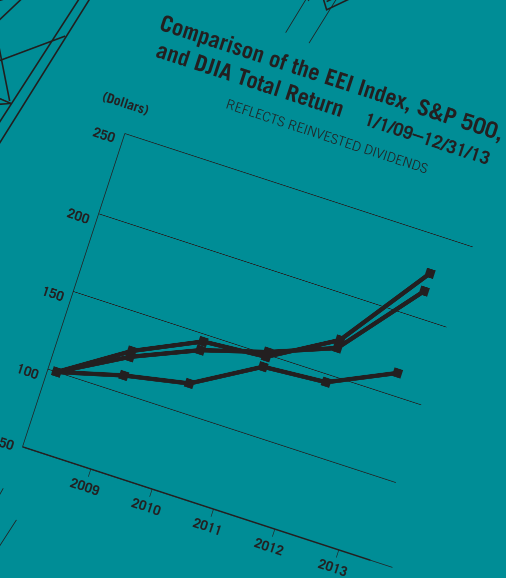
Edison Electric Institute

Power by Association℠



2013 FINANCIAL REVIEW

ANNUAL REPORT
OF THE U.S. INVESTOR-OWNED
ELECTRIC UTILITY INDUSTRY

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About EEI and the Financial Review

The Edison Electric Institute (EEI) is the Washington, D.C.-based association of investor-owned electric companies, whose members represent approximately 70% of the U.S. electric power industry. The 2013 Financial Review is a comprehensive source for critical financial data covering 49 investor-owned electric companies whose stocks are publicly traded on major U.S. stock exchanges. The Review also includes data on six additional companies that provide regulated electric service in the United States but are not listed on U.S. stock exchanges for one of the following reasons—they are subsidiaries of an independent power producer; they are subsidiaries of foreign-owned companies; or they were acquired by other investment firms. These 55 companies are referred to throughout the publication as the U.S. Investor-Owned Electric Utilities. Please refer to page 99 for a list of these companies.

Contents

Highlights of 2013

U.S. INVESTOR-OWNED ELECTRIC UTILITIES

FINANCIAL ($ Millions)	2013	2012r	% Change
Total Operating Revenues	356,492	343,465	3.8%
Utility Plant (Net)	876,218	839,327	4.4%
Total Capitalization	805,687	769,818	4.7%
Earnings Excluding Non-Recurring and Extraordinary Items	36,015	33,619	7.1%
Dividends Paid, Common Stock	20,492	19,824	3.4%

r = revised   Note: Percent changes may reflect rounding.

Abbreviations and Acronyms

AFUDC	Allowance for Funds Used During Construction
BTU	British Thermal Unit
CFTC	Commodity Futures Trading Commission
CPI	Consumer Price Index
DOE	Department of Energy
DOJ	Department of Justice
DPS	Dividends per share
EEI	Edison Electric Institute
EIA	Energy Information Administration
EITF	Emerging Issues Task Force
EPA	Environmental Protection Agency
EPS	Earnings per share
FASB	Financial Accounting Standards Board
FERC	Federal Energy Regulatory Commission
GDP	Gross Domestic Product
GW	Gigawatt
GWh	Gigawatt-hour
IPP	Independent Power Producer
IRS	Internal Revenue Service
ISO	Independent System Operator
ITC	Independent Transmission Company
kWh	Kilowatt-hour
M&A	Mergers & Acquisitions
MW	Megawatt
MWh	Megawatt-hour
NARUC	National Association of Regulatory Utility Commissioners
NERC	North American Electric Reliability Corporation
NOx	Nitrogen Oxides
NOAA	National Oceanic & Atmospheric Administration
NRC	Nuclear Regulatory Commission
O&M	Operations and Maintenance
PSC	Public Service Commission
PUC	Public Utility Commission
PUHCA	Public Utility Holding Company Act
PURPA	Public Utility Regulatory Policies Act
ROE	Return on Equity
RTO	Regional Transmission Organization
SEC	Securities and Exchange Commission
SO_2	Sulfur Dioxide
T&D	Transmission & Distribution

Company Categories

Three categories are used throughout this publication that group companies on their percentage of total assets that are regulated. These categories are used to provide an informative framework for tracking financial trends:

Regulated: Greater than 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

President's Letter

2013 Financial Review

Electricity is the engine that drives our economy and our modern lifestyle. It is the power behind the "smart" in our smart phones, smart appliances, and smart homes and businesses. With a flip of the switch our lights turn on, with a push of a button our dishwashers come to life, and with a touch of our tablet's screen we can access the Internet and connect to the online world.

Since the time of Thomas Edison, electric companies have been powering America. Through innovation and commitment, the electric power industry is moving America forward.

While American homes use more electricity today than ever, electricity prices remain an excellent value and have increased at a lower rate than the prices of other consumer goods. In fact, according to the U.S. Department of Commerce, just 1.47 percent of consumer expenditures in 2013 went to electric bills, which means that for every dollar Americans spent on goods and services, less than a penny and a half was spent on electric bills. On top of that, the electric power industry is a robust component of the nation's economy. We are an $876-billion industry, as measured by assets, which accounts for more than 2 percent of the nation's GDP and employs more than 500,000 workers.

As you will see in this year's *Financial Review*, the strong financial foundation we're building is essential for achieving our mission of providing safe, reliable, affordable, and increasingly clean electricity to all consumers. In 2013, the EEI Index returned an average of 13.0 percent, compared to the 29.7-percent return posted by the Dow Jones Industrial Average and the S&P 500's 32.4-percent return. However, for the 10 years ending December 31, 2013, the EEI Index's 144-percent return outpaced the Dow Jones Industrial's 105-percent return and S&P 500's 104-percent return. In fact, the EEI Index has recorded a positive total shareholder return in 10 of the last 11 years.

For the third consecutive year, all of the EEI Index companies paid a dividend in 2013, and strong dividend yields continue to support utility stocks. The industry's dividend yield at the end of 2013 stood at 4.0 percent, and 36 utilities, or 73 percent of the industry, increased their dividend last year, the largest percentage on record. On the policy front, Congress passed legislation in early 2013 to keep dividend tax rates low and permanently linked to the tax rates for capital gains. This important policy victory was due, in large part, to EEI's multi-faceted Defend My Dividend campaign.

During the last quarter of 2013, the pace of activity in Washington and in the states remained brisk, as EEI worked on major policy issues affecting our industry. Among them: distributed generation and the net metering policies that support it, cyber and physical security, and key environmental rulemakings.

Looking ahead, I am optimistic about our industry's future. Our companies are changing, reinventing themselves, to meet the demands of our growing digital society. We stand ready to serve our customers, to deliver value, and to power our nation forward.

We truly value the partnership that we share with the financial community, and we look forward to updating our stakeholders this time next year on the industry's 2014 policy and financial successes.

Thomas R. Kuhn
President
Edison Electric Institute

Industry Financial Performance

Income Statement

Electric Output Increases 0.1% in 2013

As shown in the table *U.S. Electric Output*, in 2013 the U.S. electric industry made available for distribution in the continental U.S. 3,993,521 gigawatt-hours (GWh) of electricity, an increase of 0.1% over 2012's total of 3,991,408 GWh. This is the first time since 2010 that there has been a year-to-year increase in U.S. electric output, and 2013's total was barely above 2005's 3,992,966 GWh. The electric output data is compiled by the Edison Electric Institute on a weekly basis and represents all electricity placed on the grid in the contiguous 48 states by investor-owned electric utilities, rural electric cooperatives, government power projects and independent power producers.

On a regional basis, four of the EEI regions experienced increases in electric output in 2013. The South Central region saw the largest year-to-year gain at 1.9%, with the New England, Mid-Atlantic, and Pacific Northwest regions also showing growth. The Pacific Southwest region saw the largest decrease in output, at -1.5%. The Central Industrial, West Central, and Southeast regions also experienced decreases in output for the year.

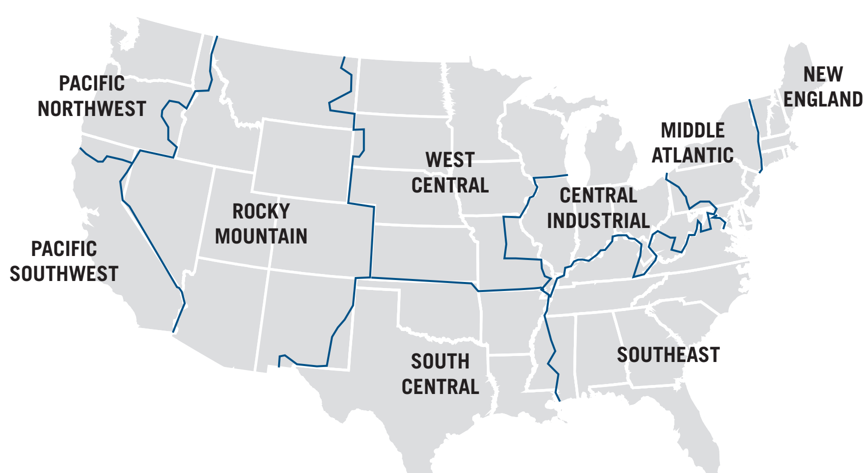
U.S. Electric Output (GWh)
Periods Ending December 31

Region	2013	2012	% Change
New England	129,906	128,410	1.2%
Mid-Atlantic	447,002	445,943	0.2%
Central Industrial	684,026	686,335	(0.3%)
West Central	332,815	334,323	(0.5%)
Southeast	1,002,499	1,006,292	(0.4%)
South Central	682,837	670,257	1.9%
Rocky Mountain	270,434	272,156	(0.6%)
Pacific Northwest	156,245	155,411	0.5%
Pacific Southwest	287,757	292,281	(1.5%)
Total United States	**3,993,521**	**3,991,408**	**0.1%**

Note: Represents all power placed on grid for distribution to end customers; does not include Alaska or Hawaii.

Source: EEI Business Information Group

EEI U.S. Electric Output – Regions



Source: EEI Business Information Group

EEI also calculates weather-normalized output using cooling degree-day (CDD) and heating degree-day (HDD) data from the National Oceanic and Atmospheric Administration (NOAA) (see table, *U.S. Weather*). On a weather-adjusted basis, electric output actually declined in 2013 by 0.6%. On a regional basis, the Rocky Mountain region had the largest decrease in output, at -2.6%, followed by the Southeast region, at -2.0%; both regions experienced a colder than normal winter and a hotter than normal summer. The South Central region had the highest year-to-year increase, at 1.7%.

Although the U.S. economy expanded for a fourth consecutive year in 2013, weakness still remained in critical areas, indicating that recovery from the Great Recession has not been complete. At year-end 2013, there were nearly two million fewer people employed than at the start of the recession in December 2007, and eight million workers had been able to find only part-time employment, three million more than before the economic downturn. Both U.S. industrial production and housing sales finally approached pre-recession levels in 2013. Inflation-adjusted annual gross domestic product (GDP), a measure of national economic output, grew at an annual average rate of only 1.9% in 2013, and has averaged just 2.4% since the recovery began; this is about half the rate at which an economy typically grows during a recovery. The anemic rebound continues to impact electricity sales in every sector, although increases in the adoption of energy efficiency are also contributing to the protracted weakness in sales.

U.S. Weather
January – December 2013

	Total	Dev from Norm	% Change	Dev from Last Year	% Change
Cooling Degree Days					
New England	614	197	47%	4	1%
Mid-Atlantic	806	150	23%	(89)	(10%)
East North Central	749	41	6%	(249)	(25%)
West North Central	975	47	5%	(244)	(20%)
South Atlantic	2,085	121	6%	(126)	(6%)
East South Central	1,584	36	2%	(201)	(11%)
West South Central	2,658	209	9%	(274)	(9%)
Mountain	1,502	259	21%	(20)	(1%)
Pacific	879	175	25%	(25)	(3%)
United States	**1,348**	**132**	**11%**	**(141)**	**(9%)**
Heating Degree Days					
New England	6,487	(124)	(2%)	867	15%
Mid-Atlantic	5,765	(146)	(2%)	861	18%
East North Central	6,653	156	2%	1,247	23%
West North Central	7,157	407	6%	1,592	29%
South Atlantic	2,780	(73)	(3%)	456	20%
East South Central	3,670	66	2%	814	29%
West South Central	2,423	136	6%	713	42%
Mountain	5,040	(169)	(3%)	633	14%
Pacific	2,919	(309)	(10%)	(48)	(2%)
United States	**4,496**	**(28)**	**(1%)**	**726**	**19%**

A mean daily temperature (average of the daily maximum and minimum temperatures) of 65 degrees Fahrenheit is the base for both heating and cooling degree day computations. National averages are population weighted.

Source: National Oceanic and Atmospheric Administration, National Weather Service, Climate Prediction Center

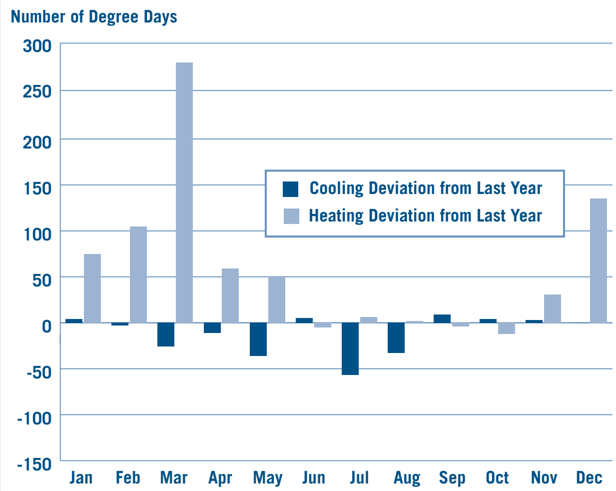
Industry Revenue Rises 3.8%

As shown in the *Consolidated Income Statement*, the industry's total revenue rose by $13.0 billion, or 3.8%, in 2013. A cold winter, indicated by a 19% rise in heating degree days, and an improving economy drove the increase. U.S. real GDP grew in each quarter of 2013, rising 1.9% for the year as a whole. The industry continued to derive support from rate case activity, as 46 cases were filed in 2013 and 53 in 2012. These provided rate relief for the industry's elevated capital spending, with the need to recover infrastructure costs as a primary reason for the rising number of rate cases (see *Rate Case Summary* section).

More than three-quarters of companies (47 of 57, or 82%) had higher revenues in 2013. The median change was a 4.8% increase, while six companies, or 11% of the industry, posted double-digit percentage gains.

2013 Weather Compared to 2012

AS MEASURED BY DEVIATIONS BETWEEN THE TWO YEARS



Source: National Oceanic and Atmospheric Administration and National Weather Service

	Cooling Deviation From Last Year	Heating Deviation From Last Year
Jan	4	75
Feb	(3)	105
Mar	(26)	283
Apr	(11)	59
May	(36)	51
Jun	5	(5)
Jul	(57)	6
Aug	(33)	2
Sep	9	(4)
Oct	4	(12)
Nov	3	31
Dec	0	135
Total	**(141)**	**726**

Heating and Cooling Degree Days and Percent Changes

January—December 2013

	COOLING DEGREE DAYS			HEATING DEGREE DAYS			PERCENTAGE CHANGE			
	Total	Deviation From Norm	Deviation From Last Yr	Total	Deviation From Norm	Deviation From Last Yr	Cooling Degree Change From Norm	Cooling Degree Change From Last Yr	Heating Degree Change From Norm	Heating Degree Change From Last Yr
Jan	10	1	4	827	(90)	75	11.1%	66.7%	(9.8%)	10.0%
Feb	7	(1)	(3)	740	8	105	(12.5%)	(30.0%)	1.1%	16.5%
Mar	10	(8)	(26)	660	67	283	(44.4%)	(72.2%)	11.3%	75.1%
First Quarter	27	(8)	(25)	2,227	(15)	463	(22.9%)	(48.1%)	(0.7%)	26.2%
Apr	36	6	(11)	358	13	59	20.0%	(23.4%)	3.8%	19.7%
May	110	13	(36)	141	(18)	51	13.4%	(24.7%)	(11.3%)	56.7%
Jun	247	34	5	27	(12)	(5)	16.0%	2.1%	(30.8%)	(15.6%)
Second Quarter	393	53	(42)	526	(17)	105	15.6%	(9.7%)	(3.1%)	24.9%
Jul	351	30	(57)	8	(1)	6	9.3%	(14.0%)	(11.1%)	300.0%
Aug	297	7	(33)	10	(5)	2	2.4%	(10.0%)	(33.3%)	25.0%
Sep	193	38	9	68	(9)	(4)	24.5%	4.9%	(11.7%)	(5.6%)
Third Quarter	841	75	(81)	86	(15)	4	9.8%	(8.8%)	(14.9%)	4.9%
Oct	59	6	4	257	(25)	(12)	11.3%	7.3%	(8.9%)	(4.5%)
Nov	17	2	3	570	31	31	13.3%	21.4%	5.8%	5.8%
Dec	11	4	0	830	13	135	57.1%	0.0%	1.6%	19.4%
Fourth Quarter	87	12	7	1,657	19	154	16.0%	8.8%	1.2%	10.2%
2013 Totals	1,348	132	(141)	4,496	(28)	726	10.9%	(9.5%)	(0.6%)	19.3%

	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013
Heating Degree Days Percentage Change from Historical Norm	(7.1)	(6.5)	(13.2)	(5.6)	(0.8)	(0.9)	(1.7)	(4.5)	(16.6)	(0.6)
Cooling Degree Days Percentage Change from Historical Norm	3.5	18.7	15.8	14.5	5.3	1.6	19.9	21.5	22.4	10.9

A mean daily temperature (average of the daily maximum and minimum temperatures) of 65°F is the base for both heating and cooling degree day computations. National averages are population weighted.

Source: National Oceanic and Atmospheric Administration and National Weather Service

Based on Business Segmentation data, about $10.9 billion of the rise in the industry's energy operating revenue came from the Regulated Electric segment. The next largest contribution came from the Natural Gas Distribution segment, where revenue grew by $3.9 billion. The *Business Segmentation* section provides a revenue breakdown by segment.

Energy Operating Expenses Outpace Revenue Growth

Total energy operating expenses rose by $6.9 billion, or 5.6%, from the prior year's level, growing more than revenue in percentage terms, although less in dollars. The two components of total energy operating expenses—total electric generation cost (+3.2%) and gas cost (+19.6%) contributed about equally to the total increase. The rise in gas cost can be traced to higher distribution volume due to colder winter weather in the North Central and New England regions, as well as natural gas prices that edged higher (see *Fuels*). Total electric generation cost, which includes electric generation fuel expense and the cost of purchased power, has fallen from 37% of total revenue in 2008, to 34% in 2009 through 2011, to 31% in 2012 and 2013.

For the consolidated industry income statement, natural gas transmission and distribution revenue is aggregated with all other revenue sources in the "Energy Operating Revenue" line. However, the cost associated with natural gas distribution (i.e., the delivery of natural gas to homes and businesses primarily for cooking and heating) is broken out

Consolidated Income Statement

U.S. INVESTOR-OWNED ELECTRIC UTILITIES

	12 Months Ended		
($ Millions)	**12/31/2013**	**12/31/2012r**	**% Change**
Energy Operating Revenues	$356,492	$343,465	3.8%
Energy Operating Expenses			
Total Electrical Generation Cost	109,828	106,394	3.2%
Gas Cost	21,100	17,644	19.6%
Total Energy Operating Expenses	**130,929**	**124,038**	**5.6%**
Revenues less energy operating expenses	**225,564**	**219,426**	**2.8%**
Other Operating Expenses			
Operations & maintenance	89,930	89,228	0.8%
Depreciation & Amortization	38,947	37,260	4.5%
Taxes (not income) - Total	16,889	16,402	3.0%
Other Operating Expenses	12,279	11,182	9.8%
Total Operating Expenses	**288,974**	**278,111**	**3.9%**
Operating Income	67,519	65,353	3.3%
Other Recurring Revenue			
Partnership Income	1,080	547	97.6%
Allowance for Equity Funds Used for Construction	1,367	1,538	(11.1%)
Other Revenue	2,425	2,215	9.5%
Total Other Recurring Revenue	**4,872**	**4,299**	**13.3%**
Non-Recurring Revenue			
Gain on Sale of Assets	471	311	51.1%
Other Non-Recurring Revenue	204	264	(22.8%)
Total Non-Recurring Revenue	**675**	**576**	**17.2%**
Interest expense	23,382	23,783	(1.7%)
Other expenses	(423)	405	(204.4%)
Asset Writedowns	3,086	5,646	(45.4%)
Other Non-Recurring Expenses	3,509	3,136	11.9%
Total Non-Recurring Expenses	6,595	8,783	(24.9%)
Net Income Before Taxes	**43,511**	**37,257**	**16.8%**
Provision for Taxes	13,416	11,845	13.3%
Dividends on Preferred Stock of Subsidiary	-	-	NM
Other Minority Interest Expense	-	-	NM
Minority Interest Expense	-	-	NM
Trust Preferred Security Payments	-	-	NM
Other After-tax Items	-	-	NM
Total Minority Interest and Other After-tax Items	-	-	NM
Net Income Before Extraordinary Items	**30,095**	**25,412**	**18.4%**
Discontinued Operations	(338)	(4,317)	(92.2%)
Change in Accounting Principles	-	-	NM
Early Retirement of Debt	-	-	NM
Other Extraordinary Items	-	-	NM
Total Extraordinary Items	(338)	(4,317)	(92.2%)
Net Income	**29,757**	**21,095**	**41.1%**
Preferred Dividends Declared	3	6	(52.7%)
Other Preferred Dividends after Net Income	3	5	(32.8%)
Other Changes to Net Income	(11)	(16)	(32.3%)
Net Income Attributable to Noncontrolling Interests	481	463	NA
Net Income Available to Common	**29,259**	**20,605**	**42.0%**
Common Dividends	**20,492**	**19,824**	**3.4%**

r = revised NM = not meaningful

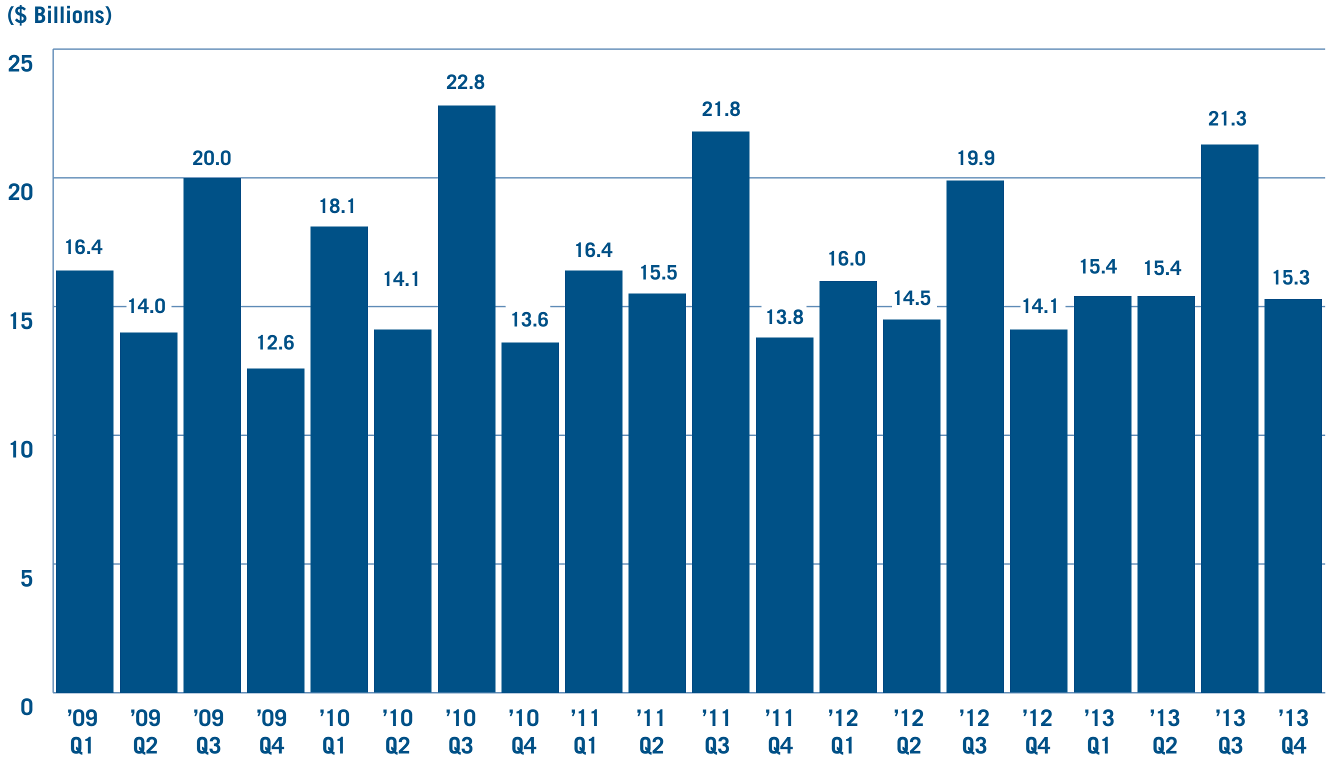
Source: SNL Financial and EEI Finance Department

- NV Energy (acquired by MidAmerican 12/19/2013): 2013 FY included (IS & CF)
- CH Energy (acquired by Fortis 6/27/2013): 2013 Q1 included (IS & CF)
- Energy Future Holdings (2013Q4 results delayed): 2013 Q1-Q3 included (IS & CF)
- Iberdrola USA (reorganization 2013Q4): 2013Y and 2012Yr, proxies used (IS & CF)

Iberdrola USA proxy: Central Maine Power Co + New York State Electric & Gas Corp (NYSEG) + Rochester Gas & Electric Corp (RG&E)

Quarterly Net Operating Income

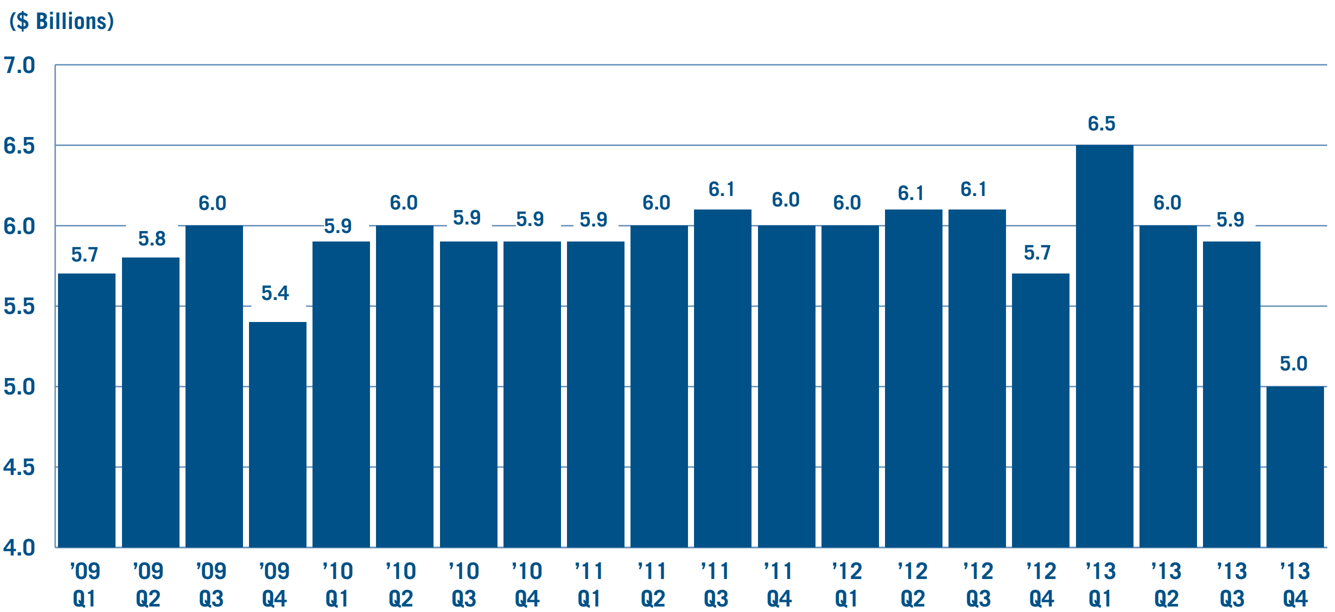
U.S. INVESTOR-OWNED ELECTRIC UTILITIES



Source: SNL Financial and EEI Finance Department

Quarterly Interest Expense

U.S. INVESTOR-OWNED ELECTRIC UTILITIES



Source: SNL Financial and EEI Finance Department

separately as "Gas Cost." Gas Cost is typically highest in the first quarter due to heating demand and lowest in the third due to the minimal heating needs during the summer.

Although gas distribution contributes a smaller portion of the industry's overall revenue and earnings than do electric operations, it helps balance the seasonal earnings stream for combined gas/electric distribution companies due to the fact that residential gas demand peaks in the colder months while electricity demand peaks in the hot summer months for most U.S. utilities.

Operations and Maintenance (O&M) Expenses Rise 0.8%

Operations and maintenance (O&M) expenses, which comprised 28% to 32% of the industry's operating expenses from 2009 through 2012, rose 0.8% in 2013. This followed a decrease of 0.5% in 2012 and increases of 3.5% in 2011 and 3.4% in 2010. Larger companies constrained the percentage increase as the median company saw O&M costs rise 2.4%. Combining "Other Operating Expenses" with O&M produces a 1.8% year-to-year increase in the aggregate total. This approach provides an alternative view of operating cost trends, as some companies report significant operating expenses in the "Other" category.

It should be noted that the consolidated industry O&M figure includes not only the electric but also the natural gas and other operating segments, and is influenced by plant and business divestitures.

Operating Income Climbs 3.3%

The industry's aggregate operating income rose by $2.2 billion, or 3.3%, with a median increase of 3.8%; 36 companies, or 63% of the industry, showed a year-to-year gain. The overall rise was produced mostly by companies with a regulated focus. The Regulated group of companies posted a $7.9 billion, or 25.9%, increase in operating income, compared to a decrease of $5.5 billion, or 16.2%, for the Mostly Regulated Group and a $306 million, or 32.8%, decline for the Diversified group.

Interest Expense Down 1.7%

Interest expense fell by $401 million, or 1.7%, to $23.4 billion from $23.8 billion in 2012, although 32 companies, or 56% of the industry, recorded an increase for this line item. The median change was an increase of 0.7%. Interest expense has, in total, held steady over the past five years, as upward pressure from greater levels of debt to fund investment was offset for much of the period by declining interest rates. The quarterly average coupon rate for newly

Individual Non-Recurring and Extraordinary Items 2004–2013

U.S. INVESTOR-OWNED ELECTRIC UTILITIES

($ Millions)	2004	2005	2006	2007	2008	2009	2010	2011	2012r	2013
Net Gain (Loss) on Sale of Assets	950	2,991	983	5,240	581	7,176	3,410	891	311	471
Other Non-Recurring Revenue	5,691	518	250	130	1,661	(494)	2,065	946	264	204
Total Non-Recurring Revenue	**6,641**	**3,509**	**1,233**	**5,370**	**2,243**	**6,682**	**5,475**	**1,837**	**576**	**675**
Asset Writedowns	(2,653)	(2,849)	(2,203)	(215)	(11,256)	(2,022)	(8,805)	(2,743)	(5,646)	(3,086)
Other Non-Recurring Charges	(751)	(1,793)	(631)	(1,091)	(1,525)	(822)	(545)	(851)	(3,136)	(3,509)
Total Non-Recurring Charges	**(3,404)**	**(4,643)**	**(2,833)**	**(1,306)**	**(12,781)**	**(2,844)**	**(9,350)**	**(3,594)**	**(8,783)**	**(6,595)**
Discontinued Operations	742	(808)	2,194	599	759	(63)	(476)	(1,011)	(4,317)	(338)
Change in Accounting Principles	24	(180)	15	(158)	–	–	–	–	–	–
Early Retirement of Debt	–	–	–	–	–	–	–	–	–	–
Other Extraordinary Items	(1,180)	(245)	–	(79)	67	(5)	10	960	–	–
Total Extraordinary Items	**(414)**	**(1,233)**	**2,208**	**362**	**826**	**(68)**	**(466)**	**(51)**	**(4,317)**	**(338)**
Total Non-Recurring and Extraordinary Items	**2,823**	**(2,366)**	**608**	**4,426**	**(9,713)**	**3,771**	**(4,341)**	**(1,808)**	**(12,524)**	**(6,258)**

r = revised Note: Figures represent net industry totals. Totals may reflect rounding.

Source: SNL Financial and EEI Finance Department

Top Net Non-Recurring and Extraordinary Gains (Losses) 2013

U.S. INVESTOR-OWNED ELECTRIC UTILITIES

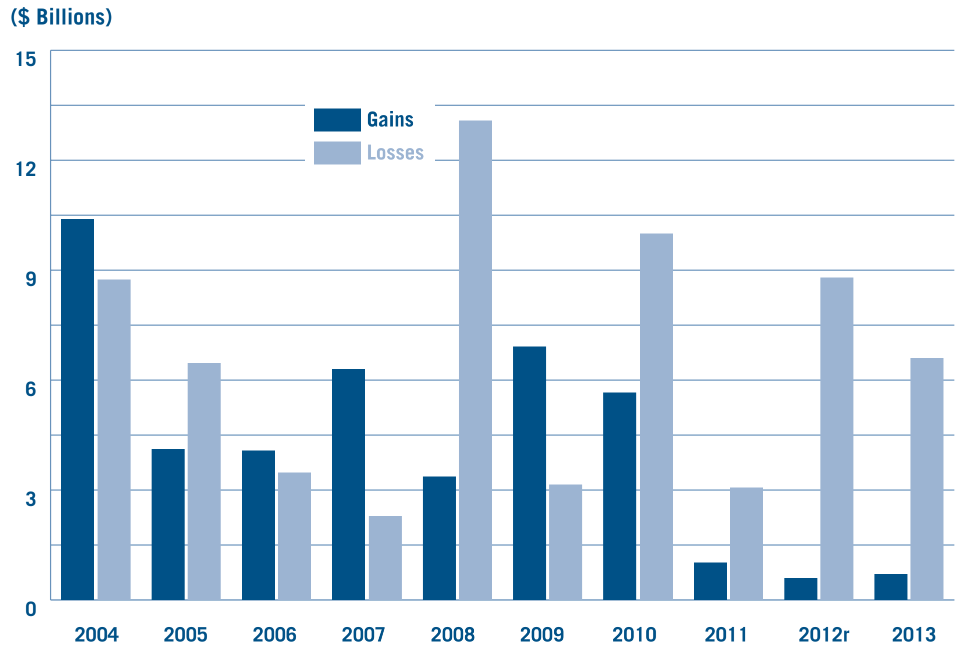
($ Millions)

Company	Gains	Losses	Net Total
Southern	-	1,180.0	1,180.0
Duke	189.0	1,135.0	946.0
FirstEnergy	-	927.0	927.0
PPL	-	698.0	698.0
Edison Int'l	-	571.0	571.0
DPL	-	335.3	335.3
Entergy	43.6	377.5	334.0
NextEra	54.0	300.0	246.0
AEP	12.0	226.0	214.0
PG&E	-	196.0	196.0

Source: SNL Financial and EEI Finance Department

Aggregate Non-Recurring and Extraordinary Items 2004-2013

U.S. INVESTOR-OWNED ELECTRIC UTILITIES



	2004	2005	2006	2007	2008	2009	2010	2011	2012r	2013	Total
Gains	10.4	4.1	4.1	6.3	3.4	6.9	5.7	1.8	0.6	0.7	43.9
Losses	8.7	6.5	3.5	2.3	13.1	3.1	10.0	3.6	8.8	6.6	66.1
Total	**1.7**	**(2.3)**	**0.6**	**4.0**	**(9.7)**	**3.8**	**(4.3)**	**(1.8)**	**(8.2)**	**(5.9)**	**(22.2)**

r = revised Note: Totals may reflect rounding.

Source: SNL Financial and EEI Finance Department

issued 10-year utility bonds essentially bottomed in late 2012, holding at about 3.0 to 3.1 percent through the second quarter of 2013 before beginning a climb tied to rising Treasury yields (see *Balance Sheet*).

Non-Recurring and Extraordinary Activity

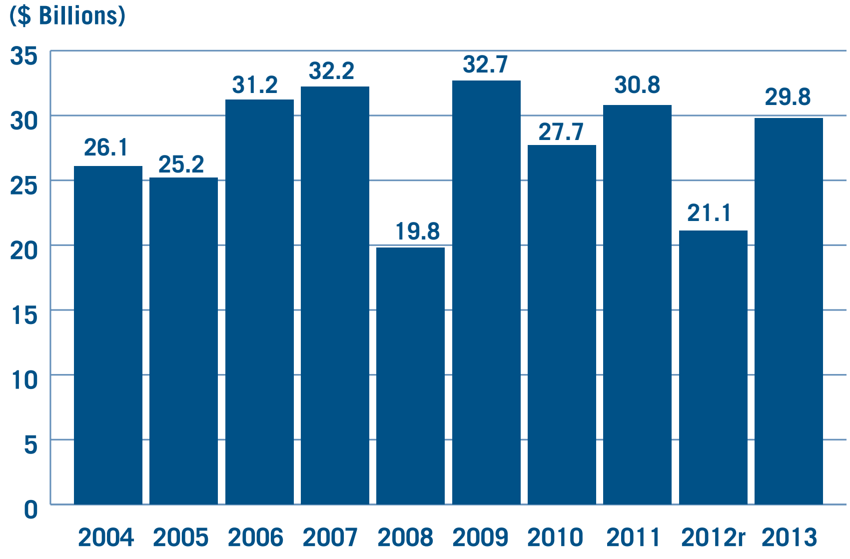
As shown in the table *Individual Non-Recurring and Extraordinary Items*, the industry reported a positive $6.3 billion year-to-year change in the impact of non-recurring and extraordinary items in 2013, mostly due to a $4.0 billion decrease in "Discontinued Operations" and a $2.6 billion decrease in "Asset Writedowns." This reversed a negative $10.7 billion change in 2012, which was mostly due to substantial asset writedowns in that year.

The expense associated with "Discontinued Operations" fell from $4.3 billion in 2012 to $0.3 billion in 2013, and 15 companies recorded this adjustment last year. The biggest change came from Edison International, which recorded a $1.3 billion full impairment of its investment in Edison Mission Energy (EME), an independent power generator, in December of 2012. Edison International booked the charge as a result of EME filing for bankruptcy; the filing was needed to reduce EME's debt and position the company for future operation following a period of depressed energy and capacity prices and high fuel costs affecting EME's coal-fired facilities, among other reasons.

"Asset Writedowns" fell to $3.1 billion in 2013 from $5.6 billion in 2012, with the lower 2013 total

Net Income 2004-2013

U.S. INVESTOR-OWNED ELECTRIC UTILITIES



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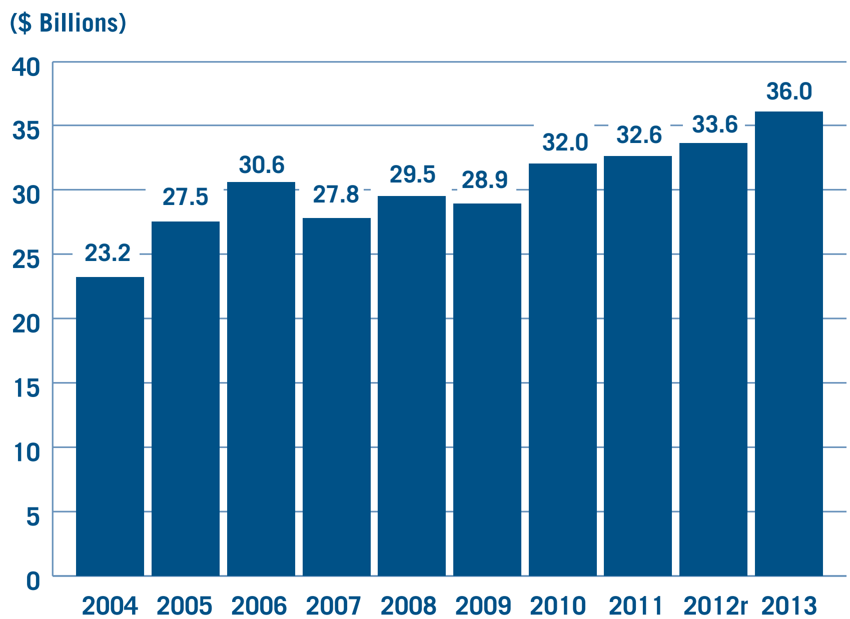
Source: SNL Financial and EEI Finance Department

Net Income Before Non-Recurring and Extraordinary Items 2004-2013

U.S. INVESTOR-OWNED ELECTRIC UTILITIES



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Source: SNL Financial and EEI Finance Department

coming mostly from the absence of DPL's $1.8 billion writedown in late 2012 of goodwill associated with its sale to The AES Corp. in November of 2011. The impairment stemmed from the impact of lower natural gas prices and growing competition from competitive retail providers on DPL's wholesale margins.

Net Income Higher at Most Companies

The industry's net income rose to $29.8 billion in 2013, up $8.7 billion, or 41.1%, from $21.1 billion in 2012. Even excluding the positive $2.3 billion impact from the year-to-year swing in non-recurring and extraordinary items, net income showed a solid increase. Thirty-seven companies, or 65% of the industry, had higher year-to-year net income, with 25 companies, or 44%, recording double-digit percentage gains.

Capitalization Structure

U.S. INVESTOR-OWNED ELECTRIC UTILITIES

Capitalization Structure	12/31/2013	12/31/2012r	12/31/2011
Common Equity	343,885	327,694	314,369
Preferred Equity & Noncontrolling Interests	5,068	5,062	4,856
Long-term Debt (current & non-current)*	456,734	437,063	411,074
Total	**805,687**	**769,818**	**730,299**
Common Equity %	42.7%	42.6%	43.0%
Preferred & Noncontrolling %	0.6%	0.7%	0.7%
Long-term Debt %	56.7%	56.8%	56.3%
Total	**100.0%**	**100.0%**	**100.0%**

* Long-term debt not adjusted for (i.e., includes) securitization bonds.
r = revised
Source: SNL Financial and EEI Finance Department

Balance Sheet

The industry's consolidated balance sheet remained healthy in 2013. The debt-to-capitalization ratio stood at 56.7% at year-end, essentially unchanged from 56.8% at year-end 2012 (see table, *Capitalization Structure*). Electric utilities were able to issue long-term debt at very low interest rates throughout the year, despite the sharp climb in Treasury yields during the summer of 2013 from their lowest levels in more than half a century (see chart, *Utilities' Cost of Debt*). After reducing short-term borrowing in 2009, companies added short-term debt at a moderate pace from 2010 through 2013 (see chart, *Short-term Debt 2004-2013*). Short-term debt has accounted for four to five percent of total industry debt in each of the last five years.

Investor demand for electric utilities' corporate bonds remained strong. New-issue volume for five-, 10- and 30-year debt reached $34.3 billion, on par with the $34.0 billion in 2012 and substantially larger than the $26.0 billion in 2011. Credit spreads (the difference between corporate bond yields and risk-free Treasury yields for the same maturity) fell to levels not seen since early 2007. For new 10-year utility bonds, spreads averaged 106 basis points (bps) in 2013 compared to 177 bps in 2012. The average coupon rate for 10-year utility bonds fell to just 3.4% in 2013 from 3.7% in 2012 and 4.3% in 2011. The quarterly average coupon rate for newly issued 10-year utility bonds essentially bottomed in late 2012, holding at about 3.0 to 3.1 percent through the second quarter of 2013 before beginning a modest climb tied to rising Treasury yields.

Debt and Leverage Rise

The industry's total consolidated long-term debt increased in 2013 for the eighth consecutive year, rising $19.7 billion or 4.5%. Total common equity rose by $16.2 billion—a number roughly on par, in percentage terms, with that of the prior three years—largely offsetting the additional debt. As a result, the industry's debt-to-capitalization ratio, at 56.7%, was essentially unchanged in 2013 after rising modestly to 56.8% at year-end 2012 from 56.3% at year-end 2011. The balance sheet shows changes in equity resulting from public offerings, which increase equity, and retained earnings or losses, which increase or decrease equity (see chart, *Proceeds from Issuance of Common Equity*).

Industry credit quality, tied closely in recent years to the management of capital spending and related financing strategies, was unchanged in 2013. Given the year's largely positive ratings actions, the industry maintained an overall credit rating of BBB (using Standard & Poor's scale) for the tenth consecutive year (see *Credit Ratings*) and moved incrementally closer to BBB+.

Total long-term debt (current and non-current) has risen by $81.9 billion, or 22%, since year-end 2008, driven higher by the need to finance consistently high levels of capital expenditures (capex). Industry capex climbed from a cyclical low of $41.1 billion in 2004 to a record high of $90.3 billion in 2013. EEI updates capital spending projections at least annually. Based on the latest data, collected in October 2013, industry-wide capex is expected to total approximately $93 billion in 2014 and $85 billion in 2015.

Date	PP&E in Service, Net ($Mil)	% Change from 12/31/2008
12/31/2013	$791,795	36%
12/31/2012r	$760,105	31%
12/31/2011	$702,285	21%
12/31/2010	$665,112	15%
12/31/2009	$625,729	8%
12/31/2008	$580,474	—

Source: SNL Financial and EEI Finance Department

Impact of Elevated Capex

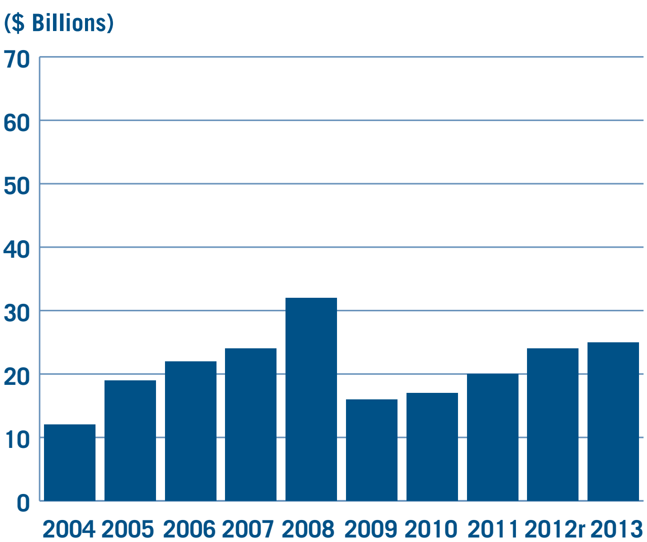
The impact of historically high levels of capital spending is evident in the industry's consolidated balance sheet. Total property, plant and equipment in service (shown in the adjacent table) jumped 36% from year-end 2008 to year-end 2013.

A rising level of construction work-in-progress (CWIP) also reflects the industry's elevated capital spending. CWIP jumped from $33.8 billion at year-end 2006 to $47.5 billion at year-end 2007 and to $61.9 billion at year-end 2008, then stabilized in a range of $59.4 billion to $64.8 billion from 2009 through 2013. CWIP, along with adjustment clauses, interim rate increases and the use of projected costs in rate cases, is especially important during large construction cycles because it helps minimize regulatory lag.

Deferred taxes rose by $13.4 billion, or 10.9%, to $136.8 billion at year-end 2013 from $123.4 billion at year-end 2012. Since 2008, deferred

Short-term Debt 2004–2013

U.S. INVESTOR-OWNED ELECTRIC UTILITIES



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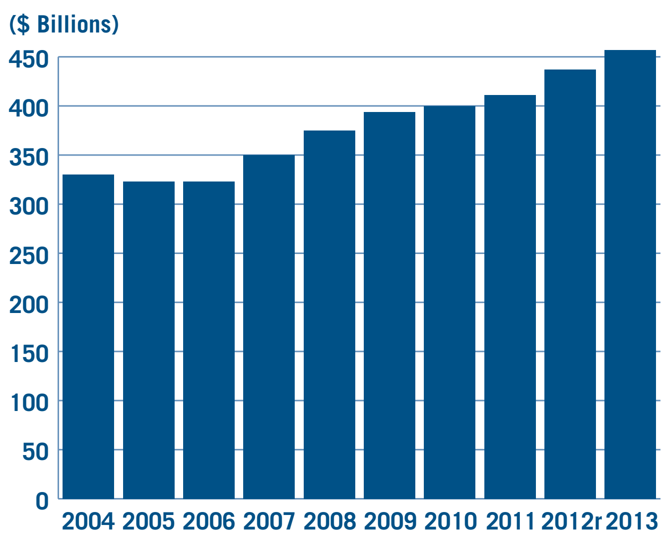
Source: SNL Financial and EEI Finance Department

Long-term Debt 2004–2013

U.S. INVESTOR-OWNED ELECTRIC UTILITIES



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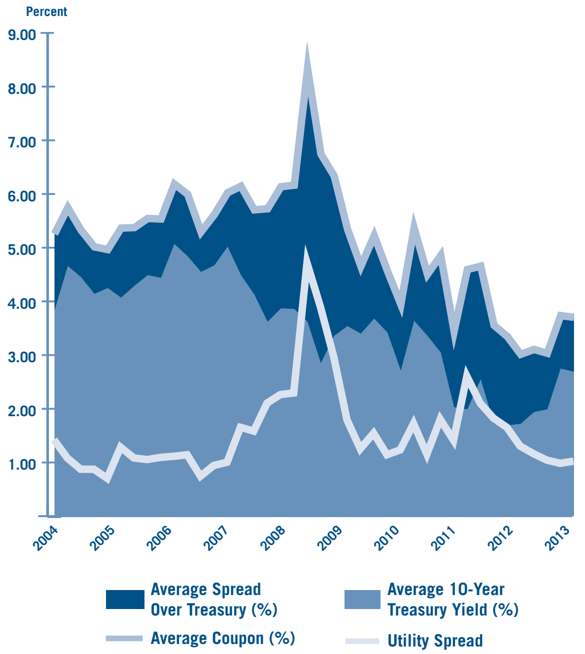
Source: SNL Financial and EEI Finance Department

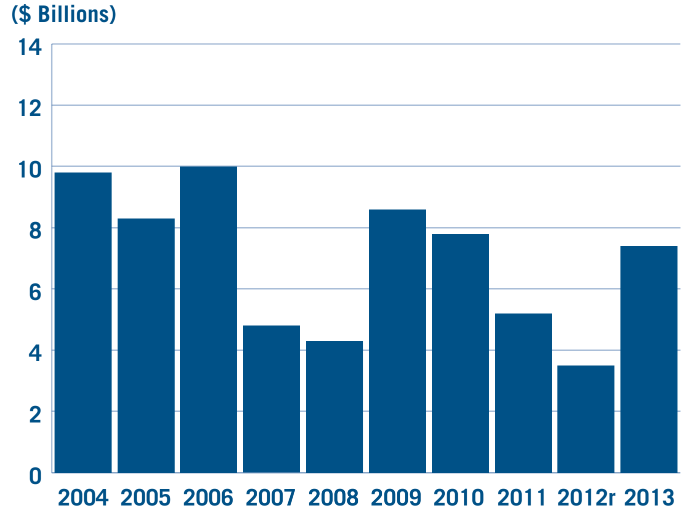
Utilities' Cost of Debt: 10-Year Treasury Yields and Bond Spreads (New Offerings)



Source: SNL Financial and EEI Finance Department

Proceeds from Issuance of Common Equity 2004–2013

U.S. INVESTOR-OWNED ELECTRIC UTILITIES



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Source: SNL Financial and EEI Finance Department

taxes have increased at a compound annual rate of 8.5%. This relatively fast pace relates to continued high capex and the impact of accelerated depreciation beginning in 2008 (see *Cash Flow Statement*).

Cash Flow Statement

Net Cash Provided by Operating Activities

Net Cash Provided by Operating Activities increased by $3.7 billion, or 4.4%, to $87.7 in 2013 from $84.0 billion in 2012. This metric increased for 58% of the industry at the holding company level. As shown in the *Statement of Cash Flows*, the primary driver of the increase was an $8.6 billion rise in Net Income.

Net Income increased for nearly two-thirds of the industry's companies, with an aggregate rise of 40.5%. Operating Income was up by $2.2 billion, or 3.3%. Most of the change in net income occurred below the operating income line; the primary contributor was a drop in the Net Loss from Non-Recurring and Extraordinary Items from a negative $12.5 billion in 2012 to a negative $6.3 billion in 2013 (see *Income Statement section*).

Deferred Taxes and Investment Credits remained very high for the sixth straight year, increasing by $782 million, or 6.4%, to $13.0 billion in 2013 from $12.2 billion in 2012. These totals are well above the $2.3 billion level in 2007. In combination with the industry's elevated capital expenditures, the effect of bonus depreciation created a significant increase in deferred taxes over the period. In the case of 50% bonus depreciation, the accelerated depreciation sched ule allows for an additional first-year depreciation deduction equal to 50% of the adjusted basis of eligible property. The "50% bonus depreciation" clause expired at the end of 2013, but may be extended another two years if a Tax Extenders package is passed. Varying levels of bonus depreciation have been in place the majority of time since September 11, 2001, ranging from 30% to 100%.

Net Cash Used in Investing Activities

Net Cash Used in Investing Activities was virtually unchanged, at $94.2 billion in both 2012 and 2013. Capital expenditures, also unchanged at $90.3 million, typically have the greatest impact on this line item. While rising only $65 million, or 0.1%, annual capex reached yet another record high for the industry in 2013. About two-thirds of investor-owned electric utilities boosted capital spending relative

Debt-to-Cap Ratio by Category 2013 vs. 2012r

U.S. INVESTOR-OWNED ELECTRIC UTILITIES

	Regulated		Mostly Regulated		Diversified		Total Industry	
	Number	%	Number	%	Number	%	Number	%
Lower	11	29.7%	7	41.2%	—	—	18	32.7%
Higher	18	48.6%	5	29.4%	1	100.0%	24	43.6%
No Change*	8	21.6%	5	29.4%	—	—	13	23.6%
Total	**37**	**100%**	**17**	**100%**	**1**	**100%**	**55**	**100%**

Note: Dec. 31, 2013 vs. Dec. 31, 2012. Refer to page v for category descriptions.
*No change defined as less than 1.0%

Source: SNL Financial and EEI Finance Department

Capitalization Structure by Category 2013 vs. 2012r

U.S. INVESTOR-OWNED ELECTRIC UTILITIES

	Total Industry			Regulated		
	2013Y	2012Yr	Change	2013Y	2012Yr	Change
Common Equity	343,885	327,694	16,191	195,512	152,237	43,275
Total Preferred Equity	5,068	5,062	7	3,861	1,834	2,028
Long-term Debt (current & non-current)*	456,734	437,063	19,672	262,004	173,679	88,326
Total Capitalization	805,687	769,818	35,870	461,378	327,750	133,628
Common Equity %	42.7%	42.6%	0.1%	42.4%	46.4%	(4.1%)
Preferred Equity %	0.6%	0.7%	0.0%	0.8%	0.6%	0.3%
Long-term Debt %	56.7%	56.8%	(0.1%)	56.8%	53.0%	3.8%
Total	**100.0%**	**100.0%**	—	**100.0%**	**100.0%**	—

	Mostly Regulated			Diversified		
	2013Y	2012Yr	Change	2013Y	2012Yr	Change
Common Equity	145,564	182,254	(36,690)	2,808	(6,798)	9,606
Total Preferred Equity	1,159	3,111	(1,952)	48	117	(69)
Long-term Debt (current & non-current)*	192,876	222,248	(29,372)	1,855	41,136	(39,281)
Total Capitalization	339,599	407,613	(68,014)	4,710	34,455	(29,744)
Common Equity %	42.9%	44.7%	(1.8%)	59.6%	(19.7%)	79.3%
Preferred Equity %	0.3%	0.8%	(0.4%)	1.0%	0.3%	0.7%
Long-term Debt %	56.8%	54.5%	2.3%	39.4%	119.4%	(80.0%)
Total	**100.0%**	**100.0%**	—	**100.0%**	**100.0%**	—

* Long-term debt not adjusted for (i.e., includes) securitization bonds.

r = revised

Refer to page v for category descriptions.

Source: SNL Financial and EEI Finance Department

Consolidated Balance Sheet

U.S. INVESTOR-OWNED ELECTRIC UTILITIES

($ Millions)	12/31/2013	12/31/2012r	% Change	$ Change
PP&E in service, gross	1,159,357	1,109,921	4.5%	49,437
Accumulated depreciation	367,562	349,816	5.1%	17,746
Net property in service	791,795	760,105	4.2%	31,691
Construction work in progress	64,758	62,514	3.6%	2,244
Net nuclear fuel	14,441	14,640	(1.4%)	(200)
Other property	5,224	2,069	152.6%	3,156
Net property & equipment	876,218	839,327	4.4%	36,891
Cash & cash equivalents	14,365	13,688	4.9%	677
Accounts receivable	37,960	35,616	6.6%	2,345
Inventories	24,587	26,012	(5.5%)	(1,425)
Other current assets	48,507	49,302	(1.6%)	(795)
Total current assets	125,419	124,618	0.6%	801
Total investments	84,933	71,772	18.3%	13,161
Other assets	205,818	227,868	(9.7%)	(22,051)
Total Assets	**1,292,388**	**1,263,585**	**2.3%**	**28,802**
Common equity	343,885	327,694	4.9%	16,191
Preferred equity	55	70	(22.1%)	(16)
Noncontrolling interests	5,014	4,992	0.4%	22
Total equity	348,953	332,755	4.9%	16,198
Short-term debt	24,957	24,383	2.4%	574
Current portion of long-term debt	25,083	30,337	(17.3%)	(5,254)
Short-term and current long-term debt	50,040	54,720	(8.6%)	(4,680)
Accounts payable	59,596	56,734	5.0%	2,862
Other current liabilities	33,753	37,383	(9.7%)	(3,630)
Current liabilities	143,389	148,837	(3.7%)	(5,448)
Deferred taxes	136,817	123,422	10.9%	13,395
Non-current portion of long-term debt	431,651	406,725	6.1%	24,926
Other liabilities	230,468	250,444	(8.0%)	(19,976)
Total liabilities	942,325	929,428	1.4%	12,897
Subsidiary preferred	1,093	1,397	(21.7%)	(304)
Other mezzanine	16	5	221.8%	11
Total mezzanine level	1,109	1,402	(20.9%)	(293)
Total Liabilities and Owner's Equity	**1,292,388**	**1,263,585**	**2.3%**	**28,802**

r = revised
Note: Balance items for all three periods have been adjusted due to M&A-related activity. In particular, the subsidiary NSTAR Electric is the proxy for the former NSTAR LLC holding company because NSTAR LLC filings are not available.

Source: SNL Financial and EEI Finance Department.

Notes for 2013Y Consolidation
- NV Energy (acquired by MidAmerican 12/19/2013): 2013 FY excluded (BS)
- CH Energy (acquired by Fortis 6/27/2013): 2013 FY excluded (BS)
- Energy Future Holdings (2013Q4 results delayed): 2013 Q3 included (BS)
- Iberdrola USA (reorganization 2013Q4): 2013Y, 2012Yr, 2011Yr proxies used (BS)
  Iberdrola USA proxy: Central Maine Power Co + New York State Electric & Gas Corp (NYSEG) + Rochester Gas & Electric Corp (RG&E)

to the previous year, compared to 74% in 2012 and 67% in 2011. For 2013, the largest year-to-year dollar gains occurred at PPL Corp. (+$1.1 billion), MidAmerican Energy (+$927 billion) and Xcel Energy (+$825 million).

Industry-wide capex began to rise in 2005, which saw the first significant full-year increase since the industry's competitive generation build-out peaked in 2001 (capex was $56.8 billion in 2001). The elevated level of capex is depicted in the *Capital Spending—Trailing 12 Months* graph. The $90.3 billion spent in 2013 is more than double the $40.2 billion invested during the 12-month period that ended September 30, 2004, which marked the cyclical low following the competitive generation build-out.

Free cash flow was a negative $23.5 in 2013, compared to a negative $26.8 in 2012 and negative $13.5 billion in 2011. Although heavy investment in infrastructure across much of the industry resulted in negative consolidated post-dividend free cash flow over the last five years, annual deficits were more moderate than the negative $28.4 billion and $38.0 billion totals in 2007 and 2008. The industry's calendar-year free cash flow was last positive in 2004. There is a strong correlation on the regulated side of the business between rising capex, declining free cash flow and regulatory lag (defined as the time between a rate case filing and decision). Regulatory lag delays the recovery of costs associated with capital investment and can result in utilities significantly under-earning their allowed return on equity (ROE).

Statement of Cash Flows

U.S. INVESTOR-OWNED ELECTRIC UTILITIES

$ Millions	12 Months Ended		
	12/31/2013	12/31/2012r	% Change
Net Income	$29,647	$21,095	40.5%
Depreciation and Amortization	41,392	39,785	4.0%
Deferred Taxes and Investment Credits	13,017	12,235	6.4%
Operating Changes in AFUDC	(1,071)	(1,170)	(8.5%)
Change in Working Capital	(2,216)	(1,475)	50.2%
Other Operating Changes in Cash	6,957	13,560	(48.7%)
Net Cash Provided by Operating Activities	**87,727**	**84,030**	**4.4%**
Capital Expenditures	(90,343)	(90,278)	0.1%
Asset Sales	13,369	11,291	18.4%
Asset Purchases	(17,163)	(14,097)	21.7%
Net Non-Operating Asset Sales and Purchases	(3,794)	(2,806)	35.2%
Change in Nuclear Decommissioning Trust	(949)	(883)	7.4%
Investing Changes in AFUDC	135	142	(5.2%)
Other Investing Changes in Cash	741	(418)	NM
Net Cash Used in Investing Activities	**(94,210)**	**(94,243)**	**(0.0%)**
Net Change in Short-term Debt	815	5,132	(84.1%)
Net Change in Long-term Debt	22,142	21,809	1.5%
Proceeds from Issuance of Preferred Equity	661	855	(22.7%)
Preferred Share Repurchases	(899)	(613)	46.6%
Net Change in Prefered Issues	(237)	242	NM
Proceeds from Issuance of Common Equity	7,429	3,529	110.5%
Common Share Repurchases	(410)	(821)	(50.0%)
Net Change in Common Issues	7,019	2,708	159.2%
Dividends Paid to Common Shareholders	(20,869)	(20,528)	1.7%
Dividends Paid to Preferred Shareholders	(137)	(151)	(8.9%)
Other Dividends	(60)	(67)	(10.7%)
Dividends Paid to Shareholders	(21,066)	(20,745)	1.5%
Other Financing Changes in Cash	(1,236)	1	NM
Net Cash (Used in) Provided by Financing Activities	**7,437**	**9,148**	**(18.7%)**
Other Changes in Cash	1	23	(96.7%)
Net increase (decrease) in cash and cash equivalents	$955	$(1,042)	NM
Cash and cash equivalents at beginning of period	$13,410	$14,730	(9.0%)
Cash and cash equivalents at end of period	$14,365	$13,688	4.9%

r = revised NM = not meaningful

Notes for 2013Y Consolidation
- NV Energy (acquired by MidAmerican 12/19/2013): 2013 FY included
- CH Energy (acquired by Fortis 6/27/2013): 2013 Q1 included
- Energy Future Holdings (2013Q4 results delayed): 2013 Q1-Q3 included
- Iberdrola USA (reorganization 2013Q4): 2013Y and 2012Yr, proxies used
  Iberdrola USA proxy: Central Maine Power Co + New York State Electric & Gas Corp (NYSEG) + Rochester Gas & Electric Corp (RG&E)

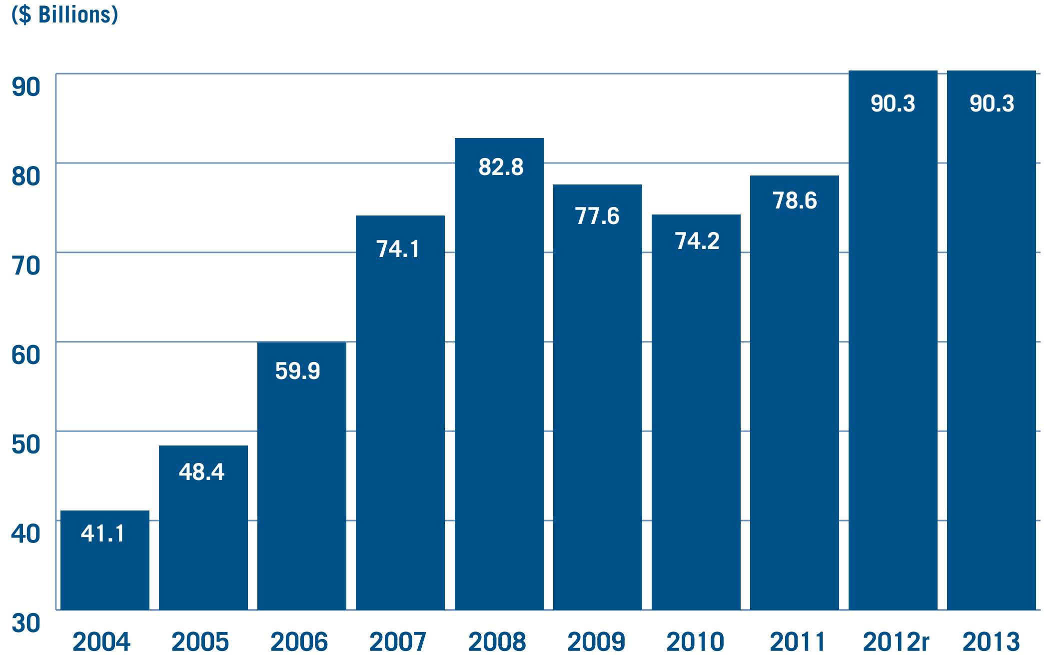
Source: SNL Financial and EEI Finance Department

Companies across the industry have boosted spending in recent years on transmission and distribution upgrades, generation projects in many power markets, and environmental compliance. In addition to the strategic decisions to boost capital spending, capex has also been impacted by construction materials cost inflation.

EEI currently projects industry capex at $93 billion in 2014 and $85 billion in 2015. The 2014

Capital Expenditures 2004–2013

U.S. INVESTOR-OWNED ELECTRIC UTILITIES



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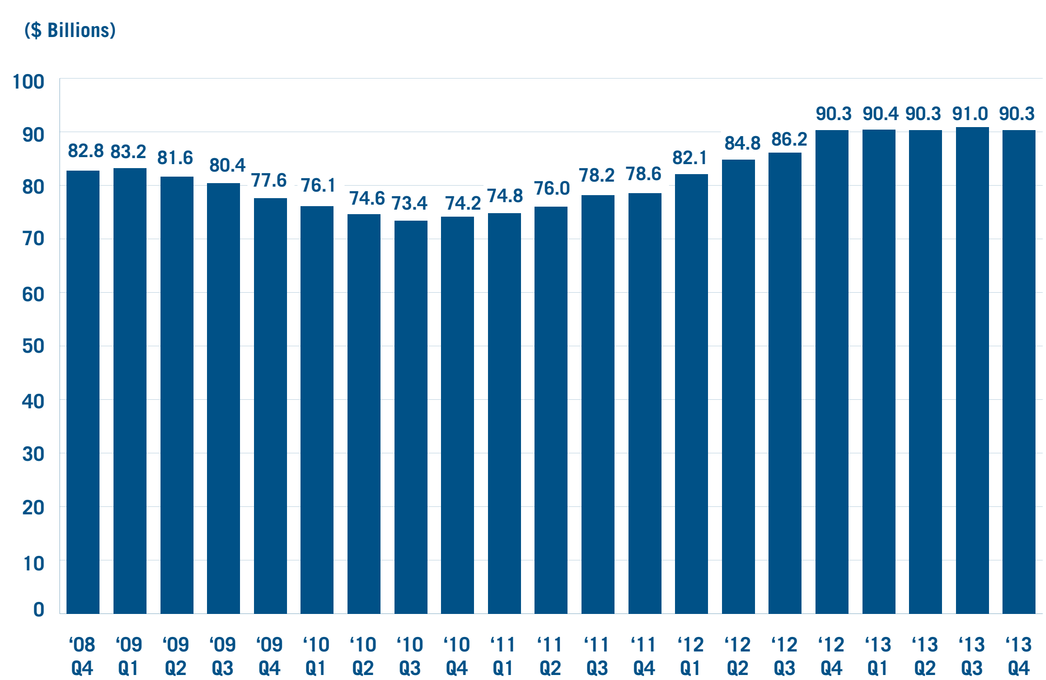
Source: SNL Financial and EEI Finance Department

Capital Spending—Trailing 12 Months

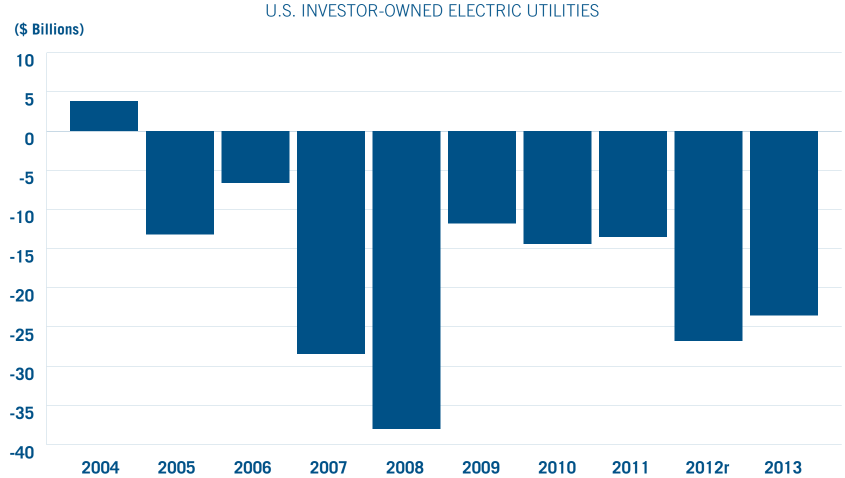
U.S. INVESTOR-OWNED ELECTRIC UTILITIES



Source: SNL Financial and EEI Finance Department

Free Cash Flow (FCF) 2004–2013

U.S. INVESTOR-OWNED ELECTRIC UTILITIES



($ Billions)	2004	2005	2006	2007	2008	2009	2010	2011	2012r	2013
Net Cash Provided by Operating Activities	58.1	50.2	69.4	61.1	61.3	82.9	77.7	84.4	84.0	87.7
Capital Expenditures	(41.1)	(48.4)	(59.9)	(74.1)	(82.8)	(77.6)	(74.2)	(78.6)	(90.3)	(90.3)
Dividends Paid to Common Shareholders	(13.2)	(15.1)	(16.1)	(15.4)	(16.5)	(17.1)	(18.0)	(19.3)	(20.5)	(20.9)
Free Cash Flow	**3.8**	**(13.2)**	**(6.6)**	**(28.4)**	**(38.0)**	**(11.8)**	**(14.4)**	**(13.5)**	**(26.8)**	**(23.5)**

r = revised
Note: Totals may not equal sum of components due to rounding.
Source: SNL Financial and EEI Finance Department

projection, if realized, will be a new high for the industry, although an actual total typically comes in slightly lower than an amount projected for the year ahead. The current projection is based on data compiled during the third quarter of 2013. EEI will update the industry's capex by business unit during the summer of 2014.

Net Cash Used in Financing Activities

Net Cash Provided by Financing Activities declined from $9.1 billion in 2012 to $7.4 billion in 2013. A $3.9 billion increase in Proceeds from Issuance of Common Equity was more than offset by a $4.3 billion decrease in Net Change in Short-term Debt. Long-term debt has ramped up in recent years, showing annual net increases of $22.1 billion, $21.8 billion, $12.0 billion, $9.3 billion, $17.9 billion and $33.0 billion from 2013 back to 2008.

Given the industry's elevated capital spending, it is not surprising that long-term debt continues to rise after the sizeable debt paydowns from 2003 through mid-year 2006. Total long-term debt fell from $349.7 billion at the end of 2003 to $322.8 billion at June 30, 2006, and has since risen to $456.7 billion (including securitized debt) at December 31, 2013.

Proceeds from Issuance of Common Equity more than doubled in 2013, following declines of 32.5% in 2012 and 32.9% in 2011. Common equity issuance totaled $7.8 billion in 2010 and $8.6 billion in 2009, rising from $4.8 billion and $4.3 billion in 2007 and 2008, as companies sought the right debt/equity balance to fund elevated capital spending. From 2003 through 2006, annual issuance ranged from $8.3 billion to $10.0 billion. This metric rose from $5.0 billion and $5.6 billion in 2000 and 2001 to $13.1 billion in 2002, before settling in the $8 to $10 billion range. The industry's strong stock market performance over the last decade, in addition to a widespread desire to strengthen debt-to-capitalization ratios, drove the higher stock issuance. Bonus depreciation has also helped finance the industry's significant capital needs in recent years.

Dividends

The investor-owned electric utility industry added to its near-decade-long trend of widespread dividend increases during 2013. Nine companies raised their dividend during the fourth quarter (Q4 and Q2 are the most active quarters after Q1) for a total of 36 companies in 2013 that either increased or reinstated their dividend. This is just below the 37 in 2012 and at the top end of the 31 to 37 range of the previous four years. While 2013's total was a step down from 2007's 43 companies, it remained well above the 27 that raised or reinstated their dividend in full-year 2003.

The percentage of companies that raised or reinstated their dividend in 2013 was 73.5%, up from 72.5% in 2012, 58% in 2011 and 60% in 2010. The 2013 result is the highest on record, based on data going back to 1988. The 15% dividend tax rate has supported the high number of increases in recent years.

At December 31, 2013, all 49 publicly traded companies in the EEI Index were paying a common stock dividend. *Dividend Patterns* shows the industry's dividend paying patterns over the past 21 years. Each company is limited to one action per year. For example, if a company raised its dividend twice during a year, that counts as one in the Raised column. Companies generally use the same quarter each year for dividend changes, typically the first quarter for electric utilities.

2013 Increases Average 5.3%

The industry's average dividend increase per company during 2013 was 5.3%, with a range of 1.2% to 27.6% and a median increase of 4.1%. PNM Resources (+27.6% total in Q1 and Q4), IDACORP (+13.2% in Q3) and Wisconsin Energy (+12.5% in Q3) posted the largest overall percentage increases. Three companies increased their dividends twice during 2013 (PNM Resources, American Electric Power and MDU Resources). If total dividend increases are raised to 39 to reflect this, then the average increase per action was 4.8%.

PNM Resources, based in Albuquerque, New Mexico, increased its dividend twice in 2013, first from $0.145 to $0.165 per share in Q1 and then to $0.185 in Q4. The company has targeted a 50% to 60% payout ratio range.

Headquartered in Boise, Idaho, IDACORP increased its quarterly dividend from $0.38 to $0.43 per share in Q3. The company anticipates having annual increases of at least 5% until the dividend payout ratio reaches the upper end of its targeted range of 50% to 60% of sustainable company earnings.

Milwaukee's Wisconsin Energy raised its quarterly dividend from $0.34 to $0.3825 per share in Q3, accelerating the original plan for a Q1 2014 move. The company reaffirmed its policy of a targeted payout ratio trending to 65% to 70% of earnings in 2017.

Payout Ratio and Dividend Yield

The industry's dividend payout ratio was 60.6% for the 12 months ending December 31, 2013, surpassing all other U.S. business sectors except the broader utilities sector (consisting of electric, gas and water utilities), which had a 62.6% result. (The industry's payout ratio was 61.5% when measured as an unweighted average of individual company ratios; 60.6% represents an aggregate figure).

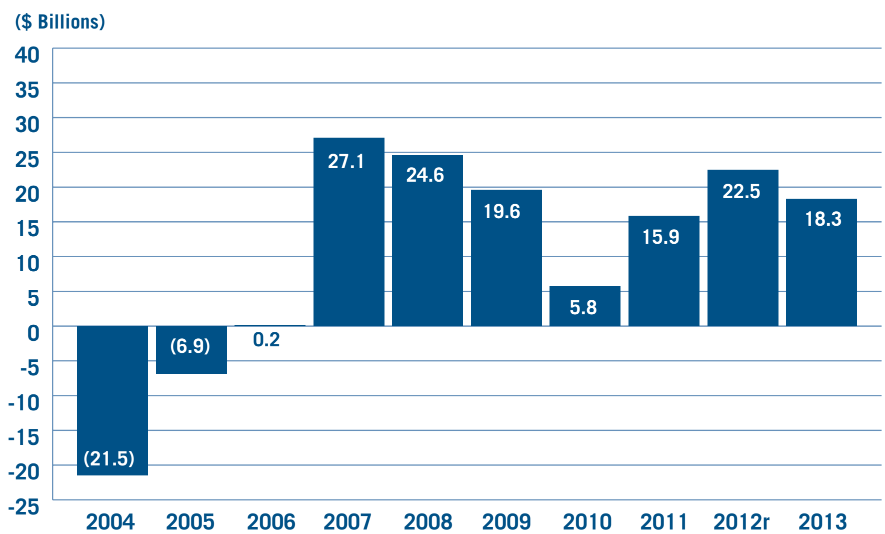
While the industry's net income has fluctuated from year to year, its payout ratio has remained relatively constant after eliminating non-recurring and extraordinary items from earnings. From 2000 through 2012, the annual unweighted average payout ratio ranged from 62.0% to 69.6%, with the highest result coming in 2009 due to the weak economy and the weather's negative impact on earnings. We use the following approach when calculating the industry's dividend payout ratio:

1. Non-recurring and extraordinary items are eliminated from earnings.
2. Companies with negative adjusted earnings are eliminated.
3. Companies with a payout ratio in excess of 200% are eliminated.

The industry's average dividend yield was 4.0% on December 31, 2013, higher than all other business sectors. The industry's yield was

Net Change in Long-term Debt 2004–2013

U.S. INVESTOR-OWNED ELECTRIC UTILITIES



r = revised

Note: Based on data from industry's consolidated balance sheet

Source: SNL Financial and EEI Finance Department

unchanged from September 30 and June 30, and just above the 3.9% on March 31, 2013. This follows yields of 4.3% at year-end 2012, 4.1% at year-end 2011, 4.5% at year-ends 2010 and 2009, and 4.9% at year-end 2008. We calculate the industry's aggregate dividend yield using an un-weighted average of the 49 publicly traded EEI Index companies' yields. The strong dividend yields prevalent among most electric utilities have helped support their share prices in recent years, especially given the period's historically low interest rates. The EEI Index rose by 13.0% in 2013 after gaining 2.1% in 2012 and 20.0%, 7.0% and 10.7% in 2011, 2010 and 2009, respectively.

Business Category Comparison

As shown in *Category Comparison, Dividend Yield*, the Mostly Regulated category had the highest dividend yield by category on December 31, 2013, at 4.1%, compared to the Regulated's 4.0% and Diversified's 2.3%. Note that Diversified category metrics have become less meaningful indicators of broad industry trends in recent years since category membership has fallen to a single publicly traded company, as industry business models migrate back to a regulated emphasis. The yields for all three categories are below their levels at December 31, 2012, when the Regulated, Mostly Regulated and Diversified yields were 4.2%, 4.4% and 4.0%, respectively.

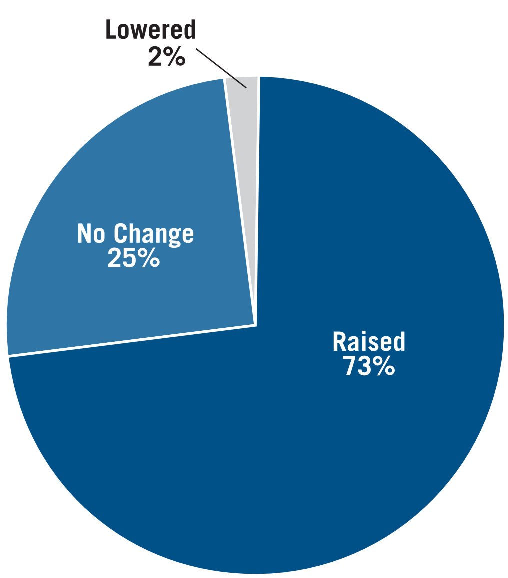
The Mostly Regulated group recorded a dividend payout ratio of 64.7% for the 12 months ended December 31, 2013, compared to 60.5% for the Regulated group and 44.7% for the Diversified group (see *Category Comparison—Dividend Payout Ratio*). The Regulated group has typically produced the highest annual payout ratio, having done so in 2010 and 2011 and each year from 2003 through 2008. It was exceeded by the Mostly Regulated group in 2009 and again in 2012.

Share Repurchases Remain Low After 2007 Spike

Ten of the industry's publicly traded companies repurchased an aggregate $410 million of common shares during 2013 as an alternate way of returning cash to shareholders. This compares to 14 companies and $821 million in 2012, 15 companies and $1.8 billion in 2011, 13 and $2.7 billion in 2010, 11 and $908 million in 2009 and a total of $2.4 billion in 2008—all levels far below the $11.9 billion of 2007. The industry's common share repurchases exceeded $6.0 billion in 2004, 2005 and 2006 after rising from only $120 million in 2003.

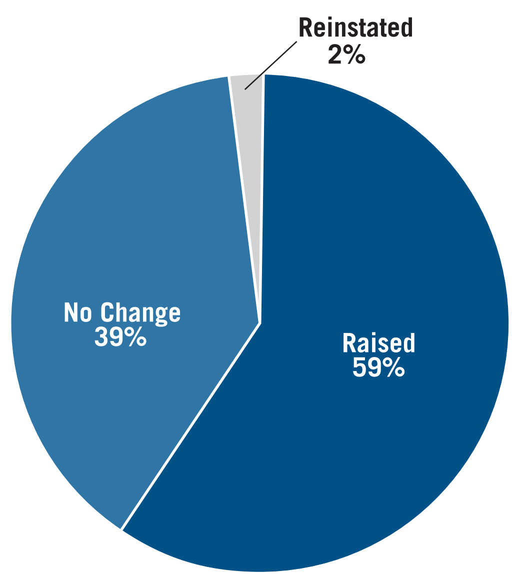
2013 Dividend Patterns

U.S. INVESTOR-OWNED ELECTRIC UTILITIES



2012 Dividend Patterns

U.S. INVESTOR-OWNED ELECTRIC UTILITIES



Source: EEI Finance Department

Free Cash Flow Deficit Continues in 2013

The industry's aggregate free cash flow remained in a deficit during 2013, at negative $23.5 billion compared to negative $26.8 billion in 2012. The change was driven by a $3.7 billion, or 4.4%, increase in net cash from operations. Capital expenditures were unchanged, while dividends inched forward by $344 million, or 1.7%. This marks the ninth consecutive year of free cash flow deficits.

The industry's capital spending remains historically high due to elevated levels of investment in environmental compliance, transmission and distribution upgrades, and new generation capacity. While some analysts define free cash flow as the difference between cash flow from operations and capital expenditures, we also deduct common dividends due to the utility industry's strong tradition of dividend payments.

EEI's latest projections (as of October 2013) for industry capex are $93 billion in 2014 and $85 billion in 2015. The projected breakdown for 2013 among business functions is as follows: Generation = 37%, Distribution = 21%, Transmission = 17%, Natural Gas-Related = 12%, Environmental = 7%, Other = 6%.

Total aggregate industry-wide cash dividends paid to common shareholders rose by $341 million

Dividend Patterns 1993–2013

U.S. INVESTOR-OWNED ELECTRIC UTILITIES

	Raised	No Change	Lowered	Omitted*	Reinstated	Not Paying	Total	Dividend Payout Ratio
1993	65	29	1	–	1	4	100	80.5%
1994	54	37	6	–	–	3	100	79.8%
1995	52	40	3	–	–	3	98	75.3%
1996	48	44	2	1	1	2	98	70.7%
1997	40	45	6	2	–	3	96	84.2%
1998	40	37	7	–	–	5	89	82.1%
1999	29	45	4	–	3	2	83	74.9%
2000	26	39	3	1	–	2	71	63.9%**
2001	21	40	3	2	–	3	69	64.1%
2002	26	27	6	3	–	3	65	67.5%
2003	26	24	7	2	1	5	65	63.7%
2004	35	22	1	–	–	7	65	67.9%
2005	34	22	1	1	2	5	65	66.5%
2006	41	17	–	–	–	6	64	63.5%
2007	40	15	–	–	3	3	61	62.1%
2008	36	20	1	–	1	1	59	66.8%
2009	31	23	3	–	–	1	58	69.6%
2010	34	22	–	–	–	1	57	62.0%
2011	31	22	–	1	1	–	55	62.8%
2012	36	14	–	–	1	–	51	64.2%
2013	36	12	1	–	–	–	49	61.5%

	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013
Average of the Increased Dividend Actions ***	5.8%	18.7%	8.4%	9.2%	7.4%	9.4%	7.2%	8.2%	6.8%	7.2%	5.3%
Average of the Declining Dividend Actions ***	(38.4%)	(47.4%)	(40.0%)	NA	NA	(45.7%)	(46.4%)	NA	(100.0%)	NA	(41.0%)

* Omitted in current year. This number is not included in the Not Paying column.

** Prior to 2000 = total industry dividends/total industry earnings, starting in 2000 = average of all companies paying a dividend.

*** Excludes companies that omitted or reinstated dividends

Note: Dividend percent changes are based on year-end comparisons.

Source: EEI Finance Department and SNL Financial

Category Comparison—Dividend Payout Ratio

Category[1]	2005	2006	2007	2008	2009	2010	2011	2012	2013
EEI Index	**66.5**	**63.3**	**62.1**	**66.8**	**69.6**	**62.0**	**62.8**	**64.2**	**61.5**
Regulated	68.4	71.5	65.0	71.2	68.2	64.1	63.4	62.1	60.5
Mostly Regulated	65.0	56.6	63.5	66.7	72.2	60.7	63.1	69.7	64.7
Diversified	64.3*	54.5	45.5	44.6	69.2	49.7	54.7	53.4	44.7

*Removing Duke's payout ratio of 151% would produce a category ratio of 54.6%
[1] Refer to page v for category descriptions.

Note: In addition to the impact of dividend strategies and company earnings, the dividend payout ratios for each category are also affected by the movement of companies between categories and by dividend reinstatements and cancellations.

Source: EEI Finance Department, SNL Financial, and company annual reports

Category Comparison, Dividend Yield
As of December 31, 2013

Category[1]	Dividend Yield
EEI Index	**4.0%**
Regulated	4.0%
Mostly Regulated	4.1%
Diversified	2.3%

[1] Refer to page v for category descriptions.
Source: EEI Finance Department and SNL Financial

over last year, increasing from $20.5 billion in 2012 to $20.9 billion in 2013. This follows a $1.0 billion, or 6.0%, increase in 2012. From 2003 through 2013, total industry-wide cash dividends rose 70%, to $20.9 billion from $12.3 billion.

Legislation Provides Permanent Dividend Tax Rates

On January 1, 2013, Congress passed the American Taxpayer Relief Act of 2012, which forestalled imminent federal spending reductions commonly referred to as the "fiscal cliff." As part of this legislation, dividend tax rates (which would have reverted to ordinary income tax levels in 2013) were kept low and permanently linked to tax rates for capital gains. The top rate for dividends and capital gains is now 20% for couples earning more than $450,000 ($400,000 for singles). For taxpayers below these income thresholds, dividends and capital gains continue to be taxed

Sector Comparison Dividend Payout Ratio
For 12-month period ending 12/31/13

Sector	Payout Ratio (%)
EEI Index Companies*	**60.6%**
Utilities	62.6%
Consumer Staples	52.2%
Materials	41.3%
Industrial	33.1%
Technology	30.6%
Health Care	30.1%
Energy	29.5%
Consumer Discretionary	26.5%
Financial	25.8%

* For this table, EEI (1) sums dividends and (2) sums earnings of all index companies and then (3) divides to determine the comparable DPR.

Note: EEI Index Companies' payout ratio based on LTM income before nonrecurring and extraordinary items.

Source: AltaVista Research, SNL Financial, and EEI Finance Department

Sector Comparison, Dividend Yield
As of December 31, 2013

Sector	Dividend Yield (%)
EEI Index Companies	**4.0%**
Utilities	4.0%
Consumer Staples	2.7%
Materials	2.1%
Energy	1.8%
Industrial	1.8%
Technology	1.8%
Financial	1.7%
Health Care	1.6%
Consumer Discretionary	1.2%

Note: EEI Index Companies' yield based on LTM cash dividends paid; other sectors' yields based on 2013E dividends.

Source: AltaVista Research, SNL Financial, and EEI Finance Department

Dividend Summary
As of December 31, 2013

U.S. INVESTOR-OWNED ELECTRIC UTILITIES

Company Name	Stock	Company Category	Annualized Dividends	Payout Ratio	Yield (%)	Last Action	To	From	Date Announced
ALLETE, Inc.	ALE	R	$1.90	71.8%	3.8%	Raised	$1.90	$1.84	2013 Q1
Alliant Energy Corporation	LNT	R	$1.88	54.5%	3.6%	Raised	$1.88	$1.80	2013 Q1
Ameren Corporation	AEE	R	$1.60	54.0%	4.4%	Raised	$1.60	$1.54	2011 Q4
American Electric Power Company, Inc.	AEP	R	$2.00	56.2%	4.3%	Raised	$2.00	$1.96	2013 Q4
Avista Corporation	AVA	R	$1.22	61.3%	4.3%	Raised	$1.22	$1.16	2013 Q1
Black Hills Corporation	BKH	R	$1.52	58.3%	2.9%	Raised	$1.52	$1.48	2013 Q1
CenterPoint Energy, Inc.	CNP	MR	$0.83	114.1%	3.6%	Raised	$0.83	$0.81	2013 Q1
Cleco Corporation	CNL	R	$1.45	53.5%	3.1%	Raised	$1.45	$1.35	2013 Q2
CMS Energy Corporation	CMS	R	$1.02	59.6%	3.8%	Raised	$1.02	$0.96	2013 Q1
Consolidated Edison, Inc.	ED	R	$2.46	67.9%	4.5%	Raised	$2.46	$2.42	2013 Q1
Dominion Resources, Inc.	D	MR	$2.25	73.8%	3.5%	Raised	$2.25	$2.11	2012 Q4
DTE Energy Company	DTE	R	$2.62	66.6%	3.9%	Raised	$2.62	$2.48	2013 Q2
Duke Energy Corporation	DUK	R	$3.12	60.7%	4.5%	Raised	$3.12	$3.06	2013 Q2
Edison International	EIX	R	$1.42	28.4%	3.1%	Raised	$1.42	$1.35	2013 Q4
El Paso Electric Company	EE	R	$1.06	47.5%	3.0%	Raised	$1.06	$1.00	2013 Q2
Empire District Electric Company	EDE	R	$1.02	65.3%	4.5%	Raised	$1.02	$1.00	2013 Q4
Entergy Corporation	ETR	R	$3.32	55.7%	5.2%	Raised	$3.32	$3.00	2010 Q2
Exelon Corporation	EXC	MR	$1.24	67.4%	4.5%	Lowered	$1.24	$2.10	2013 Q2
FirstEnergy Corp.	FE	MR	$2.20	70.1%	6.7%	Raised	$2.20	$2.00	2007 Q4
Great Plains Energy Inc.	GXP	R	$0.92	54.2%	3.8%	Raised	$0.92	$0.87	2013 Q4
Hawaiian Electric Industries, Inc.	HE	MR	$1.24	60.2%	4.8%	Raised	$1.24	$1.22	1998 Q1
IDACORP, Inc.	IDA	R	$1.72	47.3%	3.3%	Raised	$1.72	$1.52	2013 Q3
Integrys Energy Group, Inc.	TEG	R	$2.72	57.9%	5.0%	Raised	$2.72	$2.68	2009 Q1
MDU Resources Group, Inc.	MDU	D	$0.71	44.7%	2.3%	Raised	$0.71	$0.69	2013 Q4
MGE Energy, Inc.	MGEE	MR	$1.63	49.5%	2.8%	Raised	$1.63	$1.58	2013 Q3
NextEra Energy, Inc.	NEE	MR	$2.64	57.1%	3.1%	Raised	$2.64	$2.40	2013 Q1
NiSource Inc.	NI	MR	$1.00	64.7%	3.0%	Raised	$1.00	$0.96	2013 Q2
Northeast Utilities	NU	R	$1.47	58.3%	3.5%	Raised	$1.47	$1.37	2013 Q1
NorthWestern Corporation	NWE	R	$1.52	61.4%	3.5%	Raised	$1.52	$1.48	2013 Q1
OGE Energy Corp.	OGE	MR	$0.90	42.0%	2.7%	Raised	$0.90	$0.84	2013 Q4
Otter Tail Corporation	OTTR	MR	$1.19	71.8%	4.1%	Raised	$1.19	$1.17	2008 Q1
Pepco Holdings, Inc.	POM	MR	$1.08	NM	5.6%	Raised	$1.08	$1.04	2008 Q1
PG&E Corporation	PCG	R	$1.82	76.4%	4.5%	Raised	$1.82	$1.68	2010 Q1
Pinnacle West Capital Corporation	PNW	R	$2.27	53.5%	4.3%	Raised	$2.27	$2.18	2013 Q4
PNM Resources, Inc.	PNM	R	$0.74	39.9%	3.1%	Raised	$0.74	$0.66	2013 Q4
Portland General Electric Company	POR	R	$1.10	80.8%	3.6%	Raised	$1.10	$1.08	2013 Q2
PPL Corporation	PPL	MR	$1.47	48.1%	4.9%	Raised	$1.47	$1.44	2013 Q1
Public Service Enterprise Group Incorporated	PEG	MR	$1.44	54.2%	4.5%	Raised	$1.44	$1.42	2013 Q1

Dividend Summary (cont.)
As of December 31, 2013

U.S. INVESTOR-OWNED ELECTRIC UTILITIES

Company Name	Stock	Company Category	Annualized Dividends	Payout Ratio	Yield (%)	Last Action	To	From	Date Announced
SCANA Corporation	SCG	MR	$2.03	59.7%	4.3%	Raised	$2.03	$1.98	2013 Q1
Sempra Energy	SRE	MR	$2.52	52.4%	2.8%	Raised	$2.52	$2.40	2013 Q1
Southern Company	SO	R	$2.03	61.0%	4.9%	Raised	$2.03	$1.96	2013 Q2
TECO Energy, Inc.	TE	R	$0.88	96.7%	5.1%	Raised	$0.88	$0.86	2012 Q1
UIL Holdings Corporation	UIL	R	$1.73	70.8%	4.5%	Raised	$1.73	$1.69	1996 Q1
Unitil Corporation	UTL	R	$1.38	88.4%	4.5%	Raised	$1.38	$1.36	2012 Q1
UNS Energy Corporation	UNS	R	$1.74	56.7%	2.9%	Raised	$1.74	$1.72	2013 Q1
Vectren Corporation	VVC	MR	$1.44	85.9%	4.1%	Raised	$1.44	$1.42	2013 Q4
Westar Energy, Inc.	WR	R	$1.36	54.1%	4.2%	Raised	$1.36	$1.32	2013 Q1
Wisconsin Energy Corporation	WEC	R	$1.53	62.1%	3.7%	Raised	$1.53	$1.36	2013 Q3
Xcel Energy Inc.	XEL	R	$1.12	54.2%	4.0%	Raised	$1.12	$1.08	2013 Q2
Industry Average				**61.47%**	**3.97%**				

Categories:
R = Regulated: greater than 80% of total assets are regulated
MR = Mostly Regulated: 50-80% of total assets are regulated
D = Diversified: less than 50% of total assets are regulated

Annualized Dividend: Per share amounts are annualized declared figures as of 12/31/13.
Payout Ratio: Dividends paid for 12 months ended 12/31/13 divided by net income before extraordinary and nonrecurring items for 12 months ended 12/31/13.
Dividend Yield: Annualized Dividends Per Share at 12/31/13 divided by stock price at market close on 12/31/13.
"NM" applies to companies with negative earnings or payout ratios greater than 200%.

Source: EEI Finance Department and SNL Financial

at the current rates of 15% and 0%, depending on a filer's income level. Beginning with the 2013 tax year, a 3.8% Medicare tax that was included in the 2010 health care legislation is applied to all investment income for couples earning more than $250,000 ($200,000 singles).

Continued low dividend tax rates remain an important element of the industry's ability to attract capital for investment in emissions reduction, new transmission lines, distribution upgrades and new generation in the years ahead. Notably, parity between dividend and capital gains tax rates was preserved by Congress, thereby not creating a disadvantage for companies that rely on a strong dividend to attract investors.

Rate Case Summary

Investor-owned electric utilities filed 46 new rate cases in 2013, the lowest annual total since 2009. The slow pace of filings might suggest a reversal in the trend of escalating rate case activity since the year 2000. However, 24 cases were decided during the fourth quarter and utilities rarely file a case while another is in progress. The number of filings is likely to remain high, reflecting the industry's ongoing construction cycle driven by the need to replace and upgrade infrastructure and reduce the environmental impact of power generation.

Capital investment was the primary driver of filings in 2013, as it has been each year since the initiation of this report series. Utilities' efforts to implement adjustment mechanisms, such as trackers and riders, was the second major driver of filings in 2013, edging out recovery of operation and maintenance (O&M) expenses. Trackers and O&M recovery have been cited frequently as motivations for filings in recent years. Finally, storm cost recovery was a factor in several filings, as were utility efforts to recover for shortfalls caused by low demand growth.

The average allowed ROE in 2013 was 10.02%, the lowest in our more than two decades of data. The average allowed ROE in 2012 was 10.15%; the last four years have each set successive record lows. Average requested ROE for 2013 was 10.46%, a record low and below 2012's 10.72% and the fourth in a series of consecutive annual record lows.

Average regulatory lag for 2013 was 8.42 months. While slightly lower than in recent years, a review of rate case decisions does not seem to indicate the number resulted from attempts by commissions to decrease lag during a time of heavy industry investment. Around the turn of the century, during industry restructuring, regulatory lag was more volatile and generally higher.

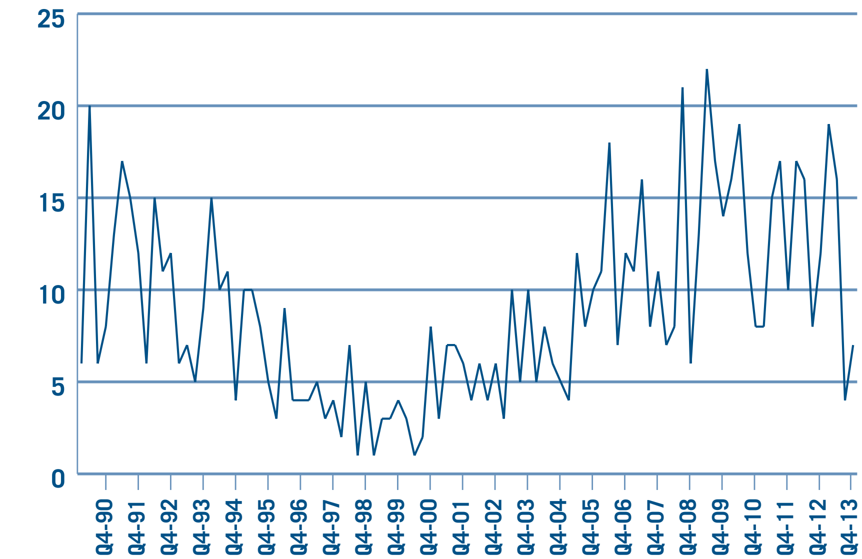
Filed Cases

Storm Cost Recovery

Storm cost recovery figured prominently in a number of rate case filings in 2013. United Illuminating filed in Connecticut in part to recover costs for storms since 2008. The company claimed $52 million in unfunded storm costs and proposed to draw on the customer's share of the company's earnings sharing mechanism for funding. The company

Number of Rate Cases Filed 1990-2013

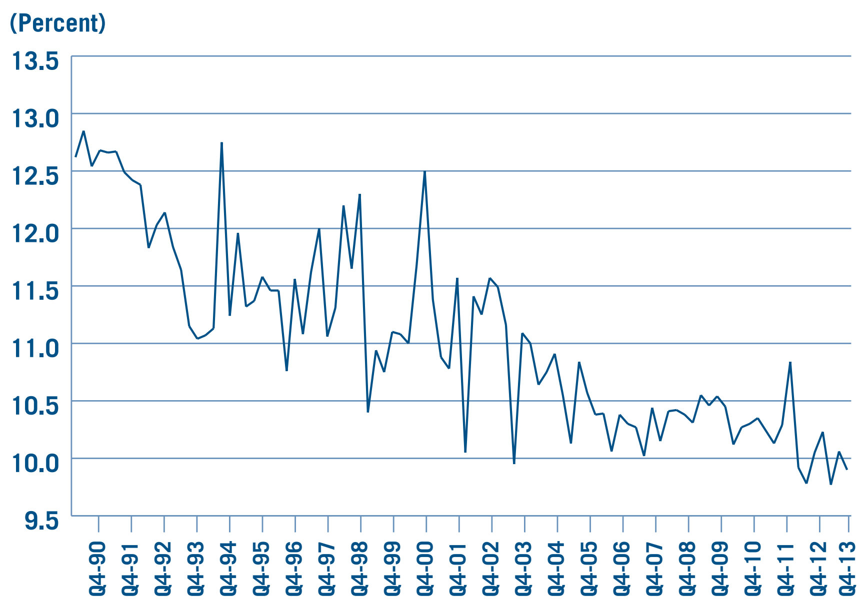
U.S. INVESTOR-OWNED ELECTRIC UTILITIES



Source: SNL Financial/Regulatory Research Assoc. and EEI Rate Department

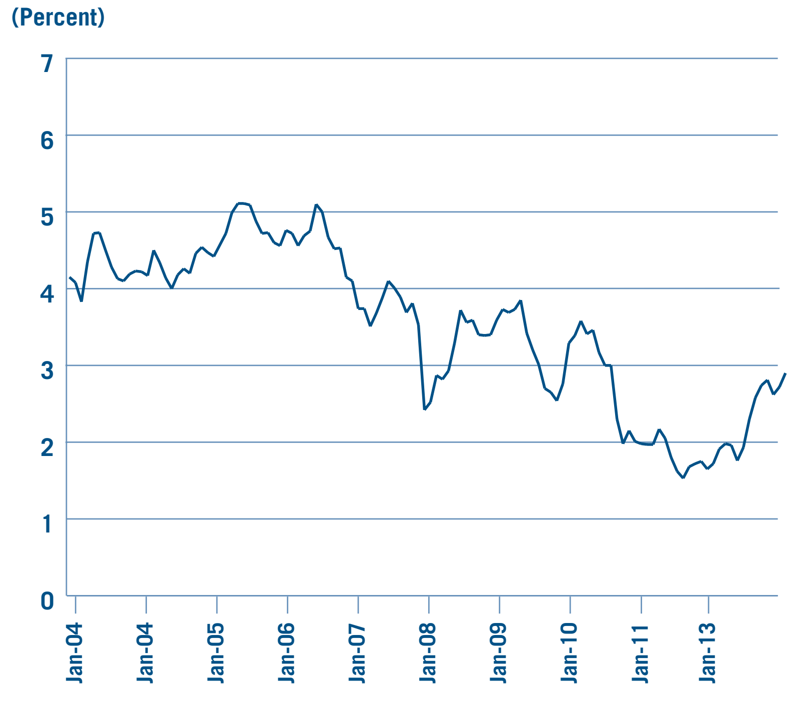
Average Awarded ROE 1990-2013

U.S. INVESTOR-OWNED ELECTRIC UTILITIES



Source: SNL Financial/Regulatory Research Assoc. and EEI Rate Department

10-Year Treasury Yield
1/1/04 through 12/31/13



Source: U.S. Federal Reserve

proposed to recover $8.7 million of storm costs annually to amortize storm expense.

As part of Baltimore Gas and Electric's filing in Maryland, the company proposed to implement an electric reliability investment (ERI) initiative and an associated tracker mechanism. Both are based on guidelines established as part of the commission's review of Maryland utilities' reliability performance and a governor's task force recommendation following a derecho storm. The ERI includes measures to be completed between 2014 and 2018 at an estimated cost of $136 million and was expected to improve the company's reliability by 10% over its average performance between 2010 and 2012.

Rockland Electric in New Jersey filed to recover costs; $11 million of the company's requested $19.3 million increase was for three storms, Hurricane Irene, a 2011 snow storm and Superstorm Sandy. The $11 million includes $2.2 million for increased storm reserves and $1 million for storm hardening. The company also filed for a surcharge for recovery of future storm-hardening projects.

Earned Return

Several companies filed cases during 2013 as a result of under-earning their authorized return, which can happen when regulatory lag prevents revenue from keeping pace with rising expenses. Potomac Electric Power, in its Washington, D.C. filing, said it earned less than half its authorized 9.5% ROE during the test year. Virginia Electric & Power said that its return had been reduced by 50 basis points by the retirement of six coal plants and by storm expenses. Baltimore Gas and Electric said that it expected to earn a 5.68% overall return for the year ending July 31, 2013.

ROE Decreases for Decoupling

Electric utilities during 2013 sought to eliminate ROE decreases imposed by commissions because the companies have decoupling programs. The commissions argued that decoupling decreases risk and the utility should therefore be awarded a lower ROE. The 10.25% ROE that Potomac Electric Power filed for in D.C. did not reflect a 50-basis-point downward adjustment for the company's decoupling mechanism. The company said the downward adjustment did not reflect current market conditions and was contrary to the vast majority of cases for decoupled utilities. Similarly, Delmarva Power & Light in its Maryland filing said it would like to dispense with the 50-basis-point reduction because it did not reflect current market conditions.

Low Growth

Low demand growth in the electric utility industry affected several filings in 2013. Lower sales volume in part drove Duke's filing in South Carolina. Sluggish revenue growth in part drove Tampa Electric's filing in 2013. And Baltimore Gas and Electric's filing references low customer growth.

Northern States Power—Minnesota

NSP proposed a "rate modernization plan" that would accelerate from eight years to three years the amortization of transmission, distribution and generation plant depreciation reserve surplus, and use funds from a settlement with the Department of Energy to mitigate the impact on ratepayers. The company also proposed a weather-normalized revenue decoupling mechanism for residential and small commercial customers, as well as interim treatment for a coal plant that is returning to service after a technical problem.

Westar Kansas

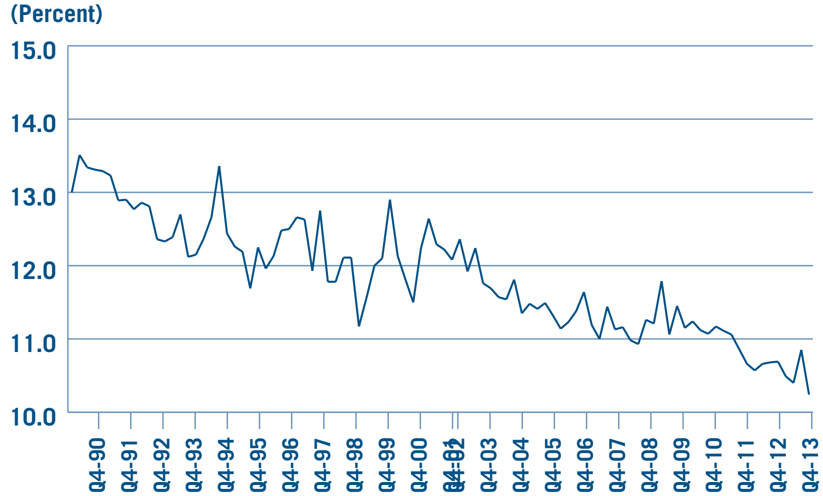
Westar filed in Kansas for recovery of incremental costs, including construction work-in-progress, for an emissions control project at a coal plant. Among the many goals Westar hopes to achieve is a reduction in cross-class subsidies, an increase in the fixed monthly residential customer charge from $9 to $13, and an increase in the small general customer charge from $19 to $20.

Other

Potomac Electric Power in Maryland filed in part because the company's earned ROE is only 6.69% (allowed ROE is 9.36%). Bangor Hydro Electric and Maine Public Service filed together; the companies merged into a single entity—Emera Maine—at the end of 2013, after the filing. They hoped to recover costs of a new customer information system and vegetation management. Kansas City Power & Light in Kansas filed an "abbreviated" case; this is allowed by law in Kansas when the filing is made within 12 months of a rate

Average Requested ROE 1990-2013

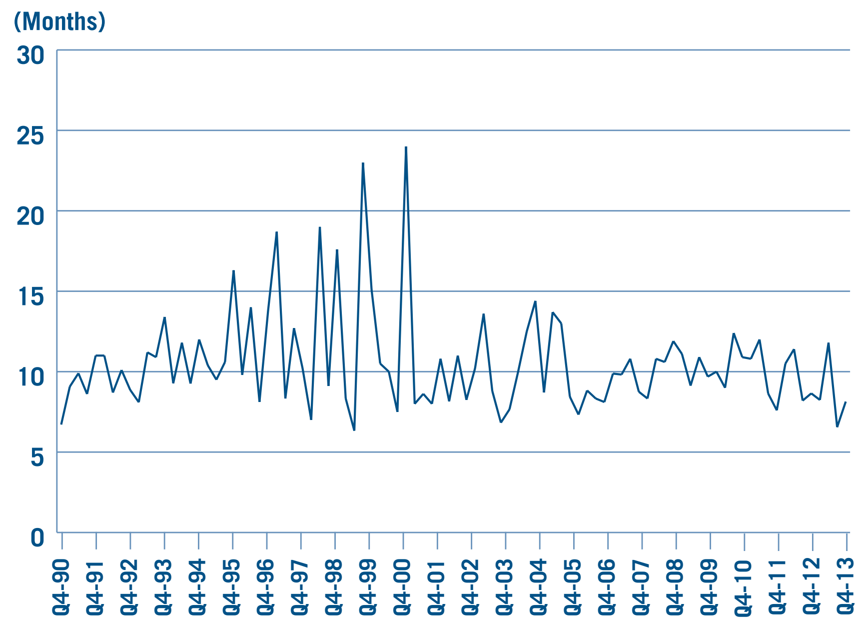
U.S. INVESTOR-OWNED ELECTRIC UTILITIES



Source: SNL Financial/Regulatory Research Assoc. and EEI Rate Department

Average Regulatory Lag 1990-2013

U.S. INVESTOR-OWNED ELECTRIC UTILITIES



Source: SNL Financial/Regulatory Research Assoc. and EEI Rate Department case order and reflects "all the regulatory procedures, principles, and rate of return [parameters] established by the Commission."

Decided Cases

ROE

In Kansas City Power & Light's subsidiaries' cases in Missouri, the companies originally requested a 10.4% ROE, later modified to 10.3%. The commission authorized 9.7%, in part because of "the downward trend in national averages of other state commissions' ROE awards, the continuing downward pressure on interest rates nationally, [and] the slower-than average recovery in Missouri."

In Indiana-Michigan Power's case in Indiana, the commission awarded a 10.2% ROE as the mid-point of all the parties' recommendations, additionally finding that the changes to the off-system sales (OSS) margin sharing mechanism and the establishment of a storm reserve reduced the company's earnings risk. The off-system sales mechanism was changed such that all variations are shared equally by customers and shareholders; the previous mechanism only shared amounts above a certain embedded amount with shareholders. The commission justified the different sharing mechanism as warranted by "market dynamics" and said that "sharing only the amount of sales in excess of the [embedded] amount and not any shortfalls does not fairly align the risk and reward of OSS sales between the company and ratepayers." The company had proposed a "fair value increment" to revenue requirement to support the company's "continued financial resilience." This increment was calculated by applying an inflation-adjusted long-term Treasury bond yield to the difference between the company's fair value rate base and net original cost rate base. The company said that the commission's approval of the increment would "provide a clear signal that the Commission is willing to use the regulatory tools at its disposal to support [the company's] efforts to maintain investment grade [credit] ratings and improve its credit standing by improving its ability to earn its allowed return." The commission concluded that the increment "artificially inflates the company's rates by arbitrarily increasing the amount of revenues [the company] is authorized to collect above that already calculated to provide a reasonable opportunity to earn its authorized return."

In Baltimore Gas and Electric's case in Maryland, the commission awarded the company a 9.75% ROE that reflected a downward adjustment of 50 basis points because the company has a decoupling mechanism. BGE had argued that such an adjustment was not necessary because all the companies in the proxy group either had decoupling mechanisms or other revenue recovery mechanisms. The commission commented that, because another recent order prevented utilities from recovering lost revenues from storms through the decoupling mechanism, "a strict basis point reduction of 50 points may no longer be warranted," but the company's decoupling mechanism is "a 'very good' decoupling mechanism, better than almost all the others in any of the experts' proxy groups, which serves to limit the risk, and therefore the appropriate ROE for BGE."

Indiana-Michigan Power (IM) Indiana

IM had proposed to include $6.2 million of storm restoration costs in its revenue requirement using a three-year average of these costs. The commission instead mandated a five-year average, at $4.2 million, but also allowed the company to implement a tracking mechanism for storm costs. The commission said "at times the cost of [storm] restoration may greatly exceed the amount of expense included in [the company's] revenue requirement . . . that risk is traditionally borne by shareholders. In the past, the Commission has allowed a utility to seek recovery of extraordinary storm restoration expenses through a separate proceeding, but only when the storm at issue was a worst-case scenario. As we have recently seen, these stand-alone cases are often heavily litigated and highly contentious. Of course, the opposite situation also occurs, where the costs of storm restoration may be substantially less than the amount of the expense included in [the company's] revenue requirement . . . the accounting [treatment] proposed by the Company . . . addresses both of these situations."

Baltimore Gas and Electric (BGE)

In the first of two cases decided for BGE during 2013 (for information on the second case, see *Decided Cases, ROE* above), the company argued that its use of a historical test year, along with rising costs, prevented it from earning its authorized return. Additionally, the company had planned more than $3 billion in capital expenditures over the next five years. As a result, BGE sought to include estimated post-test-year investments in rate base. BGE said the estimated costs meet the known and measureable test because the company is required to spend 95% of its planned capital expenditures and operation and maintenance expenses in 2012 and 2013 as a condition of the company's merger with Exelon. BGE also said it has shown a pattern of investment in safety and reliability and thus can easily estimate these costs. However, the commission found that the proposal included estimated post-test-year investments in rate base did not meet the known and measureable test, because it was "simply an estimate" and lacked sufficient support. The commission found the safety and reliability investment not used and useful or known and measureable and that "by the Company's own admission, estimates, forecasts, and budgets can prove unreliable."

Duke Energy Ohio

The Ohio commission authorized a settlement that grants Duke an $11 million vegetation management expense, the same amount the company spent in the test year, and a $4.4 million baseline expense for storms, but disallowed the company's requested storm deferral and tracking mechanism and any attempt to recover incremental expenses for 2012 storms. The company can request deferral of incremental storm costs after 2012. The settlement does not allow Duke's proposed rider to recover costs of facility relocation associated with mass transportation projects. Duke had claimed that, under pre-existing rates, it would earn a return of 4.79% on rate base. The commission said that such a rate of return is "insufficient to provide [the company] with reasonable compensation for the service it renders to customers."

San Diego Gas & Electric (SDG&E)

The California commission allowed SDG&E attrition rate increases for 2013-2015 based on changes in the Consumer Price Index-Urban, with some modifications. The commission authorized rate increases of 2.65% for 2013 and 2.75% for both 2014 and 2015. The commission also extended, subject to a $5 million deductible, the "Z-factor" mechanism that allows utilities to request recovery, under certain circumstances, for significant, unforeseen expenses between rate cases. The commission also allowed the company recovery of costs associated with the San Onofre Nuclear Generating Station, subject to refund pending a reasonableness review.

Maui Electric (MECO)

MECO entered into a settlement that would have authorized a 10% ROE, however the Hawaii commission reduced the ROE to 9% because a 10% ROE would have fallen out of the 9%-9.75% range proposed by the Division of Consumer Advocacy, one of the parties to the settlement. In addition, the commission said that half of the 100-basis-point adjustment was due, in part, to "updated economic and financial market conditions." The commission said that the second half of the adjustment reflected "apparent system inefficiencies which negatively impact MECO's customers . . . [The company] appears to have failed to adequately and sufficiently plan for and implement the necessary modifications to its existing operations to accept a more appropriate level of wind energy generation made available to MECO, negatively impacting ratepayers through higher electricity rates." The commission said the order is intended to serve notice to MECO and other Hawaiian Electric utilities that the utilities "appear to lack movement to a sustainable business model to address technological advancements and increasing customer expectations. The commission observes that some mainland electric utilities have begun to define, articulate and implement the vision for the 'electric utility of the future.' Without such a long-term, customer-focused business strategy, it is difficult to ascertain whether [the Hawaiian Electric utilities'] increasing capital investments are strategic investments or simply a series of unrelated capital projects that effectively expand utility rate base and increase profits but [appear] to provide little or limited long-term customer value."

Monongahela Power West Virginia

In Q4, the West Virginia Commission approved a settlement for Monongahela Power that transfers generation assets to Monongahela from affiliated companies and implements a surcharge for generation recovery. The settlement also requires the company to hire 50 employees from West Virginia and contribute

$500,000 annually for five years to a low-income assistance program, a weatherization program and a public school energy efficiency program. The settlement also requires the company to achieve, as part of an energy efficiency plan, 0.5% in energy savings by the year ending May 31, 2018 relative to 2013 delivery sales. Monongahela Power can recover the cost of the energy efficiency plan in rates, but the parties could not agree to recovery of lost revenue associated with the decrease in sales.

Virginia Electric & Power

In 2013, the Virginia commission decided Virginia Electric & Power's legally mandated biennial earnings review case. Virginia state law requires the commission to determine a "fair" ROE based on the market cost of equity, a state-law-determined-peer-group ROE floor, and then adjust for management performance, if necessary. Based on this formula, the company had requested an ROE of 11.5%. The commission allowed 10%, saying "a market cost of equity of 10% fairly represents the actual cost of equity in capital markets for companies comparable in risk to Dominion seeking to attract equity capital . . . We conclude that a market cost of equity of 10% is supported by reasonable proxy groups, growth rates, discounted cash flow methods, risk premium analyses, and gradualism in ROE determinations." The company proposed a 55.624% equity component in its capital structure. The commission said the proposed equity component "is neither reasonable or prudent for the purpose of setting rates [because it]: 1) significantly exceeds the average equity ratio of its peers (including peers constructing nuclear plants); 2) is higher than necessary in order for [the company] to maintain reasonable credit ratings; 3) exceeds the company's own financial targets; and, 4) is higher than necessary for Dominion to raise capital on reasonable terms to its planned capital expenditures." The commission approved a 50% equity ratio. The commission also excluded $2.3 million in incentive compensation costs.

PacifiCorp Washington

In Q4, the Washington commission rejected PacifiCorp's proposed power cost adjustment mechanism (PCAM), saying that the company failed "to demonstrate sufficient power cost variability to warrant approval for such a mechanism" and that the company did not design the mechanism in accordance with prior commission directives. The commission said "a properly designed PCAM includes dead bands and sharing bands so that the Company continues to bear some risk of under-recovery, and some opportunity to benefit from savings achieved via power cost management practices."

Baltimore Gas and Electric (BGE)

The Maryland commission approved five of eight proposals the company made related to its proposed Electric Reliability Investment initiative (ERI). The company developed this initiative (see also *Filed Cases* above) in response to guidelines established in the commission's review of Maryland utilities' performance following a derecho storm in 2012. The company proposed an annual cost recovery surcharge to recover costs associated with the initiative and crafted the surcharge to be consistent with recommendations proposed by the Maryland Governor's Grid Resiliency Task Force. The eight company's proposals were: 1) expand a feeder replacement program, 2) expand vegetation management, 3) improve the customer average interruption duration index (CAIDI), 4) expand recloser deployment on 13 kV distribution feeders, 5) expand recloser deployment on 34 kV lines, 6) diversify routing of 34 kV supply circuits, 7) implement selective undergrounding, and 8) improve substation reliability performance. The total cost for the initiative would have been $136 million between 2014 and 2018. Each surcharge would project costs through the coming year and true up at the end of the year. The commission approved 1, 4, 5, 6 and half of what the company proposed for 7. The commission said, "We respectfully disagree with those parties advocating that we wait until new [reliability] regulations are adopted, effective in 2016 and beyond, as the need to improve reliability is immediate and exigent . . . what the Commission expects to see at the end of the five-year period, is a total improvement of over 12% in SAIDI [System Average Interruption Duration Index] and at least 3.7% in SAIFI [System Average Interruption Frequency Index]."

Two commissioners dissented on recovering ERI through a surcharge, saying that "approval of a surcharge is contrary to the precedent established by this Commission as well as sound regulatory policy. The surcharge will unfairly shift risks that are properly borne by the company shareholders to ratepayers, based on a multi-year forecast of plant that has not been demonstrated to be used or useful and estimated expenses that are not known and measureable . . . we find the likelihood of 'claw back' of revenue of a future prudency review to be implausible."

BGE had also requested a 10.5% ROE, but the commission awarded a 9.75% ROE, as in BGE's previous case. The commission said that in that previous case it "determined that BGE was a low-risk investment based upon evidence it presented and past-market performance as a monopoly provider of electric and gas distribution service, its lack of ownership of any generating facilities, and its stable service territory with a BSA [decoupling] mechanism. Additionally, we found that the low interest rate environment that existed at the time . . . provided BGE with ample opportunity to obtain necessary capital at reasonable rates. The question in this case, therefore . . . is, what has changed in less than one year . . . that now might justify a different return. BGE has not demonstrated any significant changes in the economic environment faced by the company." The commission noted that it had not adjusted the ROE downward as a result of its partial approval of the ERI.

The commission rejected a non-ERI adjustment for reliability-related projects, saying "such tools must be carefully constructed to insure ratepayer interests are protected in advance and that investments are cost effective . . . we only allow recovery of post-test-year spending in rate base, if the plant investment is safety or reliability related, only if the amounts represent actual spending, and only if the amounts are known and measureable."

BGE also proposed to recover its major storm restoration expense over a three-year period, rather than the five-year period typically approved by the commission, because of the magnitude and frequency of major storms in recent years. The commission rejected the change, saying the company "has provided no demonstrable scientific evidence that the same frequency of major storms would continue in Maryland on any predictable basis, and that the five-year recovery period would not be sufficient . . . in 2013 there have been no major storms."

Other

The Kansas City Power & Light utilities proposed to modestly increase customer charges but the commission rejected the increases stating that, "Because volumetric charges are more within the customer's control to consume or conserve, the volumetric rate is the more appropriate to increase." In Tucson Electric Power's case, the commission did authorize increases in customer charges, including an increase in the residential customer charge from $7 to $10, saying the $10 charge was "a small part of the overall average bill of over $84" and well less than the $56 average monthly fixed costs per residential customer.

In Potomac Electric Power's case in Maryland, the commission denied the company recovery of $23.4 million in advanced metering infrastructure investment, saying that Pepco has yet to demonstrate that this investment is cost-effective.

In Northern States Power Company's case in Minnesota, the increase allowed by the commission was less than the interim rates the company had implemented, and consequently the company owed customers a refund. In calculating the refund, the commission departed from its usual practice of using the average prime rate (3.25% in this case) in calculating the interest due customers, and instead used the overall rate of return (7.45%).

In United Illuminating's case, the Connecticut commission rejected a 36% equity ratio capital structure proposed for the company by the Connecticut Industrial Energy Consumers (compared to a 50% ratio proposed by the company) stating that "imposing such an extreme change . . . to the company's ratemaking capitalization mix may be disruptive to its financial stability and credit rating . . . [We] will continue to monitor electric utility industry practices with regard to capitalization mix and will make changes to the ratemaking capital structure should industry standards change significantly."

In Gulf Power's case in Florida, the commission approved a settlement that authorizes an adjustment mechanism that would allow the company to raise allowed ROE by 25 basis points if the 30-year

US Treasury bond yield increases by an average of 75 basis points above 3.7947% for a six-month period.

In Ameren Illinois' case associated with the company's formula rate plan, the commission reduced the company's revenue requirement to account for revenue the company received as a result of selling "vacated microwave frequencies" to telecommunication companies. The company had argued that these frequencies had been used to transmit transmission data and consequently were FERC jurisdictional.

In Sierra Pacific's case in Nevada, the commission granted the company's demand side management investments a 500 basis point return above authorized ROE and combined-cycle natural gas generation a bonus return of 150 basis points.

In Upper Peninsula Power's case in Michigan, a settlement requires the company to spend $3.2 million on tree trimming and clear at least 1,760 miles of line or refund the difference to customers.

Business Strategies

Business Segmentation

The industry's regulated business segments, Regulated Electric and Natural Gas Distribution, showed the largest revenue gains in both dollar and percentage terms in 2013, and were the only categories with asset growth. Continuing a multi-year trend, the industry's regulated asset base grew and accounted for a larger share of total industry assets. Regulated Electric assets grew to a 66.4% share of total assets, providing most of the industry's asset growth. Regulated Electric revenue increased 4.7%, despite a minimal 0.1% increase in nationwide electric output. Competitive Energy revenue had a modest 1.5% increase, while its asset total was virtually unchanged.

2013 Revenue by Segment

Regulated Electric revenue increased by $10.9 billion, or 4.7%, to $245.4 billion from $234.5 billion in 2012. The segment's share of total industry revenue grew to 66.2% from 66.0% in 2012, totals that are now well above the 52.1% level of 2005.

Natural Gas Distribution revenue had significant gains for the second straight year, rising by $3.9 billion, or 12.2%, from $32.3 billion in 2012 to $36.3 billion in 2013. This followed a 15.6% increase the year before. Annual revenue here has historically fluctuated due to significant swings in natural gas prices.

Total regulated revenue—the sum of the Regulated Electric and Natural Gas Distribution segments—increased by $14.9 billion, or 5.6%, to $281.7 billion in 2013. The year-to-year change for this metric has

Business Segmentation—Revenues

U.S. INVESTOR-OWNED ELECTRIC UTILITIES

($ Millions)	2013	2012r	Difference	% Change
Regulated Electric	245,441	234,504	10,938	4.7%
Competitive Energy	68,171	67,187	984	1.5%
Natural Gas Distribution	36,269	32,328	3,942	12.2%
Natural Gas Pipeline	6,175	6,658	(483)	(7.3%)
Natural Gas and Oil Exploration & Production	941	1,750	(809)	(46.2%)
Other	13,641	12,773	869	6.8%
Eliminations/Reconciling Items	(14,151)	(15,303)	1,152	(7.5%)
Total Revenues	**356,488**	**339,896**	**16,592**	**4.9%**

r = revised

Note: Difference and Percent Change columns may reflect rounding. Totals may reflect rounding.

Source: Based on segment reporting from SEC filings of 57 U.S. Investor-Owned Electric Utilities

Business Segmentation—Assets

U.S. INVESTOR-OWNED ELECTRIC UTILITIES

($ Millions)	12/31/13	12/31/12r	Difference	% Change
Regulated Electric	902,569	879,092	23,476	2.7%
Competitive Energy	202,921	202,960	(39)	0.0%
Natural Gas Distribution	107,964	101,455	6,510	6.4%
Natural Gas Pipeline	36,269	36,420	(151)	(0.4%)
Natural Gas and Oil Exploration & Production	2,653	3,666	(1,013)	(27.6%)
Other	105,907	118,153	(12,246)	(10.4%)
Eliminations/Reconciling Items	(66,058)	(78,482)	12,423	(15.8%)
Total Assets	**1,292,225**	**1,263,265**	**28,960**	**2.3%**

r = revised

Note: Difference and Percent Change columns may reflect rounding. Totals may reflect rounding.

Source: Based on segment reporting from SEC filings of 55 U.S. Investor-Owned Electric Utilities

varied in recent years, falling by $13.0 billion in 2012 (-4.7%) and $2.1 billion (-0.8%) in 2011, rising $4.1 billion (+1.5%) in 2010, declining $20.6 billion (-6.9%) in 2009 and increasing $22.5 billion (+7.7%) in 2008 and $14.4 billion (+5.2%) in 2007. Despite the year-to-year dollar fluctuations, regulated operations have steadily grown as a percentage of total industry revenue in recent years. Total regulated revenue accounted for 76.0% of total industry revenue in 2013, extending a steady upward trend from 65.3% in 2005. The *Business Segmentation—Revenues* table presents the industry's revenue breakdown by business segment. Eliminations and reconciling items were added back to total revenue to arrive at the denominator for the segment percentage calculations shown in the graphs *Revenue Breakdown 2013* and *2012*.

2013 Assets by Segment

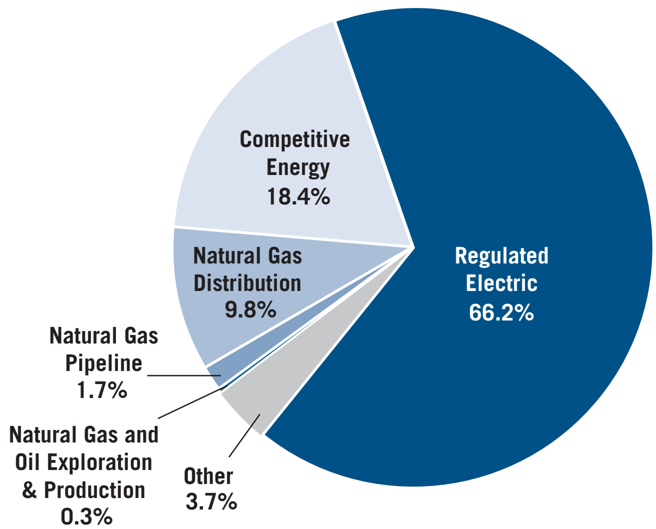
Regulated Electric assets increased from 65.5% of total industry assets at December 31, 2012 to 66.4% at December 31, 2013, rising by $23.5 billion, or 2.7%, over the year-end 2012 level. Competitive Energy assets were nearly unchanged, with a $39 million decrease from the prior year. Natural Gas Distribution assets grew by $6.5 billion, or 6.4%, while the two smaller natural-gas-related categories, Pipeline and Exploration & Production, experienced declines of 0.4% and 27.6%, respectively.

Total regulated assets (Regulated Electric plus Natural Gas Distribution) accounted for 74.3% of total industry assets at year-end 2013, up from 73.1% on December 31, 2012. This aggregate measure has grown steadily from 61.6% at year-end 2002, underscoring the industry's significant regulated rate base growth in recent years and the fact that several companies sold off non-core businesses during the period.

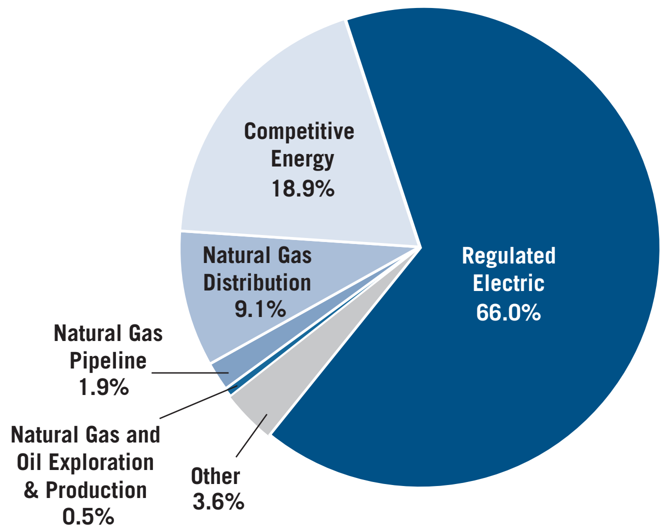
Regulated Electric

Regulated Electric segment operations include the generation, transmission and distribution of regulated electricity for residential, commercial and industrial customers. Regulated Electric revenue gains were widespread across the industry, summing to the overall $10.9 billion, or 4.7%, increase. Forty-six of 54 companies (85%) had higher revenues for this segment, with five companies (9%) reporting double-digit percentage growth. The segment's overall increase was supported by a continued record-high level of capital expenditures and a generally constructive regulatory environment at the state level. An offsetting factor was the 9% decline in cooling-degree days, although they were 11%

Revenue Breakdown 2013
U.S. INVESTOR-OWNED ELECTRIC UTILITIES



Revenue Breakdown 2012
U.S. INVESTOR-OWNED ELECTRIC UTILITIES



Source: EEI Finance Department and company annual reports

higher than normal. The industry is less impacted by heating degree days, which rose by 19%.

The 2013 revenue increase follows declines in the preceding two years, at 2.8% in 2012 and 0.6% in 2011. These were caused by a sluggish U.S. economy and the impact of continued low natural gas prices on the fuel component of rates. In 2010, favorable weather drove a 2.4% revenue increase. U.S. electric output decreased by 1.8% in 2012 and 0.6% in 2011 after growing by 3.7% in 2010, and falling 3.7% in 2009 and 0.9% in 2008. Year-to-year output declines have historically been rare events for an industry that typically experiences low-single-digit percent annual demand growth. Energy efficiency and demand-side management programs continue to be factors behind the flat growth.

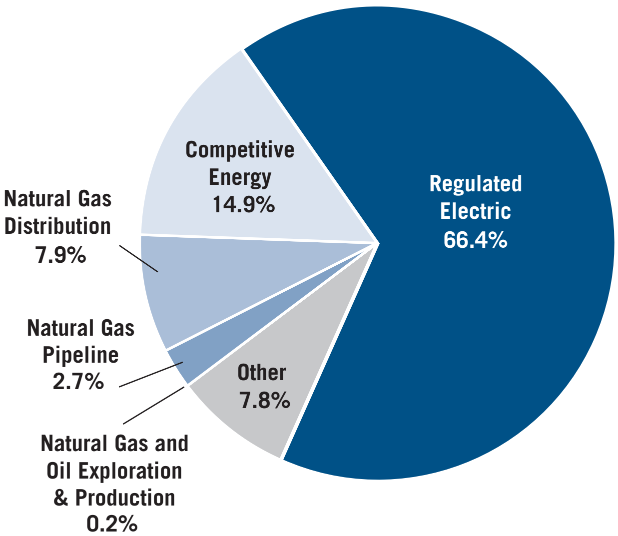
During 2013, 60% of companies increased regulated assets as a percent of total assets (or maintained a 100% regulated structure). OGE Energy had the largest increase, raising its regulated percentage from 72.8% at year-end 2012 to 84.2% at year-end 2013. The rise reflects a lower asset total for its natural gas pipeline segment. The company reduced its primary business segments from three to two over the last year, the result of its newly formed master limited partnership with CenterPoint Energy and ArcLight Capital Partners.

Competitive Energy

Competitive Energy segment revenue increased by 1.5% in 2013, gaining $984 million to $68.2 billion from $67.2 billion in 2012. This follows a sharp decline of $22.4 billion, or 26.0%, in 2012 that was due to continued weak electricity prices and a slow economic recovery, as well as plant divestitures and merchant operations sales. The segment's 2012 revenue was the lowest annual total for this category to date, based on data covering the last decade. The highest annual revenue over the last decade was $113.2 billion in 2008. Competitive Energy covers the generation and/or sale of electricity in competitive markets, including both wholesale and retail transactions. Wholesale buyers are typically electric utilities seeking to supplement generation capacity, along with regional power pools and large industrial customers. Competitive Energy also includes the trading and marketing of natural gas. Of the 29 companies that have Competitive Energy operations, approximately half (14 companies, or 48%) grew these assets during 2013, while 59% had revenue gains.

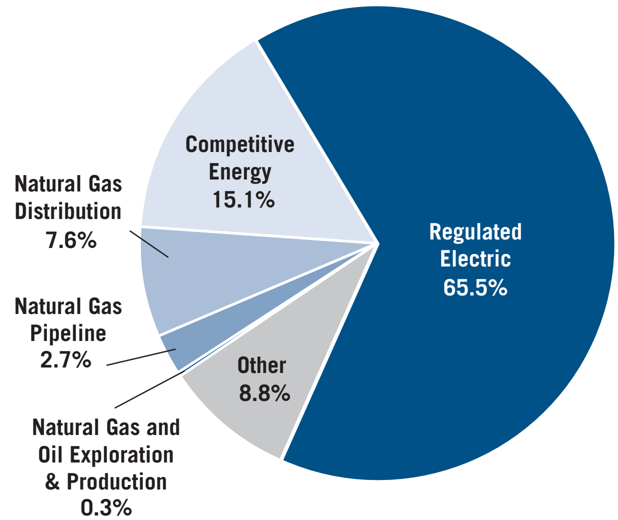
Asset Breakdown
As of December 31, 2013

U.S. INVESTOR-OWNED ELECTRIC UTILITIES



Asset Breakdown
As of December 31, 2012

U.S. INVESTOR-OWNED ELECTRIC UTILITIES



Source: EEI Finance Department and company annual reports

Natural Gas Distribution

Natural Gas Distribution revenue increased by $3.9 billion, or 12.2%, in 2013, reversing a declining trend in each of the previous four years. The higher revenues correlate with a 19% increase in heating degree days in 2013. On the other hand, natural gas prices continued to be depressed, spending much of the year under $4/mmBTU. The 2013 rise in revenue follows declines of $6.2 billion, or 15.6% in 2012, $701 million, or 1.7%, in 2011, $1.5 billion, or 3.6%, in 2010 and a much larger decline of $9.8 billion, or 19.1%, in 2009 due to sharply falling gas prices and the impact of the economic downturn. Natural gas prices peaked above $12/mmBTU in 2008, a year marked by very high price volatility. Overall, 28 of the 32 companies (88%) that report gas distribution revenue showed year-to-year revenue increases in 2013. In comparison, 94%, 62%, 75% and 91% of companies had year-to-year revenue declines in 2012, 2011, 2010 and 2009 respectively, while 89% experienced gains in 2008.

Natural Gas Distribution includes the delivery of natural gas to homes, businesses and industrial customers throughout the United States, while the Natural Gas Pipeline business concentrates on the transmission and storage of natural gas for local distribution companies, marketers and traders, electric power generators and natural gas producers. Added together, Natural Gas Distribution, Natural Gas Pipeline and Exploration & Production (E&P) activities produced $43.4 billion of the industry's revenue in 2013, up from $40.7 billion in 2012. In percentage terms, the revenue contribution from natural gas activities increased to 11.8% in 2013 from 11.5% in 2012.

The Natural Gas Pipeline and Natural Gas E&P segments had declines in both revenues and assets in 2013. Natural Gas Pipeline assets fell by $151 million, or 0.4%, while its revenues were $483 million, or 7.3%, lower. Natural Gas E&P assets decreased by $1.0 billion, or 27.6%, along with a $809 million, or 46.2%, decline in revenues.

Over the longer term, the Pipeline and E&P segments have accounted for a declining share of total industry assets. This is due to a combination of growth in the other business segments and divestitures within these two. Natural Gas Pipeline and Natural Gas E&P fell from 3.7% and 2.1% shares of total assets on December 31, 2003 to 2.7% and 0.2% on December 31, 2013, with their combined total assets down by $11.8 billion, or 23%, over this ten-year time frame.

2013 Year-End List of Companies by Category

Early in each calendar year we update our list of investor-owned electric utility holding companies by business category based on the previous year-end's business segmentation data presented in 10Ks and supplemented by discussions with parent companies. Our categories are as follows: Regulated (80% of holding company assets are regulated); Mostly Regulated (50%-79% of holding company assets are regulated); Diversified (less than 50% of holding company assets are regulated).

We use assets rather than revenue for determining categories because we think assets provide a clearer picture of strategic trends. Fluctuating natural gas and power prices can impact revenue so greatly that some companies' strategic approach to business segmentation is distorted by reliance on revenue data alone. Comparing the list of companies from year to year reveals company migrations between categories and indicates the general trend in industry business models. We also base our quarterly category financial data during the year on this list.

The overall trend toward a more regulated industry continued in 2013. The Regulated group totaled 39 companies at year-end, representing 71% of the industry's companies, up from 67% last year. OGE Energy, Otter Tail Power and Pepco Holdings migrated from the Mostly Regulated to the Regulated category. OGE's regulated asset percentage grew from 72.8% at year-end 2012 to 84.2% at year-end 2013, reflecting a lower asset total for its natural gas pipeline segment. The company reduced its primary business segments from three to two over the last year, the result of its newly formed master limited partnership with CenterPoint Energy and ArcLight Capital Partners. Otter Tail's increase from 76.5% to 80.9% relates to a decline in its Corporate asset division, which is categorized as Other for our purposes. Pepco reshuffled its segments over the prior year, removing its Other Non-Regulated Category. This was driven by the company's termination of its interests in its cross-border energy lease investments during 2013.

The Diversified category added Hawaiian Electric from the Mostly Regulated Category, as the company continues to straddle to 50.0% threshold of regulated assets. Hawaiian's regulated percentage fell from 50.3% to 49.2% over the last year, after making an opposite jump in categories the previous year.

The total number of companies in the EEI universe fell from 58 at year-end 2012 to 55 at year-end 2013, the result of merger activity. The buyouts of CH Energy (acquired by Fortis Inc. in 2013), NV Energy (acquired by MidAmerican Energy in 2013) and Central Vermont Power (acquired by Gaz Metro LP in 2012) caused the decrease. At the close of 2013, there were 39 Regulated, 13 Mostly Regulated and 3 Diversified companies (see *List of Companies by Category at December 31, 2013*).

List of Companies by Category at December 31, 2013

Regulated (39)

Allete	El Paso Electric	PG&E
Alliant Energy	Empire District Electric	Pinnacle West Capital
Ameren	Entergy	PNM Resources
American Electric Power	Great Plains Energy	Portland General Electric
Avista	Iberdrola USA	Puget Energy
Black Hills	IDACORP	Southern
Cleco	Integrys Energy Group	TECO Energy
CMS Energy	IPALCO Enterprises	UIL Holdings
Consolidated Edison	Northeast Utilities	Unitil
DPL	NorthWestern Energy	UNS Energy
DTE Energy	OGE Energy	Westar Energy
Duke Energy	Otter Tail Power	Wisconsin Energy
Edison International	Pepco Holdings	Xcel Energy

Mostly Regulated (13)

CenterPoint Energy	MidAmerican Energy Holdings	Public Service Enterprise Group
Dominion Resources	NextEra Energy	SCANA
Exelon	NiSource	Sempra Energy
FirstEnergy	PPL	Vectren
MGE Energy		

Diversified (3)

Energy Future Holdings	Hawaiian Electric	MDU Resources

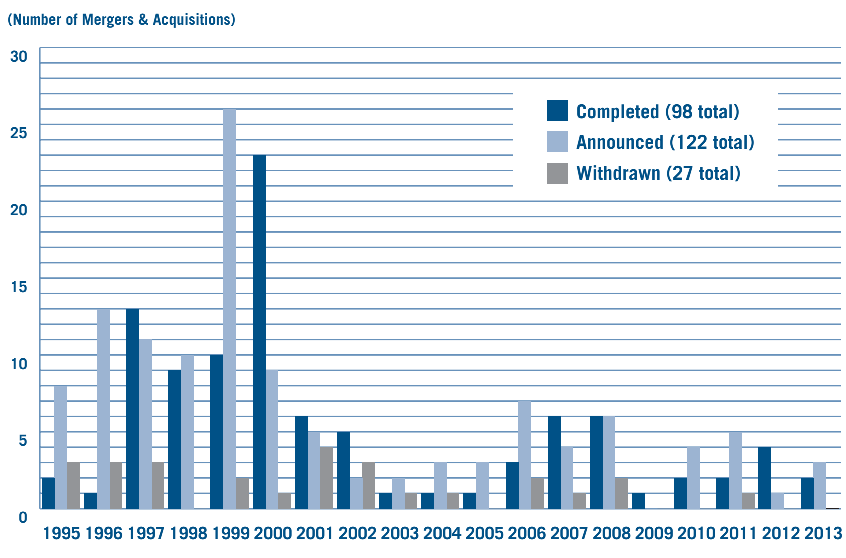
Mergers and Acquisitions

There were no proposed combinations of multi-state diversified utilities announced in 2013, an area of M&A that was quiet for the second year in a row as many of the headwinds from 2012 persisted, including weak power demand, uncertain U.S. economic growth, challenging state regulatory navigation and low natural gas prices with associated weak stock prices of utility holding companies with merchant generation. The most recent large deals were First Energy's successful bid for Allegheny (closed in February 2011), the Exelon/Constellation merger (closed in March 2012), the "merger of equals" involving New England utilities NSTAR and Northeast Utilities (completed in April 2012) and the Duke/Progress merger (completed in July 2012). However, utility M&A was alive and relatively well in 2013, emphasizing movement of merchant assets and the appeal of high-quality single state utilities with good organic growth potential as profitable additions to larger holding companies.

There were four whole company deals announced during the year: i) Ameren's divestiture of merchant coal assets to Dynegy in a "back-to-basics" move; ii) MidAmerican's acquisition of Nevada's NV Energy; iii) a pure merchant power play in NRG's bid for Edison Mission Energy; and iv) Canadian utility Fortis' proposed purchase of Arizona's UNS Energy. In each of the two deals targeting a regulated utility, the buyer wanted the utility just as it was, for its solid earnings and growth potential, and with no plans for financial engineering, re-strategizing or cost cutting to wring out value. The year also produced a failed deal. In December, Entergy and ITC Holdings abandoned plans to divest Entergy's transmission assets to ITC after a two-year struggle marked by resistance from FERC, state regulators and other stakeholders.

Status of Mergers & Acquisitions 1995–2013

U.S. INVESTOR-OWNED ELECTRIC UTILITIES



Source: EEI Finance Department

Ameren Divests Merchant Generation to Dynegy

The year's first major transaction, announced on March 14, took the form of Ameren's move to exit the competitive generation business by selling its coal-fired merchant generation fleet, comprised of five plants in Illinois, and a related energy marketing business to independent power producer Dynegy. Ameren said the sale was motivated by its desire to focus the company exclusively on rate-regulated electric, natural gas and transmission operations, clarifying both its strategic direction and source of value to shareholders. The company said it expects the transaction will reduce business risk, improve the predictability of future earnings and cash flows, strengthen its credit profile and support its dividend. The divestiture was valued at approximately $900 million, including removal of $825 million of debt from Ameren's consolidated balance sheet and an estimated $180 million of tax benefits expected to be substantially realized in 2015, partially offset by about $75 million in transaction-related costs and pension liabilities retained by Ameren. Ameren received no cash proceeds as a result of the transaction. Ameren also announced plans for $8.1 billion in infrastructure investment from 2013 to 2017, largely in delivery and transmission in Illinois and Missouri.

Seeking to boost its exposure to a power and capacity market recovery in the Midwest, Dynegy said the acquisition would build scale in a key market with assets similar to its current Illinois-based coal fleet while creating operating synergies estimated

Status of Announced Mergers & Acquisitions
1995–2013

U.S. INVESTOR-OWNED ELECTRIC UTILITIES

Year	Completed	Announced	Withdrawn
1995	2	8	3
1996	1	13	3
1997	13	11	3
1998	9	10	–
1999	10	26	2
2000	23	9	1
2001	6	5	4
2002	5	2	3
2003	1	2	1
2004	1	3	1
2005	1	3	–
2006	3	7	2
2007	6	4	1
2008	6	6	2
2009	1	–	–
2010	2	4	–
2011	2	5	1
2012	4	1	–
2013	2	3	–
Totals	**98**	**122**	**27**

Source: EEI Finance Department

at $60 million annually by 2015. It will also benefit from acquiring an established retail business (Ameren Energy Marketing) with significant scale that supports its merchant goal and gas plants. Dynegy noted that its existing coal generation fleet and the acquired plants are compliant with the EPA's Mercury and Air Toxic Standards, which should leave the combined portfolio well positioned to benefit from tightening supply as noncompliant or uneconomic generation retires. Dynegy also noted the financial terms ensured that little if any capital support would be needed for the acquired plants, thereby preserving capital allocation flexibility. The company said targeted synergies along with forward natural gas prices and its view on forward power and capacity prices should make the acquisition accretive to adjusted EBITDA in 2014 and to free cash flow by 2015.

The transaction was completed on December 2, 2013. In addition, in October 2013 Ameren entered into an agreement to sell three merchant gas-fired plants, which were not part of the Dynegy transaction, to private equity buyer Rockland Capital. With that sale, which closed in early February 2014, Ameren completed its exit from the merchant generation business.

MidAmerican Acquires NV Energy

On May 30, Berkshire Hathaway subsidiary MidAmerican Energy Holdings announced it had reached an agreement to acquire NV Energy, which serves approximately 1.3 million electric and natural gas customers in Nevada. MidAmerican agreed to purchase all outstanding shares of NV Energy's common stock for $23.75 per share in cash, for an enterprise value of approximately $10 billion. NV Energy shares jumped 23% on the announcement from their May 29 closing price of $19.28. In the weeks preceding the announcement, the shares had fallen, along with many interest rate sensitive dividend-paying stocks, about 11% off their late-April high of $21.63, evidently placing their value at an attractive level for MidAmerican.

MidAmerican cited NV Energy's solid commitment to the state of Nevada and its performance as a high-quality energy business as motivations for the deal, along with its similar corporate values, outstanding assets and superb management team. Analysts noted that NV Energy generates positive free cash flow, which supports a growing dividend, is benefitting from an improved regulatory environment in the state, and sits geographically alongside MidAmerican's presence in nearby Utah, Idaho, Oregon and northern California. Analysts also cited NV Energy's commitment to renewable energy and its growing solar generation as an attraction, with Nevada's renewable portfolio standard as one of the most aggressive in the nation, requiring that at least 25 percent of the company's retail energy sales be derived from renewable energy resources by 2025.

NV Energy cited as deal drivers MidAmerican's stability, expertise in renewable generation and ability to provide low-cost capital for NV Energy's renewable energy growth strategy. NV Energy will remain a Nevada company, operate as a separate corporate subsidiary of MidAmerican under its current name and will continue to be headquartered in Las Vegas. The merger closed on December 19, 2013, sooner than the companies' initial early 2014 estimate, after receiving state and federal regulatory approvals or clearances from the Public Utilities Commission of Nevada (PUCN), the Federal Energy Regulatory Commission (FERC), and the U.S. Department of Justice. The companies said Nevada approval came following a multi-party agreement in the state and a one-time bill credit to customers of NV Energy totaling $20 million.

NRG Bids for Edison Mission Energy

The year's second merchant deal occurred on October 18 when independent power producers NRG Energy and Edison Mission Energy (EME) agreed that NRG would acquire EME for $2.6 billion (or $1.6 billion net of approximately $1 billion retained cash within EME) for 12.7 million shares of NRG common stock, valued at approximately $350 million, and with the balance to be paid in cash. The terms imply a transaction enterprise value of approximately $2.8 billion after including $1.3 billion of adjusted non-recourse debt assumed in connection with the purchase. Santa Anna, California-based EME, a former merchant power subsidiary of Edison International, filed Chapter 11 bankruptcy in December 2012.

EME's generation portfolio consists of nearly 8,000 net MW located throughout the U.S., including 1,700 MW of wind capacity, 1,600 MW of natural gas-fired capacity, 4,300 MW of coal-fired capacity and 400 MW of oil and waste coal generation. NRG cited three primary reasons for the deal: i) it increases NRG's generation portfolio by nearly 8,000 MW, providing fuel diversity, geographic diversity and opportunities for economies of scale; ii) it significantly expands the pipeline of assets available to drive growth at NRG Yield Co. (NYSE: NYLD), with 1,600 MW of long-term, fully-contracted wind and natural gas assets; and iii) it builds off the platform and best practices developed in association with NRG's acquisition in 2012 of GenOn Energy, which created the largest competitive power provider in the U.S.

As an indication of the broad secular trends reshaping the electric generation business, the companies and Wall Street analysts stressed the renewable generation component of the combination. The deal would make NRG the nation's third-largest domestic renewable energy generator, with over 2,900 net MW of wind and solar capacity in operation or under construction, while broadening the scale and geographic diversity of NRG's renewable generation portfolio with the addition of 1,700 net MW of wind capacity, including 1,150 net MW outside the company's concentration in the Texas and southwest U.S. region.

Another key benefit cited by the company and analysts is the support the acquisition can provide to NRG Yield, a majority-owned subsidiary which NRG partially spun off through a July 2013 initial public offering. NRG Yield was set up to provide NRG with a lower cost of capital for acquisition of generation assets, benefitting from investors' hunt for yield in a very low interest rate environment. The subsidiary owns generation assets with long-term contracts and passes through cash flow to investors in the form of steady dividends. The structure's dividend can grow as assets are added to the NRG Yield portfolio. By year-end 2013, the NRG Yield shares had appreciated 80% from their July IPO price of $22 per share. The EME portfolio contains 2,600 net MW of fully-contracted generation; 1,600 MW are under long-term contracts with credit-worthy counterparties, with a weighted average remaining contract life of 14 years. NRG noted that the contracted portfolio is composed of 1,100 net MW of wind capacity and a 500 MW gas-fired facility which came online during the summer of 2013.

NRG also said the acquisition would enhance its core generation platform, balancing the geographic distribution and dispatch-level diversity of its conventional generation fleet by adding 1,200 MW of contracted gas assets in California and 4,300 MW of coal-fired capacity in PJM West.

The companies hoped to close the transaction in early 2014, following approval by the Federal Energy Regulatory Commission (FERC), the U.S. Department of Justice and the Federal Trade Commission under the Hart-Scott-Rodino Act, and the Public Utility Commission of Texas. EME will also submit notice of the acquisition to the California Public Utilities Commission.

Fortis Seeks to Acquire UNS Energy

The year's whole-company activity concluded with Canadian utility Fortis' December 11 offer to acquire Arizona regulated utility UNS Energy for $60.25 per share in cash, resulting in an aggregate value of approximately $4.3 billion, including assumption of approximately $1.8 billion of debt. UNS shares closed at $45.84 the day before the announcement, resulting in about a 31% premium to the pre-offer price. UNS Energy has approximately $1.5 billion in revenue and total assets of approximately $4.3 billion and serves 654,000 electricity and gas customers, primarily in Arizona.

Fortis cited as motivation for the deal UNS' strong management team with proven regulatory expertise and high-quality regulated utility assets located in a region of the U.S. experiencing above-average economic growth, saying the acquisition is consistent with its strategy of investing in high-quality regulated Canadian and U.S. utilities. Fortis acquired New York's Hudson Valley utility CH Energy in a deal announced in 2012, closing a year later in June 2013. Fortis' 2011 bid for Central Vermont Public Service (CVPS) was terminated when CVPS accepted what it deemed a more attractive offer from another Canadian utility (Gaz Metro). Fortis said the UNS acquisition is expected to be accretive to earnings in the first full year after closing, excluding one-time transaction costs. Fortis cited several specific reasons for its interest in UNS, including a 10-year compound annual growth rate in net income of 7.7% and in assets of 3.1%; increased geographic and regulatory diversification; a supportive regulatory environment in Arizona, with rate design that allows pass-through of costs related to fuel, purchased power, environmental compliance, renewable resources, energy efficiency and distributed generation; and a favorable local economy that can support growth. UNS previously projected that capital investment will total approximately US$2.3 billion over the period 2013 through 2018, creating rate base growth at approximately 7% annually through 2018. Fortis said UNS Energy will remain a standalone utility in the Fortis model; its headquarters and management team will remain in Tucson, Arizona and UNS customers will not pay for costs related to the transaction.

UNS said Fortis' financial strength will improve access to capital to fund the ongoing diversification of UNS' generating fleet, including growth in solar generation, as well as other infrastructure investments. Upon closing, Fortis plans to invest $200 million in UNS Energy to strengthen its balance sheet and help fund the planned purchase of a natural gas-fired plant, a transaction that will reduce UNS subsidiary Tuscon Electric Power's reliance on coal-fired generation.

Merger Impacts 1995–2013

U.S. INVESTOR-OWNED ELECTRIC UTILITIES

Date	No. of Utilities	Change
12/31/95	98	N/A
12/31/96	98	–
12/31/97	91	(7.14%)
12/31/98	86	(5.49%)
12/31/99	83	(8.79%)
12/31/00	71	(14.46%)
12/31/01	69	(2.82%)
12/31/02	65	(5.80%)
12/31/03	65	–
12/31/04	65	–
12/31/05	65	–
12/31/06	64	(1.54%)
12/31/07	61	(4.69%)
12/31/08	59	(3.28%)
12/31/09	58	(1.69%)
12/31/10	56	(3.45%)
12/31/11	55	(1.79%)
12/31/12	51	(7.27%)
12/31/13	49	(3.92%)

Number of Companies Declined by 50% since Dec.'95

Note: Based on completed mergers in the EEI Index group of electric utilities.

Source: EEI Finance Department

Mergers & Acquisitions Announcements   Updated through March 31, 2014

U.S. INVESTOR-OWNED ELECTRIC UTILITIES

Ann'cd	Buyer	Seller/Acquired/Merged	Status	New Company	Date Completed	Months to Complete	Bus.	Terms	Trans. Val. ($MM)
3/3/14	UIL Holdings	Philadelphia Gas Works	P					UIL to aquire assets & liabilities of PGW from city of Philadelphia for $1.86 B in cash	1,860.0
12/12/13	Fortis Inc.	UNS Energy	P				EE	Fortis pays $60.25/share (31% premium to announcement day's close) + $1.8B in debt	4,578.1
5/29/13	MidAmerican Energy Holdings Co.	NV Energy	C		12/19/13	7	EE	MidAmerican pays $23.75/share + assume $4.8 billion debt	10,494.3
5/25/13	TECO Energy, Inc.	New Mexico Gas Intermediate, Inc.	P				EE	TECO will pay $950 million, including assume $200 million debt to Continental Energy Systems LLC	950.0
2/20/12	Fortis Inc.	CH Energy Group	P				EE	Fortis pays $65.00/share CH Energy Group & assumes $687 mm debt	1,609.7
7/11/11	Gaz Metro LP	Central Vermont Public Service	C		6/27/12	12	GE	Gaz Métro pays $35.25/CVPS share & assumes $226 mm debt	704.2
5/27/11	Fortis Inc.	Central Vermont Public Service	W		7/11/11		EE	Fortis pays $35.10/share cash & assumes $226.4 mm debt	701.6
4/28/11	Exelon Corp.	Constellation Energy Group	C		3/12/12	11	EE	CEG receives 0.93 EXC shares/CEG share. EXC assumes $2.9 bill debt	10,623.2
4/19/11	AES Corporation	DPL Inc.	C		11/28/11	7	EE	AES pays $30.0/share cash & assumes approx. $1.1 bill of debt	4,613.2
1/8/11	Duke Energy	Progress Energy	C		7/3/12	18	EE	0.87083 Duke shares (after 1-3 reverse split) for each Progress share + assume $12.1 billion net debt	32,000
10/16/10	Northeast Utilities	NSTAR	C		4/10/12	18	EE	1.312 NU shares for each NSTAR shr, plus $3.36 bill assume debt	7,566.7
4/28/10	PPL Corp.	E.ON U.S.	C		11/1/10	6	EE	$6.83 billion cash + $764.0 million in assumed debt	7,625.0
3/12/10	Emera Inc	Maine & Maritimes	C		12/21/10	9	EE	$76 mm cash + $28.6 mm debt + $13.8mm postretirement benefits	117.4
2/10/10	FirstEnergy	Allegheny Energy	C		2/25/11	12	EE	$4.3 billion in equity + $4.7 billion in assumed debt	9,273.2
9/17/08	Berkshire Hathaway	Constellation Energy Group Inc.	W		12/17/08		PE	$4.7 bill cash + $4.4 bill net debt and adjustments	9,152.5
7/25/08	Sempra Energy	EnergySouth Inc.	C		10/1/08	3	EG	$499 million cash + 283 million debt	771.9
7/1/08	MDU Resources Group, Inc.	Intermountain Gas Co.	C		10/1/08	3	EG	$245 million cash + $82 million debt	327.0
6/25/08	Duke Energy	Catamount Energy Corp.	C		9/15/08	3	EP	$240 million cash + $80 million assumed debt	320.0
2/15/08	Unitil Corp.	Northen Utilities, Inc./ Granite State Gas Transmission, Inc.	C		12/1/08	10	EG	$160 million cash	160.0
1/12/08	PNM Resources, Inc.	Cap Rock Holding Corp.	W		7/22/08		EE		202.5
10/26/07	Macquarie Consortium	Puget Energy	C		2/6/09	16	EE	$3.5 billion cash + $3.02 billion net debt	6,520.2
6/25/07	Iberdrola S.A.	Energy East Corp.	C		9/16/08	15	EE	$4.5 billion cash + $4.1 billion net debt	8,600.0
2/26/07	KKR & Texas Pacific Group	TXU Corp.1	C	Energy Future Holdings Corp.	10/10/07	8	PE	$31.8 billion cash + $12.1 billion net debt	43,882.0
2/7/07	Black Hills Corp. / Great Plains Energy Inc.2	Aquila Inc. (CO elec. util. + CO, KS, NE, IA gas utils.)	C		7/14/08	17	EG	$940 million cash +working capital and other adjustments	940.0
7/8/06	MDU Resources Group, Inc.	Cascade Natural Gas Corporation	C		7/2/07	12	EG	$305.2mm in cash + ($173.6 in debt - $13.0 in cash equivalents)	465.8
7/8/06	WPS Resources Corporation	Peoples Energy Corporation	C	Integrys Energy Group	2/21/07	7	EG	$2.47 billion	2,472.4
7/5/06	Macquarie Consortium	Duquesne Light Holdings	C		5/31/07	10	EE	$1.59 billion cash + $1.09 billion total debt	2,674.4
6/22/06	Gaz Metro LP	Green Mountain Power Corp.	C		4/12/07	10	EE	$187 million in cash + ($100.8 debt - $9.1mm in cash equivalents)	279.5
5/11/06	ITC Holdings Corp	Michigan Electric Transmission Co.	C		10/10/06	5	EE	$485.6mm cash + $70mm common stock + $311mm assumed debt	866.6
4/25/06	Babcock and Brown Infrastructure	NorthWestern Corp.	W		7/24/07		EE	$2.2 billion cash	2,200.0
2/27/06	National Grid	KeySpan Corp.	C		8/24/07	18	EE	$7.4 billion cash + $4.5 billion long-term debt	11,877.5
12/19/05	FPL Group Inc.	Constellation Energy Inc.	W		10/25/06		EE	$11.3 billion equity + $4.1 billion net debt and pension liabilities	15,311.5
5/24/05	MidAmerican Energy Holdings Co.	Pacificorp	C		3/21/06	10	EE	$5.1 billion cash + $4.3 billion in net debt and preferred stock	9,300.0
5/9/05	Duke Energy Corp.	Cinergy Corp.	C		4/3/06	11	EE	$9.1 billion equity + $5.5 billion net debt and pension liabilities	14,600.0
12/20/04	Exelon Corp.	Public Service Enterprise Group	W		9/14/06		EE	$12.3 billion in equity + $13.4 billion in net debt and pension liabilities	25,700.0
7/25/04	PNM Resources	TNP Enterprises	C		6/6/05	12	EE	$189 million in stock and cash and $835 million in debt	1,024.0
2/3/04	Ameren Corp	Illinois Power3	C		10/1/04	8	EE	$1.9 billion in debt, pref stock, & other liab + $400 million in cash	2,300.0
11/24/03	Saguaro Utility Group L.P.	UniSource Energy	W		12/30/04		PE	$850 million cash + $2 billion in debt	2,850.0
11/3/03	Exelon Corp.	Illinois Power	W		11/22/03		EE	$275 million cash + $1.8 billion in debt + $150 million promissory note	2,225.0

4/30/02	Aquila Inc	Cogentrix Energy Inc	W		8/2/02		EIPP	$415 million cash + $1.125 billion in assumed debt	1,540.0
4/29/02	Ameren Corp	CILCORP4	C		1/31/03	9	EE	$541 million cash + $781 in assumed debt + $41 million in pref stock	1,400.0
10/8/01	Northwest Natural Gas	Portland General	W		5/16/02		GE	$1.55 billion cash + $250mm in stock	1,800.0
9/20/01	Duke Energy	Westcoast Energy	C		3/14/02	6	EG	Equity + cash valued at $27.90 per Westcoast share	8,500.0
9/10/01	Dominion Resources	Louis Dreyfus Natural Gas	C		11/1/01	2	EG	$890mm cash + $900mm stock +$505mm debt	2,295.0
2/20/01	Energy East	RGS Energy	C		6/28/02	16	EE	$1.4 bill. cash & equity + $1.0 bill. net debt	2,400.0
2/12/01	PEPCO	Conectiv	C		8/1/02	18	EE	$2.2 bill cash & equity + $2.8 bill. net debt	5,000.0
11/9/00	PNM	Western Resources5	W		1/8/02		EE	Stock transfer	4,442.0
10/2/00	NorthWestern	Montana Power6	C		2/15/02	16	EE	$1.1 billion in cash	1,100.0
9/5/00	National Grid Group	Niagara Mohawk	C		1/31/02	16	EE	$19 per share	8,900.0
8/8/00	FirstEnergy	GPU Inc.	C		11/7/01	15	EE	$35.60 per share	12,000.0
7/31/00	FPL Group	Entergy	W		4/2/01		EE	1/1 - FPL, 0.585/1 - ETR	27,000.0
7/17/00	AES Corporation	IPALCO	C		3/27/01	8	IPPE	$25 per share	3,040.0
6/30/00	NS Power	Bangor Hydro	C	Emera	10/10/01	16	EE	$26.50 per share	206.0
5/30/00	WPS Resources	Wisconsin Fuel and Light	C		4/2/01	11	EG	1.73 shares of WPSR	55.0
2/28/00	PowerGen plc	LG&E	C		12/11/00	10	EE	$24.85 per share	5,400.0
11/10/99	Energy East	Berkshire Energy Resources	C		9/1/00	10	EG	$38 per share	136.0
11/8/99	Sierra Pacific Resources	Portland General	W		4/26/01		EE	$2.1 billion	3,100.0
11/4/99	KeySpan	Eastern Enterprises	C		11/9/00	12	EG	$64 per share	2,500.0
10/25/99	Berkshire Hathaway	MidAmerican Energy	C		3/14/00	5	PE	$35.05 per share	9,000.0
10/13/99	Consolidated Edison	Northeast Utilities	W		3/15/01		EE	$25 per share	7,500.0
10/5/99	DTE Energy	MCN Energy	C		5/31/01	19	EG	$28.50 per share	4,600.0
9/23/99	Peco Energy Co.	Unicom Corp.	C	Exelon	10/23/00	13	EE	0.95/1 - UCM, 1/1 - PE	31,800.0
9/9/99	Allegheny Energy	West Virginia Power	C		1/4/00	4	EE	$75 million	75.0
8/23/99	Carolina Power & Light	Florida Progress	C	Progress Energy	11/30/00	15	EE	$54 per share	8,000.0
6/30/99	Energy East	CTG Resources	C		9/1/00	15	EG	$41 per share	575.0
6/28/99	Wisconsin Energy Corp.	Wicor Inc.	C		4/26/00	10	EG	$31.50 per share	1,275.0
6/15/99	Energy East	CMP Group, Inc.	C		9/1/00	15	EE	$29.50 per share	1,228.0
6/15/99	Northeast Utilities	Yankee Gas	C		3/1/00	9	EG	$45 per share	679.0
6/14/99	Dynegy	Illinova	C		2/2/00	7	IPPE	0.69/1 - DYN, 1/1 - ILN	2,000.0
6/14/99	Indiana Energy	SigCorp	C	Vectren	3/31/00	9	GE	1.33/1 - SIG, 1/1- IEI	1,900.0
6/7/99	Nisource Inc.	Columbia Energy	C		11/1/00	17	EG	$74/share	6,200.0
5/25/99	S.W. Acquisition Corp.	TNP Corporation	C		4/7/00	11	PE	$74 per share	100.0
5/17/99	OGE Energy	Transok LLC	C		7/1/99	2	EG	$701 million	701.0
5/11/99	Utilicorp United	Empire District Electric	W		1/3/01		EE	$29.50 per share in cash or stock	765.0
4/23/99	Energy East	Connecticut Energy	C		2/9/00	9	EG	$42 per share, 50% cash and 1.43-1.82/1 - CNE	617.0
3/25/99	Northern States Power	New Century Energies	C	Xcel Energy	8/17/00	17	EE	1.55/1 - NCE, 1/1 - NSP	6,000.0
3/5/99	Utilicorp United	St. Joseph Power & Light Co.	C		12/29/00	21	EE	$23 per share	277.0
2/22/99	Dominion Resources	Consolidated Natural Gas Co.	C		1/28/00	11	EG	$66.60 per share	6,400.0
2/17/99	SCANA Corp	PSC Of North Carolina	C		2/10/00	12	EG	$33 per share or 1.02-1.45 shares of SCG	9,000.0
2/1/99	National Grid USA/NEES	Eastern Utilities Associates	C		4/19/00	14	EE	$31 per share in cash	634.0
2/1/99	Sempra Energy	KN Energy	W		6/1/99		EG	$25 per share	6.0

[1] TXU (now Energy Future Holdings Corp.) was acquired by the Texas Energy Future Holdings Limited Partnership (TEF) on 10/10/2007.
TEF was formed by a group of investors led by Kohlberg Kravis Roberts and Texas Pacific Group to facilitate the merger.

[2] Ameren purchased Illinois Power from Dynegy Corporation. Dynegy Corp acquired Illinois Power in February 2000.

[3] Ameren purchased CILCORP from AES Corporation. AES Corp acquired CILCORP in October 1999.

[4] PNM purchased Western Resources' electric operations including generation, transmission, and distribution.

[5] NorthWestern Corporation purchased Montana Power's electric and natural gas transmission and distribution assets.

NA= Acquired company privately held or no data available
Source: EEI Finance Department and SNL Financial

C = Completed
W = Withdrawn
PN = Pending
E = Electric
G = Gas
O = Oil
IPP = Independent Power Producer
P = Privatized

The companies hope to close the transaction by the end of 2014, following approval by Arizona state regulators, the Federal Energy Regulatory Commission and satisfaction of any anti-trust concerns under the Hart-Scott-Rodino Act of 1976.

ITC and Entergy Terminate Transmission Deal

The year came to a close with news that another large proposed multi-state merger had fallen victim to dissension from regulators and stakeholders regarding division of anticipated benefits from the deal. But this was not a proposed combination of regulated utilities. Instead, it was the agreement announced two years earlier, on December 5, 2011, that Gulf Coast regional utility Entergy would divest its transmission assets to Michigan-based ITC Holdings, the nation's largest independent transmission company. The deal encountered resistance throughout 2013 from state regulators, public officials and consumer groups across Louisiana, Mississippi, Arkansas and Texas, who expressed concerns the deal would diminish state regulatory jurisdiction over rates, force consumers to pay more for power and offer no benefits that couldn't also be achieved by Entergy integrating its transmission assets with the MISO regional transmission organization. The companies withdrew their application in Texas in August 2013 and prepared to make a second attempt at gaining approval, then Arkansas regulators suspended their consideration of the deal after the Texas move. The two companies terminated the proposed merger three days after the Mississippi Public Service Commission's rejection of the deal on December 10, 2013. Since the termination was a mutual decision, there were no termination fees or penalties for either company.

While affirming its conviction the divestiture would have delivered real benefits to ratepayers and all stakeholders, upon terminating the deal Entergy said its transmission network will play an integral part in its growth plan, noting its service territory is primed for strong economic development with over $50 billion of capital investment announced by third parties over the past 12 to 18 months that has potential to add more than 2,000 megawatts of load. The company said its preliminary 2014-2016 capital plan includes $1.7 billion for transmission investment and that it's on track to transfer functional control of its transmission systems to the Midcontinent Independent System Operator, which Entergy estimates will save customers approximately $1.4 billion over the next decade. Entergy also affirmed its five to seven percent utility net income compound average growth rate outlook through 2016, off 2013 base, driven by load growth, capital investment and cost-saving initiatives.

Construction

Generation

New Capacity

After adding a record amount of new generation capacity in 2012, the electric utility industry scaled back the pace of development in 2013, particularly with respect to wind generation. A total of 17,163 MW of new capacity was added to the grid, 46% less than in 2012 and the lowest annual total of the last five years. Natural gas (7,370 MW) and solar (4,936 MW) accounted for the majority of the new capacity.

While additions were lower for most fuels when compared to prior years, the total for wind generation notably declined. The expiration of the federal production tax credit (PTC) at the end of 2012 sent developers rushing to bring new wind online, effectively meeting the need for wind capacity in 2013 in advance. As a result, wind additions fell more than 85% in 2013, declining from a record high 12,327 MW in 2012 to just 1,646 MW, a nine-year low. New coal capacity (1,618 MW) continued to decline in response to impending environmental regulations and low natural gas prices. Nuclear uprates also fell, to 172 MW, although the total was in line with historical annual activity.

While renewables were the dominant source of new capacity in 2012, natural gas regained the lead in 2013 (7,370 MW) due to the attractive economics associated with natural gas plants (comparatively low up-front capital costs, lower emissions compared to coal and low natural gas prices) as well as the drop off in wind additions.

Solar energy had a record breaking year (4,936 MW), surpassing wind for the first time as the leading source of new renewable capacity. The growth in solar has been driven by falling photovoltaic (PV) panel costs, the availability of financial incentives at both the federal and state level, and supportive policies such as renewable portfolio standards and net metering. Several large, utility-scale solar PV plants entered commercial operation, including NextEra's Desert Sunlight Solar farm and MidAmerican's Topaz Solar farm, both in California. In addition, it was a banner year for solar thermal generation despite the competition posed by PV plants and their rapidly declining costs. A total of 802 MW of solar thermal capacity entered commercial operation at the Solana Generating Station in Arizona, the Genesis Solar Energy Project and Ivanpah Solar facility in California, and Kalaeloa Solar One in Hawaii. Distributed solar generation also grew rapidly as consumers and businesses put solar panels on rooftops.

New capacity added by investor-owned electric utilities totaled 4,644 MW, only one-third the amount in 2012 and the lowest annual total in more than 10 years. While investor-owned utilities' share of overall industry development is lower than in recent years, it should be noted that most non-utility owned capacity is paid for through power purchase agreements (PPAs) or other arrangements with utility buyers.

New Capacity Online (MW) 2009-2013

	U.S. Investor-Owned Electric Utilities	Entire Industry
2013p		
New Plant	1,288	9,920
Plant expansions	3,356	7,243
Total	**4,644**	**17,163**
2012r		
New Plant	6,331	17,962
Plant expansions	7,225	13,540
Total	**13,556**	**31,503**
2011		
New Plant	1,977	10,961
Plant expansions	5,296	11,544
Total	**7,272**	**22,505**
2010		
New Plant	3,221	8,337
Plant expansions	5,847	12,256
Total	**9,068**	**20,593**
2009		
New Plant	5,182	13,710
Plant expansions	6,676	11,712
Total	**11,858**	**25,422**

p = preliminary
r = revised

Note: Totals may reflect rounding. Historical data subject to revision.

Source: Ventyx, Inc., The Velocity Suite and EEI Finance Department

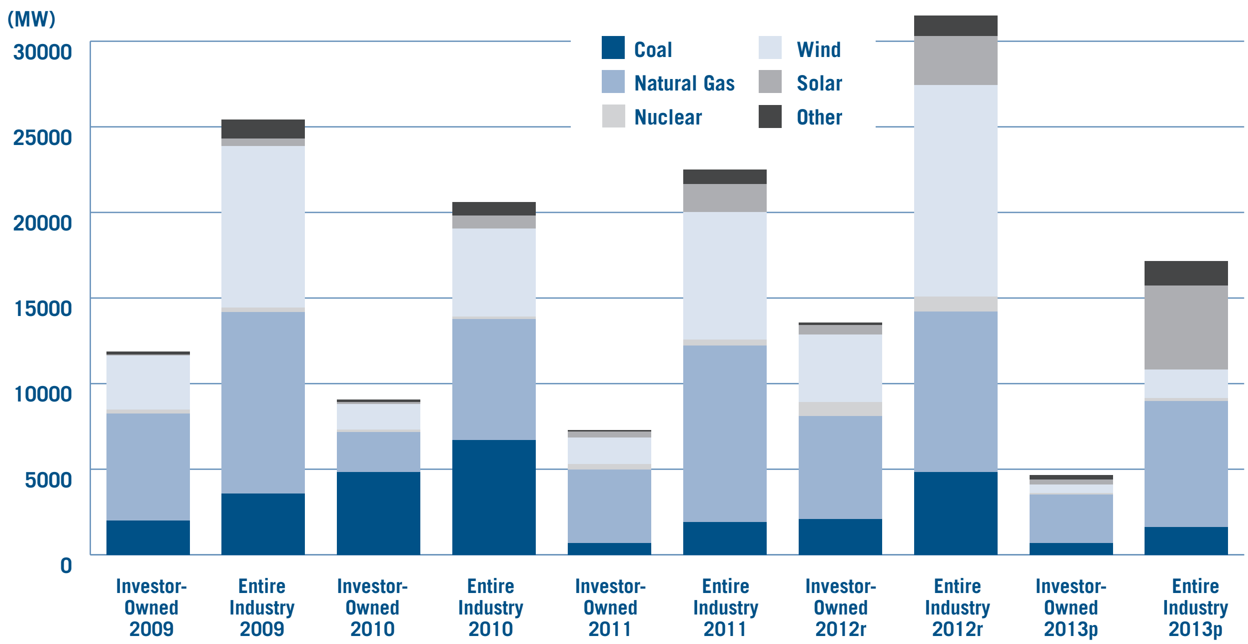
Cancelations

Capacity canceled or postponed by investor-owned utilities totaled 15,125 MW in 2013, a slight increase over 2012's level. The bulk (8,836 MW) are cancelled nuclear units or those whose estimated completion dates were delayed. Duke Energy canceled plans for a new reactor at the Levy County site in Florida and postponed plans for a new unit at their Harris plant in North Carolina. Energy Future Holdings postponed two units planned in Texas, and Southern Company postponed plans for a unit in Florida. It remains difficult to obtain financing for new nuclear units given their high upfront capital costs compared to natural gas plants.

Announcements

Investor-owned electric utilities announced plans for 9,962 MW of new capacity in 2013, a 63% increase from 2012. Natural gas generation led announcements, at 6,212 MW, a 22% increase from the prior year. The largest projects were announced by Duke Energy and San Diego Gas & Electric, in both cases for natural gas capacity that offsets retiring nuclear plants. Duke issued an RFP to build a 1,640 MW natural gas combined cycle plant in Citrus County, Florida to replace retired capacity at the nearby Crystal River Nuclear Plant. San Diego Gas & Electric announced plans to build a 1,000 MW natural gas plant at Camp Pendleton in California to

New Capacity Online by Fuel Type 2009-2013



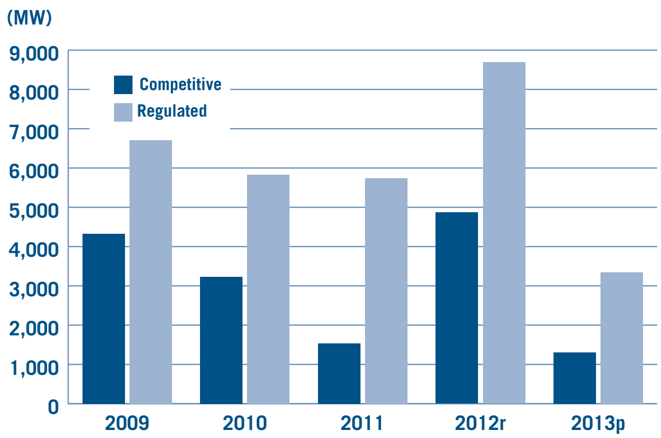
Fuel Type	U.S. Investor-Owned Elecric Utilities					Entire Industry				
	Online 2009	Online 2010	Online 2011	Online 2012r	Online 2013p	Online 2009	Online 2010	Online 2011	Online 2012r	Online 2013p
Coal	1,998	4,848	689	2,080	673	3,566	6,692	1,909	4,823	1,618
Natural Gas	6,249	2,313	4,283	6,024	2,844	10,627	7,072	10,299	9,395	7,370
Nuclear	245	154	341	799	97	245	154	353	875	172
Wind	3,146	1,496	1,546	3,958	483	9,451	5,126	7,464	12,327	1,646
Solar	40	100	322	549	301	418	772	1,614	2,882	4,936
Other	180	157	90	146	246	1,115	777	866	1,200	1,421
Total	**11,858**	**9,068**	**7,272**	**13,556**	**4,644**	**25,422**	**20,593**	**22,505**	**31,503**	**17,163**

p = preliminary
r = revised
Note: Other includes diesel, fuel oil, landfill gas, pet coke, solar/PV, waste heat, water, wood, biomass, and fuel cells.
Entire Industry includes all new capacity placed on the grid by investor-owned electric utilities, independent power producers, municipals, co-ops, government authorities and corporations. Data includes expansions and new plants.
Prior year data revised to incorporate additional data on solar projects.

Source: Ventyx, Inc., The Velocity Suite and EEI Finance Department

New Capacity Online – Regulated vs. Competitive

U.S. INVESTOR-OWNED ELECTRIC UTILITIES



	2009	2010	2011	2012r	2013p
Total Competitive	4,320	3,233	1,530	4,867	1,303
Total Regulated	7,538	5,835	5,742	8,690	3,340
Total	**11,858**	**9,068**	**7,272**	**13,556**	**4,644**

Notes: Plant category based on designated operating company owner. Totals may reflect rounding.
p: preliminary
r: revised

Source: Ventyx, Inc., The Velocity Suite and EEI Finance Department

New Capacity Online by Region 2009-2013

U.S. INVESTOR-OWNED ELECTRIC UTILITIES

	2009		2010		2011		2012r		2013p	
Region	**Online**	**Cancelled**	**Online**	**Cancelled**	**Online**	**Cancelled**	**Online**	**Cancelled**	**Online**	**Cancelled**
ECAR	—	—	—	—	—	—	—	—	—	—
ERCOT	2,589	3,935	1,229	—	—	465	304	—	402	3,632
FRCC	4,117	—	20	2,390	1,250	—	251	—	1,361	2,500
HCC	5	—	113	—	—	—	21	—	—	—
MAAC	—	—	—	—	—	—	—	—	—	—
MAIN	—	—	—	—	—	—	—	—	—	—
MRO	1,060	504	351	532	373	500	881	1,078	112	439
NPCC	8	124	3	1	39	350	245	—	17	178
RFC	486	1,288	741	3,175	1,458	93	2,202	1,618	904	2,703
SERC	567	4,131	1,770	605	2,635	—	5,091	44	646	4,921
SPP	740	630	2,347	80	431	—	1,590	150	203	751
WECC	2,287	4,519	2,495	504	1,083	2,202	2,741	10,230	100	3
Total	**11,858**	**15,131**	**9,068**	**7,287**	**7,272**	**3,609**	**13,325**	**13,121**	**4,644**	**15,125**

p = preliminary
r = revised
Note: Data includes new plants and expansions of existing plants, including nuclear uprates. Totals may reflect rounding.
Reliability*First* Corporation (RFC) began operations on 1/1/06 and includes ECAR, MAAC, and MAIN.

Source: Ventyx, Inc., The Velocity Suite and EEI Finance Department

offset lost capacity at the retiring San Onofre Nuclear Generating Station.

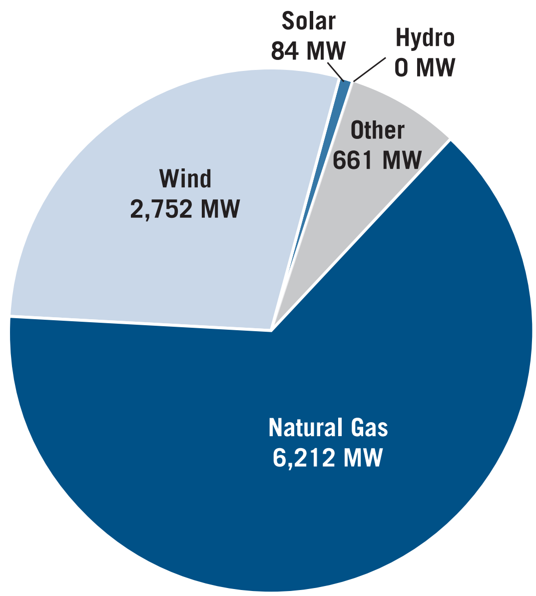
Wind announcements (2,752 MW) rebounded due to PTC extension and revision in early 2013; the changes allowed projects under construction before December 31, 2013 to be eligible for the credit. Capitalizing on this revision, MidAmerican Energy Holdings announced nearly 1,500 MW of new wind capacity at seven new sites in Iowa, 1,050 MW of which is already under construction across five sites. At the same time, MidAmerican placed the world's largest onshore wind turbine order (448 turbines) with Siemens. The projects are expected to be completed in 2015. Dominion, Duke, NextEra and Sempra also announced plans for new wind capacity

The pace of solar announcements declined, reflecting a shift from large utility-scale installations to smaller, distributed facilities. Solar announcements in 2013 were entirely for PV facilities, with the largest at 15 MW. This shift is largely a result of state policies and incentives that encourage distributed solar.

The only coal and nuclear announcements centered on rerates of existing units, reflecting the regulatory and economic challenges facing these fuels. Surprisingly, 609 MW of oil generation was announced, attributed to a planned expansion at an existing oil plant in Maine that only runs during peak load for reliability reasons. The project is expected to be completed in 2017.

2013 New Capacity Announcements by Fuel Type

U.S. INVESTOR-OWNED ELECTRIC UTILITIES



Note: Other includes biomass, diesel/fuel oil, fuel cells, landfill gas, pet coke, solar/PV, waste heat, water, wood. Totals may reflect rounding.

Source: Ventyx, Inc., The Velocity Suite and EEI Finance Department

New vs. Cancelled Capacity by Fuel Type (MW)

U.S. INVESTOR-OWNED ELECTRIC UTILITIES

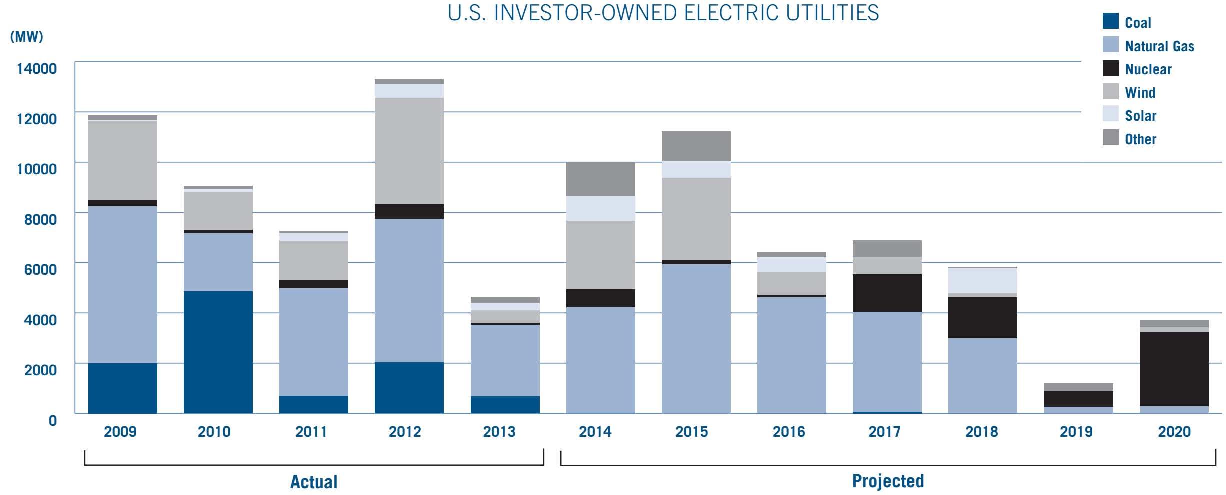
Fuel Type	Online 2009	Canceled 2009	Online 2010	Canceled 2010	Online 2011	Canceled 2011	Online 2012r	Canceled 2012r	Online 2013p	Canceled 2013p
Coal	1,998	3,634	4,848	1,428	689	—	2,080	500	673	—
Natural Gas	6,249	4,508	2,313	3,290	4,283	1,140	6,024	1,426	2,844	2,215
Nuclear	245	6,100	154	1,600	341	—	799	36	97	8,836
Solar/Photovoltaics	40	—	100	46	322	250	549	8,834	301	—
Wind	3,146	889	1,496	827	1,546	2,206	3,958	2,318	483	1,386
Other	180	—	157	96	90	13	146	6	246	2,688
Total	**11,858**	**15,131**	**9,068**	**7,287**	**7,272**	**3,609**	**13,556**	**13,121**	**4,644**	**15,125**

p = preliminary
r = revised
Note: Totals may reflect rounding. Data includes new plants and expansions of existing plants, including nuclear uprates.
Other = diesel, fuel oil, landfill gas, pet coke, solar/PV, waste heat, water, wood, biomass, and fuel cells.

Source: Ventyx, Inc., The Velocity Suite and EEI Finance Department

Actual and Projected Capacity Additions 2008-2020

U.S. INVESTOR-OWNED ELECTRIC UTILITIES



	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
Coal	1,998	4,848	689	2,025	673	18	—	—	61	—	—	—
Natural Gas	6,249	2,313	4,283	5,716	2,844	4,213	5,934	4,612	3,970	2,981	267	288
Nuclear	245	154	341	588	97	714	163	102	1,500	1,635	614	2,960
Wind	3,146	1,496	1,546	4,222	483	2,711	3,271	930	697	175	—	175
Solar	40	100	322	564	301	1,001	659	560	—	985	—	—
Other	181	157	90	209	246	1,353	1,212	219	659	50	300	300
Total	11,858	9,068	7,272	13,325	4,644	10,010	11,239	6,422	6,887	5,826	1,181	3,723

Notes: Data includes new plants and expansions of existing plants, including nuclear uprates. Data does not include projects with an expected online date beyond 2020.
Other includes biomass, diesel/fuel oil, fuel cells, landfill gas, pet coke, waste heat, water, wood. Totals may reflect rounding.
2009-2013 is actual plants brought online. 2014-2020 is projected based on projects announced as of 12/31/12.
Source: Ventyx Inc., The Velocity Suite; EEI Finance Department

Though the industry may not reach the record set in 2012, capacity additions over the next two years should rebound from 2013's low level. Announcements in 2013 were the highest since 2009, and investor-owned electric utilities are expected to bring over 21,000 MW online in the 2014-2015 timeframe. While not all announcements will be built, nearly 10,000 MW (including over 5,000 MW of natural gas and 3,000 MW of wind) is either under construction or permitted, raising the likelihood that these projects will reach completion.

Retirements

Investor-owned utilities retired 13,339 MW of capacity in 2013, including 5,561 MW of coal capacity. Coal retirements are being driven by impending emissions regulations as well as low natural gas prices. Investor-owned utilities are expected to retire 26,740 MW of coal capacity by the end of 2020, with the majority planned for 2015.

For the first time, a significant amount of nuclear capacity was also retired. This was the result of decisions to close San Onofre in California, Crystal River in Florida and Kewaunee in Wisconsin. The San Onofre and Crystal River units each required costly repairs that were deemed uneconomic. Kewaunee struggled to be economically competitive in a merchant environment characterized by excess capacity and low natural gas prices that kept wholesale electricity market prices low.

Transmission

Investment

Investor-owned electric utilities and stand-alone transmission companies invested a record $34.9 billion in transmission and distribution infrastructure in 2012, according to the latest EEI Annual Property & Plant Capital Investment Survey.

The industry's capital spending on transmission totaled $14.8 billion in 2012, a 23.9% increase over the $11.9 billion (in nominal dollars) that the industry invested in 2011. The increase represents the largest year-to-year-percentage increase in transmission investment since 2000, which saw a 39.9% jump from 1999 levels.

Stage of Projected Capacity Additions

U.S. INVESTOR-OWNED ELECTRIC UTILITIES

by MW

Fuel	Proposed	Feasibility	Application Pending	Permitted	Site Prep	Under Construction	Testing	Total
Coal	—	—	—	61	—	18	—	79
Natural Gas	2,473	3,691	4,517	4,138	1,967	3,498	1,979	22,263
Nuclear	415	—	4,836	188	—	2,250	—	7,689
Wind	4,768	10	87	735	—	2,359	—	7,960
Solar	491	—	68	2,193	—	319	4	3,074
Other	756	3,191	50	86	—	11	—	4,093
Total	**8,902**	**6,892**	**9,558**	**7,402**	**1,967**	**8,455**	**1,983**	**45,159**

Source: Ventyx Inc., The Velocity Suite; EEI Finance Department

Note: Other includes biomass, diesel/fuel oil, fuel cells, landfill gas, pet coke, waste heat, water, wood. Totals may reflect rounding.

Proposed New Nuclear Plants

U.S. INVESTOR-OWNED ELECTRIC UTILITIES

Company	Site (State)	Early Site Permit (ESP)	Design (# of Units)	Expected Construction & Operating License Submittal
DTE Energy Co.	*Fermi (MI)*	—	*ESBWR (1)*	*September 2008*
Dominion Resources Inc.	*North Anna (VA)*	*Approved November 2007*	*ESBWR (1)*	*November 2007*
Duke Energy Corp.	*William States Lee (SC)*	—	*AP1000 (2)*	*December 2007*
Exelon Corp.	*Clinton (IL)*	*Approved March 2007*	*TBD*	*TBD*
Florida Power & Light	*Turkey Point (FL)*	*TBD*	*AP1000 (2)*	*June 2009*
PPL Corp. / UniStar	*Bell Bend (PA)*	—	*EPR (1)*	*October 2008*
PSEG	*Lower Alloways Creek (NJ)*	*Submitted May 2010*	*TBD*	*TBD*
SCANA Corp.	*V.C. Summer (SC)*	—	*AP1000 (2)*	*Approved March 2012*
Southern Co.	*Vogtle (GA)*	*Approved August 2009*	*AP1000 (2)*	*Approved February 2012*

Note: As of January 2014

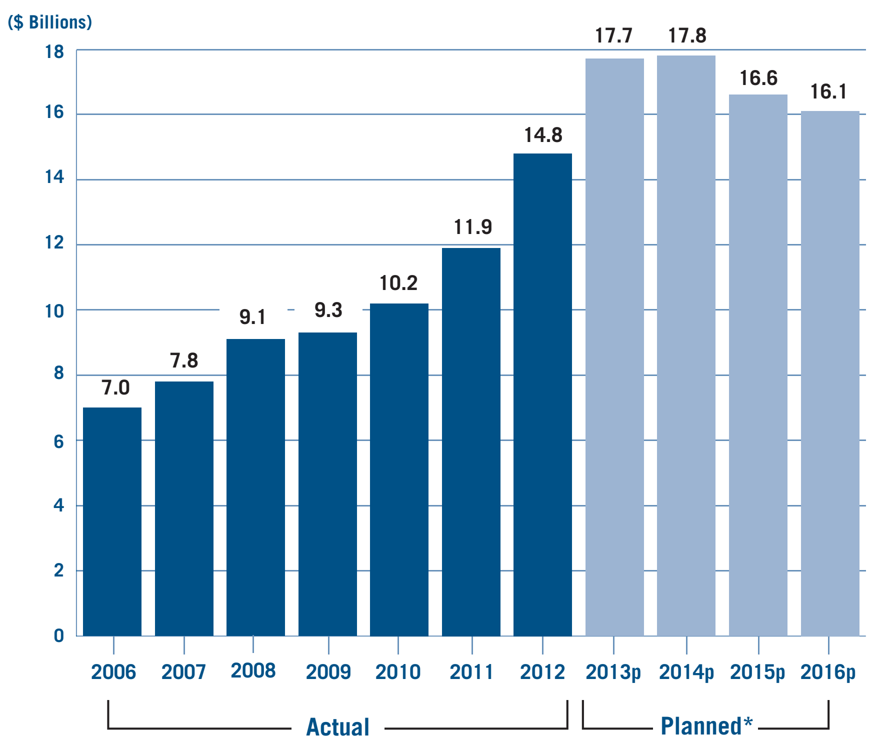
Legend:
TBD: To Be Determined
AP1000: Reactor designed by Westinghouse
APWR: Advanced Pressurized Water Reactor
EPR: Pressurized Water Reactor designed by Framatome
ESBWR: Economic Simplified Boiling Water Reactor
Those in italics represent COL applications that have been approved so far.

Source: Nuclear Energy Institute, Nuclear Regulatory Commission and EEI Finance Department

After adjusting for increases in constructions costs, actual transmission expenditures in 2012 increased 23.5% (in 2012 dollars) compared to 2011 expenditures. Transmission investment in 2012 was 160.5% higher than in 2000, after adjusting for cost increases; over the same period the industry invested a cumulative $113.3 billion in transmission. Electric utilities attribute the increased transmission investment to several key factors, including the completion of large capacity transmission projects around the country and interconnection of new generation (including renewable resources) to the grid.

Projected transmission investment for 2013 shows continued growth, reflecting significant storm hardening following Superstorm Sandy. EEI's survey results show a decrease in transmission investment after 2014, in part because several major projects have recently been modified, delayed or cancelled due to reduced forecasts for load growth in response to weak economic growth as well as demand side management and energy efficiency initiatives. As planning factors change, transmission planners must respond by adjusting system infrastructure needs to meet customer demand. Nevertheless, EEI expects investment by its members during 2013 to 2016 to be significantly higher than in 2011.

Actual and Planned Transmission Investment 2006-2016



p = preliminary

* Planned total industry expenditures are preliminary and estimated from response to EEI's Electric Transmission Capital Budget & Forecast Survey. Actual expenditures from EEI's Annual Property & Plant Capital Investment Survey and from the FERC Form 1 reports.

Source: Edison Electric Institute, Business Information Group

Given the investments needed in coming years to upgrade and expand the transmission system, it is essential that regulation remains supportive, with policies that help utilities address the risks and challenges associated with developing, constructing, operating and maintaining transmission.

Continued Investment is Needed to Increase Resiliency and Support New Technologies

Utilities invest in transmission infrastructure for a variety of reasons, including to ensure their ability to provide safe, affordable and reliable electricity, and to enable new technologies and services that meet customer needs. Electric utilities must also continuously address system requirements such as reliability mandates, infrastructure modernization and replacement, and integration of new generation. With an unprecedented number of coal plant retirements planned for the coming years, transmission upgrades will be needed to preserve reliability in areas where coal plants are shutting down. In addition, recent extreme weather events, such as Superstorm Sandy and the Derecho in 2012, have led to an increased focus on reinforcing and upgrading electric infrastructure so that it better withstands storms and recovers more quickly from them.

President Obama has highlighted the need for increased investment in the transmission system, issuing a memorandum that advocates strengthening the system against storms and cyber attacks and modernizing it for integration of new, clean generation technologies.

In addition, the first phase of the Administration's Quadrennial Energy Review is focusing on energy delivery infrastructure challenges and on policy recommendations for overcoming them.

Given the growth in distributed generation, transmission remains critical for maintaining system-wide reliability by providing access to power when intermittent local supply is unavailable. At the same time, large concentrations of distributed generation increase the need to detect and react quickly to supply/demand imbalances when distributed sources go offline or when they cannot fully meet demand. As a result, supportive regulatory frameworks and equitable cost allocation policies are essential to utilities' ability to build and manage networks that promote customer control and choice.

Several plans for grid upgrades and expansion projects were announced in 2013. PJM approved $4.6 billion to expand and upgrade the grid, citing the need to accommodate over 20,000 MW of generation expected to retire along with record amounts of new natural gas generation coming online. MISO approved the addition of 300 projects totaling $1.4 billion to its regional transmission expansion plan for improved reliability and plant retirements. ERCOT expects to complete $3.6 billion in transmission projects over the next four years to increase capacity and support reliability. The Southeastern Regional Transmission Planning organization proposed $1.8 billion in transmission upgrades to address a variety of reliability needs over the next ten years.

Distribution

The EEI survey found investment in electric distribution infrastructure rose 4.7 percent in 2012, to $20.1 billion (in nominal dollars) from $19.2 billion (nominal) invested in 2011. The increase was largely due to storm restoration, as well as development of automated meter infrastructure (AMI) and other smart grid activities.

Adjusting for a 3.2 percent increase in distribution-related construction costs in 2012, distribution investment increased 1.4 percent (in 2012 dollars) compared to the level in 2011. Since the beginning of 2000, the industry has invested $275 billion (in 2012 dollars) in the nation's distribution system.

Distribution investment is driven by the ongoing need to replace assets that have lived out their useful life, to serve new load, preserve reliability, improve system resiliency and restoration capabilities, and increasingly, to accommodate increasing amounts of distributed resources. Investment in utility infrastructure tends to move in cycles, rising as large investments are made to support major development projects, leveling off as the focus shifts toward maintenance and incremental upgrades, and then rising again as additional investments are needed to support load growth and to integrate new technologies.

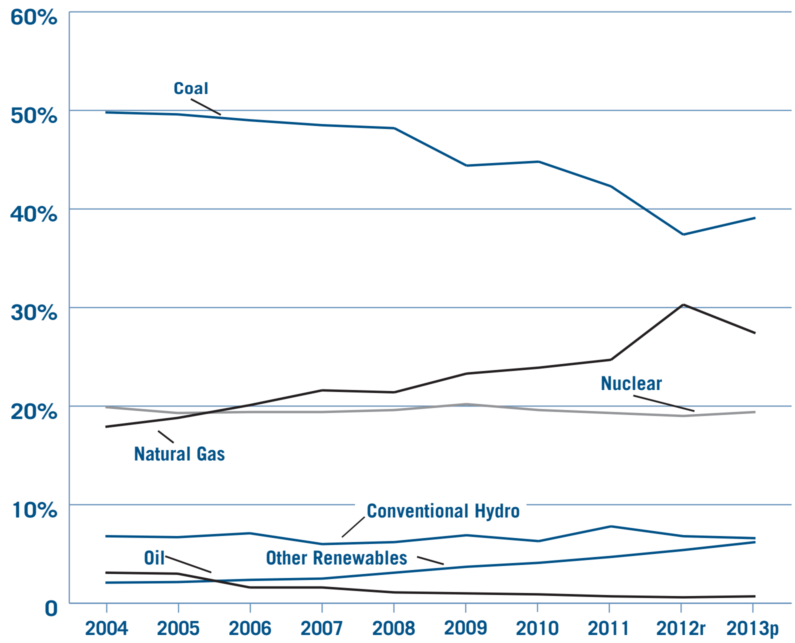
The industry faces significant distribution-related capital spending resulting from the normal replacement of old infrastructure, to harden the grid against storm damage and to expand its ability to support increased distributed generation. Updating the electric system with new technologies will also improve reliability and enable customers to adopt new technologies, such as rooftop solar and electric vehicles, and it will support provision of detailed information about grid conditions so that all resources can be used more effectively.

Fuel Sources

A stabilization of natural gas spot prices and sluggish electricity demand were the dominant trends that impacted fuel usage in 2013. The widespread fuel switching to natural gas from coal that characterized 2012 did not continue as natural gas prices rose slightly, holding in a range of $3 to $4 per million BTU throughout the year. The pace of wind capacity additions slowed to an almost non-existent level, growth in solar generation remained strong and uncertainty persisted about the future of nuclear power. Electric generation grew a mere 0.3% for the year as a whole; a colder-than-normal winter was especially influential in producing the small gain since winters in 2011 and 2012 were warmer than normal. Supply/demand rebalancing in the natural gas market helped coal's share of the generation mix rise to 39.1% from 37.4% in 2012. Natural gas generation decreased to 27.4% of the total from 30.3% in 2012. The rapid growth of wind and solar continued, gaining 19% and 113% respectively; this brought non-hydro renewables' share of generation to 6.2% from 5.4% in 2012.

Fuel Sources for Electric Generation 2004–2013

U.S. ELECTRIC UTILITY AND NON-UTILITY



r = revised
p = preliminary

U.S. Electric Utility: Owns and/or operates facilities within the United States, its territories, or Puerto Rico for the generation, transmission, distribution, or sale of electric energy primarily for use by the public. This includes investor-owned utilities, public power, and cooperatives.

Non-Utility Power Producer: Non-utility power producers include qualifying cogenerators, qualifying small power producers, and other non-utility generators (including independent power producers) without a designated franchised service area.

Source: U.S. Department of Energy, Energy Information Administration (EIA)

Fuel Sources for Net Electric Generation

U.S. ELECTRIC UTILITY AND NON-UTILITY

	2013p	2012
Coal	39.1%	37.4%
Gas	27.4%	30.4%
Nuclear	19.4%	19.0%
Oil	0.7%	0.6%
Hydro	6.6%	6.8%
Renewables	6.2%	5.4%
Biomass	1.5%	1.4%
Geothermal	0.4%	0.4%
Solar	0.2%	0.1%
Wind	4.1%	3.4%
Other fuels	0.5%	0.5%
Total	100%	100%

Note: Totals may not equal 100.0% due to rounding.
p: preliminary

U.S. Electric Utility: Owns and/or operates facilities within the United States, its territories, or Puerto Rico for the generation, transmission, distribution, or sale of electric energy primarily for use by the public. This includes investor-owned utilities, public power, and cooperatives.

Non-Utility Power Producer: Non-utility power producers include qualifying cogenerators, qualifying small power producers, and other non-utility generators (including independent power producers) without a designated franchised service area.

Source: Energy Information Administration

Coal

Coal remained the primary fuel used to generate electricity in the U.S. in 2013, and its share of the fuel mix, which had fallen sharply in 2012, rose slightly. However, the long-term trend continues to be a steady decline. Very low natural gas prices during part of 2012 drove coal's share of total generation down to 37.4% for the year, from 42.3% in 2011. In 2013 however, supply/demand rebalancing in the natural gas market helped coal's share of total generation rise back to 39.1%, higher than in 2012, yet a level still consistent with the downward trajectory of the last ten years.

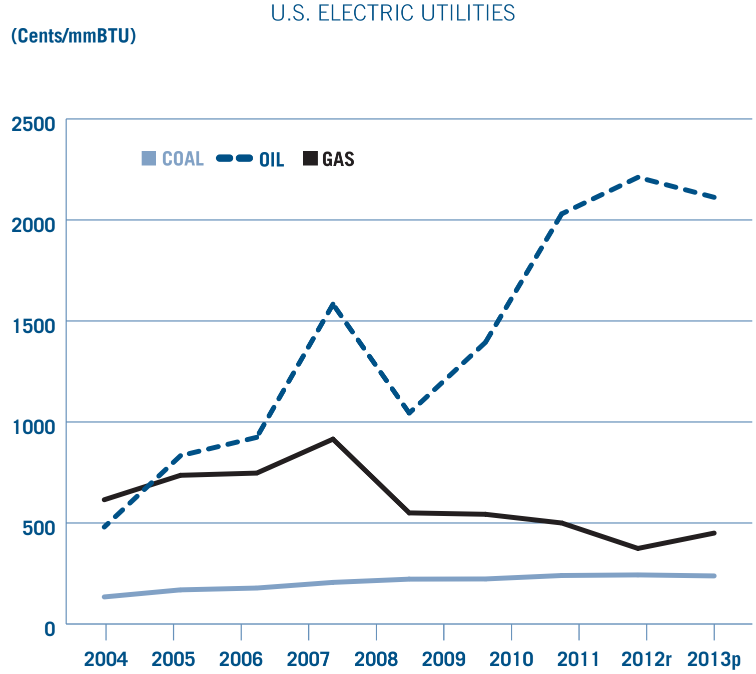
Coal prices remained relatively stable in 2013 (in the 2009-2011 period strong coal exports pushed prices higher), but basins followed different price paths throughout the year in response to location-specific market conditions. The average spot price of Central Appalachian coal was $65.13 per ton compared to $66.06 per ton in 2012, but far below 2011's $78.84 per ton. The other major basins, Northern Appalachian, Powder River and Illinois, followed similar patterns, with small changes throughout the year. Because of its relative cost-disadvantage versus natural gas, Central Appalachian coal prices started declining in the second half of the year as the fuel lost market share. However, at the same time, prices in Northern Appalachia and Powder River Basin rose since a firming of natural gas prices made burning these types of coal more economic than was the case in 2012. Demand for coal from these basins also grew as a result of an increase in installed pollution controls in power plants, which make burning low-sulfur coal relatively less advantageous.

The coal market was tighter everywhere as coal production decreased slightly (by 0.4% compared to 2012), while demand increased 4%. Despite a decline in exports resulting from weaker European and Asian demand, along with growing production from other exporting nations, overall coal demand increased because of stronger demand from the power sector in response to cold fall and winter weather. As a result, coal stockpiles decreased substantially. According to the Energy Information Administration (EIA), electricity generation between November 2013 and February 2014 was 5.3% higher than during the same period last year and coal generation supplied 59% of that increase.

Although the delivered price of coal is based on contracted prices and includes transportation costs, trends in delivered costs in 2013 mirrored those of spot prices. The average price of delivered coal from Central Appalachia fell from $93.2 per ton in 2012 to $89.5 in 2013. PRB's delivered price edged up from $35 per ton in 2012 to $35.5 per ton in 2013. According to EIA data, the average cost of coal for electric utilities was lower in 2013 than in 2012.

Average Cost of Fossil Fuels 2004-2013

U.S. ELECTRIC UTILITIES



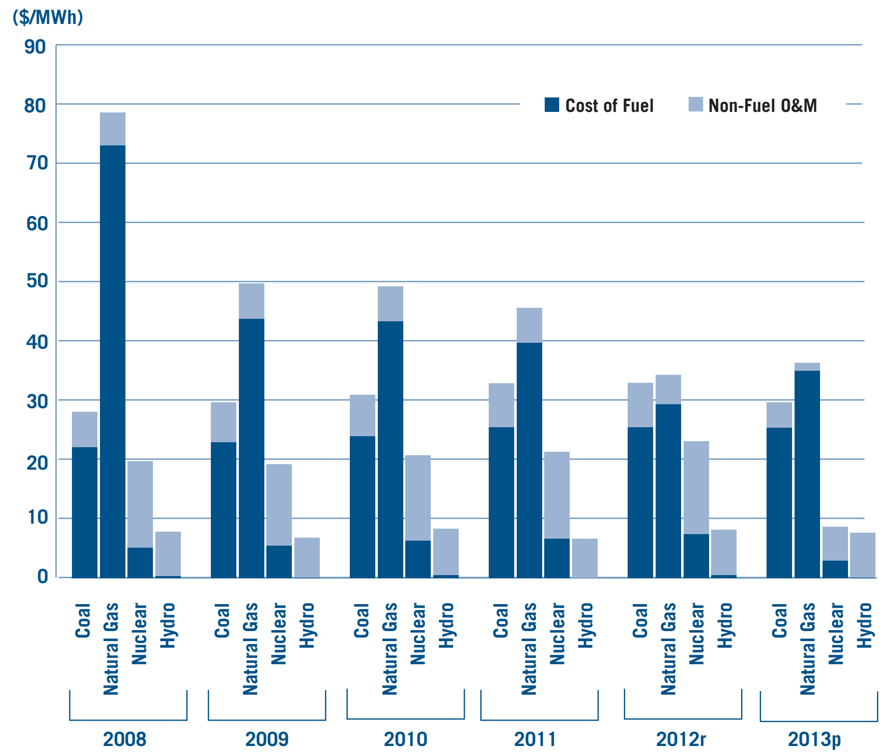
r = revised
p = preliminary

U.S. Electric Utility: Owns and/or operates facilities within the United States, its territories, or Puerto Rico for the generation, transmission, distribution, or sale of electric energy primarily for use by the public. This includes investor-owned utilities, public power, and cooperatives.

Source: U.S. Department of Energy, Energy Information Administration (EIA)

Average Cost to Produce Electricity 2008-2013

U.S. ELECTRIC UTILITY AND NON-UTILITY



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Non-Utility Power Producer: Non-utility power producers include qualifying cogenerators, qualifying small power producers, and other non-utility generators (including independent power producers) without a designated franchised service area.

* 2013 results are preliminary and based on modeled data from Ventyx, Inc., The Velocity Suite

Source: Ventyx, Inc., The Velocity Suite

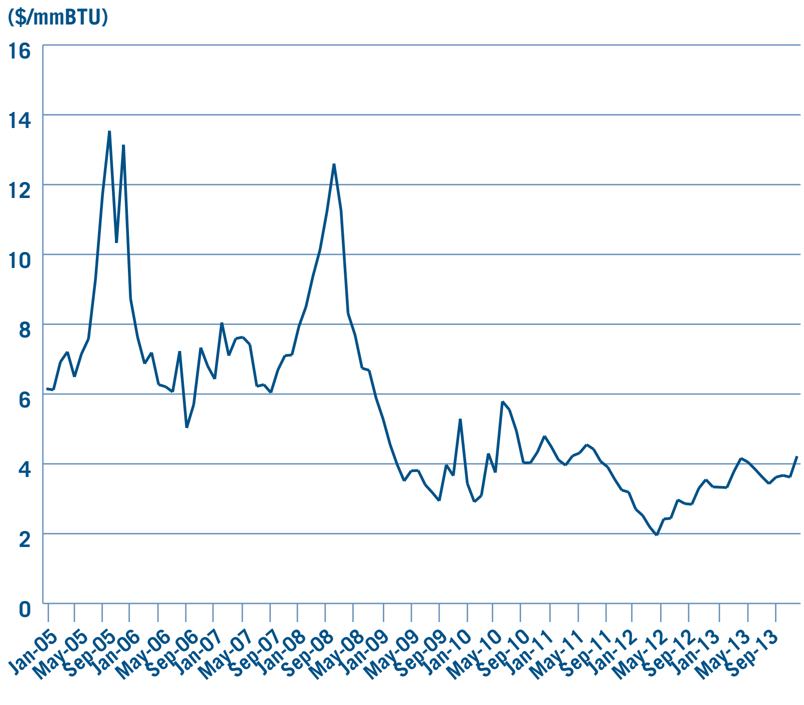
In 2007, before coal prices began rising and before the economic crisis hit, the estimated average cost to produce electricity from coal was $24.8 per MWh. The cost rose steadily beginning in 2008, reaching $32.97 per MWh in 2012. Preliminary data from 2013, however, shows a decline to $29.65 per MWh, a 10% drop from 2012's level, mostly due to a reduction in non-fuel costs.

Despite coal's declining relative contribution to nationwide generation, it is expected to remain the nation's primary generation fuel for years to come. The EIA has estimated that natural gas may surpass coal in 2035. Several factors continue to make the future of coal generation uncertain. Since 2008, increased natural gas production and growth in proved reserves from unconventional sources have driven natural gas prices down to the lowest levels of the last decade, reducing the cost-advantage of coal generation in many regions of the country. Moreover, numerous Environmental Protection Agency (EPA) regulations will increase the cost of coal generation as companies will need to invest in environmental control technologies. Some coal-fired units will likely be retired instead of retrofitted with controls. Although installed operating capacity has remained relatively constant in the last few years, at around 340 GW, this increased uncertainty has had a clear impact on new construction. For the first time in the industry's history, no new coal-fired capacity was announced in 2011, 2012 or 2013. Also, the amount of coal-fired capacity scheduled for retirement is rising. Between 2010 and 2013, over 20,000 MW of coal-fired capacity has been retired and an additional 20,000 MW of retirements has been announced for the next two years.

Natural Gas

Natural gas' share of total electricity generation declined to 27.4% in 2013 from 30.3% the previous year, although it remained above 2011's 24.7%. Production and consumption again set records in 2013. Increased demand was driven in particular by the industrial sector, which has broken its long-term trend of declining gas usage and has seen its demand grow steadily since 2010. The cold winter also drove strong demand from the residential and commercial sectors. The electric sector, however, burned about 11% less natural gas than it did in 2012 due to relatively higher prices compared with coal and a cooler summer than in 2012. Although the winter was also colder, the additional gas generation during November and December was not able to make up for the reduced demand during the rest of the year.

NYMEX-Henry Hub Natural Gas Close Prices
2005-2013



Source: NYMEX & SNL Financial

Total demand for natural gas grew by almost 2%, whereas production increased by just over 1%. This helped reduce chronic oversupply and rebalanced the market. As a result, the average Henry Hub spot price in 2013 was $3.72 per million BTU, up from $2.76 per million BTU in 2012, but still lower than all other years since 2000. The first quarter of 2014 experienced two extreme cold weather events due to a Polar Vortex, which caused natural gas prices to increase to $7-8 per million BTU briefly in February and again in March. The average monthly spot price climbed to $6 per million BTU in February but, despite the price spikes, fell back to $4.92 in March. The rise in natural gas prices in 2013 increased the average cost to produce electricity from natural gas to $36.33/MWh in 2013 from $34.29/MWh in 2012. Yet this is still far below the average cost in 2008, which was $78.43/MWh.

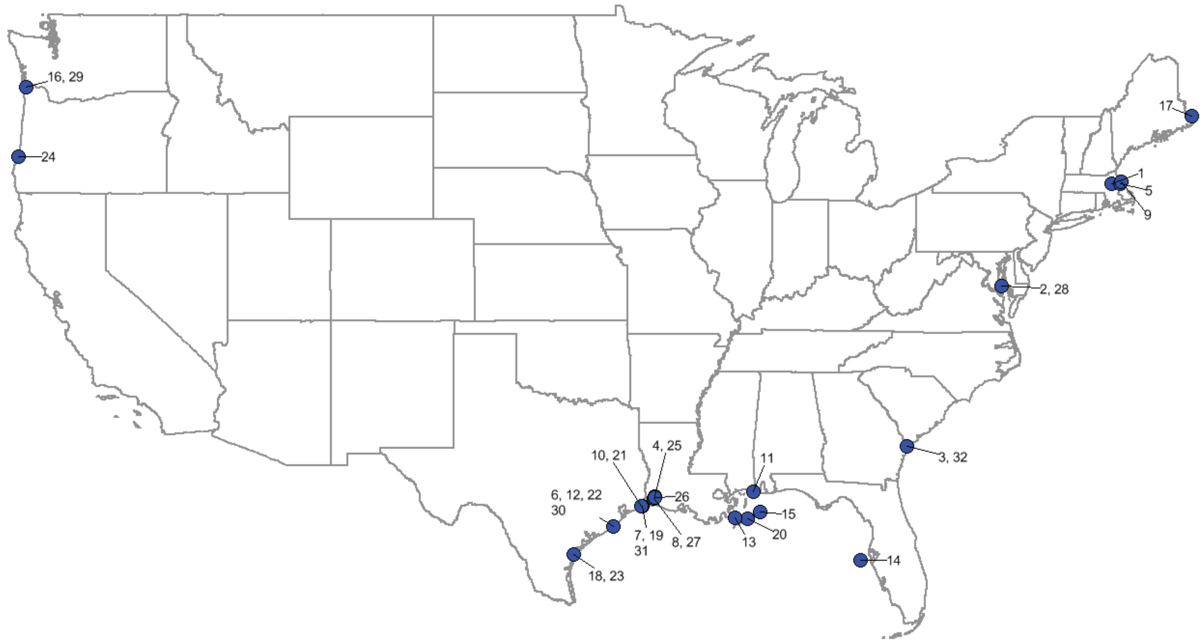
Imports have been rapidly declining since 2008, when shale gas production began increasing. Last year, imports declined by yet another 8% and barely reached the 1995-6 level. Imports from Canada continue to account for the majority of imported natural gas (97%), but they have declined since 2008 at a rate of 5-6% per year. Liquefied natural gas (LNG) imports have suffered an even greater reduction, cut in half in 2012 and then again in 2013. At the same time, exports of natural gas, which had been increasing significantly, decreased slightly (3%) for the first time in a decade.

Over the last five years, the growth of natural gas reserves and high levels of production in the U.S. domestic natural gas market have caused some LNG developers to cancel import projects and consider options for re-exporting and/or expanding terminals to add liquefaction, storage and export facilities. Thus far, the Federal Energy Regulatory Commission (FERC) has authorized facilities in Texas, Louisiana and Maryland to re-export LNG, and the Department of Energy (DOE) has approved the application of a dozen of terminals to liquefy and export domestically produced gas to countries with which the U.S. has signed a free trade agreement. DOE has also authorized the Sabine Pass project (already under construction) and several other terminals to export to countries not covered by a trade agreement. A few other projects are still waiting for DOE approval, which, as required by law, must take into consideration the cumulative impact of LNG exports on the U.S. economy.

Nuclear

The U.S. continues to be the world's largest producer of nuclear power. With 100 electricity-generating nuclear reactors, the U.S. accounts for more than 30% of worldwide nuclear generation of electricity. In 2013, nuclear's electric output grew by 2.6%. While a small increase, this was a significant one since nuclear generation had declined considerably over the previous two years and its share of total U.S. electric generation rose in 2013 back to its 2011 level, at 19.4%.

Existing and Proposed U.S. LNG Terminals
As of December 31, 2013



Constructed:
1. Everett, MA: 1.035 Bcfd (Distrigas of Massachusetts)
2. Cove Point, MD: 1.8 Bcfd (Dominion -Cove Point LNG) (a)
3. Elba Island, GA: 1.6 Bcfd (El Paso -Southern LNG)
4. Lake Charles, LA: 2.1 Bcfd (Southern Union -Trunkline LNG)
5. Offshore Boston, MA: 0.8 Bcfd (Northeast Gateway -ExcelerateEnergy)
6. Freeport, TX: 1.5 Bcfd (Freeport LNG Dev.) (a)
7. Sabine Pass, LA: 4 Bcfd (Sabine Pass Cheniere LNG) (a)
8. Hackberry, LA: 1.8 Bcfd (Cameron LNG -Sempra Energy) (a)
9. Offshore Boston, MA: 0.4 Bcfd (Neptune LNG)
10. Golden Pass, TX: 2.0 Bcfd (Golden Pass -ExxonMobil)
11. Pascagoula, MS: 1.5 Bcfd (Gulf LNG Energy LLC, TRC Companies)

Approved by FERC:
12. Freeport, TX: 2.5 Bcfd (Cheniere/Freeport LNG Dev.) – Expansion

Approved by MARAD/Coast Guard
13. Main Pass, LA: 1.0 Bcfd (Main Pass McMoRanExp.)
14. Port Dolphin, FL: 1.2 Bcfd (Hoëgh LNG – Port Dolphin Energy)
15. TORP LNG, AL: 1.4 Bcfd (Bienville Offshore Energy Terminal – TORP)

Proposed to FERC
16. Astoria, OR: 1.5 Bcfd (Oregon LNG)
17. Robbinston, ME: 0.5 Bcfd (Downeast LNG – Kestrel Energy)
18. Corpus Christi, TX: 0.4 Bcfd (Cheniere – Corpus Christi LNG)

Export terminals
Under Construction
19. Sabine Pass, LA: 2.76 Bcfd (Sabine Pass Cheniere LNG) (b) (c)

Proposed to FERC
20. Plaquemines Parish, LA: 1.07 Bcfd (CE FLNG, Cambridge Energy)
21. Golden Pass, TX: 2.0 Bcfd (Golden Pass -ExxonMobil) (b)(d)
22. Freeport, TX: 1.4 Bcfd (Freeport LNG Dev./FLNG Liquefaction) (b) (c)
23. Corpus Christi, TX: 2.1 Bcfd (Cheniere - Corpus Christi LNG) (b) (d)
24. Coos Bay, OR: 1.2 Bcfd (Jordan Cove Energy Project) (b) (c)
25. Lake Charles, LA: 2.0 Bcfd (Trunkline LNG) (b) (c)
26. Lake Charles, LA: 1.07 Bcfd (Magnolia LNG) (b)
27. Hackberry, LA: 1.7 Bcfd (Cameron LNG -Sempra Energy) (b) (c)
28. Cove Point, MD: 1.0 Bcfd (Dominion -Cove Point LNG) (b) (c)
29. Astoria, OR: 1.3 Bcfd (Oregon LNG)
30. Lavaca Bay, TX: 1.38 Bcfd (Excelerate Liquefaction) (b) (d)
31. Sabine Pass, LA: 1.4 Bcfd (Sabine Pass Liquefaction) (b) (d)
32. Elba Island, GA: 0.5 Bcfd (Southern LNG) (b) (d)

(a) Authorized to re-export
(b) Approved by DOE to export to FTA countries
(c) Approved by DOE to export to non-FTA countries
(d) Under DOE review for exports to non-FTA countries

Sources: U.S. Department of Energy, Office of Fossil Energy; Federal Energy Regulatory Commission; Ventyx Inc., The Velocity Suite.

Following the crisis in Japan in March 2011, scrutiny of nuclear plants rose and industry critics suggested some be shut down. Yet, in early 2012, the Nuclear Regulatory Commission (NRC) approved Southern Company's two new nuclear reactors at its Vogtle plant in Georgia and two at SCANA's Virgil C. Summer Nuclear Station in South Carolina. These were the first nuclear reactors approved in decades. Also, TVA's Watts Bar 2 is expected to come online in 2015 and more than 60 nuclear reactors have been granted 20-year license extensions in the last few years.

Despite these trends, nuclear power has not been immune to the broader developments impacting U.S. energy markets. In 2013, four nuclear reactors were retired, which reduced the total installed capacity by almost 4,000 MW. In fact, 2013 was the first year since 1998 that a nuclear reactor was retired. Weak pricing conditions in wholesale power markets and rapidly declining profitability caused Dominion Power to close the Kewaunee plant in Wisconsin. Concerns about maintenance and high repair costs drove Duke Energy to retire the Crystal River plant in Florida (out of service for repairs since 2009) and Edison International to permanently close the San Onofre Nuclear Generating Station (SONGS), which had been shut down since January 2012. Low profitability was also the reason cited for the announced retirement of Entergy's Vermont Yankee at the end of 2014.

Renewable Energy

Renewable fuel sources, including hydropower, produced a near-record 12.9% of total U.S. electric generation in 2013. Non-hydro generation hit another record at 6.2% of the generation mix, up from 5.4% in 2012. The increase was mainly due to a 19% jump in wind output, which accounted for 66% of total non-hydro renewable generation. Solar generation grew by 114%. Although solar generation more than doubled in just one year, it represents just 4% of non-hydro generation and 0.2% of total U.S. electric output.

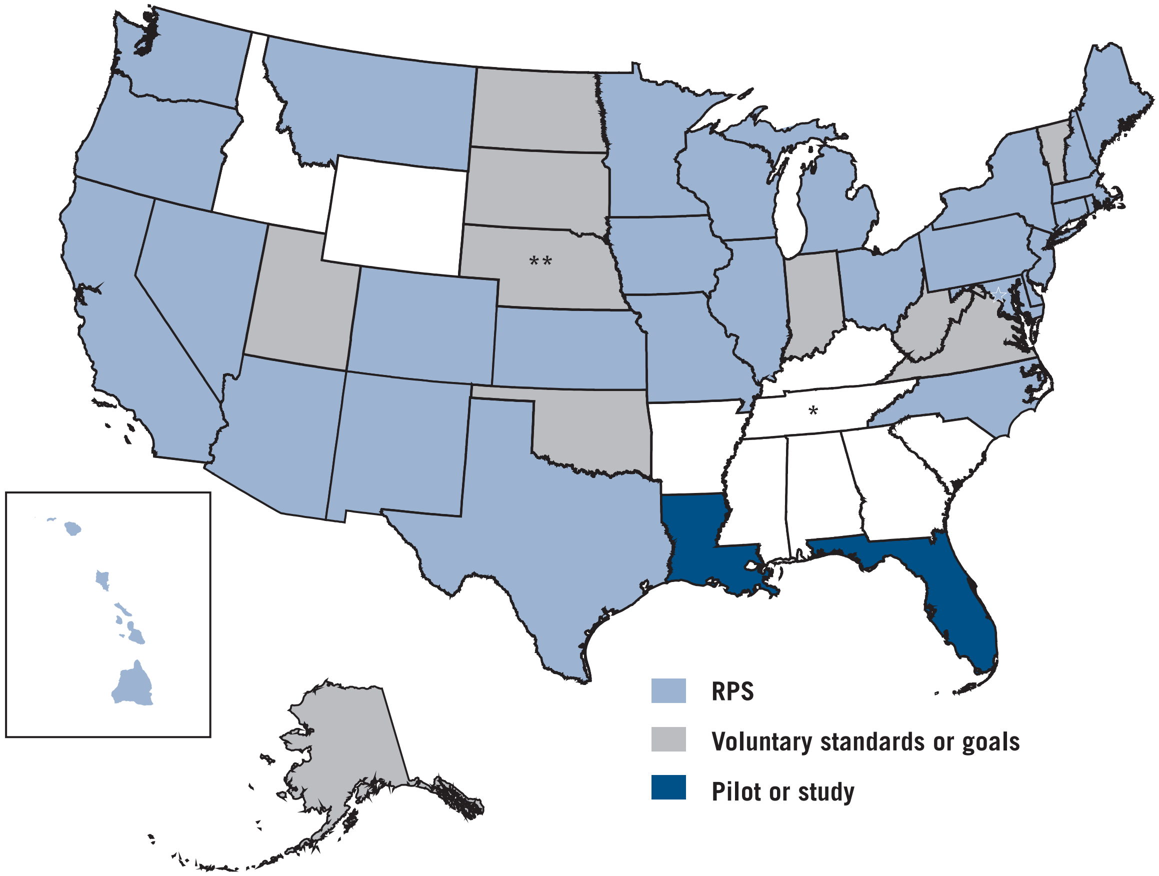
Renewable energy continues to experience strong governmental support, but changes to some policies in recent years have presented new tests for the industry. At the end of 2011, Congress did not extend section 1603 (Payments for Specified Energy Property in Lieu of Tax Credits) of the "Cash Grant" program, established by the 2009 American Recovery and Reinvestment Act; the program, which had been extended for one year in 2010, was allowed to expire. The federal production tax credit (PTC), which provides a tax credit of $22/MWh for the first ten years of operation, was set to expire at the end of 2012 for wind, biomass and geothermal resources, but was extended for an additional year. Given a change in rules, this extension will be a de facto multi-year extension as projects will be able to claim the PTC as long as they start construction in 2013. Yet it has not been extended further. The federal investment tax credit (ITC), which provides a tax credit of up to 30% of the capital investment in a project, is set to expire at the end of 2016.

State renewable energy electricity standards (RES) have also been a major driver of renewable energy development. However, some states are examining their RES policies with an eye on restraining costs. Declining costs, net metering and other state policies are also supporting deployment of distributed generation, solar rooftop photovoltaics in particular. Yet these policies were not designed to help the deployment of a maturing technology, and they will likely be revised to reduce unnecessary costs to consumers as well as unfair cost-shifts between customer types.

Low natural gas prices have presented an additional difficulty for the renewable industry. With reduced costs for natural gas generation, the need for, economic appeal of, and available financing for many renewable projects have been diminished. In 2013, for example, only slightly more than 1,000 MW of new wind capacity was added to the grid compared to a record 13,000 in 2012.

Despite these challenges, and helped by ever-lower technology costs, renewable energy (wind and solar in particular) continues to thrive. Solar generation more than doubled in 2012 and again in 2013, and wind generation grew an average of 30% per year for the last ten years, rising from 0.3% of the nation's mix in 2003 to more than 4% in 2013.

29 States and D.C. have Renewable Electricity Portfolio Standards (RES)



AK: 50% by 2025
AZ: 15% by 2025; 4.5% DG
CA: 33% by 2020
CO: 30% by 2020, 3% DG and 1.5% customer sited. (10% co-ops, munis)
CT: 27% by 2020
DC: 20% by 2020, 2.5% solar by 2023
DE: 25% by 2026, 3.5% PV + triple credit
FL: Solar Pilot 2010-2014
HI: 40% by 2030
IA: 105 MW; 1 GW wind goal by 2010
IL: 25% by 2025; wind 75%, 1.5% PV and 0.25% DG
IN: 10% by 2025
KS: 20% by 2020
LA: RES Pilot 350 MW by 2012-13
MA: 15% new by 2020, then 1% annually; 2 GW wind and 400 MW PV
MD: 20% by 2022, 2% solar by 2020
ME: 10% new by 2017; 8 GW wind goal by 2030
MI: 10% MWh and 1,100 MW by 2015. Triple credit for solar
MN: 25% by 2025; 30% by 2020 – Xcel
MO: 15% by 2021, 0.3% solar electric
MT: 15% by 2015
NC: 12.5% by 2021, 0.2% solar by 2018. (10% by 2018 co-ops, munis)
ND: 10% by 2010
NE: Public Power Districts: 10% by 2020**
NH: 24.8% by 2025
NJ: 20.38% RE by 2021 and 4.1% solar by 2028
NM: 20% by 2020, 4% solar electric, 0.6% DG. (10% - co-ops)
NV: 25% by 2025, 1.5% solar by 2025
NY: 29% by 2015, 0.4% customer sited
OH: 12.5% by 2024, 0.5% solar
OK: 15% by 2015
OR: 25% by 2025. 20 MW PV by 2020 (5-10% - smaller utilities)
PA: 18% by 2021, 0.5% PV
RI: 16% by end 2020
SD: 10% by 2015
TVA: 50% by 2020*
TX: 5,880 MW by 2015, 500 MW non-wind goal, double credit for non wind
UT: 20% by 2025, multiplier for solar electric
VA:15% by 2025
VT: 20% by 2017; from RE and CHP
WA: 15% by 2020, double credit for DG
WI: 10% by 2015
WV: 25% by 2025, various multipliers

Updated April 2014

Abbreviations: EE - Energy Efficiency; RE - Renewable Energy

Notes: An RPS requires a percent of an electric provider's energy sales (MWh) or installed capacity (MW) to come from renewable resources. Most specify sales (MWh). Map percents are final years' targets. * TVA's goal is not state policy; it calls for 50% zero- or low-carbon generation by 2020. ** Nebraska's two largest public power districts have renewable goals.

Source: Database of State Incentives for Renewables and Efficiency, http://www.dsireusa.org

Oil

Oil accounted for 0.7% of U.S. electric generation in 2013, up from 0.6% the previous year; Hawaii generated about half of that. Since 2006, oil, which had been generating around 3% of the nation's electricity, began playing an ever-smaller role in the U.S. electric fuel portfolio. It has been the smallest, and a decreasing, contributor to electricity generation since then.

Persistently high oil prices since 2006 have been an important factor contributing to the continued decline in oil use. While crude oil prices averaged $15 to $25/barrel in the mid-1990s, the price of oil began an upward climb in the early 2000s. West Texas Intermediate crude spot prices peaked at over $145/barrel in mid-July 2008. Prices since mid-2011 have fluctuated in a range of $85-105/barrel.

As has historically been the case, crude oil prices in the U.S. will remain subject to the dynamics of the international oil market, itself driven by changes in global demand, supply constraints in oil producing regions, the level of stocks and spare capacity in industrialized countries, geopolitical risks, and the relative strength of the dollar versus other currencies.

Demand for oil is expected to continue to grow globally as improving economic conditions lead to increased consumption, particularly in developing countries, driven by rapid economic and population growth. Subsidies provided to end users in some nations help mitigate the effect of high global crude oil prices, leading to sustained and increasing demand and countering decreasing demand in developed countries. The U.S. electric power sector should be shielded against oil price spikes or supply disruptions given its limited use of oil as a generation fuel and its highly diversified fuel mix. The volatility of world oil prices will, nonetheless, influence broad economic conditions and will therefore indirectly impact the sector.

Yet, substantial increased domestic production of crude oil will help alleviate energy and national security concerns and reduce oil imports. Total domestic crude production grew by a record 15% in 2013, the largest percentage gain since 1940. This new production has come mostly from shale plays in Texas (Eagle Ford) and North Dakota (Bakken). As a result of increased production, imports decreased (-10%) for the third year in a row. According to the EIA, at the beginning of 2013, the U.S. had the highest level of crude oil reserves since 1976. The same advances in drilling techniques that produced the "shale revolution" (horizontal drilling and fracking) in combination with sustained high oil prices have contributed to increased production of crude oil and natural gas condensates in the U.S. for the last five consecutive years. The International Energy Agency announced at the end of 2013 that, if current trends continue, the U.S. will surpass Russia and Saudi Arabia as the world's top oil producer by 2015.

Capital Markets

Stock Performance

The EEI Index returned 13.0% in 2013, capping a volatile year for utility shares in which the generally slow-moving changes in industry fundamentals were overwhelmed by U.S. Federal Reserve monetary policy decisions as the key driver of share price moves. The broad market surged 10% in the year's final quarter—versus the EEI Index's 2.4%—supported by signs of strength in the U.S. economy along with the Federal Reserve's decision in September to postpone any slowdown in its aggressive quantitative easing (QE) program (i.e., the monthly purchase of $85 billion in Treasury and mortgage securities as a means of holding interest rates down in hopes of stimulating economic growth). The Fed's actions produced additional support for equities at its December meeting, when it decided to slow the pace of QE by only $10 billion per month beginning in January. Such a tepid "tapering" of the Fed's unprecedented multi-year sequence of QE programs was fuel for the market's bullish spirits throughout most of the year, interrupted only when fears of a more aggressive slowdown by the Fed temporarily spooked markets in late spring.

2013 Index Comparison

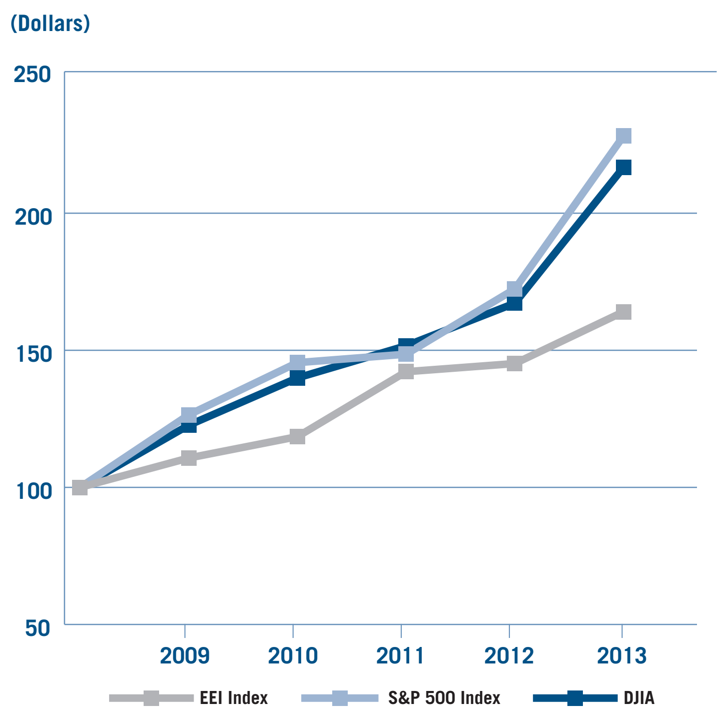
EEI Index	**13.01**
Dow Jones Industrials	29.65
S&P 500	32.39
Nasdaq Composite Index*	38.32

* Price gain/(loss) only. Other indices show total return.

Source: EEI Finance Department and SNL Financial

Comparison of the EEI Index, S&P 500, and DJIA Total Return 1/1/09–12/31/13

REFLECTS REINVESTED DIVIDENDS



All returns are annual.
Note: Assumes $100 invested at closing prices December 31, 2008.

Source: EEI Finance Department and SNL Financial

2013 Returns By Quarter

Index	Q1	Q2	Q3	Q4
EEI Index	13.28	(2.18)	(0.45)	2.44
Dow Jones Industrial Average	11.89	2.96	2.12	10.21
S&P 500	10.61	2.90	5.25	10.52
Nasdaq Composite*	8.21	4.16	10.82	10.74
Category	**Q1**	**Q2**	**Q3**	**Q4**
All Companies	13.91	(0.70)	(0.10)	3.78
Regulated	13.01	0.37	(1.08)	4.25
Mostly Regulated	15.77	(3.44)	1.37	2.34
Diversified	14.96	7.55	8.62	9.86

* Price gain/loss only. Other indices show total return.
For the Category comparison, we take straight (i.e., not market-cap-weighted) averages.

Source: EEI Finance Department, SNL Financial, and company annual reports

Sector Comparison 2013 Total Shareholder Return

Sector	Total Return %
Consumer Services	42.2%
Healthcare	42.0%
Industrials	40.6%
Financials	34.2%
Consumer Goods	30.6%
Technology	27.0%
Oil & Gas	26.1%
Basic Materials	20.4%
Utilities	15.2%
Telecommunications	14.1%
EEI Index	**13.0%**

Source: Dow Jones & Company and EEI Finance Department

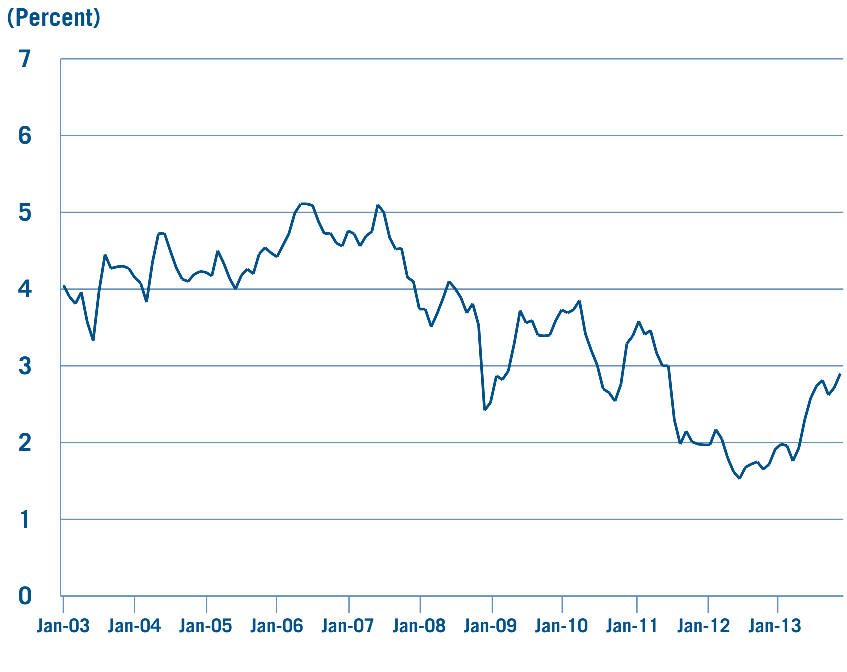
Interest Rates on the Rise

Interest rates declined early in 2013, powering strong gains for utility shares through May, but the benchmark 10-year Treasury yield then jumped from an early-May low of 1.6% to nearly 3.0% by early September on concern over comments by Fed Chairman Bernanke that the central bank would like to begin unwinding its QE program. The unexpected rate surge caused considerable volatility for market sectors where dividends are an important component of investor return expectations and utilities declined about 13% from early May through early September. The Fed surprised markets again in mid-September when Chairman Bernanke announced that the Fed had decided not to reduce the pace of QE after all, citing fears that economic growth wasn't strong enough to support further gains in employment. Interest rates pulled back and finished the third quarter around 2.6%, while utility shares jumped about 5% from their early-September lows. During Q4, yields ground slowly higher, finishing the year back near 3%. For the year as a whole, yields jumped more than 50%, with the 10-year Treasury rising from just under 2% as the year began.

Demand Growth Remains Stalled

Power demand remained weak in 2013. U.S. electric output increased only 0.1% over 2012's 3,991,408 GWh. However, after adjustment for variations in temperature, weather-normalized demand for 2013 actually declined 0.6% (see *Income Statement*). Weather is not the only factor impacting demand. In-roads made by energy efficiency and demand-side management programs into the patterns of power usage are also driving structural changes in demand, which has in recent years become decreasingly linked to the pace of broad economic growth as the economy moves farther away from an emphasis on industrial and manufacturing activity and toward services. The expected long-term growth rate in power demand remains uncertain, although the general expectation among most industry analysts is that a rate below 1% is probable for the years immediately ahead.

10-Year Treasury Yield
1/1/03 through 12/31/13



Source: U.S. Federal Reserve

Shale Gas and Renewables Crimp Competitive Outlook

Spot natural gas prices languished for most of 2013 under \$4/mmBTU, a ceiling of sorts that has held for four continuous years, before finding a bid in December and climbing to \$4.40. The natural gas futures curve however weakened from mid-year to year-end, declining \$0.20 to \$0.50 across the 2016-2017 stretch in the curve. Low natural gas prices have depressed power prices in markets where gas is the marginal price-setting fuel. Abundant zero-marginal cost renewable power (mostly wind in the mid-U.S.) has also eroded electricity prices in markets where baseload coal and nuclear generation have traditionally served load. Both forces have crimped the outlook for utilities with competitive generation and the industry at large continues its multi-year migration to a regulated focus (see *Business Segmentation*).

With shale gas evidently plentiful—the Utica and Marcellus shales across the West Virginia-Pennsylvania-New York region are cited by analysts as the next abundant source of shale gas—and production capacity high, analysts maintained their general belief that any recovery in competitive power market fortunes continues to be deferred until well into the future. This trend was evident in the fact that cap-weighted EEI Index returns in the fourth quarter and full-year 2013 were lower than the average category returns, which are not cap weighted. The stocks of several large utilities with competitive businesses were relatively weak compared to smaller companies with a regulated focus.

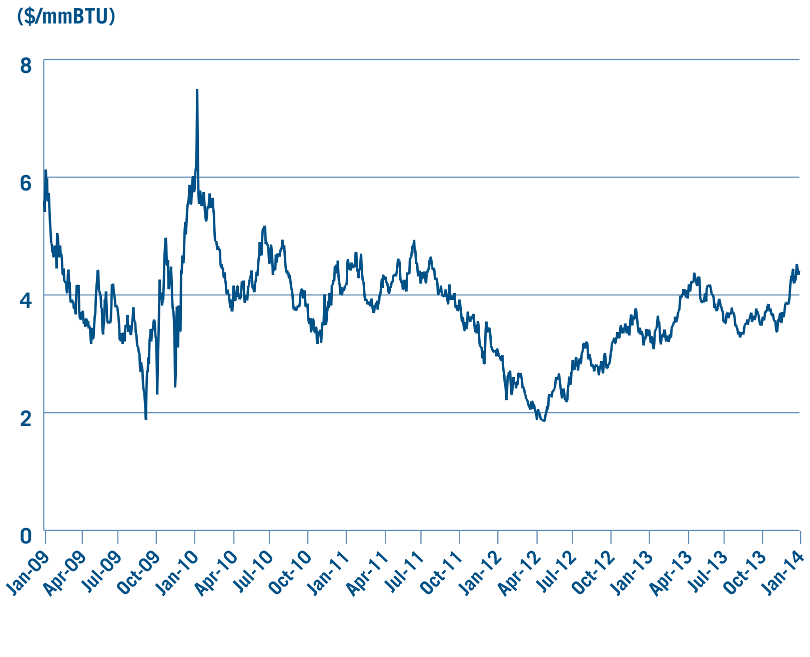
A Search for Earnings Growth

Despite slow demand growth and adequate capacity across most of the country, the industry's torrid pace of capex and rate base growth is likely to continue in the near term. EEI's latest projections (as of October 2013) for industry capex anticipate an increase to \$93 billion in 2014 from \$90.3 billion—a record—in 2013. However, many analysts have ratcheted down slightly their expectation for earnings growth by regulated utilities, although they still expect that many are capable of low- to mid-single-digit gains in both earnings and dividends.

A review of consensus analyst estimates as of early January 2014 for the 49 publicly traded EEI Index companies confirms that general outlook. The average revenue growth across the industry (calculated as an arithmetical average of analyst projections, not accounting for market capitalization) is 4.2% in 2013 slowing to 2.8% in 2014. The average projected five-year earnings growth rate for the industry is 4.0%, ranging from single-digit declines for some utilities exposed to weak prices for competitive generation to as high as 7% to 8% for regulated companies undertaking relatively strong capital investment programs and/or benefitting from supportive outcomes in recent rate cases.

There has been a minor ratcheting down of five-year earnings growth expectations since early 2013 (from 4.3% at the end of Q2 and 4.1% at the end of Q3)—a concession to both uncertainty over demand strength and a diminished outlook for competitive power. Many

Natural Gas Spot Prices - Henry Hub
12/31/08 through 12/31/13



Source: SNL Financial

companies are contending with weak demand fundamentals by working hard to restrain operations & maintenance (O&M) cost pressures. A number of others are emphasizing growth opportunities in transmission investment, while a handful with contracted generation assets are examining spinning off these assets into a separate entity (a so-called "yield company" structure, successfully implemented last summer by merchant power producer NRG Energy) that can pay a dividend with good growth potential, unlocking value that yield-seeking investors would presumably pay a higher price for were it unbundled from the integrated holding company structure.

Bulls and Bears

The bearish view of utilities as a group relies primarily on a view that interest rates are on the rise. Utilities are prized by most investors for their steady, and reasonably sturdy, dividends. This characteristic makes them trade somewhat like bonds, but with the added appeal of dividend growth potential. Rising rates cause investors to discount the price of fixed-income type investments so their yields keep pace with market rates. Analysts on the bearish side of the fence cite the industry's stock price performance in historical periods of rising rates, when shares generally lagged or declined, and also caution about the potential risks that allowed rates of return may rise more slowly than market yields, particularly if state regulatory commissions work to constrain the rate increases required to fund the industry's substantial capital investment programs.

The bullish case for utilities relies on the outlook for steady earnings growth for many companies along with strong dividend yields, which averaged 4.0% at the end of the fourth quarter. The bulls argue the combination of earnings and dividend growth offered by utilities compares favorably with the S&P 500's 2.7% dividend yield and only slightly higher projected growth rate, estimated in the high single digits. Moreover, with market interest rates depressed by Fed monetary policy, a case can be made that bond yields have headroom to rise, in relation to historical patterns, without overly threatening utility PE ratios.

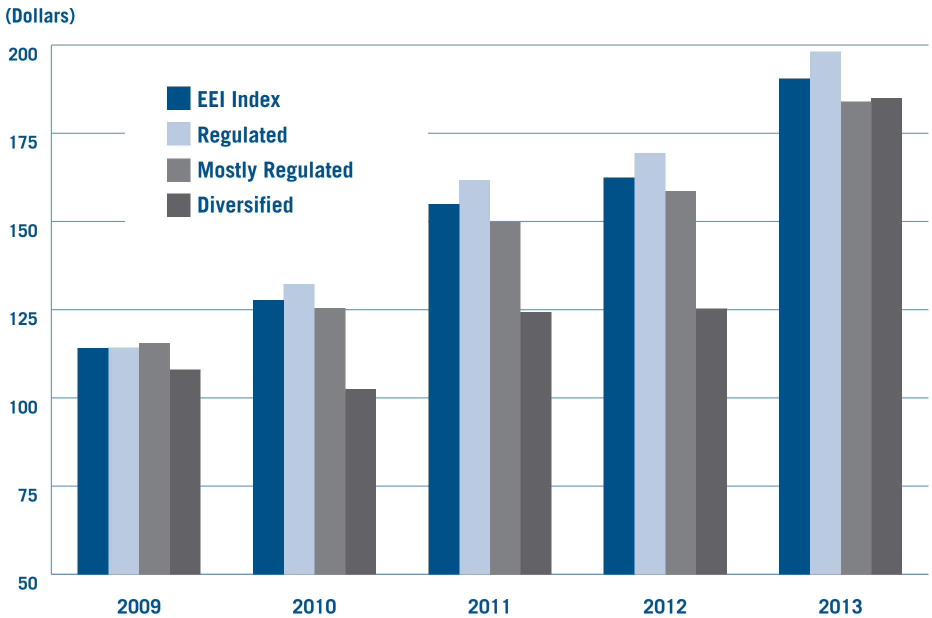
Both sides, however, warily watch stagnant power demand and agree that recent cost cutting in areas such as operations and maintenance (O&M) can only go so far to help earnings. The demand for power, direction of interest rates and future moves in natural gas prices are mostly beyond the control of utility managements—and these forces are likely to persist as the primary drivers of utility stock price performance in the near to intermediate term. See EEI's Quarterly Financial Updates (www.eei.org) for continuing analysis of the industry's financial results on a quarterly basis.

Credit Ratings

The industry's average credit rating at the end of 2013 was BBB, a level that has been steady for the past ten years. Total ratings activity, at 80 changes, was essentially the same as in 2012 and continued to reflect the moderate pace of the prior five years (see table, *Rating Agency Activity*).

Comparative Category Total Annual Returns 2009-2013

U.S. INVESTOR-OWNED ELECTRIC UTILITIES,
VALUE OF $100 INVESTED AT CLOSE ON 12/31/2008



	2009	2010	2011	2012	2013
EEI Index Annual Return (%)	14.13	11.87	21.39	4.82	17.27
EEI Index Cumulative Return ($)	114.13	127.68	154.98	162.46	190.51
Regulated EEI Index Annual Return	14.25	15.75	22.30	4.72	16.97
Regulated EEI Index Cumulative Return	114.25	132.25	161.73	169.36	198.11
Mostly Regulated EEI Index Annual Return	15.58	8.51	19.52	5.81	15.97
Mostly Regulated EEI Index Cumulative Return	115.58	125.41	149.89	158.60	183.92
Diversified EEI Index Annual Return	8.07	(5.16)	21.36	0.78	47.54
Diversified EEI Index Cumulative Return	108.07	102.49	124.38	125.35	184.94

Cumulative Return assumes $100 invested at closing prices on December 31, 2008.

Source: EEI Finance Department and SNL Financial

2013 Category Comparison

Category	Return (%)
EEI Index	**17.27**
Regulated	16.97
Mostly Regulated	15.97
Diversified	47.54

* Returns shown here are unweighted averages of constituent company returns. The EEI Index return shown in the 2013 Index Comparison table is cap-weighted.

Source: EEI Finance Department, SNL Financial, and company annual reports

EEI Index Top 10 Performers
Twelve-month period ending 12/31/13

Company	Total Return %
Black Hills Corporation	49.1
MDU Resources Group, Inc.	47.5
UNS Energy Corp	46.1
NiSource Inc.	36.5
Sempra Energy	30.4
Dominion Resources, Inc.	29.6
NorthWestern Corporation	29.3
NextEra Energy, Inc.	27.8
ALLETE, Inc.	26.5
Vectren Corporation	25.8

Note: Return figures include capital gains and dividends.
Source: EEI Finance Department and SNL Financial

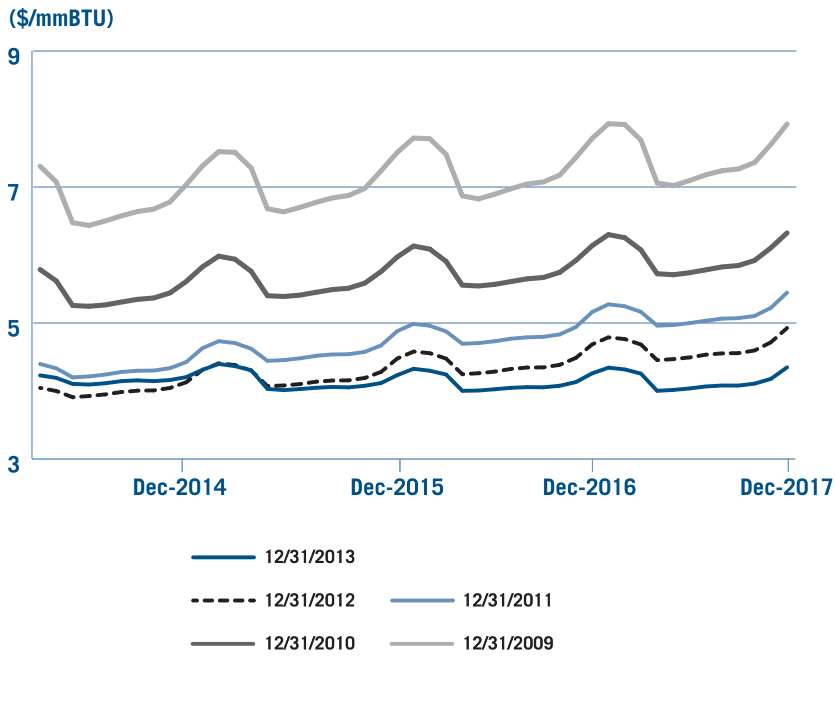
Market Capitalization at December 31, 2013 (in $MM)

U.S. INVESTOR-OWNED ELECTRIC UTILITIES

Company Name	Symbol	Market Cap.	% of Total	Company Name	Symbol	Market Cap.	% of Total
Duke Energy Corporation	DUK	48,721	9.66%	MDU Resources Group, Inc.	MDU	5,769	1.14%
Dominion Resources, Inc.	D	37,481	7.43%	Alliant Energy Corporation	LNT	5,716	1.13%
NextEra Energy, Inc.	NEE	36,286	7.19%	Pepco Holdings, Inc.	POM	4,763	0.94%
Southern Company	SO	36,095	7.16%	Integrys Energy Group, Inc.	TEG	4,342	0.86%
Exelon Corporation	EXC	23,473	4.65%	Westar Energy, Inc.	WR	4,100	0.81%
American Electric Power Company, Inc.	AEP	22,759	4.51%	Great Plains Energy Inc.	GXP	3,723	0.74%
Sempra Energy	SRE	21,914	4.34%	TECO Energy, Inc.	TE	3,710	0.74%
PPL Corporation	PPL	18,988	3.76%	Vectren Corporation	VVC	2,922	0.58%
PG&E Corporation	PCG	17,965	3.56%	Cleco Corporation	CNL	2,818	0.56%
Public Service Enterprise Group Incorporated	PEG	16,208	3.21%	IDACORP, Inc.	IDA	2,595	0.51%
Consolidated Edison, Inc.	ED	16,192	3.21%	Hawaiian Electric Industries, Inc.	HE	2,585	0.51%
Edison International	EIX	15,094	2.99%	UNS Energy Corp	UNS	2,493	0.49%
Xcel Energy Inc.	XEL	13,918	2.76%	Portland General Electric Company	POR	2,345	0.46%
FirstEnergy Corp.	FE	13,786	2.73%	Black Hills Corporation	BKH	2,321	0.46%
Northeast Utilities	NU	13,365	2.65%	ALLETE, Inc.	ALE	1,985	0.39%
DTE Energy Company	DTE	11,618	2.30%	UIL Holdings Corporation	UIL	1,976	0.39%
Entergy Corporation	ETR	11,280	2.24%	PNM Resources, Inc.	PNM	1,926	0.38%
NiSource Inc.	NI	10,286	2.04%	Avista Corporation	AVA	1,691	0.34%
CenterPoint Energy, Inc.	CNP	9,936	1.97%	NorthWestern Corporation	NWE	1,666	0.33%
Wisconsin Energy Corporation	WEC	9,376	1.86%	El Paso Electric Company	EE	1,409	0.28%
Ameren Corporation	AEE	8,772	1.74%	MGE Energy, Inc.	MGEE	1,334	0.26%
CMS Energy Corporation	CMS	7,089	1.41%	Otter Tail Corporation	OTTR	1,059	0.21%
OGE Energy Corp.	OGE	6,726	1.33%	Empire District Electric Company	EDE	973	0.19%
SCANA Corporation	SCG	6,575	1.30%	Unitil Corporation	UTL	420	0.08%
Pinnacle West Capital Corporation	PNW	5,822	1.15%				
					Total Industry	**504,365**	**100.00%**

Source: EEI Finance Department and SNL Financial

NYMEX Natural Gas Futures
February 2014 through December 2017



Source: SNL Financial

The year's actions were largely positive, with 60 upgrades outnumbering 20 downgrades. EEI captures upgrades and downgrades at the subsidiary level, therefore multiple actions within a single parent holding company are included in the upgrade/downgrade totals (see chart and table, *Credit Rating Agency Upgrades & Downgrades*, and chart, *Direction of Rating Actions*).

Parent-level upgrades centered on companies' migration toward regulated business strategies, generally through divestitures of merchant generation and other unregulated operations. The industry's shift away from competitive businesses is a theme that has produced positive ratings actions each year since 2010. Companies' creditworthiness and credit ratings also benefitted, in a number of cases, from stronger regulatory relationships and from careful management of capital expenditures and operations and maintenance costs. The year's only parent-level downgrade was at Energy Future Holdings Corp., a company that has faced some of the most severe effects of low natural gas prices.

As of March 31, 2014, approximately 82% of ratings outlooks at the parent level were Stable, 11% were Positive or Watch-Positive and 7% were Negative or Watch-Negative.

The industry's average credit rating is based on the unweighted average of all parent company ratings (see pie charts of *Bond Ratings* at December 31, 2013 and prior years). Following is a summary of the year's parent-level ratings actions by quarter.

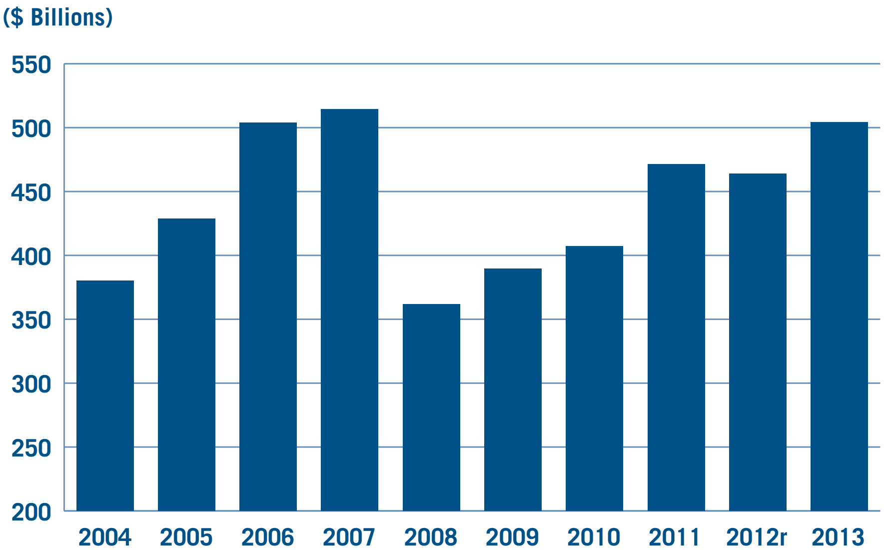
Regulatory Outcomes and Focus Prompt Q1 Upgrades

Ratings changes in the first quarter included five parent company-level upgrades.

On January 11, S&P upgraded Alliant Energy and subsidiary Interstate Power & Light to A- from BBB+ and Wisconsin Power & Light to A from A-. The moves reflected Alliant's plan to sell its renewable energy and construction business and pursue a fully regulated strategy, along with S&P's belief that its credit metrics would remain "robust." S&P maintained the companies' ratings outlooks at Stable, citing expectations that Alliant would focus on its core utility operations while supporting elevated capital expenditures and weathering a challenging economic environment that has resulted in weak industrial and wholesale sales. S&P projected that Alliant's cash flow metrics would weaken as construction projects moved ahead and the benefits of bonus depreciation diminished. However, the agency forecast that Alliant's credit ratios, under a base case scenario, would include "funds-from-operations-(FFO)-to-debt of more than 20%, debt-to-EBITDA of about 4x, and debt-to-capital averaging about 55%."

On February 20, S&P raised its corporate credit rating for NV Energy and subsidiaries Sierra Pacific Power and Nevada Power to BBB- from BB+, a move to investment-grade status.

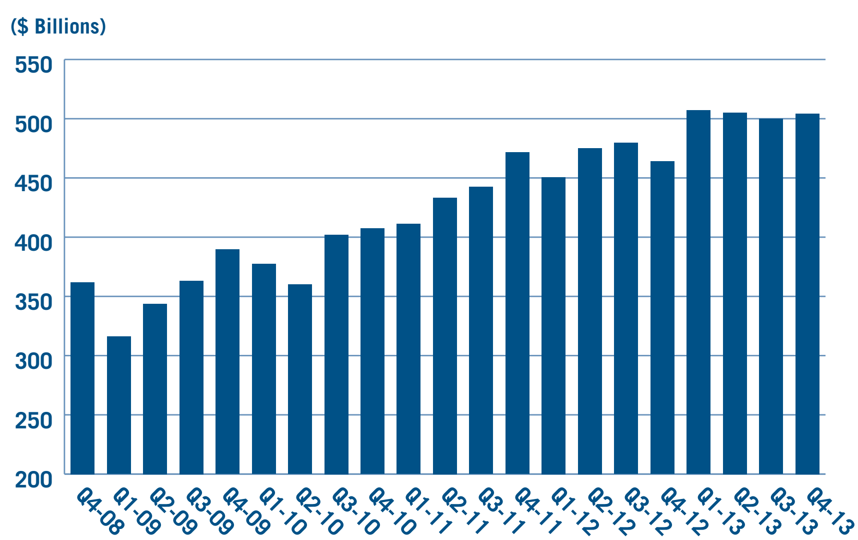
EEI Index Market Capitalization 2004–2013



Note: Results are as of December 31 of each year.

Source: EEI Finance Department and SNL Financial

EEI Index Market Capitalization
December 31, 2008–December 31, 2013



Source: EEI Finance Department and SNL Financial

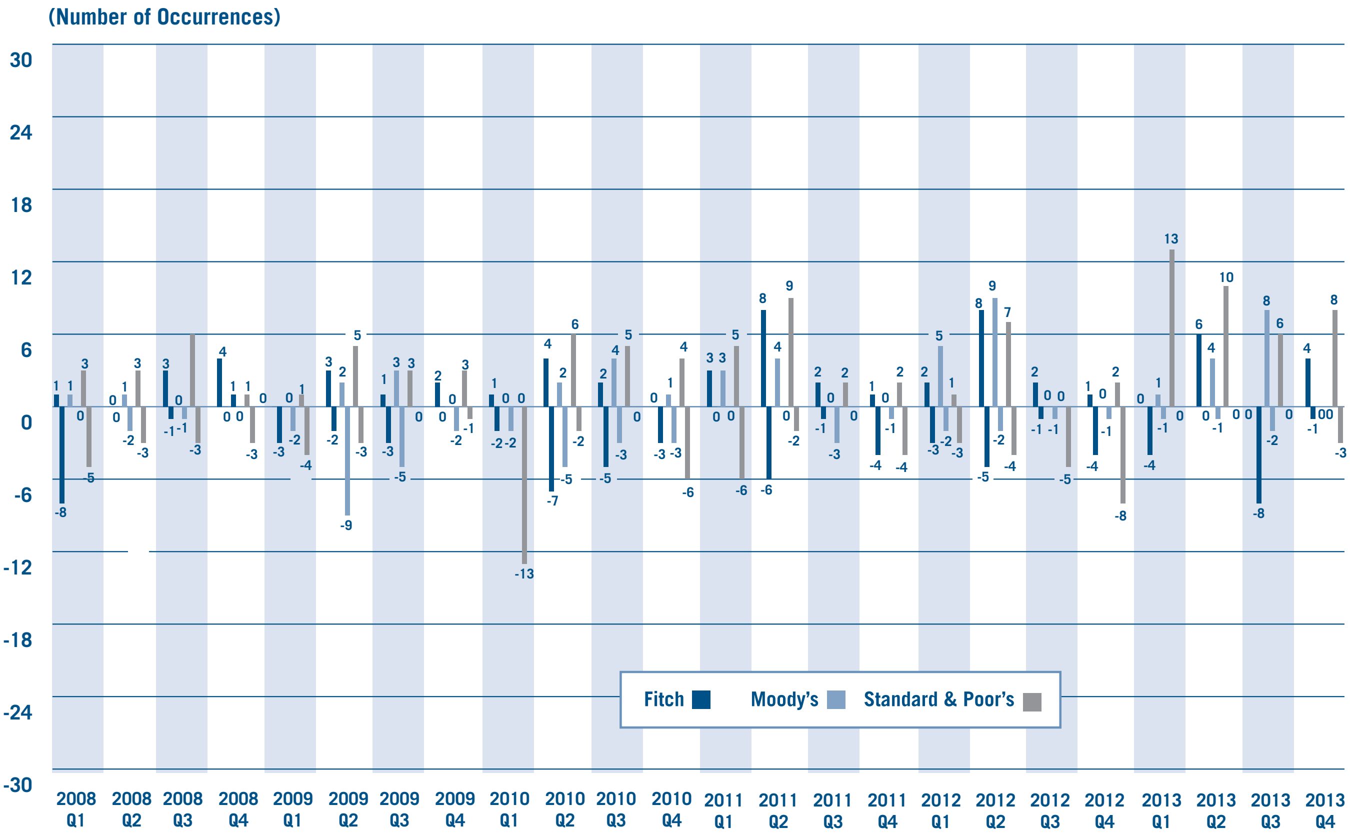
S&P said the higher ratings resulted from the company's successful regulatory strategy in Nevada, which S&P views as a credit-supportive state. S&P said it expects credit metrics to improve through continuing supportive regulation and a significant reduction in capital spending. The agency said that its base forecast assumed FFO-to-debt of 14% and a debt-to-capital ratio of about 60%.

S&P on March 6 upgraded Empire District Electric (EDE) to BBB from BBB- on constructive regulatory outcomes in Missouri, which S&P viewed as a challenging jurisdiction. S&P cited EDE's recent achievement of a rate settlement that included a 6.8% rate increase. Other positive factors included further recovery in the company's service territory from a May 2011 tornado and financial performance that exceeded expectations. Looking ahead, S&P saw potential for further rate increases, cost controls and a planned equity issuance to limit EDE's debt-to-capital ratio to 55% and maintain FFO-to-debt above 15%. S&P explained that its base forecast included increasing capital spending along with an expectation that EDE management would maintain "cash flow protection and debt leverage measures" consistent with the BBB rating.

In response to Ameren's proposal to sell its merchant generation business to a subsidiary of Dynegy, S&P on March 11 upgraded the corporate credit ratings for Ameren and subsidiaries Ameren Illinois and Union Electric (d/b/a Ameren Missouri) to BBB from BBB-. S&P said the upgrades reflected "management's

Credit Rating Agency Upgrades and Downgrades 2008 Q1-2013 Q4

U.S. INVESTOR-OWNED ELECTRIC UTILITIES



Note: Data presents the number of occurrences and includes each event, even if multiple actions occurred for a single company.

Source: Fitch Ratings, Moody's, and Standard & Poor's

Credit Rating Agency Upgrades and Downgrades 2008 Q1–2013 Q4

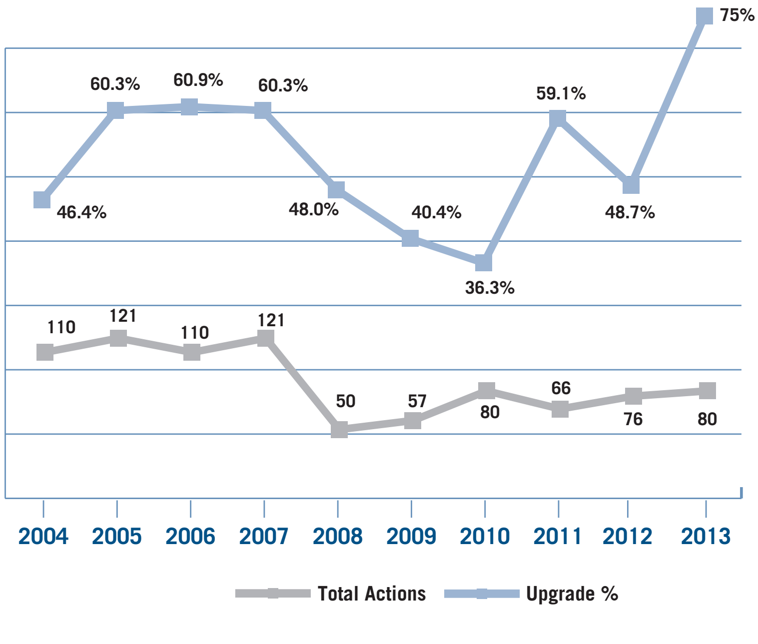
	2008		2009		2010		2011		2012		2013	
	Total Upgrades	Total Downgrades	Total Upgrades	Total Downgrades	Total Upgrades	Total Downgrades	Total Upgrades	Total Downgrades	Total Upgrades	Total Downgrades	Total Upgrades	Total Downgrades
Fitch												
Q1	1	(8)	0	(3)	1	(2)	3	0	2	(3)	0	(4)
Q2	0	0	3	(2)	4	(7)	8	(6)	8	(5)	6	0
Q3	3	(1)	1	(3)	2	(5)	2	(1)	2	(1)	0	(8)
Q4	4	0	2	0	0	(3)	1	(4)	1	(4)	4	(1)
Total	**8**	**(9)**	**6**	**(8)**	**7**	**(17)**	**14**	**(11)**	**13**	**(13)**	**10**	**(13)**
Moody's												
Q1	1	0	0	(2)	0	(2)	3	0	5	(2)	1	(1)
Q2	1	(2)	2	(9)	2	(5)	4	0	9	(2)	4	(1)
Q3	0	(1)	3	(5)	4	(3)	0	(3)	0	(1)	8	(2)
Q4	1	0	0	(2)	1	(3)	0	(1)	0	(1)	0	0
Total	**3**	**(3)**	**5**	**(18)**	**7**	**(13)**	**7**	**(4)**	**14**	**(6)**	**13**	**(4)**
S&P												
Q1	3	(5)	1	(4)	0	(13)	5	(6)	1	(3)	13	0
Q2	3	(3)	5	(3)	6	(2)	9	(2)	7	(4)	10	0
Q3	6	(3)	3	0	5	0	2	0	0	(5)	6	0
Q4	1	(3)	3	(1)	4	(6)	2	(4)	2	(8)	8	(3)
Total	**13**	**(14)**	**12**	**(8)**	**15**	**(21)**	**18**	**(12)**	**10**	**(20)**	**37**	**(3)**

Note: Chart depicts the number of occurrences and includes each event, even if multiple downgrades occurred for a single company.

Source: Fitch Ratings, Moody's, and Standard & Poor's

Direction of Rating Actions

U.S. INVESTOR-OWNED ELECTRIC UTILITIES



Source: Fitch Ratings, Moody's, and Standard & Poor's

commitment to credit quality, increased certainty in terms of strategic direction, and execution of a revised strategy to exit the merchant power business." The agency also placed these ratings on CreditWatch with positive implications to reflect a "high probability" of further upgrades if the transaction closed successfully. S&P further noted that, even if the proposed deal did not close, "Ameren would still sell its merchant business to another third party under similar terms." The deal announcement followed Ameren's announcement in December 2012 that merchant generation was no longer core to its business strategy. Also on March 11, S&P affirmed its CCC+ ratings for AmerenEnergy Generating (Genco). S&P's negative outlook on Genco reflected its expectations that credit metrics and profit margins would fall over the next few years because of continued weak power prices, weak U.S. economic growth and low natural gas prices.

On March 18, S&P upgraded CMS Energy and its electric utility subsidiary Consumers Energy to BBB from BBB-. The move reflected improvement in CMS's business risk profile. S&P cited consistent credit-supportive outcomes in rate cases since the passage in 2008 of Michigan's Energy Law and noted that, by controlling costs and capital expenditures, CMS successfully executed its strategy to limit customer base rate increases to 2% or less on an annual basis. S&P further cited a slowly improving economy in Michigan and observed that state legislators were unlikely, in the near to medium term, to lift Michigan's 10% customer choice cap, which limits the percentage of sales that can be provided by competing suppliers.

Q2 Actions Reflect Reduced Business Risks

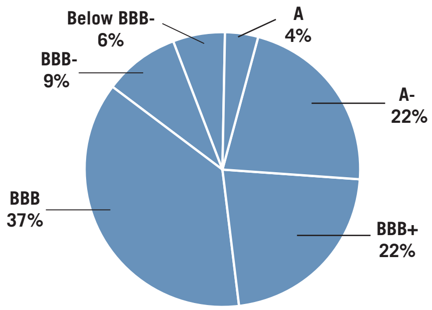
Ratings changes in the second quarter included five parent company-level upgrades.

On April 5, S&P raised its corporate ratings on PNM Resources (PNM) and subsidiaries Texas-New Mexico Power and Public Service Company of New Mexico to BBB from BBB-. The agency cited increasingly favorable regulatory relationships in New Mexico and Texas and improved credit metrics due to PNM's divestiture of its unregulated businesses. S&P's action marked its second upgrade of PNM and its utility subsidiaries since PNM's September 2011 announcement that it would sell its unregulated businesses in Texas and pursue a pure-play regulated utility strategy. Prior to that announcement, PNM and its utility subsidiaries' ratings were BB-, four notches below BBB. S&P set the companies' outlooks to Stable and said that any further upgrades would require regulatory outcomes that allowed the company to achieve credit ratios of FFO-to-debt at or exceeding 25% and an adjusted debt-to-capital ratio of less than 52%. The agency noted that reaching these levels might require lower-than-expected capital expenditures for environmental controls.

S&P on April 23 raised its corporate ratings on Public Service Enterprise Group (PSEG) and subsidiaries Public Service Electric & Gas (PSE&G) and PSEG Power to BBB+ from BBB, reflecting regulated utility PSE&G's increasing influence on holding company PSEG's consolidated cash flows. S&P noted that PSE&G would account for

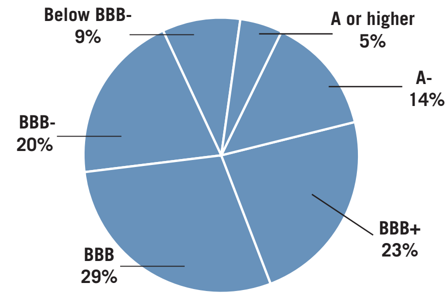
Bond Ratings December 31, 2013
as rated by Standard & Poor's

U.S. INVESTOR-OWNED ELECTRIC UTILITIES



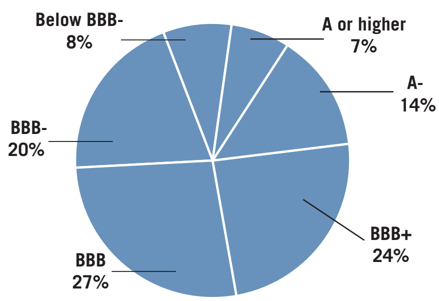
Bond Ratings December 31, 2012
as rated by Standard & Poor's

U.S. INVESTOR-OWNED ELECTRIC UTILITIES



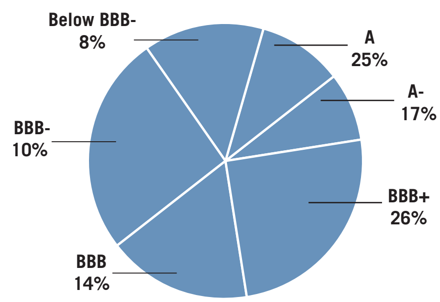
Bond Ratings December 31, 2011
as rated by Standard & Poor's

U.S. INVESTOR-OWNED ELECTRIC UTILITIES



Bond Ratings December 31, 2001
as rated by Standard & Poor's

U.S. INVESTOR-OWNED ELECTRIC UTILITIES



Note: Rating applies to utility holding company entity.

Source: Standard & Poor's, SNL Financial, EEI Finance Department, and company annual reports

about 80% of the group's capital expenditures over the following three years, shifting and reducing PSEG's business risk away from merchant subsidiary PSEG Power.

On May 2, S&P raised its long-term corporate credit ratings on OGE Energy and subsidiary Oklahoma Gas & Electric (OG&E) to A- from BBB+. The agency cited a reduced business risk profile that reflected the "strength and stability" of regulated operations at OG&E and OGE's decision to contribute subsidiary Enogex's midstream natural gas assets to a joint venture with CenterPoint Energy. In setting the companies' outlooks to Stable, S&P stated its expectation that OGE management would not pursue riskier business lines and would fund capital expenditures carefully.

Also on May 2, S&P raised its long-term ratings on CenterPoint Energy (CenterPoint) and subsidiaries CenterPoint Energy Resources and CenterPoint Energy Houston Electric to A- from BBB+. S&P's rationale was largely similar to its reasons for upgrading OGE Energy: CenterPoint's decision to contribute its higher-risk midstream assets to the joint venture with OGE reduced CenterPoint's overall business risk. S&P stated that CenterPoint's financial risk had also decreased, and the agency expected credit metrics to continue to improve over the next few years, primarily through incremental debt reduction. CenterPoint continues to wholly own regulated electric and gas distribution and retail gas supply businesses.

Rounding out the quarter's positive actions, S&P on June 21 upgraded Otter Tail to BBB from BBB-. The agency again cited a reduced business risk profile, as Otter Tail

Rating Agency Activity

U.S. INVESTOR-OWNED ELECTRIC UTILITIES

Total Ratings Changes	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013
Fitch	34	22	31	41	17	14	24	25	26	23
Moody's	42	46	39	32	6	23	20	11	20	17
Standard & Poor's	34	53	40	48	27	20	36	30	30	40
Total	**110**	**121**	**110**	**121**	**50**	**57**	**80**	**66**	**76**	**80**

Source: Fitch Ratings, Moody's, Standard & Poor's, SNL Financial, and EEI Finance Department

sold a significant portion of its unregulated businesses over the prior 12 to 18 months. S&P estimated that, going forward, about 85% of Otter Tail's EBITDA would come from regulated utility operations with the remainder from unregulated businesses. S&P also cited Otter Tail's "effective management of regulatory risk" and consistently improving financial metrics. In setting the company's outlook to Stable, S&P forecast that Otter Tail would generate consolidated FFO-to-debt of about 18% and that its ratio of adjusted debt-to-EBITDA would be about 4x over the next 12 to 18 months.

Q3 Upgrades on Regulated Focus and Outcomes

Ratings changes in the third quarter included three more parent company-level upgrades, again due largely to companies' regulated focus and effective management of regulatory risk.

S&P on July 24 upgraded Black Hills Corp. and subsidiary Black Hills Power to BBB from BBB-. The agency cited Black Hills' divestiture of a significant portion of its unregulated businesses during the prior 12 to 18 months and the resulting improvement in the company's business and financial risk profiles; the latter supported by the use of divestiture proceeds to pay down debt. Additionally, S&P noted that credit metrics had improved following completion of construction projects in Colorado. Regarding Black Hills' business risk profile, S&P observed the company still maintains several unregulated business lines including oil and gas exploration and production, merchant power generation and coal mining. Furthermore, the company's broad service territory (covering five regulatory jurisdictions) makes regulatory risk management relatively challenging. In setting Black Hills' outlook to Stable, S&P described its base forecast as supporting credit ratios of adjusted FFO-to-total-debt of about 18% and debt-to-EBITDA of about 4x; the agency said that effective regulatory risk management would be "fundamental" to achieving these levels.

On July 26, S&P raised its long-term corporate credit ratings on Cleco Corp. and subsidiary Cleco Power to BBB+ from BBB to reflect improvement in the companies' consolidated financial condition. Additionally, S&P emphasized Cleco's increasing focus on regulated operations and the resultant impact on the company's business and financial risk profiles. S&P noted that Cleco had worked to reduce holdings of merchant generation assets and had only one remaining gas-fired merchant plant, which it planned to transfer into rate base. S&P described its base case scenario for the company as assuming "constructive regulatory outcomes," the successful transfer of its remaining merchant plant into rate base, and "significant free cash flow" (as evidenced by FFO-to-total debt between 20% and 25% and debt-to-EBITDA between 3x and 2.5x) barring any increase in planned capital expenditures or acquisitions. S&P also expected that Cleco would not implement any large-scale share buybacks or increase its dividend payout ratio beyond the 50% to 60% target range before 2015.

On August 19, S&P raised its long-term corporate ratings on Tucson Electric Power, the largest subsidiary of UNS Energy, by two notches, to BBB from BB+. S&P said the revised rating reflected Tucson Electric's improved relationship with its regulator, the Arizona Corporation Commission, including a "relatively favorable" rate case settlement in 2013. S&P noted that, while it had viewed Arizona as a "less credit-supportive" state, Tucson Electric and other utilities in the state had achieved more favorable outcomes in recent years and that it was watching to see if these mark a trend. S&P described Tucson Electric's financial risk profile as "significant," with consolidated leverage (at 64.5% on June 30) that "remained high" but was incrementally better than in early periods.

In Tucson Electric's rate case settlement, the company received a rate increase and two credit-supportive rate mechanisms—a lost fixed-cost recovery mechanism and an environmental compliance adjustor. In setting the company's outlook to Stable, S&P said it expected these changes would contribute to improved credit metrics, though it also said Tucson Electric would need to continue to closely manage its operation and maintenance costs.

Q4 Changes Relate to Challenging Power Markets

The fourth quarter saw three parent-level upgrades and two downgrades that reflected a revised rating methodology, as well as the successful divestiture of Ameren Corp.'s competitive generation business and weak competitive markets in Texas.

On October 9, S&P downgraded Energy Future Holdings Corp. (EFH) and certain of its subsidiaries including Texas Competitive Electric Holdings Co. (TCEH), which manages EFH's Luminant and TXU Energy competitive generation and retail businesses. The agency reduced its corporate credit ratings on EFH and TCEH by one notch to CCC- from CCC. At the same time, S&P maintained its corporate credit rating of BBB+ on Oncor Electric Delivery Co. LLC (Oncor). Oncor is a traditional transmission and distribution utility that is "ring-fenced" by credit protection commitments that EFH's parent, Texas Holdings, and Oncor have made to the Public Utility Commission of Texas.

S&P's actions reflected its view that TCEH's capital structure was "not sustainable," essentially because the company's EBITDA had been declining in line with lower cash flow from TCEH's Luminant wholesale generation business and TXU Energy competitive retail business. Luminant, which earns money selling power from nuclear and coal plants, was experiencing the impact of low natural gas prices—then at about $4 per mmBTU—on power prices in the Electric Reliability Council of Texas (ERCOT) region. S&P noted that, while Luminant was still benefitting from production hedges transacted when gas was between $7 and $8 per mmBTU, those hedges were set to roll off in 2013 and 2014, exposing the company fully to cash market prices. The agency stated that declining cash flow at TXU Energy was resulting from "very competitive pressures" in retail markets. In keeping EFH and TCEH's outlooks at Negative, S&P cited its expectation that a restructuring of both entities was imminent.

On November 19, S&P published a revised ratings methodology for its corporate industrial and utilities ratings universe. S&P said the revised methodology was developed in order to provide greater insight into its ratings process and also to enhance the global comparability of its ratings. As part of the changes, S&P updated its "Key Credit Factors for the Regulated Utilities Industry" and stated its expectation that the overall suite of changes might affect the issuer credit ratings of about 5% of regulated utilities globally "due primarily to the introduction of new financial benchmarks." By the end of December, S&P had concluded its review of electric utility ratings under the new criteria, and the agency made the following two upgrades and one downgrade.

On December 3, S&P upgraded Puget Energy Inc. and its subsidiary Puget Sound Energy Inc. (PSE) to BBB- from BB+. The upgrade was directly attributable to a reassessment of PSE's financial risk under S&P's revised criteria. The agency noted recent financial metrics (12 months ended September 30) of FFO-to-total debt of 15.5% and debt-to-EBITDA of 4.6x, and S&P expected PSE's ratios to "remain strong" as a result of a new decoupling mechanism and an attrition adjustment approved in a 2013 rate order, as well as declining capital spending. S&P described PSE's overall financial risk as "significant" and its business risk as "strong," benefitting from the company's focus on regulated electric and gas operations.

On December 4, S&P upgraded Pinnacle West Capital Corp. and its subsidiary Arizona Public Service Co. (APS) to A- from BBB+. As with Puget Sound Energy, S&P's upgrade of APS was tied to a reassessment of APS's financial risk. S&P calculated that the company's FFO-to-total

S&P Utility Credit Ratings Distribution by Company Category

U.S. INVESTOR-OWNED ELECTRIC UTILITIES

	2008		2009		2010		2011		2012		2013	
	#	%	#	%	#	%	#	%	#	%	#	%
Regulated												
A or higher	3	8%	3	7%	3	9%	3	8%	2	6%	1	3%
A-	4	10%	6	15%	5	14%	5	14%	6	17%	7	20%
BBB+	9	23%	9	22%	6	17%	7	19%	5	14%	6	17%
BBB	9	23%	11	27%	11	31%	13	35%	13	36%	17	49%
BBB-	9	23%	8	20%	6	17%	5	14%	6	17%	2	6%
Below BBB-	5	13%	4	10%	4	11%	4	11%	4	11%	2	6%
Total	39	100%	41	100%	35	100%	37	100%	36	100%	35	100%
Mostly Regulated												
A or higher	1	5%	2	11%	1	5%	1	5%	1	6%	1	6%
A-	5	26%	2	11%	3	15%	3	16%	2	12%	5	29%
BBB+	2	11%	5	26%	6	30%	6	32%	7	41%	5	29%
BBB	8	42%	6	32%	4	20%	3	16%	3	18%	3	18%
BBB-	3	16%	4	21%	6	30%	6	32%	4	24%	3	18%
Below BBB-	0	0%	0	0%	0	0%	0	0%	0	0%	0	0%
Total	19	100%	19	100%	20	100%	19	100%	17	100%	17	100%
Diversified												
A or higher	0	0%	0	0%	0	0%	0	0%	0	0%	0	0%
A-	0	0%	0	0%	0	0%	0	0%	0	0%	0	0%
BBB+	2	29%	1	17%	2	40%	1	25%	1	33%	1	50%
BBB	2	29%	2	33%	0	0%	0	0%	0	0%	0	0%
BBB-	2	29%	2	33%	2	40%	2	50%	1	33%	0	0%
Below BBB-	1	14%	1	17%	1	20%	1	25%	1	33%	1	50%
Total	7	100%	6	100%	5	100%	4	100%	3	100%	2	100%

Note: Totals may not equal 100.0% due to rounding.

Refer to page v for category descriptions.

Source: Standard & Poor's, SNL Financial, and EEI Finance Department

debt ratio for the 12 months ending September 30 was 30.9%. The agency stated its view that while this ratio would decline as a result of capital spending, APS would continue to benefit from what S&P described as an "improving economic framework" in its service territory and "more comprehensive" rate recovery mechanisms. S&P concluded that APS's financial risk placed it in the agency's "intermediate" category while its business risk (tied to qualitative factors including the company's regulatory environment) was "excellent;" in consideration with other aspects of S&P's revised criteria, APS's credit quality was more appropriately rated A-.

On December 9, S&P's third action related to its revised rating methodology was to downgrade IPALCO Enterprises Inc. and subsidiary Indianapolis Power & Light Co. (IP&L) to BB+ from BBB-. In this instance, the change was attributable more to the companies' relationship to their parent, AES Corp. S&P described how, under its revised criteria, "some insulated subsidiaries can achieve higher ratings than their parent based on the strength of legislative, structural, and regulatory insulation … and a stand-alone credit profile that can sustain the rating on its own." In the case of AES Corp. and IPALCO and IP&L, S&P said the following factors contributed to credit protections that justified a two-notch difference in ratings: an independent director, a non-consolidation opinion, covenants, a separateness agreement and some dividend limitations. Additionally, S&P reviewed its assessments of IPALCO's (and core subsidiary IP&L's) business and financial risk profiles, describing them as "excellent" and "aggressive," respectively. The company's stand-alone credit profile was also essential to S&P's rating it higher than its weaker parent AES.

Independent of the above actions related to its revised methodology, on December 4 S&P followed up on its actions of March 11 by again raising its ratings on Ameren Corp. and subsidiaries Ameren Illinois Co. and Ameren Missouri. The agency raised the companies' ratings by an additional notch, to BBB+ from BBB. The new ratings reflected the successful closing on December 2 of Ameren's sale of its unregulated generating company, Ameren Energy Resources Co. LLC, to Dynegy Inc. S&P commented that the sale demonstrated Ameren management's "ability to effectively execute" the company's revised strategy to focus on lower-risk regulated operations.

S&P additionally noted that Ameren's decision to invest proportionally more in FERC-regulated transmission assets would improve (i.e., reduce) the company's business risk profile, which it viewed as "excellent." Reviewing Ameren's financial risk, S&P expected that core financial ratios would "moderately weaken" going forward due to the company's plans to increase capital spending. However, S&P also forecast that Ameren's credit metrics would place it "comfortably in the middle" of its "significant" financial risk category. Specifically, S&P forecast FFO-to-debt of 16% to 19% and debt-to-EBITDA of 3.9x to 4.2x for the next three years.

Looking Ahead: A More-Regulated Business under Constructive Regulation

While 2013 marked the tenth consecutive year of a BBB rating for the industry (i.e., based on EEI's unweighted average of S&P ratings at the parent or holding-company level), it was also characterized by the highest percentage of positive ratings changes (across all issuers and ratings agencies) in at least as many years. Early in 2014, both S&P and Moody's published industry-level outlooks describing why they expect U.S. regulated utilities to maintain stable credit profiles in 2014. And while both agencies described positive factors that included the de-risking of utility business models through a renewed focus on regulated activities (see *Business Segmentation*), Moody's emphasized that improving industry regulation was the "most important" driver of its outlook.

Moody's developed its view of an improving regulatory environment more fully in a report on February 3, 2014, "U.S. Utility Sector Upgrades Driven by Stable and Transparent Regulatory Frameworks." The report elaborated on the reasons behind the agency's actions in November of last year to place most regulated utilities on review for upgrade and in late January 2014 to upgrade most of these companies by one notch. Moody's described how state-level regulation had evolved over the past several years for the better, including through the implementation of a "suite of transparent and timely cost and investment recovery mechanisms." Moody's stated its expectation that the overall regulatory environment would remain "supportive and constructive" for at least the next three to five years.

Writing again in a report on February 19, "Regulation Will Keep Cash Flow Stable as Major Tax Break Ends," Moody's expressed the view that, while the end of bonus depreciation in 2013 would cause many utilities' financial metrics to decline, the improved regulatory framework featuring both cost-recovery mechanisms and annual base-rate increases would play a significant offsetting role. Moody's offered several examples of the kinds of positive rate case outcomes that were driving its industry outlook, such as for Puget Sound Energy in Washington and Westar Energy in Kansas (see above and *Rate Case Summary*). Furthermore, Moody's commented that improved regulation was also playing a critical role as utilities managed the effects of sluggish customer demand.

Writing on January 22, S&P discussed what it saw as various factors behind the industry's stability that included continued improvement in economic conditions, sustained demand for a "very critical" commodity, the "generally supportive" posture of regulators toward cost recovery for capital expenditures, and continued demand by investors for utility equity and debt securities.

Throughout these reports, neither S&P nor Moody's raised major concerns about risks to the stable progression of the sector's credit profile in the near to medium terms. S&P stated that "we see little alteration in the sector's business and financial risk profiles during periods of economic change" because of the essential nature of electricity, the regulated character of the business and the constructive regulatory environment. The agency also suggested that if the economy grows faster than it is expecting, there could be "some modest improvement" in the industry's credit profile. Moody's, for its part, commented that "a more contentious regulatory environment" or a "widespread adoption" of more-aggressive financial strategies could lead to a negative outlook but, on the other hand, a "marked increase" in allowed ROEs, or steps to scale back dividends and stock repurchases, might lead to a positive outlook.

Ratings by Company Category

The table *S&P Utility Credit Rating Distribution by Company Category* presents the distribution of credit ratings over time for the investor-owned electric utilities organized into Regulated, Mostly Regulated and Diversified categories. Ratings are based on S&P long-term issuer ratings at the holding company level, with only one rating assigned per company. At December 31, 2013, the categories had the following average ratings: Regulated = BBB, Mostly Regulated = BBB+, and Diversified = BB-/CCC+.

Long-Term Credit Rating Scales

U.S. INVESTOR-OWNED ELECTRIC UTILITIES

	Moody's	Standard & Poor's	Fitch
Investment Grade	Aaa	AAA	AAA
	Aa1	AA+	AA+
	Aa2	AA	AA
	Aa3	AA-	AA-
	A1	A+	A+
	A2	A	A
	A3	A-	A-
	Baa1	BBB+	BBB+
	Baa2	BBB	BBB
	Baa3	BBB-	BBB-

	Moody's	Standard & Poor's	Fitch
Speculative Grade	Ba1	BB+	BB+
	Ba2	BB	BB
	Ba3	BB-	BB-
	B1	B+	B+
	B2	B	B
	B3	B-	B-
	Caa1	CCC+	CCC+
	Caa2	CCC	CCC
	Caa3	CCC-	CCC-
	Ca	CC	CC
	C	C	C

	Moody's	Standard & Poor's	Fitch
Default	C	D	D

Source: Fitch Ratings, Moody's, and Standard & Poor's

Policy Overview

Introduction

In 2013, EEI and its member companies were at the center of key policy debates on Capitol Hill, as well as at the U.S. Environmental Protection Agency (EPA), Federal Energy Regulatory Commission (FERC), U.S. Department of Energy (DOE), and other federal agencies.

On the congressional front, the industry had an important policy victory in January when Congress passed legislation to keep dividend tax rates low and permanently linked to the tax rates for capital gains. This policy success was due, in large part, to EEI's multi-faceted Defend My Dividend campaign.

Looking forward, EEI does not expect to see much movement related to energy legislation on Capitol Hill this year. Yet, we will continue to educate Members of Congress on important issues for the electric power industry. It is critical that lawmakers understand how these issues impact both the industry and our customers, so they can make informed decisions when they do act.

Given the gridlock in Congress, much of EEI's efforts have shifted to working with the Administration to accomplish our objectives, and that will continue throughout 2014. EEI also will continue working with industry partners toward common policy objectives that strengthen the industry and demonstrate the Power by Association that EEI represents. The following summary provides a glimpse of the policy challenges that EEI and its member companies faced in 2013.

For a comprehensive list of EEI's policy issues and activities, please visit EEI's Web site at www.eei.org.

Comprehensive Tax Reform

EEI and the industry began 2013 with a major victory as Congress passed important legislation to keep dividend tax rates low and permanently linked to the tax rates for capital gains.

Through its multi-faceted Defend My Dividend campaign, EEI worked to educate Members of Congress and other stakeholders that millions of Americans from all income levels and age groups own stocks that pay dividends. Dividends also are an important component of shareholder value for the investor-owned electric utility industry. Today's low dividend tax rates make dividend-paying companies, like electric companies, more attractive to investors. This helps to increase the value of utility stocks and lowers the cost of capital, which is critical for electric companies at this time of record-high capital expenditures.

While comprehensive tax reform is expected to remain on the backburner in Congress this year, EEI continues its work to educate lawmakers about our industry's priorities. These include the deductibility of interest on corporate debt, dividend tax rates, normalization, and the treatment of excess deferred taxes.

Cyber & Physical Security

Protecting the nation's electric grid and ensuring a reliable supply of energy are top priorities for the industry. The power grid is a complex, interconnected network of generation, transmission, distribution, control, and communication technologies, which can be damaged by natural events, such as severe storms, and by malicious events, such as cyber and physical attacks.

The industry is forging ahead with a series of initiatives to safeguard the electric grid from threats and is partnering with federal agencies to improve sector-wide resilience to cyber and physical threats. The industry also collaborates with the National

Institute of Standards and Technology, the North American Electric Reliability Corporation (NERC), and federal intelligence and law enforcement agencies to strengthen its capabilities. EEI helped to strengthen the industry-government partnership on security and resilience by formalizing the Electricity Subsector Coordinating Council (ESCC). The ESCC includes utility CEOs and trade association leaders representing all segments of the industry. It serves as the principal liaison between the federal government and the electric power sector, with the mission of coordinating efforts to prepare for, and respond to, national-level disasters or threats to critical infrastructure.

In 2013, EEI continued to advocate for comprehensive federal cybersecurity legislation that preserves the existing regulatory structure and facilitates information sharing between the government and private sector. The House passed the Cyber Intelligence Sharing Protection Act in April 2013. The Senate Commerce Committee approved the Cybersecurity Act of 2013 in July.

EEI participated in preparation drills for extraordinary scenarios. Grid Ex II, an exercise in November 2013, organized by NERC, included both cyber and physical security threats among U.S. and Canadian utilities and participants.

The industry is committed to improving prevention strategies that include tighter physical access measures and surveillance, industry-wide physical security and cybersecurity standards and guidelines, and NERC alerts regarding significant incidents or threat information. EEI continues to concentrate on resiliency efforts to protect the grid through programs such as EEI's Spare Transformer Equipment Program, the Electric Power Research Institute's Recovery Transformer Program, and other similar initiatives.

Distributed Generation and Net Metering Policy

Across the country, there is growing interest in using rooftop solar panels and other small-scale, on-site power sources known as distributed generation (DG). To encourage the introduction of these systems when they first came to market years ago, many states approved a billing system called net metering. This billing system is still in effect today even though the circumstances of which it was introduced and the market in which these resources are evolving have both changed drastically.

While net metering policies vary by state, generally customers with rooftop solar or other DG systems are credited for any electricity they sell via the electric power grid. Electric companies are required to buy this power typically at the full retail rate, which includes all of the fixed costs of the poles, wires, meters, advanced technologies, and other infrastructure that make the grid safe, reliable, and able to accommodate rooftop solar panels or other DG systems. Through the credit they receive, net-metered customers effectively avoid paying these costs for the grid, which are shifted to customers without rooftop solar or other DG systems.

There's no question that DG, including rooftop solar, will play an important role in our generation future. In fact, the utility industry is helping to lead the solar charge, whether it is distributed solar or community-based solar. Not only have utilities installed the majority of solar power generating capacity in our country so far, but the growth in rooftop solar energy is due, in large part, to the industry's commitment to transform the electric grid, and is enabled by the industry's efforts to better manage resource and load variability and to create greater capability for electricity and information to move two-ways: from the utility to the customer and from the customer back to the utility.

But, it is time to find and apply a regulatory structure that advances along with technology and that sustainably and fairly supports both the growth of DG systems and the grid so it can enable the safe and reliable integration of these technologies.

Distributed generation came to the forefront of the industry's attention in 2013, in particular the impact that a rapidly growing DG market, as well as the state net metering policies that support it, are having on the electric grid and electricity customers respectively. EEI believes that net metering policies and rate structures in many states should be updated so that everyone who uses the electric grid shares equitably in the costs of maintaining it and keeping it operating reliably at all times. Rate structures and subsidy mechanisms should be transparent, avoid cost shifting, recognize the value of the grid, and ensure that all electricity customers who use the grid pay their fair share for its maintenance and operation. Only this change will ensure that our electric system remains safe and reliable and that electric rates are fair and affordable for all customers.

Germany and other European countries offer a cautionary tale of the consequences that heavily subsidized resources can have on electricity markets, customers, and a country overall. Germany's overgenerous subsidies to renewable energy resources have dramatically driven up electricity prices and are threatening the stability of the country's grid. Electricity prices for households in Germany have more than doubled since 2000, rising from 18 cents per kilowatt hour to more than 37 cents per kilowatt hour in 2013, and are expected to grow by an additional 35 percent by 2020. In contrast, the average residential electricity price in the United States is around 12 cents per kilowatt hour and has remained relatively stable over the last decade.

We now have the opportunity to assimilate the lessons learned from other countries to ensure the sustainable growth of distributed and other renewable resources over the long-term, for the benefit of all customers and the nation.

Environmental Roundup

Last year, EEI and its member companies worked closely with EPA and others within the Administration on a number of environmental regulatory issues that will affect the industry. Before reviewing some of the critical regulations, it is important to note that the electric power sector already has made impressive reductions in its air emissions over the past 20 years, during a time when electricity use grew by almost 40 percent. Sulfur dioxide (SO_2) and nitrogen oxides (NOx) emissions both have been cut by about 75 percent from 1990 national levels. Carbon dioxide emissions have been reduced by approximately 15 percent below 2005 levels, as of 2012. And, EPA's new rule on mercury emissions will lead to a 90-percent reduction in emissions.

- The big announcement in 2013 was the President's Climate Action Plan, which sets the stage for greenhouse gas (GHG) new source performance standards for new and existing power plants. The plan would cut U.S. carbon emissions largely by reducing emissions from power plants through new Clean Air Act regulations. EEI continues to advocate that EPA's GHG performance standards for new and existing power plants provide a range of compliance options that are cost-effective and technologically available for all fuels.
- In 2013, EEI continued to advocate that EPA's final Clean Water Act (CWA) section 316(b) rule for cooling water intake structures maintain maximum compliance flexibility. Maintaining flexibility is necessary to avoid facilities having to incur costs that are significantly out of proportion to the benefits. A rigid rule requiring unnecessary retrofits could cause negative energy, cost, and reliability impacts and force some existing facilities to retire due to the cost of meeting the new requirements. This rule requires that the location, design, construction, and capacity of cooling water intake structures reflect the best technology available for minimizing adverse environmental impact. A final rule is due in May 2014.
- Working closely with the Waters Advocacy Coalition (WAC), EEI raised concerns with Administration officials and Congress about the draft EPA-Army Corps of Engineers "Waters of the United States" rule. The rule would broadly expand federal CWA regulatory jurisdiction and trigger regulatory and permitting requirements for an array of electric utility activities, including generation construction and operations, as well as transmission construction and maintenance. Decommissioning operations would also be negatively impacted. EEI provided comments and testimony to EPA's Science Advisory Board, which is currently reviewing EPA's report concerning the underlying science. WAC submitted a letter to the Office of Management and Budget communicating industry's key concerns with the draft proposal. As a result of these efforts, the draft was modified prior to its delayed release in April 2014.
- As a result of a lawsuit brought by environmental groups and ash recyclers, EPA is facing a December 19, 2014, deadline for taking final action on its proposed rule for coal ash disposal. The agency proposed two options—regulating coal ash as either hazardous waste or as a non-hazardous waste—and the nature of EPA's final rule promises to have significant impact on ash management operations.

EEI worked last year with the Utility Solid Waste Activities Group and a broad coalition of allies to advocate that coal ash be regulated as non-hazardous waste. In addition, EEI continues to advocate for legislation that would establish a federal non-hazardous waste regulatory program for coal ash disposal, implemented by the states. This approach enjoys bipartisan support in Congress and has been endorsed by the states, ash recyclers, and the industry.

- In April 2014, the U.S. Supreme Court upheld EPA's Cross State Air Pollution Rule (CSAPR), which affects states in the eastern half of the country. Because the D.C. Circuit Court initially stayed and then vacated CSAPR, it has never been implemented. Instead, the Clean Air Interstate Rule has continued to be in effect. EPA has not yet indicated how it will address CSAPR compliance going forward.
- EEI, along with industry partners, filed extensive comments in September 2013 on EPA's proposed rule on steam electric effluent limitation guidelines (ELGs) that set technology-based water discharge limits for the industry. The rulemaking proposes strict effluent limits that will force operational changes at existing coal-based facilities, many natural gas-based combined-cycle facilities, and some nuclear generation facilities. The industry noted in its comments that most of EPA's compliance options would impose substantial costs on the generation fleet without providing corresponding benefits. This is the first significant revision of the CWA's ELGs in more than 30 years. Through its participation in the Smart Grid Interoperability Panel, EEI continued to advocate for cost-effective data access policies that protect consumer privacy and ensure operational reliability of the utility system.
- The industry continues its work on compliance timeline issues for the final utility Mercury and Air Toxics Standards rule, which will reduce emissions of mercury, SO2, particulate matter, and other emissions. The power sector is preparing to comply on schedule, in the 2015-2016 timeframe.

Fuel Diversity and Flexibility

Today, the power sector is undergoing a major transition. Companies are investing billions of dollars to create a future generating fleet that is lower emitting and uses more efficient fuels and technologies.

Having a balanced and diverse fuel mix is critical for the electric power industry and consumers alike. Fuel diversity protects against fuel unavailability, price fluctuations, and changes in regulatory practices that can drive up costs of a particular fuel. The shale gas revolution—with its promise of a seemingly permanent horizon of low natural gas prices —was by far the dominant fuel-related theme of 2013. This trend has significant financial and operational implications for the industry's generating capacity.

Today's low natural gas prices have affected all of the industry's generation sources, making even the most cost-competitive renewable energy projects less competitive. The low prices have also spurred a number of natural gas and resource adequacy-related questions that EEI is working with its members to help address, including pipeline scheduling and infrastructure issues, capacity market issues, state regulatory and legislative issues regarding long-term contracting, and the alignment or misalignment of gas and electric trading markets.

Renewables also continue to grow rapidly, and renewable capacity is expected to more than double between now and 2035. But, the growth of renewables and their impact on markets can also have unintended consequences, as demonstrated by the closure of a few nuclear reactors in recent years due to adverse economic conditions and a lack of market incentives. As described in the DG section above, the same type of negative impacts are being exemplified in Germany, as well as in other parts of Europe, where short-sighted, unsustainable renewable energy policies significantly increased consumer energy costs, left markets unstable, and added pressure on the environment and power companies.

In a February 2014 white paper, Senator Lisa Murkowski (R-Alaska) provided a cautionary tale from January's polar vortex, noting that 89 percent of the coal capacity that is slated for retirement at one particular company was called upon this year to meet demand. She also noted that nuclear power plants operated at more than 90 percent capacity through the event. This should serve as a wake-up call to the continued importance of baseload capacity—electricity generated 24 hours a day, seven days a week, from a balanced fuel mix.

As energy markets change, and with them the industry's generation fleet, preserving fuel diversity and flexibility remain at the forefront of the industry's priorities.

Transmission Investment and ROEs

Investor-owned utilities are continuing to make significant investments in the electric grid to provide customers with reliable electric service, relieve congestion, facilitate wholesale market competition, and support a diverse and changing generation portfolio for the benefit of electricity customers.

EEI's member companies remain dedicated to building needed and beneficial transmission, and enhancing the nation's electric grid to meet 21st-century demands. Investor-owned electric utilities and stand-alone transmission companies invested a record-high $34.9 billion in transmission and distribution infrastructure in 2012, demonstrating the industry's commitment to ensuring that all electricity customers benefit from a resilient electric grid.

EEI continues its efforts to advocate that FERC provide compensatory returns on equity (ROEs) that reflect the risks of development and the long asset lives of transmission and distribution facilities. Last June, EEI released a new white paper that outlines why reasonable returns are critical to attracting financing for these long-term investments. ROEs need to be predictable and sustainable over the long term in order for a robust, enhanced transmission system to produce savings for customers and other policy benefits. Otherwise, investors may reallocate their capital to sectors offering more favorable risk/return characteristics.

Capital Expenditures

The industry is leading the transformation to make the grid more resilient against threats and more flexible to meet the growing demands of our digital society. But, transforming the grid requires significant investment. In 2013, the industry spent $90.3 billion in total capital expenditures. Based on an analysis EEI performed last fall, transmission commanded 17 percent of total capital expenditure dollars, up from about 15 percent in 2012, and natural gas-related businesses comprised 12 percent of total capital expenditures, up from 10 percent in the year before.

Storm Response

Over the past year, the industry has come together to institutionalize the lessons learned from Superstorm Sandy in order to optimize restoration efforts following "national response events" that impact a large population or several regions across the United States and require resources from multiple Regional Mutual Assistance Groups (RMAGs).

In the case of the most significant events that result in widespread power outages, the industry now has the ability to coordinate emergency restoration resources at the national level.

- Three RMAGs in the northeast United States were consolidated to create the North Atlantic Mutual Assistance Group. This will allow better coordination of the resources available to the participating utilities and will increase the ability of the RMAGs to provide more self-sustaining support for most local and regional outage events. There are now seven RMAGs across the country.
- The industry continues to collaborate and work with the federal government and the states to enhance and formalize the industry-government partnership developed during Sandy. To facilitate better communication and information sharing with the federal government, industry officials will be embedded within the emergency support and response function at DOE and will coordinate with the Federal Emergency Management Agency during major outages.
- The industry is streamlining transportation by developing information resources and tools to expedite the movement of resources across state lines in partnership with the U.S. Department of Transportation and state transportation agencies. Additionally, we have negotiated a new procedure for U.S. and Canadian border crossings

with the U.S. Department of Homeland Security and the Canadian Border Services Agency to ensure timely movement of mutual assistance crews across the international border.

- Through an ongoing dialogue with the U.S. Department of Defense (DOD), the industry is examining ways to enhance logistical support, security, and road access. This includes exploring opportunities for access to DOD property and facilities for pre-staging, securing access to critical supplies and equipment from the Army Corps of Engineers, and enhancing security and road access with the National Guard.

Transportation Electrification

An area where there is enormous potential for the industry is transportation electrification. While electric vehicles are still relatively new to the automotive market, the sales numbers are beginning to show real promise. Plug-in electric vehicle (PEV) sales grew dramatically in 2013, up more than 80 percent from 2012. Last year, nearly 100,000 PEVs were sold in the United States, and there are now nearly 200,000 EVs on the road. Additional new PEV models will enter the market in 2014, joining the 16 models already for sale. PEV drivers (and car critics) love their cars, and the enthusiasm among that community is an important part of expanding this market.

And electrification goes beyond cars. It has great potential in a wide range of commercial transportation applications, including commercial fleets and seaports, helping to achieve both economic and environmental goals through lower fuel costs and reduced emissions.

Other Highlights

EEI's 2013 policy-related activities and results also include:

- EEI continued its focus on ensuring that the legislative intent of the Dodd-Frank financial reform law is preserved to avoid burdening end users. In House testimony, EEI advocated legislative action to ensure that the $8 billion de minimis threshold remains in place.
- EEI achieved changes in DOE's final energy efficiency standards for distribution transformers, ensuring that member companies have the ability to choose from multiple vendors and technologies.
- EEI expanded its outreach to state policymakers, regulators, and other stakeholders through the National Association of Regulatory Utility Commissioners, the Critical Consumer Issues Forum, and other decision-making bodies, securing several positive policy resolutions on key issues.
- EEI continued to highlight the industry's workforce development initiatives and developed the Troops to Energy Jobs National Template, which helps connect veterans to rewarding careers in the energy sector.
- EEI continued to lead industry advocacy efforts in support of increased funding for the Low-income Home Energy Assistance Program (LIHEAP).

Accounting Issues

Financial Accounting Standards Board (FASB)

The FASB continued to work during 2013 on three major convergence projects with the International Accounting Standards Board. The Boards substantially finalized their converged standard on Revenue Recognition and are scheduled to issue it in the second quarter of 2014.

The Boards redeliberated many issues on the Leases project and re-exposed a proposed Accounting Standards Update in May 2013. EEI Accounting Committees actively worked to raise and provide recommended solutions to issues affecting our industry and provided comments on the new proposal, the ultimate outcome of which remains uncertain. Work by the FASB on the various facets of the Financial Instruments projects was largely deferred.

Securities & Exchange Commission (SEC)

The SEC staff published its final staff report on its "Review of Disclosure Requirements in Regulation S-K" in December 2013, recommending that the SEC undertake a comprehensive review of its disclosure requirements as they apply to all public companies. The study was mandated by the Jumpstart Our Business Startups Act (JOBS Act), which required the SEC to analyze and consider areas within its disclosure regime that could be simplified and modernized.

International Accounting Standards Board (IASB)

The IASB continued its work on the reactivated project on Accounting for Rate-Regulated Activities. The project was taken up as a result of the IASB's agenda consultation, and the Board issued and received comments on a Request for Information during 2013. A Discussion Paper is expected to be issued in 2014. The IASB also issued an interim standard on Regulatory Deferral Accounts that permits entities adopting IFRS to retain their previous accounting for the effects of rate regulation pending completion of the larger project.

Public Company Accounting Oversight Board (PCAOB)

The PCAOB considered several proposals that would affect auditors and their reports, including proposals to modify the auditor's reporting model and the auditor's responsibilities related to information in a company's annual report outside the financial statements. The proposals also would require auditors to perform additional procedures to evaluate, based on evidence gathered during the audit, whether information outside the financial statements contained material inconsistencies with amounts or information in the financial statements, a material misstatement of fact or both. The PCAOB also dropped a proposed requirement for public companies to rotate auditors after a predetermined period of time.

US/International Convergence Projects

EEI continues to coordinate member initiatives to evaluate, respond to, and address industry-specific concerns arising from efforts by the Financial Accounting Standards Board (FASB) and the International Accounting Standards Board (IASB) to converge their accounting standards for Revenue Recognition and Lease Accounting. In anticipation of the final standard revenue recognition standard, the AICPA Financial Reporting Executive Committee (FINREC) is developing industry-specific implementation guidance, and both EEI member-company representatives and EEI staff have been selected to participate in the power and utilities task force.

Rate-Regulated Accounting

EEI, working jointly with other industry associations, successfully nominated a member-company Controller to the IASB's Consultative Group on its project on Accounting for Rate-Regulated Activities. We actively advocated for recognition of the economic effects of regulation in international accounting standards by providing comments on the IASB's Request for Information on this project, its interim standard on Regulatory Deferral Accounts, and aspects of it Discussion Paper on the international Conceptual Framework that could impact these efforts.

Major FERC Initiatives 2006-2013

BUSINESS PRACTICE STANDARDS FOR ELECTRIC UTILITIES

MAJOR PROPOSALS: RM05-5-000

- FERC proposed to incorporate by reference the first set of standards for business practice for electric utilities developed by the Whole Electric Quadrant (WEQ) of the North American Energy Standards Board (NAESB). The proposed rule would include OASIS business practice standards, OASIS standards and communications protocols and an OASIS dictionary. FERC also proposed that each electric utility's OATT include the applicable WEQ standards.
- FERC further proposed to incorporate definitions of demand response resources in the definitions of certain ancillary services, and later proposed to incorporate standards that identify operational information and performance evaluation methods.
- FERC did not propose to incorporate NAESB's Standards of Conduct standards.

MAJOR IMPLICATIONS:

- Each electric utility's OATT must include the applicable WEQ standards. For standards that do not require implementing tariff revisions, the utility would be permitted to incorporate the WEQ standard by reference in its tariff.
- Once incorporated, compliance will be mandatory for all jurisdictional utilities and for non-jurisdictional utilities voluntarily following FERC's open access requirements under reciprocity.

FERC MILESTONES

- July 18, 2013, FERC issued a Notice of Proposed Rulemaking (NOPR) to incorporate by reference in its regulations Version 003 of the Standards for Business Practices and Communication Protocols for Public Utilities adopted by WEQ of NAESB.
- February 21, 2013, FERC issued Order No. 676-G to incorporate business practice standards for categorizing various products and services for demand response and energy efficiency and to support the measurement and verification of these products and services in organized wholesale electric markets. *Standards for Business Practices and Communication Protocols for Public Utilities*, 142 FERC ¶ 61,131 (2013).
- April 15, 2010, FERC issued Order No. 676-F revising its regulations to incorporate by reference business practice standards for certain demand response services in wholesale markets administered by RTO/ISOs adopted by the NAESB. *Standards for Business Practices and Communications Protocols for Public Utilities*, 131 FERC ¶ 61,022 (2010).
- February 18, 2010, FERC issued an Order clarifying aspects of Order No. 676-E and denying rehearing. Standards for Business Practices and *Communications Protocols for Public Utilities*, 130 FERC ¶ 61,116 (2010).
- November 24, 2009, in Docket No. RM05-5-13, FERC issued Order No. 676-E revising its regulations to incorporate by reference the version 2.1 of certain standards adopted by the NAESB. *Standards for Business Practices and Communications Protocols for Public Utilities*, 129 FERC ¶ 61,162 (2009).
- On September 30, 2008, in Docket Nos. RM05-5-005 and RM05-5-006, FERC issued Order No. 676-D which clarifies Order No. 676-C. *Standards for Business Practices and Communications Protocols for Public Utilities,* 124 FERC ¶ 61,070 (2008).
- On July 21, 2008, in Docket No. RM05-5-005, FERC issued Order No. 676-C, revising its regulations to incorporate by reference the latest version (Version 001) of certain standards adopted by the WEQ of the NAESB. *Standards for Business Practices and Communications Protocols for Public Utilities,* 124 FERC ¶ 61,070 (2008).
- December 20, 2007, in Docket Nos. RM96-1-028 and RM05-5-001, FERC issued Order No. 698-A clarifying Order No. 698 and denying requests for rehearing. *Standards for Business Practices and Communications Protocols for Public Utilities,* 121 FERC ¶ 61,264 (2007).
- June 25, 2007, in Docket Nos. RM96-1-027 and RM05-5-001, FERC issued Order No. 698, amending its open access regulations governing business practices and electronic communications with interstate gas pipelines and public utilities to improve communications scheduling gas-fired generators and incorporating certain NAESB regulations. *Standards for Business Practices and Communications Protocols for Public Utilities,* 119 FERC ¶ 61,317 (2007).
- April 19, 2007, in Docket No. RM05-5-003, FERC issued Order No. 676-B, amending its regulations to incorporate, by reference, revisions to the Coordinate Interchange business practice standards adopted by WEQ of the NAESB that identify processes and communications necessary to coordinate energy transfers across boundaries between load and generation balancing entities. *Standards for Business Practices and Communications Protocols for Public Utilities,* 119 FERC ¶ 61,049 (2007).
- February 20, 2007, in Docket No. RM05-5-003, FERC issued a NOPR proposing to incorporate the Coordinate Interchange business practice standards adopted by the WEQ of the NAESB into FERC's regulations. The Coordinate Interchange standards identify the processes and communications necessary to coordinate energy transfers between load and generation balancing entities. *Standards for Business Practices and Communications Protocols for Public Utilities,* 118 FERC ¶ 61,135 (2007).
- September 21, 2006, in Docket No. RM05-5-002, FERC issued Order No. 676-A, denying rehearing of Order No. 676. *Standards for Business Practices and Communications Protocols for Public Utilities,* 116 FERC ¶ 61,255 (2006).
- April 25, 2006, FERC issued Order No. 676 that adopts by reference a number of the NAESB WEQ business practices standards. *Standards for Business Practices and Communications Protocols for Public Utilities,* 115 FERC ¶ 61,102 (2006).
- May 9, 2005, FERC issued NOPR to revise it regulations to incorporate by reference standards for business practice for electric utilities developed by WEQ of NAESB. *Standards for Business Practices and Communications Protocols for Public Utilities,* 111 FERC ¶ 61,204 (2005).

CREDIT REFORM IN ORGANIZED WHOLESALE MARKETS: DOCKET NO. RM10-13-000

- FERC issued a Final Rule amending its regulations to improve the management of risk and use of credit in organized wholesale markets.

MAJOR IMPLICATIONS:

- Each RTO and ISO will be required to submit tariff revisions to comply with the following:
- Establish billing periods of no more than seven days after issuance of bills;
  - Reduce extension of unsecured credit to no more than $50 million per market participant, $100 million per corporate family;
  - Eliminate unsecured credit for firm transmission rights positions;
  - Specification of minimum participation criteria to be eligible to participate in the organized wholesale market;
  - Specification of conditions under which the ISO/RTO will request additional collateral due to a material adverse change; and
  - Limit to tie period to post additional collateral.

FERC MILESTONES:

- June 16, 2011, in Docket No. RM10-13-002, FERC issued Order No. 741-B reaffirming its determinations in Order No. 741-A. *Credit Reforms In Organized Wholesale Markets*, 135 FERC ¶ 61,242 (2011).

- February 17, 2011, in Docket No. RM10-13-001, FERC issued Order No. 741-A denying in part and granting rehearing and clarification of Order No. 741. *Credit Reforms in Organized Markets*, 133 FERC ¶ 61,060 (2010).
- October 21, 2010, in Docket No. RM10-13-000, FERC issued Order No. 741. *Credit Reforms in Organized Markets*, 133 FERC ¶ 61,060 (2010).

DEMAND COMPENSATION IN ORGANIZED WHOLESALE ENERGY MARKETS: DOCKET NO. RM10-17-000

- FERC issued a Final Rule amending its regulations to ensure that when a demand response resources participate in wholesale energy markets administered by RTOs and ISOs has the capability to balance supply and demand and when dispatch of that demand response resource is cost-effective as determined by the net benefits test described in the rule, that demand response resource is compensated at the locational marginal price (LMP).

MAJOR IMPLICATIONS:

- Demand response resources which clear in the day-ahead market will receive the market-clearing LMP as compenstion when it is cost-effective to do so as determined by a net benefits test.
- Each ISO/RTO will implement a net benefits test described in the order to determine if demand response is cost effective.
- ISO/RTOs are directed to review their verification requirements to be sure they can verify that demand response resources have performed.
- Require ISO/RTOs to make compliance filings demonstrating that their current cost allocation methodologies appropriately allocates costs to those that benefit or proposed revisions that conform to this requirement.

FERC MILESTONES:

- February 29, 2012, in Docket No. RM10-17-002, FERC issued Order No. 745-B reaffirming its determinations in Order No. 745-A. *Demand Response Compensation in Organized Wholesale Markets,* 138 FERC ¶ 61,148 (2012).
- December 15, 2011, in Docket No. RM10-17-001, FERC issued Order No. 745-A granting clarification to the limited extent of addressing the applicability of Order No. 745 to circumstances when it is not cost-effective to dispatch demand response resources. *Demand Response Compensation in Organized Wholesale Markets*, 137 FERC ¶ 61,215 (2011).
- March 15, 2011, FERC issued Order No. 745 in Docket No. RM10-17-000. *Demand Response Compensation in Organized Wholesale Markets*, 134 FERC ¶ 61,187 (2011).

ELECTRICITY MARKET TRANSPARENCY PROVISIONS

MAJOR PROPOSALS: DOCKET NO. RM10-12-000

- The Commission revises its regulations to require market participants that are excluded from the Commission's jurisdiction under FPA section 205 and have more than a *de minimis* market presence to file Electric Quarterly Reports (EQR) with the Commission to facilitate price transparency in markets for the sale and transmission of electric energy in interstate commerce.

MAJOR IMPLICATIONS

- FERC adopted a 4,000,000 MWh de minimis threshold for all non-public utilities, including for non-public utilities that are Balancing Authorities.
- FERC revised the existing EQR filing requirements applicable to market participants in the interstate wholesale electric markets by adding new fields for: (1) reporting the trade date and the type of rate; (2) identifying the exchange used for a sales transaction, if applicable; (3) reporting whether a broker was used to consummate a transaction; (4) reporting electronic tag (e-Tag) ID data; and (5) reporting standardized prices and quantities for energy, capacity and booked out power transactions.
- Requires EQR filers to indicate in the existing ID data section whether they report their sales transactions to an index publisher and, if so, to which index publisher(s), and, if applicable, identify which types of transactions are reported.
- Eliminates the time zone from the contract section and the Data Universal Numbering System (DUNS) data requirement.

FERC MILESTONES:

- April 18, 2013, in Docket No. RM10-12-002, FERC issued Order No. 768-A affirming its determinations in Order No. 768 and providing clarification of certain reporting requirements.
- September 21, 2012, in Docket No. RM10-12-000, FERC issued Order No. 768. *Electricity Market Transparency Provisions of Section 220 of the Federal Power Act*, 140 FERC ¶ 61,232 (2012).
- April 21, 2011, in Docket No. RM10-12-000, FERC issued a Notice of Proposed Rulemaking to revise its regulations to require market participants that are excluded from the Commission's jurisdiction under FPA section 205 and have more than a *de minimis* market presence to file Electric Quarterly Reports with the Commission. *Electricity Market Transparency Provisions of Section 220 of the Federal Power Act*, 135 FERC ¶ 61,053 (2011).

ENHANCEMENT OF ELECTRICITY MARKET SURVEILLANCE AND ANALYSIS

MAJOR PROPOSALS: DOCKET NO. RM11-17-000

- Amends Commission regulations to establish ongoing electronic delivery of data relating to physical and virtual offers and bids, market awards, resource outputs, marginal cost estimates, shift factors, financial transmission rights, internal bilateral contracts, uplift, and interchange pricing. Such data will facilitate the Commission's development and evaluation of its policies and regulations and will enhance Commission efforts to detect anti-competitive or manipulative behavior, or ineffective market rules, thereby helping to ensure just and reasonable rates.

MAJOR IMPLICATIONS:

- Establishes ongoing electronic delivery of data relating to physical and virtual offers and bids, market awards, resource outputs, marginal cost estimates, shift factors, financial transmission rights, internal bilateral contracts, uplift, and interchange pricing.
- RTOs and ISOs must electronically deliver data to the Commission within seven days after each RTO and ISO creates the datasets in a market run or other procedure.

FERC MILESTONES:

- April 19, 2012, in Docket No. RM1-17-000, FERC issued Order No. 760. *Enhancement of Electricity Market Surveillance and Analysis through Ongoing Electronic Delivery of Data from Regional Transmission Organizations and Independent System Operators*, 139 FERC ¶ 61,053 (2012).
- October 20, 2011, in Docket No. RM11-17-000, FERC issued a Notice of Proposed Rulemaking proposing to require each RTO and ISO to electronically deliver to the Commission, on an ongoing basis, data related to the markets that it administers. *Enhancement of Electricity Market Surveillance and Analysis through Ongoing Electronic Delivery of Data from Regional Transmission Organizations and Independent System Operators*, 137 FERC ¶ 61,066 (2011).

FREQUENCY REGULATION COMPENSATION IN THE ORGANIZED WHOLESALE POWER MARKETS

MAJOR PROPOSALS: DOCKET NOS: RM11-7-000 AND AD10-11-000

- Found that current compensation methods for regulation service in RTO and ISO markets fail to acknowledge the inherently greater amount of frequency regulation service being provided by faster-ramping resources. In addition, certain practices of some RTOs and ISOs result in economically inefficient economic dispatch of frequency regulation resources.
- FERC requires RTOs and ISOs to compensate frequency regulation resources based on

the actual service provided, including a capacity payment that includes the marginal unit's opportunity costs and a payment for performance that reflects the quantity of frequency regulation service provided by a resource when the resource is accurately following the dispatch signal.

MAJOR IMPLICATIONS:

- Requires that all RTOs and ISOs with centrally procured frequency regulation resources must provide for marginal resource's opportunity costs in their tariffs. Further, this uniform clearing price must be market-based, derived from market-participant based bids for the provision of frequency regulation capacity.
- RTOs and ISOs are required to calculate cross-product opportunity costs, which reflect the foregone opportunity to participate in the energy or ancillary services markets, and include it in each resource's offer to supply frequency regulation capacity, for use when determining the market clearing price and which resources clear.
- RTOs and ISOs may allow for inter-temporal opportunity costs to be included in a resource's offer to sell frequency regulation service, with the requirement that the costs be verifiable.
- FERC requires use of a market-based price, rather than an administratively-determined price, on which to base the frequency regulation performance payment.
- RTOs and ISOs are required to account for frequency regulation resources' accuracy in following the Automatic Generator Control dispatch signal when determining the performance payment compensation. However, FERC will not mandate a certain method for how accuracy is measured.

FERC MILESTONES:

- February 16, 2012, in Docket No. RM11-7-001 and AD10-11-001, FERC issued Order No. 755-A reaffirming its determinations in Order No. 755. *Frequency Regulation Compensation in the Organized Wholesale Power Markets,* 138 FERC ¶ 61,123 (2012).
- October 20, 2011, FERC issued Order No. 755 in Docket No. RM11-7-000. *Frequency Regulation Compensation in the Organized Wholesale Power Markets*, 137 FERC ¶ 61,064 (2011).

GAS/ELECTRIC COORDINATION

MAJOR PROPOSALS: DOCKET NO. RM13-17-000

- Recognizing increased interdependency of the natural gas and electricity markets, FERC must ensure that outages and reliability problems are not the result of the lack of coordination between the electricity and gas industries.
- Over the last few years, natural gas is being used much more heavily in electricity generation. This trend appears likely to accelerate as coal-powered generation is retired, renewable energy resources require more backup by natural gas plants, and low natural gas prices encourage more use of gas.
- FERC issued Order No. 787 which amends the Commission's regulations to provide explicit authority to interstate natural gas pipelines and public utilities that own, operate, or control facilities used for the transmission of electric energy in interstate commerce to share non-public, operational information with each other for the purpose of promoting reliable service or operational planning on either the public utility's or pipeline's system.

MAJOR IMPLICATIONS:

- Provides explicit authority to interstate natural gas pipelines and public utilities that own, operate, or control facilities used for the transmission of electric energy in interstate commerce to share non-public, operational information with each other for the purpose of promoting reliable service or operational planning on either the public utility's or pipeline's system.
- Establishes a "No-Conduit Rule" which prohibits all public utilities and interstate natural gas pipelines, as well as their employees, contractors, consultants, or agents, from disclosing, or using anyone as a conduit for the disclosure of, non-public, operational information they receive under this rule to a third party or to its marketing function employees, as that term is defined in § 358.3 of the Commission's regulations.

FERC MILESTONES:

- November 15, 2013, in Docket No. RM13-17-000, FERC issued Order No. 787 which provides authority to interstate natural gas pipelines and public utilities that own, operate, or control facilities used for the transmission of electric energy in interstate commerce to share non-public, operational information with each other for the purpose of promoting reliable service or operational planning on either the public utility's or pipeline's system. *Communication of Operational Information Between Natural Gas Pipelines and Electric Transmission Operators*, 145 FERC ¶ 61,134 (2013).
- July 18, 2013, in Docket No. RM13-17-000, FERC issued a Notice of Proposed Rulemaking regarding the sharing of information between natural gas operators and electric transmission operators to ensure the reliability of service. *Communication of Operational Information Between Natural Gas Pipelines and Electric Transmission Operators*, 144 FERC ¶ 61,043 (2013).

INTEGRATION OF VARIABLE ENERGY RESOURCES

MAJOR PROPOSALS: DOCKET NO. RM10-11-000

- FERC determined that existing operational procedures may be unduly discriminatory and lead to unjust and unreasonable rates regarding the integration of variable energy resources (VERs) into the bulk electric transmission system. Specifically FERC proposed a limited set of reforms to addresses transmission scheduling practices and VER power production forecasts.

MAJOR IMPLICATIONS:

- FERC amends the *pro forma* Open Access Transmission Tariff (OATT) to provide all transmission customers the option of using more frequent transmission scheduling intervals within each operating hour, at 15-minute intervals to allow transmission customers the ability to mitigate Schedule 9 generator imbalance charges in situations when the transmission customer knows or believes that generation output will change within the hour.
- Amends the *pro forma* Large Generator Interconnection Agreement (LGIA) to require new interconnection customers whose generating facilities are VERs to provide meteorological and forced outage data to the public utility transmission provider with which the customer is interconnected, where necessary for that public utility transmission provider to develop and deploy power production forecasting.

FERC MILESTONES:

- September 19, 2013, in Docket No. RM10-11-002, FERC issued Order No. 764-B reaffirming its determinations in Order Nos. 764 and 764-A and offering further technical clarifications. *Integration of Variable Energy Resources*, 144 FERC ¶ 61,222 (2013).
- December 20, 2012, in Docket No. RM10-11-001, FERC issued Order No. 764-A affirming its findings in Order No. 764 and making certain technical clarifications. *Integration of Variable Energy Resources*, 141 FERC ¶ 61,232 (2012).
- June 22, 2012, in Docket No. RM10-11-000, FERC issued Order No. 764 adopting its proposals in the Notice of Proposed Rulemaking with the exception of the generic ancillary serve rate for regulation service. *Integration of Variable Energy Resources*, 139 FERC ¶ 61,246 (2012).
- November 18, 2010, in Docket No. RM10-11-000, FERC issued a Notice of Proposed Rulemaking proposing reforms to the OATT to revise scheduling and forecasting requirements and add a generic ancillary service rate schedule through which public utility transmission providers will offer regulation service to transmission customers delivering energy from a generator located

within the transmission provider's balancing authority area. *Integration of Variable Energy Resources*, 133 FERC ¶ 61,149 (2010).

- January 21, 2010, in Docket No. RM10-11-000, FERC issued a Notice of Inquiry seeking comment on the extent to which barriers may exist that impede the reliable and efficient integration of VERs into the electric grid, and whether reforms are needed to eliminate those barriers. *Integration of Variable Energy Resources*, 130 FERC ¶ 61,053 (2010).

LONG-TERM TRANSMISSION RIGHTS

MAJOR PROPOSALS: DOCKET NOS. RM06-8-000 AND AD05-7-000

- FERC adopted seven of eight proposed guidelines for independent transmission organizations to follow in developing a framework for providing long-term firm transmission rights (LTFTRs) in organized electricity markets.
- FERC proposed to allow for regional flexibility to account for different market designs and regional differences when developing the framework for LTFTRs.
- FERC proposed that LTFTRs would be required to be available with term lengths sufficient to meet the needs of load-serving entities with long-term power supply arrangements (either existing or planned) used to meet their service obligations.
- FERC required transmission organizations subject to the rule to either file tariff sheets making LTFTRs available which satisfy the seven criteria, or file an explanation of how current tariff sheets and rate schedules meet these criteria.

MAJOR IMPLICATIONS:

- FERC would require that LTFTRs be available to entities that pay for upgrades or build expansions.
- If a transmission organization cannot accommodate all requests for LTFTRs over existing transmission capacity, FERC would require that preference be given to load-serving entities with long-term power supply arrangements used to meet service obligations.

FERC MILESTONES:

- March 20, 2009, in Docket No. RM06-8-002, FERC issued Order No. 681-B, granting certain clarifications concerning allocation of long-term firm transmission rights to external load serving entities and deny requests for rehearing. *Long-Term Firm Transmission Rights in Organized Electricity Markets*, 126 FERC ¶ 61,254 (2009).
- February 25, 2008, in Docket Nos. ER07-476-000 and RM06-8-000, FERC accepted in part and rejected in part the compliance filing of ISO-NE and New England Power Pool proposing amendments to the ISO-NE OATT. *Long-Term Firm Transmission Rights in Organized Electricity Markets*, 122 FERC ¶ 61,173 (2008).
- February 4, 2007, in Docket No. ER07-521-000, the New York Independent System Operator, Inc., submitted a compliance filing in response to Order Nos. 681 and 681-A.
- January 29, 2007, in Docket No. ER07-475-000, the California Independent System Operator Corporation submitted a compliance filing in response to Order Nos. 681 and 681-A.
- January 29, 2007, in Docket No. ER07-476-000, the ISO New England, Inc., submitted a compliance filing in response to Order Nos. 681 and 681-A.
- November 16, 2006, in Docket No. RM06-8-001, FERC issued Order No. 681-A, clarifying and denying rehearing of Order No. 681. *Long-Term Firm Transmission Rights in Organized Electricity Markets*, 117 FERC ¶ 61,201 (2006).
- July 20, 2006, in Docket No. RM06-8-000, FERC issued Order No. 681 approving seven of the eight proposed guidelines for independent transmission organizations to follow in developing proposals for providing long-term firm transmission rights. *Long-Term Firm Transmission Rights in Organized Electricity Markets*, 116 FERC ¶ 61,077 (2006).
- February 2, 2006, FERC issued NOPR, in Docket No. RM06-8-000, proposing eight guidelines for independent transmission organizations to follow in developing a framework for providing long-term firm transmission rights in organized electricity markets. *Long-Term Firm Transmission Rights in Organized Electricity Markets*, 114 FERC ¶ 61,097 (2006).
- May 11, 2005, in Docket No. AD05-7-000, FERC issued notice inviting comments on establishing long-term transmission rights in markets with locational pricing. *Notice Inviting Comments On Establishing Long-Term Transmission Rights in Markets With Locational Pricing and Staff Paper, Long-Term Transmission Rights Assessment*, Docket No. AD05-7-000 (May 11, 2005).

OATT REFORM

MAJOR PROPOSALS: DOCKET NO. RM05-25-000

- FERC has indicated its preliminary view is that the OATT should be reformed to reflect lessons learned in nearly a decade of experience with open access transmission service.
- FERC has indicated concern that the public utilities' OATTs have been implemented in various ways, and greater clarification and other reforms of the OATT may be necessary to avoid undue discrimination or preferential terms and conditions.

MAJOR IMPLICATIONS:

- The final rule acknowledges that it is best to continue to require functional unbundling rather than corporate unbundling, and FERC declined to entertain proposals that would have required structural changes or that might have required the creation of new market structures.
- The final rule deems that industry consensus is the best means to develop consistent and transparent methods for calculating Available Transfer Capability (ATC) in order to address concerns over denials of transmission service.
- The final rule takes a principled, non-prescriptive approach to open, coordinated, and transparent transmission planning. FERC acknowledged the importance of both regional and local planning processes, and agreed with EEI that a transmission provider must have the ultimate authority on its transmission plan and its commitment to build transmission facilities. Moreover, the final rule recognizes that it is not necessary to impose a third-party entity to conduct transmission planning and that transmission providers must be able to recover the costs of planning.
- The fundamental structure of transmission services (network/point-to-point) is maintained. However, the final rule recognizes that it is not necessary to mandate the provision of hourly firm transmission service and that transmission providers only must provide planning redispatch and conditional firm service when doing so would not impair reliability (or if planning redispatch would interfere with existing firm service).
- The final rule makes transmission planning more rational; transmission customers must take a term of service for five years in order to obtain the right to roll over their service for an additional term of five years. Transmission customers must provide at least one year's notice that they will rollover their service.
- FERC required rules, standards and practices governing transmission service to be included in public utility OATTs, thus subject to FERC filing, notice and comment, and FERC review.

FERC MILESTONES:

- November 19, 2009, in Docket Nos. RM05-17-005 and RM05-25-005, FERC issued Order No. 890-D, affirming its determinations in previous orders and clarifying the requirement to un-designate network resources used to serve off-system sales. *Preventing Undue Discrimination and Preference in Transmission Services*, 129 FERC ¶ 61,126 (2009).
- March 19, 2009, in Docket Nos. RM05-17-004 and RM05-25-004, FERC issued Order No. 890-C clarification of the degree of consistency required in the calculation of

available transfer capability by transmission providers and denies rehearing regarding the requirement to undesignate network resources used to serve off-system sales. *Preventing Undue Discrimination and Preference in Transmission Services*, 123 FERC ¶ 61,299 (2008).

- June 23, 2008, in Docket Nos. RM05-17-003 and RM05-25-003, FERC issued Order No. 890-B clarifying the degree of consistency required in the calculation of available transfer capability by transmission providers and denies rehearing regarding the requirement to undesignate network resources used to serve off-system sales. *Preventing Undue Discrimination and Preference in Transmission Services*, 123 FERC ¶ 61,299 (2008).
- December 28, 2007, in Docket Nos. RM05-17-001 and 002 and RM05-25-000, FERC issued Order No. 890-A, granting requests for rehearing and clarification to strengthen the pro forma OATT to ensure it prevents undue discrimination, to provide reduced opportunities for undue discrimination, and to increase transparency. *Preventing Undue Discrimination and Preference in Transmission Services*, 121 FERC ¶ 61,297 (2007).
- February 16, 2007, in Docket Nos. RM05-17-000 and RM05-25-000, FERC issued Order No. 890, Final Rule. *Preventing Undue Discrimination and Preference in Transmission Services*, 118 FERC ¶ 61,119 (2007).
- September 19, 2005, in Docket No. RM05-25-000, FERC issued Notice of Inquiry inviting comments (and asking over 100 questions) on the need to reform the Order No. 888 OATT and public utilities' OATTs to ensure the provision of tariffed transmission service is just and reasonable. *Preventing Undue Discrimination and Preference in Transmission Services*, 112 FERC ¶ 61,299 (2005).

RELIABILITY: ESTABLISHMENT OF THE ERO, MANDATORY RELIABILITY STANDARDS AND THE DEFINITION OF BULK ELECTRIC SYSTEM

MAJOR PROPOSALS: DOCKET NOS. AD06-6-000, RM05-30-000, RM06-16-000, RM06-22-000, RM09-18-000, RM11-11-000, RM12-6-000 AND RM12-7-000

- Pursuant to EPAct 2005, FERC proposed criteria for the establishment of an Electric Reliability Organization (ERO) that will enforce reliability standards under the regulatory review of FERC.
- FERC accepted the North American Electric Reliability Corporation (NERC) as the ERO and directed NERC to use its compliance registry process to ensure there are no gaps or redundancies among the entities responsible for specific reliability criteria.
- FERC and NERC have refined the definition of Bulk Electric System in order to prevent uncertainty in the market.
- FERC and NERC have established mandatory reliability standards that all users, owners and operators of the Bulk Electric System must comply.

MAJOR IMPLICATIONS

- Establishes a new national regime of mandatory reliability standards subject to FERC review and oversight. Compliance with reliability standards become a legal requirement subject to substantial civil penalties.
- Establishes a process for certifying a single, independent ERO. ERO must demonstrate independence from users, owners and operators while assuring fair stakeholder representation in key areas.
- Provides some regional flexibility and variability by allowing "regional entities" to propose reliability standards through the ERO, and allow the ERO to delegate compliance monitoring and enforcement to regional entities. The delegation is subject to FERC approval and periodic review.
- Each proposed reliability standard must be submitted by NERC to FERC for approval on a case-by-case basis. FERC will not defer to NERC or a Regional Entity with respect to the effect of a proposed reliability standard on competition. FERC may remand to NERC for further consideration a proposed reliability standard that FERC disapproves.
- Order No. 672 provides a process for user, owner or operator of the transmission facilities of a transmission organization to notify FERC of a possible conflict for a timely resolution by FERC.
- NERC or a Regional Entity that is delegated enforcement authority may impose a penalty on user, owner or operator of the Bulk Electric System for a violation of a reliability standard. Order No. 672 establishes a single appeal at the NERC or Regional Entity level to ensure internal consistency in the imposition of penalties by NERC or the Regional Entity.
- Order No. 706 approved mandatory reliability standards that require certain users, owners, and operators of the Bulk Electric System to comply with specific requirements to safeguard critical cyber assets.

FERC MILESTONES

- November 22, 2013, in Docket No. RM13-5-000, FERC issued Order No. 791 approving "Version 5" of the CIP reliability standards which identify and categorize Bulk Electric System (BES) Cyber Systems using a new methodology based on whether a BES Cyber System has a Low, Medium, or High Impact on the reliable operation of the bulk electric system. *Version 5 Critical Infrastructure Protection Reliability Standards*, 145 FERC ¶ 61,160 (2013).
- December 20, 2012, in Docket Nos. RM12-6-000 and RM12-7-000, FERC issued Order No. 773 approving certain proposed modifications to the definition of "bulk electric system" and proposed revisions to NERC's Rules of Procedure which create an exception process to add elements to, or remove elements from, the definition of "bulk electric system" on a case-by-case basis. *Revisions to Electric Reliability Organization Definition of Bulk Electric System and Rules of Procedure*, 141 FERC ¶ 61,236 (2012).
- April 19, 2012, in Docket No. RM11-11-000, FERC issued Order No. 761 approving "Version 4" of the CIP reliability standards which includes "bright line" criteria for the identification of critical assets. *Version 4 Critical Infrastructure Protection Reliability Standards*, 139 FERC ¶ 61,058 (2012).
- June 18, 2009, in Docket No. RM06-22-006, FERC issued Order No. 706-C denying requests for rehearing of Order No. 706-B regarding nuclear facilities. *Mandatory Reliability Standards for Critical Infrastructure Protection*, 127 FERC ¶ 61,273 (2009).
- March 19, 2009, in Docket No. RM06-22-000, FERC issued Order No. 706-B clarifying that the facilities within a nuclear generation plant in the United States that are not regulated by the U.S. Nuclear Regulatory Commission are subject to compliance with the eight mandatory CIP reliability standards. *Mandatory Reliability Standards for Critical Infrastructure Protection*, 126 FERC ¶ 61,229 (2009).
- May 16, 2008, in Docket No. RM06-22-001, FERC issued Order No. 706-A which largely affirms its determinations in Order No. 706. FERC offered certain clarifications regarding enforceability, technical feasibility, confidentiality and technical support. *Mandatory Reliability Standards for Critical Infrastructure Protection*, 123 FERC ¶ 61,174 (2008).
- January 18, 2008, in Docket No. RM06-22-000, FERC issued Order No. 706 which established eight Critical Infrastructure Protection (CIP) mandatory reliability standards requiring certain users, owners, and operators of the Bulk Electric System to comply with specific requirements to safeguard critical cyber assets. *Mandatory Reliability Standards for Critical Infrastructure Protection*, 122 FERC ¶ 61,040 (2008).
- July 19, 2007, in Docket No. RM06-16-001, FERC issued Order No. 693-A which reaffirmed its determinations in Order No. 693 and offered certain clarifications in the preamble of the rule. *Mandatory Reliability Standards for the Bulk-Power System*, 120 FERC ¶ 61,053 (2007).

- March 16, 2007, in Docket No. RM06-16-000, FERC issued Order No. 693, Final Rule regarding mandatory reliability standards for the Bulk Electric System which approved 83 of the 107 mandatory reliability standards proposed by NERC. *Mandatory Reliability Standards for the Bulk-Power System*, 118 FERC ¶ 61,218 (2007).

- April 18, 2006, in Docket No. RM06-16-000, FERC issued a notice announcing a rulemaking process for the processing of the proposed reliability standards submitted by NERC. *Mandatory Reliability Standards for the Bulk-Power System*, 115 FERC ¶ 61,060 (2006).

- March 30, 2006, in Docket No. RM05-30-001, FERC issued Order No. 672-A which reaffirmed its determinations in Order No. 672 concerning the rules for the ERO and procedures for electric reliability standards, but clarified certain provisions, and granted rehearing in part regarding transmission organization options in cases of potential conflicts of a reliability standard with a FERC order. *Rules Concerning Certification of the Electric Reliability Organization; and Procedures for the Establishment, Approval and Enforcement of Electric Reliability Standards*, 114 FERC ¶ 61,328 (2006).

- March 17, 2011, in Docket No. RM09-18-001, FERC issued Order No. 743-A denying requests for rehearing of Order No. 743 and clarifying the discretion of Regional Entities, standard of review and local distribution facilities. *Revision to Electric Reliability Organization Definition of Bulk Electric System*, 134 FERC ¶ 61,210 (2011).

- November 18, 2010, in Docket No. RM09-18-000, FERC issued Order No. 743 which directs NERC to revise the definition of "bulk electric system" and consider eliminating the regional discretion in the current definition, maintaining a bright-line threshold that includes all facilities operated at or above 100 kV except defined radial facilities, and establishing an exemption process and criteria for excluding facilities that are not necessary for operating the interconnected transmission network. *Revision to Electric Reliability Organization Definition of Bulk Electric System*, 133 FERC ¶ 61,150 (2010).

- February 3, 2006, in Docket No. RM05-30-000, FERC issued Order No. 672 to implement provisions in EPAct 2005 by establishing criteria for ERO qualification. The Final Rule also establishes procedures under which NERC may propose new or modified reliability standards for FERC review and procedures governing an enforcement action for violation of a reliability standard. *Rules Concerning Certification of the Electric Reliability Organization; and Procedures for the Establishment, Approval and Enforcement of Electric Reliability Standards*, 114 FERC ¶ 61,104 (2006).

- September 1, 2005, in Docket No. RM05-30-000, FERC issued a notice of proposed rulemaking on developing and implementing the process and procedures under EPAct 2005 for FERC to develop and undertake with regard to the formation and functions of the ERO and Regional Entities. *Rules Concerning Certification of the Electric Reliability Organization; and Procedures for the Establishment, Approval and Enforcement of Electric Reliability Standard*s, 112 FERC ¶ 61,239 (2005).

SMALL GENERATOR INTERCONNECTION AGREEMENTS AND PROCEDURES

MAJOR PROPOSALS: RM13-2-000

- Revises the *pro forma* Small Generator Interconnection Procedures (SGIP) and pro forma Small Generator Interconnection Agreement (SGIA) originally set forth in Order No. 2006.

- Reforms are intended to ensure that the time and cost to process small generator interconnect requests will be just and reasonable and not unduly discriminatory.

- Market changes, including the growth of small generator interconnection requests and the growth in solar photovoltaic (PV) installations, driven in part by state renewable energy goals and policies, necessitate a reevaluation of the SGIP and SGIA to ensure that they continue to facilitate Commission-jurisdictional interconnections in a just and reasonable and not unduly discriminatory manner.

MAJOR IMPLICATIONS:

- Incorporates into the SGIP and SGIA provisions that provide an Interconnection Customer with the option of requesting from the Transmission Provider a pre-application report providing existing information about system conditions at a possible Point of Interconnection.

- Revises the 2 megawatt (MW) threshold for participation in the Fast Track Process included in section 2 of the *pro forma* SGIP.

- Revises the customer options meeting and the supplemental review following failure of the Fast Track screens so that the supplemental review is performed at the discretion of the Interconnection Customer and includes minimum load and other screens to determine if a Small Generating Facility may be interconnected safely and reliably.

- Revises the *pro forma* SGIP Facilities Study Agreement to allow the Interconnection Customer the opportunity to provide written comments to the Transmission Provider on the upgrades required for interconnection.

- Revise the *pro forma* SGIP and the pro forma SGIA to specifically include energy storage devices.

FERC MILESTONES:

- November 22, 2013, in Docket No. RM13-2-000, FERC issued Order No. 792. *Small Generator Interconnection Agreements and Procedures*, 145 FERC ¶ 61,159 (2013).

- January 17, 2013, in Docket No. RM13-2-000, FERC issued a Notice of Proposed Rulemaking proposing certain reforms to the pro forma SGIA and SGIP to accommodate increasing penetrations of solar PV installations. *Small Generator Interconnection Agreements and Procedures*, 142 FERC ¶ 61,049 (2013).

STANDARDS OF CONDUCT

MAJOR PROPOSALS: DOCKET NO. RM01-10-000; RM07-1-000

- FERC has conducted technical conferences and workshops to discuss Standards of Conduct for Transmission Providers under Order No. 2004.

- FERC has proposed permanent regulations regarding the standards of conduct consistent with the decisions of the U.S. Court of Appeals of the District of Columbia in *National Fuel Gas Supply Corp. v. FERC*, 468 F.3d 831 (2006), regarding natural gas pipelines. FERC is soliciting comments regarding comparable changes for electric utility transmission providers: specifically, whether or not the standards of conduct should govern the relationship between electric utility transmission providers and their energy affiliate.

MAJOR IMPLICATIONS:

- Transmission providers are permitted to communicate essential information to affiliated and non-affiliated nuclear power plants to preserve power grid reliability.

FERC MILESTONES:

- April 8, 2011, in Docket No. RM07-1-003, FERC issued Order No. 717-D, clarifying that an employee who perofrms a system impact study re a transmissions service request, that person is a transmission function employee. *Standards of Conduct for Transmission Providers*, 135 FERC ¶ 61,017 (2011).

- April 16, 2010, in Docket No. RM07-1-002, FERC issued Order No. 717-C, further clarifying "marketing function employee." *Standards of Conduct for Transmission Providers*, 129 FERC ¶ 61,045 (2010).

- November 16, 2009, in Docket No. RM07-1-002, FERC issued Order No. 717-B, clarifying whether an employee who is not making business decisions about contract non-price terms and conditions is considered a "marketing function employee." *Standards of Conduct for Transmission Providers*, 129 FERC ¶ 61,123 (2009).

- October 15, 2009, in Docket No. RM07-1-001, FERC issued Order No. 717-A, clarifying: 1) the applicability of the Standards of Conduct to transmission owners with no marketing affiliate transactions; 2) whether the Independent Functioning Rule applies to balancing authority employees; 3) which activities of transmission or marketing function employees are subject to the Rule; 4) whether local distribution companies making off-system sales on nonaffiliated pipe pipelines are subject to the Standards; 5) Whether the Standars apply to a pipeline's sale of its own production; 6) applicability of the Standards to asset management agreements; 7) whether incidental purchases to remain in balance or sales of unneeded gas supply subject the company to the Standards; 8) applicability of the No Conduit Rule; and 9) applicability of the Transparency Rule. *Standards of Conduct for Transmission Providers*, 129 FERC ¶ 61,043 (2009).

- October 16, 2008, in Docket No. RM07-1-000, FERC issued Order No. 717, amending its regulations adopted on an interim basis in Order No. 690, in order to make them clearer and to refocus the rules on the areas where there is the greatest potential for abuse. The Final Rule is designed to (1) foster compliance, (2) facilitate Commission enforcement, and (3) conform the Standards of Conduct to the decision of the U.S. Court of Appeals for the D.C. Circuit in *National Fuel Gas Supply Corporation v. FERC*, 468 F. 3d 831 (D.C. Cir. 2006). Specifically, the Final Rule eliminates the concept of energy affiliates and eliminates the corporate separation approach in favor of the employee functional approach used in Order Nos. 497 and 889. *Standards of Conduct for Transmission Providers*, 125 FERC ¶ 61,064 (2008).

- March 21, 2008, in Docket No. RM07-1-000, FERC issued a Notice of Proposed Rulemaking proposing to revise its Standards of Conduct for transmission providers to make them clearer and to refocus the rules on the areas where there is the greatest potential for affiliate abuse. By doing so, we will make compliance less elusive and facilitate Commission enforcement. We also propose to conform the Standards to the decision of the U.S. Court of Appeals for the D.C. Circuit in *National Fuel Gas Supply Corporation v. FERC*, 468 F.3d 831 (D.C. Cir. 2006). *Standards of Conduct for Transmission Providers*, 122 FERC ¶ 61,263 (2008).

- January 18, 2007, FERC issues NOPR in Docket No. RM07-1-000. Standards of Conduct for Transmission Providers, 118 FERC ¶ 61,031 (2007).

- November 17, 2006, in National Fuel Gas Supply Corporation v. Federal Energy Regulatory Commission, the United States Court of Appeals for the District of Columbia vacated Orders 2004, 2004-A, 2004-B, 2004-C, and 2004-D with respect to natural gas suppliers. *National Gas Fuel Supply Corporation v. FERC*, 468 F.3d 831 (November 17, 2006).

- February 16, 2006, FERC issued interpretive order relating to the Standards of Conduct to clarify that Transmission Providers may communicate with affiliated nuclear power plants regarding certain matters related to the safety and reliability of the transmission system on nuclear power plants, in order to comply with the requirements of the Nuclear Regulatory Commission. *Interpretive Order Relating to the Standards of Conduct*, 114 FERC ¶ 61,155 (2006).

THIRD-PARTY PROVISION OF ANCILLARY SERVICES; ACCOUNTING AND FINANCIAL REPORTING FOR NEW ELECTRIC STORAGE TECHNOLOGIES

MAJOR PROPOSALS: DOCKET NO. RM11-24-000 AND AD10-13-000

- FERC revises its *Avista Corp.* policy governing the sale of ancillary services at market-based rates to meet public utility transmission providers and reflect such reforms in Parts 35 and 37 of the Commission's regulations.

- FERC requires each public utility transmission provider to include provisions in its OATT explaining how it will determine Regulation and Frequency Response reserve requirements in a manner that takes into account speed and accuracy of resources used.

- FERC also revises the accounting and reporting requirements under its Uniform System of Accounts for public utilities and licensees and its forms, statements, and reports contained in FERC Form No. 1, Annual Report of Major Electric Utilities, Licensees and Others, FERC Form No. 1-F, Annual Report for Nonmajor Public Utilities and Licensees, and FERC Form No. 3-Q, Quarterly Financial Report of Electric Utilities, Licensees, and Natural Gas Companies to better account for and report transactions associated with the use of energy storage devices in public utility operations.

MAJOR IMPLICATIONS:

- FERC allows third-party sellers passing existing market power screens to sell Energy Imbalance and Generator Imbalance services at market-based rates to a public utility transmission provider within the same balancing authority area, or to a public utility transmission provider in a different balancing authority area, if those areas have implemented intra-hour scheduling for transmission service.

- FERC allows third-party sellers passing existing market power screens to sell Operating Reserve-Spinning and Operating Reserve-Supplemental services at market-based rates to a public utility transmission provider within the same balancing authority area, or to a public utility transmission provider in a different balancing authority area, if those areas have implemented intra-hour scheduling for transmission service that supports the delivery of operating reserve resources from one balancing authority area to another.

- The Final Rule allows applicants to engage in market-based sales of ancillary services to a public utility that is purchasing ancillary services to satisfy its OATT requirements where the sale is made pursuant to a competitive solicitation that meets specific requirements.

- Each public utility transmission provider must add to its OATT Schedule 3 a statement that it will take into account the speed and accuracy of regulation resources in its determination of reserve requirements for Regulation and Frequency Response service, including as it reviews whether a self-supplying customer has made "alternative comparable arrangements" as required by the Schedule. This statement will also acknowledge that, upon request by the self-supplying customer, the public utility transmission provider will share with the customer its reasoning and any related data used to make the determination of whether the customer has made "alternative comparable arrangements."

- The Final Rule adds new electric plant and O&M expense accounts to record the installed cost and operating and maintenance cost of energy storage assets and a new account to record the cost of power purchased for use in energy storage operations.

FERC MILESTONES:

- July 18, 2013, in Docket Nos. RM11-24-000 and AD10-13-000, FERC issued Order No. 784. *Third-Party Provision of Ancillary Services; Accounting and Financial Reporting for New Electric Storage Technologies*, 144 FERC ¶ 61,056 (2013).

- June 22, 2012, in Docket Nos. RM11-24-000 and AD-13-000, FERC issued a Notice of Proposed Rulemaking. *Third-Party Provision of Ancillary Services; Accounting and Financial Reporting for New Electric Storage Technologies*, 139 FERC ¶ 61,245 (2012).

TRANSMISSION PLANNING AND COST ALLOCATION

MAJOR PROPOSALS: DOCKET NO. RM10-23-000

- Reforms FERC's electric transmission planning and cost allocation requirements for public utility transmission providers. The rule builds on the reforms of Order No. 890 and corrects remaining deficiencies with respect to transmission planning processes and cost allocation methods.

MAJOR IMPLICATIONS:

- Establishes three requirements for

transmission planning:

- Each public utility transmission provider must participate in a regional transmission planning process that satisfies the transmission planning principles of Order No. 890 and produces a regional transmission plan.
- Local and regional transmission planning processes must consider transmission needs driven by public policy requirements established by state or federal laws or regulations. Each public utility transmission provider must establish procedures to identify transmission needs driven by public policy requirements and evaluate proposed solutions to those transmission needs.
- Public utility transmission providers in each pair of neighboring transmission planning regions must coordinate to determine if there are more efficient or cost-effective solutions to their mutual transmission needs.

- Establishes three requirements for transmission cost allocation:
  - Each public utility transmission provider must participate in a regional transmission planning process that has a regional cost allocation method for new transmission facilities selected in the regional transmission plan for purposes of cost allocation. The method must satisfy six regional cost allocation principles.
  - Public utility transmission providers in neighboring transmission planning regions must have a common interregional cost allocation method for new interregional transmission facilities that the regions determine to be efficient or cost-effective. The method must satisfy six similar interregional cost allocation principles.
  - Participant-funding of new transmission facilities is permitted, but is not allowed as the regional or interregional cost allocation method.
- Public utility transmission providers must remove from Commission-approved tariffs and agreements a federal right of first refusal for a transmission facility selected in a regional transmission plan for purposes of cost allocation, subject to four limitations:
  - This does not apply to a transmission facility that is not selected in a regional transmission plan for purposes of cost allocation.
  - This allows, but does not require, public utility transmission providers in a transmission planning region to use competitive bidding to solicit transmission projects or project developers.
  - Nothing in this requirement affects state or local laws or regulations regarding the construction of transmission facilities, including but not limited to authority over siting or permitting of transmission facilities.
- The rule recognizes that incumbent transmission providers may rely on regional transmission facilities to satisfy their reliability needs or service obligations. The rule requires each public utility transmission provider to amend its tariff to require reevaluation of the regional transmission plan to determine if delays in the development of a transmission facility require evaluation of alternative solutions, including those proposed by the incumbent, to ensure incumbent transmission providers can meet reliability needs or service obligations.

FERC MILESTONES:

- October 18, 2012, in Docket No. RM10-23-002, FERC issued Order No. 1000-B reaffirming its determinations in Order No. 1000 and Order No. 1000-A. *Transmission Planning and Cost Allocation by Transmission Owning and Operating Public Utilities*, 141 FERC ¶ 61,044.
- May 17, 2012, in Docket No. RM10-23-001, FERC issued Order No. 1000-A providing certain clarifications to the policies adopted in Order No. 1000. *Transmission Planning and Cost Allocation by Transmission Owning and Operating Public Utilities,* 139 FERC ¶ 61,132 (2012).
- July 21, 2011, FERC issued Order No. 1000 in Docket No. RM11-26-000. *Transmission Planning and Cost Allocation by Transmission Owning and Operating Public Utilities*, 136 FERC ¶ 61,051 (2011).

TRANSMISSION PRICING REFORMS/ INCENTIVES

MAJOR PROPOSALS: DOCKET NOS. RM06-4-000 AND RM11-26-000

- FERC enacted transmission pricing reforms which identifies incentives which FERC will allow utilities that demonstrate that a project ensures reliability or reduces transmission congestion.
- FERC emphasized that applicants must demonstrate a link between the incentives requested and the investment being made, that the resulting rates are just and reasonable.
- FERC stated that the incentives will only be permitted for investments which benefit consumers by promoting reliability or reducing the cost of delivered power by reducing congestion.

EXAMPLES

- FERC granted American Electric Power Service Corporation an ROE at the high end of the zone of reasonableness (the exact amount to be determined in a future proceeding), 100% inclusion of construction work in progress in its rate base, and approved AEP's request to expense pre-construction/pre-operating costs.
- FERC granted Allegheny Energy Inc., et al. an ROE at the high end of the zone of reasonableness (the exact amount to be determined in a future proceeding), 100% inclusion of construction work in progress in its rate base, their request to expense pre-commercial costs, and 100% recovery of prudently-incurred costs associated with abandoned projects.
- FERC granted ISO New England a 11.7% base-level ROE effective February 1, 2005, and 12.4% from the date of the authorizing order, and found that the ROE incentive should apply to all new transmission.
- FERC conditionally granted Dusquesne Light Company an ROE of 100 basis points, subject to a hearing, 100% inclusion of construction work in progress in its rate base, and 100% recovery of prudently-incurred costs associated with abandoned projects.

MAJOR IMPLICATIONS:

- Incentives available for traditional utilities as well as additional incentives for stand-alone transmission companies, or transcos, that include: (a) a rate of return on equity sufficient to attract new investment; (b) a recovery in rate base of 100% of prudently incurred transmission-related construction work in progress (CWIP) to increase cash flow; (c) allowing hypothetical capital structures to provide the flexibility needed to maintain viability of new capacity projects; (d) accelerating recovery of depreciation expense; (e) recovery of all prudent development costs in cases where construction of facilities may be abandoned or canceled due to circumstances beyond the control of the utility; (f) allowing deferred cost recovery; and (g) providing a higher rate of return on equity for utilities that join transmission organizations.
- A public utility would have to demonstrate that the new facilities would improve regional reliability and reduce transmission congestion in order for it to receive an incentive based rate of return on equity.
- The rule allows for recovery of costs associated with joining a transmission organization, electric reliability organizations and infrastructure development in National Interest Transmission Corridors.
- In order to encourage the formation of transcos, FERC authorized transcos to propose an acquisition premium, and an Accumulated Deferred Income Taxes incentive for companies selling transmission assets to a transco. FERC stated that it would allow a return on equity (ROE) sufficient to encourage transco formation, and that

provision of the ROE incentive would not preclude a transco from seeking other approved incentives.

FERC MILESTONES:

- For information regarding specific requests for incentive-based rate treatments, please see FERC's Transmission Investment Orders page: https://www.ferc.gov/industries/electric/indus-act/trans-invest/orders.asp
- November 15, 2012, in Docket No. RM11-26-000, FERC issued its Policy Statement on Promoting Transmission Through Pricing Reform by clarifying that it would no longer rely on the "routine vs. non-routine" analysis as part of its nexus test and thus required applicants to demonstrate that the total package of incentives requested is tailored to address demonstrable risks and challenges. The Commission also expects incentives applicants to seek to reduce the risk of transmission investment not otherwise accounted for in its base ROE by using risk-reducing incentives before seeking an incentive ROE based on a project's risks and challenges. *Promoting Transmission Through Pricing Reform*, 141 FERC ¶ 61,129 (2012).
- May 19, 2011, in Docket No. RM11-26-000, FERC issued a Notice of Inquiry given the changes in the electric industry, the Commission's experience to date applying Order No. 679, and the ongoing need to ensure that incentives regulations and policies are encouraging the development of transmission infrastructure. *Promoting Transmission Investment Through Pricing Reform*, 135 FERC ¶ 61,146 (2011).
- December 21, 2010, in Docket Nos. PA11-11-000, PA11-13-000 and PA11-14-000 respectively, FERC announced it would audit compliance with Order Nos. 679, 679-A and 679-B, and the conditions placed when FERC granted incentives.
- April 19, 2007, in Docket No. RM06-4-002, FERC issued Order No. 679-B, denying rehearing and clarifying Order No. 679-A. *Promoting Transmission Investment Through Pricing Reform*, 119 FERC ¶ 61,062 (2007).
- December 22, 2006, in Docket No. RM06-4-001, FERC issued Order No. 679-A, reaffirming in part and granting rehearing in part of Order No. 679.
- July 20, 2006, in Docket No. RM06-4-000, FERC issued Order No. 679, *Promoting Transmission Investment Through Pricing Reform*, 116 FERC ¶ 61,199 (2006).
- November 18, 2005, in Docket No. RM06-4-000, FERC issued a NOPR to amend its regulations to establish incentive-based rate treatments for transmission of electric energy in interstate commerce by public utilities. *Promoting Transmission Investment through Pricing Reform*, 113 FERC ¶ 61,182 (2005).

MARKET-BASED RATES FOR WHOLESALE SALES OF ELECTRIC ENERGY, CAPACITY AND ANCILLARY SERVICES BY PUBLIC UTILITIES

MAJOR PROPOSALS: DOCKET NO. RM04-7-000

- Replaces existing four-prong analysis with a two-part test covering horizontal and vertical market power.
- Current interim market power screens would be made a permanent part of the horizontal (generation) market power analysis.
- Newly-constructed generation would no longer be exempted from the market power analysis.
- Provide for a standard market-based rate tariff of general applicability.
- "Affiliate abuse" would cease to be a separate prong of the market power analysis, but the Commission proposed to codify existing policies governing sales between public utilities and affiliated entities.
- Certain small power sellers would not be required to submit regularly scheduled triennial reviews; other holders of MBR authority would file triennial reviews on a schedule organized by regions.

MAJOR IMPLICATIONS:

- The native load proxy for market power screens would be changed from the minimum peak day in the season to the average peak native load.
- The Delivered Price Test would be retained for companies failing the initial market power screens.
- Maintaining an Open Access Transmission Tariff (OATT) would continue to be sufficient to mitigate any vertical market power; violations of the OATT may be grounds for revocation of MBR authority.
- Consideration of "other barriers to entry" would be considered as part of the vertical market power assessment.
- Both larger and small sellers would remain under the requirement to file change in status reports.
- Corporate entities would have a single, consolidated MBR tariff.

FERC MILESTONES:

- March 18, 2010, in Docket No. RM04-7-008, FERC issued Order No. 697-D, granting in part and denying in part requests for rehearing of Order No. 697-C. *Market-Based Rates for Wholesale Sales of Electric Energy, Capacity and Ancillary Services by Public Utilities*, 130 FERC ¶ 61,206 (2010).
- June 18, 2009, in Docket No. RM04-7-006, FERC issued Order No 697-C, granting in part and denying in part requests for clarification of Order No. 697-B. *Market-Based Rates for Wholesale Sales of Electric Energy, Capacity and Ancillary Services by Public Utilities*, 127 FERC ¶ 61,284 (2009).
- December 19, 2008, in Docket No. RM04-7-005, FERC issued Order No. 697-B granting rehearing and clarification regarding certain revisions to its regulations and to the standards for obtaining and retaining market-based rate authority for sales of energy, capacity and ancillary services to ensure that such sales are just and reasonable. *Market-Based Rates for Wholesale Sales of Electric Energy, Capacity and Ancillary Services by Public Utilities*, 125 FERC ¶ 61,326 (2008).
- April 21, 2008, in Docket No. RM04-7-001, FERC issued Order No. 697-A granting rehearing and clarification regarding certain revisions to its regulations and to the standards for obtaining and retaining market-based rate authority for sales of energy, capacity and ancillary services to ensure that such sales are just and reasonable. *Market-Based Rates for Wholesale Sales of Electric Energy, Capacity and Ancillary Services by Public Utilities,* 123 FERC ¶ 61,055 (2008).
- December 14, 2007, FERC issued an order clarifying the effective compliance date, which entities are required to file and what data are required for market power analyses, and details of "seller-specific terms and conditions" for Order No. 697. *Market-Based Rates for Wholesale Sales of Electric Energy, Capacity and Ancillary Services by Public Utilities*, 121 FERC ¶ 61,260 (2007).
- June 21, 2007, FERC issued Order No. 697. *Market-Based Rates for Wholesale Sales of Electric Energy, Capacity and Ancillary Services by Public Utilities*, 119 FERC ¶ 61,295 (2007).
- August 14, 2006, FERC issued notice granting EEI's request for an extension of time to file reply comments.
- May 19, 2006, FERC issued a NOPR proposing to amend its policies regarding the granting of market-base rate authority and to formally incorporate FERC's four-prong market power analysis into the FERC's regulatory code. *Market-Based Rates for Wholesale Sales of Electric Energy, Capacity and Ancillary Services by Public Utilities*, 115 FERC ¶ 61,210 (2006).

PROMOTING A COMPETITIVE MARKET FOR CAPACITY REASSIGNMENT: DOCKET NO. RM10-22-000

- FERC issued a Final Rule lifting the price cap for all electric transmission customers reassigning transmission capacity to help facilitate the development of a market for electric transmission capacity reassignments as a competitive alternative to transmission capacity acquired directly from the transmission owner.

MAJOR IMPLICATIONS:

- The price cap for all reassignments of electric transmission capacity are lifted effective October 1, 2010

- Transmission providers will need to revise section 23 of the pro forma OATT and file them with FERC.

FERC MILESTONES:
- May 19, 2011, in Docket No. RM10-22-001, FERC issued Order No. 739-A denying rehearing and affirming its determinations in Order No. 739. *Promoting a Competitive Market for Capacity Reassignment*, 135 FERC ¶ 61,137 (2011).
- September 20, 2010, in Docket No. RM10-22-000, FERC issued Order No. 739. *Promoting a competitive Market for Capacity Reassignment*, 132 FERC ¶ 61,238 (2010).

SMART GRID POLICY

MAJOR PROPOSALS: DOCKET NO. PL09-4-000
- FERC issued a Policy Statement and Action Plan seeking comments to expedite the development of interoperability standards and implementation of projects for development of the Smart Grid.

MAJOR IMPLICATIONS:
- FERC proposes to assist NIST expedite development of Smart Grid standards, The proposal prioritizes cybersecurity and interoperability standards. Other key standards include wide-area situational awareness, demand response, and electricity storage.
- The Policy Statement prioritizes development of interoperability standards on two cross-cutting issues (system security and inter-system communications) and four key grid functionalities:

  1. wide-area situational awareness;
  2. demand response;
  3. electric storage; and
  4. electric transportation.

- The Policy Statement also permits utilities to request accelerated depreciation and abandonment authority under its Interim Rate Policy.

FERC MILESTONES:
- July 16, 2009, in Docket No. PL09-4-000, FERC issued a Smart Grid Policy Statement providing guidance on smart grid standards. *Smart Grid Policy*, 128 FERC ¶ 61,060 (2009).
- March 19, 2009, in Docket No. PL09-4-000, FERC issued a Smart Grid Proposed Policy Statement and Action Plan seeking comments. *Smart Grid Policy*, 126 FERC ¶ 61,253 (2009).

WHOLESALE COMPETITION IN REGIONS WITH ORGANIZED ELECTRIC MARKETS

MAJOR PROPOSALS: DOCKETS AD07-7, AD07-8, RM07-19
- FERC proposed to amend its regulations to improve operation of wholesale electric markets with regards to: (1) demand response and market prices during operating reserve shortages; (2) long-term power contracting; (3) market-monitoring policies; and (4) RTO and ISO responsiveness to stakeholders and customers.
- FERC held three technical conferences on improving wholesale competition in 2007.

MAJOR IMPLICATIONS:
- The NOPR proposes to allow RTOs to accept bids from demand response resources for certain ancillary services, to eliminate charges for voluntarily taking less energy in real-time markets than purchased in the day-ahead markets, allow demand response to be bid by a retail customer aggregator, and to allow market-clearing prices to reach levels that allow for rebalances of supply and demand during periods of operating reserve shortages.
- The NOPR proposes to require RTOs to support long-term power contracting by allowing market participants to post offers on their website.
- The NOPR proposes to expand the rules regarding the Market Monitoring Unit's (MMU) interaction with their RT, require the RTO to materially support the MMU, remove the MMU from tariff administration, and reduce time period before energy bid and offer data are released to the public.
- The NOPR proposes criteria to ensure RTO responsiveness to customers and stakeholders, such as: inclusiveness, fairness in balancing diverse interests, representation of minority positions and ongoing responsiveness.

FERC MILESTONES:
- December 17, 2009, in Docket No. RM07-19-002, FERC Issued Order No. 719.B affirming its determinations in Orders Nos. 719 and 719-A. *Wholesale Competition in Regions with Organized Electric Markets*, 129 FERC ¶ 61,252 (2009).
- July 16, 2009, in Docket No. RM07-19-001, FERC issued Order No 719-A, affirming and granting clarification of Order No. 719. *Wholesale Competition in Regions with Organized Electric Markets*, 128 FERC ¶ 61,059 (2009).
- October 17, 2008, in Docket Nos. AD07-7-000 and RM07-19-000, FERC issued Order No. 719 amending its regulations under the Federal Power Act to improve the operation of organized wholesale electric markets in the areas of: (1) demand response and market pricing during periods of operating reserve shortage; (2) long-term power contracting; (3) market-monitoring policies; and (4) the responsiveness of regional transmission organizations (RTOs) and independent system operators (ISOs) to their customers and other stakeholders, and ultimately to the consumers who benefit from and pay for electricity services. *Wholesale Competition in Regions with Organized Electric Markets*, 125 FERC ¶ 61,071 (2008).
- February 22, 2008, FERC issued a Notice of Proposed Rulemaking. *Wholesale Competition in Regions with Organized Electric Markets*, 122 FERC ¶ 61,167 (2008).

Finance and Accounting Division

The Business Services and Finance Division is part of EEI's Business Operations Group. This division provides the leadership and management for advocating industry policies, technical research, and enhancing the capabilities of individual members through education and information sharing. The division's leadership is used in areas that affect the financial health of the investor-owned electric utility industry, such as finance, accounting, taxation, internal auditing, investor relations, risk management, budgeting and financial forecasting. If you need research information about these issue areas, please contact an EEI Business Services and Finance Division staff member (listed in this section). Under the direction of both the Finance and the Accounting Executive Advisory Committees, the division provides staff representatives to work with issue area committees. These committees give member company personnel a forum for information exchange and training and an opportunity to comment on legislative and regulatory proposals.

Publications

Quarterly Financial Updates

A series of financial reports on the investor-owned segment of the electric utility industry. Quarterly reports include stock performance, dividends, credit ratings, construction, fuels, and rate case summary, as well as the industry's consolidated financial statements.

Financial Review

An annual report that provides a review of the financial performance of the investor-owned electric utility industry. The report also includes a policy overview section that provides an update on legislative, regulatory, environmental, and other related developments.

EEI Index

Quarterly stock performance of the U.S. investor-owned electric utilities. The index, which measures total return and provides company rankings for one- and five-year periods, is widely used in company proxy statements and for overall industry benchmarking.

Introduction to Depreciation for Utilities and Other Industries

A new edition of this book is now available for 2013. It serves as a primer on the concepts of depreciation accounting including fundamental principles, life analysis techniques, salvage and cost of removal analysis methods and depreciation rate calculation formulas and examples. The 2013 edition features updated chapters on Tax Depreciation, Accounting for Asset Retirement Obligations (AROs) and includes a new chapter on Depreciation in an IFRS Environment.

Introduction to Public Utility Accounting

This textbook contains a basic explanation of the fundamentals and practices of electric and gas utility accounting. The completion of a new edition is scheduled for 2015. With current accounting standards, regulatory requirements and industry trends, the revised textbook will include new chapters on Asset Retirement Obligations (AROs) and Internal Control & Reporting Requirements (Sarbanes-Oxley Act of 2002).

Industry directories published by the Finance and Accounting Division:

- Electric Utility Investor Relations Executives Directory
- Accounting and Internal Audit Directory

For more information, please visit the EEI website at: www.eei.org.

Conference Highlights

Annual Financial Conference

This three-day conference is the premier annual fall gathering of utilities and the financial community; it is attended by more than 1,000 industry stakeholders, including many utility CEOs and CFOs, investment analysts, and commercial and investment bankers. The General Sessions cover strategic topics of interest to the financial community. Contact Debra Henry for more information.

Investor Relations Meeting

This one-day meeting is held in the spring, normally in New York City. It is a forum for utility investor relations executives to share information on evolving industry issues and helps identify best practices within and outside the electric utility industry. Contact Debra Henry for more information.

Financial Analysts Seminar

This two-day seminar is held every two years. It is for financial and security analysts new to the industry. Contact Debra Henry for more information.

Accounting Leadership Conference

This annual meeting, held jointly with AGA as well as with the Chief Audit Executives, covers current accounting, finance, business, and management issues for the Chief Accounting Officers and key accounting leadership of EEI member companies. Contact Randall Hartman for more information.

Chief Audit Executives Conference

This annual conference provides a forum for EEI and AGA Chief Audit Executives and other management professionals to discuss issues and challenges and exchange ideas on utility-specific internal auditing topics. The conference is open to members of the Committees and other employees of EEI/AGA member companies. Contact Randall Hartman for more information.

EEI Accounting Standards Committee

Provides a forum for technical accounting, accounting research, financial reporting, and other interested member-company accounting leaders and staff, to update their knowledge on emerging accounting standards, implementation issues associated with newly issued standards, and other technical and business issues. Contact Randall Hartman for more information.

EEI Corporate Accounting and Property Accounting & Valuation Committees

Provides a forum for members to discuss current issues and challenges and exchange ideas in the electric and natural gas utility industries—convenes twice a year for two and one half days. The meetings are open to members of the Committees and other employees of EEI/AGA member companies. Contact Randall Hartman for more information.

Tax School

Provides tax professionals a forum to discuss developing tax issues impacting our member companies. This two and half day training is held every other year. Contact Mark Agnew for more information.

Accounting Courses

Introduction to Public Utility Accounting

This 4-day program, offered jointly with AGA, concentrates on the fundamentals of public utility accounting. It focuses on providing basic knowledge and a forum for understanding the elements of the utility business. It is intended primarily for recently hired electric and gas utility staff in the areas of accounting, auditing, and finance. Contact Randall Hartman for more information.

Advanced Public Utility Accounting

This intensive, 4-day course, jointly sponsored with AGA, focuses on complex and specific advanced accounting and industry topics. It addresses current accounting issues including those related to deregulation and competition, as they affect regulated companies in the changing and increasingly competitive environment of the electric and gas utility industries. Contact Randall Hartman for more information.

Accounting for Energy Derivatives

Electricity and gas commercial transacting often involve commodity purchase contracts, hedges, and trading activities that are considered derivatives for accounting purposes. EEI and AGA partner with EY to offer this three-day seminar and workshop that covers the basics of derivatives accounting as well as advanced applications. Contact Randall Hartman for more information.

Property Accounting & Depreciation Training Seminar

This is a 2-day seminar that provides an introduction to property accounting and depreciation in the electric and natural gas utility industries. Contact Randall Hartman for more information.

Utility Internal Auditor's Training

Provides utility staff auditors and directors with the fundamentals of public utility auditing and specific utility audit/accounting issues including advanced internal auditing topics and is presented jointly by EEI and AGA—convenes for two and one half days. Contact Randall Hartman for more information.

The EEI Business Services and Finance Division Staff

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Upcoming Investor Relations Meetings

For further details, please contact either Debra Henry at 202/508-5496 or Charnita Garvin at 202/508-5057.

June 19-20, 2014
Electric Utility Investor Relations Group Meeting
(Closed meeting, admittance by invitation only)
Southern Company
Atlanta, GA

November 11-14, 2014
49th EEI Financial Conference
(Closed meeting, admittance by invitation only)
Orlando World Center Marriott Resort
Orlando, FL

Chief Financial Officers Forum
Hilton Anatole
Dallas, TX

Earnings Twelve Months Ending December 31

U.S. INVESTOR-OWNED ELECTRIC UTILITIES

($ Millions)	2013	2012r
Earnings Excluding Non-Recurring and Extraordinary Items	**36,015**	**33,619**
Non-Recurring Items (pre-tax)		
Gain on Sale of Assets	471	311
Other Non-Recurring Revenues	204	264
Asset Write-downs	(3,086)	(5,646)
Other Non-Recurring Expenses	(3,509)	(3,316)
Total Non-Recurring Items	**(5,920)**	**(8,207)**
Extraordinary Items (net of taxes)		
Discontinued Operations	(338)	(4,317)
Change in Accounting Principles	—	—
Early Retirement of Debt	—	—
Other Extraordinary Items	—	—
Total Extraordinary Items	**(338)**	**(4,317)**
Net Income	**29,757**	**21,095**
Total Non-Recurring and Extraordinary Items	**(6,258)**	**(12,524)**

r = revised Note: Totals may reflect rounding. Source: SNL Financial and EEI Finance Department

U.S. Investor-Owned Electric Utilities

(At 12/31/13)

Allete, Inc.
Alliant Energy Corporation
Ameren Corporation
American Electric Power Company, Inc.
Avista Corporation
Black Hills Corporation
CenterPoint Energy, Inc.
Cleco Corporation
CMS Energy Corporation
Consolidated Edison, Inc.
Dominion Resources, Inc.
DPL, Inc.
DTE Energy Company
Duke Energy Corporation
Edison International
El Paso Electric Company
Empire District Electric Company
Energy Future Holdings Corp. (formerly TXU Corp.)
Entergy Corporation
Exelon Corporation
FirstEnergy Corporation
Great Plains Energy, Inc.
Hawaiian Electric Industries, Inc.
Iberdrola USA, Inc.
IDACORP, Inc.
IPALCO Enterprises, Inc.
Integrys Energy Group, Inc.
MDU Resources Group, Inc.
MGE Energy, Inc.
MidAmerican Energy Company
NextEra Energy, Inc.
NiSource, Inc.
Northeast Utilities
NorthWestern Corporation
OGE Energy Corporation
Otter Tail Corporation
Pepco Holdings, Inc.
PG&E Corporation
Pinnacle West Capital Corporation
PNM Resources, Inc.
Portland General Electric Company
PPL Corporation
Public Service Enterprise Group Inc.
Puget Energy, Inc.
SCANA Corporation
Sempra Energy
Southern Company
TECO Energy, Inc.
UIL Holdings Corporation
Unitil Corporation
UNS Energy Corporation
Vectren Corporation
Westar Energy, Inc.
Wisconsin Energy Corporation
Xcel Energy, Inc.

Note: Includes the 49 publicly traded electric utility holding companies plus an additional 6 electric utilities (shown in italics) that are not listed on U.S. stock exchanges for one of the following reasons—they are subsidiaries of an independent power producer; they are subsidiaries of foreign-owned companies; or they were acquired by other investment firms.

The Edison Electric Institute (EEI) is the association that represents all U.S. investor-owned electric companies. Our members provide electricity for 220 million Americans, operate in all 50 states and the District of Columbia, and directly employ more than 500,000 workers.

With more than $90 billion in annual capital expenditures, the electric power industry is responsible for millions of additional jobs. Reliable, affordable, and sustainable electricity powers the economy and enhances the lives of all Americans.

EEI has 70 international electric companies as Affiliate Members, and 250 industry suppliers and related organizations as Associate Members.

Organized in 1933, EEI provides public policy leadership, strategic business intelligence, and essential conferences and forums.

For more information, visit our Web site at www.eei.org.

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