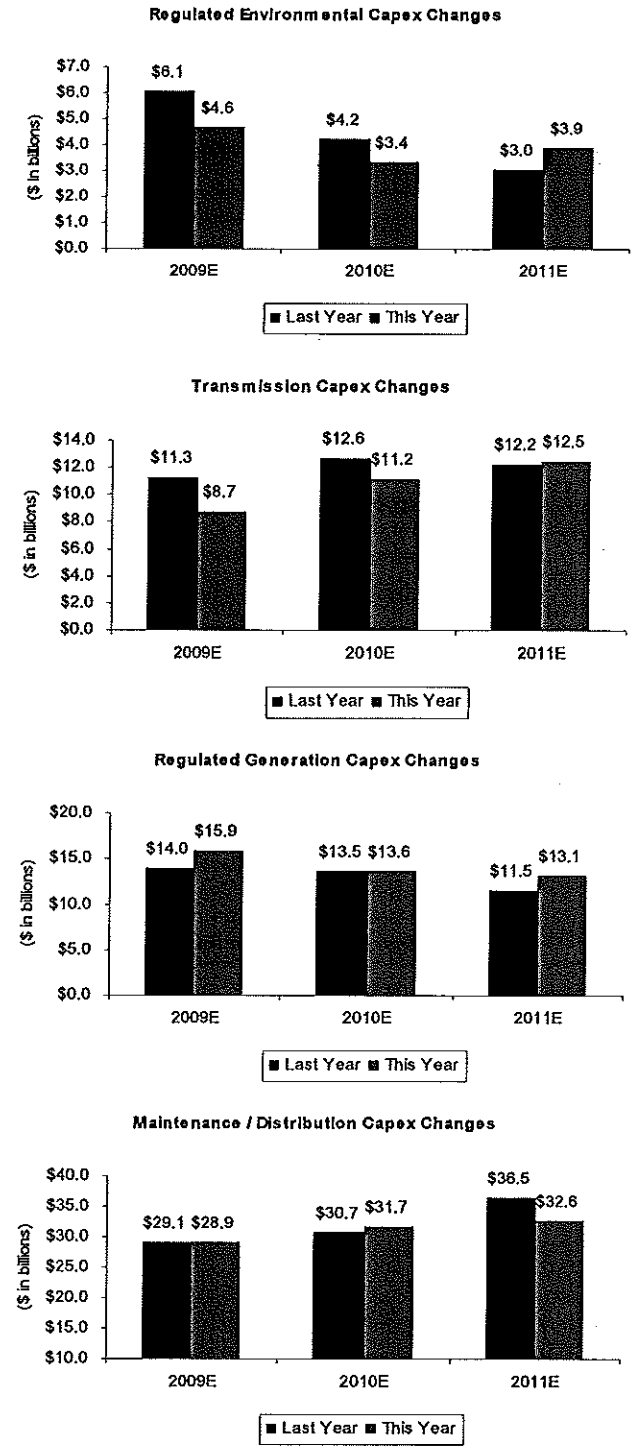
	2006	2007	2008	2009E	2010E	2011E	2012E	2013E	Total
Maintenance / Distribution				$28,950	$31,654	$32,601	$35,390	$36,760	$165,354
Generation				15,855	13,620	13,062	12,518	12,190	$67,246
Environmental				4,644	3,359	3,886	2,218	2,278	$16,384
Transmission				8,695	11,187	12,508	13,157	11,299	$56,845
Total	**$46,921**	**$55,356**	**$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 refect 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)

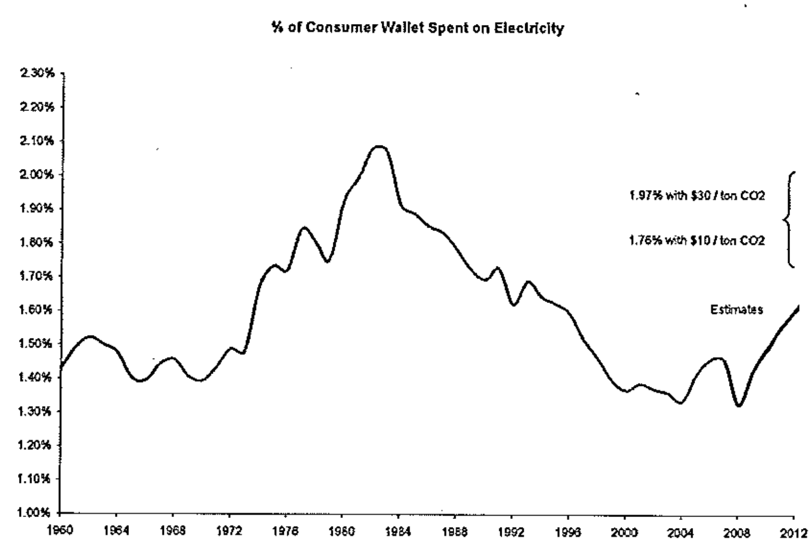
	2008	2009E	2010E	2011E	2012E	2013E
Rate Base	$452,887	$492,335	$524,266	$555,480	$586,449	$616,113
Capital Expenditures	$63,335	$58,144	$59,819	$62,057	$63,282	$62,527
D&A	$23,887	$26,213	$28,605	$31,088	$33,619	$36,120
Rate Base Additions	$39,448	$31,931	$31,214	$30,970	$29,663	$26,407
Rate Base Growth %	9.5%	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	$326,506	$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	$641	$794	$428	$399
Plus: Incremental Transmission				$2,180	$2,136	$2,556	$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	$25,840	$22,420
New Projected Revenue Base	$326,506	$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	3,721,562	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;

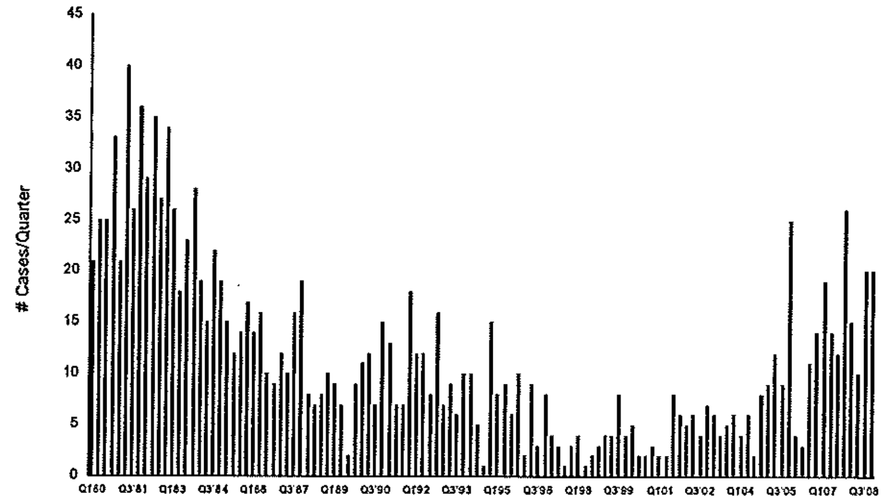
2) A squeezing of spreads as in the face of large and frequent rate increase requests, regulators tend to scrutinize allowed ROEs for excess returns; and

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

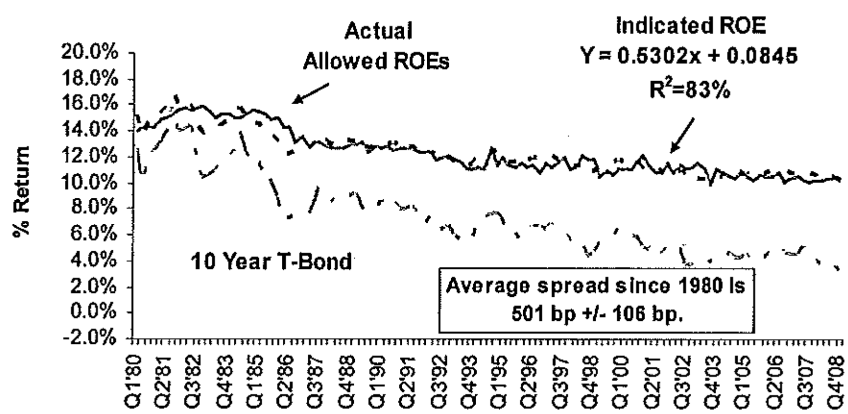
Figure 19: Average Rate Case Outcomes & Relationships, 2005-2009

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.

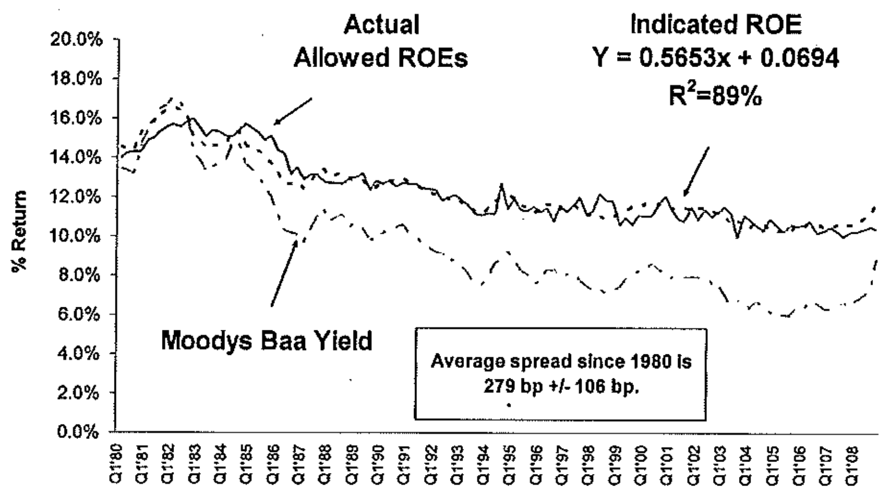
Figure 20: Allowed ROEs vs. 10 Year Bond Yields



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



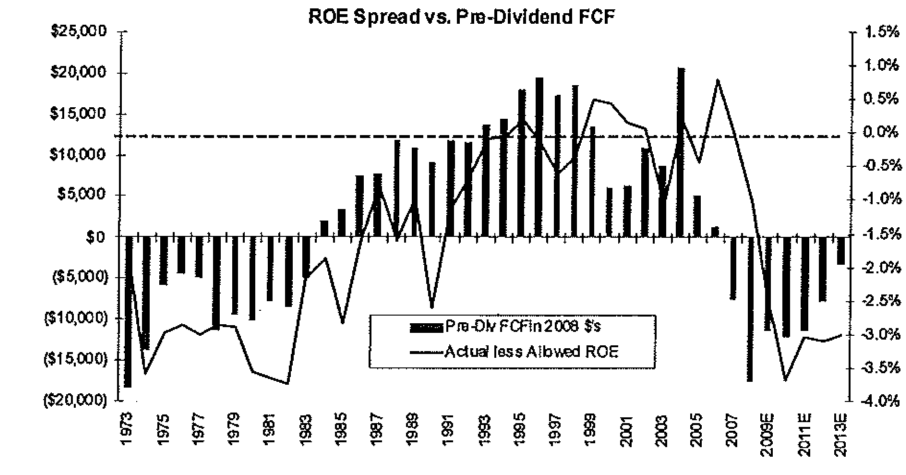
Source: SNL Financial, Federal Reserve, Barclays Capital estimates.

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.

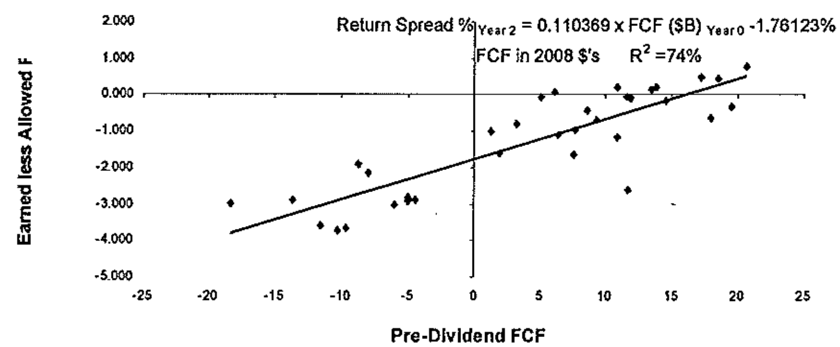
Figure 22: Regulatory Lag Throughout Capital Cycles, Historical & Projected



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

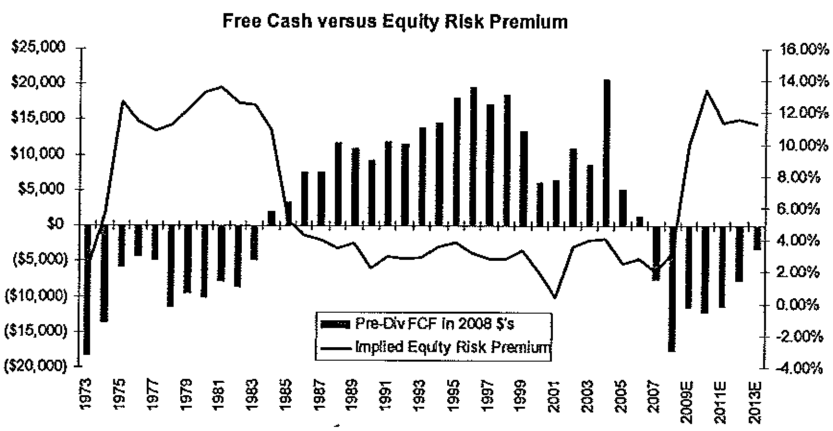
	2005A	2006A	2007A	2008A	2009E	2010E	2011E	2012E	2013E
Pre-Dividend FCF	$4,731	$1,250	($7,128)	($17,605)	($11,563)	($12,206)	($11,394)	($7,713)	($3,361)
Projected Allowed ROE	10.50%	10.38%	10.23%	10.35%	10.56%	11.16%	10.97%	10.78%	10.60%
Projected Over- (Under) Earn	-0.85%	0.07%	-1.24%	-1.62%	-2.55%	-3.70%	-3.04%	-3.11%	-3.02%
Projected Earned ROE	9.65%	10.45%	8.99%	8.73%	8.01%	7.46%	7.94%	7.68%	7.58%
Actual ROE	10.06%	11.16%	10.17%	9.34%	8.74%	8.19%	8.67%	8.41%	8.31%
Discreapancy	-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.

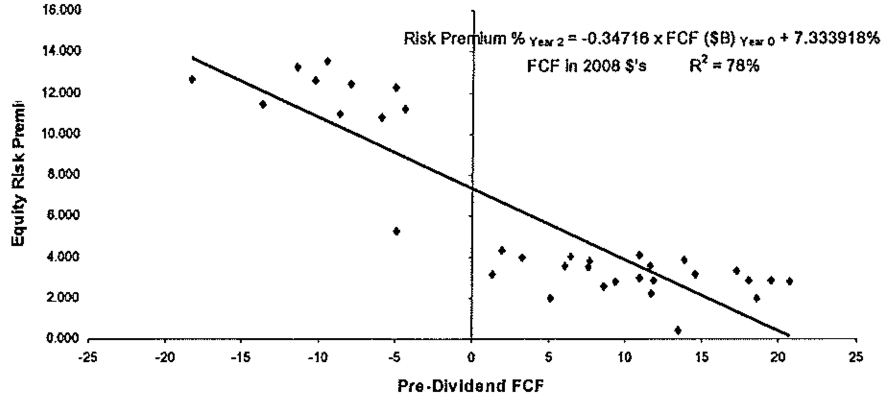
Figure 25: Risk Premiums Throughout Capital Cycles, Historical & Projected



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%)	$600	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 an 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 on 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 20'09, 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.

Figure 38: Summary of NU Regulation by Subsidiary

Subsidiary	Allowed ROE	Expected Distribution Rate Filing	Adjustment Mechanisms/Trackers			
			Fuel & Purchased Power	Electric Transmission Costs	Stranded/ Transition Costs	Pension Tracker
CL&P	9.40%	Late '09/Early '10	x	x	x	
PSNH Dist.	9.67%	Filing Made Spring '09	x	x	x	
WMECO	8% - 12%	Mid - 2010	x	x	x	x
Yankee Gas	10.10%	No Plans	x	n/a	n/a	

Source: Company Presentations

PSNH

On April 17, 2009 PSNH filed a temporary rate increase request with the Public Service Commission of New Hampshire (NH PSC). The generation side of the business is regulated at the state level with trackers and a set ROE somewhat similarly to federal transmission regulation. The temporary increase requested $36.4 million in annualized revenues to be effective on August 1, 2009. Subsequently, the company filed a notice of intent with the commission stating that they would file a new rate schedule on or before July 1, 2009 that would constitute a $51 million rate increase. The company would request rates effective as of August 1, 2009 and as is typical in New Hampshire the rate increase would be suspended by the commission pending a full general rate case review. This full GRC review would be expected to last about a year. The rate case metrics attached to either requested increase were not made public as of this writing; however, according to earlier projections by the company, we would expect the year-end average rate base to be about $774 million for distribution assets and about $389 million for generation assets. The NH PSC could grant both the temporary increase and a further increase, dependent upon the result of the full GRC review, or they could deny the temporary increase and merely adjudicate the full GRC. The company currently is regulated under a decision rendered by the commission on May 25, 2007 which allowed a $50.1 million rate increase (+4%), which was premised upon a year-end 2005 average rate base of about $668 million, a 47.66% equity ratio, and a 9.67% return on equity.

CL&P

The company has stated publicly that given current economic conditions that the anticipated rate case filing in CT would be delayed from mid-year 2009 to late year 2009 or early in 2010. We do have concerns around regulation in CT given the recent decision for a separate company, United Illuminating, in that state. To briefly review that case, in November 2008, United Illuminating requested a $52.4 million revenue increase premised upon a rate base of about $511 million, a 10.75% return on equity and a 50% equity ratio. In February 2009, the CT Department of Public Utility Control (DPUC) approved a rate increase of $6.1 million, premised upon a rate base of about $499 million, and equity ratio of 50% and a return on equity of 8.75%. After the rate order United Illuminating announced plans to cut capital expenditures by $50 million after which the CPUC and the CT Attorney General Richard Blumenthol became concerned over how this cut would impact reliability. The Attorney General filed a petition on May 18 with the DPUC asking the commission to review whether United Illuminating violated the order by reducing O&M expenses. United Illuminating then filed a petition with the DPUC saying the Attorney General's request was without factual support, and that the brief period of reduced expenditures would not impact reliability. The DPUC has stated that it wants to monitor capital and operating expenditure levels going forward.

In our view, the United Illuminating situation remains worth watching going forward and the 8.75% return on equity is a concern. If the economy recovers by early 2010 with CL&P is expected to file a better outcome may be in store in that rate case given less political pressure at that time. Based upon the company's projections as of this writing CL&P's rate base at the end of 2009 will be $2.351 billion and at the end of 2010 will be $2.557 billion.

WMECO

We anticipate that WMECO will file a rate case in mid-2010, the projected rate base at the end of 2009 is expected to be $410 million and at the end of 2010 $434 million. WMECO currently operates under an allowed ROE range of 8%–12% with tracked expenses as outlined above.

NSTAR (NST)

A seven-year rate settlement was approved by the Massachusetts Department of Public Utilities (DPU) on 12/30/05. The settlement includes annual inflation-adjusted distribution rate increases that began on January 1, 2007 and continue through 2012. These increases are generally offset by an equal and corresponding reduction in transition rates. The current rate plan incorporates a deferral mechanism for transition costs that are expected to be recovered over the 2010–2013 timeframe. The amount could approach $250 million in 2010. A 10.88% carrying charge is earned on the average balance. A 50%/50% earnings sharing mechanism is triggered if NSTAR Electric's ROE exceeds 12.5% or falls below 8.5%. NSTAR Electric can initiate a rate proceeding if the ROE falls below 7.5%.

The Green Communities Act was enacted on July 2, 2008 by the Massachusetts Legislature and the DPU issued its Decoupling order on July 16, 2008. The act covers solar installations, encourages long-term renewable energy contracts, requires implementation of a smart grid pilot program, establishes a Renewable Portfolio Standards (RPS) goal for the state of 15% by the year 2020, and requires the pursuit of all cost-effective energy efficiencies. The DPU's plan is to phase in a decoupling model between now and 2012. Utilities that are operating under a rate agreement can continue to do so, but for all incremental energy efficiency spending, NST will be able to recover any lost base revenues and earn performance incentives on that spending. NST filed a plan with the DPU for 2009 in December 2008 and has since filed a three year plan.

Transmission Initiatives Update

NST's base transmission ROE is set at 11.64% with the opportunity to earn an additional 100 bp on new construction projects. NST's approximate transmission rate base is $750 million. The company completed a second and final phase of a major underground transmission project in 2008, at a total cost of about $300 million. NST expects 2009 transmission expenditures to be about $100 million.

On May 21, 2009, NST and Northeast Utilities (NU) announced that the FERC ruled favorably on the proposed structure of a transmission arrangement that interconnects New England with the Canadian province of Quebec. FERC approved the participant-funded transmission line between New England and Quebec, and the assignment of firm transmission rights to Hydro-Quebec (HQ) to enable HQ to deliver low-carbon hydroelectric power into New England. The new tie line will use high voltage direct current (HVDC) technology to connect HQ's hydroelectric system and New England's 345-kV system in south central New Hampshire. This will provide approximately 1,200–1,500 mW of import capability into New England at a total cost of an estimated $700 million to $800 million, including NST's share of $200 million. Construction will likely take place in the 2011–2014 timeframe. This corresponds well with NST's current rate plan (described above) which incorporates a deferral mechanism for transition costs that are expected to be recovered (cash) over the 2010–2013 timeframe, including an approximate $250 million in 2010.

NV Energy (NVE)

NVE Energy is the largest utility in the state of Nevada and has two main utility subsidiaries, Sierra Pacific Resources in the northern portion of the state and Nevada Power in the southern portion of the state, whose service territory includes Las Vegas. Both subsidiaries market under the NV Energy name, and the company changed its name and stock symbol from Sierra Pacific Resources (SRP) to NV Energy (NVE) in the past year. Similarly, the two utility subsidiaries at the company whose legal names remain Sierra Pacific Power Co. in the north and Nevada Power Company in the South are now referred to as NV Energy North and NV Energy South.

Under current law in Nevada fuel and purchased power are trued up on a monthly basis and the Commission uses a hybrid test year that adjusts for known and measurable changes. Nevada Power is currently in with a rate case before the Public Utility Commission of Nevada (PUCN) and a decision was made by the commission on June 24 and rates became effective on July 1.

Nevada Legislature

In the just completed legislative session in Nevada the legislature passed some changes to utility regulation in the state. NV Energy North will file their next rate case no later than the first Monday in June 2010, and NV Energy South will file their next rate case no later than the first Monday in June 2011. Holding to the 210 day statutory limit within NV for deciding a rate case the rates from each filing will become effective, subject to Public

Utility Commission of Nevada (PUCN) approval, on January 1 of the year following the filing. Further, the PUCN will be allowed under the new law to allow deferral of rate implementation upon the request of a utility and is allowed to implement low income customer rates. The renewable portfolio standard was increased from 20% to 25% by 2025. The amount of the standard that must come from solar generated power was increased from 5% to 6% of the RPS by 2016. Procurement of power from outside the state will now also be allowed to count against the standard. Further, the commission is now authorized under the new law to develop and adopt regulations allowing for utilities to recover energy efficiency impacts.

Nevada Power

On February 27, 2009, as required under the hybrid test year structure Nevada Power filed a revised request for $305.7 million versus their original request of about $324 million made in December 2008. The revised filing is premised upon a rate base of just over $5.0 billion, an equity ratio of 44.15% and a return on equity of 11%. The Staff recommendation was issued on April 14, 2009 and called for a $202.8 million revenue increase on a rate base of just under $4.6 billion, an equity ratio of 44.15% and a return on equity of 10.5%. The subsidiary currently earns a 10.7% return on equity which is what we model going forward. On June 18' 2009, Commissioner Sam Thompson issued a draft order calling for a $218 million revenue increases premised upon a $4.7 billion rate base, a 44.15% equity ratio, and a 10.4% return on equity. The key difference between the request and the staff rec/proposed order other than the ROE was a disallowance of CWIP in rate base related to the Harry Allen plant. The company is earnings neutral to this outcome as they will book AFUDC on this CWIP going forward. There will be a cash lag related to this, however.

The draft order would de-skew rates from non-residential customers to residential customers. Residential rate increases from this de-skewing will be mitigated as the increase would coincide with a reduction in the Base Tariff Energy Rate (BTER) for fuel costs to take place on January 1, 2010. NPC's revised request called for a residential customer rate increase of 16.7%, and the commission draft order calls for a rate increase of 9.3% (12.3% with the de-skewing). With reductions to the BTER the net increase to customers from the draft order would be 6.8%. To further mitigate rate shock the commission draft order calls for a phase-in of rates in two stages. The first stage would be a 3% increase on 7/1/09 and the second increase would be for the balance of the increase of 3.8% (6.8% estimated net of the BTER less the 3% implemented on 7/1/09) and will occur on 1/1/10. The company will book revenue as though the entire rate increase had occurred on 7/1/09 and hang the cash to revenue difference on the balance sheet for future recovery.

The final order was approved by the PUCN on 6/24 and was slightly better than the draft decision. The commission approved a $222 million revenue increase premised upon a $4.7 billion rate base, a 44.15% equity ratio and a 10.5% return on equity.

PG&E Corp. (PCG)

PG&E Corp. is a large utility that serves northern California including San Francisco. The company is currently operating under a three year rate order which will expire on 1/1/11. As a result the company will be filing a General Rate Case later this year for rates to be effective on 1/1/11. We would expect that the next General Rate Case will call for a three year forward rate schedule which would take account of attrition and rate base growth over time. PCG operates in CA under nearly full sales decoupling and all energy procurement costs are passed through. Further the company operates under a multi-year cost of capital mechanism with an adjustor, if triggered, and has significant precedents in place at the California Public Utilities Commission (CPUC) related to pension recoveries. As of this writing pensions were 83% funded and the 2006 settlement with the CPUC allowed for contributions of $176 million per year through 2010. Regulatory accounting allows the use of a balancing account to neutralize pension related earnings impacts, and a balancing account is used should cash contributions rise above $176 million annually. The one major item which does get tracked in some other jurisdictions which is not tracked in California is uncollectables expense. There are several different regulatory activities set to occur for PG&E Corp. beginning later this year and throughout 2010. We detail them below.

Cost of Capital Mechanism Filing

The current cost of capital adjustment mechanism operates through the end of 2010. The mechanism sets an initial return on equity and then allows for that ROE to be adjusted on a once a year basis should a bond index move by more than 100 bp. If the mechanism were triggered in this way the ROE would be adjusted up or down by half of the move in the index. The index is measured annually from October to September each year. The company then makes an advice filing at the CPUC indicating the move in the reference bond index and the calculated ROE adjustment, if applicable. We would anticipate this advice filing is made in mid-October. There is some disagreement over which Moody's Bond index should be used as the reference index as the CPUC regulations in the mechanism do not specifically address how to treat a split rated company. However, for Edison International, the CA utility subsidiary of EIX, which is also split rated, the lower rating was applied. This is important as so far the Moody's Baa Bond Index is above the 100 bp trigger level while the Moody's A Bond Index is still below the trigger by about 40 bp. It is our view that the Baa Index will be applied this fall.

Since the ROE adjustment mechanism is only in place through 2010, another filing has to be made in the spring of 2010, likely in April, for the Cost of Capital mechanism which will be in place in 2011 and beyond. This will open the issue of whether the multi year ROE adjustment mechanism is kept or whether CA reverts to annual Cost of Capital proceedings as was done in the past. It will also allow for the potential adjustment to the allowed capital structure, which is now 52%. We expect the company to file for a multi year mechanism in April and a decision to be made by the CPUC on this matter by December 2010.

Energy Efficiency Incentives

The Energy Efficiency Incentives in California are awarded using a look back mechanism. The utility gets to book a portion of the award on an annual basis using a one year look back and after a three year "cycle" gets to book the remainder of the award by looking at the performance over that entire three year period. The company received 35% of the calculated 2006 and 2007 incentives amid debate at the CPUC over how to measure the direct impact of PG&E's programs and what portion of overall efficiency gains those programs were directly responsible for. The CPUC plans a full review of the 2006–2008 cycle by year end 2009 and completion of the true-up for the three year period by year-end 2010.

The 2009–2011 cycle is also under review at the commission with a full review of the entire mechanism under way. The CPUC has indicated that the avowed goal of the proceeding is to make the process transparent and simplified. Although there has been some opposition to the energy efficiency awards voiced in the CA Assembly, we expect some sort of long term award mechanism to be put in place by year-end 2009.

Electric General Rate Case

The current general rate case under which the utility operates terminates in January 2011. Therefore the company will file a new GRC before the CPUC. A notice of intent, which will contain the majority of the details of the filing will be made in August 2009, with the filing of the first application occurring in November 2009. Testimony would be expected to be filed in December 2009 with litigation occurring throughout 2010. Third party filings and company responses will occur in the spring, hearings will likely be held in the summer with a final decision by year-end. The CPUC has been later than this on some decisions in the past but if that delay occurs rates would be made retroactively effective to 1/1/11. In our view the process would stretch no further than March of 2011. The commission under the CA statutes will have 30 days after an ALJ decision is rendered to issue a final order.

FERC Transmission Rate Orders

In California transmission rate base is regulated by the FERC at the national level. This rate base currently earns a 12% return on equity versus the 11.35% return on other assets as awarded by the CPUC. The FERC sets this return in an annual filing with the commission which the company makes every August for a decision in approximately 12 months time. This timeline gets extended somewhat if there is a prospect for settlement which has occurred the last couple of years. The last decision was Transmission Order 10 in which the company asked for a $760.5 million revenue requirement and received a $718 million revenue requirement under a settlement in October 2008. Transmission Order 11, in which the company requested $849 million has reached a settlement which has been filed with an ALJ at FERC, a final decision is anticipated in 3Q09. Transmission Order 12 will be filed at the FERC on or about August 1, 2009.

Other Items

In what amounts to a very full regulatory year, the company will also file their next Gas Accord in the second half of 2009 with a decision likely by 3Q10 and will file their compliance filing with regard to meeting California's renewable portfolio standard (RPS) of 20% on August 1, 2009.

PNM Resources (PNM)

PNM Resources operates an integrated electric utility in New Mexico, PNM Electric (PNM-E) and an T&D utility in Texas, Texas New Mexico Power (TNMP). On May 28 the New Mexico Public Regulatory Commission (NM PRC) approved a staggered $77.1 million revenue increase for PNM-E that will take place in 2009 and 2010. As part of the order the company is prohibited from any rate increases until March of 2011. The New Mexico Legislature also passed a forward test year into law under which PNM-E's next rate case, presumably filed in 2010 for rates effective after March of 2011 will be filed under. As of this writing it is difficult to say what the timing and structure of the next PNM-E rate filing will look like.

TNMP

TNMP has an ongoing rate case in Texas which was filed by the company on August 29, 2008 requesting $8.7 million in revenue increases. An amended request was filed on March 31, 2009 which increased the requested revenue increase to $24.4 million or +16%. The request was updated for Hurricane Ike interruption costs, as Texas law now allows for such recovery, and a higher cost of debt. The amended request is premised upon a $430 million rate base, a 40% equity ratio, and a requested return on equity of 11.25%. About $6 million of the differential between the original and the amended request results from increasing cost of debt (from 7.14% to 9.43%), another $5.1 million is resultant from a proposal to recover $20.6 million in Hurricane Ike related costs over the next five years.

On June 3, 2010 the Public Utilities Commission of Texas (PUCT) Staff issued a recommended order of a $7.6 million revenue increase premised upon a rate base of just under $430 million, an equity ratio of 40% and a return on equity of 10.33%. The $7.6 million recommended increase includes a $5.0 million storm allowance per Ike, a $1.1 million transition cost recovery rider increase and a $1.5 million base rate increase. These lead to a difference of about $17 million between the $18.2 million base rate increase sought by TNMP and the staff's recommendation of $1.5 million. Approximately $14 million of the difference is made up of net operating income items while the remaining $3 million results from a lower recommended return on equity. The biggest NOI items are a reduction in D&A expense ($5 million) and a flow through of tax benefits to ratepayers ($5 million).

The company announced a settlement with all parties to the case had been filed with the PUCT on June 22, 2009. The agreement would allow a $6.8 million increase in base rates and an additional revenue increase of $5.9 million to cover Hurricane Ike restoration and increased financing costs. This settlement for a $12.7 million total revenue increase was black box in nature. Hearings were held the week of June 16 2009 and a PUCT decision is expected prior to early October

Pepco Holdings (POM)

POM's regulatory calendar on the state level in 2008 was focused towards the beginning of the calendar year, while the company remained active with FERC through the latter part of the year with regards to the Mid-Atlantic Power Pathway (MAPP) transmission line. POM did receive some good news on 10/31/2008 when FERC approved the 150 bp adder, bringing POM's allowed ROE on the project to 12.8%. The lack of activity in 2008 on the state regulatory front brings on a busy 2009 for POM, with all subsidiaries filing rate cases in at least one jurisdiction, and some additional regulatory matters (addressed below in greater detail) with regards to pension and other benefit expense trackers, stimulus funding for efficiency and smart meters, and low cost financing options from the DOE for MAPP.

Pepco

POM's Pepco subsidiary recently filed (5/22/2009) their first rate case of the year, and probably POM's most significant of 2009, in Washington D.C. The company is currently asking for a $51.7 million revenue increase, premised upon an 11.5% ROE and an equity-to-total-cap ratio of 53.8%. Washington, D.C. can at best be described as an average jurisdiction from an investor's standpoint, and as a result, we have, in our view, tempered expectations for how much of the company's current ask will actually be allowed by the PSC. This is further reinforced after looking at Pepco's most recently decided rate case in D.C. The final order included a revenue increase of $28.3 million, premised upon a 10.0% ROE and an equity to total capitalization ratio of 46.6% (for rates effective 2/20/2008), after the company originally requested a revenue increase of $50.5 million with an 11.0% ROE and 46.6% equity-total cap ratio.

Rounding out Pepco's near-term regulatory schedule is an expected filing in Maryland during 1Q10. We have baked into our estimates $44 million in rate relief for all of Pepco (the company is 53% in D.C and 47% MD by rate base), reflecting a fairly dour, however realistic, result in both cases. The asking amount in MD's rate case is not expected to be of nearly the same magnitude as D.C.'s filing, as the company manages to earn much closer to their allowed ROE. Furthermore, Pepco's rate case history in Maryland, as exhibited by the gross discrepancies between the company's initial requests and the commission's final orders, can be described as negatively leaning at best.

DPL

On 5/6/2009 DPL filed a rate case in Maryland, requesting a revenue increase of $14.15 million, premised upon an 11.25% ROE and a 49.9% equity to total cap structure. While Maryland is not, in our view, a jurisdiction that is constructive for utilities, DPL has historically had fairly good regulatory relationships. In DPL's last MD rate case, the company's final revised request was for a revenue increase of $15.8 million, with a 10.75% ROE, and a 48.6% equity to total cap ratio. The MPSC's final order was for a revenue increase of $14.9 million with a 10.0% ROE and a 48.6% equity to total cap ratio.

DPL is also expected to file an electric rate case in Delaware during 3Q09 followed by a gas rate case filing in Delaware during 2Q10. DPL's Delaware jurisdiction (58% of electric rate base) is, in our view, average to slightly better than average, and the company's better (relative) performance there (adjusted earned ROE of 8.20%) makes the upcoming case there somewhat less important relative to the current case in Maryland. Baked into our estimates is total relief for DPL's electric operations in Maryland and Delaware of $18 million. We believe that our rate case outcome assumption is reasonable, and may prove to be optimistic if Maryland's case doesn't come to fruition as constructively as the most recently decided case did.

ACE

During the third quarter of 2009, POM's ACE subsidiary will be filing a rate case in New Jersey. Baked into our estimates for ACE is rate relief of $16 million, an amount that may prove to be conservative but that we are comfortable with especially when considering NJ's historically uncertain regulatory track record.

Pension Deferral Filings

On May 1, 2009 POM filed in all of their jurisdictions a request to defer, in aggregate, $35 million in pension expense for 2009. The amount deferred would than be incorporated into the next rate case filing for each utility, respectively. In addition, POM is making a push to establish a three year moving average of pension, other employee benefit, and bad debt expense that would help to mitigate the cost increases for POM by allowing a surcharge and would dampen the rate shock consumers experience when the expenses would otherwise roll into rates after cases.

Potential Benefits from the Stimulus Package and DOE Initiatives

POM's "Blueprint for the Future" program is a good candidate for the government stimulus funds that have been earmarked for smart meters, efficiency, and conservation programs in general. Although the competition for the government funds is most likely going to be quite stiff (preliminary indications are that only six to eight projects nationwide may be in the first round to receive funding), we believe that it is definitely a possibility that POM will at least partially secure funds from the government's program. In addition, we think that POM's MAPP transmission line is a strong candidate for the DOE's loan guarantee program. If POM is successful in their application, their financing cost for the project would drop substantially (could be as much as 300–400 bp of incremental benefit in terms of reduced borrowing costs on POM's request for $684 million in MAPP financing). It is beginning to appear increasingly likely that POM will benefit from the DOE's program (on May 27 POM was told by the DOE that their application was selected for a due diligence review) with a final decision expected tentatively during 3Q09.

Portland General Electric (POR)

POR received a final order on January 22, 2009 in its most recent GRC. The corresponding rate base associated with the order was $2.278 billion. POR's authorized ROE under the order was 10.1%, with an equity structure of 50%. The order further authorized POR's proposed decoupling mechanism (described below); a condition of this mechanism was a reduction in the company's allowed ROE from 10.1% originally authorized to 10.0%. POR's general rate cases utilize a forward-looking test year. The company calculates allowance for funds used during construction (AFUDC) on construction work in progress, and when capital projects are placed into service, both capital investment and AFUDC are included in rate base. Pending or planned cases include:

- UE-204, which is a request for recovery of costs associated with Selective Water Withdrawal Project, with an estimated cost of $80 million (POR's share). An implementation date under existing rate parameters is pending. A prehearing conference will be held following the conclusion of POR's root cause analysis of certain operational complications

- Annual Power Cost Update Tariff, for which an initial filing was made in April 2009 and will be made once again in April 2010, to adjust rates to reflect updated forecasts of net variable power costs. This is expected to be implemented on January 1 of the year following the filing. Under the Annual Power Cost Update Tariff, customer prices are adjusted annually to reflect the latest forecast of net variable power costs for the following year. As required, the company's initial forecast of 2010 power costs was submitted to the Oregon PUC (OPUC) on April 1, 2009. Such forecast will be updated during the year and will be finalized in November. Based upon the final forecast, new prices, as approved by the OPUC, will become effective January 1, 2010.

- Renewable Adjustment Clause Filing, for Biglow Canyon II project made in April 2009 for deferral until the project would be included in rates on January 1, 2010. The company anticipates a similar filing for Biglow Canyon Phase III in 2010.

Decoupling Adopted

A decoupling mechanism was approved in POR's recent rate case filing (UE-197). The decoupling mechanism referred to as the "Sales Normalization Adjustment" (SNA) and the Lost Revenue Recovery (LRR). The SNA applies to residential customers is simple balancing account and rate adjustment process that would greatly diminish the disincentives of supporting and encouraging innovative and effective programs to improve customer energy efficiency. The disincentives are manifest through reduced energy usage that in turn lowers POR's revenues, particularly revenues to cover the fixed costs of POR's operations. In addition to the SNA for residential customers, the Commission approved the LRR decoupling mechanism applied to large non-residential customers the loads less than 1mW.

Advanced Metering

POR will deploy 850,000 "smart meters" to residential and commercial customers. The company deployed approximately 16,000 meters in the systems acceptance testing phase of the project. The systems acceptance testing phase has been completed and full deployment of the remaining meters began in April 2009. The project is expected to be completed in 2010 with an estimated cost of $130 million–$135 million.

PPL Corp (PPL)

PPL Corp. is a vertically integrated utility in Pennsylvania which operates an unregulated generation subsidiary, PPL Supply, a regulated T&D utility, PA Electric Delivery, and an International Delivery segment which owns and operates T&D assets in the United Kingdom.

PPL Supply and Rate Caps in PA

PPL Supply currently operates under rate caps for their provider of last resort (POLR) load that were put in place in PA when the generation industry was deregulated. These rate caps are set to expire on 1/1/10. The other companies still operating under rate caps in PA (EXC, FE, AYE) remain capped until 1/1/11. PPL Supply filed with the PA Public Utility Commission (PA PUC) in 2007 to procure power for 2010 under six auctions to be held twice a year. This was done to allow for a "dollar cost average" type approach to power procurement and not leave the entire load vulnerable to price spikes in either direction on any particular day. Power has been procured under the approved auction process in five auctions so far, with pricing as indicated in Figure 39.

Figure 39: PPL Auctions

PPL Auction Results & Expectations	5th Auction	4th Auction	3rd Auction	2nd Auction	1st Auction
Off-Peak	on 3/31/09	on 9/29/08	on 3/24/08	on 10/1/07	on 7/23/07
PJM West Hub 7x8	$ 43.00	$ 54.63	$ 48.39	$ 42.23	$ 37.71
PJM West Hub 2x16	$ 43.00	$ 68.24	$ 67.44	$ 64.34	$ 68.79
On-Peak					
PJM West Hub 5x16	$ 58.00	$ 84.41	$ 83.72	$ 78.86	$ 77.43
PJM West Hub ATC	**$ 50.14**	**$ 71.40**	**$ 68.84**	**$ 63.88**	**$ 62.54**
Total Gap to ATC (1)	$ 36.60	$ 40.82	$ 39.96	$ 41.12	$ 35.46
Expected/Actual Auction Result	**$ 86.74**	**$ 112.23**	**$ 108.80**	**$ 105.00**	**$ 98.00**
Notes:					
(1) Gap includes capacity payments, line losses, ancillary services, etc					
Multiple of ATC price	1.73x	1.57x	1.58x	1.64x	1.57x

Source: Bloomberg, Barclays Capital Estimates

The issue of rate shock came to the fore in PA in 2008 as the auction prices for power were significantly above the current capped POLR rates. To mitigate rate shock to end use customers PPL proposed a rate mitigation plan with the PA PUC under which cash collections from customers would be delayed, and the difference between actual cash rates charged to customers and revenue booked at market rates would be hung on the balance sheet. This would allow PPL to go to market but would slowly raise rates for customers over a three year period. In other words, rather than, for example, say a 24% increase in 2010 the customers would see an 8% increase per year for the next three years.

Political pressure from the Legislature increased in 2008 with attempts to extend rate caps as well as a compromise proposal that would have sanctioned the mitigation plan concept into law. Late in the 2008 session, the PA Legislature passed HB 2200 from which the extension of rate caps was removed. The bill passed 47-3 in the Senate and 157-32 in the House, and called for "least-cost" and "competitive-procurement" requirements which would allow for RFPs for power and long term contracts for procurement instead of or in addition to auction processes. The bill also included new requirements for PA PUC review of long term power contracts, demand side management targets of 2.5% around the clock, and 4.5% on-peak consumption reduction in five years time, and for smart meters to be depreciated over 15 years.

The debate over rate cap expiration, as expected, has begun anew in the 2009 legislative session. House Speaker McCall (D) has introduced House Bill 20 which would write into law rate mitigation plans similar in nature to the one PPL has filed and that has received PA PUC approval. Also, Bud George (D) has introduced a rate cap extension bill similar in nature to the one he introduced in the 2008 session which did not pass. It is likely that the budget process dominates legislative activity through the summer and rate cap or rate mitigation issues will not come to the fore until September and October of this year.

PA Electric Delivery

We anticipate that PA Electric Delivery will file a rate case with the PA PUC in the spring of 2010 for rates to be effective 1/1/11. The regulatory process in PA would be expected to take approximately nine months to complete. The company's last rate case was adjudicated in 2007 with a commission decision on 12/6, which allowed a $55 million increase in revenues, or +1.7%. Internal metrics of the rate case were not specified. The company had requested an $83.6 million revenue increase premised upon a rate base of about $2.0 billion, a 43.13% equity ratio and a return on equity of 11.5%.

International Delivery

In the U.K. regulatory and rate setting process works differently than it does in the United States. Under the U.K. rate structure all utility companies go in for a rate review at the same time under which rates are set for the next five year period, otherwise known as a Distribution Price Control Review (DPCR). The U.K. regulator will perform a regression analysis to find the theoretical maximum efficient company. The regulator will then determine the returns and overall revenue requirement that this theoretical company would earn. Then each company is placed where they belong along the regression according to various measures of efficiency and their revenue requirements and returns are thus determined. The process allows for the company to set a capital and O&M budget for the next five years. The companies also have an opportunity to earn bonuses above and beyond their revenue requirements for the highest customer service ranking (which PPL has been awarded for some time) and for the lowest cost of service, although this mechanism does not make adjustments for the natural cost differentials between a rural and an urban system. Initial proposals under the DCPR currently under way are expected in July 2009.

Progress Energy (PGN)

Progress Energy Florida (PEF)

On March 20, 2009, PEF filed with the Florida Public Service Commission (FL PSC) for a $500 million rate increase, premised upon 50.5% equity and a 12.54% ROE. The new rates would be effective for January 1, 2010. PEF is asking for a 2010 test year in the process. As part of this rate request, PEF asked for $13 million in interim rates. PEF is also filing for $63 million of rate relief associated with the repowering of the Bartow plant, which is scheduled to come on-line in June 2009. The FL PSC approved both the interim and Bartow requests in full, subject to refund, on May 19. The $76 million in higher rates were effective as of July 1. On April 9, PEF received approval for a reduction in fuel expenses of $206 million. Taking this into account, the net increase of the fuel reduction and rate increase request would result in, at most, a $294 million increase to customers by January 2010. The FL PSC is expected to rule in late December on the base rate increase. As we've noted previously, recent constructive decisions in Florida, as well as the accompanying reduction in fuel costs, suggest to us that a positive outcome is probable at PEF.

In May, PEF announced it would be postponing by 20 months the construction schedule of its proposed Levy nuclear site – suggesting an on-line date for the project of 2020 or later. The NRC has provided a limited work authorization for the green field site, and PEF has recently concluded that the authorization does not contemplate some of the more advanced site prep work they had planned until the NRC gets more comfortable around the geology and seismology of the nuclear island which is located in a wetlands environment. We expect full authorization and the COL will be issued at some point – likely in late 2011 or early 2012 – but the delay should lower capex for 2009 and 2010 by about $100 million and $350-400 million, respectively.

On the subject of cost recovery for expenses related to the Levy build, PEF updated its filings before the Florida PSC on May 1. Through 2009, PEF estimates that it will be about $300 million under-recovered in Florida. Under existing statute, PEF would be able to recover that $300 million, plus 2010 spending adjustments, that would result in a customer increase of about $446 million. Most of this amount would be a pass-through of costs and capital, and likely result in about $32 million of higher earnings (for both Levy and the CR3 uprate). In PEF's May 1 filing, it proposed to defer the $300 million under-recovery over five years – softening the 2010 rate increase to customers – if allowed to earn carrying costs on the deferred balance. The resulting change would reduce 2010 customer impact by about $210 million, but would actually increase PEF's earnings by about $29 million pre-tax (in addition to the $32 million cited above) to reflect a return on carrying charges. This could add $0.06–$0.07 versus current projections, and we don't believe this is currently included in consensus estimates. Hearings are expected in the matter from September 8–11, with a FL PSC vote likely around October 16. New rates would be effective in January 2010.

Progress Energy Carolinas (PEC)

In South Carolina, PEC filed to reduce fuel costs by $13 million on May 7. A settlement was approved by the South Carolina Public Service Commission (SCPSC) in early June, with rates effective for July 1. Also in early May, the SCPSC approved a settlement regarding demand side management (DSM) and conservation that would allow PEC to recover those investments through an annual rider.

In North Carolina, the legislature allows for utilities to recover DSM expenses as part of its 2007 energy legislation. The North Carolina Utilities Commission (NCUC) has approved a 2008 request by PEC to recover DSM and renewable energy portfolio standards costs through clause mechanisms. PEC filed to reduce fuel costs by a small amount on June 4, 2009, and also made small filings to adjust efficiency and renewable costs. Hearings are slated for September, with orders expected in October. The adjustments would take effect on December 1, 2009.

Longer term, PEC has made filings to support its goal of improving its distribution grid via a $260 million investment over five years. PEC sees these investments as a precursor to eventual smart grid upgrades, and as a part of its DSM work. A decision from the NCUC could be forthcoming with respect to both the details of the plan and its recovery mechanisms at any point.

Public Service Enterprise Group (PEG)

Public Service Electric & Gas (PSE&G)

PSE&G is in the middle of several rate filings and a fair amount of regulatory activity, as the economic situation in New Jersey has caused Governor Corzine to urge utilities to increase near-term spending on items such as energy efficiency and conservation in the interest of adding jobs to stem the recession's impact. To that end, PSE&G has filed for $1.7 billion in infrastructure, conservation, and solar spending in the early part of 2009. $698 million of infrastructure spending has already been approved by the New Jersey Board of Public Utilities (NJ BPU), which granted a 48% equity structure and 10% ROE – shy of the 51% equity and 10.5% ROE requests, but the company was also given a monthly true-up on actual spending to eliminate cash lag. The remaining $963 billion is comprised of $773 million of various solar initiatives, and $190 million of conservation spending. Both requests are expected to be reviewed by the BPU over the summer. We expect similar treatment to that received for the infrastructure projects.

PSE&G also filed an electric and gas rate case in New Jersey on May 29, asking for a gross increase of $230.6 million. This amount would be offset by $97 million in reductions associated with lower gas commodity costs, resulting in a net requested increase of about $133.6 million. The case is based on $6.2 billion of rate base ($3.8 billion electric; $2.4 billion gas), a 51.2% equity structure, and 11.5% ROE. It uses a 2009 test year, implying a part-historical / part-forward looking test year in the case. In addition, PSE&G is asking for a tracker mechanism on capex spending, which would further reduce regulatory lag. The filing should receive a ruling from the BPU within the next nine to 12 months.

Sempra (SRE)

SRE has the benefit of a very secure regulatory future in both the near and medium term. With the approval of a multi-year settlement on August 1, 2008, SRE's regulated subsidiaries (gas distributor Southern California Gas, SoCalGas) and gas and electric utility San Diego Gas and Electric (SDG&E)) have annual revenue increases of about $95 million locked up through 2011, keeping both utilities out of extensive rate case proceedings until 2012 is addressed. The more minor regulatory issue that SRE will be addressing with the CPUC in the coming months is SoCalGas's cost of capital tracking mechanism that is currently partially tied to 30 year treasury yields. SRE believes that due to government intervention in the treasury market, the artificially low yields are not adequately capturing the cost of capital for the utility. A final decision for SoCalGas is expected during 3Q09 and we believe that the commission is likely to allow the change, due in a large part to the fact that every other California utility has a cost of capital tracker tied to a utility bond index rather than a treasury bond index.

Efficiency, Conservation, and Renewables

Beyond traditional rate cases, SRE also had a successful 2008 in terms of efficiency, conservation, renewable related programs. With the rollout of SDG&E's $500 million smart meter program already in process, additional smart meter installations planned for SoCalGas (final approval expected in 4Q09 with installations expected to begin in 2011), and final approval of the Sunrise Powerlink transmission line already in hand, SRE is well positioned to benefit from policies aimed at pushing a "green" agenda.

Southern Co. (SO)

Southern Company operates four regulated utility subsidiaries, Georgia Power, Alabama Power, Mississippi Power, and Gulf Power, located in GA, AL, MS, and FL, respectively. They also operate an unregulated IPP subsidiary, Southern Power, which acquires or builds generating assets and signs them to long-term contracts, a model which minimizes risk. The only upcoming regulatory item of significance for Southern is the upcoming June 2010 filing of a GRC at Georgia Power, and the regular annual processes in Mississippi and Alabama. The company is not expected to file a rate case in Florida at this time.

A summary of regulations by subsidiary is provided in Figure 40.

Figure 40: Southern Co. Regulations by Subsidiary

Base Rates	Alabama	Georgia	Gulf	Mississippi
Alternative Ratemaking	Rate RSE			PEP-4
Traditional Regulation		ROE Band	ROE Band	
Regulatory Clauses				
Fuel	Y	y	y	y
Purchased Power Energy	Y	y	y	y
Purchased Power Capacity	Y		y	y
Environmental	Y	y	y	y
Energy Conservation			y	
New Plant Certification	Y	Integrated Resource Plan	Need Determination Process	Certification Process
Storms	Y		y	y
CWIP in Rates		New Nuclear	New Nuclear	New Baseload
Considerations				
Test Year Forward Looking	Y	y	y	y
Rate Base Avg. Original Cost	Y	y	y	For Environmental Capital
Valuation End of Period				Rate Base for PEP

Source: Company Slide Presentation

Below, we detail the regulation for each of SO's subsidiaries.

Georgia Power

Georgia Power is operating in accordance with a three-year accounting order that was settled and approved by the GA PSC on 12/18/2007. The settlement called for a base revenue increase of $222 million for environmental spending recovery and a base rate increase of $99.7 million. The company had originally requested $406.7 million in 2008, with an alternative plan with incremental increases of $191 million in 2009, and $45 million in 2010. The ROE dead band range is the same as current at 10.25%–12.25%. In addition, the settlement calls for a rider which would allow for annual true-ups/downs related to environmental spending. Greater than this range, there is a two-thirds to one-third sharing of profits between customers and shareholders, respectively.

The Georgia commission is composed of five full-time commissioners who are elected to six year staggered terms in statewide elections. The chairmanship is rotated annually according to legislative stipulations; the current chairman is Doug Everett. We view Georgia as a constructive regulatory environment, despite the elected nature of the commissioners. Lauren McDonald is back on the commission after a hiatus since 2002 replacing Angela Spier. Commissioner Robert (Bobby) Baker faces re-election in 2010.

Georgia Power is required by law to file a rate case no later than June 30 of next year. July and August will likely constitute the requesting, gathering, and submittal of various data requests. The staff should issue its recommendation in late August or early September, after which hearings will be conducted in the September/October timeframe. Cases in Georgia are filed on a forecast forward test year basis. By law Georgia Power is required to file a one year rate case, and in addition to this will likely file a recommended three-year accounting order plan. Georgia Power has done filings at the commission this way since 1995. We anticipate that the filed equity ratio will be about 51% using actual; however, it is important to note that in Georgia all short-term debt is excluded from that calculation. The Commission can adjust both the equity ratio and the ROE in its final order, so those will be two points of discussion. Historically, however, most of the discussion and any adjustments have occurred to the ROE.

Fuel recovery in Georgia is not automatic but requires a filing and a hearing before the commission to review and approve the forecast costs and the recovery of any differential balance between what was previously forecast and what was actually collected. Georgia Power is allowed to institute a fuel hedging program, which operates under a sharing mechanism whereby any benefits are allocated 75% to ratepayers and 25% to shareholders.

Alabama Power

Alabama Power operates under a rate stabilization plan. The current ROE range is 13%–14.5%, which has an adjusting point at 13.75%—i.e., if the ROE falls outside the specified range, rates will be reset to an ROE level of 13.75%. The RSE has been in effect for 20 years and will remain in effect until discontinued or modified as deemed necessary by the Alabama Public Service Commission. In fall 2004, the Alabama PSC also approved an environmental spending tracker, which allows for the forward-looking rate recovery of environmental spending. We do not currently anticipate a rate case to be filed for this subsidiary in the next 12–24 months.

The Commission saw the retirement of President Jim Sullivan, who chose not to seek re-election, in the past year. President Sullivan was the longest serving utility commissioner in the country, having served from 1983 to 2008. He was replaced by current President Lucy Baxley, a Democrat, and a former Lt. Governor and State Treasurer of Alabama. The company received $168 million in a corrective rate package for 2009 and agreed not to seek base rate increases for environmental increases for 2009. Environmental increases were deferred not foregone.

Mississippi Power

Mississippi Power operates under PEP-4, which attaches performance enhancements around a benchmark ROE. On September 30, 2004, this benchmark ROE was set to 10.70%. Mississippi Power's last rate case concluded in 2002 and instituted a rate hike based on a 12.88% ROE. In the last PEP-4 review specifies an 11.6% ROE for Mississippi Power. We do not currently anticipate a traditional rate case to be filed for this subsidiary in the next 12–24 months. The company will make another PEP filing by the end of 2009.

Southern has proposed construction of a commercially sized IGGC plant and mine in Kemper County, Mississippi. The plant would be a mine mouth facility using locally mined lignite coal. The last cost estimate made public by Southern was $1.2 billion for the IGGC plant and $0.6 billion for the mine. Because the gasifier uses air blown based technology developed at SO's Wilsonville, Alabama test facility it works with low grade coal. A higher-cost oxygen blown IGGC technology would not work on low grade MS lignite coal. The plant would also capture CO2 and use it in enhanced oil recovery to give the plant the same carbon dioxide profile as a natural gas CCGT plant. Merchant power suppliers in Mississippi opposed the plant before the MS PSC. The MS PSC has ruled that the plant will vetted by the commission in two phases. The first phase will be a determination of need for which the proceeding will begin on June 26 and a final decision is scheduled for October 9. The second phase will consider what options for resources are available to meet the need determined by the first phase. The various parties can propose alternatives to the IGCC facility in the second phase, but the PSC has stated that they must be detailed proposals with testimony on technology, cost, and timing. The second phase will begin on October 15 and a final decision is currently scheduled for May 1, 2010. This may slightly push back Mississippi Power's previously announced construction timeline of 2010–2013, as the company had previously estimated having full permitting by the end of 2009.

Westar Energy (WR)

Kansas regulation has become substantially more constructive in recent years with the implementation of a number of new recovery mechanisms. These include a fuel recovery clause that adjusts quarterly and covers plant performance, annual adjustments (Energy Cost Recovery Rider) for environmental spending that flows directly into rates, pre-determination for large scale projects that reduces the uncertainty of recovery, and favorable treatment of extraordinary storm damage that helps to reduce the volatility of earnings. On June 2, WR filed with the Kansas Corporation Commission (KCC) a limited rate case seeking cost recovery for investments in the second phase of its Emporia Energy Center, and two Westa-owned wind farms in Kansas that were under construction, but not in operation at the conclusion of the company's 2008 GRC. This rate review was agreed to as part of the settlement reached by all parties in the 2008 general rate case, which the KCC approved in January 2009. WR is seeking a $19.7 million or 1.5% increase in this abbreviated filing. The same rate case parameters of 10.4% ROE and 50.8% equity component of capital will apply. The process for this rate case will be similar to a traditional rate case filing at the KCC, with the application strictly limited to costs associated with the construction and operation of wind generation owned by Westar and the second phase of Emporia Energy Center. Assuming a 240-day statutory timeframe for the rate review, an order would be expected in late January 2010.

Rate Case components include:

- New investment of $97.5 million, including $70.8 million for wind and $26.7 million for Emporia Energy Center Phase II;
- Return on Plant-in-Service of $11.6 million;

- Depreciation of $17.2 million, including wind depreciation of $13.5 million and Emporia Energy Center Phase II of $3.7 million;

- Operations and maintenance expense of $8.1 million, including $6.4 million of wind and $1.7 million of Emporia Energy Center Phase II; and

- Production Tax Credits provide a $17.2 million offset in this rate increase request.

Update to the Environmental Cost Recovery Rider Approved

On May 29, 2009 the KCC approved an update to WR's Environmental Cost Recovery Rider (ECRR) following an audit and recommendation from KCC Staff. The KCC approved the $32.4 million ECRR to go into effect June 1, 2009. The ECRR is a tariff that permits WR to recover costs associated with federally mandated environmental improvements to its generation facilities in a timely manner.

Transmission Rate Recovery

A FERC formula rate adjustment is applied annually; the KCC has approved a Transmission Delivery Charge (TDC) tariff to allow a corresponding retail adjustment, which enables timely recovery of transmission system operating and capital costs.

Wisconsin Energy (WEC)

Wisconsin Energy's Wisconsin Electric Power Co. (WEPCO) and Wisconsin Gas (WG) initiated a general rate case proceeding for its retail customers with the Public Service Commission of Wisconsin (PSCW) on March 17, 2009 with new rates to be effective January 1, 2010. The filing includes a $76.5 million or 2.8% electric increase and a $22.1 million or 3.6% gas increase, plus $2.7 million increase for steam at WEPCO, and a $38.9 million or 4.6% increase at Wisconsin Gas. WEC is requesting to retain a 10.75% regulatory ROE on 53% equity on a rate base valued at $3.512 billion at WEPCO Electric, $412.95 million rate base at WEPCO gas operation (WE Gas) and $51.5 million in WEPCO steam operations; and 48% equity component on a rate base of $611.5 million at WEC's Wisconsin Gas subsidiary. In an adjusted proposal filed in early July, WEC is now seeking a $126 million electric revenue increase, an additional $50 million from its initial electric increase request, citing the deepening recession and correspondingly lower sales. As part of the filing WEC also has requested 1) a reduction in depreciation rates concurrent with the implementation of new base rates in this proceeding; 2) certain regulatory assets currently scheduled to be fully amortized over the next four years will, instead, be amortized over the next eight years; 3) WEPCO will be permitted to continue to record 100% AFUDC for capital expenditures on environmental control projects and renewable energy projects; and, 4) WEPCO will have the option of applying for a limited reopener of this case or for deferred accounting to address any increased costs or reduced sales that would result from the enactment of recommendations of the Governor's Global Warming Task Force. We expect a PSCW Staff recommendation by September 2009 and Commission decision in the fourth quarter.

WEC's Michigan utility, Edison Sault Electric Co., filed a General Rate Case on July 2, 2009. The company is proposing a $40 million or 33% rate increase, phased in over three stages, in 2010. The majority of the additional expenses are due to the Oak Creek Generating Units. Unlike in Wisconsin, where these costs have been gradually included in rates since 2003, Michigan does not allow power plant construction costs to be recovered until units are operational. The first phase of the increase of approximately $20 million is scheduled to start in January 2010 to coincide with Oak Creek Unit 1's commercial operation. That 16.8% increase would also cover a change to the Michigan business tax. If the Michigan Public Service Commission agrees with Edison Sault's plan, another increase would be implemented in August 2010, when Unit 2 comes on line, and a third increase of about 15% would be implemented after the PSC finishes its audit of the application. The case requests a 10.75% return on equity.

Xcel Energy (XEL)

XEL's regulatory framework continues to improve, as forward test years in Minnesota, Wisconsin, and North Dakota – along with a pending forward test year request in Colorado – as well as interim rates in the first three of those states, have the company well positioned to continue to enjoy reduced regulatory lag. Transmission, renewable, and environmental riders exist in most jurisdictions as well. Only Texas and New Mexico continue to be material challenges from a regulatory standpoint, and XEL is fortunate in that regard as well, since its Southwestern Public Service (SPS) subsidiary that operates in those states comprises only about 5% of XEL's earnings.

Northern States Power – Minnesota (NSP-MN)

In Minnesota, XEL filed a base rate increase request of $156 million in November 2008. This was based on $4.1 billion of electric rate base, a 52.5% equity structure, and an 11% ROE. An interim increase of $132 million went into effect at the beginning of January 2009, with the difference between XEL's request and the interim amount being owed to the last allowed ROE of 10.54% and the 11% requested in this case. Minnesota Department of Commerce testimony has been supportive of a rate increase closer to $73 million, based on a 10.88% ROE. A ruling is expected during 3Q09.

Not including fuel recoveries, riders pertaining to about $60 million in 2009 recoveries related to the MERP, transmission, and renewable energy mechanisms are pending before the Minnesota Public Utilities Commission (MPUC) as well.

As a final matter, NSP-MN is proposing license extensions at its Monticello and Prairie Island nuclear plants, as well as uprates of 71 MW and 164 MW, respectively. These projects are estimated to cost $1.1 billion, with construction coming form 2009–2015. The Monticello plant has received all of its approvals except NRC approval for the uprate, which is expected as early as later this year. The Prairie Island plants still require MPUC certificates of need for the additional dry cask storage and for the uprate, both of which are expected later this year, and NRC approvals for the license extension and the uprate, which are expected in 2010.

Northern States Power – Wisconsin (NSP-WI)

NSP-WI is awaiting a ruling on a request for $30.4 million in higher rates based on $644 million of rate base, a 53.12% equity structure, and a 10.75% ROE. This case assumes a 2010 test year, and a decision is expected in December 2009.

Public Service Company of Colorado (PSCo)

PSCo has been busy of late, with a rate case that just concluded, and a phase 2 case just beginning. The concluded phase allowed for a $112.2 million rate increase, versus a $159 million revised request. The request was premised upon $4.1 billion of rate base, a 58.08% equity structure, and an 11% ROE. Although the final order from the Colorado Public Utilities Commission (CPUC) didn't specify whether the 2009 forward test year had been granted, the size of the rate increase suggests that the commission was amenable to the general concept of allowing 2009 investments to be considered in the result, and is constructive in light of the phase 2 process that is currently under way.

Phase 2 is asking for a $180 million increase, based on $4.4 billion of rate base, a 58% equity structure, and an 11.25% ROE. This case assumes a 2010 test year, and a decision is expected by year end.

Southwestern Public Service Company (SPS)

In New Mexico, SPS recently filed an uncontested settlement that would allow a $14.2 million rate increase, effective July 1, 2009. This was premised upon $321 million of rate base, with a 50% equity structure and a 12% ROE. The case used a June 30, 2008 historical test year, and the terms of the settlement would prohibit SPS from filing its next base rate case until December 1, 2010. The settlement is pending approval before the NMPRC.

A base rate case in Texas that awarded a $57.4 million rate increase was approved by the PUCT on May 21. Like the settlement in the PSCo case, this was a black box settlement that did not specify return metrics. SPS in Texas would be prohibited from filing another base rate case until February 15, 2010.

Emerging Issues: Coal, Stimulus, Climate Change, DSM, & Decoupling

Coal

Coal fueled 48.5% of net generation in the United States in 2009 and is domestically supplied. While conservation efforts and renewable sources show promise to reduce peaks and supply intermittent baseload or peaking generation capacity, for high capacity factor baseload generation the two viable options remain nuclear and coal. Nuclear is in a nascent recovery, although the first plants are not expected to be on-line until the end of the next decade. Despite short-term opposition, in the long run, coal remains the United States' largest domestic supply of energy. With the return of economic growth, it is likely that coal plants will need to be built in the country in order for supply to meet growing demand.

In our view, however, coal plants, both existing and potential new build, will become relatively more expensive as a result of environmental regulations around mercury, coal ash ponds, SOx, and NOx, and greenhouse gases. The continued push toward more stringent environmental regulation will make coal plants incrementally more expensive to run and build, and it will also likely lead to a "run or shutter" analysis based upon economics for many small older coal plants in the United States. Retrofits for environmental controls on these plants would in some scenarios be too expensive to justify keeping them running. Some of these plants also have limited available land surrounding them on which to build any emission control equipment.

The fourth quartile coal plants in the United States on average were built in 1959, run at a capacity factor of 58%, and at a heat rate of 15,549. These plants have a non-fuel O&M rate of $18.21/MWh, almost 3x the 3rd quartile cost of $6.64/MWh. Most of these plants are located in the Mid-Atlantic, South, and Midwest. In our view these plants could all face retirement with the coming more stringent environmental policies. These plants approach 10% of the nation's capacity which must be replaced by other baseload resources.

Coal Ash

In December 2008, the Kingston Plant, owned and operated by the Tennessee Valley Authority (TVA) experienced a dike failure on its coal ash pond, which allowed five million cubic yards of water and coal fly ash to cover 300 acres, 292 of which were owned by TVA. Since the incident TVA has purchased seven of the eight remaining effected acres. The cause of the failure is not yet known but ash also flowed into the nearby Emory River. The Kingston facility continued to run after the breach, albeit at a low capacity factor and currently produced ash was being mixed with clean up ash to be removed together. TVA took a charge of $525 million that reflected the low end of the estimated immediate clean-up costs of $525 million to $825 million. This range does not contemplate the costs of other needed site work, or long-term clean up issues.

More broadly the Kingston incident has led to a full review by the Environmental Protection Agency (EPA) and we anticipate that further rules and regulations will eventually be developed around the disposal and storage of coal ash waste. On March 9, 2009 the EPA released measures intended to prevent similar coal ash releases to the Kingston incident. The EPA plans to survey coal plants nationwide to gather information on structural integrity, order repairs where necessary, and develop new regulations. They released a list with 44 sites they cited as having "high hazard potential" at the end of June. Importantly, this list does not indicate any structural or safety problems at these sites, but rather reflects the likelihood of loss of human life in the event of a failure. The EPA has stated that they intend to have new regulations out for public comment by the end of 2009.

North Carolina Clean Air Case

In a ruling against TVA in a suit brought by North Carolina the courts determined that TVA's coal plants were a public nuisance and were blowing emissions east into that state. A federal court judge ruled in North Carolina's favor on four of TVA's plants and declined to order relief on the rest of TVA's coal fleet. The four plants affected were Bull Run (one unit), John Sevier (four units), Kingston (nine units) all in Tennessee and Widows Creek (eight units) in Alabama. The total capacity of the impacted facilities was 4,505 MW while the non-impacted facilities constituted 9,964 MW. Of particular concern was the judge's order to accelerate the timeline of already planned and in process construction of emission controls – completion of the Kingston scrubbers and SCRs by 12/31/10, scrubbers and SCRs installed at John Sevier by 12/31/11 and scrubbers and SCRs on all Widows Creek units by 12/31/13. It is worth noting that all the plants mentioned are in current compliance with clean air rules and that TVA has invested $5.1 billion in emission reduction programs for their coal fleet from 1977 to 2008. The company estimates that a further $3.0 billion to $3.7 billion ($256/kW) could be required to be spent for new clean air and mercury regulations beginning in 2011, without contemplation of carbon.

TVA is already performing some of the court order's requirements, Bull Run and Kingston emission control programs are already within the court's guidelines. The two existing scrubbers at Widows Creek are currently being modernized. The court order would essentially require TVA to accelerate the schedule for control equipment at John Sevier and the remaining units at Widows Creek. This would cost an estimated additional $1 billion versus its current plans. Given that John Sevier is TVA's easternmost coal plant it is in a critical position for reliability in eastern Tennessee. TVA has appealed the court ruling and has announced intentions to build an $820 million natural gas plant in eastern TN in case the appeal fails and John Sevier faces potential shut down. There are concerns with shifting from coal to natural gas including more volatile fuel input costs and actual ability to obtain and secure necessary locational supplies.

The TVA lawsuit bears watching as if the company's appeal is unsuccessful several more lawsuits by states and/or environmental groups against existing coal fired generation, even with regard to carbon emissions could come to the fore and put more baseload generating capacity at risk. The case is also instructive in that replacing fourth quartile coal plants with natural gas would potentially create localized supply constraints, increase the demand and price for natural gas as well as its volatility. This would in turn impact the price, volatility, and potentially the reliability of electricity. Over the longer term, with coming mercury and carbon regulations similar situations to TVA's could play out on a national scale without the courts, as pure economic decisions begin to force contemplation of shut downs.

Stimulus Bill

The stimulus bill that was passed in February 2009 provides approximately $39 billion for energy programs, primarily focused on efficiency, renewable generation, and electric transmission and distribution.

Of this, $16.8 billion is earmarked for Department of Energy efficiency and renewable energy programs, including $3.2 billion for energy efficiency and conservation block grants, $5 billion for weatherization assistance, $2 billion for advanced battery manufacturing for electric vehicles, and $3.1 billion for state energy programs. The language surrounding the conditions for the State Energy Efficiency Grants program puts forth some potentially industry changing possibilities. The amendments declare that states receiving funds from the program must have their governor confirm that they have assurances from the state regulatory authorities that they will seek to implement policy that aligns utility financial incentives with more efficient customer use. If this is enforced as strictly and literally as possible, one could take it as indicating that commissions will need to move toward the decoupling of revenues from sales in order to receive the stimulus funds.

In addition, the bill includes $4.5 billion of new funding for a range of electric delivery and energy reliability activities, $3.4 billion in funding for fossil energy research including clean coal and industrial carbon capture, and finally, an additional $6 billion for the DOE loan guarantee program that is available only for renewable energy, electric power transmission, and leading edge transportation biofuel projects. This caveat of the loan guarantee program effectively excludes clean coal and advanced nuclear projects from the $6 billion in additional funding that is being made available. The additional money also carries the stipulation that construction must begin by September 30, 2011, and by also removing the language that previously made only "innovative" technologies eligible, established technologies like wind, solar, and electric transmission can also now benefit.

Specific to transmission, the stimulus bill also directs the DOE to expand its 2009 National Electric Transmission Congestion Study to include an analysis of the significant potential sources of renewable energy that are constrained in accessing markets by a lack of adequate transmission capacity; an analysis of the reasons for failure to develop adequate transmission capacity; recommendations for achieving adequate transmission capacity; and finally, to what extent state and federal level legal challenges are delaying transmission construction. The potential implications from the language included in the bill regard how it will affect the role of the FERC and its potentially increased siting powers.

Some of the most interesting components of the stimulus bill are on the tax incentive side and are major positives for companies with renewable exposure. Most significantly the bill:

Extended the in-service date for wind production tax credits (PTCs) to 12/31/2012, and for other renewable sources (closed-loop biomass, open-loop biomass, geothermal, small irrigation, hydropower, landfill gas, waste-to-energy, and marine renewable facilities) to 12/31/2013;

Allowed the temporary election of Investment tax credits (ITCs) in lieu of PTCs for wind facilities placed in-service by 12/31/2012, and for other qualifying facilities placed in-service by 12/31/2013; and

Created the option for taxpayers to elect to receive a treasury grant equal to 30% (10% in some cases) of the cost of the renewable energy facility (assuming construction begins in 2009 or 2010) 60 days after the facility is placed in-service or after the grant application is filed.

While it still remains unclear in terms of when money from the stimulus program will begin to flow in any meaningful way, the consensus view is implementation is expected to begin in July, 2009.

Climate Change: The American Clean Energy and Security Act of 2009 (ACES)

Below we provide a summary by topic of the ACES legislation (a.k.a. the Waxman/Markey bill):

Renewable Portfolio Standard

The combined renewable and electric savings requirement starts at 6% in 2012 and rises to 20% in 2020. Up to one-quarter of the 20% requirement can be met with savings. Upon receiving and responding to a request from a state's governor, the Federal Energy Regulatory Commission can increase the energy efficiency portion so that renewables would be 12% and efficiency 8% to meet the 20% requirement. These regulations are for retail electric suppliers in excess of 4 MMWhrs.

The definition of renewable has been expanded and includes wind, solar, geothermal, hydro, biomass and qualified waste-to-energy. An electric supplier's requirement is reduced by existing hydro, new nuclear and CO2 sequestered fossil-fueled plants. The penalty in lieu of compliance is a renewable energy credit at $25/MWhr.

CO2 Sequestration

If approved by entities representing two-thirds of fossil-based delivered electricity, the Carbon Storage Research Corporation would be formed. It would be funded by retail customers of fossil-based electricity at $1 billion annually. It would be 4.3 cents per MWhr for coal, 3.2 cents per MWhr for oil, and 2.2 cents per MWhr for gas. Fifty percent of the funds shall be provided in the form of grants to projects with funds already committed to IGCC with sequestration. New plants from 2009–2013 must sequester 50% of CO2 with 65% by 2020.

Efficiency

New building codes state 30%–50% higher energy efficiency targets from 2010–2016. Rebates up to $7,500 toward purchases of new Energy Star-rated manufactured homes for low-income families in pre-1976 manufactured homes.

Global Warming Pollution Reduction

Economy-wide reduction goal is to reduce global warming pollution to 97% of 2005 levels by 2012, 83% by 2020, 58% by 2030, and 17% by 2050. Methane scores 25 x 1 CO2 credit. Offsets are 2 billion metric tons split evenly domestic and foreign. Emission levels can be increased by Administrator by up to 1.5 billion metric tons. Strategic reserve is 1% of total from 2012–2019, 2% for 2020–2029, and 3% for 2030–2050. Initial strategic reserve price floor is $28/ton for 2012. Establishes an Offsets Integrity Advisory Board; otherwise, EPA establishes and runs the offsets program. Allowances are phased out for energy users from 2026–2030. Of the 38% for LDC rate reductions in 2012, 30% is electric, 7% is for gas, and 1% for other (government).

Figure 41: Emission Allocations & Allowances

Emission Allocations	Allocations 2012	Allocations 2020	Fossil Fuel Companies In 2020		Emission Allowances (in millions)			
Fossil Fuel and Industry	8%	25%	Energy Intensive Industries	13%	2012	4,627	2030	3,533
LDC Rate Reductions	38%	36%	Coal Plant Operators	5%	2013	4,544	2035	2,908
LDC and State Efficiency	1%	4%	Coal CCS	5%	2014	5,099	2040	2,284
Clean Energy and Climate Programs	16%	10%	Oil Refineries	2%	2015	5,003	2045	1,660
International	7%	7%			2020	5,056	2046	1,535
Deficit Reduction	14%	2%	Clean Energy and Climate		2025	4,294		
Consumer Rebates	16%	16%	(at various times)					
			Energy Efficiency/Renewable	9.5%				
			Clean Energy Research	1.5%				
			Clean Vehicles	3.0%				
			Domestic Fuels	2.0%				
			Workers	0.5%				
			Domestic Adaptation	0.9%				
			Wildlife	1.0%				

Source: American Clean Energy and Security Act of 2009; Barclays Capital estimates.

Electric Distribution Companies

Not later than 6/30/2011 and each calendar year through 2028, the Administrator would distribute 50% of allowances based on emissions of generation delivered at retail. For 2012–2013 the level would be based on 2006–2008 or any three consecutive years from 1999–2008. For 2014+, allocation would be based on the prior discussion or any three years from 2009–2012, or 2012 only if new generation is placed in service. The other 50% of distributions would be based on average annual retail electric sales from 2006–2008, unless the company selects any three consecutive years from 1999–2008. The distribution formula would be updated every three years. The allowances must go to ratepayer benefit, ratably among classes. The allowances cannot be used for a "rebate" and must track usage. The allowances cannot be authorized until the state regulatory body completes a proceeding authorizing their use.

Demand Side Management (DSM)

As talk around efficiency and conservation intensifies, we wanted to call attention to the fact that some states have made demand reduction a real point of emphasis and have pushed varying initiatives with a great deal of vigor. For instance, Michigan's implementation of a customer surcharge in order to pre-fund efficiency expenditures is among the more pro-active examples of a trend we expect to broaden to more and more states in the near future. Promoting these efforts are aggressive policy measures – at both the state and federal levels – that are meant to further encourage the implementation of efficiency technology, with a current example being the stimulus bill and the money being earmarked for states' "smart grid" and other efficiency programs.

When we looked at DTE's proposed conservation program ($110 million in total, two-thirds of which is at Detroit Edison) we found that when thinking about and valuing DetEd's 1% in forecasted load reduction as an avoided generation plant (assuming a 60% capacity factor), we arrived at a value of $800/kw. EIX's regulated subsidiary, Southern California Edison, however, had an implied value of $1,700/kw ($1.7 billion to reduce 1,000 MW of load) for its metering program.

We believe there are two logical takeaways from this: First, these early-stage programs will likely test the aggressiveness of the different states proposing and implementing this policy. For instance, SoCalEd currently works to achieve a 5% reduction in peak load, while its metering program would result in an additional 5% reduction. These are lofty targets, and stand in contrast to the more modest goals that have been set by many states. Second, in states like California, where generation is more constrained and aggressive renewable and reduction goals are in place, the cost of demand reduction should tend to be higher than it is in Michigan, for example. In other words, the avoided costs in California are higher than they are in Michigan, so the cost of the programs will naturally tend to be more expensive before running up against significant regulatory or ratepayer pushback.

We believe that reductions of about 1% annually – which have been the goals we've seen talked about in many jurisdictions – will be achievable for at least the first four to five years with targeted spending on very simple programs. These could involve such basic things as the weatherization of homes ($5 billion of the stimulus bill already has been earmarked for this), the switching of light bulbs, and new design standards for buildings under construction. We think that reductions beyond the 5% level are going to require substantially greater investment to get to the next level of incremental benefit, with costs likely rising to match the level of aggressiveness. The direction from the federal government as we work through national energy policy this year will also codify the larger goals, and therefore give us a better sense for the acceptable levels of spending.

Application of Decoupling Mechanisms on the Rise

Although initially predominantly employed by the gas utility industry, revenue decoupling has gained momentum among U.S. electric utilities as well. Ten states have approved a revenue decoupling mechanism for electric utilities: California, Connecticut, Idaho, Maryland, Massachusetts, Michigan, Minnesota, New York, Oregon, Vermont, and Wisconsin. Three are pending approval – Delaware, Hawaii and New Hampshire – according to the institute for Electric Efficiency. Revenue decoupling currently is in use in six states: California, Connecticut, Idaho, Maryland, New York and Oregon.

One driver behind decoupling is passed and pending federal legislation – specifically the American Recovery and Reinvestment Act of 2009 – and the revised climate change bill drafted by Reps. Henry Waxman, D-Calif., and Edward Markey, D-Mass, which includes targets for energy efficiency resource standards, renewable energy standards, and a cap on carbon emissions. While the federal stimulus bill does not specifically require decoupling, incentives need to be in place for utilities to engage in additional energy efficiency initiatives. The stimulus bill proves roughly $3 billion in state energy grants, and the Department of Energy has the authority to allocate these funds to the states, so long as the governor has been assured that the PUC in that state will implement regulatory policy that aligns utility financial incentives with the successful implementation of energy efficiency measures.

Decoupling has encountered some resistance from state legislatures and commissions to consumer advocates, likely because of the notion that the utility is not hurt by reduced consumption. Conversely, however, through decoupling, a utility will not see significant revenues from an increase in energy consumption. Generally accepted rate-setting practices create an inherent financial disincentive for utilities to participate in conservation programs, given that a successful energy usage reduction program would have a direct negative impact on utility revenues, and may require the utility to file a new general rate case in an attempt to recoup the related reduction in earnings. As environmental concerns have intensified, many states have adopted compulsory energy conservation standards and consequently, the need to mitigate the possible negative impacts of these programs has accelerated. Decoupling mechanisms are now being applied in some jurisdictions to encourage utilities to invest in mandated conservation programs without the associated potential negative effect on earnings. The decoupling mechanism enables the utility to defer fixed distribution costs that the utility may fail to recoup through its volumetric charges due to customers' participation in conservation programs. The utility is allowed to recover the deferrals associated with the unrecovered fixed costs through a surcharge over a period of time, generally with carrying charges on the deferred amounts.

An alternative to decoupling is a Straight Fixed Variable rate design, where a company's fixed costs are fully collected through the customer's fixed monthly charge. Consequently, the utility's fixed costs will always be recovered, regardless of the success of a company's conservation program, since the only volumetric charge is for the commodity. Therefore, by cutting back consumption, the customer would save only on the commodity portion of the monthly bill. Since these costs are also avoidable by the utility, earnings would not be negatively impacted. While the straight fixed variable rate design methodology provides a direct cause-and-effect relationship between usage and customers bill levels, and is easier to administer than a decoupling mechanism, one noted drawback is that customer rate designs tend to include relatively low fixed charges, and shifting to a fully fixed rate would likely result in rate increases for the residential customers.

Figure 42: Barclays Capital Power and Utilities Coverage Universe

REGULATED COMP SHEET

Investment Opinion	Ticker	Company	Current Price 07/16/09	Indicated Annual Dividend	Expected Annual Dividend Growth	Current Yield	Earnings per Share 2008A	Earnings per Share 2009E	Earnings per Share 2010E	5 Year Est. EPS Growth	2008A Price/ Earnings	2009E Price/ Earnings	2010E Price/ Earnings
2-EW	LNT	Alliant Energy	$26.28	$1.50	10.0%	5.7%	$2.54	$2.25	$2.55	2%	10.3x	11.7x	10.3x
1-OW	AEP	American Electric Power	$29.95	$1.56	4.0%	5.2%	$3.24	$2.91	$3.03	2%	9.2x	10.3x	9.9x
1-OW	CMS	CMS Energy Corp	$12.33	$0.50	6.6%	4.1%	$1.25	$1.27	$1.33	7%	9.9x	9.7x	9.3x
2-EW	ED	Consolidated Edison	$37.69	$2.36	1.0%	6.3%	$3.00	$3.19	$3.30	2%	12.6x	11.8x	11.4x
1-OW	DPL	DPL Inc	$23.65	$1.14	5.0%	4.8%	$2.12	$2.23	$2.65	15%	11.2x	10.6x	8.9x
2-EW	DTE	DTE Energy Co	$32.73	$2.12	0.7%	6.5%	$2.90	$2.96	$3.22	0%	11.3x	11.1x	10.2x
1-OW	DUK	Duke Energy Corp	$14.77	$0.94	4.0%	6.4%	$1.21	$1.23	$1.30	1%	12.2x	12.0x	11.4x
2-EW	GXP	Great Plains Energy	$15.54	$0.83	2.0%	5.3%	$1.16	$1.12	$1.30	2%	13.4x	13.9x	12.0x
3-UW	HE	Hawaiian Electric Inds	$17.55	$1.24	0.0%	7.1%	$1.49	$1.35	$1.38	-1%	11.8x	13.0x	12.7x
2-EW	ITC	ITC Holdings	$43.58	$1.22	4.0%	2.8%	$2.19	$2.27	$2.56	17%	19.9x	19.2x	17.0x
2-EW	NI	NiSource Inc	$12.22	$0.92	0.0%	7.5%	$1.27	$1.05	$1.04	-6%	9.6x	11.6x	11.8x
2-EW	NU	Northeast Utilities	$22.21	$0.95	5.6%	4.3%	$1.87	$1.79	$2.10	13%	11.9x	12.4x	10.6x
2-EW	NST	NSTAR	$30.93	$1.50	7.0%	4.8%	$2.22	$2.40	$2.58	5%	13.9x	12.9x	12.0x
1-OW	NVE	NV Energy	$11.29	$0.40	10.6%	3.5%	$0.89	$0.91	$1.18	13%	12.7x	12.4x	9.6x
1-OW	PCG	PG&E Corp	$37.73	$1.68	7.9%	4.5%	$2.95	$3.18	$3.46	8%	12.8x	11.9x	10.9x
2-EW	PGN	Progress Energy	$37.75	$2.48	1.0%	6.6%	$2.98	$2.96	$3.13	-1%	12.7x	12.8x	12.1x
2-EW	PNM	PNM Resources	$11.64	$0.50	0.0%	4.3%	$0.12	$0.46	$0.85	-12%	97.0x	25.3x	13.7x
RS	PNW	Pinnacle West Capital	$30.88	$2.10	0.0%	6.8%	$2.29	$2.30	$2.74	-4%	13.5x	13.4x	11.3x
2-EW	POM	Pepco Holdings	$13.86	$1.08	2.0%	7.8%	$1.93	$1.10	$1.43	-1%	7.2x	12.6x	9.7x
1-OW	POR	Portland General	$20.08	$1.02	7.5%	5.1%	$1.71	$1.80	$1.87	13%	11.7x	11.2x	10.7x
2-EW	SO	Southern Co	$31.80	$1.75	5.0%	5.5%	$2.37	$2.30	$2.45	3%	13.4x	13.8x	13.0x
2-EW	SRE	Sempra Energy	$48.99	$1.56	10.0%	3.2%	$4.43	$4.40	$5.05	7%	11.1x	11.1x	9.7x
2-EW	TE	TECO Energy Inc	$12.09	$0.80	4.7%	6.6%	$0.86	$1.08	$1.21	0%	14.1x	11.2x	10.0x
2-EW	WR	Westar Energy	$19.08	$1.20	2.0%	6.3%	$1.27	$1.65	$1.75	3%	15.0x	11.6x	10.9x
1-OW	WEC	Wisconsin Energy Corp	$41.44	$1.35	3.0%	3.3%	$3.03	$3.15	$3.90	10%	13.7x	13.2x	10.6x
2-EW	XEL	Xcel Energy	$18.94	$0.95	3.0%	5.0%	$1.45	$1.52	$1.61	8%	13.1x	12.5x	11.8x
UTILITIES (26)					4.5%	5.4%				3.8%	12.8x	12.3x	11.3x
S&P 500 Index			940.7	$28.48		3.0%	$68.80	$55.96	$68.45	-6.0%	13.7x	16.8x	13.7x

Source: Company disclosures, FactSet, Barclays Capital estimates

POWER COMP SHEET

Rating	Ticker	Company	Current Price 07/16/09	Div. Yield	Asset Value	Potential Upside	Open EBITDA - '10 $MM	Open EBITDA - '10 EV Multiple	Current EBITDA - '10 $MM	Current EBITDA - '10 EV Multiple	Earnings per Share 2008A	Earnings per Share 2009E	Earnings per Share 2010E	P/E Multiples 2009E	P/E Multiples 2010E	Open P/E- '10 EPS	Open P/E- '10 Multiple	FCF Yield/EV 2009E	FCF Yield/EV 2010E
1-OW	AES	AES Corporation	$12.09	0.0%	$13	4%	$3,290	7.2x	$3,332	7.1x	$0.99	$0.97	$1.08	12.5x	11.2x	$1.04	11.6x	-3.6%	1.2%
1-OW	AYE	Allegheny Energy	$25.04	2.4%	$40	60%	$1,721	5.0x	$1,338	6.4x	$2.30	$2.20	$2.85	11.4x	8.8x	$4.21	5.9x	1.2%	4.2%
2-EW	AEE	Ameren Corp.	$24.61	6.3%	$26	6%	$2,008	8.3x	$2,181	7.6x	$2.89	$2.83	$2.70	8.7x	9.1x	$2.21	11.1x	-2.9%	-3.3%
2-EW	CPN	Calpine Corp.	$11.47	0.0%	$8	-30%	$1,188	10.3x	$1,081	11.2x	($0.03)	$0.42	($0.14)	27.5x	NM	$0.00	NM	3.8%	2.7%
2-EW	CEG	Constellation Energy Corp	$27.89	3.4%	$43	54%	$1,729	6.3x	$1,720	6.4x	$1.67	$3.15	$3.18	8.9x	8.8x	$3.21	8.7x	1.5%	0.2%
1-OW	CVA	Covanta Holdings	$17.66	0.0%	$15	-15%	$505	7.7x	$530	7.3x	$0.90	$0.74	$1.00	23.9x	17.7x	$0.99	17.8x	2.4%	2.8%
2-EW	D	Dominion Resources Inc	$33.17	4.8%	$35	5%	$4,654	7.8x	$5,634	6.3x	$3.16	$3.08	$3.19	10.8x	10.4x	$2.60	12.8x	-0.3%	0.3%
2-EW	DYN	Dynegy Inc.	$2.03	0.0%	$4	113%	$495	11.9x	$796	7.5x	$0.03	($0.06)	$0.05	NM	NM	($0.18)	NM	0.7%	1.3%
2-EW	EIX	Edison International	$31.45	3.9%	$44	38%	$3,654	6.3x	$4,981	4.7x	$3.84	$2.88	$3.22	10.9x	9.8x	$1.92	16.4x	-4.8%	-3.6%
1-OW	ETR	Entergy Corp	$75.64	4.0%	$111	47%	$3,293	8.8x	$3,800	5.9x	$6.51	$6.76	$7.28	11.2x	10.4x	$5.58	13.6x	6.3%	6.7%
RS	EXC	Exelon	$51.93	3.9%	N/A	N/A	$5,571	7.7x	$8,950	6.2x	$4.20	$4.02	$4.28	12.9x	12.1x	$3.64	14.3x	6.5%	6.9%
1-OW	FE	FirstEnergy Corp	$40.80	5.4%	$56	37%	$3,765	6.9x	$3,510	7.4x	$4.57	$3.75	$3.47	10.9x	11.8x	$3.93	10.4x	3.3%	3.4%
1-OW	FPL	FPL Group Inc	$57.37	3.1%	$69	21%	$4,469	8.9x	$4,793	8.4x	$3.84	$4.28	$4.76	13.4x	12.1x	$3.96	14.5x	2.7%	4.7%
2-EW	MIR	Mirant Corp	$16.16	0.0%	$9	-42%	$481	7.8x	$653	4.8x	$2.60	$2.56	$1.53	6.3x	10.6x	$0.12	NM	-4.5%	-1.3%
RS	NRG	NRG Energy	$24.72	0.0%	N/A	N/A	$1,798	6.9x	$2,272	5.5x	$2.52	$2.92	$2.41	8.5x	10.3x	$1.10	22.5x	7.7%	6.6%
2-EW	ORA	Ormat Technologies	$39.11	0.5%	$33	-16%	$168	12.7x	$169	12.5x	$1.12	$1.20	$1.46	32.6x	28.8x	$1.54	25.4x	3.7%	6.0%
1-OW	PPL	PPL Corporation	$32.80	4.2%	$41	25%	$3,098	6.8x	$3,070	6.7x	$2.02	$1.73	$3.52	19.0x	9.3x	$3.57	9.2x	1.2%	2.6%
1-OW	PEG	Public Service Entrp Group	$32.47	4.1%	$41	26%	$4,362	6.4x	$4,176	6.6x	$2.92	$3.11	$3.12	10.4x	10.4x	$4.09	7.9x	3.3%	3.3%
2-EW	RRI	RRI Energy, Inc.	$5.02	0.0%	$11	119%	$413	6.0x	$507	4.9x	($0.13)	($0.66)	$0.18	NM	27.9x	$0.21	NM	-6.2%	12.0%
		Group Average (19)		3.4%		18.6%		7.5x		6.8x				12.5x	10.8x		12.1x	2.5%	3.4%

Source: Barclays Capital estimates, FactSet

Source: Barclays Capital Estimates, FactSet, Company Disclosures

Appendix

Figure 43: 2005 Rate Case Outcomes

Date	Company	State	Allowed ROE	Yield on 10-Year Treasury	Spread (bps)	Yield on Moodys Baa	Spread (bps)
01/06/05	South Carolina Electric & Gas	SC	10.70%	4.29%	641	6.13%	457
01/28/05	Aquila Networks-WPK	KS	10.50%	4.16%	634	5.91%	459
02/18/05	Puget Sound Energy	WA	10.30%	4.27%	603	5.89%	441
02/25/05	PacifiCorp	UT	10.50%	4.27%	623	5.89%	461
03/10/05	Empire District Electric	MO	11.00%	4.48%	652	5.99%	501
03/18/05	Dominion North Carolina Power	NC	--	--	--	--	--
03/24/05	Consolidated Edison of NY	NY	10.30%	4.60%	570	6.18%	412
03/31/05	Texas-New Mexico Power	TX	10.25%	4.50%	575	6.14%	411
	1st Quarter Averages		**10.51%**	**4.37%**	**614**	**6.02%**	**449**
04/04/05	Central Vermont Public Service	VT	10.00%	4.47%	553	6.12%	388
04/07/05	Arizona Public Service	AZ	10.25%	4.49%	576	6.14%	411
05/02/05	Public Service Co. of Oklahoma	OK	--	--	--	--	--
05/18/05	Entergy Louisiana	LA	10.25%	4.07%	618	5.99%	426
05/18/05	Wisconsin Electric Power	WI	--	--	--	--	--
05/25/05	Savannah Electric & Power	GA	10.75%	4.08%	667	5.99%	476
05/26/05	Atlantic City Electric	NJ	9.75%	4.08%	567	5.99%	376
05/26/05	Idaho Power	ID	--	--	--	--	--
06/01/05	Jersey Central Power & Light	NJ	9.75%	3.91%	584	5.82%	393
06/08/05	Public Service New Hampshire	NH	9.62%	3.95%	567	5.77%	385
	2nd Quarter Averages		**10.05%**	**4.15%**	**590**	**5.97%**	**408**
07/19/05	Wisconsin Power & Light	WI	11.50%	4.20%	730	5.98%	552
07/22/05	PacifiCorp	ID	--	--	--	--	--
08/05/05	Cap Rock Energy	TX	11.75%	4.40%	735	6.07%	568
08/15/05	AEP Texas Central	TX	10.13%	4.27%	586	5.98%	415
09/28/05	PacifiCorp	OR	10.00%	4.26%	574	6.08%	392
	3rd Quarter Averages		**10.85%**	**4.28%**	**656**	**6.03%**	**482**
12/09/05	Empire District Electric	KS	--	--	--	--	--
12/12/05	Madison Gas & Electric	WI	11.00%	4.56%	644	6.42%	458
12/13/05	OGE Electric Service	OK	10.75%	4.54%	621	6.42%	433
12/16/05	Pacific Gas & Electric	CA	11.35%	4.45%	690	6.30%	505
12/16/05	San Diego Gas & Electric	CA	10.70%	4.45%	625	6.30%	440
12/16/05	Southern California Edison	CA	11.60%	4.45%	715	6.30%	530
12/21/05	Cincinnati Gas & Electric	OH	10.29%	4.49%	580	6.33%	396
12/21/05	Avista	WA	10.40%	4.49%	591	6.33%	407
12/22/05	Consumers Energy	MI	11.15%	4.44%	671	6.27%	488
12/22/05	Wisconsin Public Service	WI	11.00%	4.44%	656	6.27%	473
12/28/05	Westar Energy North	KS	10.00%	4.38%	562	6.20%	380
12/28/05	Kansas Gas & Electric	KS	10.00%	4.38%	562	6.20%	380
12/28/05	Dayton Power & Light	OH	--	--	--	--	--
12/30/05	NSTAR Electric	MA	--	--	--	--	--
	4th Quarter Averages		**10.75%**	**4.46%**	**629**	**6.30%**	**445**
	2005 Average		**10.54%**	**4.32%**	**622**	**6.08%**	**446**

Source: SNL Financial, Federal Reserve

Figure 44: 2006 Rate Case Outcomes

Date	Company	State	Allowed ROE	Yield on 10-Year Treasury	Spread (bps)	Yield on Moodys Baa	Spread (bps)
01/05/06	Northern States Power	WI	11.00%	4.36%	664	6.20%	480
01/25/06	Wisconsin Electric Power	WI	--	--	--	--	--
01/27/06	United Illuminating	CT	9.75%	4.52%	523	6.30%	345
02/23/06	Aquila Networks-MPS	MO	--	--	--	--	--
02/23/06	Aquila Networks-L&P	MO	--	--	--	--	--
03/03/06	Interstate Power & Light	MN	10.39%	4.68%	571	6.35%	404
03/14/06	Kentucky Power	KY	--	--	--	--	--
03/24/06	PacifiCorp	WY	--	--	--	--	--
03/29/06	Entergy Gulf States	LA	--	--	--	--	--
	1st Quarter Averages		**10.38%**	**4.52%**	**586**	**6.28%**	**410**
04/17/06	PacifiCorp	WA	10.20%	5.01%	519	6.71%	349
04/18/06	MidAmerican Energy	IA	11.90%	4.99%	691	6.69%	521
04/26/06	Sierra Pacific Power	NV	10.60%	5.12%	548	6.76%	384
05/12/06	Idaho Power	ID	--	--	--	--	--
05/17/06	Southern California Edison[(1)]	CA	11.60%	5.16%	644	6.82%	478
06/06/06	Delmarva Power & Light	DE	10.00%	5.01%	499	6.66%	334
06/27/06	Upper Peninsula Power	MI	10.75%	5.21%	554	6.91%	384
	2nd Quarter Averages		**10.84%**	**5.08%**	**576**	**6.76%**	**408**
07/06/06	Maine Public Service	ME	10.20%	5.19%	501	6.85%	335
07/24/06	Central Hudson Gas & Electric	NY	9.60%	5.05%	455	6.74%	286
07/26/06	Appalachian Power	WV	10.50%	5.04%	546	6.72%	378
07/28/06	Commonwealth Edison	IL	10.05%	5.00%	505	6.67%	338
08/23/06	New York State Electric & Gas	NY	9.55%	4.82%	473	6.54%	301
08/31/06	Detroit Edison	MI	11.00%	4.74%	626	6.47%	453
09/01/06	Northern States Power	MN	10.54%	4.73%	581	6.46%	408
09/05/06	CenterPoint Energy Houston Elec.	TX	--	--	--	--	--
09/14/06	PacifiCorp	OR	10.00%	4.79%	521	6.49%	351
	3rd Quarter Averages		**10.18%**	**4.92%**	**526**	**6.62%**	**356**
10/06/06	Unitil Energy Systems	NH	9.67%	4.70%	497	6.43%	324
10/27/06	Entergy New Orleans	LA	--	--	--	--	--
11/21/06	Delmarva Power & Light	DE	--	--	--	--	--
11/21/06	Central Illinois Light	IL	10.12%	4.58%	554	6.18%	394
11/21/06	Central Illinois Public Service	IL	10.08%	4.58%	550	6.18%	390
11/21/06	Illinois Power	IL	10.08%	4.58%	550	6.18%	390
12/01/06	Duquesne Light	PA	--	--	--	--	--
12/01/06	PacifCorp	UT	10.25%	4.43%	582	6.08%	417
12/01/06	Public Service of Colorado	CO	10.50%	4.43%	607	6.08%	442
12/04/06	Kansas City Power & Light	KS	--	--	--	--	--
12/07/06	Central Vermont Public Service	VT	10.75%	4.49%	626	6.13%	462
12/14/06	Western Massachusetts Electric	MA	--	--	--	--	--
12/18/06	PacifCorp	ID	--	--	--	--	--
12/21/06	Duke Energy Kentucky	KY	--	--	--	--	--
12/21/06	Empire District Electric	MO	10.90%	4.55%	635	6.23%	467
12/21/06	Kansas City Power & Light	MO	11.25%	4.55%	670	6.23%	502
12/22/06	Green Moutain Power	VT	10.25%	4.63%	562	6.30%	395
12/28/06	Black Hills Power	SD	--	4.70%	--	--	--
	4th Quarter Averages		**10.39%**	**4.57%**	**582**	**6.20%**	**418**
	2006 Average		**10.45%**	**4.77%**	**567**	**6.47%**	**398**

(1) ROE was determined in previously decided cost of capital decision.

Source: SNL Financial, Federal Reserve

Figure 45: 2007 Rate Case Outcomes

Date	Company	State	Allowed ROE	10-Year Treas. Yield	Spread (bps)	Moodys Baa Yield	Spread (bps)
01/05/07	Oklahoma Gas And Electric	AR	10.00%	4.65%	535	6.25%	375
01/11/07	Wisconsin Power & Light Co.	WI	10.80%	4.74%	606	6.33%	447
01/11/07	Pennsylvania Electric Co.	PA	10.10%	4.74%	536	6.33%	377
01/11/07	Metropolitan Edison Co.	PA	10.10%	4.74%	536	6.33%	377
01/12/07	Portland General Electric Co.	OR	10.10%	4.77%	533	6.36%	374
02/06/07	PPL Gas Utilities	PA	10.40%	4.73%	567	6.28%	412
03/15/07	Pacific Gas and Electric Co.	CA	11.35%	4.54%	681	6.24%	511
03/20/07	Delmarva Power & Light Co.	DE	10.25%	4.56%	569	6.27%	398
03/22/07	Rockland Electric Company	NJ	9.75%	4.60%	515	6.35%	340
03/22/07	Southern Union Co.	MO	10.50%	4.60%	590	6.35%	415
	1st Quarter Averages		10.35%	4.66%	569	6.31%	404
05/15/07	Appalachian Power	VA	10.00%	4.71%	529	6.36%	364
05/17/07	Aquila (MPS)	MO	10.25%	4.76%	549	6.40%	385
05/17/07	Aquila (L&P)	MO	10.25%	4.76%	549	6.40%	385
05/22/07	Monongahela Pow/Potomac Ed.	WV	10.50%	4.83%	567	6.46%	404
05/22/07	Union Electric	MO	10.20%	4.83%	537	6.46%	374
05/23/07	Nevada Power	NV	10.70%	4.86%	584	6.49%	421
05/25/07	Public Service of New Hampshire	NH	9.67%	4.86%	481	6.48%	319
06/05/07	Cascade Natural Gas	OR	10.10%	4.98%	512	6.55%	355
06/13/07	Northern States Power	ND	10.75%	5.20%	555	6.78%	397
06/15/07	Entergy Arkansas	AR	9.90%	5.16%	474	6.76%	314
06/21/07	Pacificorp	WA	10.20%	5.16%	504	6.76%	344
06/22/07	Appalachian Power	WV	10.50%	5.14%	536	6.74%	376
06/28/07	Arizona Public Service	AZ	10.75%	5.12%	563	6.72%	403
06/29/07	Yankee Gas Services	CT	10.10%	5.03%	507	6.62%	348
06/29/07	Public Service of New Mexico	NM	9.53%	5.03%	450	6.62%	291
	2nd Quarter Averages		10.23%	4.96%	526	6.57%	365
07/03/07	Public Service of Colorado	CO	10.25%	5.05%	520	6.65%	360
07/12/07	Granite State Electric	NH	9.67%	5.13%	454	6.72%	295
07/13/07	Arkansas Western Gas	AR	9.50%	5.11%	439	6.70%	280
07/19/07	Delmarva Power & Light	MD	10.00%	5.04%	496	6.63%	337
07/19/07	Potomac Electric Power	MD	10.00%	5.04%	496	6.63%	337
07/24/07	Aquila	NE	10.40%	4.94%	546	6.59%	381
08/01/07	Southern Indiana Gas & Electric	IN	10.15%	4.76%	539	6.62%	353
08/15/07	Southern Indiana Gas & Electric	IN	10.40%	4.69%	571	6.72%	368
08/21/07	Consumers Energy	MI	--	4.60%	--	--	--
08/29/07	Columbia Gas of Kentucky	KY	10.50%	4.57%	593	6.62%	388
09/10/07	Northern States Power - MN	MN	9.71%	4.34%	537	6.47%	324
09/19/07	Washington Gas & Light	VA	10.00%	4.53%	547	6.64%	336
09/25/07	Consolidated Edison of NY	NY	9.70%	4.63%	507	6.65%	305
	3rd Quarter Averages		10.02%	4.80%	520	6.64%	339
10/08/07	Atmos Energy	TN	10.48%	4.65%	583	6.59%	389
10/09/07	Public Service of Oklahoma	OK	10.00%	4.67%	533	6.57%	343
10/18/07	Orange and Rockland Utilities	NY	9.10%	4.52%	458	6.46%	264
10/19/07	Delta Natural Gas	KY	10.50%	4.41%	609	6.38%	412
10/25/07	CenterPoint Energy Resources	AR	9.65%	4.37%	528	6.36%	329
10/31/07	Electric Transmission Texas	TX	9.96%	4.48%	548	6.47%	349
11/15/07	Washington Gas & Light	MD	10.00%	4.17%	583	6.39%	361
11/20/07	Arkansas Oklahoma Gas	AR	9.90%	4.06%	584	6.41%	349
11/27/07	UNS Gas	AZ	10.00%	3.95%	605	6.36%	364
11/29/07	Cheyenne Light, Fuel, & Power	WY	10.90%	3.94%	696	6.40%	450
12/06/07	Kansas City Power & Light	MO	10.75%	4.02%	673	6.61%	414
12/13/07	AEP Central Texas	TX	9.96%	4.18%	578	6.76%	320
12/14/07	Madison Gas & Electric	WI	10.80%	4.24%	656	6.79%	401
12/14/07	South Carolina Electric & Gas	SC	10.70%	4.24%	646	6.79%	391
12/18/07	Northwestern Energy Division	NE	10.40%	4.14%	626	6.66%	374
12/19/07	Avista Corporation	WA	10.20%	4.06%	614	6.60%	360
12/20/07	Duke Energy Carolinas	NC	11.00%	4.04%	696	6.55%	445
12/20/07	Bangor Hydro Electric	ME	10.20%	4.04%	616	6.55%	365
12/21/07	Pacific Gas and Electric	CA	11.35%	4.18%	717	6.68%	467
12/21/07	San Diego Gas & Electric	CA	11.10%	4.18%	692	6.68%	442
12/21/07	Southern California Edison	CA	11.50%	4.18%	732	6.68%	482
12/21/07	Brooklyn Union Gas	NY	9.80%	4.18%	562	6.68%	312
12/21/07	KeySpan Gas East	NY	9.80%	4.18%	562	6.68%	312
12/21/07	National Fuel Gas Distribution	NY	9.10%	4.18%	492	6.68%	242
12/28/07	Pacificorp	ID	10.25%	4.11%	614	6.62%	363
12/31/07	Georgia Power	GA	11.25%	4.04%	721	6.56%	469
	4th Quarter Averages		10.33%	4.19%	612	6.57%	376
	2007 Average		10.23%	4.65%	557	6.52%	371

Source: SNL Financial, Federal Reserve

Figure 46: 2008 Rate Case Outcomes

Date	Company	State	Allowed ROE	10-Year Treas. Yield	Spread (bps)	Moodys Baa Yield	Spread (bps)
01/08/08	Northern States Power Co-WI	WI	10.75%	3.86%	689	6.49%	426
01/08/08	Northern States Power Co-WI	WI	10.75%	3.86%	689	6.49%	426
01/17/08	Wisconsin Electric Power Co.	WI	10.75%	3.66%	709	6.47%	428
01/17/08	Wisconsin Electric Power Co.	WI	10.75%	3.66%	709	6.47%	428
01/17/08	Wisconsin Gas LLC	WI	10.75%	3.66%	709	6.47%	428
01/28/08	Connecticut Light & Power Co.	CT	9.40%	3.61%	579	6.58%	282
01/30/08	Potomac Electric Power Co.	DC	10.00%	3.78%	622	6.72%	328
01/31/08	Central Vermont Public Service	VT	10.71%	3.67%	704	6.63%	408
02/05/08	North Shore Gas Co.	IL	9.99%	3.61%	638	6.62%	337
02/05/08	Peoples Gas Light & Coke Co.	IL	10.19%	3.61%	658	6.62%	357
02/13/08	Indiana Gas Co.	IN	10.20%	3.70%	650	6.81%	339
02/29/08	Fitchburg Gas & Electric Light	MA	10.25%	3.53%	672	6.75%	350
03/12/08	PacifiCorp	WY	10.25%	3.49%	676	6.88%	337
03/25/08	Consolidated Edison Co. of NY	NY	9.10%	3.51%	559	6.90%	220
03/31/08	Avista Corp.	OR	10.00%	3.45%	655	6.90%	310
	1st Quarter Averages		**10.26%**	**3.64%**	**661**	**6.65%**	**360**
04/22/08	MDU Resources Group Inc.	MT	10.25%	3.74%	651	6.95%	330
04/24/08	Public Service Co. of NM	NM	10.10%	3.87%	623	7.00%	310
05/01/08	Hawaiian Electric Co.	HI	10.70%	3.78%	692	6.82%	388
05/27/08	UNS Electric Inc.	AZ	10.00%	3.93%	607	7.01%	299
05/28/08	Duke Energy Ohio Inc.	OH	10.50%	4.03%	647	7.06%	344
06/10/08	Consumers Energy Co.	MI	10.70%	4.11%	659	7.05%	365
06/24/08	Atmos Energy Corp.	TX	10.00%	4.10%	590	7.08%	292
06/27/08	Sierra Pacific Power Co.	NV	10.60%	3.99%	661	7.03%	357
06/27/08	Appalachian Power Co.	WV	10.50%	3.99%	651	7.03%	347
06/27/08	Questar Gas Co.	UT	10.00%	3.99%	601	7.03%	297
	2nd Quarter Averages		**10.34%**	**3.95%**	**638**	**7.01%**	**333**
07/10/08	Otter Tail Corp.	MN	10.43%	3.83%	660	7.00%	343
07/16/08	Orange & Rockland Utils Inc.	NY	9.40%	3.97%	543	7.21%	219
07/30/08	Empire District Electric Co.	MO	10.80%	4.07%	673	7.24%	356
07/31/08	San Diego Gas & Electric Co.	CA	10.70%	3.99%	671	7.21%	349
07/31/08	San Diego Gas & Electric Co.	CA	10.70%	3.99%	671	7.21%	349
07/31/08	Southern California Gas Co.	CA	10.82%	3.99%	683	7.21%	361
08/11/08	PacifiCorp	UT	10.25%	3.99%	626	7.23%	302
08/26/08	Southwestern Public Service Co	NM	10.18%	3.79%	639	7.10%	308
08/27/08	SourceGas Distribution LLC	CO	10.25%	3.77%	648	7.07%	318
09/02/08	Chesapeake Utilities Corp.	DE	10.25%	3.74%	651	7.07%	318
09/10/08	Commonwealth Edison Co.	IL	10.30%	3.65%	665	7.02%	328
09/17/08	Atmos Energy Corp.	GA	10.70%	3.41%	729	7.25%	345
09/24/08	Central Illinois Light Co.	IL	10.65%	3.80%	685	7.58%	307
09/24/08	Central Illinois Public	IL	10.65%	3.80%	685	7.58%	307
09/24/08	Illinois Power Co.	IL	10.65%	3.80%	685	7.58%	307
09/24/08	Central Illinois Light Co.	IL	10.68%	3.80%	688	7.58%	310
09/24/08	Central Illinois Public	IL	10.68%	3.80%	688	7.58%	310
09/24/08	Illinois Power Co.	IL	10.68%	3.80%	688	7.58%	310
09/30/08	Avista Corp.	ID	10.20%	3.85%	635	7.85%	235
09/30/08	Avista Corp.	ID	10.20%	3.85%	635	7.85%	235
	3rd Quarter Averages		**10.46%**	**3.83%**	**662**	**7.35%**	**311**
10/03/08	New Jersey Natural Gas Co.	NJ	10.30%	3.63%	667	7.98%	232
10/08/08	Puget Sound Energy Inc.	WA	10.15%	3.72%	643	8.21%	194
10/08/08	Puget Sound Energy Inc.	WA	10.15%	3.72%	643	8.21%	194
10/20/08	CenterPoint Energy Resources	TX	10.06%	3.91%	615	9.43%	63
10/24/08	Piedmont Natural Gas Co.	NC	10.60%	3.76%	684	9.30%	130
10/24/08	Public Service Co. of NC	NC	10.60%	3.76%	684	9.30%	130
11/17/08	Appalachian Power Co.	VA	10.20%	3.68%	652	9.26%	94
11/21/08	Southwest Gas Corp.	CA	10.50%	3.20%	730	9.08%	142
11/21/08	Southwest Gas Corp.	CA	10.50%	3.20%	730	9.08%	142
11/21/08	Southwest Gas Corp.	CA	10.50%	3.20%	730	9.08%	142
11/24/08	Narragansett Electric Co.	RI	10.50%	3.35%	715	9.21%	129
12/01/08	Tucson Electric Power Co.	AZ	10.25%	2.72%	753	8.84%	141
12/23/08	Columbia Gas of Ohio Inc	OH	10.39%	2.18%	821	8.12%	227
12/23/08	Detroit Edison Co.	MI	11.00%	2.18%	882	8.12%	288
12/24/08	Southwest Gas Corp.	AZ	10.00%	2.20%	780	8.10%	190
12/26/08	Northwest Natural Gas Co.	WA	10.10%	2.16%	794	8.06%	204
12/29/08	Portland General Electric Co.	OR	10.10%	2.13%	797	8.05%	205
12/29/08	Avista Corp.	WA	10.20%	2.13%	807	8.05%	215
12/29/08	Avista Corp.	WA	10.20%	2.13%	807	8.05%	215
12/31/08	Northern States Power Co. - MN	ND	10.75%	2.25%	850	8.07%	268
	4th Quarter Averages		**10.35%**	**2.96%**	**739**	**8.58%**	**177**
	2008 Average		**10.35%**	**3.60%**	**675**	**7.40%**	**295**

Source: SNL Financial, Federal Reserve

Figure 47: 1Q09 Rate Case Outcomes

Date	Company	State	Allowed ROE	Yield on 10-Year Treasury	Spread (bps)	Yield on Moodys Baa	Spread (bps)
01/14/09	Public Service of Oklahoma	OK	10.50%	2.24%	826	7.92%	258
01/21/09	Toledo Edison Co.	OH	10.50%	2.56%	794	8.14%	236
01/21/09	Ohio Edison Co.	OH	10.50%	2.56%	794	8.14%	236
01/21/09	Cleveland Electric Illuminating Co	OH	10.50%	2.56%	794	8.14%	236
01/27/09	Union Electric Co.	MO	10.76%	2.59%	817	8.06%	270
01/30/09	Idaho Power Co.	ID	10.50%	2.87%	763	8.25%	225
02/04/09	United Illuminating Co.	CT	8.75%	2.95%	580	8.24%	51
03/04/09	Indiana Michigan Power	IN	10.50%	3.01%	749	8.32%	218
03/12/09	Southern California Edison	CA	11.50%	2.89%	861	8.41%	309
03/17/09	Tampa Electric Co.	FL	8.11%	3.02%	509	8.62%	(51)
01/13/09	Michigan Gas Utilities Corp.	MI	10.45%	2.33%	812	8.05%	240
02/02/09	New England Gas Co.	MA	10.05%	2.76%	729	8.09%	196
03/09/09	Atmos Energy Corp.	TN	10.30%	2.89%	741	8.29%	201
03/25/09	Northern Illinois Gas Co.	IL	10.17%	2.81%	736	8.60%	157
	1st Quarter Averages		**10.22%**	**2.72%**	**750**	**8.23%**	**199**

Source: SNL Financial, Federal Reserve

Figure 48: Electricity Rates, by Customer Class

(cents / kWh)

State	Residential	Commercial	Industrial	Total / Avg.
Idaho	6.97	5.67	4.55	5.66
West Virginia	7.02	6.02	4.17	5.54
North Dakota	7.54	6.74	5.54	6.65
Washington	7.57	6.73	4.8	6.6
Kentucky	7.71	7.12	4.84	6.16
Nebraska	7.87	6.59	5.12	6.53
Missouri	8.01	6.6	4.98	6.84
Wyoming	8.16	6.67	4.52	5.67
South Dakota	8.26	6.81	5.31	7.07
Utah	8.37	6.8	4.7	6.61
Oregon	8.54	7.63	4.93	7.27
Tennessee	8.55	8.74	6.14	7.84
Indiana	8.76	7.67	5.49	7.01
Montana	9.16	8.48	6.4	8
Kansas	9.17	7.7	NM	7.7
Oklahoma	9.45	8.21	6.08	8.13
Arkansas	9.49	7.73	5.98	7.74
Virginia	9.55	7.24	5.54	7.87
Minnesota	9.61	7.82	5.99	7.77
Iowa	9.66	7.24	4.9	6.99
North Carolina	9.68	7.64	5.59	8.06
South Carolina	9.98	8.48	NM	7.87
New Mexico	10.02	8.65	6.45	8.38
Ohio	10.13	9.19	6.19	8.39
Georgia	10.14	9.18	6.69	8.95
Colorado	10.17	8.65	6.63	8.64
Alabama	10.24	9.7	6.02	8.45
Mississippi	10.34	9.96	6.46	8.92
Arizona	10.35	8.95	6.69	9.21
Louisiana	10.55	10.29	8.12	9.59
Illinois	10.82	8.78	NM	8.95
Michigan	10.88	9.42	6.87	9.11
U.S. Total	11.34	10.33	7.01	9.81
Wisconsin	11.44	9.19	6.52	8.93
Pennsylvania	11.47	9.41	7.04	9.36
Florida	11.6	10.06	8.27	10.7
Nevada	11.87	10.14	8.23	10.02
District of Columbia	12.64	13.76	11.55	13.56
Texas	12.94	10.8	8.97	11.07
Maryland	13.67	12.79	10.46	12.94
Delaware	13.88	12.04	10.25	12.28
California	14.37	13.12	10.28	13
Vermont	14.6	12.5	9.01	12.31
New Hampshire	15.58	14.2	13.12	14.54
Maine	15.98	12.99	11.88	13.72
New Jersey	16.01	14.9	12.55	15.04
Alaska	16.35	13.14	14.26	14.45
Rhode Island	17.26	15.25	14.08	15.88
Massachusetts	17.38	16.1	14.41	16.24
New York	18.56	16.96	10.28	16.75
Connecticut	19.29	15.96	13.8	16.88
Hawaii	32.73	29.97	26.33	29.46

Source: EIA.

Figure 49: Ranking of State Utility Commissions

Commission	Raw Score	Rank	JD Power Score
Kentucky Public Service Commission	7.29	1	710
Wyoming Public Service Commission	7.29	1	
Iowa Utilities Board	7.32	3	708
Idaho Public Utilities Commission	7.39	4	
North Carolina Utilities Commission	7.57	5	719
Florida Public Service Commission	7.86	6	700
Minnesota Public Utilities Commission	7.93	7	698
Ohio Public Utilities Commission	7.96	8	668
Alabama Public Service Commission	8.00	9	723
Colorado Public Utilities Commission	8.00	9	694
Georgia Public Service Commission	8.00	9	723
Oklahoma Corporation Commission	8.04	12	697
Texas Public Utility Commission	8.04	12	658
Michigan Public Service Commission	8.11	14	677
North Dakota Public Service Commission	8.11	14	
California Public Utilities Commission	8.18	16	681
Indiana Utility Regulatory Commission	8.25	17	669
Kansas Corporation Commission	8.29	18	653
South Carolina Public Service Commission	8.32	19	703
Wisconsin Public Service Commission	8.39	20	693
Arkansas Public Service Commission	8.46	21	654
Virginia State Corporation Commission	8.46	21	679
Delaware Public Service Commission	8.50	23	654
Massachusetts Dept of Tele and Energy	8.61	24	650
Oregon Public Utility Commission	8.64	25	691
Washington Utils and Trans Commission	8.64	25	677
Utah Public Service Commission	8.75	27	678
Hawaii Public Utilities Commission	8.79	28	
Illinois Commerce Commission	8.86	29	617
District of Columbia Public Svc Commission	8.93	30	654
West Virginia Public Service Commission	8.93	30	
Mississippi Public Service Commission	8.96	32	689
Missouri Public Service Commission	8.96	32	653
South Dakota Public Utilities Commission	8.96	32	636
Nevada Public Utilities Commission	9.18	35	639
Louisiana Public Service Commission	9.36	36	682
Vermont Public Service Board	9.39	37	
New Jersey Board of Public Utilities	9.68	38	659
Maine Public Utilities Commission	9.71	39	677
Pennsylvania Public Utility Commission	9.89	40	691
New Hampshire Public Utilities Commission	9.93	41	646
Maryland Public Service Commission	10.00	42	623
New York Public Service Commission	10.04	43	645
Rhode Island Public Utilities Commission	10.07	44	646
Connecticut Department of Pub Utility Control	10.32	45	641
Arizona Corporation Commission	10.46	46	698
Montana Public Service Commission	10.50	47	636
New Mexico Public Regulation Commission	10.57	48	667

Source: SNL Financial, JD Power & Associates, Barclays Capital estimates.

Figure 50: State Regulatory Staff Contacts

STATE	NAME	POSITION	PHONE	E-MAIL
Alabama	Janice Hamilton	Director, Energy Division	344-242-2696	janice.hamilton@psc.alabama.gov
	John Free	Manager, Energy Division, Electric	344-242-2696	john.free@psc.alabama.gov
Arizona	Michael P. Kearns	Interim Executive Director	602-542-3931	
	Rebecca Wilder	Public Information Officer	602-542-0844	
	Ernest G. Johnson	Director, Utilities Division	602-542-4251	
Arkansas	John Bethel	Executive Director - General Staff	501-682-1794	
		General Staff Information Number	501-682-1794	
California	Lynn Carew	Chief, ALJ Division	415-703-1721	
	Paul Clanon	Executive Director	415-703-3808	
	Sean Gallagher			
Colorado	Barbara Fernandez	Chief of Staff	303-894-2012	
	Doug Dean	Director	303-894-2007	
	Eugene Camp	Section Chief, Energy	303-894-2047	
Connecticut	Media Spokesperslon	Media Relatons/Public Information	860-827-2670	
	Bill Palomba	Executive Director	860-827-2802	bill.palomba@po.state.ct.us
Delaware	Karen Nickerson	Commission Secretary	302-736-7500	karen.nickerson@state.de.us
	Bruce Burcat	Executive Director	302-736-7500	
District of Columbia	Phylicia Faunteleroy Bowman	Executive Director	202-626-9176	pbowman@psc.dc.gov
	Aminta Davis	Executive Assistant, Exec. Dir. Office	202-626-5139	adaves@psc.dc.gov
	Joseph Nwude	Deputy Exec. Director, Regulation	202-626-5156	jnwude@psc.dc.gov
Florida	Mary Andrews Bane	Executive Director	850-413-6068	
		Public Information	850-413-6482	
	Charles Hill	Deputy Executive Director	850-413-6071	
Georgia	Deborah Flannagan	Executive Director	404-656-2141	
	Bill Edge	Public Information Officer	404-656-2316	bille@psc.state.ga.us
	Tom Bond	Director of Utilities	404-651-9401	
Hawaii	Paul Shigenaga	Administrative Director	808-586-2028	
	Joan Yamaguchi	Administrator - Utilities Division	808-586-2044	
	Stacy Djou	Chief Counsel	808-586-2022	
Idaho	Randy Lobb	Administrator, Utilities Division	208-334-0350	randy.lobb@puc.idaho.gov
	Gene Fadness	Public Information Officer	208-334-0339	gene.fadness@puc.idaho.gov
Illinois	Beth Bosch	Staff	217-782-5793	
	David Farrell	Director, Public Affairs	217-524-5046	
	Tim Anderson	Office of Executive Director	217-785-7456	
Indiana	Danielle Dravet	Public Information Officer	317-232-2297	
	Joseph Sutherland	Executive Director, Public Information	317-233-4723	
	Brad Borum	Director of Electricity	317-232-2304	
Iowa	Judie Cooper	Executive Secretary	515-281-5386	
	Jeff Kamen	Energy Section	515-281-3279	
	Rob Hillesland	Information Specialist	515-281-3551	
Kansas	Susan Cunningham	General Counsel	785-271-3272	
	Don Low	Director, Utilities Division	785-271-3221	
	Rosemary Foreman	Public Spokesperson	785-271-3275	
Kentucky	Stephanie Stumbo	Executive Director	502-564-3940 ext. 264	
Louisiana	Lawrence St. Blanc	Executive Secretary	225-342-4427	eve.gonzalez@la.gov
	Arnold Chauviere	Deputy Assistant Secretary, Utilities	225-342-4416	arnold.chauviere@la.gov
	Stan Perkins	Audit Director	225-342-1438	
	Brian McManus	Economist Director	225-342-2720	
Maine	Richard Kivela	Utility Analyst	207-287-1562	richard.kivela@maine.gov
	Fred Bever	Public Information Coordinator	207-287-6141	chris.simpson@maine.gov
Maryland	Gregory V. Carmean	Executive Director	410-767-8002	
	Obi Linton	External Relations, Director	410-767-8028	
Massachusetts	Timothy Shevlin	Executive Director	617-305-3691	
	Mary Cottrell	Secretary	617-305-3600	
Michigan	Robert Kehres	Regulatory Affairs Division, Director	517-241-6016	kehresr@michigan.gov
	Mary Jo Kunkle	Regulatory Affairs Division, Executive Secreta	517-241-3322	kunklem@michigan.gov
Minnesota	Burl Haar	Executive Secretary	651-201-2222	
	Janet Gonzales	Supervisor, Energy	651-201-2231	
Mississippi	Brian U. Ray	Executive Secretary	601-961-5434	brian.ray@psc.state.ms.us
	George Haynie	Central District Chief of Staff	601-961-5430	george.haynie@psc.state.ms.us
	Thomas Adams	Northern District Chief of Staff	662-983-1471	thomas.adams@psc.state.ms.us
	Jay McKnight	Southern District Staff Officer	228-396-2643	jay.mcknight@psc.state.ms.us
Missouri	Bob Shallenberg	Staff	673-751-7162	bob.schallenberg@psc.mo.gov
	Kevin Kelly	Public Information Officer	573-751-9300	kevin.kelly@psc.mo.gov
Montana	Kate Whitney	Administrator - Utilities Division	406-444-3056	kwhitney@mt.gov
New Hampshire	Debra Howland	Executive Director	603-271-2431	
New Jersey	Doyle Siddell	Public Information Officer	973-648-6135	
	Victor Fortkiewicz	Executive Director	973-648-4852	
	Mark Beyer	Chief Economist	973-648-3414	
	Kristi Izzo	Secretary	973-648-3426	
New Mexico	Daniel Mayfield	Chief of Staff	505-827-4433	daniel.mayfield@state.nm.us
	Roy Stephenson	Utilities Division Director	505-827-6980	
	Mona Varela	Management Analyst, Office of the Chief of S	505-827-4433	
Nevada	Sean Sever	Public Information Officer	775-684-6118	ssever@puc.state.nv.us
	Kirby Lampley	Director of Regulatory Operations	775-684-6137	klampley@puc.state.nv.us
New York	Debra Renner	Director, Office of Administration	518-474-2508	
	Tom Dvorsky	Director, Electric, Gas & Water	518-473-6080	
	Judith Lee	Acting Executive Deputy	518-474-4520	
North Carolina	George Sessoms	Deputy Director, Electric and Telecom	919-715-5292	sessoms@ncuc.net
	Robert Bennink, Jr.	Dir. Adm. Division and General Counsel	919-733-0833	bennink@ncuc.net
	Renne Vance	Chief Clerk	919-733-0840	vance@ncuc.net
North Dakota	Illona Jeffcoat	Director of Public Utilities Division	701-328-2407	
Ohio	Stephen Brennan	Director, Utilities Department	614-466-3705	
	Shana Gerber	Communications Liason	614-995-4168	
	Renne Jenkins	Commission Secretary	614-995-4294	
Oklahoma	David Dykeman	Director, Public Utility Division	405-521-2322	
	Andrew Tevington	Deputy Director, Public Utility Division	405-521-6953	
Oregon	Bonnie Tatom	Electricity Division, General Info	503-378-8225	Bonnie.Tatom@state.or.us
	Judy Johnson	Electricity Division, General Info and Rate cas	503-378-6636	Judy.Johnson@state.or.us
Pennslyvania	Karen O'Maury	Director of Operations	717-772-8883	
	Tom Charles	Manager of Communications	717-787-9504	thcharles@state.pa.us
Rhode Island	Luly Massaro	Commission Clerk	401-941-4500, x107	
	Sharon Colby Camara	Chief Financial Analyst	401-941-4500, x157	
	Thomas Kogut	Chief of Information	401-941-4500, x105	
South Carolina	Charles Terreni	Chief Clerk and Administrator	803-896-5133	
	Philip Riley	Energy Advisor	803-896-5154	
South Dakota	Greg Rislov	Commission Advisor	605-773-3201	greg.rislov@state.sd.us
	Patricia Van Gerpen	Executive Director	605-773-3201	patty.vangerpen@state.sd.us
Tennessee	Darlene Standley	Utilities Division, Chief	615-741-2904, x149	darlene.standley@tn.gov
	Jessica Johnson	Office of Public Information	615-741-2904, x233	jessica.johnson@tn.gov
Texas	Jess Totten	Dir. Electric Division	512-936-7235	jess.totten@puc.state.tx.us
Utah	Becky Wilson	Executive Staff Director, Electric & Gas	801-530-6770	rlwilson@utah.gov
	Julie P. Orchard	Commission Administrator	801-530-6713	jorchard@utah.gov
Vermont	Tamera Pariseau	Coordinator of Public Information Division	802-828-5262	tamera.pariseau@state.vt.us
	Judy Bruneau	Administrative Secretary	802-828-4071	judy.moody@state.vt.us
Virginia	Howard Spinner	Director, Division of Economics and Finance	804-371-9449	econfin@scc.virginia.gov
	William F. Stephens	Director, Division of Energy	804-371-9611	energyreg@scc.virginia.gov
	Kenneth Schrad	Director, Information Services	804-371-9141	ken.schrad@scc.virginia.gov
Washington	Anne Solwick	Director, General Utility Regulation	360-664-1290	asolwick@utc.wa.gov
	David Danner	Executive Director	360-664-1208	ddanner@utc.wa.gov
	Marilyn Meehan	Information Officer	360-664-1116	mmeehan@utc.wa.gov
	Mike Parvinen	Assistant Director, Electricity and Gas	360-664-1315	mparvinen@utc.wa.gov
West Virginia	Cheryl Ranson	Director, Utilities Division	304-340-0421	
	Dixie Kellmeyer	Supervisor, Energy Section	304-340-0762	
	Sandra Squire	Executive Secretary	304-340-0426	
Wisconsin	Robert Norcross	Administrator, Electric Division	608-266-0699	robert.norcross@psc.state.wi.us
Wyoming	Darrell Ziomke	Supervisor/Assistant Administrator	307-777-5724	dziomk@state.wy.us
	Denise Parrish	OCA Deputy Administrator	307-777-5743	dparri@state.wy.us
	Mary Kiser	Docketing Clerk	307-777-5749	mkiser@state.wy.us

Source: SNL Financial

Figure 51: State Regulatory Commissioners, A-M

STATE	NAME	Party	Term Ends	Experience	Contact Name	PHONE	E-MAIL
Alabama	Chair Lucy Baxley	D	Nov-12	President of Sullivan Furniture Inc.; private law practice	Lisa Parrish	334-242-5297	Lisa.parrish@psc.alabama.gov
	Susan Parker	D	Nov-10	Retired educator and former state auditor.	Brad Williams	344-242-5191	brad.williams@psc.alabama.gov
	Jan Cook	D	Nov-10	Alabama State Auditor for eight years	Kelly Mulero	344-242-5203	Jan.cook@psc.alabama.gov
Arizona	Chair Kristin K. Mayes	R	Jan-11	State Rep., Chmn. Natural Res. and Agric. Committee		602-542-4143	Mayes-web@azcc.gov
	Gary Pierce	R	Jan-11	state representative (Majority Whip)		602-542-3933	Pierce-web@azcc.gov
	Bob Stump	R	Jan-13	Attorney; State legislator; Municipal Court Judge		602-542-3935	Stump-web@azcc.gov
	Paul Newman	D	Jan-13	Attorney; Gov. Communications Director; Reporter		602-542-3682	Newman-web@azcc.gov
	Sandra Kennedy	D	Jan-13	State Rrepresentative, Chairman Energy, Utilities, & Technology Committee		602-542-3625	Kennedy-web@azcc.gov
Arkansas	Chair Paul Suskie	D	Jan-13	North Little Rock City Attorney, Major in National Guard (JAG)		501-682-5809	
	Olan Reeves	R	Jan-15	Attorney; PSC Staff Director; Governor's Liaison; Asst. General Counsel, Arkla		501-682-5809	
	Colette Honorable	D	Jan-11	anker; Gov's Budget Director; Gov's Economic Development Policy Advisor; various positions at Department of Higher Education		501-682-5809	
California	Pres. Michael R. Peevy	D	Jan-15	CEO of TruePricing Inc.; Pres. of New Energy Inc.; Pres. of Edison Intl. and Southern California Edison		415-703-3703	
	Dian Grueneich	D	Jan-11	Energy and Environmental Law Consultant; Attorney	Theresa Cho	415-703-2682	
	Rachelle Chong	R	Jan-15	Attorney, FCC Commissioner; private practice attorney, mediator arbitrator	Lynn Carew	415-703-3700	
	John Bohn	R	Jan-11	Businessman; President and CEO of Moody's; Special Assistant to former U.S. Treasury Secretary Regan		415-703-2440	
	Timothy Alan Simon	R	Jan-13	Appointments Secretary in Gov. Office; General counsel and chief compliance officer for various US Corporations	Alan Reynolds	415-703-1407	
Colorado	Chair Ron Binz	D	Jan-11	Consultant; Director of the Office of Consumer Counsel		303-894-2000	puc@dora.state.co.us
	James Tarpey	R	Jan-13	County Commissioner; Chair, Denver Regional Council of Governm		303-894-2000	puc@dora.state.co.us
	Matt Baker	D	Jan-12	State Representative; Lake County Commissioner; U.S. Army		303-894-2000	puc@dora.state.co.us
Connecticut	Chair Donald W. Downes	R	Jun-09	Attorney; Deputy Secretary of State Office of Policy and Management		860-827-2801	
	Kevin M. DelGobbo	R	Jun-11	Private law practice; newspaper reporter		860-827-2802	
	Amalia Vazquez Bzdyra	R	Jun-11	Governor's Special Counsel on Energy; Chief Legal Counsel to Governor		860-827-2802	
	John W. Betkoski	D	Jun-09	State legislator; House Chair of the Joint Commerce Committee		860-827-2802	
	Anthony J. Palermino	D	Jun-11	Private law practice; Consulting		860-827-2802	
Delaware	Chair Arnetta McRae	D	May-06	Attorney; Trademark and copyright counsel to E.I. DuPont de Nemours.	Karen Nickerson	302-739-4247	karen.nickerson@state.de.us
	Dallas Winslow	R	May-10	Attorney; Chief of legal services for State Public Defender; Private Law Practice	Karen Nickerson	302-739-4247	karen.nickerson@state.de.us
	James Bruce Lester	R	May-12	Manager, Richland Farms	Karen Nickerson	302-739-4247	karen.nickerson@state.de.us
	Joann Conaway	D	May-12	Realtor	Karen Nickerson	302-739-4247	karen.nickerson@state.de.us
	Jeffrey J. Clark	D	May-09	Attorney; U.S. Army Captain	Karen Nickerson	302-739-4247	karen.nickerson@state.de.us
District of Columbia	Chair Betty Anne Kane	D	Jun-10	Attorney; Acting Deputy Director of the D.C. Office of Labor Relations and Collective Bargaining		202-626-5125	bakane@psc.dc.gov
	Richard E. Morgan	D	Jun-11	Energy Analyst U.S. EPA; PSC Staff member		202-626-0518	rmorgan@psc.dc.gov
	Lori Murphy Lee	D	Jun-12			202-626-5115	llee@psc.dc.gov
Florida	Chair Matthew M. Carter II	R	Jan-10	Attorney; Baptist Minister, US Army	Lois Graham	850-413-6036	Chairman@psc.state.fl.us
	Katrina J. McMurrian	R	Jan-10	Advisor to PSC Commissioners; PSC Division of Policy Analysis	Kay Posey	850-413-6024	Commissioner.McMurrian@psc.state.fl.us
	Lisa Polak Edgar	I	Jan-13	Attorney; Deputy Secretary for Dept. of Environmental Protection; Gov. Office of Policy and Budget	Kelly McLanahan	850-413-6018	Commissioner.Edgar@psc.state.fl.us
	Nathan Skop	R	Jan-11		Cristina Slaton	850-413-6030	Commissioner.Skop@psc.state.fl.us
	Nancy Argenziano	R	Jan-11		Steve Larson	850-413-6004	Commissioner.Argenziano@psc.state.fl.us
Georgia	Doug Everett	R	Dec-14	Real estate developer		404-656-4501	deverett@psc.state.ga.us
	Stan Wise	R	Dec-12	Insurance business owner; county commissioner; Atlanta Regional Commission member		404-656-4501	stanwise@psc.state.ga.us
	Lauren McDonald	R	Dec-14	Business Recruiter; assistant administrator of a medical complex at a children's home		404-656-4501	lmcdonald@psc.state.ga.us
	Chuck Eaton	R	Dec-12	Member of State House of Representatives; City Commissioner for Albany, GA		404-656-4501	ceaton@psc.state.ga.us
	Bobby Baker	R	Dec-10	Attorney; Gwinnett County Planning Commissioner		404-656-4501	bbaker@psc.state.ga.us
Hawaii	Chair Carlito P. Caliboso	R	Jun-10	Attorney; Partner, private practice		808-586-2020	
	John E. Cole	R	Jun-12	Attorney,Executive Director Division of Consumer Advocacy;Governor's Policy Team		808-586-2020	
	Leslie Kondo		Jun-14			808-586-2020	
Idaho	Pres Mack A. Redford	R	Jan-13	hair of the Legislative Task Force on the Federal Telecommunications Act of 1996; Distance Learning Director of Boise State University		208-334-0338	
	Marsha H. Smith	D	Jan-15	Idaho Deputy Attorney General; PUC Director of Policy and External Relations		208-334-0338	
	Jim Kempton	R	Jan-11	Attorney; general counsel for several engineering firms; Deputy Attorney General		208-334-0338	
Illinois	Chair Charles E. Box	D	Jan-09	Attorney; private consultant; Mayor, Rockford, IL		217-782-7907	
	Lula M. Ford	D	Jan-13	Asst. Dir. Central Management Services; Chicago School's Educ. Liaison to Housing Authority; Teacher		217-782-7907	
	Robert F. Lieberman	D	Jan-10	CFO Private Technology Firm; Positions at Illinois Office of Coal Development and Dept. of Natural Resources		217-782-7907	
	Erin M. O'Connell-Diaz	I	Jan-13	Attorney; Manager Chicago Office of ICC Administrative Law Judges (ALJs) Div.; ALJ; Asst. Attorney General		217-782-7907	
	Sherman Elliott	R	Jan-12			217-782-7907	
Indiana	Chair David L. Hardy	R	Apr-10	Attorney, private practice		317-232-2701	
	David Ziegner	D	Apr-11	Attorney; URC General Counsel; Staff attorney, Indiana Legislative Services Agency		317-232-2701	
	Greg D. Server	R	Apr-09	Member, State Legislature; Dir. Administration, Evansville Water & Sewer Utility		317-232-2701	
	Larry Landis	R	Jan-12	President of marketing and communications firm; experience in advertising and software development		317-232-2701	
	Jeffery Golc	D	Jan-10	sioner, Indiana Bureau of Motor Vehicles and Indiana Dept. of Workforce Development; public affairs manager for Kroger Company		317-232-2701	
Iowa	Chair Rob Berntsen	D	Apr-15	Attorney; Chief of Staff for Governor, Congressman; State Chairman, Iowa Democratic Party		515-281-5167	
	Krista Tanner	D	Apr-11	Attorney, private practice; positions at Qwest; IUB legislative liaison		515-281-3941	
	Darrell Hanson	R	Apr-13			515-281-3941	
Kansas	Chair Thomas Wright	D	Mar-10	General Counsel for KCC, Kansas Insurance Dept.; State Representative; Adjunct Professor		785-271-3166	public.affairs@kcc.state.ks.us
	Michael Moffet	R	Mar-08	nate Committee on Commerce, Science & Transportation, Aviation Subcommittee; various positions, Federal Aviation Administration		785-271-3350	public.affairs@kcc.state.ks.us
	Joe Harkins	D	Mar-11	Attorney; Private practice		785-271-3350	public.affairs@kcc.state.ks.us
Kentucky	Chair David Armstrong	D	Jun-11	Attorney; Immediate Past President, Southeastern Association of Regulatory Utility Commissioners		502-564-3940	psc.info@ky.com
	John W. Clay	R	Jun-09	xuty Secretary of the EPPC; Executive Directory of the Office of Alcohol Beverage Control in Kentucky's Dept. of Public		502-564-3940	psc.info@ky.com
	James Gardner	D	Jun-12			502-564-3941	psc.info@ky.com
Louisiana	Chair Lambert C. Boissiere	D	Dec-10	Attorney; member of various civic organizations; Board Member of Parish National Bank		225-342-6687/504-680-9529	alicee@lpsc.org
	Eric Skrmetta	R	Dec-14	State legislator; businessman	Janet Caharin	985-624-4660	janetc@lpsc.org
	James M. Field	R	Dec-12	Attorney; NFL contract advisor	Peggy Lantrip	225-342-6900	peggy.lantrip@la.gov
	Foster L. Campbell Jr.	D	Dec-14	State legislator; Insurance agent; Farmer		318-676-7464	foster.campbell@la.org
	Clyde Holloway	R	Dec-10	New Orleans City Constable		337-457-7395	joannd@lpsc.org
Maine	Chair Sharon Reishus	D	Mar-09	Chief Legal Counsel to Gov. Baldacci; Attorney		207-287-3831	maine.puc@maine.gov
	Vendean Vafiades	I	Mar-13	Energy consultant; PUC Staff analyst		207-287-3831	maine.puc@maine.gov
	Jack Cashman	D	Mar-11			207-287-3831	maine.puc@maine.gov
Maryland	Chair Douglas Nazarian	D	Jun-13	Attorney; Exec. Vice President Amerigroup Corp.; commissioner Maryland Insurance Administration		410-767-8073	
	Harold Williams	D	Jun-12	Dir., Corp. Procurement for Baltimore Gas & Electric		410-767-8116	
	Allen M. Freifeld	D	Jun-09	Attorney; PSC Staff Counsel and Hearing Examiner		410-767-8072	
	Susanne Brogan	D	Jun-11			410-767-8072	
	Lawrence Brenner	D	Jun-10	Attorney; Member House of Delegates; Mayor of Aberdeen		410-767-8017	
Massachusetts	Chair Paul Hibbard	D	Jan-11	Chief of Staff Mass. Dept. of Business and Technology		617-305-3500	
	Tim Woolf	D	Jan-11	Energy division of General Electric; Consultant for Deloitte; Project Manager with Georgia Power		617-305-3500	
	Jolette Westbrook	R	Apr-13	Manager Government Relations, Tenneco; Consultant		617-305-3500	
Michigan	Chair Orjiakor Isiogu	D	Jul-13	Assistant Attorney General and Head of the Special Litigation Div. of the MI Attorney General's Office		517-241-6200	
	Stephen Transeth	I	Jul-09	Dep. Dir. Governor's Legislative Affairs Division; Analyst for Senate Democratic Office		517-241-6180	
	Monica Martinez	D	Jul-11	rmer Gov. Engler's Deputy Legal Counsel; Regulatory Affairs Advisor to MI House Republicans; other legislative aid positions		517-241-6180	
Minnesota	Chair David C. Boyd	R	Jan-15	Dairy farmer; State Legislator, including Assistant House Minority Leader and House Republican Whip		651-201-2200	David.C.Boyd@state.mn.us
	Phyllis Reha	D	Jan-13	Attorney; Member of MN House of Representatives (1983-2004) and House Minority Leader (1996-2002)		651-201-2200	Phyllis.Reha@state.mn.us
	Thomas W. Pugh	D	Jan-11	Chief Administrative Law Judge; Deputy Commissioner/Assistant Comm. at Minnesota DPS		651-201-2200	Tom.Pugh@state.mn.us
	Dennis O'Brien	R	Jan-14	Consultant to the Econ. Development Div. of the Iron Range Resources and Rehab. Board; business exec.		651-201-2200	Dennis.Obrien@state.mn.us
	Betsy L. Wergin	R	Jan-10			651-201-2200	Betsy.Wergin@state.mn.us
Mississippi	Chair Lynn Posey	D	Dec-11	Mississippi House of Representatives; PSC Utility Investigator, Harris Country Dep. Sheriff		601-961-5430	central.district@psc.state.ms.us
	Brandon Presley	D	Dec-11	Mississippi House of Representatives; Monroe County Sheriff		601-961-5450	nothern.district@psc.state.ms.us
	Leonard L. Bentz	R	Dec-11	Mississippi House of Representatives; PSC Utility Investigator, Harris Country Dep. Sheriff		601-961-5440	southern.district@psc.state.ms.us

Source: SNL Financial

Figure 52: State Regulatory Commissioners, M-W

Missouri	Robert Clayton III	D	Apr-09	Attorney; various positions in state government		573-751-4221	robert.clayton@psc.mo.gov
	Terry Jarrett	R	Sep-13	Attorney; Missouri House of Representatives		573-751-3243	terry.jarrett@psc.mo.gov
	Kevin Gunn	D	Mar-14	Attorney; Speaker, Missouri House of Representatives; City Prosecutor		573-751-0946	kevin.gunn@psc.mo.gov
	Jeffrey Davis	R	Apr-12	Attorney; Missouri House of Representatives		573-751-3233	jeff.davis@psc.mo.gov
Montana	Chair Greg Jergeson	D	Jan-11	State Senator; Montana State University-Northern Foundation; Farmer		406-444-6199	gjergeson@mt.gov
	John Vincent	D	Jan-13	State Legislator		406-444-6199	jvincent@mt.gov
	Gail Gutsche	D	Jan-13	Speaker, State House of Representatives		406-444-6199	ggutsche@mt.gov
	Brad Molnar	R	Jan-13	State Legislator; Building contractor		406-444-6199	bmolnar@mt.gov
	Ken Toole	D	Jan-11	State Senator and Montana Caucus Chair of the Northwest Energy Coalition.		406-444-6199	ktoole@mt.gov
Nebraska	Frank Landis	R	Jan-13			800-526-0017	frank.landis@nebraska.gov
	Gerald Vap	R	Jan-11			800-526-0017	jerry.vap@nebraska.gov
	Anne Boyle	D	Jan-15			800-526-0017	anne.boyle@nebraska.gov
	Tim Schram	R	Jan-13			800-526-0017	tim.schram@nebraska.gov
	Rod Johnson	R	Jan-11			800-526-0017	rod.johnson@nebraska.gov
New Hampshire	Chair Thomas Getz	D	Jun-13	Attorney, PUC Executive Director; Counsel for electric utility, Staff member of New York Public Service Commission		603-271-2431	TOM.GETZ@PUC.NH.GOV
	Graham J. Morrison	R	Jun-09	Vice President Marketing at Novitt, Inc., various positions at U.S. corporations		603-271-2431	GRAHAM.MORRISON@PUC.NH.GOV
	Clifton Below	D	Jun-11	Member of State House of Representatives and Senate; Commercial real estate developer		603-271-2290	CLIFTON.BELOW@PUC.NH.GOV
New Jersey	Pres. Jeanne M. Fox	D	Mar-14	onal Administrator; Deputy Commissioner, NJ Dept. Environmental Protection & Energy; Dir. BPU Div. Water & Waste Water Services		973-648-2350	
	Elizabeth Randall	R	Mar-13	Gov's Chief of Management & Policy; Deputy Commissioner, NJ Dept. of Labor		973-648-2350	
	Joseph L. Fiordaliso	D	Mar-10	Dep. Chief of Staff for former Gov. Richard Codey; Mayor, Livingston, NJ; Essex County Executive		973-648-2350	
	Frederick Butler	D	Mar-09	Executive Dir., Dem. Office of NJ General Assembly; Dir., Budget & Fiscal Analysis for NJ General Assembly		973-648-2350	
	Nicholas Asselta	R	Mar-14	Attorney in private practice; Commissioner, NJ Highway Authority		973-648-2350	
New Mexico	Chair Sandy Jones	D	Dec-10	Health care consultant	Elizabeth Martin	505-827-8020	Elizabeth.Martin@state.nm.us
	Carol Sloan	D	Dec-10	Served as McKinley County Clerk.	Luis Ledezma	505-827-8019	Luis.Ledezma@state.nm.us
	Jerome Block Jr.	D	Dec-12	Administrative Services Dir., CRO state Dept. of Cultural Affairs	Charlotte Duran	505-827-4533	charlotte.duran1@state.nm.us
	David King	R	Dec-10	New Mexico State University CFO; State Treasurer	Stacey Starr-Garcia	505-827-4531	Stacey.Starr-Garcia@state.nm.us
	Jason Marks	D	Dec-12	Chairman State Fair Commission; has run his own construction business.	Leroy Aragon	505-827-8015	Leroy.Aragon@state.nm.us
Nevada	Chair Jo Ann Kelly	I	Sep-09	CPA; Commissioner (1985-1996); Temporary Commissioner (2000)	Crystal Jackson	775-684-6101	cjackson@puc.state.nv.us
	Rebecca Wagner	R	Sep-11	Gov. Guinn's Energy Advisor; PUC Public Information Officer	Crystal Jackson	775-684-6101	cjackson@puc.state.nv.us
	Samuel Thompson	R	Sep-12		Crystal Jackson	775-684-6101	cjackson@puc.state.nv.us
New York	Chair Garry A. Brown	R	Feb-09			518-474-7080	
	Maureen F. Harris	R	Feb-12	Attorney in private practice; Asst. Attorney General		518-474-7080	
	Robert E. Curry Jr.	I	Feb-12	Attorney		518-474-7080	
	James Larocca	D	Feb-12	Chairman, New York State Pricing and Wagering Board		518-474-7080	
	Patricia Acampora	R	Feb-09	Member New York Assembly; Asst. to Suffolk County Executive		518-474-7080	
North Carolina	Edward S. Finley	D	Jun-11		Rose Glover	919-733-0829	
	Robert V. Owens Jr.	D	Jun-13	Dare County Board of Commissioners; Director of the Governor's Eastern Office; restaurant owner	Kathy House	919-733-4071	
	Susan Rabon	D	Jun-15	State Senator; Secretary of Dept. of Natural Resources; Mayor of Chapel Hill (NC)	Kathy House	919-733-4249	
	Bryan Beatty	D	Jun-09	Attorney in private practice	Melissa Watson	919-733-0825	
	Lorinzo Little Joyner	D	Jun-09	Government Attorney, including a Staff Attorney for the Public Staff of the NCUC	Debra Fearing	919-733-0826	
	William T. Culpepper	D	Jun-13	North Carolina House of Representatives; Attorney	Patti Almekinder	919-733-0828	
North Dakota	Chair Kevin Cramer	R	Dec-10	President of the Bismarck School Board; Licensed Social Worker; Certified Consumer Credit Counselor		701-328-2400	kcramer@nd.gov
	Brian Kalk	R	Dec-14	Director of a Leadership Foundation at the University of Bismarck		701-328-2400	bkalk@nd.gov
	Anthony Clark	R	Dec-12	State Labor Commissioner; state legislator		701-328-2400	tclark@nd.gov
Ohio	Chair Alan R. Schriber	I	Apr-14	Economist; Former owner of several radio stations; PUC Commissioner (1983-1989); economics professor		614-466-3204	
	Cheryl Roberto	D	Apr-13	Attorney; Deputy Dir., Div. of Oil and Gas of Ohio Dept. of Natural Resources; Mayor of Zanesville, Ohio		614-466-3905	
	Valerie A. Lemmie	I	Apr-11	Kettering Research Foundation; Cincinnati City Manager; U.S. Dept. Consumer & Regulatory Affairs		614-466-3101	
	Paul Centolella	D	Apr-12	Toledo City Council; Toledo Metropolitan Council of Governments; Ohio School Boards Association			
	Ronda H. Fergus	R	Apr-10	Attorney; PUC Chief of Telecommunications		614-644-8213	
Oklahoma	Chair Bob Anthony	R	Jan-13	Attorney; various state government positions; petroleum landman.	Jackie Hollinshead	405-521-2261	
	Dana Murphy	R	Jan-11	President, Independent Petroleum Association of America; Staff of U.S. Senator David Boren	Billie Rodely	405-521-2267	
	Jeff Cloud	R	Jan-15	Formerly President/Chairman of C.R. Anthony (clothing retailer) that is no longer in business	Lisa Roberts	405-521-2264	
Oregon	Chair Lee Beyer	D	Mar-12	State Senator; State Representative		503-378-6611	
	John Savage	D	Mar-09	Director of PUC Utility Program; Director of Oregon Department of Energy		503-378-6611	
	Raymond Baum	R	Aug-11	Attorney; Oregon Liquor Control Commission; State Legislator		503-378-6611	
Pennsylvania	James H. Cawley	D	Apr-10	Attorney; PUC Commissioner (1990-1993); Private practice		717-783-1197	jhc@state.pa.us
	Kim Pizzingrilli	R	Apr-12	Secretary of the Commonwealth; Positions at Department of State		717-772-0692	kpizzin@state.pa.us
	Tyrone Christy	D	Apr-11	Attorney; PUC Commissioner (1999-2004); Administrative Law Judge (ALJ); PUC Counsel		717-783-1763	tchristy@state.pa.us
	Robert Powelson	R	Apr-14	Attorney; PUC Commissioner (1979-1985); Private practice		717-787-4301	rfp@state.pa.us
	Wayne Gardner	D	Apr-13			717-787-1031	weg@state.pa.us
Rhode Island	Chair Elia Germani	R	Mar-13	eneral Counsel for Blue Cross and Blue Shield; partner of private law firm; attorney for a Rhode Island electric utility		401-941-4500 ext 100	
	Mary E. Bray	D	Mar-11	Controller, Senior Vice President in banking		401-941-4500 ext 102	
South Carolina	Chair Elizabeth B. Fleming	U	Jun-10	Chairman of the Marlboro SC, City Council; former member of Bennettsville, SC City Council	Nina Gates	803-896-5259	Chairman.Fleming@psc.sc.gov
	David A. Wright	U	Jun-10	Former member of SC House of Representatives; public	Melissa Purvis	803-896-5180	Commissioner.Wright@psc.sc.gov
	Swain Whitfield	U	Jun-12	Insurance agency owner	Melissa Purvis	803-896-5180	Commissioner.Whitfield@psc.sc.gov
	Randy Mitchell	U	Jun-12	Owner and manager of a poultry farm and a rental business; Probate judge.	Nina Gates	803-896-5259	Commissioner.Mitchell@psc.sc.gov
	John E. Howard	U	Jun-12	Printing and furniture sales	Melissa Purvis	803-896-5180	ViceChairman.Howard@psc.sc.gov
	G. O'Neal Hamilton	U	Jun-12	Former member of the Spartanburg, SC City Council	Nina Gates	803-896-5259	Commissioner.Hamilton@psc.sc.gov
	Mignon L. Clyburn	D	Jun-10	Newspaper Owner	Melissa Purvis	803-896-5180	Commissioner.Clyburn@psc.sc.gov
South Dakota	Chair Dustin Johnson	R	Jan-11	Senior Policy Advisor, Governor; Truman Fellow, U.S. Department of Agriculture	Greg Rislov	605-773-3201	
	Steve Kolbeck	D	Jan-13	Held several positions within the telecommunications industry		605-773-3201	
	Gary Hanson	R	Jan-15	Real estate broker; State legislator; Utilities Commissioner of Sioux Falls; Mayor of Sioux Falls		605-773-3201	
Tennessee	Chair Eddie Roberson Jr.	D	Jun-11	Attorney; Memphis City Court Judge; private law practice; public defender; various state government positions	Vicky Nelson	615-741-0917	eddie.roberson@tn.gov
	Sara Kyle	D	Jun-14	Chief of TRA Consumer Services, Div.; TRA Telecommunications Analyst	Thomas Pearson	615-741-3125	sara.kyle@tn.gov
	Mary Freeman	D	Jun-11	Attorney; Legislative Liaison, Tennessee Supreme Court; Chief of Staff, Lt. Governor and Speaker of Senate	Shiri Anderson	615-741-3668	mary.w.freeman@tn.gov
Texas	Chair Barry T. Smitherman	R	Aug-13	Attorney; Assistant DA; Public Finance Investment Banker		512-936-7025	barry.smitherman@puc.state.tx.us
	Donna L. Nelson	R	Aug-09	Dir. Policy for Gov. Perry; Gov.'s Liaison to PUC; Advisor to former PUC Commissioner Perlman		512-936-7015	donna.nelson@puc.state.tx.us
	Kenneth W. Anderson	R	Aug-11	Attorney; Solicitor General		512-936-7005	kenneth.anderson@puc.state.tx.us
Utah	Chair Ted Boyer	R	Feb-15	Accountant; Economist; Dir. of Division of Public Utilities		801-530-6712	tboyer@utah.gov
	Richard M. Campbell	R	Feb-13	Attorney; Exec. Dir. of Utah Dept. of Commerce; Dir. of Utah Real Estate Division		801-530-6492	rcampbell@utah.gov
	Ron Allen	D	Feb-11	State Senator; Fire Chief; Adjunct Professor		801-530-6763	rallen@utah.gov
Vermont	Chair James Volz	U	Feb-11	Attorney; Director for Public Advocacy of the Department of Public Service		802-828-2358	psb.clerk@state.vt.us
	David Coen	U	Feb-13	Dept. store president; "business/community specialist" for the Vermont Inst. for Science, Math and Tech.		802-828-2358	psb.clerk@state.vt.us
	John D. Burke	U	Feb-15	Attorney in private practice; Adjunct Law Profe		802-828-2358	psb.clerk@state.vt.us
Virginia	James C. Dimitri	U	Feb-14	Attorney, former member of the Virginia House of Delegates		804-371-9608	
	Judith Williams Jagdmann	U	Feb-12	Attorney General; SCC General Counsel		804-371-9608	
	Mark C. Christie	U	Feb-10	Attorney, Pres. State Board of Ed.; Staff former Gov. Allen		804-371-9608	
Washington	Chair Jeffrey Goltz	D	Jan-15	Attorney in private practice; Attorney for City of Seattle		360-664-1173	
	Patrick J. Oshie	D	Jan-13	Attorney, private practice; Assistant Attorney General		360-664-1171	
	Philip Jones	R	Jan-11	International trade consultant; Legislative aide to U.S. Senator		360-664-1169	
West Virginia	Chair Michael A. Albert	R	Jun-13	Chemical Engineer; Management positions at Flexsys Nitro Corp. and Monsanto	Karen Marion	304-340-0306	
	Edward Staats	D	Jun-09	CPA; Gov.'s Dir. of Operations	Teresa Tierno	304-340-0303	
	Jon W. McKinney	R	Jun-11	Attorney; Business Law Division of Jackson Kelly, PLLC	Sherry Kennedy	304-340-0307	
Wisconsin	Chair Eric Callisto	D	Mar-15	Exec. Asst. to former commissioner,Governor's staff; Congressional staff member	Sandra Paske	608-267-7897	sandra.paske@psc.state.wi.us
	Mark Meyer	D	Mar-11	State Senate and Assembly, La Crosse, WI City Council; WI Medical Society; assistant general hotel manager	Alice Heilman	608-267-7898	alice.heilman@psc.state.wi.us
	Lauren Azar	D	Mar-13		Sandra Paske	608-267-7897	sandra.paske@psc.state.wi.us
Wyoming	Chair Alan Minier	D	Mar-15	Executive Director, Wyoming Board of Parole; Assistant Bar Counsel, Wyoming State Bar		307-777-7427	aminie@state.wy.us
	Steve Oxley	R	Mar-13	Division Administrator for Economic Analysis in the Wyoming Dept. of Administration and Information		307-777-7427	soxley@state.wy.us
	Kathleen A. Lewis	D	Mar-11	Analyst, Wyoming Legislative Service Office; Consultant, Wyoming Division of Economic Analysis		307-777-7427	klewis@state.wy.us

Source: SNL Financial

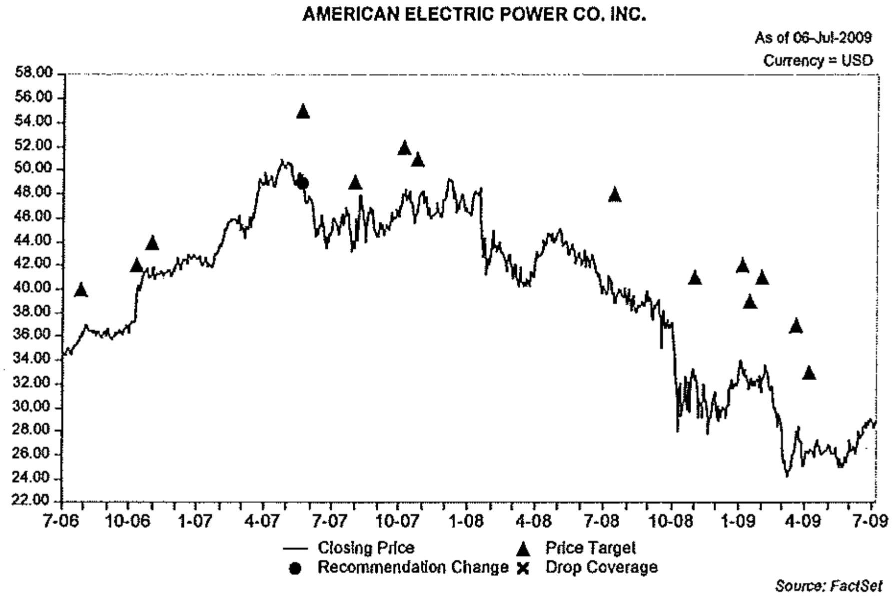
On September 20, 2008, Barclays Capital acquired Lehman Brothers' North American investment banking, capital markets, and private investment management businesses. All ratings and price targets prior to the acquisition date relate to coverage under Lehman Brothers Inc.

Analyst Certification:
We, Daniel Ford, CFA, Gregg Orrill, Theodore W. Brooks, CFA and Ross A. Fowler, hereby certify (1) that the views expressed in this research report accurately reflect our personal views about any or all of the subject securities or issuers referred to in this research report and (2) no part of our compensation was, is or will be directly or indirectly related to the specific recommendations or views expressed in this research report.

Important Disclosures:

American Electric Power (AEP) **US$ 28.59 (09-Jul-2009)** **1-Overweight / 2-Neutral**

Rating and Price Target Chart:



Currency=US$

Date	Closing Price	Rating	Price Target
06-Apr-09	26.32		33.00
19-Mar-09	28.01		37.00
30-Jan-09	31.35		41.00
15-Jan-09	31.76		39.00
05-Jan-09	33.69		42.00
03-Nov-08	32.31		41.00
15-Jul-08	39.75		48.00
24-Oct-07	46.51		51.00

Date	Closing Price	Rating	Price Target
05-Oct-07	47.97		52.00
31-Jul-07	43.49		49.00
22-May-07	48.88		55.00
22-May-07	48.88	1-Overweight	
31-Oct-06	41.43		44.00
10-Oct-06	39.31		42.00
27-Jul-06	35.88		40.00

FOR EXPLANATIONS OF RATINGS REFER TO THE STOCK RATING KEYS LOCATED ON THE BACK PAGE.

Barclays Capital and/or Lehman Brothers Inc. and/or one of their affiliates has managed or co-managed within the past 12 months a 144A and/or public offering of securities for American Electric Power.

Barclays Capital and/or an affiliate makes a market or provides liquidity in the securities of American Electric Power.

Barclays Capital and/or Lehman Brothers Inc. and/or one of their affiliates has received compensation for investment banking services from American Electric Power in the past 12 months.

Barclays Capital and/or an affiliate expects to receive or intends to seek compensation for investment banking services from American Electric Power within the next 3 months.

Barclays Capital and/or one of their affiliates beneficially owns 1% or more of any class of common equity securities of American Electric Power.

Barclays Capital and/or an affiliate trade regularly in the shares of American Electric Power.

Barclays Capital and/or Lehman Brothers Inc. and/or one of their affiliates has received non-investment banking related compensation from American Electric Power within the last 12 months.

American Electric Power is or during the past 12 months has been an investment banking client of Barclays Capital and/or Lehman Brothers Inc. and/or one of their affiliates.

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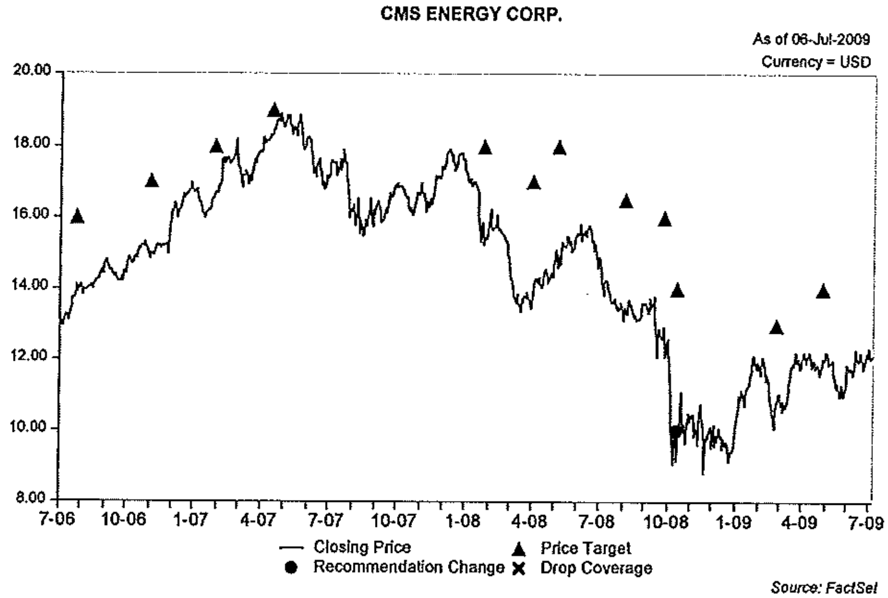
Risks Which May Impede the Achievement of the Price Target: Key risks include wholesale commodity prices, state and federal regulation, interest rates, and asset sale execution.

Important Disclosures Continued:

CMS Energy (CMS) **US$ 11.81 (09-Jul-2009)** **1-Overweight / 2-Neutral**

Rating and Price Target Chart:



Currency=US$

Date	Closing Price	Rating	Price Target
28-Apr-09	11.87		14.00
25-Feb-09	10.75		13.00
14-Oct-08	10.00		14.00
14-Oct-08	10.00	1-Overweight	
26-Sep-08	12.92		16.00
05-Aug-08	13.49		16.50
05-May-08	14.60		18.00

Date	Closing Price	Rating	Price Target
01-Apr-08	13.78		17.00
25-Jan-08	15.22		18.00
13-Apr-07	18.31		19.00
26-Jan-07	16.71		18.00
02-Nov-06	15.02		17.00
25-Jul-06	13.98		16.00

FOR EXPLANATIONS OF RATINGS REFER TO THE STOCK RATING KEYS LOCATED ON THE BACK PAGE.

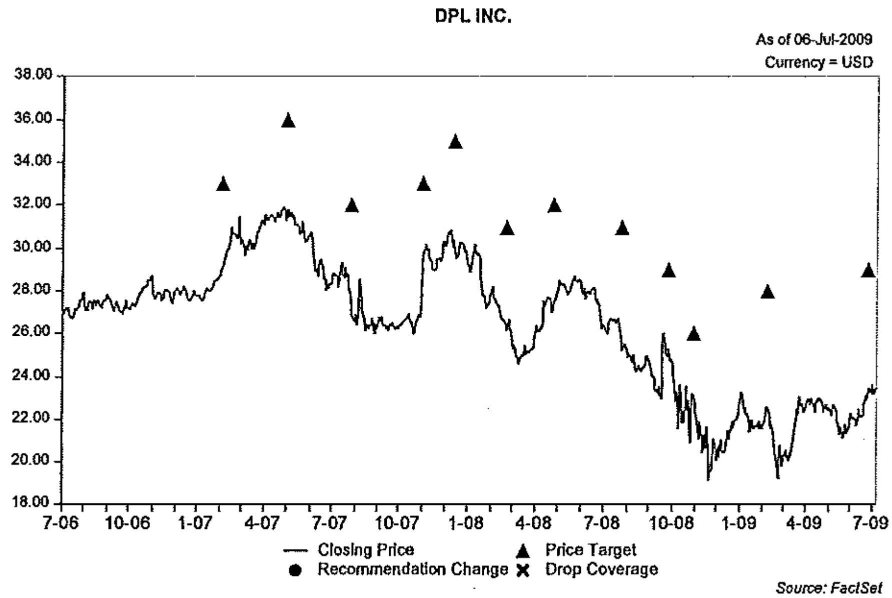
Barclays Capital and/or Lehman Brothers Inc. and/or one of their affiliates has managed or co-managed within the past 12 months a 144A and/or public offering of securities for CMS Energy.
Barclays Capital and/or an affiliate makes a market or provides liquidity in the securities of CMS Energy.
Barclays Capital and/or an affiliate trade regularly in the shares of CMS Energy.
Barclays Capital and/or Lehman Brothers Inc. and/or one of their affiliates has received non-investment banking related compensation from CMS Energy within the last 12 months.
CMS Energy is or during the last 12 months has been a non-investment banking client (securities related services) of Barclays Capital and/or Lehman Brothers Inc. and/or one of their affiliates.
CMS Energy is or during the last 12 months has been a non-investment banking client (non-securities related services) of Barclays Capital and/or Lehman Brothers Inc. and/or one of their affiliates.
Barclays Capital is associated with specialist firm Barclays Capital Market Makers who makes a market in CMS Energy stock. At any given time, the associated specialist may have "long" or "short" inventory position in the stock; and the associated specialist may be on the opposite side of orders executed on the Floor of the Exchange in the stock. Barclays Capital and/or an affiliate makes a market in the securities of this company.

Risks Which May Impede the Achievement of the Price Target: CMS Energy faces risk from Michigan utility regulation, commodity prices, and interest rates.

Important Disclosures Continued:

DPL Inc. (DPL) **US$ 22.80 (09-Jul-2009)** **1-Overweight / 2-Neutral**

Rating and Price Target Chart:



Currency=US$

Date	Closing Price	Rating	Price Target
24-Jun-09	23.15		29.00
06-Feb-09	22.56		28.00
30-Oct-08	23.14		26.00
26-Sep-08	25.34		29.00
24-Jul-08	25.70		31.00
24-Apr-08	27.35		32.00
22-Feb-08	26.26		31.00

Date	Closing Price	Rating	Price Target
13-Dec-07	30.41		35.00
31-Oct-07	29.04		33.00
26-Jul-07	27.61		32.00
01-May-07	31.50		36.00
02-Feb-07	29.07		33.00

FOR EXPLANATIONS OF RATINGS REFER TO THE STOCK RATING KEYS LOCATED ON THE BACK PAGE.

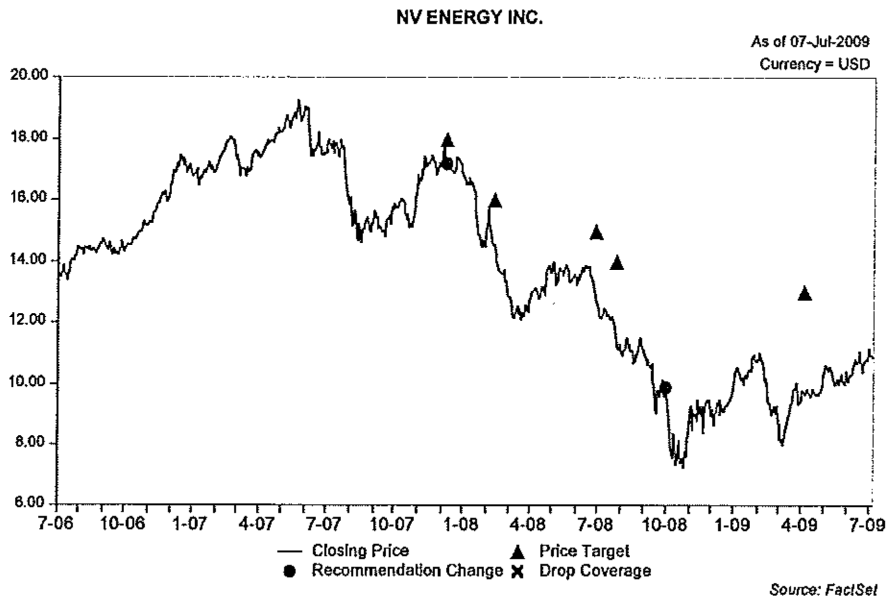
Barclays Capital and/or an affiliate makes a market or provides liquidity in the securities of DPL Inc..
Barclays Capital and/or an affiliate hold a short position of at least 1% of the outstanding share capital of DPL Inc..
Barclays Capital and/or an affiliate trade regularly in the shares of DPL Inc..

Risks Which May Impede the Achievement of the Price Target: Risks to the outlook include wholesale commodity prices, generation development market conditions, the outcome of regulatory proceedings, rating agency actions, interest rates, and access to the capital markets.

Important Disclosures Continued:

NV Energy, Inc. (NVE) **US$ 10.66 (09-Jul-2009)** **1-Overweight / 2-Neutral**

Rating and Price Target Chart:



Currency=US$

Date	Closing Price	Rating	Price Target
06-Apr-09	9.74		13.00
01-Oct-08	9.89	1 -Overweight	
25-Jul-08	11.27		14.00
30-Jun-08	12.71		15.00

Date	Closing Price	Rating	Price Target
12-Feb-08	14.57		16.00
10-Dec-07	17.20		18.00
10-Dec-07	17.20	2 -Equal weight	

FOR EXPLANATIONS OF RATINGS REFER TO THE STOCK RATING KEYS LOCATED ON THE BACK PAGE.

Barclays Capital and/or Lehman Brothers Inc. and/or one of their affiliates has managed or co-managed within the past 12 months a 144A and/or public offering of securities for NV Energy, Inc..
Barclays Capital and/or an affiliate makes a market or provides liquidity in the securities of NV Energy, Inc..
Barclays Capital and/or Lehman Brothers Inc. and/or one of their affiliates has received compensation for investment banking services from NV Energy, Inc. in the past 12 months.
Barclays Capital and/or an affiliate trade regularly in the shares of NV Energy, Inc..
Barclays Capital and/or Lehman Brothers Inc. and/or one of their affiliates has received non-investment banking related compensation from NV Energy, Inc. within the last 12 months.
NV Energy, Inc. is or during the past 12 months has been an investment banking client of Barclays Capital and/or Lehman Brothers Inc. and/or one of their affiliates.
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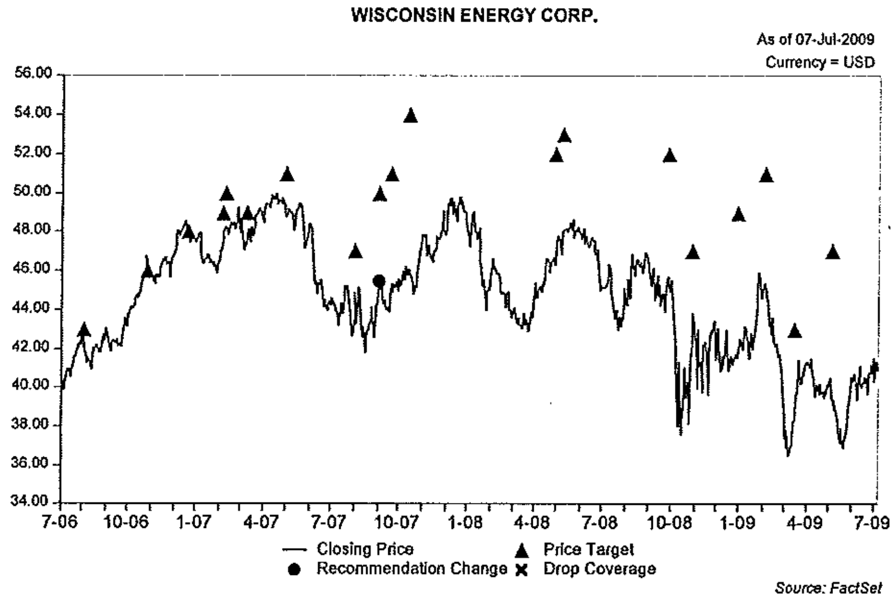
Risks Which May Impede the Achievement of the Price Target: Risks to the outlook include wholesale commodity prices, generation development market conditions, the outcome of regulatory proceedings, rating agency actions, interest rates, and access to the capital markets.

Important Disclosures Continued:

Wisconsin Energy (WEC) **US$ 40.87 (09-Jul-2009)** **1-Overweight / 2-Neutral**

Rating and Price Target Chart:



Currency=US$

Date	Closing Price	Rating	Price Target
06-May-09	39.40		47.00
17-Mar-09	38.31		43.00
04-Feb-09	45.38		51.00
30-Dec-08	41.50		49.00
30-Oct-08	43.80		47.00
29-Sep-08	45.32		52.00
08-May-08	48.08		53.00
29-Apr-08	46.31		52.00
12-Oct-07	46.11		54.00
19-Sep-07	45.33		51.00

Date	Closing Price	Rating	Price Target
04-Sep-07	45.50		50.00
04-Sep-07	45.50	1-Overweight	
01-Aug-07	43.64		47.00
01-May-07	48.78		51.00
08-Mar-07	47.67		49.00
08-Feb-07	48.26		50.00
05-Feb-07	47.48		49.00
20-Dec-06	47.94		48.00
26-Oct-06	46.38		46.00
02-Aug-06	42.39		43.00

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Barclays Capital and/or Lehman Brothers Inc. and/or one of their affiliates has received compensation for investment banking services from Wisconsin Energy in the past 12 months.
Barclays Capital and/or an affiliate trade regularly in the shares of Wisconsin Energy.
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Risks Which May Impede the Achievement of the Price Target: Risks that could affect the company include: time and budget execution of the "Power the Future" generation plan, Wisconsin regulation, and interest rates.

Important Disclosures Continued:

Sector Coverage Universe

Below is the list of companies that constitute the sector coverage universe:

Alliant Energy (LNT)
CMS Energy (CMS)
DPL Inc. (DPL)
Duke Energy (DUK)
Hawaiian Electric Inds (HE)
NiSource, Inc. (NI)
NSTAR (NST)
Pepco Holdings (POM)
Pinnacle West Capital (PNW)
Portland General Electric Co. (POR)
Sempra Energy (SRE)
TECO Energy (TE)
Wisconsin Energy (WEC)
American Electric Power (AEP)
Consolidated Edison (ED)
DTE Energy (DTE)
Great Plains Energy Inc. (GXP)
ITC Holdings (ITC)
Northeast Utilities (NU)
NV Energy, Inc. (NVE)
PG&E Corp. (PCG)
PNM Resources (PNM)
Progress Energy (PGN)
Southern Co. (SO)
Westar Energy (WR)
Xcel Energy (XEL)

Barclays Capital offices involved in the production of Equity Research:

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Barclays Capital, the investment banking division of Barclays Bank Plc (Barclays Capital, London)

New York
Barclays Capital Inc. (BCI, New York)

Tokyo
Barclays Capital Japan Limited (BCJL, Tokyo)

São Paulo
Banco Barclays S.A. (BBSA, São Paulo)

Mentioned Company	Ticker	Price	Price Date	Stock / Sector Rating
American Electric Power	AEP	US$ 28.59	09 Jul 2009	1-Overweight / 2-Neutral
CMS Energy	CMS	US$ 11.81	09 Jul 2009	1-Overweight / 2-Neutral
DPL Inc.	DPL	US$ 22.80	09 Jul 2009	1-Overweight / 2-Neutral
NV Energy, Inc.	NVE	US$ 10.66	09 Jul 2009	1-Overweight / 2-Neutral
Wisconsin Energy	WEC	US$ 40.87	09 Jul 2009	1-Overweight / 2-Neutral

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745 SEVENTH AVENUE, 17TH FLOOR, NEW YORK, NY 10019
OR
REFER TO THE FIRM'S DISCLOSURE WEBSITE AT www.lehman.com/disclosures**

Important Disclosures Continued:

The analysts responsible for preparing this report have received compensation based upon various factors including the firm's total revenues, a portion of which is generated by investment banking activities.

Guide to the Barclays Capital Fundamental Equity Research Rating System:

Our coverage analysts use a relative rating system in which they rate stocks as 1-Overweight, 2-Equal Weight or 3-Underweight (see definitions below) relative to other companies covered by the analyst or a team of analysts that are deemed to be in the same industry sector ("the sector coverage universe"). To see a list of companies that comprise a particular sector coverage universe, please go to www.lehman.com/disclosures.

In addition to the stock rating, we provide sector views which rate the outlook for the sector coverage universe as 1-Positive, 2-Neutral or 3-Negative (see definitions below). A rating system using terms such as buy, hold and sell is not the equivalent of our rating system. Investors should carefully read the entire research report including the definitions of all ratings and not infer its contents from ratings alone.

Stock Ratings:

1-Overweight - The stock is expected to outperform the unweighted expected total return of the sector coverage universe over a 12-month investment horizon.

2-Equal Weight - The stock is expected to perform in line with the unweighted expected total return of the sector coverage universe over a 12-month investment horizon.

3-Underweight - The stock is expected to underperform the unweighted expected total return of the sector coverage universe over a 12-month investment horizon.

RS-Rating Suspended - The rating and target price have been suspended temporarily due to market events that made coverage impracticable or to comply with applicable regulations and/or firm policies in certain circumstances including when Barclays Capital is acting in an advisory capacity in a merger or strategic transaction involving the company.

Sector View:

1-Positive - sector coverage universe fundamentals/valuations are improving.

2-Neutral - sector coverage universe fundamentals/valuations are steady, neither improving nor deteriorating.

3-Negative - sector coverage universe fundamentals/valuations are deteriorating.

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September 29, 2009

United States: Utilities: Power - Electric Utilities

Powering On: Tilting to commodity oriented utilities and IPPs

Upgrading IPPs from Neutral to Attractive; RRI Energy to CL Buy

With expected improvements in spot commodity prices, along with a continued uptick in power demand, we upgrade Independent Power Producers (IPPs) and reiterate our Attractive view on Diversified Utilities. Commodity levered utilities and IPPs lagged other energy/commodity sectors YTD, creating mean reversion potential going forward. While dividend yield spreads still remain attractive, we downgrade Regulated Utilities to Neutral, given limited average upside to larger cap targets. Within the regulated space, we tilt more towards smaller cap stocks.

We upgrade RRI Energy (RRI) to Conviction Buy, as the most un-hedged name in our universe. We also reiterate our Conviction Buy rating on large-cap nuclear generator Entergy (ETR) and remove small-cap Great Plains Energy (GXP) from the Conviction List, although we maintain our Buy rating. We downgrade Portland General (POR) to Neutral from Buy due to recent share price performance and concerns about 2010 guidance. Since being added to Americas Buy List on August 17, 2009 POR is up 5.7% and since being to the CL Buy List on the same date, GXP is up 4.9% vs. the XLU up 2.8% and the S&P500 up 8.5%.

Industry context and estimate changes

As weather-adjusted electricity demand declined 4%-5% YTD and industrial demand decreased over 10%, we now expect YoY comparisons for power demand to improve as GDP and industrial production accelerate. We revise our demand forecast slightly for 2010, from 0.6% to 0.4%, due to our new bottoms-up versus top-down demand forecast, but still expect a pick-up next year in industrial and residential demand.

Overall, we revise estimates to reflect this new demand forecast. We increase multiples to levels slightly below historical mean levels, given our gas/power price forecast levels remain in most areas near forward strip estimates.

Catalysts and risks

Key sector risks include (1) lower than expected commodity prices, (2) decreased power demand, (3) higher expected financing and capital spending needs, and (4) rising interest rates and inflation. Catalysts include an industry conference in November, auctions in various regional power markets and signs of improvement in weekly demand.

RELATED RESEARCH

Stepping up the voltage: Upgrading Regulated & Diversified Utilities. June 25, 2009.

Dimming the lights: Downgrading Utilities on relative outperformance and weak demand. December 11, 2008.

RATINGS, TARGETS, AND RETURNS

	Identification		Close		Tot Ret
	Ticker	Rating	09/28/09	Target	to Target
Diversified Utilities					
Ameren	AEE	Sell	$25.74	$25	3%
Allegheny Energy	AYE	Neutral	$26.96	$31	17%
Edison International	EIX	Neutral	$34.01	$39	19%
Entergy	ETR	CL Buy	$79.64	$101	31%
Exelon	EXC	Buy	$50.12	$62	28%
Sempra Energy	SRE	Neutral	$50.17	$59	20%
Mean					***20%***
Median					***19%***
Large Cap Regulated Utilities					
American Elec Power	AEP	Buy	$31.13	$37	24%
Duke Energy	DUK	Neutral	$15.93	$15	0%
Consolidated Edison	ED	CL Sell	$41.40	$38	-3%
PG&E	PCG	Neutral	$40.91	$43	9%
Progress Energy	PGN	Neutral	$39.60	$40	7%
Mean					***8%***
Median					***7%***
Mid & Small-Cap Regulated Utilities					
Cleco	CNL	Neutral	$25.10	$25	3%
El Paso Electric	EE	Neutral	$17.84	$21	18%
Great Plains Energy	GXP	Buy	$18.17	$22	26%
NSTAR	NST	Sell	$32.09	$29	-5%
Northeast Utilities	NU	Neutral	$23.99	$26	12%
Portland General Electric	POR	Neutral	$20.07	$23	20%
SCANA Corporation	SCG	Neutral	$35.30	$40	19%
NV Energy	NVE	Neutral	$11.59	$14	24%
Wisconsin Energy	WEC	Neutral	$45.11	$48	9%
Westar Energy	WR	Neutral	$19.60	$23	23%
Mean					***15%***
Median					***18%***
Special Situation Utilities and IPPs					
NRG Energy	NRG	Buy	$27.20	$37	36%
Ormat Technologies	ORA	Neutral	$41.03	$41	1%
RRI Energy	RRI	CL Buy	$6.98	$9	29%
Mean					***22%***
Median					***29%***

Source: Goldman Sachs Research estimates

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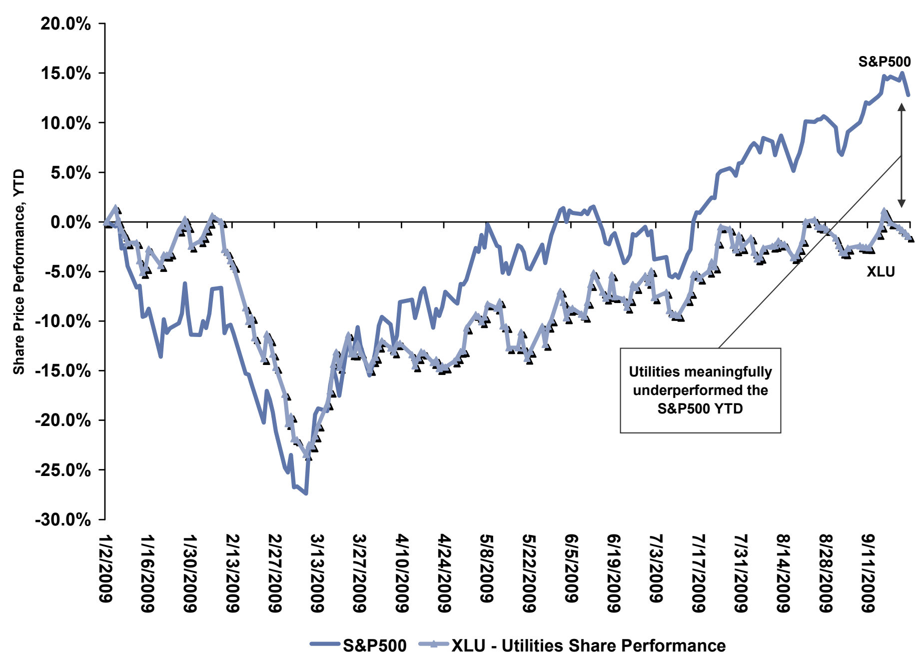
Portfolio Manager Summary – Own utilities, given improving fundamentals, relative under-performance and valuation

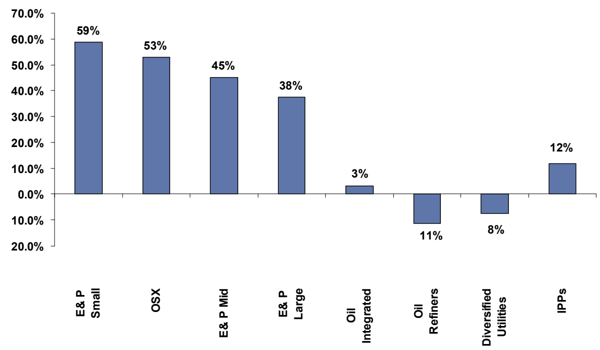
The broader utilities sector, especially the commodity levered names within the space, screen attractively after sizable underperformance YTD versus the S&P500 and since January 2008 versus other commodity oriented sectors. We reiterate our Attractive coverage view on Diversified Utilities, while upgrading the Independent Power Producer (IPP) sub-sector to Attractive, due to (1) improving YoY demand trend comparisons and improving spot commodity prices, (2) significant relative underperformance versus the S&P500 and commodity-exposed sectors, as shown in Exhibit 1-3 below, (3) valuation on longer term metrics, and (4) a continued low interest rate and inflationary environment, as forecast by the GS Economics team. We lower our coverage view on Regulated Utilities to Neutral, since few of the larger cap bell-weather names screen attractively here. Equity issuances, a significant sector-wide overhang entering 2009, no longer weigh on the group, as only a few names require infusions in 2010. We still expect YoY demand growth in 2010, with improving fundamentals, up 0.4% from 2009 levels, as well as forecasting a sizable increase in spot commodity prices next year from current levels.

Exhibit 1: Utilities sector screens attractively after significant YTD underperformance
share price performance, ytd



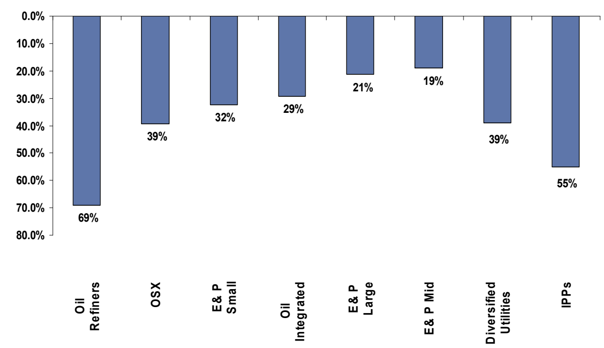
Source: Goldman Sachs Research.

Exhibit 2: IPPs and Diversified Utilities underperformed other commodity sensitive equities YTD…
share price performance, ytd



Source: Goldman Sachs Research.
Note: Performance is from equities under GS coverage

Exhibit 3: IPPs and Diversified Utilities underperformed other commodity sensitive equities January 2008
share price performance, since 1/1/2008



Source: Goldman Sachs Research.
Note: Performance is from equities under GS coverage

After a painful 2009 YTD trajectory for electricity demand, we revise our forecast to reflect a more bottoms up (versus top-down) approach – projecting consumption across the industrial, commercial and residential classes. Historically, a top-down approach tied to GDP accurately predicted electricity demand, where trends showed that every 1% change in real GDP growth drove a 0.6%-0.7% change in electricity demand. Entering 2009, we remained bearish on electricity demand fundamentals and therefore consensus estimates – our bearish forecasts still understated demand, as GDP weakened and industrial production collapsed. A GDP-based top down forecast holds long-term value in our view, but a more bottoms up approach appears more viable going forward to capture changes by customer class.

- **A series of correlation analyses show that Industrial Production (IP), total fixed investment and unemployment emerge as key drivers of power demand.** We analyzed a host of factors across each class, as shown in Exhibit 6, determining that forecasts for Industrial Production maintain a greater statistical correlation than GDP forecasts in terms of assessing MWh sales to industrial customers. Similarly, metrics tied to unemployment rates and total fixed investment – albeit as lagging indicators – drive sales to commercial customers. Weather drives residential demand growth, historically at 1.5%-2.0% annually, with minimal signs to date of efficiency gains on a national scale, although some level should emerge in the coming years given sizable stimulus-related investments.
- **Sentiment around electricity demand will improve, given better YoY comparisons and accelerating GDP growth**. Early signs should emerge that electricity demand will stabilize, with QoQ and then YoY comparisons improving. Demand for 2H2009 should decline only 2%-3% from 2H2008 levels – an improvement from trough-like levels in 1H2009, with a pick-up in industrial and residential MWh sales driving growth in 2010. Normalized demand growth for 2011-2012 could reach 1.5%-1.7% even with slight efficiency gains included, with sales to commercial customers presenting the biggest near-term risks

For merchant generators, improving demand fundamentals and spot commodity prices over the next 6-12 months should lead to multiple expansion. We raise multiples on pure-play IPPs in our universe – NRG Energy and RRI Energy – to reflect improved sentiment and the significant FCF generation likely in a $5.50-$7/MMBtu natural gas price environment. Applying a 7.0X multiple on these predominantly base-load generators remains somewhat below historical mean/median levels of approximately 7.25X, reflecting improving, but still below trend electricity demand growth in 2010.

Regulated Utilities still trade below historical multiples, but few large caps screen well, driving our change in coverage view. Regulated Utilities currently trade near 9.9X our 2012 expected EPS, implying an 8% discount to the long-term average of 10.9X (since 2005). On near-term multiples, Regulated Utilities trade at roughly 12.4X on our FY2 estimates and 11.9X on consensus– below historical levels closer to 12.5X. We anticipate a mean reversion toward the historic average over the next 12-months – given better demand fundamentals and higher earnings and rate base growth – driving our increase of P/E multiples from 9X to 10-10.5X on 2012 EPS. However, many of the bellwether names screen less attractively than small/mid cap regulated stocks, with less upside to target prices.

We add RRI Energy (RRI) to our Americas Conviction Buy list, while reiterating our Conviction Buy on Entergy (ETR) and removing Great Plains Energy (GXP) from the Conviction Buy list, although maintaining our Buy rating on this regulated name. We upgrade RRI Energy (RRI), an Independent Power Producer (IPP) from Neutral to Conviction Buy, as we raise estimates on lower expected coal costs at one of its key coal facility that burns waste coal, not traditional Appalachian based coal. RRI provides the best FCF profile within our universe and maintains the commodity leverage, with the shares still below historical levels, as RRI trades at 70%-75% below January 2008 levels and 50% below January 2007 pricing. We remove GXP from the Conviction Buy list, but maintain our Buy rating, given a lack of near-term catalysts and concern on 3Q weather impacting estimates.

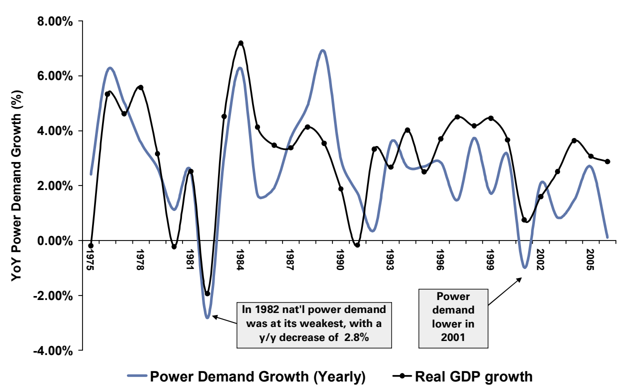
Given recent performance and concerns on 2010 guidance, we downgrade Portland General (POR), while reiterating a Buy rating on large-cap American Electric Power (AEP). After upgrading POR on August 17, the shares have outperformed other Regulated Utilities by 250-300bps, although lagging the S&P 500. We downgrade POR given our concerns that 2010 guidance will disappoint, given our forecast of $1.63 versus consensus levels of $1.75. We reiterate our Buy rating on AEP, the one large cap Regulated Utility we prefer, primarily on valuation, as AEP trades at a 16%-18% discount to peers on 2010-2011 estimates.

Lighten up with a deep dive into electricity demand fundamentals

Top-down, GDP-based demand forecasts – a good long-term forecasting tool, but less effective in the near-term

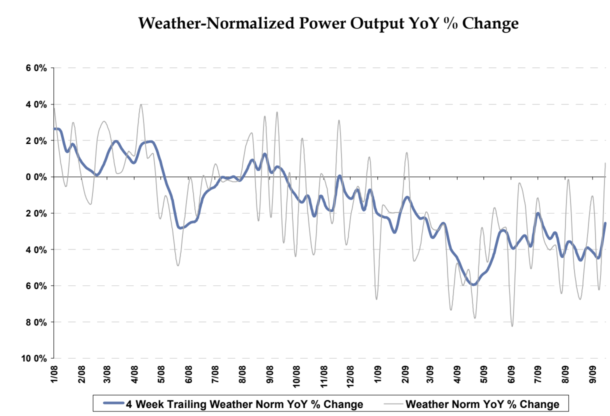
The historical top-down relationship between real GDP growth and electricity demand "broke down" earlier this year. As outlined in our December 11, 2008 note, *"Dimming the Lights,"* annual weather-adjusted electricity demand growth historically correlates well to YoY real GDP growth, as detailed in Exhibit 4. Over time, every 1% change in GDP growth drove a 0.6%-0.7% change in electricity demand. We entered 2009 assuming a 1% YoY decline in weather-normalized demand, driven by an expected 1.6% decline in real GDP. However, real GDP decelerated faster than expected, down 3-4% in 1H2009, but the historical correlation with power demand "broke down" in 1H2009, with actual power demand down 4%, worse than the 2-2.5% that a top-down GDP-driven model would imply.

Exhibit 4: Historically, every 1% change in YoY GDP, drives a 0.6-0.7% change in electricity demand…
yoy power demand and gdp growth (1975-2007)



Source: Goldman Sachs Research, GS Global ECS Research.

Exhibit 5: …but, the historical correlation with power demand broke down in 2009, with actual power demand worse than a top-down GDP model would imply
yoy weekly power demand, weather-normalized



Source: Goldman Sachs Research, EEI.

We primarily attribute the 2009 dislocation of GDP-to-electric sales from this historical trend to the steep fall off in industrial electricity demand. The industrial customer class represents a disproportionately high share of total electric consumption relative to industrial-related activity as a percentage of the total economy. Therefore, the recent sharp fall off of in usage by industrial customers appears to be understated in a GDP-based model.

A top-down model approach remains relevant, particularly as a sanity check in more normal GDP environments. As industrial demand normalizes in 2010 and 2011, we expect electricity demand to converge with its historical relationship with GDP. Weather-adjusted demand growth under a US real GDP forecast of 2.0% in 2010 would be 1.25% under our top-down model – a modestly higher outcome near-term than our new model approach (discussed below) derives – and 1.5-2% in 2011 and beyond, given a long-term real GDP growth rate of 2.5-3%.

Bottom-up demand forecasts – implementing a more granular electricity demand forecast

Our new demand deck, based on a bottoms-up approach by customer class, also shows electricity demand should improve in 2010. We adopt a new bottoms-up approach to forecasting electricity demand by customer class for industrial, commercial and residential customers – through 2012 and expect 0.4% YoY weather normal growth in 2010. As highlighted in Exhibit 6 below, after assessing a variety of factors and variables for industrial MWh demand, industrial production assumptions – and not GDP – emerge as the most highly correlated. For commercial demand, total fixed investment and unemployment drive our bottoms-up approach and show continued risk in demand for this segment, while a more basic trend analysis, incorporating efficiency gains, remains the best method for estimating residential demand.

Exhibit 6: Industrial production is the key driver for industrial electricity demand, while total fixed investment and unemployment rates are among the best predictors for commercial demand

correlation of various macroeconomic statistics to customer class-specific electricity demand

		Coefficient of Determination (R^2) (Low / Medium / High)	Metric Definition	Comments
Industrial MWh	Industrial Production	67%	IP measures domestic output by manufacturing, mining, and utility firms	Relationship with industrial production is statistically significant on a coincidental
Industrial MWh	GDP	54%	Aggregate market value of all f nal goods/services = consumer + investment + net exports + government	Industrial sales maintains highest correlation with GDP among customer classes
Commercial MWh	Unemployment Rate (3m lag)	48%	The percentage of the labor force that is not employed but is actively seeking work	Correlation on a one quarter lag is strongest
Commercial MWh	GDP	27%	Aggregate market value of all f nal goods/services = consumer + investment + net exports + government	
Commercial MWh	Total Fixed Investment (9m lag)	58%	Fixed capital spent for residential and business purposes, including equipment and structures	Correlation is tightest on a 9 month lag likely due to delay between initial fixed investment and time that equipment/structure actually goes into operation
Commercial MWh	Occupied Retail & Commercial Space	52%	Occupied retail/office space = stock (total square footage outstanding) x (1 - vacancy rate)	Vacancy rates are likely to move higher from current levels
Commercial MWh	Personal Consumer Expenditures	28%	Gauge of changes in price of consumer services and goods	
Commercial MWh	Retail Sales	23%	This report tracks sales by retail establishments, including food services	Based on the GS Composite Comparable-Store Sales Index
Residential MWh	GDP	3%	Aggregate market value of all f nal goods/services = consumer + investment + net exports + government	Lowest relationship with GDP among customer classes
Residential MWh	Unemployment Rate	7%	The percentage of the labor force that is not employed but is actively seeking work	
Residential MWh	Household Growth	23%	Growth of occupied housing units	Household growth is a reasonable indicator, but does not drive a statistically significant correlation

Source: Goldman Sachs Research, EIA, GS Global ECS Research.

Electricity demand growth will rebound via three key stages, with the first stage occurring in 2H2009. As outlined in Exhibit 7, the trajectory of the recovery in electricity demand will likely experience three stages: (1) exiting a cyclical bottom, with YoY demand declines improving from 1H2009 trough-like levels even with continued industrial weakness, (2) a more steady recovery of electricity sales in 2010, with modest growth of 0.4% even though commercial MWh sales will disappoint, and (3) more "normalized" for 2011-2012, although pressured somewhat by efficiency gains. We adjust our weather normalized estimates to factor in the YoY impact of weather, as detailed in Exhibit 8.

Exhibit 7: Our bottoms-up, weather normalized forecasts shows slight growth in 2010, driven by a pickup in industrial demand

weather-normalized YoY demand forecasts

	3Q2009	4Q2009	1Q2010	2Q2010	3Q2010	4Q2010	FY2010	FY2011	FY2012
National	**-2.9%**	**-2.2%**	**-0.6%**	**0.0%**	**0.8%**	**1.3%**	**0.4%**	**1.5%**	**1.7%**
Industrial	-9 2%	-6.1%	-1.5%	1.4%	1.6%	1.4%	0.7%	0.2%	0.1%
Residential	0.1%	0.9%	1.4%	0.9%	1.4%	1.4%	1.3%	1.9%	1 9%
Commercial	-2 2%	-2.6%	-2.4%	-1.9%	-0.3%	1.1%	-0.9%	1.9%	2 6%

Phase 1:
Exiting Demand Bottom

Industrial sales improving significantly, driving us out of the cyclical bottom in demand

Phase 2:
Steady Recovery

Residential and industrial sales are positive YoY, while commercial to remain weak

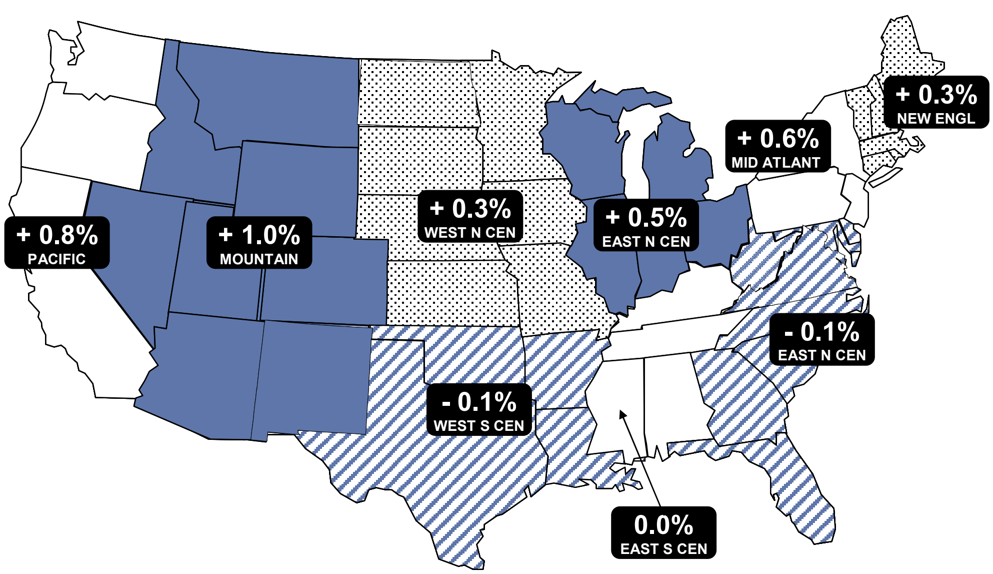
Phase 3:
Return to Normal

Return to long-run growth rate of 1 5 - 1 7%, with commercial demand growth outpacing industrial and residential sales

Source: Goldman Sachs Research, EIA, GS Global ECS Research.

Exhibit 8: We normalize for weather impacts in our electricity demand forecasts, driving various regional forecasts and a national forecast of +0.4% YoY in 2010

2010 weather-normalized demand by EIA region

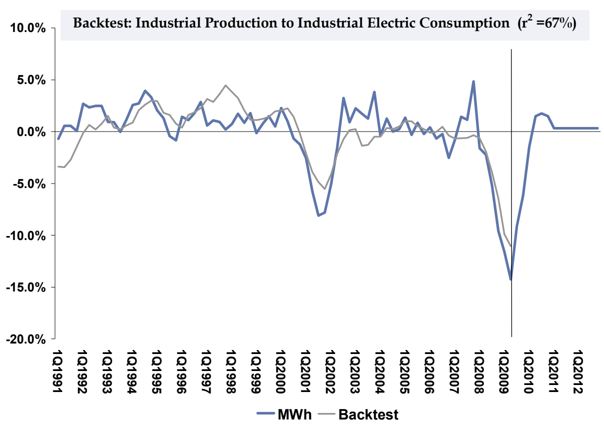


Source: Goldman Sachs Research, EIA.

ATTACHMENT E - 7

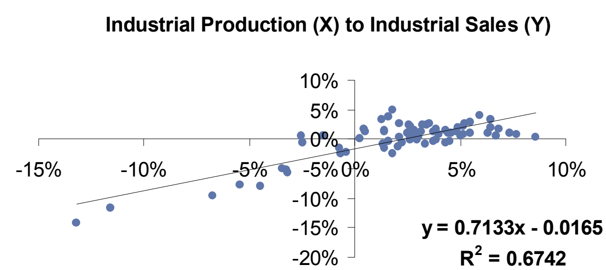
Industrial MWh sales should increase in 2010 with a rebound in Industrial Production, but longer-term trends in industrial MWh sales remain challenging. As shown in Exhibit 9-10 below, industrial MWh sales appear highly correlated with Industrial Production (IP) with an R-squared of approximately 67%. IP declined approximately 13% in 2Q2009, leading to a significant downtick in industrial electricity demand. The Goldman Sachs Global ECS team projects a robust IP recovery in 2Q-4Q2010, likely leading to an increase of 1-2% in electricity consumption by industrial customers. However, in a more normalized production environment post-2010, we believe industrial electricity demand will once again lag other customer classes, as we believe it takes at least a YoY 3.7% increase in IP (above historical trend) to drive just a 1% increase in industrial MWh sales.

Exhibit 9: Economists forecast a strong increase in industrial production will drive the economic recovery – a positive for 2010 industrial MWh demand
backtest of industrial production-based forecasting methodology to industrial electric consumption



Source: Goldman Sachs Research.

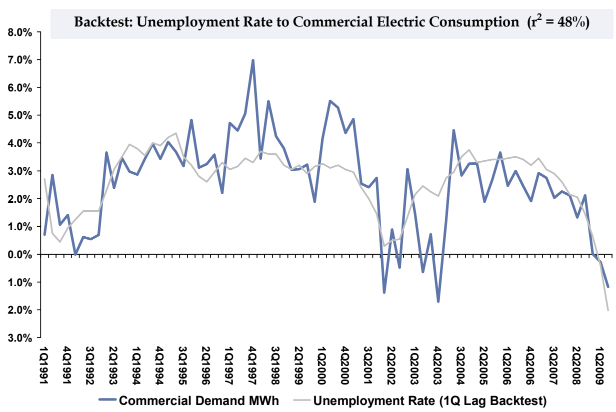
Exhibit 10: However, it takes above trend US production growth to drive a just 1% increase in industrial MWh sales – a long-term risk to industrial demand
correlation between IP and industrial sales



Source: Goldman Sachs Research.

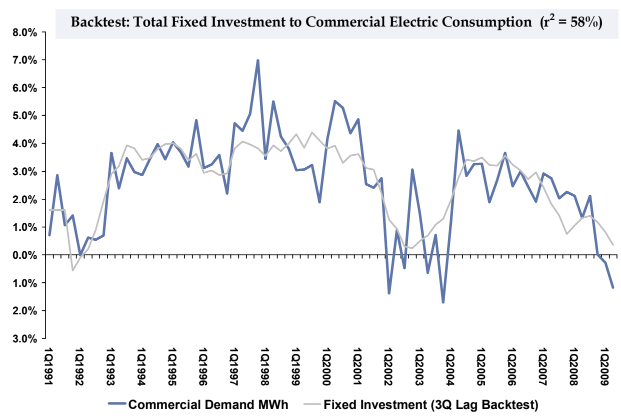
Commercial demand growth appears closely correlated with total fixed business investment and unemployment rate variables. Unemployment rate levels and total fixed investment, at a 3 month and 9 month lag, respectively, emerge as the best predictors of electricity demand for commercial customers. Long-term commercial demand growth will likely outpace growth rates for industrial and residential customers, but risk exists for 2010 expectations, as continued high unemployment and below-trend investment levels will weigh on demand from this segment. We expect a YoY increase in weather-normalized sales to commercial customers of 0.9% versus a historical growth rate closer to 2.5%.

Exhibit 11: We use a 50-50 blend of unemployment …
backtest of unemployment rate-based forecasting methodology to commercial electric consumption



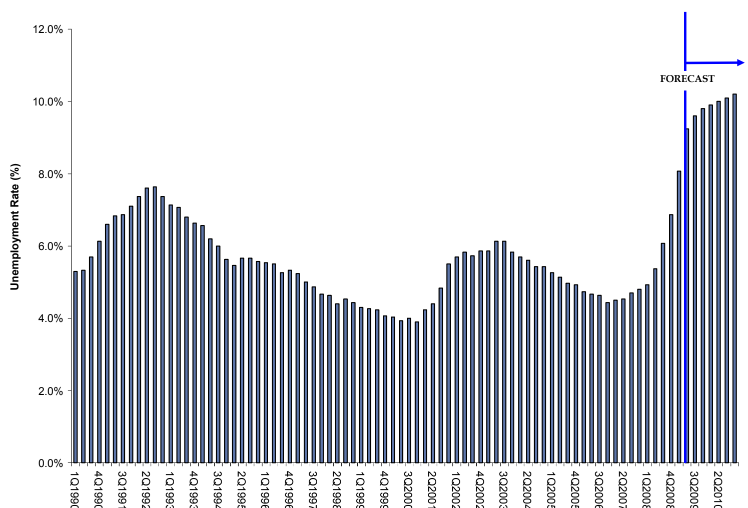
Source: Goldman Sachs Research.

Exhibit 12: …and total fixed investment to drive our commercial customer class MWh demand forecasts
backtest of total fixed investment-based forecasting methodology to commercial electric consumption



Source: Goldman Sachs Research.

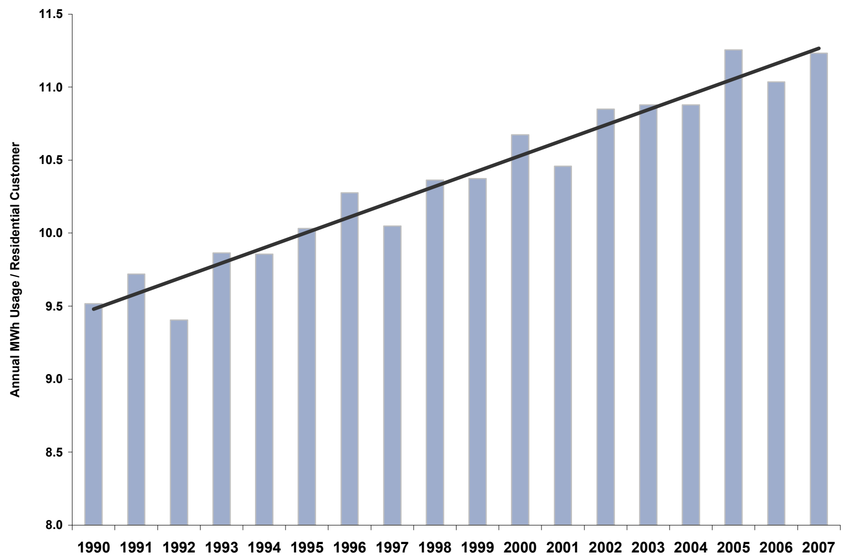
Exhibit 13: GS Global ECS forecast unemployment rates will be near or above 10% through 2010, weighing on commercial electricity demand
unemployment rate forecasts



Source: GS Global ECS Research, Goldman Sachs Research.

Historically, residential electricity demand increased annually by 2.0%-2.5% and upside to our expectation exists if efficiency gains do not emerge. We utilize a trend based analysis to predict weather-normalized power demand for the residential customer class and assume 1.9% growth for 2011/2012. This incorporates a rough estimate for efficiency gains – gains we incorporate to reflect the significant spending brought by the American Recovery and Reinvestment Act. We note that usage per residential customers, especially over the last 5-10 years, continued to increase, not decrease, so upside to our forecasts for residential demand growth for 2011-2012 exists if even modest 10-20 bps efficiency gains that we assume do not emerge.

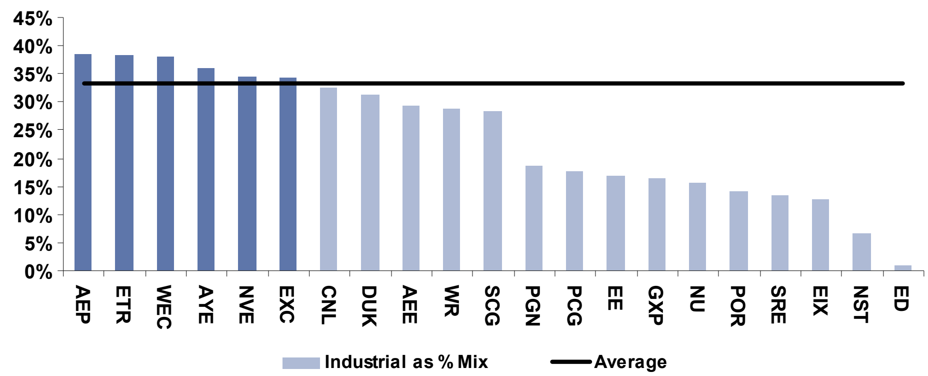
Exhibit 14: From 1990-2007, we observed MWh usage per residential customer increase, so upside to our demand growth forecasts exist if efficiency gains do not materialize
annual MWh usage per residential customer

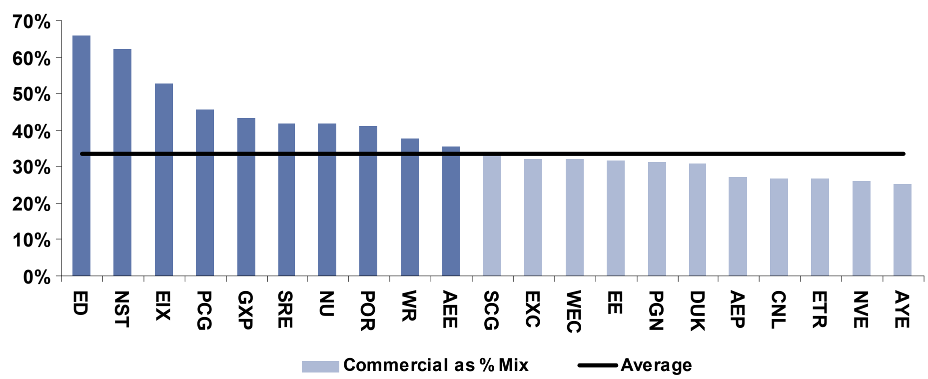


Source: Goldman Sachs Research.

Utilities in the Midwest, the South and the Plains states should benefit in 2010 as industrial MWh sales respond to higher industrial production levels. In our universe, on 2007 estimates, Conviction Buy-rated ETR and Buy-rated AEP remain among the most levered to electricity sales to industrial customers, given a greater proportion of total sales to this segment, as highlighted in Exhibit 15 below. We note companies with sizable exposure to commercial customer demand – including Sell-rated NSTAR (NST) – may experience demand weakness above peer levels given higher-than-average exposure to MWh sales to commercial customers. California and NY based utilities, even though they maintain sizable exposure to the commercial segment, maintain rate structures that include decoupling from demand, thus significantly less exposed to demand trends overall.

Exhibit 15: American Electric Power and Entergy are among the most levered to industrial demand, while NSTAR is among the most commercially-exposed
2007 customer class breakdown by regulated utility segment





Source: SNL.

We revise estimates to reflect our new demand forecast and minor changes to power price assumptions

For both Regulated Utilities and Diversified Utilities, we update our estimates to reflect new electricity demand assumptions for their regulated businesses. As detailed above and summarized in Exhibit 16 below, we revise our electricity demand growth assumptions, impacting EPS estimates for regulated segments prior to rate case adjustments in future periods. On average, our 2010 estimates for Regulated Utilities remain approximately 4% below consensus – with below consensus views on Duke Energy (DUK-Neutral), Portland General (POR-Neutral) and NSTAR (NST-Sell) and an above consensus view for Great Plains Energy (GXP-Buy).

Exhibit 16: Old versus new demand forecasts
weather-normalized YoY demand forecasts

	Weather-Normal YoY Nat'l. Demand Forecasts (%)		
	Old	**New**	**Differ.**
3Q2009	0.0%	-2.9%	-2.9%
4Q2009	-0.3%	-2.2%	-1.9%
1Q2010	0.6%	-0.6%	-1.2%
2Q2010	0.6%	0.0%	-0.6%
3Q2010	0.6%	0.8%	0.2%
4Q2010	0.6%	1.3%	0.7%
FY2010	**0.6%**	**0.4%**	**-0.2%**
FY2011		**1.5%**	
FY2012		**1.7%**	

Source: Goldman Sachs Research.

For Diversified Utilities and the IPPs, we also make modest changes to power price forecasts. In addition to revising demand estimates for regulated segments, we also implement minor power price adjustments in the Midwest and industrial portions of the Mid-Atlantic/Northeast. Natural gas prices continue to drive power price assumptions – as forecast by the Goldman Sachs E&P research team, we continue to expect a significant uplift in 2010/2011 power prices, driven by higher natural gas levels. Among commodity levered names, our 2010 forecasts differ significantly for Sell-rated Ameren (AEE) and for Buy-rated Exelon (EXC), although we recognize that a large portion of the upside inherent in EXC remains tied to eventual implementation of carbon regulations, as detailed in our June 25 note, "Carbonomics: Measuring impact of US carbon regulation on select industries."

Exhibit 17: Old versus new commodities forecasts

	WTI Oil		Henry Hub Gas		CAPP Coal	PRB Coal
	new	old	new	old	unchanged	unchanged
3Q 2009E	$67.00	$65.00	$3.40	$4.00	$50.00	$10.50
4Q 2009E	$77.00	$70.00	$4.00	$4.50	$55.00	$11.00
FY 2009E	$61.72	$59.47	$3.98	$4.25	$52.23	$10.22
1Q 2010E	$85.00	$80.00	$5.00	$5.00	$55.00	$12.00
2Q 2010E	$85.00	$80.00	$5.00	$5.00	$55.00	$12.00
3Q 2010E	$90.00	$80.00	$5.50	$5.50	$55.00	$12.50
4Q 2010E	$100.00	$80.00	$6.50	$6.50	$55.00	$13.00
FY 2010E	$90.00	$80.00	$5.50	$5.50	$55.00	$12.38
2011E	$110.00	$100.00	$7.00	$7.00	$60.00	$14.00
2012E	$105.00	$105.00	$6.50	$6.50	$65.00	$14.00
2013N	$85.00	$85.00	$6.50	$6.50	$70.00	$13.00

Source: Goldman Sachs Research.

We forecast significant FCF yields for the IPPs, providing opportunities for debt reduction, buybacks, or growth. Based on our commodity price forecasts and capital spending estimates, we expect from 2010-2012 RRI will deliver FCF/sh of $0.86-$1.18 and NRG will generate FCF/sh of $3.84-2.40, representing average FCF yields of 17% and 12%, respectively. This 2010-2012 free cash flow equals roughly 51% and 38% of the current market capitalizations for RRI and NRG, or 48% and 30% of their respective debt

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outstanding. We expect capital deployment across the balance sheet over the next few years, barring significant new investments in growth, M&A, or environmental projects.

Exhibit 18: We forecast 13% and 17% 2010-2012 FCF yields for NRG and RRI
independent power producers FCF forecast

Independent Power Producers FCF Forecasts				
	2010	2011	2012	Average
RRI				
FCF/share	$0.86	$1.64	$1.04	$1.18
FCF Yield	12.3%	23.5%	15.0%	16.9%
NRG				
FCF/share	$3.84	$3.19	$3.30	$3.44
FCF Yield	14.1%	11.7%	12.1%	12.7%

Source: Goldman Sachs Research estimates

Exhibit 19: GS EPS estimates versus consensus forecasts

GS EPS estimates versus consensus

	2009			2010			2011		
Ticker	GS EPS	Cons EPS	% Ch	GS EPS	Cons EPS	% Ch	GS EPS	Cons EPS	% Ch
Large Cap Regulated									
AEP	$2.70	$2.87	-6%	$2.99	$3.03	-1%	$3.33	$3.22	3%
DUK	$1.11	$1.21	-8%	$1.17	$1.30	-10%	$1.30	$1.36	-4%
ED	$2.99	$3.11	-4%	$3.21	$3.29	-2%	$3.31	$3.41	-3%
PCG	$3.08	$3.16	-3%	$3.45	$3.40	2%	$3.81	$3.70	3%
PGN	$2.88	$3.03	-5%	$2.99	$3.20	-6%	$3.32	$3.34	-1%
Mean			-5%			-4%			-3%
Small&Mid Cap Regulated									
CNL	$1.64	$1.65	0%	$2.14	$2.07	3%	$2.27	$2.27	0%
EE	$1.34	$1.32	2%	$1.28	$1.55	-17%	$1.47	$1.66	-11%
GXP	$1.17	$1.19	-2%	$1.54	$1.45	6%	$2.01	$1.82	11%
NST	$2.33	$2.36	-1%	$2.29	$2.48	-8%	$2.50	$2.62	-5%
NU	$1.68	$1.84	-8%	$1.85	$1.98	-7%	$2.00	$2.18	-8%
POR	$1.45	$1.39	4%	$1.63	$1.75	-7%	$2.21	$2.09	6%
SCG	$2.85	$2.83	1%	$2.98	$3.05	-2%	$3.35	$3.28	2%
NVE	$0.69	$0.92	-25%	$0.94	$1.13	-17%	$1.12	$1.19	-6%
WEC	$3.05	$3.12	-2%	$4.01	$3.76	7%	$4.13	$4.10	1%
WR	$1.45	$1.71	-15%	$1.64	$1.83	-11%	$1.57	$1.84	-15%
Mean			-5%			-5%			-3%
Diversified Utilities									
AEE	$2.21	$2.72	-19%	$2.12	$2.59	-18%	$2.50	$2.50	0%
AYE	$2.15	$2.22	-3%	$2.47	$2.49	-1%	$3.57	$3.25	10%
ETR	$6.50	$6.52	0%	$6.67	$6.91	-3%	$7.95	$7.25	10%
EIX	$2.92	$3.04	-4%	$3.56	$3.49	2%	$3.84	$3.61	6%
EXC	$4.02	$4.11	-2%	$3.58	$4.03	-11%	$4.11	$4.60	-11%
SRE	$4.46	$4.53	-1%	$4.93	$5.14	-4%	$5.55	$5.55	-3%
Median			-3%			-4%			3%
Mean			-5%			-6%			2%
Independent Power Producers									
NRG	$1.86	$2.94	-37%	$2.34	$2.72	-14%	$2.25	$2.33	-4%
ORA	$1.23	$1.32	-7%	$1.27	$1.54	-17%	$1.25	$1.68	-26%
RRI	($0.77)	($0.55)	-40%	$0.19	$0.06	224%	$0.64	$0.32	101%
Median			-37%			-14%			-4%
Mean			-28%			64%			24%

Note: NRG EPS assumes contract amortizations associated with the acquisition of Reliant

GS EBITDA estimates versus consensus

Independent Power Producers

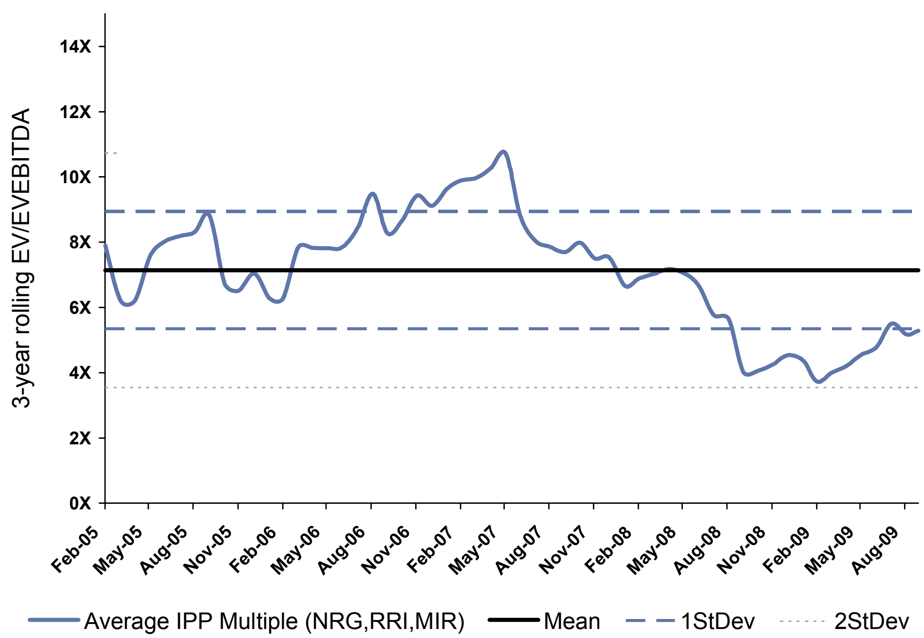
	2009			2010			2011		
Ticker	GS EBITDA	Cons EBITDA	% Ch	GS EBITDA	Cons EBITDA	% Ch	GS EBITDA	Cons EBITDA	% Ch
NRG	$2,448	$2,280	7%	$2,620	$2,358	11%	$2,513	$2,467	2%
ORA	$148	$151	-2%	$180	$185	-3%	$248	$223	11%
RRI	$141	$331	-57%	$567	$582	-3%	$664	$727	-9%
Median			-2%			-3%			2%
Mean			-17%			2%			2%

Source: Goldman Sachs Research estimates, Factset.
Note: *EBITDA estimates are Adjusted EBITDA, not GAAP EBITDA.*

We upgrade Independent Power Producers to Attractive and remain Attractive on commodity oriented Diversified Utilities

As power demand and commodity prices improve, IPP multiples should continue to expand – and we upgrade RRI Energy from Neutral to Conviction Buy. Improving natural gas prices, power prices and electricity demand all should support and enhance valuations for merchant generators and the merchant generation segments owned by Diversified Utilities. We raise multiples on pure-play IPPs in our universe – NRG Energy and RRI Energy – to reflect improved sentiment and the significant FCF generation likely in a $5.50-$7/MMBtu natural gas price environment. Applying a 7.0x multiple on these predominantly base-load generators remains somewhat below historical mean/median levels of 7.25x-7.5x, reflecting improving, but still below trend electricity demand growth in 2010.

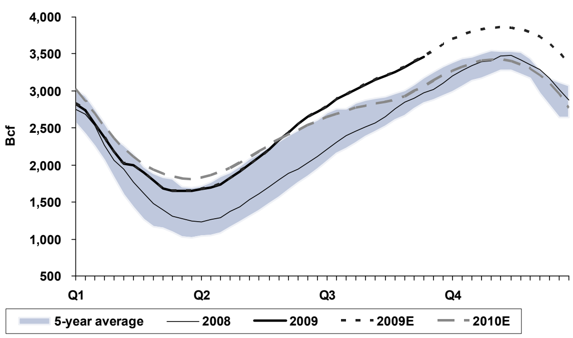
Exhibit 20: Base-load IPPs still trade one standard deviation below their LT mean despite recent multiple expansion
3YR forward EV/EBITDA multiples of base-load IPPs (NRG, RRI, MIR) on consensus estimates



Source: GS Research Estimates, Factset

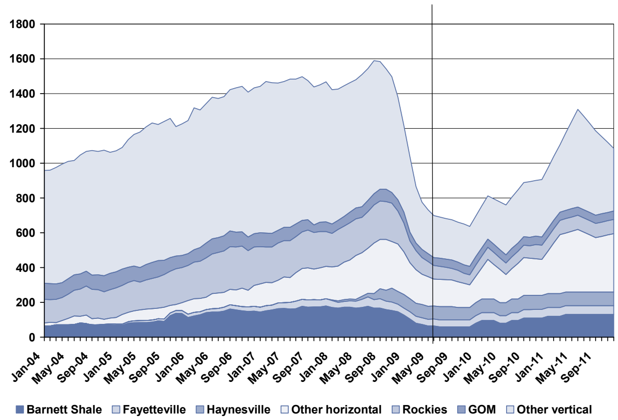
Natural gas prices should improve and will likely emerge over the coming 12 months as a catalyst, not a headwind, for IPPs and merchant generation. The Goldman Sachs E&P team sees the potential for near term bullish weekly data builds due to (1) industrial demand improvements, (2) lower production due to natural declines and lower rig count, (3) lower production due to maintenance, shut ins, and/or drilled but not completed wells, and (4) coal-to-gas substitution. We continue to focus on 1H2010 gas prices as a key driver for FY2011. Assuming gas prices stay below $5.00/MMBtu Henry Hub gas in 1H2010, our E&P team forecasts a normalization of gas storage in 2Q/3Q 2010, leading to tightness and a spike in prices during Winter 2010-2011.

Exhibit 21: Near term storage data could turn bullish
natural gas storage



Source: Goldman Sachs Research estimates, US DOE

Exhibit 22: ....and further rig count declines should lead to $6+/MMBtu gas beyond 2010
US natural gas rig count



Source: Baker Hughes

Within our universe, RRI maintains the most sensitivity to changes in commodity prices, although others maintain sizable commodity leverage. As highlighted in Exhibit 23 below, RRI Energy maintains the greatest exposure to natural gas and power prices, given minimal hedges for its generation output. Above-market coal contracts weigh on 2009 significantly and have a modest impact on 2010, but roll-off by 2011. Diversified Utilities also maintain sizable exposure to natural gas and power prices, with hedges rolling off at different times for each – Allegheny Energy (AYE) remains significantly unhedged for 2011, while few maintain hedges beyond 2011.

Exhibit 23: RRI and NRG remain the most sensitive to a $1.00 change in Gas, AYE is most sensitive Diversified Utility
EPS Sensitivity to + or - $1.00/mmbtu of natural gas in 2010,2011

EPS sensitivity + or - $1.00/mmbtu of Natural Gas			
	2010	2011	2012
Indepent Power Producers			
NRG	12%	17%	208%
RRI	167%	60%	36%
Average	90%	39%	122%
Diversified Utilities			
AEE	4%	7%	10%
AYE	9%	23%	37%
EIX	10%	13%	15%
ETR	3%	7%	11%
EXC	2%	9%	26%
SRE	1%	1%	2%
Average	5%	10%	17%

***Our "base-case" implies our E&P Team's forecast of $5.50/mmbtu in 2010 and $7.00/mmbtu in 2011**

Source: Goldman Sachs Research estimates.

We raise estimates for RRI and increase target prices for IPPs, upgrading RRI to CL Buy, with around 30-35% upside in both RRI and NRG. We continue to apply a sum of the parts valuation methodology for IPPs and the IPP segments within Diversified Utilities, now utilizing a 7.0x base-line EV/EBITDA multiple on average 2011/2012 EBITDA, then making adjustments for expected average FCF yields, returns on invested capital, anticipated carbon impact, and broader attractiveness of regional markets. For RRI, we increase estimates to reflect lower than previously forecast coal costs for its Seward unit, a waste coal facility competitively advantaged due to coal that costs roughly half the cost of traditional Appalachian coal. We lower our 12-month, DCF based, price target on Neutral-rated ORA from $43 to $41, on (1) lower forecasted backlog, (2) lower gross margins forecasts, and (3) lower power prices in Hawaii, implying 5% upside.

Exhibit 24: We upgrade RRI from Neutral to Buy and remain buyers of NRG
SoTP Valuation of IPPS ($mn unless per share estimates)

Company	RRI	NRG
Average 2011-2012 EBITDA	**$560**	**$2,434**
Baseline EV/EBITDA Multiple	7.0x	7.0x
Adjustments to Baseline Multiple		
Attractiveness of Regional Markets	0.0x	-0.3x
Carbon Exposure	-1.5x	-1.0x
Returns on Capital	0.0x	0.0x
Free Cash Flow Yield	1.75x	1.25x
Target EV/EBITDA Multiple	**7.2x**	**7.0x**
Enterprise Value	**$4,056**	**$17,019**
Net debt	$1,053	$6,465
Equity Value - Generation & Other Non-Utility	**$3,002**	**$10,266**
Current Diluted Share Count	351	275
Equity Value per Share - Generation & Other Non-Utility	**$8.56**	**$37.33**
Target Price per Share	**$9**	**$37**
Current Share Price	$6.98	$27.20
Dividend yield	0.0%	0.0%
Total Return to Target	**29%**	**36%**
Carbon NPV, $/sh	$ **(2)**	$ **(9)**
Generation Returns on Capital 2011-2012	3.4%	5.7%
Generation Free Cash Flow Yield 2011-2012	19.2%	11.9%

Source: Goldman Sachs Research estimates.

Multiple expansions will also benefit Diversified Utilities, as we forecast improving valuations for their non-regulated subsidiaries and regulated segments. We value the "parts" of Diversified Utilities using two methodologies: (1) P/E metrics on regulated earnings power, and (2) an EV/EBITDA multiple on the non-regulated merchant generation or IPP segments, with adjustments for (a) returns of capital, (b) free cash flow, (c) exposure to potential carbon regulations, and (d) attractiveness of regional markets.

Exhibit 25: Multiple expansion benefits Diversified Utilities at both segments
SoTP valuation methodology

Company	AEE	AYE	EIX	EXC
Utility 2012 EPS	$2.44	$1.44	$3.48	$1.08
Applied Targe PE Multiple	10.0x	10.0x	10.5x	10.5x
Utility Equity Value per Share	**$24**	**$14**	**$36**	**$11**
Average EBITDA on Generation (2011-2012)	$410	$690	$849	$3,604
Other 2011-2012 EBITDA	$0	$0	($30)	($102)
Total Generation & Other Non-Utility EBITDA	**$410**	**$690**	**$819**	**$3,502**
Baseline EV/EBITDA Multiple	7.0x	7.0x	7.0x	7.0x
Adjustments to Baseline Multiple				
Attractiveness of Regional Markets	-0.8x	-1.0x	-0.3x	-0.5x
Carbon Exposure	-1.3x	-0.5x	0.2x	3.7x
Returns on Capital	-0.3x	0.5x	0.0x	0.3x
Free Cash Flow Yield	-0.3x	0.8x	0.0x	0.0x
Target EV/EBITDA Multiple	**4.5x**	**6.8x**	**7.0x**	**10.5x**
Enterprise Value - Generation & Other Non-Utility	**$1,835**	**$4,675**	**$5,699**	**$36,661**
Generation & Non-Utility Net Debt	$1,682	$1,795	$4,942	$3,140
Equity Value - Generation & Other Non-Utility	**$153**	**$2,880**	**$757**	**$33,521**
Current Diluted Share Count	214	170	327	659
Equity Value per Share - Generation & Other Non-Utility	**$1**	**$17**	**$2**	**$51**
Target Price per Share	**$25**	**$31**	**$39**	**$62**
Current Share Price	$25.74	$26.96	$34.01	$50.12
Dividend yield	6.0%	2.2%	3.8%	4.2%
Total Return to Target	**3%**	**17%**	**19%**	**28%**
Carbon NPV, $/sh	**-$2**	**-$2**	**$1**	**$20**
Generation Returns on Capital 2011-2012	2.9%	8.7%	3.6%	8.0%
Generation Free Cash Flow Yield 2011-2012	-0.8%	7.3%	1.1%	0.1%

CL Buy rated Entergy target price is $101/sh, while Neutral rated Sempra target price is $59/sh

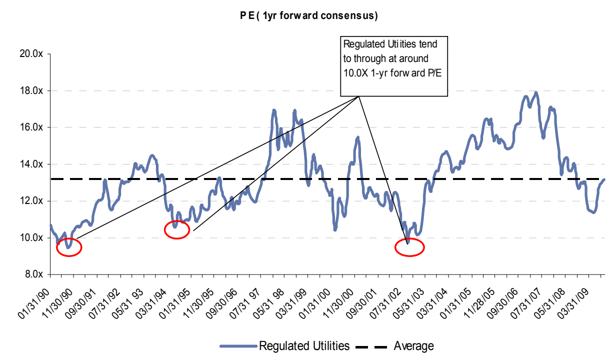
Source: Goldman Sachs Research estimates.

We downgrade Regulated Utilities to Neutral, as few bell-weathers screen attractively

With large cap Regulated Utilities screening less attractive than small/mid cap peers, we downgrade this sub-sector to Neutral. While Regulated Utilities trade below historical levels on Price to Book and on longer term (2012) P/E multiples, multiples on FY2 screen less attractively. More importantly, upside on average in the sub-sector remains tilted toward smaller/mid cap names versus the large cap stocks, driving our sub-sector downgrade to Neutral. Dividend yield spreads remain attractive, but few sector-wide catalysts exist.

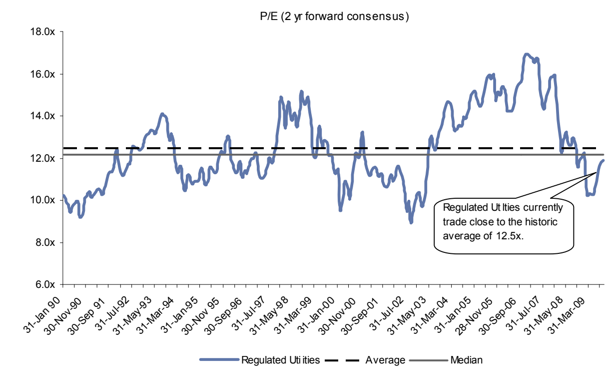
Regulated Utilities currently trade near long-term historic average P/E multiples on 2010 estimates. As shown in Exhibit 27 below, Regulated Utilities currently trade near 12.0x on FY2 or 2010 estimates, versus long-term average levels closer to 12.5x, only a modest discount. We note the long-term average includes trough levels from the high inflationary period in the 1970s and the "electricity crash" from 2001-2002, with the mean and median on FY2 much higher utilizing ranges from just the last 5-7 years, although expected rate base growth currently lags expected levels from 2005-2008 due to cuts in capital spending.

Exhibit 26: Regulated Utilities currently trade inline with the historic average of 13.2x on FY1 consensus estimates
Jan 1, 1990 - current



Source: Factset, Goldman Sachs Research estimates.

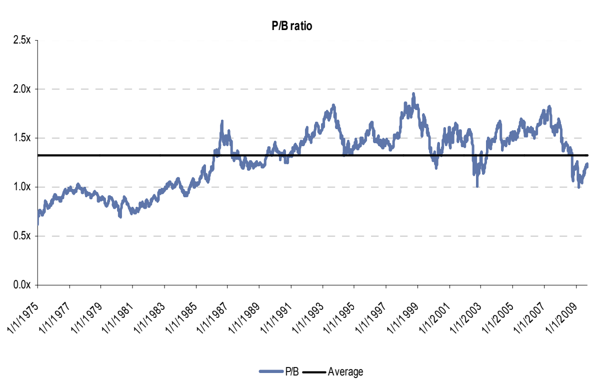
Exhibit 27: Regulated Utilities currently trade below the historic average of 12.5x on FY2 consensus estimates
Jan 1, 1990 - current



Source: Factset, Goldman Sachs Research estimates.

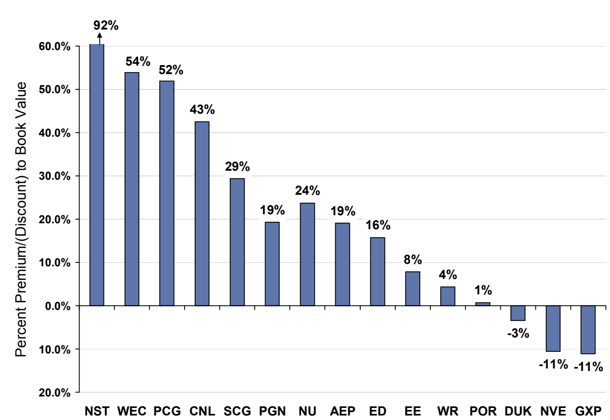
Regulated Utilities trade slightly below average Price to Book levels and equity issuances in 2010 are not a major overhang. As detailed in Exhibit 28 below, Regulated Utilities historically traded at Price/Book multiples on average near 1.3-1.4x, with group levels currently near 1.2x. Removing the 1970s trough period, the historical Price/Book level appears closer to 1.5x-1.6x, implying regulated names trade only slightly below historical levels, as outlined in Exhibit 29 below. Since we do not expect significant equity financing needs over 2010, with only a handful of companies likely issuing shares versus a broad wave of issuances in 2009, Regulated Utilities could close this gap on a Price to Book basis, although many key names already have done so.

Exhibit 28: Regulated Utilities currently trade below historic P/B average of 1.3x – which includes the trough period of the 1970s
Jan 1, 1975 - current



Source: Factset, Goldman Sachs Research estimates.

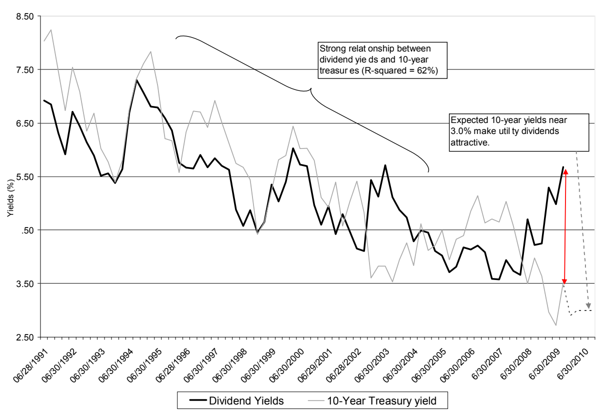
Exhibit 29: Companies like GXP and NVE trading below book provides opportunities for mean reversion
Percent premium/(discount) to book value



Source: Factset, Goldman Sachs Research estimates.

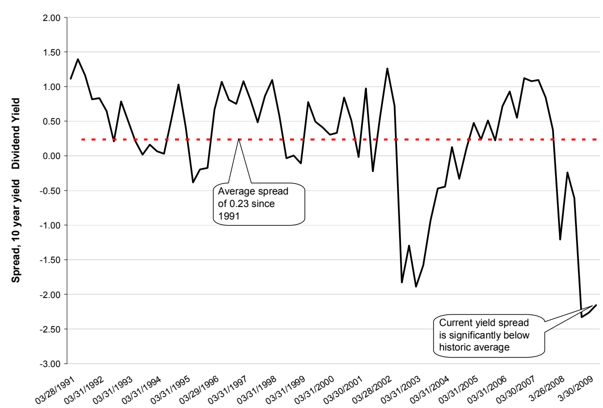
Relative to treasury yields, regulated names and the broader group appear attractive. The Goldman Sachs Global ECS team forecasts lower interest rates over the next 12-months, with 10-year Treasury yield expected to decline from the current levels near 3.5% to approximately 3% through 1H2010, as shown in Exhibit 30. Under this scenario, the average dividend yields of Regulated Utilities appear attractive versus the near-term expected 10-year yield. Historically, for Regulated Utilities, lower dividend yields implied higher share prices. As detailed in Exhibit 31, the spread between the dividend yield and the 10-year yield is at a historic low, versus the long-term average of 0.23. We believe that the current spread levels provide a potential for mean reversion, resulting into lower dividend yield for the Regulated Utilities and implying upside to share prices.

Exhibit 30: Low 10-year Treasury yields indicate share price upside for Regulated Utilities
Yields, 10-year Treasury note and dividends on Regulated Utilities



Source: Factset, Goldman Sachs Research estimates.

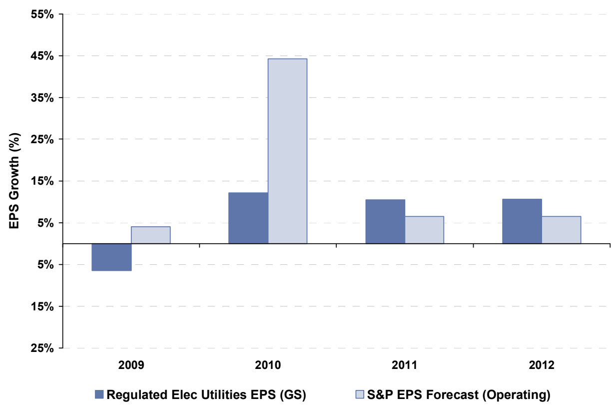
Exhibit 31: The current yield spread is significantly below the historic average
Spread, 10-year Treasury yield and average dividend yield on Regulated Utilities



Source: Factset, Goldman Sachs Research estimates.

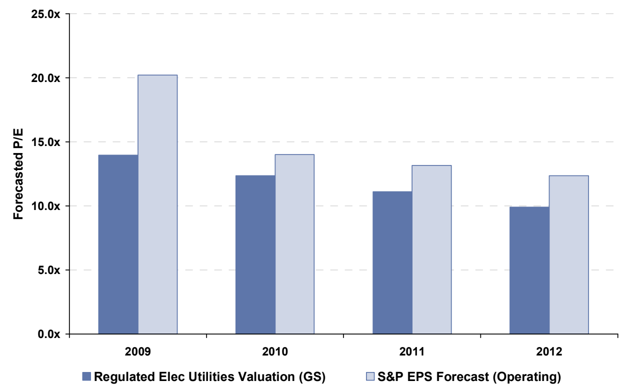
Regulated Utilities screen attractively relative to S&P 500, trading at a 12%-20% discount despite stable multi-year average earnings growth. As shown in Exhibit 32 below, we expect a CAGR EPS growth of approximately 12% through 2012 for Regulated Utilities, below the earnings growth for the S&P 500 of 21%. However, the Regulated Utilities have a less volatile earnings growth profile, with a 5% decline in 2009 given the weak demand fundamentals in 1H2009, followed by a 11%-12% yearly growth over 2010-2012 . The S&P 500 index currently trades at 14.0/13.2/12.4X on forecasted 2010-2012 earnings, versus Regulated Utilities at 12.4/11.1/9.9X , implying a 1.0x-1.6x or 12%-20% discount for the regulated group, as shown in Exhibit 33 below. However, the S&P estimates assume a more normal 6%-6.5% growth after 2010, likely conservative given economic improvements and therefore potentially overstating the relative valuation of Regulated Utilities.

Exhibit 32: We expect Regulated Utilities to post 12% CAGR growth in EPS…
Annual forecasted EPS growth, 2009E-2012E



Source: Goldman Sachs Research estimates.

Exhibit 33: …while Regulated Utilities trade at a discount to S&P 500 on P/E multiples
P/E of Regulated Utilities and the S&P 500, 2009E-2012E



Source: Goldman Sachs Research estimates.

Given expected improvements in utility demand and broader/improved market views overall, we adjust our target prices for Regulated Utilities. We continue to utilize a dual approach for valuing Regulated Utilities, a blend of dividend discount model analysis (assuming a 9% cost of equity and a 2.5% terminal growth rate) and a P/E multiple on projected longer-term 2012 earnings power. We increase our baseline target P/E multiples for Regulated Utilities to reflect improving fundamentals for the group. We also apply a differential in target multiples for the two sub-groups: large cap and small/mid cap regulated utilities-- to reflect the historic premium exhibited by the large cap regulated utilities on long-term earnings power.

- **On longer-term earnings power, large cap group trades at a 7%-13% premium versus the small/mid cap peers.** As shown in Exhibit 34, we observe a trading disparity between the two sub groups, with large cap regulated utilities trading at a note worthy premium to its small/mid cap peers on longer-term earnings power. We expect this pattern to hold going forward, and alter our P/E based valuation methodology by introducing a 5% differential between the target multiples for the two groups.

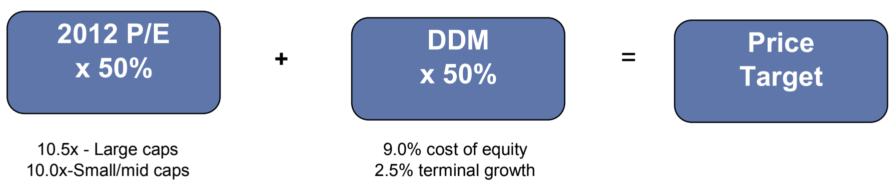
Exhibit 34: Yearly comparison of the trading multiples for large cap and small/mid cap Regulated Utilities, on FY3 consensus estimates
Over years 2005-2009

Year	Large cap	Small/cap	Pre/(disc.) (%)
Over 2005	14.2x	13.3x	7%
Over 2006	14.2x	14.1x	0%
Over 2007	14.6x	13.0x	13%
Over 2008	12.0x	11.1x	8%
Over 2009	10.4x	9.6x	8%

Source: Factset, Goldman Sachs Research estimates.

- **Our new target prices imply a 12% average upside from current levels for Regulated Utilities.** As shown in Exhibit 35, we value regulated utilities using a 50/50 weighting on: (1) P/E multiples for longer-term regulated earnings power, and (2) a DDM model. Given the improving demand fundamentals and historic trading patterns, we increase our expected base-line P/E multiple from 9.0x to 10.5x for large cap group and 10.0x small/mid cap group, a 5% valuation differential between the two sub-sectors. While we increase the P/E side of our valuation, we maintain our DDM model which incorporates a 2.5% terminal growth rate, roughly in line with expected long-term GDP growth trends.

Exhibit 35: We use a blend of P/E on 2012 EPS and DDM, with a discounted target multiple for the small/mid group versus large cap Regulated Utilities
Our price target methodology



Source: Goldman Sachs Research.

Exhibit 36: Valuation of Regulated Utilities on a dividend discount model basis are attractive and our blended target prices imply a 12% total return potential

	Ticker	Rating	9/28 Close	DDM Value	Current Yield	Total Return, DDM Only	2012 EPS	Multiple Applied	P/E-Based Value	Total Return, P/E Only	12-month Target Price	Total Return to 12-Month Target
Large-Cap												
American Electric Power	AEP	Buy	$31.13	$38	5.3%	**27%**	$3.45	10.5x	$36	**22%**	**$37**	**24%**
Consolidated Edison	ED	Sell	$41.40	$39	5.7%	**1%**	$3.45	10.5x	$36	**-7%**	**$38**	**-3%**
Duke Energy	DUK	Neutral	$15.93	$15	5.8%	**2%**	$1 34	10.5x	$14	**-6%**	**$15**	**0%**
PG&E	PCG	Neutral	$40.91	$43	4.1%	**10%**	$4 02	10.5x	$42	**7%**	**$43**	**9%**
Progress Energy	PGN	Neutral	$39.60	$43	6.3%	**14%**	$3 55	10.5x	$37	**0%**	**$40**	**7%**
Large-Cap Mean					***5.4%***	***11%***				***3%***		***8%***
Large-Cap Median					***5.7%***	***10%***				***0%***		***7%***
Mid & Small-Cap												
Cleco	CNL	Neutral	$25.10	$26	3.6%	**7%**	$2 39	10.0x	$23.87	**-1%**	**$25**	**3%**
El Paso Electric	EE	Neutral	$17.84	$20	0.0%	**12%**	$2.10	10.0x	$21	**18%**	**$21**	**18%**
Great Plains Energy	GXP	Buy	$18.17	$22	4.6%	**28%**	$2.13	10.0x	$21	**22%**	**$22**	**26%**
Northeast Utilities	NU	Neutral	$23.99	$28	4.0%	**19%**	$2 51	10.0x	$25	**8%**	**$26**	**12%**
NSTAR	NST	Sell	$32.09	$32	4.7%	**3%**	$2 55	10.0x	$26	**-16%**	**$29**	**-5%**
NV Energy	NVE	Neutral	$11.59	$15	3.5%	**31%**	$1.41	9 0x	$13	**13%**	**$14**	**24%**
Portland General	POR	Neutral	$20.07	$24	5.1%	**24%**	$2 20	10.0x	$22	**15%**	**$23**	**20%**
SCANA	SCG	Neutral	$35.30	$42	5.3%	**24%**	$3 80	10.0x	$38	**13%**	**$40**	**19%**
Westar	WR	Neutral	$19.60	$24	6.0%	**28%**	$2.18	10.0x	$22	**17%**	**$23**	**23%**
Wisconsin Energy	WEC	Neutral	$45.11	$49	3.0%	**12%**	$4 63	10.0x	$46	**6%**	**$48**	**9%**
Mid & Small-Cap Mean					***4.0%***	***19%***				***9%***		***15%***
Mid & Small-Cap Median					***4.3%***	***21%***				***13%***		***18%***
Regulated Utilities Mean					***4.5%***	***16%***				***7%***		***12%***
Regulated Utilities Median					***4.7%***	***14%***				***8%***		***12%***

Source: Goldman Sachs Research estimates.

As investors begin to gain visibility on the improving power fundamentals in 2010, we believe multiples will expand for Regulated Utilities and the regulated segments within Diversified Utilities. We utilize a dual approach for valuing Regulated Utilities, applying a 50% weighting to our dividend discount model analysis (assuming a 9% cost of equity and a 2.5% terminal growth rate) and a 50% weighting to P/E multiples on projected longer-term 2012 earnings power. We raise our baseline P/E multiple on 2012 from 9.0X to 10.0X for Small & Mid Cap Regulated Utilities and 10.5X for large cap Regulated Utilities.

- **We reiterate our BUY rating on large-cap American Electric Power (AEP), our favorite large-cap regulated name, while affirming our Conviction Sell rating on Con Edison (ED).** AEP trades at a 16%-18% discount on projected 2010-2012 earnings power and provides an attractive dividend yield. We maintain our Conviction Sell rating on Con Edison given (1) relative valuation, (2) a projected $400mm equity issuance, which is at the high end of management guidance, and which we believe is imminent, and (3) unimpressive earnings growth.

We reiterate our Buy rating on Great Plains Energy (GXP), but remove it from the Conviction Buy list, and downgrade Portland General Electric (POR) from Buy to Neutral. We believe GXP trades at a substantial discount to peers on LT normalized estimates despite its top quartile earnings growth trajectory. We downgrade POR because we remain (1) below consensus estimates on 2010, and (2) see a better a better opportunity in CL Buy-rated GXP.

Primary catalysts and key risks

Catalysts:

In our view, a series of events, including various regulatory proceedings, a major industry conference and 3Q2009 reporting season will drive share prices in the near-term.

- **A number of rate cases and regulatory proceedings in the next 90-120 days are key to monitor:** Multiple companies within our universe – both among Regulated and Diversified Utilities – currently face key decision dates or interim recommendations on requests for revenue increases in rate case proceedings. Large cap names such as Progress Energy (Florida), Duke Energy (Carolinas) and Ameren (Missouri) will receive PSC staff recommendations or final orders in key rate cases that impact 2010.

- **A major industry conference – the EEI conference – in November will provide greater insight into 2010-2011 outlooks.** We expect many Regulated and Diversified Utilities in our universe to introduce guidance at the Edison Electric Institute's (EEI) Conference in early November. Given our 2010 forecasts, we anticipate guidance ranges for most companies reporting to be within the range of consensus expectations, with only a handful of disappointments or surprises.

- **Third quarter earnings presents a risk, although with EEI approaching, investors likely will focus more on 2010-2011:** While we are positioned below consensus into the 3Q2009 earnings season, our conversations with investors suggest the buy-side is ahead of sell-side estimates in anticipating that weak weather and commodity pricing will weigh on the quarter. We believe investors are more likely to be focused on long-term earnings potential and growth, and should react favorably to management commentary on (1) lower-than-expected equity financing needs in 2010, and (2) stabilizing demand fundamentals.

Exhibit 37: We are below consensus on Q3 2009 after incorporating new gas and demand forecasts, however we are increasingly confident investors will look through the quarter

	EPS GS FY 2009 Q3	EPS Cons FY 2009 Q3	% Dif.
NVE	$0.59	$0.74	-19 6%
NST	$0.80	$0.83	-2.6%
PGN	$1.11	$1.18	-5.5%
DUK	$0.36	$0.40	-8.3%
AEP	$0.80	$0.86	-6.3%
POR	$0.27	$0.27	1.3%
NU	$0.32	$0.38	-16 9%
PCG	$0.91	$0.92	-1.4%
CNL	$0.75	$0.76	-1.6%
SCG	$0.83	$0.79	4.5%
WEC	$0.49	$0.57	-14 6%
EE	$0.52	$0.58	-10 6%
GXP	$0.68	$0.78	-12.4%
WR	$0.81	$0.91	-10 6%
Average			**-7.5%**
AEE	$0.89	$1.00	-11 0%
EIX	$1.12	$1.03	8.7%
EXC	$0.92	$0.98	-6.0%
SRE	$1.17	$1.21	-2.7%
ETR	$2.58	$2.55	1.1%
Average			**-2.0%**

	EBITDA GS FY 2009 Q3	EBITDA Cons FY 2009 Q3	% Dif.
NRG	$699	$848	-17 5%
ORA	$38	$40	-5.7%
RRI	$133	$90	47 3%
Average			**8.0%**

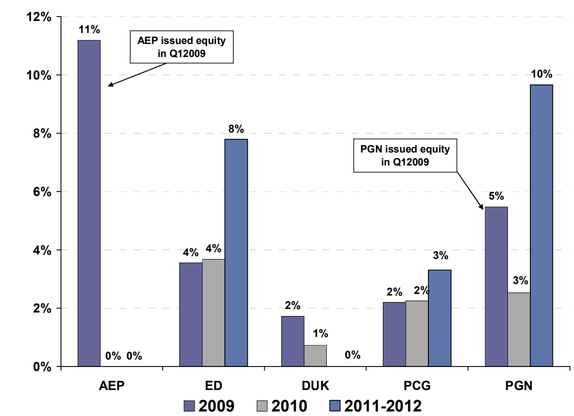
Source: Goldman Sachs Research, Quantum.

Risks:

Primary risks for utilities and power generators include (1) lower than expected power demand or power pricing, (2) increased environmental spending, and (3) higher than forecast financing needs.

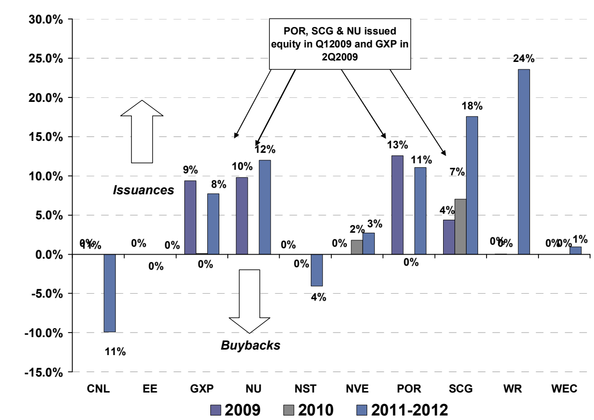
- **Demand risk –** Lower-than-expected electricity demand could decrease earnings for regulated segments and weaken overall commodity prices, negatively impacting IPPs and Diversified Utilities.
- **Environmental capital risk –** Increased requirements for pollution controls to reduce SOx, NOx or mercury emissions could drive higher spending or litigation risk for companies with coal fired generation.
- **Financing risk –** Unlike when entering 2009, where we forecast a sizable level of equity issuances for 1H2009, we do not see a broader "wave" of equity issuances in 2010, primarily due to company efforts to reduce spending levels. Higher than expected equity financing needs or rising cost of debt would negatively impact utility shares.

Exhibit 38: Among the large cap Regulated Utilities, ED has significant equity financing needs over 2009/2010
Net equity issuances among large cap regulated utilities as a percentage of market capitalization



Source: Goldman Sachs Research estimates.

Exhibit 39: Among the mid/small cap regulated utilities, there are few with significant equity needs
Net equity issuances among small/mid cap regulated utilities as a percentage of market capitalization



Source: Goldman Sachs Research estimates.

ATTACHMENT E - 24

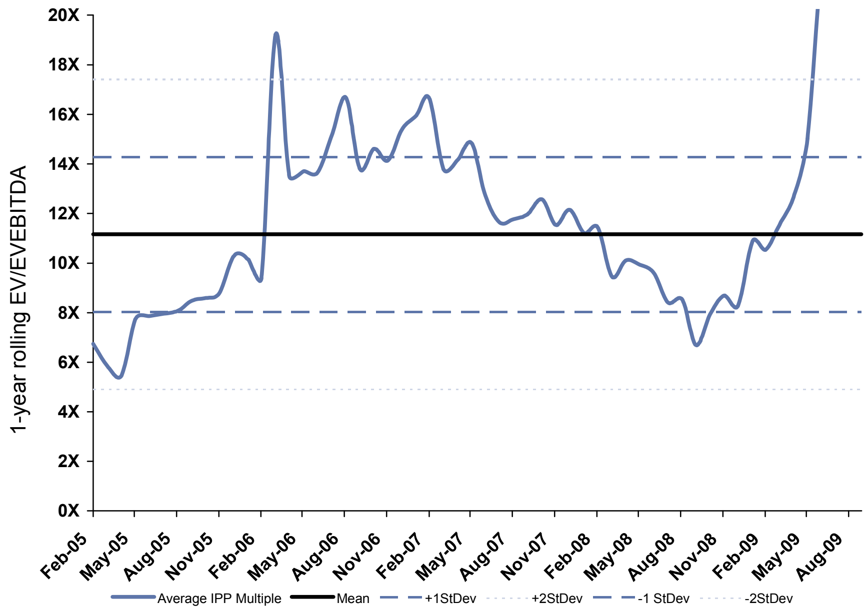
Appendices

Appendix A: Sum of the parts valuation for Sempra Energy

Sempra Energy Sum of the Parts Valuation				
	Segment Earnings or Equiv.	**Multiple / Value Applied**	**Metric Desc.**	**Per Share Value**
California Utilities				
SDG&E 2012E EPS	$2.01			
SoCalGas 2012E EPS	$1.11			
Total	**$3.13**	**10.5x**	**(P/E)**	**$33**
Generation				
2011/2012 EBITDA	274	7.0x	(EV/EBITDA)	
Implied EV	$1,921			
Debt	$0			
Equity Value	**$1,921**			**$8**
Pipelines & Storage				
2012 EBITDA Forecast	$549	6.5x	(EV/EBITDA)	
Implied EV	$3,569			
Equity Value	**$3,569**			**$14**
LNG				
Cameron and Energia Costa Azul			(DCF)	**$11**
Commodities				
Book Value, SRE Por ion	$1,600	1.0x	(P/B)	**$6**
Parent/Other				
Net Debt	$3,179			**($13)**
Total SoP Value				**$59**

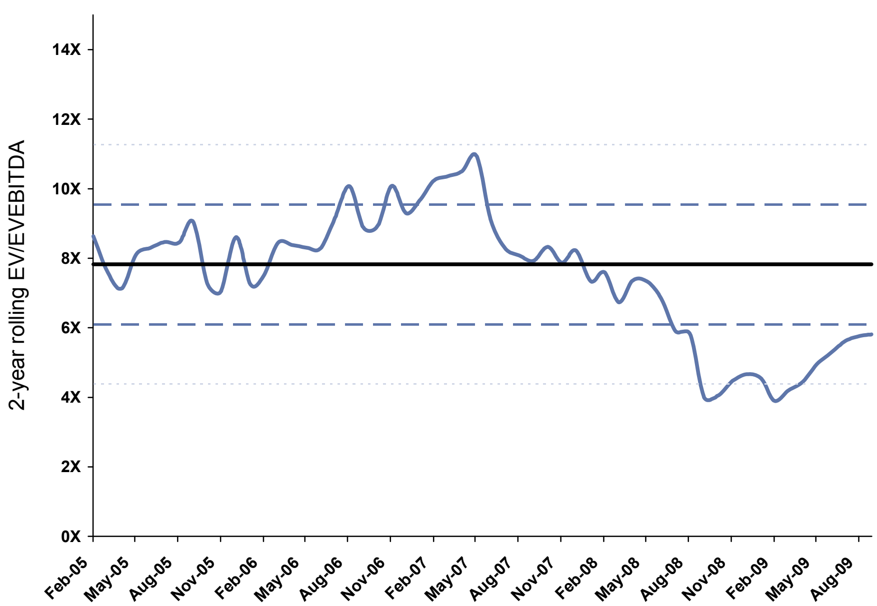
Source: Goldman Sachs Research estimates.

Appendix B: One year forward EV/EBITDA multiples are extremely volatile
1 yr forward EV/EBITDA multiples of base-load IPPs (NRG, RRI, and MIR)



Source: Goldman Sachs Research Estimates, Factset.

Appendix C: Two year forward EV/EBITDA multiples remain one standard deviation below mean
2 yr forward EV/EBITDA multiples of base-load IPPs (NRG, RRI, and MIR)



Source: Goldman Sachs Research Estimates, Factset.

Appendix D: Old versus new EPS and EBITDA estimates

EPS Revisions		2009			2010			2011			2012		
	Ticker	Old	New	%	Old	New	%	Old	New	%	Old	New	%
Large Cap Regulated Utilities													
American Elec Power	AEP	$2.85	$2.70	-5%	$3.09	$2.99	-3%	$3.39	$3 33	-2%	$3.47	$3.45	-1%
Duke Energy	DUK	$1.19	$1.11	-7%	$1.17	$1.17	0%	$1.32	$1 30	-2%	$1.34	$1.34	0%
Consolidated Edison	ED	$3.03	$2.99	-1%	$3.22	$3.21	0%	$3.31	$3 31	0%	$3.45	$3.45	0%
PG&E	PCG	$3.08	$3.08	0%	$3.45	$3.45	0%	$3.81	$3 81	0%	$4.02	$4.02	0%
Progress Energy	PGN	$2.92	$2.88	-1%	$3.05	$2.99	-2%	$3.31	$3 32	0%	$3.46	$3.55	3%
Large Cap Average				-3%			-1%			-1%			0%
Mid & Small Cap Regulated Utilities													
Cleco	CNL	$1.68	$1.64	-2%	$2.14	$2.14	0%	$2.29	$2 27	-1%	$2.38	$2.39	0%
El Paso Electric	EE	$1.40	$1.34	-4%	$1.34	$1.28	-4%	$1.52	$1.47	-3%	$2.10	$2.10	0%
Great Plains Energy	GXP	$1.24	$1.17	-6%	$1.56	$1.54	-1%	$2.01	$2 01	0%	$2.13	$2.13	0%
NSTAR	NST	$2.32	$2.33	1%	$2.25	$2.29	2%	$2.49	$2 50	1%	$2.53	$2.55	1%
Northeast Utilities	NU	$1.76	$1.68	-4%	$1.89	$1.85	-2%	$2.02	$2 00	-1%	$2.52	$2.51	-1%
Portland General Electric	POR	$1.43	$1.45	1%	$1.66	$1.63	-2%	$2.21	$2 21	0%	$2.20	$2.20	0%
SCANA Corporation	SCG	$2.85	$2.85	0%	$3 07	$2.98	-3%	$3.35	$3 35	0%	$3.82	$3.80	-1%
NV Energy	NVE	$0.80	$0.69	-14%	$1 03	$0.94	-9%	$1.24	$1.12	-10%	$1.42	$1.41	0%
Wisconsin Energy	WEC	$3.14	$3.05	-3%	$3 98	$4.01	1%	$4.55	$4.13	-9%	$4.60	$4.63	1%
Westar Energy	WR	$1.75	$1.45	-17%	$1 80	$1.64	-9%	$1.79	$1 57	-13%	$2.36	$2.18	-8%
Mid & Small Cap Average				-5%			-3%			-4%			-1%
Regulated Average				**-4%**			**-2%**			**-3%**			**0%**
Diversified Utilities													
Ameren	AEE	$2.35	$2.21	-6%	$2.23	$2.12	-5%	$2.65	$2 50	-5%	$2.72	$2.60	-4%
Allegheny Energy	AYE	$2.15	$2.15	0%	$2.52	$2.47	-2%	$3.78	$3 57	-6%	$2.64	$2.42	-8%
Edison International	EIX	$2.97	$2.92	-2%	$3.57	$3.56	0%	$3.91	$3 84	-2%	$3.45	$3.33	-3%
Entergy	ETR	$6.56	$6.50	-1%	$6.82	$6.67	-2%	$8.07	$7 95	-1%	$8.35	$8.21	-2%
Exelon	EXC	$4.03	$4.02	0%	$3.62	$3.58	-1%	$4.11	$4.11	0%	$3.10	$3.04	-2%
Sempra Energy	SRE	$4.48	$4.46	0%	$4.95	$4.93	0%	$5.54	$5 55	0%	$5.60	$5.61	0%
Average				-2%			-2%			-2%			-3%
Independent Power Producers (IPPs)													
NRG Energy	NRG	$1.89	$1.86	-2%	$2.34	$2.34	0%	$2.31	$2 25	-3%	$2.11	$2.05	-3%
Ormat Technologies	ORA	$1.29	$1.23	-4%	$1.56	$1.27	-18%	$1.49	$1 25	-16%	$1.77	$1.35	-24%
RRI Energy	RRI	($0.84)	($0.77)	9%	$0.10	$0.19	103%	$0.53	$0 64	21%	$0.05	$0.21	NA
Average				1%			28%			1%			-13%

EBITDA Revisions		2009			2010			2011			2012		
IPPs	Ticker	Old	New	%	Old	New	%	Old	New	%	Old	New	%
NRG Energy	NRG	$2,462	$2,448	-1%	$2,620	$2,620	0%	$2,534	$2,513	-1%	$2,377	$2,355	-1%
Ormat Technologies	ORA	$151	$148	-2%	$197	$180	-9%	$263	$248	-6%	$297	$272	-8%
RRI Energy	RRI	$98	$141	44%	$513	$567	10%	$604	$664	10%	$386	$455	18%
Average				14%			1%			1%			3%

Source: Goldman Sachs Research Estimates, Factset; EBITDA estimates are Adjusted EBITDA, not GAAP EBITDA

Appendix E: Old versus new price targets

	Ticker	Old Price Target	New Price Target
Large Cap Regulated			
American Elec Power	AEP	$34	$37
Duke Energy	DUK	$14	$15
Consolidated Edison	ED	$35	$38
PG&E	PCG	$40	$43
Progress Energy	PGN	$36	$40
Small / Mid Cap Regulated			
Cleco	CNL	$24	$25
El Paso Electric	EE	$19	$21
Great Plains Energy	GXP	$21	$22
Northeast Utilities	NU	$25	$26
NSTAR	NST	$27	$29
NV Energy	NVE	$13	$14
Portland General Electric	POR	$22	$23
SCANA Corporation	SCG	$38	$40
Westar Energy	WR	$23	$23
Wisconsin Energy	WEC	$45	$48
Diversified Utilities			
Ameren	AEE	$23	$25
Allegheny Energy	AYE	$30	$31
Edison International	EIX	$33	$39
Entergy	ETR	$93	$101
Exelon	EXC	$60	$62
Sempra Energy	SRE	$54	$59
IPPs			
NRG Energy	NRG	$32	$37
Ormat Technologies	ORA	$43	$41
RRI Energy	RRI	$6	$9

Source: Goldman Sachs Research estimates, Factset.

Appendix F: National and regional weather-adjusted demand – YoY weather a headwind in 3Q09, but benefit in 4Q09/1Q10

Demand Forecasts		3Q2009	4Q2009	1Q2010	2Q2010	3Q2010	4Q2010	2010	2011	2012
National Weather Adjusted		**-2.9%**	**-2.2%**	**-0.6%**	**0.0%**	**0.8%**	**1.3%**	**0.4%**	**1.5%**	**1.7%**
National Non-Weather Adjusted		**-2.7%**	**-2.4%**	**-0.9%**	**0.3%**	**0.8%**	**1.3%**	**0.4%**	**1.5%**	**1.7%**
Mountain	NVE	-4.7%	-1.8%	0.5%	1.3%	0.8%	1.3%	1.0%	1.5%	1.7%
Pacific	POR	-1.9%	-2.4%	-0.5%	1.6%	0.8%	1.3%	0.8%	1.5%	1.7%
Middle Atlantic	EXC*	-3.0%	-2.3%	-1.4%	1.7%	0.8%	1.3%	0.6%	1.5%	1.7%
E. N. Central	EXC* AEP* DUK* WEC	-4.9%	-3.3%	-1.3%	1.2%	0.8%	1.3%	0.5%	1.5%	1.7%
W. N. Central	AEE GXP WR	-4.3%	-2.6%	-0.9%	0.0%	0.8%	1.3%	0.3%	1.5%	1.7%
New England	NST NU	-3.2%	-2.5%	-2.2%	1.2%	0.8%	1.3%	0.3%	1.5%	1.7%
East South Central	ETR*	-3.4%	-2.3%	0.71%	-3.01%	0.85%	1.28%	0.0%	1.5%	1.7%
South Atlantic	DUK* PGN SCG	-2.2%	-1.4%	-0.3%	-2.1%	0.8%	1.3%	-0.1%	1.5%	1.7%
West South Central	ETR* AEP* CNL EE	-0.2%	-1.4%	0.4%	-3.2%	0.9%	1.3%	-0.1%	1.5%	1.7%

* OPERATES IN MULTIPLE EIA JURISDICTIONS

NOTE - ASSUME HIGHER LONG-TERM GROWTH RATES FOR EE AND NVE GIVEN CUSTOMER GROWTH IN JURISDICTIONS

Source: GS Research Estimates, Factset.

Appendix G: AEP and GXP screen as Buys, while NST and ED screen as Sells

Target price and EPS summary

Target Price and EPS Summary

			Close	Price	Tot Ret	EPS				P/E				Dividend
	Ticker	Rating	09/28/09	Target	to Target	2009	2010	2011	2012	2009	2010	2011	2012	Yield
Regulated Utilities														
Large-Cap														
American Elec Power	**AEP**	**Buy**	$31.13	$37	**24%**	$2.70	$2.99	$3.33	$3.45	11.5x	10.4x	9.3x	9.0x	5.3%
Duke Energy	**DUK**	**Neutral**	$15.93	$15	**0%**	$1.11	$1.17	$1.30	$1.34	14.4x	13.7x	12.3x	11.9x	5.8%
Consolidated Edison	**ED**	**Sell**	$41.40	$38	**-3%**	$2.99	$3.21	$3.31	$3.45	13.8x	12.9x	12.5x	12.0x	5.7%
PG&E	**PCG**	**Neutral**	$40.91	$43	**9%**	$3.08	$3.45	$3.81	$4.02	13.3x	11.8x	10.7x	10.2x	4.1%
Progress Energy	**PGN**	**Neutral**	$39.60	$40	**7%**	$2.88	$2.99	$3.32	$3.55	13.7x	13.2x	11.9x	11.2x	6.3%
Large-Cap Mean					**8%**					13.3x	12.4x	11.4x	10.8x	5.4%
Large-Cap Median					**7%**					13.7x	12.9x	11.9x	11.2x	5.7%
Mid & Small-Cap														
Cleco	**CNL**	**Neutral**	$25.10	$25	**3%**	$1.64	$2.14	$2.27	$2.39	15.3x	11.7x	11.0x	10.5x	3.6%
El Paso Electric	**EE**	**Neutral**	$17.84	$21	**18%**	$1.34	$1.28	$1.47	$2.10	13.3x	13.9x	12.1x	8.5x	0.0%
Great Plains Energy	**GXP**	**Buy**	$18.17	$22	**26%**	$1.17	$1.54	$2.01	$2.13	15.5x	11.8x	9.0x	8.5x	4.6%
NSTAR	**NST**	**Sell**	$32.09	$29	**-5%**	$2.33	$2.29	$2.50	$2.55	13.7x	14.0x	12.8x	12.6x	4.7%
Northeast Utilities	**NU**	**Neutral**	$23.99	$26	**12%**	$1.68	$1.85	$2.00	$2.51	14.2x	13.0x	12.0x	9.6x	4.0%
NV Energy	**NVE**	**Neutral**	$11.59	$14	**24%**	$0.69	$0.94	$1.12	$1.41	16.8x	12.3x	10.3x	8.2x	3.5%
Portland General Electric	**POR**	**Neutral**	$20.07	$23	**20%**	$1.45	$1.63	$2.21	$2.20	13.9x	12.3x	9.1x	9.1x	5.1%
SCANA Corporation	**SCG**	**Neutral**	$35.30	$40	**19%**	$2.85	$2.98	$3.35	$3.80	12.4x	11.8x	10.5x	9.3x	5.3%
Wisconsin Energy	**WEC**	**Neutral**	$45.11	$48	**9%**	$3.05	$4.01	$4.13	$4.63	14.8x	11.2x	10.9x	9.7x	3.0%
Westar Energy	**WR**	**Neutral**	$19.60	$23	**23%**	$1.45	$1.64	$1.57	$2.18	13.5x	12.0x	12.5x	9.0x	6.0%
Small / Mid Cap Mean					**15%**					14.3x	12.4x	11.0x	9.5x	4.0%
Small / Mid Cap Median					**18%**					13.8x	12.0x	11.0x	9.2x	4.3%
Regulated Utilities Mean					**12%**					14.0x	12.4x	11.1x	9.9x	4.5%
Regulated Utilities Median					**12%**					13.8x	12.3x	11.0x	9.6x	4.7%

Note: ED is on the Conviction List

Source: Goldman Sachs Research Estimates, Factset.

Appendix H: We reiterate Buy ratings on ETR and EXC, while upgrading RRI

target price and eps summary

P/E Multiples Summary														
			Close	Price	Tot Ret	Estimates				P/E Multiples			
	Ticker	Rating	09/28/09	Target	to Target	2009	2010	2011	2012	2009	2010	2011	2012
Natural Gas Price Forecast ($/MMBtu)						**$4.25**	**$5.50**	**$7.00**	**$6.50**				
Diversified Utilities													
Ameren	**AEE**	**Sell**	**$25.74**	**$25**	**3%**	$2 21	$2.12	$2 50	$2.60	11.7x	12 2x	10.3x	9.9x
Allegheny Energy	**AYE**	**Neutral**	**$26.96**	**$31**	**17%**	$2.15	$2.47	$3 57	$2.42	12 5x	10 9x	7.6x	11.1x
Edison International	**EIX**	**Neutral**	**$34.01**	**$39**	**19%**	$2 92	$3 56	$3 84	$3.33	11 6x	9 6x	8.9x	10.2x
Entergy	**ETR**	**Buy**	**$79.64**	**$101**	**31%**	$6 50	$6 67	$7 95	$8.21	12 3x	11 9x	10.0x	9.7x
Exelon	**EXC**	**Buy**	**$50.12**	**$62**	**28%**	$4 02	$3 58	$4.11	$3.04	12 5x	14 0x	12.2x	16.5x
Sempra Energy	**SRE**	**Neutral**	**$50.17**	**$59**	**20%**	$4.46	$4.93	$5 55	$5.61	11 2x	10.2x	9.0x	8.9x
		Diversified Utilities Mean			***20%***					**12.0x**	**11.5x**	**9.7x**	**11.1x**
		Diversified Utilities Median			***19%***					**12.0x**	**11.4x**	**9.5x**	**10.0x**
IPP's													
NRG Energy	**NRG**	**Buy**	**$27.20**	**$37**	**36%**	$1 86	$2 34	$2 25	$2.05	14.7x	11 6x	12.1x	13.3x
RRI Energy	**RRI**	**Buy**	**$6.98**	**$9**	**29%**	($0.77)	$0.19	$0 64	$0.21	NA	35 9x	10.9x	33.1x
		Special Situation and IPP Median			**22%**					**24.0x**	**26.6x**	**18.6x**	**25.6x**
		Special Situation and IPP Mean			**29%**					**24.0x**	**32.2x**	**12.1x**	**30.5x**

Note: ETR and RRI are on the Conviction List
Source: Goldman Sachs Research estimates, Factset.

Appendix I: Action Off: Americas Buy List – Portland General

Since being added to Americas Buy List on August 17, 2009 POR is up 5.7% versus the XLU up 2.8% and the S&P500 up 8.5%. In the last 12 months, POR is down 17.5% versus the S&P500 down 12.4%.

Company	Ticker	Primary analyst	Price currency	Price as of 09/28/09	Price performance since 08/17/09	3 month price performance	6 month price performance	12 month price performance
Americas Power & Utilities Peer Group								
Portland General Electric Co.	**POR**	**Michael Lapides**	**$**	**20.09**	**5.7%**	**2.4%**	**16.9%**	**-17.5%**
AGL Resources Inc.	AGL	Theodore Durbin	$	35.08	3.3%	11.2%	30.5%	8.6%
Allegheny Energy, Inc.	AYE	Michael Lapides	$	27.01	9.3%	4.0%	15.4%	-29.4%
Ameren Corp.	AEE	Michael Lapides	$	25.74	-1.3%	4.9%	10.4%	-35.9%
American Electric Power	AEP	Michael Lapides	$	31.18	0.9%	9.0%	18.7%	-16.1%
Atmos Energy Corp.	ATO	Theodore Durbin	$	28.31	2.6%	12.8%	19.9%	3.1%
Cleco Corp.	CNL	Michael Lapides	$	25.14	3.8%	15.3%	12.7%	-1.5%
Consolidated Edison, Inc.	ED	Michael Lapides	$	41.41	5.2%	11.8%	7.9%	-5.2%
Duke Energy Corporation	DUK	Michael Lapides	$	15.94	4.4%	10.6%	11.5%	-11.6%
Edison International	EIX	Michael Lapides	$	34.07	7.5%	8.9%	17.7%	-15.0%
El Paso Electric Co.	EE	Michael Lapides	$	17.84	13.3%	25.5%	29.7%	-16.8%
Entergy Corp.	ETR	Michael Lapides	$	79.80	2.1%	4.4%	17.4%	-11.9%
Exelon Corp.	EXC	Michael Lapides	$	50.22	1.9%	-0.9%	9.8%	-25.2%
Great Plains Energy Inc.	GXP	Michael Lapides	$	18.17	4.9%	17.8%	32.1%	-19.1%
Northeast Utilities	NU	Michael Lapides	$	24.02	1.7%	8.6%	10.7%	-7.3%
NRG Energy Inc.	NRG	Michael Lapides	$	27.15	-2.0%	14.1%	54.3%	2.8%
NSTAR	NST	Michael Lapides	$	32.11	1.0%	1.7%	2.3%	-6.3%
NV Energy, Inc.	NVE	Michael Lapides	$	11.60	-1.7%	7.7%	21.0%	14.7%
Ormat Technologies, Inc.	ORA	Michael Lapides	$	41.18	12.4%	4.5%	48.3%	-0.9%
PG&E Corporation	PCG	Michael Lapides	$	40.96	2.5%	7.9%	5.6%	6.8%
Progress Energy Inc.	PGN	Michael Lapides	$	39.66	1.3%	5.0%	10.0%	-9.6%
RRI Energy, Inc.	RRI	Michael Lapides	$	7.00	26.6%	54.2%	105.9%	-42.7%
SCANA Corp.	SCG	Michael Lapides	$	35.32	5.2%	10.0%	14.2%	-13.0%
Sempra Energy	SRE	Michael Lapides	$	50.24	-0.2%	0.9%	12.2%	-5.5%
Westar Energy Inc.	WR	Michael Lapides	$	19.62	-3.3%	6.5%	12.1%	-17.7%
WGL Holdings, Inc.	WGL	Theodore Durbin	$	33.60	1.7%	4.3%	1.2%	0.9%
Wisconsin Energy Corp.	WEC	Michael Lapides	$	45.16	0.9%	11.0%	10.5%	-1.2%
S&P 500				**1062.98**	**8.5%**	**15.7%**	**30.3%**	**-12.4%**
Index performance in stock price currency				**1062.98**	**8.5%**	**15.7%**	**30.3%**	**-12.4%**

Note: Prices as of most recent available close, which could vary from the price date indicated above
This table shows movement in absolute share price and not total shareholder return. Results presented should not and cannot be viewed as an indicator of future performance.

Source: Factset, Quantum database.

Appendix J: Action Off: Americas Conviction Buy List – Great Plains Energy

Since being added to Americas Conviction Buy List on August 17, 2009 GXP is up 4.9% versus the XLU up 2.8% and the S&P500 up 8.5%. In the last twelve months, GXP is down 19.1% versus the S&P500 down 12.4%.

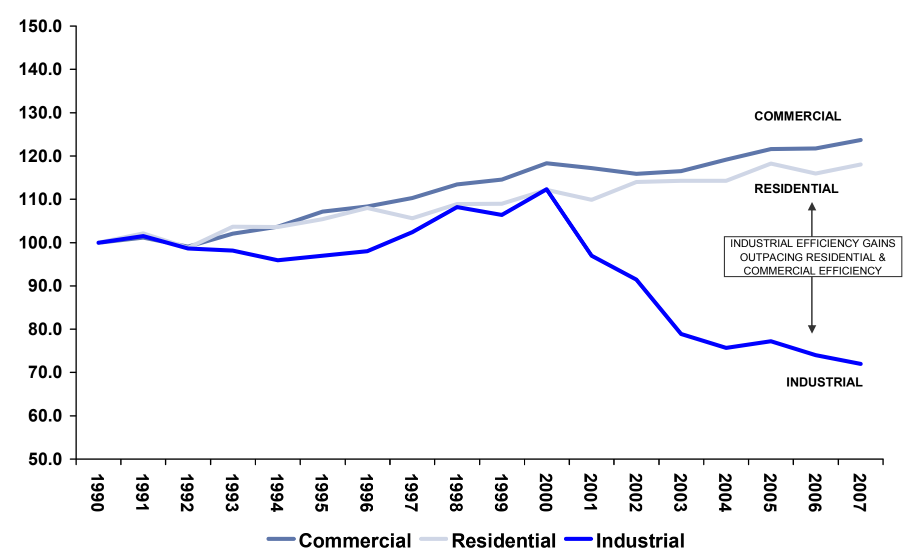
Company	Ticker	Primary analyst	Price currency	Price as of 09/28/09	Price performance since 08/17/09	3 month price performance	6 month price performance	12 month price performance
Americas Power & Utilities Peer Group								
Great Plains Energy Inc.	**GXP**	**Michael Lapides**	**$**	**18.17**	**4.9%**	**17.8%**	**32.1%**	**-19.1%**
AGL Resources Inc.	AGL	Theodore Durbin	$	35.08	3.3%	11.2%	30.5%	8.6%
Allegheny Energy, Inc.	AYE	Michael Lapides	$	27.01	9.3%	4.0%	15.4%	-29.4%
Ameren Corp.	AEE	Michael Lapides	$	25.74	-1.3%	4.9%	10.4%	-35.9%
American Electric Power	AEP	Michael Lapides	$	31.18	0.9%	9.0%	18.7%	-16.1%
Atmos Energy Corp.	ATO	Theodore Durbin	$	28.31	2.6%	12.8%	19.9%	3.1%
Cleco Corp.	CNL	Michael Lapides	$	25.14	3.8%	15.3%	12.7%	-1.5%
Consolidated Edison, Inc.	ED	Michael Lapides	$	41.41	5.2%	11.8%	7.9%	-5.2%
Duke Energy Corporation	DUK	Michael Lapides	$	15.94	4.4%	10.6%	11.5%	-11.6%
Edison International	EIX	Michael Lapides	$	34.07	7.5%	8.9%	17.7%	-15.0%
El Paso Electric Co.	EE	Michael Lapides	$	17.84	13.3%	25.5%	29.7%	-16.8%
Entergy Corp.	ETR	Michael Lapides	$	79.80	2.1%	4.4%	17.4%	-11.9%
Exelon Corp.	EXC	Michael Lapides	$	50.22	1.9%	-0.9%	9.8%	-25.2%
Northeast Utilities	NU	Michael Lapides	$	24.02	1.7%	8.6%	10.7%	-7.3%
NRG Energy Inc.	NRG	Michael Lapides	$	27.15	-2.0%	14.1%	54.3%	2.8%
NSTAR	NST	Michael Lapides	$	32.11	1.0%	1.7%	2.3%	-6.3%
NV Energy, Inc.	NVE	Michael Lapides	$	11.60	-1.7%	7.7%	21.0%	14.7%
Ormat Technologies, Inc.	ORA	Michael Lapides	$	41.18	12.4%	4.5%	48.3%	-0.9%
PG&E Corporation	PCG	Michael Lapides	$	40.96	2.5%	7.9%	5.6%	6.8%
Portland General Electric Co.	POR	Michael Lapides	$	20.09	5.7%	2.4%	16.9%	-17.5%
Progress Energy Inc.	PGN	Michael Lapides	$	39.66	1.3%	5.0%	10.0%	-9.6%
RRI Energy, Inc.	RRI	Michael Lapides	$	7.00	26.6%	54.2%	105.9%	-42.7%
SCANA Corp.	SCG	Michael Lapides	$	35.32	5.2%	10.0%	14.2%	-13.0%
Sempra Energy	SRE	Michael Lapides	$	50.24	-0.2%	0.9%	12.2%	-5.5%
Westar Energy Inc.	WR	Michael Lapides	$	19.62	-3.3%	6.5%	12.1%	-17.7%
WGL Holdings, Inc.	WGL	Theodore Durbin	$	33.60	1.7%	4.3%	1.2%	0.9%
Wisconsin Energy Corp.	WEC	Michael Lapides	$	45.16	0.9%	11.0%	10.5%	-1.2%
S&P 500				**1062.98**	**8.5%**	**15.7%**	**30.3%**	**-12.4%**
Index performance in stock price currency				**1062.98**	**8.5%**	**15.7%**	**30.3%**	**-12.4%**

Note: Prices as of most recent available close, which could vary from the price date indicated above
This table shows movement in absolute share price and not total shareholder return. Results presented should not and cannot be viewed as an indicator of future performance.

Source: Factset, Quantum database.

Appendix K: We observed significant efficiency gains by the industrial customer class
electricity usage by customer, indexed to 1990 levels

Energy Efficiency By Customer Class: MWh per Customer Indexed to 1990 Levels



Source: Goldman Sachs Research estimates, Factset.

Appendix L: Valuation Methodology and Risks

Company	Ticker	Method.	Risks to Our Thesis
Diversified Utilities			
Ameren	AEE	SoP	Lower-than-expected environmental spending on its Illinois coal fleet, worse-than-expected outcome at the next Illinois power auction; Rate case risk
Allegheny Energy	AYE	SoP	LT Commodity prices as non-regulated business contributes bulk of earnings; higher-than-expected environmental spending at the coal plants
Edison International	EIX	SoP	Environmental capex potentially significant; Commodity risk due to minimal hedging
Entergy	ETR	SoP	LT Commodity prices put non-regulated earnings at risk; Hurricane cost recovery
Exelon	EXC	SoP	LT Commodity prices as company becomes increasingly dependent on nonregulated business; Regulatory risk in Illinois
Sempra Energy	SRE	SoP	Lower-than-expected earnings from trading business; Commodity price risk; SoCal utilities rate case risk
Regulated Utilities			
Large-Cap Regulated Utilities			
American Elec Power	AEP	DDM & P/E	Cost recovery of capital invested in major projects; Greater-than-expected wholesale margins and environmental capex; Above-average debt levels
Duke Energy	DUK	DDM & P/E	Rate case risk at DUK's regulated Franchise Electric business
Consolidated Edison	ED	DDM & P/E	Above-average growth; Equity issuances below guidance
PG&E	PCG	DDM & P/E	Delays in rate base growth
Progress Energy	PGN	DDM & P/E	Lower-than-expected rate base growth, regulatory proceedings, greater-than-anticipated financing requirements
Mid and Small-Cap Regulated Utilities			
Cleco	CNL	DDM & P/E	Rate case exposure in Louisiana after Rodemacher completion; worse-than-anticipated cash flows from non-regulated plants
El Paso Electric	EE	DDM & P/E	Operational risk at Palo Verde may lead to less FCF and lower-than-expected equity repurchases
Great Plains Energy	GXP	DDM & P/E	Risks to RoE in KS/MD; Greater-than-expected declines
Northeast Utilities	NU	DDM & P/E	Regulatory approval of transmission projects, construction risk, and general regulatory and rate case risk
NSTAR	NST	DDM & P/E	Higher-than-expected load growth, success in capturing incentive revenues, lower-than-expected O&M
NV Energy	NVE	DDM & P/E	Lower-than-expected rate base or load growth, long-term rate case risk
Portland General Electric	POR	DDM & P/E	Regulatory risk from the OPUC; long-term rate base growth that varies from our estimates
SCANA Corporation	SCG	DDM & P/E	Rate case risk, lower-than-expected gross margins, customer growth or market share at Scana Energy
Wisconsin Energy	WEC	DDM & P/E	Construction delays; Regulatory environment may become less friendly
Westar Energy	WR	DDM & P/E	Regulatory risk
Special Situation Utilities and IPPs			
NRG Energy	NRG	SoP	Delay/cost increases on planned construction; LT Commodity price risk; Lower-than-expected retail margins
Ormat Technologies	ORA	DCF	Elimination or reduction of Production Tax Credits; decreased capacity factors at existing plants; lower long-term commodity prices
RRI Energy	RRI	SoP	Lower L T commodity prices; Higher coal to gas switching; Higher than expected environmental capital spending

Source: Goldman Sachs Research.

Reg AC

I, Michael Lapides, hereby certify that all of the views expressed in this report accurately reflect my personal views about the subject company or companies and its or their securities. I also certify that no part of my compensation was, is or will be, directly or indirectly, related to the specific recommendations or views expressed in this report.

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Regulatory Research Associates
REGULATORY FOCUS

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MAJOR RATE CASE DECISIONS--CALENDAR 2010

The average return on equity (ROE) authorized electric utilities in 2010 approximated 10.3% compared to 10.5% in 2009. There were 59 electric ROE determinations in 2010, up substantially from 39 in 2009. The average ROE authorized gas utilities approximated 10.1% in 2010, compared to 10.2% in 2009. There were 37 gas cases that included an ROE determination in 2010, and 29 in 2009. Not included in these averages is a Sept. 16, 2010, New York Public Service Commission decision authorizing Consolidated Edison of New York's steam operations a 9.6% ROE. We note that this report utilizes the simple mean for the return averages.

After reaching a low in the early-2000's, the number of rate case decisions for energy companies has generally increased over the last several years. There were 126 electric and gas rate decisions in 2010, versus 95 in 2009, and only 32 back in 2001. Increased costs, including environmental compliance expenditures, the need for generation and delivery infrastructure upgrades and expansion, renewable generation mandates, and higher employee benefit costs argue for a continuation of the increased level of rate case activity over the next few years.

We note that electric industry restructuring in certain states has led to the unbundling of rates and retail competition for generation. Commissions in those states are now authorizing revenue requirement and return parameters for delivery operations only (which we footnote in our chronology beginning on page 5), thus complicating historical data comparability. We also note that while the heightened business risk associated with the sluggish economy may have increased corporate capital costs, higher average authorized ROEs did not materialize in 2010 or in 2009. In fact, average authorized ROEs have declined slightly over the last two years, and some state commissions have cited customer hardship as a significant factor influencing their equity return authorizations.

The table on page 2 shows the average ROE authorized in major electric and gas rate decisions annually since 1990, and by quarter since 2004, followed by the number of observations in each period. The tables on page 3 show the composite electric and gas industry data for all major cases summarized annually since 1997 and by quarter for the past eight quarters. The individual electric and gas cases decided in 2010 are listed on pages 5-9, with the decision date (generally the date on which the final order was issued) shown first, followed by the company name, the abbreviation for the state issuing the decision, the authorized rate of return (ROR), return on equity (ROE), and percentage of common equity in the adopted capital structure. Next we show the month and year in which the adopted test year ended, whether the commission utilized an average or a year-end rate base, and the amount of the permanent rate change authorized. The dollar amounts represent the permanent rate change ordered at the time decisions were rendered. Fuel adjustment clause rate changes are not reflected in this study. We note that the cases and averages included in this study may be slightly different from those in our online rate case history database, with any differences likely the result of this study's inclusion of ROE determinations that are rendered in cost-of-capital-only proceedings in California.

(Text continued on page 4.)

Average Equity Returns Authorized January 1990 - December 2010

		Electric Utilities		Gas Utilities	
Year	**Period**	**ROE %**	**(# Cases)**	**ROE %**	**(# Cases)**
1990	Full Year	12.70	(44)	12.67	(31)
1991	Full Year	12.55	(45)	12.46	(35)
1992	Full Year	12.09	(48)	12.01	(29)
1993	Full Year	11.41	(32)	11.35	(45)
1994	Full Year	11.34	(31)	11.35	(28)
1995	Full Year	11.55	(33)	11.43	(16)
1996	Full Year	11.39	(22)	11.19	(20)
1997	Full Year	11.40	(11)	11.29	(13)
1998	Full Year	11.66	(10)	11.51	(10)
1999	Full Year	10.77	(20)	10.66	(9)
2000	Full Year	11.43	(12)	11.39	(12)
2001	Full Year	11.09	(18)	10.95	(7)
2002	Full Year	11.16	(22)	11.03	(21)
2003	Full Year	10.97	(22)	10.99	(25)
	1st Quarter	11.00	(3)	11.10	(4)
	2nd Quarter	10.54	(6)	10.25	(2)
	3rd Quarter	10.33	(2)	10.37	(8)
	4th Quarter	10.91	(8)	10.66	(6)
2004	**Full Year**	**10.75**	(19)	**10.59**	(20)
	1st Quarter	10.51	(7)	10.65	(2)
	2nd Quarter	10.05	(7)	10.54	(5)
	3rd Quarter	10.84	(4)	10.47	(5)
	4th Quarter	10.75	(11)	10.40	(14)
2005	**Full Year**	**10.54**	(29)	**10.46**	(26)
	1st Quarter	10.38	(3)	10.63	(6)
	2nd Quarter	10.68	(6)	10.50	(2)
	3rd Quarter	10.06	(7)	10.45	(3)
	4th Quarter	10.39	(10)	10.14	(5)
2006	**Full Year**	**10.36**	(26)	**10.43**	(16)
	1st Quarter	10.27	(8)	10.44	(10)
	2nd Quarter	10.27	(11)	10.12	(4)
	3rd Quarter	10.02	(4)	10.03	(8)
	4th Quarter	10.56	(16)	10.27	(15)
2007	**Full Year**	**10.36**	(39)	**10.24**	(37)
	1st Quarter	10.45	(10)	10.38	(7)
	2nd Quarter	10.57	(8)	10.17	(3)
	3rd Quarter	10.47	(11)	10.49	(7)
	4th Quarter	10.33	(8)	10.34	(13)
2008	**Full Year**	**10.46**	(37)	**10.37**	(30)
	1st Quarter	10.29	(9)	10.24	(4)
	2nd Quarter	10.55	(10)	10.11	(8)
	3rd Quarter	10.46	(3)	9.88	(2)
	4th Quarter	10.54	(17)	10.27	(15)
2009	**Full Year**	**10.48**	(39)	**10.19**	(29)
	1st Quarter	10.66	(17)	10.24	(9)
	2nd Quarter	10.08	(14)	9.99	(11)
	3rd Quarter	10.26	(11)	9.93	(4)
	4th Quarter	10.30	(17)	10.09	(12)
2010	**Full Year**	**10.34**	(59)	**10.08**	(37)

Electric Utilities--Summary Table*

	Period	ROR %	(# Cases)	ROE %	(# Cases)	Eq. as % Cap. Struc.	(# Cases)	Amt. $ Mil.	(# Cases)
1997	Full Year	9.16	(12)	11.40	(11)	48.79	(11)	-553.3	(33)
1998	Full Year	9.44	(9)	11.66	(10)	46.14	(8)	-429.3	(31)
1999	Full Year	8.81	(18)	10.77	(20)	45.08	(17)	-1,683.8	(30)
2000	Full Year	9.20	(12)	11.43	(12)	48.85	(12)	-291.4	(34)
2001	Full Year	8.93	(15)	11.09	(18)	47.20	(13)	14.2	(21)
2002	Full Year	8.72	(20)	11.16	(22)	46.27	(19)	-475.4	(24)
2003	Full Year	8.86	(20)	10.97	(22)	49.41	(19)	313.8	(12)
2004	Full Year	8.44	(18)	10.75	(19)	46.84	(17)	1,091.5	(30)
2005	Full Year	8.30	(26)	10.54	(29)	46.73	(27)	1,373.7	(36)
2006	Full Year	8.24	(24)	10.36	(26)	48.67	(23)	1,465.0	(42)
2007	Full Year	8.22	(38)	10.36	(39)	48.01	(37)	1,401.9	(46)
2008	Full Year	8.25	(35)	10.46	(37)	48.41	(33)	2,899.4	(42)
	1st Quarter	8.19	(8)	10.29	(9)	48.52	(8)	857.0	(14)
	2nd Quarter	8.05	(9)	10.55	(10)	47.66	(9)	1,425.0	(17)
	3rd Quarter	8.48	(3)	10.46	(3)	47.20	(3)	317.1	(7)
	4th Quarter	8.30	(18)	10.54	(17)	49.41	(17)	1,593.2	(20)
2009	Full Year	8.23	(38)	10.48	(39)	48.61	(37)	4,192.3	(58)
	1st Quarter	7.95	(17)	10.66	(17)	48.36	(16)	2,010.0	(19)
	2nd Quarter	7.95	(15)	10.08	(14)	47.07	(13)	937.5	(19)
	3rd Quarter	8.16	(12)	10.26	(11)	49.52	(11)	730.6	(18)
	4th Quarter	7.95	(15)	10.30	(17)	49.00	(14)	1,889.6	(21)
2010	**Full Year**	**7.99**	**(59)**	**10.34**	**(59)**	**48.45**	**(54)**	**5,567.7**	**(77)**

Gas Utilities--Summary Table*

	Period	ROR %	(# Cases)	ROE %	(# Cases)	Eq. as % Cap. Struc.	(# Cases)	Amt. $ Mil.	(# Cases)
1997	Full Year	9.13	(13)	11.29	(13)	47.78	(11)	-82.5	(21)
1998	Full Year	9.46	(10)	11.51	(10)	49.50	(10)	93.9	(20)
1999	Full Year	8.86	(9)	10.66	(9)	49.06	(9)	51.0	(14)
2000	Full Year	9.33	(13)	11.39	(12)	48.59	(12)	135.9	(20)
2001	Full Year	8.51	(6)	10.95	(7)	43.96	(5)	114.0	(11)
2002	Full Year	8.80	(20)	11.03	(21)	48.29	(18)	303.6	(26)
2003	Full Year	8.75	(22)	10.99	(25)	49.93	(22)	260.1	(30)
2004	Full Year	8.34	(21)	10.59	(20)	45.90	(20)	303.5	(31)
2005	Full Year	8.25	(29)	10.46	(26)	48.66	(24)	458.4	(34)
2006	Full Year	8.51	(16)	10.43	(16)	47.43	(16)	444.0	(25)
2007	Full Year	8.12	(32)	10.24	(37)	48.37	(30)	813.4	(48)
2008	Full Year	8.48	(30)	10.37	(30)	50.47	(30)	884.8	(41)
	1st Quarter	8.11	(5)	10.24	(4)	44.97	(4)	167.6	(7)
	2nd Quarter	8.05	(7)	10.11	(8)	48.84	(7)	92.5	(8)
	3rd Quarter	8.30	(2)	9.88	(2)	51.00	(2)	19.2	(4)
	4th Quarter	8.19	(14)	10.27	(15)	49.35	(15)	195.7	(18)
2009	Full Year	8.15	(28)	10.19	(29)	48.72	(28)	475.0	(37)
	1st Quarter	8.20	(10)	10.24	(9)	50.27	(9)	177.3	(11)
	2nd Quarter	7.80	(11)	9.99	(11)	46.31	(11)	230.2	(12)
	3rd Quarter	8.13	(4)	9.93	(4)	49.00	(4)	290.5	(10)
	4th Quarter	7.84	(13)	10.09	(13)	49.11	(14)	118.7	(16)
2010	**Full Year**	**7.95**	**(38)**	**10.08**	**(37)**	**48.56**	**(38)**	**816.7**	**(49)**

* Number of observations in each period indicated in parentheses.

The table below tracks the average equity return authorized for all electric and gas rate cases combined, by year, for the last 21 years. As the table reveals, since 1990 the authorized ROEs have generally trended downward, reflecting the significant decline in interest rates that has occurred over this time frame. The combined average equity returns authorized for electric and gas utilities in each of the years 1990 through 2010, and the number of observations for each year are as follows:

1990	12.69%	(75)	2000	11.41%	(24)
1991	12.51	(80)	2001	11.05	(25)
1992	12.06	(77)	2002	11.10	(43)
1993	11.37	(77)	2003	10.98	(47)
1994	11.34	(59)	2004	10.67	(39)
1995	11.51	(49)	2005	10.50	(55)
1996	11.29	(42)	2006	10.39	(42)
1997	11.34	(24)	2007	10.30	(76)
1998	11.59	(20)	2008	10.42	(67)
1999	10.74	(29)	2009	10.36	(68)
			2010	10.24	(96)

Dennis Sperduto

ELECTRIC UTILITY DECISIONS

Date	Company (State)	ROR %	ROE %	Common Eq. as % Cap. Str.	Test Year & Rate Base	Amt. $ Mil.
1/11/10	Detroit Edison (MI)	7.02	11.00	39.48 *	6/10-A	217.4 (I)
1/12/10	Northern States Power (SD)	8.32	---	---	---	10.9 (B)
1/19/10	Interstate Power & Light (IA)	8.91	10.80	49.52	12/08-A	83.7 (I)
1/22/10	Portland General Electric (OR)	---	---	---	---	9.8 (B)
1/26/10	PacifiCorp (OR)	8.08	10.13	51.00	12/10-A	41.5 (B)
1/27/10	Westar Energy (KS)	8.49	10.40	50.13	---	8.5 (B)
1/27/10	Kansas Gas & Elec. (KS)	8.49	10.40	50.13	---	8.5 (B)
1/27/10	Duke Energy Carolinas (SC)	8.41	10.70 (1)	53.00	12/08-YE	74.1 (B)
2/9/10	Narragansett Electric (RI)	7.20	9.80	42.75 (Hy)	12/08-A	23.5 (D)
2/18/10	PacifiCorp (UT)	8.34	10.60	51.00	6/10-A	32.4
2/24/10	Idaho Power (OR)	8.06	10.18	49.80	12/09	5.0 (B)
3/2/10	Potomac Electric Power (DC)	8.01	9.63	46.18	12/08-A	19.8 (D)
3/4/10	Kentucky Utilities (VA)	7.85	10.50	53.62	12/08-A	10.6 (I,B)
3/5/10	Florida Power (FL)	7.88	10.50	46.76 *	12/10-A	126.2 (I,2)
3/11/10	Virginia Electric and Power (VA)	---	11.90 (3)	---	12/08	0.0 (I,B)
3/11/10	Virginia Electric and Power (VA)	7.81 (E)	12.30 (4)	47.71	---	71.0 (I,B,4)
3/11/10	Virginia Electric and Power (VA)	7.81 (E)	12.30 (5)	47.71	---	64.0 (I,B,5)
3/17/10	Florida Power & Light (FL)	6.65	10.00	47.00 *	12/10-A	75.5
3/26/10	Consolidated Edison of New York (NY)	7.76	10.15	48.00	3/11-A	1,127.6 (D,B,Z)
2010	***1ST QUARTER: AVERAGES/TOTAL***	**7.95**	**10.66**	**48.36**		**2,010.0**
	MEDIAN	**8.01**	**10.50**	**48.76**		**---**
	OBSERVATIONS	**17**	**17**	**16**		**19**
4/2/10	Puget Sound Energy (WA)	8.10	10.10	46.00 (Hy)	12/08-A	74.1 (R)
4/16/10	Southwestern Electric Power (TX)	---	---	---	3/09	25.0 (B)
4/29/10	Central Illinois Light (IL)	8.05	9.90	43.61	12/08-YE	4.9 (D,R)
4/29/10	Central Illlinois Public Service (IL)	8.02	10.06	48.67	12/08-YE	23.7 (D,R)
4/29/10	Illinois Power (IL)	8.97	10.26	43.55	12/08-YE	28.2 (D,R)
5/12/10	Atlantic City Electric (NJ)	8.69	10.30	49.10	12/09-YE	20.0 (D,B)
5/12/10	Rockland Electric (NJ)	8.21	10.30	49.85	12/09-YE	9.8 (D,B)
5/14/10	PacifiCorp (WY)	8.33	---	---	---	35.5 (B,Z)
5/26/10	MDU Resources (WY)	8.25	10.00	49.77	12/08-YE	2.7
5/28/10	Union Electric (MO)	8.06	10.10	51.26	3/09-YE	229.6
6/7/10	Public Service Electric & Gas (NJ)	8.21	10.30	51.20	12/09-YE	73.5 (D,B)
6/15/10	PacifiCorp (UT)	---	---	---	---	30.8 (B,6)
6/18/10	Central Hudson Gas & Electric (NY)	7.43	10.00	48.00	6/11-A	30.2 (D,B,Z)
6/23/10	Entergy Arkansas (AR)	5.04	10.20	29.32 *	6/09-YE	63.7 (B,R)
6/23/10	Empire District Electric (KS)	---	---	---	---	2.8 (B)
6/25/10	Monongahela Power/Potomac Ed. (WV)	8.71	---	---	12/08-A	60.0 (B,Z)
6/28/10	Kentucky Power (KY)	---	10.50	---	9/09-YE	63.7 (B)
6/28/10	Public Service of New Hampshire (NH)	7.51	9.67	52.40	---	57.4 (D,I,B)
6/30/10	Connecticut Light & Power (CT)	7.68	9.40	49.20	6/09-DC	101.9 (D,Z)
2010	***2ND QUARTER: AVERAGES/TOTAL***	**7.95**	**10.08**	**47.07**		**937.5**
	MEDIAN	**8.10**	**10.10**	**49.10**		**---**
	OBSERVATIONS	**15**	**14**	**13**		**19**

ELECTRIC UTILITY DECISIONS (continued)

7/1/10	Wisconsin Electric Power (MI)	6.99	10.25	47.61 *	12/10-A	23.5 (I)
7/15/10	South Carolina Electric & Gas (SC)	8.56	10.70	52.96	9/09-YE	101.2 (B,Z)
7/15/10	Appalachian Power (VA)	7.85	10.53	41.53	12/08-YE	61.5
7/30/10	Maui Electric (HI)	8.67	10.70	54.89	12/07-A	13.2 (B,I)
7/30/10	Kentucky Utilities (KY)	---	---	---	10/09-YE	98.0 (B)
7/30/10	Louisville Gas & Electric (KY)	---	---	---	10/09-YE	74.0 (B)
7/30/10	El Paso Electric (TX)	---	---	---	6/09	17.2 (B,7)
8/4/10	Black Hills Colorado Electric Utility (CO)	9.32	10.50	52.00	7/09	17.9 (B)
8/6/10	Potomac Electric Power (MD)	8.18	9.83	48.87	12/09-A	7.8
8/11/10	Black Hills Power (SD)	8.26	---	---	6/09-A	22.0 (B,I)
8/18/10	Empire District Electric (MO)	---	---	---	6/09-YE	46.8 (B)
8/25/10	Northern Indiana Public Service (IN)	7.29	9.90	49.95 *	12/07-YE	-48.9
9/14/10	Hawaiian Electric (HI)	8.62	10.70	55.10	12/07-A	77.5 (B,I)
9/16/10	New York State Electric & Gas (NY)	7.48	10.00	48.00	8/11-A	88.7 (D,B,Z,8)
9/16/10	Rochester Gas and Electric (NY)	8.47	10.00	48.00	8/11-A	54.2 (D,B,Z,8)
9/21/10	Avista Corp. (ID)	---	---	---	12/09	21.3 (B)
9/30/10	UNS Electric (AZ)	8.28	9.75	45.76	12/08-YE	7.4
9/30/10	South Carolina Electric & Gas (SC)	---	---	---	---	47.3 (9)
2010	***3RD QUARTER: AVERAGES/TOTAL***	**8.16**	**10.26**	**49.52**		**730.6**
	MEDIAN	**8.27**	**10.25**	**48.87**		**---**
	OBSERVATIONS	**12**	**11**	**11**		**18**
10/14/10	Indiana Michigan Power (MI)	7.53	10.35	44.14 *	12/10-A	35.7 (B,I)
10/28/10	Hawaii Electric Light (HI)	8.33	10.70	51.19	12/06-A	24.6 (B,I)
11/2/10	Minnesota Power (MN)	8.18	10.38	54.29	12/10-A	67.5 (I)
11/4/10	Consumers Energy (MI)	6.98	10.70	41.59 *	6/11-A	145.7 (I)
11/19/10	Avista Corp. (WA)	7.91	10.20	46.50	12/09-A	29.5 (B)
11/22/10	Kansas City Power & Light (KS)	8.37	10.00	49.66	9/09-YE	21.8
12/1/10	Entergy Texas (TX)	8.52	10.13	---	6/09	68.0 (B,I,Z)
12/6/10	Baltimore Gas & Electric (MD)	8.06	9.86	51.93	7/10-A	31.0
12/9/10	NorthWestern Corp. (MT)	7.80	10.00	48.00	12/08-A	6.5 (D,B,I,E)
12/15/10	Interstate Power & Light (IA)	---	10.00	---	12/09-A	114.5 (I,10)
12/13/10	Dominion North Carolina Power (NC)	8.22	10.70	51.00	12/08-YE	3.1 (B)
12/14/10	PacifiCorp (OR)	8.08	10.13	51.00	12/11-A	84.6 (B)
12/17/10	Portland General Electric (OR)	8.03	10.00	50.00	12/11-A	100.2 (B)
12/20/10	Sierra Pacific Power (NV)	8.06	10.60	44.11	12/09-YE	13.1
12/21/10	Upper Peninsula Power (MI)	7.12	10.30	50.42 *	---	8.9 (B)
12/21/10	PECO Energy (PA)	---	---	---	12/10	225.0 (D,B)
12/21/10	PPL Electric Utilities (PA)	---	---	---	12/10	77.5 (D,B)
12/21/10	PacifiCorp (UT)	---	---	---	---	33.3 (B,11)
12/27/10	PacifiCorp (ID)	7.98	9.90	52.10	12/09-A	13.8
12/29/10	Georgia Power (GA)	---	11.15	---	---	562.3 (B)
12/30/10	Georgia Power (GA)	---	---	---	12/11	223.0 (12)
2010	***4TH QUARTER: AVERAGES/TOTAL***	**7.95**	**10.30**	**49.00**		**1,889.6**
	MEDIAN	**8.06**	**10.20**	**50.21**		**---**
	OBSERVATIONS	**15**	**17**	**14**		**21**
2010	***FULL YEAR: AVERAGES/TOTAL***	**7.99**	**10.34**	**48.45**		**5,567.7**
	MEDIAN	**8.06**	**10.25**	**49.36**		**---**
	OBSERVATIONS	**59**	**59**	**54**		**77**

GAS UTILITY DECISIONS

Date	Company (State)	ROR %	ROE %	Common Eq. as % Cap. Str.	Test Year & Rate Base	Amt. $ Mil.
1/11/10	CenterPoint Energy Resources (MN)	8.09	10.24	52.55	12/09-A	40.8 (I)
1/20/10	Empire District Gas (MO)	---	---	---	---	2.6 (B)
1/21/10	Peoples Gas Light & Coke (IL)	8.05	10.23	56.00	12/10-A	69.8
1/21/10	North Shore Gas (IL)	8.19	10.33	56.00	12/10-A	13.9
1/26/10	Atmos Energy (TX)	8.60	10.40	48.91	6/08-YE	2.7 (E)
2/10/10	Southern Union (MO)	7.72	10.00	38.66	12/08-YE	16.2 (Bp)
2/23/10	CenterPoint Energy Resources (TX)	8.65	10.50	55.60	3/09-YE	5.1
3/9/10	SourceGas Distribution (NE)	7.80	9.60	49.96	12/08-YE	1.6 (I)
3/19/10	Mountaineer Gas (WV)	8.72	---	---	12/08-A	19.0 (B)
3/24/10	MidAmerican Energy (IL)	7.60	10.13	47.08	12/08-YE	2.7
3/31/10	Atmos Energy (GA)	8.61	10.70	47.70	10/10-A	2.9
2010	***1ST QUARTER: AVERAGES/TOTAL***	**8.20**	**10.24**	**50.27**		**177.3**
	MEDIAN	**8.14**	**10.24**	**49.96**		**---**
	OBSERVATIONS	**10**	**9**	**9**		**11**
4/2/10	Puget Sound Energy (WA)	8.10	10.10	46.00 (Hy)	12/08-A	10.1 (R)
4/14/10	UNS Gas (AZ)	8.00	9.50	49.90	6/08-YE	3.5
4/29/10	Central Illinois Light (IL)	7.83	9.40	43.61	12/08-YE	-5.7 (R)
4/29/10	Central Illlinois Public Service (IL)	7.59	9.19	48.67	12/08-YE	0.3 (R)
4/29/10	Illinois Power (IL)	8.59	9.40	43.55	12/08-YE	-7.4 (R)
5/17/10	Consumers Energy (MI)	7.02	10.55	40.78 *	9/10-A	65.9 (I)
5/24/10	Chattanooga Gas (TN)	7.41	10.05	46.06	4/11-A	0.1
5/28/10	Atmos Energy (KY)	---	---	---	---	6.1 (B)
6/3/10	Michigan Consolidated Gas (MI)	7.19	11.00	38.78 *	12/10-A	118.6 (I)
6/3/10	Questar Gas (UT)	8.42	10.35	52.91	12/10-A	2.6 (B,13)
6/18/10	Public Service Electric & Gas (NJ)	8.21	10.30	51.20	12/09-YE	26.5 (B)
6/18/10	Central Hudson Gas & Electric (NY)	7.43	10.00	48.00	6/11-A	9.6 (B,Z)
2010	***2ND QUARTER: AVERAGES/TOTAL***	**7.80**	**9.99**	**46.31**		**230.2**
	MEDIAN	**7.83**	**10.05**	**46.06**		**---**
	OBSERVATIONS	**11**	**11**	**11**		**12**

GAS UTILITY DECISIONS (continued)

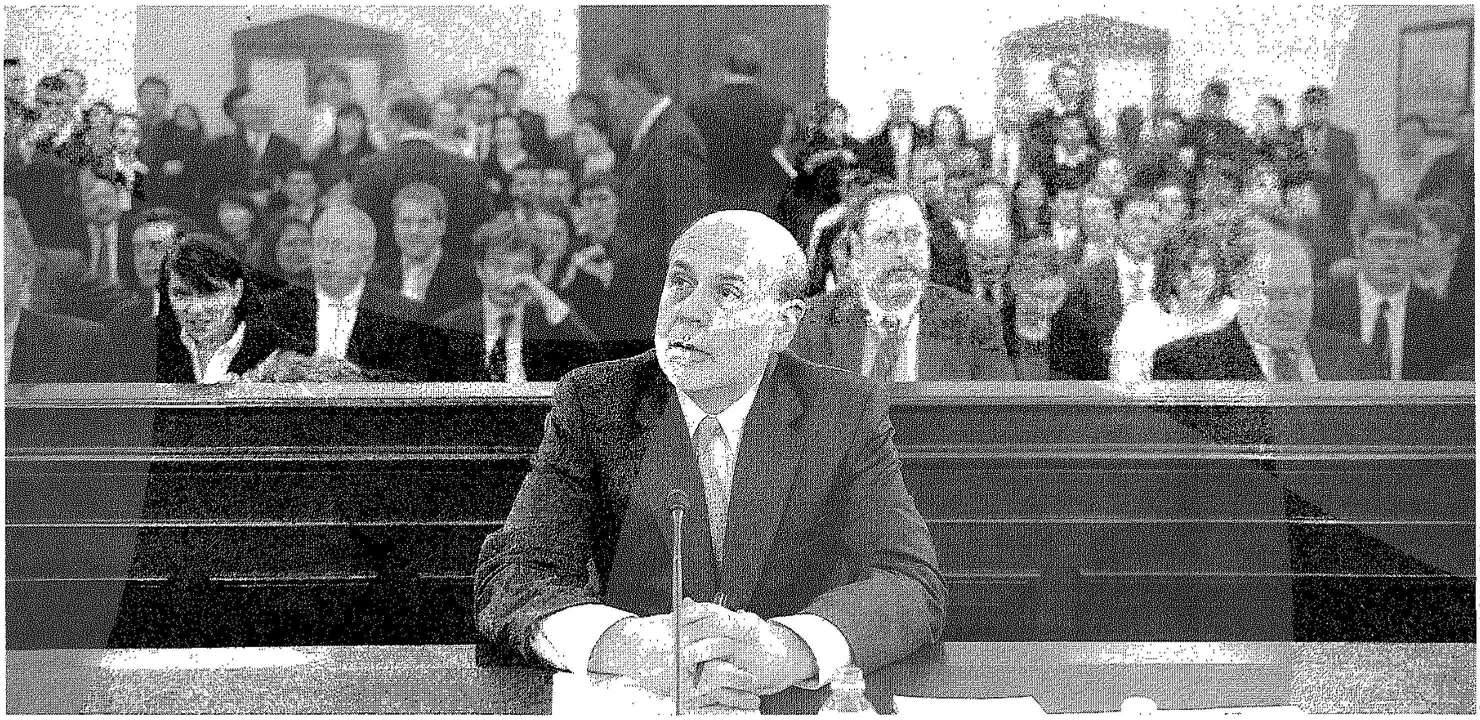
7/30/10	Atmos Energy (KS)	---	---	---	---	3.9 (B)
7/30/10	Louisville Gas & Electric (KY)	---	---	---	10/09-YE	17.0 (B)
8/17/10	Black Hills Nebraska Gas Utility (NE)	9.11	10.10	52.00	7/09-YE	8.3 (R,I)
8/18/10	Atmos Energy (MO)	---	---	---	---	5.7 (B)
8/18/10	Laclede Gas (MO)	---	---	---	---	31.4 (B)
8/18/10	Columbia Gas of Pennsylvannia (PA)	---	---	---	9/09	12.0 (B)
9/16/10	New York State Electric & Gas (NY)	7.48	10.00	48.00	8/11-A	34.0 (B,Z,8)
9/16/10	Rochester Gas and Electric (NY)	8.47	10.00	48.00	8/11-A	34.6 (B,Z,8)
9/21/10	Avista Corp. (ID)	---	---	---	12/09	1.9 (B)
9/22/10	Consolidated Edison of New York (NY)	7.46	9.60	48.00	9/11-A	141.7 (B,Z)
2010	***3RD QUARTER: AVERAGES/TOTAL***	**8.13**	**9.93**	**49.00**		**290.5**
	MEDIAN	**7.98**	**10.00**	**48.00**		**---**
	OBSERVATIONS	**4**	**4**	**4**		**10**
10/6/10	South Carolina Electric & Gas (SC)	---	---	---	3/10	-10.4 (M)
10/21/10	Delta Natural Gas (KY)	7.97	10.40	44.49	12/09-YE	3.5 (R)
11/2/10	Boston Gas (MA) (14)	7.91	9.75	50.00 (Hy)	12/09-YE	41.5
11/2/10	Colonial Gas (MA)	8.16	9.75	50.00 (Hy)	12/09-YE	16.5
11/3/10	Atlanta Gas Light (GA)	8.10	10.75	51.00	5/11-A	26.6
11/4/10	Northern Indiana Public Service (IN)	---	---	46.29 *	12/09-YE	-14.8 (B)
11/19/10	Avista Corp. (WA)	7.91	10.20	46.50	12/09-A	4.6 (B)
12/1/10	SourceGas Distribution (CO)	8.02	10.00	50.48	12/09-A	2.8 (B)
12/6/10	Nothern States Power-Minnesota (MN)	8.28	10.09	52.46	12/10-A	7.3 (I)
12/6/10	Baltimore Gas & Electric (MD)	7.90	9.56	51.93	7/10-A	9.8
12/9/10	NorthWestern Corp. (MT)	7.92	10.25	48.00	12/08-A	-1.0 (B,I)
12/14/10	Texas Gas Service (TX)	8.65	10.33	59.24	6/09-YE	0.8
12/17/10	Columbia Gas of Virginia (VA)	7.92	10.10	42.70	12/09	4.9 (B)
12/20/10	Sierra Pacific Power (NV)	5.18	10.05	44.11	12/09-YE	2.7
12/23/10	SourceGas Distribution (WY)	7.98	9.92	50.34	8/09-YE	4.3
12/29/10	PECO Energy (PA)	---	---	---	12/10	19.6 (B)
2010	***4TH QUARTER: AVERAGES/TOTAL***	**7.84**	**10.09**	**49.11**		**118.7**
	MEDIAN	**7.97**	**10.09**	**50.00**		**---**
	OBSERVATIONS	**13**	**13**	**14**		**16**
2010	***FULL YEAR: AVERAGES/TOTAL***	**7.95**	**10.08**	**48.56**		**816.7**
	MEDIAN	**7.99**	**10.10**	**48.34**		**---**
	OBSERVATIONS	**38**	**37**	**38**		**49**

FOOTNOTES

A- Average
B- Order followed stipulation or settlement by the parties. Decision particulars not necessarily precedent-setting or specifically adopted by the regulatory body.
Bp- Order followed partial stipulation or settlement by the parties. Decision particulars not necessarily precedent-setting or specifically adopted by the regulatory body.
CWIP- Construction work in progress
D- Applies to electric delivery only
DC- Date certain
E- Estimated
Hy- Hypothetical capital structure
I- Interim rates implemented prior to the issuance of final order, normally under bond and subject to refund.
M- "Make-whole" rate change based on return on equity or overall return authorized in previous case.
R- Revised
YE- Year-end
Z- Rate change implemented in multiple steps.
* Capital structure includes cost-free items or tax credit balances at the overall rate of return.

(1) While the authorized rate increase is based on a 10.7% ROE, the settlement specifies that the company is permitted to earn up to an 11% ROE.
(2) The permanent rate increase includes a $126.2 million increase that was authorized by the PSC on 5/19/09 in a separate proceeding related to the repowering of the Bartow generating plant. The company had also requested recovery of the Bartow repowering costs in this base rate proceeding. In adddition, the $126.2 million Bartow-related increase, when adjusted for 2010 billing determinants, increases to $132.1 million.
(3) Authorized 11.9% ROE includes an 11.3% base ROE and a 60-basis-point management efficiency premium.
(4) Parameters apply to rider for the Virginia City Hybrid Energy Center, and the specified ROE includes an 11.3% base equity return and a 100-basis-point premium.
(5) Parameters apply to rider for the Bear Garden generation facility, and the specified ROE includes an 11.3% base equity return and a 100-basis-point premium.
(6) Case is a limited-issue proceeding involving PacifiCorp's incremental investment in a transmission line and an environmental upgrade project.
(7) The rate increase is effective retroactive to 7/1/10.
(8) The 2010 rate increase is effective retroactive to 8/25/10.
(9) Authorized rate increase represents a current cash return on incremental V.C. Summer nuclear plant CWIP. The increase incorporates a previously authorized 11% ROE and incremental CWIP of $399.1 million as of June 30, 2010.
(10) The authorized 10% ROE relates to the portion of the company's rate base not associated with the Emery Generating Station and Whispering Willow Wind Farm.
(11) Case is a limited-issue proceeding involving PacifiCorp's incremental investment in a transmission line and a wind facility.
(12) Authorized rate increase represents a current cash return on incremental Plant Vogtle Units 3 & 4 nuclear plant CWIP. The increase incorporates a previously authorized 11.15% equity return.
(13) Rate increase effective 8/1/10.
(14) The rate increase approved for Boston Gas reflects the combined revenue requirement for both Boston Gas and Essex Gas. Boston Gas and Essex Gas merged their operations (effective Nov. 1, 2010), with Boston Gas the surviving entity.

Dennis Sperduto


Getty Images(top); Reuters (below)

Federal Reserve Chairman Ben Bernanke testified Wednesday before the House Budget Committee, his first appearance since Republicans took control of the chamber in January.

Bernanke Tries to Soothe GOP

Fed Chief Says Inflation Won't Be Allowed to Take Hold but Shows No Sign of Tightening Policy

BY JON HILSENRATH
AND LUCA DI LEO

WASHINGTON—Federal Reserve Chairman Ben Bernanke sought to reassure wary Republicans that he won't allow inflation to take root, though he gave no indication that he is ready to reverse the cental bank's easy-money policies.

"We do not now have a problem," Mr. Bernanke said amid repeated questions about inflation from lawmakers during an appearance before the House Budget Committee on Wednesday.

It was his first testimony before the House since Republicans took control in January, and lawmakers pressed him on when and how he will begin tightening policy. "I do want to repeat that we are extremely vigilant," he said. "We will be very careful to make sure that we don't wait too long."

Mr. Bernanke, who served as the top economic adviser to President George W. Bush in 2005 and 2006 before being picked by Mr. Bush to run the Fed, is now mistrusted by many Republicans after pushing the central bank's money-pumping powers to their limits during the financial crisis of 2008 and 2009.

Rep. Paul Ryan, the Wisconsin Republican who heads the House panel, said he worried Mr. Bernanke wouldn't see inflation until after it has already begun to accelerate. "It's hard to overstate the consequences of getting this wrong," Mr. Ryan said.

In November, the Fed embarked on a $600 billion bond-purchase program aimed at holding down long-term interest rates and stimulating economic growth. In another effort to calm wary Republicans, Mr. Bernanke said it was "certainly possible" that the Fed could end the program before its scheduled completion in June, but only if inflation picked up or the economy began to grow "very quickly."

The Fed chairman's forecasts suggest he isn't likely to shift his stance anytime soon. Though the recovery has strengthened, Mr. Bernanke dismissed worries about inflation. "Inflation made here in the U.S. is very, very low," he said, even though it is picking up abroad. The unemployment rate isn't likely to fall back to desirable levels between 5% and 6% for four years at the earliest, he added, and could take as long as 10 years given present economic growth rates.


House Budget Committee Chairman Paul Ryan held up a copy of The Wall Street Journal with an article on emerging-market inflation worries.

Mr. Bernanke also dismissed concerns about rising yields on U.S. Treasury bonds. These yields sometimes rise when investors are getting worried about inflation and demand a higher return as compensation. The yield increase of late, he said, primarily reflects more optimism about economic growth. "I'm not concerned" about the rise, he said.

Treasurys broke a seven-day losing streak Wednesday, as investors flocked to a $24 billion sale of 10-year notes by the Treasury. Late afternoon, the benchmark 10-year note was up 21/32 in price to yield 3.636%. (Related article on page C11.)

Mr. Bernanke might have a more sympathetic audience on Wall Street. "I don't think inflation is going to explode like wildfire and catch the Fed flat-footed," Christopher Rupkey, an economist at Bank of Tokyo-Mitsubishi, said after the hearing.

While lawmakers questioned him about inflation, Mr. Bernanke waded more deeply into fiscal issues than he is usually willing to go. For months Mr. Bernanke has been urging lawmakers to come up with a long-term plan to narrow the U.S. budget deficit. But he has tried to stay out of partisan squabbles about how to handle the budget.

He is becoming more outspoken, addressing issues such as corporate tax rates, government spending priorities and the charged debate about the government's self-imposed debt limit. Mr. Bernanke sided with the Obama administration and urged lawmakers for the second time in a week to raise the debt limit and avoid a self-imposed default on government bonds.

He also urged a revamp of the corporate-tax code, calling on lawmakers to eliminate loopholes while at the same time lowering the overall rate for corporate taxes.

ATTACHMENT G